Information Documents

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Information Document
Acceptable Operational Reasons
ID #2009-003R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 203.1 of the ISO rules, *Offers and Bids for Energy* ("Section 203.1");
- Section 203.3 of the ISO rules, *Energy Restatements* ("Section 203.3");
- Section 203.4 of the ISO rules, *Delivery Requirements for Energy* ("Section 203.4"); and
- Section 203.6 of the ISO rules, *Available Transfer Capability and Transfer Path Management*.

The purpose of this Information Document is to provide information with respect to the AESO's interpretation of the acceptable operational reason ("AOR") definition, and the practical application of the AOR definition as it relates to the ISO rules.

2 Clarification of Acceptable Operational Reason

The AOR definition outlines six scenarios that are considered "acceptable operational reasons". The five situations examined below, are intended to assist pool participants in determining when an AOR exists.

Market participants are encouraged to refer to the full text of the AOR definition found in the AESO's *Consolidated Authoritative Document Glossary*.

a) Restatements for Operating Reserves Dispatches

Subsection (ii) of the AOR definition states:

> "(ii) re-positioning a generating **source asset** within the energy market due to the need to meet a **dispatch** given to that **source asset** from the **ISO** to serve the stand-by **operating reserves** market;"

The purpose of this subsection is to allow generating units to comply with dispatches to provide operating reserves that were offered in the stand-by operating reserve market without becoming non-compliant in the energy market. While the AESO acquires stand-by operating reserves no later than noon the day before they are required, the actual issuance of dispatches for stand-by operating reserves is not predictable.

The AESO issues dispatches for standby operating reserves when active operating reserve amounts are inadequate, which is often caused by an unexpected generating unit trip. The unpredictable nature of the issuance of dispatches for stand-by operating reserves may find the generating unit at an output level where it is unable to provide the product. Subsection (ii) of the AOR definition contemplates this situation and, therefore, allows the legal owner of the generating unit to restate the generating unit's energy so that the legal owner can reposition the generating unit to provide stand-by operating reserves.

b) Restatements for Asset Constraints

Subsection (iii) of the AOR definition states:

> "(iii) re-positioning a generating **source asset** within the energy market to manage physical or operational constraints associated with the **source asset**;"

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

The purpose of this subsection is to allow the pool participant to restate the source asset's energy when there is a physical or operational constraint with the source asset. It is expected that these constraints are unanticipated or could not have been avoided by the exercise of reasonable diligence. For example, if a source asset's fuel is constrained or unavailable, and reasonable diligence is exercised, the definition of AOR is met and the source asset's available capability is restated in the energy market. However, if a source asset has available yet limited fuel supply, the AESO expects that the pool participant will not reflect rationing of the fuel supply by the pool participant or legal owner of the source asset in the available capability.

Subsection (iii) is not intended to allow the legal owner of a generating unit to re-position offers to allow the generating unit to provide ancillary services from the active market. It is expected that since active ancillary services are acquired the day before they are required and the provider is aware of the time of day their product will be required, that the legal owner's energy offers can be submitted at least two (2) hours in advance of the delivery hour to allow the generating unit to properly position to respond to the ancillary service dispatch.

Unlike subsection (ii), which accommodates stand-by operating reserves, neither subsection (iii) nor any other part of the AOR definition recognizes a source asset being dispatched for active ancillary services as an AOR. This approach is aligned with providing a more stable merit order within two (2) hours of the delivery hour and within the delivery hour.

c) Asset Minimum On/Off Time

Certain generating units require minimum on and off cycle times to prevent excessive and premature wear of their equipment. In order to remain compliant with Section 203.1, the pool participant is advised to use subsection (iii) of the AOR definition to address this dynamic. An example of this situation is a generating unit that has to be on for a minimum of thirty (30) minutes and, when shut down, must be off for a minimum of thirty (30) minutes.

The following protocol can be used to manage this situation:

> Whenever the generating unit is dispatched on, sufficient MW should be moved from a non-zero (0) price block down to the zero (0) dollar price block through a MW restatement to ensure the generating unit remains dispatched on for the minimum thirty (30) minutes. After the thirty (30) minutes have expired the offer should be restated back to its original structure using a second MW restatement. Similarly, whenever the generating unit is dispatched off, the AC should be restated to zero (0) MW for the required thirty (30) minute off time. After the thirty (30) minutes have expired, the AC would be restated back to the AC of the generating unit.

d) Generating units capable of dual or secondary fuel operation

Certain legal owners have the ability to operate their generating units using multiple fuel types on either a temporary or long term basis. These legal owners may:

(i) regularly switch between different fuel types based on the relative cost or availability of the fuel source, or predominantly use one fuel type but rely on another to backstop fuel requirements as needed; or

(ii) utilize a secondary fuel source only to manage short term operational requirements.

Of particular concern is the question of the extent to which switching from a primary to a secondary fuel source is to be reflected in the offers made to the power pool and the related use of an AOR, if applicable.

It is anticipated that generally two (2) types of dual or secondary fuel scenarios exist:

<u>Type 1 - The generating unit can only operate on a limited basis in back-up fuel mode:</u>

> On a case by case basis, the AESO does not generally consider the consistent utilization of back-up fuel for purposes such as start-up and flame stabilization, where such situations reflect short-term operational requirements, to be a dual or secondary fuel generating unit. Therefore an acceptable operational reason is not applicable to those situations.

Type 2 - The generating unit can reliably operate utilizing more than one fuel type

The AESO considers a generating unit to be a dual or secondary fuel unit if it has *historically exhibited* the operational and commercial ability to utilize more than one (1) fuel type to operate for either a prolonged period or to backstop primary fuel requirements. The AESO expects that the legal owner will reflect such capability in the AC of the generating unit. In such a situation, the use of an AOR as a result of fuel switching would not be appropriate. Even though a generating unit may be able to effectively operate using a secondary fuel source for a prolonged period of time, such use is not indefinite. The AESO expects that the specific operational characteristics of the generating unit will drive how long the AC will reflect the two (2) fuel types. In the case of a generating unit fitting the description in (ii) above, the AESO's view is that secondary fuel capability is properly reflected in the declaration of AC and all such changes to AC need to consider the extent of possible operation of the generating unit with a secondary fuel. In this example, the legal owner also has the obligation to promptly begin supplementing its primary fuel with secondary fuel to maintain output within the allowable dispatch variance of the dispatched level in accordance with Section 203.4.

e) Peak firing capability

In general the AESO does not consider MW restatements for assets with peak firing capability relating to operational conditions that can be foreseen outside of T-2 to be an AOR.

However, a pool participant whose asset is an industrial system, designated as such by the Alberta Utilities Commission, with on-site operations may submit an AC restatement in accordance with subsection 2(1)(a) of Section 203.3 and subsection (vi) of the AOR definition, where there is a change in the industrial process requirements of the on-site operations. Where the industrial system has the ability to generate electric energy through peak firing, the change in the industrial process requirements of on-site operations, and the submission of the corresponding AC restatement, may result in the peak firing generation of the industrial system being dispatched on at a price that is lower than the offer price of the peak firing generation reflected in the offer(s) made at T-2 hours. In such circumstances, the inability of the pool participant to accurately predict the industrial process requirements of on-site operations results in an operational constraint, as the pool participant is unable to plan for when the peak firing generation will be dispatched. Subsection 4(2)(a)(i) of Section 203.3 and subsection (iii) of the AOR definition are applicable where the offer(s) for the peak firing generation are re-positioned to reflect the offer(s) made at T-2 hours. Where an AC and MW restatement are submitted to address this situation, the AESO expects that the MW restatement will correspond, in both frequency and volume, with the AC restatement.

3 Battery Energy Storage Facilities

The AESO has received questions regarding the applicability of ISO rules and Alberta reliability standards to battery energy storage facilities. The AESO is in the process of reviewing these questions and will issue further communications on this matter once the review is complete.

Revision History

Posting Date	Description of Changes
2017-10-20	Clarification of subsection (iii) of the AOR definition
2017-06-27	Clarification of peak firing capability in subsection 2(e)
2017-05-11	Addition of section 3
2016-05-11	Clarification of subsection (iii) and (vi) of the AOR definition and the treatment of assets with peak firing capability Administrative updates
2013-11-12	Administrative updates
2012-04-03	Inclusion of practical applications of the defined term
2009-09-30	Inclusion of additional applications

Information Document
Facility Modelling Data
ID #2010-001R

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1 Purpose

This Information Document relates to the following Authoritative Documents[1]:

- Section 304.6 of the ISO rules, *Unplanned Transmission Facility Limit Changes* ("Section 304.6"); and
- Section 502.15 of the ISO rules, *Reporting Facility Modelling Data* ("Section 502.15").

The purpose of this Information Document is:

(a) to provide a link to the list of electrical and physical parameters referred to in Section 502.15;

(b) to set out the *Guideline on the Electrical and Physical Parameters for Transmission System Model List*;

(c) to provide contact information for the purposes of providing modelling data, records, written submissions or other information to the AESO in accordance with Section 502.15; and

(d) to provide contact information for the purposes of notifying the AESO of an unplanned limit change to a transmission facility in accordance with Section 304.6.

2 Overview of Authoritative Documents

Section 304.6 concerns communication to the AESO of unplanned transmission facility limit changes, typically derates, that may have implications in the immediate and near term time frames for the manner in which portions of the Alberta interconnected electric system ("AIES") can be reliably operated. Subsection 2(2) of Section 304.6 requires an operator to provide the AESO with its plan to restore the transmission facility to its previous rating. The AESO acknowledges that, in some cases, it may not be appropriate to restore a transmission facility to its previous rating, where the previous rating is excessive for the anticipated future use of the transmission facility.

Section 502.15 concerns the submission of modelling data and records, including ratings, relating to new facilities or planned, urgent or unplanned changes to equipment within existing facilities, which the AESO uses to accurately represent the AIES in system studies.

A legal owner is required to submit information to the AESO in accordance with subsection 3 of Section 502.15, where an unplanned transmission facility limit change described in Section 304.6 precludes the legal owner from complying with the submission timing requirements under subsection 2(3) of Section 502.15. The AESO uses the information provided by the legal owner to accurately model the power system.

Note that while notification of the time period is required to be provided to the AESO pursuant to subsection 2(1) of Section 304.6 and subsection 3(1)(c) of Section 502.15, the information provided under Section 304.6 is made in real time and may be preliminary, whereas the information provided under Section 502.15 is expected to be more refined.

3 The AESO's Modelling of the AIES

The AESO maintains: (i) a transmission-system object model, (ii) a state-estimator model component to the energy management system, and (iii) a geographic transmission system mapping database. Together

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these models constitute a comprehensive model of the AIES. A comprehensive model of the AIES is essential to the safe planning and operation of the interconnected electric system.

3.1 The List of Electrical and Physical Parameters

The AESO's *Electrical and Physical Parameters for Transmission System Model List*, is the list of electrical and physical parameters referred to in Section 502.15, and is available on the AESO website.

The modelling data and records provided by the legal owners of transmission system equipment and facilities to the AESO, set out in the *Electrical and Physical Parameters for Transmission System Model List*, support the AESO's maintenance of an accurate and comprehensive data model of the AIES. Data models are used for regulatory analysis, power system studies, asset type and location impact assessments, and real-time power-system coordination.

The AESO's *Guideline on the Electrical and Physical Parameters for Transmission System Model List* (the "Guideline") (attached as Appendix 1), provides further information on the modelling data and records set out in the *Electrical and Physical Parameters for Transmission System Model List*. The Guideline is a technical document that describes the objects in the list and the: (i) attributes of and associations between those objects; (ii) the terminology and nomenclature for referencing modelling objects; (iii) units of measure for expressing those attributes; and (iv) limitations on how objects and attributes are expressed.

4 Modelling Data and Records Submission Process

Section 502.15 sets out the requirements for the submission of modelling data and records. Modelling data may include, but is not limited to, the model of the new or modified equipment and the associated parameters. Records associated with the modelling data includethe provenance and effective dates of the data, and any other supporting documents.

References in Section 502.15 to modifications to existing equipment, machinery or other facility components include the decommissioning of facilities.

4.1 Connection Projects

For new facilities or modifications to existing facilities made pursuant to Section 502.15 that relate to a connection project under the AESO's connection process or the AESO's market participant choice process, a legal owner may provide modelling data and records as described in the *Project Data Update Package - Instruction Manual* ("PDUP IM"). The PDUP IM is available on the AESO website.

Subsection 2(3) of Section 502.15 authorizes the AESO to specify the timeframe within which the modelling data and records are to be submitted by the legal owner to the AESO. The AESO's connection process specifies that modelling data and records are to be submitted in stages with the Stage 5 Project Data Update Package to be submitted one hundred (100) days prior to energization.

Legal owners may submit modelling data and records for a connection project to the AESO in accordance with Section 502.15, in the forms that are available on the AESO website. It is recommended that legal owners consult the PDUP IM in order to properly input the modelling data into these forms.

The AESO is in the process of developing new generating unit ISO rules to replace the requirement in Operating Policy and Procedure 1306, *Reporting Equipment Changes*, which is no longer in effect, for the validation of generating unit modelling data and records to be provided to the AESO. In the interim, the AESO will request generating unit modelling data and records as part of the AESO's connection process, pursuant to subsection 6 of Section 502.15.

4.2 All Other Modifications

For all facility modifications made outside the scope of a connection project, a legal owner may provide the following modelling data and record submissions pursuant to Section 502.15:

- List of equipment(s) subject to modification;
- Date of modification;
- Type of change (e.g. addition, upgrade, replacement, modification or retirement);
- Description (e.g. change of rating, capacity, settings or characteristics);
- Additional supporting documentation which might include:
  - Amended single-line diagrams showing the change;
  - Name plate information and/or test reports; or
  - Engineering calculations of modelled characteristics; and
- Electronic PSS.E Input Data files recording the modelling change.
- A line data update for a line modification where there is a change in connectivity or an impedance change from previous impedance data that is greater than 5%.

In accordance with subsection 2(3) of Section 502.15, legal owners are required to submit this modelling data and records to the AESO no later than thirty (30) days prior to the proposed date of energization of new equipment or the modification of existing equipment, or thirty (30) days prior to the application of new ratings to existing equipment, unless otherwise specified by the AESO.

For facility modifications that are complex in nature, legal owners may choose to provide such modelling data and records to the AESO through the forms that are used for connection projects, in the manner described above.

4.3 Modelling data requests from the AESO

For written requests made by the AESO pursuant to subsections 5 and 6 of Section 502.15, the AESO specifies the required modelling data in the written notice.

5 Contact Information

5.1 Section 502.15

Modelling data and records and written submissions may be submitted to the AESO in accordance with subsections 2 and 4 of Section 502.15 at both of the following email addresses: PSMM@aeso.ca and OPTRAProjects@aeso.ca

Modelling data and records and written submissions may be submitted to the AESO in accordance with subsection 3 of Section 502.15 at the following email address: ops.coordination@aeso.ca

5.2 Section 304.6

Notification of an unplanned limit change to a transmission facility in accordance with Section 304.6 is as follows:

(a) a verbal notification in accordance with subsection 2(1) of Section 304.6 may be made by phone to the AESO system controller; and

(b) a written notification in accordance with subsection 2(2) of Section 304.6 may be submitted to the AESO at the following email address: ops.coordination@aeso.ca

Appendix

Appendix 1 - *Guideline on the Electrical and Physical Parameters for Transmission System Model List*

Revision History

Posting Date	Description of Changes
2018-12-20	Amended section 4.2 updated to include update of line data Amended Appendix section 5.2 to clarify modelling of voltage regulators Amended Appendix section 5.5 to clarify the applicability of various types of machines Amended Appendix sections to reflect adoption of FAC-008-AB-3, *Facility Ratings*.
2017-03-23	Appendix updated to reflect revised List; Bus ranges added to Table 1 of Appendix; Overviews added to Appendix for clarity; Glossary removed from Appendix; and Administrative amendments
2016-09-28	Administrative amendments
2016-07-26	Initial release

Appendix 1 – Guideline on the Electrical and Physical Parameters for Transmission System Model List (the "Guideline")

This Guideline provides technical information on the modelling data and records associated with each type of transmission system object in the *Electrical and Physical Parameters for Transmission System Objects List*. Each heading has the following format:

(a) a short definition of the data categories covering that equipment type (if necessary);

(b) a check list of the required data indicated by check boxes; and

(c) short paragraphs expanding on, or explaining, the check list where necessary.

Changes to the nomenclature for some transmission system modelling objects have been made to align with *IEC 61970-301 Common Information Model* (CIM). The former nomenclature is identified by an asterisk (*) and is included in parentheses after the standard nomenclature. Object nomenclature used in this Guideline are identified in **bold underlined** print.

1. Load and Generation Measurement

1.1 Measurement Point

Overview: A "Measurement Point" is the point where electric power flows into or out from the transmission system into the facilities of the system access contract holder.

Checklist:

☐ Unique **MP_ID**

Explanation:

(i) The Measurement Point identifier or **<u>MP_ID</u>** is defined by the Metering Services Provider. The data submitter obtains the **<u>MP_ID</u>** from the Metering Services Provider and forwards it to the AESO. The AESO may assign an interim, temporary **<u>MP_ID</u>** in consultation with the data submitter. In the case of "Behind-the-Fence" loads (loads which are served by self-generation and which therefore represent power both generated and used at the same site without passing through a revenue meter) a unique **<u>MP_ID</u>** beginning with the letters "*BTF_*" will be assigned by the AESO.

2. Load

Overview: A "Load" is a non-rotating sink or source of MW.

Checklist:

☐ The bus to which load connects

☐ NAICS code

☐ Load response characteristic

☐ Load at energization

Explanation:

(i) Loads are to be aggregated to the first non-transmission bus or generation bus upstream of the physical loads.

(ii) "Unmetered Volumes" (also called "Behind the Fence" loads) are to be submitted in the same way as any other load.

(iii) Every Load is characterized by some industrial type, or group of industries, as identified in the North American Industrial Classification System (NAICS).

(iv) NAICS code is typically one of the codes listed in Table 1.2-1. If using a different NAICS code, submit the supporting reference material from NAFTA.

(v) Specify a separate ***energyConsumer.name*** (**ELEMENT_CODE**) for each different industry to be represented.

(vi) If submitting a NAICS code of "99", specify the load response characteristic as a breakdown of constant power, constant impedance, and constant current, in percent for both real and reactive components, to a total of 100%, with a default value of 100% constant power if no other information is available. Submit unmetered volumes (also called behind-the-fence loads) in the same way as any other load.

TABLE 1.2-1 STANDARD INDUSTRY TYPES

NAICS CODE	Industry
11	Agriculture
32	Manufacturing - general
33	Heavy Manufacturing
40	Commercial and Services
71	Arts, Entertainment and Recreation
113	Forestry and Logging
211	Oil And Gas Extraction
486	Pipelines
814	Private Households
22131	Farming – Irrigation
99	Unspecified

(vii) Specify a separate Element Code for each different industry to be represented.

(viii) Load at energization is the estimate of peak load after reaching steady state on day one (1) of energization.

3. Transmission Facilities

Overview: A "transmission facility" is a substation or transmission line.

Checklist:

☐ **FACILITY_CODE**

☐ Geographic location

☐ **operatorCompany (OWNER*)**

Explanation:

(i) The **FACILITY_CODE** is the unique identifier assigned to each transmission facility assigned by the AESO. The identifier can be up to to twenty characters consisting only of capital letters, the digits 0 through 9, periods and hyphens. The data submitter may request a particular identifier. The preferred **FACILITY_CODE** is a simple, pronounceable, unambiguous word; or a short number optionally combined with one or more letters, for example:

- ROSSDALE
- D05
- 14.83L

(ii) When Transmission Facilities are segmented or merged, the AESO will issue new **FACILITY_CODE**(s) as appropriate. The data submitter may consult with the AESO regarding the new **FACILITY_CODE**(s).

(iii) Geographic location describes the detailed location of the transmission facility. A data submitter may submit geographic location data either as a shape file or as a 1:10,000 scale map showing the line route or substation polygon. The geographic location includes a GPS location for any substation; and GPS locations may be submitted for every structure of a Transmission Line, or for the line termini and for points where the line route significantly changes direction.

(iv) ***operatorCompany*** is the legal corporate name of the entity that holds title to the transmission facility.

3.1 Substations and Switching Devices

Overview: A substation is a facility designed for transformation or switching operations. A switching device is a device designed to close, or open or both, one or more electric circuits.

Checklist:

☐ Component substation Single-Line Diagram or Diagrams, indicating for each switching device the:

  ☐ Type of equipment

  ☐ Type of control

☐ Communications block diagram

☐ ***substation.description*** (***SUBSTATION_NAME**)

☐ **LAND_LOCATION**

☐ ***subGeographicRegion*** (***AREA_CODE**)

Explanation:

(i) A Single Line Diagram shows **ELEMENT_CODE**(s), locations of switching devices with their switch numbers, electrical connectivity of all Elements, and ratings of each component of the current path, metering and control CTs and PTs. Switching devices are identified on a Single Line Diagram using annotation or symbols for:

   a. equipment, such as circuit breakers, disconnects, circuit switches; and

   b. controls, such as synchrocheck, synchronizer, motor operated, and supervisory controls.

   The data submitter may submit multiple Single Line Diagrams to cover all required information.

(ii) **substation.description** is included only where the facility owner assigns names to their substations. The ISO will, upon request, provide assistance in selecting a **substation.description** (*SUBSTATION_NAME). **Substation.description** is a pronounceable text string of 50 characters or less, consisting only ofthe letters, digits 0-9, spaces, and hyphens. Substation names may not include corporate names. Substation names may not include variations on geographical names that are already used for other substations.

(iii) **LAND_LOCATION** is the Dominion Land Survey designation at minimum resolution to the quarter-section, and preferably the legal sub-division.

(iv) **LAND_LOCATION** is to conform to the following format: LL-SS-TT-RRWP where:

A. LL is the legal subdivision or quarter-section

B. SS is the section number

C. TT is the township

D. RR is the range

E. P is the parallel.

The AESO assigns a ***subGeographicRegion*** according to the planning needs of the interconnected electric system.

3.2 Transmission Lines

Overview: A transmission line begins and ends with connection to a substation bus or at its connection to a transmission line of a different owner. A transmission line may have two or more terminals.

Checklist:

☐ Structure List or Line Survey

☐ Transmission Line Segment Summary

☐ Structure Drawings

Explanation:

(i) A Structure List or Line Survey describes the line construction structure by structure

(ii) A transmission line comprises one or more line segments. The Transmission Line Segment Summary consists of a drawing or table showing how the segments connect.

(iii) Structure Drawings are comprised of dimensioned drawings of every tangent structure-type mentioned on the Structure List or Line Survey.

4. topologicalNode (*Busses)

Overview: A ***topologicalNode*** is a node that serves as a common connection for two or more circuits. A ***topologicalNode*** may comprise any number of zero-impedance equipment such as switches, ***connectivityNodes***, and busbars or physical bus segments which are subsumed into the ***topologicalNode***.

Checklist:

☐ Unique ***topologicalNode.name*** (***BUS_ID**)

☐ ***nominalVoltage*** (***NOMINAL_VOLTAGE**)

☐ ***equipmentContainer.name*** (***FACILITY_CODE**)

Explanation:

(1) A new ***topologicalNode.name*** will generally follow the pattern used by existing ***topologicalNode***s in the same area. The ***topologicalNode.name*** is an integer assigned by the AESO consistent with the following:

TABLE 1 – STANDARD BUS RANGES

BUS-RANGE DESCRIPTION	BUSRANGE BUSRANGE_HIGH	
	From_	**To _**
General transmission busses	1	999
	1000	1999
	540001	549999
Distribution busses	2000	4999
	15000	19999
	20001	29999
	30000	39999
	40000	49999
	550001	558999
Transformer midpoint busses	5000	8999
	10000	14999
	559001	559999
Temporary busses	9000	9999
Isolated system busses	50000	59999
Collector System (renewable) busses	60000	69999
	560001	569999
Resource Adequacy generation busses	70000	79999
	570001	579999
Unassigned	80000	99999
	580001	599999
Projects at Stage 1	990001	999001

(2) ***nominalVoltage*** on the transmission system is one of 500kV, 240kV, 138kV, or 69kV. ***nominalVoltage*** may differ somewhat from the actual operating voltage of the transmission system at any location. The owner of a distribution facility will assign nominal bus voltage on the distribution-voltage bus

(3) ***equipmentContainer.name*** (*__FACILITY_CODE__) is the exact ASCII text string previously assigned by the AESO for the facility containing the ***topologicalNode***.

5. Equipment (*ELEMENTS)

*5.1 General requirements for conductingEquipment (*Elements)*

Overview: A ***conductingEquipment*** is a current-carrying device that, by virtue of having inherent impedance, contributes to the admittance matrix of the power-flow model.

Checklist:

☐ ***Equipment.name*** (***ELEMENT_CODE**)

☐ ***equipmentContainer.name*** (***FACILITY_CODE**)

☐ ***operatorCompany*** (***OWNER_NAME**)

☐ ***normallyInService*** (***NORMALLY_INSERVICE**)

☐ Equipment in-service date or project

☐ Equipment decommission date or project (if known)

Explanation:

(i) The ***equipment.name*** is the unique identifier assigned to each piece of conducting equipment. The identifier can be up to twenty characters consisting only of capital letters, the digits 0 through 9, periods and hyphens. The AESO may, upon request, provide assistance in selecting a unique identifier. Preferred identifiers are a simple, pronounceable, unambiguous word; or a short number optionally combined with one or more letters.

(ii) ***equipmentContainer.name*** provides clarity in identifying which facility contains the Element. The ***equipmentContainer.name*** is the exact ASCII string the AESO previously assigned as the ***FACILITY_CODE*** for the facility containing the equipment.

(iii) ***operatorCompany*** is the legal corporate name of the entity that holds title to the Element.

(iv) ***normallyInService*** is identified as TRUE if the equipment is normally energized and able to carry current; and is identified as FALSE if the equipment is normally on standby or de-energized.

(v) If the equipment is put in service by maintenance change-out, the data submitter is to submit the date on which the change-out takes effect. If the equipment is put in service by an AESO project, the AESO will associate the equipment with that project number and energization number. Note that one energization may cover a period no longer than three months.

(vi) If the equipment is decommissioned by maintenance change-out, the data submitter is to submit the date on which the change-out takes effect. If the equipment is decommissioned by an AESO project, the AESO will associate the equipment with that project number and energization number. Note that one energization may cover a period no longer than three months.

5.1.1 Element-to-Measurement Point Mapping

Overview: Each Measurement Point is cross-referenced to elements that either sink or supply the metered power. Every **MP_ID** serves one or more elements (either machines or loads).

Checklist:

☐ **MP_ID**

☐ ***conductingEquipment.names*** (***ELEMENT_CODE**s)

☐ Portion of **MP_ID** delivered to or from each ***conductingEquipment***.

Explanation:

(i) **MP_ID** is the unique identifier assigned by the Metering Services Provider

(ii) ***conductingEquipment.name*** is the exact ASCII string the data submitter previously assigned for the equipment.

(iii) The portions of the **MP_ID** summed over all the ***conductingEquipment*** that serve that **MP_ID** equal to one hundred percent (100%).

5.1.2 Applicable Dynamic Control Systems

Overview: A Dynamic Control System is an automated system that operates within a 0.01s to 10.0s timeframe, to achieve prescribed relationships between selected system variables by comparing functions of these variables to effect control of an identified element. For the purposes of this Guideline, the transfer function inherent to a machine itself is considered a "control system".

Checklist:

- ☐ ***conductingEquipment.name*** (*__ELEMENT_CODE__)
- ☐ Control System Type
- ☐ Manufacturer
- ☐ Model
- ☐ Control System Block Diagram

Explanation:

(i) **conductingEquipment.name** is the exact ASCII string the data submitter previously assigned for the equipment.

(ii) Control system type is one of those listed in Table 1.5-1:

TABLE 1.5-1 STANDARD CONTROL SYSTEM TYPES

CONTROL_SYS	Applies to
Compensator	Large individual machines
Exciter	Large individual machines
Exciter limiter	Large individual machines
Generator/condenser	Machines
Synchronous/induction motors	Machines
Stabilizer	Large individual machines
Turbine governor	Large individual machines
Remedial action scheme	All element types
Load	Loads
Converter controls	Direct current converter
Other power electronics	All elements

(iii) The equipment manufacturer generally provides the data submitter with the control system block diagram.

The AESO may identify the protection data that is to be provided to the AESO on a case-by-case basis through discussions with legal owners. In general, underfrequency load shedding relays, under voltage load shed relays, synchrocheck relays and synchronizers are essential to transmission modeling.

5.1.3 Applicable PSS/E or PSLF Model Data

Overview: Submit dynamic model data that accurately represents the element's dynamic behaviour and appears on the WECC list of accepted standard PSS/E and PSLF library models[2]. A user-written model may be submitted along with the library model.

Checklist:

- ☐ **conductingEquipment.name** (***ELEMENT_CODE**)
- ☐ Model Name
- ☐ Description of Model
- ☐ Model Block Diagram
- ☐ Parameter Names
- ☐ Parameter Values
- ☐ Source-code or compiled object

Explanation:

(i) The **conductingEquipment.name** is the exact ASCII string that was previously assigned for the equipment.

(ii) "Model Name" is the name of a standard library model on the WECC approved models list, to be submitted for every dynamic control system, regardless of whether a user-written model is submitted.

In the case of power electronic control systems that the AESO determines cannot be adequately represented by a standard library model complete with its submitted parameters, an adequate detailed user-written model is to be submitted IN ADDITION to the standard library model. This user-written model is to be adequate for dynamic study of the transmission system in the point zero one second (.01s) to ten second (10s) timeframe and need not simulate proprietary detail of the flexible alternating current transmission system device. Any detailed user-written model submitted to meet this Guideline is to be provided to the AESO for distribution with the AESO dynamic data files.

Models are to be submitted for PSS/E software and / or PSLF software. IEEE models may be submitted in addition to the PSS/E and PSLF models. If models are submitted in only one of PSS/E or PSLF the party responsible for submitting the data is to consult with AESO regarding converting the data to the other format.

(iii) A description is to accompany each model, providing a high-level assessment of the model's accuracy and the scenarios under which it is applicable.

(iv) A Model Block Diagram is to be submitted for all user-written models, except for standard library models.

(v) Parameter names are to be the same as specified for the model in the relevant software documentation.

(vi) All parameter values are to be provided; do not leave any parameter values blank.

(vii) The source-code is a text listing of programmatic commands that represent a control system model. The compiled object is the machine-code produced by a compiling the source-code, which can then be called by the power system simulation program to simulate the control system behavior (often distributed as a .dll file).

[2] The WECC list of accepted standard PSS/E and PSLF library models is available on the WECC website at the following link under the "Approved Documents" tab: https://www.wecc.biz/PCC/Pages/MVWG.aspx.

(viii) Model source-code or compiled object is to be submitted for all user-written models, except for standard library models.

5.2 Transformers

Overview: "Transformer" refers to a voltage transformer, phase-shifting transformer, voltage regulator or grounding transformer. Transformers have significant scope for variation from one transformer to the next. The data is requested in a standard format that can accommodate both common transformers and their variations; and more unusual transformers. Voltage regulators are modelled as the transformer tap changer of the associated power transformer. Test reports are not required for regulators.

Checklist:

☐ Transformer nameplate

☐ Test report

Explanation:

(a) A ***powerTransformer*** contains multiple windings and optionally tap-changers. A single name-plate describes all the ***conductingEquipment*** that the ***powerTransformer*** contains.

(b) Test data in the test report is defined in IEEE Standard C57.12.00. Test data is to be provided for both positive and zero sequence. If the transformer has a tertiary delta winding, test data is provided for the tertiary delta winding closed, and the tertiary delta open circuited. Transformer impedances are not required for regulators.

5.2.1 Transformer Windings

Overview: Refer to the AESO's *Transformer Modelling Guide* for derivation of the Transformer equivalent circuit and windings.

Checklist:

☐ **equipment.name** (***ELEMENT_CODE**)

☐ Winding identifier

☐ Connection (delta/wye)

☐ Neutral Grounding status

☐ Grounding impedance

☐ Ratings

☐ Rated voltage

☐ Identification of the bus to which winding connects

Explanation:

(i) ***equipment.name*** is the exact ASCII string previously assigned to the ***powerTransformer*** that contains this winding.

(ii) Provide the two seasonal normal ratings and four seasonal emergency ratings and terminations for each winding identifier consistent with the methodology documented in accordance with FAC-008-AB-3, *Facility Ratings*.

(iii) Submit the winding connection as either Y or D for each winding. For other connections, please contact the AESO.

(iv) For each winding, neutral grounding status is "TRUE" if the winding is grounded and "FALSE" if the winding is ungrounded. The grounding impedance shall be resistance and reactance values expressed in ohms. Indicate solidly grounded windings by a grounding impedance of zero.

(v) The ratings of the windings may be:

A. identical (for example, in a two-winding transformer, primary and secondary windings are equally rated);

B. related (for example, the two secondaries of a split-secondary are each half the rating of the primary);

C. arbitrary (for example, the windings of a three-winding transformer may all be differently rated.)

Each winding may have one or more ratings, expressed in MVA. Provide all ratings for each winding, including provisional ratings. For each rating, indicate the condition under which the rating is valid. Clearly indicate which ratings are available and which are provisional. If the transformer capacity is limited by separate equipment in addition provide the limiting condition and its rating.

5.2.2 Transformer Tap Changers

Overview: Windings may be associated with tap-changers. For each tap-changer on a winding, provide all of the following information:

Checklist:

- ☐ Tap points
- ☐ Tap-changing strategy (manual, automatic)
- ☐ On-load tap changing (True/False)
- ☐ Control band
- ☐ Actual Tap

Explanation:

(i) The voltage rating of each tap (for a voltage controlling tap-changer), or the phase shift for each tap (for a phase-shifting transformer), or indicate that no tap-changer exists for this termination;

(ii) The tap-changing strategy, one of:

TABLE 1.5-1 STANDARD TAP-CHANGING STRATEGIES

TAP_CHANGING_CODE	TAP_CHANGING_DESCR
OFF	Off-load tap changing (having external controls on the transformer tank but requiring de-energization)
OLTC-M	On-load tap changing (manual-local)
OLTC-S	On-load tap changing (supervisory, i.e. manual-remote)
OLTC-A	On-load tap changing (automatic, i.e. under voltage regulation)
FIXED	Fixed taps (having no external control)
PHASE-P	Phase shifting, controlling MW
PHASE-Q	Phase shifting, controlling MVAr

(iii) Indicate which transformer termination is intended to be controlled by the tap-changing action - usually the "X" bushing of a distribution load transformer. If a remote bus is intended to be controlled, enter the bus number. Provide the voltage range for tap-changer control, in per-unit of the system nominal voltage.

(iv) For a voltage controlling tap-changer, specify the control band as the maximum and minimum allowed voltage at the controlled bus. For a phase-shifting tap changer specify the control band as the power flow into the termination.

(v) Model the voltage regulator as a tap-changer on the directly connected winding.

5.2.3 Transformer Impedances

Overview: Refer to the AESO's *Transformer Modelling Guide* for derivation of the Transformer equivalent circuit. The equivalent circuit is to include positive and zero sequence resistance and reactance for every series branch in the equivalent circuit. The equivalent circuit is to include conductance and susceptance to ground for every shunt branch in the equivalent circuit.

Checklist:

- ☐ Transformer equivalent circuit
- ☐ Positive and zero-sequence real and reactive impedances
- ☐ Positive and zero-sequence real and reactive shunt admittances
- ☐ Short Circuit Impedances and Load Losses
- ☐ Open Circuit Excitation Currents and No-Load Losses
- ☐ Phase angle shift
- ☐ Significant Off-neutral impedance of tap-changing transformers

Explanation:

(i) The equivalent circuit impedances are expressed in per-unit based on rated voltage of the transformer and on the MVA rating that was used to establish impedances.

(ii) Express short circuit impedance in per-cent and load loss in kW.

(iii) Express open-circuit excitation in per-cent and no-load loss in kW.

(iv) If the transformer is a voltage transformer, submit the phase angle shift as a fixed value. If the transformer is a phase-shifting transformer, submit the phase angle limits. If the impedance of a transformer with taps differs by 15% or more from the impedance at the rated tap, then the tested impedance shall be submitted at the maximum and minimum taps in addition to the neutral tap, and at enough of the intervening taps so that the total difference from one submitted impedance to the next is always 25% or less.

(v) The AESO will assign a two-character circuit identifier for each impedance branch in the equivalent circuit.

5.3 Reactor and Capacitor Banks

Overview: A "Reactor and Capacitor Bank" is a simple switched or un-switched bank.

Checklist:

- ☐ Bank nameplate
- ☐ Capacitance (Farads)
- ☐ Inductance (Henrys)

- ☐ Rated MVA (Capacitive)
- ☐ Rated MVA (Inductive)
- ☐ Rated voltage
- ☐ Control strategy
- ☐ Control Bus
- ☐ Maximum control-band voltage
- ☐ Minimum control-band voltage
- ☐ Connection (Delta/Y)
- ☐ Neutral Grounding status
- ☐ Grounding impedance

Explanation:

(i) Express the rated MVA at the bank rated voltage.

(ii) Express the Control strategy as one of the following:

TABLE 1.5-3 STANDARD SHUNT-SWITCHING STRATEGIES

Strategy	Explanation of Strategy
Fixed	The Shunt cannot be switched
Manual	The Shunt can be switched on or off by personnel on site
Supervisory	The Shunt can be switched on or off remotely
Automatic	The Shunt switches on or off under control of an automated control system

(iii) The "Control Bus" is the bus at which the voltage is monitored for the purpose of controlling this shunt device. Refer to the bus by the **BUS_CODE** assigned to the bus by the AESO.

(iv) Express maximum and minimum voltages of the control band in per-unit of the system nominal kV at the Control Bus.

(v) Express grounding resistance and reactance in ohms, with zero indicating a solidly grounded bank.

5.4 Line Segments

5.4.1 Line Segments Construction

Overview: A "Line Segment" is a portion of a transmission line that has consistent physical attributes of conductor and cross-section throughout the length of the segment.

Checklist:

- ☐ **conductingEquipment.name**
- ☐ Line Segment length (km)
- ☐ Conductor type
- ☐ # of conductors per bundle

- ☐ Bundle spacing (m)
- ☐ Average sag (m)
- ☐ Typical tangent structure
- ☐ Typical structure height (m)
- ☐ Positive-sequence real and reactive impedances and susceptances
- ☐ Zero-sequence real and reactive shunt admittance

Explanation:

(i) A tap off a line that enters a substation, irrespective of length, is to be designated as a separate Line Segment. However, if a Line Segment is:

A. less than 500 meters and less than 20% of the line's total length from substation to substation;

B. less than 50 meters; or

C. less than 5% of the line's total length from substation to substation,

it can be considered part of the adjacent Line Segment.

(ii) Conductor type is defined by name as shown in Table 1.5-4. If using a different conductor type, the conductor data sheet is to be submitted.

TABLE 1.5-4 CONDUCTORS

CONDUCTOR_NAME
CHICKADEE
COCHIN
COREOPSIS
COSMOS
CROWSNEST
CURLEW
DOVE
DRAKE
HADDOCK
HAWK
HORNBILL
IBIS
LINNET
MERLIN
OSPREY
PARTRIDGE
PELICAN

CONDUCTOR_NAME
PENGUIN
PIGEON
RAVEN
SPARROW
TRILLIUM
WAXWING

(iii) The tangent structure is designated with a reference to the relevant Structure Drawings.

(iv) The structure height is measured from the ground to the lowest conductor.

(v) Submit Line Segment impedance in ohms.

(vi) Submit Line Segment susceptance and terminal-shunt admittance in Siemens.

(vii) The submission includes the assumed ground resistivity (ohm-m) on which the values are calculated.

5.4.2 Line Segment Ratings

Overview: None

Checklist:

☐ Conditions

☐ Ratings

☐ Limiting Factors

Explanation:

(i) The ampere ratings of the Line Segment for each of Summer Normal, Summer Emergency, Winter Normal and Winter Emergency conditions consistent with the methodology documented in accordance with FAC-008-AB-3, *Facility Ratings*.

(ii) The Line Segment rating as limited by the unconstrained line conductor thermal rating is identified for each condition. If the Line Segment has a more limiting rating, identify the most limiting factor that limits the rating of the Line Segment. The Line Segment is considered to terminate at the breaker or breakers. Submit the rating corresponding to that limiting factor for each condition. Describe limiting factor(s) as one of:

TABLE1.5-5 CAPACITY-LIMITING CONDITIONS

CONDITION_DESCR
Circuit Breaker
Current Transformer
Line conductor Thermal rating
Ground clearance
SLAPAC dampers
Underbuild
Disconnect Switch
Jumpers

Buswork
Protection setting
Connectors

If some other factor limits the capacity of the Line Segment, describe the factor in detail in a letter to the AESO.

5.4.3 Line Mutuals

Overview: None

Checklist:

The following is submitted for each Line Segment Branch in the pair of Line Mutuals:

☐ ***conductingEquipment.name***s of the two Line Segment Branches

☐ Real and reactive mutual impedances (ohms)

☐ Start-of-parallel distance (m)End-of-parallel distance (m)

☐ Assumed direction of flow for the mutual calculation

Explanation:

(i) When two Line Segments form any part of a parallel between two Transmission Lines where:

A. the length of the cumulative parallel is greater than 20% of the length of either line, from substation to substation; and

B. the separation of the parallel is less than 500 m,

the mutual impedances are submitted on a Line Segment-by-Line Segment basis..

(ii) Direction of flow is indicated by reference to the ***topologicalNode***s at the line ends by declaring which ***topologicalNode*** current is presumed to be flowing from.

(iii) Start-of-parallel is the distance from the “from” end of the Line Segment Branch to the point where the mutual coupling begins. If the entire length of the Line Segment Branch parallels the other Line Segment Branch this value will be 0.

(iv) End-of-parallel is the distance from the “from” end of the Line Segment Branch, to the point at which the parallel ends. If the entire length of the Line Segment Branch parallels the other Line Segment Branch, this value will be the same as the Line Segment Branch length.

(v) Direction of flow is indicated by reference to the ***topologicalNode***s at the line ends by declaring which ***topologicalNode*** current is presumed to be flowing from.

5.5 Generating Units, Aggregated Generating Facilities, Large Motors and Battery Energy Storage Facility

Overview: A “Machine” is a rotating generator or motor or large power electronic converter set. In the case of a collector-based generating “collector” such as wind, or mini-hydro; “Machine” means the aggregated equivalent machine representing the power plant.

The following table summarizes how this section 5.5 applies to each type of machine:

Relevant Section	Type	Connection	Applicable MARP Size

5.5.1	Generating Unit	Directly connected to transmission system or industrial complex	Greater than 4.5 MW for individual unit
5.5.2	Aggregated Generating Facility		Greater than 4.5 MW for each AGF
5.5.3	Battery Energy Storage Facility	Directly connected to transmission system or industrial complex	Greater than 4.5 MW
5.5.1	Motors	Directly connected to transmission system	Greater than 4.5 MW for individual unit
5.5.1 and 5.5.4		In an industrial complex	Individual unit at > 0.9 MW and aggregate to > 4.5 MW at each point of delivery
		Connected to distribution system at 1kV+	
5.5.1 and 5.5.5	Generating Unit	Connected to distribution system	Greater than 5 MW at each point of delivery
5.5.2 and 5.5.5	Aggregated Generating Facility		

5.5.1 Large individual machines

Overview: “Large individual machines” are generating units or large electric motors of 4.5 MW or more directly connected to the transmission system or connected to an industrial complex..

Checklist: (as applicable to the specific machine or converter type)

- ☐ Nameplate
- ☐ Manufacturer’s datasheet, including at a minimum:
  - ☐ Rated MVA
  - ☐ Rated kV
  - ☐ Maximum Authorized Real Power (MARP in MW)
  - ☐ Minimum stable generation (MW)
  - ☐ Reactive Power capability curve
  - ☐ Inertia constant
  - ☐ Positive-sequence saturated and unsaturated subtransient reactance

- ☐ Positive-sequence saturated and unsaturated subsynchronous reactance
- ☐ Positive-sequence saturated and unsaturated synchronous reactance
- ☐ Transient time constant
- ☐ Subtransient time constant
- ☐ Negative sequence resistance
- ☐ Negative sequence synchronous reactance
- ☐ Zero-sequence resistance
- ☐ Zero-sequence synchronous reactance
- ☐ Station Service load (MW at zero generation)
- ☐ Unit Service load (incremental MW per MW of generation)
- ☐ Saturation
- ☐ “G” for “generator or “M” for “Motor”
- ☐ The bus to which machine connects
- ☐ The “D” curve (for Generators)
- ☐ The “V” curve (for Generators)
- ☐ Power Variation Curve as a function of Temperature
- ☐ Nameplate of Exciter (for synchronous Generators)
- ☐ Model Validation test report

Explanation:

(i) Machine inertia constant is the combination of the Generator and Driver (or for the motor and the connected load).

(ii) Express machine impedances in per-unit on machine MVA rating and machine kV rating.

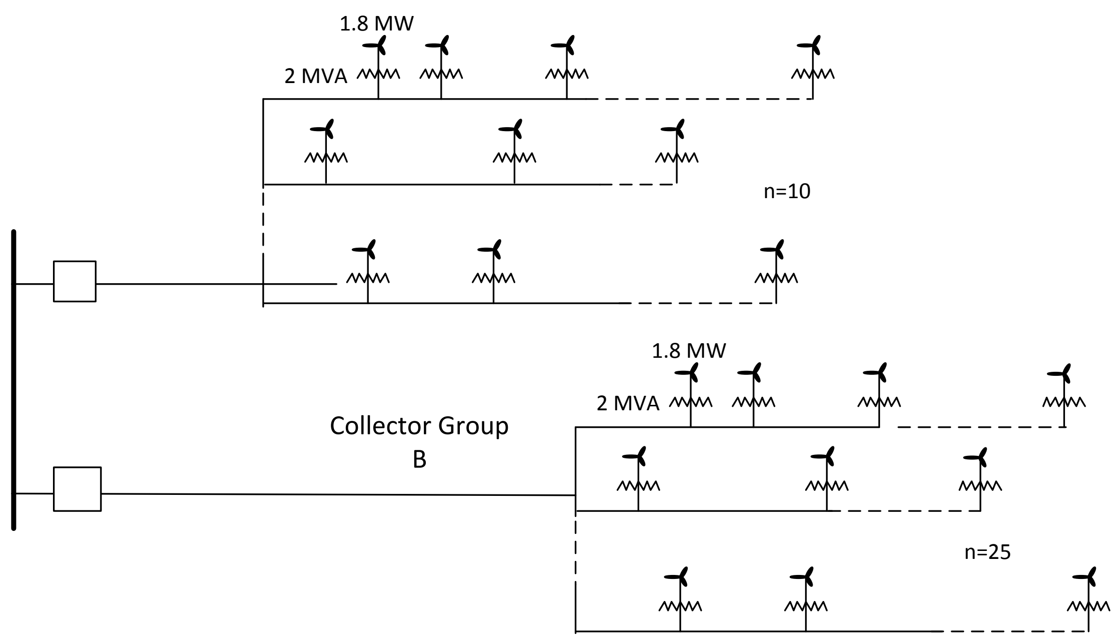
(iii) For synchronous machines, submit both direct-axis and quadrature-axis impedances and time constants.

(iv) Express saturation either as saturation factors or as a saturation curve.

5.5.2 Aggregated Generating Facilities

Overview: Aggregated Generating Facilities are comprised of: a collector switch; a number of individual matched generator units complete with individual step-up transformers; and a collector network made up of line segments of varying length joining the individual generator-transformer units to the main collector switch where the total aggregated capacity is 4.5 MW or more and directly connected to the transmission system or connected to an industrial complex. Data is separately for each collector group in accordance with Figure 1-1.

FIGURE 1-1: TYPICAL COLLECTOR SYSTEM GENERATORS



Checklist: (as applicable to the specific machine or converter type)

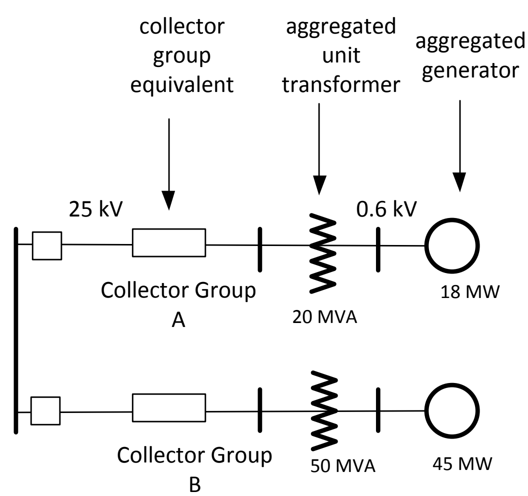
- ☐ Reduced representation diagram of Collector System
- ☐ Positive-sequence total real and reactive impedance of the collector system
- ☐ Zero-sequence total real and reactive impedance of the collector system if grounded
- ☐ Positive-sequence real and reactive shunt admittance of the collector system
- ☐ Zero-sequence real and reactive shunt admittance of the collector system if grounded
- ☐ Step-up transformer Impedances
- ☐ Typical generator nameplate
- ☐ Count of individual generators
- ☐ Maximum Authorized Real Power at collector bus (MARP in MW)
- ☐ Generator's Manufacturer's data sheet, including at a minimum
  - ☐ Generator type
  - ☐ Maximum real power out
  - ☐ Minimum real power operation
  - ☐ Maximum reactive power out
  - ☐ Minimum reactive power out
  - ☐ Equivalent positive-sequence impedance for three-phase fault calculations
  - ☐ Equivalent zero-sequence impedance for single-phase fault calculations

- ☐ Houseload
- ☐ Generator impedance
- ☐ Generator step-up transformer data
- ☐ Shunt device nameplate for shunt devices residing within turbine units
- ☐ Shunt device manufacturer's data for shunt devices residing within turbine units
- ☐ Count of individual shunt devices

Explanation:

(i) The reduced model represents each collector group as the equivalent impedance of the collector network, a single aggregate wind generator and a single aggregate step-up transformer representing the sum of the individual turbines and turbine step-up transformers on that collector group. Figure 1-2 shows the reduced model of the collector systems shown in in Figure 1-1.

FIGURE 1-2: EQUIVALENT COLLECTOR SYSTEM



(ii) Collector equivalent impedances are expressed per-unit on collector nominal voltage and a 100 MVA base.

(iii) The individual data for a single wind turbine generator, and a typical generator nameplate, is to be submitted for each group of identical generators. If all wind turbine generators in a wind power facility are identical, only one nameplate and one set of manufacturer's data need be submitted.

(iv) Generator type will be one of: conventional synchronous, conventional induction, wound rotor induction with variable rotor resistance, doubly-fed induction, or full converter.

(v) Generator impedances are expressed in per-unit on the machine rated MVA base

(vi) Include with the collector-system generator data only those shunt devices that are distributed throughout the collector system within or at the turbine generator locations. Refer to section 1.5.3 to submit data for any centrally located shunt devices.

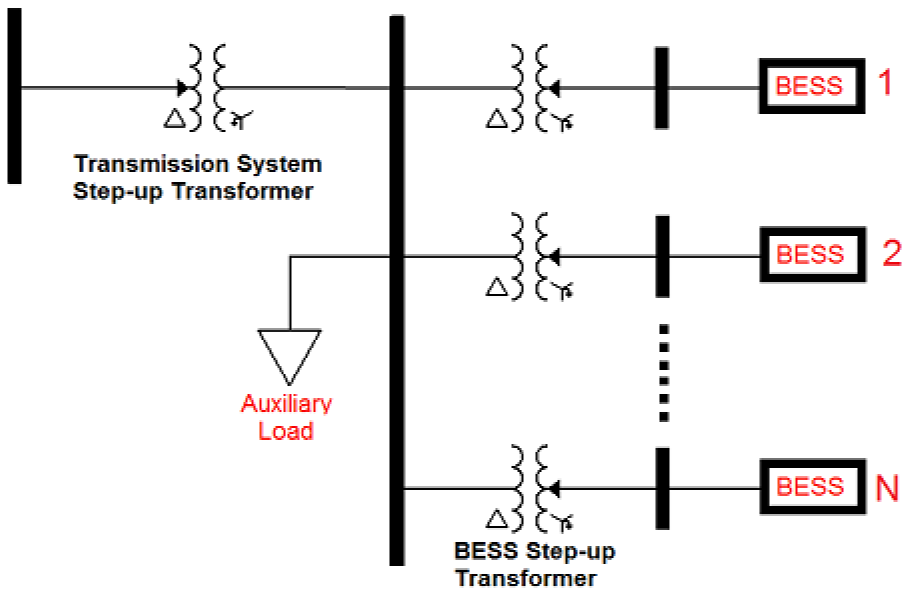
(vii) Refer to section1.5.2 to submit the data for the generator step-up transformer. If all wind turbine generators in a wind power facility are identical, only one set of data need be submitted.

(viii) The requirements to submit controls system data and dynamic modelling dataapply to equivalent collector-system generators.

5.5.3 Battery Energy Storage Facility

Overview: Battery Energy Storage Facilities (BESFs) are facilities governed by Section 502.13 of the ISO rules, *Battery Energy Storage Facility Technical Requirements* and Section 502.14 of the ISO rules, *Battery Energy Storage Facility Operating Requirements* with aggregated capacity greater than 4.5 MW. Data is submitted separately for each collector group in accordance with Figure 1-3.

FIGURE 1-3: TYPICAL BATTERY ENERGY STORAGE FACILITY



Checklist:

- ☐ Reduced representation diagram of Collector System
- ☐ Maximum Authorized Charging Power (MACP in MW)
- ☐ Maximum Authorised Discharing Power (MADP in MW)
- ☐ Generator’s Manufacturer’s data sheet, including at a minimum
  - ☐ Number of BES Converter Units
  - ☐ Unit Converter Rating (MVA)
  - ☐ Rated Terminal Voltage (kV)
  - ☐ Maximum Temporary Ratings and Time Characteristics
  - ☐ Minimum real power operation
  - ☐ Maximum reactive power out
  - ☐ Minimum reactive power out
  - ☐ Equivalent positive-sequence impedance for three-phase fault calculations

- ☐ Equivalent zero-sequence impedance for single-phase fault calculations
- ☐ Converter Type
- ☐ Equivalent Converter Series Impedance
- ☐ Battery Type
- ☐ Bulk Electric System Step-Up Transformers

☐ Auxiliary Load Characteristics

☐ Maximum Continous Operation under MADP (Hours)

☐ Model Validation Report

Explanation:

(i) See Section 502.13 and AESO's *Consolidated Authoritative Document Glossary* for definitions of maximum authorized charging power (MACP) and maximum authorized discharging power (MADP).

(ii) Maximum reactive power out and minimum reactive power are calculated based on the MACP and MADP.

(iii) The equivalent positive-sequence impedance is the impedance of the converter filter behind the converter step-up transformer. The total impedance of this equivalent impedance and converter step up transformer determines the three-phase fault level at the point of connection.

(iv) Each BES Converter Unit consists of a step-up converter transformer, a converter and a set of battery racks.

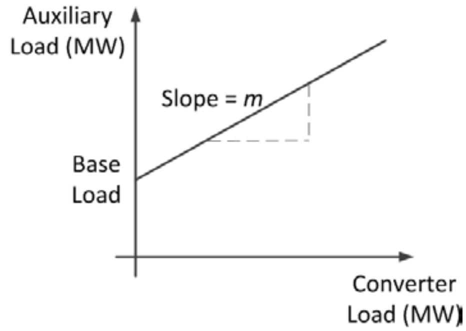
(v) A BESF consists of one or more BES Converter units to reach the required MVA rating and an auxiliary load representing the total cooling load of the BES Converter units. If the BES converter units have different MVA ratings, each unit rating should be provided.

(vi) The auxiliary load consists of the converter cooling load and the substation base load. The cooling load, which is the major part of the auxiliary load in BESFs, is usually a motor load and is a function of the power converted by the converter. When the converter operates at its maximum capacity, the cooling load and consequently the auxiliary load is maximum. The auxiliary load may have a nonlinear characteristics versus converter load but, for the purpose of modelling a simplified liner model as described in the following equation is preferred.

$$P_{Auxiliary} = m \times P_{Converter} + P_{Base\ Load}$$

Figure 1-4 shows the characteristics of this simplified load:

FIGURE 1-3 - AUXILIARY LOAD CHARACTERISTICS VERSUS CONVERTER LOAD (MW)



(vii) The auxiliary load may have a low power factor because it is a motor load. The load power factor or the reactive power at the auxiliary load value should be provided.

5.5.4 Industrial Complex Aggregated Machines and Distribution Connected Motors

Overview: Aggregated machines are a totaled MVA equivalent for induction motors, synchronous motors and motors controlled by a power electronic drive located on the load side of a point of delivery or generating units connected to an industrial complex where:

(i) the individual machines are connected at 1000 V or higher;

(ii) the individual machines have a capacity of 0.9 MW or more; and

(iii) the total connected capacity is 4.5 MW or more.

If any of the foregoing three conditions is not true, the data does not need to be submitted.

Checklist

The checklist includes all applicable items of Large individual machines or Aggregated Generating Facilities and:

- ☐ ½-cycle Fault contribution on the high voltage side of the Point of delivery
- ☐ 3-cycle Fault contribution on the high voltage side of the Point of delivery
- ☐ Aggregate MVA (low-voltage induction motors)
- ☐ Aggregate MVA (medium-voltage induction motors)
- ☐ Aggregate MVA (medium-voltage synchronous motors)
- ☐ Aggregate MVA (synchronous generators)
- ☐ Aggregate MVA (induction generators)

Explanation:

(i) ½-cycle Fault contribution is the asymmetric fault current in amperes coming from the site system for a fault on the transmission system side of each of the supply transformers.

(ii) 3-cycle Fault contribution is the symmetrical fault current in amperes coming from the site system for a fault on the transmission system side of each of the supply transformers.

(iii) Where multiple transformers supply a site, the faults are to be applied simultaneously to all supplying transformers.

(iv) Aggregate MVA is the sum of the rated MVA of all induction motors or generators in the specified class.

(v) Low-voltage motors are those motors directly connected at 1000 V or below, excluding all motors connected through variable-frequency drives.

(vi) Medium-voltage motors are those motors directly connected at greater than 1000 V, excluding all motors connected through variable-frequency drives.

(vii) Aggregate MVA values are to include any machines that are also submitted as large individual machines.

5.5.5 Distributed Generators

Overview: Aggregated distribution generators are a totaled MVA equivalent for distribution-connected generators located on the distribution side of a point of delivery, where the total distribution-connected capacity is 5 MW or more

Checklist:

The checklist includes all applicable items of of Large individual machines or Aggregated Generating Facilities and:

☐ Aggregate MVA for the Metering Point

Explanation:

(i) Aggregate MVA is the sum of the rated MVA of all generators downstream from the Metering Point.

5.6 HVDC Converter Terminals

Overview: detail to be established through discussion with the ISO.

5.7 Series Compensation

Overview: Series Compensation is a series component, typically a reactor or capacitor, which modifies the series reactance of a line.

Checklist:

☐ Nameplate

☐ MVAR rating

☐ Rated voltage

☐ Rated current

☐ Control strategy

Explanation:

(i) Discuss the control strategy with the AESO to identify which details are to be submitted.

5.8 Static VAr Compensators

Overview: A “Static VAr Compensator” is a shunt-connected capacitive or inductive conducting equipment whose output is automatically and rapidly adjusted to maintain or control some parameter of the electrical power system, typically voltage.

Checklist:

☐ Nameplate

- ☐ Maximum/Minimum MVA (Capacitive)
- ☐ Maximum/Minimum MVA (Inductive)
- ☐ Rated voltage
- ☐ Control strategy
- ☐ Control Bus
- ☐ Maximum control-band voltage
- ☐ Minimum control-band voltage
- ☐ Connection (Delta/Y)
- ☐ Neutral Grounding status
- ☐ Grounding impedance

Explanation:

(i) MVAr rating is to be expressed at the bank rated voltage.

(ii) The Control Strategy is one of the following:

TABLE 1.5-6 SVC-SWITCHING STRATEGIES

☐ Strategy	☐ **Explanation** of Strategy
Manual	The SVC output can be adjusted by personnel on site
Automatic	The SVC output is adjusted under control of an automated control system
Supervisory	The SVC output can be adjusted remotely via SCADA

(iii) The "Control Bus" is the bus at which the voltage is monitored for the purpose of controlling this shunt device. Refer to the bus by the (**BUS_CODE)** assigned to the bus by the AESO.

(iv) The maximum and minimum voltages of the control band are expressed in per-unit of the system nominal kV at the control bus.

(v) Grounding resistance and reactance expressed in ohms, with zero indicating a solidly grounded bank.

6. Other FACTS Devices

Overview: "FACTS Devices" or "Flexible AC Transmission System Devices" refer to power electronic based systems and their associated static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability.

Checklist:

- ☐ Nameplate
- ☐ Component Single-Line Diagram
- ☐ Manufacturer's Test report
- ☐ Manufacturer's Data Sheet
- ☐ Details established by discussion with the AESO

☐ Description of operation

Explanation:

(i) A Component Single-Line Diagram is used to show all the main circuit components of the FACTS installation, including Transformers, Line Segments, capacitors, and reactors.

(ii) Provide a text description of the operation of the FACTS installation, to a level of detail to be discussed with AESO.

(iii) Submit the data for any Transformers, Line Segments, capacitors, reactors, or dynamic control systems associated with the FACTS device as detailed in the relevant section of this Guideline.

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:[1]

- Section 201.1 of the ISO rules, *Pool Participant Registration* ("Section 201.1").

The purpose of this Information Document is to provide guidance to a market participant intending to participate in the Alberta electricity market or the ancillary services market, thereby becoming a pool participant.

2 How to Become a Pool Participant

The AESO recommends that the applicant contact the AESO at info@aeso.ca at least two (2) to three (3) months in advance of the in-service date and before submitting the *Pool Participant Application*. This ensures that the application process is complete by the time the applicant intends to participate in the Alberta electricity market.

An applicant completes the *Pool Participant Application*, as required by subsection 3 of Section 201.1 of the ISO rules, along with the *Pool Asset Addition Form* and the *Agent Appointment Request Form* where appropriate. Requirements concerning the appointment of an agent can be found in Section 201.2 of the ISO rules, *Appointment of an Agent*. The *Pool Participant Application* also requires the *Request for Banking Information* to be completed and attached. The *Request for Banking Information* form cannot be processed unless signed by an authorized corporate officer. If applying to the AESO as the legal owner of a generating unit, an applicant also submits a copy of the Alberta Utilities Commission site permit and a copy of a single line diagram.

An applicant that is properly registered to carry on business in Alberta, in accordance with the *Business Corporations Act*, may facilitate transactions in the power pool.

In accordance with section 103.3 of the ISO rules, *Financial Security Requirements*, an applicant is subject to a financial review by the AESO. The intent of the review is to assess the creditworthiness of an applicant in order to determine whether the AESO is able to grant the applicant an unsecured credit limit pursuant to section 103.3 of the ISO rules. An AESO credit analyst will contact the applicant to determine the amount of security the applicant is required to post with the AESO.

The corporate contact information required on the *Pool Participant Application* is for the purposes of the Energy Trading System. This individual is responsible for the authorization of all digital certificate requests, revocations and any contact information updates in the Energy Trading System.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the Electric Utilities Act and regulations, and that contain binding legal requirements for market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

3 Pool Asset Addition Forms

Before the AESO approves an application to become a pool participant, an applicant provides the following supporting documents along with the *Pool Participant Application* form as appropriate:

(a) *Generator Asset Addition Form* - if the applicant is applying as the legal owner of a generating unit;

(b) *Unmetered Asset Addition Form* - if the applicant is applying as a marketer (importing or exporting power) or requesting virtual assets (no physical assets) located within the interconnected electric system for the purposes of registering net settlement instructions.

(c) *Distribution Retail & Self-Retail Asset Addition Request Form* - if the applicant is applying as a retailer or self-retailer.

(d) *Transmission Retail & Self-Retail Asset Addition Request Form* - if the applicant is applying for transmission connected load.

(e) If applying as an ancillary service provider, in addition to providing the *Pool Participant Application*, *Request for Banking Information* and *Ancillary Services Asset Request Form*, the applicant submits a single line diagram, an *Automated Dispatch and Messaging System Form*, and one or all of the Technical Characteristics and Contact Information Forms located on the AESO's website.

(f) If applying as a marketer (importing/exporting power), in addition to providing the *Pool Participant Application*, *Request for Banking Information*, *Unmetered Asset Addition Form* and *Automated Dispatch and Messaging System Form,* the applicant also provides an *Application for Import or Export Service*.

(g) If applying as a marketer registering net settlement instructions, the applicant submits the *Pool Participant Application*, *Request for Banking Information*, and *Unmetered Asset Addition Form*. No *Automated Dispatch and Messaging System Form* is required.

4 Digital Certificate

To ensure that the internet based communication between pool participants and the AESO is secure, pool participants purchase a digital certificate to access the AESO's Energy Trading System. Digital certificates allow pool participants to access their invoices and reports specific to the pool assets registered under their profile in the Energy Trading System. As per section 103.6 of the ISO rules, *ISO Fees and Charges,* the AESO charges an annual fee for each digital certificate requested, which appears on the applicable monthly pool statement. For security reasons, digital certificates require renewal on the anniversary date of the installation. The AESO sends an automatic notification to pool participants, via email, one month prior to the annual renewal date.

The *Participant ETS User Access Request and Authorization Form*, along with other information on digital certificates, is found on the AESO's website. This form is submitted by email to cert.admin@aeso.ca.

The pool participant name and the corporate contact name on the *Participant ETS User Access Request and Authorization Form* must be exactly as they appear in the Energy Trading System in order for the digital certificate to be approved.

The AESO notifies the pool participant, via email, when the digital certificate is ready for pickup.

5 Automated Dispatch and Messaging System

In accordance with subsection 3(1) of section 203.1 of the ISO rules, *Offers and Bids for Energy*, a pool participant must submit an offer for each of its source assets with a maximum capability of five (5) MW or greater. A pool participant that submits an offer may receive a dispatch or directive. In accordance with Table 1 of subsection 7 of section 502.4 of the ISO rules, *Automated Dispatch and Messaging System and Voice Communication System Requirements*, a pool participant who may receive a dispatch or directive must have an Automated Dispatch and Messaging System. To request an Automated Dispatch and Messaging System, an applicant completes and submits the *Automated Dispatch and Messaging System Request Form*.

6 Disputes

If the applicant is not satisfied with any AESO decision, it may use the processes set out in section 103.2 of the ISO rules, *Dispute Resolution,* to resolve the matter.

7 Pool Participant Application Amendments

The following guidelines provide information on how to amend a *Pool Participant Application*. The documentation may be submitted via email to info@aeso.ca, with the original to follow via courier.

a) Submit a *Generator Asset Addition Form* to amend or add pool assets. The request to add a new pool asset comes from the corporate contact. Alternatively, the corporate contact can be copied on the request.

b) Send an email notification to a member of the Operations Support team to request an amendment to company contact information in the Energy Trading System. The request comes from the corporate contact. Alternatively, the corporate contact can be copied on the request.

c) For a company name change, provide written notice (i.e. corporate registry documents).

d) For a transfer of a pool asset from one registered Energy Trading System party to another, provide a letter in writing that outlines the change, the parties involved and the effective date. In order for the transfer to be completed, the letter must be signed by an individual with signing authority for each party. Contact a member of the Operations Support team for a letter template.

e) For a pool asset retirement, the pool participant provides the request in writing. This request comes from the corporate contact. Alternatively the corporate contact can be copied on the request.

8 Voluntary Termination of Registration by a Pool Participant

A pool participant may voluntarily terminate its pool participant registration as provided in subsection 8 of Section 201.1, *Pool Participant Registration*, by providing the request in writing and forwarding to the AESO at info@aeso.ca.

In order to voluntarily terminate its registration, a pool participant retires all pool assets listed opposite its name in the Energy Trading System or transfers them to another registered party so that the outcome is to have the pool participant's status changed from "active" to "inactive" in the Energy Trading System.

9 Pool Participant List and Pool Asset List

The AESO maintains a Pool Participant List which contains the registered names of all current pool participants. A pool participant's name remains on the list of pool participants until the AESO directs that it be removed.

The pool participant list contains the following information:

(a) contact individual's name, phone number, mailing address, and fax number; and

(b) where applicable, the agent's name.

The AESO maintains a Pool Asset List. This list contains every pool asset (source/generation or sink/consumption) and the pool participant to which the pool asset is registered.

10 Contact Information

For additional clarification or further questions, please call the AESO FirstCall at 1-888-588-AESO (2376), or email info@aeso.ca.

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendments
2014-12-23	Administrative updates
2013-02-01	Updates to sections of the ISO rules
2012-12-05	Updates to links
2011-08-05	Updated links to various documents, removal of Appendix 2 – *Prudential Requirement and ISO Fees*. Addition of Appendix 2 – *Financial Security Requirements* and Appendix 3 – *ISO Fees and Charges*
2011-06-10	Updating links to various documents
2011-02-09	Revised Digital Certificate link
2010-09-17	Revised pool participant application
2010-06-10	Addition of Appendices, update of ISO Fee Schedule

Information Document
Disturbance Monitoring Equipment Locations
ID #2010-003RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) govern.

1 Purpose

This information document relates to the following Authoritative Documents[1]:

- Alberta Reliability Standard PRC-018-AB-1, *Disturbance Monitoring Equipment Installation and Data Reporting* ("PRC-018-AB-1").

The purpose of this Information Document is to provide a link to the Disturbance Monitoring Equipment List and describe the list amendment procedures. This information document pertains primarily to any legal owner of a transmission facility, legal owner of a generating unit and legal owner of an aggregated generating facility that owns disturbance monitoring equipment.

2 Disturbance Monitoring Equipment Locations

Pursuant to requirement R1 of PRC-018-AB-1, the Disturbance Monitoring Equipment List is available on the AESO website.

3 Amending Procedures

For retrofitting disturbance monitoring equipment at existing substations, the AESO:

1. upon determining that new disturbance monitoring equipment is to be installed, adds the location to the list of disturbance monitoring equipment locations, notifies the affected legal owner and determines a date by which a new disturbance monitor will be installed; and
2. posts the amended list of disturbance monitoring equipment locations on the AESO website.

For new capital projects that also require new disturbance monitoring equipment to be installed, the AESO:

1. adds the required disturbance monitoring equipment location to the list in section 2 above;
2. includes the required disturbance monitoring equipment in the project functional specification; and
3. posts the amended list of disturbance monitoring equipment locations on the AESO website.

The effective date of required compliance will align with the project's in-service date.

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendments
2013-09-20	Moved the Disturbance Monitoring Equipment List to a separate document
2012-12-04	Updated the effective date of required compliance; added amending procedures for new projects
2012-01-17	Initial release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
Changes Related to Implementation of Fair, Efficient and Open Competition Regulation
ID #2010-004R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents[1]:

- Section 201.2 of the ISO rules, *Appointment of an Agent* ("Section 201.2");
- Section 201.3 of the ISO rules, *Offer Control Information* ("Section 201.3");
- Section 306.3 of the ISO rules, *Load Planned Outage Reporting*;
- Section 306.4 of the ISO rules*, Transmission Planned Outage Reporting and Coordination* ("Section 306.4"); *and*
- Section 306.5 of the ISO rules, *Generation Outage Reporting and Coordination* ("Section 306.5")*.*

The purpose of this Information Document is to help market participants understand those Authoritative Documents and to provide clarity on how the AESO has implemented incidental process and administrative changes deemed necessary as a result of the *Fair, Efficient and Open Competition Regulation* (the "FEOC Regulation").

This information document is likely of most interest to pool participants that appoint an agent, to pool participants that submit bids and offers, and to market participants that utilize the outage records the AESO publishes.

2 Background

The FEOC Regulation was released by the Alberta Department of Energy on June 18, 2009, and came into force on September 1, 2009.

3 Implementation of Specific Rule Changes and Procedures

3.1 Regulation Section 3 – Preferential Sharing of Records That Are Not Available to the Public

Section 201.2 of the ISO rules identifies the requirements for the AESO's approval of certain information sharing relationships between pool participants and their respective agents. The AESO functions as the administrator of agency appointments whereby a pool participant may appoint an agent to represent the pool participant in dealings with the AESO. The *Agency Appointment Request Form* is located on the AESO website.

Section 3(2) of the FEOC Regulation allows for certain exemptions from the prohibition against the sharing of "*records that are not available to the public relating to any past, current or future price and quantity offer made to the power pool or for the provision of ancillary services.*"

One of the exemptions for the sharing of records between market participants is where a market participant appoints an agent to trade, among other things, electric energy on their behalf. This agency relationship is recognized once an AESO *Agency Appointment Request Form* is submitted, which the AESO approved prior to September 1, 2009. If a pool participant wishes to appoint an agent to act on its behalf in dealings with the AESO and such relationship is otherwise prohibited by section 3 of the FEOC Regulation, then the pool participant needs to

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

obtain an order from the Alberta Utilities Commission under section 3(3) of the FEOC Regulation before the AESO approves of such relationship.

Market participants are reminded that, as set out in Section 201.2 of the ISO rules, "the ISO must not approve the appointment of an agent if the subject matter of the agency extends, in whole or in part, to the preferential sharing of records in violation of or noncompliance with the provisions of subsection 3(1) of the *Fair, Efficient and Open Competition Regulation*, unless there is an exception to the prohibition against the sharing of records, as specified in section 3(2) of that Regulation." In accordance with the *Electric Utilities Act* section 21.1, "…if the Independent System Operator suspects that a market participant has contravened an ISO rule, the Independent System Operator, must refer the matter to the Market Surveillance Administrator."

3.2 Regulation Section 4 – Restrictions on Trading Using Outage Records That Are Not Available to the Public

Section 4 of the FEOC Regulation prohibits trading on outage information. Section 4 reads, "[A] market participant shall not, directly or indirectly, use outage records to trade unless permitted to do so under this section"*.* However, in order to facilitate market participants' ability to properly trade using information contained in the outage records, subsection 4(2) imposes an obligation on market participants to provide outage records to the AESO that are used to comply with subsection 4(3): to populate and publish certain outage records, as described more fully below. Under the FEOC Regulation, the AESO is responsible for the administrative and management responsibilities for outage report information gathering and publication.

Accordingly, when the AESO publishes these reports, it further is required under section 4(3) to "…include the effective date and time of the most recent outage records received from market participants…" The following provides additional detail on how the AESO fulfills these obligations as required by the FEOC Regulation:

(a) Generating Unit Fuel Type

The AESO publishes outage information on the AESO website in the form of a "*Daily Outage Report*" and a "*Monthly Outage Report*", (the "Generator Outage Reports") both aggregated by fuel type. The reports are time and date stamped in accordance with the above mentioned obligations imposed by the FEOC Regulation.

Section 306.5 of the ISO rules requires market participants to "by the (1st) day of every month subsequent to the date of commissioning, submit scheduled generator outages that are planned to occur at any time within the next twenty four (24) months after that day…". Under subsection 4(6) of the FEOC Regulation, the AESO exempts a market participant from providing outage schedule for planned outages that are scheduled to occur at a time the beyond the next twenty-four (24) months. As such, market participants are not required to submit any information in addition to that which is required under Section 306.5 of the ISO rules. The Generator Outage Reports are populated based solely on outage volume (MW) submitted to the AESO by pool participants and do not reflect any other information related to an offer such as minimum stable generation or an acceptable operational reason.

Note that the AESO is currently assessing whether there are circumstances in which outage records beyond twenty four (24) months may be material. Depending on the outcome of this assessment, the AESO may implement a process for market participants to provide an outage schedule for planned outages beyond twenty four (24) months for publication by the AESO.

(b) Transmission Facility

The AESO publishes two (2) reports addressing outages to transmission equipment, *Long Term Long Term Significant Transmission Outages* and *System Coordination Plan -*

Approved Outages. These include a time and date stamp in accordance with the requirements of the FEOC Regulation.

The current requirement for the AESO to publish these two (2) reports is addressed in Section 306.4 of the ISO rules Market participants are not required to submit any additional information pursuant to the FEOC Regulation.

The AESO also publishes the *AIES Event Log* report to communicate unplanned transmission outages the AESO has assessed and are determined to have a material impact to system reliability and/or have a material impact on available generation. This report is updated with unplanned transmission outage information as soon as reasonably practical upon the AESO receiving such information from market participants.

(c) Electric Distribution System

The AESO does not currently collect and publish information regarding outages on the electric distribution system. The AESO does not see a need for any changes at this time, and has granted an exemption under subsection 4(6) of the FEOC Regulation to market participants from providing such outage records.

(d) Market Participant Capability to Consume Electric Energy

Section 306.2 of the ISO rules, *Load Planned Outage Reporting* sets out the obligation for a market participant to provide information to the AESO relating to a decrease in its capability to consume load. The information collected from market participants is used to produce the *Load Outage Report*. In preparing the *Load Outage Report*, the AESO aggregates load outage records, and determines daily load outages in MW as:

the sum of MWh of all submitted outages by time period

divided by

the number of hours in the time period.

Specifically, a market participant with a planned decrease in its capability to consume load of forty (40) MW or greater, is required to provide load outage records to the AESO. The AESO has provided an exemption under subsection 4(6) of the FEOC Regulation to market participants who do not meet the forty (40) MW threshold.

The AESO prepares a daily load outage report on each business day and posts it daily on the AESO website including:

(i) time and date the report was prepared; and

(ii) daily average MW load outage, rounded to the nearest MW, for each day of the current month and the next three (3) months.

All market participants that meet the above noted criteria are required to provide the following load outage records to the AESO in the form and manner provided for at load.outage@aeso.ca:

(iii) start date/start time;

(iv) end date/end time; and

(v) decrease in the capability to consume (MW) equal to forty (40) MW or greater.

The *Load Outage Report Form* is posted on the AESO website:

3.3 Regulation Section 6 – ISO matters

(a) Merit Order Snapshots

Under section 6 of the FEOC Regulation, the AESO is required to "make available to the public the price, quantity and asset identification associated with each offer made to the power pool that is available for dispatch" on a 60-day delayed basis. As a result, three (3) historical reports (*Merit Order Snapshot-Energy, Merit Order Snapshot-Ancillary Service* and *Merit Order Snapshot Report-DDS*) are published on the AESO's website. Market participants are not required to submit any additional information pursuant to the FEOC Regulation.

The above reports are snapshots of the System Controller Dispatch Tool taken at the mid-point of the settlement interval. The reports are published sixty (60) days after the date of the snapshot and capture twenty-four (24) snapshots representing the prior twenty-four (24) hour period.

Please see attached Appendix 1 for examples of the three (3) reports.

(b) Offer Control Reporting

Subsection 6(2)(a) of the FEOC Regulation requires the AESO to "develop information technology systems capable of identifying and tracking the market participant that holds the offer control associated with each price and quantity offer made to the power pool". To facilitate this requirement, ISO rule Section 201.3, *Offer Control Information* requires pool participants to provide the identity of offer control parties to the AESO. Pool participants are encouraged to refer to the ETS Manuals for "Submission" and "Ancillary service restatements and substitutions" for further information on the IT related changes and the impacts to pool participants.

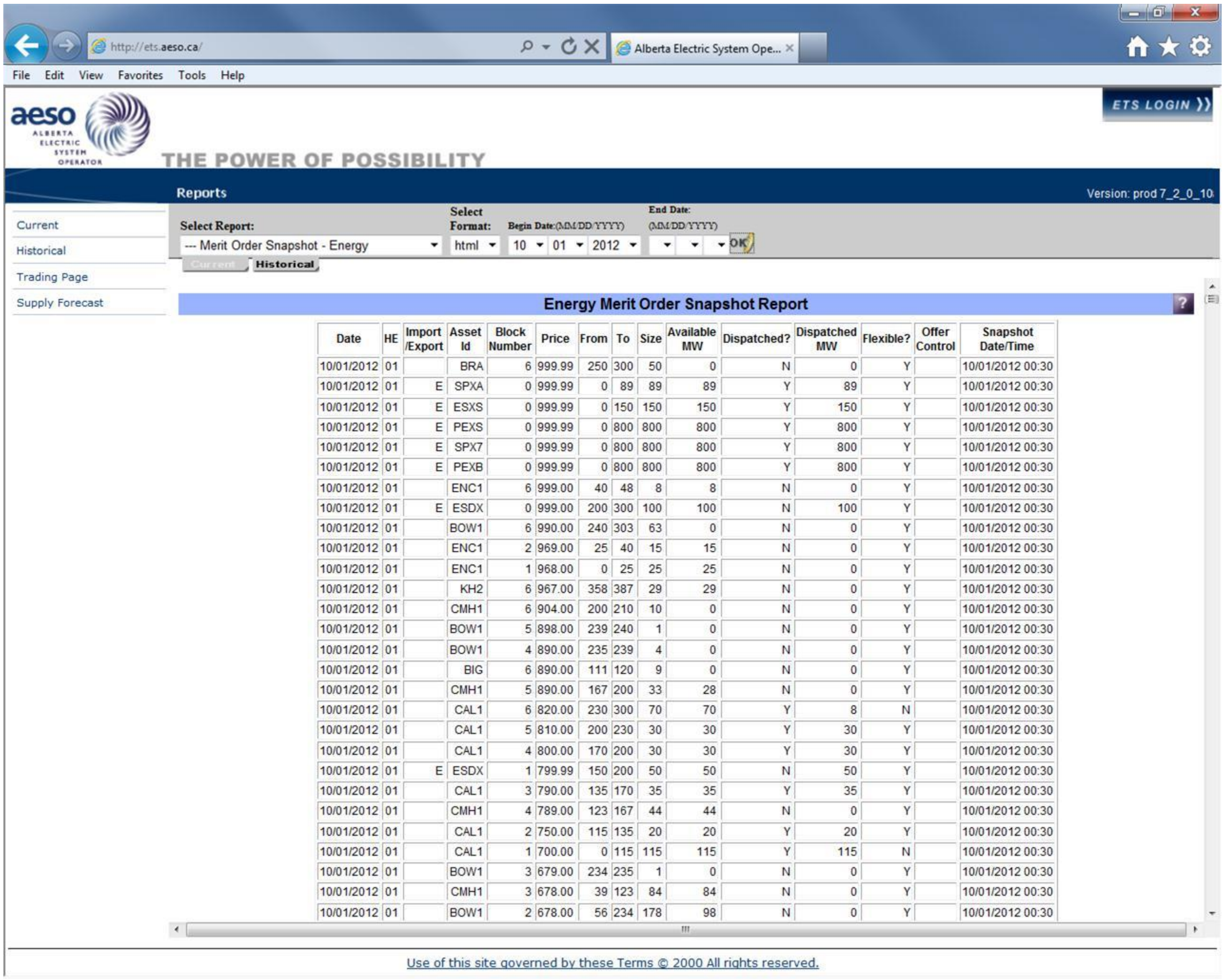
5 Appendices

Appendix 1 – *Merit Order Snapshot Reports*

Revision History

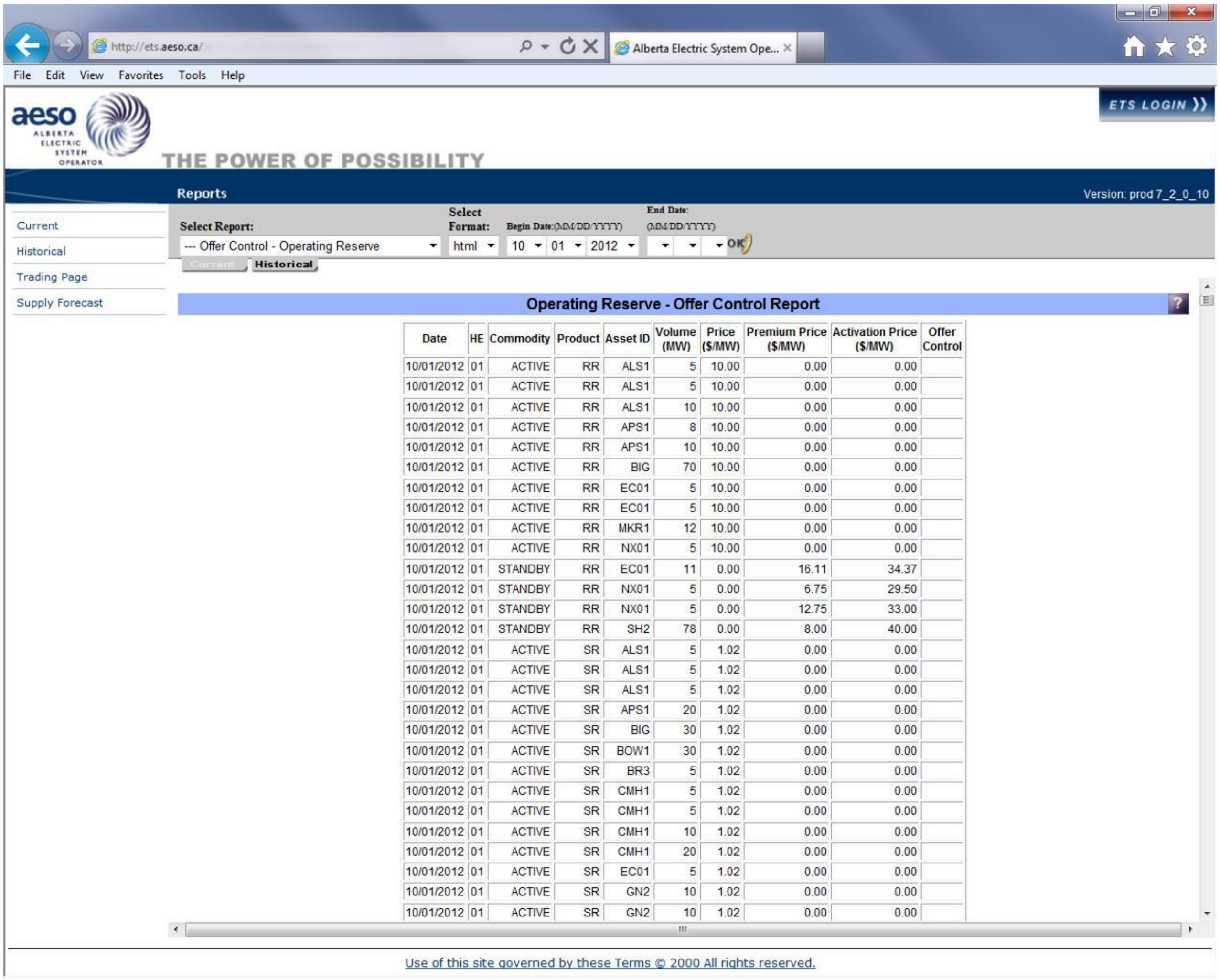
Effective Date	Description of Changes
2017-06-22	Update to section 3.2(a).
2016-09-28	Administrative amendments
2014-07-15	Updated to revise references to ISO Authoritative Documents and related changes.
2012-12-04	Updated to reflect the implementation of ISO Rules Section 201.3 and related IT changes and general clarification updates.
2012-07-19	Updated to include proposed new ISO Rules Section 201.3
2012-04-28	Update of AESO Implementation Details
2009-08-31	Update of AESO Implementation Details
2009-08-07	Initial Release

Appendix 1 – Merit Order Snapshot Reports



Energy Merit Order Snapshot Report

Date	HE	Import /Export	Asset Id	Block Number	Price	From	To	Size	Available MW	Dispatched?	Dispatched MW	Flexible?	Offer Control	Snapshot Date/Time
10/01/2012	01		BRA	6	999.99	250	300	50	0	N	0	Y		10/01/2012 00:30
10/01/2012	01	E	SPXA	0	999.99	0	89	89	89	Y	89	Y		10/01/2012 00:30
10/01/2012	01	E	ESXS	0	999.99	0	150	150	150	Y	150	Y		10/01/2012 00:30
10/01/2012	01	E	PEXS	0	999.99	0	800	800	800	Y	800	Y		10/01/2012 00:30
10/01/2012	01	E	SPX7	0	999.99	0	800	800	800	Y	800	Y		10/01/2012 00:30
10/01/2012	01	E	PEXB	0	999.99	0	800	800	800	Y	800	Y		10/01/2012 00:30
10/01/2012	01		ENC1	6	999.00	40	48	8	8	N	0	Y		10/01/2012 00:30
10/01/2012	01	E	ESDX	0	999.00	200	300	100	100	N	100	Y		10/01/2012 00:30
10/01/2012	01		BOW1	6	990.00	240	303	63	0	N	0	Y		10/01/2012 00:30
10/01/2012	01		ENC1	2	969.00	25	40	15	15	N	0	Y		10/01/2012 00:30
10/01/2012	01		ENC1	1	968.00	0	25	25	25	N	0	Y		10/01/2012 00:30
10/01/2012	01		KH2	6	967.00	358	387	29	29	N	0	Y		10/01/2012 00:30
10/01/2012	01		CMH1	6	904.00	200	210	10	0	N	0	Y		10/01/2012 00:30
10/01/2012	01		BOW1	5	898.00	239	240	1	0	N	0	Y		10/01/2012 00:30
10/01/2012	01		BOW1	4	890.00	235	239	4	0	N	0	Y		10/01/2012 00:30
10/01/2012	01		BIG	6	890.00	111	120	9	0	N	0	Y		10/01/2012 00:30
10/01/2012	01		CMH1	5	890.00	167	200	33	28	N	0	Y		10/01/2012 00:30
10/01/2012	01		CAL1	6	820.00	230	300	70	70	Y	8	N		10/01/2012 00:30
10/01/2012	01		CAL1	5	810.00	200	230	30	30	Y	30	Y		10/01/2012 00:30
10/01/2012	01		CAL1	4	800.00	170	200	30	30	Y	30	Y		10/01/2012 00:30
10/01/2012	01	E	ESDX	1	799.99	150	200	50	50	N	50	Y		10/01/2012 00:30
10/01/2012	01		CAL1	3	790.00	135	170	35	35	Y	35	Y		10/01/2012 00:30
10/01/2012	01		CMH1	4	789.00	123	167	44	44	N	0	Y		10/01/2012 00:30
10/01/2012	01		CAL1	2	750.00	115	135	20	20	Y	20	Y		10/01/2012 00:30
10/01/2012	01		CAL1	1	700.00	0	115	115	115	Y	115	N		10/01/2012 00:30
10/01/2012	01		BOW1	3	679.00	234	235	1	0	N	0	Y		10/01/2012 00:30
10/01/2012	01		CMH1	3	678.00	39	123	84	84	N	0	Y		10/01/2012 00:30
10/01/2012	01		BOW1	2	678.00	56	234	178	98	N	0	Y		10/01/2012 00:30



Operating Reserve - Offer Control Report

Date	HE	Commodity	Product	Asset ID	Volume (MW)	Price ($/MW)	Premium Price ($/MW)	Activation Price ($/MW)	Offer Control
10/01/2012	01	ACTIVE	RR	ALS1	5	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	ALS1	5	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	ALS1	10	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	APS1	8	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	APS1	10	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	BIG	70	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	EC01	5	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	EC01	5	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	MKR1	12	10.00	0.00	0.00	
10/01/2012	01	ACTIVE	RR	NX01	5	10.00	0.00	0.00	
10/01/2012	01	STANDBY	RR	EC01	11	0.00	16.11	34.37	
10/01/2012	01	STANDBY	RR	NX01	5	0.00	6.75	29.50	
10/01/2012	01	STANDBY	RR	NX01	5	0.00	12.75	33.00	
10/01/2012	01	STANDBY	RR	SH2	78	0.00	8.00	40.00	
10/01/2012	01	ACTIVE	SR	ALS1	5	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	ALS1	5	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	ALS1	5	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	APS1	20	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	BIG	30	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	BOW1	30	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	BR3	5	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	CMH1	5	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	CMH1	5	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	CMH1	10	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	CMH1	20	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	EC01	5	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	GN2	10	1.02	0.00	0.00	
10/01/2012	01	ACTIVE	SR	GN2	10	1.02	0.00	0.00	

Information Document
Bulk Transmission Line Technical Requirements
ID#2010-005R

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1. Purpose and Background

This Information Document supports new ISO Rules Part 500, Division 502, Section 502.2 and provides additional information to assist market participants who are the legal owners of bulk transmission lines. Section 502.2 stipulates the minimum technical requirements for the design of a bulk transmission line connecting to the interconnected electric system.

To assist users, the section numbering in this document matches the corresponding subsection in section 502.2, as far as possible.

In Alberta, bulk transmission lines can be designed and constructed by a number of entities, including the legal owners of a transmission facility, industrial system designation area owners and others such as developers of wind aggregated generating facilities and those developing merchant lines for power import and/or export.

To ensure a consistent approach to the design of bulk transmission lines within Alberta, the AESO has implemented section 502.2, which addresses the minimum technical requirements in the areas of line design while considering reliability, safety and economics.

2. Applicability to New and Existing Bulk Transmission Lines

The new section 502.2 provisions in general do not apply to retrofit or change existing systems presently connected to the interconnected electric system. However, as noted in Subsection 2(5) of section 502.2, the AESO reserves the right, on a case-by-case basis, to endorse retrofitting an existing non compliant bulk transmission line with this standard for those lines the AESO deems critical to the interconnected electric system.

Existing bulk transmission lines, including maintenance replacements, additions and alterations, meeting the original designs that currently comply with the requirements of previous and current versions of the *Alberta Electrical Utility Code*, need not be modified to comply with section 502.2, except as might be required for safety reasons by the authority having jurisdiction.

In general, section 502.2 applies to new construction. For maintenance of existing bulk transmission lines, or additions to existing lines having a length less than 1500 m, the AESO Technical Standard in effect at the time of the original design (or a subsequent edition with which the installation has been brought into compliance) applies. However, when an extension having a length equal to or greater than 1500 m, or reconstruction of relatively large proportions is being carried out, the AESO may request the reconstruction of other portions of the bulk transmission line to comply with section 502.2.

The value of 1500 m was chosen to avoid application of the section 502.2 to minor taps and bulk transmission line extensions. It is normally not reasonable to design a very short portion of a line to meet criteria that may significantly exceed those of the majority of the line.

The 1500 m length represents approximately ten spans of single circuit 138 kV or 144 kV wood pole line, or approximately four spans of a 240 kV lattice tower bulk transmission line.

3. Functional Specifications

Any design aspect that deviates from the requirements of section 502.2, must be approved by the AESO and documented in the approved functional specification for the bulk transmission line project.

4. Successor to Prior Requirements

Information is not required at this time.

5. Other Code Requirements

See section 5 for a listing of other standards, codes and regulations that must be adhered to with regard to bulk transmission line design and construction. It should be noted that in Alberta the *Alberta Electrical Utility Code* (AEUC) has force of legislation. In general, the AEUC refers to the requirements of CSA C22.3 No. 1-06 but there are some requirements in the AEUC (most notably ground clearances) that exceed the values in CSA C22.3 No. 1. Designers need to be familiar with the requirements in both documents, and where there is a conflict, the requirements of the *Alberta Electrical Utility Code* will govern.

6A. Structural Design

This subsection 6A provides general information related to structural loading requirements outlined in section 502.2 and does not relate to specific subsections in those rules.

Requirements of subsections 6 through 15 are applicable to the determination of loads, and strength of structures and foundations, and the selection of conductors and overhead shieldwires.

A probability based approach is required for loads and is reflected in the requirements of section 502.2.

Both the 2006 and the 2010 versions of CSA C22.3 No. 1 state (Clause 10) that **"*Supply and communication lines shall be designed using the deterministic design method or the reliability-based design method*."** Since data for application of reliability based design is available and is provided in the AESO loading maps, there is no need to include deterministic design loads for the design of bulk transmission lines.

A probability based approach can be used for strength determination (as per CSA C22.3 No. 60826) but is not mandatory. Strength factors are used in Section 502.2 to account for strength variation of wood and similar materials, and as a method of designing for the desired sequence of failure.

As an alternative to using the specified strength factors in the design calculations, the strength factors can be converted to equivalent overload factors and are to be applied to the loads specified in section 502.2. For example, the strength factor of zero point nine (0.9) which is to be applied to angle and deadend structures for sequence of failure purposes can be converted to an equivalent overload factor equal to 1.0/0.9 = 1.1. The calculated loads for the angle and deadend structures are then multiplied by the additional 1.1 overload factor and the resulting factored loads are used for structure design.

Alberta legal owners of transmission facilities expressed concern with some requirements of CSA C22.3 No. 60826. Hence, adoption of C22.3 No. 60826 as published and in its entirety was determined to not meet the needs for design of bulk transmission lines in Alberta. Section 502.2 does accurately reflect weather loadings and other operating conditions in Alberta.

6B. Selection of Return Periods

It is recognized that there may be situations where the return period values specified in section 502.2 are not appropriate. Examples include:

(1) Critical river crossings (design return period may be higher);

(2) Line built and operated at a transmission voltage that actually performs the function of a distribution line (design return period may be lower); or

(3) A line that is designated as "system critical" by the AESO (design return period may be higher).

As per subsection 6(4) of section 502.2, for those situations where the AESO wishes to have a specific bulk transmission line designed for a non-standard return period, the requirements will be identified in the functional specification for the project.

For situations where the legal owner believes a non-standard return period should be used for all or part of a specific bulk transmission line, the legal owner is required to obtain approval from the AESO prior to beginning design of the line.

6C. Earthquake Loads

Section 502.2 does not include requirements for earthquake loads because these are not applicable to bulk transmission line structures. There was, however, a desire to include information in the Information Document explaining why earthquake loads are not applicable. Bulk transmission line structures need not be designed for ground-induced vibrations caused by earthquake motion and therefore this is not addressed in the new rule. This is because:

(1) Historically, bulk transmission line structures have performed extremely well under earthquake events; and

(2) Bulk transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.

This may not be the case if the bulk transmission line structure is partially erected or if the foundations fail due to earth fracture or liquefaction.

Transmission structures are designed to resist large horizontal loads of wind blowing on the wires and structures. These loads and the resulting strengths provide ample resistance to the largely transverse motions of the majority of earthquakes. Decades of experience with transmission lines of all sizes has shown that the very infrequent transmission line damages have resulted from soil liquefaction or when earth failures affect the structural capacity of the foundation.

The above information is taken from *ASCE Manual 74 Guidelines for Electrical Transmission Line Structural Loading, Third Edition.*

7. Weather Loads for Wind

It has been determined that the values of gust response factors for wires (G_w) calculated by the ASCE method are not representative of wind structure in Alberta (open terrain and laminar wind flow). The values given in section 502.2 are more appropriate for Alberta weather conditions.

The AESO wind map referenced in section 502.2 and which is to be used for values of design wind, is posted on the AESO website.

There have been a number of bulk transmission line failures in Alberta resulting from tornado or downburst winds. However, given the difficulty in determining the expected location and magnitude of this type of loading, these wind loadings have not been included in section 502.2.

8. Weather Loads for Wet Snow and Wind

The magnitudes of combined wet snow and wind loadings for probability based design were determined through the use of a computer based analytical model. Alberta does not experience significant glaze ice accretion but does experience major wet snow and wind events, which have caused extensive damage to bulk transmission lines. Hence, the work to develop probability based combined loadings was focused on combined wet snow and wind events.

The AESO map that provides values of combined wet snow and wind for probability based design is posted on the AESO website.

Under the rule, there is no specified minimum requirement to design 138 or 144 kV bulk transmission lines for the probability based wet snow and wind loads. These lines normally have lower reliability requirements than lines of higher voltages, and there are usually redundant paths so an outage on one line does not have a major impact on the interconnected electric system. If the AESO determines that a specific 138 or 144 kV bulk transmission line should be designed to withstand the probability based wet snow and wind load, the loading requirement will be identified in the functional specification for the project.

9. Weather Loads for Vertical Load Alone

Since studies to determine specific rime ice loadings are not available, the radial accretion values from the combined wet snow and wind loads, with a density of 350 kg/ m^3 and a temperature of -20°C and with no wind, are used to represent the rime ice vertical loading condition. Experience in Alberta indicates that this is a reasonable approach.

10. Failure Containment Loads

Longitudinal loads on bulk transmission lines can result from different wet snow loads on adjacent spans, or from the failure of line components, including structures, wires, insulators or hardware.

In the past, bulk transmission lines were not specifically designed to withstand longitudinal loads, and a significant number of longitudinal cascades, which involved the failure of many structures from a single initiating event, took place. Several longitudinal cascades have been observed in Alberta.

Current bulk transmission line design standards and practice include requirements for unbalanced longitudinal, or failure containment, loads as part of the line design. The failure containment loading requirements in section 502.2 reflect conditions in Alberta and strike a balance between reliability and cost. Hence, the loading conditions specified are not the worst possible conditions that could occur, but were chosen to reflect conditions that might reasonably be expected to occur in Alberta. Designing bulk transmission lines to withstand the specified loads should limit the extent of line failure, in the event of an unbalanced longitudinal loading event, to a relatively small number of structures.

In section 502.2, the loading value for the broken wire case is specified as bare wires, no wind, at final tension and 0°C. For northern Alberta, where low temperatures are common, it may be prudent to use a temperature of -30°C for the broken wire load case. The values of load for this loading case are commonly referred to as residual static loads.

The wet snow load used for the unbalanced wet snow case are to be equal to the return period values required by subsections 6(1) and 8(2). For example, if the given line is to be designed for a vertical load of 70 mm radial wet snow, the loading used for the unbalanced wet snow load case is 70 mm wet snow.

The loading values calculated for the two (2) loading conditions set out in subsection 10(3) of section 502.2 should be determined using a computer program model that can model bulk transmission line sections with a number of spans.

The bulk transmission line computer program model should include the following specifications and assumptions:

(a) it should be a thirty (30) span section consisting of all tangent structures, with level ground;

(b) for the broken wire case, the break should be assumed to occur at any point in the bulk transmission line section, and the highest loading values obtained from the analysis should be used for structure design;

(c) for the unbalanced wet snow case, the bulk transmission line should be assumed to have an initial state of all wires with the specified wet snow loading, with wet snow then dropped from four (4) spans in the middle of the thirty (30) span section;

(d) for a single circuit bulk transmission line, wet snow should be assumed to be dropped from any one (1) phase or overhead shieldwire; and

(e) for a double circuit bulk transmission line, wet snow should be assumed to be dropped from any two (2) phases or overhead shieldwires, or one (1) phase and one (1) overhead shieldwire.

The above paragraph provides detailed recommendations for the line model used to determine values of broken wire and unbalanced wet snow loads. These recommendations reflect the outcome of extensive work, for bulk transmission lines in Alberta, to develop realistic models for failure containment loading. It was found that with line sections 30 spans or longer the magnitude of longitudinal load did not change with the addition of more spans. Long line sections of only tangent structures are also typical of numerous existing bulk transmission lines in Alberta, so the 30 span criteria is realistic.

The criteria described above for unbalanced wet snow represents realistic loading expectations for bulk transmission lines in Alberta. Observations of large diameter accretions of wet snow loads on bulk transmission lines in the province indicates that the wet snow tends to drop off in short sections, and in multiple spans at more or less the same time. Situations with a large number of spans with no snow, and adjacent bulk transmission line sections with full snow accretion have not been observed. Hence, the criteria of wet snow dropped from only four (4) spans is a realistic representation of unbalanced loading for Alberta.

It is recognized that the criteria recommended above does not represent a worst possible case situation. The intent is to reflect reasonable, or most likely, loading cases, not worst possible cases. Alberta does not experience significant glaze ice accretion, but does experience very significant wet snow events. That is why the unbalanced loading case assumes wet snow, rather than glaze ice.

Where the bulk transmission line structures are self supporting lattice towers and the requirement for failure containment loading is met by providing longitudinal strength at all suspension type structures, the towers should be of square base design. This recommendation is based on the practice of most major utilities in Canada and the U.S., including Hydro One and BPA and is further supported by the requirements of the *American Society of Civil Engineering Manual 74 –Guidelines for Electrical transmission Line Structural Loading Third Edition*.

The process of determining appropriate loading conditions and corresponding structural load values for longitudinal or failure containment loads is not a straightforward process. General practice is to use the tension of bare wires, under everyday conditions, with no ice or wind, as the basis for broken wire loads. In reality, broken wires (or failed deadend hardware) are more likely to take place when the wires are under ice and/or wind loading.

Unbalanced ice loads are also difficult to predict, since the degree of ice loading and shedding and many other variables make it very difficult to calculate accurate values of structure design loads for this situation.

With a square base tower, the overall structure normally has some “reserve” longitudinal capability should the actual unbalanced longitudinal loads be higher than the values specified for the tower design. With a rectangular base tower, this may not be the case and hence if a rectangular base is an option for the tower design, higher design values of longitudinal loads may be needed to ensure that the rectangular base tower will, in practice, have a reliability with respect to longitudinal and failure containment loads equal to that of a standard square base tower.

Towers of existing designs which do not have square bases may be used for any short tap or short extension project of an existing bulk transmission line, until such time as new towers are developed.

Subsection 10(5) specifies the interval between anti cascade structures. However, this interval can take into account the relative importance of the line and the availability of replacement material, should a line failure occur. If the bulk transmission line designer believes that a different interval is appropriate taking into account these factors, a request should be made to the AESO for use of the alternative interval.

It should be noted that wood structures are inherently flexible and the deflection of the poles under unbalanced longitudinal loads tends to limit the cascade to a small number of structures. Hence, section 502.2 allows use of a computer analysis to determine whether the number of wood structures that will fail under the specified longitudinal loading is acceptable. If it is determined that no structures are likely to fail, or if the number of structures that are likely to fail is acceptable, given the nature of the line, then anti-cascade structures are not required.

11A Construction and Maintenance Safety

Although section 502.2 does not have requirements for construction and maintenance loadings, these are an important consideration in the design of bulk transmission lines and were included in this Information Document as reference information for bulk transmission line designers.

These loadings are intended to ensure the safety of personnel during construction and maintenance operations. The magnitude of these loads, and the applied overload factors, are set so as to provide a reasonable safety margin relative to failure. The loads are considered constant and are treated in a deterministic manner. There is no requirement to include ice or high wind as part of the construction and maintenance loadings, since it is reasonable to assume that the operations included in these situations are not normally conducted during storm conditions.

The following criteria reflect generally accepted practice in terms of design loadings for bulk transmission line structures, to ensure a reasonable margin for the safety of personnel during construction and maintenance operations on any bulk transmission line:

(a) for structure erection, the strength of all lifting points and related components can withstand two (2) times the static loads produced by the proposed erection method, subject to the discretion and responsibility of any on site engineer in situations where the erection operations are under the direct supervision of that engineer;

(b) with regard to conductor stringing and sagging, structures can withstand wire tensions equal to the greater of either:

  (i) one point five (1.5) times the sagging tension; and

  (ii) two point zero (2.0) times the stringing or pulling tension;

(c) all tensions are calculated at the minimum temperatures likely to be encountered by personnel during the stringing and sagging operations for the bulk transmission line, and take into account wind speeds expected to occur while the stringing and sagging operations are underway where such personnel are reasonably expected to be present;

(d) tension increase due to conductor overpull for deadending, particularly in short spans between deadend structures, are to be taken into account;

(e) the arms of structures are designed to withstand the loads imposed by conductor tie down operations, with an overload factor of two point zero (2.0);

(f) for maintenance operations, all wire attachment points are able to support at least two point zero (2.0) times the bare vertical weight of wire on the structure at sagging tensions;

(g) any temporary lifting or deadending points located near permanent wire attachment points are able to resist at least two point zero (2.0) times the bare wire loads at sagging tensions;

(h) all structural members that may be required to support personnel are designed for a force of at least 1500 N applied vertically at the most critical point of the member, in addition to the stresses imposed by external bare wire loadings; and

(I) bulk transmission line structures are designed with clearances, strength and rigging points necessary for live line maintenance work methods.

11B. Overload and Strength Factors for Reliability Based Loads

Reliability based design uses weather loading values that are probabilistic in nature and are therefore return period based.

In the application of the probabilistic methodology, the objective is to design a structure (or structural system) with resistance greater than the maximum calculated design load. The structure must also have an acceptable level of safety and reliability.

The strength factor, which is used to adjust the allowable strength of line components, is used to account for the strength variability of wood poles and also to adjust the relative strengths of components on a steel structure line to produce a target sequence of failure. The strength factors provided in Table 2 of section 502.2 are from the *National Electrical Safety Code Standard C2-2007*. The NESC data was used since it includes both steel and wood structures and the information was not readily available from applicable CSA standards. The NESC values are reasonable for use in Alberta.

For laminated wood or fibre-reinforced composite poles, a strength factor equal to that of metal structures may be used if the manufacturer of the poles can demonstrate, by way of certified test reports, that the coefficient of variation, COV (standard deviation divided by the mean) for poles manufactured with the given material, is 10% or less.

As noted in Section 6 above, the strength factors can be converted to equivalent overload factors, which are applied to the basic load values to produce factored loads. If this approach is adopted, the strength factors are not applied, or are assumed to be equal to 1.0.

12. Conductor Selection

With reference to subsection 12 of section 502.2, the use of standard conductor sizes will simplify the process of maintaining emergency spare material and allow sharing of spare material for emergency restoration. Common ACSR and ACSR/TW conductor sizes used in Alberta are listed in Table 1, below.

Table 1
Bulk Transmission Line
Conductor Types Commonly Used in Alberta.

266 kcmil Partridge
397 kcmil Ibis
477 kcmil Hawk
795 kcmil Drake
1033 kcmil Curlew
1192 kcmil Grackle
1234 kcmil Yukon / TW
1590 kcmil Falcon

The conductor types in Table 1 are ACSR with high strength strandings (high ratio of steel to aluminum). These conductor designs are more able to withstand the heavy wet snow and wind loads, and heavy rime ice loadings, experienced in Alberta.

For major 240 kV and 500 kV bulk transmission lines, additional factors may apply to conductor selection and bundle configuration, such as system compatibility, line impedance, electrical load sharing and other system related issues. These factors will be identified in the AESO's functional specification for the project.

Non-standard conductors may be the correct choice for certain situations, such as reconductoring of existing bulk transmission lines or long spans such as major river or lake crossings. The use of non-standard conductors will be identified in the AESO's functional specification for the project.

To address the issue of electrical losses, section 502.2 includes requirements for conductor or line optimization studies. The studies include consideration of capital costs and the net present value of electrical losses in the selection of a conductor for a given project.

The purpose of the conductor (or line) optimization study is to identify the optimum conductor based on expected average load flow and estimated values of losses. In reality, it's an estimate based on currently available information. The risk associated with a wrong guess is relatively small – additional costs for losses.

The purpose of the 100°C requirement of subsection 17(2)(b) of section 502.2 is to ensure that bulk transmission lines are capable of carrying the maximum amount of power. Although AESO planners determine maximum load transfer values based on the best available information, unexpected load growth can easily take place in the future. If a given bulk transmission line is designed for a maximum conductor temperature less than 100C, and the line load (steady state or emergency) results in a temperature higher than the design value, then a new bulk transmission line would need to be built (or system operation would need to be limited) even though an existing bulk transmission line is not fully utilized.

Hence, the requirements for conductor (or line) optimization studies and the requirement for bulk transmission lines less than 500 kV to be designed for ground clearance at 100°C are not in conflict.

For small and medium size projects, which are assumed to include bulk transmission lines having the following characteristics:

a) rated design voltages of 138 or 144 kV and length exceeding 10 km; and

b) rated design voltage of 240 kV or above and length between 10 and 50 km

conductor selection is to be based on either a conductor optimization study or a line optimization study, at the discretion of the line designer. For large projects, which are assumed to include bulk transmission lines having a rated design voltage of 240 kV or above and a length greater than 50 km, a full bulk transmission line optimization study is required.

Although section 502.2 does not require an economic study for conductor selection for bulk transmission lines less than 10 km long, the cost of losses should be considered for heavily loaded lines regardless of the length.

The AESO will provide information on loading levels, cost of losses and other economic parameters and this data is to be used in the economic studies.

Conductors considered in the conductor and line optimization studies noted above need not be limited to those in Table 1, above. The legal owner of the bulk transmission line should use good engineering judgment in the selection of conductor sizes and types to be included in the study. Should the study results indicate a significant benefit from the use of a conductor other than standard ACSR or ACSR/TW types, the legal owner should discuss with the AESO the possibility of using the alternative conductor for the project.

Line optimization studies for a bulk transmission line with lattice steel structures will often calculate estimated tower weights as part of the optimization process. At the completion of the study, the legal owner of the bulk transmission line should consider whether it is best to use standard towers, for which design and detail information is available, or to develop new structures. The legal owner is to discuss with the AESO the rationale for development of new towers before proceeding with tower design.

13. Sequence of Failure

The following criteria (based on *CSA Standard C22.3 No. 60826:06*) were used to develop the sequence of failure specified in subsection 13 of section 502.2 and are recommended for establishing a failure sequence:

(1) The first component to fail should introduce the least secondary load effect (dynamic or static) on other components, in order to minimize cascading failure;
(2) Repair time and costs following a failure should be kept to a minimum; and
(3) A low cost component in series with a high cost component should be at least as strong and reliable as the high cost component, in particular when the consequences of failure are high.

Conductors and related components (in particular deadend insulators and hardware) are chosen as the last to fail because of the possible large extent of a longitudinal cascade failure, and the time and cost associated with bulk transmission line restoration following such a failure.

Although the failure of suspension insulators or their associated hardware is unlikely to initiate a longitudinal cascade, such a failure can initiate a vertical cascade, which can result in extensive structural damage and significant outage time and restoration cost.

It may not be appropriate to rigorously apply the sequence of failure specified in section 502.2 to all bulk transmission line components. For example, it is commonly accepted practice to design the foundations for angle structures to withstand only the loads imposed by the tower with the actual line angle, not the maximum loads for which the tower is designed. In this case, it is not appropriate to design the foundations to be stronger than the tower. Applying an overload factor to the calculated footing reactions which is higher than the overload factor applied to footing reactions for tangent structures would be appropriate.

It is also recognized that where angle structures are used at line angles significantly less than the maximum values, the structures may not fail prior to components of the conductor system. This is acceptable since it is expected that a large number of tangent towers will have failed prior to the conductor system reaching a failure condition. Significant amounts of conductor are likely to be on the ground, which should retain the integrity of the conductor system and hence avoid initiation of a longitudinal cascade, which is the objective of the specified failure sequence.

For long span river crossings, the crossing structures could be designed stronger than the conductors.

In addition, where the conductor tension for the most severe loading case does not exceed approximately 60% of the rated tensile strength and non-standard insulators and/or hardware would be required to meet the sequence of failure criteria, consideration should be given to the use of standard insulators and hardware. It is expected that the strength of the standard insulators and hardware will be equal to at least 85% of the conductor rated tensile strength.

Based on the above, the legal owner therefore should seek and obtain the AESO approval for any derivations on the sequence of failure minimum requirements set out in subsection 13.

14. Overhead Shieldwires

Subsection 14(7) specifies that for bulk transmission lines having average span lengths in excess of 150 m, the minimum size of the shieldwire must be 3/8" Gr. 220. Stronger shieldwire is intended to avoid failure under heavy loadings such as those resulting from wet snow or in-cloud icing, which are common in Alberta. Some older bulk transmission lines in Alberta were designed and constructed with 5/16" overhead shieldwires, and there have been failures of these shieldwires under icing and wet snow conditions.

It should be noted that 3/8" Gr. 220 shieldwire is the minimum size required for bulk transmission lines with average span lengths greater than 150 m. Where bulk transmission lines must be designed for heavy wet snow and wind loadings, a larger size (higher strength) overhead shieldwire may be required, as indicated in Subsection 14(6) of section 502.2.

For bulk transmission lines having average spans shorter than 150 m, but with individual long spans in excess of 200 m, the use of 3/8" Gr. 220 shieldwire for the long spans is recommended. This requirement is intended to apply to individual long spans (such as river crossings) with deadend type structures at each end of the span. The recommendation is not intended to create the need for deadend type structures where they would not otherwise be required. For example, if a section of bulk transmission line consisting of tangent type structures has a span longer than 200 m and would otherwise not require use of 3/8" overhead shieldwire, the recommendation for 3/8" Gr. 220 in long spans should not be the only reason to install deadend structures at each end of the long span so that the larger overhead can be installed on that span.

The purpose of shieldwires, as addressed in subsection 14, is to provide adequate reliability with respect to lightning caused outages. The report *Forced Outage Performance of Transmission Equipment*, published by the Canadian Electricity Association, provides information on historical reliability of transmission lines of various voltage levels and structure types operated by Canadian utilities. The AESO believes it is appropriate to use this data as one of the tools for establishing a target level of lightning performance for a new bulk transmission line. Another tool is the historical lightning performance of bulk transmission lines of similar voltage and construction, located in the same general area as the proposed new line, provided that the performance is better (lower outage rates) than the applicable values given in the CEA report.

Where a bulk transmission line has two shield wires, it may generally be assumed that the fault current is shared equally between both wires.

The AESO recommends that the calculated value of the maximum temperature of shield wires should not exceed the values given in Table 2, below, unless the cable manufacturer can provide documented, independent testing which proves the wire can withstand such temperatures with no loss of strength, functionality, or other damage which may affect its long-term performance. If a bulk transmission line designer wishes to use higher temperature values, a request for approval is to be made to the AESO, supported by the cable manufacturer data noted above.

Table 2

Allowable Maximum Temperatures For Shield Wires

Product	Maximum Temp (°C)
Galvanized Steel (CSA G12)	400
Aluminum Coated Steel	600
Copper Coated Steel	1000
ACSR	400
All Aluminum Conductor	340
OPGW	215

Although overhead shieldwires are a general requirement for bulk transmission lines of 138 or 144 kV and above, there may be special circumstances where it is appropriate to not have an overhead shieldwire for specific spans. Where one bulk transmission line crosses under another bulk transmission line, it may be necessary to remove the overhead shieldwire from the spans of the lower line at the crossing. On long river crossing spans where it is not practical to design the crossing structures to avoid contact of the overhead shieldwire with the phase conductors under differential loading conditions, the overhead shieldwire can be removed in the crossing span.

Removal of the overhead shieldwire from specific spans or line sections should not result in a significant increase in lightning related outages for the subject bulk transmission line.

15. Aeolian Vibration Control

Spacer dampers are specified in the subsection for bulk transmission lines having a rated design voltage of 500 kV or greater. This includes both AC and HVDC bulk transmission lines. Lines at these voltage levels have bundles of three or four subconductors where industry practice is to use spacer dampers rather than spacers.

Subsection 15(5) prohibits the use of spacer dampers with two part metal clamps that result in metal to metal contact between the conductor and the clamp. This requirement is based on field experience, in different parts of the world, where cold flow in the aluminum of the conductor and/or the clamp, or other problems, resulted in loosening of the clamp on the conductor. The loose clamps resulted in damage to the conductor, in some cases leaving only the steel core undamaged.

Examples of spacer damper designs that would be acceptable are those using an elastomer insert between the conductor and clamp, or a clamp that uses preform rods to attach the conductor to the clamp of the spacer damper.

For bulk transmission lines having a rated design voltage of 240 kV or less, with bundled conductors, vibration control is to be achieved either by use of spacer dampers or wireform spacers in the span and dampers at the ends of the span.

The tension limits specified in subsection 15 are based on historical experience with bulk transmission lines in Alberta. The open terrain in the southern part of the province results in laminar wind flow, which creates high levels of Aeolian vibration. Tension limits higher than those specified in subsection 15 have resulted in fatigue failure of conductors. The tension limits assume use of properly designed and installed vibration dampers.

It is recognized that other standards allow conductor tension values higher than the values specified here, but as indicated above operating experience in Alberta (including data from vibration recorders) does not support use of those higher tension limits in Alberta.

It is further recommended that the tension limits be verified using the CIGRE methodology, as outlined in CIGRE Technical Brochure No. 273 *Overhead Conductor Safe Design Tension with Respect to Aeolian Vibrations*, taking into account wire characteristics, spans, tensions and terrain. The CIGRE methodology should only be applied to conductors (not overhead shieldwires). If the CIGRE method indicates tension limits lower than those specified in section 502.2, the CIGRE tension values should be used. The CIGRE approach should not be used to justify tension limits higher than those indicated in section 502.2.

16. Voltage Values for Electrical Clearances

Information is not required at this time.

17. Basic Design Clearances

It should be noted that clearance requirements of the *Alberta Electrical Utility Code* include values contained in its Tables and also requirements specified in CSA C22.3 No. 1-06. Should there be a conflict between values in the *Alberta Electrical Utility Code* and those of CSA C22.3 No. 1-06, the values in the *Alberta Electrical Utility Code* will govern.

In general, ground clearance requirements in the Alberta Electrical Utility Code exceed those in CSA C22.3 No. 1. These higher ground clearance requirements recognize the large farm and other equipment that are common in Alberta.

CSA C22.3 No. 1 allows lines to be designed with maximum temperature for thermal loading conditions less than 100° C. In Alberta, the location of future loads is not clearly defined, as oilfield development, gas compression load and other large loads can develop at unexpected locations. In order to provide the best flexibility for future load development and to ensure the maximum possible utilization of existing facilities, all lines less than 500 kV are to be designed assuming a maximum operating temperature of 100° C. The 100C requirement also maximizes the capability of bulk transmission lines for emergency operation.

The requirement for 12.2 m of clearance for 500 kV alternating current or +/- 500 kV high voltage direct current bulk transmission lines is based in part on the ever increasing size and height of farm equipment in Alberta. Equipment having a height of over 6 m is common, and this height significantly exceeds the value assumed for the clearance calculations in the AEUC (4.9 m, or 16 ft). Also, 12.2 m of clearance is the accepted standard for 500 kV lines used by other major utilities in Canada, including Hydro One.

Ground clearances under conditions of maximum design loading of combined wet snow and wind, or vertical loading alone, should be maintained for any crossings of roads, railways, other bulk transmission lines and for all other locations where the normal activities associated with the given locations are likely to be carried out while the loadings represented by the extreme events are in place. This recommendation is included to address safety under all weather conditions that the line is designed to withstand.

The *Alberta Electrical Utility Code* clearances apply only to the maximum loading conditions specified by that *Code*, which would be maximum temperature and the applicable CSA ice and wind loadings. Therefore, it is not necessary to maintain *Alberta Electrical Utility Code* clearances in all locations under the combined wet snow and wind loads or vertical wet snow alone loads. The rationale is based on recognizing that high farm and other similar equipment is unlikely to be operating under bulk transmission lines at the same time as the extreme wet snow and wind loads, or wet snow loads alone, are affecting the lines. However, large highway vehicles and trains are likely to pass under bulk transmission lines under all loading conditions.

A number of highways in Alberta are specified as high load corridors. Bulk transmission lines crossing these highways must be designed to accommodate loads of at least 9.0 metres in height. A map showing the high load corridors is available on the Alberta Transportation web site. The link to the web site and map is: http://www.transportation.alberta.ca/3192.htm

Prior to building a bulk transmission line that crosses a designated high load corridor, the required clearance should be confirmed with the appropriate authorities.
Clearances to both structures and to the edge of the right of way use a five year return wind gust. The value of the five (5) year gust can be calculated directly from the basic wind data, using the appropriate probability distribution and calculation method. An alternative method is to use the fifty (50) year return gust from the AESO wind loading map, multiplied by a factor of 0.78.

Values of 60 Hz wet flashover distances are given in the following Table 3:

Table 3

60 Hz Flashover Distances

	Air Gap (mm)	
Nominal Voltage	**Phase to Ground**	**Phase to Phase**
69 kV	190	320
72 kV	200	330
138 kV	350	600
144 kV	370	630
240 kV	590	1020
500 kV	1240	2230

Clearance buffers (additional clearance above minimum AEUC requirements) are commonly used in the design of bulk transmission lines. The purpose of these buffers is to ensure that the minimum requirements are met after construction and under normally expected operating conditions, Since the risks associated with meeting AEUC electrical clearance requirements vary depending on many factors, such as the type of construction, terrain, etc. no specific requirements for clearance buffers are included in section 502.2.

Insulator Swing - Historical Basis

With the growth in 138kV transmission through the 1950's and 1960's, most utilities in Alberta became aware that high winds acting on transmission lines with suspension insulators frequently resulted in flashovers to the pole or crossarms resulting from insulator swing. This was the fact even though design code requirements of the day were met or exceeded.

There were no comprehensive meteorological studies available at the time which could have been used to establish a rational basis for design of insulator swing. However, through a process of trial and error, wind criteria were established indirectly and were found to provide an acceptable level of performance.

In 1977 a series of meteorological studies were conducted to establish design wind speeds for the 500kV Keephills-Ellerslie-Genesee loop and for the 500kV British Columbia Tie Line. The wind studies were updated a number of times and ultimately formed the basis for the AESO wind map which is used for bulk transmission line design in Alberta. The AESO wind map is provided on the AESO's web site.

TransAlta Utilities compared their performance-based insulator swing design criteria with the original 500kV wind study results. TransAlta Utilities found that the performance based criteria roughly approximated a 5-year return gust speed throughout their service area (which also incorporated the windy South West region of the province). As a result, TransAlta adopted a 5-year return wind gust for conductor swing considerations in the design of transmission structures. This criteria is included as part of section 502.2.

Insulator Swing - Requirements

Three separate criteria are applicable to the clearance between conductors attached to suspension insulators and the supporting structures. Each of the three criteria should be checked in order to determine which will govern. The insulator swing criteria are an important aspect of bulk transmission line design and are required to ensure that the bulk transmission lines are reliable.

The following items address the three swing clearance criteria of subsection 17(5):

(a) The requirements of CSA C22.3 No. 1-06 are part of the *Alberta Electrical Utility Code* and hence are mandatory. Switching surge factors, switching surge crest voltage values and switching surge flashover-to-ground distances are to be as specified in Table A.1 of CSA C22.3 No. 1-06 unless a switching study is completed by the designer of the bulk transmission line and provides other values.

(b) The five (5) year gust criteria address the situation of reasonably high winds (which occur infrequently) and minimum clearance requirements (60 Hz power frequency stress).

(c) The moderate wind gust criteria provide adequate clearance for electrical stresses that occur occasionally on the system (e.g. switching surge). The following overlapping probabilities apply to this criterion:

(1) Probability of switching surge occurring while the insulators are in the defined swing position;

(2) Probability of the switching surge voltage having the maximum value; and

(3) Probability of the switching surge causing a flashover at the location of the reduced clearance.

The loading areas specified for the moderate gust wind pressure values are the same as those on the AESO wet snow and wind loading map. The pressure values are based on operating experience.

Air gap distances for use with the moderate wind gusts of Table 3 of subsection 17 are to be calculated in accordance with the methodology described in *IEEE Standard 1313.2 The Application of Insulation Coordination,* for transmission line phase to ground switching overvoltages.

It should be noted that while the IEEE Standard does not provide a formula for the calculation of strike distance (air gap), it does provide a formula giving the relationship between critical flashover (CFO) and strike distance. This formula can be rearranged to solve for strike distance although an adjusted equation for CFO, taking into account actual air density (elevation) must be used. For further details of the IEEE calculation methodology, including example calculations, see the book *Insulation Coordination for Power Systems*, by Andrew R. Hileman, in particular the chapter on Insulation Strength Characteristics.

For angle structures with suspension type insulators, the required clearances are to be met with both forward and reverse wind, and for both initial and final tensions. This approach is expected to provide acceptable reliability for the angle structures for a range of operating conditions.

18. Clearances Under Differential Loading

The requirement for specified clearances under differential loading conditions recognizes the situation where an overhead shieldwire or upper phase is loaded with ice or wet snow, and the wires below have reduced loading, or are bare. Operating experience in Alberta indicates that these conditions occur on a reasonably frequent basis, and resulted in line outages prior to the adoption of clearance requirements for these loading situations.

The first loading case represents a condition with glaze ice or in-cloud (rime) ice accumulation on the shieldwire or upper phase conductor, with the wires below being bare. The temperature of -20°C is typical for in-cloud icing events in Alberta. The requirement applies to bulk transmission lines of all voltages. The specified value of 12.5 mm radial glaze ice is a reasonable representation of rime icing events that have been observed in all parts of the province.

The second loading requirement is more severe, and hence is applied only to those bulk transmission lines which normally require higher levels of reliability. The specified loading represents a situation where rime ice has dropped off of the lower phase and remains on the upper phase or overhead shieldwire(s). The temperature of 0°C represents a melting point for the ice. The specified value of ice accretion and the density are typical of rime icing events observed in Alberta.

19. Clearances to Edge of Right of Way

The right of way width should meet the requirements of conductor swing out under a five (5) year return wind gust, with a switching surge clearance distance from the conductor in the blown out position to the edge of the right of way, and clearance distances should be as specified either in Table 4 of Section 502.2, for voltages below 500 kV, or from an insulation design study for voltages at 500 kV.

Conductor blow out should be calculated for a full span, and with a span factor of one point zero (1.0), and conductor sag must be the calculated final sag at four (4) degrees Celsius.

The requirements in subsection 19 and the above paragraph were developed jointly by the AESO and the major legal owners of transmission facilities in Alberta, and meet the following criteria:

(1) Recognize the possible high cost and sometimes impractical nature of meeting a “maximum design wind” requirement;

(2) Provide consistency in the approach to right of way width for all parties building bulk transmission lines in the province; and

(3) Result in a reasonable probability that structures built up to the edge of the right-of-way, that could be contacted by swinging conductors under high wind conditions, will be identified (with remedial action taken) before a line contact occurs.

The 4°C temperature specified for conductor blowout, and for other requirements in Section 502.2, is the annual average temperature for Alberta.

Subsection 19(1) of section 502.2 refers to horizontal clearance requirements in CSA C22.3 No. 1. The CSA Standard does not specifically address the issue of clearance to edge of right of way but the requirements of CSA C22.3 No. 1 will be met if the edge of the right of way is assumed to coincide with the location of a building or other structure, as specified in CSA C22.3 No. 1.

In urban areas there are set back requirements that usually prevent structures from being built up to the edge of transmission line rights of way. However, in rural areas structures can, and have been, built up to the edge of the transmission line right of way.

The requirements in subsection 19 of section 502.2 are intended to manage the risk of conductors of a bulk transmission line contacting or flashing over to structures located adjacent to the location of the bulk transmission line. Hence, the term “Edge of Right of Way”, as used in subsection 19 should be interpreted to mean those boundaries that are adjacent to areas where structures such as buildings, trees and high equipment are likely to be found. The boundary of a bulk transmission line that is adjacent to the right of way of another powerline or other linear facilities (such as pipelines or roads) does not need to be interpreted as “Edge of Right of Way” for the purposes of subsection 19.

In Alberta, single circuit 138 kV and 144 kV bulk transmission lines are commonly built on road allowances. In general there are no easements for these lines and hence the requirements of subsection 19 should not apply. Subsection 19(4) exempts 138 kV and 144 kV bulk transmission lines located on road allowances from the requirements of clearances to edge of right of way.

20. Fall Free Spacing

Subsection 20(2) allows the failure location on a structure to be taken as other than the groundline if analysis, or a full scale structure test, indicates a different failure point. If the structure analysis or full scale test is not carried out, the structure failure point is to be assumed as the groundline.

It is recognized that where bulk transmission lines enter and exit substations, and for other situations such as lines in congested and limited width corridors, it may not be possible to meet the fall free spacing requirements outlined in subsection 20 of section 502.2. Where the required spacing cannot be maintained, additional steps should be taken to improve the structural reliability of either the lower voltage bulk transmission lines or the 500 kV alternating current or +/- 500 kV high voltage direct current bulk transmission lines (as applicable). These steps could include use of H-frame structures, instead of single pole structures (for lower voltage lines) and use of shorter spans for lines of all voltages. To the extent reasonably possible, the length of bulk transmission lines in the vicinity of substations that does not meet the fall free criteria should be minimized.

21 Insulation

Use of synthetic insulators with silicone rubber skirts should be considered for areas of high contamination. The silicone rubber material has performed very well in Alberta under contaminated conditions that range from moderate to extreme. Given that synthetic insulators with silicone rubber skirts are readily available from a number of manufacturers, and that the material is cost competitive with other materials that are less consistent in terms of contaminated area performance, use of silicone rubber is required for synthetic insulators in contaminated areas. Where synthetic insulators are used in areas not subjected to significant contamination, the shed material can be determined by the line designer.

Dovetail and straight head designs are shown in Figure 1. The dovetail design results in stress concentrations that have resulted in insulator failures. The straight head design is used by major insulator manufacturers and is the preferred option.

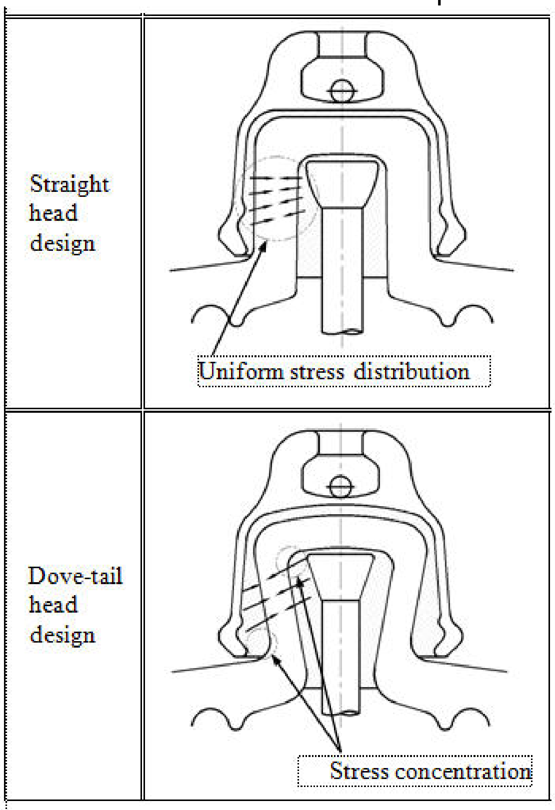


Figure 1
Insulator Head Designs

The insulation levels given in section 502.2 were calculated from system Basic Impulse Level (BIL) values, as shown in the following Table 4. The relationship between Basic Impulse Level and Critical Impulse Flashover is given by CIFO = BIL / 0.91

Table 4 Values of Basic Impulse Level and Critical Impulse Flashover Voltage

Nominal Voltage (kV)	System Basic Impulse Level (kV)	Critical Impulse Flashover (kV)
25	150	165
69/72	350	385
138/144	650	715
240	1050	1155

As noted in section 502.2, the 25 kV insulation requirement applies only to those 25 kV distribution lines placed on bulk transmission line structures. This requirement recognizes the need for insulation coordination between circuits of different voltages located on common structures, and further recognizes the operating experience with combined 138 or 144 kV and 25 kV structures in Alberta.

Insulation levels for 500 kV alternating current or +/- 500 kV high voltage direct current lines are determined from insulation studies carried out for each such line, as part of the design process. Hence, section 502.2 does not include insulation levels for 500 kV class lines.

22. Conductor Thermal Ratings Methodology

Under subsection 22(3) the AESO will consider requests to operate non-standard conductors (in particular those of the high temperature low sag design) at temperatures exceeding 100ºC.

Dynamic line rating is an effective method of improving the utilization of line capacity in certain circumstances. Requirements for dynamic rating will be identified by the AESO in the functional specification for a given bulk transmission line.

Subsection 22 deals only with the thermal rating methodology for the conductor of a bulk transmission line. For system operating purposes, thermal ratings are established for complete line segments, which take into account all components that affect the capability of the segment, including jumpers, current transformers, switches and circuit breakers.

23. Conductor Emergency Thermal Ratings Methodology

Subsection 23(1) requires that emergency thermal ratings of bulk transmission line conductors be based on a thirty (30) minute time period. This is based on the time required by system operators to assess a given contingency condition and complete remedial action.

For conductors of sizes commonly used on bulk transmission lines, the conductor will reach a steady state temperature in approximately thirty (30) minutes, or even less. Hence, the emergency rating for new bulk transmission lines has been set equal to the static rating.

24. Galloping

Conductor galloping has been observed on lines in various locations within Alberta. Although glaze ice is not a major loading condition in the province, small glaze accumulations do occur and are adequate to initiate galloping. Also, wet snow events are common, and the wet snow accretion profiles on conductors appear to be at least as efficient in terms of creating lift forces as glaze ice. As a result, galloping associated with wet snow events is a common occurrence.

The galloping criteria outlined in subsection 24 is based on methods from *CIGRE Brochure #322,* modified based on discussions with Dr. David Havard, a recognized authority on conductor galloping.

Galloping envelopes are to be calculated as required under the Appendices to section 502.2. Galloping is to be assumed as single loop regardless of the span length. This assumption reflects operating experience in Alberta, where spans in excess of 400 m have been observed to gallop in a single loop mode. The limit of 12 m for maximum galloping amplitude will prevent very large ellipse amplitudes from being used for long spans, such as river crossings.

The 12 m limit for maximum galloping amplitude is based upon the numerous observations of galloping summarized by Dr. Havard in the following Figure 2 as noted in his CIGRE presentation (Lilien & Havard, TF B2.11.06).

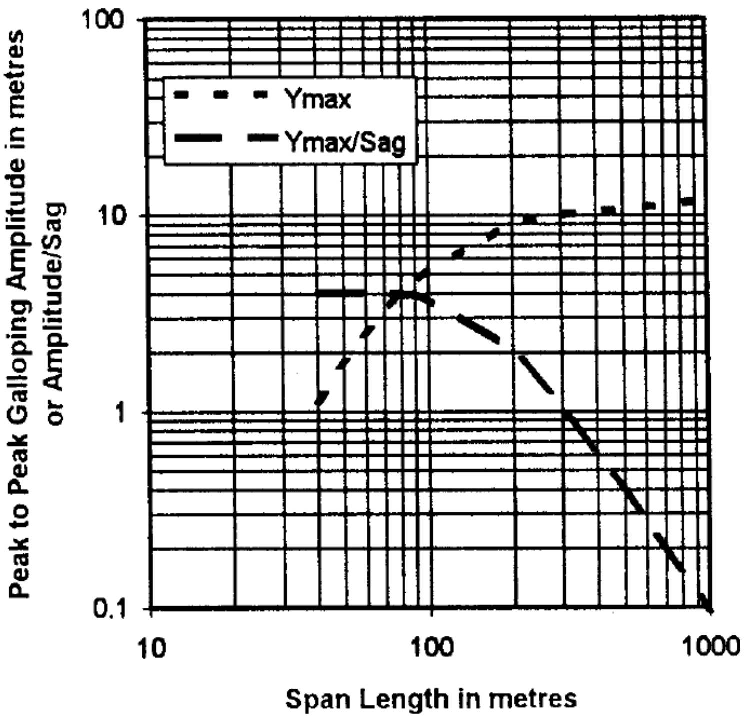


Figure 2 Observed Galloping Amplitude vs. Span Length

These observations from Figure 2 tend to support a practical upper limit in the order of 12m for galloping amplitude; regardless of span length.

Based on extensive plotting of actual galloping Dr. Havard has reported that galloping is primarily a vertical motion, and that the predicted inclinations of the galloping ellipse by the REA method were not generally observed during the recorded events. Lateral deviations tended to be within about 5 degrees of the vertical axis.

Dynamic loads on towers due to galloping are not considered. Static loads are used for tower design. While dynamic loads can be roughly quantified, their comparison against static strength is not considered representative of the structure's ability to resist dynamic loads.

The compact line designs specified in subsection 24(5) may be required in congested areas such as urban areas or the vicinity of large substations with multiple existing bulk transmission lines. Compact line designs would not normally be used where there is adequate space to allow construction of standard configuration bulk transmission lines.

25. Hardware Requirements

Bulk transmission lines in Alberta are subject to low temperatures (-50°C or lower in the northern parts of the province) sometimes combined with wet snow or in-cloud icing events.

Hence, there is a significant risk of impact loads from dropped ice accretions or other events, such as vehicle impacts, occurring at times of low temperature. Brittle fracture of ferrous hardware as the result of an impact load could trigger a major line failure. Hence, it is prudent to include a requirement for low temperature impact properties for ferrous hardware.

The CSA C83 Standard contains two levels of impact toughness. The less stringent of the two is specified in section 502.2, and is consistent with the requirements of several other electrical utilities in Canada. One or more of the large utilities in Canada requires the more stringent of the two criteria in C83, but this level of impact toughness was deemed to be excessive for Alberta requirements.

The concept of low temperature impact toughness is not applicable to hardware components manufactured from aluminum, and hence the requirement is specific to ferrous materials.

26. Provisions for Maintenance

Bulk transmission line maintenance is an important aspect of overall line reliability. Effective planning for maintenance as part of the initial line design is a key component of the overall maintenance process.

Designing bulk transmission lines with the ability for live line maintenance work procedures reduces the need for planned outages and improves overall system reliability.

In order to minimize the duration of a forced line outage, ready access to the location of the failed structure or line component is essential. Access by means of roads or trails on the ground is not always possible or feasible. This is recognized by use of the words “or otherwise” in subsection 28(b). It is expected that the legal owner of a bulk transmission line will have a plan for access to all structures of the line, which will include identification of the equipment required (such as helicopters or swamp vehicles) and the availability of the equipment.

27. Transposition Structures

Although section 502.2 does not have requirements for voltage unbalance, it may be an important consideration in the design of longer bulk transmission lines and is included in this Information Document as a way of ensuring that the issue is not overlooked.

The **ISO** is presently reviewing the need to limit voltage unbalance on bulk transmission lines to not more than 1% of the nominal voltage. For now the AESO will identify any requirements for voltage unbalance in the project functional specification.

28. Radio Interference

A bulk transmission line should be designed so that conductors and hardware will not operate in positive corona under normal operating conditions.

A bulk transmission line design in addition should satisfy the federal provisions of *Industry Canada ICES-004 Spectrum Management and Telecommunications Policy, Interference-Causing Equipment Standard, Alternating Current High Voltage Power Systems.*

Radio interference results from corona discharge from conductors or line hardware. Positive corona generates significantly higher levels of radio noise than negative corona, which is why it is recommended that the conductors and hardware of bulk transmission lines should not operate in positive corona under normal operating conditions.

The Canadian government regulation (ICES-004) sets the limits for RI from powerlines. The regulation also contains information on the measurement methodology and requirements. There is a requirement for field measurements to be taken, within six months after the bulk transmission line is placed in operation, to verify that the lines meet the specified RI limits.

When a new bulk transmission line is of the same design as an existing bulk transmission line for which measurements demonstrating compliance with ICES-004 have been made and documented, the legal owner of the new bulk transmission line may choose to request a waiver from the measurement requirements for the new bulk transmission line. The request for a waiver is to be made in consultation with the Industry Canada Regional Office.

29. Documentation of Design Criteria

The design criteria of a bulk transmission line should be documented in accordance with *IEEE Standard 1724 Guide for the Preparation of a Transmission Line Design Criteria Document.*

It is good engineering practice to document the design criteria for each new bulk transmission line. The practice is followed by most utilities and consulting firms, for their own purposes and records. The noted IEEE standard, which is currently in the final stages of review and approval, provides a consistent format for the documentation. Until such time as the IEEE Standard is readily available, legal owners of new bulk transmission lines are to use their own format for the Design Criteria documents.

Revision History

Version	Effective Date	Description of Changes
Rev 1	December 16, 2010	New document created to support ISO rules, section 502.2.

Information Document
PRC-001-AB3-1.1(ii) Protection System Coordination
ID #2010-006RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta Reliability Standard PRC-001-AB3-1.1(ii), *Protection System Coordination* ("PRC-001").

The purpose of this Information Document is to provide information regarding the coordination of protection systems among operating entities. This Information Document also provides a link to the List of Additional Facilities referred to in the Applicability section of PRC-001. This Information Document is likely of most interest to the legal owners and operators of transmission facilities, generating units and aggregated generating facilities in Alberta.

2 List of Additional Facilities (Applicability)

A List of Additional Facilities, as referenced in subsections 2(a)(ii)(B), (b)(iv), (c)(iv), (d)(ii)(B), (e)(iv) and (f)(iv) of PRC-001, is posted on the AESO website at: List of Additional Facilities PRC-001-AB3-1.1(ii)

3 Supplemental Information for Certain Requirements of PRC-001

3.1 Notification of Failure (Requirement R2 and R2.1)

Notification to the AESO of a failure described in requirements R2(a), R2(b) and R2(d), is to the AESO's System Coordination Centre by phone, followed by an email to the AESO's Operations Engineering group at ops.eng@aeso.ca.

Notification to the AESO of a failure described in requirement R2(c) is by email to the AESO's Operations Engineering group at ops.eng@aeso.ca.

The AESO requests that a market participant wishing to use SCADA to provide notifications to the AESO for specific facilities receive the AESO's agreement in advance, as modifications to the AESO's SCADA system may be required.

Following receipt of notification, and if the operator of a transmission facility has not already done so, the AESO may, in accordance with Section 305.4 of the ISO rules, *System Security*, issue a directive instructing that the transmission facility be taken out of service until the repairs are complete.

Requirement R2(a) refers to a protection system that protects a specific transmission facility and as such does not include remedial action schemes. Remedial action schemes are installed primarily to protect the Alberta interconnected electric system, or a portion thereof, by maintaining stability, maintaining acceptable transmission system voltage levels, maintaining acceptable transmission system power flows and limiting the impact of cascading or extreme events.

3.2 Provision of New Estimate to Return to Service (Requirement R2.2)

The provision of a new estimate of the return to service date to the AESO, as described in requirement R2.2, is by email to the AESO's Operations Engineering group at ops.eng@aeso.ca.

3.3 Coordination of Generating Unit Protection System Changes (Requirement R3)

For projects following the AESO's customer connection processes, including behind-the-fence and market participant choice, or the AESO's system connection projects, all communications to the AESO confirming protection system coordination with the affected parties pursuant to requirement

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

R3, is by email to the AESO's Project Manager.

All other communications to the AESO confirming protection system coordination with the affected parties pursuant to requirement R3 is by email to PRC-001@aeso.ca.

The AESO generally agrees with the information contained in the NERC *Power Plant and Transmission System Protection Coordination* technical reference document and recognizes that it may be a useful reference for the legal owner of a generating and the legal owner of an aggregated generating facility in coordinating protection systems with affected interconnecting legal owners of transmission facilities under requirement R3. As with every Alberta reliability standard, each responsible entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements in PRC-001.

The legal owner of a generating unit or a legal owner of an aggregated generating facility, who also owns protection systems associated with transmission facilities, must ensure the protection systems of its generating unit or aggregated generating facility are coordinated with the protection systems of its transmission facilities.

Examples of how the legal owner of a generating unit or the legal owner of an aggregated generating facility may establish which protection system changes are to be coordinated with the affected parties can be found in Appendix 1, *Examples for PRC-001-AB3-1.1(ii) Requirement R3 – Guidelines for Protection System Change Coordination and Notification by the Legal Owner of a Generating Unit or Aggregated Generating Facility* ("Appendix 1"). These examples in Appendix 1 were developed by an industry work group to assist market participants in determining when protection system changes may affect others and require coordination with the affected parties in accordance with requirement R3. As with every Alberta reliability standard, each responsible entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements in PRC-001.

