Alberta Reliability Standard
Automatic Generation Control
BAL-005-AB-0.2b

1. Purpose

The purpose of this **reliability standard** is to establish the necessary related requirements for the **ISO**`s **automatic generation control**.

2. Applicability

This **reliability standard** applies to:

(a) the **legal owner** of a **transmission facility** that provides frequency data the **ISO** uses for **automatic generation control** which such frequency data is collected from the source the **ISO** identifies and 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 provides frequency data the **ISO** uses for **automatic generation control** which such frequency data is collected from the source the **ISO** identifies 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 **ISO**.

3. Requirements

R1 The **ISO** must maintain **regulating reserve** to meet the **control performance standard**.

R2 The **ISO** must, when providing regulation service, have adequate metering, communications, and control equipment employed to prevent such regulation service from becoming a burden on the **interconnection** or other **balancing authority areas**.

R3 The **ISO** must, when providing regulation service, notify the host **balancing authority** for which it is controlling if it is unable to provide the regulation service and must also notify any intermediate **balancing authorities**.

R4 The **ISO** must, when receiving regulation service, have backup plans in place to provide replacement regulation service should the supplying **balancing authority** no longer be able to provide this service.

R5 The **ISO** must use **area control error** calculations in its **automatic generation control** that compare total **net actual interchange** to total **net scheduled interchange** plus frequency bias obligation except that the **automatic generation control** of the **ISO** may use alternative **area control error** calculations when the **ISO** is operating the **interconnected electric system** asynchronously.

R6 The **ISO** must notify the **WECC** Reliability Coordinator if the **ISO** is unable to calculate the **area control error** for more than thirty (30) minutes consecutively.

R7 Subject to requirement R8, the **ISO** must operate its **automatic generation control** continuously.

R8 The **ISO** must, if **automatic generation control** has become inoperative or operation of **automatic generation control** could adversely impact the reliability of the **interconnection**, use manual controls to adjust generation to maintain the **net scheduled interchange**.

R9 The **ISO** must acquire data for, and calculate, the **area control error** at least every nine (9) seconds.

R9.1 The **ISO** must use frequency data from redundant and independent frequency **metering equipment** that automatically activates upon detection of failure of the primary source; and

R9.2 The **ISO** must provide frequency metering data to its **automatic generation control** with a minimum availability of 99.95%.

R10 Subject to requirement R10.1 the **ISO** must include all **interchange schedules** with **adjacent balancing authorities** in the **ISO**'s calculation of **net scheduled interchange** for the **area control error** calculation.

R10.1 The **ISO** may omit the **interchange schedule** for a high voltage direct current link to another **balancing authority** from the **area control error** calculation if such **interchange schedule** is modeled by the **ISO** as internal generation or load.

R11 The **ISO** must include all dynamic schedules in the calculation of **net scheduled interchange** for the **area control error** calculation.

R12 The **ISO** must include the effect of **ramp rates**, which must be identical and agreed to between affected **balancing authorities**, in the scheduled **interchange** values to calculate the **area control error**.

R13 The **ISO** must include all synchronous **interconnection** flows of **real power** in the **area control error** calculation.

R13.1 The **ISO** must use MW metering data for each synchronous **interconnection** that:

(a) emanates from a common, agreed-upon source using common primary **metering equipment**; and

(b) is telemetered to its system coordination centre and the control centre of the **adjacent balancing authority**;

R13.2 The **legal owner** of a **transmission facility** must not filter:

(a) MW metering data for synchronous **interconnections**; or

(b) **area control error** signals transmitted to the **ISO**, except for the anti-aliasing filters of **interconnections**;

R13.3 The **ISO** must use unfiltered:

(a) MW metering data for synchronous **interconnections**; or

(b) **area control error** signals;

provided by the **legal owner** of a **transmission facility** for calculating the **ISO**'s performance under the **control performance standard**, except for the **anti-aliasing filters** of **interconnections**; and

R13.4 The **ISO** must ensure that common **metering equipment** is installed where dynamic schedules or pseudo-ties are implemented between two (2) or more **balancing authorities** to deliver the output of jointly owned **generating units** or to serve remote load.

R14 The **ISO** must perform hourly error checks using **intertie** MWh meters with common time synchronization to determine the accuracy of its control equipment.

