January 26, 2018

Dear Stakeholders:

Re: **Comprehensive Market Design First Draft**

In January 2017, the Government of Alberta directed the AESO to design and implement a capacity market in Alberta. The first capacity market auction is to commence in 2019 with first delivery of capacity to occur in 2021. To assist with the delivery of this mandate, the AESO is leveraging the collective expertise of Alberta's electricity sector participants and stakeholders.

During the course of 2017, the AESO engaged both working groups and the broader stakeholder community at multiple stages to advance the technical elements of the capacity market design. Three iterations of a Straw Alberta Market proposal document (SAM 1.0, 2.0 and 3.0), which reflected the AESO's analysis and the recommendations of the working groups, were developed and posted for stakeholder comment.

To initiate the next stage in the advancement of the capacity market design, the AESO is posting its first draft of the proposed Comprehensive Market Design (CMD 1). CMD 1 sets out the AESO's proposed framework of the technical design of the capacity market, as informed by SAM 3.0 recommendations, stakeholder feedback, third party expert advice and internal AESO analysis. Given certain legislative changes required to enable the development and implementation of the capacity market have not yet been enacted, CMD 1 is premised on the assumptions that the preliminary technical design work can continue to proceed and that the authority, roles and responsibilities of Alberta's electricity-related agencies will ultimately be specified in legislation. Such legislation could necessitate the modification of some market design elements discussed in this draft of the CMD.

Concurrently with CMD 1, the AESO is posting an accompanying rationale, which contains the AESO's support and other considerations for design proposals made in CMD 1. Both CMD 1 and the accompanying rationale, while posted as separate documents that each contain a number of discrete sections, are intended to be read holistically, and together. In addition, as part of its design activities the AESO modelled the Comprehensive Market Design to simulate capacity and energy market conditions under forecast scenarios to review various potential market conditions and determine the revenue sufficiency of select generating assets under those conditions. This analysis is presented in the report titled Summary of Integrated Capacity and Energy Revenue Modelling accompanying the CMD 1 and rationale documents. This collective set of documentation will facilitate discussions amongst three new streams of working groups scheduled to begin meeting in early February.

The CMD proposal and the accompanying rationale document will evolve over the coming months. The AESO will develop two drafts of the CMD, CMD 1 and CMD 2, before releasing a third draft, CMD 3, on April 24, 2018 for broad industry review and feedback. In February and March, CMD 1 and CMD 2 will be reviewed with working groups, and working group members will have the opportunity to provide feedback via this process. The AESO's objective for CMD 1 and CMD 2 is to leverage the working groups to ensure that CMD 3 will be sufficiently developed to allow for meaningful review and feedback by industry stakeholders in April. Stakeholders who wish to provide comments on CMD 1 or the accompanying documents before the formal comment period on CMD 3 (April 24 – May 11) can submit them to capacitymarket@aeso.ca.

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Any comments should be provided by February 22, 2018 to ensure they can be considered for CMD 2, which will be released on March 15, 2018. Please note that comments received will be considered but not formally responded to. Please click here for the AESO CMD engagement schedule. The technical design of the capacity market is currently scheduled to be completed by June 30, 2018 with the issuance of a final CMD. Subsequent engagement on the final CMD is currently scheduled to be completed by July 25, 2018. Stakeholder feedback received during this period will inform the next phase of capacity market implementation which is the formalization of the CMD into authoritative documents.

Sincerely,

Kevin Dawson

Director, Market Design

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Proposal Document

Section 1: Overview of the Alberta Capacity Market

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

Public

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1 Overview of the Alberta Capacity Market

1.1 Introduction

In January 2017, the Government of Alberta directed the AESO to design and implement a capacity market in Alberta.[1] The Alberta capacity market will be a mechanism to achieve resource adequacy and meet a government-defined resource adequacy standard at least cost by enabling broad competition among capacity resources. The capacity market will work efficiently and effectively with the energy and ancillary services markets and will be consistent with the lower-carbon electricity system of the future. The first capacity market auction is to commence in 2019 with first delivery of capacity to occur in 2021.

1.2 Summary of Design Process

During the course of 2017, the AESO engaged both working groups and the broader stakeholder community at multiple stages to advance the technical elements of the capacity market design. Three iterations of a Straw Alberta Market proposal document (SAM 1.0, 2.0 and 3.0), which reflected the AESO's analysis and the recommendations of the working groups, were developed and posted for stakeholder comment.

To initiate the next stage in the advancement of the capacity market design, the AESO is posting its first draft of the proposed Comprehensive Market Design (CMD 1). CMD 1 sets out the framework of the technical design of the capacity market, as informed by SAM 3.0 recommendations, stakeholder feedback, third party expert advice and internal AESO analysis. Given certain legislative changes required to enable the development and implementation of the capacity market have not yet been enacted, CMD 1 is premised on the assumptions that the preliminary technical design work can continue to proceed and that the authority, roles and responsibilities of Alberta's electricity-related agencies will ultimately be specified in legislation. Such legislation could necessitate the modification of some market design elements discussed in this draft of the CMD.

Concurrently with CMD 1, the AESO is posting an accompanying rationale document, which contains the AESO's support and other considerations for positions taken in CMD 1. Both CMD 1 and the accompanying rationale document, while posted as separate documents that each contain a number of discrete sections, are intended to be read holistically, and together. In addition, as part of its design activities the AESO modelled the Comprehensive Market Design to simulate capacity and energy market conditions under forecast scenarios to review various potential market conditions and determine the revenue sufficiency of select generating assets under those conditions. This analysis is presented in the report titled *Summary of Integrated Capacity and Energy Revenue Modelling* accompanying the CMD 1 proposal and rationale documents.

It is expected that both the CMD proposal and the accompanying rationale document will evolve over the coming months. Feedback from working group members as well as the broader stakeholder community will be invited at various stages throughout the first and second quarters of 2018. The technical design of the capacity market is currently scheduled to be finalized by June 30, 2018 with the issuance of a final draft of the CMD.

1.3 CMD 1 Proposal

The CMD 1 proposal is colour coded in red and black text to focus discussions with the working groups over the coming months. **Red text** indicates design areas where further AESO analysis and/or stakeholder engagement is expected in order to advance refinement of the technical design proposal. **Black text** indicates design areas where minimal to no further changes to the proposed technical design

[1] Government of Alberta Mandate Letter: https://www.aeso.ca/assets/Uploads/capacity-market-design-AESO-mandate-letter-Jan-10-2017.pdf

are expected at this time; however, areas of black text may still evolve based on ongoing stakeholder consultation and analysis. The CMD 1 proposal as a whole is expected to evolve based on ongoing AESO analysis and continued engagement with stakeholders.

1.4 Overview of Proposed Design

Category	High-level Design Choices
Supply Participation	• Resource-neutral participation of all resource types with demand response only participating on the supply side of the capacity market. Energy efficiency will not be eligible for the initial auction. Resources which do not have the ability to deliver through the entire delivery period will not be eligible. • Prequalification and qualification requirements will be resource specific, ensure feasibility of physical delivery, and reasonably accommodate different resource types. All existing generating assets greater than 5 MW maximum capacity will be prequalified for the capacity market auction. • UCAP determination will be unit specific for existing resources. • An availability factor based calculation will be utilized for thermal resources and large hydro. • A capacity factor based calculation will be utilized for all other resources excluding external resources (interties). • Unforced capacity (UCAP) for most resources will be determined by measuring the availability factor, capacity factor or intertie schedule during the 100 hours per year of smallest supply cushion for each of the previous five years. The UCAP for variable generators will use the same number of hours as will be used for thermal generation resources. • New units will utilize class averages utilizing the same methodology to determine class average UCAP as per above. New variable resources will use class average by geography. • External resources will use the minimum of firm transmission, the Alberta scheduling limit, or the observed historical scheduled energy flow during defined tight supply cushion hours.

Calculation of Capacity Market Demand Curve Parameters	• AESO will forecast demand based on gross Alberta load.
	• The target capacity volume will be set to meet the resource adequacy standard.
	• Forward-looking probabilistic resource adequacy modelling will be used to determine target capacity volume based on the resource adequacy standard. Target volume will be adjusted to account for self-supplied volumes, non-qualified import volumes, and ineligible resources (including successful Renewable Electricity Program (REP) Round 1 projects). Reference technology will be simple-cycle. The reference technology will be limited to a plant capacity of approximately 150 MW or less.
	• A comprehensive gross-CONE estimate will be completed by an independent consultant once every three to five years.
	• Energy and Ancillary Services (EAS) revenue offset for the reference technology will be determined via a forecast methodology.
	• Demand-curve parameters will be set to create a downward-sloping, convex demand curve with:
	  - The price cap at the maximum of 1.75 x net-CONE or 0.5 x gross-CONE;
	  - the minimum quantity will be set at a value of capacity commensurate with 800 MWh of Expected Unserved Energy (EUE) in one year;
	  - Price at the target capacity level is 1.5 x net-CONE;
	  - The inflection point is set at 0.875 x net-CONE;
	  - The foot is 13 per cent above the target capacity volume and at a price of zero.
	• Prior to each auction a defined process to update gross-CONE and net-CONE for changing cost parameters and EAS revenue offset will be applied to recalculate net-CONE.

Forward Capacity Auction	• Three-year forward period. • One-year delivery period, running November-October. • No option for seasonal capacity commitments (annual obligations only). • REP resources will continue to be ineligible as long as payment mechanisms stay the same. No other adjustments for out-of-market payments will be made.

Category	High-level Design Choices
	• Uniform price, sealed bid, single round auction. • Alberta will clear as a single capacity region with one capacity price. • The capacity market auction clearing mechanism will maximize social surplus and minimize deadweight loss. • Import offers and any transmission-constrained offers exceeding transmission delivery limits will be rationed based on offered capacity price in supply curve, then by the offer maximizing social surplus, then by pro rata allocation. Cleared resources will receive market clearing price determined by highest price offer accepted.
Rebalancing Auctions	• Two rebalancing auctions will be held and completed at 18, and 3 months before the delivery period. • Suppliers may offer buy-out bids and incremental sell offers into the rebalancing auction. • The rebalancing auction may clear with a net purchase or sale from the AESO, consistent with an updated administrative demand curve. • Demand curve shape will stay the same in the rebalancing auction.
Physical Bilateral Transactions and Self Supply	• Physical bilateral capacity procurement of capacity is not permitted; however, a site may choose to self-supply capacity provided the load is capable of being served in whole or in part by generation that is located on the same site, and at the same point of interconnection to the electric system (includes industrial system designations (ISD and DAT). • Sites with onsite generation that cannot physically flow their gross volumes due to system connection limitations must self-supply. • Self-suppliers can be connected to either the transmission system or the distribution system. • The City of Medicine Hat will be treated as a self-supplied load within the capacity market. • Self-suppliers who intend to change from participating on a net basis to a gross basis or from a gross basis to a net basis must declare their intention. Changes will only be allowed every three years.
Monitoring and Mitigation	• A must-offer requirement will apply to all suppliers except for: - New resources which have not achieved commercial operation or cleared a previous auction. - Demand response and external resources which have not prequalified and cleared a previous auction. • Resources wishing to retire, mothball, or derate capacity will need to apply for a must-offer exemption prior to the auction. The request will be reviewed and approved if net going-forward costs are demonstrated to be above the capacity auction price cap or if the resource cannot clear the capacity auction at its net going-forward costs. • Sellers with a portfolio UCAP of 15 per cent or greater of target capacity volume will be subjected to a capacity market offer cap of 0.5 x net-CONE on all existing assets. Assets may be allowed to offer at higher prices subject to demonstrating higher net going-forward costs, and offering at cost up to the overall market cap. • There will be no minimum offer price requirements for capacity resource suppliers due to net-short capacity positions or out-of-market payments.
Supply Obligations and Performance Assessments	• Capacity resources will be required to deliver on obligations or face adjustments to payments. • Resources may be required to provide data necessary to calculate UCAP and assess performance. • New resources clearing the market will be required to meet development milestones tracked by the AESO. If failing to meet development milestones, new resources will be required to replace their capacity obligation through asset substitution arrangements or by buying back in the rebalancing auction up to the market price cap. • Within the obligation period there will be two assessments: - Availability Assessment: will be assessed annually relative to sold UCAP volume using actual energy production plus offered energy and ancillary services obligations. The assessment will be carried out over the 100 tightest hours of each delivery year. Failure to demonstrate dispatched or offered energy volume being equal to or greater than the obligation of the resource will result in a payment adjustment on a $/MW-yr basis at 40 per cent of the maximum of 1.3 multiplied by the actual capacity revenue of the supplier divided by 100, or 1.3 multiplied by the last

Category	High-level Design Choices
	rebalancing auction clearing price divided by 100. - Performance assessment: provider will be assessed relative to sold UCAP volume adjusted by a balancing ratio (energy and reserves produced by committed resources during a performance assessment period/total capacity purchased) using actual energy production, level of consumption and/or provision of reserves during all energy emergency alert event (EEA) levels. Payment adjustment will be calculated on a $/MWh basis at 60 per cent of the maximum of 1.3 multiplied by the actual capacity revenue of the supplier divided by an expectation of EEA hours at the demand curve cap, or 1.3 multiplied by the last rebalancing auction clearing price divided by an expectation of EEA hours at the demand curve cap. • During performance assessment conditions, over-performing resources with an existing capacity obligation will be eligible for over-performance payment adjustments. Resources without a capacity obligation will not receive any performance payments. Performance payment adjustments will be funded on a revenue neutral basis. • Inability to deliver due to derates, forced or planned outage conditions or force majeure will not exempt a resource from performance or availability requirements. Inability to deliver due to intra-Alberta transmission constraints will provide an exemption from performance and availability requirements. • Total combined payment adjustment assessments will not exceed the greater of 1.3 multiplied by the actual capacity revenue of the supplier, or 1.3 multiplied by the last rebalancing auction clearing price as applied to the seller's volume. Payment adjustments in one month will not exceed 300 per cent of any one month's revenue of the supplier. • The management of payment adjustment risk through asset substitution will be allowed on an *ex ante* basis up until the start of the energy market settlement interval.
Settlements and Credit Requirements	• Payments will not be made to providers prior to the start of the delivery period. • Consistent with the energy market, capacity market statements will be issued monthly. • Monthly capacity payment is equal to the capacity market price for the delivery year multiplied by the capacity obligation cleared in the base auction, minus the difference in cleared quantity between the rebalancing auctions, multiplied by relevant rebalancing price. • Costs of procuring capacity will be allocated to customers according to the approved capacity cost allocation methodology. • No net settlement instructions (NSI) for capacity will be enabled. • Resources looking to buy back in rebalancing auctions, as well as new capacity resources, will need to demonstrate sufficient credit. • Capacity obligation is the last obligation following the final rebalancing auction prior to the delivery year. This obligation must be actively tracked by the AESO.
Confirming Changes in the Energy and Ancillary Services Markets	**Status quo continues** • Current self-commitment rules will continue. • Current must-offer requirement will continue to apply to all generation resources – capacity or non-capacity (AC must be offered). • Non-committed load resources (demand response and price-responsive load) may offer or may continue to self-dispatch. • All generation participants (capacity-committed and otherwise) must submit information related to asset outages for the market, and AESO information based on current rules (no outage approval). • All offers can be between price cap and floor, unless mitigated as per below. • The current market structure for ancillary services will remain the same (subject to security constrained economic dispatch (SCED) evaluation as per below). • *Ex post* monitoring and mitigation of the market will continue. **Roadmap** • Over time, the AESO and stakeholders will implement a roadmap of reforms to enhance energy and ancillary services markets to meet growing system flexibility needs, and enable new technologies to

Category	High-level Design Choices
	compete. Further evaluation is required to specify timing for implementation of market changes. Dates and classification of changes (prior to first auction delivery (2021) or beyond) will be included in the next draft of the CMD.

Additional rule changes for capacity market delivery

- Offer control information must be submitted.
- Mothball rule adjusted to shorter one-year period (or eliminated for non-capacity resources).
- Minor changes to the supply adequacy or supply shortfall rules to include demand-capacity resources, and self-supplied demand.
- Capacity-committed load resources must offer similar to generation assets, and follow dispatch. Capacity-committed load resources can offer to be last-directed assets at price cap or part of EEA1 directives (subject to evaluation of tools and rules. Capacity-committed load resources that are "down-to" must offer at the cap (part of directives)).
- Intertie assets, imports and exports will be provided the option to submit offers in price quantity pairs upon request of a new asset, in which case they will be dispatched during the settlement period, and may set SMP.
- Capacity-committed imports must offer the capacity-committed volumes into the energy market.
- Capacity-committed load resources must follow a similar rule for outage information (no outage approval).
- The energy market will adopt an *ex ante* market power mitigation based on an hourly residual supplier index (RSI) structural screen will be set at RSI of 0.9.
- An hourly conduct test will be evaluated against a bid threshold at 3x marginal costs measured at variable cost. All resource offers from a supplier that fails the conduct test will be mitigated to the 3x marginal cost threshold by fuel type.
  - The bid threshold will be calculated at 3 x marginal cost defined as heat rate x fuel price + variable O&M + carbon cost.
  - For non-thermal resources, market participants will have the ability to submit opportunity cost for approval.
  - Calculation of marginal cost will likely be subject to a regulatory approval process.
- Offer cap will be kept at $999.99.

Rule changes for price fidelity/flexibility

- Dispatch will continue on a minute-by-minute basis from a merit order created by hourly submissions. An alternative SCED model will be evaluated against other options like a ramp product. The SCED model runs an algorithm, period ahead, constrained by balancing supply with demand and expected need for ramp. The forward SCED would run in advance sufficient to support a self-commitment decision. The SCED will run during the hour to also support five minute dispatch optimizing for these constraints.
- Some incremental energy market rule changes will be required to ensure efficient dispatch and price signals related to system ramp, including rules related to dispatch tolerance, ramp by block, and rules related to supply surplus.
- Fifteen minute settlement will be applied for pool assets, except hourly settlement will be applied for retail loads.
- Real-time or co-optimized ancillary services market for purchases of energy and ancillary services may be introduced (part of SCED evaluation).

Out-of-Scope Components for Energy and Ancillary Services Market Reforms

- These items may be reconsidered if proposed market rules are insufficient to address market evolution; however, they would be taken out of scope of current market roadmap discussions.
  - Increasing offer-cap above $999.99

Category	High-level Design Choices
	- Negative pricing - Shortage pricing (operating reserve demand curve-type pricing) - Locational marginal pricing (LMP) - Intertie dynamic scheduling - Security constrained unit commitment (SCUC) may be reconsidered due to high supply surplus events or issues of market power mitigation - Day-ahead market (DAM)

1.5 Auction Timeline

Figure 1
Steady State Timeline for Capacity Auction

In the transition to the capacity market, auctions will be conducted on a compressed forward period starting with a November 2019 auction for delivery in 2021/2022. Auctions will be held approximately every six months until the full three-year forward period is achieved with an auction in November 2020 for delivery year 2023/2024. During this transition period, rebalancing auctions will be held less frequently than under the standard auction timeline. See Sections 4 and 5 for additional detail.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Proposal Document

Section 2: Supply Participation

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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2 Supply Participation

The AESO will use a two-stage process to determine who can participate in auctions:

1. Prequalification Stage – the AESO will determine what resources are eligible to participate in auctions.
2. Qualification Stage – the process for determining the unforced capacity (UCAP) of resources that have been prequalified by the AESO.

2.1 Prequalification of Capacity Resources

This section defines the prequalification requirements for capacity resources to be eligible to participate in the capacity market for the first time. Once a capacity resource is deemed eligible it will continue to be eligible for future capacity market auctions until such time as the resource delists or the AESO has determined the resource to be ineligible.

2.1.1 General Prequalification Requirements for Capacity Resources

- New capacity resources will be required to submit a prequalification package to the AESO.
- Planned internal generation will have a planned commissioning date that is before the delivery period to be prequalified.
- All capacity resources that have an obligation in the delivery year prior to the delivery year for which the next base auction is being held will be prequalified to participate in that base auction and are deemed qualified capacity resources.
- The minimum size for a capacity resource will be one MW.
- All existing energy-only market generation resources over one MW (estimated UCAP) will be prequalified and deemed to be qualified capacity resources. Existing external resources (import) will be required to prequalify.
- REP Round 1 resources are not eligible, and will not be prequalified.
- All prequalification packages, including delisting, will be subject to review before approval.
- To prequalify a new capacity resource, the resource owner will be required to:
  - Become a pool participant, if not already.
  - Submit a complete prequalification package that includes the appropriate connection request(s).
  - Post full financial assurance to cover risk from the payment adjustment mechanism stemming from non-delivery , which may be refunded upon demonstrating delivery requirements have been met.
  - Agree to meet all project and technical requirements, including supervisory control and data acquisition (SCADA) requirements. All capacity resources will need to provide real-time visibility to the AESO System Controller.

2.1.2 Submission and Approval of the Prequalification Package

- Upon receipt of a complete prequalification package, the AESO will review and assess the submission within the timeline indicated. If the prequalification package is completed to the satisfaction of the AESO, the AESO will prequalify the resource.
- If the prequalification package does not meet the AESO's defined requirements, the AESO may request additional information or reject the prequalification package at the AESO's discretion.
- The AESO will notify all applicants of the results of the prequalification package review.
- The AESO shall have the right to verify and audit all technical, financial, and operational data. The AESO shall have the right to visit the resource site(s) to ensure that there is no project amendment that has not been consented to as required in this section.

2.1.3 AESO Requirements for Prequalification

Before the start of the prequalification window, the AESO will publish guidelines for the capacity auction (auction guidelines). The auction guidelines will contain:

- The provisional date the capacity auction is to start.
- Details of how to apply to prequalify in the capacity auction.
- The timetable for submission and determination of applications which must, in particular, include the closing date for submission of applications.
- Such other information as may be required.

2.1.4 External Capacity Resources Prequalification

External capacity resources are capacity resources located outside of Alberta.

- External capacity resources may prequalify as Alberta capacity resources.
- Export will not be considered a valid demand side capacity resource.
- External capacity resources will be required to:
    - Demonstrate firm transmission service from the external capacity resource to the border of Alberta.
    - Demonstrate that firm transmission service has been obtained to deliver at least the UCAP amount of the capacity resource seeking to be qualified on the transmission system from the external capacity resource(s).
    - Demonstrate that any external capacity resources or portions thereof being registered as Alberta capacity resources are not used as non-recallable capacity resources in any other resource adequacy program.
    - Demonstrate that the source as defined in the transmission service request (TSR) must be a qualified external capacity resource.
    - Be available in the event of an emergency.
    - Be able to produce and report generation data as required by the AESO.

2.1.5 Demand Response Resource Prequalification

Demand Response (DR) is a demand-capacity resource, individually or in aggregate, that can respond to a dispatch issued by the AESO System Controller to reduce metered load – either manually by the customer, or automatically in response to a communication signal.

- DR resources must be retail or self-retail assets belonging to a valid pool participant.
- In addition to general prequalification requirements, a DR project prequalification package will be required to include:
    - A description of the data acquisition procedure, and the analytical methodology that will be used by the DR resource to determine the delivery of demand response curtailment by the DR project, who the likely contributors are, and how they will be procured.
    - A description of how the DR curtailment will reduce demand
- Demand response aggregators will be required to maintain records for all contributors as well as activation notices sent to their contributors specifying the start time, stop times, and dates of DR activations, in addition to a record of contributors demonstrating the eligible portion of the DR resource that the contributor is providing to the demand response aggregator.
- Pre-delivery period commissioning is needed to ensure that a DR resource will be able to deliver capacity when needed by the AESO. Tests must be included as a project milestone once the resource has been developed to prove the new DR resource is functional, allowing the credit requirement for non-delivery to be returned, and the DR resource to receive a capacity payment. The test will check the control systems and processes for dispatch, and also check that a

relationship exists between the provider and the contributing resource that will result in reduced load for at least four continuous hours.

2.1.6 Energy Efficiency Resource Prequalification

- An energy efficiency resource is a capacity resource that achieves a permanent, continuous reduction in electric energy consumption at the end-use customer's site that is not reflected in the peak load forecast used for the auction delivery year.
- Energy efficiency resources will not be eligible in the initial implementation of the market.

2.1.7 Variable Energy Resources Prequalification

- New variable energy resources will be eligible to provide capacity up to their UCAP as long as the resource does not receive indexed renewable energy credit (REC) payments for its committed capacity in a manner similar to the payment mechanism in REP Round 1.

2.1.8 Storage Resources Prequalification

- Storage resources may prequalify as capacity resources provided that the estimated UCAP exceeds the minimum size requirement of one MW and the storage resource can maintain its energy production at the proposed UCAP level for at least four hours.

2.1.9 Aggregate Capacity Resource Prequalification

- Aggregate capacity resources are resources that choose to combine individual resources through multiple locations into a single pool asset to either improve the stability of their UCAP or meet the minimum UCAP size requirement.
- Aggregate capacity resources will be eligible provided that each individual resource of the aggregation is:
  - Able to meet the requirements for an eligible capacity resource, and the aggregate UCAP of the resource is equal to or greater than the minimum UCAP size, or;
  - Have appropriate metering; and,
  - Be located in the same settlement zone.
- Disaggregation of a qualified aggregate capacity resource will require an amended prequalification package be submitted and be subject to prequalification review.
- Aggregation beyond a single enterprise is not permitted unless clear ownership share percentage can be specified for billing purposes.
- A prequalification package for aggregate resources must itemize the individual contributing capacity resources, if available, and demonstrate that the estimated sum of the contributing capacity resource's UCAP is greater than or equal to the minimum UCAP size requirement. Aggregation for the purposes of dealing with seasonality will require the pool participant to demonstrate that aggregate estimated UCAP is greater than or equal to the minimum UCAP size requirement of one MW over the entire term.
- The individual contributing capacity resources of the aggregation must have appropriate metering.

2.1.10 Self-supply Prequalification

Self-supply is load that is served by generation that:

- Is located on the same site at the same point of interconnection to the electric system. Does not include arrangements where loads are served by generation that requires delivery through the transmission system or distribution system, and are not located at the same point of interconnection, except for:
  - Sites with Industrial Systems Designation.
  - Sites under a Duplication Avoidance Tariff.

- The City of Medicine Hat.

- Sites with onsite generation that are net-metered and cannot physically flow their gross volumes due to system connection limitations will be required to self-supply.
- The self-supply site will be required to have a bi-directional net-interval meter at the connection to the system.
- An owner of a capacity resource choosing to self-supply for the first time or change its self-supply status will be required to submit a self-supply designation request before the self-supply deadline for the base auction. Self-supply designations will remain in effect for at least three years.
- The load resource in the self-supply arrangement may offer demand response based on its net load only. The self-supply site cannot be both demand response and supply capacity resource in the same delivery year. The type of capacity resource will be determined as part of the prequalification process.
- The City of Medicine Hat will be considered self-supply.

2.1.11 Existing Capacity Resources

- Existing qualified capacity resources that have been prequalified by the AESO for previous auctions will be presumed to have met the prequalification requirements for future auctions unless the market participant:
    - No longer maintains pool participant status.
    - Has a resource flagged for a significant decrease in capacity, and submits a restoration plan by the existing capacity delist deadline.
    - Submits a request to remove capacity via a retirement or mothballing delist bid by the existing capacity delist deadline.
    - Has modified the composition of the separate contributing capacity resources defined within the aggregate capacity asset subject to the details outlined in Section 2.2—*Calculation of Unforced Capacity (UCAP) Ratings*.
    - Submits a change to their self-supply designation by the self-supply deadline.
    - No longer holds firm transmission for the delivery year as an external capacity resource.

2.2 Qualification for All Resources

- When a capacity resource has passed the qualification stage in respect of an auction, the qualified capacity resource will be eligible to participate in such auction and will receive a UCAP value for such auction.
- The above qualification process will take place prior to each capacity auction.

2.2.1 General Qualification Requirements for Prequalified Capacity Resources

- In order to qualify, the capacity resource will be required to:
    - Be prequalified for this or qualified for a prior capacity auction.
    - Be a pool asset.
    - Be capable of meeting the availability and performance requirements set out in Section 8—*Supply Obligations and Performance Assessments.*
    - Maintain a UCAP equal to or greater than 1 MW.

2.2.2 AESO Requirements for Qualification

- The AESO will be required to develop:
    - Details of the qualification process, and procedures.
    - The timetable for submission of data requirements, which must in particular include the closing date for submission of data requirements.
    - A UCAP review process.
    - Locational constraints that may impact capacity resource obligations.

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2.3 Calculation of Unforced Capacity (UCAP) Ratings

In a capacity auction, a UCAP rating represents the amount of capacity that a capacity resource can be expected to provide, on average, during tight supply and demand conditions. The UCAP amount will be the volume of capacity an eligible resource will be able to offer into the capacity market. The reliability value of one MW of UCAP is meant to be equivalent across different resource types.

Due to the different operating characteristics of variable and dispatchable capacity resources, two approaches will be used to determine capacity resource UCAP. The AESO will use a capacity factor approach for variable capacity resources. This approach will review the actual output of the variable resource during historical periods of tight supply cushion. The AESO will use an availability factor approach for dispatchable capacity resources. This approach will review the dispatched plus the offered energy and operating reserves during historical periods of tight supply cushion.

An annual UCAP is being determined to align with the annual capacity product the AESO is procuring. The table below describes the approach that will be used for each resource type

Resource Type	Resource Volume UCAP Methodology
Existing Wind/Solar/ Run-of-River Hydro	• A capacity factor will be established for these resources. • The capacity factor is based on historical operating data. • The calculation of the capacity factor will use a single-year capacity factor for each of the prior five years. Single-year capacity factors are based upon average energy production observed during the 100 tightest supply cushion hours per year. • The single-year capacity factors for each of the previous five years will be averaged to create the final capacity factor for the capacity resource to be used in the auction. • The capacity factor, when multiplied by the maximum capability, will yield the UCAP of the resource. • Capacity factors will reflect historical derates, forced outages and planned outages and force majeure outages. • Capacity factors will exclude Alberta-driven transmission based outages or derates.
New Wind New Solar New Run-of-River Hydro and New Self-supply	• The UCAP of these new resources will be established using a combination of class-average capacity factors and the new resource's observed capacity factor. A combination of these two metrics will be used until the resource has achieved a five-year history of operations. • Class-average capacity factors shall be determined by the AESO based upon review of operating data for similarly operated or geographically located resources. In the absence of comparable units, the capacity factor may be determined using production estimates using engineering and or historical meteorological studies for resource. The class-average capacity factor will be based upon average energy production observed during the 100 tightest supply cushion hours per year. The AESO will calculate class-average capacity factors for each of the prior five years. • As operating history is realized, the new resource’s UCAP will be determined using the resource's single-year capacity factors. Single-year capacity factors are based upon average energy production observed during 100 tightest supply cushion hours per year. The single-year capacity factors will be supplemented with the class-average capacity factors in order to obtain five years average capacity. • The capacity factor, when multiplied by the maximum capability, yields the capacity value for the new capacity resource. This provides the UCAP of the resource. • Capacity factors will reflect historical derates, forced outages and planned outages and force majeure outages. They will exclude Alberta-driven transmission-based outages.

	• Self-supply resources will be required to indicate future load expectations to the AESO.
REP 1 Assets	Not eligible to participate in the capacity market.
External Resources	• The volume of capacity that may be delivered by an external resource may be limited by the volume of capacity the AESO allows to flow over an intertie. External resources will use the minimum of firm transmission to the Alberta interconnection allocated for the resource by the resource holder, the Alberta scheduling limit for that intertie, or the observed historical scheduled energy flow plus operating reserves during defined tight supply cushion hours. • UCAP determination for external resources will follow a two part process: 1. Determination of the capacity-value limit of the intertie: The capacity volume limit of an energy flows and operating reserve obligations as observed during the 100 tightest supply cushion hours per year over the previous five years. The capacity value limit of an intertie will be determined without adjustment for: forced and planned derates, forced and planned outages or force majeure. The limit will reflect any intertie scheduling limitations. 2. Determination of the UCAP of the named external capacity resource: A UCAP value will be determined separately for an external capacity resource providing capacity into Alberta's over an intertie. An external capacity resource will have a capacity value determined in the same manner as an internal capacity resource. The AESO may require historical production data from external capacity resources in order to complete these calculations. The qualification of external capacity resources will be subject to Section 2.1.3.
Existing Thermal Resources **Gross Cogeneration Resources** **Existing Storage Resources**	• An availability factor will be established for these resources. • The availability factor will be based on historical declarations of availability capacity. • The calculation of an availability factor will use a single-year availability factor for each of the prior five years. Single-year availability factors are based upon average available capacity observed during the 100 tightest supply cushion hours per year. • The single-year availability factors for each of the previous five years will be averaged to create the final availability factor for the capacity resource to be used in the auction. • The availability factor, when multiplied by the resource's maximum capability, will yield the UCAP of the resource. • Availability factors will reflect historical derates, forced outages and planned outages and force majeure outages. • Availability factors will exclude Alberta driven transmission based outages or derates.
New Thermal resources/ Coal-to-Gas conversions/ New Gross Cogeneration	• The UCAP of these new resources will be established using a combination of class-average availability factors and the new resource's observed availability factor. A combination of these two metrics will be used until the resource has achieved a five year history of operations. • Class-average availability factors shall be determined by the AESO based upon review of operating data for similar operated resources. The class-average availability factor will be based upon average availability observed during the 100 tightest supply cushion hours per year for these similarly operated resources. The AESO will calculate class-average availability actors for each of the prior five years. • As operating history is realized, the new resource’s UCAP will be determined using the resource's single-year availability factors. Single-year availability factors are based upon average availability observed during 100 tightest supply cushion hours per year. The single-year availability factors will be supplemented with the class average

	availability factors in order to obtain five years average availability. • The availability factor, when multiplied by the maximum capability, yields the capacity value for the new resource. This provides the UCAP of the resource. • Availability factors will reflect historical derates, forced outages and planned outages and force majeure outages. They will exclude Alberta-driven transmission-based outages. • In the absence of comparable units, the availability factor may be determined using production estimates and engineering studies for resources.
Self-Supply (Existing)	• A capacity factor will be established for these resources. • The capacity factor will be based on observed net-historical generation data. • The calculation of a capacity factor will use a single-year capacity factor for each of the prior five years. Single-year availability factors are based upon average production plus dispatched, but not directed, operating reserves observed during the 100 tightest supply cushion hours per year. • The single-year availability factors for each of the previous five years will be averaged to create the final capacity factor for the capacity resource to be used in the auction. • The capacity factor, when multiplied by the maximum generation output observed over the previous five years, will yield the UCAP of the resource. • Capacity factors will reflect historical derates, forced outages and planned outages and force majeure outages. They will exclude Alberta-driven transmission-based outages or derates.
Large Hydro **The Bow River system, Brazeau and Big Horn**	• An availability factor will be established for these resources. The Availability Factor will be based on historical declarations of Availability Capacity. • The calculation of an availability factor will use a single-year availability factor for each of the prior five years. Single-year availability factors are based upon average available capacity observed during the 100 tightest supply cushion hours per year. • The single-year availability factors for each of the previous five years will be averaged to create the final availability factor for the capacity resource to be used in the auction. • The availability factor, when multiplied by the resource's maximum capability, will yield the UCAP of the resource. • Capacity factors will reflect historical derates, forced outages and planned outages and force majeure outages. They will exclude Alberta-driven transmission-based outages or derates.
New Large-hydro	• Given the uniqueness of new large-hydro capacity resources, the UCAP of these resources will be determined through the evaluation of engineering data and or meteorological data.
Capacity Demand Response	• There are two types of demand response for which UCAP will need to be determined: demand response which reduces consumption to a pre-established level, referred to as “down-to-demand response” and demand response which reduces consumption by a predetermined amount, referred to as “down-by-demand response.” 1. Down-to-demand response The AESO will calculate an Average Tight Supply Cushion Load (ATSCL) to establish the upper boundary of a "down-to" demand resource (DR) capacity resource based on the average consumption during the 100 tightest supply cushion hours in Alberta over the last one-year historical period.

	The Emergency Event Maximum Consumption Level (EEMCL) is the maximum demand level that the DR resource commits to consume during a capacity performance period. The difference between the ATSCL and EEMCL will then be multiplied by a load derating factor in order to establish a UCAP for the resource. The derating factor is analogous to the forced and outage derating applied to thermal units. The approach to determining the derating factor will be established during the detailed design process of the capacity market. 2. Down-by-demand response The AESO will calculate an average ATSCL to establish the upper boundary of a "down-by" DR capacity resource based on the average consumption of its load during the 100 tightest supply cushion hours in Alberta over the last one-year historical period. In prequalifying, the down-by resource owner will declare an amount of energy that the resource will reduce consumption by when required during performance events. This volume will be multiplied by a load derating factor in order to establish a UCAP for the resource. The derating factor is analogous to the forced and outage derating applied to thermal units. The approach to determining the derating factor will be established during the detailed design process of the capacity market.
Energy Efficiency	• Not eligible for the initial auction. The AESO will release a schedule to determine future participation requirements.
Storage Resources (New)	• An availability factor will be established for these resources. Given the uniqueness and lack of historical comparators for new storage resources in Alberta, the UCAP of these resources will be determined through the evaluation of engineering data. The UCAP of a storage resource will be capped at its maximum sustainable four-hour discharge capability.

2.4 Credit Requirements for Participation as a New Capacity Resource

To mitigate the risks associated with new entry, the AESO will impose capacity market credit requirements on new resources selling into forward capacity auctions and rebalancing auctions. The credit requirement consists of 15 per cent of annual net-CONE with a minimum value of $7.30/kW-year. Consistent with other existing forward capacity markets, the AESO will impose its credit requirement of 15 per cent of annual net-CONE for each delivery year. Under this framework, a resource clearing three forward auctions would incur a total credit requirement of 45 per cent of annual net-CONE before delivery begins. To reflect the diminishing risk of non-delivery for a new resource as it progresses through its development, the AESO will reduce the credit requirement in accordance with project development milestones such as commencement of construction, commercial operation date, etc.

Guidelines governing payment for the capacity market credit requirement for new resources will be consistent with the AESO's existing credit policy, which includes such things as limits on unsecured credit, and acceptable forms of secured credit for participants across the AESO's markets.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Proposal Document

Section 3: Calculation of Capacity Market Demand Parameters

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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3 Calculation of Capacity Market Demand Parameters

The demand parameters for capacity market auctions will be expressed through a capacity market demand curve. The calculation detail components of the demand curve are provided in this section.

3.1 Alberta Load Forecasts

- The AESO will develop a forecast of gross Alberta load which will be used to model resource adequacy and determine the quantity of capacity to procure in the capacity market.
- The load forecast will include multiple annual hourly (8,760) load profiles based on weather and economic uncertainty.
- The AESO may need to perform post-modelling adjustments to the load forecast.

3.2 Establishment of the Resource Adequacy Standard

- The Government of Alberta is expected to decide the resource adequacy standard.

3.3 Modelling to Estimate the Resource Adequacy Requirement

The AESO will use a Monte Carlo simulation to probabilistically model supply-and-demand uncertainty to determine the amount of capacity required to meet the defined resource adequacy standard. To do so, the AESO will complete the following steps.

Supply and Demand Factors

- The resource adequacy model will capture the relevant factors that impact overall supply and demand balance, including:
    - Load levels and variability
    - Variable generation outputs
    - Planned and forced outages, derates
    - Import behavior (capability, and availability)
    - Correlation of load
    - Generation at self-supply sites
    - Operating reserves
    - Demand response

Further details on resource availability modelling are provided below:

- *Thermal Generation* – The AESO will use historical available capability (AC) data, or more granular data made available through the UCAP calculation process, to inform the planned outage periods, forced outage rates and temperature derates for assets in the model.
- *Renewable Profiles* (wind, solar) – The AESO will model wind and solar using historical weather data to create synthetic future output profiles to account for geographical diversities and technological advancements, or use historical data if simulated data is unavailable.
- *Hydroelectric Generation* – The AESO will model hydro using historical values to develop dispatch schemes for hydro so that simulated dispatch of the hydro fleet closely mimics the actual dispatch of the fleet, taking into account the hydrological nature of a year, month, and system conditions.
- *Import Modelling* – The AESO will utilize market simulations with consideration for historical availability (based on tie-line availability), usage (to account for external jurisdictions' ability to provide supply), intertie restoration or other capability increases.

- *Transmission Constraints* – At this time, transmission constraints within Alberta will not be considered as a factor that will impact resource availability. The availability of the interconnections will be modelled.

Capacity Requirement from the Resource Adequacy Model

- The AESO will assess physical resource adequacy, considering expected availability of all resource types and variability in gross demand.
- The AESO will use the resource adequacy model output to:
    - Assess expected unserved energy.
    - Determine the target capacity volume required to meet the defined resource adequacy standard.
- The AESO may use the resource adequacy model output to assess the overall relationship between capacity and unserved energy to inform nuances of the demand curve shape.
- The AESO will add or remove generation from the resource adequacy model until the defined resource adequacy standard is met to determine the required generation capacity.
- The type and characteristics of the generation added will align with the reference technology.
- The required generation capacity that meets the resource adequacy standard will be translated to a system-wide UCAP through the same methodology used to calculate asset level UCAP.
- All existing and expected capacity will be included in the resource adequacy model irrespective of its eligibility and technology type. Any non-eligible capacity and self-supply will be accounted for when conducting the resource adequacy modelling.
- Once the required generation capacity is estimated, the AESO will reduce that volume by the qualified volume of self-supply and ineligible resources, and take into account unqualified import UCAP to determine the target procurement level for the capacity auction.

3.4 Calculation of Gross-Cost and Net-Cost of New Entry

Gross-cost of new entry (gross-CONE) and net-cost of new entry (net-CONE) estimates certain set market parameters, including inflection points on the capacity market demand curve and offer caps for mitigated capacity market offers.

Recommended Reference Technology

- The gross-CONE and net-CONE will be based on a reference technology.
- For the initial demand curve, the reference technology will be a simple-cycle technology limited to a plant capacity of 150 MW or less.
- The AESO will determine the exact type of simple-cycle technology will be through more detailed cost screening. Examples of the technologies that may be assessed in greater detail include, but will not be limited to:
    - Two LM6000PH aeroderivative gas turbines (110 MW)
    - One LMS100PB aeroderivative gas turbine (118 MW)
    - 7 Wartsila 18V50SG reciprocating internal combustion engines (130 MW)
    - One MS7001EA frame gas turbine (91 MW)
- For comparative purposes and for due diligence, the AESO will also assess a 400 MW to 500 MW combined-cycle technology unit.

Approach to Gross-CONE

- The AESO will contract with an independent consultant that has Alberta-specific experience in power plant development, engineering/construction, and finance to determine gross-CONE and net-CONE estimates.

- The AESO will work with the independent consultant to develop appropriate financing assumptions for the reference technology for use in the gross-CONE calculation.

- The consultant will provide a credible gross-CONE estimate, which properly reflects the appropriate financing, and plant development costs for the reference technology in Alberta:
    - Financing costs for the reference plant will be measured as an after-tax weighted average cost of capital (ATWACC).
    - The ATWACC will be composed of equity and debt rate components that are weighted according to a debt/equity split.
    - The ATWACC will be used to calculate the levelized annual return on, and return of capital associated with the reference technology. The levelized annual return will be added to the annual fixed operating and maintenance (O&M) costs for the reference facility to arrive at the annual gross-CONE value.

Frequency of Updated Gross-CONE estimates

- The AESO will to use its gross-CONE curve study for three to five years, indexing the gross-CONE estimates to changes in publicly available indices such as labour and materials costs.

Approach to Net-CONE and Energy and Ancillary Service Offset

- The net-CONE will be derived from the gross-CONE, less the energy and ancillary services offset.
- The AESO will use a forward-looking approach to energy and ancillary services revenues that will identify production and the resulting energy and ancillary services revenues for the reference technology.
- The net-CONE estimate will measure the capacity market based revenue required to ensure the new reference technology will recover a return on and of capital
- The net-CONE will have a minimum of zero.

3.5 Administrative Demand Curve

The demand curve parameters will be finalized prior to June 2018 once further information on the resource adequacy standard and outputs from the resource adequacy modelling are available. Until that information is available, the proposed curve is being carried forward as working assumptions.

Alberta's capacity market demand curve will be a downward-sloping, convex curve[1] consisting of three segments:

1. Horizontal section from zero quantity to minimum quantity

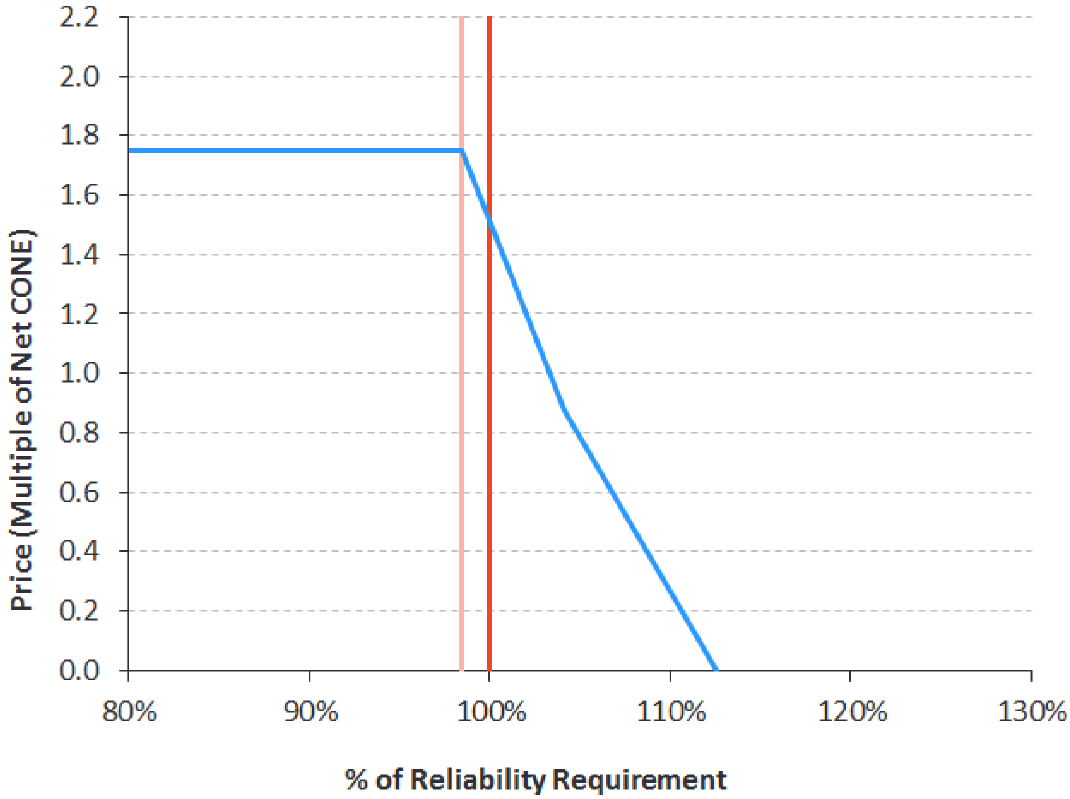
2. Downward-sloping section from minimum quantity to inflection point

3. Downward-sloping section from inflection point to the foot, at zero price

[1] Convexity reflects the diminishing value of capacity resources, as the curve extends beyond target resource adequacy levels and increasing value of capacity resources in times of scarcity.

