Information Document
Minimum Procurement Volume
ID #XXXX-XX

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 207.1 of the ISO rules, *Gross Minimum Procurement Volume* ("Section 207.1").

The purpose of this Information Document is to provide details on the model and methodologies that the AESO uses to assess resource adequacy and determine the gross minimum procurement volume.

2 Background

The AESO uses a model to assess resource adequacy and determine a gross minimum procurement volume that meets a resource adequacy standard defined by the Government of Alberta. The AESO has chosen a probabilistic model for this purpose. The AESO has selected the Strategic Energy and Risk Valuation Model ("SERVM") software to house its Resource Adequacy Model.

3 Gross Minimum Procurement Volume

3.1 Translating the Resource Adequacy Standard

The AESO anticipates[2] the Government of Alberta's resource adequacy standard will be defined in regulation. The resource adequacy standard uses a normalized expected unserved energy metric. This is the allowable expected percentage of total gross load in megawatt-hours that is not served in a given 12-month period as a result of demand exceeding the available capacity.

The AESO utilizes 150 load scenarios to evaluate resource adequacy. To translate the resource adequacy standard into an expected unserved energy value for an obligation period, the AESO calculates a weighted average total load value using the same weights that are used to evaluate scenarios within the probabilistic model. This total load value will then have the resource adequacy standard's percentage applied to arrive at the expected unserved energy value.

[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] This refers to the expected Resource Adequacy Standard as the regulation anticipated to define this level is still going through stakeholder consultations. https://www.energy.alberta.ca/AU/electricity/AboutElec/Pages/Stakeholder.aspx

Table 1 – Translating the Resource Adequacy Standard Example

Weather Year	Economic Scenario (MWh)				
	Min	**Low**	**Ref**	**High**	**Max**
2013	88,201,701	88,745,839	89,318,404	89,998,857	90,643,171
2014	88,309,346	88,851,730	89,423,371	90,104,017	90,749,550
2015	87,810,217	88,350,305	88,919,059	89,595,404	90,236,244
2016	87,606,332	88,147,448	88,716,259	89,391,709	90,030,718
2017	88,291,771	88,837,906	89,412,574	90,096,199	90,744,033
Average of weather years	88,043,873	88,586,646	89,157,933	89,837,237	90,480,743
Weighted Average of Load Scenarios	0.1	0.2	0.4	0.2	0.1
Sum product of Average Weather years and Weighted Average					89,200,412
Apply the Resource Adequacy Standard (i.e. NEUE of 0.0011%)					981

3.2 Addition or Subtraction of Capacity from the Model

The AESO adds or subtracts volumes of maximum capability from the modeled fleet (base) to identify the relationship between capacity and resource adequacy (i.e. expected unserved energy). The AESO runs different defined asset mixes in the model to evaluate the reliability metrics at each level. The type and characteristics of the capacity added or removed to the Resource Adequacy Model aligns with the characteristics of the reference technology. The AESO then identifies the appropriate maximum capability values that meet resource adequacy standard based on the maximum capability-expected unserved energy relationship.

3.3 Calculation of Procurement Volume

Due to the fact that the Resource Adequacy Model fleet runs are in increments of generic technology, the exact expected unserved energy output from the various fleet runs may not achieve the resource adequacy standard exactly.

To align the gross minimum procurement volume from the Resource Adequacy Model with the resource adequacy standard, the AESO applies a curve line fit to the results of the model for the 6 modelled fleets that are closest to the resource adequacy standard (3 below and 3 above).

Table 2 - Resource Adequacy Standard Curve Fitting Example:

Maximum Capability	%NEUE	EUE (MWh)
Base Fleet (+46.5 MW)	0.001784%	1,591
Base Fleet (+93)	0.001434%	1,279
Base Fleet (+139.5)	0.001148%	1,023
Min Procurement Volume (+156)	**0.001100%**	**981**
Base Fleet (+186)	0.000957%	853
Base Fleet (+232.5)	0.000798%	712
Base Fleet (+279)	0.000668%	595

This example shows using the resource adequacy standard on a curve line fit on the three normalized expected unserved energy values above the resource adequacy standard and the three normalized expected unserved energy values below the resource adequacy standard. The AESO is then able to calculate a minimum procurement volume.

4 Probabilistic Resource Adequacy Model

The AESO uses a probabilistic approach to estimate the gross minimum procurement volume for each base auction and rebalancing auction. A probabilistic approach provides information on the relationship between capacity and supply adequacy and captures the correlations between supply and demand variability. This results in an informed and accurate estimation of the gross minimum procurement volume.

