

**NORMES DE FIABILITÉ DE LA NERC  
(VERSION ANGLAISE)**



## A. Introduction

1. **Title:** Real Power Balancing Control Performance
2. **Number:** BAL-001-2
3. **Purpose:** To control Interconnection frequency within defined limits.
4. **Applicability:**
  - 4.1. Balancing Authority
    - 4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.
    - 4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group.
  - 4.2. Regulation Reserve Sharing Group
5. **(Proposed) Effective Date:**
  - 5.1. First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

## B. Requirements

- R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

## C. Measures

- M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

- M2.** Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

**D. 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. Data Retention**

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

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its Compliance Enforcement Authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

<b>R #</b>	<b>Lower VSL</b>	<b>Moderate VSL</b>	<b>High VSL</b>	<b>Severe VSL</b>
R1	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes for the applicable Interconnection.

**E. Regional Variances**

None.

**F. Associated Documents**

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

## Standard BAL-001-2 – Real Power Balancing Control Performance

---

### Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added “a” to end of standard number In Section F, corrected automatic numbering from “2” to “1” and removed “approved” and added parenthesis to “(October 23, 2007)”	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to “0.1a”	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision
1	December 19, 2012	Adopted by NERC Board of Trustees	
2	August 15, 2013	Adopted by the NERC Board of Trustees	

**Attachment 1**  
**Equations Supporting Requirement R1 and Measure M1**

CPS1 is calculated as follows:

$$CPS1 = (2 - CF) * 100\%$$

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent preceding 12 consecutive calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\epsilon_{1l})^2}$$

Where  $\epsilon_{1l}$  is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection  $\epsilon_{1l} = 0.018$  Hz
- Western Interconnection  $\epsilon_{1l} = 0.0228$  Hz
- ERCOT Interconnection  $\epsilon_{1l} = 0.030$  Hz
- Quebec Interconnection  $\epsilon_{1l} = 0.021$  Hz

The rating index  $CF_{12\text{-month}}$  is derived from the most recent preceding 12 consecutive calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting ACE, Frequency Error, and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left( \frac{RACE}{-10B} \right)_{\text{clock-minute}} = \frac{\left( \frac{\sum RACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}} \right)}{-10B}$$

And,

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor ( $CF_{\text{clock-minute}}$ ) calculation is:

$$CF_{\text{clock-minute}} = \left[ \left( \frac{RACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ( $CF_{\text{clock-hour}}$ ).

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ( $CF_{\text{clock-hour average-month}}$ ) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor ( $CF_{\text{month}}$ ):

$$CF_{\text{clock-hour average-month}} = \frac{\sum [(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum [n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{\text{month}} = \frac{\sum [(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum [n_{\text{one-minute samples in clock-hour averages}}]}$$

To calculate the 12-month compliance factor ( $CF_{12\text{ month}}$ ):

$$CF_{12\text{-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-}i})(n_{(\text{one-minute samples in month-}i)})}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month-}i)}]}$$

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias



## **Standard BAL-001-2 – Real Power Balancing Control Performance**

---

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

## Attachment 2

### Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency,  $BAAL_{High}$  and  $BAAL_{Low}$  do not apply.

When actual frequency is less than Scheduled Frequency,  $BAAL_{High}$  does not apply, and  $BAAL_{Low}$  is calculated as:

$$BAAL_{Low} = (-10B_i \times (FTL_{Low} - F_S)) \times \frac{(FTL_{Low} - F_S)}{(F_A - F_S)}$$

When actual frequency is greater than Scheduled Frequency,  $BAAL_{Low}$  does not apply and the  $BAAL_{High}$  is calculated as:

$$BAAL_{High} = (-10B_i \times (FTL_{High} - F_S)) \times \frac{(FTL_{High} - F_S)}{(F_A - F_S)}$$

Where:

**$BAAL_{Low}$**  is the Low Balancing Authority ACE Limit (MW)

**$BAAL_{High}$**  is the High Balancing Authority ACE Limit (MW)

**10** is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

**$B_i$**  is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

**$F_A$**  is the measured frequency in Hz.

**$F_S$**  is the scheduled frequency in Hz.

**$FTL_{Low}$**  is the Low Frequency Trigger Limit (calculated as  $F_S - 3\epsilon_{1_i}$  Hz)

**$FTL_{High}$**  is the High Frequency Trigger Limit (calculated as  $F_S + 3\epsilon_{1_i}$  Hz)

Where  $\epsilon_{1_i}$  is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection  $\epsilon_{1_i} = 0.018$  Hz
- Western Interconnection  $\epsilon_{1_i} = 0.0228$  Hz
- ERCOT Interconnection  $\epsilon_{1_i} = 0.030$  Hz
- Quebec Interconnection  $\epsilon_{1_i} = 0.021$  Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period

## **Standard BAL-001-2 – Real Power Balancing Control Performance**

---

data is available or valid, then that one-minute interval is excluded from the BAAL calculation and the 30-minute clock would be reset to zero.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Overlap Regulation Service.



## Standard BAL-001-2 — Real Power Balancing Control Performance

### Appendix QC-BAL-001-2

#### Provisions specific to the standard BAL-001-2 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:** Real Power Balancing Control Performance
2. **Number:** BAL-001-2
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Effective Date:**
  - 5.1. Adoption of the standard by the Régie de l'énergie: Month xx, 201x
  - 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx, 201x
  - 5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

#### B. Requirements

No specific provision

#### C. Measures

No specific provision

#### D. Compliance

##### 1. Compliance Monitoring Process

###### 1.1. Compliance Enforcement Authority

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

###### 1.2. Data Retention

No specific provision

###### 1.3. Compliance Monitoring and Assessment Processes

No specific provision

###### 1.4. Additional Compliance Information

No specific provision

##### 2. Violation Severity Levels

No specific provision

#### E. Regional Variances

No specific provision

**F. Associated Documents**

No specific provision

**Attachment 1**

No specific provision

**Attachment 2**

No specific provision

**Revision History**

Revision	Adoption Date	Action	Change Tracking
0	Month xx, 201x	New appendix	New

## A. Introduction

1. **Title:** **Communications**
2. **Number:** COM-001-2
3. **Purpose:** To establish Interpersonal Communication capabilities necessary to maintain reliability.
4. **Applicability:**
  - 4.1. Transmission Operator
  - 4.2. Balancing Authority
  - 4.3. Reliability Coordinator
  - 4.4. Distribution Provider
  - 4.5. Generator Operator
5. **Effective Date:** The first day of the second calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

## B. Requirements

- R1. Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
  - 1.1. All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.
  - 1.2. Each adjacent Reliability Coordinator within the same Interconnection.
- R2. Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
  - 2.1. All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.
  - 2.2. Each adjacent Reliability Coordinator within the same Interconnection.
- R3. Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
  - 3.1. Its Reliability Coordinator.
  - 3.2. Each Balancing Authority within its Transmission Operator Area.

