Rebuttal Evidence of the Alberta Electric System Operator

Appendix “A”

Proceeding 23757

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Demand Curve and Energy and Ancillary Services Offset

RESPONSE TO INTERVENER EVIDENCE IN ALBERTA UTILITIES COMMISSION PROCEEDING #23757

PREPARED FOR

AESO
ALBERTA ELECTRIC SYSTEM OPERATOR

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I. Background and Context

Since October 2017, we have provided analytical support for the Alberta Electric System Operator's (AESO's) development of a demand curve for Alberta's capacity market. In this report, we review evidence submitted by interveners that commented on the AESO's proposed demand curve design and energy and ancillary services offset methodology, and offer our comments in response to:

- **Exhibit 23757-X0356**: Further Comments on the Design of the Alberta Capacity Market by Peter Cramton prepared for the Alberta Utilities Commission ("Cramton Report");
- **Exhibit 23757-X0364**: Comments on Selected Market Design Elements prepared for Capital Power Corporation by ESAI Power LLC ("Capital Power/ESAI Report");
- **Exhibit 23757-X0369**: Capacity Market Design Recommendations For Alberta for Pembina Institute by Rob Gramlich of Grid Strategies LLC ("Pembina/Gramlich Report)";
- **Exhibit 23757-X0370**: Testimony prepared for Consumers' Coalition of Alberta by Dr. David P. Brown ("CCA/Brown Report");
- **Exhibit 23757-X0371**: Testimony prepared for Consumers' Coalition of Alberta by Raj Retnanandan ("CCA/Retnanandan Report");
- **Exhibit 23757-X0372**: Capacity Market Quantitative Analytics prepared for Consumers Coalition of Alberta by EDC Associates Ltd. ("CCA/EDC Report", collectively we refer to the CCA/Brown Report, the CCA/Retnanandan Report and the CCA/EDC Report as the "CCA-Sponsored Reports").
- **Exhibit 23757-X0375**: Appendix A to Evidence of Suncor Energy Inc., Evidence prepared for the Cogeneration Working Group (CWG) by Kris Aksomitis and Christine Runge, of Power Advisory LLC ("CWG/Power Advisory Report");
- **Exhibit 23757-X0380:** Deficiencies in Proposed ISO Rules Related to Energy Market Mitigation and Setting of Net-Cost of New Entry (CONE), and Responses to AUC Questions prepared for TransAlta by Julia Frayer of London Economic International LLC ("TransAlta/LEI Report");
- **Exhibit 23757-X0390**: Market Design Issues in the Alberta Capacity and Energy Markets prepared for Alberta Markets Surveillance Administrator (MSA) by Christopher Russo, Dr. David B. Patton and Jordan Kwok ("MSA Report");
- **Exhibit 23757-X0392**: Evidence prepared for the Utilities Consumer Advocate (UCA) by DePal Consulting Limited ("UCA/DePal Report");

- **Exhibit 23757-X0401**: Consideration of ISO Rules to Implement and Operate the Capacity Market, Intervenor Evidence from Dr. Paul Sotkiewicz, prepared for ENMAX Energy Corporation ("ENMAX/Sotkiewicz Report");
- **Exhibit 23757-X0404**: Written Evidence to Consider Rules to Implement and Operate the Capacity Market by Solas Energy Consulting ("CanSIA/Solas Report");
- **Exhibit 23757-X0485**: Rebuttal Testimony Prepared for Consumers' Coalition of Alberta (CCA) by Dr. David P. Brown ("CCA/Brown Rebuttal");
- **Exhibit 23757-X0497**: TransAlta Rebuttal Evidence ("TransAlta Rebuttal");
- **Exhibit 23757-X0498**: Rebuttal comments related to capacity market demand curve prepared for TransAlta by Julia Frayer of London Economic International LLC ("TransAlta/LEI Rebuttal");
- **Exhibit 23757-X0508**: Rebuttal Evidence of Suncor Energy Inc. ("Suncor Rebuttal");
- **Exhibit 23757-X0514**: Rebuttal Evidence of Susan L. Pope (FTI Consulting) on Behalf of the Industrial Power Consumers Association of Alberta (IPCAA) and Alberta Direct Connect Consumer Association (ADC) ("IPCAA/ADC/FTI Consulting Rebuttal"); and
- **Exhibit 23757-X0518**: Rebuttal Evidence for Dr. Paul Sotkiewicz on Behalf of ENMAX Energy Corporation ("ENMAX/Sotkiewicz Rebuttal").

II. Demand Curve Shape

We respond to comments within the CCA-Sponsored, CWG/Power Advisory, MSA, UCA/DePal, and CanSIA/Solas Reports on the AESO's proposed demand curve parameters. Each of these interveners is concerned that the demand curve could lead to over-procurement of capacity, though the specific reasons for this concern and anticipated implications differ from each commenter. We have assessed the evidence presented by each intervener and respond to each individually, clarifying the extent to which we agree or disagree with the evidence presented in each report. As an overall response however, we continue to view the AESO's proposed curve as aligned with the resource adequacy standard, the AESO's design principles, and best practice in other capacity markets. Though we agree that a more left-shifted curve as proposed by some interveners could reduce procurement volume and cost, a more left-shifted curve would reduce resource adequacy levels and would lead to the capacity market not meeting the minimum resource adequacy standard of 0.0011% Normalized Expected Unserved Energy (Normalized EUE) 95% of the time. Further, several of the interveners' concerns appear to be based partly on a misplaced focus on their expectations regarding the short-term performance of the demand curve over the first few years of the auction. We do not focus in these near-term issues in our response because we view the long-term performance of the demand curve as more pertinent for assessing the sustainability of the Alberta capacity market.

Other interveners have submitted comments that generally support the AESO's proposed demand curve. The AUC/Crampton Report reports that "the proposed demand curve is a sensible one that should perform well."[1] The TransAlta/LEI Report and associated analysis also supports the AESO proposed demand curve, highlighting the outsized impacts of under-procurement compared to over-procurement. We do not provide a detailed response to these interveners, given that their evidence in support of the AESO's proposed demand curve aligns with our own analysis.

A. Supply Resource Modeling Assumptions

In our analytical support for the AESO, we developed a Monte Carlo simulation model to analyze the long-term performance of selected demand curves.[2] The model includes a stylized representation of supply entry and exit in the context of year-to-year fluctuations in market conditions. We use it to estimate the likely reliability and price volatility outcomes that would be produced by different demand curves. In their Reports, CWG/Power Advisory, CanSIA/Solas,

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1 Cramton Report, PDF 8.

2 For more information, see Spees, Kathleen, David Luke Oates, Cathy Wang, John Imon Pedtke, and Matthew Witkin, *Alberta's Capacity Market Demand Curve*, January 2019 ("Exhibit 23757-X0341").

and UCA/DePal offered critiques of our approach to modeling assumptions of supply resources. The CWG/Power Advisory and UCA/DePal Reports expressed concern that the assumed supply curve shape does not accurately reflect likely market conditions in Alberta over the coming years; and the CWG/Power Advisory and CanSIA/Solas Reports assert that the quantity of supply modeled should be larger to account for additional supply that they anticipate will be available at the advent of the Alberta capacity auction.[3]

We have evaluated these critiques, but maintain that our modeling approach produces a realistic representation of the likely performance of the demand curve, because: (1) the modeled supply curve shape is consistent with both theory and experience of how suppliers participate in capacity markets, including the uncertainty range of how sellers are likely to participate in Alberta; and (2) the initial supply quantity expected in the early years of the capacity market is not a relevant comparison point for our purposes, given that the demand curve must be designed to support orderly entry and exit under long-run equilibrium conditions.

Supply Curve Shape

The CWG/Power Advisory Report expressed a concern that the supply curve shape we have assumed is too steep.[4] The UCA/DePal Report disagreed with our use of the PJM data to represent the potential supply curve shape, given the differences between the PJM and Alberta markets (according to size, population density, and various other regulatory considerations).[5] In response, we provide additional discussion that further explains why we view our modeled supply curves as within the uncertainty range of likely supply offer curves in Alberta, in line with both economic theory and historical experience.

With respect to the CWG/Power Advisory Report's concern that they view the supply curve as being too steep, we agree that the supply curves become relatively steep at high prices, but argue that this is realistic. As a theoretical question, the supply curve shape should align with the economics governing a fleet of long-lived, capital-intensive resources. In a uniform price auction, the competitive offer price is at the minimum capacity payment needed to break even for operating one more year. In other words, capacity sellers should offer at net avoidable going forward costs.[6] Over the lifecycle of a typical generating plant, this translates to different types of offer prices at different stages of the economic life cycle:

- **Initial Offer Year(s):** Prior to its first year of operation and before commencing plant construction, a new resource would offer at above-zero prices, representing a willingness

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3 CWG/Power Advisory Report, PDF 15. UCA/DePal Report, PDF 29. CanSIA/Solas Report, PDF 18, 20.

4 CWG/Power Advisory Report, PDF 15.

5 UCA/DePal Report, PDF 29.

6 Simply put, Offer Price = Going-Forward Capital and Fixed Costs – Expected Energy and Ancillary Services Net Revenue.

to enter the market only if first-year capacity prices are high enough to justify developing a new resource (though as we discuss below, this does not necessarily mean making an offer exactly at Net CONE);

- **Most Years over the Asset's Economic Life:** After the developer has committed to significant irreversible costs to begin plant construction and for the large majority of the asset's economic life, a seller will likely offer into the capacity market at zero or low prices. A resource will offer at low prices as long as their projected net energy and ancillary services (E&AS) revenues are expected to exceed their going-forward fixed costs, because even a small capacity payment would incrementally improve net revenues. The original investment costs and any ongoing debt service payments would be ignored in developing a capacity offer, given that these sunk costs cannot be avoided regardless of whether the resource takes on a capacity obligation; and
- **Approaching Retirement or Refurbishment:** Once an aging plant is facing a major reinvestment or refurbishment decision, it would again offer at above-zero prices. Because E&AS revenues alone would not be sufficient to justify a major reinvestment, the owner may require a relatively higher capacity price in order to justify investing in any refurbishment needed to postpone retirement.

