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.

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	≤ 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

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

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

1. 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

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:

Device	Accuracy
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 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.

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: October 30, 2013
   - **5.2.** Adoption of the appendix by the Régie de l'énergie: October 30, 2013
   - **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2016

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

F. Associated Documents

No specific provision

Appendix 1

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	October 30, 2013	New appendix	New
1	Month xx, 201x	Requirement 2 retired	

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.

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.

R8. Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

8.1. Its Balancing Authority.

8.2. Its Transmission Operator.

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

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

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

C. Measures

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

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

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

- physical assets, or

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

M3. Each Transmission Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority, Distribution Provider, and Generator Operator within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously or synchronously connected, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communication. (R3.)

M4. Each Transmission Operator shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously and synchronously connected, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R4.)

M5. Each Balancing Authority shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator and Generator Operator that operates Facilities within its Balancing Authority Area, each Distribution Provider within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R5.)

M6. Each Balancing Authority shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator that operates Facilities within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R6.)

M7. Each Distribution Provider shall have and provide upon request evidence that it has Interpersonal Communication capability with its Transmission Operator and its Balancing Authority, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R7.)

M8. Each Generator Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Balancing Authority and its Transmission Operator, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R8.)

M9. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it tested, at least once each calendar month, its Alternative Interpersonal Communication capability designated in Requirements R2, R4, or R6. If the test was unsuccessful, the entity shall have and provide upon request evidence that it initiated action to repair or designated a replacement Alternative Interpersonal Communication capability within 2 hours. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R9.)

M10. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it notified entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasted 30 minutes or longer. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R10.)

M11. Each Distribution Provider and Generator Operator that detected a failure of its Interpersonal Communication capability shall have and provide upon request evidence that it consulted with each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine mutually agreeable action to restore the Interpersonal Communication capability. Evidence could include, but is not limited to: dated operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R11.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

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

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

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

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

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.

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.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R10	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.
R11	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

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard COM-001-2.1 — Communications

United States

Standard	Requirement	Enforcement Date	Inactive Date
COM-001-2.1	All	11/13/2015	

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

B. Requirements

No specific provision

C. Requirements

No specific provision

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

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

   1.2. Compliance Monitoring and Enforcement Processes

   No specific provision

   1.3. Data Retention

   No specific provision

   1.4. Additional Compliance Information

   No specific provision

2. **Violation Severity Levels**

   No specific provision

E. Regional Differences

No specific provision

F. Associated Documents

No specific provision

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

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Xx month 201x	New appendix	New

A. Introduction

1. **Title:** Operating Personnel Communications Protocols

2. **Number:** COM-002-4

3. **Purpose:** To improve communications for the issuance of Operating Instructions with predefined communications protocols to reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of the Bulk Electric System (BES).

4. **Applicability:**

    4.1. Functional Entities

    4.1.1 Balancing Authority

    4.1.2 Distribution Provider

    4.1.3 Reliability Coordinator

    4.1.4 Transmission Operator

    4.1.5 Generator Operator

5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements

R1. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*

1.1. Require its operating personnel that issue and receive an oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations.

1.2. Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions:

- Confirm the receiver's response if the repeated information is correct.
- Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver.

- Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.

1.3. Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions:

- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct.
- Request that the issuer reissue the Operating Instruction.

1.4. Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.

1.5. Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification.

1.6. Specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction.

R2. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*

R3. Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*

- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
- Request that the issuer reissue the Operating Instruction.

R4. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: *[Violation Risk Factor: Medium][Time Horizon: Operations Planning]*

4.1. Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols.

4.2. Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.

R5. Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: *[Violation Risk Factor: High][Time Horizon: Real-time Operations]*

- Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6).
- Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or
- Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.

R6. Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: *[Violation Risk Factor: High][Time Horizon: Real-time Operations]*

- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
- Request that the issuer reissue the Operating Instruction.

R7. Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. *[Violation Risk Factor: High][Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide its documented communications protocols developed for Requirement R1.

M2. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide its initial training records related to its documented communications protocols developed for Requirement R1 such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R2.

M3. Each Distribution Provider and Generator Operator shall provide its initial training records for its operating personnel such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R3.

M4. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide evidence of its assessments, including spreadsheets, logs or other evidence of feedback, findings of effectiveness and any changes made to its documented communications protocols developed for Requirement R1 in fulfillment of

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

M5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority that issued an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence that the issuer either: 1) confirmed that the response from the recipient of the Operating Instruction was correct; 2) reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver; or 3) took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. Such evidence could include, but is not limited to, dated and time-stamped voice recordings, or dated and time-stamped transcripts of voice recordings, or dated operator logs in fulfillment of Requirement R5.