- 3.3. Each Distribution Provider within its Transmission Operator Area.
  - 3.4. Each Generator Operator within its Transmission Operator Area.
  - 3.5. Each adjacent Transmission Operator synchronously connected.
  - 3.6. Each adjacent Transmission Operator asynchronously connected.
- R4.** Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- 4.1. Its Reliability Coordinator.
  - 4.2. Each Balancing Authority within its Transmission Operator Area.
  - 4.3. Each adjacent Transmission Operator synchronously connected.
  - 4.4. Each adjacent Transmission Operator asynchronously connected.
- R5.** Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- 5.1. Its Reliability Coordinator.
  - 5.2. Each Transmission Operator that operates Facilities within its Balancing Authority Area.
  - 5.3. Each Distribution Provider within its Balancing Authority Area.
  - 5.4. Each Generator Operator that operates Facilities within its Balancing Authority Area.
  - 5.5. Each Adjacent Balancing Authority.
- R6.** Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
- 1.1. Its Reliability Coordinator.
  - 1.2. Each Transmission Operator that operates Facilities within its Balancing Authority Area.
  - 1.3. Each Adjacent Balancing Authority.
- R7.** Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- 7.1. Its Balancing Authority.
  - 7.2. Its Transmission Operator.
- R8.** Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal



Communication capability in which case Requirement R11 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

**8.1.** Its Balancing Authority.

**8.2.** Its Transmission Operator.

**R9.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]*

**R10.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

**R11.** Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

### **C. Measures**

**M1.** Each Reliability Coordinator shall have and provide upon request evidence that it has Interpersonal Communication capability with all Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and with each adjacent Reliability Coordinator within the same Interconnection, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R1.)

**M2.** Each Reliability Coordinator shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with all Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and with each adjacent Reliability Coordinator within the same Interconnection, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R2.)

- M3.** Each Transmission Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority, Distribution Provider, and Generator Operator within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously or synchronously connected, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communication. (R3.)
- M4.** Each Transmission Operator shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously and synchronously connected, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R4.)
- M5.** Each Balancing Authority shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator and Generator Operator that operates Facilities within its Balancing Authority Area, each Distribution Provider within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R5.)
- M6.** Each Balancing Authority shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator that operates Facilities within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R6.)
- M7.** Each Distribution Provider shall have and provide upon request evidence that it has Interpersonal Communication capability with its Transmission Operator and its Balancing Authority, which could include, but is not limited to:

- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R7.)
- M8.** Each Generator Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Balancing Authority and its Transmission Operator, which could include, but is not limited to:
- physical assets, or
  - dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R8.)
- M9.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it tested, at least once each calendar month, its Alternative Interpersonal Communication capability designated in Requirements R2, R4, or R6. If the test was unsuccessful, the entity shall have and provide upon request evidence that it initiated action to repair or designated a replacement Alternative Interpersonal Communication capability within 2 hours. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R9.)
- M10.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it notified entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasted 30 minutes or longer. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R10.)
- M11.** Each Distribution Provider and Generator Operator that detected a failure of its Interpersonal Communication capability shall have and provide upon request evidence that it consulted with each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine mutually agreeable action to restore the Interpersonal Communication capability. Evidence could include, but is not limited to: dated operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R11.)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

## **1.2. Compliance Monitoring and Enforcement Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

## **1.3. Data Retention**

The Reliability Coordinator, Transmission Operator, Balancing Authority, Distribution Provider, and Generator Operator 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 Reliability Coordinator for Requirements R1, R2, R9, and R10, Measures M1, M2, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Transmission Operator for Requirements R3, R4, R9, and R10, Measures M3, M4, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Balancing Authority for Requirements R5, R6, R9, and R10, Measures M5, M6, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Distribution Provider for Requirements R7 and R11, Measures M7 and M11 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Generator Operator for Requirements R8 and R11, Measures M8 and M11 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Distribution Provider, or Generator Operator 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.

## **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	The Reliability Coordinator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R1, Parts 1.1 or 1.2, except when the Reliability Coordinator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Reliability Coordinator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R1, Parts 1.1 or 1.2, except when the Reliability Coordinator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R2	N/A	N/A	The Reliability Coordinator failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R2, Parts 2.1 or 2.2.	The Reliability Coordinator failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R2, Parts 2.1 or 2.2.
R3	N/A	N/A	The Transmission Operator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R3, Parts 3.1, 3.2, 3.3, 3.4, 3.5, or 3.6, except when the Transmission Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Transmission Operator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R3, Parts 3.1, 3.2, 3.3, 3.4, 3.5, or 3.6, except when the Transmission Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R4	N/A	N/A	The Transmission Operator failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R4, Parts 4.1, 4.2, 4.3, or 4.4.	The Transmission Operator failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R4, Parts 4.1, 4.2, 4.3, or 4.4.

**Standard COM-001-2 — Communications**

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	The Balancing Authority failed to have Interpersonal Communication capability with one of the entities listed in Requirement R5, Parts 5.1, 5.2, 5.3, 5.4, or 5.5, except when the Balancing Authority detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Balancing Authority failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R5, Parts 5.1, 5.2, 5.3, 5.4, or 5.5, except when the Balancing Authority detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R6	N/A	N/A	The Balancing Authority failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R6, Parts 6.1, 6.2, or 6.3.	The Balancing Authority failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R6, Parts 6.1, 6.2, or 6.3.
R7	N/A	N/A	The Distribution Provider failed to have Interpersonal Communication capability with one of the entities listed in Requirement R7, Parts 7.1 or 7.2, except when the Distribution Provider detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.	The Distribution Provider failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R7, Parts 7.1 or 7.2, except when the Distribution Provider detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.

**Standard COM-001-2 — Communications**

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R8</b>	N/A	N/A	The Generator Operator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R8, Parts 8.1 or 8.2, except when a Generator Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.	The Generator Operator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R8, Parts 8.1 or 8.2, except when a Generator Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.
<b>R9</b>	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 2 hours and less than or equal to 4 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 4 hours and less than or equal to 6 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 6 hours and less than or equal to 8 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to test the Alternative Interpersonal Communication capability once each calendar month.  OR The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 8 hours upon an unsuccessful test.
<b>R10</b>	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 60 minutes but less than or equal to 70 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 70 minutes but less than or equal to 80 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 80 minutes but less than or equal to 90 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 90 minutes.

**Standard COM-001-2 — Communications**

---

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11	N/A	N/A	N/A	<p>The Distribution Provider or Generator Operator that detected a failure of its Interpersonal Communication capability failed to consult with each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of the Interpersonal Communication capability.</p>



**E. Regional Differences**

None identified.