- With the convexity, the slope on the minimum-to-inflection segment of the curve will be steeper than the slope of the inflection-to-foot segment.
- The Y-axis points for the demand curve will be set in reference to price $/kW-year ($/kW-yr).
- The price cap (zero quantity-to-minimum segment) will be set based on the maximum value of either a 1.75 net-CONE multiple or a 0.5 gross-CONE multiple.
- The foot will be set at a price of zero.
- The X-axis points for the demand curve will be set in reference to quantity of megawatts of capacity.
- The foot of the demand curve will be set at a level such that the resource adequacy target is expected to be met on average, and price outcomes can be expected to average at a net-CONE level while also balancing capacity price volatility and maintaining the desired convexity of the curve.
- The AESO's demand curve design is based on the assumptions in Figure 1 below:
- The minimum quantity point has will be set at a value of capacity commensurate with 800 MWh of expected unserved energy in one year, based on the outcome of a resource adequacy study (peach line in figure below).
- The target quantity has been set at the 400 MWh of Expected Unserved Energy (Orange line in figure below).
- The price at the minimum quantity is set at 1.75 x net-CONE.
- The inflection point is set at 0.875 x net-CONE, at a quantity four per cent above the target quantity.
- The foot is set at 13 per cent above the target quantity, at a price of zero.

Figure 1
Illustration of proposed demand curve parameters



Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Proposal Document

Section 4: Forward Capacity Auction

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

Public

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4 Forward Capacity Auction

To effectively allow for new entry, the AESO proposes to facilitate a forward-capacity auction. This section outlines the specific timeline, format and mechanics of this auction.

4.1 Auction Forward Period and Timeline

The AESO will conduct, and finalize results of the forward auction three years before the start of the obligation period. In the transition period when the market begins, the forward period will be less than three years to allow the market to take effect more rapidly. Procedures for these transitional auctions will take place on a compressed timeline. After the transition period is concluded, auction procedures will be conducted on a pre-determined schedule, allowing sufficient time for qualification, market monitoring actions, bidding, and auction clearing.

4.1.1 Transition into the Three-year Forward Period

The implementation of the proposed three-year forward period will occur over several auctions, as shown in Table 1. This transition will begin with the first auction process commencing in November 2019 for delivery in 2021/22 with a compressed, approximately two-year forward period. Two additional transitional auctions will be held at approximately six month intervals. An auction will be held in May of 2020 with an approximately two-and-a-half-year forward period. The November 2020 auction, for delivery year 2023/24, will be the first auction conducted with the full three-year forward period, though auction procedures for this auction will still be conducted on a compressed timeline.

Table 1
Timeline of forward capacity auction

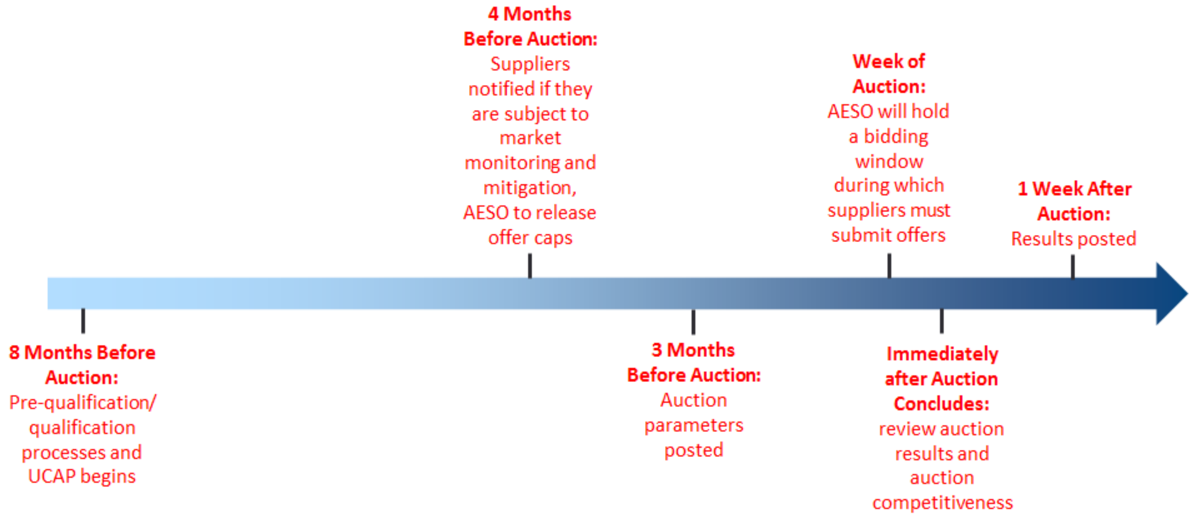
Auction Date	Obligation Period
Nov 2019	Nov-Oct 2021/22
May 2020	Nov-Oct 2022/23
Nov 2020	Nov-Oct 2023/24

4.1.2 Auction Timeline Post Transition

Once the transition period is complete, a predetermined timeline for each step of the auction process will be used. Figure 1 shows the major process steps required for each forward auction.[1] Resource qualification and the determination of UCAP requirements (discussed in Section 2) will be conducted well in advance of the auction to provide sufficient time for the receipt and review of market participant data. The rules with respect to the auction will be finalized prior to the commencement of the first auction. Pivotal suppliers will be notified of market mitigation implications (described in Section 7 – *Capacity Auction Monitoring and Mitigation*), and receive notice of the auction parameters (described in Section 3 – *Calculation of Capacity Market Demand Parameters*) prior to offer submission. The offering window, during which market participants can submit offers to sell capacity, will be one week long. Auction clearing will be followed by a review of auction results and the posting of results one week after the auction.

[1] These procedures will be elaborated on in future versions of the Consolidated Market Design and may include steps such as data submissions by market participants, review by AESO staff, etc.

Figure 1
Auction Timeline After Transition Period is Concluded



The obligation term will be one year for all resources. The annual obligation period will run from November 1 of each calendar year through October 31 of the following calendar year.

4.2 Supply Participation and Offer Format

Each resource must specify in its offer a number of characteristics that will be required in the clearing process. Examples of such characteristics include the following:

- The number of blocks in, up to a maximum number of seven blocks per offer.
- Whether a block is divisible or indivisible; Divisible blocks can be cleared mid-block at the required MW, whereas indivisible blocks can only clear at their total offered capacity volume.
- The price (in $/kW-year) for each block.
- The quantity (UCAP MW) pairing for each block.
- Offers will have a minimum at $0/kW-year and a maximum of the price cap established for the demand curve with exceptions for resources buying out of previous capacity obligations in rebalancing auctions (see Section 5).
- For offer quantities, the proposed minimum block size is 1 MW.

All qualified capacity resources must offer their entire qualified UCAP in each base auction.

4.3 Out-of-Market Capacity Payments

No adjustments will be made to capacity market offers from qualified resources for the purposes of correcting for out-of-market payments. Capacity market offers may be mitigated as per Section 7.

4.4 Single-Round Uniform Price Auction

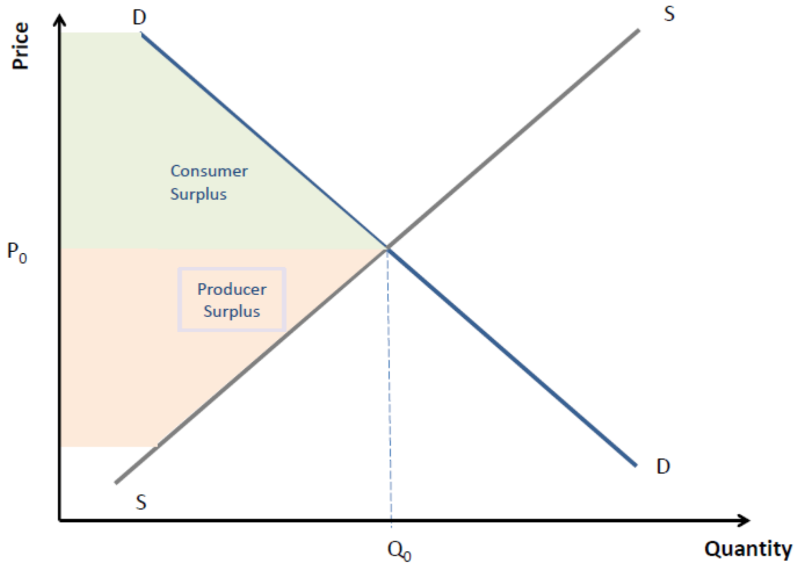
A sealed-bid, single-round, uniform pricing auction will be utilized for forward and rebalancing capacity auctions. A single capacity price will be established for all supply which clears the market.

4.5 Auction Clearing and Price-Setting

The AESO expects that the supply curves created in the capacity auction will not be smooth, but will be built up by a number of independent supply offers resulting in a supply curve with a number of discrete steps. This will create scenarios where the market cannot clear at the intersection of the supply and demand curves, possibly due to the demand curve intersecting the supply curve between offer blocks, the marginal offer being inflexible or possibly due to the supply curve being below the demand curve. This section describes the principles that will be used to clear the capacity market.

The capacity market auction clearing algorithm will seek to maximize social surplus and in so doing, minimize deadweight loss. Social surplus represents the total value, to buyers and sellers, of transacting in the market. It is represented by the area between the demand curve and the supply curve to the left of the cleared quantity (see **Figure 2)**. Social surplus has two components: producer surplus and consumer surplus. Producer surplus represents the difference between total market revenues from the sale of the product, and the total marginal costs of production. Consumer surplus represents the difference between a buyer's (in this case, the AESO's) willingness to pay for a product and the price of the product, summed over all units sold. When the market clears at the intersection of the supply and demand curves, the social surplus is maximized.

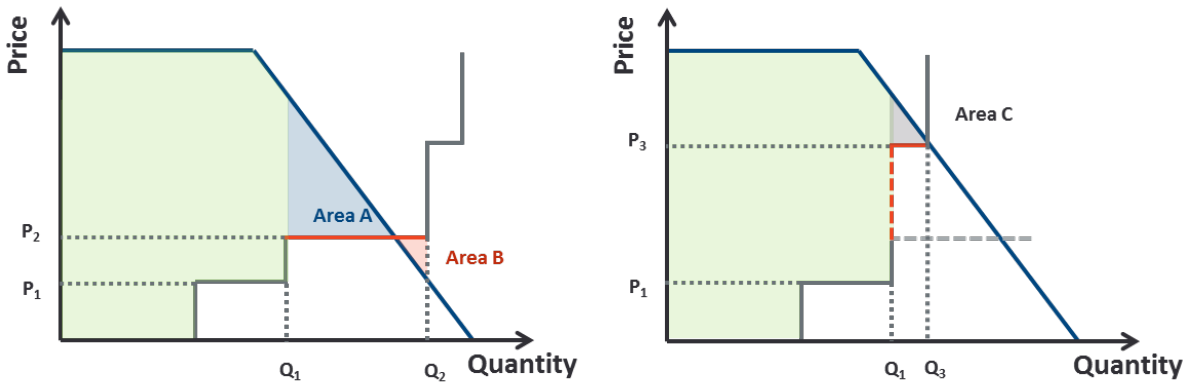
Figure 2: Consumer Surplus, Producer Surplus, and Social Surplus



In circumstances where the capacity market cannot clear at the intersection of the supply and demand curves due to the marginal capacity offer being an inflexible block, the market will then clear the marginal resource provided it maximizes social surplus. **Figure 3** illustrates two scenarios: (1) on the left: a scenario where the entire inflexible block is cleared; and (2) on the right: a scenario where the inflexible block is skipped and the offer above the inflexible offer is cleared on the right. The social surplus resulting from clearing at P_1 and Q_1 is the same in both figures, depicted as the light green region. In the figure on the left, the additional social surplus from clearing the inflexible block (clearing at P_2 and Q_2) is indicated by the blue region (area A) minus the red region (area B). In the figure on the right the additional social surplus from skipping the inflexible block and clearing the offer above the inflexible block (clearing at P_3 and Q_3) is indicated by the grey region (area C). In these illustrations, we see that the additional social surplus from clearing the inflexible block at P_2 and Q_2 (area A minus area B) is larger than the additional surplus if the inflexible block was skipped, and the next block was cleared at P_3 and Q_3 (area C). Therefore, selecting the entire inflexible block creates the greatest additional social surplus and would be cleared (auction clears at P_2 and Q_2). The market-clearing engine used by the AESO to clear the capacity market will use the same approach. Maximizing social surplus is also the approach used by the AESO in the energy market.

Figure 3: Illustration – Maximizing Social Surplus

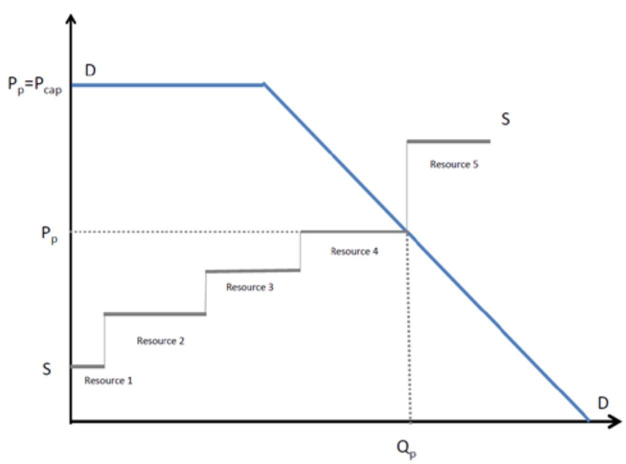
Inflexible Block *Inflexible Block Skipped*



Price-Setting When the Entire Capacity Supply Curve or the Portion of the Capacity Supply Curve Cleared in the Auction Lies below the Demand Curve

When clearing the auction to maximize social surplus, the auction clearing price is set at the intersection between the supply and the demand curves, P_p (**Figure 4)**.

Figure 4: Auction Cleaning Price Determination



However, it is possible that the entire capacity supply curve or the portion of the capacity supply curve cleared in the auction lies below the demand curve as shown in **Figure 5** and **Figure 6** respectively. In **Figure 5** and **Figure 6**, if the procurement volume is Q_p, the price value is not unique as the cost of the capacity at quantity Q_p (represented by the supply curve SS at P_s) and willingness to pay at quantity Q_p (represented by the demand curve DD at P_d) are not equal. In these situations, the AESO will set the capacity auction clearing price at the intersection between the vertical line drawn from the procured quantity Q_p and the demand curve, i.e., the P_d in the charts.

Figure 5: The Entire Supply Curve Lies Below the Demand Curve

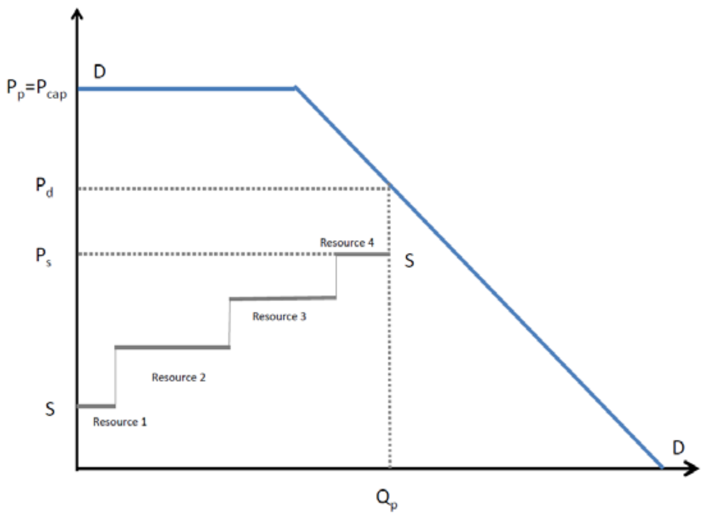
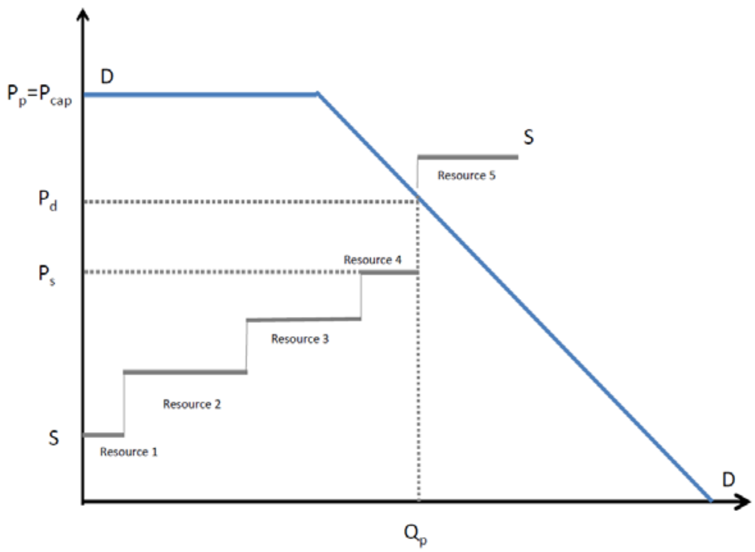


Figure 6: The Supply Curve of Selected Resources Lies Below the Demand Curve



4.6 Addressing Intertie Transmission Constraints

Alberta has limits on the amount of capacity that can participate through interties. Section 2.3 discusses how capacity values are determined for qualified external resources utilizing interties. Ahead of the auctions, the AESO will determine expected joint scheduling limits across interties. Should a constraint be identified which prevents the simultaneous delivery of external capacity resources across multiple interties, external resources will not have their individual UCAP ratings reduced, but rather will be cleared in the auction using the following method:

1. From lowest to highest capacity offer price.
2. For multiple resources at the constraint volume level, resources that maximize the social surplus in the auction will be cleared first. This will provide priority to offers that are divisible.
3. If there is still more capacity resource available than can be delivered after steps 1 and 2, the resources will be cleared via a prorata allocation of remaining expected transmission capability.
4. Volumes remaining after the transmission constraint level has been reached will be skipped over in remaining market clearing steps. All cleared resources will receive the overall market clearing price.

4.7 Addressing Internal Transmission Constraints

Prior to the auctions, the AESO will identify the location and impact of any intra-Alberta transmission constraints that are anticipated to impact the ability for capacity to be delivered during the relevant obligation delivery period.

Clearing of qualified capacity resources that are located behind an identified transmission constraint will be done based on qualified resource UCAP levels up until the level of the constraint. Resources will be cleared as follows:

1. From lowest to highest-capacity offer price.
2. For multiple resources at the constraint volume level, resources that maximize the social surplus in the auction will be cleared first. This will provide priority to offers that are divisible.
3. If there is still more capacity resource available than can be delivered after steps 1 and 2, the resources will be cleared via a pro rata allocation of remaining expected transmission capability.
4. Volumes remaining after the transmission constraint level has been reached will be skipped over in remaining market clearing steps. All cleared resources will receive the overall market clearing price

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Section 5: Rebalancing Auctions

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

Public

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5 Rebalancing Auctions

After the three-year forward base auction, the AESO will conduct two rebalancing auctions. The rebalancing auctions will allow the AESO to purchase additional capacity or release previously committed capacity in response to changes to the load forecast. They will also allow market participants the opportunity to either increase or reduce their capacity commitments closer to the delivery year. Many of the details and procedures for the rebalancing auctions are the same as for the forward auction, and are described in Section 4. This section focuses on key differences between the forward and rebalancing auctions.

The rebalancing auctions will be settled on a net basis, (i.e. settled only based on changes from the previous auction). Under this net settlement process[1], resources that do not submit offers or bids into a rebalancing auction will not have any settlements in that rebalancing auction. However, forward cleared resources that have a lower UCAP rating in the rebalancing auction, or are new resources and have not met development milestones, may be required to submit bids to buy in the rebalancing auction in order to cover their positions. Resources that clear in a rebalancing auction will be settled at the relevant rebalancing price on the difference in cleared quantity between that rebalancing auction and the previous auction (i.e. quantity cleared in that auction minus quantity cleared in the previous auction). While the rebalancing auctions will be settled on a net basis, they will be cleared on a gross basis with the full AESO demand curve constituting the demand side, and all market participant offers and bids represented on the supply side. Gross clearing is discussed further in Sections 5.3 and 5.4 below.

5.1 Auction Timeline and Procedures

5.1.1 Auction Timeline:

The AESO will hold two rebalancing auctions, 18 and 3 months prior to the start of the delivery year. Table 1 shows an example schedule for the 2023 /24 delivery year, including both the forward auction, and both rebalancing auctions.[2] In the transition period that starts with the November 2019 auction, fewer rebalancing auctions will be held, with the timing selected such that the forward and rebalancing auctions will be conducted at times staggered during each calendar year. See Section 4.1 for the compressed base auction timeline.

Table 1
Timeline of Rebalancing Auctions
Example for Delivery Year 2023/24

Auction Date	Forward Period	Auction Type
Nov. 2020	36 Months	Base Auction
May 2022	18 Months	First Rebalancing Auction
Aug. 2023	3 Months	Second Rebalancing Auction
Nov. 2023	n/a	Start of Delivery Period

5.1.2 Procedures

Process steps for the rebalancing auctions will be similar to those for the forward auction described in Section 4. Figure 1 shows the timeline of rebalancing auction procedures. Each rebalancing auction will include a resource qualification step for all resources, conducted eight months ahead of the auction (although for resources already qualified at the time of the forward auction, the qualification processes will be limited). At the end of this qualification step, the AESO will notify participants of their UCAP ratings.

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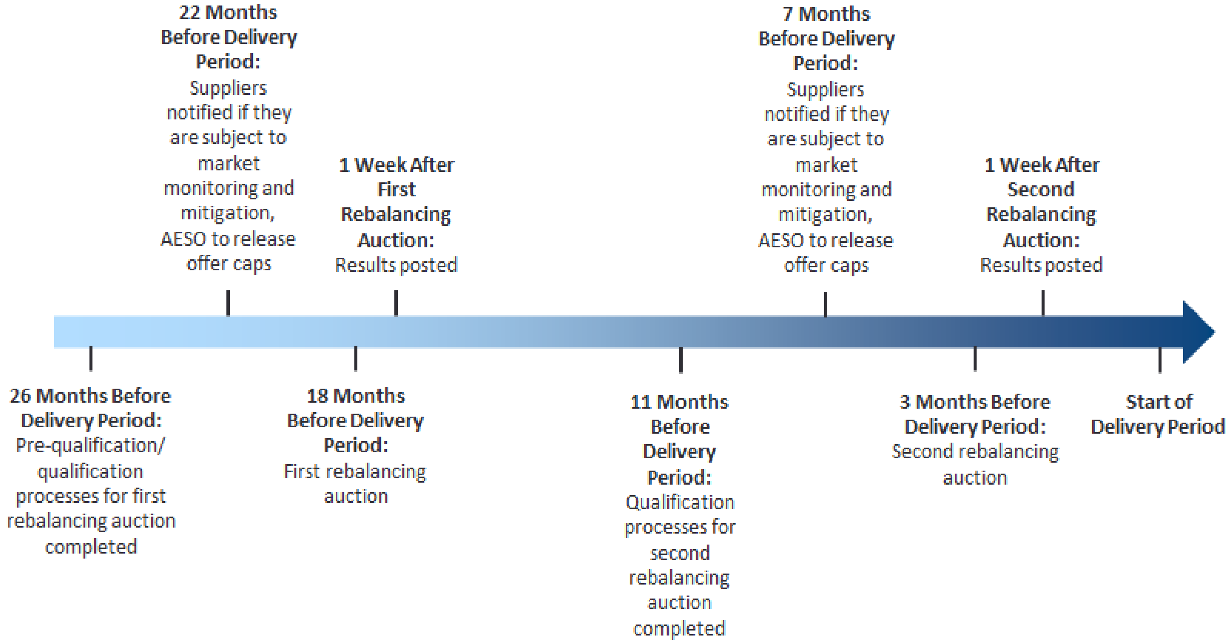
[1] Net settlements here refers to the fact that the rebalancing auctions are settled based on changes from the previous auction. This is not referring to the net settlements Instructions mechanism in the energy market.
[2] See recommendation for two rebalancing auctions from working group here: https://www.aeso.ca/assets/Uploads/Recommendation-Rebalancing-Auctions-2017-11-14.pdf

The auction itself will consist of a one-week bidding window during which providers can submit offers to sell, and bids to buy back some or all of their obligation. The AESO will notify participants of the auction results one week after the end of the bidding window.

Figure 1
Timeline for Rebalancing Auctions



5.2 Market Participant Buy Bids and Sell Offers

Market participants will have the opportunity to participate in the rebalancing auctions to adjust their positions ahead of the delivery year. The only entities that can reduce their obligation in the rebalancing auction (i.e. "buy-out") are forward cleared supply and the AESO. Qualified incremental supply can submit offers to sell into the rebalancing auctions in order to obtain a capacity payment. This incremental supply can be provided by resources that did not clear the forward auction, or from uprates and UCAP increases of resources that did clear the forward auction. Suppliers that wish to reduce their forward commitments can submit repricing bids to buy out of their positions. Forward-cleared resources that are physically unable to meet their commitments due to UCAP downrates or because they have not achieved development milestones will be required to offer above the price cap, and will be guaranteed to clear. All forward-cleared supply that does not submit a repricing or UCAP reduction bid will be treated as a price taker in the rebalancing auctions and will not be subject to settlements. These options are described in more detail below:

- **Incremental Sell Offers:** Capacity sellers with uncommitted capacity (including UCAP uprates) that have been qualified by the AESO can submit offers to sell incremental capacity into the rebalancing auction, at a price specified by the market participant in their offer. If the rebalancing price clears above the incremental sell offer price, the resource will be committed in the rebalancing auction, and will be paid the rebalancing price for its cleared quantity in settlements.

- **Repricing (Buy-Out) Bids (treated as supply offers under gross clearing):** Capacity sellers that have already taken on a capacity obligation, and wish to reduce their commitment through the rebalancing auction can submit repricing bids. If the rebalancing auction price clears below the offer price of that resource, the resource will be de-committed, and will need to pay the rebalancing auction clearing price in settlements in order to buy out of their capacity obligation. If the rebalancing auction clears at a price above the offer price, the resource will retain its capacity obligation, and will not have any financial settlement as a result of the auction.

- **UCAP Reduction Bids (Treated as supply offers above the price cap under gross clearing)**: A seller that is physically unable to deliver on a prior capacity commitment can submit a non-price UCAP adjustment offer. For auction-clearing purposes, the capacity supply will be treated as not available even at the auction price cap. This type of offer will be used for: (a) sellers wishing to guarantee a reduction of their capacity commitment regardless of capacity clearing price, (b) new resources that have not achieved development milestones and that are required to buy out of their capacity obligations, and (c) existing or new resources whose qualified UCAP at the time of the final rebalancing auction is below the previously committed UCAP quantity.
- **Non-Participating Supply:** As a default, capacity sellers that have already taken on a capacity obligation will be assumed to be "non participants" that do not wish to adjust their UCAP of capacity commitments, and whose UCAP ratings have not been adjusted according to AESO processes. For auction-clearing purposes, all such previously committed supply will be accounted for in auction clearing but will not incur any financial settlements out of the auction, nor have their capacity commitments adjusted.

5.3 Administrative Demand Curve

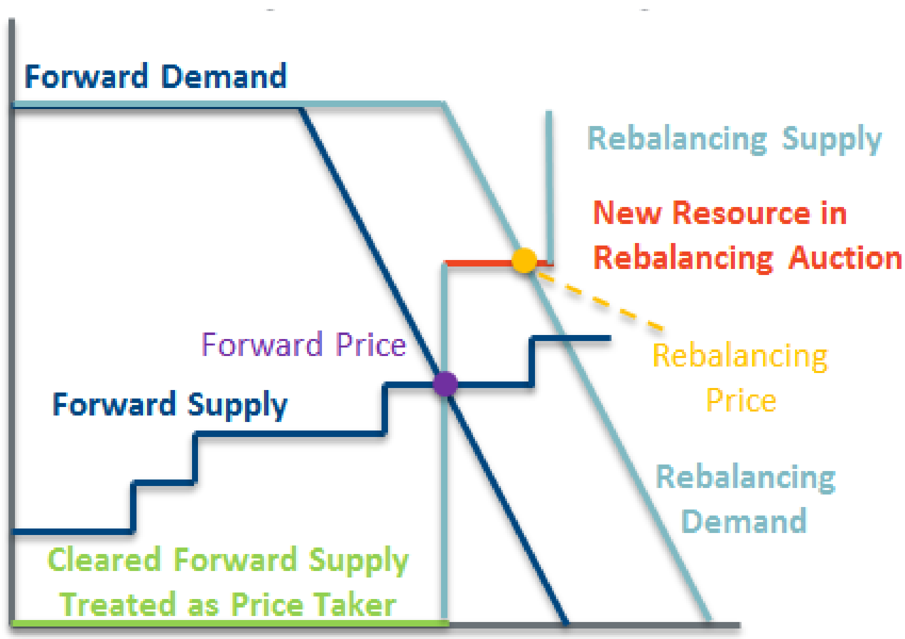
The rebalancing demand curve will have the same shape as the forward auction demand curve, as described in Section 4.3. It will use the same net-CONE, and reliability requirement as the forward auction, but several other parameters will be updated in the rebalancing auction:

- **Load Forecast:** The sloped demand curve will reflect the most up-to-date load forecast available at the time of the rebalancing auction. If the load forecast has increased since the forward auction, the rebalancing auction demand curve will be right-shifted relative to the forward auction demand curve. If the load forecast has decreased, the rebalancing demand curve will be left-shifted. However, the reliability requirement remains the same as in the forward auction with target capacity volumes adjusted as appropriate. Note that the AESO may elect not to update its load forecast in the first rebalancing auction demand curve, but will use the most up-to-date forecast in the final rebalancing auction.
- **Capacity Import Limits:** Individual and simultaneous import limits from adjacent areas will be updated to reflect the most up-to-date information as of the rebalancing auction. If import limits have increased since the forward auction, additional external supply will be able to sell into the auction. If incremental external supply offers in the rebalancing auction exceed incremental import capability, incremental import capability will be rationed among incremental external supply in same manner as described in Section 4.7. If import limits have decreased since the forward auction, imports will be rationed among forward cleared market participants as described in Section 4.7. External suppliers that have cleared in a forward auction will not be subject to reduced capacity payments if import limits decrease in the rebalancing auction, but may have their cleared volumes reduced.
- **Intra-provincial Transmission Constraints:** Intra-provincial transmission constraints will be updated to reflect the most up-to-date information as of the rebalancing auction. If intra-provincial transmission constraints prevent delivery of all incremental supply offers, incremental supply offers behind the constraint will be rationed in the manner described in Section 4.8. If intra-provincial transmission constraints prevent delivery of forward cleared supply, forward cleared supply will be rationed in the manner describe in Section 4.8. Capacity resources that have sold in the forward auction, but are no longer feasible after a change in intra-provincial transmission constraints, will not be subject to reduced capacity payments, but may have their cleared volumes reduced.

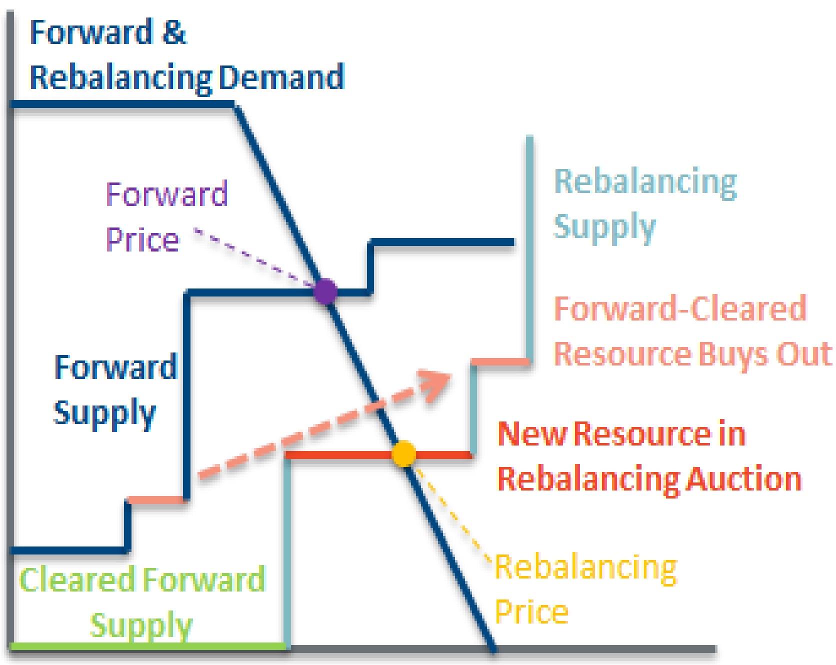
5.4 Auction Clearing and Price Setting

The rebalancing auctions will be cleared on a gross basis. The AESO's demand curve (updated as described in Section 5.3) will constitute the demand side. All pricing and reduction bids to buy out obligations, and incremental sell offers to sell incremental supply will be represented on the supply side. Cleared resources from the forward auction that do not submit bids to buy will be treated as price takers in the rebalancing auctions. The auctions will clear using the same mechanics as the forward auction, as described in Section 4.5. The resulting auction clearing price will be used to settle *differences* between cleared quantities in the rebalancing auction and the forward auction. The four examples below illustrate how the rebalancing auctions will function.

Example 1: Load Forecast Increases, and Incremental Supply Sells to the AESO. The AESO's load forecast increases in the rebalancing auction relative to the forward auction, shifting the demand curve to the right. One incremental supply offer is received, and clears the market at a higher price than the forward auction. The incremental supply offer receives the rebalancing price multiplied by its rebalancing cleared quantity in settlements. The AESO pays the rebalancing price multiplied by its incremental rebalancing cleared quantity. Settlements for all previously cleared forward supply are unaffected by the rebalancing auction.

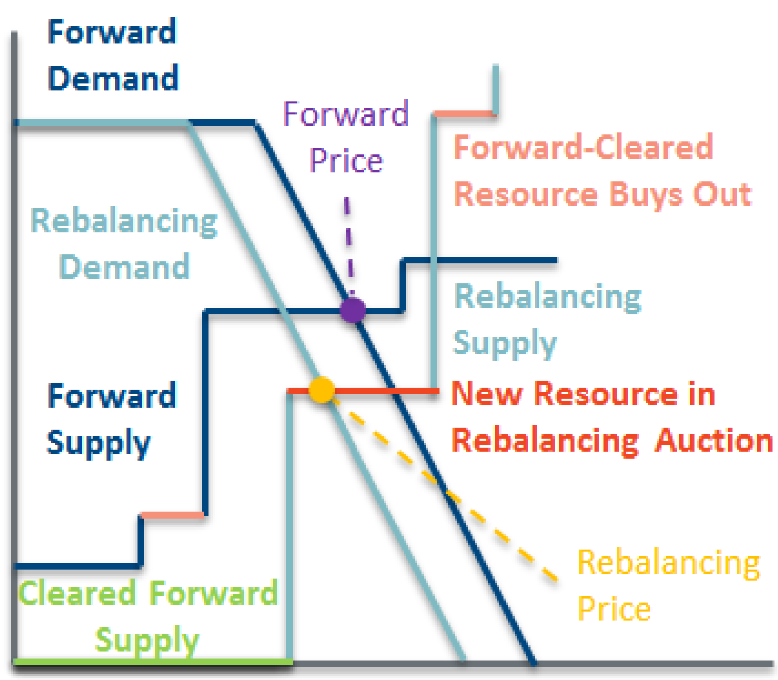


Example 2: Incremental Supply Sells to Resource Buying Out, and to the AESO. The AESO's load forecast is unchanged from the forward auction, and the rebalancing demand curve is the same as the forward demand curve. One incremental supplier offers, and partially clears, setting the rebalancing price below the forward price. One forward-cleared resource fully buys out of its capacity obligation. Since the rebalancing price is lower than the forward price, the AESO buys incremental supply from the incremental resource. In settlements, the incremental supplier receives the rebalancing price multiplied by its rebalancing cleared quantity. The forward-cleared resource that is buying out pays the rebalancing price multiplied by its rebalancing cleared quantity (and also receives the forward price multiplied by its forward cleared quantity, resulting in net revenue for the resource). The AESO pays the rebalancing price multiplied by the incremental rebalancing cleared quantity. Settlements for all forward supply that did not buy out in the rebalancing auction are unaffected.



Example 3: Load Forecast Decreases, and the AESO Sells to Resource Buying Out. The AESO's load forecast decreases from the forward auction, shifting the rebalancing demand curve to the left. One forward-cleared resource submits a UCAP reduction bid above the price cap, and fully buys out. The rebalancing auction clears below the forward price. In settlements, the resource buying out pays the rebalancing price multiplied by its rebalancing cleared quantity (and also receives the forward price times its forward cleared quantity, resulting in net revenue for the resource) and the AESO receives the rebalancing price multiplied by the difference between its forward and rebalancing-cleared quantities. Settlements for all forward supply that did not buy out in the rebalancing auction are unaffected.

Example 4: Load Forecast Decreases, and Incremental Supply and the AESO Sell to Resource Buying Out. The AESO's load forecast decreases from the forward auction, shifting the rebalancing demand curve to the left. One forward-cleared resource buys out of its capacity obligation. One incremental supplier offers, and partially clears, setting the rebalancing price below the forward price. At the rebalancing price, the AESO sells some if its supply in the incremental auction. In settlements, the resource buying out pays the rebalancing price multiplied by its rebalancing cleared quantity (and also receives the forward price times its forward cleared quantity, resulting in net revenue for the resource). The incremental supplier receives the rebalancing price multiplied by its rebalancing cleared quantity. The AESO receives the rebalancing price multiplied by the difference between its forward, and rebalancing cleared quantities. Settlements for all forward supply that did not buy out in the rebalancing auction are unaffected.



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Comprehensive Market Design (CMD 1)
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Section 6: Physical Bilateral Transactions and Self-Supply

Prepared by: Alberta Electric System Operator

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6 Physical Bilateral Transactions and Self-Supply

6.1 Physical Bilateral Transactions and Support for Self-Supply

A physical bilateral transaction is defined as a contractual arrangement between a load market participant and a specific capacity resource utilizing the transmission or distribution system for physical delivery of all or a portion of the load's capacity needs, removing both the supply and demand volumes from the AESO-administered capacity market. Physical bilateral transactions will not be permitted; however, a site may choose to self-supply capacity.

6.2 Self-Supply Requirements

- A site may self-supply capacity provided it meets the eligibility requirements set out in Section 2.1 – *Prequalification of Capacity Resources.*
- Sites with onsite generation that cannot physically flow their gross volumes due to system connection limitations must self-supply.
- The city of Medicine Hat meets the "must self-supply" criteria and will be required to self-supply within the capacity market.
- Self-suppliers who intend to change from participating on a net basis to a gross basis or from a gross basis to a net basis must declare their intention to the AESO. Changes will only be allowed once every three years.

6.3 *Ex ante* Asset Substitution within the Capacity Market

- Asset substitution between a committed-capacity resource and a qualified but non-committed capacity resource will be allowed on an *ex ante* basis up until the start of the energy market settlement interval.
- With asset substitution, the payment adjustments associated with under-performance and over-performance of the substituted asset will be assessed to the original obligation holder and not to the substituted asset owner. The capacity obligation during the substitution period will not be transferred to the substituted resource.

Ex ante asset substitutions must be registered with the AESO specifying:

- The start date and time and end date and time of the substitution. The start date and time must not be prior to the registration date and time.
- The volume of the capacity obligation to be substituted. This volume must be less than or equal to the unforced capacity (UCAP) of the substituted asset. The substituted volume must not be greater than the substituting assets capacity obligation.
- The approval of the substation by both counterparties is required before the begin date and time of the substitution.
- The financial arrangement between the two counterparties is not required in the asset substitution registration.

6.4 Capacity Obligations Tracking Infrastructure and Processes

The AESO will develop a platform to track capacity supply and demand data to support several functions in the capacity market.[1] Capacity resource owners will use the platform to track their qualification status, UCAP ratings, auction results including the capacity obligation volumes and associated prices for each obligation period. The tracking system will also support self-supply and asset substitution arrangements among owners of a capacity resource.

[1] This platform will be similar to tools used in other capacity markets, specifically the Module E-1 Capacity Tracking Tool (MECT) used in MISO.

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Section 7: Capacity Auction Monitoring and Mitigation

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7 Capacity Market Monitoring and Mitigation

The AESO will implement a capacity market monitoring and market power mitigation regime that will include market power screens to identify capacity suppliers with market power and mitigation mechanisms to restrict the offers submitted to the market by entities deemed to have market power. This section provides an overview of the proposed screens and mechanisms the AESO will implement to mitigate market power. This section describes the market power mitigation measures to be implemented in the AESO capacity auctions, including the rules and processes that will govern the application of these measures and potential exemptions to the mitigation measures.

7.1 Mitigation of Supply-side Market Power

The AESO supply-side market power mitigation regime will consist of several *ex ante* measures designed to prevent the exercise of market power. The AESO's supply-side market power mitigation regime will include a must-offer requirement, capacity delisting rules to prevent physical withholding, a market power screen to identify suppliers that have the potential to profitably withhold capacity from the market, a default offer cap to prevent economic withholding by suppliers that fail the market power screen and unit-specific offer caps for mitigated resources with demonstrated net going-forward costs above the default offer cap. These measures will be implemented before each forward capacity auction and rebalancing auction. *Ex post* reviews of auction competitiveness will be conducted after each auction.

Must-offer Requirement: The AESO will require suppliers to submit offers into the forward capacity auction for the full quantity of the unforced capacity (UCAP) rating of all qualified capacity resources This must-offer requirement will apply to all suppliers regardless of whether or not the supplier is identified as having the incentive or ability to exercise market power. New capacity resources will be exempt from the must-offer requirement in the forward capacity auctions and rebalancing auctions. Upon commercial operation and once successfully cleared in a capacity market auction the new resources will be required to submit an offer into all future forward capacity auctions for the full quantity of their UCAP rating. Demand response and external capacity resources will have a must-offer requirement once prequalified and cleared in any auction.

Must-Offer Requirement Exemption (Capacity Delisting): All qualified capacity resources that wish to retire, mothball or derate a resource's capacity will need to apply for a must-offer requirement exemption. Capacity suppliers will inform the AESO of a request for a must-offer requirement exemption before the forward capacity auction or rebalancing auction, prior to an established deadline specified by the AESO. The capacity supplier must indicate to the AESO at that time whether they wish to retire, mothball, or derate the capacity of the resource. The application for a must-offer requirement exemption will need to be approved. Capacity resources that wish to retire, mothball or derate must demonstrate that their request for a must-offer requirement exemption is justified on physical (e.g., inability to deliver due to regulatory restrictions) or economic grounds. To obtain a must-offer requirement exemption on economic grounds, the capacity supplier will need to demonstrate that the net going-forward costs of maintaining the resource in operational status at the current capacity level exceeds revenues that can be earned in the capacity market. Each must-offer requirement exemption request will be reviewed on a case-by-case basis based on the facts and circumstances that exist at the time of the exemption request.

The review of a must-offer requirement exemption request made on economic grounds may result in a number of outcomes, including that:

1. If the supplier demonstrates that the net going-forward costs of maintaining the resource at current capacity levels are higher than the capacity market price cap, the request will be approved such that the supplier will be permitted to retire, mothball, or derate the resource according to the notification provided prior to the capacity auction, but subject to such terms and conditions as may be imposed as part of the exemption approval. Net going-forward costs will be defined in the same way as described under the unit-specific offer mitigation below.

2. If the supplier demonstrates that the net going-forward costs of maintaining the resource at current capacity levels are not higher than the capacity market price cap, then the exemption request will be approved, such that the supplier will be permitted to offer the resource into the capacity auction at a price level that reflects the net going-forward costs. If the supplier does not clear at that level, the supplier will be allowed to retire, mothball, or derate according to the notification it provided prior to the capacity auction, but subject to such terms and conditions as may be imposed as part of its exemption approval.

Market Power Screen: The AESO will conduct an *ex ante* screen to identify suppliers that have the potential to exercise market power in the forward-capacity auctions and rebalancing auctions. Prior to each auction, the AESO will calculate the aggregate target UCAP requirement to be procured in the auction to meet the reliability requirement. The AESO will also determine the UCAP owned by each supplier. The UCAP owned by each supplier will be determined through mandatory reporting requirements for suppliers as part of prequalification/qualification described in section 2.

Each capacity resource supplier that owns or controls existing asset UCAP totaling more than 15 per cent of the aggregate UCAP requirement for the auction will fail the market power screen. Each capacity resource supplier that fails the market power screen will be required to offer at or below a default offer cap, as described in below. The 15 per cent threshold will be reviewed periodically alongside the multi-year review period for the capacity demand curve to establish a new threshold. The threshold will reflect the smallest size portfolio of a supplier that may have the incentive and ability to exercise market power.

In the rebalancing auctions, the same 15 per cent threshold for mitigation will be applied based on an updated assessment of each supplier's portfolio size (regardless of whether those resources already have a capacity obligation).

Default Offer Cap: Offers for existing resources from all capacity resource suppliers that fail the market power screen will be mitigated to be at or below a default offer threshold price of 50 per cent of net-CONE.

Unit-Specific Offer Mitigation: The AESO recognizes that certain capacity market resources may have net going-forward costs higher than the default offer cap. Therefore, suppliers that fail the market power screen but wish to offer capacity resources at prices higher than the default offer cap will be able to request a resource-specific offer cap. The unit-specific offer cap will be calculated based on the net going-forward costs of the resource in question and will be allowed to exceed the default offer cap. For purposes of obtaining approval to exceed the default offer cap, the supplier will be required to justify the requested resource-specific offer cap by demonstrating the resource's avoidable net going-forward costs, which will be subject to review and approval consistent with calculation methods that will be standardized by unit technology type. The calculation method will consider the following types of costs in determining the unit-specific offer cap:

- Going-forward investment and fixed costs

- Expected penalty costs
- Opportunity costs
- A demonstrated asset life after major capital expenditures and considering the need for a return on capital investments.
- *Minus* an offset for expected energy and ancillary services revenues, as well as any other revenues that may be available to that resource.

7.2 Mitigation of Suppliers with Net-short Capacity Position

The minimum offer price for all participants will be a price floor of $0/kW-year. No mechanisms for mitigating net-short (or buyer-side) market power will exist.