Given the economic lifecycle of a typical plant, we would expect that in most years, much of the capacity fleet should be expected to offer at prices near zero.[7] Traditional generators would offer substantially above zero only prior to making major irreversible capital investments in construction, and once again may offer at higher prices much later when approaching end of the economic life.[8] When these entry and exit decision points do arise, the specific economics of each plant will drive a wide range of different offer prices (though resources with very high net going-forward costs may simply choose to retire without making an offer). We reflect these underlying economics using supply curve shape in which many resources offer at a zero price, and the remaining offers from potentially marginal resources are made across a range of prices.

With respect to the UCA/DePal concern that the supply curve shapes from PJM may not be fully reflective of Alberta market conditions, we acknowledge the point that there is uncertainty regarding how sellers may participate in the new market that will not be resolved until after several years of market experience. Though we have made adjustments in the assumed supply curve shape to account for market size, inflation, and exchange rate, we have not attempted to reflect all resource economics that may affect the individual resources within Alberta's fleet in a

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7 This does not mean those resources would earn low capacity prices however, given that the auction price will be set at a higher level based on the intersection of the demand curve with the marginal supply resources.

8 Note that the auction format and one-year-at-a-time duration of the capacity auction also contribute to this relatively steep supply curve shape; auctions for 10- or 20-year contracts and pay-as-bid auctions would both be expected to produce higher and flatter supply curves.

bottom-up fashion.[9] We do not view such a bottom-up approach as the most useful method for the purpose of evaluating the long-term performance of the demand curve. The costs and revenues of any one resource in any one specific future year can become increasingly challenging to accurately characterize when projecting into the long run (even for the asset's owner). It is more feasible and accurate to assume that a certain proportion of the fleet will be subject to significant net going-forward costs at any given time, as we have done.

Figure 1 provides additional evidence illustrating the general reasonableness of our stylized approach to representing the supply curve shape. We have used a range in supply curve shapes based on those observed in PJM over eight years of empirical market data, reflecting a wide range of market conditions including: years with an abundance and contraction of demand response and import offers; years with high and low gas prices that placed coal and nuclear plants in relative strong and relative poor financial condition; years when most of the coal fleet faced an all-at-once retire-or-retrofit decision with the introduction of the Mercury and Air Toxics Standard; years with few or no new plants offering to enter the market; and years with large quantities of offers coming from new gas plants seeking to replace aging coal plants.[10] The figure also shows that the supply curve shapes are similar to what has been observed across other capacity markets including PJM, the Independent System Operator of New England (ISO-NE), the Midcontinent Independent System Operator (MISO), and Great Britain. Collectively these markets offer 24 years of empirical evidence that supply resources offer in capacity markets in a way that is more or less driven by the underlying economic incentives for long-lived, capital-intensive resources.

We observe that among the four jurisdictions, PJM and ISO-NE's three-year forward market designs have attracted offers with a relatively similar supply curve shape. To offer a bit of contrast, MISO's offer curves seem steeper, and Great Britain's offer curves seem flatter. This is likely due to differences in those capacity market designs. For example, MISO's prompt auctions have a short forward period with no price lock-in, this would tend to produce a steeper supply curve shape given that there are relatively few entry and exit decisions that can be made between the time of the auction and delivery.[11] The Great Britain's auctions are conducted four years forward and offer the option for more multi-year contracts than other markets (up to 15 years for new resources), which may partly explain the relatively flatter shape of the supply

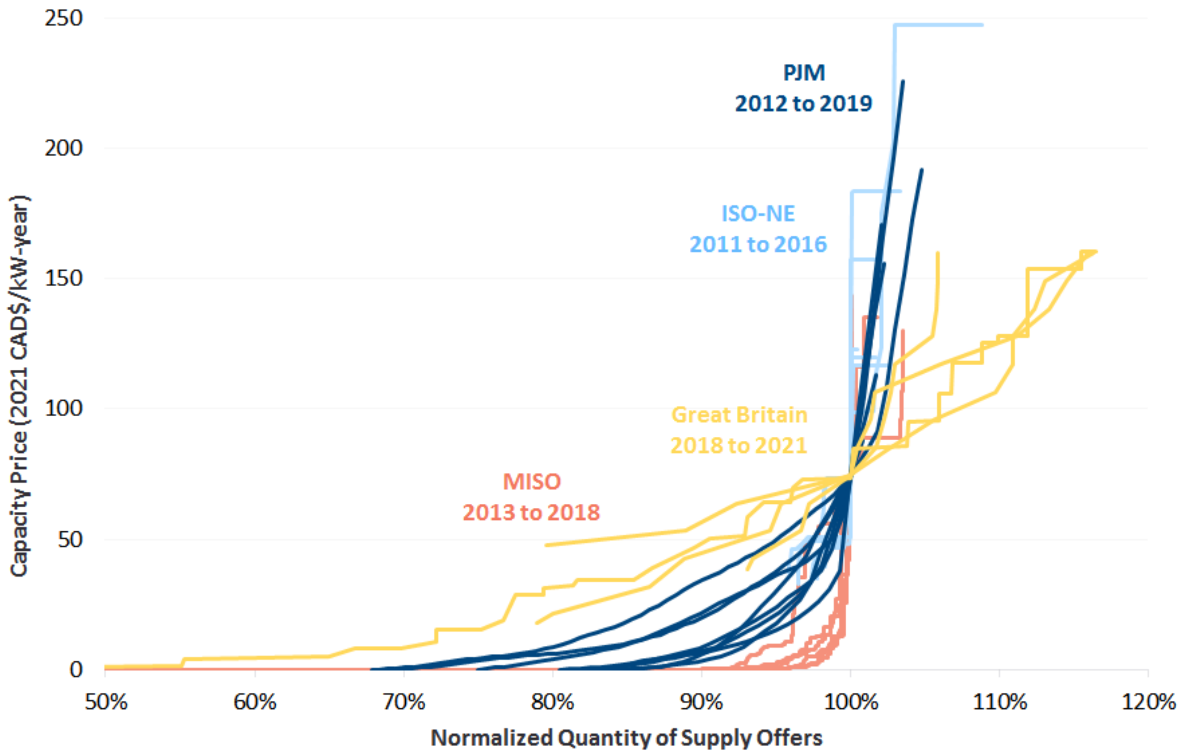
9 Exhibit 23757-X0341, PDF 16.

10 See for example, Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Ann Murray, and Ioanna Karkatsouli, *Third Triennial Review of PJM's Variable Resource Requirement Curve*, May 15, 2014. Newell, *et al.*, *Fourth Review of PJM's Variable Resource Requirement Curve*, April 19, 2018.

11 Because few resources can enter or exit between these times, most retirement and new build decisions must be made in advance of the auction. Few resources can choose to enter or exit conditional on the auction price, and thus they will tend to offer at zero or not at all (producing a near-vertical supply curve). We observe similarly steeper supply curves in NYISO's non-forward capacity market and the non-forward reconfiguration (or "Incremental") capacity auctions in PJM.

curves in that market.[12] Overall, Figure 1 shows that while there is a range of supply curves, they are similar across markets, across a wide range of market conditions and market designs. Of these, we view the PJM curves as being relatively representative; the factors that likely contribute to flatter and steeper curves in Great Britain and MISO do not apply in Alberta.

Figure 1
All Supply Curves in ISO-NE, PJM, MISO, and Great Britain



Sources and Notes: Labels indicate delivery years. Offer prices are expressed in 2021 Canadian dollars. Normalization price is set to $75/kW-year. For ISO-NE and Great Britain, only a portion of the supply curve is shown because only the offers above the clearing price was made publicly available in those auctions. PJM data from Samuel A. Newell, David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, J. Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin, *Fourth Review of PJM's Variable Resource Requirement Curve*, April 19, 2018. ISO-NE data from Newell, Samuel A., and Kathleen Spees, *Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve*, April 1, 2014. MISO data from annual capacity auction results reports: MISO, *PRA Results*, 2013/2014, 2014/2015, 2015/2016, 2016/2017, and 2017/2018. Great Britain data from annual capacity auction results reports: National Grid, *T-4 Capacity Market Auction*, 2014, 2015, 2016, and 2017.

The CWG/Power Advisory Report expressed concern that a steep supply curve indicates that "new supply resources are not available at some price point to respond to a shock such as a

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12 Longer forward periods allow more types of resources to enter or exit contingent on the auction price. Longer lock-in periods will also induce more offers at higher prices, given that sellers may be willing to accept very low prices for one individual year (but would not wish to lock in such a low price for many consecutive years). Department for Business, Energy & Industrial Strategy, Capacity Market and Emissions Performance Standard Review, August 2018, p. 32.

retirement."[13] This concern is misplaced for two reasons. First, we do account for the potential for new entry through an offer stack or "shape block" that represents the potential for entry (and exit) from a variety of resources as well as through a "smart block" adjustment that represents the entry (and exit) of supply on a long-run basis.[14] The CWG/Power Advisory Report's comment appears to reflect the intuitive (but incorrect) expectation that capacity markets will attract large quantities of supply offers at or near Net CONE in every year. In reality, this is not how new entrants tend to participate. Instead experience from other markets shows that new resources often choose to offer at a range of prices above and below Net CONE including zero.[15] This is because new entrants make investment decisions not just on the first year auction price, but also on their long-run view of energy and capacity market fundamentals and the unique economics of a particular project. For example, if the new entrant is optimistic about energy and capacity market fundamentals for many years, the first year capacity price will have a minor impact on the overall financial outlook (they would likely offer below the administrative Net CONE); if they are pessimistic about the future, they will not offer into the auction, even at a high price.

All of these factors considered, we continue to view our supply curve shape assumptions as realistic, although we acknowledge uncertainties in how suppliers in Alberta will offer that will not be resolved until we can observe several years of actual market data.

Supply Entry

The CWG/Power Advisory and CanSIA/Solas Reports expressed concern that we modeled the Alberta market with less unforced capacity (UCAP) supply than they would have expected. The CWG/Power Advisory Report points to an additional 6,000 MW of gas-powered generation under development; similarly, CanSIA/Solas estimates that some 1,000 MW more supply will participate in the initial auctions than we report in our model results.[16] They argued that the additional supply will improve reliability compared to what we have modeled, and reduced energy and capacity prices to consumers.