3.4 Coordination of Transmission Facility Protection System Changes (Requirement R4)

For projects following the AESO's customer connection processes, including behind-the-fence projects, all information exchanges confirming protection system coordination with the AESO pursuant to requirement R4 is to the AESO's Project Manager.

All other communications to the AESO confirming protection system coordination with the affected parties pursuant to requirement R4 is by email to PRC-001@aeso.ca.

The AESO generally agrees with the information contained in the NERC *Power Plant and Transmission System Protection Coordination* technical reference document and recognizes that it may be a useful reference for the legal owner of a transmission facility in coordinating protection systems with affected parties under requirement R4. As with every Alberta reliability standard, each responsible entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements in PRC-001.

Examples of how the legal owner of a transmission facility may establish which protection system changes are to be coordinated with the affected parties, other than the AESO, can be found in Appendix 2, *Examples for PRC-001-AB3-1.1(ii) Requirement R4 – Guidelines for Protection System Change Coordination and Notification by the Legal Owner of a Transmission Facility*. The examples in Appendix 2 were developed by an industry work group to assist market participants in determining when protection system changes may affect others and require coordination with the affected parties, in accordance with requirement R4.

Examples of protection system changes that affect the AESO include protection system changes to:

- synch-check relays;
- transmission system synchronizer relays;
- power swing relays;
- underfrequency load shed relays that are part of the AESO's underfrequency load shedding

program; and

- under voltage load shed relays that are part of the AESO's under voltage load shed program.

As with every Alberta reliability standard, each responsible entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements in PRC-001.

3.5 Coordination of Changes in the Operating Conditions of Generating Units and Aggregated Generating Facilities (Requirement R5.1)

Most generating units and aggregated generating facilities in Alberta are designed such that planned changes in generation, load, or operating conditions do not affect the protection systems of others. If, however, the operator of a generating unit or the operator of an aggregated generating facility identifies a planned change that would require a notification to the AESO pursuant to requirement R5.1, such notification is by email to the AESO's Operations Coordination group at ops.coordination@aeso.ca.

3.6 Coordination of Changes in the Opoerating Conditions of Transmission Facilities (Requirement R5.2)

Most transmission facilities in Alberta are designed such that planned changes in transmission, load, or operating conditions do not affect protection systems of others. If, however, an operator of a transmission facility identifies a planned change that would require a notification to the AESO pursuant to requirement R5.2, such notification is by email to the AESO's Operations Coordination group at ops.coordination@aeso.ca.

3.7 Monitoring and Reporting of Remedial Action Scheme Status (Requirement R6)

For remedial action scheme status changes in real time, the notification provided pursuant to requirement R6, is to the AESO's System Coordination Centre. This may be done either by a discrete SCADA point to the system controller or by phone call.

For remedial action scheme status changes arising from scheduled outages or commissioning activities, the notification provided pursuant to requirement R6, is by email to the AESO's Operations Coordination group at outage.scheduling@aeso.ca.

Notifications for changes in status to new remedial action schemes will be managed as part of the AESO's connection, behind the fence or system project processes.

4 Appendices

Appendix 1 – *Examples for PRC-001-AB3-1.1(ii) Requirement R3 – Guidelines for Protection System Change Coordination and Notification by the Legal Owner of a Generating Unit or Aggregated Generating Facility*

Appendix 2 – *Examples for PRC-001-AB3-1.1(ii) Requirement R4 – Guidelines for Protection System Change Coordination and Notification by the Legal Owner of a Transmission Facility*

Revision History

Posting Date	Description of Changes
October 4, 2017	Revised to align with new version of PRC-001-AB3-1.1(ii) Other administrative amendments
July 5, 2012 Concurrent with PRC-001-AB1-1	Added section on "Additional Applicable Facilities"
September 30, 2010	Further detail provided for R2, R3, R5, R6, R8 & R9. Link updated to final NERC document. Examples referenced regarding when to

	exchange settings.
November 15, 2010	Initial version

Appendix 1
Examples for PRC-001-AB3-1.1(ii) Requirement R3 – Guidelines for Protection System Change Coordination by the Legal Owner of a Generating Unit or Aggregated Generating Facility

The examples in the table below were developed by an industry work group to assist market participants in determining when protection system changes may affect others and require coordination with the affected parties in accordance with requirement R3 of PRC-001. As with every Alberta reliability standard, each responsible entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements in PRC-001.

An example of a typical protection system for a generating unit is provided in Figure 1 for ease of reference.

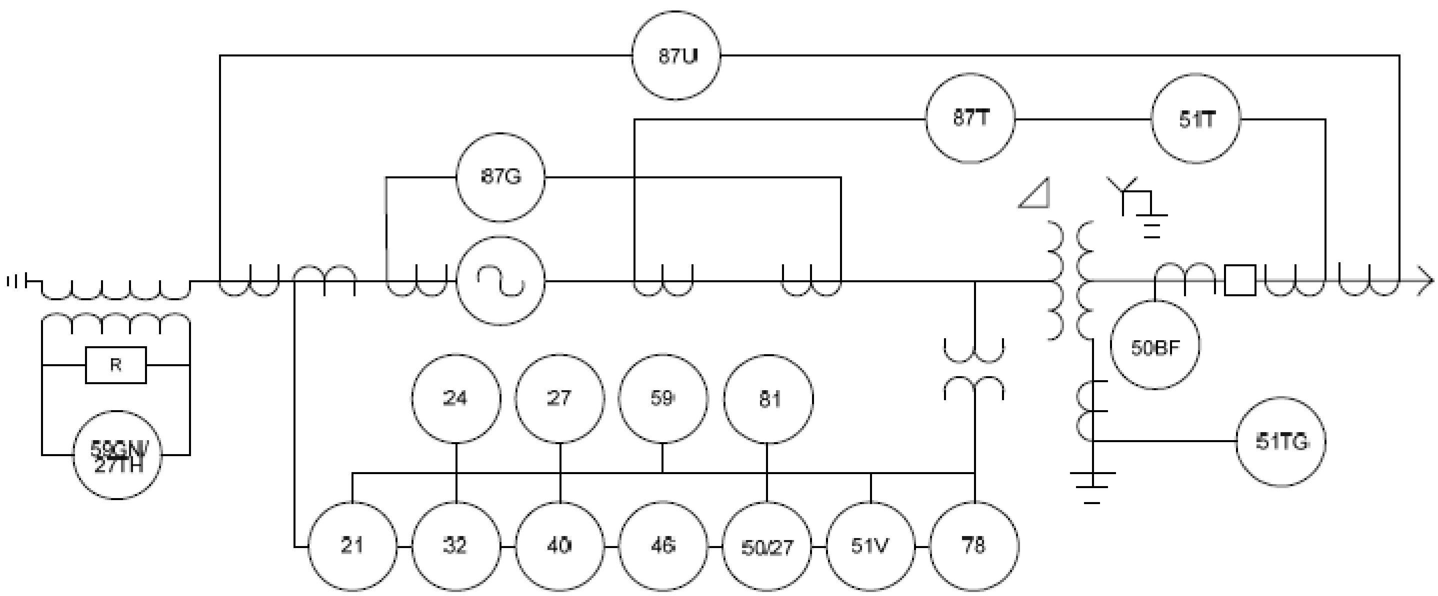
Relay Setting Coordination

Protection System	Coordinate with Affected Parties	Not Likely to Affect Other Parties
Function 21 Relay Generator Phase Distance		Change of R-X plane trip setting in primary ohms at the generator terminals
		Change of relay trip timer settings
		Change in total clearing times for the generator breakers Relay
Function 21L Relay Line Phase Distance	Change of impedance trip zone reach settings	
	Change of relay trip zone timer settings	
Function 24 Relay		Change of V/Hz trip setting
Overexcitation (Volts/Hz)		Change of relay trip timer setting
		Change of relay inputs
Function 27 Relay Generator Unit UV(undervoltage)	Change of voltage trip primary setting	
	Change of relay trip timer setting	
Plant Auxiliary MV System UV	Change of voltage primary setting	
	Change of relay timer setting	
High Voltage Side UV	Change of voltage trip primary setting	
	Change of relay trip timer setting	
Function 32 Relay Reverse Power		Change of reverse power setting in percentage and relay timer setting
Function 40 Relay Loss of Field (LOF)		Change of impedance trip zone reach
		Change of relay trip timer setting

Protection System	Coordinate with Affected Parties	Not Likely to Affect Other Parties
Function 46 Relay Negative Phase Sequence overcurrent		Change of negative phase sequence overcurrent alarm/trip setting
		Change of relay trip timer setting
Function 50/27 Relay Inadvertent Energizing		Change of undervoltage setting
		Change of current detector pick up setting
		Change of relay timer setting
Function 50/51L Transmission Line O/C Relay	Change of O/C trip settings	
	Change of relay trip timer settings	
Function 50BF Relay Breaker Failure	Change of relay trip timer setting	
Function 50/51T/51TG Relay Back up Overcurrent for GSU	Change of phase overcurrent trip primary setting	
	Change of ground overcurrent trip setting	
	Change of relay trip timer setting	
	Change in total clearing time for generator breaker	
Function 51V Relay Voltage Controlled/Restrained Overcurrent		Change of controlled/ restrained voltage trip primary setting
		Change of overcurrent trip primary setting
		Change of relay trip timer setting
Function 59 Relay Overvoltage	Change of over-voltage trip primary setting	
	Change of relay trip timer setting	
Function 59GN/27 Relay Stator Ground		Change of relay timer setting
Function 78 Relay Out of Step		Change of impedance trip zone blinder setting
		Change of relay trip timer setting
		Change on protection scheme
Function 81 Relay Over/Under frequency		Change of frequency trip setting
		Change of relay trip time setting

Protection System	Coordinate with Affected Parties	Not Likely to Affect Other Parties
Function 87L Relay Transmission Line Differential		No notification is required for protection setting change of any existing differential protection

Figure 1 - Typical Protection System for a Generating Unit



Appendix 2

Examples for PRC-001-AB3-1.1(ii) Requirement R4 – Guidelines for Protection System Change Coordination and Notification by the Legal Owner of a Transmission Facility

The examples in the table below were developed by an industry work group to assist market participants in determining when protection system changes may affect others and require coordination with the affected parties in accordance with requirement R4 of PRC-001. As with every Alberta reliability standard, each responsible entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements in PRC-001.

PRC-001 R4: Protection Coordination
Requirement for Notification: Power System Element(s) & Bus(es) Defined

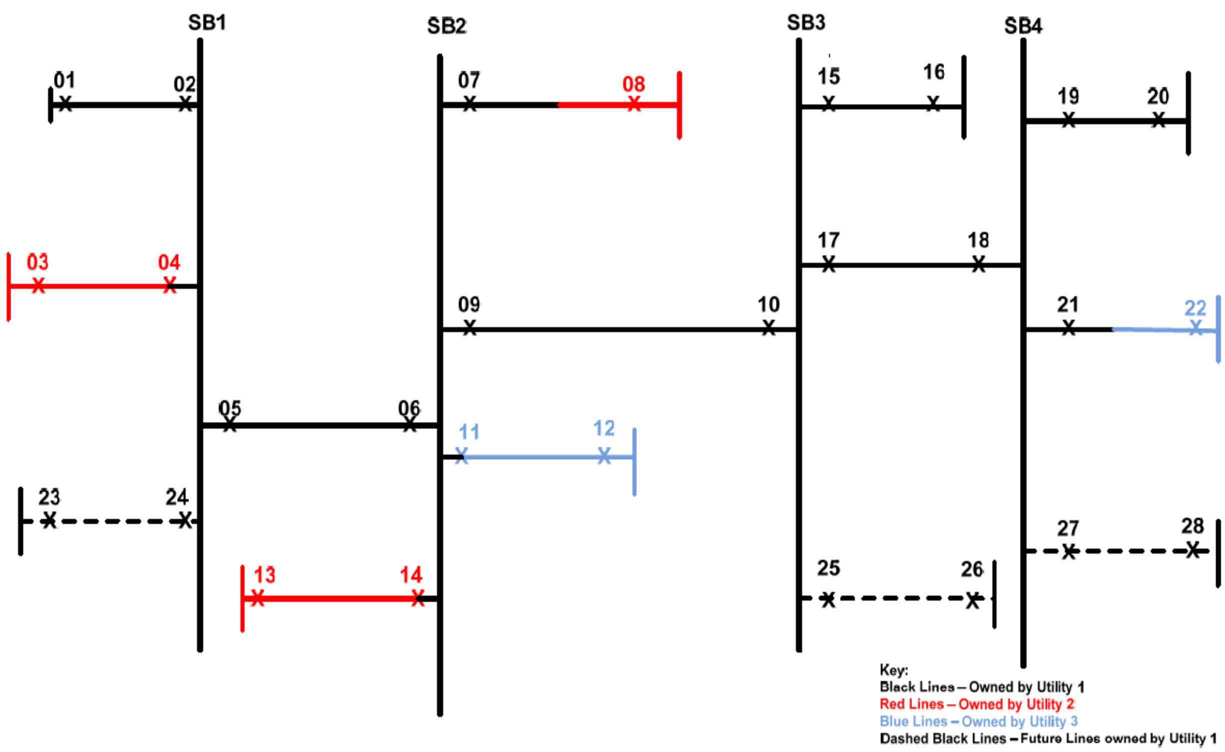


Diagram Information:

- 4 Substation Buses: SB1 is Substation Bus 1, SB2 is Substation Bus 2, SB3 is Substation Bus 3, and SB4 is Substation Bus 4.
- Terminals: SB1 has 4 terminals, SB2 has 5 terminals, SB3 has 4 terminals, and SB4 has 4 terminals.
- 14 Lines: Line 01-02, Line 03-04, Line 05-06, Line 07-08, Line 09-10, Line 11-12, Line 13-14, Line 15-16, Line 17-18, Line 19-20, Line 21-22, Line 23-24, Line 25-26, and Line 27-28.

Interconnecting and Non-interconnecting Bus/Elements:

- Interconnecting Bus is: A substation bus with connected terminals that belong to more than one utility. Examples: SB1 and SB2.
- Non-interconnecting Bus is: A substation bus with connected terminals that belong to only one utility. Examples: SB3 and SB4.

- Power System Elements: For simplicity, only elements with 2 terminals are considered. Therefore, only 2-terminal lines are indicated in the diagram.
- Interconnecting Element is: A Power System Element with connected terminals that belong to more than one utility. Examples: Line 07-08 and Line 21-22.
- Non-interconnecting Element is: A Power System Element with connected terminals that belong to only one utility. Examples: Line 01-02, Line 03-04, Line 05-06, Line 09-10, Line11-12, Line 13-14, Line 15-16, Line 17-18, Line 19-20, Line 23-24, Line 25-26 and Line 27-28.

The following six examples indicate when to coordinate with affected parties in accordance with requirement R4:

For Terminal 05 (Connected to SB1): The Remote Terminal is: 06 The Upstream terminals are: 01, 03 & 23 The Downstream terminals are: 07, 09, 11 & 14 (Note: All four terminals are connected to SB2) The “Same Bus” Adjacent terminals are: 02, 04 & 24 If protection settings are to be changed (or added) at terminal 05: ***Coordinate with the owners of terminals 03, 11, 14 & 04*.**	**For Terminal 06 (Connected to SB2):** The Remote Terminal is: 05 The Upstream terminals are: 08, 10, 12 & 13 The Downstream terminals are: 02, 04 & 24 (Note: All three terminals are connected to SB1) The “Same Bus” Adjacent terminals are: 07, 09, 11 & 14 If protection settings are to be changed (or added) at terminal 06: ***Coordinate with the owners of terminals 08, 12, 13, 04, 11 & 14*.**
For Terminal 09 (Connected to SB2): The Remote Terminal is: 10 The Upstream terminals are: 08, 05, 12 & 13 The Downstream terminals are: 15, 17 & 25 (Note: All three terminals are connected to SB3) The “Same Bus” Adjacent terminals are: 06, 07, 11 & 14 If protection settings are to be changed (or added) at terminal 09: ***Coordinate with the owners of terminals 08, 12, 13, 11 & 14*.**	**For Terminal 10 (Connected to SB3):** The Remote Terminal is: 09 The Upstream terminals are: 16, 18, & 26 The Downstream terminals are: 07, 06, 11 & 14 (Note: All four terminals are connected to SB2) The “Same Bus” Adjacent terminals are: 15, 17 & 25 If protection settings are to be changed (or added) at terminal 10: ***Coordinate with the owners of terminals 11 & 14*.**

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents[1]:

- VAR-001-AB-4, *Voltage and Reactive Control* ("VAR-001-AB-4");
- VAR-002-AB-3, *Generator Operation for Maintaining Network Voltage Schedules* ("VAR-002-AB-3");
- VAR-501-WECC-AB-1, *Power System Stabilizer*;
- VAR-002-WECC-AB-1, *Automatic Voltage Regulators and Voltage Regulating Systems*;
- Section 203.4 of the ISO rules, *Delivery Requirements*;
- Section 301.2 of the ISO rules, *ISO Directives* ("Section 301.2"); and
- Section 304.4 of the ISO rules, *Maintaining Network Voltage*.

This Information Document describes the AESO's voltage control operating practices. This Information Document is likely of interest to an operator of a transmission facility, legal owner of a generating unit, legal owner of an aggregated generating facility, operator of a generating unit and operator of an aggregated generating facility.

2 Background

The AESO is responsible for the overall reliability of the interconnected electric system, including ensuring that transmission system voltages (which include 500 kV, 240 kV, 144 kV, 138 kV, 72 kV and 69 kV) are maintained within acceptable levels. Operators of transmission facilities, generating units and aggregated generating facilities are responsible for operating facilities connected to the transmission system.

The transmission system must be capable of steady state operation within acceptable voltage ranges during normal and abnormal conditions.

3 Voltage Control Operating Practices of the AESO

This section provides information regarding the AESO's voltage control operating practices used to maintain transmission system voltage levels within acceptable limits. The system voltage ranges with associated tolerance bands are provided in Voltage Control – Table 1: *Voltage Limits and Operating Ranges and Limits* ("Table 1"), which is available on the AESO's website.

3.1 General

The AESO's general voltage control operating practices include:

(a) The AESO Energy Management System voltage limits that the AESO operates to are based on Table 1. The AESO refers to Table 1, and monitors the AESO real time Voltage Stability Analysis tool in the AESO Energy Management System.

(b) In the event that the AESO real time Voltage Stability Analysis establishes a more conservative voltage limit for an area than the limit indicated in Table 1, the AESO informs the

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

operators of transmission facilities of the more conservative Voltage Stability Analysis limit and operates to the more conservative limit for the area of concern.

(c) If the Voltage Stability Analysis tool is not functioning, refer to Voltage Control – Table 2: *Fallback Minimum Voltage Limit Table(s)* ("Table 2") for the identified area, which is available on the AESO's websiteIf Table 2 does not provide a minimum fallback voltage limit, the AESO may, if required, perform an assessment to determine whether a temporary minimum voltage limit should be established.

(d) The Alberta interconnected electric system operates with sufficient reactive resources within its boundaries to support the voltage for the next contingency (N - 1).

(e) Procedures in Section 4.2 and Section 4.3 below are followed to maintain voltage within the established limits.

(f) Capacitive and inductive reactive resources are operated to maintain system and interconnection voltages within established limits.

(g) When reactive resources are insufficient to maintain voltage within the minimum limits, corrective action is taken including load reduction.

(h) Voltage adjustments are coordinated by the AESO.

(i) When the AESO issues an instruction or directive to the operator of a generating unit or an aggregated generating facility for reactive support, the AESO references either a voltage level at the point of connection to the transmission system or the reactive power to be achieved by the generators.

(j) To reduce the risk of system instability and to be prepared for contingencies, voltage levels should be at the upper end of the desired range during heavy load periods. Refer to Table 1.

(k) Instructions or directives for reactive resources are issued to maintain voltage within the voltage limits identified in Table 1. The AESO expects that such instructions or directives will be followed unless an acceptable explanation is provided as to why the directive cannot be followed. Directives are issued using three-part communication.

3.2 Voltages Fall Below the Desired Range

The AESO implements one or more of the following operating practices if voltages fall below the desired range in Table 1:

(a) Switch capacitor banks "ON" and reactors "OFF" in the area.

(b) Adjust taps on transformer onload tap-changers.

(c) Raise bus voltage or adjust reactive output at generating stations including wind aggregated generating facilities.

(d) Raise Static Var Compensator and sync-condenser set points.

(e) Consider reconfiguring the transmission system to avoid possible voltage collapse.

(f) Cancel outages that would contribute to the low voltages.

(g) Perform a real time assessment to determine if a lower voltage limit is acceptable.

(h) Consider effective TMR generation that would support area voltage.

(i) Take other actions as deemed effective by the AESO, including shedding firm load.

3.3 Voltages Rise Above the Desired Range

The AESO implements one or more of the following operating practices when voltages rise above the desired range in Table 1:

(a) Switch capacitor banks "OFF" and reactors "ON" in the area.

(b) Lower set points on transformer tap-changers.

(c) Lower bus voltage or adjust reactive output at generating stations including wind aggregated generating facilities.

(d) Lower Static Var Compensator or sync-condenser set points.

(e) Consider switching out lightly loaded lines after confirming by a study that there are no next contingency concerns.

(f) Take other actions as deemed necessary by the AESO to reduce voltage.

4 Operator Requests

This section provides general information regarding the processes for requests from an operator of a transmission facility, an operator of a generating unit, or an operator of an aggregated generating facility for voltage adjustments.

An operator of a transmission facility may initiate a request to the AESO for a voltage adjustment on its transmission system or an adjacent transmission system. The AESO assesses such requests considering the overall system voltage and immediate or upcoming events of which the AESO is aware. If the AESO does not agree with the need for the adjustment, the AESO provides an explanation to the operator.

Similarly, an operator of a generating unit or aggregated generating facility may initiate a request to the AESO for a voltage adjustment on the generating unit or aggregated generating facility. The AESO assesses such requests considering the overall system voltage and immediate or upcoming events of which the AESO is aware. If the AESO does not agree with the need for the adjustment, the AESO provides an explanation to the operator.

As part of its assessment, the AESO considers whether the generating unit or aggregated generating facility is able to supply dynamic reactive power reserves. Of particular concern to the AESO is whether a generating unit or aggregated generating facility is operating at a limit, as communicated by the operator of the generating unit or aggregated generating facility as part of its request.

5 Concurrent Voltage (Reactive Power) Directives and Real Power Dispatches

There may be instances where the AESO issues a directive for voltage or reactive power adjustments to the operator of a generating unit or an aggregated generating facility and it is only possible to comply with this directive by lowering the real power output of the generating unit or aggregated generating facility.

6 Information on VAR-001-AB-4

6.1 Information on the Requirements

Requirement R1.1 of VAR-001-AB-4 describes a situation where the AESO must provide information upon request. A request is submitted by email at: ARSsubmittals@aeso.ca.

7 Information on VAR-002-AB-3

7.1 Information on the Requirements

Requirement R2.2 of VAR-002-AB-3 requires the operator of a generating unit or the operator of an aggregated generating facility to provide an explanation of why a directive or instruction cannot be met. Subsection 3 of Section 301.2 of the ISO rules sets out the requirement to comply with a directive received from the AESO, and the exceptions to this requirement.

Requirements R1.5, R1.6, R3, R4, R5 and R6 of VAR-002-AB-3 describe situations where a market participant must notify or provide information to the AESO.

The AESO contact for requirements R3 and R4 is the AESO system controller. AESO system controller contact information can be obtained from the following source:

(a) AESO First Call 1-888-588-AESO(2376).

The AESO contact for requirements R1.5, R1.6, R5 and R6 is ARSsubmittals@aeso.ca.

Send all requests to schedule an outage to outage.scheduling@aeso.ca

7.2 Explanations regarding start-up, shutdown, offline and testing modes

For a generating unit, start-up is considered to have ended when the generating unit is ramped up to its minimum continuously sustainable load and the generating unit is prepared for continuous operation.

For a generating unit, shutdown is considered to begin after the generating unit is ramped down to its minimum continuously sustainable load and the generating unit is prepared to go offline.

For a wind aggregated generating facility, shutdown and start-up modes do not apply.

A generating unit or wind aggregated generating facility is considered to be offline when the generating unit has been electrically disconnected from the power system.

For a description of when a generating unit is considered to be testing, refer to Section 505.3 of the ISO rules, *Coordinating Energization, Commissioning and WECC Testing Activities*, and associated Information Document #2012-012R, *Coordinating Synchronization, Commissioning, WECC Testing, Ancillary Services Testing, or Operational Testing*, for further information.

Revision History

Posting Date	Description of Changes
2018-10-15	Updated to include references to requirements R1.5 and R1.6 in subsection 7.1; and to add AESO contact information for submission of requests to schedule an outage
2016-09-28	Administrative amendments.
2016-04-01	Amendments to Sections 1, 3, 4, 5 and 6.Removal of "Related Authoritative Documents" section and renumbering. Removal of Appendix 1. Revisions to reflect change in version number of VAR-001 and VAR-002.
2014-12-04	Amendments to Sections 1, 4, 4.1, 4.2, 4.3 and 5
2014-10-07	Amendments to Sections 1, 4, 4.1, 4.2 and 4.3. Removing Appendix 1. Re- naming Appendix 2 to Appendix 1.
2014-09-19	Changes to minimum operating limits and desired ranges in Table 1: Voltage Limits and Operating Changes and Limits. Change to Section 1 to remove reference to contact information.
2013-10-01	Initial release

Information Document
Available Transfer Capability and Transfer Path Management
ID #2011-001R

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1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 203.6 of the ISO rules, *Available Transfer Capability and Transfer Path Management* ("Section 203.6");
- Section 303.1 of the ISO rules, *Load Shed Service* ("Section 303.1"); and
- Alberta Reliability Standard IRO-006-WECC-AB-1, *Qualified Transfer Path Unscheduled Flow Relief*.

The purpose of this Information Document is to provide information on the limits and calculations related to the import and export of energy in interchange transactions. This Information Document is likely of most interest to market participants who import and export energy to and from Alberta.

2 Tables and acronyms contained in this Information Document

The tables set out in this Information Document are intended to reflect the total transfer capabilities under various Alberta internal load levels and transmission element outage conditions.

The following acronyms are used in this Information Document:

a) Alberta internal load (AIL);

b) Available Transfer Capability (ATC)

c) Direct transfer trip (DTT);

d) Kilovolt (kV);

e) Line (L);

f) Load shed service for import (LSSI);

g) Montana Alberta Tie Line (MATL);

h) Megawatts (MW);

i) Megavolt-ampere reactive (MVAr);

j) Most severe single contingency (MSSC);

k) Northern American Electric Reliability Corporation (NERC).

l) Remedial action scheme (RAS);

m) Substation (S);

n) System Operating Limit (SOL)

o) Transmission reliability margin (TRM);

p) Total transfer capability (TTC); and

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

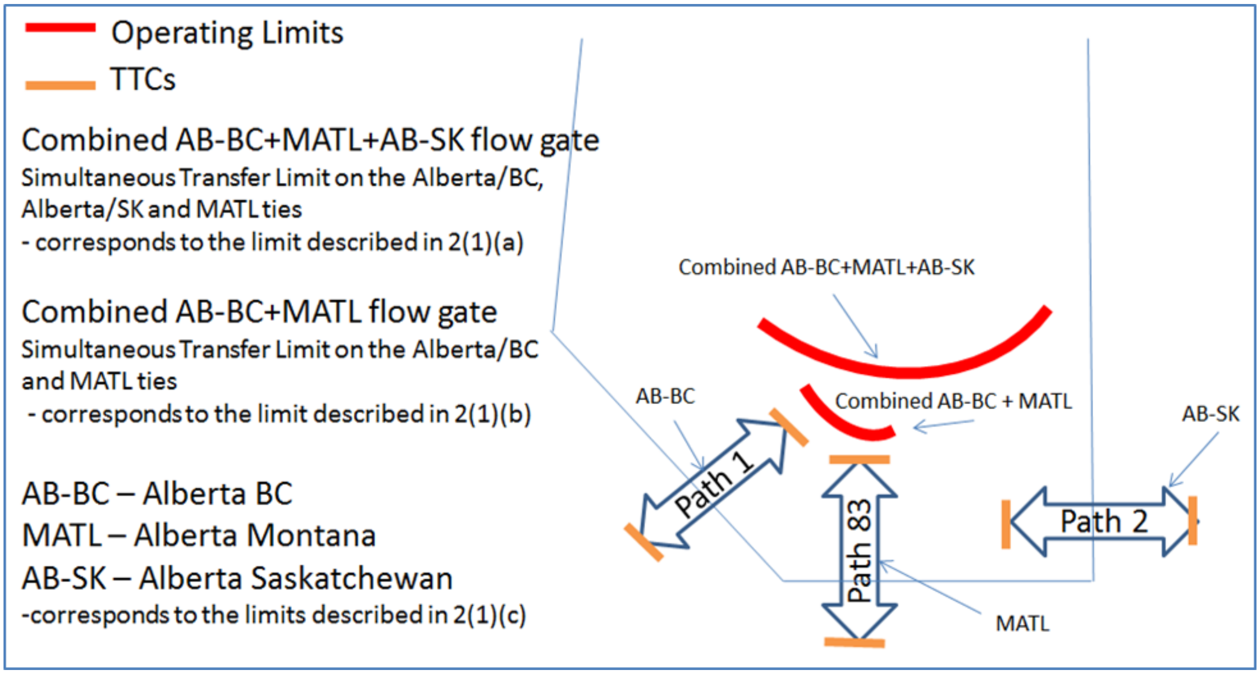
q) Western Electricity Coordinating Council (WECC).

3 Capability Limits Determinations by the ISO

This section provides information on subsection 2 of Section 203.6. Figure 1 below illustrates the available transfer capability on the interties as limited by individual line total transfer capabilities, system operating limits, and transmission reliability margin.

Figure 1: Alberta Capability Levels

(references to 2(1)(a)(b) and (c) correspond to the subsections within Section 203.6)



4 Total Transfer Capability Determinations by the ISO

This section provides information on subsection 3 of Section 203.6.

The calculation of total transfer capability and available transmission capability in Section 203.6 is based upon requirements established in NERC's reliability standards MOD-001-1a, *Available Transmission System Capability* and MOD-029-1a, *Rated System Path Methodology*.

In general, when determining Alberta's total transfer capability, the AESO considers factors such as:

a) Alberta internal load levels;

b) any interconnected electric system forecast or real time conditions, including outages of bulk transmission line and generating units; and

c) other conditions, including any seasonal restrictions based on AIL.

4.1 Alberta-British Columbia Transfer Path Import Total Transfer Capability Determinations

The Alberta-British Columbia transfer path import total transfer capability varies based on Alberta internal load system normal conditions and transmission element outage conditions. Tables 1(a) and 1(b) below set out the total transfer capability under these various conditions.

Table 1(a): British Columbia to Alberta Import Total Transfer Capability

Summer Season (May 1 to October 31)

AIL	System Normal[1]		1201L Out of Service	Path 1 Out of Service
MATL Status	In	Out	Out	
All AIL	800	700	65	0

Table 1(b): British Columbia to Alberta Import Total Transfer Capability

Winter Season (November 1 to April 30)

AIL	System Normal (MW)[1]		1201L Out of Service	Path 1 Out of Service
MATL Status	In	Out	Out	
All AIL	800	700	65	0

4.2 Alberta-British Columbia Transfer Path Export Total Transfer Capability Determinations

For any given system condition, the export total transfer capability will not exceed the maximum export total transfer capability as specified in Table 2(a) and Table 2(b) below.

For multiple outages to more than one transmission element, or for accumulated capacitor bank unavailability in the Calgary area greater than 395 MVAr, the maximum export total transfer capability limits are determined by studies based on the specific system conditions at the time of the multiple outages or unavailability. If such studies are not available, the export total transfer capability is reduced to 50 MW if the Alberta-Montana intertie is in service, or 65 MW if MATL is out of service.

Table 2(a): Alberta to British Columbia Export Total Transfer Capability

Summer Season (May 1 to October 31)

AIL	System Normal (MW)[1]		1201L Out of Service	Path 1 Out of Service
MATL Status	In	Out	Out	
All AIL	1000	1000	80	0

Table 2(b): Alberta to British Columbia Export Total Transfer Capability

Winter Season (November 1 to April 30)

AIL	System Normal (MW) [1]		1201L Out of Service	Path 1 Out of Service
MATL Status	In	Out	Out	
All AIL	1000	1000	105	0

4.3 Alberta-Montana Transfer Path Import Total Transfer Capability Determinations

The Alberta-Montana transfer path import total transfer capability varies based on Alberta internal load system normal conditions and transmission element outage conditions. Table 3(a) below sets out the total transfer capability under these various conditions.

Table 3(a): Montana to Alberta Import Total Transfer Capability[1]

AIL	System Normal (MW)	1201L out of service[2] or 1201L DTT is out of service or MATL Local RAS is out of service or AIES islanded from the Western Interconnection through BC Hydro[3] (MW)
All AIL	310	0

Notes:

1. If the high speed communication equipment used for orderly shutdown and line protection schemes is out of service, Path 83 (MATL 240/230 kV line) will be removed from service.
2. A 1201L outage in real time results in a direct transfer trip to MATL. For a planned outage to 1201L the AESO takes Path 83 (MATL 240/230 kV line) out of service prior to removing 1201L.
3. For any outage in British Columbia that causes the interconnected electric system to be islandedfrom the WECC, the AESO takes Path 83 (MATL 240/230 kV line) out of service.

4.4 Alberta-Montana transfer Path Export Total Transfer Capability Determinations

The AESO determines the Alberta-Montana transfer path export total transfer capability at the Alberta-Montana border.

Table 3(b): Alberta to Montana Export Total Transfer Capability[1]

AIL	System Normal (MW)	1201L out of service[2] or 1201L DTT is out of service or MATL Local RAS is out of servide or AIES islanded from the Western Interconnection through BC Hydro[3] (MW)
All AIL	315	0

Notes:

1. If the high speed communication equipment used for orderly shutdown and line protection schemes is out of service, Path 83 (MATL 240/230 kV line) will be removed from service.
2. A 1201L outage in real time results in a direct transfer trip to MATL. For a planned outage to 1201L the AESO takes Path 83 (MATL 240/230 kV line) out of service prior to removing 1201L.
3. For any outage in British Columbia that causes the interconnected electric system to be islanded from the WECC, the AESO takes Path 83 (MATL 240/230 kV line) out of service.

4.5 Alberta-Saskatchewan Transfer Path Import Total Transfer Capability

Table 4(a): Saskatchewan to Alberta Import Total Transfer Capability

AIL	Import TTC (MW)	
	Winter	Summer
For any AIL	153	153

4.6 Alberta-Saskatchewan Transfer Path Export Total Transfer Capability

Table 4(b): Alberta to Saskatchewan Export Total Transfer Capability

AIL	Export TTC (MW)		
	System Normal	One McNeill capacitor unavailable	Two McNeill capacitors unavailable
For any AIL	153	130	90

5 Available Transfer Capability Determinations by the ISO for a Transfer Path

This section provides information on subsection 4 of Section 203.6.

The AESO calculates both the import available transfer capability and the export available transfer path capability for each transfer path according to the formula below:

the total transfer capability; *minus*

the transmission reliability margin;

where the transmission reliability margin is:

that amount of transfer capability the AESO determines is necessary to ensure the reliable operation of the Alberta interconnected electric system taking into account uncertainties in system conditions and the need for operating flexibility; and

the transmission reliability margin is composed of (TRM_s) for variations due to balancing of generation and load on the interconnected electric system

plus

the allocation transmission reliability margin (TRM_a) associated with joint operation of the transfer paths in the presence of a combined system operating limit.

Or simply: $ATC = TTC – (TRM_s + TRM_a)$

Please refer to section 5.2 of this Information Document for further information regarding the determination of system transmission reliability margin and section 5.3 of this Information Document for the determination of allocation transmission reliability margin.

5.1 Posting the Available Transfer Capability

The AESO posts available transfer capability for 24 hour periods on the AESO website in the Real-time ATC Allocation Report. The posting automatically updates at 85 minutes in advance of the settlement interval, at 15 minutes in advance of the settlement interval if required, and in real-time if system operating limits change in the current settlement interval. In addition to the Real-time ATC Allocation Report, the AESO provides forward looking intertie capability reports, and historical intertie capability reports.

At 25 minutes prior to each settlement interval, the AESO updates the Real-time ATC Allocation Report for the next settlement interval plus one settlement interval and beyond as follows:

a) the AESO recalculates total transfer capabilities and system transmission reliability margin based on forecast system conditions according to the tables described within this Information Document; and

b) the AESO calculates allocation transmission reliability margin as described in section 5.3 below.

Within 15 minutes prior to the start of the settlement interval, if the operating limit on a given path(s) changes, and the sum of the e-tags violates a path limit, the AESO will curtail e-tags as per subsection 11 of Section 203.6. As soon as practicable, the AESO will update the Real-time ATC Allocation Report for the next settlement interval, due to system operating limit and/or total transfer capability and/or transmission reliability margin changes since the last update.

During the settlement interval, the AESO updates the Real-time ATC Allocation Report and recalculates the transfer path scheduling parameters, if required due to real-time changes to total transfer capability and/or system operating limits and/or transmission reliability margin.

5.2 Determination of System Transmission Reliability Margin

5.2.1 System Transmission Reliability Margin for the Alberta-British Columbia and Alberta-Montana Transfer Paths

For other system conditions that are not listed below, the AESO may change the transmission reliability margin if it is required to ensure system reliability.

Table 5(a): Import Transmission Reliability Margin for the Alberta-British Columbia and Alberta-Montana transfer paths under various system conditions

System Conditions	Import TRM (MW)				
	BC		MT	BC/MT	System
	MATL in service	MATL out of service	MATL in service	Connected to WECC	BC/MT/SK
System Normal (N-0)	50	65	15	65	65
1201L Out of Service	n/a	65	n/a		
1201L in service with insufficient contingency reserves	50	65	15	Higher value of 65 **or** TRM=TTC-Calculated ATC	
Path 1 Out of Service	0	0	0	0	0
1201L in service; **and** BC Hydro transmission outage(s) result in BC Hydro area load being serviced by or potentially being served by Alberta.					
2L113 outage	50; **plus** MW flow on 887L and 786L	65; **plus** MW flow on 887L and 786L	15	Higher value of 65 **or** TRM=TTC-Calculated ATC[1]	65
5L92 outage	50	65	15	Higher value of 65 **or** TRM=TTC-Calculated ATC[2]	65
2L294 outage	50	65	15	Higher value of 65 **or** TRM=TTC-Calculated ATC[3]	65
1L274/L274 Any section between Natal and Fording Coal Britt Creek	50; **plus** MW flow on 887L	65; **plus** MW flow on 887L	15	Higher value of 65 **or** TRM=TTC-Calculated ATC[4]	65

Notes:

1. Calculation for British Columbia/Montana Import ATC = calculated available transfer capability minus the flow on 887L and 786L into BC.
2. Calculation for British Columbia/Montana Import ATC = calculated available transfer capability – MSSC.
3. Calculation for British Columbia/Montana Import ATC = calculated available transfer capability minus British Columbia Island load.
4. Calculation for British Columbia/Montana Import ATC = calculated available transfer capability minus the flow on 887L into BC.

Table 5(b): Export Transmission Reliability Margin for the Alberta-British Columbia and Alberta-Montana transfer paths under various system conditions

<table>
<tr><th rowspan="3">System Conditions</th><th colspan="5">Export TRM (MW)</th></tr>
<tr><th colspan="2">BC</th><th rowspan="2">MT</th><th>BC/MT</th><th>System[1]</th></tr>
<tr><th>MATL in service</th><th>MATL out of service</th><th>Connected to WECC</th><th>BC/MT/SK</th></tr>
<tr><td>System Normal (N-0)</td><td>50</td><td>65</td><td>15</td><td rowspan="2">65</td><td rowspan="2">65</td></tr>
<tr><td>1201L Out of Service</td><td>N/A</td><td>65</td><td>N/A</td></tr>
<tr><td>Path 1 Out of Service</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
</table>

5.2.2 System Transmission Reliability Margin for the Alberta-Saskatchewan Transfer Path

Because the Alberta-Saskatchewan intertie is a direct current connection, and controls to a set point with no variance, the system transmission reliability margin equals zero (0).

The minimum flow over the McNeill back-to-back direct current converter is 15 MW in either direction due to technical limitations and, therefore, the net interchange schedule over the converter cannot be less than 15 MW (other than zero) in either direction.

If the minimum flow limit is not met, the AESO curtails the net interchange schedule to plus 15 MW, 0 MW, or minus 15 MW, whichever is the least.

5.3 Determination of Allocation Transmission Reliability Margin

Allocation transmission reliability margins are required to reflect the system limitations associated with joint operation of the transfer paths. Engineering studies determine system operating limits for the Alberta interconnected electric system which may apply to combinations of transfer paths to ensure that the Alberta interconnected electric system is operated in a reliable state. If the operating limits described in this subsection 5.3 of this Information Document are less than the sum of the total transfer capability of the affected transfer paths, and are expected to be binding based on energy offers received, then the AESO reduces the available transfer capability of each applicable transfer path by increasing allocation transmission reliability margins such that the final sum of available transfer capabilities equals the operating limit adjusted for a transmission reliability margin. To determine the available transfer capability limit which applies to the transfer path combination, or maximum volume which can be scheduled across the transfer path combination, the AESO subtracts a transmission reliability margin, generally composed of the sum of the individual transfer path system transmission reliability margin values, from the operating limit.

The AESO determines the allocation transmission reliability margin for a transfer path as follows:

a) if the volume of offers and bids for a transfer path combination is greater than the relevant operating limit then the AESO calculates the allocation transmission reliability margin for each transfer path based on the results of the available transfer capability allocation protocol defined in subsection 10 of Section 203.6 where TRM_a=TTC-TRM_s-ATC; or

If the volume of offers and bids for a transfer path combination is not greater than the relevant operating limits then the AESO sets the allocation transmission reliability margin to zero (0). This indicates there were not enough offers or bids to require an available transfer capability allocation. Even though an allocation is not required, the operating limit is still the constraining factor on the transfer path, or combinations of transfer paths. The AESO identified operating limits for the following intertie combinations:

a) combined British Columbia/Montana to Alberta as per subsection 2(1)(b) of Section 203.6;

b) Alberta to combined British Columbia/Montana as per subsection 2(1)(b) of Section 203.6;

c) combined British Columbia/Montana and Saskatchewan to Alberta as per subsection 2(1)(a) of Section 203.6; and

d) Alberta to Combined British Columbia, Montana and Saskatchewan as per subsection 2(1)(a) of Section 203.6.

5.3.1 The Combined British Columbia and Montana to Alberta operating limit for Import

The British Columbia and Montana to Alberta system operating limit for import under various system conditions is provided in Tables 6(a) and 6(b) below.

The transmission reliability margin applied to the combined British Columbia and Montana to Alberta cutplane is normally the sum of the individual transmission reliability margins for each of the British Columbia and Montana interties. The AESO may also increase the combined British Columbia and Montana to Alberta transmission reliability margin during normal opeating conditions if the available load under load shed service for import is insufficient (refer to Table 7 below). Further details on load shed service for import can be found in Section 303.1.

Table 6(a): Combined British Columbia and Montana to Alberta Operating Limit for Import

Summer Season (May 1 to October 31)

AIL	System Normal Import Limit	1201L Out of Service	Path 1 Out of Service
All AIL	1110	65	0

Table 6(b): Combined British Columbia and Montana to Alberta Operating Limit for Import

Winter Season (November 1 to April 30)

AIL	System Normal Import Limit	1201L Out of Service	Path 1 Out of Service

All AIL	1110	65	0

Table 7: Minimum Amount of Load Shed Service for Import Load Requirement

Minimum amount of load shed service for import load requirement is based on the combined British Columbia/Montana net import schedule and the Alberta internal load.

BC / MT ATC Import (MW)[2,3]	AIL (MW)[1]										
	7500 to 7999	8000 to 8499	8500 to 8999	9000 to 9499	9500 to 9999	10000 to 10499	10500 to 10999	11000 to 11499	11500 to 11999	12000 to 12499	12500 and above
Below 600	0	0	0	0	0	0	0	0	0	0	0
601 to 650	10	10	10	10	10	10	0	0	0	0	0
651 to 700	15	12	10	10	10	10	10	10	10	10	10
701 to 750	51	41	35	31	27	25	22	20	19	17	16
751 to 800	106	86	75	67	61	55	51	47	44	41	38
801 to 850	163	137	122	112	104	97	92	87	82	79	75
851 to 900	212	186	171	160	151	145	139	134	129	125	122
901 to 950	261	234	218	207	199	192	186	181	176	172	169
951 to 1000	310	283	267	255	246	239	233	228	223	219	215
1001 to 1050	359	331	314	302	293	286	279	274	269	265	261
1051 to 1100	412	382	364	351	341	333	327	321	315	311	307
1101 to 1150	462	430	411	398	388	380	373	367	361	356	352
1151 to 1200	511	478	459	445	435	426	419	412	407	402	397
1201 to 1250	561	526	506	492	481	472	464	458	452	447	442

Notes:

1. If the Alberta internal load falls on or very close to a boundary of Table 1 ranges, the AESO uses the lower Alberta internal load range to determine the amount of load shed service for imports to arm.
2. When 5L92 is out of service, the AESO uses the total net combined British Columbia/Montana import plus the Alberta interconnected electric system most severe single contingency to determine the import level when applying this table.
3. When 2L294, 2L113, 1L274/L274 or the Natal transformers are out of service, the AESO uses the total net combined British Columbia/Montana import and the AIES load plus the British Columbia load served from Alberta via the 138 kV system to determine the LSSi required level.

5.3.2 The Alberta to the combined British Columbia and Montana operating limit for export

The British Columbia and Montana to Alberta system operating limits for export under various system conditions are given in Table 8(a) and Table 8(b) below.

Table 8(a): Alberta to Combined British Columbia and Montana Operating Limit for Export

Summer Season (May 1– October 31)

AIL	System Normal Export Limit	1201L Out of Service	Path 1 Out of Service
All AIL	1000	80	0

Table 8(b): Alberta to Combined British Columbia and Montana Operating Limit for Export

Winter Season (November 1 – April 30)

AIL	System Normal Export Limit	1201L Out of Service	Path 1 Out of Service
All AIL	1000	80	0

5.3.3 The Alberta (British Columbia/Montana/Saskatchewan) Operating Limit for Export

The AESO calculates the summer system operating limit for export from Alberta by adding the results derived from Table 4(b), which describes the Alberta to Saskatchewan total transfer capability for export, to the results of Table 8(a), which defines the maximum summer export system operating limits affecting the combination of the British Columbia and Montana transfer paths.

The AESO calculates the winter system operating limit for export from Alberta by adding the results derived from Table 4(b), which describes the Alberta to Saskatchewan total transfer capability for export, to the results of Table 8(b), which defines the maximum winter export system operating limits affecting the combination of the British Columbia and Montana transfer paths.

5.3.4 The Alberta (British Columbia/Montana/Saskatchewan) Operating limit for Import

The AESO calculates the system operating limit for import into Alberta by adding the results derived from Table 4(a), which describes the Alberta to Saskatchewan total transfer capability for import, to the results of Tables 6(a) and 6(b), which defines the maximum import system operating limits affecting the combination of the British Columbia and Montana transfer paths.

6 Submission of Interchange Transaction Bids and Offers by Pool Participants

This section provides information on subsection 5 of Section 203.6.

Subsection 5 of Section 203.6 may be read together with other general bid, offer and dispatch provisions contained in Division 203, Energy Market, of the existing ISO rules. In this regard, the AESO encourages Section 203.3 of the ISO rules, *Energy Restatements* to be read in concert with Section 203.6 and that an importing pool participant must continue to submit offers for their available capability, in accordance with Section 203.3.

7 Validation of E-tags by the ISO

This section provides information on subsection 7 of Section 203.6.

Any balancing authority or transmission provider impacted by an interchange transaction schedule has its own criteria, priorities and timelines and the authority to validate and deny an e-tag. In current practice, some adjacent balancing authorities curtail e-tag transactions up to 15 minutes prior to the settlement interval according to their priority order to ensure that the total of the schedules submitted are within capacity limits. However, the AESO takes steps at approximately 15 minutes prior to the settlement interval to address any constraint that continues to exist even if the adjacent balancing authority is still in the process of taking action. The balancing authorities adjacent to the AESO are BC Hydro, SaskPower and Northwestern Energy.

8 Interchange Schedules and Dispatches by the AESO

This section provides information on subsection 8 of Section 203.6.

The current ramp rates for hourly fixed transactions are as follows, but may be subject to change based on agreement between the AESO and the adjacent balancing authority:

1. the Alberta-Saskatchewan interchange ramping duration is 10 minutes and ramping starts 5 minutes before the interchange schedule start time and end time;
2. the Alberta-British Columbia interchange ramping duration is 20 minutes and ramping starts 10 minutes before the interchange schedule start time and end time; and
3. the Alberta-Montana interchange ramping duration is 20 minutes and ramping starts 10 minutes before the interchange schedule start time and end time.

9 Available Transfer Capability Allocations for Transfer Paths

This section provides information on subsection 10 of Section 203.6.

9.1 Allocation examples

The following is intended to provide examples of the available transfer capability allocations for transfer paths set out in subsection 10 of Section 203.6. In these examples, assume the AESO determined the following available transfer capability limits based on the procedure detailed in subsection 2 of Section 203.6.

Import capability limits and export capability limits in Table 9 below are for the example purposes only, and are not meant to imply any particular ongoing or expected future limitations. Please refer to sections 4 and 5 of this Information Document for more detail regarding the calculation of import capability limits and export capability limits.

Table 9: Capability Limits Illustration

Transfer Path	Import Available Transfer Capability (TTC – TRM_S)	Export Available Transfer Capability (TTC – TRM_S)
British Columbia intertie	600	600
Montana intertie	300	300
Saskatchewan intertie	150	150
Grouping	Import Capability Limit (operating limit – TRM)	Export Capability Limit (operating limit – TRM)

Combined British Columbia/Montana intertie	600	600
Combined British Columbia/Montana/Saskatchewan interties	725	600

Example 1 – All Limits Exceeded on Import

Assume the following energy offers received at T-2 as referenced in subsection 5(1) of Section 203.6. Assume also that all import offers are priced at $0/MWh and all exports at $999.99/MWh:

British Columbia Intertie			Montana Intertie			Saskatchewan Intertie		
Import	Export	Net	Import	Export	Net	Import	Export	Net
1,000	200	800 (Import)	450	0	450 (Import)	200	0	200 (Import)

Combined British Columbia/Montana Interties			Combined British Columbia/Montana/Saskatchewan Interties		
Import	Export	Net	Import	Export	Net
1,450	200	1,250 (Import)	1,650	200	1,450 (Import)

In accordance with subsection 10(1) of Section 203.6 the assessment of this example is as follows:

> Based on energy offers received 2 hours prior to the settlement interval, all three individual transfer paths would exceed their available transfer capability limits if the interchange transactions were realized during the settlement interval. Additionally, both the combined British Columbia/Montana and combined British Columbia/Montana/Saskatchewan capability limits would be exceeded. Therefore, the AESO determines and posts individual transfer path available transfer capability allocations by adjusting allocation transmission reliability margin (TRM_a) values as detailed in section 4.3 of this Information Document.

The AESO must make available transfer capability allocation calculations in accordance with subsection 10(2)(a) of Section 203.6, so net import volumes for each individual transfer path are first compared to the respective transfer path import available transfer capability limit and, if the net import volume exceeds the respective transfer path import available transfer capability limit, the allocation is set at that limit. After this step, the individual transfer path allocations would be:

British Columbia intertie	600 MW (Import)
Montana intertie	300 MW (Import)
Saskatchewan intertie	150 MW (Import)

In accordance with subsection 10(2)(b) and (c) of Section 203.6, the combined allocations for the British Columbia and Montana interties are compared to the combined British Columbia/Montana capability limit. In this example, the combined allocation is a net import of 900 MW, while the combined British Columbia/Montana import capability limit is 600 MW. A further allocation of capability on these two transfer paths is required such that their total allocation does not exceed 600 MW.

Furthermore, as all transactions are priced equally, the step under subsection 10(2)(c)(i) of Section 203.6 does not result in any change to the allocations calculated under subsection 10(2)(a) of Section 203.6. As there are equally priced transactions, allocations are reduced on a pro rata basis in accordance with subsection 10(2)(c)(ii) of Section 203.6 as follows:

the allocation resulting from subsection 10(2)(a) of Section 203.6;

divided

by the sum from subsection 10(2)(b) of Section 203.6;

multiplied

by the amount by which the combined British Columbia/Montana import capability limit is exceeded.

In this example, the reduction for British Columbia is:

600 / 900 x 300 = 200 MWIn this example, the reduction for MATL is:

300 / 900 x 300 = 100 MW

After completing the requirements of subsection 10(2)(c) of Section 203.6 are as follows:

British Columbia intertie	400 MW (Import)
Montana intertie	200 MW (Import)
Saskatchewan intertie	150 MW (Import)

In accordance with subsection 10(2)(d) and (e) of Section 203.6, the combined allocations for the British Columbia, Montana and Saskatchewan interties are now compared to the combined British Columbia/Montana/Saskatchewan capability limit. In this example, the combined allocation at this stage is a net import of 750 MW, while the combined British Columbia/Montana/Saskatchewan import capability limit is 725 MW. A further allocation of combined British Columbia/Montana/Saskatchewan capability on all three transfer paths is required such that their total allocation does not exceed 725 MW.

In this example, as all transactions are priced equally, the step under subsection 10(2)(e)(i) of Section 203.6 does not result in any change to the allocations calculated under subsections 10(2)(a) or 10(2)(c) of Section 203.6. As there are equally priced transactions, allocations are reduced on a pro rata basis in accordance with subsection 10(2)(e)(ii) which proceeds as follows:

the allocation resulting from subsections 10(2)(a) or 10(2)(c) of Section 203.6;

divided

by the sum from subsection 10(2)(d) of Section 203.;

multiplied

by the amount by which the combined British Columbia/Montana/Saskatchewan import capability limit is exceeded.

In this example, the reduction for British Columbia is:

400 / 750 x 25 = 13 MW

In this example, the reduction for MATL is:

200 / 750 x 25 = 7 MW

In this example, the reduction for Saskatchewan is:

150 / 750 x 25 = 5 MW

The resulting individual transfer path allocations after completing the requirements of subsection 10(2)(e) of Section 203.6 are as follows:

British Columbia intertie	387 MW (Import)
Montana intertie	193 MW (Import)
Saskatchewan intertie	145 MW (Import)

If interchange transactions were implemented in the volumes as allocated above, all individual transfer paths and relevant combinations of transfer paths would be within capability limits. The AESO would use the above available transfer capability allocations for the individual transfer paths in the determination of the allocation transmission reliability margin as described in section 5.3 above and would post them at approximately 85 minutes prior to the start of the settlement interval. The AESO would then use these allocations, if necessary, in the curtailment procedures described in subsection 11 of Section 203.6.

Example 2 – Wheel Through Transaction with Capability Limit Exceeded

Assume the following energy offers are received at T-2 as referenced in subsection 5(1) of Section 203.6. Assume that all import offers are priced at $0/MWh and all exports at $999.99/MWh. In this case, the AESO identifies a wheel through transaction from Montana to British Columbia, as the same market participant submits an import offer and an export bid in the same volume, but across two separate interties.

British Columbia Intertie			Montana Intertie			Saskatchewan Intertie		
Import	Export	Net	Import	Export	Net	Import	Export	Net
800	200	600 (Import)	200	0	200 (Import)	0	0	0

British Columbia/Montana Combined			British Columbia/Montana/Saskatchewan Combined		
Import	Export	Net	Import	Export	Net
1,000	200	800 (Import)	1,000	200	800 (Import)

In accordance with subsection 10(1) of Section 203.6 the assessment of this example is as follows:

> Based on energy offers received at T-2, all three individual transfer paths are within their available transfer capability limits if the interchange transactions were realized during the settlement interval. However, both the combined British Columbia/Montana import capability limit and the combined British Columbia/Montana/Saskatchewan import capability limit would be exceeded. Therefore, the AESO determines and posts individual transfer path available transfer capability allocations. As the AESO has identified a wheel through transaction from Montana to British Columbia and it does not result in the violation of the capability limits on either the Montana or British Columbia interties, the AESO excludes this transaction from the allocation calculation in accordance with subsection 10(1)(b) of Section 203.6.

The AESO makes available transfer capability allocation calculations in accordance with subsection 10(2)(a) of Section 203.6, so net import volumes for each individual transfer path are first compared to the respective transfer path available transfer capability limit and, if the net amount exceeds the limit, the allocation is set at the limit. After this step, the individual transfer path allocations would be:

British Columbia intertie	600 MW (Import)
Montana intertie	200 MW (Import)
Saskatchewan intertie	0 MW

In accordance with subsections 10(2)(b) and (c) of Section 203., the combined allocations for the British Columbia and Montana interties are now compared to the combined British Columbia/Montana capability limit. In this example, the combined allocation is a net import of 800 MW, while the combined British Columbia/Montana import capability limit is 600 MW. A further allocation of available transfer capability on these two transfer paths is required such that their total allocation does not exceed 600 MW.

In this simple example, as all transactions are priced equally, the step under subsection 10(2)(c)(i) of Section 203.6 does not result in any change to the allocations calculated under subsection 10(2)(a). As the AESO has identified a wheel through transaction from Montana, these volumes are excluded from the allocation calculations. After adjusting for the wheel through transaction, the allocation in accordance with subsection 10(2)(c)(ii) of Section 203.6 proceeds as follows:

the allocation resulting from subsection 10(2)(a) of Section 203.6;

divided

by the sum from subsection 10(2)(b) of Section 203.6;

multiplied

by the amount by which the combined British Columbia/Montana capability limit is exceeded.

In this example, the reduction for British Columbia is:

600 / (800 – wheel through of 200) x 200 = 200 MW

In this example, the reduction for MATL is:

(200 – wheel through of 200) / (800 – wheel through of 200) x 200 = 0 MW

The individual transfer path allocations after the application of subsection 10(2)(c) of Section 203.6 are as follows:

British Columbia intertie	400 MW (Import)
Montana intertie	200 MW (Import)
Saskatchewan intertie	0 MW

In accordance with the provisions of subsection 10(2)(d) and (e) of Section 203.6, the combined allocations for the British Columbia, Montana and Saskatchewan interties are now compared to the combined British Columbia/Montana/Saskatchewan capability limit. In this wheel through example, the combined allocation at this stage is a net import of 600 MW while the combined British Columbia/Montana/Saskatchewan import capability limit is 725 MW, so no further allocation is required. If the AESO implemented interchange transactions in the volumes as allocated above, all individual transfer paths and relevant combinations of transfer paths would be within capability limits. The AESO would post the above available transfer capability allocations for the individual transfer paths at approximately 85 minutes prior to the start of the settlement interval. The AESO would then use these allocations, if necessary, in the curtailment procedures described in subsection 11 of Section 203.6.

10 Transfer Path Constraint Management

This section provides information on subsection 11 of Section 203.6.

At any time at or after 15 minutes prior to the settlement interval the AESO determines whether any of the current available transfer capability or system operating limits are exceeded and if so, curtails the effective e-tags to the available transfer capability limits of the individual transfer paths. If the constraint still exists, the AESO curtails the effective e-tags on both the Alberta-British Columbia transfer path and the Alberta-Montana transfer path to the combined British Columbia/Montana capability limit. If the constraint still continues to exist, the AESO curtails e-tags to the combined British Columbia/Montana/Saskatchewan capability limit.

11 Unscheduled Flow Reduction and Reliability Standard IRO-006-WECC-AB-1, *Qualified Transfer Path Unscheduled Flow Relief*

This section provides additional information on reliability standard IRO-006-WECC-AB-1, *Qualified Transfer Path Unscheduled Flow Relief*, which details the AESO's standards for managing unscheduled flows across a transfer path, further describing the impact to pool participants of the AESO acting to reduce or prevent additional unscheduled flow across a transfer path.

When a reduction to an interchange transaction is required to reduce unscheduled flow on a constrained qualified path, the sink control area can reduce the contributing interchange transaction or any other interchange transaction, provided the reduction achieves the equivalent effect on reducing unscheduled flow on the affected transfer path.

The AESO denies new e-tags submitted after an unscheduled flow event is declared with a transfer distribution factor on the qualified path in the qualified direction of 5% or more.

The AESO denies adjustments or extensions to (non-expired) or replacements of (expired) e-tags submitted after an unscheduled flow event is at step 4 (first level curtailment) or higher, as set out in Appendix 1 of reliability standard IRO-006-WECC-AB-1, *Qualified Transfer Path Unscheduled Flow Relief*, and with a transfer distribution factor on the qualified path in the qualified direction of 5% or more.

12 Intertie Restatements

Pursuant to subsection 6(4) of Section 203.6, where a pool participant's transmission service is curtailed by a transmission provider, the pool participant is required to submit an energy restatement or an ancillary services restatement. The AESO recognizes that interchange transactions may be impacted by scheduling practices of different jurisdictions , and recommends the following courses of action to pool participants:

(a) For one or more curtailments that are issued prior to or at the settlement interval and that take effect at the start of the settlement interval, restate the associated offer or bid to the curtailed volume as soon as reasonably practicable after the curtailment is issued.

(b) For one or more curtailments that take effect after the start of the settlement interval, make best efforts to restate the associated offer or bid to the curtailed volume at the time the curtailment becomes effective.

(c) At the time a curtailment is no longer in effect, make best efforts to restate the associated offer or bid to the e-tag(s) volume, in MW, taking into account any curtailment(s) that remains in effect for the associated offer or bid.

In any event, the AESO expects the offer or bid at the close of the settlement interval to match the associated e-tag(s), in MW, at the close of the settlement interval.

While the AESO recognizes that the energy restatement is of limited use to the AESO System Controller as the interties are dispatched based on e-tags, the energy restatement is required for other AESO downstream systems and processes including the energy market merit order, ancillary service merit order, market reporting and compliance tools and processes. The AESO may consider whether there is an option to automate energy restatements at a future time.

Revision History

Posting Date	Description of Changes
2018-07-20	Updated Table 7 with newly implemented LSSi values Updated Table 5(a) and the associated "Notes" section
2018-06-01	Addition of Table 7b which included the new LSSi values as of 10:00 am July 3, 2018
2017-06-15	Updated section 12
2017-06-01	Updated Tables 1(a), 1(b), 2(a), 2b, 5(a), 5(b), 6(a), 6(b), 8(a), 8(b) for Path 1 out-of-service TTC; Updated section 2 and section 12; and Administrative amendments.
2017-02-28	Updated section 12; and Administrative revisions.
2016-11-30	Updated Tables 1(a), 1(b), 2(a), 2b; Addition of Table 5(a); Table renumbering; and Administrative revisions.
2016-08-23	Addition of section 12, Intertie Restatements.
2015-10-29	Updated Tables 1(b), 3, 9(b) and 12; revised definition of transmission reliability margin in section 5; updated section 5.1 to reflect the AESO's operating procedure in the event of a change to the operating limit within 15 minutes prior to the start of a settlement interval; revised section 5.3 to reflect that the transmission reliability margin will be increased to reflect available load shed service for import volumes; administrative changes to improve consistency and alignment.
2015-08-20	Updated Table 4.
2015-06-04	Updated Tables 1(a), 2, 9(a) and 11.
2014-12-11	Updated Tables 1(a), 9(a) and 10.
2014-11-01	Updated Tables 3, 8, 10 and 12.
2014-05-01	Updated Table 1 and Table 9.
2014-02-27	Updated Table 4.
2014-01-30	Updated Table 1, Table 4, Table 9 and Table 10; administrative changes to improve consistency and alignment.
2013-11-12	Administrative Updates.

2013-08-13	Initial release.
2013-03-14	Second draft release.
2011-10-01	Initial draft release.

Information Document
Power Pool Settlement Guide
ID #2011-002R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- Section 103.4 of the ISO rules, *Power Pool Financial Settlement* (“Section 103.4”). The purpose of this document is to provide guidance to market participants regarding the power pool financial settlement process.

2 Power Pool Settlement Process

Appendix 1 of this Information Document illustrates the steps in the power pool financial settlement process.

3 Power Pool Statements

Power pool statements are located in the Energy Trading System on the Alberta Electric System Operator (“AESO”) website. To access power pool statements, login to the Energy Trading System on the AESO website using a digital certificate. To request a digital certificate, contact the AESO’s Digital Certificate Administrator at cert.admin@aeso.ca.

When power pool statements become available on the AESO website, all pool participants receive a message in the Energy Trading System. Additionally, a schedule of power pool settlement dates is available on the AESO website.

3.1 Preliminary Power Pool Statement

Preliminary power pool statements are available on the AESO website by the end of the fifth (5th) business day after the end of each settlement period. Preliminary power pool statements provide pool participants the opportunity to review settlement information and contact the AESO if there is a potential discrepancy prior to a final power pool statement being issued.

3.2 Final Power Pool Statement

Final power pool statements are available on the AESO website by the end of the fifteenth (15th) business day after the end of each settlement period. Final power pool statements include updated information and corrections to preliminary power pool statements, if applicable. Financial transactions between the AESO and pool participants are made based on final power pool statements.

3.3 Components of the Power Pool Statement

The following information explains the line items that generally appear on preliminary and final power pool statements for a settlement month. A preliminary or final power pool statement for a given pool participant may not include all of the items listed below. An example of a power pool statement is available on the AESO website.

(a) Consumption

(i) Energy Charge – the amount of electric energy consumed or exported by a pool participant (purchaser), minus net settlement instructions.

[1] “Authoritative Documents” is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

(ii) Prior Period Energy Charge – charges resulting from the resettlement of prior period production, listed by month. Supporting documentation is available in the Energy Trading System, which shows the amount of the prior period change for each pool asset by hour. Once logged into the Energy Trading System, click on the following path: Reports/Historical/Settlement Changes Detail - Consumption.

(iii) Energy Market Trading Charge (Spot Trading Charge) – the energy market trading charge is calculated in accordance with subsection 6 of section 103.6 of the ISO rules, *Fees and Charges*. The energy market trading charge in effect for the current year is located in ID #2011-003R, *Schedule of ISO Fees* ("ID #2011-003R") and on the AESO website.

The MWh amount to which the trading charge is applied is shown as a line item on a power pool statement.

The energy market trading charge may apply to the following pool asset types:

(A) metered physical generation pool assets;

(B) metered physical load pool assets;

(C) unmetered sell pool assets; or

(D) unmetered buy pool assets.

All pool assets are assigned an asset ID when they are initially set up in the Energy Trading System. The asset list can be found on the AESO website. All metered physical load pool assets are assigned an asset ID that identifies the pool participant, load settlement zone and the legal owner of the applicable electric distribution system. An unmetered pool asset has a plus or minus sign included in the asset ID. For example, ABC+ is an unmetered buy pool asset and ABC- is an unmetered sell pool asset.

Some pool participants have unmetered pool assets for trading purposes. These pool assets allow pool participants to trade physical energy without associating it directly with a metered pool asset at the time of trade, and they facilitate the registration of net settlement instructions. The unmetered pool assets also allow pool participants to have a separate reporting unit for their net settlement instructions.

The energy market trading charge is calculated on a pool asset-by-pool asset basis for each hour. It is applied to the greater of the metered volume or the net settlement instructions for each asset for each hour.

(iv) Prior Period Spot Trading Charge – charges resulting from the resettlement of prior period production, listed by month.

(v) Charges for Payments to a Supplier on the Margin (PSM Charges) – total PSM Charges for the current production month. PSM Charges are calculated based on a pool participant's consumption in a settlement interval. PSM Charges are applied to all load based on their proportion of total load in a settlement interval where a pool participant is eligible to receive a PSM Payment.

(vi) Prior Period PSM Charge – charges resulting from the resettlement of the prior period production and the recalculation of PSM Charges, listed by month.

(b) Production

(i) Energy Payment – the amount of electric energy supplied or imported by a pool participant (supplier), minus net settlement instructions.

(ii) Prior Period Energy Payment – payments resulting from the resettlement of prior period production, listed by month. Supporting documentation is available in the Energy Trading System, which shows the amount of the prior period change for each pool asset by hour. Once logged into the Energy Trading System, click on the following path: Reports/Historical/Settlement Changes Detail - Production.

(iii) Energy Market Trading Charge (Spot Trading Charge) – the energy market trading charge is calculated in accordance with subsection 6 of section 103.6 of the ISO rules, *Fees and Charges*. The energy market trading charge in effect for the current year is located in ID#2011-003R and on the AESO website. For more information on the energy market trading charge, refer to the subsection 3.3(a)(iii) of this Information Document.

(iv) Prior Period Spot Trading Charge – charges resulting from the resettlement of prior period production, listed by month.

(v) Payments to a Supplier on the Margin (PSM Payment) – total monthly PSM Payment based on the difference between a pool participant's offer price and the pool price for volumes produced from operating blocks for which dispatches are issued above the pool price. In any hourly dispatch, a pool participant is eligible for either a transmission constraint rebalancing payment (described below) or a PSM Payment, not both.

(vi) Transmission Constraint Rebalancing Payment (TCR Payment) – total monthly payment based on the difference between the pool price and the pool participant's offer price for each dispatched operating block, multiplied by the volume of transmission constraint rebalancing energy requested in the settlement interval above the pool price for that operating block. In any hourly dispatch, a pool participant is eligible for either a transmission constraint rebalancing payment or a payment to suppliers on the margin, not both.

(vii) Prior Period Production PSM Payment – payments resulting from the resettlement of prior period production and the recalculation of PSM Payments, listed by month.

(viii) Prior Period Production TCR Payment – payment resulting from the resettlement of prior period production and the recalculation of transmission constraint rebalancing payments, listed by month.

(ix) Dispatch Down Service Payment – total monthly payment to generators which offered in the dispatch down service merit order and were dispatched down in a settlement interval.

(x) Prior Period Dispatch Down Service Payment – dispatch down service payments resulting from the resettlement of prior period production, and the recalculation of dispatch down service payments.

(xi) Dispatch Down Service Charge – total monthly charges collected from all source assets active in a settlement interval when a generating pool asset was dispatched down. Pool participants receiving a dispatch down service payment also pay a portion of the dispatch down service charge.

(xii) Prior Period Dispatch Down Service Charge – charges resulting from the resettlement of the prior production period and the recalculation of dispatch down service charges.

(c) Special Transactions and Adjustments

(i) Participation Fee – a non-refundable fee pursuant to section 103.6 of the ISO rules, *Fees and Charges*, which all pool participants pay to maintain their pool participant status with the AESO. This charge appears on a pool participant's December power pool statement for the period January to December.

(ii) Digital Certificate – a fee pursuant to section 103.6 of the ISO rules, *Fees and Charges*, paid by pool participants for a digital certificate required to log in to the Energy Trading System. Digital certificates are renewed annually.

(iii) Interest and Penalties – any amounts charged pursuant to section 103.7 of the ISO rules, *Financial Default and Remedies*, for a late payment related to settlement.

(iv) Cash on Deposit – funds held by the AESO and applied on the current power pool statement as a prepayment.

(v) Retailer Specific Adjustment – an adjustment to a retailer's statement amount related to updated load settlement data for a specific retailer's consumption. This adjustment is made after final load settlement has occurred and it may be positive or negative. For further information, refer to the AESO website.

(vi) Retailer Adjustment to Market (RAM Adjustment) – a post-final adjustment mechanism adjustment made to all retailers in a settlement zone (as defined in Commission Rule 021, *Settlement System Code*) for the collection or payment required to offset the retailer specific adjustment, described above. This adjustment may be positive or negative. For further information, refer to the AESO website.

(vii) Transmission Administrator Adjustment – a post-final adjustment mechanism for system level meter errors. The AESO makes necessary adjustments in billings between the transmission line losses account and all retailers in the affected zone. This adjustment may be positive or negative. For further information, refer to the AESO website.

3.4 Power Pool Statement Verification

There are various reports used to verify power pool statements in the Energy Trading System. These reports are available in an html or csv (comma separated value) format. The html format is a static web report, while the csv format allows the conversion of reports into an Excel spreadsheet.

Metered volume reports are updated five (5) business days after production, while the information for scheduled energy on the transfer paths is updated the next business day. Import and export interchange transactions should be reconciled daily, if possible.

The AESO recommends that pool participants frequently review the settlement reports posted by the AESO throughout the month. By frequently reviewing the settlement reports, pool participants are more likely to identify potential discrepancies and resolve them with the AESO early in the power pool financial settlement process. If any potential discrepancies are identified, please contact the AESO at settlement@aeso.ca as soon as possible.

The following is a list of settlement reports located in the Energy Trading System, which contain pool participant specific data:

Settlement Report	**Location in the Energy Trading System**
Metered Volumes	Reports/Historical/Daily Detail, Daily Summary, or Monthly Summary. Specifically for production or consumption: Reports/Historical/Metering (Specific)
Net Settlement Instructions	Reports/Historical/Reports/NSI and Meter Volume Breakdown or NSI Detail Report
Power Pool Statement	Reports/Historical/Pool Statement
Prior Period Reports	Reports/Historical/Settlement Changes, specifically Production or Consumption
Energy Market Trading Charges	Reports/Historical/Trading Charge, specifically for Production or Consumption
PFAM Summary	Reports/Historical/PFAM Summary

DDS Payments and Charges	Reports/Historical/DDS Payment Summary/DDS Charge Summary or DDS Payment Detail. Hourly DDS Payments and Charges are also included in the Daily Detail Production Report
PSM and TCR Payments and PSM Charges	Reports/Historical/Uplift Payments Summary/PSM Charges Summary or Detail Uplift Payment. Hourly PSM and TCR Payment and PSM Charge information can also be found in the Daily Detail Production and Daily Detail Consumption Reports, respectively

The hourly pool price can be found on the AESO website by clicking on the following path: Market & System Reporting/Current and Historical Market Reports/Historical, then select “Pool Price” and the applicable dates.

4 Settlement Dates and Payment Obligations

In accordance with subsection 20 of Section 103.4 of the ISO rules, the settlement of the final power pool statement occurs on the twentieth (20th) business day following the end of each production period, unless that date has been accelerated under subsection 21 because of any prior late payments. All amounts owed to pool participants by the AESO are paid or accounted for on the twentieth business day following the end of each production period.

4.1 Agent Arrangements

In accordance with section 201.2 of the ISO rules, *Appointment of Agent*, a pool participant may, with the approval of the AESO, appoint an agent to act on its behalf.

4.2 Method of Receiving and Sending Payment

As required by subsection 23 of Section 103.4 of ISO rules, a pool participant must pay any net dollar amount the pool participant owes, as set out in its final power pool statement, to the AESO by wire transfer to the bank account the AESO specifies. Please note that the AESO does not accept cheques, counter deposits or bank drafts for the payment of final power pool statements.

The AESO uses wire transfers to pay pool participants. Each payment is deposited into a pool participant’s bank account on the due date. Wire transfers provide the AESO the ability to track all payments made, which is especially important for the payment of large amounts. Any wire transfer fees are generally charged to a pool participant by its bank.

The AESO facilitates the cash clearing of the market, whereby suppliers to the market are paid and purchasers from the market make payments on the same business day. To facilitate this process, amounts owed to the AESO must be received on the specified cash settlement day.

Please submit inquiries regarding banking instructions to: accounting@aeso.ca.

4.3 Late Payment

If a pool participant fails to make a payment by its due date, the pool participant is considered to be in default and it should immediately contact the AESO at accounting@aeso.ca. While contacting the AESO does not relieve the pool participant from potential interest charges or the potential temporary change of settlement dates in accordance with subsection 21 of Section 103.4 of ISO rules, it may avoid other consequences for late payment. For additional information regarding the consequences for late payment, please refer to section 103.7 of the ISO rules, *Financial Default and Remedies*.

The AESO generally contacts a pool participant that is in default in order to understand the circumstances surrounding the default and to determine when the payment is expected to be made. If the AESO is not satisfied with the reasons for late payment, or the expected payment date, the AESO may enforce its rights, including those referred to in section 103.7 of the ISO rules, *Financial Default and Remedies*, such as realizing on the pool participant's financial security.

In accordance with subsection 19 of Section 103.4 of the ISO rules, the AESO must issue on its website a final power pool statement to each pool participant on the fifteenth (15th) business day after the end of each settlement period. Subsection 21 provides, among other things, that, if a pool participant has defaulted in the payment for a settlement period one (1) time in its first (1st) calendar year of pool participant registration, then the AESO may require that the pool participant pay the AESO on the nineteenth (19th) business day following the end of the settlement period for the next six (6) settlement periods following the date of the first (1st) default. If four business days are not sufficient for the pool participant to process the settlement payment, the AESO recommends that the pool participant estimate its final net energy charges and pay to the AESO by the due date an amount that is higher than what is expected to be owed in order to avoid late payment and short payment charges.

Any excess amounts received by the AESO from a pool participant are returned to that pool participant, if requested, less any applicable wire transfer fees. If not requested, excess amounts are applied as a prepayment for the next settlement period. No interest is paid to the pool participant as a result of any prepayment.

5 Power Pool Statement Discrepancies and Disputes

5.1 Discrepancies on Preliminary Power Pool Statements

(a) Generation/Production

If a pool participant identifies a potential discrepancy in the amount of production on its preliminary power pool statement, the pool participant may contact the meter data manager that it has engaged in order to confirm that all applicable generation has been submitted to the AESO.

(b) Interchange Transaction Importer or Exporter

Pool participants are encouraged to contact the AESO at settlement@aeso.ca to resolve any potential discrepancies related to import/export settlement for interchange transactions. The following information is required to investigate such potential discrepancies:

(i) the day;

(ii) the hour ending;

(iii) the pool asset;

(iv) the e-Tag number;

(v) the e-Tag status; and

(vi) the megawatt hours according to a pool participant's records.

Pool participants are encouraged to review import/export data on a regular basis and to report any discrepancies immediately so that corrections can be incorporated into the applicable final power pool statements. The import/export settlement data is posted to the AESO website on the business day following the production date.

For the Montana-Alberta intertie, the import/export settlement volume is determined by applying an adjustment to the e-Tag volume to account for the allocation of the losses on the Alberta portion (from the Alberta border to the point of connection) of the intertie.

(c) Load/Consumption

If the consumption on the preliminary power pool statement does not reconcile to the information provided by a pool participant's load settlement agent, the pool participant is encouraged to confirm the data with the AESO. The metering information used to prepare the preliminary pool statement is the initial settlement data provided by the load settlement agent and it is adjusted for monthly settlements appearing on the final power pool statement. Any adjustment to interim or final data is provided to the AESO in accordance with Commission Rule 021, *Settlement System Code*, and the adjustments appear as a prior period energy charge on the power pool statement.

(d) Settlement Timelines

Each production month is settled three times as part of the regular AESO settlement cycle. The production month is settled one (1) month (initial), two (2) months (interim) and four (4) months (final) after the end of the production month in order to comply with Commission Rule 021, *Settlement System Code.* Any settlement data (generation or load) that is received by the AESO in advance of these timelines is resettled at the next settlement iteration. Details regarding settlement timing can be found on the AESO website in Settlement Dates.

Please review the pool participant specific report for all net settlement instructions accepted for settlement purposes in the *NSI and Meter Volume Breakdown Report* located on the Energy Trading System. To determine which net settlement instructions were in effect for a specific time period, view the *NSI Detail Report*, which can be found on the Energy Trading System by clicking on the following path: Reports/Historical/NSI Detail.

For additional information on net settlement instructions, please refer to section 103.5 of the ISO rules, *Net Settlement Instructions*.

5.2 Discrepancies on Final Power Pool Statements

Pursuant to subsection 27 of Section 103.4 of the ISO rules, if a pool participant disputes the information contained in a final power pool statement, then the pool participant must submit a written dispute to the AESO in accordance with subsection 3 of section 103.2 of the ISO rules, *Dispute Resolution*, prior to the expiry of the applicable formal dispute submission period published by the AESO. Information regarding the formal dispute submission periods can be found on the AESO website.

However, any dispute with respect to load settlement data does not require the pool participant to submit a written dispute to the AESO prior to the expiry of the applicable formal dispute submission period, because such a dispute is governed by Commission Rule 021, *Settlement System Code*, which provides for the post-final adjustment mechanism.

Notwithstanding any written dispute, the final power pool statement amount must be paid in full in accordance with subsections 19 and 20 of Section 103.4 of the ISO rules. Any adjustments made to the amounts owing in a final power pool statement as a result of a written dispute are reconciled on subsequent power pool statements.

6 Appendix

Appendix 1 – Settlement Process

Revision History

Posting Date	Description of Changes
2017-01-12	Administrative amendments
2016-09-28	Administrative amendments

2016-02-16	Replaced references to “uplift” with either “PSM” or “TCR” Administrative updates
2015-11-26	Amended “pool participant fee” to “pool participation fee”, addition of “non-refundable” and added “for the period January to December to 3.3(c)(i). Addition of transmission constraint rebalancing information to section 3.
2014-04-01	General update to content
2013-08-13	Updated interchange transaction information to include MATL
January 2013	Updated trading charges and settlement dates
January 2012	Updated trading charges and links to website documents
July 2011	Updated the information to align with AUC Rule 021 changes and ISO rules 103.4, *Power Pool Financial Settlement*
January 2010	General update to content

Appendix 1 – Settlement Process

The following is a step-by-step guide to help you access and review your wholesale electricity market settlement.

When are the Pool Statements available?

- Your **preliminary** statement is available on the fifth business day of each month.
- This statement is for you to **review.**
- Payment is not made on this statement.
- Your **final** statement is available on the 15th business day.
- This is the statement that is **paid** on the **20th** business day.

A message will be posted on the Energy Trading System (ETS) when your statement is ready.

How do I retrieve my statement?

- Statements are available on the secure Energy Trading System (ETS section of the AESO's website www.aeso.ca
- Click the 'ETS log-in' button on the top right-hand corner of the AESO's home page to access the ETS.
- The ETS Section contains your statement and other specific participant reports and information related to the wholesale electricity market settlement.
- You need a digital certificate to access this portion of the website.
- **We do not mail or fax statements.**

How do I print my statement?

Once you've used your digital certificate to log onto the AESO's ETS section, click on:

- Reports
- Historical
- Pool Statement
- OK (choose the relevant production month)
- Print your Pool Statement.

How do I review my statement?

There are a number of reports available in the secure area of the AESO's website under "Reports" to help you review your statement.

⇩

To check wholesale electricity market settlement information click on: Reports/Historical/Daily Detail, Daily Summary, Monthly Summary, Trading Charge, Settlement Changes, PFAM Summary or Meter Volumes (Specific).

⇩

To check Net Settlement Instructions click on: Reports/Historical/NSI Details or NSI and Meter Volumes.

What if I have a question, or find a discrepancy in the information?

First check your statement using the reports on the website. If you find a discrepancy please refer to the Settlement Information Document:.

⇩

Generator/Production: contact your Meter Data Manager to ensure all current generation has been submitted to the AESO.

⇩

Importer/Exporter: contact the Energy Market Settlement Analyst to resolve any discrepancy related to import/export settlement.

⇩

Load/Consumption: Confirm your consumption information with the AESO or Load Settlement Agent.

Who do I call if I have questions?

For Pool Settlement and Reports :
settlement@aeso.ca

aesofirstcall
1.888.588.AESO(2376)
Your one-stop information resource for electricity market and transmission inquiries, AESO application inquiries as well as research, data and publication requests.

Payment

Payment must be made by wire transfer as the AESO does not accept cheques, credit cards or bank drafts. If, according to your Pool Statement, the AESO owes you funds, you will receive this amount through wire transfer on the 20th business day.

Information Document
Schedule of ISO Fees
ID #2011-003R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 103.6 of the ISO rules, *ISO Fees and Charges*.

The purpose of this Information Document is to provide information on the AESO's fees that it is required to publish. Below are the fees in effect for 2019.

Fee Type	Fee Amount
Non-refundable Pool participation fee; Covers the period January to December of the year the fee is paid.	$150.00 plus Goods and Services Tax
Energy Market Trading Charge per MWh	$0.46
Digital Certificate Charge	$100.00 plus Goods and Services Tax per digital certificate
Information Technology Service Charge Data Request Charge	$100.00 per hour for special queries plus Goods and Services Tax
Other Services	Other services are charged for on a cost recovery basis.
Load Settlement	Load settlement costs are recovered on a cost recovery basis.
Supply Shortfall	Supply Shortfall costs are recovered on a cost recovery basis.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities* Act and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1").

The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits in two (2) regions in the northwest area. In this Information Document the AESO has defined the northwest area as the area illustrated by the maps and diagrams in Appendix 2 and 3.

Section 302.1 sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the Alberta interconnected electric system. These steps are referenced in Table 1 of this Information Document as they are applied to the northwest area.

2 General

The northwest area consists of long 144 kV and 240 kV bulk transmission lines, generally with a low degree of redundancy of transmission paths. The northwest area total generating capacity is substantially less than the area load, leading to inflows of energy under normal operation.

The outage of a single bulk transmission line or a generating unit may result in voltage depressions outside of the acceptable system operating limits set out in Alberta Reliability Standard TPL-002-AB-0, *System Performance Following Loss of a Single BES Element*. The AESO can partially mitigate this risk by ensuring a sufficient minimum amount of transmission must-run generating unit capacity is available. The availability of transmission must-run services reduces the risk of losing firm load due to low voltages and of a voltage collapse for certain critical transmission or generation contingencies.

Appendix 2 provides a geographical map of the northwest area indicating bulk transmission lines, substations and cutplanes. Appendix 3 provides a detailed diagram of the generating units effective in managing the regional constraints through transmission must-run.

A cutplane is a common term used in engineering studies and is a theoretical boundary or plane crossing two (2) or more bulk transmission lines or electrical paths. The cumulative power flow across the cutplane is measured and can be utilized to determine flow limits that approximate conditions that would ensure the safe and reliable operation of the interconnected electric system.

3 Constraint Conditions and Limits

3.1 Non-Studied Constraints and Limits

For system conditions that have not been pre-studied, the AESO uses energy management system tools and dynamic stability tools to assess unstudied system operating limits in real time.

3.2 Studied Constraints and Limits

When managing a transmission constraint in the northwest area of Alberta that results from total generating capacity of the area being substantially less than the area load, the AESO uses regional

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities* Act and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

cutplane inflow limits to manage area reliability. The AESO calculates the cutplane inflow limits for the Grande Prairie and Rainbow Lake cutplanes in accordance with voltage requirements and bulk transmission line transfer limits. A further description of the cutplane inflow limits for the Grande Prairie and Rainbow Lake cutplanes is set out below.

Cutplane Inflow Limits

There are 2 cutplanes in the northwest area: (1) the Grande Prairie region; and (2) the Rainbow Lake region. These cutplanes are reflected on the maps and diagrams in Appendices 2 and 3. The northwest area generation capacity is substantially less than the area load, which leads to inflows of energy into the northwest area under normal conditions. The specific contingency conditions and inflow limits for the Grande Prairie cutplane are set out in Appendix 4 and 5 of this Information Document.

The Rainbow Lake cutplane inflow limits are conditional based on summer and winter seasons and the status of the listed elements. The inflow limits are provided in Appendices 6, 7, 8 and 9.

Rainbow Area High Generation Mitigation (Export)

With high generation in the Rainbow area, there are transient concerns for RL1 and RB5.

If either 7L64 or 7L93 is out of service and Fort Nelson (FNG1 (units 1 and 2) and Rainbow Lake (RL1 and RB5 in service) RL1 is limited to 40 MW and RB5 is limited to 35 MW.

4 Application of Transmission Constraint Management Procedures

While the AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of Section 302.1, not all of those provisions are effective in the northwest area due to certain unique operating conditions that exist in that area. This Information Document represents and clarifies the application of the general provisions of Section 302.1 to the northwest area.

The protocol steps which are effective in managing transmission constraints are outlined in Table 1 below, followed by additional steps which may be required.

Table 1 Transmission Constraint Management

Sequential Procedures for the Northwest Area

Section 302.1, subsection 2(1) protocol steps	Applicable to the Grande Prairie cutplane inflow?	Applicable to the Rainbow cutplane inflow?
(a) Determine effective pool assets	Yes	Yes
(b) Ensure maximum capability not exceeded	No	No
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No	No
(d) Curtail effective demand opportunity service on the downstream constraint side	No	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	Yes	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	Yes	Yes
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	No	No
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	Yes	Yes

Applicable Protocol Steps

The first step in managing constraints in any area is to identify those generating units effective in managing the constraint. All generating units and loads operating in the northwest area are indicated in Appendix 3 (single line diagram), the generating units effective in managing constraints are identified in Appendix 1.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Ensuring maximum capabilities are not exceeded is not applicable to the northwest due to the deficiency of generation and inflow scenario.

Step (c) in Table 1

There is no effective export or import opportunity service to curtail for either the Grande Prairie or Rainbow cutplane.

Step (d) in Table 1

There is no demand opportunity service load in the area to curtail.

Steps (e)(i) and (ii) in Table 1

Issue dispatches to effective contracted pool assets or directives to effective non-contracted pool assets for transmission must-run.

Step (f) in Table 1

Reverse merit order curtailment is not effective and therefore not required because the constraint is caused by not having enough in-merit generation in the downstream constrained area.

Step (g) in Table 1

Curtailing effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment is available for both Grande Prairie and Rainbow cutplanes.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the northwest area that are known to have an impact on the information contained in this Information Document.

6 Appendices to this Information Document

Appendix 1 – *Effective Pool Assets*

Appendix 2 –*Northwest Area Geographical Map*

Appendix 3 – *Northwest Area Transmission System*

Appendix 4: Grande Prairie Inflow Cutplane N-0 (System Normal) Thermal and Voltage Limits

Appendix 5: Grande Prairie Inflow Cutplane N-1 Thermal and Voltage Limits

Appendix 6: Rainbow Lake Inflow Cutplane N-0 (System Normal) Transient Limits

Appendix 7: Rainbow Lake Inflow Cutplane N-1 Transient Stability Limits

Appendix 8: Rainbow Lake Inflow Cutplane Thermal Limits

Appendix 9: Rainbow Lake Inflow Cutplane Voltage Stability Limits

Revision History

Posting Date	Description of Changes
2019-03-19	Amended Section 3.2 to include Rainbow Area High Generation Mitigation (Export) information.
2019-02-11	Updates to sections 1,2, 3 and 4 Revised map in Appendix 2 to reflect metering point changes to the Grande Prairie Cutplane. Revised Appendix 5, Appendix 6, Appendix 7, Appendix 8 and Appendix 9 based on updated area studies.
2018-05-01	Revised Appendix 1. Revised Appendix 6 based on updated studies.
2018-03-07	Revised the Appendix 6 based on updated studies.
2016-04-14	Administrative updates. Added section 3.1 to describe how the AESO assesses unstudied system operating limits. Revised Table 1 and 2 of Appendix 4 to remove reference to maximum area load level used in studies.

	Revised Appendix 6 and added Appendix 7 based on updated studies.
2014-12-16	Appendices 1 and 3 were amended to reflect the addition of the asset WCD1. In addition typographical errors were amended in Note 2 in Appendix 6.
2014-07-29	Subsection 4.1 updated and Appendix 7 removed in its entirety to reflect the elimination of generation capacity limits for Poplar Hill and Northern Prairie Power Project.
2014-05-12	Appendix 2 amended to reflect the addition of Chickadee Creek 259S
2014-04-03	Appendices 1 and 3 amended to reflect the decommissioning of assets ST1 and ST2.
2013-02-14	Updated Table 4 to reflect changes to the Rainbow Lake Cutplane limit and Dynamic Reactive Reserve requirements. Minor drafting edit to geographical map.
2013-01-01	Updated to include minor drafting edits Updated to include Table 4 which reflects changes to the Rainbow Lake Cutplane limits and Dynamic Reactive Reserve requirements
2012-06-14	Updated to include material content from existing section 302.4 of the ISO rules, *Northwest Area Transmission Constraint Management*
2012-03-03	Updated to reflect transmission upgrades in the area
2011-06-30	Initial Release

Appendix 1 – Effective Pool Assets

The effective generation pool assets for the Grande Prairie cutplane, listed alphabetically by their pool IDs, are:

BCR2

BRCK

DAI1

GPEC

NPC1

NPP1

PH1

VVW1

WCD1

The effective generation pool assets for the Rainbow cutplane, listed alphabetically by their pool IDs, are:

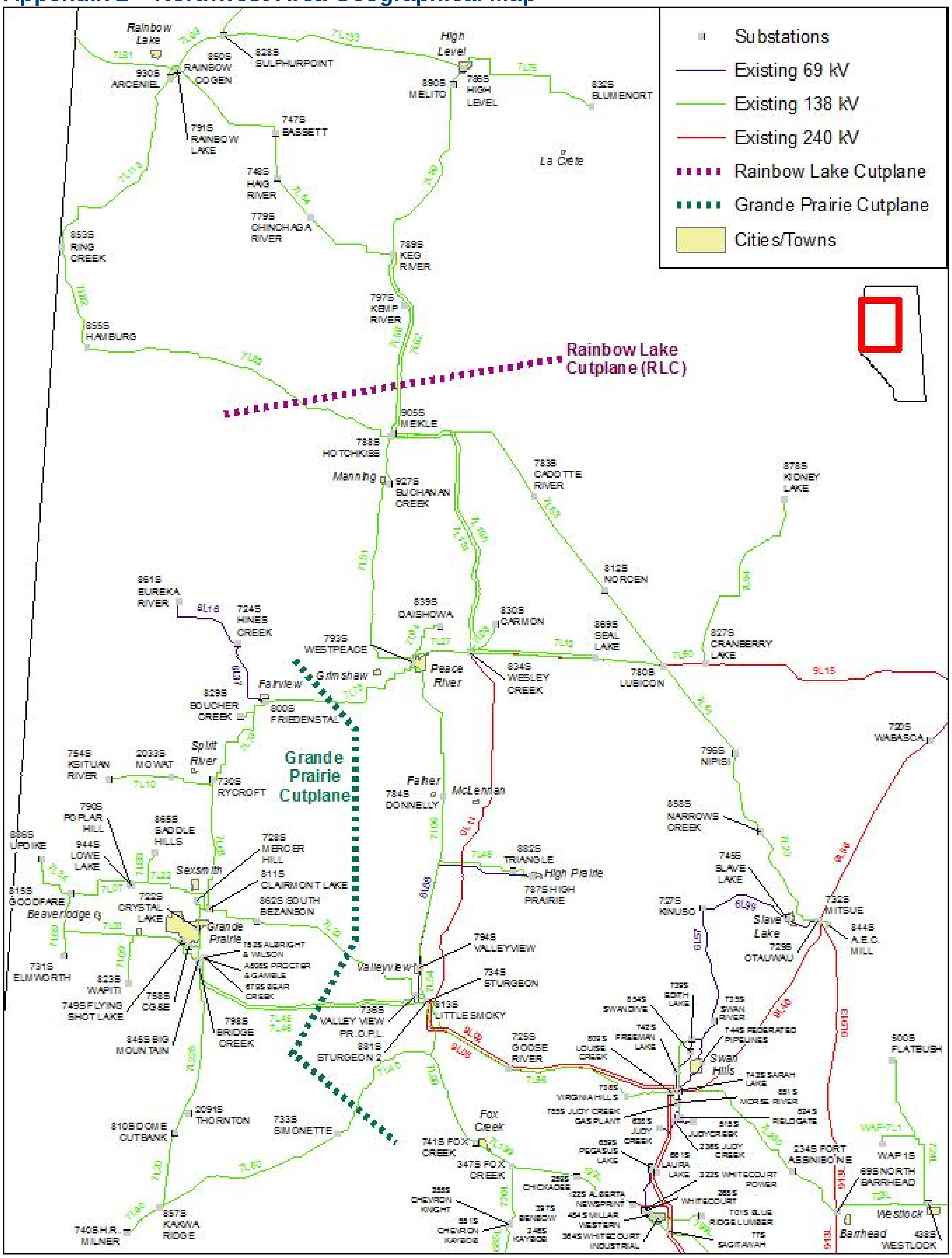
FNG1

FNG2

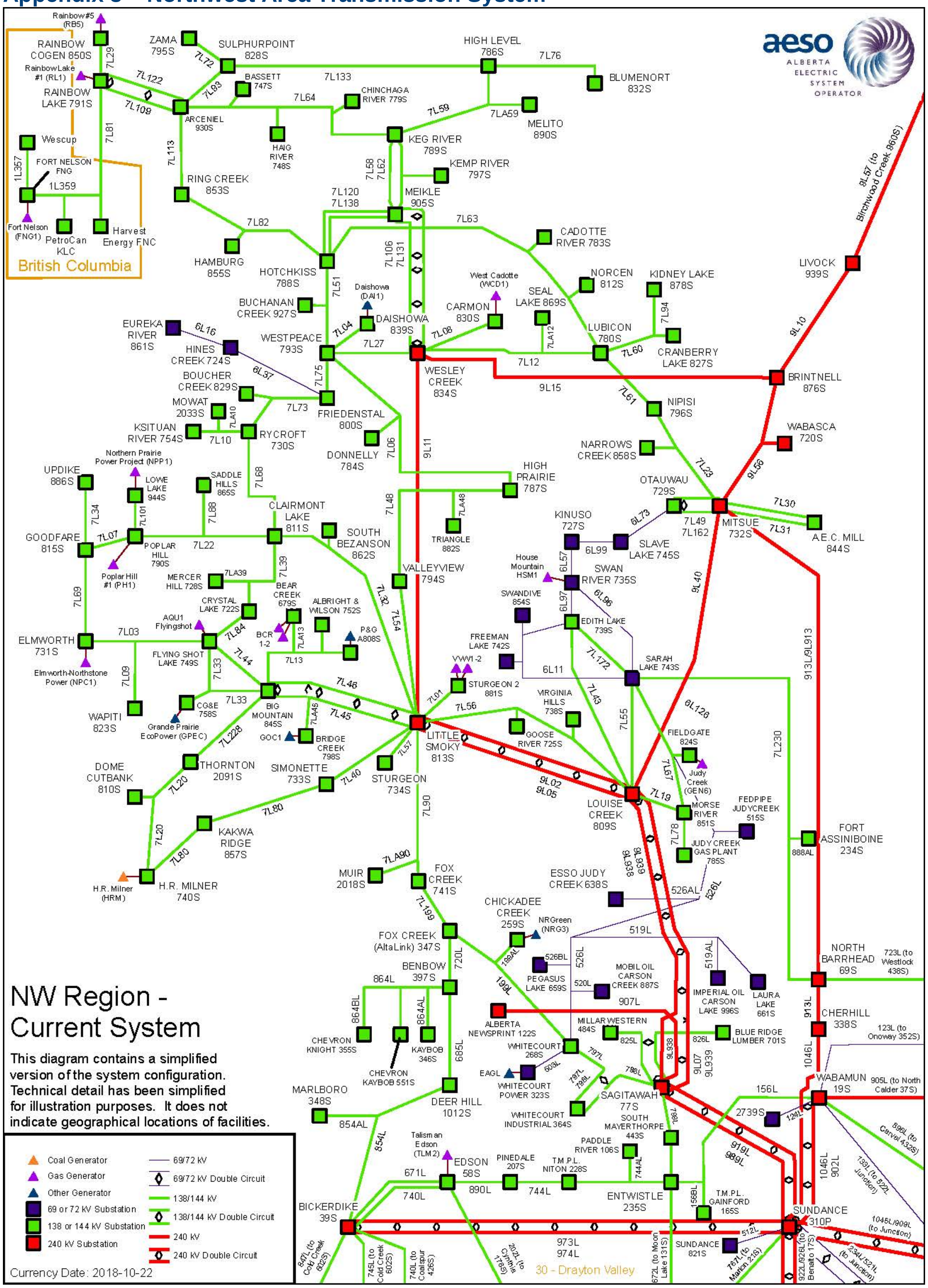
RB5

RL1

Appendix 2 – Northwest Area Geographical Map



Appendix 3 – Northwest Area Transmission System



Appendix 4: Grande Prairie Inflow Cutplane N-0 (System Normal) Thermal and Voltage Limits

Outage	Thermal (MW)		Voltage (MW)
	Summer May 1 – Oct. 31	Winter Nov 1 – April 30	
System Normal (N-0)	430		
		455	
			420

Appendix 5: Grande Prairie Inflow Cutplane N-1 Thermal and Voltage Limits

If real time contingency analysis or real time voltage stability analysis allows a higher thermal or voltage limit for the contingencies listed in the table below, the AESO operates to the higher limit.

Outage	Thermal (MW)		Voltage (MW)
	Summer May 1–Oct. 31	Winter Nov 1–April 30	
7L46	290	350	340
7L45	290	350	340
7L33	315	340	355
7L44	315	340	350
7L03	360	410	415
7L69	390	455	415
7L07	390	455	415
7L34	430	455	420
7L22	425	430	405
7L84	350	370	375
7L39	415	430	420
7L32	360	390	365
7L68	390	440	420
7L75	340	395	370
7L73	355	395	380
7L20	385	435	415
7L228	405	450	420
7L80	390	420	400
7L40	390	425	400
9L02	330	345	355
9L05	330	345	355

Appendix 6: Rainbow Lake Inflow Cutplane N-0 (System Normal) Transient Limits

Generator in Service[1]	Number of SC, ASVC, and HSVC in Service (MW)[2]	
	1	2 or 3
0	155	169
1	138	161
2	132	165
3	124	153
4	129	149

Note: [1] Rainbow area generators are FNG1, FNG2, RL1, and RB5.
[2] Rainbow area DRR equipment: Arcenciel Synchronous Condenser, Arcenciel SVC, and High Level SVC

Appendix 7: Rainbow Lake Inflow Cutplane N-1 Transient Stability Limits

Outage	Generator in Service[1]	Number of SC, ASVC, and HSVC in Service (MW)	
		1	2 or 3
N-7L51	0	120	141
	1	138	138
	2	131	155
	3	129	140
	4	129	140
N-7L63	0	122	143
	1	125	150
	2	132	160
	3	125	141
	4	105	135
N-7L82	0	115	136
	1	118	137
	2	102	122
	3	102	130
	4	105	130
N-7L106	0	116	139
	1	137	140
	2	110	129
	3	110	133
	4	95	130
N-7L113	0	116	136
	1	126	126
	2	111	128
	3	106	130
	4	100	128
N-7L131	0	116	139
	1	137	140
	2	110	129
	3	110	133
	4	95	130

Outage	Generator in Service[1]	Number of SC, ASVC, and HSVC in Service (MW)	
		1	2 or 3
N-7L58[2]	0	93	88
	1	74	81
	2	82	83
	3	100	87
	4	96	95
N-7L59[2]	0	100	99
	1	80	88
	2	85	84
	3	88	89
	4	75	89
N-7L62[2]	0	94	87
	1	80	82
	2	86	87
	3	100	90
	4	102	100
N-7L64[2]	0	105	98
	1	91	91
	2	85	87
	3	106	120
	4	95	112
N-7L93[2]	0	125	138
	1	118	150
	2	114	123
	3	90	100
	4	90	105

Outage	Generator in Service[1]	Number of SC, ASVC, and HSVC in Service (MW)	
		1	2 or 3
N-7L133[2]	0	121	127
	1	88	88
	2	86	116
	3	90	116
	4	95	89

Note:[1] Rainbow Lake area generators consist of FNG1, FNG2, RL1, and RB5.

[2] If FNG1 and FNG2 are out of service, the output for each individual Rainbow unit is limited to 35 MW.

Appendix 8: **Rainbow Lake Inflow Cutplane Thermal Limits**

If real time contingency analysis allows a higher thermal limit for the contingencies listed in the table below, the AESO operates to the higher limit.

Outage		Thermal (MW)	
		Summer May 1 – Oct. 31	**Winter** Nov 1 – April 30
System Normal (N-0)	None	125	145
N-1	7L51	123	138
	7L58	84	86
	7L59	75	86
	7L62	82	86
	7L63	123	140
	7L64	97	99
	7L82	82	86
	7L93	124	143
	7L106	113	118
	7L113	84	89
	7L131	113	118
	7L133	120	138

Appendix 9: Rainbow Lake Inflow Cutplane Voltage Stability Limits

If real time voltage stability analysis allows a higher voltage limit for the contingencies listed in the table below, the AESO operates to the higher limit.

Outage		Voltage (MW)
System Normal (N-0)	None	173
N-1	7L51	145
	7L58	90
	7L59	92
	7L62	90
	7L63	144
	7L64	93
	7L82	140
	7L93	150
	7L106	141
	7L113	142
	7L131	141
	7L133	143

Information Document

Markets Suspension or Limited Markets Operations ID # 2011-006R

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1. Purpose

This Information Document relates to the following Authoritative Documents[1]:

(1) Section 202.7 of the ISO rules, *Limited Markets Operations or Markets Suspension.*

This Information Document provides additional information regarding the requirements of section 202.7 of the ISO rules, and its practical operation and implementation.

2. State of Limited Markets Operations

The AESO uses several key information technology applications to perform various functions in operating the wholesale electricity markets. These include:

1. the Energy Trading System, which facilitates the submissions of energy offers and bids:
2. the Energy Management System, which monitors system conditions and parameters;
3. the Dispatch Tool, which performs inter-market dispatch calculations for the energy market, the dispatch down service market and the ancillary services market;
4. the Automated Dispatch and Messaging System, which facilitates issuing dispatches;
5. the OATI Webtrans or the Western Electricity Coordinating Council Interchange Tool which facilitates interchange scheduling; and
6. the AESO's interchange tool used to calculate and post interchange capabilities.

In addition, there are multiple electronic communication paths among these systems.

If one or more of these systems or the communication paths are unavailable, the AESO's operation of the markets may be affected which could result in limited markets operations. Examples of situations which could result in limited markets operations include:

(a) Where the Energy Trading System or the Dispatch Tool, or the communication path between these systems is out of service, such that the AESO may not have access to the current energy market merit order. As the AESO continues to issue dispatches to manage the interconnected electric system supply and demand balance, it may need to invoke limited markets operations.

(b) When the AESO is forced to evacuate the primary system coordination center and, while in transit to the backup coordination centre, cannot access one or more of the market operation systems. To continue to manage interconnected electric system supply and demand balance, the AESO may issue dispatches based on the last printed copy of the energy market merit order or the last saved energy market merit order on the AESO laptop computer.

1 "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities* Act and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

(c) In situations when there is a planned or unplanned Dispatch Tool outage or unavailability, the AESO initiates limited markets operations only if an energy market dispatch needs to be issued. If the outage is of very short duration and system changes do not require an energy market dispatch to be issued, limited markets operations is not initiated by the AESO.

(d) In situations when there is a planned or unplanned Energy Trading System outage, the market participant phones the AESO for any restatement. In accordance with subection 3(3)(i) of ISO rule 201.4 *Submission Methods and Coordination of Submissions*, this information is not used to determine the energy market merit order. This information informs the AESO of the operational information that affects the pool participant's ability to comply with dispatches or directives. If the Energy Trading System outage is of short duration, it is typically not necessary to initiate limited markets operations. If the Energy Trading System outage is prolonged, then the AESO makes an assessment on the impact to market operations and decides whether or not limited markets operations needs to be initiated.

(e) In situations where OATI Webtrans, the Western Electricity Coordinating Council Interchange Tool or the AESO interchange tool are unavailable and the AESO is unable to accurately calculate and post an available transfer capability allocation due to more bids and offers than capacity on the Britiish Columbia/Montanna interface then the AESO would initiate limited market operations.

3. Declaration of State of Limited Markets Operations

The declaration invoking a state of limited markets operations contains the information specified in subsection 3(2) of section 202.7 of the ISO rules. If the commencement time of the state of limited market operations is unknown, the AESO provides its best estimate and verifies it later. If the AESO System Controller has determined the version of the energy market merit order, ancillary service merit order or dispatch down service merit order that is being used for issuing dispatches, such details may also be provided in the declaration.

4. Dispatches during State of Limited Markets Operations

4.1 Energy Market

During limited markets operations, the AESO may issue dispatches from a snapshot of the energy market merit order which is the latest available deemed to be appropriate. The snapshot may be a hard copy of the energy market merit order printed prior to the initiation of the limited markets operations or an electronic copy of the energy market merit order downloaded on an AESO portable computer.

4.2 Ancillary Services Market – Operating Reserves

Any dispatched providers of operating reserves at the beginning of limited markets operations remain dispatched to provide those operating reserves while limited market operations remains in effect. If additional operating reserves are required, the AESO uses the best available ancillary services merit order for issuing those dispatches. However, if the required volume of operating reserves decreases, the AESO does not reduce dispatches for operating reserves so that changes to dispatches for the energy market can be minimized.

If limited markets operations move from an on-peak period to an off-peak period, or vice versa, the AESO does not switch to the off-peak ancillary services merit order from the on-peak ancillary services merit order, or vice versa. It is anticipated that the duration of limited markets operations is not generally prolonged, and the AESO uses best efforts to minimize the risk of limited markets operations crossing over the on-peak and off-peak periods, for example by taking this into consideration when planning Dispatch Tool outages.

4.3 Dispatch Down Service Market

In order to minimize the need to issue dispatches for dispatch down service, the AESO maintains the dispatch down service dispatch level at the start of limited markets operations. If the dispatch down service requirement volume changes (e.g. due to changes to the transmission must run levels, the AESO does not adjust (i.e. does not increase or decrease) the dispatch down service dispatches. If the hour moves to the next operating hour, the AESO does not switch to that next hour dispatch down service merit order.

However, the AESO changes the dispatches for dispatch down service if the AESO has issued dispatches up to the reference price. In that case, the AESO partially dispatches off dispatch down service until it is completely dispatched off. If the AESO subsequently dispatches back down to the reference price, the AESO does not increase dispatch down service dispatches in order to minimize the impact to the energy market dispatches.

5. Payment to Suppliers on the Margin During Limited Market Operations

The uplift payment referred to in subsection 6(c) of the section 202.7 of the ISO rules is the payment to suppliers on the margin. Since the calculation for the uplift payments to suppliers on the margin depends on data exchange between the Energy Trading System and the Dispatch Tool, when either one of these systems is unavailable, the calculation may be incorrect. Therefore it may be necessary to suspend the uplift payment for all or some of the hours that limited markets operations occur.

6. Termination of State of Limited Markets Operations

When access is restored to the market operating tools, the AESO terminates limited markets operations, and issues a declaration as soon as possible, using the methods outlined in subsection 3(5) of section 202.7 of the ISO rules.

7. State of Markets Suspension

The AESO only uses markets suspension as outlined in subsection 8 of section 202.7 of the ISO rules, when it is not possible to continue limited markets operations, or when the interconnected electric system is not in a state that makes normal markets operations possible.

8. Effect of the State of Markets Suspension

During a state of markets suspension, the AESO may not follow any merit order (i.e. energy market merit order, ancillary services merit order or dispatch down service merit order) and is primarily focused on maintaining or restoring system reliability through the issuance of directives for energy supply and ancillary services.

9. System Marginal Price during State of Markets Suspension

When markets suspension is in effect, the AESO determines the system marginal price based on the prior thirty (30) day average on peak or off peak price as described in subsection 11. These daily thirty (30) day average prices are posted on the AESO website.

10. Operating Cost Recovery

Subsection 12 of section 202.7 of the ISO rules outlines a cost recovery payment mechanism to allow a market participant to recover any shortfall between the energy receipts and its operating costs while generating during a market suspension. The intent of the mechanism is to keep the market participant whole, to the extent that energy receipts received do not cover its operating costs.

11. Termination of State of Markets Suspension

The AESO terminates the state of markets suspension when the interconnected electric system is in a reliable state, access to the markets operations tool is available, and the AESO deems that normal markets operations can be resumed. The AESO issues a declaration of the termination of markets suspension as soon as possible, using the methods described in subsection 9(5) of section 202.7 of the ISO rules. The declaration specifies a time and date when normal markets operations resumed.

Revision History

Posting Date	Description of Changes
	New document created to support ISO Rule section 202.7.
2015-04-16	Administrative updates, removal of authoritative language.

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents[1]:

(a) Section 304.9 of the ISO rules, *Wind and Solar Aggregated Generating Facility Forecasting* ("Section 304.9"), effective September 1, 2018; and

(b) Section 502.1 of the ISO rules, *Wind Aggregated Generating Facilities Technical Requirements* for wind power forecasting requirements, version effective April 1, 2015 ("Section 502.1")[2].

The purpose of this Information Document is to assist the legal owner of a wind or solar aggregated generating facility in understanding the wind and solar forecasting requirements, including the data transfer process, data transfer technical requirements, message formats, and onboarding instructions.

2 Effective Dates and Compliance Timelines

Effective September 1, 2018, Section 304.9 outlines the revised requirements for wind power forecasting and new requirements for solar power forecasting. The legal owner of an existing wind or solar aggregated generating facility that has connected in accordance with any previous forecasting requirements prior to September 1, 2018 is required to become compliant with the requirements under Section 304.9 no later than 12 months after September 1, 2018 (for clarity, the transition to the Section 304.9 forecasting requirements occurs prior to September 1, 2019). Prior to transitioning, the legal owner must remain in compliance with the previously effective forecasting requirements in accordance with which they operated prior to September 1, 2018.

This Information Document provides information regarding two different forecast processes:

(a) **Appendix A:** The wind and solar aggregated generating facility forecast process in accordance with the requirements under Section 304.9, effective September 1, 2018.

(b) **Appendix B:** The wind aggregated generating facility forecast process in accordance with the requirements under Section 502.1, under which existing wind aggregated generating facilities previously connected and may continue to use for 12 months after September 1, 2018.

Upon the completion of the transition of all wind and solar aggregated generating facilities to the new forecast requirements under Section 304.9, the AESO will remove Appendix B from this Information Document.

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[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

[2] Section 304.9 will succeed and replace Section 502.1 once Section 304.9 comes into effect on September 1, 2018. However, existing wind aggregated generating facilities may continue to provide forecast data under the Section 502.1 forecasting requirements (which are included as Appendix B to this document) during the transition period, as outlined in subsection 3 of Section 304.9.

Table 1

As of September 1, 2018	Transition Period Sept 1, 2018 – Sept 1, 2019	As of September 1, 2019
If you are a wind or solar aggregated generating facility that connected in accordance with any previous forecasting requirements	Continue providing forecast data under previous forecasting requirements **OR** Update to Section 304.9 requirements	All wind and solar aggregated generating facilities must meet Section 304.9 requirements
If you are a wind or solar aggregated generating facility that connects after September 1, 2018	Meet the Section 304.9 requirements as of connection date	
If you are an existing wind or solar aggregated generating facility that did not connect in accordance with any previous forecasting requirements Meet the Section 304.9 requirements as of September 1, 2018		

Legend: Appendix A
Appendix B

3 Appendices

This information document is structured as follows:

- Appendix A: Forecast Process as per Section 304.9 Wind and Solar Aggregated Generating Facility
    1. Overview of Wind Power Forecasting
    2. Onboarding Process
    3. Wind and Solar Data Transfer Process
    4. Data Definitions
        - 4.1 Meteorological data
        - 4.2 Power data
        - 4.3 Facility data
    5. Data Transmission Timeline
    6. Wind and Solar Message Schema - XSD
- Appendix B: Forecast Process as per Section 502.1 Wind Aggregated Generating Facility
    1. Overview of Wind Power Forecasting
    2. Wind Data Transfer Process
    3. Data Transfer Technical Specification

4. Message Formats - XSD
5. On-Ramping Instructions
6. References

Revision History

Posting Date	Description of Changes
2019-05-16	Added minimum Transfer Layer Security requirements to section 3.1 in Appendix A.
2019-01-30	Dew point calculation methodology added in section 4.1.1 in Appendix A. Added table names in Appendix B.
2018-10-29	Updated sections 4.1.1 and 4.1.2 in Appendix A, additional information provided for Meteorological data. Updated Figure 1 in Appendix A to clarify that eligibility for the transition period is dependent on whether an aggregated generating facility connected in accordance with previous forecasting requirements. Updated position IDs from 0-5 to 1-6 in Appendix A, section 5.1 Minor updates to XML schema. Added figure and table names in Appendix A
2018-09-04	Removed 1 hour limit in section 2.2
2018-08-07	Revised to include the wind and solar aggregated generating facility forecast process required under Section 304.9.
2016-09-28	Administrative amendments
2011-06-23	Initial Release

APPENDIX A

Forecast Process as per Section 304.9 Wind and Solar Aggregated Generating Facility

1 Overview of Wind Power Forecasting

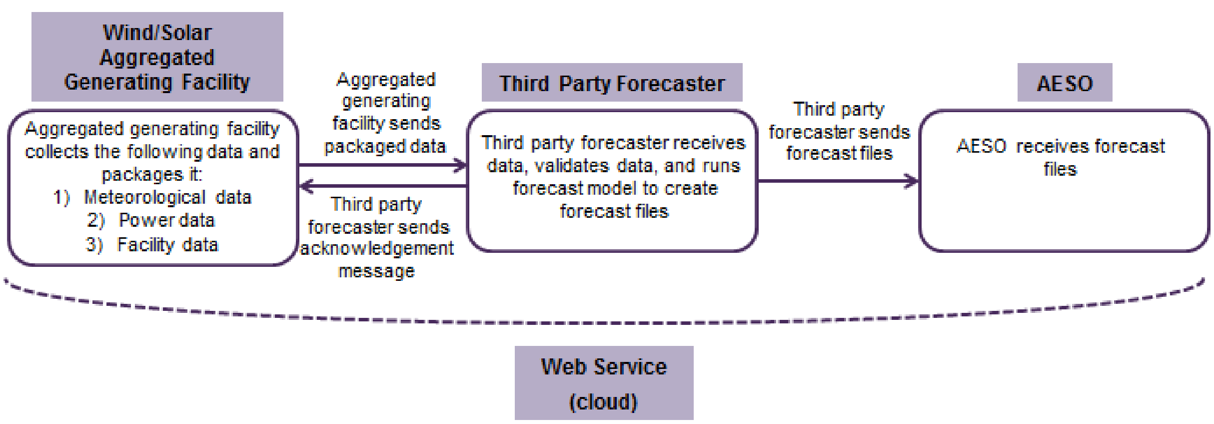
This Information Document focuses on the wind and solar aggregated generating facility data and transfer process required for wind and solar forecasting services to support the AESO's centralized wind and solar forecasting program.

This Information Document applies to wind and solar aggregated generating facilities, including those situated within an industrial complex, that have a gross real power capability greater than or equal to 5 MW and are connected to either:

- the interconnected electric system as defined by the AESO's *Consolidated Authoritative Document Glossary*, which includes transmission facilities and distribution systems; or
- an electric system in the service area of the City of Medicine Hat.

Section 304.9 requires that a wind or solar aggregated generating facility provide data to the AESO via a third party forecaster. The following Figure 1 is an illustration of how the process is carried out:

Figure 1: Provision of data to third party forecaster



2 Onboarding Process

The legal owner of a wind or solar aggregated generating facility works with the AESO third party forecaster to onboard to the AESO wind and solar forecasting process. The AESO will also be available for support during the onboarding process. Each legal owner is responsible for providing Subject Matter Experts to meet the requirements of this Information Document.

Onboarding will be required for the legal owner of a wind or solar aggregated generating facility that has not previously provided forecast data for the aggregated generating facility under the Section 304.9 requirements. This may include the legal owner of a new aggregated generating facility, or a new legal owner of an existing aggregated generating facility, or a legal owner of an existing aggregated generating facility that was connected in accordance with Section 502.1, but is transitioning to the new Section 304.9 requirements.

2.1 User Access

The legal owner of a wind or solar aggregated generating facility will work with the AESO and the third party forecaster to acquire a unique user name and access key to log in to the wind and solar forecast data upload URL. This will ensure the wind or solar aggregated generating facility is authenticated to the third party forecaster for the upload of data.

Requests for access to the forecast data upload URL are sent to: info@aeso.ca.

The legal owner can use the user name and access key to access both the pre-production and production environments.

2.2 Pre-production Testing

The legal owner of a wind or solar aggregated generating facility can use the following pre-production URL to test their systems and connection:

https://windsolardata.aeso.ca/preprod/

The user name and access key provided to the legal owner can be used to log in and upload test data. Legal owners are encouraged to use this preproduction URL while updating and testing their system.

2.3 Historical Data

Pursuant to subsection 8(3) of Section 304.9, the AESO may request that the legal owner of a wind or solar aggregated generating facility provide certain historical meteorological data. The legal owner is to supply the data in the same method and format described in this Information Document for "current data".

3 Wind and Solar Data Transfer Process

3.1 Aggregated Generating Facilities Responsibility

See subsection 4(1) of Section 304.9 for details of the legal owner's obligations related to the purchase, installation, and appropriate operation and maintenance of all equipment involved with the data transfer process.

The minimum Transfer Layer Security (TLS) protocol requirement for the data upload under Section 304.9 is as follows:

(a) TLS v1.2 or newer to support the https protocol on the aggregated generating facility client side.

3.2 Annual Availability

See subsection 5(3) of Section 304.9 for details of the legal owner's obligations related to the availability of its forecast data transfer process. The AESO expects the legal owner to apply the threshold on an annual basis, with the result being availability of approximately 358 days.

3.3 Data Upload URL

The production URL for uploading production data is as follows:

https://windsolardata.aeso.ca/prod

The user name and access key provided to the legal owner can be used to log in and upload production data.

3.4 XML Schemas

The legal owner and the third party forecaster will use the following XML schemas, as applicable, for the transfer of data:

(a) facility data schema:

- (i) wind facility data schema; and
- (ii) solar facility data schema;

(b) meteorological data schema:

- (i) wind meteorological data schema; and
- (ii) solar meteorological data schema;

(c) power data schema;

(d) gross real power capability schema;

(e) acknowledgement schema; and

(f) communication layer schema.

Additional details on the XML schemas can be found in section 6 of this Appendix.

3.5 Data Transfer Frequency and Time Stamps

Subsection 5(2) of Section 304.9 refers to submission of certain data to the AESO in the method and format the AESO specifies. Forecast data is submitted through the data upload production URL under the timing requirements specified below. The different types of data have different transfer frequency requirements, which are outlined as follows:

1. Meteorological data is transmitted to the third party forecaster at one minute intervals:

   See subsections 4(4) and 5(1) of Section 304.9 for details of the legal owner's obligations related to measurement intervals and submitted data.

2. Power data is transmitted to the third party forecaster at one-minute intervals:

   See subsection 4(7) of Section 304.9 for the legal owner's obligation to collect and submit the instantaneous real power limits and actual net to grid production.

3. Gross real power capability is transmitted to the third party forecaster at 30 minute intervals:

   See subsection 4(6) of Section 304.9 for the legal owner's obligation to collect and submit the gross real power capability.

4. Facility data is submitted to the forecaster upon initial onboarding of a wind or solar aggregated generating facility, and is re-submitted if any of the facility data attributes change:

   For example, if new wind turbines are added to an existing wind aggregated generating facility, the legal owner of the aggregated generating facility will submit new facility data that captures this change.

The aggregated generating facility shall provide two time stamps (in UTC) with each data transfer: one that indicates the time the data was processed, and one that indicates the time the data was sent. This will provide the third party forecaster with more accurate data if there is a delay between data processing and send times.

Table 1

Activity	Source	Date/Time Stamp
Process	Facility	ValidTimeOfData
Send	Facility	Generation_of_XML_and_Send

3.6 Multiple Aggregated Generating Facilities Owned by the Same Legal Owner

The WindSolarComLayer allows for the legal owner of multiple wind or solar aggregated generating facilities to post all data as one message, rather than sending multiple messages for every interval specified in section 3.5. This reduces the number of messages that are sent; therefore the AESO encourages the legal owners of multiple wind or solar aggregated generating facilities to utilize this option. The details of the WindSolarComLayer schema are provided in section 6.7.

3.7 Data Integrity Check

The legal owner of the wind or solar aggregated generating facility is to calculate the SHA256 checksum hash value for the entire message, which will be added into the http header.

The third party forecaster will recalculate the SHA256 checksum hash value upon receiving the forecast data from the wind or solar aggregated generating facility, and compare them to ensure that data integrity is maintained throughout the data transfer process.

3.8 Data Transfer Failure

See subsections 6 and 7 of Section 304.9 for details of the legal owner's obligations when a wind or solar aggregated generating facility's data collection equipment or data transfer process becomes unavailable.

Notifications under subsection 6 of Section 304.9 are sent to: info@aeso.ca.

In the case of a delay or outage, once the connection is restored, the AESO expects the legal owner of the aggregated generating facility to send all of the most recent unsent power, gross real power capability, and meteorological data to the third party forecaster, up to a maximum of 12 hours.

3.9 Message Acknowledgement and Error Messages

The third party forecaster will provide the wind or solar aggregated generating facility with an acknowledgement response for every data submission they receive. This response will include a return code ("0" for failure, "1" for success) and an error level code, if there is an error with the data transfer. Error level details are outlined in the subsequent section, and the details of the acknowledgment schema are provided in Section 6.8.

3.9.1 Error Message Examples in Acknowledgment Response

In the case of an acknowledgement response with return code "0" (failure), the WindSolarData web service will respond to the wind or solar aggregated generating facility with an error message. The table below provides some typical examples of such error messages and their respective error level code. Note that error level codes have no direct relevance for the understanding of the error, and the relevant information for the aggregated generating facility is provided in the error message.

Table 2: Error Message Examples

Return Code	Error Level	Message Example
0	2	Authentication problem
0	2	No valid XML header found
0	3	Access not granted for facility=xx with Access Key=xx for schema=xx
0	4	Invalid request structure - got xx bytes out of expected xx
0	8	validation result: line:19: element BarometricPressure: Schemas validity error
0	9	The process time and send time differ with more than 3 minutes
0	10	The send time is more than 12 hours old

3.9.2 Email Error alerts

In addition, the third party forecaster will also send email error alerts to wind or solar aggregated generation facilities every two hours, if there is an issue with the data validity. For example, if there is a constant repeat value or missing values for power or meteorological data in the last two hour timeframe. These email error alerts will continue to be sent until the error has been resolved.

4 Data Definitions

4.1 Meteorological Data

The meteorological information required from wind and solar aggregated generating facilities is outlined and defined under Table 1 of Section 304.9. The table is split into wind and solar requirements. For each measurement type, the legal owner must ensure that the meteorological data collection equipment and related sensing devices are installed at the height specified in the table.

4.1.1 Wind Meteorological Data

For clarity, with respect to the requirement in subsection 4(2) of Section 304.9 for a legal owner to equip its wind aggregated generating facility with 2 sets of instruments, both sets of data must be complete with all measurement types, i.e., the legal owner sends values for all of the data points. The precision mentioned in Table 2 below is the minimum data accuracy as per Section 304.9. Legal owners may choose to send data with higher accuracy.

The following Table 3 provides further explanation of the data requirements set out in Table 1 of Section 304.9:

Table 3: Wind Aggregated Generating Facility Meteorological Data Requirements

Measurement Type*	Units	Precision	Notes
Meteorological Tower Unique ID	N/A	N/A	This is a facility-specific unique ID which differentiates multiple meteorological towers. The legal owner may choose this unique ID. The AESO recommends using the facility ID followed by measurement height and GPS co-ordinates. For example: “ABCD3550115” The AESO further recommends that this unique ID be consistent with the Meteorological Tower Unique ID provided in the wind facility data schema.
Wind Speed	Meters/ Second (m/s)	0.1 m/s	Provide two measurements of wind speed; (1) sensor at hub height, and (2) sensor at 35 meters.
Wind Direction	Degrees from True North	1 degree	Provide two measurements of wind direction; (1) sensor at hub height, and (2) sensor at 35 meters.
Barometric Pressure	HectoPascals (HPa)	1 hPa	Provide two measurements of barometric pressure; install sensors at convenient locations.
Ambient Temperature	Degree Celsius (°C)	0.1° C	Provide two measures of ambient temperature; (1) sensor at hub height, and (2) sensor at 35 meters. In the case where the temperature sensor is installed a few meters below the hub height anemometers and wind vanes, provide the exact height where the sensor is installed to the third party forcaster.
Dewpoint	Degrees Celsius (°C)	0.1° C	Provide two measurements of dewpoint; install sensors at convenient locations. The AESO prefers a dedicated instrument for the dew point measurement. In the case where a suitable instrument is not available, the legal

Measurement Type*	Units	Precision	Notes
			owner may calculate dew point using temperature and relative humidity data.
Relative Humidity	Percentage (%)	1.00%	Provide two measurements of relative humidity; install sensors at convenient locations.
Ice-up Parameter Measured with an Icing Sensor	Scale 0.0 to1.0	0.1	This represents the measurement of ice build-up as measured by an independent instrument in mm (e.g. 0 mm icing thickness = 0; 40 mm icing thickness = 0.4 and 80mm of icing thickness =0.8). Provide two measurements; install sensors at convenient locations.
Precipitation	Millimeters/ minute (mm/min)	0.1	Provide two measurements of precipitation; install sensors at convenient locations. Only consider rain measurement for the precipitation measurement.

*Additional details on each Measurement Type can be found under Table 1 of Section 304.9.

Dew Point Calculation Methodology:

A legal owner may use the following formula to calculate the dew point from the temperature and relative humidity.

$$P_{\mathrm{s,m}}(T) = a e^{\left(b-\frac{T}{d}\right)\left(\frac{T}{c+T}\right)};$$

$$\gamma_{\mathrm{m}}(T,\mathrm{RH}) = \ln\left(\frac{\mathrm{RH}}{100} e^{\left(b-\frac{T}{d}\right)\left(\frac{T}{c+T}\right)}\right);$$

$$T_{dp} = \frac{c\gamma_m(T,\mathrm{RH})}{b-\gamma_m(T,\mathrm{RH})};$$

where

$a = 6.112$ mb, $b = 17.67$, $c = 243.5$ °C, $d = 234.5$ °C.

Other additional reference material;

(1) https://doi.org/10.1175/1520-0493(1980)108<1046:TCOEPT>2.0.CO;2\

(2) https://en.wikipedia.org/wiki/Dew_point

4.1.2 Solar Meteorological Data

Where, as a result of applying the requirements of subsection 4(3) of Section 304.9, there are multiple measurement points for a solar aggregated generating facility, a complete set of meteorological data is sent for each measurement point. The precision mentioned in Table 4 below is the minimum data accuracy as per Section 304.9. Legal owners may choose to send data with higher accuracy.

Table 4: Solar Aggregated Generating Facility: Meteorological Data Requirements

Measurement Type*	Units	Precision	Notes
Meteorological Tower Unique ID	N/A	N/A	This is a facility-specific unique ID which differentiates multiple meteorological towers. The legal owner may choose this unique ID. The AESO recommends using the facility ID followed by measurement height and GPS co-ordinates. For example: "ABCD850115" The AESO further recommends that this unique ID be consistent with the Meteorological Tower Unique ID provided in the solar facility data schema.
Wind Speed	Meters/ Second (m/s)	0.1 m/s	For each 49 Km^2, provide one measurement of wind speed; install sensor at a height between 2-10 meters from the ground level.
Wind Direction	Degrees from True North	1 degree	For each 49 Km^2, provide one measurement of wind direction; install sensor at a height between 2-10 meters from the ground level.
Barometric Pressure	HectoPascals (HPa)	1 hPa	For each 49 Km^2, provide one measurement of barometric pressure; install sensor at a height between 2-10 meters from the ground level.
Ambient Temperature	Degree Celsius (°C)	0.1° C	For each 49 Km^2, provide one measurement of ambient temperature; install sensor at a height between 2-10 meters from the ground level.
Dewpoint	Degrees Celsius (°C)	0.1° C	For each 49 Km^2, provide one measurement of dewpoint; install at a height between 2-10 meters from the ground level.
Relative Humidity	Percentage (%)	1.00%	For each 49 Km^2, provide one measurement of relative humidity; install sensor at a height between 2-10 meters from the ground level.
Precipitation	Millimeters/ minute (mm/min)	0.1	For each 49 Km^2, provide one measurement of precipitation; install sensor at a height between 2-10 meters from the ground level.
Back Panel Temperature	Degree Celsius (°C)	0.1° C	For each 49 Km^2, provide one measurement of back panel temperature; install sensor at a height between 2-10 meters from the ground level.
Global	Watts/	0.1	For each 49 Km^2, provide one measurement of

Measurement Type*	Units	Precision	Notes
Horizontal Irradiance	Square Meter (W/m^2)		global horizontal irradiance; install sensor at a height between 2-10 meters from the ground level.
Diffused Horizontal Irradiance	Watts/ Square Meter (W/m^2)	0.1	For each 49 Km^2, provide one measurement of diffused horizontal irradiance; install sensor at a height between 2-10 meters from the ground level.
Direct Normal Irradiance[3]	Watts/ Square Meter (W/m^2)	0.1	For each 49 Km^2, provide one measurement of direct normal irradiance; install sensor at a height between 2-10 meters from the ground level. The AESO will decide the requirement of this parameter based on the technology the legal owner uses.

*Additional details on each Measurement Type can be found under Table 1 of Section 304.9

4.2 Power and Gross Real Power Capability Data

The following Tables 5 and 6 describe the power and gross real power capability information that is required as per subsections 4(6) and 4(7) of Section 304.9. The power and gross real power capability data requirements for wind and solar aggregated generating facilities are the same.

Table 5: Wind or Solar Aggregated Generating Facility Gross Real Power Capability Data Requirements

Measurement Type	Units	Precision	Notes
Gross Real Power Capability	MW	2.0 MW	The sum of the real power capability of the generating units behind the aggregated generating facility. Reduction may be due to unscheduled outages.

Table 6: Wind or Solar Aggregated Generating Facility Power Data Requirements

Measurement Type	Units	Precision	Notes
Real Power Limits	MW	0.1 MW	This is the AESO power limit sent from the AESO to a wind or solar aggregated generating facility, which is the current value in the power limiting control system at the wind or solar aggregated facilities.
Net To Grid Real Power Production	MW	0.1 MW	The real power output at the point of connection.

4.3 Facility Data

[3] The requirement to provide this parameter will be determined by the AESO based on solar technology used in the project.

The following Tables 7 and 8 provide additional details regarding the facility data requirements under subsections 8(4) and 8(5) of Section 304.9.

Table 7: Wind Aggregated Generating Facility – Facility Data Requirements

Measurement Type	Units	Precision	Notes
Meteorological Tower Unique ID	N/A	N/A	This is a facility-specific unique ID which differentiates multiple meteorological towers. The legal owner may choose this unique ID. The AESO recommends using the facility ID followed by measurement height and GPS co-ordinates. For example: "ABCD3550115" The AESO further recommends that this unique ID be consistent with the Meteorological Tower Unique ID provided in the wind meteorological data schema.
Meteorological Tower Data Collection Height	Meters	1 Meter	The height at which the meteorological data is measured.
Turbine Model Name	Name	N/A	The manufacturer's turbine model name
Turbine Model Capacity	MW	0.1MW	The manufacturer's turbine model capacity
Turbine Wind Cut-in	Meters/ Second (m/s)	0.1 m/s	The manufacturer's turbine wind cut-in point
Turbine Wind Cut-out	Meters/ Second (m/s)	0.1 m/s	The manufacturer's turbine wind cut-out point
Turbine Temperature Cut-out Lower*	Degree Celsius	1° C	The manufacturer's turbine temperature cut-out lower point
Turbine Temperature Cut-out Upper*	Degree Celsius	1° C	The manufacturer's turbine temperature cut-out upper point
Site Latitude and Longitude	Degrees	0.000001	Site latitude and longitude. Latitude falls between 48 degrees and 60 degrees and longitude falls between -110 degrees and -120 degrees.
Turbine Power Curves	MW, wind speed (m/s)	0.1 MW 1.0 m/s	Submit the manufacturer's turbine power curve in the table (MW v/s wind speed) format.

* There is normally a lower and higher temperature cut-out; both are relevant in Alberta. The AESO requires an indicator to confirm that the numbers are ambient temperature within the rotor or air temperature.

Table 8: Solar Aggregated Generating Facility – Facility Data Requirements

Measurement Type	Units	Precision	Notes
Meteorological Tower Unique ID	N/A	N/A	This is a facility-specific unique ID which differentiates multiple meteorological towers. The legal owner may choose this unique ID. The AESO recommends using the facility ID followed by measurement height and GPS co-ordinates. For example: “ABCD850115” The AESO further recommends this unique ID be consistent with the Meteorological Tower Unique ID provided in the solar meteorological data schema.
Site Latitude and Longitude	Degrees	0.000001	Site latitude and longitude. Latitude falls between 48 degrees and 60 degrees and longitude falls between -110 degrees and -120 degrees.
Direct Current (DC) Real Power Rating	MW	0.1	Direct current real power rating of the aggregated generating facility
Alternating Current (AC) Real Power Rating	MW	0.1	Alternating current real power rating of the aggregated generating facility
Inverter Manufacturer and Model	Name	N/A	Details of the inverter used
Mounting Height from Ground	Meters	1 Meter	Height of the weather station from the ground
Tilt Angle or Range of Tilt Angles to Horizontal Plane	Degrees	1 degree	Tilt angle of the solar panel relative to the horizontal plane, or in the case of a tracking type mounting, the range of tilt angles relative to the horizontal plane.
Azimuth Angle	Degrees	1 degree	Azimuth is the angle between the horizontal direction (of the sun) and a reference direction (usually North).
Alternating Current (AC) Real Power Capacity per Solar Array	MW	0.1MW	Alternating current real power rating per array
Mounting Type, Tracking	Name	N/A	Details of the type of mounting, e.g. fixed tracking, single tracking or double tracking

Module Type	Name	N/A	Details of the module used, e.g. crystalline, thin-film, etc.

5 Data Transmission Timeline

5.1 1 Minute Interval Data

As per subsection 3.5 above, provide the following data provided at one minute intervals:

(a) Meteorological data

(b) Power data – net to grid production and real power limits

The maximum allowed tolerance to package and submit this data to the third party forecaster is 5 seconds.

In order for an aggregated generating facility to slice the data sending interval, position ID with sub-position ID will be used to divide the time interval i.e.

1. There are **six** 10-min position IDs within one hour i.e.
   (a) Position ID 1 (00:00 - 9:59 in mm:ss)
   (b) Position ID 2 (10:00 - 19:59 in mm:ss)
   (c) Position ID 3 (20:00 - 29:59 in mm:ss)
   (d) Position ID 4 (30:00 - 39:59 in mm:ss)
   (e) Position ID 5 (40:00 - 49:59 in mm:ss)
   (f) Position ID 6 (50:00 –59:59 in mm:ss)
2. There are **ten** 1-min sub-interval IDs within one position ID i.e.,
   (a) Position ID 1, sub-interval min 0 (00:00 – 00:59 in mm:ss),
   (b) Position ID 1, sub-interval min 1 (01:00 – 01:59 in mm:ss), etc.

   For example, from 00:00 – 9:59 in mm:ss:

Table 9

Position ID	Time Range of Data Processing by Facility (MM:SS)	Time Range of Transmission by Facility (MM:SS)
1 sub 0	00:00 – 0:59	XXh:01:00 – 01:05
1 sub 1	01:00 – 1:59	XXh:02:00 – 02:05
1 sub 2	02:00 – 2:59	XXh:03:00 – 03:05
1 sub 3	03:00 – 3:59	XXh:04:00 – 04:05
1 sub 4	04:00 – 4:59	XXh:05:00 – 05:05
1 sub 5	05:00 – 5:59	XXh:06:00 – 06:05
1 sub 6	06:00 – 6:59	XXh:07:00 – 07:05
1 sub 7	07:00 – 7:59	XXh:08:00 – 08:05
1 sub 8	08:00 – 8:59	XXh:09:00 – 09:05
1 sub 9	09:00 – 9:59	XXh:10:00 – 10:05

Position IDs and sub-interval IDs are included as part of the XML schema.

5.2 30 Minute Interval Data

As per subsection 3.5 above, gross real power capability data should be provided at 30 minute intervals. The maximum allowed tolerance to package and submit this data to the third party forecaster is 5 seconds.

Table 10

Time Range of Data Processing by Facility (MM:SS)	Time Range of Transmission by Facility (MM:SS)
00:00 – 29:59	XXh:30:00 – 30:05
30:00 – 59:59	(XXh+1):00:00 – (XXh +1):00:05

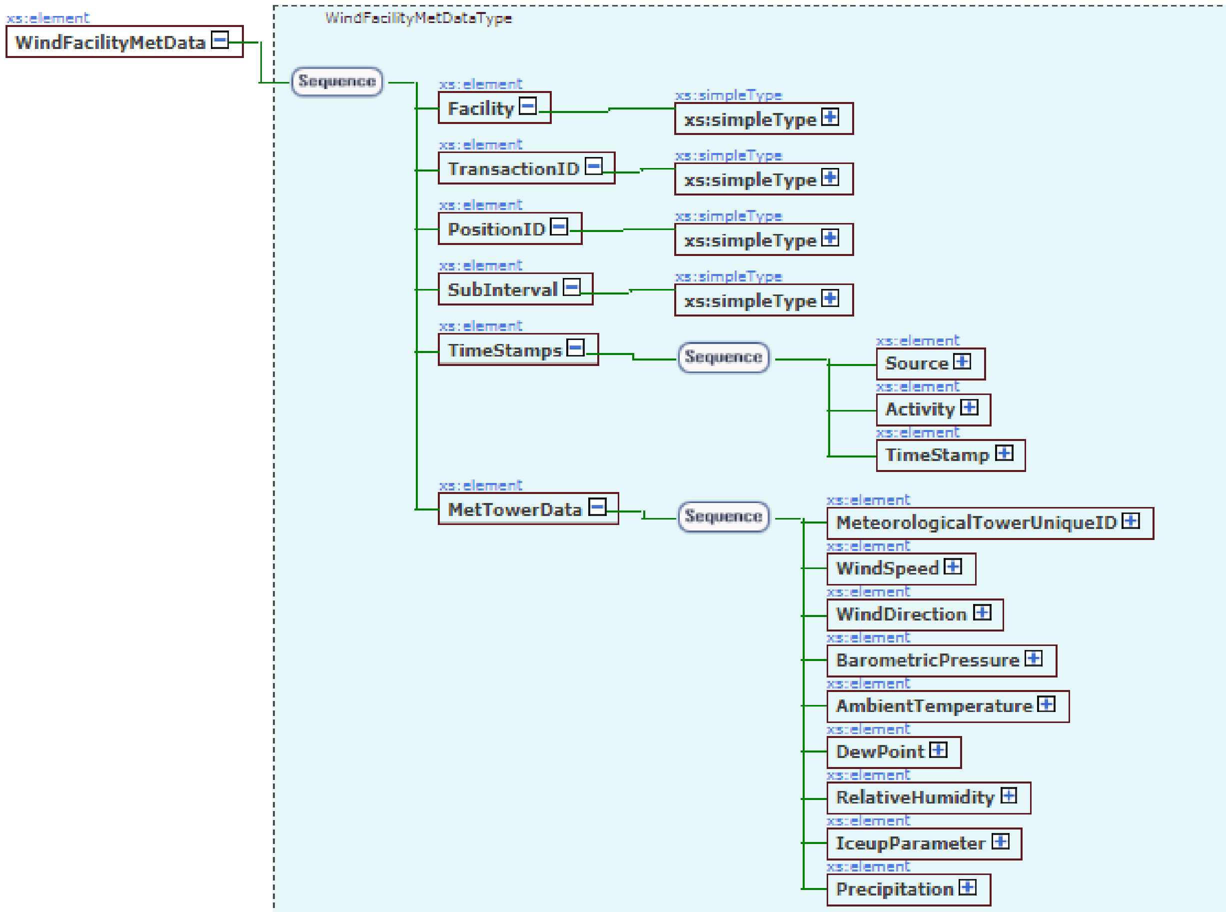
5.3 Facility Data

As per subsection 3.5 above, provide facility data upon first sending forecast data, or at any time that the facility data changes.

