4 Calculation of Demand Curve Parameters

This section addresses the demand curve for the Alberta capacity market, including the calculations for the components of the demand curve.

4.1 Resource adequacy standard

4.1.1 The Government of Alberta announced it will legislate a minimum resource adequacy standard. This value represents a maximum of 0.0011% unserved energy, described as normalized expected unserved energy. The AESO will develop the demand curve to meet this minimum resource adequacy standard.

4.2 Resource adequacy model & procurement volume determination

4.2.1 The AESO will develop and run a resource adequacy model (RAM), which performs a Monte Carlo simulation to probabilistically model hundreds of inputs to consider supply adequacy factors and understand their impacts on reliability. The simulation tool for performing the RAM is a computer program that uses data inputs, methodologies and assumptions to identify the relationship between expected unserved energy (EUE) and installed capacity (ICAP). The RAM will consider factors that impact the supply and demand balance in Alberta, such as:

(a) ***Load forecast.*** The AESO's forecast of gross load includes multiple annual hourly load profiles based on historical hourly weather patterns of the past 30 years and a set of economic growth scenarios.

(b) ***Supply availability.*** Current and anticipated generation and demand response assets with maximum capability of 5 megawatts (MW) or greater are included in the RAM irrespective of technology type or eligibility to participate in the Alberta capacity market.

(c) ***Characteristics of thermal assets***. Thermal assets are modelled using market simulation input assumptions and will be dispatched to load and optimized for both energy and ancillary services. Historical available capability data informs planned outage periods, forced outage rates and temperature derates:[1]

i. *Forced outages* – a seasonal distribution of time-to-fail hours (TTF) and time-to-repair (TTR) hours will be calculated for each generating unit to capture historical estimated forced outage rates in the RAM, which are then used in simulating unit forced outage events.

ii. *Planned outages* – hours on planned maintenance will either be calculated as a percentage maintenance rate or manually scheduled based on historical data. This information will then be used to schedule maintenance events in the RAM.

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[1] At this time, transmission constraints within Alberta will not be considered as a factor that will impact resource availability.

iii. *Seasonal outage* – technology output curves that are calculated using historical available capability data and corresponding weather data to capture ambient temperature derates. Such curves will be used to model weather related derates for combined cycle and simple cycle units. The RAM references the curve to an hourly temperature value to look up an associated capacity multiplier to determine the output capacity of a unit.

(d) ***Load served by onsite generation.*** The gross availability of generating assets which serve load onsite (typically large industrial facilities that produce electricity and steam for other processes) in aggregate is correlated to gross load. Using historical hourly data, the daily gross peak load and daily gross peak generation availability can be calculated in aggregate and grouped into a number of different normalized load levels with a number of distribution points. The distributions will be defined seasonally to account for seasonal variances in availability within annual industrial production. The RAM will estimate gross availability in the hourly simulation by drawing an output from the daily gross availability distribution based on the daily peak load.

(e) ***EEA event measurement.*** For purposes of the RAM, an EEA event will be defined as the activation and utilization of contingency reserves to meet demand when there is no remaining available supply. The RAM will begin measuring simulated firm load shed once estimated contingency reserves are depleted. In the estimation of unserved energy, regulating reserves will be maintained during load shed events.

(f) ***Renewable profiles.*** Wind and solar hourly output profiles will be developed to account for geographical diversities and technological advancements:

i. *Wind* – the RAM 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. Wind profiles are developed by using metered output from existing wind farms and simulated for weather years for which there is no historical metered output. Correlations between aggregated wind zones are maintained.

ii. *Solar* – the RAM 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. Solar profiles are developed using the National Renewable Energy Laboratories data and simulated for weather years for which there is no data.

(g) ***Hydroelectric generation.*** Hydro is modelled 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 a year, month, and system conditions.

(h) ***Imports****.* Historical available transfer capacity (ATC) data is used 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. In addition to historical ATC, the AESO will also use historical gross offers to develop a distribution of supply availability over the Saskatchewan intertie. For this interconnection, ATC alone does not accurately represent the availability of supply during tight supply situations.

4.2.2 The AESO will add or subtract volumes of ICAP to identify the relationship between capacity and resource adequacy (i.e., EUE). The type and characteristics of the capacity added to the RAM will align with the characteristics of the reference technology. The AESO will identify the appropriate ICAP values that meet resource adequacy requirements based on the ICAP-EUE relationship.

4.2.3 The AESO will use a formula to translate the ICAP values into fleet-wide unforced capacity values. The formula will align with the UCAP calculation approach defined in subsection 3.1.4 of Section 3, *Calculation of Unforced Capacity (UCAP)* to ensure consistency of the resource adequacy requirements from the RAM and the resource adequacy contribution of the various capacity assets. The AESO reduces the fleet-wide unforced capacity value by the prequalified volume of self-supply and ineligible assets to determine the procurement volume for the capacity auction.

