Resource Adequacy Model and Gross Minimum Procurement Volume Technical Report

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1. Introduction

On March 22, 2019, the Alberta Utilities Commission (“**Commission**”) issued a direction to the Alberta Electric System Operator (“**AESO**”) to conduct a technical meeting on the resource adequacy model (“**RAM**”) and the gross minimum procurement volume (“**GMPV**”) and submit a report to the Commission. On March 29, 2019, the AESO invited participants to provide input on the technical meeting agenda, process and issues for discussion. The AESO’s March 29, 2019 letter is attached as Appendix A.

Following the incorporation of this input, the AESO held the technical meeting on May 6 and 7, 2019.

In accordance with the Commission’s direction, this report contains the following:

(a) The AESO’s proposed treatment of the RAM inputs and calibration issues listed in the Commission’s direction and the concerns raised by parties (Section 4);

(b) The views expressed by each participant on the RAM inputs and calibration issues, and the AESO’s reasons for accepting or rejecting them (Section 4);

(c) An explanation of the modifications and updates to the elements of the RAM (Section 5); and

(d) The gross minimum procurement volumes resulting from the modifications and updates to the RAM (Sections 3 and 5).

On May 15, 2019, the AESO circulated meeting notes and a statement of the meeting process and outcomes to all technical meeting participants. The outcomes reflected a high level summary of the discussions that occurred at the meeting, which were more comprehensively captured in the meeting notes. Each participant was asked to provide (i) their agreement with the AESO’s description of the meeting process and outcomes; and (ii) any revisions to the meeting notes, as applicable. Participants had the opportunity to qualify their agreement if the meeting process and outcomes, as described by the AESO, did not align with their views on how the meeting transpired. The AESO’s statement of meeting process and outcomes is attached as Appendix L.

The following participants returned comments on the meeting process and outcomes to the AESO : Alberta Direct Consumer and the Industrial Power Consumers Association of Alberta (“**ADC/IPCAA**”); Alberta Federation of Rural Electrification Associations (“**AFREA**”); ATCO Power (“**ATCO**”), Canadian Solar Industries Association (“**CanSIA**”), Capital Power Corporation (**Capital Power**”), the Consumer Coalition Advocate (“**CCA**”), ENMAX Energy Corporation (”**ENMAX**”), Powerex Corp (“**Powerex**”); Suncor Energy (“**Suncor**”); TransAlta Utilities (“**TransAlta**”); TransCanada Energy (“**TCE**”); and the Utilities Consumer Advocate (“**UCA**”). Some participants agreed with the AESO’s description of process and outcomes with qualifications, while others declined to provide their agreement. These comment matrices and signature pages are attached as Appendix N.

2. Background

The GMPV is the estimate of the minimum amount of installed maximum capability that meets the legislated resource adequacy standard of 0.0011% normalized expected unserved energy (“**EUE**”) in an obligation period.[1] The GMPV is calculated using a probabilistic hourly chronological simulation model – the RAM – to capture uncertainties of supply and demand to identify the relationship between EUE and

[1] *Capacity Market Regulation*, AR 260/2018, s. 2(2).

total installed maximum capability of the assets that supply capacity.[2] The GMPV is later translated to a uniform capacity value ("**UCAP**") to develop the capacity market demand curve.

The AESO's approach, methodologies and inputs for the RAM were developed, tested and refined through a robust stakeholder consultation process that leveraged the collective wisdom of industry over the course of nearly two years. During the Straw Alberta Market ("**SAM**") and Comprehensive Market Design ("**CMD**") consultation processes, the AESO's consultation on the RAM relied on an iterative process where the AESO: presented model assumptions, methodologies and aggregated data to the working group; solicited oral and written feedback from working group members; conducted internal in-depth evaluations of the feedback; refined the RAM in response; and presented the draft results back to the working group.[3] The AESO conducted 18 working group sessions on the demand curve, 12 of which included focused presentations on the RAM.[4] Additionally, there were eight opportunities for working group members to provide written feedback on the RAM in the design phase.[5]

Meeting materials and session summaries for each working group meeting were published on the AESO website.

Beyond the general guidance and input provided throughout the SAM and CMD consultation processes, there were several areas where stakeholder feedback directly led to changes to the RAM modelling approach. These include: expanding the number of economic scenarios from three to five; separating the forced outage distribution from annual to seasonal; separating the cogeneration availability distribution from annual to seasonal; as well as additional validation of the hydro modelling with the hydro plant operators and wind modelling with wind generation experts from the working groups.

Recognizing the depth and complexities of RAM topics, the AESO conducted an industry wide stakeholder session prior to launching consultation on the demand curve rules in order to build an understanding of the RAM and how the GMPV is determined with a broader audience.[6]

During the ISO rules consultation process conducted pursuant to the requirements of AUC Rule 017: *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission*, stakeholders provided comments on the demand curve rules through three rounds of feedback – one oral and two written.[7] Many stakeholders expressed concern that the proposed GMPVs for the first two auctions would result in over procurement and requested that the AESO provide RAM input and output data for additional transparency of the RAM.

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[2] Exhibit X0284, PDF 49.

[3] The AESO provided an initial list of inputs, assumptions, and methodologies to the working group in August 2017. See Exhibit X0292, PDF 291-294.

[4] See Exhibit X0292, PDF 122-161, 200-250, 291-294, 310-315, 328-353, 414-467, 537-542, 570-575, 583; Exhibit 309.01, PDF 1-14, 50-76, 103-112, 131-147, 183-217, 310-330, 418-449, 492-517.

[5] [5] See Exhibit X291.01, PDF 88-552 (SAM 2.0 Feedback), 640-1201 (SAM 3.0 Feedback); Exhibit 309.01, PDF 126-130 (April 6, 2018 Comment Matrix), 292-294 20 (May 4, 2018 Comment Matrix), 415-417 20 (June 14, 2018 Comment Matrix); Exhibit 302.01, PDF 523-653 (CMD 1.0 Feedback); Exhibit X0304.01, PDF 244-1035 (CMD 2.0 Feedback); Exhibit 308.01, PDF 263-624 (CMD Final Feedback)

[6] See Exhibit X0313.01, PDF 3, 49-84.

[7] See Exhibit X0317, PDF 1100-1162, 1406; Exhibit X0318, PDF 468-470.

In response to the aforementioned stakeholder comments, the AESO performed a calibration of the RAM outputs against the year 2018 and conducted another review of the RAM inputs underpinning the initial GMPVs. The AESO concluded that further refinements to planned and forced outages for biomass units, regulating reserve and intertie distributions were warranted.[8] The result of these RAM refinements lowered the GMPV for the base auction for the 2021/2022 obligation period from 18,516 MW to 18,305 MW, and lowered the GMPV for the base auction for the 2022/2023 obligation period from 18,597 MW to 18,400 MW.[9] In December 2018, the AESO published spreadsheets containing the following data with its replies to stakeholder comments on the new proposed GMPVs: load profiles, outage summary statistics, wind and solar profiles, cogeneration availability distributions, intertie availability distribution, hydro generation parameters, ancillary services (emergency operations) parameters; and RAM output data.[10]

The AESO application filed in Proceeding 23757 was based on these lowered GMPV for each of 2021/2022 and 2022/23 and the data made available to stakeholders in December 2018.

Using the AESO methodologies and assumptions and the RAM data released at the end of the ISO rules consultation process, three parties independently developed their own resource adequacy models.[11] The resulting GMPV outputs from these models were similar to the AESO's GMPVs for the first two obligation periods. Such results give confidence to the AESO's modelling approach. It is noteworthy that the participants in Proceeding 23757 are not contesting the RAM as a whole; rather, the issues that have been raised are narrowly focused on specific RAM input methodologies and assumptions and the validation of the RAM outputs. The outcome of the technical meeting reinforced that parties are likely to have differing views on how to treat the various elements of the RAM depending on whether they believe the GMPV will result in over procurement or under procurement. Furthermore, participants who are aligned on the over/under procurement question may differ with respect to their recommendations of how to treat various elements of the RAM.

With respect to the calculation of a GMPV that meets the resource adequacy standard, the AESO's goal remains achieving an estimate that balances future uncertainties and that is defensible from both an over and under procurement perspective.

3. Summary of Resource Adequacy Model Modifications and Updates and Resulting GMPVs

During the weeks following the technical meeting, the AESO conducted an in-depth assessment of the RAM considering the feedback received at the meeting and the recommendations and alternative solutions proposed by participants. On May 17, 2019, the AESO released a summary of the conclusions it had reached at that point in time, but indicated that it was continuing to evaluate the appropriateness of updating certain inputs. The AESO's May 17, 2019 letter is attached as Appendix M.

Following the meeting the AESO considered the material, discussion and feedback received from meeting participants and concluded that it would not make modifications to price responsive load ("**PRL**"), regulating reserve, the planned outage algorithm or ambient temperature derates for the reasons outlined

[8] See Exhibit X0321, PDF 9-15.

[9] See Exhibit X0321, PDF 7.

[10] See Exhibits X0323 to X0336, AESO Application, Appendix I.

[11] See Exhibit X0372, CCA Evidence; Exhibit X0385, TransAlta Evidence; Exhibit X0387.01, ENMAX Evidence.

in Section 4. The AESO has made modifications or updates to the load forecast, intertie, outages, and cogeneration as described in Section 5.

In aggregate, the modifications and updates have lowered the GMPV for the base auction for the 2021/2022 obligation period from 18,305 MW to 18,167 MW, and lowered the GMPV for the base auction for the 2022/2023 obligation period from 18,400 MW to 18,299 MW.

The AESO will release data associated with the updated GMPVs and calibration results on its website and file it on the record of Proceeding 23757 on Monday June 3, 2019.

4. Discussion of the Resource Adequacy Model

On April 15, 2019 the AESO invited participants to provide their written views and proposed solutions on the RAM inputs and calibration topics for discussion at the technical meeting. The comments received from participants are attached in Appendix B.

The AESO received requests from both the Consumers Coalition of Alberta ("CCA") and ENMAX Energy Corporation ("ENMAX") for additional process and data, which are attached as Appendix C and D, respectively. The AESO responded to these requests on April 29, 2019.[12]

During the meeting, the AESO presented its proposed treatment first followed by presentations of the participants. There was an opportunity to ask clarifying questions to improve understanding of the topic or the presenter's position. Time was then reserved at the conclusion of all presentations for open discussion on the issue. The AESO clearly communicated that it would assess whether any modifications or updates to the RAM were required post meeting. As noted above, the meeting notes are attached as Appendix L. Presentations are attached in Appendices F through K.

4.1 Load Forecast

4.1.1. AESO Proposed Treatment

The AESO's proposed treatment of the load forecast is described in detail in Appendix Q to the AESO's application.[13] In summary, the AESO is proposing to forecast Alberta gross load for the obligation period using an econometric-based methodology. Forecast inputs include:

- historical load data, including PRL;
- five different economic scenarios based on Alberta Gross Domestic Product ("**GDP**"), Alberta Labour, Alberta population, and Alberta oil sands production;[14]
- temperature data from 30 weather years; and
- calendar and time-of-day variables.

[12] Exhibit X0600.

[13] Exhibit X0346.01, PDF 2-3; see also Exhibit X0284, PDF 49-50 and Exhibit X0390.01, PDF 2-14.

[14] Alberta GDP, Alberta Labour and Alberta population are sourced from the Conference Board of Canada. Alberta oil sands production is sourced from the Canadian Association of Petroleum Producers.

The load forecast methodology tests different model specifications and different combinations of temperature and economic trends in order to determine a model specification that appropriately accounts for economic growth and weather uncertainty during the obligation period. The combination of the weather years and economic scenarios produced 150 load profiles for study in the RAM. The 150 profiles are provided in Exhibits X0324 and X0325 in Proceeding 23757.

4.1.2 Views and Concerns of Participants

ADC/IPCAA, CanSIA, ENMAX, Suncor, TransAlta and UCA submitted written views to the AESO on the load forecast in advance of the meeting:

- ADC/IPCAA noted that demand transmission service ("**DTS**") and Alberta internal load ("**AIL**") are not moving in lockstep. ADC/IPCAA also questioned the relationship between the RAM load forecast and the AESO's 2017 Long Term Outlook ("**LTO**") forecast.
- CanSIA and UCA requested additional data.
- ENMAX and Suncor recommended that the AESO adjust the Conference Board of Canada ("**CBoC**") GDP forecast downward to account for historical forecast bias.
- Suncor also suggested the AESO re-estimate the GMPV for each of the 5 load scenarios to determine the impact the scenarios and scenario weighting have on the overall GMPV.
- TransAlta was of the view that the AESO's approach to the load forecast is reasonable.

ADC/IPCAA and ENMAX presented their views at the meeting. ADC/IPCAA maintained their view that the AESO should be forecasting for DTS plus Fort Nelson DTS plus losses. ENMAX supported forecasting AIL, but maintained that the forecast needed to be adjusted for error. The ADC/IPCAA and ENMAX presentations are attached as Appendix F.