6.0 Wind and Solar Message Schema - XSD

6.1 Wind Facility Meteorological Data Schema

The following schema is used for wind meteorological data, and each wind aggregated generating facility is required to translate their data into the format below:




```
<?xml version="1.0" encoding="UTF-8"?>
<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.aeso.ca" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" attributeFormDefault="unqualified">
    <xs:element name="WindFacilityMetData" type="WindFacilityMetDataType"></xs:element>
    <xs:complexType name="WindFacilityMetDataType">
        <xs:sequence>
            <xs:element name="Facility">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
            <xs:element name="TransactionID">
                <xs:simpleType>
```

```
        <xs:restriction base="xs:string">
          <xs:maxLength value="255"></xs:maxLength>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="PositionID">
      <xs:simpleType>
        <xs:restriction base="xs:integer">
          <xs:minInclusive value="1"></xs:minInclusive>
          <xs:maxInclusive value="6"></xs:maxInclusive>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="SubInterval">
      <xs:simpleType>
        <xs:restriction base="xs:integer">
          <xs:minInclusive value="0"></xs:minInclusive>
          <xs:maxInclusive value="9"></xs:maxInclusive>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="TimeStamps" maxOccurs="unbounded">
      <xs:complexType>
        <xs:sequence>
          <xs:element name="Source">
            <xs:simpleType>
              <xs:restriction base="xs:string">
                <xs:enumeration value="Wind Facility"></xs:enumeration>
                <xs:enumeration value="Wind Forecaster"></xs:enumeration>
                <xs:enumeration value="B2B Provider"></xs:enumeration>
              </xs:restriction>
            </xs:simpleType>
          </xs:element>
          <xs:element name="Activity">
            <xs:simpleType>
              <xs:restriction base="xs:string">
```

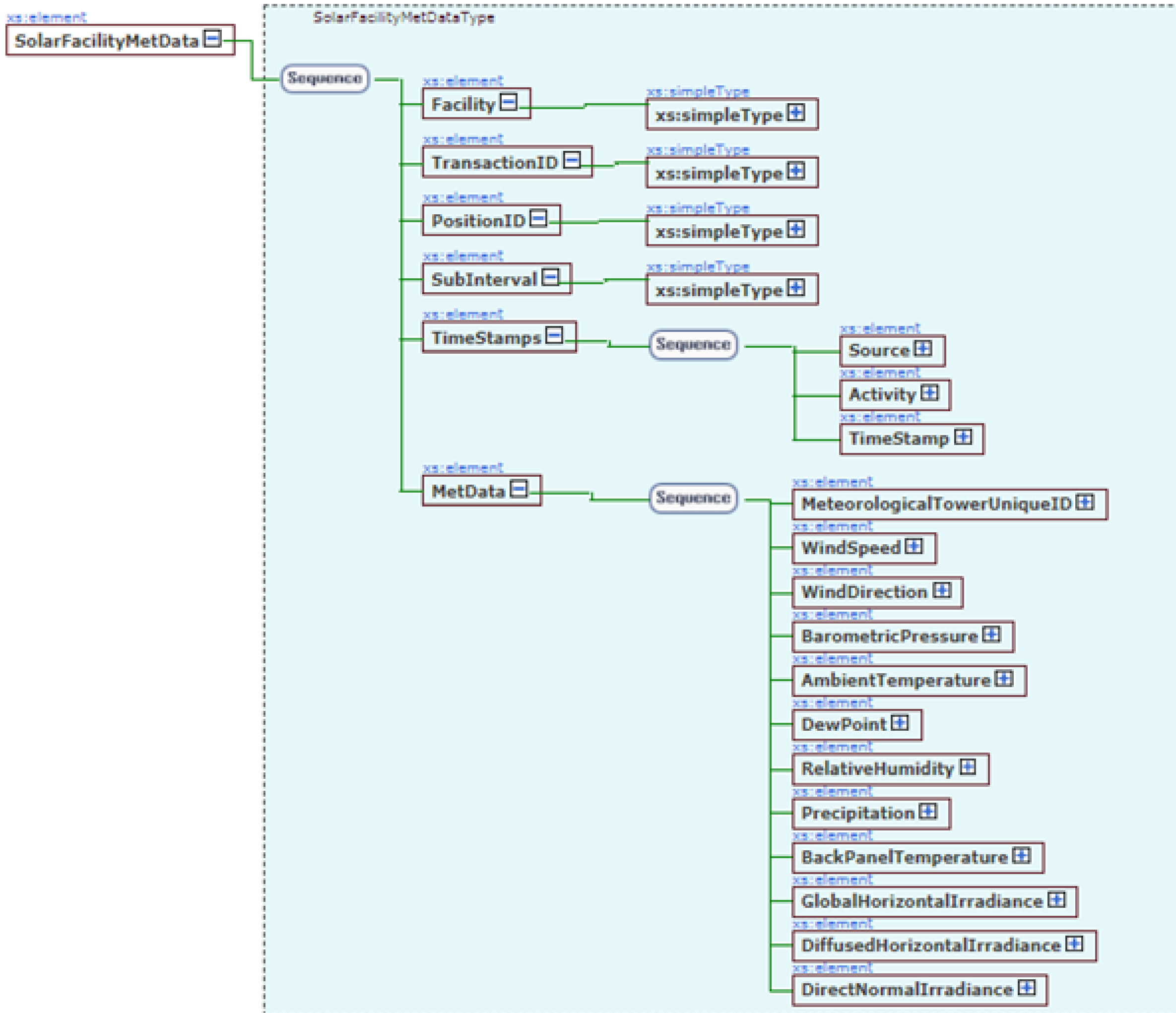
```
                <xs:enumeration value="Send"></xs:enumeration>
                <xs:enumeration value="Receive"></xs:enumeration>
                <xs:enumeration value="Process"></xs:enumeration>
              </xs:restriction>
            </xs:simpleType>
          </xs:element>
          <xs:element name="TimeStamp">
            <xs:simpleType>
              <xs:restriction base="xs:dateTime">
                <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ"></xs:pattern>
              </xs:restriction>
            </xs:simpleType>
          </xs:element>
        </xs:sequence>
      </xs:complexType>
    </xs:element>
    <xs:element name="MetTowerData" maxOccurs="unbounded">
      <xs:complexType>
        <xs:sequence>
          <xs:element name="MeteorologicalTowerUniqueID">
            <xs:simpleType>
              <xs:restriction base="xs:string">
                <xs:minLength value="0"></xs:minLength>
                <xs:maxLength value="90"></xs:maxLength>
              </xs:restriction>
            </xs:simpleType>
          </xs:element>
          <xs:element name="WindSpeed">
            <xs:simpleType>
              <xs:restriction base="xs:float">
                <xs:minInclusive value="0"></xs:minInclusive>
                <xs:maxInclusive value="50"></xs:maxInclusive>
              </xs:restriction>
            </xs:simpleType>
          </xs:element>
          <xs:element name="WindDirection">
```

```
      <xs:simpleType>
        <xs:restriction base="xs:float">
          <xs:minInclusive value="0"></xs:minInclusive>
          <xs:maxInclusive value="360"></xs:maxInclusive>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="BarometricPressure">
      <xs:simpleType>
        <xs:restriction base="xs:float">
          <xs:minInclusive value="800"></xs:minInclusive>
          <xs:maxInclusive value="1000"></xs:maxInclusive>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="AmbientTemperature">
      <xs:simpleType>
        <xs:restriction base="xs:float">
          <xs:minInclusive value="-50"></xs:minInclusive>
          <xs:maxInclusive value="50"></xs:maxInclusive>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="DewPoint">
      <xs:simpleType>
        <xs:restriction base="xs:float">
          <xs:minInclusive value="-50"></xs:minInclusive>
          <xs:maxInclusive value="50"></xs:maxInclusive>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="RelativeHumidity">
      <xs:simpleType>
        <xs:restriction base="xs:float">
          <xs:minInclusive value="0"></xs:minInclusive>
          <xs:maxInclusive value="100"></xs:maxInclusive>
```

```
						</xs:restriction>
					</xs:simpleType>
				</xs:element>
				<xs:element name="IceupParameter">
					<xs:simpleType>
						<xs:restriction base="xs:float">
							<xs:minInclusive value="0"></xs:minInclusive>
							<xs:maxInclusive value="1"></xs:maxInclusive>
						</xs:restriction>
					</xs:simpleType>
				</xs:element>
				<xs:element name="Precipitation">
					<xs:simpleType>
						<xs:restriction base="xs:float">
							<xs:minInclusive value="0"></xs:minInclusive>
							<xs:maxInclusive value="11"></xs:maxInclusive>
						</xs:restriction>
					</xs:simpleType>
				</xs:element>
			</xs:sequence>
		</xs:complexType>
	</xs:element>
</xs:sequence>
</xs:complexType>
</xs:schema>
```

6.2 Solar Facility Meteorological Data Schema

The following schema is used for solar meteorological data, and each solar aggregated generating facility is required to translate their data into the format below:




```
<?xml version="1.0" encoding="UTF-8"?>
<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.aeso.ca" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" attributeFormDefault="unqualified">
    <xs:element name="SolarFacilityMetData" type="SolarFacilityMetDataType"></xs:element>
    <xs:complexType name="SolarFacilityMetDataType">
        <xs:sequence>
            <xs:element name="Facility">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
```

```
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="TransactionID">
        <xs:simpleType>
            <xs:restriction base="xs:string">
                <xs:maxLength value="255"></xs:maxLength>
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="PositionID">
        <xs:simpleType>
            <xs:restriction base="xs:integer">
                <xs:minInclusive value="1"></xs:minInclusive>
                <xs:maxInclusive value="6"></xs:maxInclusive>
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="SubInterval">
        <xs:simpleType>
            <xs:restriction base="xs:integer">
                <xs:minInclusive value="0"></xs:minInclusive>
                <xs:maxInclusive value="9"></xs:maxInclusive>
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="TimeStamps" maxOccurs="unbounded">
        <xs:complexType>
            <xs:sequence>
                <xs:element name="Source">
                    <xs:simpleType>
                        <xs:restriction base="xs:string">
                            <xs:enumeration value="Solar Facility"></xs:enumeration>
                            <xs:enumeration value="Solar Forecaster"></xs:enumeration>
                            <xs:enumeration value="B2B Provider"></xs:enumeration>
                        </xs:restriction>
```

```
                &lt;/xs:simpleType&gt;
            &lt;/xs:element&gt;
            &lt;xs:element name="Activity"&gt;
                &lt;xs:simpleType&gt;
                    &lt;xs:restriction base="xs:string"&gt;
                        &lt;xs:enumeration value="Send"&gt;&lt;/xs:enumeration&gt;
                        &lt;xs:enumeration value="Receive"&gt;&lt;/xs:enumeration&gt;
                        &lt;xs:enumeration value="Process"&gt;&lt;/xs:enumeration&gt;
                    &lt;/xs:restriction&gt;
                &lt;/xs:simpleType&gt;
            &lt;/xs:element&gt;
            &lt;xs:element name="TimeStamp"&gt;
                &lt;xs:simpleType&gt;
                    &lt;xs:restriction base="xs:dateTime"&gt;
                        <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ">&lt;/xs:pattern&gt;
                    &lt;/xs:restriction&gt;
                &lt;/xs:simpleType&gt;
            &lt;/xs:element&gt;
        &lt;/xs:sequence&gt;
    &lt;/xs:complexType&gt;
&lt;/xs:element&gt;
&lt;xs:element name="MetData" maxOccurs="unbounded"&gt;
    &lt;xs:complexType&gt;
        &lt;xs:sequence&gt;
            &lt;xs:element name="MeteorologicalTowerUniqueID"&gt;
                &lt;xs:simpleType&gt;
                    &lt;xs:restriction base="xs:string"&gt;
                        &lt;xs:minLength value="0"&gt;&lt;/xs:minLength&gt;
                        &lt;xs:maxLength value="90"&gt;&lt;/xs:maxLength&gt;
                    &lt;/xs:restriction&gt;
                &lt;/xs:simpleType&gt;
            &lt;/xs:element&gt;
            &lt;xs:element name="WindSpeed"&gt;
                &lt;xs:simpleType&gt;
                    &lt;xs:restriction base="xs:float"&gt;
                        &lt;xs:minInclusive value="0"&gt;&lt;/xs:minInclusive&gt;
```

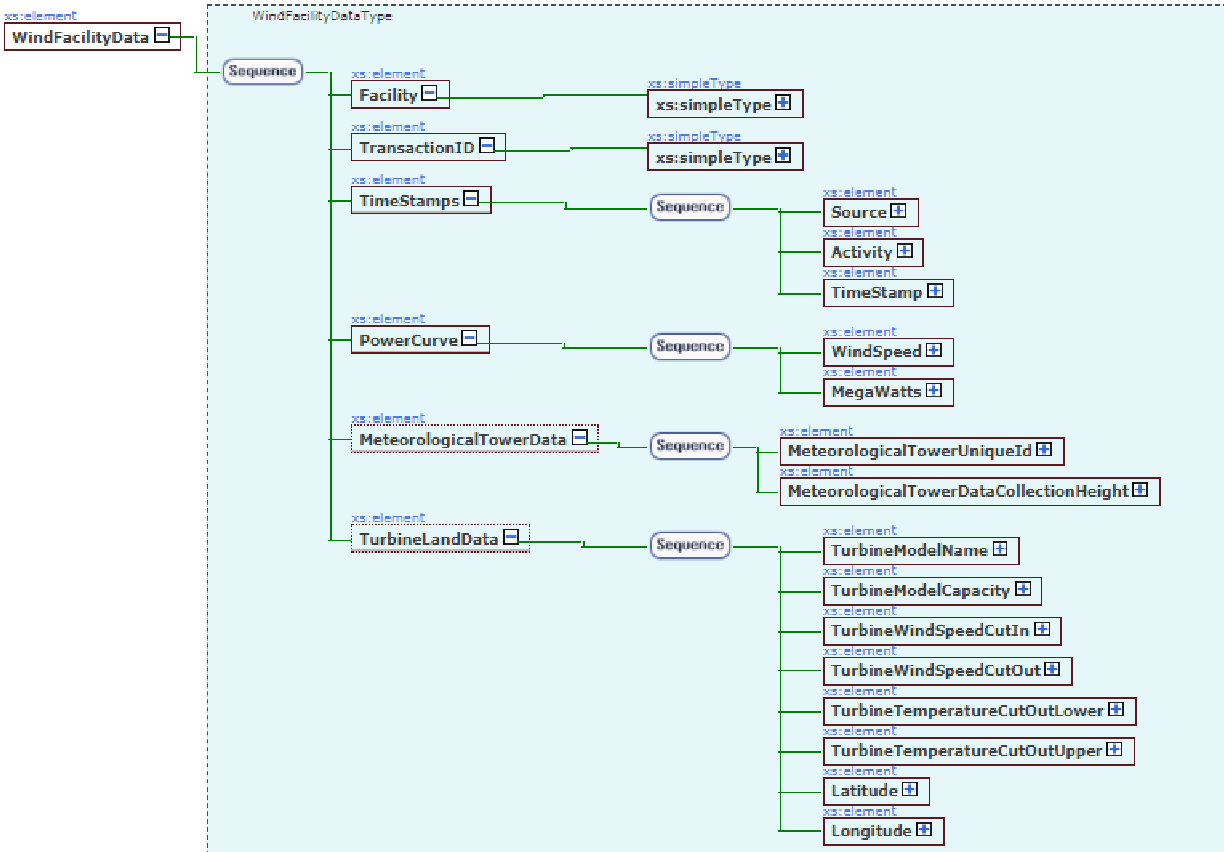
```
            <xs:maxInclusive value="50"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="WindDirection">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="0"></xs:minInclusive>
            <xs:maxInclusive value="360"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="BarometricPressure">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="800"></xs:minInclusive>
            <xs:maxInclusive value="1000"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="AmbientTemperature">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="-50"></xs:minInclusive>
            <xs:maxInclusive value="50"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="DewPoint">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="-50"></xs:minInclusive>
            <xs:maxInclusive value="50"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
```

```
<xs:element name="RelativeHumidity">
    <xs:simpleType>
        <xs:restriction base="xs:float">
            <xs:minInclusive value="0"></xs:minInclusive>
            <xs:maxInclusive value="100"></xs:maxInclusive>
        </xs:restriction>
    </xs:simpleType>
</xs:element>
<xs:element name="Precipitation">
    <xs:simpleType>
        <xs:restriction base="xs:float">
            <xs:minInclusive value="0"></xs:minInclusive>
            <xs:maxInclusive value="11"></xs:maxInclusive>
        </xs:restriction>
    </xs:simpleType>
</xs:element>
<xs:element name="BackPanelTemperature">
    <xs:simpleType>
        <xs:restriction base="xs:float">
            <xs:minInclusive value="-50"></xs:minInclusive>
            <xs:maxInclusive value="50"></xs:maxInclusive>
        </xs:restriction>
    </xs:simpleType>
</xs:element>
<xs:element name="GlobalHorizontalIrradiance">
    <xs:simpleType>
        <xs:restriction base="xs:float">
            <xs:minInclusive value="0"></xs:minInclusive>
            <xs:maxInclusive value="4000"></xs:maxInclusive>
        </xs:restriction>
    </xs:simpleType>
</xs:element>
<xs:element name="DiffusedHorizontalIrradiance">
    <xs:simpleType>
        <xs:restriction base="xs:float">
            <xs:minInclusive value="0"></xs:minInclusive>
```

```
                                    <xs:maxInclusive value="4000"></xs:maxInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                        <xs:element name="DirectNormalIrradiance">
                            <xs:simpleType>
                                <xs:restriction base="xs:float">
                                    <xs:minInclusive value="0"></xs:minInclusive>
                                    <xs:maxInclusive value="2000"></xs:maxInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                    </xs:sequence>
                </xs:complexType>
            </xs:element>
        </xs:sequence>
    </xs:complexType>
</xs:schema>
```

6.3 Wind Facility Data Schema

The following schema is used for wind facility data, and each wind aggregated generating facility is required to translate their data into the format below:




```
<?xml version="1.0" encoding="UTF-8"?>

<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.
aeso.ca" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" at
tributeFormDefault="unqualified">
    <xs:element name="WindFacilityData" type="WindFacilityDataType"></xs:element>
    <xs:complexType name="WindFacilityDataType">
        <xs:sequence>
            <xs:element name="Facility">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
            <xs:element name="TransactionID">
```

```
<xs:simpleType>
    <xs:restriction base="xs:string">
        <xs:maxLength value="255"></xs:maxLength>
    </xs:restriction>
</xs:simpleType>
</xs:element>
<xs:element name="TimeStamps" maxOccurs="unbounded">
    <xs:complexType>
        <xs:sequence>
            <xs:element name="Source">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:enumeration value="Wind
Facility"></xs:enumeration>
                        <xs:enumeration value="Wind
Forecaster"></xs:enumeration>
                        <xs:enumeration value="B2B
Provider"></xs:enumeration>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
            <xs:element name="Activity">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:enumeration value="Send"></xs:enumeration>
                        <xs:enumeration value="Receive"></xs:enumeration>
                        <xs:enumeration value="Process"></xs:enumeration>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
            <xs:element name="TimeStamp">
                <xs:simpleType>
                    <xs:restriction base="xs:dateTime">
                        <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ"></xs:pattern>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
        </xs:sequence>
```

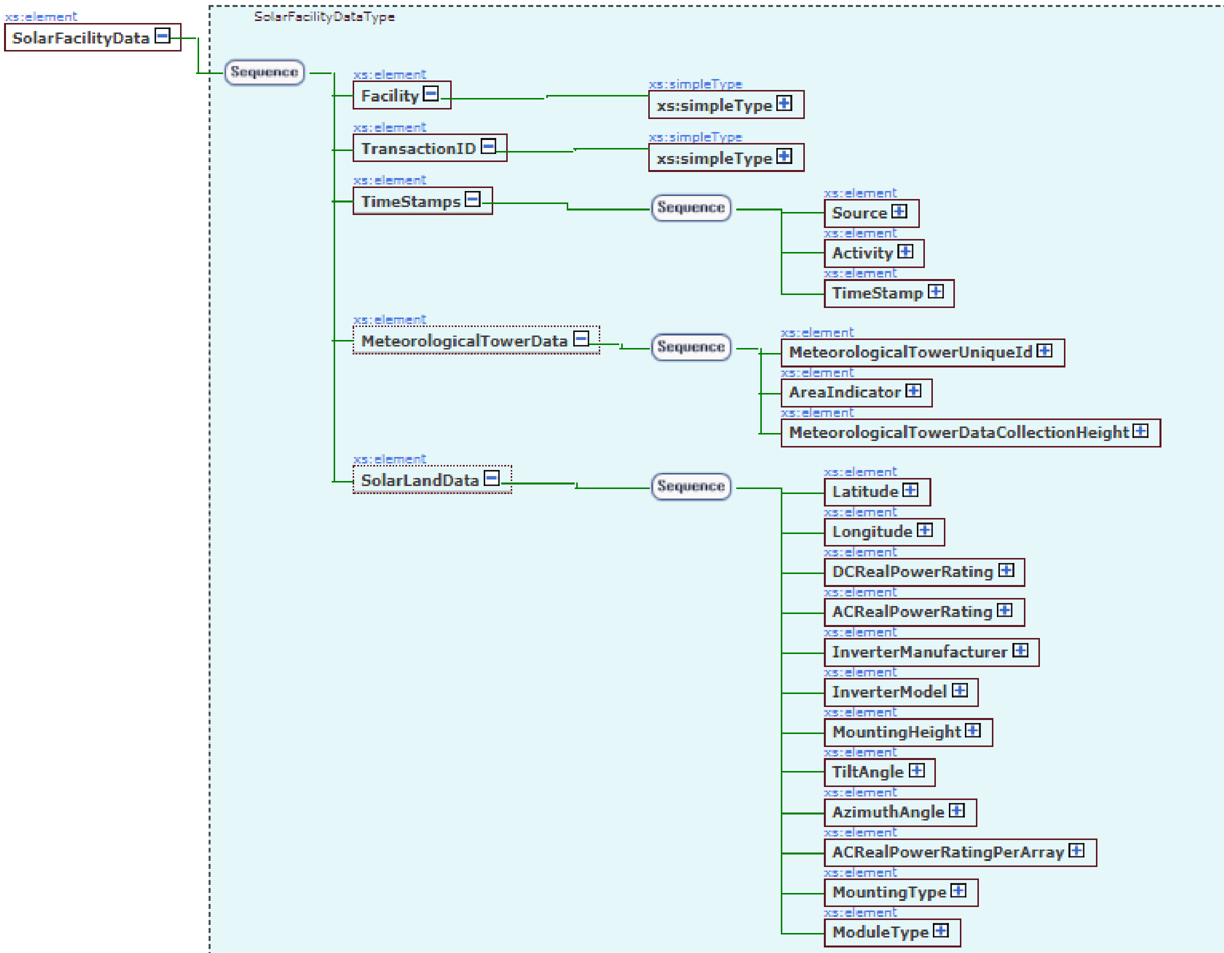
```
                </xs:complexType>
            </xs:element>
            <xs:element name="PowerCurve" maxOccurs="unbounded">
                <xs:complexType>
                    <xs:sequence>
                        <xs:element name="WindSpeed">
                            <xs:simpleType>
                                <xs:restriction base="xs:float">
                                    <xs:minInclusive value="0"></xs:minInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                        <xs:element name="MegaWatts">
                            <xs:simpleType>
                                <xs:restriction base="xs:float">
                                    <xs:minInclusive value="0"></xs:minInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                    </xs:sequence>
                </xs:complexType>
            </xs:element>
            
<xs:element name="MeteorologicalTowerData" minOccurs="0" maxOccurs="unbounded">
                <xs:complexType>
                    <xs:sequence>
                        <xs:element name="MeteorologicalTowerUniqueId">
                            <xs:simpleType>
                                <xs:restriction base="xs:string">
                                    <xs:minLength value="0"></xs:minLength>
                                    <xs:maxLength value="90"></xs:maxLength>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                        <xs:element name="MeteorologicalTowerDataCollectionHeight" type="xs
:float"></xs:element>
                    </xs:sequence>
                </xs:complexType>
```

```
</xs:element>
<xs:element name="TurbineLandData" minOccurs="0" maxOccurs="unbounded">
  <xs:complexType>
    <xs:sequence>
      <xs:element name="TurbineModelName" type="xs:string"></xs:elemen
t>
      <xs:element name="TurbineModelCapacity">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="0.1"></xs:minInclusive>
            <xs:maxInclusive value="20.0"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="TurbineWindSpeedCutIn">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="0"></xs:minInclusive>
            <xs:maxInclusive value="50"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="TurbineWindSpeedCutOut">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="0"></xs:minInclusive>
            <xs:maxInclusive value="99"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="TurbineTemperatureCutOutLower">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="-50"></xs:minInclusive>
            <xs:maxInclusive value="+50"></xs:maxInclusive>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
```

```
                        <xs:element name="TurbineTemperatureCutOutUpper">
                            <xs:simpleType>
                                <xs:restriction base="xs:float">
                                    <xs:minInclusive value="-50"></xs:minInclusive>
                                    <xs:maxInclusive value="50"></xs:maxInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                        <xs:element name="Latitude">
                            <xs:simpleType>
                                <xs:restriction base="xs:float">
                                    <xs:minInclusive value="48"></xs:minInclusive>
                                    <xs:maxInclusive value="65"></xs:maxInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                        <xs:element name="Longitude">
                            <xs:simpleType>
                                <xs:restriction base="xs:float">
                                    <xs:minInclusive value="-125"></xs:minInclusive>
                                    <xs:maxInclusive value="-98"></xs:maxInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                    </xs:sequence>
                </xs:complexType>
            </xs:element>
        </xs:sequence>
    </xs:complexType>
</xs:schema>
```

6.4 Solar Facility Data Schema

The following schema is used for solar facility data and each solar aggregated generating facility is required to translate their data into the format below:




```
<?xml version="1.0" encoding="UTF-8"?>
<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.aeso.ca" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" attributeFormDefault="unqualified">
    <xs:element name="SolarFacilityData" type="SolarFacilityDataType"></xs:element>
    <xs:complexType name="SolarFacilityDataType">
        <xs:sequence>
            <xs:element name="Facility">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
                    </xs:restriction>
                </xs:simpleType>
```

```
</xs:element>
<xs:element name="TransactionID">
  <xs:simpleType>
    <xs:restriction base="xs:string">
      <xs:maxLength value="255"></xs:maxLength>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="TimeStamps" maxOccurs="unbounded">
  <xs:complexType>
    <xs:sequence>
      <xs:element name="Source">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:enumeration value="Solar Facility"></xs:enumeration>
            <xs:enumeration value="Solar Forecaster"></xs:enumeration>
            <xs:enumeration value="B2B Provider"></xs:enumeration>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="Activity">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:enumeration value="Send"></xs:enumeration>
            <xs:enumeration value="Receive"></xs:enumeration>
            <xs:enumeration value="Process"></xs:enumeration>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="TimeStamp">
        <xs:simpleType>
          <xs:restriction base="xs:dateTime">
            <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ"></xs:pattern>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
```

```
                </xs:sequence>
            </xs:complexType>
        </xs:element>
        <xs:element name="MeteorologicalTowerData" minOccurs="0" maxOccurs="unbounded">
            <xs:complexType>
                <xs:sequence>
                    <xs:element name="MeteorologicalTowerUniqueId">
                        <xs:simpleType>
                            <xs:restriction base="xs:string">
                                <xs:minLength value="0"></xs:minLength>
                                <xs:maxLength value="90"></xs:maxLength>
                            </xs:restriction>
                        </xs:simpleType>
                    </xs:element>
                    <xs:element name="AreaIndicator">
                        <xs:simpleType>
                            <xs:restriction base="xs:integer">
                                <xs:minInclusive value="1"></xs:minInclusive>
                                <xs:maxInclusive value="2"></xs:maxInclusive>
                            </xs:restriction>
                        </xs:simpleType>
                    </xs:element>
                    <xs:element name="MeteorologicalTowerDataCollectionHeight" type="xs:integer"></xs:element>
                </xs:sequence>
            </xs:complexType>
        </xs:element>
        <xs:element name="SolarLandData" minOccurs="0" maxOccurs="unbounded">
            <xs:complexType>
                <xs:sequence>
                    <xs:element name="Latitude">
                        <xs:simpleType>
                            <xs:restriction base="xs:float">
                                <xs:minInclusive value="48"></xs:minInclusive>
                                <xs:maxInclusive value="65"></xs:maxInclusive>
                            </xs:restriction>
                        </xs:simpleType>
```

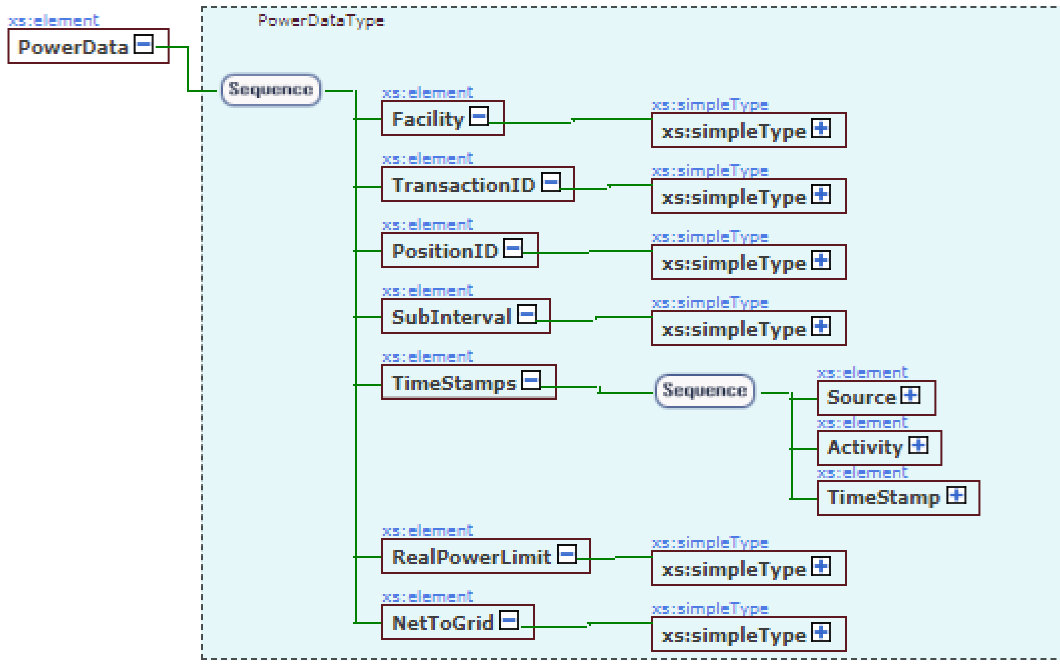
```
</xs:element>
<xs:element name="Longitude">
  <xs:simpleType>
    <xs:restriction base="xs:float">
      <xs:minInclusive value="-125"></xs:minInclusive>
      <xs:maxInclusive value="-98"></xs:maxInclusive>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="DCRealPowerRating">
  <xs:simpleType>
    <xs:restriction base="xs:float">
      <xs:minInclusive value="0.1"></xs:minInclusive>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="ACRealPowerRating">
  <xs:simpleType>
    <xs:restriction base="xs:float">
      <xs:minInclusive value="0.1"></xs:minInclusive>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="InverterManufacturer">
  <xs:simpleType>
    <xs:restriction base="xs:string">
      <xs:minLength value="0"></xs:minLength>
      <xs:maxLength value="90"></xs:maxLength>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="InverterModel">
  <xs:simpleType>
    <xs:restriction base="xs:string">
      <xs:minLength value="0"></xs:minLength>
      <xs:maxLength value="90"></xs:maxLength>
```

```
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
- <xs:element name="MountingHeight">
  - <xs:simpleType>
    - <xs:restriction base="xs:float">
        <xs:minInclusive value="0"></xs:minInclusive>
        <xs:maxInclusive value="50"></xs:maxInclusive>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
- <xs:element name="TiltAngle">
  - <xs:simpleType>
    - <xs:restriction base="xs:string">
        <xs:minLength value="1"></xs:minLength>
        <xs:maxLength value="30"></xs:maxLength>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
- <xs:element name="AzimuthAngle">
  - <xs:simpleType>
    - <xs:restriction base="xs:float">
        <xs:minInclusive value="0"></xs:minInclusive>
        <xs:maxInclusive value="360"></xs:maxInclusive>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
- <xs:element name="ACRealPowerRatingPerArray">
  - <xs:simpleType>
    - <xs:restriction base="xs:float">
        <xs:minInclusive value="0"></xs:minInclusive>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
- <xs:element name="MountingType">
  - <xs:simpleType>
```

```
                <xs:restriction base="xs:string">
                    <xs:minLength value="0"></xs:minLength>
                    <xs:maxLength value="90"></xs:maxLength>
                </xs:restriction>
            </xs:simpleType>
        </xs:element>
        <xs:element name="ModuleType">
            <xs:simpleType>
                <xs:restriction base="xs:string">
                    <xs:minLength value="0"></xs:minLength>
                    <xs:maxLength value="90"></xs:maxLength>
                </xs:restriction>
            </xs:simpleType>
        </xs:element>
      </xs:sequence>
    </xs:complexType>
  </xs:element>
 </xs:sequence>
</xs:complexType>
</xs:schema>
```

6.5 Power Data Schema

The following schema is used for power data, and each wind or solar aggregated generating facility is required to translate their data into the format below:




```xml
<?xml version="1.0" encoding="UTF-8"?>
<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.aeso.ca" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" attributeFormDefault="unqualified">
    <xs:element name="PowerData" type="PowerDataType"></xs:element>
    <xs:complexType name="PowerDataType">
        <xs:sequence>
            <xs:element name="Facility">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
            <xs:element name="TransactionID">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
                    </xs:restriction>
```

```
        </xs:simpleType>
    </xs:element>
    <xs:element name="PositionID">
        <xs:simpleType>
            <xs:restriction base="xs:integer">
                <xs:minInclusive value="1"></xs:minInclusive>
                <xs:maxInclusive value="6"></xs:maxInclusive>
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="SubInterval">
        <xs:simpleType>
            <xs:restriction base="xs:integer">
                <xs:minInclusive value="0"></xs:minInclusive>
                <xs:maxInclusive value="9"></xs:maxInclusive>
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="TimeStamps" maxOccurs="unbounded">
        <xs:complexType>
            <xs:sequence>
                <xs:element name="Source">
                    <xs:simpleType>
                        <xs:restriction base="xs:string">
                            <xs:enumeration value="Wind Facility"></xs:enumeration>
                            <xs:enumeration value="Solar Facility"></xs:enumeration>
                            <xs:enumeration value="Wind Forecaster"></xs:enumeration>
                            <xs:enumeration value="Solar Forecaster"></xs:enumeration>
                            <xs:enumeration value="Forecaster"></xs:enumeration>
                            <xs:enumeration value="B2B Provider"></xs:enumeration>
                        </xs:restriction>
                    </xs:simpleType>
                </xs:element>
                <xs:element name="Activity">
                    <xs:simpleType>
                        <xs:restriction base="xs:string">
```

```
                        <xs:enumeration value="Send"></xs:enumeration>
                        <xs:enumeration value="Receive"></xs:enumeration>
                        <xs:enumeration value="Process"></xs:enumeration>
                      </xs:restriction>
                    </xs:simpleType>
                  </xs:element>
                  <xs:element name="TimeStamp">
                    <xs:simpleType>
                      <xs:restriction base="xs:dateTime">
                        <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ"></xs:pattern>
                      </xs:restriction>
                    </xs:simpleType>
                  </xs:element>
                </xs:sequence>
              </xs:complexType>
            </xs:element>
            <xs:element name="RealPowerLimit">
              <xs:simpleType>
                <xs:restriction base="xs:float">
                  <xs:minInclusive value="0"></xs:minInclusive>
                </xs:restriction>
              </xs:simpleType>
            </xs:element>
            <xs:element name="NetToGrid">
              <xs:simpleType>
                <xs:restriction base="xs:float">
                  <xs:minInclusive value="0"></xs:minInclusive>
                </xs:restriction>
              </xs:simpleType>
            </xs:element>
          </xs:sequence>
        </xs:complexType>
      </xs:schema>
```

6.6 Gross Real Power Capability Data Schema

The following schema is used for gross real power capability data, and each wind or solar aggregated generating facility is required to translate their data into the format below:

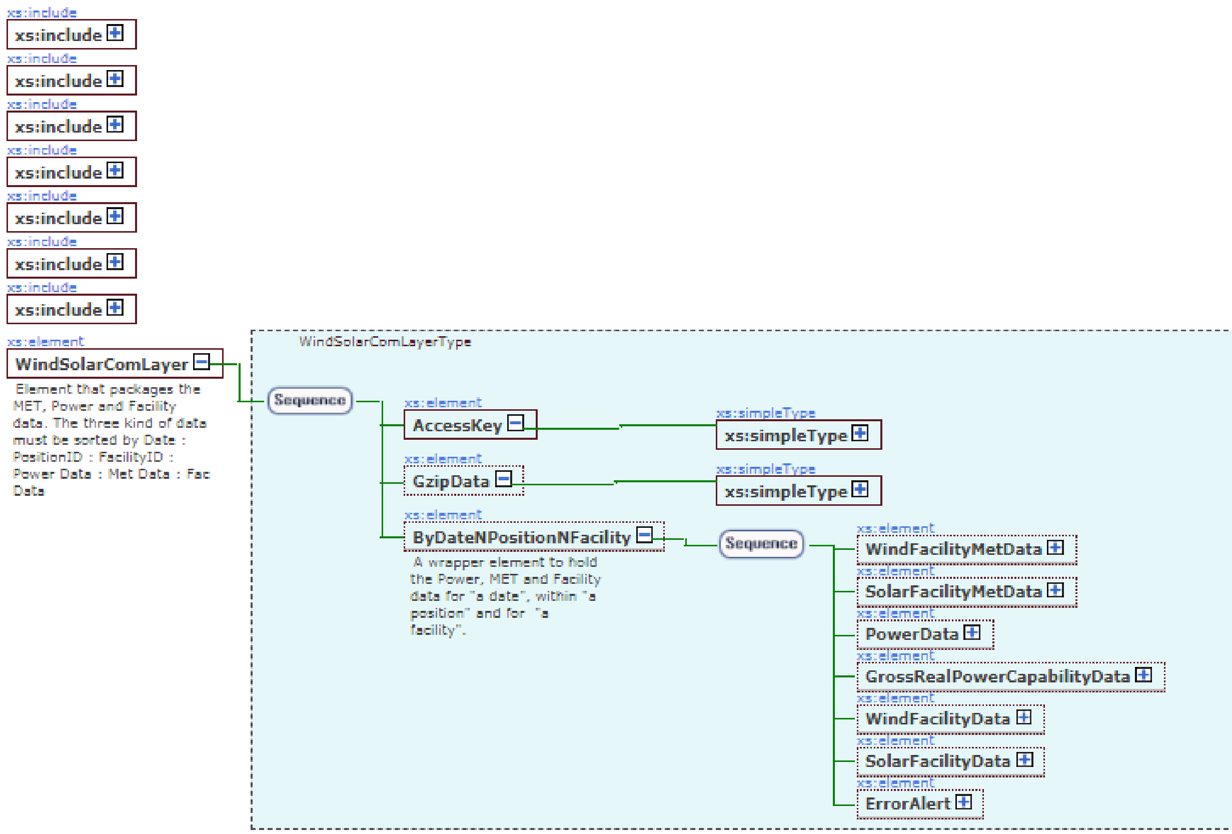

```
<?xml version="1.0" encoding="UTF-8"?>
<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.aeso.ca" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" attributeFormDefault="unqualified">
    <xs:element name="GrossRealPowerCapabilityData" type="GrossRealPowerCapabilityDataType"></xs:element>
    <xs:complexType name="GrossRealPowerCapabilityDataType">
        <xs:sequence>
            <xs:element name="Facility">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
            <xs:element name="TransactionID">
                <xs:simpleType>
                    <xs:restriction base="xs:string">
                        <xs:maxLength value="255"></xs:maxLength>
                    </xs:restriction>
                </xs:simpleType>
            </xs:element>
            <xs:element name="TimeStamps" maxOccurs="unbounded">
                <xs:complexType>
                    <xs:sequence>
                        <xs:element name="Source">
                            <xs:simpleType>
                                <xs:restriction base="xs:string">
                                    <xs:enumeration value="Wind Facility"></xs:enumeration>
                                    <xs:enumeration value="Solar Facility"></xs:enumeration>
                                    <xs:enumeration value="Forecaster"></xs:enumeration>
                                    <xs:enumeration value="Solar Forecaster"></xs:enumeration>
                                    <xs:enumeration value="Wind Forecaster"></xs:enumeration>
```

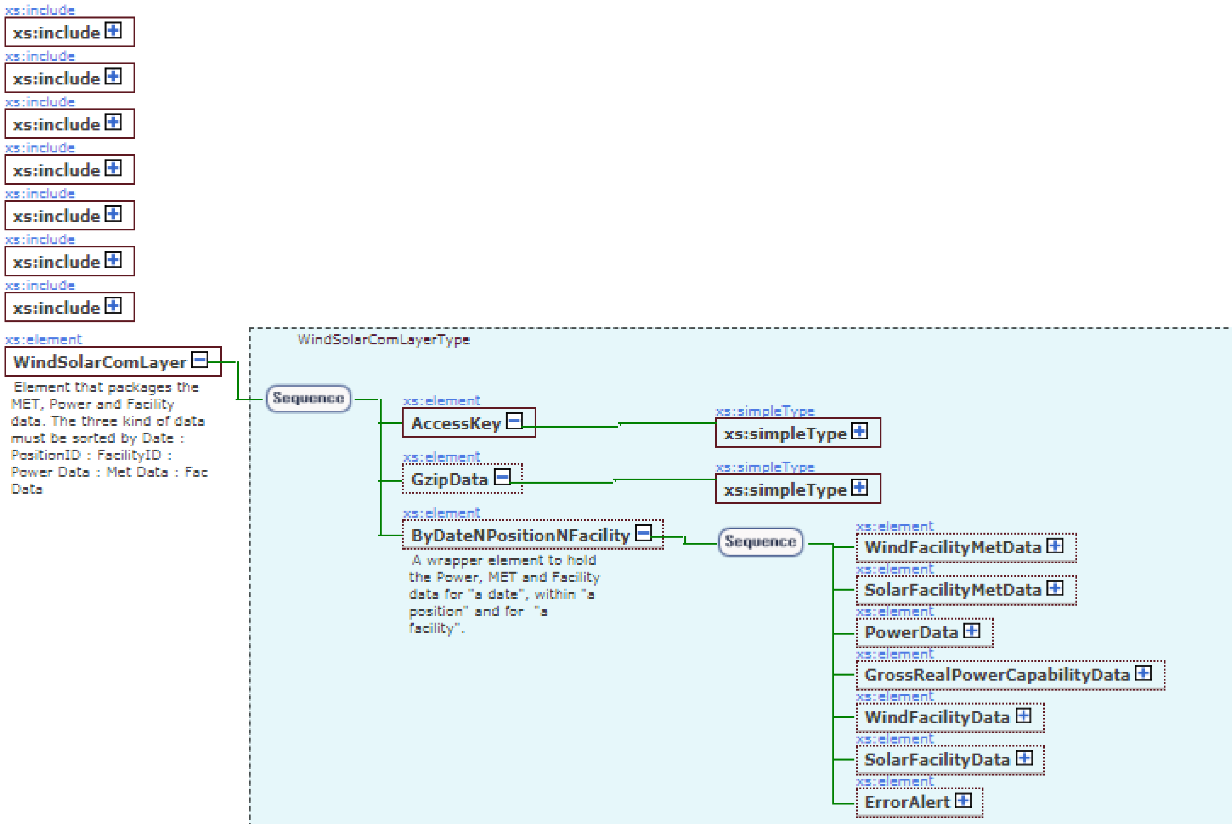
```
                    <xs:enumeration value="B2B
Provider"></xs:enumeration>
                  </xs:restriction>
                </xs:simpleType>
              </xs:element>
              <xs:element name="Activity">
                <xs:simpleType>
                  <xs:restriction base="xs:string">
                    <xs:enumeration value="Send"></xs:enumeration>
                    <xs:enumeration value="Receive"></xs:enumeration>
                    <xs:enumeration value="Process"></xs:enumeration>
                  </xs:restriction>
                </xs:simpleType>
              </xs:element>
              <xs:element name="TimeStamp">
                <xs:simpleType>
                  <xs:restriction base="xs:dateTime">
                    <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ"></xs:pattern>
                  </xs:restriction>
                </xs:simpleType>
              </xs:element>
            </xs:sequence>
          </xs:complexType>
        </xs:element>
        <xs:element name="GrossRealPowerCapability" maxOccurs="unbounded">
          <xs:complexType>
            <xs:sequence>
              <xs:element name="TimeStampBegin">
                <xs:simpleType>
                  <xs:restriction base="xs:dateTime">
                    <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ"></xs:pattern>
                  </xs:restriction>
                </xs:simpleType>
              </xs:element>
              <xs:element name="TimeStampEnd">
                <xs:simpleType>
                  <xs:restriction base="xs:dateTime">
```

```
                                    <xs:pattern value="\d\d\d\d-\d\d-
\d\dT\d\d:\d\d:\d\dZ"></xs:pattern>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                        <xs:element name="CapacityAverage">
                            <xs:simpleType>
                                <xs:restriction base="xs:float">
                                    <xs:minInclusive value="0"></xs:minInclusive>
                                </xs:restriction>
                            </xs:simpleType>
                        </xs:element>
                    </xs:sequence>
                </xs:complexType>
            </xs:element>
        </xs:sequence>
    </xs:complexType>
</xs:schema>
```

6.7 Wind Solar Communication Layer Schema

The communication layer is an envelope around the meterological, power, gross real power capability, and facility data allowing a wind or solar aggregated generating facility to fill the envelope with all four kinds of data from multiple facilities. This layer provides the authentication in combination with the encoded facility name; only the valid combination authorizes for delivery of the envelope.






```
<?xml version="1.0" encoding="UTF-8"?>

<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.aeso.c
a" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" attributeFor
mDefault="unqualified">
    <xs:include schemaLocation="WindFacilityMetData.xsd"></xs:include>
    <xs:include schemaLocation="SolarFacilityMetData.xsd"></xs:include>
    <xs:include schemaLocation="PowerData.xsd"></xs:include>
    <xs:include schemaLocation="GrossRealPowerCapabilityData.xsd"></xs:include>
    <xs:include schemaLocation="WindFacilityData.xsd"></xs:include>
    <xs:include schemaLocation="SolarFacilityData.xsd"></xs:include>
    <xs:include schemaLocation="Error_Alert.xsd"></xs:include>
    <xs:element name="WindSolarComLayer" type="WindSolarComLayerType">
        <xs:annotation>
            <xs:documentation>Element that packages the MET, Power and Facility data. The three
kind of data must be sorted by Date : PositionID : FacilityID : Power Data : Met Data : Fac
Data</xs:documentation>
        </xs:annotation>
    </xs:element>
    <xs:complexType name="WindSolarComLayerType">
```

```
<xs:sequence>
    <xs:element name="AccessKey">
        <xs:simpleType>
            <xs:restriction base="xs:string">
                <xs:maxLength value="255"></xs:maxLength>
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="GzipData" minOccurs="0">
        <xs:simpleType>
            <xs:restriction base="xs:string">
                <xs:maxLength value="100000"></xs:maxLength>
            </xs:restriction>
        </xs:simpleType>
    </xs:element>
    <xs:element name="ByDateNPositionNFacility" minOccurs="0" maxOccurs="unbounded">
        <xs:annotation>
            <xs:documentation>A wrapper element to hold the Power, MET and Facility data for "a date", within "a position" and for "a facility".</xs:documentation>
        </xs:annotation>
        <xs:complexType>
            <xs:sequence>
                <xs:element name="WindFacilityMetData" type="WindFacilityMetDataType" minOccurs="0" maxOccurs="unbounded"></xs:element>
                <xs:element name="SolarFacilityMetData" type="SolarFacilityMetDataType" minOccurs="0" maxOccurs="unbounded"></xs:element>
                <xs:element name="PowerData" type="PowerDataType" minOccurs="0" maxOccurs="unbounded"></xs:element>
                <xs:element name="GrossRealPowerCapabilityData" type="GrossRealPowerCapabilityDataType" minOccurs="0" maxOccurs="unbounded"></xs:element>
                <xs:element name="WindFacilityData" type="WindFacilityDataType" minOccurs="0" maxOccurs="unbounded"></xs:element>
                <xs:element name="SolarFacilityData" type="SolarFacilityDataType" minOccurs="0" maxOccurs="unbounded"></xs:element>
                <xs:element name="ErrorAlert" type="ErrorAlertType" minOccurs="0" maxOccurs="unbounded"></xs:element>
            </xs:sequence>
        </xs:complexType>
    </xs:element>
```

```
        </xs:sequence>
    </xs:complexType>
</xs:schema>
```


6.8 Message Response Schema

The following schema is used for the message acknowledgement response that is sent from the third party forecaster to the wind or solar aggregated generating facility to acknowledge the transmission of data, and includes error messages if applicable.


```
<?xml version="1.0" encoding="UTF-8"?>
<WindSolarResponse xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xmlns="http://windforecasting.public.aeso.ca" xsi:schemaLocation="http://windforecasting.public.aeso.ca WindSolarResponse.xsd">
    <ReturnCode>0|1</ReturnCode>
    <TransactionID>unique_string</TransactionID>
    <ErrorLevel>detailed_error_number</ErrorLevel>
    <Message>descriptive_text</Message>
</WindSolarResponse>
```

APPENDIX B: Forecast Process as per Section 502.1 Wind Aggregated Generating Facilities

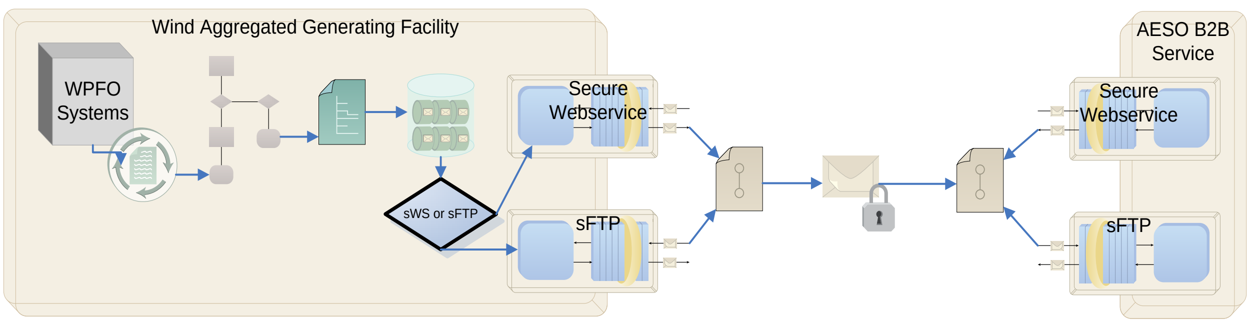
Note that this Appendix B is an excerpt from the Wind Power Forecasting Information Document ID #2011-007R posted 2016-09-28; notably this excerpt does not include the "Purpose" section and subsequent sections have been renumbered to reflect this exclusion. As this Appendix B is an excerpt, it should be read as a stand-alone process. For example, references to "this guide" in Appendix B refer to Appendix B as the guide, and not to the entirety of this Wind and Solar Power Forecasting ID as the guide.

1 Overview of Wind Power Forecasting

1.1. Introduction

This Information Document focuses on the wind aggregated generating facility data required for wind forecasting services to support the AESO's centralized wind forecasting program, and applies only to those facilities.

The cited ISO rules in effect require that a wind aggregated generating facility transmit data to the AESO. The following is an illustration of how that requirement is to be carried out in practise:



1.2. Terminology

Below is a list of terms and definitions used in this Information Document. For any additional formally defined terms and conditions please consult the *Consolidated Authoritative Document Glossary*.

"AESO B2B Service" means the external AESO Service responsible for the secure electronic movement of data between wind aggregated generating facility operators, the Forecaster and the AESO.

"Centralized Forecast Service" means the entire program of forecasting wind power in real-time and day-ahead for wind aggregated generating facilities in Alberta, using a centralized approach of collecting the data and predicting output for all plants. The AESO has contracted with a forecast vendor to produce all of the forecasts.

"Computer System" means any or all such systems employed by the wind aggregated generating facility operator, AESO or the Forecaster for the distinct purpose of transmitting meteorological, power and facility data.

"Data Communications Interface" means the physical communication channels employed by the wind aggregated generating facility operator to transmit meteorological data over the Internet to the AESO.

"Data Transfer Process" means the entire process of measuring, collecting, storing, and transmitting of meteorological data, including the Computer Systems, Forecast Data and Data Communications Interface.

"Facility Data" means all data as described in Section 3.4.4. of this Information Document.

"Forecast" means the Wind Power Forecast and the Weather Forecast.

"Forecaster" means Weprog ApS (GmbH, Ltd.).

"Forecasting Application" means the proprietary software developed and used by the Forecaster to produce Forecasts.

"Historical Data" means the numerical data collected by the AESO consisting of up to 2 years' of Meteorological Data, from wind aggregated generating facility connected to the interconnected electric system on or prior to the initial date of this Information Document.

"Meteorological Data" means all data as described in Section 3.4.2 of this guide.

"MC" means the maximum capability rating for an aggregated generating facility as displayed on the Current Supply Demand report on http://ets.aeso.ca

"Near Real Time" means within 15 seconds of real-time actual data production.

"Power Data" means all data as described in Section 3.4.3 of this Information Document.

"Secure Web-Interface" means an internet-based human interface that is secured by requiring the user to enter a password for access.

"Time Stamp" means a string of numerical data that indicates the time at which a set of Input Data was collected including the year, month, day, hour and second.

"Turbine Availability" used for planned or unplanned outages to indicate temporarily reduced Maximum Capacity (in MW) for a Wind Aggregated Generating Facility. In normal operations, TA = MC

"Web Service Interface" means the point in the Forecasting System that receives Input Data.

"Wind Power Forecast" means the prediction, based upon the use of a Forecasting Method, of the amount of power in MW that could be generated by wind energy at a specific time by a specific aggregated generating facility (an "Individual Forecast") and at a specific time by all of the operating Wind Power Facilities combined (the "Aggregate Forecast").

In this Information Document, the ISO may refer to wind aggregated generating facilities as a "facility".

2 Wind Data Transfer Process

This section presents the Data Transfer Process for wind aggregated generating facilities.

2.1 Aggregated Generating Facilities Responsibility

Each of the wind aggregated generating facilities is responsible for the cost assumed with purchase, installation, and appropriate maintenance of all equipment involved with the Data Transfer Process.

Each facility is expected to monitor and control its computer systems and data communications interfaces.

Each facility is expected to transmit data according to the specification as defined in the Data Transfer Technical Specification of this guide.

2.2 Availability

The Data Transfer Process is designed to operate fifty two weeks a year, seven (7) days a week and twenty four (24) hours each day.

2.3 Data Transfer Technical Specification

Please see the Data Transfer Technical Specification section for details of the data transfer technical specification for wind aggregated generating facilities. It is recommended that all such facilities use Secure File Transfer Protocol for transfer of data. The backup solution for data transfer is Secure Web services.

2.4 Wind Aggregated Generating Facility Data

This section describes the detailed data elements that the wind aggregated generating facilities need to provide. The data are Meteorological, Power and individual facility specific data.

2.4.1 XML Document / Schema Representation / Zip File Transfer

The standard protocol for submitting data is "XML" documents, based on the schemas outlined later in this Information Document. All dates, times, and date/times shall be in ISO 8601 format. All dates, times and date/times shall be in UTC time zone. For example, 2008-01-31, 23:19:22Z, and 2008-12-01T11:32:23Z. XML Document file names will be transmitted with the following internal file name structure:

{EncodedFacilityId}_{Type}_{dateTimes}_{PositionID}.xml {dateTimes} being the time of transmission in this instance.

{TYPE} being constrained to MET (Meteorological), PWR (Power) and FAC (Facility)

Note: Understanding that facility data does not have a PositionID in the data, in its absence facility data will use the Position ID of when it is transferred.

Example: EncodedFacilityId_MET_2008_12_01T11_32_23Z_1.xml (underscores will replace colons for Windows file system issues). This will also ensure that all internal files are unique and current as well as historical data, if required can be transmitted.

The aggregation of the internal files will be transferred in a zip file. Contained within the zipped file will be measurement data consisting of MET, PWR and FAC data, as specified in Sections 3.4.2, 3.4.3 and 3.4.4. An example of the files and extensions that will be included in the zipped file are:

EncodedFacilityId_MET_2008_12_01T11_32_23Z_1.xml

EncodedFacilityId_PWR_2008_12_01T11_32_23Z_1.xml

EncodedFacilityId_FAC_2008_12_01T11_32_23Z_1.xml

The aggregated zip files will be transferred in the following naming convention:

{EncodedFacilityId}_{dateTimes}.zip {dateTimes} – being the time of creation of he zip file

Example: EncodedFacilityId_ 2008_12_01T11_32_23Z.zip. This will also ensure that all aggregated files are unique and current as well as historical data, if required can be transmitted in a single package.

The process flow between wind aggregated generating facilities and the AESO is:

1. A zipped file containing the MET, PWR and/or FAC is created at the facilities.
2. Facilities connect using the secure FTP mailbox and send the file(s) to the AESO B2B Server
3. A zipped file containing either the MET and PWR or MET, PWR and FAC is sent to the AESO B2B server.
4. If there are communication errors during the connection, facilities will retry the send until successful. During the on-ramp process facilities will supply support contact information so the AESO can contact the facility if the problem persists.
5. The AESO suggest that facilities operators keep a week of data that has been sent in the event the AESO finds errors.

Detailed secure FTP specifications for facilities will be supplied during the onramp process. However, in Section 4.1 there is an overview of the FTP and parameters. The backup solution for data transfer is Secure Webservices.

Facilities' user name and password is to be supplied to the AESO in a separate email during the onramp process.

2.4.2 Meteorological (MET) Data

2.4.2.1 Data Definitions for Meteorological Data

The following table describes the meteorological information required from wind aggregated generating facilities:

Table 11

Measurement	Units	Precision for Instantaneous Measurements (to the nearest…)	Range	Notes	Required /Optional
Meteorological Tower Unique ID		N/A	N/A {Recommendation is to use facility ID followed by measurement height and perhaps GPS co-ordinates.}	This is a unique ID, facility specific to depict multiple Met towers. (This should match up with the ID in the facility schema)	R
Wind Speed	Meters/Second (m/s)	0.1 m/s	0 to 50	10 minute average	R
Wind Direction	Degrees from True North	1 degree	0 to 360	10 minute average	R
Surface Pressure	HectoPascals (HPa)	1 hPa	800 to 1100	10 minute average	R
Temperature	Degree Celsius	0.1° C	-50 to +50	10 minute average	R
Dewpoint	Degrees Celsius (°C)	0.1° C	-50 to +50	10 minute average	O
Relative Humidity	(Percentage)	1.0 %	0 to 100 %	10 minute average	O
Ice-up Parameter	Scale 0.0 to1.0	0.1° C	0 to 1	10 minute average	O

2.4.2.2 Logical Data Model for Meteorological Data

The following table describes the logical domain model of the message to be used by the wind aggregated generating facilities to provide meteorological information.

Table 12

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required /Optional
Facility Met Data		1	N	N/A			R
Facility	Encoded Facility ID.	2	N	String	Length = 255	AESO will provide the ID for specific Facility during the on-ramping process.	R
Transaction ID	Generated by the B2B provider.	2	N	String	Will be inserted by the AESO B2B provider upon reception of transmission of data.	This is the unique transaction ID used by the AESO B2B Service.	O,R – AESO B2B provider is required to insert
Position ID	This is generated by the facility.	2	N	Number	Min=1 Max=6 Please refer to Section 3.4.5 for values.	See 3.4.5 Hourly Position Description	R
Time Stamps	Data transmission trace	2	Y	N/A			R
Source	Source organization of the transmission	3	N	String	"Wind facility" or "B2B Provider" or "Wind Forecaster" or "AESO"	In this guide this will always be “facility”.	R
Activity	Transmission activity	3	N	String	“Send”, “Receive” or “Process”	In this guide it will always be “Process”	R
Time Stamp	Timestamp of the transmission	3	N	DateTime	ISO 8601 format in UTC time	This is the transaction time of the	R

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required /Optional
					zone	send process generated by the facility when sending the data.	
Met Tower Data		2	Y	N/A			R
Meteorological Tower Unique ID	Concatenation of Encoded Facility ID and Land Co-ordinates [EncodedFacilityID][LandCoOrdinates]	3	N	String	Length = 90	This tag was created to accommodate multiple met towers at different heights and locations. Note however only one measurement point is required.	R
Wind Speed		3	N	Float	Min=0 .0Max=50.0	10 minute average	R
Wind Direction		3	N	Float	Min=0.0 Max=360.0	10 minute average, please note that if it blows N for half and E for half, the average of the NE should be provided. In some wind events, wind can blow N then S, the AESO recommends providing the value with the higher wind speed as this usually indicates an incoming system.	R
Surface Pressure		3	N	Float	Min=800.0 Max=1100.0	10 minute average	R
Temperature		3	N	Float	Min=-50.0	10 minute	R

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required /Optional
					Max=50.0	average	
DewPoint		3	N	Float	Min=-50.0 Max=50.0	10 minute average	O
Relative Humidity		3	N	Float	Min=0.0 Max=100.0	10 minute average	O
Ice up Parameter		3	N	Float	Min=0.0 Max=1.0		O

2.4.3 Power (PWR) Data

2.4.3.1 Data Definitions for Power Data

The following table describes the power output information that is required to be provided by the wind aggregated generating facilities.

Table 13

Measurement	Units	Precision for Instantaneous Measurements (to the nearest…)	Range	Notes	Required /Optional
Current Turbine Availability (CTA)	MW	0.1 MW	Greater Than 0	Outage-related temporary reduction in Maximum Capacity (in MW) for an aggregated generating facility. In normal operations, CTA = MC.	R
Real Power Limit	MW	0.1 MW	Greater Than 0	The current value in the power limiting control system at the wind aggregated facilities.	R
Net To Grid	MW	0.1 MW	Greater Than 0	The real power output (MW) at the point of connection.	R

2.4.3.2 Logical Data Model for Power Data

The following table describes the logical domain model of the message to be used by the wind aggregated generating facilities to provide power information.

Table 14

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required/Optional
Facility Power Data		1	N	N/A			R
Facility	Encoded Facility ID. AESO will provide the ID for each specific Facility	2	N	String	Length = 255	AESO will provide the ID for specific Facility during the on-ramping process.	R
Transaction ID	Generated by the B2B provider.	2	N	String	Will be inserted by the AESO B2B Provider upon reception of transmission of data.	This is the unique transaction ID used by the AESO B2B Service.	O, R AESO B2B provider is required to insert
Position ID	See 3.4.5 Hourly Position Description	2	N	Number	Min=1 Max=6	See 3.4.5 Hourly Position Description	R
Time Stamps	Data transmission trace	2	Y	N/A			R
Source	Source organization of the transmission	3	N	String	"Facility" or "B2B Provider" or "Wind Forecaster" or "AESO"	In this Information document this will always be “Facility”.	R
Activity	Transmission activity	3	N	String	“Send”, “Receive” or “Process”	In this Information Document it will always be “Process”	R

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required/Optional
Time Stamp	Timestamp of the transmission	3	N	DateTime	ISO 8601 format in UTC time zone	This is the transaction time of the send process generated by the facility when sending the data.	R
Current Turbine Availability (CTA)	Outage-related temporary reduction in Maximum Capacity (in MW) for an aggregated generating facility	2	N	Float	Min=0.0	In normal operations, CTA = MC.	R
Real Power Limit	The current value in the power limiting control system at the wind aggregated facilities	2	N	Float	Min=0.0	.	R
Net To Grid	The real power output (MW) at the point of connection	2	N	Float	Min=0.0	.	R

2.4.4 Facility (FAC) Data

The following table describes the information that is required to be provided by the wind aggregated generating facility. These data elements are required to be provided whenever there is a change in the value. Additionally, the Planned Turbine Availability is required to be provided whenever a new value has become available (144 hours upcoming). The FAC data needs to be provided by the wind aggregated generating facilities at least once per day (to best ensure accuracy of the 6 day ahead Forecasts).

Table 15

Measurement	Units	Precision for Instantaneous Measurements (to the nearest…)	Range	Notes	Required/Optional
Planned Turbine Availability (PTA)	MW	0.1 MW	Greater Than 0	(PTA) Planned temporary reduction in Maximum Capacity (in MW) for a facility during the next 144 hours (6 days). In normal operations, PTA = MC.	R
Meteorological Tower Unique ID	N/A	N/A	N/A	{Recommendation is to use facility ID followed by measurement height and perhaps GPS co-ordinates.} This is a unique ID, Facility specific to depict multiple Met towers. (This should match up with the ID in the Metrological schema)	R
Meteorological Tower Data Collection Height	Meters	1 Meter		The height at which the meteorological data is measured at.	R
Turbine Model Name	Name		Length=255	The manufacturer's turbine model name.	R
Turbine Model Capacity	KW	0.1KW	Min=1 Max=100000	The manufacturer's turbine model capacity. As set for production.	R

Measurement	Units	Precision for Instantaneous Measurements (to the nearest…)	Range	Notes	Required/Optional
Turbine Wind Cut-In	Meters/Second (m/s)	0.1 m/s	0 to 50	The manufacturer's turbine wind cut-in point. As set for production.	R
Turbine Wind Cut-Out	Meters/Second (m/s)	0.1 m/s	0 to 50	The manufacturer's turbine wind cut-out point. As set for production.	R
Turbine TemperatureCut-Out Lower*	Degree Celsius	1° C	-50 to +50	The manufacturer's turbine temperatureCut-out lower point.	R
Turbine TemperatureCut-Out Upper*	Degree Celsius	1° C	-50 to +50	The manufacturer's turbine temperatureCut-out upper point.	R

Note: There is normally a lower and higher temperature cutout. Both are relevant in Alberta. The AESO requires an indicator to confirm that the numbers are ambient temperature within the rotor or air temperature.

2.4.4.1 Logical Data Model for Facility Data

The following table describes the recommended logical domain model to be used by the wind aggregated generating facilities to provide facility information:

Table 16

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required/ Optional
Facility Data		1	N	N/A			R
Facility	AESO will provide the ID for specific Facility during the on-ramping process	2	N	String	Length = 255	.	R
Transaction ID	This is the unique transaction ID used by the AESO B2B Service.	2	N	String	TBD	Generated by the AESO B2B provider.	O, R AESO B2B provider is required to insert
TimeStamps	Data transmission trace	2	Y	N/A			R

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required/ Optional
Source	Source organization of the transmission	3	N	String	" Facility" or "B2B Provider" or "Wind Forecaster" or "AESO"	In this guide this will always be "Facility".	R
Activity	Transmission activity	3	N	String	"Send", "Receive" or "Process"	In this guide it will always be "Process"	R
TimeStamp	Timestamp of the transmission	3	N	DateTime	ISO 8601 format in UTC time zone	This is the transaction time of the send process generated by the facility when sending the data.	R
Planned Turbine Availability	(PTA) Planned temporary reduction in Maximum Capacity (in MW) for a facility during the next 144 hours (6 days).	2	Y	N/A		In normal operations, PTA = MC	O
Start Date	Beginning data time of the period of planned turbine availability	3	N	DateTime	ISO 8601 format in UTC time zone		R
End Date	End date time of the period of planned turbine availability.	3	N	DateTime	ISO 8601 format in UTC time zone		R
MegaWatts	Hourly weighted average planned turbine availability. See following section for example.	3	N	Float	> 0.0	The real power that would have been produced at the point of connection without any facility curtailment and based on real time meteorological conditions at each available wind turbine generator.	R

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required/ Optional
Meteorological Tower Data		2	Y	N/A			O, R if more than one towers are used
Meteorological Tower Unique ID	Concatenation of Encoded Facility ID and Land Co-ordinates [EncodedFacilityID][LandCoOrdinates]	3	N	String	Length = 90	{Recommendation is to use Facility ID followed by measurement height and perhaps GPS co-ordinates. This is a unique ID, facility specific to depict multiple Met towers. (This should match up with the ID in the Metrological schema)	O, R if more than one tower is used and/or if there is data to be reported.
Meteorological Tower Data Collection Height	The height at which the meteorological data is measured at.	3	N	Float			R
Turbine Land Data		2	Y				O
Turbine Model Name	The manufacturer's turbine model name.	3	N	String	Length=255		R
Turbine Model Capacity	The manufacturer's turbine model capacity. As set for production	3	N	Number	Min=1 Max=100000	.	R
Turbine Wind CutIn	The manufacturer's turbine wind cut-in point. As set for production.	3	N	Float			R
Turbine Wind Cut Out	The manufacturer's turbine wind cut-out point. As set for production.	3	N	Number			R
Turbine Temperature Cut Out Lower	The manufacturer's turbine temperature Cut-out lower point.	3	N	Float	Min=-50 Max=50		R

Data Name	Description	Depth Level	Looping	Data Type	Constraints	Notes	Required/ Optional
Turbine Temperature Cut Out Upper	The manufacturer's turbine temperatureCut-out upper point	3	N	Float	Min=-50 Max=50	.	R

2.4.4.2 Wind Aggregated Generating Turbine Availability Example

The Planned Turbine availability data is expected to be reported to the hour based on a time range of 6 days (144 hours).

Example: When there is no planned outage for facility; the following planned turbine availability should be provided to AESO:

Start = 2010-12-01T13:00Z

End = 2010-12-07T13:00Z

MW = 82 (MC @ 2 MW per turbine X 41 turbines)

Example: When there is planned outage for one turbine between 2010 12 01 13:40 to 16:10. The following planned turbine availability should be provided to AESO:

1st hour of outage

Start = 2010-12-01T13:00Z

End = 2010-12-01T14:00Z

MW = 81 (82-2*20/60 = 81.3)

2nd hour of outage

Start = 2010-12-01T14:00Z

End = 2010-12-01T15:00Z

MW = 80 (82-2)

3rd hour of outage

Start = 2010-12-01T15:00Z

End = 2010-12-01T16:00Z

MW = 80 (82-2)

4th and final hour of outage

Start = 2010-12-01T16:00Z

End = 2010-12-01T17:00Z

MW = 82 (82-2*10/60 = 81.7)

2.4.5 Hourly Position Description

The Position ID is the indicator of which 10 minute span within an hour is being aggregated in any given transaction.

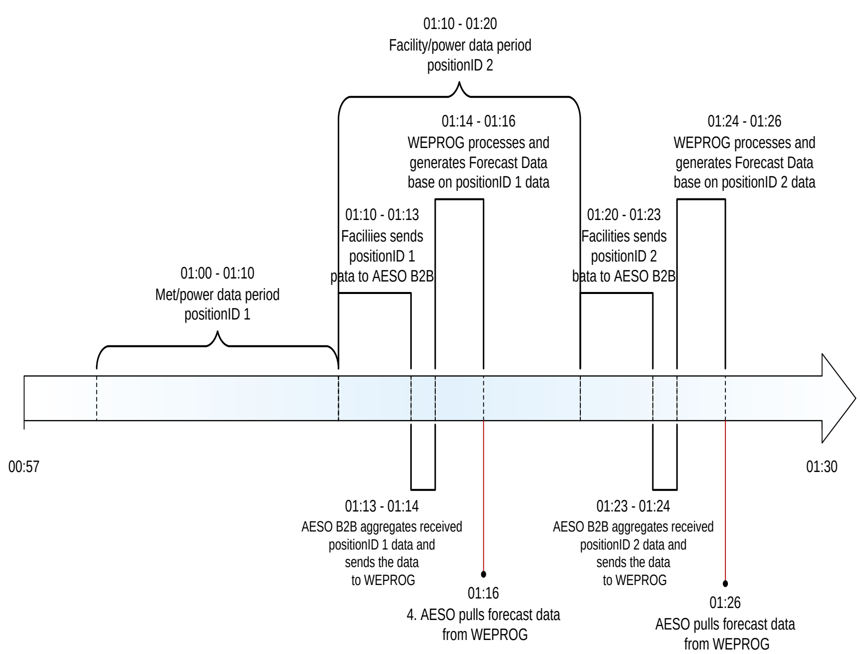
Table 17

PositionID	Time Range of Data Process by Facility	Time Range of Transmission by Facility	AESO B2B Aggregates and Sends to WEPROG	Description
1	00:00 – 09:59	XXh:10:00 – 12:59	XXh:13:00 – 13:59	MM:SS
2	10:00 – 19:59	XXh:20:00 – 22:59	XXh:23:00 – 23:59	MM:SS
3	20:00 – 29:59	XXh:30:00 – 32:59	XXh:33:00 – 33:59	MM:SS
4	30:00 – 39:59	XXh:40:00 – 42:59	XXh:43:00 – 43:59	MM:SS
5	40:00 – 49:59	XXh:50:00 – 52:59	XXh:53:00 – 53:59	MM:SS
6	50:00 – 59:59	XXh:00:00 – (XXh +1):02:59	(XXh: +1):03:00– (XXh +1):03:59	MM:SS

2.4.6 Data Transmission Timeline

The following are the requirements for the data transfer timeline:

- The MET and PWR data needs to be measured and provided by the wind aggregated generating facilities operator at the end of every 10 minute period.
- The maximum allowed tolerance to transfer this data over to the AESO B2B provider, is 3 minutes. Facilities should, and report any failure to the AESO at each instance.
- In case of the delays or outage, the facilities should ensure that the data is sent to the AESO B2B provider after the fact.



2.4.7 Software/Security Updates

Computer system hardware and software should be maintained and upgraded, per manufacturer's recommendations.

2.4.8 Errors and Alerting

Error and Alerting is being implemented by the AESO, however, it is not required by the wind aggregated generating Facilities to produce error codes for the AESO B2B Service and/or the Forecaster.

3 Data Transfer Technical Specification

This specification provides details of the standard formats and protocols to be followed to enable data exchange between wind aggregated generating facilities and the AESO.

3.1 Secure FTP

3.1.1 Connection Details

AESO B2B SFTP Server Address: sftp.tradinggrid.gxs.com

Port Number: 22

User/Password: {to be obtained during on-ramping process}

If using Public Key authentication, exchange public keys with GXS.

3.1.2 Virtual File System

The AESO B2B Service has implemented a virtual file system for SFTP. File name path follows the following convention: **/user/partner/opt1/opt2**

- User – is the signed-on facility. After login, the use is in its home directory.
- Partner – is the trading partner and has a corresponding directory under the home directory. The partner directory contains all files received from or sent to this partner.
- Opt1 (optional) – document type or ARPF depends on the command used.
- Opt2 (optional) – control number of document status depends on the command used.

3.1.3 Commands

The following SFTP commands can be used to upload the MET, PWR and FAC data to the AESO B2B.

- pwd – show current virtual file name path
- cd – change directory
- put – to upload document to partner

Note: During the On-Ramping Process, detailed commands and uses will be provided and configured with each wind aggregated generating facility.

3.2 Secure Web Services

The wind aggregated generating facilities are to use a Secure Web Service provided by the AESO to transfer the MET, PWR and FAC data. MET, PWR and FAC data has to be made available as XML documents, as per the individual message schemas provided later in this Information Document. The Web service can be implemented with any Web services technology. Adherence to this specification guarantees interoperability regardless of the chosen technology platform.

Note: That individual .xml files will need to be sent to the AESO B2B Webservice **NOT** consolidated into a zip file like the sFTP service.

Specific security protocols will be given on a one-to-one basis while on-ramping each aggregated generating facility to ensure protection of security information. The AESO B2B Provider has Secure Socket Layer (SSL) for encrypted sessions of HTTP and Secure FTP (SFTP and FTPs). All data is also transferred through AESO B2B commercial firewalls.

3.2.1 AESO B2B Provider Web Service Specification

The following Web Service is provided by the AESO B2B Provider. This service will be primarily used by the wind aggregated generating facilities to submit MET, PWR and FAC specific data to the AESO B2B Provider.

List of services provided by AESO:

Table 18

Service Name	Functionality
mailboxList	Provides the list of items in their mailbox
getLogEntries	Returns the activity log entries for a document with a particular document ID.
requeueDocument	Re-queues the document with a particular document ID.
upload	Uploads a document to the AESO B2B Provider.
download	Downloads a document from AESO B2B Provider.

3.2.1.1 Upload Service

Each of the wind aggregated generated facilities are to use the “upload” service from the AESO B2B Provider to submit MET, PWR and FAC data.

The following parameters are required to be provided as input to the “upload” service:

Table 19

Parameter	Description
Userid	Enterprise Mailbox ID of the sender
receiverid	Enterprise Mailbox ID of the Receiver.
Datatype	Optional. It can be EDI, XML or Binary. XML will be the chosen option.
Aprf	Optional. Application reference.
Snrf	Optional. Document control number.
Destination	Optional. ‘ICSCSR’ is default;
InputData	The inputData that needs to be uploaded.

The following parameters will be provided as output from the “upload” service.

Table 20

Parameter	Description
DocTimeStamp	To be given during on-ramp process.
InternalID	To be given during on-ramp process.
SERVICEREF	To be given during on-ramp process.
LogEntry	To be given during on-ramp process.

3.2.2 Web Service Description Language

Web Service Description Language (WSDL) is used to describe the technical details of each message and operation defined in the service to be called. The WSDL below describes the AESO's B2B Web service that serves as a common interface for wind aggregated generating facilities.

The following is the WSDL describing various the "upload" service hosted by the AESO B2B Service to be used by the operator of wind aggregated generating facilities to submit MET, PWR, and FAC data.

```
<?xml version="1.0" encoding="UTF-8"?>

<wsdl:definitions name="gxs_ws_comm" targetNamespace="http://icslinux7/"
xmlns:tns="http://icslinux7/" xmlns:mime="http://schemas.xmlsoap.org/wsdl/mime/"
xmlns:http="http://schemas.xmlsoap.org/wsdl/http/"
xmlns:xsd="http://www.w3.org/2001/XMLSchema"
xmlns:soap="http://schemas.xmlsoap.org/wsdl/soap/"
xmlns:wsdl="http://schemas.xmlsoap.org/wsdl/">

  <wsdl:types>

    <xsd:schema targetNamespace="http://localhost/gxs/ws/comm/upload"
xmlns:tns="http://localhost/gxs/ws/comm/upload" xmlns:xsd="http://www.w3.org/2001/XMLSchema">

        <xsd:complexType name="__uploadInput">

          <xsd:sequence>

            <xsd:element name="inputData" nillable="true" type="xsd:string"/>

            <xsd:element name="userid" nillable="true" type="xsd:string"/>

            <xsd:element name="receiverid" nillable="true" type="xsd:string"/>

            <xsd:element minOccurs="0" name="datatype" nillable="true" type="xsd:string"/>

            <xsd:element minOccurs="0" name="aprf" nillable="true" type="xsd:string"/>

            <xsd:element minOccurs="0" name="snrf" nillable="true" type="xsd:string"/>

            <xsd:element name="destination" nillable="true" type="xsd:string"/>

          </xsd:sequence>

        </xsd:complexType>

        <xsd:complexType name="__uploadOutput">

          <xsd:sequence>

            <xsd:element name="DocTimestamp" nillable="true" type="xsd:string"/>

            <xsd:element name="InternalID" nillable="true" type="xsd:string"/>

            <xsd:element name="SERVICEREF" nillable="true" type="xsd:string"/>

            <xsd:element name="LogEntry" nillable="true" type="xsd:string"/>

          </xsd:sequence>

        </xsd:complexType>

      </xsd:schema>

  </wsdl:types>

  <wsdl:message name="_uploadOutput">
```

```
    <wsdl:part name="DocTimestamp" type="xsd:string"/>
    <wsdl:part name="InternalID" type="xsd:string"/>
    <wsdl:part name="SERVICEREF" type="xsd:string"/>
    <wsdl:part name="LogEntry" type="xsd:string"/>
  </wsdl:message>
  <wsdl:message name="_uploadInput">
    <wsdl:part name="inputData" type="xsd:string"/>
    <wsdl:part name="userid" type="xsd:string"/>
    <wsdl:part name="receiverid" type="xsd:string"/>
    <wsdl:part name="datatype" type="xsd:string"/>
    <wsdl:part name="aprf" type="xsd:string"/>
    <wsdl:part name="snrf" type="xsd:string"/>
    <wsdl:part name="destination" type="xsd:string"/>
  </wsdl:message>
  <wsdl:portType name="gxs_ws_commPortType">
    <wsdl:operation name="upload">
      <wsdl:input message="tns:_uploadInput"/>
      <wsdl:output message="tns:_uploadOutput"/>
    </wsdl:operation>
  </wsdl:portType>
  <wsdl:binding name="gxs_ws_commBinding" type="tns:gxs_ws_commPortType">
    <soap:binding style="rpc" transport="http://schemas.xmlsoap.org/soap/http"/>
    <wsdl:operation name="upload">
      <soap:operation soapAction=""/>
      <wsdl:input>
        <soap:body use="encoded" encodingStyle="http://schemas.xmlsoap.org/soap/encoding/"
namespace="http://icslinux7/gxs.ws.comm"/>
      </wsdl:input>
      <wsdl:output>
        <soap:body use="encoded" encodingStyle="http://schemas.xmlsoap.org/soap/encoding/"
namespace="http://icslinux7/gxs.ws.comm"/>
      </wsdl:output>
    </wsdl:operation>
  </wsdl:binding>
  <wsdl:service name="gxs_ws_commService">
    <wsdl:port name="gxs_ws_commPort0" binding="tns:gxs_ws_commBinding">
      <soap:address location="https://ws.tradinggrid.gxs.com:443/smg/ws_comm/upload"/>
```

</wsdl:port>

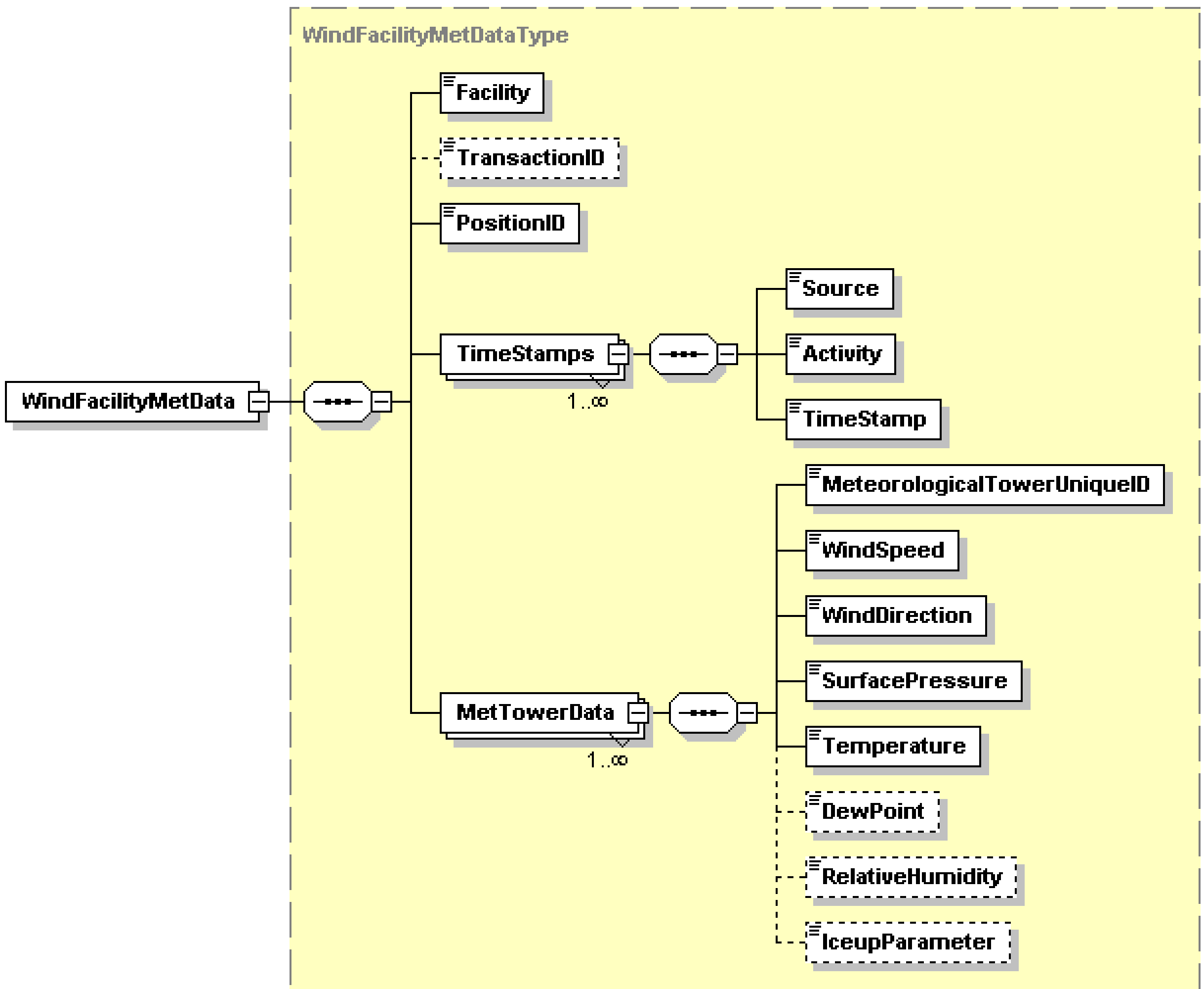
</wsdl:service>

</wsdl:definitions>

4 Message Formats - XSD

4.1 Met Data Schema

The following schema is used for all Meteorological Data and each wind aggregated facility is required to translate their data into the format below.



<?xml version="1.0" encoding="UTF-8"?>

<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema" xmlns="http://windforecasting.public.aeso.ca" targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified" attributeFormDefault="unqualified">

<xs:element name="WindFacilityMetData" type="WindFacilityMetDataType"/>

<xs:complexType name="WindFacilityMetDataType">

<xs:sequence>

```xml
<xs:element name="Facility">
  <xs:simpleType>
    <xs:restriction base="xs:string">
      <xs:maxLength value="255"/>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="TransactionID" type="xs:string" minOccurs="0"/>
<xs:element name="PositionID">
  <xs:simpleType>
    <xs:restriction base="xs:integer">
      <xs:minInclusive value="1"/>
      <xs:maxInclusive value="6"/>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="TimeStamps" maxOccurs="unbounded">
  <xs:complexType>
    <xs:sequence>
      <xs:element name="Source">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:enumeration value="Wind Facility"/>
            <xs:enumeration value="B2B Provider"/>
            <xs:enumeration value="Wind Forecaster"/>
            <xs:enumeration value="AESO"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="Activity">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:enumeration value="Send"/>
            <xs:enumeration value="Receive"/>
            <xs:enumeration value="Process"/>
          </xs:restriction>
```

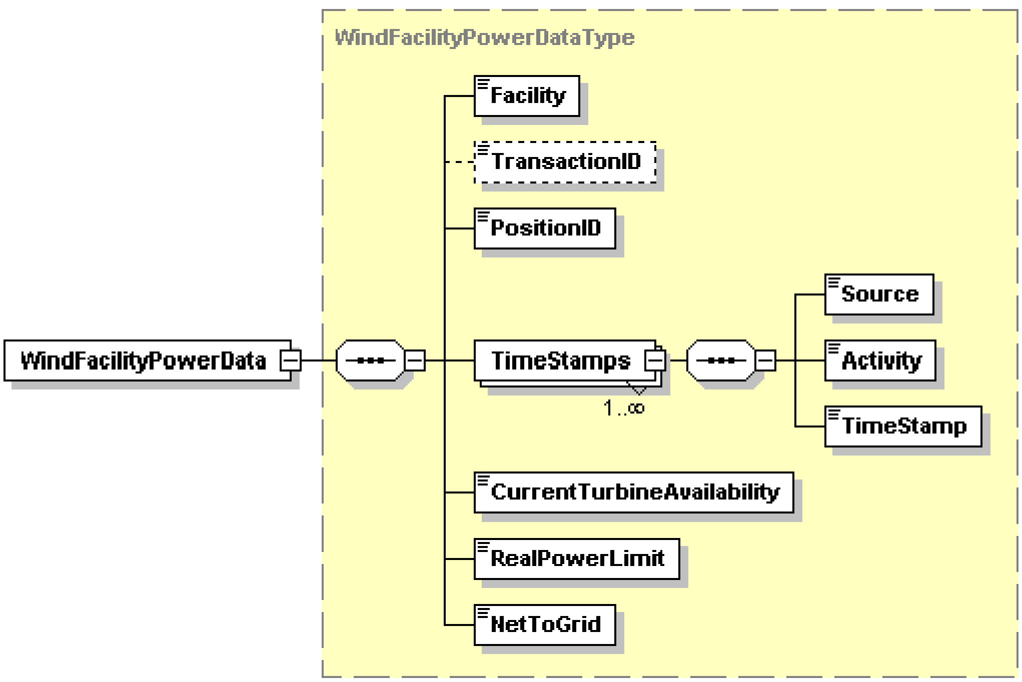
```
        </xs:simpleType>
      </xs:element>
      <xs:element name="TimeStamp" type="xs:dateTime"/>
    </xs:sequence>
  </xs:complexType>
</xs:element>
<xs:element name="MetTowerData" maxOccurs="unbounded">
  <xs:complexType>
    <xs:sequence>
      <xs:element name="MeteorologicalTowerUniqueID">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:minLength value="0"/>
            <xs:maxLength value="90"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="WindSpeed">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="0"/>
            <xs:maxInclusive value="50"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="WindDirection">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="0"/>
            <xs:maxInclusive value="360"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="SurfacePressure">
        <xs:simpleType>
          <xs:restriction base="xs:float">
```

```
        <xs:minInclusive value="800"/>
        <xs:maxInclusive value="1100"/>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
  <xs:element name="Temperature">
    <xs:simpleType>
      <xs:restriction base="xs:float">
        <xs:minInclusive value="-50"/>
        <xs:maxInclusive value="50"/>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
  <xs:element name="DewPoint" minOccurs="0">
    <xs:simpleType>
      <xs:restriction base="xs:float">
        <xs:minInclusive value="-50"/>
        <xs:maxInclusive value="50"/>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
  <xs:element name="RelativeHumidity" minOccurs="0">
    <xs:simpleType>
      <xs:restriction base="xs:float">
        <xs:minInclusive value="0"/>
        <xs:maxInclusive value="100"/>
      </xs:restriction>
    </xs:simpleType>
  </xs:element>
  <xs:element name="IceupParameter" minOccurs="0">
    <xs:simpleType>
      <xs:restriction base="xs:float">
        <xs:minInclusive value="0"/>
        <xs:maxInclusive value="1"/>
      </xs:restriction>
    </xs:simpleType>
```

```
          </xs:element>
        </xs:sequence>
      </xs:complexType>
    </xs:element>
  </xs:sequence>
</xs:complexType>
</xs:schema>
```

4.2 Power Data Schema

The following schema is used for all Power Data and each wind aggregated facility is required to translate their data into the format below.




```
<?xml version="1.0" encoding="UTF-8"?>
<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema"
xmlns="http://windforecasting.public.aeso.ca"
targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified"
attributeFormDefault="unqualified">
  <xs:element name="WindFacilityPowerData" type="WindFacilityPowerDataType"/>
  <xs:complexType name="WindFacilityPowerDataType">
    <xs:sequence>
      <xs:element name="Facility">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:maxLength value="255"/>
```

```
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="TransactionID" type="xs:string" minOccurs="0"/>
<xs:element name="PositionID">
  <xs:simpleType>
    <xs:restriction base="xs:integer">
      <xs:minInclusive value="1"/>
      <xs:maxInclusive value="6"/>
    </xs:restriction>
  </xs:simpleType>
</xs:element>
<xs:element name="TimeStamps" maxOccurs="unbounded">
  <xs:complexType>
    <xs:sequence>
      <xs:element name="Source">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:enumeration value="Wind Facility"/>
            <xs:enumeration value="B2B Provider"/>
            <xs:enumeration value="Wind Forecaster"/>
            <xs:enumeration value="AESO"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="Activity">
        <xs:simpleType>
          <xs:restriction base="xs:string">
            <xs:enumeration value="Send"/>
            <xs:enumeration value="Receive"/>
            <xs:enumeration value="Process"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="TimeStamp" type="xs:dateTime"/>
    </xs:sequence>
```

```
      </xs:complexType>
    </xs:element>
    <xs:element name="CurrentTurbineAvailability">
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          <xs:minInclusive value="0"/>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="RealPowerLimit">
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          <xs:minInclusive value="0"/>
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="NetToGrid">
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    </xs:element>
  </xs:sequence>
 </xs:complexType>
</xs:schem
```
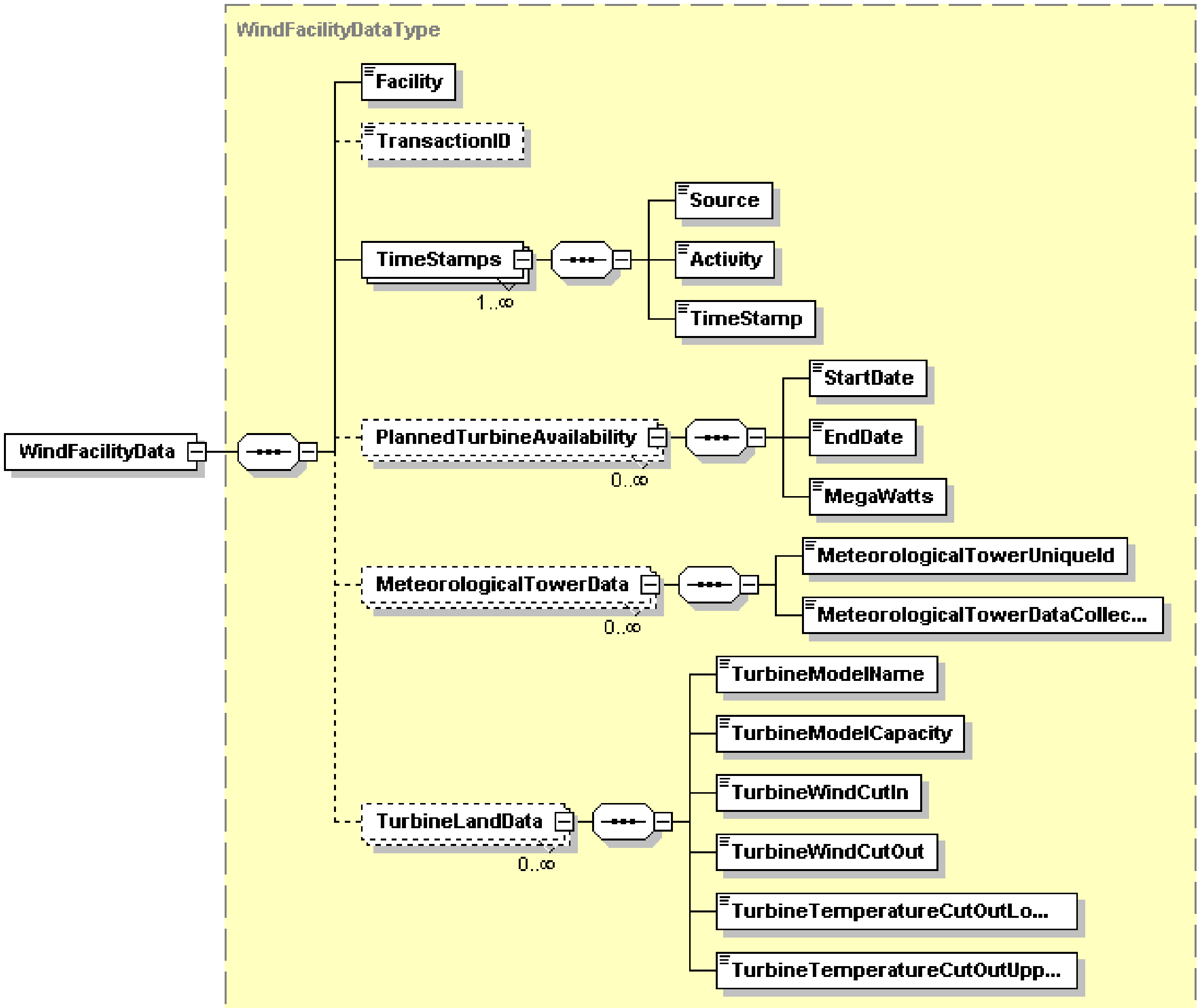

4.3 FAC Schema Data

The following schema is used for all Facility Data and each wind aggregated facility is required to translate their data into the format below.




```
<?xml version="1.0" encoding="UTF-8"?>

<xs:schema xmlns:xs="http://www.w3.org/2001/XMLSchema"
xmlns="http://windforecasting.public.aeso.ca"
targetNamespace="http://windforecasting.public.aeso.ca" elementFormDefault="qualified"
attributeFormDefault="unqualified">

 <xs:element name="WindFacilityData" type="WindFacilityDataType"/>

 <xs:complexType name="WindFacilityDataType">

  <xs:sequence>

   <xs:element name="Facility">

    <xs:simpleType>

     <xs:restriction base="xs:string">

      <xs:maxLength value="255"/>
```

```
        </xs:restriction>
      </xs:simpleType>
    </xs:element>
    <xs:element name="TransactionID" type="xs:string" minOccurs="0"/>
    <xs:element name="TimeStamps" maxOccurs="unbounded">
      <xs:complexType>
        <xs:sequence>
          <xs:element name="Source">
            <xs:simpleType>
              <xs:restriction base="xs:string">
                <xs:enumeration value="Wind Facility"/>
                <xs:enumeration value="B2B Provider"/>
                <xs:enumeration value="Wind Forecaster"/>
                <xs:enumeration value="AESO"/>
              </xs:restriction>
            </xs:simpleType>
          </xs:element>
          <xs:element name="Activity">
            <xs:simpleType>
              <xs:restriction base="xs:string">
                <xs:enumeration value="Send"/>
                <xs:enumeration value="Receive"/>
                <xs:enumeration value="Process"/>
              </xs:restriction>
            </xs:simpleType>
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      </xs:complexType>
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        <xs:sequence>
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          <xs:element name="EndDate" type="xs:dateTime"/>
          <xs:element name="MegaWatts" type="xs:float"/>
```

```
    </xs:sequence>
  </xs:complexType>
</xs:element>
<xs:element name="MeteorologicalTowerData" minOccurs="0" maxOccurs="unbounded">
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    <xs:sequence>
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          <xs:restriction base="xs:string">
            <xs:minLength value="0"/>
            <xs:maxLength value="90"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
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  </xs:complexType>
</xs:element>
<xs:element name="TurbineLandData" minOccurs="0" maxOccurs="unbounded">
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      <xs:element name="TurbineModelCapacity">
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            <xs:maxInclusive value="100000"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="TurbineWindCutIn" type="xs:float"/>
      <xs:element name="TurbineWindCutOut" type="xs:float"/>
      <xs:element name="TurbineTemperatureCutOutLower">
        <xs:simpleType>
          <xs:restriction base="xs:float">
            <xs:minInclusive value="-50"/>
```

```
            <xs:maxInclusive value="+50"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
      <xs:element name="TurbineTemperatureCutOutUpper">
        <xs:simpleType>
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            <xs:minInclusive value="-50"/>
            <xs:maxInclusive value="50"/>
          </xs:restriction>
        </xs:simpleType>
      </xs:element>
    </xs:sequence>
  </xs:complexType>
</xs:element>
</xs:sequence>
</xs:complexType>
</xs:schema>
```


5 On-Ramping Instructions

Each of the wind aggregated generating facilities operators should work with the AESO B2B Service provider to on-ramp to the AESO Wind Power Forecasting Service. The AESO B2B Service will provide mapping services to each wind aggregated generating facility and support for initial on-ramping purposes. Each Facility is responsible for providing Subject Matter Experts (SME's) to meet the requirements of this Information Document.

5.1 Test and Production Environments

During the On-Ramp Process each wind aggregated generating facility will be provided test and production environments to validate their connections to the AESO Wind Power Forecasting Service.

5.2 Historical Data

Historical Data will be used to test the translations between the Wind Aggregated Generating Facility and the AESO's B2B Service. Historical data is expected to be supplied in the same format as described in this document for 'current' data. Two (2) years of data is to be supplied for testing purposes. This will be used by the Forecaster to train their system for the generation of optimal forecasts.

At this point only MET data is expected for historical purposes, however, if PWR and FAC data is available it would be used.

5.3 Technical Support

Technical Support documentation will be provided during the on-ramping process for each wind aggregated generating facility.

6 References

- Web Services: http://www.w3.org/2002/ws/
- WSDL: http://www.w3.org/2002/ws/desc/

Information Document
Northeast Area Transmission Constraint Management
ID #2011-008R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1")

The purpose of this Information Document is to provide information regarding the unique operating characteristics and resulting constraint conditions and limits in the northeast area of the Alberta interconnected electric system. In this Information Document the AESO has defined the northeast area as the area illustrated by the maps in Appendix 2 and 3.

Section 302.1 sets out the general transmission constraint management protocol steps the AESO uses to manage constraints in real time on the interconnected electric system. These steps are referenced in Table 1 of this Information Document as they are applied to the northeast area.

2 General

The northeast area is connected to the Alberta interconnected electric system by: (i) the Fort McMurray 500kV West transmission path (12L41/12L44); (ii) three long 240 kV bulk transmission line paths consisting of multiple 240 kV line segments; and (iii) several 144 kV transmission lines.

The transfer-in and transfer-out limits for the northeast area are dependent on the status of the Fort McMurray 500 kV West transmission path (12L41/12L44) and line segments of the three 240kV bulk transmission line paths. Loss of the Fort McMurray 500 kV West transmission path (12L41/12L44) or any of the 240 kV line segments affects the volume of MW that can be transferred in and out of the Fort McMurray area due to transient instability, voltage instability or unacceptable low voltage excursions under high transfer-out conditions.

The AESO has established the Fort McMurray Transfer-In Cutplane limits and the Fort McMurray Transfer-Out Cutplane limits. The map attached as Appendix 3 of this Information Document illustrates these cutplanes.[2]

The AESO respects the Fort McMurray Cutplane limits when managing transfer-in and transfer-out flow from the northeast area.

Appendix 1 lists the effective generation units for managing regional constraints in the northeast area. Appendix 2 provides a detailed geographical map of the northeast area indicating bulk transmission lines and substations.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

[2] A cutplane is a common term used in engineering studies and is a theoretical boundary or plane crossing two (2) or more bulk transmission lines or electrical paths. The cumulative power flow across the cutplane is measured and can be utilized to determine flow limits that approximate conditions that would allow safe, reliable operation of the Alberta Interconnected Electric System.

3 Constraint Conditions and Limits

When managing a transmission constraint in the Fort McMurray area, the AESO ensures that bulk transmission line flows out of the area are managed in accordance with bulk transmission line ratings established by the legal owner of the transmission facility to protect transmission facilities and ensure the continued reliable operation of the Alberta Interconnected Electric System.

3.1 *Non-Studied Constraints and Limits*

For system conditions that have not been pre-studied, the AESO uses energy management system tools and dynamic stability tools to assess system operating limits in real time.

3.2 Studied Constraints and Limits

The AESO establishes cutplane limits to avoid transient instability or voltage violations or thermal violations in the event of certain contingencies.

Fort McMurray Transfer-Out Cutplane Limits

Fort McMurray Transfer-Out cutplane power flow is calculated at specific substations in the northeast area as the total of outflow on:

9L57 @ 888S Dover; plus

9L07 @ 888S Dover; plus

9L23 @ 848S Ruth Lake; plus

9L84 @ 934S Black Fly; plus

848S Ruth Lake transformers 901T and 902T; plus

12L44 @ 951S Thickwood

The specific contingency and the corresponding transfer-out limits are provided in Appendix 4: Table 1, Table 2, and Table 3 Fort McMurray Transfer-Out Cutplane tables.

Fort McMurray Transfer-In Cutplane Limits

The Fort McMurray Transfer-In cutplane power flow is calculated at specific substations in the northeast area and is calculated as the total of inflow on:

9L10 @ 939S Livock; plus

1117L @ 167S Ipiatik Lake; plus

9L47 @ 852S Round Hill; plus

9L930 @ 72S Leismer; plus

12L44 @ 951S Thickwood

The specific contingency and the corresponding transfer-in limits are provided in Appendix 4: Tables 4, Table 5, and Table 6 Fort McMurray Transfer-In Cutplane tables .

4 Transmission Constraint Management

The AESO manages transmission constraints in all areas of the Alberta Interconnected Electric System in accordance with the provisions of Section 302.1. However, not all of those provisions are effective in the Fort McMurray area due to certain operating conditions that exist in that area. This Information Document describes the application of the general provisions of Section 302.1 to the Fort McMurray area, and the additional clarifying steps required to effectively manage transmission constraints in that area.

The protocol steps which are effective in managing transmission constraints in the northeast area are outlined in Table 1 below, followed by additional steps which may be required.

Table 1 – Transmission Constraint Management Sequential Procedures for Northeast Area

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to manage Fort McMurray cutplane inflow?	Applicable manage Fort McMurray cutplane outflow?
(a) Determine effective pool assets	Yes	Yes
(b) Ensure maximum capability not exceeded	No	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No	No
(d) Curtail effective demand opportunity service on the downstream constraint side	No	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	No	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No[3]	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	No	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	Yes	No

[3] An exception would be if the inflow limit does not allow for non-industrial system designation firm load to be served.

Applicable Protocol Steps

The first step in managing constraints in any area is to identify those generating units effective in managing a constraint. All of the generating units and loads operating in the Fort McMurray area are indicated in the single line diagram in Appendix 3 and the generating units effective in managing a transmission constraint in the Fort McMurray area are identified in Appendix 1.

Step (a)

The Fort McMurray Transfer-In cutplane is managed by curtailing effective downstream load for inflow constraints. The Fort McMurray Transfer-Out cutplane has effective generation pool assets which are identified in Appendix 1.

Step (b)

Curtailing generation pool assets to their maximum capability is not effective for the Fort McMurray import constraints, but it is effective for Fort McMurray export outflow constraints and is used when a Fort McMurray export constraint occurs.

Step (c)

There are no interties within the northeast area and southern Alberta import and export flows on the system are not effective in managing a transmission constraint.

Step (d)

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing transmission constraints in the Fort McMurray area since there is no demand opportunity service.

Steps (e)(i) and (ii)

There are no transmission must-run contracts in the northeast area and transmission must-run is not effective in managing a transmission constraint in the northeast area.[4]

Step (f)

To address a long-term constraint, curtailing effective generating units using the reverse merit order followed by pro-rata curtailment is only effective when outflow limits are exceeded for Fort McMurray Transfer-Out Cutplane limit. A short term constraint is considered to include the hour the constraint occurred, plus the following two hours, when the reverse merit order is utilized. For long-term constraints, the pro-rata curtailment of identified effective generation pool assets occurs.

Step (g)

Curtailing load pool assets in reverse energy market merit order followed by pro-rata load curtailment of identified generation pool assets is the last step of the protocol and is used when inflow limits are exceeded for the Fort McMurray Transfer-In Cutplane or Fort McMurray Transfer-Out Cutplane. When pro-rata load curtailment is required, the AESO issues directives to effective direct connect industrial loads and to the northeast area legal owner of transmission facilities specifying the required pro-rata curtailment levels.

4 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Fort McMurray area that are known to have an impact on the information contained in this Information Document.

[4] In the unusual circumstance that the northeast area is being supported by a single path and the inflow is limited to an amount less than the non-industrial system designation firm load, the AESO may issue directives to effective generation pool assets to provide sufficient energy to meet such firm load.

5 Appendices

Appendix 1 – *Effective Pool Assets*

Appendix 2 – *Geographical Map of the Northeast Area*

Appendix 3 – *Northeast Area Cutplanes: Transfer-In and Transfer-Out Single Line Diagram*

Appendix 4 – *Cutplane Transfer Limits for the Northeast Area*

Revision History

Posting Date	Description of Changes
2019-05-14	Amended Section 3 to include the Fort McMurray Transfer-In/Transfer-Out constraints resulting from of the energization of the Fort McMurray 500kV West Transmission Line. Updated Appendix 1 list of effective assets. Updated Appendix 2 and Appendix 3 maps. Amended Appendix 4: revised Tables 1 through 3 Fort McMurray Transfer-Out Cutplane Limits and Tables 4 through 6 McMurray Transfer-In Cutplane Limits to reflect constraints from energization of the Fort McMurray 500kV West Transmission Line. Administrative amendments.
2018-02-13	Amended Appendix 4, Table 4 - N-0 Fort McMurray Export Cutplane Transfer-out Limits.
2015-08-25	With energization of Christina Lake 240 kV transmission development, maps amended to include the new Ipiatik Lake 167S substation and new line numbers 1116L and 1117L. Transfer-in (import) cutplane limits in Appendix 4 have been revised. Table 5 revised to reflect that the Livock phase shifting transformer is not applicable to table limits.
2015-08-13	Maps amended to include the new Dawes 2011S substation and new line number 9L89. Also, transfer-out (export) cutplane limits have been revised.
2014-05-29	Updated to remove Kinosis-Leismer Cutplane.
2014-05-08	Appendix 4 amended to reflect changes to the Kinosis-Leismer Cutplane Transfer-in Limits. Section 2, Section 3.2, Appendix 2 and Table 4 amended to reflect a portion of 9L990 renamed to 9L45.
2014-05-01	Maps amended to include Kettle River 2049S substation, Bohn 931S substation and the 7L05 line.
2014-02-14	Map amendments to include Engstrom 2060S substation and the 7L167 Line
2013-12-11	Updated to include map amendments, cutplane table amendments, and minor drafting edits.
2012-12-04	Updated to include cutplane name changes, updated maps and minor drafting edits.
2012-09-13	Updated to include minor drafting edits
2012-06-14	Updated to include material content from existing Section 302.5 of

	the ISO rules, Northeast Area Transmission Constraint Management
2011-06-30	Initial Release

Appendix 1 – Effective Pool Assets

1. The effective pool assets for the Fort McMurray Transfer-Out Cutplane, listed alphabetically by their pool IDs, are:

   CNR5

   IOR5

   MKR1

   MKRC

   SCL1

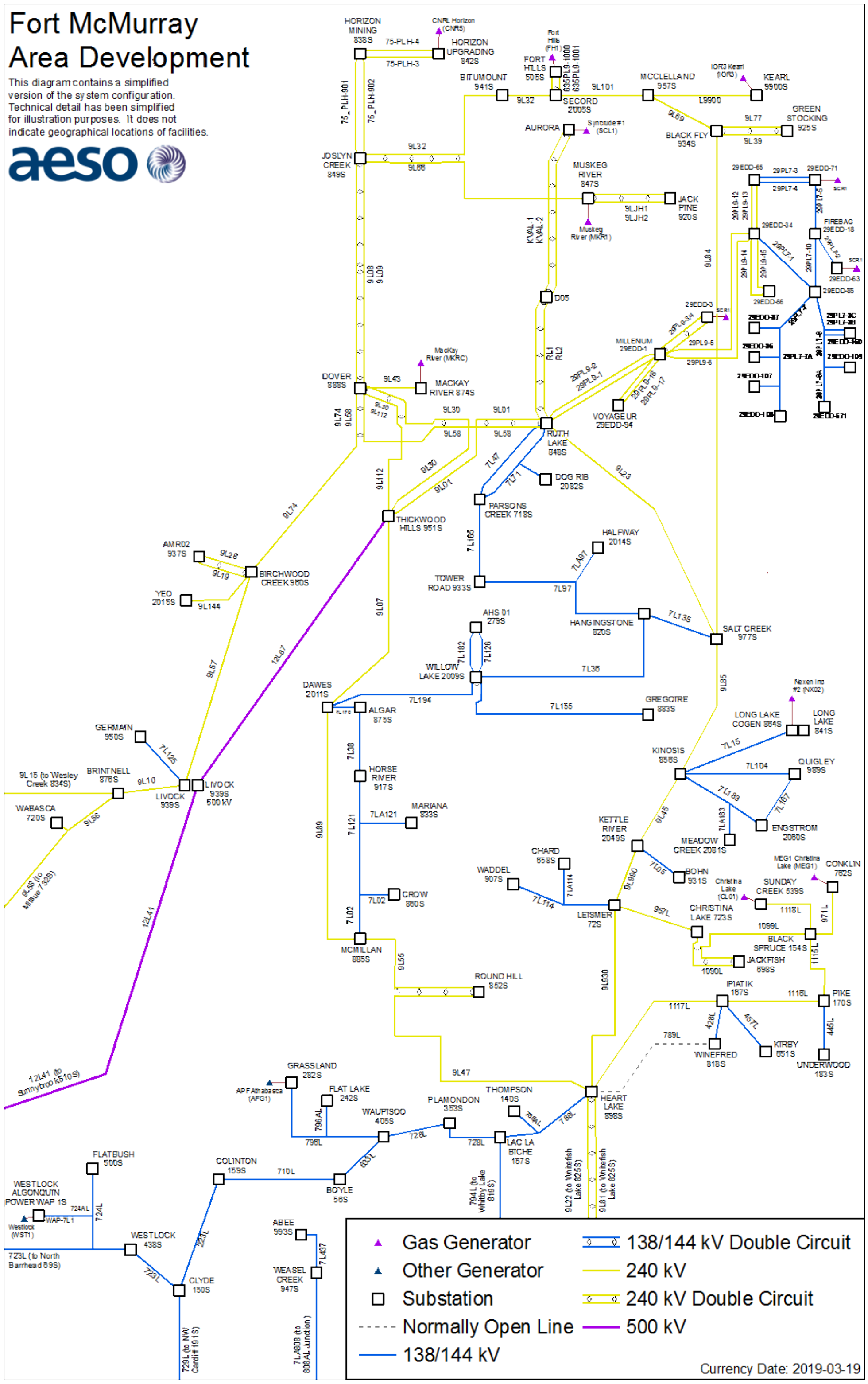
   SCR1, SCR5, SCR6

   FH1

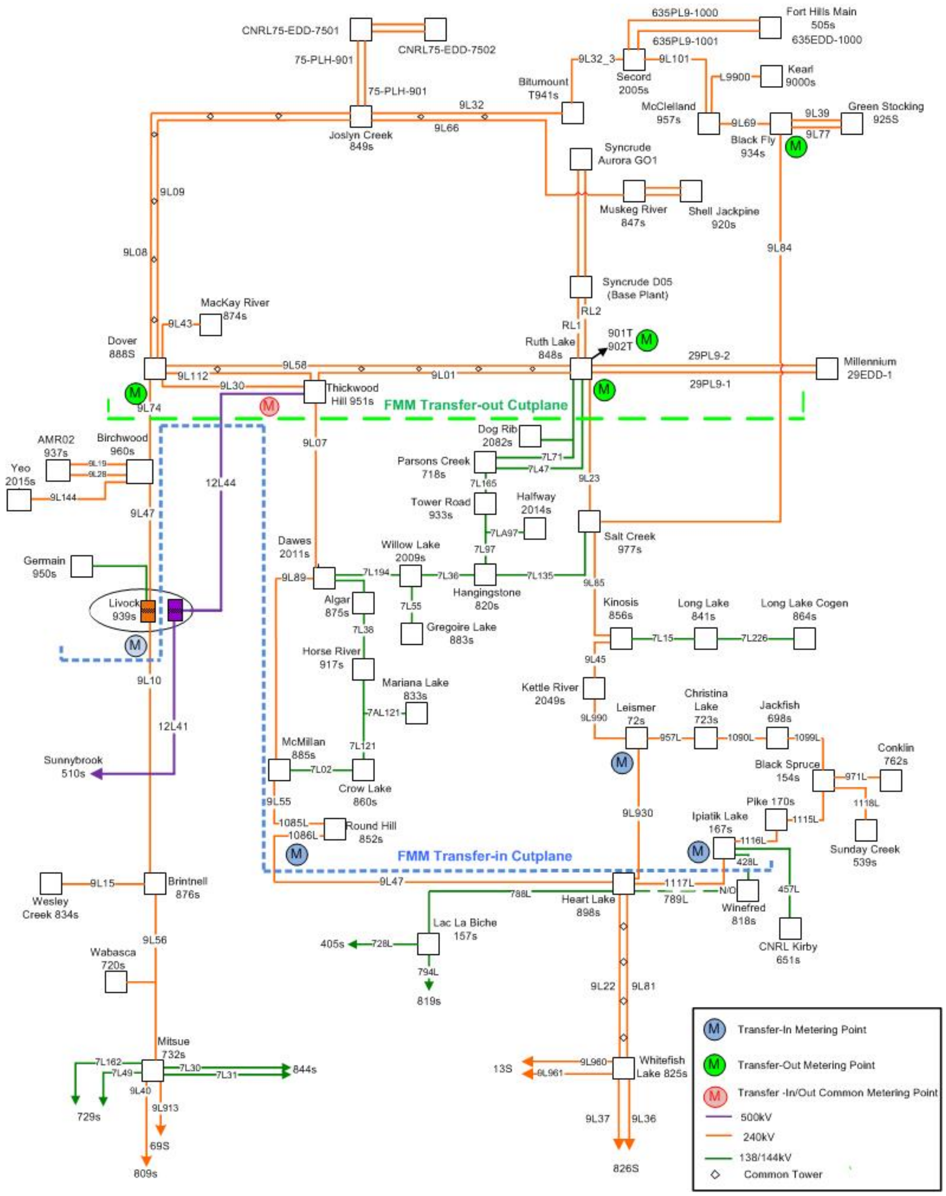
The effective pool assets for the Fort McMurray Transfer-In Cutplane are:

Load – curtailed in accordance with the transmission facility owner load curtailment plan, if applicable.

Appendix 2 – Geographical Map of the Northeast Area



Appendix 3 – Northeast Area Cutplanes: Transfer-In and Transfer-Out Single Line Diagram



Appendix 4 – Cutplane Transfer Limits for the Northeast Area

Table 1 - Fort McMurray Transfer –Out Cutplane Transient Limits

Note: Transient stability limits are not exceeded.

If Real Time tools (RTCA and RTVSA) are not available, the area is operated to the most restrictive limit for the contingency.

Outage	Element	FMM Transfer-Out Transient Limits (MW)	Next Contingency
N-0 System Normal	N/A	1410	12L41 (939s Livock to 510s Sunnybrook)
N-1	FMM West 500 kV	970	9L74
	1090L	1200	12L41 (939s Livock to 510s Sunnybrook)
	1099L		
	1115L		
	1116L		
	1117L		
	2011s Dawes 901T		
	848s Ruth Lake 901T		
	848s Ruth Lake 902T		
	885s McMillian 902T		
	957L		
	977s Salt Creek 901T		
	9L01		
	9L07		
	9L08 or 9L09		
	9L10	955	
	9L101	1200	
	9L112		
	9L15		
	9L22 or 9L81	1200	
	9L23		
	9L30		
	9L32		
	9L45	1175	
	9L47	1200	
	9L55		
	9L56		
	9L57	955	
	9L58	1200	
	9L66		
	9L69		
	9L74	925	
	9L84	1200	
	9L85		
	9L89		
	9L930		

Outage	Element	FMM Transfer-Out Transient Limits (MW)	Next Contingency
	9L990	1180	

Table 2 - Fort McMurray Transfer- Out Cutplane Voltage Limits

Note: If real-time tools allow a higher cutplane limit for the contingencies listed in the tables below, the AESO operates to the higher limit.

Outage	Element	FMM Transfer-Out Voltage Stability Limit (MW)	Next Contingency	Limiting Element
N-0 System Normal	N/A	930	Limited by FMM generation	
N-1	FMM West 500 kV	870	9L74	Area Voltage
	1090L	930	N/A	N/A
	1099L			
	1115L			
	1116L			
	1117L			
	2011s Dawes 901T			
	848s Ruth Lake 901T			
	848s Ruth Lake 902T			
	885s McMillian 902T			
	957L			
	977s Salt Creek 901T			
	9L01			
	9L07			
	9L08 or 9L09			
	9L10	810	FMM West 500 kV	Area Voltage
	9L101	930	N/A	N/A
	9L112			
	9L15			
	9L22 or 9L81			
	9L23			
	9L30			
	9L32			
	9L45			
	9L47			
	9L55			
	9L56			
	9L57	805	FMM West 500 kV	Area Voltage
	9L58	930	N/A	N/A
	9L66			
	9L69			
	9L74	770	FMM West 500 kV	Area Voltage
	9L84	930	N/A	N/A

Outage	Element	FMM Transfer-Out Voltage Stability Limit (MW)	Next Contingency	Limiting Element
	9L85			
	9L89			
	9L930			
	9L990			

Table 3 - Fort McMurray Transfer-Out Cutplane Thermal Limits

Note: If real-time tools allow a higher cutplane limit for the contingencies listed in the tables below, the AESO operates to the higher limit.

Outage	Element	Fort McMurray Transfer-Out Thermal Limit (MW)	Next Contingency
N-0 System Normal	None	930	Fort McMurray Generation limitations
N-1	FMM West 500 kV	560	9L74
	1090L	930	N/A
	1099L	930	9L85
	1115L	930	N/A
	1116L	930	
	1117L	930	
	2011s Dawes 901T	930	
	848s Ruth Lake 901T	930	
	848s Ruth Lake 902T	930	
	885s McMillian 902T	930	
	957L	930	
	977s Salt Creek 901T	930	
	9L01	705	9L23
	9L07	585	9L85
	9L08 or 9L09	930	N/A
	9L10	600	FMM West 500 kV
	9L101	410	9L23
	9L112	930	N/A
	9L15	750	FMM West 500 kV
	9L22 or 9L81	500	9L81 or 9L22
	9L23	410	9L101
	9L30	930	N/A
	9L32	730	9L23
	9L45	740	9L07
	9L47	830	FMM West 500 kV
	9L55	830	
	9L56	810	
	9L57	595	
	9L58	905	9L01
	9L66	930	N/A

Outage	Element	Fort McMurray Transfer-Out Thermal Limit (MW)	Next Contingency
	9L69	765	9L23
	9L74	560	FMM West 500 kV
	9L84	795	9L23
	9L85	585	9L07
	9L89	640	9L85
	9L930	930	N/A
	9L990	750	9L07

Table 4 - Fort McMurray Transfer-In Cutplane Transient Limits

Note: If real-time tools allow a higher cutplane limit for the contingencies listed in the tables below, the AESO operates to the higher limit.

Outage	Element	FMM Transfer-In Transient Limits (MW)	Next Contingency
N-0 System Normal	N/A	1240	12L44 939s Livock to 951S Thickwood
N-1	FMM West 500 kV	860	9L10
	1090L	1200	12L44 939s Livock to 951s Thickwood
	1099L	1190	
	1115L	1230	
	1116L		
	1117L	1220	
	2011s Dawes 901T	1240	
	848s Ruth Lake 901T		
	848s Ruth Lake 902T		
	885s McMillian 902T		
	957L	1210	
	977s Salt Creek 901T	1240	
	9L01		
	9L07	1140	
	9L08 or 9L09	1240	
	9L10	820	
	9L101	1240	
	9L112		
	9L15	1140	
	9L22 or 9L81	1180	
	9L23	1220	
	9L30	1240	
	9L32		
	9L45	920	
	9L47	1040	
	9L55	1000	
	9L56	1100	
	9L57	820	

Outage	Element	FMM Transfer-In Transient Limits (MW)	Next Contingency
	9L58	1240	
	9L66	1210	
	9L69	1240	
	9L74	860	
	9L84	1240	
	9L85	930	
	9L89	1130	
	9L930	1180	
	9L990	890	

Table 5 - Fort McMurray Transfer-In Cutplane Voltage Limits

Note: If real-time tools allow a higher cutplane limit for the contingencies listed in the tables below, the AESO operates to the higher limit.

Outage	Element	Fort McMurray Transfer-In Voltage Stability Limit (MW)	Next Contingency
N-0 System Normal	None	800	Limited by Fort Mac generation
N-1	FMM West 500 kV	580	9L10
	1090L	800	FMM West 500 kV
	1099L	770	
	1115L	800	
	1116L	800	
	1117L	770	
	2011s Dawes 901T	800	
	848s Ruth Lake 901T 848s Ruth Lake 902T	800	
	885s McMillian 902T	800	
	957L	800	
	977s Salt Creek 901T	800	
	9L01	800	
	9L07	740	
	9L08 or 9L09	800	
	9L10	580	
	9L101	740	
	9L112	800	
	9L15	760	
	9L22 or 9L81	755	
	9L23	760	
	9L30	800	
	9L32	790	9L23
	9L45	710	FMM West 500 kV
	9L47	595	

Outage	Element	Fort McMurray Transfer-In Voltage Stability Limit (MW)	Next Contingency
	9L55	625	
	9L56	635	
	9L57	580	
	9L58	800	
	9L66	800	
	9L69	800	
	9L74	575	
	9L84	800	
	9L85	720	
	9L89	700	
	9L930	780	
	9L990	670	

Table 6 - Fort McMurray Transfer-In Cutplane Thermal Limits

Note: If real-time tools allow a higher cutplane limit for the contingencies listed in the tables below, the AESO operates to the higher limit.

Outage	Element	Fort McMurray Transfer-In Thermal Limit (MW)	Next Contingency
N-0	None	920	FMM West 500 kV
N-1	FMM West 500 kV	630	9L10 or Livock PST
	1090L	920	FMM West 500 kV
	1099L		
	1115L		
	1116L		
	1117L		
	2011s Dawes 901T		
	848s Ruth Lake 901T		
	848s Ruth Lake 902T		
	885s McMillian 902T		
	957L		
	977s Salt Creek 901T	900	
	9L01	920	9L23
	9L07	770	FMM West 500 kV
	9L08 or 9L09	920	
	9L10	620	
	9L101	830	9L990
	9L112	920	FMM West 500 kV
	9L15	870	
	9L22 or 9L81	770	

Outage	Element	Fort McMurray Transfer-In Thermal Limit (MW)	Next Contingency
	9L23	920	9L990
	9L30	920	FMM West 500 kV
	9L32	810	9L23
	9L45	790	FMM West 500 kV
	9L47	760	
	9L55	770	
	9L56	830	
	9L57	620	
	9L58	910	9L01
	9L66	890	FMM West 500 kV
	9L69	920	
	9L74	650	
	9L84	920	
	9L85	640	Conklin Units
	9L89	790	FMM West 500 kV
	9L930	920	
	9L990	780	

Reviewer	Approved	Name	Date
Real Time Manager or Delegate	☒	Jason Bucholtz	March 14, 2019
Market Manager or Delegate	☐	Lane Belsher	
Regulatory Manager or Delegate	☐		

Information Document
Supply Surplus
ID #2011-010R

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1. Purpose

This Information Document relates to the following Authoritative Documents[1]:

(1) Section 202.5 of the ISO rules, *Supply Surplus*.

This Information Document provides additional information to market participants regarding the steps used to manage a state of supply surplus.

2. Supply Surplus Procedures

The interconnected electric system is considered to be in a state of supply surplus when the supply of energy available at $0 exceeds system demand. The steps used to balance the interconnected electric system while in a state of supply surplus are set out in section 202.5 of the ISO rules. Additional information on the practical implementation of those steps is provided below.

2.1. Curtailment of next hour import interchange transactions

Under subsection 2(1) of section 202.5 of the ISO rules, the AESO may curtail next hour import interchange transactions to manage a state of supply surplus. The AESO exercises this option if the forecasted pool price for the next hour is $0. The AESO's price forecasting application forecasts a dispatch level and system marginal prices for 6, 10-minute intervals in the next hour. The AESO uses the maximum forecast dispatch level in the next hour when determining the amount of import interchange transactions to curtail.

2.2. Curtailment of current hour import interchange transactions

Where the AESO determines that a state of supply surplus is imminent in the current hour or already exists, subsection 2(2)(a) of section 202.5 of the ISO rules obligates the AESO to "initiate curtailmentof import interchange transactions", as required to balance supply and system load.

2.3. Allowing export transactions within the price restatement period

Where the AESO determines that a state of supply surplus is imminent in the current hour or already exists, subsection 2(2)(b) of section 202.5 of the ISO rules obligates the AESO to "allow pool participants to submit bids to increase export interchange transactions within two (2) hours of the start of the settlement interval", as required to balance supply and system load. The AESO publishes a message through the automated dispatch and messaging system, indicating that market participants are able to schedule export interchange transactions within the price restatement period if they so

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

choose. If a market participant chooses to increase the amount of its export interchange transactions in response to this message, the market participant can do so by:

(i) restating the appropriate export bid, as outlined in section 203.3 of the ISO rules, *Energy Restatements*, indicating that the reason for the restatement is in response to the AESO's message; and

(ii) submitting the corresponding e-tag in order to enable the export transaction.

Once a sufficient response has been received, or if sufficient time for a response has elapsed, the AESO then publishes a second message through the automated dispatch and messaging system, indicating that export interchange transactions are no longer allowed within the price restatement period.

2.4. Allowing voluntary import curtailment within the price restatement period

Where the AESO determines that a state of supply surplus is imminent in the current hour or already exists, subsection 2(2)(c) of section 202.5 of the ISO rules obligates the AESO to "allow pool participants to submit offers to decrease import interchange transactions within two (2) hours of the start of a settlement interval", as required to balance supply and system load. The AESO publishes a message to market participants through the automated dispatch and messaging system, indicating that market participants are able to voluntarily decrease import interchange transactions within the price restatement period if they so choose. If a market participant chooses to decrease the amount of its import interchange transactions in response to this message, the market participant can do so by:

(i) restating the appropriate import offer, as outlined in section 203.3 of the ISO rules, *Energy Restatements*, indicating that the reason for the restatement is in response to the AESO's message; and

(ii) adjusting the corresponding e-tag to reflect the intended import transaction.

Once a sufficient response has been received, or if sufficient time for a response has elapsed, the AESO then publishes a second message through the automated dispatch and messaging system, indicating that import interchange transactions are no longer allowed within the price restatement period.

2.5. Allowing voluntary generating unit curtailment within the price restatement period

Where the AESO determines that a state of supply surplus is imminent in the current hour or already exists, subsection 2(2)(d) of section 202.5 of the ISO rules states that the AESO must "allow pool participants to submit restatements reducing generating unit and aggregated generating facility output within two (2) hours of the start of a settlement interval", as required to balance supply and system load. The AESO publishes a message to market participants through the automated dispatch and messaging system, indicating that market participants are able to voluntarily curtail their generating unit output during the price restatement period if they so choose. If a market participant chooses to voluntarily curtail its generating unit output in response to this message, the market participant restates the output volume, as outlined in subsection 203.3 of the ISO rules, *Energy Restatements,* indicating that the reason for the restatement is in response to the AESO's message. Once a sufficient response has been received, or if sufficient time for a response has elapsed, the AESO publishes a second message through the automated dispatch and messaging system indicating that voluntary generating unit curtailments are no longer allowed within the price restatement period.

3. Revision History

Posting Date	Description of Changes
2018-09-04	The addition of s. 2.4 to reflect amendments to Section 202.5 of the ISO rules.
2014-12-18	Administrative Updates
2011-11-22	Initial Release

Information Document
AESO Compliance or Complaint Contact Information
ID #2011-011R

Information documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between the Information document and the related Authoritative Document(s) in effect, the Authoritative document(s) governs. Please submit any questions or comments regarding this Information Document to InformationDocuments@AESO.ca.

Purpose

The purpose of this information document is to provide the AESO contact information for market participants seeking to communicate information to the AESO with regard to ISO rules, Section 12 – ISO Compliance Monitoring.

Related Authoritative Documents

The AESO's authoritative documents consist of ISO rules, the ISO tariff and Alberta Reliability Standards. Authoritative documents contain binding rights, requirements and obligations for market participants and the AESO. Market participants and the AESO are required to comply with provisions set out in authoritative documents.

The AESO encourages market participants to review the related authoritative documents which include:

ISO Rules, Section 12, *ISO Compliance Monitoring*.

Compliance or Complaint Communications with the AESO

The AESO contact information with respect to communicating information regarding a complaint, internal referral, external referral, referral made by the Market Surveillance Administrator, the Alberta Utilities Commission or the Crown, or any other matter related to ISO Rules Section 12 is as follows:

Electronic Address:	compliance@aeso.ca
Phone Number:	(403) 539 - 2546
Facsimile Number:	(403) 539 - 2949
Courier Address:	Alberta Electric System Operator Calgary Place Attention: Compliance 2500, 330 - 5th Ave SW Calgary, Alberta T2P 0L4.

Revision History

Effective	Description
2011-10-27	Initial Release

Information documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between the information document and the related authoritative document(s) in effect, the authoritative document(s) governs. Please submit any questions or comments regarding this information document to InformationDocuments@aeso.ca.

1 Purpose

This information document supports section 502.1 of the ISO rules, *Wind Technical Requirements* and applicable reliability standards to provide stakeholders with the criteria the AESO will use to designate a generating unit as an aggregated generating facility. This information document is of most interest to wind facility developers and legal owners.

2 Background

A new defined term “aggregated generating facilities” was proposed as part of Package 4 Amendments to ISO rule definitions, consulted on and approved in August 2010 in coordination with the proposed section 502.1 of the ISO rules, *Wind Generating Facilities Technical Requirements*. This term is currently used in existing and upcoming authoritative documents, including various reliability standards, section 502.1 of the ISO rules, *Wind Generating Facilities Technical Requirements*, and other ISO rules

The term “aggregated generating facilities” is not intended to cover all power plants. It was created for small generating units in the same proximate location. As of the effective date of this information document the term "aggregated generating facilities" is only applicable to transmission connected wind facilities. However, the AESO may need to include other technologies (e.g. small hydro, solar, battery facilities, etc.) or facility designs in the future.

3 Designation Criteria

The AESO will use the following criteria to designate generating units as an aggregated generating facility:

(a) the facility has one (1) or more points of connection with a transmission facility; and

(b) the facility consists of two (2) or more generating units; and

(c) each generating unit is less than ten (10) MVA; or

(d) a facility as otherwise identified by the AESO.

The criteria the AESO may use in making a determination under paragraph (d) above includes whether the facility uses a collector bus or reactive power resources external to the generating units to meet the reactive power requirements of the AESO.

4 Designating an aggregated generating facility

The AESO intends to incorporate into the functional specification for a project whether the facility is to be designated as an aggregated generating facility. As appropriate, where a facility is already in service or the final functional specification has been issued, the AESO will issue a notice in the stakeholder newsletter designating such facility as an aggregated generating facility.

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5 Rescinding the aggregated generating facility designation

If the legal owner of an aggregated generating facility alters its facility in such a manner that it is no longer consistent with the above criteria, the AESO will rescind the facility's designation as an aggregated generating facility.

Revision History

2012-02-14	Initial Release

Information documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between the information document and the related authoritative document(s) in effect, the authoritative document(s) governs. Please submit any questions or comments regarding this information document to InformationDocuments@aeso.ca.

1 Purpose

This information document supports requirement R2 of reliability standard COM-001-AB-1.1. The purpose of this information document is to provide stakeholders with clarification on the use of "where applicable" as it applies to the requirement for diversely routed and redundant voice and message telecommunication facilities within the text of requirement R2 in reliability standard COM-001-AB-1.1. This information document is likely of most interest to the operator of a transmission facility.

2 Wording Clarification

Table 1 in subsection 7 of section 502.4 of the ISO rules, *Automated Dispatch and Messaging System and Voice Communication System Requirements* identifies specific requirements for diversely routed and redundant voice and message telecommunication facilities as identified in requirement R2 in reliability standard COM-001-AB-1.1.

Revision History

Effective Date	Description of Changes
2012-03-07	Initial release
2013-10-01	Updated the authoritative document reference and combined the "Background" section with the "Purpose" section.

1 Purpose

This information document supports section 304.2 of the ISO rules, *Electric Motor Start Requirements*,. The purpose of this information document is to provide additional information for the application of section 304.2. This information document is likely of most interest to operators in the Empress area, parties affected by both the Edson Gas Storage industrial complex and Shell Limestone industrial complex electric motor starts, and the operators of the transmission facilities that include the Bickerdike, Benbow and Marlboro substations.

2 Related Authoritative Documents

The AESO's authoritative documents consist of the ISO rules, the ISO tariff and the reliability standards. Authoritative documents contain binding rights, requirements and obligations for market participants and the AESO. Market participants and the AESO are required to comply with provisions set out in authoritative documents.

Market participants are encouraged to review the authoritative document related to this information document including:

Section 304.2 of the ISO rules, *Motor Start Approval Requirements*.

3 Approach to Rule Language

In creating section 304.2, the AESO has considered three (3) separate areas of the interconnected electrical system in which certain electric motor starts require special permission or consideration. There exist some provisions and conditions which are common to all these areas and are unlikely to change in the near future. Additionally, each area may have specific requirements to allow electric motor starts, based on operational studies. The AESO may modify these conditions as changes are made to the interconnected electric system and new operational studies are performed.

The AESO has determined that given the features of these requirements, the most appropriate format for section 304.2 is for the common provisions to exist in a general section of the ISO rule that governs electric motor starts in all these areas. Area-specific requirements are contained in Appendix 1 of section 304.2 to allow for possible changes as operational studies are performed that may change these requirements in a specific area.

4 Area-Specific Background Information

4.1 Electric Motor Start Requirements in the Empress Area

Multiple electric motors twenty five thousand horse power (25 000 hp) or larger, exist in the Empress area. With the exception of the Sand Hills electric motor, electric motor starts in the Empress area are not considered to be an issue when transmission system serving the area is operating with all elements in service and both Sheerness Plant generating units are on-line. However, simultaneous starts of large electric motors could result in low voltage in the Empress area. To avoid two (2) or more large electric

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motors starting at once, the AESO must coordinate the starting of all electric motors twenty five thousand horsepower (25 000 hp) or larger as outlined in section 302.4. The intent is to delay electric motor starts only for the time required to avoid simultaneous starts.

4.2 Electric Motor Start Requirements for Shell Limestone

The Shell Limestone eighteen thousand horsepower (18 000 hp) synchronous electric motor is vital to the operation of the Shell Canada Limited (“Shell”) gas field and is normally in operation. The electric motor is normally started with a variable frequency drive. However, Shell has requested that under emergency conditions, when the electric motor is offline and the variable frequency drive is unavailable, the electric motor be permitted to start by direct connection to the AltaLink transmission system (across-the-line start).

The other loads in the Shell Limestone industrial complex area (see Appendix 4) comprise twenty five (25) kV loads that are fed from the same one hundred and thirty eight (138) kV 304S Shell Limestone substation, and some other low voltage industrial complex loads that are fed from the one hundred and thirty eight (138) kV Shell Limestone system. If the main eighteen thousand horsepower (18 000 hp) compressor is shut down, most of the twenty five (25) kV loads will also be shut off, and Shell is confident that the low voltage power plant loads which remain will not be significantly affected by the reduced voltages expected.

The across-the-line start tests performed by Shell of the eighteen thousand horsepower (18 000 hp) electric motor produced no negative effects on neighbouring loads (See Appendix 2) despite exceeding the AESO voltage flicker limits. Shell, Fortis Alberta and the AESO had agreed to the tests.

4.3 Electric Motor Start Requirements for Marlboro

348S Marlboro substation supplies the TransCanada load, and is fed by a T-tap connection on bulk transmission line 854L between 39S Bickerdike substation and 397S Benbow substation; see Appendix 4. TransCanada has installed five (5) five thousand horsepower (5 000 hp) electric motor-driven compressors with a total expected load of twenty four (24) MW at the Edson Gas Storage industrial complex, with the provision to add additional electric motors in the future. TransCanada has installed an autotransformer on each electric motor, initially in the sixty five percent (65%) tap position to reduce the voltage flicker when 348S Marlboro substation is fed only from 397S Benbow substation. During normal electrical supply conditions, the flicker level is expected to be about zero point eight six percent (0.86%). The maximum number of electric motor starts within an hour would range from three (3) to five (5), while the gas storage operation changes from injection to withdrawal electric mode.

5 Appendices

Appendix 1: Empress Area Market Participants Receiving Service Under Rate DTS

Appendix 2: Shell Limestone Affected Market Participants

Appendix 3: Empress Area Schematic

Appendix 4: Caroline/ Limestone Area Schematic

Appendix 5: Hinton/Edson Area Schematic

Revision History

Version	Effective Date	Description of Changes
1.0		Initial version

Appendix 1: Empress Area Market Participants receiving Rate DTS

The following is a list of market participants receiving service under Rate DTS of the ISO tariff in the Empress area:

Substation (point of delivery)	DTS Customer	Operational Contact Personnel
275S Jenner	FortisAlberta	AltaLink South Transmission (speed dial)
164S Empress Liquid		
204S Sandy Point		
163S Amoco Empress/ 341S Sand Hills		
394S Empress		
394S Empress	Provident Energy	Provident Energy Control
163S Amoco Empress	Foothills Pipeline	BP Empress Control
230S Wardlow	Kinder Morgan Canada	Express Pipeline Control Centre
914S Bindloss	ATCO Electric	ATCO Electric System Control Centre

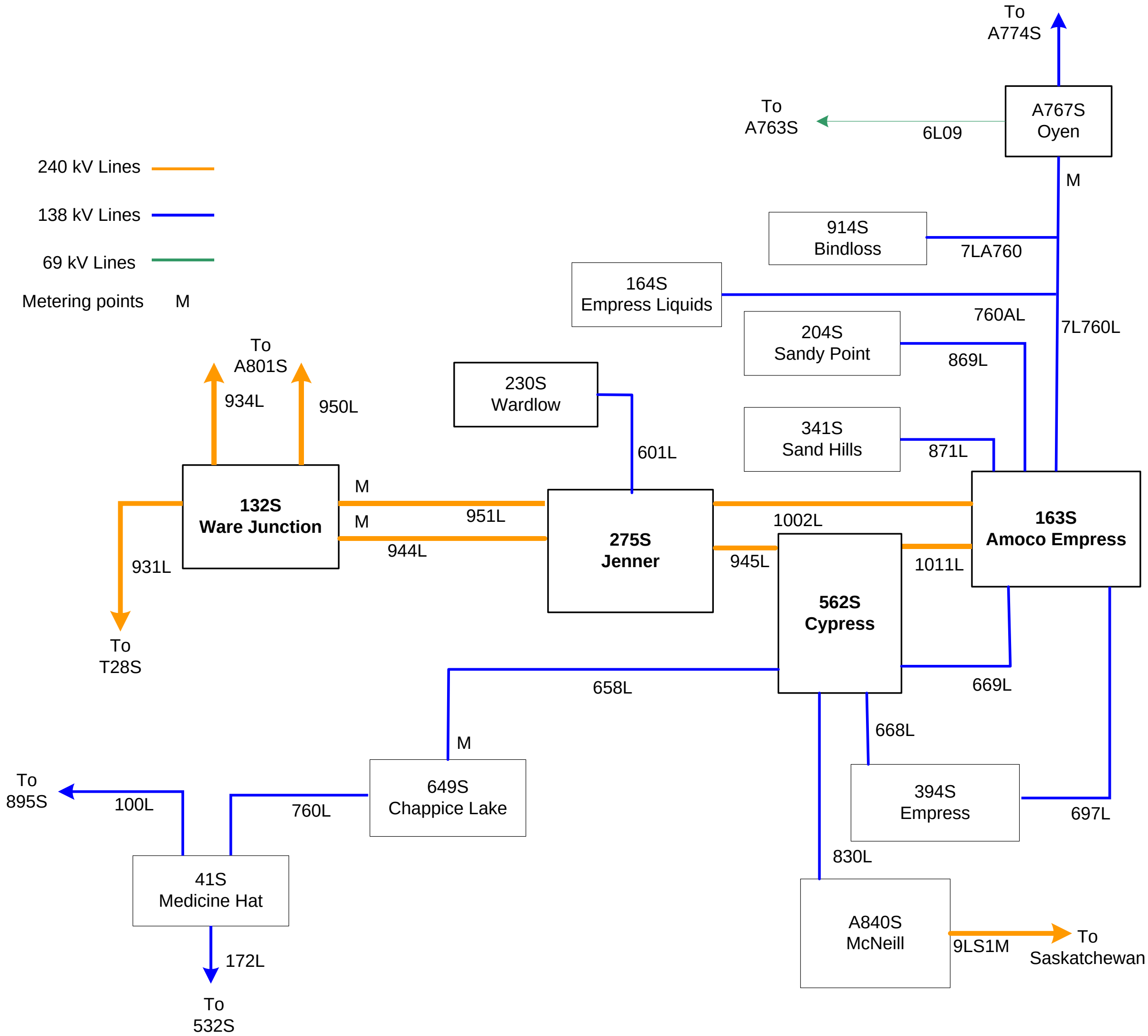
Appendix 2: Shell Limestone Affected Market Participants

The following is a list of **market participants** served from the 581S Amoco Ricinus substation that may experience voltage excursions during starts of the eighteen thousand horsepower (18 000 hp) electric motor located at the Shell Limestone industrial complex:

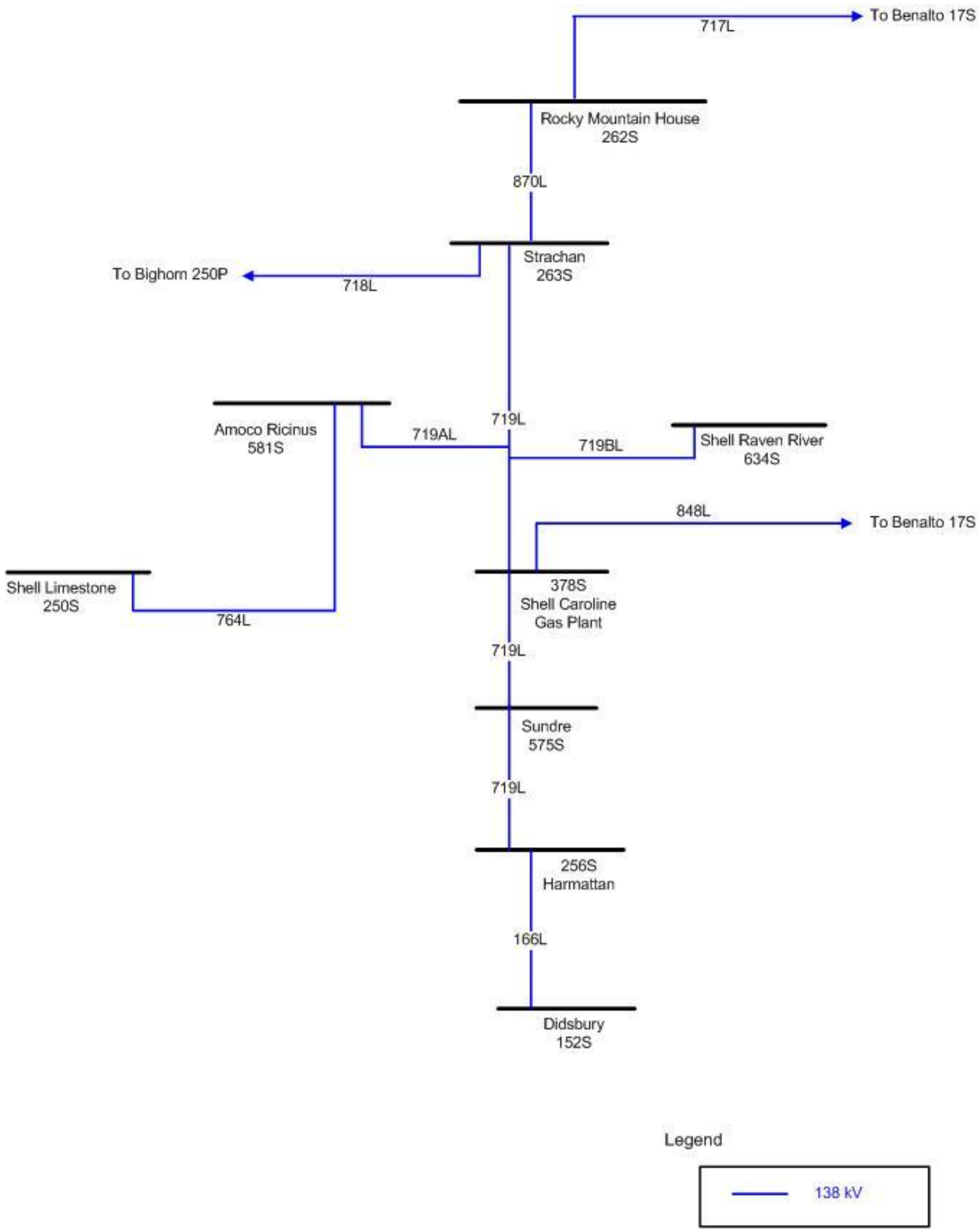
(a) BP Ricinus Gas Plant; and

(b) Mountain Air Lodge.

