

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



**A. Introduction**

- 1. Title:** Automatic Generation Control
- 2. Number:** BAL-005-0.2b
- 3. Purpose:** This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.
- 4. Applicability:**
  - 4.1.** Balancing Authorities
  - 4.2.** Generator Operators
  - 4.3.** Transmission Operators
  - 4.4.** Load Serving Entities
- 5. Effective Date:** May 13, 2009

**B. Requirements**

- R1.** All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.
  - R1.1.** Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.
  - R1.2.** Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.
  - R1.3.** Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.
- R2.** Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard. (Retirement approved by FERC effective January 21, 2014.)
- R3.** A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.
- R4.** A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.
- R5.** A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.
- R6.** The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

- R7.** The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.
- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.
- R8.1.** Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.
- R12.3.** Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.
- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error ( $I_{ME}$ ) term of the ACE equation to compensate for any equipment error until repairs can be made.
- R14.** The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical

locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

- R16.** The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.
- R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	$\leq 0.001$ Hz
MW, MVAR, and voltage transducer	$\leq 0.25$ % of full scale
Remote terminal unit	$\leq 0.25$ % of full scale
Potential transformer	$\leq 0.30$ % of full scale
Current transformer	$\leq 0.50$ % of full scale

**C. Measures**

Not specified.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

- 1.1.1.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.
- 1.1.2.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Not specified.

**1.3. Data Retention**

- 1.3.1.** Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.
- 1.3.2.** Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or

## Standard BAL-005-0.2b — Automatic Generation Control

Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

### 1.4. Additional Compliance Information

Not specified.

### 2. Levels of Non-Compliance

Not specified.

### E. Regional Differences

None identified.

### F. Associated Documents

- Appendix 1 — Interpretation of Requirement R17 (February 12, 2008).

### Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from “BAL-005-1” to “BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	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.	
0.2b	November 21, 2013	R2 and associated elements approved by FERC	

		for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	
--	--	--	--

**Appendix 1**

**Effective Date: August 27, 2008 (U.S.)**

**Interpretation of BAL-005-0 Automatic Generation Control, R17**

**Request for Clarification received from PGE on July 31, 2007**

*PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:*

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

**BAL-005-0**

**R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

<b>Device</b>	<b>Accuracy</b>
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

**Existing Interpretation Approved by Board of Trustees May 2, 2007**

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

**Interpretation provided by NERC Frequency Task Force on September 7, 2007 and Revised on November 16, 2007**

As noted in the existing interpretation, BAL-005-0 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and

## **Standard BAL-005-0.2b — Automatic Generation Control**

---

frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.



## Standard BAL-005-0.2b — Automatic Generation Control

### Appendix QC-BAL-005-0.2b

#### Provisions specific to the standard BAL-005-0.2b 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:** Automatic Generation Control
2. **Number:** BAL-005-0.2b
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: December 22, 2016
  - 5.2. Adoption of the appendix by the Régie de l'énergie: December 22, 2016
  - 5.3. Effective date of the standard and its appendix in Québec: January 1, 2017

#### B. Requirements

No specific provision

#### C. Measures

No specific provision

#### D. Compliance

##### 1. Compliance Monitoring Process

###### 1.1. Compliance Monitoring Responsibility

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. Compliance Monitoring Period and Reset Timeframe

No specific provision

###### 1.3. Data Retention

No specific provision

###### 1.4. Additional Compliance Information

No specific provision

##### 2. Levels of Non-Compliance

No specific provision

#### E. Regional Differences

No specific provision

**Standard BAL-005-0.2b — Automatic Generation Control**

**Appendix QC-BAL-005-0.2b**

**Provisions specific to the standard BAL-005-0.2b applicable in Québec**

---

**F. Associated Documents**

No specific provision

**Appendix 1**

No specific provision

**Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	October 30, 2013	New appendix	New
1	December 22, 2016	Requirement 2 retired	Revised

## Standard COM-001-2.1 — Communications

---

### A. Introduction

1. **Title:** **Communications**
2. **Number:** COM-001-2.1
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.

## Standard COM-001-2.1 — Communications

---

- 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]*
- 6.1. Its Reliability Coordinator.
  - 6.2. Each Transmission Operator that operates Facilities within its Balancing Authority Area.
  - 6.3. 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.

## Standard COM-001-2.1 — Communications

---

- 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

## Standard COM-001-2.1 — Communications

---

- 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.)

## Standard COM-001-2.1 — Communications

---

- 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**

## Standard COM-001-2.1 — Communications

---

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.



## **Standard COM-001-2.1 — Communications**

---

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

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

None.

**Standard COM-001-2.1 — Communications**

**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-001-2.1 — 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-001-2.1 — Communications**

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	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.
R9	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.

**Standard COM-001-2.1 — Communications**

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
<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.
<b>R11</b>	N/A	N/A	N/A	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.