Supply shortfalls can have many drivers, including: high load, low conventional generator availability, low variable resource output, low water inflows to energy-limited hydro, and low or zero intertie availability. Developing robust results requires accurately characterizing the magnitude of uncertainties associated with each driver, preferably by calibrating model inputs and outputs against historical data whenever possible. Also important is reviewing the underlying drivers of historical reliability events and ensuring that each driver is represented in the Resource Adequacy Model.

4.1 Available Generation

The AESO models thermal assets using consistent input assumptions with other simulation modeling within the AESO, and simulates system generation availability relative to total load, taking into account both energy and ancillary services' needs. Historical available capability data informs planned outage periods, forced outage rates, and temperature derates used in the simulation. At this time, the AESO does not consider transmission constraints within Alberta as a factor that impacts resource availability.

Current and anticipated generation and demand response assets with a maximum capability of 5 MW or greater are included in the Resource Adequacy Model, including assets that are not eligible to participate in the Alberta capacity market.

Currently, the AESO has visibility of generating units with a maximum capability of 5 MW and greater, and is able to reasonably determine outage rates and other key characteristics for these generating units. The AESO currently does not have sufficient visibility of assets with a maximum capability of less than 5 MW to include data in the Resource Adequacy Model. In the future, the Resource Adequacy Model will account for capacity assets with a maximum capability of less than 5 MW as data becomes available from their participation in the capacity, energy, and ancillary services markets.

4.2 Outages of Thermal Assets

The Resource Adequacy Model simulates the unavailability of conventional generators based on forced outage events. The current model accounts for the possibility of partial unavailability (i.e. temperature de-rates), the time-sequence and duration of outages, and differences in forced outages and planned outages.

4.2.1 Planned Outages

The maintenance scheduling algorithm in SERVM is based on daily peak loads, and schedules significant maintenance events in the spring and fall due to lower loads in those periods. The objective of the algorithm is to add maintenance events such that each event added impacts the lowest load days. The capacity from the maintenance event is added to the daily peak load for the calculations for the next asset to be placed on maintenance. In this way, the daily peak load plus planned maintenance is minimized.

Historical analysis indicates that cogeneration output is lower during the periods when the algorithm schedules maintenance events, and the cogeneration aggregation method described in subsection 4.5 of Section 207.1 does not take into account in the maintenance scheduling algorithm. As a result, preliminary runs of the Resource Adequacy Model showed elevated reliability issues in the spring and fall. To mitigate this issue and better capture historic scenarios, the AESO will manually reschedule some planned outages from the algorithm original schedule in such a way that reliability issues are more evenly spread out through the year, rather than concentrated in a few months.

The planned maintenance outage rate is a percentage of time in a year that the generating unit will be on a maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods. The AESO did not assign any planned maintenance rates to natural gas generating units with less than 20 MW of nameplate capacity due to data limitations. The forced outage rate for these generating units captures all outage hours.

The AESO calculates maintenance rates using the latest 2-year period of available capability data. While the maintenance patterns vary from year-to-year for individual generators, the aggregate MWh on maintenance for the entire system is relatively stable, so a 2-year view of events is a reasonable proxy for the duration and magnitude of planned maintenance events for the fleet. While the simulations may over- or under-estimate the impact on reliability of an individual generating unit's planned outage schedules, the aggregate impact on reliability of the entire fleet's outage schedule is realistic.

4.2.2 Forced Outages

To simulate forced outages the AESO enters historical forced outage events for each generating unit, and SERVM randomly draws from these events to simulate the generating unit forced outages. The AESO enters historical forced outage events using the following variables:

Full Outage Modeling

Time-to-Repair Hours

Time-to-Fail Hours

Partial Outage Modeling

Partial Outage Time-to-Repair Hours

Partial Outage Derate Percentage

Partial Outage Time-to-Fail Hours

The Resource Adequacy Model uses historical thermal forced outage event data from the previous 5 years to create sets of forced outage distributions. The AESO calculates a seasonal distribution of time-to-fail and time-to-repair hours for each generating unit that is available in order to ensure that the historical behaviour is captured in SERVM. The AESO calculates forced outage rates and partial outage rates for each generating unit with historical available capability data. The forced outage data captures both delayed forced outages and automatic forced outages.