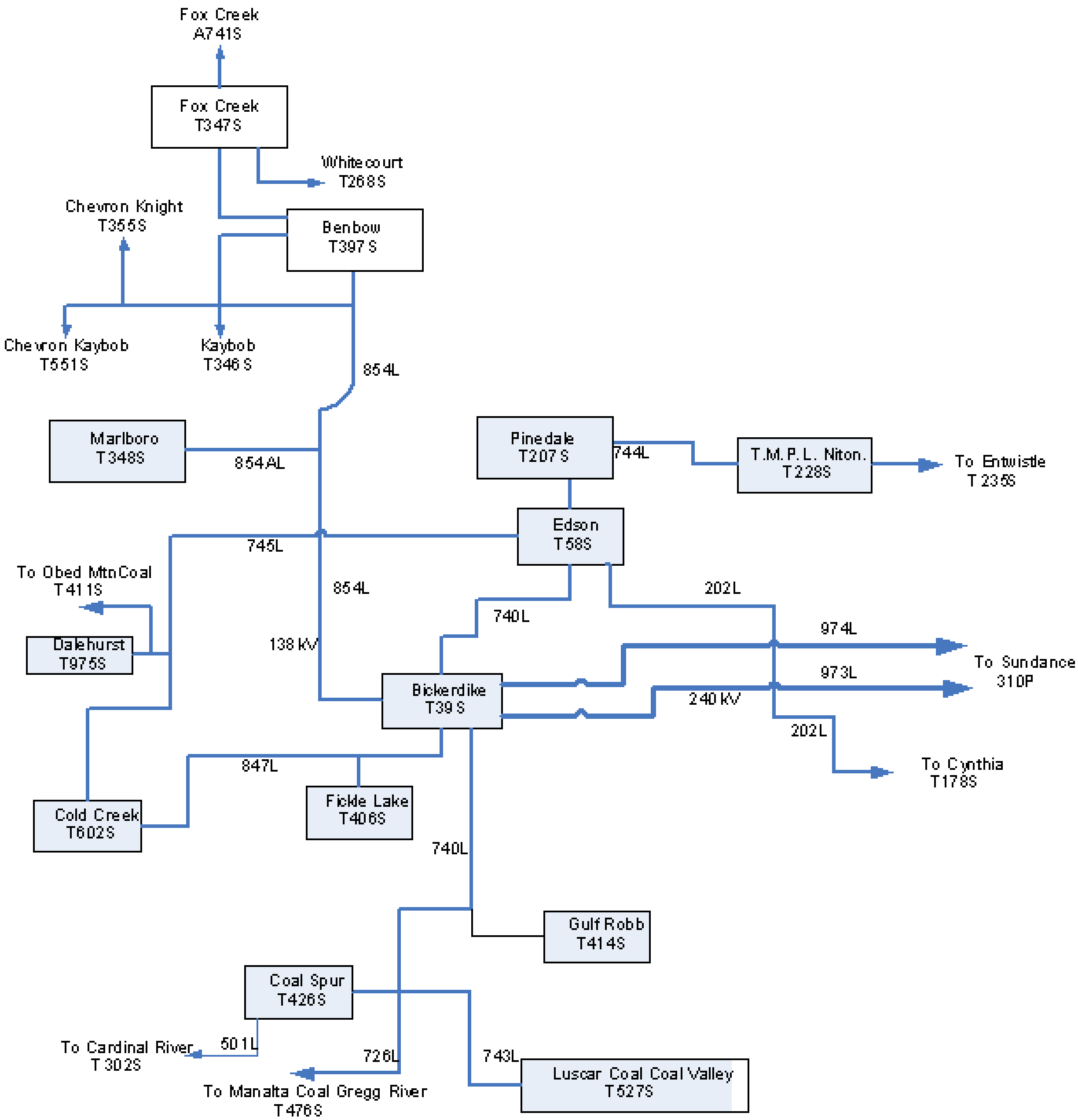
Appendix 3: Empress Area Schematic



Appendix 4: Caroline/Limestone Area Schematic



Appendix 5: Hinton/Edson Area Schematic



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1 Purpose

This information document supports section 9.1 of the ISO rules, *Transmission Facility Projects*. The purpose of this information document is to provide additional clarity on the AESO's interpretation of the following:

a) the definition of a transmission Project;

b) the AESO's compliance monitoring audit rights of such Projects;

c) specific examples of Project Materials; and

d) project reporting requirements.

2 Transmission Project

The term "Project" is defined within the *Consolidated Authoritative Document Glossary* and, in part, "means the project generally described as any one of the following: (i) the means or manner by which a constraint or condition affecting the operation or performance transmission system could be alleviated as identified in a NID approved by the EUB pursuant to s.34(3) of the Act…".

As such, notwithstanding the fact that a given Project, which is the subject of a needs identification document the Commission approves, may be divided into multiple phases for which there are multiple facilities applications, the AESO's position is that all such phases remain part of one, large Project which is the subject of the needs identification document. In other words, the AESO sees a Project as completed when all of the phases within that particular Project are complete.

3 Compliance Monitoring Audit Right of the AESO

Subsection 9.1.5.8 of the ISO rules, *Compliance Review Right of ISO* ("Section 9.1.5.8") gives the AESO the authority to examine the books and records of a legal owner of a transmission facility provided the AESO makes the request to perform a Compliance Monitoring Audit of a given Project within one (1) year from the date a legal owner has provided the Final Cost Report for such Project.

Given the likely interdependencies on the phases of a particular transmission Project, it is the AESO's position that it is unreasonable to restrict the AESO from exercising its compliance monitoring rights on a facilities application or Project phase basis. This is consistent with the AESO's position that a Project is not considered to be complete until all the phases for such Project are completed in their entirety. As such, provided one (1) year has not yet elapsed since the submission of the last Final Cost Report relevant to the entire Project, the AESO may request a Compliance Monitoring Audit for any phase of such Project, regardless of when the Final Cost Reports were submitted in respect of any of the phases.

Furthermore, the AESO's position is that the intent of Section 9.1.5.8 is to permit the AESO the right to request, but not necessarily complete, a Compliance Monitoring Audit within one (1) year from the date the legal owner has delivered the last Final Cost Report in respect of the overall Project. The AESO will, however, make best efforts to commence work on this Compliance Monitoring Audit shortly after making such a request.

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4 Definition of Project Materials

Project Materials, as defined in the *Consolidated Authoritative Document Glossary*, “means with respect to a Project, all equipment, material and construction, installation, testing and commissioning services required for the construction of the project and provided by a third party, but excluding any engineering services”.

For greater clarity, the AESO’s position with respect to whether specific types of services may or may not be included in Project Materials, is as follows:

1. Construction management services performed by a third party qualify as Project Materials and therefore, are subject to the competitive bidding requirements of subsection 9.1.5 of the ISO rules, *Project Procurement* (“Section 9.1.5”).

2. Surveying services are not considered Project Materials. These are deemed part of engineering costs because surveying is required in order to perform the line design. A legal owner of a transmission facility is therefore not required to competitively procure surveying services, in accordance with the requirements of Section 9.1.5. However, the legal owner is not prohibited from doing so if it deems it to be appropriate.

5 Project Reporting Requirements

Subsection 9.1.3 of the ISO rules, *Project Reporting by Designated TFOs* (“Section 9.1.3”), describes reporting obligations of legal owners of transmission facilities while carrying out transmission Projects, including the submission of Final Cost Reports, Project Progress Reports and Project Change Proposals. The AESO provides templates and guidelines as to the expected content of each of these types of reports on the AESO website. The definitions in the ISO *Consolidated Authoritative Document Glossary* associated with each of these report types stipulate that they be completed substantially in the form of the templates on the AESO website.

The AESO’s position is that Section 9.1.3 obligates market participants to:

1. submit the reports referred to above in accordance with the timelines specified in the ISO rules; and

2. ensure that the reports submitted in 1 above, are complete, accurate and in accordance with the guidelines and templates posted on the AESO website.

Revision History

Effective Date	Description of Changes
2012-05-16	Initial Release

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1 Purpose

This Information Document provides general information supporting section 502.3 of the ISO rules, *Interconnected Electric* System *Protection Requirements*. Sections 5 to 10 in this Information Document provide additional information that stakeholders may find useful. Each section 5 to 10 indicates the corresponding ISO rules subsection.

2 Related Authoritative Documents

The AESO's authoritative documents consist of ISO rules, the ISO tariff and the Alberta reliability standards. Authoritative documents contain binding rights, requirements and obligations for market participants and the AESO. Market participants and the AESO are required to comply with provisions set out in its authoritative documents.

Market participants are encouraged to review the following related authoritative documents:

(1) Section 502.3 of the ISO rules, *Interconnected Electric* System *Protection Requirements*. Section 502.3 sets out the minimum technical protection requirements when designing and constructing facilities.

3 Background

In Alberta, transmission facilities and generating facilities can be designed and constructed by a number of entities, including the legal owner of a transmission facility, the legal owner of an industrial complex and others such as wind farm developers and those developing merchant lines for power import and/or export.

To ensure a consistent approach to the design, engineering and construction of protection systems within Alberta, the AESO has developed section 502.3, which addresses the minimum technical requirements in the areas of protection systems while considering reliability, safety and economics.

4 Definitions

In section 502.3 there are a number of references to the defined term "protection system". For clarity, the definition of protection system does not include:

(a) non-electrical protection, such as gas pressure relays, temperature relays, etc.; or

(b) the main contacts of the circuit breakers or other interrupting devices; and

regarding the attributes of the breaker trip coils, does not include:

(c) the availability and readiness of the trip coils is part of the protection system (i.e. the trip coil is not burnt out);

(d) the activation of the trip coils is part of the protection system (i.e. the trip coil is energized correctly when required); or

(e) the energization of the trip coils operating the breaker is NOT part of the protection system (i.e. the circuit breaker main contact open correctly when required).

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5 Applicability to New and Existing Facilities Connected to the Interconnected Electric System (Subsection 1)

Section 502.3, in general, does not apply to existing protection systems presently connected to the interconnected electric system. However, as noted in subsection 3(2) of section 502.3, the AESO reserves the right, on a case-by-case basis, to require retrofitting existing, non-compliant transmission facilities or generation facilities in accordance with the provisions of section 502.3 for those facilities the AESO deems critical to the interconnected electric system.

Existing protection systems, including maintenance replacements, meeting the original designs do not normally need to be modified to comply with section 502.3, except as might be required for safety reasons by the authority having jurisdiction.

In general, section 502.3, applies to the design, engineering and construction on or after the effective date of section 502.3. For maintenance of existing protection systems, the authoritative document in effect at the time of the original design (or a subsequent edition with which the installation has been brought into compliance) applies.

For those legal owners of a transmission facility that own both facilities greater than one hundred (100) kV and facilities less than one hundred (100) kV, these requirements only apply to the facilities with a rated voltage equal to or greater than one hundred (100) kV. The AESO will address facilities with a rated voltage less than one hundred (100) kV directly in a project's functional specification.

6 Functional Specifications (Subsection 4)

From time to time, it may be necessary to design facilities that deviate from section 502.3. In these cases, the AESO will document the deviations in the approved functional specification for the project.

7 Protection System General Requirements (Subsection 6)

All protection systems must remain coordinated for any single power system element out of service.

7.1 Requirement for Two (2) Protection Systems (Subsection 7)

Each protection system is to be independent such that no single element failure will prevent both protection systems from working. Typically, the "A" protection system trips the "A" breaker coil, and the "B" protection system trips the "B" breaker coil. Cross triggering (the "A" protection system tripping both the "A" and "B" breaker coils) or other arrangements are acceptable provided no single element failure will prevent both protection systems from working.

Given the importance of the protection systems, it is generally expected that modern protection relays will be used which have a life expectancy of twenty (20) years or more.

7.2 Protection Relay Operate Times (Subsection 8)

To ensure appropriate protection relays are specified, maximum operate times are provided in subsection 8. These operate times may be determined by manufacture specifications or test results. Total clearing times which include the protection relay operate times, communication time, and breaker operate time will either be addressed in future requirements or in the projects functional specification.

7.3 Voltage Transformers

To ensure that protection systems have accurate voltage inputs and are not isolated for the protected element by an open breaker, potential transformers are required on each segment of bus.

If a bus tie breaker is installed on a substation bus, then three-phase voltage transformers are to be installed on each section of the bus that can be isolated by this breaker. This will only apply if the sectionalizing device (i.e. breaker) can be controlled or is automatically opened through protection operation and will not apply if the sectionalizing device is a manually operated switch.

This will apply to all bus configurations including simple bus, breaker and a half, breaker and a third, and ring bus arrangements.

7.4 Current Transformers (Subsection 12)

Per subsection 7(2) of section 502.3, each protection systems must be independent and may not share the same current core or voltage transformer winding. However, other devices used for other purposes such as metering, digital fault recorders, SCADA, power quality, or other unrelated protection systems may share a current core with the protection system where necessary, provided appropriate analysis has been undertaken.

Typically, current transformer ratios are selected to accommodate the present and anticipated ten (10) year fault level as identified in the project functional specification such that the current transformer ratios do not have to be changed for the first ten (10) years. The maximum available current transformer ratio is selected based on the ultimate fault level.

For each protection system application, saturation should be reviewed and account for both alternating current and direct current components in the primary current. The pre-magnetization of the current transformer core should also be consideration along with the X/R ratio. In IEEE C37.110-2007, recommendations are given in section 4.5.3 to determine the effects if no detailed calculation formula are provided by the relay manufacturer.

7.5 Protection System Power Supply (Subsection 13)

Regarding the redundancy of direct current battery systems, it is considered redundant if right at the batteries, a main “A” fuse is used to feed all “A” protection systems and a main “B” fuse is used to feed all “B” protection systems. This topic will be reviewed in further detail as part of the development of the ISO rules related to substations.

7.6 Event Capture (Subsection 14)

For new protection systems, event capture is required. For retrofits into existing facilities, consideration should be given to connecting adjacent protection systems but it is not mandatory. To meet the 1.0ms requirement GPS clocks are typically utilized.

Generally, it is recommended that a sampling rate of at least sixteen (16) samples per cycle and COMTRATE format should be used per IEEE C37.111-1999.

8 Bulk Transmission Line

8.1 Ground Fault Resistance Coverage (Subsection 15)

Ground fault impedance has been changed from “20 ohms” in the December 1, 2004 version of the *Alberta Interconnected Electric System Protection Standard* to “a minimum of five (5) ohms” in subsection 15 of section 502.3.

The reasoning for this change is as follows:

(a) Past practices on the interconnected electric system for line-to-ground fault protection using Mho characteristic impedance protection has been to provide a minimum of five (5) ohms coverage as follows:

  (i) for a ten (10) ohm line with a Mho characteristic impedance protection, the maximum fault resistance coverage is five (5) ohms without any infeed consideration; and

  (ii) legal owners of transmission facilities have not had issues with fault resistance coverage with this approach.

(b) For the last few years, some line protection settings have been applied with twenty (20) ohms fault resistance coverage. However, there is no clear indication that this approach increases the operational reliability of the line protections, but it did increase the efforts and resources to a large degree in developing the relay settings.

(c) A review of industry technical papers provided the following:

  (i) Page 127 of *Protective Relaying for Power Systems* (IEEE Press) states “Even with a 100-ohm tower-footing resistance and low-conductivity ground wires, the L-G fault impedance is only 3 ohms".

(ii) Page 10-61 of *Applied Protective Relaying* (Westinghouse) states "While the ground wires have reduced the tower footing effect from 10 ohms to 2.8 ohms….". This implies the fault resistance is about 2.8 ohms with ground wires installed.

(iii) Page 249 of *Protective Relaying Theory & Applications* (ABB) states "While the ground wires have reduced the tower footing effect from 10 ohms to 2.8 ohms….". This implies the fault resistance is about 2.8 ohms with ground wires installed.

(d) In the opinion of the Protection Rules Working Group, the increase in efforts, resources and cost does not result in any measureable enhancement in the reliability of line protections.

Given the above points, the Protection Rules Working Group decided to change the ground fault resistance coverage requirement from "20 ohms" to "a minimum of five (5) ohms".

For further clarity, the required protection relay operate times identified in subsection 7 are not intended to be applied in conjunction with the five (5) ohm impedance. Slower clearing times for ground faults are acceptable as they do not cause stability issues.

8.2 Auto Reclosing – 240kV and higher (Subsection 16)

IEEE C37.104 provides guidance regarding minimum line dead times. In Alberta, zero point seven five (0.75) seconds has typically been applied for single pole trip and reclose times. For evolving faults that start as single pole and evolve to multi-phase, all phases are to be tripped and no reclosing is permitted.

As one attempt to reclose is permitted, and single pole trip and reclose is done unconditionally from both ends (and possibly with multiple breakers at each end), reclosing may involve multiple breakers closing. This multi breaker closing is an acceptable practice.

8.3 Line Distance or Impedance Protection (Subsection 20)

At a minimum, two (2) zones of protection are required.

8.4 Line Differential Protection Systems (Subsection 21(2))

Upon failure of communications, the line differential element is typically blocked and a distance or overcurrent element can be utilized to provide backup protection.

8.5 Stub Protection (Subsection 22)

For breaker and a half bus configuration, a stub will occur when a transmission line's motorized air break is open leaving a section of bus and very short piece of line. This section must be protected utilizing high speed overcurrent protection.

8.6 Protection System Communications (Subsection 23)

The existing AESO Protection Standard calls for an availability of 99.99% which can be achieved with overhead power ground wire or digital microwave. A communication system with a lower availability may be considered if it designed in "fail safe" manner such that the protected facility is removed from service upon failure of the communication system.

8.7 Positive, Negative, Zero and Mutual Impedances (Subsection 27)

Based on recent experience by Alberta legal owners of transmission facilities, it has been identified that actual impedance values (positive, negative, zero, sequence and mutuals) can differ significantly from calculated values.

For five hundred (500) kV alternating current bulk transmission lines, the AESO recommends that actual measurements be taken to confirm calculated values for positive, negative, zero, sequence and mutual impedances. As measuring mutual impedances requires line outages, if the values differ, it is up to the legal owner of the transmission facility to determine which measurements are more appropriate to use for protection setting purposes.

8.8 Protection System Setting Verification (Subsection 28)

In addition to the real time digital simulator (RTDS) testing, legal owners may wish to consider the use of electromagnetic transients program (EMTP) simulation to verify settings. Further details may be found in the following paper:

[Morched, A.S.] Morched, A.S., Ottenvangers, J.H., Marti, L., "Multi-port Frequency Dependent Network Equivalents for the EMTP" IEEE Transactions on Power Delivery, Vol.8, No.3, July 1993

9 Substations

9.1 Transformers (Subsection 29)

Alarm levels for thermal alarms must be set such that action may be taken to unload the transformer. An overload trip level is also acceptable but must be set at least at the level of the second alarm.

9.2 138kV and 144kV Substation Bus Protection (Subsection 31(2))

Subsection 31(2) is intended to allow studies to be undertaken to determine if remote protection systems provide adequate coverage such that redundant bus protections is not required. If studies indicate remote clearing occurs within 0.6 seconds then this subsection may be utilized. It is anticipated that this may allow for lower cost solutions for simple in / out substations in remote areas.

9.3 Substation Shunt Capacitor Banks (Subsection 33)

Ungrounded capacitor banks are allowed at one hundred and thirty eight/one hundred and forty four (138/144) kV provided sufficient switching capacity of the circuit breaker and insulation of the capacitor banks are taken into account.

For substations where parallel capacitors banks are installed, consideration should be given to:

(a) the over-current protection to be immune from sympathetic tripping during switching of the second capacitor banks;

(b) over-voltage protection to protect capacitor banks against continuous over-voltage condition; and

(c) under-voltage protection to ensure the capacitor is discharged prior to re-energization.

9.4 Breaker Fail Protection (Subsection 35)

For breaker fail protection there is no need for redundancy if a standalone relay is used (independent of the primary protection relays). However, if the breaker fail function is incorporated into the primary protection, then it must be redundant such that if one protection system is taken out for maintenance, there is still one protection system and breaker fail functionality in service.

Consideration should be given to the use of breaker status contacts (52b contact) as an input to the breaker failure protection to supplement the current supervised element with respect to low level fault conditions. Low level faults will not cause stability issues so the breaker fail times have been specified for solid single line to ground or three phase faults.

For new one hundred and forty four (144) kV or lower voltage substations, remote protections will easily cover faults at least to the high side of the transformer, but will not see faults located at the secondary bus. If there is no transformer breaker, this creates a risk of a fault not being cleared.

If communications are planned for other purposes, then the additional requirement to send a breaker fail signal to the remote breakers can be accommodated at minimal cost.

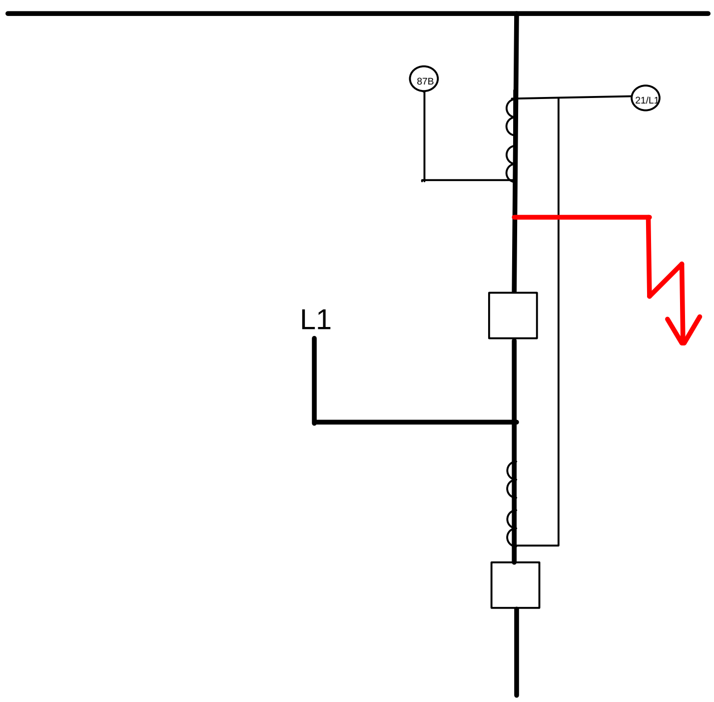
If no communications are planned for other purposes, then communications can be added that are only required to meet a ninety nine point five (99.5%) percent availability. The use of a “fail safe” communication system (i.e. upon communications failure the facility is automatically disconnected) with a lower availability may also be proposed to the AESO for consideration.

Further, as a fault on the high side of the transformer with a breaker failure will most likely be cleared by remote zone 2 elements, stability issues or thermal overloads are not a concern. For secondary transformer faults, remote zone 2 or zone 3 elements will not see the fault. However, the fault magnitude will be low due to the transformers impedance. Given the low fault level, it is unlikely that this will cause issues on the high voltage system. Therefore, provided the legal owner of the facility can demonstrate that they have a means of clearing the remote ends without damaging any equipment beyond the faulted transformer, an extended clearing time is acceptable.

If the above cannot be met and the substation location is such that any communications are prohibitively costly, consideration should be given to adding a transformer high side fault interrupting device and eliminating this issue.

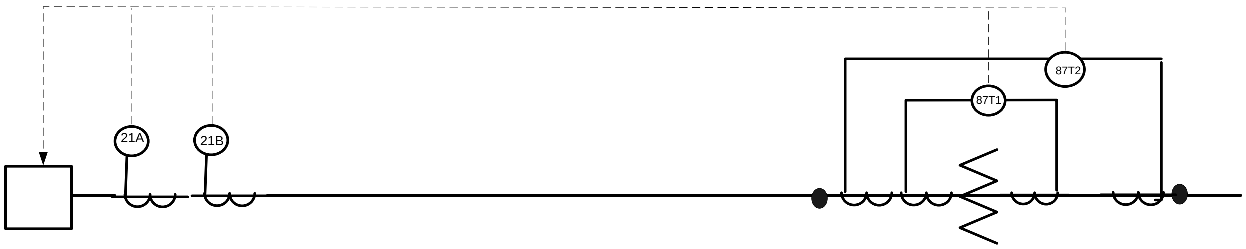
Further to subsection 35(7) of section 502.3, system stability is based on the primary redundant protection systems clearing the fault. For breaker fail conditions it is assumed one (1) breaker opens, and two (2) out of three (3) poles open on the failed breaker as at five hundred (500) kV and two hundred forty (240) kV the poles are independent. The remaining single line-to-ground fault can be cleared per the breaker fail times and with additional time for communications to remote ends without stability concerns.

Further to subsection 35(8) of section 502.3, the following diagram shows an inherent issue of using free standing current transformers. The fault shown will cause the line protection and breakers to operate but will not clear the fault. The breaker fail protection will detect this and clear the adjacent breakers. The likelihood of this event is very low. This is a common industry practice and is acceptable.



9.5 Substation Transformer Ended Lines (Subsection 36)

The following arrangement is considered an acceptable substation transformer ended line. Typically, space is left to add a breaker in the future to either accommodate a second transformer or to add a second line for the sake of system development.



10 Generating Unit and Aggregated Generating Facility Protection

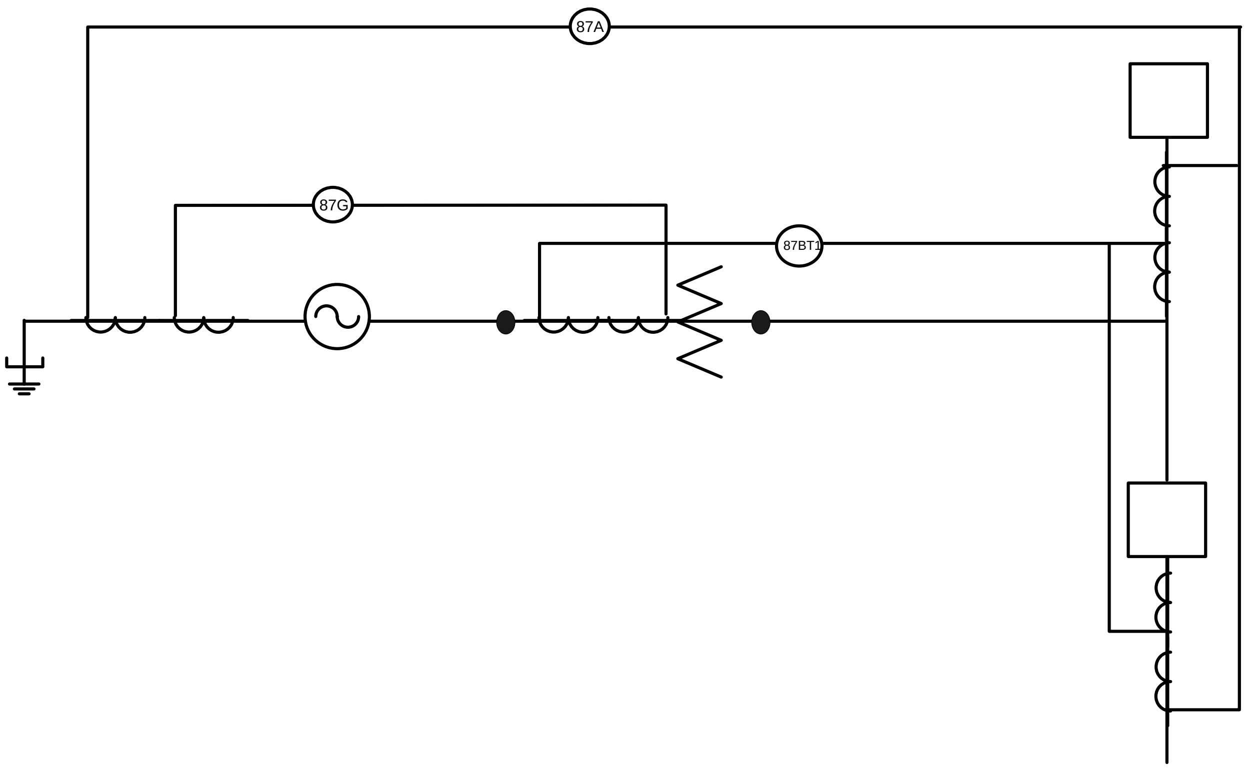
The following documents provide a good overview regarding generating unit and transmission facility coordination:

1) NERC – "*Power Plant and Transmission System Protection Coordination*" – Technical Reference Document Revision 1 - 08/02/10.
2) IEEE Work Group J5 of PSRC "*coordination of generator protection with generator excitation control and generator capability*"

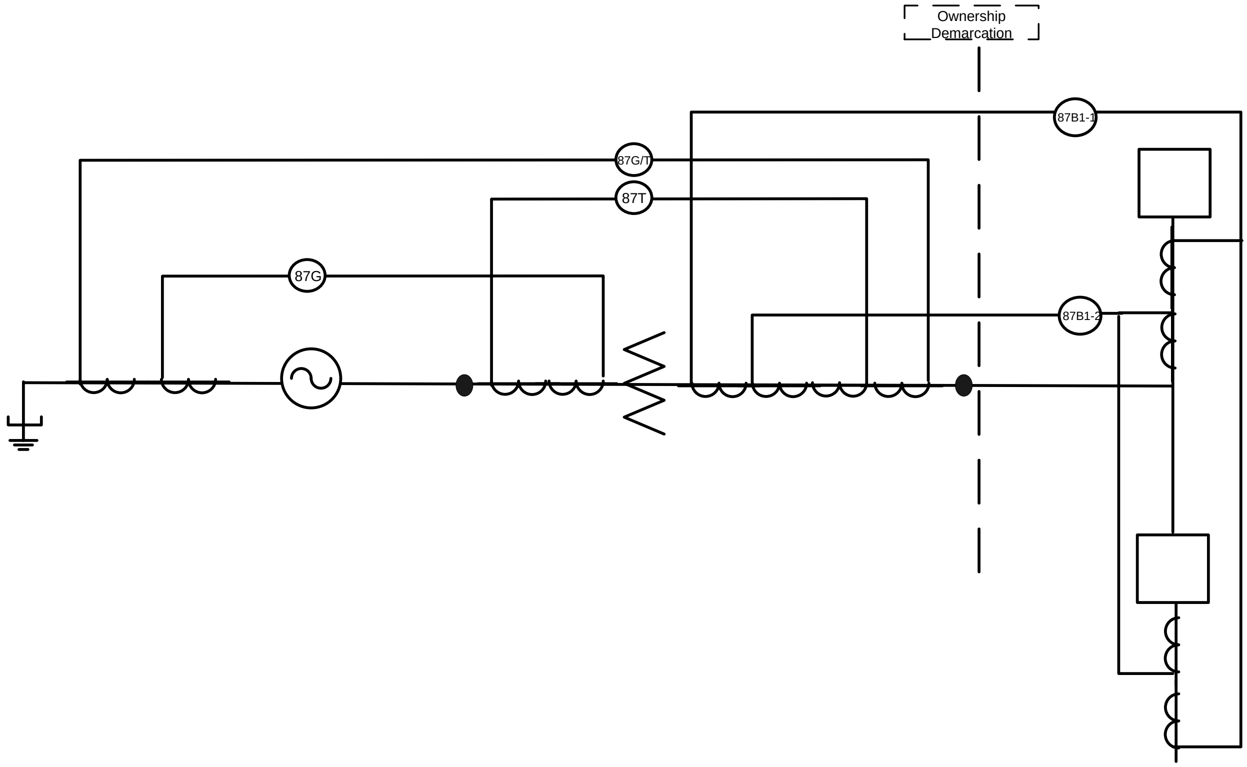
10.1 Sixty (60) Hz Synchronous Generating Units (other than wind) Electrical Protection (Subsection 42)

Two (2) electrical protection systems are required for the generating unit, unit transformer and high side bus. Depending on the facility layout, legal owners may wish to combine these zones and have one protection system cover one (1), two (2) or all three (3) of these zones. At a minimum, two (2) protection systems would be required to provide the required redundancy. Further, careful consideration should be given to combining these zones as the ability to identify the fault location will be reduced. Also, on past projects, concerns have arisen where different parties owned overlapping zones as their construction and energization schedules have not aligned and concerns were also expressed regarding liability for equipment damage if protection failures occurred. For facilities with multiple parties involved, careful consideration should be given to the following alternate arrangement.

Minimum Requirement:



Alternate:



Typically one (1) of the protection systems for the generating unit provides one hundred (100%) percent stator ground fault protection.

11 Power Swing Blocking or Tripping

Nothing specific has been included in section 502.3 regarding power swing blocking or tripping. If the AESO identifies a need for this functionality it will be identified in the projects functional specification.

12 Remedial Action Schemes

The AESO is presently reviewing WECC's remedial action scheme criteria and will determine how to implement this criteria in the future. At this time all remedial action scheme requirements will be identified in project functional specifications.

Revision History

2012-12-31	Initial Release

Information Document
Transmission Protection Relay Loadability
ID #2012-004RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta Reliability Standard PRC-023-AB-2, Transmission Relay Loadability ("PRC-023-AB-2").

The purpose of this Information Document is to provide a link to the list of circuits that the Alberta Electric System Operator ("AESO") must maintain pursuant to requirement R6 of PRC-023-AB-2 and to provide additional information to assist market participants who are the legal owner of a transmission facility, a generating unit or an aggregated generating facility ("the legal owner") with load-responsive phase protection systems, to meet the requirements of PRC-023-AB-2.

2 List of Circuits

The list of circuits that the AESO must maintain pursuant to requirement R6 of PRC-023-AB-2 is available on the AESO website. All submissions to the AESO can be made to ARSsubmittals@aeso.ca.

3 Background and Scope

The Measures section of PRC-023-AB-2, describes in general terms the type of information to be provided by legal owners to demonstrate that requirements R1.1 through R1.14 have been met. This Information Document is to provide additional description and illustrative examples of the information to be provided.

This Information Document is intended to be complimentary to the North America Electric Reliability Corporation document entitled *Determination of Practical Transmission Relaying Loadability Settings, NERC, December, 2017, (the "PRC-023 NERC ID")* which provides clarification regarding the application of NERC reliability standard PRC-023, *Transmission Relay Loadability*. The AESO generally agrees with the information contained within the *PRC-023 NERC ID* and the AESO recognizes that both the *PRC-023 NERC ID* and this Information Document may be useful references for market participants as they implement PRC-023-AB. In addition, the AESO may use the information contained within these documents as reference material in assessing compliance with PRC-023-AB where it determines that the guidance information is applicable.

The NERC document entitled *"Considerations for Power Plant and Transmission System Protection Coordination – Technical Reference Document* – Revision 2", July 2015 provides background information applicable to this Information Document.

As described in requirement R1, the legal owner must use one of the criteria set out in requirements R1.1 through R1.14 inclusive, to meet the requirements of PRC-023-AB-2 for a particular facility. This Information Document only describes additional guidance information for requirement R1.1 regarding transmission line relays. This Information Document does not include guidance for the other requirements of R1.

4 Clarification of Evidence

Requirement R1 sets out criteria for each specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the bulk

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

electric system for all fault conditions.

To effectively comply with the requirements of PRC-023-AB, it is only necessary to provide evidence that the protection relays settings do not limit transmission loadability. PRC-023-AB does not require evidence that the protection relays reliably detect all fault conditions and protect the electrical network from these faults.

5 Clarification of Requirements

Requirement R1 states the requirement to evaluate the phase protection relays' loadability at 0.85 per unit voltage. When the voltage on a bus is reduced to 0.85 per unit voltage and 0.85 per unit voltage is measured by an associated impedance protection function, for a given protection relay impedance setting and a fixed line current rating, the impedance function is more likely to falsely trip than when the voltage is 1.00 per unit voltage. The application of this voltage effect is shown within *PRC-023 NERC ID*, requirement R1.1, page 6. This effect is further explained in this Information Document in Section 7 - Background Concepts. Given the requirement to "evaluate the phase protective relay's loadability at zero point eight five (0.85) per unit voltage", the added sensitivity of impedance functions to the 0.85 per unit voltage must be evaluated and included in the evidence submitted to the ISO.

Requirement R1.1 refers to "the highest seasonal facility rating of a circuit". Usually, in Alberta, the highest seasonal rating is the winter rating. Emergency ratings are applicable to R1.2.

Regarding requirements R1.3, R1.4, R1.5, R1.7, R1.8, and R1.9, refer to the *PRC-023 NERC ID* for a description of the calculation method and typical single line diagrams illustrating the applicability of each requirement.

Requirement R1.13 only applies to line protection relays that do not include a load encroachment function.

If a line protection relay includes a load encroachment function, it may be used to meet the line loadability requirement in a manner described by the protection relay manufacturer, while determining the protection relay's loadability at 0.85 per unit voltage and a load angle of 30°, as described in requirement R1. If the use of the load encroachment feature is not the limiting factor that determines the line loadability, then the evidence for this usage is only needed upon initial energization, when the line electrical properties are changed, or when the protection relay settings are changed.

Regarding requirement R6, it is the responsibility of the legal owners to ensure the loadability information provided to the AESO is updated when the lines or transformers listed as part of R6 have an updated facility rating.

Regarding Appendix 1, subsections 1(b) (out-of-step tripping), and 2(c) (protection systems intended for protection during stable power swings), dynamic short circuit data is required to perform the analysis needed to provide evidence that these requirements have been met. The basic idea of this requirement is that phase protection functions detect faults and trip circuit breakers to clear faults, but do not falsely trip during power swings between generators that occur for approximately 10 seconds after a fault has been cleared. This situation is described more fully in section 7 of the *PRC-023 NERC ID*. This type of analysis is typically performed for 500 kV and critical 240 kV transmission facilities, but can be applied at any location or voltage level. Additional information regarding the setting of protection systems during stable power swings is provided in this Information Document in section 9.

Example Application of Requirement R1.1 Using the PRC-023-AB Step 1-2-3 Process

The following information illustrates the use of a three step process, referred to as the PRC-023-AB Step 1-2-3 process within this Information Document, which can be used to help meet requirement R1.1. These steps can also similarly be used to meet requirements R1.2 through R1.11. The use of the PRC-023-AB Step 1-2-3 process is not necessary and is included in this Information Document for illustrative purposes only.

Step 1 – Clarify Facility Rating

The facility rating excludes any restriction caused by protective relays or current transformers. The transmission facility load rating can be described in the following three equivalent ways:

1. The ampacity or current rating:

For example, an ampacity or current rating of 1,250 amps at 240 kV.

2. The apparent power capacity rating:

A current rating of 1,250 amps at a voltage of 240 kV line-to-line is equivalent to an apparent power capacity rating of 520 MVA, calculated by the following equation:

$$S = I \times VLL \times \sqrt{3} \qquad \text{Equation (1)}$$

Where:

S is the apparent power capacity rating

I is the phase current

VLL is the line to line voltage

$$S = 1{,}250\ amps \times 240{,}000\ volts \times \sqrt{3}$$

$$S = 520{,}000{,}000\ volt\ amps$$

$$S = 520\ MVA$$

3. The apparent impedance capacity rating:

A current rating of 1,250 amps at a voltage of 240 kV line-to-line is equivalent to an apparent impedance capacity rating of 111 ohms, calculated by the following equation:

$$Z = \frac{VLL^2}{S} \qquad \text{Equation (2)}$$

Where:

Z is the apparent impedance capacity rating, or apparent impedance of the power flow

$$Z = \frac{240{,}000^2\ volts}{520{,}000{,}000\ \text{volt amps}}$$

$$Z = 111\ \text{ohms}$$

Alternately, Z can be calculated by the following equation:

$$Z = \frac{S}{3 \times I^2} \qquad \text{Equation (3)}$$

$$Z = \frac{520{,}000{,}000\ \text{volt amps}}{3 \times (1{,}250)^2\ \text{amps}}$$

$$Z = 111\ \text{ohms}$$

Alternately, Z can be calculated by the following equation:

$$Z = \frac{VLL/\sqrt{3}}{I} \qquad \text{Equation (4)}$$

$$Z = \frac{240{,}000 \text{ volts}/\sqrt{3}}{1{,}250 \text{ amps}}$$

$$Z = 111\ ohms$$

The calculations above demonstrate the following ways to describe the same power flow, or power flow capacity rating, which are all equivalent to one another:

- A line current flow of 1,250 amps at 240 kV;
- An apparent power flow of 520 MVA at 240 kV; and
- An apparent impedance of the power flow of 111 ohms at 240 kV

Step 2 – Check Relays For Loadability

The purpose of Step 2 is to ensure that protective relays do not restrict the capacity of a transmission facility.

A list can be created of all, or the most loadability limiting of the following: 1) phase current detection functions; and 2) phase impedance detection functions within the protection relay system that can cause circuit breaker tripping in response to a fault. For each of these detection functions the protection relay loadability is determined, as described within this Information Document. The protection relay loadability is the current, apparent power or apparent impedance that results in the operation of the detection function. The protection relay loadability is compared to the transmission facility load rating, using the margins and factors described within PRC-023-AB. If the protection relay loadability, with the associated margins and factors, is greater than the transmission facility loadability, then the protection relay does not create a restriction of the transmission facility loadability, and no further action is required. If the protection relay loadability is equal to or less than the transmission facility loadability, then the protection relay creates a restriction of the transmission facility loadability and Step 3, shown below, is required.

Step 3 – Use of Protection Relay Settings That Restrict Loadability – Only if Required

In some cases, the transmission facility loadability cannot be met due to protection relay settings that are needed to ensure the protection relays can detect all fault conditions, and for the case of transformers, to ensure that no transformer damage occurs due to current and time values that exceed parameters (sometimes referred to as 'damage curves') provided by the transformer manufacturer.

If Step 3 is required, then requirements R1.12, R1.13 or R1.14 are used to determine the protection relay settings.

Figure 2 provides a graphical interpretation of the use of the PRC-023-AB Step 1-2-3 process for requirements R1.1 through R1.14. The first column indicates the facility type. The second column shows the relationship between a facility type, Steps 1 and 2 and the various requirements within requirement R1.

The relay loadability requirements of PRC-023-AB for impedance detection functions can often be met through the use of a load encroachment function. However if this function is not available or does not meet the requirement of PRC-023-AB, then Step 3 is required.

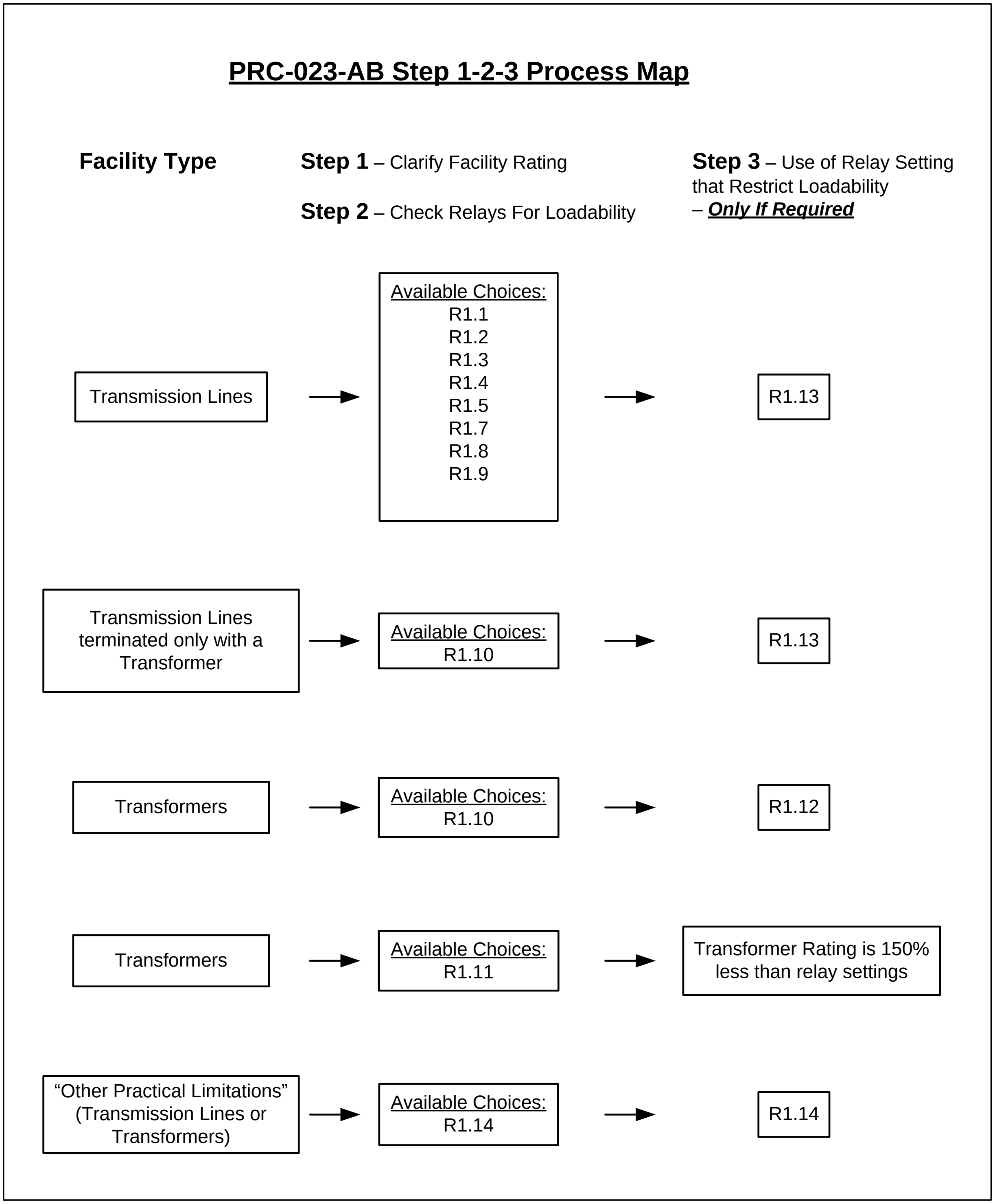


Figure 2 – PRC-023-AB Step 1-2-3 Process Map

6 General Clarification of PRC-023-AB

Protection relays can contain one or more of the following phase detection functions:

(a) phase overcurrent detection functions:

 (i) instantaneous phase overcurrent (non-directional or directional);

 (ii) inverse time or time phase overcurrent (non-directional or directional); and

 (iii) switch-on-to-fault phase overcurrent; and

(b) phase impedance detection functions (forward or reverse looking).

Older protection relays typically include only one detection function within one physical protection relay, in which case a number of separate protection relays would be used when a number of detection functions were required. Newer protection relays can have one or many detection functions within one physical protection relay.

When a fault occurs on a transmission line or within a transformer, one or more phase detection functions are activated. It is generally assumed in industry that the following minimum fault detection capability must exist:

(a) for redundant, independent protection systems (e.g. using both an “A” and “B” independent, physical protection relay) all types of fault conditions must be detected by at least one detection function within each of the independent protection systems; and

(b) for non-redundant protection systems all types of fault conditions must be detected by at least one detection function, in accordance with the intended design.

Prior to considering protection relay loadability, it is necessary that the selected protection relay type and associated settings will provide adequate fault detection for all types of fault conditions. The selection of the protection relay and associated settings is the responsibility of the legal owner, as required by Section 502.3 of the ISO rules, *Interconnected Electric System Protection Requirements*. As previously described in section 4 of this Information Documet, PRC-023-AB does not require evidence that the protection relays reliably detect all fault conditions and protect the electrical network from these faults.

7 Background Concepts

Figure 3 shows a complex impedance plot of reactance versus resistance (an “R-X Plot”) used for a typical transmission line. The tripping characteristic of a typical mho impedance detection function for balanced 3-phase faults or balanced 3-phase loads is shown as a circle with a diameter of Zrelay. The magnitude of Zrelay is a user selectable setting within a protection relay. The diameter of the circle is tilted at an angle called the Maximum Torque Angle (MTA).

PRC-023-AB requires loadability calculations to be performed with a 30° angle for the load, so a 30° load apparent impedance loci is shown, with two specific values of load indicated by dots, which are:

1. 222 ohms at 240 kV, which is equivalent to 260 MVA at 240 kV, which is also equivalent to 625 amps at 240 kV; and
2. 111 ohms at 240 kV, which is equivalent to 520 MVA at 240 kV, which is also equivalent to 1,250 amps at 240 kV.

The method to calculate these equivalent values is shown in section 5 of this Information Document.

In other words, if a protective relay measures a voltage of 240,000 volts line-to-line and a current of 1,250 amps at 30°, the relay will determine a measured apparent impedance of the power flow to be 111 ohms.

Referring to Figure 3, if the load apparent impedance 30° loci passes within the mho characteristic with a magnitude of Zrelay30 or less, then the protection relay will operate and trip one or more circuit breakers to de-energize the transmission line.

The parameters Zrelay and Zrelay30 are defined within the *PRC-023 NERC ID* and are shown in Figure 3. These two parameters are useful when describing and calculating line loadability and relay loadability. Zrelay is the relay setting which is the diameter of the mho operating characteristic, which is associated with a second relay setting of the MTA. Zrelay30 is the impedance reach of the operating characteristic when the power flow has a 30° angle between the voltage and current.

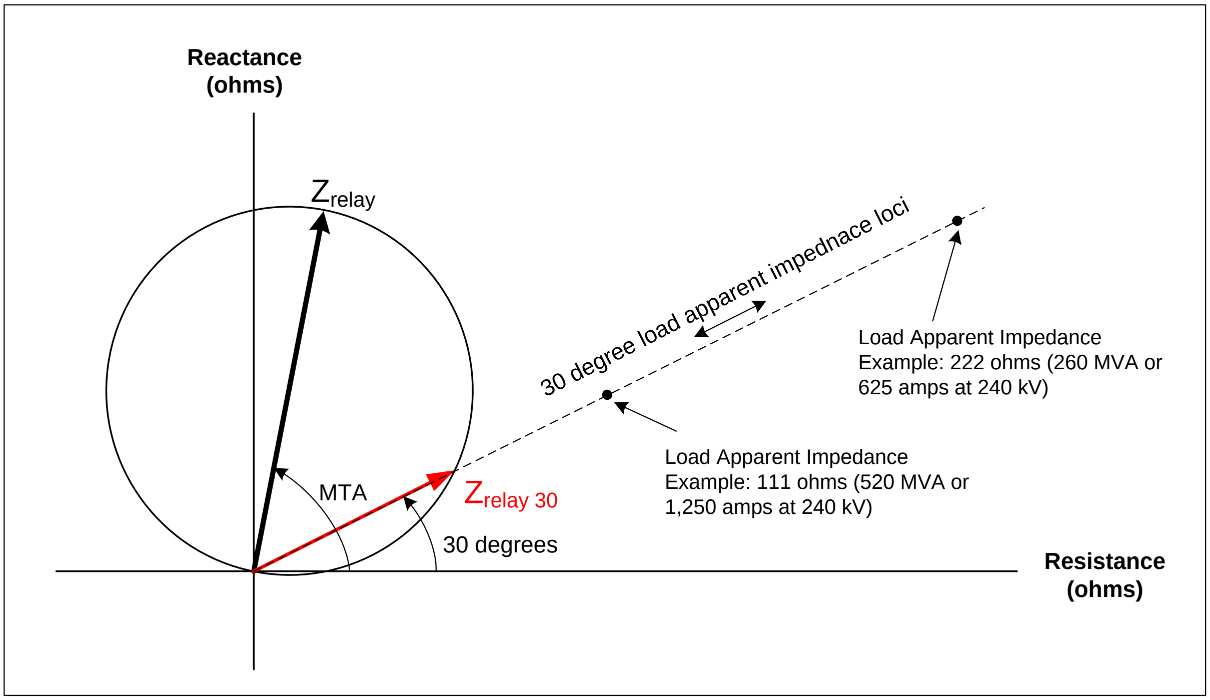


Figure 3 – Impedance Detection Function

Figure 4 shows the same mho operating characteristic as Figure 3 and illustrates specific values for Zrelay and Zrelay 30. The following equation describes the relationship between these two parameters, as described in the *PRC-023 NERC ID*.

$$\mathrm{Zrelay30} = \mathrm{Zrelay} \times \cos(\mathrm{MTA} - 30\ \mathrm{deg}) \qquad \text{Equation (5)}$$

Or, alternately Zrelay can be calculated using the following equation.

$$\mathrm{Zrelay} = \frac{\mathrm{Zrelay30}}{\cos(\mathrm{MTA} - 30\ \mathrm{deg})} \qquad \text{Equation (6)}$$

Using example data, if Zrelay30 = 63 ohms and the MTA = 85°

$$Zrelay = \frac{63\ ohms}{\cos(85 - 30)}$$

Zrelay = 110 ohms

Figure 4 illustrates the case when the MTA is 85°, Zrelay30 is 63 ohms and Zrelay is 110 ohms.

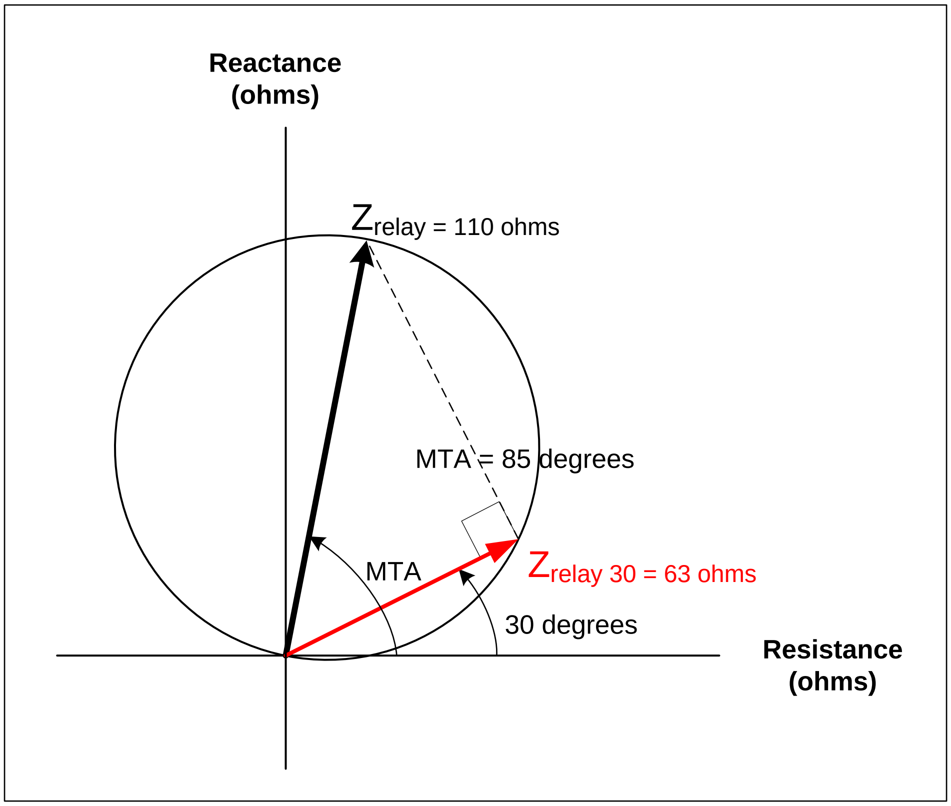


Figure 4 – Zrelay and Zrelay30

Using adifferent example data, if Zrelay30 = 63 ohms and the MTA = 87°

$$Zrelay = \frac{63\ ohms}{\cos(87-30)}$$

Zrelay = 116 ohms

Consideration of the 0.85 Per Unit Voltage Effect On an Impedance Detection Function

When the voltage on a bus is reduced to 0.85 per unit, for a given fixed relay setting and given fixed line current rating, the relay is more likely to falsely trip than when the voltage is 1.00 per unit. This is illustrated by means of example data, as follows.

In requirement R1.1, page 6 of the *PRC-023 NERC ID* the following equation is shown.

$$Zrelay30 = \frac{0.85 \times VLL}{\sqrt{3} \times 1.5 \times Irating} \qquad \text{Equation (7)}$$

As described in the *PRC-023 NERC ID* the 0.85 factor in the equation is included in reference to the 0.85 per unit voltage requirement within PRC-023 requirement R1. The 1.5 factor is included in reference to the 150% factor used within PRC-023 requirement R1.1. Irating is the fixed line current rating.

This equation may be generalized for any of the requirements in requirement R1 of PRC-023 by removing the 1.5 factor, and by removing the 0.85 factor, in the following equation.

$$Zrelay30 = \frac{VLL}{\sqrt{3} \times Irating} \qquad \text{Equation (8)}$$

Equation (8) can be used to illustrate two situations as follows:

Situation 1: At 100% voltage and a line current rating of 1,250 amps

$$Zrelay30 = \frac{240{,}000\ volts}{\sqrt{3} \times 1{,}250\ amps}$$

$$Zrelay30 = 111\ ohms$$

This means that at 100% voltage a relay setting of 111 ohms will cause a load current of 1,250 amps or greater to trip the relay.

Situation 2: At 85% voltage and a line current rating of 1,250 amps

$$Zrelay30 = \frac{0.85 \times 240{,}000\ volts}{\sqrt{3} \times 1{,}250\ amps}$$

$$Zrelay30 = 94\ ohms$$

This means that at 85% voltage a relay setting of 94 ohms will cause a load current of 1,250 amps or greater to trip the relay. To ensure the relay will only trip for a load current of 1,250 amps or greater, for either 100% or 85% voltage, the relay setting needs to be 94 ohms (or less).

Figure 5 illustrates the line capacity rating of 111 ohms being changed to 94 ohms to account for the 0.85 per unit voltage effect.

Equation (7), which is from requirement R1.1 of the *PRC-023 NERC ID*, using the same data, is calculated as follows.

$$Zrelay30 = \frac{0.85 \times 240{,}000\ volts}{\sqrt{3} \times 1.5 \times 1{,}250\ amps}$$

$$Zrelay30 = 63\ ohms$$

Figure 5 illustrates Zrelay30 being equal to 63 ohms and Zrelay being equal to 110 ohms, as previously calculated.

The blue arrows in Figure 5 illustrate how, for requirement R1.1, for a relay MTA = 85°, a line with an apparent impedance rating of 111 ohms results in a value of Zrelay30 = 63 ohms and Zrelay = 110 ohms. The green arrows in Figure 5 illustrate how, for requirement R1.1, for a relay MTA = 85°, a relay setting of Zrelay = 110 ohms results in a value of Zrelay30 = 63 ohms and a line apparent impedance rating = 111 ohms.

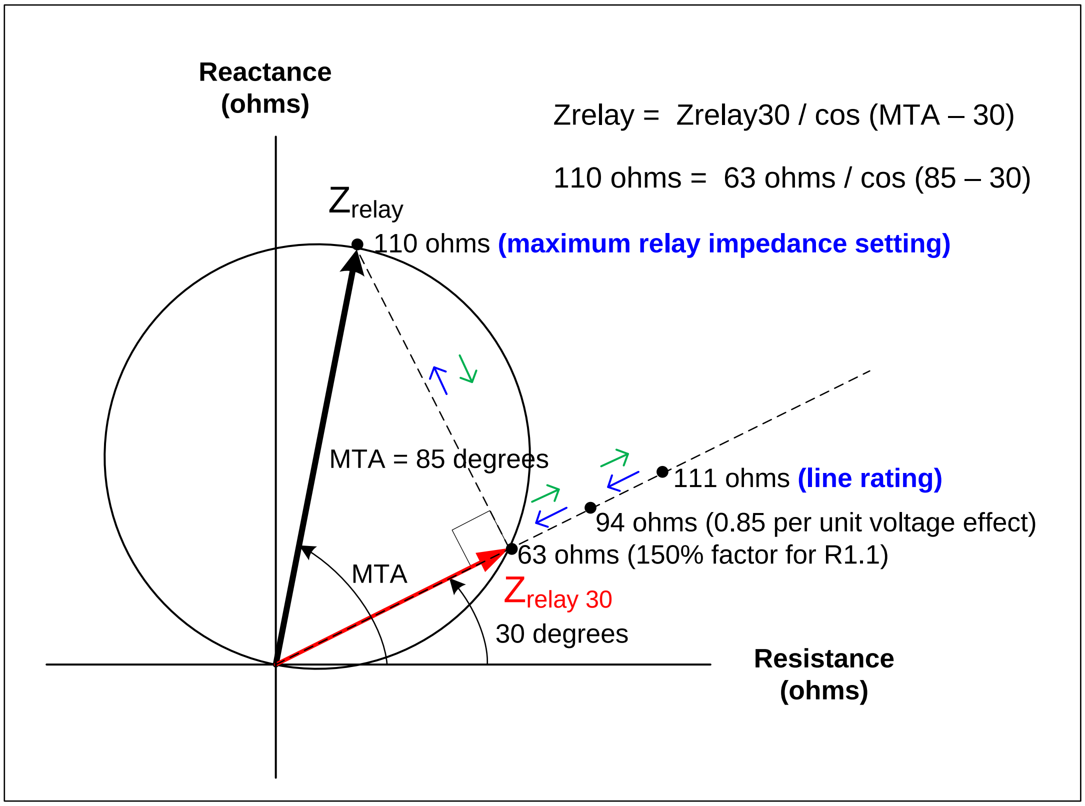


Figure 5 – Example Data

Figure 6 shows an R-X plot that illustrates the advantage of using a load enchroachment function within a line protection relay. The load encroachment function is designed to ensure the relay will not trip when the the impedance loci stays to the right hand side of the function. This diagram includes a mho operating characteristic set to 110 ohms with an MTA set to 85°, the 30° load line, and a typical load encroachment function set to 32 ohms at an angle slightly greater than +/- 30°. If a load encroachment function was not available, then the maximum loadability would be equal to ZRelay30, which is equal to 63 ohms. When a load encroachment function is used and is set to 32 ohms, this results in a loadability improvement of 31 ohms and also results in an arc accommodation of 23 ohms, all of which is shown in Figure 6.

The use of a load encroachment function is more fully explained in the document *Increase Line Loadability by Enabling Load Encroachment Functions of Digital Relays*, NERC, December 7, 2005.

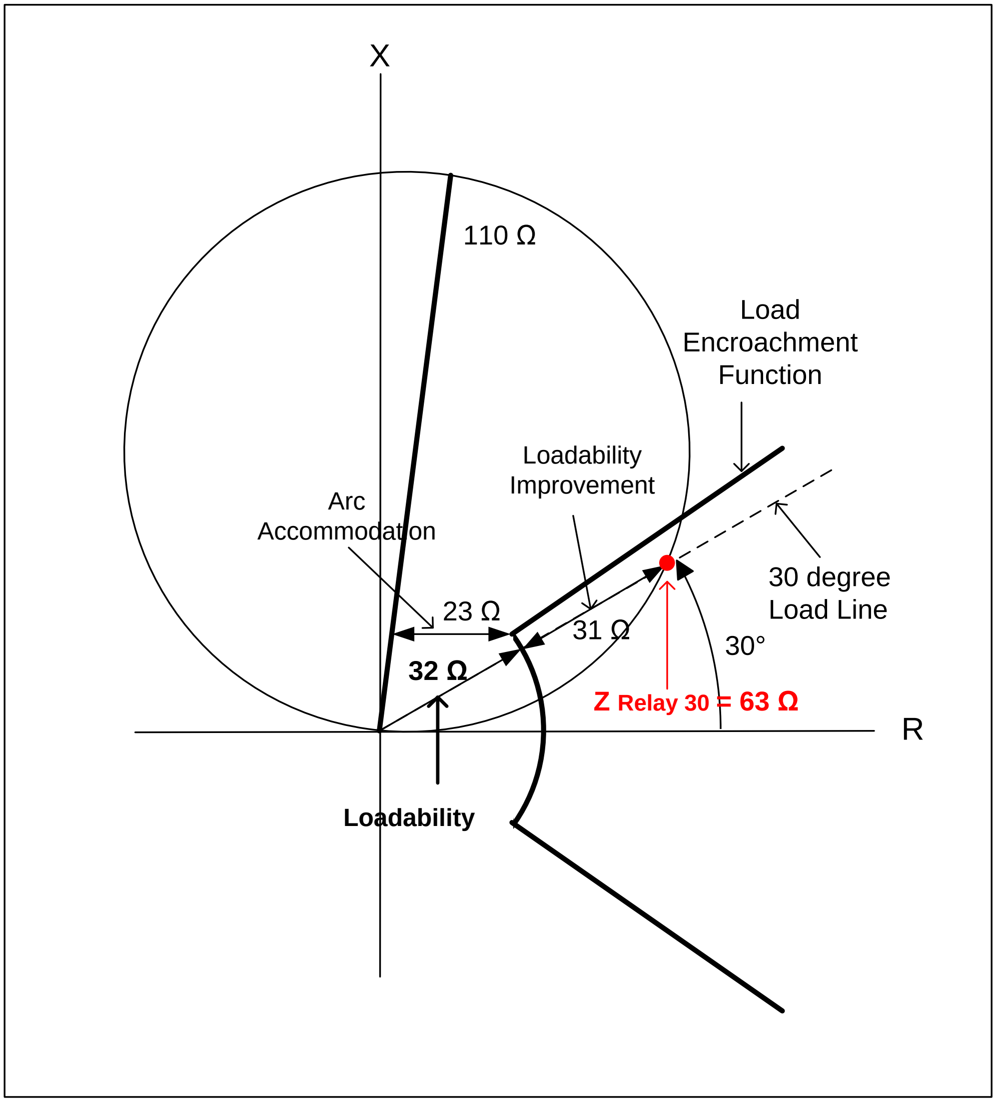


Figure 6 – Load Encroachment Function

8 Requirement R1.1 – Information Template

Figure 7 shows an example of a blank information template for Step 1 and Step 2 for requirement R1.1. This template illustrates the typical type of information to be provided as evidence of compliance with requirement R1.1. This template may be used at the discretion of the legal owner but its use is not required.

Figure 8 shows the same template that was shown in Figure 7 and also includes example data, for a hypothetical transmission line identified as “Line A”.

Some of the data shown in the R-X plots in Figure 5 and Figure 6 has been added into the information template shown in Figure 8.

As shown in Figure 8, the legal owner completes Step 1 by entering the indicated data regarding the transmission line capacity rating.

As also shown in Figure 8, the legal owner completes Step 2 by entering the indicated information for the current detection functions and impedance detection functions that can trip a circuit breaker and de-energize Line A. The legal owner also indicates for each individual detection function whether it “Meets

Limits?", meaning it meets the loadability requirement, by entering either "Yes" or "No'.

To determine whether a current function meets the loadability requirements, the current setting value must be greater than the current loadability limit, in this particular example, of 1,875 amps. To determine whether an impedance function meets the loadability requirement the impedance setting value, converted from Zrelay to Zrelay30, must be less than line loadability impedance limit, Zrelay30, in this particular example, of 63 ohms.

When all data is entered and if the "Meets Limits?" column for all individual functions is "Yes", then the loadability evaluation is completed for requirement R1.1.

As also shown in Figure 8, a brief report is intended to be included with the information template, or similar document, to provide relevant background information for the data provided within the information template, which includes at a minimum, the manufacturer and model number of the relays, the relay setting, the PT ratio, and the CT ratio.

PRC-023-AB Section R1.1

(Example Data)

Step 1 – Clarify Facility Rating

Transmission Line Id: ____________

Line Rating

Current:	______ (amps)
Apparent power at 1.0 p.u. voltage of _______ kV:	______ (MVA)
Current loadability limit using 150% of facility rating: (current values assume a 30 degree load angle)	______ (amps)
Impedance at 1.00 p.u. Voltage: (at _____ amps)	______ (ohms)
Impedance at 0.85 p.u. Voltage:	______ (ohms)
Impedance at 0.85 p.u. Voltage and 150% of facility rating which is also the line Impedance loadability limit Zrelay30 (at 30 deg):	______ (ohms)

Step 2 – Check Relays For Loadability

Line Terminal 1

Relay Id	Function ID	Setting	Zrelay30	Most Limiting ?	Meets Limits ?

Line Terminal 2

Relay Id	Function ID	Setting	Zrelay30	Most Limiting ?	Meets Limits ?

Facility Owners's Report Name:_________________

Provided by: _________________
Contact info:_________________
Date: ___________

Figure 7 – R1.1 InformationTemplate – Blank

PRC-023-AB Section R1.1

(Example Data)

Step 1 – Clarify Facility Rating

Transmission Line Id: **Line A**

Line Rating

Current:	1,250	(amps)
Apparent power at 1.0 p.u. voltage of 240 kV:	520	(MVA)
Current loadability limit using 150% of facility rating: (current values assume a 30 degree load angle)	1,875	(amps)
Impedance at 1.00 p.u. Voltage: (at 1,250 amps)	111	(ohms)
Impedance at 0.85 p.u. Voltage:	94	(ohms)
Impedance at 0.85 p.u. Voltage and 150% of facility rating which is also the line Impedance loadability limit Zrelay30 (at 30 deg):	63	(ohms)

Step 2 – Check Relays For Loadability

Line Terminal 1

Relay Id	Function ID	Setting	Zrelay30	Most Limiting ?	Meets Limits ?
Relay A	50P-1	1,900 amps	-	Yes	Yes
	50P-2	2,400 amps	-	-	Yes
	51P-1	2,000 amps	-	-	Yes
	21P-Z1 (Z_{relay})	40 ohms (at MTA = 85 deg)	23 ohms	-	Yes
	21P-Z2 (Z_{relay})	56 ohms (at MTA = 85 deg)	32 ohms	-	Yes
	21P-Z3 (Z_{relay})	105 ohms (at MTA = 85 deg)	60 ohms	Yes	Yes
Relay B	51P-X	1,970 amps	-	-	Yes
	SOTF	2,000 amps	-	-	Yes
	21P-Z1 (Z_{relay})	40 ohms (at MTA = 87 deg)	22 ohms	-	Yes
	21P-Z2 (Z_{relay})	56 ohms (at MTA = 87 deg)	30 ohms	-	Yes
	21P-Z3 (Z_{relay})	95 ohms (at MTA = 87 deg)	52 ohms	-	Yes

Line Terminal 2

Relay Id	Function ID	Setting	Zrelay30	Most Limiting ?	Meets Limits ?
Relay C	50P-1	2.200 amps	-	Yes	Yes
	50P-2	2,400 amps	-	-	Yes
	51P-1	2,000 amps	-	-	Yes
	21P-Z1 (Z_{relay})	40 ohms (at MTA = 85 deg)	23 ohms	-	Yes
	21P-Z2 (Z_{relay})	56 ohms (at MTA = 85 deg)	32 ohms	-	Yes
	21P-Z3 (Z_{relay})	102 ohms (at MTA = 85 deg)	59 ohms	Yes	Yes
Relay D	Load Encroachment Feature Loadability	32 ohms (at 30 deg)	n/a		Yes

Provided by: ______________
Contact info: ______________
Date: __________

Facility Owners's Report Name: Report abc

Figure 8 – R1.1 InformationTemplate – With Example Data

Figure 9 illustrates the same example data shown in Figure 8 entered into a spreadsheet. A copy of the spreadsheet template accompanies this Information Document. As described within the spreadsheet, if this spreadsheet is submitted to the AESO as evidence for line loadability, then the legal owner is responsible for the applicability and accuracy of all data and calculations. All cells except those with brown shading are locked to protect the calculations. A user can add new columns to add supplementary information and calculations.

The spreadsheet includes cells to provide background information as to the manufacturer and model number of the relay, the relay setting, the PT ratio, and CT ratio.

PRC-023-AB R1.1 Calculation
Refer to the ISO PRC-023-AB Information Document (ID), for a description of the methods and calculations included within this spreadsheet.
Intended For Discussion Purposes Only
If this spreadsheet is submitted to the AESO as evidence for line loadability, then the facility owner is responsible for the applicability and accuracy of all data and calculations.
All cells except those with brown shading are locked. A user is able to add new columns to add supplementary information and calculations.
User Data Entry Only In Brown Shaded Cells

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
3	Line Rating Data												Relay Settings													
4													Overcurrent Function				Mho Impedance Function (if no load encroachment feautre is available)						Load Encroachment Function			
5	Line ID	Line Current Rating (amps)	Line Voltage (kV L-L)	Line Apparent Power Rating (MVA)	Line Current Rating x 150% (using R1.1)	Line Apparent Impedance Rating at 1 pu Voltage and the rated line current (ohms)	Line Apparent Impedance Rating at 0.85 pu voltage and the rated line current (ohms)	Line Loadability Maximum Allowable Zrelay30 for R1.1 using 150% Factor (ohms)	Line Terminal ID	Relay MFR & Model Number	PT Ratio	CT Ratio	Lowest Relay Current Setting (Secondary amps)	Lowest Relay Current Setting (Primary amps)	Current Setting Meets Loadability Requirement?	Overcurrent Function Line Loadability using 150% Factor (MVA)	Greatest Relay Setting of Zrelay (Secondary ohms)	Greatest Relay Setting of Zrelay (Primary ohms)	Relay Maximum Torque Angle (degrees)	Calculated Zrelay30 (Primary ohms)	Impedance Function Meets Loadability Requirement?	Line Loadability using 150% Factor and 85% Voltage Factor (MVA)	Relay Loadability (Secondary ohms)	Relay Loadability (Primary ohms)	Loadability Meets Requirements?	Load Encroachment Feature Line Loadability using 150% Factor and 85% Voltage Facytor (MVA)
6	The example data within the following two rows corresponds to the example data described and calculated within the AESO PRC-023 Information Document (ID)																									
7	L1	1,250	240	520	1,875	111	94	63	LT1	Relay A				1,900	Yes	527		105	85	60	Yes	542			-	0
8	L1	1,250	240	520	1,875	111	94	63	LT1	Relay B				1,970	Yes	546		95	87	52	Yes	631			-	0
9	L1	1,250	240	520	1,875	111	94	63	LT2	Relay C				2,200	Yes	610		102	85	59	Yes	550			-	0
10	L1	1,250	240	520	1,875	111	94	63	LT3	Relay D					-	0				0	-	0		33	Yes	1,030
11				0	0	0	0	0							-	0				0	-	0			-	0
12				0	0	0	0	0							-	0				0	-	0			-	0
13				0	0	0	0	0							-	0				0	-	0			-	0
14				0	0	0	0	0							-	0				0	-	0			-	0
15				0	0	0	0	0							-	0				0	-	0			-	0
16				0	0	0	0	0							-	0				0	-	0			-	0
17				0	0	0	0	0							-	0				0	-	0			-	0
18				0	0	0	0	0							-	0				0	-	0			-	0
19				0	0	0	0	0							-	0				0	-	0			-	0
20				0	0	0	0	0							-	0				0	-	0			-	0

Figure 9 – Loadability Data Within A Spreadsheet

9 Protection Relay Loadability During Power Swings

As referenced in PRC-023, Appendix 1, 1(b) (out-of-step tripping) and 2(c) (protection systems intended for protection during stable power swings), dynamic short circuit data is required to perform the analysis needed to provide evidence these requirements have been met, as shown below. This type of analysis is typically performed for 500 kV and critical 240 kV transmission facilities, but can be applied at any location or voltage level, as determined by the AESO.

When a fault occurs on the transmission system, the individual, nearby generators will have a response similar to what is shown in Figure 10, for a time period both: 1) prior to and during fault clearing; and 2) after fault clearing. The generator protection relays will measure this power swing. The parameter Pstep indicates the change in real power during the fault, and Pswing1 and Pswing2 illustrate real power oscillations (swings) occurring after fault clearing. The time duration of the power swings after fault clearing can last a number of seconds and be of significant magnitude. The general idea is that generator protection relays do not falsely trip in response to faults occurring on the transmission system.

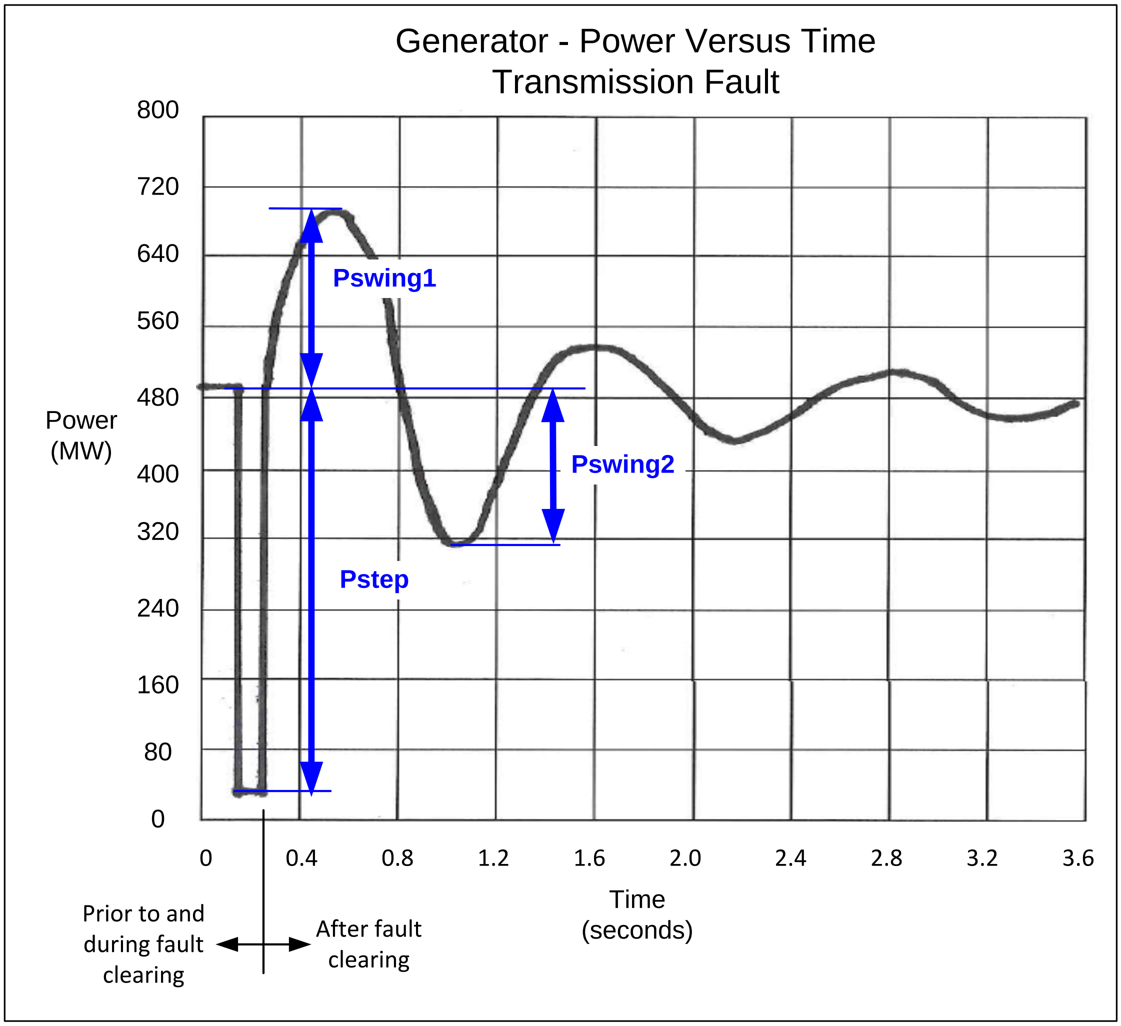


Figure 10 – Generator Power Swings

When a fault occurs on the transmission system, the line terminals will measure a power flow similar to what is shown in Figure 11, for a time period both: 1) prior to and during fault clearing; and 2) after fault clearing. The power oscillations are created both by the initial fault and line auto-reclose events following the fault clearing. The transmission line protection relays will measure these power swings. The shape of the power curve can be complex, as illustrated in Figure 11, due to the mechanical oscillation interaction of various generators, all of which can have different inertial time constants. The time duration of the power swings after fault clearing can last a number of seconds and be of significant magnitude. The general idea is that transmission line protection relays do not falsely trip in response to power swings on the transmission system.

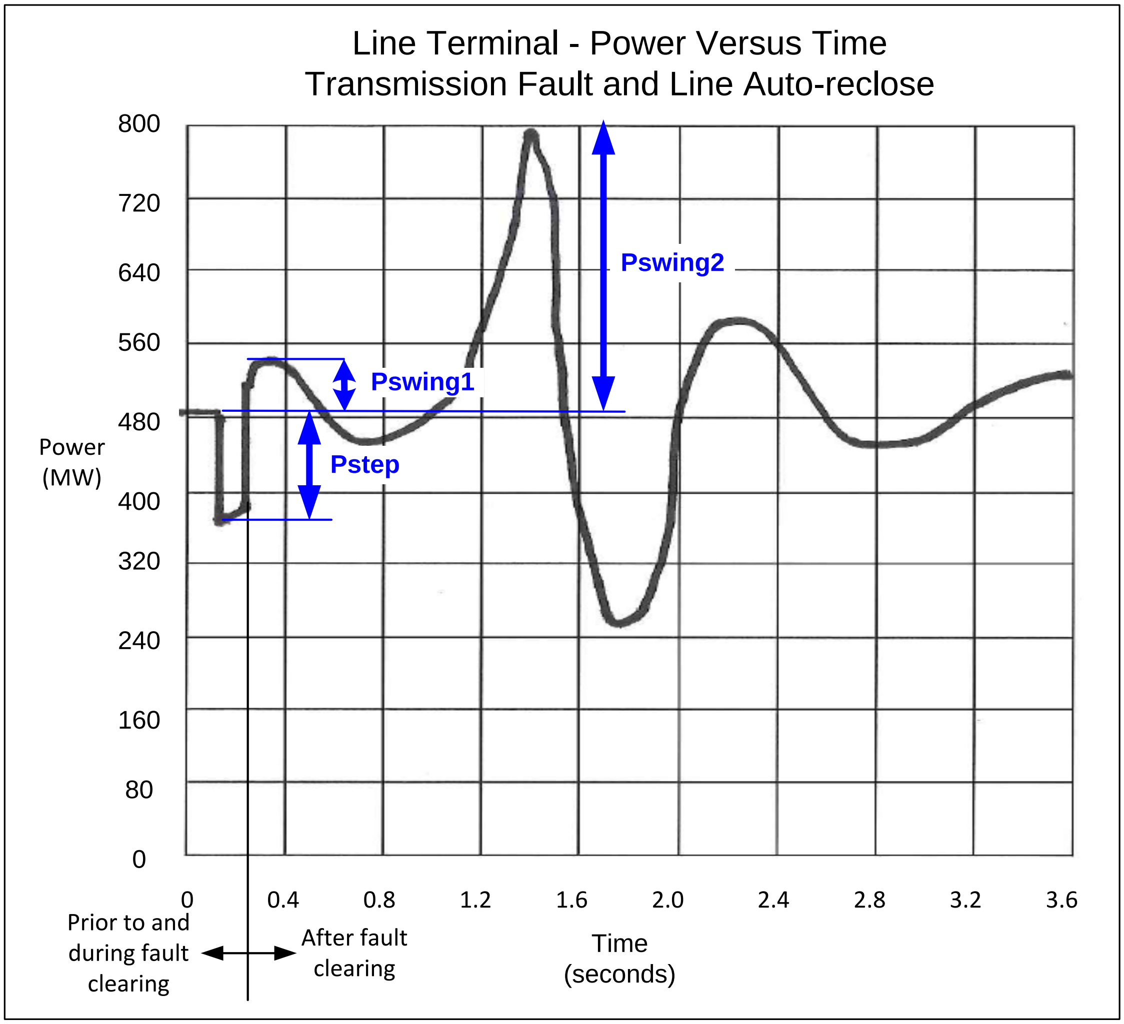


Figure 11 – Line Terminal Power Swing

Figure 12 provides a concept R-X plot for the apparent impedance loci measured by transmission line protection relays or generator protection relays. The dots represent the value of the apparent impedance of the power flow at regular time intervals, for example every 10 milli-seconds. The impedance loci has a ‘Start’ and ‘End’ for a particular time period. For example, a time period that includes time both prior to a fault and for a few second following a fault, for the time period similar to what is shown in Figures 10 and 11. This concept R-X plot shown in Figure 12 includes only a few dots for illustrative purposes, but illustrates the ideas that the dots are ‘far apart’ shortly after the Start, when the fault occurs, but then the dots become ‘close together’ after any circuit breakers have tripped to clear the fault. In other words, when the dots are far apart, the rate-of-change of the apparent impedance loci is fast, and when the dots are close together, the rate-of-change of the apparent impedance loci is slow. When the rate-of-change of the apparent impedance loci is fast, this indicates the presence of a fault, which results in the tripping ofcircuit breakers. When the rate-of-change of the apparent impedance loci is slow, this indicates the presence of a power swing, which requires the circuit breaker to not be tripped. Both the rate-of-change and magnitude of the apparent impedance loci are used to create the protection relay settings to avoid false tripping during power swings.

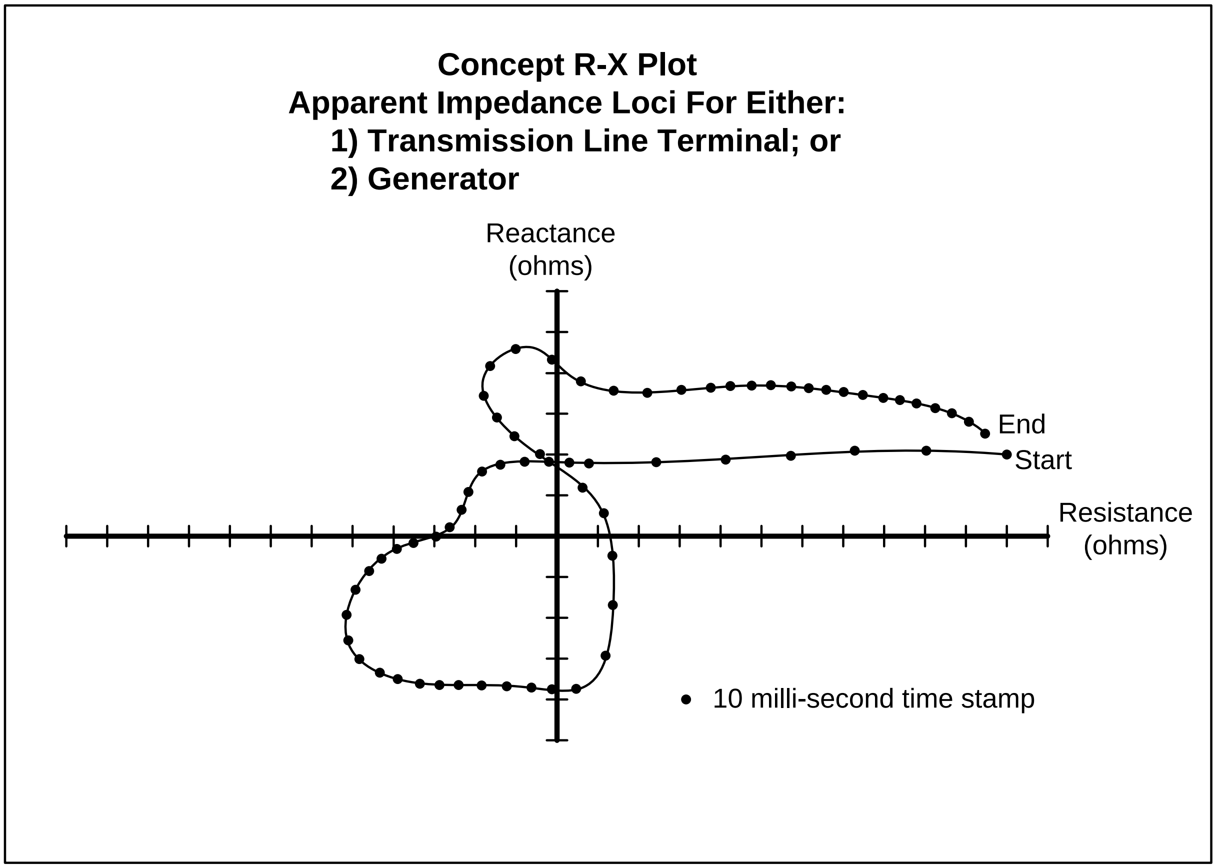


Figure 12 – Concept R-X Plot

Transmission line protection relays often include a function called ‘power swing block’ that is set to ensure the protection relay does not operate during power swings. The power swing block function is available in most new impedance protection relays. Transmission line protection relays can also include a function called ‘power swing trip’ that is used to detect power swings that can thermally damage the associated transmission line and cause circuit breakers to trip to remove the power swing. The use of a power swing tripping function is not common, but can be found on medium voltage transmission lines connected between major generating plants, for the situation of black start conditions when the high voltage transmission lines have not yet been returned to service, and large power swings could occurr between generating units through the medium voltage transmission lines.

Generator protection relays almost always include a function called ‘out-of-step’ tripping to detect a ‘pole slipping’ condition, to remove the generator from service if this occurs, yet is not supposed to trip for stable power oscillations (swings) occurring between generators, through the transmission system.

The required dynamic fault R-X loci data is usually stored as time series data, every 1.0 milli-second, as illustrated in Table 1 and Table 2, using a spreadsheet for convenient analysis and plotting.

Table 1 - Generator - Apparent Impedance Loci Data								
Time (seconds)	Apparent Resistance (ohms)	Apparent Reactance (ohms)	IA (amps)	IB (amps)	IC (amps)	VAG (volts)	VBG (volts)	VCG (volts)
0.001								

0.002								
0.003								
etc.								

Table 2 -Line Terminal - Apparent Impedance Loci Data								
Time (seconds)	Apparent Resistance (ohms)	Apparent Reactance (ohms)	IA (amps)	IB (amps)	IC (amps)	VAG (volts)	VBG (volts)	VCG (volts)
0.001								
0.002								
0.003								
etc.								

The data shown in Table 1 and Table 2 is usually plotted as shown in Figure 12. A plot is created for each of many transmission line fault scenarios.

The main concepts in using the R-X loci data are:

1. A generator should not be tripped and removed from service for faults on transmission facilities (lines, transformers and buses) and not be tripped and removed from service for the subsequent power swings.
2. A transmission line with a fault should be tripped and removed from service to clear the fault, possibly followed by auto-reclose to restore the line to service following a temporary fault, for example, a lightning strike.
3. A transmission line that does not have a fault should not be tripped and removed from service due to power swings caused by a fault on a different transmission line or other nearby transmission or generation facilities.

Revision History

Posting Date	Description of Changes
2018-12-06	Inclusion of guidance information and template provided
2016-09-28	Inclusion of submission instructions
	Administrative amendments
2014-05-01	Moved the list of circuits to a separate document
2013-11-12	Administrative Updates
2013-04-30	Initial Release

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

(a) Section 201.7 of the ISO rules, *Dispatches* ("Section 201.7");

(b) Section 203.2 of the ISO rules, *Issuing Dispatches for Energy*;

(c) Section 204.2 of the ISO rules, *Issuing Dispatches for Dispatch Down Service*; and

(d) Section 205.8 of the ISO rules, *Transmission Must Run* ("Section 205.8").

The purpose of this Information Document is to provide guidance regarding the content of dispatches for energy, dispatch down service and transmission must-run that are issued by the AESO, and the process for a pool participant to acknowledge receipt of a dispatch. This information document is likely of most interest to pool participants who receive these dispatches.

2 Dispatch Content

In accordance with subsection 3 of Section 201.7, pool participants are required to comply with dispatches that they receive from the AESO for energy, dispatch down service and transmission must-run.

Dispatches in the Automated Dispatch and Messaging System ("ADaMS") include the information set out below (see Appendix 1):

(a) Name of the pool asset;

(b) The instruction for the pool asset:

- (i) for source assets:
  - (A) Dispatch On (deliver energy or dispatch down service); or
  - (B) Dispatch Off (reduce energy or dispatch down service or dispatch down service delivery)
- (ii) for sink assets:
  - (A) Dispatch On (consume additional energy); or
  - (B) Dispatch Off (reduce consumption)
- (iii) for transmission must-run, the service to be provided;

(c) specific MW value to which the pool asset is receiving a dispatch; and

(d) date and time the dispatch is to take effect.

For more information regarding dispatches in ADaMS, please see the *Automated Dispatch and Messaging System Participant Manual* in the help section of ADaMS, which is available to registered users only.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

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3 Acknowledging Dispatches

Subsection 5 of Section 201.7 requires pool participants to acknowledge receipt of a dispatch. In the case of an automated message, pool participants may acknowledge receipt of the dispatch by selecting the "Ack Disp" radio button within the ADaMS dispatch pane (see Appendix 1).

4 Declaration of Transmission Must-Run Capability

Under subsection 2(2) of Section 205.8, a pool participant under contract for transmission must-run (TMR) is required to submit a declaration of TMR capability via the Energy Trading System (ETS) before 12:00 hours on the day before the day that the offer is effective. The AESO recognizes that the current version of ETS may inhibit pool participant's from submitting a TMR declaration in accordance with subsection 2(2) of Section 205.8 and is considering alternatives to resolve this issue. In the interim, pool participants under contract for TMR are asked to submit TMR declarations to the AESO when the information becomes available.

5 Appendices

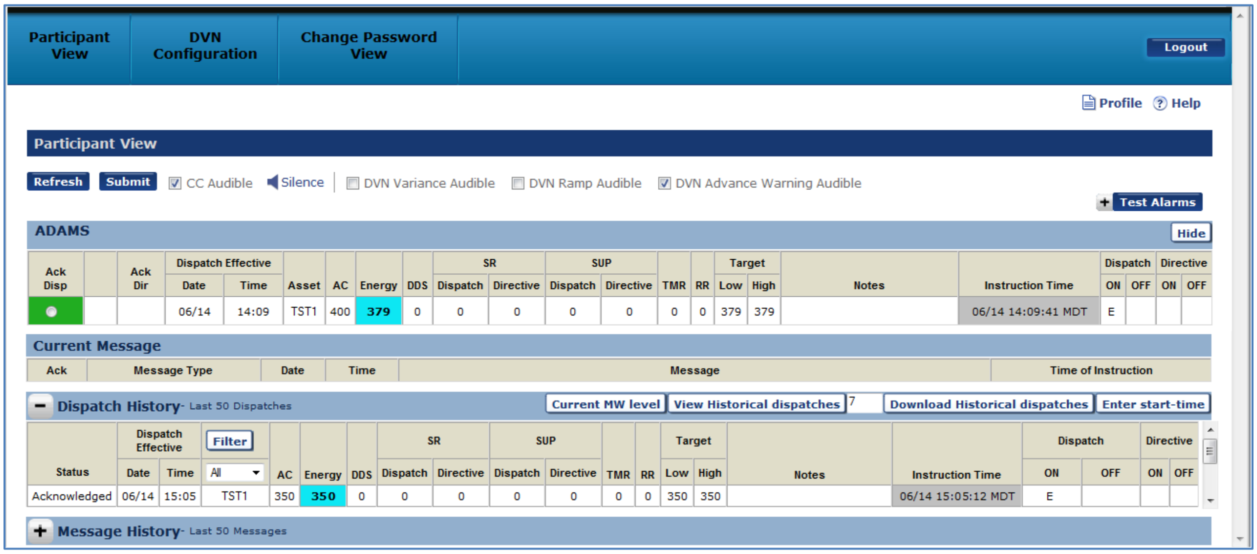
Appendix 1: Figure 1 – ADaMS Dispatch Pane

Revision History

Posting Date	Description of Changes
2017-03-28	Addition of section 4
2016-09-13	Amended section 3 to reflect change to ADaMS dispatch pane for acknowledging receipt of a dispatch. Administrative updates.
2013-01-08	Initial Release

Appendix 1

Figure 1 – ADaMS Dispatch Pane



Information Document
Automatic Generation Control
ID #2012-005RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- Alberta Reliability Standard BAL-005-AB2-0.2b, *Automatic Generation Control* ("BAL-005").

The purpose of this Information Document is to provide a link to the list of metering points and their associated data used for automatic generation control by the AESO, and to provide additional information relating to requirement R12.

2 Background

BAL-005 establishes the requirements for the automatic generation control application within the AESO's energy management system. Included in BAL-005 are requirements detailing quality and calibration of those metering points owned by the legal owner of a transmission facility or a generating unit that the AESO uses for automatic generation control. The inter-control center communications protocol (ICCP) name of the metering points the AESO uses for automatic generation control are provided to enable the legal owner of a transmission facility or a generating unit to map to the physical meter providing the data.

3 Identified Source of Frequency and Intertie Metering Data

The source of the frequency data and intertie metering data identified by the AESO for the purposes of the Applicability section of BAL-005, is available in the document entitled *Identified Source of Frequency Data and Intertie Metering Data* on the AESO website at.

4 Unfiltered Data

Requirement R12.2 states that the legal owner of a transmission facility must not filter megawatt metering data for interconnections or area control error signals transmitted to the AESO. The purpose of requirement R12.2 is to ensure the instantaneous megawatt metering data and area control error signals from the originating site (i.e. remote terminal unit) are the same as the data and signalsreceived by the AESO. Note that this requirement does not prohibit the scaling of data.

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendments
2016-07-01	Moving tables into separate document and including a link to document on AESO website; Adding Section 4, Unfiltered Data; Administrative Updates
2013-09-19	Updated Table 2: Intertie Metering –Bennett (520S) due to recent work at the 102S and 520S substations
	Removed the initial release Table 5 as this is not a synchronous intertie
	Added a new Table 5 for MATL

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

2013-08-22	Initial Release

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:[1]

(a) section 202.2 of the ISO rules, *Short Term Adequacy and Supply Shortfall*;

(b) section 202.4 of the ISO rules, *Managing Long Lead Time Assets*; and

(c) section 202.6 of the ISO rules, *Adequacy of Supply*.

This Information Document provides background information regarding the steps the AESO uses to manage a supply shortfall event and the criteria used for conducting both short-term and long-term adequacy assessments. This Information Document is likely of most interest to pool participants, legal owners and operators of sink assets and source assets, and legal owners of electric distribution systems.

2 AESO Steps in Managing Supply Shortfall

Appendix 1 of this Information Document outlines steps that the AESO takes in managing a supply shortfall event. Certain steps may be more effective than others in differing supply shortfall events.

The AESO continues to meet the control performance standard as defined in the *Consolidated Authoritative Document Glossary* during a supply shortfall event. As such, if the AESO determines that a step in Appendix 1 is not effective in managing the supply shortfall event such that the control performance standards are met, the AESO skips that step and proceeds to steps deemed more effective. If the AESO does skip one or more steps in Appendix 1 when managing a supply shortfall event, the AESO returns to the skipped steps and reduces the requirements for energy from later steps if time and operating conditions permit.

3 Voluntary Efforts to Alleviate Supply Shortfall

The AESO may request the assistance of the following market participants in alleviating the supply shortfall event as follows:

3.1 Pool Participants in General

In response to the message issued pursuant to subsection 3(1) of section 202.2 of the ISO rules, a pool participant may voluntarily curtail load. If a pool participant can no longer voluntarily curtail load, the AESO encourages the pool participant to provide notice to the AESO before restoring large amounts of load.

3.2 Legal Owners of Electric Distribution Systems

The AESO encourages the legal owner of an electric distribution system to make best efforts to achieve a 3% voltage reduction on the electric distribution system. The AESO encourages those who are able to reduce voltage to provide notice to the AESO before restoring voltage to normal.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards and the ISO tariff.

4 Determining Short-term Supply Adequacy

On occasion, the amount of demand is greater than the amount of energy offered in the energy market merit order. When the AESO has issued dispatches for all energy in the energy market merit order, the interconnected electric system may experience a supply shortfall event. Various events such as generation contingencies, transmission contingencies, energy market deficiencies, or unexpected demand levels can produce a supply shortfall event.

The AESO assesses short term adequacy to determine the likelihood of a supply shortfall event in upcoming settlement periods. If the short term adequacy assessment indicates that a supply shortfall event is likely to occur, then the AESO takes steps to maintain regulating reserves and avoid shedding firm load.

5 Long Lead Time Asset Priority Order for Supply Shortfall

If a short term adequacy assessment leads the AESO to take the steps outlined in subsection 3(2) of section 202.2 of the ISO rules, the AESO issues directives to long lead time assets in the following priority order:

(a) shortest start-up time;

(b) largest incremental availability capability;

(c) shortest minimum run time; and

(d) lowest loss factor.

6 Short Term Adequacy Assessment Assumptions

The AESO makes certain assumptions when conducting the calculation described in subsection 3 of section 202.6 of the ISO rules, including using a forecast output from wind and solar aggregated generating facilities, persisting current values for price-responsive loads and behind the fence generation for the next 36 hours, and then applying a fixed number for the remainder of the 7 day period based on statistical data. Currently, the AESO uses 200 MW for price-responsive load and 355 MW for behind the fence generation..

7 Long Term Adequacy Metrics and Reporting

The AESO posts a quarterly report to the AESO website every February, May, August, and November, that contains long term adequacy metrics. The long term adequacy metrics include: new generation projects and retirements, a reserve margin, a supply cushion, and the two year probability of supply adequacy shortfall.

7.1 New Generation Projects and Retirements Metric

The new generation projects and retirement metrics includes four tables. All four tables include the sponsor, project name, fuel type and unit capacity and either the announced in-service date or the retirement date. The metric further classifies projects into the following four categories to provide additional information:

(a) generation projects under active construction, as determined by the AESO;

(b) generation projects which have received government permits or approvals to proceed from the Electric Utilities Board, Alberta Utilities Commission or other Alberta agencies;

(c) generation projects which have a connection application before the AESO or have been publicly announced and have an ongoing commitment to proceed, as determined by the AESO; and

(d) existing generating assets which are known to be retiring as indicated by the public announcements of the owners of such assets or by other publicly available sources of information.

The AESO may provide additional public generation project information regarding the magnitude of the impact of a project on long term adequacy and may identify potential impediments to the timely completion and connection of the projects if appropriate.

7.2 Reserve Margin Metric

The reserve margin metric is a comparison of generation supply and demand during annual peak demand in Alberta. This metric is a calculation of the installed generation capacity and future generation capacity, accounting for seasonal hydro capacity and generation with on-site load, and excluding wind and solar capacity at the time of system peak that is in excess of the system annual peak demand, expressed as a percentage of the system peak. Three forecast reserve margins are presented, each with different future supply additions. The different supply additions correspond to the stage of the generation projects in the new generation projects and retirements metric. The metric may be calculated with or without intertie capacity, as appropriate for the specific study, since full import capability may not always be available at the time of system peak demand.

7.3 Supply Cushion Metric

The supply cushion metric illustrates the ability of installed generation capacity and future generation capacity, accounting for seasonal hydro capacity and generation with on-site load, and excluding wind and solar capacity to meet peak demand on a daily basis. This metric includes existing generation and generation under construction less announced retirements but it does not include transmission outages unless submitted as a generator outage or derate by an asset owner. A deficiency of supply to meet daily peak demand does not mean a supply shortfall exists as there may be other resources such as wind, solar, or imports available to meet demand. Any confidential information used in the metric is only shown in aggregate form.

7.4 Two-year Probability of Supply Adequacy Shortfall Metric

The two-year probability of supply adequacy shortfall metric provides information on potential energy supply shortfall events during the two year period in terms of number of hours of supply shortfalls, largest supply shortfall hour in MW, and total MWh not served. The calculated total MWh not served represents the cumulative total of MW of demand not served during each hour of all supply shortfall events modeled during the two year period.

The AESO may establish other metrics deemed appropriate for the assessment of long term adequacy in Alberta. The other metrics may not necessarily be published in the quarterly report but would be used to assist the AESO in fulfilling its obligations under section 202.6 of the ISO rules and under the *Electric Utilities Act*.

The AESO updates the long term adequacy metric methodology as appropriate. Generally, the methodology:

(a) covers the key elements which directly or indirectly measure long term adequacy;

(b) is relatively simple to understand and promotes understanding of the energy market;

(c) to the extent possible, is based on publicly available and verifiable information; and

(d) provides an outlook on long term adequacy.

8. Long Term Adequacy Threshold Determination and Use

To calculate the long term adequacy threshold, as per the methodology in subsection 5(1) of section 202.6 of the ISO rules, the AESO assumes an average hourly Alberta internal load and uses a one in ten year one-hour supply shortfall. An example of the calculation for an average load of 8000 MW produces a one in ten year one-hour supply shortfall equivalent to 800 MW (8000 MW / 10 years). Applying this over a two year period produces a threshold value of 1600 MWh (800 MWh x 2 years).

9. Long Term Adequacy Threshold Actions

The long term adequacy threshold actions the AESO may procure are described below:

(a) load shed – the AESO contracts with pool participants for the right to curtail load in certain circumstances and under specific terms and conditions.

(b) self-supply and back-up generation – the AESO contracts with the legal owners of self-supply and back-up generating units for the ability to call on such generating units to provide energy production to the system. The contracted generating units normally only produce energy solely for use at the generation site, or are normally available to provide back-up when there is an outage at the generation site, and would not otherwise have been available to participate in the energy market.

(c) emergency portable generation – the AESO would contract with the legal owners of emergency portable generating units for the ability to call on such generating units to provide energy production to the system. Emergency portable generating units are portable units that are not currently located in Alberta but which can be interconnected on short notice if a suitable site is available.

10 Appendices

Appendix 1 – *Table 1: Supply Shortfall Management*

Revision History

Posting Date	Description of Changes
2018-09-04	Updates to reflect addition of solar and clarify assumptions for short term adequacy assessments.
2015-10-19	Addition of Step 20, Appendix 1, Table 1, requesting BC emergency energy.
2013-12-20	Admin update to remove, re-organize and clarify information. Addition of long-term supply adequacy sections relating to section 202.6 of the ISO rules.
2013-07-26	Reordered steps in Table 1 to reflect more efficient process
2013-06-24	Changes to steps in Table 1 to reflect more efficient process
2013-01-08	Initial Release

Appendix 1

Table 1: Supply Shortfall Management

The AESO performs the following steps in managing a supply shortfall event as outlined in section 2 of this Information Document. When returning to normal operations after a supply shortfall event, the AESO follows these steps in reverse order.

(1)	When the short term adequacy program issues an alarm, perform a short term adequacy assessment in accordance with section 202.2.
(2)	Perform planning steps, which may include: (a) if step 8 is anticipated to be reached, cancel transmission maintenance to remove generation constraints or increase import available transfer capability on all interconnections with neighbouring balancing authorities; (b) if it is assessed that shedding of firm load is likely to occur, and sufficient time is available for a public appeal to reduce electrical energy consumption to reduce load, arrange for AESO Corporate Communication to issue a public appeal; (c) allow for 1 hour notice if it is anticipated that the demand opportunity service 1 hour loads are to be curtailed in step 7; (d) determine in which future hours during the potential supply shortfall export available transfer capability on all interconnections with neighbouring balancing authorities are to be posted to 0 MW in step 6 so new export available transfer capability levels can be posted 1 hour in advance (e) if the AESO reasonably anticipates an Energy Emergency Alert 1 or 2 is likely to be reached, notify the adjacent balancing authorities; and (f) allow for 1 hour notice if it is anticipated that the AESO Voluntary Load Curtailment Program loads are to be issued dispatches to terminate load in step 13.
(3)	Issue a dispatch to terminate dispatch down service with respect to a directive for energy from a long lead time asset.
(4)	Internal notifications within the AESO.
(5)	Declare Energy Emergency Alert 1.
(6)	Reduce export available transfer capability to zero on all interconnections with neighbouring balancing authorities and post the updated available transfer capability to the AESO website.
(7)	Curtail demand opportunity service loads.
(8)	Cancel transmission maintenance.
(9)	Issue directives for dispatched contingency reserves that are in excess of the contingency reserve requirement.
(10)	Issue directives for out-of-market energy from long lead time assets.
(11)	Declare Energy Emergency Alert 2.
(12)	Request legal owners of an electric distribution system institute a 3% distribution voltage reduction.

(13)	Issue dispatches to terminate load in the AESO's voluntary load curtailment program as identified by the AESO in internal procedures.
(14)	If available transfer capability is limited because of the lack of offers for load shed service for imports, then disregard this constraint and increase the posted Alberta-BC and Alberta-Montana interconnection import available transfer capability up to the limit as if all available load shed service for imports loads are in service. This step is performed as weather and other operating conditions allow.
(15)	If import available transfer capability is available, permit intra-hour interchange transactions up to the posted import available transfer capability limit.
(16)	Issue directives for supplemental reserves and excess spinning reserves.
(17)	Issue directives for spinning reserves.
(18)	If there is available capacity (i.e., surplus available transfer capability) on the interconnections, request emergency energy from the NWPP.
(19)	If there is available capacity (i.e., surplus available transfer capability) on the interconnections, request emergency energy from Saskatchewan.
(20)	If there is available capacity (i.e., surplus available transfer capability) on the interconnections, request emergency energy from British Colombia.
(21)	Declare Energy Emergency Alert 3. Issue a directive to curtail firm load and set pool price to $1000/MWh

Information Document
List of Facilities Materials to VAR-501-WECC-AB-1
ID #2012-006RS

Except for the lists of facilities in section 3, this information document is for information purposes only and is intended to provide guidance. In the event of any discrepancy between the information document and the related authoritative document(s) in effect, the authoritative document(s) governs. Please submit any questions or comments regarding this information document to InformationDocuments@aeso.ca.

1 Purpose

This information document supports *Alberta Reliability Standard VAR-501-WECC-AB-1 Power System Stabilizer*. The purpose of this information document is to provide the necessary clarification to the Applicability section.

This information document is likely of most interest to legal owners and operators of synchronous generating units.

2 Related Authoritative Documents

The following are the related authoritative documents:

(a) VAR-501-WECC-AB-1.

3 Additional Applicable Facilities

Pursuant to the Applicability section of the reliability standard, the AESO has determined that *VAR-501-WECC-AB-1* also applies to the operator of any of the following facilities, being material to the reliability standard and to the reliability of either the interconnected electric system or the City of Medicine Hat electric system:

(a) Generating units regardless of maximum authorized real power rating:

(i) None identified at this time.

4 Revision History

Effective Date	Description of Changes
2013-10-01	Initial release

1 Purpose

This information document supports Section 202.4 of the ISO rules, *Long Lead Time Energy*. The purpose of this information document is to provide examples of the practical application of that section of the ISO rules. This information document is likely of most interest to pool participants who own or operate long lead time assets.

2 Background

There are essentially two (2) types of generating source assets that are categorized as long lead time assets. As set out in the AESO's *Consolidated Authoritative Document Glossary*:

"**long lead time asset**" means a generating **source asset** that:

(i) requires more than one (1) hour to synchronize to the system under normal operating conditions; or

(ii) is synchronized but has varying start-up times for distinct portions of its MW and which requires more than one (1) hour to deliver such additional portions of its MW; and

which is not delivering all of its energy for reasons other than an **outage**.

3 Long Lead Time Assets Which Take More Than One (1) Hour to Synchronize

This section 3 provides additional information in relation to long lead time assets whose entire maximum capability takes greater than one (1) hour to synchronize.

3.1 Start-up Time

Long lead time assets that fit the criteria in subsection (i) of the definition are required to enter an initial start-up time operating constraint in the Energy Trading System. In the case of long lead time assets whose entire maximum capability takes greater than one (1) hour to synchronize to the grid, this initial start-up time operating constraint in the Energy Trading System is equal to or greater than 1. The AESO expects that this operating constraint accurately portrays the length of time required for the MW to be delivered to the grid. Since the AESO uses initial start-up operating constraint to determine eligible start times, pool participants should ensure that this operating constraint is accurate.

3.2 Start Time

As set out in subsection 2(1) of Section 202.4, long-lead time assets whose entire maximum capability takes greater than one (1) hour to synchronize must enter a start time in the Automatic Dispatch and Messaging System in order to receive a dispatch. This requirement applies only when those pool participants wish to receive a dispatch and participate in the energy market. Long lead time assets do not need to have a start time entered at all times. However, they are still subject to Section 203.1 of the ISO rules, which states that pool participants must offer in the MW, meaning the MW that are currently being produced, from their generating pool assets in all hours.

4 Long Lead Time Assets with Varying Start-up Times for its MW

This section 4 provides additional information in relation to long lead time assets that are synchronized to the grid but are only providing a portion of its maximum capability within that hour, with the remaining

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defined portion of its energy requiring a start time greater than one (1) hour.

4.1 Available Capability Restatements

Long lead time assets that fit the criteria in subsection (ii) of the above definition should reflect the availability of their additional energy through the use of available capability restatements. This might include multi-unit single generating pool assets or plants where MW would not be available from a second generating unit for at least one (1) hour after a cold start, because its operation is dependent on the operation of another generating unit, e.g., a combined cycle plant where the steam generating unit is dependent on the operation of a gas generating unit.

These long lead time assets should have a value of 0 or 1 (the value that is most appropriate) for their initial start-up time operating constraint in the Energy Trading System.

The following is an example of what a pool participant's submissions in the Energy Trading System would look like if they wish to receive a dispatch for their additional long lead time energy, as set out in subsection 3 of section 202.4.

Note: Generating pool assets that are synchronized to the grid and have varying start times for distinct portions of their MW but where start times are all less than one (1) hour do not qualify as long lead time assets. The example below does not apply to them. These assets are subject to ISO rules Section 203.1 subsection 5, in that their available capability must equal their maximum capability unless they have an acceptable operational reason.

Ex. A long lead time asset consists of two (2) generating units. One can be synchronized to the grid in thirty (30) minutes and is capable of generating one hundred (100) MW. The second generating unit can only be started after the first generating unit is synchronized and takes an additional two (2) hours to start, eventually generating fifty (50) MW.

When this long lead time asset is offline, AC=100. When the first generating unit is started up and providing MW, the pool participant may wish to receive a dispatch for the additional fifty (50) MW from the second generating unit. At least two (2) hours prior to the settlement interval in which they wish to provide the additional fifty (50) MW, the pool participant restates their available capability up to one hundred and fifty (150) MW starting in the settlement interval in which the pool participant wishes to receive a dispatch for the MW.

4.2 Offers

Although the situation described in 4.1 constitutes an acceptable operational reason long lead time assets are subject to subsection 3(4)(a) of Section 203.1 of the ISO rules which requires a pool participant to ensure that the total offered MW is equal to the maximum capability of the pool asset. This applies even when the pool asset is a long lead time asset with additional capacity not currently reflected in the available capability. In the example used above, the sum of all offers must be one hundred and fifty (150) MW, even if the second generating unit is offline and there is no intention of bringing it online. See ID# 2012-009R Restatements for an example of how these offers appear in the merit order when available capability does not equal maximum capability.

Revision History

Version	Effective Date	Description of Changes
1.0	2013-01-08	Initial Release

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 203.1 of the ISO rules, *Offers and Bids for Energy* (“Section 203.1”).

The purpose of this information document is to provide additional background information on the requirements for offers and to clarify procedural applications of the requirements contained in Section 203.1. This information document is likely to be of interest to pool participants who own or operate source assets and/or sink assets.

2 Net-to-Grid Offer Requirements

Subsection 3 of Section 203.1 sets out the obligation for all source assets five (5) MW or greater to submit offers. Pool participants with on-site load may choose to offer their energy net-to-grid rather than offering their gross generation. They may do so by entering the source asset’s maximum capability as only the energy that they expect to export to the grid rather than the entire generating capacity of the source asset. The AESO then deems the source asset’s size to be equivalent to such maximum capability. If a pool participant expects to export energy net-to-grid of more than five (5) MW (i.e. their maximum capability is greater than five (5) MW), the pool participant is obligated to submit offers.

3 Inflexible Market Offers

Subsection 3 of Section 203.1 sets out the information that must be included in an offer. Offers can be made up of up to seven operating blocks. Subsection 3(3)(c) of Section 203.1 requires pool participants to indicate whether each operating block is flexible or inflexible. When an operating block is flexible, the AESO may issue a dispatch for all or a portion of the energy contained in that operating block. When an operating block is inflexible, the AESO may only issue a dispatch for the total volume of the energy in the operating block.

If the total volume of the energy in an inflexible operating block is not required, the AESO may bypass that operating block in the energy market merit order and dispatch the next operating block that satisfies current volume requirements. The pool participant’s inflexible operating block will not be dispatched until the real time energy requirements reach a point where the full volume of the operating block is required.

Please also note that Section 202.5 of the ISO rules, *Supply Surplus* includes specific provisions regarding the treatment of flexible/inflexible operating blocks during events of supply surplus.

4 Operating Constraints

Subsection 6 of Section 203.1 sets out the obligation for submitting a source asset’s relevant operating constraints. Clarification of those operating constraints is set out below. As well, subsection 6(2) requires pool participants to re-submit operating constraint information “as soon as reasonably practicable” when those operating constraints change. The AESO expects that when a pool asset’s operating constraints (as listed below) change, the pool participant also updates that operating constraint within fifteen (15) minutes of becoming aware of the change. Minimum on-time, minimum off-time and maximum run-up time are not mandatory operating constraints required Section 203.1 but the capability exists to enter them in the Energy Trading System.

[1] “Authoritative Documents” is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

4.1 Ramp Rate

Ramp rate is defined in the AESO's *Consolidated Authoritative Document Glossary*. Regarding subsection 6(2), the AESO expects that when a source asset's ramp rate changes, the pool participant also updates the ramp rate within fifteen (15) minutes of becoming aware of the change, and ideally no later than the beginning of the settlement interval in which the new ramp rate is to be used.

4.2 Initial Start-up Time

Additional detail on the initial start-up time operating constraint can be found in Section 202.4 of the ISO rules, *Long-lead Time Energy*.

4.3 Minimum On-time and Minimum Off-time

Minimum on-time describes the amount of time, in minutes, needed for a source asset to fully warm up and reach a point where shutting down the generating unit would not cause undue wear and tear. Minimum off-time describes the amount of time needed for a generating unit to fully cool down and reach a point where starting up the generating unit again would not cause undue wear and tear.

4.4 Maximum Run-up Time

Maximum run-up time is the time, in minutes, required for the generating unit to reach minimum stable generation once it is synchronized to the grid.

In general, the AESO uses the operating constraints a pool participant submits to gauge compliance with the applicable ISO rules, making it in a pool participants' best interest to ensure that they are kept accurate.

Revision History

Posting Date	Description of Changes
2017-04-04	Addition of Section 3; and Administrative Amendments
2013-01-08	Initial Release

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 203.3 of the ISO rules, *Energy Restatements* ("Section 203.3").

The purpose of this Information Document is to describe how available capability restatements in subsection 2 of Section 203.3 are applied to an energy offer. This Information Document is likely of most interest to pool participants submitting restatements for energy offers.

2 Available Capability Restatements

Section 203.3 gives pool participants the ability to restate their available capability for source assets under certain operational conditions as set out in subsection 2(1) of Section 203.3. Restating available capability up or down to a level where available capability is less than the generating source asset's maximum capability causes the Energy Trading System to remove portions of the offer from the merit order, as outlined below.

When a pool participant has restated their available capability to a level below their maximum capability, their offers must still total the maximum capability of the generating source asset. However, the only operating blocks for that generating source asset that appear in the merit order for dispatch by the ISO are those which contain the energy up to the current available capability value. Table 1 below shows hypothetical offer structures for a generating source asset with maximum capability equal to one hundred and fifty (150) MW.

Table 1 – Offer Operating Blocks

Block	MW	Price
0	40	$0.00
1	60	$25.00
2	80	$49.00
3	100	$60.00
4	130	$700.00
5	140	$900.00
6	150	$990.00

The total MW in the highest priced operating block is equal to the maximum capability of the generating source asset and as long as available capability equals maximum capability, all seven (7) operating blocks would appear in the merit order in full.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

As an example, assume the pool participant has to restate the available capability of the source asset down to one hundred (100) MW for an acceptable operational reason. Restatements of available capability to a lower level are applied first to the highest priced operating blocks. In this case therefore, only operating blocks 0 through 3 would appear in the merit order.

Table 2 – Offer Operating Blocks with Available Capability = 100MW

Block	MW	Price
0	40	$0.00
1	60	$25.00
2	80	$49.00
3	100	$60.00
4	130	$700.00
5	140	$900.00
6	150	$990.00

When the generating source asset is able to be restated to a higher available capability (e.g. an increase of thirty-five (35) MW) but not all the way to one hundred and fifty (150) MW, the pool participant would submit an available capability restatement to one hundred and thirty-five (135) MW. Restatements of available capability to a higher level are applied first to the lowest priced blocks that are currently not fully in the merit order – in this case, blocks 0 through 4 would appear in the merit order for their full amounts and block 5 would appear in the merit order for one hundred and thirty-five (135) MW instead of one hundred and forty (140) MW.

Table 3 – Offer Operating Blocks with Available Capability = 135MW

Block	MW	Price
0	40	$0.00
1	60	$25.00
2	80	$49.00
3	100	$60.00
4	130	$700.00
5	140	$900.00
6	150	$990.00

3 Price Restatements

Section 203.3 gives pool participants the ability to restate the price associated with an offer or bid for a pool asset. To make a price restatement, pool participants may change the price associated with a bid or offer prior to two (2) hours before the start of a settlement interval. Price restatements do not require an acceptable operational reason.

As an example, see Table 4 below. Since this offer has been submitted for HE12, at any time prior to 9:00 am, the pool participant change the offer as follows:

Table 4 – Offer Operating Blocks for HE12

Block	MW	Price
0	40	$0.00
1	60	$40.00
2	80	$55.00
3	100	$60.00
4	130	$800.00
5	140	$900.00
6	150	$990.00

4 MW Restatements

Section 203.3 gives pool participants the ability to submit a MW restatement, redistributing the MW associated with an offer or bid for a pool asset. MW restatements are only permitted under certain operating conditions, as set out in subsection 4(2) of Section 203.3.

As an example, see Table 5 below. Assume that Table 1 above reflected the original offer for this pool asset.

Table 5 shows the new offer after making a MW restatement where operating conditions required the pool asset to produce a minimum of fifty-five (55) MW.

Table 5 – Offer Operating Blocks

Block	MW	Price
0	55	$0.00
1	60	$25.00
2	80	$49.00
3	100	$60.00
4	130	$700.00
5	140	$900.00
6	150	$990.00

Fifteen (15) MW have been moved from Block 1 into Block 0, into the $0.00 offer block.

Note that when submitting a MW restatement, prices remain constant for each block.

5 Battery Energy Storage Facilities

The AESO has received questions regarding the applicability of ISO rules and Alberta reliability standards to battery energy storage facilities. The AESO is in the process of reviewing these questions and will issue further communications on this matter once the review is complete.

Revision History

Posting Date	Description of Changes
2017-05-11	Addition of section 5
2014-06-13	Rule reference amendment
2013-11-12	Administrative Updates
2013-01-08	Initial Release

Information Document
Dispatch and Directive Records
ID # 2012-010 (R)

Information documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between the information document and the related authoritative document(s) in effect, the authoritative document(s) governs. Please submit any questions or comments regarding this information document to InformationDocuments@aeso.ca.

1 Purpose

This information document supports the following sections of the ISO rules:

(a) Section 201.7 *Dispatches*;

(b) Section 203.2 *Issuing Dispatches for Energy*;

(c) Section 204.2 *Issuing Dispatches for Dispatch Down Service*;

(d) Section 205.8 *Transmission Must Run*; and

(e) Section 301.2 *Directives for the Reliable Operations of the Interconnected Electric System*.

The purpose of this information document is to provide background material regarding the AESO's retention policy for dispatch and directive records. This information document is likely of most interest to pool participants who receive dispatches and directives.

2 Dispatch and Directive Records

The AESO retains an electronic record of all Automated Dispatch and Messaging System dispatches, directives and responses suitable for audit purposes. In the case of voice dispatches, the AESO records all voice conversations that occur on the communication systems.

The AESO keeps dispatch and directive records for no less than forty-five (45) days, and may use them to assess compliance.

3 Requests for Records

Although the AESO expects that pool participants keep their own records of dispatches and directives, pool participants may request to review a record of a dispatch or directive. Pool participants must make such request in writing to info@aeso.ca. The AESO requires the request to contain the following in order to provide correct records to the pool participant:

(a) the pool asset or pool assets affected; and

(b) the approximate date and time of the dispatch or directive which is to be reviewed.

Because of the AESO's policy for retaining these records, the AESO must receive a request for records no more than forty-five (45) days from the date of the dispatch or directive.

If a pool participant requests to review a voice dispatch or directive, the AESO copies the pertinent portions of the voice record and sends them to the requesting pool participant.

The AESO retains voice records that have been requested until any disputes arising from that dispatch or directive have been resolved.

Revision History

Version	Effective Date	Description of Changes
1.0	2013-01-08	Initial Release

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
www.aeso.ca www.poweringalberta.com

Information documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between the information document and the related authoritative document(s) in effect, the authoritative document(s) governs. Please submit any questions or comments regarding this information document to InformationDocuments@aeso.ca.

1 Purpose

This information document provides general information relating to the coordination of energization, commissioning, ancillary services testing and operational testing activities.

2 Related Documents

Legal owners are encouraged to review the following related authoritative documents:

(1) Section 504.3 of the ISO rules, *Coordinating Energization and Commissioning, and Ancillary Services Testing*. Section 504.3 sets out the requirements for coordinating energization, commissioning and ancillary services testing for legal owners of transmission facilities or load facilities. The AESO wishes to point out that section 504.3 does not set out any specific tests that must be performed. Section 504.3 focuses only on the need to coordinate energization commissioning and ancillary services testing with the AESO.

(2) Section 504.4 of the ISO rules, *Coordinating Operational Testing*. Section 504.4 sets out the requirements for coordinating operational testing activities. The AESO wishes to point out that section 504.4 does not set out any specific tests that must be performed. Section 505.4 focuses only on the need to coordinate operational testing activities with the AESO.

(3) The AESO also contracts for ancillary services and the technical requirements for ancillary services are set out in *an Ancillary Services Technical Requirements* document that is available on the AESO website. A legal owner conducting any testing with respect to those requirements is required to coordinate those tests in accordance with the requirements set out in section 504.3.

(4) AESO Processes

a. The AESO's connection process which sets out the process and procedures for connecting facilities to the system.

b. The AESO's behind-the-fence process which sets out the process and procedures for facilities that are behind the fence but connected to the system.

c. The AESO's system projects process[1].

For purposes of this information document, the three (3) processes described above are referred to as "AESO processes".

3 What Kinds of Tests Can a Legal owner Perform?

A legal owner can perform any tests it determines necessary. However, the testing should be coordinated with the AESO so that the AESO can maintain reliable operations of the interconnected

[1] The AESO is presently updating the AESO system project process and will provide a link once the process has been updated.

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
www.aeso.ca www.poweringalberta.com

electric system while the tests are being performed. Section 6 below provides examples of the types of tests that a legal owner needs to coordinate with the AESO.

4 Does the AESO Specify Any Tests?

Yes, the AESO specifies certain tests. The only tests the AESO specifies are those tests relating to ancillary services demonstrating the capability of providing ancillary services. As mentioned above, ancillary services tests are set out in the *Ancillary Services Technical Requirements* document.

5 What Tests Need to be Coordinated with the AESO?

When assessing if a test needs to be coordinated with the AESO, consider whether the test is being performed on:

(a) energized transmission facilities; or

(b) commissioning new transmission facilities; or

(c) commissioning large loads of sufficient size to cause operational concerns (particularly, motor starting that might cause significant voltage depressions).

Following are examples of tests that a legal owner needs to coordinate with the AESO. These examples are intended to provide guidance. The examples are not intended to provide a complete listing of tests that a legal owner needs to coordinate with the AESO.

(a) commissioning a new transmission breaker (date and time);

(b) commissioning a new transformer (date and time);

(c) commissioning a new capacitor bank (date and time);

(d) commissioning or testing motor starting (e.g. variable frequency drives) where the motor size has been identified to cause operational concerns (date and time, test details);

(e) commissioning or testing a static VAr compensator (date and time, test details); and

(f) commissioning or testing a phase shifting transformer (date and time, test details).

6 Commissioning Plans

The commissioning plan, sometimes referred to as the testing plan, or in the case of operational testing an operational test plan, is the generic term used in this information document, to represent a plan a legal owner prepares setting out its testing activities whether those testing activities are commissioning, WECC testing, ancillary services testing or operational testing. The commissioning plan should describe the activities in enough detail such that the AESO can assess these tests and possible impacts on system reliability.

7 Submission and Approval of the Commissioning Plan

<u>Section 504.3</u>

As described in the AESO's processes, for transmission system connections relating to new or modified transmission or load facilities, a legal owner submits the preliminary commissioning plan to the AESO Transmission Project Delivery Project Manager leading the specific project. The AESO's processes set out the timeframes for submitting the preliminary commissioning plans. The AESO reviews this preliminary commissioning plan to determine changes that may be required.

As described in the AESO's processes, a legal owner submits a final commissioning plan to the AESO Operations Coordination group for approval. Subsection 4 of section 504.3 requires that:

> Each of the legal owner of a transmission facility and the legal owner of a transmission-connected load facility must provide final, written commissioning or testing plans to the ISO:
>
> (a) which the ISO approves as being able to be implemented without impacting the reliable operation of the interconnected electric system;
>
> (b) detailing the types of tests the legal owner proposes to conduct;

(c) in sufficient time to allow the ISO to approve the plans a minimum of thirty (30) days prior to commissioning; and

(d) containing the minimum detail as noted in subsection 5 and 6, as appropriate.

In order to have the approved plan in place thirty (30) days prior to commissioning, the a legal owner needs to submit the plan to the AESO ahead of the thirty (30) days to allow the AESO sufficient time for review and approval. The amount of lead time necessary to review and approve a commissioning plan depends on many factors including:

(1) the number and complexity of the tests the legal owner wishes to perform;

(2) the number of other test plans submitted to the AESO by other legal owners, which also need to be reviewed and approved;

(3) the number of planned and unplanned outages that may be occurring during the same time period for which commissioning plans are submitted for review and approval; and

(4) the number and magnitude of reliability issues that the AESO may be dealing with in the same time period that commissioning plans are submitted for review and approval.

As a general guideline and consistent with AESO processes, the AESO suggests that legal owner submit a commissioning plan at least sixty (60) days in advance of the testing to allow the AESO time to review and approve the plan (30) days prior to commencing any of the tests. The lead time for the submission of plans can vary based on the volume and nature of the tests and to provide flexibility a specific lead time is not set out in ISO rules 504.3. As such, legal owners are encouraged to work with the assigned AESO project manager to ensure that the commissioning plans are submitted in timely manner to facilitate having an approved plan in place 30) days prior to commencing any of the tests.

Following is the submission information for commissioning plans relating to section 504.3:

(a) a preliminary commissioning plan for a project administered through the AESO's processes is submitted to the AESO Project Manager leading the project;

(b) a final commissioning plan for a project administered through the AESO's processes is submitted to the AESO's Operations Coordination group at ops.coordination@aeso.ca; and

(c) a final commissioning plan for WECC testing and ancillary testing is submitted to the AESO's Operations Coordination group at ops.coordination@aeso.ca..

Section 504.4

Section 504.4 focuses on any testing a legal owner may wish to perform after energization and commission are complete. Subsection 2 section 504.4 requires that:

> The legal owner of a transmission facility and the legal owner of a transmission-connected load facility that provides final, operational testing plans to the ISO under subsection 3(1) must ensure that:
>
> (a) the ISO approves such plans as being able to be implemented without impacting the reliable operation of the interconnected electric system; and
>
> (e) the legal owner provides such plans in sufficient time to allow the ISO to approve the plans a minimum of fifteen (15) days prior to the desired testing date.

Again, if an approved plan needs to be in place fifteen (15) days prior to commencing any tests, it is prudent for a legal owner to submit the plan ahead of the fifteen (15) days to allow the AESO sufficient time for to review and approve the plan. As a general guideline, the AESO suggests that a legal owner submit commissioning plans for operational tests at least thirty (30) days in advance of the planned testing to allow time for the AESO to review and approve the plan. Also, when a legal owner knows that a specific operational test occurs at very regular points in time (valve testing, for example), the AESO will accept a single (e.g. semi-annual), submission listing the requested dates for such testing. The legal owner will have to submit any changes to the dates in the grouped submission as appropriate for the AESO to be able to approve the revised dates fifteen (15) days in advance of testing.

Furthermore, the AESO wishes to point out that section 504.4 does accommodate testing of a more urgent nature to recover from unexpected operating problems. Legal owners are encouraged to read subsection 3(4) of section 504.4 to understand the specific requirements related to testing of a more urgent nature.

Following is the submission information for commissioning plans relating to section 504.4:

(1) Commissioning plans related to planned operational testing should be submitted to the AESO's Operations Coordination group ops.coordination@aeso.ca.

(2) Requests for testing of an urgent nature necessary to recover from unexpected operation problems should be communicated and coordinated with the AESO System Controller directly. Additional assessment and coordination may involve the AESO's Operations Coordination group.

8 Real Time Approval of Testing

In addition to approving commissioning plans as described above, the AESO also provides the legal owner to obtain the AESO's verbal authorization one (1) hour in advance of the testing, as indicated in section 504.3 and section 504.4. The AESO will provide such approval if the real time conditions of the system allow for the specific tests. If, based on the real time system conditions, the system cannot be operated in a safe and reliable manner, then the AESO will work with the legal owner to re-schedule those tests.

9 Information to Include in a Commissioning Plan

Each project differs due to the nature, size and complexity of the project. Therefore, the information contained in a commissioning plan differs. A legal owner's commissioning plan should include enough information such that the AESO can assess the impact those tests may have on the transmission system. Any legal owner that is unsure of what to include in a commissioning plan may contact the AESO Project Manager leading the project or the AESO Operations Coordination group (ops.coordination@aeso.ca) for direction.

Revision History

2012-12-31	Initial Release

Information documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between the information document and the related authoritative document(s) in effect, the authoritative document(s) governs. Please submit any questions or comments regarding this information document to InformationDocument@aeso.ca.

1 Purpose

This information document provides general information relating to the coordination of synchronization, energization, base line and model validation (formerly known as WECC testing) testing activities, ancillary services testing and operational testing activities.

2 Related Documents

Legal owners are encouraged to review the following related documents:

(1) Section 505.3 of the ISO rules, *Coordinating Energization, Commissioning and WECC Testing Activities*. Section 505.3 sets out the requirements for coordinating synchronization, commissioning, WECC testing, and ancillary services testing activities with the AESO. The AESO wishes to point out that section 505.3 does not set out any specific tests that must be performed. Section 505.3 focuses only on the need to coordinate testing activities with the AESO.

(2) Section 505.4 of the ISO rules, *Coordinating Operational Testing Activities*. Section 505.4 sets out the requirements for coordinating operational testing activities with the AESO. The AESO wishes to point out that section 505.4 does not set out any specific test that must be performed. Section 505.4 focuses only on the need to coordinate testing activities with the AESO.

(3) Section 502.16 of the ISO rules, *Aggregated Generating Facilities Operating Requirements* sets out specific model validation testing that wind and solar aggregated generating facilities must perform. The coordination of these tests is subject to the requirements in section 505.3.

(4) Section 502.6 of the ISO rules, *Generating Unit Operating Requirements* sets out the baseline and model validation testing a generating unit must perform. The coordination of those tests is subject to the requirements in section 505.3.

(5) Section 502.14 of the ISO rules, *Battery Energy Storage Facility Operating Requirements* sets out the baseline and model validation testing a battery energy storage facility must perform. As part of good electric industry operating practice, the AESO expects the legal owner to coordinate those tests in the manner set out for generating units and aggregated generating facilities in section 505.3 of the ISO rules, *Coordinating Energization, Commissioning and WECC Testing Activities*.

(6) The AESO also contracts for ancillary services and the technical requirements for ancillary services are set out in the Section 205.4 of the ISO rules, *Regulating Reserve Technical Requirements and Performance Standards*, Section 205.5 of the ISO rules, *Spinning Reserve Technical Requirements and Performance Standards*, and Section 205.6 of the ISO rules, *Supplemental Reserve Technical Requirements and Performance Standards* that are available on the AESO website. A legal owner conducting any testing with respect to those requirements is required to coordinate those tests in accordance with the requirements set out in section 505.3.

(7) AESO Processes:

(a) the AESO’s connection process which sets out the process and procedures for connecting facilities to the system;

(b) the AESO’s behind-the-fence process which sets out the process and procedures for facilities that are behind the fence but connected to the system; and

(c) the AESO's system projects process[1]

For purposes of this information document, the 3 processes described above are referred to as "AESO processes".

3 What Kind of Tests Can a Legal Owner Perform?

A legal owner can perform any tests it determines necessary. However, the AESO expects that testing will be coordinated with the AESO so that the AESO can maintain reliable operations of the interconnected electric system while the tests are being performed. Section 6 below provides examples of the types of tests to be coordinated with the AESO.

4 Does the AESO Specify Any Tests?

Yes, the AESO specifies certain tests. The AESO specifies the base line and model validation testing, formerly referred to as WECC testing. In addition, the AESO specifies ancillary services tests demonstrating the capability of providing ancillary services.

Section 502.16 sets out the model validation testing for wind and solar aggregated facilities.

Section 502.6 sets out the baseline and model validation testing for generating units.

Section 502.14 sets out the baseline and model validation testing for battery energy storage facility.

Ancillary services tests are set out in the . Section 205.4 of the ISO rules, *Regulating Reserve Technical Requirements and Performance Standards*, Section 205.5 of the ISO rules, *Spinning Reserve Technical Requirements and Performance Standards*, and Section 205.6 of the ISO rules*, Supplemental Reserve Technical Requirements and Performance Standards*.

5 What Tests are to be (?)Coordinated with the AESO?

When assessing if it's appropriate to coordinate a test with the AESO, consider whether the test:

(a) affects the net-to-grid output (real power or reactive power) of a generating unit or aggregated generating facility;

(b) imposes an operational limitation concerning a generating unit's or aggregated generating facility's net-to-grid output (real power or reactive power) that is not encountered during routine operation (e.g. it is unavailable or derated, or cannot respond to dispatches or directives from the AESO); or

(c) exposes a generating unit or aggregated generating facility to increased risk of tripping compared to routine operation.

If a legal owner is unsure if a test should be coordinated with the AESO, then contact the AESO's Operations Coordination group at gen.testing@aeso.ca. The AESO's goal is to help legal owners complete their testing; the AESO is in the best position to help legal owners complete their tests if it

[1] The AESO grid connection process is available at https://www.aeso.ca/grid/connecting-to-the-grid/connection-process/

knows about those tests.

Following are examples of tests to coordinate with the AESO. These examples are intended to provide guidance. The examples are not intended to provide a complete listing of tests to coordinate with the AESO.

Examples of Types of Testing

(1) A legal owner wishes to perform baseline and model validation testing, including reactive power verification testing

Do you coordinate baseline and model validation testing with the AESO?

Yes, coordinate baseline and model validation testing with the AESO because this type of testing may:

(a) be impacted by transmission constraints, whether due to planned outages or unplanned real-time conditions;

(b) require transmission system conditions to be pre-configured;

(c) impose restrictions on grid operations; or

(d) affect grid conditions, requiring the AESO's awareness.

(2) A legal owner wishes to perform ancillary services testing to demonstrate its capability of providing ancillary services.

Do you coordinate ancillary services tests with the AESO.

Yes, coordinate ancillary services tests with the AESO because this type of testing may:

(a) be impacted by transmission constraints, whether due to planned outages or unplanned real-time conditions;

(b) require transmission system conditions to be pre-configured;

(c) impose restrictions on grid operations; or

(d) affect grid conditions, requiring the AESO's awareness.

(3) After a generating unit or aggregating generating facility is synchronized, a legal owner wishes to perform initial commissioning tests such as load rejection tests, testing of automated voltage regulators and power system stabilizer systems, and boiler controls tuning.

Do you coordinate these type of tests with the AESO?

Yes, coordinate these type of tests with the AESO because this type of testing may:

(a) be impacted by transmission constraints, whether due to planned outages or unplanned real-time conditions;

(b) require transmission system conditions to be pre-configured;

(c) impose restrictions on grid operations; or

(d) affect grid conditions, requiring the AESO's awareness.

(4) A legal owner wishes to perform efficiency testing whereby the output of a generating unit will be held at a specific output level for a period of time.

Do you coordinate this test with the AESO?

Yes, coordinate this type of test with the AESO so that the AESO knows that the output level is inflexible for a period of time. And the test may:

(a) be impacted by transmission constraints, whether due to planned outages or unplanned real-time conditions;

(b) impose restrictions on grid operations; or

(c) affect grid conditions, requiring the AESO's awareness.

(5) A legal owner wishes to perform a test which will not change the output of the generating unit or facility but during the test, the legal owner will not be able to respond to a dispatch.

Do you coordinate this test with the AESO?

Yes, coordinate this type of test with the AESO for the AESO to be aware of the operational limitations of the generating unit during the test period.

(6) A legal owner wishes to perform operator training activities.

Do you coordinate operator training activities with the AESO?

Yes, coordinate operator training activities with the AESO if those activities impose operating conditions or restrictions not normally encountered in routine operation affecting the net-to-grid real or reactive output. Please note however, the AESO does not anticipate that operator training will normally affect net-to-grid or reactive power output.

(7) A legal owner wishes to perform relative accuracy test audits ("RATA testing").

Do you coordinate RATA testing with the AESO?

Yes, coordinate RATA testing with the AESO because this type of testing may:

(a) be impacted by transmission constraints, whether due to planned outages or unplanned real-time conditions;

(b) impose restrictions on grid operations; or

(c) affect grid conditions, requiring the AESO's awareness.

(8) A legal owner wishes to perform safety valve testing.

Do you coordinate safety valve testing with the AESO?

Yes, coordinate safety valve testing with the AESO because this type of testing may:

(a) be impacted by transmission constraints, whether due to planned outages or unplanned real-time conditions;

(b) impose restrictions on grid operations; or

(c) affect grid conditions, requiring the AESO's awareness.

(9) A legal owner wishes to perform tests following planned and unplanned outages.

Do you coordinate these tests with the AESO?

Yes, coordinate these tests with the AESO if those tests will affect the net-to-grid output (real power or reactive power) of a generating unit or aggregating generating gacility, or impose an operational limitation concerning a generating unit's net-to-grid output (real power or reactive power) that is not encountered during routine operation because such testing may:

(a) be impacted by transmission constraints, whether due to planned outages or unplanned real-time conditions;

(b) require transmission system conditions to be pre-configured;

(c) impose restrictions on grid operations; or

(d) affect grid conditions, requiring the AESO's awareness.

The AESO makes all reasonable efforts to assist legal owners to complete operational testing. However, various system conditions, including planned or forced transmission outages, may impact operational testing.

6 Commissioning Plans

The commissioning plan, sometimes referred to as the testing plan, or in the case of operational testing an operational test plan, is the generic term used in this information document, to represent a plan a legal owner prepares setting out its testing activities, whether those testing activities are commissioning, WECC testing, ancillary services testing, or operational testing. The commissioning plan should describe the activities in enough detail that the AESO can assess these tests and possible impacts on system reliability.

7 Submission and Approval of the Commissioning Plan

<u>Section 505.3</u>

Section 505.3 focuses on coordinating energization, commissioning, WECC testing and ancillary services testing. Subsection 3 of section 505.3 sets a deadline of 30 days prior to commissioning or testing for a final, ISO-approved commissioning or testing plan to be in place.

In order to have the approved plan in place 30 days prior to commencing any of the tests, the legal owner needs to submit the plan to the AESO ahead of the 30 days to allow the AESO sufficient time for review and approval. The amount of lead time necessary to review and approve a commissioning plan depends on many factors including:

(1) the number and complexity of the tests the legal owner wishes to perform;

(2) the number of other test plans submitted to the AESO by other legal owners, which also need to be reviewed and approved;

(3) the number of planned and unplanned outages that may be occurring during the same time period for which commissioning plans are submitted for review and approval; and

(4) the number and magnitude of reliability issues that the AESO may be dealing with in the same time period that commissioning plans are submitted for review and approval.

As a general guideline and consistent with AESO processes, the AESO suggests that a legal owner submit a commissioning plan at least 60 days in advance of the testing to allow the AESO time to review and approve the plan 30 days prior to commencing any of the tests. The lead time for the submission of plans will vary based on the volume and nature of the tests and to provide flexibility, a specific lead time is not set out in section 505.3. As such, legal owners are encouraged to work with the assigned AESO project manager to ensure that the commissioning plans are submitted in a timely manner to facilitate having an approved plan in place 30 days prior to commencing any of the tests.

Following is the submission information for commissioning plans relating to section 505.3:

(1) a preliminary commissioning plan for a project administered through the AESO's processes is submitted to the AESO Project Manager leading the project;

(2) a final commissioning plan for a project administered through the AESO's processes is submitted to the AESO's Operations Coordination group at gen.testing@aeso.ca; and

(3) a final commissioning plan for WECC testing and ancillary testing is submitted to the AESO's Operations Coordination group at gen.testing@aeso.ca.

Section 505.4

Section 505.4 focuses on any testing a legal owner may wish to perform after energization and commission are complete. Subsection 2 of section 505.4 sets a deadline of 15 days prior to the desired testing date for for a final, ISO-approved operational testing plan to be in place.

Again, if an approved plan needs to be in place 15 days prior to commencing any tests, it is prudent for a legal owner to submit the plan ahead of the 15 days to allow the AESO sufficient time to review and approve the plan. As a general guideline, the AESO suggests that a legal owner submit a commissioning plan for operational tests at least 30 days in advance of the planned testing to allow time for the AESO to review and approve the plan. Also, when a legal owner knows that a specific operational test occurs at very regular points in time (valve testing, for example), the AESO will accept a single (e.g. semi-annual) submission listing the requested dates for such testing. The legal owner will have to submit any changes to the dates in the grouped submission as appropriate for the AESO to be able to approve the revised dates 15 days in advance of testing.

Furthermore, the AESO wishes to point out that section 505.4 does accommodate testing of a more urgent nature to recover from unexpected operating problems. Legal owners are encouraged to read subsection 3(4) of section 505.4 to understand the specific requirements related to testing of a more urgent nature.

Following is the submission information for commissioning plans relating to section 505.4:

(1) Commissioning plans related to planned operational testing are submitted to the AESO's Operations Coordination group gen.testing@aeso.ca.

(2) Requests for testing of an urgent nature necessary to recover from unexpected operation problems are communicated and coordinated with the AESO System Controller directly. Additional assessment and coordination may involve the AESO's Operations Coordination group.

8 Real Time Approval of Testing

In addition to approving commissioning plans as described above, the legal owner also needs to obtain the AESO`s verbal authorization one hour in advance of the testing, as indicated in subsection 6(2) of section 505.3 and subsection 3(2) of section 505.4. The AESO will provide such approval if the real time conditions of the system allow for the specific tests. If, based on the real time system conditions, the system cannot be operated in a safe and reliable manner, the AESO will work with the legal owner to re-schedule those tests.

9 Information to Include in a Commissioning Plan

Each project differs due to the nature, size, and complexity of the project. Therefore, the information contained in a commissioning plan varies. It is important that a legal owner's commissioning plan include enough information for the AESO toassess the impact those tests may have on the transmission system.

The information required for WECC testing, ancillary services testing, and operational plans also varies. As examples:

(a) WECC testing requires specific mention of both real power and reactive power output levels (net-to-grid);

(b) RATA testing must specify real power output (net-to-grid), but may describe reactive power output (net-to-grid) in a generic manner, such as “As required for real time conditions” or “AVR in automatic mode”; and

(c) transformer commissioning should include the required unloaded soak period.

Any legal owner that is unsure of what to include in a commissioning plan may contact the AESO Project Manager leading the project or the AESO Operations Coordination group (gen.testing@aeso.ca) for direction.