7.3 Reporting of Auction Results and Market Competitiveness

After each forward capacity auction and rebalancing auction, public reports will be provided describing auction results as follows:

- **Immediately After the Auction:** the AESO will provide a report of auction statistics, including supply, demand, and clearing results. Offered and cleared supply by resource type and new/existing status will be reported. Significant changes in the fleet mix will be identified, as will primary drivers of price compared to prior auctions. The public report will be supplemented with data files describing the same market outcomes. An abbreviated version of this report will be issued after each rebalancing auction.
- **Within Three Months After the Auction** (sooner in the case of the transition period): it is expected that the MSA may conduct an independent assessment reviewing auction competitiveness, the consistency of market results with market conditions, potential changes to the market design to pursue before the next auction, or issues that should be more thoroughly investigated in triennial reviews. This report will be provided after each primary auction, but not after each rebalancing auction.
- **Triennial Performance Reviews:** Every three years, the AESO will commission an independent review of market performance and results. The first triennial review will have a comprehensive scope, and specifically address the following issues on a retrospective and prospective basis. Once the capacity market is found to have a sustainable well-functioning design, the scope of the review can be narrowed as appropriate. The initial reviews will consider at a minimum:
  - Demand curve shape and performance
  - The reliability analysis including whether all key drivers of reliability events are considered (for example for annual and seasonal reliability drivers)
  - The accuracy of capacity ratings by resource type
  - Performance assessments
  - Monitoring and mitigation parameters

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Section 8: Supply Obligations and Performance Assessments

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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8 Supply Obligations and Performance Assessments

8.1 Overview of Payment Adjustment Mechanism

Capacity resource performance will be measured prior to and during the obligation period.

Prior to the obligation period the AESO will monitor resources with capacity market obligations and assess in two ways:

- Failure to deliver assessment for new committed capacity resources to ensure development in time to meet capacity obligations; and
- Resources with capacity obligations that experience unforced capacity (UCAP) deterioration relative to their prequalification level.

During the obligation period resources with capacity market obligations will be assessed on an availability and performance basis:

- Unavailability payment adjustments to existing resources that are unavailable during periods of supply tightness; and
- Performance assessment will assess resource performance during energy emergency alert (EEA) events and will assess under-performance payment adjustments to resources that are unavailable relative to their obligations while providing the opportunity for over-performance payment adjustment for resources that over-perform relative to their obligations.

8.2 Supply Obligations: Failure to Deliver for New Resources

The AESO will use milestone tracking to assess the timely completion of new resources based on predefined milestones for both generation and demand resources and to establish credit requirements (see discussion regarding Market Participant Buy Bids and Sell Offers in Section 5.2 and Credit Requirements in Section 2.4).

New resource owners must demonstrate that they have fulfilled development milestone requirements prior to each rebalancing auction. New resources that have not met development milestones will be deemed to have failed to deliver on the new capacity resource and will be required to buy out their obligation in one of the rebalancing auctions up to the market price cap or engage in asset substitution prior to the final rebalancing auction such that their obligation is met via supply from another qualified capacity resource.

Detailed milestone tracking requirements for different resource types will be established in the detailed design phase of the development of the capacity market.

8.3 Updates to Qualified UCAP Ratings

UCAP ratings of resources with capacity obligations will be recalculated in advance of each rebalancing auction to reflect changes in the resource's capabilities. Resources with capacity obligations that experience a reduction in UCAP relative to their prequalification UCAP for a delivery period will be required to:

- Buy out their obligation in the final rebalancing auction up to the market price cap; or
- Engage in asset substitution prior to the final rebalancing auction such that their obligation is met via supply from another qualified capacity resource.

8.4 Unavailability Payment Adjustment Mechanism

The AESO will apply an unavailability payment adjustment to resources that are not available to provide their capacity obligation during the obligation period. Availability assessments will be conducted during hours with tight supply cushion, when the system faces reliability risks. Note that these hours will not necessarily correspond to emergency event hours where performance payment adjustments, described in Section 8.5 are assessed. Rather, availability will be assessed during those hours in a year during which the UCAP assessments described in Section 2.3 are assessed. In the event performance and availability assessment hours overlap, availability and performance of the capacity resources will be assessed separately and, if applicable, both types of payment adjustments will be applied.

Resources that have higher available capacity than committed capacity will not be eligible to receive an over-availability payment adjustment. Unavailability payment adjustments collected by the AESO will be returned to customers.

8.5 Availability Assessment Period

Unavailability payment adjustments will be assessed by comparing each resource's capacity obligation to its availability during a fixed number of hours in a year (annual assessment hours). Such hours determined by the AESO will be the 100 tightest supply cushion hours over the course of a delivery period (Nov. 1 through Oct. 31). Variable resources, such as wind and solar resources may be assessed over fewer hours per year to match the period of time over which their UCAP is determined. For dispatchable resources availability will be measured as the amount of MW offered to the energy and ancillary services market (including any dispatched volumes) during the annual assessment hours. For non-dispatchable resources availability will be measured as the amount of MW generated during the annual assessment hours.

Given that the tightest supply cushion hours are not known in advance, the specific availability assessment hours will be known only after the year is complete and will be determined based on supply cushion analysis to be performed by the AESO.

8.5.1 Unavailability Volume Definition

During each year resources with capacity commitments will be required to demonstrate that their actual availability was at least equal to their committed UCAP (expected availability) during the availability assessment hours.

A committed resource's unavailability volume, which will be defined as:

Unavailability Volume (MW) = (Expected Availability, MW – Actual Availability, MW) > 0

Where Actual Availability = average availability during relevant tightest supply cushion hours

8.5.2 Unavailability Payment Adjustment Rate

Resources with positive unavailability volume throughout the year will be assessed a payment adjustment equal to the product of their annual unavailability volume and the unavailability payment adjustment rate multiplied by the number of assessment hours. The unavailability payment adjustment rate is based on a 40 per cent share of the maximum of the base capacity price or the last rebalancing auction price annual amount, multiplied by 1.3.

Unavailability Payment Adjustment Rate ($/MWh) = 40% x 1.3 x MAX [Annual Base Capacity Auction Price; Annual Last Rebalancing Auction Price]) / 100 hours

For example, assume the clearing price of the last rebalancing auction was $100,000/MW which was greater than the clearing price in the base auction. The resulting unavailability payment adjustment rate would be:

(0.4 x 1.3 x $100,000/MW-year) / 100 hours = $520/MWh for each assessment hour in the year

Alberta's capacity market will not include over-availability payment adjustments for resources that demonstrate availability exceeding their capacity commitments. All unavailability payment adjustments collected by the AESO will serve to reduce capacity charges to consumers.

8.5.3 Unavailability Payment Adjustment Exemptions

Resources with capacity obligations that are constrained down due to limits on the Alberta internal transmission system will be exempt from unavailability payment adjustments on that volume of their obligation. Capacity obligation volume that is unavailable due to forced or planned derates or forced or planned outages and force majeure will not be exempt from availability obligations.

Down-by-demand response units may require different availability performance measures that take into consideration how the resource's average tight supply cushion load compares to more recent energy consumption of the load. These measures will be developed in subsequent versions of the CMD.

8.6 Performance Payment Adjustment Mechanism

Resources with capacity obligations will be assessed performance relative to capacity obligations during EEA events.

8.6.1 Performance Assessment Period

Performance assessment periods will occur during EEA events. When the AESO declares an EEA 1, EEA2 or EEA3 event the performance assessment period will begin from the time of such declaration until the AESO declares an EEA-0 event, at which point the performance assessment period will end. Resources will not be given any prior notification before a performance assessment period is declared by the AESO. There will be no limit on the duration of a performance assessment period; resources with a capacity obligation will be measured against performance for the full duration of the performance assessment period.

8.6.2 Performance Volume Definition

Performance volume of a capacity resource will be calculated as a resource's actual energy and or operating reserve dispatch minus its expected performance during a performance assessment periods. Performance volume will be measured in MWh and the expected performance will be multiplied by the balancing ratio (BR)[1] to determine the volume of a resource's capacity that will be subject to either over-performance or under-performance payment adjustments.

A committed resource's performance volume will be defined as:

*Performance Volume (MWh) = Actual Performance MWh -- (Expected Performance MWh * Balancing Ratio)*

[1] The Balancing Ratio is the ratio of the energy and reserves produced by committed resources during a performance assessment period to the total procured capacity for that obligation year and is a number less than or equal to

8.6.3 Non-performance Payment Adjustment Rate

Resources with capacity obligations that have a negative performance volume will be subject to a non-performance payment adjustment. The non-performance payment adjustment rate will be set based on the higher of a resource's base capacity auction price or the last rebalancing auction price. The non-performance payment adjustment rate will also be dependent upon the expected number of EEA hours for that year as determined in the base capacity auction. The non-performance payment adjustment rate will be calculated using the following formula:

Non-performance payment adjustment rate ($/MWh) = 60% x 1.3 x MAX[Annual Base Capacity Auction Price; Annual Last Rebalancing Auction Price]) / Expected EEA hours

The specific value of expected EEA hours will be revised for each delivery year based on reliability modelling.

8.6.4 Over-performance Payment Adjustment Rate

Resources with capacity obligations that have a positive performance volume will be eligible to receive an over-performance payment adjustment which will be wholly funded from the non-performance payment adjustments from resources with negative performance volumes. Over-performance payment adjustments will be made for each MWh of over-delivery during EEA events and will be paid at the $/MWh Payment Adjustment Rate:

Over-performance Payment Adjustment Rate ($/MWh) = Total Non-Performance Payment Adjustments *Collected $ / Total volume of positive Performance Volume MWh*

If there is no positive performance volume, all Non-performance payment adjustment funds will be allocated to load.

8.6.5 Non-performance Payment Adjustment Exemption for Transmission Constraints

Resources with capacity obligations that are constrained down due to limits on the Alberta internal transmission system will be exempt from performance payment adjustments on that volume of their obligation. Capacity obligation volume that is unavailable due to forced or planned derates or forced or planned outages and force majeure will not be exempt from performance obligations.

Down-by-demand response units may require different availability performance measures that take into consideration how the resource's average tight supply cushion load compares to more recent energy consumption of the load. These measures will be developed in the detailed design phase.

***Maximum Amounts for Unavailability and Under-performance* Payment Adjustments**

For any one capacity resource, the combined payment adjustment exposure to availability and performance payment adjustments will be capped monthly and annually.

- Cumulative monthly unavailability and non-performance payment adjustments of an individual capacity resource will be capped at 300 per cent of the monthly capacity revenue based on the higher of the annual base auction capacity price received by that resource, or the latest rebalancing auction price.
- Cumulative annual unavailability and non-performance payment adjustments of an individual capacity resource will be capped at 130 per cent of the annual capacity revenue based on the higher of the annual base auction capacity price received by that resource, or the latest rebalancing auction price.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Proposal Document

Section 9: Settlements and Credit Requirements

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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9. Settlements and Credit Requirements

9.1 Capacity Market Statements

Capacity payments and charges will be invoiced monthly, consistent with the energy market invoicing cycle in the form of a capacity market statement. The capacity market statements will be issued separate from the energy market statement and separate from cost allocation invoices.

9.2 Settlements Applicable to Capacity Resources

9.2.1 Capacity Payments

- Capacity payments will not be made to capacity resources prior to the start of the delivery period.
- Capacity payments will be made by monthly payments to capacity resources for their commitment to meet a capacity obligation during a delivery period. Payments are based on the capacity cleared price achieved in the auction that the capacity obligation was awarded from.
- Monthly capacity payment is based on the following formula:

  Capacity payment $= \{ [O_b * P_b] - [(O_b - O_{r1}) * P_{r1}] - [(O_{r1} - O_{r2}) * P_{r2}] \} / \#$ *months in term*

  Where, for the delivery year:

  O_b equals cleared obligation of the capacity resource in the base auction

  P_b equals the capacity market price of the base auction

  O_{r1} equals the cleared obligation of the capacity resource in the first rebalancing auction

  P_{r1} equals the capacity market price of the first rebalancing auction

  O_{r2} equals the cleared obligation of the capacity resource in the second rebalancing auction

  P_{r2} equals the capacity market price of the second rebalancing auction
- Should the settlement result in a charge rather than a payment to the capacity resource, resulting from a buy back through the rebalancing auction, a further credit requirement will be assigned the capacity resource.
- Below is an example of a capacity market settlement where the capacity resource sells 80 MW in the base auction and buys back 50 MW in the first rebalancing auction and then buys back another 20 MW in the second rebalancing auction.

12-month term	Remaining Obligation (O)	Price (P)
Base ($_b$)	80	20
1st rebal ($_{r1}$)	30	15
2nd rebal ($_{r2}$)	10	40

Capacity Payment $= \{ [O_b * P_b] - [(O_b - O_{r1}) * P_{r1}] - [(O_{r1} - O_{r2}) * P_{r2}] \} / \#$ *months in term*

Capacity Payment $= \{ [80 * 20] - [(80 - 30) * 15] - [(30 - 10) * 40] \} / 12 = \$ 4.17$ *per month*

9.2.2 Settlement of the Failure to Deliver Payment Adjustment Mechanism for New Resources

- Payment adjustment mechanism for failure to deliver for a new resource is specified in Section 8.2.
- In the event that the capacity resource fails to bid in the rebalancing auction or register for asset substitution, the AESO will apply the failure to deliver payment adjustment mechanism.

9.2.3 Payment Adjustment Mechanism for Performance

- Payment adjustments for performance are as specified in Section 8.5.
- Non-performance payment adjustments are assessed in the same statement period for which the non-performance event occurred.
- Performance assessment will assess resource performance during energy emergency alert (EEA) events and will assess under-performance payment adjustments to resources that are unavailable relative to their obligations while providing the opportunity for over-performance payment adjustment for resources that over-perform relative to their obligations.
- If there is less over-performance than under-performance the remaining under-performance payment adjustments will be allocated to consumers.

9.2.4 Payment Adjustment Mechanism for Unavailability

- The payment adjustment mechanism for unavailability is specified in Section 8.4.
- Unavailability payment adjustments will be assessed at the end of the delivery period and applied to the settlements of the following delivery period whether or not the resource has a capacity obligation in that delivery period.

9.2.5 Settlement of Non-performance Payment Adjustment Mechanism to Existing Resources

- Additional payment adjustment amounts calculated in the statement period will be added to the outstanding payment adjustment balance for the capacity resource.
- The AESO will claw back capacity payments for payment adjustments.
- The AESO's settlement will limit the monthly payment adjustmentclaw back amount to 100 % of the capacity market payment each statement until the sum of all payment adjustments are collected.
- If the capacity resource does not receive a capacity market payment in the statement period, then the payment adjustment balance will be assessed against the proceeds from energy and ancillary services markets until the sum of all payment adjustments are collected.

9.3 Settlements Applicable for Consumers

- "Capacity market customer charges" means charges which electricity consumers are required to pay under electricity capacity tariff to meet the cost of funding capacity payments.
- The AESO must, as soon as reasonably practicable after the end of the first capacity market statement period:
  - Calculate the amount of the settlement costs to be paid by each applicable capacity market wholesale consumers; and
  - Issue an invoice to each applicable capacity market wholesale consumers for the amount to be paid by that consumer.
- The general concepts used to allocate costs to customers are not available yet.

9.4 Capacity Market Net Settlement Instructions (NSI)

- Net settlement instructions will not be facilitated within the capacity market.

9.5 Capacity Market Credit Requirements for Existing Capacity Resources

- Existing market participants comply with ISO Rules – Division 103, Section 103.3 – *Financial Security Requirements*.

- The AESO will not require financial security for capacity market non-performance and unavailability payment adjustments as long as the capacity resource is receiving capacity payments.
    - As stated above, the AESO will track the total payment adjustment owing for each capacity resource. This payment adjustment claw back will occur in each of the following months until the full balance is recovered.

9.6 Measurement and Verification of Capacity Resources

- The AESO will measure and verify the capabilities and performance of all capacity resources throughout the delivery year against their obligation. Each resource with a capacity obligation will be required to provide data sufficient to measure performance, and will be held to the same overall measurement and verification standards. The specific methods and data sources used to measure performance, however, will accommodate the differences across supply types.
- To facilitate AESO measurement, and verification, all capacity resources will participate in data collection or submission processes, and must meet certain requirements prior to the delivery year. Availability will be measured based on data collected for reliability purposes, and in the energy and ancillary services markets. Resources must also have the ability to measure production on a sub-hourly basis and provide that data to the AESO via SCADA.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Proposal Document

Section 10: Roadmap for Changes in the Energy and Ancillary Services Markets

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10. Roadmap for Changes in the Energy and Ancillary Services Markets

This section outlines how the energy and ancillary services markets will evolve with the introduction of the capacity market, and in anticipation of expected system changes. These changes include rules that are required to facilitate delivery of the capacity market product, to integrate the anticipated Alberta generation fleet (increased variable generation, coal retirements, etc.), as well as to improve market efficiency.

Section 10.1 outlines the energy market offer obligations; Section 10.2 identifies the changes related to energy market monitoring, and mitigation, and Section 10.3 addresses reviews pricing methodologies for price cap, and shortage pricing. And Section 10.4 is a summary of market changes that have been evaluated as part of the Energy and Ancillary Services (EAS) scope but are now recommended to be taken out of scope of the current design project. While some of these design elements may still be linked to a future market or system operation trigger or a new business case, these items, as explained in the rationale document, have been identified as not pressing to the current design project for implementation of a capacity market and pending system changes given changes to the fleet.

The timeline for implementation of changes in the energy and ancillary services markets is still being evaluated, and is anticipated to be included in Comprehensive Market Design 2. Once the dates are applied, the section will overall refer to the EAS Roadmap (related to the key design elements of study), noting what changes will be implemented when to address market evolution.

10.1 EAS Rules – Status Quo and Pending Changes

10.1.1 Offer Obligations, Dispatch and Scheduling

The following resource types will have the following offer obligations in the EAS markets.

- A generating unit, aggregated generating facility or energy storage facility:
  - That has a capacity commitment, and a maximum capability (MC) of 5 MW or greater, must offer its MC volume into the energy or AS market unless its AC is reduced from its MC due to an acceptable operating reason (AOR). It must offer, and be available for dispatch up to its AC volume.
  - That has a capacity commitment, and has a maximum capability (MC) of less than 5 MW, does not have to offer but has an option to offer if its AC is 1 MW or greater.
  - That does not have a capacity commitment, and has a maximum capability (MC) of 5 MW or greater, must offer its MC volume into the energy or AS market unless its AC is reduced from its MC. A restatement of its AC will be accepted with an acceptable operating reason (AOR). It must offer and be available for dispatch up to its AC volume.
- An import asset:
  - That has a capacity commitment (capacity committed import or CCI), must offer its capacity obligation volume into the energy or AS market. It may offer in a price taker block at $0 or it may request priced assets and will receive seven price-quantity pairs. If its offer block is dispatched from a priced block, it may set system marginal price, and intra-hour schedule changes may be performed. It must ensure balancing authorities and transmission providers along the transmission path into Alberta will approve interchange transactions at any time during a settlement period (having an E-Tag request not approved for scheduling practice reasons is not an AOR).
  - That does not have a capacity commitment continues to have optional offer obligations, however, when offering, they may offer in a price taker block at $0 or request priced assets and offer in seven price-quantity blocks. If its offer block is dispatched from a priced block, it may set system marginal price, and intra-hour schedule changes may be

performed. It must ensure balancing authorities and transmission providers along the transmission path into Alberta will approve interchange transactions at any time during a settlement period (having an E-Tag request not approved for scheduling practice reasons is not an AOR).

- An export asset may bid in as a price taker at $999.99 or may request priced assets and receive seven price-quantity blocks. If its priced bid block is dispatched, it may set system marginal price, and intra-hour schedule changes may be performed. It must ensure balancing authorities and transmission providers along the transmission path into Alberta will approve interchange transactions at any time during a settlement period (having an E-Tag request not approved for scheduling practice reasons is not an AOR).
- A load or an aggregated load:
  - That has a capacity commitment of 5MW or more must submit bids for its capacity obligation volume into the energy or AS market. Capacity committed loads have the option to bid at the price cap and will be directed last prior to releasing contingency reserves (as part of supply shortfall procedures). Capacity committed loads that are considered “down-to” must bid at the price cap. System and IT tools impacts will need to be assessed.
  - That has a capacity commitment of less than five MW, does not have to submit bids but has an option to bid if its capacity commitment is 1 MW or greater.
  - That does not have a capacity commitment, will continue to have the option to submit bids of at least 1 MW. It may also continue to act as a price responsive load or demand response resource.
- All offers and bids must be submitted with prices between the market offer cap and offer floor except for capacity load bids as described above, or unless *ex ante* mitigated as per the rules below.
- All offers including import offers must submit a ramp rate by block and comply with tighter ramping compliance dispatch tolerance around these levels.
- Accepted ancillary services offers will continue to be netted off energy offer obligation volumes.
- Offers into the AS market will continue to be optional.
- Long lead-time energy (LLTE) will continue to offer with a start-up time of greater than an hour. Rules for directives to LLTE will be aligned with incentives for capacity obligations and proposed rules for self-commitment.
- The mothball rule will be amended to align with delist requirements in the capacity market.

10.1.2 Dispatch and Scheduling

- Dispatch of the energy and ancillary services markets will continue using the respective energy and ancillary services merit orders as today independent of any capacity obligations (further evaluation of Security-Constrained Economic Dispatch (SCED) will impact this conclusion). Any energy dispatched must comply with dispatch instructions and remain within dispatch tolerance, including for ramp rate.
- The Security Constrained Economic Dispatch (SCED) model will be evaluated as part of a flexibility package including consideration of a ramp product and co-optimization of EAS. In this model, the merit orders will be dispatched in real time on five minute basis to meet load, and in anticipation of any ramp constraints. Prices will be set for energy, and ramp. An advanced SCED will be run to support self-commitment.
- Shorter settlement (15 minute settlement) will be applied for pool assets except hourly settlement will be applied for retail loads.
- Capacity-committed loads must be dispatched to reduce volumes at submitted prices, and must follow dispatch instructions. Non-committed capacity loads acting as price responsive load or demand response can continue to dispatch without a bid.

- Priced imports will be dispatched as other generating assets in the merit order at any time during the settlement period. If a priced import offer is dispatched on during a scheduling hour, it may set system marginal price as dispatched. If the import offer is dispatched off during the hour, intra-hour schedule changes may be performed.
- All priced imports and exports must make arrangements to ensure the interchange energy can flow as dispatched at any time during a settlement period (balancing authorities, and transmission providers will approve interchange transactions intra-hour).
- Any asset in the merit order may be directed as required to meet reliability reasons.
- Supply shortfall events will be managed by a procedure that provides for a priority to capacity committed loads that are bid at the cap to be directed last prior to releasing reserves.
- Supply surplus event to be managed as defined by the current Rule: dispatch down the $0 blocks to the minimum stable generation (MSG) levels, then dispatch off generating units as needed to balance supply and demand.

10.1.3 Dispatch Variance

- The dispatch variance rules will be tightened to reflect dispatch compliance by block to comply with submitted ramp rates by block.
- Allowable dispatch variance (ADV) will remain applicable to wind generation and extended to solar facilities (ADV definition amendment is to become effective on Sept. 01, 2018).

10.1.4 Unit Commitments

- Self-commitment will continue as per current ISO Rules for all resources.
- Generation resources, variable generation resources, intertie resources and energy storage resources, regardless whether capacity resources or not will self-commit to be ready to meet dispatch requirements as per ISO Rules Section 201.7, *Dispatches*.
- Self-commitment requirements also apply to capacity-committed load resources.
- Long Lead Time Energy (LLTE) resources will also submit offers to manage their self-commitment. Rules will be examined to align with capacity obligations and incentives related to a self-commitment model that leaves risks and costs with assets to manage.

10.1.5 Outage Scheduling:

- Generation capacity resources, variable generation capacity resources, energy storage capacity resources and capacity-committed load resources, with MC 5 MW or greater, must comply with ISO Rules section 306.5, Generation Outage Reporting, and Coordination. A new rule will be written to reflect load obligations.
- Generation resources, variable generation resources, and storage resources that are not capacity resources, with MC 5 MW or greater, must also comply with ISO Rules section 306.5 Generation Outage Reporting, and Coordination. Loads that have not capacity commitments must continue to comply with ISO Rules section 306.3 *Load Planned Outage Reporting*.
- The AESO does not provide approval of outage scheduling, and may cancel an outage as required.
- Long-Term Adequacy (LTA) and Short-Term Adequacy (STA) rules will be adjusted to reflect capacity resources.

10.2 Energy Market Monitoring and Mitigation

- *Ex ante* (in advance of the delivery hour) mitigation will be developed to supplement the current Ex post (after the delivery hour) monitoring and mitigation.
- *Ex ante* market power screens will be introduced into the energy market. An hourly pivotal supplier screen will be calculated to determine potential for market power. Companies that fail the screen must submit offers below the acceptable mitigated levels as measured on a fuel type or opportunity cost assessment as detailed below.

- *Ex post* market market-power evaluation will continue.

Pivotal Supplier Screen

- A pivotal supplier screen will be evaluated based on a residual supplier index (RSI) as calculated hourly at T-3, based on company offer control as a share of the market.
- The pivotal supplier calculation used provides adjustments for certain resource types such as dedicated supply (supplier purchases to serve its load), and suppliers with only wind/solar variable type resources. Import MW offers will only be limited to up to the intertie transfer capability.
- The approach can be summarized by the following equation :
- $$RSI_{it} = \frac{\sum_{j=1}^{n} Supply_{jt} + Imp_t - (Supply_{it} + Imp_{it} - Obligation_{it})}{Total\ Market\ Demand_t + Export_t + \ Reserves_t}$$

  The RSI for *Supplier*$_i$ in period *t* is:
- where the sum of *supply*$_{jt}$ represents the total capacity in the market at the relevant time *t*. *Total market demand* is the total demand in the market at time *t*. *Supply*$_{it}$ represents *supplier*$_i$'s total resources made available to the market at time *t.*
- *Supply* $_i$ includes full capability of units as measured by AC that may be offered in the energy or AS markets, and long lead time assets that have not been synchronized to the system. This threshold will be adjusted on occasion to ensure it is sufficient to restrict the abuse of market power.
- The RSI threshold will be set at 0.9. $RSIi$ < 0.9 will indicate companies that fail the screen based on their composite offer control.

Conduct Mitigation – Offer caps by assets of failed pivotal companies:

- Companies that fail the RSI screen as measured at T-3 must submit offers for each of their associated assets at T-2 that are restricted to the conduct mitigation levels (i.e., limits on offer behaviour) as outlined below:
- The conduct threshold will set an offer cap by asset fuel type as determined by 3 x short run marginal cost or by exception as noted below.
- The fuel-based bid threshold will be calculated at 3 x marginal cost defined as heat rate x fuel price + variable O&M + carbon cost.
- Owner of a capacity resource will have the opportunity to submit an exception request for approval and submit actual short-run marginal cost and if approved, these costs will be included as part of the 3 x conduct threshold evaluation for associated relevant assets.
- For non-thermal resources, owners of capacity resources will have the ability to submit opportunity cost for approval and these costs if approved will be included as part of the 3 x conduct threshold for associated company assets.
- The gas price used in the fuel price is the monthly Canadian natural gas price for the month in $/gigaJoule at AECO C, and Nova Inventory Transfer, the Alberta Bidweek Spot Price, as published on www.ngx.com, and also in the "Canadian Gas Price Reporter." [reference: ISO Rule section 201.6 Pricing].
- Market power screen and mitigation apply to both capacity and non-capacity resources on a company offer control basis.
- *Ex post* monitoring and mitigation will continue.

10.3 Pricing Methodologies

- Offer cap – no change from current $999.99/MWh subject to offer mitigation in Section 10.2.
- Offer floor – no change from current $0/MWh.
- Current shortage pricing is $1,000/MWh which is triggered when a directive has been issued to shed firm load. No change to shortage pricing.

10.4 Out-of-Scope Components for Energy and Ancillary Services Market Reforms

- The following design changes will not be included as part of the capacity market rule package or market roadmap, though they may be considered as part of a separate evaluation at another time as the need arises. The reason for this categorization is outlined in the rationale document though a brief explanation is summarized here.
  - Locational marginal pricing – with the current policy related to unconstrained and recent system build-out, pricing on transmission grid is not required at this time.
  - Offer cap above $999.99.
  - Negative pricing – the supply surplus events are currently cleared administratively and few issues have resulted. Introduction of negative pricing comes with some issues as well but will be reviewed as warranted.
  - Shortage pricing – supply shortfall events are also managed administratively and with few issues. Further, it is anticipated that with the introduction of a capacity market, shortage events will be even fewer. However, this concept will be further reviewed as required to incent price responsive behaviour near shortages.
  - Security-constrained unit commitment – centralized unit commitment will be evaluated in the future if identified by reliability issues caused by increasing supply surplus events or as part of an integrated solution like time ahead market. A self-commitment model maintains the risk with generators and sends incentive for flexible resources.
  - Intertie dynamic scheduling.
  - Co-optimization of energy, and ancillary services – on its own, not passing the modelling evaluation when considered against implementation costs; however, it may be considered as part of pending SCED evaluation.
  - Day-ahead Market (DAM) – the value of a DAM is heightened if concerns about market power are not mitigated or if the market values moving to a security-constrained unit commitment model are required to manage reliability risk. As a separate design element, the DAM effectively acts as a financial trading model, which most participants can handle independently outside of the market.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Rationale Document

Section 1: Alberta Capacity Market Framework

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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1. Alberta Capacity Market Framework

To supplement the Comprehensive Market Design proposal (CMD 1), this document discusses the input from the working groups and the feedback from industry stakeholders, as well as discusses the rationale for the AESO's proposed design.

Each working group developed and voted on recommendations on primary design elements, which were based on the submissions of the AESO, individual working group members, and external consultants. Working group recommendations were also summarized through the Straw Alberta Market (SAM) iterations and the broader stakeholder community had the opportunity to submit feedback on the content. This document details the analyses, rationale, working group feedback and broader stakeholder feedback used to arrive at the proposed design elements in CMD 1.

In 2017, the AESO, with input from industry stakeholders, identified design criteria that would drive the capacity market design. The proposed design is intended to satisfy the criteria. An assessment of alignment between the criteria and proposed design elements is also contained in this rationale document. These design criteria are outlined below:

Design Principles
Market
Capacity market should be fair, efficient, and openly competitive
Procurement of capacity should employ market-based mechanisms, and a competitive market for capacity should be developed
A wide variety of technologies should be able to compete to provide capacity, provided they are qualified to meet the eligibility criteria
Capacity market mechanisms, outcomes and relevant data should be transparent
There should be a well-defined product and an effective and efficient price signal
Cost and Risk
Investment risks should continue to be largely borne by investors rather than consumers
The market structure, which includes the capacity market, energy market and ancillary services market, should create conditions such that private investment can be reasonably expected
There should be an effective balance between capacity cost and supply adequacy
The term of the capacity obligation should be as short as possible, while ensuring supply adequacy objectives are achieved through sufficient investment in new capacity supply
The design should allow consumers to manage the cost of capacity, if and where appropriate
Supply Adequacy and Reliability

The capacity market should achieve desired reliability objectives by creating a measurable supply adequacy product designed to provide energy production or reduced consumption when needed
The capacity market should contribute to the reliable operation of the electricity grid, and implementation should be consistent with, and complementary to, existing measures aimed at reliability
Flexibility
Unique aspects of Alberta's electricity system should be considered in the design of the capacity market
The capacity market should be compatible with other components of the electricity framework
Timely Development
Market should be targeted to open in 2019 with start of first capacity procurement for delivery of capacity starting in 2021
Changes to energy and ancillary services markets required to achieve the most efficient steady-state electricity market possible may need to be staged to ensure timely initial implementation
To the extent a staged implemention of the overall electricity market is pursued, the expected timing and nature of future changes should be provided before opening the first procurement
The risks of regulatory delay and need for re-design should be minimized
Common practices and lessons learned from other capacity market implementations should be leveraged as much as practicable and applicable
Simple and straightforward initial implementation should be a priority

Going forward, the AESO will continue to engage stakeholders – both through working groups and broadly – to continue to develop and refine the CMD. A final design recommendation will be provided by the AESO in June 2018.

Alberta Capacity Market

Comprehensive Market Design (CMD 1): Design Rationale Document

Section 2: Supply Participation

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2. Supply Participation

2.1 Prequalification for Capacity Resources

2.1.1 General Prequalification Requirements

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Many of the prequalification topics identified were not discussed by the Eligibility working group through SAM 3.0.
- Resources 1 MW and greater should be eligible to participate in the capacity market.
  - The working group unanimously supported resources 1 MW and greater participating in the capacity market. They indicated that resources 1 MW to less than 5 MW should be eligible to participate on a “may offer” basis while resources 5 MW and greater “must offer” into the capacity market.
  - Stakeholder feedback received through SAM 3.0 suggested that 1 MW is an acceptable size; however, additional work could be completed to determine if it should be lower (or higher) than 1 MW.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0.

AESO Rationale:

- Requiring qualified resources to participate in future auctions, unless delisted, gives the AESO visibility to auction participants and more accuracy in determining supply adequacy.
- A 1 MW minimum size aligns with energy market minimum block size and the declaration of available capacity (AC). In order to perform the availability assessment, an AC must be captured and maintained for the capacity resource.The requirement for capacity resources to demonstrate the ability to sustain energy for at least four hours derives from the historical observation of the duration of system stress events (emergency energy alerts, or EEAs, last on average four hours). This is not to say that the capacity resource does not have an obligation past four hours; it’s simply to say that in order to prequalify the capacity resource must be able to sustain its unforced capacity (UCAP) in energy production for four hours.

2.1.2 ISO Requirements for Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- ISO requirements for prequalification topics identified were not discussed by the working group through SAM 3.0.

2.1.3 External Capacity Resources Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Resources external to Alberta should be eligible to participate in the capacity market.
- The working group unanimously supported resources external to Alberta participating in the capacity market.
- Stakeholder feedback received through SAM 3.0 suggested that the capacity market should be inclusive, subject to resources competing on a level playing field.

- As it relates to imports, stakeholders suggested that importing resources should have bids reviewed for out-of-market payments.

AESO Rationale:

- Allowing external resources to participate in auctions provides an additional source of supply and increases market liquidity and competition.
- Prequalification requirements for external resources are intended to ensure that external resource capacity is deliverable to Alberta under required system conditions.

2.1.4 Demand Response Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Demand response resources and price responsive load should be eligible to participate in the capacity market.
- The working group unanimously supported the participation of demand response resources and price responsive load on the supply side of the capacity market with the ability to choose between down-by and down-to offers.
- The working group was also directionally aligned that demand response participation on the demand side of the capacity market should be allowed.
  - The working group did not vote on demand response participation on the demand side of the market given the uncertainty related to cost allocation, and would consider that resource's participation once the approach to cost allocation is resolved.
- Stakeholder feedback received through SAM 3.0 suggested that the capacity market should be inclusive, subject to resources competing on a level playing field.
  - As it relates to demand response, some stakeholders also suggested the various rules that demand response should be excluded from, or have exceptions with, including UCAP calculation, and must-offer requirements.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0 in terms of demand side resources participating on the supply side of the market. The design differs from SAM 3.0 in that the participation of demand response resources on the demand side of the capacity market is not proposed at this time.

AESO Rationale:

- A demand response resource must be a retail or self-retail asset belonging to a valid pool participant to ensure the appropriate metering is captured and collected.
- Demand response and price-responsive load will only be eligible to participate on the supply side of the market in the initial capacity market because demand-side participation adds extra complexity for the auction bidding process and clearing. Additionally, the mechanism for cost allocation is unknown at this time and there are no assurances that a demand side resource will have its costs reduced by the volume cleared in the capacity market.
- Participation on the demand side of the capacity market may be considered as a future market enhancement once the cost allocation methodology is completely understood.

A demand response resource must be a retail or self-retail asset belonging to a valid pool participant to ensure the appropriate metering is captured and collected. The capacity market will leverage the existing load settlement processes to ensure accurate and consistent measurement. This restriction will limit aggregation of component resources to the pre-defined load settlement zones.

2.1.5 Energy Efficiency Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The working group did not reach a recommendation on energy efficiency. Additional information regarding eligibility and performance measurement is required.
  - The working group had requested additional questions be answered prior to a recommendation on the eligibility of energy efficiency (EE), including:
    - How are out-of-market payments handled for energy efficiency resources?
    - What are the administrative costs for participating on the supply side of the capacity market? On the demand side?
    - Will historical EE projects be eligible? How far back?
    - How is energy efficiency reflected in the adequacy target?
- At some point, do energy efficiency projects move from a supply offer to be reflected and adjusted in the total demand procured?
  - Stakeholder feedback received through SAM 3.0 suggested that the capacity market should be inclusive, subject to resources competing on a level playing field.
    - As it relates to EE, stakeholders shared a mixture of support or opposition to energy efficiency participation, often citing that the market should not pay for a resource whose delivery of capacity cannot be effectively measured.
    - Those in support of energy efficiency resource participation cited it as a low-cost, short lead time resource that can reduce capacity costs to consumers.

Comparison to SAM 3.0 Position:

- The design is materially different from what was described in SAM 3.0.

Energy efficiency resources will not be eligible in the initial implementation of the market.

AESO Rationale:

- While EE is a capacity resource in other capacity markets, the complexities other markets have faced with determining UCAP and assessing performance for EE requires further study of the implementation issues associated with EE, which precludes participation in the initial auction. In recognition of the potential benefit that EE resources may provide to the capacity market, a roadmap will be developed to determine EE participation in future auctions.

2.1.6 Variable Energy Resources Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The working group assumed conventional and variable generation would be eligible to participate, excluding Renewable Electricity Program (REP) resources, subject to the same performance requirements for all resources in the capacity market.
- Stakeholder feedback received through SAM 3.0 suggested that the capacity market should be inclusive, subject to resources competing on a level playing field.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0.

AESO Rationale:

- Including variable resources will increase overall market competition provided that their reliability value is appropriately reflected.

2.1.7 Storage Resources Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0;

- Storage resources should be eligible to participate in the capacity market.
- The working group unanimously supported the participation of storage resources in the capacity market.
- Stakeholder feedback received through SAM 3.0 suggested that the capacity market should be inclusive, subject to resources competing on a level playing field.
- As it relates to storage, some participants noted that the existing tariff may warrant a redesign to encourage storage participation, and that the AESO should consider a UK model for its UCAP calculations for storage resources.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0.

AESO Rationale:

- Including storage resources will increase overall market competition provided that their reliability value is appropriately reflected. Requirements for storage resources to maintain their energy production to the UCAP level for at least four hours are intended to ensure sufficient reliability value from the resource.

2.1.8 Aggregate Capacity Resources Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Resources should be able to aggregate when participating in the capacity market.
- The working group unanimously supported resource aggregation in the capacity market provided that one of two conditions are met:
  - Aggregation of resources allows the UCAP of the combined resources to be higher than the UCAP of each individual resource; or
  - Aggregation allows the resources to meet the minimum size threshold in the market.
- The working group also agrees that resources behind a single meter may aggregate to form one capacity supply resource.
- Stakeholder feedback received through SAM 3.0 was supportive of aggregation.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0.

AESO Rationale:

- The AESO supports aggregation because it increases overall market competition while providing the opportunity for resources smaller than 1 MW to participate in the market.
- Aggregation beyond a single enterprise is not permitted, as is the case in the energy market, because the AESO can only produce a bill/statement for a single entity or divide the settlement results according to per cent ownership share.

2.1.9 Self-supply Resources Prequalification

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- A majority of the working group (all 14 agreed, one with reservation) recommended that the following requirements apply for loads to be eligible to self-supply:

- The load must be capable of being served in whole or in part by generation that is located on the same site, and at the same point of interconnection to the electric system, or under an Industrial System Desgination or Duplication Avoidance Tariff.
  - Sites with onsite generation that cannot physically flow their gross volumes due to system connection limitations must self-supply.
  - Sites with onsite generation and no connection flow limitation can choose to self-supply with the following conditions:
    - The site must have a bi-directional net interval meter at the connection to the electric system.
    - Be a pool participant.
    - On-site generation (gross) must meet the minimum eligibility requirements for capacity resources (i.e., size, project milestones for new resources).
  - Self-suppliers can be connected to either the transmission system or the distribution system provided they meet the requirements listed above.
  - Self-suppliers must declare their intention to self-supply prior to the base auction for the delivery year.
    - This would not limit a new resource's participation in rebalancing auctions.
- Industry feedback on SAM 3.0 indicated:
  - General support for the requirements with certain language suggestions as modifications.
  - Physical constraints that limit generation volumes from being delivered to, and the load from being served from, the interconnected electricity system should be recognized.
  - Self-supply eligibility should not be limited to self-supply where the load and generation are owned by the same participant. The requirements should not restrict arrangements from being considered by application of the condition that the on-site generation must be a pool participant.
  - The cost allocation approach chosen by the government should be taken into account and it is important to strive to ensure fairness, avoid cross subsidization, and avoid any unintended reliability consequences.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0.

AESO Rationale:

- A limitation has been put on self-suppliers such that they can only switch self-supply status every three years to increase market certainty because the AESO needs to know how much self-supply capacity to remove from the procurement volume in order to build an accurate demand curve. Accordingly, the AESO needs to know a self-supplier's intention in the delivery year before each base auction for that delivery year.

2.1.10 Prequalification of Existing Capacity Resources

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The prequalification of existing capacity resources was not discussed by the working group through SAM 3.0.

AESO Rationale:

- Prequalifying existing assets reduces administrative burden. Changes in prequalification status are intended to reflect changes in the ability or intention of the resource to provide UCAP, which needs to be reflected in subsequent auctions.

2.2 Qualification for All Resources

- Allowing prequalified resources to remain eligible for future auctions until delisted or deemed ineligible by the AESO reduces the administrative burden of prequalifying resources every year for every auction.
- The qualification process will occur before every auction in order to ensure that UCAPs have not changed for prequalified resources from auction to auction.

2.3 Unforced capacity (UCAP) Ratings

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The working group unanimously supported using UCAP to represent capacity values, with reservations related to flexibility of behind-the-fence generation, subject to an appropriate performance and payment adjustment mechanism and subject to reasonable data requirements for new assets.
- Stakeholder feedback received through SAM 3.0 was supportive of using UCAP as a calculation method.
- The working group also explored various methodologies for calculating UCAP of various technologies, including effective load carrying capability (ELCC) and other resource-specific calculations used in other markets. Many working group members and industry stakeholders suggested that the AESO should strive for a single methodology to calculate UCAP for all resource types.
- The working group was supportive of forced outage rates being included in the calculation of UCAP, with some stakeholders suggesting that planned outages should also be included in the calculation.
- Working group members and stakeholders have expressed concern with the AESO's ability to calculate UCAP with the current data it collects through the Energy Trading System (ETS).

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0 as UCAP is being utilized. Calculation details of UCAP were not defined in detail in SAM 3.0.

UCAP for Self-supply: Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The working group achieved directional alignment that the UCAP for self-supply sites with installed capacity of onsite generation greater than their total load should be determined based on ELCC.
  - The working group members expressed concerns with the complexity and lack of transparency with the approach; however, felt it represented the best way to determine UCAP for these types of sites.
  - It was recognized that further exploration of this option is required and the AESO and working groups should investigate whether a simpler process could proxy for full-blown effective load-carrying capability modelling.
- Industry feedback on SAM 3.0 indicated general agreement that the UCAP calculation be done on a net basis for behind-the-fence resources, such as ELCC or analysis of relevant historical data.

Comparison to SAM 3.0 Position:

- The proposed design is different from the SAM 3.0 recommendation, in that the AESO proposes not to use an ELCC methodology to calculate UCAP for self-supply resources. The proposed design is to calculate UCAP for net self-supply resources using a capacity factor methodology.

AESO Rationale:

Why UCAP instead of ICAP in Alberta's capacity market?

- The AESO selected UCAP for the Alberta capacity market because linking UCAP determination for capacity resources to performance during scarcity conditions creates an incentive for capacity resources to maintain high availability and perform when the system needs them most.
- Installed capacity (ICAP) reflects only the technical specification of the capacity resource while UCAP captures the observed operational performance over a defined historical period.
- Capacity resources that perform better than or equal to their UCAP during periods of system stress will receive a higher UCAP rating and will also avoid payment adjustments. Both these factors may allow the resource owner to submit competitive offers in the capacity auction, making them more likely to clear in the capacity auction.
- UCAP methodology is based on sound principles for capacity market design:
  - UCAP methodology: accounts for performance risk. Suppliers—and not consumers—bear the risk and the rewards associated with their resource's performance and thus UCAP rating. This places risk in the right place, in order to incent investment by suppliers to maintain high resource reliability (high UCAP) and to enable the capacity market's price signal to select a reliable, cost-effective resource portfolio.
  - UCAP methodology is resource neutral. All capacity resources receive a UCAP rating based on performance during a subset of tight supply cushion hours. A supplier of 1 MW of UCAP will be able to deliver the same amount of system reliability and receive the same compensation regardless of their technology.

Why not ELCC?

- The use of an ELCC approach was suggested and considered through the working group process for quantifying the UCAP of certain technology types, and even all asset types.
- ELCC measures the capacity of a particular resource by simulating the resource adequacy effects through isolation of the impact of the resource in question from those of all the other sources. This is accomplished by calculating the unserved energy expectation of two different cases: one with and one without the resource. Some other jurisdictions have chosen to use an ELCC methodology to quantify the value of variable generation resources. MISO uses ELCC for wind UCAP determination. Ireland uses a form of ELCC for all resource types.
- The AESO proposes to not use an ELCC approach to estimate the UCAP technology types in the initial capacity market auction for the following reasons:
  - First, it is less transparent than the chosen methodology and market participants would not be able to assess how investment and operation decisions would impact their UCAP in the future.
  - Second, it is more complex than the chosen methodology, and with the limited experience with the new resource adequacy modeling tool and limited time for market implementation, the increased complexity and risk wasn't considered feasible.

Why not EFORd?

- The AESO proposes not to use the equivalent forced outage rate (EFORd) under demand conditions to determine UCAP in the auction because the AESO does not have the data available to accurately calculate an EFORd statistic for all assets. While the data could be obtained, the capacity and availability factor approach, which uses energy market data in its determination, will provide an equivalent measure of unit reliability during periods of tight supply conditions.

Why an annual rather than a seasonal UCAP?

An annual UCAP is being determined to align with the annual capacity product the AESO is procuring.

- The AESO selected an annual UCAP based on working group analysis and discussion that a seasonal capacity market product introduced complexity into the capacity auction. The working group idenitified that a seasonal UCAP and market could:
  - Reduce investor certainty due to the difficulty in forecasting capacity market revenues.
  - Present difficulties associated with the need for a higher price cap in a seasonal auction (which is required for resources that might only clear one season but require a full year's worth of capacity revenue to remain in the market).
- The working group also discussed that the estimation of a seasonal capacity volume and seasonal UCAP became increasingly difficult as the period of estimation became more granular given the data available to the AESO.
- The work group and SAM 3.0 feedback is generally split equally between the selection of a seasonal and annual capacity product. While a seasonal product differentiates between the seasonal capacity needs and allows resource types with seasonal capacity to monetize such value, it was decided that the additional complexity of a seasonal auction would negate these benefits.

Why tight supply cushion hours for the determination of UCAP?

