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 is currently evaluating whether the demand curve can be developed using this minimum resource adequacy standard or whether it is necessary to also define a target resource adequacy standard value.

> The AESO continues to evaluate whether the demand curve can be developed using the minimum resource adequacy standard, and intends to release further analysis for review by the Technical Working Group on June 14, 2018.

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 is 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 (AC) data informs planned outage periods, forced outage rates and temperature derates:[1]

i. *Forced outages* – a 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 resource adequacy model, which are then used in simulating unit forced outage events.

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

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 resource adequacy model.

iii. *Seasonal outage* – technology output curves that are calculated using historical AC 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 availability can be calculated in aggregate and grouped into a number of different normalized load levels with a number of distribution points. The RAM will estimate gross availability in the hourly simulation, and draw an output from the daily gross peak availability distribution based on the daily peak load.

Based on feedback received from the Technical Working Group, the AESO will adjust the modelling approach described in subsection 4.2.1(d) for cogeneration to account for seasonal variability of output from facilities with load served by onsite generation. Daily gross peak loads of such sites are generally higher in the winter than in the summer. While it has been observed that, at times, these sites do have similar values in the different seasons, their facility daily peak availability does vary winter to summer. Defining seasonal distributions takes these observed variations into account to better capture the variability in supply from cogeneration. Therefore, they should be included in the RAM.

As noted in CMD 2, using historical hourly data, the daily gross peak load and daily gross peak availability of generating assets that serve load onsite can be calculated in aggregate and grouped into a number of different normalized load levels with a number of distribution points. The distributions will now be defined seasonally to account for yearly variances in availability within the annual industrial production season. The RAM will estimate gross availability in the hourly simulation, and draw an output from the daily gross peak availability distribution based on the daily peak load.

(e) ***EEA event measurement.*** The RAM will define an EEA event as the activation and utilization of contingency reserves and measure the average amount of hours that supplemental reserves and spinning reserves are dispatched over the number of iterations that are run. The RAM will begin measuring simulated firm load shed once contingency reserves are depleted. Regulating reserves will be maintained during load shed events.

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, and such event will measure the average amount of hours that supplemental reserves and spinning reserves are dispatched over the number of iterations that are run.

As contingency reserves are used in real time for other reasons, those types of events are not captured in the RAM estimation unless the event leads to an overall supply shortfall.

(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 by using 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 for hydro so that 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****.* Historic available transfer capacity (ATC) data is used to develop a distribution of transmission availability to model the impact of committed and uncommitted import capability from neighbouring power grids and capture the effect of transmission constraints and outages.

> The Final CMD will clarify that, in addition to historic ATC, the AESO will also use historic gross offers to develop a distribution of transmission availability for Saskatchewan and Montana. For these interconnections, 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 (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 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 pre-qualified volume of self-supply and ineligible assets, taking into account unqualified import UCAP, to determine the procurement volume for the capacity auction.

> The red text in subsection 4.2.3 will turn to black in CMD Final, except for the “taking into account unqualified import” qualification, which the AESO intends to remove. At this time, the AESO is finalizing details of the methodology for translating the maximum capability from the RAM into a fleet-wide unforced capacity value. The methodology being used was discussed with the Technical Working Group and posted on the AESO website in May. Subject to further consultation with the Technical Working Group in June, the AESO expects that the translation process will be finalized as described in CMD 2 in the Final CMD.
>
> Interties will be treated in a similar fashion to other capacity resources by utilizing calculated eligible UCAP for external resources to align procurement volumes from the RAM. There will be no reduction to the fleet-wide unforced capacity value to account for unqualified imports. As external resources are eligible and their eligible UCAP is calculated in a manner consistent with internal resources no further adjustment is needed.

At this time, the Final CMD is expected to contain a description of the processes and methodologies associated with adjustments to the fleet-wide unforced capacity value to account for demand and supply shocks that are not captured in the RAM, subject to further stakeholder consultation with the Technical Working Group on June 14, 2018.

