

Alberta Reliability Standards

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Alberta Reliability Standards Contents



BAL Resource and Demand Balancing

BAL-001-AB-2 Real Power Balancing Control Performance

BAL-002-AB-3 Contingency Reserve for Recovery from a Balancing

Contingency Event

BAL-002-WECC-AB1-2 Contingency Reserve
BAL-003-AB-1.1 Frequency Response

BAL-004-WECC-AB-2 Automatic Time Error Correction

BAL-005-AB-1 Balancing Authority Control

CIP Critical Infrastructure Protection

CIP-SUPP-001-AB1 Cyber Security – Supplemental CIP Alberta Reliability Standard

CIP-SUPP-002-AB Cyber Security – Supplemental CIP Alberta Reliability Standard

Technical Feasibility Exceptions

CIP-002-AB-5.1 Cyber Security – BES Cyber System Categorization

CIP-003-AB-5 Cyber Security – Security Measurement Controls

CIP-004-AB-5.1 Cyber Security – Personnel & Training

CIP-005-AB-5 Cyber Security – Electronic Security Perimeter(s)

CIP-006-AB-5 Cyber Security – Physical Security of BES Cyber Systems

CIP-007-AB-5 Cyber Security – System Security Management

CIP-008-AB-5 Cyber Security – Incident Reporting and Response

CIP-009-AB-5 Cyber Security – Recovery Plans for BES Cyber Systems

CIP-010-AB-1 Cyber Security – Configuration Change Management and

Vulnerability Assessments

CIP-011-AB-1 Cyber Security – Information Protection

CIP-PLAN-AB-1 Cyber Security – Implementation Plan for Version 5 CIP

Security Standards

COM Communications

COM-001-AB1-1.1 Telecommunications

COM-002-AB1-2a Communications and Coordination

EOP Emergency Preparedness and Operations

EOP-001-AB1-2.1b Emergency Operations Planning

EOP-002-AB1-2 Capacity and Energy Emergencies

EOP-003-AB1-1 Load Shedding Plans

EOP-004-AB-2 Event Reporting

EOP-005-AB-2 System Restoration from Blackstart Resources

Alberta Reliability Standards Contents



EOP-006-AB-2 System Restoration Coordination
EOP-008-AB-1 Loss of Control Centre Functionality

FAC Facilities Design, Connections and Maintenance

FAC-001-AB-0 Facility Connection Requirements

FAC-002-AB-0 Coordination of Plans for New Facilities

FAC-003-AB1-1 Transmission Vegetation Management Program

FAC-008-AB-3 Facility Ratings

FAC-010-AB1-2.1 System Operating Limits Methodology for the Planning Horizon

FAC-011-AB-2 System Operating Limits Methodology for the Operations

Horizon

FAC-014-AB1-2 Establish and Communicate System Operating Limits

FAC-501-WECC-AB2-1 Transmission Maintenance

INT Interchange Scheduling and Coordination

INT-006-AB-2 Response to Interchange Authority

INT-009-AB-2.1 Implementation of Interchange

INT-010-AB-2.1 Interchange Initiation and Modification for Reliability

IRO Interconnection Reliability Operations and Coordination

IRO-001-AB1-1.1 Reliability Coordination Responsibilities and Authorities

IRO-002-AB-2 Reliability Coordination Facilities

IRO-003-AB-2 Reliability Coordination Wide Area View

IRO-005-AB-3.1 Reliability Coordination Current Day Operations

IRO-006-AB-5 Reliability Coordination Transmission Loading Relief

IRO-006-WECC-AB-2 Qualified Transfer Path Unscheduled Flow Relief

IRO-008-AB-1 Reliability Coordinator Operational Analysis and Real-time

Assessments

IRO-009-AB-1 Reliability Coordinator Actions to Operate Within IROLs IRO-010-AB-1a Reliability Coordinator Data Specification and Collection

IRO-014-AB-1 Procedures, Processes, or Plans to Support Coordination

Between Reliability Coordinators

IRO-015-AB-1 Notifications and Information Exchange Between Reliability

Coordinators

IRO-016-AB-1 Coordination of Real-Time Activities Between Reliability

Coordinators

MOD Modeling, Data and Analysis

Alberta Reliability Standards Contents



MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System

Modeling and Simulation

MOD-031-AB-2 Demand and Energy Data

PER Personnel Performance, Training, and Qualifications

PER-003-AB-1 Operations Personnel Credentials
PER-004-AB-2 Reliability Coordination – Staffing
PER-005-AB-2 Operations Personnel Training

PRC Protection and Control

PRC-001-AB3-1.1(ii) Protection System Coordination

PRC-004-AB2-1 Analysis and Mitigation of Transmission and Generation

Protection System Misoperation

PRC-004-WECC-AB1-1 Protection System and Remedial Action Scheme

Misoperation

PRC-009-AB-0 Underfrequency Load Shedding Performance Following an

Underfrequency Event

PRC-010-AB-0 Assessment of the Design and Effectiveness of Under

Voltage Load Shed Program

PRC-018-AB-1 Disturbance Monitoring Equipment Installation and Data

Reporting

PRC-021-AB1-1 Under Voltage Load Shed Program Data

PRC-022-AB-1 Under Voltage Load Shedding Program Performance

PRC-023-AB-2 Transmission Relay Loadability

TOP Transmission Operations

TOP-005-AB3-1 Operational Reliability Information

TPL Transmission Planning

TPL-001-AB-0 System Performance Under Normal Conditions

TPL-002-AB1-0 System Performance Following Loss of a Single BES Element

TPL-003-AB-0 System Performance Following Loss of Two or More Bulk

Electric System Elements

TPL-004-AB-0 System Performance Following Extreme Bulk Electric

System Events

VAR Voltage and Reactive

VAR-001-AB-4 Voltage and Reactive Control

VAR-002-AB-3 Generator Operation for Maintaining Network Voltages

VAR-002-WECC-AB-1 Automatic Voltage Regulators and Voltage Regulating Systems

Alberta Reliability Standards Contents



VAR-501-WECC-AB-1

Power System Stabilizer



1. Purpose

The purpose of this reliability standard is to control Interconnection frequency within defined limits.

2. Applicability

This reliability standard applies to:

- (a) the **ISO** except when:
 - (i) the **ISO** is receiving overlap regulation service;
 - (ii) the **ISO** is a member of a regulation reserve sharing group and remains in active status under the applicable agreement or the governing rules for the regulation reserve sharing group; or
 - (iii) the interconnected electric system is not synchronously connected to the Interconnection.

3. Requirements

- **R1** The **ISO** must operate such that the **control performance standard** 1, calculated in accordance with Appendix 1, is greater than or equal to 100% for each preceding 12 consecutive **month** period, evaluated monthly.
- **R2** The **ISO** must operate such that its clock-minute average of **reporting area control error** does not exceed the clock-minute **area control error** limit of the **balancing authority** for more than 30 consecutive clock-minutes, calculated in accordance with Appendix 2.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of operating such that the **control performance standard** 1 is greater than or equal to 100% as required in requirement R1 exists. Evidence may include dated calculation output from spreadsheets, system logs, or other equivalent evidence.
- **MR2** Evidence of operating such that the clock-minute average of **reporting area control error** does not exceed the clock-minute **area control error** limit of the **balancing authority** for more than 30 consecutive clock-minutes as required in requirement R2 exists. Evidence may include dated calculation output from spreadsheets, system logs, or other equivalent evidence.

5. Appendices

Appendix 1 - Equations Supporting Requirement R1 and Measure M1

Appendix 2 - Equations Supporting Requirement R2 and Measure M2

Revision History

Date	Description
2019-07-01	Initial release.

Effective: 2019-07-01 Page 1 of 4 Public



Appendix 1 – Equations Supporting Requirement R1 and Measure M1

The control performance standard 1 (CPS1) is calculated as follows:

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

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

$$CF = \frac{CF_{12-\text{month}}}{(\varepsilon 1_1)^2}$$

where $\mathbf{\epsilon}\mathbf{1}_{\mathbb{I}}$ is the constant derived from a targeted frequency bound for the **western interconnection** or as revised by the **NERC**.

The rating index CF_{12-month} is derived from the most recent preceding 12 consecutive **months** of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of **reporting area control error**, frequency error, and frequency bias settings. A clock-minute average is the average of the reporting **balancing authority**'s valid measured variable (i.e., for **reporting area control error** (*RACE*) and for **frequency error**) for each sampling cycle during a given clock-minute.

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

And,

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

The balancing authority's clock-minute compliance factor (CF_{clock-minute}) calculation is:

$$\mathit{CF}_{\mathrm{clock-minute}} = \left[\left(\frac{RACE}{-10B} \right)_{\mathrm{clock-minute}} \times \Delta F_{\mathrm{clock-minute}} \right]$$

Normally, 60 clock-minute averages of the **reporting area control error** and **frequency error** will be used to compute the hourly average compliance factor ($CF_{clock-hour}$).

$$\textit{CF}_{\rm clock-hour} = \frac{\sum \textit{CF}_{\rm clock-minute}}{n_{\rm clock-minute \ samples \ in \ hour}}$$



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

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} \left[(\text{CF}_{\text{clock-hour}}) \left(n_{\text{one-minute samples in clock-hour}} \right) \right]}{\sum_{\text{days-in-month}} \left[n_{\text{one-minute samples in clock-hour}} \right]}$$

$$\text{CF}_{\text{month}} = \frac{\sum\limits_{\text{hours-in-day}} [(\text{CF}_{\text{clock-houraverage-month}})(n_{\text{one-minute-samples in clock-houraverages}})]}{\sum\limits_{\text{hours-in day}} [n_{\text{one-minute-samples in clock-houraverages}}]}$$

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

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

To ensure that the average **reporting area control error** and **frequency error** calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of both the **reporting area control error** and **frequency error** sample data during the one-minute interval is valid. If the recording of **reporting area control error** or **frequency error** is interrupted such that less than 50% of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A balancing authority providing overlap regulation service to another balancing authority calculates its CPS1 performance after combining its reporting area control error and frequency bias settings with the reporting area control error and frequency bias settings of the balancing authority receiving the regulation service.



Appendix 2 - Equations Supporting Requirement R2 and Measure M2

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

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

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

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

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

Where:

BAAL_{Low} is the low area control error limit of the balancing authority (MW)

BAAL_{High} is the high area control error limit of the balancing authority (MW)

10 is a constant to convert the frequency bias setting from MW/0.1 Hz to MW/Hz

 B_i is the frequency bias setting for a balancing authority (expressed as MW/0.1 Hz)

 F_A is the measured frequency in Hz.

F_s is the **scheduled frequency** in Hz.

 FTL_{Low} is the low frequency trigger limit (calculated as $F_S - 3\varepsilon 1_I Hz$)

 FTL_{High} is the high frequency trigger limit (calculated as $F_S + 3\varepsilon 1_I Hz$)

Where $\mathbf{E}\mathbf{1}_{I}$ is the constant derived from a targeted frequency bound for the **western** interconnection or as revised by the **NERC**.

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50% of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the **area control error** limit of the **balancing authority** calculation and the 30-minute clock would be reset to zero.

A balancing authority providing overlap regulation service to another balancing authority calculates its area control error limit of the balancing authority performance after combining its frequency bias setting with the frequency bias setting of the balancing authority receiving overlap regulation service.

Effective: 2019-07-01 Page 4 of 4 Public

Alberta Reliability Standard Contingency Reserve for Recovery from a Balancing Contingency Event BAL-002-AB-3



1. Purpose

The purpose of this **reliability standard** is to ensure the **ISO** balances resources and **demand** and returns the **area control error** to defined values, subject to applicable limits, following a reportable **balancing contingency event**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**, only in periods during which the **ISO** is not in active status under a **reserve sharing group** agreement or governing rules for a **reserve sharing group**.

3. Requirements

- R1 The ISO, when it is experiencing a reportable balancing contingency event must:
 - **R1.1** within the **contingency** event recovery period, demonstrate recovery by returning its **reporting area control error** to at least the recovery value of:
 - (a) zero (if its pre-reporting **contingency** event **area control error** value was positive or equal to zero); or
 - (b) its pre-reporting **contingency** event **area control error** value (if its pre-reporting **contingency** event **area control error** value was negative);

however, any **balancing contingency event** that occurs during the **contingency** event recovery period must reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual **balancing contingency event**;

- **R1.2**. document all reportable **balancing contingency events** using the form the **NERC** designates; and
- **R1.3**. deploy **contingency reserve**, within system constraints, to respond to all reportable **balancing contingency events**; however, the **ISO** is not subject to compliance with requirement R1.1 if the **ISO**:
 - R1.3.1 (a) is experiencing an ISO declared energy emergency alert level;
 - (b) is using its **contingency reserve** to mitigate an operating emergency in accordance with its emergency operating plan;
 - (c) has depleted its contingency reserve to a level below its most severe single contingency; and
 - (d) intentionally left blank; or
 - R1.3.2 (a) experiences multiple **contingencies** where the combined MW loss exceeds its most severe single **contingency** and that are defined as a single **balancing contingency event**; or
 - (b) experiences multiple balancing contingency events within the sum of the time periods defined by the contingency event recovery period and contingency reserve restoration period whose combined magnitude exceeds the ISO's most severe single contingency.

Alberta Reliability Standard Contingency Reserve for Recovery from a Balancing Contingency Event BAL-002-AB-3



- **R2** The **ISO** must develop, review, and maintain annually, and implement an operating process as part of its operating plan to determine its most severe single **contingency** and make preparations to have **contingency reserve** equal to, or greater than the **ISO**'s most severe single **contingency** available for maintaining system **reliability**.
- R3 The ISO, following a reportable balancing contingency event, must restore its contingency reserve to at least its most severe single contingency, before the end of the contingency reserve restoration period, but any balancing contingency event that occurs before the end of a contingency reserve restoration period resets the beginning of the contingency event recovery period.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1.1** Evidence of demonstrating the recovery of the **reporting area control error** as required in requirement R1.1 exists. Evidence may include documented reportable **balancing contingency events** using the designated form, or other equivalent evidence.
 - **MR1.2** Evidence of documenting all reportable **balancing contingency events** as required by requirement R1.2 exists. Evidence may include documented reportable **balancing contingency events** using the designated **NERC** form, or other equivalent evidence.
 - **MR1.3** Evidence of deploying **contingency** reserve, within system constraints, to respond to all reportable **balancing contingency events**, as required in requirement R1.3 exists. Evidence may include **directive** logs, phone calls, designated forms, or other equivalent evidence.
- MR2 Evidence of developing, reviewing, maintaining and implementing an operating process to determine the most severe single contingency and to have contingency reserves as required in requirement R2 exists. Evidence may include a dated operating process with a revision history, or other equivalent evidence.
- **MR3** Evidence of restoring **contingency reserve** as required in requirement R3 exists. Evidence may include historical data, computer logs, operator logs, or other equivalent evidence.

Revision History

Date	Description
2019-07-01	Initial release.

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Alberta Reliability Standard Contingency Reserve BAL-002-WECC-AB1-2



1. Purpose

The purpose of this **reliability standard** is to specify the quantity and types of **contingency reserve** required to ensure reliability under normal and abnormal conditions.

2. Applicability

This reliability standard applies to:

(a) the ISO, which may meet the requirements of this reliability standard through participation in a reserve sharing group that the ISO has designated as its agent.

This **reliability standard** does not apply in the case of contingencies that result in the **interconnected electric system** losing synchronism with the **western interconnection**.

3. Requirements

- R1 The ISO must have held, at a minimum, an average amount of contingency reserve that is:
 - R1.1 the greater of either:
 - (a) an amount equal to the loss of the most severe single contingency; or
 - (b) an amount equal to the sum of:

three percent (3%) of the hourly integrated amount of load, being the hourly integrated amount of net generation the **ISO** determines is delivered to the grid minus **net actual interchange**;

plus

three percent (3%) of the hourly integrated amount of net generation the **ISO** determines is delivered to the grid;

where "net generation the **ISO** determines is delivered to the grid" is equal to the sum of:

- (i) generation from a **generating unit** or **aggregated generating facility** but not including unit service and station service loads;
 - plus
- (ii) generation from an industrial complex or facility that has on-site generation but not including generation serving on-site load;
 - plus
- (iii) generation delivered to the grid by the City of Medicine Hat;
- R1.2 comprised of any combination of the operating reserve types specified below:
 - (a) spinning reserve;
 - (b) supplemental reserve;

Effective: 2015-07-26 Page 1 of 3

Alberta Reliability Standard Contingency Reserve BAL-002-WECC-AB1-2



- (c) **interchange transactions** sourced within Alberta that the **ISO** designates as **supplemental reserve**;
- (d) interchange transactions sourced external to Alberta that the ISO designates as spinning reserve or supplemental reserve and that, by agreement, is deliverable to Alberta on firm transmission service;
- (e) a resource, other than a **generating unit**, an **aggregated generating facility** or load, that can provide energy or reduce energy consumption;
- (f) load, including demand response resources, demand-side management resources, direct control load management, interruptible load or interruptible demand, or any other load made available for curtailment by the ISO via contract or agreement; and
- (g) during capacity and energy emergencies, load that can be interrupted; and
- **R1.3** an amount of capacity from a resource that is capable of fully responding within ten (10) minutes;

except within the first sixty (60) minutes following a **disturbance** resulting from a loss of supply and requiring the activation of **contingency reserve** or except following the deployment of **contingency reserve** during implementation of the **ISO**'s capacity and energy emergency plan.

- **R2** The **ISO** must maintain at least fifty percent (50%) of its minimum amount of **contingency reserve** required in requirement R1 as **spinning reserve** that is immediately and automatically responsive to frequency deviations through the action of a **governor** or other control system.
- R3 The ISO must, when operating as a sink balancing authority, maintain an amount of operating reserve, in addition to the minimum contingency reserve required in requirement R1, equal to the amount of supplemental reserve for any interchange transaction designated as part of the supplemental reserve of the source balancing authority or source reserve sharing group, except within the first sixty (60) minutes following an event requiring the activation of contingency reserve or except following the deployment of contingency reserve during implementation of the ISO's capacity and energy emergency plan.
- R4 The ISO must, when operating as a source balancing authority, maintain an amount of operating reserve, in addition to the minimum contingency reserve amounts required in requirement R1, equal to the amount and type of operating reserve for any operating reserve transactions for which it is the source balancing authority.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Evidence of having held **contingency reserve** as required in requirement R1 exists. Evidence may include:

 (a) a reserve sharing group agreement including an agent appointment agreement, documentation of the methodology of the contingency reserve calculation, or ancillary services contracts; or

Effective: 2015-07-26 Page 2 of 3

Alberta Reliability Standard Contingency Reserve BAL-002-WECC-AB1-2



- (b) records of **disturbances** or implementation of the **ISO**'s capacity and emergency plan as required in requirement R1.
- **MR1.1** Evidence of calculating the amount of **contingency reserve** as required in requirement R1.1 exists. Evidence may include records of the required and available **contingency reserve**.
- **MR1.2** Evidence of having **contingency reserve** that is comprised of the **operating reserve** types as required in requirement R1.2 exists. Evidence may include a **reserve sharing group** agreement including an agent appointment agreement or **ancillary services** contracts.
- **MR1.3** Evidence of having access to **contingency reserve** that is capable of fully responding in ten (10) minutes as required in requirement R1.3 exists. Evidence may include a **reserve sharing group** agreement including an agent appointment agreement or technical requirements for **contingency reserve**.
- **MR2** Evidence of maintaining at least fifty percent (50%) of the ISO's minimum amount of **contingency reserve** as **spinning reserve** that is immediately responsive to frequency deviations as required in requirement R2 exists. Evidence may include a **reserve sharing group** agreement including an agent appointment agreement or records of **dispatches** of **ancillary services**.
- **MR3** Evidence of maintaining an amount of **operating reserve** as required in requirement R3 exists. Evidence may include a sworn affidavit from an appropriate **ISO** representative, authoritative documents that restrict or permit the transactions set out in requirement R3, documents that demonstrate the **ISO** was in a capacity and energy emergency, or a **reserve sharing group** agreement including an agent appointment agreement.
- **MR4** Evidence of maintaining an amount of **operating reserve** as required in requirement R4 exists. Evidence may include a sworn affidavit from an appropriate **ISO** representative or a **reserve sharing group** agreement including an agent appointment agreement.

Revision History

Effective Date	Description
2015-07-26	Revised Applicability section to include exclusion for contingencies that result in the interconnected electric system losing synchronism with the western interconnection
2014-10-01	Initial release.

Effective: 2015-07-26 Page 3 of 3



1. Purpose

The purpose of this reliability standard is to:

- require sufficient frequency response from the ISO to maintain Interconnection frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value; and
- (b) provide consistent methods for measuring **frequency response** and determining the **frequency bias setting**.

2. Applicability

This reliability standard applies to:

(a) the ISO, unless the interconnected electric system is not synchronously connected to the Interconnection.

3. Requirements

R1 The ISO must:

- (a) achieve an annual **frequency response** measure (as calculated in accordance with Appendix A) that is equal to or more negative than its **frequency response** obligation; and
- (b) report, in accordance with Appendix A, the annual **frequency response** measure calculated pursuant to requirement R1(a),

which obligations the **ISO** may meet through participation in a frequency **reserve sharing group** which the **ISO** has designated as its agent.

- **R2** The **ISO** must, if it is not receiving overlap regulation service and uses a fixed **frequency bias** setting:
 - **R2.1** implement the **frequency bias setting** determined in accordance with Appendix A, as validated by the Electric Reliability Organization, into its **area control error** calculation during the implementation period specified by the Electric Reliability Organization; and
 - **R2.2** use this **frequency bias setting** until directed to change by the Electric Reliability Organization.
- R3 The ISO must, if it is not receiving overlap regulation service and is utilizing a variable frequency bias setting, maintain a frequency bias setting that is:
 - R3.1 less than zero at all times; and
 - **R3.2** equal to or more negative than its **frequency response** obligation when frequency varies from 60 Hz by more than +/- 0.036 Hz.
- **R4** The **ISO** must, if it is performing overlap regulation service, modify its **frequency bias setting** in its **area control error** calculation, in order to represent the **frequency bias setting** for the combined **balancing authority area**, to be equivalent to either:
 - **R4.1** the sum of the **frequency bias settings**, as shown on the **NERC** *FRS Form 1* and *FRS Form 2* for the participating **balancing authorities** and as validated by the Electric Reliability Organization, or

Effective: 2019-07-01 Page 1 of 7 Public



R4.2 the **frequency bias setting** shown on the **NERC** *FRS Form 1* and *FRS Form 2* for the entirety of the participating **balancing authority areas**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- MR1 Evidence of achieving an annual frequency response measure as required in requirement R1, and of reporting the annual frequency response measure as required in requirement R1 exists. Evidence may include dated data plus documented formula in either hardcopy or electronic format that shows an annual frequency response measure was achieved that is equal to or more negative than the frequency response obligation, a dated document in hard copy or electronic format showing submission of a completed report, or other equivalent evidence.
- MR2 Evidence of implementing the frequency bias setting as validated by the Electric Reliability Organization into the area control error calculation as required in requirement R2 exists. Evidence may include a dated document in hard copy or electronic format showing the frequency bias setting as validated by the Electric Reliability Organization was implemented into the area control error calculation within the implementation period specified, or other equivalent evidence.
- MR3 Evidence of maintaining a frequency bias setting as required in requirement R3 exists. Evidence may include a dated report in hard copy or electronic format showing the average clock-minute average frequency bias setting was less than zero and, during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz, was equal to or more negative than the frequency response obligation, or other equivalent evidence.
- MR4 Evidence of modifying the frequency bias setting in the area control error calculation as required in requirement R4 exists. Evidence may include a dated operating log, database or list, in hard copy or electronic format, showing that when overlap regulation service was performed the frequency bias setting was modified in the area control error calculation, or other equivalent evidence.

5. Appendices

Appendix A - BAL-003-AB-1.1 Frequency Response & Frequency Bias Setting Standard Supporting Document

Revision History

Date	Description
2019-07-01	Initial release.

Effective: 2019-07-01 Page 2 of 7 Public



Appendix A

BAL-003-AB-1.1 Frequency Response & Frequency Bias Setting Standard Supporting Document

Interconnection Frequency Response Obligation

The Electric Reliability Organization, in consultation with regional representatives, has established a target contingency protection criterion for each **frequency response** obligation of the **Interconnection**. The default **frequency response** obligation of the **Interconnection** listed in Table 1 is based on the resource contingency criteria, which is the largest category C (N-2) event identified. A maximum delta frequency is calculated by adjusting a starting frequency for each **Interconnection** by the following:

- Prevailing underfrequency load shedding first step;
- CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data;
- CB_R which is the statistically determined ratio of the Point C to Value B; and
- BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary **frequency response** withdrawal.

The **frequency response** obligation for each **Interconnection** in Table 1 is then calculated by dividing the resource **contingency** criteria MWs by 10 times the maximum delta frequency. In the Eastern Interconnection there is an additional adjustment (BC' Adj) for the event nadir being below the Value B due to primary **frequency response** withdrawal. This **frequency response** obligation for the **Interconnection** includes uncertainty adjustments at a 95% confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response* and *Frequency Bias Setting Standard*.

Table 1

Interconnection	Eastern	Western	ERCOT	HQ	Units
Starting Frequency (F _{start})	59.974	59.976	59.963	59.972	Hz
Prevailing UFLS First Step	59.5*	59.5	59.3	58.5	Hz
Base Delta Frequency (DF _{Base})	0.474	0.476	0.663	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta Frequency (DF _{CC})	0.467	0.472	0.651	1.472	Hz
CB _R	1.000	1.625	1.377	1.550	
Delta Frequency (DF _{CBR})	0.467	0.291	0.473	0.949	Hz
BC' _{ADJ}	0.018	N/A	N/A	N/A	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	
Resource Contingency Criteria	4,500	2740	2,750	1700	MW
Credit for Load Resources		300	1400**		MW

Effective: 2019-07-01 Page 3 of 7 Public



Units

Interconnection (CLR)

IFRO

Eastern	Western	ERCOT	HQ
-1002	-840	-286	-179

*The Eastern Interconnection **underfrequency load setting** set point listed is a compromise value set midway between the stable frequency minimum established in the **NERC** standard PRC-006-1, *Automatic Underfrequency Load Shedding* (59.3 Hz) and the local protection **underfrequency load setting** setting of 59.7 Hz used in Florida and Manitoba.

In the base obligation measure for ERCOT, 1400 MW (load resources triggered by under frequency relays at 59.70 Hz) was reduced from its resource **contingency criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from load resources within 30 cycles.

An **Interconnection** may propose alternate **frequency response** obligation protection criteria for that **Interconnection** to the Electric Reliability Organization by submitting a *Standard Authorization Request* with supporting technical documentation.

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

The Electric Reliability Organization will manage the administrative procedure for annually assigning a **frequency response** obligation and implementation of the **frequency bias setting** for each **balancing authority**. The annual timeline for all activities described in this section are shown below.

For an **Interconnection** with multiple **balancing authorities**, the **frequency response** obligation shown in Table 1 is allocated based on the **balancing authority** annual load and annual generation. The **frequency response** obligation allocation will be based on the following method:

 $FRO_{BA} = IFRO \times Annual Gen_{BA} + Annual Load_{BA}$

Annual Genint + Annual Loadint

Where:

- Annual Gen_{BA} is the total annual "Output of Generating Plants" within the balancing authority area, on FERC Form 714, column c of Part II - Schedule 3.
- Annual Load_{BA} is total annual load within the **balancing authority area**, on FERC *Form 714*, column e of Part II Schedule 3.
- Annual Gen_{Int} is the sum of all annual gen_{BA} values reported in that Interconnection.
- Annual Load_{Int} is the sum of all annual load_{BA} values reported in that Interconnection.

The data used for this calculation is from the most recently filed *Form 714*. As an example, a report to the **NERC** in January 2013 would use the *Form 714* data filed in 2012, which utilized data from 2011.



Balancing authorities that are not FERC-jurisdictional should use the *Form 714 Instructions* to assemble and submit equivalent data to the Electric Reliability Organization for use in the **frequency response** obligation allocation process.

Balancing authorities that elect to form a frequency response sharing group will calculate a frequency response sharing group frequency response obligation by adding together the individual frequency response obligations of the balancing authority.

Balancing authorities that elect to form a **frequency response** sharing group as a means to jointly meet the **frequency response** obligation will calculate their **frequency response** measure performance in one of two ways:

- Calculate a group **net actual interchange** and measure the group response to all events in the reporting year on a single *FRS Form 1*, or
- Jointly submit the individual **balancing authorities**' *FRS Form 1*s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Balancing authorities that merge or that transfer load or generation are encouraged to notify the Electric Reliability Organization of the change in footprint and corresponding changes in allocation such that the net obligation to the **Interconnection** remains the same and so that **control performance standard** limits can be adjusted.

Each **balancing authority** reports its previous year's **frequency response** measure, **frequency bias setting** and **frequency bias** type (fixed or variable) to the Electric Reliability Organization each year to allow the Electric Reliability Organization to validate the revised **frequency bias settings** on *FRS Form 1*. If the Electric Reliability Organization posts the official list of events after the date specified in the timeline below, **balancing authorities** will be given 30 **days** from the date the Electric Reliability Organization posts the official list of events to submit their *FRS Form 1*.

Once the Electric Reliability Organization reviews the data submitted in FRS Form 1 and FRS Form 2 for all **balancing authorities**, the Electric Reliability Organization will use FRS Form 1 data to post the following information for each **balancing authority** for the upcoming year:

- frequency bias setting; and
- frequency response obligation.

Once the data listed above is fully posted, the Electric Reliability Organization will announce the three-day implementation period for changing the **frequency bias setting** if it differs from that shown in the timeline below.

A balancing authority using a fixed frequency bias setting sets its frequency bias setting to the greater of (in absolute value):

- Any number the balancing authority chooses between 100% and 125% of its frequency response measure as calculated on FRS Form 1; or
- The Interconnection minimum as determined by the Electric Reliability Organization.

For purposes of calculating the minimum **frequency bias setting**, a **balancing authority** participating in a **frequency response** sharing group will need to calculate its stand-alone **frequency response** measure using *FRS Form 1* and *FRS Form 2* to determine its minimum **frequency bias setting**.



A **balancing authority** providing overlap regulation will report the historic peak demand and generation of its combined **balancing authority areas** on FRS Form 1 as described in requirement R4.

There are occasions when changes are needed to **frequency bias settings** outside of the normal schedule. Examples are footprint changes between **balancing authorities** and major changes in load or generation or the formation of new **balancing authorities**. In such cases, the changing **balancing authorities** will work with their regions, the **NERC**, and the Resources Subcommittee to confirm appropriate changes to **frequency bias settings**, **frequency response** obligation, **control performance standard** limits and **inadvertent interchange** balances.

If there is no net change to the **Interconnection** total **frequency bias**, the **balancing authorities** involved will agree on a date to implement their respective change in **frequency bias settings**. The **balancing authorities** and Electric Reliability Organization will also agree to the allocation of **frequency response** obligation such that the sum remains the same.

If there is a net change to the **Interconnection** total **frequency bias**, this will cause a change in CPS2 limits and **frequency response** obligation for other **balancing authorities** in the **Interconnection**. In this case, the Electric Reliability Organization will notify the impacted **balancing authorities** of their respective changes and provide an implementation window for making the **frequency bias setting** changes.

Frequency Response Measure

The balancing authority will calculate its frequency response measure from single event frequency response data, defined as: "the data from an individual event from a balancing authority that is used to calculate its **frequency response**, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the Electric Reliability Organization using the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard. The frequency response measure for a typical balancing authority in an Interconnection with more than one balancing authority is basically the change in its net actual interchange on its intertie with its adjacent balancing authorities divided by the change in Interconnection frequency. (Some balancing authorities may choose to apply corrections to their net actual interchange values to account for factors such as nonconforming loads.) FRS Form 1 and FRS Form 2 show the types of adjustments that are allowed. Note that with the exception of the contingent balancing authority column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the nonconforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the balancing authority. The Electric Reliability Organization will use a standardized sampling interval of approximately 16 seconds before the event up to the time of the event for the pre-event **net actual interchange**, and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event net actual interchange (B values) in the computation of frequency response measure values, dependent on the data scan rate of the balancing authority's Energy Management System.

All events listed on *FRS Form 1* need to be included in the annual submission of *FRS Form 1* and *FRS Form 2*. The only time a **balancing authority** should exclude an event is if its **intertie** data or its frequency data is corrupt or its Energy Management System was unavailable. *FRS Form 2* has instructions on how to correct the **balancing authority**'s data if the given event is internal to the **balancing authority** or if other authorized adjustments are used.



Assuming data entry is correct, *FRS Form 1* will automatically calculate the **frequency response** measure of the **balancing authority** for the past 12 **months** as the median of the **frequency response** measure values. A **balancing authority** electing to report as an **frequency response** sharing group or a provider of overlap regulation service will provide an *FRS Form 1* for the aggregate of its participants.

To allow a **balancing authority** to plan its operations, events with a "Point C" that cause the **Interconnection** frequency to be lower than that shown in Table 1 above or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that **Interconnection**. However, the calculation of the **balancing authority** response to such an event will be adjusted to show a frequency change only to the target minimum frequency shown in Table 1 above or a high frequency amount of an equal quantity. Should such an event happen, the Electric Reliability Organization will provide additional guidance.

Alberta Reliability Standard Automatic Time Error Correction BAL-004-WECC-AB-2



1. Purpose

The purpose of this **reliability standard** is to maintain the frequency of the **western interconnection** and to ensure that **time error corrections** and **primary inadvertent interchange** payback are effectively conducted in a manner that does not adversely affect the **reliability** of the **western interconnection**.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 Following the conclusion of each month, the ISO must verify that the absolute value of its accumulated primary inadvertent interchange for both the monthly on peak period and the monthly off peak period are each individually less than or equal to 150% of the previous calendar year's peak demand, where peak demand is the highest hourly integrated net energy for load.
- R2 The ISO must, within ninety (90) days of discovery of an error in the calculation of hourly **primary** inadvertent interchange, recalculate the value of hourly primary inadvertent interchange and adjust the accumulated primary inadvertent interchange from the time of the error.
- R3 The ISO must, while synchronously connected to the **western interconnection**, keep its **automatic time error correction** in service, with an allowable exception period of less than or equal to an accumulated twenty-four (24) hours per calendar quarter for **automatic time error correction** to be out of service.
 - **R3.1** Notwithstanding requirement R3, the **ISO** may disable automatic **time error correction** if there is a **reliability** concern on the **interconnected electric system** while executing an automatic **time error correction**, and this time will not be included as part of the allowable exception period.
- R4 The **ISO** must compute the following by fifty (50) minutes after each hour:
 - R4.1 the hourly primary inadvertent interchange;
 - R4.2 the accumulated primary inadvertent interchange; and
 - R4.3 the automatic time error correction term.
- **R5** The **ISO** must be able to change its **automatic generation control** operating mode between flat frequency, flat tie line, tie line bias, and tie line bias plus **time error** control, to correspond to current operating conditions.
- The ISO must recalculate the hourly primary inadvertent interchange and accumulated primary inadvertent interchange for the on peak and off peak periods whenever adjustments are made to hourly inadvertent interchange or the hourly change in system time error, as distributed by the Interconnection time monitor.
- R7 The ISO must make the same adjustment to the accumulated **primary inadvertent interchange** as it did for any **month**-end meter reading adjustments to **inadvertent interchange**.
- R8 The ISO must payback inadvertent interchange using automatic time error correction rather than bilateral and unilateral payback.



Alberta Reliability Standard Automatic Time Error Correction BAL-004-WECC-AB-2

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- MR1 Evidence of verifying the absolute value of the ISO's accumulated primary inadvertent interchange as required in requirement R1 exists. Evidence may include, but is not limited to, data, screen shots from the WECC Interchange Tool, production of data from any other databases, spreadsheets, displays, or other equivalent evidence.
- MR2 Evidence of recalculating the value of hourly primary inadvertent interchange and adjusting the accumulated primary inadvertent interchange from the time of the error as required in requirement R2 exists. Evidence may include, but is not limited to, data, screen shots from the WECC Interchange Tool, production data from any other databases, spreadsheets, displays, or other equivalent evidence.
- **MR3** Evidence of keeping the **automatic time error correction** in service as required in requirement R3 exists. Evidence may include, but is not limited to, dated archived files, historical data, or other equivalent evidence.
- MR4 Evidence of computing the hourly primary inadvertent interchange, accumulated primary inadvertent interchange and automatic time error correction as required in requirement R4 exists. Evidence may include, but is not limited to, data, screen shots from the WECC Interchange Tool, data from any other databases, spreadsheets, displays, or other equivalent evidence.
- MR5 Evidence of having the ability to change the automatic generation control operating mode as required in requirement R5 exists. Evidence may include, but is not limited to, snapshots of the operating interface provided in the energy management system for changing its automatic generation control operating mode, or other equivalent evidence.
- MR6 Evidence of recalculating hourly primary inadvertent interchange and accumulated primary inadvertent interchange as required in requirement R6 exists. Evidence may include, but is not limited to, data, screen shots from the WECC Interchange Tool, data from any other databases, spreadsheets, displays, or other equivalent evidence.
- MR7 Evidence of making the adjustments to accumulated primary inadvertent interchange as required in requirement R7 exists. Evidence may include, but is not limited to, data, screen shots of the WECC Interchange Tool, data from any other databases, spreadsheets, displays, or other equivalent evidence.
- **MR8** Evidence of paying back the **inadvertent interchange** as required in requirement R8 exists. Evidence may include, but is not limited to, historical **inadvertent interchange** data, data from the **WECC** Interchange Tool, or other equivalent evidence.

Revision History

Date	Description
2016-12-19	Initial release.

Alberta Reliability Standard Balancing Authority Control BAL-005-AB-1



1. Purpose

The purpose of this **reliability standard** is to establish requirements for acquiring data necessary to calculate **reporting area control error** and specify a minimum periodicity, accuracy, and availability requirement for acquisition of the data.

2. Applicability

This **reliability standard** applies to:

(a) the ISO.

3. Requirements

- **R1** The **ISO** must use a design scan rate of no more than 9 seconds in acquiring data necessary to calculate **reporting area control error**.
- R2 Intentionally left blank.
- R3 The ISO must use frequency metering equipment for the calculation of reporting area control error:
 - R3.1 that is available a minimum of 99.95% for each calendar year; and
 - R3.2 with a minimum accuracy of 0.001 Hz.
- **R4** The **ISO** must make available to its operating personnel information associated with **reporting area control error** including quality flags indicating missing or invalid data.
- **R5** The **ISO** must ensure the system it uses to calculate **reporting area control error** is available a minimum of 99.5% of each calendar year.
- **R6** The **ISO** must implement an operating process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of **reporting area control error** for its **balancing authority area**.
- **R7** The **ISO** must ensure that each **interconnection**, pseudo-tie, and dynamic schedule with an **adjacent balancing authority** is equipped with:
 - **R7.1** a common source to provide information to both the **ISO** and the **adjacent balancing authority** for the scan rate values used in the calculation of **reporting area control error**; and,
 - **R7.2** a time synchronized common source to determine hourly MWh values agreed-upon to aid in the identification and mitigation of errors.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of using a design scan rate as required in requirement R1 exists. Evidence may include data files, database, spreadsheets, system logs, display information, other data, or other equivalent evidence.
- MR2 Intentionally left blank.

Effective: 2019-07-01 Page 1 of 2 Public

Alberta Reliability Standard Balancing Authority Control BAL-005-AB-1



- **MR3** Evidence of using frequency metering equipment for the calculation of **reporting area control error** as required in requirement R3 exists. Evidence may include dated documents, data files, database, system logs, other data, or other equivalent evidence.
- **MR4** Evidence of making available information associated with **reporting area control error** as required in requirement R4 exists. Evidence may include graphical display or dated alarm log that provides indication of data validity for the real-time **reporting area control error** based on both the calculated result and all of the associated inputs, or other equivalent evidence.
- **MR5** Evidence of ensuring the system used to calculate **reporting area control error** was available as required in requirement R5 exists. Evidence may include data files, database, system logs, other data, or other equivalent evidence.
- **MR6** Evidence of implementing an operating process as required in requirement R6 exists. Evidence may include evidence that shows the operating process was implemented, such as dated communications, incorporation in operator task verification, or other equivalent evidence.
- **MR7** Evidence of ensuring that each **interconnection**, pseudo-tie and dynamic schedule with an adjacent **balancing authority** is equipped with a common source as required in requirement R7 exists. Evidence may include technical documentation, electronic communications, or other equivalent evidence.

Revision History

Date	Description
2019-07-01	Initial release.

Effective: 2019-07-01 Page 2 of 2 Public

Alberta Reliability Standard Cyber Security – Supplemental CIP Alberta Reliability Standard CIP-SUPP-001-AB1



A. Introduction

- 1. Title: Cyber Security Supplemental CIP Alberta Reliability Standard
- 2. Number: CIP-SUPP-001-AB1
- Purpose: The purpose of this reliability standard is to allow the ISO to approve variances to the requirements of a CIP Cyber Security reliability standard, other than technical feasibility exceptions.
- 4. Applicability:

This **reliability standard** applies to those Responsible Entities listed in CIP-002-AB-5.1, *Cyber Security – BES Cyber System Categorization*, section 4, Applicability.

B. Requirements and Measures

- R1 A Responsible Entity, other than the ISO, must, where it seeks a variance to the requirements of a CIP Cyber Security reliability standard, make a request in writing to the ISO outlining (i) the requirements of the particular CIP Cyber Security reliability standard in respect of which the variance is sought; (ii) the grounds in support of the requested variance, which grounds must not be frivolous or of little merit; and (iii) the requested effective dates of the variance.
- M1 Evidence of a request for a variance being made in writing as required in requirement R1 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request.
- R2 The ISO and the Responsible Entity must treat a request for a variance under requirement R1, all records related to such a request, and a variance approved under requirement R3, as confidential in accordance with the provisions of section 103.1 of the ISO rules, Confidentiality, provided however that where the request for a variance is made by a Responsible Entity whose rights and obligations are the subject of a power purchase arrangement that Responsible Entity may disclose to its counterparties such information in respect of the variance as and if required under the terms of the power purchase arrangement.
 - **R2.1** Where the **ISO** determines that the disclosure of a request for a variance under requirement R1, all records related to such a request, or a variance approved under requirement R3:
 - (a) would have no material impact on the **reliability** of the interconnected electric system; and
 - (b) does not contain information which, in the opinion of the ISO, is commercially sensitive.

requirement R2 of this standard does not apply and the **ISO** may publicly disclose the request and all records related to the request in accordance with subsection 2(6)(b)(i) of section 103.1 of the **ISO rules**.

M2 Evidence of treating the request as confidential as described in requirement R2 exists, unless requirement R2.1 applies.

Effective: 2017-03-21 Page 1 of 2 Public

Alberta Reliability Standard Cyber Security – Supplemental CIP Alberta Reliability Standard CIP-SUPP-001-AB1



- R3 The ISO must, where it approves a variance requested under requirement R1:
 - (a) indicate the effective dates of the variance;
 - (b) identify the Responsible Entity to which the variance applies;
 - (c) maintain a copy of the variance, in writing; and
 - (d) provide a copy of the variance, in writing, to the Responsible Entity that has requested the variance.
- M3 Evidence of taking the steps required in requirement R3 exists. Evidence may include, but is not limited to, a written copy of the variance including its effective dates, correspondence to the Responsible Entity enclosing a copy of the variance or other equivalent evidence.
- R4 The ISO must not, in any event, approve a variance requested under requirement R1 unless the ISO determines, by its own assessment, that the variance has merit and will not have a material impact on the reliability of the interconnected electric system.
- **M4** Evidence of performing an assessment in accordance with requirement R4 exists. Evidence may include, but is not limited to, a copy of the **ISO**'s business practices relating to variances of a CIP Cyber Security **reliability standard**.
- R5 The ISO must, where it does not approve a variance requested under requirement R1, provide a copy of its decision, including reasons, in writing, to the Responsible Entity that has requested the variance.
- **M5** Evidence of issuing a decision denying the variance requested exists. Evidence may include, but is not limited to, a hard copy or electronic copy of a letter from the **ISO** denying the variance requested.
- R6 Notwithstanding any of the requirements of this **reliability standard**, a Responsible Entity must make a request for a **technical feasibility exception** in accordance with the provisions of CIP-SUPP-002-AB, *Technical Feasibility Exceptions*.
- **M6** Evidence of requesting a **technical feasibility exception** as required in requirement R6 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request, or other equivalent evidence.

Revision History

Date	Description	
2017-03-21	Addition of requirement R6 and associated measure. Revision to purpose statement.	
2015-06-05	Initial release.	

Effective: 2017-03-21 Page 2 of 2 Public

Alberta Reliability Standard Cyber Security – Supplemental CIP Alberta Reliability Standard Technical Feasibility Exceptions CIP-SUPP-002-AB

A. Introduction

- 1. Title: Cyber Security Supplemental CIP Alberta Reliability Standard Technical Feasibility Exceptions
- 2. Number: CIP-SUPP-002-AB
- 3. Purpose: The purpose of this **reliability standard** is to allow the **ISO** to approve **technical feasibility exceptions** to the requirements of a CIP Cyber Security **reliability standard**.
- 4. Applicability:

This **reliability standard** applies to those Responsible Entities listed in CIP-002-AB-5.1, *Cyber Security – BES Cyber System Categorization*, section 4, Applicability.

B. Requirements and Measures

- R1 A Responsible Entity other than the ISO must, where:
 - (a) a requirement in the CIP Cyber Security **reliability standards** uses the phrase "where technically feasible"; and
 - (b) the Responsible Entity seeks a variance from the requirement referenced in sub-requirement R1(a) on the grounds of technical feasibility,

request that the ISO approve a technical feasibility exception.

- **MR1** Evidence of a request for a **technical feasibility exception** as required in requirement R1 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request, or other equivalent evidence.
- **R2** A Responsible Entity must make a request under requirement R1 in writing in the form specified by the **ISO**.
- **MR2** Evidence of making a request in writing as described in requirement R1 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request, or other equivalent evidence.
- **R3** At the **ISO**'s request, a Responsible Entity must provide:
 - (a) any additional information relating to a request for a **technical feasibility exception**; or
 - (b) the reasons why the additional information will not be provided.
- **MR3** Evidence of providing additional information or reasons in accordance with requirement R3 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request and the response, or other equivalent evidence.
- R4 The ISO and the Responsible Entity must treat a request for a technical feasibility exception under requirement R1, and all records related to such a request, as confidential in accordance with the provisions of section 103.1 of the ISO rules, Confidentiality, provided however that where the request for a technical feasibility exception is made by a Responsible Entity whose rights and obligations are the subject of a power purchase arrangement, that Responsible Entity may disclose to its counterparties such information in respect of the technical feasibility exception as and if required under the terms of the power purchase arrangement.
- **MR4** Evidence of treating the request as confidential as described in requirement R4 exists.