The supply cushion is the difference between the energy that Alberta supply is capable of supplying at a given moment in time, and what is actually demanded by load.

Supply cushion is a proxy for real-time system reliability risk. A large supply cushion indicates less real-time system reliability risk, because more energy remains available to the AESO to respond to unplanned market events. A low supply cushion indicates that the system has fewer resources available to react to unexpected outages or load increases.

Supply shortfall conditions arise when the supply cushion is zero. When the supply cushion falls to zero, all available power in the merit order has been utilized, and System Controllers may be required to take emergency action to ensure system stability.

- The AESO chose tight supply cushion hours to reflect the reliability value of a resource when it is most required by the system. Measuring asset performance during a historical subset of tight supply cushion hours would be indicative of future performance of the capacity resource.

Why 5 years of history and 100 tight supply cushion hours each year for determination of UCAP?

- Assessing a resource's capacity contribution over a five-year period will provide a reasonable estimate of future unit performance. This large sample over periods of low supply captures the variability in system conditions over different seasons.
- The number of recommended hours for the availability assessment (100 hours annually) is based on the average number of hours historically between 2011 and 2017 in which supply cushion was below 400 MW, conditions which characterize system tightness. On average, 100 hours split evenly between the summer and winter seasons should result in 35 days of the availability assessments annually. When using the availability assessment days for the past five historical years (175 independent samples) to calculate UCAP, the statistical error in the UCAP estimate is approximately 2%, providing a robust estimate or resource capability during tight supply cushion hours, including EEA events.

Why capacity factor for variable generating units?

The capacity factor is the ratio of actual electrical energy produced over a given period of time to the maximum possible electrical energy output over the same amount of time.

- Run-of-river hydro, wind and solar generators have capacity factors limited by the availability of their fuel source (water, wind or sunlight). The amount of energy produced by variable resources is independent from energy market signals. In other words, variable generators cannot change production output to respond to tight system conditions (when energy prices are at their peak) and only generate if the fuel source is available. The capacity factor methodology proposed by the AESO serves as a good proxy for capturing the level of reliability that a variable resource can provide the system in tight system stress conditions.

- Self-supply resources are built primarily to supply onsite load and, similar to variable generators, operate for the most part independent from market energy signals. However, some self-supply resources are capable of providing operating reserves and those may not be captured using a simple capacity factor calculation. The AESO will explore whether modifying the capacity factor calculation to better capture the level of reliability that a self-supply resource can provide the system is required in order to reflect this.

- The AESO proposes that a capacity factor methodology that captures both historical energy and dispatched operating reserves will allow approximation of the level of reliability that the intertie can provide when also taking into consideration transmission transfer capabilities. Historical scheduled amounts allow for interactions between energy markets throughout the Western Electricity Coordinating Council's jurisdiction and other complex factors that may impact external supply to be reflected in intertie capacity values.

Why availability factor for dispatchable resources?

The availability factor measures the energy plus operating reserve capability of a dispatchable unit during historical periods of tight supply.

- The availability factor of a large hydro or thermal resource measures the percentage of the time that resource has historically been available to provide energy to the grid. The AESO considers the hydro assets on the Big Horn, Brazeau and Bow River systems to be large hydro assets. By reviewing unit availability over a significant number of historical hours, the AESO expects this factor will be a good determination of the resource's ability to deliver energy over future periods of tight supply.

- The must-offer, must-comply framework ensures that the available capability declared by these resources in the past reflects actual unit capability to generate energy or provide operating reserves at any given hour.

- The availability factor provides a good representation of a resource's future ability to perform under similar conditions.

- The data required to complete the availability factor calculation is available to the AESO through unit specific historical available capability submission in ETS, which is representative of a unit's actual availability given the must-offer, must-comply obligation under the ISO rules.

- The availability factor methodology:
  - Is unit specific.

  - Aligns individual performance with capacity market revenues.
  - Captures both the energy and the operating reserve potential of a generation unit.
- The maximum capability values of a unit are stable and only increase when a unit upgrades its capability

Why does the UCAP value capture both planned and forced outages?

In eastern capacity markets, the UCAP value only reflects resource forced-outage rates. , which are assumed to be random and do not reflect planned maintenance outages. The determination of capacity requirements in these ISOs assumes that planned maintenance outages (including the refueling outages of nuclear plants) occur during low-load periods of the year in which the capacity is unlikely to be needed. Capacity market systems, therefore, restrict the scheduling of planned maintenance outages by capacity market resources. NYISO, ISO-NE, and PJM require that generators provide advance notification of all planned outages, and outages are subject to being rescheduled by the ISO based on reserve adequacy or reliability needs.

- In eastern capacity markets the UCAP value only reflects resource forced-outage rates. However, Alberta's capacity market needs to ensure that planned maintenance outages are, in practice, scheduled in a manner consistent with the assumptions used in developing the capacity requirement. Currently, the AESO does not restrict the duration and frequency of planned maintenance outages scheduled by the participant, as long as notification of the planned outage is provided to the AESO 24 months in advance (ISO Rule 306.5).

- ISO Rule 306.5 is expected to remain unchanged (see Section 10 for further details). The AESO will be informed of generator planned outages but not act as an approver. In other words, there will be no restriction on market participants in regard to schedule timing, duration and frequency of planned outages in Alberta’s capacity market. Added flexibility in selecting the timing and duration of maintenance outages translates into special considerations in estimation of the resource’s contribution to system reliability. The probability of resource unavailability due to planned outages should be reflected in a resource’s UCAP values as they better reflect the realities of Alberta’s outage planning rules.

Including planned outages in UCAP calculations is intended to incent the overall reliability characteristics required by the system.

- See PJM: Generator Planned Outages http://www.pjm.com/~/media/committees-groups/subcommittees/raas/20170530/20170530-generation-outage-categories.ashx
- See ISO-NE FCM https://www.iso-ne.com/static-assets/documents/2017/02/m20_forward-capacity-market_rev24_20170203.pdf
- See AESO Rule 306.5 https://www.aeso.ca/rules-standards-and-tariff/iso-rules/section-306-5-generation-outage-reporting-and-coordination/

2.4 Credit Requirements for Participation as a New Capacity Resource

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Topic was not discussed by the working group through SAM 3.0.
- The AESO intends to impose capacity market credit requirements for new resources selling into the forward and rebalancing capacity markets. These credit requirements for new resources selling into the capacity market will help mitigate the risk of new resources failing to deliver on their obligations,

and becoming unable to pay for all of their obligations to the AESO The AESO developed its credit requirement proposal in consideration of Alberta's unique needs, and after reviewing the credit rules used in PJM, ISO New England, and the UK – the three most established forward capacity markets. Table 1 below summarizes the capacity market credit requirements in these other markets.

- The AESO intends to adopt this rationale as well. New resources pose a much greater risk of non-delivery compared to existing resources, since they are not in service at the time they clear the forward auction. Any number of factors could interfere with a new resource's ability to come online by the start of the delivery year, including: delays in permitting, failure to secure financing, delays in equipment delivery, delays in construction and equipment installation, issues with installation that lead to a lower than expected capacity rating, and insolvency of the developer. These factors drive the capacity market credit requirement. In contrast, most of the credit risk associated with existing resources is due to their participation in energy and ancillary services markets, and is already covered under the AESO's current credit policy.
- The credit requirement mitigates the risk of non-delivery and failure to pay adjustments by:
  - Allowing the AESO to recover some of the payment adjustments it is owed, and replacement capacity costs it incurs due to non-delivery.
  - Creating an additional incentive for new resources to physically deliver.
- In order to reduce costs to consumers, the AESO must establish a credit requirement sufficiently high to minimize the impacts of defaults.[1] At the same time, credit requirements cannot be set so high as to create unnecessary barriers to participation by smaller investors. While ISO New England (ISO-NE), and the UK have comparable credit requirements, PJM's is much higher. PJM's higher requirement may be due to a more conservative approach to credit risk, and the fact that PJM increases market participants' unsecured credit limit if they earn net revenues in PJM's markets. The AESO's proposal to impose a capacity market credit requirement of 15% of annual net-CONE (with a minimum value of $7.30/kW-year) strikes a reasonable balance between these factors, and is consistent with the requirements in other jurisdictions shown in Table 1.
- The cost to the AESO of non-delivery increases with each forward auction cleared by a new resource, which is why the AESO is proposing to impose the 15% of net-CONE credit requirement for each delivery year. As Table 1 shows, this proposal is consistent with the approaches of PJM, ISO-NE, and the UK.
- The AESO's proposed capacity market credit requirement for new resources will supplement its existing credit policy which specifies limits on unsecured credit, and the acceptable forms of secured credit for participants across the AESO's markets. In Table 1 we report unsecured credit limits, and acceptable forms of secured credit for the two U.S, and the UK forward-capacity markets. Unsecured credit limits in U.S. markets were tightened by the Federal Energy Regulatory Commission (FERC) following the 2008 financial crisis when U.S. RTOs faced severe credit stresses. In Order 741 and its subsequent modification, the FERC limited unsecured credit to $50 million per market participant.[2] In both U.S. markets, unsecured credit limits increase with the credit rating of the market participant and its net worth up to the $50 million limit. PJM also allows a market participant's historical net revenues across PJM's markets to count toward its unsecured credit limit for the purposes of its capacity market credit requirement. These differences across markets may be explained by differences in volatility. Generally, a more volatile market will require higher credit requirements. At this time, the AESO does not believe that any change is required to its current guidelines on unsecured credit or acceptable forms of secured credit.

[1] The other objective of credit policy, to protect the AESO's liquidity in the event of a default, is less pressing in the case of the capacity market since the AESO is the only buyer in the forward capacity market.

[2] In the same order, the FERC also imposed several other requirements intended to reduce the liquidity risks and costs to ISO/RTOs of a market participant default. Most of these requirements are not directly applicable in the capacity market context. See: Credit Reforms in Organized Wholesale Electric Markets, Order No. 741, 75 FR 65942 (Oct. 21, 2010), FERC Stats. & Regs. ¶ 31,317 (2010) (Order No. 741) and Order No. 741-A, 76 FR 10492 (Feb. 25, 2011), FERC Stats. & Regs. ¶ 31,320 (2011).

Table 1

Capacity Market Credit Requirements for New Resources in Other Forward Capacity Markets

Component	PJM[3]	ISO-NE[4]	UK[5]
Applicability	New capacity only	New capacityoOnly	New capacity only
Credit Requirement (After Clearing a Forward Auction)	~50% Annual net- CONE	8.3% Annual Clearing Price	£10,000/MW (~12% Annual net-CONE)
Adjustment of Credit Requirement Over Time	Increases with each forward auction cleared for separate delivery years	Increases with each forward auction cleared for separate delivery years	Increases with each forward auction cleared for separate delivery years
Unsecured Credit Limit	Increases with credit rating, net worth, and historical net revenues across all PJM markets Maximum: $50 million per market participant	Increases with credit rating, and net worth Maximum: $50 million per market participant	N/A
Acceptable Forms of Secured Credit	Cash Letter of Credit	Cash Letter of Credit Mutual Fund Shares	Cash Letter of Credit

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- As project milestones are achieved, the AESO will reduce the capacity market credit requirement since the risk that a new resource will fail to deliver decreases. The quantitative reduction in credit requirement with each completed milestone is intended to reflect the associated reduction in non-delivery risk.
- Reducing credit requirements as milestones are completed also provides incentive for resources to adhere to development timelines.

2.5 Supply Participation Assessment Against the Capacity Market Design Criteria

- By adopting a standard capacity product based on UCAP, the capacity market should achieve desired reliability objectives by creating a real and measurable supply adequacy product that will allow a wide variety of technologies to compete to provide capacity.
- Supply participation considers the unique aspects of Alberta's electricity system in the design – in particular, the treatment of cogeneration – and the calculation of UCAP for capacity providers given the fact that our highest demand for capacity is when capacity resources are restricted the most.
- The UCAP methodology, while unique, is consistent with the criteria around best practices and lessons learned from other capacity markets' adoption of UCAP as a standard capacity market product definition.

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[3] Credit Overview and Supplement to the PJM Credit Policy, October 6, 2017.

[4] Exhibit IA, ISO New England Financial Assurance Policy, June 1, 2017.

[5] Applicant's Credit Cover Process, July 6, 2015. Government Response to the March 2016 consultation on further reforms to the Capacity Market, 2016.

- The eligibility of energy efficiency will be included as part of the market evolution roadmap. This is consistent with the criteria for pursuing staged implementation where appropriate.

Alberta Capacity Market

Comprehensive Market Design (CMD 1) Design Rationale Document

Section 3: Calculation of Capacity Market Demand Parameters

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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3. Calculation of Capacity Market Demand Parameters

3.1 Alberta System Load Forecasts

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

Not all working group members agree with using Alberta Internal Load (AIL) to forecast load, and propose that using Alberta Interconnected Electric System (AIES) or system load would be a simpler and more accurate approach.

The Supply Adequacy working group did not establish a provisional recommendation on the methodology to forecast load; however, the approach was reviewed and comments were provided to the AESO by working group members.

AESO Rationale:

Key objectives for the AESO's capacity market load forecast are transparency, accuracy and following industry best practices.

Gross demand (i.e. AIL) is currently the best measure of total provincial demand for which Alberta will need to procure capacity. Gross demand, as opposed to net-to-grid demand, is best suited to capture the overall behaviour between economic activity and load.

Forecasting gross demand aligns with the AESO's current planning and reliability mandate.

Utilizing multiple hourly weather and economic profiles introduces load-related uncertainty to the resource adequacy modelling, which provides a better reflection of the range of potential future conditions through which the reliability performance of differing capacity volumes can be tested.

A key intent of the AESO's load forecast models is to minimize model error.

Additional details of the proposed load forecast methodology and process can be found here: www.aeso.ca/assets/Uploads/Capacity-market-load-forecast-model-description-and-process.pdf.

3.2 Establishment of the Resource Adequacy Standard

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

Generally, the working group agrees on the following points:

The Government of Alberta should set the physical resource adequacy requirement with target values for expected unserved energy (EUE) and/or loss of load hours (LOLH).

The AESO and/or working group should provide the Government of Alberta with a recommendation on setting the reliability targets and measures.

LOLH or EUE are acceptable resource adequacy criteria, but loss of load expectation (LOLE) is not the optimal resource adequacy criterion because it is an overly conservative measure.

AESO Rationale:

- Based on public policy announcements, the Government of Alberta is expected to establish the supply adequacy standard.

Through the working group process, a working assumption on the resource adequacy standard was required to evaluate the demand curve options. An initial working assumption of 100 MWh/yr of expected unserved energy was established. Following additional review of historical data, the AESO is revising this working assumption to 400 MWh/yr. The impact of this revision to the demand curve analysis can be found in Section 3.5. The government is expected to define the resource adequacy standard for Alberta, which will be used in developing the capacity demand curve.

3.3 Modelling to Estimate Resource Adequacy Standard

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

The working group agrees that target procurement volume should be based on probabilistic resource adequacy requirement modelling, considering supply adequacy impacts of all resources regardless of their capacity market eligibility.

The working group reviewed and approved a set of methodologies and inputs for the resource adequacy modelling. Continued transparency is requested in the ongoing consultation process.

AESO Rationale:

- A probabilistic approach is expected to provide greater information on the relationship between capacity and supply adequacy, as well as better capture the correlations between supply and demand variability. This results in a more informed and accurate estimation of the target procurement volume.

Additional material on the model inputs and methodologies were evaluated within the Adequacy and Demand Curve working group and additional material can be found here:

https://www.aeso.ca/assets/Uploads/Best-Practice-Comparison.pdf

https://www.aeso.ca/assets/Uploads/ReliabilityModeling-Final.pdf

https://www.aeso.ca/assets/Uploads/ReliabilityModeling-Materials-Nov8.pdf

https://www.aeso.ca/assets/Uploads/1.2-WIG-Recommendation-Reliability-Modeling.pdf

- The AESO continues to explore other assumptions/inputs as it implements the resource adequacy modelling tool, including modelling operating procedures during emergency energy alerts, modelling regulating reserves, correlating demand and supply at specific sites, and the availability and capability of imports.

- The required generation capacity volume will be reduced by the qualified volume of self-supply and ineligible resources, and take into account unqualified import UCAP to determine the target procurement level for the capacity auction. This ensures all capacity volumes are accounted for, such that the target level of reliability is achieved at lowest cost to consumers and capacity is not over-procured.

3.4 Calculation of Gross-Cost and Net-Cost of New Entry

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

The working group reached directional alignment on:

Using an independent consultant with Alberta-specific expertise in financing and developing power plants to calculate gross-cost of new entry (gross-CONE).

Selecting the reference technology based on the following criteria: most frequently developed (historically); most economic (lowest net-cost of new entry or net-CONE); lowest capital cost (lowest gross-CONE); and shortest time to energization (development timeframe).

Stakeholders and working group members shared similar comments that the financing inputs are to consider Alberta's market context.

The working group was directionally aligned with the AESO's rationale that simple-cycle technology currently best fits these criteria.

SAM 3.0 industry stakeholder comments supported having independent experts calculate gross-CONE and net-CONE using a simple-cycle gas turbine as the reference technology.

AESO Rationale:

Gross-CONE Calculation

- The gross-CONE and net-CONE are significant inputs into the capacity market demand curve, and for a functioning capacity market. Accurate estimation ensures that new resources are attracted to enter the market when appropriate price signals are present. Contracts with independent financing and engineering services firms, to determine appropriate detailed cost estimates for the gross-CONE, increase the objectivity and accuracy of estimates. Using an independent and experienced consultant will provide a more accurate gross-CONE value, which properly reflects the appropriate financing and plant development costs for the generic reference plant.

- Due to the in-depth nature of the gross-CONE estimate, the AESO expects that the comprehensive study will be used for three to five years. The gross-CONE estimate will be updated using indices which reflect changing market conditions and capture changes in capital costs between study updates. This approach will ensure efficient, timely and transparent annual gross-CONE studies, while maintaining an updated accurate measure of the cost of new entry.

Reference Technology

- The reference technology selection is designed to ensure the capacity market provides adequate revenue for required generation additions.

- As described by the criteria outlined above (i.e. frequency of historic generation project developments, the lowest gross-CONE, the lowest net-CONE, timeline to delivery, and the generation source of last resort), the reference technology should represent a technology that can be developed to meet the capacity needs during the capacity auction timeframe at a low cost and, philosophically, be the unit most likely to be developed under predicted future market conditions.

- Currently, simple-cycle technology best fits all these criteria in Alberta.

- In all capacity market jurisdictions, the reference technology is based on a gas-fired power station. Some capacity markets refer to a combined-cycle plant, while other markets prefer a simple-cycle reference technology.

- The AESO anticipates that limits on greenhouse gas emissions from large facilities will constrain the development of simple-cycle facilities larger than 150 MW in the future. Based on this, the AESO is expecting that the default size of the reference technology selection will be 150 MW or less. This level also corresponds roughly to the size of the annual average growth of the Alberta mAeroderivative turbines including LM6000's, E-class turbines, reciprocating internal combustion engines and LMS100 turbines all represent simple-cycle technologies with recent developments in the province. Fuel efficiency tends to favor LMS100 turbines and reciprocating internal combustion engines, while availability and maintenance costs may favour LM6000 or E-class power plants.

- Further analysis to support this recommendation can be found here:

www.aeso.ca/assets/Uploads/2.2-Cost-of-New-Entry-Document-for-Adequacy-Demand-Curve-Working-Group-Final-2017Nov22.pdf

Financing Costs

- Using an approach that considers Alberta-specific conditions for financing generation projects will most accurately characterize on-the-ground conditions for developing supply to meet adequacy needs. The AESO will work with the external consultant to provide realistic financing assumptions in the gross-CONE calculation, based on observable cost, and leverage data applicable to Alberta-based power projects.

- The ATWACC for individual firms is expected to vary greatly as different participants and projects will have asymmetric credit ratings, costs of debt and debt/equity ratios.

Energy and Ancillary Services Net Revenues

There are several methods that can be used to determine the net energy and ancillary services revenues which will determine the net-CONE. Some capacity markets use historical revenue analysis to determine future energy and ancillary services revenues for the reference plant, while other markets prefer to forecast or forward prices using a specific formula. An additional option is to approach the net energy and ancillary services revenues using a simulated forecast approach.

- The methodology will dictate the production and the resulting energy and ancillary services revenues for the reference plant. Annual energy and ancillary services net revenues can be subtracted from the gross-CONE to determine net-CONE for the reference plant.

- The AESO selected a forward-looking approach to energy and ancillary services revenues because, based on Alberta's circumstances, historical revenue anlaysis and forward electricity pricing are not adequate for developing an energy price outlook. First, historical prices reflect volatility that may be dampened in the future with a capacity market and potential market power mitigation in the energy market. Second, Alberta's energy market is undergoing a significant change based on fleet make-up and broader policy impacts, thus a forward-looking approach is needed to reflect market conditions faced by participants. Further, incorporating the forward power price curve is challenging in the Alberta context given that forward curve liquidity significantly decreases beyond a two-year time horizon, and average on-peak prices do not provide sufficient pricing granularity to inform the level of revenues that can be captured by gas peaking plants that will be considered as reference technologies.

3.5 Capacity Market Demand Curve

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

The working group developed a set of demand curve principles, which provide guidance on balancing resource adequacy, cost and volatility in the demand curve:

Supply adequacy: demand curve parameters should be set to ensure procurement of a sufficient amount of capacity for reliable operation of the electricity grid and to achieve the resource adequacy target, while avoiding significant over-procurement or under-procurement.

Efficient price formation: demand curve parameters should be set to send an efficient price signal in the capacity market, avoid excessive capacity price volatility and reduce the opportunity for the exercise of market power.

Demand curve parameters should be set to balance between achieving resource adequacy and lowest possible long-term cost to consumers, and to sustain resource adequacy over time through a market-based outcome.

- Demand curve parameters and the dependence on net-CONE should be set to ensure that Alberta's market attracts investment in new capacity and maintains existing capacity in order to achieve the resource adequacy target.
- Demand curve parameters should be compatible with, and robust to, reasonably foreseeable changes in supply, demand, energy prices and other factors in the electricity market.
- To the extent applicable to the Alberta context, the demand curve analysis should incorporate experience and lessons learned from other jurisdictions.
- Unique aspects of Alberta's electricity system (e.g. small size of the market, market transition) should be considered.

- Three demand curves were developed as candidates to continue to be tested. Each curve is downward-sloping, convex, and has price caps ranging between 1.6 and 1.9 x net-CONE (or 0.5 gross-CONE, whichever is greater).
  - Brattle simulations revealed that the three curves were a workable range of well-performing curves, noting that across the three curves there were trade-offs surrounding robustness to market conditions, price volatility, reliability outcomes and market power exposure.
  - While these curves met the desired outcomes of ensuring resource adequacy, provided a price signal of net-CONE on average, and mitigated against net-CONE error, participants raised concern that the curves would lead to consistent over-procurement.
- The AESO believes that further discussion is required on demand curve design with the working group on the trade-offs between a steeper demand curve (resulting in increased volatility), versus a more gradual demand curve (resulting in greater risk of over-procurement).
- Industry stakeholders and working group members raised concerns of the right-shifted nature of all the candidate curves and their risk of over-procuring or overpaying for capacity and limiting dynamic pricing in the energy market. It was also noted that the effectiveness of the demand curve through the capacity market implementation and supply mix transition should be considered.
- Independence, stakeholder engagement, and appropriate governance were all noted by the working group to be important considerations for the design of and ongoing management of the capacity market and the establishment of the demand curve.

AESO Rationale:

- The AESO's development of the demand curve was guided by principles developed by the working group, as described above.
- The AESO re-evaluated the working assumption being used for the resource adequacy standard and adjusted to a 400 MWh expected unserved energy target; the demand curve analysis was reassessed with this value to develop three new candidate curves. The results of that analysis are displayed below in Figure 1.
- With the revised resource adequacy target assumption, the width of the candidate demand curve narrows and becomes steeper overall. Also, the volume between the target volume and the volume at 1 x net-CONE is reduced, thereby reducing the risk of over-procurement.
- The middle of the three curves was evaluated in the revenue sufficiency analysis and chosen for the CMD proposal, as this curve is thought to best meet the design curve criteria stated above.
- Based on the defined principles, a downward-sloping, convex curve was selected (the slope on the minimum-to-target segment of the curve is steeper than the slope of the target-to-foot segment).
  - The downward-sloping section from minimum quantity to target inflection point reflects increased demand under scarcity conditions, compared with the kink-to-foot portion, where demand has more elasticity (less marginal value at high levels of reliability).
- The Y-axis points for the demand curve will be set in reference to a multiple of net-CONE parameters.
  - The price cap (zero quantity-to-minimum segment) is set based on the maximum value of either a 1.75 net-CONE multiple or a 0.5 gross-CONE multiple.

The price cap is a tool that helps mitigate the exercise of market power, beyond a known limit.

Higher price caps can allow for steeper curves, with associated pros and cons.

A minimum price cap is proposed as curves with a minimum price cap, set at the maximum of net-CONE or a proportion of Gross-CONE, and is resilient to reliability erosion in cases of low net-CONE or underestimation of net-CONE. Without a minimum on the price cap, reliability can erode in instances of low net-CONE or underestimation of net-CONE as the market will clear at a low volumetric level.

The inflection point is set between 0.8 to 1.0 x net-CONE.

The justification for the inflection point being at or slightly below the 1.0 x net-CONE multiple relates to the asymmetry of possible quantitative reliability outcomes. From a reliability perspective, it is generally less concerning to be over-supplied than under-supplied, given an equivalent volume. Although being over-supplied will dampen energy market price signals, being under-supplied could lead to supply shortfalls or increased unserved energy. Further resource adequacy modelling indicates that the risk of supply shortfall grows exponentially as capacity volume tightens below a certain threshold. Therefore the “kink” in the demand curve can be offset slightly to the right of the target level, and at a lower multiple of net-CONE.

The foot is set at zero.

Negative pricing would not incentivize capacity additions.

An above zero price floor is not desirable because it would have the potential to attract and retain excess quantities of capacity resources, particularly if the cost of incremental supply is low. This was the experience in the early years after implementation of ISO-NE’s capacity market with a price floor that attracted incremental low-cost supply into the already long market. By allowing capacity prices to drop to zero at higher quantities, the demand curve will ensure that customer costs are more aligned with reliability value and mitigate the potential for sustained periods with excess supply.

The X-axis points for the demand curve will be set in reference to quantity of megawatts of capacity.

The X-axis points will be set in reference to resource adequacy metrics, and demand curve performance simulations.

The minimum point will be set at a value of capacity commensurate with 800 MWh of expected unserved energy, based on the outcome of a resource adequacy study.

This minimum value is guided by current ISO Rule 202.6 *Resource Adequacy Level,* in which the AESO would take action to ensure supply adequacy stays above a certain threshold.

The inflection point will be set at a level slightly higher than the level associated with 400 MWh of EUE (revised working assumption), based on the reasoning for the inflection point described above.

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

Considerations or trade-offs considered in evaluating the width of the demand curve include:

Steeper curves are more robust to a wide range of market conditions, have less reliability risk from underestimated net-CONE, and less risk of excess capacity above the reliability requirement.

Flatter curves have lower price volatility and less exposure to exercise of market power and need for strict mitigation; however, there is a risk of procuring more capacity than required to meet the resource adequacy target.

Assessments of Alberta' s system indicate that a curve based on the marginal reliability value is too steep to achieve reliability.

Through the working group, Brattle completed simulation of various demand curves to evaluate their performance under a broad range of plausible capacity market outcomes; those simulations provided quantitative outcomes against which to evaluate the demand curve principles.

In the final working group meeting, three candidate curves were reviewed and considered. Brattle and the AESO identified these curves as a workable range of well-performing curves, noting that across the three curves there were trade-offs surrounding robustness to market conditions, price volatility, reliability outcomes and market power exposure.

Further material on these candidate curves, along with the rationale for their selection, can be found here: www.aeso.ca/assets/Uploads/2.1-2017-11-29-Candidate-Demand-Curves-ForPosting.pdf

Figure 1
Revised Candidate Curves

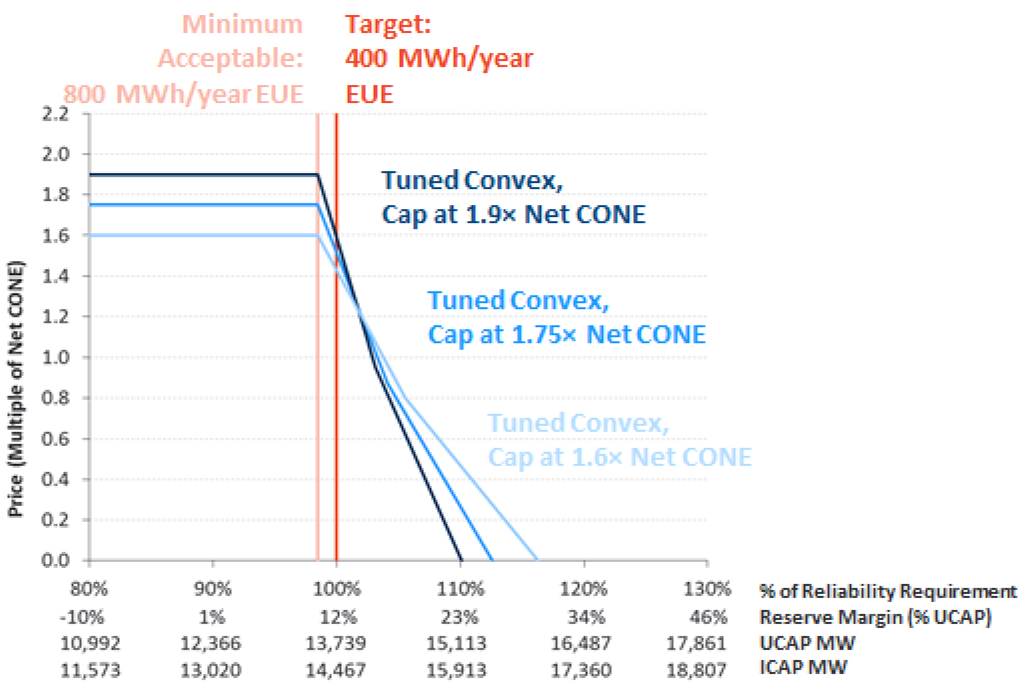

Table 1: Candidate Curve Results with 400 MWh/year EUE Target

	Price			Reliability						
Demand Curve	Average ($/kW-year)	Standard Deviation ($/kW-year)	Frequency at Cap (%)	Average EUE (MWh)	Average LOLH (Hours)	Average Reserve Margin (%)	Average Quantity as % of Rel. Req. (%)	Average Excess (Deficit) Above Rel. Req. (MW)	Average Uncleared Supply (MW)	Frequency Below Rel. Req. (%)
Cap at 1.6x Net CONE	$139	$51	10%	400	3.2	15%	104%	514	299	18%
Cap at 1.75x Net CONE	$139	$61	10%	401	3.2	15%	103%	458	332	18%
Cap at 1.9x Net CONE	$139	$70	10%	403	3.2	14%	103%	409	367	18%

The shape and parameters of the demand curve will be reviewed once the outputs of the detailed resource adequacy modelling are available, and again when the resource adequacy standard is defined.

3.6 Calculation of Capacity Market Demand Parameters Assessment Against the Capacity Market Design Criteria

- The government-mandated resource adequacy standard along with a forward-looking probabilistic resource adequacy model will ensure the capacity market contributes to the reliable operation of the electricity grid. This approach and implementation will be consistent with, and complementary to, other measures aimed at ensuring reliability that already exist within the energy market.
- Consistent with the design criteria, the procurement of capacity to meet load will employ market-based mechanisms by developing a convex, downward-sloping demand curve that considers the cost of new entrants to Alberta's capacity market, while at the same time promoting an effective balance between capacity cost and supply adequacy.
- Publication of all demand curves prior to each auction ensures that capacity market mechanisms, outcomes and information are transparent.
- A demand curve approach is used in almost all other capacity markets. In the development of the demand curve, the AESO has adopted best practices and lessons learned from other capacity market implementations, while still considering the unique aspects of Alberta.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Rationale Document

Section 4: Forward Capacity Auction

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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4. Forward Capacity Auction

To allow for effective new entry, the AESO proposes to conduct a forward-capacity auction. This section contains the reasoning behind the proposed auction timeline, format and mechanics.

4.1 Forward Period

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The auction should be held three years prior to the obligation period:
  - The WG unanimously recommended that the auction should be held three years in advance of the obligation period
- Industry stakeholders were largely supportive of a three-year forward period, with those not in support noting:
  - A three-year forward period is too long for short-lead resource types (e.g., energy efficiency, demand response, etc.) to meaningfully participate
  - The rules and regulations could change between the forward period and the delivery period

Comparison to SAM 3.0 Position:

- The proposed design is not substantially different from what was described in SAM 3.0

AESO Rationale:

The three-year forward period is long enough to achieve the benefits of a forward auction: orderly entry, and exit of resources, and reduced price volatility. At the same time, while supply and demand conditions are less certain three years forward, they can still be forecast with reasonable accuracy. Many capacity markets have adopted similar forward periods, including PJM, and ISO-NE (three years), and the UK, and Ireland (four years). The three-year forward period has also received unanimous support from the Capacity Market Technical Design Working Industry Group.[1]

Forward auctions support orderly entry-and-exit decisions by establishing market expectations well in advance of delivery. Resources will be able to complete their interconnection and have additional time to complete construction prior to the start of the delivery period.[2] Similarly, resources can signal to the market their intention to retire well in advance, or choose to retire in response to a reduction in forecasted load.

All else equal, a three-year forward market should have lower price volatility than a prompt market due to a more elastic supply curve. With three years of lead time, new resources can make investment decisions based on auction results, allowing more effective competition between new and existing resources. When prices are high, substantial amounts of capacity are available to enter the market. Conversely, existing resources may retire and less new supply will enter if prices are low. This reflects the adequate time for course correction provided by the three-year forward market. The impact of these factors can be

[1] See Capacity Market Technical Design Working Industry Group Recommendation, SAM 2.0, and https://www.aeso.ca/assets/Uploads/Capacity-Forward-Period-DAS.pdf

[2] The AESO connection process shows that the target timeline between the initiation and the approval of energization of a connection project is 96 weeks. After the connection period, extra time and activities are also required before a project can begin commercial operation.

observed in comparing the PJM supply curves with MISO's. MISO, with its prompt capacity market, has a much steeper supply curve compared to PJM's three-year forward market.[3]

Some larger resources require more than three years of lead time to come online and therefore might prefer a longer forward period. These longer-term resources might need to make significant investments before entering and potentially clearing the capacity market. While these resources take on some additional risk by making investments prior to clearing the capacity auction, they are by no means excluded from the market. The capacity market's transparent price signal allows these resources to make investment decisions based on market fundamentals. The additional risk taken on by resources with longer development timelines is mitigated by the sloped demand curve, and more elastic supply curve in the forward capacity market, which serves to reduce price volatility and help stabilize long-run prices around net-CONE. While a longer forward period might benefit the subset of long lead-time resources, these benefits would likely be offset by the costs of increased forecast error.

While the AESO has proposed a three-year forward auction, we acknowledge that the forward approach has drawbacks. In its report to Alberta's Market Surveillance Administrator, Potomac Economics drew a different conclusion and recommended a prompt auction, conducted only weeks or months before the start of the delivery year.[4] Potomac observed that forward auctions lead to greater uncertainty in load, and supply availability relative to prompt auctions. We agree with this observation, but consider the increased forecast error an acceptable tradeoff given the orderly entry-and-exit decisions and reduced price volatility associated with forward auctions. We also acknowledge Potomac's observations that forward auctions are less beneficial for new resources with longer construction lead times.[5] As we discussed above, we believe that such resources can still participate in forward auctions, and may benefit from their reduced price volatility relative to prompt markets.

The three-year forward period strikes a balance between allowing enough lead time for new resources to complete construction after clearing the capacity market and managing uncertainty about future demand, and supply conditions. While a longer forward period would allow larger resources more flexibility before making significant financial commitments, and a shorter forward period would reduce market uncertainty, a three-year forward period provides a balance of market participants needs to run a successful capacity market.

Auction Timeline and Procedures

As discussed in Section 4 of the CMD 1 proposal document, the forward capacity auction will involve a series of sequential process steps that begin eight months before the auction itself and end at the start of the delivery period three years later. Prior to the auction, AESO will release information on capacity qualification, market mitigation and auction parameters. Doing so in advance of the auction will allow market participants to effectively incorporate this information into their decision-making process.

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[3] Newall, Samuel A., Kathleen Spees and David Luke Oates (2016), Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution., November 1, 2016. Available: http://files.brattle.com/files/1026_testimony_of_newell__spees_and_oates_docket_no._er17-284-000.pdf

[4] See Section III.2. of Potomac Economics, "Report on Best Practices in Wholesale Electricity Market Design," November 2017, Prepared for the Alberta MSA, Available: https://albertamsa.ca/uploads/pdf/Archive/00000-2017/2017%2011%2029%20Report%20to%20Alberta%20MSA%20Final.pdf

[5] Potomac also observed that a single year of capacity revenues is a small portion of the revenue requirement of a new resource. While this is of course true, this is a feature of capacity markets generally, and has no bearing on the choice of forward period.

4.2 Obligation Term and Period

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The WG recommended that the obligation term will be one year for all resource types, however, opinions were split between a one-year term and an option for a longer lock-in for new or uprated resources:
  - A one-year term for all was viewed as the best and lowest-cost option and would be non-discriminatory between asset types, would provide better liquidity in the market and would reduce the risk of over-procurement.
  - Those who voted against the recommendation preferred a seven-year obligation term for new assets. They were concerned that a one-year obligation term would not be long enough to attract new entrants and it would increase financing costs for new resources which may result in higher capacity market costs for consumers.
  - Industry stakeholders were also split on the obligation term, restating the same concerns noted by the working group members.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0

AESO Rationale:

Additional examination of the expectation that a one-year term will meet the objective of ensuring sufficient investment in new capacity as well as the pros and cons of alternative approaches, will need to be undertaken in the weeks and months ahead. As is evident from stakeholder feedback on the issue, there are a wide range of views which require further examination before a position can be finalized.

The one-year obligation proposed establishes a fair and competitive market for capacity resources.[6] A one-year timeframe allows the capacity market to promptly reflect current supply, and demand conditions, responding to trends and changes as necessary. A longer obligation term may be more prone to inefficiencies due to forecast errors, reduce the incentive to capacity providers to innovate and cut costs, and not allow resources to promptly make retirement, mothball, and upgrade decisions. A potential downside of a shorter obligation term is that it could fail to provide enough certainty to attract new resources and investment. A one-year obligation term for existing resources is a proven timeframe, already implemented in PJM, ISO-NE, MISO, UK, and Ireland.[7]

Some capacity markets allow new or uprated resources to lock-in the forward capacity price for a term longer than one year. ISO-NE currently allows a lock-in of seven years, and the UK allows lock-ins of up to 15 years. Price lock-ins protect investors from the risk of regulatory intervention to suppress price and reduce financing costs of new resources. However, lock-ins are not consistent with the core design principle that all resources should receive equal compensation for providing the same product. Granting new and uprated resources a price lock-in provides different treatment to these resource types, distorts investment incentives, and reduces the efficiency of investment in the market. Lock-ins also distort prices by creating a block of supply that does not respond to price, and that may displace lower-cost resources. For example, if prices are falling over time, a new resource that cleared at a higher price will continue to receive a capacity payment even if a lower-cost existing resource is no longer able to clear. In the long

[6] See AESO (2017). AESO (2017). *Design Alternatives Sheet: Obligation Period* 2017. Available at: https://www.aeso.ca/assets/Uploads/Capacity-Obligation-Period-DAS.pdf

[7] NYISO is the only major capacity market that does not use a one-year obligation period. It uses a six month seasonal obligation, with monthly adjustment auctions.

run, these inefficiencies run the risk of resulting in higher prices for customers. By reducing price risk for new, and refurbished resources, price lock-ins transfer risk from investors to customers and as such are not consistent with that aspect of design criteria.

Evidence from other jurisdictions indicates that a one-year obligation term, without the possibility of a multi-year price lock-in, is capable of providing sufficient incentive to attract new investment. The approach has been successful in PJM, which has attracted substantial new supply even with relatively volatile prices. The AESO's downward-sloping demand curve is designed to reduce variability as supply and demand conditions vary over time and, as such, is another element of the market design that contributes to revenue stability. [8]

A one-year obligation period allows all resources to compete and receive payments on an equal playing field, which ultimately decreases market inefficiencies, and still allows new resources to enter the capacity market.

An obligation period running Nov. 1 through Oct. 31 allows the final rebalancing auction to be held closest to the winter peak load. This provides the most accurate forecast for this period and ensures maximum likelihood that reliability objectives will be maintained during the winter period through more accurate forecasts of load and capacity volume estimates.

Allowing seven offer blocks is expected to be more than sufficient for sellers to represent a wide range of different resource configurations, and is consistent with the allowed number of segments in other jurisdictions. A minimum block size of 1 MW is consistent with the overall market minimum resource size. Information on the divisibility of a block is required for market clearing.

4.3 Resources Supported by Out-of-Market Payments

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The WG was directionally aligned that out of-market payments should be addressed prior to the auction clearing:
  - For new resources that are eligible to participate in the capacity market and receive an out-of-market payment most group members favoured a minimum offer price (MOPR) approach that would adjust the cost of these resources by having their capacity offer reflect their go-forward fixed costs without consideration of the out-of-market payment.
  - For resources that are not eligible to participate in the capacity market and receive an out-of-market payment, most group members favoured a method in which those resources would be inserted at the top of the supply curve after the market clears to avoid over-procurement of supply and to promote a higher capacity market settlement price.
  - The WG members who represented load customers were not in favour of either approach and preferred treatment where these resources did not have their offer prices adjusted for any out-of-market payments.
  - The WG was not aligned on the definition of an out-of-market payment.
- Industry stakeholders were split on its opinions of how to deal with out-of-market payments, with numerous proposed solutions including:
  - Applying a MOPR rule to account for the out-of-market payment.

[8] Pfeifenberger, Johannes P., Samuel A. Newell, Robert Earle, Attila Hajos, and Mariko Geronimo (2008). *Review of PJM's Reliability Pricing Model (RPM)*, June 30, 2008. Retrieved from: http://files.brattle.com/files/6328_review_of_pjm's_reliability_pricing_model_pfeifenberger_et_al_jun_30_2008.pdf

- Deem resources that receive a true out-of-market payment (e.g. REP Round 1 resources) ineligible to participate:
  - Reduce the overall procurement volume by the MW that have already received a capacity payment outside of the market.
- Do not apply a MOPR and allow resources to bid in at their subsidized cost (to keep capacity costs low).

Consistency with SAM 3.0 Position:

- The AESO's proposal does not generally align with the WG directional indication. Note that the majority vote was completed without support of load representatives. The AESO's proposal is aligned with stakeholder feedback that REP Round 1 resources should not be eligible to participate in the capacity market.

AESO Rationale:

Assets who have entered a Renewable Electricity Support Agreement (RESA) under the first round of the REP auction will be ineligible to participate in the capacity market, but their quantities will be accounted for in auction clearing. Compensation for the capacity value of these resources is provided by the form of payment contained in the RESA. Subtracting this capacity value from the target capacity volume avoids over-procurement of capacity and reduces costs to load. Any potential distortionary impact to the capacity market is expected to be minimal, given the expected magnitude of capacity value for the REP Round 1 assets. Alternative adjustments may be considered depending on the details of future REP rounds with respect to volumes and pricing mechanism.

On a more general basis, there could be many forms of out-of-market payments made to capacity market-eligible resources. However not all out-of-market payments need to be addressed in the price formation in the capacity market. The definition below recognizes that potential distortions to the capacity market price signal from direct subsidies should be addressed while recognizing that other policy objectives should be considered and consumers should have the opportunity to benefit. The payment types that should be considered are:

- Payments made by the provincial government or a regulated entity, funded by Alberta rate-payers or tax payers made outside the existing wholesale market and meant to contribute to the return on and/or of investments in the provision of capacity:
  - As discussed above, REP Round 1 assets have received payments that match this description, and will not be eligible to participate in the capacity market.

In the AESO's assessment, other than REP Round 1 assets, there are currently no other assets that are deemed to receive out-of-market payments utilizing the definition above. Should such resources be identified, a MOPR mechanism as described below could be applied. However, given that no assets have been identified, adoption of the MOPR concept for out-of-market payments into the initial set of rules is not being recommended given time and resource considerations.

Under a potential MOPR mechanism resources that receive out-of-market capacity payments as defined above would have their offer prices in the auction adjusted to account for the benefit received by the out-of-market capacity payment.

4.4 Single-Round Uniform Price Auction Format

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The WG recommended that the auction should be a single round, sealed bid auction.

  - The majority of the group believed this auction approach promotes the lowest offer prices to be submitted, is easier to implement and helps to level the playing field between new entrants and incumbents.
  - Three dissenting members favoured a descending-clock auction believing this approach allows for price discovery and provides participants the opportunity to adjust to the new capacity market.
- Industry stakeholders are largely supportive of a single, sealed bid auction as simpler, however some comments reflect a desire for a descending-clock auction to avoid a winners curse and to aid in price discovery.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0

AESO Rationale:

The AESO is proposing to use a sealed-bid, single-round, uniform pricing auction for its forward and rebalancing capacity auctions. This is the most common auction format among existing capacity markets and is used in PJM, MISO and NYISO. It has a number of benefits relative to the other potential auction format: the descending-clock design used in New England and the UK's capacity markets. The sealed-bid, single-round design minimizes the opportunity for gaming, and encourages participants to offer at cost, a particularly important consideration given Alberta's small size and relatively concentrated market. The sealed-bid auction is also simpler to administer. Overall, a sealed-bid, single-round, uniform pricing auction should help facilitate a fair, efficient, and openly competitive capacity market in Alberta.

Sealed-bid, single-round auctions minimize the opportunity for gaming by limiting market participants' access to information about competitors' bids. Sealed bids ensure that market participants cannot directly observe their competitors' offers. The single-round format allows auction participants to submit offers into only one clearing round. There are no further auction rounds that allow participants to revise their offers after seeing the result of previous rounds. While participants have some insight into how their competitors will offer based on the outcome of previous auctions, and their knowledge of market conditions, this information is very incomplete. Without information about competitors' offers, market participants are incentivized to offer at cost, find it difficult to tacitly collude, and have a hard time exerting market power by withholding supply. This also allows the market to provide accurate price signals to suppliers entering or exiting the market. These considerations are particularly relevant given Alberta's relatively small electricity market.

During a descending clock auction the auctioneer starts each round by issuing a price and asking capacity sellers to state the quantities they wish to sell at this price. If the quantity offered exceeds the target quantity to be procured, the auctioneer issues a lower price, and again asks capacity sellers the quantities they want to offer at the new price (hence, descending clock). This process continues until the quantity offered matches the quantity to be procured or until excess supply is negligible.