R15 The **ISO** must adjust the component of the **area control error** that is in error, if known, or use the

interchange meter error (I_{ME}) term of the **area control error** equation, to compensate for any **metering equipment** error until repairs can be made.

R16 The **ISO** must provide its operating personnel with real-time values for the **area control error**, **interconnection** frequency and **net actual interchange** with each **adjacent balancing authority**.

R17 The **ISO** must provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate the monitoring of the **control performance standard**, generation response and after-the-fact analysis of area performance.

R18 The **ISO** must have adequate and reliable backup power supplies at the **ISO**'s system coordination centre and at the **ISO**'s backup system coordination centre, which must be periodically tested, to maintain continuous operation of the **automatic generation control** and vital data recording equipment during loss of the normal power supply.

R19 The **ISO** must:

(a) sample **area control error**-related data at least at the same periodicity with which the **area control error** is calculated;

(b) flag missing or bad **area control error**-related data for **operator** display and archival purposes; and

(c) collect coincident **area control error**-related data to the greatest extent practical.

R20 Each **legal owner** of a **transmission facility, legal owner** of a **generating unit,** and the **ISO** must:

(a) at least once every calendar year, check and calibrate its time error and frequency devices used for **automatic generation control** against a common reference; but if these devices cannot be calibrated,

(b) cross-check its time error and frequency devices used for automatic generation control against other properly calibrated equipment at least once every calendar year;

and replace them if they do not meet the required level of accuracy as specified in requirements R21.

R21 Each **legal owner** of a **transmission facility, legal owner** of a **generating unit,** and the **ISO** must adhere to the following accuracy values for measuring devices used for **automatic generation control** data as identified in requirement R20:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz

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 maintaining **regulating reserve** as required in requirement R1 exists. Evidence may include data files showing the **control performance standard** was met.

MR2 Evidence of having adequate metering, communications, and control equipment employed as required in requirement R2 exists. Evidence may include regulation reserve service agreements or other documentation confirming that metering, communications and control equipment employed are adequate

to prevent such service from becoming a burden.

MR3 Evidence of notifying the host **balancing authority** and any **intermediate balancing authorities** as required in requirement R3 exists. Evidence may include voice recordings or **operator** logs.

MR4 Evidence of having backup plans in place as required in requirement R4 exists. Evidence may include a dated and in effect backup plans.

MR5 Evidence of using **area control error** calculations in the **automatic generation control** of the **ISO** as required in requirement R5 exist. Evidence may include the algorithm or codes of the calculation of the **area control error**.

MR6 Evidence of notifying the **WECC** Reliability Coordinator as required in requirement R6 exists. Evidence may include **operator** logs or voice recordings.

MR7 Evidence of operating **automatic generation control** continuously as required in requirement R7 exists. Evidence may include:

(a) data files showing the **automatic generation control** was operated continuously;

(b) where the **automatic generation control** was not operated continuously documentation of the rationale of not operating **automatic generation control** continuously; and

(c) **operator** logs and voice recordings.

MR8 Evidence of using manual controls to adjust generation as required in requirement R8 exists. Evidence may include **operator** logs or voice recordings.

MR9 Evidence of acquiring data for, and calculating **area control error** as required in requirement R9 exists. Evidence may include documentation of data acquisition and calculation rate.

MR9.1 Evidence of using frequency data as required in requirement R9.1 exists. Evidence may include a list of independent and redundant frequency **metering equipment**.

MR9.2 Evidence of providing frequency metering data as required in requirement R9.2 exists. Evidence may include records of frequency metering data availability to its **automatic generation control**.

MR10 Evidence of including all **interchange schedules** with **adjacent balancing authorities** in the **ISO**'s calculation as required in requirement R10 exists. Evidence may include the algorithm or codes of the calculation of the **area control error**.

MR10.1 Evidence of omitting the **interchange schedule** for a high voltage direct current link as allowed in requirement R10.1 exists. Evidence may include modeling data documentation showing that the omitted **interchange schedule** for a high voltage direct current link was modeled as internal generation or load.

MR11 Evidence of including dynamic schedules in the calculation of **net scheduled interchange** as required in requirement R11 exists. Evidence may include modeling data documentation showing dynamic schedules, if they exist, are included in the **area control error** equation.