As part of this process, the AESO validates the data and uses judgement to identify and classify events. The AESO reviews historical data and categorizes outage events based on a reason code with full and partial forced outage events categorized as ‘1’ and all other events/hours as ‘0’. The AESO used total declared energy, defined analysis period and a maximum value to calculate the partial outage rates. Planned outages were removed from the data based on analyst judgement and knowledge. Analytical judgement is applied to assess if any impactful forced outage events are extremely rare or abnormal to determine if they should be excluded or reduced in the forced outage distribution.

The AESO divides forced outage events into seasonal distributions - November through April for winter, and May through October for summer.

The AESO split generating units in Alberta by 4 fuel types, being coal, combined cycle gas, simple cycle gas, and other thermal assets, for the forced outage analysis.

4.2.3 Temperature Derates

The AESO calculates technology output curves, estimated by the AESO using historical available capability data and corresponding weather data to capture adjustments in maximum capability due to ambient temperature derates, and uses them to model weather related derates for combined cycle and simple cycle generating units. The Resource Adequacy Model references the temperature derate curve with the applicable hourly temperature value being used in the simulation to look up an associated capacity multiplier to determine the output capacity of the generating unit under the simulated hour’s temperature assumption. This methodology ensures consistent temperature drivers across demand and combined cycle and simple cycle generation output.

4.3 Intermittent Resources

The AESO uses historical hourly (or sub-hourly) wind and solar output profiles to simulate the variability of these sources over an annual time series. The AESO incorporates 30 years of annual profiles into the modeling to be consistent with historical weather, wind, and solar conditions. The AESO uses plant-level data to build regional profiles for each resource type. As a best practice, the AESO maps these profiles to the same weather year used in each load profile in order to capture the correlation between load and intermittent generation profiles.

4.3.1 Wind Profiles

The Resource Adequacy Model maps wind resource profiles to the same weather year used for the load profiles in order to capture the correlation between load and intermittent wind generation. The AESO develops wind profiles for the Resource Adequacy Model by using metered output from existing wind farms and simulated output for weather years for which there is no historical metered output. When simulating the AESO maintains correlations between aggregated wind zones.

It is necessary to develop wind profiles to take into account the diversity of production from intermittent sources in Alberta. When evaluating resource adequacy, it is important to use multiple hourly weather correlated profiles to represent uncertainty in renewable generation. There is insufficient historical data to cover 30 years of weather uncertainty for all sites. The AESO develops simulated wind shapes incorporating historical metered output from existing sites. The AESO aggregates shapes by geographic locations and maintained correlations between wind output sites.