## 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	
2.1	August 25, 2015	Changed numbered parts under Requirement R6 to line up with the appropriate requirement.	Errata
2.1	November 13, 2015	FERC Letter Order approved errata to COM-001-2.1. Docket RD15-6-000	Errata

## Standard COM-001-2.1 —Communications

### Appendix QC-COM-001-2.1 Provisions specific to the standard COM-001-2.1 applicable in Québec

---

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

#### A. Introduction

1. **Title:** Communications
2. **Number:** COM-001-2.1
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: December 22, 2016
  - 5.2. Adoption of the appendix by the Régie de l'énergie: December 22, 2016
  - 5.3. Effective date of the standard and its appendix in Québec: April 1, 2017

#### 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-001-2.1 —Communications**

**Appendix QC-COM-001-2.1**

**Provisions specific to the standard COM-001-2.1 applicable in Québec**

---

**Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	December 22, 2016	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: December 22, 2016
- 5.2. Adoption of the appendix by the Régie de l'énergie: December 22, 2016
- 5.3. Effective date of the standard and its appendix in Québec: January 1, 2018

#### 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	December 22, 2016	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: December 22, 2016
  - 5.2. Adoption of the appendix by the Régie: December 22, 2016
  - 5.3. Effective date of the standard and its appendix in Québec: January 1, 2018

#### 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	December 22, 2016	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:**

##### Functions

No specific provision

##### Facilities

For the purposes of the standard, Transmission Facilities, Generation Facilities and End-user Facilities are defined as follow:

##### Transmission Facilities:

- Transmission System operated at 44 kV or above ;
- Any lines from the Transmission System operated at 44 kV or above ;
- Transmission facility operated at 44 kV and above, connected to the Main Transmission System (RTP).

##### Generation Facilities:

- Any generation facility with an installed capacity of 50 MVA or greater ;
- Any generation facility connected to the Main Transmission System (RTP).

##### End-user Facilities:

- Addition of a line feeder at 25 kV in a Distribution substation ;
- New connection of an Industrial Customer operated at 44 kV and above, connected to the Main Transmission System (RTP).

5. **Effective Date:**

5.1. Adoption of the standard by the Régie: December 22, 2016

5.2. Adoption of the appendix by the Régie: December 22, 2016

5.3. Effective date of the standard and its appendix in Québec: January 1, 2018

#### B. Requirements and Measures

No specific provision

#### C. Compliance

1. **Compliance Monitoring Process**

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

### Appendix QC-FAC-002-2

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

---

##### 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

#### Revision History

Revision	Adoption Date	Action	Change Tracking
0	December 22, 2016	New appendix	

## Effective Dates

### Generator Owners

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

**Transmission Owners** [transferred from FAC-003-2]

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

4.1.1.1 Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2 Applicable Generator Owners

4.1.2.1 Generator Owners that own generation Facilities defined in 4.3

#### 4.2. Transmission Facilities: Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

4.2.1 Each overhead transmission line operated at 200kV or higher.

4.2.2 Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3 Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

4.2.4 Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

#### 4.3. Generation Facilities: Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

4.3.1 Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line

---

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>2</sup> *Id.*

of sight<sup>3</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

**4.3.1.1** Operated at 200kV or higher; or

**4.3.1.2** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

**4.3.1.3** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

## **5. Background:**

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

---

<sup>3</sup> "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome*?
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system*?
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

Performance-based: Requirements 1 and 2

Competency-based: Requirement 3



Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

- R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,<sup>5</sup>
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,<sup>6</sup>
  3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>7</sup>,
  4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.<sup>8</sup>
- M1.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)
- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>9</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,<sup>10</sup>

---

<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

<sup>5</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>6</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

<sup>7</sup> *Id.*

<sup>8</sup> *Id.*

<sup>9</sup> See footnote 4.

<sup>10</sup> See footnote 5.

2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,<sup>11</sup>
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,<sup>12</sup>
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>13</sup>

**M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence

---

<sup>11</sup> See footnote 6.

<sup>12</sup> *Id.*

<sup>13</sup> *Id.*

may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

- R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)
- R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>14</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)
- R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

---

<sup>14</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>15</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

## **C. Compliance**

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

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

The Regional Entity shall serve as the Compliance Enforcement Authority 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.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

#### **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 applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

---

<sup>15</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance 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 requested and submitted subsequent audit records.

### **1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

### **1.4 Additional Compliance Information**

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an

- IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
  - Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
  - Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
  - Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
  - Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
  - Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line</li> </ul>



						<p>ROW</p> <ul style="list-style-type: none"> <li>Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity’s applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity’s applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity’s applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations	Medium	The responsible entity	The responsible entity failed	The responsible entity failed to	The responsible entity failed to

	Planning		failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

**D. Regional Differences**

None.

**E. Interpretations**

None.

**F. Associated Documents**

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party

such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

#### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

**Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and High for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of

the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

### **Requirement R3:**

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

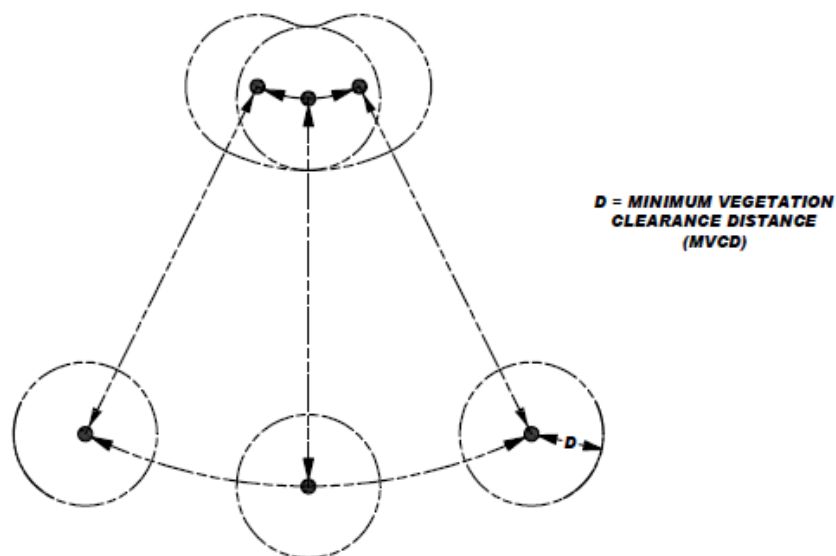
An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an

applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

#### **Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include

communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time



constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

#### **Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles =  $12.5\%$  failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>16</sup>  
 For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>17</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>16</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>17</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>8</sup>	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>**  
**For Direct Current Voltages feet (meters)**