Alberta Reliability Standard Cyber Security – Supplemental CIP Alberta Reliability Standard Technical Feasibility Exceptions CIP-SUPP-002-AB

- R5 The ISO must post the criteria that it considers when determining whether to approve or disapprove a request for a **technical feasibility exception** on the AESO website, and must notify Responsible Entities at least thirty (30) **days** in advance of any amendments to the criteria.
- **MR5** Evidence of posting the criteria and notifying Responsible Entities as described in requirement R5 exists. Evidence may include, but is not limited to, a dated copy of the AESO website posting and a dated posting in the AESO stakeholder newsletter.
- R6 The ISO must, upon reviewing a Responsible Entity's request submitted under requirement R1 and any additional information provided to the ISO, approve the request in whole or in part, or disapprove the request.
 - **R6.1** The **ISO** must, where the request submitted under requirement R1 is approved, provide a copy of its decision, in writing, to the Responsible Entity that has requested the **technical feasibility exception** and set out:
 - (a) any terms and conditions of the approval; and
 - (b) the expiration date of the approval.
 - **R6.2** The **ISO** must, where the request submitted under requirement R1 is disapproved, provide a copy of its decision, including reasons, in writing, to the Responsible Entity that has requested the **technical feasibility exception**.
- **MR6** Evidence of an approval or disapproval of the request as described in requirement R6 exists. Evidence may include but is not limited to a dated copy of the approval or disapproval.
- R7 A Responsible Entity must, where there is a material change in the facts underlying the request for or approval of a **technical feasibility exception**, submit a revised request to the **ISO** under requirement R2 within sixty (60) **days** of becoming aware of the material change.
- **MR7** Evidence of submitting a revised request to the **ISO** in accordance with requirement R7 exists. Evidence may include, but is not limited to, a dated record of becoming aware of a material change in facts and a dated hard copy or electronic copy of the revised request, or other equivalent evidence.
- R8 The ISO may, after providing written notice to the Responsible Entity, amend or terminate a **technical feasibility exception** prior to the expiration date of the **technical feasibility exception** where:
 - (a) a Responsible Entity does not fulfill the terms and conditions of the approval;
 - (b) there is a material change in the facts underlying the approval; or
 - (c) the Responsible Entity advises the **ISO**, in writing, that the **technical feasibility exception** is no longer required.
- MR8 Evidence of amending or terminating a **technical feasibility exception** and providing notice prior to the expiration date of the approval as described in requirement R8 exists. Evidence may include, but is not limited to, a dated hard copy or electronic copy of the amended or terminated **technical feasibility exception** provided to the Responsible Entity.

Revision History

Date	Description	
2017-03-21	Initial release.	

Effective: 2017-03-21 Page 2 of 2 Public

A. Introduction

1. Title: Cyber Security – BES Cyber System Categorization

2. Number: CIP-002-AB-5.1

- 3. Purpose: To identify and categorize BES cyber systems and their associated BES cyber assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES cyber systems could have on the reliable operation of the bulk electric system. Identification and categorization of BES cyber systems support appropriate protection against compromises that could lead to misoperation or instability in the bulk electric system.
- 4. Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility:
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;

4.1.5. [Intentionally left blank.]

Effective: 2017-10-01 Page 1 of 8

- 4.1.6. [Intentionally left blank.]
- 4.1.7. the operator of a transmission facility;
- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more:
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more generating units or aggregated generating facilities with a combined maximum authorized real power of less than or equal to 67.5 MW and does not connect a contracted blackstart resource: or

Effective: 2017-10-01 Page 2 of 8

- 4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**:
- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource;
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 67.5 MW unless the **aggregated** generating facility is part of an industrial complex;
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.4.3. a contracted blackstart resource;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

Effective: 2017-10-01 Page 3 of 8

- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:
 - (i) control centres and backup control centres;
 - (ii) transmission stations and substations;
 - (iii) generating units and aggregated generating facilities;
 - (iv) systems and facilities critical to system restoration, including contracted **blackstart resources** and **cranking paths** and initial switching requirements;
 - remedial action schemes that support the reliable operation of the bulk electric system; and
 - (vi) for the legal owner of an electric distribution system or legal owner of a transmission facility, protection systems specified in Applicability subsection 4.2.1 above.
 - **1.1.** Identify each of the high impact **BES cyber systems** according to Attachment 1, Section 1, if any, at each asset;
 - **1.2.** Identify each of the medium impact **BES cyber systems** according to Attachment 1, Section 2, if any, at each asset; and
 - **1.3.** Identify each asset that contains a low impact **BES cyber system** according to Attachment 1, Section 3, if any (a discrete list of low impact **BES cyber systems** is not required).
- **M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by requirement R1, and Parts 1.1 and 1.2.
- **R2.** The Responsible Entity shall:
 - **2.1.** review the identifications in requirement R1 and its parts (and update them if there are changes identified) at least once every 15 **months**, even if it has no identified items in requirement R1, and
 - 2.2. have its CIP senior manager or delegate approve the identifications required by requirement R1 at least once every 15 months, even if it has no identified items in requirement R1.
- M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in requirement R1 and its parts, and has had its CIP senior manager or delegate approve the identifications required in requirement R1 and its parts at least once every 15 months, even if it has none identified in requirement R1 and its parts, as required by requirement R2.

Effective: 2017-10-01 Page 4 of 8

Attachments

Attachment 1 - Impact Rating Criteria

Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 5 of 8

CIP-002-AB-5.1 Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES cyber system used by and located at any of the following:

- 1.1. the ISO's control centre and backup control centre;
- 1.2. [Intentionally left blank.]
- 1.3. each **control centre** or backup **control centre** used to perform the functional obligations of an **operator** of a **transmission facility** for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.8, 2.9, or 2.10; and
- 1.4. each **control centre** or backup **control centre** used to perform the functional obligations of the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** for one or more of the assets that meet criterion 2.1, 2.3, 2.6, 2.8, or 2.9.

2. Medium Impact Rating (M)

Each BES cyber system, not included in Section 1 above, associated with any of the following:

- 2.1. commissioned generation, by each group of generating units or aggregated generating facilities at a single plant location, with an aggregate maximum authorized real power rating of each of the generating units minus the station service load equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units or aggregated generating facilities, the only BES cyber systems that meet this criterion are those shared BES cyber systems that could, within 15 minutes, adversely impact the reliable operation of any combination of generating units and/or aggregated generating facilities that in aggregate equal or exceed 1500 MW in a single Interconnection;
- 2.2. each bulk electric system reactive resource or group of resources at a single location (excluding generating units and aggregated generating facilities) with an aggregate maximum reactive power nameplate rating of 1000 MVAR or greater(excluding those at generating units or aggregated generating facilities). The only BES cyber systems that meet this criterion are those shared BES cyber systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR;
- 2.3. each generating unit and aggregated generating facility that the ISO designates, and informs the legal owner of the generating unit or legal owner of the aggregated generating facility, as necessary to avoid an adverse reliability impact in the planning horizon of more than one year;
- 2.4. **transmission facilities** operated at 500 kV or higher;

Effective: 2017-10-01 Page 6 of 8

2.5. transmission facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing bulk electric system transmission line that is connected to another transmission station or substation:

Voltage Value of a Line	Weight Value per Line
Less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. **generating units** at a single plant location, **aggregated generating facilities** or **transmission facilities** at a single station or substation location that are identified by the **ISO** as critical to the derivation of **interconnection reliability operating limits** and their associated contingencies:
- 2.7. [Intentionally left blank.]
- 2.8. transmission facilities and switchyards associated with generating units or aggregated generating facilities that connect the generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of a generating unit or an aggregated generating facility identified by any legal owner of a generating unit or any legal owner of an aggregated generating facility as a result of its application of Attachment 1, criterion 2.1 or 2.3;
- 2.9. each remedial action scheme, or automated switching system that operates system element(s) of the bulk electric system, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more interconnection reliability operating limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable;
- 2.10. each system or group of element(s) that performs automatic load shedding under a common control system, without human operator initiation, of 300 MW or more implementing under voltage load shed or underfrequency load shedding under a load shedding program that is subject to one or more requirements in a reliability standard;
- 2.11. each **control centre** or backup **control centre**, not already included in High Impact Rating (H) above, used to perform the functional obligations of the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** for an aggregate highest rated net **real power** capability of the preceding 12 **months** equal to or exceeding 1500 MW; and
- 2.12. each **control centre** or backup **control centre** used to perform the functional obligations of the **operator** of a **transmission facility** not included in High Impact Rating (H), above, with

Effective: 2017-10-01 Page 7 of 8

Alberta Reliability Standard Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1

the exception of the **operator** of a transmission facility whose only transmission facility is a radial connection from either a **generating unit**, **aggregated generating facility** or industrial complex to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat.

2.13. [Intentionally left blank.]

3. Low Impact Rating (L)

BES cyber systems not included in sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in subsection 4.2 of this **reliability standard**:

- 3.1. control centres and backup control centres;
- 3.2. transmission stations and substations;
- 3.3. generating units and aggregated generating facilities;
- 3.4. systems and facilities critical to system restoration, including contracted **blackstart resources** and **cranking paths** and initial switching requirements;
- 3.5 remedial action schemes that support the reliable operation of the bulk electric system; and
- 3.6. for a legal owner of an electric distribution system or legal owner of a transmission facility, protection systems specified in subsection 4.2.1 of this reliability standard.

Effective: 2017-10-01 Page 8 of 8



A. Introduction

- 1. Title: Cyber Security Security Management Controls
- 2. Number: CIP-003-AB-5
- 3. Purpose: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.
- 4. Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more:
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the operator of a transmission facility;

Effective: 2017-10-01, except R2 Effective: 2018-10-01 Page 1 of 5



- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started:
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**:
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or
 - 4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

Effective: 2017-10-01, except R2 Effective: 2018-10-01 Page 2 of 5



of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource:
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW: or
 - 4.2.2.4.3. a contracted **blackstart resource**;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

Effective: 2017-10-01, except R2 Effective: 2018-10-01



B. Requirements and Measures

- **R1.** Each Responsible Entity, for its High Impact and Medium Impact **BES cyber systems**, shall review and obtain **CIP senior manager** approval at least once every 15 **months** for one or more documented cyber security policies that collectively address the following topics:
 - 1.1 Personnel & training (CIP-004-AB-5.1);
 - 1.2 Electronic security perimeters (CIP-005-AB-5) including interactive remote access;
 - 1.3 Physical security of BES cyber systems (CIP-006-AB-5);
 - 1.4 System security management (CIP-007-AB-5);
 - **1.5** Incident reporting and response planning (CIP-008-AB-5);
 - **1.6** Recovery plans for **BES cyber systems** (CIP-009-AB-5);
 - 1.7 Configuration change management and vulnerability assessments (CIP-010-AB-1);
 - 1.8 Information protection (CIP-011-AB-1); and
 - **1.9** Declaring and responding to CIP exceptional circumstances.
- M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 months; and documented approval by the CIP senior manager for each cyber security policy.
- **R2.** Each Responsible Entity for its assets identified in CIP-002-AB-5.1, requirement R1, part 1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain **CIP senior manager** approval for those policies at least once every 15 **months**:
 - **2.1** Cyber security awareness;
 - 2.2 Physical security controls;
 - 2.3 Electronic access controls for external routable protocol connections and dial-up connectivity; and
 - **2.4** Incident response to a **cyber security incident**.
 - An inventory, list, or discrete identification of Low Impact BES cyber systems or their BES cyber assets is not required.
- M2. Examples of evidence may include, but are not limited to, one or more documented cyber security policies and evidence of processes, procedures, or plans that demonstrate the implementation of the required topics; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 months; and documented approval by the CIP senior manager for each cyber security policy.
- **R3.** Each Responsible Entity shall identify a **CIP senior manager** by name and document any change within 30 **days** of the change.

Effective: 2017-10-01, except R2 Effective: 2018-10-01 Page 4 of 5



- **M3.** An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the **CIP senior manager**.
- R4. The Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP reliability standards, the CIP senior manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP senior manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator.
- **M4.** An example of evidence may include, but is not limited to, a dated document, approved by the **CIP senior manager**, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

Revision History

Date	Description
2017-10-01	Initial release.

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A. Introduction

1. Title: Cyber Security – Personnel & Training

2. Number: CIP-004-AB-5.1

- Purpose: To minimize the risk against compromise that could lead to misoperation or instability in the **bulk electric system** from individuals accessing **BES cyber systems** by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting **BES cyber systems**.
- Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more:
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]

Effective: 2017-10-01 Page 1 of 14



- 4.1.7. the operator of a transmission facility;
- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or
 - 4.2.2.1.4. radially connects to load and one or more generating units or aggregated

Effective: 2017-10-01 Page 2 of 14



generating facilities that have a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**:

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use:
- 4.2.2.3. a **generating unit** that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an **aggregated generating facility**;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource;
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.4.3. a contracted blackstart resource;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized

Effective: 2017-10-01 Page 3 of 14



as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R1 Security Awareness Program.*
- **M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R1 Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-004-AB-5.1 Table R1 – Security Awareness Program		
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES cyber systems Medium Impact BES cyber systems	Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity's personnel who have authorized electronic or authorized unescorted physical access to BES cyber systems.	An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as: • direct communications (for example, e-mails, memos, computer-based training); or • indirect communications (for example, posters, intranet, or brochures); or

R2. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-AB*-

Effective: 2017-10-01 Page 4 of 14



- 5.1 Table R2 Cyber Security Training Program.
- **M2.** Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-AB-5.1 Table R2 Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

	CIP-004-AB-5.1 Table R2 – Cyber Security Training Program		
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES cyber systems and their associated:	Training content on: 2.1.1. cyber security policies;	Examples of evidence may include, but are not limited to,
	electronic access control and monitoring systems; and	2.1.2. physical access controls;	training material such as power point presentations, instructor notes, student notes,
	physical access control systems.	2.1.3. electronic access controls;	handouts, or other training materials.
	Medium Impact BES cyber systems with external	2.1.4. the visitor control program;	
	routable connectivity and their associated:	2.1.5. handling of BES cyber system information and its storage;	
	electronic access control and monitoring systems; and physical access control systems.	2.1.6. identification of a cyber security incident and initial notifications in accordance with the entity's incident response plan;	
		2.1.7. recovery plans for BES cyber systems;	
		2.1.8. response to cyber security incidents; and	
		2.1.9. cyber security risks associated with a BES cyber system 's electronic interconnectivity and interoperability with other cyber assets .	
2.2	High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and	Require completion of the training specified in part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable	Examples of evidence may include, but are not limited to, training records and documentation of when CIP exceptional circumstances were invoked.

Effective: 2017-10-01 Page 5 of 14



	CIP-004-AB-5.1 Table R2 – Cyber Security Training Program		
Part	Applicable Systems	Requirements	Measures
	physical access control systems.	cyber assets, except during CIP exceptional circumstances.	
	Medium Impact BES cyber systems with external routable connectivity and their associated:	circumstances.	
	electronic access control and monitoring systems; and		
	physical access control systems.		
2.3	High Impact BES cyber systems and their associated:	Require completion of the training specified in part 2.1 at	Examples of evidence may include, but are not limited to,
	electronic access control and monitoring systems; and	least once every 15 months	dated individual training records.
	physical access control systems.		
	Medium Impact BES cyber systems with external routable connectivity and their associated:		
	electronic access control and monitoring systems; and		
	physical access control systems.		

- **R3.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented personnel risk assessment programs to attain and retain authorized electronic or authorized unescorted physical access to **BES Cyber Systems** that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R3 Personnel Risk Assessment Program*.
- **M3.** Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R3 Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

Effective: 2017-10-01 Page 6 of 14



	CIP-004-AB-5.1 Tab	le R3 – Personnel Risk Assessn	nent Program
Part	Applicable Systems	Requirements	Measures
3.1	High Impact BES cyber systems and their associated:	Process to confirm identity.	An example of evidence may include, but is not limited to, documentation of the
	electronic access control and monitoring systems; and		Responsible Entity's process to confirm identity.
	physical access control systems.		
	Medium Impact BES cyber systems with external routable connectivity and their associated:		
	electronic access control and monitoring systems; and		
	physical access control systems.		
3.2	High Impact BES cyber systems and their associated:	Process to perform a seven year criminal history records	An example of evidence may include, but is not limited to,
	electronic access control and monitoring systems; and	check as part of each personnel risk assessment that includes:	documentation of the Responsible Entity's process to perform a seven year criminal history records check.
	physical access control systems.	3.2.1. current residence, regardless of duration; and	Chiminal history records check.
	Medium Impact BES cyber systems with external routable connectivity and their associated:	3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has	
	electronic access control and monitoring systems;	resided for six consecutive months or more.	
	and 2. physical access control systems.	If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.	

Effective: 2017-10-01 Page 7 of 14



	CIP-004-AB-5.1 Tab	le R3 – Personnel Risk Assessn	nent Program
Part	Applicable Systems	Requirements	Measures
3.3	High Impact BES cyber systems and their associated:	Criteria or process to evaluate criminal history records checks	An example of evidence may include, but is not limited to,
	electronic access control and monitoring systems; and	for authorizing access.	documentation of the Responsible Entity's process to evaluate criminal history records checks.
	physical access control systems.		
	Medium Impact BES cyber systems with external routable connectivity and their associated:		
	electronic access control and monitoring systems; and		
	physical access control systems.		
3.4	High Impact BES cyber systems and their associated:	Criteria or process for verifying that personnel risk	An example of evidence may include, but is not limited to,
	electronic access control and monitoring systems; and	assessments performed for contractors or service vendors are conducted according to parts 3.1 through 3.3.	documentation of the Responsible Entity's criteria or process for verifying contractors or service vendors
	physical access control systems.	pante on unough ordi	personnel risk assessments.
	Medium Impact BES cyber systems with external routable connectivity and their associated:		
	electronic access control and monitoring systems; and		
	physical access control systems.		
3.5	High Impact BES cyber systems and their associated:	Process to ensure that individuals with authorized	An example of evidence may include, but is not limited to,
	electronic access control and monitoring systems; and	electronic or authorized unescorted physical access have had a personnel risk	documentation of the Responsible Entity's process for ensuring that individuals

Effective: 2017-10-01 Page 8 of 14



Part	Applicable Systems	Requirements	Measures
rait	physical access control systems.	assessment completed according to parts 3.1 to 3.4 within the last seven years.	with authorized electronic or authorized unescorted physical access have had a
	Medium Impact BES cyber systems with external routable connectivity and their associated:		personnel risk assessment completed within the last seven years.
	electronic access control and monitoring systems; and		
	2. physical access control systems.		

- **R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access management programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R4 Access Management Program*.
- **M4.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R4 Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

	CIP-004-AB-5.1 Table R4 – Access Management Program		
Part	Applicable Systems	Requirements	Measures
4.1	High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems. Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control and monitoring systems; and	Process to authorize based on need, as determined by the Responsible Entity, except for CIP exceptional circumstances: 4.1.1. electronic access; 4.1.2. unescorted physical access into a physical security perimeter; and 4.1.3. access to designated storage locations, whether physical or electronic, for BES cyber system information.	An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a physical security perimeter, and access to designated storage locations, whether physical or electronic, for BES cyber system information.

Effective: 2017-10-01 Page 9 of 14



	CIP-004-AB-5.1 Table R4 – Access Management Program		
Part	Applicable Systems	Requirements	Measures
	physical access control systems.		
4.2	High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems. Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems.	Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.	 Examples of evidence may include, but are not limited to: dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).
4.3	High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems. Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control and monitoring systems; and 2. physical access control	For electronic access, verify at least once every 15 months that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.	An example of evidence may include, but is not limited to, documentation of the review that includes all of the following: 1. a dated listing of all accounts/account groups or roles within the system; 2. a summary description of privileges associated with each group or role; 3. accounts assigned to the group or role; and 4. dated evidence showing verification of the privileges for the group are

Effective: 2017-10-01 Page 10 of 14



	CIP-004-AB-5.1 Table R4 – Access Management Program			
Part	Applicable Systems	Requirements	Measures	
	systems.		authorized and appropriate to the work function performed by people assigned to each account.	
4.4	High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems. Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control and monitoring systems; and	Verify at least once every 15 months that access to the designated storage locations for BES cyber system information, whether physical or electronic, are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.	An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following: 1. a dated listing of authorizations for BES cyber system information; 2. any privileges associated with the authorizations; and 3. dated evidence showing a verification of the	
	physical access control systems.		authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.	

- **R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access revocation programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R5 Access Revocation*.
- **M5.** Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R5 Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-004-AB-5.1 Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures	
5.1	High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and	A process to initiate removal of an individual's ability for unescorted physical access and interactive remote access upon a termination action, and complete the	An example of evidence may include, but is not limited to, documentation of all of the following: 1. dated workflow or sign-off	

Effective: 2017-10-01 Page 11 of 14



	CIP-004-AB-5.1 Table R5 – Access Revocation		
Part	Applicable Systems	Requirements	Measures
	physical access control systems. Medium Impact BES cyber systems with external routable connectivity and their associated: electronic access control	removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).	form verifying access removal associated with the termination action; and 2. logs or other demonstration showing such persons no longer have access.
	and monitoring systems; and 2. physical access control systems.		
5.2	High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems. Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control and monitoring systems; and 2. physical access control	For reassignments or transfers, revoke the individual's authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next day following the date that the Responsible Entity determines that the individual no longer requires retention of that access.	An example of evidence may include, but is not limited to, documentation of all of the following: 1. dated workflow or sign-off form showing a review of logical and physical access; and 2. logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.
5.3	systems. High Impact BES cyber systems and their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems. Medium Impact BES cyber systems with external routable connectivity and	For termination actions, revoke the individual's access to the designated storage locations for BES cyber system information, whether physical or electronic (unless already revoked according to requirement R5.1), by the end of the next day following the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or signoff form verifying access removal to designated physical areas or cyber systems containing BES cyber system information associated with the terminations and dated within the next day of the termination action.

Effective: 2017-10-01 Page 12 of 14



	CIP-004-AB-5.1 Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures	
	their associated: 1. electronic access control and monitoring systems; and 2. physical access control systems.			
5.4	High Impact BES cyber systems and their associated: electronic access control and monitoring systems.	For termination actions, revoke the individual's non-shared user accounts (unless already revoked according to parts 5.1 or 5.3) within 30 days of the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or signoff form showing access removal for any individual BES cyber assets and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions.	
5.5	High Impact BES cyber systems and their associated: • electronic access control and monitoring systems.	For termination actions, change passwords for shared account(s) known to the user within 30 days of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 days following the date that the Responsible Entity determines that the individual no longer requires retention of that access. If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 days following the end of the operating circumstances.	Examples of evidence may include, but are not limited to: • workflow or sign-off form showing password reset within 30 days of the termination; • workflow or sign-off form showing password reset within 30 days of the reassignments or transfers; or • documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 days following the end of the operating circumstance.	

Effective: 2017-10-01 Page 13 of 14



Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 14 of 14

A. Introduction

- 1. Title: Cyber Security Electronic Security Perimeter(s)
- 2. Number: CIP-005-AB-5
- 3. Purpose: To manage electronic access to **BES cyber systems** by specifying a controlled **electronic security perimeter** in support of protecting **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.
- 4. Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more:
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the operator of a transmission facility;

Effective: 2017-10-01 Page 1 of 7

- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more:
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started:
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**:
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or
 - 4.2.2.1.4. radially connects to load and one or more generating units or aggregated generating facilities that have a combined maximum authorized real power

Effective: 2017-10-01 Page 2 of 7

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource:
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex:
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW: or
 - 4.2.2.4.3. a contracted **blackstart resource**;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

Effective: 2017-10-01 Page 3 of 7

categorization processes.

- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-AB-5 Table R1 Electronic Security Perimeter*.
- **M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-005-AB-5 Table R1 Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-005-AB-5 Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures	
1.1	High Impact BES cyber systems and their associated: • protected cyber assets Medium Impact BES cyber systems and their associated: • protected cyber assets	All applicable cyber assets connected to a network via a routable protocol shall reside within a defined electronic security perimeter.	An example of evidence may include, but is not limited to, a list of all electronic security perimeters with all uniquely identifiable applicable cyber assets connected via a routable protocol within each electronic security perimeter.	
1.2	High Impact BES cyber systems with external routable connectivity and their associated: • protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: • protected cyber assets	All external routable connectivity must be through an identified electronic access point.	An example of evidence may include, but is not limited to, network diagrams showing all external routable communication paths and the identified electronic access points.	
1.3	Electronic access points for High Impact BES cyber systems Electronic access points for Medium Impact BES cyber	Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.	An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed	

Effective: 2017-10-01 Page 4 of 7

	CIP-005-AB-5 Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures	
	systems		and that each access rule has a documented reason.	
1.4	High Impact BES cyber systems with dial-up connectivity and their associated: • protected cyber assets Medium Impact BES cyber systems with dial-up connectivity and their associated: • protected cyber assets	Where technically feasible, perform authentication when establishing dial-up connectivity with applicable cyber assets.	An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.	
1.5	Electronic access points for High Impact BES cyber systems Electronic access points for Medium Impact BES cyber systems at control centres	Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.	An example of evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, etc.) are implemented.	

- R2. Each Responsible Entity allowing Interactive Remote Access to **BES cyber systems** shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-AB -5 Table R2 Interactive Remote Access Management*.
- **M2.** Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-AB -5 Table R2 Interactive Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-005-AB-5 Table R2 – Interactive Remote Access Management			
Part	Applicable Systems	Requirements	Measures	
2.1	High Impact BES cyber systems and their associated: • protected cyber assets Medium Impact BES cyber systems with external routable connectivity and	Utilize an intermediate system such that the cyber asset initiating interactive remote access does not directly access an applicable cyber asset.	Examples of evidence may include, but are not limited to, network diagrams or architecture documents.	

Effective: 2017-10-01 Page 5 of 7

	CIP-005-AB-5 Table R2 – Interactive Remote Access Management			
Part	Applicable Systems	Requirements	Measures	
	their associated:			
	protected cyber assets			
2.2	High Impact BES cyber systems and their associated: • protected cyber assets Medium Impact BES cyber	For all interactive remote access sessions, utilize encryption that terminates at an intermediate system.	An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.	
	systems with external routable connectivity and their associated: protected cyber assets			
2.3	High Impact BES cyber systems and their associated: • protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: • protected cyber assets	Require multi-factor authentication for all interactive remote access sessions.	An example of evidence may include, but is not limited to, architecture documents detailing the authentication factors used. Examples of authenticators may include, but are not limited to, • something the individual knows such as passwords or PINs. This does not include User ID; • something the individual has such as tokens, digital certificates, or smart cards; or • something the individual is such as fingerprints, iris scans, or other biometric characteristics.	

Revision History

Effective: 2017-10-01 Page 6 of 7

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 7 of 7

A. Introduction

- 1. Title: Cyber Security Physical Security of BES Cyber Systems
- 2. Number: CIP-006-AB-5
- Purpose: To manage physical access to BES cyber systems by specifying a physical security plan in support of protecting BES cyber systems against compromise that could lead to misoperation or instability in the bulk electric system.
- 4. Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities." For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more:
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the operator of a transmission facility;

Effective: 2017-10-01 Page 1 of 10

- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more:
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started:
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**:
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or
 - 4.2.2.1.4. radially connects to load and one or more generating units or aggregated generating facilities that have a combined maximum authorized real power

Effective: 2017-10-01 Page 2 of 10

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource:
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex:
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW: or
 - 4.2.2.4.3. a contracted **blackstart resource**;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

Effective: 2017-10-01 Page 3 of 10

categorization processes.

- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented physical security plans that collectively include all of the applicable requirement parts in CIP-006-AB-5 Table R1 Physical Security Plan.
- **M1.** Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-AB-5 Table R1 Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

	CIP-006-AB-5 Table R1 – Physical Security Plan		
Part	Applicable Systems	Requirements	Measures
1.1	Medium Impact BES cyber systems without external routable connectivity	Define operational or procedural controls to restrict physical access.	An example of evidence may include, but is not limited to, documentation that operational
	Physical access control systems associated with:		or procedural controls exist.
	High Impact BES cyber systems, or		
	Medium Impact BES cyber systems with external routable connectivity		
1.2	Medium Impact BES cyber systems with external routable connectivity and their associated:	Utilize at least one physical access control to allow unescorted physical access into each applicable physical security perimeter to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes
	electronic access control or monitoring systems; and		each physical security perimeter and how unescorted physical access is controlled by one or more
	2. protected cyber assets		different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

Effective: 2017-10-01 Page 4 of 10

CIP-006-AB-5 Table R1 – Physical Security			Plan
Part	Applicable Systems	Requirements	Measures
1.3	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets	Where technically feasible, utilize two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into physical security perimeters to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the physical security perimeters and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.
1.4	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets	Monitor for unauthorized access through a physical access point into a physical security perimeter.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a physical security perimeter.
1.5	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated:	Issue an alarm or alert in response to detected unauthorized access through a physical access point into a physical security perimeter to the personnel identified in the bulk electric system cyber security incident response plan within 15 minutes of detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a physical security perimeter and additional evidence that the alarm or alert was issued and communicated as

Effective: 2017-10-01 Page 5 of 10

	CIP-006-AB-5 Table R1 – Physical Security Plan		
Part	Applicable Systems	Requirements	Measures
	electronic access control or monitoring systems; and protected cyber assets		identified in the bulk electric system cyber security incident response plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.
1.6	Physical access control systems associated with: High Impact BES cyber systems, or Medium Impact BES cyber systems with external routable connectivity	Monitor each physical access control system for unauthorized physical access to a physical access control system.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a physical access control system.
1.7	Physical access control systems associated with: High Impact BES cyber systems, or Medium Impact BES cyber systems with external routable connectivity	Issue an alarm or alert in response to detected unauthorized physical access to a physical access control system to the personnel identified in the bulk electric system cyber security incident response plan within 15 minutes of the detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to physical access to physical access control systems and additional evidence that the alarm or alerts was issued and communicated as identified in the bulk electric system cyber security incident response plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated.
1.8	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and	Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access	An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of

Effective: 2017-10-01 Page 6 of 10

	CIP-006-AB-5 Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures	
	2. protected cyber assets	into each physical security perimeter , with information to	physical entry into each physical security perimeter	
	Medium Impact BES cyber systems with external routable connectivity and their associated:	identify the individual and date and time of entry.	and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into	
	electronic access control or monitoring systems; and		physical security perimeters that show the individual and the date and time of entry into physical security perimeter.	
	2. protected cyber assets			
1.9	High Impact BES cyber systems and their associated:	Retain physical access logs of entry of individuals with	An example of evidence may include, but is not limited to,	
	electronic access control or monitoring systems; and	authorized unescorted physical access into each physical security perimeter for at least ninety days.	dated documentation such as logs of physical access into physical security perimeters that show the date and time of	
	2. protected cyber assets	, ,	entry into physical security	
	Medium Impact BES cyber systems with external routable connectivity and their associated:		perimeter.	
	electronic access control or monitoring systems; and			
	2. protected cyber assets			

- **R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented visitor control programs that include each of the applicable requirement parts in *CIP-006-AB-5 Table R2 Visitor Control Program*.
- **M2.** Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-AB-5 Table R2 Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-AB-5 Table R2 – Visitor Control Program

Effective: 2017-10-01 Page 7 of 10

Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control or monitoring systems; and	Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each physical security perimeter, except during CIP exceptional circumstances.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within physical security perimeters and additional evidence to demonstrate that the process was implemented, such as visitor logs.
	2. protected cyber assets		
2.2	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets	Require manual or automated logging of visitor entry into and exit from the physical security perimeter that includes date and time of the initial entry and last exit, the visitor's name, and the name of an individual point of contact responsible for the visitor, except during CIP exceptional circumstances.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within physical security perimeters and additional evidence to demonstrate that the process was implemented, such as dated visitor logs that include the required information.
2.3	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and	Retain visitor logs for at least ninety days .	An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety days.

Effective: 2017-10-01 Page 8 of 10

CIP-006-AB-5 Table R2 – Visitor Control Program					
Part	Applicable Systems	Requirements	Measures		
	their associated:				
	electronic access control or monitoring systems; and				
	2. protected cyber assets				

- **R3.** Each Responsible Entity shall implement one or more documented **physical access control system** maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-AB-5 Table R3 Maintenance and Testing Program*.
- **M3.** Evidence must include each of the documented **physical access control system** maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-AB-5 Table R3 Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-AB-5 Table R3 – Maintenance and Testing Program				
Part	Applicable Systems	Requirements	Measures	
3.1	Physical access control systems associated with: High Impact BES cyber systems, or Medium Impact BES cyber systems with external routable connectivity Locally mounted hardware or devices at the physical security perimeter associated with: High Impact BES cyber systems, or Medium Impact BES cyber systems with external routable connectivity	Maintenance and testing of each physical access control system and locally mounted hardware or devices at the physical security perimeter at least once every 24 months to ensure they function properly.	An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each physical access control system and locally mounted hardware or devices associated with each applicable physical security perimeter at least once every 24 months and additional evidence to demonstrate that this testing was done, such as dated maintenance records, or other documentation showing testing and maintenance has been performed on each applicable device or system at least once every 24 months.	

Revision History

Effective: 2017-10-01 Page 9 of 10

Alberta Reliability Standard Cyber Security – Physical Security of BES Cyber Systems CIP-006-AB-5

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 10 of 10



A. Introduction

1. Title: Cyber Security – System Security Management

2. Number: CIP-007-AB-5

- 3. Purpose: To manage system security by specifying select technical, operational, and procedural requirements in support of protecting **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.
- 4. Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more:
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the operator of a transmission facility;

Effective: 2017-10-01 Page 1 of 14



- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more:
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started:
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**:
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more generating units or aggregated generating facilities with a combined maximum authorized real power of less than or equal to 67.5 MW and does not connect a contracted blackstart resource; or
 - 4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

Effective: 2017-10-01 Page 2 of 14



of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource:
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 67.5 MW unless the **aggregated** generating facility is part of an industrial complex:
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW: or
 - 4.2.2.4.3. a contracted blackstart resource;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

Effective: 2017-10-01 Page 3 of 14





categorization processes.

- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R1 Ports and Services*.
- **M1.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R1 Ports and Services* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-007-AB-5 Table R1 – Ports and Services		
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed.	 Examples of evidence may include, but are not limited to: documentation of the need for all enabled ports on all applicable cyber assets and electronic access points, individually or by group. listings of the listening ports on the cyber assets, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others.
1.2	High Impact BES cyber systems Medium Impact BES cyber systems at control centres	Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or removable	An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either

Effective: 2017-10-01 Page 4 of 14





CIP-007-AB-5 Table R1 – Ports and Services			
Part	Applicable Systems	Requirements	Measures
		media.	logically through system configuration or physically using a port lock or signage.

- **R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R2 Security Patch Management*.
- **M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R2 Security Patch Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-007-AB-5	Table R2 – Security Patch Mana	ngement
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES cyber systems and their associated:	A patch management process for tracking, evaluating, and	An example of evidence may include, but is not limited to,
	electronic access control or monitoring systems;	installing cyber security patches for applicable cyber assets. The tracking portion	documentation of a patch management process and documentation or lists of
	physical access control systems; and	shall include the identification of a source or sources that the	sources that are monitored, whether on an individual BES
	3. protected cyber assets	Responsible Entity tracks for the release of cyber security	cyber system or cyber asset basis.
	Medium Impact BES cyber systems and their associated:	patches for applicable cyber assets that are updateable and for which a patching source exists.	
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		
2.2	High Impact BES cyber systems and their associated:	At least once every 35 days, evaluate security patches for	An example of evidence may include, but is not limited to, an
	electronic access control or monitoring systems;	applicability that have been released since the last evaluation from the source or sources identified in part 2.1.	evaluation conducted by, referenced by, or on behalf of a Responsible Entity of
	physical access control systems; and		sources identified in part 2.1. security-related patches released by the docume
	3. protected cyber assets		sources at least once every 35 days.

Effective: 2017-10-01 Page 5 of 14



	CIP-007-AB-5 Table R2 – Security Patch Management			
Part	Applicable Systems	Requirements	Measures	
	Medium Impact BES cyber systems and their associated: 1. electronic access control			
	 or monitoring systems; physical access control systems; and protected cyber assets 			
2.3	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	For applicable patches identified in part 2.2, within 35 days of the evaluation completion, take one of the following actions: • apply the applicable patches; or • create a dated mitigation plan; or • revise an existing mitigation plan. Mitigation plans shall include the Responsible Entity's planned actions to mitigate the vulnerabilities addressed by each security patch and a timeframe to complete these mitigations.	Examples of evidence may include, but are not limited to: • records of the installation of the patch (e.g., exports from automated patch management tools that provide installation date, verification of BES cyber system component software revision, or registry exports that show software has been installed); or • a dated plan showing when and how the vulnerability will be addressed, to include documentation of the actions to be taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch and a timeframe for the completion of these mitigations.	
2.4	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and	For each mitigation plan created or revised in part 2.3, implement the plan within the timeframe specified in the plan, unless a revision to the plan or an extension to the timeframe specified in part 2.3 is approved by the CIP senior	An example of evidence may include, but is not limited to, records of implementation of mitigations.	

Effective: 2017-10-01 Page 6 of 14





	CIP-007-AB-5 Table R2 – Security Patch Management			
Part	Applicable Systems	Requirements	Measures	
	3. protected cyber assets	manager or delegate.		
	Medium Impact BES cyber systems and their associated:			
	electronic access control or monitoring systems;			
	physical access control systems; and			
	3. protected cyber assets			

- **R3.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R3 Malicious Code Prevention*.
- **M3.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R3 Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-007-AB-5 Table R3 – Malicious Code Prevention		
Part	Applicable Systems	Requirements	Measures
3.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems;	Deploy method(s) to deter, detect, or prevent malicious code.	An example of evidence may include, but is not limited to, records of the Responsible Entity's performance of these processes (e.g., through
	physical access control systems; and		traditional antivirus, system hardening, policies, etc.).
	3. protected cyber assets		
	Medium Impact BES cyber systems and their associated:		
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		
3.2	High Impact BES cyber systems and their associated:	Mitigate the threat of detected malicious code.	Examples of evidence may include, but are not limited to:

Effective: 2017-10-01 Page 7 of 14



	CIP-007-AB-5 Table R3 – Malicious Code Prevention		
Part	Applicable Systems	Requirements	Measures
	electronic access control or monitoring systems;		records of response processes for malicious
	physical access control systems; and		code detectionrecords of the performance
	3. protected cyber assets		of these processes when malicious code is detected.
	Medium Impact BES cyber systems and their associated:		a.io.ouo oouo lo uotootiou.
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		
3.3	High Impact BES cyber systems and their associated:	For those methods identified in part 3.1 that use signatures or	An example of evidence may include, but is not limited to,
	electronic access control or monitoring systems;	patterns, have a process for the update of the signatures or patterns. The process must	documentation showing the process used for the update of signatures or patterns.
	physical access control systems; and	address testing and installing the signatures or patterns.	organismos en paniermos
	3. protected cyber assets		
	Medium Impact BES cyber systems and their associated:		
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		

- **R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R4 Security Event Monitoring*.
- **M4.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R4 Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

Effective: 2017-10-01 Page 8 of 14





	CIP-007-AB-5	Table R4 – Security Event Mon	itoring
Part	Applicable Systems	Requirements	Measures
4.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	Log events at the BES cyber system level (per BES cyber system capability) or at the cyber asset level (per cyber asset capability) for identification of, and after-the-fact investigations of, cyber security incidents that includes, as a minimum, each of the following types of events: 4.1.1. detected successful login attempts; 4.1.2. detected failed access attempts and failed login attempts;	Examples of evidence may include, but are not limited to, a paper or system generated listing of event types for which the BES cyber system is capable of detecting and, for generated events, is configured to log. This listing must include the required types of events.
	,	4.1.3. detected malicious code.	
4.2	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	Generate alerts for security events that the Responsible Entity determines necessitates an alert, that includes, as a minimum, each of the following types of events (per cyber asset or BES cyber system capability): 4.2.1. detected malicious code from part 4.1; and 4.2.2. detected failure of part 4.1 event logging.	Examples of evidence may include, but are not limited to, paper or system generated listing of security events that the Responsible Entity determined necessitate alerts, including paper or system generated list showing how alerts are configured.
4.3	High Impact BES cyber systems and their associated:	Where technically feasible, retain applicable event logs identified in part 4.1 for at least	Examples of evidence may include, but are not limited to, documentation of the event log

Effective: 2017-10-01 Page 9 of 14



	CIP-007-AB-5 Table R4 – Security Event Monitoring		
Part	Applicable Systems	Requirements	Measures
	electronic access control or monitoring systems;	the last 90 consecutive days except under CIP exceptional circumstances.	retention process and paper or system generated reports showing log retention
	physical access control systems; and		configuration set at 90 days or greater.
	3. protected cyber assets		
	Medium Impact BES cyber systems at control centres and their associated:		
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		
4.4	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and	Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 days to identify undetected cyber	Examples of evidence may include, but are not limited to, documentation describing the review, any findings from the review (if any), and dated documentation showing the
	2. protected cyber assets	security incidents.	review occurred.

- **R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R5 System Access Controls*.
- **M5.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts *in CIP-007-AB-5 Table 5 System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-007-AB-5 Table R5 - System Access Controls			
Part	Applicable Systems	Requirements	Measures	
5.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems;	Have a method(s) to enforce authentication of interactive user access, where technically feasible.	An example of evidence may include, but is not limited to, documentation describing how access is authenticated.	
	2. physical access control			

Effective: 2017-10-01 Page 10 of 14



	CIP-007-AB-	5 Table R5 – System Access Co	entrols
Part	Applicable Systems systems; and	Requirements	Measures
	3. protected cyber assets		
	Medium Impact BES cyber systems at control centres and their associated:		
	electronic access control or monitoring systems;		
	physical access control systems; and		
Ì	3. protected cyber assets		
	Medium Impact BES cyber systems with external routable connectivity and their associated:		
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		
5.2	High Impact BES cyber systems and their associated:	Identify and inventory all known enabled default or other	An example of evidence may include, but is not limited to, a
	electronic access control or monitoring systems;	generic account types, either by system, by groups of systems, by location, or by	listing of accounts by account types showing the enabled or generic account types in use
	physical access control systems; and	system type(s).	for the BES cyber system.
	3. protected cyber assets		
	Medium Impact BES cyber systems and their associated:		
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		

Effective: 2017-10-01 Page 11 of 14



	CIP-007-AB-	5 Table R5 – System Access Co	ontrols
Part	Applicable Systems	Requirements	Measures
5.3	High Impact BES cyber systems and their associated: 1. electronic access control	Identify individuals who have authorized access to shared accounts.	An example of evidence may include, but is not limited to, listing of shared accounts and
	or monitoring systems;		the individuals who have authorized access to each
	physical access control systems; and		shared account.
	3. protected cyber assets		
	Medium Impact BES cyber systems with external routable connectivity and their associated:		
	electronic access control or monitoring systems;		
	physical access control systems; and		
	3. protected cyber assets		
5.4	High Impact BES cyber systems and their associated:	Change known default passwords, per cyber asset	Examples of evidence may include, but are not limited to:
	electronic access control or monitoring systems;	capability.	records of a procedure that passwords are changed
	physical access control systems; and		when new devices are in production; or
	3. protected cyber assets		documentation in system manuals or other vendor
	Medium Impact BES cyber systems and their associated:		documents showing default vendor passwords
	electronic access control or monitoring systems;		were generated pseudo- randomly and are thereby unique to the device.
	physical access control systems; and		aque to a.e. ueee.
	3. protected cyber assets		
5.5	High Impact BES cyber systems and their associated:	For password-only authentication for interactive	Examples of evidence may include, but are not limited to:
	electronic access control or monitoring systems;	user access, either technically or procedurally enforce the following password	system-generated reports or screen-shots of the

Effective: 2017-10-01 Page 12 of 14





	CIP-007-AB-5 Table R5 – System Access Controls			
Part	Applicable Systems	Requirements	Measures	
	2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	parameters: 5.5.1. password length that is, at least, the lesser of eight characters or the maximum length supported by the cyber asset ; and 5.5.2. minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, nonalphanumeric) or the maximum complexity supported by the cyber asset .	system enforced password parameters, including length and complexity; or • attestations that include a reference to the documented procedures that were followed.	
5.6	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems with external routable connectivity and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	Where technically feasible, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 months.	Examples of evidence may include, but are not limited to: • system-generated reports or screen-shots of the system enforced periodicity of changing passwords; or • attestations that include a reference to the documented procedures that were followed.	
5.7	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control	Where technically feasible, either: • limit the number of unsuccessful authentication attempts; or	Examples of evidence may include, but are not limited to: documentation of the account-lockout parameters; or	

Effective: 2017-10-01 Page 13 of 14



	CIP-007-AB-5 Table R5 – System Access Controls			
Part	Applicable Systems	Requirements	Measures	
	systems; and	generate alerts after a	rules in the alerting	
	3. protected cyber assets	threshold of unsuccessful	configuration showing how	
	Medium Impact BES cyber systems at control centres and their associated:	authentication attempts.	the system notified individuals after a determined number of unsuccessful login	
	electronic access control or monitoring systems;		attempts.	
	physical access control systems; and			
	3. protected cyber assets			

Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 14 of 14

A. Introduction

- 1. Title: Cyber Security Incident Reporting and Response Planning
- 2. Number: CIP-008-AB-5
- 3. Purpose: To mitigate the risk to the reliable operation of the **bulk electric system** as the result of a **cyber security incident** by specifying incident response requirements.
- 4. Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more:
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each cranking path and group of elements meeting the initial switching requirements from a contracted blackstart resource up to and including the first point of supply and/or point of delivery of the next generating unit or aggregated generating facility to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility:
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the **operator** of a **transmission facility**;

Effective: 2017-10-01 Page 1 of 8

- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or
 - 4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

Effective: 2017-10-01 Page 2 of 8

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted **blackstart resource**:
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.4.3. a contracted blackstart resource:

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

Effective: 2017-10-01 Page 3 of 8

categorization processes.

- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- R1. Each Responsible Entity shall document one or more **cyber security incident** response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-AB-5 Table R1 Cyber Security Incident Response Plan Specifications*.
- **M1.** Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-AB-5 Table R1 Cyber Security Incident Response Plan Specifications*.

	CIP-008-AB-5 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	Applicable Systems	Requirements	Measures	
1.1	High Impact BES cyber systems Medium Impact BES cyber systems	One or more processes to identify, classify, and respond to cyber security incidents .	An example of evidence may include, but is not limited to, dated documentation of cyber security incidents response plan(s) that include the process to identify, classify, and respond to cyber security incidents.	
1.2	High Impact BES cyber systems Medium Impact BES cyber systems	One or more processes to determine if an identified cyber security incident is a reportable cyber security incident and notify the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), unless prohibited by law. Initial notification to the ES-ISAC, which may be only a preliminary notice, shall not exceed one hour from the determination of a reportable cyber security incident.	Examples of evidence may include, but are not limited to, dated documentation of cyber security incident response plan(s) that provide guidance or thresholds for determining which cyber security incidents are also reportable cyber security incidents and documentation of initial notices to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC).	
1.3	High Impact BES cyber systems Medium Impact BES cyber systems	The roles and responsibilities of cyber security incident response groups or individuals.	An example of evidence may include, but is not limited to, dated cyber security incident response process(es) or procedure(s) that define roles and responsibilities (e.g.,	

Effective: 2017-10-01 Page 4 of 8

	CIP-008-AB-5 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	Applicable Systems	Requirements	Measures	
			monitoring, reporting, initiating, documenting, etc.) of cyber security incident response groups or individuals.	
1.4	High Impact BES cyber systems	Incident handling procedures for cyber security incidents.	An example of evidence may include, but is not limited to,	
	Medium Impact BES cyber systems		dated for cyber security incident response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).	