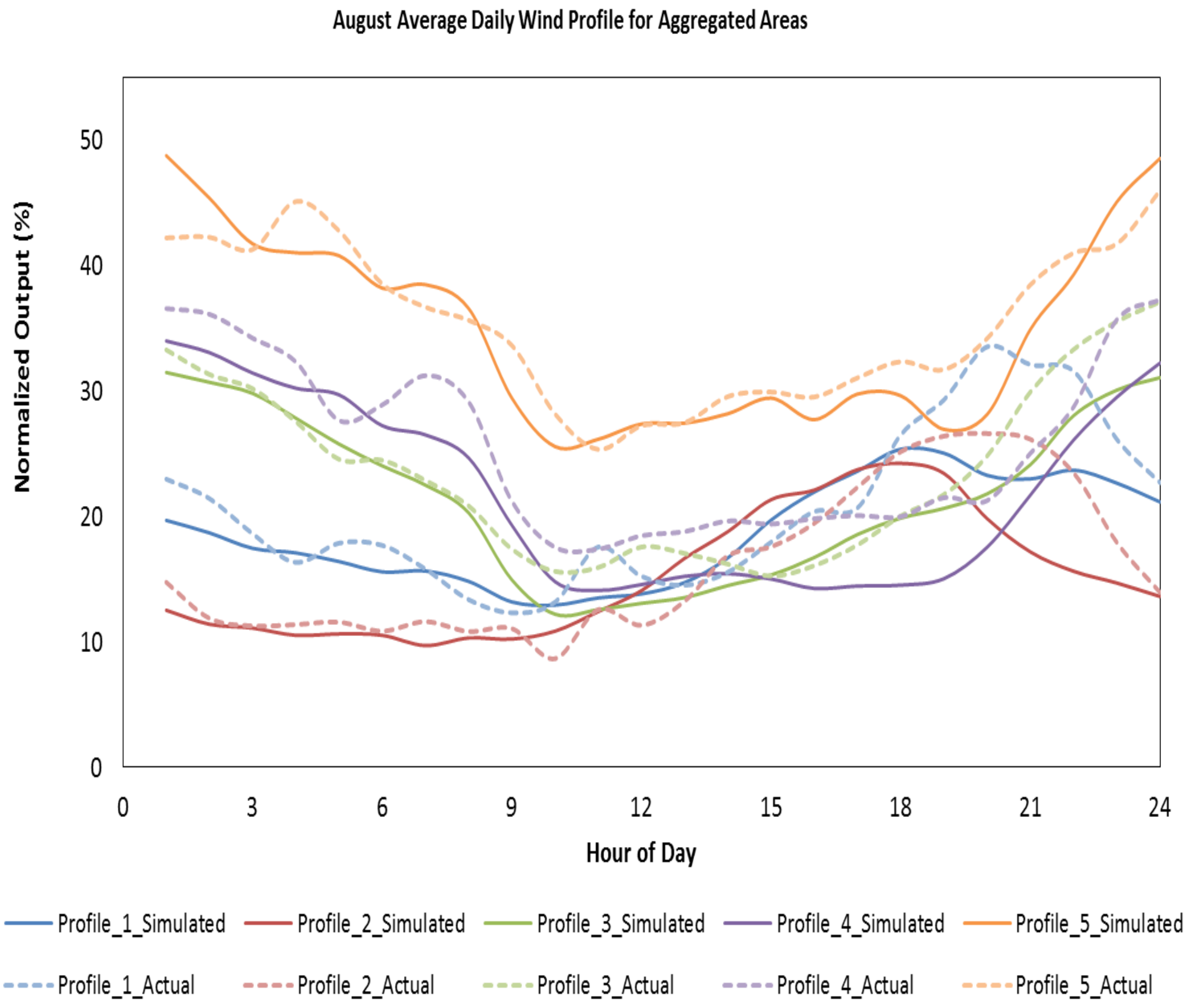
To develop wind shapes using historical metered output from existing sites, the AESO normalized the raw data to 100% by dividing each value by the maximum output of the site. The AESO aggregates wind weather shapes by geographical locations according to wind output correlations, and groups projects that were approximately 80% or more correlated. As expected, the correlations closely matched geographic proximity.

The AESO creates aggregated profiles by averaging the outputs of all the sites in the area.

The AESO imported the aggregated average wind profiles into SERVM, and tied all wind farms modeled (existing and future sites) to the proper wind shapes.

The figure below illustrates indicative daily wind profiles.

Figure 1



4.3.2 Solar Profiles

The Resource Adequacy Model maps solar resource profiles to the same weather year used for the load profiles in order to capture the correlation between load and intermittent solar generation. The AESO develops solar profiles using the National Renewable Energy Laboratories data, and simulates for weather years for which there is no data.

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The AESO develops solar shapes for the Resource Adequacy Model from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB -

https://nsrdb.nrel.gov/nsrdb-viewer) Data Viewer. Historical solar data from the NREL NSRDB Data Viewer included variables such as temperature, cloud cover, humidity, dew point, and global solar irradiance.

The AESO inputs the data obtained from the NSRDB Data Viewer into NREL's System Advisory Model (SAM - https://sam.nrel.gov/download) for each year and location to generate the hourly solar profiles based on the solar weather data for both a fixed solar photo voltaic plant and a tracking solar photo voltaic plant. Inputs in SAM included the direct current to alternating current ratio of the inverter module, and the tilt and azimuth angle of the photo voltaic array.

The AESO developed solar profiles to be used in on-going RAM modeling for 1987 to 1998 and 2017 by using the daily solar profiles from the day that most closely matched the peak load out of all the days +/- 2 days of the source day that is available for the 19-year interval. The profiles for the remaining years 1998 to 2016 came directly from the normalized raw data.

The figures below illustrate the solar shapes.