M6. Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that was the recipient of an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence to show that the recipient either repeated, not necessarily verbatim, the Operating Instruction and received confirmation from the issuer that the response was correct, or requested that the issuer reissue the Operating Instruction in fulfillment of Requirement R6. Such evidence may include, but is not limited to, dated and time-stamped voice recordings (if the entity has such recordings), dated operator logs, an attestation from the issuer of the Operating Instruction, memos or transcripts.

M7. Each Balancing Authority, Reliability Coordinator and Transmission Operator that issued a written or oral single or multiple-party burst Operating Instruction during an Emergency shall provide evidence that the Operating Instruction was received by at least one receiver. Such evidence may include, but is not limited to, dated and time-stamped voice recordings (if the entity has such recordings), dated operator logs, electronic records, memos or transcripts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

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

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

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

Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Additional Compliance Information

None

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	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 OR 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.	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.	The responsible entity did not include Requirement R1, Part 1.4 in its documented communication protocols.	The responsible entity did not include Requirement R1, Part 1.2 in its documented communications protocols OR The responsible entity did not include Requirement R1, Part 1.3 in its documented communications protocols OR The responsible entity did not develop any documented communications protocols as required in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	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.
R3	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.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	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 AND 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	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 OR 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 OR The responsible entity assessed the effectiveness of its documented communications protocols	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 OR 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.	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 AND 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.

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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Real-time Operations	High	N/A	The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions: • Confirmed the receiver's response if the repeated information was correct (in accordance with Requirement R6). • Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver. • Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver.	N/A	The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions: • Confirmed the receiver's response if the repeated information was correct (in accordance with Requirement R6). • Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver. • Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. AND Instability, uncontrolled separation, or cascading failures occurred as a result.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	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.
R7	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

Version	Date	Action	Change Tracking
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	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard COM-002-4 — Operating Personnel Communications Protocols

United States

Standard	Requirement	Enforcement Date	Inactive Date
COM-002-4	All	07/01/2016	

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

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

A. Introduction

1. **Title:** **Operating Personnel Communications Protocols**
2. **Number:** COM-002-4
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision

   Functional entities

   No specific provision

   Facilities

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

5. **Effective Date:**

   5.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x

   5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x

   5.3. Effective date of the standard and its appendix in Québec: Month xx 201x

B. Requirements

No specific provision

C. Requirements

No specific provision

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

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

   1.2. Data Retention

   No specific provision

   Compliance Monitoring and Assessment Processes

   No specific provision

   1.3. Additional Compliance Information

   No specific provision

E. Regional Variances

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Xx month 201x	New appendix	New

A. Introduction

1. **Title:** **Facility Interconnection Studies**

2. **Number:** FAC-002-2

3. **Purpose:** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator

   4.1.2 Transmission Planner

   4.1.3 Transmission Owner

   4.1.4 Distribution Provider

   4.1.5 Generator Owner

   4.1.6 Applicable Generator Owner

   4.1.6.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

   4.1.7 Load-Serving Entity

5. **Effective Date:** The first day of the first calendar quarter that is one year after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is one year after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities. The following shall be studied: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s);

1.2. Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements;

1.3. Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and

1.4. Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

M1. Each Transmission Planner or each Planning Coordinator shall have evidence (such as study reports, including documentation of reliability issues) that it met all requirements in Requirement R1.

R2. Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R2.

R3. Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R3.

R4. Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Transmission Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R4.

R5. Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each applicable Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R5.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Planning Coordinator, Transmission Planner, Transmission Owner, Distribution Provider, Generator Owner, applicable Generator Owner, and Load-Serving Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	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.
R2	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.
R3	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.

R4	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.
R5	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

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.	

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

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

A. Introduction

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

B. Requirements and Measures

No specific provision

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

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

   1.2. Evidence Retention

   No specific provision

   1.3. Compliance Monitoring and Assessment Processes

   No specific provision

   1.4. Additional Compliance Information

   No specific provision

Table of Compliance Elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretation

No specific provision

F. Associated Documents

No specific provision

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

Revision History

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

A. Introduction

1. Title: **System Operating Limits Methodology for the Planning Horizon**

2. Number: FAC-010-2.1

3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Planning Authority

5. Effective Date: April 19, 2010

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

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

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6	The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was

Requirement	Lower	Moderate	High	Severe
		The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5 (Retirement	The Planning Authority received documented technical comments on its SOL Methodology and	The Planning Authority received documented technical comments on its SOL Methodology and	The Planning Authority received documented technical comments on its SOL Methodology and	The Planning Authority received documented technical comments on its SOL Methodology and

Requirement	Lower	Moderate	High	Severe
approved by FERC effective January 21, 2014.)	provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2.1	November 5, 2009	Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	February 7, 2013	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.	