( DC ) Nominal Pole to Ground Voltage (kV)	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters
Over sea level up to 500 ft  (Over sea level up to 152.4 m)	Over 500 ft up to 1000 ft  (Over 152.4 m up to 304.8 m)	Over 1000 ft up to 2000 ft  (Over 304.8 m up to 609.6m)	Over 2000 ft up to 3000 ft  (Over 609.6m up to 914.4m)	Over 3000 ft up to 4000 ft  (Over 914.4m up to 1219.2m)	Over 4000 ft up to 5000 ft  (Over 1219.2m up to 1524m)	Over 5000 ft up to 6000 ft  (Over 1524 m up to 1828.8 m)	Over 6000 ft up to 7000 ft  (Over 1828.8m up to 2133.6m)	Over 7000 ft up to 8000 ft  (Over 2133.6m up to 2438.4m)	Over 8000 ft up to 9000 ft  (Over 2438.4m up to 2743.2m)	Over 9000 ft up to 10000 ft  (Over 2743.2m up to 3048m)	Over 10000 ft up to 11000 ft  (Over 3048m up to 3352.8m)	
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-

service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.



**Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

**Rationale:**

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

**Rationale for Applicability (section 4.2.4):**

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

**Rationale for Applicability (section 4.3):**

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

**Rationale for R1 and R2:**

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

**Rationale for R3:**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**Rationale for R4:**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**Rationale for R5:**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**Rationale for R6:**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable.

Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

**Rationale for R7:**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	
2	March 21, 2013	FERC Order issued approving FAC-003-2	
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from “Medium” to “High.”	
3	May 9, 2012	FAC-003-3 adopted by Board of Trustees	
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	
3	November 22, 2013	Updated the VRF for R2 from “Medium” to “High” per a Final Rule issued by FERC	

3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	
---	---------------	--	--

## Standard FAC-003-3 — Transmission Vegetation Management

### Appendix QC-FAC-003-3 Provisions specific to the standard FAC-003-3 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:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Background:** No specific provision
6. **Effective Date:**
  - 6.1. Adoption of the standard by the Régie: December 22, 2016
  - 6.2. Adoption of the appendix by the Régie: December 22, 2016
  - 6.3. Effective date of the standard and its appendix in Québec:  
R3: July 1, 2017  
R1, R2, R4 to R7 : January 1, 2018

#### B. Requirements and Measures

- R1. No specific provision
- R2. No specific provision
- R3. No specific provision
- R4. No specific provision
- R5. No specific provision
- R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)
  - at least once per calendar year, with no more than 18 calendar months between inspections on the same ROW, except the lines that have been designated for at least 12 months as having a vegetation control cycle of 5 years or more.
  - at least once per 2 calendar years with no more than 30 calendar months between inspections on the same ROW for the lines that have been designated for at least 12 months as having a vegetation control cycle of 5 years or more. The Transmission Owner or Generator Owner can designate a line as having a vegetation control cycle of 5 years or more, but this designation must have an insignificant impact on the risk of MVCD encroachment, considering, for the last 6 years, both the results of the of Vegetation Inspections and vegetation management interventions as well as the relevant geographical, meteorological and vegetation data.

## Standard FAC-003-3 — Transmission Vegetation Management

### Appendix QC-FAC-003-3

#### Provisions specific to the standard FAC-003-3 applicable in Québec

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted the inspections specified in R6. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records (R6).

Each applicable Transmission Owner and applicable Generator Owner that has designated lines as having a vegetation control cycle of 5 years, has a report with, for each line, a designation date and, for the past 6 years, the results of Vegetation Inspections and vegetation management interventions as well as the relevant geographical, meteorological and vegetation data.

## 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 Enforcement Processes

No specific provision

#### 1.4. Additional Compliance Information

The periodic data is submitted to the Régie de l'énergie. The Régie de l'énergie will report the information provided quarterly to NERC.

### Table of Compliance Elements

The violation severity level for requirement 6 is modified.

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R6	Operations Planning	Medium	The responsible entity has an inspection coverage of 95% or more.	The responsible entity has an inspection coverage of more than 90% and less than 95%.	The responsible entity has an inspection coverage of more than 85% and less than 90%.	The responsible entity has an inspection coverage of less than 85%.

The inspection coverage is defined as the ratio of all applicable lines inspected and all applicable lines (measured in units of choice – circuit, pole line, line miles or kilometers, etc.)

If the entity has not designated lines as having a vegetation control cycle of 5 years or more, “all applicable lines inspected” is the lines whose inspections respect Requirement 6, bullet 1.

If the entity has designated lines as having a vegetation control cycle of 5 years or more, the “all applicable lines inspected” is calculated as follows:

## Standard FAC-003-3 — Transmission Vegetation Management

### Appendix QC-FAC-003-3

#### Provisions specific to the standard FAC-003-3 applicable in Québec

---

- Add all lines whose inspections respect Requirement 6 - first bullet (whether designated or not)
- Add all designated lines that do not respect Requirement 6 - first bullet, that respect Requirement 6 - second bullet and have a complete, correct justification.
- Add half of each designated line that does not respect Requirement 6 - first bullet but which has a partial justification (for example, a piece of evidence is missing or a conclusion is flawed).

