NORMES INT ET VAR

(VERSION ANGLAISE)

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3.1
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**
   4.1. Balancing Authority
   4.2. Purchasing-Selling Entity
5. **Effective Date:**
   See implementation plan.
6. **Background:**
   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.
   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support

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[1] Please refer to the timing tables of INT-006-4.

congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority 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 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	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
  - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services	Attaining BA	Native BA

FERC OATT Schedules 3–6 and other ancillary services as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

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 R1:

This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Rationale R2:

This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	February 6, 2014	Adopted by the NERC Board of Trustees	Revised

3	June 30, 2014	FERC letter order issued approving INT-004-3	
3.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
3.1	November 26, 2014	FERC letter order approving errata changes.	

Appendix QC-INT-004-3.1
Provisions specific to Standard INT-004-3.1 applicable in Québec

This appendix establishes specific provisions for 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:** **Dynamic Transfers**
2. **Number:** INT-004-3.1
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: February 22nd, 2018
   - **5.2.** Adoption of the appendix by the Régie de l’énergie: February 22nd, 2018
   - **5.3.** Effective date of the standard and its appendix in Québec: April 1st, 2018

B. Requirements and measures

R1. No specific provision

R2. No specific provision

R3 Each Balancing Authority shall only implement or operate a Pseudo-Tie after it has requested that the Pseudo-Tie be identified in the Register of Entities Subject to Reliability Standards in Québec. If the Pseudo-Tie is not entirely in the Québec jurisdiction, it must also be included in the NAESB Electric Industry Registry in order to support congestion management procedures. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

M3.The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the Register of Entities Subject to Reliability Standard in Québec. If the Pseudo-Tie is not entirely in the Québec jurisdiction it must also be included in the NAESB Electric Industry Registry in order to support congestion management procedures. [Violation Risk Factor: Lower] [Time Horizon:Operations Planning]

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not identified in the Register of Entities Subject to Reliability Standards in Québec or, if applicable, was not included in the NAESB Electric Industry Registry.

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

Guidelines and Technical Basis

No specific provision

Rationale

No specific provision

Version History

Revision	Date	Action	Change Tracking
0	February 22nd, 2018	New appendix	New

A. Introduction

1. **Title: Implementation of Interchange**
2. **Number: INT-009-2.1**
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.
4. **Applicability:**

   4.1. Balancing Authority.

5. **Effective Date:**

   See implementation plan.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite

Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority 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

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).
R3	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

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D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Rationale:

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

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards	Errata

		Committee approved errata changes on August 20, 2014.	
2.1	November 26, 2014	FERC letter order approving errata changes.	

Appendix QC-INT-009-2.1
Provisions specific to Standard INT-009-2.1 applicable in Québec

This appendix establishes specific provisions for 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:** **Implementation of Interchange**
2. **Number:** INT-009-2.1
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: February 22nd, 2018
   - **5.2.** Adoption of the appendix by the Régie de l'énergie: February 22nd, 2018
   - **5.3.** Effective date of the standard and its appendix in Québec: April 1st, 2018

B. Requirements and Measures

No specific provision

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

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

   1.2. Evidence Retention

   No specific provision

   1.3. Compliance Monitoring and Assessment Processes

   No specific provision

   1.4. Additional Compliance Information

   No specific provision

Table of Compliance Elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

Appendix QC-INT-009-2.1
Provisions specific to Standard INT-009-2.1 applicable in Québec

Guidelines and Technical Basis

No specific provision

Version History

Revision	Date	Action	Change Tracking
0	February 22nd, 2018	New appendix	New

A. Introduction

1. **Title: Interchange Initiation and Modification for Reliability**
2. **Number: INT-010-2.1**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority
5. **Effective Date:**

   See implementation plan.
6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority 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

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

Rationale:

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

Rationale for R1:

This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	February 6, 2014	Board of Trustees Adoption	Revised
2	June 30, 2014	FERC letter order issued approving INT-010-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	

Appendix QC-INT-010-2.1
Provisions specific to Standard INT-010-2.1 applicable in Québec

This appendix establishes specific provisions for 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:** **Interchange Initiation and Modification for Reliability**
2. **Number:** INT-010-2.1
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: February 22nd, 2018
   - **5.2.** Adoption of the appendix by the Régie de l'énergie: February 22nd, 2018
   - **5.3.** Effective date of the standard and its appendix in Québec: April 1st, 2018
6. **Background:** No specific provision

B. Requirements and Measures

No specific provision

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

Table of Compliance Elements

No specific provision

D. Regional Differences

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

Guidelines and Technical Basis

No specific provision

Revisions History

Revision	Date	Action	Change Tracking
0	February 22nd, 2018	New appendix	New

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-4.2

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:**

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

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to 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 a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operations Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

E.A.15 Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

E.A.16 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.17 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.18 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.18.1. Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures[1]

M.E.A.13 Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14 The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15 Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16 The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17 The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

[1] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

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

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Appendix QC-VAR-001-4.2
Provisions specific to the standard VAR-001-4.2 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:** Voltage Reactive Control
2. **Number:** VAR-001-4.2
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: February 22nd, 2018

5.2. Adoption of the appendix by the Régie de l'énergie: February 22nd, 2018

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

B. Requirements and Measures

Specific provision applicable to requirement R6:

The Transmission Operators is not required to provide documentation to the Generator Owner specifying necessary tap changes, a timeframe for making the changes and technical justification for these changes considering that the Transmission Operator will give instructions based on the voltage to be maintained on the transmission system.

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	Date	Action	Change Tracking
0	February 22nd, 2018	New appendix	New