- **R2.** Each Responsible Entity shall implement each of its documented **cyber security incident** response plans to collectively include each of the applicable requirement parts in *CIP-008-AB-5* Table R2 Cyber Security Incident Response Plan Implementation and Testing.
- **M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-AB-5 Table R2 Cyber Security Incident Response Plan Implementation and Testing.*

CII	CIP-008-AB-5 Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures	
2.1	High Impact BES cyber systems Medium Impact BES cyber systems	Test each cyber security incident response plan(s) at least once every 15 months: • by responding to an actual reportable cyber security incident; • with a paper drill or tabletop exercise of a reportable cyber security incident; or • with an operational exercise of a reportable cyber security incident.	Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises.	
2.2	High Impact BES cyber systems	Use the cyber security incident response plan(s)	Examples of evidence may include, but are not limited to,	
	Medium Impact BES cyber	under Requirement R1 when responding to a reportable	incident reports, logs, and notes that were kept during the	

Effective: 2017-10-01 Page 5 of 8

	•	ecurity Incident Response Plan	
Part	Applicable Systems	Requirements	Measures
	systems	cyber security incident or performing an exercise of a reportable cyber security incident. Document deviations from the plan(s) taken during the response to the incident or exercise.	incident response process, and follow-up documentation that describes deviations taken from the plan during the incident or exercise.
2.3	High Impact BES cyber systems	Retain records related to reportable cyber security	An example of evidence may include, but is not limited to,
	Medium Impact BES cyber systems	incident.	dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to reportable cyber security incidents.

- **R3.** Each Responsible Entity shall maintain each of its **cyber security incident** response plans according to each of the applicable requirement parts in *CIP-008-AB-5 Table R3 Cyber Security Incident Response Plan Review, Update, and Communication.*
- **M3.** Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each **cyber security incident** response plan according to the applicable requirement parts in CIP-008-AB-5 Table R3 Cyber Security Incident Response Plan Review, Update, and Communication.

	CIP-008-AB-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	Applicable Systems	Requirements	Measures	
3.1	High Impact BES cyber systems Medium Impact BES cyber systems	No later than 90 days after completion of a cyber security incident response plan(s) test or actual reportable cyber security incident response: 3.1.1. document any lessons learned or document the absence of any lessons learned; 3.1.2. update the cyber	An example of evidence may include, but is not limited to, all of the following: 1. dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the cyber security incident response plan(s) test or actual reportable cyber security incident	

Effective: 2017-10-01 Page 6 of 8

	CIP-008-AB-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication		
Part	Applicable Systems	Requirements	Measures
		security incident response plan based on any documented lessons learned associated with the plan; and	response or dated documentation stating there were no lessons learned;
		3.1.3. notify each person or group with a defined role in the cyber security incident response plan of the updates to the cyber security	dated and revised cyber security incident response plan showing any changes based on the lessons learned; and
		incident response plan based on any documented lessons learned.	evidence of plan update distribution including, but not limited to:
			• emails;
			 USPS or other mail service;
			 electronic distribution system; or
			training sign-in sheets.
3.2	High Impact BES cyber systems	No later than 60 days after a change to the roles or	An example of evidence may include, but is not limited to:
	Medium Impact BES cyber systems	responsibilities, cyber security incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan:	dated and revised cyber security incident response plan with changes to the roles or responsibilities, responders or technology; and
		3.2.1. update the cyber security incident response plan(s); and	evidence of plan update distribution including, but not limited to:
		3.2.2. notify each person or group with a defined role in	• emails;
		the cyber security incident response plan of the updates.	USPS or other mail service;
			electronic distribution system; or
			 training sign-in sheets.

Effective: 2017-10-01 Page 7 of 8

Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 8 of 8

A. Introduction

- 1. Title: Cyber Security Recovery Plans for BES Cyber Systems
- 2. Number: CIP-009-AB-5
- Purpose: To recover reliability functions performed by BES cyber systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the bulk electric system.
- 4. Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the operator of a transmission facility;

Effective: 2017-10-01 Page 1 of 9

- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more:
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard;
 - 4.2.1.4. each cranking path and group of elements meeting the initial switching requirements from a contracted blackstart resource up to and including the first point of supply and/or point of delivery of the next generating unit or aggregated generating facility to be started;
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more generating units or aggregated generating facilities with a combined maximum authorized real power of less than or equal to 67.5 MW and does not connect a contracted blackstart resource: or
 - 4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**of less than or equal to 67.5 MW and does not connect a contracted **blackstart**

Effective: 2017-10-01 Page 2 of 9

resource:

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use:
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource;
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 67.5 MW unless the **aggregated** generating facility is part of an industrial complex;
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.4.3. a contracted blackstart resource;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

Effective: 2017-10-01 Page 3 of 9

- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall have one or more documented recovery plans that collectively include each of the applicable requirement parts in *CIP-009-AB-5 Table R1 Recovery Plan Specifications*.
- **M1.** Evidence must include the documented recovery plan(s) that collectively include the applicable requirement parts in CIP-009-AB-5 Table R1 Recovery Plan Specifications.

Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES cyber systems and their associated:	Conditions for activation of the recovery plan(s).	An example of evidence may include, but is not limited to,
	electronic access control or monitoring systems; and		one or more plans that include language identifying conditions for activation of the recovery plan(s).
	2. physical access control systems		pan(o).
	Medium Impact BES cyber systems and their associated:		
	electronic access control or monitoring systems; and		
	2. physical access control systems		
1.2	High Impact BES cyber systems and their associated:	Roles and responsibilities of responders.	An example of evidence may include, but is not limited to,
	electronic access control or monitoring systems; and		one or more recovery plans that include language identifying the roles and responsibilities of responders.
	2. physical access control systems		- Coperior and Comparison
	Medium Impact BES cyber systems and their associated:		
	electronic access control or monitoring systems; and		
	2. physical access control		

Effective: 2017-10-01 Page 4 of 9

	CIP-009-AB-5 Table R1 – Recovery Plan Specifications			
Part	Applicable Systems	Requirements	Measures	
1.3	High Impact BES cyber systems and their associated:	One or more processes for the backup and storage of	An example of evidence may include, but is not limited to,	
	electronic access control or monitoring systems; and	information required to recover BES cyber system functionality.	documentation of specific processes for the backup and storage of information required to recover BES cyber system	
	2. physical access control systems		functionality.	
	Medium Impact BES cyber systems and their associated:			
	electronic access control or monitoring systems; and			
	2. physical access control systems			
1.4	High Impact BES cyber systems and their associated:	One or more processes to verify the successful completion of the backup processes in Part 1.3 and to address any backup failures.	An example of evidence may include, but is not limited to, logs, workflow or other documentation confirming that the backup process completed successfully and backup failures, if any, were addressed.	
	electronic access control or monitoring systems; and			
	2. physical access control systems			
	Medium Impact BES cyber systems at control centres and their associated:			
	electronic access control or monitoring systems; and			
	2. physical access control systems			
1.5	High Impact BES cyber systems and their associated:	One or more processes to preserve data, per cyber asset capability, for determining the cause of a cyber security incident that triggers activation of the recovery plan(s). Data preservation should not	An example of evidence may include, but is not limited to,	
	electronic access control or monitoring systems; and		procedures to preserve data, such as preserving a corrupted drive or making a data mirror of the system before	
	2. physical access control systems		proceeding with recovery.	

Effective: 2017-10-01 Page 5 of 9

	CIP-009-AB-5 Table R1 – Recovery Plan Specifications			
Part	Applicable Systems	Requirements	Measures	
	Medium Impact BES cyber systems and their associated:	impede or restrict recovery.		
	electronic access control or monitoring systems; and			
	2. physical access control systems			

- **R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, its documented recovery plan(s) to collectively include each of the applicable requirement parts in CIP-009-AB-5 Table R2 Recovery Plan Implementation and Testing.
- **M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-009-AB-5 Table R2 Recovery Plan Implementation and Testing.*

	CIP-009-AB-5 Table R2 – Recovery Plan Implementation and Testing		
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems Medium Impact BES cyber systems at control centres and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems	Test each of the recovery plans referenced in requirement R1 at least once every 15 months: • by recovering from an actual incident; • with a paper drill or tabletop exercise; or • with an operational exercise.	An example of evidence may include, but is not limited to, dated evidence of a test (by recovering from an actual incident, with a paper drill or tabletop exercise, or with an operational exercise) of the recovery plan at least once every 15 months. For the paper drill or full operational exercise, evidence may include meeting notices, minutes, or other records of exercise findings.
2.2	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and	Test a representative sample of information used to recover BES cyber system functionality at least once every 15 months to ensure that the information is useable	An example of evidence may include, but is not limited to, operational logs or test results with criteria for testing the usability (e.g. sample tape load, browsing tape contents)

Effective: 2017-10-01 Page 6 of 9

	CIP-009-AB-5 Table R2 – Recovery Plan Implementation and Testing				
Part	Applicable Systems	Requirements	Measures		
	physical access control systems Medium Impact BES cyber systems at control centres and their associated: electronic access control or monitoring systems; and physical access control systems	and is compatible with current configurations. An actual recovery that incorporates the information used to recover BES cyber system functionality substitutes for this test.	and compatibility with current system configurations (e.g. manual or automated comparison checkpoints between backup media contents and current configuration).		
2.3	High Impact BES cyber systems	Test each of the recovery plans referenced in requirement R1 at least once every 36 months through an operational exercise of the recovery plans in an environment representative of the production environment. An actual recovery response may substitute for an operational exercise.	Examples of evidence may include, but are not limited to, dated documentation of: • an operational exercise at least once every 36 months between exercises, that demonstrates recovery in a representative environment; or • an actual recovery response that occurred within the 36 month timeframe that exercised the recovery plans.		

- **R3.** Each Responsible Entity shall maintain each of its recovery plans in accordance with each of the applicable requirement parts in CIP-009-AB-5 Table R3 Recovery Plan Review, Update and Communication.
- **M3.** Acceptable evidence includes, but is not limited to, each of the applicable requirement parts in *CIP-009-AB-5 Table R3 Recovery Plan Review, Update and Communication.*

	CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication				
Part	Applicable Systems	Requirements	Measures		
3.1	High Impact BES cyber systems and their associated: 1. electronic access	No later than 90 days after completion of a recovery plan test or actual recovery:	An example of evidence may include, but is not limited to, all of the following:		
	control or monitoring	3.1.1. document any lessons	1. dated documentation of		

Effective: 2017-10-01 Page 7 of 9

	CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication				
Part	Applicable Systems	Requirements	Measures		
	systems; and 2. physical access control systems Medium Impact BES cyber systems at control centres and their associated:	learned associated with a recovery plan test or actual recovery or document the absence of any lessons learned; 3.1.2. update the recovery plan based on any documented lessons	identified deficiencies or lessons learned for each recovery plan test or actual incident recovery or dated documentation stating there were no lessons learned; 2. dated and revised		
	electronic access control or monitoring systems; and physical access control systems	learned associated with the plan; and 3.1.3. notify each person or group with a defined role in the recovery plan of the updates to the recovery plan based on any documented lessons learned.	recovery plan showing any changes based on the lessons learned; and 3. evidence of plan update distribution including, but not limited to: • emails; • USPS or other mail service; • electronic distribution system; or • training sign-in sheets.		
3.2	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems Medium Impact BES cyber systems at control centres and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems	No later than 60 days after a change to the roles or responsibilities, responders, or technology that the Responsible Entity determines would impact the ability to execute the recovery plan: 3.2.1. update the recovery plan; and 3.2.2. notify each person or group with a defined role in the recovery plan of the updates.	An example of evidence may include, but is not limited to, all of the following: 1. dated and revised recovery plan with changes to the roles or responsibilities, responders, or technology; and 2. evidence of plan update distribution including, but not limited to: • emails; • USPS or other mail service; • electronic distribution system; or		

Effective: 2017-10-01 Page 8 of 9

CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication				
Part Applicable Systems Requirements Measu		Measures		
			training sign-in sheets.	

Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 9 of 9

Alberta Reliability Standard Cyber Security – Configuration Change Management and Vulnerability Assessments CIP-010-AB-1

A. Introduction

- 1. Title: Cyber Security Configuration Change Management and Vulnerability Assessments
- 2. Number: CIP-010-AB-1
- 3. Purpose: To prevent and detect unauthorized changes to **BES cyber systems** by specifying configuration change management and vulnerability assessment requirements in support of protecting **BES cyber systems** from compromise that could lead to misoperation or instability in the **bulk electric system**.
- Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more:
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the operator of a transmission facility;

Effective: 2017-10-01 Page 1 of 9

Alberta Reliability Standard Cyber Security – Configuration Change Management and Vulnerability Assessments CIP-010-AB-1

- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more:
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each cranking path and group of elements meeting the initial switching requirements from a contracted blackstart resource up to and including the first point of supply and/or point of delivery of the next generating unit or aggregated generating facility to be started;
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more generating units or aggregated generating facilities with a combined maximum authorized real power of less than or equal to 67.5 MW and does not connect a contracted blackstart resource: or
 - 4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**of less than or equal to 67.5 MW and does not connect a contracted **blackstart**

Effective: 2017-10-01 Page 2 of 9

Alberta Reliability Standard Cyber Security – Configuration Change Management and Vulnerability Assessments CIP-010-AB-1

resource;

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use:
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an aggregated generating facility;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource;
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 67.5 MW unless the **aggregated** generating facility is part of an industrial complex;
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.4.3. a contracted blackstart resource;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

Effective: 2017-10-01 Page 3 of 9



- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in CIP-010-AB-1 Table R1 Configuration Change Management.
- **M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R1 Configuration Change Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-010-AB-1 Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures	
1.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	Develop a baseline configuration, individually or by group, which shall include the following items: 1.1.1. operating system(s) (including version) or firmware where no independent operating system exists; 1.1.2. any commercially available or open-source application software (including version) intentionally installed; 1.1.3. any custom software installed; 1.1.4. any logical network accessible ports; and 1.1.5. any security patches applied.	 Examples of evidence may include, but are not limited to: a spreadsheet identifying the required items of the baseline configuration for each cyber asset, individually or by group; or a record in an asset management system that identifies the required items of the baseline configuration for each cyber asset, individually or by group. 	
1.2	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and	Authorize and document changes that deviate from the existing baseline configuration.	Examples of evidence may include, but are not limited to: a change request record and associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a	

Effective: 2017-10-01 Page 4 of 9



	CIP-010-AB-1 Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures	
	3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and		change management system for each change; or documentation that the change was performed in accordance with the requirement.	
1.3	 protected cyber assets High Impact BES cyber systems and their associated: electronic access control or monitoring systems; physical access control 	For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 days of completing the change.	An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 days of the date of the completion of the change.	
	systems; and			
	3. protected cyber assets			
	Medium Impact BES cyber systems and their associated:			
	electronic access control or monitoring systems;			
	physical access control systems; and			
1.4	3. protected cyber assets High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated:	For a change that deviates from the existing baseline configuration: 1.4.1. prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change; 1.4.2. following the change, verify that required cyber security controls determined	An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.	

Effective: 2017-10-01 Page 5 of 9



	CIP-010-AB-1 Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures	
	electronic access control or monitoring systems; physical access control systems; and	in 1.4.1 are not adversely affected; and 1.4.3. document the results of the verification.		
	3. protected cyber assets			
1.5	High Impact BES cyber systems	Where technically feasible, for each change that deviates from the existing baseline configuration: 1.5.1. prior to implementing any change in the production environment, test the changes in a test environment or test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and	An example of evidence may include, but is not limited to, a list of cyber security controls tested along with successful test results and a list of differences between the production and test environments with descriptions of how any differences were accounted for, including the date of the test.	
		1.5.2. document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.		

R2. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R2 – Configuration Monitoring*.

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R2 – Configuration*

Effective: 2017-10-01 Page 6 of 9

Alberta Reliability Standard Cyber Security – Configuration Change Management and Vulnerability Assessments CIP-010-AB-1

Monitoring and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-AB-1 Table R2 – Configuration Monitoring			
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and	Monitor at least once every 35 days for changes to the baseline configuration (as described in requirement R1, part 1.1). Document and investigate detected	An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any
	2. protected cyber assets	unauthorized changes.	unauthorized changes that were detected.

R3. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R3–Vulnerability Assessments*.

M3. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R3 – Vulnerability Assessments* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-010-AB-1 Table R3 – Vulnerability Assessments		
Part	Applicable Systems	Requirements	Measures
3.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. physical access control systems; and 3. protected cyber assets	At least once every 15 months, conduct a paper or active vulnerability assessment.	Examples of evidence may include, but are not limited to: a document listing the date of the assessment (performed at least once every 15 months), the controls assessed for each BES cyber system along with the method of assessment; or a document listing the date of the assessment and the output of any tools used to perform the assessment.

Effective: 2017-10-01 Page 7 of 9



	CIP-010-AB-1 Table R3 – Vulnerability Assessments			
Part	Applicable Systems	Requirements	Measures	
3.2	High Impact BES cyber systems	Where technically feasible, at least once every 36 months: 3.2.1 perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration of the BES cyber system in a production environment; and 3.2.2 document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.	
3.3	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; 2. protected cyber assets	Prior to adding a new applicable cyber asset to a production environment, perform an active vulnerability assessment of the new cyber asset, except for CIP exceptional circumstances and like replacements of the same type of cyber asset with a baseline configuration that models an existing baseline configuration of the previous or other existing cyber asset.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the new cyber asset) and the output of any tools used to perform the assessment.	
3.4	High Impact BES cyber systems and their associated: 1. electronic access	Document the results of the assessments conducted according to parts 3.1, 3.2, and 3.3 and the action plan to	An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a	

Effective: 2017-10-01 Page 8 of 9



	CIP-010-AB-1 Table R3 – Vulnerability Assessments		
Part	Applicable Systems	Requirements	Measures
	control or monitoring systems;	remediate or mitigate vulnerabilities identified in the	list of action items, documented proposed dates
	physical access control systems; and	assessments including the planned date of completing the action plan and the execution	of completion for the action plan, and records of the status of the action items (such as
	3. protected cyber assets	status of any remediation or	minutes of a status meeting,
	Medium Impact BES cyber systems and their associated:	mitigation action items.	updates in a work order system, or a spreadsheet tracking the action items).
	electronic access control or monitoring systems;		3 · · · · · · · · · · · · · · · · · · ·
	physical access control systems; and		
	3. protected cyber assets		

Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 9 of 9



A. Introduction

1. Title: Cyber Security – Information Protection

2. Number: CIP-011-AB-1

- Purpose: To prevent unauthorized access to BES cyber system information by specifying information protection requirements in support of protecting BES cyber systems against compromise that could lead to misoperation or instability in the bulk electric system.
- Applicability:
 - 4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.
 - 4.1.1. [Intentionally left blank.]
 - 4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:
 - 4.1.2.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;
 - 4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.1.2.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;
 - 4.1.3. the operator of a generating unit and the operator of an aggregated generating facility;
 - 4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating** facility;
 - 4.1.5. [Intentionally left blank.]
 - 4.1.6. [Intentionally left blank.]
 - 4.1.7. the operator of a transmission facility;

Effective: 2017-10-01 Page 1 of 6



- 4.1.8. the legal owner of a transmission facility; and
- 4.1.9. the **ISO**.
- 4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.
 - 4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal** owner of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:
 - 4.2.1.1. each underfrequency load shedding or under voltage load shed system that:
 - 4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and
 - 4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;
 - 4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;
 - 4.2.1.3. each protection system (excluding underfrequency load shedding and under voltage load shed) that applies to transmission where the protection system is subject to one or more requirements in a reliability standard; and
 - 4.2.1.4. each cranking path and group of elements meeting the initial switching requirements from a contracted blackstart resource up to and including the first point of supply and/or point of delivery of the next generating unit or aggregated generating facility to be started;
 - 4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:
 - 4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:
 - 4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;
 - 4.2.2.1.2. radially connects only to load;
 - 4.2.2.1.3. radially connects only to one or more generating units or aggregated generating facilities with a combined maximum authorized real power of less than or equal to 67.5 MW and does not connect a contracted blackstart resource: or
 - 4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**of less than or equal to 67.5 MW and does not connect a contracted **blackstart**

Effective: 2017-10-01 Page 2 of 6



resource;

- 4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use:
- 4.2.2.3. a generating unit that is:
 - 4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 18 MW unless the **generating unit** is part of an industrial complex;
 - 4.2.2.3.2. within a power plant which:
 - 4.2.2.3.2.1. is not part of an **aggregated generating facility**;
 - 4.2.2.3.2.2. is directly connected to the **bulk electric system**; and
 - 4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;
 - 4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.3.4. a contracted blackstart resource;
- 4.2.2.4. an aggregated generating facility that is:
 - 4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum** authorized real power rating greater than 67.5 MW unless the **aggregated** generating facility is part of an industrial complex;
 - 4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - 4.2.2.4.3. a contracted **blackstart resource**;

and

- 4.2.2.5. **control centres** and backup **control centres**.
- 4.2.3. The following are exempt from this **reliability standard**:
 - 4.2.3.1. [Intentionally left blank.]
 - 4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.
 - 4.2.3.3. [Intentionally left blank.]
 - 4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.
 - 4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

Effective: 2017-10-01 Page 3 of 6



- 5. [Intentionally left blank.]
- 6. [Intentionally left blank.]

B. Requirements and Measures

- **R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-AB-1 Table R1 Information Protection*.
- **M1.** Evidence for the information protection program must include the applicable requirement parts in *CIP-011-AB-1 Table R1 Information Protection* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-011-AB-1 Table R1 – Information Protection			
Part	Applicable Systems	Requirements	Measures	
1.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems Medium Impact BES cyber systems and their associated:	Method(s) to identify information that meets the definition of BES cyber system information.	Examples of acceptable evidence include, but are not limited to: documented method to identify BES cyber system information from entity's information protection program; or indications on information (e.g., labels or	
	electronic access control or monitoring systems; and physical access control systems		classification) that identify BES cyber system information as designated in the entity's information protection program; or training materials that provide personnel with sufficient knowledge to	
			recognize BES cyber system information; or • repository or electronic and physical location designated for housing BES cyber system information in the entity's information protection program.	
1.2	High Impact BES cyber	Procedure(s) for protecting	Examples of acceptable	

Effective: 2017-10-01 Page 4 of 6



	CIP-011-AB-1 Table R1 – Information Protection		
Part	Applicable Systems	Requirements	Measures
	 systems and their associated: electronic access control or monitoring systems; and 	and securely handling BES cyber system information, including storage, transit, and use.	evidence include, but are not limited to: procedures for protecting and securely handling,
	2. physical access control systems		which include topics such as storage, security during transit, and use of BES
	Medium Impact BES cyber systems and their associated:		cyber system information; or
	electronic access control or monitoring systems; and		records indicating that BES cyber system information is handled in
	2. physical access control systems		a manner consistent with the entity's documented procedure(s).

- **R2.** Each Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts in *CIP-011-AB-1 Table R2 BES Cyber Asset Reuse and Disposal.*
- **M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-011-AB-1 Table R2 BES Cyber Asset Reuse and Disposal* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-011-AB-1 Table R2 – BES Cyber Asset Reuse and Disposal		
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and	Prior to the release for reuse of applicable cyber assets that contain BES cyber system information (except for reuse within other systems identified in the "Applicable Systems" column), the Responsible Entity shall take action to prevent the unauthorized retrieval of BES cyber system information from the cyber asset data storage media.	Examples of acceptable evidence include, but are not limited to: • records tracking sanitization actions taken to prevent unauthorized retrieval of BES cyber system information such as clearing, purging, or destroying; or • records tracking actions such as encrypting, retaining in the physical security perimeter or

Effective: 2017-10-01 Page 5 of 6



	CIP-011-AB-1 Table R2 – BES Cyber Asset Reuse and Disposal			
Part	Applicable Systems	Requirements	Measures	
	2. physical access control systems; and3. protected cyber assets		other methods used to prevent unauthorized retrieval of BES cyber system information.	
2.2	High Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems; and 3. protected cyber assets Medium Impact BES cyber systems and their associated: 1. electronic access control or monitoring systems; and 2. physical access control systems; and	Prior to the disposal of applicable cyber assets that contain BES cyber system information, the Responsible Entity shall take action to prevent the unauthorized retrieval of BES cyber system information from the cyber asset or destroy the data storage media.	Examples of acceptable evidence include, but are not limited to: • records that indicate that data storage media was destroyed prior to the disposal of an applicable cyber asset; or • records of actions taken to prevent unauthorized retrieval of BES cyber system information prior to the disposal of an applicable cyber asset.	
	3. protected cyber assets			

Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 6 of 6

Alberta Reliability Standard Cyber Security – Implementation Plan for Version 5 CIP Security Standards CIP-PLAN-AB-1

1. Purpose

The purpose of this **reliability standard** is to set the effective dates for the Version 5 CIP Cyber Security **reliability standards** and describe compliance timelines for planned and unplanned changes that result in a higher categorization for a **BES cyber system**.

2. Applicable Reliability Standards

This reliability standard applies to the Version 5 CIP Cyber Security reliability standards, which are:

- CIP-002-AB-5.1, Cyber Security BES Cyber System Categorization;
- CIP-003-AB-5, Cyber Security Security Management Controls;
- CIP-004-AB-5.1, Cyber Security Personnel and Training;
- CIP-005-AB-5, Cyber Security Electronic Security Perimeter(s);
- CIP-006-AB-5, Cyber Security Physical Security of BES Cyber Systems;
- CIP-007-AB-5, Cyber Security Systems Security Management,
- CIP-008-AB-5, Cyber Security Incident Reporting and Response Planning;
- CIP-009-AB-5, Cyber Security Recovery Plans for BES Cyber Systems;
- CIP-010-AB-1, Cyber Security Configuration Change Management and Vulnerability Assessments; and
- CIP-011-AB-1, Cyber Security Information Protection.

3. Compliance with Reliability Standards

Once the Version 5 CIP Cyber Security **reliability standards** become effective, the "Responsible Entities" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** must comply with the requirements of those **reliability standards**.

4. Proposed Effective Date

The Version 5 Cyber Security **reliability standards**, except for requirement R2 of CIP-003-AB-5, become effective on the first **day** of the calendar quarter (January 1, April 1, July 1 or October 1) that follows eight (8) full calendar quarters after approval by the **Commission**. Requirement R2 of CIP-003-AB-5 becomes effective on the first **day** of the calendar quarter (January 1, April 1, July 1 or October 1) that follows twelve (12) full calendar quarters after approval by the **Commission**.

5. Initial Performance of Certain Periodic Requirements

Specific Version 5 CIP Cyber Security **reliability standards** have periodic requirements that contain time parameters for subsequent and recurring iterations of the requirement, such as, but not limited to, ". . . at least once every fifteen (15) **months** . . .", and "Responsible Entities" must comply initially with those periodic requirements as follows:

1. on or before the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirements:

Effective: 2017-10-01 Page 1 of 3

Alberta Reliability Standard Cyber Security – Implementation Plan for Version 5 CIP Security Standards CIP-PLAN-AB-1

- · CIP-002-5, requirement R2; and
- CIP-003-5, requirement R1;
- 2. on or before the Effective Date of CIP-003-5, Requirement R2 for the following requirement:
 - CIP-003-5, requirement R2;
- 3. within fourteen (14) days after the effective date of the Version 5 CIP Cyber Security **reliability** standards for the following requirement:
 - · CIP-007-5, requirement R4, Part 4.4;
- 4. within thirty-five (35) **days** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirements:
 - CIP-010-1, requirement R2, Part 2.1;
- 5. within three (3) **months** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirement:
 - CIP-004-5, requirement R4, Part 4.2;
- 6. within twelve (12) months after the effective date of the Version 5 CIP Cyber Security reliability standards for the following requirements:
 - · CIP-004-5, requirement R2, Part 2.3;
 - CIP-004-5, requirement R4, Parts 4.3 and 4.4;
 - CIP-006-5, requirement R3, Part 3.1;
 - CIP-008-5, requirement R2, Part 2.1;
 - CIP-009-5, requirement R2, Parts 2.1 and 2.2; and
 - · CIP-010-1, requirement R3, Part 3.1; and
- 7. within twenty-four (24) **months** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirements:
 - CIP-009-5, requirement R2, Part 2.3; and
 - CIP-010-1, requirement R3, Part 3.2.

Planned or Unplanned Changes Resulting in a Higher Categorization

Planned changes refer to any changes of the electric system or **BES cyber system** as identified through the annual assessment under CIP-002-AB-5.1, requirement R2, which were planned and implemented by the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard**.

In contrast, unplanned changes refer to any changes of the electric system or **BES cyber system**, as identified through the annual assessment under CIP-002-AB-5.1, Requirement R2, which were not planned by the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard**.

Effective: 2017-10-01 Page 2 of 3

Alberta Reliability Standard Cyber Security – Implementation Plan for Version 5 CIP Security Standards CIP-PLAN-AB-1

For planned changes resulting in a higher categorization, the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** shall comply with all applicable requirements in the Version 5 CIP Cyber Security **reliability standards** on the update of the identification and categorization of the affected **BES cyber system** and any applicable and associated **physical access control systems**, **electronic access control or monitoring systems** and **protected cyber assets**, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* above.

For unplanned changes resulting in a higher categorization, the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** shall comply with all applicable requirements in the Version 5 CIP Cyber Security **reliability standards**, according to the following timelines, following the identification and categorization of the affected **BES cyber system** and any applicable and associated **physical access control systems**, **electronic access control or monitoring systems** and **protected cyber assets**, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* above.

Scenario of Unplanned Changes After the Effective Date for Each Version 5 CIP Cyber Security Reliability Standard	Compliance Implementation
New High Impact BES cyber system	twelve (12) months
New Medium Impact BES cyber system	twelve (12) months
Newly categorized High Impact BES cyber system from Medium Impact BES cyber system	twelve (12) months for requirements not applicable to Medium Impact BES Cyber Systems
Newly categorized Medium Impact BES cyber system	twelve (12) months
The "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security reliability standard identifies first Medium Impact or High Impact BES cyber system (i.e., the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security reliability standard previously had no BES cyber systems categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes)	twenty-four (24) months

Revision History

Date	Description
2017-10-01	Initial release.

Effective: 2017-10-01 Page 3 of 3



1. Purpose

The purpose of this **reliability standard** is to ensure the **ISO** and each **operator** of a **transmission facility** have adequate and reliable voice and message telecommunication facilities internally and with others for the exchange of **interconnection** and operating information necessary to maintain reliability.

2. Applicability

This reliability standard applies to the following:

- (a) the operator of a transmission facility that is:
 - (i) part of the bulk electric system; or
 - (ii) not part of the bulk electric system but which the ISO:
 - (A) determines is necessary for the reliable operation of either the **interconnected electric system** or the City of Medicine Hat electric system; and
 - (B) publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1; and
- (b) the ISO.

3. Requirements

- **R1** The **ISO** must, as necessary to maintain reliability, provide adequate, reliable, and, where applicable, diverse and redundant voice and message telecommunication facilities for the exchange of **interconnection** and internal Alberta operating information with the following:
 - (a) each operator of a transmission facility;
 - (b) each adjacent interconnected transmission operator directly connected to Alberta;
 - (c) each adjacent balancing authority directly connected to Alberta; and
 - (d) the adjacent reliability coordinators.
- **R2** Each **operator** of a **transmission facility** must, as necessary to maintain reliability, provide adequate, reliable, and, where applicable, diversely routed and redundant voice and message telecommunication facilities for the exchange of **interconnection** and Alberta operating information with the following:
 - (a) each adjacent operator of a transmission facility;
 - (b) each adjacent **interconnected transmission operator** that is directly connected to Alberta; and
 - (c) the ISO.
- **R3** The **ISO** and each **operator** of a **transmission facility** must manage and test its alternate voice and message telecommunication facilities.
- R4 The ISO must provide a means to coordinate voice and message telecommunications with each operator of a transmission facility, adjacent interconnected transmission operator, adjacent

Alberta Reliability Standards Effective: 2015-05-01



balancing authority and adjacent reliability coordinators, which coordination must include the ability to investigate and recommend solutions to voice and message telecommunications problems within Alberta.

- **R5** Each **operator** of a **transmission facility** must provide a means to coordinate voice and message telecommunications with the **ISO** and adjacent **interconnected transmission operators**, which coordination must include the ability to investigate and recommend solutions to voice and message telecommunications problems within Alberta.
- **R6** The **ISO** and each **operator** of a **transmission facility** must use the English language for all communications between their respective operating personnel responsible for the real-time generation control and operation of the **interconnected electric system**.
- **R7** The **ISO** and each **operator** of a **transmission facility** must have written operating instructions and procedures to enable continued operation of the **interconnected electric system** during the loss of voice and message telecommunications facilities.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of providing voice and message telecommunication facilities as required in requirement R1 exists. Evidence may include:

- (a) a list identifying each telecommunication facility for the exchange of **interconnection** and Alberta operating information; and
- (b) documentation demonstrating the implementation of diverse routing and redundancy capability.

MR2 Evidence of providing voice and message telecommunication facilities as required in requirement R2 exists. Evidence may include:

- (a) a list identifying each telecommunication facility for the exchange of **interconnection** and Alberta operating information; and
- (b) documentation demonstrating the implementation of diverse routing and redundancy capability, if applicable.

MR3 Evidence of managing and testing its alternate voice and message telecommunication facilities as required in requirement R3 exists. Evidence may include:

- (a) a list identifying each telecommunication facility as determined to be alternate;
- (b) documented procedures describing how to manage and test its alternate telecommunication facilities; and
- (c) records of testing.

MR4 Evidence of providing a means to coordinate voice and message telecommunications as required in requirement R4 exists. Evidence may include a documented procedure in place which identifies a process for coordinating telecommunications and a process for investigating and recommending solutions to telecommunications problems.

MR5 Evidence of providing a means to coordinate voice and message telecommunications as required in requirement R5 exists. Evidence may include a documented procedure in place which identifies a

Alberta Reliability Standards Effective: 2015-05-01



process for coordinating telecommunications and a process for investigating and recommending solutions to telecommunications problems.

MR6 Evidence of using the English language as required in requirement R6 exists. Evidence may include **operator** logs, voice recordings, electronic communications or **e-tag** records.

MR7 Evidence of having written operating instructions and procedures as required in requirement R7 exists. Evidence may include electronic or hard copy of the operating instructions and procedures.

5. Appendices

Appendix 1 - Amending Process for List of Facilities

Revision History

Effective	Description
2013-10-01	Initial Release
2015-05-01	Revised for ISO assumption of RC functionality for the Alberta footprint



Appendix 1 Amending Process for List of Facilities

In order to amend the list referenced in subsections (a)(ii)(B) of section 2, Applicability, the ISO must:

- (a) upon determining that a **transmission facility** is to be added, notify the **operator** in writing and determine an effective date, which must be no less than thirty (30) **days** after the date of notice, for the **operator** to meet the applicable requirements;
- (b) upon determining that a **transmission facility** is to be deleted, notify the **operator** in writing and determine an effective date for the **operator** to no longer be required to meet the applicable requirements; and
- (c) publish the amended list with effective dates on the AESO website.

Alberta Reliability Standards Effective: 2015-05-01



Alberta Reliability Standards Communications and Coordination COM-002-AB1-2a Communications and Coordination

1. Purpose

The purpose of this **reliability standard** is to ensure the **ISO** and entities subject to this **reliability standard** have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition, and to ensure communications by operating personnel are effective.

2. Applicability

This reliability standard applies to:

- (a) the operator of a generating unit that is:
 - (i) directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and
 - (ii) not part of an aggregated generating facility;
- (b) the **operator** of an **aggregated generating facility** that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;
- (c) the operator of a transmission facility; and
- (d) the ISO.

3. Requirements

- R1 The ISO must have voice and data communication facilities with:
 - (a) each operator of a transmission facility;
 - (b) each adjacent interconnected transmission operator directly connected to Alberta; and
 - (c) each adjacent balancing authority directly connected to Alberta;
- **R2** The operator of a transmission facility must have voice and data communication facilities with:
 - (a) each adjacent operator of a transmission facility;
 - (b) each adjacent interconnected transmission operator directly connected to Alberta; and
 - (c) the ISO.
- **R3** Each operator of a generating unit and each operator of an aggregated generating facility must have voice and data communication facilities with:
 - (a) each operator of a transmission facility to which it is directly connected; and
 - (b) the ISO.
- R4 The ISO, each operator of a transmission facility, each operator of an aggregated generating facility and each operator of a generating unit must have personnel available for all hours of the day, seven (7) days a week, to receive and respond to any voice or data communication regarding a real-time system emergency condition via the communication facilities as identified in requirements R1 through R3.
- R5 The ISO must notify all potentially affected adjacent interconnected transmission operators and adjacent balancing authorities through predetermined communication paths:
 - (a) of any threat to the reliability of the interconnected electric system; or

Effective: 2014-01-01 Page 1 of 2

- (b) if the ISO anticipates shedding firm load.
- **R6** The **ISO** must, when issuing a verbal **directive**, do so in a clear, concise and definitive manner, identify the instruction as a **directive**, and:
 - (a) if the recipient of the **directive** does not respond by repeating the information in the **directive**, then the **ISO** must request the recipient to repeat the information in the **directive**;
 - (b) if the information in the response is not correct, the **ISO** must repeat the **directive** to resolve any misunderstandings; and
 - (c) if the information is repeated correctly, the ISO must acknowledge this to the recipient.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of having voice and data communication facilities as required in requirement R1 exists. Evidence may include a list of communication facilities or other equivalent evidence that confirms that the communications have been provided.

MR2 Evidence of having voice and data communications as required in requirement R2 exists. Evidence may include a list of communication facilities or other equivalent evidence that confirms that the communications have been provided.

MR3 Evidence of having voice and data communications as required in requirement R3 exists. Evidence may include a list of communication facilities or other equivalent evidence that confirms that the communications have been provided.

MR4 Evidence of having personnel available as required in requirement R4 exists. Evidence may include **operator** logs, timesheets, on-call lists or shift schedules.

MR5 Evidence of notifying entities as required in requirement R5 exists. Evidence may include **operator** logs or voice recordings.

MR6 Evidence of issuing verbal **directives** as required in requirement R6 exists. Evidence may include voice recordings or **operator** logs.

Revision History

Effective	Description
2013-10-01	Initial release
2014-01-01	Administrative update to standardize formatting, definitions and drafting style.
	Removed references to the WECC Reliability Coordinator.

Effective: 2014-01-01 Page 2 of 2



1. Purpose

The purpose of this **reliability standard** is to define requirements for the development, maintenance, implementation and coordination of plans to mitigate operating emergencies.

2. Applicability

This reliability standard applies to:

- (a) the operator of a transmission facility that is part of the bulk electric system; and
- (b) the ISO.

This **reliability standard** does not apply to the **operator** of a **transmission facility** whose **transmission facility** is a radial connection from a **generating unit** or an **aggregated generating facility** to either the **transmission system** or to **transmission facilities** within the city of Medicine Hat.

3. Requirements

- R1 The ISO must, as appropriate, have operating agreements with adjacent balancing authorities that contain provisions for emergency assistance.
- R2 The ISO must develop, maintain and implement a capacity and energy emergency plan to mitigate insufficient generating capacity.
- R3 Each of the ISO and the operator of a transmission facility must develop, maintain and implement plans to mitigate operating emergencies on the transmission system.
- R4 Each of the ISO and the operator of a transmission facility must develop, maintain and implement plans for load shedding.
- **R5** Each of the **ISO** and the **operator** of a **transmission facility** must include, at a minimum, when developing emergency plans as identified in requirements R2, R3 and R4, the following:
 - (a) communication protocols to be used during operating emergencies:
 - (b) a list of controlling actions to resolve the operating emergency within **NERC** established timelines, including, where appropriate, a controlling action to reduce load:
 - (c) the tasks to be coordinated with and among any affected **operator** of a **transmission facility**, adjacent **interconnected transmission operator** and adjacent **balancing authority**, as appropriate; and
 - (d) a procedure for adjusting staffing levels for the emergency, where appropriate.



- R6 The ISO must consider the elements in Appendix 1 when developing a capacity and energy emergency plan in accordance with requirement R2.
- R7 The ISO must review its capacity and energy emergency plan, plans to mitigate operating emergencies on the **transmission system** and plans for load shedding once every calendar year and update as required.
- **R8** Each **operator** of a **transmission facility** must review its plans for load shedding once every calendar year and update as required.
- R9 The ISO must provide a copy of its updated capacity and energy emergency plan, plans for load shedding and plans to mitigate operating emergencies on the transmission system to any affected:
 - (a) operator of a transmission facility;
 - (b) adjacent interconnected transmission operator; and
 - (c) adjacent balancing authority.
- **R10** Each **operator** of a **transmission facility** must provide a copy of its updated plans to mitigate operating emergencies on the **transmission system** and plans for load shedding to any affected adjacent **operator** of a **transmission facility** and the **ISO**.

4 Measures

The following measures correspond to the requirements identified in Section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

- **MR1** Evidence of having at least one (1) operating agreement with an adjacent **balancing authority** as required in requirement R1 exists.
- **MR2** Evidence of developing, maintaining and implementing a capacity and energy emergency plan as required in requirement R2 exists. Evidence may include a dated, current capacity and energy emergency plan and communications or training to the operating personnel.
- MR3 Evidence of developing, maintaining and implementing plans to mitigate operating emergencies on the **transmission system** as required in requirement R3 exists. Evidence may include dated, current plans to mitigate operating emergencies on the **transmission system** and communications or training to the operating personnel.
- **MR4** Evidence of developing, maintaining and implementing load shedding plans as required in requirement R4 exists. Evidence may include dated, current plans for load shedding and communications or training to the operating personnel.
- **MR5** Evidence of including the items in emergency plans as required in requirement R5 exists. Evidence may include emergency plans that contain items listed in requirement R5.



- MR6 Evidence of considering the elements in Appendix 1 as required in requirement R6 exists. Evidence may include documentation indicating which elements from Appendix 1 were not included in the capacity and emergency plan and the rationale why they were not included.
- **MR7** Evidence of reviewing and updating each plan as required in requirement R7 exists. Evidence may include documentation confirming each plan was reviewed once every calendar year and updated as required.
- **MR8** Evidence of reviewing and updating plans as required in requirement R8 exists. Evidence may include documentation confirming each plan was reviewed once every calendar year and updated as required.
- **MR9** Evidence of providing each updated plan as required in requirement R9 exists. Evidence may include email or mail to appropriate recipients that identifies contents submitted.
- **MR10** Evidence of providing updated plans as required in requirement R10 exists. Evidence may include email or mail to appropriate recipients that identifies contents submitted.

5. Appendix 1

Elements for Consideration in Development of Capacity and Energy Emergency Plan

- 1. **Bulk electric system** energy use The reduction of the **bulk electric system**'s own energy use to a minimum.
- 2. Public appeals Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
- Load management Implementation of load management and voltage reductions, if appropriate.
- 4. Interruptible and curtailable loads Use of interruptible and curtailable load to reduce capacity requirements or to conserve the fuel in short supply.
- 5. Maximizing **generating unit** output and availability The operation of all generating sources to maximize output and availability. This should include plans to winterize **generating units** and **aggregated generating facilities** during extreme cold weather.
- 6. Notifying independent power producers (IPP) Notification of cogeneration and independent power producers to maximize output and availability.
- 7. Requests of government Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.



- 8. Load curtailment A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety and welfare of the community. Address firm load curtailment.
- 9. Notification of government agencies Notification of appropriate government agencies as the various steps of the operating emergency plan are implemented.
- 10. Notifications to operating entities Notifications to other operating entities as steps in the operating emergency plan are implemented.

Revision History

Effective	Description
2015-05-01	Revised for ISO assumption of RC functionality for the Alberta footprint
2014-01-01	Initial Release



Alberta Reliability Standard Capacity and Energy Emergencies EOP-002-AB1-2

EOP-002-AB1-2 Capacity and Energy Emergencies

1. Purpose

The purpose of this *reliability standard* is to ensure the ISO is prepared for a supply shortfall event.

2. Applicability

This *reliability* standard applies to:

ISO

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

- R1 The ISO must exercise its authority to alleviate a supply shortfall event in the AIES.
- **R2** The ISO must implement its capacity and energy emergency plan by following ISO rules.
- R3 The ISO must communicate its current and its forecast of future system conditions to adjacent balancing authorities during a supply shortfall event.
- R4 The ISO must follow plans in ISO rules when it anticipates a supply shortfall event may occur. The ISO plans must include any one of or combination of the following:
 - Issuing directives as necessary, including bringing on all available generation;
 - Postponing equipment maintenance;
 - Posting interconnection *TTC* to maximum *reliability* based capacity and being prepared to reduce firm *load*.
- **R5** The *ISO* must, during a supply shortfall event:
 - Only use the assistance provided by the *Interconnection's frequency bias* for the time needed to manage the event.
 - Not direct generating units in an attempt to return the *Interconnection* frequency to normal beyond that supplied through *frequency bias* action and *interchange* schedule changes.
- R6 The *ISO* must comply with the control performance and disturbance control standards during a supply shortfall event. If necessary to do so, the *ISO* must implement remedies including without limitation, any one of or combination of the following:
 - Loading all available generating capacity.
 - Deploying all available operating reserves.

Effective: 2014-01-01 Page 1 of 5

- Interrupting interruptible load and exports.
- Requesting emergency assistance from other balancing authorities.
- Declaring, in accordance with ISO rules, an Energy Emergency Alert(s); and
- Reducing *load*, through procedures such as public appeals, voltage reductions, and curtailing interruptible *loads*.
- R7 The ISO must comply with the control performance and disturbance control reliability standards during a supply shortfall event. The ISO must perform the following if all the remedies listed in requirement R6 have been implemented and the control performance and disturbance control standards are not being met:
 - **R7.1** Issue directives for the manual shedding of firm *load* without delay to return its *ACE* to zero; and
 - **R7.2** In accordance with the *ISO* rules, declare an Energy Emergency Alert.
- **R8** The *ISO* must notify each affected *adjacent balancing authority* in the *WECC* that a supply shortfall event exists before revising *system operating limits*.
- **R9** The *ISO* must complete an "Energy Emergency Alert 3 Report", using the template in Appendix 1, within two business *days* of downgrading or termination of an Energy Emergency Alert 3.