These concerns appear to stem either from a misunderstanding of how our model works, or from a different view of the purpose of the demand curve in a sustainable capacity market. Focusing first on the purpose of the demand curve, it is not relevant to debate the initial quantity of supply might be offered in the first years of the capacity market. If the market were to start with 1,000 MW more supply (as CanSIA/Solas indicated) with an associated more vertical or more left-shifted demand curve as they recommend, the resulting capacity prices would be low in the

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13 CWG/Power Advisory Report, PDF 15.

14 See description of the "smart block" in Exhibit 23757-X0341, Section III.B.

15 See, for example, Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Ann Murray, and Ioanna Karkatsouli, *Third Triennial Review of PJM's Variable Resource Requirement Curve*, May 15, 2014, p. 34.

16 CWG/Power Advisory Report, PDF 15. CanSIA/Solas Report, PDF 20, 30.

initial years of the auction. As a result, supply would exit until prices eventually rise to a high enough level to attract new entry (at Net CONE). The quantity of supply that would exit the market would need to exceed 1,000 MW due to the introduction of a curve that is left-shifted compared to what the AESO has proposed. The resulting equilibrium quantity of capacity would be less than what we have modeled due to the left-shifted nature of the demand curve, and below what is needed to maintain the resource adequacy standard over the longer-term.

Our modeling approach simulates this long-run equilibrium concept. It does not matter what "initial guess" of UCAP supply is assumed in the model, it will not affect final model results because the model simulates the real-world effect that will cause excess supply to exit until equilibrium pricing at Net CONE is achieved. Under this approach, if the model were to start with 1,000 MW of excess supply, there would be a temporary surplus with temporary low prices. However, the "smart block" would reduce supply quantities until prices rise to Net CONE.

A similar logic applies to the 6,000 MW of potential supply entry identified in the CWG/Power Advisory Report. This development activity is a promising indication that the market should be able to attract entry if prices are expected to reach Net CONE on a long-run average basis. However, only a portion of these resources should be expected to offer into any individual capacity auction, given that some of these resources may be less economically viable than others and some may be less far along in project development. Clearing in a capacity auction introduces a binding financial commitment to build that not all projects in the development pipeline will be prepared to deliver on. Those that are the most promising will be incentivized to proceed with making an offer, but ultimately they will only build if prices are expected to reach the levels needed to recover investment costs over many years. Our approach of assuming that new supply will enter if (and only if) prices are consistent with Net CONE on a long-run average basis is consistent with the assumption of rational decision-making of potential new entrants.

B. Comparison to Other Markets' Curves

The CWG/Power Advisory and MSA Reports expressed concern that the AESO proposed demand curve could lead to increased costs because the AESO has proposed a demand curve that is seemingly wider or more right-shifted than other jurisdictions. Specifically, the MSA argues that in comparison to other markets, the AESO's proposed curve appears "aggressive in terms of the volume that it seeks to procure and the price that the market is willing to pay."[17] The CWG/Power Advisory Report echoes the concerns about over procurement due to the curve being wider and more right-shifted than necessary.[18]

We view the AESO proposed demand curve as reasonable compared to demand curves in other capacity markets, when considering Alberta's relatively small size and the AESO's resource

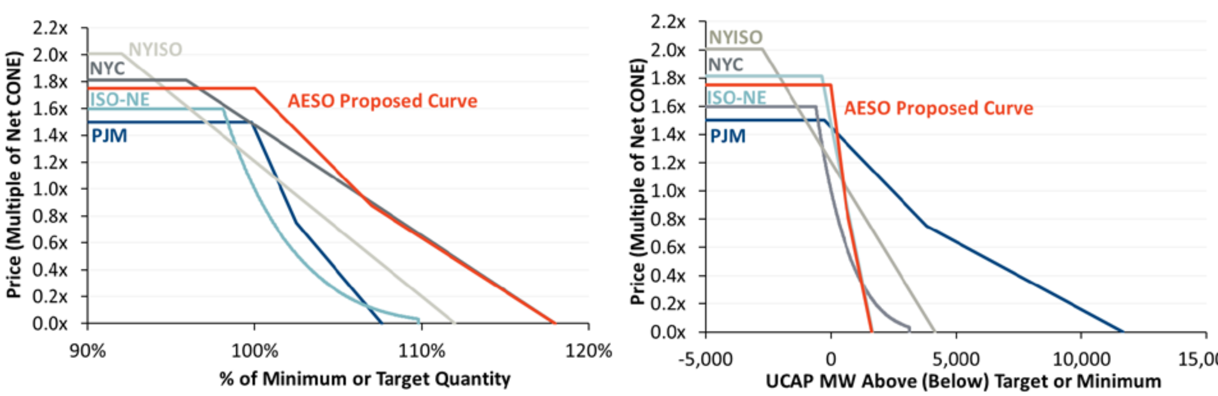
[17] MSA Report, PDF 83.

[18] CWG/Power Advisory Report, PDF 16.

adequacy standard. Figure 2 provides a comparison of the AESO's proposed demand curve compared to other markets' curves on both a percentage and an absolute capacity basis. When comparing on a percentage basis (left chart), the AESO's proposed curve appears similar to the New York Independent System Operator (NYISO) and New York City (NYC), but wider than PJM and ISO-NE's demand curves. The relatively wider shape is reasonable when considering the small size of Alberta's market and the need for a wider curve to dampen the price-influencing effect of small changes to supply and demand.

The AESO curve also appears somewhat more right-shifted compared to other markets (other than the NYC curve). This apparent difference is primarily optical and relates to the difference in the nature of the resource adequacy standard in Alberta compared to the other markets. Alberta's standard is a *minimum* resource adequacy standard, meaning that the curve must be drawn entirely to the right of 100% on the x-axis. All of the other markets depicted here have adopted a *target* resource adequacy standard, meaning that the market is intended to achieve that level of reliability on average over many years. In those markets, the curve can be drawn through a point that is near or a bit above 100% on the x-axis and at Net CONE. Thus, Alberta's a demand curve that is based on a minimum will necessarily appear right-shifted when compared to a demand curve from another market that is based on an average target.

Figure 2
The AESO Proposed Demand Curve Compared to Curves in Existing Capacity Markets Shown on a Percentage Basis (Left) versus an Absolute MW Basis (Right)



Sources and Notes: Curves represent: New York Independent System Operator (NYISO) and New York City's (NYC's) 2019 summer period curves, ISO-NE's Forward Capacity Auction 10 Marginal Reliability Impact curve, and PJM's 2021/22 BRA VRR curve. Alberta is expressed with reference to its minimum, whereas the other curves are expressed in reference to their reliability requirements.

While the AESO proposed demand curve appears wider on a percentage basis, the width is much smaller on an absolute basis than other capacity markets, as shown in the right figure as well as Table 1. Smaller markets necessitate wider demand curves on a percentage basis to act as a "shock absorber" and ensure that the demand curve has enough quantity to moderate the potential extremes from auction outcomes, mitigating price volatility and the potential for exercise of market power. A larger market can adopt a steeper demand curve based on a smaller percentage of the overall market, since a larger market size means that the entry or exit of a single resource would not cause excessive swings in price. This relationship between market size and demand curve width is observed in existing markets, as demonstrated in Table 1.[19] The width of Alberta's demand curve is much smaller on an absolute basis than other markets, indicating that the curve may be subject to more price volatility even though the curve is wider than most other markets on a percentage basis.

Table 1
Comparison of Capacity Market Demand Curve Widths

	Minimum or Target Reliability Requirement *(UCAP MW)*	Demand Curve Width *(% of Requirement or Min)*	Demand Curve Width *(UCAP MW)*
PJM	153,161	8%	11,904
ISO-NE	34,150	12%	3,990
NYISO	34,558	20%	6,889
NYC	9,217	22%	2,036
AESO Proposed Curve	**9,001**	**18%**	**1,620**

Sources and Notes: AESO curve is represented as a percentage of its minimum requirement, whereas other curves are presented as a percentage of their target requirements. See footnotes to Figure 2 for sources.

Another comparison between the AESO's proposed curve and other markets' curves was introduced in the MSA Report and later recreated in the TransAlta/LEI Rebuttal that compares the y-axis on an absolute $/kW-year basis rather than as a percentage of Net CONE.[20] The MSA Report argued that the AESO's proposed curve is higher when represented on a price basis, and could become even higher if the Net CONE were to rise (due to a lower E&AS offset). The TransAlta/LEI Rebuttal provides a different version of the same chart that leads to a different conclusion that the AESO's proposed curve has prices in line with other markets.

We have developed our own version of this price-based comparison as shown in Figure 3. Our version of this figure aligns with that presented in the TransAlta/LEI Rebuttal (though there are some small differences associated with differences in exchange rate, dollar year adjustments, and delivery year). We agree with the TransAlta/LEI Rebuttal that the AESO's proposed demand curve has prices that are the same or below the price levels in other markets. On an absolute dollars basis, the Alberta demand curve price cap is in line with that of PJM, below that adopted in NYISO and ISO-NE, and far below the price cap in NYC.

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19 This result was also supported by some of our earlier modeling efforts, where we showed that a curve from a larger market, such as PJM, would yield excessive price volatility and risk meeting the minimum reliability target if applied proportionately in Alberta. See Kathleen Spees, Judy Chang, Johannes Pfeifenberger, David Luke Oates, Peter Cahill, Elliott Metzler, *Demand Curve Shape: Preliminary Modeling Results and Scoping Questions*, October 10, 2017, slides 13-14 (Exhibit 23757-X0292, PDF 385).