Consequently, the “all applicable lines inspected” has no contribution from

- designated lines that do not respect Requirement 6, first bullet and whose justification for designation is absent or seriously flawed;
- designated lines that do not respect Requirement 6 – second bullet and
- non-designated lines that do not respect Requirement 6 – first bullet.

#### D. Regional Differences

No specific provision

#### E. Interpretations

No specific provision

#### F. Associated Documents

No specific provision

#### Guidelines and Technical Basis

No specific provision

#### FAC-003-3 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)

No specific provision

#### Notes

No specific provision

#### Rationale

No specific provision

#### Revision History

Revision	Adoption Date	Action	Change Tracking
0	December 22, 2016	New appendix	New





**A. Introduction**

- 1. Title:** Facility Ratings
- 2. Number:** FAC-008-3
- 3. Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
- 4. Applicability**
  - 4.1.** Transmission Owner.
  - 4.2.** Generator Owner.
- 5. Effective Date:** The first day of the first calendar quarter that is twelve months beyond the date approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter twelve months following BOT adoption.

**B. Requirements**

- R1.** Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
  - 1.1.** The documentation shall contain assumptions used to rate the generator and at least one of the following:
    - Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
    - Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.
  - 1.2.** The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
- R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
  - 2.1.** The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:
    - Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.

- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
  - A practice that has been verified by testing, performance history or engineering analysis.
- 2.2.** The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:
- 2.2.1.** Equipment Rating standard(s) used in development of this methodology.
  - 2.2.2.** Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.
  - 2.2.3.** Ambient conditions (for particular or average conditions or as they vary in real-time).
  - 2.2.4.** Operating limitations.<sup>1</sup>
- 2.3.** A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
- 2.4.** The process by which the Rating of equipment that comprises a Facility is determined.
- 2.4.1.** The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.
  - 2.4.2.** The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.
- R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 3.1.** The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:
    - Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
    - One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
    - A practice that has been verified by testing, performance history or engineering analysis.
  - 3.2.** The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:
    - 3.2.1.** Equipment Rating standard(s) used in development of this methodology.

---

<sup>1</sup> Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

- 3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.
      - 3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).
      - 3.2.4. Operating limitations.<sup>2</sup>
    - 3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
    - 3.4. The process by which the Rating of equipment that comprises a Facility is determined.
      - 3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.
      - 3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.
- R4. Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)
- R5. If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)
- R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R7. Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R8. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s),

---

<sup>2</sup> Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 8.1.** As scheduled by the requesting entities:
  - 8.1.1.** Facility Ratings
  - 8.1.2.** Identity of the most limiting equipment of the Facilities
- 8.2.** Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:
  - 8.2.1.** Identity of the existing next most limiting equipment of the Facility
  - 8.2.2.** The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.

**C. Measures**

- M1.** Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.
- M2.** Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.
- M3.** Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.
- M4.** Each Transmission Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement 4. The Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its documentation for determining its Facility Ratings or its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement R4. (Retirement approved by NERC BOT pending applicable regulatory approval.)
- M5.** If the Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology or a Generator Owner's documentation for determining its Facility Ratings, the Transmission Owner or Generator Owner shall have evidence, (such as a copy of a dated electronic or hard copy note, or other comparable evidence from the Transmission Owner or Generator Owner addressed to the commenter that includes the response to the comment,) that it provided a response to that commenting entity in accordance with Requirement R5. (Retirement approved by NERC BOT pending applicable regulatory approval.)
- M6.** Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).
- M7.** Each Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings to its associated Reliability

Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R7.

- M8.** Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.

## **D. Compliance**

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

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

Regional Entity

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

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

#### **1.3. Data Retention**

The Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.

The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.

The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.

The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.

The Generator Owner and Transmission Owner shall each keep evidence for Measure M4, and Measure M5, for three calendar years. (Retirement approved by FERC effective January 21, 2014.)

The Generator Owner shall keep evidence for Measure M7 for three calendar years.

The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.

If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Additional Compliance Information**