5. Processes and Procedures

No procedures have been defined for this reliability standard.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

- **MR1** The following must exist:
 - An authorization letter signed by an officer of the ISO stating that the persons in the position of system controller have the authority to carry out actions and exercise the authority in the requirement.
 - Job descriptions for system controllers identify the responsibilities of the system controller to operate to ISO rules and reliability standards.
- **MR2** Procedures to manage a supply shortfall event exist in *ISO rules*.
 - Disturbance reports, operator logs, voice recordings and/or other data exist that demonstrate the *ISO* managed a supply shortfall event in accordance with its procedures.
- **MR3** Evidence of communicating current and forecast system conditions as described in requirement R3 exists. Evidence may include operator logs, voice recordings, electronic communications and/or other data.
- MR4 /SO rules must include the planning as identified in R3. Operator logs, voice recordings, electronic communications exist to show that procedures in planning for such an event were met.
- **MR5** Operator logs, voice recordings, electronic communications and/or other data exist to show that the requirement was met.

Effective: 2014-01-01 Page 2 of 5

- MR6 /SO rules include the remedies identified in the requirement. Operator logs, voice recordings, electronic communications and/or other data exist to show that the requirement was met.
- **MR7** Operator logs, voice recordings, electronic communications exist to show that requirement was met.
- **MR8** Evidence of notifying affected *adjacent balancing authorities* as described in requirement R8 exists. Evidence may include operator logs, voice recordings, electronic communications, electronic data or other equivalent evidence.
- **MR9** An "Energy Emergency Alert 3 Report" exists for each event where an Energy Emergency Alert 3 was declared.

7. Appendices

Appendix 1 - Energy Emergency Alert 3 Report (see below)

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Effective	Description
2014-01-01	Removed references to the VRC.
2009-10-03	New Issue

Effective: 2014-01-01 Page 3 of 5

Appendix 1 - Energy Emergency Alert 3 Report Requesting balancing authority: Entity experiencing energy deficiency (if different from balancing authority): **Date/Time Implemented:** Date/Time Released: **Declared Deficiency Amount (MW):** Total energy supplied by other balancing authority during the Alert 3 period: Conditions that precipitated call for "Energy Deficiency Alert 3": If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain: Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost. 2. All firm and nonfirm purchases were made regardless of cost. 3. All nonfirm sales were recalled within provisions of the sale agreement.

Effective: 2014-01-01 Page 4 of 5

4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.
5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).
6. Operating Reserves being utilized.
Comments:
Reported By:
Organization:
Title:

Effective: 2014-01-01 Page 5 of 5



Alberta Reliability Standard Load Shedding Plans EOP-003-AB1-1

EOP-003-AB1-1 Load Shedding Plans

1. Purpose

The purpose of this *reliability standard* is to ensure plans are in place and plans are implemented to shed *load* when there is insufficient generation or transmission capacity, to mitigate the risk of an uncontrolled failure of the *Interconnection*.

2. Applicability

This *reliability standard* applies to the entities listed below:

- (a) the operator of a transmission facility that is part of the bulk electric system;
- (b) a market participant receiving service under Rate DTS of the ISO tariff, unless such service is used solely for supplying station service to a generating unit or an aggregated generating facility;
- (c) the *operator* of an *electric distribution system* who is a counterparty to an agreement with a *market participant* receiving service under Rate DTS of the *ISO tariff*, for the provision of *load* shedding services; and
- (d) the ISO.

This reliability standard does not apply to the operator of a transmission facility whose transmission facility is a radial connection from a generating unit or an aggregated generating facility to either the transmission system or to transmission facilities within the city of Medicine Hat.

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the *Consolidated Author<u>itative Document Glossary</u>.*

4. Requirements

- **R1** When the AIES is operating with insufficient generation or transmission capacity and after considering all remedial steps, the *ISO* must issue *directives* to shed *load*.
 - **R1.1** Each *market participant* and *operator* of an *electric distribution system* must shed *load* or reduce *MW* inflow as directed by the *ISO*.
 - **R1.2** When coordination with the *ISO* is not possible or practicable, and after considering all remedial steps, the *operator* of a *transmission facility*, when operating with insufficient generation or transmission capacity, must shed *load* rather than risk an uncontrolled failure of components or *cascading* of the *Interconnection*.
- **R2** The *ISO* must establish plans for automatic *load* shedding for *underfrequency* or under voltage conditions.

Effective: 2012-12-17 Page 1 of 3

EOP- 003- AB-1 Load Shedding Plans

- R3 The ISO must submit UFLS plans to WECC for coordination of UFLS plans among other interconnected transmission operators and balancing authorities.
- **R4** The *ISO* must coordinate *UVLS* plans among other *interconnected transmission* operators and balancing authorities external to Alberta.
- **R5** The *ISO* must consider one or more of these factors in designing an automatic *load* shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.
- **R6** The *ISO* must implement automatic *load* shedding in *MW* blocks established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
- R7 After the AIES separates from the *Interconnection*, if there is insufficient generating capacity to restore frequency following automatic *underfrequency load shedding*, the ISO must issue *directives* to shed additional *load*.
- **R8** The *ISO* must coordinate automatic *load* shedding throughout Alberta with *underfrequency* isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.
- **R9** The *ISO* must have procedures for directing operator controlled manual *load* shedding to respond to real-time emergencies.
- **R10** The *ISO* must be capable of directing manual *load* shedding in a time frame adequate for responding to the emergency.
- **R11** Each *market participant* and *operator* of an *electric distribution system* must be capable of implementing manual *load* shedding in a time frame adequate for responding to the emergency.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

These measures will be used by the *ISO* in carrying out its *compliance monitor*ing duties in accordance with *ISO rule* 12. The *ISO* may consider other data and information, including any provided by a *market participant*.

- **MR1** Voice recordings and logs exist to confirm the ISO issued directives to shed load.
 - **MR1.1** Electronic logs, metering or electronic data exists to confirm the *market* participant or operator of an electric distribution system shed load.
 - **MR1.2** Electronic logs and/or electronic data exist to confirm the *operator of a transmission facility* shed *load*.
- **MR2** Automatic *load* shedding plans exist. Plans meet the defined need of *load* shedding situations.
- MR3 Written confirmation from WECC that the ISO submitted UFLS plans.

Effective: 2012-12-17 Page 2 of 3

EOP-003-AB-1 Load Shedding Plans

- **MR4** Written confirmation from *interconnected transmission operators* and *balancing authorities* external to Alberta indicating that the *ISO* coordinated *UVLS* plans.
- **MR5** One or more of these factors were considered in the design of the *load* shed scheme.
- MR6 One or more MW blocks exist in load shed plans or schemes.
- **MR7** Voice recordings and logs exist to confirm the *ISO* issued *directives* to shed additional *load*.
- **MR8** *ISO rules*, *interconnection* standards or studies exist to show coordination with automatic actions.
- **MR9** Procedures exist for directing operator controlled manual *load* shedding.
- **MR10** Electronic logs, and/or voice recordings exist to confirm the *ISO* directed manual *load* shedding. Manual *load* shedding is performed in a time frame adequate to respond to the emergency as defined in operating procedures or equipment ratings.
- **MR11** Electronic logs, metering or electronic data exists to confirm the manual *load* shedding. Manual *load* shedding is performed in a time frame adequate to respond to the emergency as defined in operating procedures or equipment ratings.

7. Appendices

No appendices have been defined for this reliability standard.

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Effective	Description
2012-12-17	Administrative update – "TFO", "demand customer" and "WSP" replaced with "operator of a transmission facility", "market participant receiving service under Rate DTS of the ISO tariff" and "operator of an electric distribution system"; and other cleanup items.
2009-06-17	New Issue

Effective: 2012-12-17 Page 3 of 3

Alberta Reliability Standard Event Reporting EOP-004-AB-2



1. Purpose

The purpose of this **reliability standard** is to improve the reliability of the **bulk electric system** by requiring the reporting of events by the **ISO**.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- **R1** The **ISO** must have an event reporting operating plan to report the events identified in Appendix 1 to the **NERC** and other organizations, as appropriate.
- **R2** The **ISO** must, upon recognition of a reportable event identified in Appendix 1, report the event in accordance with its event reporting operating plan as soon as practicable, but no more than five (5) **business days** following such recognition.
- **R3** The **ISO** must validate all contact information contained in its event reporting operating plan each calendar year.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of having an event reporting operating plan as required in requirement R1 exists. Evidence may include, but is not limited to, an event reporting operating plan for the events identified in Appendix 1.
- **MR2** Evidence of reporting events as required in requirement R2 exists. Evidence may include, but is not limited to, a copy of the completed report, operator logs, voice recordings, electronic communications, or other equivalent evidence.
- **MR3** Evidence of validating all contact information contained in the event reporting operating plan as required in requirement R3 exists. Evidence may include, but is not limited to, dated records showing contact information, electronic communications or other equivalent evidence.

5. Appendices

Appendix 1 – Reportable Events

Revision History

Date	Description
2016-08-30	Initial release.

Alberta Reliability Standard Event Reporting EOP-004-AB-2



Appendix 1

Reportable Events

The following are the reportable events to be contained in the **ISO**'s event reporting operating plan, as described in requirement R1:

- 1. a physical threat to a **control centre** of the **ISO**, excluding a weather or natural disaster related threat, which has the potential to degrade the normal operation of a **control centre** of the **ISO**;
- 2. a suspicious device or activity at a control centre of the ISO;
- 3. a situation on the bulk electric system requiring a public appeal for load reduction;
- 4. a situation on the **bulk electric system** requiring a system-wide voltage reduction greater than or equal to 3%;
- 5. a situation on the **bulk electric system** requiring manual firm load shedding greater than or equal to 100 MW:
- 6. exceeding an interconnection reliability operating limit within the interconnected electric system for an amount of time that is greater than interconnection reliability operating limit Tv, or exceeding a system operating limit for a major transmission path identified in the table "Major WECC Transfer Paths in the Bulk Electric System", as provided by the WECC, for more than thirty (30) minutes;
- 7. a loss of firm load greater than or equal to 300 MW for fifteen (15) minutes or more;
- 8. an unintended **transmission system** separation within the **interconnected electric system** that results in an island of greater than or equal to 100 MW, excluding an island created by the loss of:
 - a) a transmission system radial connection;
 - b) non-transmission system facilities (distribution level); or
 - c) the interconnection;
- 9. total generation loss, within one (1) minute, of greater than or equal to 2000 MW;
- 10. an unplanned evacuation of the **control centre** of the **ISO** for thirty (30) continuous minutes or more;
- 11. a complete loss, for thirty (30) continuous minutes or more, of voice communication systems for the **control centre** of the **ISO**; or
- 12. a complete loss of monitoring capability affecting the **control centre** of the **ISO** for thirty (30) continuous minutes or more that renders analysis capability, such as state estimator or contingency analysis, inoperable.



Alberta Reliability Standard System Restoration from Blackstart Resources EOP-005-AB-2

1. Purpose

The purpose of this **reliability standard** is to ensure plans, facilities, and personnel are prepared to enable restoration of the **interconnected electric system** starting from **blackstart resources**, to ensure **reliability** is maintained during restoration, and priority is placed on restoring the **interconnected electric system** and the **interconnection** in accordance with the **ISO**'s restoration plan.

2. Applicability

This reliability standard applies to:

- (a) the ISO;
- (b) the operator of a transmission facility that the ISO includes in its restoration plan and in a list published on the AESO website that the ISO may amend from time to time in accordance with the process set out in Appendix 1;
- (c) the operator of a generating unit that:
 - (i) is not part of an aggregated generating facility;
 - (ii) has a maximum authorized real power rating greater than 18 MW; and
 - (iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and
- (d) the **operator** of an **electric distribution system** that is identified in the restoration plan of an **operator** of a **transmission facility**.

3. Requirements

- **R1** Each **operator** of a **transmission facility** must have a restoration plan approved by the **ISO** that allows for the restoration of the **transmission facilities** that it operates to a state whereby the choice of the next load to be restored is not driven by the need to control frequency or voltage, regardless of where the **blackstart resource** is located, following a **disturbance** in which:
 - (a) one or more areas of the interconnected electric system shuts down; and
 - (b) the use of **blackstart resources** is required to restore the shut-down area(s) to service.

The restoration plan must include:

- R1.1 Strategies for system restoration that are coordinated with the ISO's restoration plan.
- R1.2 Intentionally left blank.
- R1.3 Procedures for restoring:
 - (a) connections with other operators of transmission facilities; and
 - (b) **interconnections** with any adjacent **interconnected transmission operators** under the direction of the **ISO**.



Alberta Reliability Standard System Restoration from Blackstart Resources EOP-005-AB-2

- **R1.4** The characteristics of each **blackstart resource** that is connected to the **transmission facilities** of the **operator** of a **transmission facility**, including but not limited to the:
 - (a) name;
 - (b) location;
 - (c) megawatt and megavar capacity; and
 - (d) type of generating unit.
- **R1.5** The identification of the initial switching requirements for any facilities, operated by the **operator** of a **transmission facility**, that are a part of the **cranking paths** identified in the **ISO**'s restoration plan.
- **R1.6** Acceptable operating voltage and frequency limits during restoration.
- R1.7 Operating processes to reestablish connections between the transmission facilities of the operator of a transmission facility for areas that have been restored and are prepared for reconnection.
- **R1.8** Operating processes to restore loads required to restore the **interconnected electric system**, such as:
 - (a) station service for substations;
 - (b) generating units to be restarted or stabilized; and
 - (c) load needed to stabilize generation and frequency, and to provide voltage control.
- **R1.9** Operating processes for accepting authority from and transferring authority back to the **ISO** in accordance with the **ISO**'s restoration plan.
- R2 In the event of changes to the roles and specific tasks of entities identified in a restoration plan:
 - (a) the **ISO** must provide the affected entities identified in its restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan; and
 - (b) each **operator** of a **transmission facility** must provide the affected entities identified in its approved restoration plan with a description of their roles and any changes to their roles and specific tasks prior to the effective date of the plan.
- **R3** Each **operator** of a **transmission facility** must within sixty (60) **days**, or another time period agreed to by the **ISO**, after receiving an updated copy of the **ISO**'s restoration plan:
 - (a) review its restoration plan;
 - (b) align its restoration plan, as necessary, with the ISO's restoration plan; and
 - (c) submit its plan to the ISO for approval.
 - **R3.1** The **operator** of a **transmission facility** must, where the **ISO** disapproves a restoration plan submitted pursuant to requirement R3(c), resolve the issues described in the reasons provided by the **ISO** within a timeframe agreed to by the **ISO**.



- **R4** Each **operator** of a **transmission facility** must update and submit its revised restoration plan to the **ISO** for approval:
 - (a) within ninety (90) days after identifying an unplanned permanent interconnected electric system modification; and
 - (b) no less than ninety (90) days prior to implementing a planned interconnected electric system modification

that would change the implementation of its restoration plan.

- **R4.1** The **operator** of a **transmission facility** must, where the **ISO** disapproves a revised restoration plan submitted pursuant to requirement R4, resolve the issues described in the reasons provided by the **ISO** within a timeframe agreed to by the **ISO**.
- **R5** Each **operator** of a **transmission facility** must have a copy of its current **ISO** approved restoration plan within its primary and backup control rooms for the purpose of ensuring it is available to its **real time** operating personnel.
 - **R5.1** Each **operator** of a **transmission facility** must provide a copy of its current **ISO** approved restoration plan to each **operator** of an **electric distribution system** identified in that plan.
- **R6** The **ISO** must verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This must be completed every five (5) years at a minimum. Such analysis, simulations or testing must verify:
 - **R6.1** the capability of **blackstart resources** to meet the **real power** and **reactive power** requirements of the **cranking paths** and the dynamic capability to supply initial loads;
 - **R6.2** the location and magnitude of loads required to control voltages and frequency within acceptable operating limits; and
 - **R6.3** the capability of **generating units** required to control voltages and frequency within acceptable operating limits.
- R7 Each affected operator of a transmission facility must, following a disturbance in which one or more areas of the interconnected electric system shuts down and the use of blackstart resources is required to restore the shut-down area to service, implement its restoration plan. If the restoration plan cannot be executed as expected, the operator of a transmission facility must use the strategies for system restoration referred to in requirement R1.1 to facilitate restoration.
- **R8** Each affected **operator** of a **transmission facility** must, following a **disturbance** in which one or more areas of the **interconnected electric system** shuts down and the use of **blackstart resources** is required to restore the shut-down area to service, resynchronize these areas with each applicable:
 - (a) neighbouring operator of a transmission facility's area; and
 - (b) interconnected transmission operator's area,

but only with the prior authorization of the **ISO** and in accordance with the procedures included in the **ISO**'s restoration plan.

- **R9** The **ISO** must have **blackstart resource** testing requirements to verify that each **blackstart resource** is capable of meeting the requirements of the **ISO**'s restoration plan. These **blackstart resource** testing requirements must include:
 - **R9.1** The frequency of testing such that each **blackstart resource** is tested at least once every three (3) calendar years.

Effective: 2018-07-01 Page 3 of 9 Public



R9.2 A list of required tests including:

- (a) a test to verify the ability of the blackstart resource to:
 - (i) start the **generating unit(s)** associated with the **blackstart resource** when isolated with no support from the **interconnected electric system**; or
 - (ii) remain energized without connection to the remainder of the **interconnected electric system**, if designed to do so; and
- (b) upon completion of (a), a test to verify the ability of the **generating unit(s)** associated with the **blackstart resource** to energize a bus. If it is not possible to energize a bus during the test, the testing entity must otherwise demonstrate that the **generating unit(s)** associated with the **blackstart resource** has the capability to energize a bus.
- R9.3 The minimum duration of each of the required tests.
- **R10** Each **operator** of a **transmission facility** must include system restoration training for its operating personnel once each calendar year in its operations training program. This training program must include training on the following:
 - (a) the **operator** of a **transmission facility**'s restoration plan including coordination with the **ISO** and each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** included in its restoration plan;
 - (b) restoration priorities;
 - (c) the building of **cranking paths** as included in its restoration plan; and
 - (d) synchronizing re-energized sections of the interconnected electric system.
- R11 Each operator of a transmission facility and operator of an electric distribution system must provide a minimum of two (2) hours of system restoration training every two (2) calendar years to its field switching personnel identified as performing unique tasks associated with the operator of a transmission facility's restoration plan that are outside of their normal tasks.
- **R12** Each **operator** of a **transmission facility** must participate in the **ISO**'s restoration drills, exercises, or simulations if requested by the **ISO**.
- R13 The ISO must have written blackstart resource agreements or mutually agreed upon procedures or protocols with each operator of a generating unit with a blackstart resource, specifying the terms and conditions of their arrangement. Such agreements must include references to the blackstart resource testing requirements, including those specified in requirement R9.
- R14 Each operator of a generating unit with a blackstart resource must have documented procedures for starting each blackstart resource and energizing a bus.
- R15 Each operator of a generating unit with a blackstart resource must notify the ISO of any known changes to the capabilities of that blackstart resource affecting the ability of the operator of a generating unit to fulfill the requirements of the ISO's restoration plan within twenty-four (24) hours of becoming aware of such change.
- R16 Each operator of a generating unit with a blackstart resource must perform blackstart resource tests, and maintain records of such testing, in accordance with the testing requirements set by the ISO as referenced in the blackstart resource agreements or mutually agreed upon procedures or protocols.

Effective: 2018-07-01 Page 4 of 9 Public



- **R16.1** Testing records must include at a minimum:
 - (a) name of the blackstart resource;
 - (b) generating unit tested;
 - (c) date of the test;
 - (d) duration of the test;
 - (e) time required to start the generating unit; and
 - (f) an indication of any testing requirements not met under requirement R9.
- **R16.2** Each operator of a generating unit with a blackstart resource must provide the blackstart resource test results within thirty (30) days after receiving a request from the ISO.
- R17 Each operator of a **generating unit** with a **blackstart resource** must provide a minimum of two (2) hours of training every two (2) calendar years to each of its operating personnel responsible for:
 - (a) the startup of its blackstart resource; and
 - (b) energizing a bus.
 - **R17.1** The training program must include training on the following:
 - (a) those elements of the **ISO**'s restoration plan that are applicable to the **blackstart resource**, including coordination with the **ISO** and the adjacent **operator** of a **transmission facility**; and
 - (b) the procedures documented in requirement R14.
- **R18** Each **operator** of a **generating unit** must participate in the **ISO**'s restoration drills, exercises, or simulations if requested by the **ISO**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of having a restoration plan that is approved by the **ISO** and includes the elements as required in requirement R1 exists. Evidence may include, but is not limited to:
 - (a) email, mail or other equivalent evidence demonstrating approval of the restoration plan by the ISO; and
 - (b) a documented restoration plan including the elements identified in requirement R1.
- MR2 Evidence of providing a description of any changes to the roles and specific tasks of affected entities identified in the restoration plan as required in requirement R2 exists. Evidence may include, but is not limited to, a documented restoration plan showing the effective date and dated emails with receipts or registered mail with receipts, including a description of any changes to roles and specific tasks, or other equivalent evidence.
- **MR3** Evidence of reviewing, aligning and submitting the restoration plan as required in requirement R3 exists. Evidence may include, but is not limited to, a documented restoration plan, including a review or revision history, and emails with receipts or registered mail with receipts, or other equivalent evidence.

Effective: 2018-07-01 Page 5 of 9 Public



- MR3.1 Evidence of resolving the issues described in the reasons provided by the ISO within a timeframe agreed to by the ISO as required in requirement R3.1 exists. Evidence may include, but is not limited to, emails with receipts or registered mail with receipts, or other equivalent evidence.
- **MR4** Evidence of updating and submitting the revised restoration plan as required in requirement R4 exists. Evidence may include, but is not limited to:
 - (a) for the date of identifying any unplanned permanent modifications: logs, a dated report, emails, or other equivalent evidence;
 - (b) for the date of implementing planned modifications: logs, a dated report, emails, or other equivalent evidence;
 - (c) for updating the restoration plan: a dated documented restoration plan and revision histories, or other equivalent evidence; and
 - (d) for submitting the revised restoration plan: emails with receipts or registered mail receipts including submission date, or other equivalent evidence.
 - **MR4.1** Evidence of resolving the issues described in the reasons provided by the **ISO** within a timeframe agreed to by the **ISO** as required in requirement R4.1 exists. Evidence may include, but is not limited to, emails with receipts or registered mail with receipts, or other equivalent evidence.
- **MR5** Evidence of having a copy of the current **ISO** approved restoration plan within the primary and backup control rooms as required in requirement R5 exists. Evidence may include but is not limited to dated records to show that the latest **ISO** approved copy of the restoration plan is available in the primary and backup control rooms and to the **real time** operating personnel in accordance with requirement R5, or other equivalent evidence.
 - **MR5.1** Evidence of providing a copy of the current **ISO** approved restoration plan to each **operator** of an **electric distribution system** as required in requirement R5.1 exists. Evidence may include dated emails with receipts or registered mail receipts, or other equivalent evidence.
- **MR6** Evidence of verifying every five (5) years that the restoration plan accomplishes its intended function as required in requirement R6 exists. Evidence may include, but is not limited to, dated event analysis assessments, dated study results, or other equivalent evidence.
- MR7 Evidence of executing the restoration plan or using the restoration strategies as required in requirement R7 exists. Evidence may include, but is not limited to, sequence of events records, data files, operator logs, voice recordings, electronic communications, or other equivalent evidence.
- MR8 Evidence of resynchronizing shut down area(s) with the ISO's prior authorization and in accordance with the procedures included in the ISO's restoration plan as required in requirement R8 exists. Evidence may include, but is not limited to, a dated copy of the ISO's restoration plan and a combination of the following evidence as appropriate:
 - (a) sequence of events records;
 - (b) data files;
 - (c) operator logs;
 - (d) voice recordings;



- (e) electronic communications, or other equivalent evidence.
- **MR9** Evidence of having **blackstart resource** testing requirements as required in requirement R9 exists. Evidence may include, but is not limited to, **blackstart resource** testing requirement documentation, or other equivalent evidence.
- **MR10** Evidence of including system restoration training within the operations training program as required in requirement R10 exists. Evidence may include, but is not limited to, a documented operations training program including system restoration training for operating personnel, or other equivalent evidence.
- **MR11** Evidence of providing a minimum of two (2) hours of system restoration training every two (2) calendar years as required in requirement R11 exists. Evidence may include, but is not limited to, training records, training documentation including dates and duration, or other equivalent evidence.
- **MR12** Evidence of participating in the **ISO**'s restoration drills, exercises, or simulations as required in requirement R12 exists. Evidence may include, but is not limited to:
 - (1) documentation of the ISO's request; and
 - (2) training records, participation records, training documentation, or other equivalent evidence.
- **MR13** Evidence of having written **blackstart resource** agreements or mutually agreed upon procedures or protocols as required in requirement R13 exists. Evidence may include, but is not limited to, executed agreements, procedures or protocols, or other equivalent evidence.
- **MR14** Evidence of having documented procedures for starting each **blackstart resource** and energizing a bus as required in requirement R14 exists. Evidence may include, but is not limited to, documented procedures, or other equivalent evidence.
- MR15 Evidence of notifying the ISO of any known changes to the capabilities of the blackstart resource as required in requirement R15 exists. Evidence may include, but is not limited to, emails with receipts, registered mail receipts, time stamped voice record(ing)s or operator logs, showing when the operator of a generating unit with a blackstart resource became aware of changes to the blackstart resource capabilities and that it notified the ISO within twenty-four (24) hours of becoming aware of such changes as required in requirement R15, or other equivalent evidence.
- MR16 Evidence of performing blackstart resource tests, maintaining records of such testing, and providing the blackstart resource test results as required in requirement R16 exists. Evidence may include, but is not limited to, test records, test results, and emails with receipts or registered mail receipts that show that it provided these records to the ISO when requested, or other equivalent evidence.
- **MR17** Evidence of providing a minimum of two (2) hours of training every two (2) calendar years as required in requirement R17 exists. Evidence may include, but is not limited to, training records, training dates, durations and training materials provided, or other equivalent evidence.
- **MR18** Evidence of participating in the **ISO**'s restoration drills, exercises, or simulations as required in requirement R18 exists. Evidence may include, but is not limited to:
 - (1) documentation of the ISO's request; and
 - (2) training records, participation records, training documentation, or other equivalent evidence.



5. Appendices

Appendix 1 – Amending Process for List of Operators of Transmission Facilities Included in the AESO Restoration Plan

Revision History

Date	Description
2018-07-01	Initial release.



Appendix 1

Amending Process for List of Operators of Transmission Facilities included in the AESO Restoration Plan

In order to amend the list referenced in subsection (b) of section 2, Applicability, the ISO must:

- (a) upon determining that an **operator** of a **transmission facility** is to be added to the list, notify each affected **operator** of a **transmission facility** in writing and determine the date on which the amended list comes into effect, which must be no less than the first day of the month following three (3) full calendar quarters (January 1, April 1, July 1, October 1) after the date of notice, for the **operator** to meet the applicable requirements;
- (b) upon determining that an operator of a transmission facility is to be deleted, notify each affected operator of a transmission facility in writing and determine the date on which the amended list comes into effect such that the operator will no longer be required to meet the applicable requirements; and
- (c) post the amended list with effective dates on the AESO website.

Effective: 2018-07-01 Page 9 of 9 Public



1. Purpose

Ensure plans are established and personnel are prepared to enable effective coordination of the system restoration process to ensure **reliability** is maintained during restoration of the **interconnected electric system** in the event of a complete or partial **blackout**.

2. Applicability

This reliability standard applies to:

- (a) the ISO.
- 3. Requirements
- R.1. The ISO must have a restoration plan for its area. The scope of the ISO's restoration plan starts when contracted blackstart resources are utilized to re-energize a shut down area of the bulk electric system. The scope of the ISO's restoration plan ends when each operator of a transmission facility is interconnected and the ISO's area is connected to all of its neighbouring reliability coordinator areas, provided facilities are available to be returned to service. The restoration plan shall include:
 - R1.1. a strategy to be employed during restoration events for restoring the interconnected electric system including minimum criteria for meeting the objectives of the ISO's restoration plan;
 - **R1.2.** operating processes for restoring the interconnected electric system;
 - **R1.3.** the elements of coordination between the **ISO** and each **operator** of a **transmission facility** in accordance with the **ISO**'s system restoration plan;
 - **R1.4.** descriptions of the elements of coordination of restoration plans with neighbouring reliability coordinators;
 - R1.5. criteria and conditions for reestablishing connections between each **operator** of a **transmission facility** within its area, with **transmission operators** in other **reliability coordinator** areas, and with other **reliability coordinators**:
 - **R1.6.** reporting requirements for the entities within the **ISO**'s area during a restoration event;
 - R1.7. criteria for sharing information regarding restoration with neighbouring reliability coordinators and with operators of transmission facilities within the ISO's area; and
 - **R1.8.** identification of the **ISO** as the primary contact for disseminating information regarding restoration to neighbouring **reliability coordinators**, and to **operators** of **transmission facilities** within its area.

R1.9. Intentionally left blank.

Effective: 2015-09-01 Page 1 of 4



- **R2.** The **ISO** must distribute its most recent restoration plan to each **operator** of a **transmission facility**, as referenced in the **ISO**'s restoration plan, and to neighbouring **reliability coordinators** within thirty (30) **days** of creation or revision.
- R3. The ISO must review its restoration plan within thirteen (13) months of the last review.
- **R4.** The **ISO** must review its neighbouring **reliability coordinator**'s restoration plans.
 - **R4.1.** If the **ISO** finds conflicts between its restoration plans and any of its neighbours, the conflicts must be resolved in thirty (30) **days**.
- **R5.** The **ISO** must review the restoration plans or procedures of **operators** of **transmission facilities** within its area that are required to be submitted to the **ISO** under any **ISO rules** or **reliability standards**.
 - **R5.1.** The **ISO** must determine whether each of the restoration plans or procedures referenced in requirement R5 is coordinated and compatible with the **ISO**'s restoration plan and each of the other restoration plans or procedures referenced in requirement R5. The **ISO** must approve or disapprove, with stated reasons, the restoration plan or procedure submitted by an **operator** of a **transmission facility** within thirty (30) **days** following the receipt of the restoration plan or procedure.
- **R6.** The **ISO** must have, within its primary and backup control rooms, so that it is available to all of its operating personnel, a copy of its latest restoration plan and copies of the latest restoration plans or procedures of each **operator** of a **transmission facility** in the **ISO**'s area that is required to have an approved plan or procedure in accordance with any **ISO rule** or **reliability standard**.
- R7. The ISO must work with each affected operator of a generating unit, operator of an aggregated generating facility, and operator of a transmission facility as well as neighbouring reliability coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the bulk electric system frequency within acceptable operating limits. If the restoration plan cannot be completed as expected, the ISO must utilize its restoration plan strategies to facilitate restoration of the interconnected electric system.
- **R8.** The **ISO** must coordinate or authorize resynchronizing islanded areas that bridge boundaries between each **operator** of a **transmission facility** or a boundary between the **ISO**'s area and a **reliability coordinator area**. If the resynchronization cannot be completed as expected the **ISO** must utilize its restoration plan strategies to facilitate resynchronization.
- **R9.** The **ISO** must include within its operations training program, annual **interconnected electric system** restoration training for its operating personnel to assure the proper execution of its restoration plan. This training program must address the following
 - **R9.1.** the coordination role of the **ISO**; and
 - R9.2. reestablishing WECC Paths 1 and 83.
- **R10.** The **ISO** must conduct two (2) scheduled instances of a system restoration drill, exercise, or simulation per calendar year, which must provide an opportunity for each **operator** of a **transmission facility**, **operator** of a **generating unit** and **operator** of an **aggregated generating**

Effective: 2015-09-01 Page 2 of 4



facility to attend as dictated by the particular scope of the drill, exercise, or simulation that is being conducted.

R10.1. The ISO must request each operator of a transmission facility, operator of a generating unit and operator of an aggregated generating facility, as identified in the ISO's restoration plan, to participate in a drill, exercise, or simulation at least once every two calendar years

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of having a restoration plan as required in requirement R1 exists. Evidence may include, but is not limited to, a dated copy of the restoration plan.
- **MR2** Evidence of distributing the restoration plan as required in requirement R2 exists. Evidence may include, but is not limited to, e-mails with receipts or other equivalent evidence.
- **MR3.** Evidence of reviewing the restoration plan as required in requirement R3 exists. Evidence may include, but is not limited to, a review signature sheet, or revision histories, or other equivalent evidence.
- **MR4.** Evidence of reviewing neighboring **reliability coordinator**'s restoration plans and resolving any conflicts within thirty (30) **days** as required in requirement R4 exists.
- **MR5.** Evidence of reviewing, approving or disapproving, and notifying each **operator** of a **transmission facility** as required in requirement R5 exists. Evidence may include, but is not limited to, a review signature sheet or emails, or other equivalent evidence.
- **MR6.** Evidence of having copies of restoration plans as required in requirement R6 exists. Evidence may include, but is not limited to, e-mails, restoration plans or procedures documentation, or other equivalent evidence.
- **MR7.** Evidence of monitoring and coordinating restoration progress as required in requirement R7 exists. Evidence may include, but is not limited to, voice recordings, e-mail, dated computer printouts, **operator** logs or other equivalent evidence.
- MR8. If there has been a resynchronizing of an islanded area, the ISO and each reliability coordinator involved may have evidence that it coordinated or authorized resynchronizing in accordance with requirement R8. Evidence may include, but is not limited to, voice recordings, e-mails, operator logs or other equivalent evidence.
- **MR9.** The **ISO** may have an electronic or hard copy of its training records available showing that it has provided training in accordance with requirement R9.
- MR10. The ISO may have evidence that it conducted two scheduled instances of a system restoration drill, exercise, or simulation per calendar year and that operators of a transmission facility and operators of a generating unit and operators of an aggregated generating facility as identified in the ISO's restoration plan were invited in accordance with requirement R10. Evidence may include, but is not limited to, e-mails or other equivalent evidence.

Effective: 2015-09-01 Page 3 of 4



Revision History

Effective Date	Description
2015-09-01	Initial release.

Effective: 2015-09-01 Page 4 of 4



1. Purpose

The purpose of this **reliability standard** is to ensure continued reliable operations of the **bulk electric system** in the event that a **control centre** becomes inoperable.

2. Applicability

This reliability standard applies to:

- (a) the ISO; and
- (b) the operator of a transmission facility who operates a control centre that controls transmission facilities that are part of the bulk electric system.

This **reliability standard** does not apply to the **operator** of a **transmission facility** whose **transmission facilities** are only:

- (a) radial transmission facilities connecting to:
 - load
 - one or more generating units; and / or
 - one or more aggregated generating facilities; or
- (b) either part of an industrial complex or connected to an industrial complex and cannot interrupt power flow on the interconnected electric system, other than power flow on its own transmission facilities.

3. Requirements

R1 The ISO and each operator of a transmission facility must have a current operating plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the bulk electric system in the event that its primary control centre functionality is lost.

This operating plan for backup functionality must include the following, at a minimum:

- (a) the location and method of implementation for providing backup functionality;
- (b) a summary description of the items required to support the backup functionality. These items must include, at a minimum:
 - tools and applications to ensure that system operators have situational awareness of the bulk electric system;
 - (ii) data communications;
 - (iii) voice communications;
 - (iv) power source(s); and
 - (v) physical and cyber security;
- (c) an operating process for keeping the backup functionality consistent with the primary control centre:
- (d) operating procedures, including decision authority, for use in determining when to implement the operating plan for backup functionality;

Effective: 2019-07-01 Page 1 of 4



- (e) a transition period between the decision to transfer functionality to the back up control
 centre following the loss of primary control centre functionality and the time to fully
 implement the backup functionality that is less than or equal to two (2) hours; and
- (f) an operating process describing the actions to be taken during the transition period between the loss of primary control centre functionality and the time to fully implement the backup functionality items identified in requirement R1, part (b). The operating process must include at a minimum:
 - (i) a list of all entities to notify when there is a change in operating locations;
 - (ii) actions to manage the risk to the **bulk electric system** during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality; and
 - (iii) identification of the roles for personnel involved during the initiation and implementation of the operating plan for backup functionality.
- **R2** The **ISO** and each **operator** of a **transmission facility** must have a copy of its current operating plan for backup functionality available at its primary **control centre** and at the location providing backup functionality.
- R3 The ISO must have a backup control centre facility (provided through its own dedicated backup facility or at another entity's control centre staffed with NERC certified "reliability coordinator operators" when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all reliability standards that depend on primary control centre functionality. To avoid requiring a tertiary facility, a backup facility is not required during:
 - (a) planned outages of the primary or backup facilities of two (2) weeks or less; or
 - (b) unplanned outages of the primary or backup facilities.
- **R4** Each **operator** of a **transmission facility** must, when control has been transferred to the backup functionality location, have backup functionality provided either through:
 - (a) a facility staffed by operators that are certified in accordance with any applicable reliability standards; or
 - (b) contracted services staffed by operators that are certified in accordance with any applicable reliability standards

that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all **reliability standards** that depend on the **operator** of a **transmission facility**'s primary **control centre** functionality.

To avoid requiring tertiary functionality, backup functionality is not required during:

- (i) planned outages of the primary or backup functionality of two (2) weeks or less; or
- (ii) unplanned outages of the primary or backup functionality.
- **R5** The **ISO** and each **operator** of a **transmission facility** must annually review and approve its operating plan for backup functionality.
 - **R5.1** An update and approval of the operating plan for backup functionality must take place within sixty (60) **days** of identifying any necessary changes to any part of the operating plan described in requirement R1.

Effective: 2019-07-01 Page 2 of 4



- **R6** The **ISO** and each **operator** of a **transmission facility** must have primary and backup functionality that do not depend on each other for the **control centre** functionality required to maintain compliance with **reliability standards**.
- **R7** The **ISO** and each **operator** of a **transmission facility** must conduct and document results of an annual test of its operating plan that demonstrates:
 - **R7.1** The transition time between the decision to transfer functionality to the backup **control centre** following the simulated loss of primary **control centre** functionality and the time to fully implement the backup functionality; and
 - R7.2 The backup functionality for a minimum of two (2) continuous hours.
- **R8** The following requirements apply in the event of a loss of primary or backup functionality that is anticipated to last for more than six (6) months:
 - **R8.1** Where the **operator** of a **transmission facility** loses primary or backup functionality as described in requirement R8, it must provide a plan to the **ISO** within six (6) **months** of the date when the functionality is lost, showing how it will re-establish primary or backup functionality; and
 - **R8.2** Where the **ISO** loses primary or backup functionality as described in requirement R8, it must provide a plan to the **WECC** within six (6) **months** of the date when the functionality is lost, showing how it will re-establish primary or backup functionality.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of having a current operating plan for backup functionality as required in requirement R1 exists. Evidence may include, but is not limited to, a dated, current operating plan with specified elements or other equivalent evidence.
- **MR2** Evidence of having an electronic or paper copy of the current operating plan for backup functionality available at its primary **control centre** and at the location providing backup functionality as required in requirement R2 exists.
 - Evidence may include, but is not limited to, a current electronic or paper copy of the operating plan, operator log identifying when the plan was put into the **control centre**, or other equivalent evidence.
- MR3 Evidence of having a backup control centre facility that provides the functionality and is staffed as required in requirement R3 exists. Evidence may include, but is not limited to, documentation identifying that the backup control centre facility is staffed with NERC certified "reliability coordinator operators" and provides the same functionality to maintain compliance with all reliability standards as the primary control centre, or other equivalent evidence.
- **MR4** Evidence of having backup functionality provided either through a facility or contracted services staffed as required in requirement R4 exists. Evidence may include, but is not limited to, documentation identifying that the backup functionality includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all **reliability standards** that depend on the primary **control centre** functionality, or other equivalent evidence.
- **MR5** Evidence of reviewing and approving annually the operating plan for backup functionality as required in requirement R5 exists. Evidence may include, but is not limited to, a dated, current,

Effective: 2019-07-01 Page 3 of 4



operating plan for backup functionality, including a revision and approval history, or other equivalent evidence.

- **MR5.1** Evidence of updating and approving the operating plan for backup functionality as required in requirement R5.1 exits. Evidence may include, but is not limited to, an updated and approved operating plan for backup functionality within sixty (60) **days** of any changes to any part of the operating plan described in requirement R1, or other equivalent evidence.
- **MR6** Evidence of having primary and backup functionality that do not depend on each other for the **control centre** functionality required to maintain compliance with **reliability standards** as required in requirement R6 exists. Evidence may include, but is not limited to, documentation or drawings that show the independence of the two (2) **control centres**, or other equivalent evidence.
- **MR7** Evidence of conducting an annual test for backup functionality and documenting the results of the operating plan as required in requirement R7 exists. Evidence may include, but is not limited to, testing documentation or other equivalent evidence.
- **MR8** Evidence for requirement R8 is included in the following measures:
 - **MR8.1** Evidence of providing a plan to the **ISO** as required in requirement R8.1 exists. Evidence may include, but is not limited to, a dated email or letter providing the plan to the **ISO**, or other equivalent evidence.
 - **MR8.2** Evidence of providing a plan to the **WECC** as required in requirement R8.2 exists. Evidence may include, but is not limited to, a dated email or letter to the **WECC**, or other equivalent evidence.

Revision History

Date	Description	
2019-07-01	Initial release.	

Effective: 2019-07-01 Page 4 of 4



Alberta Reliability Standard Facility Connection Requirements FAC-001-AB-0

FAC-001-AB-0 Facility Connection Requirements

1. Purpose

The purpose of this *reliability standard* is to establish connection and performance requirements for *facilities* connecting to the *AIES*.

2. Applicability

This *reliability standard* applies to:

ISO

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the <u>Alberta Reliability Standards Glossary of Terms</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

- **R1** The *ISO* must document transmission *interconnection* requirements to comply with all *reliability standards*. The *ISO's* transmission *interconnection* requirements must address connection requirements for:
 - R1.1 Generating units
 - R1.2 Transmission facilities
 - R1.3 Transmission connected end-use customer's facilities
- **R2** The *ISO*'s transmission *interconnection* requirements or project functional specification must address, but is not limited to, the following items:
 - **R2.1** Voltage level and MW and MVAR capacity or demand at point of connection
 - **R2.2** Breaker duty and *surge* protection
 - **R2.3** System protection and coordination
 - **R2.4** Metering and telecommunications
 - R2.5 Grounding and safety issues
 - **R2.6** Insulation and insulation coordination
 - **R2.7** Voltage, reactive power, and power factor control
 - **R2.8** Power quality impacts
 - R2.9 Equipment ratings
 - R2.10 Synchronizing of facilities
 - **R2.11** Maintenance coordination
 - **R2.12** Operational issues (abnormal frequency and voltages)

Effective: 2010-09-24 Page 1 of 2

FAC-001-AB-0 Facility Connection Requirements

- **R2.13** Inspection requirements for existing or new facilities
- **R2.14** Communications and procedures during normal and emergency operating conditions
- R3 The ISO must assess the long term implications to the AIES of any facility to be connected to it.
- **R4** The *ISO* must maintain and update as required and post on its website its transmission *interconnection* requirements.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 The ISO transmission interconnection requirements include requirements for generating units, transmission facilities and transmission connected end use customer facilities.

The ISO transmission interconnection requirements include content that is compliant and consistent with all reliability standards.

- **MR2** The *ISO* transmission *interconnection* requirements or project functional specifications contain information addressing each item identified in R2.
- **MR3** The assessment made in R3 is included in either the transmission *interconnection* requirements or project functional specification.
- **MR4** The ISO transmission interconnection requirements are posted on its website.

A revision history for the *ISO* transmission *interconnection* requirements shows that updates were made for each change to *reliability standards*, as appropriate.

Changes to the *ISO* transmission *interconnection* requirements are completed within 12 months of the *Commission* approving a change in the *reliability standards*.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Effective	Description
2010-09-24	New Issue

Effective: 2010-09-24 Page 2 of 2



Alberta Reliability Standard Coordination of Plans for New Facilities FAC-002-AB-0

FAC-002-AB-0 Coordination of Plans for New Facilities

1. Purpose

The purpose of this *reliability standard* is to demonstrate that proper evaluation of potential *reliability* impacts of new *transmission facilities* to be connected to the *AIES* has occurred.

2. Applicability

This *reliability standard* applies to:

ISO

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the <u>Alberta Reliability Standards Glossary of Terms</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

- R1 The ISO must retain the documentation of its evaluation of the potential *reliability* impact of the new *transmission facilities* and their connections on the AIES for three years after energization.
- R2 The ISO must provide the documentation referred to in requirement R1 to the WECC within 30 calendar days of its request, provided such request is made with the three year period referred to in requirement R1.

5. Processes and Procedures

No procedures have been defined for this reliability standard.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

- **MR1** Documentation exists for the past three years and is made available when requested per R1.
- MR2 Confirmation exists that documentation was received if requested.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Effective: 2010-03-22 Page 1 of 2

FAC-001-AB-0 Coordination of Plans for New Facilities

Revision History

Effective	Description
2010-03-22	New Issue

Effective: 2010-03-22 Page 2 of 2



Alberta Reliability Standards Facilities Design, Connections and Maintenance FAC-003-AB1-1

FAC-003-AB1-1 Transmission Vegetation Management Program

1. Purpose

The purpose of this *reliability standard* is to improve the *reliability* of electric transmission systems by preventing *outages* from vegetation located on a right-of-way, corridor or other route (collectively "ROW") and minimizing *outages* from vegetation located adjacent to a ROW, maintaining clearances between *transmission facilities* and vegetation on and along a ROW, and reporting vegetation related *outages* of electric transmission systems to the *ISO* and *WECC*.

2. Applicability

This reliability standard applies to:

- (a) the *legal owner* of a *transmission facility* with *transmission facilities* operated at 200 kV and above and any lower voltage *transmission facilities* designated by the *ISO* as critical to the *reliability* of the *AIES* as identified in Appendix A; provided that *transmission facilities* on ROWs that are assessed and identified on an annual basis not to have vegetation capable of growing higher than 2 meters are excluded; and
- (b) the ISO.

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the *Consolidated Authoritative Document Glossary.*

4. Requirements

- **R1** Each *legal owner* of a *transmission facility* must prepare a *TVMP*. This program is to be updated at least annually. The *TVMP* must include the objectives, practices, approved procedures, and work specifications ¹ of the *legal owner* of a *transmission facility*.
 - R1.1 The *TVMP* must define a schedule for and the type (aerial or ground) of ROW vegetation inspections. This schedule must be flexible enough to adjust for changing conditions. The inspection schedule must be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the *transmission facilities* of the *legal owner* of a *transmission facility*. The *legal owner* of a *transmission facility* must perform vegetation inspections as identified in the schedule.

Effective: 2012-12-17 Page 1 of 6

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¹ ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this *reliability standard*, is considered by *NERC* to be an industry best practice.