Revision History

2018-09-04	Solar facilty added, updated rule reference to ISO rule 502.16 and 502.6, ancillary service technical requirement reference changed to ISO rules 205.4,205.5 and 205.6
2014-06-26	Email Address Update
2013-11-12	Administrative Updates
2012-12-31	Initial Release

Information Document
Supervisory Control and Data Acquisition
ID #2012-013R

Information documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

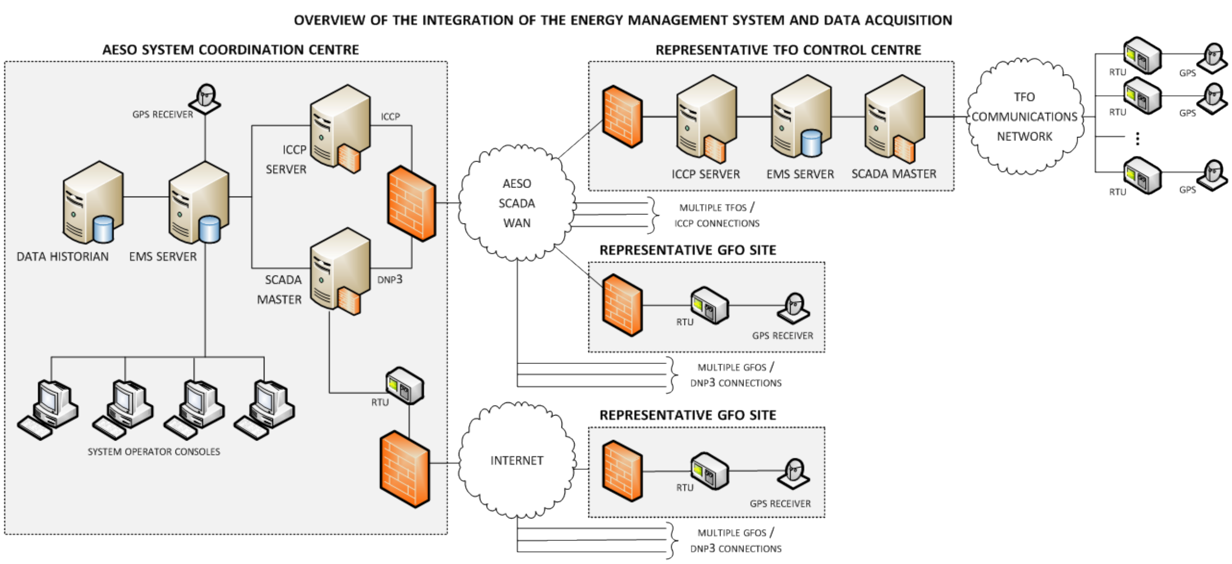
This Information Document relates to the following Authoritative Document[1]:

- Section 502.8 of the ISO rules, *Supervisory Control and Data Acquisition Technical and Operating Requirements* ("Section 502.8").

The purpose of this Information Document is to provide general information relating to supervisory control and data acquisition. Section 502.8 is focused on the design and build domain. For clarity, Section 502.8 requires that a market participant, while designing and building its facilities, design and build the facilities in accordance with the requirements and obligations set out in Section 502.8.

2 AESO Coordination Center System Overview

The AESO Energy Management System is designed to support the safe, reliable and economic operation of the interconnected electric system. It consists of several components as illustrated and described below:



<u>Data Historian</u>

The data historian contains a record of selected supervisory control and data acquisition data and system data for retrieval at a later date. The data historian allows the viewing of data trends over long periods of time. Some of the uses of this data are to support the review of system events, sequence of events, determination of peak loads, forecasting using load flow records, and trending.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

System Operator Consoles

The system operator consoles provide the AESO system controllers with the data and visual displays they require for operating the interconnected electric system. Real time data is displayed in a variety of ways to allow operating decisions to be made. A variety of applications are used to assist with dispatch of generation and ancillary services, network analysis of power flow, and system security analysis for contingencies. These applications depend on the validity of supervisory control and data acquisition data to function properly.

AESO Energy Management System

The AESO Energy Management System collects all the supervisory control and data acquisition data and arranges it for use by the various applications and systems that depend on the data. Data validation is done by the AESO Energy Management System to ensure that the supervisory control and data acquisition data is being received correctly and reliably. Subsystems within the AESO Energy Management System include:

- State Estimator: The state estimator calculates and evaluates power flow on the system based on supervisory control and data acquisition data and the transmission system model. The results of the state estimator are used by the AESO Energy Management System security applications, which provide real time contingency analysis and dispatcher load flows.
- Automatic Generation Control (for Regulating Reserves): The automatic generation control regulates the generation on the system to balance load, import/export, and generation. The automatic generation control also calculates the area control error and adjusts generator output to maintain the desired import or export of energy.

Inter Control Centre Protocol Server

The Inter Control Centre Protocol Server serves as the data concentrator for supervisory control and data acquisition data obtained from third party Inter Control Centre Protocol Servers via wide area network connections. These connections are depicted as the ‘Representative TFO Control Centre’ in the above diagram.

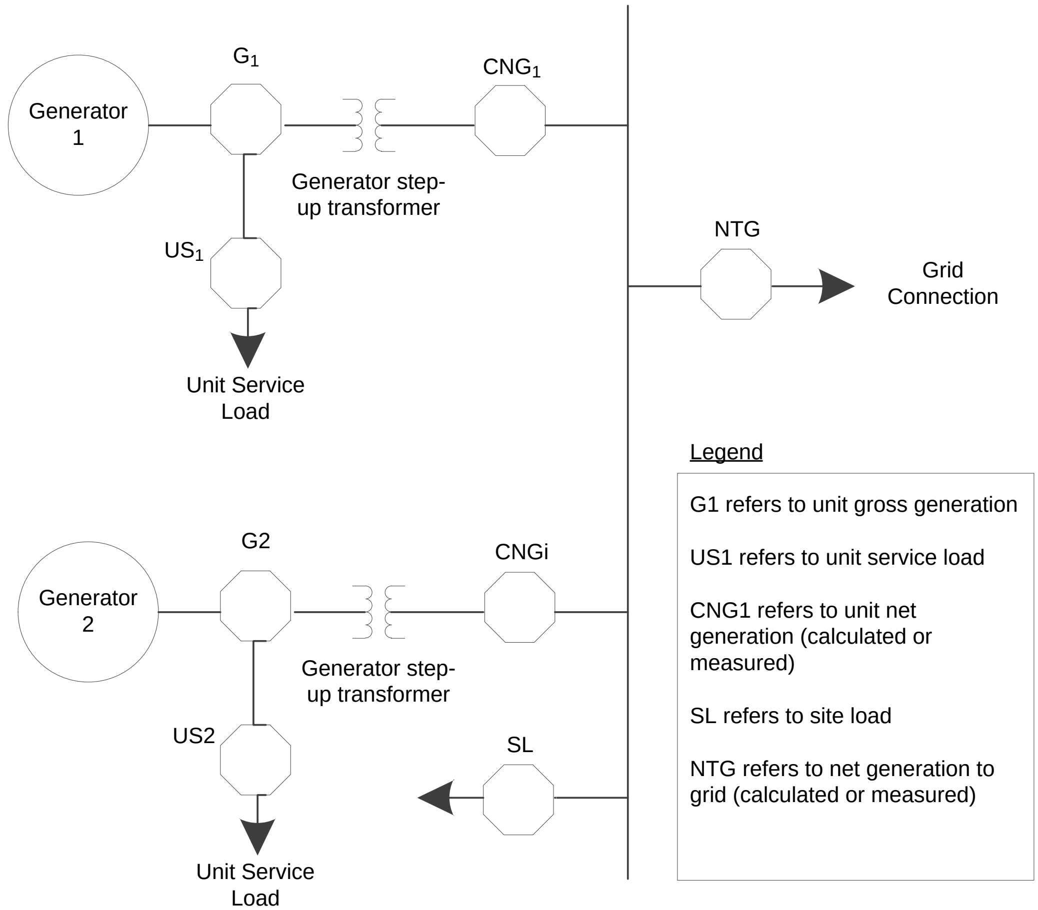
Supervisory Control and Data Acquisition Master

The Supervisory Control and Data Acquisition Master serves as a data concentrator for the supervisory control and data acquisition data collected by the AESO from remote terminal units and other intelligent electronic devices. A dedicated remote terminal unit collects data for internet-based connections. Direct communications using dedicated wide area network connectivity occur directly with the Supervisory Control and Data Acquisition Master. These connections are depicted via the ‘Representative GFO Site’ in the above diagram.

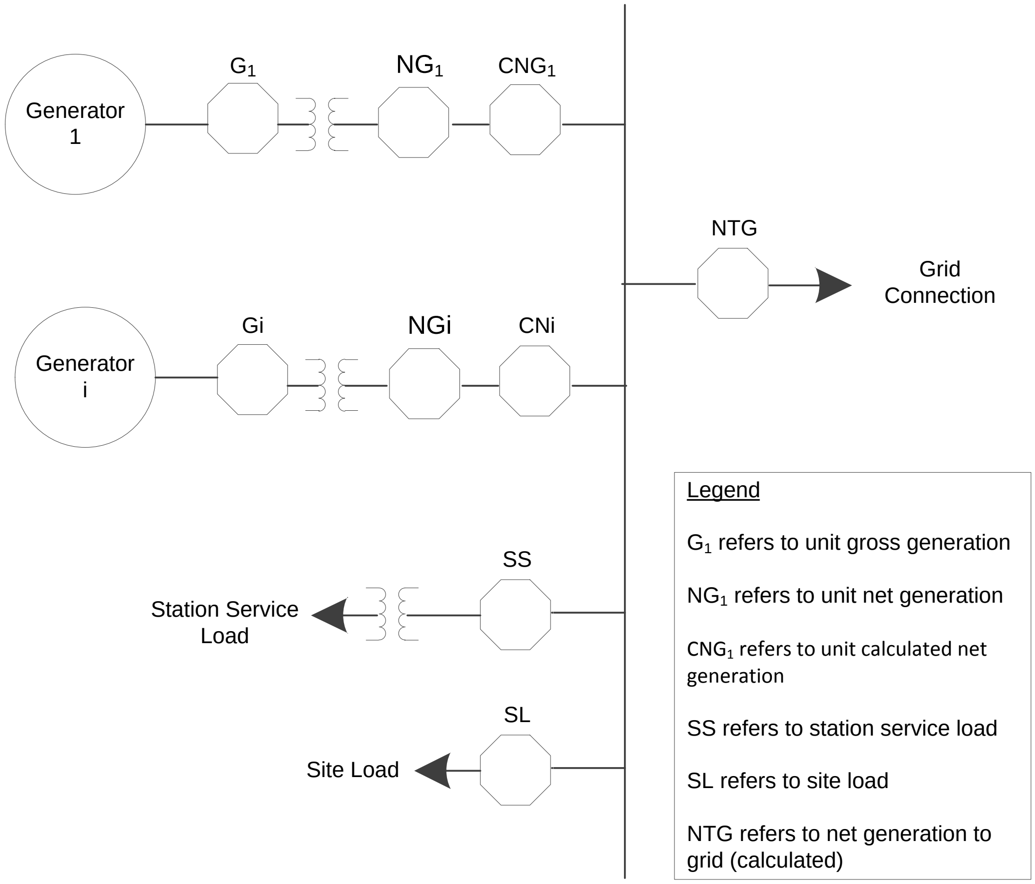
3 Facility Configurations

Below are example diagrams which illustrate common facility configurations. These diagrams are intended to help market participants understand point names as identified in the diagram legend.

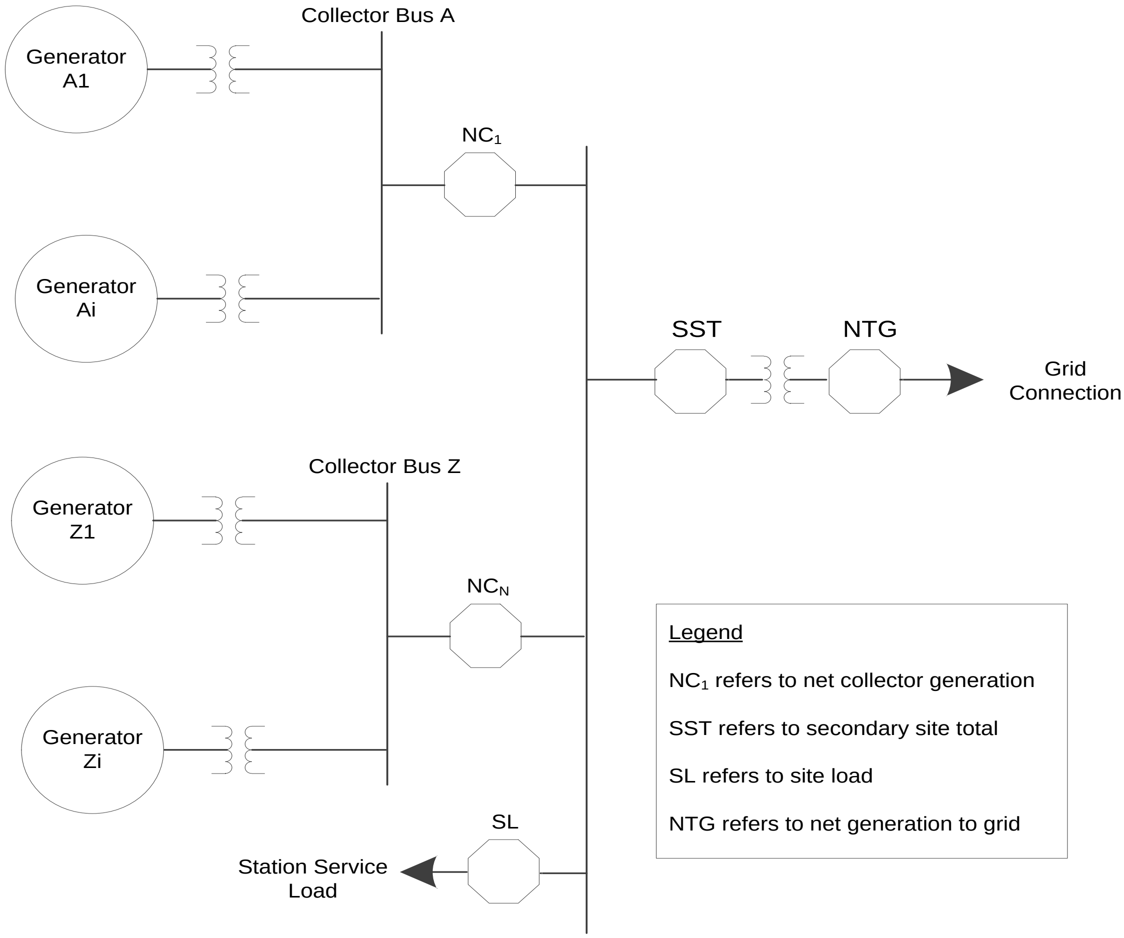
Power Plant with Separate Service for Each Generating Unit within the Power Plant



Power Plant with Single Station Service for Several Generating Units within the Power Plant



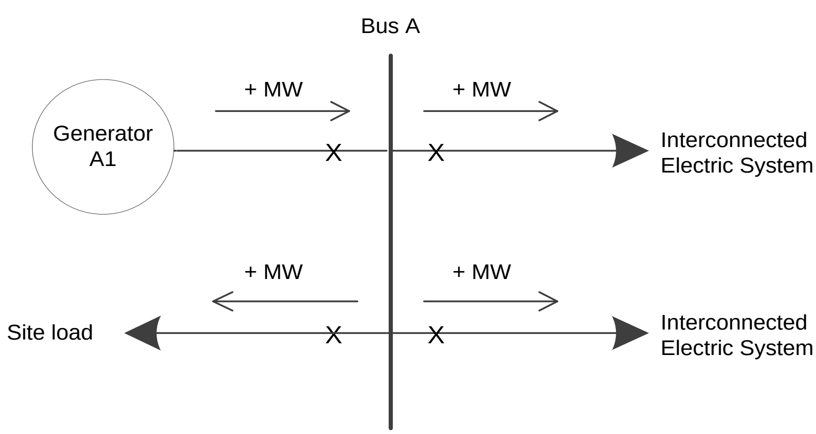
Collector System for Multiple Distributed Units



4 Polarity (Sign) Convention

Section 502.8 requires that analog values be reported with the positive sign convention of positive power flow from a bus. Refer to the examples below for additional interpretation on polarity (sign) conventions.

The example below depicts the direction of power flow. Power flows in the opposite direction are to be reported as negative numbers.



5 Generic Communication Block Diagrams

Understanding the communication path between a market participant's facility and the AESO's coordination center can help both the AESO and the market participant understand communication issues and develop an action plan to resolve those issues.

Prior to energizing and connecting new facilities it is important for the market participant to select the communication block diagram that represents the communication path between the market participant's facility and the AESO's coordination center.

Rather than have each market participant depict its own communication path the AESO has developed two generic communication block diagrams which represent the typical communication paths. Please refer to Appendix 1 to review these diagrams. A market participant will be expected to inform the AESO which diagram represents the communication path for its facilities with amendments if necessary.

6 Notification of Unplanned Availability, Suspected Failure or Erroneous Data

Each market participant must, in accordance with Section 502.8, notify the AESO system controller if the legal owner experiences an unplanned outage to its supervisory control and data acquisition system or any component of the supervisory control and data acquisition system.Each market participant must notify the AESO system controller if the legal owner suspects the remote terminal unit has failed or is providing erroneous data to the AESO.

The AESO monitors the DNP/ICCP application communication status alarms between the AESO Energy Management System and a market participant's supervisory control and data acquisition system, and will contact the market participant when it identifies a communication connection issue. Market participants are encouraged to notify the AESO at EMS_SCADA@aeso.ca of their appropriate contact information for addressing SCADA matters.

For the purposes of the availability requirements in the appendices to Section 508.2, connection availability is calculated on an annual calendar basis (i.e., 98% availability * 365 days = 357.7 days available and 7.3 days unavailable per annum). The corresponding "mean time to repair" is representative of the AESO's expectations for re-establishing communications after an unplanned unavailability event is discovered. The AESO recommends that if a market participant's resolution plan (submitted in accordance with subsection 9 of Section 502.8) exceeds this value, that the plan submitted to the AESO provide sufficient explanation for why the repairs will exceed the "mean time to repair" value. If a MP makes a request pursuant to subsection 11 of Section 502.8 and the plan and expected date for repair is reasonable and acceptable to the AESO then the unavailability during the repair period is not included in the availability calculation.

If a market participant wishes to set up real time monitoring through the AESO Energy Management System such that the market participant can directly monitor the entire communication path to the AESO, the AESO will give consideration to such a request on a case-by-case basis. Requests for real time monitoring may be sent to EMS_SCADA@aeso.ca.

7 Positive Polarity Example

Normal convention for polarity at substations is, "positive out of the bus". However, measurements representing an injection of real or reactive power into the system, such as from a generator or capacitor bank, are represented with positive magnitudes into a bus.

8 Full Scale Example

A field device is monitoring a line voltage with a nominal (i.e. designed operating range) rating of 138 kV. The transducer is providing an analog value based on a 4-20 mA input signal, where 20 mA indicates the full scale value (i.e. the upper limit of the input).

By the ISO rules, the line rating must have a maximum value of 120% of the nominal rating.
Ergo: 138 kV * 120% = 165.6 kV

This means that the input signal should be calibrated so that the transducer reports a "full scale" value of 165.6 kV when at its maximum of 20 mA.

9 Analog Accuracy Example

In the table, AESO has asked that value be +/- 2% of a "full scale" value. Using the above example:

i. A 138 kV measurement has a "full scale" value of 165.6 kV. 2% of this value is 165.5 kV * 2% = 3.3 kV.

ii. A generator has a nominal equipment rating to produce 50 MW of real power. As per subsection 7(6) of Section 502.8, the full scale value must be within 120% to 200% of the nominal equipment rating; the generator owner has decided to implement a 200% rating. The minimum acceptable accuracy of the unit is:

   Full scale value = 50 MW * 200% = 100 MW

   2% Accuracy = 100 MW * 2% = +/-2 MW of actual output power

10 Time Stamped Data

Where the legal owner is required to install a global positioning system clock under subsection 7(11) of Section 502.8, subsection 7(12) requires all supervisory control and data acquisition data provided to the AESO pursuant to subsections 5 and 7 to be time stamped.

Revision History

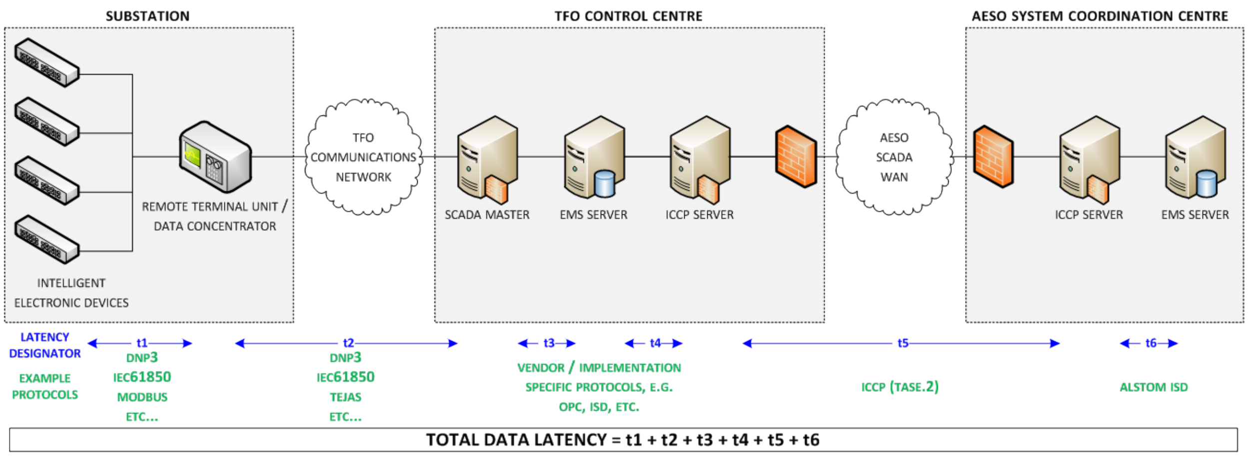
2017-04-06	Addition to section 6 Amendment to section 9, section reference changed
2017-02-09	Addition of Section 10 - Time Stamped Data. Administrative Amendments
2013-02-28	Initial Release

Appendix 1 – Generic Communication Block Diagrams

Below are two generic communication block diagrams depicting the typical communication paths.

ISO Communications Block Diagram 1

The first diagram depicts the communication path where the market participant is using a transmission facilities owner’s communications network for transmitting the supervisory control and data acquisition data between its facility and the AESO’s coordination center.



Notes:

1. Substation Communications Schematic

Intended to be a simplified representation of data collection devices located at the substation (or other field facility). Should be provided on a project-by-project basis (or indicate that follows a specific template). Desired information includes:
- protocol(s) used
- scan rate from RTU to IED (**t1**)

2. TFO Control Centre Schematic

Intended to represent all intermediate data collection/processing devices and the information transfer rates between them. Note this is a generic representation; actual flow of data will need to be provided by the operating entity. It is expected that this information will be relatively static and only need to updated when a significant change occurs to the TFO’s SCADA/EMS systems, but may be inclusive of several different data streams with unique configurations.
- protocol(s) used
- scan rate from SCADA master or front-end processor (FEP) to RTU (**t2**)
- data transfer rate from SCADA master to primary EMS server (**t3**).
(NB: It is expected that any communication device (e.g. modem, router, firewall, switch multiplexor, etc.) processing delays are minimal. Please indicate if this is not the case.)
- data transfer rate from the EMS server to ICCP server (**t4**)

3. AESO System Coordination Centre

The AESO configures its ICCP data sets to meet the latency rates specified in the SCADA standard; these are typically sampled at twice the latency rate. This representation is for information only.

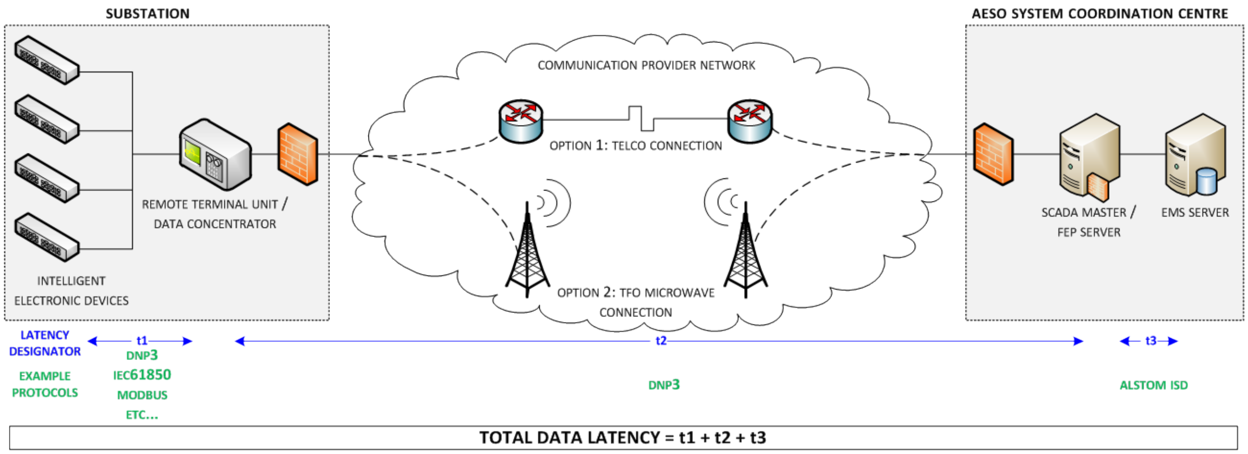
t5 = 2s, 7s, or 15s (as required)
t6 = 1s (data transfer between the AESO’s ICCP and EMS servers)

4. For applicable facilities, it is expected that data is time-stamped from a GPS source at the source of the data (or applicable sampling device) and transmitted to the AESO.

5. Note that data connections are required to both the AESO System Coordination Centre (SCC) and Backup Coordination Centre (BUCC). Circuit redundancy may be required based on facility size and criticality.

ISO Communications Block Diagram 2

The second diagram depicts the communication path where the market participant is using either an independent network provider or the transmission facilities owner's microwave connection for transmitting the supervisory control and data acquisition data between its facility and the AESO's coordination center.



Notes:

1. Substation Communications Schematic

Intended to be a simplified representation of data collection devices located at the substation (or other field facility). Should be provided on a project-by-project basis (or indicate that follows a specific template). Desired information includes:
- protocol(s) used
- scan rate from RTU to IED (**t1**)

2. Communication Provider Network

This is intended to be a generic representation of possible communication paths where SCADA data is acquired directly form site. Current options include use of:
A) Commercial telecommunications provider (e.g. Telus)
B) TFO (transmission facility owner) microwave communications system

The AESO will configure the scan rate from SCADA master or front-end processor (FEP) to RTU (**t2** = 2s, 7s, or 15s as required) using the DNP3 protocol
(NB: It is expected that any communication device (e.g. modem, router, firewall, switch multiplexor, etc.) processing delays are minimal. Please indicate if this is not the case.)

3. AESO System Coordination Centre

This representation is for information only. **t3** = 1s (data transfer between the AESO's FEP and EMS servers)

4. For applicable facilities, it is expected that data is time-stamped from a GPS source at the source of the data (or applicable sampling device) and transmitted to the AESO.

5. Note that data connections are required to both the AESO System Coordination Centre (SCC) and Backup Coordination Centre (BUCC). Circuit redundancy may be required based on facility size and criticality.

Information Document
Cold Lake Area Transmission Constraint Management
ID# 2012-015R

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents[1]: Section 302.1, *Real Time Transmission Constraint Management*. The AESO issues Information Documents to provide additional information and interpretations regarding certain subject matter set out in the AESO's Authoritative Documents. The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits in the Cold Lake area of the Alberta interconnected electric system. In this Information Document the AESO has defined the Cold Lake area as the area illustrated by the maps in Appendix 2 and 3.

Section 302.1 of the ISO rules sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the interconnected electric system. These steps are referenced in Table 1 of this Information Document as they are applied to the Cold Lake area.

2 General

Given existing generation, bulk transmission lines in the Cold Lake area may be overloaded under certain contingencies. To guard against these possibilities, ATCO Electric has in place a two-stage remedial action scheme.

Protection against thermal overloading of transmission facilities is governed by TFO policies, which stipulate the thermal limits for transmission conductors under normal operating and system emergency conditions.

The remedial action scheme is based on SEL-49 thermal relays, which estimate conductor temperature based on a number of input variables.

The ATCO Electric operators and the AESO have remote visibility of the status of the thermal protection scheme (i.e., armed vs. disarmed, which generating unit is selected to trip and the status of the alarm and trip signals) and net output from the generating units.

A detailed geographical map of the Cold Lake area indicating bulk transmission lines, substations and cutplanes is provided in Appendix 2 to this information document. For a schematic of the Cold Lake area indicating generating asset locations relative to major power flow paths and cutplanes see Appendix 3 in this Information Document.

The AESO respects the Cold Lake inflow cutplane limits when managing the inflow to the Cold Lake area, and the AESO respects the Marguerite Lake-Bourque-Leming Lake outflow cutplane limits when managing the outflow from the Cold Lake area. The map attached as Appendix 3 illustrates these cutplanes.

A cutplane is a common term used in engineering studies and is a theoretical boundary or plane crossing two (2) or more bulk transmission lines or electrical paths. The cumulative power flow across the cutplane is measured and can be utilized to determine flow limits that approximate conditions that would allow safe, reliable operation of the interconnected system.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards and the ISO tariff.

3 Constraint Conditions and Limits

When managing a transmission constraint in the Cold Lake area, the AESO ensures that bulk transmission line flows out of the area are managed in accordance with bulk transmission line ratings established by the legal owner of the transmission facility to protect transmission facilities and ensure the continued reliable operation of the interconnected electric system.

3.1 Non-Studied Constraints and Limits

For system conditions that have not been pre-studied, the AESO uses the energy management system tools and dynamic stability tools to assess system operating limits in real time.

3.2 Studied Constraints and Limits

The AESO also monitors the remedial action schemes that are in place in the area. A further description of these remedial action schemes is set out below.

In accordance with subsection 2(1) of section 302.1, the AESO follows the transmission constraint management procedures and applies the procedures to the Cold Lake area as outlined in section 4 of this Information Document. Transmission constraint management is employed as set out in section 4 of this Information Document in all of the following circumstances:

(a) when the remedial action scheme is unavailable;

(b) prior to remedial action scheme activation (if required); and

(c) for an appropriate period after the remedial action scheme has been activated once the system is operating in a safe and reliable mode.

The first remedial action scheme provides alarm signals in the event of bulk transmission line overload on either 7L89 or 7L66. These alarm signals initiate an automatic generation curtailment at both the Mahkeses and Foster Creek units to the levels specified in Appendix 4, Table 1. As this automated remedial action scheme is the primary method of generation curtailment, it is intended that the remedial action scheme be armed at all times.

The ATCO Electric transmission operator and the AESO have remote visibility of the status of the remedial action scheme (that is, armed vs. disarmed, which generating units are selected to trip, and the status of the run-back and trip signals) and the net-to-grid generation from the Mahkeses and Foster Creek generating units. For the Mahkeses plant, the operator selects one (1) generating unit to trip. For the 877S Foster Creek plant the operator selects both generating units to trip.

The remedial action scheme, based on thermal relays, has the following functionality:

(a) The thermal relay at 826S Marguerite Lake monitors the loading of 7L89.

(b) The thermal relay at 715S Leming Lake monitors the loading of 7L66.

(c) Each thermal relay will provide two (2) staged alarm outputs:

  (i) Stage one alarm output, which is triggered for calculated conductor temperature of eighty five degrees Celsius (85°C), initiates automatic generation run-back to the level as outlined in Appendix 4.

  (ii) Stage two alarm output, which is triggered for calculated conductor temperature of one hundred degrees Celsius (100°C), trips one (1) pre-selected generating unit at 889S Mahkeses and both generating units at 877S Foster Creek as noted in Appendix 4.

A second remedial action scheme that sheds load at CNRL Primrose 859S and Cenovus Foster Creek 1200S is also necessary in the Cold Lake area to prevent voltage collapse during critical contingencies, including the loss of 7L587 and 7L95 or the loss of both Mahkeses generators.

In addition, the 7L53 Thermal Protection Scheme is necessary in the Cold Lake area until the thermal rating of the 7L53 is restored as part of the Central East Transmission Development. The 7L53 Thermal Protection Scheme sheds load at Bonnyville 700S to support area voltage.

Cutplane Limits

With the increase of load in the Cold Lake area, there could be potential thermal overloads or low limit voltage violations under certain conditions. Table 2 and Table 3 within Appendix 5 contain the cutplane limits described below.

The Marguerite Lake-Bourque-Leming Lake Outflow Cutplane is defined as the algebraic sum of:

7L89 flow out of 826S Marguerite Lake to 700S Bonnyville

plus

7L146 flow out of 970S Bourque to 700S Bonnyville

plus

7L66 flow out of 715S Leming Lake to 717S Ethel Lake.

The Cold Lake Inflow Cutplane is defined as the algebraic sum of:

9L36 flow out of 825S Whitefish Lake to 826S Marguerite Lake

plus

9L37 flow out of 825S Whitefish Lake to 826S Marguerite Lake

plus

7L70 flow out of 819S Whitby Lake to 700S Bonnyville

plus

7L53 flow out of 706S Irish Creek to 700S Bonnyville.

4 Transmission Constraint Management

The AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of section 302.1. However, not all of those provisions are effective in the Cold Lake area due to certain operating conditions that exist in that area. This Information Document describes the application of the general provisions of section 302.1 to the Cold Lake area, and the additional clarifying steps required to effectively manage transmission constraints in that area.

The section 302.1 subsection 2(1) protocol steps which are effective in managing transmission constraints in the Cold Lake area are outlined in Table 1 below.

Table 1

Transmission Constraint Management

Sequential Procedures for the Cold Lake Area

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to the Cold Lake area?
(a) Determine effective pool assets	Yes
(b) Ensure maximum capability not exceeded	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to the Cold Lake area?
(d) Curtail effective demand opportunity service on the downstream constraint side	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No

Applicable Protocol Steps

The first step in managing constraints in any area is to identify those generating units effective in managing a constraint. All of the generating units and loads operating in the Cold Lake area are indicated in Appendix 3 (single line diagram) and the generating units effective in managing a transmission constraint are identified in Appendix 1. As per subsection 2(4) of section 302.1, when a transmission constraint has been or is expected by the AESO to activate a remedial action scheme, the AESO recommences the procedural sequence in Table 1 (above) once the AESO ensures that the system is operating in a safe and reliable mode.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Ensuring maximum capabilities are not exceeded is effective in managing Cold Lake area transmission constraints.

Step (c) in Table 1

There are no interties in the Cold Lake area and curtailing import and export flows elsewhere on the system is not effective in managing a transmission constraint.

Step (d) in Table 1

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing transmission constraints in the Cold Lake area because there is no demand opportunity service.

Steps (e)(i) and (ii) in Table 1

There are no transmission must-run contracts in the Cold Lake area and using transmission must-run is not effective in managing a transmission constraint.

Step (f) in Table 1

Curtailing effective pool assets using reverse energy market merit order followed by pro-rata curtailment is effective in managing Cold Lake area transmission constraints.

Step (g) in Table 1

Curtailing load is not effective in managing Cold Lake transmission constraints. Curtailing load would exacerbate a constraint where there is an abundance of generation in relation to load.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Cold Lake area that are known to have an impact on the information contained in this Information Document.

6 Appendices to this Information Document

Appendix 1 – Effective Pool Assets

Appendix 2 – Geographical Map of the Cold Lake Area

Appendix 3 – Cold Lake Area Curtailment Monitoring Points Single Line Diagram

Appendix 4 – Remedial Action Scheme Conditions

Revision History

Posting Date	Description of Changes
2012-11-27	Initial Release
2013-11-12	Administrative Updates
2014-02-14	Maps amended to include 970S Bourque and minor drafting edits.
2014-05-22	Maps amended to include 940S Beartrap and section 3.2 amended to include a temporary remedial action scheme.
2014-12-18	Amended to include Marguerite Lake-Bourque-Leming Lake outflow cutplane limits and Cold Lake inflow cutplane limit. Maps amended to include Nabiye and 7L146. Amended the description of the RAS that sheds load at CNRL Primrose 859S and Cenovus Foster Creek 1200S. Amended to include a new temporary Thermal Protection Scheme for 7L53.

Appendix 1 – Effective Pool Assets

The effective pool assets for the Cold Lake area, listed alphabetically by their pool IDs, are:

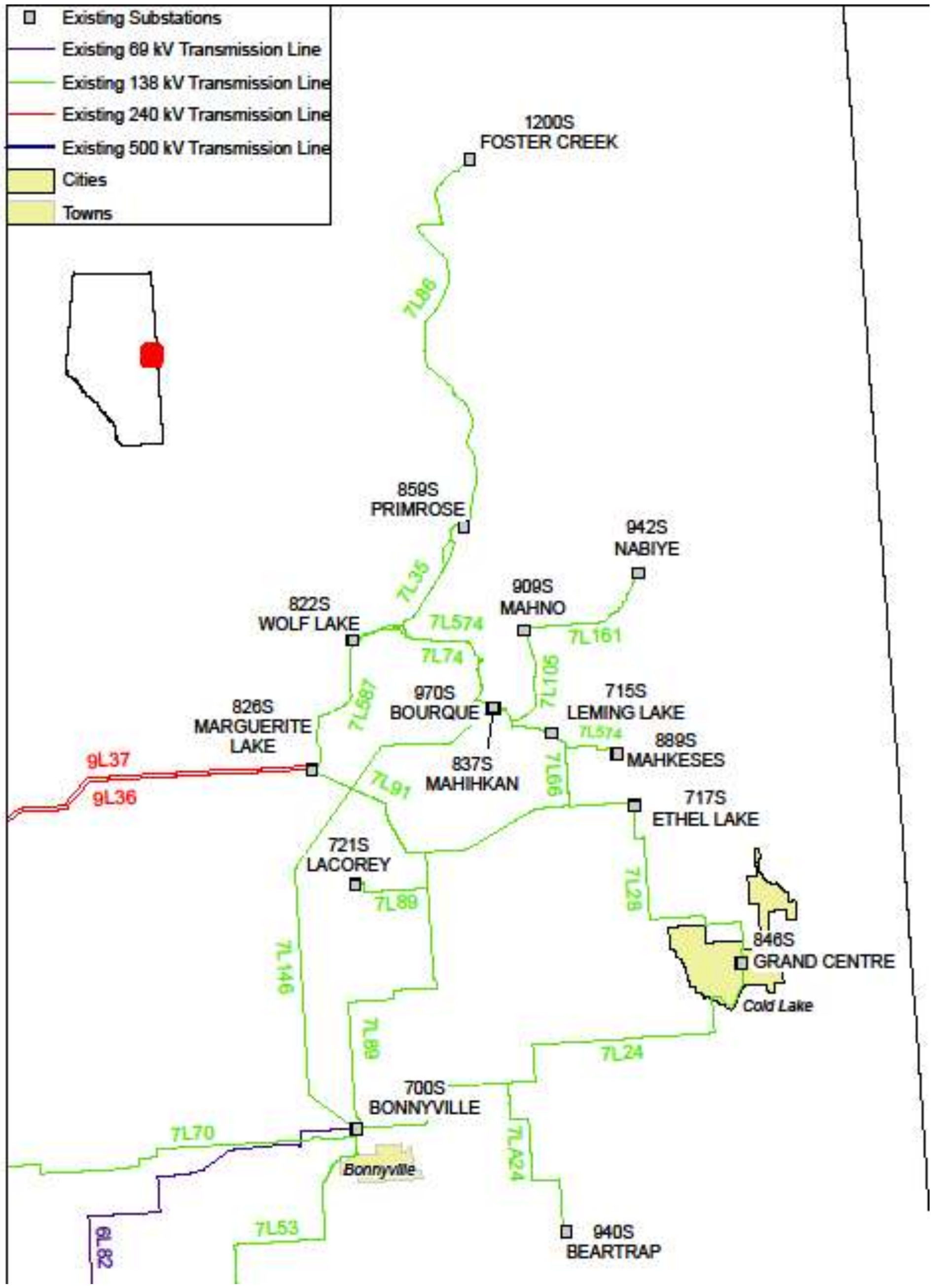
EC04

IOR1

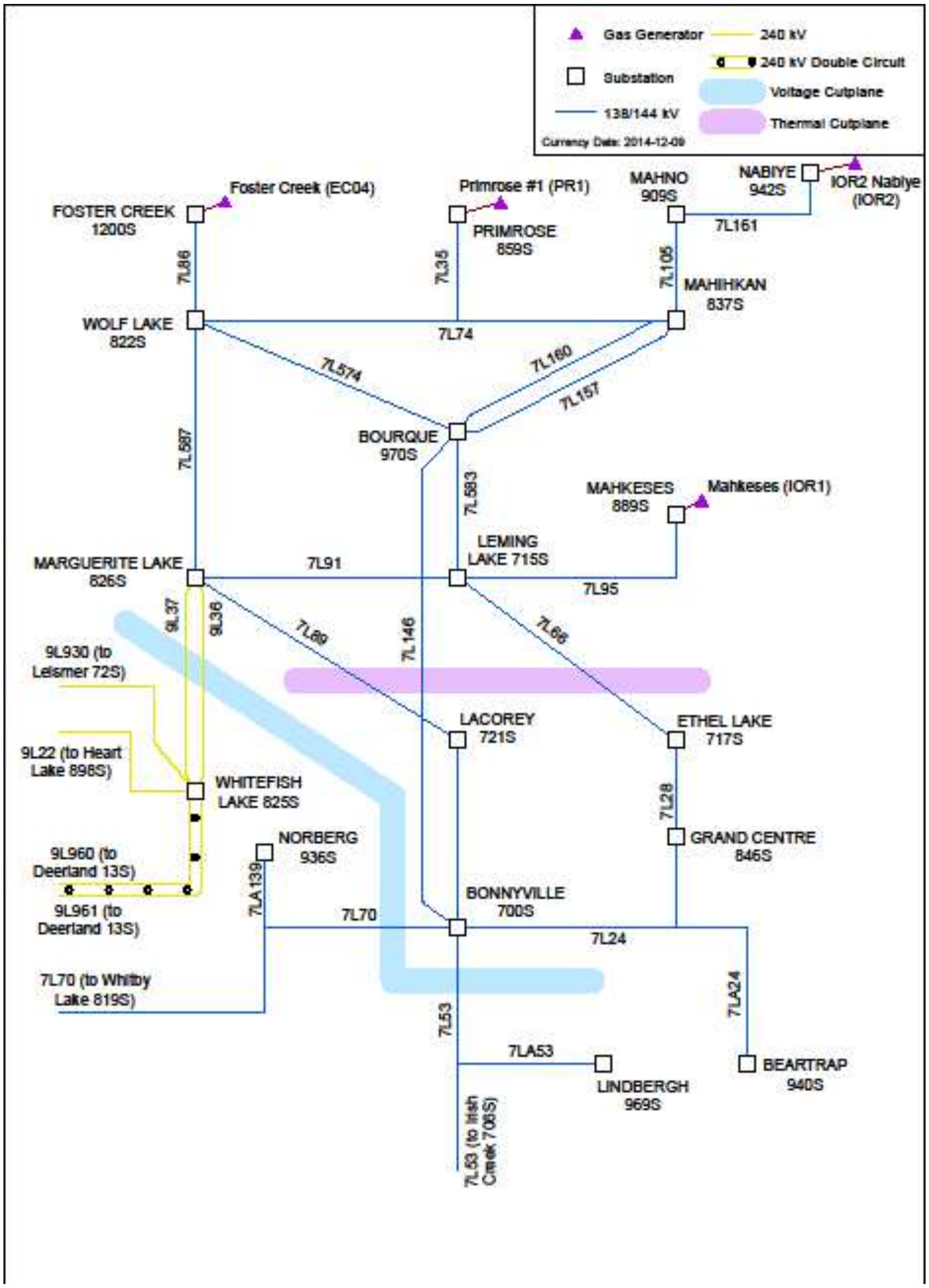
IOR2

PR1

Appendix 2 – Geographical Map of the Cold Lake Area



Appendix 3 – Cold Lake Area Cutplane Single Line Diagram



Appendix 4 – Remedial Action Scheme Conditions

Table 1 below sets out the conditions of the Cold Lake area remedial action scheme:

Table 1: Remedial Action Scheme Generation Levels

Remedial Action Scheme Output Status	Imperial Oil Mahkeses Plant net-to-grid generation level (MW)		EnCana Foster Creek Plant net-to-grid generation level (MW)
	Summer (May 1 to October 31)	**Winter (November 1 to April 30)**	**All Year**
Alarm (Triggered on calculated conductor temperature of 85°C)	Run-back to 115 MW at maximum unit ramp down rate within 7.5 minutes or less	Run-back to 130 MW at maximum unit ramp down rate within 7.5 minutes or less	Run-back to 0 MW at maximum unit ramp rate within 5.5 minutes or less
Trip (Triggered on calculated conductor temperature of 100°C)	Trips one pre-selected generating unit		Trips both generating units

Appendix 5 – Cutplane Transfer-Limits

Table 2: Marguerite Lake-Bourque-Leming Lake Outflow Cutplane Limit

MBL Outflow Cutplane "Thermal"			
Contingency	**Summer Limit** May 1 – Oct. 31	**Winter Limit** Nov. 1 – April 30	**Next Contingency**
None	210	250	7L146 or 7L587
826S Marguerite Lake 240/144 kV T1; or 240/144 kV T2	210	240	826S Marguerite Lake 240/144 kV T2; or 240/144 kV T1
9L36; or 9L37	210	240	9L37; or 9L36
7L91	200	230	7L146; or 7L587
7L583	200	230	7L146; or 7L587
7L587	180	220	7L146; or 7L587
7L89	130	170	7L146; or 7L587
7L66	120	160	7L146; or 7L587
7L146	120	160	7L66

Table 3: Cold Lake Inflow Cutplane Limit

Cold Lake Inflow Cutplane "Voltage"		
Contingency	**Limit (MW)**	**Next Contingency**
None	120	7L105; or 7L161
Nabiye Generators; or 7L105; or 7L161	90	7L95
7L587	70	Primrose G1
7L91	60	7L583
9L36; or 9L37	50	9L37; or 9L36
826S Marguerite Lake 240/144 kV T1; or 240/144 kV T2	50	826S Marguerite Lake 240/144 kV T2; or 240/144 kV T1
Foster Creek and Primrose Generators	40	7L587
7L89	30	7L146; or 7L66

Information Document
Fort Saskatchewan Area Transmission Constraint Management
ID #2012-016R

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1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1").

The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits in the Fort Saskatchewan area of the interconnected electric system. In this information document the AESO has defined the area cutplane as the area illustrated by the map in Appendix 3.

Section 302.1 sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the interconnected electric system. These steps are referenced in Table 1 of this information document as they are applied to the Dow cutplane.

2 General

The Dow Chemical Site (the "Dow Site") is located in the Fort Saskatchewan area. The Dow Site is serviced by 138 KV substations consisting of 166S Dow Chemical, 258S Dow Hydro Carbon, 906S and 218S Fort Saskatchewan Co-Gen.

Generation from the Dow Site is restricted by thermal limitation of the bulk transmission lines 707L, 787L and 862L connected to the 166S substation. The AESO has established a Dow cutplane with outflow limits which are currently determined by monitoring Real Time Contingency Analysis to ensure flows do not reach an unsafe level after N-1 events.

Two (2) maps of the Fort Saskatchewan area are provided in Appendix 2 and 3 to this information document. Appendix 2 of this information document provides a detailed geographical map of the Fort Saskatchewan area indicating bulk transmission lines, substations and the Dow cut plane. Appendix 3 provides a detailed schematic of the Dow cutplane including the generating unit effective in managing the transmission constraint.

A cutplane is a common term used in engineering studies and is a theoretical boundary or plane crossing two (2) or more bulk transmission lines or electrical paths. The cumulative power flow across the cutplane is measured and can be utilized to determine flow limits that approximate conditions that would allow safe, reliable operation of the interconnected system.

3 Constraint Conditions and Limits

When managing a transmission constraint on the Dow cutplane which results from bulk transmission line flows over the cutplane being above reliable system operating limits, the AESO calculates the cutplane flow limits for the Dow cutplane and uses those cutplane flow limits in a manner that protects transmission facilities and ensures the continued reliable operation of the interconnected electric system. A further description of those limits and the remedial action scheme is set out below.

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[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

3.1 Non-Studied Constraint Conditions and Limits

For system conditions that have not been pre-studied, the AESO uses the resultant limits from the Energy Management System Voltage Stability Analysis and the Contingency Analysis tools to determine real time system operating limits when limits are related to voltage or thermal concerns. For system conditions that have not been pre-studied, the AESO uses dynamic analysis software to determine the real time system operating limits when limits are related to dynamic stability concerns. Where studies are not possible, Table 2 in Appendix 4 is used to determine the seasonal Dow Site outflow limits.

3.2 Studied Constraints and Limits

Transfer-Out Limits at the Dow Cutplane

Dow cutplane outflow means MVA outflow measured on 707L, 787L and 862L at 166S. It is determined by algebraically adding MW and MVAR on each of these bulk transmission lines. When 787L is open-ended or out of service, 787L MVA flow is assumed to be zero (0). Also, when either 861L or 862L is open-ended or out of service, 862L MVA flow is assumed to be zero (0). The line ratings of 707L, 787 L and 862 L are provided in Table to of Appendix 4.

Dow Cutplane Outflow Limits and Real Time Contingency Analysis

In accordance with subsection 2(1) of Section 302.1 the AESO follows the transmission constraint management procedures and applies the procedures to the Fort Saskatchewan area as outlined in section 5 of this information document to ensure the electrical grid is operated in a safe and reliable manner. Transmission constraint management procedures are employed when the Dow cutplane outflow contributes to voltage instability, or when the Dow cutplane outflow exceeds the limit determined by the Real Time Contingency Analysis.

4 Application of Transmission Constraint Management Procedures

The AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of Section 302.1. However, not all of those provisions are effective in the Dow Site area due to certain operating conditions that exist in that area and so this information document represents the application of the general provisions of Section 302.1 to the Dow Site area, and provides additional clarifying steps as required to effectively manage transmission constraints in that area.

The protocol steps which are effective in managing transmission constraints are outlined in Table 1 below.

Table 1

Transmission Constraint Management

Sequential Procedures for Fort Saskatchewan area

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to the Dow cutplane?
(a) Determine effective pool assets	Yes
(b) Ensure maximum capability not exceeded	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No
(d) Curtail effective demand opportunity service on the downstream constraint side	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No

Applicable Protocol Steps

The first step in managing a constraint in any area is to identify those generating units effective in managing a constraint. All of the generating units and loads operating in the Fort Saskatchewan area are shown in Appendix 3 (single line diagram) and the generating units effective in managing a constraint are identified in Appendix 1.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1

Step (b) in Table 1

Ensuring maximum capabilities are not exceeded is applicable to the area as more generation can be produced than can be handled by the transmission lines referred to earlier. However as there is only one (1) effective pool asset, this step is automatically enforced when that pool asset is curtailed under step (f).

Step (c) in Table 1

There are no interties in the Fort Saskatchewan area and curtailing import or export flows elsewhere on the system is not effective in managing a transmission constraint.

Step (d) in Table 1

There is no demand opportunity service load in the area to curtail.

Step (e)(i) and (ii) in Table 1

There are no transmission must-run contracts in the area and using transmission must-run is not effective in managing constraints in the Fort Saskatchewan area.

Step (f) in Table 1

Curtailing effective pool assets using reverse energy market merit order followed by pro-rata curtailment is effective in managing a Fort Saskatchewan area transmission constraint. However as there is only one (1) effective pool asset, therefore pro-rata curtailment is not necessary.

Step (g) in Table 1

Curtailing load is not effective in managing Dow Site transmission constraints. Curtailing load may exacerbate a constraint where there is an abundance of generation in relation to load and transmission capacity.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Fort Saskatchewan area that are known to have an impact on the information contained in this information document.

6 Appendices

Appendix 1 – Effective Pool Assets

Appendix 2 – Geographical Map of the Fort Saskatchewan Area

Appendix 3 – Dow Cutplane Single Line Diagram

Appendix 4 – Tables

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendments
2013-02-01	Geographical map and Dow cutplane single line updated to reflect new transmission facilities within the area.
2012-11-27	Initial Release

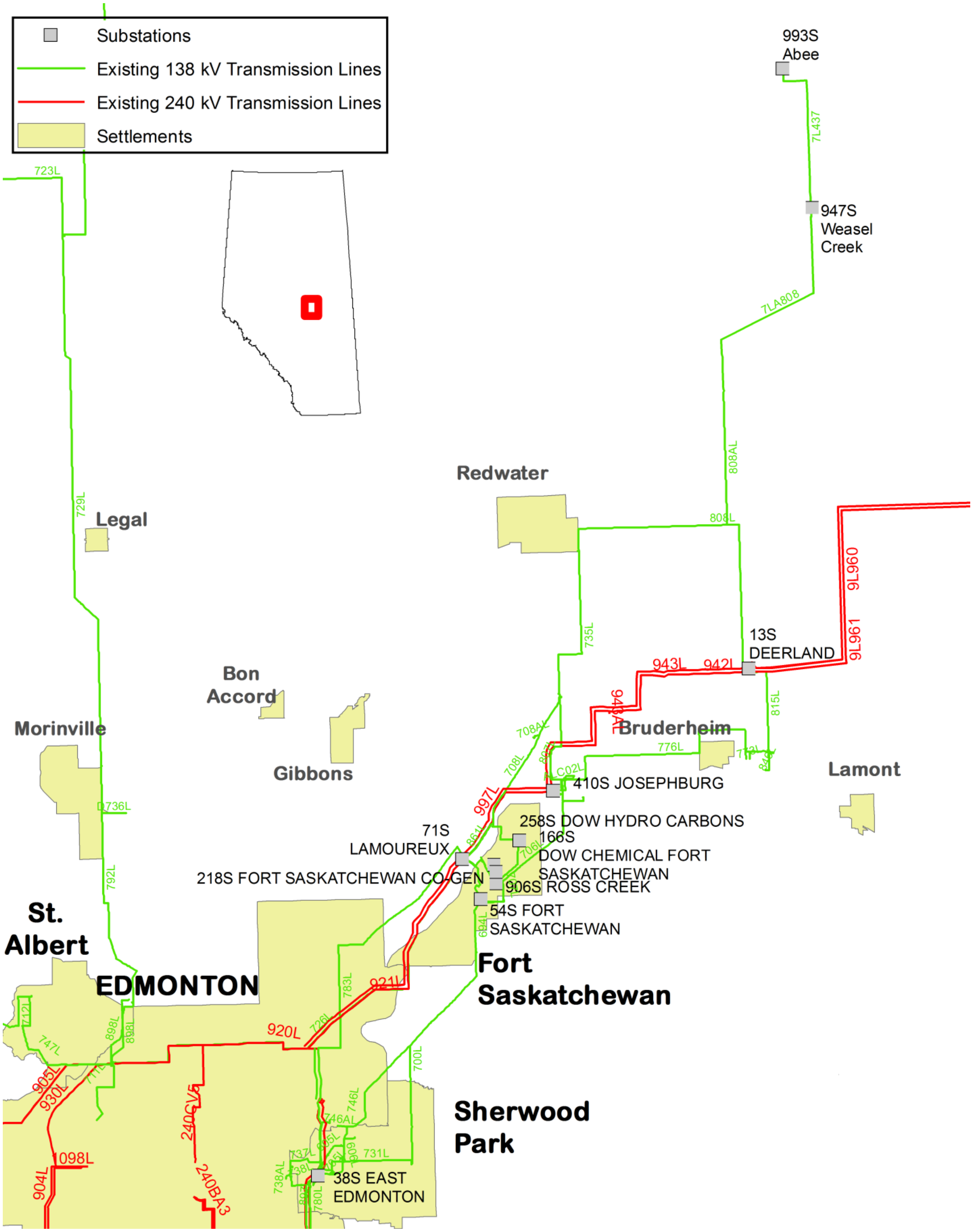
Appendix 1

Effective Pool Assets

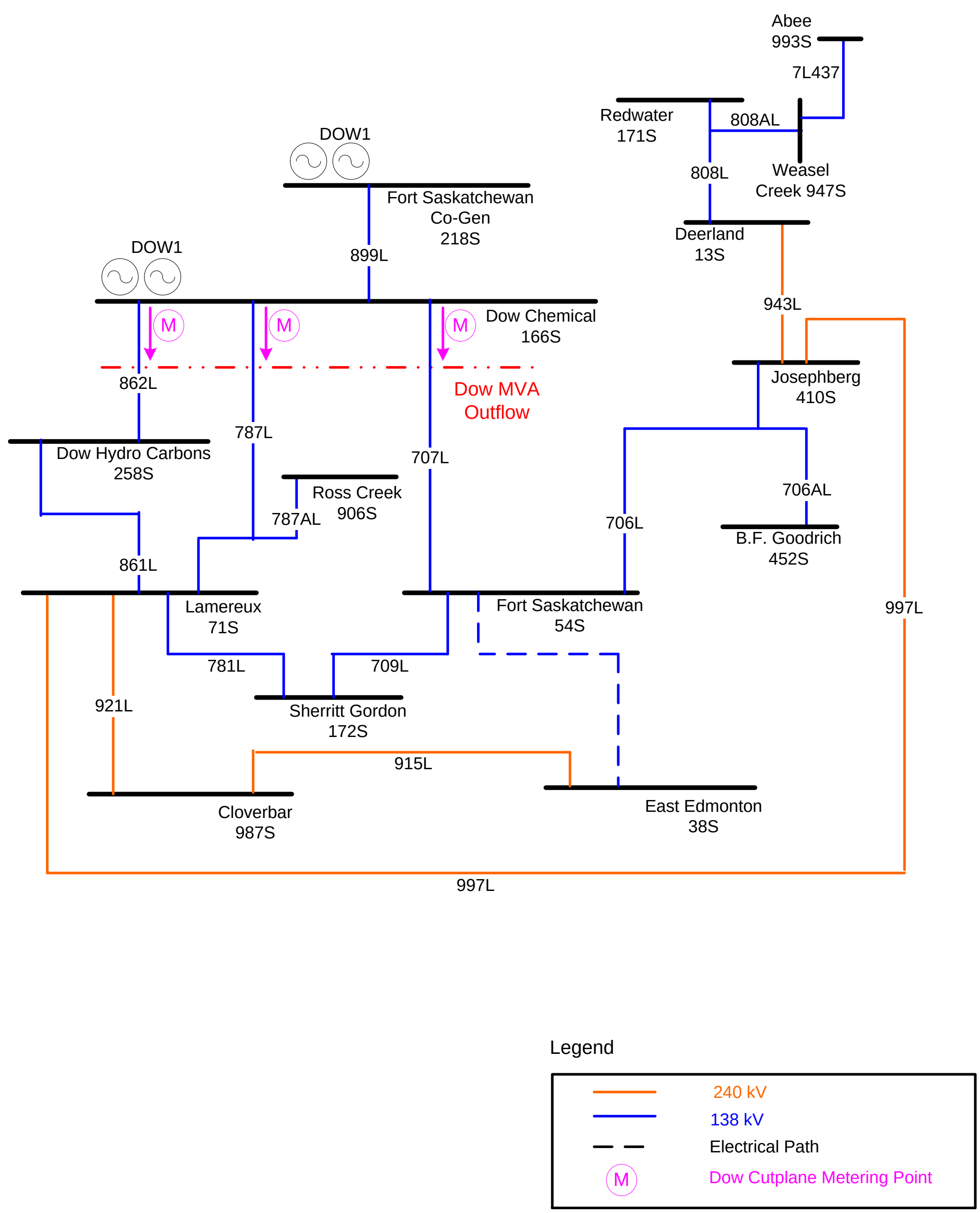
The effective pool asset for the Dow cutplane, is:

DOW1

Appendix 2 – Geographical Map of the Fort Saskatchewan Area



Appendix 3 – Dow Cutplane Single Line Diagram



Appendix 4 – Tables

Table 2 below sets out the conditions and the transfer-out limits at the Dow cutplane:

Table 2: Dow Outflow Limit

System Contingency	Dow Outflow Limit (MVA)	
	Summer (May 1 – Oct 31)	Winter (Nov 1 – Apr 30)
Normal Operation[1]	190	230
707L out of service[2]	165	200
787L open ended[3] or out of service[2]	120	145
861L open ended[4] or out of service[2]	120	145
862L open ended[4] or out of service[2]	120	145

1. All transmission system elements in service in the Fort Saskatchewan area.
2. All other transmission system elements in service in the Fort Saskatchewan area.
3. Real time MW and MVAR of 787L at 166s is treated as zero (0) under this contingency.
4. Real time MW and MVAR of 862L at 166s is treated as zero (0) under this contingency.

Table 3: AltaLink Bulk Transmission Line Ratings

Transmission Line	Summer (May 1 – Oct 31)		Winter (Nov 1 – Apr 30)	
	100% Line Rating MVA	110% Line Rating MVA	100% Line Rating MVA	110% Line Rating MVA
707L	119	131	146	161
787L	167	184	201	221
862L	167	184	201	221

Information Document
Crossfield Area Transmission Constraint Management
ID #2012-017R

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1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1").

The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits near the Crossfield area (north of Calgary) on the interconnected electric system.

Section 302.1 sets out the general transmission constraint management protocol steps the ISO uses to manage transmission constraints in real time on the interconnected electric system. These steps are referenced in Table 1 of this information document as they are applied to the Crossfield area.

2 General

The transmission and generation facilities in the Crossfield/Airdrie area are shown in a geographical map in Appendix 2. Two generation facilities: ENMAX Crossfield Energy Centre ("ENMAX Crossfield") and Nexen Inc # 1 ("Nexen") are located in the area.

ENMAX Crossfield consists of three generating assets totaling 144 MW which are connected to the AIES via the 653S Summit substation. The generation pool asset ID's for Crossfield are CRS1, CRS2 and CRS3.

Nexen consists of three generating assets totaling 120 MW and is connected to the AIES via 391S Balzac substation. The generation pool asset ID for Nexen is NXO1.

AESO transmission system studies indicate that 752L (653S Summit – 64S East Crossfield) and 688L (653S Summit – 199S East Airdrie) may become overloaded under certain contingency conditions, and require a remedial action scheme (RAS) to mitigate such a contingency. Several RAS are in place in the Crossfield area to ensure system reliability until the area transmission system is strengthened. The AESO has also established two monitoring points or cutplanes on each of 752L and 688L.

For a schematic of the Crossfield area 752L cutplane inflow and 688L cutplane outflow, see Appendix 3 in this information document. Appendix 4 of this information document provides relevant bulk transmission line ratings.

A cutplane is a common term used in engineering studies and is a theoretical boundary or plane crossing two (2) or more bulk transmission lines or electrical paths. The cumulative power flow across the cutplane is measured and can be utilized to determine flow limits that approximate conditions that would allow safe, reliable operation of the interconnected system.

3 Constraint Conditions and Limits

When managing a transmission constraint in the Crossfield area, the ISO ensures that bulk transmission line flows out of the area are managed in accordance with bulk transmission line ratings established by the legal owner of the transmission facility to protect transmission facilities to ensure the continued

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

reliable operation of the interconnected electric system. In addition, the ISO monitors the remedial action schemes that are in place on each of 752L and 688L.

Further descriptions of those transmission constraints and the remedial action schemes are set out below.

3.1 Non-Studied Constraints and Limits

For system conditions that have not been pre-studied, the ISO uses the resultant limits from the Energy Management System Voltage Stability Analysis and the Contingency Analysis tools to determine real time system operating limits when limits are related to voltage or thermal concerns. For system conditions that have not been pre-studied, the ISO uses dynamic analysis software to determine the real time system operating limits when limits are related to dynamic stability concerns.

3.2 725L Remedial Action Scheme

With respect to the Crossfield area, a remedial action scheme is required and in place on each of 752L and 688L to ensure system reliability.

In accordance with subsection 2(1) of ISO rule Section 302.1, *Real Time Transmission Constraint Management*, the ISO follows the transmission constraint management procedures and applies the procedures to the Crossfield area as outlined in section 5 of this information document. Transmission constraint management is employed in all of the following circumstances:

(a) when the remedial action scheme is unavailable;

(b) prior to remedial action scheme activation (if required); and

(c) for an appropriate period after the remedial action scheme has been activated once the system is operating in a safe and reliable mode.

The 752L remedial action scheme provides mitigation action in relieving an overload on 752L when the direction of line flow is towards 64S East Crossfield. The seasonal bulk transmission line ratings which are monitored by the 752L remedial action scheme are specified in Appendix 4 of this information document. The 752L remedial action scheme functions as follows once the AESO has received an overload alarm:

(a) If the direction of bulk transmission line flow on 752L is towards 64S East Crossfield and:

- (i) the bulk transmission line flow exceeds one hundred percent (100%) but is not greater than one hundred and ten percent (110%) of the seasonal bulk transmission line rating for ten (10) seconds, then the ENMAX Crossfield operator will manually run-back the CRS1,CRS2, CRS3 units to mitigate the 752L overload in response to the run-back signal;
- (ii) the bulk transmission line flow exceeds one hundred percent (100%) but is not greater than one hundred and ten percent (110%) of the seasonal bulk transmission line rating for ten (10) minutes, then pool assets CRS1, CRS2 and CRS3 will be automatically tripped in a pre-defined sequence in response to the trip signal, or
- (iii) the bulk transmission line flow exceeds one hundred and ten percent (110%) of the seasonal line rating for ten (10) seconds, then pool assets CRS1,CRS2, CRS3 units will be automatically tripped in a pre-defined sequence in response to the trip signal.

(b) Once the run-back or trip signal starts, as applicable, the 752L remedial action scheme timer will not reset until the bulk transmission line flow decreases to ninety five percent (95%) of the applicable seasonal rating or below for at least one (1) second.

688L Remedial Action Scheme

The 688L remedial action scheme provides mitigation action in relieving an overload on 688L when the direction of 688L bulk transmission line flow is towards 199S East Airdrie. The related seasonal bulk transmission line ratings which are monitored by the 688L remedial action scheme are specified in Appendix 4 of this information document. The 688L remedial action scheme functions as follows once an overload alarm has been received:

(a) If the direction of bulk transmission line flow on 688L is towards 199S East Airdrie and:

- (i) the bulk transmission line flow exceeds one hundred percent (100%) but is not greater than one hundred and ten percent (110%) of the seasonal bulk transmission line rating for ten (10) seconds, then the ENMAX Crossfield operator will manually run-back pool assets CRS1, CRS2 and CRS3 to mitigate the 688L overload in response to the run-back signal;
- (ii) the bulk transmission line flow exceeds one hundred percent (100%) but is not greater than one hundred and ten percent (110%) of the seasonal bulk transmission line rating for ten (10) minutes, then pool assets CRS1, CRS2 and CRS3 will be automatically tripped in a pre-defined sequence in response to the trip signal, or
- (iii) the bulk transmission line flow exceeds one hundred and ten percent (110%) of the seasonal bulk transmission line rating for ten (10) seconds, then the ENMAX CRS1,CRS2, CRS3 units will be automatically tripped in a pre-defined sequence in response to the trip signal.

(b) Once the run-back or trip signal starts as applicable, the 688L remedial action scheme timer will not reset until the flow decreases to ninety five percent (95%) of the applicable seasonal bulk transmission line rating or below for at least one (1) second.

4 Application of Transmission Constraint Management Procedures

The AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of Section 302.1. However, not all of those provisions are effective in the Crossfield area due to certain operating conditions that exist in that area and so this information document represents the application of the general provisions of Section 302.1 to the Crossfield area, and provides additional clarifying steps as required to effectively manage transmission constraints in that area.

The protocol steps which are effective in managing transmission constraints are outlined in Table 1 below.

Table 1

Transmission Constraint Management

Sequential Procedures for Crossfield Area

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to a 752L transmission constraint?	Applicable to a 688L transmission constraint?
(a) Determine effective pool assets	Yes	Yes
(b) Ensure maximum capability not exceeded	Yes	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No	No
(d) Curtail effective demand opportunity service on the downstream constraint side	No	No

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to a 752L transmission constraint?	Applicable to a 688L transmission constraint?
(e)(i) Issue a dispatch for effective contracted transmission must-run	No	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No	No

Applicable Protocol Steps

The first step in managing constraints is to identify those pool assets, both generating units and loads, effective in managing constraints. A list of the generating assets that are effective in managing constraints are identified in Appendix 1. As per section 2(4) of 302.1, when a transmission constraint has been or is expected by the ISO to activate a remedial action scheme, the ISO recommences the procedural sequence in Table 1 (above) once the ISO has ensured that the system is operating in a safe and reliable mode.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Ensuring maximum capability levels are not exceeded is effective in managing Crossfield area transmission constraints. The effective pool assets that the AESO may curtail are listed in Appendix 1.

Step (c) in Table 1

There are no interties in the Crossfield area and curtailing import and export flows elsewhere on the system is not effective in managing a transmission constraint.

Step (d) in Table 1

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing Crossfield area constraints because there is no demand opportunity service in the area.

Step (e) in Table 1

With respect to steps (e)(i) and (ii), there are no transmission must-run contracts in the Crossfield area and using transmission must-run is not effective in managing a transmission constraint.

Step (f) in Table 1

Curtailing effective generating units in reverse energy market merit order followed by pro-rata curtailment is effective in managing Crossfield area transmission constraints. The effective pool assets that the AESO may curtail are listed in Appendix 1.

Step (g) in Table 1

Because of the configuration of the interconnected electrical system curtailing load on the upstream side is not effective in managing Crossfield area constraints.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Crossfield area that are known to have an impact on the information contained in this information document.

6 Appendices

Appendix 1 – Effective Pool Assets

Appendix 2 – Geographical Map of the Crossfield Area

Appendix 3 – Crossfield Area Single Line Diagram

Appendix 4 – AltaLink Bulk Transmission Line Ratings

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendments
2012-11-27	Initial Release

Appendix 1 – Effective Pool Assets

The effective pool assets for transmission constraints on 752L, listed alphabetically by their pool IDs, are:

CRS1

CRS2

CRS3

NX01

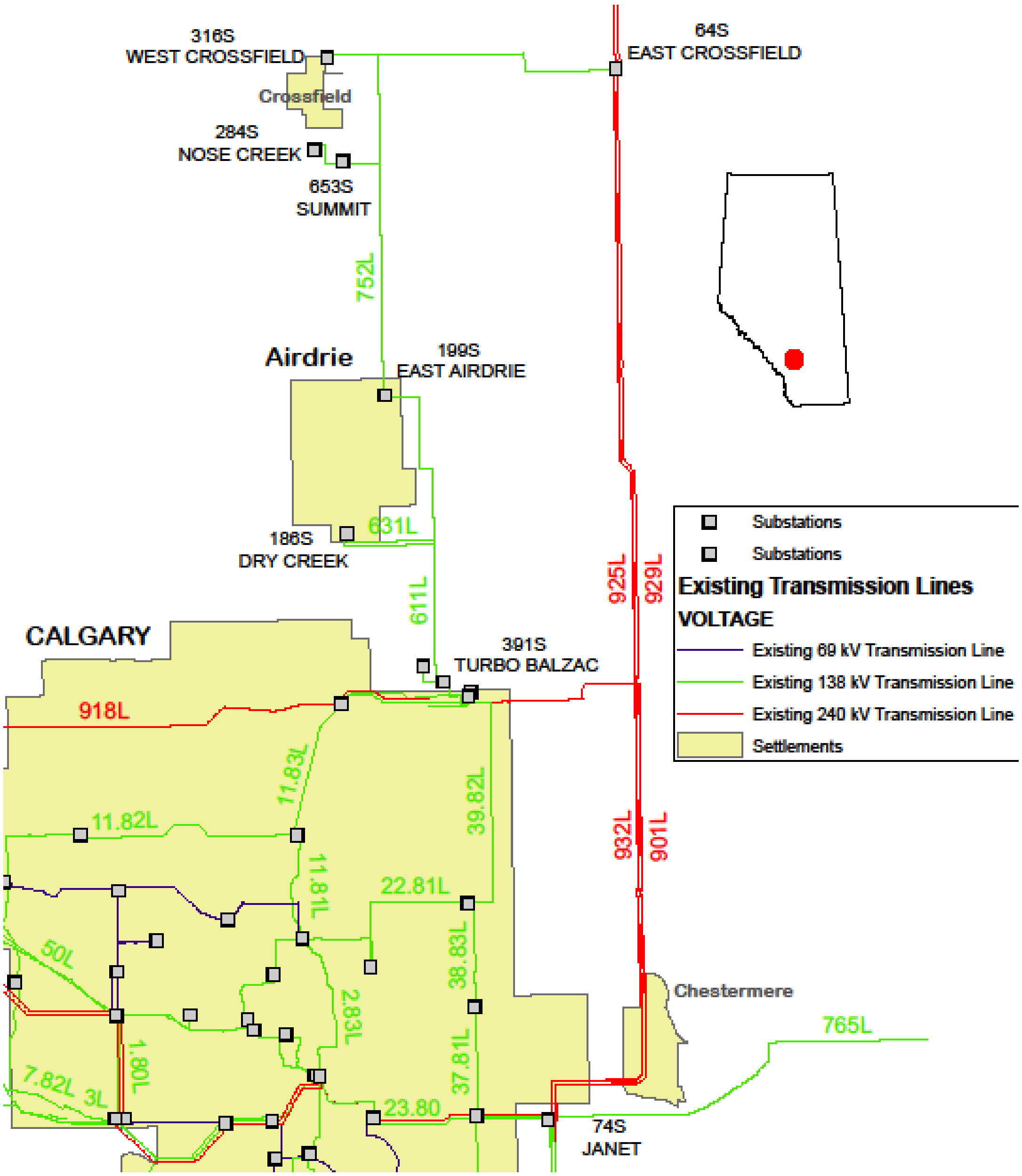
The effective pool assets for transmission constraints on 688L, listed alphabetically by their pool IDs, are:

CRS1

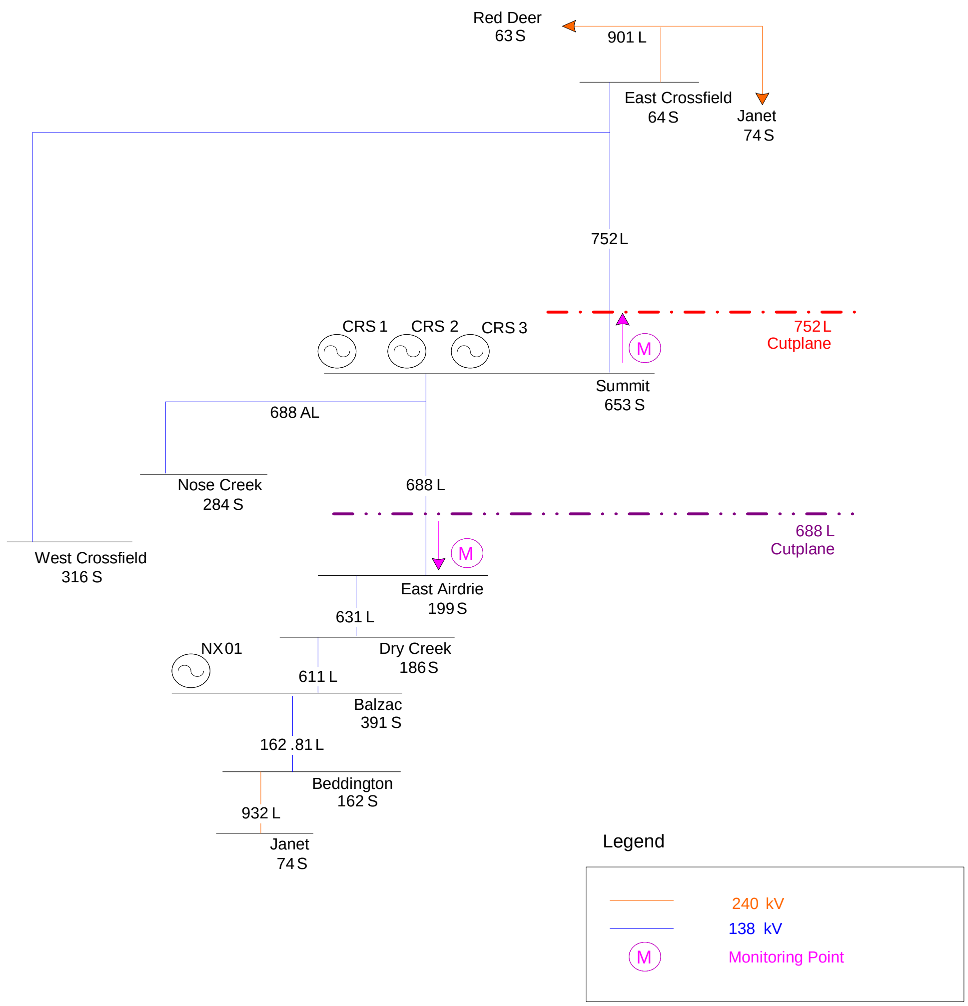
CRS2

CRS3

Appendix 2 – Geographical Map of the Crossfield Area



Appendix 3 – Crossfield Area Single Line Diagram



Appendix 4 – AltaLink Bulk Transmission Line Ratings

AltaLink Bulk Transmission Line Ratings

Transmission Line	**Summer** **(May 1 to October 31)**		**Winter** (November 1 to April 30)	
	100% Line Rating MVA	**110% Line Rating MVA**	**100% Line Rating MVA**	**110% Line Rating MVA**
752L	119	131	136	150
688L	121	133	142	156

Information Document
Central East Area Transmission Constraint Management
ID #2012-018R

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1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1").

The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits in the Central East area of the interconnected electric system.

Section 302.1 sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the interconnected electric system. These steps are referenced in Table 1 of this information document as they are applied to the Central East area.

2 General

The transmission and generation facilities in the Central East area are shown in a geographical map in Appendix 2. Several generation facilities, including Ghost Pine, Wintering Hills, Battle River 3, 4, and 5, Sheerness 1 and 2, and Halkirk, are located in the area. The associated generation pool IDs for these Central East assets are; NEP1, SCR4, BR3, BR4, BR5, SH1, SH2 and HAL1, respectively.

Operational studies show that transmission congestion occurs on 7L50, 174L, 757s Battle River 240/138kV transformer or the 766s Nevis 240/138kV transformer. For a schematic single line diagram of the Central East area, see Appendix 3 in this information document.

3 Constraint Conditions and Limits

When managing a transmission constraint in the Central East area, the AESO ensures that bulk transmission line flows out of the area are managed in accordance with bulk transmission line ratings. These ratings are established by the legal owner of the transmission facility to protect transmission facilities, ensuring the continued reliable operation of the interconnected electric system. .

3.1 Non-Studied Constraints and Limits

For system conditions that have not been pre-studied, the AESO uses the resultant limits from the Energy Management System Voltage Stability Analysis and the Contingency Analysis tools to determine real-time system operating limits when limits are related to voltage or thermal concerns. For system conditions that have not been pre-studied, the AESO uses dynamic analysis software to determine the real-time system operating limits when limits are related to dynamic stability concerns.

3.2 Studied Constraints and Limits

With respect to the Central East area, a remedial action scheme is required and in place on each of 7L50, 174L and the 766s Nevis 240/138kV transformer to ensure system reliability. In accordance with subsection 2(1) of Section 302.1, the AESO follows the transmission constraint management

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

procedures and applies the procedures to the Central East area as outlined in section 5 of this information document in the following circumstances:

(a) prior to remedial action scheme activation, if required; and

(b) to manage a constraint after the remedial action scheme has been activated.

Battle River N-1-1 Stability Concerns

If the 757s Battle River 240/144 kV transformer is out of service, there are transient stability concerns on Battle River 3 and 4 for the loss of either 7L50 or 7L701. Refer to Appendix 4.

4 Application of Transmission Constraint Management Procedures

The AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of Section 302.1. However, not all of those provisions are effective in the Central East area due to certain operating conditions that exist in that area. This information document represents the application of the general provisions of Section 302.1 to the Central East area and provides additional clarifying steps as required to effectively manage transmission constraints in that area.

The protocol steps which are effective in managing transmission constraints are outlined in Table 1 below.

Table 1

Transmission Constraint Management

Sequential Procedures for Central East Area

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to a Central East Area transmission constraint?
(a) Determine effective pool assets	Yes
(b) Ensure maximum capability not exceeded	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No
(d) Curtail effective demand opportunity service on the downstream constraint side	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No

Applicable Protocol Steps

The first step in managing constraints is to identify those pool assets, both generating units and loads, effective in managing constraints. A list of the generating pool assets that are effective in managing constraints are identified in Appendix 1. As per section 2(4) of 302.1, when a transmission constraint has been or is expected by the AESO to activate a remedial action scheme, the AESO recommences the procedural sequence in Table 1 (above) once the AESO has ensured that the system is operating in a safe and reliable mode.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Ensuring maximum capability levels are not exceeded is effective in managing Central East area transmission constraints. The effective pool assets that the AESO may curtail are listed in Appendix 1.

Step (c) in Table 1

There are no interties in the Central East area and curtailing import and export flows elsewhere on the system is not effective in managing a transmission constraint.

Step (d) in Table 1

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing Central East area constraints because there is no demand opportunity service in the area.

Step (e) in Table 1

With respect to steps (e)(i) and (ii), there are no transmission must-run contracts in the Central East area and using transmission must-run is not effective in managing a transmission constraint.

Step (f) in Table 1

Curtailing effective generating units in reverse energy market merit order followed by pro-rata curtailment is effective in managing Central East area transmission constraints. The effective pool assets that the AESO may curtail are listed in Appendix 1.

Step (g) in Table 1

Because of the configuration of the interconnected electrical system, curtailing load on the upstream side is not effective in managing Central East area constraints.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Central East area that are known to have an impact on the information contained in this information document. Presently, there are no known projects underway that are known to have an impact.

6 Appendices

Appendix 1 – *Effective Pool Assets*

Appendix 2 – *Geographical Map of the Central East Area*

Appendix 3 – *Central East Area Single Line Diagram*

Revision History

Posting Date	Description of Changes
2019-03-19	Amendments to Section 2 to include 757s Battle River 240/138kV transformer and 766s Nevis 240/138kV transformer
	Addition of Appendix 4 Battle River Transient Stability Limits
2016-09-28	Administrative amendments
2014-10-21	Amendment to remedial action schemes
2012-10-11	Initial Release

Appendix 1 – Effective Pool Assets

The effective pool assets for transmission constraints in the Central East area, listed alphabetically by their pool IDs, are:

BR3

BR4

BR5

HAL1

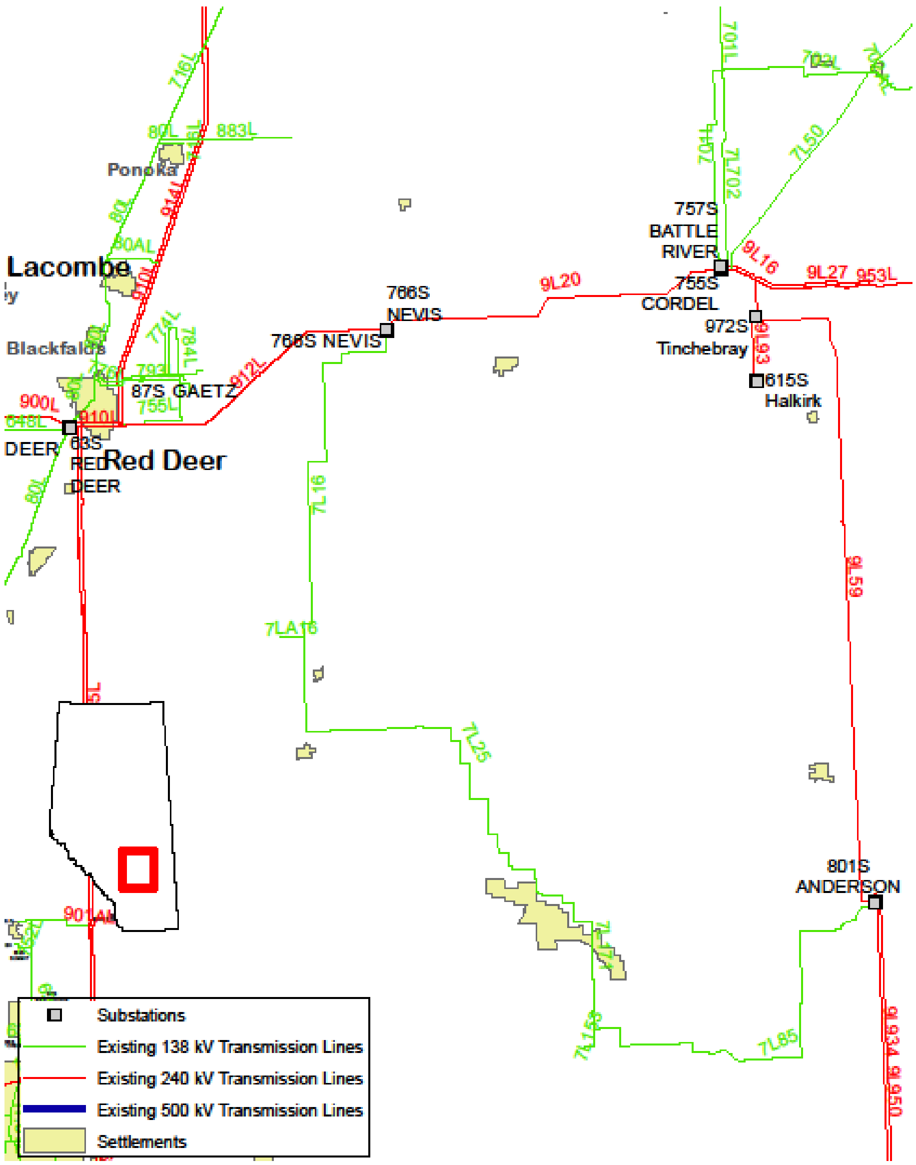
NEP1

SCR4

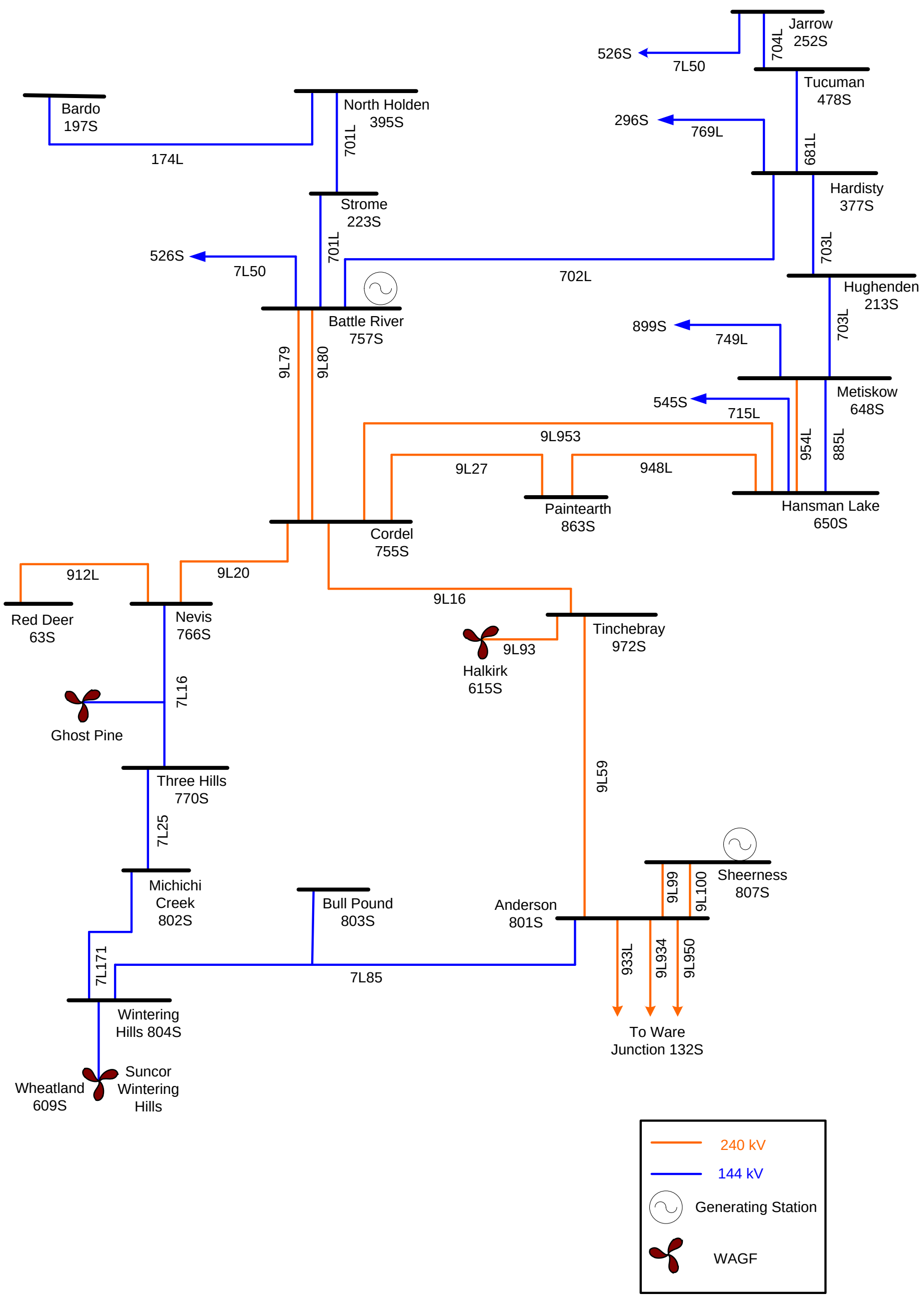
SH1

SH2

Appendix 2 – Geographical Map of the Central East Area



Appendix 3 – Central East Area Single Line Diagram



Appendix 4: Battle River Transient Stability Limits

Transmission Outage	Next Contingency	BR3/BR4 Status	Output limit of BR3 and/or BR4 net-to-grid (MW)
Battle River 757s 240/144 kV Transformer	7L50 or 7L701	BR3 in-service BR4 in-service	240
		BR3 on-line BR4 off-line	115
		BR3 off-line BR4 on-line	135

Information Document
Energy Emergency Alerts
ID #2012-024R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents[1]:

- Section 305.1 of the ISO rules, *Energy Emergency Alerts* ("Section 305.1"), and
- Alberta Reliability Standard EOP-002-AB1-2, *Capacity and Energy Emergencies* ("EOP-002-AB1-2").

The purpose of this Information Document is to provide information on requirements contained in Authoritative Documents regarding Energy Emergency Alerts. This Information Document is likely of most interest to market participants that are affected by Energy Emergency Alerts.

2 Notification of Energy Emergency Alerts

Generally, Section 305.1 of the ISO rules focuses on the Energy Emergency Alerts that occur during a supply shortfall event. In comparison, EOP-002-AB1-2 sets out requirements the AESO carries out during a supply shortfall event and ensures the AESO is prepared for such an event.

Subsection 4 of Section 305.1 of the ISO rules requires the AESO to notify market participants of an Energy Emergency Alert.

Table 1 below lists the general notification protocols carried out by the AESO when notifying market participants of an Energy Emergency Alert.

Table 1 – Notification Methods

Party to be Notified	Notification Method
All market participants with bids or offers in the energy market merit order	Automated Dispatch and Messaging System
Owners or operators of transmission facilities	Phone call
Adjacent Balancing Authorities	Phone call
Owners or operators of electric distribution systems that are responsible for implementing firm load curtailment procedures	Phone call
Other entities, as determined by the AESO, that may be impacted by the state of supply shortfall	Phone call

When the AESO notifies market participants regarding an Energy Emergency Alert, the AESO and the market participants identify and discuss any work that increases the risk of tripping a generating unit or an intertie and which could subsequently be stopped.

After notifying parties of an Energy Emergency Alert, the AESO also posts notice of the Energy Emergency Alert on the AIES Event Log located on the AESO website.

Additionally market participants may also find the Supply Adequacy Report located on the AESO website to be useful information.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendments
2014-02-04	Amended to reflect amended Section 305.1 of the ISO rules and incidental amendments.
2012-10-31	Initial Release

Information Document
Synchrophasor Measurement Unit
ID# 2012-028R

Information documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between the information document and the related authoritative document(s) in effect, the authoritative document(s) governs. Please submit any questions or comments regarding this information document to InformationDocuments@aeso.ca.

1 Purpose

This information document provides general information relating to supervisory control and data acquisition and supports ISO Rules Section 502.9 *Synchrophasor Measurement Unit Technical Requirements*.

2 Related Authoritative Documents

The AESO's authoritative documents consist of ISO rules, the ISO tariff and the Alberta reliability standards. Authoritative documents contain binding rights, requirements and obligations for market participants and the AESO. Market participants and the AESO are required to comply with provisions set out in its authoritative documents.

Market participants are encouraged to review the following related authoritative documents:

(1) Section 502.9 of the ISO rules, *Synchrophasor Measurement Unit Technical Requirements* ("Section 502.9").

3 Contacting the AESO

Section 502.9 sets out a requirement for a legal owner of a generating unit, legal owner of an aggregated generating facility or legal owner of a transmission facility to notify the AESO if it identifies or suspects a failure or malfunction of a synchrophasor measurement unit. The appropriate party to contact in this circumstance is the AESO system controller.

Revision History

2013-02-28	Initial Release

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1 Purpose

This information document supports the following sections of the ISO rules:

(a) ISO rules Section 201.4 *Submission Methods and Coordination of Submissions*;

(b) ISO rules Section 202.4 *Managing Long Lead Time Assets*;

(c) ISO rules Section 203.1 *Offers and Bids for Energy*;

(d) ISO rules Section 203.3 *Energy Restatements*;

(e) ISO rules Section 204.1 *Offers for Dispatch Down Service*;

(f) ISO rules Section 204.3 *Dispatch Down Service Restatements*; and

(g) ISO rules Section 5 *Reliability Assessment and Scheduled Generator Outage Cancellation*.

The purpose of this information document is to provide examples to market participants on how to submit information to the ISO in the methods required in Section 201.4. This information document is likely of most interest to pool participants that use the Energy Trading System to submit information to the ISO. It is specifically intended for staff involved in entering and maintaining submissions data or staff involved in entering and maintaining pool asset constraints.

This information document differs from other information documents created by the AESO in that it contains some obligatory language. This is due to the nature of this information document, as it deals with the Energy Trading System and instructs pool participants on the proper use of that system. The Energy Trading System requires pool participants to submit information using specific methods and formats in order for submissions to be valid. Consequently, this information document contains words such as “must” to convey these requirements, but pool participants should understand that these are not binding authoritative requirements. Not complying with Energy Trading System requirements only results in invalid submissions and errors in the Energy Trading System, and does not constitute non-compliance with ISO rules or other authoritative documents.

2 Background

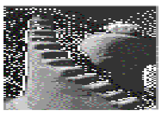
This manual is for general information purposes only. It is based upon information which is subject to change. While the AESO endeavours to keep this manual up-to-date, the AESO assumes no obligation to do so or to notify any party of any changes, updates or new versions of this manual. Under no circumstances is the AESO, its members, officers, employees, contractors or agents, or any of their respective affiliates, liable for any errors or omissions in, or any losses, damages or claims whatsoever, whether in contract, tort or otherwise, arising from use of or reliance upon, this manual or any information contained herein. Parties using or relying on this manual do so solely at their own risk, and all information contained in this manual should be independently verified.

3 System Requirements and Digital Certificates

The supported platform for the Energy Trading System is Windows XP, Windows Vista, Windows 7, Windows 2000 Professional, Windows 2000 Server, Windows 2003 Server, Windows 2008 Server and Internet Explorer 9.

Certain communication with the AESO, including the process to submit bids and offers, register/accept net settlement instructions (NSI), and retrieve statements is handled through the Internet. To ensure that the Internet-based communication between participants and the AESO is secure, participants cannot receive access to the Energy Trading System without purchasing a digital certificate.

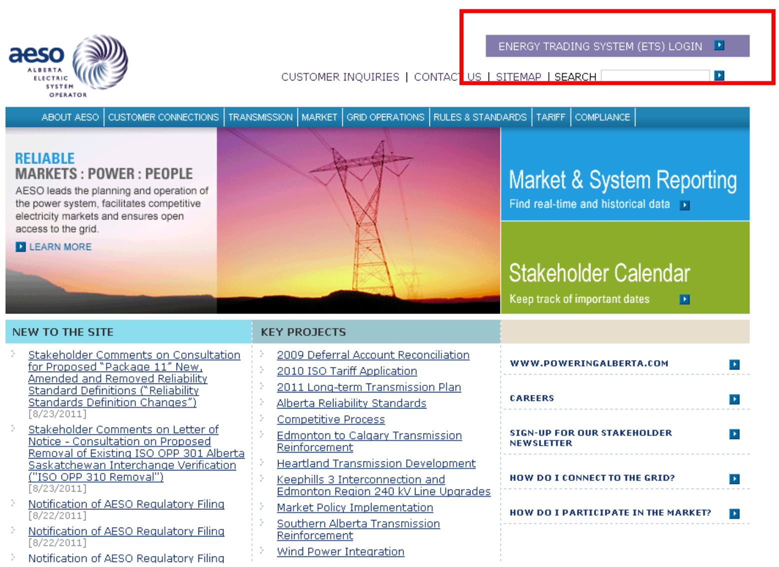
4 Create a New Energy Submission from Scratch



Steps

4.1 Navigate to the Submission Screen

(a) Through the [AESO website](), log on to the system, click on the [Energy Trading System (ETS) Login] icon on the top right corner of the screen.

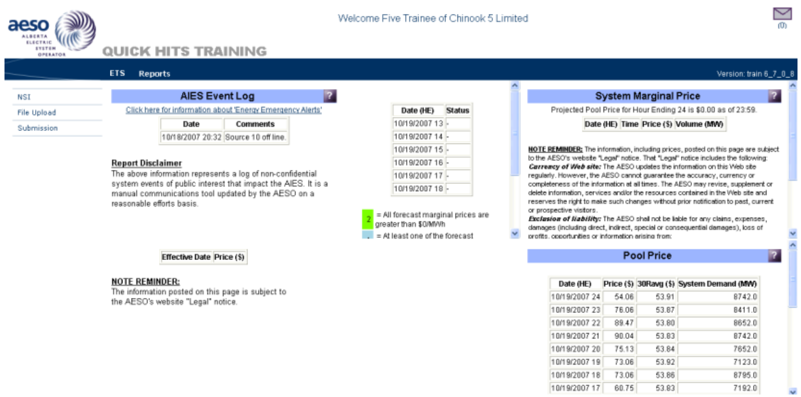


(b) Select the desired certificate and click on the [OK] button.

Select [Grant Permission] when prompted with “Grant or deny this application permission to use this key”. Click [OK].

(c) Select the ETS menu.

Note: The left-hand side of the screen populates with links to which the pool participant has access.



(d) Under the ETS menu, select [Submission].

Note: The screen opens to the [Submission Information] tab by default.

(e) Click on the [Energy Submission] tab.

(f) From the [Select Submission Type] list box, choose New Submission.

(g) From the [Select Submission Action] list box, choose Create New from Scratch.

Note: From this list, the user also has the option of modifying an existing submission, creating a new submission from an existing one or editing an existing energy submission.

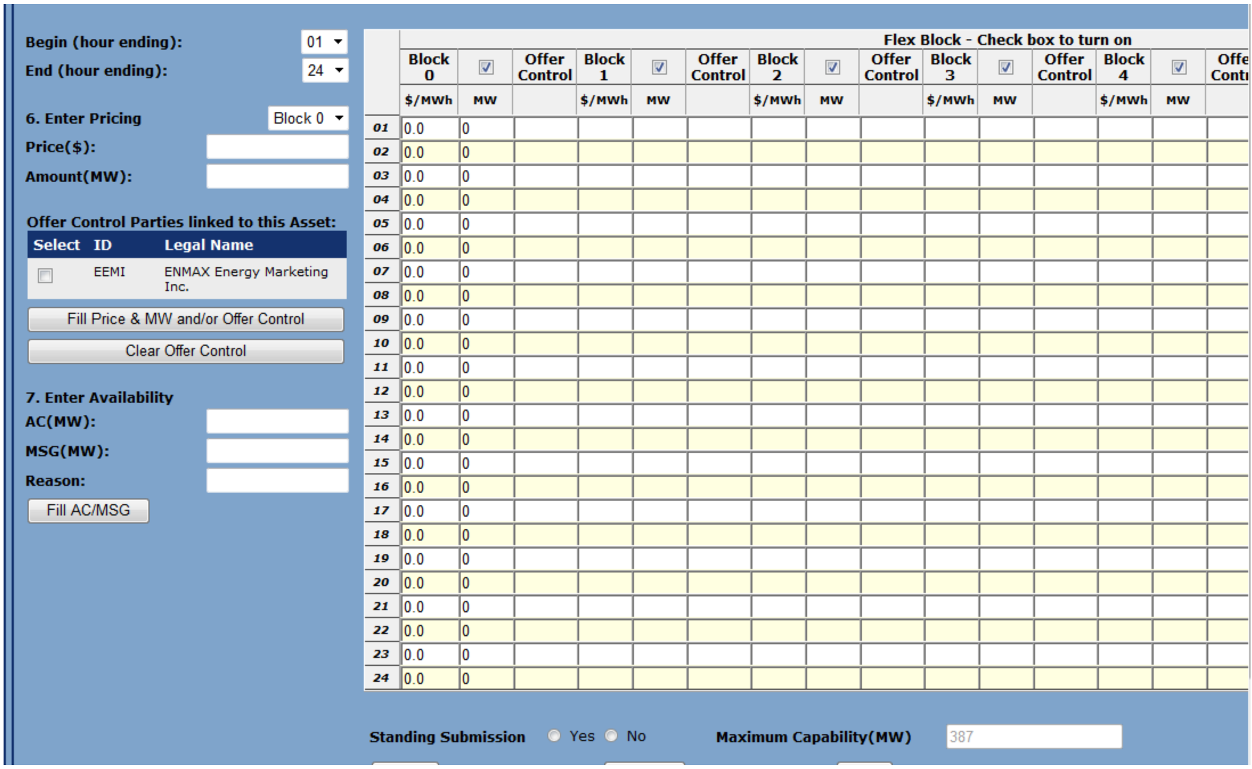
(h) From the [Select Dispatch Date] list box, choose Default Date.

Note: The dispatch date defaults to the next effective submission date. The next seven (7) days are accessible to create new from scratch, create new from existing and edit existing for energy submissions. These seven days (7) are deemed the forecast scheduling period.

(i) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. Click [Next].

Note: A pool asset which is a [Sink] consumes electricity whereas a [Source] generates electricity.

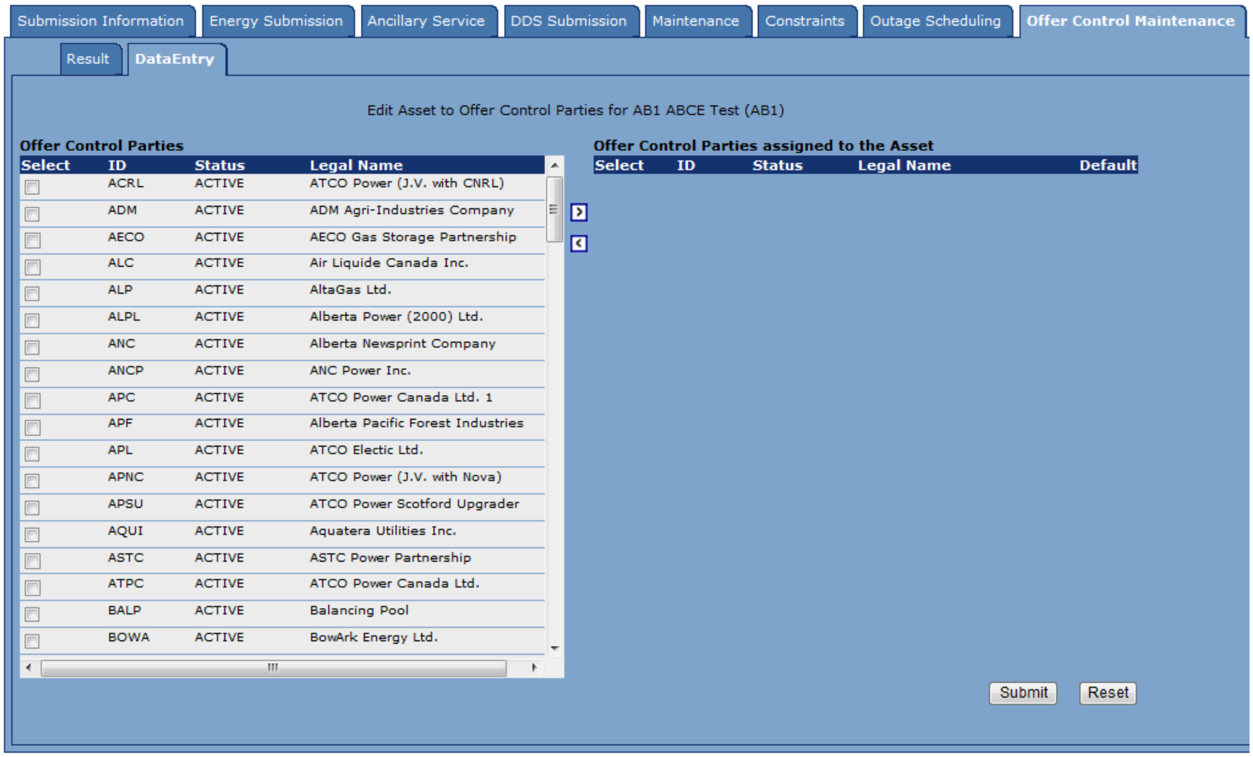
(j) From the [Select Asset] list box, choose the desired pool asset.



Note: The energy submission screen displays the submission filler to the left and the submission entry grid is enabled (all fields are empty). Using the Filler, pool participant can enter price/MW and select Offer Control Party, available capability, minimum stable generation and acceptable operational reason.

4.2 Link Offer Control and Default Offer Control Parties to Asset

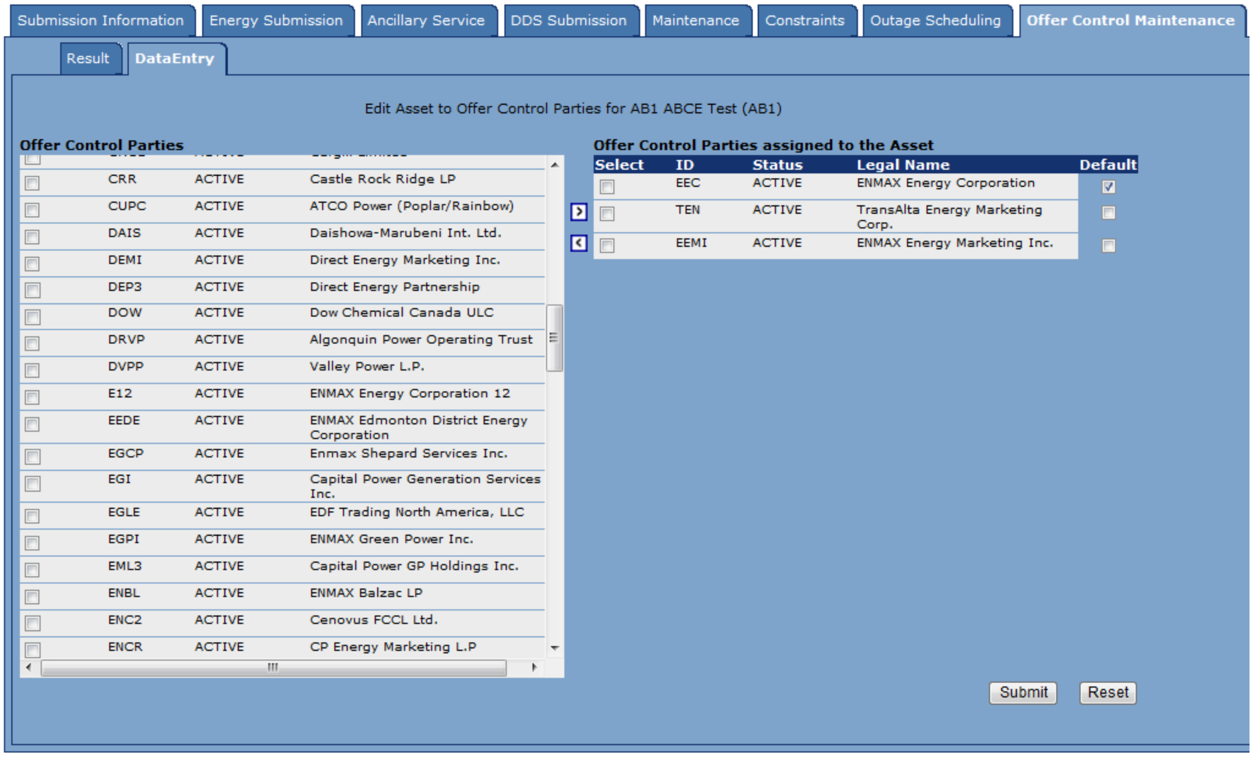
(a) Click on the [Offer Control Maintenance] tab and all active Offer Control Parties are listed (they are not specific to any one company).



(b) Select Offer Control Parties from [Offer Control Parties] and use the arrows to remove and add Offer Control Parties as applicable. The Offer Control Parties listed are active as of the last 30 days.

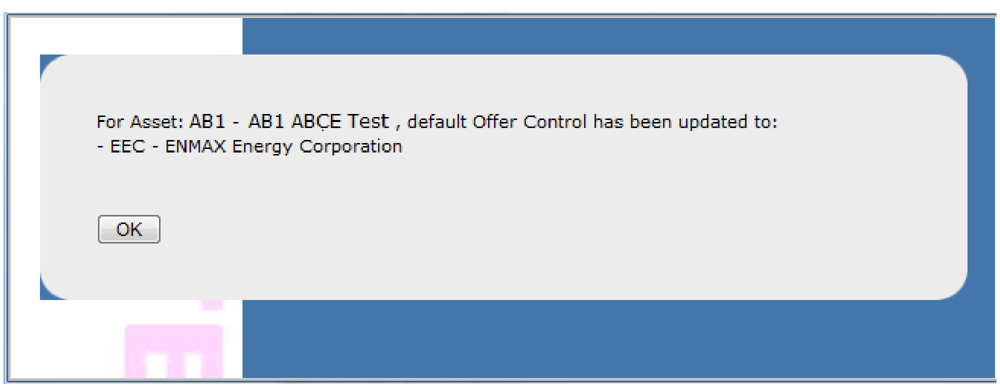
(c) Select [Submit]. Submission links the selected Offer Control Parties to the asset.

Note: Offer Control Parties are to be linked to specific assets (including Import and Export assets) prior to inputting energy submissions, dispatch down service (DDS) submissions or historical Offer Control Party submissions in ETS.



(d) A participant may also optionally select one or more of the linked Offer Control Parties from c) to be designated as Default Offer Control Parties for energy submissions and DDS submissions. This is done by checking the 'Default' checkbox beside each linked Offer Control Party that is to be designated as a Default Offer Control Party.

(e) Select [Submit]. Submission implements any Default Offer Control Party designations.



Note: If any Default Offer Control Party is designated, ETS will apply the Default Offer Control Party to future energy submissions and DDS submissions where no Offer Control Party is specified in the ETS submission or restatement. The Default Offer Control Party will not be applied to any blocks for which the Offer Control Party has already been specified at the time of submission.

Note: The application of a Default Offer Control Party at the time of submission will be evident from the ETS submission acknowledgement window.

Note: The designation of Default Offer Control Parties does not add Offer Control Parties to any current submissions that are missing Offer Control, nor does it add Offer Control Parties to historical submissions. Details on updating Historical Offer Control can be found in Section 7.

Note: The Default Offer Control Party will not be applied to offers for operating reserve (OR) as there is a separate process in ETS for making this specification (see Ancillary Services Restatements and Substitutions manual which can be found on the AESO website at www.aeso.ca > Market > Market Participant Information > Pool Participant Manuals).

4.3 Enter the Submission Data for each Applicable Operating Block

(a) Click on [Energy Submission] tab.

(b) From the [Select Submission Type] list box, choose New Submission.

(c) Under [Select Submission Action] choose Create New from Scratch.

(d) Under [Select Dispatch Date] choose a date.

(e) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example Source asset is being used. Click [Next].

(f) From the [Select Asset] list box, choose the desired pool asset.

(g) From [Begin and End (hour ending)] list boxes on the [Filler] tab, choose the desired begin and end time for the desired operating block.

Note: HE 01 and 24 are the default begin and end times.

(h) From the [Enter Pricing] section on the [Filler] tab, choose an operating block number. In this example Block 0.

Note: [Block 0] is the initial default operating block number.

(i) Enter pricing under [Price ($)]. Press the tab key to move to the next field. In the [Amount (MW)] field, enter a MW amount.

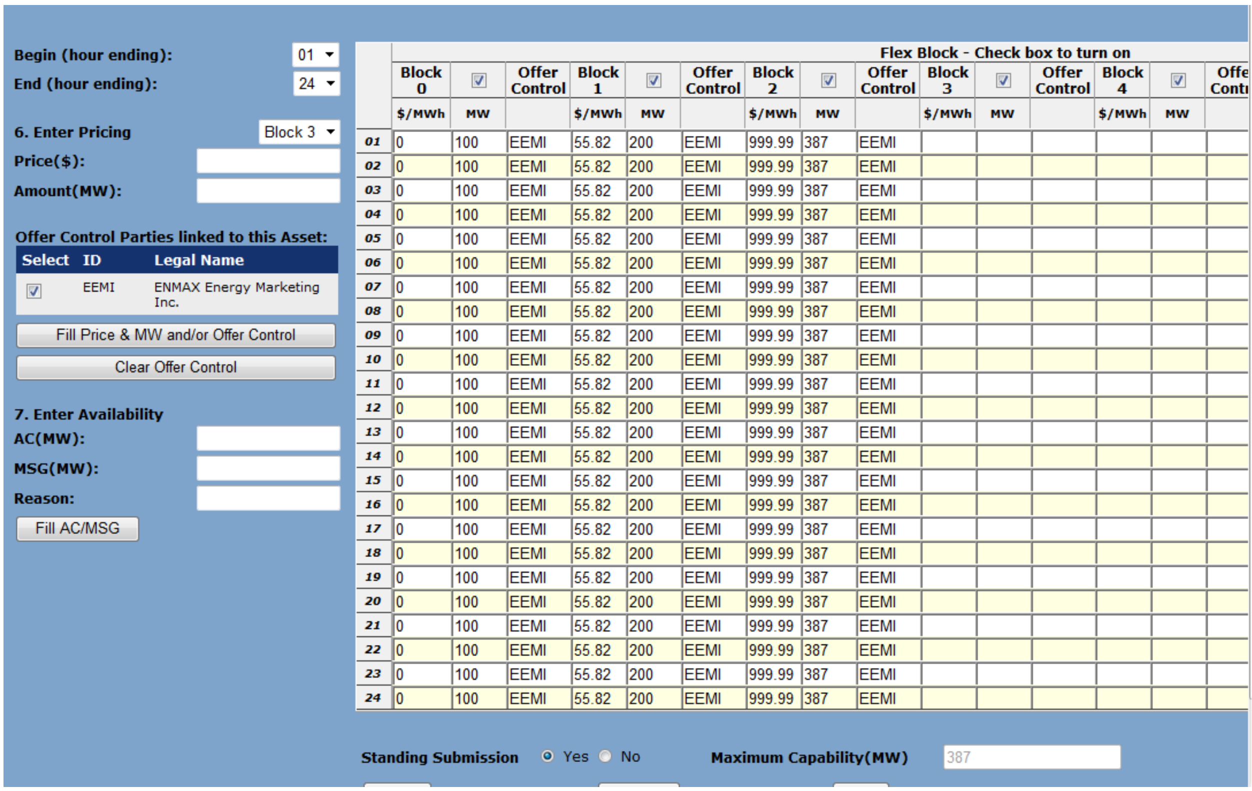
Note: MW amounts must be entered in whole numbers, while prices can have up to two (2) decimal places.

(j) Select [EEMI] under [Offer Control Parties[1] linked to this Asset] then select [Fill Price & MW and/or Offer Control].

(k) Enter [AC (MW)].

(l) Enter [MSG (MW)].

(m) Enter [Reason]. Select [Fill AC/MSG].



Begin (hour ending): 01
End (hour ending): 24

6. Enter Pricing — Block 3
Price($):
Amount(MW):

Offer Control Parties linked to this Asset:

Select	ID	Legal Name
☑	EEMI	ENMAX Energy Marketing Inc.

Fill Price & MW and/or Offer Control
Clear Offer Control

7. Enter Availability
AC(MW):
MSG(MW):
Reason:
Fill AC/MSG

Flex Block - Check box to turn on

	Block 0		Offer Control	Block 1		Offer Control	Block 2		Offer Control	Block 3		Offer Control	Block 4		Offe Contr
	$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW	
01	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
02	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
03	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
04	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
05	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
06	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
07	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
08	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
09	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
10	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
11	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
12	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
13	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
14	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
15	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
16	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
17	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
18	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
19	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
20	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
21	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
22	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
23	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
24	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						

Standing Submission ◉ Yes ○ No Maximum Capability(MW) 387

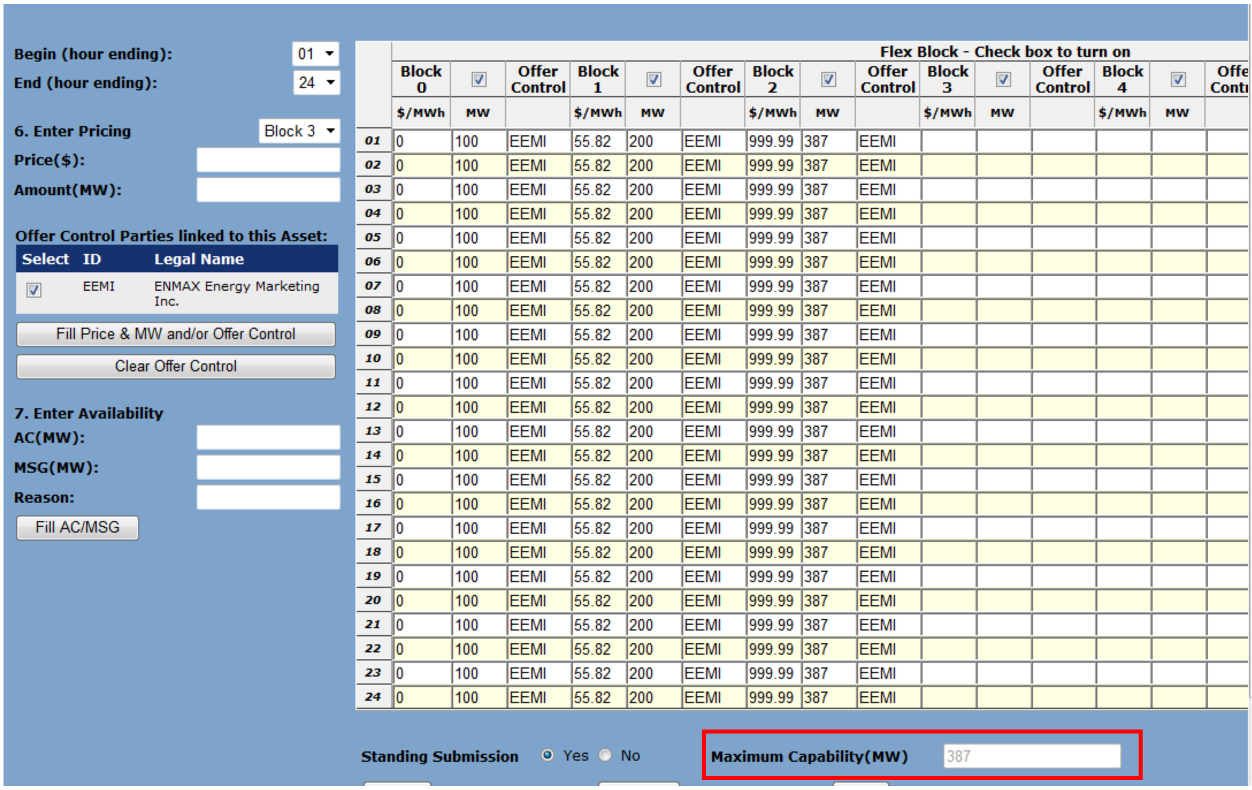
Note: To add data individually to each cell, click on the cell, add the data and press enter. Remember to exit that cell before exiting the screen, or the data from that cell will not be added.

Note: When utilizing multiple operating block offers, the price value must be greater than the price in the previous operating block. The MW amount must be equal to or greater than the previous MW operating block offer.

Note: The pool asset's available capability must be equal to the maximum capability unless the pool participant has submitted an acceptable operational reason. The maximum capability is displayed below the entry grid. In this example the maximum capability is 387 MW.

[11] See Appendix 1 for How to Identify Offer Control Parties

The final operating block of the offer **must** equal the maximum capability of the pool asset.



	Block 0 $/MWh	MW	Offer Control	Block 1 $/MWh	MW	Offer Control	Block 2 $/MWh	MW	Offer Control	Block 3 $/MWh	MW	Offer Control	Block 4 $/MWh	MW	Offe Contr
01	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
02	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
03	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
04	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
05	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
06	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
07	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
08	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
09	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
10	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
11	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
12	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
13	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
14	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
15	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
16	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
17	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
18	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
19	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
20	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
21	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
22	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
23	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						
24	0	100	EEMI	55.82	200	EEMI	999.99	387	EEMI						

Note: Above each operating block is a [Flex Block] flag, which indicates whether an operating block can be partially dispatched. A pool participant must submit whether an operating block is flexible or inflexible as per Section 203.1 subsection 3(3)(c).

When checked, the "flex block" status applies to the entire operating block for all hours of the submission; it is checked by default. Click on the [Flex Block] flag to deselect it indicating that operating block as inflexible.

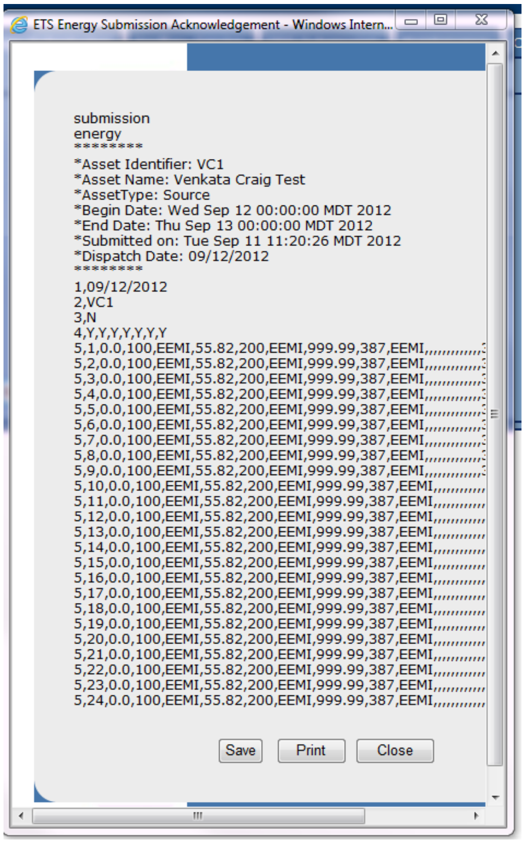
Note: Located below the entry grid is the [Clear All] and [Reset] buttons. The [Clear All] button removes all entries on the existing screen. The [Reset] button removes any changes made to the entries and return them to their original values.

(n) Click on the [Yes] radio button beside [Standing Submission] at the bottom of the screen.

Selecting [Yes] allows this submission to be used as a default for future submissions. These standing submissions can be restated closer to the actual dispatch date.

Note: In order to set up a standing submission the entire forecast scheduling period must have offers entered, and [Yes] standing submission must be selected on every day. However the price and MW offers are structured on the seventh day of the forecast scheduling period is the standing submission that becomes the new default offer structure.

(o) Select [Submit].



A confirmation screen appears containing the acknowledgement results of the submission.

Error messages are generated if data is not correct upon submission of the values and the submission is not accepted.

(p) [Save] or [Print] the acknowledgement.

4.4 Troubleshooting

Why can't I access ETS?

A valid digital certificate is required to access the ETS. Please view our website for more information about digital certificates at www.aeso.ca > Market > Market Participant Information > Energy Trading System Information > Digital Certificates.

The acknowledgement indicates that the submission failed and that there was a validation error – what does this mean?

A validation error occurs if the final block of offers does not equal the maximum capability. Even if the available capability is lower than the maximum capability, the last operating block offer must always offer the full maximum capability as per Section 203.1 subsection 3(4)(a).

I tried using the [Fill Price & MW] function and received an error – why?

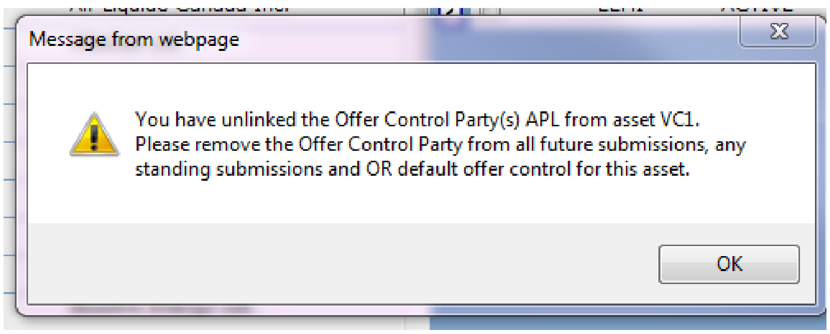
When utilizing multiple operating block offers, the price value must be greater than the previous operating block price. The MW amount must be equal or greater than the previous MW operating block offer.

An Offer Control Party is no longer active but they are showing up in the Offer Control Party List. Why?

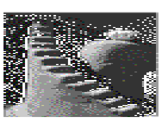
It is up to pool participants to contact the AESO via info@aeso.ca and advise of the "inactive" status of an Offer Control Party. The change is immediate but it is the sole responsibility of the pool participant to ensure that they clean up any future submissions, standing submissions and operating reserve default offer control information where the inactive Offer Control Party resides.

I've removed my Offer Control Party but it is still showing up in my standing submissions?

When a pool participant removes (or un-maps) an Offer Control Party from a pool asset they receive a message similar to the one below. Pool participant should ensure that they remove the Offer Control Party from all future submissions, any standing submissions and operating reserves default offer control.



5 Create a New Energy Offer from an Existing Offer



Steps

5.1 Create a New Submission using an Existing Submission

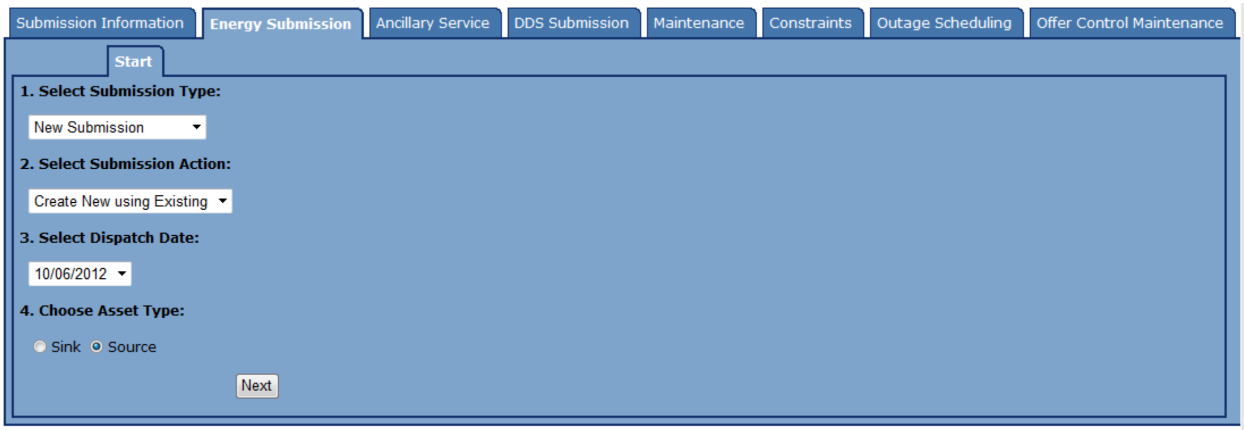
(a) Click on [Energy Submission] tab.

(b) From the [Select Submission Type] list box, choose New Submission.

(c) Under [Select Submission Action] choose Create New using Existing.

(d) Under [Select Dispatch Date] choose a date. In this example the new energy offer is being created for October 6, 2012.

Note: The dispatch date defaults to the next available submission date.

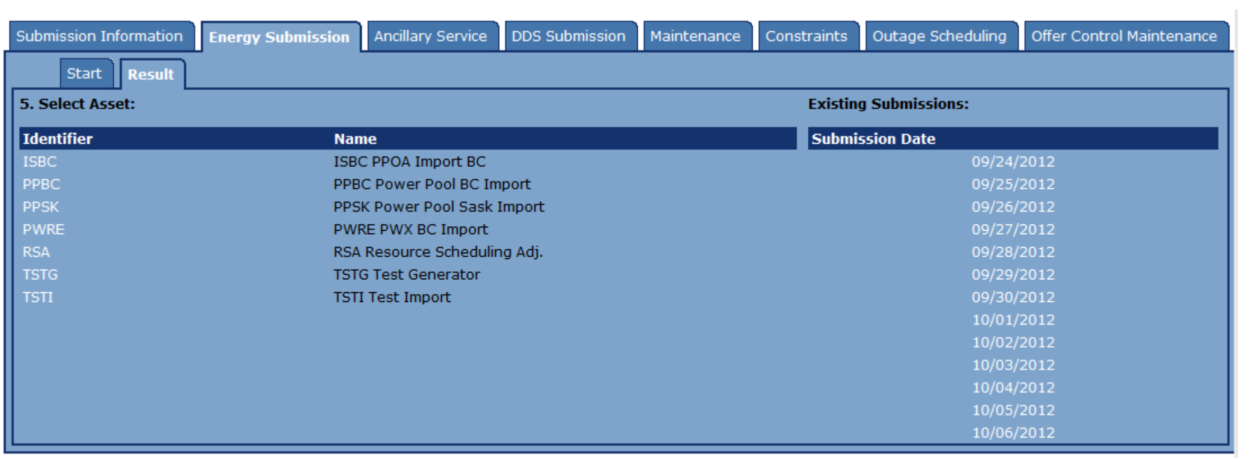


(e) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example Source asset is being used. Click [Next].

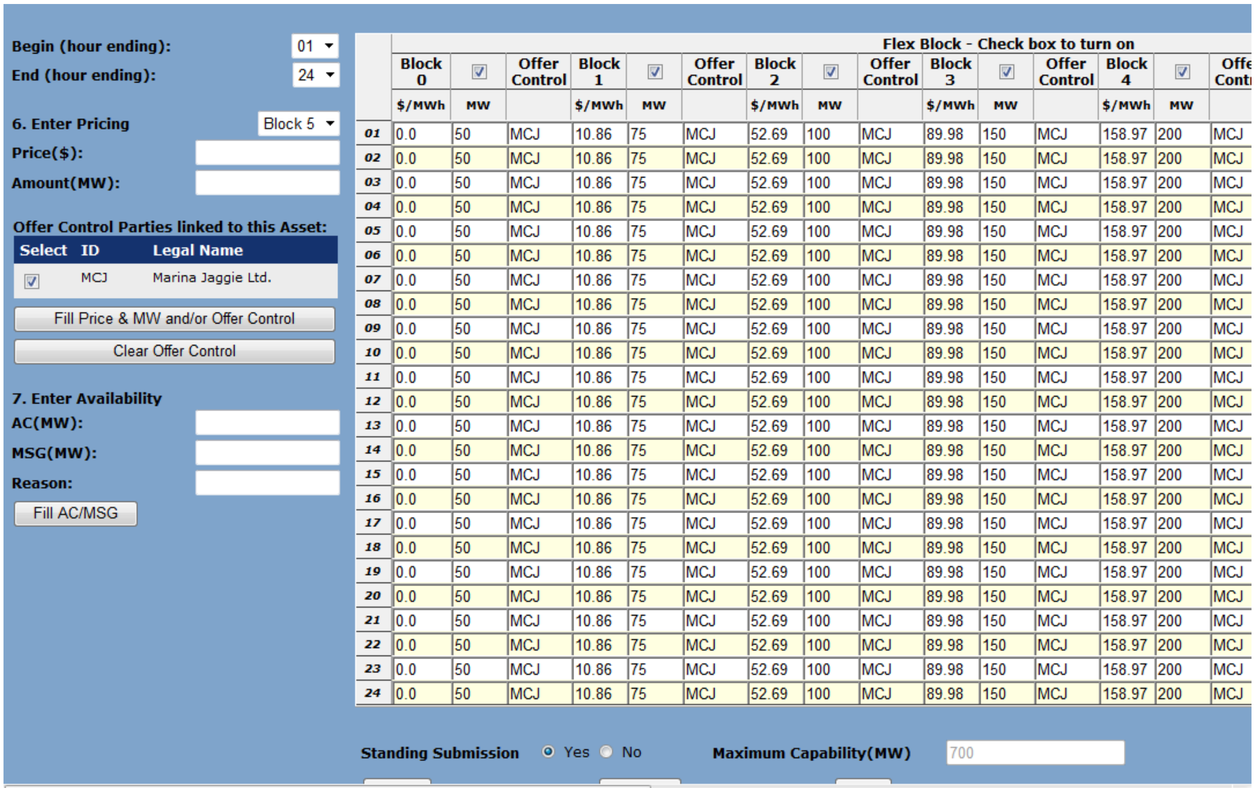
(f) From the [Select Asset] list box, choose the desired pool asset.

(g) Select the desired submission date from the selection box.

Note: The [Existing Submissions] screen appears on the right hand side and provides a listing of available historical submissions to select from.



Note: The energy submission grid is populated with previously entered data for the selected date.



Begin (hour ending): 01
End (hour ending): 24

6. Enter Pricing — Block 5
Price($):
Amount(MW):

Offer Control Parties linked to this Asset:

Select	ID	Legal Name
☑	MCJ	Marina Jaggie Ltd.

Fill Price & MW and/or Offer Control
Clear Offer Control

7. Enter Availability
AC(MW):
MSG(MW):
Reason:
Fill AC/MSG

Flex Block - Check box to turn on

	Block 0	☑	Offer Control	Block 1	☑	Offer Control	Block 2	☑	Offer Control	Block 3	☑	Offer Control	Block 4	☑	Offe[r] Cont[rol]
	$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW	
01	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
02	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
03	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
04	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
05	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
06	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
07	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
08	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
09	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
10	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
11	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
12	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
13	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
14	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
15	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
16	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
17	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
18	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
19	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
20	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
21	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
22	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
23	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ
24	0.0	50	MCJ	10.86	75	MCJ	52.69	100	MCJ	89.98	150	MCJ	158.97	200	MCJ

Standing Submission ◉ Yes ○ No   Maximum Capability(MW) 700

Note: To add or modify data in an individual cell, click on the cell, add the data and press enter. Remember to exit that cell before exiting the screen or the data from that cell will not be added.

(h) Select [Submit].

(i) [Save] or [Print] the acknowledgement.

Error messages are generated if data is not correct upon submission of the values and the submission is not accepted.

```
submission
energy
********
*Asset Identifier: TSTG
*Asset Name: TSTG Test Generator
*AssetType: Source
*Begin Date: Sat Oct 06 00:00:00 MDT 2012
*End Date: Sun Oct 07 00:00:00 MDT 2012
*Submitted on: Thu Oct 04 17:24:27 MDT 2012
*Dispatch Date: 10/06/2012
********
1,10/06/2012
2,TSTG
3,Y
4,Y,Y,Y,Y,Y,Y,Y
5,1,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,2,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,3,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,4,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,5,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,6,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,7,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,8,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,9,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MCJ,
AC
5,10,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MC
AC
5,11,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MC
AC
5,12,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MC
AC
5,13,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MC
AC
5,14,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MC
AC
5,15,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MC
AC
5,16,0.0,50,MCJ,10.86,75,MCJ,52.69,100,MCJ,89.98,150,MC
```

5.2 Troubleshooting

If I make changes to an existing submission does it change my standing submission going forward?

No, making an edit to an existing submission does not change the standing submission.

6 Energy Restatements

The following section details the steps involved for creating two (2) types of energy restatements:

(a) An available capability restatement consists of restating the pool asset's available capability when a pool participant is unable to provide the pool asset's maximum capability. A pool participant may submit an available capability restatement.

A pool participant **must** provide an acceptable operational reason with the available capability restatement.

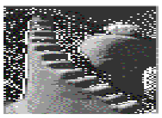
(b) A MW restatement is to be used when a pool participant has submitted an offer and needs to re-submit a revised offer for its pool asset by redistributing the quantity (MW) to represent the operating state of the pool asset. This type of restatement can only be used under the following conditions:

(i) the pool asset can no longer comply with the current submission;

(ii) an available capability restatement cannot reasonably accommodate the pool asset's operating state; and

(iii) the pool participant can no longer submit a price restatement.

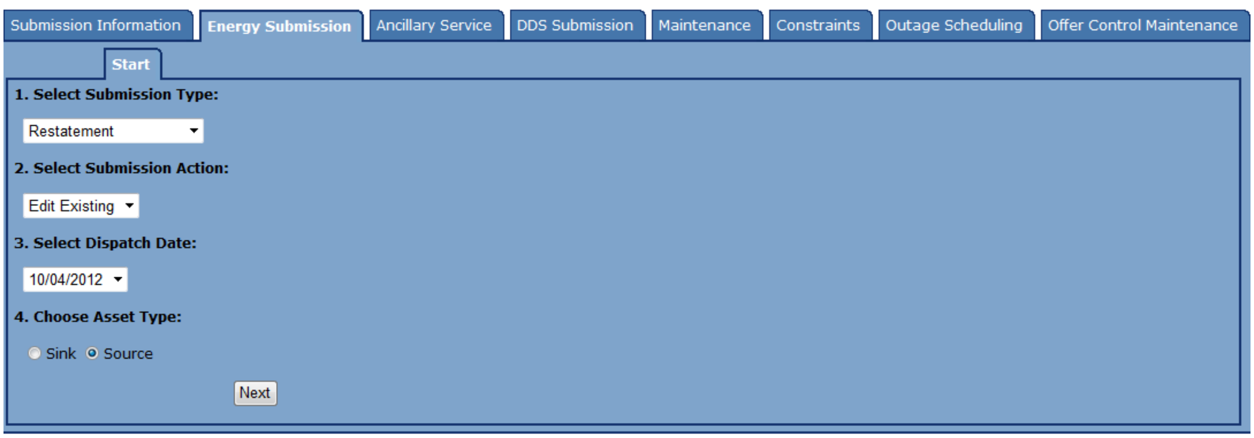
For further clarification on acceptable operational reasons, please refer to the Consolidated Authoritative Document Glossary on the AESO website or ID# 2009-003(R) *Acceptable Operational Reasons*.



Steps

6.1 Create an Available Capability Restatement

(a) Click on the [Energy Submission] tab.



(b) From the [Select Submission Type] list box, choose Restatement.

(c) From the [Select Submission Action] list box, choose Edit Existing.

(d) From the [Select Dispatch Date] list box, choose Default Date. In this example the date is October 4, 2012.

Note: Valid restatement dates are those within the current restatement period. For example, if the date is October 4, 2012, and it is before 12 p.m., restatements can only occur for October 4. However, if it is after 12 p.m., restatements can occur for October 4 and October 5.

(e) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example, Source asset is being used. Click [Next].

(f) From the [Select Asset Type] list box, choose the desired pool asset.

Note: The restatement screen appears. In this example, the current time is 5:29 pm.

Flex Block - Check box to turn on

k	☑	Offer Control	Block 3	☑	Offer Control	Block 4	☑	Offer Control	Block 5	☑	Offer Control	Block 6	☑	Offer Control				
h	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		DDS Offer	AC	MSG	
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387			387	5	Default AC
	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387			387	5	Default AC
	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387			387	5	Default AC
	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387			387	5	Default AC

um Capability(MW) 387

As shown in the above restatement screen, the ETS automatically greys out the cells in each operating block that are unavailable for modification. During the T-2 period (current hour ending plus next two (2) hours), the price values are greyed out, as pool participants are tied to prices for this duration.

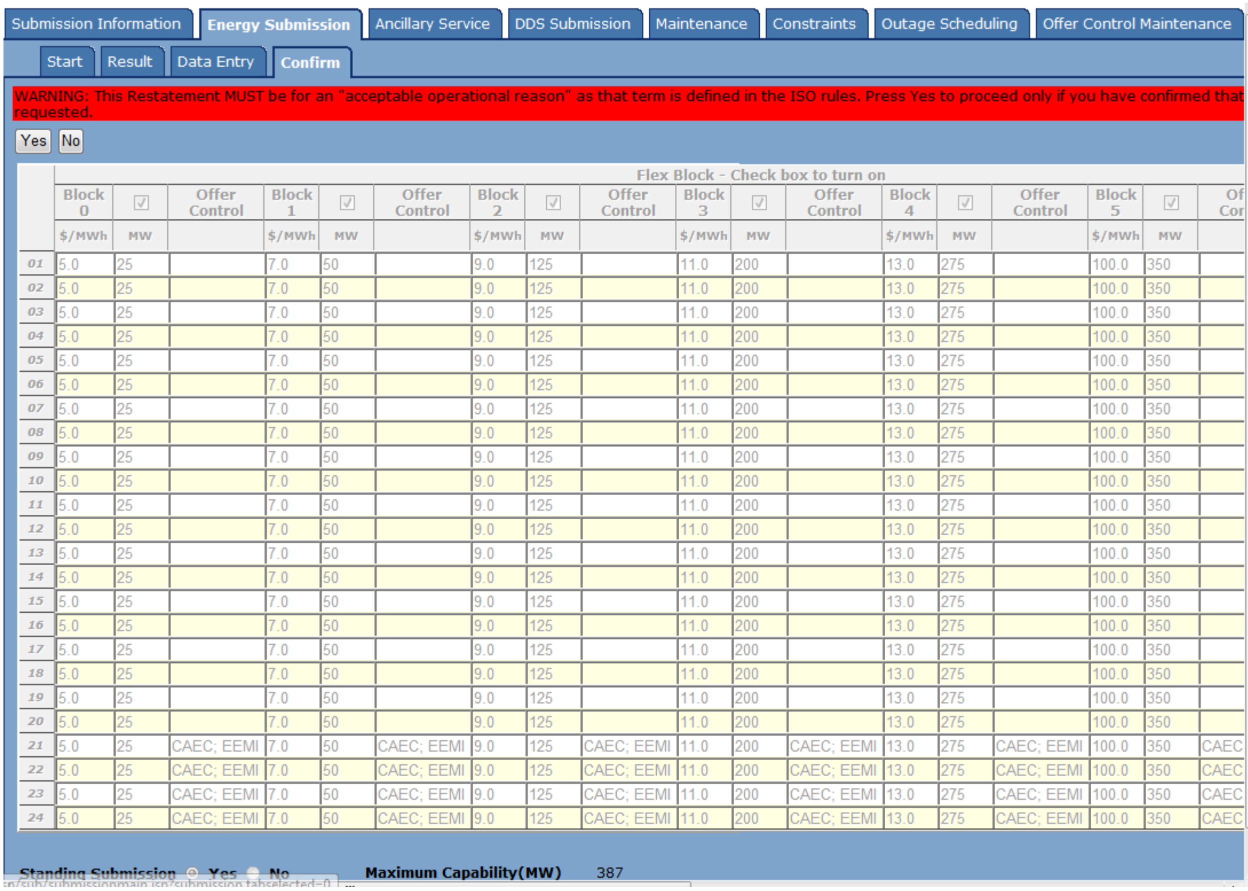
On the [Filler] tab on the left, the [Enter Availability] section can be used to update available capability values. However, the [Begin (hour ending)] field is only accessible outside of T-2. All available capability updates within T-2 must be manually entered on the grid under the AC column.

(g) Under the available capability (AC) column enter the desired restated available capability and the associated reason.

Offer Control	Block 5 $/MWh	MW	Offer Control	Block 6 $/MWh	MW	Offer Control	DDS Offer	AC	MSG	Reason
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			387	5	Default AC
	100.0	350		300.0	387			200	5	Test
CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387	CAEC; EEMI		387	5	Default AC
CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387	CAEC; EEMI		387	5	Default AC
CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387	CAEC; EEMI		387	5	Default AC
CAEC; EEMI	100.0	350	CAEC; EEMI	300.0	387	CAEC; EEMI		387	5	Default AC

(h) At the bottom of the screen, click on the [Submit] button to complete the submission.

Note: Warning: AOR Required. The warning shown in the following screenshot appears whether an acceptable operational reason was entered or not. If an acceptable operational reason was entered, select [Yes] to continue with the submission. Select [No] to return to the energy grid to edit or complete the acceptable operational reason requirement



	Block 0	☑	Offer Control	Block 1	☑	Offer Control	Block 2	☑	Offer Control	Block 3	☑	Offer Control	Block 4	☑	Offer Control	Block 5	☑	Of Cor
	$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW	
01	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
02	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
03	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
04	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
05	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
06	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
07	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
08	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
09	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
10	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
11	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
12	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
13	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
14	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
15	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
16	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
17	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
18	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
19	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
20	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275		100.0	350	
21	5.0	25	CAEC; EEMI	7.0	50	CAEC; EEMI	9.0	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC
22	5.0	25	CAEC; EEMI	7.0	50	CAEC; EEMI	9.0	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC
23	5.0	25	CAEC; EEMI	7.0	50	CAEC; EEMI	9.0	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC
24	5.0	25	CAEC; EEMI	7.0	50	CAEC; EEMI	9.0	125	CAEC; EEMI	11.0	200	CAEC; EEMI	13.0	275	CAEC; EEMI	100.0	350	CAEC

(i) [Save] or [Print] the acknowledgement.

6.2 Troubleshooting

The [Filler] tool won't make the available capability change in the hour ending I require – how come?

The [Filler] tool does not work during the T-2 period. Click directly in the cell to be changed and manually enter the available capability amount and reason.

How much detail should I provide for my appropriate acceptable operational reason?

The ETS has up to 1024 characters to record and communicate an acceptable operational reason. AESO Compliance Monitoring should understand the purpose of the update and be able to differentiate the reasons from an available capability restatement, MW restatement or MSG restatement.

What is T-2?

T-2 is the current hour ending plus two (2) hour endings. For example, if the current time is 10:05 a.m. it is considered Hour Ending 11. Add two (2) hours to the current hour ending; in this example the T-2 period is Hour Ending 11, 12 and 13.

6.3 Create a MW Restatement

This type of restatement is to be used when a pool participant has submitted an offer and needs to submit a revised offer for its pool asset by redistributing the quanitity (MW) to represent the operating state of the pool asset.

(a) Click on the [Energy Submission] tab.

(b) From the [Select Submission Type] list box, choose Restatement.