The descending clock's "multiple-round" structure reveals information on supply offers after each round of bids (such as how many MW exited the auction), providing opportunities for some supply resources to take advantage, and coordinate offers or use market power to sway the auction results. Given the size and concentration of the Alberta market, this feature of the descending clock auction format introduces additional opportunities for gaming which could potentially offset benefits from increased price discovery that this format might provide. In addition, the descending clock format favors incumbents relative to new entrants. Under the descending-clock auction, established participants are better able to take advantage of the information revealed during the auction itself due to their better information about the system. Given Alberta's unique characteristics of relatively small size and concentration of incumbents, the AESO's view is that a seal-bid, single-round auction is more appropriate.

Uniform pricing provides a single clearing price for every supply bid that clears the auction. This feature incentivizes market participants to submit cost-based offers to ensure they are cleared in the auction and make at least enough revenue to cover their net going forward costs. Uniform pricing is also fair, in the sense that resources providing the same product (capacity) receive the same price. In contrast, auctions with non-uniform pricing introduce incentives to offer above cost. For example, pay-as-bid auctions encourage low-cost resources to offer above cost in order to capture a higher price for greater revenues.

Sealed-bid, single-round and uniform pricing auctions are also simple and straightforward to implement. The operator builds the supply curve (based on all of the bids received in the single-round) and the system demand curve implements any constraints (such as locational or import constraints), and then clears the market at a single price by maximizing social surplus between the two curves. By contrast, the descending clock auction is more challenging to implement: (1) it requires additions parameters like step size, price band width, and infrastructure to enable communication between the ISO and market participants during the auction; (2) it creates challenges for handling of scarce import capability, and (3) is intended for a single-buyer auction, and it is thus unclear how the descending clock auction would work for a rebalancing auction if market participants are trying to buy out of their obligation.[9]

The sealed-bid, single-round uniform pricing auction format supports a fair, efficient, and competitive capacity market by reducing gaming opportunities, limiting the possibility of tacit collusion, leveling the playing field between incumbent and new market participants, providing clear and accurate price signals, and incentivizing cost-based supply offers.

4.5 Auction Clearing and Price-Setting

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The WG reached directional alignment that the objective function used to clear the capacity market auction should target maximizing social surplus.
- The price setting method was not determined but the group was not supportive of a UK clearing approach where price is set at the highest priced supply offer cleared rather than where the supply and demand curve intersect. The concern being that when the supply curve is below the demand curve the price could be set at the last offer price rather than the price which would be set by the demand curve at that level of procurement.

Comparison to SAM 3.0 Position:

- The design is not materially different from what was described in SAM 3.0

AESO Rationale:

The social surplus-maximizing clearing algorithm is the most common clearing algorithm among all existing capacity markets, with the exception of the UK.[10] Maximizing social surplus will result in the most efficient long-term price signals which should provide the most efficient resource mix and lowest societal costs over time. This approach is also consistent with the clearing approach used in the current AESO energy market.

[9] See ISO-NE discussion, https://www.iso-ne.com/static-assets/documents/2016/07/20160711-dca-v-sealed-bid.pdf.

[10] In the UK, if the lump offer is marginal, it is only cleared if doing so economically benefits customers. May result in lower short-run customer prices in some cases, but less efficient resource selection will increase prices over the long term.

Under a different clearing algorithm this may not be the case. For example, in the UK, if the inflexible block is marginal, it is only cleared if it is beneficial to the customers. Figures 1 and 2 illustrate examples where this clearing algorithm does not maximize social surplus. Under the UK clearing algorithm, the auction clears at P_1 and Q_1 in Figures 1 and 2 as shown in the graphs on the left.[11] In these situations the clearing algorithm would have the AESO purchasing less capacity than its target purchase level. While this procurement level would still be above the level which would cause reliability concerns over time the AESO is concerned that it may systematically purchased less capacity than its target purchase levels.

For example, in Figure 1 if the market had cleared at P_2 and Q_2, social surplus would be larger. In the graph on the right of Figure 1, the green triangle is larger than the red triangle, and thus there is additional social surplus by clearing at P_2 and Q_2; social surplus being the difference between the two triangles. In the graph on the right of Figure 1, the green triangle indicates the additional social surplus by clearing P_2 and Q_2. In the graph on the left of both Figures 1 and 2, if Area A is bigger than the net social surplus gain, a net loss in consumer surplus may occur in the auction. Maximizing net consumer surplus instead of maximizing social surplus would clear the market at P_1 and Q_1 instead of P_2 and Q_2.

Figure 1: Illustration – Maximizing Customer Benefits: Clearing at the Block Below the Inflexible Block

Inflexible Block Does Not Clear (Area A > Area B)

Potential Addition Social Surplus

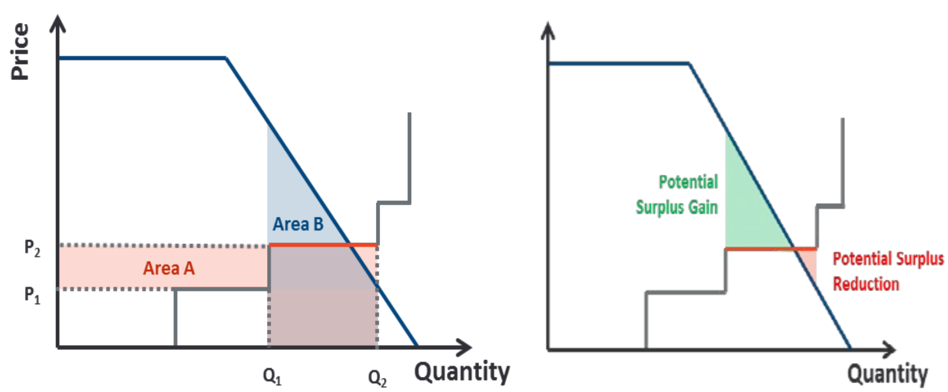
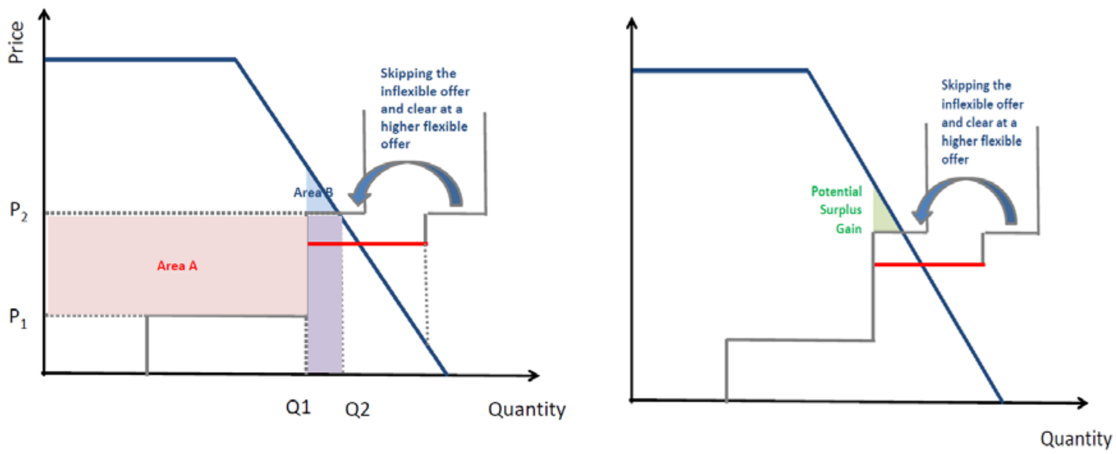


Figure 2: Illustration – Maximizing Customer Benefits: Not Clearing at the Flexible Block Above the Inflexible Block

The Flexible Offer above the inflexible Block Does Not Clear (Area A > Area B)

Potential Addition Social Surplus



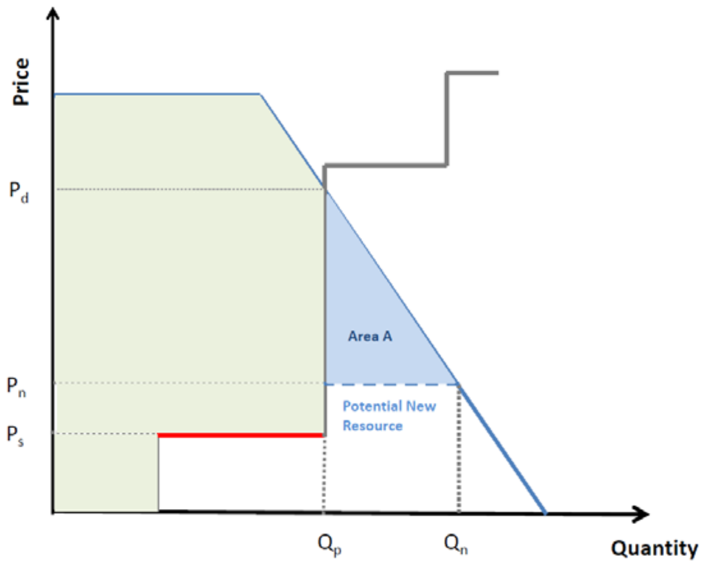
By clearing at P_1, and Q_1 consumer surplus is maximized, but this reduces the effectiveness of the price signal by creating no market incentive for new supply resources that could offer between P_1 and P_2. Instead, when social surplus is maximized in the clearing algorithm (auction clears at P_2 and Q_2), a more accurate price signal is provided compared to a clearing algorithm that maximizes consumer surplus only. Maximizing social surplus would attract new supply resources to enter the market at price levels between P_1 and P_2, providing more capacity at a lower price.

Price setting:

The AESO proposes to set the capacity market clearing price at the demand curve when the entire supply curve is below the demand curve, or when the entire procurement volume is below the demand curve. Setting the clearing price at the demand curve enables the price to reflect the market's value of additional capacity. Although it does not lead to the lowest procurement cost in one particular auction, it does provide price signals to support the efficient entry of additional, lower-cost capacity resources over time. When the clearing price is set at the demand curve, (P_d) in Figure 3, it provides an strong price signal for new or additional resources to enter the market during the next auction. In the example below, the new resource enters at P_n (indicated by the teal line in Figure 3), leading to additional social surplus (denoted by Area A) in the long run.

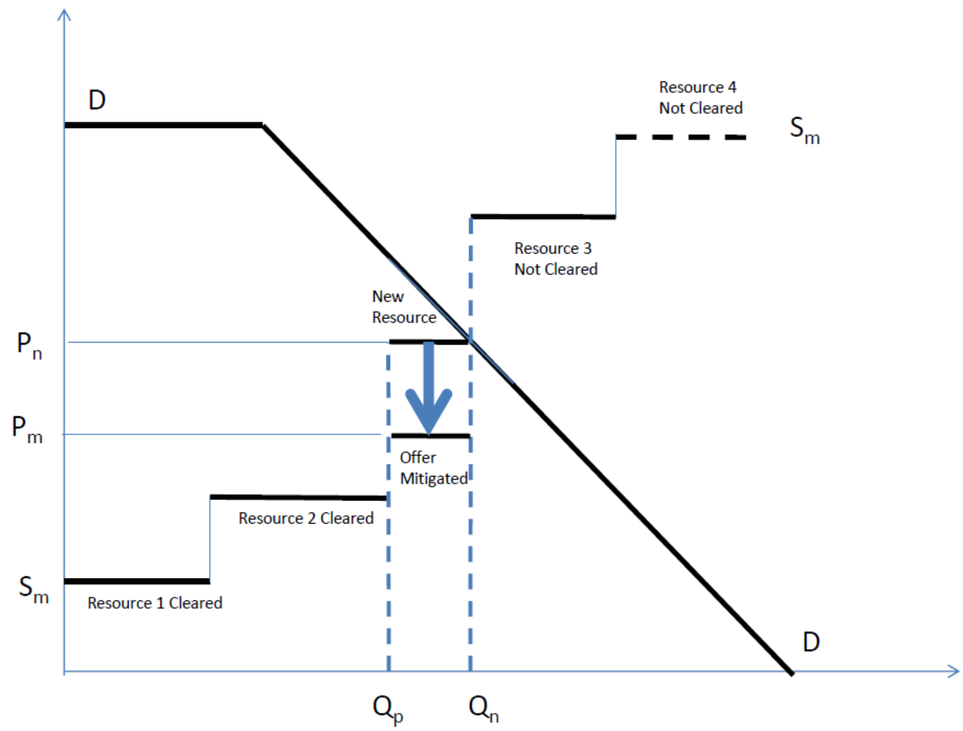
If the clearing price was set at P_s instead of at the demand curve (P_d), this would result in a lower price but would not provide the price signal the new resource may need to enter the market. Over the long term this could lead to inefficient outcomes and reliability issues due to under procurement.

Figure 3: The Supply Curve of Selected Resources Lies Below the Demand Curve



Setting the market price at the demand curve also prevents a situation where the entry of a new resource in one auction can cause the market clearing price to collapse in the following auction (when it is the marginal unit, and there is no change in market supply and demand). This feature helps to ensure the overall market structure is attractive for new investment. Figure 4 illustrates a scenario assuming a new resource enters the market and sets the clearing price at P_n in its first auction and as it transistions to being an existing resource in subsequent auctions it reduces its offer price to P_m due to lower going forward cost and, potentially market power mitigation. As illustrated in Figure 4, if the supply and demand remain the same, and the resource offers at price P_m in future auctions after recovering some of its fixed costs in earlier auctions, the market price would drop from P_n to P_m if the market price is set by the the marginal offer instead of the demand curve, even though there's no change in market supply and demand. This would discourage future resources from entering into the market if they can offer at a price between $P_{n,}$ and P_m. However, when the price is set at the demand curve, the market price in the subsequent auction would stay at P_n; correctly reflecting the fact that there is no change in market supply and demand and providing accurate price signals to other supply resources

Figure 4: Illustration – Price Set by Demand Curve Avoid New Entry Causing Price to Collapse



4.6 Addressing Intertie Transmission Constraints

Input from Working Group Members and Industry Stakeholders through SAM 3.0

- WG members pointed out that Alberta is an unconstrained transmission system and with a three year forward period there should be sufficient time to build out of the constraint.
  - There are no firm transmission rights in Alberta.
  - An additional alternative to explore could be assessing the incremental cost of transmission vs. the incremental cost of capacity.
- The working group discussed how the market should address transmission constraints, were it to occur in the future, and generally agreed that price should be the first determination to prorate transmission to participants

Comparison to SAM 3.0 Position:

- The design is not materially different from what was discussed during working group sessions (but not formally noted in SAM 3.0), however the working groups discussed that having an unconstrained transmission system in Alberta would suggest that the province would build its way out of any congestion issues without having to impact market participants.

AESO Rationale:

Section 2.3 discusses how capacity volumes are determined for individual external capacity resources. Alberta has limits on the amount of capacity that can be delivered through interties. Joint intertie scheduling limits will be determined and made available as part of the overall auction process. There may be auctions in which there are more qualified external capacity resources than there is available import capacity when joint scheduling limits across multiple interties are considered. For example, transmission delivery constraints may be observed for capacity sellers on the Alberta–BC Intertie and Montana–Alberta Tie-line. The constraints will be a result of the combined flow limit on those two interties. The unforced capacity (UCAP) volumes of the external capacity resources will not be reduced to reflect the level of the joint scheduling constraint because this may result in an inefficient outcome where the higher cost resources are cleared prior to fully utilizing the lower cost resources.

Clearing lower-priced resources first, results in a more efficient outcome and lower costs for consumers. Considering overall social surplus in situations where offers are priced the same also results in more efficient outcomes.

4.7 Addressing Internal Transmission Constraints

Input from Working Group Members and Industry Stakeholders through SAM 3.0

- The WG members pointed out that Alberta is an unconstrained transmission system and with a three-year forward period there should be sufficient time to build out of the constraint.
  - There are no firm transmission rights in Alberta.
  - An additional alternative to explore could be assessing the incremental cost of transmission vs. the incremental cost of capacity.
- The working group discussed how the market should address transmission constraints, were it to occur in the future, and generally agreed that price should be the first determination to prorate transmission to participants.

Comparison to SAM 3.0 Position

- The design is not materially different from what was discussed during working group sessions (but not formally noted in SAM 3.0), however the working groups discussed that having an unconstrained transmission system in Alberta would suggest that the province would build its way out of any congestion issues without having to impact market participants.

AESO Rationale:

Alberta's transmission system is designed to support unconstrained operations under system-normal conditions. It should be noted, however, that transmission development timelines can often extend beyond three years when considering regulatory approval and construction timelines. Development cycles of five to seven years are not uncommon. While constraints are not anticipated, any potential transmission constraints will need to be accounted for when clearing the capacity market so that the AESO does not procure volume that cannot be delivered. This would fail to provide value to customers and would not meet reliability requirements.

While not expected to occur, if there are anticipated transmission constraints in the Alberta interconnected system that could affect capacity market offers from qualified participants, the AESO will identify the location and implication of any transmission constraints so that participants have full information with which to form their offers.

UCAP volumes of available resources behind a transmission constraint will not be adjusted to reflect the limit of the transmission constraint. Doing so could result in the capacity market clearing some volume of the higher-priced resource prior to clearing all of the lower cost resource. Clearing lower-priced resources first results in a more efficient outcome and lowers costs for consumers. Resources compete for capacity sales based on their price structure. This competition promotes a fair and efficient market that treats all resources equally provided they meet the eligibility criteria. Considering overall social surplus in situations where offers are priced the same also results in more efficient outcomes.

4.8 Forward Capacity Auction assessment against Capacity Market Design Criteria

Adopting a sealed-bid, single-round auction with a three-year forward period and a one-year delivery period for all participants promotes a capacity market that is fair, efficient, and openly competitive, employs a market-based mechanism that incents competition in a transparent fashion, and should result in a well-defined product and an effective and efficient capacity price signal. The one-year term for the capacity obligation is as short as possible and satisfies the design principle that investment risk should continue to be borne by investors.

The auction design considers Alberta's unique approach to import and transmission constraint management by creating single price for capacity regardless of location. This is a simple and straightforward initial implementation. While it is not completely consistent with the best practices and lessons learned from other capacity market implementations, it is the design that best fits the needs of Alberta.

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Section 5: Rebalancing Auctions

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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5. Rebalancing Auctions

The rebalancing auctions provide a market-based mechanism for the AESO and participants to adjust to changes in load and transmission parameters since the forward auction. Updated reliability requirements are reflected in the AESO's rebalancing auction demand curve, which determines the value of capacity under current system conditions. If the system is tight in the rebalancing auction timeframe, rebalancing auction prices will be high. Resources with forward commitments will be strongly incentivized to deliver on their commitments to avoid buying out at the high rebalancing price, and new suppliers will be strongly incentivized to enter. If the system is long, prices in the rebalancing auction will be low. Resources with forward commitments will be able to buy out of those commitments relatively inexpensively, and new suppliers may not wish to enter.

The rebalancing auctions are an important component of the AESO's effort to create an efficient capacity market that ensures the reliability of the Alberta electricity system. The rebalancing auctions support efficiency, and reliability by:

- **Allowing the AESO to update demand for capacity based on a revised load forecast.** Load forecast error is an unavoidable component of a forward capacity market. While the AESO will aim to produce an accurate, and unbiased forecast, there will inevitably be some level of error. A key function of the rebalancing auctions is to minimize the reliability, and economic impacts of this error. If the AESO under-forecasted load in the forward auction, the rebalancing auctions provide opportunities to buy additional supply, and ensure the reliability of the system. If the AESO over-forecasted load in the forward auction, the rebalancing auctions provide opportunities to sell excess supply and recover some costs for customers.
- **Allowing new resources to enter with less lead time than the three-year forward period.** The rebalancing auctions provide a mechanism for resources that were unwilling or unable to offer into the forward auction to obtain a capacity obligation. Demand response providers may not have enough information about their underlying load three years ahead of the auction, but may be willing to accept a capacity obligation a few months ahead of the auction. Additionally, new resources that cleared the forward auction but came online in less than three years would be able to sell capacity early into a rebalancing auction. Accessing this additional supply should also reduce costs for customers.
- **Allowing resources with a forward commitment to buy out if they are unable or unwilling to deliver.** Some new resources that have cleared in the forward auction will be unable or unwilling to bring their plant online in time for the start of the delivery year. The rebalancing auctions will provide these resources with an opportunity to buy out of their obligations, and ensure that the system has enough capacity online by the start of the delivery year.
- **Allowing up-rates or down-rates to forward-committed resources.** Similarly, resources that are able to increase the output of their plants through incremental modifications may wish to do so in order to capture a high energy price. Resources that must derate their plants to account for poorer-than-expected operating conditions or equipment problems will be able to find replacement supply.

Auction Timeline and Procedures

Input from Working Group Members and Industry Stakeholders through SAM 3.0

- The WG unanimously recommended that there should be two rebalancing auctions with the second auction held as close as possible to the start of the obligation term.
- Industry stakeholders were supportive the WG recommendation of two rebalancing auctions and added the following comments:
  - Rebalancing auctions should take place regardless on if the AESO needs to adjust its position.
  - Liquidity in the rebalancing auctions is incredibly important.

- Should the AESO have an obligation to act as a “market maker” during rebalancing auctions?

Comparison to SAM 3.0 Position

- The design is not materially different from what was described in SAM 3.0

AESO Rationale:

After the auction itself has concluded, two rebalancing auctions will be held prior to the delivery period. In addition to ensuring an efficient response to rebalancing needs, the timing of the rebalancing auctions occurs such that market participants are not overwhelmed by administrative duties for the forward capacity auctions that are occurring concurrently. The AESO’s proposal recommends holding two rebalancing auctions for each delivery period, conducted on a fixed schedule. The first rebalancing auction will occur 18 months prior to the delivery period, and the second will occur three months prior to the delivery period.

The fixed schedule for rebalancing auctions will facilitate participation in the auctions, and reduce participant uncertainty. With a fixed schedule, market participants offering new capacity into a rebalancing auction can ensure that their resource plan is sufficiently well developed to qualify by the time of the auction. Participants at risk of being unable to meet their forward commitments know exactly how much time is available to achieve their next construction milestones before the rebalancing auction bidding window opens. The AESO can establish an auction schedule that allows sufficient time to qualify, and establish UCAP ratings for all resources, publish auction parameters, and determine auction results, andthat evenly distributes the administrative requirements of running auctions over each calendar year. The alternative to fixed schedules—running auctions only when certain criteria are met—results in less predictability.

The AESO’s proposal to hold two rebalancing auctions between the forward auction and the start of the delivery period strikes a reasonable balance between several competing factors.[1] Holding more rebalancing auctions promotes transparency and rapid price discovery by making relevant information available to the market soon after it becomes available. For example, if a new capacity resource determines it will not be available in time for the delivery year and immediately buys out its obligation in a rebalancing auction, the rest of the market will quickly become aware of the increased supply tightness through a higher rebalancing price. On the other hand, holding fewer rebalancing auctions increases liquidity in each individual auction, reducing transaction costs and reduces the administrative burden of facilitating the auctions.

The proposed rebalancing auction schedule was also based on a balance of factors. The final rebalancing auction should take place close enough to the start of the delivery period that load forecasts, and generator availability are essentially final, but should also allow enough time for the AESO to take out-of-market actions if it comes up very short after the auction. The first rebalancing auction should be scheduled to evenly distribute auctions between the forward auction, and the start of the delivery period, but should also keep in mind the administrative overhead of running all auctions in a calendar. The AESO’s proposed schedule strikes a reasonable balance between these factors.

5.1 Market Participant Buy Bids and Sell Offers

Input from Working Group Members and Industry Stakeholders through SAM 3.0

[1] During the transition period, some delivery years will have zero or one rebalancing auctions.

- These details were not discussed by the WG through SAM 3.0

The AESO's proposal allows market participants to submit several types of offers, and bids into the rebalancing auctions. Each offer and bid type corresponds directly to one or more of the rebalancing auction objectives:

- **Incremental Sell Offers.** Enable new resources to enter with less than the three-year forward period. Allow up-rates and UCAP increases of already-committed resources.
- **Repricing (Buy Out) Bids.** Enable resources with forward commitments to buy out of their obligations, or to derate their cleared capacity, contingent on a sufficiently low rebalancing price. Resources that are physically unable to deliver will be required to submit UCAP reduction bids rather than demand bids in the final rebalancing auction.
- **UCAP Reduction Bids.** Enable resources that are physically unable to deliver on their obligations, in part or in full, to buy out of their obligations regardless of the rebalancing auction price. UCAP reduction bids will be entered at a price in the final rebalancing auction just above the rebalancing auction price cap to ensure that they clear.
- **Non-Participating Supply.** Allows the majority of suppliers who do not wish to alter their positions in the rebalancing auctions to avoid the administrative burden of active participation in the auction. These resources will be automatically entered as price takers on the supply side of the auction, but will not incur any settlements as a result of the auction.

5.2 Administrative Demand Curve

Input from Working Group Members and Industry Stakeholders through SAM 3.0

- These details were not discussed by WG through SAM 3.0

The AESO proposes to participate in the rebalancing auctions using the same demand curve shape it uses in the forward auction. As described in Section **Error! Reference source not found.**, this curve represents the AESO's willingness to pay for capacity to achieve its reliability objectives. Since this fundamental willingness to pay for capacity does not change in the Rebalancing Auction, the shape of the AESO's demand curve will not change either.

Using the same demand curve shape in the rebalancing auctions will also help to avoid the market distortions that would occur if the rebalancing demand curve were systematically different than the forward demand curve. If the AESO's rebalancing auction demand curve were systematically lower than the forward demand curve, market participants would have an incentive to sell in the forward auction, and buy out in the rebalancing auction at a lower price. If the rebalancing auction demand curve were systematically higher than the forward demand curve, market participants would have an incentive not to offer in the forward auction, and instead sell in the rebalancing auction at a higher price.

The AESO will update load forecast and resource adequacy parameters of the demand curve using the load forecast and resource adequacy parameters from the most recent reliability study completed prior to the auction. Similarly, the AESO will update transmission data used to determine import limits from external areas and to evaluate the deliverability of capacity resources cleared in Alberta. These updates will allow the AESO to ensure reliability if it has under-forecasted load, reduce customer cost impacts if it has over-forecasted load, and send an accurate updated price signal to suppliers about the tightness of supply and demand in the market.

The AESO proposes not to update the net-cost of new entry (net-CONE) parameter in the rebalancing auctions. Net-CONE will likely be the subject of an extensive stakeholder process involving public release of draft parameter values. Since draft net-CONE values may be available more than a year before they are used in a forward capacity auction, use of an updated net-CONE parameter in a rebalancing auction would introduce an opportunity for gaming. Since market participants would know with reasonable confidence whether net-CONE is likely to increase or decrease in the rebalancing auction at the time they offer into the forward auction, they would have incentives similar to those described above for systematic differences in demand curve shape.

5.3 Auction Clearing and Price Setting

Input from Working Group Members and Industry Stakeholders through SAM 3.0

- These details were not discussed by WG through SAM 3.0

The AESO proposes to clear the rebalancing auction on a gross basis (i.e., including all supply, and demand in the market in the same way as the forward auction), but to settle the auction on net basis (i.e. only differences between forward and rebalancing cleared quantities would be settled at the rebalancing price). Gross clearing in the rebalancing auctions increases transparency by allowing market participants to easily see the effect of updated auction parameters on the AESO's demand curve. Clearing the rebalancing auctions in the same way as the forward auction reduces the likelihood of unanticipated outcomes due to idiosyncratic differences between forward and rebalancing auction mechanics. The gross clearing with net settlements approach is used by ISO-NE in its forward capacity market, and is also used in US real-time energy markets, which follow and rebalance day-ahead markets.

5.4 Rebalancing Auction Assessment Against Capacity Market Design Criteria

The design allows for two rebalancing auctions to occur before the delivery year. These rebalancing adjustments employ market-based mechanisms that should provide an effective balance between capacity cost and supply adequacy resulting in a reasonable capacity costs for consumers while still contributing to the reliable operation of the electricity grid.

Rebalancing auctions are an effective best practice found in other capacity market implementations for dealing with forecast risk in the capacity procurement volume and availability risk for capacity resources. This satisfies the criteria of maintaining reliability objectives at lowest cost to consumers.

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Section 6: Physical and Bilateral Transactions and Self-Supply

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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6. Physical Bilateral Transactions and Self-supply

6.1 Physical Bilateral Transactions and Support for Self-Supply

In order for the capacity market to be fair, efficient and openly competitive (FEOC), the market must have liquidity. By not allowing resources and load to arrange for capacity outside of the market through physical bilateral arrangements, liquidity and competition are promoted. The design requires the capacity market to achieve the desired reliability objectives through a real and measurable supply adequacy product that still respects the unique aspects of Alberta's electricity system.

The concept of self-supply, a best practice found in other capacity market implementations, was leveraged to facilitate the need to properly incorporate the roughly 2,000 MW of cogeneration/onsite generation while ensuring the reliable operation of the electricity grid consistent with, and complementary to, other measures aimed at ensuring reliability. This also recognizes the unique nature of Alberta's system. The proposed mechanism for accounting for self-supply without risking reliability and addressing fairness issues caused by the free rider concern was a simple and straightforward initial implementation using cost allocation to incent self-suppliers to not consume energy in excess of what they self-supplied.

Asset substitution is a best practice found in other jurisdictions that has been adopted for Alberta's capacity market as a tool for stakeholders to manage their capacity obligation risk.

6.1.1 Physical Bilateral Transactions

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The working group recommended that physical bilateral transactions not be permitted in the capacity market reservations (and the objection) at the time was related to the wording of the recommendation and insufficiently clear definitions. However, the concept was generally agreed to, as reflected in the vote.
- Industry feedback on SAM 3.0 indicated that most (nine of 11 comments related) agree to not allow physical bilateral procurement between load and generation.

AESO Rationale:

- The design is not materially different from what was described in SAM 3.0.
- Physical bilateral transactions are not permitted.
- Physical bilateral transactions, defined, take place outside of the centralized capacity market. Buyers and sellers find each other (i.e. self-matching) and report their matched commitments to the centralized market (the AESO) prior to the capacity auction. Contract prices are not reported to the AESO, and remain private information between the buyer and seller.
- The rationale for not including physical bilateral transactions is as follows:
  - Negatively impacts size of the centralized market by potentially reducing liquidity, thereby making the market less competitive.
  - Contract-for-differences (CfD) or other financial hedging mechanisms exist and do not require ISO administration eliminating the need for physical bilateral.
  - Legislation currently requires all energy be exchanged through the power pool. A legislative requirement may be extended to the capacity market as well in order to support a FEOC market.
  - Does not require individual loads to be allocated a capacity market volume obligation (consumption threshold) and be managed to that obligation.

6.1.2 *Support for Self-Supply*

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The nature of the support for self-supply by the working group is reflected in three provisional recommendations, two of which are summarized below, and the other summarized in Section 2.1.5 Self-Supply Prequalification of this document:
- **Self-Supply Choice**: The working group recommended that self-supplied load may choose to participate as gross or net provided the appropriate metering is installed, they meet the eligibility criteria for self-supply, and an adequate connection to the electric system (transmission or distribution) exists to support gross or net participation; sites with onsite generation that cannot physically flow their gross volumes due to system connection limitations must self-supply (all 14 agree, two with reservations)
- Self-Supply Options:
  - Four options for how self-supply should be incorporated into the market were identified:
    - Require the self-supplier be curtailed by the AESO during performance events if not meeting their performance obligation.
    - Penalize the self-supplier at the value of lost load plus the curtailed loads capacity payment (penalties + liquidated damages).
    - Procure some capacity based on a probabilistic assessment of each self-supplier's dependence on the capacity market.
    - Apply the cost allocation formula to net load; if a self-supplier takes capacity in a prior year they pay for it in the future year.
  - Based on these four options, the working group recommended that, assuming the self-supplier does not choose to be curtailed during performance events, that the cost allocation formula be applied to net load. If a self-supplier "takes" capacity in a prior year they pay for it in the future year. This recommendation has the caveat that the cost allocation methodology adequately mitigates the risk of self-suppliers consuming their gross load as net during performance events and the following demand curve assumptions are true (all 14 agree, five with reservations):
    - The AESO will forecast Alberta Internal Load (AIL) and estimate how much capacity is required to meet adequacy standards based on a probabilistic assessment.
    - The AESO will reduce its procurement target by the forecast volume of self-supply. This is calculated as probabilistic determinations of forecast AIL minus forecast system load minus forecast system net load. The AESO will need to know who intends to self-supply in order to forecast the system net load.
    - Cost allocation for each self-supplier will be based on net-to-grid load of each self-supplier (e.g., during cost allocation hours). The methodology for cost allocation has yet to be determined.
    - It was widely recognized that the design for self-supply was dependent on the cost allocation methodology to be determined by government.
- Industry feedback on SAM 3.0 indicated that:
  - Most support behind-the-fence participation on either a net-to-grid or gross-to-grid basis based on the stated requirements (with modifications suggested).
  - Self-supply recommendations may require revisiting once cost allocation is decided by the Department of Energy.
  - Concerns that free ride scenarios for behind-the-fence (BTF) self-suppliers may result from design.
  - Concerns regarding design being workable for smaller, distribution connected self-suppliers.

Comparison to SAM 3.0 Position

- The design is not materially different from what was described in SAM 3.0

AESO Rationale:

A site may choose to self-supply capacity provided they meet the eligibility requirements in Section 2.1. Alberta's market does not have integrated utilities acting as load serving entities, as found in other capacity markets, but over 20% of the internal load is served by onsite generation. The market design must include consideration for this form of participant. Self-supply provides the market with a methodology to deal with BTF with limited transmission capability. In addition, the ability to self-supply allows cogeneration sites that are tied to a host customers' load to be exempt from offering all of its capability into the AESO-operated capacity market. The *AESO 2017 Long-Term Outlook* defines BTF: as "industrial load served in whole, or in part by onsite generation built on the host's site."

The allowance provided to certain customers to self-supply will be designed with these principles in mind:

1. ***Ensure Supply Adequacy:*** Net-to-grid treatment for self-suppliers supports achieving the desired reliability objectives.

2. ***Fairness, Equal Treatment and Market Efficiency:*** Self-suppliers' load and generation are treated fairly and equitably compared to the treatment of other loads and generators in the market.

3. ***Fair Cost Allocation:*** All customers pay their fair share of capacity costs.

4. ***Simplicity and Consistency:*** The approach for net-to-grid resource participation should be simple to administer, facilitate market transparency and participation, and be consistent with the overall market design.

What are the concerns related to self-supply?

An independent load and generator may pay, and is paid differently, from sites that are combined load and generation. Using a simple-settlement example for the capacity market, it can be demonstrated that a site that is self-supplied will be allocated less of the reserve margin than a similar load without the ability to self-supply. The following example demonstrates the payment difference when comparing gross settlement to net settlement.

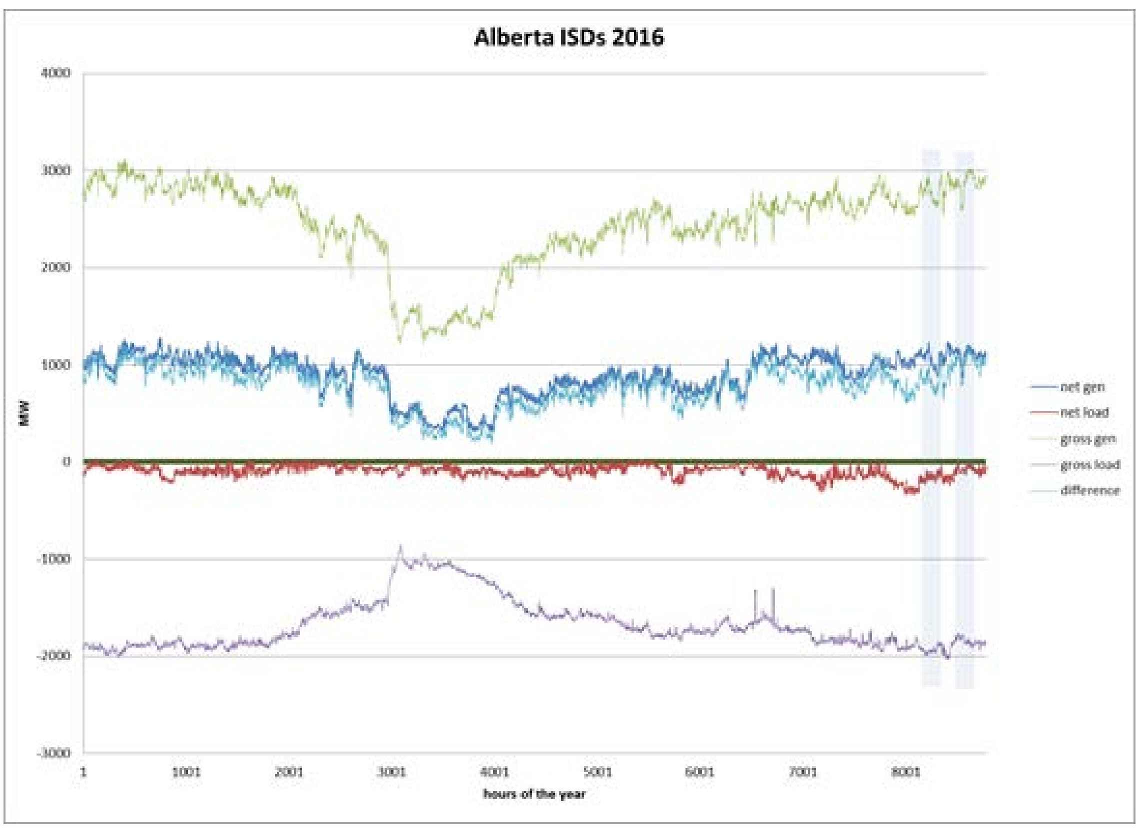
Assume a simple system with four cogeneration sites (I1 through I4) and 1 pure load site (I5) and one new entrant pure generator (A1). This example assumes a reserve margin requirement of 15% as the additional amount to procure in the capacity market to ensure reliability. The internal load of this system is 44 MW, adding an additional 15% brings the procurement target for this system to 50.6 MW of capacity less 18 MW of self-supply equaling 32.6 MW. The volume of self-supply is calculated as the difference between the sites gross load and its net load. The size of the resource procured to serve this sample of load portfolio is calculated as difference of the necessary amount for the gross load minus the sum of the generators' UCAP.

Once the AESO clears the capacity market, the load will be allocated the cost of the capacity procured. The cost allocation formula used here is the total payment to all capacity resources multiplied by the load of the site divided by the total load of all sites. The illustrative example includes both a gross load and a net load calculation. The payments that generators receive in this illustrative example is based on assumes a capacity market price of $40/MW (over a particular delivery period). The capacity payment is simply the capacity obligation multiplied by capacity market price. The example includes both a gross generation and a net generation calculation. When we look at the settlement totals is calculated, this illustrative example shows by allowing netting the generation out of the load, the rest of the load on the system (pure load represented by (I5) will pays more than it would otherwise if netting were not allowed, and the loads that have cogeneration sites pay less if short of generation or the generators would be are paid more if long on generation. Currently in Alberta 20% of the gross load is self-supplied.

	Net		Gross		cost allocation				payments		totals		Volume of
sites	net load	net gen	gross load	gross gen	net	$	gross	$	net	gross	sum net	sum gross	Self-supply
I1	2	0	5	3	2.507692	$ 100	5.75	$ 230	$ -	$ 120	$ (100)	$ (110)	3
I2	0	3	3	6	0	$ -	3.45	$ 138	$ 120	$ 240	$ 120	$ 102	3
I3	4	0	8	4	5.015385	$ 201	9.2	$ 368	$ -	$ 160	$ (201)	$ (208)	4
I4	0	3	8	11	0	$ -	9.2	$ 368	$ 120	$ 440	$ 120	$ 72	8
I5	20	0	20	0	25.07692	$ 1,003	23	$ 920	$ -	$ -	$ (1,003)	$ (920)	0
Sum:	26	6	44	24	32.6	$ 1,304	50.6	$ 2,024	$ 240	960	$ (1,064)	$ (1,064)	18
A1	0	26.6	0	26.6					$1,064	$1,064	$1,064	$1,064	
Sum:		32.6	44	50.6	32.6	$ 1,304	50.6	$ 2,024	$ 1,304	$ 2,024	0		
	amount to procure:		32.6	26.6									

The difference between the gross and net calculation is an additional 2.08 MW is allocated to the pure load at a cost of $83 ($1003 to 920) in this illustrative example. This is because the netted load is not carrying their reserve requirement under the same level of reliability criteria as the rest of the system. The rationale submitted by the cogeneration owners for this acceptable difference is that cogeneration provides a reliability benefit due to the fact that the load and generation are tightly coupled. When looking in aggregate at Alberta industrial systems there is a correlation between the load and generation. In the following graph you can see as the generation at the site drops the load drops too. This correlation makes sense as, by definition, the electricity is a by-product of the steam used in the industrial process. If no steam is generated, then no generation output is provided and no industrial process supported by the cogeneration. The reduction in generation was roughly 500 MW greater than the decrease in load over the same period. This is partially due to the fact that some ISD sites are not cogeneration sites.

What is the rationale for non-cogeneration to be allowed to net?



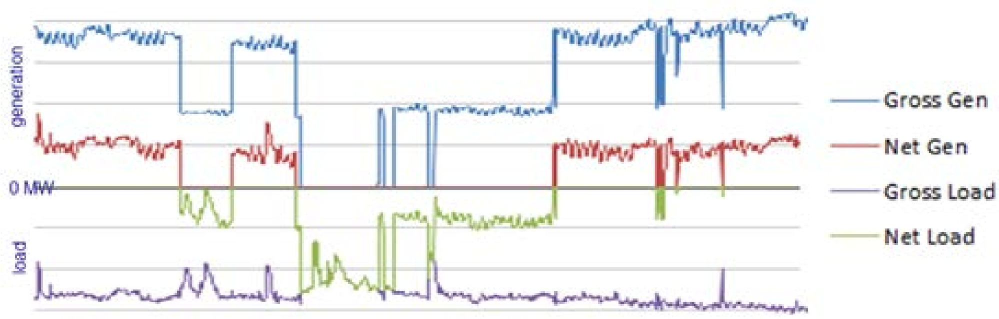
Public

It has been stated in AESO's earlier documentation that our capacity market is a physical market. The original criteria and assumptions for the capacity market state that "a capacity obligation is a forward obligation on capacity suppliers that requires the capacity sold in the capacity market be available to provide energy production or reduced consumption when needed." Based on this statement, sites with onsite generation that are net-metered and cannot physically flow their gross volumes due to system connection limitations must self-supply. Not all sites under this configuration are cogeneration sites and some manage their load with their own generation investments to avoid transmission costs. It has been suggested that some of these customers would not be able to participate in the capacity market if they need to electrically reconfigure their metering and connection to the transmission system.

How should self-supply volumes be determined?

Self-supply volume is the difference between a site's gross load and net load. Depending on when that difference is measured the value can change dramatically.

If it can be assured that in the event of generation failure during a performance event the load will be at its' net-load volume levels, no reliability risk exists. Examination of historical individual net site behavior has not demonstrated this in all cases. Loads are not always reduced when the generation is down and we find net loads increase to gross load levels in some instances. In the example graph below, when the generation at the site (blue line) goes to or approaches zero, the net load at the site (green line) increases. The gross load at the site (purple line) remains relatively constant. Further analysis indicated seven of the 15 current ISD sites demonstrated a high correlation of their load and generation.



Due to this observation, the AESO proposed four options to industry for mitigating this risk in the form of the following question.

How the AESO determine how much capacity to procure for self-supplied load? Four options are listed below:

1. The AESO does not procure capacity for the netted-out load and require the net load to be curtailed by the ISO during performance events if not meeting their performance obligation.
2. The AESO does not procure capacity for the self-supplied load, but charge the load at the value of lost load plus the curtailed loads capacity payment (liquidated damages) if they rely on the system under shortage events.
3. The AESO procures some capacity based on a probabilistic assessment of each self-supplier's dependence on the system's capacity market
4. Apply the cost allocation formula to net load only. If a self-supplier takes capacity in a prior year they pay for it in the future year.

Public

It was determined by the working group that option 1, curtailment, is a true form of opting out of the market and would not compromise reliability; however, there are very few self-suppliers that could utilize this option, and the cost of mandating this on all sites would be prohibitive. Option 2 and 4 are variations on a similar theme, providing a financial incentive for self-suppliers to make sure resources manage their consumption during performance events. The most important difference is that Option 2 sets a maximum load obligation that is assessed during performance periods, where the cost allocation method (option 4) is tied to cost allocation periods. Option 3 is a combination of option 4 plus an additional premium, equal to some fraction of the system reserve margin percentage, placed on the self-supplied load to cover the risk of the load exceeding typical net levels during performance events. This was seen by some stakeholders as incurring a double cost allocation and by the AESO as a highly administrative calculation requiring actuarial science to determine the right premium.

Option 4, applying the cost allocation formula to net load, was seen by a majority of the working group as the simplest method to manage self-supply as it is consistent with the current energy market treatment of generator station service load and net-measured sites. Some members felt this mechanism did not adequately address the reliability issue. The reliability concern comes from two places. 1) The method of cost allocation may not provide proper incentives for self-supplied load to not consume during system stress events if there is no alignment of performance events and the times where costs are allocated. 2) The net load is highly variable, and most sites can incur non-coincident peaks in the 100s of MW even though net loads are mostly in the 10s of MW range.

With the high variability of net loads combined with the fact that these loads are large, the treatment of self-supply must ensure the appropriate incentives are in place to discourage self-supply loads from consuming during the capacity performance periods. To not do so could present a reliability risk. The cost allocation methodology will be set by the Government of Alberta, and may or may not provide the appropriate incentives. Following the outcome of the cost allocation policy discussion, the AESO may have to reconsider Option 4 in favor of options 2 or 3.

Why does the City of Medicine Hat need to be considered a self-supplier within the capacity market?

- The City of Medicine Hat is a site with onsite generation that is net metered at the connection to the Alberta Interconnected Electric System (AIES), and cannot physically flow their gross generation volumes due to system connection limitations and therefore must self-supply.
- The City of Medicine Hat has special treatment within the *Electric Utilitities Act* with respect to energy market participation, however no such treatment exists for capacity market participation. Unless the City of Medicine Hat is exempted by law, they will be required to participate in the capacity market as a self-supplier as they meet the self-supplier definition.

6.2 Asset Substitution

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- The working group was directionally aligned that allowing asset substitution was good for the market by helping suppliers manage risk which should result in lower capacity market costs. The approach to managing performance risk should incorporate as much flexibility as possible and be allowed on an *ex ante* basis and possibly an *ex post* basis, between market participants and between resource types.
- Working group members were interested in learning more about the *ex post* approach that is employed in other markets, but felt they did not have enough information to support it at the time.
  - Some working group members and industry stakeholders raised concerns with substitution on an *ex post* basis as this could be considered a free option, or that it may dilute the penalty signal.