None

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	<ul style="list-style-type: none"> <li>The Generator Owner’s Facility Rating documentation did not address Requirement R1, Part 1.1.</li> </ul>	The Generator Owner’s Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2	<p>The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> <li>2.1.</li> <li>2.2.1</li> <li>2.2.2</li> <li>2.2.3</li> <li>2.2.4</li> </ul>	<p>The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> <li>2.1</li> <li>2.2.1</li> <li>2.2.2</li> <li>2.2.3</li> <li>2.2.4</li> </ul>	<p>The Generator Owner’s Facility Rating methodology did not address all the components of Requirement R2, Part 2.4.</p> <p>OR</p> <p>The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> <li>2.1.</li> <li>2.2.1</li> <li>2.2.2</li> <li>2.2.3</li> <li>2.2.4</li> </ul>	<p>The Generator Owner’s Facility Rating methodology failed to recognize a facility’s rating based on the most limiting component rating as required in Requirement R2, Part 2.3</p> <p>OR</p> <p>The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> <li>2.1</li> <li>2.2.1</li> <li>2.2.2</li> <li>2.2.3</li> <li>2.2.4</li> </ul>
R3	<p>The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> <li>3.1</li> <li>3.2.1</li> </ul>	<p>The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> <li>3.1</li> <li>3.2.1</li> </ul>	<p>The Transmission Owner’s Facility Rating methodology did not address either of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> <li>3.4.1</li> <li>3.4.2</li> </ul>	<p>The Transmission Owner’s Facility Rating methodology failed to recognize a Facility’s rating based on the most limiting component rating as required in Requirement R3, Part 3.3</p> <p>OR</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<ul style="list-style-type: none"> <li>• 3.2.2</li> <li>• 3.2.3</li> <li>• 3.2.4</li> </ul>	<ul style="list-style-type: none"> <li>• 3.2.2</li> <li>• 3.2.3</li> <li>• 3.2.4</li> </ul>	<p>OR</p> <p>The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> <li>• 3.1</li> <li>• 3.2.1</li> <li>• 3.2.2</li> <li>• 3.2.3</li> <li>• 3.2.4</li> </ul>	<p>The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> <li>• 3.1</li> <li>• 3.2.1</li> <li>• 3.2.2</li> <li>• 3.2.3</li> <li>• 3.2.4</li> </ul>
<p>R4</p> <p>(Retirement approved by FERC effective January 21, 2014.)</p>	<p>The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 21 calendar days but less than or equal to 31 calendar days after a request.</p>	<p>The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 31 calendar days but less than or equal to 41 calendar days after a request.</p>	<p>The responsible entity made its Facility Rating methodology or Facility Ratings documentation available within more than 41 calendar days but less than or equal to 51 calendar days after a request.</p>	<p>The responsible entity failed to make its Facility Ratings methodology or Facility Ratings documentation available in more than 51 calendar days after a request. (R3)</p>
<p>R5</p> <p>(Retirement approved by FERC effective January 21, 2014.)</p>	<p>The responsible entity provided a response in more than 45 calendar days but less than or equal to 60 calendar days after a request. (R5)</p>	<p>The responsible entity provided a response in more than 60 calendar days but less than or equal to 70 calendar days after a request.</p> <p>OR</p> <p>The responsible entity provided a response within 45 calendar days, and the response indicated that a change will not be made to the Facility Ratings methodology or Facility Ratings documentation but did not indicate why no change will be made. (R5)</p>	<p>The responsible entity provided a response in more than 70 calendar days but less than or equal to 80 calendar days after a request.</p> <p>OR</p> <p>The responsible entity provided a response within 45 calendar days, but the response did not indicate whether a change will be made to the Facility Ratings methodology or Facility Ratings documentation. (R5)</p>	<p>The responsible entity failed to provide a response as required in more than 80 calendar days after the comments were received. (R5)</p>



R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 15% of its solely owned and jointly owned Facilities. (R6)
R7	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days.  OR The Generator Owner failed to provide its Facility Ratings to the requesting entities.
R8	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1)  OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1)  OR The responsible entity provided the required Rating information to the requesting entity, but the information	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1)  OR The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1)  OR	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1)  OR The responsible entity provided less than 90%, but not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1)  OR	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1)  OR The responsible entity provided less than 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1)  OR The responsible entity provided the required Rating information to the requesting entity, but did so more

**Standard FAC-008-3 — Facility Ratings**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>was provided up to and including 15 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2)</p>	<p>The responsible entity provided the required Rating information to the requesting entity, but did so more than 15 calendar days but less than or equal to 25 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)</p>	<p>The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal to 35 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2)</p>	<p>than 35 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1)</p>

**E. Regional Variances**

None.

**F. Associated Documents**

**Version History**

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from “Lower” to “Medium”	
3	February 7, 2013	R4 and R5 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.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	



## Standard FAC-008-3 — Facility Ratings

### Appendix QC-FAC-008-3 Provisions specific to the standard FAC-008-3 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 Ratings
2. **Number:** FAC-008-3
3. **Purpose:** No specific provision
4. **Applicability:**
  - Functions**  
No specific provision
  - Facilities**  
This standard only applies to the facilities of the Main Transmission System (RTP)
5. **Effective Date:**
  - 5.1. Adoption of the standard by the Régie de l'énergie: December 22, 2016
  - 5.2. Adoption of the appendix by the Régie de l'énergie: December 22, 2016
  - 5.3. Effective date of the standard and its appendix in Québec: July 1, 2017

#### 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. 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

## Standard FAC-008-3 — Facility Ratings

### Appendix QC-FAC-008-3 Provisions specific to the standard FAC-008-3 applicable in Québec

---

#### **E. Regional Differences**

No specific provision

#### **F. Associated Documents**

No specific provision

#### **Revision History**

<b>Revision</b>	<b>Adoption Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	December 22, 2016	New appendix	New

## **A. Introduction**

- 1. Title: Data for Power System Modeling and Analysis**
- 2. Number: MOD-032-1**
- 3. Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

- 4. Applicability:**

- 4.1. Functional Entities:**

- 4.1.1** Balancing Authority
- 4.1.2** Generator Owner
- 4.1.3** Load Serving Entity
- 4.1.4** Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)

This proposed standard combines “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority,” and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

- 4.1.5** Resource Planner
- 4.1.6** Transmission Owner
- 4.1.7** Transmission Planner
- 4.1.8** Transmission Service Provider

- 5. Effective Date:**

MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 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, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority

is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### 6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

[http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012\\_Dec\\_PC%20Agenda.pdf](http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf)).