**F. Associated Documents**

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Regulatory Approval — Effective Date	New
1	April 6, 2007	Requirement 1, added the word “for” between “facilities” and “the exchange.”	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to “1.1”	Errata
2	November 7, 2012	Adopted by Board of Trustees	Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Replaced R1 with R1-R8; R2 replaced by R9; R3 included within new R1; R4 remains enforce pending Project 2007-02; R5 redundant with EOP-008-0, retiring R5 as redundant with EOP-008-0, R1; retiring R6, relates to ERO procedures; R10 & R11, new.
2	April 16, 2015	FERC Order issued approving COM-001-2	



## Standard COM-001-2 —Communications

### Appendix QC-COM-001-2 Provisions specific to the standard COM-001-2 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:** Communications
2. **Number:** COM-001-2
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Effective Date:**
  - 5.1. Adoption of the standard by the Régie de l'énergie: Month xx, 201x
  - 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx, 201x
  - 5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

#### B. Requirements

No specific provision

#### C. Requirements

No specific provision

#### D. Compliance

##### 1. Compliance Monitoring Process

###### 1.1. Compliance Enforcement Authority

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

###### 1.2. Compliance Monitoring and Enforcement Processes

No specific provision

###### 1.3. Data Retention

No specific provision

###### 1.4. Additional Compliance Information

No specific provision

##### 2. Violation Severity Levels

No specific provision

#### E. Regional Differences

No specific provision

#### F. Associated Documents

No specific provision

**Standard COM-001-2 —Communications**

**Appendix QC-COM-001-2**

**Provisions specific to the standard COM-001-2 applicable in Québec**

---

**Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	Xx month 201x	New appendix	New

## A. Introduction

1. **Title:** Operating Personnel Communications Protocols
2. **Number:** COM-002-4
3. **Purpose:** To improve communications for the issuance of Operating Instructions with predefined communications protocols to reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of the Bulk Electric System (BES).
4. **Applicability:**
  - 4.1. **Functional Entities**
    - 4.1.1 Balancing Authority
    - 4.1.2 Distribution Provider
    - 4.1.3 Reliability Coordinator
    - 4.1.4 Transmission Operator
    - 4.1.5 Generator Operator
5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*
  - 1.1. Require its operating personnel that issue and receive an oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations.
  - 1.2. Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions:
    - Confirm the receiver's response if the repeated information is correct.
    - Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver.

- Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.
- 1.3.** Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions:
- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct.
  - Request that the issuer reissue the Operating Instruction.
- 1.4.** Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.
- 1.5.** Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification.
- 1.6.** Specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction.
- R2.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*
- R3.** Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*
- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
  - Request that the issuer reissue the Operating Instruction.
- R4.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: *[Violation Risk Factor: Medium][Time Horizon: Operations Planning]*
- 4.1.** Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols.
- 4.2.** Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.

- R5.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [*Violation Risk Factor: High*][*Time Horizon: Real-time Operations*]
- Confirm the receiver’s response if the repeated information is correct (in accordance with Requirement R6).
  - Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or
  - Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.
- R6.** Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [*Violation Risk Factor: High*][*Time Horizon: Real-time Operations*]
- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
  - Request that the issuer reissue the Operating Instruction.
- R7.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [*Violation Risk Factor: High*][*Time Horizon: Real-time Operations*]

**C. Measures**

- M1.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide its documented communications protocols developed for Requirement R1.
- M2.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide its initial training records related to its documented communications protocols developed for Requirement R1 such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R2.
- M3.** Each Distribution Provider and Generator Operator shall provide its initial training records for its operating personnel such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R3.
- M4.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide evidence of its assessments, including spreadsheets, logs or other evidence of feedback, findings of effectiveness and any changes made to its documented communications protocols developed for Requirement R1 in fulfillment of

Requirement R4. The entity shall provide, as part of its assessment, evidence of any corrective actions taken where an operating personnel's non-adherence to the protocols developed in Requirement R1 is the sole or partial cause of an Emergency and for all other instances where the entity determined that it was appropriate to take a corrective action to address deviations from the documented protocols developed in Requirement R1.

- M5.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority that issued an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence that the issuer either: 1) confirmed that the response from the recipient of the Operating Instruction was correct; 2) reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver; or 3) took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. Such evidence could include, but is not limited to, dated and time-stamped voice recordings, or dated and time-stamped transcripts of voice recordings, or dated operator logs in fulfillment of Requirement R5.
- M6.** Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that was the recipient of an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence to show that the recipient either repeated, not necessarily verbatim, the Operating Instruction and received confirmation from the issuer that the response was correct, or requested that the issuer reissue the Operating Instruction in fulfillment of Requirement R6. Such evidence may include, but is not limited to, dated and time-stamped voice recordings (if the entity has such recordings), dated operator logs, an attestation from the issuer of the Operating Instruction, memos or transcripts.
- M7.** Each Balancing Authority, Reliability Coordinator and Transmission Operator that issued a written or oral single or multiple-party burst Operating Instruction during an Emergency shall provide evidence that the Operating Instruction was received by at least one receiver. Such evidence may include, but is not limited to, dated and time-stamped voice recordings (if the entity has such recordings), dated operator logs, electronic records, memos or transcripts.

## **D. 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. Data Retention**

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



provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, and Transmission Operator shall each keep data or evidence for each applicable Requirement for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

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

**Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.3. Additional Compliance Information**

None

**COM-002-4 – Operating Personnel Communications Protocols**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R1</b>	Long-term Planning	Low	<p>The responsible entity did not specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required in Requirement R1, Part 1.5</p> <p>OR</p> <p>The responsible entity did not specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction, as required in Requirement R1, Part 1.6.</p>	<p>The responsible entity did not require the issuer and receiver of an oral or written Operating Instruction to use the English language, unless agreed to otherwise, as required in Requirement R1, Part 1.1. An alternate language may be used for internal operations.</p>	<p>The responsible entity did not include Requirement R1, Part 1.4 in its documented communication protocols.</p>	<p>The responsible entity did not include Requirement R1, Part 1.2 in its documented communications protocols</p> <p>OR</p> <p>The responsible entity did not include Requirement R1, Part 1.3 in its documented communications protocols</p> <p>OR</p> <p>The responsible entity did not develop any documented communications protocols as required in Requirement R1.</p>

**COM-002-4 – Operating Personnel Communications Protocols**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R2</b>	Long-term Planning	Low	N/A	N/A	An individual operator responsible for the Real-time operation of the interconnected Bulk Electric System at the responsible entity issued an Operating Instruction, prior to being trained on the documented communications protocols developed in Requirement R1.	An individual operator responsible for the Real-time operation of the interconnected Bulk Electric System at the responsible entity issued an Operating Instruction during an Emergency prior to being trained on the documented communications protocols developed in Requirement R1.
<b>R3</b>	Long-term Planning	Low	N/A	N/A	An individual operator at the responsible entity received an Operating Instruction prior to being trained.	An individual operator at the responsible entity received an Operating Instruction during an Emergency prior to being trained.