20 MSA Report, PDF 83. TransAlta/LEI Rebuttal Report, PDF 9.

Our version of this figure and associated conclusions are significantly different from that presented in the MSA report. One difference is that that the MSA Report depicts the y-axis using UCAP-based prices, while we report the y-axis using ICAP prices.[21] We present prices on an ICAP basis because it more uniformly reflects the costs faced to developers to enter the market; comparing on a UCAP basis as the MSA has done fails to adjust for differences in the definition of UCAP across markets. This has the effect of appearing to inflate the prices in Alberta's market compared to other markets due to the lower UCAP:ICAP ratio of the reference unit in Alberta. The other primary difference from the MSA report is that we (consistent with the TransAlta/LEI Rebuttal) show much higher NYISO prices.[22]

We do not share the MSA Report's concern that the prices could be higher if the estimated E&AS offset were to fall. The increase or decrease in prices in alignment with the estimated Net CONE is a necessary and beneficial component of the demand curve design. The demand curve must be allowed to increase or decrease in alignment with the estimated Net CONE, if the curve is to support the necessary entry and exit in alignment with system needs. The MSA's analysis has further focused only on the possibility of increases in Net CONE, and has not considered equally plausible scenarios in which Net CONE might fall due to increasing E&AS offset or due to a change in the reference technology. Whether Net CONE increases or decreases, the demand curve should similarly adjust in order to align with market fundamentals.

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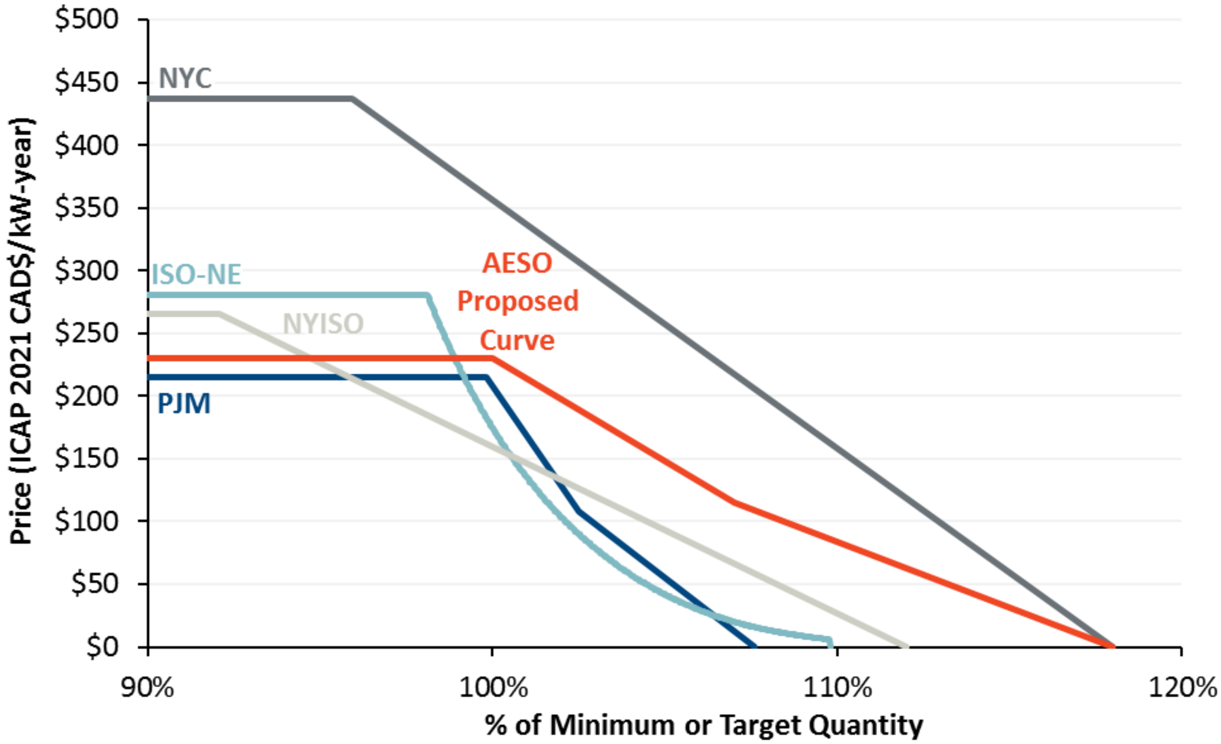
21 We assume the MSA Report uses UCAP prices, although this is never explicitly stated. Other known differences between the figures, such as our explicit use of a consistent dollar year or discrepancies in chosen auction year parameters, yield relatively minor impacts. There are differences between our recreation and the original that we are unable to clearly identify, such as the placement of the New York demand curves.

22 We believe that the low NYISO demand curve prices reported in the MSA Report are likely associated with a transcription error.

Figure 3
Recreation of MSA Demand Curve Comparison Figure



Notes: Prices are adjusted to be in 2021 CAD$ using a 2% inflation rate from posted delivery year and a 1.3 exchange rate to convert USD to CAD. The curves are sourced from the same materials as Figure 2. The fleet wide average EFORd was used to adjust from UCAP to ICAP prices in PJM. The AESO Net CONE is ICAP 2021 CAD $132/kW-year as outlined in Exhibit 23757-X0309, PDF 577.

C. Volatility as a Consideration

The CanSIA/Solas Report has expressed a view that mitigating price volatility should be de-emphasized as a priority in the development of the demand curve, stating that "it is not the role of the AESO to limit price volatility in cases where unit entry or exit is large compared to the size of the market," and that "price volatility in the Capacity Market is less concern than over-procurement."[23]

We partly agree and partly disagree with this assessment. We take the positon that while the primary objective of the demand curve should be to meet the resource adequacy standard, capacity price volatility is nonetheless an important consideration in the evaluation of potential demand curves. However, price volatility must be evaluated within the context of other important and sometimes competing objectives. For example, a flatter curve will mitigate price volatility and the ability to exercise market power, while a steeper curve will provide more acute price signals in response to changes in market conditions. We find that the AESO's proposed

[23] CanSIA/Solas Report, PDF 27, 30.

demand curve strikes a reasonable balance among these competing objectives. However, we view the AESO proposed curve as only one option with a range of reasonable curves; a somewhat steeper or flatter curve could also have been selected, with a somewhat different balance of objectives.

Where we more strongly disagree with the CanSIA/Solas Report is in their view that the emphasis on price volatility has introduced a tendency toward over-procurement. If the curve is to incent adequate capacity development so that the capacity auctions can meet the minimum procurement volume 95% of the time, it must be sufficiently right-shifted to manage the year-to-year fluctuations in net supply variability. The resource adequacy standard by its nature dictates that the procurement volume must exceed the minimum the majority of the time; this should not be mischaracterized as over-procurement. Thus, the primary objective of meeting the resource adequacy standard (not the secondary consideration of mitigating price volatility) is what dictates the outcome that average procurement volumes should exceed the minimum procurement volume under in the AESO's proposed demand curve. We agree with the AESO that it is advantageous to achieve the necessary procurement volumes with a relatively flatter curve, all else equal, because of the price volatility and market power mitigation benefits.

The disadvantages of a steeper curve have been illustrated through experience in both ISO-NE and MISO that have both operated with a vertical demand curve at their respective reliability requirements. In ISO-NE, the capacity market used a vertical demand curve until its ninth Forward Capacity Auction (for the 2018/2019 delivery year), which resulted in a bimodal capacity price distribution. For many years, the market cleared at the administrative price floor, both when the market started in a supply surplus condition and as the market began to approach a shortage. Then when supply was finally needed, market prices increased suddenly to the price cap and the market cleared at a shortage.[24] Similarly, MISO's vertical demand curve is producing prices that are very low (near zero) on a persistent basis even as the market approaches the need for new supply in some locations with one occasion of a moderate price spike in one zone.[25]

In both these cases, the system operators found that a vertical demand curve would not achieve the resource adequacy standard on a long-run average basis.[26] That is, a curve that is vertical at the resource adequacy standard would achieve the target in some years as long as the market has started with a long supply condition; however, the low prices during long market conditions would result in poor incentives to invest as the market approaches a shortfall. Eventually, enough supply would exit to produce a shortfall (and induce prices at the price cap). These

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24 Newell, Sam and Kathleen Spees, *Testimony on Behalf of ISO New England Inc.*, 2014, p. 7.

25 Newell, Sam, Kathleen Spees, and David Luke Oates, *Testimony on Behalf of MISO Regarding the Competitive Retail Solution*, November 2016, p. 10.

26 See, for example, MISO, *Resource Adequacy in Restructured Competitive Retail Markets, Issues Statement*, October 2015. Order Accepting Tariff Revisions, 147 FERC ¶ 61,173 (May 30, 2014). Newell, Sam and Kathleen Spees, *Testimony on Behalf of ISO New England Inc.*, 2014, p. 8.

shortages would have to be allowed to continue on a frequent and sustained basis (without intervention) for prices to be high enough on average to attract new generation investments. The frequent shortages would bring down system reliability on average. This sort of outcome was deemed to be unacceptable by both market operators as it would produce excess price volatility and also fail to support reliability. Since that time, ISO-NE has addressed the concern by introducing a sloped curve while MISO is still working to address the issue.

The CanSIA/Solas Report also claimed that any capacity price volatility would be offset by the energy market stating:

> "Solas submits that price volatility in the Capacity Market is less concern than over-procurement. This is because changes in the Capacity Market price will be offset by changes in the Energy Market price. A resource that receives a higher capacity market price has a reduced need to recover capital costs in the energy market, and can make lower priced energy market offers, compared to a resource that receives a low Capacity Market price."[27]

This explanation is not entirely correct. It is true that in the long run, energy and capacity prices will offset each other on an expected average basis; higher reserve margins and lower energy prices would result in higher capacity prices needed to attract entry. However, this a long-run effect that would only be observed over the course of the many years of an investment cycle. There is no similar effect on a shorter year-to-year timeframe as the CanSIA/Solas Report seems to describe. In fact, energy and capacity prices should be expected to be somewhat correlated (rather than offsetting) on such a short year-to-year timeframe. During years with excess supply, both energy and capacity prices are likely to be lower; years with a shortage of supply would drive both energy and capacity prices higher.

D. Analysis of Alternative Demand Curves Proposed by Interveners

We evaluated the performance of alternative demand curves that were analyzed by CCA/EDC and described in the CCA-Sponsored and UCA/DePal Reports.[28] These alternative demand curves attempt to address the respective interveners' concerns about the potential for over-procurement by shifting the demand curve left.[29] We assessed these curves' likely performance

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27 CanSIA/Solas Report, PDF 29, 30-31.