MR12 Evidence of including the effect of **ramp rates** in the scheduled **interchange** values as required in requirement R12 exists. Evidence may include:

(a) documentation showing the effect of **ramp rates** was included in the calculation of the **area**

control error; and

(b) documentation showing the **ramp rates** were identical and agreed to between affected **balancing authorities**.

MR13 Evidence of including all synchronous **interconnection** flows of **real power** in the calculation as required in requirement R13 exists. Evidence may include the algorithm or codes of the calculation of the **area control error**.

MR13.1 Evidence of using MW metering values for synchronous **interconnections** as required in requirement R13.1 exists. Evidence may include measurement definition records and documentation showing the agreement on the source and **metering equipment** with the **adjacent balancing authority**.

MR13.2 Evidence of not filtering metering data or **area control error** signals as required in requirement R13.2 exists. Evidence may include data files showing that the MW metering data for synchronous **interconnections** or **area control error** signals transmitted to the **ISO** are not filtered prior to transmission.

MR13.3 Evidence of using unfiltered metering data or **area control error** signals as required in requirement R13.3 exists. Evidence may include data files showing that the unfiltered data received by the **ISO** is the same data used in the **area control error** calculation.

MR13.4 Evidence of ensuring that common **metering equipment** is installed as required in requirement R13.4 exists. Evidence may include documentation showing the agreement on the common **metering equipment** with the other **balancing authority**.

MR14 Evidence of performing MWh hourly error checks as required in requirement R14 exists. Evidence may include records of hourly error checks and records of adjustments made for each discrepancy, if any, identified in the hourly error checks.

MR15 Evidence of adjusting the component of the **area control error** that is in error as required in requirement R15 exists. Evidence may include files or data showing the error was included in the **area control error**.

MR16 Evidence of providing real-time values for **area control error**, **interconnection** frequency and **net actual interchange**, as required in requirement R16 exists. Evidence may include screen shots of the interface displaying the real-time data.

MR17 Evidence of providing sufficient instrumentation and data recording equipment as required in requirement R17 exists. Evidence may include a list of instrumentation, data and recording equipment and screen shots of the interface displaying the **control performance standard** generation response and after-the-fact analysis of area performance.

MR18 Evidence of having adequate and reliable backup power supplies and of periodically testing these supplies as required in requirement R18 exists. Evidence may include a list of backup power supplies, a periodic testing plan for these backup power supplies and records of the tests.

MR19 Evidence of sampling, flagging and collecting **area control error**-related data as required in requirement R19 exists. Evidence may include:

(a) algorithms of the sampling **area control error**-related data;

(b) screenshots of the **operator** display;

(c) archived files for missing or bad **area control error** related data; and

(d) archived files for coincident **area control error** data.

MR20 Evidence of checking, calibrating and replacing time error and frequency devices as required in requirement R20 exists. Evidence may include:

(a) a list of time error and frequency devices used for **automatic generation control**;

(b) records of checking and calibrating against a common reference;

(c) where the manufacturer's specification does not require calibration of these devices, records of cross-checking against a properly calibrated equipment.

MR21 Evidence of adhering to the minimum values for measuring devices as identified in requirement R21 exists. Evidence may include:

(a) records of calibration against a common reference showing the accuracy values of these devices; and

(b) where these devices cannot be calibrated, records of cross-checking against a properly calibrated equipment showing the accuracy values of these devices.

5. Appendices

Appendix 1 – *Amending Process for List of Frequency Data*

Revision History

Effective	Description
2014-04-01	Initial release

Appendix 1

Amending Process for List of Frequency Data

In order to amend the lists referenced in subsections (a) and (b) of section 2, *Applicability*, the **ISO** must:

(a) upon determining that a source of frequency data is to be added to the list, notify each affected **legal owner** of a **generating unit** or **legal owner** of a **transmission facility** in writing and determine an effective date, which must be no less than thirty (30) **days** after the date of notice, for the **legal owner** to meet the applicable requirements;

(b) upon determining that a source of frequency data is to be deleted, notify each affected **legal owner** of a **generating unit** or **legal owner** of a **transmission facility** in writing and determine an effective date for the **legal owner** to no longer be required to meet the applicable requirements; and

(c) post the amended list with effective dates on the AESO website.