2.1	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2.1	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	

Appendix QC-FAC-010-2.1
Provisions specific to the standard FAC-010-2.1 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:** **System Operating Limits Methodology for the Planning Horizon**
2. **Number:** FAC-010-2.1
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: May 4, 2015

   5.2. Adoption of the appendix by the Régie de l'énergie: May 4, 2015

   5.3. Effective date of the standard and its appendix in Québec: January 1, 2016

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 Time Frame

   No specific provision

   1.3. Data Retention

   No specific provision

   1.4. Additional Compliance Information

   No specific provision

2. **Levels of Non-Compliance for Western Interconnection**

   No specific provision

3. Violation Severity Levels

No specific provision

E. Regional Differences

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	May 4, 2015	New appendix	New
1	Month xx, 201x	Requirement 5 retired	

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**
2. **Number:** FAC-011-2
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   4.1. Reliability Coordinator
5. **Effective Date:** April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

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

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology (Retirement approved by FERC effective January 21, 2014.)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.
R3.6	N/A	N/A	N/A	N/A
R4	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3

Requirement	Lower	Moderate	High	Severe
	OR For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to30 days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of the required entities more than30 calendar days after the effectiveness of the change.
R5 (Retirement approved by FERC effective January 21, 2014.)	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	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.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	

Appendix QC-FAC-011-2
Provisions specific to the standard FAC-011-2 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:** **System Operating Limits Methodology for the Operations Horizon**
2. **Number:** FAC-011-2
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: May 4, 2015

   5.2. Adoption of the appendix by the Régie de l'énergie: May 4, 2015

   5.3. Effective date of the standard and its appendix in Québec: January 1, 2016

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 Time Frame

   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

3. Violation Severity Levels

All occurrences of the term “BES” are replaced by “RTP”.

E. Regional Differences

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	May 4, 2015	New appendix	New
1	Month xx, 201x	Requirement 5 retired	

A. Introduction

1. **Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

   In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

   In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M4. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

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

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3 (Retirement approved by FERC effective January 21, 2013.)	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.

R4	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.

R5	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF’s for Requirements R1. and R4. be changed from “Lower” to “Medium.” FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 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.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard FAC-013-2 — Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

United States

Standard	Requirement	Enforcement Date	Inactive Date
FAC-013-2	R1.	04/01/2013	
FAC-013-2	R2.	04/01/2013	
FAC-013-2	R3.	04/01/2013	01/21/2014
FAC-013-2	R4.	04/01/2013	
FAC-013-2	R5.	04/01/2013	
FAC-013-2	R6.	04/01/2013	

Appendix QC-FAC-013-2
Provisions specific to the standard FAC-013-2 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: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon**

2. **Number:** FAC-013-2

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: Month xx 201x

   5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x

   5.3. Effective date of the standard and its appendix in Québec: The latter of the first day of the calendar quarter after applicable regulatory approval or the first day of the first calendar quarter after MOD-001-1 and MOD-029-1 are effective.

B. Requirements

No specific provision

C. Measures

No specific provision

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

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

   1.2. Data Retention

   No specific provision

   1.3. Compliance Monitoring and Assessment Processes

   No specific provision

Appendix QC-FAC-013-2
Provisions specific to the standard FAC-013-2 applicable in Québec

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Variances

No specific provision

F. Associated Documents

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Month xx, 201x	New appendix Requirement 3 retired	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	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.) OR 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) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR 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)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.) OR 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)
R2	Long-term Planning	Medium	None	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR

				related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
R3	**Long-term Planning**	**High**	**None**	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)	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) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement	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)

					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)	
R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	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) OR 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)

R5	**Long-term Planning**	**Medium**	**None**	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)
R6	**Long-term Planning**	**Medium**	**None**	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.

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

(3) ADDIE – 1975, Florida State University

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

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

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

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,* *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.

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	

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: Month xx, 201x

   5.2. Adoption of the appendix by the Régie de l'énergie: Month xx, 201x

   5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

B. Requirements and Measures

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

Guidelines and Technical Basis

No specific provision

Revision History

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

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

    b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

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

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

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

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	

Appendix QC-TPL-001-4
Provisions specific to the standard TPL-001-4 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:** **Transmission System Planning Performance Requirements**
2. **Number:** TPL-001-4
3. **Purpose:** No specific provision
4. **Applicability:**

4.1. Functional entities

No specific provision

Facilities

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

5. **Effective Date:**

5.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x

5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x

5.3. Effective date of the standard and its appendix in Québec: The first day of the first calendar quarter after applicable regulatory approval. However, before January 1, 2022, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) that would not otherwise be permitted by the requirements of TPL-001-4 :

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

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 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. Compliance Monitoring and Enforcement Processes:

No specific provision

1.4. Data Retention

No specific provision

1.5. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Variances

No specific provision

Table 1

This table only applies to the facilities of the Bulk Power System (BPS) for:

- Categories
- Contingencies
- System Limits or Impacts

Attachment 1

No specific provision

Revision History

Version	Date	Action	Change Tracking
0	xx/xx/201x		New