During the open discussion, several participants expressed concerns that the AESO's load forecast was over-estimating load growth and causing over procurement. Participants proposed various ways that the AESO could adjust the load forecast:

- ENMAX and Suncor repeated their recommendation to adjust the CBoC's forecast to account for forecast error. ENMAX agreed that if there was a history of under-forecasting, the CBoC economic forecast should be adjusted upward.
- ADC/IPCAA maintained its view that the AESO should be forecasting demand transmission service and recommended that the AESO assess actual data and create a new load forecast three months before the auction. Alternatively, ADC/IPCAA suggested that the AESO remove roughly 300 MW from the load forecast to adjust for over procurement concerns in the GMPVs for the base auctions in respect of the first two obligation periods.
- The CCA and IPPSA queried whether the AESO could use a different economic forecast that is more conservative than CBoC.
- IPPSA suggested developing a more conservative load forecast for the base auction forecast and use the rebalancing auctions to correct under procurement issues, if necessary.

CanSIA, ENMAX, and Suncor recommended that the AESO update the load forecast used in the RAM and establish the GMPV closer to the applicable auction. EDC Associates ("**EDC**") and Suncor proposed that the AESO develop the load forecast in collaboration with industry.

AFREA, ATCO, Capital Power, Powerex, TransAlta, and TCE did not express their positions on the above matters during the open discussion.

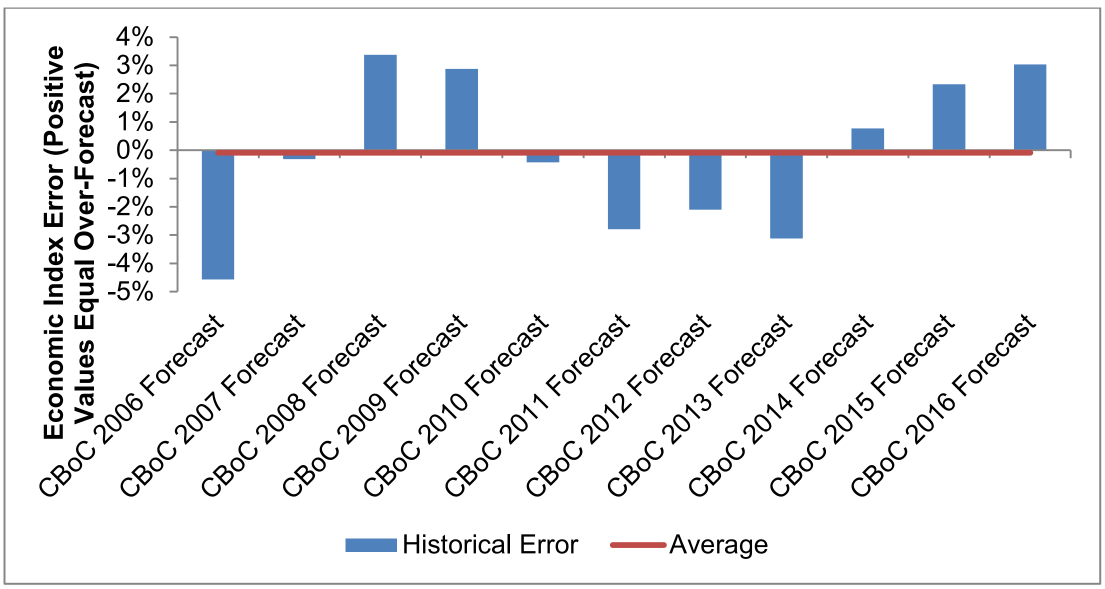
4.1.3 AESO Response to Views and Concerns

The AESO accepted the recommendations to update the load forecast with the most recent data available. As described in more detail in Section 5.1, the AESO has updated the load forecast for the first two obligation periods with the most recent Conference Board of Canada economic forecast, updated oilsands production forecast, and additional historical data.

As described in its Rebuttal Evidence[15] and its witness testimony during Proceeding 23757, the AESO does not agree that there is a systemic over forecast bias in the CBoC economic forecast. The AESO is relying on its econometric forecast methodology and forecast inputs and does not consider it appropriate to make discretionary adjustments under the circumstances. Therefore, the AESO did not adjust the economic forecast as recommended by some participants.

The AESO updated its assessment of historical CBoC 3 year forecast errors. Figure 0 below shows the update to the CBoC accuracy chart in the AESO's evidence.[16] Recent updated data shows the CBoC over-forecasted recent forecasts; however, the CBoC has a history of both over- and under-forecasting and, on average, tends to have low forecast error. The AESO is of the view that this continues to show that there is no systematic bias within the CBoC economic forecast.

Figure 0: CBoC Historical Economic Growth Forecast Error



Source: Conference Board of Canada, AESO: Each bar of this chart denotes the accuracy from AESO EDVs as though they were developed at the time. The CBoC 2006 Forecast, for example, is based off the CBoC's 2006 forecast. The CBoC 2006 Forecast bar shows how accurate the CBoC 2006 Forecast was. This chart provides data to CBoC 2016 Forecast as complete 2019 actual data is not yet available for 2017 and after.

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[15] Exhibit X0549.02. PDF 12-17.

[16] Exhibit X0549.02, PDF 13, Figure 3.3

In the AESO's view, forecasting Alberta gross load is consistent with the definition and measure of load set out in the *Capacity Market Regulation*, AR 260/2018. DTS plus FTS plus losses excludes load served by distribution-connected generators and load at behind-the-fence sites, which are eligible to participate in the capacity market. It is not appropriate to exclude the load served by these generators in the forecast of load and unserved energy. For these reasons, the AESO rejected the recommendation to forecast DTS plus FTS plus losses as an alternative to AIL.

4.2 Price Responsive Load

4.2.1 AESO Proposed Treatment

The AESO's proposed treatment for PRL is described in Appendix Q to the AESO's Application and in the AESO's Rebuttal Evidence.[17] For the first two auctions, historic PRL behaviour is included in the load forecast to capture the impact of PRL on overall load patterns used to forecast demand. PRL is not included in the RAM as a source of supply because PRL participation as a capacity resource is currently voluntary, uncertain and difficult to quantify. Assuming that a PRL asset will be available as a capacity asset in the RAM creates a risk of over-procurement because at this time it is not known if the PRL assets will take on an obligation to reduce consumption to a certain level when the system needs supply. Once these resources have capacity commitments they will be modelled within the RAM as supply side assets in subsequent updates for future auctions and their load capability will be taken into account within the capacity market load forecast by including their entire load in the forecast.

At the meeting, the AESO presented three alternatives that it considered for the treatment of PRL: (1) model PRL as a supply side capacity asset and reconstitutes load upward for PRL behavior; (2) implicitly include PRL in load forecast (proposed option); and (3) model PRL as a demand side capacity asset and reconstitutes load downward for PRL behavior. The AESO's presentation is attached as Appendix G.

4.2.2 Views and Concerns of Participants

CanSIA, ENMAX, ADC/IPCAA, Suncor and TransAlta submitted written views to the AESO on PRL in advance of the meeting:

- CanSIA, ADC/IPCAA and Suncor requested clarification on the AESO's treatment of PRL.
- Suncor recommended that the AESO add PRL back into the forecast load and then include price-responsive load as a flexible resource.
- ENMAX recommended that the AESO remove the impact of PRL from historical load, forecast load, and then include the PRL in the RAM as a supply resource.
- TransAlta agreed with the AESO's treatment of PRL.

DePal Consulting ("DePal") on behalf of UCA presented its views at the meeting. DePal proposed an option similar to the AESO's supply-side option whereby PRL is treated as demand response as though it is participating in the capacity market with the difference that the AESO would add these assets on the supply side after qualification when they are known with loads otherwise modelled according to historically observed behaviour.

During the open discussion, participants discussed and acknowledged the challenges associated with assuming that PRL will participate on the supply side of the capacity market and the risks of over-

[17] Exhibit X0346.01, PDF 3, 19; Exhibit X0549.02, PDF 24.

procuring if PRL does not show up as a capacity resource. Generally, the participants that voiced their opinions acknowledge the challenges with proposed alternatives for PRL and the corresponding impacts to under- or over-estimating the GMPV.

There was general agreement among the participants that contributed to the discussion that the AESO could run the RAM after the qualification stage when it is known whether PRL is participating on the supply side of the capacity market.

ADC/IPCAA, ATCO, ENMAX, Suncor, UCA, TCE converged around an option proposed by Suncor that assumes all PRL on the demand side, as though they are always curtailed, in the RAM, which would reduce the GMPV resulting in a demand curve further to the left than the AESO's proposal. If a PRL offers into the auction as a supply asset, the demand curve would then be right-shifted to include the amount of UCAP that was submitted by the PRL at all prices above the offer price.

AFREA, Capital Power, CanSIA, the CCA, Powerex, TransAlta and IPPSA did not express positions during the discussion. TransAlta later confirmed that it did not endorse Suncor's proposed option.

4.2.3 AESO Response to Views and Concerns

At the meeting, the AESO explained the reasonableness of its approach in consideration of the risk tradeoffs identified in the table of options. The key issue for the AESO is that PRL participation in the capacity market as capacity resources is unknown until following qualification and ultimately clearing of the base auction is complete. Until that can be observed, the AESO will assume their real time curtailment practices will be the same as their past practices. Once it is known which PRL sites will chose to provide capacity, the AESO will be able to adjust the load forecast to reconstitute these sites' load and explicitly model the sites as capacity resources within the RAM. However, until it is known with certainty that the identified PRL sites will participate as demand response capacity market assets and clear the market to become capacity providers, there is over- or under-procurement risk if the AESO makes an assumption about them which turns out to be incorrect.

DePal Proposed Option

DePal presented an approach to incorporate PRL by re-running the RAM after qualification to account for the volume of UCAP value associated with PRL sites that qualify as potential capacity sellers. This would involve updating load to reflect the PRL sites as though they were not curtailing and adding the sites into the RAM as supply assets.

The advantage of this approach is that it helps to mitigate the risk of over-procurement identified by the AESO as a result of adding all price responsive load sites to the demand curve prior to understanding whether or not they would be participating as capacity assets. However, the option does not fully eliminate the over-procurement risk and it introduces a new issue with regard to timing and governance.

While the DePal proposal ensures that PRL sites that do not intend to participate as capacity assets are not added to the minimum procurement volume, the assumption is made that all capacity market qualified PRL sites will clear in the auction. If they do not clear, there remains a risk of over-procurement because the AESO will have increased load on their behalf while still possibly getting load curtailment during the future obligation period due to energy market and tariff cost signals from loads which qualify but do not clear in the capacity market. The AESO acknowledges that this over-procurement risk would be less than if the AESO were to include all identified price-responsive sites on the supply side.

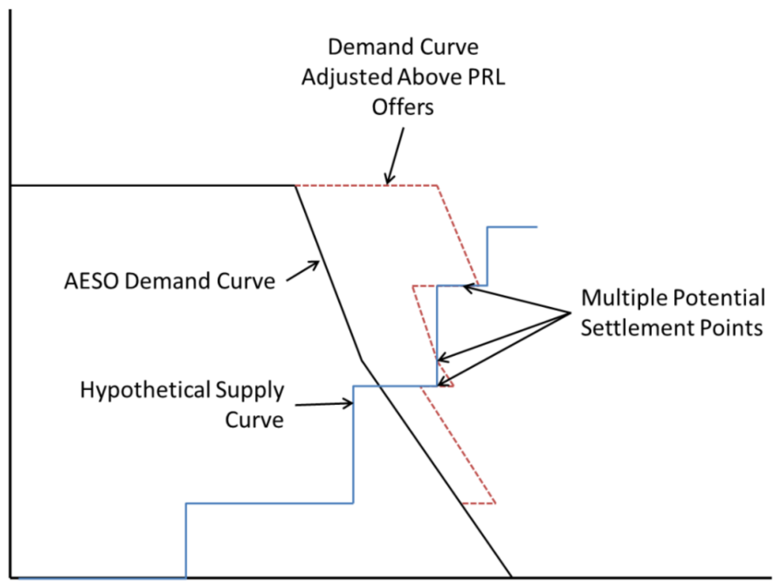
Even with over-procurement risks partially mitigated, the DePal option introduces governance timing risk. Updating the RAM after qualification compromises the AESO's ability to engage in adequate stakeholder consultation, and would require unreasonably quick AUC decisions on the RAM and GMPV within the auction timelines. Section 6 below discusses governance in more detail.

Suncor Proposed Option

The AESO assessed Suncor's proposed option and is of the view that it is not feasible for two reasons. First, the option requires the AESO to change the final demand curve after offers are submitted in the auction. As a result, the market will not know what the shape of the demand curve is until after the auction clears. Capacity market power mitigation may also be impacted by the change in the demand curve shape.

Second, adjusting the demand curve at prices above the offer price may result in a demand curve which curves back upon itself and contains multiple corners. Depending on the offers submitted by PRL sites, the demand curve may take on a shape which allows for multiple intersections of the demand curve and the supply curve causing challenges in determining where to settle the market. Figure 1 below shows a stylized version of a demand curve under Suncor's proposed option:

Figure 1: Impact of Adjusting Demand Curve above Price Responsive Load Supply-Side Offers



Notes: The dotted red line shows how the demand curve would be adjusted for three PRL offers as supply-side assets. Depending on the magnitude and price of those offers, as well as the supply curve, there could be multiple potential settlement points.

For the reasons stated above, the AESO is of the view that Suncor's proposed option is not feasible to implement and could result in sub-optimal market outcomes. .