**COM-002-4 – Operating Personnel Communications Protocols**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R4</b>	Operations Planning	Medium	<p>The responsible entity assessed adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions and provided feedback to those operating personnel and took corrective action, as appropriate</p> <p>AND</p> <p>The responsible entity assessed the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modified its documented communication</p>	<p>The responsible entity assessed adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, but did not provide feedback to those operating personnel</p> <p>OR</p> <p>The responsible entity assessed adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions and provided feedback to those operating personnel but did not take corrective action, as appropriate</p> <p>OR</p> <p>The responsible entity assessed the effectiveness of its documented communications protocols</p>	<p>The responsible entity did not assess adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions</p> <p>OR</p> <p>The responsible entity did not assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions.</p>	<p>The responsible entity did not assess adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions</p> <p>AND</p> <p>The responsible entity did not assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions.</p>

**COM-002-4 – Operating Personnel Communications Protocols**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>protocols, as necessary</p> <p>AND</p> <p>The responsible entity exceeded twelve (12) calendar months between assessments.</p>	<p>in Requirement R1 for its operating personnel that issue and receive Operating Instructions, but did not modify its documented communication protocols, as necessary.</p>		

**COM-002-4 – Operating Personnel Communications Protocols**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Real-time Operations	High	N/A	<p>The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions:</p> <ul style="list-style-type: none"> <li>Confirmed the receiver’s response if the repeated information was correct (in accordance with Requirement R6).</li> <li>Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver.</li> <li>Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver.</li> </ul>	N/A	<p>The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions:</p> <ul style="list-style-type: none"> <li>Confirmed the receiver’s response if the repeated information was correct (in accordance with Requirement R6).</li> <li>Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver.</li> <li>Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver.</li> </ul> <p>AND</p> <p>Instability, uncontrolled separation, or cascading failures occurred as a result.</p>

**COM-002-4 – Operating Personnel Communications Protocols**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R6</b>	Real-time Operations	High	N/A	The responsible entity did not repeat, not necessarily verbatim, the Operating Instruction during an Emergency and receive confirmation from the issuer that the response was correct, or request that the issuer reissue the Operating Instruction when receiving an Operating Instruction.	N/A	The responsible entity did not repeat, not necessarily verbatim, the Operating Instruction during an Emergency and receive confirmation from the issuer that the response was correct, or request that the issuer reissue the Operating Instruction when receiving an Operating Instruction  AND  Instability, uncontrolled separation, or cascading failures occurred as a result.
<b>R7</b>	Real-time Operations	High	N/A	The responsible entity that that issued a written or oral single-party to multiple-party burst Operating Instruction during an Emergency did not confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.	N/A	The responsible entity that that issued a written or oral single-party to multiple-party burst Operating Instruction during an Emergency did not confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction  AND  Instability, uncontrolled separation, or cascading failures occurred as a result.

**E. Regional Variances**

None

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	February 7, 2006	Adopted by Board of Trustees	Added measures and compliance elements
2	November 1, 2006	Adopted by Board of Trustees	Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Retired R1, R1.1, M1, M2 and updated the compliance monitoring information. Replaced R2 with new R1, R2 and R3.
2a	February 9, 2012	Interpretation of R2 adopted by Board of Trustees	Project 2009-22
3	November 7, 2012	Adopted by Board of Trustees	
4	May 6, 2014	Adopted by Board of Trustees	
4	April 16, 2015	FERC Order issued approving COM-002-4	



## Standard COM-002-4 —Operating Personnel Communications Protocols

### Appendix QC-COM-002-4

#### Provisions specific to the standard COM-002-4 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:** Operating Personnel Communications Protocols
2. **Number:** COM-002-4
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision

##### Functional entities

No specific provision

##### Facilities

Any reference to the term "BES" shall be replaced by the term "RTP".

5. **Effective Date:**

- 5.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x
- 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x
- 5.3. Effective date of the standard and its appendix in Québec: Month xx 201x

#### B. Requirements

No specific provision

#### C. Requirements

No specific provision

#### D. Compliance

1. **Compliance Monitoring Process**

- 1.1. **Compliance Enforcement Authority**

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

- 1.2. **Data Retention**

No specific provision

##### Compliance Monitoring and Assessment Processes

No specific provision

- 1.3. **Additional Compliance Information**

No specific provision

#### E. Regional Variances

No specific provision

**Standard COM-002-4 —Operating Personnel Communications Protocols**

**Appendix QC-COM-002-4**

**Provisions specific to the standard COM-002-4 applicable in Québec**

---

**Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	Xx month 201x	New appendix	New

### A. Introduction

1. **Title:** Facility Interconnection Requirements
2. **Number:** FAC-001-2
3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Applicable Generator Owner
      - 4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.
5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is one year after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is one year after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### B. Requirements and Measures

- R1.** Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
  - 1.1. generation Facilities;
  - 1.2. transmission Facilities; and
  - 1.3. end-user Facilities.
- M1.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.
- R2.** Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is

used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- M2.** Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.
- R3.** Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*
  - 3.1.** Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).
  - 3.2.** Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.
- M3.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.
- R4.** Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*
  - 4.1.** Procedures for coordinated studies of new interconnections and their impacts on affected system(s).
  - 4.2.** Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.
- M4.** Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

## **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 and applicable Generator Owner 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 responsible entities shall retain documentation as evidence for three years.

If a responsible 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 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 Check

Compliance Investigation

Self-Reporting

Complaint

**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
<b>R1</b>	Long-term Planning	Lower	N/A	<p>The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request.</p> <p>OR</p> <p>The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed.</p> <p>OR</p> <p>The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but</p>	<p>The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request.</p> <p>OR</p> <p>The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.</p>	<p>The Transmission Owner did not document Facility interconnection requirements.</p>

**FAC-001-2 — Facility Interconnection Requirements**

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
<b>R2</b>	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.

**FAC-001-2 — Facility Interconnection Requirements**

---

<b>R3</b>	Long-term Planning	Lower	N/A	N/A	The Transmission Owner addressed either R3, Part 3.1 or Part 3.2 in its Facility interconnection requirements, but did not address both.	The Transmission Owner addressed neither R3, Part 3.1 nor Part 3.2 in its Facility interconnection requirements.
<b>R4</b>	Long-term Planning	Lower	N/A	N/A	The applicable Generator Owner addressed either R4, Part 4.1 or Part 4.2 in its Facility interconnection requirements, but did not address both.	The applicable Generator Owner addressed neither R4, Part 4.1 nor Part 4.2 in its Facility interconnection requirements.

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.



### Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

#### **Requirement R3:**

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

## Application Guidelines

---

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

## Standard FAC-001-2 — Facility Interconnection Requirements

### Appendix QC-FAC-001-2 Provisions specific to the standard FAC-001-2 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:** Facility Interconnection Requirements
2. **Number:** FAC-001-2
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Effective Date:**
  - 5.1. Adoption of the standard by the Régie: Month xx, 201x
  - 5.2. Adoption of the appendix by the Régie: Month xx, 201x
  - 5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

#### 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 enforcement 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 provision

###### Table of compliance elements

No specific provision

#### D. Regional Variances

No specific provision

#### E. Interpretations

No specific provision

#### F. Associated Documents

No specific provision

**Standard FAC-001-2 — Facility Interconnection Requirements**

**Appendix QC-FAC-001-2**

**Provisions specific to the standard FAC-001-2 applicable in Québec**

---

**Revision history**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	Month xx, 201x	New appendix	New

## A. Introduction

1. **Title:** Facility Interconnection Studies
2. **Number:** FAC-002-2
3. **Purpose:** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Planning Coordinator
    - 4.1.2 Transmission Planner
    - 4.1.3 Transmission Owner
    - 4.1.4 Distribution Provider
    - 4.1.5 Generator Owner
    - 4.1.6 Applicable Generator Owner
      - 4.1.6.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.
    - 4.1.7 Load-Serving Entity
5. **Effective Date:** The first day of the first calendar quarter that is one year after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is one year after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements and Measures

- R1. Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities. The following shall be studied:  
*[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
  - 1.1. The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s);
  - 1.2. Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements;
  - 1.3. Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and

- 1.4.** Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.
- M1.** Each Transmission Planner or each Planning Coordinator shall have evidence (such as study reports, including documentation of reliability issues) that it met all requirements in Requirement R1.
- R2.** Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M2.** Each Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R2.
- R3.** Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M3.** Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R3.
- R4.** Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M4.** Each Transmission Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R4.
- R5.** Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M5.** Each applicable Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R5.

## 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 Planning Coordinator, Transmission Planner, Transmission Owner, Distribution Provider, Generator Owner, applicable Generator Owner, and Load-Serving Entity 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 responsible entities shall retain documentation as evidence for three years.

If a responsible 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 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 Check

Compliance Investigation

Self-Reporting

Complaint

#### 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
<b>R1</b>	Long-term Planning	Medium	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities, but failed to study one of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities but failed to study two of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities but failed to study three of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator failed to study the reliability impact of: interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) materially modifying existing interconnections of, generation, transmission, or electricity end-user Facilities.
<b>R2</b>	Long-term Planning	Medium	The Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, coordinated and cooperated on studies	The Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, coordinated and cooperated on studies	The Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, coordinated and cooperated on studies	The Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, failed to coordinate and cooperate on



			with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	studies with its Transmission Planner or Planning Coordinator.
<b>R3</b>	Long-term Planning	Medium	The Transmission Owner, Distribution Provider, or Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	The Transmission Owner, Distribution Provider, or Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	The Transmission Owner, Distribution Provider, or Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	The Transmission Owner, Distribution Provider, or Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator.

**FAC-002-2 — Facility Interconnection Studies**

<b>R4</b>	Long-term Planning	Medium	The Transmission Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested new or materially modified interconnections to its Facilities, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	The Transmission Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested new or materially modified interconnections to its Facilities, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	The Transmission Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested new or materially modified interconnections to its Facilities, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	The Transmission Owner failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator regarding requested new or materially modified interconnections to its Facilities.
<b>R5</b>	Long-term Planning	Medium	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	The applicable Generator Owner failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities.

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None

## Application Guidelines

---

### Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of “Regional Reliability Organizations(s).	Errata
1	August 5, 2010	Modified to address Order No. 693 Directives contained in paragraph 693. Adopted by the NERC Board of Trustees.	Revised
1	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
1	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees.	
2	November 6, 2014	FERC letter order issued approving FAC-002-2.	

## Standard FAC-002-2 — Facility Interconnection Studies

### Appendix QC-FAC-002-2 Provisions specific to the standard FAC-002-2 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:** Facility Interconnection Studies
2. **Number:** FAC-002-2
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Effective Date:**
  - 5.1. Adoption of the standard by the Régie: Month xx, 201x
  - 5.2. Adoption of the appendix by the Régie: Month xx, 201x
  - 5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

#### 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 enforcement 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 provision

##### Table of Compliance Elements

No specific provision

#### D. Regional Variances

No specific provision

#### E. Interpretation

No specific provision

#### F. Associated Documents

No specific provision

**Standard FAC-002-2 — Facility Interconnection Studies**

**Appendix QC-FAC-002-2**

**Provisions specific to the standard FAC-002-2 applicable in Québec**

---

**Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	Month xx, 201x	New appendix	New

## A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
  - Functional Entities:**
    - 4.1 The Responsible Entity is:
      - 4.1.1 Eastern Interconnection – Planning Coordinator
      - 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator
      - 4.1.3 Western Interconnection – Reliability Coordinator
      - 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator
    - 4.2 Transmission Owner
    - 4.3 Generator Owner
5. **Effective Dates:**

See Implementation Plan

## B. Requirements and Measures

- R1.** Each Transmission Owner shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
  - 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.
  - 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.
  - 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.
- M1.** The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

- R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- M2.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.
- R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 3.1** Phase-to-neutral voltage for each phase of each specified BES bus.
- 3.2** Each phase current and the residual or neutral current for the following BES Elements:
- 3.2.1** Transformers that have a low-side operating voltage of 100kV or above.
- 3.2.2** Transmission Lines.
- M3.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.
- R4.** Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 4.1** A single record or multiple records that include:
- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
  - At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.
- 4.2** A minimum recording rate of 16 samples per cycle.
- 4.3** Trigger settings for at least the following:
- 4.3.1** Neutral (residual) overcurrent.
- 4.3.2** Phase undervoltage or overcurrent.



- M4.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.
- R5.** Each Responsible Entity shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
- 5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:
- 5.1.1** Generating resource(s) with:
- 5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA.
- 5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.
- 5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).
- 5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.
- 5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).
- 5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.
- 5.2** Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:
- 5.2.1** One BES Element; and
- 5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.
- 5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.
- 5.4** Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.
- M5.** The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each Transmission Owner or Generator

Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

- R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 6.1** One phase-to-neutral or positive sequence voltage.
  - 6.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.
  - 6.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.
  - 6.4** Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.
- M6.** The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.
- R7.** Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 7.1** One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.
  - 7.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.
  - 7.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.
  - 7.4** Frequency of at least one of the voltages in Requirement R7, Part 7.1.
- M7.** The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.
- R8.** Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and

is not capable of continuous recording, triggered records must meet the following:  
*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

**8.1** Triggered record lengths of at least three minutes.

**8.2** At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

**M8.** Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

**R9.** Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following:  
*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