Comparison to SAM 3.0 Position

- The AESO's proposal is largely consistent with SAM 3 directional alignment with respect to *ex ante* substitution. No clear stakeholder position was taken on *ex post* substitution.

AESO Rationale:

The Comprehensive Market Design supports *ex-ante* asset substitution but not *ex-post* asset substitution.

Asset substitution allows a pool participant to assign the performance and availability assessments to another uncommitted capacity resource as a tool to manage performance risk while maintaining overall system reliability objectives.

The proposed *ex ante* asset substitution approach is modelled on the existing AESO approach found in the ancillary services market for operating reserve. Financial arrangements made are outside the AESO's purview. Asset substitution will not transfer the obligation from one customer to another, but rather transfer the performance and availability assessment to another qualified, but uncleared resource.

The potential benefits of *ex post* substitution for stakeholders to manage risk within their portfolios are minimal given the proposed structure for performance payment adjustments (see Section 8). In addition, *ex post* substitution may increase the risk of gaming availability measurements in an availability measure.

An uncommitted resource is one that was qualified to participate in the market but did not clear in the auction. The AESO must track performance and availability of all eligible resources whether they clear or not because of the must-offer requirement and for the purposes of future market UCAP calculations. In asset substitution we can simply point the assessments at any resource provided it is known which resources are expected to perform and when. Performance and availability payment adjustment mechanisms apply to the official obligation holder and not the owner of the substituting resource. This simplifies settlement, does not impact credit requirements, and allows counterparties to work out the terms of their agreement independently.

6.3 Capacity Obligations Tracking Infrastructure and Processes

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

These details were not discussed by the working group through SAM 3.0.

AESO Rationale:

A system of record is required to track and manage qualification status, UCAP ratings, auction results including the capacity obligation volumes and associated prices for each obligation period. The systemwill also support self-supply and asset substitution arrangements among market participants.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Rationale Document

Section 7: Capacity Auction Monitoring and Mitigation

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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7. Monitoring and Mitigation

Capacity markets may be subject to structural market power, meaning suppliers may have the incentive and ability to influence prices to enhance the value of their capacity resources at the expense of other capacity suppliers or electricity consumers. Some capacity suppliers will have the incentive and ability to physically or economically withhold supply from the market to increase prices and augment the value of their remaining capacity resources, while other suppliers may have a large enough net-short capacity position to have an incentive to offer capacity at uneconomic prices below cost to suppress prices. The purpose of effective market power mitigation mechanisms is to prevent behaviour that would introduce inefficiently high or low prices to the benefit of one participant, at a detriment to the market as a whole.

7.1 The Need for Market Power Mitigation

The AESO has determined that the capacity market in Alberta may be subject to the exercise of market power under certain conditions based on an analysis conducted by AESO staff and The Brattle Group that evaluated the level of market competitiveness.

7.1.1 The Need for Supply-side Mitigation

The need for supply-side market power mitigation arises when the market for capacity resources is concentrated, and certain large capacity suppliers control enough resources to effectively exercise market power. Market power in this context refers to the ability of a supplier or group of suppliers to withhold capacity from the market to increase prices to the benefit of their remaining supplier resources. The AESO and Brattle have conducted analyses to test how concentrated the market for capacity potentially is in Alberta, and to determine whether certain capacity suppliers would have the incentive and ability to withhold supply from the market.

Market concentration in the Alberta capacity market can be observed by calculating the percentage of the total capacity controlled by the largest suppliers in the market. Based on the asset mix assumptions from the *AESO 2017 Long-term Outlook* and other simplifying assumptions, the AESO has estimated the portion of the total unforced capacity (UCAP) supply available in the market that is controlled by the top five firms. The results of that calculation are shown in Table 1. The results indicate that the largest five firms in Alberta control over 70 per cent of all the UCAP in the market, and that the majority of that portion is held by the two largest firms in the market, which together control almost 45 per cent of all the UCAP in Alberta.

Table 1: Portion of the Total UCAP in the Alberta Market Controlled by the Top 5 Firms

Firm	Offer controls based on UCAP (includes wind)
Firm 1	26.0%
Firm 2	17.6%
Firm 3	11.6%
Firm 4	8.8%
Firm 5	6.3%
Grand total	**70.3%**

The data shown in Table 1 indicates that the Alberta capacity market is sufficiently concentrated to raise concerns of market power by the larger suppliers. Nevertheless, it is not clear that all the large-capacity suppliers in Alberta have the incentive to exercise market power and increase prices to a non-competitive level. The incentive to withhold capacity depends on two factors: 1) how responsive the auction clearing price is to withheld capacity; and 2) how much additional capacity a firm has left in the market to benefit from the increased price. For example, consider a firm that controls 500 MW of UCAP, and a competitive market clearing price of capacity at $75/kW-year. If, by withholding 200 MW of UCAP, the firm can increase the clearing price to $100-kW/year it would gain $25/kW-year on the remaining 300 MW of UCAP in its portfolio (worth $7.5 million), but would lose $75/kW-year on the 200 MW of UCAP withheld from the market (worth $15 million). Therefore, this firm would not have the incentive to withhold capacity from the market.

The AESO and Brattle conducted a preliminary test to determine the size of the capacity portfolio at which a firm begins to have an incentive to withhold capacity. The test is dependent on the shape of the demand curve utilized in the capacity auction, as this will determine how sensitive the auction clearing price is to changes in supply due to withholding. Therefore, the test was conducted using six different demand curve shapes being considered for the Alberta market and an estimated supply curve developed by Brattle. Table 2 shows, for each demand curve option, and at three different quantities of withheld capacity, the minimum portfolio size at which a firm would have the incentive to withhold capacity. For example, Table 2 shows that using a demand curve with a price cap at 1.75 x net-cost of new entry (net-CONE) based on a reliability requirement of 400 MWh of Expected Unserved Energy (EUE), a firm with 1,290 MW of UCAP could profitably withhold 110 MW, which would cause the auction clearing price to increase by $13/kW-year. In general, the results of this test indicate that some large capacity suppliers, with portfolios of 1,100 MW of UCAP or larger, may have the incentive to withhold capacity from the market.

Table 2: Preliminary Market Power Incentive Test Results

	550 MW Withheld	225 MW Withheld	110 MW Withheld
Flattest Alberta Curve ***400E 1.6x Net CONE Cap***	2,090 MW *$50/kW-yr*	1,770 MW *$20/kW-yr*	1,630 MW *$10/kW-yr*
Middle Alberta Curve ***400E 1.75x Net CONE Cap***	1,760 MW *$63/kW-yr*	1,420 MW *$26/kW-yr*	1,290 MW *$13/kW-yr*
Steepest Alberta Curve ***400E 1.9x Net CONE Cap***	1,550 MW *$77/kW-yr*	1,210 MW *$32/kW-yr*	1,080 MW *$16/kW-yr*
Flattest Alberta Curve **100E 1.6x Net CONE Cap**	2,790 MW $34/kW-yr	2,440 MW $14/kW-yr	2,310 MW $7/kW-yr
Middle Alberta Curve **100E 1.75x Net CONE Cap**	2,310 MW $43/kW-yr	1,980 MW $18/kW-yr	1,840 MW $9/kW-yr
Steepest Alberta Curve **100E 1.9x Net CONE Cap**	2,020 MW $52/kW-yr	1,690 MW $21/kW-yr	1,560 MW $11/kW-yr

When taken together, these analyses demonstrate that the Alberta capacity market is structurally concentrated, and multiple entities when acting alone or together would have the incentive and ability to exercise market power. Therefore, the AESO has determined that supply-side market power mitigation measures are necessary.

7.1.2 The Need for Mitigation of Net-short Capacity Positions

Capacity suppliers that have a large enough net-short position (i.e., they benefit from a reduced capacity auction clearing price due to a load serving obligation that requires them to pay for capacity) may have the ability and incentive to offer capacity into the market below cost in order to reduce prices in the market. This outcome would harm all other capacity suppliers in the market, and could potentially discourage future capacity investment. Brattle has conducted a preliminary test to estimate the minimum net-short capacity position needed to create the incentive to uneconomically offer capacity into the market. Similar to the supply-side incentive test described in the previous section, the results of this test depend on the shape of the demand curve used in the capacity auction, the cost of the capacity to be offered below cost, and the overall size of a firm's net-short position. This analysis assumes that the capacity offered below cost is equal to 1.2 x net-CONE, and tests the six different demand curves under consideration for use in the Alberta market. Table 3 indicates that, assuming the steepest demand curve with the highest cap and a reliability standard of 100 MWh EUE, a firm would need to have at least a net-short position of 370 MW to have an incentive to offer 110 MW of capacity into the market below cost. Under other demand curve assumptions the net-short position needed to have the incentive increases.

Table 3: Preliminary Estimate of Net-short Capacity Position Incentive Test

	550 MW Net Short	225 MW Net Short	110 MW Net Short
Flattest Alberta Curve ***400E 1.6x Net CONE Cap***	1,200 MW *$31/kW-yr*	770 MW *$14/kW-yr*	640 MW *$7/kW-yr*
Middle Alberta Curve ***400E 1.75x Net CONE Cap***	1,150 MW *$33/kW-yr*	640 MW *$18/kW-yr*	520 MW *$9/kW-yr*
Steepest Alberta Curve ***400E 1.9x Net CONE Cap***	1,100 MW *$35/kW-yr*	650 MW *$17/kW-yr*	480 MW *$9/kW-yr*
Flattest Alberta Curve **100E 1.6x Net CONE Cap**	1,050 MW $38/kW-yr	570 MW $21/kW-yr	460 MW $10/kW-yr
Middle Alberta Curve **100E 1.75x Net CONE Cap**	990 MW $42/kW-yr	530 MW $24/kW-yr	380 MW $12/kW-yr
Steepest Alberta Curve **100E 1.9x Net CONE Cap**	950 MW $46/kW-yr	500 MW $25/kW-yr	370 MW $13/kW-yr

There are some entities in Alberta that may have net-short capacity positions, such as competitive retail entities or self-supplying loads, but the characteristics of the Alberta market imply that these market participants are unlikely to carry net-short positions large enough to cause a market power concern. Most competitive retail providers do not own capacity resources, and statistics published by the MSA indicate that, of the competitive retail providers that do own capacity resources, none have a net-short position.

Based on this, the AESO has determined that no mechanism for mitigating net-short (or buyer-side) market power is required at the current time. This may need to be reviewed in the future should portfolio compositions change.

7.2 Mitigation of Supply-side Market Power

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- With respect to market power screening, the Working Group reached directional alignment that market power tests for capacity market offers should be completed on an *ex ante* basis and that resource owners that are not pivotal should not have their capacity offers mitigated
  - Three approaches to capacity market mitigation were discussed: a) mitigation should be on a "no-look" basis at some fraction of net-CONE; b) mitigation should be on a "no-look" basis at a fixed $/kW month; and c) mitigation should be a fixed $/kW level that would be applied to all auction participants, pivotal or not.
  - Some working group members have suggested the $/kW month level be set at a price to allow incumbent assets to achieve fair compensation for investments made under the energy-only market and avoid the consequences of early retirement.
- The Working Group agreed that each of the three approaches should be further reviewed. Some working group members were concerned that capacity market power mitigation not be determined in isolation of energy and ancillary services market power mitigation.
- Industry stakeholders have provided comments that they are are supportive of market power mitigation only on pivotal suppliers, on an *ex ante* basis, using a no-look threshold.

AESO Rationale:

The supply-side mitigation measures utilized in other capacity markets can provide helpful context, and comparison for the measures proposed by the AESO. Table 4 provides a summary of the supply-side mitigation mechanisms employed in several other capacity markets. All the markets described in Table 4 utilize the same basic supply-side mitigation measures proposed by the AESO. These are a must-offer requirement to mitigate physical withholding of capacity, a market power screen to determine which capacity suppliers could potentially exercise market power, a default offer cap that applies to all the suppliers that failed the market power screen, and a unit-specific offer cap that a resource can apply for to override the default cap if the resource can demonstrate that its costs are higher than the default offer cap.

The significant differences between the markets arise in the type of market power screens each applies and the level where the default offer cap is set. In the U.S. markets the use of a pivotal supplier test is the common method to determine whether a market participant has the potential to exercise market power, although the nature of the pivotal supplier test can vary by market. For example, PJM chooses to apply a stricter version of the screen that takes into account the potential for capacity suppliers to collude in exercising market power. The European markets do not apply market power screens, rather these jurisdictions choose to mitigate all capacity suppliers to a default offer cap.

Each market also applies a slightly different methodology in establishing the level of the default offer cap. In PJM the new capacity performance rules set the default offer cap at net-CONE times the balancing ratio from the previous three years, which has resulted in a default offer cap around 85 per cent of net-CONE. NYISO sets the default offer cap at the higher of the projected auction clearing price or an estimate of net going forward costs, while ISO-NE uses an estimate of the cost to supply capacity in the market. The two European markets use a default offer cap of 50 per cent of net-CONE.

Table 4: Supply-side Mitigation Measures in Other Jurisdictions

Component	PJM	ISO-NE	NYISO	UK	Ireland
Must-offer requirement	Yes	Yes	Yes	Yes	Yes
Market power screen	3 Joint Pivotal Supplier	Pivotal Supplier	Pivotal Supplier	All resources are mitigated	All resources are mitigated
Default offer cap	Net-CONE x previous three balancing ratios	Dynamic Delist Bid is the cap; Estimated cost of supplying capacity	Higher of projected auction price or net going forward costs	50% of net-CONE	50% of net-CONE
Unit-specific offer caps	Yes, based on net going forward costs	Yes, based on net going forward costs	Yes, based on net going forward costs	Yes, based on net going forward costs	Yes, based on net going forward costs

The AESO is proposing a similar approach to supply-side mitigation as utilized in other capacity market jurisdictions. The rationale for each proposed mitigation rule is provided below.

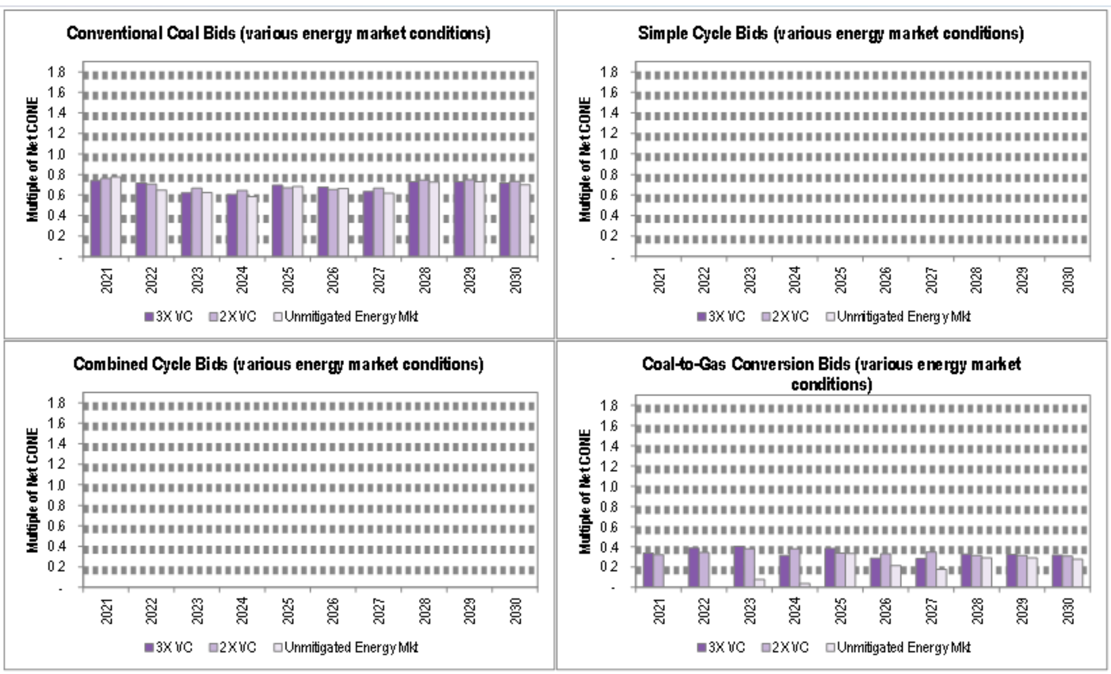
- **Must-offer requirement:** The must offer requirement is designed to prevent physical withholding in the capacity market. The must-offer requirement is an administratively simple and effective way to address physical withholding. A requirement of this nature is employed by every other capacity market. Requiring all non-exempt capacity resources to offer into the market ensures that the full capacity supply is being offered into the auction, which will generate competitive prices for customer, and capacity resources. The removal of a capacity resource can only occur by delisting (see Section 2.1.1)
- **Must-offer requirement exemption (capacity delisting):** While the mitigation of physical withholding through a must-offer requirement is necessary to mitigate the risk of physical withholding, there must be simple and clear rules that will allow capacity resources to retire for legitimate economic reasons. The AESO's proposal requires resources that wish to delist to demonstrate their net avoidable costs so that the economics of the delist decision can be evaluated. Capacity resources should not be allowed to retire if their demonstrable net avoidable costs can be recovered in the capacity market as this would remove economic resources from the supply mix and potentially provide a capacity supplier the ability to exercise market power. The AESO's proposal balances the need to accommodate capacity suppliers that want to delist and the need to preserve the protection against physical withholding provided by the must-ffer requirement.
- **Market power screen:** The market power screen proposed by the AESO is a structural test designed to mitigate the larger capacity suppliers in the market, but leave the smaller suppliers unmitigated to offer as they would like in the market. This proposal is based on the supply-side incentive test conducted by Brattle. The results of this analysis are shown in the previous section in Table 5. The incentive test indicates that, depending on the demand curve assumptions, the smallest UCAP portfolio size needed to create the incentive to withhold capacity from the market ranges from about 1,100 MW of UCAP to about 2,300 MW of UCAP. The proposed market power screen is to mitigate all capacity suppliers that control more than 15 per cent of the UCAP in the market, which under current market conditions would mitigate the two largest capacity suppliers that have UCAP portfolios of 3,500

MW, and 2,400 MW respectively. The remaining suppliers, with UCAP portfolios of about 1,500 MW of UCAP or less, would not be mitigated. The 15 per cent threshold will need to be re-evaluated by the AESO once the exact assumptions of the demand curve are determined. Moreover, once the capacity market begins operating the AESO will need to re-evaluate this market power screen on a regular basis alongside updates to the demand curve, to determine whether or not the 15 per cent threshold is effective in mitigating the suppliers that have the incentive, and ability to exercise supply-side market power.

- **Default offer thresholds:** The use of default offer thresholds limits the administrative burden on the market monitor of assessing the competitiveness of non-exempt suppliers, and focuses mitigation efforts on those resources most likely to have made offers that deviated from competitive levels.

  The proposed default offer cap of 50 per cent of net-CONE was determined based on a preliminary assessment of net going-forward costs for different technology types conducted by the AESO analytical group. This analysis estimated net going forward costs, which would need to be recovered in the capacity market, based on different energy market operation assumptions including three different energy market mitigation scenarios. The AESO analysis shows that combined-cycle and simple-cycle gas-fired generation have expected energy and ancillary services revenues above their going forward costs, while coal-to-gas conversion units have net going forward cost of less than 20 to 40 per cent of net-CONE left to be recovered in the capacity market (the higher number applying before conversion costs are expended and the smaller number applying after conversion costs become sunk costs). The net going forward costs for conventional coal units that need to be recovered in capacity market range from 60 to 80 per cent of net-CONE depending on the year and energy market mitigation scenario. The results of the AESO analysis are shown in Figure 5.

Figure 5: Preliminary Estimate of Net Going-forward Costs by Technology Type



Based on the preliminary results from the AESO analysis of estimated net going forward costs, the default offer cap was set at 50 per cent of net-CONE. This level would allow most technology types to recover their full net going forward costs without applying for a unit specific offer cap.

- **Unit-specific offer caps:** Competitive offer levels from some non-exempt resources may be above the default offer threshold. Unit-specific offer mitigation facilitates participation of these resources in the market, allows such resources to offer at levels reflective of net going forward costs, and avoids over-mitigation that can drive economic capacity resources out of the market. The rationale for using net going forward costs as the basis for unit-specific offer caps is that this reflects the price at which a rational seller without market power would be willing to offer into the auction (i.e., they would be willing to supply the resource at that price level or above).

7.3 Mitigation of Suppliers with Net-short Positions

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Topic was not discussed by the working groups through SAM 3.0.

The AESO has determined that implementation of a minimum offer price requirement (MOPR) on identified net-short participants for the purpose of mitigating market power that may arise due to net-short positions in the Alberta market is not required at this time. This is due to the preliminary expectation that there are no market participants with a large enough net-short position to create the incentive and ability to gain from artificially suppressing capacity prices. The incentive analysis conducted by Brattle, and presented earlier in this section, indicates that a market participant in Alberta would need to have a net-short capacity position over 370 MW in order to have the incentive to offer capacity into the market uneconomically.

A preliminary analysis of the Alberta market suggests that no market participants are likely to have such a large net-short position. The main difference between Alberta and other capacity markets, where net-short capacity positions would be more likely, is that there are no load serving entities (LSEs) in Alberta with captive customers and that control a small amount of supply. LSEs with captive customers would be able to build new capacity resources and recover costs from their ratepayers, while offering the capacity into the market below cost. Although this is not expected to be as significant a concern in Alberta as in other markets, there are certain market participants that may have a net-short position. These are Regulated Rate Option (RRO) providers, competitive retail entities, or self-supplying loads. Based on the market structure and conditions faced by each of these market participants it does not seem likely that they would have a net-short position large enough to provide the incentive to suppress market prices.

- **RRO providers:** The RRO providers in Alberta either do not own capacity resources or are prohibited to share information with an affiliated provider that owns capacity resources. Therefore, although the RRO providers are ‘naturally’ net-short and maybe exposed to the capacity market price, they do not have the ability to exercise buyer-side market power in the capacity auction.
- **Competitive retail entities:** Most competitive retail providers in Alberta do not own capacity resources. Even those competitive retail providers that do control some capacity do not have captive customers, implying that they do not have stable and predictable net-short or long capacity positions. If their load migrates to another provider a net-short capacity position can turn into a net-long position, eliminating the incentive to suppress prices.
- **Self-supplying loads:** The Brattle analysis indicates that a net-short position of over 370 MW is necessary to create the incentive to suppress prices. However, the net-short positions of self-suppliers are limited by nature due to the size of their industrial processes.

While the AESO is currently not recommending any mitigation of net-short capacity positions, if additional analysis or later review of capacity auction results indicates that some market participants in Alberta may have the incentive to uneconomically suppress prices, mitigation efforts will be implemented on those participants. Participants without net-short positions, such as merchants or utilities with a balanced load/supply profile, would be exempted. The following approaches would be used to mitigate offers of resources owned by such entities or with contractual arrangements with the large net buyers.

- **Minimum offer price rule:** If AESO does implement market power mitigation measures on entities with net-short capacity positions, a minimum offer price based on the expected net goingforward costs of incremental capacity resources will be established. The minimum offer price rule would only apply to new capacity resources in the market.

- **Exempt resources:** All new capacity resources controlled by market participants without a net-short position, such as merchant generation owners or utilities that can demonstrate that they have a balanced load/generation position may be exempt. Capacity resources that have a long construction period, such as nuclear plants, may also be exempt given that it is unlikely to be possible for the net-short entity to predict market outcomes accurately enough to benefit from artificial price suppression.
- **Unit-specific offer floors:** Competitive offer levels from some non-exempt resources may be below the default offer floor. Unit-specific offer mitigation facilitates participation of these resources in the market, allows such resources to offer at levels reflective of net going forward costs, and avoids risk of over-mitigation. If in the future buyer-side mitigation is deemed to be needed, a process will be developed to follow when developing unit-specific offers that balances administrative burden with accuracy.

7.4 Assessment of Auction Results and Market Competitiveness

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Topic was not discussed by the working groups through SAM 3.0.

Public assessments of the capacity auction performance and results are necessary to continually assess and improve the capacity market design to ensure the market is competitive, efficient, and supporting reliability needs. This process will also provide sufficient information to support market participants' business decisions, support investor confidence, and allow for public stakeholder engagement on potential design flaws and possible solutions.

7.5 Monitoring and Mitigation Assessment Against the Capacity Market Design Criteria

The procurement of capacity should employ market-based mechanisms and a competitive market for capacity should be developed. Market-based mechanisms include tools for monitoring and mitigating market power. These tools were developed by assessing the best practices and lessons learned from other capacity market implementations. These tools prevent abuses within the market to ensure the capacity market remains fair, efficient, and openly competitive (FEOC) without adversely affecting investor confidence and private investment. To protect investor confidence the design proposes to exempt a subset of capacity resources from offer caps.

It was determined that a minimum offer price requirement was not required reflecting the unique aspects of Alberta’s electricity system in the design of the capacity market.

To ensure capacity market mechanisms, outcomes and relevant data are transparent the design requires resources wishing to retire, mothball, or derate capacity to inform the AESO prior to any auction. The request will be reviewed and approved if net going forward costs are demonstrated to be above the capacity auction price cap or if the resource cannot clear the capacity auction at its net going forward costs. This maintains a FEOC market. Regular and clear reporting of and assessment on capacity market outcomes provides transparency to the market.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Rationale Document

Section 8: Supply Obligations and Performance Assessments

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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8. Availability and Performance Assessments

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- A majority of working group members agreed:
  - There is a need for a performance measurement framework to assess delivery against capacity obligations.
  - Increasing the number of performance measurement events will recognize the uniqueness of the Alberta market and make payment adjustments more manageable.
  - Non-energy emergency alert (EEA) event performance should be measured on resource availability (where “availability” means that the resource is available for energy market dispatch).
- Working group members were concerned that performance assessment periods only consisting of EEA events (as originally proposed in SAM 1.0) could result in aperformance assessment framework that was difficult to manage, would not incent the appropriate behaviour, and could increase capacity costs.
- Many industry stakeholders shared the working group opinion that the performance period should include tight supply cushion hours as well as EEA events.
  - Some stakeholders disagreed with a performance period beyond EEA events, suggesting that:
    - Additional performance periods will weaken the incentive (i.e. any payment adjustment risk) for resources to show up when capacity is needed the most.
    - Measuring the tight supply hours may have a negative impact on variable generators (e.g. there is an inverse correlation between the tight supply hours and high levels of wind generation) which could act as a barrier for certain resource participation in the capacity market.
  - Generally, working group members and stakeholders were supportive of payment adjustments being revenue-neutral; however, some stakeholders suggested that payment adjustments could be returned to rate payers.

Comparison to SAM 3.0 Rationale:

The AESO's payment adjustment framework is largely consistent with the payment adjustment framework generally agreed to by the working group.

- The framework to be implemented will have both availability and performance measures for capacity resources.
- Capacity resources that over-perform during the performance periods will have the opportunity to benefit from strong performance by being eligible to receive over-performance payment adjustmentss funded by the payment adjustments collected from non-performance payment adjustments.
- The AESO is not providing over-availability payment adjustments to the resources that over-perform during the availability assessment periods. The availability measurement averages the performance of these units over the assessment period, allowing these resources' over-performance relative to their unforced capacity (UCAP) rating during some review hours to offset possible underperformance during other review hours. Any unavailability payment adjustments collected during the obligation period will be returned to load customers.

8.1 Overview of Payment Adjustments

In exchange for capacity payments, capacity resources take on an obligation to maintain their availability throughout the year, to perform when called upon by the AESO during shortage conditions, and to offer into the energy market. These performance assessments and payment adjustment mechanisms provide a resource-neutral mechanism to encourage supply resources to perform in accordance with their obligations. Capacity resources are expected to reflect the cost of payment adjustments, and the cost of maintaining and improving their reliability into their capacity offers. In the long run, the payment adjustment mechanism will provide a financial signal to capacity resource owners to maintain supply adequacy at lowest cost to consumers, as resources with lower performance risk will have a competitive advantage.

Prior to the start of the obligation period, new resources that are delayed in meeting their in-service date and existing resources that anticipate not being available during the obligation period can engage in asset substitution and purchases in rebalancing auctions to reduce their capacity market obligations in order to avoid payment adjustment risk.

Annual and Monthly Payment Adjustment Exposure Cap:

Under-performing resources will be subject to annual and monthly caps on payment adjustment exposure from the combination of availability and performance assessments. The payment adjustment caps are necessary to protect participants from excessively high risk of participating in the capacity market by keeping payment adjustment exposure in line with revenues. This helps maintain the investment attractiveness of the Alberta market. Total payment adjustment exposure will be capped in two ways:

1. Annual payment adjustment cap: at 130 per cent of the annual capacity revenue based on the higher of i) the annual base auction capacity price, or ii) the last rebalancing auction price, including both performance and availability payment adjustments.
2. Monthly payment adjustment cap: at 300 per cent of the monthly capacity revenue based on the higher of i) the annual base auction capacity price, or ii) the last rebalancing auction price, including both performance and availability payment adjustments. Given annual unavailability payment adjustment settlement as described in the Section 8.4 below, the monthly payment adjustment cap will be applied to the unavailability payment adjustment amount on an average basis during each year (i.e. divide the total annual unavailability payment adjustment by 12 months, and then apply the monthly cap). The monthly cap will prevent a situation in which an annual revenue sized payment adjustment is charged to a capacity resource in a single month. This monthly cap is not set to 100 per cent of monthly revenue, because in a situation when a capacity resource is being charged a non-availability and a non-performance payment adjustment in the same month, a 100 per cent monthly cap could exempt such capacity resource from one of the payment adjustment amounts, reducing incentives to perform as expected.

8.2 Failure to Deliver for New Resources

The non-delivery process provides a mechanism for the AESO to take action prior to the delivery period if it appears that supply will not be available during the delivery period. This helps to ensure required levels of supply adequacy. This process will apply to new resources at significant risk of failing to come online for any reason (such as construction delays). The non-delivery process encourages resources that have sold capacity to bring that capacity online by the start of the obligation period.

Prior to the final rebalancing auction, the AESO will identify committed capacity resources that are unlikely to be operational by the start of the delivery period. For new resources, this assessment will be based on the completion of the development milestones. Resources identified by the AESO will have two options to address their shortcoming: 1) buy out their obligation in the final rebalancing auction, or 2) engage in asset substitution prior to the final rebalancing auction to cover their obligation with supply from another resource.

The goal of this approach is to have resources manage their non-delivery risk prior to the delivery period and to ensure that the AESO is able to meet its reliability obligations through market mechanisms.

8.3 Updates to Qualified UCAP Ratings

In addition to availability and performance assessment in the delivery period, the capacity resources have an incentive for delivering, and maintaining strong ability to perform because the UCAP rating of capacity resources will be annually updated in each auction prequalification round, taking into consideration their recent operational performance. Strong availability and performance in recent years translates to higher UCAP ratings, and therefore, greater potential capacity revenue in the future year. UCAP values will be assessed and updated for every base and rebalancing auction to reflect changes in the resources' capabilities. Payment adjustments during the obligation period create incentives for sellers to meet their forward capacity obligations before the oibligation period by delivering new supply on time, retaining existing capacity, or by securing a replacement capacity resource through rebalancing auction or asset substitution.

8.4 Unavailability Payment Adjustments

Utilizing tight supply cushion hours for conducting availability assessments is intended to encourage availability when the system is at risk of reliability challenges. These hours will not necessarily correspond to emergency event hours where performance payment adjustments are assessed. Availability will be assessed during the same number of hours as the UCAP assessments described in Section 2.3 in order to align incentives and measurement to periods of greatest reliability risk to the system. The goal of this design element is to encourage readiness to be available and compliance to dispatch instructions during the delivery year, particularly in times when the system is at risk.

As the availability assessment is completed through the delivery period on a large number of hours, providers are able to use periods of higher availability to offset periods of lower availability. Due to this ability to average performance throughout the year, over-availability payment adjustments will not be paid in the availability performance assessment framework. Any unavailability payment adjustment amounts collected will be returned to load customers.

The difference in approach is due to the differing goals of performance incentives. While availability payment adjustments are intended to incentivize resources with capacity obligations to be available, on average, over the delivery year, performance incentives are intended to encourage delivery of energy production, ancillary services or demand reduction during a limited number of emergency hours to at least the level of the resources obligation. The need to encourage availability across the year is not as acute as the need to encourage delivery during emergency events, and does not require payments to over-available capacity. We expect energy and ancillary services' prices to provide a strong enough centive to encourage additional availability from resources that are meeting their capacity obligations.

Availability Assessment Period

Unavailability payment adjustments will be assessed by comparing each resource's capacity obligation to its availability during a fixed number of annual availability assessment hours. Availability assessment will be conducted during the delivery period over the 100 tightest supply cushion hours.

Assessing availability during these hours is consistent with how resource UCAP will be determined. The number of recommended hours for the availability assessment (100 hours annually) is based on the average number of hours historically between 2011 and 2017 in which supply cushion was below 400 MW; conditions which characterize system tightness (see Section 2.3) .

Unavailability Volume Definition

During each year, resources with capacity commitments will be required to demonstrate that their actual availability was at least equal, on average, to their committed UCAP (expected availability) during the availability assessment hours.

- For dispatchable resources, actual availability is the amount of MW offered and available during the 100 tightest availability hours in the obligation period.
- For non-dispatchable resources, actual availability is the amount of energy generated during the 100 tightest availability hours in the obligation period, calculated as follows:

Unavailability (MW) = (Expected Availability, MW – Actual Availability, MW) > 0

where Actual Availability = average availability during relevant tightest supply cushion hours, multiplied by total number of assessment hours.

Unavailability Payment Adjustment Rate

Resources with positive unavailability in each year will be assessed a payment adjustment based on the maximum of the capacity resource's base auction price or the latest rebalancing auction price as follows:

Unavailability Payment Adjustment Rate ($/MWh) = 40% x 1.3 x MAX [Annual Base Capacity Auction Price; Annual Last Rebalancing Auction Price]) / 100 hours

Tying the payment adjustment to the auction clearing prices ensures that the payment adjustment level is consistent with the value of supply reflected in the capacity market demand curve. Including the base auction price in the formula ensures that resources will still be exposed to a payment adjustment commensurate with the capacity payment it receives, and will still have an incentive to be available during the delivery period, even if the rebalancing auction clears at a low price. To the extent the rebalancing auction price is higher, this approach also recognizes the most recent price of capacity, which could be reflective of tighter supply conditions, and hence, greater reliability risk.

The factor of 40% is an allocation factor representing the amount of the total payment adjustment to a unit that will occur through the unavailability payment adjustment mechanism. The AESO's choice of a 60% allocation factor to non-performance payment adjustments reflects a higher importance of the committed capacity being delivered during performance events.

The factor of 1.3 scales the total payment adjustment level up above the capacity auction price. A value greater than 1 ensures that resources failing to deliver are exposed to a net payment adjustment, after accounting for capacity revenues they will receive. A value larger than one also discourages speculative capacity sales because by committing to a capacity obligation the resource is at risk of losing more through poor availability and performance than through what might be earned through capacity payments. The value is believed to be of a magnitude that is sufficient enough for capacity resources to retain the incentive to become available later rather than never, but will not be so large that new entrants will be discouraged from participating.

Unavailability Payment Adjustment Mechanism Exemptions

The AESO is proposing to limit the exemption from unavailability payment adjustments to resources constrained by internal Alberta transmission constraints. If a resource's availability is constrained below its obligation due to a binding transmission constraint, the resource will not be exposed to unavailability payment adjustments on the constrained volume of the capacity obligation. Transmission limitations are beyond the control of participants, and given Alberta's transmission policy, would not be expected as normal course of business by participants. Transmission constraints that are foreseeable sufficiently ahead of time will be considered in capacity market clearing as discussed in Section 4.

There will be no other exemptions to availability payment adjustments. As the UCAP calculation for each asset will reflect reduced commitment levels from observed planned and forced outages as well as de-rated conditions, none of these events will be payment adjustment exempt. Committed resources can use the rebalancing auctions and asset substitution process to avoid unavailability and non-performance payment adjustments.

All capacity resources are expected to be available as committed, and to be able to forecast tight conditions on the system per their best judgment. Additionally, it is expected that capacity resources will price their risk of payment adjustments into their capacity offers, which in the long run will ensure that only the most efficient and high-performing resources are participating in the market.

8.5 Performance Payment Adjustment Payments

Resources failing to deliver during EEA events will be assessed a nonperformance payment adjustment based on the shortfall between their actual and expected performance. Similarly, resources with capacity obligations that over-deliver will receive favourable over-performance payment adjustment . These payment adjustment are intended to create a strong marginal incentive to deliver energy and operating reserves during periods when the system is most in need of supply. By applying a payment adjustment mechanism during EEA events, all resources with capacity obligations effectively face a similar $/MWh incentive, incremental to the energy price, during these events.

Performance Assessment Period

Performance assessment periods will occur during EEA events, when the system is in need of all available capacity in order to maintain reliability, and operating reserve targets. Any time the AESO declares an EEA level 1 (i.e. all available resources are in use) or higher (i.e. EEA level 2: load management procedure is in effect; EEA level 3: firm load interruption is imminent), the performance assessment period will begin, and declaration of EEA 0 (i.e. a termination alert issued when energy supply is sufficient to meet AIES load and reserve requirements) will be an end time of a performance assessment period. These events are hard to predetermine, and as such, there will be no explicit prior notification before such periods occur. Likewise, there is no maximum duration of the performance events that can be predicted or pre-defined ahead of time. The AESO will continue to provide the real-time supply adequacy report to market participants which may be a help in identifying periods of tight supply adequacy.

Performance Volume Definition

Performance of a capacity resource is calculated as the resource's expected performance minus the actual performance, measured during performance assessment periods in MWh. The capacity resource's expected performance is multiplied by the balancing ratio (which is intended to adjust required performance volumes to reflect system conditions) to determine the volume subject to an over-performance or non-performance payment adjustment .

The balancing ratio is the ratio of energy and reserves produced by committed resources during a performance event to the total committed capacity in that delivery year, and is a number less than or equal to 1. The balancing ratio is intended to adjust required performance volumes to reflect system conditions. The ratio is also meant to adjust an individual resource's capacity market obligation in a performance period to its pro rata share of the total capacity market need during the performance event.

Non-Performance Payment Adjustment Rate

Non-performance payment adjustments will be set based on the higher of base capacity auction price or the latest rebalancing auction price, which would link the payment adjustment rate to the resource's maximum available revenues from the capacity market. The base capacity price and rebalancing auction price will be reset every auction period, and the payment adjustment level will be adjusted accordingly.

The non-performance payment adjustment rate will be calculated using the following formula:

Non-performance payment adjustment rate ($/MWh) = (60% x 1.3 x MAX [Annual Base Capacity Auction Price; Annual Last Rebalancing Auction Price]) / Expected EEA hours

The formula is based on the maximum of the base capacity auction price and the last rebalancing auction price, expressed on an annual basis. Tying the payment adjustments to the auction clearing prices ensures that the payment adjustment level is consistent with the value of supply reflected in the capacity market demand curve. Including the forward auction price in the maximum ensures that resources will still be assessed at to a payment adjustment commensurate with the capacity payment it receives, and will still have an incentive to be available during the delivery year, even if the rebalancing auction clears at a low price.

The factor of 60% preceding the non-performance payment adjustment rate formula is an allocation factor, representing the amount of the total expected payment adjustment a non-delivering unit will incur through the performance payment adjustment mechanism. The AESO's choice of a 60% allocation factor reflects the ultimate focus of capacity construct and payment adjustment mechanism: ensuring delivery during periods of supply shortfall.

The factor of 1.3 scales the total payment adjustment level up above the capacity auction price. A value greater than 1 ensures that resources failing to deliver are exposed to a net payment adjustment, after accounting for capacity revenues they will receive. A value larger than one also discourages speculative capacity sales because by committing to a capacity obligation the resource is at risk of losing more through poor availability and performance than through what might be earned through capacity payments. The value is believed to be of a magnitude that is sufficient enough for capacity resources to retain the payment adjustment mechanism to become available later rather than never, but will not be so large that new entrants will be discouraged from participating.

Normalizing by the expected EEA hours ensures that on average, the total non-performance payment adjustment for a non-delivering resource will be 1.3 times the relevant capacity price. Due to variability in system conditions, the number of EEA hours during which performance payment adjustments are assessed will vary from year to year. Since the payment adjustment rate is based on the expected number of hours, it will not vary as much from year to year as the actual number of EEA hours. The specific value of expected EEA hours will be revised each year based on reliability modelling.

Over-Performance Payment Adjustment Rate

As described above, the over-performing resources with capacity obligations are eligible to receive payment adjustment payments funded from 100% of the collected non-performance payment adjustments. Over-performance payment adjustments are additive to the energy and ancillary services prices, creating strong incentives to deliver energy and capacity during shortage events.Over-performance payment adjustments will be made for each MWh of over-delivery during EEA events, and will be paid at the $/MWh over-performacne payment adjustment rate:

Over-performance Payment Adjustment Rate ($/MWh) = Total Collected non-performance payment adjustment funds / All eligible for over-performance payment adjustment MWh

The over-performance payment adjustment rate is defined in this way in order to ensure that performance payment adjustment s are a revenue-neutral from the perspective of the AESO and customers. All non-performance payment adjustment funds collected from under-performing resources are distributed to over-performing resources proportional to their over-performance.

Over-performacne payment adjustment payments will also allow resources to recover from non-performance payment adjustments through strong performance during future events.

Non-performance Payment Adjustment Exemptions

The AESO is proposing to limit the exemption from payment adjustments to resources constrained by internal Alberta transmission constraints. If a resource's availability is constrained below its obligation due to a binding transmission constraint, the resource will not be exposed to under-performacne payment adjustments on the constrained volume of the capacity obligation. Transmission limitations are beyond the control of participants, and given Alberta's transmission policy, would not be expected as normal course of business by participants. Transmission constraints that are foreseeable sufficiently ahead of time will be considered in capacity market clearing as discussed in Section 4.

There will be no other exemptions to availability or performance payment adjustments. As the UCAP calculation for each asset will reflect reduced commitment levels from observed planned and forced outages as well as de-rated and force majeure conditions, none of these events will be payment adjustment exempt. Committed resources can use the rebalancing auctions and asset substitution process to avoid unavailability and non-performance payment adjustments.

All capacity resources are expected to be available as committed, and to be able to forecast tight conditions on the system per their best judgement. Additionally, it is expected that capacity resources will price their risk of payment adjustments into their capacity offers, which in the long run will ensure that only the most efficient and high-performing resources are participating in the market.

8.6 Supply Obligations and Performance Assessment vis-a-vis the Capacity Market Criteria

The capacity market can achieve desired reliability objectives by creating a real and measurable supply adequacy product in which to assess whether capacity resources met their capacity market obligation and incent providers to live up to their obligation. The incentives are designed in such a way that a wide variety of technologies should be able to compete to provide capacity while ensuring a fair, efficient, openly competitive (FEOC) market. Costs to consumers are minimized by creating a product for which value can be demonstrated via delivery. The capacity market incentive mechanisms, outcomes and relevant data are also transparent.

Leveraging best practices and lessons learned from other capacity market implementations to inform the payment adjustment framework is expected to maintain investor confidence and trigger sufficient private investment.

[1] Forced outage means the unavailability of a facility which is not anticipated as part of a legal owner's regular maintenance, and occurs as a result of an automatic or accidental action. (Source: p.11, AESO Consolidated Authoritative Document Glossary, https://www.aeso.ca/assets/downloads/Consolidated-Authoritative-Document-Glossary-March-21-2017-2.pdf)

[2] Planned outage means the full or partial unavailability of a facility which is anticipated as part of a legal owner's regular maintenance, including for the purposes of construction, commissioning or testing, and occurs as a result of a deliberate manual action. (Source: AESO Consolidated Authoritative Document Glossary, https://www.aeso.ca/assets/downloads/Consolidated-Authoritative-Document-Glossary-March-21-2017-2.pdf)

[3] In Alberta's current definition, force majeure means any occurrence, and its effects, which: (a) is beyond the reasonable control of the market participant; (b) could not have been avoided through the use of good electric industry practice, or by the exercise of reasonable diligence; and (c) prevents a market participant from performing its obligations under the ISO rules, ISO tariff or reliability standards, as applicable; but does not include a lack of finances or any occurrence which can be overcome by incurring reasonable additional expenses. (Source: p. 11, AESO Consolidated Authoritative Document Glossary, https://www.aeso.ca/assets/downloads/Consolidated-Authoritative-Document-Glossary-March-21-2017-2.pdf)

Alberta Capacity Market

Comprehensive Market Design (CMD) 1.0
Design Rationale Document

Section 9: Settlements and Credit Requirements

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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9. Settlements and Credit Requirements

9.1 Capacity Market Statements

Input from Working Group Members and Industry Stakeholders through SAM 3.0:

- Topic was not discussed by the Procurement and Hedging working group through SAM 3.0.

AESO Rationale:

- The capacity market should also operate on a monthly billing cycle to align with the energy market.
- The capacity market should use metering data for the purposes of capacity settlement, as is done with the energy market.
- Aligning settlement of the two markets will reduce the administrative burden by leveraging existing processes.
- A decision as to whether the capacity market and energy market invoices will be consolidated will be made later, and will depend on the system implementation, and the energy and ancillary services roadmap.

9.2 Settlements Applicable to Capacity Sellers

- Capacity sellers will receive capacity payments for their cleared obligation in the year of their obligation. This is consistent with other capacity markets and Alberta's current energy market.
- In addition to the obligation payment, a capacity seller may receive a payment adjustment as described in Section 8.

9.3 Settlements Applicable for Customers

The general concepts used to allocate costs to customers are not available yet.

9.4 Capacity Market Net Settlement Instructions

Input from Procurement and Hedging Working Group Members and Industry Stakeholders through SAM 3.0:

- The Procurement and Hedging working group (working group) recommended that the capacity market design (CMD) should facilitate capacity market net settlement instructions (NSI). This recommendation was based on the following key assumptions:
  - Asset substitution is the tool to facilitate the management of capacity resource obligation risk, not NSI.
  - Implementation costs are not significant for NSI.
  - NSI for capacity may require changes to the *E*UA [section 19(1) and 19(2)].
- The working group determined that NSI would be a useful tool for capacity market consumers to hedge their exposure to variable capacity market prices year to year. The idea was that these resources could lock in a capacity volume with a specified supplier, and that volume would be subtracted from their capacity market exposure volumes (meter volumes). Capacity resources would be paid the capacity obligation less the volume of NSI, multiplied by the capacity market price.
- Industry feedback on SAM 3.0 indicated widespread support for having NSI included in the design, with the only reservation related to ensuring the cost of implementing would not outweigh the benefits.

Comparison to SAM 3.0 Position

- The CMD does not adopt the SAM 3.0 recommendation that NSI should be facilitated. The CMD provides that NSI will not be facilitated.