- R1.2 The *TVMP* must identify and document clearances between vegetation and any overhead ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the *legal owner* of a *transmission facility* must establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and must also establish and maintain a set of clearance requirements identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.
 - R1.2.1 Clearance 1 Each *legal owner* of a *transmission facility* must determine and document appropriate clearance distances to be achieved at the time of vegetation management work based upon local conditions and the expected time frame in which the *legal owner* of a *transmission facility* plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances must be greater than those defined in Clearance 2.
 - R1.2.2 Clearance 2 Each *legal owner* of a *transmission facility* must determine and document specific minimum radial clearance distances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum radial clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. Subject to R1.2.2.1 and R1.2.2.2, the documented specific minimum radial clearance distances must be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.
 - R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances must be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.
 - **R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances must be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
- **R1.3** All personnel directly involved in the design and implementation of the *TVMP* must hold appropriate qualifications and must have taken appropriate training, as defined by the *legal owner* of a *transmission facility*, to perform their duties.
- **R1.4** Each *legal owner* of a *transmission facility* must develop mitigation measures to achieve sufficient clearances for the protection of its *transmission facilities*

Effective: 2012-12-17 Page 2 of 6

- when it identifies locations on the ROW where it is restricted from attaining Clearance 1 distances.
- **R1.5** Each *legal owner* of a *transmission facility* must establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line *outage*.
 - This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.
- R2 The *legal owner* of a *transmission facility* must create and implement an annual plan for vegetation management work to ensure the *reliability* of its *transmission facilities*. The plan must describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan must be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the *reliability* of the *AIES*. Adjustments to the plan must be documented as they occur. The plan must include the time required to obtain permissions or permits from landowners or regulatory authorities. Each *legal owner* of a *transmission facility* must have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to its work specifications.
- **R3** Each *legal owner* of a *transmission facility* must report quarterly to the *ISO*, *sustained outages* to its transmission lines determined by the *legal owner* of a *transmission facility* to have been caused by vegetation.
 - **R3.1** Multiple *sustained outages* on an individual transmission line, if caused by the same vegetation, must be reported as one *outage* regardless of the actual number of *outages* within a 24-hour period.
 - **R3.2** The *legal owner* of a *transmission facility* is not required to report to the *ISO*, sustained outages to its transmission lines caused by either:
 - vegetation falling onto a transmission line from outside the ROW caused by a natural disasters are not considered reportable (examples of disasters include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, ice storms, floods, major storms as defined either by the *legal owner* of a *transmission facility* or an applicable regulatory body); or
 - vegetation falling onto a transmission line caused by human or animal activity are not considered reportable (examples of human or animal activity include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural, horticultural or agricultural activities, or removal/digging of vegetation).
 - **R3.3** The *outage* information provided by the *legal owner* of a *transmission facility* to the *ISO* must include at a minimum:
 - number or name of the transmission line(s) forced out of service;
 - date and time:
 - duration of the outage;

Effective: 2012-12-17 Page 3 of 6

- description of the cause of the outage;
- · other pertinent comments; and
- remedial action taken by the *legal owner* of a *transmission facility*.
- **R3.4** An *outage* must be categorized by the *legal owner* of a *transmission facility* as one of the following:
 - **R3.4.1** Category 1 Grow-ins: *Outages* caused by vegetation growing into transmission lines from vegetation inside and/or outside of the ROW;
 - **R3.4.2** Category 2 Fall-ins: *Outages* caused by vegetation falling into transmission lines from inside the ROW; or
 - **R3.4.3** Category 3 Fall-ins: *Outages* caused by vegetation falling into transmission lines from outside the ROW.
- **R4** The *ISO* must report quarterly to *WECC*, sustained outages to transmission lines determined by the *legal owner* of a transmission facility to have been caused by vegetation.
 - **R4.1** Multiple *sustained outages* within a 24-hour period on an individual transmission line, if caused by the same vegetation, must be reported as one *outage* regardless of the actual number of *outages*.
 - **R4.2** The *ISO* is not required to report to *WECC*, sustained outages to transmission lines caused by either:
 - outages from vegetation falling onto transmission lines from outside the ROW caused by natural disasters are not reportable (examples of disasters include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, ice storms, floods, major storms as defined either by the legal owner of a transmission facility, or an applicable regulatory body); or
 - outages from vegetation caused by human or animal activity are not considered reportable (examples of human or animal activity include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural, horticultural or agricultural activities, or removal/digging of vegetation).
 - **R4.3** The *outage* information provided by the *ISO* to *WECC* must include at a minimum:
 - number or name of the transmission line(s) forced out of service;
 - date and time:
 - duration of the *outage*;
 - description of the cause of the outage;
 - · other pertinent comments; and
 - remedial action taken by the *legal owner* of a *transmission facility*.
 - **R4.4** An *outage* must be categorized by the *legal owner* of a *transmission facility* as one of the following:

Effective: 2012-12-17 Page 4 of 6

- **R4.4.1** Category 1 Grow-ins: *Outages* caused by vegetation growing into transmission lines from vegetation inside and/or outside of the ROW;
- **R4.4.2** Category 2 Fall-ins: *Outages* caused by vegetation falling into transmission lines from inside the ROW; or
- **R4.4.3** Category 3 Fall-ins: *Outages* caused by vegetation falling into transmission lines from outside the ROW.

5. Procedures

No procedures have been defined for this reliability standard.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

These measures will be used by the *ISO* in carrying out its compliance monitoring duties in accordance with *ISO* rule 12. The *ISO* may consider other data and information, including any provided by a *market participant*.

- MR1 A revision history of the *TVMP* is provided annually to the *ISO*. A *TVMP* exists and is provided in the format specified in the *ISO TVMP* template. The *TVMP* is provided within 30 *days* of request. The *TVMP* is complete and includes the required component sections specified in the template.
 - **MR1.1** A vegetation inspection schedule exists in the *TVMP*. The schedule is completed in accordance with the *ISO TVMP* template. The schedule includes all applicable transmission lines. Documentation exists to show that the vegetation inspections have been performed.
 - MR1.2 Clearance 1 and Clearance 2 values exist in the TVMP
 - **MR1.2.1** Clearance 1 values exist for every transmission line. Clearance 1 values specified are greater than those of Clearance 2.
 - MR1.2.2 Clearance 2 values exist for every transmission line. Clearance 2 values specified are greater than the minimum clearances set in IEEE standards for the applicable scenarios.
 - **MR1.3** Requirements, training, and qualifications for positions responsible for preparing and implementing the *TVMP* exist. Documentation exists to confirm that personnel meet the requirements, training, and qualifications of the position. Acceptable documentation includes training records, licenses, certificates, and resumes.
 - MR1.4 A list exists and specifies locations on the ROW where Clearance 1 is not attainable. Mitigation measures exist where there are restrictions. Mitigating measures are appropriate and meet the intent of this reliability standard.
 - **MR1.5** A documented process or procedure for communication exists. The process is appropriate and of sufficient detail to meet the intent of the requirement.
- MR2 A work plan exists in the form of the *ISO* vegetation management work plan template. The work plan is complete. The work plan is submitted annually and within 30 *day*s of being requested.

Effective: 2012-12-17 Page 5 of 6

Evidence exists to show that the work plan is implemented. Evidence may include status and inspection reports, work orders, and/or contracts. The work plan is being followed in accordance to the schedule. The work is completed in accordance with the work plan. Revision documentation exists where the plan has been revised. Evidence is provided to the *ISO* within 30 *day*s of a request.

- MR3 to 3.4.3 Quarterly reports are submitted to the *ISO* by the dates specified by the *ISO*. Quarterly reports contain all sustained outages caused by vegetation for that reporting period. Quarterly reports contain the specific information in the requirement.
- MR4 to 4.4.3 Quarterly reports are submitted to the WECC by dates specified by WECC. Quarterly reports contain all sustained *outages* caused by vegetation received by the ISO for that reporting period. Quarterly reports contain the specific information in the requirement.

7. Appendices

Appendix A - Transmission Facilities Designated as Critical to the AIES

The following facilities have been identified as critical to the *AIES* and require the application of this *reliability standard*:

- 887L (Pocaterra T48S Alberta / BC border);
- 777L (Pocaterra T48S Seebe T245S):
- 786L (Coleman T799S Alberta / BC border); and
- 170L (Coleman T799S Pincher Creek T396S).

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2012-12-17	Administrative update – "TFO" replaced with the "legal owner of a transmission facility"; and other minor cleanup items.
2010-01-26	R1 and R2
2013-10-01	New Issue

Effective: 2012-12-17 Page 6 of 6



Public

1. Purpose

The purpose of this **reliability standard** is to ensure that the **facility ratings** used in the reliable planning and operation of the **transmission system** are determined based on technically sound principles. A **facility rating** is an essential component in the determination of **system operating limits**.

2. Applicability

This reliability standard applies to:

- (a) the legal owner of a transmission facility:
 - (i) that is part of the **bulk electric system**, except for transformers that do not have a primary terminal and at least one (1) secondary terminal engerized at 100 kV or higher;
 - (ii) that the ISO:
 - (A) determines is necessary for the reliable operation of either the interconnected electric system or the City of Medicine Hat electric system; and
 - (B) publishes on the AESO website and may amend from time to time on notice to **market participants** in accordance with the process set out in Appendix 1;
 - (iii) who owns a **generating unit** step-up transformer for those generating units listed in subsection (b); or
 - (iv) who owns a transformer connected to a blackstart resource;
- (b) the legal owner of a generating unit that is:
 - (i) directly connected to the **bulk electric system** and has a **maximum authorized real power rating** greater than 18 MW, unless the **generating unit** is part of an industrial complex;
 - (ii) within a power plant that:
 - (A) is not part of an aggregated generating facility;
 - (B) is directly connected to the bulk electric system; and
 - (C) has a combined **maximum authorized real power rating** greater than 67.5 MW, unless the power plant is part of an industrial complex;
 - (iii) a blackstart resource;
 - (iv) directly connected to the **bulk electric system** and within an industrial complex with **supply transmission service** greater than 67.5 MW; or
 - (v) material to this reliability standard and to the reliability of the bulk electric system, regardless of maximum authorized real power rating, as the ISO determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1; and
- (c) the legal owner of an aggregated generating facility that is:
 - directly connected to the bulk electric system and has a maximum authorized real power rating greater than 67.5 MW, unless the aggregated generating facility is part of an industrial complex;
 - (ii) a blackstart resource;
 - (iii) directly connected to the **bulk electric system** and within an industrial complex with **supply transmission service** greater than 67.5 MW; or

Effective: 2019-01-01 for new facilities; and Page 1 of 6

Effective: 2020-01-01 for existing facilities



(iv) regardless of maximum authorized real power rating, material to this reliability standard and to the reliability of the bulk electric system as the ISO determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1.

3. Requirements

- R1 Each legal owner of a generating unit and legal owner of an aggregated generating facility must have documentation for determining the facility ratings of its facilities:
 - (a) up to the low side terminals of the step-up transformer if the **legal owner** of the **generating unit** or **legal owner** of the **aggregated generating facility** does not own the step-up transformer; or
 - (b) including the step-up transformer and associated terminal equipment (as applicable based on ownership) if the legal owner of the generating unit or legal owner of the aggregated generating facility owns the step-up transformer.
 - **R1.1** The documentation must contain assumptions used to rate the facilities and at least one (1) of the following:
 - (a) design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. the American National Standards Institute and the Institute of Electrical and Electronic Engineers ("IEEE")), or an established engineering practice that has been verified by testing or engineering analysis; or
 - (b) operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.
 - **R1.2** The documentation must be consistent with the principle that the **facility ratings** do not exceed the most limiting applicable **equipment rating** of the individual equipment that comprises that facility.
- R2 Each legal owner of a generating unit and legal owner of an aggregated generating facility must have a documented methodology for determining the facility ratings of its facilities connected between the location specified in requirement R1 and the interface with a transmission facility (based on equipment ownership) that contains all of the following:
 - **R2.1** the method used to establish the **equipment ratings** of the equipment that comprises the facility must be consistent with at least one (1) of the following:
 - (a) ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications, such as the nameplate rating;
 - (b) one (1) or more industry standards developed through an open process such as the IEEE or the International Council on Large Electric Systems ("CIGRE"); or
 - (c) a practice that has been verified by testing, performance history or engineering analysis;
 - **R2.2** the underlying assumptions, design criteria, and methods used to determine the **equipment ratings** identified in requirement R2.1, including identification of how each of the following were considered:
 - (a) **equipment rating** standard(s) used in development of this method;
 - (b) ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications;
 - (c) ambient conditions (for particular or average conditions or as they vary in **real time**);

Page 2 of 6



- (d) operating limitations; and
- (e) both summer and winter season operations, where summer is defined as May 1st at 12:01 AM Mountain Time to October 31st at 12:00 midnight Mountain Time and winter is defined as November 1st at 12:01 AM Mountain Time to April 30th at 12:00 midnight Mountain Time;
- **R2.3** a statement that a **facility rating** must not exceed the most limiting applicable **equipment** rating of the individual equipment that comprises that facility;
- **R2.4** the process by which the **equipment ratings** of the equipment that comprises a facility are determined, where:
 - **R2.4.1** the scope of equipment that comprises the facility, addressed in accordance with requirement R2.4 must include (based on equipment ownership), but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices; and
 - **R2.4.2** the scope of **equipment ratings** addressed in accordance with requirement R2.4 must include, as a minimum, both **normal ratings** and **emergency ratings**, such that:
 - **R2.4.2.1** the **emergency ratings** for equipment comprising power transformers must be specified for a 30 minute duration and the next 3.5 hour duration; and
 - **R2.4.2.2** the **emergency ratings** for transmission lines must be specified for a ten (10) minute duration.
- R3 Each legal owner of a transmission facility must have a documented methodology for determining the facility ratings of its facilities (except for those facilities associated with a generating unit or aggregated generating facility addressed in requirements R1 and R2) that contains all of the following:
 - **R3.1** the method used to establish the **equipment ratings** of the equipment that comprises the facility must be consistent with at least one (1) of the following:
 - (a) ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications, such as the nameplate rating;
 - (b) one (1) or more industry standards developed through an open process such as the IEEE or CIGRE; or
 - (c) a practice that has been verified by testing, performance history or engineering analysis;
 - **R3.2** the underlying assumptions, design criteria, and methods used to determine the **equipment ratings** identified in requirement R3.1, including identification of how each of the following were considered:
 - (a) **equipment rating** standard(s) used in development of this method;
 - (b) ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications;
 - (c) ambient conditions (for particular or average conditions or as they vary in **real time**);
 - (d) operating limitations; and
 - (e) both summer and winter season operations, where summer is defined as May 1st at 12:01 AM Mountain Time to October 31st at 12:00 midnight Mountain Time and winter is defined as November 1st at 12:01 AM Mountain Time to April 30th at 12:00 midnight Mountain Time;

Effective: 2019-01-01 for new facilities; and Effective: 2020-01-01 for existing facilities



- R3.3 a statement that a facility rating must not exceed the most limiting applicable equipment rating of the individual equipment that comprises that facility; and
- R3.4 the process by which the equipment ratings of the equipment that comprises a facility are determined, where:
 - R3.4.1 the scope of equipment that comprises the facility, addressed in accordance with requirement R3.4, must include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices;
 - R3.4.2 the scope of equipment ratings addressed in accordance with requirement R3.4 must include, at a minimum, both **normal ratings** and **emergency ratings**, such that:
 - R3.4.2.1 the emergency ratings for equipment comprising power transformers must be specified for a 30 minute duration and the next 3.5 hour duration; and
 - R3.4.2.2 the emergency ratings for transmission lines must be specified for a ten (10) minute duration.
- R4 Intentionally left blank.
- R5 Intentionally left blank.
- R6 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must have facility ratings for its facilities that are consistent with:
 - (a) the facility ratings methodology in accordance with requirements R2 or R3, for a transmission facility, a generating unit and an aggregated generating facility; and
 - (b) the documentation in accordance with requirement R1, for a generating unit and an aggregated generating facility.
- R7 Intentionally left blank.
- **R8** Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- MR1 Evidence of having documentation for determining the facility ratings as required in requirements R1, R1.1 and R1.2 exists.
- MR2 Evidence of having a documented facility ratings methodology as described in requirement R2
- MR3 Evidence of having a documented facility ratings methodology as described in requirement R3
- MR4 Intentionally left blank.
- MR5 Intentionally left blank.
- MR6 Evidence of having facility ratings that are consistent with the facility ratings methodology in accordance with requirements R2 and R3, and the documentation in accordance with requirement R1 exists.
- MR7 Intentionally left blank.
- MR8 Intentionally left blank.

Page 4 of 6



5. Appendices

Appendix1 - Amending Process for List of Facilities

Revision History

Date	Description
2019-01-01	Initial release

Effective: 2019-01-01 for new facilities; and Effective: 2020-01-01 for existing facilities



Appendix 1

Amending Process for List of Facilities

In order to amend a list referenced in subsections (a)(ii), (b)(iv) and (c)(iii) of section 2, Applicability, the **ISO** must:

- (a) upon determining that a **transmission facility**, **generating unit** or **aggregated generating facility** is to be added, notify the **legal owner** and **operator** in writing and determine an effective date, which must be no less than:
 - (i) eight (8) full calendar quarters after the date of notice, where the **transmission facility**, **generating unit** or **aggregated generating facility** is commissioned prior to the date of notice; and
 - (ii) no less than four (4) full calendar quarters after the date of notice, where the **transmission facility**, **generating unit** or **aggregated generating facility** is commissioned on or after the date of notice:
- (b) upon determining that a transmission facility, generating unit or aggregated generating facility is to be deleted, notify the legal owner and operator in writing and determine an effective date on which the legal owner and operator will no longer be required to meet the applicable requirements; and
- (c) publish the amended list with effective dates on the AESO website.

Effective: 2019-01-01 for new facilities; and Effective: 2020-01-01 for existing facilities



1. Purpose

The purpose of this **reliability standard** is to ensure that **system operating limits** used in the reliable planning of the **bulk electric system** are determined based on an established methodology or methodologies.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must have a documented system operating limit methodology for use in developing system operating limits that:
 - (a) is applicable for developing system operating limits used in the ISO's planning horizon;
 - (b) states that system operating limits must not exceed any associated facility rating; and
 - (c) includes a description of how to identify the subset of **system operating limits** that qualify as **interconnected reliability operating limits**.
- R2 The system operating limit methodology of the ISO must include a requirement:
 - **R2.1** That **system operating limits** developed in the pre-**contingency** state, and with all facilities in service:
 - (a) result in:
 - bulk electric system performance that demonstrates transient, dynamic and voltage stability;
 - ii. all facilities operating within their facility ratings; and
 - iii. system conditions within thermal, voltage and stability limits;

and

- (b) reflect expected system conditions and changes to **bulk electric system** topology.
- **R2.2** That **system operating limits** developed starting with all facilities in service and following any single **contingency** including:
 - (a) single line to ground fault or three-phase fault, whichever is most severe, with normal clearing, on any generating unit, line, transformer or shunt device;
 - (b) loss of any generating unit, line, transformer or shunt device without a fault; or
 - (c) single pole block, with **normal clearing**, in a monopolar or bipolar high voltage direct current system;

result in bulk electric system performance that:

(d) demonstrates transient, dynamic and voltage stability;

Effective: 2016-08-30 Page 1 of 5



- (e) has all facilities operating within their facility ratings;
- (f) is within voltage and stability limits; and
- (g) has no cascading or uncontrolled separation,

with either or both of the following responses to the single **contingency** being acceptable:

- (h) planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the facility on which the fault occurred or by the affected area; or
- (i) **bulk electric system** reconfiguration through manual or automatic control or protection actions.
- **R2.3** Intentionally left blank.
- R2.4 That following a single **contingency**, in preparation for the next **contingency** when developing **system operating limits**, the **ISO** may make system adjustments, including changes to generation, uses of the **transmission system**, and the **transmission system** topology.
- R2.5 That system operating limits developed starting with all facilities in service and following any of the multiple contingencies identified in reliability standard TPL-003-AB, result in bulk electric system performance that:
 - (a) demonstrates transient, dynamic and voltage stability;
 - (b) has all facilities operating within their facility ratings;
 - (c) is within voltage and stability limits; and
 - (d) has no **cascading** or uncontrolled separation,

with any of the following responses to such multiple **contingencies** being acceptable:

- (e) planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the facility on which the fault occurred or by the affected area;
- (f) **bulk electric system** reconfiguration through manual or automatic control or protection actions; or
- (g) planned or controlled interruption of demand to demand customers, the planned removal of a generating unit, or the curtailment of firm, non-recallable power transfers.
- R2.6 Intentionally left blank.
- R3 In addition to requirements R1 through R2, the ISO must include within the system operating limit methodology a description of the:
 - (a) study model, which must include at least the Alberta system as well as the critical modeling details from other interconnected jurisdictions that would impact any facility under study;

Effective: 2016-08-30 Page 2 of 5



- (b) selection of applicable contingencies;
- (c) level of system detail included in the study model used to determine system operating limits;
- (d) allowed uses of remedial action schemes;
- (e) anticipated transmission system configuration, generation dispatch and load level;
- (f) criteria for determining when violating a **system operating limit** qualifies as an **interconnection reliability operating limit** and criteria for developing any associated **interconnection reliability operating limit** T_v; and
- (g) any reliability margins applied.
- R4 The ISO must provide its system operating limit methodology, and any update to that methodology, to all of the following prior to implementation of the methodology or any update to the methodology:
 - (a) each adjacent planning authority; and
 - (b) each planning authority that indicated it has a reliability-related need for the methodology.
- **R5** Intentionally left blank.
- R6 The system operating limit methodology of the ISO must include a requirement that:
 - **R6.1** for **interconnections** with other systems within the **WECC**, starting with all facilities in service and following any of the multiple **contingencies** identified in **reliability standard** TPL-003-AB or any of the following multiple **contingencies**:
 - (a) simultaneous permanent phase to ground faults of each of two (2) 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 (5) towers at each station, this condition is an acceptable risk and therefore can be excluded;
 - (b) a permanent phase to ground fault on any generating unit, transmission circuit, transformer, or collector bus section with delayed fault clearing except for collector bus sectionalizing breakers or collector bus tie breakers as specified in requirement R6.2;
 - (c) simultaneous permanent loss of both poles of a direct current bipolar facility without an alternating current **fault**;
 - (d) the failure of a circuit breaker associated with a remedial action scheme to operate when required following the loss of any system element without a fault, or a permanent phase to ground fault, with normal clearing, on any transmission circuit, transformer or collector bus section; or
 - (e) a single-line-to-ground **fault** with **normal clearing** on common mode **contingency** of two (2) adjacent circuits on separate towers unless the **ISO** determines the event frequency is less than one (1) in thirty (30) years,

Effective: 2016-08-30 Page 3 of 5



the system operating limits result in bulk electric system performance that:

- (f) demonstrates transient, dynamic and voltage stability;
- (g) has all facilities operating within their facility ratings;
- (h) is within voltage and stability limits; and
- (i) has no **cascading** or uncontrolled separation,

with any of the following responses to such multiple contingencies being acceptable:

- planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the facility on which the fault occurred or by the affected area;
- (k) **bulk electric system** reconfiguration through manual or automatic control or protection actions; or
- (I) planned or controlled interruption of **demand** to **demand customers**, the planned removal of a **generating unit**, or the curtailment of firm, non-recallable power transfers.
- **R6.2** for **interconnections** with other systems within the **WECC**, starting with all facilities in service and following either of these multiple **contingencies**:
 - (a) a common mode outage of two (2) generating units connected to the same switchyard not otherwise addressed by reliability standard FAC-010-AB; or
 - (b) the loss of multiple collector bus sections as a result of failure or delayed clearing of a collector bus tie or collector bus sectionalizing breaker to clear a permanent phase to ground fault, the system operating limits result in bulk electric system performance such that cascading does not occur on other systems in other jurisdictions within the WECC.
- **R6.3** where the **ISO** makes changes to any **contingencies** and required responses identified in requirements R6.1 and R6.2 for specific facilities on **interconnections** to other systems within the **WECC** in accordance with the **WECC** performance category adjustment process based upon system performance and robust design, the **system operating limits** result in **bulk electric system** performance that satisfies the performance requirements in requirements R2.4.

4. Measures

The following measures correspond to the requirements identified in Section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

- **MR1** Evidence of having a documented **system operating limit** methodology as required in requirement R1 exists.
- **MR2** Evidence of the **system operating limit** methodology including requirements as required in sub requirements R2.1, R2.2, R2.4 and R2.5 exists.
- **MR3** Evidence of the **system operating limit** methodology including the description(s) as required in requirement R3 exists.

Effective: 2016-08-30 Page 4 of 5



- **MR4** Evidence of providing the **system operating limit** methodology as required in requirement R4 exists. Evidence may include, but is not limited to, email or mail to an appropriate recipient that identifies contents submitted.
- MR5 Intentionally left blank.
- **MR6** Evidence of the **system operating limit** methodology including requirements as required in sub requirements R6.1 through R6.3 exists.

Revision History

Effective	Description
2012-07-01	Initial Release
2015-09-01	Revised for ISO assumption of RC functionality for the Alberta footprint
2016-08-30	Inclusion of the defined term system element.

Effective: 2016-08-30 Page 5 of 5

Alberta Reliability Standard System Operating Limits Methodology for the Operations Horizon FAC-011-AB-2



1. Purpose

To ensure that **system operating limits** used in the reliable operation of the **bulk electric system** are determined based on an established methodology or methodologies.

2. Applicability

This **reliability standard** applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must have a documented methodology for use in developing system operating limits (system operating limit methodology) within its area. This system operating limit methodology must:
 - **R1.1** be applicable for developing **system operating limits** used in the operations horizon;
 - R1.2 state that system operating limits must not exceed associated facility ratings; and
 - R1.3 include a description of how to identify the subset of system operating limits that qualify as interconnection reliability operating limits.
- R2 The system operating limit methodology of the ISO must include a requirement that system operating limits provide bulk electric system performance consistent with the following:
 - R2.1 in the pre-contingency state, the bulk electric system must demonstrate transient, dynamic and voltage stability; all facilities must be within their facility ratings and within their thermal, voltage and stability limits. In the determination of system operating limits, the bulk electric system condition used must reflect current or expected system conditions and must 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 must demonstrate transient, dynamic and voltage stability; all facilities must be operating within their **facility ratings** and within their thermal, voltage and stability limits; and **cascading** or uncontrolled separation must not occur:
 - **R2.2.1** single line to ground or three (3) -phase **fault** (whichever is more severe), with **normal clearing**, on any **generating unit**, **aggregated generating facility**, line, transformer, or shunt device that is **faulted**;

¹ The **contingencies** identified in FAC-011-AB-2 requirement R2.2.1 through requirement R2.2.3 are the minimum **contingencies** that must be studied but are not necessarily the only **contingencies** that are studied.

Alberta Reliability Standard



System Operating Limits Methodology for the Operations Horizon

FAC-011-AB-2

- **R2.2.2** loss of any **generating unit**, **aggregated generating facility**, line, transformer, or shunt device without a **fault**; and
- **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 will 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;
 - **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; and
 - **R2.3.3** system reconfiguration through manual or automatic control or protection actions: and
- **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 **ISO**'s methodology for determining **system operating limits**, must 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 **ISO** 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** (as determined by the **ISO** in accordance with FAC-014 requirement R6) are applicable for use in the operating horizon given the actual or expected system conditions;
 - **R3.3.1.** this process must 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 system operating limits;
 - **R3.5.** allowed uses of remedial action schemes or remedial action plans;
 - **R3.6.** anticipated **transmission system** configuration, generation **dispatch** and load level; and

Alberta Reliability Standard System Operating Limits Methodology for the



FAC-011-AB-2

Operations Horizon

- R3.7. criteria for determining when violating a system operating limit qualifies as an interconnection reliability operating limit and criteria for developing any associated interconnection reliability operating limit Tv.
- **R4.** The **ISO** must issue its **system operating limit** methodology and any changes to that methodology, prior to the effective date 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 **ISO**'s area.
 - **R4.3.** each **operator** of a **transmission facility** that operates in the **ISO**'s area.
- R5. Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** The **system operating limit** methodology of the **ISO** may address all of the items listed in requirement R1.1 through requirement R1.3. Evidence may include, but is not limited to, a documented **system operating limit** methodology, or other equivalent evidence as required in requirement R1.
- MR2 Evidence of including requirements in the **system operating limit** methodology as set out in requirement R2. Evidence may include, but is not limited to, a documented **system operating limit** methodology, or other equivalent evidence as set out in requirement R2.
- **MR3** Evidence of including all of the items as required in requirement R3.1 through R3.7 in the **system operating limit** methodology. Evidence may include, but is not limited to, a documented **system operating limit** methodology, documented processes or other equivalent evidence as required in requirement R2.
- **MR4** The **ISO** may have evidence of issuing the **system operating limit** methodology, and any changes to that methodology, including the date they were issued, as required in requirement R4. Evidence may include, but is not limited to, emails, or other equivalent evidence.

MR5 Intentionally left blank.

Revision History

Date	Description
2015-09-01	Initial release.

Alberta Reliability Standard Establish and Communicate System Operating Limits FAC-014-AB1-2

1. Purpose

The purpose of this **reliability standard** is to establish and communicate **system operating limits** to be used in the reliable planning and operation of the **bulk electric system**.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- The ISO must ensure that system operating limits, including interconnection reliability operating limits, for its area are established and that the system operating limits (including interconnection reliability operating limits) are consistent with its system operating limit methodology.
- R2 Intentionally left blank.
- R3 Intentionally left blank.
- R4 Intentionally left blank.
- R5 The ISO must provide its system operating limits and interconnection reliability operating limits in the operating horizon to:
 - (a) each adjacent reliability coordinator;
 - (b) each **operator** of a **transmission facility** within its area that has a **reliability**-related need for those limits; and
 - (c) each entity that has a reliability-related need for those limits and provides a written request for delivery of those limits.
 - **R5.1** For each **interconnection reliability operating limit**, the **ISO** must provide the following supporting information:
 - **R5.1.1** identification and status of the associated **system element** (or group of **system elements**) that is (are) critical to the derivation of the **interconnection reliability operating limit**;
 - **R5.1.2** the value of the **interconnection reliability operating limit** and its associated Tv;
 - **R5.1.3** the associated **contingency**(ies); and
 - **R5.1.4** the type of limitation represented by the **interconnection reliability operating limit** (e.g., voltage collapse, angular stability).
 - **R5.2** Intentionally left blank.
 - R5.3 The ISO must provide its system operating limits (including the subset of system operating limits that are interconnection reliability operating limits) in the planning horizon to adjacent planning authorities.
 - **R5.4** Intentionally left blank.

Alberta Reliability Standard Establish and Communicate System Operating Limits FAC-014-AB1-2

R6 The ISO must identify and develop a list of the subset of multiple **contingencies** from **reliability standard** TPL-003-AB, which result in stability limits as determined if any that exist in its planning horizon.¹

R6.1 Intentionally left blank.

R6.2 Intentionally left blank.

4 Measures

The following measures correspond to the requirements identified in Section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence that the ISO's system operating limits, including interconnection reliability operating limits, for its area are established and consistent with its system operating limit methodology. Evidence may include, but is not limited to, dated reports, voice recordings, business practices or other equivalent evidence.

MR2 Intentionally left blank.

MR3 Intentionally left blank.

MR4 Intentionally left blank.

MR5 Evidence to confirm the ISO provided its system operating limits and interconnection reliability operating limits and supporting information as required in requirement R5 exists. Evidence may include, but is not limited to, records of email communication to appropriate recipients that identify contents submitted, or other equivalent evidence.

MR6 Evidence that the **ISO** identified and listed the subset of multiple **contingencies** as required in requirement R6 exists. Evidence may include, but is not limited to, dated reports, letters, or other documentation containing the list of multiple **contingencies**.

MR6.1 Intentionally left blank.

MR6.2 Intentionally left blank.

5. Appendices

No appendices have been defined for this reliability standard.

Revision History

Date	Description
2016-08-30	Inclusion of the defined term system element.
2015-09-01	Revised for ISO assumption of RC functionality for the Alberta footprint
2012-10-01	Initial Release

Effective: 2016-08-30 Page 2 of 2

¹ Requirement R6 is referenced in requirement R3.3 of FAC-011-AB

Alberta Reliability Standard Transmission Maintenance FAC-501-WECC-AB2-1



1. Purpose

The purpose of this **reliability standard** is to ensure the **legal owner** of a **transmission facility** of a major transmission path, including any associated **transmission facility**, has a *Transmission Maintenance and Inspection Plan* such that a reliable path is available.

2. Applicability

This **reliability standard** applies to the **legal owner** of a **transmission facility** that is, or is part of, a major transmission path identified in the table "*Major WECC Transfer Paths in the Bulk Electric System*" as provided by the **WECC**.

3. Requirements

- R1 The *Transmission Maintenance and Inspection Plan* of the **legal owner** of a **transmission facility** must detail its inspection and maintenance requirements and must apply to each **transmission facility** that is associated with each of the transmission paths identified by the **ISO**.
 - **R1.1** The **legal owner** of a **transmission facility** must review its *Transmission Maintenance and Inspection Plan* annually and update it as required.
 - **R1.2** The **legal owner** of a **transmission facility** must annually submit its *Transmission Maintenance and Inspection Plan* and any updates to the **ISO**.
- R2 The *Transmission Maintenance and Inspection Plan* of the **legal owner** of a **transmission facility** must include without limitation the following maintenance categories:
 - **R2.1** Transmission line maintenance details:
 - **R.2.1.1** patrol/inspection;
 - R.2.1.2 contamination control; and
 - **R.2.1.3** tower and wood pole structure management:
 - **R2.2** Station maintenance details:
 - R.2.2.1 inspections;
 - R.2.2.2 contamination control; and
 - **R.2.2.3** equipment maintenance for the following:
 - (a) circuit breakers;
 - (b) power transformers (including phase-shifting transformers);

(c) regulators; and

Alberta Reliability Standard Transmission Maintenance FAC-501-WECC-AB2-1



- (d) **reactive power** devices (including, but not limited to, shunt capacitors, series capacitors, static VAR compensators, synchronous condensers, shunt reactors, and tertiary reactors).
- **R3** The maintenance practices of the **legal owner** of a **transmission facility** in the *Transmission Maintenance and Inspection Plan* must be either performance-based, time-based, or condition-based, or a combination of all three (3).
 - The *Tranmsision Maintenance and Inspection Plan* of the **legal owner** of a **transmission facility** must include scheduled intervals for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance practices including a description of the condition or performance based trigger.
- R4 The **legal owner** of a **transmission facility** must implement its *Transmission Maintenance and Inspection Plan* and retain records that demonstrate such implementation including without limitation the following:
 - **R4.1** The names of individual or crew members responsible for performing the work or inspection;
 - **R4.2** The date(s) the work or inspection was performed:
 - **R4.3** The **transmission facility** on which the work or inspection was performed; and
 - **R4.4** A description of the inspection or maintenance performed.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- MR1 A documented *Transmission Maintenance and Inspection Plan* as identified in requirement R1 exists and covers each **transmission facility** as identified by the ISO.
 - **MR1.1** Evidence exists that shows the **legal owner** of a **transmission facility** reviewed their *Transmission Maintenance and Inspection Plan* annually and updated it as needed.
 - **MR1.2** The *Transmission Maintenance and Inspection Plan* and updates, if any, are received by the **ISO** annually.
- **MR2** The *Transmission Maintenance and Inspection Plan* addresses the required maintenance details of requirement R2.
- MR3 The *Transmission Maintenance and Inspection Plan* addresses the items in requirement R3.

Alberta Reliability Standard Transmission Maintenance FAC-501-WECC-AB2-1



MR4 Records exist that show the **legal owner** of a **transmission facility** implemented and followed its *Transmission Maintenance and Inspection Plan*.

Revision History

Effective	Description
2015-07-01	Transmission paths identified by the AESO for the purposes of requirement R1 updated to include new Bennett 520S equipment and 632 Russell equipment and moved from the Appendix to another document.
	Administrative update to standardize formatting, definitions and drafting style.
2012-12-17	Administrative update – "TFO" replaced with "legal owner of a transmission
2012-12-17	facility"; and other minor clean up items.
2010-09-10	Initial Release



1. Purpose

The purpose of this **reliability standard** is to ensure that responsible entities conduct a **reliability** assessment of each **arranged interchange** before it is implemented.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- **R1** The **ISO** must approve or deny each on-time **arranged interchange** or emergency **arranged interchange** that it receives and must do so prior to the expiration of the time period defined in Appendix 1, column B.
 - **R1.1** The **ISO** must, when it is either the source **balancing authority** or sink **balancing authority** deny the **arranged interchange** or curtail **confirmed interchange** if it does not expect to be capable of supporting the magnitude of the **interchange**, including ramping, throughout the duration of the **arranged interchange**.
 - R1.2 The ISO must deny the arranged interchange or curtail confirmed interchange if the scheduling path (proper connectivity of adjacent balancing authorities) between it and its adjacent balancing authorities is invalid.
- **R2** The **ISO** must approve or deny each on-time **arranged interchange** or emergency **arranged interchange** that it receives and must do so prior to the expiration of the time period defined in Appendix 1, column B.
 - **R2.1** The **ISO** must deny the **arranged interchange** or curtail **confirmed interchange** if the transmission path (proper connectivity of adjacent transmission service providers) between it and its adjacent transmission service providers is invalid.
- **R3** The **ISO** must, when it receives a **reliability** adjustment **arranged interchange**, approve or deny it prior to the expiration of the time period defined in Appendix 1, column B.
- **R4** The **ISO** must when it is a sink **balancing authority** confirm that none of the following conditions exist prior to transitioning an **arranged interchange** to **confirmed interchange**:
 - (a) it is a **reliability** adjustment **arranged interchange**, the time period specified in Appendix 1, column B has elapsed, and the **ISO** or the source **balancing authority** associated with the **arranged interchange** has not communicated its approval of the transition;
 - (b) it is not a **reliability** adjustment **arranged interchange**, the time period specified in Appendix 1, column B, has elapsed, and not all **balancing authorities** and transmission service providers associated with the **arranged interchange** have communicated their approval of the transition; or
 - (c) it is not a reliability adjustment arranged interchange, the time period specified in Appendix 1, column B, has elapsed, and any entity associated with the arranged interchange has communicated its denial of the transition.



- **R5** For each **arranged interchange** that is transitioned to **confirmed interchange**, the **ISO** must, when it is the sink **balancing authority**, notify the following entities of the on-time **confirmed interchange** such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Appendix 1, column D:
 - R5.1 the source balancing authority;
 - R5.2 each intermediate balancing authority;
 - **R5.3** each **reliability coordinator** associated with each **balancing authority** included in the **arranged interchange**;
 - R5.4 each transmission service provider included in the arranged interchange; and
 - **R5.5** each purchasing selling entity included in the arranged interchange.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of either approving or denying **arranged interchange** as required in requirement R1 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs or other equivalent evidence.
- **MR2** Evidence of either approving or denying **arranged interchange** as required in requirement R2 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs or other equivalent evidence.
- **MR3** Evidence of either approving or denying **reliability** adjustment **arranged interchange** as required in requirement R3 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs, studies or other equivalent evidence.
- **MR4** Evidence of confirming none of the conditions exist prior to transitioning an **arranged interchange** to **confirmed interchange** as required in requirement R4 exists. Evidence may include, but is not limited to, an interchange transaction without an implemented e-tag, or other equivalent evidence.
- **MR5** Evidence of notifying entities of the on-time **confirmed interchange** as required in requirement R5 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs, voice recordings or other equivalent evidence.

5. Appendices

Appendix 1 - Timing Tables

Revision History

Date	Description
2018-10-01	Initial release.

Effective: 2018-10-01 Page 2 of 4 Public



Appendix 1 – Timing Tables Timing Requirements for WECC

		Α	В	С	D
If arranged interchange ¹ is submitted	Time Classification	Sink BA makes initial distribution of arranged interchange ²	BA and TSP conduct reliability assessments	Compilation and distribution status ²	BA prepares confirmed interchange for implementation
>1 hour after the start time	ATF	- moronango	Entities have up to 2 hours to respond.		N/A
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of confirmed interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of confirmed interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from arranged interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from arranged interchange receipt		≥ 3 minutes prior to ramp start
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from arranged interchange receipt		≥ 3 minutes prior to ramp start

¹ Time classifications and deadlines apply to both initial **arranged interchange** submittal and any subsequent modifications to the **arranged interchange**.

See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.



		Α	В	С	D
If arranged interchange ¹ is submitted	Time Classification	Sink BA makes initial distribution of arranged interchange ²	BA and TSP conduct reliability assessments	Compilation and distribution status ²	BA prepares confirmed interchange for implementation
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from arranged interchange receipt		≥ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from arranged interchange receipt		≥ 3 minutes prior to ramp start
< 1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from arranged interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from arranged interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the arranged interchange was recieved		≥ 1 hour 58 minutes prior to ramp start

Alberta Reliability Standard Implementation of Interchange INT-009-AB-2.1



1. Purpose

The purpose of this **reliability standard** is to ensure that **balancing authorities** implement the **interchange** as agreed upon in the **interchange** confirmation process.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must 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-AB not yet captured in the composite confirmed interchange, is:
 - R1.1 identical in magnitude to that of the adjacent balancing authority; and
 - R1.2 opposite in sign or direction to that of the adjacent balancing authority.
- R2 The ISO when it is either the attaining balancing authority or the native balancing authority must use a dynamic value emanating from a common source that is agreed upon with the other balancing authority to account for the pseudo-tie in the net actual interchange term of its control area control error or alternate control process.
- **R3** The **ISO** must, if it is the **balancing authority** in whose area the high-voltage direct current **intertie** is controlled, coordinate the **confirmed interchange** prior to its implementation with the **operator** of the high-voltage direct current **intertie**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of agreeing on composite **confirmed interchange** with **adjacent balancing authorities** as required in requirement R1 exists. Evidence may include, but is not limited to dated logs, voice recordings, electronic records or other equivalent evidence.
- **MR2** Evidence of using a dynamic value emanating from an agreed upon common source as required in requirement R2 exists. Evidence may include, but is not limited to dated logs, voice recordings, electronic records, written agreement or other equivalent evidence.
- **MR3** Evidence of coordinating the **confirmed interchange** prior to its implementation with the **operator** of the high-voltage direct current **intertie** as required in requirement R3 exists. Evidence may include, but is not limited to dated logs, electronic records or other equivalent evidence.

Revision History

Date	Description
2018-10-01	Initial release.

Alberta Reliability Standard Interchange Initiation and Modification for Reliability INT-010-AB-2.1

1. Purpose

The purpose of this **reliability standard** is to provide guidance for required actions on **confirmed interchange** or **implemented interchange** to address **reliability**.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- **R1** The **ISO** must, if it experiences a loss of resources covered by an energy sharing agreement or other **reliability** needs covered by an energy sharing agreement, ensure that a request for **interchange** is submitted with a start time no more than sixty (60) minutes beyond the resource loss or **reliability** need. If the use of the energy sharing agreement does not exceed sixty (60) minutes from the time of the resource loss or **reliability** need, no request for **interchange** is required.
- R2 The ISO must, when it is the sink balancing authority, after modifying a confirmed interchange or implemented interchange for actual or anticipated reliability-related reasons, ensure that a reliability adjustment arranged interchange reflecting the modification is submitted within sixty (60) minutes of the start of the modification.
- **R3** The **ISO** must, when it is a sink **balancing authority**, after scheduling **interchange** for actual or anticipated **reliability**-related reasons, ensure that a request for **interchange** is submitted reflecting that **interchange schedule** within sixty (60) minutes of the start of the scheduled **interchange**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- MR1 Evidence of ensuring that a request for interchange is submitted as required in requirement R1 exists. Evidence may include, but is not limited to, dated and time-stamped request for interchange, electronic logs or other equivalent evidence.
- **MR2** Evidence of ensuring that a **reliability** adjustment **arranged interchange** is submitted as required in requirement R2 exists. Evidence may include, but is not limited to, dated and time-stamped **reliability** adjustment **arranged interchange**, electronic logs or other equivalent evidence.
- MR3 Evidence of ensuring that a **reliability** adjustment **arranged interchange** is submitted as required in requirement R2 exists. Evidence may include, but is not limited to, dated and time-stamped **reliability** adjustment **arranged interchange**, electronic logs or other equivalent evidence.

Revision History

Date	Description
2018-10-01	Initial release.

Effective: 2018-10-01 Page 1 of 1 Public



1. Purpose

The **ISO** must have the authority, plans, and agreements in place to immediately direct entities within its area to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If the **ISO** delegates tasks to others, the **ISO** retains its responsibilities for complying with **reliability standards**.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 Intentionally left blank.
- **R2** The **ISO** must develop a reliability plan for its area.
- R3 Intentionally left blank.
- R4 If the ISO delegates reliability coordination-type tasks to other Alberta entities, it must have formal operating agreements with each entity to which tasks are delegated. The ISO must verify that all delegated tasks are understood, communicated, and addressed within its area. All responsibilities for complying with reliability standards applicable to the ISO will remain with the ISO.
- R5 The ISO must list within its reliability plan all Alberta entities to which the ISO has delegated reliability coordination-type required tasks.
- R6 The ISO must verify that all delegated reliability coordination-type tasks are carried out by NERC-certified reliability coordinator operating personnel.
- R7 The ISO must have clear, comprehensive coordination agreements with adjacent reliability coordinators to ensure that system operating limit or interconnection reliability operating limit violation mitigation requiring actions in adjacent reliability coordinator areas are coordinated.
- **R8** Intentionally left blank.
- **R9** Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- MR1 Intentionally left blank.
- **MR2** Evidence of developing a reliability plan in accordance with requirement R2 may include, but is not limited to, a dated, current reliability plan.
- MR3 Intentionally left blank.
- **MR4** If the **ISO** has delegated reliability coordination-type tasks to other entities, the **ISO** may have current formal operating agreements with entities that have been delegated such tasks in accordance with requirement R4.

Alberta Reliability Standard Reliability Coordination – Responsibility and Authorities IRO-001-AB1-1.1

The **ISO** may also have evidence that could include, but is not limited to, job descriptions, signed agreements, records of training sessions, monitoring procedures or other equivalent evidence that will be used to confirm that all reliability coordination-type tasks that have been delegated to other entities are understood, communicated, and addressed within its area in accordance with requirement R4.