**9.1** Input sampling rate of at least 960 samples per second.

**9.2** Output recording rate of electrical quantities of at least 30 times per second.

**M9.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

- R10.** Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 10.1** Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.
- 10.2** Synchronized device clock accuracy within  $\pm 2$  milliseconds of UTC.
- M10.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or (3) station drawings.
- R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.
- 11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.
- 11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.
- 11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.
- 11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.
- M11.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.
- R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- Restore the recording capability, or
  - Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

**M12.** The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

## 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 Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

**1.3. Compliance Monitoring and Assessment Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

**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	Lower	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other</p>	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part</p>	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part</p>	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by</p>

**PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
<b>R2</b>	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
<b>R3</b>	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,



**PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
<b>R4</b>	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
<b>R5</b>	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1.  OR

**PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

			<p>OR</p> <p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.</p>	<p>OR</p> <p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.</p>	<p>OR</p> <p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.</p>	<p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days.</p> <p>OR</p> <p>The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.</p>
<b>R6</b>	Long-term Planning	Lower	<p>The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the</p>	<p>The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the</p>	<p>The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the</p>	<p>The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.</p>

**PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

			total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	
<b>R7</b>	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
<b>R8</b>	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

**PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

<b>R9</b>	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
<b>R10</b>	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

**PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

<p><b>R11</b></p>	<p>Long-term Planning</p>	<p>Lower</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in</p>
-------------------	---------------------------	--------------	---	--	--	---

**PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

			than 90 percent of the data but less than 100 percent of the data in the proper data format.	than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	the proper data format.
<b>R12</b>	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure.  OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure.  OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**G. References**

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

**Version History**

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

## Attachment 1

### Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

#### (Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.



If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

**Attachment 2**  
**Sequence of Events Recording (SER) Data Format**  
**(Requirement R11, Part 11.3)**

Date, Time, Local Time Code, Substation, Device, State<sup>1</sup>

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

---

<sup>1</sup> "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO   GO			X		
R3	TO   GO				X	
R4	TO   GO				X	
Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation	
R5	RE (PC   RC)	X	X	X	X	
R6	TO			X		
R7	GO			X		
R8	TO   GO			X		
R9	TO   GO			X		
Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data		SER, FR, DDR Availability	
R10	TO   GO	X				
R11	TO   GO		X			
R12	TO   GO				X	

### **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 Functional Entities:**

When the term “Responsible Entity” is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

### **Rationale for R1:**

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT’s data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

### **Rationale for R2:**

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

### **Rationale for R3:**

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

### **Rationale for R4:**

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

### **Rationale for R5:**

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is

outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

### **Rationale for R6:**

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

### **Rationale for R7:**

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

### **Rationale for R8:**

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

### **Rationale for R9:**

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

### **Rationale for R10:**

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to  $\pm 2$  ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within  $\pm 2$  ms accuracy will suffice with respect to providing time synchronized data.

### **Rationale for R11:**

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-



calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

### **Rationale for R12:**

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

### Guidelines and Technical Basis Section

#### Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses “what” data is recorded, not “how” it is recorded.

#### Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
  - a. Only tangible substation or switchyard buses are included.
  - b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
  - Electrically distant BES buses or electrically distant from other DME devices
  - Voltage sensitive areas
  - Cohesive load and generation zones
  - BES buses with a relatively high number of incident Transmission circuits
  - BES buses with reactive power devices
  - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

**Guideline for Requirement R2:**

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

**Guideline for Requirement R3:**

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

### Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

### Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.

Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current  $I_r$ , is calculated as a sum of vectors of three phase currents:

$$I_r = 3 \cdot I_0 = I_A + I_B + I_C$$

$I_0$  - Zero-sequence current

$I_A, I_B, I_C$  - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

### Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

### **Guideline for Requirement R4:**

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

### **Guideline for Requirement R5:**

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of **why** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size

thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES

Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

### **Guideline for Requirement R6:**

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.



For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

### **Guideline for Requirement R7:**

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

### **Guideline for Requirement R8:**

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

### **Guideline for Requirement R9:**

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term

and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

**Guideline for Requirement R10:** Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization...”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized...”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

### **Guideline for Requirement R11:**

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files

did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

### **Guideline for Requirement R12:**

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

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:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** No specific provision
4. **Applicability:**
  - Functional Entities:**

No specific provision
  - Facilities:**
    - This standard only applies to the facilities of the *Main Transmission System* (RTP)
    - Any reference to the term "BES" shall be replaced by the term "RTP".
5. **Effective Date:**
  - 5.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x
  - 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x
  - 5.3. Effective date of the standard and its appendix in Québec: Month xx 201x

## B. Requirements and Measures

- R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Régie de l'énergie in accordance with the following: *[Violation Risk Factor(VRF): Lower] [Time Horizon: Long-term Planning]*
- 11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.
  - 11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.
  - 11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.
  - 11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.
  - 11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

**R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor (VRF): Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit Corrective Action Plan (CAP) to the Régie de l'énergie

**M12.** The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Régie de l'énergie and evidence that it implemented the CAP.

## **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 Compliance**

No specific provision

#### **1.3. Compliance Monitoring and Assessment Processes:**

No specific provision

#### **1.4. Additional Compliance Information**

No specific provision

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Régie de l'énergie more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Régie de l'énergie more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Régie de l'énergie more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure.  OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Régie de l'énergie failed to implement it.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Régie de l'énergie more than 120- calendar days after discovery of the failure.  OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Régie de l'énergie .

## **D. Regional Variances**

No specific provision

## **E. Interpretations**

No specific provision

## **F. Associated Documents**

No specific provision

## **G. References**

No specific provision

## **Attachment 1**

No specific provision

## **Attachment 2**

No specific provision

## **High Level Requirement Overview**

No specific provision

## **Rationale**

No specific provision

## **Guidelines and Technical Basis Section**

### **Guideline for Requirement R11:**

This requirement directs the applicable entities, upon requests from the Responsible Entity or Régie de l'énergie, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

### **Guideline for Requirement R12:**

This requirement directs the applicable entities, upon requests from the Responsible Entity or Régie de l'énergie, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.



**Standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements**

**Appendix QC-PRC-002-2**

**Provisions specific to the standard PRC-002-2 applicable in Québec**

---

**Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	Month xx, 201x	New Appendix	New



## A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-2
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

- 4.1. Planning Coordinators

- 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

- 4.2.1 Transmission Owners

- 4.2.2 Distribution Providers

- 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **Effective Date:**

This standard is effective on the first day of the first calendar quarter six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

## B. Requirements and Measures

- R1.** Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*
- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- R2.** Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*
- 2.1.** Those islands selected by applying the criteria in Requirement R1, and
  - 2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and
  - 2.3.** A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*
- 3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

- 3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
- Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
  - Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
  - Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- 4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.
  - 4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.
  - 4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.
  - 4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.
  - 4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.
  - 4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA

(gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

- 4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- R5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation , including any Corrective Action Plan, per Requirement R9.
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall

conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**11.1.** The performance of the UFLS equipment,

**11.2.** The effectiveness of the UFLS program.

**M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

**R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

**M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

**R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

**M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same



islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

- R14.** Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following [*VRF: Lower*][*Time Horizon: Long-term Planning*]:
- 14.1.** UFLS program, including a schedule for implementation
  - 14.2.** UFLS design assessment
  - 14.3.** Format and schedule of UFLS data submittal
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.
- R15.** Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. [*VRF: High*][*Time Horizon: Long-term Planning*]
- 15.1.** For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.
  - 15.2.** For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.
- M15.** Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

## 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

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year’s UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

**1.4. Additional Compliance Information**

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R1</b>	N/A	<p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>	<p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>	<p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>
<b>R2</b>	N/A	<p>The Planning Coordinator identified an island(s) to</p>	<p>The Planning Coordinator identified an island(s) to serve</p>	<p>The Planning Coordinator identified an island(s) to serve</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>	<p>as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>	<p>as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p>
<p><b>R3</b></p>	<p>N/A</p>	<p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = <math>[(\text{load} - \text{actual generation output}) / (\text{load})]</math>, of up to 25 percent within the identified island(s), but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p>	<p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = <math>[(\text{load} - \text{actual generation output}) / (\text{load})]</math>, of up to 25 percent within the identified island(s), but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p>	<p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = <math>[(\text{load} - \text{actual generation output}) / (\text{load})]</math>, of up to 25 percent within the identified island(s), but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
<b>R4</b>	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.  OR  The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R5</b>	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
<b>R6</b>	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
<b>R7</b>	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.  OR

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
<b>R8</b>	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator’s UFLS database.	<p>The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator’s UFLS database.</p> <p>OR</p> <p>The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator’s UFLS database.</p>	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator’s UFLS database.	<p>The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator’s UFLS database.</p> <p>OR</p> <p>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator’s UFLS database.</p>
<b>R9</b>	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation,



**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	program design and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.
<b>R10</b>	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
<b>R11</b>	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program,

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p>	<p>the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p>	<p>UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts 11.1 or 11.2.</p>	<p>conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				as specified in Requirement R11, Parts 11.1 and 11.2.
<b>R12</b>	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.  OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
<b>R13</b>	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13</p>
<b>R14</b>	N/A	N/A	N/A	<p>The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.</p>
<b>R15</b>	N/A	<p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement</p>	<p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement</p>	<p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.</p>	<p>R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.</p>	<p>R3, but failed to develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area.</p> <p>OR</p> <p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.</p>

## D. Regional Variances

### D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

- D.A.3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s).  
*[VRF: High][Time Horizon: Long-term Planning]*
- D.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- D.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- D.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
- DA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES
- DA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES
- DA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.
- M.D.A.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through DA3.3.

- D.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*
- D.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and
  - D.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and
  - D.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- M.D.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>DA3</b>	N/A	<p>The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions</p>	<p>The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions</p>	<p>The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program.</p>
<b>DA4</b>	N/A	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 but simulation failed to include one (1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include two (2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include all of the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3.</p> <p>OR</p>



**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

---

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

**D.B. Regional Variance for the Western Electricity Coordinating Council**

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

**D.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

**M.D.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

**D.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

**D.B.2.1.** Those islands selected by applying the criteria in Requirement D.B.1, and

**D.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

**M.D.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

**D.B.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

**D.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

- D.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- D.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
  - D.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
  - D.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
  - D.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- M.D.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.
- D.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
  - D.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.
  - D.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.
  - D.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation

above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

**D.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

**D.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

**D.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

**D.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**M.D.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

**D.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**D.B.11.1.** The performance of the UFLS equipment,

**D.B.11.2** The effectiveness of the UFLS program

**M.D.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

- D.B.12.** Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- M.D.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>D.B.1</b>	N/A	<p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p>	<p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p>	<p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>D.B.2</b>	N/A	N/A	<p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2</p>	<p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.</p>
<b>D.B.3</b>	N/A	<p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in</p>	<p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions</p>	<p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		simulations of underfrequency conditions		simulations of underfrequency conditions  OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
<b>D.B.4</b>	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as



**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	<p>specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2</p>
<b>D.B.11</b>	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p>	<p>evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p>	<p>evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.</p>	<p>evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.</p>
<b>D.B.12</b>	N/A	<p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p>	<p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p>	<p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in</p>

**Standard PRC-006-2 — Automatic Underfrequency Load Shedding**

---

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

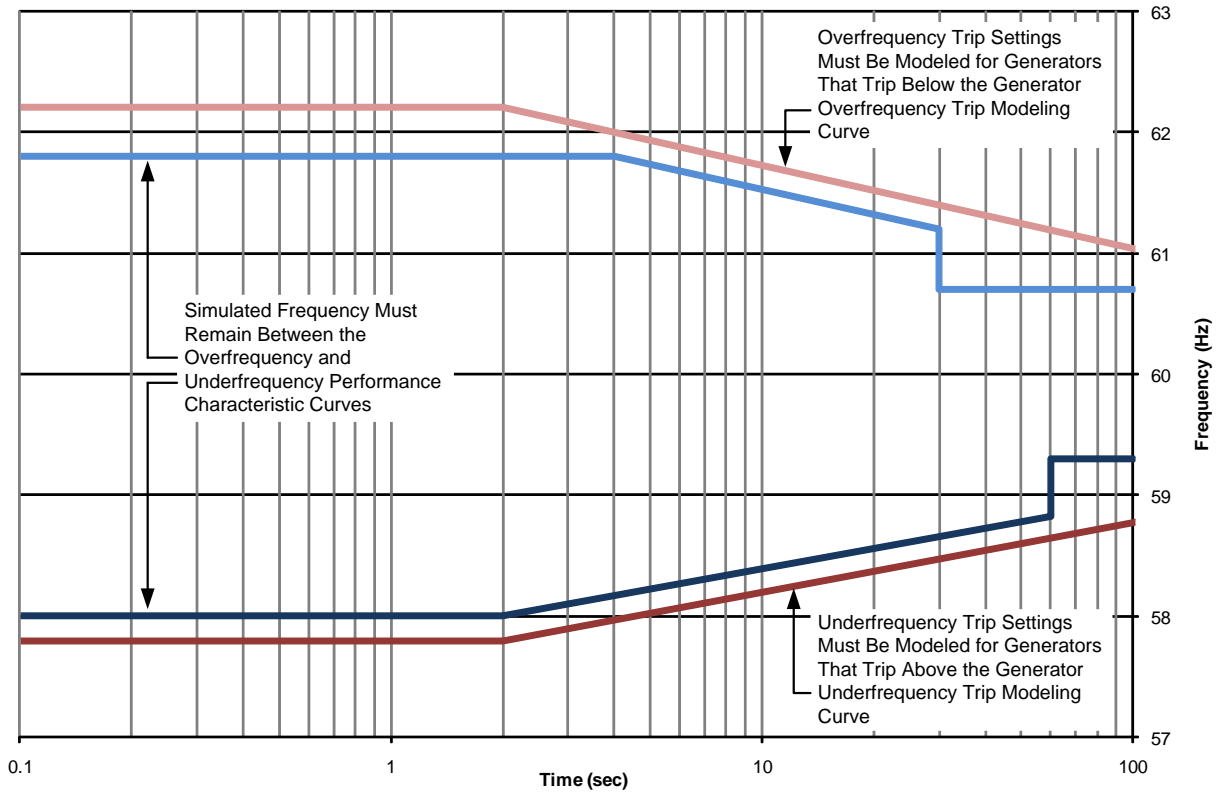
## E. Associated Documents

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the 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.  Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-2 – Attachment 1