Figure 2 - August Daily Tracking Solar Profile

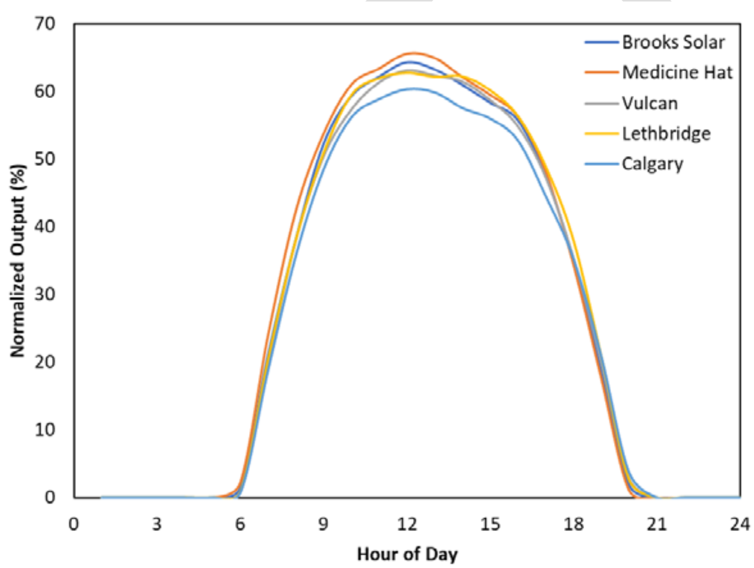
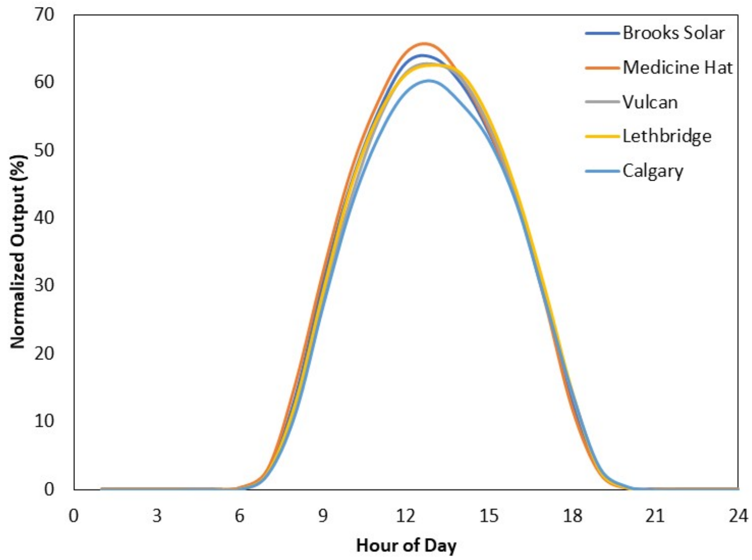


Figure 3 - August Daily Fixed Solar Profile



4.4 Hydroelectric Generation

The AESO models hydro using historical values to develop dispatch schemes so that the simulated dispatch of the hydro fleet closely mimics the actual dispatch of the fleet, taking into account the hydrological nature of annual and monthly system conditions. Furthermore, the model considers weather correlated historic profiles to accurately assess the contribution of hydro to the system accounting for hourly, daily, and monthly constraints while allowing for flexibility inherent in the hydro system to meet load.

The hydro fleet is aggregated as a single asset within SERVM. The process is to analyze actual hourly hydro data for the different hydro sites for the previous 5 year historical period to create one hourly total hydro output profile for the province. For the assessment, the AESO identified 4 components from the historical hourly data:

- the average daily minimum dispatch levels;
- the average maximum dispatch levels;
- the monthly maximum dispatch level; and
- the total monthly energy.

The minimum and maximum daily dispatch levels and monthly maximum dispatch levels are defined as a function of the total monthly energy based on the historical data, as shown in figures 4 to 6 below. These relationships between the total monthly energy and dispatch levels will be re-evaluated with each minimum procurement volume determination as additional hydro output data is available.