The AESO appreciates the suggestions from market participants regarding potential treatment options for known PRL sites within the RAM. However, after careful consideration, the AESO remains of the view that allowing PRL behavior to be projected in the obligation period as captured by the load forecast remains the most reasonable option in balancing under procurement and over procurement risk.

In conclusion, the AESO will not be revising the PRL methodology in the RAM for the development of the GMPV for the 2021/2022 and 2022/2023 obligation periods. The AESO maintains its view that the current approach to modeling PRL to calculate GMPV is reasonable. The qualification outcomes and observed capacity and energy market participation for load assets that choose to participate in the capacity market as demand response will be accounted for in future procurement volumes. Further, demand side participation in the capacity market has been identified as an area to review in the market roadmap and will be reviewed as per the roadmap timing.

4.3 Performance of the Intertie

4.3.1 AESO Proposed Treatment

The AESO's proposed treatment for the intertie is described in detail in Appendix Q to the AESO's application.[18] The AESO uses historical available transfer capability ("**ATC**") data to model the availability of import capability from neighbouring jurisdictions and to capture the impacts of transmission constraints and outages that affect the interties. The RAM assumes that the interties are at full unconstrained capacity when the pool price is at the cap and that planned outages for the intertie are generally flexible and can be adjusted for tight supply conditions. For the first two base auctions, the AESO identified full outages lasting more than seven days as planned outages and excluded these events from the distribution. Intertie availability data was provided in Exhibit X0323 in Proceeding 23757.

4.3.2 Views and Concerns of Participants

CanSIA, ENMAX, TransAlta and UCA submitted written views to the AESO on the performance of the intertie:

- CanSIA and UCA requested additional information on hourly total intertie capacity.
- ENMAX agreed with the AESO's modeling of intertie availability.
- TransAlta disagreed with the AESO's assumptions regarding the amount of capacity available from the intertie during supply shortfall hours.

PowerEN Corporation ("**PowerEN**") on behalf of TransAlta presented its views at the technical meeting. PowerEN presented statistics on imports during EEA hours and concluded that capacity from other jurisdictions that appears available during periods of supply shortfall cannot be relied on. PowerEN's presentation is attached as Appendix H.

During the open discussion:

- TransAlta expressed concern that the RAM is over assessing the contribution of interties to supply adequacy and is therefore resulting in under procurement.
- Powerex agreed with TransAlta, but was not overly concerned with the issue because Powerex believed the RAM was trending toward over procurement.
- TCE suggested that the AESO should take planned outages on pseudo units representing the intertie in the model into consideration.
- CanSIA recommended performing an hourly assessment of elements that are contributing to over procurement.

AFREA, ADC/IPPCA, Capital Power, ATCO, IPPSA, the CCA, Suncor, and the UCA did not express positions during the open discussion.

[18] Exhibit X0346.01, PDF 19; see also Exhibit X0284, PDF 51.

4.3.3 AESO Response to Views and Concerns

Following the meeting, the AESO investigated the performance of the intertie in the RAM to determine whether the availability distribution and the absence of explicitly modelling intertie planned outages led to reasonable performance within the RAM compared to what has been observed historically.

The non-zero availability was reasonable and approximated intertie availability during tight supply similar to history. When compared to the historical observations during tight supply hours, it was determined that the availability distributions in the RAM were over-characterizing 0 MW availability occurrences compared with history. Therefore, the AESO determined that an adjustment to the percentage of zero values in the distribution was warranted to better align with historical observations. Additionally, it was determined that explicitly modeling planned outages would further overstate the zero availability and not lead to a more reasonable representation of intertie availability. The revisions to the intertie distribution are described in Section 5.

4.4 Regulating Reserve

4.4.1 AESO Proposed Treatment

The AESO's proposed treatment of regulating reserve is described in detail in Appendix Q to the AESO's application.[19] The RAM assumes that contingency reserves (spinning reserve and supplemental reserve) are deployed once the system enters an EEA event. The RAM begins measuring simulated firm load shed once estimated contingency reserves are depleted. To mimic current system operator procedures, 0.72% of load representing regulating reserves are maintained during simulated load shed events in the estimation of unserved energy. The portion of regulating reserve maintained during a load shed event in the model is estimated as a percentage of Alberta gross load and is consistent with observed regulating reserve levels during historical tight supply. Regulating reserve data was provided in Exhibit X0323.

4.4.2 Views and Concerns of Participants

ENMAX and TransAlta submitted written views to the AESO on regulating reserve:

- ENMAX recommended that the AESO decrease the generation available to meet load by the average amount of regulating reserve the AESO has held onto during historical EEA events.
- TransAlta held the view that the increased need for capacity to respond to increased short term net demand variability arising from anticipated large increases in wind generation needs to be recognized in the AESO's RAM.

Solas Energy Consulting ("**Solas**") on behalf of CanSIA, and PowerEN on behalf of TransAlta, presented their views at the technical meeting. Both presented on the impacts of wind on regulating reserve in the RAM, but came to opposite conclusions on whether there is a need to increase the amount carried. The Solas and PowerEN presentations are attached as Appendix I.

During the open discussion, there were mixed views from the few participants contributing to the discussion on whether the AESO should increase the amount of regulating reserves in the RAM to account for increased wind resources on the system:

[19] Exhibit X0346.01, PDF 20; see also Exhibit X0284, PDF 51.

- TransAlta maintained its view that regulating reserves should be increased.
- Suncor recommended that the model be designed to anticipate how much capacity is required and set regulating reserve based on the amount of wind on the system.
- Powerex acknowledged the arguments for increasing regulating reserve, but expressed that it was more concerned about over procurement bias in the RAM.
- Power Advisory acknowledged that more regulating reserve may be needed in certain hours but supported the current regulating reserve assumptions in the RAM.

ADC/IPCAA, AFREA, ATCO, CanSIA, Capital Power, the CCA, IPPSA, ENMAX, TCE and the UCA did not express positions during the open discussion. ADC/IPCAA, CanSIA and the CCA later confirmed that they agree regulating reserve in the RAM should not be increased.

4.4.3 AESO Response to Views and Concerns

The AESO rejected the recommendation that regulating reserve in the RAM should increase. The AESO relies on historical regulating reserve data from times when the system is near unserved energy conditions to inform the treatment of regulating reserve in the RAM. Consideration of regulating reserve in all system conditions or system requirements to manage wind fluctuations is irrelevant, given such conditions are different than the condition where there is a shortage of available generation, which is the focus for the RAM and GMPV determination. The AESO maintains the view that the current approach to modeling regulating reserve, as described in its Rebuttal Evidence,[20] is reasonable.

4.5 Outages and Derates

4.5.1 AESO Proposed Treatment

The AESO's proposed treatment of forced outages, planned outages and ambient temperature derates is described in detail in Appendix Q to the AESO's application.[21] In summary, the RAM simulates the unavailability of thermal generating units to account for when planned outages, forced outages and temperature derates impact the availability of these units. The simulations are based on historical outage data.

The AESO is not aware of what type of outage a thermal asset is on in all circumstances. To classify the historical outage data used in the RAM for the 2021/2022 and 2022/2023 base auctions, the AESO reviewed the data and made assumptions about whether an asset was historically on a planned or forced outage.

Planned outages are scheduled in the RAM using an algorithm based on daily peak loads, and significant planned outage events are scheduled in the spring and fall due to lower loads in those periods. The objective of the algorithm is to add planned outage events such that each event added would impact the remaining periods with the lowest peak load days. The capacity from the planned outage event was added to the daily peak load for the calculations for the next asset to be placed on planned outage. In this way, the daily peak load plus planned outage was minimized. Additionally, the AESO manually rescheduled 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.

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[20] Exhibit 549.02, PDF 26-27.

[21] Exhibit X0346.01, PDF 5-8; see also Exhibit X0284, PDF 50.

To simulate forced outages, the RAM calculates a seasonal distribution of time-to-fail and time-to-repair hours for each generating unit (November through April for winter, and May through October for summer). Forced outage rates and/or partial outage rates are then calculated from the distribution for each season for four fuel types: coal, combined cycle gas, simple cycle gas, and other thermal assets. For the GMPVs for the 2021/2022 and 2022/2023 base auctions, the AESO made adjustments to exclude the Keephills 1 (KH1) March 5, 2013 full generator rewind, lasting approximately 5,000 hours, and to adjust the Sheppard (EGC1) May 23, 2015 outage weighting to represent an approximately one in five year occurrence.

The AESO calculates temperature de-rate curves based on historical available capability data and corresponding weather data to capture adjustments in maximum capability due to ambient temperature de-rates. The de-rate curves are used to model weather related de-rates for combined cycle and simple cycle generating units. The RAM references the temperature de-rate 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. This methodology ensures consistent temperature drivers across demand and combined cycle and simple cycle generation output.

Outage data was provided in Exhibit X0323 of Proceeding 23757.

4.5.2 Views and Concerns of Participants

ADC/IPCAA, CanSIA, ENMAX, TransAlta, Suncor and UCA submitted written views to the AESO on outages:

- CanSIA and UCA requested additional information.
- ENMAX recommended that planned outage rates should be shaped to reflect when outages were actually taken historically and noted that coordinating outages would allow the AESO to have more control over ensuring that reliability targets are met.
- ADC/IPCAA recommended that the RAM account for suppliers delaying outages and maintenance in response to market conditions and requested that the AESO provide greater transparency of scheduled maintenance outages.
- Suncor recommended that the AESO: (i) evaluate the impacts of outage flexibility by reducing the outage rates to simulate the portion of the outages that are flexible; (ii) collect data on what portion of outages are flexible; and (iii) provide greater transparency around scheduled maintenance.
- TransAlta recommended that the AESO: (i) evaluate at least 6 years of historical data to estimate planned outage rates; (ii) rely on NERC outage rates; and (iii) not assume a specific maintenance schedule in the RAM.

On April 22, 2019, the AESO filed an errata to correct an error in the temperature de-rate curves in Appendix Q.[22] Following the AESO's clarification and updated evidence, ENMAX changed its evidence in Proceeding 23757 to agree with the AESO's treatment of ambient temperature de-rates in the RAM.[23] No

[22] Exhibit X0346.01, PDF 9 (blackline version).

[23] Exhibit X0387.03, PDF 71.

other party expressed disagreement with the treatment of ambient temperatures de-rates in Proceeding 23757, or requested the opportunity to present their views on the issue at the meeting. Therefore, this issue was removed from the meeting agenda.

At the meeting, ENMAX on behalf of ENMAX and Suncor, Power Advisory on behalf of Suncor and TCE, and PowerEN on behalf of TransAlta presented their views on outages. The ENMAX, Power Advisory and PowerEN presentations are attached as Appendix J.

During the open discussion, there were mixed views on planned outage coordination:

- TransAlta suggested that the AESO's analysis of maintenance outages is suboptimal and the RAM is assuming an overly optimized view of planned outages.
- Suncor (including Power Advisory) and ENMAX offered some support for the AESO's scheduling algorithm in principle, but expressed concern that the planned outage algorithm is missing data.
- ENMAX maintained its view above that there should be shape to planned outages, as opposed to randomization.
- ENMAX and UCA requested more granular outage information.

Regarding forced outages, several participants expressed concern that the RAM is under representing the system's ability to delay forced outages to periods of less risk. Participants generally acknowledged that the data required to properly model delayed forced outages in the RAM does not exist in the AESO's ETS system today. However, recommendations for how the AESO could perform the indicative analysis on delayed forced outages were put forward:

- Power Advisory, on behalf of Suncor, recommended looking at market level data to calculate conditional probabilities for delayed forced outages that could feed into the RAM.
- ENMAX suggested deferring forced outages to weekends.
- TransAlta and EDC suggested that accounting for delayed forced outages without the data would add complexity with possibly little benefit.
- CanSIA generally supported including a delayed forced outage parameter in the RAM to account for the potential to defer forced outages.
- IPCAA requested more transparency on outage classification.
- Suncor offered to work with the AESO to develop methodologies for delay forced outages through an iterative process.

AFREA, ATCO, Capital Power, the CCA, IPPSA, Powerex and TCE did not express positions during the open discussion.

4.5.3 AESO Response to Views and Concerns

Planned Outage Scheduling

The AESO maintains the view that the current approach to modeling planned outages for the purpose of calculating the GMPV is reasonable, as described in its Rebuttal Evidence in Proceeding 23757.[24] While

[24] Exhibit X0549.02, PDF 23-24.

market participants may have flexibility to move planned outages based on its own risk assessment of forced outages and de-rates, expected import availability and wind and hydro expectations, the AESO is unable to capture these specific portfolio positions and risk profile considerations in its planned outage scheduling in the RAM. The planned outage algorithm in the RAM is based on the peak load pattern and is consistent with what is observed in the AESO's monthly outage report.

Historical data presented at the technical meeting by the AESO and Power Advisory, on behalf of Suncor,[25] supports the AESO's approach to modeling planned outages, as it indicates that the market has generally been effective in self-scheduling planned outages to times of lower demand throughout the year, which is similar to how these outages are currently modelled in the RAM.

Delayed Forced Outages

Upon further investigation of the available capability data, the AESO determined it was possible to discern a pattern of behavior regarding delayed forced outages for coal plants that could be included in the inputs to the RAM. Further details are provided in Section 5.4 below.