Underfrequency Load Shedding Program  
 Design Performance and Modeling Curves for  
 Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



- Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
- Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
- Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
- Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

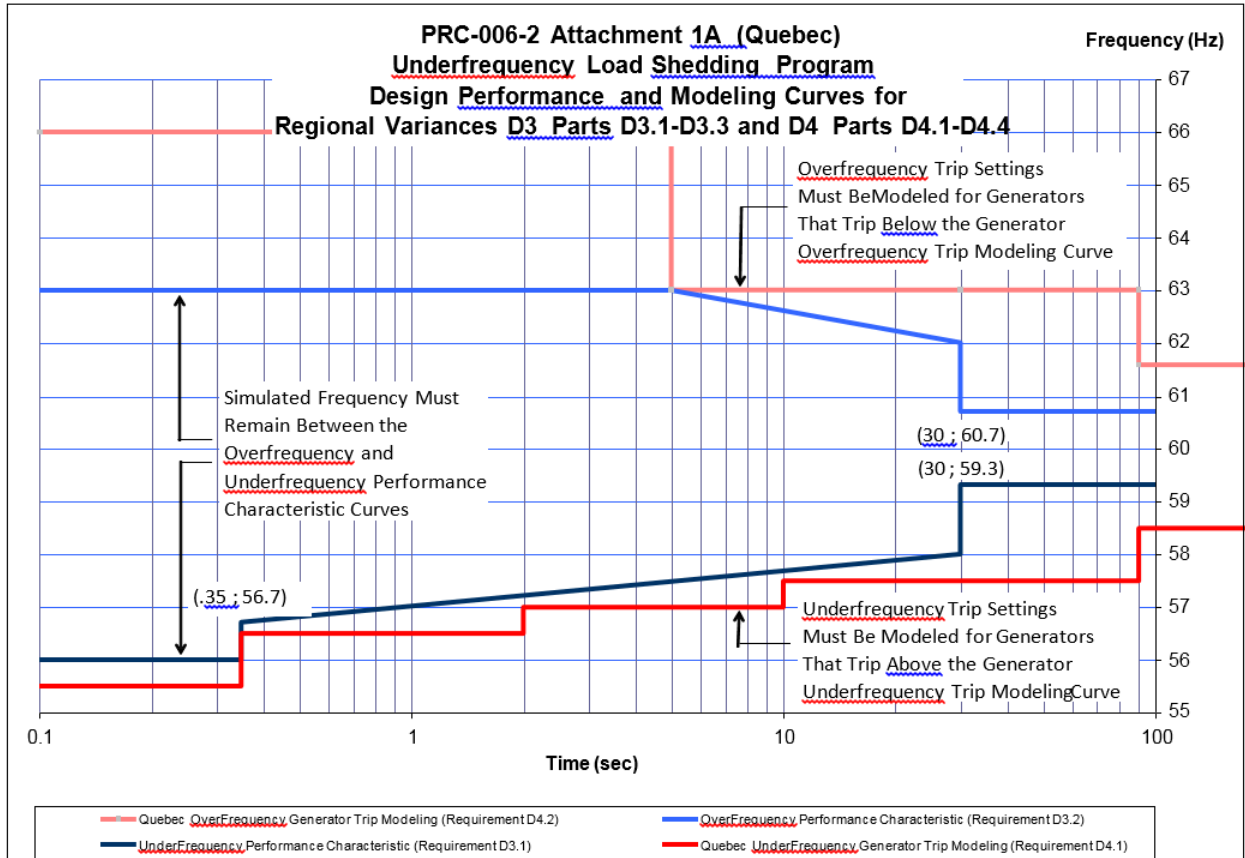
Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
$t \leq 2 \text{ s}$	$t > 2 \text{ s}$	$t \leq 4 \text{ s}$	$4 \text{ s} < t \leq 30 \text{ s}$	$t > 30 \text{ s}$
$f = 62.2 \text{ Hz}$	$f = -0.686\log(t) + 62.41 \text{ Hz}$	$f = 61.8 \text{ Hz}$	$f = -0.686\log(t) + 62.21 \text{ Hz}$	$f = 60.7 \text{ Hz}$

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic
--	---

## Standard PRC-006-2 — Automatic Underfrequency Load Shedding

---

$t \leq 2 \text{ s}$	$t > 2 \text{ s}$	$t \leq 2 \text{ s}$	$2 \text{ s} < t \leq 60 \text{ s}$	$t > 60 \text{ s}$
$f = 57.8$ Hz	$f = 0.575\log(t) + 57.63$ Hz	$f = 58.0$ Hz	$f = 0.575\log(t) + 57.83$ Hz	$f = 59.3$ Hz





### **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 R9:**

The “Corrective Action Plan” language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word “application” was replaced with “implementation.” (See Requirements R3, R14 and R15)

### **Rationale for R10:**

The “Corrective Action Plan” language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word “application” was replaced with “implementation.” (See Requirements R3, R14 and R15)

### **Rationale for R15:**

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A “Corrective Action Plan” is defined in the NERC Glossary of Terms as, “a list of actions and an associated timetable for implementation to remedy a specific problem.” Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.



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:** Automatic Underfrequency Load Shedding
- 2. Number:** PRC-006-2
- 3. Purpose:** No specific provision
- 4. Applicability:**  
No specific provision
- 5. Effective Date:**
  - 5.1.** Adoption of the standard by the Régie de l'énergie: Month xx 201x
  - 5.2.** Adoption of the appendix by the Régie de l'énergie: Month xx 201x
  - 5.3.** Effective date of the standard and its appendix in Québec: Month xx 201x
- 6. Background:**  
No specific provision

**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 provision

**2. Violation Severity Levels**

No specific provision

**D. Regional Variances**

**D.A. Regional Variance for the Quebec Interconnexion**

No specific provision

**D.B. Regional Variance for the Western Electricity Coordinating Council**

No specific provision

**E. Associated Documents**

No specific provision

**Appendix 1**

No specific provision

**Appendix 1A**

No specific provision

**Rationale**

No specific provision

**Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	Mont xx, 201x	New appendix	New