Figure 4 - Monthly Maximum Hydro Dispatch Levels

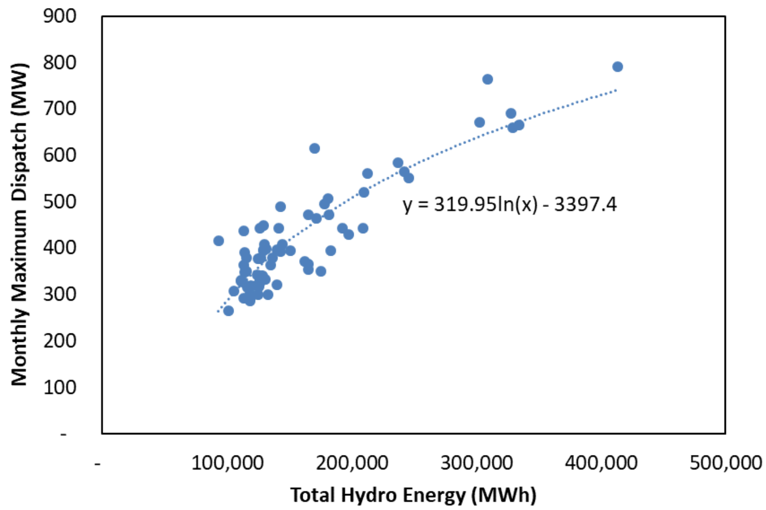


Figure 5 - Average Maximum Daily Dispatch Levels

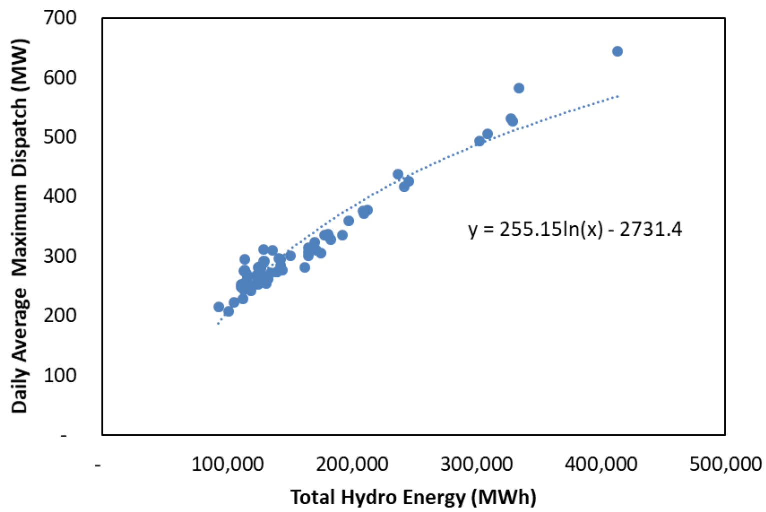
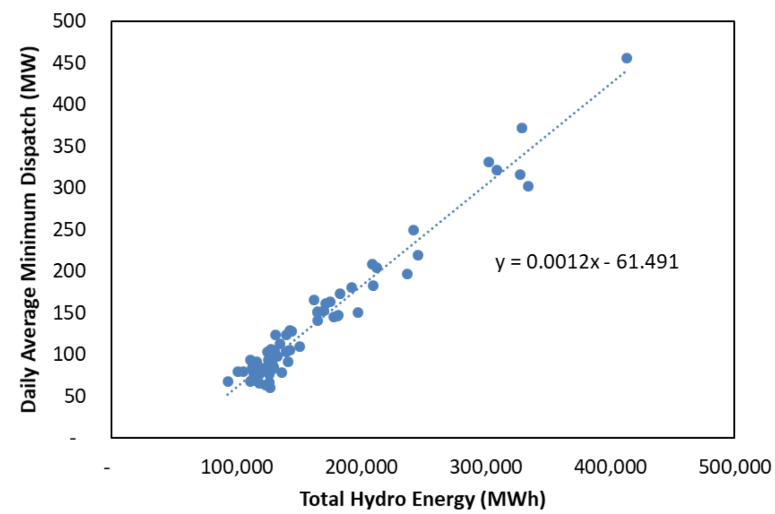


Figure 6 - Average Minimum Daily Dispatch Levels



Given the above information, the AESO applies the curve fit equations to estimate the average daily minimum dispatch levels, the average maximum dispatch levels and the monthly maximum dispatch level from historical monthly energy for the years with historical information (2001 forward) for modelling hydro constraints.

SERVM optimally schedules the hourly hydro energy while respecting these constraints. The daily maximum and minimum dispatch, and monthly maximum dispatch, in conjunction with the total monthly energy are parameters that go into the determination of the hourly hydro schedule, which follows the daily load shape. The daily minimum hydro dispatch is scheduled at the minimum load hour of the day, and the daily maximum hydro is scheduled at the maximum load hour of the day. The monthly maximum hydro is scheduled at the maximum load hour of the month.

While the dispatch data was highly correlated with monthly energy, the AESO identified some deviation in some periods. The divergence reflects emergency dispatch or some capability not captured by the general dispatch heuristic. To capture this capability, the AESO models an emergency hydro block of up to 150 MW (subject to the maximum system hydro capability and the observed historical maximum dispatch). The AESO only used the emergency capacity to prevent firm load shed and the model allows the emergency mode to “borrow” energy from the future dispatch of the scheduled hydro portion with the constraint that the energy amount is for only up to 10 hours. The applicability and size of this block will be re-evaluated with each minimum procurement volume determination as additional hydro output data is available.