Outage Data Quality and Availability

To address participants' requests for more granular outage data, the AESO will review its existing practices for collecting outage data through ETS and evaluate opportunities for improvement. If it is determined that ISO rule changes are required to facilitate the collection of more granular outage data, the AESO will consult with stakeholders in accordance with AUC Rule 017.

4.6 RAM calibrations and perceived discrepancies between forecast and actual unserved energy

4.6.1 AESO Proposed Treatment

The AESO performed calibration tests of the RAM against 2017 and 2018.[26] EUE output data was posted to the AESO website in December 2018 and is provided in Exhibit X0336 in Proceeding 23757.

The AESO described the distinction between expected unserved energy (EUE) and observed (or actual) unserved energy in its Rebuttal Evidence:

> …Observed unserved energy is backward-looking, representing the actual level of unserved energy in a year. EUE is the average of estimated unserved energy across 7,500 forward-looking potential hourly supply and demand iterations. Some of these iterations capture low-probability, high-impact possible events that result in higher volumes of unserved energy.
>
> The only way to have 0 MWh of EUE for 2017 and 2018 would be if all of the 7,500 scenarios had 0 MWh of unserved energy. On a probabilistic basis, the most likely outcome from the RAM for the 2017 and 2018 calibrations was 0 MW of unserved energy, as acknowledged by Suncor and TransAlta, because there are more instances of 0 MW unserved energy across the 7,500 scenarios than any other outcome (see Figure 3.10 below). The 0 MWh of observed unserved energy in 2017 and 2018 is therefore consistent with the calibrations for those years.

[25] See slide 7 of the AESO presentation and slide 5 of the Power Advisory presentation in Appendix J.

[26] Exhibit X0345, PDF 7.

However, this does not mean the risk of unserved energy was removed or did not exist in those years. In particular, there were observed EEA events in both 2017 and 2018 which show that the system was at risk of an observation of unserved energy.

The 2017 and 2018 calibrations demonstrate that had there been an additional generator or intertie outages during the observed tight supply events, it is plausible that unserved energy would have occurred.[27]

4.6.2 *Views and Concerns of Participants*

ENMAX, Suncor, TransAlta and the UCA submitted written views to the AESO on the RAM calibrations:

- ENMAX concluded that the demand curve will result in much lower unserved energy compared to the normalized EUE forecasted by the RAM and submitted that setting the UCAP associated with the normalized EUE at net-CONE will reduce the discrepancy.
- Suncor recommended that the AESO use hourly supply cushions to calibrate the RAM and provide calibration data for 2013 through 2018, which includes years with relatively tight conditions as well as years with over supply conditions.
- TransAlta suggested that it is a fallacy to equate observed unserved energy with the EUE and that it is inappropriate to calibrate the RAM based on historical and forecast reserve margin.
- UCA requested additional information

Solas and Power Advisory on behalf of CanSIA, TCE and Suncor, and ENMAX on behalf of ENMAX and Suncor, presented their views at the technical meeting. The Solas/Power Advisory, ENMAX and PowerEN presentations are attached as Appendix K.

During the open discussion, several participants expressed concern over the information asymmetry between the AESO and market participants. As a result, several participants claimed that they were unable to provide specific recommendations to the AESO regarding the calibration of the RAM. In general, participants are looking for more information from the AESO to perform their own analysis, evaluate the AESO's calibration conclusions, and increase their confidence in the RAM and the resulting GMPV. There was general consensus among the participants to the discussion that the AESO should publish more RAM output data. The AESO was asked to provide the following for as many weather years as possible:

- Hourly output of the following across all, or a subset, of the iterations for the 2018 calibration, 2021/2022 GMPV and 2022/2023 GMPV: load, supply cushion, generation by fuel/technology type, total intertie capacity, total planned outage, total forced outages, cogeneration output.
- Count of EEA hours resulting from each iteration for the 2018 calibration, 2021/2022 GMPV and 2022/2023 GMPV;
- An index to match released economic/weather load scenarios to the EUE iteration for the 2018 calibration;
- Information on the impact of the AESO's cogeneration modeling approach.

Regarding the AESO's approach to calibration:

[27] Exhibit X0549.02, PDF 26-27.

- CanSIA, ENMAX, Power Advisory and Suncor and expressed concerns with calibrating the model using only events that are rare (e.g. EEA events, loss of load hours / events, etc.) and suggested that calibrating to the supply cushion (8760 events / year) would be a better solution.
- TransAlta offered some support for calibrating the model against the normalized EUE metric.

AFREA, ATCO, Capital Power, the CCA, IPPSA, TCE and the UCA did not express positions during the open discussion.

4.6.3 AESO Response to Views and Concerns

While certain parties raised concerns that the AESO released insufficient data to validate the RAM and GMPV, the AESO notes there were three parties that were able to develop RAM models using the information released by the AESO in December 2018 and estimate similar results. These parties used their modeling to identify their concerns with the AESO inputs and methodologies, and this guided the majority of the issues discussed at the meeting. The majority of the RAM inputs and outputs that were evaluated by the AESO to validate the model in the first instance were released in consultation or during Proceeding 23757. The additional data requested by participants, as noted above, amounts to nearly 1.3 billion records in total for each obligation period.

In the AESO's view, evaluating the hourly output from each of the 7,500 iterations associated with one annual period is not an effective way to validate the RAM. The AESO's model validation relied on evaluating the input distributions, overall availability of assets types, direction and magnitude of change resulting from modifications to the RAM and the resulting EUE distribution. Additional validation work included the RAM simulation the AESO completed of 2017 and 2018 using a mix of actual and forecast information as a calibration of the model results. However, comparing the RAM output to historical outcomes has limited value as it is comparing a risk assessment to only one outcome, as noted in our Rebuttal Evidence in 3.2.3.

Beyond the information included in this report, on Monday June 3, 2019, the AESO will post data associated with the updated GMPVs and calibration results on its website and file it on the record of Proceeding 23757. Beyond what has previously provided for the calibrations and GMPV, additional data will include: planned outage profile by day; EEA hours by iteration, EUE by economic scenario and hourly supply cushions for a select set of 2018 calibration iterations.

4.7 Cogeneration

4.7.1 AESO Proposed Treatment

The AESO's proposed treatment of cogeneration is described in detail in Appendix Q to the AESO's application.[28] The relationship between the gross availability of cogeneration sites and gross load is used to simulate cogeneration availability in the RAM. Using five years of historical hourly data, the daily gross peak load and daily gross peak generation availability for each cogeneration site are calculated. For cogeneration sites that do not have consistent available capability data, the AESO developed a synthetic shape by using the maximum hourly generation (from SCADA data) or available capability. The data is aggregated into a number of different normalized load levels with an associated distribution for winter months (January to April, November and December) and for summer months (May to October). The

[28] Exhibit X0346.01, PDF 16.

distributions are defined seasonally to account for seasonal variances in availability. The RAM then estimates gross availability in the hourly simulation by drawing an output from the daily gross availability distribution based on the daily peak load and multiplying that drawn value by the capacity of the cogeneration fleet.

Cogeneration data was provided in Exhibit 323 in Proceeding 23757.

4.7.2 Views and Concerns of Participants

Suncor submitted written views to the AESO on cogeneration. Suncor requested calibration data to clearly show how cogeneration is modelled in the RAM. It was not clear to Suncor whether the AESO's approach to cogeneration accounted for the relationship between generation availability and the onsite load.

During the additional discussion time, Suncor and Power Advisory sought clarification on the treatment of cogeneration within the RAM and the behaviour the AESO is intending to capture. Power Advisory expressed concern with the linkage of cogeneration availability to Alberta internal load in the RAM.

4.7.3 AESO Response to Views and Concerns

At the meeting, the AESO clarified that it does not have the level of information required to model the unique relationship of each cogeneration site's output and load. The AESO maintains that the methodology for treating cogeneration in the RAM is appropriate as it uses the data available to model the relationship between cogeneration output and demand levels, albeit at a system wide level as opposed to a site level.

Following the discussion at the meeting, the AESO further evaluated the seasonal cogeneration output distributions to ensure that they were reasonable. It was determined that an adjustment should be made to account for the Fort McMurray fires. The adjustment is described in Section 5.5 below.

5. Modifications and Updates to the Resource Adequacy Model and GMPVs

5.1 Load forecast

The AESO updated the load forecast for the 2021/2022 and 2022/2023 obligation periods with more recent information including the latest CBoC economic outlook, up-to-date oilsands production information and historical load data. Throughout this section the capacity market load forecast used in the AESO's initial application is compared to the May 2019 update.

Conference Board of Canada Economic Forecast Update

The most recent complete CBoC forecast update is the Provincial Outlook Economic Forecast: Alberta – Winter 2019 ("**CBoC Winter 2019 Forecast**"), released March 19, 2019. The AESO compared the CBoC Winter 2019 Forecast to the CBoC's Provincial Outlook Economic Forecast: Spring 2018 ("**CBoC Spring 2018 Forecast**"),[29] which was used in the AESO's application load forecast ("**AESO August 2018 Load Forecast**"). The CBoC became relatively less optimistic about Alberta's near term economic growth, largely due to the anticipated impacts of oilsands production cuts and declines in energy investment. Accordingly, the CBoC Winter 2019 Forecast is lower than the CBoC's Spring 2018 Forecast in the near

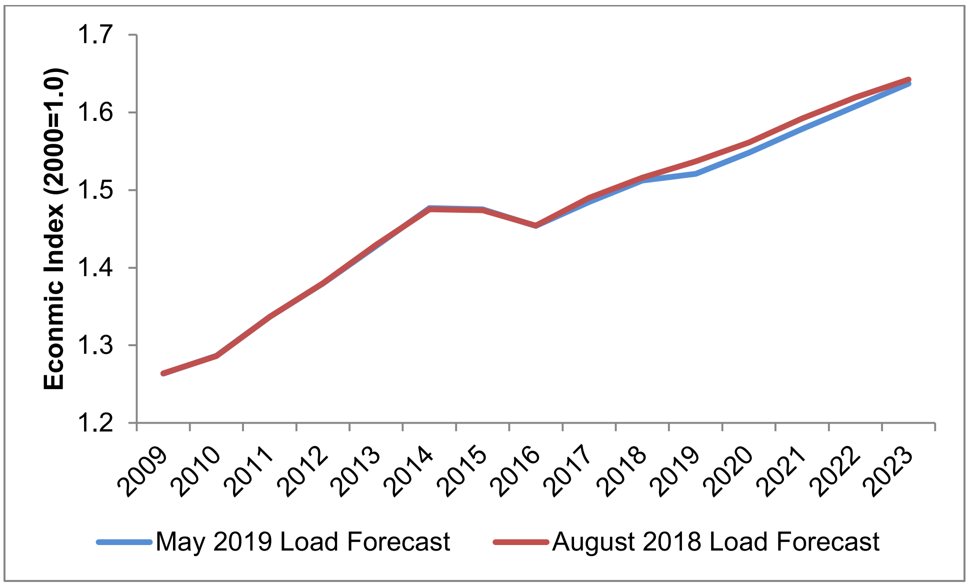
[29] Available on the CBoC website: https://www.conferenceboard.ca/e-library/abstract.aspx?did=9713.

term. The CBoC Winter 2019 Forecast contains economic forecast data that was updated on February 5, 2019. However, the AESO also assessed the more recent economic forecast data available from the CBoC's e-data website on May 7, 2019.[30] This forecast data is lower than the February 5, 2019 forecast data in the CBoC Winter 2019 Forecast. The AESO opted to use the more recent May 7 data to update the load forecast for the RAM.

On May 28, 2019, the CBoC published an Executive Summary of its forthcoming Spring 2019 Provincial Outlook. While the full Spring 2019 Forecast has not been released yet, the May 7, 2019 data from the CBoC's e-data website is consistent with the underlying narrative and assumptions outlined in the Executive Summary. In the AESO's view, the May 7, 2019 economic forecast data reasonably represents up-to-date economic information and expectations.

Figure 2 below shows the impact to the economic driver variable in the RAM resulting from the update. In particular, it can be seen that, compared to the CBoC Spring 2018 Forecast used in the AESO August 2018 Load Forecast, the May 2019 data results in lower economic growth in 2019. The two indices then begin converge by 2023.

Figure 2: Updated Economic Driver Variable



Oilsands Production Update

The oilsands production forecast used in the AESO August 2018 Load Forecast was sourced from the Canadian Association of Petroleum Producers' June 2018 forecast ("**CAPP June 2018 Forecast**"). CAPP has not released an updated oilsands production forecast since June 2018. While the AESO prefers the CAPP forecast because it is publicly available without a subscription, a comparable option is the IHS *North American Crude Oil Markets Canadian Fundamentals Data: Q1 2019,* which the AESO receives through its subscription service. The updated IHS forecast is lower in the near term than the CAPP June 2018 Forecast as it captures recent industry changes and trends, including the Alberta Government-imposed oilsands production cut and related impacts to energy development and investment. The

[30] https://www.conferenceboard.ca/e-data/MetaData.aspx?SessionExpired=true, accessed May 7, 2013

forecast then grows with eventual convergence by 2023 to the CAPP June 2018 Forecast. In the AESO's view, this forecast reflects recent information and expectations pertaining to oilsands production during the 2021/2022 and 2022/2023 obligation periods.