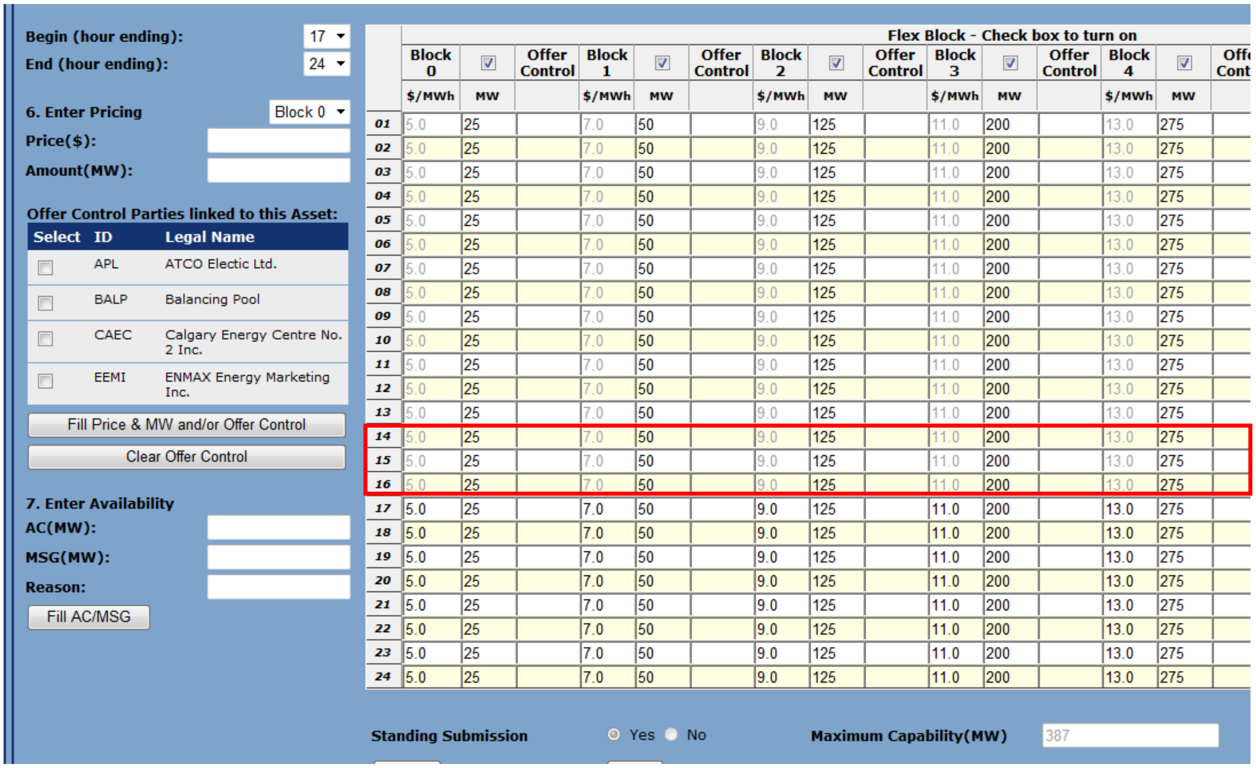
(c) From the [Select Submission Action] list box, choose Edit Existing.

(d) From the [Select Dispatch Date] list box, choose Default Date. In this example the date is September 28, 2012.

(e) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example Source asset is being used. Click [Next].

(f) From the [Choose Asset] list box, choose the desired pool asset.

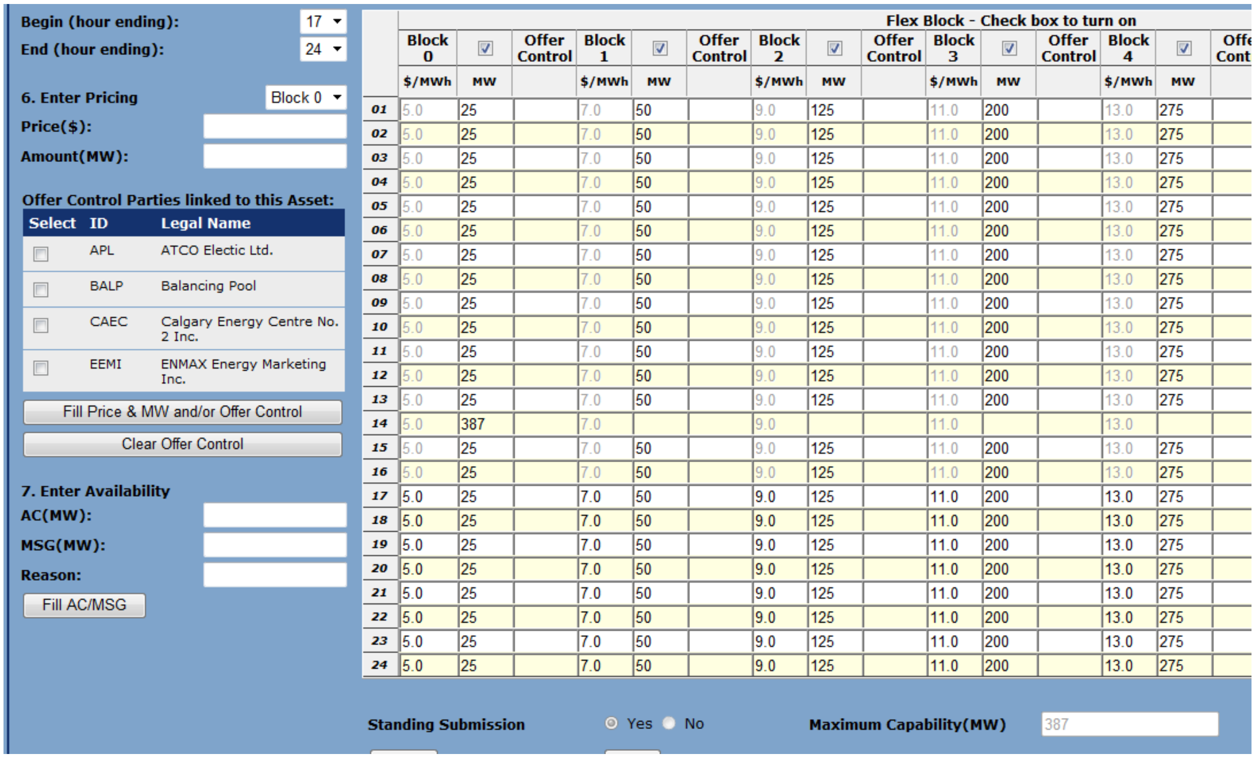
Note: The restatement screen appears. In this example, the current time is 1:53 pm.



(g) During the T-2 period, the pool asset has experienced an operational issue that requires the generating unit to run all three hundred eighty-seven (387) MW. In this situation, the pool asset cannot comply with its current offer, a price restatement can no longer be submitted, and the situation cannot be addressed through a change to the available capability.

(h) All three hundred eighty-seven (387) MW are manually moved to operating block zero and an acceptable operational reason is provided.

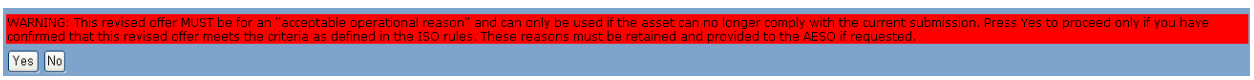
Note: During T-2, tab over to remove MW from the operating blocks. Price is greyed out and unable to be changed.



	Block 0	☑	Offer Control	Block 1	☑	Offer Control	Block 2	☑	Offer Control	Block 3	☑	Offer Control	Block 4	☑	Offe Cont
	$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW	
01	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
02	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
03	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
04	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
05	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
06	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
07	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
08	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
09	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
10	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
11	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
12	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
13	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
14	5.0	387		7.0			9.0			11.0			13.0		
15	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
16	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
17	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
18	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
19	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
20	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
21	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
22	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
23	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
24	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	

(i) At the bottom of the screen, click on the [Submit] button to complete the submission.

(j) Warning: AOR Required.



(k) [Save] or [Print] the acknowledgement.

6.4 Creating a Price/Quantity Restatement Prior to T-2

A price/quantity restatement allows a pool participant to change their price and/or operating block MW size for time periods greater than two (2) hours before the start of the settlement interval (outside T-2), and does not require an acceptable operational reason.

(a) Click on the [Energy Submission] tab.

(b) From the [Select Submission Type] list box, choose Restatement.

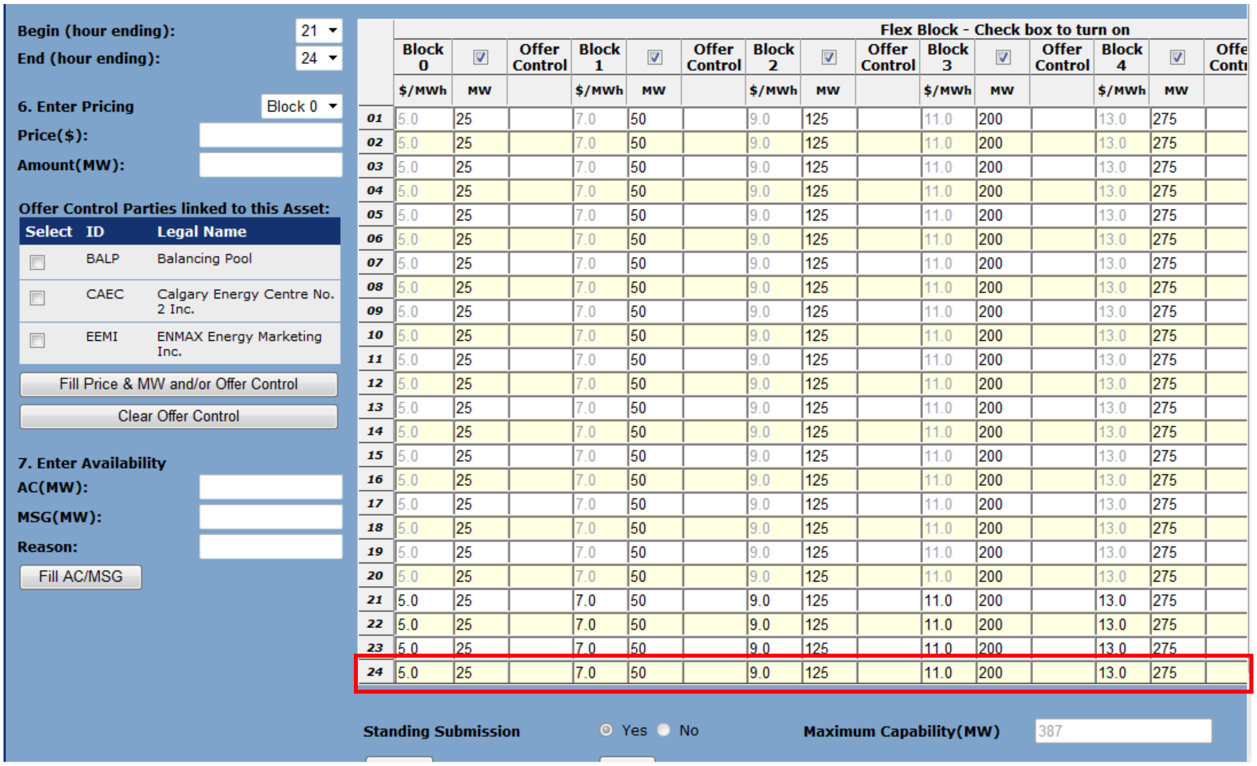
(c) From the [Select Submission Action] list box, choose Edit Existing.

(d) From the [Select Dispatch Date] list box, choose Default Date.

(e) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example, Source asset is being used. Click [Next].

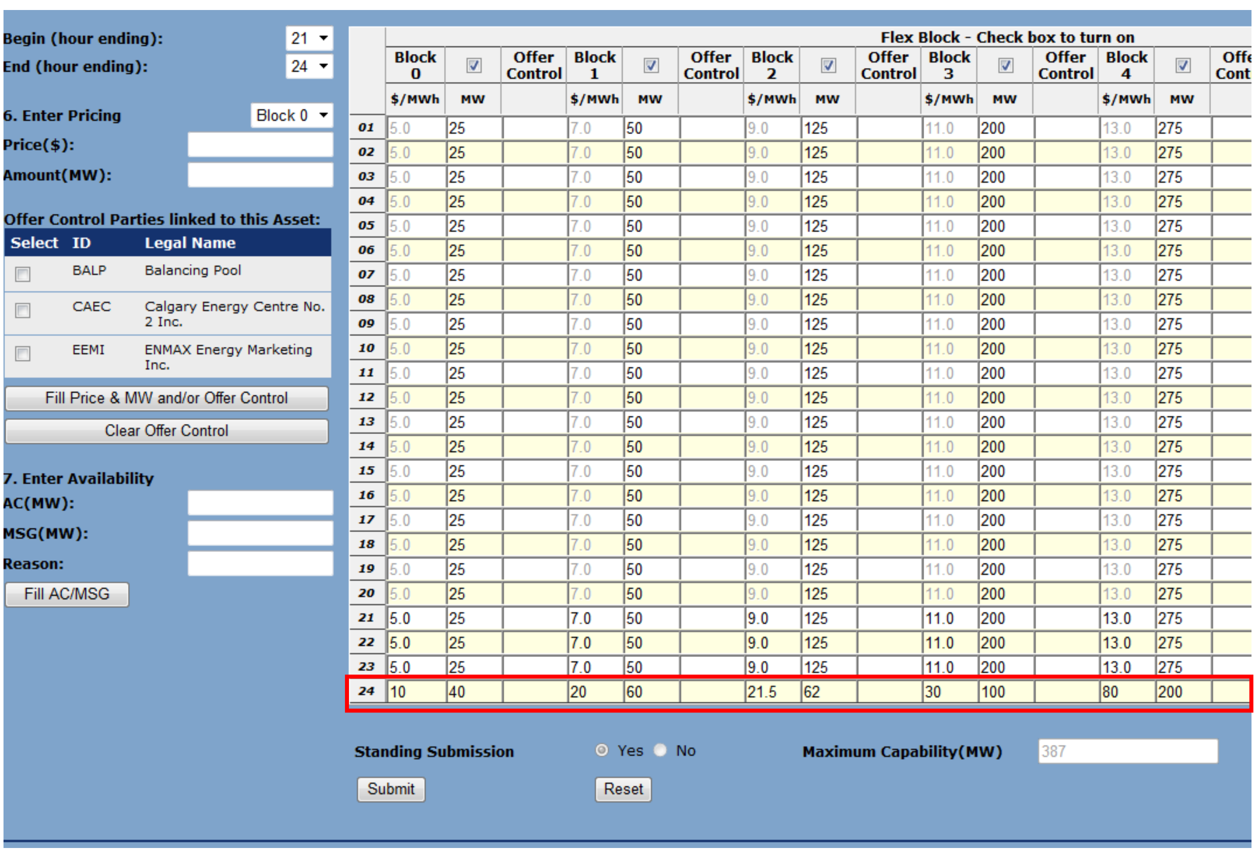
(f) From the [Choose Asset] list box, choose the desired pool asset.

Note: The restatement screen appears. In this example, the current time is 5:48 pm and the restatement is for an offer that is to be effective in HE24.



	Block 0 $/MWh	MW	Offer Control	Block 1 $/MWh	MW	Offer Control	Block 2 $/MWh	MW	Offer Control	Block 3 $/MWh	MW	Offer Control	Block 4 $/MWh	MW	Offer Control
01	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
02	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
03	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
04	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
05	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
06	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
07	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
08	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
09	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
10	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
11	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
12	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
13	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
14	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
15	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
16	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
17	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
18	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
19	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
20	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
21	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
22	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
23	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
24	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	

To update information outside of T-2 both methods, [Filler] or manually entering the data can be utilized.



	Block 0 $/MWh	MW	Offer Control	Block 1 $/MWh	MW	Offer Control	Block 2 $/MWh	MW	Offer Control	Block 3 $/MWh	MW	Offer Control	Block 4 $/MWh	MW	Offer Control
01	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
02	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
03	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
04	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
05	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
06	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
07	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
08	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
09	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
10	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
11	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
12	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
13	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
14	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
15	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
16	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
17	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
18	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
19	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
20	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
21	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
22	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
23	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275	
24	10	40		20	60		21.5	62		30	100		80	200	

(g) Click on the [Submit] button.

(h) [Save] or [Print] the acknowledgement.

6.5 Troubleshooting

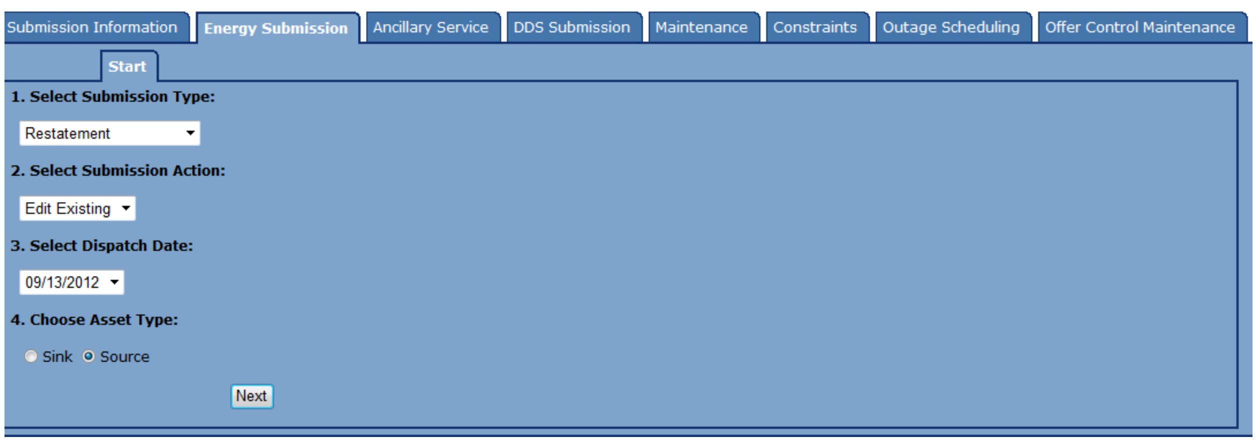
Some of the price cells are greyed out and I cannot change them – why?

Prices within two (2) hours of the start of the settlement interval are locked in. During this T-2 period, only the available capability can be restated with an acceptable operational reason (Available Capability Restatement) or the MW amount can be changed with an acceptable operational reason (MW Restatement).

In a voluntary price/quantity restatement, price and/or MW amount may be changed outside of T-2 without an acceptable operational reason.

6.6 Offer Control Party Restatement

(a) Click on the [Energy Submission] tab.



(b) From the [Select Submission Type] list box, choose the Restatement.

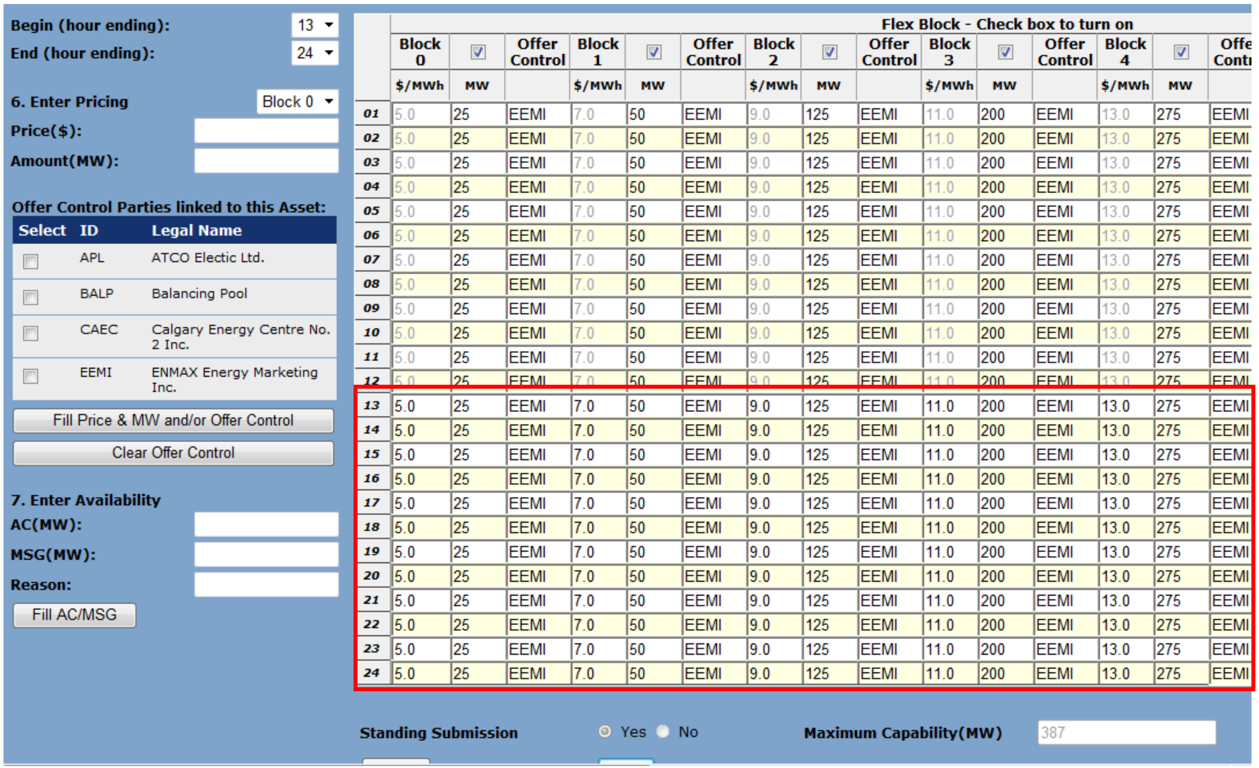
(c) From the [Select Submission Action], choose Edit Existing.

(d) From the [Select Dispatch Date] list box, choose the current day or the next trading day.

(e) From the [Choose Asset Type] list box, choose the desired pool asset.

(f) In this example the Offer Control Party for Block 0 for HE13 -24 is restated from EEMI to APL. As this is outside of T-2 the [Filler] can be used.

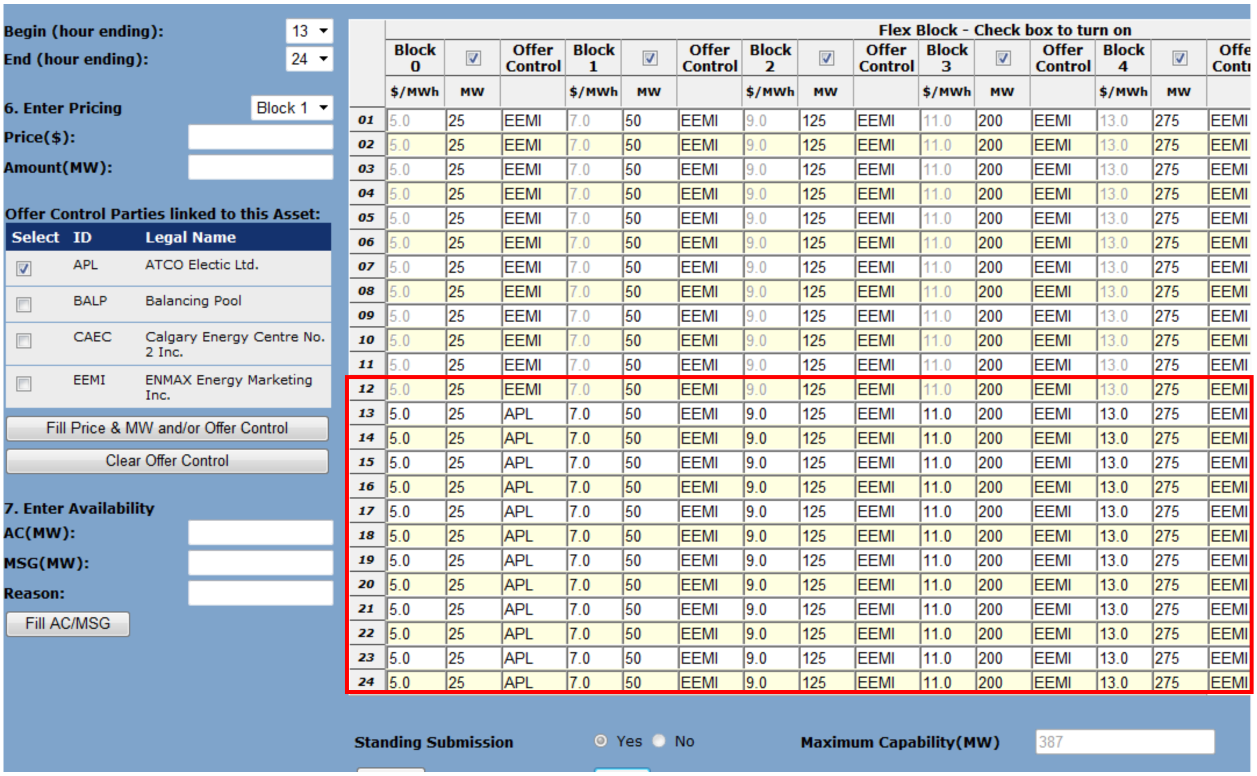
Note: If only the Offer Control Party is being restated no acceptable operational reason is required.



(g) Under the [Offer Control Parties linked to this Asset], select the Offer Control Party desired.

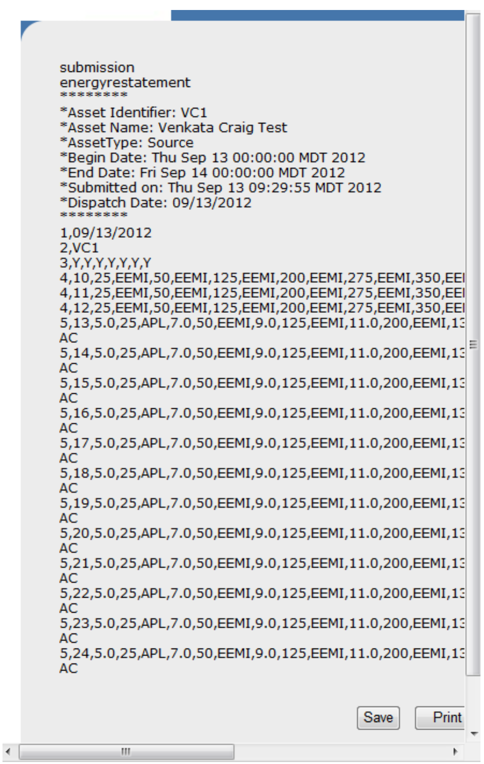
(h) Select [Fill Price & MW and/or Offer Control].

(i) Select [Submit].



	Block 0 $/MWh	MW	Offer Control	Block 1 $/MWh	MW	Offer Control	Block 2 $/MWh	MW	Offer Control	Block 3 $/MWh	MW	Offer Control	Block 4 $/MWh	MW	Offe Contr
01	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
02	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
03	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
04	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
05	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
06	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
07	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
08	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
09	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
10	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
11	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
12	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
13	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
14	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
15	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
16	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
17	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
18	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
19	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
20	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
21	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
22	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
23	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
24	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI

(j) [Save] or [Print] the acknowledgement.



submission
energyrestatement
****
*Asset Identifier: VC1
*Asset Name: Venkata Craig Test
*AssetType: Source
*Begin Date: Thu Sep 13 00:00:00 MDT 2012
*End Date: Fri Sep 14 00:00:00 MDT 2012
*Submitted on: Thu Sep 13 09:29:55 MDT 2012
*Dispatch Date: 09/13/2012
****
1,09/13/2012
2,VC1
3,Y,Y,Y,Y,Y,Y,Y
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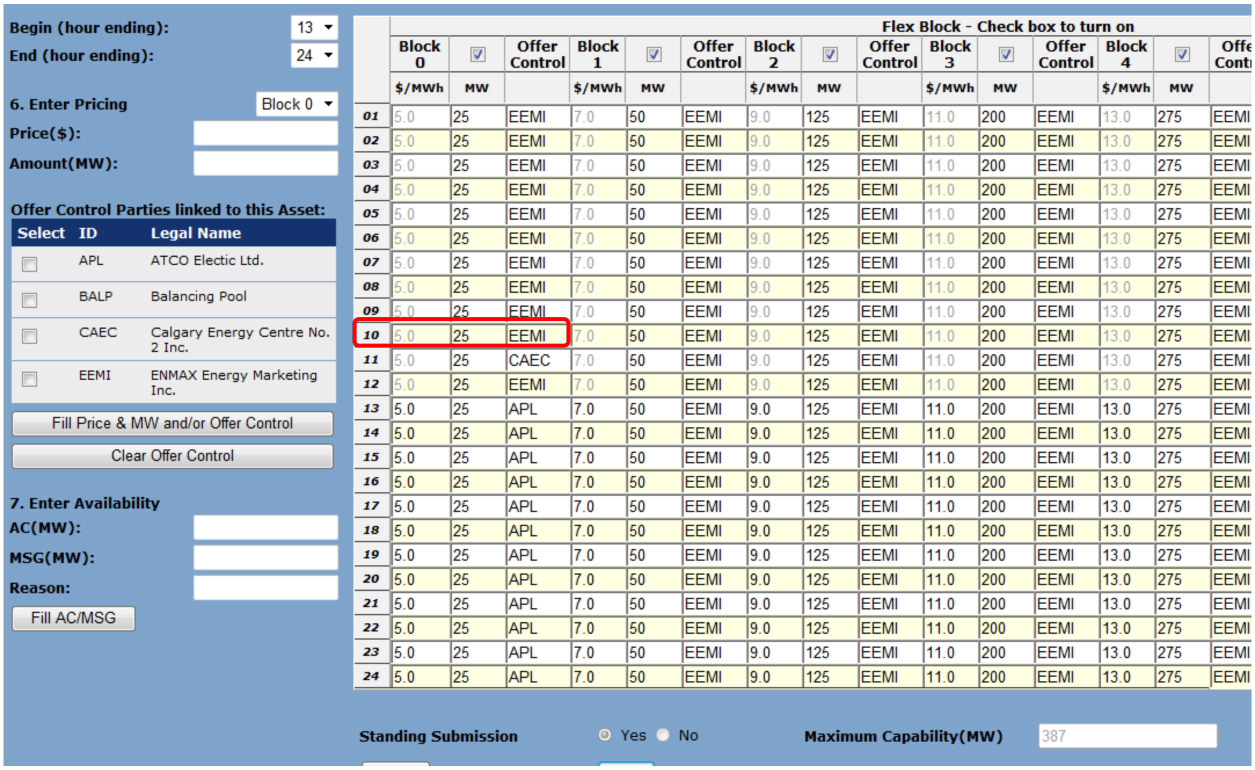
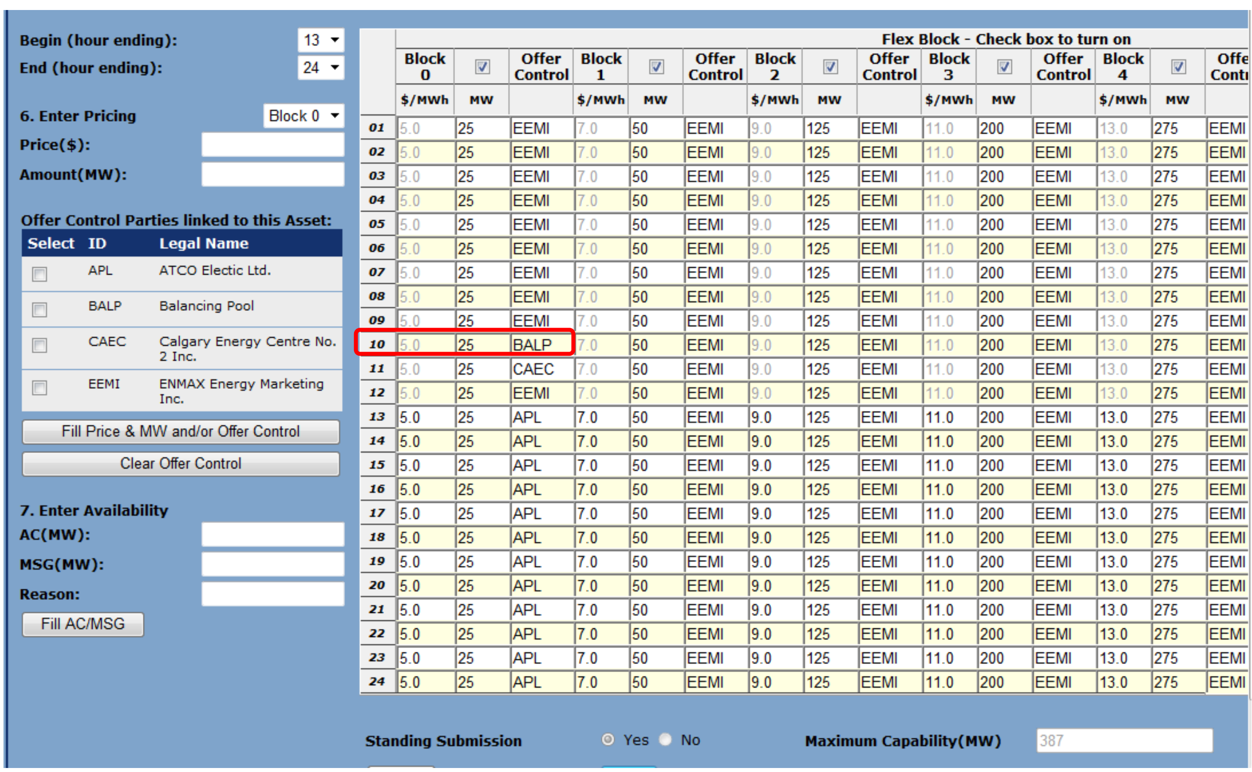
5,24,5.0,25,APL,7.0,50,EEMI,9.0,125,EEMI,11.0,200,EEMI,13
AC

Save Print

(k) *Within* T-2, changes to Offer Control Parties can only be made in the grid – the [Filler] cannot be used. In this example the Offer Control Party is changing from EEMI to BALP within T-2.



	Block 0 $/MWh	MW	Offer Control	Block 1 $/MWh	MW	Offer Control	Block 2 $/MWh	MW	Offer Control	Block 3 $/MWh	MW	Offer Control	Block 4 $/MWh	MW	Offe Cont
01	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
02	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
03	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
04	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
05	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
06	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
07	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
08	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
09	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
10	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
11	5.0	25	CAEC	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
12	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
13	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
14	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
15	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
16	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
17	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
18	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
19	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
20	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
21	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
22	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
23	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
24	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI



	Block 0 $/MWh	MW	Offer Control	Block 1 $/MWh	MW	Offer Control	Block 2 $/MWh	MW	Offer Control	Block 3 $/MWh	MW	Offer Control	Block 4 $/MWh	MW	Offe Cont
01	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
02	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
03	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
04	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
05	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
06	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
07	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
08	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
09	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
10	5.0	25	BALP	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
11	5.0	25	CAEC	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
12	5.0	25	EEMI	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
13	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
14	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
15	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
16	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
17	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
18	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
19	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
20	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
21	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
22	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
23	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI
24	5.0	25	APL	7.0	50	EEMI	9.0	125	EEMI	11.0	200	EEMI	13.0	275	EEMI

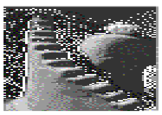
6.7 Troubleshooting

I restated my Offer Control Party within T-2 but wasn't asked to provide any Acceptable Operational Reason – why?

If a pool participant changes MW and Offer Control Party or MW *within* T-2, the pool participant needs to provide an acceptable operational reason. However, if they are only restating the Offer Control Party *within* T-2, they are not required to provide an acceptable operational reason.

7 Energy Historical Offer Control

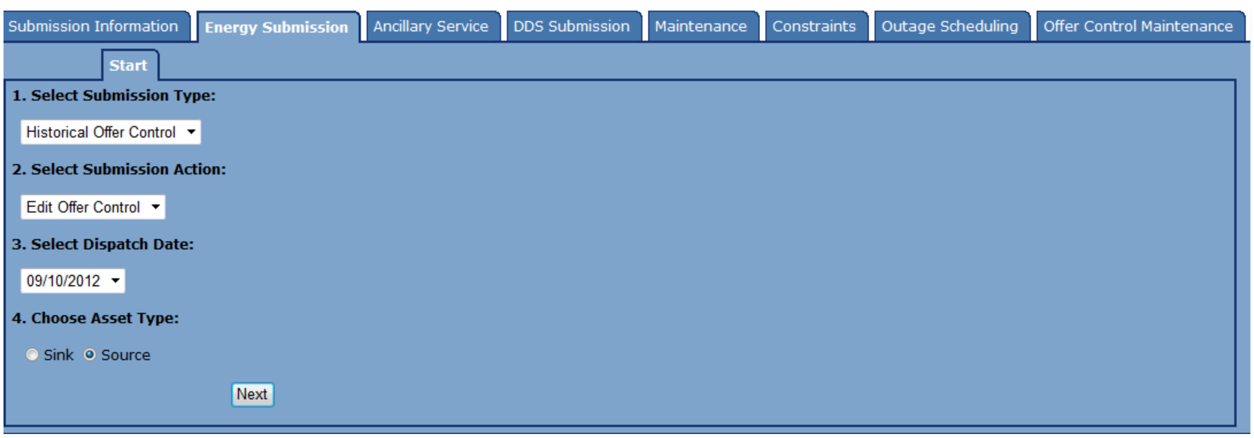
Pool participants have the ability to submit Offer Control Party information on a historical basis if they are unable to submit the Offer Control Party at the same time as their submission data. Participants can edit historical offer control parties up to 30 days from the dispatch date.



Steps

7.1 Edit Offer Control

(a) Click on the [Energy Submission] tab.

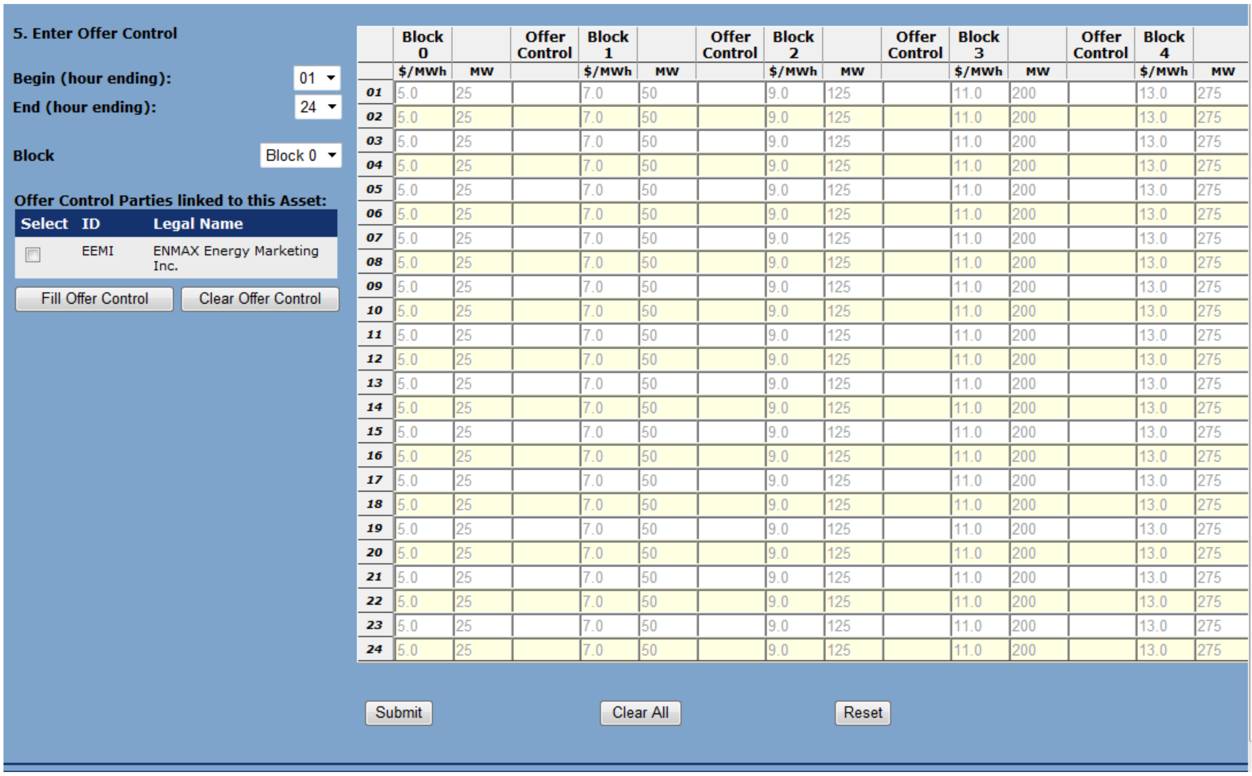


(b) From the [Select Submission Type] list box, choose the Historical Offer Control.

(c) From the [Select Submission Action] list box, choose Edit Offer Control.

(d) From the [Select Dispatch Date] – choose any date up to 30 days from the dispatch date. In this example the date is September 10, 2012.

(e) Under [Choose Asset Type], click on [Sink] or [Source] radio button. In this example Source asset being used. Click [Next].


5. Enter Offer Control

Begin (hour ending): 01
End (hour ending): 24

Block: Block 0

Offer Control Parties linked to this Asset:

Select	ID	Legal Name
☐	EEMI	ENMAX Energy Marketing Inc.

Fill Offer Control | Clear Offer Control

	Block 0		Offer Control	Block 1		Offer Control	Block 2		Offer Control	Block 3		Offer Control	Block 4	
	$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW
01	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
02	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
03	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
04	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
05	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
06	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
07	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
08	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
09	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
10	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
11	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
12	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
13	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
14	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
15	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
16	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
17	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
18	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
19	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
20	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
21	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
22	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
23	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275
24	5.0	25		7.0	50		9.0	125		11.0	200		13.0	275

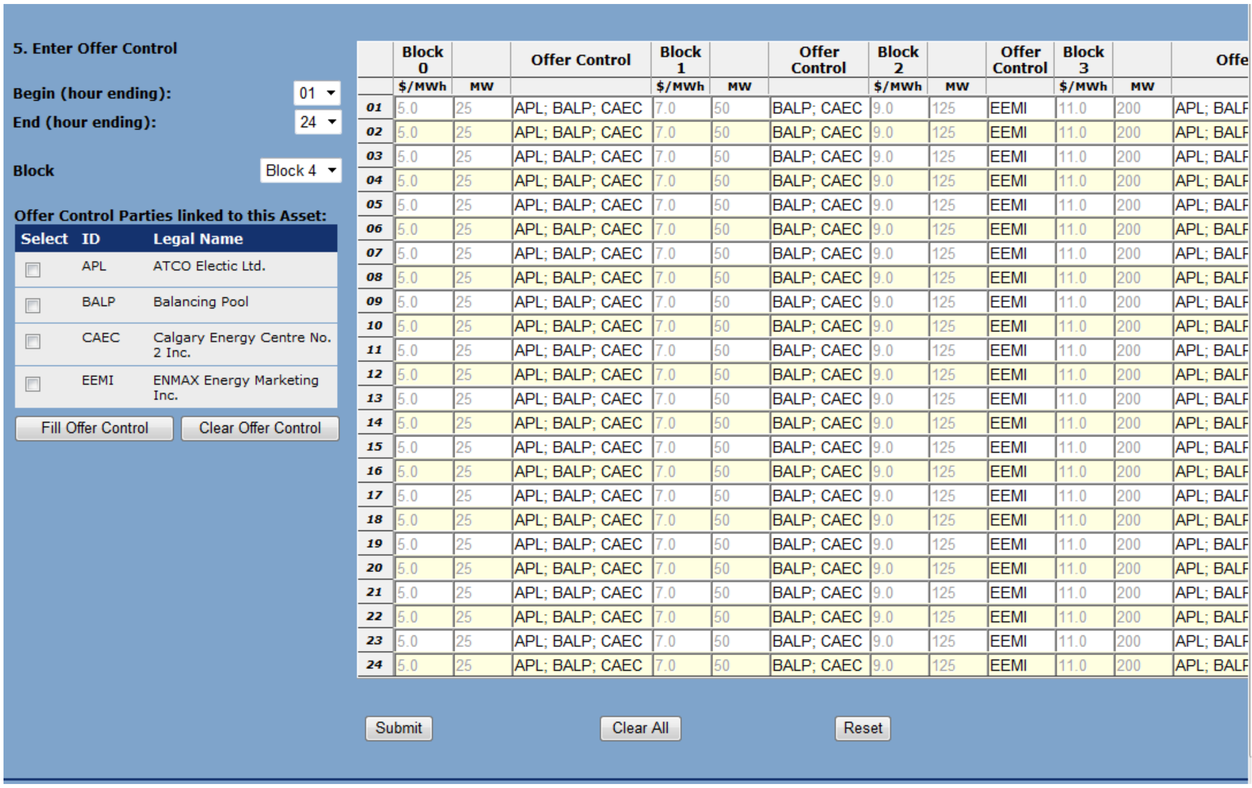
Submit | Clear All | Reset

Note: Because the Offer Control Party is being entered historically (i.e. after the dispatch date) all cells are greyed out.

Note: Participant cannot edit historical Offer Control Party information for the current day. Edits are only available after midnight.

(f) Select Offer Control ID from [Offer Control Parties linked to this Asset].

(g) Select [Fill Offer Control].



5. Enter Offer Control

Begin (hour ending): 01
End (hour ending): 24

Block: Block 4

Offer Control Parties linked to this Asset:

Select	ID	Legal Name
☐	APL	ATCO Electic Ltd.
☐	BALP	Balancing Pool
☐	CAEC	Calgary Energy Centre No. 2 Inc.
☐	EEMI	ENMAX Energy Marketing Inc.

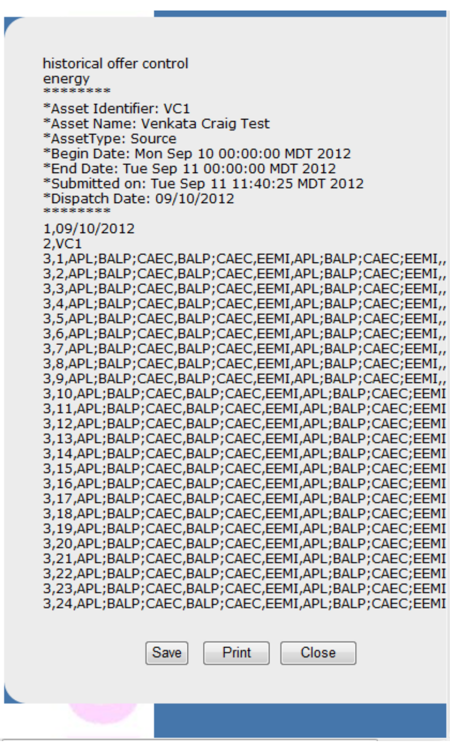
Fill Offer Control | Clear Offer Control

	Block 0		Offer Control	Block 1		Offer Control	Block 2		Offer Control	Block 3		Offe
	$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW	
01	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
02	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
03	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
04	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
05	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
06	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
07	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
08	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
09	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
10	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
11	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
12	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
13	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
14	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
15	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
16	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
17	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
18	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
19	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
20	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
21	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
22	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
23	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP
24	5.0	25	APL; BALP; CAEC	7.0	50	BALP; CAEC	9.0	125	EEMI	11.0	200	APL; BALP

Submit | Clear All | Reset

(h) Select [Submit].

(i) [Save] or [Print] the acknowledgement.



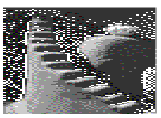
historical offer control
energy
****
*Asset Identifier: VC1
*Asset Name: Venkata Craig Test
*AssetType: Source
*Begin Date: Mon Sep 10 00:00:00 MDT 2012
*End Date: Tue Sep 11 00:00:00 MDT 2012
*Submitted on: Tue Sep 11 11:40:25 MDT 2012
*Dispatch Date: 09/10/2012
****
1,09/10/2012
2,VC1
3,1,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,2,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,3,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,4,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,5,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,6,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,7,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,8,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,9,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI,,
3,10,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,11,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,12,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,13,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,14,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,15,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,16,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,17,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,18,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,19,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,20,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,21,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,22,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,23,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI
3,24,APL;BALP;CAEC,BALP;CAEC,EEMI,APL;BALP;CAEC;EEMI

Save | Print | Close

8 Outage Scheduling

Pool participants must enter all available capability values for the next two (2) years into the Outage Scheduling tab in ETS. These values include any changes to the available capability along with the associated reason.

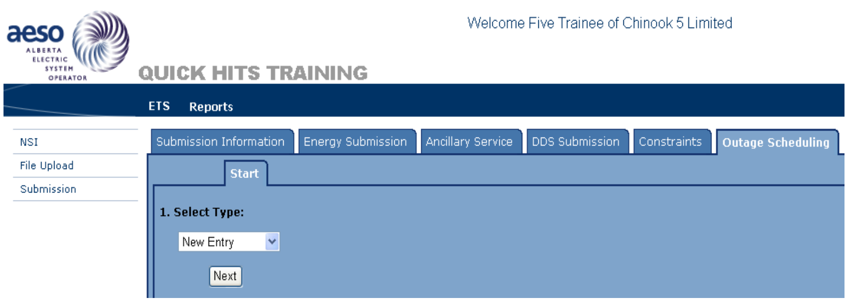
Maintenance of available capability is done through the Energy Submission tab and the Outage Scheduling tab in the ETS. During the forecast scheduling period, pool participants should be modifying their available capability values through the Energy Submission tab in the ETS. Outside of the forecast scheduling period, pool participants have the ability to modify their available capability values in the Outage Scheduling tab.



Steps

8.1 Create New Entry

(a) Click on the [Outage Scheduling] tab.

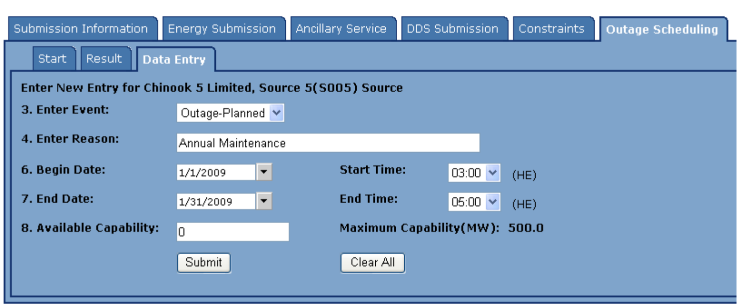


(b) From the [Select Type] list box, choose New Entry.

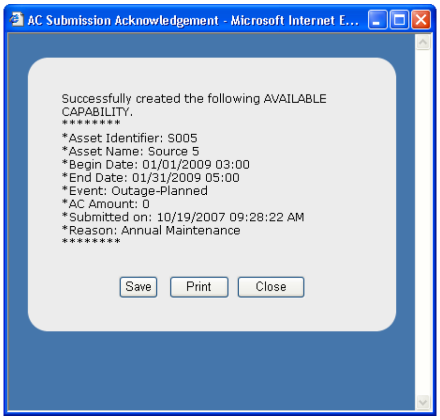
(c) From the [Result] screen, choose the pool asset.

(d) Enter required information in the [Data Entry] tab.

(e) Select [Submit].



(f) [Save] or [Print] the acknowledgement.



8.2 View Existing Available Capability

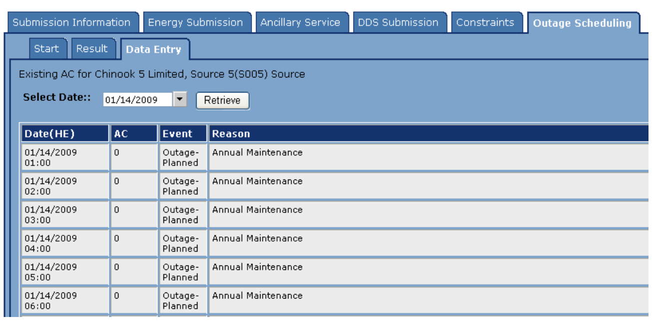
(a) Click on the [Outage Scheduling] tab.

(b) From the [Select Type] list box, choose View Entry.

(c) From the [Result] screen, choose the desired pool asset.

(d) Enter requested date in the [Select Date] calendar.

Note: Pool participants may only view one (1) day's twenty four (24) hour period at a time.



8.3 Edit Daily Entry for Available Capability

(a) Click on the [Outage Scheduling] tab.

(b) From the [Select Type] list box, choose Edit Daily Entry.

(c) From the [Result] screen, choose the desired pool asset.

(d) Enter requested date in the [Select Date] calendar. In this example the date is January 10, 2009.

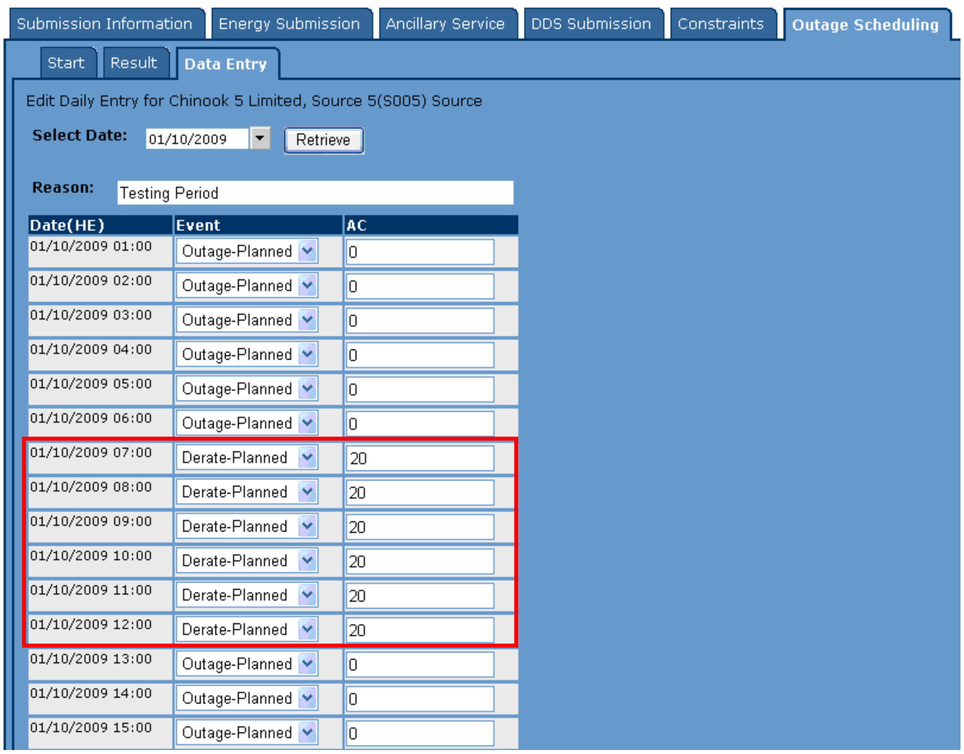
Note: Pool participants are unable to use Edit Daily Entry during the forecast scheduling period.

Prior to 12:00 pm Mountain Time (MT), the restatement period only includes the current trading day. Past 12:00 pm MT, gate close, the restatement period includes the current trading day plus the next trading day.

Pool participants may only edit one (1) day's twenty four (24) hour period in the Data Entry screen. Changes for a longer period of time can be completed through 'New Entry'.

The system displays the available capability information for the selected date including Amount, Event, and Reason. Information can only be edited here for the 24 hour period.

(e) Update Information



(f) [Save] or [Print] the acknowledgement.

8.4 Troubleshooting

My submission is very slow, how do I know if it has gone through successfully?

The AESO does require twenty four (24) months outage scheduling information. When using the ETS Outage Scheduling tab, a max of two (2) years of information can be entered. To confirm that information was successfully submitted, an acknowledgement pop-up appears; additionally, pool participants can 'View Entry' for the appropriate date to ensure the data has been populated. If utilizing the File Upload option to update the Outage Scheduling, only thirty one (31) days of information at a time are accepted

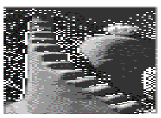
Do I have to save or print the acknowledgement pop-up?

No. However the AESO strongly encourages pool participants to do so as this may be used for proof of submission.

9 Minimum Stable Generation

Pool participants require the ability to declare their minimum stable generation for their facility so that the ISO has up-to-date information as to how low the MW volume can be dispatched down without having to completely shut down a pool asset.

The following description explains how to enter hourly minimum stable generation values in ETS.



Steps

9.1 Energy Submission Screen

Hourly declared minimum stable generation values for the stated twenty four (24) hour period automatically populates all hours for the next six (6) days so that a standing submission is maintained. This is entered into ETS using the Energy Submission screen.

Flex Block - Check box to turn on																					
lock 1	☑	Offer Control	Block 2	☑	Offer Control	Block 3	☑	Offer Control	Block 4	☑	Offer Control	Block 5	☑	Offer Control	Block 6	☑	Offer Control				
/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		$/MWh	MW		DDS Offer	AC	MSG	
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC
.0	50		9.0	125		11.0	200		13.0	275		100.0	350		300.0	387			387	5	Default AC

9.2 Minimum Stable Generation Restatements

An acceptable operational reason is required for any minimum stable generation restatements *within* T-2. The ETS rejects submissions that do not have an acceptable operational reason.

Outside of T-2, a pool participant must have an acceptable operational reasonbut the ETS does not force pool participants to submit one.

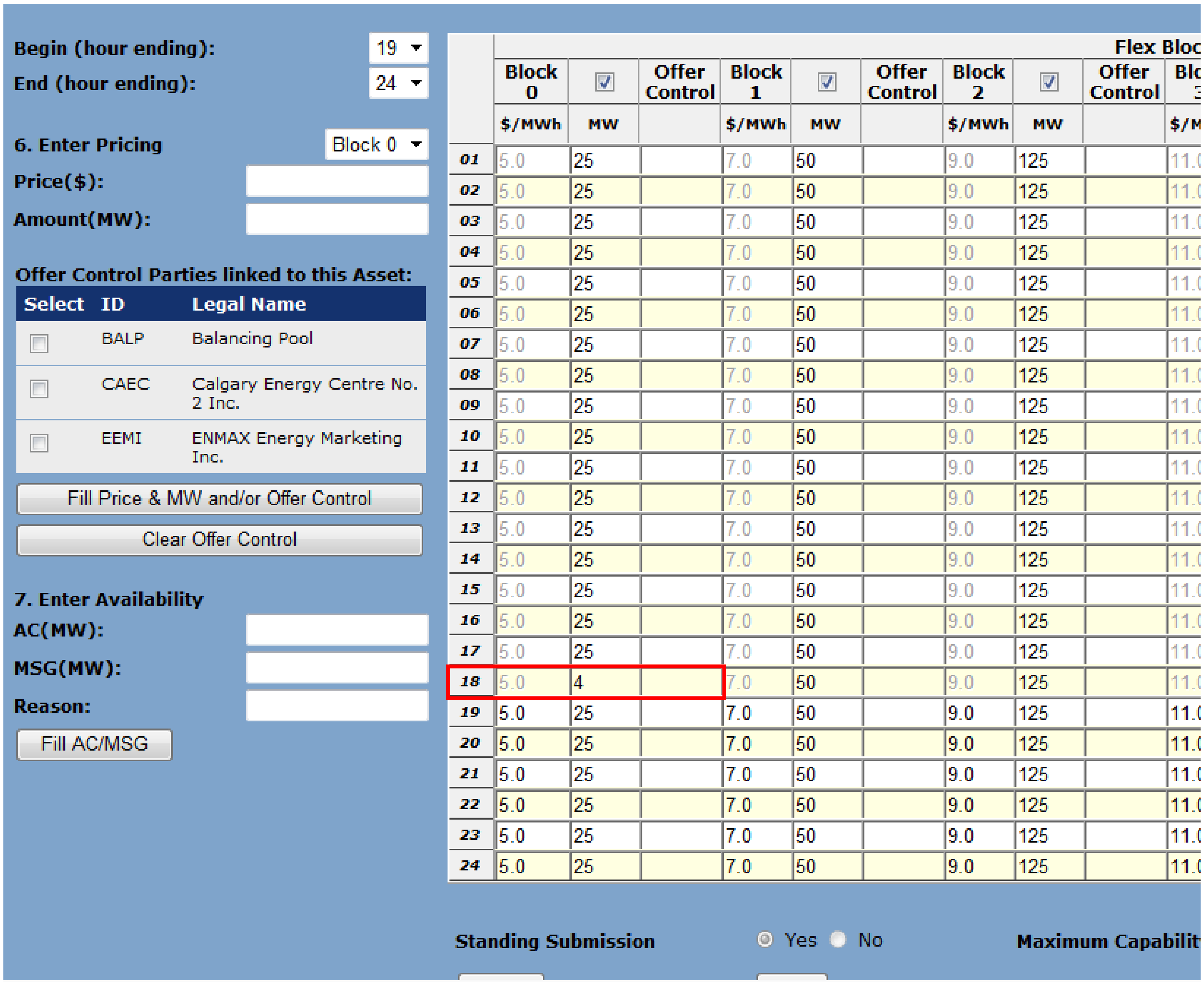
If the restated minimum stable generation is lower than the previously submitted minimum stable generation, then pool participants are not permitted to restate the MW of their operating bloc. In the example below the MSG was 5 MW and was restated to 4 MW.

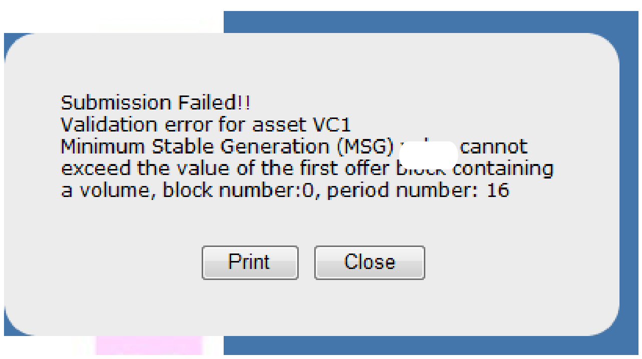
Flex Block - Check box to turn on

Offer Control	Block 3 $/MWh	☑ MW	Offer Control	Block 4 $/MWh	☑ MW	Offer Control	Block 5 $/MWh	☑ MW	Offer Control	Block 6 $/MWh	☑ MW	Offer Control	DDS Offer	AC	MSG	Reason
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	4	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC
	11.0	200		13.0	275		100.0	350		300.0	387		25	387	5	Default AC

If the restated minimum stable generation is higher, then the pool participant must ensure the minimum stable generation volume is contained in one (1) operating block and if the operating block size needs to be increased, then such volume must be taken from the next highest priced operating blocks in ascending order.

In the example below, the current MSG is 5 MW and block 0 has a price quantity pair of $5.00/25 MW. If Block 0 is restated to 4 MWs during T-2 the following error message appears.





This system message can be addressed by either increasing the size of the lowest priced non-zero block or by restating the MSG with an acceptable operational reason.

9.3 Troubleshooting

If submission is not successful, check the following:

Minimum stable generation value must be greater than or equal to zero (0).

Minimum stable generation value must be an integer.

Minimum stable generation value cannot exceed maximum capability.

Minimum stable generation value plus offer for dispatch down service cannot exceed available capability.

Minimum stable generation value must be less than or equal to the value of the first operating block containing a volume.

Minimum stable generation must be declared in hourly intervals.

Minimum stable generation value for importers cannot be greater than zero (0).

10 File Upload Formats

The following description explains the formats used for creating energy offers and ancillary services file uploads in the ETS.

File uploads are a flexible method for submitting information via the ETS. Data for file uploads may be entered for multiple days and multiple pool assets for each submission through the ETS.

10.1 Energy Market Submission Format

A single form is used to provide submission information, which includes the volumes, prices and Offer Control Party information for the submission periods defined within the forecast scheduling period.

submission																			
energy																			
********																			
*Asset Identifier: <asset ID>																			
*Asset Name: <asset name>																			
*AssetType: <source/sink>																			
*Begin Date: <date/time/year>																			
*End Date: <date/time/year>																			
*Submitted on: <date/time/year>																			
*Dispatch Date: <MM/DD/YYYY>																			
********																			
1	<dispatch	<dispatch	<dispatch	<dispatch	<dispatch	<dispatch	<dispatch date 7>												
2	<asset ID>																		
3	<standing flag>																		
4	<flex bloc	<flex bloc	<flex bloc	<flex bloc	<flex bloc	<flex bloc	<flex block 6>												
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b
5	<submissi	<block 0 p	<block 0 M	<block 0 o	<block 1 p	<block 1 M	<block 1 o	<block 2 p	<block 2 M	<block 2 o	<block 3 p	<block 3 M	<block 3 o	<block 4 p	<block 4 M	<block 4 o	<block 5 p	<block 5 M	<b

Note: This is an abbreviated table. The fully expanded table format includes all operating block prices, operating block MW, Offer Control Parties,available capability and minimum stable generation along with the associated reason.

10.2 Definitions

To indicate that the line is a comment line Column A must contain the descriptor **"*"**. Only a complete line can be declared a comment and comments are only for the benefit of the pool participant.

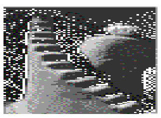
Submission Volume and Price Row/Column Definitions:

Row / Column	Definitions
R1	Dates for which the submission data < in R5 > applies. Column A must contain the numbers 1 through 5. Each number indicates the type of data that must follow in the row.
R2	Pool asset short name for which the submission data < in R5 > applies. This is the short name identifier for each pool asset submitted to the power pool.
R3	Standing flag for all dates and pool assets stated in rows 1 and 2. An **"N** "declares that the submitted pool asset's volumes and prices are not a standing submission. A **"Y"** declares that the submitted pool asset's volumes and prices are a standing submission.
R4	Flex flag for each operating block submitted (0 through 6). An **"N"** declares that the submitted pool asset's volumes are inflexible and the ISO cannot partially dispatch them. A **"Y"** declares that the submitted pool asset's volumes are flexible and the ISO can partially dispatch them.
R5	Submission data for each dispatched submission period for the specified date for up to seven (7) operating blocks.
R5CB	Submission period is the period of the trading day specified on row 1.
R5CC	Block Price 0 is the desired price of electric energy when the pool asset is issued a dispatch to the submitted minimum MW level.
R5CD	Block MW 0 is the minimum level to which a pool asset can be issued a dispatch.
R5CE	Block 0 Offer Control Parties
R5CF	Block Price 1 is the desired price of electric energy when the pool asset is issued a dispatch to the defined Operating Block 1 MW level.
R5CG	Block MW 1 is the next level to which the pool asset can be issued a

Row / Column	Definitions
	dispatch.
R5CH	Block 1 Offer Control Parties.
R5CI	Block Price 2 is the desired price of electric energy when the pool asset is issued a dispatch to the defined Operating Block 2 MW level.
R5CJ	Block MW 2 is the next level to which the pool asset can be dispatched.
R5CK	Block 2 Offer Control Parties.
R5CL	Block Price 3 is the desired price of electric energy when the pool asset is dispatched to the defined Operating Block 3 MW level.
R5CM	Block MW 3 is the next level to which the pool asset can be dispatched.
R5CN	Block 3 Offer Control Parties.
R5CO	Block Price 4 is the desired price of electric energy when the pool asset is dispatched to the defined Operating Block 4 MW level.
R5CP	Block MW 4 is the next level to which the pool asset can be dispatched.
R5CQ	Block 4 Offer Control Parties
R5CR	Block Price 5 is the desired price of electric energy when the pool asset is dispatched to the defined Operating Block 5 MW level.
R5CS	Block MW 5 is the next level to which the pool asset can be issued a dispatch.
R5CT	Block 5 Offer Control Parties.
R5CU	Block Price 6 is the desired price of electric energy when the pool asset is issued a dispatch to the defined Operating Block 6 MW level.
R5CV	Block MW 6 is the next level to which the pool asset can be issued a dispatch.
R5CW	Block 6 Offer Control Parties.
R5CX	Available capability for the hour.
R5CY	Minimum stable generation for the hour.

Row / Column	Definitions
R5CZ	The reason, if necessary, for the difference between available capability and maximum capability, and/or the reason for a change to the minimum stable generation and/or if there is a change to available capability and Offer Control Party.

11 Submissions through a File Upload



Steps

The steps are similar for Dispatch Down Submissions, Restatements and Historical Offer Control.

11.1 Create a New File Upload

(a) Create a new file upload by entering the submission information into one of the templates provided on the AESO website under Market > Market Participant Information > Energy Trading System Information > File Upload.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	
1	submission																			
2	energy																			
3	********																			
4	*Asset Identifier: S005																			
5	*Asset Name: Source 5																			
6	*AssetType: Source																			
7	*Begin Date: Tue Sep 25 00:00:00 MDT 2012																			
8	*End Date: Wed Sep 26 00:00:00 MDT 2012																			
9	*Submitted on: Mon Sep 24 12:18:17 MDT 2012																			
10	*Dispatch Date: 09/25/2012																			
11	*																			
12	*Line Types:																			
13	** Comment; these lines are not processed																			
14	*1	Dispatch Date (MM/DD/YYYY)																		
15	*2	Asset Short Name																		
16	*3	Standing Submission (Y/N)																		
17	*4	Flex block for 7 blocks (Y/N)																		
18	*5	<period n	<block 0 p	<block 0 N	<block 0 o	<block 1 p	<block 1 N	<block 1 o	<block 2 p	<block 2 N	<block 2 o	<block 3 p	<block 3 N	<block 3 o	<block 4 p	<block 4 N	<block 4 o	<block 5 p	<block 5 N	<bl
19	*																			
20	*Notes:																			
21	* - Only the periods and blocks in this file will be restated; all other periods will remain as they were																			
22	* - For a l	2	3	...24	25															
23	*- For a short day in the spring skip period 2																			
24	*- The submission must contain all 24 periods																			
25	* - Use the shortname for offer control parties																			
26	* - Multiple offer control parties for a single block should be separated by a semi-colon ';'																			
27	* - Offer control parties may be blank																			
28	* - Include multiple submissions in one file by repeating lines 1 through 5																			
29	*																			
30	*******																			
31	1	09/25/2012																		
32	2	S005																		
33	3	N																		
34	4	Y	Y	Y	Y	Y	Y	Y												
35	5	1	0	50	OCP1;OCF	10.86	75	OCP1;OCF	52.69	100	OCP1;OCF	89.98	150	OCP1;OCF	158.97	200	OCP1;OCF	589.97	250	OCI
36	5	2	0	50	OCP1;OCF	10.86	75	OCP1;OCF	52.69	100	OCP1;OCF	89.98	150	OCP1;OCF	158.97	200	OCP1;OCF	589.97	250	OCI
37	5	3	0	50	OCP1;OCF	10.86	75	OCP1;OCF	52.69	100	OCP1;OCF	89.98	150	OCP1;OCF	158.97	200	OCP1;OCF	589.97	250	OCI
38	5	4	0	50	OCP1;OCF	10.86	75	OCP1;OCF	52.69	100	OCP1;OCF	89.98	150	OCP1;OCF	158.97	200	OCP1;OCF	589.97	250	OCI
39	5	5	0	50	OCP1;OCF	10.86	75	OCP1;OCF	52.69	100	OCP1;OCF	89.98	150	OCP1;OCF	158.97	200	OCP1;OCF	589.97	250	OCI
40	5	6	0	50	OCP1;OCF	10.86	75	OCP1;OCF	52.69	100	OCP1;OCF	89.98	150	OCP1;OCF	158.97	200	OCP1;OCF	589.97	250	OCI

Note: The submissions file upload document should be created in an application external to the ETS i.e. Excel.

(b) From the [File] menu, choose [Save As] to save the new file upload.

The ETS does not require a specific filename. However, the ETS only accepts files in the .csv format (comma, separated, values).

11.2 Create New from an Existing File Upload

(a) Open an existing file upload document in Excel.

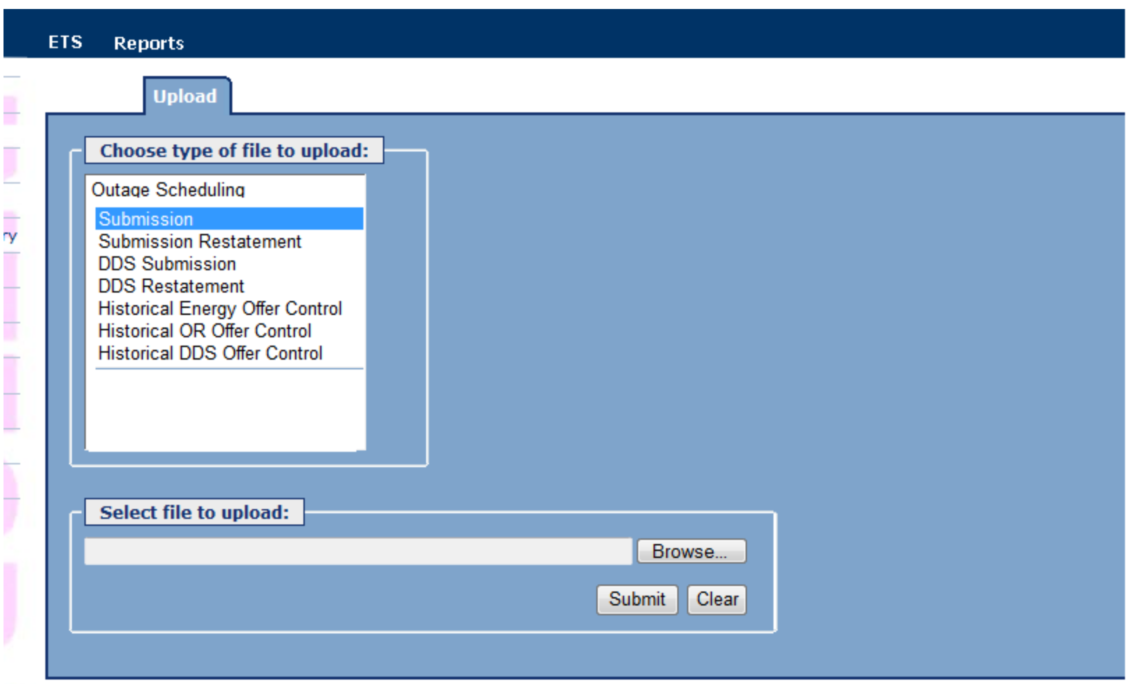
(b) Change the date to that of the next submission.

(c) From the [File] menu, choose [Save As].

11.3 Submit the File Upload

(a) Under the ETS menu, select [File Upload].

(b) Under [Choose type of file to upload] choose the appropriate option. In this example [Submission].



(c) Under [Select file to upload] click on the [Browse] button. Locate the appropriate file then click [Open].

Note: Rather than searching for the file with the [Browse] button, pool participants may also type the file path and name in the text box to the left of [Browse].

(d) The file name appears in the [Select the file to upload] box.

(e) Click on the [Submit] button.

(f) [Print] or [Save] the acknowledgement.

11.4 Troubleshooting

The file upload was not successful – how come?

Ensure the proper formatting has been used (i.e. the "*" and blank lines match the example) as the slightest change can alter the successfulness of the file.

I have attempted to submit my file upload and an error message displays – what do I do?

If all or part of the submission data is invalid, the submission is rejected. Correct the relevant data indicated by the error message and resubmit the corrected file.

The acknowledgement does not provide details about the submission – how do I know it was accepted?

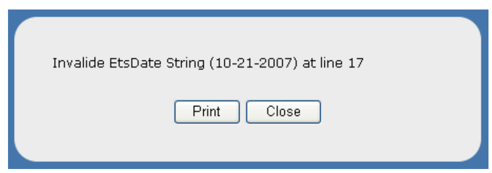
In the training environment, an acknowledgement without the submission details included is a failed submission.

My file wasn't accepted – how come?

Ensure the file is saved in .csv format, not in the default Excel .xls format.

I receive an error indicating that there is an error with the date – how do I fix this?

Dates need to be represented in the format DD/MM/YYYY. Excel often converts dates to be DD-MM-YYYY. To remedy this, add an apostrophe at the end of the date DD/MM/YYYY'.



If ETS File Upload continues to produce an error rather than adding an apostrophe:

(a) right click on the cell with the date;

(b) select [Format];

(c) [Custom];

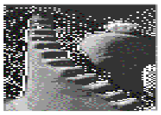
(d) adjust format to DD/MM/YYYY;

(e) [OK]; and

(f) directly save and close the document then upload it into ETS.

Note: When the .csv file is opened again it is likely to convert the date back to DD-MM-YYYY and the file will need to be reformatted again before closing.

12 Dispatch Down Service Submissions

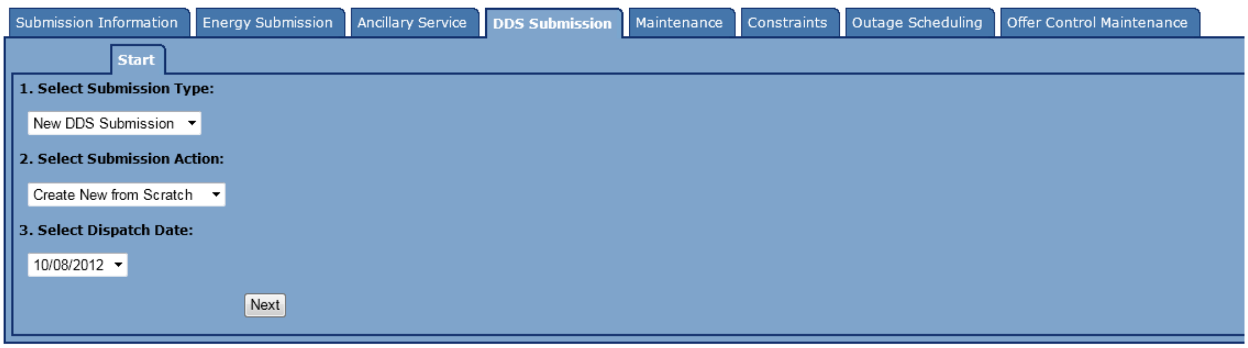


Steps

12.1 Create a New Dispatch Down Service Submission

(a) Under the ETS menu, select [Submission].

(b) Click on the [DDS Submission] tab.



(c) From the [Select Submission Type] list box, choose New DDS Submission.

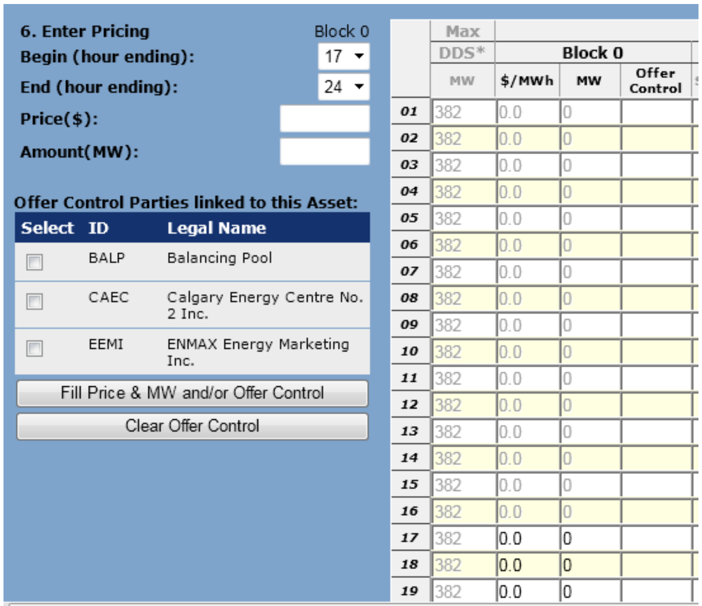
(d) From the [Select Submission Action] list box, choose Create New from Scratch.

Note: From this list, the pool participant also has the option of modifying an existing dispatch down service submission or creating a new submission from an existing one. This is done in a similar manner to the energy submissions.

(e) From the [Select Dispatch Date] list box, choose Default Date. Click [Next].

(f) From the [Select Asset] list, select the desired pool asset.

Note: The dispatch date defaults to the next effective submission date.



Note: This displays the Submission Filler on the left and enable the dispatch down service submission entry grid (all fields are empty).

The column noted as "Max DDS" is grayed out and refers to available capability minus minimum stable generation = maximum dispatch down service.

The quantity of each offer for dispatch down service must not exceed the available capability less the minimum stable generation level of the source asset.

Note: At this time, offers for dispatch down service are only one (1) operating block in size. A dispatch down service operation block is a flexible block. There is no 'Standing Submission' option for dispatch down service.

12.2 Enter the Dispatch Down Service Submission Data

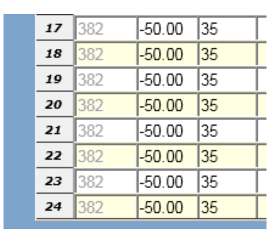
(a) Use the [Filler] tab on the left hand side. From [Begin and End Time (hour ending)] list boxes, choose the desired begin and end time for Block 0. In this example HE17-24.

(b) In the [Price ($)] field, enter a price that is indexed to the pool price.

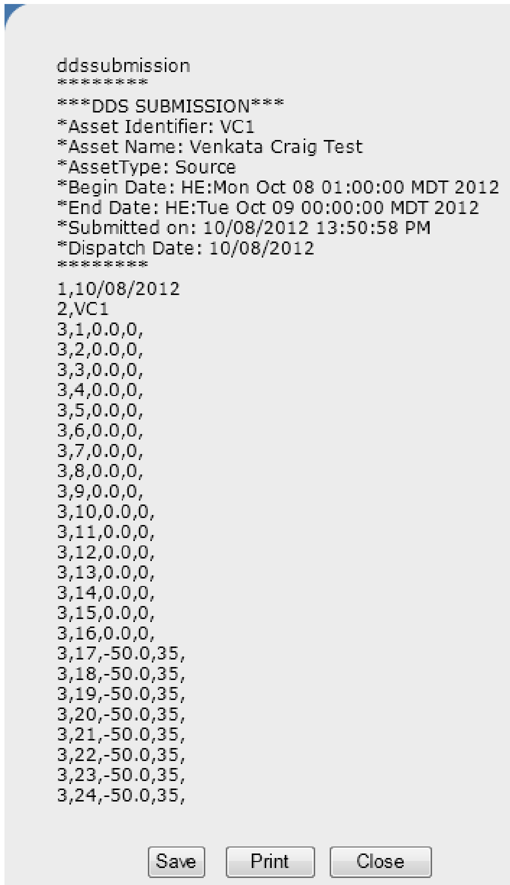
Note: Dispatch down service offer price is entered as a negative value.

(c) In the [Amount (MW)] field, enter a MW amount.

(d) Click on the [Fill Price and MW and/or Offer Control] button.



(e) Select [Submit].

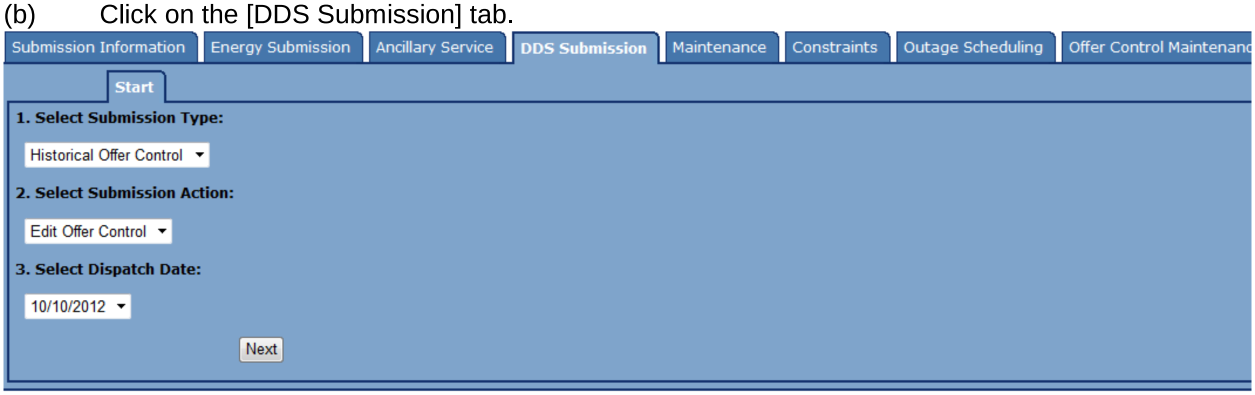


(f) [Save] or [Print] the acknowledgement.

12.3 Create a New Dispatch Down Historical Offer Control Submission

(a) Under the ETS menu, select [Submission].

(b) Click on the [DDS Submission] tab.

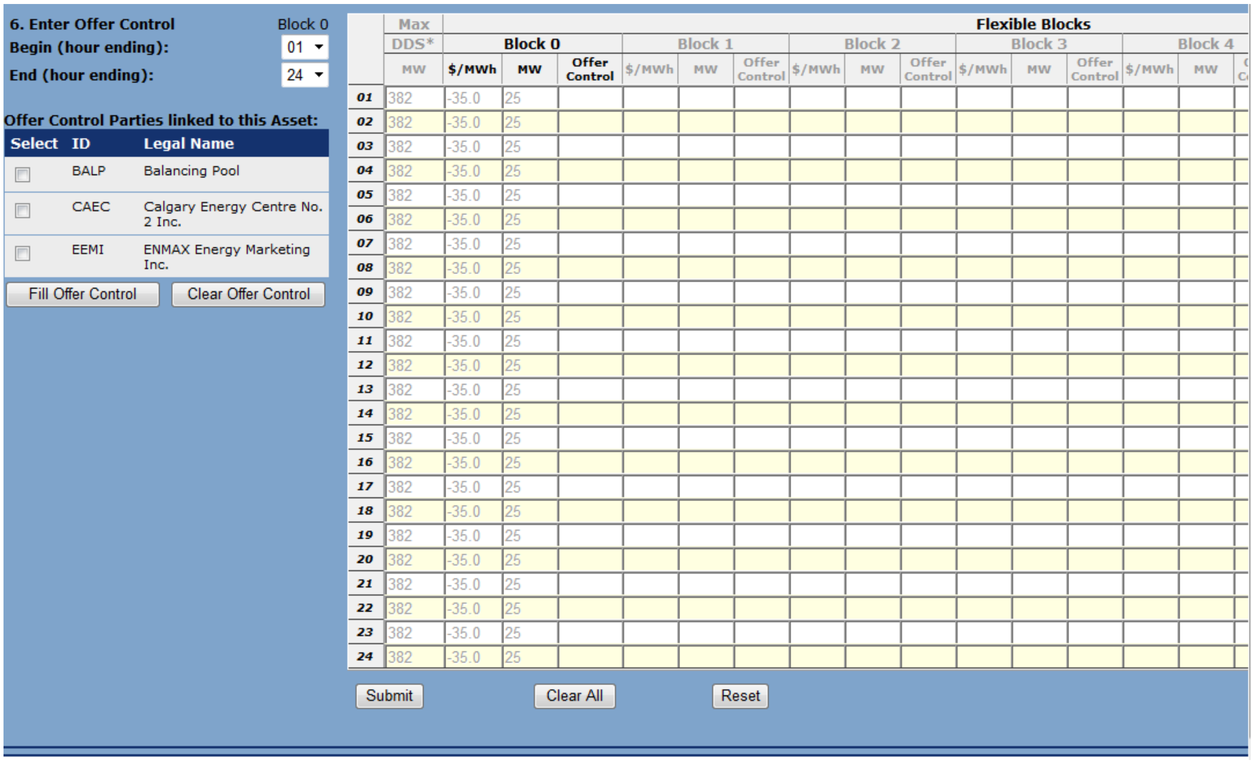


(c) From the [Select Submission Type] list box, choose Historical Offer Control.

(d) From the [Select Submission Action] list box, choose Edit Offer Control.

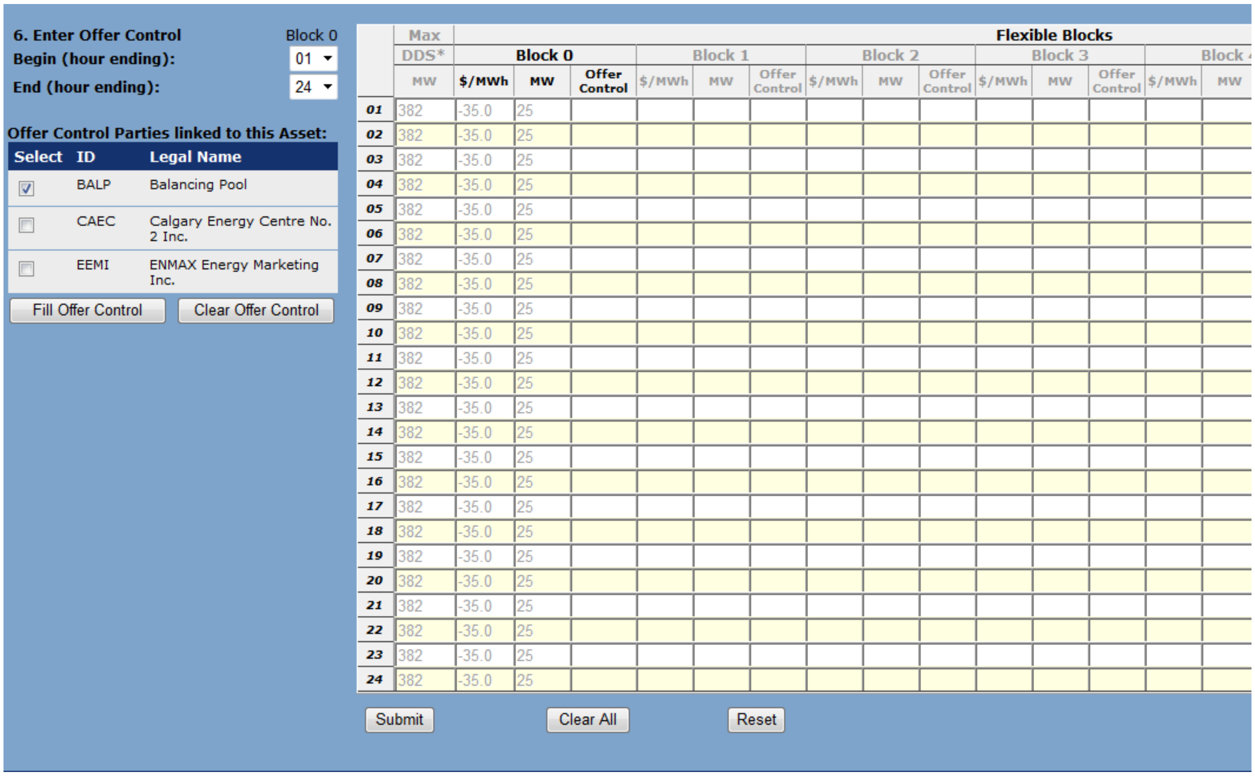
(e) From the [Select Dispatch Date] list box, choose applicable historical date. Click [Next].

(f) From the [Select Asset] list box, select the desired pool asset.

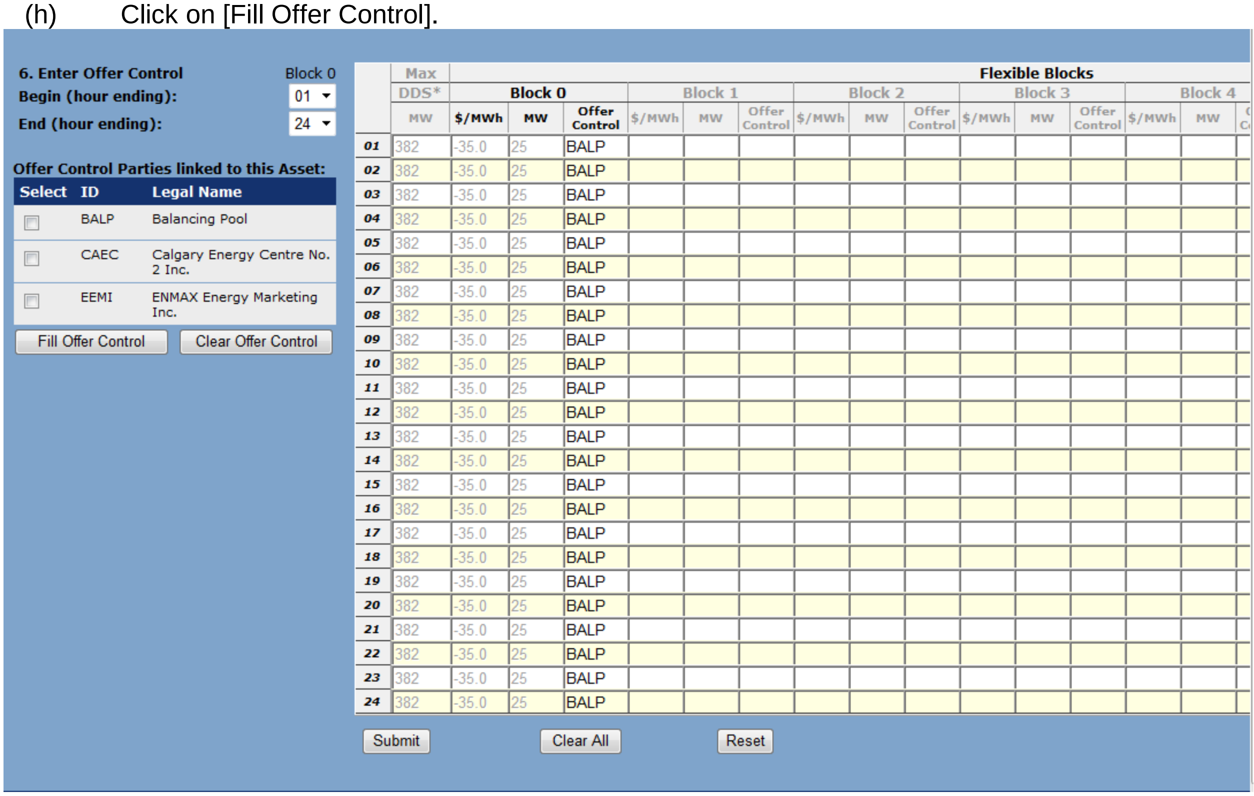


	Max DDS* MW	Block 0 $/MWh	Block 0 MW	Block 0 Offer Control	Block 1 $/MWh	Block 1 MW	Block 1 Offer Control	Block 2 $/MWh	Block 2 MW	Block 2 Offer Control	Block 3 $/MWh	Block 3 MW	Block 3 Offer Control	Block 4 $/MWh	Block 4 MW
01	382	-35.0	25												
02	382	-35.0	25												
03	382	-35.0	25												
04	382	-35.0	25												
05	382	-35.0	25												
06	382	-35.0	25												
07	382	-35.0	25												
08	382	-35.0	25												
09	382	-35.0	25												
10	382	-35.0	25												
11	382	-35.0	25												
12	382	-35.0	25												
13	382	-35.0	25												
14	382	-35.0	25												
15	382	-35.0	25												
16	382	-35.0	25												
17	382	-35.0	25												
18	382	-35.0	25												
19	382	-35.0	25												
20	382	-35.0	25												
21	382	-35.0	25												
22	382	-35.0	25												
23	382	-35.0	25												
24	382	-35.0	25												

(g) Under [Offer Control Parties linked to this Asset] select the appropriate parties. In this example BALP is being selected for HE 01-24.



(h) Click on [Fill Offer Control].



(i) Select [Submit].

(j) [Save] or [Print] the acknowledgement.

12.4 Troubleshooting

Why has the MW amount of my offer been flagged as invalid?

The MW value of the offer for dispatch down service cannot be greater than the pool asset's available capability less minimum stable generation.

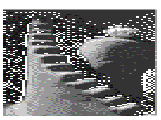
Why am I getting the message that offers are being reset for HE1 and HE2 to $0.00 and 0MW?

This error occurs when pool participants attempt to create a new dispatch down service submission for the following day from an existing offer after 22:00.

If the message is ignored, this action results in the resetting of the offers for dispatch down service for HE1 and potentially HE2 to $0.00 and 0MW.

To prevent this from occurring, exit and perform a dispatch down service restatement instead.

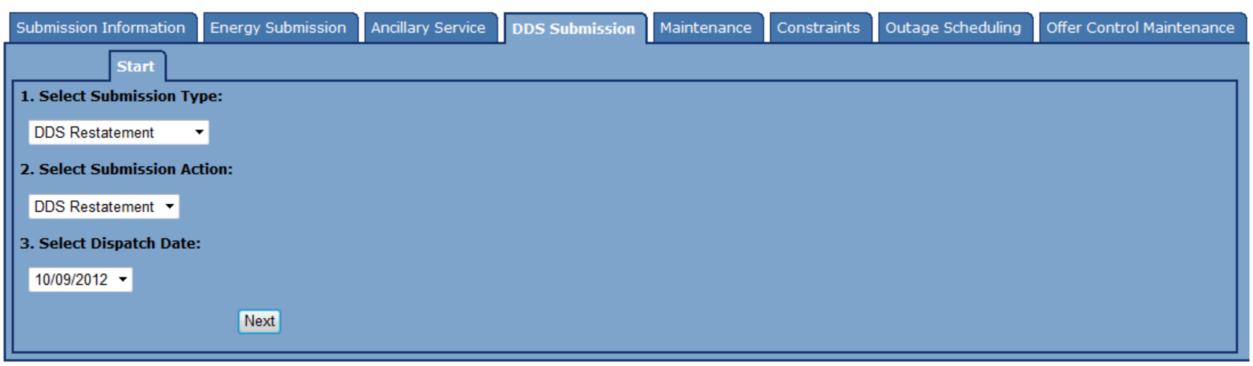
13 Dispatch Down Service Restatements



Steps

13.1 Enter Dispatch Down Service Restatement

(a) Click on the [DDS Submission] tab.



(b) From the [Select Submission Type] list box, choose DDS Restatement.

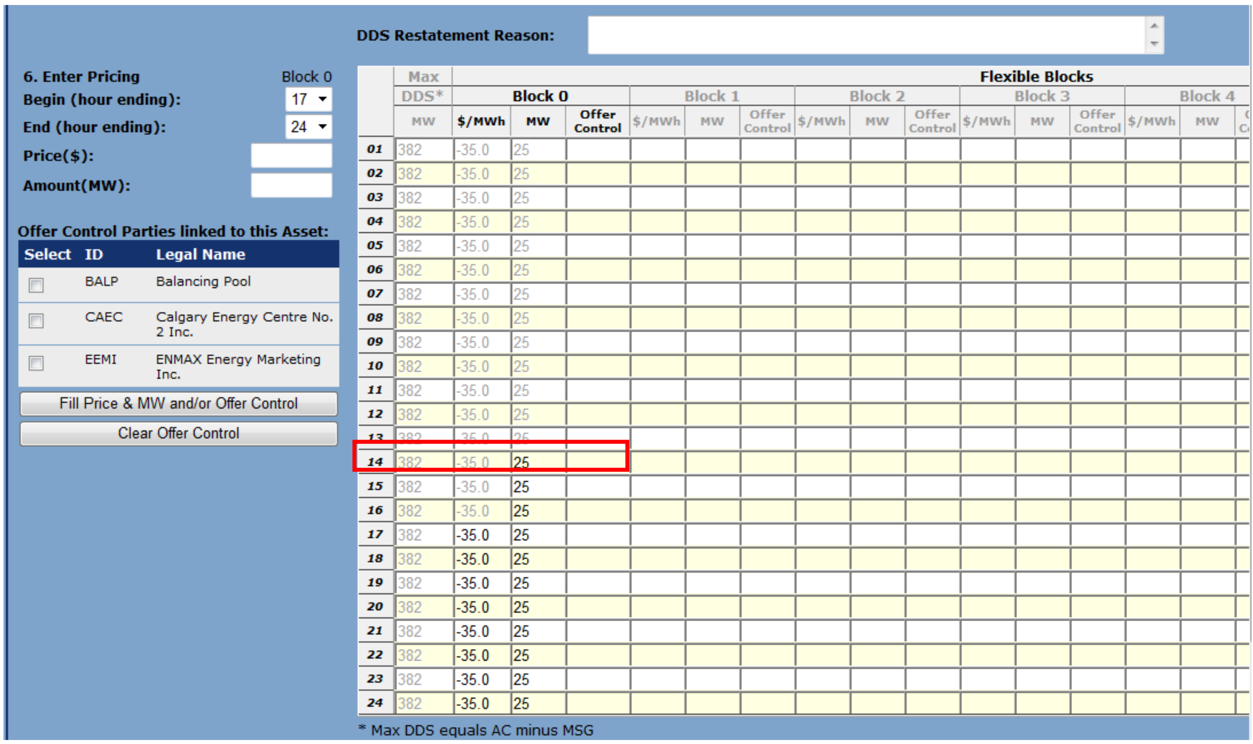
(c) From the [Select Submission Action] list box, choose DDS Restatement.

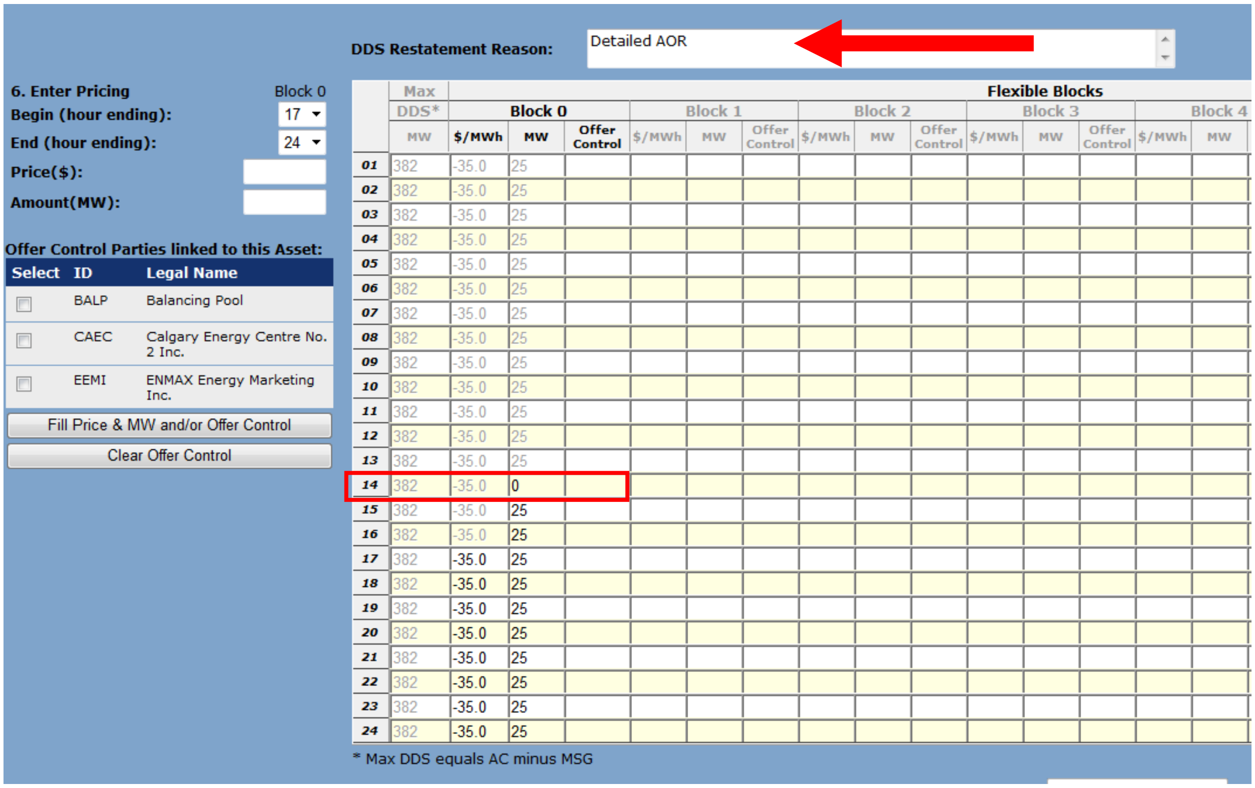
(d) From the [Select Dispatch Date] list box, choose Default Date. In this example the date is October 9, 2012. Click [Next].

Note: Valid restatement dates are those within the current restatement period.

(e) Under [Select Asset], click on the applicable pool asset.

Note: The restatement screen appears. In the example below, the time is 1:00 pm and the restatement is occurring within T-2. Changes within T-2 can only be made manually through the grid and not the filler.





(f) Within T-2 only the MW amount can be restated. In this example HE 14, 25 MW is being restated to 0 MW.

(g) Manually enter the reason for the change in the [DDS Restatement Reason] field at the top of the page.

(h) Click [Submit].

(i) [Save] or [Print] the acknowledgement.

13.2 Troubleshooting

Why can't I choose the desired hour ending from the Fill box?

Within T-2, the restatement has to be made by manually entering the data into each appropriate cell.

Can I view my current offers for DDS?

Pool participants can view a dispatch down service submission in a similar manner to how they view energy submissions (under the DDS Submission tab choose 'View DDS Submission' under 'Select Submission Type'). In addition, dispatch down service can be viewed from the Energy Submission Grid.

Note: Dispatch down service cannot be modified from the Energy Submission tab, it is only presented for reference sake.

14 Energy Restatement Requiring a Dispatch Down Service Restatement

The following walk-through explains the relationship between offers for energy and offers for dispatch down service. The example illustrates when a restatement of an offer for energy may require a dispatch down service restatement.

14.1 Attempt to Enter an Energy Restatement

(a) Click on the [Energy Submission] tab.

(b) From the [Select Submission Type] list box, choose Restatement.

(c) From the [Select Submission Action] list box, choose Edit Existing.

(d) From the [Select Dispatch Date] list box, choose Default Date.

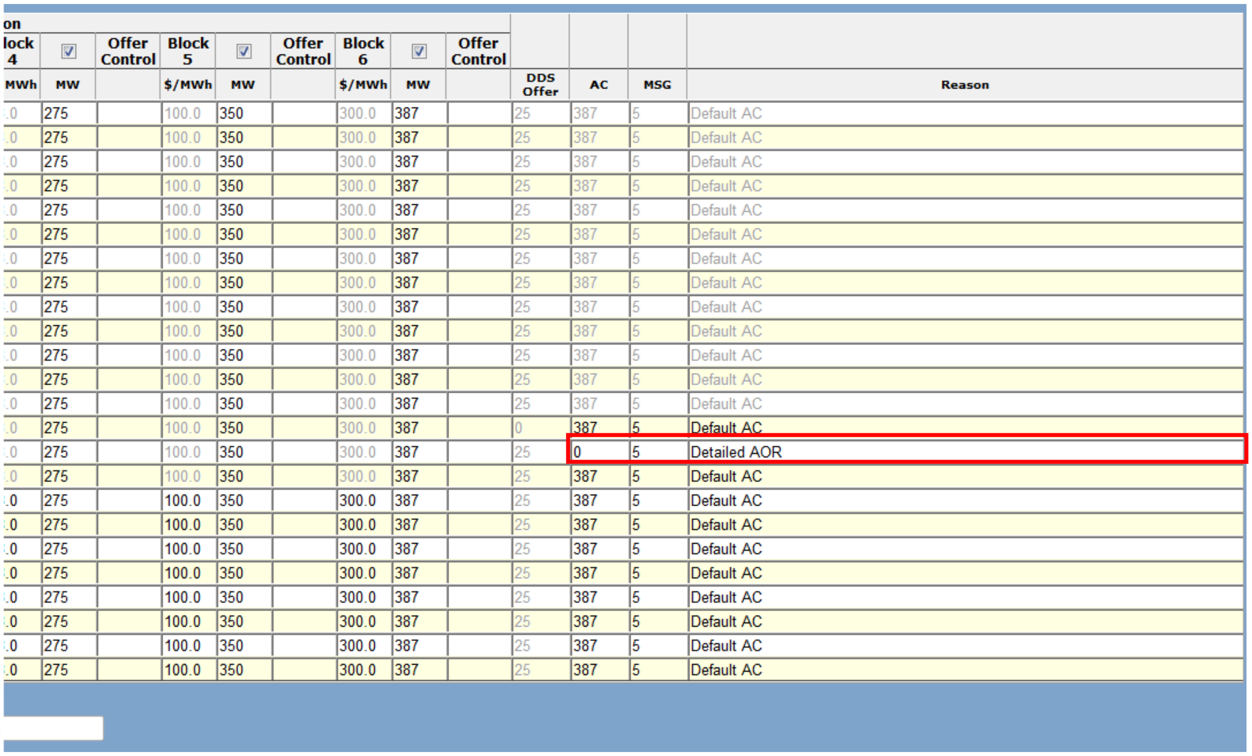
Note*:* Valid restatement dates are those within the current restatement period.

(e) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example Source is being used. Click [Next].

(f) From the [Select Asset] list box, choose the desired pool asset.

Note: The restatement screen appears. In this example the current time is 1:14 pm.

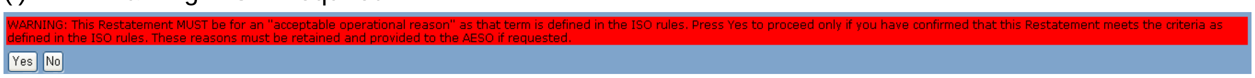
(g) In this example the available capability is being restated to 0 MW for HE15 within T-2 and an acceptable operational reason is provided.



on lock 4			Block 5			Block 6						
MWh	MW	Offer Control	$/MWh	MW	Offer Control	$/MWh	MW	Offer Control	DDS Offer	AC	MSG	Reason
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		0	387	5	Default AC
.0	275		100.0	350		300.0	387		25	0	5	Detailed AOR
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC
.0	275		100.0	350		300.0	387		25	387	5	Default AC

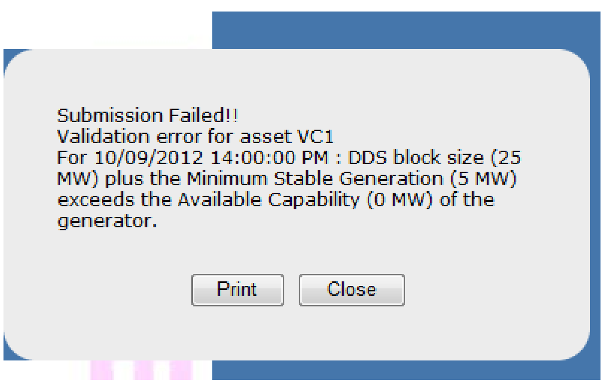
(h) Select [Submit].

(i) Warning: AOR Required.



This warning appears whether an acceptable operational reason has already been entered or not. If an acceptable operational reason has been entered, select [Yes] to continue with the submission. Select [No] to return to the energy grid to edit or complete the acceptable operational reason requirement.

(j) [Save] or [Print] the acknowledgement.



Note: This restatement failed because the dispatch down service plus minimum stable generation cannot exceed the pool asset's available capability.

If an energy restatement invalidates the offer for dispatch down service, the energy restatement can only be submitted if the dispatch down offer is restated first.

14.2 Troubleshooting

ETS does not process my energy restatement. It says I must adjust my offer for dispatch down service. Why?

If an energy restatement invalidates the offer for dispatch down service, the energy restatement can only be submitted after the offer for dispatch down service has been restated. Invalid offers for dispatch down service occur when offers for dispatch down service exceed the available capability minus minimum stable generation. To restate an offer for dispatch down service, refer to page 41, then resubmit the energy restatement.

15 Entering and Maintaining Pool Asset Constraints

Each pool participant who has submitted an offer must submit operating contraints with respect to each generating pool asset.

15.1 Definitions

Pool Asset Constraint	Definition[2]
Ramp Rate	Rate at which a pool asset will change its level of supply or demand in MW per minute in response to an energy market dispatch or directive.
Minimum Off Time	Minimum amount of time in hours required by a generation pool asset once it has been fully dispatched off before it can comply to another energy market dispatch[3].
Minimum On Time	Minimum amount of time in hours required by a generation pool asset to be on-line before it can be dispatched off.[4]
Initial Start-up Time	Time in hours required for a generation pool asset to synchronize to the interconnected electric system from an offline state.
Maximum Run-up Time	Time in minutes required for the generation pool asset to reach minimum stable generation from the point it is synchronized to the grid.

[2] As defined in the AESO's Consolidated Authoritative Document Glossary

[3] These values are purely for information purposes and are not used to determine a pool participant's dispatches; however, minimum off time may be used as an acceptable operational reason in circumstances such as those outlined in ID# 2009-003(R) *Acceptable Operational Reasons* section 4(c).

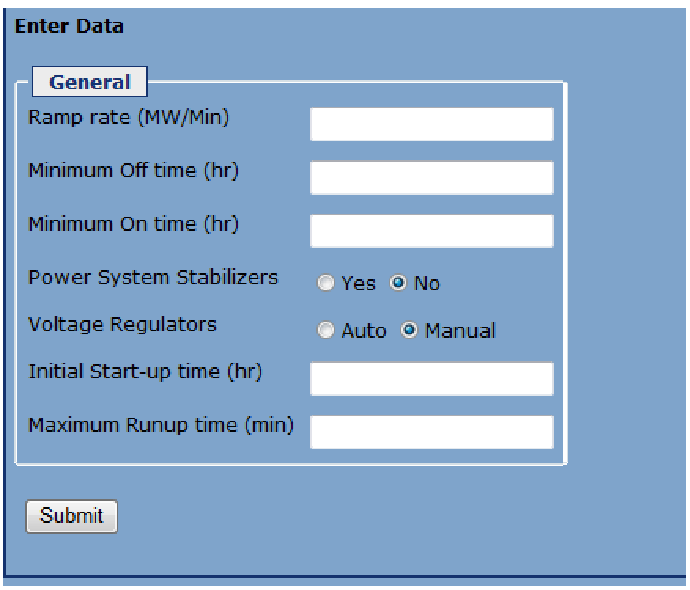
[4] These values are purely for information purposes and are not used to determine a pool participant's dispatches; however, minimum on time may be used as an acceptable operational reason in circumstances such as those outlined in ID# 2009-003(R) *Acceptable Operational Reasons* section 4(c).

15.2 Navigate to the Constraints

(a) From the [Submission] page, click on the [Constraints] tab.

(b) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example Source is being used. Click [Next].From the [Result] tab, choose the desired pool asset.

(c) In the [Data Entry] tab, enter the applicable information for Ramp rate (MW/Min), Minimum Off time (hr), Minimum On time (hr), Initial Start-up time (hr) and Maximum Runup time (min)



(d) Select [Submit].

(e) [Save] or [Print] the acknowledgement.

15.3 Troubleshooting

How do I view my changes?

Once constraints are submitted, they remain visible under the constraints tab. To view:

(a) Go to the Submission page

(b) Click on the Constraints tab

(c) Choose Asset Type then click [Next].

(d) Select Asset

Is there a limit to how often I can update the constraints information?

The constraints tab is available for timely updates whenever constraints information changes. There are no limit restrictions.

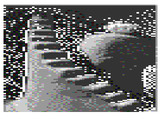
Does this information effect how the pool asset is dispatched?

If the Initial Start-up Time is anything other than zero (0) or one (1), the pool asset is considered a long lead time pool asset. There are different procedures that exist when a pool asset is considered long lead time in order to be dispatched by the ISO.

16 Long Lead Time

To be considered long lead time, the pool asset must require more than one (1) hour to synchronize to the grid as set out in the ISO definition of “long lead time asset”. These pool assets must submit to the AESO the time of day that such pool asset will be synchronized to the interconnected electric system.

For more information on long lead time pool assets, please see ID# 2012-007(R) *Long Lead Time Energy*.



Steps

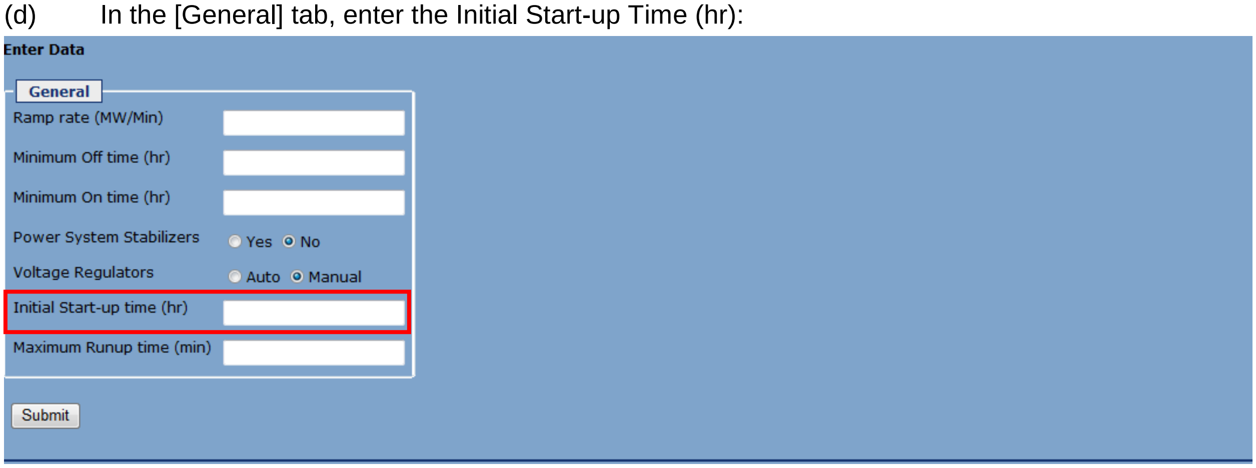
16.1 Long Lead Time Pool Asset Planning to Return from an Offline State

(a) Click on the [Constraints] tab.

(b) Under [Choose Asset Type], click on the [Sink] or [Source] radio button. In this example Source is being used. Click [Next].

(c) From the [Result] tab, choose the desired pool asset.

(d) In the [General] tab, enter the Initial Start-up Time (hr):

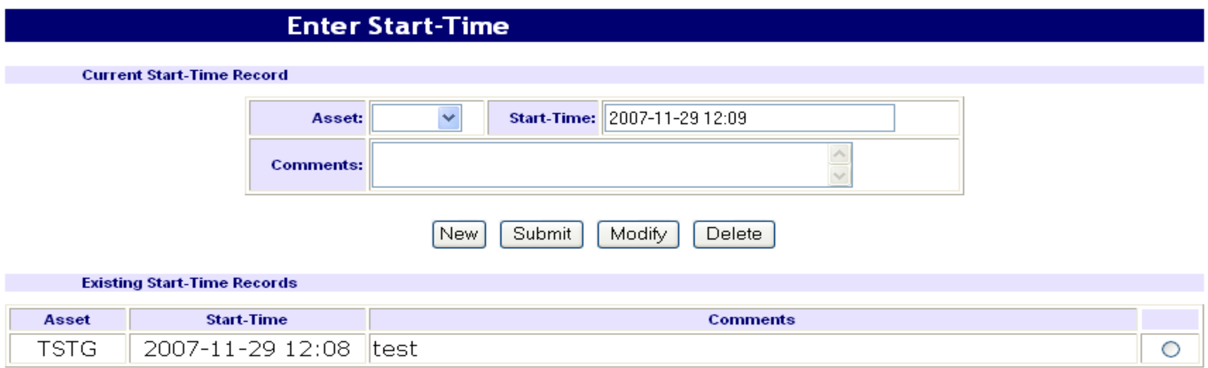


Note: If a generation pool asset can synchronize or provide any MWs to the interconnected electric system in less than one (1) hour when returning from a cold start, the initial start-up time should reflect a zero (0) value. This pool asset would reflect the availability of the delayed energy through their available capability declarations as described in section 4 of ID# 2012-007(R) *Long Lead Time Energy*.

(e) Select [Submit].

(f) [Save] or [Print] the acknowledgement.

(g) In ADaMS in the Enter Start Time section, enter the following information select the desired pool asset and enter an appropriate start time. The start time should reflect the time expected to synchronize to the grid.



Note: The Start Time must be submitted at least two (2) hours prior to the beginning of the settlement interval.

Note: Currently, a training environment does not exist for ADaMS. This step is described for reference only.

(h) Select [Submit]

Note: Once the Start Time has been submitted in ADaMS, the information appears in the energy market merit order. This step must be executed in order to appear in the energy market merit order as per Section 202.4 subsection 2(2). If a pool participant deletes an existing Start Time record, the pool asset is filtered out of the energy market merit order and does not receive a dispatch.

A pool asset that has previously indicated a Start Time may withdraw its intention up to two (2) hours prior to the start of the settlement interval.

16.2 Troubleshooting

Why can't I access ADaMS?

To access ADaMS go to: https://adams-2010.aeso.ca/dt-web/

ADaMS requires a security certificate to be installed on a computer in order to access any ADaMS account. These certificates expire annually and require the completion of an ADaMS Request Form which can be located at:

www.aeso.ca > Market > How to Join > Automated Dispatch and Messaging System Request Form

What happens if I restate my long lead time generation to 0 MW? Do I have to restate my start time in ADaMS when my pool asset comes back to an online state?

Once an available capability restatement has been made, long lead time pool assets must re-enter their new start time in ADaMS as per Section 202.4 subsection 2(2).

17

18 Contact Information

For additional clarification or further questions, please call the AESO FirstCall at 1-888-588-AESO (2376), or email info@aeso.ca. The Operations Support team would be happy to provide further assistance.

19 Appendices

Appendix 1 – How to Identify an Offer Control Party

Revision History

Posting Date	Description of Changes
2016-01-26	Amended to include process to designate a default offer control party in the ETS
	Amended to include Internet 9 as a supported platform
	Removed reference to planned outages, testing or commissioning of the pool asset, or any changes within plus or minus five MW in section 8
	Administrative updates
2013-01-08	Initial release.

APPENDIX 1 – How to Identify an Offer Control Party

The AESO collects Offer Control Party information from pool participants at an operating block level. That means that for every price and quantity pair in an offer to the energy market (up to seven (7) operating blocks) and in an offer to the dispatch down service market (one (1) operating block), pool participants provide the identity of the Offer Control Party or Parties for each operating block. For offers made to the ancillary services market (operating reserves for the purpose of compliance with section 6 of the *Fair, Efficient and Open Competition Regulation* [the "FEOC Regulation"]), the AESO collects Offer Control Party information for each transaction that has been cleared by the Watt Exchange (or alternative market) that is available to be issued a dispatch by the AESO. This includes offers for both standby and active operating reserves.

It is anticipated that in the majority of situations a single Offer Control Party exists for each operating block and that relationship may never change. In the instance that the Offer Control Party does change, the market participant submits the identity of such party to the AESO.

If more than one (1) party has an ownership stake in a pool asset, the AESO only needs to receive the identity of the party or parties that take an active role in the determination of the offers (on an operating block specific basis) for that pool asset. "Active role" also includes a party that may not be involved in day-to-day offer determinations, but has a standing position on the make-up of the offer.

Examples:

(a) A pool asset is jointly owned by Company A and Company B. However, Company B's interest is purely financial and it has absolutely no influence in the determination of offers for the pool asset. The market participant should show offer control for each operating block as Company A.

(b) A pool asset is owned by a partnership/joint venture, etc.

  (i) If a delegation of authority has been agreed to between the parties, formally or implicitly, then the delegate is the Offer Control Party. In the absence of such an agreement the parties need to determine if one (1) or more parties is behaving in such a manner that suggests that they are the ultimate decision maker and they should then identify themselves as the Offer Control Party accordingly.

  (ii) If the decisions are made collectively amongst more than one (1) party then the market participant should show each of the Offer Control Parties on an operating block specific basis, as applicable.

(c) If individual operating blocks within an offer are controlled by different parties then the market participant should show the respective parties for each operating block.

In all situations regarding coordinated efforts between market participants for submitting offers for energy into the power pool, market participants are reminded to avail themselves of the complete set of requirements under the FEOC Regulation.

The focus is on collecting the identity of the pool participants that function as Offer Control Parties. This approach aids in ensuring that the identities collected are reflective of the actual active players in the market.

Hypothetical Examples:

(d) Alberta Generator Company Ltd. (AGC) is a pool participant and a wholly owned subsidiary of FEOC Alberta Ltd. AGC is the entity that decides how the energy from the generating pool asset is offered and as such they would be identified as the Offer Control Party, not AGC's parent company.

(e) Canada Electricity Ltd. (CE) is not a pool participant, but it alone decides how the energy from the generating pool asset it owns is offered. CE is a wholly owned subsidiary of

06XX29 Alberta Ltd., which is owned entirely by 12YY56 Alberta Ltd. In this situation, the Offer Control Party would be identified as the highest company in that corporate hierarchy (the ultimate parent company, 12YY56 Alberta Ltd.) as none of the companies in the hierarchy are pool participants. However, as the search moves up the corporate structure in search of the ultimate parent company, if any of the entities is a pool participant then that company is reported as the Offer Control Party.

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 306.3 of the ISO rules, *Load Planned Outage Reporting* ("Section 306.3");
- Section 306.4 of the ISO rules, *Transmission Planned Outage Reporting and Coordination* ("Section 306.4");
- Section 306.5 of the ISO rules, *Generation Outage Reporting and Coordination* ("Section 306.5"); and
- Section 306.7 of the ISO rules, *Mothball Outage Reporting* ("Section 306.7").

The *Fair, Efficient and Open Competition Regulation* imposes an obligation on market participants to provide outage records to the AESO. In accordance with section 4(3) of the *Fair, Efficient and Open Competition Regulation* and Section 306.4, the AESO makes outage records received from market participants available to the public in the form of reports. The purpose of this Information Document is to provide additional information regarding the outage reporting process and the related reports posted on the AESO's website.

2 Transmission Planned Outages

2.1 Planned Outages

Applicability

Section 306.4 applies to all transmission planned outages, including live-line work, terminal equipment and reclose-block situations. Terminal equipment includes elements associated with supervisory control and data acquisition, as well as communication and protection systems. Another term commonly used by legal owners for reclose-block situations is "hold-off permits".

Planned Outage Requests

For an outage that is being actively planned and is beyond a speculative stage, the legal owner of a transmission facility submits a planned outage request to the AESO pursuant to subsection 2 of Section 306.4 by sending an email to outage.scheduling@aeso.ca.

To enable the AESO to foresee coordination concerns, the AESO requests that legal owners submit planned outage requests as early as possible. Where a legal owner foresees that a planned outage has particular coordination challenges, the AESO encourages the legal owner to submit the requests as early as possible on a consultative basis. The AESO requests that a legal owner submit a complete list of all the planned outages that it is requesting for the upcoming operating week so that the AESO may reconcile the list with previously submitted planned outage requests.

Further details concerning a transmission planned outage request submitted to the AESO pursuant to subsection 5(2) of Section 306.4 are as follows:

(i) "the transmission facility being taken out of service": this is identified by the element designation as it appears on the legal owner operating documents;

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

(ii) "dates and times": this indicates the start of switching to isolate a facility and the end of switching to return the facility to service. For major elements, such as transmission lines, the switching time might add approximately thirty (30) minutes to the start and end of the intended planned outage activity. In other situations, such as protection or telecommunication element planned outages, the switching time is expected to be negligible;

(iii) "nature of work and any related elements that will be affected": this is a high level description, including any "related elements affected", which may include but are not limited to remedial action schemes (RAS), telecom channels and protection package(s) still in-service. Switching procedures and other lengthy descriptions are not required as they cannot be accommodated by the AESO's outage tool;

(iv) "details of the contingency assessment and any mitigation plans": details of contingency assessments may be submitted to the AESO in a separate document. Contingency assessments utilize steady-state powerflow and voltage stability analytic tools to identify concerns, such as thermal constraints, low voltage, high voltage and voltage collapse situations. The legal owner of a transmission facility is encouraged to contact the AESO by sending an email to outage.coordination@aeso.ca confirming the scope of contingency assessments. The AESO does not anticipate that a legal owner will typically perform transient stability assessments. This does not preclude a legal owner from undertaking transient stability assessments or from assisting the AESO with such an assessment. In cases where the legal owner's contingency assessment has not identified any concerns, the legal owner may submit a statement such as "No concerns identified";

(v) "confirmation of coordination with affected market participants and adjacent transmission operators": this condition is satisfied by a policy statement from the requesting legal owner generally describing its coordination practice or policy with affected market participants and adjacent interconnected transmission operators. In particular circumstances, the AESO may request that the legal owner specifically confirm coordination with impacted market participants, such as system access customers or interconnected facility owners;

(vi) "isolation points": are important for the AESO's energy management system model to properly account for elements taken out of service and include at least one (1) point greater than twenty-five (25) kV; and

(vii) "time to restore the transmission facility in an emergency": the information submitted indicates a realistic estimate of the time it would take to restore the transmission facility in an emergency given the particular conditions of the outage.

Planned Outage Pre-Work and Information

Pursuant to subsection 5(1)(a) of Section 306.4, the legal owner of a transmission facility coordinates with other affected legal owners to determine a mutually agreed upon planned outage schedule before submitting a planned outage request to the AESO.

Coordination

From time to time, a transmission facility owner will take facilities out of service to conduct maintenance and to construct new facilities. A number of conditions may compel a transmission facility owner to undertake these maintenance and construction outages in a particular period.

Pursuant to subsection 9 of Section 306.4, the legal owner of a generating unit, the legal owner of an aggregated generating facility, the legal owner of an electric distribution system and the legal owner of load coordinate planned outages with the affected legal owners on a reasonable efforts basis.

The AESO takes the priority of the work and the importance of the requested timeframe into account when approving the outage request, and may approve the request even if an agreement on coordinating the outage has not been reached among the affected legal owners.

Assessments

The AESO assesses planned outage requests as far in advance as it considers feasible. Assessments may take into account many factors including the AESO's estimation of future conditions on the interconnected electric system and the extent to which market participants can be made aware of the outage. As per subsection 6 of Section 306.4, the AESO may decide not to assess late-submitted planned outage requests. If the AESO does not assess a planned outage, the planned outage cannot proceed.

The AESO generally assesses planned outage requests using the following guidelines, although they may not be universally applicable:

(i) a planned transmission outage is considered to be the next credible contingency and every contingency thereafter is considered to be a subsequent contingency;

(ii) the AESO may use steady-state, voltage stability and transient stability analyses to assess next credible contingency and subsequent contingency conditions;

(iii) the AESO assesses the impacts of planned transmission outages to load and to the supply margin, including operating reserves;

(iv) where appropriate, the AESO consults with the parties affected by an outage and shares the study results; and

(v) based on the results of its analyses, the AESO may develop mitigation strategies for contingency situations or request changes to a legal owner's planned outage request.

Clarification of Specific Outage Request Issues

The following provide clarification of specific aspects of outage requests:

(i) Coordination with customers: The power system is always operated with regard for the next contingency. The AESO suggests that an outage be communicated by the transmission facility owner to a customer if it will likely affect how they will operate during the outage to mitigate the impacts of the N-1-1 condition.

(ii) Live Line and Reclose Block activities: Live line and reclose block activities do not result in any physical change to a facility and do not affect the manner in which the facility is operated. Therefore, regardless of voltage class, live line and reclose block activities may not be considered significant outages. However, these activities are still within the definition of a planned outage, therefore are to be included in the Tuesday week-ahead outage requests.

(iii) A request for an outage to a transformer that is energized but not normally carrying load and for which the isolation is a single breaker connected off of a bus, may be submitted to the AESO in the Tuesday week-ahead outage requests regardless of the voltage level of the transformer.

(iv) A request for an outage to a transformer that is energized but not normally carrying load and for which the isolation requires the momentary opening of a breaker(s) that will impact a ring bus or bus diameter, may be submitted in the Tuesday week-ahead outage requests regardless of the voltage level of the transformer.

(v) An outage to terminal equipment such as remote terminal units (RTUs), telecom radios, or an individual protection group may not be significant. If such an outage does not result in loss of visibility to generation or loss of control to a switched device (e.g. capacitor), regardless of the voltage level of the transformer it may not be significant.

Planned Outage Changes

Subsection 4 of Section 306.4 sets out the times by which changes to a previously submitted planned outage are to be submitted to the AESO. The sooner a legal owner submits a change to an outage, the more likely the AESO can assess and approve the change prior to the scheduled time of the outage. All changes to planned outages are made by sending an email to outage.scheduling@aeso.ca.

Notifications of emergency or forced outages submitted after ten (10) am on the business day before the change, may be made by phoning the AESO System Controller in addition to sending an email to the address noted above.

In order to cancel a previously requested planned outage in the time period up to and including the day before the start-date of the planned outage, and if the cancellation occurs during AESO business hours, being eight (8) am to five (5) pm, the legal owner sends an email to outage.scheduling@aeso.ca clearly indicating its intention to proceed not with the planned outage. In order to cancel a planned outage on the intended start-day of the planned outage, the legal owner phones the AESO System Controller in addition to sending an email notice to outage.scheduling@aeso.ca.

Examples regarding changes to a previously submitted planned outage request, pursuant to subsection 4(1) of Section 306.4, include:

(i) If a day is being added to a previously approved outage, notice of the addition is sent by ten (10) am on the business day before the additional day.

(ii) If a previously approved outage is being reduced by a day, notice of the reduction is sent by ten (10) am on the business day before the day being removed from the outage.

(iii) If, in the current operating week, an outage is completed early and a previously related planned outage for the subsequent operating week can be started earlier, the legal owner may request that the new start date of the subsequent planned outage be moved into the current operating week. Notice is to be sent by ten (10) am on the day before the requested change to the start date of the related outage. The AESO may assess the changed start date of the subsequent planned outage, dependent on available resources and other scheduling concerns.

The AESO considers a market participant’s compliance with subsection 4(2) of Section 306.4 independently of the requirements set out in subsection 4(1) of Section 306.4.

2.2 Transmission Planned Outage Reports

The AESO reports transmission planned outages to market participants in two separate reports: the *Approved Outages* report and the *Long Range Significant Transmission Outages* report. These reports are located on the Market & System Reporting page of the AESO’s website. Previous versions of these two reports are available.

In addition, the *System Coordination Plan* is sent directly to the legal owners of transmission facilities each week.

Approved Outages

The *Approved Outages* report lists the transmission planned outages that the AESO has approved. This report is time stamped when posted.

Long Range Significant Transmission Outages

The principal purpose of *Long Range Significant Transmission Outages* report is to assist in the coordination of planned outages between legal owners. The report lists transmission planned outages by month for the subsequent twenty-four (24) months. Planned outages listed in this report are tentative and may not have the AESO’s approval. The report includes planned outages of facilities that meet one or more of the criteria listed in subsection 3(3) of Section 306.4. The *Long Range Significant Outages* report is time stamped when posted.

System Coordination Plan

The *System Coordination Plan* provides information to the legal owners of transmission facilities about the conditions that must be in place before particular outages can occur or mitigation strategies for contingency conditions, or both. The information is provided for outages scheduled for the upcoming operating week. The report is updated every Wednesday and may be updated at other times, if necessary.

3 Generation Outage

3.1 Generation Outage Communication

A pool participant submits contact information to the AESO pursuant to subsection 2(2) of Section 306.5 by sending an email to info@aeso.ca.

A pool participant submits generation planned outage information to the AESO pursuant to subsection 3 of Section 306.5 through the Energy Trading System.

A pool participant submits delayed forced outage and automatic forced outage information to the AESO pursuant to subsections 4(2) and 5 of Section 306.5 by making a telephone call to the AESO as soon as reasonably practicable following a determination by the pool participant that the outage is necessary.

3.2 Generation Outage Reports

The AESO reports generation outages to market participants in three separate reports: the *Daily Outage* report, the *7 Day Hourly Available Capability* report and the *Monthly Outage* report. These reports can be found on the Market & System Reporting page of the AESO's website. All three generation outage reports are current and no historical reports are available.

The purpose of these reports is to illustrate generation outages based on pool participant submissions in the Energy Trading System made in accordance with Section 306.5. These reports reflect generation availability, but do not take constrained down generation into account. The expected impact of transmission and other operating constraints, including outages, is reflected in the 24 Month Supply and Demand report.

Description of the Generation Outage Reports

<u>Daily Outage Report</u>

The *Daily Outage* report illustrates generation outages by the daily average amount of supply by fuel type and by time period on outage for the subsequent three (3) months. The report shows the difference between the maximum capability and the available capability of pool assets as submitted by pool participants in the Energy Trading System. Supply within the same fuel type category is aggregated to create one final outage amount for each fuel type for each time block. The aggregated volume of each fuel type is then rounded off to the nearest 10 MW.

For most generating units, the maximum capability and maximum continuous rating are similar. However, for generating units that primarily supply onsite load and only offer electric energy net-to-grid, the maximum continuous rating may be considerably larger than the maximum capability.

Some generating units do not report a maximum capability. These include wind aggregated generating facilities, small power producers and generating units smaller than 5 MW. Outages for generating units that do not report a maximum capability value are not included in the outage reports.

The *Daily Outage* report is available in HTML and CSV formats.

Load is also included in the Daily Outage report. See section 4 "Load Outage Reporting", below.

Monthly Outage Report

Similar to the *Daily Outage* report, the *Monthly Outage* report shows the difference between the maximum capability and the available capability of a generating pool asset, as submitted by pool participants in the Energy Trading System. The report illustrates monthly data on a rolling twenty-four (24) month basis. The data is aggregated by fuel type for each hour. The hourly data is then combined into a monthly number by averaging the hourly volumes for all hours of the month by fuel type. The aggregated volume for each fuel type is then rounded off to the nearest 10 MW.

The *Monthly Outage* report is available in Graph, HTML and CSV formats.

7 Day Hourly Available Capability Report

The *7 Day Hourly Available Capability* report illustrates the aggregate available capability factor by fuel type for each hour over the upcoming seven (7) days. The availability factor is calculated as the sum of the available capability divided by the total maximum capability of the fuel type.

Updating of the Generation Outage Reports

All three of the generation outage reports are updated at regular intervals, illustrated by a “last updated time” stamp within the report. Outage report updating is subject to a small delay due to calculation and posting. On average, the outage reports are updated every five (5) to ten (10) minutes, with a maximum update time of twenty (20) minutes. On rare occasions, the *Daily Outage* and *Monthly Outage* reports may not be updated. If after refreshing the report the last updated time is more than twenty (20) minutes earlier, please contact info@aeso.ca.

An outage may not appear in the report immediately. If the time at which the outage was submitted is after the “last updated” time on the report then no action needs to be taken, as the outage should appear following the next update.

If the time at which the outage was submitted is prior to the “last updated” time on the outage report, check that the new available capability values were submitted correctly into the Energy Trading System. This can be verified by logging into the Energy Trading System and viewing the submission in the “Outage Scheduling” tab for the specific time period of that the outage. Determine the impact the submission would have on the outage report, noting that:

(i) outages are pro-rated across the time period (for example, an outage for one hour today during the on-peak period shows as an outage on the daily report of 1/16th of the magnitude); and

(ii) outages are rounded to the nearest 10 MW.

If a problem with the outage report is still suspected after completing these checks, contact info@aeso.ca.

Even where an outage appears to be missing from an outage report, the report may still be accurate since a countervailing outage of similar magnitude and time could result in a zero (0) net impact.

Note that the AESO does not provide individual pool participant outage information and does not indicate whether such information has or has not been included in an outage report.

New Generating Units

A new generating unit is only included in the outage reports once it has access to the Energy Trading System and once available capability and maximum capability values are entered for the unit. A pool participant is only able to access the Energy Trading System once it has a valid supply transmission service contract in place. Typically, this occurs on the first day of the month during which the generating unit is expected to start generating.

While the generating unit is testing according its testing plan, submitted under Section 505.3 of the ISO rules, *Coordinating Synchronization, Commissioning, WECC Testing, Ancillary Services Testing, or Operational Testing*, the outage reports reflect its available capability submissions. Typically, testing and commissioning activities for simple cycle gas generating units are relatively short. Testing and commissioning activities for coal generating units and some cogeneration generating units, where commissioning may be staged, may last a number of months.

To ensure that all market participants know when a new unit is reflected in the outage report, the AESO has adopted the business practice of including the pool asset name on the list of pool assets and placing the generating unit on the Current Supply & Demand page on the AESO's website. While the AESO is able to add a generating unit to the Current Supply & Demand page, the AESO may not display the unit's total net generation until it has verified that it is receiving accurate data.

If a generating unit is added to the Current Supply & Demand page before all parts of its supervisory control and data acquisition system are operational, the values under the headings "Total Net Generation" and "Dispatched (and accepted) Contingency Reserve" display a dash instead of zero (0).

Generating Unit Retirement

A generating unit that is subject to an upcoming retirement is still required to submit availability information as specified by Section 306.5. In such cases, an available capability of 0 MW is recorded in each hour after the expected retirement date. This appears as an "outage" for the corresponding periods in the *Daily Outage* and *Monthly Outage* reports. Once the generating unit is retired, the pool participant no longer enters available capability values and the generating unit no longer appears in the *Daily Outage* and *Monthly Outage* reports. The AESO has adopted the business practice of changing the generating unit's entry in the list of pool assets to show an 'Operating Status' of 'retired' and removing the generating unit from the Current Supply & Demand page of the AESO's website.

4 Load Outage Reporting

As noted previously, load outages are combined with generation outages within the *Daily Outage* report. As with generation outages, the report displays load outages submitted for the current month and the subsequent three (3) month period. The load outage records are aggregated to determine the daily load outage based on market participant submissions. Pursuant to Section 306.3, a market participant with a planned decrease in its capability to consume load at a facility, where such planned decrease is 40 MW or greater, must report load outage records to the AESO. The load outage portion of the *Daily Outage* report is time stamped separately as it is not updated as frequently as the generation outage portion. Load outages associated with pipelines do not have to be reported to the AESO unless the outage behind a single point of delivery is 40 MW or greater.

5 Month Supply and Demand Graphs

In addition to the outage reports described above, the AESO publishes twenty-four (24) month supply and demand graphs on the AESO website.

The purpose of these graphs is to provide information to assist in the planning of generation and intertie outages. The graphs represent the anticipated available supply compared with expected system demand. The system demand includes load and required operating reserves. The supply portion accounts for planned outages and derates of generation, including those caused by transmission outages, and reductions in intertie capability caused by transmission system conditions. Generation outages are aggregated such that individual generating unit outages are not disclosed. The timeframe is a rolling window of twenty-four (24) months. The graphs are updated each weekday, sometimes more than once per day, and are time-stamped.

Revision History

Date	Description
2019-02-11	Add clarficiations to Section 4, Load Outage Reporting.
2018-11-13	Added clarification to subsection 2.1, Clarification of Specific Outage Request Issues (iii) and (iv).
2017-12-06	Added clarifications and new section entitled “Clarification of Specific Outage Request Issues” under section 2.1. Assessments. Included examples for subsection 4(1) of section 306.4, “Changes to Requests and Cancellations”.
2016-09-28	Administrative amendments
2016-06-16	Revised the contact information in subsection 3.1
2016-06-07	Revisions to Sections 1 and 3 to add reference to Section 306.7, *Mothball Outage Reporting* and to provide contact information for mothball outage reporting.
2014-08-28	Initial Release

Information Document
Keephills Ellerslie Genesee Area Transmission Constraint Management
ID #2013-004R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1").

The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits on the Keephills Ellerslie Genesee cutplane of the Alberta interconnected electric system. Section 302.1 sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the Alberta interconnected electric system. These steps are referenced in Table 1 of this Information Document as they are applied to the Keephills Ellerslie Genesee area.

2 General

The Keephills Ellerslie Genesee cutplane is defined as the flows across the Keephills 240/138 kV transformer and all transmission lines connecting the Keephills and Genesee substations to the Alberta interconnected electric system. To ensure the safe and reliable operation of the Alberta interconnected electric system, the AESO has established operating limits for the Keephills Ellerslie Genesee cutplane, and has developed policies and procedures to manage Keephills Ellerslie Genesee cutplane transmission constraints.

The AESO has provided a geographical map of the Keephills Ellerslie Genesee area indicating bulk transmission lines in Appendix 2 of this Information Document. The AESO has also provided a schematic of the Keephills Ellerslie Genesee cutplane, including the pool assets effective in managing a transmission constraint, in Appendix 3 of this Information Document.

A cutplane is a common term used in engineering studies and is a theoretical boundary or plane crossing two or more bulk transmission lines or electrical paths. The cumulative power flow across the cutplane is measured and can be utilized to determine flow limits that approximate conditions that would allow safe, reliable operation of the Alberta interconnected electric system.

3 Constraint Conditions and Limits

3.1 Non-Studied Constraints and Limits

For system conditions that have not been pre-studied, the AESO uses energy management system tools and dynamic stability tools to assess unstudied system operating limits in real time.

3.2 Studied Constraints and Limits

Constraints Under System Normal Conditions or When One Element is Out of Service

The Keephills Ellerslie Genesee cutplane thermal limits, corresponding to summer and winter seasons, system normal conditions and certain transmission facility statuses, are provided in Appendix 4.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Based on studies which considered power flow, voltage, and transient stability, no voltage or transient stability limits have been identified under normal system conditions. The system is capable of reliably transferring all anticipated flow across the Keephills Ellerslie Genesee and North-South cutplanes under system normal conditions.

For system conditions under forced or planned outages, the studies identified that an N-1 outage of either the 1209L transmission line or the 1202L transmission line would have the greatest impact on the Keephills Ellerslie Genesee System Operating Limit. The following bus reconfiguration procedures will be used in the event of an outage of one of these lines:

- In the event that 1209L is out of service and transient stability limits shown in Appendix 5 are at risk of being exceeded, the bus at substation 320P Keephills will be reconfigured to disconnect Keephills 3 from the Alberta interconnected electric system for next loss of 1202L and the system will be operated in accordance with Appendix 6.
- In the event that 1202L is out of service and transient stability limits shown in Appendix 5 are at risk of being exceeded, the bus at substation E330 Genesee will be reconfigured to disconnect Genesee 3 from the Alberta interconnected electric system for next loss of 1209L and the system will be operated in accordance with Appendix 6.

Keephills Ellerslie Genesee cutplane transient stability limits without bus reconfiguration and with bus reconfiguration are included in Appendices 5 and 6, respectively.

Constraints information during the Most Severe Single Contingency

In the Keephills Ellerslie Genesee area, if the Genesee generation pool assets are connected to the Alberta interconnected electric system by a single radial feed, then the combined MW output of the Genesee generation pool assets, consisting of the net-to-grid energy and dispatches issued for operating reserve for GN1, GN2, and GN3, becomes the Alberta interconnected electric system's most severe single contingency.

The AESO has determined the maximum allowable most severe single contingency for the combined output of the Genesee generation pool assets through engineering studies. The maximum allowable combined output of the Genesee generation under these conditions is equal to the lesser of 1,000 MW or intertie total transfer capability minus 65 plus dispatched contingency reserve. When the Genesee pool assets become the most severe single contingency, the AESO adjusts the intertie import available transmission capability to ensure the safe and reliable operation of the Alberta interconnected electric system. The import available transfer capability of the combined Alberta-British Columbia and Alberta-Montana interconnection when the Genesee pool assets become the most severe single contingency is determined as follows:

1. If the Genesee total generation exceeds or is equal to the maximum allowable most severe single contingency for the combined output of the Genesee generation pool assets, then the available transfer capability is set at 0.
2. If the Genesee total generation is less than the maximum allowable most severe single contingency for the combined output of the Genesee generation pool assets, then the intertie available transfer capability is set at the maximum allowable contingency minus the anticipated Genesee total generation.

4 Application of Transmission Constraint Management Procedures

The AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of Section 302.1. However, due to certain unique operating conditions that exist in that area, not all of those provisions are effective on the Keephills Ellerslie Genesee cutplane. Because of those unique operating conditions, this Information Document represents the application of the general provisions of Section 302.1 to the Keephills Ellerslie Genesee cutplane, and provides additional clarifying steps as required to effectively manage transmission constraints in that area.

The protocol steps which are effective in managing transmission constraints are outlined in Table 1 below.