4.3 Calculation of gross-CONE & net-CONE

Reference technology

4.3.1 The AESO will select a reference technology for use in the development of the demand curve. During the transition period, the reference technology for the capacity auctions will be a natural gas-fired technology determined through detailed cost screening. The technologies that will be assessed in greater detail include:

(a) an aeroderivative simple-cycle gas turbine generation facility, comprised of two LM6000 turbines;

(b) a simple-cycle frame gas turbine generation facility, comprised of one F-class turbine; and

(c) a combined-cycle frame gas turbine generation facility, comprised of one H-class gas turbine and one steam turbine.

Additional details on the reference technology will be developed by the AESO and subject to further consultation.

4.3.2 The AESO will use the following selection criteria to determine the reference technology during each demand curve review cycle (i.e., every four to five years):

(a) ***Frequency of development****.* An assessment of the historical development activities of multiple generation assets, that are the same or a similar type of technology, provides an indication of a generation developer's optimal choice of asset for the Alberta market. This assessment will take into account factors such as overall economics, system requirements and environmental requirements.

(b) ***Impact to market***. An assessment of whether an asset is a suitable new entrant into the Alberta market given the market size and unique market characteristics, as understood by the AESO.

(c) ***Reference plant costs****.* An assessment of the gross and net cost of a new asset will provide an indication of the potential future economic viability of a new asset in the Alberta power market. The assessment of net cost will consider energy margins and factors such as environmental costs and operational limitations.

(d) ***Generation source of last resort / fastest time to energization (months)****.* An assessment of the ability to add new capacity in the timeline required to meet the forward period obligation.

Approach to gross-CONE estimate

4.3.3 The AESO will contract with an independent consultant that has Alberta-specific experience in power plant development, engineering/construction and finance to develop appropriate cost, and financing assumptions for the reference technology.

4.3.4 The independent consultant will provide the AESO with a credible gross-CONE estimate, reflecting the plant development and financing costs for the reference technology in Alberta. Plant development costs will incorporate, among other things, equipment, construction labour and materials, emissions control, and related owner costs. Financing costs for the reference technology will be measured as an after-tax weighted average cost of capital (ATWACC). ATWACC will be composed of equity and debt rate components that are weighted according to a debt/equity split. The ATWACC will be used to calculate the levelized annual return on, and return of, capital associated with the reference technology. The levelized annual return will be added to the annual fixed operating and maintenance costs for the reference technology to arrive at the annual gross-CONE value. Additional details on gross-CONE will be developed by the AESO and subject to further consultation.

4.3.5 The AESO will submit an updated gross-CONE study during each demand curve review cycle. In between review cycles, the AESO will follow a defined process to adjust the gross-CONE estimate, annually, using applicable cost indices and interest rates.

Approach to energy and ancillary services offset

4.3.6 To calculate the energy and ancillary services offset (EAS offset) that will then be used to estimate net-CONE, the AESO will use a forward market methodology that is conducted in accordance with the following assumptions:

(a) the new entrant will be a stand-alone entity not within a portfolio of assets;

(b) the EAS offset will be estimated using an approach as if the new entrant will use forward power and natural gas prices to generate a forward commodity margin in the energy market;[2]

(c) the EAS offset will initially exclude revenues from ancillary services; and

(d) the new entrant will assess different forward products (i.e., baseload versus peak products) to maximize its offsets.

Additional details on the EAS offset will be developed by the AESO and subject to further consultation.

Approach to net-CONE estimate

4.3.7 The AESO will determine net-CONE by subtracting the EAS offset from the gross-CONE:

net-CONE = gross-CONE – EAS offset

4.3.8 The net-CONE will have a minimum of zero and a maximum of gross-CONE. The net-CONE estimate will measure the capacity market based revenue required to ensure the reference technology will recover an annualized return on and of capital. The inflection point and the capacity price cap on the demand curve will be set in reference to net-CONE.

[2] Other components of the commodity margin will include but not be limited to carbon costs, variable operations and maintenance and losses.

4.4 Shape of the demand curve

4.4.1 The demand curve for the Alberta capacity market will be a downward-sloping, convex curve consisting of three segments: (i) horizontal section from zero to the minimum quantity; (ii) downward-sloping section from the minimum quantity to inflection point; and (iii) downward-sloping section from inflection point to the foot, at zero price.

(a) In order to achieve a convex shape, the slope on the minimum-to-inflection segment of the curve will be steeper than the slope of the inflection-to-foot segment.

(b) The Y-axis points for the demand curve will be set in reference to price and will be expressed as a multiple of net-CONE and/or gross-CONE. Prices will be expressed in units of dollars per kW (UCAP) per year ($/kW-yr).

(c) The foot will be set at a price of zero.

(d) The X-axis points for the demand curve will be set in reference to the quantity of UCAP MW of capacity and will be expressed as a multiple of the quantity corresponding to the maximum acceptable EUE.

(e) The foot and inflection point of the demand curve will be set at prices and quantities that balance the combined objectives of clearing at procurement volumes above the minimum level at least 95% of the time, controlling capacity price volatility and keeping customer cost low.