Historical Load Update

To update historical load data, the AESO updated the training period on which the RAM is based.[31] It is within this training period that the statistical relationships between load and load drivers are established and used to forecast future load. The 5-year training period used in the AESO August 2018 Load Forecast was shifted forward when the AESO undertook an update on May 13, 2019 ("**May 13, 2019 Load Forecast**"). As shown in Figure 3 and Table 1 below, the forward shift in the 5-year training period results in higher average historical load in the May 13, 2019 Load Forecast update training period compared to the AESO August 2018 Load Forecast training period.

Figure 3: Historical Monthly Alberta Internal Load (AIL) and Load Forecast Model Training Periods

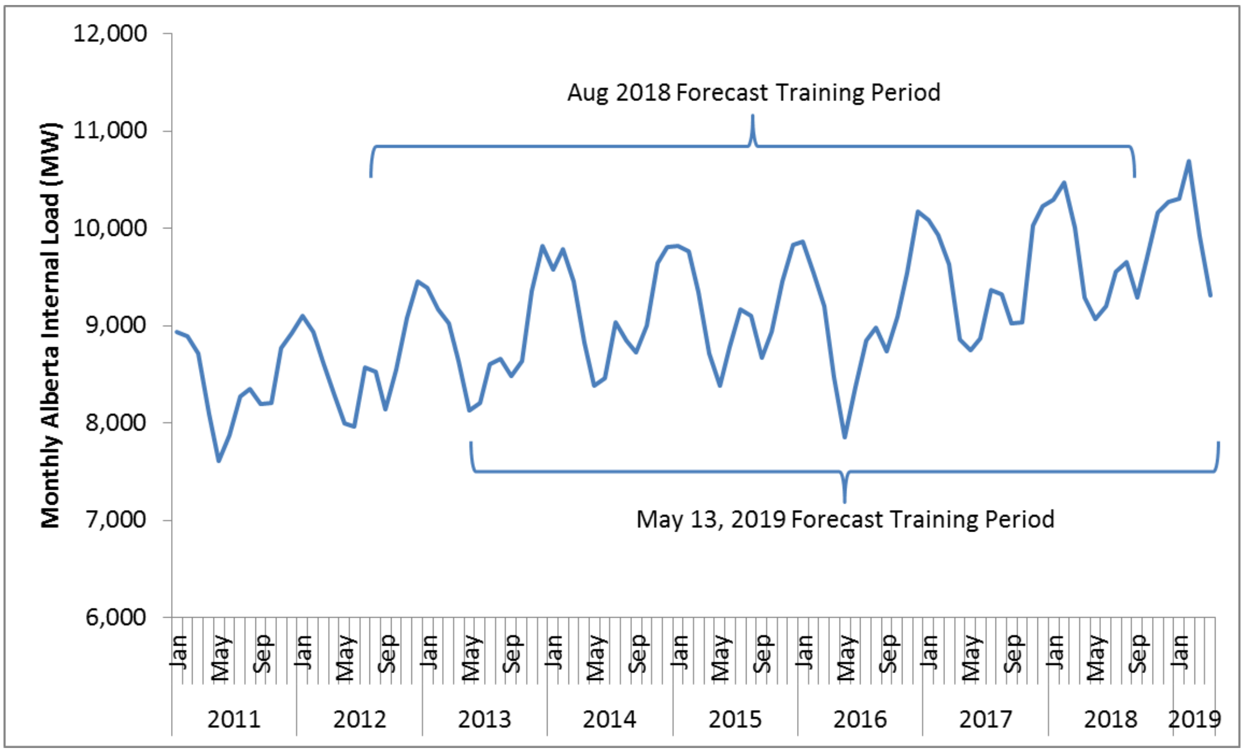


Table 1: Average Load across Training Periods

Load Forecast Update	Time Period	Average Load (MW)
August 2018 Forecast	August 1, 2012 - August 12, 2018	9,155
May 13, 2019 Forecast	May 1, 2013 - April 30, 2019	9,280

[31] Training period denotes the historical data set on which the load forecast regression model is developed.

Load since August 2018 Training Period Ended	August 12, 2018 - April 30, 2019	9,923

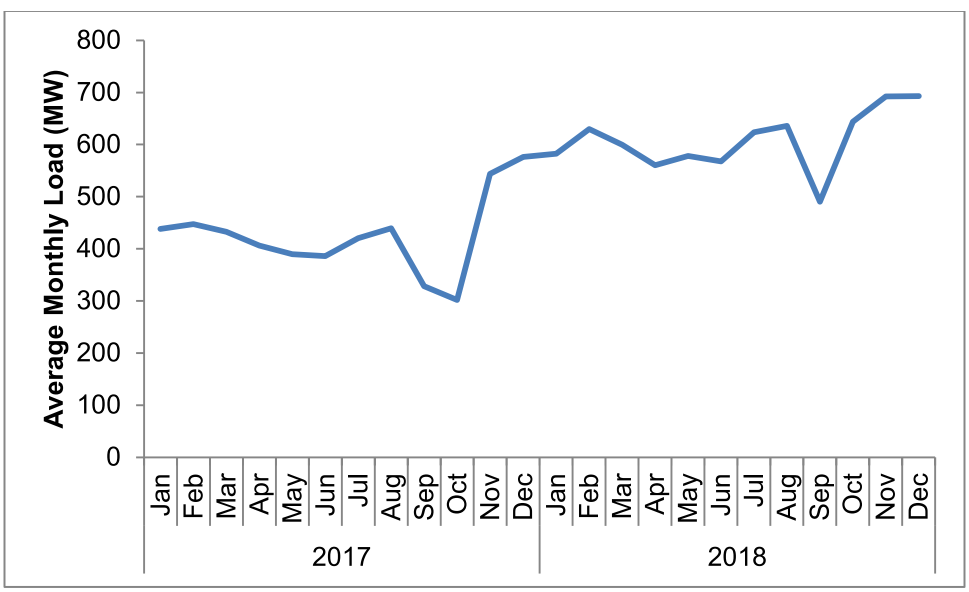
Updating the load forecast with the new training period yielded unanticipated impacts to the forecast results. Specifically, the average load forecast and energy forecast increased despite a lower economic forecast and monthly results revealed additional unexpected results. In the time available to the AESO to assess the May 13, 2019 Load Forecast update, it was determined that there was strong growth towards the end of 2018 which likely impacted the load forecast model and the underlying relationship between load and economic inputs.

To determine if weather was a factor, the AESO assessed whether the late-2018 load growth was temperature-driven. The AESO looked at load and temperature over the recent data and compared it to past years to determine whether load is growing rapidly due to weather or due to other factors. It was determined that load across May 2018 to December 2018 was substantially higher than load during the same periods in 2017 and 2016, across the full temperature spectrum. This means that there was significant underlying (non-temperature-driven) load growth during that period.

The substantial increase in non-weather-driven load growth in the last half of 2018 impacted how the May 13, 2019 Update statistically established the relationship between load and load drivers, which had a corresponding impact on forecast load.

The AESO further examined underlying sources of load growth in the second half of 2018 and early 2019 to determine whether the impacts on the economic-load relationship from that period was reasonable to expect going forward. The AESO found that load growth in this time frame was primarily driven by a select number of large industrial sites. These sites were approximately 200 MW higher in June 2018 to December 2018 than they were from June 2017 to December 2017 (see Figure 4 below). Figure 4 also shows a dip in the September-October timeframe in both years. However, the dip is less pronounced in 2018 compared to 2017. It is the AESO's understanding that this relates to the timing and length of maintenance cycles at certain industrial sites.

Figure 4: Average Monthly Load of Select Industrial Sites



Overall, the AESO is of the view that the strong growth witnessed in late 2018 is anomalous and is unlikely to occur again leading up to the 2021/2022 and 2022/2023 obligation periods. The AESO is of the view that the historical data from this timeframe should be included in the load forecast to reflect recent information. However to mitigate the other forecast issues, on May 22, 2019, the AESO updated the load forecast training period with an additional year of historical load data (the "**May 22, 2019 Load Forecast**"). The training period for the May 22, 2019 Forecast is May 1, 2012 to April 30, 2019.

Overall Results and Conclusions

The results of the May 22, 2019 Load Forecast are presented in Table 2 and Table 3 below.

Table 2: May 22, 2019 Load Forecast Update Results by Economic Scenario (2021-2022 Obligation Period)

	Min	Low	Ref	High	Max
Max Values (MW)	12,211	12,248	12,292	12,375	12,435
Average Values (MW)	10,058	10,102	10,146	10,238	10,324
Average Total Annual Energy (GWh)	88,107	88,497	88,879	89,683	90,440

Notes: Max Values represent the max values from all weather years (i.e. 1 in 30 weather-year peak), Average Values and Average Total Energy are averaged across all weather years.

Table 3: May 22, 2019 Load Forecast Update Results by Economic Scenario (2022-2023 Obligation Period)

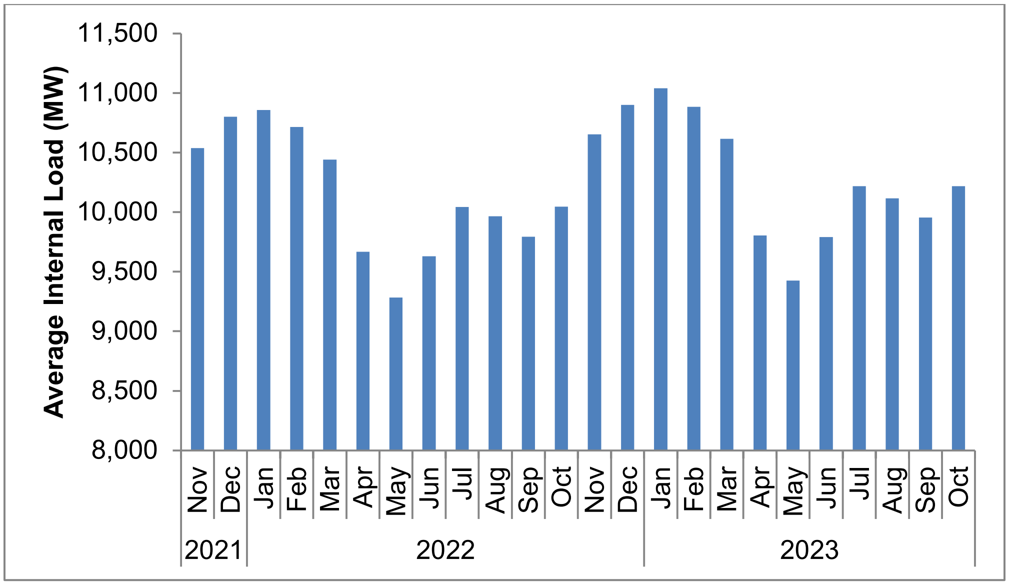
	Min	Low	Ref	High	Max
Max Values (MW)	12,325	12,405	12,479	12,539	12,597
Average Values (MW)	10,155	10,227	10,300	10,369	10,437
Average Total Annual Energy (GWh)	88,958	89,586	90,225	90,837	91,426

Notes: Max Values represent the max values from all weather years (i.e. 1 in 30 weather-year peak), Average Values and Average Total Energy are averaged across all weather years.

Compared to the AESO August 2018 Load Forecast, the May 22, 2019 Load Forecast has consistently lower peak load values across both obligation periods and across economic scenarios. In the 2021/2022 obligation period, average load and total energy are lower in the Low, Reference, and High economic scenarios and are very similar in the Minimum and Maximum scenarios. In the 2022/2023 obligation period, average load and total energy marginally increased in the Minimum, Low, Reference, and High scenarios and decreased slightly in the Maximum scenario.

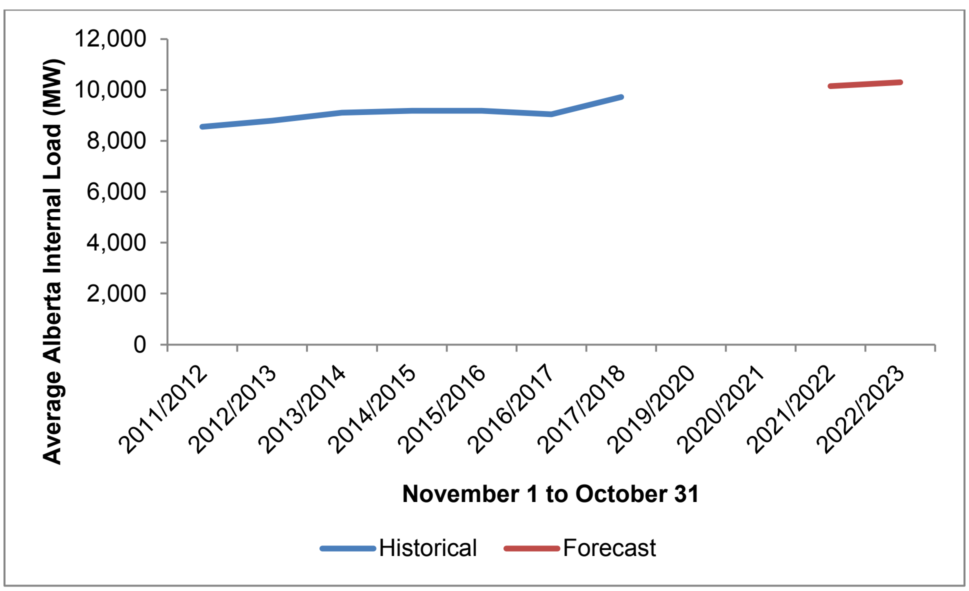
The 2021/2022 obligation load forecast is down, overall, due to the lower economic forecasts (the economic index and the oilsands production forecast) discussed above. By 2023, the updated economic forecasts converge to the economic forecasts used in the AESO August 2018 Load Forecast. The similarity of the economic forecast in 2023 combined with retraining the load forecast model on updated historical load data results in this minor increase in average load in the 2022/2023 obligation period. Further a review of the monthly output from the May 22, 2019 forecast shows reasonable results.