To populate hydro data for years without monthly energy availability (1987 to 2001), the AESO used the data from the year that most closely matched to total snowfall from 2001 to 2017. Table 3 below shows the years 1987 to 2000 matched to their corresponding snowfall levels. The AESO uses monthly snowfall totals (% of normal snowfall from 1981 to 2010) from 1987 to 2017 from *Monthly Climate Summaries* provided by the Government of Canada. The AESO uses snowfall data from December to April the following year for the matching.

Table 3

Match Year for 1987 to 2000 for Hydro

Year	Annual Average % of Normal Snowfall	Matched Year	Annual Average % of Normal Snowfall
1987	-87.75	2004	-88.87
1988	-81.77	2016	-76.97
1989	-94.51	2002	-100.69
1990	-119.51	2005	-123.47
1991	-121.70	2014	-121.26
1992	-101.51	2002	-100.69
1993	-120.48	2012	-124.51
1994	-117.62	2007	-111.20
1995	-81.20	2006	-83.93
1996	-107.62	2010	-109.81
1997	-99.78	2015	-102.02
1998	-68.89	2016	-76.97
1999	-104.33	2002	-100.69
2000	-91.93	2004	-88.87

4.5 Cogeneration

The gross availability of generating units which serve load onsite (typically large industrial facilities that produce electricity and steam for other processes) in aggregate is correlated to gross load. This relationship is used in the model to simulate cogeneration availability. Using historical hourly data, the daily gross peak load, and daily gross peak generation availability is calculated in aggregate and grouped into a number of different normalized load levels with a number of distribution points. The distributions are defined seasonally to account for seasonal variances in availability within annual industrial production. The Resource Adequacy Model estimates gross availability in the hourly simulation by drawing an output from the daily gross availability distribution based on the daily peak load.

Sites with load served by onsite generation exhibit a wide range of generation, load, and availability patterns. By aggregating the data across these sites, the AESO is able to capture the correlation between onsite generation and gross load. The individual unique characteristics of each site require detailed specifications and modelling challenges prevents the AESO from being able to model them like other generators. Daily gross peak loads of such sites are generally higher in the winter than in the summer. While the AESO has observed that, at times, these sites do have similar load levels in different seasons, their facility daily peak availability varies from winter to summer. Defining seasonal distributions takes these observed variations into account to better capture the variability in supply from cogeneration.

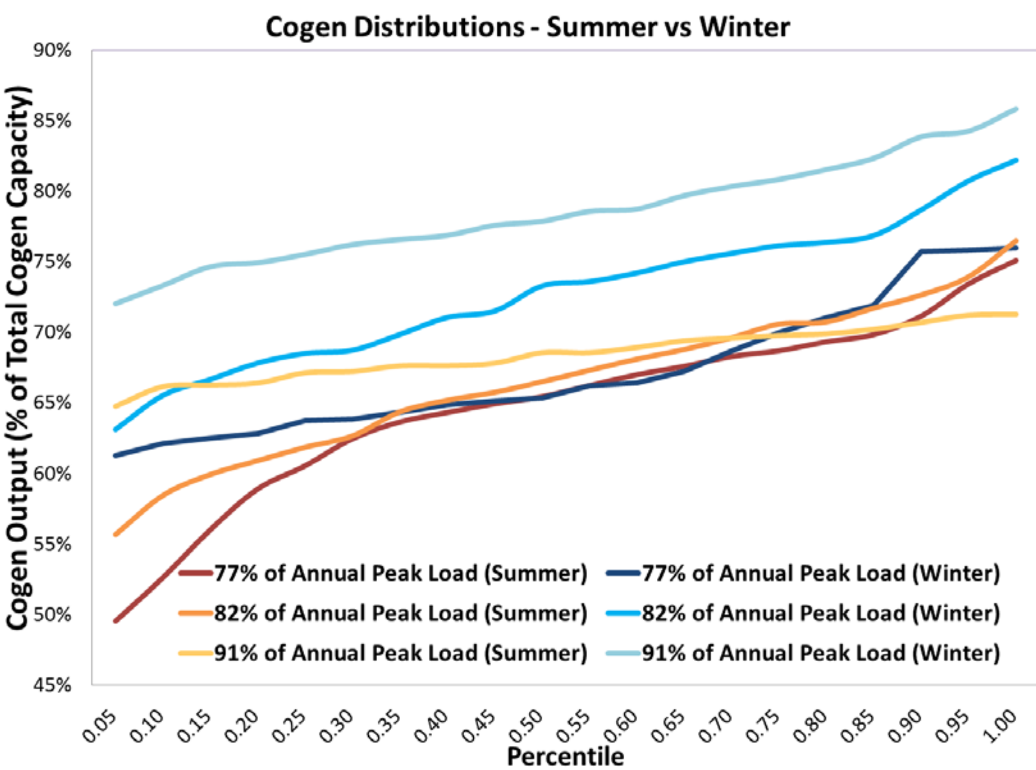
The cogeneration generating units in the Alberta electricity system individually exhibit widely ranging generation or availability patterns. In aggregate however, their availability is correlated with the Alberta gross load. Some of the generating units in this class are at least partially price responsive, but rather than attempt to tease the individual dispatch heuristics out of the historical data, the AESO modeled the fleet in aggregate.