4.4.2 The proposed demand curve shape is described below and in Table 1 and illustrated in Figure 1:

(a) The minimum quantity point will be set at a value of capacity equivalent to achieving the Government set minimum of 0.0011% of EUE (for the first auction this is expected to be 964 MWh) in one year, based on the output of the RAM, which is translated into UCAP volume and reduced by ineligible REP capacity (see peach-coloured line in Figure 1). The minimum acceptable quantity point will be defined in terms of the *gross* supply in the market (i.e., *including* self-supply MWs). The point will be left-shifted by the self-supply MWs prior to each auction (i.e., the self-supply MWs will be subtracted from the 964 MWh EUE quantity).

(b) The AESO has determined that the quantity procured in the base auction should only fall below the Government's minimum reliability level, at most, 5% of years. In years where the base auction clears below the minimum, the AESO will be able to achieve the Government's minimum through the rebalancing auctions and, on rare occasions, out-of-market procurements.

(c) The price cap will be set based on the maximum value of either a 1.75 net-CONE multiple or a 0.5 gross-CONE multiple.

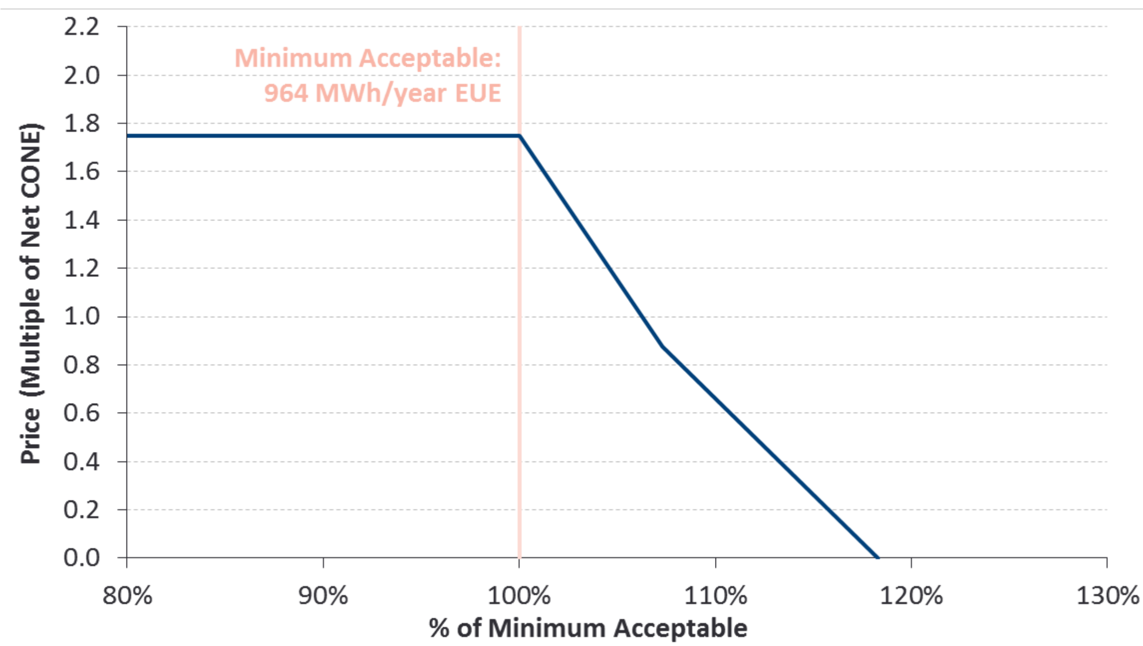
(d) The inflection point is set at 0.875 x net-CONE, at a quantity 7% above the minimum acceptable quantity. The inflection point will be defined relative to the minimum acceptable quantity in terms of the *gross* supply in the market (i.e., *including* self-supply MWs). The inflection point will be left-shifted by the self-supply MWs prior to each auction (i.e., the self-supply MWs will be subtracted from the inflection point based on gross supply).

(e) The foot is set at 18% above the minimum acceptable quantity, at a price of zero.

Table 1 – *Candidate curve points*

Point	Price	*Gross* Quantity	*Net* Quantity for Auction
Price Cap	Max (1.75 x net-CONE, 0.5 x gross-CONE)	100% x Minimum Acceptable UCAP MW	100% x (Minimum Acceptable UCAP MW – Self-Supply MW)
Inflection Point	0.875 x net-CONE	107% x Minimum Acceptable UCAP MW	107% x (Minimum Acceptable UCAP MW – Self-Supply MW)
Foot	0	118% x Minimum Acceptable UCAP MW	118% x (Minimum Acceptable UCAP MW – Self-Supply MW)

Figure 1 – *Illustration of proposed demand curve*



4.5 Demand curve for rebalancing auctions

4.5.1 The rebalancing demand curve will have the same shape as the base auction demand curve and it will be based on the same net-CONE. However, the procurement volume will be updated using an updated resource adequacy assessment completed prior to the commencement of each rebalancing auction.