Figure 5: May 22, 2019 Load Forecast Update Monthly Average Load across All Reference Scenario Load Profiles



The forecast load growth is reasonable given historical growth rates. Over the November to October periods from the past 5 years, compounded average load growth was 2.1 percent annually. The compounded average growth rate to both the 2021/2022 and 2022/2023 obligation periods is 1.4 percent meaning forecast load growth is lower than historical.

Figure 6: Historical and Forecast Average Load by Obligation Period



5.2 Generation fleet in the obligation period

As described in Appendix Q to the AESO's Application in Proceeding 23757, the RAM requires a starting point of the installed generation – or "base fleet" – for the obligation period to assess its level of reliability. The base fleet is then adjusted using the reference technology or a generating unit that is similar to the reference technology to determine the GMPV that meets the resource adequacy standard.[32] The AESO uses the current and anticipated generation assets that have a maximum capability of 5 MW or greater to populate the RAM.[33]

Since November 2018, there have been a few small generation additions and retirements. Accordingly, the installed generation used within the RAM has been updated with the specific changes shown in Table 4. Further information from the Renewable Energy Program Rounds 2 and 3 has also been used to update the nameplate values and locations of the successful projects. These adjustments are shown below in Table 5 and 6.

Table 4: Available Generation Adjustments

Unit	Technology Type	Action	Change in MC Value
TC02	Cogen	Expansion	(+46)
MUL	Cogen	Addition	(+5)
BFD1	Cogen	Addition	(+6)
BHL1	SC	Addition	(+5)
MFG1	SC	Retired	(-16)
REP 2/3	Wind	Adjusted	(+63)
		Total	(+109)

Table 5: Original REP 2/3 Units

Wind ID	Region	MC (MW)
Generic Wind 1	Future Central Wind	100
Generic Wind 2	Future Central Wind	100

[32] Exhibit X0346.01, PDF 4-5.

[33] This includes assets that are not eligible to participate in the Alberta capacity market because those assets will impact resource adequacy during the obligation period.

Generic Wind 3	Future Central Wind	100
Generic Wind 4	Future FM2 Wind	200
Generic Wind 5	Future Leth Wind	100
Generic Wind 6	Future Central Wind	100
Total		700

Table 6: Updated REP 2/3 Wind Units

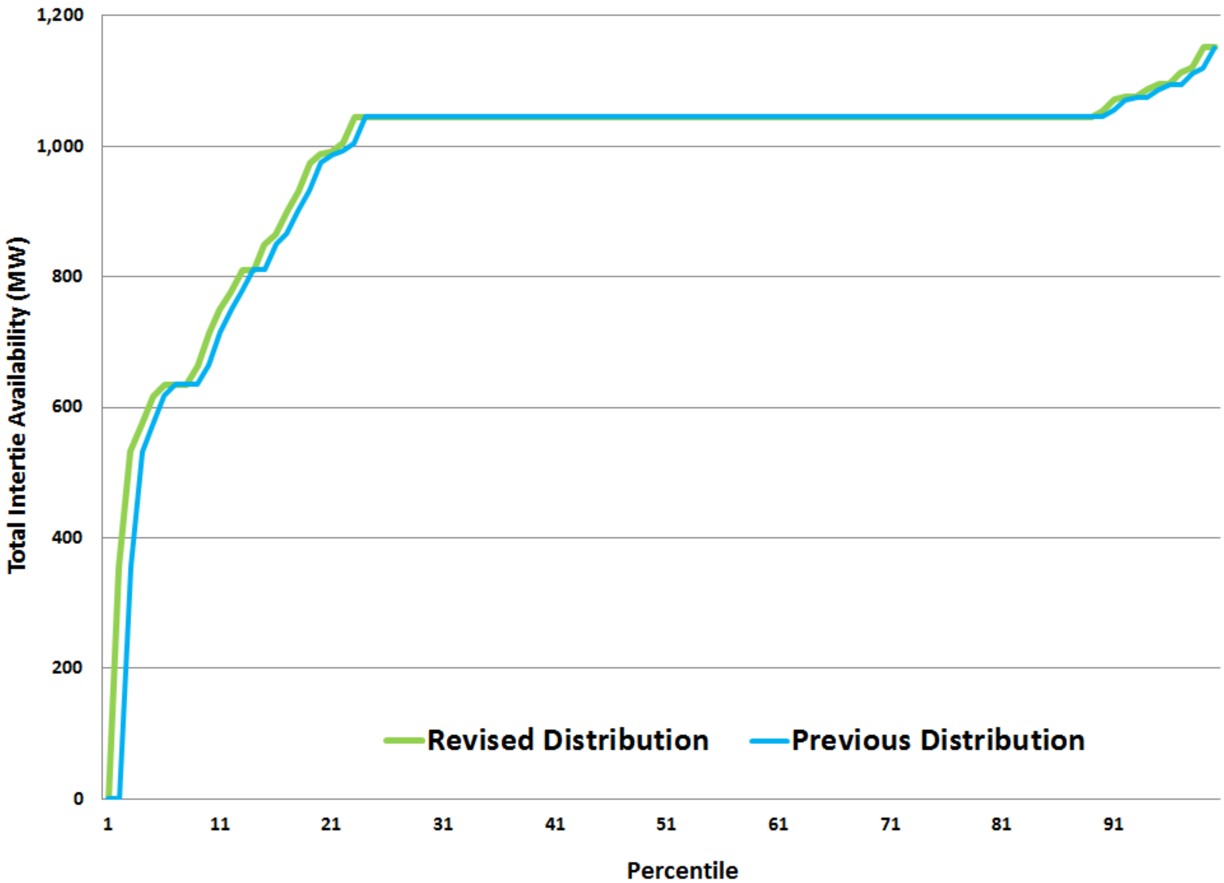
Wind ID	Region	MC (MW)
CYP1	Future Leth Wind	202
STL1	Future Leth Wind	113
BUF123	Future Leth Wind	48
WIN1	Future FM1 Wind	207
JEN1	Future Leth Wind	122
JEN2	Future Leth Wind	71
Total		763

5.3 Interties

The AESO reviewed the performance of the intertie during tight supply conditions historically and compared it against the intertie performance under similar conditions within a sample of iterations within the RAM. The comparison indicated that non-zero availability reasonably approximated intertie availability during tight supply hours, but that the intertie availability distribution in the RAM was overstating the zero draws. Accordingly, the AESO determined that it was reasonable to adjust the percentage of zero draws from 2% to 1% to better align with historical observations but left the remainder of the distribution unchanged. The updated intertie availability distribution is shown below in Figure 7.

As the zero availability draw was originally over represented in the model results, it was determined that adding planned outages would not lead to a more reasonable representation of intertie availability.

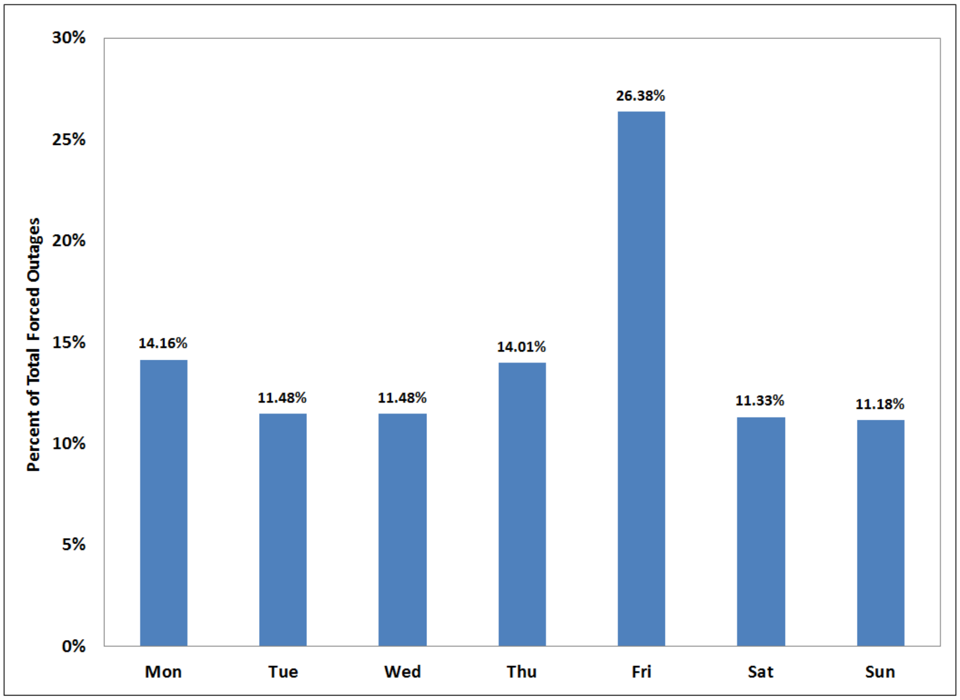
Figure 7: Updated Intertie Availability Distribution



5.4 Outages

To better understand the delayed forced outage behavior discussed at the meeting, the AESO reviewed the available capability data from 2012-2017 of the 14 coal units that are expected to be available in the obligation periods. The AESO analyzed the forced outage start date of each unit according to the day of the week. Figure 8 demonstrates a pattern that a larger portion of coal forced outages started on Fridays. The AESO further analyzed the coal forced outages that occurred on Fridays and found more than half of those forced outage events occurred on or after HE19. This pattern gave the AESO confidence that a portion of coal forced outages could be delayed to periods of lower demand.

Figure 8: Forced Outage Start Date for Fourteen Coal Units



The AESO relied on its analysis of the historical available capability data to develop model parameters to capture the ability for coal units to delay some portion of their forced outages.

The AESO assumed that all outage events in the data set that started on Friday on or after HE19 and lasted less than 73 hours to be delayed forced outage events. This represents approximately 10% of the total coal forced outage rates. A delayed forced outage rate and the average time-to-repair of those delayed forced outage events were estimated for each of the 14 coal units and were modelled as maintenance outages in the RAM. The RAM then randomly drew maintenance outage start dates and schedules each maintenance outage during low load hours from the random start date to the end of the next weekend. The updated forced outage rates are shown in Table 7 below.

Table 7: Forced Outage Rates

	Forced Outage Rates						
	Winter			Summer			NERC FOF*
	Minimum	Maximum	Weighted Average	Minimum	Maximum	Weighted Average	All Size
Coal**	0.8%	10.7%	4.1%	1.6%	11.8%	4.4%	4.9%
Combined Cycle	0.0%	6.6%	2.7%	0.0%	6.8%	3.5%	2.5%
Simple Cycle	0.5%	13.6%	2.9%	1.1%	8.5%	3.9%	3.8%
Other	0.0%	25.9%	1.9%	0.2%	28.6%	3.0%	N/A
	Partial Outage Rates						
Coal**	0.5%	11.5%	3.8%	0.9%	9.3%	4.4%	N/A
Combined Cycle	0.0%	14.7%	2.1%	0.0%	22.4%	3.0%	N/A
Other	0.0%	42.5%	19.4%	0.0%	44.5%	20.7%	N/A
	Maintence Outage Rates						
Coal	0.0%	1.1%	0.4%	0.0%	1.1%	0.4%	3.4%

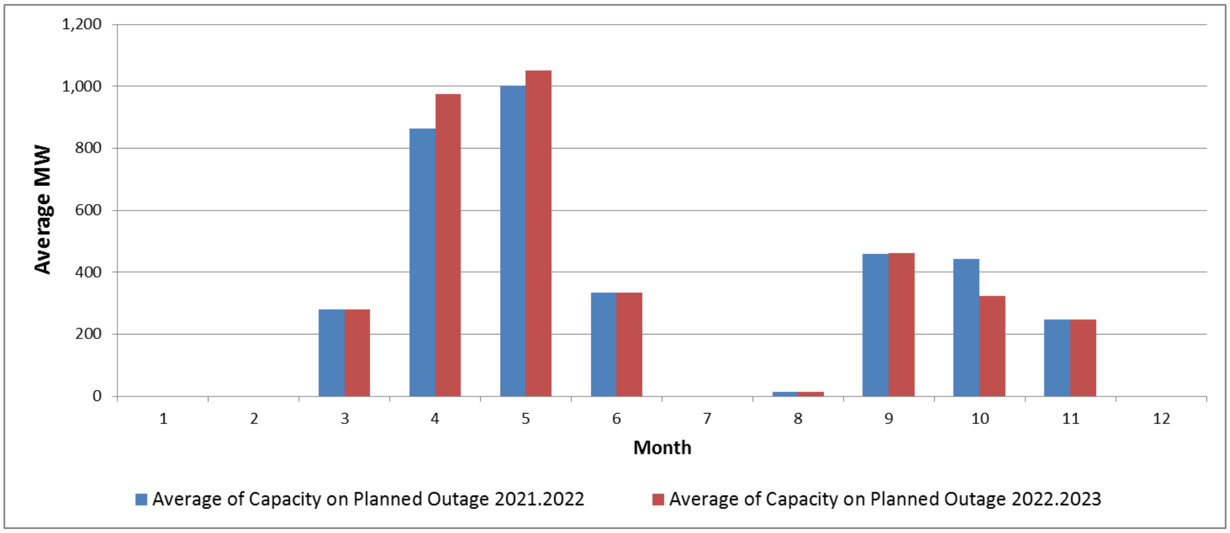
Sources and Notes: Forced Outage Factor (FOF) (Brochure4) is sourced from NERC: https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx/. The maximum under the Forced Outage Rates section and the Partial Outage Rates for coal is based on different coal generating units.