- **MR5** Evidence of the list within the **ISO**'s reliability plan may include, but is not limited to, a list within the documented reliability plan or other equivalent evidence, in accordance with requirement R5.
- MR6 The ISO may have evidence that could include, but is not limited to, records that show each operating person assigned to perform a delegated reliability coordination-type task has a NERC reliability coordinator certification credential, or equivalent evidence confirming that delegated tasks were carried out by NERC-certified reliability coordinator operating personnel, as specified in requirement R6.
- MR7 The ISO may have as evidence signed agreements with adjacent reliability coordinators that will be used to confirm that the ISO will coordinate corrective actions in the event system operating limit and interconnection reliability operating limit mitigation actions within adjacent reliability coordinator areas must be taken.
- MR8 Intentionally left blank.
- MR9 Intentionally left blank.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Reliability Coordination - Facilities IRO-002-AB-2



1. Purpose

The **ISO** needs information, tools and other capabilities to perform its responsibilities.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must have adequate communications facilities (voice and data links) to appropriate entities within its area. These communications facilities must be staffed and available to act in addressing a real-time emergency condition.
- R2 The ISO must provide, or arrange provisions for, data exchange to reliability coordinators or transmission operators and balancing authorities via a secure network.
- R3 The ISO must have multi-directional communications capabilities with each **operator** of a **transmission facility** within the **interconnected electric system**, and with neighboring **reliability coordinators**, for both voice and data exchange as required to meet reliability needs of the **Interconnection**.
- R4 The ISO must have detailed real-time monitoring capability of its area and sufficient monitoring capability of its surrounding areas to ensure that potential or actual system operating limit or interconnection reliability operating limit violations are identified. The ISO must have monitoring systems that provide information that can be easily understood and interpreted by the ISO's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.
- R5 The ISO must monitor system elements of the bulk electric system that could result in system operating limit or interconnection reliability operating limit violations within its area. The ISO must monitor both real power and reactive power system flows, and operating reserves, and the status of system elements of the bulk electric system that are or could be critical to system operating limit s and interconnection reliability operating limit s and system restoration requirements within its area.
- **R6** The **ISO** must have adequate analysis tools such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and **wide-area** overview displays.
- R7 The ISO must continuously monitor its area. The ISO must have provisions for backup facilities that must be exercised if the main monitoring system is unavailable. The ISO must ensure system operating limit or interconnection reliability operating limit monitoring and derivations continue if the main monitoring system is unavailable.
- R8 The ISO must control its analysis tools (referred to in requirement R6), including approvals for planned maintenance. The ISO must have procedures in place to mitigate the effects of analysis tool outages.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

Alberta Reliability Standard Reliability Coordination - Facilities IRO-002-AB-2



- **MR1** Evidence may include, but is not limited to, a document that lists communications facilities (voice and data links) with applicable entities within its area.
 - Evidence of having personnel available to act in addressing a real-time emergency condition as required in requirement R1 exists. Evidence may include, but is not limited to, shift schedules.
- **MR2** Evidence of providing or arranging provisions as required in requirement R2 exists. Evidence may include, but is not limited to, network description documentation.
- MR3 The ISO may have evidence that could include, but is not limited to, a document that lists multi-directional communications facilities with each operator of a transmission facility and with neighboring reliability coordinators, that will be used to confirm that it has multi-directional communications facilities, for both voice and data exchange, in accordance with requirement R3.
- MR4 The ISO may have evidence that could include, but is not limited to, energy management system description documents, computer printouts, SCADA data collection system communications performance or equivalent evidence to demonstrate that it has real-time monitoring capability of its area and monitoring capability of its surrounding areas to identify potential or actual system operating limit or interconnection reliability operating limit violations.
- MR5 Evidence of monitoring bulk electric system elements and both real power and reactive power system flows, and operating reserves, and the status of system elements of the bulk electric system as required in requirement R5 exists. Evidence may include, but is not limited to, SCADA displays, single line diagram print screens or other equivalent evidence.
- **MR6** The **ISO** may have evidence that could include, but is not limited to, EMS displays, or other equivalent evidence to show that it has analysis tools in accordance with requirement R6.
- MR7 The ISO may have evidence such as equipment documentation, operating procedures, or other equivalent evidence to show that it has a backup monitoring facility that can be used to identify and monitor system operating limit s and interconnection reliability operating limits.
- **MR8** The **ISO** may have evidence that could include, but is not limited to, a documented procedure for approval of planned maintenance to analysis tools (referred to in requirement R6).
 - The **ISO** may have procedures that are used to mitigate the effects of analysis tool outages as specified in requirement R8.

Revision History

Effective Date	Description
2015-04-01	Initial release.
2016-08-30	Inclusion of the defined term system element.

Effective: 2016-08-30 Page 2 of 2



Alberta Reliability Standard Reliability Coordination – Wide-Area View IRO-003-AB-2

1. Purpose

The ISO must have a wide-area view of its area and neighbouring reliability coordinator areas.

2. Applicability

This **reliability standard** applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must monitor all bulk electric system facilities, which may include subtransmission information, within its area and adjacent reliability coordinator areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the ISO is able to determine any potential system operating limit and interconnection reliability operating limit violations within its area.
- R2 The ISO must know the current status of all critical facilities whose failure, degradation or disconnection could result in an system operating limit or interconnection reliability operating limit violation. The ISO must also know the status of any facilities that may be required to assist area restoration objectives.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- MR1 Evidence may include, but is not limited to, energy management system description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that the ISO monitors all bulk electric system facilities within its area and adjacent reliability coordinator areas as necessary to ensure that, regardless of prior planned or unplanned events, it is able to determine any potential system operating limit and interconnection reliability operating limit violations within its area.
- MR2 Evidence may include, but is not limited to, SCADA displays or other equivalent evidence that demonstrates knowledge of the current status of all critical facilities whose failure, degradation or disconnection could result in an system operating limit or interconnection reliability operating limit violation. Evidence of knowledge of the status of any facilities that may be required to assist area restoration objectives.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Reliability Coordination – Current Day Operations IRO-005-AB-3.1a

1. Purpose

The **ISO** must be continuously aware of conditions within its area and include this information in its reliability assessments. The **ISO** must monitor **bulk electric system** parameters that may have significant impacts upon its area and neighbouring **reliability coordinator areas**.

2. Applicability

This **reliability standard** applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must monitor parameters in its area, including but not limited to the following:
 - R1.1 current status of system elements that are part of the bulk electric system (transmission or generation including critical auxiliaries such as automatic voltage regulators and remedial action schemes) and system loading;
 - R1.2 current pre-contingency system element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate system operating limit or interconnection reliability operating limit violations, including the plan's viability and scope;
 - R1.3 current post-contingency system element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate system operating limit or interconnection reliability operating limit violations, including the plan's viability and scope;
 - R1.4 system real power and reactive power reserves (actual versus required);
 - **R1.5** capacity and energy adequacy conditions;
 - R1.6 current area control error;
 - R1.7 current local or transmission loading relief procedures in effect;
 - R1.8 planned generation dispatches;
 - R1.9 planned transmission or generation outages; and
 - R1.10 contingency events.
- R2 The ISO must monitor parameters in its area to ensure that the required amount of operating reserves is provided and available as required to meet the control performance standard and disturbance control standard requirements. If necessary, the ISO must arrange for assistance from neighboring balancing authorities. The ISO must issue energy emergency alerts as needed.
- R3 The ISO must ensure that it is aware of geomagnetic disturbance forecast information and develop any required response plans.
- R4 Intentionally left blank.

Alberta Reliability Standard Reliability Coordination – Current Day Operations IRO-005-AB-3.1a

- R5 The ISO must monitor system frequency and rebalance as necessary to return to control performance standard and disturbance control standard compliance. The ISO must utilize all resources, including issuing directives for firm load shedding, to relieve the emergent condition.
- R6 The ISO must develop and implement action plans to mitigate anticipated or actual system operating limit, control performance standard or disturbance control standard violations. The ISO must coordinate pending transmission maintenance outages with any operator of a transmission facility, adjacent transmission operator, adjacent balancing authority, operator of a generating unit or operator of an aggregated generating facility, as needed, in both the real-time and next-day reliability analysis timeframes.
- R7 As necessary, the **ISO** must arrange for assistance from neighboring **reliability coordinator areas** or **balancing authorities**.
- **R8** Intentionally left blank.
- Whenever a **remedial action scheme** that may have an inter-balancing authority, or inter-transmission operator / inter-operator of a **transmission facility** impact (e.g., could potentially affect transmission flows resulting in a **system operating limit** or **interconnection reliability operating limit** violation) is armed, the **ISO** must be aware of the impact of the operation of that **remedial action scheme** on inter-area flows.
- R10 In instances where there is a difference in derived limits, the ISO must always operate the **bulk electric system** to the most limiting parameter.
- R11 The ISO must respect system operating limits and interconnection reliability operating limits in accordance with regional total transfer capability and available transfer capability processes.
- R12 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- MR1 The ISO may have evidence that could include, but is not limited to, energy management system description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in requirement R1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors its area parameters specified in requirements R1.1 through R1.9.
- **MR2** The **ISO** must have evidence of monitoring parameters as required in requirement R2. Evidence may include but is not limited to: voice recordings, operator logs, data files or other equivalent evidence.
- MR3 The ISO may have evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence to demonstrate that it was aware of geomagnetic disturbance (GMD) forecast information and evidence of the development of any required response plans.

MR4 Intentionally left blank.

Effective: 2016-08-30 Page 2 of 4



MR5 The ISO may have evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and rebalanced, as specified in requirement R5.

The **ISO** may have evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including issuing directives for firm load shedding, to relieve an emergent condition.

MR6 The ISO may have evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it developed and implemented action plans to mitigate anticipated or actual system operating limit, control performance standards or disturbance control standard violations. The ISO may have evidence that could include, but is not limited to, electronic communications, operator logs or equivalent evidence that will determine if it coordinated pending transmission maintenance outages with an operator of a transmission facility, adjacent transmission operator, adjacent balancing authorities, operator of a generating unit or operator of an aggregated generating facility.

MR7 The ISO may have evidence that could include, but is not limited to, computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the ISO arranged for assistance from neighboring reliability coordinator areas or balancing authorities.

MR8 Intentionally left blank.

MR9 If a remedial action scheme is armed and that system could have had an inter-area impact, the ISO may have evidence that could include, but is not limited to, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that remedial action scheme on inter-area flows.

MR10 If there is an instance where there is a disagreement on a derived limit, the ISO may have evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated the bulk electric system to the most limiting parameter.

MR11 The ISO may have evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the system operating limits or interconnection reliability operating limits in accordance with regional total transfer capability and available transfer capability processes.

MR12 Intentionally left blank.

Effective: 2016-08-30 Page 3 of 4



Revision History

Effective Date	Description
2015-04-01	Initial release.
2016-08-30	Inclusion of the defined term system element.

Effective: 2016-08-30 Page 4 of 4



Alberta Reliability Standard Reliability Coordination – Transmission Loading Relief IRO-006-AB-5

1. Purpose

To ensure coordinated action between **Interconnections** when implementing **Interconnection**-wide transmission loading relief procedures to prevent or manage potential or actual **system operating limit** and **interconnection reliability operating limit** exceedances to maintain reliability of the **bulk electric system**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 When the ISO receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection Transmission Loading Relief, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any reliability coordinator, balancing authority, or transmission operator in another Interconnection to curtail an interchange transaction that crosses an Interconnection boundary, the ISO must comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 The ISO may have evidence (such as dated logs, voice recordings, e-tag histories, and studies, in electronic or hard copy format) that, when a request to curtail an interchange transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another reliability coordinator, balancing authority, or transmission operator in that other Interconnection, the ISO complied with the request or provided a reliability reason why it could not comply with the request.

Revision History

Effective Date	Description
2015-04-01	Initial release.



Alberta Reliability Standard Qualified Transfer Path Unscheduled Flow Relief IRO-006-WECC-AB-2

1. Purpose

The purpose of this **reliability standard** is to mitigate transmission overloads due to unscheduled flow on **qualified transfer paths**.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

R1 The ISO must approve schedule curtailment requests submitted to mitigate transmission overloads on qualified transfer paths, implement alternative actions, or a combination thereof that collectively meets the relief requirement.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard.** For example, MR1 is the measure for requirement R1.

MR1 E-tags, voice recordings or operator logs exist and are provided on request. **E-tags**, voice recordings or operator logs contain content confirming requirement R1 is met.

Revision History

Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Reliability Coordinator Operational Analysis and Real-time Assessments IRO-008-AB-1



1. Purpose

To prevent instability, uncontrolled separation, or **cascading** that adversely impact the reliability of the **Interconnection** by ensuring that the **bulk electric system** is assessed during the operations horizon.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must perform an operational planning analysis to assess whether the planned operations for the next day within its wide-area will exceed any of its interconnection reliability operating limits during anticipated normal and contingency event conditions.
- R2 The ISO must perform a real-time assessment at least once every 30 minutes to determine if its wide-area is exceeding any interconnection reliability operating limits or is expected to exceed any interconnection reliability operating limits.
- R3 When the ISO determines that the results of an operational planning analysis or real-time assessment indicate the need for specific operational actions to prevent or mitigate an instance of exceeding an interconnected reliability operating limit, the ISO must share its results with those entities outside Alberta that are expected to take those actions.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- **MR1** The **ISO** may have the results of its **operational planning analysis** in accordance with requirement R1.
- MR2 The ISO may have evidence to show it conducted a real-time assessment at least once every 30 minutes, in accordance with requirement R2. This evidence may include, but is not limited to, a dated computer log showing times the assessment was conducted, dated checklists, or other equivalent evidence.
- MR3 The ISO may have evidence to confirm that it shared the results of its operational planning analysis or real-time assessments with those entities outside Alberta expected to take actions based on that information in accordance with requirement R3. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated transcripts of voice records, dated facsimiles, or other equivalent evidence.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Reliability Coordinator Actions to Operate Within Interconnection Reliability Operating Limits IRO-009-AB-1



1. Purpose

To prevent instability, uncontrolled separation, or **cascading** that adversely impact the reliability of the **Interconnection** by ensuring prompt action to prevent or mitigate instances of exceeding **interconnection reliability operating limits**.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 For each interconnection reliability operating limit that the ISO identifies one or more days prior to the current day, the ISO must have one or more operating processes, operating procedures, or operating plans that identify actions to take or actions to direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those linterconnection reliability operating limits.
- R2 For each interconnection reliability operating limit that the ISO identifies one or more days prior to the current day, the ISO must have one or more operating processes, operating procedures, or operating plans that identify actions to take or actions to direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that interconnection reliability operating limit such that the interconnection reliability operating limit is relieved within the interconnection reliability operating limit's Tv.
- R3 When an assessment of actual or expected system conditions predicts that an interconnection reliability operating limit in its area will be exceeded, the ISO must implement one or more operating processes, operating procedures or operating plans (not limited to the operating processes, operating procedures, or operating plans developed for requirement R1) to prevent exceeding that interconnection reliability operating limit.
- R4 When actual system conditions show that there is an instance of exceeding an interconnection reliability operating limit in its area, the ISO must, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that interconnection reliability operating limit within the interconnection reliability operating limit's Tv.
- R5 If unanimity cannot be reached between a reliability coordinator and the ISO on the value for an linterconnection reliability operating limit or its Tv for a facility (or group of facilities) that is part of an interconnection and that both entities are responsible to monitor, the ISO must, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Evidence may include but is not limited to a list of any **interconnection reliability operating limits** (and each associated T_v) identified in advance, along with one or more dated operating processes, operating procedures, or operating plans that will be used to confirm that the **ISO**

Alberta Reliability Standard Reliability Coordinator Actions to Operate Within Interconnection Reliability Operating Limits IRO-009-AB-1



has operating processes, operating procedures, or operating plans to address both preventing and mitigating instances of exceeding **interconnection reliability operating limits** in accordance with requirement R1.

- MR2 Evidence may include but is not limited to a list of any interconnection reliability operating limits (and each associated Tv) identified in advance, along with one or more dated operating processes, operating procedures or operating plans that will be used to confirm that the ISO has operating processes, operating procedures, or operating plans to address both preventing and mitigating instances of exceeding interconnection reliability operating limits in accordance with requirement R2.
- MR3 Evidence may include, but is not limited to, operating processes, operating procedures or operating plans from requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence that will be used to confirm that the ISO implemented one or more operating processes, operating procedures or operating plans in accordance with requirement R3.
- **MR4** Evidence may include, but is not limited to, operating processes, operating procedures, or operating plans from requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence that will be used to confirm that the **ISO** acted or directed others to act in accordance with requirement R4.
- MR5 Evidence may include, but is not limited to dated computer printouts, dated operator logs, dated voice recordings, or other equivalent evidence that will be used in a situation where any reliability coordinator and the ISO disagree on the value of an interconnection reliability operating limit or its Tv, to confirm the ISO used the most conservative of the values under consideration, without delay.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Reliability Coordinator Data Specification and Collection IRO-010-AB-1a



1. Purpose

To prevent instability, uncontrolled separation, or **cascading** that adversely impacts the reliability of the **Interconnection** by ensuring the **ISO** has the data it needs to monitor and assess the operation of its area.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must have a documented specification(s) for data and information to build and maintain models to support real-time monitoring, operational planning analyses, and real-time assessments of its area to prevent instability, uncontrolled separation, and cascading. The specification must include the following:
 - R1.1 list of required data and information needed by the ISO to support real-time monitoring, operational planning analyses, and real-time assessments;
 - R1.2 mutually agreeable format;
 - R1.3 timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its operational planning analyses); and
 - **R1.4** process for data provision when automated **real-time** system operating data is unavailable.
- R2 Intentionally left blank.
- R3 The ISO must provide data and information, as specified upon, to each reliability coordinator with which it has a reliability relationship.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- **MR1** The **ISO** may have evidence that could include, but is not limited to, a documented specification(s) for data and information that contains all specifications identified in requirement R1.
- MR2 Intentionally left blank.
- MR3 The ISO may have evidence to confirm that it provided data and information, as specified and mutually agreed upon in requirement R3. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated computer printouts, dated SCADA data, or other equivalent evidence.

Alberta Reliability Standard Reliability Coordinator Data Specification and Collection IRO-010-AB-1a



Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Procedures, Processes or Plans to Support Coordination Between Reliability Coordinators IRO-014-AB-1



1. Purpose

To ensure that the **ISO**'s operations are coordinated such that it will not have an **adverse reliability impact** on any **reliability coordinator area** and to preserve the reliability benefits of interconnected operations.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must have operating procedures, operating processes or operating plans in place for activities that require notification, exchange of information or coordination of actions with one or more reliability coordinators to support Interconnection reliability. These operating procedures, operating processes or operating plans must address anticipated events that affect reliability coordinator areas as well as those developed in coordination with reliability coordinators.
 - **R1.1** These operating procedures, operating processes or operating plans must collectively address, as a minimum, the following:
 - **R1.1.1** communications and notifications, including the conditions under which the **ISO** notifies a **reliability coordinator**; the process to follow in making those notifications; and the data and information to be exchanged with a **reliability coordinator**;
 - **R1.1.2** energy and capacity shortages;
 - **R1.1.3** planned or unplanned outage information;
 - **R1.1.4** voltage control, including the coordination of reactive resources for voltage control;
 - **R1.1.5** coordination of information exchange to support reliability assessments; and
 - **R1.1.6** authority to act to prevent and mitigate instances of causing **adverse** reliability impacts to a reliability coordinator area.
- R2 The ISO's operating procedure, operating process or operating plan that requires one or more **reliability coordinators** to take action (e.g., make notifications, exchange information or coordinate actions) must be:
 - **R2.1** agreed to by all the **reliability coordinators** required to take the indicated action(s); and
 - **R2.2** distributed to all **reliability coordinators** that are required to take the indicated action(s).
- R3 The ISO's operating procedures, operating processes or operating plans developed to support an ISO-to-reliability coordinator operating procedure, operating process or operating plan must include:

Alberta Reliability Standard Procedures, Processes or Plans to Support Coordination Between Reliability Coordinators IRO-014-AB-1



- **R3.1** a reference to the associated **ISO**-to-**reliability coordinator** operating procedure, operating process or operating plan; and
- **R3.2** the agreed-upon actions from the associated **ISO**-to-**reliability coordinator** operating procedure, operating process or operating plan.
- R4 The **ISO** must, for each of the operating procedures, operating processes and operating plans addressed in requirement R1 and requirement R3 of this **reliability standard**:
 - **R4.1** include a version control number or date;
 - R4.2 include a distribution list; and
 - **R4.3** conduct a review, at least once every three years, and updated if needed.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- **MR1** The **ISO** may have available for real-time use, the latest approved version of operating procedures, operating processes or operating plans that require notifications, information exchange or the coordination of actions between **reliability coordinators** and the **ISO**.
 - **MR1.1** These operating procedures, operating processes or operating plans may address:
 - MR1.1.1 communications and notifications, including the conditions under which the ISO notifies reliability coordinators; the process to follow in making those notifications; and the data and information to be exchanged between the ISO and reliability coordinators;
 - MR1.1.2 energy and capacity shortages;
 - **MR1.1.3** planned or unplanned outage information;
 - **MR1.1.4** voltage control, including the coordination of reactive resources for voltage control;
 - **MR1.1.5** coordination of information exchange to support reliability assessments; and
 - MR1.1.6 authority to act to prevent and mitigate instances of causing adverse reliability impacts to a reliability coordinator area.
- **MR2** The **ISO** may have evidence that these operating procedures, operating processes or operating plans were:
 - MR2.1 agreed to by all the reliability coordinators required to take the indicated action(s); and
 - MR2.2 distributed to all reliability coordinators required to take the indicated action(s).
- MR3 The ISO's operating procedures, operating processes or operating plans developed to support an ISO-to-reliability coordinator operating procedure, operating process or operating plan may include:

Alberta Reliability Standard Procedures, Processes or Plans to Support Coordination Between Reliability Coordinators IRO-014-AB-1



- MR3.1 a reference to the associated source document; and
- MR3.2 the agreed-upon actions from the source document.
- MR4 The ISO's operating procedures, operating processes or operating plans that address ISO-toreliability coordinator coordination may:
 - MR4.1 each include a version control number or date;
 - MR4.2 each include a distribution list; and
 - **MR4.3** the **ISO** may have evidence that these operating procedures, operating processes or operating plans were reviewed within the last three years.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Notifications and Information Exchange Between Reliability Coordinators IRO-015-AB-1



To ensure that the **ISO**'s operations are coordinated such that it will not have an **adverse reliability impact** on adjacent **reliability coordinator areas** and to preserve the reliability benefits of interconnected operations.

2. Applicability

This **reliability standard** applies to:

(a) the ISO.

3. Requirements

- R1 The ISO must follow its operating procedures, operating processes or operating plans for making notifications and exchanging reliability-related information with adjacent reliability coordinators.
 - R1.1 The ISO must make notifications to adjacent reliability coordinators of conditions in its area that may have an adverse reliability impact on adjacent reliability coordinator areas.
- R2 The ISO must participate in agreed upon conference calls and other communication forums with synchronously connected adjacent reliability coordinators.
 - **R2.1** The frequency of these conference calls must be agreed upon by the **ISO** and all involved **reliability coordinators** and must be at least weekly.
- R3 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- **MR1** The **ISO** may have evidence that it has followed its operating procedures, operating processes or operating plans for notifying adjacent **reliability coordinators** of conditions in its area that may adversely impact adjacent **reliability coordinator areas** in accordance with requirement R1. Such evidence may include, but is not limited to, operator logs or other data sources.
- MR2 The ISO may have evidence that it participated in agreed upon (at least weekly) conference calls and other communication forums with synchronously connected reliability coordinators in accordance with requirement R2. Such evidence may include, but is not limited to, operator logs or other data sources.

MR3 Intentionally left blank.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Coordination of Real-time Activities Between Reliability Coordinators IRO-016-AB-1



1. Purpose

To ensure that the **ISO**'s operations are coordinated such that they will not have an **adverse reliability impact** on other **reliability coordinator areas** and to preserve the reliability benefits of interconnected operations.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 When the ISO identifies a potential, expected, or actual problem that requires the actions of one or more reliability coordinators, the ISO must contact the involved reliability coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.
 - R1.1 If the ISO and the involved reliability coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, the ISO must implement the agreed-upon solution, and notify the involved reliability coordinators of the action(s) taken.
 - R1.2 If the ISO and the involved reliability coordinators cannot agree on the problem(s), the ISO must re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).
 - **R1.2.1** If time permits, this re-evaluation must be done before taking corrective actions.
 - **R1.2.2** If time does not permit, then the ISO must operate as though the problem(s) exist(s) until the conflicting system status is resolved.
 - **R1.3** If the **ISO** and the involved **reliability coordinators** cannot agree on the solution, the more conservative solution must be implemented.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 For each event that requires coordination between the **ISO** and the involved **reliability coordinator**(s), the **ISO** may have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard Steady-State and Dynamic Data for Transmission System Modeling and Simulation MOD-010&012-AB-0

1 Purpose

The purpose of this **reliability standard** is to provide for the delivery of data and information necessary to establish consistent power flow and dynamic models to be used in the analysis of the reliability of the **Interconnection**.

2 Applicability

This reliability standard applies to:

- (a) the legal owner of a generating unit that is:
 - directly connected to the transmission system or to transmission facilities within the City of Medicine Hat; and
 - (ii) not part of an aggregated generating facility;
- (b) the **legal owner** of an **aggregated generating facility** that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;
- (c) the legal owner of a transmission facility; and
- (d) the ISO.

3 Requirements

- R1 Each legal owner of a generating unit, legal owner of an aggregated generating facility and legal owner of a transmission facility must provide, within thirty (30) days of the ISO's written request, equipment characteristics and system data that the ISO requires to meet requirements R2 and R3.
- **R2** Subject to requirement R3, the **ISO** must provide equipment characteristics and system data, including dynamics system modeling, simulation data and interchange schedules, to the **WECC** in compliance with the appropriate **Interconnection**-wide **WECC** steady-state and dynamics system modeling and simulation data requirements and reporting procedures.
- **R3** The **ISO** must provide the equipment characteristics and system data, including modeling data and information specified in requirement R2, according to the data bank compilation schedule the **WECC** publishes but if no such schedule has been published, then the **ISO** must provide such equipment characteristics and system data no later than:
 - (a) thirty (30) **days** from the date the **WECC** requests it if the **ISO** has received the requested information prior to the date that **WECC** requested it; or
 - (b) sixty (60) **days** from the date the **WECC** requests it if the **ISO** has not received the information prior to the date that **WECC** requested it.

4 Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of providing equipment characteristics and system data as required in requirement R1. Evidence may include data files, email or mail.

Alberta Reliability Standard Steady-State and Dynamic Data for Transmission System Modeling and Simulation MOD-010&012-AB-0

MR2 Evidence of providing equipment characteristics and system data as required in requirement R2. Evidence may include data files, email or mail.

MR3 Evidence of providing equipment characteristics and system data within the timelines specified in requirement R3. Evidence may include email or mail.

Revision History

Effective	Description
2014-01-01	Initial Release – The first day of the calendar quarter that follows three full calendar quarters after approval by the Commission

Effective: 2014-01-01 Page 2 of 2

Alberta Reliability Standard Demand and Energy Data MOD-031-AB-2



1. Purpose

The purpose of this **reliability standard** is to identify the requirements for the **ISO** to provide to the **WECC**, demand, energy and related data to support **reliability** studies and assessments.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 Intentionally left blank.
- R2 Intentionally left blank.
- R3 The ISO must provide the data listed below, for the Alberta balancing authority area, to the WECC within 75 days of receiving a request for such data, unless the WECC and the ISO agree otherwise:
 - **R3.1** any or all of the following actual data:
 - **R3.1.1** integrated hourly **demands** in MWs for the prior calendar year;
 - **R3.1.2 monthly** and annual integrated peak hour **demands** in MWs for the prior calendar vear:
 - **R3.1.2.1** if the annual peak hour actual **demand** varies due to weather related conditions (e.g., temperature, humidity or wind speed), the **ISO** must also provide the weather normalized annual peak hour actual **demand** for the prior calendar year;
 - **R3.1.3** monthly and annual net energy for load in GWhs for the prior calendar year; and
 - **R3.1.4 monthly** and annual peak hour controllable and dispatchable **demand** side management under the control or supervision of the **ISO** in MWs for the prior calendar year including, reporting for each hour: 1) the committed MWs (the amount under control or supervision); 2) the MWs issued in a **dispatch** (the amount, if any, activated for use by the system operator); and 3) the realized MWs (the amount of actual demand reduction);
 - **R3.2** any or all of the following forecast data:
 - **R3.2.1 monthly** peak hour forecast total internal **demands** in MWs for the next 2 calendar years;
 - **R3.2.2** monthly forecast net energy for load in GWhs for the next 2 calendar years;
 - **R3.2.3** peak hour forecast total internal **demands** (summer and winter) in MWs for 10 calendar years into the future;
 - **R3.2.4** annual forecast net energy for load in GWhs for 10 calendar years into the future; and
 - **R3.2.5** total and available peak hour forecast of controllable and dispatchable **demand** side management (summer and winter), in MWs, under the control or supervision of the system operator for 10 calendar years into the future;

Alberta Reliability Standard Demand and Energy Data MOD-031-AB-2



- **R3.3** any or all of the following summary explanations:
 - **R3.3.1** the assumptions and methods used in the development of aggregated peak **demand** and net energy for load forecasts;
 - **R3.3.2** the **demand** and energy effects of controllable and dispatchable **demand** side management under the control or supervision of the system operator;
 - **R3.3.3** how **demand** side management is addressed in the forecasts of its peak **demand** and annual net energy for load;
 - R3.3.4 how the controllable and dispatchable demand side management forecast compares to actual controllable and dispatchable demand side management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted; and
 - **R3.3.5** how the peak **demand** forecast compares to actual **demand** for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.
- R4 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- MR1 Intentionally left blank.
- MR2 Intentionally left blank.
- **MR3** Evidence of providing the data as required in requirement R3 exists. Evidence may include dated emails or dated transmittal letters, or other equivalent evidence.
- MR4 Intentionally left blank.

Revision History

Date	Description
2018-08-01	Initial release.

Alberta Reliability Standard Operations Personnel Credentials PER-003-AB-1



1. Purpose

The purpose of this **reliability standard** is to ensure that operating personnel performing the reliability-related tasks of an **operator** of a **transmission facility** are certified through the NERC System Operator Certification Program when filling a **real time** operating position responsible for control of the **bulk electric system**.

2. Applicability

This reliability standard applies to:

(a) an operator of a transmission facility that is part of the bulk electric system.

This **reliability standard** does not apply to the **operator** of a **transmission facility** who only operates **transmission facilities** that are:

- (a) radial transmission facilities connected to:
 - (i) load;
 - (ii) one or more generating unit; and/or
 - (iii) one or more aggregated generating facility;
- (b) connected to an industrial complex, or part of an industrial complex, and the removal of any or all of these transmission facilities cannot interrupt power flow on the interconnected electric system, other than power flow on its own transmission facilities when all transmission facilities in the rest of the interconnected electric system are in service; or
- (c) transmission facilities where the operation of all these facilities is covered by an operating agreement with a NERC-certified operator whereby the NERC-certified operator has the operating authority for these facilities.

3. Requirements

- R1 Intentionally left blank.
- **R2** An **operator** of a **transmission facility** must staff each of its **real time** operating positions performing reliability-related tasks with operating personnel who have obtained and maintained one of the following NERC certificates:
 - (a) Reliability Operator;
 - (b) Balancing, Interchange and Transmission Operator; or
 - (c) Transmission Operator.
- R3 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- MR1 Intentionally left blank.
- **MR2** Evidence of staffing its **real time** operating positions performing reliability-related tasks with operating personnel certified in accordance with the requirement R2 exists. This evidence may include, but it is not limited to:
 - (a) the list of **real time** operating positions performing reliability-related tasks;

Alberta Reliability Standard Operations Personnel Credentials PER-003-AB-1



- (b) the list of operating personnel assigned to the **real time** operating positions performing reliability-related tasks;
- (c) a copy of each of its operating personnel's NERC certificate; and
- (d) work schedules, logs, or other equivalent evidence showing which operating personnel were assigned to work in **real time** operating positions performing reliability-related tasks.

MR3 Intentionally left blank.

Revision History

Date	Description	
2019-01-01	Initial release.	



Alberta Reliability Standard Reliability Coordination - Staffing PER-004-AB-2

1. Purpose

The ISO must have sufficient, competent staff to perform the functions of the ISO.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

R1 The **ISO** must be staffed with adequately trained operating personnel, each possessing a valid NERC Reliability Operator certificate, 24 hours per **day**, seven **days** per week.

R2 The ISO must ensure that ISO operating personnel have adequate information regarding system operating limits, interconnection reliability operating limits and intertie facility limits available.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence may include, but is not limited to, NERC certificate / certification records, shift schedules or other equivalent evidence that will be used to confirm that the **ISO** is staffed with operating personnel possessing a valid NERC Reliability Operator certificate 24 hours per **day**, seven **days** per week.

MR2 Evidence may include but is not limited to, EMS screenshots, methodology documentation or other equivalent documentation that will be used to confirm that ISO operating personnel have adequate information regarding system operating limits and interconnection reliability operating limits and intertie facility limits.

Revision History

Effective Date	Description
2015-05-01	Initial release.



1. Purpose

The purpose of this **reliability standard** is to ensure that personnel performing or supporting **real time** operations on the **bulk electric system** are trained using a systematic approach.

2. Applicability

This reliability standard applies to:

- (a) the **ISO**;
- (b) the operator of a transmission facility that has personnel who can act independently to operate in real time, or to direct the real time operation of, those transmission facilities that are part of the bulk electric system from a control centre. This does not include field switching personnel.

This reliability standard does not apply to the **operator** of a **transmission facility** whose only **transmission facilities** are:

- (i) radial transmission facilities connecting to:
 - (a) load:
 - (b) one or more generating units; and / or
 - (c) one or more aggregated generating facilities; or
- (ii) either part of an industrial complex or connected to an industrial complex and cannot interrupt power flow on the **interconnected electric system**, other than power flow on its own **transmission facilities**.

3. Requirements

- **R1** The **ISO** and each **operator** of a **transmission facility** must use a systematic approach to develop and implement a training program for its **real time** operating personnel, as follows:
 - R1.1 The ISO and each operator of a transmission facility must:
 - (a) create a definition of a company-specific **real time** reliability-related task;
 - (b) develop a documented methodology for determining company-specific real time reliability-related tasks: and
 - (c) create a list of **bulk electric system** company-specific **real time** reliability-related tasks based on that methodology.
 - R1.1.1 The ISO and each operator of a transmission facility must review, and update if necessary, its list of bulk electric system company-specific real time reliability-related tasks identified in R1.1 each calendar year.
 - **R1.2** The **ISO** and each **operator** of a **transmission facility** must design and develop training materials according to its training program, based on the **bulk electric system** company-specific **real time** reliability-related task list created in R1.1.
 - **R1.3** The **ISO** and each **operator** of a **transmission facility** must deliver training to its **real time** operating personnel according to its training program.

Effective: 2018-04-01 Page 1 of 4



- **R1.4** The **ISO** and each **operator** of a **transmission facility** must conduct an evaluation each calendar year of the training program established in requirement R1 to identify any needed changes to the training program, and must implement the changes identified.
- **R2** Intentionally left blank.
- R3 The ISO and each operator of a transmission facility must verify, at least once, the capabilities of its real time operating personnel, identified in requirement R1, assigned to perform each of the bulk electric system company-specific real time reliability-related tasks identified under requirement R1.1.
 - R3.1 Within six (6) months of a modification or addition of a **bulk electric system** company-specific **real time** reliability-related task, the **ISO** and each **operator** of a **transmission facility** must verify the capabilities of each of its **real time** operating personnel identified in requirement R1 to perform the new or modified **bulk electric system** company-specific **real time** reliability-related tasks identified in requirement R1.1.
- R4 The ISO must provide its real time operating personnel identified in requirement R1 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the bulk electric system if the ISO:
 - (1) has operational authority or control over **facilities** with established **interconnection reliability operating limits**, or
 - (2) has established **protection systems** or operating guides to mitigate **interconnection reliability operating limit** violations,
 - **R4.1** The **ISO** must comply with requirement R4 within twelve (12) months of meeting either of the criteria identified in requirements R4(1) or R4(2).
- **R5** The **ISO** and each **operator** of a **transmission facility** must use a systematic approach to develop and implement training for its identified **operations support personnel** on how their job function(s) impact those **bulk electric system** company-specific **real time** reliability-related tasks that it has identified pursuant to requirement R1.1.
 - **R5.1** The **ISO** and each **operator** of a **transmission facility** must conduct an evaluation each calendar year of the training established in requirement R5 to identify and implement changes to the training.
- R6 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

Effective: 2018-04-01 Page 2 of 4



- **MR1** Evidence of using a systematic approach to develop and implement a training program for its **real time** operating personnel as required in requirement R1 exists. Evidence may include, but is not limited to, training program descriptions, meeting minutes, design notes, or other equivalent evidence.
 - MR1.1 Evidence of having a definition, methodology and bulk electric system company-specific real time reliability-related task list and review history, as required in requirement R1.1 exists. Evidence may include, but is not limited to, a definition for real time reliability-related tasks, a documented methodology for determining company-specific real time reliability-related tasks, a list of real time reliability related tasks, a documented revision history or other equivalent evidence.
 - **MR1.2** Evidence of designing and developing training materials as required in requirement R1.2 exists. Evidence may include, but is not limited to, course design documents and examples of training materials or other equivalent evidence.
 - **MR1.3** Evidence of delivering **real time** operating personnel training, as required in requirement R 1.3 exists. Evidence may include, but is not limited to, training records showing the names of the attendees, the title of the training delivered, and the dates of delivery or other equivalent evidence.
 - MR1.4 Evidence of conducting an evaluation of the training program each calendar year and implementing the identified changes, as required in requirement R1.4 exists. Evidence may include, but is not limited to, instructor observations, trainee feedback, course evaluations, meeting minutes, training program document revision history, or other equivalent evidence.
- MR2 Intentionally left blank.
- **MR3** Evidence of verifying, at least once, the capabilities of the **real time** operating personnel, as required in requirement R3 exists.

Evidence may include, but is not limited to, documented records to show that it verified the capability of each of its **real time** personnel on company-specific **real time** reliability-related tasks with the date of verification, employee name, supervisor signature and check sheets for each company-specific **real time** reliability-related task completed, the results of learning assessments, or other equivalent evidence.

MR3.1 Evidence of verifying the capabilities of real time operating personnel within six (6) months of a modification or addition of a bulk electric system company-specific real time reliability-related task, as required in requirement R3.1 exists. Evidence may include, but is not limited to, documented records to show that it verified the capability of each of its personnel on company-specific real time reliability-related tasks with the date of verification, employee name, supervisor signature and check sheets for each company-specific real time reliability-related task completed, the results of learning assessments, or other equivalent evidence.

Effective: 2018-04-01 Page 3 of 4



- **MR4** Evidence of providing emergency operations training as required in requirement R4 exists. Evidence may include, but is not limited to, dated training records or other equivalent evidence.
 - **MR4.1** Evidence of complying with requirement R4 as required in requirement R4.1 exists. Evidence may include, but is not limited to, dated training records or other equivalent evidence.
- **MR5** Evidence of using a systematic approach to develop and implement training for identified **operations support personnel** as required in requirement R5 exists. Evidence may include, but is not limited to, training records showing employee name, date of training and completion of training, or other equivalent evidence.
 - **MR5.1** Evidence of conducting an evaluation each calendar year of the training established in requirement R5 and that any identified changes were implemented as required in requirement R5.1 exists. Evidence may include, but is not limited to, instructor observations, trainee feedback, course evaluations, meeting minutes, training program document revision history or other equivalent evidence.

MR6 Intentionally left blank.

Revision History

Date	Description
2018-04-01	Initial release.

Effective: 2018-04-01 Page 4 of 4



1. Purpose

The purpose of this **reliability standard** is to ensure **protection systems** are coordinated among operating entities.

2. Applicability

This reliability standard applies to:

- (a) the legal owner of a transmission facility that is:
 - (i) part of the bulk electric system; or
 - (ii) not part of the **bulk electric system** and which the **ISO**:
 - (A) determines is necessary for the reliable operation of either the **interconnected electric system** or the City of Medicine Hat electric system; and
 - (B) publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;
- (b) the legal owner of a generating unit that is:
 - (i) directly connected to the bulk electric system and has a maximum authorized real power rating greater than 18 MW;
 - (ii) within a power plant which:
 - (A) is not part of an aggregated generating facility;
 - (B) is directly connected to the bulk electric system; and
 - (C) has a combined maximum authorized real power rating greater 67.5 MW;
 - (iii) a blackstart resource; or
 - (iv) material to this reliability standard and to the reliability of the bulk electric system, regardless of its maximum authorized real power rating, as the ISO determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;
- (c) the legal owner of an aggregated generating facility that is:
 - directly connected to the bulk electric system and has a maximum authorized real power rating greater than 67.5 MW;
 - (ii) within a power plant or industrial complex which:
 - (A) is directly connected to the **bulk electric system**; and
 - (B) has a combined **maximum authorized real power** rating greater than 67.5 MW;
 - (iii) a blackstart resource; or
 - (iv) material to this reliability standard and to the reliability of the bulk electric system, regardless of its maximum authorized real power rating, as the ISO determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;



- (d) the operator of a transmission facility that is:
 - (i) part of the bulk electric system; or
 - (ii) not part of the bulk electric system and which the ISO:
 - (A) determines is necessary for the reliable operation of either the **interconnected electric system** or the City of Medicine Hat electric system; and
 - (B) publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;
- (e) the operator of a generating unit that is:
 - (i) directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW;
 - (ii) within a power plant which:
 - (A) is not part of an aggregated generating facility;
 - (B) is directly connected to the bulk electric system; and
 - (C) has a combined maximum authorized real power rating greater than 67.5 MW;
 - (iii) a blackstart resource; or
 - (iv) material to this reliability standard and to the reliability of the bulk electric system, regardless of its maximum authorized real power rating, as the ISO determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1; and
- (f) the operator of an aggregated generating facility that is:
 - (i) directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW;
 - (ii) within a power plant or industrial complex which:
 - (A) is directly connected to the bulk electric system; and
 - (B) has a combined maximum authorized real power rating greater than 67.5 MW;
 - (iii) a blackstart resource; or
 - (iv) material to this reliability standard and to the reliability of the bulk electric system, regardless of its maximum authorized real power rating, as the ISO determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1.

3. Requirements

- R1 Each operator of a generating unit and operator of an aggregated generating facility must, upon failure of any component of a protection system of a generating unit or an aggregated generating facility which it operates, take the actions listed in requirement R1.1 and R1.2.
 - **R1.1** Notify the **operator** of a **transmission facility** to which the **generating unit** or **aggregated generating facility** is connected as soon as possible, but no longer than twenty-four (24) hours after becoming aware of such a failure, and provide the following information, regardless of whether or not the **generating unit** or **aggregated generating facility** remains on-line:

Effective: 2017-10-01 Page 2 of 7 Public



- (a) identify the protection system that failed; and
- (b) identify whether or not a functionally equivalent protection system remains in service.
- R1.2 Correct the failure as soon as possible.
- R2 Each operator of a transmission facility, operator of a generating unit and operator of an aggregated generating facility must take the actions listed in requirements R2.1 through R2.3 after becoming aware of the failure of any of the following protection systems or teleprotection communication channels under its authority:
 - (a) a **protection system**, other than a related teleprotection communication channel referred to in requirement R2(c) or R2(d), that protects a **transmission facility** operated at a nominal voltage greater than 200 kV, whether or not a **functionally equivalent protection system** remains in service;
 - (b) a **protection system**, other than a related teleprotection communication channel referred to in requirement R2(c) or R2(d), that protects a **transmission facility** that is part of the **bulk electric system** where a **functionally equivalent protection system** is not available;
 - (c) a teleprotection communication channel, that is part of a **protection system** for a **transmission facility** operated at a nominal voltage greater than 200 kV, where there is an equivalent backup teleprotection communication channel, and where the failure lasts for more than twenty-four (24) continuous hours; or
 - (d) a teleprotection communication channel, where there is no equivalent backup teleprotection communication channel, and where the failure lasts for more than ten (10) consecutive minutes.
 - R2.1 Provide notification to the ISO, and to each directly affected operator of a transmission facility, directly affected operator of a generating unit, directly affected operator of an aggregated generating facility and directly affected interconnected transmission operator as soon as possible, but no longer than twenty-four (24) hours after becoming aware of a failure identified in requirements R2(a), R2(b) and R2(d), and no longer than forty-eight (48) hours after becoming aware of a failure identified in requirement R2(c), regardless of whether or not the transmission facility is removed from service following the awareness of such failure, that includes the following information:
 - (a) the identification of the **protection system** or teleprotection communication channel(s) that failed:
 - (b) when the **protection system** or teleprotection communication channel(s) failed or when such failure was first discovered; and
 - (c) an estimate of the date when the **protection system** or teleprotection communication channel(s) will be returned to service.
 - **R2.2** Where the protection system or teleprotection communication channel(s) are not returned to service by the estimated return to service date identified in requirement R2.1, provide a new estimate of the return to service date up to five (5) **days** after the previous estimated return to service date to the entities that received the notification in accordance with requirement R2.1.
 - **R2.3** Correct the failure as soon as possible.



- R3 Each legal owner of a generating unit and legal owner of an aggregated generating facility must coordinate all new protection systems and all protection system changes with each affected interconnecting legal owner of a transmission facility and notify the ISO that such coordination has occurred.
- R4 Each legal owner of a transmission facility must coordinate all new protection systems and all protection system changes with:
 - (a) each affected adjacent legal owner of a transmission facility;
 - (b) each affected legal owner of a generating unit;
 - (c) each affected legal owner of an aggregated generating facility;
 - (d) each affected interconnected transmission operator; and
 - (e) the ISO, as affected,

and must notify the ISO that such coordination has occurred.

- **R5** Each operator of a generating unit, operator of an aggregated generating facility and operator of a transmission facility must identify, notify and coordinate planned changes that may require changes in the **protection systems** of others as described in requirements R5.1 and R5.2.
 - **R5.1** Each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must identify planned changes to its generation, load, or operating conditions that may require changes to the **protection systems** of others, and must notify the **ISO** and coordinate with each affected **operator** of a **transmission facility** in advance of making such changes.
 - **R5.2** Each **operator** of a **transmission facility** must identify planned changes to its transmission, load or operating conditions that may require changes to the **protection systems** of others, and must notify the **ISO** and coordinate with each affected:
 - (a) operator of a transmission facility;
 - (b) adjacent interconnected transmission operator;
 - (c) operator of a generating unit; and
 - (d) operator of an aggregated generating facility,

in advance of making such changes.

- **R6** Each **operator** of a **transmission facility** must monitor the status (on/off) of each **remedial action scheme** in its area, and must notify the **ISO** and each affected:
 - (a) operator of a transmission facility;
 - (b) adjacent interconnected transmission operator;
 - (c) operator of a generating unit; and
 - (d) operator of an aggregated generating facility,

of each change in status.



4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of notifying, providing information and correcting failures of any component of a **protection system** as required in requirement R1 exists. Evidence may include, but is not limited to:
 - **MR1.1** voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence; and
 - MR1.2 work orders, setting change files, electronic records or other equivalent evidence.
- **MR2** Evidence of providing notification, providing an estimate and correcting failures of any of the **protection systems** or teleprotection communication channel(s) as required in requirement R2 exists. Evidence may include, but is not limited to:
 - MR2.1 voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence;
 - MR2.2 voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence; and
 - MR2.3 work orders, setting change files, electronic records or other equivalent evidence.
- **MR3** Evidence of coordinating **protection systems** and notifying the **ISO** as required in requirement R3 exists.
 - Evidence of coordinating **protection systems** may include, but is not limited to, a fault analysis study, letters of agreement on settings, notifications of changes or other equivalent evidence.
 - Evidence of notifying the **ISO** may include, but is not limited to, electronic notifications (emails), hard copy notifications, or other equivalent evidence.
- **MR4** Evidence of coordinating **protection systems** and notifying the **ISO** as required in requirement R4 exists.
 - Evidence of coordinating **protection systems** may include, but is not limited to, a fault analysis study, letters of agreement on settings, notifications of changes or other equivalent evidence.
 - Evidence of notifying the **ISO** may include, but is not limited to, electronic notifications (emails), hard copy notifications or other equivalent evidence.
- MR5 Measures for this requirement are identified in the subsections below:
 - **MR5.1** Evidence of identifying, notifying and coordinating planned changes that may require changes to the **protection systems** of others as required in requirement R5.1 exists.
 - Evidence may include, but is not limited to, voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence.
 - **MR5.2** Evidence of identifying, notifying and coordinating planned changes that may require changes to the **protection systems** of others as required in requirement R5.2 exists.
 - Evidence may include, but is not limited to, voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence.