## B. Requirements and Measures

**R1.** Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

**1.1.** The data listed in Attachment 1.

**1.2.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

**1.2.1.** Data format;

**1.2.2.** Level of detail to which equipment shall be modeled;

**1.2.3.** Case types or scenarios to be modeled; and

**1.2.4.** A schedule for submission of data at least once every 13 calendar months.



- 1.3.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.
- M1.** Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.
- R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M2.** Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.
- R3.** Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
  - 3.1.** Provide either updated data or an explanation with a technical basis for maintaining the current data;
  - 3.2.** Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.
- M3.** Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

- R4.** Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M4.** Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

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

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

#### 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>	<b>Long-term Planning</b>	<b>Lower</b>	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1;  OR  The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified

						in Requirement R1.
<b>R2</b>	<b>Long-term Planning</b>	<b>Medium</b>	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided</p>	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service</p>	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service</p>	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s);</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission</p>

			<p>steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified</p>	<p>Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning</p>	<p>Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning</p>	<p>Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p>
--	--	--	---	---	---	---

			by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
<b>R3</b>	<b>Long-term Planning</b>	<b>Lower</b>	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service

			<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>	<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>	<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>	<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>
--	--	--	---	--	--	--



<b>R4</b>	<b>Long-term Planning</b>	<b>Medium</b>	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.
-----------	---------------------------	---------------	---	--	--	--

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**MOD-032-01 – ATTACHMENT 1:**

**Data Reporting Requirements**

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity<sup>1</sup> responsible for reporting the respective data in the table is identified by brackets “[functional entity]” adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

<b>steady-state</b> <i>(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)</i>	<b>dynamics</b> <i>(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)</i>	<b>short circuit</b>
<ol style="list-style-type: none"> <li>1. Each bus [TO]               <ol style="list-style-type: none"> <li>a. nominal voltage</li> <li>b. area, zone and owner</li> </ol> </li> <li>2. Aggregate Demand<sup>2</sup> [LSE]               <ol style="list-style-type: none"> <li>a. real and reactive power*</li> <li>b. in-service status*</li> </ol> </li> <li>3. Generating Units<sup>3</sup> [GO, RP (for future planned resources only)]               <ol style="list-style-type: none"> <li>a. real power capabilities - gross maximum and minimum values</li> <li>b. reactive power capabilities - maximum and minimum values at</li> </ol> </li> </ol>	<ol style="list-style-type: none"> <li>1. Generator [GO, RP (for future planned resources only)]</li> <li>2. Excitation System [GO, RP(for future planned resources only)]</li> <li>3. Governor [GO, RP(for future planned resources only)]</li> <li>4. Power System Stabilizer [GO, RP(for future planned resources only)]</li> <li>5. Demand [LSE]</li> </ol>	<ol style="list-style-type: none"> <li>1. Provide for all applicable elements in column “steady-state” [GO, RP, TO]               <ol style="list-style-type: none"> <li>a. Positive Sequence Data</li> <li>b. Negative Sequence Data</li> <li>c. Zero Sequence Data</li> </ol> </li> <li>2. Mutual Line Impedance Data [TO]</li> <li>3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling</li> </ol>

<sup>1</sup> For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

<sup>2</sup> For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

<sup>3</sup> Including synchronous condensers and pumped storage.

<p style="text-align: center;"><b>steady-state</b></p> <p style="text-align: center;"><i>(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)</i></p>	<p style="text-align: center;"><b>dynamics</b></p> <p style="text-align: center;"><i>(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)</i></p>	<p style="text-align: center;"><b>short circuit</b></p>
<ul style="list-style-type: none"> <li>c. real power capabilities in 3a above</li> <li>c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above).</li> <li>d. regulated bus* and voltage set point* (as typically provided by the TOP)</li> <li>e. machine MVA base</li> <li>f. generator step up transformer data (provide same data as that required for transformer under item 6, below)</li> <li>g. generator type (hydro, wind, fossil, solar, nuclear, etc)</li> <li>h. in-service status*</li> <li>4. AC Transmission Line or Circuit [TO] <ul style="list-style-type: none"> <li>a. impedance parameters (positive sequence)</li> <li>b. susceptance (line charging)</li> <li>c. ratings (normal and emergency)*</li> <li>d. in-service status*</li> </ul> </li> <li>5. DC Transmission systems [TO]</li> <li>6. Transformer (voltage and phase-shifting) [TO] <ul style="list-style-type: none"> <li>a. nominal voltages of windings</li> <li>b. impedance(s)</li> <li>c. tap ratios (voltage or phase angle)*</li> <li>d. minimum and maximum tap position limits</li> <li>e. number of tap positions (for both the ULTC and NLTC)</li> <li>f. regulated bus (for voltage regulating transformers)*</li> <li>g. ratings (normal and emergency)*</li> <li>h. in-service status*</li> </ul> </li> <li>7. Reactive compensation (shunt capacitors and reactors) [TO] <ul style="list-style-type: none"> <li>a. admittances (MVars) of each capacitor and reactor</li> <li>b. regulated voltage band limits* (if mode of operation not fixed)</li> <li>c. mode of operation (fixed, discrete, continuous, etc.)</li> <li>d. regulated bus* (if mode of operation not fixed)</li> <li>e. in-service status*</li> </ul> </li> <li>8. Static Var Systems [TO]</li> </ul>	<ul style="list-style-type: none"> <li>6. Wind Turbine Data [GO]</li> <li>7. Photovoltaic systems [GO]</li> <li>8. Static Var Systems and FACTS [GO, TO, LSE]</li> <li>9. DC system models [TO]</li> <li>10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]</li> </ul>	<p style="text-align: center;">purposes. [BA, GO, LSE, TO, TSP]</p>

<p style="text-align: center;"><b>steady-state</b></p> <p style="text-align: center;"><i>(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)</i></p>	<p style="text-align: center;"><b>dynamics</b></p> <p style="text-align: center;"><i>(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)</i></p>	<p style="text-align: center;"><b>short circuit</b></p>
<ul style="list-style-type: none"> <li>a. reactive limits</li> <li>b. voltage set point*</li> <li>c. fixed/switched shunt, if applicable</li> <li>d. in-service status*</li> </ul> <p>9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]</p>		

### Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

## Application Guidelines

---

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

### **Rationale:**

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

### **Rationale for R1:**

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, [here](#):

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

- 1) reduce the quantity of MOD standards;
- 2) add short circuit data as a requirement to the MOD standards; and
- 3) supply data and models:

## Application Guidelines

---

- a. add requirement identifying who provides and who receives data;
  - b. identify acceptability;
  - c. standard format;
  - d. how to deal with new technologies (user written models if no standard model exists); and
  - e. shareability.
- 4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
  - 5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
  - 6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

### **Rationale for R2:**

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that “the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.”