The treatment of delayed forced outages in the RAM leverages the data available. There is a possibility that not all forced outages in the data set used to define delayed forced outages are actually delayed forced outages. Any over-estimate of the ability to delay forced outages would lead to an under-estimate of the GMPV, however that AESO expects any such error would be nominal in size.

With respect to coal units, incentives under the PPAs may have been a driver of delaying forced outages to Friday. However, going forward the AESO expects the capacity market performance framework and energy market price signals to similarly incent coal plants to delay forced outages to lower price, higher supply availability time periods.

Additionally, while completing the modifications and updates to the RAM the AESO identified the need to manually schedule one additional coal planned outage from October to another month to are more evenly spread reliability issues throughout the year. This revision aligns with one of the scenarios ENMAX requested in the letter included in Appendix D. The updated planned outage by month included in the RAM is displayed below in Figure 9.

Figure 9: Planned outage schedule for both obligation periods



The AESO also reviewed and re-estimated planned outage rates of combined cycle and simple cycle units[34]. The AESO determined that using two years of historical data to estimate gas-fired planned outages does not accurately capture the planned outage behavior of those asset types as accurately as a longer historical data set, as the longer data set better captures the true planned outage rates. The updated planned outage rates for gas fired assets are listed in table 8. The 2014-2018 annual period of available capability data (2015-2018 for Shepard) was used to develop those planned outage rates. In similar analysis the AESO validated that relying on a two year historical data period was the most representative approach for coal. Extending the historical data period to four to six years resulted in a planned outage rate consistent with that of two years. However, the AESO assessed that the two year period was more informative of the coal fleet's planned outage patterns as the varying lengths of coal plants planned outages were better captured using a two year cycle as opposed to averaging across a longer-time period.

Table 8: Planned Outage Rates

Fuel Type	Minimum	Maximum	Weighted Average	NERC POF* (2013-2017)
Coal	0.0%	9.0%	3.9%	7.8%
Combined Cycle	0.7%	4.8%	3.4%	8.0%
Simple Cycle	0.0%	3.7%	1.4%	4.0%
Other	0.0%	7.4%	2.3%	N/A

Sources and Notes: Planned Outage Factor (FOF) (Brochure4) is sourced from NERC: https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx

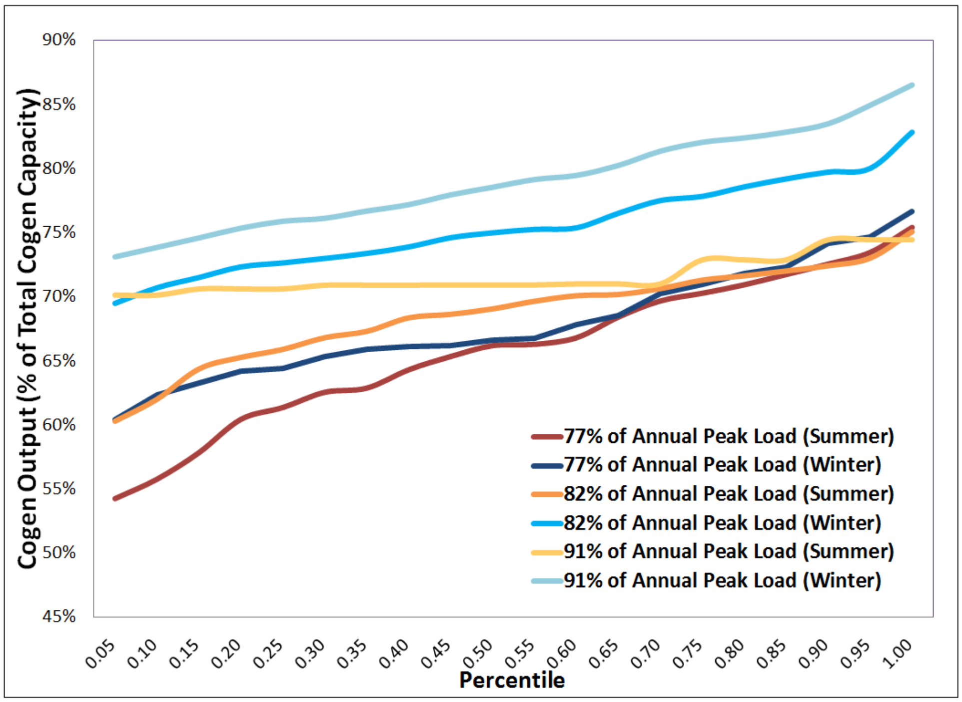
[34] In the review the AESO did not change the City of Medicine Hat due to its data complexity.

5.5 Cogeneration

In its review of the seasonal cogeneration availability distributions, the AESO found that the Fort McMurray fire that occurred in Summer 2016 had an abnormal impact on the cogeneration availability during the same time period and should not be carried forward in the cogeneration availability distributions. Therefore, the AESO updated the seasonal cogeneration availability distributions by using the historical hourly available capability from every cogeneration unit over the 2014-2018 period, excluding the Summer of 2016 due to the Fort McMurray fire.

Figure 10 displays a subset of the seasonal cogeneration output distribution used to update the GMPVs for the first two base auctions. As an example, when daily peak load was 82% of the annual peak load (middle blue line) in winter months (January to April, November and December), the RAM drew a cogeneration output multiplier between 70% and 84%. This output multiplier then was multiplied by the cogeneration fleet capacity to determine the daily generation availability of the cogeneration fleet.

Figure 10: Cogeneration Output Distribution



5.6 Calibration

Following the modifications and updates to the RAM inputs described in Sections 5.1 to 5.5 above, the AESO updated the 2017 and 2018 RAM calibrations. Table 9 below shows the 2017 calibration results. Table 10 and Figure 11 below show the 2018 calibration results. The 2017 calibration used 2017 actual load whereas the 2018 calibration used 150 forecast load profiles developed through the same methodology as the GMPV load profiles.

Table 9: Updated 2017 Calibration Results

2017 Calibration	Min	Average	Max	Actual
UE (MWh)	0	0.2*	150	0
% when UE = 0 MWh		99.8%		N/A
LOLH (Hours)	0	0.002	2	0
EEA Event (Hours Spanned)	0	0.269	13	5 (2 events)

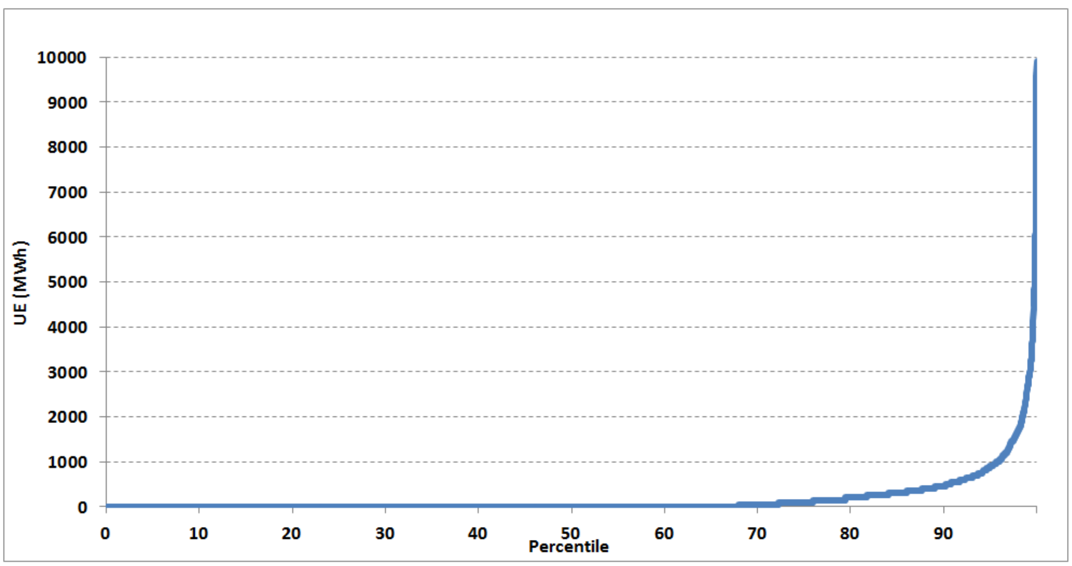
* units expressed in EUE

Table 10: Updated 2018 Calibration Results

2018 Calibration	Min	Average	Max	Actual
UE (MWh)	0	169*	9,900	0
% when UE = 0 MWh		68%		N/A
LOLH (Hours)	0	0.77	32	0
EEA Event (Hours Spanned)	0	8	82	5 (2 events)

*units expressed in EUE

Figure 11: 2018 Calibration Unserved Energy Distribution



The following table shows the generation availability in the RAM for the 2018 calibration as compared to the 2018 actuals. The availability of the majority of fuel types aligns with historical observations.

Table 11: Generation Availability

Fuel Type	(1) RAM Availability Factor (%)	(2) 2018 Actual (%)
Coal Units (excl. SD3 & SD5)	87	91
Cogen	74	74
CC	83	82
SC	87	81
Hydro	24	24
Wind	34	32
Solar	16	17
Other	77	67

Figure 12 compares a sample of supply cushion duration curves from the 2018 calibration reference economic scenario across the five weather years from 2013-2017, each with their own forced outage draw, with the actual 2018 supply cushion duration curve. Generally, the duration curves align with what has been observed historically in 2018, with the exception of tight supply conditions at the bottom left of the distribution.

From the observations, it can be discerned that the RAM shows more availability than historical outcomes. This is a result of how the intertie is modelled within each hour simulation. As described in the AESO's Rebuttal Evidence[35] in Proceeding 23757 and AESO's intertie presentation material in Appendix H, the intertie availability distribution in the RAM is based on unconstrained ATC to align with ISO rules. During times of supply shortfall (i.e., EEA events) limits on the intertie can be lifted to make maximum import capability (i.e., unconstrained ATC) attainable regardless of available contingency reserves in order to avoid shedding load.

Thus, within the RAM, during simulated tight supply conditions, which are near the bottom of the duration curve, there is access to additional imports that do not exist during standard market operations (i.e., outside of EEA conditions). This difference explains the difference in shape at the bottom of the supply cushion duration curve. However, this difference is not seen throughout the entire duration curve due to the modeling function of the RAM. The RAM sets up imports as binary and only includes available supply from import if conditions are tight enough that imports are required to serve demand, and when imports are relied on the full availability is included.

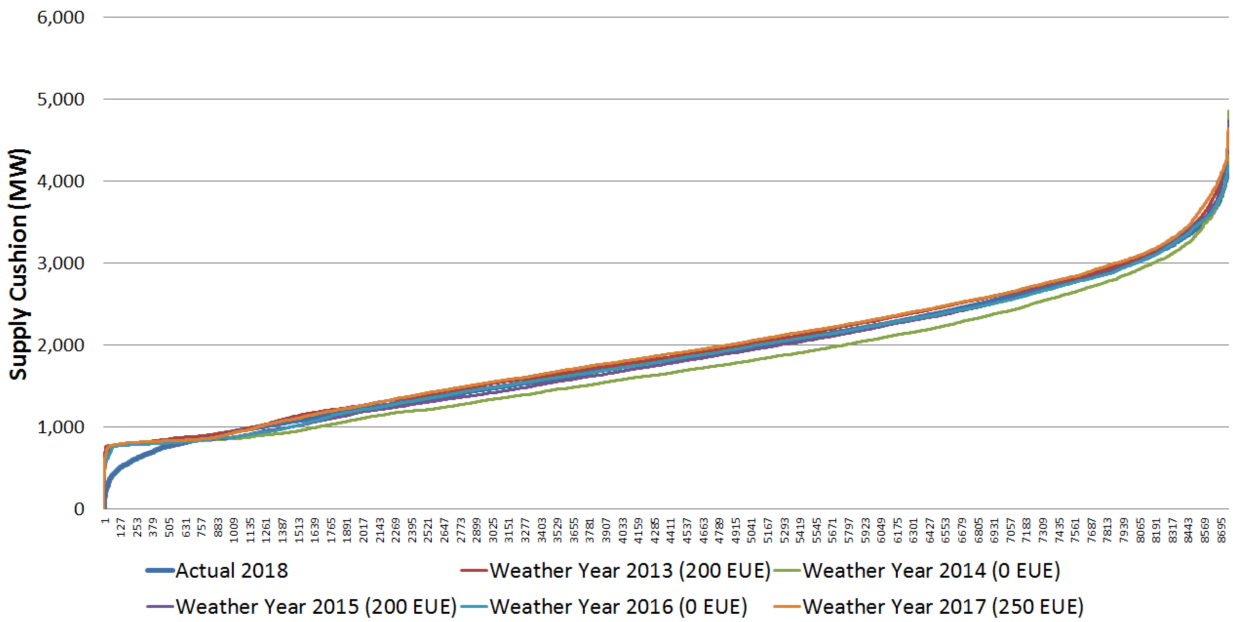
These discrepancies between actual supply cushions, which rely on constrained ATC in all hours, and the model characterizations limits the comparison of supply cushion to some degree. However, the general alignment of duration curve shapes does indicate that the available supply in the 2018 calibration aligns with 2018 actuals.