Table 1
Transmission Constraint Management
Sequential Procedures for Keephills Ellerslie Genesee Cutplane

Section 302.1, subsection 2(1) protocol steps		Is the procedure applicable to the Keephills Ellerslie Genesee cutplane?
(a)	Determine effective pool assets	Yes
(b)	Ensure maximum capability not exceeded	Yes
(c)	Curtail effective downstream constraint side export service and upstream constraint side import service	No
(d)	Curtail effective demand opportunity service on the downstream constraint side	No
(e)(i)	Issue a dispatch for effective contracted transmission must-run	No
(e)(ii)	Issue a directive for effective non-contracted transmission must-run	No
(f)	Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes
(g)	Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No

Applicable Protocol Steps

The first step in managing a transmission constraint is to identify those pool assets, both generating units and loads, effective in mitigating the transmission constraint. A list of the generating pool assets that are effective in managing constraints are identified in Appendix 1.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Curtailing effective generation pool assets to their maximum capability as per step (b) is an effective step in managing Keephills Ellerslie Genesee area transmission constraints.

Step (c) in Table 1

There are no interties in the Keephills Ellerslie Genesee area and curtailing import and export flows elsewhere on the system is not effective in managing a transmission constraint.

Step (d) in Table 1

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing Keephills Ellerslie Genesee area constraints because there is no demand opportunity service in the area.

Step (e) in Table 1

With respect to steps (e)(i) and (ii), there are no transmission must-run contracts in the Keephills Ellerslie Genesee area and using transmission must-run is not effective in managing a transmission constraint in this area.

Step (f) in Table 1

Curtailing effective pool assets using reverse energy market merit order followed by pro-rata curtailment is effective in managing Keephills Ellerslie Genesee area transmission constraints.

Step (g) in Table 1

Downstream load curtailment is not effective in managing Keephills Ellerslie Genesee area transmission constraints, as curtailing downstream load does not directly lessen the flow across the cutplane and available downstream generation pool assets can reasonably supply that load.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Keephills Ellerslie Genesee area that are known to have an impact on the information contained in this Information Document.

6 Appendices

Appendix 1 – *Effective Pool Assets*

Appendix 2 – *Geographical Map of the Keephills Ellerslie Genesee Area*

Appendix 3 – *Single Line Drawing Showing Keephills Ellerslie Genesee Cutplane*

Appendix 4 – *Keephills Ellerslie Genesee Cutplane Thermal Limit*

Appendix 5 – *Keephills Ellerslie Genesee Cutplane Transient Stability Limits Without Bus Reconfiguration*

Appendix 6 – *Keephills Ellerslie Genesee Cutplane Transient Stability Limits With Bus Reconfigurationt*

Revision History

Posting Date	Description of Changes
2018-05-03	Revised map in Appendix 3 and updated thermal limits in Appendix 4 to reflect the 1045L Tap entering into service.
2016-09-29	Revised maps in Appendices 2 and 3 and updated thermal limits in Appendix 4 to reflect transmission line 1043L in the Edmonton area entering into service.

	Administrative updates.
2016-04-14	Section 3.2 amended to communicate the bus reconfiguration process if either the 1202L transmission line or the 1209L transmission line is out of service and transient stability limits shown in Appendix 5 are at risk of being exceeded.
	Revised Appendix 5 and added Appendix 6 based on updated studies.
2015-12-10	Section 3.2 amended to reflect studied constraints and limits with WATL in service, Appendix 2 and 3 revised and Appendix 4 replaced with new Appendices 4 and 5 which include information on cutplane limits.
2015-02-19	Appendix 4 amended to include changes to cutplane limits.
2014-10-02	Appendix 4 amended to remove Keephills T6 contingency from the 500 kV KEG Outages Table and Appendix 3 amended to include a new single line diagram.
2014-07-17	Section 5 amended to remove temporary cutplane operating limits and Appendix 4 amended to reflect changes to cutplane operating limits.
2014-03-13	Amended to include temporary cutplane operating limit changes in section 5 due to the Edmonton Region 240 kV Line Upgrades.
2014-02-27	Initial Release

Appendix 1 – Effective Pool Assets

The effective pool assets for the Keephills Ellerslie Genesee cutplane, listed alphabetically by their pool IDs, are:

GN1

GN2

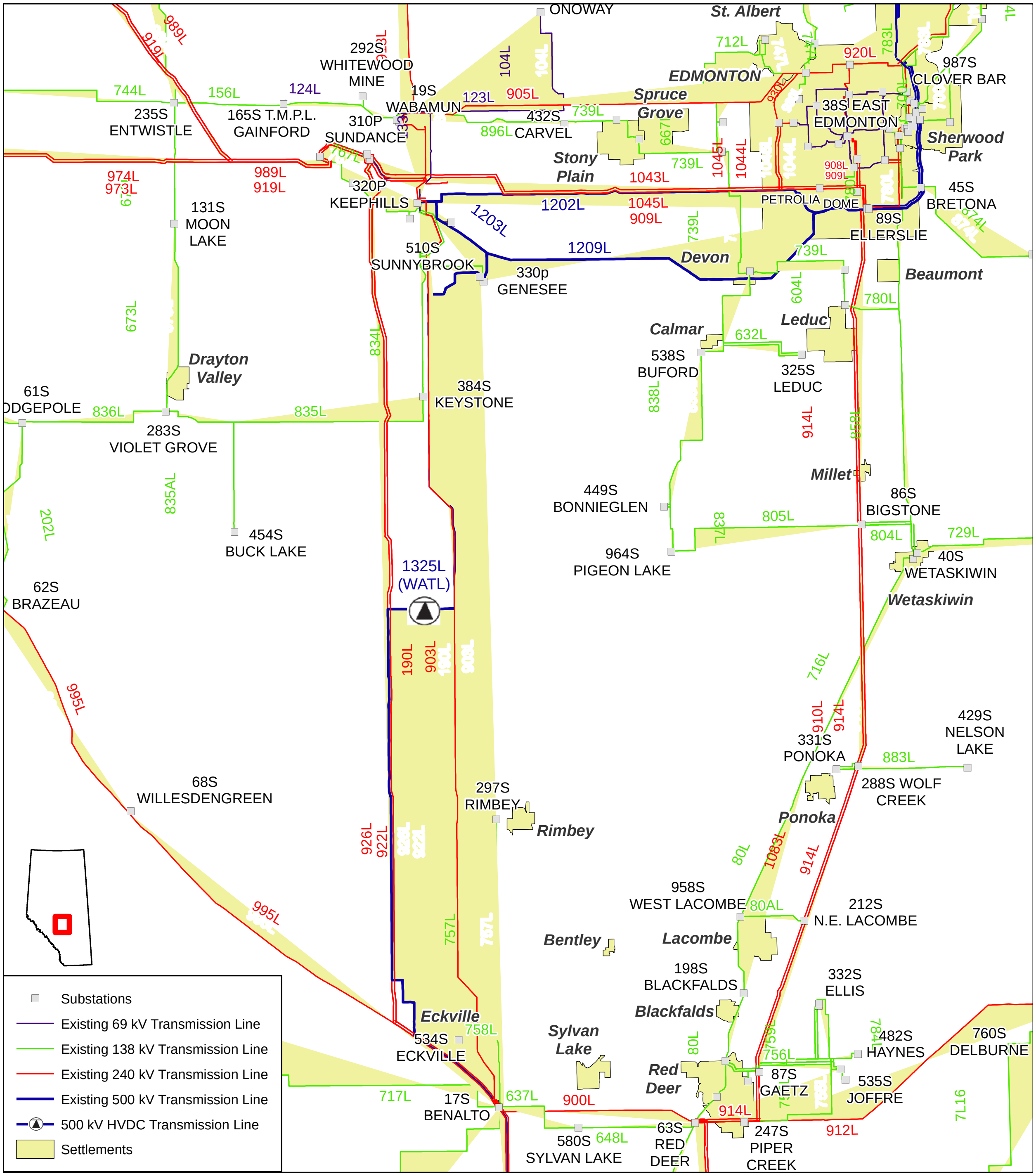
GN3

KH1

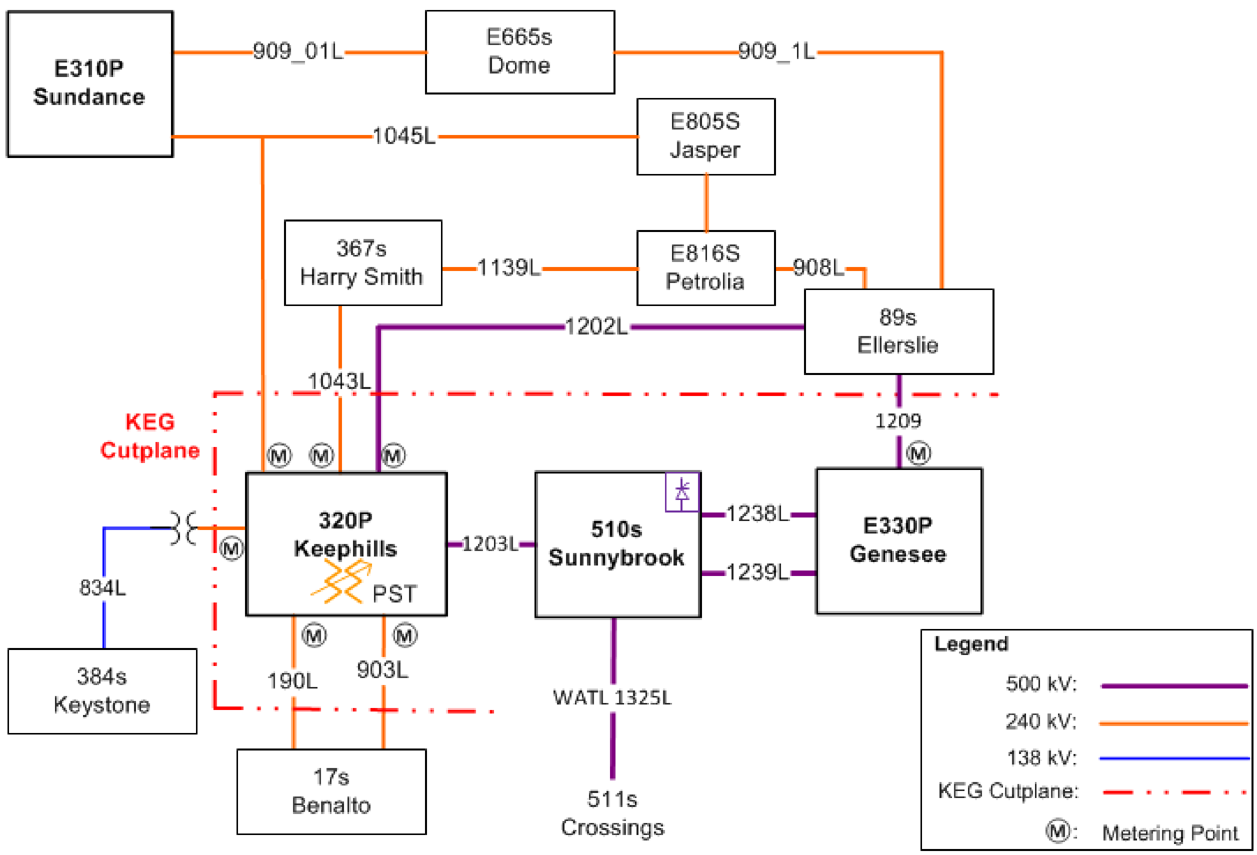
KH2

KH3

Appendix 2 – Geographical Map of the Keephills Ellerslie Genesee Area



Appendix 3 – Single Line Drawing Showing Keephills Ellerslie Genesee Cutplane



Appendix 4 – Keephills Ellerslie Genesee Cutplane Thermal Limit

If real time contingency analysis allows a higher cutplane limit for the contingencies listed in the tables below, the AESO operates to the higher limit.

Outage		Summer (MW)		Winter (MW)	
		KEG_{AC}	KEG_{AC}+ WATL	KEG_{AC}	KEG_{AC}+ WATL
System Normal (N-0)	None	N/A[1]	N/A[1]	N/A[1]	N/A[1]
N-1	1202L	1270	2270	1270	2270
	1209L	1270	2270	1270	2270
	Ellerslie T1	2580	N/A[1]	2700	N/A[1]
	Ellerslie T2	2580	N/A[1]	2700	N/A[1]
	190L	2780	N/A[1]	2910	N/A[1]
	903L	2780	N/A[1]	2910	N/A[1]
	1043L	2600	N/A[1]	2690	N/A[1]
	1045L(Tap)	2780	N/A[1]	2910	N/A[1]

Note:

1. Maximum Keephills Ellerslie Genesee generation reached before a limit was established.

Appendix 5 – Keephills Ellerslie Genesee Cutplane Transient Stability Limits Without Bus Reconfiguration

Outage	Contingency	WATL (North to South) (MW)	KEG Total Net to Grid Output
N-0	None	N/A[1]	N/A[1]
N-1	1209L or 1202L	0	1856
		100	1896
		200	1936
		300	1976
		400	2016
		500	2056
		600	2096
		700	2136
		800	2176
		900	2216
		1000	2256

Note:

1. Maximum Keephills Ellerslie Genesee generation reached before a limit was established.

Appendix 6 – Keephills Ellerslie Genesee Cutplane Transient Stability Limits With Bus Reconfiguration

Condition	Outage	WATL (North to South) (MW)	Remaining 5 Generator KEG Total Net to Grid output[1]
System Normal (N-0)	None	N/A	N/A
N-1	Either 1209L or 1202L out of service	0	1612
		100	1652
		200	1692
		300	1732
		400	1772
		500	1812
		600	1852
		700	1892
		800	1932
		900	1972
		1000	2012

Note:

1. Does not include the Keephills Ellerslie Genesee area generator which would be disconnected for next loss of either 1202L or 1209L (depending on whether the initial event was loss of 1209L or 1202L, as described in section 3.2) after 500kv bus reconfiguration.

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 205.1 of the ISO rules, *Offers for Operating Reserve*;
- Section 205.2 of the ISO rules, *Issuing Dispatches for Operating Reserve*;
- Section 205.3 of the ISO rules, *Restatements for Operating Reserve* ("Section 205.3");
- Section 205.4 of the ISO rules, *Regulating Reserve Technical Requirements and Performance Standards* ("Section 205.4");
- Section 205.5 of the ISO rules, *Spinning Reserve Technical Requirements and Performance Standards* ("Section 205.5");
- Section 205.6 of the ISO rules, *Supplemental Reserve Technical Requirements and Performance Standards* ("Section 205.6"); and
- Section 302.1 of the ISO rules, *ISO Directives* ("Section 302.1").

The purpose of this Information Document is to assist pool participants in understanding the operating reserve market. This Information Document is likely of most interest to market participants who currently provide or may in the future provide operating reserve.

2 What is Operating Reserve

Operating reserve acts as a safety net, making extra power available to help balance the supply of and demand for electricity in real time, and stabilizing and protecting the interconnected electric system in the event of unforeseen problems.

There are two types of operating reserve: regulating reserve and contingency reserve. Each type of operating reserve performs a unique function and has unique technical requirements.

2.1 Regulating Reserve

Regulating reserve is used to provide a balance between generation and load within the AESO's balancing authority area, while maintaining the interchange schedule on the interconnections with British Columbia and Montana at a frequency of 60 Hz. Further details on regulating reserve can be found in Information Document #2013-006R, *Regulating Reserve*.

2.2 Contingency Reserve

Contingency reserve is used to restore the balance between the supply of and demand for electricity following a contingency or unforeseen event threatening the reliable operation of the interconnected electric system. Contingencies can include events such as the sudden loss of a generating unit or the disruption of one of the interconnections that links Alberta to a neighboring jurisdiction.

Contingency reserve is further divided into spinning reserve and supplemental reserve[2].

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[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

[2] Supplemental reserve is sometimes referred to as "non-spinning reserve in jurisdictions outside Alberta.

Additional details on spinning reserve and supplemental reserve can be found in Information Document #2013-007R, *Contingency Reserve*.

3 Eligibility to Participate in the Operating Reserve Market

Operating reserve may be provided by pool assets with eligible regulating reserve, spinning reserve, or supplemental reserve resources. Eligibility criteria is found in subsection 3(1) of each of Section 205.4, Section 205.5 and Section 205.6, respectively. The pool asset must be qualified by the AESO to participate in the operating reserve market in accordance with subsection 4(1) of each rule.

In determining the amount of real power a pool asset is capable of providing, the AESO considers whether a resource participates in a remedial action scheme (RAS) as a factor because a pool asset may not be able to provide operating reserve if a RAS is armed.

4 Procurement in the Operating Reserve Market

Under Alberta's electricity market structure, the AESO is the sole buyer of operating reserve (regulating reserve, spinning reserve and supplemental reserve). The AESO's objective is to procure operating reserve in a transparent, competitive and well-documented manner.

Each day the AESO procures operating reserve for the Alberta market from pool participants through Alberta Watt Exchange Limited ("Watt-Ex"), a for-profit third party clearing house. Watt-Ex enters into an Ancillary Services Exchange Customer Agreement ("Watt-Ex Agreement") with all of its customers, including pool participants who offer supply into the operating reserve market and the AESO who bids to purchase the operating reserve. Pool participants receive payment directly from Watt-Ex for operating reserve sold, and in turn, the AESO receives an invoice from and settles financially with Watt-Ex.

The exchange operated by Watt-Ex offers complete transparency of all transactions with all pool participants, but allows sellers to remain anonymous to one another and to the buyer.

4.1 Active and Standby Reserve

The AESO procures active and standby volumes of each type of operating reserve. The AESO uses the terms "active" and "standby" to differentiate the timing and order in which dispatches for operating reserve are issued.

The AESO procures enough active operating reserve to meet the volume requirements set out by Alberta Reliability Standard BAL-002-WECC-AB1-2, *Contingency Reserve*. Normally, all active reserve volumes are dispatched to ensure these requirements are met at all times.

The purpose of standby operating reserve is to provide additional operating reserve for use when the volume available from active operating reserve assets is not sufficient to meet the real-time operating and reliability requirements of the interconnected electric system. Often, this insufficiency occurs when an active asset has a forced outage and is unable to provide the active reserve volume that the AESO has procured. The AESO issues dispatches for all pool assets in the active portfolio before issuing dispatches for any pool assets from the standby portfolio. There is a standby portfolio of pool assets for each type of operating reserve procured in the operating reserve market.

4.2 Block Procurement

The AESO's approach to buying operating reserve is described as block procurement. Operating reserve is purchased in four time offer blocks, as follows:

(a) On peak means the period from 07:00 to 22:59:59;

(b) Off peak means the period from 00:00 to 06:59:59 and from 23:00 to 23:59:59;

(c) AM super peak means the period from 05:00:00 to 07:59:59; and

(d) PM super peak includes the period from 16:00:00 to 23:59:59 in November, December and January and in all other months the period from 17:00:00 to 23:59:59.

The volumes procured in each of these offer blocks are consistent across all hours in the block.

Only active regulating reserve is purchased for super peak blocks, while all three types of operating reserve (i.e. regulating, spinning and supplemental reserve) are procured for the on peak and off peak time blocks.

4.3 Forecasting

The *7 Day Forecast of Operating Reserves Volumes* report can be found on the AESO website. This report estimates the volume of operating reserve the AESO anticipates will be required from the current day to seven days forward. The forecast is updated daily and the volumes procured each day can change according to the forecast.

Table 1 below provides an example of how the AESO procures active regulating reserve based on data from September 21, 2011. As described above, active regulating reserve is procured for four time blocks – on peak, off peak, AM super peak, and PM super peak. The AESO first procures the minimum volume forecast in each of the on peak and off peak time blocks. In the example portrayed in Table 1, the AESO would procure 135 MW for the off peak time block and 150 MW for the on peak time block. The AESO then procures the additional active regulating reserve volume for the AM super peak and the PM super peak time blocks. In the example portrayed in Table 1, the AESO would procure 65 MW for the AM super peak time block and 20 MW for the PM super peak time block.

Table 1: Example Forecast of Operating Reserve Volumes

		Active			Standby		
Date	Time Period	RR	SR	SUP	RR	SR	SUP
09/21/2011	00:00 to 00:59:59	135	225	225	100	105	35
09/21/2011	01:00 to 01:59:59	135	225	225	100	105	35
09/21/2011	02:00 to 02:59:59	135	225	225	100	105	35
09/21/2011	03:00 to 03:59:59	135	225	225	100	105	35
09/21/2011	04:00 to 04:59:59	135	225	225	100	105	35
09/21/2011	05:00 to 05:59:59	200	225	225	100	105	35
09/21/2011	06:00 to 06:59:59	200	225	225	100	105	35
09/21/2011	07:00 to 07:59:59	215	257	257	100	105	45
09/21/2011	08:00 to 08:59:59	150	257	257	100	105	45
09/21/2011	09:00 to 09:59:59	150	257	257	100	105	45
09/21/2011	10:00 to 10:59:59	150	257	257	100	105	45
09/21/2011	11:00 to 11:59:59	150	257	257	100	105	45
09/21/2011	12:00 to 12:59:59	150	257	257	100	105	45
09/21/2011	13:00 to 13:59:59	150	257	257	100	105	45
09/21/2011	14:00 to 14:59:59	150	257	257	100	105	45

Legend
Off peak
On peak
AM super peak
PM super peak

09/21/2011	15:00 to 15:59:59	150	257	257	100	105	45
09/21/2011	16:00 to 16:59:59	150	257	257	100	105	45
09/21/2011	17:00 to 17:59:59	170	257	257	100	105	45
09/21/2011	18:00 to 18:59:59	170	257	257	100	105	45
09/21/2011	19:00 to 19:59:59	170	257	257	100	105	45
09/21/2011	20:00 to 20:59:59	170	257	257	100	105	45
09/21/2011	21:00 to 21:59:59	170	257	257	100	105	45
09/21/2011	22:00 to 22:59:59	170	257	257	100	105	45
09/21/2011	23:00 to 23:59:59	155	225	225	100	105	35

4.4 Timing of Operating Reserve Procurement

Operating reserve is procured one day in advance of when it is required. Procurement does not occur on weekends and holidays; therefore, procurement for the weekend (Saturday, Sunday and Monday) takes place on Friday. Since the market is closed on Sunday, Monday is included in the weekend. On holidays, the AESO procures operating reserve on the last business day before the holiday. If a holiday occurs in conjunction with a weekend, then the AESO procures operating reserve for the holiday in addition to the weekend.

The daily schedule for offer submission is set by Watt-Ex. Watt-Ex receives submissions from 09:00 am through to 10:10 am as follows:

(a) in the case of offers for active regulating reserve for the on peak and off peak periods, no later than 09:10 am on the business day before the day that the offer is effective;

(b) in the case of offers for active regulating reserve for the super peak periods, no later than 09:20 am on the business day before the day that the offer is effective;

(c) in the case of offers for active spinning reserve, no later than 09:30 am on the business day before the day that the offer is effective;

(d) in the case of offers for active supplemental reserve, no later than 09:40 am on the business day before the day that the offer is effective;

(e) in the case of offers for standby regulating reserve, no later than 09:50 am on the business day before the day that the offer is effective;

(f) in the case of offers for standby spinning reserve, no later than 10:00 am on the business day before the day that the offer is effective; and

(g) in the case of offers for standby supplemental reserve, no later than 10:10 am on the business day before the day that the offer is effective.

The order of market closure is related to the technical requirements for each product. Regulating reserve has the strictest technical requirements and is therefore the highest value product. Supplemental reserve has the least restrictive technical requirements and is therefore the lowest value product.

The sequential closing of the market ensures that if a pool participant fails to sell their entire highest value product (i.e., regulating reserve), they have an opportunity to sell any remaining capacity in other operating reserve markets (i.e., spinning reserve, then supplemental reserve).

4.5 Trade Cancellations

A trade cancellation can occur in the active and standby markets for any product for reasons outlined in the Watt-Ex Agreement.

4.6 Internal Controls for Procurement of Operating Reserve

The procurement of operating reserve is governed by AESO policy. Once a year, or whenever changes to any relevant policies occur, the AESO is required to sign an acknowledgement letter indicating they have read, understood, and are in compliance with the policies that govern AESO practices.

On a daily basis, the AESO's Settlement and Risk department monitors trading activity. Watt-Ex transactions are scrutinized for compliance with the Watt-Ex Agreement and all internal risk management guidelines.

5 Pricing

5.1 Active Reserve Market

The AESO bids for a volume of operating reserve defined as either on peak, off peak, AM super peak, or PM super peak, at a price that is at a discount (lower) or at a premium (higher) to the pool price.

Pool participants submit their price and quantity offers into the operating reserve market for each product at a discount or a premium to the pool price, referred to as indexing to the pool price. When the market closes, offers are sorted based on price, and the lowest priced offers that fill the AESO's bid quantity are selected. The highest priced offer that satisfies the quantity required is referred to as the marginal or clearing offer.

For active operating reserve, a pool participant is paid the pool price plus the equilibrium price. The equilibrium price is the average of the AESO bid price and the marginal offer.

Equilibrium Price = (Bid + Marginal Offer)/2

The seller is not required to pay the AESO if pool price + $X is negative. For example, for an equilibrium price of $X, the AESO pays Max (0, pool price + $X) times quantity.

When the AESO issues a directive for contingency reserve or a dispatch for regulating reserve to a pool participant to provide the real power offered for operating reserve, the pool participant is paid the current pool price for the real power they are providing, in addition to the payment they receive for providing the operating contingency reserve.

The general process for trading on Watt-Ex is illustrated in this example:

> The AESO needs to buy 100 MW of on peak spinning reserve and the AESO's bid price is $10. Here are the offers:
>
> Offer 1: 10 MW at -$10 (Pool Price plus -$10)
>
> Offer 2: 30 MW at -$5 (Pool Price plus -$5)
>
> Offer 3: 40 MW at $0 (Pool Price plus $0)
>
> Offer 4: 10 MW at $5 (Pool Price plus $5)
>
> Offer 5: 10 MW at $10 (Pool Price plus $10)
>
> Offer 6: 25 MW at $15 (Pool Price plus $15)

Offer 7: 30 MW at $20 (Pool Price plus $20)

In this example, the marginal offer is Offer 5 ($10) because it is the last offer, when combined with Offers 1, 2, 3 and 4, that makes up the quantity of 100 MW the AESO requires. The equilibrium price is then calculated as the average of the AESO's bid and the marginal offer. In this example, the equilibrium price is ($10 + $10)/2 = $10.

For on-peak hour ending X, pool price is $31. The payment the AESO makes to pool participants providing active operating reserve for hour ending X is $10 + $31=$41/MW.

If the pool participant subsequently receives a directive or, in the case of regulating reserve, is receiving a control signal, the pool participant also receives the pool price for the real power provided.

5.2 Standby Reserve Market

The standby market utilizes a two-part pricing model with a premium price and an activation price.

(i) Premium Price – the price paid to the seller to provide the AESO the option to call on the operating reserve if required.

(ii) Activation Price – the price paid to the seller if the AESO issues a dispatch for the operating reserve.

The AESO clears the market using a blended price formula, which ranks the standby offers based on the following algorithm:

Blended Price = Premium + (Activation % x Activation Price)

Activation percentages are based on historical product activation rates for on peak and off peak hours. They are subject to change as market conditions change. If there is a change, the AESO gives notice to market participants.

If two (2) blended prices are equal, the AESO selects the offer that was submitted to the Watt-Ex system first until its quantity requirements are filled.

When the contingency reserve provider receives a directive to provide a quantity of contingency reserve, the provider continues to receive the activation price and also receives the pool price for the real power provided.

After a dispatch for regulating reserve, the provider continues to receive the activation price and also receives the pool price for the real power provided.

The standby operating reserve merit order sorts all the standby quantities procured for each product from lowest activation cost to highest activation cost. The lowest cost quantities are activated first. The AESO only issues dispatches for the quantity required to address the deficiency in active operating reserve.

6 Merit Order

The AESO uses the ancillary service merit order to determine how dispatches are issued. The ancillary service merit order is sorted by supply type, type of operating reserve, and the maximum contract amount for each pool asset that has submitted an offer. The ancillary service merit order contains two supply types: active and standby. The AESO issues dispatches for all pool assets providing active operating reserve. Dispatches are only issued for pool assets providing standby reserve if required.

7 Dispatches and Directives

The AESO issues dispatches and directives by way of the Automated Dispatch and Messaging System. However, if the Automated Dispatch and Messaging System is unavailable, the secondary means of communication between the AESO and market participants is via telephone.

The AESO uses a two-step process to contact pool participants providing operating reserve:

1) Dispatch for Operating Reserve

   The AESO sends a dispatch for operating reserve to notify the pool participant to maintain additional capacity on its pool asset to ensure it can provide the additional real power to the interconnected electric system. The dispatch contains the following information for spinning reserve, supplemental reserve, and regulating reserve: the pool asset, the type of operating reserve, the amount of MW to be supplied, and the date and time the dispatch takes effect.

   For regulating reserve, the additional capacity is the regulating reserve range. The regulating reserve resource provides real power within that range as directed by the automatic generation control.

2) Directive for Contingency Reserve

   If required, the AESO sends a contingency reserve directive to a previously dispatched pool participant to notify the pool participant to provide the additional real power to the interconnected electric system.

   Under normal market conditions, the contingency reserve directive is effective for one (1) hour. Under abnormal market conditions, such as supply shortfall, the AESO may issue a directive for more than one hour.

   If the asset is not able to respond to a directive, the pool participant is required to: provide notice to the AESO as soon as practicable pursuant to subsections 4(1) and 4(2) of Section 301.2; submit a restatement to reflect the operating state of the pool asset pursuant to subsection 3(4) of Section 205.3; and potentially submit a Notification of Force Majeure if the failure to respond to the directive is a result of a force majeure as defined in the Watt-Ex Agreement. Refer to subsection 9 below for additional detail on force majeure events.

7.1 Conscription of Operating Reserve

The AESO may conscript non-contracted operating reserve by issuing a directive when all contracted operating reserve has been dispatched in accordance with Section 301.2. If the AESO deems this out of market action to be necessary, the conscripted pool asset would receive a directive. The pool participant is compensated in accordance with the ISO tariff for the non-contracted amount provided.

7.2 Concurrent Energy and Operating Reserve

If the AESO issues dispatches for a pool asset to provide both operating reserve capacity and energy in the energy market for the same period, then the AESO deducts the MW quantity of such operating reserve capacity from the available capability of the pool asset for the purposes of determining the MW quantity of the energy market dispatch.

7.3 Failure to meet Dispatch or Directive requirements

Failure to respond to a dispatch in accordance with the performance requirements in Section 205.4, Section 205.5 and Section 205.6 may result in remedies under the Watt-Ex Agreement, (i.e. claw back of payment to the pool participant for the operating reserve during the hour in question and assessment of liquidated damages).

Failure to respond to a directive in accordance with the performance requirements in Section 205.5 and Section 205.6 may result in remedies under the Watt-Ex Agreement, (i.e. a claw back of payment to the pool participant for the operating reserve during the hour in question, assessment of liquidated damages), and pursuit of the event as a potential ISO rule contravention.

When failure to comply with a dispatch or directive is a result of an Event of Force Majeure as defined in the Watt-Ex Agreement and the pool participant notifies the AESO within two business days of the occurrence, then both liquidated damages and pursuit as an ISO rule contravention may be waived. However, payment may still be clawed back for the service not provided. Please refer to subsection 9 for more information on submitting a Notification of an Event of Force Majeure to the AESO.

8 Restatements and Substitutions

Pool participants that are providing operating reserve may restate the quantity of MW they are able to provide in accordance with subsections 3(1) and 3(2) of Section 205.3 and must restate the quantity of MW in certain circumstances in accordance with subsection 3(3) of Section 205.3.

A pool participant may be pre-approved to substitute operating reserve from one pool asset to another within its portfolio under certain circumstances as outlined in subsection 4 of Section 205.3. An asset that is pre-approved to provide a type of operating reserve can only substitute with other assets within its portfolio that are also qualified by the AESO to provide that type of operating reserve. The pre-approval is a standing arrangement unless there is a compliance issue or a change to the asset that will affect the operating reserve capability. In any event, the substituted volume should not exceed the asset's qualified capacity for the type of reserve.

9 Notification of Event of Force Majeure

In accordance with the terms of the Watt-Ex Agreement, a pool participant must notify the AESO within two business days if a failure to supply the operating reserves is a result of an "Event of Force Majeure". The notification form for submitting an event of force majeure, available on the AESO website, contains an area for the pool participant to explain how the event satisfies the definition of "Event of Force Majeure" in the Watt-Ex Agreement. The AESO expects the explanation to sufficiently describe the event, cause(s) of the event, when the event was discovered, what was known at the time of the event at the operating reserve was offered, and whether and how the event was out of the reasonable control of the pool participant which could not have been avoided through the use of good electric industry practice.

When an "Event of Force Majeure" occurs, the pool participant remains subject to the restatement requirements of Section 205.3. Where a portion of the contracted operating reserves is subject to the Event of Force Majeure, the remaining volume are still subject to the requirements of ISO rules, including the dispatch and/or directive performance requirements of Section 205.4, Section 205.5 and Section 205.6.

Revision History

Posting Date	Description of Changes
2018-02-01	Revisions to align with amended Operating Reserve rules in effect as of February 1, 2018, and addition of subsection 9
2016-09-28	Administrative amendments
2014-12-23	Initial Release

Information Document
Regulating Reserve
ID #2013-006R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 205.4 of the ISO rules, *Regulating Reserve Technical Requirements and Performance Standards* ("Section 205.4").

The purpose of this Information Document is to assist pool participants in understanding regulating reserve. This Information Document is likely of most interest to market participants who currently provide or may in the future provide regulating reserve.

2 What is Regulating Reserve?

Regulating reserve is used to provide a balance between generation and load within the AESO's balancing authority area, while maintaining the interchange schedule on the interconnections with British Columbia and Montana at a frequency of 60 Hz.

Regulating reserve is provided by partially loaded, synchronized regulating reserve resources that are able to immediately respond to automatic generation control signals from the AESO system coordination centre, and that have governor systems such that the resources are frequency responsive. A regulating reserve resource is controlled by an automatic generation control system that adjusts output levels within an established regulating reserve range to compensate for the moment-to-moment changes in load and generation on the Alberta interconnected electric system.

3 Eligibility to Provide Regulating Reserve

Regulating reserve may be provided by a pool asset with one or more regulating reserve resources. A regulating reserve resource may be a single resource that individually meets the eligibility criteria in subsection 3(1) of Section 205.4, or an aggregate of resources controlled by a single governor or governor system that collectively meet the eligibility criteria in subsection 3(1) of Section 205.4. The pool asset must be qualified by the AESO to provide regulating reserve in accordance with subsection 4(1) of Section 205.4.

Regulating reserve resources require a governor system that dynamically responds to a change in frequency to provide an automatic response. Under section 3(1)(b)(iii) of Section 205.4, in the case of synchronous generators, the maximum operating range of a regulating reserve resource is usually the difference of the maximum authorized real power (MARP) value and the minimum stable generation (MSG) value of the resource. In the case of a battery storage system, the maximum operating range of a regulating reserve resource is the difference of (maximum authorize charging power plus maximum authorized discharging power) and (maximum authorized charging power or maximum authorized discharging power).

Market participants can apply to the AESO to provide regulating reserve by completing and submitting the application form on the AESO's website. In accordance with subsection 2(2) of Section 205.4, the AESO must receive a completed application before it can make any determination on resource eligibility and pool asset qualification.

4 Procurement

The AESO procures regulating reserve based on regulating reserve levels identified in the *7 Day*

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Forecast of Operating Reserves Volumes report located on the AESO's website. The AESO normally procures regulating reserve from the Alberta Watt-Ex Exchange, operated by Watt-Ex, but may use other means under certain circumstances. The AESO may adjust the volume of regulating reserve in real-time based on actual system conditions. Refer to ID #2013-005R, *Operating Reserve* for more information on procurement.

5 Dispatches

When regulating reserve is dispatched, the operator of a pool asset with a regulating reserve resource that supplies regulating reserve provides the AESO with the high regulating reserve limit, the low regulating reserve limit and the control status through Supervisory Control and Data Acquisition (SCADA). The low regulating reserve limit for generators equals the energy dispatch or transmission must run output, whichever is greater, plus the amount of contingency reserve directed by the AESO for that asset. The high regulating reserve limit equals the low regulating reserve limit plus the amount of regulating reserve dispatched by the AESO for that asset. The difference between the high and low limits is the regulating reserve range.

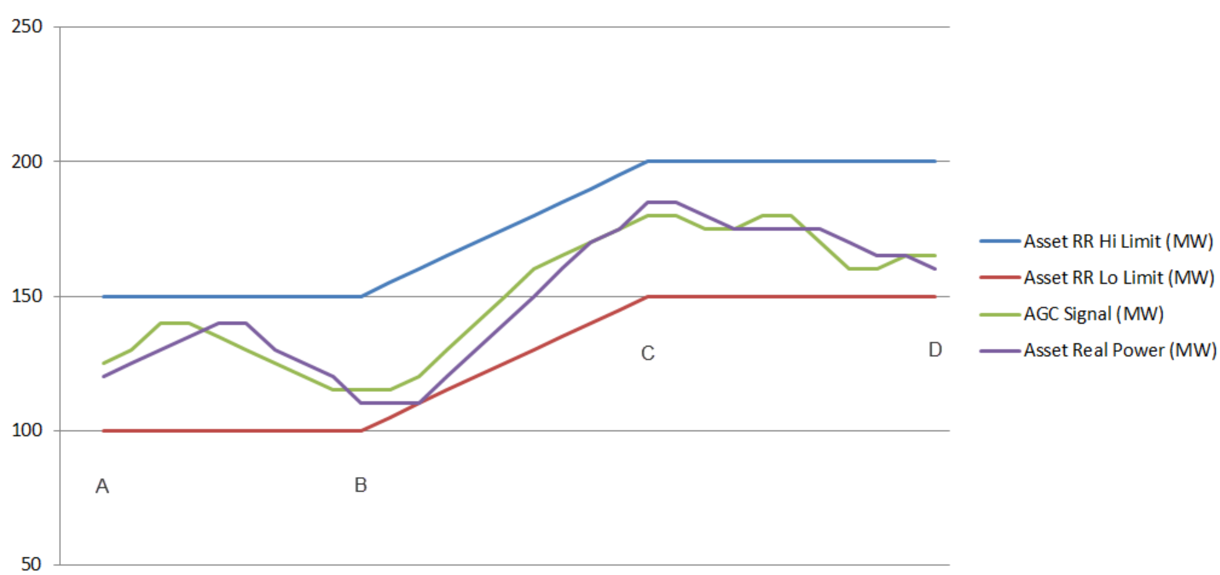
The regulating reserve range consists of the total amount of real power (MW) made available for automatic generation control operation between the upper and lower regulating limits of each regulating reserve resource. Automatic generation control performance is monitored using the NERC control performance standards as defined in Alberta Reliability Standard BAL-001-AB-0a, *Real Power Balancing Control Performance*.

The AESO then sends a signal through automatic generation control to a pool asset that establishes the pool asset's output level within its regulating reserve range.

If the pool asset has more than one regulating reserve resource, the pool participant may use an aggregate of those regulating reserve resources to produce the required response to the dispatch.

5.1 Concurrent Regulating Reserve and Energy Dispatches

If a pool participant receives an energy dispatch while providing regulating reserve, it must continue to fully provide the regulating reserve in accordance with Section 205.4. While the pool asset is ramping up or down to the new energy dispatch level, the pool asset should also continue to fully provide the regulating reserve; the high regulating reserve limit and the low regulating reserve limit move up and down accordingly while maintaining the regulating reserve range. The diagram below provides an example of expected behaviour.



A – Pool asset at initial energy dispatch (100MW) & RR dispatch (50MW).

B – Pool asset receives new energy dispatch (150MW).

B to C – Pool asset ramps up to new energy dispatch (150MW), full RR range provided while ramping, RR provided in accordance with Section 205.4 while ramping.

C – Pool asset at new energy dispatch (150MW) & RR dispatch (50MW).

6 Technical Requirements and Performance Standards

During normal automatic generation control operation, the AESO master controller issues MW set point signals that are representative of the real power level that the asset is required to ramp to. A set point signal to increase the real power level may follow a previous set point signal to increase the real power level, and similarly, a set point signal to reduce the real power level may follow a previous set point signal to reduce the real power level. MW set point signals may also include reversals, where a set point signal to increase the real power level follows a set point signal to reduce the real power level, or a set point signal to decrease the real power level follows a set point signal to increase real power level. The automatic generation control master controller may issue reversals as often as every four (4) seconds.

Section 205.4 sets out the requirements for a minimum ramp rate. There is no limit to the maximum ramp rate.

The coordinated response expectation stated in subsection 6(1)(c) of Section 205.4 mean that plants participating in automatic generation control must be designed such that governor control to off-frequency conditions is coordinated with any other controls at the plant (e.g., unit load controllers, plant load controllers, etc). The coordination is such that:

- non-governor control loops do not alter the natural MW response of the resource's governor;
- non-governor control loops can be adjusted by a change in the automatic generation control signal;
- the resource output will change due to the change in automatic generation control signal and still include the natural MW response of the resource's governor; and
- “actual” pool asset output equals automatic generation control signal + frequency response of the resource(s).

NERC's Reliability Guideline: Primary Frequency Control document outlines how this coordinated response can be achieved. The document can be found here:

http://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Primary_Frequency_Control_final.pdf

A pool asset that is under dispatch to provide regulating reserve is required to maintain its output within a tolerance of the latest automatic generation control signal in accordance with subsection 5(7) of Section 205.4. This tolerance is applied at the pool asset level. For example, when multiple regulating reserve resources within the same pool asset are providing regulating reserve at the same time, the tolerance applies to the pool asset as a whole and not to each resource individually.

7 Test Description

The pool asset providing regulating reserve is tested, in accordance with subsection 10 of Section 205.4, to determine whether it demonstrates an ability to ramp in response to automatic generation control master controller set point signals. The pool asset providing regulating reserve is made available to the system controller according to a pre-arranged schedule for at least an eight (8)-hour period. A general guideline for testing is set out in the regulating reserve test description below, and illustrated in Appendix 1. The regulating reserve test may be adjusted in real time as deemed necessary by the AESO based on system conditions and/or observed responses from the pool asset undergoing the test.

The regulating reserve test is conducted as follows:

a) the regulating reserve range for a pool asset providing regulating reserve is set at the maximum regulating reserve range the pool asset is capable of;

b) the pool asset providing regulating reserve is ramped to approximately the mid-point of the regulating reserve range and then the following tests are carried out;

   (i) ramp the real power of the pool asset providing regulating reserve to the high limit of the regulating reserve range, using automatic generation control signals;

   (ii) ramp the real power of the pool asset providing regulating reserve from the high limit down to the low limit of the regulating reserve range at the lower ramp rate, using automatic generation control signals;

   (iii) ramp the real power of the pool asset providing regulating reserve from the low limit back up to the high limit of the regulating reserve range at the raise ramp rate, using automatic generation control signals;

   (iv) ramp the real power of the pool asset providing regulating reserve down to about mid-point of its regulating reserve range at the lower ramp rate, using automatic generation control signals;

   (v) ramp up the real power of the pool asset providing regulating reserve by a real power value of approximately 1/10th of the regulating reserve range, using automatic generation control signals. Without delay, using automatic generation control signals, ramp down the real power of the pool asset providing regulating reserve by a real power value of approximately 1/10th of the regulating reserve range; and

   (vi) record the real power of the pool asset providing regulating reserve at the last target position for five (5) minutes and observe any drift.

c) the response of the pool asset providing regulating reserve is recorded and the following characteristics are observed:

   (i) delay to start response of the pool asset providing regulating reserve as measured from the start of a ramp sequence;

   (ii) overshoot or undershoot of the pool asset providing regulating reserve upon termination of a control sequence, as measured from the expected target point;

   (iii) ability of the pool asset providing regulating reserve to meet the minimum ramp rate; and

   (iv) stability of the pool asset providing regulating reserve at the end of each test ramp and at the conclusion of the test, measured as the drift from the desired target point.

If, throughout this test, the pool asset providing regulating reserve is able to operate within the regulating reserve range without manual intervention of the operator with respect to the pool asset providing regulating reserve, the pool asset has met the requirements of this test.

8 Appendices

Appendix 1 – *Test Sequence for Regulating Reserve*

Revision History

Posting Date	Description of Changes
2018-02-01	Revisions to align with amended Operating Reserve rules in effect as of February 1, 2018
2016-09-28	Administrative amendments
2014-12-23	Initial Release

Appendix 1 – Test Sequence for Regulating Reserve

The typical generating unit response, as shown in the curve below, demonstrates a different type of response at each of the indicated points. It is assumed that there are no energy market dispatches to the generating unit during the test time period.

A – represents the real power instability of the pool asset providing regulating reserve prior to the beginning of the test.

B – represents a delay of the real power in responding to the automatic generation control signal. This delay should not exceed twenty-eight seconds.

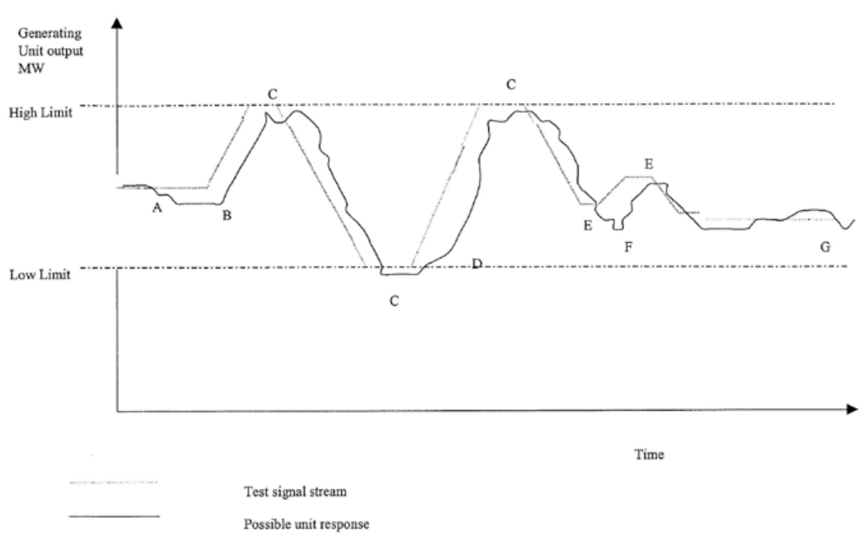
C – is a “settling out period” of no more than five minutes. This is a manual delay.

D – represents a situation in which the pool asset providing regulating reserve real power is not following automatic generation control signals. This would represent a case where the generating unit falls behind with respect to the automatic generation control signals.

E – is a delay of up to forty seconds, provided by the automatic generation control master controller, between ramps.

F – represents a situation of overshoot of the pool asset providing regulating reserve where real power exceeds the automatic generation control signals.

G – represents a situation of real power instability sometime after automatic generation control signals have stopped being received by the generating unit.



Information Document
Contingency Reserve
ID #2013-007R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 205.5 of the ISO rules, *Spinning Reserve Technical Requirements and Performance Standards* ("Section 205.5");
- Section 205.6 of the ISO rules, *Supplemental Reserve Technical Requirements and Performance Standards* ("Section 205.6"); and
- Alberta Reliability Standard BAL-002-WECC-AB1-2, *Contingency Reserves* ("BAL-002-WECC-AB1-2").

The purpose of this Information Document is to assist pool participants in understanding spinning reserve and supplemental reserve. This Information Document is likely of most interest to market participants who currently provide or may in the future provide supplemental reserve or spinning reserve.

2 What is Contingency Reserve?

Spinning and supplemental reserves (collectively referred to as contingency reserves) are used to restore the balance between the supply and demand for electricity following an unexpected event affecting the reliable operation of the interconnected electric system, such as the sudden loss of a generating unit or a disruption to one of the interties linking Alberta to a neighbouring jurisdiction. Contingency reserves provide capacity the AESO system controller can call on with short notice to correct any imbalance.

Spinning reserves are the fastest acting contingency reserve. Generators or loads providing spinning reserves are synchronized to the grid (the turbine is "spinning" but not generating power). This feature allows the reserve to be provided very quickly. In addition to responding quickly, spinning reserves also provide frequency support to the system. Supplemental reserve is similar to spinning reserve except that providers of supplemental reserve are not required to be synchronized to the grid and respond to frequency deviations.

These reserves can come from the supply side (generators increasing their output to the system) or from the demand side (load curtailment by reducing demand from large electrical consumers). Sufficient contingency reserve is required to reduce the area control error to zero, or to its pre-disturbance level, within fifteen minutes of a contingency. The Alberta balancing authority area is operated using reasonable best efforts to recover from any multiple supply contingency within fifteen minutes, with all available resources, including assistance from neighbouring balancing authority areas. In accordance with subsection 10(1) in Section 205.5 and subsection 6(1) of Section 205.6, real power must be delivered to the interconnected electric system within ten minutes of receiving a directive to provide the power to replace a loss of supply on the system.

3 Eligibility to Provide Contingency Reserve

Spinning and supplemental reserve may be provided by a pool asset with one or more resources that meet the eligibility criteria in subsection 3(1) of Section 205.5 and in subsection 3 of Section 205.6, respectively. A spinning reserve resource may be a single resource that individually meets the eligibility criteria in subsection 3(1) of Section 205.5, or an aggregate of resources controlled by a single governor or a governor system that collectively meet the eligibility criteria in subsection 3(1) of Section 205.5. A supplemental reserve resource may be a single resource that individually meets the eligibility criteria in

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

subsection 3 of Section 205.6, or an aggregate of resources that collectively meet the eligibility criteria in subsection 3 of Section 205.6. The pool asset must be qualified by the AESO to provide contingency reserve in accordance with subsection 4(1) of each rule.

Spinning reserve resources require a governor system that dynamically responds to a change in frequency to provide an automatic response. Under section 3(1)(b)(iii) of Section 205.5, in the case of synchronous generators, the maximum operating range of a spinning reserve resource is usually the difference of the maximum authorized real power (MARP) value and the minimum stable generation (MSG) value of the resource. In the case of battery storage system, the maximum operating range of a regulating reserve resource is the difference of (maximum authorize charging power plus maximum authorized discharging power) and (maximum authorized charging power or maximum authorized discharging power).

Market participants can apply to the AESO to provide contingency reserves by completing and submitting the application form on the AESO's website. In accordance with subsection 2(2) of Section 205.5 and Section 205.6, the AESO must receive a completed application before it can make any determination on resource eligibility and pool asset qualification.

4 Procurement

The AESO procures spinning reserve and supplemental reserve based on spinning reserve and supplemental reserve levels identified in the *7 Day Forecast of Operating Reserves Volumes* report located on the AESO website. The AESO's contingency reserve requirements are set out in Alberta reliability standards BAL-002-AB-1 and BAL-002-WECC-AB1-2.

The AESO normally procures spinning reserve and supplemental reserve through the Alberta Watt-Ex Exchange, operated by Watt-Ex, but may use other means under certain circumstances. The AESO may adjust the volume of contingency reserve in real-time based on actual system conditions. Refer to Information Document #2013-005R, *Operating Reserve*, for more information on procurement.

5 Dispatches and Directives

5.1 Dispatches

When the AESO issues a dispatch to a pool asset to provide supplemental reserve or spinning reserve, the dispatch is sent with one of the following acronyms to indicate the service type:

- SUPG – to identify a generating unit connected to the interconnected electric system that is supplying supplemental reserve;
- SUPL – to identify a load connected to the interconnected electric system that is supplying supplemental reserve; or
- SR – to identify any type of asset providing spinning reserve.

A pool asset that receives a dispatch to provide contingency reserve is required to move into a position such that the pool asset is capable of providing the real power set out in the dispatch within the tolerances set out in subsection 5(1) of Section 205.5 and Section 205.6. This tolerance is applied at the pool asset level. For example, when multiple spinning reserve resources within the same pool asset are providing spinning reserve at the same time, the tolerance applies to the pool asset as a whole and not to each resource individually.

5.2 Directives

In each contingency reserve directive, the AESO indicates the requested real power quantity, the remaining quantity of contingency reserve attributed to that pool asset and the time the directive was issued.

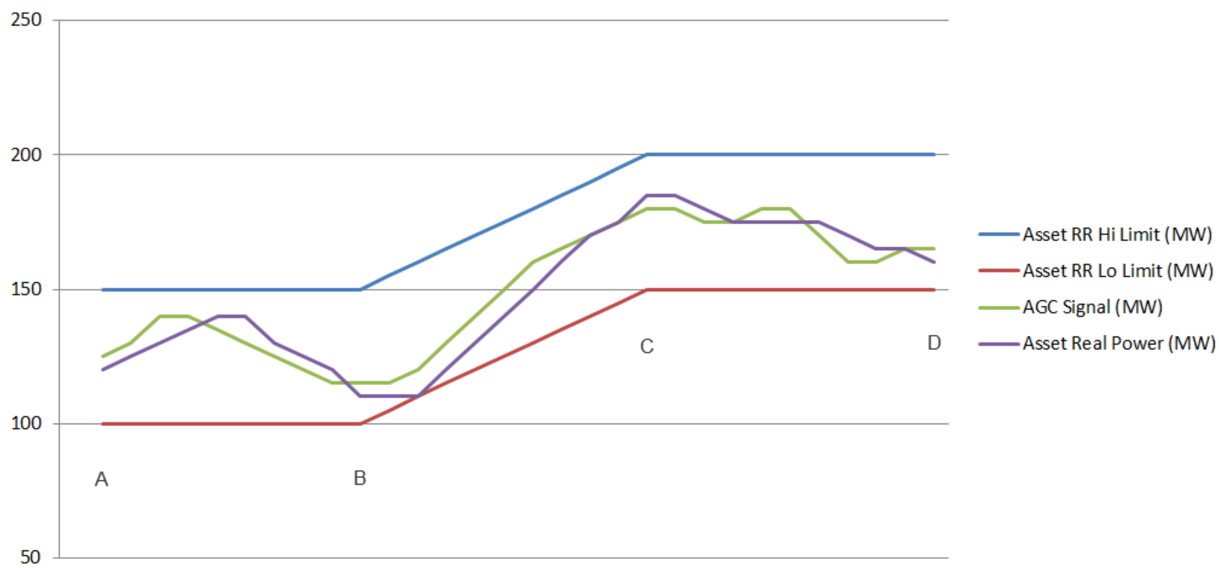
During an under frequency event, if a pool asset has already provided some or all of the requested real power quantity through the action of the governor system, that quantity may be subtracted from the requested real power quantity. Even if the frequency returns to normal, the total requested real power quantity must continue to be supplied in accordance with subsection 10 of Section 205.5 or subsection 6 of Section 205.6.

When a pool asset is providing both regulating reserve and contingency reserve (i.e. spinning reserve or supplemental reserve), and is subject to a directive for contingency reserve, the directive performance requirements outlined in subsection 10 of Section 205.5 or subsection 6 of Section 205.6 may be met in the following manner:

Some or all of the real power increase set out in the contingency reserve directive may be provided by:

- increasing the low and high limit values of the regulating reserve range above their instantaneous values at the time of the contingency reserve directive; and
- continuing to provide the full dispatched amount of regulating reserve in accordance with Section 205.4 of the ISO rules, *Regulating Reserve Technical Requirements and Performance Standards*.

In such a case, the increase in the low limit value is considered to be part or all of the real power increase required in subsection 10 of Section 205.5 or subsection 6 of Section 205.6.



A	Pool asset at energy dispatch (100MW), RR dispatch (50MW), contingency reserve dispatch (50MW).
B	Pool asset receives contingency reserve directive (50MW).
B to C	Pool asset ramps up to provide response to contingency reserve directive (50MW), full RR range provided while ramping, RR provided in accordance with Section 205.4 while ramping.
C	Pool asset at energy dispatch (100MW), RR dispatch (50MW), contingency reserve directive (50MW).

As an example, when a pool asset is comprised of two or more generating units, the real power increase set out in the contingency reserve directive may be provided through the cumulative response from those generating units not providing regulating reserve and adjustments, as described above, to generating units providing regulating reserve.

For all cases other than those contemplated by subsection 4 of Section 205.2, of the ISO rules, *Issuing Dispatches and Directives for Operating Reserve* when an asset with a current energy dispatch level receives a directive for contingency reserve, compliance with the combined energy dispatch and contingency reserve directive is assessed against the requirements in subsection 10 of Section 205.5 or subsection 6 of Section 205.6, as applicable. The AESO considers any real power provided pursuant to subsection 10(2) of Section 205.5 and subsection 6(2) of Section 205.6 that is in excess of the quantities set out in subsection 10(1) of Section 205.5 and subsection 6(1) of Section 205.6 to form part of a pool participant's response to the amount of real power set out in the directive.

While the provision of the required real power increase in response to a contingency directive is critical for the reliable operation of the interconnected electric system, the provision of real power in excess of the directed amount can also pose a risk to reliability. Contingency reserve providers are cautioned to keep this in mind when responding to a directive for contingency reserve.

6 Test Description

The pool asset providing contingency reserve may be tested in accordance with subsection 12 of Section 205.5 and subsection 8 of Section 205.6. The pool asset providing contingency reserve is made available to the AESO system controller according to a pre-arranged schedule for at least an eight hour period. A general guideline for testing is set out in the contingency reserve test description below, and illustrated in Appendices 1 through 3 of this Information Document. The contingency reserve test may be adjusted in real time, as deemed necessary by the AESO, based on system conditions and/or observed responses from the pool asset undergoing the test.

During the eight hour period, the AESO issues a dispatch to the spinning reserve or supplemental reserve provider. The pool asset providing spinning reserve or supplemental reserve must be in position, within fifteen minutes of receiving the dispatch, to provide the real power quantity as indicated in the dispatch, in accordance with subsection 5 of Sections 205.5 and 205.6. At some random times during the eight hour testing period, the AESO issues directives to reduce or increase the real power corresponding to the declared quantity of spinning reserve or supplemental reserve.

The response of the pool asset providing the spinning reserve or supplemental reserve is monitored for the following characteristics, which both the pool participant and the AESO record:

a) the initial real power of the pool asset providing spinning reserve or supplemental reserve at the dispatch time;

b) that the pool asset providing spinning reserve or supplemental reserve has positioned itself to provide supplemental reserve within fifteen minutes of the AESO dispatch;

c) the real power of the pool asset providing spinning reserve or supplemental reserve at the time of the directive;

d) the delay between the time of the AESO directive and the start of the real power response from the pool asset providing spinning reserve or supplemental reserve;

e) for a generating asset, that the maximum real power from the pool asset providing spinning reserve or supplemental reserve is delivered within ten minutes of the AESO directive; or

   for a load asset, that the real power is reduced by the pool asset providing spinning reserve or supplemental reserve within ten minutes of the AESO directive; and

f) the maximum and minimum real power from the pool asset providing spinning reserve or supplemental reserve during the ten to sixty minute time period following the AESO directive.

7 North West Power Pool Reserve Sharing Agreement

The North West Power Pool Reserve Sharing Agreement may be invoked in the event of both single and multiple contingencies. As a member of the North West Power Pool Reserve Sharing Agreement, the AESO is obligated to provide contingency reserve to another balancing authority if requested. The documentation for the North West Power Pool Reserve Sharing Program can be found on the North West Power Pool website at: www.nwpp.org.

8 Appendices

Appendix 1 – *Test Sequence for a Generator Pool Asset Supplying Spinning Reserve or Supplemental Reserve that is Synchronized to the Interconnected Electric System*

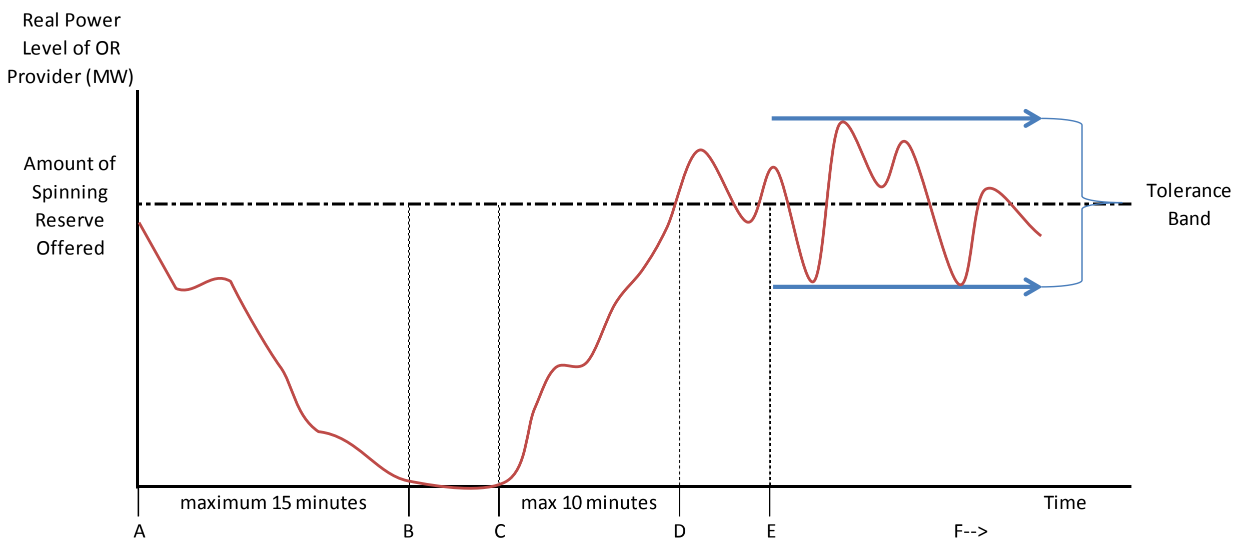
Appendix 2 – *Test Sequence for a Generator Pool Asset Supplying Supplemental Reserve that is Not Synchronized to the Interconnected Electric System*

Appendix 3 – *Test Sequence for a Load Pool Asset Supplying Supplemental or Spinning Reserve to the Interconnected Electric System*

Revision History

Posting Date	Description of Changes
2018-02-01	Revisions to align with amended Operating Reserve rules in effect as of February 1, 2018
2017-03-14	Section 5.2 amended
2017-02-09	Section 5.2 amended
2016-09-28	Administrative amendments
2014-12-23	Initial Release

Appendix 1 – Test Sequence for a Generator Pool Asset Supplying Spinning Reserve or Supplemental Reserve that is Synchronized to the Interconnected Electric System



This figure illustrates a possible response from a pool asset that is synchronized to the interconnected electric system and is providing either spinning reserve or supplemental reserve. It is assumed that there are no energy market dispatches during the test time period. The meaning of the labeled points is as follows:

A represents the real power of the pool asset providing spinning or supplemental reserve prior to the beginning of the test.

B represents the AESO's dispatch to the pool asset providing spinning or supplemental reserve volume. Within fifteen (15) minutes the spinning or supplemental reserve asset(s) should be at a real power level to provide the supplemental reserve volume requested by the AESO.

B to C at this point there may be up to an eight hour delay before the AESO issues a directive.

C to D the AESO issues a directive to deploy a volume of spinning or supplemental reserve. Within ten minutes of the AESO directive the pool asset providing spinning or supplemental reserve should be providing a quantity of real power equal to the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive.

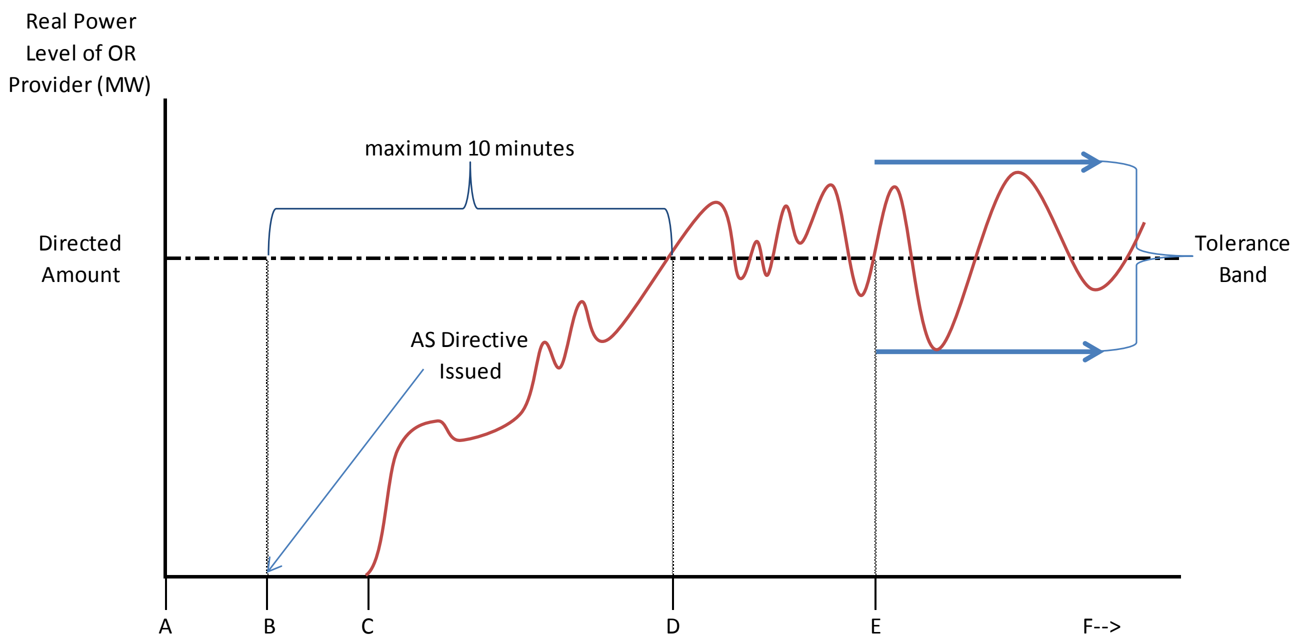
D to E represents the spinning or supplemental reserve asset(s) that, from the first time the spinning or supplemental reserve asset achieves this quantity to fifteen minutes after the time of the directive, maintains an average quantity of real power that is equal to or more than the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive.

E to F represents the spinning or supplemental reserve asset(s) that, for each consecutive ten minute interval starting fifteen minutes following the receipt of a directive, maintains an average quantity of real power that is equal to the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive, within a tolerance of:

(a) five MW for a load pool asset or a generating pool asset with a maximum capability of two hundred MW or less; or

(b) ten MW for a load pool asset or a generating pool asset with a maximum capability of greater than two hundred MW.

Appendix 2 – Test Sequence for a Generator Pool Asset Supplying Supplemental Reserve that is Not Synchronized to the Interconnected Electric System



This figure shows a possible response from a generator that is not synchronized to the interconnected electric system providing supplemental reserve. The meaning of the labeled points is as follows:

A — represents the off-line state of the asset providing supplemental reserve prior to the beginning of the test.

B to C — represents a delay in synchronizing to the interconnected electric system.

C to D — represents the supplemental reserve asset(s) ramping to deliver the volume of supplemental reserve directed by the AESO. Within ten minutes of the directive, the asset providing supplemental reserve should be providing a quantity of real power equal to the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive.

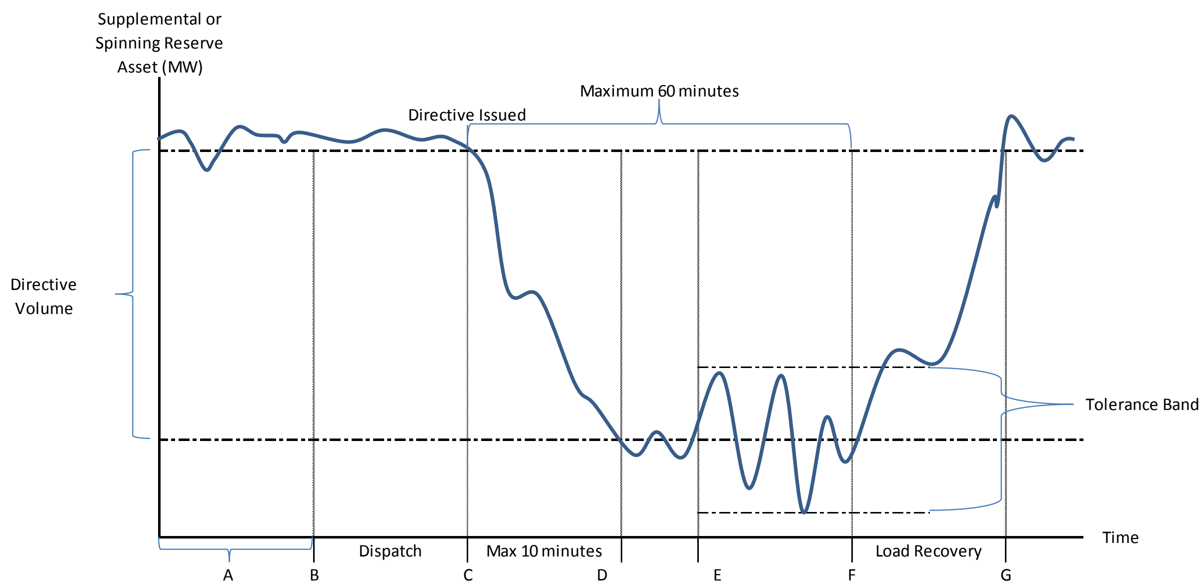
D to E — represents the supplemental reserve asset(s) that, from the first time the supplemental reserve asset achieves this quantity to fifteen minutes after the time of the directive, maintains an average quantity of real power that is equal to or more than the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive.

E to F — represents the supplemental reserve asset(s) that, for each consecutive ten minute interval starting fifteen minutes following the receipt of a directive, maintains an average quantity of real power that is equal to the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive, within a tolerance of:

(a) five MW for a load pool asset or a generating pool asset with a maximum capability of two hundred MW or less; or

(b) ten MW for a load pool asset or a generating pool asset with a maximum capability of greater than two hundred MW

Appendix 3 – Test Sequence for a Load Pool Asset Supplying Supplemental or Spinning Reserve to the Interconnected Electric System



This figure illustrates a possible response from a load pool asset that is providing either spinning reserve or supplemental reserve. The meaning of the labeled points is as follows:

A represents the real power of the supplemental or spinning reserve asset(s) prior to the beginning of the test.

B represents the dispatch by the AESO to the pool asset providing supplemental or spinning reserve volume. Within fifteen minutes the supplemental reserve asset(s) should be at a real power level to provide the supplemental reserve volume requested by the AESO.

B to C at this point there may be up to an eight hour delay before the AESO issues a directive.

C to D the AESO issues a directive to reduce the volume of supplemental or spinning reserve corresponding to the volume of the directive. Within ten minutes of the directive, the asset providing spinning or supplemental reserve should be providing a quantity of real power equal to the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive.

D to E represents the spinning or supplemental reserve asset(s) that, from the first time the spinning or supplemental reserve asset achieves this quantity to fifteen minutes after the time of the directive, maintains an average quantity of real power that is equal to or more than instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive.

E to F represents the spinning or supplemental reserve asset(s) that, for each consecutive ten minute interval starting fifteen minutes following the receipt of a directive, maintain an average quantity of real power that is equal to the instantaneous amount of real power of the pool asset at the time of the directive plus the amount of real power set out in the directive, within a tolerance of:

(a) five MW for a load pool asset or a generating pool asset with a maximum capability of two hundred MW or less; or

(b) ten MW for a load pool asset or a generating pool asset with a maximum capability of greater than two hundred MW.

F to G is the load recovery period. The AESO has cancelled the directive or the time has exceeded sixty minutes and the supplemental or spinning reserve asset(s) restores the real power output to the pre directive level.

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1 Purpose

This Information Document relates to the following Authoritative Document:[1] Section 302.1, *Real Time Transmission Constraint Management*. The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits in the South area of the Alberta interconnected electric system.

Section 302.1 sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the Alberta interconnected electric system. These steps are referenced in Table 1 of this Information Document as they are applied to the South area.

2 General

The transmission and generation facilities in the South area are shown in a geographical map in Appendix 2. For a schematic single line diagram of the South area, see Appendix 3.

Several remedial action schemes are in place in the South area to ensure system reliability. The remedial action schemes for the South area are listed in Appendix 4, with their locations labeled on the single line diagram located in Appendix 3.

3 Constraint Conditions and Limits

When managing a transmission constraint in the South area, the AESO ensures that transmission line flows out of the area are managed in accordance with transmission line ratings. These ratings are established by the legal owner of the transmission facility to protect transmission facilities, ensuring the continued reliable operation of the Alberta interconnected electric system. The existing remedial action schemes are designed to ensure line flows are managed to safely maintain emergency transmission line ratings.

The AESO monitors the remedial action schemes in the South to ensure that they are available when required. If a remedial action scheme is not available or partially inoperable, the AESO proactively curtails generation in anticipation of contingencies in order to ensure safe, reliable operation of the system. The remedial action schemes are outlined in Appendix 4.

The AESO uses wind power management tools to curtail during constraints. Wind power management does not apply to any wind aggregated facilities that have been constrained down for a local area constraint. Once the transmission constraint management directive is cancelled, wind power management is again applied to the asset.

3.1 *Non-Studied Constraints and Limits*

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities* Act and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

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For system conditions that have not been pre-studied, the AESO uses energy management system tools and dynamic stability tools to assess unstudied system operating limits in real time.

3.2 Studied Constraints and Limits

System studies have identified several specific transmission constraints in the South which have required the installation of appropriate remedial action schemes to take automatic action to manage the constraint. The identified constraints and the pool assets that are included in the specific remedial action schemes are shown in Appendix 4. The constraints can arise under abnormal operating conditions; however, constraints can also occur under normal operating conditions when there are high levels of wind production in addition to high British Columbia intertie flows. The constraints on transmission lines 786L, and on transmission line 225L at Spring Coulee can occur under normal operating conditions.

Loss of a 138 kV path (164L, 863L or 820L) could also result in a possibility of voltage collapse on the 69 kV system (N-1-1 contingency). When such a contingency occurs the AESO may be required to prepare the 69 kV system for the next contingency by proactively curtailing generation as required.

4 Application of Transmission Constraint Management Procedures

The AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of section 302.1 of the ISO rules. However, not all of those provisions are effective in the South area due to certain operating conditions that exist in that area. This Information Document represents the application of the general provisions of section 302.1 to the South area, and provides additional clarifying steps as required to effectively manage transmission constraints in that area before and after the activation of a remedial action scheme. The protocol steps which are effective in managing transmission constraints are outlined in Table 1 below.

Table 1

Transmission Constraint Management

Sequential Procedures for South Area

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Is the procedure applicable to the South area?
(a) Determine effective pool assets	Yes
(b) Ensure maximum capability not exceeded	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	Yes
(d) Curtail effective demand opportunity service on the downstream constraint side	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No

Applicable Protocol Steps

The first step in managing constraints is to identify those pool assets, both generating units and loads, which are effective in managing constraints. A list of those effective generating pool are identified in Appendix 1. As per subsection 2(4) of section 302.1, when a transmission constraint has been or is expected by the AESO to activate a remedial action scheme, the AESO recommences the procedural sequence in Table 1 (above) once the AESO has ensured that the system is operating in a safe and reliable mode.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Ensuring maximum capability levels are not exceeded is effective in managing South area transmission constraints. The effective pool assets that the AESO may curtail are listed in Appendix 1.

Step (c) in Table 1

There may be situations where curtailment of import flows is effective in managing a transmission constraint in the South area.

Step (d) in Table 1

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing South area constraints because there is no demand opportunity service in the area.

Step (e) in Table 1

With respect to steps (e)(i) and (ii), there are no transmission must-run contracts in the South area and using transmission must-run is not effective in managing a transmission constraint.

Step (f) in Table 1

Curtailing effective generating units in reverse energy market merit order followed by pro-rata curtailment is effective in managing South area transmission constraints. The effective pool assets that the AESO may curtail are listed in Appendix 1.

Step (g) in Table 1

Because of the configuration of the Alberta interconnected electrical system, curtailing load on the upstream side is not effective in managing South area constraints.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the South area that are known to have an impact on the information contained in this Information Document.

6 Appendices to this Information Document

Appendix 1 – *Effective Pool Assets*

Appendix 2 – *Geographical Map of the South Area*

Appendix 3 – *South Area Single Line Diagram*

Appendix 4 - Remedial *Action Schemes In Effect in South Alberta*

Revision History

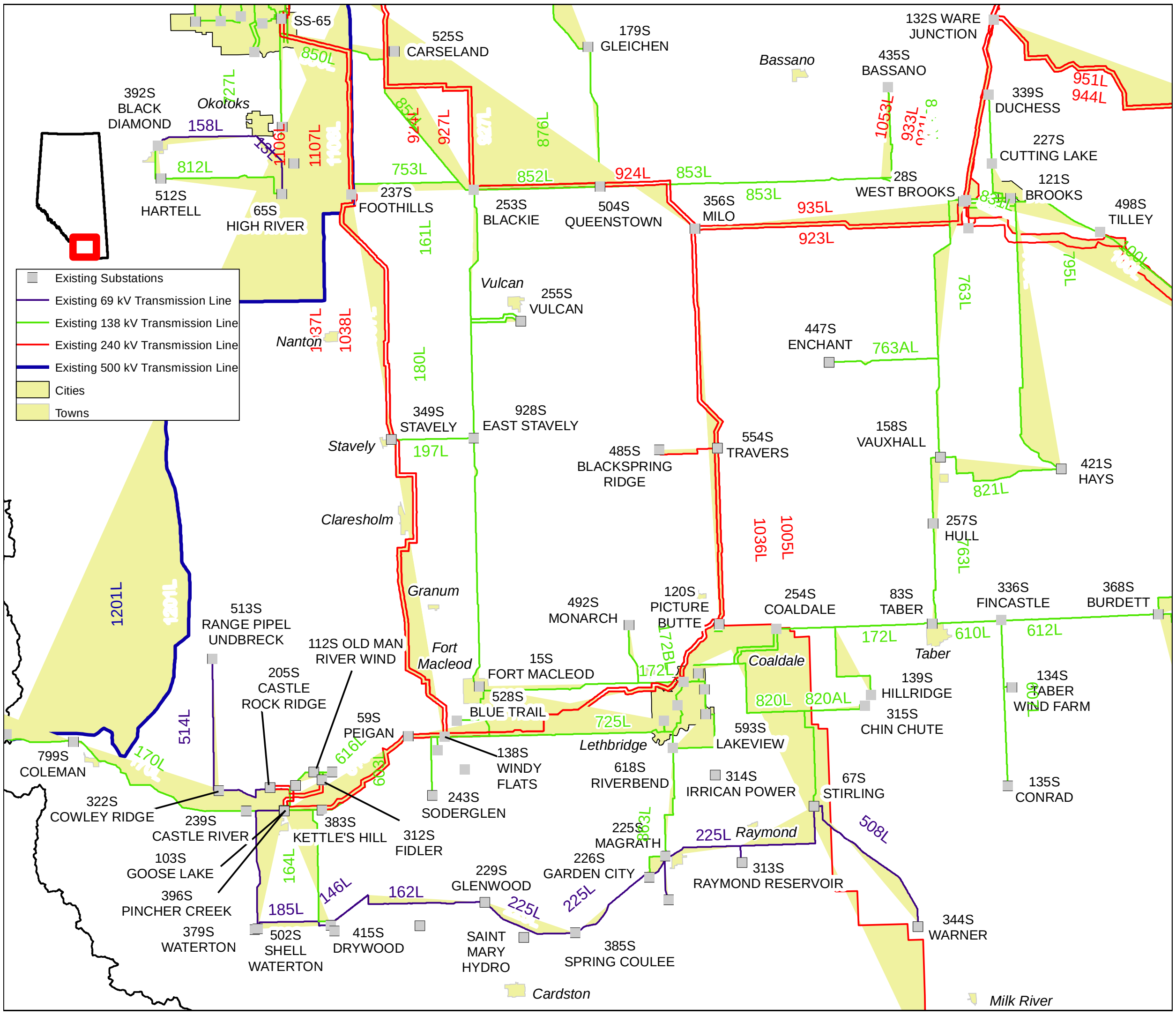
Version	Posting Date	Description of Changes
1.0	2014-02-27	Initial Release
2.0	2014-04-08	Appendix 1 through 3 amended to include pool asset BSR1
3.0	2014-05-29	Appendix 1 through 3 amended to include Old Man River Wind 112S (OWF1).
4.0	2014-06-26	Appendix 3 amended to include Fidler Substation with associated line amendments and Appendix 4 amended to renumber and add note concerning Remedial Action Scheme at 103S Goose Lake 893L .
5.0	2015-08-20	With energization of components of Southern Area Transmission Reinforcement (SATR) and Foothills Area Transmission Development (FATD), changes to the description of constraints and removal of four Remedial Action schemes.

Appendix 1 – Effective Pool Assets

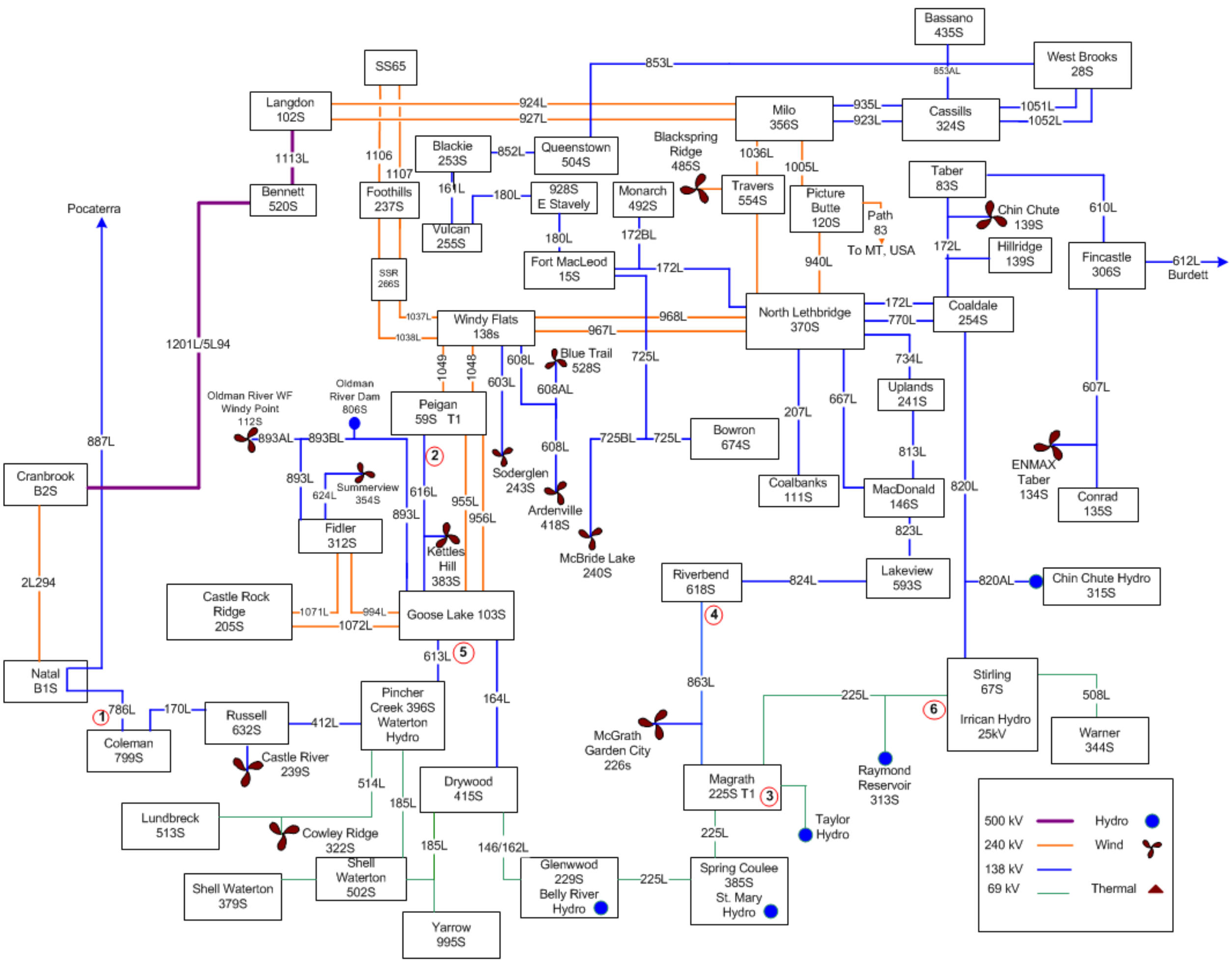
The effective pool assets for the South cutplane, listed alphabetically by their pool IDs, are:

AKE1
ARD1
BSR1
BTR1
CHIN
CR1
CRR1
CRWD
DRW1
GWW1
ICP1
IEW1
IEW2
KHW1
OMRH
OWF1
RYMD
TAB1
TAY1
SCR2
SCR3
STMY
WTRN

Appendix 2 – Geographical Map of the South Area



Appendix 3 – South Area Single Line Diagram



Note: 893L Goose Lake (103s) to Oldman River Dam (806s) is decommissioned but can be temporarily re-energized.

Appendix 4 – Remedial Action Schemes in South Alberta

#	Remedial Action Scheme Monitoring Point
1	At 799S Coleman **786L** (799S Coleman – BC Hydro Natal)
2	At 59S Peigan **616L** Terminal
3	Loss of the 225S Magrath transformer **T1**
4	At 225S Magrath or 618S Riverbend **863L**
5	At 103S Goose Lake 613L Terminal
6	At 67S Sterling 225L Terminal
7	At 28S West Brooks 853L Terminal (not represented in the map)

Information Document
Calgary Area Operations
ID 2014-001R

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1 Purpose

This Information Document relates to the following Authoritative Document:[1] section 302.1 of the ISO rules, *Real Time Transmission Constraint Management*. The purpose of this Information Document is to provide information on transmission must-run requirements in the Calgary Area, specifically as it relates to the provision of dynamic reactive reserve.

2 Background

In order to ensure reliability of the Alberta interconnected electric system, a minimum amount of dynamic reactive reserve is required in the Calgary Area, which is normally supplied by area generators and the Langdon static VAR compensator. If the minimum required dynamic reactive reserve is not available through normal energy market dispatches, then transmission-must-run dispatches or directives are issued to bring Calgary Area generating units online to provide dynamic reactive reserve.

3 Generating Plants in the Calgary Area

The generating units that provide dynamic reactive reserve in the Calgary Area are:

1. Calgary Energy Centre generating units;
2. Balzac generating units;
3. Cavalier generating units;
4. Carseland generating units; and
5. Bow Hydro generating units.

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[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for both market participants and the AESO. Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

5 Dynamic Reactive Reserve

Table 1 below outlines the minimum dynamic reactive reserve under various conditions.

Table 1 – Dynamic Reactive Reserve

<table>
<tr><th>Condition</th><th>Calgary Area Dynamic Reactive Reserve</th></tr>
<tr><td>Static VAR compensator is in service and the north to south flow south of Keephills-Ellerslie-Genesee cutplane flow is less than or equal to 1800 MW.</td><td>A minimum of 160 MVAr is provided by the static VAR compensator.</td></tr>
<tr><td>Static VAR compensator is in service and the north to south flow south of Keephills-Ellerslie-Genesee cutplane flow is between 1801 MW and 2150 MW.</td><td>A minimum of 160 MVAr is provided by the static VAR compensator and a minimum of 40 MVAr must be collectively provided by the Calgary Energy Centre generating units, the Balzac generating units, the Cavalier generating units, the Carseland generating units and the Bow Hydro generating units, for a total of 200 MVAr.</td></tr>
<tr><td>Static VAR compensator is out of service and the Calgary Energy Centre generating units are offline.</td><td>
<table>
<tr><th>Alberta Internal Load (MW)</th><th>Minimum Calgary Area Dynamic Reactive Reserve (MVAr)</th></tr>
<tr><td>9100 to 10000</td><td>140</td></tr>
<tr><td>8900 to 9099</td><td>140</td></tr>
<tr><td>8700 to 8899</td><td>140</td></tr>
<tr><td>8500 to 8699</td><td>140</td></tr>
<tr><td>8300 to 8499</td><td>120</td></tr>
<tr><td>8100 to 8299</td><td>80</td></tr>
<tr><td>8001 to 8099</td><td>40</td></tr>
<tr><td>0 to 8000</td><td>0</td></tr>
</table>
The MVAr requirements in the list directly above are provided by the Balzac generating units, the Cavalier generating units, the Carseland generating units and the Bow Hydro generating units.</td></tr>
</table>

Revision History

Posting Date	Description of Changes
2014-02-20	Initial Release

Information Document
FAC-501-WECC-AB2-1 R1 Identified Transmission Paths
ID #2014-002RS

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:[1]

- Alberta Reliability Standard FAC-501-WECC-AB2-1, *Transmission Maintenance* ("FAC-501-WECC-AB2-1").

The purpose of this Information Document is to provide a link to the list of transmission facilities associated with each of the transmission paths identified by the Alberta Electric System Operator ("AESO") for the purposes of requirement R1 of FAC-501-WECC-AB2-1, and to provide information on the AESO's procedures for amending this document.

2 Identified Transmission Paths

The list of transmission facilities associated with each of the transmission paths identified by the AESO for the purposes of requirement R1 of FAC-501-WECC-AB2-1, is available on the AESO website.

3 Amending Procedures

In order to amend the document entitled *Identified Transmission Facilities*, the AESO:

1. upon determining that amendments to the document are required, notifies the affected legal owner of a transmission facility prior to posting the amendment; and
2. posts the amended document on the AESO website.

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendment
2015-01-13	Initial Release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
System Operating Limits Methodology
ID #2014-003RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:[1]

- Alberta Reliability Standard *FAC-010-AB-2.1 System Operating Limits Methodology for the Planning Horizon* (“FAC-010-AB-2.1”).

The purpose of this Information Document is to provide a link to the system operating limits methodology referred to in requirement R1 of FAC-010-AB-2.1.

2 System Operating Limits Methodology

The System Operating Limits Methodology for the Planning Horizon the Alberta Electric System Operator (“AESO”) uses for any studies conducted on the interconnected electric system in the planning horizon for the purposes of requirement R1 of FAC-010-AB-2.1 is available on the AESO website.

This Information Document and the linked AESO System Operating Limits Methodology for the Planning Horizon document relate only to system operating limits studies conducted in the planning horizon, including generation and load connection studies. System operating limits studies conducted in the operating horizon are conducted pursuant to requirement R1 in *FAC-014-AB-2 Establish and Communicate System Operating Limits*, and are consistent with the *WECC Reliability Coordinator’s System Operating Limits Methodology for the Operations Horizon*.

Revision History

Posting Date	Description of Changes
2016-10-04	Administrative amendments
2014-09-04	Initial Release

[1] “Authoritative Documents” is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]:

(a) Section 302.1, *Real Time Transmission Constraint Management*.

The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits in the Calgary area of the Alberta interconnected electric system.

Section 302.1 of the ISO rules sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the Alberta interconnected electric system. These steps are referenced in Table 1 of this Information Document as they are applied to the Calgary area.

2 General

The Shepard cutplane is defined as the net to grid generation of the Shepard pool asset as measured across the generator transformer circuit breakers. To ensure the safe and reliable operation of the Alberta interconnected electric system, the AESO has established operating limits for the Shepard cutplane. For flow into the Calgary area greater than 250 MW, if the Shepard remedial action scheme is not available, an AESO real-time contingency analysis study determines the Shepard cutplane limit, ensuring the 138 kV system is protected.

The AESO has provided a geographical map of the Calgary area, indicating bulk transmission lines, in Appendix 2 of this Information Document. The AESO has also provided a schematic of the Shepard cutplane, including the pool assets effective in managing a transmission constraint, in Appendix 3 of this Information Document.

A cutplane is a common term used in engineering studies and is a theoretical boundary or plane crossing two (2) or more bulk transmission lines or electrical paths. The cumulative power flow across the cutplane is measured and can be utilized to determine flow limits that approximate conditions that would allow safe, reliable operation of the Alberta interconnected electric system.

3 Constraint Conditions and Limits

3.1 Non-Studied Constraints and Limits

For system conditions that have not been pre-studied, the AESO uses energy management system tools and dynamic stability tools to assess unstudied system operating limits in real time.

3.2 Studied Constraints and Limits

Constraints information during the Most Severe Single Contingency

In the Calgary area, the Shepard generating pool asset is connected to the Alberta interconnected electric system by a radial feed when two (2) of the three (3) 240 KV lines line are out of service (985L, 1003L or 1080L). When this situation occurs, the Shepard generating pool asset may be the most severe single

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

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www.aeso.ca www.poweringalberta.com

contingency.

The AESO has determined the maximum allowable most severe single contingency for the combined output of the Shepard generating pool asset through engineering studies. The maximum allowable combined output of the Shepard generating pool asset under these conditions is equal to the lesser of (a) 1,000 MW or (b) the British Columbia import total transfer capability, plus the Montana import total transfer capability, minus sixty-five (65), plus dispatched contingency reserve. When the Shepard generating pool asset becomes the most severe single contingency, the AESO adjusts the intertie import available transfer capability to ensure the safe and reliable operation of the Alberta interconnected electric system. The import available transfer capability of the combined Alberta-British Columbia and Alberta-Montana interconnection when the Shepard generating pool asset becomes the most severe single contingency is determined as follows:

1. If the Shepard total generation exceeds or is equal to the maximum allowable most severe single contingency for the combined output of the Shepard generating pool asset, then the intertie available transfer capability is set at zero (0).
2. If the Shepard total generation is less than maximum allowable most severe single contingency for the combined output of the Shepard generating pool asset, then the intertie available transfer capability is set at the maximum allowable contingency, minus the anticipated Shepard total generation.

Remedial Action Scheme

The Shepard remedial action scheme in the Calgary area is designed to protect the Enmax 138 KV system at SS-65. This remedial action scheme will shed Shepard pool asset generation upon the loss of both 985L and 1003L. For flow into the Calgary area greater than 250 MW, if the Shepard remedial action scheme is not available, then an AESO real-time contingency analysis study determines the Shepard cutplane limit, ensuring the 138 kV system is protected.

4 Application of Transmission Constraint Management Procedures

The AESO manages transmission constraints in all areas of Alberta in accordance with the provisions of section 302.1 of the ISO rules. However, not all of those provisions are effective on the Shepard cutplane due to certain unique operating conditions that exist in that area. This Information Document represents the application of the general provisions of section 302.1 to the Shepard cutplane, and provides additional clarifying steps as required to effectively manage transmission constraints in that area.

The protocol steps which are effective in managing transmission constraints are outlined in Table 1 below.

Table 1

Transmission Constraint Management

Sequential Procedures for Shepard Cutplane

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Is the procedure applicable to the Shepard cutplane?
(a) Determine effective pool assets	Yes
(b) Ensure maximum capability not exceeded	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No
(d) Curtail effective demand opportunity service on the downstream constraint side	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No

Applicable Protocol Steps

The first step in managing a transmission constraint is to identify those pool assets, both generating units and loads that are effective in mitigating the transmission constraint. A list of the generating pool assets that are effective in managing constraints are identified in Appendix 1.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Ensuring maximum capability levels are not exceeded is effective in managing Calgary area transmission constraints.

Step (c) in Table 1

There are no interties that impact the Shepard cutplane, and curtailing import and export flows elsewhere on the system is not effective in managing a transmission constraint.

Step (d) in Table 1

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing Calgary area constraints because there is no demand opportunity service in the area.

Step (e) in Table 1

With respect to steps (e)(i) and (ii), there are no transmission must-run contracts in the Calgary area and using transmission must-run is not effective in managing a transmission constraint in this area.

Step (f) in Table 1

Curtailing effective pool assets using reverse energy market merit order, followed by pro-rata curtailment, is effective in managing Calgary area transmission constraints.

Step (g) in Table 1

Downstream load curtailment is not effective in managing Calgary area transmission constraints, as curtailing downstream load does not directly lessen the flow across the cutplane, and available downstream generating pool assets can reasonably supply that load.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Calgary area that are known to have an impact on the information contained in this Information Document.

6 Appendices

Appendix 1 – Effective Pool Assets

Appendix 2 – Geographical Map of the Calgary Area

Appendix 3 – Single Line Drawing showing Calgary Area

Appendix 4 – Shepard Cutplane Operating Limits

Revision History

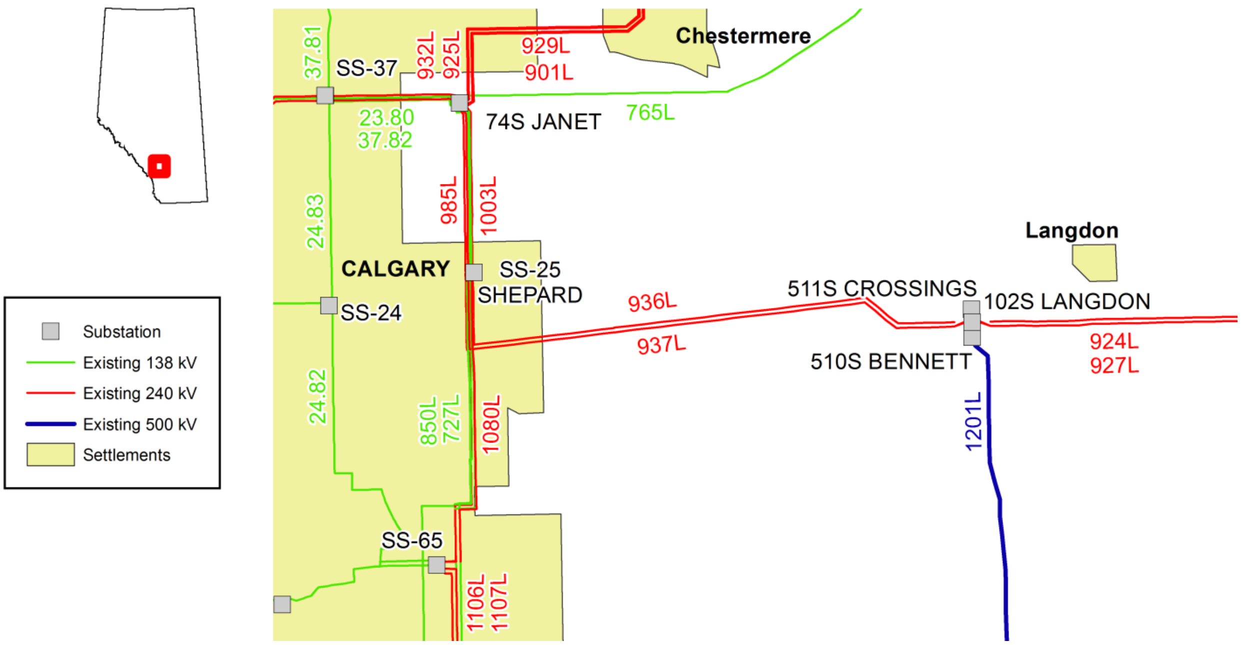
Version	Posting Date	Description of Changes
1.0	2015-01-15	Initial Release
2.0	2015-04-16	Revised note 3 in appendix 4 to clarify that the limits have been established based on a split 138 kV bus at SS-65.
3.0	2015-08-20	With energization of components of Foothills Area Transmission Development (FATD), maps updated to include new lines. Sections 2 and 3.2 revised to account for the possibility of RAS being unavailable and real-time contingency analysis being performed to determine limits.

Appendix 1 – Effective Pool Assets

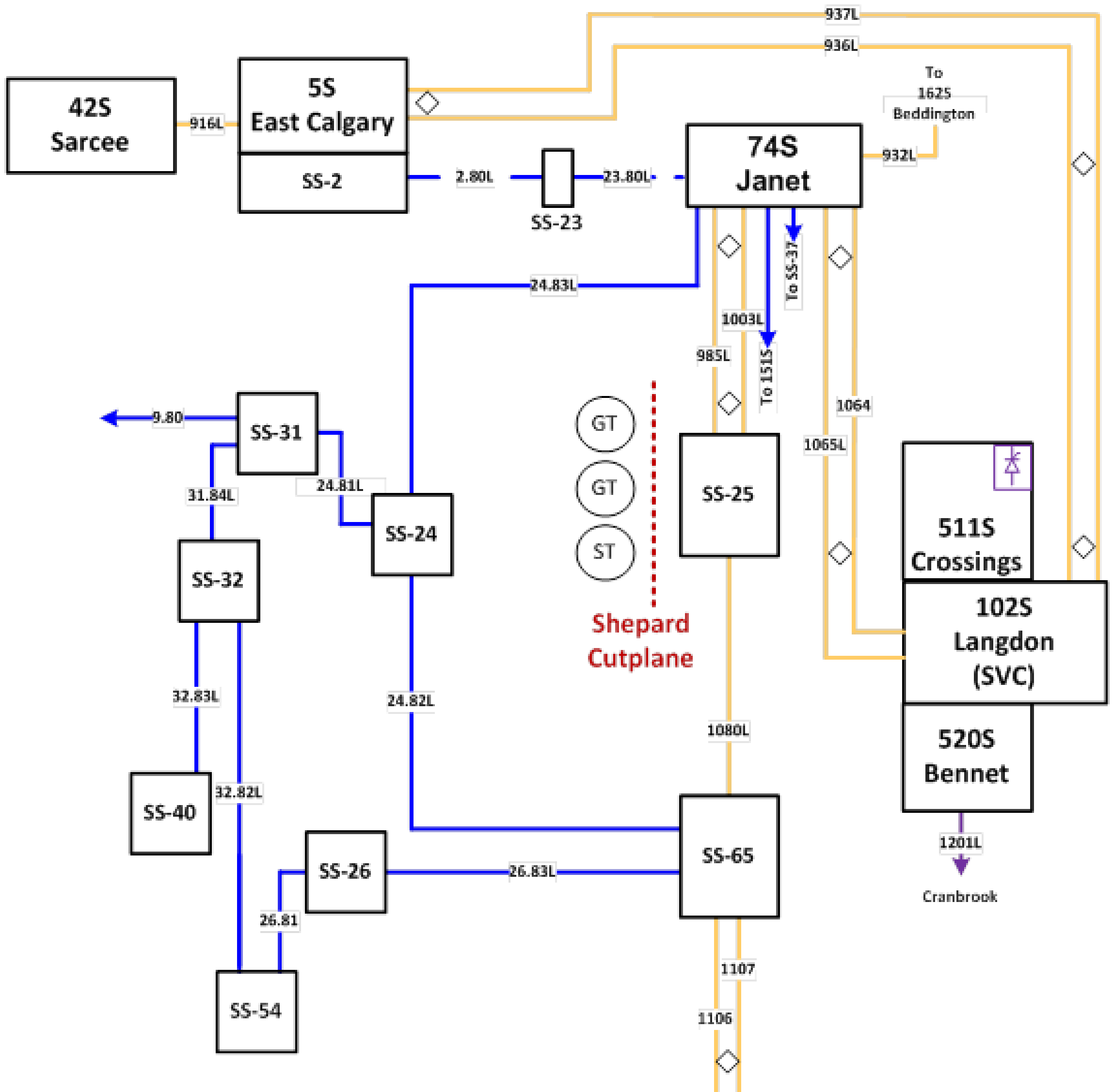
The effective pool assets for the Shepard cutplane, listed alphabetically by their pool IDs, are:

EGC1

Appendix 2 – Geographical Map of the Calgary Area



Appendix 3 – Single Line Drawing showing Calgary Area



Appendix 4 – Shepard Cutplane Operating Limits

If real time contingency analysis allows a higher or lower cutplane limit for the contingencies listed in the tables below, the AESO operates to that higher or lower limit.

<table>
<tr><th colspan="4">Shepard Cutplane Limits</th></tr>
<tr><td>N – 0
System Normal</td><td colspan="3">851</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td rowspan="2">N-1
Contingency</td><td colspan="2">1106L and 1107L flow <u>into</u> SS-65 ≤ 250MW[1]</td><td rowspan="2">Limiting Contingency</td></tr>
<tr><td>Summer
(May 1 – Oct. 31)</td><td>Winter
(Nov. 1 – April 30)</td></tr>
<tr><td>985L</td><td>670[3, 4]</td><td>750[3, 4]</td><td>1003L</td></tr>
<tr><td>1003L</td><td>670[3, 4]</td><td>750[3, 4]</td><td>985L</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>N-2
Contingency</td><td colspan="2"></td><td>Limiting Contingency</td></tr>
<tr><td>1080L and 985L</td><td colspan="2">The Shepard Cutplane limit is dependent on the real time most severe single contingency this ranges between 466 MW and 851 MW.</td><td>1003L[2]</td></tr>
<tr><td>1080L and 1003L</td><td colspan="2">The Shepard Cutplane limit is dependent on the real time most severe single contingency this ranges between 466 MW and 851 MW.</td><td>985L[2]</td></tr>
</table>

Note:

1. For 1106L and 1107L flow into SS-65 greater than 250 MW, the AESO real-time contingency analysis study determines the Shepard cutplane limit, ensuring the 138 kV system is protected.
2. For the simultaneous loss of 985L and 1003L, the Shepard N-2 remedial action scheme operates. After the operation of this remedial action scheme, the Shepard pool asset output on 1080L is not to exceed Alberta's most severe single contingency or the thermal limits for 1080L.
3. These limits have been established based on a split 138 kV bus at SS-65 to protect against thermal overload on 24.82L or 26.83L.
4. If an AESO real-time contingency analysis study determines either a higher or lower Shepard cutplane limit is warranted, then the AESO will operate to that higher or lower limit.

Information Document
Service Proposals and Cost Estimating
ID #2015-002R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 504.5 of the ISO rules, *Service Proposals and Cost Estimating* ("Section 504.5").

The purpose of this Information Document is to provide guidance on preparing service proposals and cost estimates for a transmission facility project. This Information Document will be of interest to the legal owner of a transmission facility ("TFO") that the AESO requests to provide a service proposal and/or a cost estimate for a transmission facility project.

2 Service Proposal

The service proposal provides an overview of the transmission facility project,[2] including:

- a project summary;
- an overview of the TFO's scope of work;
- a cost estimate; the planned schedule; and
- any assumptions and risks.

In accordance with subsections 2 and 3 of Section 504.5, the AESO may request that the TFO provide a service proposal, along with a service proposal cost estimate, within a specified time period. Typically, the AESO issues this request before directing the TFO to submit a transmission facility proposal ("facility application") to the Alberta Utilities Commission ("AUC" or "Commission") for approval. The service proposal is to be completed in accordance with the Service Proposal Guidelines in Appendix 1.[3]

For the purpose of preparing a needs identification document ("NID"), the AESO relies on information provided by the TFO in the service proposal to satisfy certain information requirements in AUC Rule 007, *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("AUC Rule 007"). Service proposals completed in accordance with the Service Proposal Guidelines in Appendix 1 generally provide the AESO with a sufficient level of detail to satisfy the applicable AUC Rule 007 information requirements.

3 Cost Estimate

To ensure that cost estimates prepared by TFOs are consistent, the AESO created a Cost Estimate Template, which is posted on the AESO website. The Cost Estimate Template is used for all classes of cost estimates set out in Table 1 below.

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[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

[2] For service proposals and cost estimates, the AESO will use "project" to refer to the proposed transmission development only. This differs from the use of the term "project" in relation to system access service requests where "project" includes both the proposed transmission development and any Rate STS, *Supply Transmission Service*, or Rate DTS, *Demand Transmission Service*, requests.

[3] See the definition of "service proposal" in the AESO's *Consolidated Authoritative Documents Glossary*.

Pursuant to subsection 9(1) of Section 504.5, a TFO is required to ensure that a cost estimate is "accurate, complete and in an appropriate level of detail". The term "accurate" in this regard means "free from material error". The term "complete" means that all applicable sections have been filled in, or that the TFO has provided reasons in the "Assumptions" column of the Cost Estimate Template in sufficient detail to explain why the information was not provided. The phrase "in an appropriate level of detail" means that the cost estimate should include a reasonable level of detail requested in the Cost Estimate Template.

3.1. Use of American Association of Cost Engineers Practices

The American Association of Cost Engineers ("AACE") is a non-profit association that provides cost management practices for various industries. The AESO adopted the AACE practices as a foundation for estimating the costs of transmission facility projects. The AESO has aligned Section 504.5 and the Cost Estimate Template with AACE practices. However, where AACE class level estimates are inconsistent with legislation or AUC rules, the legislation or AUC rules will govern.

AACE practices relating to cost management are available on the AACE website (https://web.aacei.org) to members free of charge and to non-members for a fee.

TABLE 1: AACE Class Level Estimates

AACE Class Level Estimate	Class 5	Class 4	Class 3	Class 2	Class 1
Project Definition	0% to 2%	1% to 15%	10% to 40%	30% to 75%	65% to 100%
Accuracy Range	L: -20% to -50% H: +30 to +100%	L: -15% to -30% H: +20 to +50%	L: -10% to -20% H: +10 to +30%	L: -5% to -15% H: +5 to +20%	L: -3% to -10% H: +3 to +15%
Industry Usage	Order of Magnitude (OOM)	Needs Identification Document Estimate	Service Proposal Estimate	Post Permit and License Estimate (180 days after permit and license)	Final Cost Estimate

3.1.1. Project Definition

For the purpose of Table 1, the project definition is a percentage of the total project deliverables that have been completed throughout the life of the project. Deliverables include project scope, requirements documents, specifications, project plans and schedules, drawings, learnings from past projects, calculations, and other necessary information to complete the project. The set of deliverables becomes more complete as the project progresses; therefore, the project definition has a correlation with the various AACE classes.

3.1.2. Class Levels

The AACE class level estimates are labeled Class 1, 2, 3, 4 and 5, to correspond with the levels of project definition. A Class 5 estimate is based on the lowest percentage of project definition and a Class 1 estimate is based on the highest percentage of project definition (see Table 1). AACE practices contain additional detail on the characteristics of each of the AACE classes.

3.1.3. Estimate Accuracy Ranges[4]

Estimate accuracy range is an expression of a cost estimate's predicted closeness to final costs for a given project. It is typically expressed as high/low percentages by which actual results may be over or under the estimate. As the project definition increases, the expected accuracy of the estimate tends to improve, as indicated by a narrower high/low accuracy ranges. The estimate accuracy is affected by the project definition and other systemic risks such as:

- complexity of the project;
- quality of reference cost estimating data;
- quality of assumptions used in preparing the estimate;
- experience and skill level of the estimator;
- level of non-familiar technology on the project;
- estimating techniques employed; and
- time and level of effort budgeted to prepare the estimate.

The accuracy range can also reflect unexpected or unknown changes in costs, unknown risks, and minor changes in the quality of the estimate for various project items that are not accounted for in the contingency (which accounts for known risks – see below in Section 3.1.4).

In accordance with subsection 3 of Section 504.5, the AESO may request the TFO to provide a class level estimate within a specified accuracy range, as shown in Table 1. The AESO retains the flexibility to request that a TFO provide a cost estimate in a narrower high/low accuracy range than the maximum upper and lower limits of the ranges in Table 1. This narrower accuracy range may be suitable for smaller, less complex projects.

3.1.4. Project Risk & Contingency[5]

The Cost Estimate Template includes a contingency / risk register that is to be used for the determination of the contingency allowance for a project.

Project contingency is an allowance added to a cost estimate for items, conditions or events where the state, occurrence or effect is uncertain and is likely to result in additional costs. At the early stages of a project, contingency may not be easily identifiable or is assumed, becoming more defined later in the project. Significant known risks are factored into the contingency calculation. As such, contingency is an allowance for "known" risks, while estimate accuracy range is an allowance for systemic or "unknown" risks.

Since risk generally decreases as the amount of work completed increases, the contingency amount included in the cost estimate will typically decrease as a project advances, and reduce to zero once the project is completed. The contingency allowance is not used as a source of funding for scope changes, which must be managed through the change proposal process.

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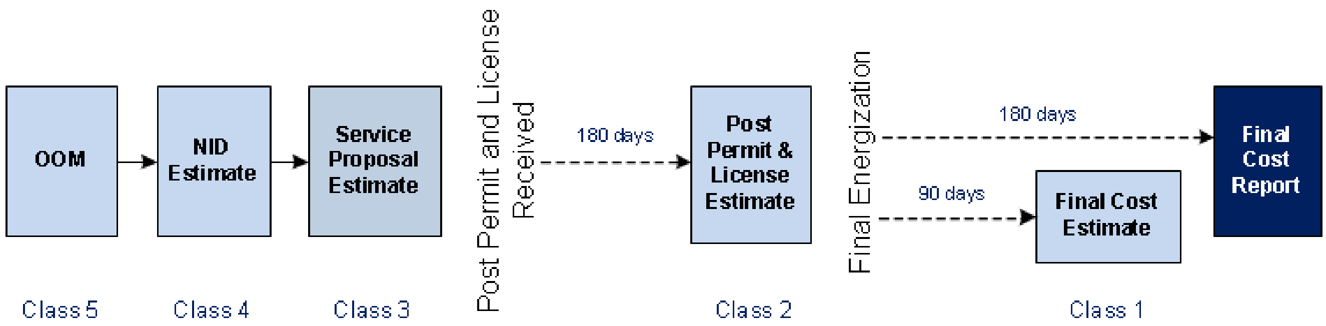
[4] AACE® International Recommended Practice No. 17R-97, Cost Estimate Classification System, TCM Framework: 7.3 – Cost Estimating and Budgeting, Rev. November 29, 2011, Page 2.

[5] AACE® International Recommended Practice No. 10S-90, Cost Engineering Terminology, TCM Framework: General Reference, Rev. November 14, 2014, Page 27.

3.2. Industry Usage Estimates

As illustrated below, class level estimates are prepared throughout the project life cycle:



3.2.1. Long Term Plan Estimate / System Access Service Request

In developing the transmission system plan, the AESO prepares and relies on high-level cost estimates, commonly referred to as order of magnitude cost estimates or Class 5 estimates, which are used to assess and screen transmission development alternatives during the planning stage.

In responding to system access service requests, a Class 5 estimate is required in Stage 2 of the AESO Connection Process.

3.2.2. Needs Identification Document Estimate

As the AESO advances the system development outlined in the long term transmission plan, the estimates are further refined and included in the NID filed with the Commission. A NID estimate or Class 4 estimate may be requested to screen alternatives.

As the AESO responds to system access service requests, the AESO may request Class 4 estimates to screen alternative(s).

3.2.3. Service Proposal Estimate

A Class 3 estimate is included with the service proposal provided to the AESO by the TFO. A summary of this same estimate is included with the facility application filed with the Commission.[6]

The Class 3 estimate is defined as the “original budget” in subsection 6 of Section 504.5 as it is considered the baseline estimate for the project against which cost performance will be measured and assessed.

[6] For combined filings, the AESO requests that Class 3 estimates align with TFO facility application requirements. AUC Rule 007 requires the AESO to provide Class 4 estimates, and the AESO requests such estimates for sequential filings.

3.2.4. Post-Permit and License Estimate

If the Commission approves a facility application, it grants permits and licenses to the TFO. After permit and license has been granted, a Class 2 estimate in accordance with subsection 7(1) of Section 504.5 may be required within 180 days after receipt of permits and licences, or as provided in the AESO's direction letter to the TFO.

3.2.5. Final Cost Estimate

After construction and energization of the transmission facilities, a Class 1 estimate in accordance with subsection 8(1) of Section 504.5 may be required within 90 days after final energization, or as provided in the AESO's direction letter to the TFO. The final cost estimate is a Class 1 estimate that includes actual costs and any remaining cost estimates for activities that are required to be completed before the project is closed.

4 Final Cost Report

Under subsection 10 of Section 504.5, the TFO provides the AESO with a final cost report within 180 days after final energization. The final cost report includes all final actual costs for the transmission project. If the 180 day time limit cannot be met, the TFO must apply for an extension, subject to the AESO's approval.

Revision History

2018-10-18	Administrative amendments
2018-06-26	Administrative amendments to subsection 3.2.2 and Appendix A, subsection 2.4
2017-11-09	Revisions to subsection 3.2.4 and subsection 3.2.5
	Addition of Service Proposal Guidelines as Appendix 1
2017-05-08	Addition of footnotes 2 and 3 for clarification.
	Administrative Amendments
2016-09-28	Administrative amendments
2016-04-29	Initial release

Appendix 1 – Service Proposal Guidelines (“Guidelines”)

A completed service proposal submitted to the AESO in accordance with subsection 2 of Section 504.5 is comprised of four parts:

- Main report
- Appendix A – Figures
- Appendix B – Cost Estimate
- Appendix C – Project Schedule

These Guidelines are organized as an annotated table of contents intended to provide instruction on the structure and content of the main report of the service proposal. Although these Guidelines are not a template, the AESO encourages TFOs to organize the main report by the following headings and subheadings.

1 Project Overview

The project overview section provides a brief summary of the project, including the scope, total capital cost estimate, and scheduled in-service date. This section also:

a) confirms that all parts of the service proposal meet the requirements outlined in the AESO’s direction letter, functional specifications, Authoritative Documents, and other technical requirements; or

b) provides a clear rationale for why these requirements are not applicable.

A bullet list or table may be used to present information about the project.

2 Scope of Work

The scope of work section includes sufficient information to:

a) discern units of measure;

b) demonstrate that the TFO’s proposed design meets the requirements described in the AESO’s functional specifications for the project; and

c) support the TFO’s cost estimate for the project.

This section is organized in a list or table under subheadings for each facility type, such as transmission lines, substations, and telecommunication facilities. Facility descriptions are drafted in a clear and comprehensive manner in the service proposal, however the TFO may find it useful to include additional details in the Cost Estimate Template.

If the proposal exceeds the AESO’s requirements, the scope of work section includes rationale for the additional equipment. Any additional information within the TFO’s knowledge that supports the project’s functional requirements or cost estimate may be included in this section.

2.1. Transmission Lines

Relevant information for transmission line equipment includes:

- Location, nominal voltage, line length, and list of any studies conducted by the TFO;
- Structure type;
- Conductor type, bundled, including overhead shield wire description;

- Meteorological, geotechnical and mechanical design parameters[7];
- Line impedance, surge impedance and charging;
- Basic insulation levels and current ratings, both seasonal continuous and emergency ratings for winter and summer;
- Special or unique engineering and design standards utilized for the project;
- Right-of-way survey and preparation, access right-of-way, clearance, brushing and environment impact mitigations (e.g., access matting);
- Line foundation work scope;
- Major line crossings, including rivers, highways and other lines;
- Mobilization and de-mobilization areas;
- Camp requirements;
- Laydown / storage yards; and
- Alternating current mitigation on pipeline.

2.2. Substations

Relevant information for substation equipment includes:

- Location of facility, size, configuration, major equipment additions complete with description(s) and list of any studies conducted by the TFO[8];
- Conceptual substation diagrams, including location, single line diagrams and bus layout drawings (see Appendix A for reference);
- Equipment descriptions with voltage, basic insulation levels, current ratings, quantity of current transformers and potential transformers where appropriate[9];
- An overview and proposed implementation of protection schemes and control schemes, including any remedial action schemes;
- Supervisory control and data acquisition (“SCADA”) and synchrophasor measurement unit;
- Special or unique engineering and design standards utilized for this project, as applicable;
- Site preparation, access and grading environment impact mitigations (e.g., access matting);
- Mobilization and de-mobilization areas;

[7] Meteorological, geotechnical and mechanical design parameters are based on the TFO’s knowledge at the service proposal stage. It is advisable to include data such as wind, snow, soil conditions and any special considerations for line design that affects the cost estimate.

[8] Typical studies conducted by a TFO for substations can include, but are not limited to: grounding; system protection coordination; insulation coordination; power quality and harmonic study. Additional studies may be required by the AESO, such as sizing of line shunt reactors.

[9] Current transformer and potential transformer locations must be shown on the single line diagrams.

- Camp requirements;
- Laydown / storage yards;
- Grounding requirements and design;
- Control and switchgear building description, including size, structure, and physical security;
- Alternating current station power supply and backup generator, if required; and
- Meter, including revenue meter.

2.3. Telecommunications Facilities

Relevant information for telecommunication facility equipment includes:

- Location, communication medium (e.g., fibre, microwave) and a list of studies conducted by the TFO;
- Description of the proposed development and equipment additions;
- Telecommunication tower height and type (e.g., guyed, self-support) if applicable;
- Quantity and type of radio equipment;
- Quantity and type of routers or multiplexers;
- Quantity of fiber and synchronous optical networking (“SONET”) equipment;
- Building description, including size, structure, and physical security;
- Battery or backup generator, if applicable; and
- Special or unique engineering and design standards utilized for this project, as applicable.

2.4. Salvaged Equipment

Salvaged equipment includes any equipment that will be discontinued from transmission service. Relevant information that pertains to salvaged equipment includes the TFO’s plan for the discontinued equipment (e.g., whether it will be refurbished, retired or stored) and how the costs of salvage will be paid.

2.5 Spatial and Technical Diagrams

The spatial and technical diagrams section provides a brief overview of the spatial and technical diagrams, which are attached as Appendix A to the service proposal. These diagrams include, but are not limited to:

- *Project Area Map*: provides a bird’s eye view map of the project area. The map should identify: the facilities that are being added as a part of the project; access routes; nearby infrastructure and geographic features; surrounding communities, First Nation reserves and Metis settlements; provincial and federal parks; and protected areas.
- *Conceptual Substation Single Line Diagram*: provides a single line diagram showing current transformers, potential transformers, and metering locations. The diagram indicates the facilities that are being added as a part of the transmission facility project.
- *Substation Layout*: shows the top view of substation(s).

- *Protection and Control and Metering Drawings*: shows the type of protection and installation locations of meters.
- *Telecommunication System Map*: shows the telecommunication facility proposed to meet the AESO's functional specification, Authoritative Documents and other technical requirements.

3 Cost Estimate

The cost estimate is a cost baseline that informs the AESO's NID and/or the TFO's facility proposal submitted to the Commission. The cost estimate follows the requirements of the functional specification, and takes into account all applicable AESO Authoritative Documents and technical standards. This section of the service proposal specifies the currency used to prepare the Cost Estimate Template (e.g., CAD, USD).

3.1. Cost Estimate Template

The cost estimate is prepared using the Cost Estimate Template and is attached as Appendix B to the service proposal. It is recommended that the file is named: **P[4-digit AESO project no.] Service Proposal Cost Estimate V1.xlxs**

The cost estimate considers the following:

- site visits, engineering, design and due diligence sufficient to achieve the accuracy range stipulated by the AESO;
- estimated costs broken down into system-related and participant-related costs as per the ISO tariff Section 8, as shown in the Cost Estimate Template;
- material and labour costs as available;
- escalation costs, including costs and calculations under Tab 8 of the Cost Estimate Template.
- the period of time for which the cost estimate is valid.

If the TFO is proposing exceptions to the scope of work described in the AESO functional specification, then the cost estimate includes:

- the rationale for each proposed exception; and
- a description of the incremental costs or savings resulting from each proposed exception.

3.2. Additional Work

Section 8 of the ISO tariff outlines the requirements that apply if the costs for proposed additional work (including operations and maintenance work) for a project are "deemed to be in excess of those required by the good electric industry practice".

Cost estimates and explanations for the proposed additional work are outlined in this section of the service proposal, not in the Cost Estimate Template. Along with estimated costs, the following information is included in this section:

- a description of the proposed additional work;
- a clear rationale for the proposed additional work, including any advantages related to carrying it out in conjunction with the project; and
- the timing of the proposed additional work relative to the project schedule (e.g., will capital maintenance be delayed to coincide with the project schedule?).

4 Project Schedule

The detailed project schedule is attached as Appendix C to the service proposal. The AESO prefers the detailed project schedule to be submitted in a table format (e.g., Excel). The schedule enables the AESO, the TFO and the customer to share a common timeline throughout the project life that is based on a single source.

The AESO normally provides the implementation schedule to the Commission. For combined filings, the AESO relies on the TFO to provide the implementation schedule in its facility application. The service proposal project schedule is, therefore, consistent with the project implementation schedule the TFO includes with its facility application.

The project schedule section of the service proposal contains a summary of the detailed project schedule, including:

- a list of the schedule and project milestones, where applicable, organized under subheadings for transmission lines, substation(s), and telecommunication facilities;
- the scheduled in-service date(s); and
- a description of construction limitations and constraints.

4.1. Transmission Line(s)

- *Engineering Schedule:* preliminary and detailed beginning and end dates.
- *Procurement Schedule:* beginning and end date for procurement of major equipment and miscellaneous materials (e.g., conductor, poles, insulators and hardware).
- *Construction Schedule:* beginning and end date for construction and installation of foundations, assembly, erections and stringing (including impacts of weather and environmental constraints).
- *Commissioning Schedule:* beginning and end date for commissioning activities, including required outages.

4.2. Substation(s)

- *Engineering Schedule:* preliminary and detailed beginning and end dates.
- *Procurement Schedule:* beginning and end date for procurement of major equipment (e.g., transformers, breakers, instrument transformers, capacitor banks, reactors, and steel) and miscellaneous materials (e.g., hardware, bus pipe and conductor).
- *Construction Schedule:* beginning and end date for construction and installation (including impacts of weather and environmental constraints) for: site preparation; foundations; assembly and erections; equipment installation; protection and controls; and functional checks.
- *Commissioning Schedule:* beginning and end date for commissioning activities, including required outages.

4.3. Telecommunication Facilities

- *Engineering Schedule:* preliminary and detailed beginning and end dates.
- *Procurement Schedule:* beginning and end date for procurement of major equipment (e.g., radios, multiplexers, and towers) and miscellaneous materials (e.g., hardware).

- *Construction Schedule:* beginning and end date for construction and installation (including the impacts of weather and environmental constraints) for: site preparation; foundations; assembly and erections; equipment installation; and functional checks.
- *Commissioning Schedule:* beginning and end date for commissioning activities, including required outages.

4.4. Scheduled In-Service Date

The scheduled in-service date is the date when the project is expected to be energized.

4.5. Construction Limitations and Constraints

The schedule includes potential limitations and constraints that might affect the in-service date, with regard for the environmental factors and assessments required by the Commission, including those listed below:

- *Construction window limitations:* description of no-construct periods.
- *Wildlife studies schedule:* preliminary and detailed beginning and end dates.
- *Schedule for any other required studies and approvals:* preliminary and detailed beginning and end dates.

5 Assumptions

This section lists the assumptions provided by the TFO in the Cost Estimate Template, including but not limited to the following:

- *Scope*: assumptions used to determine work scope and cost estimate.
- *Weather and Environmental*: assumptions about the weather and environment that impact the project scope or cost.
- *Operational Outages*: assumptions regarding outages for construction, line crossings and energization.
- *Allowances*: allowances for funds used during construction and/or construction work in progress.
- *Escalation*: assumptions that were used to calculate the estimated cost of escalation for the project, including: an itemized list of the project-related costs for which escalation was calculated; the annual escalation factor that was assumed for each itemized project-related cost; and the number of years of escalation that was applied for each itemized project-related cost.

6 Deviations from the Functional Specification

This section describes any deviations from the AESO's functional specification, and includes a brief description addressing the rational for each deviation.

7 Risk Management

The risk management section summarizes project-specific risks, including project delays, along with contingencies and mitigation for these risks.

8 Operation and Outages

The operation and outages section of the service proposal contains an outage schedule to identify significant planned outages or required outages, in addition to their duration and impact on other operational facilities, in the AESO planning area.

9 Approvals

The TFO signs and approves the completed service proposal before submitting it to the AESO.

Information Document
Guidance Information for CIP Standards
ID #2015-003RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) [1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

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

(collectively, the "CIP Standards").

The purpose of this Information Document is to provide information on the use of the North American Electric Reliability Corporation's ("NERC") Critical Infrastructure Protection ("CIP") Guidance Information, as published from time to time by NERC, in relation to the CIP Standards.

Note that the CIP Standards will become effective in accordance with the timelines set out in CIP-PLAN-AB-1.

2 Use of NERC Guidance Information for the CIP Standards

As with every Alberta reliability standard, each responsible entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements in the CIP Standards.

The AESO generally agrees with the information contained within the NERC CIP Guidance Information and recognizes that it may be a useful reference for market participants as they implement the CIP Standards. In addition, the AESO may use the NERC CIP Guidance Information as reference material in assessing compliance with the CIP Standards where it determines that the Guidance Information is applicable.

3 Clarification Regarding Industrial Complexes

3.1 Generating Unit that is part of an Industrial Complex

Subsection 4.2.2.3.1. of the CIP Standards refers to a generating unit that is:

"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;"

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

For clarity, the wording “unless the generating unit is part of an industrial complex” is intended to indicate that, if the generating unit is part of an industrial complex, the only applicable subsection is 4.2.2.3.3. In other words, if the generating unit is part of an industrial complex, then the CIP Standards apply if the industrial complex has supply transmission service greater than 67.5 MW, unless the generating unit is a contracted blackstart resource, in which case subsection 4.2.2.3.4. is applicable to that generating unit.

3.2 Generating Unit that is within a Power Plant that is part of an Industrial Complex

Subsection 4.2.2.3.2.3. of the CIP Standards refers to a generating unit that is:

> “has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;”

For clarity, the wording “unless the power plant is part of an industrial complex” is intended to indicate that, if the generating unit is within a power plant that is part of an industrial complex, the only applicable subsection is 4.2.2.3.3. In other words, if the generating unit is within a power plant that is part of an industrial complex, then the CIP Standards apply if the industrial complex has supply transmission service greater than 67.5 MW, unless the generating unit is a contracted blackstart resource, in which case subsection 4.2.2.3.4. is applicable to that generating unit.

3.3 Aggregated Generating Facility that is part of an Industrial Complex

Subsection 4.2.2.4.1. of the CIP Standards refers to 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;”

For clarity, the wording “unless the aggregated generating facility is part of an industrial complex” is intended to indicate that, if the aggregated generating facility is part of an industrial complex, the only available subsection is 4.2.2.4.2. In other words, if the aggregated generating facility is part of an industrial complex, then the CIP Standards apply if the industrial complex has supply transmission service greater than 67.5 MW, unless the aggregated generating facility is a contracted blackstart resource, in which case subsection 4.2.2.4.3. is applicable to that aggregated generating facility.

4 Clarification Regarding Applicability

For clarity, the wording “the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;” in subsection 4.1.3. of the CIP Standards is intended to indicate that the operator of a generating unit and the operator of an aggregated generating facility are each considered to be a “Responsible Entity”.

For clarity, the wording “the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;” in subsection 4.1.4. of the CIP Standards is intended to indicate that the legal owner of a generating unit and the legal owner of an aggregated generating facility are each considered to be a “Responsible Entity”.

5 Identify, Assess, and Correct

In this section, the requirement in a CIP Standard to “identify, assess and correct” is referred to as the “self-correcting” part of the requirement, and the underlying requirement is referred to as the “technical requirement”.

The AESO anticipates that the “identify, assess and correct” wording will be removed from the next version of the CIP Standards adopted in Alberta. Until such time, the AESO recommends that market participants identify, assess and correct deficiencies in meeting the technical parts of these requirements as follows:

(a) identify deficiencies by self-reporting contraventions to the Market Surveillance Administrator

("MSA"); and

(b) assess and correct deficiencies that are the same as the first identified deficiency through a mitigation plan submitted to the MSA as described in the MSA Compliance Process.

The following evidence may be used to demonstrate compliance with the self-correcting part of the requirement:

(a) evidence that the market participant is able to identify deficiencies in meeting the technical part of the requirement;

(b) records of each identified deficiency in meeting the technical part of the requirement;

(c) records of the result of an assessment made of each identified deficiency in meeting the technical part of the requirement;

(d) records of the mitigating actions made to correct each identified deficiency in meeting the technical part of the requirements; and

(e) evidence that each identified deficiency in meeting the technical part of the requirement was corrected.

If a market participant does not have evidence that it has complied with the self-correcting part of the requirement, self-reporting to the MSA would be appropriate.

Revision History

Posting Date	Description of Changes
2017-05-16	Addition of subsection 5
2017-05-04	Addition of subsections 3 and 4
2015-09-21	Initial publication

Information Document
Variance Requests Under CIP-SUPP-001-AB1
ID #2015-005RS

Information Documents are not authoritative. Information Documents are provided for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

(a) CIP-SUPP-001-AB1, *Cyber Security – Supplemental CIP Alberta Reliability Standard*

The purpose of this document is to: (1) provide information relating to Variance Requests under CIP-SUPP-001-AB1, including contact information; (2) describe the AESO's process for reviewing and determining variances requested under CIP-SUPP-001-AB1, and (3) provide a link to the AESO's Variance Request Report.

2 Contact Information

Variance requests under requirement R1 of CIP-SUPP-001-AB1 may be submitted by email to the AESO at RFI@aeso.ca.

3 Grounds of the Request

Requirement R1 specifies that the grounds in support of the variance request must not be frivolous or of little merit. Any application that would frustrate the purpose of the CIP ARS will be dismissed.

4 Material Impact on Reliability

In accordance with requirement R4, a variance granted under CIP-SUPP-001-AB1 must not have a material impact on the reliability of the Alberta interconnected electric system. The AESO expects variance requests to be very rare and that any Responsible Entities seeking a variance will have taken all steps (or be prepared to take all steps) necessary and appropriate to mitigate any reliability impacts associated with the variance.

In each case where a variance request is made, the AESO will undertake an assessment to identify and evaluate any and all impacts to the reliability of the system associated with the requested variance. Given that the AESO is responsible for the safety and reliability of the Alberta interconnected electric system, variances will only be granted in circumstances where the impacts to the reliability of the system as a whole are minimal, and where there are appropriate mitigation measures available to recover from any such impacts.

As the scope of Responsible Entities and the facilities (including their specific location on the system) in respect of which the Critical Infrastructure Alberta reliability standards ("CIP ARS") apply are broad, it would not be appropriate in this context to establish a one-size-fits-all materiality threshold.

5 Time for Processing of a Request

The AESO conducts an appropriate case-by-case assessment of the particular facts and circumstances of each variance request and therefore the processing times for each request will vary. The CIP ARS are new to Alberta, and the AESO's and market participant's experience with them is at an early stage.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

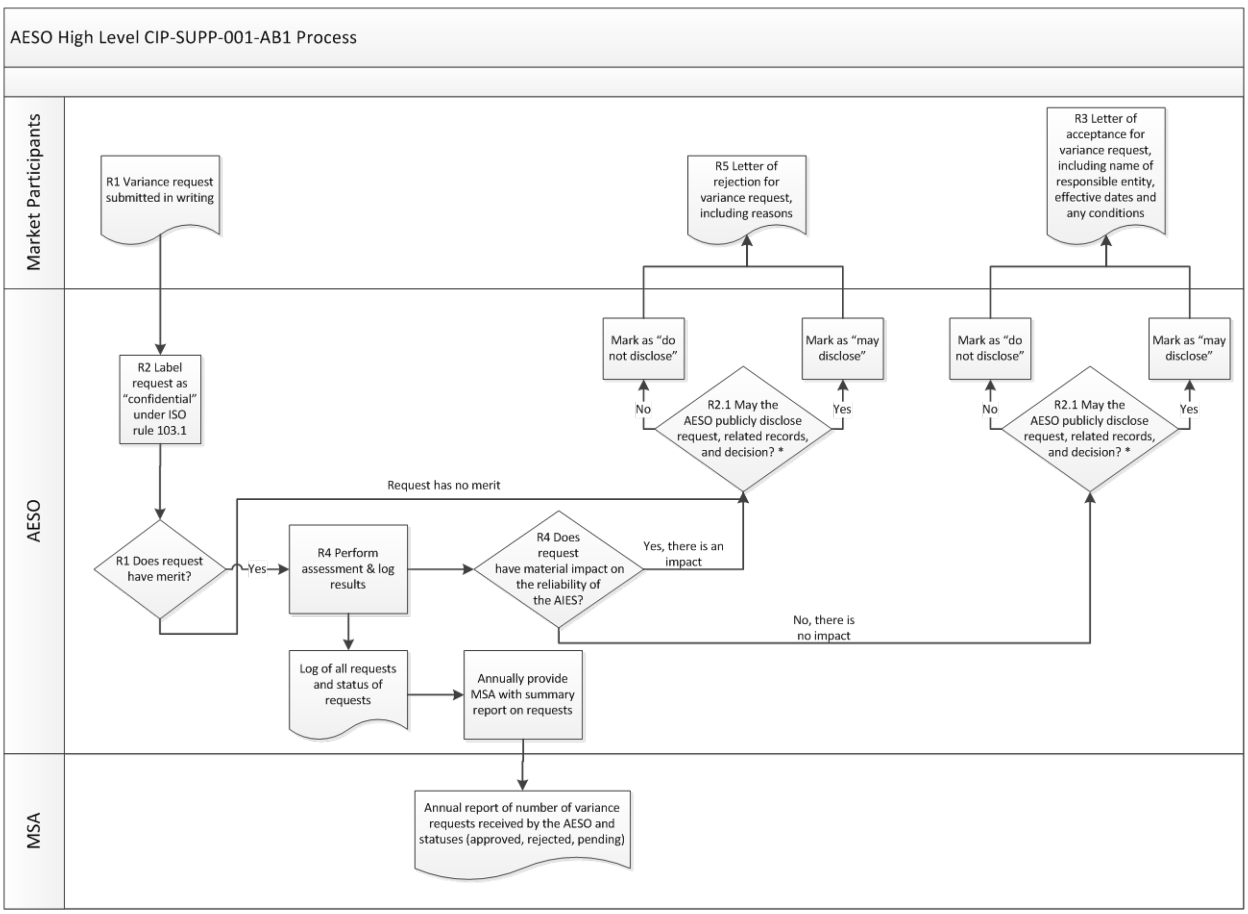
6 Variance Request Report

The AESO's variance request report will contain information regarding the number of variance requests received, accepted, rejected or pending in a calendar year. The report will be located on the AESO's website or by the following path: Rules, Standards and Tariff > Alberta Reliability Standards > CIP-SUPP-001 Cyber Security – Supplemental CIP Alberta Reliability Standard, and will be updated annually in January for the previous calendar year, beginning in January 2017.

7 Variance Process

Figure 1 below depicts the AESO's process for reviewing and considering variance requests:

Figure 1 – AESO Variance Process



* The AESO may disclose if the answer to both the following questions is no:
a) Would the disclosure of this request, records related to the request and variance granted have a material impact on the reliability of the AIES?
b) Are the request, records related to the request and variance granted commercially sensitive?

Revision History

Posting Date	Description of Changes
2017-03-21	Amendments to the ARS number, the website link and the AESO's email address.
2015-12-08	Initial Release

Information Document
Calculation of Pool Price and Transmission Constraint Rebalancing Costs During a Constraint Event
ID #2015-006R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents[1]:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1"); and
- Section 103.4 of the ISO Rules, *Power Pool Financial Settlement* ("Section 103.4").

The purpose of this Information Document is to provide information regarding the determination of pool price, the calculation of transmission constraint rebalancing payments and the display of information relating to the location and estimated cost of constraint events.

2 Inflow and Outflow Constraints

Transmission constraints are generally described as either inflow or outflow constraints.

- An inflow constraint occurs when there is insufficient in-merit generation in an area to reliably serve load, resulting in excess load in the area, and insufficient transmission capability to flow energy into the area to serve such load. In the case of an inflow constraint, the area containing excess load is considered to be located at the "downstream constraint side", and the area outside the area containing excess load is considered to be located at the "upstream constraint side".
- An outflow constraint occurs when there is insufficient transmission capability to permit all in-merit generators to deliver the full amount of their offered energy to the Alberta interconnected electric system. In the case of an outflow constraint, generators and, in some circumstances, importers are considered to be located at the "upstream constraint side", while loads are considered to be located at the "downstream constraint side".

This Information Document applies only to the mitigation of an outflow constraint, as the mitigation of an inflow constraint does not involve curtailing in-merit generation. Therefore, the mitigation of an inflow constraint does not result in transmission constraint rebalancing payments, which are described below, because dispatches or directives for transmission must-run energy from generating units located at the downstream constraint side are generally effective in mitigating an inflow constraint. Any potential impact associated with the dispatch of out-of-merit energy by way of a dispatch or directive for transmission must-run energy is offset through the use of dispatch down service.

3 Determination of Pool Price

The pool price is the single clearing price of energy in the Alberta electricity market, which reflects the intersection of the unconstrained supply and demand curves. When there are no constraints, the AESO dispatches up the energy market merit order to ensure supply-demand balance. The highest asset marginal price at the point of balance during a given minute determines the system marginal price upon which the AESO sets the pool price in accordance with subsection 4 of Section 201.6 of the ISO rules, *Pricing* ("Section 201.6"). As there is no curtailed generation and no transmission constraint rebalancing, the AESO sets the pool price based on the unconstrained system marginal price.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

In order to ensure supply-demand balance is maintained during an outflow constraint event in which in-merit energy is curtailed to mitigate a constraint, the AESO dispatches up the constrained energy market merit order, with constrained units removed, in accordance with subsection 2 of Section 203.2 of the ISO rules, *Issuing Dispatches for Energy*. The AESO IT system identifies the constrained system marginal price, which is the highest asset marginal price at the point where there is supply-demand balance in a one minute period. The AESO IT system then determines the following information in order to calculate a transmission constraint rebalancing volume for each minute during the constraint event:

- The volume of in-merit energy which has been constrained down;
- For the first hour in which there is a constraint event, the volume of the import interchange transactions that have been reduced due to an intra-Alberta constraint. During subsequent hours, a new schedule is implemented to reflect reduced available transfer capability and the constrained down import volume is considered to be zero; and
- The amount of transmission must-run energy dispatched when the system marginal price is less than or equal to the reference price.[2]

The transmission constraint rebalancing volume is then applied to an energy market merit order containing all supply resources, regardless of constraint conditions. The AESO IT system starts at the point in the unconstrained merit order where there is supply-demand balance, and moves down the unconstrained merit order by a volume equal to the transmission constraint rebalancing volume calculated above. By doing so, the AESO IT system determines what the system marginal price would have been if the constraint event(s) had not occurred. These are the unconstrained system marginal price values upon which pool price is set in accordance with subsection 4 of Section 201.6.

Note that transmission must-run energy dispatched in accordance with subsection 2(2)(b) of Section 302.1 may offset some or all of the volume of in-merit energy which has been constrained down, decreasing the transmission constraint rebalancing volume. The AESO dispatches other generating units off by an amount equal to the transmission must-run dispatch volume in order to balance supply and demand.[3] Therefore, where transmission must-run is dispatched instead of transmission constraint rebalancing, pool price is determined based on the unconstrained system marginal price values.

4 Calculation of Transmission Constraint Rebalancing Payments

When the AESO dispatches up the energy market merit order in order to replace in-merit generation that has been curtailed due to a constraint, those generators with offers located above the unconstrained price are eligible to receive a transmission constraint rebalancing payment determined in accordance with Section 103.4. The AESO IT system determines the energy production volume of each block of energy priced between the constrained system marginal price and the unconstrained system marginal price and multiplies that volume by the difference between the unconstrained pool price and the offer price associated with the MW level of energy provided by that eligible offer block in order to determine the amount of the transmission constraint rebalancing payment.

5 Display of Real Time Information Relating to the Location and Estimated Cost of Constraint Events

Information regarding the location and estimated cost of constraint events is displayed on the AESO website once hourly pool price has been posted. Regions are as indicated by color in the map included in Appendix 1.

The following information will be displayed on the AESO website:

(a) the estimated cost of constraints;

[2] The reference price is calculated in accordance with subsection 5 of Section 201.6.
[3] Note that dispatch down service is not dispatched when the volume of in-merit energy that has been constrained down is equal to or greater than the volume of dispatched transmission must-run energy.

(b) the estimated TCR charge; and

(c) the location of constraints

(collectively referred to as the "real time information") .

The real time information will be displayed on the AESO website Trading Page in the form of an *Estimated Cost of Constraint Report*. See the example in Appendix 2. Historical information will be available via a historical report query.

6 Appendices

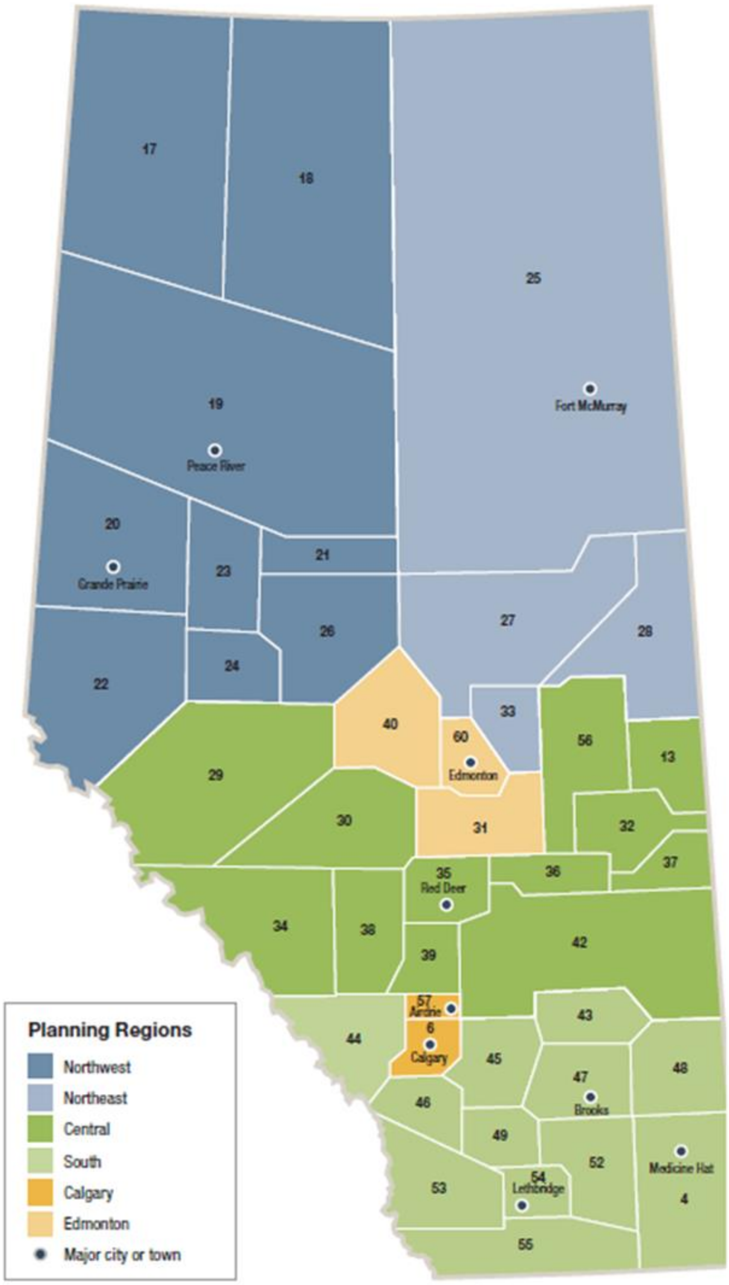
Appendix 1 – Map Indicating Geographic Areas

Appendix 2 – Example Estimated Cost of Constraint Report

Revision History

Posting Date	Description of Changes
2016-09-28	Administrative amendment
2015-11-26	Addition of information in sections 2, 3 and 4 and Appendices.
2015-11-04	Initial Release.