AESO Rationale:

- Not to provide NSI.
- Having NSI as proposed by the working group and in SAM 3.0 works well in the energy market because the price paid for a MW of energy is equal to the price a consumer will pay for a MW of energy in the same time period. Given the current thinking on cost allocation in the capacity market, the AESO did not think this would be the same for the capacity market. This is because the current thinking by those influencing the policy on cost allocation suggests capacity cost will be allocated to load based on rates set within a capacity market tariff. This was not considered in the working group's initial assumptions when NSI was discussed.
- A volume-based NSI approach no longer works because the price paid for capacity no longer equals the price paid by load in that same time period. Facilitating NSIs will cause discrepancy between the amount paid to capacity providers and the amount collected from capacity consumers. This does not eliminate the ability for counterparties to enter into independent financial hedges with each other; however, these will not be registered with the AESO and accounted for in capacity market settlement.

9.5 Capacity Market Credit Requirements for Existing Capacity Resources

Will capacity resources have to provide financial security to cover the risks associated with the payment adjustment mechanism?

Comparison with other Markets:

- Capacity resources do not have to provide financial security (credit) in most other capacity markets to cover penalty risk provided the resource will receive a positive capacity payment.

In Alberta:

- The assessment of availability is performed at the end of the delivery period and looks back at the entire 12 months.

AESO Rationale:

- To minimize the credit risk, the AESO settlement will only claw back up to 100% of the capacity market payment on any one statement until the balance of payment adjustment mechanism is paid.

9.6 Measurement and Verification of Capacity Resources

Input from Working Group and Industry Stakeholders through SAM 3.0:

- The Eligibility working group briefly discussed the measurement and verification of capacity delivery and challenges with using the current Energy Trading System (ETS) system which would have implications on the calculation of UCAP for resources in the early stages of the capacity market.
- The Eligibility working group also discussed the application and use of the Generating Availability Data System (GADS) as a measurement and verification system; however, no recommendations or directional alignment were established by the working group.
- Industry stakeholders have not provided comments on measurement and verification systems.

Comparison to SAM 3.0 Position

- The CMD recommends not using GADS, but rather using the existing data collected for the existing energy market.

AESO Rationale:

- Capacity will be measured based on historical observed availability factor or capacity factor in the obligation period depending on the type of capacity resource being settled.
- See section 2.3 for the rationale for using availability and capacity factors.

9.7 Settlement and Credit Requirements Assessed Against the Capacity Market Design Criteria

- The CMD should provide mechanisms for consumers to hedge the cost of capacity if and where appropriate. It was determined that facilitating capacity market NSI was not an appropriate tool for hedging the costs of capacity. Financial hedges may still be developed by market participants.
- Settlement design ensured the capacity market is compatible with other components of the electricity framework, such as load settlement and retail customer choice, and should be robust and adaptable to different government policy initiatives related to the electricity sector.

Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Rationale Document

Section 10: Roadmap for Confirming Changes to the Energy and Ancillary Services Markets

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

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10. Roadmap for Confirming Changes in the Energy and Ancillary Services Market

Changes to the energy and ancillary services markets are required to facilitate the implementation of the capacity market, respond to changing Alberta generation fleet (i.e. increased variable generation, coal retirements, etc.) and to improve market efficiency. The timelines for implementation of these changes are still being evaluated, but may be variable, as some of the changes have more defined implementation timelines driven by studied system needs .

Section 10.1 outlines the energy market offer obligations; section 10.2 identifies the changes related to energy market monitoring and mitigation, and section 10.3 reviews pricing methodologies for price cap, and shortage pricing.

Section 10.4 is a summary of changes to the Energy and Ancillary Services (EAS) markets that have been evaluated as part of the EAS scope and that have been taken out of scope of the current design project. While some of these design elements may be linked to a future market or system operation trigger or a new business case, these items have been identified as nonessential for implementation of a capacity market and changes to the Alberta generation fleet at this time based on the evaluation completed.

10.1 EAS Offer Obligations

Offer Obligations Summary:

- All generation resources – including capacity resources and non-capacity resources – continue to have a must-offer obligation into the energy market.
- Imports that are capacity resources have a must-offer obligation and will be able to submit offers either with priced asset\blocks or through a price taker asset at $0.
- Capacity committed loads have a must-offer obligations and must be able to be dispatched. Capacity committed loads can offer at the offer cap to be dispatched last in the event of an energy emergency alert (EEA).
- Changes to mothball rules to align with delist capacity requirements and terms between auctions.

Rationale:

- Pool assets with capacity commitments, by receiving payments for capacity, have taken on obligations to offer their resources into the energy or ancillary service (AS) markets.This approach is consistent with current energy market obligations that all available capacity must be offered into the market.

Generating units, aggregated generating facilities and energy storage facilities

The existing ISO rules contain must-offer requirements for the maximum capability (MC) of source assets (defined as generating units, aggregated generating facilities and imports). The AESO proposes to maintain those requirements for capacity resources that are generating units, aggregated generating facilities and energy storage facilities. In contrast, other market jurisdictions typically use the concept of must-offering the ICAP equivalent of the UCAP a capacity resource supplies. However, the AESO has determined that it would be more efficient from an implementation perspective that Alberta continues the must-offer requirement for the maximum capability of a source asset outlined in the current ISO Rules.

Currently, the existing ISO rules require a generating unit or aggregated generating facility with a MC of 5 MW or greater to offer to the energy market. The AESO considers it reasonable that this 5 MW threshold continues to be applied. Those assets with a MC of 1 MW or greater and less than 5 MW will continue to have the option to offer into the energy market.

For generating units, aggregated generating facilities and energy storage facilities that are not capacity resources, the AESO considers that, in order to ensure system reliability, the system controller must have visibility of the physical capability of these assets to assess supply adequacy in and near real time . Two options for this approach were considered. First, it was contemplated that the assets could just not enter a start time when they are not available for dispatch. However, this method would not allow a reduced level of the asset's total availability, (an "all or nothing" approach). The second option considered was to continue to apply the must-offer requirement to the assets but allow them to restate their available capability (AC) without an acceptable operational reason (AOR). However, the restated AC must still reflect the maximum MW that the asset is physically capable of providing in order for the system controller to assess supply adequacy. This option would provide the flexibility of the non-capacity asset to make a portion of its total capability available to the market. However, without an AOR, the AESO was concerned about availability for dispatch.

Accordingly, it was determined that the current ISO rules would continue whether there is a capacity obligation or not. All assets must-offer to prevent physical withholding and allow for proper assessment for outages and directives.

Loads

Based on the overarching principle that capacity resources have obligations to offer into the energy or AS market, it is reasonable that capacity committed load assets must also offer into the energy or AS market. This will enable the system controller to take these load assets into consideration when assessing supply adequacy. Other market jurisdictions take a similar approach[1].

Additionally, it is reasonable that the same 5 MW threshold applied to capacity committed generators also apply to capacity committed loads. A load or aggregated load facility with capacity commitment of 5 MW or greater must-offer into the energy or ancillary services markets.Those with capacity commitments 1 MW or greater and less than 5 MW will have the option to offer.

Loads that have no capacity commitment will not have the must-offer requirement, but will continue to have the option to offer into the energy or AS market if they are equal to or greater than 1 MW in accordance to the current ISO rules.

While some capacity committed loads (i.e., price responsive loads) may offer at prices lower than the offer cap ($999.99), other capacity committed loads (i.e., demand response loads) may want to offer at much higher prices so they will not have to come off until required as part of the EEA events. Supply shortfall procedures will be developed to facilitate bids at the price cap being dispatched in a priority fashion is this option cannot be facilitated through system changes. .

For capacity committed loads that are measured based on a targeted level (i.e., referred to as "down to" as they will reduce loads to a set point), the AESO deems it appropriate that they must offer at the offer cap and be included in the shortfall steps since their energy offer MW volumes can change frequently. . Further analysis, including an assessment on market and dispatch systems, is required.

Imports and Exports

[1] https://www.aeso.ca/assets/Uploads/EAS4-Action-Item-2-load-participation-in-energy-market.pdf

Only imports will be eligible for capacity commitments. Similar to other capacity resources, an import asset that has a capacity commitment must offer the commitment volume into the energy or AS market.

The current ISO rules require imports to offer at $0 which would mean that all import offers are in-merit and will be dispatched and scheduled. As a result, it would mean that the commitment volume will always be dispatched and scheduled even when they are uneconomical. Allowing imports to request and use priced assets addresses this issue and is aligned will all other energy market assets.

An alternative approach is for imports to be provided priced assets which are allowed to offer at prices anywhere in the merit order similar to other pool assets meaning that priced import blocks would only be dispatched and scheduled when they are in-merit. In order to implement this option, intra-hour scheduling of intertie will be required. The AESO wouldaccommodate the submission of an e-tag by an import pool participant following their receipt of a dispatch from the energy market and will approve e-tag submitted intra-hour corresponding to the dispatch. However, the import pool participant would be accountable for ensuring that balancing authorities and transmission providers along the transmission path into Alberta will approve the e-tag at any time during the hour. In addition, the AESO will continue to make available the option for import as price taker at $0 and be scheduled at an hourly interval. The AESO recommends this option since it provides flexibility to import pool participants to either offer using priced assets or to continue to be price taker at $0.

The option to offer using priced assets will be made available to all imports and exports whether they are capacity committed resources or now . However, the must-offer requirement will only apply to import assets that have a capacity commitment.

Unit Commitment Summary:

- No change from status quo – the self commitment model will continue. Assets must-offer in order to manage the physical operations and financial obligations of their plants including responding to pending cycling and ramping.

Rationale:

The current self-commitment model continues to work in Alberta, given that directives issued to assets for reliability reasons occurs rarely. This means that assets have been able to respond to market signals to self-position their assets in the self-commitment model. Additionally, as shown below, the centralized commitment model yields similar results as the self-commitment model in terms of efficiency. Given that the centralized commitment model, in comparison to the self-commitment model, costs more to consumers for the same energy delivery by shifting the risk from generators to loads (through uplift payments), it was determined that the self-commitment model should continue in Alberta. An asset owner is in the best position to manage its commitment decisions. Accordingly, there is no need or value to shift away from the self-commitment model.

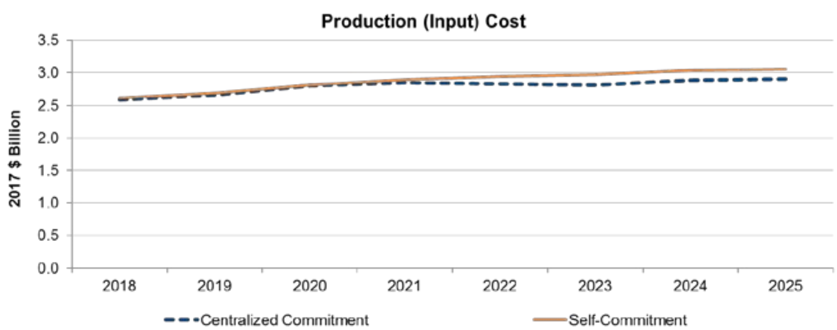
Self-commitment is supported by the following incentives and rules:

- All resources have the proper market incentives to position their assets to deliver energy and manage their own operational cost.
- Capacity resources have additional financial incentive to be available during system stressed periods in order to avoid performance payment adjustments and earn market-based revenues.
- The AESO publishes the short-term adequacy (STA) assessment report to provide a signals to market on supply tightness.
- Directives have not been required for reliability reasons; however, if required, the AESO may direct long lead time assets (i.e. Long Lead Time Energy or LLTE) resources to start up to provide energy. If

required, the AESO may direct resources to start up, and to provide energy for reliability reasons through reliability unit commitment rules. The metrics for system controller intervention will be reviewed to ensure they do not interfere with the incentives required to self commit.

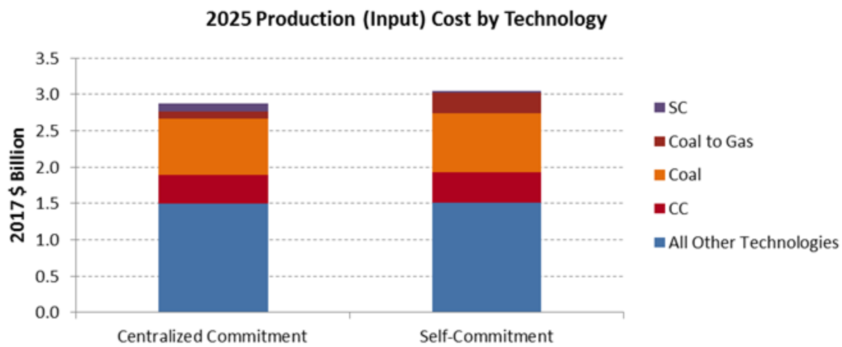
- The AESO net-demand variability (NDV) study indicated increased cycling of large commitment units (300 MW, and larger) from current level of about 5 on/off starts per unit in 2017 to about 50 on/off starts per unit in 2020/2022, and to about 90 on/off starts per unit in 2030 under the current market model. However, all scenarios tested show sufficient flexibility provided by assets assumed to be part of the overall system fleet in order to manage this flexibility within current market rules. Additional rule changes are under consideration to provide incentives and value for flexibility – which in concert with current rules will enforce the ability of the self-commitment model to continue even with future variability changes on the grid.
- The AESO commitment modelling study indicated potential but limited efficiency gains from switching to a centralized commitment model. This study showed that assets with a forward view of the market will self-position their assets to respond to expected changes. The modelling showed a reduction in unit starts in the centralized commitment model compared to the self-commitment model.
- Analysis results showed that production cost in the self-commitment model was higher than the centralized commitment model by approximately 6% higher in later years (mid 2020s). See **Figure 1** below.

Figure 1



- Further analysis of the 2025 period indicated that the estimated increase in production costs in the self-commitment model was related to lower efficient units, such as converted coal to gas units, staying online because of higher start costs and unit operational characteristics. These units displaced more efficient units, resulting in higher fuel, emission, and start-up costs. As such, the self-commitment model has higher costs related to lower efficiency commitment units producing more energy. However, these costs remained with the generator owner based on their decisions and were not assigned to loads through uplift in a centralized model. Figure 2 below shows the input cost per units modelled to be on line in 2025 and their contribution to overall production costs.

Figure 2



- The results of the modelling is that the self-commitment model can continue to support reliability objectives as participants will manage their assets to stay on line even during variability.Additionally, the AESO will continue to have the ability to direct units for reliability unit commitment, and LLTE as required. Further analysis may be required on the compensation model rules that trigger directives and costs if directed and to ensure incentives are appropriate to limit directives that limit directives where asset self-commitment could be used. The AESO will continue to monitor the impact of NDV on the fleet and continue to assess whether the rules are sufficient in the longer term.
- Moving to a centralize commitment model will require a more complicated bid offer structure (i.e.,a three part bid model that requires prices for start up, minimum run and no load in addition to energy price and ramp rates). This is a fundamental change to the energy market systems. Further, the centralized commitment model shifts some of the risk from generators to loads because the commitment model is designed to cover costs as submitted (i.e., keep whole payments if revenues are insufficient from the energy market).

Outage Scheduling Summary:

- No change from status quo – participants including new capacity committed load resources are required to submit outage information. While the AESO can cancel an outage, the AESO will not approve outages.

Rationale:

The AESO anticipates that the current outage model aligned with a capacity model will continue to work appropriately. Given that the CMD proposal does not contemplate exemptions for performance measurement due to outage approval, an examination into changes to the outage model is not required.

The AESO already has existing market rules that pertain to outage scheduling of load and generation. The AESO reviewed the options for outage scheduling for generation resources and proposes to maintain the current outage scheduling requirements for both capacity committed generation and non-capacity committed generation. The AESO also proposes that loads contracted for capacity will have to follow similar outage scheduling rules.

The current ISO rules require outage reporting where a generating unit or aggregated generating facility with a MC of 5 MW or greater changes its AC by 5 MW of more, and load decrease to its AC of 40 MW or more. Loads that have capacity commitments greater than 5 MW will be required to follow outage reporting requirements similar to the generator outage reporting requirements..

The AESO considers it reasonable that these requirements continue to apply to support the ongoing assessment of system adequacy. The AESO uses this outage information in order to assess and report Alberta's supply adequacy for both the short-term and the longer-term (next two years). The AESO needs to assess supply adequacy to manage the reliability of the system.

Supporting reasons for maintain the current outage submission process include:

- All resources have a financial incentive to plan outages to avoid stressed and higher priced times.
- Capacity resources have financial incentive to be available during system stressed periods so to avoid performance based payment adjustments.
- The risks of taking a planned outage during system stressed period should reside with the market participant.
- The CMD does not contemplate that performance exemption for a capacity resource taking an outage during performance period.
- Stakeholders expressed concerns in comments on SAM 2.0 that the requirement for AESO approving outages would pose challenges to the operation of assets and other processes.
- The AESO will continues to have the ability to issue a directive to direct cancellation of a planned outage including a mothball outage, and to direct the starting up of a long lead time asset through reliability unit commitment rules.

Dispatch and Scheduling Summary:

- Status quo dispatch of the merit orders with the inclusion of priced import assets within the merit order and a priority rule for capacity committed loads at the price cap with the exception of:
  - Further evaluation of the security constrained economic dispatch (SCED)model in terms of flexibility value to be assessed prior to CMD 2.0.
  - Consideration of rule changes at supply shortfall to address directives for capacity committed load resources and incentives for long lead time assets.
  - Consideration of rule changes at supply surplus to consider dispatch of flexible units.
  - Rules for ramp rate submissions by block and requirements for compliance of dispatch at directed levels to address system management especially during increased variability.
  - 15 minute settlement will be examined for pool assets except hourly settlement for retail loads.
- Energy and AS markets will continue to be cleared separately and dispatched sequentially subject to further coordination with a possible SCED dispatch. To be assessed prior to CMD 2.0.

Rationale:

The current dispatch rules continue to be appropriate; however, further options may be considered to address incentives and value for provision of asset flexibility needed to manage pending increased variability.

SCED is being evaluated as it is intended to provide a price for energy separate from ramp which then provides additional incentives and value for ramp capability from assets across the system. The signals for flexibility rely on a combination of rules that ensure the assets follow dispatch. Further analysis is ongoing to assess rule options individually or as a group that provide value for flexibility including submitting ramp rate by block offers, tighter dispatch tolerance in addition to pricing signals that optimize and pay for ramping response across the system. SCED will be evaluated against these other options.

SCED is an optimization process that determines what dispatch schedules will meet electricity demand at the lowest cost, given a specific set of constraints. In today's market, the constraints would be offers and supply sufficient to meet forecasteddemand. Energy price and dispatch schedules would be an output. Ramp could be included as a constraint to the algorithm where the output of the algorithm would be energy price, dispatch schedules, and the shadow price of the ramp requirement (if the ramp constraint is binding). The dispatch schedules output from SCED would provide the least cost solution to meet the ramp requirements in the future interval. In this way, ramp would be valued separately from energy to ensure price fidelity. The SCED would run in advance to support the system controllers in dispatching for these constraints.

Current settlement interval is hourly. Shortening the settlement interval to 15 minutes will improve price fidelity as the settlement price will be closer to the value of the energy at the time when it is produced, and may provide financial incentives for market participants to respond more quickly to dispatches

Cooptimization of EAS on its own generates some production savings (based on further study results). However, the results are likely not sufficient to warrant the required system changes but will be reviewed as part of SCED. The summary of the results are as follows:

- The AESO uses sequential selection where ancillary services offers are selected first to meet the reserve requirement and then remaining MW are selected from the energy market to meet demand. A single clearing price in the energy market results, with offers priced from $0 to 999.99 and AS offers priced from $-999.99/MWh to the bid are used to calculate an AS clearing price. Due to the nature of the clearing price mechanism, the gains from co-optimization are limited compared to how other jurisdictions price, based on the analysis refinement to comparison between sequential selection and co-optimization between energy and ancillary service markets.
- Other jurisdictions that have implemented co-optimization have done so on a premise of positively priced offers.
- The analysis concludes that in years that exhibit relatively lower system marginal prices, benefits from co-optimization ranged from 1% to 2% of total EAS revenue, under the assumptions stated in the paper. The benefits from co-optimization can increase with changes to ancillary services offer structure to cost based offers.
- Priced imports and capacity committed loads are no different than generation assets currently in the merit order.

Other considerations

- While the decrease in revenues is an implication, choosing whether to co-optimize or run a realtime AS market can result in other benefits.

- Currently, the AESO procures contingency reserves one day ahead based on forecasted contingency reserve volumes, and if procurement of active reserves falls short during real time, the AESO will use standby reserves. This introduces forecast error and could potentially lead to situations where there insufficient active contingency reserve to facilitate imports.

  With co-optimization, the full ancillary services offer curve can be optimized closer to real time to meet contingency reserve requirements and therefore the likelihood of falling short of active reserves decreases.

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

- The majority of the EAS working group members agreed that all committed supply capacity must-offer physical availability (including loads that are committed on the supply side of the capacity market) and all non-capacity resources do not have a must-offer requirement but must provide visibility.
  - Although there were no objections to this approach, there were continuing reservations, including:
    - An unclear understanding what information is required for ‘visibility’ for non-capacity resources; and
    - An unclear understanding of whether any differences will exist on bid mitigation for non-capacity resources.
  - Reservations to this provisional recommendation were based on:
    - Not clearly understanding what information is required for visibility for non-capacity resources.
    - Requiring a better understanding of whether any differences will exist on bid mitigation for non-capacity resources.

- Note: No working group members objected to this provisional recommendation.

- Industry feedback on SAM 3.0 provided similar commentary to that of the EAS working group:
  - Industry is supportive of cleared capacity resources having a must-offer obligation, and providing visibility of non-committed resources to the AESO.
  - In providing visibility information for non-committed resources, the AESO should consider options that focus on providing only availability and operation related information (e.g. start-up time, ramp rate, etc.).
- Additional commentary provided on imports as it relates capacity committed resources:
  - A must-offer requirement must permit capacity committed imports to price into the Energy market. However, in doing so, the AESO must ensure that this does not exacerbate jurisdictional seams issues. If this issue cannot be resolved prior to the implementation of the capacity market, then the must-offer requirement be suspended for imports on a temporary basis.

Rationale for Deviation from SAM 3.0 Position:

- Current must offer obligations are best able to address requirements for visibility and ensure consistency across assets.
- SAM 3.0 position on imports was incomplete; the priced import alternative will be discussed at the working group.
- Some working group members asked for evaluation of a ramp product; however, after preliminary assessment, this options should be evaluated against a fulsome SCED model Accordingly, the SCED option will be explored with the working group.

10.2 Energy Market Monitoring and Mitigation

Market Power Mitigation Summary:

- The energy market will adopt an *ex ante* market power mitigation based on an hourly residual supplier index (RSI) structural screen will be set at RSI of 0.9,
- Companies that fail the *ex ante* mitigation screen will be have their offers automatically mitigated to a multiple of a reference bid price that is based on fuel and variable O&M costs by technology type
- The bid threshold will be calculated at 3 x marginal cost defined as heat rate x fuel price + variable O&M + carbon cost.
  - For non-thermal resources, market participants will have the ability to submit opportunity cost for approval. In those cases, if approved, the opportunity cost would replace the reference bid price, upon which the bid threshold will be set.
- *Ex poste* monitoring and mitigation will continue

Rationale:

In Alberta's current energy-only market framework, all revenues, including those attributed to return on and of capital, are enabled through a price-formation mechanism that includes economic withholding (in-market offers resulting in scarcity pricing, especially during tight supply conditions). With the introduction of a capacity market, the need for acceptable economic withholding to recover cost of capacity was removed. While it is expected that the capacity market will capture a significant portion of the revenues attributed to return on capital, the majority of aggregate revenues will be captured in the Energy and Ancillary Services market, and these two markets will continue to have a role in incenting the appropriate investment in flexible resources, and optimal operational behaviour. This will be done through the energy market, and Ancillary Service market price signal. In a capacity market framework, some portion of the return on capital will be captured through revenues from the capacity market. As such, the need for these revenues to be captured in the Energy and Ancillary Services market through economic withholding, and in-market scarcity pricing is lessened, and the justification for economic withholding is weakened.

It is expected that competition in the energy market should tend to short run marginal costs (SRMC) in normal conditions (that is, except in scarcity or shortage events where the price will reflect market conditions.)

In other jurisdictions, capacity committed resources are required to offer at costs; however in Alberta's market where it is proposed that we continue with a one part bid/offer model with self-commitment, an acceptable range on costs will be determined to proxy "at cost". This range on costs will also address future cycling of assets that is more than reflected in historic data. Further, because of the expected competition in the energy market, assets that pass an *ex ante* screen will be able to submit their offers at any price below the offer cap.

Ex post mitigation will continue. However, with current uncertainty in Alberta's market, a move to an *ex ante* model was accepted and will be proposed. An *ex ante* mitigation approach provides control of risk of market power while still providing for scarcity pricing. The *ex ante* market power mitigation approach provides participants a forward looking assessment of whether they are a pivotal supplier in certain hours and a range of acceptable offers. This model does not prevent *ex post* mitigation of dispatch volumes, real time behavior and issues related to gaming by the Market Surveillance Administrator (MSA). However, this model provides greater certainty of how offers will be assessed.

Several options were considered for the *ex ante* mitigation model including different variations of the structural screen/pivotal supplier test and conduct and impact test. The AESO is considering the practicality of implementing the screen and setting the threshold for bid mitigation. There will be a tradeoff in determining the precision of the screen, and cost band, and the administrative and systems impact of any choice the AESO proposes. The AESO has determined that the use of an hourly pivotal supplier test will be the most practical to implement. The AESO is also proposing to use levels of RSI<0.9 to reduce the issues related to false positives. However, the AESO recognizes that having an RSI<0.9 will leave some suppliers (those above 0.9) opportunities to exercise their market power and will need to continue to evaluate the competitive nature of the market.

A conduct and impact test was considered. However, the AESO considered the test to be overly onerous from a implementation perspective. The AESO proposes to strike a balance between complications associated with conducting a cost-based hourly conduct and impact test but may still consider it for the future if the concentration level is sufficient to warrant further assessment.

Based on the historical bid analysis conducted by Brattle and AESO, the AESO has evaluated the potential revenues supplier can earn when bids were mitigated down to 3x costs. Brattle has found that mitigating down to 3x costs would be sufficient to cover most resources' start up and no-load costs based on historic costs and some expectation of future cycling and would not allow suppliers to earn more than the market's cost of new entry. Thus, the AESO is proposing 3x costs as a reasonable band on costs for setting the mitigation levels.

The AESO has based its proposal related to mitigation on its own assessment and work conducted by Brattle. The full paper will be circulated to the working group. Excerpts from the Brattle report are included below.

RSI Screen

The RSI screen is based on the concept of a "pivotal supplier." In a market with a fixed supply and inelastic demand, when nearly all-available supplier capacity is needed to meet demand, some suppliers may become "pivotal" in meeting the demand. The RSI test is typically used to detect market conditions when a supplier would have the capability to raise prices profitably by exercising market power through withholding a portion of their supply. The RSI's prescribed arithmetic formula, when applied to the specific market conditions, means a supplier is pivotal when that supplier's RSI is less than or equal to 1.0.[2]

Equation [1]

The RSI for $Supplier_i$ in period *t* is:

$$RSI_{it} = \frac{\sum_{j=1}^{n} Supply_{jt} - Supply_{it}}{Total\ Market\ Demand_t}$$

Where the sum of $Supply_{jt}$ represents the total capacity in the market at the relevant time *t*. *Total Market Demand* is the total demand in the market at time *t*. $Supply_{it}$ represents $Supplier_i$'s total resources made available to the market at time *t.*

The equation shows that RSI compares (1) the amount of capacity held by other suppliers in the market that are not owned and controlled by $Supplier_i$ (supply margin) to (2) the total demand of the market. If the supply margin is greater the total market demand, the RSI is greater than 1.0 and demand can be met without any of $Supplier_i$'s resources. When $Supplier_{i'}$'s RSI in period *t* is less than or equal to 1, *Supplier i* is deemed to be pivotal and its resources in whole or in part are required to satisfy demand in the market. Thus, an RSI < 1.0 indicates conditions under which *Supplier i* would be able (and may have the incentive) to exercise its market power and raise prices.

If the AESO chooses to use the RSI for market power mitigation in the energy and ancillary services markets, adjustments to account for Alberta-specific characteristics in the calculation of the RSI for each supplier (including all of the resources in each supplier's portfolio) would be highly recommended.

The formula in Equation [1] can and should be refined to better reflect a supplier's ability and incentive to exercise market power. The proposed refinements of Equation [1], include:

An adjustment for load and sales obligations: *Supplier i*"s total supply available at time *t* would be adjusted downward to reflect *Supplier i*"s load and long-term contract obligations, if any exists. As shown in Equation [2], the second term of the numerator reflects *Supplier i*"s net buyer/seller position in the market. This adjustment is particularly important when suppliers must purchase power to meet their obligations through the market with no ability to pass through the entire cost to their buyers/customers.

- Adjustment for imported resources/supplies:
  - In a given period, the total supply available in the market would include the amount of imports up to the interties' available transfer capacities.
  - If *Supplier i* has import offer bids, the total import bids should be included in *Supplier i*'s total supply.
- Adjustment for exports:
  - If the market allows participants to purchase from the market for exports, the total demand (in the denominator) should include the amount of exports.
- Adjustment for certain suppliers' must-run resources.

[2] Because a supplier is pivotal does not necessarily result in an incentive to exercise market power. For example, if the supplier would need to withhold 90 % of its capacity, it would be difficult for increased profits on the remaining 10% to make up for the losses on the withheld 90 percent.

- Certain suppliers may be exempt from the test if their entire portfolios consist solely of must-run resources such as wind, solar, or run-of-river hydro. Such an exemption would not be applied to suppliers that own or control dispatchable resources. Although a supplier typically cannot withhold the output of the must-run resources, the supplier with dispatchable resources has the ability and potentially an incentive to withhold the controllable resources in the portfolio to raise prices if the must-run resources' revenues depend on the market prices.

Equation [2]

Equation [2] presents these proposed adjustments to Equation [1] and may serve as an approach for Alberta to consider:

$$RSI_{it} = \frac{\sum_{j=1}^{n} Supply_{jt} + Imp_t - (Supply_{it} + Imp_{it} - Obligation_{it})}{Total\ Market\ Demand_t + Export_t + \ Reserves_t}$$

Conduct-Impact Test

A Conduct-Impact Test assesses a seller's specific conduct and its associated impact on market prices. The conduct in question includes bidding above cost (economic withholding) or engaging in physical withholding of output, and other anomalous bidding behavior. A Conduct-Impact test can be used to trigger bid mitigation if bids and their market price impacts exceed certain thresholds. The test is applied after bids (offer prices) are submitted to the AESO, but before the actual market-clearing price is determined. When applied, bids will be mitigated to reference cost levels before market prices are determined whenever both bid offers and associated market price impacts exceed the set thresholds.

The Conduct-Impact Test is a two-part test. The first part, the Conduct test, identifies bids that are deemed to signal a seller's anti-competitive behavior. A supplier's bids would be compared to a competitive Reference Cost level. The Impact analysis would be triggered only if suppliers' offers are above the Reference level by more than a defined threshold, which can be in the form of dollars or percentage of cost-based reference level. If the offers are below this level (the "No Look Threshold"), there would be no subsequent investigation via the Impact test. But if suppliers' bid offers are above the Reference Cost level, their bids' impacts on market prices will be evaluated in the second part of the test, the Impact Test.

The Impact test quantifies the likely impact of the identified bids on the market-clearing price. Only when the identified bids increase market prices by more than the impact threshold (relative to bids that would have been submitted at the reference level), would the action fail the Impact test and trigger mitigation. The process compares the market-clearing price with the supplier's initial (failed) bid, to the price of a simulated "competitive" scenario in which the supplier's failed bids are adjusted to the Reference level. The scenario with the mitigated bid is simulated by assuming that the supplier would have submitted its bids at the competitive reference level.

Like the Conduct test, there would be a "no look" threshold for the Impact test. Such a threshold is predefined as the magnitude of the adverse price impact, in dollars or percentage of a market-clearing price, which would be tolerated.

Mitigation levels under the Conduct-Impact tests need to consider short- and long-term impacts. Because suppliers to the Alberta's energy market participate with a "one-part bid," a seller's offer is expected to cover both their marginal operating costs and commitment costs over the period of the plant's generating hours. For example, if a natural gas combined-cycle (CC) plant, once turned on, expects to operate for at least eight hours before having to shut down again, the supplier would consider the costs associated with starting up the plant, operating it at no-load levels, its minimum generating level, and the other costs the facility might incur by being dispatched for eight hours—in addition to its marginal operating costs per MWh of power generation—and include those costs in its bid offer prices.[3]

Brattle conducted a historic analysis of costs per asset based on operations over the period of 2012-2016. This analysis concludes that, historically approximately 2x base marginal costs by fuel type appear a reasonable threshold to recover historic costs based on the assumptions in the calculations. In anticipation of increased ramping and cycling of assets in the future (as summarized in the NDV studies), the proposed threshold of 3x allow a mitigated market participant to address historic costs while accounting for increased cycling costs should the asset be dispatched off. Relevant excerpts from the Brattle analysis are included below, and will be discussed with the working group.

Excerpts from Brattle paper:

The Conduct test threshold needs to consider the relevant costs faced by the supplier. Because suppliers to the AESO's energy market participate with "one-part" offers, market prices need to cover a generating resource's start-up, shutdown, and no-load costs, in addition to its marginal operating costs. For example, if a natural gas combined-cycle (CC) plant, once turned on, expects to operate only for several hours before having to shut down again, the supplier would only be willing to start up the plant if the expected market-clearing prices over the dispatch hours would be sufficiently high to cover the costs of starting up the plant and operating it at various output levels during this period.[4]

Table 1 below shows that—based on the historic (2012-2016) cost profile and minimum operating hours—once a typical CC or a coal plant is turned on, the average per MWh costs of both CC and coal plants exceed their marginal operating costs by up to 1.5 times. The ratios of average per MWh costs to marginal costs of typical Coal and CT plants also are shown in Column [10] of Table 1.[5] Since a thermal plant's commitment cost can vary according to the plant's temperature status at its start time, the longer a plant has been in a shutdown condition, the more fuel it needs to burn to bring its plant to an operating temperature requirement. To cover a broad range of start-up costs, this analysis includes two levels of start-up conditions—one with significantly higher start-up cost (with Cold Start) and another for Coal plants with higher heat rate to start than the other (with High Commitment Cost). While a CT typically has low start-up costs,[6] their dispatch period tends to be quite short. Assuming that a CT may be started up to serve only 30 minutes of peak load per cycle, a CT's average cost is about 2.7 times its marginal costs.

[3] In jurisdictions where supplier bids are multi-parts, the supplier can explicitly submit information about its start-up costs, no-load costs, minimum run time, and minimum down time and allow the unit-commitment process to optimize these costs across competing resources.

[4] In jurisdictions where supplier offers are multi-parts, the supplier submits separate information about unit characteristics—such as start-up costs, no-load costs, minimum run-time, and minimum down time—and allows the system-operator's unit-commitment process to optimize and compensate these costs across competing resources.

[5] The current calculations use generic CC and coal plant characteristics data from the AESO database and public sources. The coal plant with "High Commitment Costs" is based on the characteristics of the AESO coal unit with the highest start-up cost and no load cost with the heat rate of 15,137 kilojoules/kWh. The AESO database does not have a fixed start-up cost for a CC and coal unit. We therefore assume the cost for typical hot starts for CC and coal units to be CAD$49/MW/Cycle and CAD$81/MW/Cycle. The cost is based on converting the median costs of US$39/MW and US$65, obtained from *Power Plant Cycling Costs*, NREL (2012), to the Canadian dollars using the exchange rate of US$1=CAD$1.26. The NREL data are based on the lower bound of estimates. See Appendix B for more details.

[6] We assume that a typical CT's cold start-up cost is CAD$18/MW/Cycle. See Appendix B for the sources and calculations.

Table 1
Comparison of Estimated Commitment Costs and Marginal Costs of Proxy Combined Cycle and Coal-Fired Power Plants in Alberta

Plant Type	Start-up Cost ($/cycle)	Shut Down Cost ($/cycle)	No Load Cost $/cycle)	Total Commit-ment Cost ($/cycle)	Marginal Cost ($/MWh)	Output @ Full Load (MW)	Average Incremental Output (MW)	Assumed Run Time @ Full Output	Total Cost ($/cycle)	Average Cost ($/MWh)	Ratio of Avg. Cost to Marginal Cost
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
CC (with Hot Start)	$9,160	$2,062	$25,981	$37,202	$17.28	400	240	9	$73,152	$21.10	1.2.
CC (with Cold Start)	$25,808	$2,062	$25,981	$53,851	$17.28	400	240	9	$89,800	$25.90	1.5
Coal (with Hot Start)	$14,688	$2,707	$319,896	$1,616,875	$15.92	400	240	600	$3,909,248	$16.58	1.0
Coal (with High Commitment Cost)	$39,708	$2,707	$512,581	$2,562,907	$15.92	400	186	600	$4,381,911	$18.96	1.1
CT	$2,146	-	-	2,146	$24.88	100	100	0.5	3,389	$67.79	2.7

Sources and Notes: [1]: Calculated based on average fuel cost plus other start-up costs. The data were obtained from the AESO and NREL (2012). [2] Calculated based on Brattle assumptions. [3] Calculated based on (commitment hours) x (marginal cost) x (minimum MW) required for a unit's operation, which is assumed to be approximately 40 % of the unit's full capacity or the difference between [6] and [7]. The commitment hours for coal and CC units are 600 hours and 9 hours, respectively. [8]: Assumed run time at full output based on economic dispatch. [9]: [4]+([5]x[7]x[8]). [10]: [9]/[6]. [11]: [10]/[5]. All $ are Canadian dollars. See Appendix B for full sources.

Going forward, the average operating costs per cycle may increase relative to the levels shown in Table 1. As variable resources are added to the AESO system, the thermal units would likely be committed less and cycle more. This would increase the ratios of average costs to marginal costs.[7] In addition, since we do not have the actual commitment costs for certain plants in Alberta, we recognize that actual amount of start-up, shut-down, and no-load costs for plants may deviate from these estimates. For example, if a CC has a much higher start-up cost than shown in Table 1, the resulting ratio of the average operating cost per cycle could be higher as well.[8] Given the results in Table 1 and these additional considerations, setting the Conduct test's safe-harbor threshold at 300 per cent above resources' marginal costs would appear to be reasonable. If costs change, the AESO can re-evaluate these comparisons and reassess the range of the tolerance thresholds.

[7] For example, if we assume that the CC unit would only run at its full output for only 6 hours instead of 9 hours, the ratio of the CC with Cold Start would increase closer to 2. Similarly, if we assume that the coal unit would be used for cycling more than providing energy, the ratio of its average cost to marginal cost could increase significantly.

[8] The start-up cost data we obtained from NREL (2012) are also based on the lower bound cost estimates.

Table 2 below summarizes the advantages and disadvantages of the RSI Screen and the Conduct-Impact test.

Table 2
Advantages and Disadvantages of Structural and Conduct-Impact Screens

Type of Tests	Advantages	Disadvantages
RSI Screen	• Can be used to identify conditions under which market power concerns are the greatest. • Avoids having to set bid-level and price-impact thresholds that trigger mitigation, which could lead to mitigation errors.	• Does not directly detect whether market power has been exercised. • Suppliers may not be able to control the conditions under which mitigation would be implemented. • As a bright line standard, it may fail to mitigate exercises of market power that may arise even when a supplier is not pivotal.
Conduct-Impact Test	• Explicitly identifies bid and price-impact thresholds that exceed the stated tolerance levels of policy makers. • Suppliers can directly control their bids based on transparent thresholds. • Can be implemented in a way to test the price impact of multiples suppliers' bids' jointly	• The market monitor must determine the "correct" tolerance threshold for both bid levels and the price impact of the bidding behavior. • Relies on either an assumed or actually observed cost for each resource. • Concerns exist that suppliers can "game the system" by keeping their exercises of market power just below the mitigation threshold.

Risks and Mitigations:

With a new *ex ante* market power mitigation approach, the AESO and industry are interested in ensuring that the industry will be able to set prices that reflect that market conditions. The concerns are as follows:

- Over-mitigation.
  - Over-mitigation has the potential to dampen the Energy and Ancillary Services market price signals and result in a sub-optimal generation fleet mix and real-time operational behaviour from both supply and demand side market participants.
- Under-mitigation.
  - Under-mitigation would result in prices set by an exercise of market power and means that consumers are paying more than is necessary.

The proposal strikes a balance both in implementation practicality and in ensuring that market power is mitigated. The proposal is based on historic cost assessments and expected prices when the market is at a competitive level. The approach may be adjusted if further issues are identified in the market.

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

The EAS working group recommendation supported an *ex ante* process to evaluate market power with varying degrees of support (7 members agreed, 4 members agreed with reservations and 5 objected).

- Reservations to this recommendation were based on:
  - Not understanding the position of the MSA.
  - If being bid mitigated, there needs to be reasonable opportunity for scarcity (and shortfall) pricing to be realized.
- Objections were based on the following concerns:

- Concerns that the market will be over mitigated.
- Participants require a price signal and volatility, and therefore, would prefer a market based solution without mitigation.
- There is a need to incent flexible generation.

- The EAS working group voted on pre-defined screens and mitigation to a multiple of short-run marginal cost by fuel type based on the assumption that *ex ante* process would be recommended by the AESO.
  - The working group was supportive of using an RSI screen, with an hourly conduct and impact model.
    - Reservations to this recommendation were based on:
      - Any bid mitigation mechanism put in place, needs to support appropriate price signals.
      - One member disagreed with any form of screen, but was more supportive of a conduct and impact test.
      - Initial modeling results from Brattle did not include carbon tax implications, and would like to better understand the implications of carbon tax on the analysis completed.
  - The EAS working group recommendation was supportive of bid mitigation to a multiple of short-run marginal cost by fuel type with varying degrees of support (5 members agreed, 5 agreed with reservations, and 6 members objected).
    - Reservations to this recommendation were based on:
      - Dependent on what the cap value is, and the approach that is used to calculate and determine the value of short-run marginal cost.
      - Wanted to better understand the implications if Natural Gas is trading negative (i.e., what is the floor?).
    - Objections to the recommendation were based on:
      - Objecting to mitigating by fuel type, and would propose using a process that selects one reference technology (e.g. SCGT) and some multiplier of that reference technology (e.g. 2x – 3x).
      - Concerns that administering by fuel type could be burdensome on the AESO.

- Industry feedback on SAM 3.0 was consistent with the commentary provided by the working group.
  - Many participants expressed that the energy market should not be over mitigated and must allow for a high-fidelity price signal, including a scarcity and shortage pricing mechanism during periods of tight-supply.
  - The energy market should not be over mitigated reducing its efficiency, and the value should be maintained in the energy market, and not driven into the capacity market.
  - There was general support for using an *ex ante* market power mitigation process with an RSI screen, and a Conduct and Impact test.
  - Industry participants should only be mitigated if they fail the screen and the Conduct and Impact Test (i.e., those that both have, and have exercised market power are mitigated).
  - Bid mitigation should not be set strictly at short-run marginal cost, and a multiplier like 300% of the reference technology is more appropriate. Those participants that supported a narrower band (e.g. 1.2X) would want the calculation of short-run marginal cost to include variable operating and maintenance costs, startup costs, operating risks, and other opportunity costs.
  - Industry participants that were not supportive to an *ex ante* process, believe the current pricing framework, in conjunction with a must-offer requirement has proven to be successful, ensuring price fidelity and incenting appropriate new investment.
  - Differing perspectives from industry stakeholders on whether portfolio bidding should be permitted to continue.

Rationale for Deviation from SAM 3.0 Position:

- The AESO proposal is based on the ongoing assessment of the mitigation options, input from working group members and practical application.
- The use of the hourly RSI model instead of a Conduct and Impact Test is due to a practical implementation and it is expected that market participants can be self-disciplined by the competitive levels when capacity resources are committed to offer into the energy and ancillary services market in addition to non-committed capacity resources in the market. The AESO's proposal allows the market to compete while identifying and limiting the potential for larger, pivotal suppliers to exercise their market power and raise the pool prices.
- Setting the RSI at 0.9 was discussed in the working group. This level will continue to be monitored and may be adjusted as required for over or under mitigation.
- Setting the mitigation level at 300% of the resources' variable cost is supported by the Brattle analysis that 300% is sufficiently high for most resources to cover their operating costs based on historic data and expected increases to cycling costs.
- Further rule development is required to set a standard for suppliers' submission of actual operating and opportunity costs such that when necessary, suppliers have the ability to demonstrate that their costs are higher than the ones that that AESO estimates.

10.3 Pricing Model

Pricing Model Summary:

- No change to offer or price cap
- No change to price floor
- Administrative shortage pricing will remain at $1000.

Rationale:

- The suppliers offer prices in the energy market are bounded by the price cap and floor. The price cap does not appear to be limiting especially given pending changes to bid mitigation; however, a pricing signal may be of value to clear surpluses in the energy market. The cap and floor need to be wide enough to allow scarcity pricing to occur.
- The price signals in the energy and ancillary services markets will serve to provide incentives for flexible operational behavior (for dispatch, and operational reliability needs), and incent an economically efficient level of investment in flexible resources especially in combination with potential changes to the dispatch and settlement models (SCED and shorter settlement))
  - Depending on the type, and level of offer mitigation, and the degree of in-market scarcity pricing resultant from mitigation, additional administrative shortage pricing may need to be considered to enable an effective price signal. The AESO understands the value associated with shortage pricing but has determined that it is not required at this time
  - As the frequency and impact of supply surplus increases, negative pricing may assist in addressing supply surplus. This enables a market-based approach to address surplus rather than the current administrative curtailment mechanism. However, given the additional risks identified in a negative pricing model and in concert with increasing renewables on the system with competing pricing incentives, the negative pricing model will not be considered at this time.

Administrative Shortage Pricing

- Administrative shortage pricing provides a mechanism for increasing EAS market prices above offered prices during times of supply shortage—typically measured by release, or depletion, of operating reserves. The purpose of adminstrative shortage pricing is to enhance market price signals for response to these events and to provide an enhanced investment signal for quick-start and fast-ramping resources (such as peakers and demand response) both designed to avoid loss of load while capacity is tight in the energy market. Administrative shortage pricing has been adopted by many independent system operators with centralized wholesale markets. In our discussions, it should be noted that administrative shortage pricing is separate from scarcity pricing which can occur within the market when offer prices are higher than resources' actual short-term marginal costs.

Considerations in design of administrative shortage pricing:

- There may be little or no regulatory tolerance for energy and ancillary services prices above $1,000/MWh. Price tolerances like this are not uncommon in other jurisdictions.
- Shortage pricing will be activated infrequently (0–50 hours per year, depending on planning and operating reserve levels),
- The magnitude and frequency of shortage pricing (when it is triggered and what price it is triggered to) is dependent on market design objectives across all markets (Energy, Ancillary Service and Capacity). Capturing an effective price signal for flexible investment and operational behavior will be accomplished through mechanisms in all three markets.
- Shortage pricing levels and maximum price levels ($/MWh)—

  the entire price signal (from all markets, not just energy and ancillary services) in the worst shortage conditions when involuntary load-shedding occurs should theoretically reflect cost of that load-shedding: value of lost load, or VOLL.

