Alberta Reliability Standard
Automatic Generation Control
BAL-005-AB3-0.2b

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 or **intertie** metering data the **ISO** uses for **automatic generation control**, which such frequency or **intertie** metering 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 Intentionally left blank.

R2 Intentionally left blank.

R3 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**.

R4 The **ISO** must, when providing regulation service, notify the host **balancing authority** for which it is providing regulating service if it is unable to provide the regulation service and must also notify any intermediate **balancing authorities**.

R5 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.

R6 The **ISO** must include the calculation of **area control error**, which compares total **net actual interchange** to total **net scheduled interchange** plus **frequency bias** obligation, in the design of its **automatic generation control**, except that the **ISO** may include an alternative calculation of **area control error** in the design of its **automatic generation control** for periods in which the **ISO** operates the **interconnected electric system** asynchronously.

R7 Subject to requirement R7.1, the **ISO** must operate its **automatic generation control** continuously.

R7.1 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**.

R8 The **ISO** must use a design scan rate of no more than nine (9) seconds in acquiring data necessary to calculate **area control error**.

R8.1 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

R8.2 The **ISO** must provide frequency metering data to its **automatic generation control** with a minimum availability of 99.95%.

R9 Subject to requirement R9.1, 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.

R9.1 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.

R10 The **ISO** must include all dynamic schedules in the calculation of **net scheduled interchange** for the **area control error** calculation.

R11 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**.

R12 The **ISO** must include all **interconnection** flows of **real power** in the **area control error** calculation, except those flows that are excluded by the application of requirement R9.1.

R12.1 The **ISO** must use MW metering data for each **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**;

R12.2 The **legal owner** of a **transmission facility** must not filter:

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

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

R12.3 The **ISO** must use unfiltered:

(a) MW metering data for **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

R12.4 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.

R13 The **ISO** must perform hourly error checks using **intertie** MWh meters with common time synchronization to determine the accuracy of its control equipment.

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.

R14 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**.

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.

R15 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.

R16 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.

R17 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit**, and the **ISO** must:

(a) check and calibrate its digital frequency transducer used for **automatic generation control** against a common reference, at least once every calendar year;

but if these transducers cannot be calibrated,

(b) cross-check its digital frequency transducer used for **automatic generation control** against at least two (2) other frequency transducers or pieces of equipment, calibrated by the manufacturer, at least once every calendar year; and

(c) replace any digital frequency transducer that is not accurate to within 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 requirement R1.

MR1 Intentionally left blank.

MR2 Intentionally left blank.

MR3 Evidence of having adequate metering, communications, and control equipment employed as required in requirement R3 exists. Evidence may include, but is not limited to, regulation service agreements or other documentation confirming that metering, communications and control equipment employed are adequate to prevent such service from becoming a burden.

MR4 Evidence of notifying the host **balancing authority** and any intermediate **balancing authorities** as required in requirement R4 exists. Evidence may include, but is not limited to, voice recordings or **operator** logs.

MR5 Evidence of having backup plans in place as required in requirement R5 exists. Evidence may include, but is not limited to, a dated and in effect backup plan(s).

MR6 Evidence of including **area control error** calculations in the design of the **automatic generation control** of the **ISO** as required in requirement R6 exists. Evidence may include, but is not limited to, the algorithm or code for **automatic generation control** that show the calculation of the **area control error** is included in the design of the **automatic generation control** of the **ISO** or other equivalent evidence.

MR7 Evidence of operating **automatic generation control** continuously as required in requirement R7 exists. Evidence may include, but is not limited to:

(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.

MR7.1 Evidence of using manual controls to adjust generation as required in requirement R7.1 exists. Evidence may include, but is not limited to, operator logs or voice recordings.

MR8 Evidence of using a design scan rate of no more than nine (9) seconds in acquiring data necessary to calculate **area control error** as required in requirement R8 exists. Evidence may include, but is not limited to, documentation of data acquisition rate or other equivalent evidence.

MR8.1 Evidence of using frequency data as required in requirement R8.1 exists. Evidence may include, but is not limited to, a list of independent and redundant frequency metering equipment.