### **Rationale for R3:**

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

## Application Guidelines

---

### Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the “ERO or its designee” supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, “industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*” (Emphasis added).

This requirement is about the Planning Coordinator’s obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the “designee” for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection-wide cases.

### Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving	See Implementation Plan



## Application Guidelines

---

		MOD-032-1.	posted on the Reliability Standards web page for details on enforcement dates for Requirements.
--	--	------------	---



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:** Data for Power System Modeling and Analysis
- 2. Number:** MOD-032-1
- 3. Purpose:** No specific provision
- 4. Applicability:**
  - 4.1. Functional entities**  
No specific provision
- 5. Effective Date:**
  - 5.1.** Adoption of the standard by the Régie de l'énergie: December 22, 2016
  - 5.2.** Adoption of the appendix by the Régie de l'énergie: December 22, 2016
  - 5.3.** Effective date of the standard and its appendix in Québec:  
R1: April 1, 2017  
R2, R3, R4: January 1, 2018
- 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**  
Compliance Audit  
Self-Certification  
Spot Check  
Compliance Investigation  
Self-Reporting  
Periodic Data Submittal  
Exception Reporting

Investigation following a complaint

**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

**MOD-032-1 – Attachment 1**

No specific provision

**Guidelines and Technical Basis**

No specific provision

**Revision History**

Version	Date	Action	Change Tracking
0	December 22, 2016	New appendix	New

## **A. Introduction**

- 1. Title: Steady-State and Dynamic System Model Validation**
- 2. Number: MOD-033-1**
- 3. Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.
- 4. Applicability:**
  - 4.1. Functional Entities:**
    - 4.1.1 Planning Authority and Planning Coordinator** (hereafter referred to as “Planning Coordinator”)

This proposed standard combines “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority,” and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.
    - 4.1.2 Reliability Coordinator**
    - 4.1.3 Transmission Operator**
- 5. Effective Date:**

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 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 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- 6. Background:**

MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: [http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012\\_Dec\\_PC%20Agenda.pdf](http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf)).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

### B. Requirements and Measures

- R1.** Each Planning Coordinator shall implement a documented data validation process that includes the following attributes: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
  - 1.1.** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation;
  - 1.2.** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;
  - 1.3.** Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

**1.4.** Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

- M1.** Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.
- R2.** Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation. [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
- M2.** Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

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

Refer to Section 3.0 of Appendix 4C of the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

#### 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>	<b>Long-term Planning</b>	<b>Medium</b>	<p>The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as</p>	<p>The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months;</p> <p>OR</p>	<p>The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months;</p> <p>OR</p>	<p>The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar</p>

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
<b>R2</b>	<b>Long-term Planning</b>	<b>Lower</b>	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.
--	--	--	--	--	--	---

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Application Guidelines

---

### Guidelines and Technical Basis

#### Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator’s planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

## Application Guidelines

---

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a “month 23” dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event’s occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event’s occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator’s system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator’s system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the

## Application Guidelines

---

modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

### **Rationale:**

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

### **Rationale for R1:**

In FERC Order No. 693, paragraph 1210, the Commission directed inclusion of "a requirement that the models be validated against actual system responses." Furthermore, the Commission directs in paragraph 1211, "that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

- A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and
- B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

## Application Guidelines

---

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of “how” it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

### Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

### Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.
1	May 1, 2014	FERC Order issued approving MOD-033-1.	





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:** Steady-State and Dynamic System Model Validation
- 2. Number:** MOD-033-1
- 3. Purpose:** No specific provision
- 4. Applicability:**
  - 4.1. Functional entities**  
No specific provision
- 5. Effective Date:**
  - 5.1.** Adoption of the standard by the Régie de l'énergie: December 22, 2016
  - 5.2.** Adoption of the appendix by the Régie de l'énergie: December 22, 2016
  - 5.3.** Effective date of the standard and its appendix in Québec: January 1, 2019
- 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**  
Compliance Audit  
Self-Certification  
Spot Check  
Compliance Investigation  
Self-Reporting  
Periodic Data Submittal  
Exception Reporting  
Investigation following a complaint
  - 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

**Guidelines and Technical Basis**

No specific provision

**Revision History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	December 22, 2016	New Appendix	New

## A. Introduction

1. **Title:** Operations Personnel Training
2. **Number:** PER-005-2
3. **Purpose:** To ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Reliability Coordinator
    - 4.1.2 Balancing Authority
    - 4.1.3 Transmission Operator
    - 4.1.4 Transmission Owner that has:
      - 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time.
    - 4.1.5 Generator Operator that has:
      - 4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.
5. **Effective Date:**
  - 5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements and Measures

- R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.
    - 1.1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.
  - 1.2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.
  - 1.3.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.
  - 1.4.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.
- M1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its System Operators, as specified in Requirement R1.
- M1.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.
  - M1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.
  - M1.3** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

- M1.4** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.
- R2.** Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 2.1.** Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.
- 2.1.1.** Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.
- 2.2.** Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.
- 2.3.** Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.
- 2.4.** Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.
- M2.** Each Transmission Owner shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its applicable personnel, as specified in Requirement R2.
- M2.1** Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.
- M2.2** Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.
- M2.3** Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.
- M2.4** Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

- R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 3.1.** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.
- M3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.
- M3.1** Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.
- R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.
- M4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed

training that includes the use of simulation technology, as specified in Requirement R4.