28 Each of these commenters rely on the same underlying analysis described in the CCA/EDC Report. CCA/Brown Report PDF 41; CCA/Retnanandan Report PDF 10-11; CCA/EDC Report PDF 12-19; UCA/DePal Report PDF 28.

29 The CWG/Power Advisory, MSA Report, and Pembina/Gramlich Reports advised adopting a curve influenced by the marginal reliability impact of additional capacity to address concerns of the AESO

Continued on next page

using the same Monte Carlo model that we have previously used to evaluate the AESO's proposed curve.[30]

Figure 4 shows the alternative demand curves that we evaluated. The CCA/EDC report provided specific parameters for a demand curve anchored with 100% of the minimum procurement volume at Net CONE.[31] The UCA/DePal Report focused on a similar demand curve but did not provide parameters for the demand curve points. The curves described in the other CCA-Sponsored Reports provided an approximate description of various curves anchored to different "capacity target levels," but also did not provide specific demand curve parameters. Therefore, we tested variations of the AESO's proposed demand curve that were left-shifted such that Net CONE would align with 100%, 102%, or 104% of the minimum procurement volume.[32] The ENMAX/Sotkiewicz Report, also proposes adjusting the demand curve to anchor where 100% of the minimum procurement volume intersects with Net CONE.

Continued from previous page

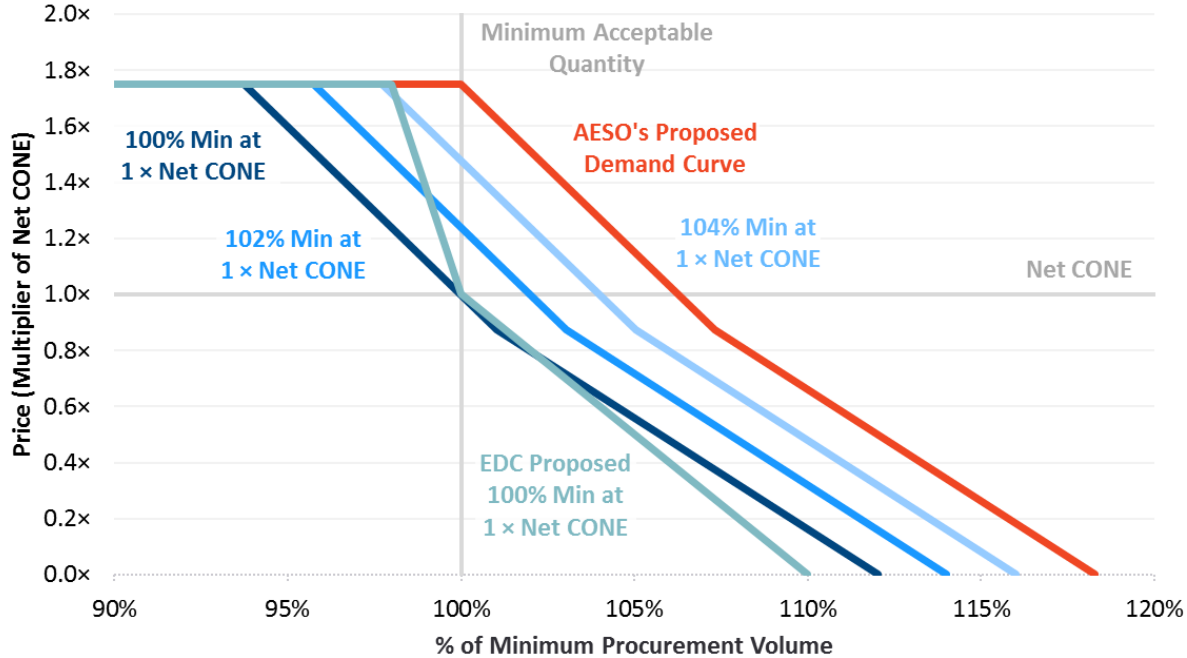
demand curve being too flat and right shifted (CWG/Power Advisory Report PDF 16; MSA report, PDF 87; Pembina/Gramlich PDF 20). We have previously addressed such a demand curve in Spees, Kathleen, David Luke Oates, Cathy Wang, and Matthew Witkin, *Alberta's Capacity Market Demand Curve, Response to Additional Application Requirement #29: Analysis of a Demand Curve Based on Marginal Reliability Impact*, January 2019 (Exhibit 23757-X0342).

30 See description of the modeling approach in Exhibit 23757-X0341, Section III.A.

31 We tested a curve that reflects what is shown in Figure 7 of the CCA/EDC Report (PDF 13), with the price cap at 98% of the minimum requirement, the inflection point at 100% of the minimum requirement and Net CONE, and the foot at 110% of the minimum requirement.

32 The CCA-Sponsored Reports also evaluated a curve corresponding to 1-in-10 LOLE, which fell between the 104% minimum at Net CONE and the AESO Proposed Demand Curve. We did not evaluate this curve since it is very similar to the surrounding curves. It is important to note that the 1-in-10 LOLE is often a capacity *target* rather than a capacity *minimum* as is implied in the CCA/Brown Report (see PDF 34, paragraph 74).

Figure 4
Comparison of Alternative Demand Curves with the AESO's Proposed Demand Curve



Sources and Notes: CCA/EDC Proposed 100% min at 1 × Net CONE: CCA/EDC Report, PDF 13. Other Curves: UCA/DePal Report, PDF 27-28; CCA/Brown Report, PDF 31-42, CCA/Ratnanandan Report, PDF 9-11.

Table 2 summarizes our estimated performance metrics for the alternative demand curves (top panel), and the change in each performance metric compare to the AESO's proposed curve (bottom panel). Figure 5 shows the price and quantity distributions from each of the considered demand curves. Each of the curves proposed by the interveners would reduce the average procured volume and produce lower reliability across auction outcomes, as expected given their left-shifted placement (the more left-shifted the curve the lower the equilibrium level of capacity incented, the poorer the expected reliability). This would also reduce procurement costs.[33] As evidenced by the frequency below the minimum quantity results in Table 2, none of the alternative demand curves meet the reliability objective of meeting the minimum procurement volume at least 95% of the time. The most left-shifted curve, which anchors the demand curve at the minimum acceptable quantity and Net CONE, procures less than the minimum procurement volume 45% of the time, as is further illustrated in Figure 5. These results highlight

[33] In our analysis, we report approximately $100 million per year in reduced capacity procurement costs from shifting from the AESO proposed curve to the curve with Net CONE at 100% of the minimum procurement volume. We caveat that the cost differences reported in our table are not intended to reflect a comprehensive assessment of energy and capacity market costs that would be introduced by a material change in average reserve margins. Our stylized model estimates changes in costs that would be produced if Net CONE were to remain constant across increasing reserve margins; we have not estimated the effects of increasing Net CONE and dropping energy market prices that would occur at higher reserve margins. If accounting for these effects, the net cost impact of increasing and decreasing reserve margins could be greater or less than those that we report.

how reliability erodes more quickly at lower reserve margins. Dropping from the AESO proposed curve to the 104%, 102%, and 100% curves would result in under-procurements increasing from 5% up to 14%, 27%, and 45% respectively. The left-shifted curves would also increase annual average EUE from 266 up to 734, 1,635, and 3,222 MWh per year respectively if there were no backstop capacity interventions.[34]

These results illustrate why a more left-shifted curve would not align with the Alberta resource adequacy standard, as was proposed by several interveners. For example, the ENMAX/Sotkiewicz Rebuttal correctly pointed out that the U.S. capacity markets have adopted demand curves anchored on Net CONE at (or a bit right-shifted from) their resource adequacy standards.[35] This approach makes sense in those U.S. markets given that the resource adequacy standard is an *average* that is to be achieved across many years. The demand curve can be centered at the target capacity in those U.S. markets, since it is acceptable to clear above or below the target capacity in any given year, as long as it hits the target on average.

However, we disagree with the ENMAX/Sotkiewicz Rebuttal that the same approach should be applied in Alberta. Alberta has adopted a *minimum* resource adequacy standard. A minimum resource adequacy standard requires that the market clear above the standard under nearly all conditions (specifically, 95% of the time in this case). This means that the curve must be entirely to the right of the minimum procurement volume, to ensure that all in-market opportunities to procure capacity are secured before allowing a shortfall.

In terms of price volatility, most of the curves perform similarly well to the AESO's proposed curve given that they have the same shape and width. The EDC curve produces higher price volatility because of its steeper shape. The similarities are apparent in the price distributions in Figure 5 where only the EDC proposed curve exhibits a somewhat more volatile price distribution.

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34 See TransAlta/LEI Report PDF 52-55 for their modeling results, which also highlight the asymmetrical relationship between procurement volume and reliability. See also, Samuel A. Newell, David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, J. Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin, *Fourth Review of PJM's Variable Resource Requirement Curve*, April 19, 2018, Figure 16. Newell, Samuel A., and Kathleen Spees, *Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve*, April 1, 2014, Figure 7.