MR6 Evidence of monitoring the status of each **remedial action scheme** in its area and notifying entities of each change in status as required in requirement R6 exists.

Evidence of monitoring the status of each **remedial action scheme** may include, but is not limited to, SCADA data, wiring diagrams or other equivalent evidence.

Evidence of notifying entities may include, but is not limited to, SCADA data, voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence.

Revision History

Date	Description			
2017-10-01	Alberta specific revisions made to improve clarity.			
2015-05-01	Revised for ISO assumption of RC functionality for the Alberta footprint			
2013-01-02	Administrative update – "TFO" and "GFO" replaced with "legal owner of a transmission facility", "operator of a transmission facility", "legal owner of a generating unit", "operator of a generating unit", "legal owner of an aggregated generating facility", and "operator of an aggregated generating facility"; applied standard at the bulk electric system level; added Appendix 1; and other minor cleanup items.			
2011-01-13	R1			
2010-01-22	New Issue			



Appendix 1 Amending Process for List of Facilities

In order to amend any list referenced in subsections (a)(ii)(B), (b)(iv), (c)(iv), (d)(ii)(B), (e)(iv) and (f)(iv) of section 2, *Applicability*, the **ISO** must:

- (a) upon determining that a transmission facility, generating unit or aggregated generating facility is to be added, notify the legal owner and operator in writing and determine an effective date, which must be no less than thirty (30) days after the date of notice, by which the transmission facility, generating unit or aggregated generating facility is to meet the applicable requirements;
- (b) upon determining that a transmission facility, generating unit or aggregated generating facility is to be deleted, notify the legal owner and operator in writing and determine an effective date on which the transmission facility, generating unit or aggregated generating facility will no longer be required to meet the applicable requirements; and
- (c) publish the amended list with effective dates on the AESO website.

Alberta Reliability Standard Analysis and Mitigation of Transmission and Generation Protection System Misoperation PRC-004-AB2-1



1. Purpose

The purpose of this **reliability standard** is to ensure all **misoperations** of transmission and generation **protection systems** affecting the **reliability** of the **bulk electric system** are analyzed and mitigated.

2. Applicability

This **reliability standard** applies to:

- (a) the legal owner of a transmission facility;
- (b) the legal owner of a generating unit that:
 - (i) is not part of an aggregated generating facility;
 - (ii) has a maximum authorized real power rating greater than 4.5 MW;
 - (iii) is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and
 - (iv) has protection systems that directly affect the reliability of the bulk electric system;
- (c) the legal owner of an aggregated generating facility that:
 - is directly connected to the transmission system or to transmission facilities within the City
 of Medicine Hat;
 - (ii) has a maximum authorized real power rating greater than 4.5 MW; and
 - (iii) has protection systems that directly affect the reliability of the bulk electric system; and
- (d) the ISO.

3. Requirements

- R1 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must analyze misoperations of its protection systems affecting the reliability of the bulk electric system, and develop and implement a corrective action plan to avoid future misoperations of a similar nature.
- R2 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must provide to the ISO documentation of its misoperations analyses and corrective action plans upon request by the ISO.
- **R3** The **ISO** must provide to the **WECC** documentation of the **misoperations** analyses and corrective action plans upon request by the **WECC**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

- **MR1** Evidence of analyzing **misoperations**, and developing and implementing a corrective action plan as required in requirement R1 exists. Evidence may include reports that include analysis and corrective action plans, emails, work orders, or other equivalent evidence.
- **MR2** Evidence of providing to the **ISO** documentation of **misoperations** analyses and corrective action Effective: 2019-04-01 Page 1 of 2 Publ

Alberta Reliability Standard Analysis and Mitigation of Transmission and Generation Protection System Misoperation PRC-004-AB2-1



plans as required in requirement R2 exists. Evidence may include emails, dated correspondence, or other equivalent evidence.

MR3 Evidence of providing to the WECC documentation of the misoperations analyses and corrective action plans as required in requirement R3 exists. Evidence may include emails, dated correspondence, or other equivalent evidence

Revision History

Date	Description		
2019-04-01	Clarification to ensure the protections system misoperations that must be analyzed are those affecting the reliability of the bulk electric system. Administrative update: existing PRC-004-AB1-1 is being renamed PRC-004-AB2-1; and amendments to ensure consistent use of defined terms as included in the AESO's Consolidated Authoritative Document Glossary ("CADG"); formatting and grammatical corrections; the deletion of the following sections: (a) "Definitions"; (b) "Processes and Procedures", (c) "Appendices"; and (d) "Guidelines"		
2013-01-02	Administrative update – "TFO" and "GFO" replaced with "legal owner of a transmission facility", "legal owner of a generating unit" and "legal owner of an aggregated generating facility"; and other minor clean up items.		
2010-02-11	Initial release.		



1. Purpose

The purpose of this **reliability standard** is to ensure all **misoperations** of transmission and generation **protection systems** and RASs on transmission paths are analyzed and mitigated.

2. Applicability

This reliability standard applies to:

- (a) the **legal owner** of a **transmission facility** that is the **legal owner** of a **WECC** major transmission path **facility** or **RAS** listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC**;
- (b) the **operator** of a **transmission facility** that operates a **WECC** major transmission path **facility** or **RAS** listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC**;
- (c) the legal owner of a generating unit that owns components of RASs listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the WECC;
- (d) the **legal owner** of an **aggregated generating facility** that owns components of **RASs** listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC**;
- (e) the operator of a generating unit that operates RASs listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the WECC;
- (f) the **operator** of an **aggregated generating facility** that operates **RASs** listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC**; and
- (g) the **ISO**.

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the **Consolidated Authoritative Document Glossary**.

4. Requirements

- R1 Each legal owner of a transmission facility, legal owner of a generating unit, legal owner of an aggregated generating facility, operator of a transmission facility, operator of a generating unit and operator of an aggregated generating facility must ensure that its system operators and protection personnel analyze all protection system and RAS operations as follows:
 - R1.1 Each operator of a transmission facility, operator of a generating unit and operator of an aggregated generating facility must review all tripping of transmission system elements and RAS operations to identify apparent misoperations within 24 hours.
 - R1.2 Protection personnel of the legal owner of a transmission facility, the legal owner of a generating unit and the legal owner of an aggregated generating facility must analyze all operations of protection systems and RAS within 20 business days of the

Effective: 2016-08-30 Page 1 of 7



operation of either such system or **RAS** to determine whether a **misoperation** has occurred.

R2 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must perform the actions listed in requirements R2.1 to R2.4 inclusive for each misoperation of the protection system or RAS, subject to the following:

Requirements R2.1 to R2.4 inclusive do not apply to **protection system** and/or **RAS** operations that appear to have operated correctly at the time of occurrence. If the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** later finds through **system** protection personnel analysis that the **protection system** or **RAS** misoperated, the requirements of R2.1 to R2.4 inclusive become applicable at the time the **legal owner** of a **transmissionfacility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** identifies the **misoperation**.

Table 1 is provided as a simplified summary of the requirements in R2.1 to R2.4 inclusive.

- 2.1 If the protection system or RAS has a security-based misoperation and two or more FEPS or FERAS remain in service to ensure BES reliability, the legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must remove from service the protection system or RAS that misoperated, within 22 hours following the identification of the misoperation.
 - Repair or replacement of the failed **protection system** or **RAS** is at the discretion of the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility**.
- R2.2 If the protection system or RAS has a security-based misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility responsible for the protection system or RAS, as the case may be, must perform the following:
 - **R2.2.1** Remove from service, within 22 hours for repair or modification, the **protection** system or RAS that misoperated.
 - **R2.2.2** Repair or replace any **protection system** or **RAS** that misoperated with a **FEPS** or **FERAS** within 20 business **days** of the date of removal.
 - **R2.2.3** Remove the **system element** from service or disable the **RAS** if repair or replacement is not completed within 20 business **days**.
- R2.3 If the protection system or RAS has a security-based or dependability-based misoperation and a FEPS or FERAS is not in service to ensure BES reliability, the legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility responsible for the protection system or RAS, as the case may be, must repair and place back in service within 22 hours the protection system or RAS that misoperated.

If this cannot be done, the responsible legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must perform the following:

R2.3.1 When a **FEPS** is not available, remove the associated **system element** from service.

Effective: 2016-08-30 Page 2 of 7

- **R2.3.2** When **FERAS** is not available, meet one of the following requirements:
 - R2.3.2.1 If the responsible entity is a legal owner of a generating unit or legal owner of an aggregated generating facility, it must advise the ISO, and the operator of a generating unit or operator of an aggregated generating facility must adjust generation to a reliable operating level as directed by the ISO.
 - R2.3.2.2 If the responsible entity is a **legal owner** of a**transmission facility**, it must advise the **ISO**, and the **operator** of a **transmission facility** must operate the **facilities** within the adjusted **SOL** as determined and directed by the **ISO**.
- R2.4 If the protection system or RAS has a dependability-based misoperation, but has one or more FEPS or FERAS that operated correctly, the associated system element or transmission path may remain in service without removing from service the protection system or RAS that failed, provided one of the following is performed
 - R2.4.1 The legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must repair or replace any protection system or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the misoperation identification, or
 - R2.4.2 The legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must remove from service the associated system element or RAS.
- R3 The legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must submit a misoperation incident report to the ISO within six business days of identifying the misoperation for the following:
 - R3.1 Identification of a misoperation of a protection system and/or RAS
 - **R3.2** Completion of repairs or the replacement of the protection system and/or **RAS** that misoperated.
- **R4** The **ISO** must submit **misoperation** incident reports to **WECC** within 10 business **days** of identifying the **misoperation**.

5. Processes and Procedures

No procedures have been defined for this **reliability standard**.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

- **MR1** Measures for this requirement are identified in the subsections below.
 - **MR1.1** Documentation exists that confirms a review was completed within the timelines as specified in requirement R1.1.
 - **MR1.2** Documentation exists that confirms an analysis was completed and in the timelines as specified in requirement R1.2.

Effective: 2016-08-30 Page 3 of 7

- ALBERTA ELECTRIC SYSTEM OPERATOR
- MR2 Measures for this requirement are identified in the subsections below.
 - **MR2.1** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.1.
 - MR2.2 Measures for this requirement are identified in the subsections below.
 - **MR2.2.1** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.2.1.
 - **MR2.2.2** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.2.2.
 - **MR2.2.3** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.2.3.
 - **MR2.3** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3.
 - **MR2.3.1** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3.1.
 - MR2.3.2 Measures for this requirement are identified in the subsections below.
 - **MR2.3.2.1** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3.2.1.
 - **MR2.3.2.2** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3.2.2.
 - MR2.4 Measures for this requirement are identified in the subsections below
 - **MR2.4.1** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.4.1.
 - **MR2.4.2** Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.4.2.
- MR3 Misoperation incident report is submitted within timelines as specified in requirement R3.
 - MR3.1 Misoperation incident report contains content as specified in requirement R3.1.
 - MR3.2 Misoperation incident report contains content as specified in requirements R3.2.
- MR4 Confirmation exists that incident reports as specified in requirement R4 were received within the timelines specified, or evidence that requests for confirmation were made for the incident reports provided as specified in requirement R4.

7. Appendices

Appendix 1 – Requirement R2: Table of Required Actions for Protection Systemor RAS Misoperation (see below)

Effective: 2016-08-30 Page 4 of 7

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2016-08-30	Inclusion of the defined term system element.
2013-01-02	Administrative update – "TFO and GFO" replaced with "legal owner of a transmission facility" "legal owner of a generating unit" and "legal owner of an aggregated generating facility"; and other minor cleanup items.
2010-02-11	New Issue

Effective: 2016-08-30 Page 5 of 7



Appendix 1 – Requirement R2: Table of Required Actions for Protection System or RAS Misoperation

Protective System/RAS Situation			Required Mitigatin	Required Mitigating Actions		
Protection Basis:	Number of FEPS or RAS in place after misoperation	Misoperating protection system is:	Protection System/RAS Removal Requirement	Protection System/RAS Repair or Replacement Requirement	System Element Removal Requirement	
	2 or more	PS	Remove within 22h.	At owners discretion.		
	1	PS	Remove within 22h.	Repair within 20 days.	Remove system element from service.	
	0	PS	None.	Repair within 22 hours.	If not repaired in 22 hours then remove system element from service.	
	2 or more	RAS	Remove within 22h.	At owners discretion.		
	1	RAS	Remove within 22h.	Repair within 20 days.	If not repaired in 20 days then disable RAS or remove system element from service.	
Security	0	RAS	None.	Repair within 22 hours.	Either the legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must advise the ISO, and the operator of a generating unit or operator of an aggregated generating facility must adjust generating operating levels to a reliable operating level as directed by the ISO or the ISO will adjust the SOL and the operator of a transmission facility will operate the facilities within established limits.	

Effective: 2016-08-30 Page 6 of 7

	1 or more that operated correctly	PS	Can leave in service.	Repair in 20 days or remove system element from service.	
	0	PS	None.	Repair within 22 hours.	If not repaired in 22 hours then remove system element from service.
	1 or more that operated correctly	PS	Can leave in service.	Repair in 20 days or remove RAS or system element from service.	
Dependability	0	RAS	None.	Repair within 22 hours.	Either the legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must advise the ISO, and the operator of a generating unit or operator of an aggregated generating facility must adjust generating operating levels to a reliable operating level as directed by the ISO or the ISO will adjust the SOL and the operator of a transmission facility will operate the facilities within established limits.

Effective: 2016-08-30 Page 7 of 7



Alberta Reliability Standard UFLS Performance Following an Underfrequency Event PRC-009-AB-0

PRC-009-AB-0 UFLS Performance Following an Undefrequency Event

1. Purpose

The purpose of this *reliability standard* is to ensure effectiveness of the *UFLS* program performance.

2. Applicability

This *reliability* standard applies to:

ISO

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the <u>Alberta Reliability Standards Glossary of Terms</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

- R1 The ISO must analyze and document its UFLS program performance in accordance with WECC's UFLS program. The analysis must address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis must include, without limitation the following:
 - A description of the system event including initiating conditions.
 - A review of the UFLS set points and tripping times.
 - A simulation of the system event.
 - A summary of the findings.
- R2 The *ISO* must provide documentation of the analysis of the *UFLS* program performance to *WECC* on request and within the timeframe agreed to by the *ISO* and *WECC*.

5. Processes and Procedures

No procedures have been defined for this reliability standard.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Disturbance document(s) exist for each *UFLS* event. The disturbance document(s) contain analysis of the event.

MR2 Written confirmation from *WECC* that documentation was received.

Effective: 2009-10-03 Page 1 of 2

7. Appendices

No appendices have been defined for this reliability standard.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2009-10-03	New Issue

Effective: 2009-10-03 Page 2 of 2



Alberta Reliability Standard Assessment of the Design and Effectiveness of UVLS Program PRC-010-AB-0

PRC-010-AB-0 Assessment of the Design and Effectiveness of Under Voltage Load Shedding Program

1. Purpose

The purpose of this *reliability standard* is to ensure the effectiveness of each *UVLS* program.

2. Applicability

This *reliability* standard applies to:

ISO

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the <u>Alberta</u> Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

- R1 The ISO must conduct and document an assessment of the effectiveness of each UVLS program every five years. In the event the AESO determines that conditions affecting the UVLS operation have occurred, it may conduct and document an assessment within such five year period as it deems appropriate.
- **R2** The assessment of the effectiveness of each *UVLS* program must include without limitation, the following:
 - Coordination of the *UVLS* programs with other protection and control systems in the *WECC* as appropriate.
 - Simulations that demonstrate that the performance of each *UVLS* program is consistent with *reliability standards* TPL-001-AB-0, TPL-002-AB-0, TPL-003-AB-0 and TPL-004-AB-0.
 - A review of the voltage set points and timing
- R3 The ISO must provide documentation of its most recent assessment of UVLS programs to WECC on request and within the timeframe agreed to by the ISO and WECC.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Documentation of the most recent assessment of the effectiveness of each *UVLS* program exists and was carried out within the last five years.

Effective: 2009-10-03 Page 1 of 2

- MR2 Documentation of the most recent assessment includes the elements of R2.
- **MR3** Written confirmation from *WECC* that the documentation requested by it pursuant to R3 has been received.

7. Appendices

No appendices have been defined for this reliability standard.

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2009-10-03	New Issue

Effective: 2009-10-03 Page 2 of 2

Alberta Reliability Standard Disturbance Monitoring Equipment Installation and Data Reporting PRC-018-AB-1



1. Purpose

The purpose of this **reliability standard** is to ensure that **disturbance monitoring equipment** is installed and that **disturbance** data is reported in accordance with regional requirements to facilitate analyses of events.

2. Applicability

This reliability standard applies to:

- (a) the legal owner of a transmission facility that owns disturbance monitoring equipment as identified in the list of *Disturbance Monitoring Equipment Locations* as required in requirement R1, as published by the ISO on the AESO website and as amended from time to time by the ISO on notice to market participants;
- (b) the legal owner of a generating unit that owns disturbance monitoring equipment as identified in the list of *Disturbance Monitoring Equipment Locations* as required in requirement R1, as published by the ISO on the AESO website and as amended from time to time by the ISO on notice to market participants;
- (c) the **legal owner** of an **aggregated generating facility** that owns **disturbance monitoring equipment** as identified in the list of *Disturbance Monitoring Equipment Locations* as required in requirement R1, as published by the **ISO** on the AESO website and as amended from time to time by the **ISO** on notice to **market participants**; and
- (d) the ISO.

3. Requirements

- R1 The ISO must maintain and publish a list of all disturbance monitoring equipment that this reliability standard applies to which includes all disturbance monitoring equipment the WECC requires to be installed in Alberta.
- R2 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility that the ISO directs to install disturbance monitoring equipment must install such disturbance monitoring equipment with internal clocks synchronized to within two (2) milliseconds or less of the Universal Coordinated Time scale.
- R3 The ISO must have recorded **disturbance** data available for retrieval for at least ten (10) days.
- R4 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must install disturbance monitoring equipment as directed by the ISO.
- R5 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must report, within thirty (30) days of the ISO's request, the following information on the disturbance monitoring equipment:
 - **R5.1** type of disturbance monitoring equipment;
 - **R5.2** make and model of **disturbance monitoring equipment**;

Effective: 2016-08-30 Page 1 of 3

Alberta Reliability Standard Disturbance Monitoring Equipment Installation and Data Reporting PRC-018-AB-1



- **R5.3** installation location:
- R5.4 operational status;
- R5.5 date last tested:
- **R5.6** monitored **system elements** which may include transmission circuit and bus section:
- **R5.7** monitored devices which may include circuit breaker, disconnect status and alarms; and
- **R5.8** monitored electrical quantities, which may include voltage and current.
- R6 The ISO must provide the information received from the legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility in requirement R5 to the WECC within forty-five (45) days of the WECC's written request.
- R7 If the ISO is unable to directly access disturbance data, then each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must provide all available disturbance data recorded by disturbance monitoring equipment to the ISO within forty-five (45) days of the ISO's written request.
- R8 The ISO must provide all available disturbance data recorded by the disturbance monitoring equipment of a legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility to the WECC within sixty (60) days of the WECC's written request.
- R9 The ISO must archive all data recorded by **disturbance monitoring equipment** for all **WECC** or ISO identified events for at least three (3) years.
- R10 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility that the ISO directs to have disturbance monitoring equipment must develop, implement and maintain a maintenance and testing program for disturbance monitoring equipment that includes:
 - R10.1 maintenance and testing intervals and their basis; and
 - R10.2 a summary of maintenance and testing procedures.

4 Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

- **MR1** Evidence of maintaining and publishing a list as required in requirement R1 exists. Evidence may include a list published on the AESO's website that identifies the effective date and revision history.
- MR2 Evidence of having internal clocks in the installed **disturbance monitoring equipment** synchronized as required in requirement R2 exists. Evidence may include: the manufacturer's equipment specification, commissioning documents or GPS clock records that demonstrate each installed **disturbance monitoring equipment**'s internal clock is synchronized in accordance with R2.

Effective: 2016-08-30 Page 2 of 3

Alberta Reliability Standard Disturbance Monitoring Equipment Installation and Data Reporting PRC-018-AB-1



- **MR3** Evidence of having recorded **disturbance** data available for retrieval as required in requirement R3 exists. Evidence may include **disturbance** records.
- MR4 Evidence of installing disturbance monitoring equipment as required in requirement R4 exists. Evidence may include documentation of the installation of the disturbance monitoring equipment.
- **MR5** Evidence of reporting information as required in requirement R5 exists. Evidence may include email or mail to the appropriate **ISO** recipient that identifies information submitted.
- **MR6** Evidence of providing data as required in requirement R6 exists. Evidence may include email or mail to the appropriate **WECC** recipient that identifies data submitted.
- **MR7** Evidence of providing data as required in requirement R7 exists. Evidence may include email or mail to the appropriate **ISO** recipient that identifies data submitted.
- **MR8** Evidence of providing data as required in requirement R8 exists. Evidence may include email or mail to appropriate **WECC** recipient that identifies data submitted.
- **MR9** Evidence of archiving data as required in requirement R9 exists. Evidence may include dated archived data files.
- MR10 Evidence of developing, implementing and maintaining a maintenance and testing program as required in requirement R10 exists. Evidence may include a documented maintenance and testing program, maintenance and testing records showing the test date, type of test, what was tested and test results.
 - **MR10.1** Evidence of developing, implementing and maintaining a maintenance and testing program as required in requirement R10.1 exists. Evidence may include a documented maintenance and testing program that includes the provision as required in requirement R10.1.
 - **MR10.2** Evidence of developing, implementing and maintaining a maintenance and testing program as required in requirement R10.2 exists. Evidence may include a documented maintenance and testing program that includes the provision as required in requirement R10.2.

5. Appendices

No appendices have been defined for this **reliability standard**.

Revision History

Effective	Description
2013-01-01	Initial Release
2016-08-30	Inclusion of the defined term system element.

Effective: 2016-08-30 Page 3 of 3



Alberta Reliability Standard Under Voltage Load Shedding Program Data PRC-021-AB1-1

PRC-021-AB1-1 Under Voltage Load Shedding Program Data

1. Purpose

The purpose of this *reliability standard* is to ensure data is provided to support the *WECC* database maintained for *UVLS* programs.

2. Applicability

This reliability standard applies to:

- (a) the legal owner of a transmission facility that owns an under voltage load shed system;
- (b) a market participant receiving service under Rate DTS of the ISO tariff that owns an under voltage load shed system; and
- (c) the ISO.

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the *Consolidated Authoritative Document Glossary*.

4. Requirements

- R1 The ISO must update its UVLS data annually to support the WECC UVLS database.
- **R2** The *ISO* must provide the following data to the *WECC* for each installed *UVLS* system in Alberta that is in the *WECC UVLS* database:
 - Size and location of *load*, or percent of connected *load*, to be interrupted;
 - Corresponding voltage set points and overall scheme clearing times;
 - Time delay from initiation to trip signal;
 - Breaker operating times; and
 - Any other schemes that are part of or impact the UVLS programs, including without limitation related generation protection, islanding schemes, automatic load restoration schemes, UFLS and RAS (identified as special protection systems by WECC).
- R3 Each *legal owner* of a *transmission facility* and *market participant* must, upon request by the *ISO*, provide *UVLS* data to the *ISO*. The *legal owner* of a *transmission facility* or *market participant* may meet this requirement R3 by providing *UVLS* data in accordance with *ISO* rules.
- **R4** The *ISO* must provide its *UVLS* data to the *WECC* within 30 calendar *days* of a written request to do so from *WECC*.

5. Processes and Procedures

No procedures have been defined for this reliability standard.

Effective: 2013-01-02 Page 1 of 2

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

- **MR1** Evidence that the *UVLS* data update process was completed within 12 months of the previous update.
- MR2 Written confirmation from WECC that UVLS data was received.
- MR3 Written confirmation from the ISO that UVLS data was received.
- **MR4** Written confirmation from *WECC* that data was received within 30 calendar *days* of a request.

7. Appendices

No appendices have been defined for this reliability standard.

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2013-01-02	Administrative update – "TFO" and "demand customers" replaced with "legal owner of a transmission facility" and "market participant receiving service under Rate DTS of the ISO tariff"; and other minor cleanup items.
2009-09-19	New Issue

Effective: 2013-01-02 Page 2 of 2



Alberta Reliability Standard Under Voltage Load Shedding Program Performance PRC-022-AB-1

PRC-022-AB-1 Under Voltage Load Shedding Program Performance

1. Purpose

The purpose of this *reliability standard* is to ensure that *UVLS* programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the *AIES*.

2. Applicability

This *reliability standard* applies to:

ISO

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the <u>Alberta Reliability Standards Glossary of Terms</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

- **R1** The *ISO* must analyze and document *UVLS* operations and *misoperations* in accordance with *ISO* rules.
- **R2** The *ISO*'s analysis of *UVLS* operations and *misoperations* must include without limitation, the following:
 - A description of the *UVLS* event including initiating conditions.
 - A review of the UVLS set points and tripping times.
 - An analysis of the sequence of events.
 - A summary of the findings.
 - For any *misoperation*, a corrective action.
- R3 The ISO must simulate the UVLS event, within the timeframe agreed to by the ISO, if WECC makes a written request for a simulation.
- R4 The ISO must provide documentation of its analysis of a UVLS program performance to the WECC within 90 calendar days of a request from WECC.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

- **MR1** Event reports exist for *UVLS* events that require a report in accordance with *ISO* rules.
- **MR2** Documentation of the analysis includes the items listed in R2.

Effective: 2009-10-03 Page 1 of 2

MR3 Results of the simulation exists.

MR4 Written confirmation from the *WECC* that documentation was received within 90 calendar *days*.

7. Appendices

No appendices have been defined for this reliability standard.

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2009-10-03	New Issue

Effective: 2009-10-03 Page 2 of 2



Page 1 of 8

Alberta Reliability Standard Transmission Relay Loadability PRC-023-AB-2

1. Purpose

The purpose of this **reliability standard** is to ensure the protective relay settings do not limit transmission loadability, do not interfere with an **operator**'s ability to take remedial action to protect the **reliability** of the system, and are set to reliably detect all fault conditions and protect the electrical network from these faults.

2. Applicability

This reliability standard applies to:

- (a) a **legal owner** of a **transmission facility** with load-responsive phase **protection systems**, as described in Appendix 1 applied to any one (1) or more of the following facilities:
 - (i) transmission lines operated at two hundred (200) kV and above;
 - (ii) transmission lines operated below two hundred (200) kV which the **ISO** identifies as essential to the **reliability** of the **bulk electric system** as required in requirement R6.2;
 - (iii) transformers with low voltage terminals connected at two hundred (200) kV and above; or
 - (iv) transformers with low voltage terminals connected below two hundred (200) kV which the **ISO** identifies in accordance with requirement R6.2;
- (b) a legal owner of a generating unit, that also owns the associated switch yard, with load-responsive phase protection systems, as described in Appendix 1 applied to any one (1) or more of the following facilities:
 - (i) transmission lines operated at two hundred (200) kV and above;
 - (ii) transmission lines operated below two hundred (200) kV which the **ISO** identifies as essential to the **reliability** of the **bulk electric system** as required in requirement R6.2;
 - (iii) transformers with low voltage terminals connected at two hundred (200) kV and above; or
 - (iv) transformers with low voltage terminals connected below two hundred (200) kV which the ISO identifies in accordance with requirement R6.2;
- (c) a legal owner of an aggregated generating facility, that also owns the associated switch yard, with load-responsive phase protection systems, as described in Appendix 1 applied to any one
 (1) or more of the following facilities:
 - (i) transmission lines operated at two hundred (200) kV and above;
 - (ii) transmission lines operated below two hundred (200) kV which the **ISO** identifies as essential to the **reliability** of the **bulk electric system** as required in requirement R6.2;
 - (iii) transformers with low voltage terminals connected at two hundred (200) kV and above; or
 - (iv) transformers with low voltage terminals connected below two hundred (200) kV which the **ISO** identifies in accordance with requirement R6.2; and
- (d) the ISO.

Effective: R6: 2014-04-01,



3. Requirements

- R1 Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must use one of the criteria set out in requirements R1.1 through R1.14, inclusive, for each specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the bulk electric system for all fault conditions and evaluate the phase protective relay's loadability at zero point eight five (0.85) per unit voltage and a **power factor** angle of thirty (30) degrees.
 - R1.1 Set transmission line relays so they do not operate at or below one hundred and fifty (150 %) percent of the highest seasonal facility rating of a circuit for the available defined loading duration nearest to four (4) hours, expressed in amperes;
 - R1.2 Set transmission line relays so they do not operate at or below one hundred and fifteen (115 %) percent of the highest seasonal 15-minute facility rating of a circuit, expressed in amperes;
 - R1.3 Set transmission line relays so they do not operate at or below one hundred and fifteen (115%) percent of the maximum theoretical power transfer capability, using a ninety (90) degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit, expressed in amperes, using one of the following to perform the power transfer calculation:
 - R1.3.1 an infinite source, i.e. zero source impedance, with a one point zero zero (1.00) per unit bus voltage at each end of the transmission line; or
 - R1.3.2 an impedance at each end of the transmission line, which reflects the actual system source impedance with a one point zero five (1.05) per unit voltage behind each source impedance;
 - R1.4 Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the transmission line, determined as the greater
 - (a) one hundred and fifteen (115 %) percent of the highest emergency rating of the series capacitor, or
 - (b) one hundred and fifteen (115%) percent of the maximum power transfer capability of the circuit, expressed in amperes, calculated in accordance with requirement R1.3, using the full transmission line inductive reactance;
 - R1.5 Set transmission line relays on weak source systems so they do not operate at or below one hundred and seventy (170%) percent of the maximum end-of-line three-phase fault magnitude, expressed in amperes:
 - R1.6 Set transmission line relays applied on transmission lines connected to a generating unit or aggregated generating facility remote to load so they do not operate at or below two hundred and thirty (230%) percent of the total nameplate capability of all the generating units at the facility;
 - R1.7 Set transmission line relays applied at the load center terminal, remote from a generating unit or aggregated generating facility, so they do not operate at or below one hundred and fifteen (115%) percent of the maximum current flow from the load to the generation source under any system configuration:
 - R1.8 Set transmission line relays applied on the system-end of transmission lines that serve load remote to the system so they do not operate at or below one hundred and fifteen (115%) percent of

Effective: R6: 2014-04-01.



the maximum current flow from the system to the load under any system configuration;

- **R1.9** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the system so they do not operate at or below one hundred and fifteen (115%) of the maximum current flow from the load to the system under any system configuration;
- **R1.10**Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:
 - (a) one hundred and fifty (150%) percent of the applicable maximum transformer nameplate rating, expressed in amperes, including the forced cooled ratings corresponding to all installed supplemental cooling equipment; or
 - (b) one hundred and fifteen (115%) percent of the highest established emergency transformer rating;
- **R1.11**Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability;
- R1.12For transformer overload protection relays that do not comply with requirement R1.10:
 - (a) set the relays to allow the transformer to be operated at an overload level of at least one hundred and fifty (150%) percent of the maximum applicable nameplate rating, or one hundred and fifteen (115%) percent of the highest emergency transformer rating, whichever is greater;
 - (b) the protection relay must allow overload in subsection 1.12(a) for at least fifteen (15) minutes to allow the **ISO** to take controlled action to relieve the overload;
 - (c) install supervision for the relays using either a top oil or simulated winding hot spot temperature element; and
 - (d) the relay setting should be no less than one hundred (100°C) degrees Celsius for the top oil or one hundred and forty (140°C) degrees Celsius for the winding hot spot temperature;
- **R1.13**When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of one hundred and twenty five (125%) percent of the apparent impedance, at the impedance angle of the transmission line, subject to the following constraints:
 - **R1.13.1** Set the maximum torque angle to ninety (90) degrees or the highest setting supported by the manufacturer;
 - **R1.13.2** Evaluate the relay loadability in amperes at the relay trip point at zero point eight five (0.85) per unit voltage and a **power factor** angle of thirty (30) degrees; and
 - R1.13.3 Include a relay setting component of eighty seven (87%) percent of the current calculated in requirement R1.13.2 in the facility rating determination for the circuit; and
- **R1.14**Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below one hundred and fifteen (115%) percent of such limitations.
- **R2** Each legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay

Effective: R6: 2014-04-01, R1-R5: 2015-04-01, 2016-04-01



loadability per requirement R1.

- R3 Any legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility that uses a circuit capability with the practical limitations described in requirements R1.6, R1.7, R1.8, R1.9, R1.13, or R1.14 must use the calculated circuit capability as the facility rating of the circuit and must obtain the agreement of the ISO to use the calculated circuit capability.
- **R4** Any **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** that uses requirement R1.2 as the basis for verifying transmission line relay loadability must provide the **ISO** with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than fifteen (15) months between reports.
- R5 Any legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility that uses requirement R1.13 as the basis for verifying transmission line relay loadability must provide the ISO with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than fifteen (15) months between reports.
- R6 The ISO must conduct an assessment at least once each calendar year, with no more than fifteen (15) months between assessments, by applying the criteria in Appendix 2 to identify the circuits in its Planning Coordinator area for which the legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility must comply with requirements R1 through R5. The ISO must:
 - **R6.1** Maintain a list of circuits per the application of Appendix 2, including an effective date that is no earlier than twenty-four (24) months from identification of the circuits; and
 - **R6.2** Provide the list of circuits to the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** within its Planning Coordinator area within thirty (30) days of the establishment of the initial list and within thirty (30) days of any changes to that list.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of using one of the criteria set out in requirements R1.1 through R1.14 as required in requirement R1 exists. Evidence may include:

- (a) spreadsheets or summaries of calculations to show that each of its transmission relays is set in accordance with one of the criteria set out in requirements R1.1 through R1.14; and
- (b) coordination curves or summaries of calculations that show that relays set per criterion set out in requirement R1.11 do not expose the transformer to fault levels and durations beyond those indicated in the **reliability standard**.

MR2 Evidence of setting its out-of-step blocking elements as required in requirement R2 exists. Evidence may include spreadsheets or summaries of calculations.

MR3 Evidence of using, and obtaining the agreement to use, the calculated circuit capability as required in requirement R3 exists. Evidence may include:

(a) facility rating spreadsheets or facility rating database to show that the calculated circuit

Effective: R6: 2014-04-01, R1-R5: 2015-04-01, 2016-04-01



capability was used as the facility rating of the circuit; and

(b) dated correspondence to show that the ISO agreed to the calculated circuit capability.

MR4 Evidence of providing the **ISO** with an updated list of circuits as required in requirement R4 exists. Evidence may include email or mail to the appropriate **ISO** recipient with the updated list which may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list.

MR5 Evidence of providing the **ISO** with an updated list of circuits as required in requirement R5 exists. Evidence may include email or mail to the appropriate **ISO** recipient with the updated list which may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list.

MR6 Evidence of conducting an assessment as required in requirement R6 exists. Evidence may include power flow results, calculation summaries or study reports that the **ISO** used the criteria established within Appendix 2 to identify the circuits in its Planning Coordinator area.

MR6.1 Evidence of maintaining the list of circuits as required in requirement R6.1 exists. Evidence may include a documented list of circuits with the effective date and the revision history captured.

MR6.2 Evidence of providing the list of circuits as required in requirement R6.2 exists. Evidence may include email or mail to the applicable entities.

5. Appendices

Appendix 1 - Associated Switch Yard with Load-Responsive Phase Protection Systems

Appendix 2 - Criteria for Identifying Circuits and Establishing a List

Revision History

Effective	Description
	for requirements R1, R2, R3, R4 and R5 for:
April 1, 2015	(a) transmission lines operated at two hundred (200) kV and above; and
	(b) transformers with low voltage terminals connected at two hundred (200) kV and above.
April 1, 2014	for requirement R6
	for requirements R1, R2, R3, R4 and R5 for:
April 1, 2016	(a) transmission lines operated below two hundred (200) kV which the ISO identifies as essential to the reliability of the bulk electric system ; and
	(b) transformers with low voltage terminals connected below two hundred (200) kV the ISO identifies as essential to the reliability of the bulk electric system.

Effective: R6: 2014-04-01, R1-R5: 2015-04-01, 2016-04-01



Appendix 1 - Associated Switch Yard with Load-Responsive Phase Protection Systems

- 1. This **reliability standard** includes any protective functions which could trip with or without time delay, on load current, including:
 - (a) phase distance;
 - (b) out-of-step tripping;
 - (c) switch-on-to-fault;
 - (d) overcurrent relays;
 - (e) communications aided protection schemes including:
 - (i) permissive overreach transfer trip;
 - (ii) permissive under-reach transfer trip;
 - (iii) directional comparison blocking; and
 - (iv) directional comparison unblocking; and
 - (f) phase overcurrent supervisory elements (i.e. phase fault detectors) associated with currentbased, communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
- 2. The following protection systems are excluded from the requirements of this reliability standard:
 - (a) relay elements that are only enabled when other relays or associated systems fail, including:
 - (i) overcurrent elements that are only enabled during loss of potential conditions; and
 - (ii) elements that are only enabled during a loss of communications except as noted in subsection 1(f) above;
 - (b) **protection systems** intended for the detection of ground fault conditions;
 - (c) **protection systems** intended for protection during stable power swings;
 - (d) generator protection relays that are susceptible to load;
 - (e) relay elements used only for **remedial action scheme** purposes;
 - (f) protection systems that are designed only to respond in time periods which allow fifteen (15) minutes or greater to respond to overload conditions;
 - (g) thermal emulation relays which are used in conjunction with dynamic facility ratings; and
 - (h) relay elements associated with direct current lines.

Effective: R6: 2014-04-01.



Appendix 2 – Criteria for Identifying Circuits and Establishing a List

The ISO must evaluate the following circuits:

- (a) transmission lines operated at one hundred (100) kV to two hundred (200) kV and transformers with low voltage terminals connected at one hundred (100) kV to two hundred (200) kV; and
- (b) transmission lines operated below one hundred (100) kV and transformers with low voltage terminals connected below one hundred (100) kV that are essential to the reliability of the bulk electric system.

Criteria

If any of the following criteria apply to a circuit, the ISO must identify the circuit as required in requirement R6.

- 1 A major transfer path within the Western Interconnection as defined by the Regional Entity.
- The circuit is a monitored facility of an interconnection reliability operating limit, where the interconnection reliability operating limit was determined in the planning horizon pursuant to reliability standard FAC-010-AB-2.1, System Operation Limits Methodology for the Planning Horizon.
- 3 The circuit is identified through the following sequence of power flow analyses:
 - (a) simulate double **contingency** combinations selected by engineering judgment, without manual system adjustments in between the two (2) contingencies (reflects a situation where a system operator may not have time between the two (2) contingencies to make appropriate system adjustments), performed by the ISO for the one-to-five-year planning horizon;
 - (b) for circuits operated between one hundred (100) kV and two hundred (200) kV, evaluate the post-contingency loading, in consultation with the legal owner, against a threshold based on the facility rating assigned for that circuit and used in the power flow case by the ISO;
 - (c) when more than one (1) facility rating for that circuit is available in the power flow case, the **ISO** must base the threshold for selection on the facility rating for the loading duration nearest four (4) hours;
 - (d) the threshold for selection of the circuit will vary based on the loading duration assumed in the development of the facility rating:
 - (i) if the facility rating is based on a loading duration of up to and including four (4) hours, the circuit must comply with the standard if the loading exceeds one hundred and fifteen percent (115%) of the facility rating:
 - (ii) if the facility rating is based on a loading duration greater than four (4) and up to and including eight (8) hours, the circuit must comply with the standard if the loading exceeds one hundred and twenty percent (120%) of the facility rating; or
 - (iii) if the facility rating is based on a loading duration of greater than eight (8) hours, the circuit must comply with the standard if the loading exceeds one hundred and thirty percent (130%) of the facility rating; and
 - (e) radially operated circuits serving only load are excluded.

Effective: R6: 2014-04-01.



- The ISO must select the circuit based on technical studies or assessments, other than those specified in criteria 1 through 3, in consultation with the legal owner.
- The **ISO** and the **legal owner** must mutually agree upon the circuit for inclusion.

Effective: R6: 2014-04-01,

Alberta Reliability Standard Operational Reliability Information TOP-005-AB3-1



1. Purpose

The purpose of this **reliability standard** is to require the **ISO** to provide operating data to entities responsible for reliable power system operation so that those entities have the operating data needed to monitor system conditions within their areas.

2. Applicability

This reliability standard applies to:

(a) the ISO.

3. Requirements

- R1 Intentionally left blank.
- R2 Upon request, the ISO must provide to other balancing authorities and transmission operators external to Alberta with immediate responsibility for operational reliability, the operating data that is necessary to allow these balancing authorities and transmission operators external to Alberta to perform operational reliability assessments and to coordinate reliable operations. The ISO must provide the types of operating data as listed in Appendix 1 of this reliability standard, unless otherwise agreed to by these balancing authorities and transmission operators.
- R3 Upon request, the ISO must provide to each operator of a transmission facility with immediate responsibility for operational reliability, the operating data that is necessary to allow such operator of a transmission facility to perform operational reliability assessments and to coordinate reliable operations. The ISO must provide the types of operating data as listed in Appendix 1 of this reliability standard, unless otherwise agreed to by the operator of a transmission facility and with immediate responsibility for operational reliability.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

- **MR1** Intentionally left blank.
- MR2 A confirmation letter from the ISO confirming that the ISO has provided the data as requested by the **balancing authorities** or **transmission operators**. The letter is dated and signed by an authorized representative of the **balancing authorities** and **transmission operators** external to Alberta.

Effectuve: 2015-10-01 Page 1 of 4

Alberta Reliability Standard Operational Reliability Information TOP-005-AB3-1



MR3 A confirmation letter from the ISO confirming that the ISO has provided the data as requested by the **operator** of a **transmission facility**. The letter is dated and signed by an authorized representative of the **operator** of a **transmission facility**.

5. Appendices

Appendix 1 - TOP-005-AB3-1 Electric System Reliability Data

Revision History

Date	Description
2015-10-01	Revised for ISO assumption of RC functionality for the Alberta footprint.
2013-04-01	Remove requirements R2 and R5 applicable to non-ISO Alberta entities.
2013-01-02	Administrative update – "TFO" replaced with "operator of a transmission facility"; clarified "pool participant"; specified "operator of a generating unit"; and specified "operator of an aggregated generating facility".
2009-05-26	New Issue

Effective: 2015-10-01 Page 2 of 4

Alberta Reliability Standard Operational Reliability Information TOP-005-AB3-1



Appendix 1 - TOP-005-AB3-1 Electric System Reliability Data

Appendix 1 lists the types of data that the **ISO** is expected to provide to:

- (i) other **balancing authorities** and **transmission operators** external to Alberta; and
- (ii) each operator of a transmission facility;

with immediate responsibility for operational reliability.

- 1. The following operating data must be updated at least every ten (10) minutes.
 - **1.1** Transmission data. Transmission data for all **interconnections** plus all other facilities considered key, from a **reliability** standpoint:
 - **1.1.1** Status
 - 1.1.2 MW or ampere loadings
 - **1.1.3** MVA capability
 - **1.1.4** Transformer tap and phase angle settings
 - 1.1.5 Key voltages
 - 1.2 Generator data:
 - **1.2.1** Status
 - **1.2.2** MW and MVAr capability
 - 1.2.3 MW and MVAr net output
 - **1.2.4** Status of automatic voltage control facilities
 - **1.3.** Operating reserves:
 - **1.3.1** MW reserve available within ten minutes
 - **1.4. Balancing authority** demand:
 - 1.4.1 Instantaneous
 - 1.5. Interchange:
 - **1.5.1** Instantaneous actual **interchange** with each **balancing authority**
 - **1.5.2** Current **interchange schedules** with each **balancing authority** by individual **interchange transaction**, including **interchange** identifiers, and reserve responsibilities
 - **1.5.3** Interchange schedules for the next twenty-four (24) hours

Effective: 2015-10-01 Page 3 of 4

ALBERTAL ELECTRIC SYSTEM OPERATOR

Alberta Reliability Standard Operational Reliability Information TOP-005-AB3-1

- **1.6.** Area control error and frequency:
 - 1.6.1 Instantaneous area control error
 - 1.6.2 Clock hour area control error
 - **1.6.3** System frequency at one (1) or more locations in the **balancing** authority
- **2.** The following information must be updated as soon as the information becomes available.
 - **2.1. Interconnection reliability operating limits** and **system operating limits** in effect
 - **2.2.** Forecast of operating reserves at peak, and time of peak for current **day** and next **day**
 - 2.3. Forecast peak demand for current day and next day
 - **2.4.** Forecast changes in equipment status
 - 2.5. New facilities in place
 - 2.6. New or degraded remedial action schemes
 - **2.7.** Emergency operating procedures in effect
 - **2.8.** Severe weather, fire, or earthquake
 - 2.9. Multi-site sabotage

Effective: 2015-10-01 Page 4 of 4



1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements, with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This reliability standard applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the <u>Consolidated</u> <u>Authoritative Document Glossary</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

R1 The **ISO** must demonstrate through a planning assessment that a transmission system is planned such that, with all **transmission facilities** in service and with pre-**contingency** operating procedures in effect, the transmission system can be operated to accommodate forecasted customer **demands**, supply and forecasted **firm** (non- recallable reserved) transmission services at all **demand** levels over the range of forecast system **demands**, under the conditions defined in Category A of Appendix 1.

The **ISO** planning assessment must:

- R1.1 Be carried out annually.
- R1.2 Be conducted for years one through five and years six through ten planning horizons.
- **R1.3** Be supported by a study and/or system simulation testing, conducted within the last five years, that addresses each of the requirements in requirement R1.3.1 to R1.3.9, showing system performance for the conditions defined in Category A of Appendix 1.
 - R1.3.1 Cover critical system conditions and study years as determined necessary by the ISO.
 - **R1.3.2** Be conducted annually unless the **ISO** determines that changes to system conditions do not warrant such analyses.
 - **R1.3.3** Be conducted beyond the five year planning horizon only as needed to address identified marginal conditions that may have longer lead time solutions.
 - **R1.3.4** Have pre-contingency operating procedures established and in place.
 - R1.3.5 Have all projected firm transfers modeled, if any.
 - **R1.3.6** Be performed for selected **demand** levels over the range of forecast system **demands** as considered necessary by the **ISO**.
 - **R1.3.7** Demonstrate that system performance meets the conditions defined in Category A of Appendix 1.