**M4.1** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

**M5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

**M5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

**R6.** Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

**M6.** Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

- M6.1** Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

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

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

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information

None



**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	<p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)</p>	<p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)</p>	<p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)</p>
R2	Long-term Planning	Medium	None	<p>The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-</p>	<p>The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)</p>	<p>The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.)</p> <p>OR</p>

**PER-005-2 — Operations Personnel Training**

				<p>related task list each calendar year. (2.1.1.)</p> <p>OR</p> <p>The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4)</p> <p>OR</p> <p>The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)</p>	<p>OR</p> <p>The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)</p>	<p>The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)</p>
<b>R3</b>	<b>Long-term Planning</b>	<b>High</b>	<b>None</b>	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)</p>	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement</p>	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)</p>

**PER-005-2 — Operations Personnel Training**

					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
<b>R4</b>	<b>Long-term Planning</b>	<b>Medium</b>	<b>None</b>	<b>None</b>	<b>None</b>	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)</p>

**PER-005-2 — Operations Personnel Training**

<b>R5</b>	<b>Long-term Planning</b>	<b>Medium</b>	<b>None</b>	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5)  OR  The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
<b>R6</b>	<b>Long-term Planning</b>	<b>Medium</b>	<b>None</b>	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6)  OR  The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

### Guidelines and Technical Basis

#### Requirement R1 and R2:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

#### Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

*Or*

How accurately must the task be performed?

*Or*

With what quality must it be performed?

*Or*

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

## Application Guidelines

---

### **Reference #2: Systematic Approach to Training References:**

The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

- (1) DOE-HDBK-1078-94, A Systematic Approach to Training

<http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf>

- (2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

[http://www.catagle.com/112-1/download\\_php-spec\\_DOE-HDBK-1074-95\\_003254\\_1.htm](http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm)

- (3) ADDIE – 1975, Florida State University

[http://www.nwlink.com/~donclark/history\\_isd/addie.html](http://www.nwlink.com/~donclark/history_isd/addie.html)

- (4) DOE Standard - Table-Top Needs Analysis

DOE-HDBK-1103-96

<http://energy.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf>

### **Reference #3: Recognized Operator Training Topics**

See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.

[http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC\\_Program\\_Manual\\_February\\_2012\\_Final.pdf](http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf)

### **Reference #4: Definitions of Simulation and Simulators**

**Georgia Institute of Technology – Modeling & Simulation for Systems Engineering**

[http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE\\_ID=840](http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840)

**University of Central Florida – Institute for Simulation & Training**

Just what is "simulation" anyway (or, Simulation 101)?

And what about "modeling"?

But what does IST do with simulations?

<http://www.ist.ucf.edu/overview.htm>

## Application Guidelines

---

### **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 System Operator:**

The definition of the existing NERC Glossary Term “System Operator” has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term “System Operator” contains another NERC Glossary term “Control Center”, which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of “System Operator” do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

### **Rationale for Operations Support Personnel:**

The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

### **Rationale for TO:**

Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *“exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap.”* See FERC Order 693 at P 1343 and 1347.

### **Rationale for GOP:**

Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that *“although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions,*



## Application Guidelines

---

*particularly in an emergency situation in which instructions may be succinct and require immediate action.”* Order No. 742 further clarified that the directive “*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2.*” Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

### **Rationale for changes to R2:**

Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

### **Rationale for R3:**

This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

### **Rationale for changes to R4:**

The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations within 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement R4.1 covers the FERC directive for the creation of an implementation plan for simulation technology.

### **Rationale for R5:**

This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

## Application Guidelines

---

### Rationale for R6:

This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

### Version History

Version	Date	Action	Change Tracking
1	2/10/2009	Adopted by the NERC Board of Trustees	
1	11/18/2010	FERC Approved	
1	8/26/2013	Updated VSLs based on June 24, 2013 approval.	
2	2/6/2014	Adopted by the NERC Board of Trustees	
2	6/19/2014	FERC Approved	

## Standard PER-005-2 —Operations Personnel Training

### Appendix QC-PER-005-2

#### Provisions specific to the standard PER-005-2 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:** Operations Personnel Training
2. **Number:** PER-005-2
3. **Purpose:** No specific provision
4. **Applicability:**

##### **Functional Entities**

No specific provision

##### **Facilities**

In the application of this standard, all references to the terms "Bulk Electric System" or "BES" shall be replaced by the terms "Main Transmission System" or "RTP" respectively.

5. **Effective Date:**
  - 5.1. Adoption of the standard by the Régie de l'énergie: December 22, 2016
  - 5.2. Adoption of the appendix by the Régie de l'énergie: December 22, 2016
  - 5.3. Effective date of the standard and its appendix in Québec: July 1, 2018

#### 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

**Standard PER-005-2 —Operations Personnel Training**

**Appendix QC-PER-005-2**

**Provisions specific to the standard PER-005-2 applicable in Québec**

---

**Table of Compliance Elements**

No specific provision

**D. Regional Variances**

No specific provision

**E. Interpretations**

No specific provision

**F. Associated Documents**

No specific provision

**Guidelines and Technical Basis**

No specific provision

**Revision History**

Revision	Adoption Date	Action	Change Tracking
0	December 22, 2016	New appendix	New