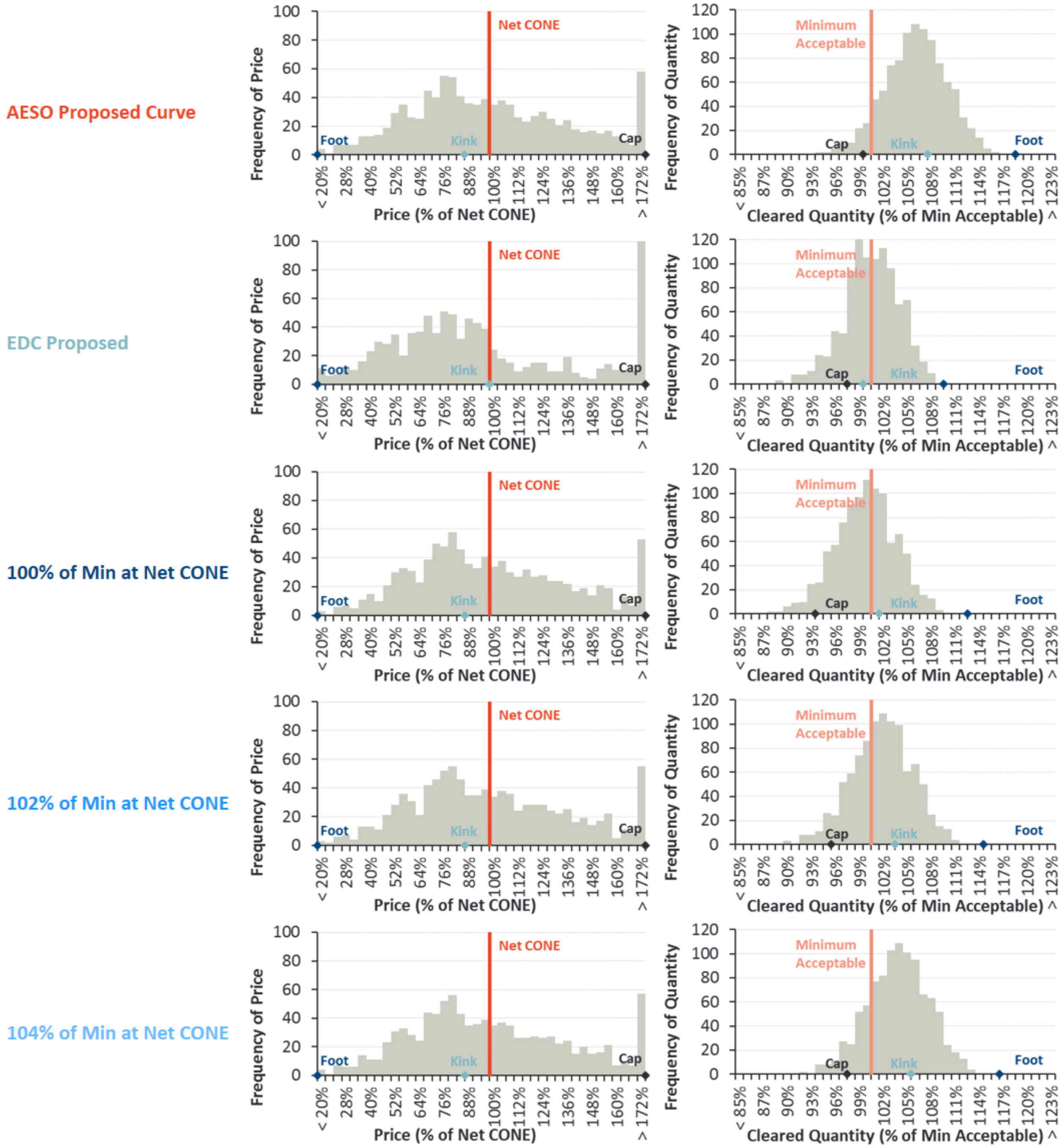
35 ENMAX/Sotkiewicz PDF 20-21.

Table 2
Simulated Performance of Alternative Demand Curves and the AESO's Proposed Demand Curve

	Price and Cost			Reliability				
	Average Price	Standard Deviation of Price	Average Cost	Average EUE (Before Intervention)	Average EUE (After Intervention)	Avg. Cleared Quantity	Average Uncleared Supply	Frequency Below Min Quantity
	($/kW-yr)	*($/kW-yr)*	*($mil/yr)*	*(MWh)*	*(MWh)*	*(MW)*	*(MW)*	*(%)*
Simulated Performance								
AESO's Proposed Curve	$139	$53	$1,665	266	118	12,042	247	5%
EDC Proposed	$139	$64	$1,576	2,216	530	11,417	273	39%
100% Min at 1 × Net CONE	$139	$52	$1,565	3,222	593	11,335	245	45%
102% Min at 1 × Net CONE	$139	$52	$1,597	1,635	404	11,561	245	27%
104% Min at 1 × Net CONE	$139	$52	$1,628	734	243	11,787	246	14%
Delta Above (Below) the AESO's Proposed Curve								
EDC Proposed	($0)	$12	($89)	1,950	412	(625)	26	34%
100% Min at 1 × Net CONE	($0)	($1)	($100)	2,956	475	(707)	(2)	40%
102% Min at 1 × Net CONE	($0)	($1)	($68)	1,369	286	(482)	(2)	22%
104% Min at 1 × Net CONE	($0)	($0)	($37)	468	125	(255)	(1)	9%

Notes: Curves correspond to those depicted in Figure 4. Numbers in parentheses indicate negative values, or lower values than the AESO Proposed curve.

Figure 5
Price and Quantity Distributions of Considered Demand Curves



III. Energy and Ancillary Services Revenue Offset Methodology

We respond to comments in the Capital Power/ESAI, TransAlta/LEI, and MSA Reports concerning the AESO's proposed approach to setting the E&AS revenue offset. We provide first a summary of our response to the main points by the interveners followed by more detail on each topic below.

- The MSA Report suggest that other markets have developed standardized approaches to estimating the E&AS offset. However, the existing U.S. capacity markets have not relied on a single standardized approach for calculating the E&AS net revenues of the reference technology, instead utilizing several different approaches that have changed over time. Their history of modifying the E&AS approach illustrates that there are a wide range of approaches that each have their relative strengths and weaknesses and that there is not a single consensus approach for the AESO to apply to its own market. In general, both a forwards-based approach and a simulation-based approach can result in reasonable estimates of forward-looking E&AS net revenues.
- The MSA Report claims that relying on forward market products adds uncertainty and volatility to the capacity market because electricity futures are a poor predictor of spot energy prices and the E&AS offset is highly sensitive to futures prices. The MSA Report mischaracterizes the relationship between forward prices and spot prices. Forward prices should not be expected to match realized spot prices in any one delivery period; instead they are more correctly interpreted as market participants' estimate of future spot prices, taking into account the wide range of potential outcomes that could occur in the future weighted by their relative probability of occurring. In that way, forwards represent a weighted average expectation of the spot price. Further, both forwards-based and simulation-based approaches to setting the E&AS offset will be sensitive to forward prices and other key drivers of market fundamentals.
- The Capital Power/ESAI Report and the TransAlta/LEI Report commented that the AESO's E&AS revenue offset approach should account for long-term changes in the E&AS net revenues of the reference technology. We agree that these considerations could impact the E&AS margins that the reference technology earns over the long-term and could influence how developers choose to offer into the capacity market. However instead of incorporating these long-term trends into the E&AS revenue offset, we account for these considerations in the long-term cost recovery path and the approach to

levelizing capital costs for the reference technology in the AESO CONE Report.[36] Including these considerations in both the levelization approach for Gross CONE and the E&AS offset would result in double-counting these effects, possibly resulting in a somewhat overstated Net CONE value.

A. E&AS Approaches Used in Other Markets

The MSA Report commented that the approach for estimating the E&AS offset is consistent across the U.S. capacity markets.[37] That is not the case: There is no consensus on the best approach for setting the E&AS offset across existing capacity markets. Instead, the U.S. capacity markets have used several different approaches that rely on different market data and tools for setting the E&AS offset and calculating Net CONE.

- NYISO: During its most recent Demand Curve Reset process in 2016, NYISO modified its E&AS approach for setting Net CONE in upcoming auctions from a forward-looking approach to an approach that relies instead on historical prices. Prior to 2016 NYISO used a statistical model of historical hourly prices to estimate future prices under projected assumptions for load, gas prices, and temperatures.[38] They then ran a production cost simulation model to adjust the prices to account for excess capacity above the capacity requirement.[39] NYISO estimated the net E&AS revenues for calculating Net CONE by simulating the operation of the reference technology based on the projected hourly prices. In 2016, NYISO modified its approach by adopting a backward-looking approach that simulates the operation of the reference technology based on hourly prices from the three most recent historical years.[40] NYISO continues to use production cost simulations to adjust historical prices for excess capacity above the capacity requirement, which is required by their tariff.

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36 See Pfeifenberger, Spees, Hagerty, *et al.*, *AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date*, September 4, 2018, PDF 55. ("AESO CONE Report") AESO submitted the AESO CONE Report as Appendix K to its Application for the Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market (AUC Proceeding 23757).

37 MSA Report, PDF 59.

38 NERA, *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator*, August 2, 2013, pp. 60-81.

39 The NYISO Services Tariff requires that the Reference Price (which is similar to Net CONE) and the E&AS revenue offset reflect system conditions with capacity equal to the minimum Installed Capacity Requirement plus the capacity of the peaking plant in NYCA and each Locality. NYISO Services Tariff, Section 5.14.1.2.1, p. 255.

40 Analysis Group, *Study to Establish New York Electricity Market ICAP Demand Curve Parameters*, August 13, 2016, pp. 67-85.

- **ISO-NE**: ISO-NE initially estimated its net E&AS revenues by first calculating historical E&AS net revenues for existing plants that are representative of the reference technology over the most recent 3-year period. They then adjusted the historical net revenues by the ratio of futures settlement price to historical prices to account for changes in market conditions. However, ISO-NE recently adopted a different approach that is also forward-looking but instead develops hourly prices over the 20-year economic life of the reference technology using a production cost simulation model.[41] ISO-NE then simulates the operation of the reference technologies based on the projected prices to estimate their net E&AS revenues.
- **PJM**: PJM estimates the E&AS net revenues by simulating the operation of the reference technology based on three years of historical prices during peak hours in each load zone. This approach, essentially unchanged since capacity market implementation, is similar to the one recently adopted by NYISO, but without the tariff-mandated adjustment that NYISO makes for excess capacity.

While PJM's approach has remained mostly unchanged over time, both NYISO and ISO-NE adopted alternative approaches in their most recent review of the E&AS offset. In addition, all three markets use a different approach, with the NYISO and PJM approaches being the most similar.

The Capital Power/ESAI, MSA, CCA/EDC, and TransAlta Reports recommend that the AESO adopt a simulation-based approach, even though this approach is not common across the existing U.S. capacity markets. ISO-NE does not use its market simulations to directly estimate the E&AS net revenues of the reference technology, but instead uses the simulations to develop hourly prices, which are then used to estimate the E&AS net revenues of the reference technology. NYISO uses a production cost simulation but only for a small aspect of their approach which is not applicable in Alberta.