Effective: 2016-08-30 Page 1 of 6



- R1.3.8 Include existing and planned facilities as considered necessary by the ISO.
- **R1.3.9** Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.
- **R1.4** Address any planned upgrades needed to meet the performance requirements for the conditions defined in Category A of Appendix 1.
- **R2** When system simulations indicate an inability of the systems to respond as set out in R1.3.7 in this reliability standard, the ISO must:
 - **R2.1** Develop corrective plans to achieve the required system performance as described above throughout the planning horizon.
 - **R2.1.1** Including a schedule for implementation.
 - R2.1.2 Including a discussion of expected required in-service dates of facilities.
 - **R2.1.3** Consider lead times necessary to implement corrective plans.
 - **R2.2** Review in subsequent annual assessments, where sufficient lead time exists, the continuing need for identified system **facilities**. Detailed implementation plans are not needed.
 - R3 The ISO must provide the planning assessment to WECC on an annual basis.

5. Processes and Procedures

No procedures have been defined for this reliability standard.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

- MR1 The planning assessment will be valid and meet requirement in R1 through the following measures:
 - (a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.
 - (b) The planning assessment includes time horizons as specified in R1.2.
 - (c) The planning assessment has been prepared within the last year.
 - (d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.
 - (e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.
- MR2 The area studies and needs identification documents contain recommendations and projects for corrective plans where an inability of the systems to respond to requirements specified in R1 has been identified. The area studies and needs identification documents are provided on request. The

Effective: 2016-08-30 Page 2 of 6



area studies and needs identification documents contain the technical components as specified in R2 and its subsections.

MR3 A written or email confirmation from WECC that it has received the planning assessment from the ISO. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards - Normal and Emergency Conditions (see below)

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2010-09-24	New Issue
2016-08-30	Inclusion of the defined term system element.

Effective: 2016-08-30 Page 3 of 6



Appendix 1 - Transmission System Standards - Normal and Emergency Conditions

	Contingencies	Syste	System Limits or Impacts			
Category	Initiating Event(s) and Contingency System Element(s)	System Stable and Both Thermal and Voltage Limits Within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transmission Service Transfers	Cascading		
A No contingencies	All facilities in service	Yes	No	No		
B Event resulting in	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with normal clearing :	Yes	No ^b	No		
the loss of a single	1. Generator	Yes	No ^b	No		
system element	2. Transmission circuit	Yes	No ^b	No		
	3. Transformer	Yes	No ^b	No		
С	SLG fault, with normal clearing e:					
Event(s) resulting	1. Bus section	Yes	Planned/ Controlled ^c	No		
in the loss of two or more (multiple)	Breaker (failure or internal fault)	Yes	Planned/ Controlled ^c	No		
system elements	SLG or 3Ø fault, with normal clearing ^e , manual system adjustments, followed by another SLG or 3Ø fault, with normal clearing ^e 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another	Yes	Planned/ Controlled ^c	No		
	Category B (B1, B2, B3, or B4) contingency					
	Bipolar block, with normal clearing e:					
	4. Bipolar (dc) line fault (non 3Ø), with normal clearing ^e :	Yes	Planned/ Controlled ^c	No		
	Any two circuits of a multiple circuit towerline ^t	Yes	Planned/ Controlled ^c	No		
	SLG fault, with delayed clearing ^e (stuck breaker or protection system failure)					

Effective: 2016-08-30 Page 4 of 6



	2 2	V		
	6. Generator	Yes	Planned/ Controlled ^c No	
	7. Transformer	Yes	Planned/ Controlled ^c No	
	8. Transmission circuit	Yes	Planned/ Controlled ^c No	
	9. Bus section	Yes	Planned/ Controlled ^c No	
D d	3Ø fault, with delayed clearing ^e (stuck system failure):	breaker or protection	Evaluate for risks and consequences	
resulting in two or	,	smission circuit	May involve substantial loss of	
more (multiple) system elements	3. Transformer 4. Bus s	section	customer demand and generation in a widespread	
removed or	3Ø fault, with normal clearing ^e :		area or areas	
cascading out of service	5. Breaker (failure or internal fault)	Portions or all of the		
	6. Loss of towerline with three or more circuits		interconnected systems may or may not achieve a new,	
	7. All transmission lines on a common right-of -way		stable operating point	
	Loss of a substation (one voltage level plus transformers)		Evaluation of these events may require joint studies with	
	Loss of a switching station (one voltransformers)	ltage level plus	neighboring systems	
	10. Loss of all generating units at a sta	tion		
	11. Loss of a large load or major load	center		
	12. Failure of a fully redundant specia (or remedial action scheme) to op			
	13. Operation, partial operation, or mis redundant special protection sys action scheme) in response to an system	tem (or remedial		
	Impact of severe power swings or odisturbances in another Regional F			

- a) Applicable rating refers to the applicable normal and emergency facility thermal and voltage rating as applied by the facility owner or system voltage limit as determined and consistently applied by the ISO. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established by the applicable entity consistent with applicable ISO rules addressing facility ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted **system element** or by the affected area, may occur in certain areas without impacting the overall **reliability** of the **interconnected** transmission systems. To prepare for the next **contingency**, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

Effective: 2016-08-30 Page 5 of 6



- c) 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) transmission service electric power transfers may be necessary to maintain the overall **reliability** of the **interconnected** transmission systems.
- d) A number of extreme **contingencies** that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible **facility outages** under each listed **contingency** of Category D will be evaluated.
- e) **Normal clearing** is when the **protection system** operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed **protection systems**. Delayed clearing of a fault is due to failure of any **protection system** component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.

Effective: 2016-08-30 Page 6 of 6



1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This reliability standard applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the <u>Consolidated</u> <u>Authoritative Document Glossary</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

R1 The ISO must demonstrate for transmission facilities rated 69 kV and above, through a planning assessment, that a transmission system is planned such that the transmission system can be operated to accommodate forecasted customer demands and forecasted firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Appendix 1.

The ISO planning assessments must:

- R1.1 Be carried out annually.
- **R1.2** Be conducted for near term (year one through five) and longer term (year six through ten) planning horizons.
- **R1.3** Be supported by a study and/or system simulation testing, conducted within the last five years that addresses each of the requirements in requirement R1.3.1 to R1.3.12, showing system performance for the conditions defined in Category B of Appendix 1.
 - **R1.3.1** Be performed and evaluated only for those Category B **contingencies** that the **ISO** has determined would produce the more severe system results or impacts. The rationale for the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe system results must be included in the study.
 - **R1.3.2** Cover critical system conditions and study years as determined necessary by the **ISO**.
 - **R1.3.3** Be conducted annually unless the **ISO** determines that changes to system conditions do not warrant such analyses.
 - **R1.3.4** Be conducted beyond the five year horizon only as needed to address identified marginal conditions that may have longer lead time solutions.
 - **R1.3.5** Have all projected firm transfers modeled, if any.



- **R1.3.6** Be performed and evaluated for selected **demand** levels over the range of forecast system **demands** as considered necessary by the *ISO*.
- **R1.3.7** Demonstrate that system performance meets the conditions defined in Category B of Appendix 1.
- R1.3.8 Include existing and planned facilities as considered necessary by the ISO.
- **R1.3.9** Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.
- **R1.3.10** Include the effects of existing and planned **protection systems**, including any backup or redundant systems.
- R1.3.11 Include the effects of existing and planned control devices.
- R1.3.12 Include the planned outage and maintenance of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. For stations supplied by two lines, if one line is out for maintenance, then those stations are considered to be supplied by a radial line.
- **R1.4** Address any planned upgrades needed to meet the performance requirements for the conditions defined in Category B of Appendix 1.
- **R1.5** Consider all **contingencies** applicable to Category B of Appendix 1.
- **R2** When system simulations indicate an inability of the systems to respond as set out in R1.3.7 of this reliability standard the **ISO** must:
 - **R2.1** Provide corrective plans to achieve the required system performance as described above throughout the planning horizon:
 - **R2.1.1** Including a schedule for implementation.
 - **R2.1.2** Including a discussion of expected required in-service dates of **facilities**.
 - **R2.1.3** Consider lead times necessary to implement corrective plans.
 - **R2.2** Review, in subsequent annual assessments, where sufficient lead time exists, the continuing need for identified system **facilities**. Detailed implementation plans are not needed.
- R3 The ISO must provide the planning assessment to WECC on an annual basis.

5. Processes and Procedures

No procedures have been defined for this reliability standard.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

- MR1 The planning assessment will be valid and meet requirements in R1 through the following measures:
 - (a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and

Effective: 2017-10-30 Page 2 of 6 Public



are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.

- (b) The planning assessment includes time horizons as specified in R1.2.
- (c) The planning assessment has been prepared within the last year.
- (d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.
- (e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.
- MR2 The area studies and needs identification documents contain recommendations and projects for the corrective plans where an inability of the systems to respond to requirements specified in R1 has been identified. The area studies and needs identification documents must be provided on request.
- MR3 A written or email confirmation from WECC that it has received the planning assessment from the ISO. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards - Normal and Emergency Conditions (see below)

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2017-10-30	Initial release.

Effective: 2017-10-30 Page 3 of 6 Public



Appendix 1 - Transmission System Standards - Normal and Emergency Conditions

	Contingencies	Syste	em Limits or Impacts	
Category	Initiating Event(s) and Contingency System Element(s)	System Stable and Both Thermal and Voltage Limits Within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transmission Service Transfers	Cascading
A No contingencies	All facilities in service	Yes	No	No
B Event resulting in	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with normal clearing :	Yes	No ^b	No
the loss of a single	1. Generator	Yes	No ^b	No
system element	2. Transmission circuit	Yes	No ^b	No
	3. Transformer	Yes	No ^b	No
С	SLG fault, with normal clearing e:			
Event(s) resulting	1. Bus section	Yes	Planned/ Controlled ^c	No
in the loss of two or more (multiple)	2. Breaker (failure or internal fault)	Yes	Planned/ Controlled ^c	No
system elements	SLG or 3Ø fault, with normal clearing ^e , manual system adjustments, followed by another SLG or 3Ø fault, with normal clearing ^e 3. Category B (B1, B2, B3, or B4) contingency, manual system	Yes	Planned/ Controlled ^c	No
	adjustments, followed by another Category B (B1, B2, B3, or B4) contingency			
	Bipolar block, with normal clearing e:			
	4. Bipolar (dc) line fault (non 3Ø), with normal clearing ^e :	Yes	Planned/ Controlled ^c	No
	Any two circuits of a multiple circuit towerline ^t	Yes	Planned/ Controlled ^c	No
	SLG fault, with delayed clearing ^e (stuck breaker or protection system failure)			



	6. Generator	Yes	Planned/ Controlled ^c	No	
	7. Transformer	Yes	Planned/ Controlled ^c	No	
	8. Transmission circuit	Yes	Planned/ Controlled ^c	No	
	9. Bus section	Yes	Planned/ Controlled ^c	No	
D d	3Ø fault, with delayed clearing ^e (stuck system failure):	breaker or protection	Evaluate for risks and consequences		
resulting in two or more (multiple)	,	smission circuit	May involve substacustomer demand		
system elements	3. Transformer 4. Bus	section	generation in a wic		
removed or	3Ø fault, with normal clearing ^e :		area or areas	•	
cascading out of service	5. Breaker (failure or internal fault)		Portions or all of the		
	6. Loss of towerline with three or more circuits		interconnected systems may or may not achieve a new,		
	7. All transmission lines on a commor	All transmission lines on a common right-of -way stab		stable operating point	
	Loss of a substation (one voltage level plus transformers)		 Evaluation of these events may require joint studies with neighboring systems 	tudies with	
	Loss of a switching station (one vo transformers)	ltage level plus	Heighboring systems		
	10. Loss of all generating units at a sta	ition			
	11. Loss of a large load or major load	center			
	12. Failure of a fully redundant specia (or remedial action scheme) to op				
	13. Operation, partial operation, or mis redundant special protection sys action scheme) in response to an system	tem (or remedial			
	Impact of severe power swings or disturbances in another Regional F				

- a) Applicable rating refers to the applicable normal and emergency facility thermal and voltage rating as applied by the facility owner or system voltage limit as determined and consistently applied by the ISO. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established by the applicable entity consistent with applicable ISO rules addressing facility ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted **system element** or by the affected area, may occur in certain areas without impacting the overall **reliability** of the **interconnected** transmission systems. To prepare for the next **contingency**, system

Effective: 2017-10-30 Page 5 of 6 Public



adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

- c) 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) transmission service electric power transfers may be necessary to maintain the overall **reliability** of the **interconnected** transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) **Normal clearing** is when the **protection system** operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed **protection systems**. Delayed clearing of a fault is due to failure of any **protection system** component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.



1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements, with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This reliability standard applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the <u>Consolidated</u> <u>Authoritative Document Glossary</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

R1 The ISO must demonstrate for transmission facilities rated 100 kV and above, through a planning assessment that the AIES is planned such that the AIES can be operated to accommodate forecasted customer demands, supply and forecasted firm (non- recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Appendix 1. The controlled interruption of demand to demand customers, the planned removal of generating units, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this reliability standard.

The ISO planning assessments must:

- **R1.1** Be carried out annually.
- **R1.2** Be conducted for near term (year one through five) and longer term (year six through ten) planning horizons.
- **R1.3** Be supported by a study and/or system simulation testing, conducted within the last five years that addresses each of the requirements in requirement R1.3.1 to R1.3.1, showing system performance for the conditions defined in Category C of Appendix 1.
 - **R1.3.1** Be performed and evaluated only for those Category C **contingencies** that the **ISO** determines would produce the more severe system results or impacts. The rationale for the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe system results must be included in the study.
 - R1.3.2 Cover critical system conditions and study years as determined necessary by the ISO.
 - **R1.3.3** Be conducted annually unless the ISO determines that changes to system conditions do not warrant such analyses.
 - **R1.3.4** Be conducted beyond the five year planning horizon only as needed to address identified marginal conditions that may have longer lead- time solutions.

R1.3.5 Have all projected firm transfers modeled, if any.

Effective: 2016-08-30 Page 1 of 6



- **R1.3.6** Be performed and evaluated for selected **demand** levels over the range of forecast system **demands** as considered necessary by the **ISO**.
- **R1.3.7** Demonstrate that system performance meets the conditions defined in Category C of Appendix 1.
- R1.3.8 Include existing and planned facilities as considered necessary by the ISO.
- **R1.3.9** Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.
- **R1.3.7** Demonstrate that system performance meets the conditions defined in Category C of Appendix 1.
- R1.3.8 Include existing and planned facilities as considered necessary by the ISO.
- **R1.3.9** Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.
- **R1.3.10** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- **R1.3.11** Include the effects of existing and planned control devices.
- R1.3.12 Include the planned outage and maintenance of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. This requirement applies only to BES facilities greater than 200 kV or other facilities as specified by the ISO.
- **R1.4** Address any planned upgrades needed to meet the performance requirements for the conditions defined in Category C of Appendix 1.
- R1.5 Consider all contingencies applicable to Category C of Appendix 1.
- **R2** When system simulations indicate an inability of the systems to respond as set out inR1.3.7 of this reliability standard, the **ISO** must:
- **R2.1** Provide corrective plans to achieve the required system performance as described above throughout the planning horizon:
 - **R2.1.1** Including a schedule for implementation.
 - R2.1.2 Including a discussion of expected required in-service dates of facilities.
 - **R2.1.3** Consider lead times necessary to implement plans.
- **R2.2** Review in subsequent annual assessments where sufficient lead time exists, the continuing need for identified system **facilities**. Detailed implementation plans are not needed.
- R3 The ISO must provide the planning assessment to WECC on an annual basis.

5. Processes and Procedures

No procedures have been defined for this **reliability standard**.

Effective: 2016-08-30 Page 2 of 6



6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 The planning assessment will be valid and meet requirements in R1 through the following measures:

- (a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.
- (b) The planning assessment includes time horizons as specified in R1.2.
- (c) The planning assessment has been prepared within the last year.
- (d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.
- (e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.
- **MR2** The area studies and needs identification documents contain recommendations and projects that correct the situations where an inability of the systems to respond to requirements specified in R1 has been identified. The area studies and needs identification documents are provided on request.

The area studies and needs identification documents contain the technical components as specified in R2 and its subsections.

MR3 A written or email confirmation from WECC that it has received the planning assessment from the ISO. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards - Normal and Emergency Conditions (see below)

8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2010-09-24	Initial release.
2016-08-30	Inclusion of the defined term system element.

Effective: 2016-08-30 Page 3 of 6



Appendix 1 - Transmission System Standards - Normal and Emergency Conditions

	Contingencies	Syste	System Limits or Impacts		
Category	Initiating Event(s) and Contingency System Element(s)	System Stable and Both Thermal and Voltage Limits Within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transmission Service Transfers	Cascading	
A No contingencies	All facilities in service	Yes	No	No	
B Event resulting in	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with normal clearing :	Yes	No ^b	No	
the loss of a single	1. Generator	Yes	No ^b	No	
system element	2. Transmission circuit	Yes	No ^b	No	
	3. Transformer	Yes	No ^b	No	
С	SLG fault, with normal clearing e:				
Event(s) resulting	1. Bus section	Yes	Planned/ Controlled ^c	No	
in the loss of two or more (multiple)	2. Breaker (failure or internal fault)	Yes	Planned/ Controlled ^c	No	
system elements	SLG or 3Ø fault, with normal clearing ^e , manual system adjustments, followed by another SLG or 3Ø fault, with normal clearing ^e				
	3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No	
	Bipolar block, with normal clearing e:				
	4. Bipolar (dc) line fault (non 3Ø), with normal clearing ^e :	Yes	Planned/ Controlled ^c	No	
	Any two circuits of a multiple circuit towerline ^t	Yes	Planned/ Controlled ^c	No	
	SLG fault, with delayed clearing ^e (stuck breaker or protection system failure)				

Effective: 2016-08-30 Page 4 of 6



	6. Generator	Yes	Planned/ Controlled ^c	No
	7. Transformer	Yes	Planned/ Controlled ^c	No
	8. Transmission circuit	Yes	Planned/ Controlled ^c	No
	9. Bus section	Yes	Planned/ Controlled ^c	No
D d	3Ø fault, with delayed clearing ^e (stuck breaker or protection system failure):		Evaluate for risks and consequences	
resulting in two or	1. Generator 2. Trans	smission circuit	May involve substa	
more (multiple) system elements	3. Transformer 4. Bus s	section	customer demand generation in a wid	
removed or cascading out of	3Ø fault, with normal clearing ^e :		area or areas	·
service	5. Breaker (failure or internal fault)		Portions or all of the	
	6. Loss of towerline with three or more circuits		<pre>interconnected systems may or may not achieve a new,</pre>	
	7. All transmission lines on a common right-of -way		stable operating point	oint
	Loss of a substation (one voltage le transformers)	evel plus	Evaluation of these events may require joint studies wit	
	Loss of a switching station (one vol transformers)	tage level plus	neighboring systems	
	10. Loss of all generating units at a sta	tion		
	11. Loss of a large load or major load center			
	12. Failure of a fully redundant special (or remedial action scheme) to op			
	13. Operation, partial operation, or mis redundant special protection systaction scheme) in response to an system	tem (or remedial		
	Impact of severe power swings or odisturbances in another Regional R			

- a) Applicable rating refers to the applicable normal and emergency facility thermal and voltage rating as applied by the facility owner or system voltage limit as determined and consistently applied by the ISO. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established by the applicable entity consistent with applicable ISO rules addressing facility ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted system element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

Effective: 2016-08-30 Page 5 of 6



- c) 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) transmission service electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme **contingencies** that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible **facility outages** under each listed **contingency** of Category D will be evaluated.
- e) **Normal clearing** is when the **protection system** operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed **protection systems**. Delayed clearing of a fault is due to failure of any **protection system** component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.

Effective: 2016-08-30 Page 6 of 6



1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This reliability standard applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the <u>Consolidated</u> <u>Authoritative Document Glossary</u> and Part 1 of the <u>ISO Rules</u>.

4. Requirements

R1 The ISO must demonstrate for transmission facilities rated 100 kV and above, through a planning assessment that a transmission system is planned such that it has been evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Appendix 1.

The ISO planning assessments must:

- **R1.1** Be carried out annually.
- **R1.2** Be conducted for near term (year one through five).
- **R1.3** Be supported by a study and/or system simulation that addresses each of the following categories, showing system performance following Category D **contingencies** of Appendix 1.
 - **R1.3.1** Be performed and evaluated only for those Category D **contingencies that** *ISO* determines would produce the more severe system results or impacts. The rationale for the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe system results must be included in the study.
 - R1.3.2 Cover critical system conditions and study years as considered necessary by the ISO.
 - **R1.3.3** Be conducted annually unless the **ISO** determines that changes to system conditions do not warrant such analyses.
 - R1.3.4 Have all projected firm transfers modeled, if any.
 - R1.3.5 Include existing and planned facilities as considered necessary by the ISO.
 - **R1.3.6** Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.

Effective: 2016-08-30 Page 1 of 6



- **R1.3.7** Include the effects of existing and planned **protection systems**, including any backup or redundant systems.
- R1.3.8 Include the effects of existing and planned control devices.
- R1.3.9 Include the planned **outage** and maintenance of any bulk electric equipment (including **protection systems** or their components) at those **demand** levels for which planned (including maintenance) **outages** are performed. This requirement applies only to **BES facilities** greater than 200 kV or other **facilities** as specified by the **ISO**.
- R1.4 Consider all contingencies applicable to Category D of Appendix 1.
- R2 The ISO must provide the planning assessment to WECC on an annual basis.

5. Processes and Procedures

No procedures have been defined for this reliability standard.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

- **MR1** The planning assessment will be valid and meet requirement in R1 and associated sub-sections through the following measures:
 - (a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.
 - (b) The planning assessment includes time horizons as specified in R1.2.
 - (c) The planning assessment has been prepared within the last year.
 - (d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.
 - (e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.
- MR2 A written or email confirmation from WECC that it has received the planning assessment from the ISO. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards - Normal and Emergency Conditions (see below)

Effective: 2016-08-30 Page 2 of 6



8. Guidelines

No guidelines have been defined for this reliability standard.

Revision History

Date	Description
2010-09-24	Initial release.
2016-08-30	Inclusion of the defined term system element.

Effective: 2016-08-30 Page 3 of 6



Appendix 1 - Transmission System Standards - Normal and Emergency Conditions

	Contingencies	Syst	em Limits or Impacts	
Category	Initiating Event(s) and Contingency System Element(s)	System Stable and Both Thermal and Voltage Limits Within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transmission Service Transfers	Cascading
A No contingencies	All facilities in service	Yes	No	No
B Event resulting in the loss of a single system element	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with normal clearing :	Yes	No ^b	No
	1. Generator	Yes	No ^b	No
	2. Transmission circuit	Yes	No ^b	No
	3. Transformer	Yes	No ^b	No
С	SLG fault, with normal clearing e:			
Event(s) resulting	1. Bus section	Yes	Planned/ Controlled ^c	No
in the loss of two or more (multiple)	2. Breaker (failure or internal fault)	Yes	Planned/ Controlled ^c	No
system elements	SLG or 3Ø fault, with normal clearing ^e , manual system adjustments, followed by another SLG or 3Ø fault, with normal clearing ^e			
	3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar block, with normal clearing e:			
	4. Bipolar (dc) line fault (non 3Ø), with normal clearing ^e :	Yes	Planned/ Controlled ^c	No
	Any two circuits of a multiple circuit towerline ^t	Yes	Planned/ Controlled ^c	No
	SLG fault, with delayed clearing ^e (stuck breaker or protection system failure)			

Effective: 2016-08-30 Page 4 of 6



	6. Generator	Yes	Planned/ Controlled ^c	No	
	7. Transformer	Yes	Planned/ Controlled ^c	No	
	8. Transmission circuit	Yes	Planned/ Controlled ^c	No	
	9. Bus section	Yes	Planned/ Controlled ^c	No	
D ^d Extreme event	3Ø fault, with delayed clearing ^e (stuck breaker or protection system failure):		Evaluate for risks and consequences		
resulting in two or	1. Generator 2. Trans	smission circuit	May involve substantial los		
more (multiple) system elements removed or cascading out of service	3. Transformer 4. Bus s	section	customer demand and generation in a widespread		
	3Ø fault, with normal clearing ^e :		area or areas		
	5. Breaker (failure or internal fault)		Portions or all of the		
	Loss of towerline with three or more circuits interconnected system or may not achieve a				
	7. All transmission lines on a common right-of -way		stable operating point		
	Loss of a substation (one voltage level plus transformers)		Evaluation of these events may require joint studies with neighboring systems		
	Loss of a switching station (one voltage level plus transformers)				
	10. Loss of all generating units at a station				
	11. Loss of a large load or major load center				
	2. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required				
	13. Operation, partial operation, or mis redundant special protection sys action scheme) in response to an system	tem (or remedial			
	14. Impact of severe power swings or of disturbances in another Regional F				

- a) Applicable rating refers to the applicable normal and emergency facility thermal and voltage rating as applied by the facility owner or system voltage limit as determined and consistently applied by the ISO. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established by the applicable entity consistent with applicable ISO rules addressing facility ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted **system element** or by the affected area, may occur in certain areas without impacting the overall **reliability** of the **interconnected** transmission systems. To prepare for the next **contingency**, system

Effective: 2016-08-30 Page 5 of 6

Alberta Reliability Standard System Performance Following Extreme BES Events TPL-004-AB-0



- adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.
- c) 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) transmission service electric power transfers may be necessary to maintain the overall **reliability** of the **interconnected** transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.

Effective: 2016-08-30 Page 6 of 6



Alberta Reliability Standard Voltage and Reactive Control VAR-001-AB-4

1. 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**.

2. Applicability

This reliability standard applies to:

(a) the **ISO**.

3. Requirements

- R1 The ISO must specify a system voltage range with an associated tolerance band, as part of its plan to operate within system operating limits and interconnection reliability operating limits.
 - **R1.1** The **ISO** must provide a copy of the system voltage range with an associated tolerance band to an **interconnected transmission operator** within thirty (30) **days** of a request.
- R2 The ISO must operate with sufficient reactive power resources available within Alberta to protect the voltage levels of the transmission system under normal and contingency conditions.
- R3 The ISO must be able to regulate transmission voltage and **reactive power** flow by issuing **directives** or instructions to operate the devices necessary to do so.
- R4 The ISO must specify the criteria that will exempt a generating unit or an aggregated generating facility from:
 - a) following a voltage or reactive power instruction or directive;
 - having its automatic voltage regulator or voltage regulating system in service or being in voltage control mode; or
 - c) making any associated notifications.
 - **R4.1** If the **ISO** determines that a **generating unit** or an **aggregated generating facility** has satisfied the exemption criteria, the **ISO** must notify the associated **operator** of a **generating unit** or **operator** of an **aggregated generating facility**.
- **R5** The **ISO**, when issuing **directives** or instructions for voltage level or **reactive power**, to the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility**, must specify the following:
 - a) the voltage level at the point of connection between the transmission system and a generating unit or an aggregated generating facility, including those in a power plant or an industrial complex; or
 - b) the reactive power to be achieved by the generating unit, aggregated generating facility,

Effective: 2016-04-01 Page 1 of 4



Alberta Reliability Standard Voltage and Reactive Control VAR-001-AB-4

power plant or industrial complex.

R6 The ISO must, after a review with the legal owner of a generating unit or the legal owner of an aggregated generating facility regarding necessary off-load tap changes for the step-up transformer that connects to the transmission system, provide documentation to the legal owner of a generating unit or the legal owner of an aggregated generating facility specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1. Evidence of specifying a system voltage range with an associated tolerance band as required in requirement R1 exists.

MR1.1 Evidence of providing a copy of the system voltage range with an associated tolerance band as required in requirement R1.1 exists. Evidence may include, but is not limited to, emails, website postings, or any other equivalent evidence.

MR2 Evidence of operating with sufficient **reactive power** resources as required in requirement R2 exists. Evidence may include, but is not limited to, data files or any other equivalent evidence.

MR3 Evidence of being able to regulate transmission voltage and **reactive power** flow as required in requirement R3 exists. Evidence may include, but is not limited to, relevant **ISO** authoritative documents.

MR4 Evidence of specifying the criteria that will exempt a **generating unit** or an **aggregated generating facility** as specified in requirement R4 exists.

MR4.1 Evidence of notifying the associated **operator** of a **generating unit** or **operator** of an **aggregated generating facility** if the **ISO** determines that the exemption criteria were satisfied. Evidence may include, but is not limited to, emails, data files or other equivalent evidence.

MR5 Evidence of issuing **directives** or instructions to the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** as required in requirement R5 exists. Evidence may include, but is not limited to, voice recordings or other equivalent evidence.

MR6 Evidence of providing documentation as required in requirement R6 exists. Evidence may include, but is not limited to, dated study results or email to appropriate recipients that identifies contents submitted or other equivalent evidence.

5. Appendices

Appendix 1 - Exemptions

Effective: 2016-04-01 Page 2 of 4



Alberta Reliability Standard Voltage and Reactive Control VAR-001-AB-4

Revision History

Date	Description
2012-10-01	Initial release
2016-04-01	Revised to align with NERC version 4.

Effective: 2016-04-01 Page 3 of 4



Alberta Reliability Standard Voltage and Reactive Control VAR-001-AB-4

Appendix 1 - Exemptions

1. Exemption Criteria

A **generating unit** or **aggregated generating facility** must, in order to meet the exemption criteria referred to in requirement R4 of this **reliability standard**:

- (a) be a wind aggregated generating facility;
- (b) not be equipped with a **voltage regulating system**; and
- (c) be the subject of an executed *Construction Commitment Agreement* and have completed the **ISO**'s approval process for connection to the **transmission system** under the *Technical Requirements for connecting generators (1999)*.

Effective: 2016-04-01 Page 4 of 4

1. Purpose

To ensure **generating units** and **aggregated generating facilities** provide reactive support and voltage control, within generating facility capabilities, in order to protect equipment and maintain reliable operation of the **Interconnection**.

2. Applicability

This reliability standard applies to:

- (a) the legal owner of a generating unit, including a generating unit that operates as a synchronous condenser, that:
 - (i) is not part of an aggregated generating facility;
 - (ii) has a maximum authorized real power rating greater than 4.5 MW; and
 - (iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat;
- (b) the **operator** of a **generating unit**, including a **generating unit** that operates as a synchronous condenser, that:
 - (i) is not part of an aggregated generating facility;
 - (ii) has a maximum authorized real power rating greater than 4.5 MW; and
 - (iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat;
- (c) the legal owner of an aggregated generating facility that:
 - (i) has a maximum authorized real power rating greater than 4.5 MW; and
 - (ii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and
- (d) the **operator** of an **aggregated generating facility** that:
 - (i) has a maximum authorized real power rating greater than 4.5 MW; and
 - (ii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat.

Notwithstanding subsections (c) and (d) above, this **reliability standard** does not apply to the **legal owner** of an **aggregated generating facility** or the **operator** of an **aggregated generating facility** that meets the criteria listed in Appendix 1 of VAR-001-AB.

Requirements

R1 The operator of a generating unit and the operator of an aggregated generating facility must, while a generating unit or aggregated generating facility is electrically connected to the transmission

Effective: 2016-04-01 Page 1 of 4

system, operate the generating unit or aggregated generating facility with its automatic voltage regulator or voltage regulating system in service and in voltage control mode unless:

- a) exempted by the **ISO**;
- b) the operator of the generating unit or operator of the aggregated generating facility
 provides voice notification to the ISO of its intention to operate the generating unit or
 aggregated generating facility otherwise;
- the generating unit or aggregated generating facility is being operated in start-up or shutdown mode in accordance with the procedure of the operator of a generating unit or operator of an aggregated generating facility; or
- d) the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** has previously obtained approval from the **ISO** allowing the **generating unit** or **aggregated generating facility** to be in a testing mode.
- R2 Unless exempted by the **ISO**, each **operator** of a **generating unit** and each **operator** of an **aggregated generating facility** must, upon receiving an instruction from the **ISO** regarding voltage levels or **reactive power**, comply with that instruction.
 - **R2.1** Each operator of a generating unit and each operator of an aggregated generating facility must, when:
 - a) the automatic voltage regulator of a generating unit or the voltage regulating system of an aggregated generating facility is out of service; or
 - (b) the **generating unit** does not have an **automatic voltage regulator**, or the **aggregated generating facility** does not have a **voltage regulating system**,

use an alternative method to control the generator reactive output to comply with an instruction from the **ISO** regarding voltage levels or **reactive power**.

- **R2.2** Notwithstanding requirement R2, where the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** cannot comply with an instruction to modify voltage, the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** must provide an explanation for why the instruction cannot be met.
- **R2.3** Each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** that does not monitor the voltage or **reactive power** at the location specified in an instruction from the **ISO**, or at the location specified in a **directive** issued by the **ISO** in accordance with section 301.2 of the **ISO rules**, *ISO Directives*, must have a methodology for converting the voltage or **reactive power** at the location specified by the **ISO**.
- R3 Each operator of a generating unit and operator of an aggregated generating facility must notify the ISO within thirty (30) minutes after a status change of the automatic voltage regulator, voltage regulating system or alternative voltage controlling device and power system stabilizer, as applicable, on any generating unit or aggregated generating facility.

Effective: 2016-04-01 Page 2 of 4

- **R3.1** If the status has been restored within thirty (30) minutes of such change, then the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** is not required to notify the **ISO** of the status change.
- **R3.2** If a **generating unit** or an **aggregated generating facility** is in testing, start-up, shut-down or offline mode, requirement R3 does not apply.
- R4 Each operator of a generating unit and operator of an aggregated generating facility must notify the **ISO** within thirty (30) minutes after becoming aware of a change in reactive capability due to factors other than a status change described in requirement R3.
 - **R4.1** If the capability has been restored within thirty (30) minutes of the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** becoming aware of such change, then the **operator** is not required to notify the **ISO** of the change in reactive capability.
 - **R4.2** If a **generating unit** or an **aggregated generating facility** is in testing, start-up, shut-down or offline mode, requirement R4 does not apply.
- R5 Each legal owner of a generating unit and each legal owner of an aggregated generating facility whose step-up transformer for connecting to the transmission system or auxiliary transformer has primary voltages equal to or greater than the generating unit terminal voltage must provide any one (1) or more of the following to the ISO within thirty (30) days of a request:
 - a) tap settings;
 - b) available fixed tap ranges; and
 - c) impedance data.
- R6 Each legal owner of a generating unit and each legal owner of an aggregated generating facility that has a step-up transformer, with off-load taps for connecting to the transmission system must, change the tap positions according to the specifications the ISO provides.
 - **R6.1** Each **legal owner** of a **generating unit** and each **legal owner** of an **aggregated generating facility** that cannot comply with requirement R6 must notify the **ISO** within thirty (30) **days** of the **ISO** providing the specifications, and must include the technical justification along with the notice.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of operating the **generating unit** or **aggregated generating facility** in automatic voltage control mode as required in requirement R1 exists. Evidence may include, but is not limited to, exemption letters, data files, start-up or shut-down procedures, **operator** logs, voice recordings, e-mail, or other equivalent evidence.

Effective: 2016-04-01 Page 3 of 4

MR2 Evidence of complying with an instruction as required in requirement R2 exists. Evidence may include, but is not limited to, data files or **operator** logs.

- **MR 2.1** Evidence of using an alternative method to control generator **reactive power** output as required in requirement R2.1 exists. Evidence may include, but is not limited to, data files, **operator** logs or voice recordings.
- **MR 2.2** Evidence of providing an explanation to the **ISO**, as required in requirement R2.2 exists. Evidence may include, but is not limited to, voice recordings or **operator** logs.
- **MR 2.3** Evidence of having a methodology as required in requirement R2.3 exists. Evidence may include, but is not limited to, a documented methodology or other equivalent evidence.
- **MR3** Evidence of notifying the **ISO** within thirty (30) minutes of any status change as required in requirement R3 exists. Evidence may include, but is not limited to, data logs, SCADA logs, voice recordings or **operator** logs.
- **MR4** Evidence of notifying the **ISO** within thirty (30) minutes of becoming aware of a change in capability as required in requirement R4 exists. If the capability has been restored within the first thirty (30) minutes of the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** becoming aware of such change, no evidence of notification is necessary. Evidence may include, but is not limited to, voice recordings or **operator** logs.
- **MR5** Evidence of providing the **ISO** with information on its step-up transformer or auxiliary transformer, as required in requirement R5 exists. Evidence may include, but is not limited to, dated written or electronic records.
- **MR6** Evidence of changing step-up transformer taps in accordance with the **ISO**'s specifications as required in requirement R6 exists. Evidence may include, but is not limited to, written or electronic records.
 - **MR6.1** Evidence of notifying the **ISO** as required in requirement R6.1 exists. Evidence may include, but is not limited to, written or electronic notifications.

Revision History

Date	Description
2013-10-01	Initial release
2016-04-01	Revised to align with NERC version 3.

Effective: 2016-04-01 Page 4 of 4

Alberta Reliability Standard Automatic Voltage Regulators and Voltage Regulating Systems VAR-002-WECC-AB-1



1. Purpose

The purpose of this reliability standard is to ensure that:

- (a) **automatic voltage regulators** on **generating units** and synchronous condensers are in service and controlling voltage; and
- (b) **voltage regulating systems** at **aggregated generating facilities** are in service and controlling voltage.

2. Applicability

This **reliability standard** applies to:

- (a) the operator of a generating unit, including those that operate as a synchronous condenser, that:
 - (i) is not part of an aggregated generating facility;
 - (ii) has a maximum authorized real power rating greater than four point five (4.5) MW; and
 - (iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat;
- (b) the operator of an aggregated generating facility that:
 - (i) has a maximum authorized real power rating greater than four point five (4.5) MW; and
 - (ii) is directly connected to either the transmission system or to transmission facilities within the City of Medicine Hat; and
- (c) the **operator** of a **transmission facility** that operates a synchronous condenser.

3. Requirements

- R1 Each operator of a generating unit, operator of an aggregated generating facility and operator of a transmission facility that operates a synchronous condenser, must have the automatic voltage regulator or voltage regulating system in service and in automatic voltage control mode for ninety-eight percent (98%) of all operating hours except that the operating hours determined in accordance with requirements R1.1 through R1.12 inclusive may be extended to achieve the ninety-eight percent (98%) requirement.
 - **R1.1** The operating hours during which the **generating unit**, **aggregated generating facility** or synchronous condenser operates for less than five percent (5%) of all hours during any calendar quarter;
 - **R1.2** The operating hours during which maintenance or testing on any of the foregoing was performed, up to a maximum of seven (7) calendar **days** per calendar quarter;
 - **R1.3** The operating hours during which the **automatic voltage regulator** or **voltage regulating system** exhibits instability due to an abnormal system configuration;

Effective: 2013-10-01 Page 1 of 3

Alberta Reliability Standard Automatic Voltage Regulators and Voltage Regulating Systems VAR-002-WECC-AB-1



- **R1.4** The operating hours, up to a maximum of sixty (60) consecutive **days** per incident, during which the **automatic voltage regulator** or **voltage regulating system** is out of service for repair due to component failure;
- R1.5 The operating hours, up to a maximum of twelve (12) consecutive months, during which the automatic voltage regulator or voltage regulating system had a component failure, provided the operator of a generating unit, operator of an aggregated generating facility or operator of a transmission facility submitted documentation to the ISO identifying the need for time to obtain replacement parts and, if required, to schedule an outage;
- R1.6 The operating hours, up to a maximum of twenty-four (24) consecutive months during which the automatic voltage regulator or voltage regulating system had a component failure, provided the operator of a generating unit, operator of an aggregated generating facility or operator of a transmission facility submitted documentation to the ISO identifying the need for time for replacement of the excitation system including replacing the automatic voltage regulator or voltage regulating system, limiters, and controls but not necessarily the power source and power bridge, and to schedule an outage;
- **R1.7** The operating hours during which the synchronous **generating unit**, **aggregated generating facility** or synchronous condenser is not in **commercial operation**;
- **R1.8** The operating hours for which the **ISO** has issued a **directive** to the **operator** of a **generating unit** to operate the **generating unit** when the **automatic voltage regulator** is unavailable for service;
- R1.9 The operating hours for which the ISO has issued a directive to the operator of an aggregated generating facility to operate the aggregated generating facility when the voltage regulating system is unavailable for service;
- **R1.10** The operating hours for which the **ISO** has issued a **directive** to an **operator** of a **transmission facility** to operate a synchronous condenser when the **automatic voltage regulator** is unavailable for service:
- **R1.11** The operating hours during which an **automatic voltage regulator** exhibits instability due to operation of an on-load tap changer transformer in the area when the **ISO** has authorized the **operator** of a **generating unit** or **operator** of a **transmission facility** to operate the excitation system in modes other than automatic voltage control until the **transmission system** configuration changes; and
- **R1.12** The operating hours during which a **voltage regulating system** exhibits instability due to operation of an on-load tap changer transformer in the area when the **ISO** has authorized the **operator** of an **aggregated generating facility** to operate the **voltage regulating system** in modes other than automatic voltage control until the **transmission system** configuration changes.
- **R2** Each operator of a generating unit, operator of an aggregated generating facility and operator of a transmission facility must have documentation supporting the identification of the number of operating hours excluded for each requirement in requirements R1.1 through R1.12 inclusive.

Effective: 2013-10-01 Page 2 of 3

Alberta Reliability Standard Automatic Voltage Regulators and Voltage Regulating Systems VAR-002-WECC-AB-1



4. Measures

MR1 Evidence of having the **automatic voltage regulator** or **voltage regulating system** in service and in automatic voltage control mode as required in requirement R1 exists. Evidence may include documentation that summarizes for each calendar quarter:

- (a) the number of hours the automatic voltage regulator or voltage regulating system was in service and in automatic voltage control mode while the generating unit, the aggregated generating facility or synchronous condenser was operating;
- (b) the number of hours the automatic voltage regulator or voltage regulating system was out of service while the generating unit, the aggregated generating facility or synchronous condenser was operating;
- (c) the number of operating hours excluded in accordance with requirements R1.1 through R1.12; and
- (d) the percentage of operating hours that the **automatic voltage regulator** or **voltage regulating system** was in service, excluding the number of operating hours determined in accordance with requirements R1.1 through R1.12.

MR2 Evidence of having documentation as required in requirement R2 exists. Evidence may include a document identifying the subject of each applicable exclusion, the date and the period of time that the exclusion refers to, reasons, the supporting data and the supporting logs.

Revision History

Effective	Description
2013-10-01	

Effective: 2013-10-01 Page 3 of 3



1. Purpose

The purpose of this **reliability standard** is to ensure that **power system stabilizers** on **generating units** are kept in service.

2. Applicability

This reliability standard applies to:

- (a) the operator of a generating unit equipped with a power system stabilizer that is either:
 - (i) directly connected to the **bulk electric system** or part of an industrial complex that is directly connected to the **bulk electric system**, and has a **maximum authorized real power** rating greater than eighteen (18) MW; or
 - (ii) within a power plant which:
 - (A) is not part of an aggregated generating facility;
 - (B) is directly connected to the bulk electric system; and
 - (C) has a combined **maximum authorized real power rating** greater than sixty-seven point five (67.5) MW;
 - (iii) a black start resource; or
 - (iv) regardless of maximum authorized real power rating, material to this reliability standard and to the reliability of the bulk electric system as the ISO determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1.

3. Requirements

- R1 Each operator of a generating unit equipped with a power system stabilizer must have the power system stabilizer in service ninety-eight (98%) of all operating hours except that the operating hours determined in accordance with requirements R 1.1 through 1.12 inclusive may be excluded to achieve the ninety-eight percent (98%) requirement.
 - **R1.1** The operating hours during which the **generating unit** operates for less than five percent (5%) of all hours during any calendar quarter.
 - **R1.2** The operating hours during which maintenance or testing on the **power system stabilizer** was performed, up to a maximum of seven (7) **days** per calendar quarter.
 - **R1.3** The operating hours during which the **power system stabilizer** exhibits instability due to abnormal system configuration.
 - **R1.4** The operating hours during which the **generating unit** is operating in the synchronous condenser mode and the **generating unit** is very near or at a zero (0) **real power** level.
 - **R1.5** The operating hours during which the **generating unit** is generating less **real power** than its design limit for effective **power system stabilizer** operation.
 - **R1.6** The operating hours during which the **generating unit** is passing through a range of output that is a known "rough zone" being a range in which a **generating unit** is experiencing excessive

Effective: 2013-10-01 Page 1 of 4



vibration.

- **R1.7** The operating hours during which the **automatic voltage regulator** of the **generating unit** is not in service.
- **R1.8** The operating hours, up to a maximum of sixty (60) consecutive **days** per incident, during which the **power system stabilizer** is out of service for repair due to a component failure.
- **R1.9** The operating hours, up to a maximum of twelve (12) consecutive **months**, during which the **power system stabilizer** had a component failure, but only if the **operator** of a **generating unit** submitted documentation to the **ISO** identifying the need for time to obtain replacement parts and identifying a scheduled **outage**, if required.
- **R1.10** The operating hours, up to a maximum of twenty-four (24) consecutive **months**, during which the **power system stabilizer** had a component failure, but only if the **operator** of a **generating unit** submitted documentation to the **ISO** identifying the need for time to replace the **power system stabilizer** and to schedule an **outage**.
- **R1.11** The operating hours during which the **generating unit** is not in **commercial operation**.
- **R1.12** The operating hours for which the **ISO** has issued a **directive** to the **operator** of a **generating unit** to operate the **generating unit** when the **power system stabilizer** is unavailable for service
- R2 Each operator of a generating unit must have documentation supporting the identification of the number of operating hours excluded for each requirement in requirements R1.1 through R1.12 inclusive.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of having the **power system stabilizer** in service as required in requirement R1 exists. Evidence may include documentation that summarizes for each calendar quarter:

- the number of hours the power system stabilizer was in service while the generating unit was operating;
- (b) the number of hours the **power system stabilizer** was out of service while the **generating unit** was operating;
- (c) the number of operating hours excluded in accordance with requirements R1.1 through R1.12;and
- (d) the percentage of operating hours that the **power system stabilizer** was in service excluding the number of operating hours determined in accordance with requirements R1.1 through R1.12

MR2 Evidence of having documentation as required in requirement R2 exists. Evidence may include a document identifying the subject of each exclusion, the date and the period of time that the exclusion refers to, reasons, the supporting data and the supporting logs.

Effective: 2013-10-01 Page 2 of 4



5. Appendices

Appendix 1 – Amending Process for List of Generating Units

Revision History

Effective	Description
2013-10-01	

Effective: 2013-10-01 Page 3 of 4



Appendix 1

Amending Process for List of Generating Units

In order to amend the list referenced in subsection (a)(iv) of section 2, Applicability, the ISO must:

- (a) upon determining that a **generating unit** is to be added, notify each affected **operator** of a **generating unit** in writing and determine an effective date, which must be no less than thirty (30) **days** after the date of notice, for the **operator** to meet the applicable requirements;
- (b) upon determining that a **generating unit** is to be deleted, notify each affected **operator** of a **generating unit** in writing and determine an effective date for the **operator** to no longer be required to meet the applicable requirements; and
- (c) post the amended list with effective dates on the AESO website.

Effective: 2013-10-01 Page 4 of 4