The AESO performed the aggregation by assimilating the historical hourly available capability from every generator. The AESO calculated the daily peak load and the daily peak total available capability for the aggregated cogeneration fleet. The AESO normalized the daily peak load by dividing by the peak load for the obligation period. The AESO normalized the daily peak total available capability by dividing by the total cogeneration capacity for the obligation period. The AESO then grouped these normalized peak pairs into several different normalized load levels each with several distribution points for winter months (January to April, November and December) and for summer months (May to October) respectively. SERVM then uses this data to draw cogeneration multipliers for each day. In the example cogeneration output distributions are shown in the Figure 7 below. When daily peak load is 82% of the annual peak load (middle blue line), SERVM draws a cogeneration output multiplier of 66% to 82%. It then multiplies the drawn value by the fleet capacity to determine the daily generation of the cogeneration fleet.

Some cogeneration generating units did not have accurate available capability data, so the AESO developed a synthetic shape by using the maximum hourly generation (from PI tag generation) or available capability (from available capability data).

- JOF1 and SCR(1,5,6) used the maximum available generation or available capability.
- CRN5, CRG1, UOA1, SHCG, PEC1, TLM2 and SCL1 used PI tag generation as a proxy for availability assuming they are baseload generation.

Figure 7



4.6 Interties

The AESO used historical available transfer capability data in part to develop a distribution of transmission availability to model the impact of import capability from neighbouring power grids and capture the effects of transmission constraints and outages. For British Columbia and Montana, the AESO identified transmission availability as the binding import constraint rather than generation availability within adjacent jurisdictions during tight supply conditions. Consequently, imports within the Resource Adequacy Model from British Columbia and Montana are a function of transmission availability with other jurisdictions.

In addition to historical available transfer capability for Saskatchewan, the AESO also incorporates historical gross offers to develop a distribution of supply availability over the Saskatchewan transfer path, which better reflects availability of supply during tight supply situations.

The AESO models interties as pseudo generating units given that the transmission capability was generally identified as the binding market support constraint rather than the generation availability from neighboring markets. For this reason, the AESO set the model to have the generating capacity of the combined path of British Columbia and Montana as able to supply power to the transmission interface less periods of outages.

The amount of imports into Alberta was a function of transmission availability during emergency situations within Alberta. For Saskatchewan, some generation availability is reflected in the transmission availability rather than explicitly modelling the loads and resources in those regions.

4.7 Regulating Reserve

For purposes of the Resource Adequacy Model, an energy emergency alert event is defined as set out in the Alberta reliability standards. The Resource Adequacy Model begins measuring simulated firm load shed once estimated contingency reserves are depleted. In the estimation of unserved energy, regulating reserves are maintained during load shed events.

The Resource Adequacy Model is set up to align with current system controller procedures for supply shortfall events. The activation and utilization of contingency reserves to meet energy requirements is consistent with current energy emergency alert procedures.

Ancillary services in the model are estimated as a percent of Alberta gross load

Table 4 – Ancillary Services Estimated Volumes

Ancillary Service Type	Estimated volume (% of gross load)
Regulating Reserve	1.5%
Contingency Reserve - Supplemental	2.5%
Contingency Reserve - Spinning	2.5%

Revision History

Posting Date	Description of Changes
	Initial release