A forward-looking estimate of the E&AS revenue offset is preferable to historical approaches in many markets because it provides a weather-normalized estimate of the net E&AS revenues that will be less volatile than historical approaches and reflects changes in market fundamentals expected by participants, such as gas prices and changes in the resource mix. Both a forwards-based approach and a simulation-based approach can result in reasonable estimates of the E&AS net revenues that developers of the reference resource can expect to earn during the commitment period. Each approach has its strengths and weaknesses.

Electricity futures tend to have limited liquidity beyond one year ahead, so they may not as reliably reflect market participant's expectations of the changes in the market beyond that timeframe due to the limited volume of trades behind the futures prices. However, futures prices are reset, or "marked", each day by the futures exchange to account for changes in the market.

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[41] Concentric Energy Advisors, *ISO-NE CONE and ORTP Analysis*, January 13, 2017, pp. 49-65.

For that reason, even futures prices in the less liquid or illiquid portion of the forward curve will to some extent reflect changes in the market regardless of the actual trade volumes. It is also worth noting that natural gas futures are particularly liquid in Alberta for the multi-year timeframe under consideration with open interest through 2027; the "flat" all-hours electricity futures also have open interest through 2024 with monthly granularity through 2021 and annual granularity for 2022 to 2024. In addition, the operation of the reference resource may not align well with the available forwards products. Nevertheless, forwards have a key advantage in that they are the best market-based source available and are often used by developers as an input to estimating future net energy market revenues, which they will need to develop their capacity market bid.[42]

In cases where there are significant changes in market conditions expected beyond a year ahead, simulation-based approaches can offer the advantage of providing more information regarding the impact of any such changes to market fundamentals. However, this advantage of a simulation-based approach comes along with the disadvantage of relying more heavily on administrative judgement to project outcomes that are fundamentally uncertain. For example, in our review of the PJM E&AS approach we note that simulation-based approaches can be difficult to conduct with enough simplicity, transparency, and objectivity to gain widespread stakeholder support.[43]

B. Relying on Forwards Prices

MSA claims that relying on forwards "is likely to be unstable and to elicit controversy" because forwards are a "poor predictor of actual E&AS outcomes" and "introduce significant volatility into the capacity market."[44] Their concern however misrepresents the information provided by forward prices. The purpose of forwards is not to predict the realized spot prices, but to forecast the "expected" energy market prices based on currently predicted market conditions and actual market transactions. Forward prices reflect market participants' estimates of future spot prices, accounting for the wide range of potential outcomes and prices that could occur in the future market weighted by their relative probability of occurring. Realized prices however reflect a single outcome that will necessarily deviate from these forecasts. For that reason, realized prices should be a distribution around the forward prices, in some cases higher and in some cases lower. However, forward prices should reflect the realized prices on average over the long-term.

The results that MSA presented in Table 22 of their report demonstrate that this can be the case over the relatively small period of time analyzed.[45] For example, from 2014 to 2018 the forwards-based approach differs from the simplified dispatch approach in most years, but on

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42 See Newell and Ungate ISO-NE Testimony, pp. 56-57.

43 See Pfeifenberger, *et al.*, p. 16.

44 MSA Report, PDF 60.

45 MSA Report, PDF 62.

average the forwards approach is $101/kW-year and the simplified dispatch approach is $102/kW-year.[46]

MSA also states that their primary concern about the AESO's approach is that it is "highly volatile relative to its two primary inputs, the forward gas and power prices."[47] However, MSA does not demonstrate how the sensitivity of the simulation-based approach to gas forward prices would be improved upon the forwards-based approach in this respect. We expect that a market simulation approach would be similarly sensitive to forwards prices because they will rely on the gas futures prices as a key assumption into the simulation.

C. Long-Term E&AS Considerations

The TransAlta/LEI Report and the Capital Power/ESAI Report comment that AESO's approach for setting the E&AS offset does not account for long-term changes in E&AS net revenues of the reference technology and recommend that AESO develop a longer-term view of the E&AS revenue offset for calculating Net CONE.[48] The Capital Power/ESAI Report specifically points to technological improvements and wear and tear of the reference technology as drivers of decreased E&AS net revenues over time, while the TransAlta/LEI Report mentions planned outages as the main driver.

As we describe in Section VII of the AESO CONE Report, we accounted for how a new resource's net revenues will be impacted in the long term by technological innovation and the introduction of newer resources with improved heat rates in setting the CONE value.[49] In addition, the reference technology is also likely to see a marginal decrease in its efficiency due to wear and tear that will similarly result in an erosion of E&AS net revenues relative to a new plant.[50] Specifically, these long-term impacts to the net E&AS revenues for a new resource were accounted for in setting the long-term cost recovery path for the reference technology, which is used to levelize the capital costs over time and calculate the Gross CONE value.

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46 Including the results for 2013 skews the results due to the significant divergence in results, which is likely to occur due to the small sample size provided in the MSA Report.

47 MSA Report, PDF 62.

48 See TransAlta/LEI Report, PDF 27 and Capital Power/ESAI Report, PDF 12.

49 "Investors in new generating resources have to consider the possibility that their future net revenues may erode (relative to increasing with inflation) as technological innovation and environmental policies favor different types of technologies, such as renewable generation combined with storage." AESO CONE Report, PDF 55.

50 For a longer description of the factors that should be considered in setting the levelization approach to calculating CONE, see: Pfeifenberger, *et al.*, *Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15*, August 26, 2011, pp. 82-85; and Newell, Hagerty, et al., *PJM Cost of New Entry: Combustion Turbine and Combined-Cycle Plants with June 1, 2022 Online Date*, April 19, 2018, pp. 48-50.

Gross CONE represents the total net revenue that a resource will need to earn on average over the reference technology's economic life to enter the market, regardless of whether the resource earns those net revenues in the energy, ancillary service, or capacity markets. Resources that will receive lower E&AS net revenues over time than they otherwise would have will need to front-load more of its revenues than a resource that would be expected to earn similar or increasing amount of net revenues. On the other hand, there are in some cases valid reasons for a developer to expect that total net revenues will increase over time. For example, as we have noted in previous reports, the costs of gas turbines had been rising faster than inflation over the long-term.[51] In such a case, the cost of new gas-fired resources entering the market in future auctions would tend to be higher than in the present auction, such that a similar resource could accordingly expect its total net revenues to rise over time. This trend would tend to result in a more back-weighted cost recovery path, and the need for lower near-term net revenues to enter the market. Similarly, rising natural gas prices would also increase the dollar value of the investment costs recovered through energy and ancillary services markets, even if current generating technologies will be less efficient than future generating technologies.

We took these trends and considerations into account in choosing to calculate the Gross CONE value using a "level-nominal" approach, as described in the AESO CONE Report. Accounting for them also in the estimate of E&AS net revenues would double count these effects and could result in a somewhat overstated Net CONE estimate. Therefore, we do not recommend that the AESO attempt to account for these effects in the E&AS offset estimate.

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51 Pfeifenberger, *et al.*, *Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15*, August 26, 2011, pp. 82-85.

IV. Ex Post Energy and Ancillary Services Offset Approach

The AESO proposes an E&AS offset that is determined on an ex ante basis, consistent with the design of all other North American capacity markets. The AUC asked questions of the AESO to introduce the concept of using an ex post E&AS offset that would be clawed back on an after-the-fact basis from capacity market sellers based on realized energy market prices. The AUC asked for input to better understand the potential advantages and disadvantages of such an ex post approach. The AESO opined that moving to an ex post E&AS offset would increase all resources' capacity offer prices to include the cost of the anticipated E&AS clawback and introduce other challenges that would make the ex post approach undesirable.[52]

Evidence submitted against using an ex post approach includes: the CanSIA/Solas Report, the ENMAX/Sotkiewicz Report and Rebuttal, and the TransAlta Rebuttal. The CanSIA/Solas Report agreed with the AESO's assessment against the ex post approach, positing that such an approach would reduce opportunities for consumers to manage their own costs.[53] As explained in the ENMAX/Sotkiewicz Report and expanded upon in the ENMAX/Sotkiewicz Rebuttal, an ex post E&AS offset approach would have detrimental effects on capacity and energy market efficiency.[54] The TransAlta Rebuttal provided additional evidence on why the ex post E&AS offset approach would not be workable, expressing concerns regarding uncertainties imposed on sellers, discrepancies between actual plants' revenues that may differ from the hypothetical proxy plant, and the potential for an ex post approach to distort market signals.[55]

Evidence submitted in support of the ex post approach includes: the Cramton Report, the CWG/Power Advisory Report, the MSA Report, and the Suncor Rebuttal. The Cramton Report argued that an ex post approach would introduce more liquidity than other opportunities to manage risk through forward contracting.[56] The CWG/Power Advisory Report stated that it would reflect the "correct" energy market revenue thereby eliminating any risk to generators and customers that the E&AS offset could be calculated incorrectly.[57] The MSA Report stated that the ex post approach "holds promise", but did not attempt to fully analyze the impacts of

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52 AESO, *Responses to the Additional Application Requirements* ("AESO Appendix J"), PDF 29-33.

53 CanSIA/Solas Report, PDF 45-46.

54 ENMAX/Sotkiewicz Report, PDF 75-76. ENMAX/Sotkiewicz Rebuttal, PDF 23-24.

55 TransAlta Rebuttal, PDF 19-20.

56 Cramton Report, PDF 4-5.

57 CWG/Power Advisory Report, PDF 19-22.

using such a methodology.[58] The Suncor Rebuttal maintained that the other interveners had misunderstood the proposed design, and that an ex post approach would better achieve desired reliability at "reasonable cost".[59]

The IPCAA/ADC/FTI Consulting Rebuttal took a relatively neutral position on the ex post option. That report explained that the ex post E&AS offset approach would impose a forced hedge that may impose undesirable costs on customers and limit participation in the forward markets, but concluded that the hedge may become more valuable if the Alberta forward market does not improve its liquidity in the near future.[60]

We agree with the AESO, CanSIA/Solas, ENMAX/Sotkiewicz, and TransAlta Report/Rebuttal arguments that a prospective approach is the preferred market design. The ex post design could introduce several inefficiencies and design challenges, without offering material benefits.