Appendix 1 – Map Indicating Geographic Regions



AESO transmission planning areas

NUMERICAL

4 Medicine Hat
6 Calgary
13 Lloydminster
17 Rainbow Lake
18 High Level
19 Peace River
20 Grande Prairie
21 High Prairie
22 Grande Cache
23 Valleyview
24 Fox Creek
25 Fort McMurray
26 Swan Hills
27 Athabasca/Lac La Biche
28 Cold Lake
29 Hinton/Edson
30 Drayton Valley
31 Wetaskiwin
32 Wainwright
33 Fort Saskatchewan
34 Abraham Lake
35 Red Deer
36 Alliance/Battle River
37 Provost
38 Caroline
39 Didsbury
40 Wabamun
42 Hanna
43 Sheerness
44 Seebe
45 Strathmore/Blackie
46 High River
47 Brooks
48 Empress
49 Stavely
52 Vauxhall
53 Fort Macleod
54 Lethbridge
55 Glenwood
56 Vegreville
57 Airdrie
60 Edmonton

ALPHABETICAL

34 Abraham Lake
57 Airdrie
36 Alliance/Battle River
27 Athabasca/Lac La Biche
47 Brooks
6 Calgary
38 Caroline
28 Cold Lake
39 Didsbury
30 Drayton Valley
60 Edmonton
48 Empress
53 Fort Macleod
25 Fort McMurray
33 Fort Saskatchewan
24 Fox Creek
55 Glenwood
22 Grande Cache
20 Grande Prairie
42 Hanna
21 High Prairie
18 High Level
46 High River
29 Hinton/Edson
54 Lethbridge
13 Lloydminster
4 Medicine Hat
19 Peace River
37 Provost
17 Rainbow Lake
35 Red Deer
44 Seebe
43 Sheerness
49 Stavely
45 Strathmore/Blackie
26 Swan Hills
23 Valleyview
52 Vauxhall
56 Vegreville
40 Wabamun
32 Wainwright
31 Wetaskiwin

Appendix 2 – Example Estimated Cost of Constraint Report

Date (HE)	Estimated Cost ($)	Estimated TCR Charge ($/MWh)	Location of Constraints
01/01/9999 15	-	-	-
01/01/9999 14	0.00	0.00	-
01/01/9999 13	353.48	0.05	Region Name
01/01/9999 12	0.00	0.00	-
01/01/9999 11	3.87	0.00	Region Name
01/01/9999 10	1.15	0.00	Region Name
01/01/9999 09	1.51	0.00	Region Name
01/01/9999 08	0.00	0.00	-
01/01/9999 07	0.00	0.00	-
01/01/9999 06	0.00	0.00	-
01/01/9999 05	0.00	0.00	-
01/01/9999 04	0.00	0.00	-
01/01/9999 03	20.00	0.00	Region Name
01/01/9999 02	0.00	0.00	-
01/01/9999 01	0.00	0.00	-
01/02/9999 24	0.00	0.00	-
01/02/9999 23	0.00	0.00	-
01/02/9999 22	0.00	0.00	-
01/02/9999 21	0.00	0.00	-
01/02/9999 20	0.00	0.00	-
01/02/9999 19	0.00	0.00	-
01/02/9999 18	0.00	0.00	-
01/02/9999 17	0.00	0.00	-
01/02/9999 16	579.42	0.08	Region Name

Information Document
Battery Energy Storage Facility Technical and Operating Requirements
ID #2016-001R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 502.13 of the ISO rules, *Battery Energy Storage Facility Technical Requirements* ("Section 502.13"); and
- Section 502.14 of the ISO rules, *Battery Energy Storage Facility Operating Requirements* ("Section 502.14").

The purpose of this Information Document is to provide additional guidance that may be of interest to the legal owners and operators of battery energy storage facilities in Alberta.

2 Background

Section 502.13 sets out the minimum technical requirements for a battery energy storage facility connecting to the transmission system.

Section 502.14 sets out the requirements for a legal owner and operator of a battery energy storage facility to operate the battery energy storage facility, and to notify the AESO and mitigate any issues in the event of component failure. Section 502.14 also contains the ongoing testing requirements associated with a battery energy storage facility.

3 Battery Energy Storage Facility Technical Requirements

Section 502.13 requires the legal owner of the battery energy storage facility to determine various parameters associated with the facility, including, but not limited to, voltages, maximum authorized charging power and maximum authorized discharging power. During the connection process of a project for a battery energy storage facility, the AESO may request these parameters and other information from the legal owner for use in the connection process, including preparing the functional specification and studies.

3.1 Maximum Authorized Charging Power, Maximum Authorized Discharging Power and Reactive Power Requirements

The examples below relate to subsections 3 and 4 of Section 502.13, and are intended to provide guidance on the relationship between the maximum authorized discharging power, maximum authorized charging power and reactive power requirements for a battery energy storage facility.

Example 1: Where the legal owner of a battery energy storage facility has determined that the facility will have a maximum authorized charging power and maximum authorized discharging power of 100 MW, the following reactive power capabilities for the battery energy storage facility would meet the minimum reactive power requirements under subsection 5 of Section 502.13:

(a) over-excited reactive power obligation (0.90 power factor) = 48.4 MVAr;

(b) under-excited reactive power obligation (0.95 power factor) = 32.9 MVAr; and

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

(c) MVA rating at this value = 111.1 MVA.

Example 2: Some battery energy storage facilities may have a lower maximum authorized charging power rate when compared to the maximum authorized discharging power rate for the facility.

Where the legal owner of a battery energy storage facility has determined that the facility will have a maximum authorized charging power of 40 MW, while still having a maximum authorized discharging power of 100 MW, the following reactive power capabilities for the battery energy storage facility would meet the minimum reactive power requirements under subsection 4 of Section 502.13, while charging the facility:

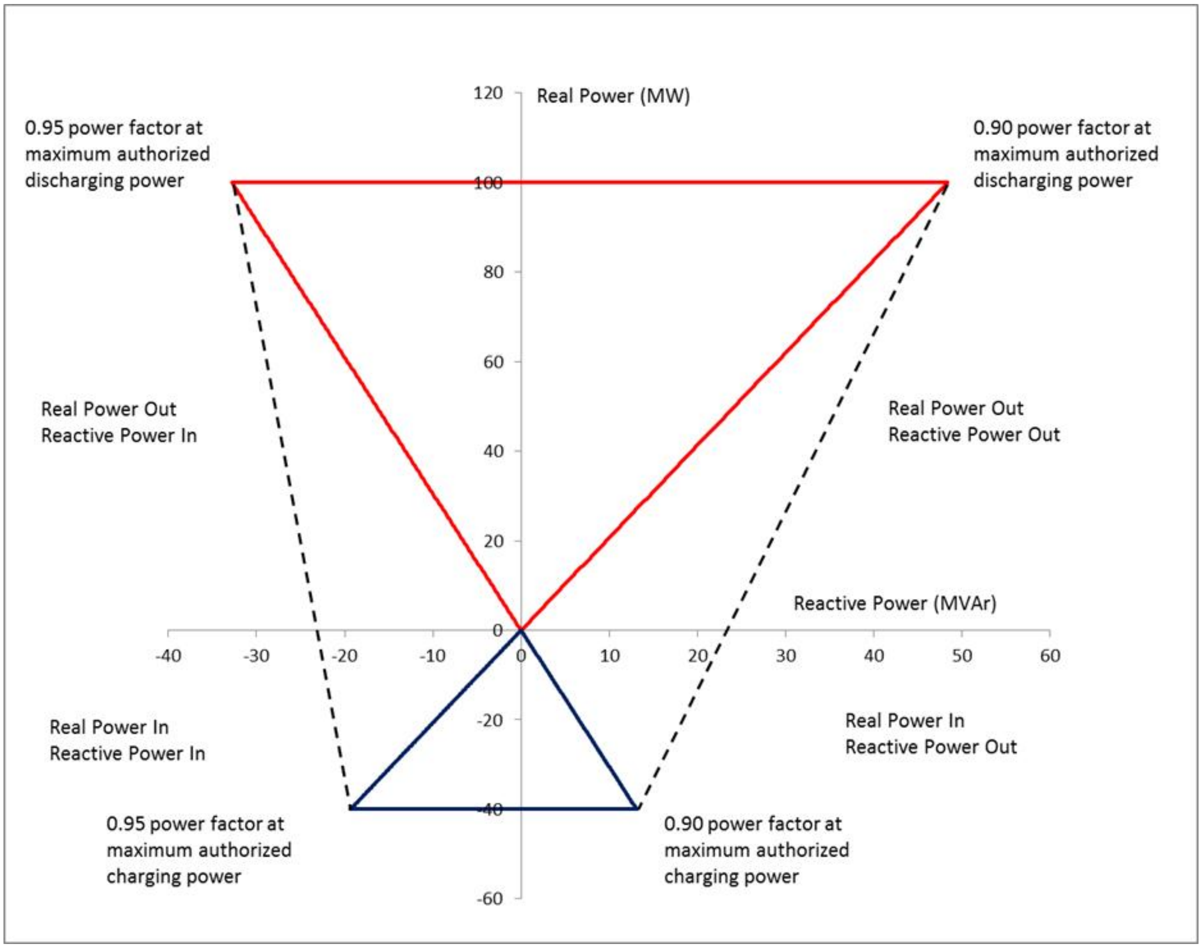
(a) over-excited reactive power obligation (0.90 power factor) = 19.4 MVAr; and

(b) under-excited reactive power obligation (0.95 power factor) = 13.1 MVAr.

The relationship between maximum authorized charging power, maximum authorized discharging power and reactive power is illustrated in Figure 1, below. Figure 1 is based on the following maximum authorized discharging power and maximum authorized charging power values:

- maximum authorized discharging power = 100 MW; and
- maximum authorized charging power = 40 MW

Figure 1 - The relationship between maximum authorized charging power, maximum authorized discharging power and reactive power



Example 3: Where the legal owner of a generating facility is considering the addition of a battery energy storage facility, such that the two facilities would share a common point of connection, and where there is excess reactive power available from the generating facility, the excess reactive power may be used to supplement the reactive power capability of a battery energy storage facility, in accordance with subsection 4(4) of Section 502.13.

Where the generating facility is a wind aggregated generating facility rated at 100 MW that has an existing static reactive power device, the reactive power capability of the wind aggregated generating facility (as required in Section 502.1 of the ISO rules, *Wind Aggregated Generating Facilities Technical Requirements*) would be similar to the reactive power capability described in Example 1 above:

(a) over-excited reactive power obligation (0.90 power factor) = 48.4 MVAr; and

(b) under-excited reactive power obligation (0.95 power factor) = 32.9 MVAr.

If a battery energy storage facility is added to the existing wind aggregated generating facility, such that the two facilities share a common point of connection, and the battery energy storage facility is rated at 10 MW for both the maximum authorized discharging power and the maximum authorized charging power, the following reactive power capabilities for the battery energy storage facility would meet the reactive power requirements under subsection 4(4) of Section 502.13:

(a) over-excited reactive power obligation (0.90 power factor) = 4.8 MVAr; and

(b) under-excited reactive power obligation (0.95 power factor) = 3.3 MVAr.

However, the battery energy storage facility would not be required to have reactive power capability if the existing static reactive power device at the wind aggregated generating facility had additional reactive power capability totaling at least:

(a) over-excited reactive power obligation (0.90 power factor) = 53.2 MVAr; and

(b) under-excited reactive power obligation (0.95 power factor) = 36.2 MVAr.

3.2 Auxiliary Systems

Just as a complex may contain more than one generating unit, a complex may also contain more than one battery energy storage facility. Subsection 11 of Section 502.13 and subsection 2(6) of Section 502.14 relate to the auxiliary systems a of battery energy storage facility that is located in a complex with more than one battery energy storage facility.

In general, where the various battery cells, inverters, and other components in a complex operate cohesively under a single governor system and voltage regulating system, the complex is considered to be composed of a single battery energy storage facility.

Where the operation of the various battery cells, inverters, and other components in a complex is controlled by separate governor systems and voltage regulating systems, the complex is considered to be composed of multiple battery energy storage facilities.

Subsection 11 of Section 502.13 includes requirements to prevent the loss of multiple battery energy storage facilities as a result of a single point of failure of an auxiliary system, such as a common power supply to pumps for flow batteries.

The AESO recognizes that there may be times when the battery energy storage facilities located within a complex are operated with a single point of failure of an auxiliary system. When operating with a single point of failure of an auxiliary system for multiple battery energy storage facilities, the AESO requires notification in accordance with subsection 2(6) of Section 502.14.

4 Participation of Battery Energy Storage Facilities in the Market

The AESO has received questions regarding how other ISO rules and Alberta reliability standards apply to battery energy storage facilities. The AESO is in the process of reviewing these questions and will issue further communications on this matter once the review is complete. See also ID #2009-003R, *Acceptable Operational Reasons* and ID #2012-009R, *Restatements.*

Revision History

Posting Date	Description of Changes
2017-05-11	Addition of section 4
2016-04-25	Initial release

Information Document
Event Notification and Reporting
ID #2016-002R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

(a) Section 304.7 of the ISO rules, *Event Reporting* ("Section 304.7");

(b) Section 304.8 of the ISO rules, *Event Analysis* ("Section 304.8");

(c) Section 305.4 of the ISO rules, *System Security* ("Section 305.4"); and

(d) Alberta Reliability Standard PRC-004-WECC-AB1-1, *Protection System and Remedial Action Scheme Misoperation* ("PRC-004-WECC-AB1-1").

The purpose of this Information Document is to provide guidance to market participants on providing information to the AESO regarding event reporting, event analysis and misoperation reporting. This Information Document is likely of most interest to market participants that own or operate transmission systems, generating facilities and distribution systems, and to providers of ancillary services.

2 Notification, Reporting and Analysis of Events

Notifications to the AESO under Section 305.4 are made in real time, and are intended to ensure that the AESO is aware of circumstances that have adversely affected or may adversely affect the transmission system or transmission system control facilities.

An event report under Section 304.7 is provided after an event has occurred and is intended to assist the AESO in facilitating Alberta electric industry awareness of such events in order to allow potentially impacted parties to prepare for and possibly mitigate any associated reliability risk associated with a future event. Event reports also provide the AESO with information to identify emerging patterns of reliability concerns.

An event analysis may be carried out following an event on the Alberta interconnected electric system in accordance with Section 304.8. The event analysis process is intended to promote self-critical review and analysis by the AESO or a market participant, and allows the AESO to identify and disseminate valuable information to owners, operators, and users of the Alberta interconnected electric system to promote reliable operation.

3 System Security – Notifications

Section 305.4 requires a market participant to advise the AESO of any circumstances that could adversely affect system security or the ability of the Alberta interconnected electric system to deliver energy.

A notification to the AESO under subsection 3 of Section 305.4 is made by real time verbal communication to the AESO system controller. These notifications are intended to communicate conditions that are unplanned or differ from the planned conditions for the Alberta interconnected electric system. Such notifications provide situational awareness to the AESO system controller with respect to the real time condition of the Alberta interconnected electric system. Accordingly, market participants are encouraged to provide as much information as is available at the time a notification is submitted to the AESO, including but not limited to:

(a) a description of the conditions; and

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

(b) the anticipated duration of the conditions.

The following are examples of situations in which a market participant may consider notifying the AESO system controller of a circumstance under subsection 3 of Section 305.4:

(a) any change or potential change in the status of transmission lines and substations that could affect the reliability of the Alberta interconnected electric system. This may include, but is not limited to, a change in the status of line and substation equipment, protection systems, outage duration, remedial action schemes or communication capability;

(b) events or circumstances relating to the market participant's facilities that could affect the reliability of the Alberta interconnected electric system. This may include, but is not limited to, adverse weather conditions, fires or bomb threats; and

(c) forced outages on transmission lines or substation equipment that could affect the reliability of the Alberta interconnected electric system.

Events giving rise to a notification under Section 305.4 may also be the subject of an event report under Section 304.7 or event analysis under Section 304.8.

Note that notifications of planned outages are submitted to the AESO under Section 306.4 of the ISO rules, *Transmission Planned Outage Reporting and Coordination* or Section 306.5 of the ISO rules, *Generation Outage Reporting and Coordination*.

4 Event Reporting

Section 304.7 requires a market participant to report events to the AESO, the NERC and other organizations as appropriate, that have impacted the operation of the transmission system or generating units.

4.1 Transient vs Sustained Forced Outage

A forced outage generally results from the removal of a system element or a facility from the Alberta interconnected electric system due to circumstances such as defective equipment, adverse weather, adverse environment or a system condition. A forced outage may or may not cause an interruption of service to customers, depending on the transmission system configuration.

Subsection (a) of Appendices 1 and 4 of Section 304.7 refers to a "sustained outage". The following definitions published by the Canadian Electricity Association may provide guidance in determining whether a forced outage is sustained or transient (momentary):

"**Sustained Forced Outage:** A transmission line related forced outage the duration of which is one minute or more. It does, therefore, not include automatic reclosure events.

Transient Forced Outage: A transmission line forced outage the duration of which is less than one minute and is therefore, recorded as zero. It covers only automatic reclosure events."[2]

4.2 Protection System Failure

Examples of protection system failures that may impact the transmission system for the purposes of Appendix 1(f) include, but are not limited to, the failure of:

(a) a protection system, excluding the related telecommunications, that protects a transmission facility greater than 200 kV, regardless of whether or not a functionally equivalent protection system remains in service;

(b) a protection system, excluding the related telecommunications, that protects a transmission facility where a functionally equivalent protection system is not available;

[2] Canadian Electricity Association, *2012 Annual Report (2008-2012 data): Forced Outage Performance of Transmission Equipment; Equipment Reliability Information System*, at p. 4.

(c) a teleprotection communication channel, where there is an equivalent backup teleprotection communication channel, and where the failure lasts for more than 24 consecutive hours; or

(d) a teleprotection communication channel, where there is no equivalent backup teleprotection communication channel, and where the failure lasts for more than 10 consecutive minutes.

4.3 Event Reporting Form

Events under Section 304.7 are reported to the AESO using the *Event Reporting Form Template*, located on the AESO website. A market participant provides information regarding the impact of the event on its own facilities in the *Event Reporting Form Template*.

The form may be emailed to:

(a) opsevents@aeso.ca for all events, except for those events described under (b) below; or

(b) security@aeso.ca for:

  (i) damage or destruction that results from actual or suspected intentional human action;

  (ii) physical threats which have the potential to degrade normal operation of a control centre; or

  (iii) a suspicious device or activity.

5 Misoperation Reporting

Reports to the AESO under requirement R3 of PRC-004-WECC-AB1-1 are provided following the misoperation of a protection system or remedial action scheme to confirm that the legal owner has analyzed and mitigated the misoperation of protection systems or remedial action schemes on transmission paths.

Such misoperations are reported to the AESO by email at: opsevents@aeso.ca.

6 Event Analysis

The purpose of Section 304.8 is to promote a structured and consistent approach to performing event analyses in Alberta, which aligns with the NERC's Electric Reliability Organization Event Analysis Process.[3] An event analysis involves identifying what happened, why it happened and what can be done to prevent a reoccurrence of such events on the Alberta interconnected electric system.

6.1 Event Analysis – Event Categories

In accordance with subsection 2(3) of Section 304.8, when the AESO conducts an event analysis, the AESO may categorize the event using the highest applicable category in Appendix 1, where Category 1 is the lowest and Category 5 is the highest. The AESO categorizes an event that is listed in Appendix 1as applicable. However, the events listed in Appendix 1 are not exhaustive and the AESO categorizes events based on the impact of the event on the reliability of the Alberta interconnected electric system.

6.2 Event Analysis – Reports

Depending on the nature of the event, the AESO may request a brief report or an event analysis report or both from a market participant, pursuant to subsection 3 of Section 304.8. For such requests, the AESO includes the event category and type of report to be provided to the AESO.

When a Responsible Entity requests that the AESO provide an extension to the timeframes indicated in subsection 4(1) of Section 304.8, the AESO provides a written response to the extension request.

[3] Materials relating to the NERC's Electric Reliability Organization Event Analysis Process are available on the NERC website at the following link: http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx. Please note that this link may change periodically.

Where multiple Responsible Entities are involved in an event, or if portions of the event apply only to the AESO, the AESO may prepare a brief report or event analysis report which summarizes information received from Responsible Entities, pursuant to subsection 6(1) of Section 304.8.

6.3 Event Analysis – Brief Report

Upon the AESO's request, a Responsible Entity prepares a brief report using the Brief Report Template located on the NERC's website.

A Responsible Entity may consider the following guidance when completing the Brief Report Template:

1. **Reported Event Title**

   Title used to further identify the event (provided by the AESO in its request), including the date of the event (YYYYMMDD), entity name, substation name or location as appropriate.

2. **Submittal Date**

   Date brief report was first submitted.

3. **Subsequent Submittal Date**

   Date brief report was updated, if applicable.

4. **Entity Name (Item 1)**

   Responsible Entity submitting the report.

5. **Brief Description (Item 4)**

   A brief summary of what happened, when it happened and where it happened, as applicable. The brief summary does not describe the causes and conditions surrounding the event.

6. **Proposed Event Categorization (e.g. 1a, 2b)**

   See the list of categories in Appendix 1 of Section 304.8.

7. **Items 6 -12**

   If the event did not involve generation, frequency, transmission facilities or load, items 6 - 12 may be left blank.

8. **Generation Tripped Off-line (Item 6)**

   Total MW loss (gross) and names of the units that tripped off-line due to the event.

9. **Outage/Restoration Time (Item 12)**

   Total outage time for each affected transmission facility, generating unit, or load, or a time estimate of pending restoration.

10. **Sequence of Events (Item 13)**

    A chronological timeline of the events that took place leading up to and through the event for the purpose of causal analysis. This timeline does not include potential causes or narratives identifying the impact of various activities throughout the event.

11. **Narrative (Item17)**

    A detailed description of the event using the sequence of events, single-line diagrams, available data and any assumptions, as necessary. The narrative explains the "what", "when", "how" and "where" aspects of the event in detail, as well as the impact. The narrative describes the potential causes of the event, preventive measures that could have prevented the event, corrective measures taken after the event, and any extent of the conditions identified.

6.4 Event Analysis – Event Analysis Report

An event analysis report will typically be requested by the AESO for more significant events (Category 3 and above), but may be requested for lower category events.

Upon the AESO's request, a Responsible Entity prepares an event analysis report using the Event Analysis Report Template located on the NERC's website.

A Responsible Entity may consider the following guidance when completing the Event Analysis Report Template:

1. **Report Cover Sheet**
    a. Reported Event Title used to further identify the event (provided by the AESO in its request), including the date of the event (YYYYMMDD), entity name, substation name or location as appropriate.);
    b. Date of Report;
    c. Responsible Entity Name; and
    d. Individual Author's Name.
2. **Table of Contents**
3. **Executive Summary**
4. **Event Overview**

    A description of the pertinent facts related to the event, including pre and post event periods.

5. **Sequence of Events**

    A sequence of events includes the date, time and duration (until restoration) of the event . This timeline is a building block for all other aspects of the analysis and is a starting point for the root cause analysis.

6. **Root Cause Analysis**
    a. A list of the causal factors of the event. The root cause analysis is a factual record to support the conclusions in the report; and
    b. Assign cause code (assigned by the Responsible Entity).
7. **Detailed System Analysis**
    a. System conditions prior to the event;
    b. Generation outage summary (relevant outage, planned or unplanned);
    c. Transmission outage summary (relevant outage, planned or unplanned);
    d. Effect on other entities and customers
        1. MW lost, in each of the following categories:
            a) Load (both DOS and DTS): include the number of customers affected and how long they were without service if this information is available; and
            b) Remedial action schemes, including the number of generators and customers affected, and the duration of interupped service, if available;

e. Event response

1. Frequency excursions: frequency plot, from T-0 until the frequency reached steady-state;
2. Under-frequency load shed (UFLS): details of operation, including what blocks were shed and the MW per block;
3. Voltage excursions: voltage plots, from T-0 until the voltage reached steady-state;
4. Digital fault recording[4];
5. Protection schemes (including remedial action schemes): operation with respect to design;
6. Details of any equipment malfunction that contributed to the disturbance, or equipment damage resulting from the disturbance; and
7. SCADA information; and

f. Restoration observations.

8. Findings, Conclusions, and Recommendations

a. Specific findings and conclusions;

b. Recommendations including corrective actions, lessons learned and good industry practices; and

c. A lesson learned is knowledge or understanding gained by experience that has a significant impact for an organization. The experience may be either positive or negative. Successes are also sources of lessons learned.

9. Appendices

Responsible Entities are encouraged to include the following in an event analysis report:

a. Single-line diagrams;

b. Graphic representations (see event response in 7(e) above);

c. Team members contributing in the report preperation; and

d. Other relevant data.

6.5 Event Analysis – Cause Code

An event analysis report uses cause codes to identify characteristics and attributes of events. The purpose of cause coding is to provide a structured, measurable, and continuously improvable approach to rationally characterize the causes of reportable events which can be used to identify trends and develop actionable transmission system risk reduction knowledge.

Responsible Entities are encouraged to use the NERC's *Cause Code Quick Reference* located on the NERC website. These codes may be updated from time to time to align with the NERC's cause codes.

[4] In most cases printed traces from digital fault recording are adequate. However, if digital files are provided it is recommended that, to the extent possible, the disturbance data be reported in a format capable of being viewed, read and analyzed with a generic COMTRADE (IEEE C37.111-XXXX Standard Common Format for Transient Data Exchange for Power Systems) analysis tool, and that the data files be named in conformance with the IEEE C37.232-XXXX Recommended Practice for Naming Time Sequence Data Files.

For further information on cause codes, Responsible Entities may review the *NERC Cause Code Assignment Process* and *Root Cause Analysis Methods for NERC, Regional Entities, and Registered Entities*[5], available on the NERC website.

6.6 Event Analysis – Lessons Learned

The AESO may determine, as a result of an event analysis, that a lessons learned document should be prepared and shared with the industry to facilitate the reliability of the Alberta interconnected electric system. The AESO prepares Lessons Learned documents using the NERC template.

The lessons learned document is reviewed by the AESO and the Responsible Entities involved in the event for completeness prior to posting on the AESO website.

6.7 Close of Event Analysis

The AESO closes the event analysis upon completion of its event analysis, or upon providing a brief report, an event analysis report or a lessons learned document to the NERC and the WECC.

Revision History

Posting Date	Description of Changes
2018-04-30	Addition of section 6, Event Analysis
2017-12-12	Clarifying revisions to section 4.2 and administrative revisions
2016-08-30	Initial release

[5] Please note that the links to the *NERC Cause Code Assignment Process* and the *Root Cause Analysis Methods for NERC, Regional Entities, and Registered Entities* may change periodically.

Information Document
Automatic Time Error Correction Formula
ID #2016-003RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]: BAL-004-WECC-AB-2, *Automatic Time Error Correction*. The purpose of this Information Document is to provide the formula that is used to calculate automatic time error correction.

2 Automatic Time Error Correction Formula

Automatic time error correction is only applicable in the western interconnection. Automatic time error correction is calculated using the following formula:

$\mathbf{I}_{ATEC} = \dfrac{\mathbf{PII}_{accum}^{on/off\ peak}}{(1-Y)*H}$ when operating in automatic time error correction mode. The absolute value of I_{ATEC} shall not exceed L_{max}.

I_{ATEC} shall be zero when operating in any other automatic generation control (AGC) mode.

The variables referenced in the discussion of the automatic time error calculation formula are defined below.

- L_{max} is the maximum value allowed for I_{ATEC} set by each balancing authority between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$
  - $L_{10} = 1.65 * \varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$.
    - ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every balancing authority area within an Interconnection.
- $Y = B_i / B_S$.
  - B_i = frequency bias setting for the balancing authority area (MW / 0.1 Hz).
  - B_S = Sum of the minimum frequency bias settings for the Interconnection (MW / 0.1 Hz).
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
  - primary inadvertent interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$.
    - II_{actual} is the hourly inadvertent interchange for the last hour.
    - ΔTE is the hourly change in system time error as distributed by the Interconnection time monitor, where: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
      - TD_{adj} is the reliability coordinator adjustment for differences with Interconnection time monitor control centre clocks.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

- t is the number of minutes of manual time error correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.

- PII_{accum} is the balancing authority area's accumulated PII_{hourly} in MWh. An on peak and off peak accumulation accounting is required, where:

$$\mathbf{PII}_{accum}^{on/offpeak} = last\ period's\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Revision History

Posting Date	Description of Changes
2017-01-24	Initial release

Information Document
CIP-002-AB-5.1 Impact Rating Criteria
ID #2016-004RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- Alberta Reliability Standard CIP-002-AB-5.1, *Cyber Security – BES Cyber System Categorization* ("CIP-002-AB-5.1").

The purpose of this Information Document is to identify any generating unit, aggregated generating facility, transmission facility, remedial action scheme or automated switching system described under criteria 2.3, 2.6 and 2.9 of Attachment 1 – *Impact Rating Criteria* ("Attachment 1") of CIP-002-AB-5.1.

Note that CIP-002-AB-5.1 will become effective in accordance with the timelines set out in CIP-PLAN-AB-1, *Implementation Plan for Version 5 CIP Security Standards*.

2 Identified Generating Units, Aggregated Generating Facilities, Transmission Facilities, Remedial Action Schemes and Automated Switching Systems

2.1 Criterion 2.3 of Attachment 1

"each **generating unit** and **aggregated generating facility** that the **ISO** designates, … as necessary to avoid an **adverse reliability impact** in the planning horizon of more than one year;"

None identified.

2.2 Criterion 2.6 of Attachment 1

"**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 the **interconnection reliability operating limits** …"

None identified.

2.3 Criterion 2.9 of Attachment 1

"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 …"

None identified.

Revision History

Posting Date	Description of Changes
2016-09-30	Initial Release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
Technical Feasibility Exceptions
ID #2016-005RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- Alberta Reliability Standard CIP-SUPP-002-AB, *Technical Feasibility Exceptions* ("CIP-SUPP-002-AB").

The purpose of this Information Document is to describe the process by which a Responsible Entity, as referenced in Alberta Reliability Standard CIP-002-AB-5.1, *Cyber Security BES Cyber System Categorization* ("CIP-002-AB-5.1"), may request and obtain approval for a technical feasibility exception ("TFE") to those requirements of the Critical Infrastructure Protection Alberta reliability standards[2] ("CIP ARS") that use the phrase "where technically feasible." This Information Document is likely of most interest to Responsible Entities to whom the CIP ARS apply.

2 Background

The AESO is mandated under Sections 19(2) and 23(1) of the *Transmission Regulation* to develop reliability standards and establish practices and procedures for monitoring market participants' compliance with the reliability standards. Under this mandate, the AESO filed the CIP ARS and CIP ARS Definitions with the Alberta Utilities Commission ("Commission"), which were approved on September 14 and September 15, 2015, respectively.[3] The CIP ARS and CIP ARS Definitions will become effective on October 1, 2017.

A number of the CIP ARS requirements include the phrase "where technically feasible" to recognize that a wide range of equipment already installed by market participants has not been designed nor can be easily upgraded to fully align with the applicable CIP ARS requirements. Requirement R1 in CIP-SUPP-002-AB allows a Responsible Entity, where a CIP ARS requirement uses the phrase "where technically feasible," to seek a variance from the requirement by requesting that the AESO approve a TFE.

3 Technical Feasibility Exceptions

An approved TFE authorizes an alternative means of compliance with the CIP ARS requirement through the use of compensating and/or mitigating actions that achieve a comparable or higher level of reliability of the Alberta interconnected electric system as would compliance with the requirement.

4 Submission of a TFE Request

4.1 Components of a TFE Request

A TFE request includes the following information:

(a) a completed TFE request form posted on the AESO's website (see Appendix A), that contains:

(i) the applicable CIP ARS requirement,

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.
[2] CIP-005-AB-5, CIP-006-AB-5, CIP-007-AB-5, CIP-010-AB-1.
[3] AUC Decisions 3441-D01-2015 and 3442-D01-2015.

(ii) a description of the asset(s),[4]

(iii) the grounds for the TFE request, as set out in subsection 5 of this ID,

(iv) the proposed expiration date of the TFE, and

(v) written approval of the TFE request by the senior manager associated with the overall responsibility for leading and managing the Responsible Entity's implementation and adherence to the CIP ARS, hereinafter referred to as the "primary contact"; and

(b) a documented mitigation plan associated with the TFE, including a schedule for the completion of milestones and a completion date for the implementation of the mitigation plan; and

(c) a documented remediation plan to eliminate the TFE and achieve compliance with the applicable CIP ARS requirement, including milestones and a reasonable expiration date of the TFE or, when remediation is not possible, ongoing and effective mitigation strategies.

A market participant may submit a TFE request prior to the effective date of CIP-SUPP-002-AB. The AESO may issue conditional approvals for these requests, as described in subsection 6.2 below.

4.2 Submission of a Single TFE Request for Multiple Assets

A Responsible Entity may submit a single TFE request from the same requirement for multiple assets, at one or more locations, when all of the following criteria are met:

(a) the grounds for the TFE request is the same for all assets;

(b) the mitigation and remediation plans are the same for all assets; and

(c) the proposed expiration date of the TFE is the same for all assets.

4.3 Contact Information for Submission of TFE Requests

A TFE request, new or revised, and any related inquiries regarding a TFE request may be directed to RFI@aeso.ca.

The AESO directs all communications regarding TFEs to the primary contact identified in the TFE request form, unless notified by the Responsible Entity, in writing.

5 Approval of a TFE Request

5.1 Criteria for Approval of a TFE Request

Pursuant to requirement R5 of CIP-SUPP-002-AB, in determining whether to approve a TFE request, the AESO considers the following criteria:

(a) whether, in the determination of the AESO, the grounds relied on by the Responsible Entity for making the TFE request, as described below, are satisfactory;

(b) where the grounds relied upon are determined to be satisfactory, whether:

(i) the proposed mitigation plan, in the determination of the AESO, would achieve a level of reliability of the Alberta interconnected electric system comparable to or higher than compliance with the requirement; and

[4] Asset means any of the following defined terms: "BES cyber asset", "BES cyber system", "protected cyber asset", "electronic access control" or "monitoring system", or "physical access control system", as posted on the AESO's website with the effective date of October 1, 2017.

(ii) the proposed remediation plan to eliminate the TFE, in the determination of the AESO, is satisfactory.

5.2 Grounds for a TFE Request

A Responsible Entity may request a TFE on the grounds that compliance with a CIP ARS requirement, evaluated in the context or environment of the Responsible Entity's asset that is subject of the TFE request:

(a) is not technically possible or is precluded by technical limitations;

(b) is operationally infeasible or could adversely affect reliability of the Alberta interconnected electric system to an extent that outweighs the reliability benefits of compliance with the requirement;

(c) while technically possible and operationally feasible, cannot be achieved by the date the Responsible Entity is required to comply with the CIP ARS due to factors such as scarce technical resources, limitations on the availability of required equipment or components, or the need to construct, install or modify equipment during planned outages;

(d) would pose safety risks or issues that outweigh the reliability benefits of compliance with the requirement;

(e) would conflict with, or cause the Responsible Entity to be non-compliant with, a separate statutory or regulatory requirement applicable to the Responsible Entity, the asset or the related facility that must be complied with and cannot be waived or exempted; or

(f) would require the incurrence of costs that far exceed the benefits to the reliability of the Alberta interconnected electric system of compliance with the requirement, such as requiring the retirement of existing equipment that is not capable of compliance with the requirement but is far from the end of its useful life and replacement with newer-generation equipment that is capable of compliance, where the incremental risk to the reliable operation of the asset and to the reliable operation of the facility and the Alberta interconnected electric system of continuing to operate with the existing equipment is minimal.

6 Review and Approval/Disapproval Process for a TFE Request

6.1 Review of a TFE Request

The Responsible Entity is responsible for applying, substantiating, obtaining approval of and maintaining a TFE.

A Responsible Entity may revise a pending TFE request that is under review by the AESO, for the purpose of providing additional or revised information, including changes to the mitigation or remediation plans. The objective of the AESO's review is to make a determination as to whether a TFE request substantiates the criteria for approval.

The AESO's review process is intended to be an exchange of information that maximizes the chances of a TFE request being approved. However, the AESO may need to expand its review beyond the CIP ARS requirement specified in the TFE request when the proposed mitigation or remediation measures involve CIP ARS requirements that are not subject to the TFE request. In such circumstances, if the AESO suspects a possible breach of these CIP ARS requirement(s), it may initiate a formal compliance assessment.

The AESO conducts an appropriate case-by-case assessment of the particular facts and circumstances of each TFE request and therefore the processing time for each request will vary. The CIP ARS are new to Alberta, and the AESO's and market participant's experience with them is at an early stage.

6.2 Approval/Disapproval of a TFE Request

Pursuant to requirement R6 of CIP-SUPP-002-AB, the AESO issues a notice of approval or disapproval of the TFE request that may contain the following:

(a) a statement of approval/disapproval of each TFE request;

(b) any terms and conditions of the approval;

(c) the expiration date of the approval;

(d) the milestones and completion date the Responsible Entity is required to achieve with respect to the implementation of the mitigation plan;

(e) the milestones the Responsible Entity is required to achieve with respect to the implementation of the remediation plan to achieve compliance with the CIP ARS requirement(s);

(f) the Responsible Entity’s reporting requirements to the AESO regarding the implementation of mitigation and remediation plans; and

(g) any other requirements or information the AESO has determined to be necessary in the circumstances.

Prior to the effective date of CIP-SUPP-002-AB, the AESO may issue approvals of TFE requests that are conditional upon CIP-SUPP-002-AB coming into effect. The effective date of these approvals will be the effective date of CIP-SUPP-002-AB.

6.3 Approval in Whole or in Part

The AESO may approve or disapprove the TFE request in whole or in part where the TFE request is for two or more assets subject to the same requirement.

6.4 Decision Dispute Process

A Responsible Entity may use the dispute process in Section 103.2 of the ISO rules, *Dispute Resolution*, in addition to other legislative avenues, to dispute the AESO’s decisions related to approving or disapproving of a TFE.

6.5 Transfer of an Approved TFE

An approved TFE may be transferred from one Responsible Entity to another as a result of changes to the asset ownership. To complete the transfer, the new owner notifies the AESO within sixty days of the effective date of the transfer.

7 Compliance Information

7.1 Compliance Monitoring

The AESO will monitor compliance with a CIP ARS from its effective date.

In the absence of a TFE approval, the AESO will treat a TFE request as evidence of non-compliance with a requirement of the CIP ARS. Issues of non-compliance will be referred to the Market Surveillance Administration (“MSA”) and Responsible Entities may work directly with the MSA to seek forbearance or self-report.

Compliance with a CIP ARS requirement subject to an approved TFE will be monitored in accordance with the approved TFE and its associated terms and conditions from the date of its approval. The AESO will monitor compliance with a CIP ARS requirement after the date of expiration or termination of a TFE.

7.2 Conditions of TFE Approval

To maintain approval of a TFE, the Responsible Entity fulfills the terms and conditions of approval, as set out by the AESO pursuant to requirement R6.2 of CIP-SUPP-002-AB, including:

(a) implementation and maintenance of the mitigation plan specified in the TFE request, in accordance with the time schedule specified, and

(b) implementation of the remediation plan specified in the TFE request, in accordance with the time schedule specified.

8 Submitting a Revised TFE Request

Pursuant to requirement R7 of CIP-SUPP-002-AB, when a material change in the facts underlying the request for or approval of a TFE is identified, the Responsible Entity submits a revised TFE request within sixty days of the identification or discovery of the material change. The revised TFE request may include, where applicable:

(a) a reference to the applied-for or approved TFE;

(b) a description of the material change in the facts;

(c) justification of the continuing need for the approved TFE; and

(d) notice that the Responsible Entity has achieved compliance with the CIP ARS requirement.

A material change in the facts underlying the request for or approval of a TFE is a change that may cause the AESO to amend or terminate an approved TFE, or to arrive at a different determination regarding the approval or disapproval of a requested TFE. A material change may include, but is not limited to, a change in the facts which would have caused the AESO to disapprove the TFE request, a change in the Responsible Entity's ability to meet a term or condition in the approved TFE, a change resulting in an adverse effect on the reliability of the interconnected electric system, or a change in the market participant's ability to successfully comply with the applicable CIP ARS requirement.

Note that a breach of a term or condition of an approved TFE constitutes a material change and also constitutes a breach of the applicable CIP ARS requirement.

9 Amendment or Termination of the TFE

Pursuant to requirement R8 of CIP-SUPP-002-AB, the AESO may amend or terminate a TFE prior to the expiration date of the TFE. The Responsible Entity will be notified, in writing, of the AESO's intent to amend the TFE or terminate the TFE early and of the effective date of the amendment or termination.

10 Information Document Amendment

The AESO will issue a notification of amendment to this Information Document in the stakeholder newsletter 30 days prior to the effective date of the amendment(s).

11 Appendices

Appendix A – TFE Request Form

Revision History

Posting Date	Description of Changes
2017-02-13	Initial release

Information Document
Radial Circuit
ID #2016-006RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 502.1 of the ISO rules, *Wind Aggregated Generating Facilities Technical Requirements*;
- Section 502.2 of the ISO rules, *Bulk Transmission Technical Requirements*;
- Section 502.4 of the ISO rules, *Automated Dispatch and Messaging System and Voice Communication System Requirements*;
- Section 502.13 of the ISO rules, *Battery Energy Storage Facility Technical Requirements*;
- Alberta Reliability Standard CIP-002-AB-5.1, *Cyber Security – BES Cyber System Categorization*;
- Alberta Reliability Standard CIP-003-AB-5, *Cyber Security – Security Management Controls*;
- Alberta Reliability Standard CIP-004-AB-5.1, *Cyber Security – Personnel & Training*;
- Alberta Reliability Standard CIP-005-AB-5, *Cyber Security – Electronic Security Perimeter(s)*;
- Alberta Reliability Standard CIP-006-AB-5, *Cyber Security – Physical Security of BES Cyber Systems*;
- Alberta Reliability Standard CIP-007-AB-5, *Cyber Security – System Security Management*;
- Alberta Reliability Standard CIP-008-AB-5, *Cyber Security – Incident Reporting and Response Planning*;
- Alberta Reliability Standard CIP-009-AB-5, *Cyber Security – Recovery Plans for BES Cyber Systems*;
- Alberta Reliability Standard CIP-010-AB-1, *Cyber Security – Configuration Change Management and Vulnerability Assessments*;
- Alberta Reliability Standard CIP-011-AB-1, *Cyber Security – Information Protection*;
- Alberta Reliability Standard EOP-001-AB1-2.1b, *Emergency Operations Planning*;
- Alberta Reliability Standard EOP-003-AB1-1, *Load Shedding Plans*;
- Alberta Reliability Standard EOP-004-AB-2, *Event Reporting*;
- Alberta Reliability Standard FAC-010-AB1-2.1, *System Operating Limits Methodology for the Planning Horizon*;
- Alberta Reliability Standard FAC-011-AB-2, *System Operating Limits Methodology for the Operations Horizon*;
- Alberta Reliability Standard PRC-023-AB-2, *Transmission Relay Loadability*;
- Alberta Reliability Standard TPL-001-AB-0, *System Performance Under Normal Conditions*;
- Alberta Reliability Standard TPL-002-AB-0, *System Performance Following Loss of a Single BES Element*;

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

- Alberta Reliability Standard TPL-003-AB-0, *System Performance Following Loss of Two or more BES Elements*;
- Alberta Reliability Standard TPL-004-AB-0, *System Performance Following Extreme BES Events*; and
- the ISO Tariff.

The purpose of this Information Document is to provide guidance regarding the term “radial circuit”.

2 Radial Circuit

The following terms are currently used in the AESO’s authoritative documents (“AESO ADs”) to refer to a “radial circuit”:

- radial bulk transmission line;
- radial connection;
- radial customers;
- radial line;
- radially operated circuits;
- radial transmission line;
- radial transmission system;
- transmission facility that radially connects;
- radial transmission lines;
- double-radial configurations; and
- radial transmission facilities.

The AESO expects to add the below definition of “radial circuit” to the AESO’s *Consolidated Authoritative Document Glossary* for use in the ISO rules, Alberta reliability standards and the ISO tariff in due course. The AESO ADs will be amended concurrently to use the term “radial circuit” in place of the terms listed above.

Until such time as the new definition of “radial circuit” and the related AESO AD amendments are published for stakeholder comment and filed with the Alberta Utilities Commission, the AESO is publishing this Information Document to provide the following guidance regarding the above listed terms.

The AESO considers the term “radial circuit” to include the above listed terms and to mean:

> An arrangement of contiguous system elements extending from a single system element on the networked transmission system in a linear or branching configuration to the facilities of one or more market participants, which is the only circuit for power to flow between the networked transmission system and the facilities of one or more market participants under normal operating conditions, including when the circuit is connected to another circuit through a switching device that is operated normally open.

Revision History

Posting Date	Description of Changes
2017-06-15	Initial release

Information Document
Transition to Mothball Outage Reporting
ID #2016-008R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]: New Section 306.7 of the ISO rules, *Mothball Outage Reporting* ("New Section 306.7"). The purpose of this Information Document is to provide guidance to the legal owners of generating source assets that are on a mothball outage at the time New Section 306.7 becomes effective.

2 Mothball Outage Notification and Cancellation Requirements

In order to transition to the requirements of New Section 306.7, a market participant may take the following actions:

1. Determine whether the market participant is the legal owner of a generating source asset that, as of 11:59 pm (23:59) on Monday June 6, 2016, is in a state that meets the new definition of "mothball outage".
2. If so, in respect of the generating source asset that is on a mothball outage:
    a. ensure that the information required to comply with subsection 3 of New Section 306.7 is entered into the Energy Trading System ("ETS") no later than 11:59 pm (23:59) on Wednesday June 8, 2016; and
    b. submit to the AESO a request for a waiver of the requirement to revise the mothball outage information three months prior to the day the revision takes effect or the mothball outage is to start, as provided for under section 3(3) of New Section 306.7, as soon as practicable.

Subject to the foregoing, legal owners of generating source assets that are on a mothball outage at the time New Section 306.7 becomes effective will be required to comply with the provisions of New Section 306.7, including the requirement to provide a minimum of three months' written notice prior to cancelling a mothball outage under subsection 4(1).

For additional information relating to the reporting of mothball outages under New Section 306.7, please see Information Document #2013-003R, *Outages*.

Revision History

Posting Date	Description of Changes
June 6, 2016	Initial release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
Emergency Operations Planning
ID #2017-001RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- EOP-001-AB1-2.1b, *Emergency Operations Planning* ("EOP-001").

The purpose of this Information Document is to provide guidance regarding the requirements for emergency operations planning relating to the operation of a transmission facility that either connects to or is part of an industrial complex, and to provide contact information for the provision of updated plans to mitigate operating emergencies to the AESO.

2 Development of Emergency Operating Plans

2.1 Requirement R3

Each operator of a transmission facility determines which plans are appropriate for its transmission facilities for the purposes of requirement R3 of EOP-001. The operator of a transmission facility that is within or connects to an industrial complex may consider including:

- plans for coordination with the adjacent operator of a transmission facility and the AESO following the loss of a connection to the interconnected electric system and for restoring the connection; and
- plans for system or regional blackout conditions.

2.2 Requirement R4

Requirement R4 of EOP-001 requires the AESO and the operator of a transmission facility to develop, maintain and implement plans for load shedding. The operator of a transmission facility that is within or connects to an industrial complex may consider the following in developing plans for load shedding.

When the AESO issues a directive for net to grid load reduction (a "load shed directive") that includes a specified timeframe, an industrial complex with both generation and load may increase generation in lieu of curtailing load if, at the time it receives a load shed directive from the AESO, the industrial complex has unloaded generating capacity that can be increased within the time requirements of the load shed directive.

The operator of transmission facility that is within or connects to an industrial complex that is part of a parallel connection may consider including plans for managing overloads on a remaining line where a parallel connection is lost in its plans for load shedding.

2.3 Requirement R5

In developing communication protocols to be used during operating emergencies in accordance with requirement R5(a) of EOP-001, the operator of a transmission facility may consider using three-way communication protocols in accordance with good utility operating practice. The operator of a transmission facility may also consider any safety code related communications for instructions given within an industrial complex, for example, from an operator to a maintenance technician.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

The controlling actions that the operator takes to resolve the operating emergency, referred to in requirement R5(b) of EOP-001, are determined based on the type of emergency. Examples of possible controlling actions include: (a) reconfiguration of the entity's transmission system to address an overload; (b) re-dispatch of generation; and (c) a defined sequence of manual tripping of load if needed.

The NERC established timelines referred to in requirement R5(b) include:

- timelines set out in ISO rules or Alberta reliability standards, which are generally 30 minutes to return the system to an operating condition such that the next contingency resulting in the loss of a system element will not cause a limit to be exceeded on other system elements; and
- timelines included in a directive from the AESO to the operator of a transmission facility which are issued to mitigate an actual or potential limit violation in accordance with the timelines and operating limits provided by the legal owner of the transmission facility. Those timelines could be from immediate to 30 minutes.

2.4 Requirement R10

Requirement R10 of EOP-001 requires the operator of a transmission facility to 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 AESO.

Updated plans are provided to the AESO at systemcontrollerprocedures@aeso.ca.

It is the responsibility of the operator of a transmission facility to determine whether the adjacent operator of a transmission facility is affected by its updated plans, such that the plans must be provided to that adjacent operator in accordance with requirement R10.

Revision History

Posting Date	Description of Changes
2017-02-02	Initial Release

Information Document
CIP-004 Clarification of Terms
ID #2017-003RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta reliability standard CIP-004-AB-5.1, *Cyber Security – Personnel Training* ("CIP-004").

The purpose of this Information Document is to provide clarification regarding the use of the defined term "electronic access control and monitoring systems" within CIP-004 and to provide registered entities clarification on the use of "Responsible Entity's personnel" as it applies to requirement R1 Part 1.1.

2 Electronic access control and monitoring systems

Where the defined term "electronic access control and monitoring systems" is used, refer to the definition of "electronic access control or monitoring systems" [emphasis added to both].

The AESO will update all references to be "electronic access control and monitoring systems" in CIP-004-AB-5.1 in due course.

3 Responsible Entity's personnel

For the purposes of requirement R1, Part 1.1 of CIP-004, the AESO considers the Responsible Entity's personnel, to include any person, regardless of their relationship to the Responsible Entity, who has authorized electronic or authorized unescorted physical access to the Responsible Entity's BES cyber systems.

Revision History

Posting Date	Description of Changes
2017-04-26	Initial release
2019-01-09	Updated to rename the Information Document, to remove the reference to the "Critical Infrastructure Protection terms and definitions"; and to add section 3 in relation to clarification on the use of Reponsible Entity's personnel.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
FAC-008-AB-3 Facility Ratings
ID #2017-004RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta Reliability Standard FAC-008-AB-3, *Facility Ratings* (“FAC-008-AB-3”).

The purpose of this Information Document is to provide guidance information to assist market participants in identifying:

- the meaning of “new facilities” and “existing facilities” in regards to the application of FAC-008-AB-3 effective dates;
- the facilities that are subject to FAC-008-AB-3;
- the type of ratings for which a legal owner may consider developing documentation or a methodology for its facilities in the application of FAC-008-AB-3;
- the entity responsible for either the “documentation for determining the facility ratings” or the “documented methodology for determining the facility ratings” of various facilities in accordance with the requirements of FAC-008-AB-3; and
- the use of dynamic thermal line ratings in the application of FAC-008-AB-3.

2 Meaning of new and existing facilities

In the context of FAC-008-AB-3, the AESO considers the term “new facilities” to mean transmission facilities, generating units, and aggregated generating facilities (collectively “facilities”) energized after January 1, 2019 and “existing facilities” to mean facilities energized prior to January 1, 2019.

The AESO expects facilities energized after January 1, 2019 to meet the requirements of FAC-008-AB-3 upon energization. However, facilities energized prior to January 1, 2019, must meet the FAC-008-AB-3 requirements by January 1, 2020.

3 Applicable Ratings in the context of FAC-008-AB-3

The following table identifies, at a minimum, the type of facility ratings for which a legal owner may consider developing documentation or a methodology for its facilities in the application of FAC-008-AB-3.

Facility	Voltage	Current	MW	MVAr	MVA*
Transmission Line		X			X
Bus	X				
Transformer					X
Generating unit			X	X	
Aggregated Generating Facility			X	X	
Shunt Capacitor Bank or Shunt Reactor	X			X	
Static VAr Compensator	X			X	
Series Capacitor Bank	X	X		X	

[1] “Authoritative Documents” is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Facility	Voltage	Current	MW	MVAr	MVA*
Filter Bank	X			X	
HVDC	X		X		

*Note: MVA is typically calculated at nominal voltage and this voltage used in its MVA calculation is to be stated in data submissions to the AESO as per Section 502.15 of the ISO rules, *Reporting Facility Modelling Data* ("Section 502.15") and Section 304.6 of the ISO rules, *Unplanned Transmission Facility Limit Changes* ("Section 304.6").

Facility rating methodologies apply to steady state and not transient conditions.

4 Dynamic Thermal Line Ratings in the context of FAC-008-AB-3

For transmission lines that use a dynamic thermal line rating process, the AESO recommends that the legal owner also maintain a static seasonal line capacity ratings methodology for both normal and emergency ratings in addition to the dynamic thermal line rating methodology as identified in requirement R3.2 of FAC-008-AB-3.

5 Facility Ratings in the context of FAC-008-AB-3

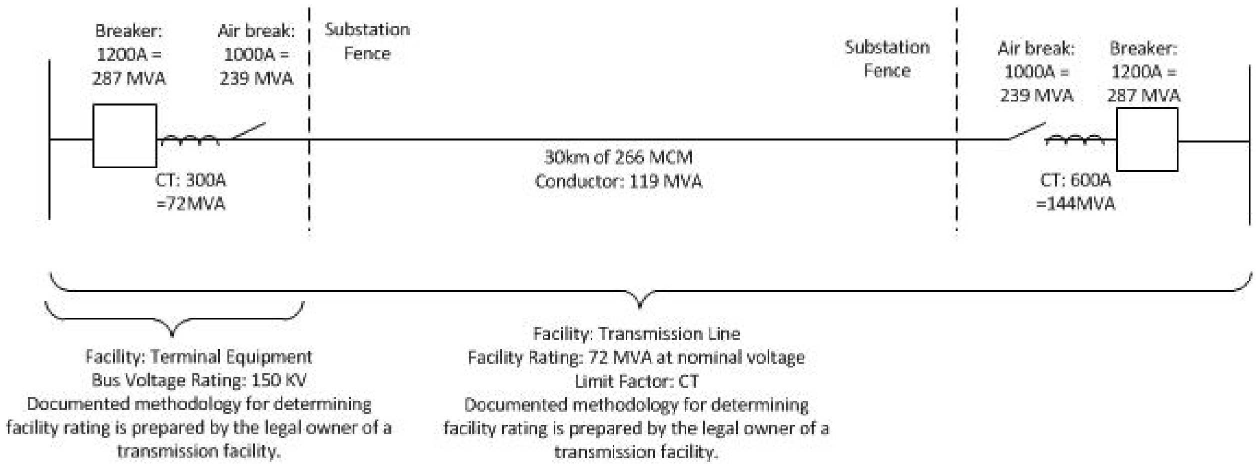
This Information Document contains examples of facilities for the purpose of determining ampacity/MVA ratings and the most limiting applicable equipment rating. Where appropriate, examples of other facility ratings are also shown in the figures below. The examples also identify the entity responsible for either the "documentation for determining the facility ratings" or the "documented methodology for determining the facility ratings". The figures below include:

- a transmission line;
- a transformer;
- a T-tapped transmission line;
- an aggregated generating facility;
- a generating unit; and
- lines with breaker and a half configuration.

5.1 Transmission Line

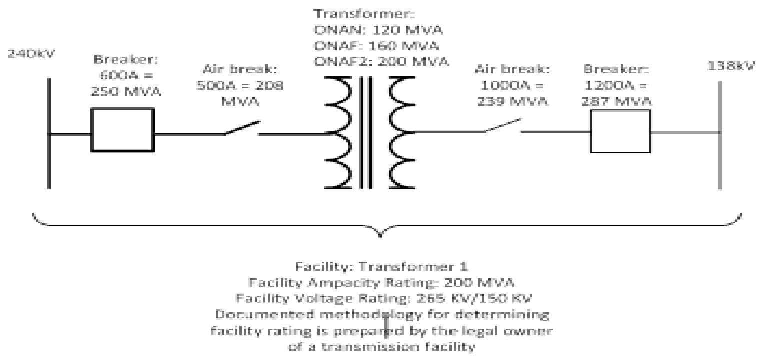
The AESO considers point-to-point ampacity/MVA to be "facility ratings" for the purpose of applying FAC-008-AB-3 to transmission lines.

The MVA calculated is typically based on the nominal voltage, and needs to be stated with the data submitted to the AESO in accordance with Sections 502.15 and 304.6 of the ISO rules.

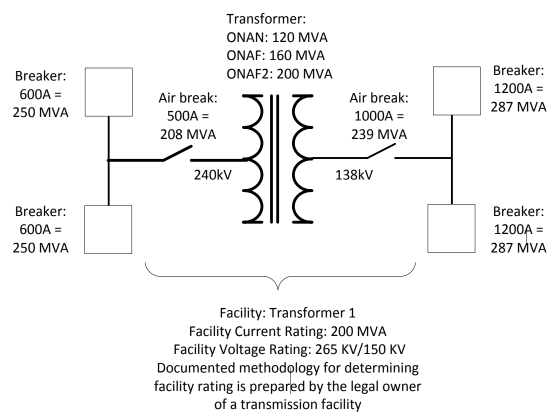


5.2 Transformer

The AESO considers point-to-point ampacity/MVA to be the facility rating for the purpose of applying FAC-008-AB-3 to transformers.

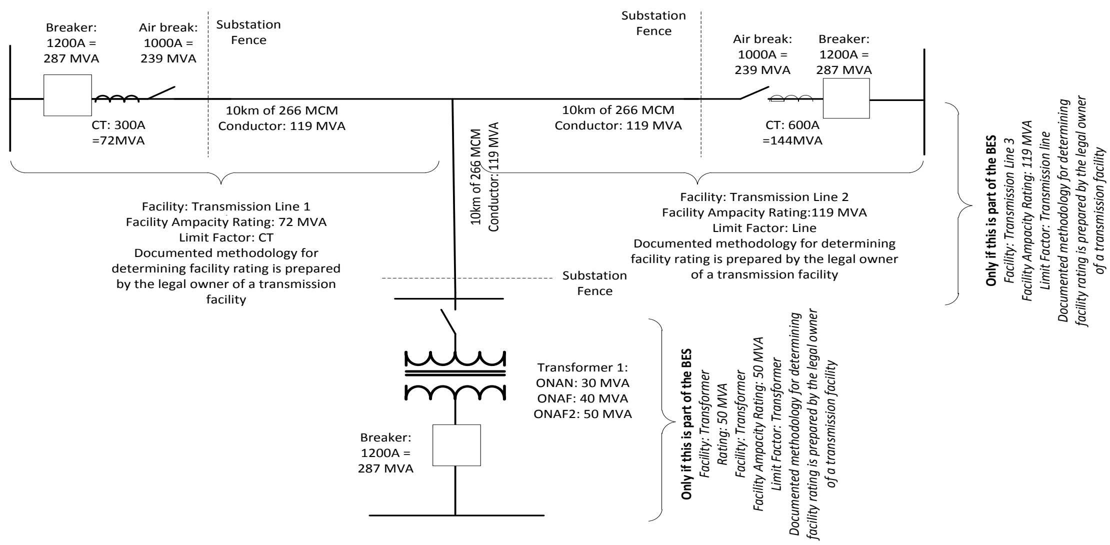


The transformer rating methodology may or may not include the limiting effect of the breaker and a half terminal equipment. If this terminal configuration poses a potential limit to the transformer capability with one of the two breakers open, then the AESO expects this limitation to be included in the rating methodology and that it be calculated and part of data submitted to the AESO as per Sections 502.15 and 304.6.

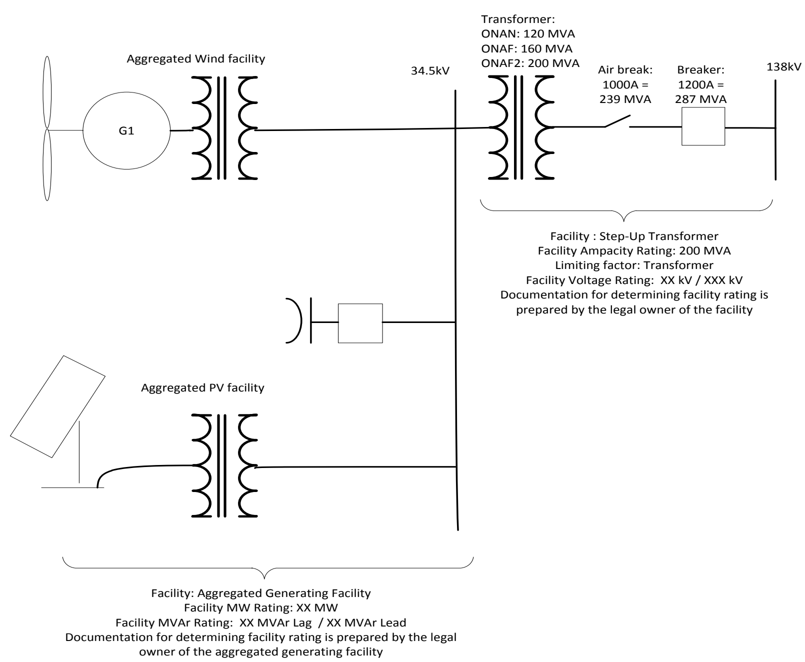


Transformers have two time-based emergency ratings associated with their capacity. The first rating is based on 30 minutes of overload. The second rating is based on a subsequent 3.5 hrs loading that follows the 30 minute overload rating.

5.3 T-Tap transmission lines

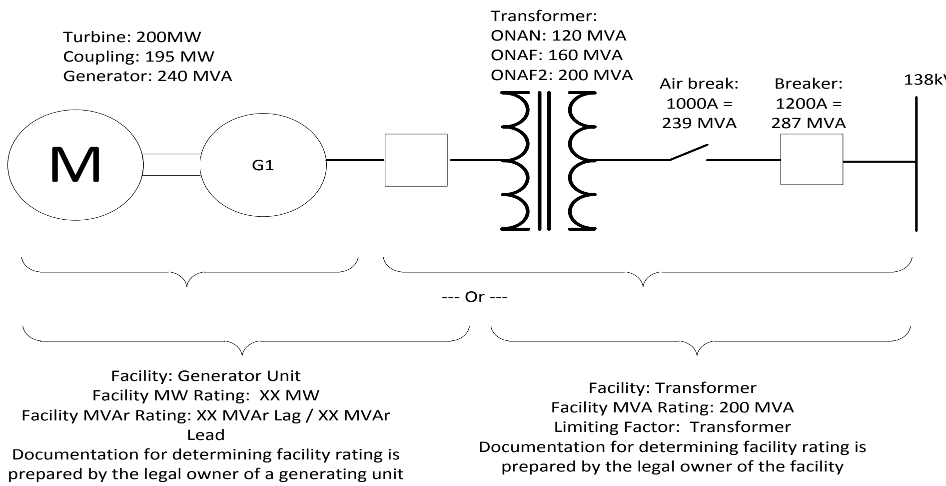


5.4 Aggregated Generating Facility



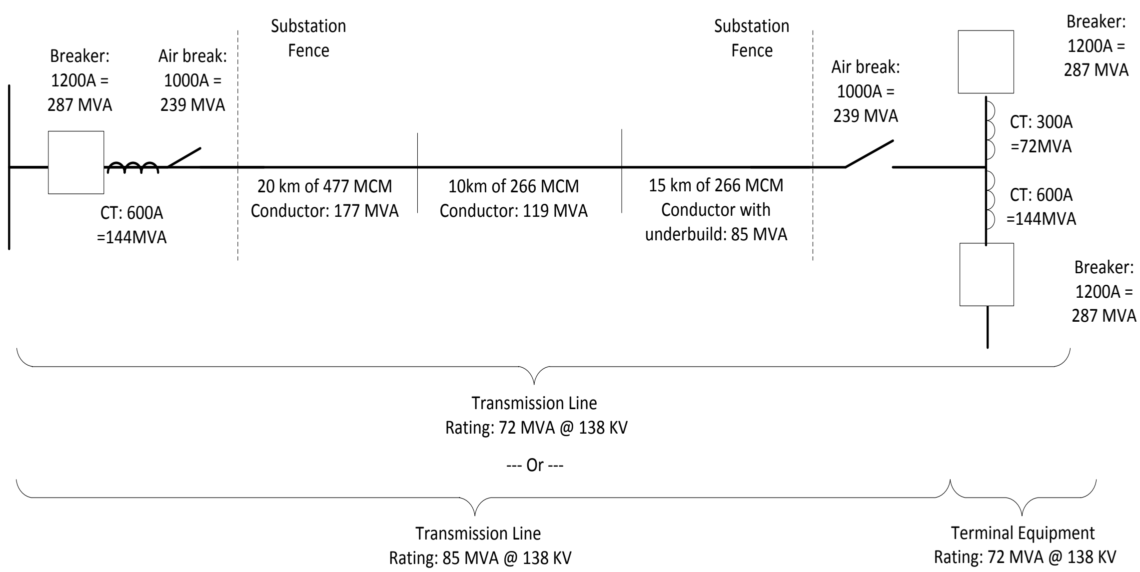
5.5 Generating Unit

Under FAC-008-AB-3, each legal owner is accountable for the facility rating methodology for the equipment it owns. With respect to generation facilities, this equipment ownership varies from site to site and so the facility rating methodology aligns with the equipment ownership. In the drawing below are two examples.



5.6 Lines with Breaker and a Half configuration

The transmission line rating methodology may or may not include the limiting effect of the breaker and a half terminal equipment. If this terminal configuration poses a potential limit to the transmission line capability with one of the two breakers open, then the AESO expects this limitation to be included in the rating methodology and that it be calculated and part of data submitted to the AESO.



Revision History

Posting Date	Description of Changes
2019-01-29	Updated to provide clarity on the meaning of “new” and “existing” facilities.
2017-11-09	Initial release.

Information Document
Automated Dispatch and Messaging System and Voice Communication System Requirements
ID #2017-006R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 502.4 of the ISO rules, *Automated Dispatch and Messaging System and Voice Communication System Requirements* ("Section 502.4").

The purpose of this Information Document is to provide general information relating to primary and emergency and backup voice communication system requirements.

2 Primary and Emergency and Backup Voice Communication System Requirements

The AESO recognizes that the manner in which the technologies specified in Section 502.4 are referred to may have changed over time and will be reviewing these requirements. The AESO encourages market participants to use the most robust technology and infrastructure possible for the purpose of primary and backup voice communication with the AESO's coordination centre.

3 Automatic Forwarding of Primary Direct Access Telephone Connection

Section 5(3) of Section 502.4 requires that a primary direct access telephone connection be a primary number with automatic forwarding to another number if the primary number is busy or otherwise not available. The intent of this requirement is for the forwarding to another number to achieve the same result as if the primary number had been answered. As such, the AESO encourages market participants to use any forwarding number that will be answered by a person who is available twenty four (24) hours a day, seven (7) days a week and is able to take or initiate immediate action, as appropriate.

4 Emergency and Backup Requirements for a Pool Participant who may receive an Ancillary Service Dispatch or a Directive

The intent of the emergency or backup requirement option for a pool participant who may receive an ancillary service dispatch or a directive to have a "mobile satellite network telephone and dispatch service", as outlined in subsection 7 of Section 502.4, row 2 of Table 1, is for the pool participant to have available a satellite network telephone that can be used to communicate with the AESO's coordination centre, as well as the generation plant's control room, so that an ancillary service dispatch or directive can be implemented without delay.

5 Appendices

Revision History

Posting Date	Description of Changes
2017-05-30	Initial release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 502.6 of the ISO rules, *Generating Unit Operating Requirements* ("Section 502.6").
- Section 502.16 of the ISO rules, *Aggregated Generating Facilities Operating Requirements* ("Section 502.16").

The purpose of this Information Document is to provide guidance on the content of a generating unit Model Validation and Reactive Power Verification Report, as described in

(a) subsection 13 of Section 502.6, and is related to the testing required under:

(i) subsection 10, Baseline Testing;

(ii) subsection 11, Model Revalidation Testing; and

(iii) subsection 12, Reactive Power Verification Testing; and

(b) subsection 13 of Section 502.16, and is related to the testing required under:

(i) subsection 10, Baseline Testing;

(ii) subsection 11, Model Revalidation Testing; and

(iii) subsection 12, Reactive Power Verification Testing.

The AESO has reviewed NERC reliability standards MOD-025-2 and MOD-026-1 and determined that the rules referenced above collectively adequately cover the requirements of MOD-025-2 and MOD-026-1 and as such the AESO has assessed MOD-025-2 and MOD-026-1 to not be applicable in Alberta.

The AESO generally agrees with the information contained in the following NERC technical reference documents and recognizes that they may be useful reference for the legal owner of a generating and the legal owner of an aggregated generating facility in the testing and reporting of subsections 10, 11, 12, and 13 of Sections 502.6 and 502.16.

- *NERC: Power Plant Model Verification using PMUs*
- *NERC: Power Plant Model Verification and Testing for Synchronous Machines*

2 Generating Unit Model Validation and Reactive Power Verification Report Content

The *Generating Unit Model Validation and Reactive Power Verification Report*, also known as "MVQ Report" described in subsection 13 of Section 502.6 was known in the past as the "WECC Report". It serves to document the purpose of the tests, description of the generating unit at the time of the tests, test processes employed, model derivation process, resulting simulation models, and the limitation of these models.

If more than one generating unit's test results are provided in the report, the AESO suggests providing items listed in (b) through (h) below for each generating unit.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

A *Model Validation and Reactive Power Verification Repo*rt includes the following information:

(a) a cover page that contains:

   (i) the generating facility name and generating unit name or in the case of aggregated generating factiy, the facility name;

   (ii) the name of the legal owner;

   (iii) the name, stamp and signature of the Professional Engineer licensed to practice engineering in the province of Alberta, who takes the engineering responsibility for the Model Validation and Reactive Power Verification Report;

   (iv) the date on which the tests were performed;

   (v) the report date; and

   (vi) the revision number of report;

   Additional information can be provided in the report itself.

(b) for non-aggregated generating facilities, a detailed description of each generating unit that contains:

   (i) the generating unit name and ID;

   (ii) the name of the legal owner;

   (iii) the location of the generating facility including the station name;

   (iv) the generating unit maximum authorized real power;

   (v) Nameplate data of the components of the generating unit:

      A. the generator nameplate data, including:

         - manufacturer;
         - frame/model number;
         - serial number;
         - ratings (MVA, RPM, kV, P.F.);
         - rated field current;
         - rated field voltage;
         - temperature rise;
         - cooling;
         - insulation class; and
         - date of manufacture;

      B. the excitation system nameplate, including:

         - type of excitation system;
         - manufacturer;
         - rotating exciter ratings (MVA, RPM, kV, P.F.);
         - excitation transformer name plate data (kVA, kV, impedance, etc.);
         - rated and maximum (ceiling) voltage and current; and

- o excitation control system (manufacturer, type and model number);

C. the power system stabilizer nameplate data (if applicable) , including:
- o manufacturer;
- o type; and
- o model number;

D. the prime mover nameplate, including:
- o manufacturer;
- o frame/model number;
- o ratings (MW, RPM, pressure, temperature, etc.);
- o model number;
- o fuel source; and
- o turbine type;

E. the turbine controller (governor) nameplate, including:
- o manufacturer;
- o type; and
- o model number;

If any item on the list is not applicable (i.e., induction machines having no exciter), explicitly state why.

(c) for aggregated generating facilities a detailed description of each generating unit that contains:

(i) the aggregated generating facility name and code;

(ii) the name of the legal owner;

(iii) the name and location of the connecting substation of the aggregated generating facility;

(iv) the aggregated generating facility maximum authorized real power;

(v) the modeled single line diagram of the aggregated generating facility showing the reduced representation diagram of collector system or systems and aggregated machine modeled at each collector bus and their ID;

(vi) equivalent impedance of the collector system; and

(vii) nameplate data of each type of generator or converter if there is more than one type in the aggregated generating facility:

A. the generator/converter nameplate data, including:
- o generator or converter type;
- o number of generating units with the aggregated generating facility;
- o manufacturer;
- o frame/model number;
- o ratings (MVA, RPM, kV, P.F.) including maximum and minimum real power and reactive power
- o rated field current (if applicable);

- rated field voltage (if applicable);
- temperature rise (if applicable); and
- cooling (if applicable);

B. the excitation system nameplate (if applicable), including:

- type of excitation system;
- manufacturer;
- rotating exciter ratings (MVA, RPM, kV, P.F.);
- excitation transformer name plate data (kVA, kV, impedance, etc.);
- rated and maximum (ceiling) voltage and current; and
- excitation control system (manufacturer, type and model number);

C. the power system stabilizer nameplate data (if applicable) , including:

- manufacturer;
- type; and
- model number;

D. the prime mover including photo voltaic module nameplate (if applicable), including:

- manufacturer;
- frame/model number;
- ratings (MW, RPM, pressure, temperature, etc.);
- fuel source; and
- turbine type;

E. the turbine controller (governor) or plant controller nameplate (if applicable), including:

- manufacturer;
- type; and
- model number;

(vii) reactive power compensation devices (if applicable), including:

A. manufacturer;

B. type (mechanically switched capacitor banks, STATCOM, etc.); and

C. ratings (MVAr and kV rating);

If any item on the list is not applicable (i.e., induction machines having no exciter), explicitly state the reason.

(d) a description for each of the transmission system step-up transformers in the generating facility that contains:

(i) the nameplate information including the MVA and kV ratings, impedance, and tap positions;

(ii) the transformer type (three 1-phase or one 3-phase) and also an indication of whether the transformer is an auto-transformer; and

(iii) the number of windings (2 or 3);

(e) a description of the testing and model validation process used to determine or validate the model parameters that contains:

(i) a summary paragraph identifying how the test(s) meet the AESO's testing requirements as stated in

A. subsections 10 to 12 of Section 502.6; and

B. subsections 10 to 12 of Section 502.16;

(ii) a plot of the performance of each model, overlaid on the test result for the same conditions;

(iii) the actual test data recorded during the test, in electronic tabular form;

(iv) in the case of a re-test report, the model parameters and model plot submitted may be taken directly from a prior test report, provided that the test data matches the test data from the prior test report;

(v) a description of the deficiencies and or limitations of each model when compared to the test data, including an assessment of the "quality of fit" between the test data and modelled data; and

(vi) discussion on any limitations encountered during the test and their effect on the model validation and reactive power testing;

In addition, stating the reason for testing in accordance with subsection 10(2) of Section 502.6 will assist the AESO's review process.

(f) simulation models for each generating unit that contains:

(i) the exact model being submitted to produce the performance plot;

(ii) block diagrams representing:

A. a standard PSS/E model, run with quarter-cycle time step; and

B. a standard PSLF model, run with a quarter-cycle time step;

(iii) a tabular listing of the parameters for each block diagram, including the validated values for all parameters for each PSS/E and PSLF model, with no parameters left blank;

(iv) the model as provided by the manufacturer or prior test reports. If a parameter chosen for the block diagram conflicts with manufacturer's datum or prior report for that parameter, provide an explanation for the difference; and

(v) any limitation of the models due to the generating unit operation modes. For example applicability of a turbine governor for steam turbines operating in sliding pressure mode;

Models should cover a wide range of operations, including maximum authorized real power.

No specific software package is mandated for performing the simulation and plot. Regardless of the software used to plot the model performance, the models must comply with the "Applicable PSS/E or PSLF model data" as stated in the *List of Electrical and Physical Parameters* referred to in Section 502.15 of the ISO rules, *Reporting Facility Modelling Data*. This includes the usage of the WECC's list of accepted standard PSS/E and PSLF library models.[2]

[2] The WECC's list of accepted standard PSS/E and PSLF library models is available on the WECC website at the following link https://www.wecc.biz/RAC/Pages/MVWG.aspx under the "Approved Dynamic Model" tab.

The AESO may validate the test results using the provided data in DYR and DYD files accompanied with the test report as follows:

(f.1) for each synchronous generating unit:

(i) the generator's MVA and kV used for per-unit calculations;

(ii) the generator's winding resistance, reactance (unsaturated) and time constants including Xd, Xq, X'd, X'q, X"d, X"q, Xl, T'do, T'qo, T"do, T"qo, Ta, and saturation factors;

(iii) the inertia of the generating unit including generator, turbine, rotating exciter and gearbox, if applicable;

(iv) the open circuit saturation curve with air-gap line;

(v) the generator's reactive power capability curve; and

(vi) the saturated positive, negative and zero-sequence impedances from manufacturer's data;

This data can be found on generator name plates and manufacturer's data sheets. Include the units of measure for each data point including per-unit base value.

(f.2) the generator capability curve (D Curve) at rated voltage should be superimposed with control limiter and protection curves:

(i) generator capability curve;

(ii) the generating unit's defined operating reactive power capability;

(iii) the generating unit's maximum authorized real power line;

(iv) the AESO's reactive power requirements limits in accordance with subsection 5(3) of Section 502.5 of the ISO rules, *Generating Unit Technical Requirements*;

(v) the generating unit's under-excitation limiter and over-excitation limiter setting curves; and

(vi) the effects of relays that encroach into the generating unit capability curve, i.e. loss of excitation relay curves;

(f.3) control systems are the major components of the generating unit directly controlling its terminal outputs. The AESO may validate provided data in DYR and DYD files for the following components of the generating unit's control systems:

(i) the turbine and controller (i.e. a governor or governor system);

(ii) the excitation system and automatic voltage regulator;

(iii) the power system stabilizer;

(iv) the compensators; and

(v) other important control functions such as limiters.

The type and settings of the over-excitation limiter, under-excitation limiter, stator current limiter and load compensator within automatic voltage regulator should be also provided if applicable.

Where manufacturer's data is not available, the report should explain the circumstances resulting in the omission and the assumptions made to compensate for the missing data.

A power system stabilizer validation report that contains plots of:

A. system performance measured response without power system stabilizer in service overlaid on system performance measured response with power system stabilizer in service, showing effective damping;

B. system simulated response without power system stabilizer in service overlaid on system performance measured response without power system stabilizer in service; and

C. system simulated response with power system stabilizer in service overlaid on system performance measured response with power system stabilizer in service.

A positive effect on system stability is expected from power system stabilier validation reporting.

(f.4) for converter based generating units:

(i) for solar photo voltaic plants [3]:

A. the power flow single line diagram as shown in Figure 1;

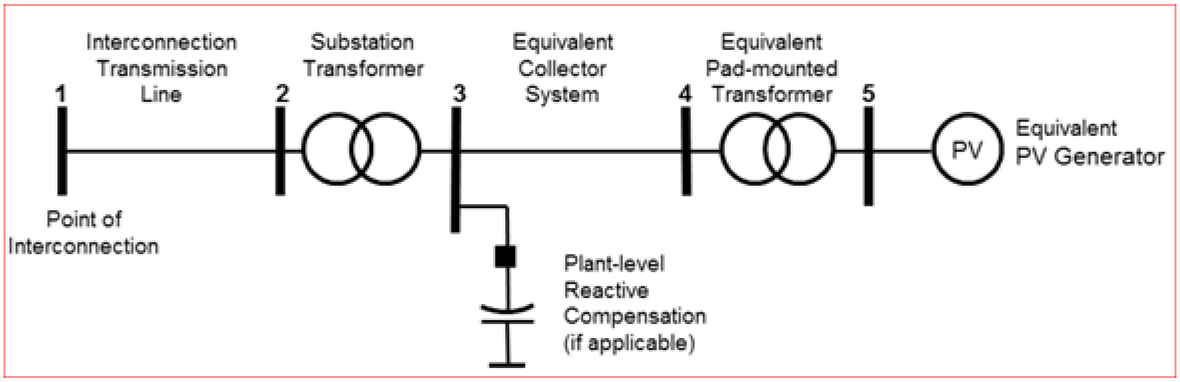


Figure 1- Single-Generator Equivalent Power Flow Representation for a PV Power Plant (from WECC Guideline)

B. the equivalent collector system parameters;

C. the reactive power compensator type, model, capabilities, and dynamics model and data;

D. in addition to the transmission system step-up transformers in the aggregated generating facility, the equivalent pad montoued transformer model; and

[3] There are two generic dynamic models for photo voltaic plants approved by WECC to be used in planning studies:

1) model consisting of plant controller, electrical controls and grid interface modules, intended for large-scale photo voltaic plants, and
2) simplified model intended for distribution-connected, aggregated photo voltaic plants.

This information document intends to provide guidance for large-scale photo voltaic plants connectedto the transmission system only. As described in *WECC Solar Plant Dynamic Modeling Guidelines* dynamic representation of large-scale photo voltaic plants requires the use of 3 renewable energy control modules as explained in this WECC guideline. For more information please refer to this guideline.
https://www.wecc.biz/Reliability/WECC%20Solar%20Plant%20Dynamic%20Modeling%20Guidelines.pdf

E. the photo voltaic plant's renewable energy control modules dynamics data as listed in Table 1;

Table 1- Renewable Energy Control Modules for solar and wind power plants implemented in the PSLF™, PSS®E, and PowerWorld platforms (from WECC Guideline)

Module	PSLF™modules	PSS®E modules	PowerWorld
Grid interface	regc_a	REGCAU1	regc_a
Electrical controls	reec_b	REECBU1	reec_b
Plant controller (if applicable)	repc_a	REPCAU1	repc_a

(ii) for wind power plants [4]:

A. the power flow single line diagram as shown in Figure 2;

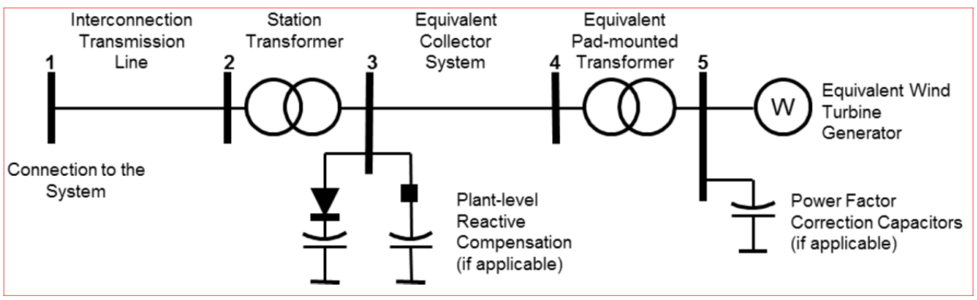


Figure 2- Single-Generator Equivalent Power Flow Representation for a Wind Power Plant

B. type of wind turbine technology;

C. the equivalent collector system parameters;

D. the reactive power compensator type, model, capabilities, dynamics model, and data;

E. the equivalent pad montoued transformer model;

F. the wind plant's renewable energy control modules dynamics data as listed in Table 1; and

G. the power factor correction capacitor capacity;

(g) all plots, raw data from test and simulation of the report:

(i) detailed and precise labels for the axes and traces;

[4] This information document provides guidance fore commercial wind power plants which use one of the 4 types wind turbine-generator technologies. For more information about the wind power plant power flow or dynamics modeling, please refer to the following WECC documents:

WECC Wind Plant Dynamic Modeling Guidelines :

https://www.wecc.biz/Reliability/WECC%20Wind%20Plant%20Dynamic%20Modeling%20Guidelines.pdf

WECC Wind Power Plant Power Flow Modeling Guide:
(https://www.wecc.biz/Reliability/WECC%20Wind%20Plant%20Power%20Flow%20Modeling%20Guide.pdf)

(ii) traces distinguishable in a black-and-white printed copy;

(iii) clear titles for each graph indicating the test that was performed;

(iv) appropriate scales for both axes; and

(v) the measured response of the test over an adequate period to confirm the modelled results; and

(h) include an accompanying data-file containing all test data and model simulation data in machine-readable tabular form (such as a comma-separated-variable text file and .DYR/.DYD files).

3 Model Revalidation and Partial Baseline Testing Reports

Model revalidation and partial baseline testing for conditions listed in subsections 10(2)(b) to (g) of Section 502.6; and also in subsections 10(2) of Section 502.16 may refer to the previously submitted *Model Validation and Reactive Power Verification Report* if the data source is appropriately referenced.

4 Contact Information

Please submit *Model Validation and Reactive Power Verification Reports* and associated data electronically to the AESO at psmm@aeso.ca. For *Model Validation and Reactive Power Verification Reports* conducted as part of an AESO connection project, please submit the *Model Validation and Reactive Power Verification Report* and associated data to the AESO Project Manager.

Revision History

Posting Date	Description of Changes
2018-09-04	Aggregated generation facilities included
2017-11-21	Initial release.

Information Document
Incidental ISO Rule Amendments
ID #2018-001R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Documents:

- Section 202.3 of the ISO rules, *Issuing Dispatches for Equal Prices* ("Section 202.3");
- Section 203.1 of the ISO rules, *Offers and Bids for Energy* ("Section 203.1"); and
- Section 203.6 of the ISO rules, *Available Transfer Capability and Transfer Path Management* ("Section 203.6").
- Section 304.9 of the ISO rules, *Wind and Solar Aggregated Generating Facility Forecasting* ("Section 304.9").

The purpose of this Information Document is to provide clarification for market participants in regards to outdated ISO rule references contained in certain existing ISO rules. The below table identifies each outdated ISO rule reference and the updated ISO rule reference where the related content is located.

2 Table of Concordance

Outdated ISO rule reference	Updated ISO rule reference
Section 202.3 Subsection 2(3): "Notwithstanding subsection 2(1), the **ISO** must: (a) determine **dispatch** volumes for a **pool asset** that is an import asset or an export asset in accordance with the procedures set out in OPP 301, *Alberta – BC Interconnection Scheduling* and OPP 302, *Alberta-Saskatchewan Interconnection Scheduling* …"	The updated reference is Section 203.6. Relevant content from Operating Policy and Procedure ("OPP") 301, *Alberta – BC Interconnection Scheduling* and OPP 302, *Alberta-Saskatchewan Interconnection Scheduling* was transitioned into the current ISO rule format.
Section 203.1 Subsection 3(4)(b): "… when submitted as part of a restatement under subsection 5(2) of section 203.4, *Energy Restatements*."	The updated reference is Section 203.3, *Energy Restatements*. The reference to Section 203.4 was intended to read Section 203.3, *Energy Restatements*.
Section 203.6 Subsection 5(1): "Notwithstanding subsection 3.5.2 of the ISO rules, *Submission Timing*…"	The updated reference is Section 203.1 of the ISO rules, *Offers and Bids for Energy.* Relevant content from the ISO rules, *Submission*

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Outdated ISO rule reference	Updated ISO rule reference
	Timing was transitioned into the current ISO rule format.
Section 203.6 Subsection 6(4)(b): "then the pool participant must submit, as applicable: (i) an energy restatement in accordance with either subsection 3.5.3.2 or subsection 3.5.4.2 of the **ISO rules**, *Mandatory Energy Restatements*; or	The updated reference is Section 203.3 of the ISO rules, *Energy Restatements*. Relevant content from the ISO rules, *Mandatory Energy Restatements* was transitioned into the current ISO rule format.
Section 203.6 Subsection 6(4)(b): "then the pool participant must submit, as applicable: (ii) an ancillary services restatement in accordance with subsection 3.6.3 of the **ISO rules**, *Restatements*."	The updated reference is Section 203.3 of the ISO rules, *Energy Restatements.* Relevant content from the ISO rules, *Restatements* was transitioned into the current ISO rule format.
Section 304.9 Subsection 4(6): "The **legal owner** of a wind or solar **aggregated generating facility** must determine, at 30 minute intervals, and submit to the ISO, the **gross real power capability** with a precision to the nearest 2.0 MW"	"**gross real power capability**" is intended to read "**gross real power** capability".

Revision History

Posting Date	Description of Changes
2018-05-11	Initial release

Information Document
System Restoration from Blackstart Resources
ID #2018-003RS

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta Reliability Standard *EOP-005-AB-2, System Restoration from Blackstart Resources* ("EOP-005-AB-2").

The purpose of this Information Document is to provide clarity to requirement R1 of EOP-005-AB-2. This Information Document is likely of most interest to operators of transmission facilities.

2 Areas of the Alberta Interconnected Electric System

Requirement R1 requires the operator of a transmission facility, that the ISO has identified in a list published on its website, to have a restoration plan. Such plan should enable the restoration of the transmission facility following a disturbance in which one or more areas of the Alberta interconnected electric system shuts down, and the use of blackstart resources is required to restore the area(s) to service.

3 Guidance Regarding Specificity of Processes

The AESO recognizes that specific control actions to stabilize voltage and frequency after an event on the transmission system may vary. The AESO expects each operator of a transmission facility to determine how general or specific their processes, under EOP-005-AB-2, need to be depending on the variables associated with each system restoration situation. For example, in situations where a system condition is anticipated, such as areas that are designed to island, it may be appropriate for the processes to be more specific. In situations where it may be difficult to predict how the events will unfold then a general process may be warranted.

4 Initial Switching Requirements

For clarity, "initial switching requirements", to be identified in accordance with requirement R1.5, are those that are needed to prepare transmission facilities on a cranking path for energization. These requirements may include opening line terminals, bus reconfigurations, transformer tap position adjustments, switching reactive elements, and coordination of any necessary switching with other entities such as an operator of generating unit, an operator of an electric distribution system or an adjacent operator of a transmission facility.

Revision History

Posting Date	Description of Changes
2018-06-07	Initial release

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Information Document
Central West Area Transmission Constraint Management
ID #2018-005R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* ("Section 302.1").

The purpose of this Information Document is to provide additional information regarding the unique operating characteristics and resulting constraint conditions and limits in the Central West area of the Alberta interconnected electric system (AIES). For the purposes of this Information Document, the Central West area is the area illustrated by the maps in Appendix 2 and 3.

Section 302.1 sets out the general transmission constraint management protocol steps the AESO uses to manage transmission constraints in real time on the AIES. These steps are referenced in Table 1 of this Information Document as they are applied to the Central West area.

2 General

Given the existing load, generation and transmission system configuration in the Central West area, with the loss of certain transmission lines or the Brazeau Generation Tripping Scheme (Remedial Action Scheme ("RAS") 25) being out of service, transient issues may occur for the next contingency.

A detailed geographical map of the Central West area indicating bulk transmission lines and substations is provided in Appendix 2 of this Information Document.

3 Constraint Conditions and Limits

When managing a transmission constraint in the Central West area, the AESO ensures that bulk transmission line flows out of the area are managed in accordance with bulk transmission line ratings established by the legal owner of the transmission facility to protect transmission facilities and ensure the continued reliable operation of the AIES.

3.1 Non-Studied Constraints and Limits

For system conditions that have not been pre-studied, the AESO uses energy management system tools and dynamic stability tools to assess unstudied system operating limits in real time. The limits are determined by monitoring Real Time Contingency Analysis to ensure flows do not reach an unsafe level after N-1 events.

3.2 Studied Constraints and Limits

The AESO's study of the Central West area identified the following constraints and limits:

Brazeau 62s Stability Concerns

The AESO monitors the Brazeau Generation Tripping Scheme (RAS 25) that is in place in the Central West area. When the Brazeau Generation Tripping Scheme is available, it monitors the status of 995L and the Brazeau units output to protect against N-1 thermal overloads by tripping Brazeau Unit 2 under certain conditions.

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Studies have indicated that with 995L, 202L or the Brazeau Generation Tripping Scheme (RAS 25) out of service, transient issues at Brazeau may occur for the next contingency. Refer to Appendix 4 for Brazeau N-1 Transient Stability Limits with the Brazeau Generation Tripping Scheme (RAS 25) Armed. With the Brazeau Generation Tripping Scheme (RAS 25) Not Armed, refer to Appendix 5 for N-1 Transient Stability Limits. For Brazeau N-1 Thermal Limits refer to Appendix 6.

Bighorn

With the loss of 848L, 870L, 717L, 166L, or 719L, transient issues at Bighorn generators occur when Bighorn generation is greater than 70MW and the next contingency occurs. Transmission reconfiguration is the preferred method to eliminate the transient stability concerns; however, depending on system conditions this may not be possible and curtailing Bighorn generation may be necessary.

4 Application of Transmission Constraint Management Procedures

The AESO manages transmission constraints in all areas of the AIES in accordance with the provisions of Section 302.1. However, not all of those provisions are effective in the Central West area due to certain operating conditions that exist in that area. Table 1 below describes the applicability of subsection 2(1) of Section 302.1 to the Central West area, and additional clarifying steps required to effectively manage transmission constraints in the area.

Table 1
Transmission Constraint Management
Sequential Procedures for the Central West Area

Section 302.1 of the ISO rules, subsection 2(1) protocol steps	Applicable to the Central West area?
(a) Determine effective pool assets	Yes
(b) Ensure maximum capability not exceeded	Yes
(c) Curtail effective downstream constraint side export service and upstream constraint side import service	No
(d) Curtail effective demand opportunity service on the downstream constraint side	No
(e)(i) Issue a dispatch for effective contracted transmission must-run	No
(e)(ii) Issue a directive for effective non-contracted transmission must-run	No
(f) Curtail effective pool assets in reverse energy market merit order followed by pro-rata curtailment	Yes
(g) Curtail effective loads with bids in reverse energy market merit order followed by pro-rata load curtailment	No

Applicable Protocol Steps

The first step in managing constraints in Alberta is to identify those generating units effective in managing a constraint. All of the generating units and loads operating in the Central West area are indicated in the single line diagram in Appendix 3 and the generating units effective in managing a transmission constraint in the Central West area are identified in Appendix 1. Pursuant to subsection 2(4) of Section 302.1, when a transmission constraint has been or is expected by the AESO to activate a RAS, the AESO recommences the procedural sequence in Table 1 (above) once the AESO ensures that the system is operating in a safe and reliable mode.

Step (a) in Table 1

The effective pool assets are as shown in Appendix 1.

Step (b) in Table 1

Ensuring maximum capabilities are not exceeded is effective in managing Central West area transmission constraints.

Step (c) in Table 1

There are no interties in the Central West area and curtailing import and export flows elsewhere on the system is not effective in managing a transmission constraint.

Step (d) in Table 1

Curtailing effective demand opportunity service on the downstream constraint side is not effective in managing transmission constraints in the Central West area because there is no demand opportunity service.

Steps (e)(i) and (ii) in Table 1

There are no transmission must-run contracts in the Central West area and using transmission must-run is not effective in managing a transmission constraint.

Step (f) in Table 1

Curtailing effective pool assets using reverse energy market merit order followed by pro-rata curtailment is effective in managing Central West area transmission constraints.

Step (g) in Table 1

When the local voltage RAS is not available, curtailing load is not effective in managing Central West transmission constraints.

5 Project Updates

As necessary, the AESO intends to provide information in this section about projects underway in the Central West area that are known to have an impact on the information contained in this Information Document.

6 Appendices

Appendix 1 – *Effective Pool Assets*

Appendix 2 – *Geographical Map of the Central West area*

Appendix 3 – *Central West Area Single Line Diagram*

Appendix 4 –*Brazeau N-1 Transient Stability Limits with Brazeau Generation Tripping Scheme (RAS 25) Armed*

Appendix 5 – *Brazeau N-1 Transient Stability Limits with Brazeau Generation Tripping Scheme (RAS 25) Not Armed*

Appendix 6 - Brazeau N-1 Thermal Limits

Revision History

Posting Date	Description of Changes
2019-02-07	Administrative amendments to Section 3, title changes to Appendix 4, and Appendix 5, addition of Appendix 6.
2018-09-19	Administrative amendments to Section 3. Table layout and title changes to Appendix 4, and Appendix 5. Removal of Appendix 6.
2018-04-25	Initial release

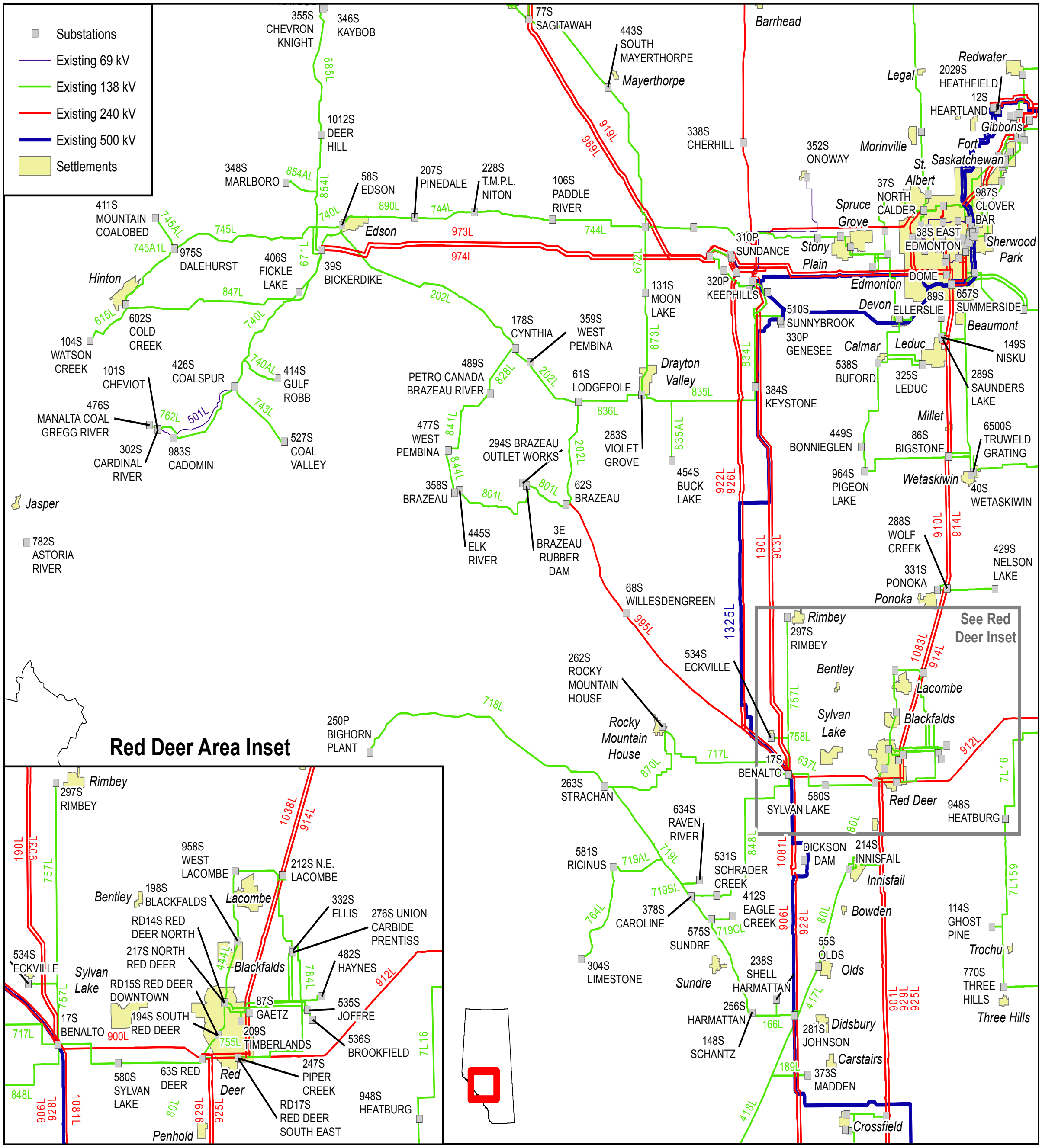
Appendix 1 – Effective Pool Assets

The effective pool assets for the Central West area, listed alphabetically by their pool IDs, are:

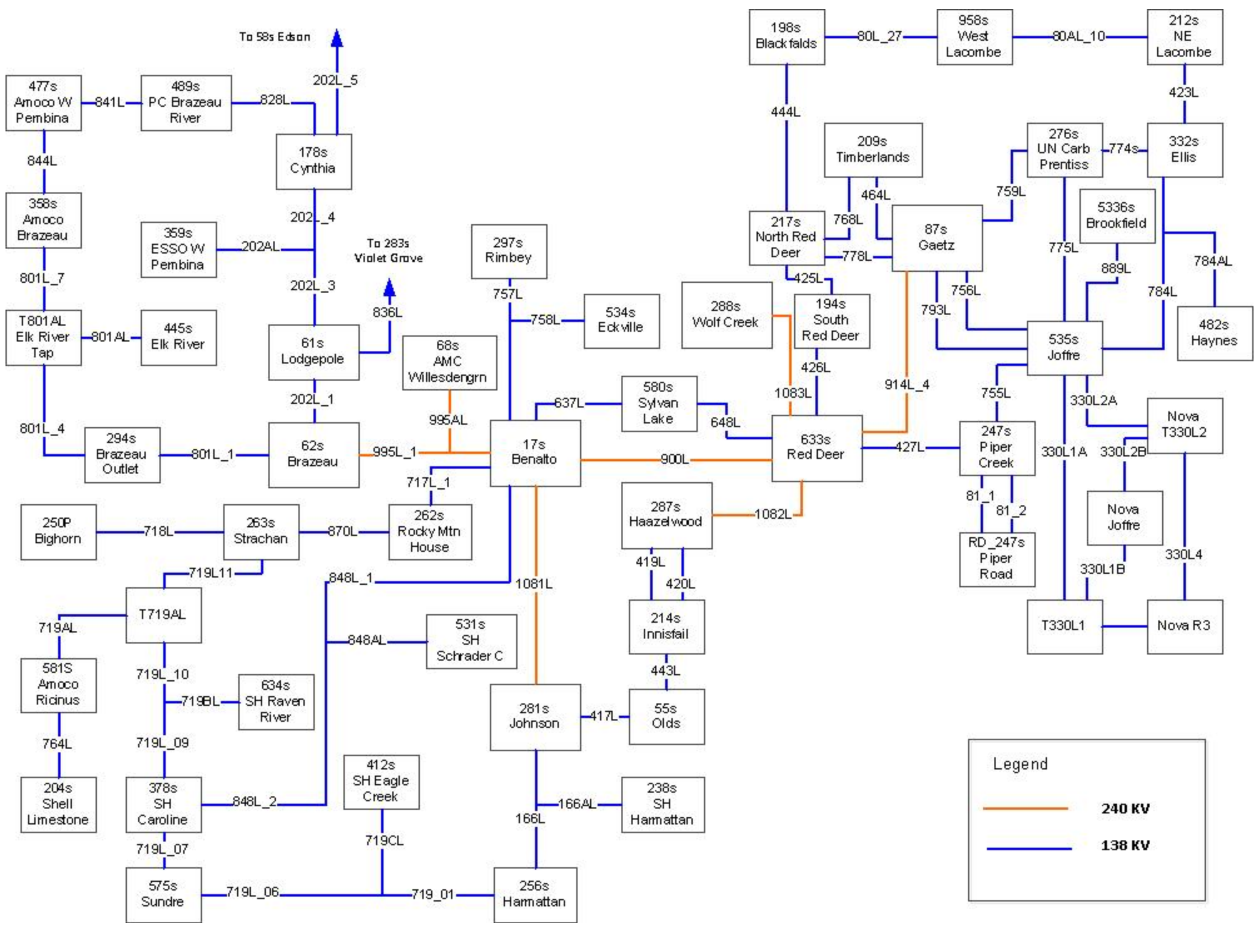
Big Horn (BIG)

Brazeau (BRA)

Appendix 2 – Central West Geographic Map



Appendix 3 – Central West Single Line Diagram



Appendix 4 – Brazeau N-1 Transient Stability Limits with Brazeau Generation Tripping Scheme (RAS 25) Armed

<table>
<tr><th colspan="2">Outage</th><th>Brazeau Units on line</th><th colspan="2">Transient Stability Limit (MW)</th></tr>
<tr><td>N-0 System Normal</td><td>None</td><td>Any combination</td><td colspan="2">N/A</td></tr>
<tr><td rowspan="7">N-1</td><td rowspan="4">202L
61s Lodgepole - 62s Brazeau</td><td rowspan="2">both units online</td><td>G1</td><td>150</td></tr>
<tr><td>G2</td><td>No Limit</td></tr>
<tr><td>only G1 online</td><td colspan="2">150</td></tr>
<tr><td>only G2 online</td><td colspan="2">135</td></tr>
<tr><td rowspan="3">995L[1]
62s Brazeau - 17s Benalto</td><td>both units online</td><td colspan="2">130</td></tr>
<tr><td>only G1 online</td><td colspan="2">95</td></tr>
<tr><td>only G2 online</td><td colspan="2">75</td></tr>
</table>

Note

1. Includes outages on either section of 995L.

Appendix 5 – Brazeau N-1 Transient Stability Limits with Brazeau Generation Tripping Scheme (RAS 25) Not Armed

<table>
<tr><th colspan="2">Outage</th><th colspan="2">Brazeau Output Limit (MW)</th></tr>
<tr><td>N-0
System
Normal</td><td>None</td><td>Any combination of Brazeau Units</td><td>255</td></tr>
<tr><td rowspan="18">N-1</td><td rowspan="3">995L
62s Brazeau - 17s Benalto</td><td>both units online</td><td>130</td></tr>
<tr><td>only G1 online</td><td>95</td></tr>
<tr><td>only G2 online</td><td>75</td></tr>
<tr><td rowspan="3">202L
61s Lodgepole - 62s Brazeau</td><td>both units on line</td><td>170</td></tr>
<tr><td>only G1 online</td><td>150</td></tr>
<tr><td>only G2 online</td><td>135</td></tr>
<tr><td>202L
178s Cynthia- 58s Edson</td><td colspan="2">225</td></tr>
<tr><td>202L
61s Lodgepole- 178s Cynthia</td><td colspan="2">255</td></tr>
<tr><td>672L
235s Entwistle - Moon Lake 131s</td><td colspan="2">235</td></tr>
<tr><td>673L
131s Moon Lake - 283s Violet Grove</td><td colspan="2">235</td></tr>
<tr><td>801L
62s Brazeau - 294s Brazeau Outlet Works</td><td colspan="2">240</td></tr>
<tr><td>801L
294s Brazeau Outlet Works - 358s Amoco Brazeau</td><td colspan="2">242</td></tr>
<tr><td>828L
489s P.C. Brazeau River - 178s Cynthia</td><td colspan="2">245</td></tr>
<tr><td>834L
320P Keephills - 384s Keystone</td><td colspan="2">250</td></tr>
<tr><td>835L
384s Keystone - 283s Violet Grove</td><td colspan="2">250</td></tr>
<tr><td>836L
283s Violet Grove - 61s Lodgepole</td><td colspan="2">200</td></tr>
<tr><td>841L
477s West Pembina - 489s P.C. Brazeau River</td><td colspan="2">245</td></tr>
<tr><td>844L
358s Amoco Brazeau - 477s West Pembina</td><td colspan="2">242</td></tr>
</table>

Note

1. Includes outages on either section of 995L.

Appendix 6 – Brazeau N-1 Thermal Limits

If real time contingency analysis allows a higher thermal limit for the contingencies listed in the table below, the AESO operates to the higher limit.

Outage		Brazeau Output Limit (MW) Summer (May 1-Oct 31)	Brazeau Output Limit (MW) Winter (Nov 1-April 30)
N-1	202L 61s Lodgepole - 62s Brazeau	140	170
	801L 62s Brazeau - 294s Brazeau Outlet Works	140	170
	801L 294s Brazeau Outlet Works - 358s Amoco Brazeau	145	175
	828L 489s P.C. Brazeau River - 178s Cynthia	165	195
	836L 283s Violet Grove - 61s Lodgepole	155	160
	841L 477s West Pembina - 489s P.C. Brazeau River	160	190
	844L 477s West Pembina - 489s P.C. Brazeau River	155	185
	995L 17s Benalto – 68s Willesdengreen	150	170
	995L 62s Brazeau – 68s Willesdengreen	140	160
	62sT5	300	300
	17s13 or 17s 12	205	235
	61s 138kV Bus 1	145	175

Information Document
PRC-005 Supplemental Information
ID #2018-009

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s) in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document[1]:

- PRC-005-AB-6 *Protection* System, *Automatic Reclosing, and Sudden Pressure Relaying Maintenance and Testing* ("PRC-005").

The purpose of this Information Document is to provide information on PRC-005 and the AESO's endorsement of the North American Electric Reliability Corporation's (NERC) *Supplementary Reference and FAQ PRC-005-6 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance and Testing* ("*Supplementary Reference and FAQ document*").

2 Applicability

The entities identified in subsection 2.1 of the Applicability section are required to apply the requirements of PRC-005 to the devices listed in subsection 2.2 of the Applicability section. The entity is responsible for determining, for its facilities, what actions are necessary to meet the requirements of PRC-005.

Note that PRC-005 will become effective in accordance with the timelines set out in the implementation plan in Appendix 5 of PRC-005.

3 NERC Supplementary Reference and FAQ document for PRC-005-6

The AESO generally agrees with the information contained within the *Supplementary Reference and FAQ document* and recognizes that it may be a useful reference for market participants as they implement PRC-005. In addition, the AESO may use the *Supplementary Reference and FAQ document* as reference material in assessing compliance with PRC-005.

4 Component Type

NERC's definition of "Component Type" from the *Supplementary Reference and FAQ document* refers to the "specific elements" of a protection system, automatic reclosing, and sudden pressure relaying. For convenience and to assist market participants in applying the information in the maintenance activities and intervals tables in Appendix 1, the component types for each device are listed below:

Device	Component Type
Protection System	• protective relay • communication system • voltage and current sensing devices providing inputs to protective relays • protection system station dc supply • control circuitry associated with protective functions
Automatic Reclosing	• reclosing relay • supervisory relay(s) or function(s) – relay(s) or function(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay • voltage sensing devices associated with the supervisory relay(s) or function(s) • control circuitry associated with the reclosing relay or supervisory

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

	relay(s) or function(s)
Sudden Pressure Relay	• fault pressure relay • control circuitry associated with a fault pressure relay

The AESO notes that PRC-005 splits Table 5 of Appendix 1 of the NERC standard into two tables, one for each component type.

5 Clarification of Other Terms Used in PRC-005

The AESO encourages market participants to consult NERC's definitions of the following terms in the *Supplementary Reference and FAQ document* when implementing PRC-005:

- Protection system maintainence program
    - Verify
    - Monitor
    - Test
    - Inspect
    - Calibrate
- Component
- Countable Event
- Automatic Reclosing
- Sudden Pressure Relaying

6 Cross Reference Table

The following table cross-references the content of the applicability section in the Alberta reliability standard with the corresponding section of the NERC standard to assist with finding related information in the *NERC Supplementary Reference and FAQ document* for PRC-005-6.

PRC-005-AB-6	NERC PRC-005-6
2.1(a) the legal owner of a transmission facility;	3.1.1 Transmission Owner 3.1.3 Distribution Provider
2.1(b) the legal owner of a generating unit; 2.1(c) the legal owner of an aggregated generating facility.	3.1.2 Generator Owner
2.2(a) protection systems and sudden pressure relays that are installed for the purpose of detecting faults on system elements as identified in section 2.1;	4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
2.2(b) protection systems used for the ISO's underfrequency load shedding program;	4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
2.2(c) protection systems used for undervoltage load shed systems installed to prevent system voltage collapse or voltage instability for the reliability of the interconnected electric system;	4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

PRC-005-AB-6	NERC PRC-005-6
2.2(d) protection systems installed as a remedial action scheme for the reliability of the interconnected electric system	4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

PRC-005-AB-6	NERC PRC-005-6
2.2(e) protection systems and sudden pressure relaying for generating units, including: (i) protection systems that act to trip the generating unit either directly or via lockout or auxiliary tripping relays; (ii) protection systems and sudden pressure relaying for generating unit step-up transformers; and (iii) protection systems and sudden pressure relaying for station service or excitation transformers connected to the generating unit bus, that act to trip the generating unit either directly or via lockout or tripping auxiliary relays;	4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including: 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. 4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES. 4.2.5.3 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
2.2(f) protection systems and sudden pressure relaying for aggregated generating facilities from and including the collector bus to a common point of connection at 100kV or above;	4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition: 4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.
2.2(g) automatic reclosing, including: (i) automatic reclosing applied on all transmission lines connected to a bus operated at a voltage level of 100 kV or higher located at generating plant substations where the combined maximum authorized real power is greater than 500 MW; (ii) automatic reclosing applied on all transmission line terminals operated at a voltage level of 100 kV or higher at substations one bus away from generating plants specified in Section 2.2 (g)(i) when the substation is less than 10 circuit-miles from the generating plant substation; and (iii) automatic reclosing applied as an	4.2.7 Automatic Reclosing , including: 4.2.7.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. 4.2.7.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less

PRC-005-AB-6	NERC PRC-005-6
integral part of a remedial action scheme specified in subsection (d).	than 10 circuit-miles from the generating plant substation. 4.2.7.3. Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

Revision History

Posting Date	Description of Changes
2019-04-10	Initial publication

Information Document
PRC-004 Supplemental Information
ID #2018-011

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta seliability standard PRC-004-AB2-1, *Analysis and Mitigation of Transmission and Generation Protection System Misoperation* ("PRC-004-AB2-1").

The purpose of this Information Document is to provide clarification related to protection system misoperations that affect the reliable operation of the bulk electric system.

2 Requirement R1

Requirement R1 refers to analyzing misoperations of protection systems that affect the reliable operation of the bulk electric system. This would include the misoperation of a protection system that protects a:

- bulk electric system element; or
- non-bulk electric system element that results in an unintended operation of a protection system that protects a bulk electric system element.

Revision History

Posting Date	Description of Changes
2019-04-10	Initial release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
Wind and Solar Power Ramp up Management
ID #2018-013R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Section 304.3 of the ISO rules, *Wind and Solar Power Ramp up Management*

The purpose of this Information Document is to describe the methodology used to calculate the Alberta system wind and solar aggregated generating facilities power limit and how the pro rata share is distributed.

2 Methodology Used to Calculate System Wind and Solar Power Limit

Pursuant to subsection 7(1) of section 304.3, the AESO is required to post "the methodology used to calculate the Alberta system wind and solar aggregated generating facilities power limit". The wind and solar power limit in MW for all non-exempt wind and solar aggregated generating facilities for a power ramp monitoring interval, with the interval not to exceed 20 minutes and the initial interval set at 10 minutes, will be the greater of (A) and (B), calculated as follows:

(A) (i) the total Alberta real power output from all non-exempt wind and solar aggregated generating facilities;

plus

(ii) the AESO estimates, in MW, of:

(a) the ramp rate-down capability, in MW per minute, of all pool assets in the energy market merit order for the power ramp monitoring interval;

plus

(b) any increases or decreases in the Alberta internal load for the power ramp monitoring interval;

plus

(c) any increases or decreases in any interchange schedule quantities for the power ramp monitoring interval*;* and

(B) (i) the total Alberta real power output from all non-exempt wind and solar aggregated generating facilities;

plus

(ii) 6.5 MW per minute for the power ramp monitoring interval.

The table below shows an example to illustrate the calculation of system wind and solar power limit.

A	B
A(i) = 250 MW	B(i) = 250 MW
A(ii) = 50 MW	B(ii) = 6.5 MW/min x 10 min monitoring interval = 65 MW
A = A(i) + A(ii) = **300 MW**	B = B(i) + B(ii) = **315 MW**

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

In the example above, since B is greater than A, the Alberta system wind and solar power limit is **315 MW**.

3 Methodology Used to Calculate the Pro Rata Share of the System Wind and Solar Power Limit

Pursuant to subsection 7(1) of section 304.3, the AESO is required to post “the methodology used to calculate the pro rata share of the Alberta system wind and solar aggregated generating facilities power limit to the AESO”. The AESO calculates the pro rata share for each of the non-exempt wind or solar aggregated generating facilities at the beginning of a power ramp monitoring interval, and may re-calculate the pro-rata share as frequently as every 1 minute until the next monitoring interval. The pro rata share calculation is not applicable to the aggregated generating facilities that are already limited by any curtailment directive or dispatch, other than a power ramp management directive. The AESO calculates the pro rata share using configurable weighting factors for potential MW, maximum capability and last ramp using the following equation:

$$Pro\ Rata\ Share = (A + B + C) * (D - E)$$

Where

A = the potential real power capability weighting of the non-exempt wind or solar aggregated generating facility as provided to the AESO under Appendix 2 of section 502.8 of the ISO rules, *SCADA Technical Requirements*. A is calculated as follows.

$$A = A1 * \frac{A2}{A3}$$

Where

A1 = the weighting percentage for the potential real power capability. This is currently 0%.

A2 = the wind or solar aggregated generating facility’s potential real power capability.

A3 = the sum of all potential real power capability for non-exempt wind and solar aggregated generating facilities participating in the pro rata calculation.

B = the max capability weighting of the non-exempt wind or solar aggregated generating facility. B is calculated as follows.

$$B = B1 * \frac{B2}{B3}$$

Where

B1 = the weighting percentage for the maximum capability. This is currently 20%.

B2 = the wind or solar aggregated generating facility’s maximum capability.

B3 = the sum of all maximum capabilities for non-exempt wind and solar aggregated generating facilities participating in the pro rata calculation.

C = the last ramp interval weighting of the non-exempt wind or solar aggregated generating facility as calculated based on the difference from start to finish of the look back interval period). C is calculated as follows.

$$C = C1 * \frac{C2}{C3}$$

Where

C1 = the weighting percentage for the last ramp value. This is currently 80%.

C2 = the wind or solar’s last ramp value.

C3 = the sum of last ramp values for all non-exempt wind and solar aggregated generating facilities participating in the pro rata calculation.

D = the Alberta system wind and solar power limit.

E = the total real power output from all non-exempt wind and solar aggregated generating facilities.

Below is an example to illustrate the pro rata calculation with 2 non-exempt wind and solar aggregated generating facilities. For this example, the Alberta system wind and solar power limit is **223 MW**. As mentioned above, the pro rata calculation weighting factor is 0% for potential MW, 20% for maximum capability, and 80% for last ramp value.

Wind/Solar Facility	Maximum Capability (MW)	Actual Output (MW)	Potential Output (MW)	Last Ramp
Facility 1	250	93	95	15
Facility 2	100	65	66	20
Total	**350**	**158**	**161**	**35**

The pro rata share for Facilities 1 and 2 are calculated as follows.

$$Facility\ 1\ Pro\ Rata\ Share = (\ 0 + 20\% * \left(\frac{250}{350}\right) + 80\% * \left(\frac{15}{35}\right)) * (223 - 158) = 32\ MW$$

$$Facility\ 2\ Pro\ Rata\ Share = (\ 0 + 20\% * \left(\frac{100}{350}\right) + 80\% * \left(\frac{20}{35}\right)) * (223 - 158) = 33\ MW$$

The resulting pro rata limits for Facility 1 and 2 are shown below.

Wind/Solar Facility	Maximum Capability (MW)	Actual Output (MW)	Pro Rata Share (MW)	Pro Rata Limit (MW)
Facility 1	250	93	32	93+32 = 125
Facility 2	100	65	33	65+33 = 98
Total	**350**	**158**	**65**	**223**

Revision History

Posting Date	**Description of Changes**
2018-09-04	Initial release

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document

- Section 502.1 of the ISO rules, *Aggregated Generating Facilities Technical Requirements,* ("Section 502.1")

The purpose of this Information Document is to provide general information relating to aggregated generating facilities. Section 502.1 is focused on the design and build domain. For clarity, Section 502.1 requires that a market participant, while designing and building its facilities, design and build the facilities in accordance with the requirements and obligations set out in Section 502.1.

2 Aggregated Generating Facility

An aggregated generating facility can have many devices and apparatuses at the generating units, through the collection system to the collector bus that can affect the real power, reactive power, and voltage delivered to the collector bus. Section 502.1 requires that the determination of the real and reactive power is done at the voltage that is the 1.00 per unit voltage for the collector bus.

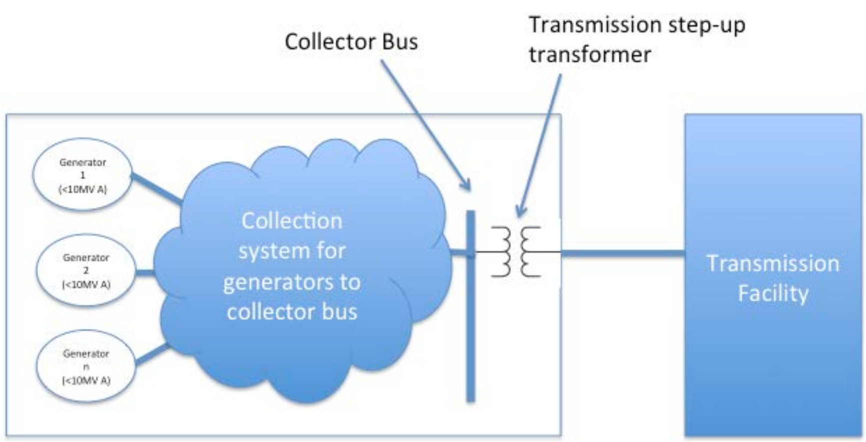


Figure 1

As shown in Figure 1, the collection system can be very simple to very complex, and can have lengthy arrangements of lines and apparatuses. The generating units can be sourced from energy such as solar, wind, hydro, or natural gas.

The collector bus can be a simple arrangement of a connection to the low voltage side of the transmission step-up transformer to a physical bus where multiple collection feeders connect prior to the connection of any transmission step-up transformers.

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3 Reactive Power Requirements

This section provides guidance on the reactive power requirements in subsection 4 of Section 502.1.

There are some key considerations for reactive power such as the physical point at which reactive power is determined, the voltage level at which reactive power is determined, the minimum amount of dynamic reactive power, and the use of fixed reactive resources such as capacitors or reactors.

An aggregated generating facility can have many devices and apparatuses at the generating sources, through the collection system to the collector bus that can affect the real power, reactive power, and voltage delivered to the collector bus. Figure 1 illustrates the location of a collector bus. Because some reactive devices are voltage sensitive to the amount of reactive power that can be supplied or absorbed, Section 502.1 has set 1.00 per unit as the voltage at which the reactive power is determined.

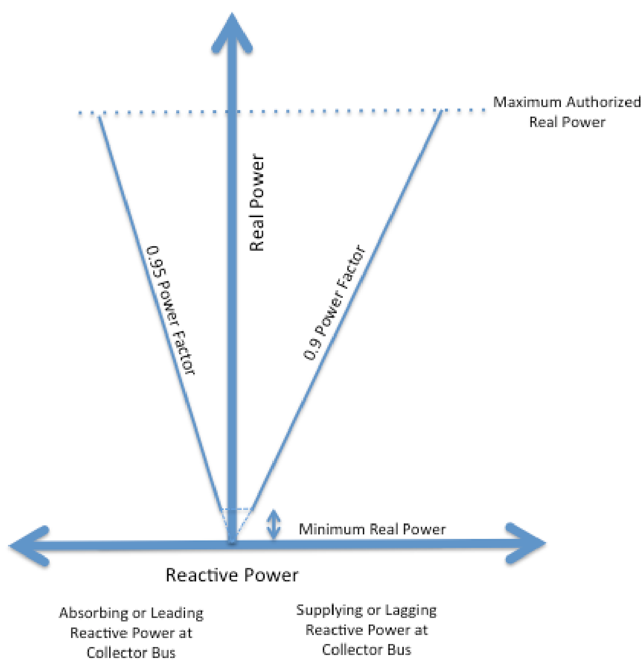

Figure -2

Another consideration for reactive power is that, as set out in subsection 4(3) of Section 502.1, the reactive power range from 0.9 power factor supplying to 0.95 power factor absorbing is to be fully dynamic. Figure 2 above illustrates that the minimum amount of reactive power supplied at the collector bus meets or exceeds 0.9 power factor for real power operation from a minimum real power level to the maximum authorized real power level. Figure 2 above also illustrates that the minimum amount of reactive power absorbed at the collector bus meets or exceeds 0.95 power factor for real power operation from a minimum real power level to the maximum authorized real power level. For example, if the maximum authorized real power is 100 MW, the requirement of 0.9 power factor would be 48.43 MVAr supplying and 31.22 absorbing, or a range from supplying to absorbing of 79.65 MVArs.

In many cases the dynamic reactive power is produced from the generating units. In some facility designs where the collection system is lengthy, it is possible that the dynamic reactive power may be offset by the reactive power characteristics of the collection system.

If a legal owner finds, for example, that the facility has an adequate range of dynamic reactive power but cannot achieve the required 0.9 power factor supplying, or 0.95 power factor absorbing, the facility design could incorporate fixed shunt devices to correct the dynamic reactive power range to the required power factor requirements at 1.00 per unit voltage on the collector bus. If the legal owner uses fixed shunt devices, the AESO will accept a load flow study report as evidence that full dynamic reactive power will be available at the collector bus level and fixed shunt devices will only be used to compensate internal system losses.

If fixed shunt devices are required at specific real power levels to satisfy the 0.9 power factor supply and 0.95 power factor absorbing requirements, these shunt devices may or may not be under the control of the voltage regulation system.

a. Voltage Regulation Requirements

This section provides guidance regarding the voltage regulation requirements in subsection 6 of Section 502.1. There are some key considerations for voltage regulation such as the difference between where a voltage can be measured and where the voltage is controlled, and the response time of a voltage regulation system.

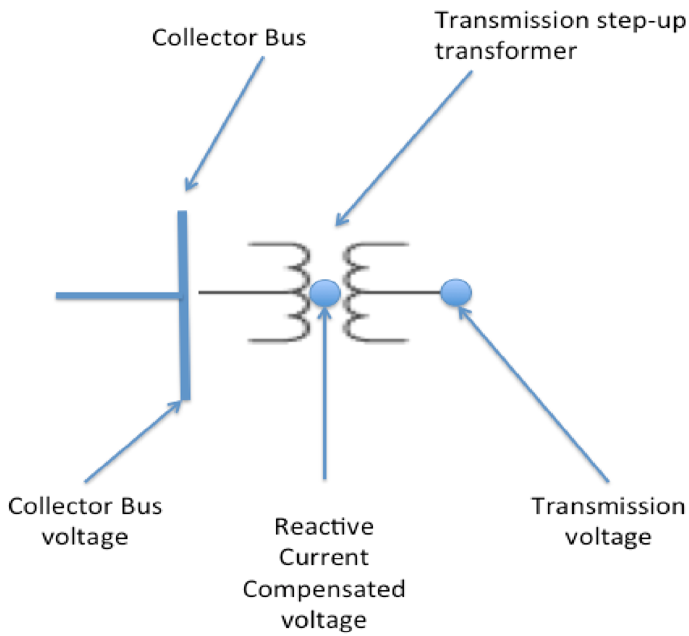

Figure 3

As set out out in subsection6 (2) of Section 502.1 of the ISO rules, the AESO does not permit any generating unit or aggregated generating facility to directly control transmission voltage. It is possible to measure transmission voltage at a facility. However, reactive current compensation is required to create a voltage control point between the collector bus and mid-impedance of the transmission step-up transformer. Figure 3 illustrates 3 voltage points: 2 that can be directly measured and 1 that can be determined through measurement based on the impedance of the transmission step-up transformer.

Where the facility configuration is such that an aggregated generating facility is to measure the transmission voltage, the reactive current compensator would be set to a value where the voltage is determined closer to the collector bus. The voltage regulation system would use this compensated voltage and control the reactive resources to maintain collector bus voltage within the requirements set out in subsection 6 of Section 502.1.

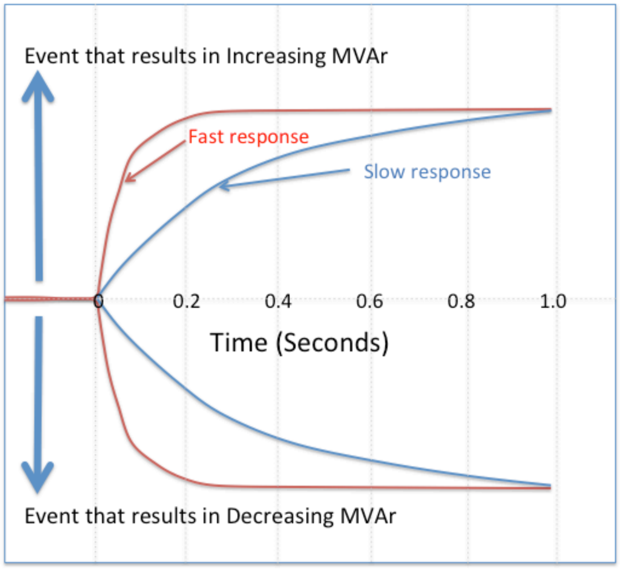

Figure 4

Subsection 6(10) of Section 502.1 outlines a response time for voltage regulating systems or automatic voltage regulators of “no sooner than zero point one (0.1) seconds and no later than 1.0 second following a step change in voltage”. The intent of a response of no later than 1.0 second is to ensure reasonable response time to coordinate voltage regulation with other generation facilities. The intent of a response of no sooner than 0.1 seconds is to prevent system instability that may result under weak system conditions, which can occur with transmission line outages. Figure 4 is a simple illustrative example of the reactive power response. Actual reactive power response will be dependent on many conditions and will not likely match the simple example shown in Figure 4.

b. Voltage Ride-Through Requirements

The voltage ride-through requirements set out in subsection 5 of Section 502.1 are based on the 1.00 per unit voltage of the transmission voltage at the high voltage side of the transmission syste step-up transformer (see Figure 3). An aggregated generating facility is required to remain connected to the transmission system for conditions described in subsection 5 and Appendix 1 of Section 502.1. When transmission voltages rise above or drop below a threshold and time duration, a facility may trip off. The voltage ride-through requirements are a “must ride-through” requirement and not a “must trip” requirement.

Transmission voltages can increase or decrease rapidly, or they may exhibit a swing or oscillatory type behavior as shown in Figure 4. Rapid behavior is often nearly instantaneous, and swings or oscillatory behavior could be at rates less than 1 Hz or rates up to 10 Hz or higher. These over and under voltage behaviors are illustrated in Figure 5.

As set ot in subsection 5(2)(b) of Section 502.1, if the transmission voltage rises above or drops below the voltage thresholds and period of time described in Appendix 1 of Section 502.1, an aggregated generating facility is allowed to trip.

Figure 6 illustrates 2 transmission voltage behaviors where an aggregated generating facility is allowed to trip. The over voltage example is a rapid change where the voltage exceeds 1.20 per unit and the aggregated generating facility is allowed to trip off instantaneously. The under voltage example shows a swing behavior where the voltage behavior drops below a 0.75 per unit threshold and a 0.65 per unit threshold. The 0.75 per unit threshold has a 2.0 second duration and the 0.65 per unit threshold has a 0.30 second duration. The example shows where the voltage dips below the 0.65 per unit then rises above the 0.65 per unit threshold. The voltage then drops below the 0.65 per unit threshold and exceeds the 0.30 second duration, where the aggregated generating facility is allowed to trip off.

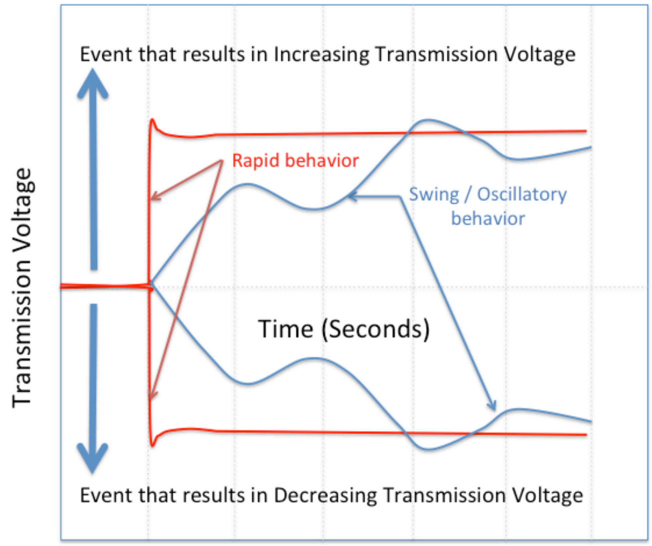

Figure 5

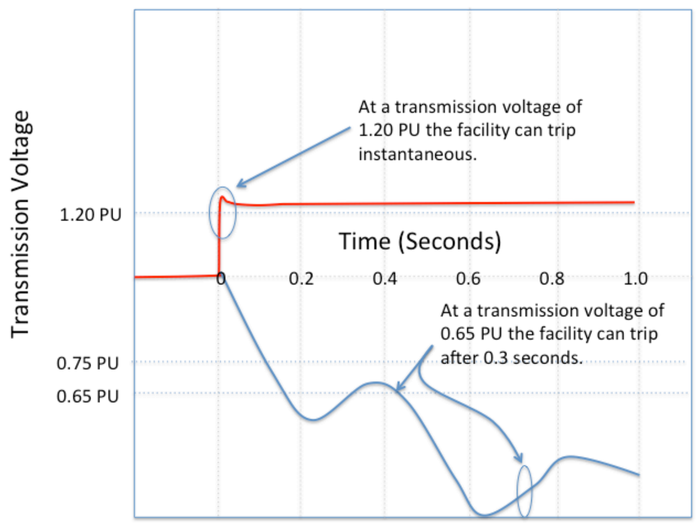

Figure 6

c. Frequency and Speed Governing Requirements

The frequency and speed requirements of subsection 7 of Section 502.1 are based on the frequency of the voltage at the aggregated generating facility. Subsection 7 describes 2 types of requirements. The first type of requirement is outlined in subsection 7(1)(b) and describes governor system requirements where an aggregated generating facilities' real power ouput is reduced when frequency exceeds 60 Hz. The second is outlined in subsection 7(3) and describes the scenarios of over- and under-frequency thresholds and durations where a facility is not permitted to trip, and where a facility is permitted to trip, if the threshold and duration is exceeded.

Frequency can increase or decrease and exhibit a swing or oscillatory type behavior. The rate of change of frequency is often slower than voltage changes as frequency is subject to the inertia of the system.

System frequency will always have some movement up and down, and the governor systems can have up to a 0.036 Hz deadband so that the controls are not reacting to small frequency changes. When frequency deviates, such as in the the over-frequency example shown in Figure 7, the real power will reduce at a rate set by the governor system droop, which can be set between 3% and 5% as described in subsection 7. As frequency is restored, the real power will increase back to the real power capability or real power limit if a power limit was put into effect for the aggregated generating facility.

For an under-frequency event shown in Figure 8, it is likely that the aggregated generating facility would be operating at its maximum real power capability or at a real power limit, and the real power output would not increase for the under-frequency event. However, if the aggregated generating facility is providing ancillary services, where the real power output of the aggregated generating facility is less than the real power capability, then the real power output would increase subject to the deadband and droop requirements.

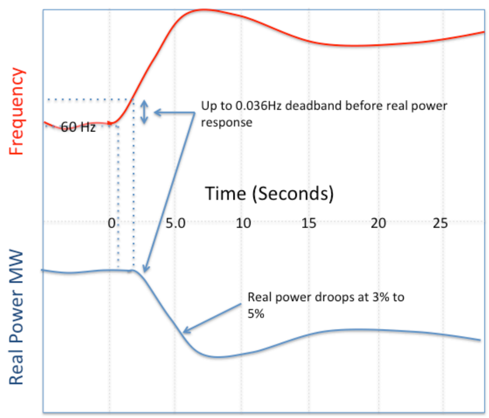

Figure 7

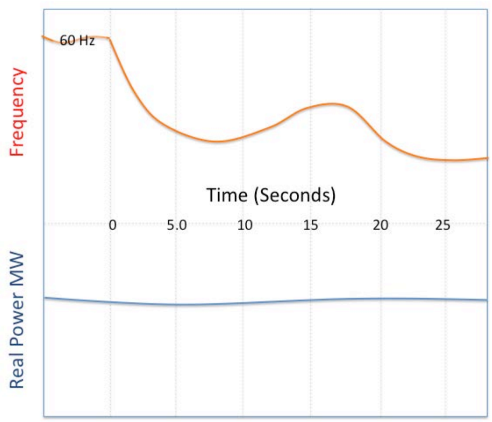

Figure 8

The second type of requirement is outlined in subsection 7(3) and describes the scenario where an aggregated generating facility is not permitted to trip within a specified frequency threshold and duration unless there is an equal amount of load tripped simulatenously that satisfies the requirements set out in subsection 7. Subsection 7 does not have requirements for an aggregated generating facility to trip, though an aggregated generating facility is allowed to trip outside the zone created between the blue and red lines in Appendix 2 of Section 502.1.

As set out in subsection 7(3) of Section 502.1, if the frequency rises above or drops below the frequency thresholds and period of time described in Appendix 2, an aggregated generating facility is allowed to trip.

Figure 9 illustrates 2 frequency behaviors where an aggregated generating facility is allowed to trip. The over-frequency example is where the frequency exceeds 61.7 Hz and the aggregated generating facility is allowed to trip off instantaneously. The under frequency example is where the frequency drops below 57.8 Hz threshold for more than 7.5 seconds at which point the aggregated generating facility is allowed to trip.

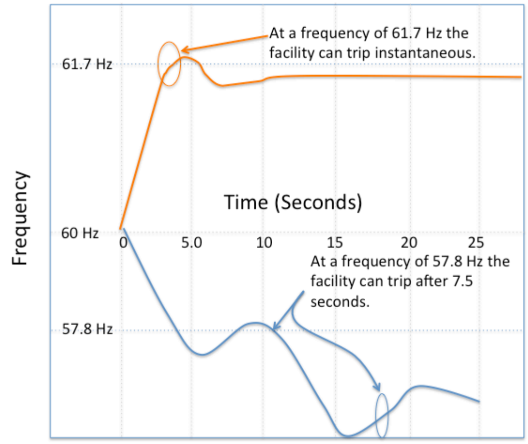

Figure 9

Revision History

Posting Date	Description of Changes
2018-09-04	Initial release

Information Document
AESO Designation of Generating Units
ID #2018-015R

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This information document provides general information relating to existing generation facilities the AESO designates as generating units, as provided for in the definition of "aggregating generating facility" which is effective on September 1, 2018.

This Information Document relates to the following Authoritative Documents:

(a) Section 502.1 of the ISO rules, *Aggregated Generating Facilities Technical Requirements*; and

(b) Section 502.16 of the ISO rules, Aggregated Generating Facilities Operating Requirements.

2 Background and History

The AESO amended the definition of "aggregated generating facility". The new definition, set out below is effective on September 1, 2018.

> "**aggregated generating facility**" means, unless otherwise designated by the **ISO**, an aggregation of two (2) or more **generating units**, including any associated **reactive power** resources, where:
>
> (i) each **generating unit** is rated less than 9 MW;
>
> (ii) all **generating units** are situated in the same proximate location and have a common collector bus or multiple collector busses that can be operated as a common collector bus; and
>
> (iii) the **aggregated generating facility** is connected to the **interconnected electric system** or the electrical system in the service area of the City of Medicine Hat.

The AESO has realised that this definition will put some generation facilities, existing on September 1, 2018, which are using generating units smaller than 9MW and connected at the common collector bus, into the regime of aggregating generating facilities. The AESO does not intend to treat those facilities under the definition of aggregating generating facilities and those facilities will continue to operate as generating units.

The aggregated generating facilities that the AESO designates as generating units are listed in the attached Appendix 1. The AESO may amend the list as required.

3 Appendices

Appendix 1 – *List of facilities the ISO designates as a generating unit*

Revision History

Posting Date	Description of Changes
2018-09-04	Initial Release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Appendix 1 – List of facilities the ISO designates as a generating unit

Generator	FACILITY_CODE	CSD Name	Asset ID
Horseshoe1	3S	Bow Hydro	BOW
Horseshoe2	3S	Bow Hydro	BOW
Horseshoe3	3S	Bow Hydro	BOW
Horseshoe4	3S	Bow Hydro	BOW
Kananaskis1	2S	Bow Hydro	BOW
Kananaskis2	2S	Bow Hydro	BOW
Kananaskis3	2S	Bow Hydro	BOW
AB Newsprint G1	122S	AB Newsprint	ANC1
AB Newsprint G10	122S	AB Newsprint	ANC1
AB Newsprint G2	122S	AB Newsprint	ANC1
AB Newsprint G3	122S	AB Newsprint	ANC1
AB Newsprint G4	122S	AB Newsprint	ANC1
AB Newsprint G5	122S	AB Newsprint	ANC1
AB Newsprint G6	122S	AB Newsprint	ANC1
AB Newsprint G7	122S	AB Newsprint	ANC1
AB Newsprint G8	122S	AB Newsprint	ANC1
AB Newsprint G9	122S	AB Newsprint	ANC1
Drywood 1	415S	Drywood	DRW1
Drywood 2	415S	Drywood	DRW1
Slave Lake Pulp	844S	Slave Lake	SLP1
University of Alberta	N/A	University of Alberta	UOA1
Northstone Power	N/A	NPC1 Denis St. Pierre	NPC1
University of Calgary	N/A	U of C Generator	UOC1
Altagas Edson	N/A	Edson	TLM2
Dickson Dam	N/A	Dickson Dam	DKSN
Minnehik-Buck Lake	N/A	Minnehik-Buck Lake	PW01
House Mountain	N/A	House Mountain	HSM1
Lethbridge Taber	N/A	Lethbridge Taber	ME02
Lethbridge Burdett	N/A	Lethbridge Burdett	ME03
Lethbridge Coaldale	N/A	Lethbridge Coaldale	ME04
JL Landry	N/A	JL Landry	NPC2
ALP	N/A	ALP	ALP2

Generator	FACILITY_CODE	CSD Name	Asset ID
MFC Mazeppa	N/A	MFC Mazeppa	MFG1
Ralston	N/A	Ralston	NAT1
West Cadotte	N/A	West Cadotte	WCD1

Information Document
PRC-002-AB-2 Disturbance Monitoring and Reporting Requirements
ID #2018-022

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta Reliability Standard PRC-002-AB-2, *Disturbance Monitoring and Reporting Requirements*

The purpose of this Information Document is to provide information regarding fault recording data and will be of most interest to any legal owner of a transmission facility, legal owner of a generating unit, or legal owner of an aggregated generating facility that owns fault recording data.

2 Supplemental Information For Fault Recording Data (Requirement R4)

The intent of requirement R4 is to capture the fault recording data of the connected system elements on the bulk electric system buses identified in requirement R1.1 for the duration specified in requirement R11.1. If setting triggers solely pursuant to requirements R4.3.1 and R4.3.2, i.e. neutral (residual) overcurrent and phase under voltage or overcurrent, would result in undesired events being captured and pose the risk of overwriting the data required by requirement R4, the legal owner may add additional triggers with the associated thresholds in accordance with their own practices and standards.

Revision History

Posting Date	Description of Changes
2019-01-10	Initial release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
PER-003-AB-1 Clarification of Terms
ID #2018-023

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta Reliability Standard PER-003-AB-1, *Operations Personnel Credentials* ("PER-003-AB-1")

The purpose of this Information Document is to provide further information regarding item (c) of the Applicability section of PER-003-AB-1, specifically, the meaning of "operating authority".

2 Meaning of operating authority

PER-003-AB-1 only applies to those transmission facilities that are part of the bulk electric system. Item (c) of the Applicability section of PER-003-AB-1 is worded such that it only applies if all transmission facilities of the operator meet the criteria. If an operator of a transmission facility has even one transmission facility that is not covered by "an operating agreement with a NERC-certified operator", item (c) does not apply.

In the context of item (c), the AESO considers the term "operating authority" to mean that the NERC-certified operator has the authority and accountability for decision-making in relation to the operation of the subject transmission facility. The AESO expects an operator of any transmission facilities that is subject to item (c) to only operate those transmission facilities on the bulk electric system in coordination with, and approval of, a NERC-certified operator with which they have an operating agreement that specifies the coordination protocol.

3 Meaning of direct supervision

Requirement R2 requires that each real time operating position that performs reliability-related tasks be staffed with a NERC certified operator. However, NERC provides the following footnote in relation to requirement R2:

> "Non-NERC certified personnel performing any reliability-related task of an operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-relate[d] tasks."

The AESO agrees with this clarification.

Revision History

Posting Date	Description of Changes
2018-12-20	Initial release

[1] "Authoritative Documents" is the general name given by the AESO to categories of documents made by the AESO under the authority of the *Electric Utilities Act* and associated regulations, and that contain binding legal requirements for either market participants or the AESO, or both. AESO Authoritative Documents include: the ISO rules, the Alberta reliability standards, and the ISO tariff.

Information Document
FAC-003-AB1-1 Guidance Information
ID#2019-002

Information Documents are not authoritative. Information Documents are for information purposes only and are intended to provide guidance. In the event of any discrepancy between an Information Document and any Authoritative Document(s)[1] in effect, the Authoritative Document(s) governs.

1 Purpose

This Information Document relates to the following Authoritative Document:

- Alberta Reliability Standard FAC-003-AB1-1, *Transmission Vegetation Management Program* ("FAC-003-AB1-1").

The purpose of this Information Document is to provide guidance information to assist market participants in preparing a Transmission Vegetation Management Program (TVMP), the Transmission Vegetation Management Annual Plan (TVMAP) and reporting changes and events in accordance with FAC-003-AB1-1.

2 TVMP and TVMAP Templates

Requirement R1.1 specifies the TVMP must define a schedule for and the type (aerial or ground) of right-of-way (ROW) vegetation inspections, whereas requirement R2 specifies an annual plan for vegetation management work plan (such as manual or mechanical clearing, and herbicide treatment) which is referred to TVMAP.

The templates for completing the TVMP and the TVMAP, as referenced in MR1 and MR2 of FAC-003-AB1-1, are available on the AESO website:

- The Management Program Template is the template for the TVMP.
- The Management Program Template Instructions.
- The Management Plan Template is the template for TVMAP.

The AESO recommends treating and submitting the plans separately as the objectives, practices, approved procedures, and work specifications are different for R1 and R2 of FAC-003-AB1-1.

3 Changes to TVMP

Requirement R1 specifies that the TVMP program is to be updated at least annually and Requirement R1.1 specifies that the schedule for the type of inspections must be flexible enough to adjust for changing conditions.

If details in the TVMP change, the AESO expects that these changes are documented, preferably in a revised TVMP, as soon as the changes are identified.

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4 Changes to TVMAP

When a change to the vegetation management plan as specified in TVMAP occurs due to uncontrollable circumstances such as environmental factors, outage constraints or safety concerns, the AESO expects that the changes are documented as they occur, preferably in a revised TVMAP, including the reasons for the change, measures to mitigate the impact and the proposed schedule.

5 Quarterly Reporting for R3

Where a reportable event occurs as per R3, the legal owner of the transmission facility may use the Quarterly Outage Report Template to report the event to the AESO.

Should no reportable events have occurred in the past quarter, the AESO expects that the legal owner of a transmission facility to submit an e-mail stating that no such outages occurred in such quarter on a quarterly basis by the 10th day of the following month (Q1 – April 10, Q2 – July 10, Q3 – October 10, Q4 – January 10).

Event reports and confirmation e-mails of no events occurring within a quarter should be sent to both the following email addresses:

rscompliance@aeso.ca

ars@aeso.ca

Revision History

Posting Date	Description of Changes
2019-04-02	Initial release