MR8.2 Evidence of providing frequency metering data as required in requirement R8.2 exists. Evidence may include, but is not limited to, records of frequency metering data availability to its **automatic generation control**.

MR9 Evidence of including all **interchange schedules** with **adjacent balancing authorities** in the **ISO**'s calculation as required in requirement R9 exists. Evidence may include, but is not limited to, the algorithm or codes of the calculation of the **area control error**.

MR9.1 Evidence of omitting the **interchange schedule** for a high voltage direct current link as allowed in requirement R9.1 exists. Evidence may include, but is not limited to, modeling data documentation showing that the omitted **interchange schedule** for a high voltage direct current link was modeled as internal generation or load.

MR10 Evidence of including dynamic schedules in the calculation of **net scheduled interchange** as required in requirement R10 exists. Evidence may include, but is not limited to, modeling data documentation showing dynamic schedules, if they exist, are included in the **area control error** equation.

MR11 Evidence of including the effect of ramp rates in the scheduled **interchange** values as required in requirement R11 exists. Evidence may include, but is not limited to:

(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**.

MR12 Evidence of including all **interconnection** flows of **real power** in the calculation as required in requirement R12 exists. Evidence may include, but is not limited to, the algorithm or codes of the calculation of the **area control error**.

MR12.1 Evidence of using MW metering data for **interconnections** as required in requirement R12.1 exists. Evidence may include, but is not limited to, measurement definition records and documentation showing the agreement on the source and metering equipment with the **adjacent balancing authority**.

MR12.2 Evidence of not filtering metering data or **area control error** signals as required in requirement R12.2 exists. Evidence may include, but is not limited to, data files showing that the MW metering data for **interconnections** or **area control error** signals transmitted to the **ISO** are not filtered prior to transmission.

MR12.3 Evidence of using unfiltered metering data or **area control error** signals as required in requirement R12.3 exists. Evidence may include, but is not limited to, data files showing that the unfiltered data received by the **ISO** is the same data used in the **area control error** calculation.

MR12.4 Evidence of ensuring that common metering equipment is installed as required in requirement R12.4 exists. Evidence may include, but is not limited to, documentation showing the agreement on the common metering equipment with the other **balancing authority**.

MR13 Evidence of performing MWh hourly error checks as required in requirement R13 exists. Evidence may include, but is not limited to, records of hourly error checks and records of adjustments made for each discrepancy, if any, identified in the hourly error checks.

Evidence of adjusting the component of the **area control error** that is in error as required in requirement R13 exists. Evidence may include, but is not limited to, files or data showing the error was included in the **area control error**.

MR14 Evidence of providing real-time values for **area control error**, **interconnection** frequency and **net actual interchange**, as required in requirement R14 exists. Evidence may include, but is not limited to, screen shots of the interface displaying the real-time data.

Evidence of providing sufficient instrumentation and data recording equipment as required in requirement R14 exists. Evidence may include, but is not limited to, 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.

MR15 Evidence of having adequate and reliable backup power supplies and of periodically testing these supplies as required in requirement R15 exists. Evidence may include, but is not limited to, a list of backup power supplies, a periodic testing plan for these backup power supplies and records of the tests.

MR16 Evidence of sampling, flagging and collecting **area control error**-related data as required in requirement R16 exists. Evidence may include, but is not limited to:

(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.

MR17 Evidence of checking, calibrating and replacing digital frequency transducers as required in requirement R17 exists. Evidence may include, but is not limited to:

(a) a list of digital frequency transducers used for **automatic generation control**;

(b) records, including the dates and measured accuracy values, of checking and calibrating against a common reference;

(c) where the manufacturer's specification does not require calibration of these digital frequency transducers or these digital transducers cannot be calibrated, evidence to substantiate this

and records showing the dates of cross-checking against other frequency transducers or pieces of equipment and the accuracy values of these devices.

5. Appendices

Appendix 1 – *Amending Process for List of Frequency Data and Intertie Metering Data*

Revision History

Date	Description
2017-06-12	Intial release

Appendix 1

Amending Process for List of Frequency Data and Intertie Metering 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 or **intertie** metering 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 or **intertie** metering 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.