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. For the transitional capacity auctions, the reference technology 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;

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

The technologies that will be assessed in greater detail are the three listed in subsection 4.3.1. The AESO anticipates that the F-class turbine will be black in the Final CMD. There was discussion of adding a reciprocating engine to the list of technologies, however lack of strong support from the Technical Working Group did not warrant its addition.

Further to information shared in CMD 2, the reference technology selection for the Alberta capacity market is dependent on the gross-CONE estimates that have been provided to the AESO by the Brattle Group. The AESO intends to consult with the Technical Working Group on the preliminary gross-CONE results on June 14, 2018. The gross-CONE estimate will be augmented with the EAS offset approach to inform the ultimate selection of the reference technology. There will be additional consultation following the Final CMD on the resulting net-CONE and reference technology selection. As further guidance to the reference technology selection, the Final CMD will be updated to include the following criteria that the AESO expects will guide the initial selection and subsequent selections of a reference technology:

- *Frequency of Development* – Historic generation development activities of multiple assets of the same or similar technology type provide a strong indication to a generation developer's optimal choice of asset for the Alberta market. Such development would take into account overall economics, system requirements, and environmental requirements.
- *Impact to Market* – A reasonableness assessment will indicate whether an asset is a suitable new entrant into the Alberta market given the relatively small market size and unique market characteristics, as understood by the AESO.
- *Reference Plant Costs* – The gross and net cost of a new asset will be considered as it will indicate the potential future economic viability of a new asset in the Alberta power market. The net cost will include the energy and ancillary service margins, whilst incorporating factors such as environmental limitations.
- *Generation Source of Last Resort / Fastest Time to Energization (months)* -- Another perspective on the reference technology relates to the concept of adding new capacity quickly. For example, In the event that the electrical system experienced a near term capacity requirement, a simple cycle generation facility could be developed in 2-3 years, whereas a combined cycle facility would require 3-5 years of development time. Given the potential uncertainty around future coal unit retirements and/or conversions, the ability to respond quickly with new generation may be of value.

Approach to gross-CONE estimate

4.3.2 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.

4.3.3 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 equipment, construction labour, 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 facility to arrive at the annual gross-CONE value.

> The AESO received a range of feedback on the ATWACC that was proposed for the gross-CONE estimate. The AESO continues to evaluate and consultation on this item continues in the Technical Working Group.

4.3.4 The AESO will update the gross-CONE study at regular intervals (i.e., every 3 to 5 years), and in the interim will follow a defined process to adjust the gross-CONE estimate annually using applicable cost indices and interest rates.

> The updating process referred to in subsection 4.3.4 will ensure that the reference technology is reflective of long term changes in the market and generation costs, while avoiding the administrative burden and cost of an annual gross-CONE study.
>
> Interim CONE estimates, from year-to-year, will be indexed to reflect changes in capital cost of the reference unit generation technology. The indices will reflect changes in labour, materials, and turbines (machinery and equipment) in order to track changes in the development cost of the reference unit generation technology. A composite index will be developed by weighting component indices by their relative contribution to installed costs initially. The specific indices will be shared with the Technical Working Group and included as part of the on-going consultation on net-CONE and the demand curve.

Approach to energy and ancillary services offset

4.3.5 To calculate the energy and ancillary services offset (EAS offset) that will then be used to estimate net-CONE, the AESO will use a revenue certainty 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 exclude revenues from ancillary services;

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

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

The AESO reviewed feedback on the proposed approach to calculating the EAS offset from Technical Working Group members and other industry stakeholders. While some stakeholders are supportive of the proposed methodology with some requesting additional analysis, other stakeholders prefer a simulation model to determine the EAS offsets for a given reference technology. The AESO will continue to move forward with the revenue certainty approach as it remains the preferred option given its replicability and captures the collective assessment of the market. However, the AESO continues to assess the opportunities and challenges with the methodology. The AESO will share these assessments with the Technical Working Group on June 14, 2018. The EAS offset calculation will also continue to be included as part of the ongoing consultation on net-CONE and the demand curve.