The reasons to consider an ex post approach include that it would: (1) hedge load from exposure to volatile energy market spot prices; (2) reduce capacity sellers' risks by replacing peak energy market rents with a less volatile capacity payment; and (3) reduce incentives for exercise of market power in the energy market. We do not view any of these reasons as compelling or necessary in Alberta, because:

- **Mandatory Hedging against Prices above the Strike Price:** While a built-in hedge to energy prices could potentially reduce total energy plus capacity price volatility for consumers, this hedge will come at an additional cost that customers may not want to pay. Already, there is a retail market in which customers can choose their retail supplier and opt to lock in prices for their preferred time period. Retail providers can lock in prices on behalf of their customers for shorter or longer forward periods through some combination of futures market contracts, self-supply, or bilateral contracts with energy producers. In other words, there are already opportunities for retail suppliers and customers to hedge electricity prices; these hedging opportunities have assisted customers and their retail providers to mitigate price volatility through a wide range of prices and occasionally severe price spikes over Alberta's history as an energy-only market. The hedge would also be imposed on industrial customers whether or not they have a need for the hedge. For example, some of these loads are sophisticated and are already managing their electricity costs through operational flexibility. The cost of the forced hedge would introduce an unnecessary cost to customers' overall energy price.
- **Increased Supplier Risk:** While the ex post approach introduces a hedge for capacity sellers, the nature of this hedge is not well aligned with the business needs of most capacity sellers. For a seller with perfect resource performance and a technology with

58 MSA Report, PDF 64-65.

59 Suncor Rebuttal, PDF 2.

60 IPCAA/ADC/FTI Consulting Rebuttal, PDF 11-13.

variable dispatch costs close to the strike price, the hedge could in fact be close to the expected value of the clawback. Only in this "aligned" case, it transforms upside energy market risk into a more stable revenue source (realized as a higher capacity market clearing price).[61] However, if such a seller has materially different resource performance risk or variable dispatch costs compared to the proxy plant, then the ex post approach transforms upside energy market risk into downside risks that are much less desirable from a cash flow perspective. For resources such as demand response, peaking gas plants with higher dispatch costs, storage assets, and imports with high or variable costs, the clawback poses challenging risk implications. These resources would face much larger downside risks from the ex post approach by being forced to "refund" energy payments they have never received, since the clawback will not be aligned with any offsetting energy market net revenues.

- **Market Power Mitigation:** We agree that the ex post approach would moderate incentives to exercise market power in the energy market, because the higher net revenues achieved by infra-marginal suppliers would be partly clawed back by the ex post offset mechanism. Thus there would be fewer gains from economic or physical withholding (though sellers would still have the incentive to withhold to cause prices to reach as high as the strike price). However, this ex post mechanism is not the only nor the best way to address the potential exercise of market power. We recommend market power mitigation to be dealt with more directly and more effectively via the energy market mitigation rules that have been proposed by the AESO.

Thus, we do not view any of the purported benefits of the ex post E&AS mechanism as being compelling in the Alberta context. Further, we have identified several disadvantages that would be introduced by such a mechanism:

- **Fundamental Change to the Capacity Product**: A move to the ex post mechanism would result in the procurement of a combination capacity product (as the current design establishes) combined with a mandatory peak energy option contract. This additional contract changes the nature of the capacity product and the full capacity market that would be designed to procure such a product. The addition of the peaking energy contract will introduce higher capacity procurement costs sufficient to cover the expected value of the clawback, plus an additional risk premium that that capacity sellers will need to recover. The effect could be to require customers to pay more to cover the cost and risk for a hedge that they likely do not value.
- **Higher Capacity Market Offer Prices and Customer Costs**: An ex post approach would cause all capacity sellers to increase their offer prices by at least the size of the expected E&AS clawback. In the best case scenario, customers would be equally well off with the ex post approach (if sellers are all entirely risk neutral and increase their offer prices only up to the expected value of the E&AS clawback). However, it is more likely that

[61] AESO Appendix J, PDF 32.

customers will be worse off under the ex post approach because many capacity sellers will increase their capacity offer prices by more than the expected value of the E&AS clawback (in order to cover a premium associated with risk aversion and the misalignment of the strike price with their technology's variable costs or operational performance).

- **Discrimination of Resources and Associated Increase in Societal Costs**: An ex post approach would offer a hedge that is relatively aligned with the characteristics of plants whose variable costs are at or below the strike price (because the size of the clawback would be likely to align with and offset their net energy market revenues). However, the same hedge would impose excess and disproportionately large risks on any resources whose variable costs exceed the strike price (because they face a possibility of large clawbacks that would not be offset by energy market revenues). Thus higher-variable-cost resources including demand response, imports, peaking gas, and storage would face disproportionately large risks in order to sell the peak energy option contract. Under an ex post approach, these resources may need to offer at disproportionately higher prices (or may not offer at all) compared to other resources that are not as adversely affected by the ex post mechanism. This would change the merit order and resource selection of the capacity market, which would increase total societal costs.

As the ENMAX/Sotkiewicz Report and Rebuttal discussed, the proposed ex post E&AS mechanism is similar to the Peak Energy Rent (PER) adjustment in ISO-NE. The PER adjustment was intended to act as a hedge for load against price volatility in the energy market and to help mitigate market power (not as an alternative to estimating an E&AS offset). In 2015, ISO-NE filed revisions to remove PER provisions starting in the 2019/20 delivery year, stating that "retaining the mechanism could result in higher capacity market costs without producing any substantial benefits."[62] The reasons for removing the PER mechanism were similar to the concerns that we have outlined here.

While we agree with the Suncor Rebuttal that there are different variations of the ex post approach that could be considered, we disagree with the characterization that other interveners have misunderstood the design. All of the discussed variations involve two bundled products (capacity plus a peak energy hedge), with the variations depending primarily on the strike price above which the peak energy hedge would settle.[63] The determination of the strike price is important because it determines how much of customers' energy price is forced to be hedged

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62 ISO-NE, *ISO New England Inc. and New England Power Pool, PER Mechanism Changes*, March 2015. See FERC's approval in 151 FERC ¶ 61,096 (May 5, 2015).

63 See, for example, Crampton Report, PDF 4. "In the ex post approach, energy rents above a strike price are returned to consumers. Thus, the capacity product consists of two components: (1) the physical capability to supply energy during tight hours, and (2) a price hedge for prices above a high strike price."

along with the procurement of capacity.[64] The version that the Suncor Rebuttal described would have a low strike price based on the heatrate of a hypothetical peaking unit (12 GJ/MWh plus $10/MWh).[65] This would translate to about $34/MWh at current gas prices.[66] In contrast, ISO-NE's PER mechanism is a variation on the same concept with a higher strike price based on a high-cost proxy plant with a heatrate of 22,000 Btu/kWh (about 23 GJ/MWh), which roughly translates to a $260/MWh strike price (the design was based on the higher of gas or oil price).[67] We view these two designs as different points on a continuum of options (rather than entirely distinct designs as the Suncor Rebuttal suggests). The lower the strike price drops, the more substantial we anticipate the efficiency and cost challenges would become, because: (1) more resources would have a greater share of their expected revenues embedded together within the bundled capacity plus peak energy product sales; (2) lower strike prices would introduce more risks on higher-heatrate plants and demand response resources, introducing risks and exacerbating the resource discrimination problems; and (3) customers would be required to pay increasingly higher prices for the peaking energy hedge.

The Suncor Rebuttal also claimed that market participants face a similar or greater market risk under the ex ante approach than the ex post, and attempted to illustrate this point using an example that applies to gas plants with different heatrates. There are several problems with their analysis. First, the Suncor Rebuttal has not discussed or addressed the particular problems facing high heatrate plants that have acute downside risk under the ex post approach, and the concern that this excess risk may impose discriminatory excess costs on a subset of resource types. Second, while we agree that a subset of resources may face less revenue uncertainty with an ex post offset under special circumstances (e.g., plants similar to the reference resource, plants with very low variable costs, plants whose performance is guaranteed during high price events). However, these circumstances do not apply for the majority of the fleet. Thus, the Suncor Rebuttal's analysis applies primarily to a subset of resources, consisting of generating plants with the same fuel type and dispatch characteristics as the reference resource. Their analysis does not apply to lower-cost resources that may face the risk of becoming higher cost in the merit order (due to fuel price changes, or carbon price changes), nor does it apply to other resource types such as imports, storage, or demand response. Finally, the analysis seems to imply that the combined risks faced by customers and resources are somehow reduced by the peak energy price hedge. However, fundamentals-driven risks such as those represented in the energy market

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64 In the extreme case of a $0 strike price, customers would be forced to hedge the procurement of the full energy bill as part of capacity procurement. On the other extreme, in the case of a $1,000 strike price, none of the peak energy prices would be hedged and the design would revert to the AESO's proposal with no ex post offset.

65 We note that this was an example given by the AUC.

66 Gas prices in Alberta in March were around $2/GJ. See Gas Alberta Inc., *Alberta Natural gas Prices – Current Month*, accessed April 2019.

67 US$200/MWh, converted using a 1.3 exchange rate to convert USD to CAD. See ISO-NE, *Forward Capacity Market (FCM) Peak Energy Rent (PER)*, accessed April 2019.

cannot be eliminated by imposing a forced hedge (although they can be shifted to different parties). The overall result of this mechanism may be to slightly de-risk some resource types, but would also impose more risks on other resource types. Customers would bear less variability in total cost, but the improvement in revenue stability provided to a few specific resource types would come at a higher total cost to customers and other resources.

Overall, we view the ex ante approach to accounting for E&AS revenues as a better approach than an ex post E&AS clawback approach in Alberta's capacity market. The ex post mechanism would have the effect of forcing generators and customers into a hedging agreement that is misaligned with their private needs, increasing customer and societal costs, and not directly addressing any clear design requirement.