The AESO has provided this sample of supply cushion duration curves to address concerns around insufficient data to validate the RAM and the GMPV. The AESO maintains its view that comparing RAM

[35] Exhibit X0549.02, PDF 26.

output to historical outcomes has limited value as it is comparing a risk assessment of 7,500 iterations to only one outcome, as noted in its Rebuttal Evidence from Proceeding 23757.[36] The supply cushion curves included in the comparison in Figure 12 do not capture the full distribution of UE produced from the calibration shown in Figure 11.

Figure 12: 2018 Supply Cushion Actual vs Modelled



5.7 Revised GMPVs for the First Two Auctions

In aggregate, the modifications and updates have lowered the GMPV for the base auction for the 2021/2022 obligation period from 18,305 MW to 18,167 MW, and lowered the GMPV for the base auction for the 2022/2023 obligation period from 18,400 MW to 18,299 MW. Further information on the risk metrics associated with GPMV estimations and other fleet definitions are provided in the table and figures below.

[36] Exhibit X0549.02, PDF 26-29.

Table 12: Unserved Energy by Gross Volume for 2021/2022

Base (addition/subtraction)	Procurement Volume	%NEUE	EUE (MWh)	LOLE Capacity (Events per Year)	LOLH Capacity (Hours)
Base(-390)	18,081	0.001649%	1,469	2.57	5.57
Base(-340)	18,131	0.001296%	1,155	2.12	4.34
GMPV	**18,167**	0.001100%	980	1.85	3.79
Base(-290)	18,181	0.001041%	927	1.77	3.59
Base(-240)	18,231	0.000824%	734	1.41	2.80
Base(-192)	18,279	0.000659%	588	1.24	2.39
Base(-144)	18,327	0.000519%	463	0.97	1.84
Base (-96)	18,375	0.000402%	358	0.79	1.42
Base (-48)	18,423	0.000318%	283	0.64	1.16
Base	18,471	0.000254%	227	0.54	0.91
Base (+46.5)	18,518	0.000201%	179	0.45	0.77
Base (+93)	18,564	0.000156%	139	0.34	0.60
Base (+139.5)	18,611	0.000122%	109	0.28	0.47
Base (+186)	18,657	0.000100%	89	0.22	0.34
Base (+232.5)	18,704	0.000077%	69	0.19	0.30
Base (+279)	18,750	0.000059%	53	0.16	0.25
Base (+325.5)	18,797	0.000046%	41	0.13	0.20
Base (+372)	18,843	0.000036%	32	0.09	0.14
Base (+418.5)	18,890	0.000029%	26	0.07	0.10
Base (+465)	18,936	0.000021%	19	0.06	0.09
Base (+511.5)	18,983	0.000016%	15	0.05	0.07
Base (+558)	19,029	0.000012%	11	0.04	0.04
Base (+604.5)	19,076	0.000010%	9	0.03	0.04

Figure 13: 2021/2022 Obligation Period Changes from Initial Application

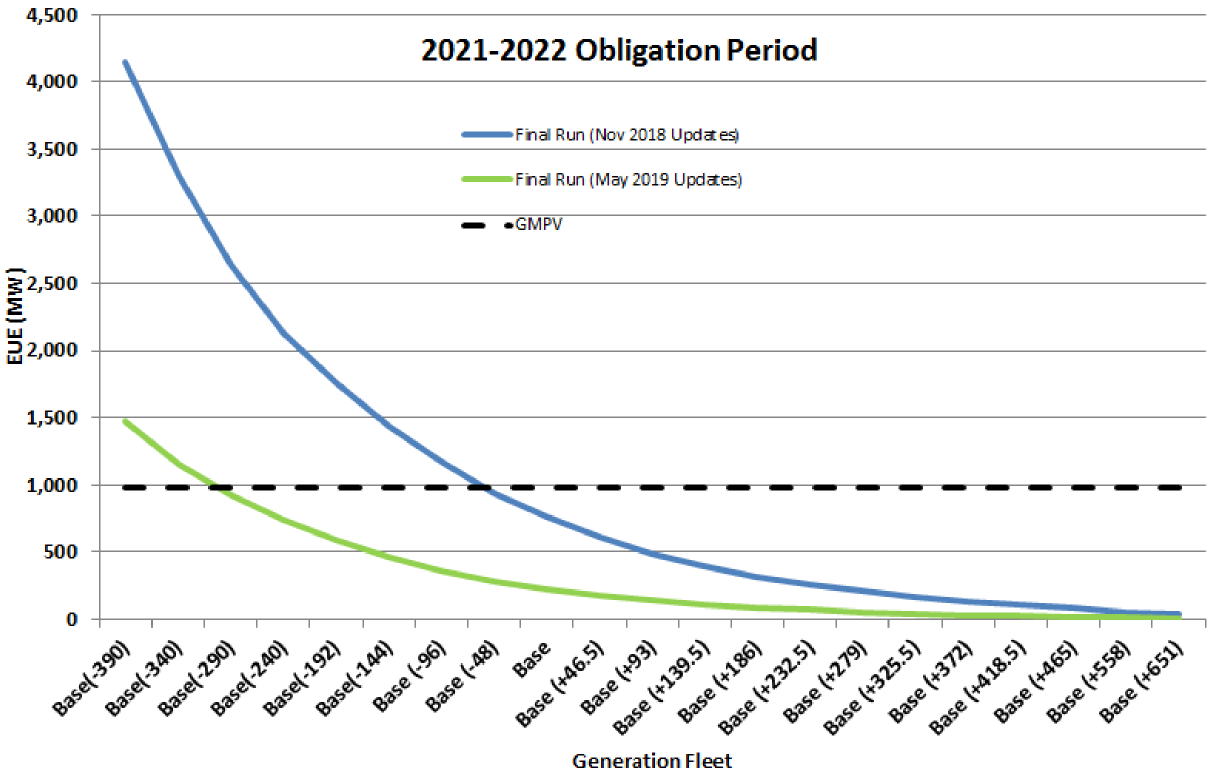
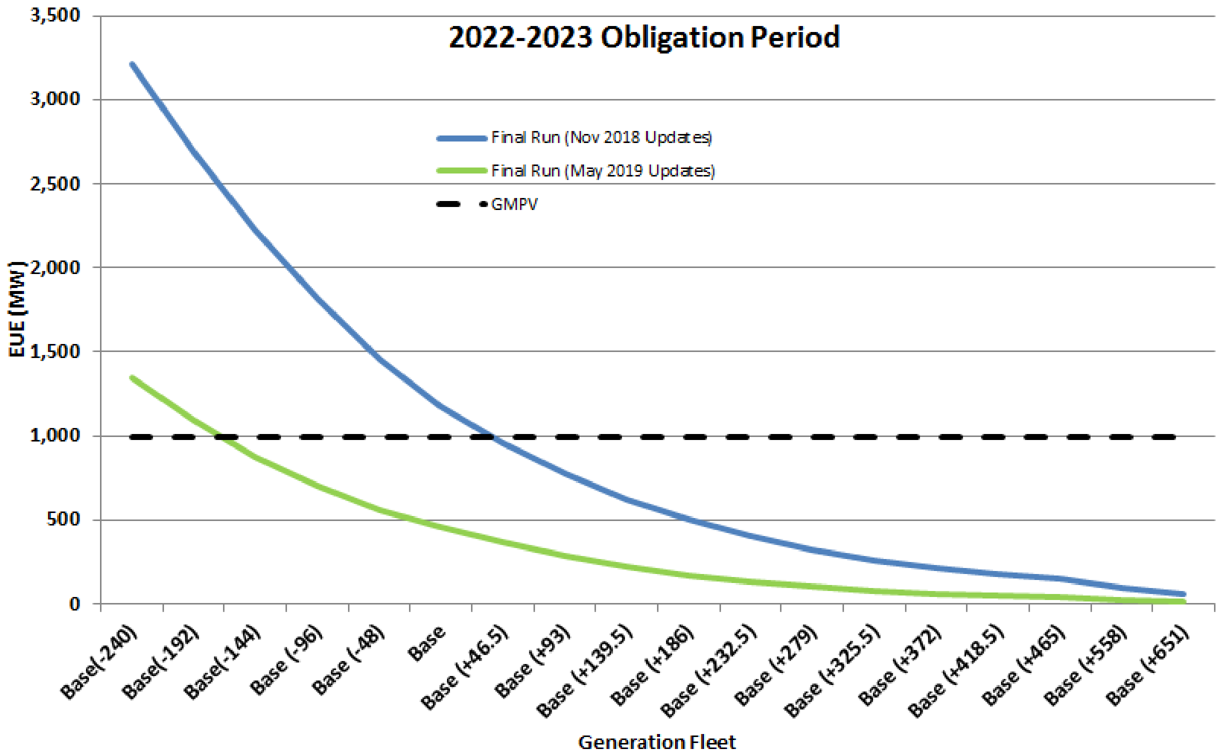


Table 13: Unserved Energy by Gross Volume for 2022/2023

Base (addition/subtraction)	Procurement Volume	%NEUE	EUE (MWh)	LOLE Capacity (Events per Year)	LOLH Capacity (Hours)
Base(-390)	18,081	0.003256%	2,946	4.51	10.57
Base(-340)	18,131	0.002574%	2,329	3.80	8.48
Base(-290)	18,181	0.002094%	1,895	3.25	7.18
Base(-240)	18,231	0.001484%	1,343	2.49	5.16
Base(-192)	18,279	0.001206%	1,092	2.09	4.22
GMPV	18,299	0.001096%	992	1.96	3.89
Base(-144)	18,327	0.000964%	872	1.77	3.43
Base (-96)	18,375	0.000776%	702	1.47	2.79
Base (-48)	18,423	0.000618%	559	1.18	2.21
Base	18,471	0.000502%	454	1.00	1.82
Base (+46.5)	18,518	0.000401%	362	0.85	1.55
Base (+93)	18,564	0.000313%	284	0.67	1.16
Base (+139.5)	18,611	0.000242%	219	0.56	0.95
Base (+186)	18,657	0.000188%	170	0.44	0.72
Base (+232.5)	18,704	0.000142%	128	0.34	0.54
Base (+279)	18,750	0.000112%	102	0.30	0.47
Base (+325.5)	18,797	0.000085%	77	0.22	0.33
Base (+372)	18,843	0.000066%	60	0.16	0.24
Base (+418.5)	18,890	0.000055%	49	0.14	0.22
Base (+465)	18,936	0.000040%	36	0.12	0.17
Base (+511.5)	18,983	0.000033%	30	0.10	0.15
Base (+558)	19,029	0.000026%	24	0.07	0.09
Base (+604.5)	19,076	0.000021%	19	0.06	0.09

Figure 14: 2022/2023 Obligation Period Changes from Initial Application



6. Procurement Volume Governance

At several points during the technical meeting participants raised concerns with respect to the time lapse between the development of the GMPV and the final stages of auction clearing, in addition to their desire to capture more up-to-date information by estimating the GMPV closer to auction clearing.

Estimating the GMPV closer to auction clearing would enable the incorporation of more up-to-date data and forecast information into the GMPV. However, as it relates to the proposed governance and oversight of the GMPVs, as set forth in section 6.6.2 of the AESO's Application, the timing of when certain information is incorporated into the GMPV is one of the multiple factors that needed to be considered. Incorporating timely data and information, conducting effective and meaningful stakeholder consultation, ensuring appropriate AUC oversight, structuring a process that achieves administrative efficiency, maintaining on-going auction schedules and providing market information that is certain in a timely manner in order to support a competitive capacity market were all relevant factors that the AESO considered and balanced in the development of its proposed governance process.[37]

The technical meeting process provided the AESO additional insights regarding how to better share information and seek input from stakeholders on the GMPV. The AESO believes these learnings can be

[37] Exhibit X0284, PDF 64-70.

incorporated into the proposed process set out in Figure 9 and Table 2 of the AESO Application.[38] In its application, the AESO included a relatively detailed process with respect to the development of the RAM and GMPV so that stakeholders would have an advanced understanding of how the AESO expected to engage with them. In order to incorporate the recent lessons learned, as well as those that will arise moving forward, it would be beneficial for a level of flexibility within the specific steps of the consultation process to be maintained. In addition, it will be important for there to be sufficient time allotted within the process for due diligence regarding the RAM inputs and methodologies, how these are interacting within the RAM, and a vetting of the GMPV results.

[38] Exhibit X0284 PDF 66.