Approach to net-CONE estimate

4.3.6 The AESO will determine net-CONE by subtracting the energy and ancillary services offset from the gross-CONE:

$$\text{net CONE} = \text{gross CONE} - \text{EAS Offset}$$

4.3.7 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.

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) With the convexity, 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 ($/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 quantity of megawatts of capacity.

(e) The foot of the demand curve will be set at a level such that the resource adequacy target is expected to be met on average, and price outcomes can be expected to average at a net-CONE level while also balancing capacity price volatility and maintaining the desired convexity of the curve.

4.4.2 The demand curve parameters continue to be evaluated by the AESO considering further information on the resource adequacy standard and outputs from the resource adequacy modelling. The proposed curve from CMD1 continues to be carried forward as the working assumption. The proposed curve is described below and illustrated in Figure 1:

(a) The minimum quantity point will be set at a value of capacity commensurate with 800 MWh (similar to the government set minimum of 0.0011% of EUE) in one year, based on the output of the RAM (peach line in figure below).

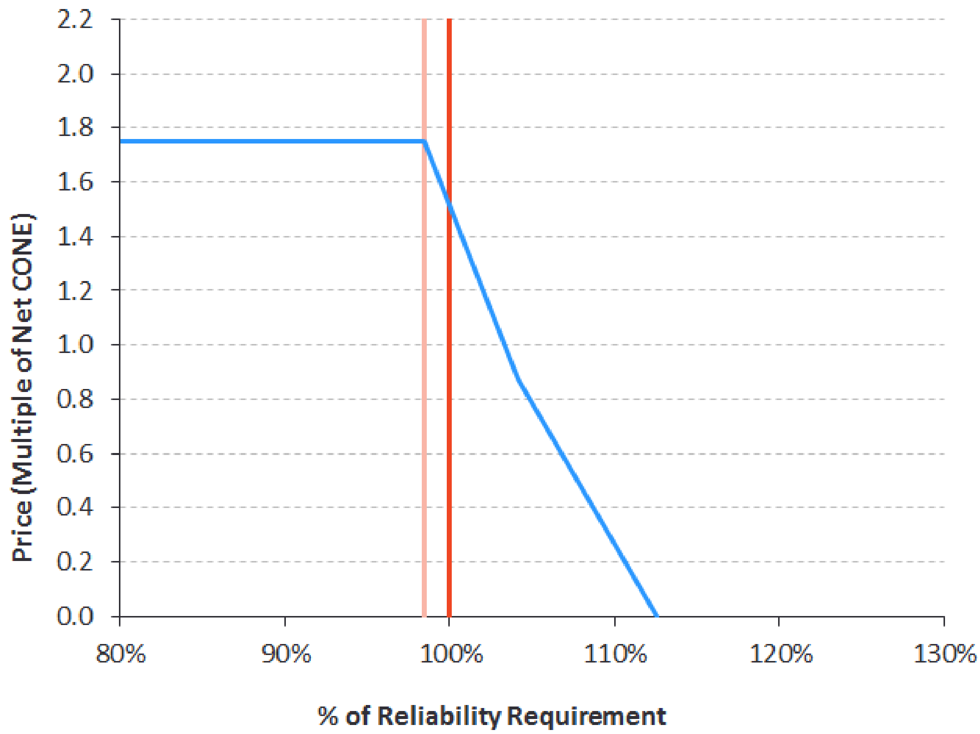
(b) The target quantity has been set at 400 MWh of Expected Unserved Energy (orange line in figure below).

(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 4% above the target quantity.

(e) The foot is set at 13% above the target quantity, at a price of zero.

Figure 1 – *Illustration of proposed demand curve*



The AESO continues to evaluate the demand curve parameters and intends to release further analysis for the Technical Working Group on June 14, 2018, as well as in the Final CMD. The AESO anticipates that additional consultation will be carried out on the demand curve following the release of the Final CMD.

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 capacity auction.