Negative Pricing

The AESO currently employs an administrative mechanism to address supply surplus. Upon reaching $0/MWh in the energy market merit order, the AESO first curtails import assets, then $0 flexible blocks, including renewables, then $0 non-flexible blocks, and finally curtailing generation offline. Negative pricing is widely considered an improved alternative to manage congestion and over-generation that improves market efficiency and liquidity, particularly with increasing variable energy production. However, other jurisdictions may be encountering issues with negative pricing, where subsidized resource offers may be capable of offering even below inflexible generation. As noted in various forms by PJM and the US DOE in 2017, as well as the creation of resource specific offer floors by the IESO, there may be potential concerns on the impact of subsidies distorting market outcomes and eroding revenue streams.

Further Considerations and Risks for Implementing Negative Pricing:

- **Setting the Price Floor**: A negative price floor may simply move the high level of equal price offers to a new floor thus moving the supply surplus issue to a new price. The price floor must be set low enough to promote additional depth in the merit order.
- **Products Indexed to Pool Price:** Active operating reserves are indexed to pool price and currently cannot go below $0/MWh. However, the real power provided for a product (e.g. regulating reserve) during negative pricing would incur a cost to the provider. Requires consideration on whether they are isolated from the effect.
- **Importers**: If importers continue to submit $0 offers and are not eligible to set pool price, there may be an issue with negative pricing.
- **System Changes:** Scope of changes to ETS, DT and settlement processes to be assessed.
- **Impact on Transmission Constraint Management (TCM):** TCM may require adjustments to accommodate negative pricing; further assessment required.
- **Dispatch:** Would need to align with current or potential SCED dispatch algorithm.

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

- The EAS working group members recommendation was supportive of introducing a shortage pricing mechanism. Support for this was driven by the assumption that the market would have an *ex ante* bid mitigation process and the price cap was to remain unchanged.
  - Reservations to this l recommendation were based on:
    - A shortage pricing mechanism is appropriate, but not as a tradeoff for a stringent mitigation model.
    - Shortage pricing may not be politically acceptable, or supportive from a consumer point of view.
  - Note: No working group members objected to this provisional recommendation.
- The EAS working group members recommendation was that that no change is required to the price cap, assuming an administrative shortage pricing mechanism is introduced.
  - Objections to this recommendation were based on:
    - Supportive if settlement remains at one hour, but if it went to a 15-minute settlement period this should be further investigated.
    - Belief that additional analysis is required to explore the price cap value as it has not been reviewed since it was established.
- The EAS working group members recommendation was supportive of further evaluating negative pricing to address supply surplus.
  - Reservations to this l recommendation were based on:
    - Need to be further explored and understand the implications on co-gen assets.
    - Dependent on market structure for clean energy attributes.
  - Working group members that were not supportive of the recommendation raised the following concerns:
    - There are other higher priority items to explore than changing the price floor as there are other ways to deal with supply surplus.
- Industry feedback on SAM 3.0 was consistent with the commentary provided by the.
  - There was broad support for the introduction of both a scarcity and shortage pricing mechanism and leaving value in the Energy market to create real-time incentives for flexible resources.
  - Introduction of scarcity and shortage pricing mechanisms is favorable with a shorter pricing interval.
  - The impacts of a bid mitigation model need to be carefully evaluated, so that they do not negatively impact price and investment signals.

Rationale for Deviation from SAM 3.0 Position:

- While the AESO as part of the working group considered changes to the pricing methodology, at this time it was proposed that no changes are required so these items would be considered as a separate item in another consultation as required. These items are not a priority and would need to be carefully considered prior to implementation, so they are set aside for now.

10.4 Out of scope items

Summary:

The AESO has determined that the following design changes will not be included as part of the capacity market design, but may be considered as part of a separate evaluation in the future:

- Locational marginal pricing
- Offer cap above $999.99
- Negative pricing
- Administrative shortage pricing

- Security constrained unit commitment (SCUC)
- Dynamic I-intertie scheduling
- Co-optimization of EAS (will be evaluated as part of SCED)
- Day-ahead market (DAM)

Rationale:

- Locational Marginal Pricing – With the current policy related to unconstrained and recent system build out, pricing on transmission grid is not required at this time.
- Offer cap above $999.99 --

  The current offer cap is effectively non binding and will increasingly not be an issue with the introduction of the capacity market. While the majority of revenues will be expected to remain in the EAS markets, the offer cap consultation is not a priority at this time.
- Negative pricing – The supply surplus events are currently cleared administratively and few issues have resulted. The introduction of negative pricing comes with some issues as well and will be reviewed as warranted. Requires futher review to implement. However, the AESO does not consider negative pricing to be a priority at this time.
- Administrative Shortage Pricing --

  Supply shortfall events are also managed administratively and with few issues arising. Further, it is anticipated that with the introduction of a capacity market, the frequency of shortage events will be lessened. However, this concept may befurther reviewed as required to incent price responsive behaviour near shortages but is not a priority at this time.

  Security Constrained Unit commitment --

Centralized unit commitment will be evaluated in the future if reliability issues develop from increased frequency of supply surplus events or as part of an integrated solution like time ahead market . A self commitment model maintains the risk with generators and provides incentive for flexible resources.

- Dynamic Intertie scheduling — Moving to a priced intertie model with real-time scheduling addresses the issues in the market today without excessive system changes. A dynamic model is complex and not a priority at this time.
- Co-optimization of EAS --

  On its own, shows marginal benefits which are likely less than the implementation costs to do so. However, may be considered as part of pending SCED evaluation.
- Day-ahead Market (DAM) --

  The value of a DAM is heightened if concerns about market power are not mitigated or if the market values moving to a SCUC model are required to manage reliability risk. As a separate design element, the DAM effectively acts as a financial trading model, which most participants can handle independently outside of the market and accordingly this design element has been taken out of scope at present.

  In other jurisdictions, particularly those with larger markets, the BDAM has been implemented as part of a larger market including SCUC, SCED, cooptimization and in order to establish net settlement positions as part of market power mitigation . Given that the concept of BDAM has previously been been raised by industry two times before and each time rejected each time, the AESO through this working group process intended to evaluated each element of a full BDAM separately and develop conclusions based on its modelling efforts. As noted in the conclusions of this modelling analysis, which were presented to the working group, and as summarized in this rationale paper:

  1. The centralized unit commitment model (SCUC) does not show increased in production efficiency and as it would result in shifting the risk from a generator to the AESO (and charged to loads), this signal was viewed to be counter-intuiative to pricing and valuing flexibility in the market to handle additional future system variability;

2. Market power mitigation is being addressed through *ex ante* RSI screens as indicated above and a mitigation level in addition to continued *ex post* monitoring and accordingly the creation of an imbalance market (net settlement) is not required;

3. Given the current indexed model for AS, partial optimization is occurring. Modelling for cooptimization of EAS is showing small incremental value in converting to a co-optimized model, likely less than the systems change required. However this element will further be considered with SCED; and

4. SCED is under consideration as an alternative to addressing current and future variability but is best incorporated as a look ahead or five minute dispatch format. .

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

The EAS working group and industry provided feedback on some of the items that were not included as part of the capacity market rule package. Presented below is a summary of that feedback:

- Security Constrained Unit Commitment (SCUC):
  - EAS working group feedback: The majority of working group members voted that self-commitment can continue.
    - Reservations to this provisional recommendation were based on the belief that self-commitment can continue in the short-term, but going forward in the long-term other unit commitment models should be investigated.
    - Objections to this provisional recommendation were based on the belief that there is a cost that comes with self-commitment, and it is in everyone's best interest for efficient unit commitment decisions to be made. There are also secondary benefits of unit commitment for generators as there will be lower cycling with larger units. In addition, if we continue with self-commitment, the AESO should improve forward market information to make informed unit commitment decisions.
  - Industry feedback on SAM 3.0:
    - The majority of industry participants support the continued use of self-commitment in the Energy market.
    - There is a belief that moving away from self-commitment would subsidize less flexible generation, causing increased costs to consumers. The benefit of potential of SCUC should be balanced against reduced incentives for operational flexibility and ramp.
    - Maintaining self-commitment will help ensure timely, simple, and straightforward initial implementation and will minimize changes to EAS markets and the risk of regulatory delay.
    - There are industry participants while are supportive of self-commitment in the short-term, believe it would be valuable for the AESO to further explore centralized commitment models for changes in the long-term, and inclusion in the Energy and AS roadmap.
    - Those that oppose self-commitment and are supportive of the further exploration of a central commitment model believe that it may prove to be more efficient in the long-term. In addition, there is a cost with self-commitment, as sub-optimal commitment decisions may be made by participants with less than full information of future market conditions. Without centralized commitment, it may result in higher and more volatile costs to consumers.
- Co-optimization of EAS Markets:
  - EAS working group Feedback: The majority of EAS working group members voted that the current AS market (sequential model) can continue, and there is no need for co-optimization of EAS markets.
  - Two working group members objected to this recommendation and believe that the AS market is an antiquated design. Co-optimization will facilitate the effective integration of Energy and AS.
- Industry Feedback on SAM 3.0:

- Some industry participants do not believe that further consideration of co-optimization is required given the initial study results by the AESO on net demand variability. These participants indicate that no additional time should be spent on this topic given the volume and importance of other work.
- There are participants that believe that additional investigation should be spent on the co-optimization of EAS.

- Time Ahead Market (i.e. BDAM):
  - EAS working group Feedback: The working group was unwilling to vote on further investigation of a time ahead market. There was support from six members for further investigation and exploration of a time ahead market.
  - Industry Feedback on SAM 3.0:
    - Similar to comments on changing to a centralized commitment model, that the benefit of a time ahead market should be balanced against reduced incentives for operational flexibility and ramp.
    - Participants that are also not supportive of further investigation a time ahead market, believe that it would impose unneeded complexity, with minimal or no recognized long-term efficiency benefits. Belief that a time ahead market, particularly with cost guarantees, does not support inventive to build more flexible generation.
    - The exploration and development of a recommendation to move to a time ahead market, requires a broader consultation process and to allow industry to participate given the complexity of this topic.
    - There are participants that believe that additional investigation should be spent exploring time ahead market models.
    - Some participants that are supportive of additional investigation of a time ahead market, believe it would be valuable for the AESO to further and inclusion in the EAS roadmap.
- Ramp Product:
  - The EAS working group was equally divided on whether a ramp product was required at this time.
    - Working group members that agreed, or agreed with reservations, that a ramp product was not required at this time. This was based on the initial results from the NDV study, and it was viewed that additional rule changes could help incent flexibility.
    - Working group members that were supportive of the introduction of a ramp product believed that generators with that capability, should be compensated for the capability. This also allows generators to select and participate with resources that are best suited to meet the defined ramp requirement. In addition, there is a view that the AESO should pay for the attributes that it requires (i.e., reliance on over-dispatching the EMMO ; impacts the fidelity of the price signal).

- Industry Feedback on SAM 3.0:
  - There are some participants that believe that given that changes to the fleet and introduction of more variability, that the AESO may require additional ancillary services market products to address the need for flexibility.
  - Appropriate product differentiation in the AS market will help ensure that the function and purpose of each electricity product is maintained.
  - Early adoption of a ramping product is warranted given the level of new variable generation contemplated in Alberta's Climate Leadership Plan.
  - There are some industry participants that believe a shorter settlement period (e.g. 5 minutes) would be more valuable to investigate, than an AS ramp product.

10.5 EAS changes Assessed Ggainst the Capacity Market Design Criteria

The proposed design includes modifications to the EAS markets that are simple and straightforward for the initial implementation. As part of the roadmap discussions, the EAS team will consider limiting the initial degree of change to the current EAS market to only those modifications necessary to help ensure the capacity market opens in 2019 for start of first capacity procurement, and minimize the risk of regulatory delay and need for re-design. Some projects have already been indicated as out of scope to manage the delivery and to respond to market needs.

In an ongoing effort to ensure our Alberta’s markets are fair, efficient, and openly competitive, a staged implementation of enhancements to meet growing system flexibility needs (possibilty in stages), and to enable new technologies to compete will be pursued. These efforts will be provided in a roadmap highlighting the expected timing and nature of these future changes before the first capacity procurement. Provision of a roadmap also meets the criteria of providing the expected timing and nature of future changes before opening the first procurement.

Summary of Integrated Capacity and Energy Revenue Modelling

Prepared by: Alberta Electric System Operator

Date: January 26, 2018

Public

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1. Summary of Integrated Capacity and Energy Revenue Modelling

The AESO has simulated capacity and energy market conditions for the proposed Alberta capacity market under forecast future scenarios. The purpose of this document is to review various potential future capacity and energy market conditions, and determine the revenue sufficiency of select generating assets under those conditions. This analysis is based on a broad set of assumptions and inputs which test, at a high level, the revenue sufficiency of the capacity market design described in the first draft of the Comprehensive Market Design (CMD 1).

The resulting energy and capacity payment cash flow streams demonstrated sufficient and stable returns for new generators that ensure the reliability of electricity supply during a period of significant supply transition. The results indicated that new combined-cycle and simple-cycle assets could expect returns in line with the weighted average cost of capital for a new entrant, while consumers could expect stable pricing and reliable electricity generation across the scenarios.The results are provided as information and should not be considered to be the AESO's view of future market outcomes.

Energy and Natural Gas Price Scenarios

A significant input into the total capacity and energy market revenue modelling is the hourly energy price. The focus of this document is to provide an explanation of key components and assumptions of the energy price scenarios.

1.1 Modelling Tool

The AURORA market simulation model (AURORA model) was used to develop the energy price scenarios. The AURORA model is a cost-production model that applies economic principles, dispatch simulation and bidding strategies to model the relationships of supply, demand and interconnection to forecast market prices[1]. It produces Monte Carlo stochastic analyses, and forecasts market prices and operation based on key fundamental drivers such as demand, fuel prices and renewable generation profiles. The model incorporates unit characteristics, including startup costs, minimum up time, minimum down time and ramp rate to build an economic dispatch. All operating units in an area receive the hourly market-clearing price for the power they generate.[2]

The AESO analyzed historical data of the entire Alberta generating fleet, researched industry cost information, surveyed potential developers, and set up an AURORA model to reflect the supply and demand fundamentals of the future Alberta power market. The model is a forward-looking tool, subject to continual change as new information becomes available. Results are dependent on individual participant behaviour, which is dynamic and difficult to model within the limitations of the tool.

1.2 Scenario Assumptions

The three scenarios for the energy price scenarios were the *AESO 2017 Long Term Outlook* (2017 LTO) Reference Case Scenario, the 2017 LTO High-Coal-to-gas Conversion Scenario and a low reserve margin case. The 2017 LTO Reference Case Scenario and the 2017 High-Coal-to-gas-Conversion

[1] Source: EPIS AURORA Help Information Document

[2] Source: EPIS AURORA Help Information Document

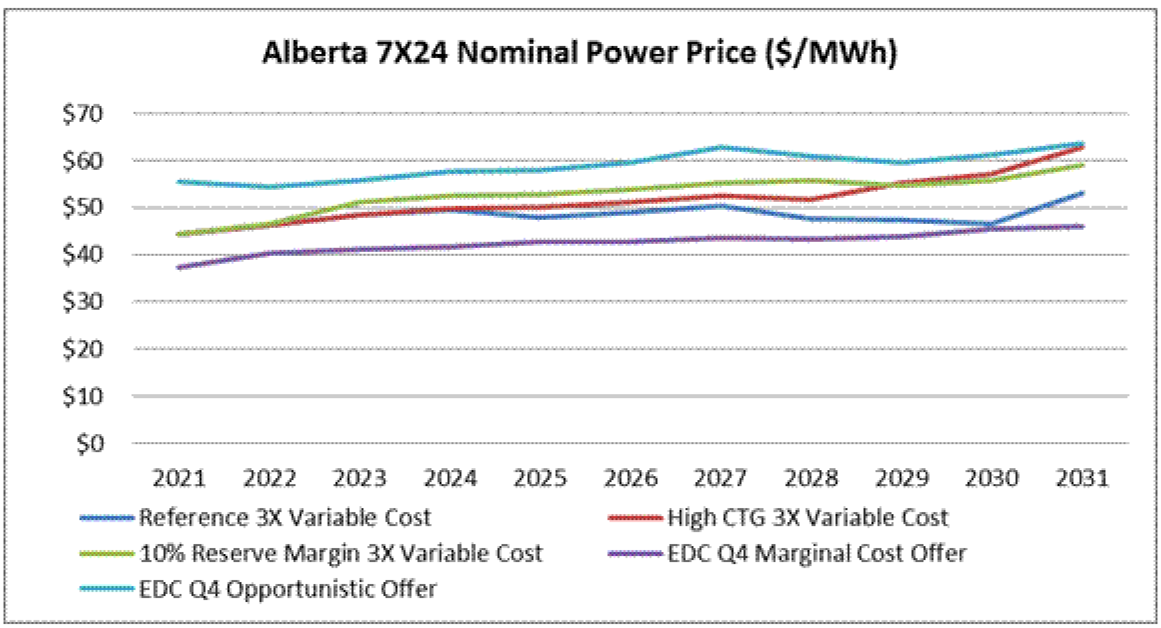
Scenario were predicated upon the 2017 LTO. The low reserve margin case moved from a 15 per cent reserve margin to a 10 per cent reserve margin within the 2017 LTO by reducing future generation development. The lower reserve margin is to test the impacts of a tighter supply mix within the capacity and energy market design being proposed.

To align with the proposed energy market mitigation in CMD 1, participants who failed the residual supply index (RSI) screen were deemed to have market power and subject to offer mitigation at 3x variable cost. Other large participant offers were adjusted from historic behaviour, assuming competition would drive more efficient generating units to shadow bid less efficient, mitigated units.

Due to time constraints, a single iteration was conducted for each scenario.

In addition to the AESO internal price scenarios, the *Marginal Cost* and the *Opportunistic Offer Strategy* energy price forecasts from the *EDC Q4 2017 Quarterly Update: Capacity Market Scenarios* are included for reference. These two EDC forecasts bound the AESO internal scenarios. The price strips are presented in Figure 1.

Figure 1: Alberta Power Prices for Total Revenue Modelling



1.3 Modelling Assumptions

In the reference 3x variable cost case, the offer strategy for the existing assets is based on historical observations, including shadow bidding and coal-to-gas units. New gas assets are also assumed to offer competitively. Offers from those assets that belong to pool participants where the firm fails an RSI screen are deemed to have market power and are mitigated to 3x the estimated variable cost. Bids of large generating portfolios reflect shadow bidding behaviour. A generic variable cost was estimated for each technology, which includes fuel cost, emission cost and variable operating and maintenance (VOM) cost.

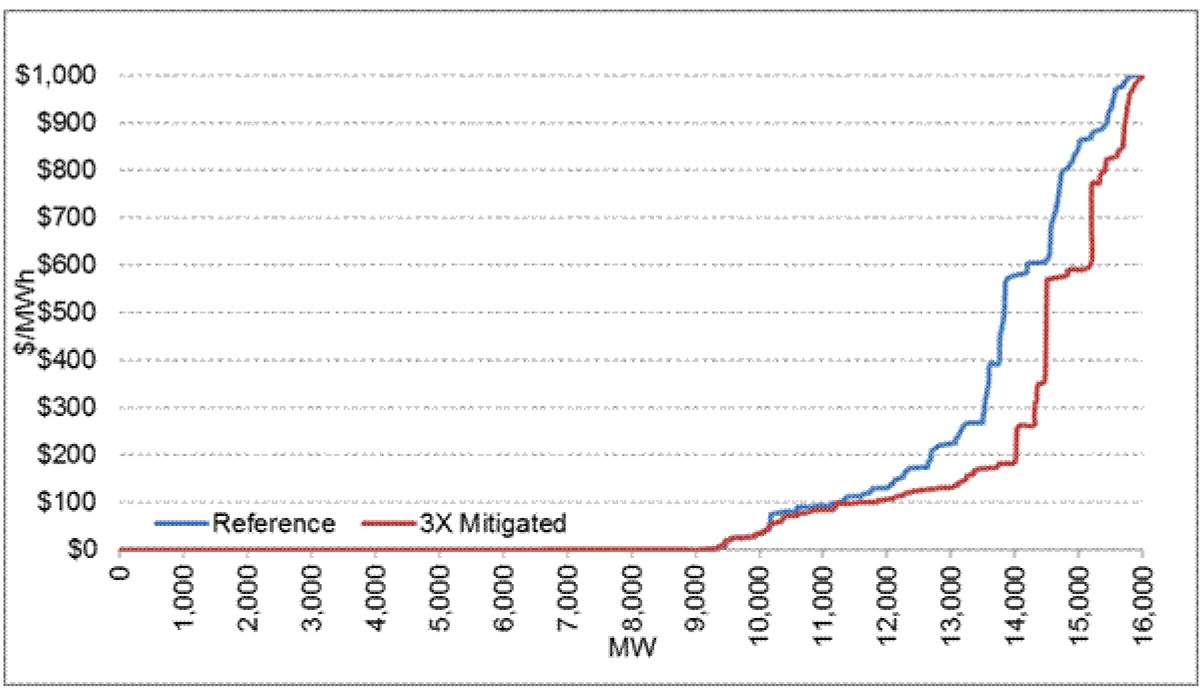
VOM costs were estimated based on Black & Veatch's 2012 study[3] and adjusted to 2017 Canadian dollars by technology. Start-up costs were conducted according to Aptech's 2011 study of cycling costs adjusted to 2017 Canadian dollars by technology[4]. Interties are modelked as pseudo units, which seek the arbitrage opportunities.

Since all scenarios were run before the finalized output-based allocation (OBA), the proposed recommendations in the Government of Alberta's Climate Leadership Plan were assumed in this modelling. The electricity emission standard was based on a baseline of 0.42 tonnes / MWh and a 0.2 per cent annual reduction to the standard.

Resulting merit order and price-setting by fuel type containing the above assumptions are reflected in Figure 2 and Figure 3 respectively, and compared to the unmitigated energy market, titled reference scenario. Figure 2 depicts an indicative snapshot of the annual average energy market merit order in 2021. The upper part of the merit order curve was shifted to the right for the 3x variable cost mitigated scenario compared to the unmitigated reference scenario to account for reduced offers for participants that failed the RSI screen.

Figure 3 shows price setters by fuel type across the two scenarios. Since certain higher offers from coal, combined-cycle and simple-cycle units were mitigated, there is a slight reduction from these units' setting prices. The reduction in price setting was replaced predominantly by dispatchable cogeneration units, and to a lesser extent, by coal-to-gas units.

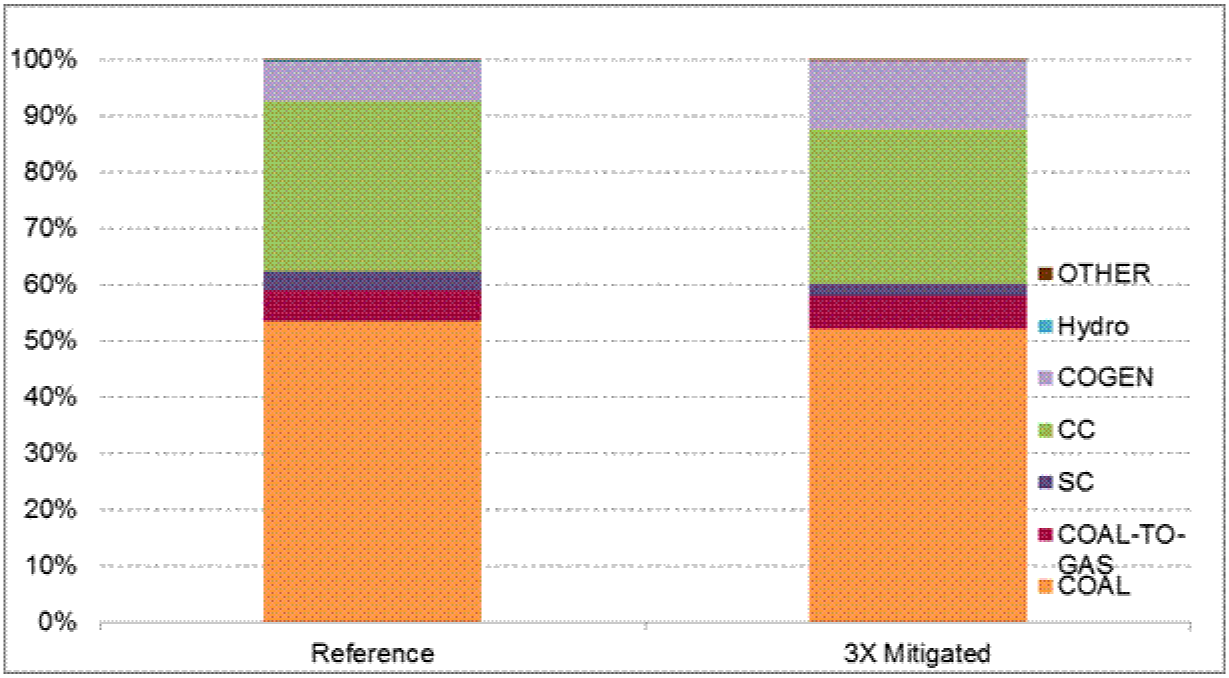
Figure 2: Indicative Snapshot of the 2021 Energy Market Merit Order (Annual Average Offers)



3 https://www.bv.com/docs/reports-studies/nrel-cost-report.pdf

4 http://wind.nrel.gov/public/wwis/aptechfinalv2.pdf

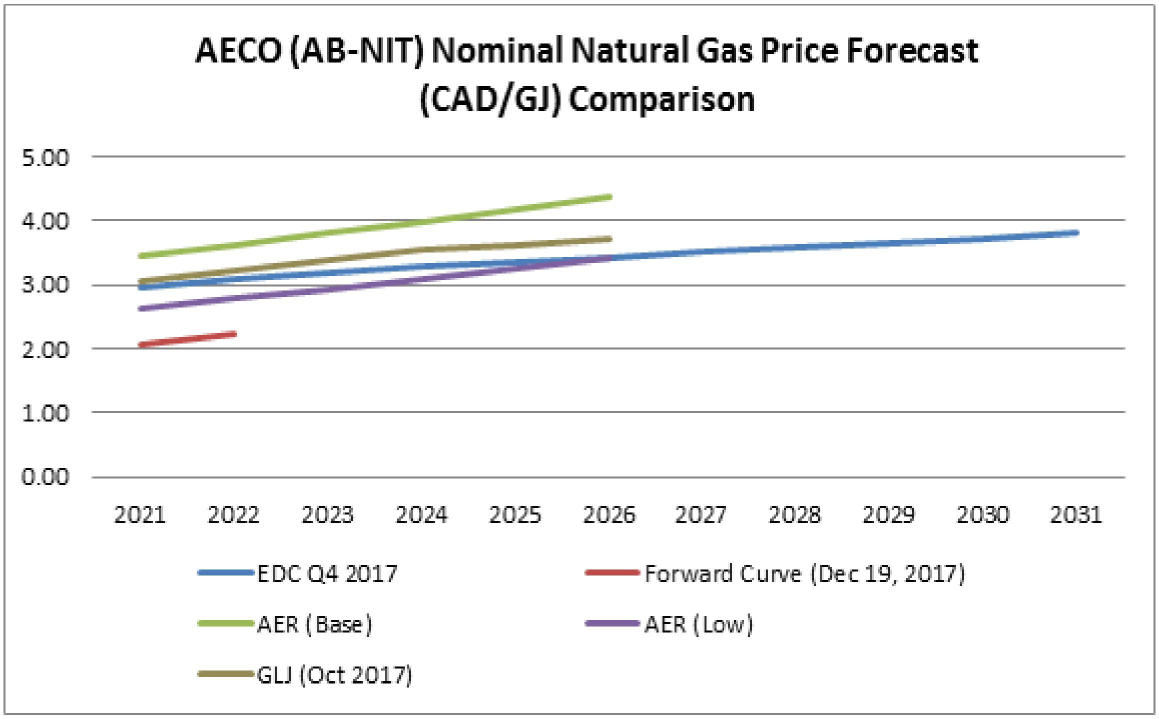
Figure 3: 2021 Price Setters by Fuel Type



1.4 Natural Gas Price Forecast

The natural gas price forecast is an integral input for the simulation modelling as natural gas-fired generation will be at the margin for significant periods of time in the future due to the retirement and/or conversion of coal generation to natural gas. For the total capacity and energy market revenue modelling, the *EDC Q4 Natural Gas Price Forecast* was incorporated into the power price scenarios. For comparative purposes, the *Alberta Energy Regulator (AER) ST98 AECO Natural Gas Price Forecast* updated March 2017 and revised July 2017 was reviewed. The *EDC Q4 Natural Gas Price Forecast* trends toward the AER low case and is below the *October 2017 GLJ Petroleum Consultants October 2017 Natural Gas Price Forecast* highlighted in Figure 4.

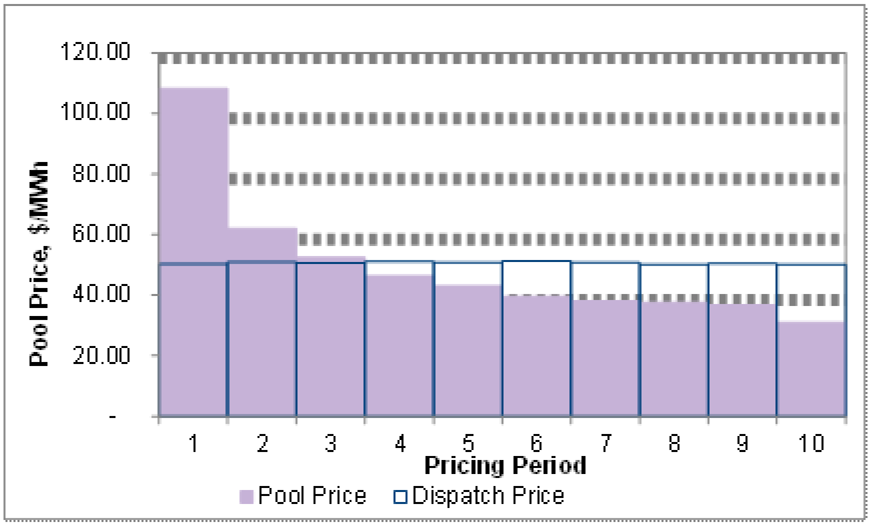
Figure 4: EDC Natural Gas Price Forecast Versus Other Forecasts



1.4.1 Energy Market Revenues for New Assets

These energy price scenarios are used to estimate the energy market revenue for a hypothetical new asset. Energy market revenues for new assets have been estimated by comparing asset variable costs against the energy price scenarios. A simplified dispatch model incorporated the hourly energy pricing, based on the three energy market scenarios, and distilled the prices into 10 pricing periods per year. When the dispatch cost (fuel costs, plus the variable operating costs, plus $10/MWh dispatch premium) was less than the forecast energy price for the period, the asset was deemed to be dispatched, and its unit net revenue was equal to the energy price, less the variable cost (fuel plus VOM costs). The unit net revenue ($/MWh) was multiplied by the number of hours represented by the pricing period, for each pricing period in the year, to determine the annual net revenue for the asset. This dispatch process was performed for each year of useful life for the asset, resulting in a life-cycle forecast energy revenue for the asset. Ancillary services revenues were not modelled in this analysis, but will be considered in future revenue analysis.

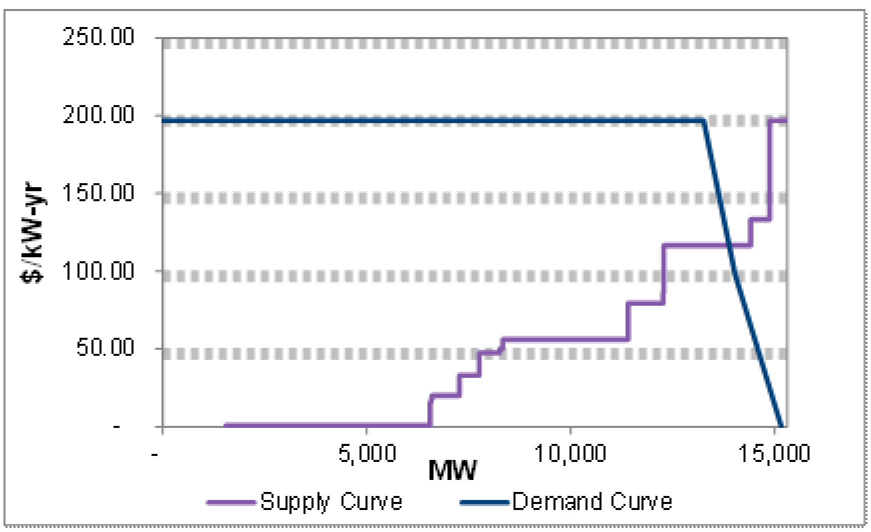
Figure 5: Simple-cycle Natural Gas-fired Generation Dispatch by Pricing Period



1.4.2 Capacity Market Revenue

Based on the design elements in CMD 1, capacity market revenue was modelled in a deterministic equilibrium model using the expected generation supply in each year, and the demand curve described below. The solved clearing price for 2021 was modelled as $116/kw-yr with 13,885 MW of unforced capacity (UCAP) supply clearing.

Figure 6: Reference Case Scenario Capacity Market Supply & Demand Curve – 2021

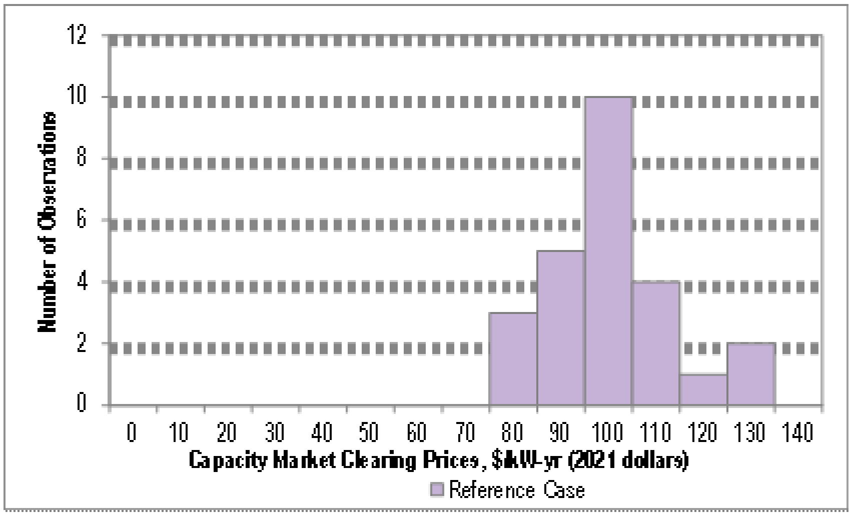


Subsequent years were modelled using the same procedure, with clearing prices and volumes determined for each year by intersecting supply and demand curves. Clearing prices were used to calculate the capacity market revenue that a new generator could expect to receive.

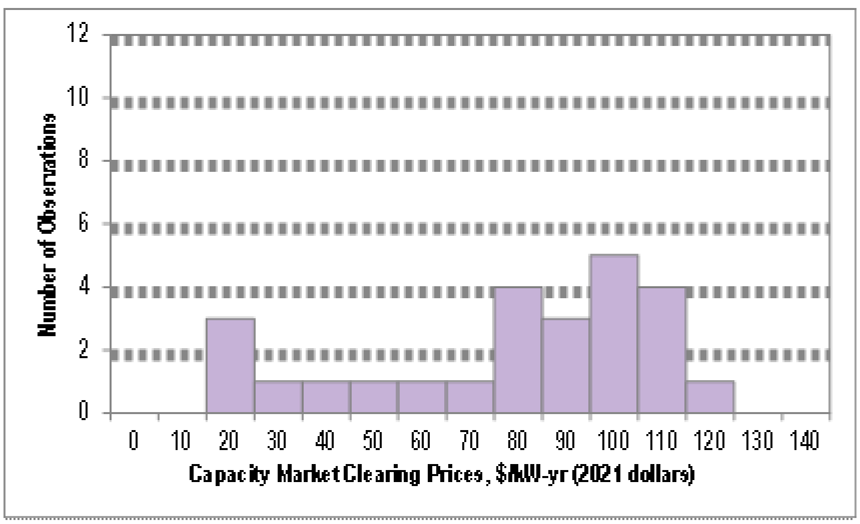
The distribution of annual capacity market clearing prices is depicted in Figure 7. The observations have been separated between the energy price scenarios to depict the range portrayed in each scenario.

Figure 7: Distribution of Capacity Market Clearing Prices

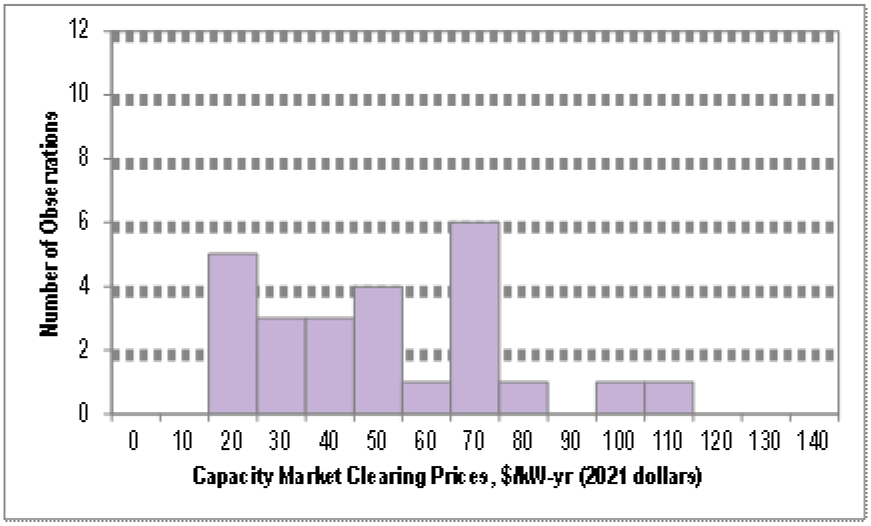
Reference Case



High Coal-to-gas Scenario



Low Reserve Margin Scenario



The capacity market clearing prices ranged between $22/kW-yr to $132/kW-yr (measured in 2021 dollars) in the three energy market scenarios, over the 2021 to 2045 period.

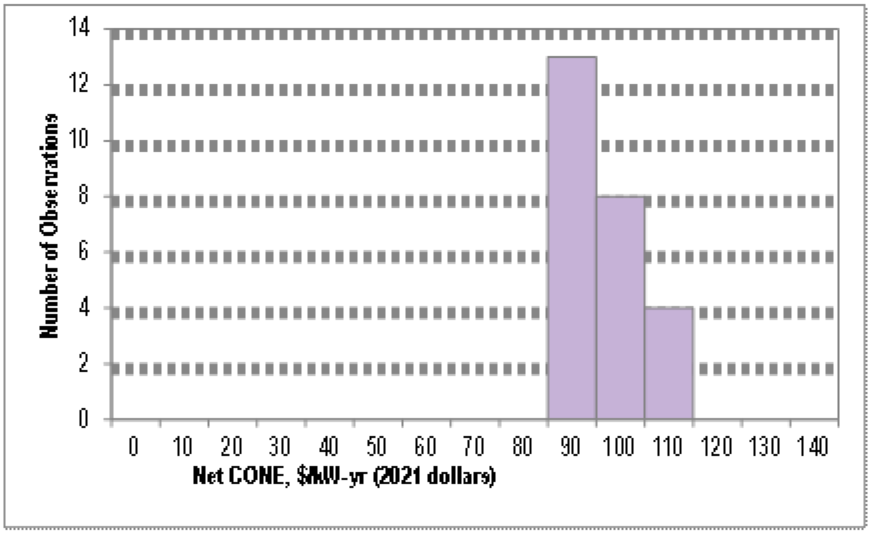
The Reference Case energy price forecast resulted in a concentration of prices near the net-CONE range, while prices in the High Coal-to-gas Conversion Scenario resulted in a wider dispersion of prices skewed to the left. The low reserve margin scenario had a wide range of distribution skewed to the right. This scenario resulted in the highest energy margins, and as a result, the capacity market was typically small compared to the other energy price scenarios.

Figure 8 illustrates the distribution of annual net-CONE values across the three energy price scenarios. The distribution has been divided such that the frequency of net-CONE values for each energy scenario can be observed.

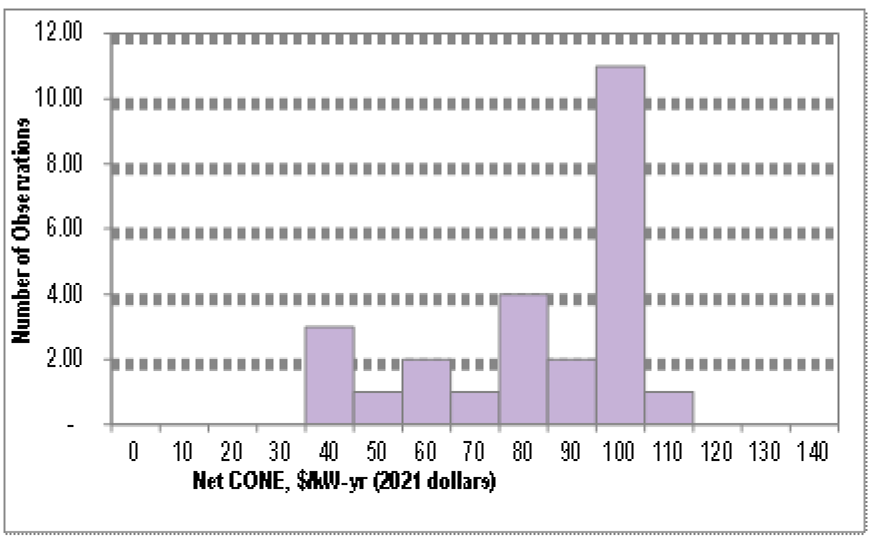
The net-CONE range was significant between scenarios. The Reference Case Scenario resulted in a tight range of net-CONE values between $91/kW-yr and $116/kW-yr, while the High Coal-to-gas and low reserve margin scenarios exhibited a much wider range of net-CONE values. The distribution of net-CONE values significantly influences the clearing prices in each scenario, since the demand curve is indexed to this variable.

Figure 8: Distribution of net-CONE Values

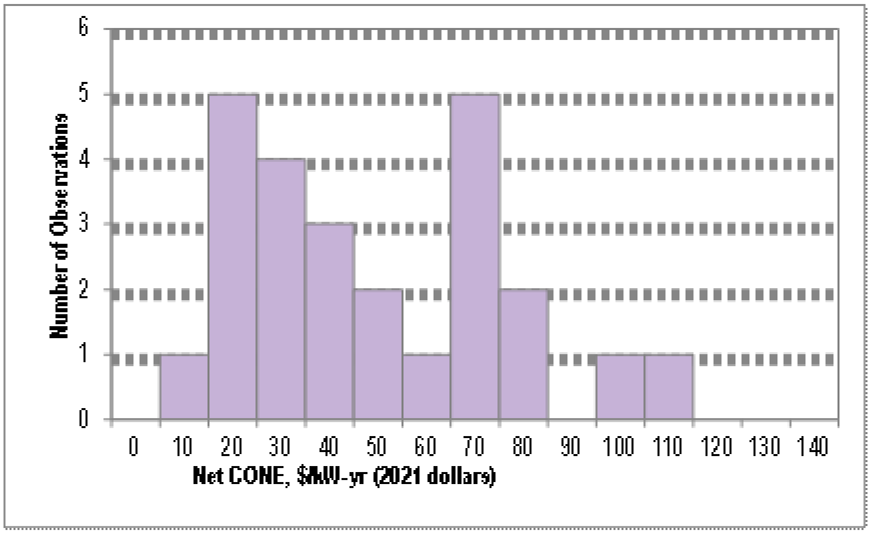
Reference Case



High Coal-to-gas Conversion Scenario



Low Reserve Margin Scenario



1.4.3 Supply Curve

A high-level supply curve was simulated by the AESO, based on the supply projected in each of the scenarios and priced based on the net go-forward cost of generation. For most plants, the net go-forward cost was deemed to be the annualized capital costs, plus annual fixed O&M costs, less the expected net energy revenue received by the facility. For this analysis, performance and availability payment adjustment costs were not included in the net go-forward cost estimates, it is expected that offers may include such costs. Plants with large maintenance capital requirements were bid higher to reflect the required reinvestment capital. Portfolios representing more than 15 per cent of the capacity market UCAP target were deemed to have market share, and all of the generators belonging to those portfolios were subject to mitigation via a bid cap at 0.5 x net-CONE. The UCAP of each unit was approximated as a proportion of its installed capacity. For thermal capacity the proportion was 100 per cent and for intermittent assets a range of 5–50 per cent was used, dependent on the resource type. This simplified approximation is a reasonable approach for this indicative assessment, noting that the actual offers will depend on more detailed assessment and data by owners, and actual UCAP calculation for each asset is dependent on design proposed in CMD 1.

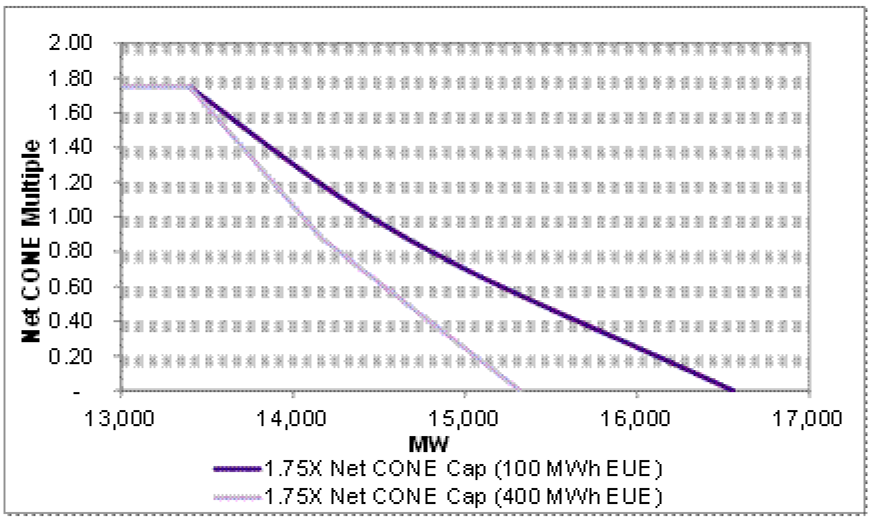
Table 1: 2021 Illustrative Net Go-forward Costs for Select Technologies

Technology	2021 Net Go-Forward Costs $/kW-yr
Conventional Coal	$116
Coal-to-gas Conversion	$39
Combined-cycle Natural Gas	$3
Simple-cycle Natural Gas	$34
Cogeneration	$0

1.4.4 Demand Curve

The 2021 modelling incorporated a demand curve that performs to the 400 MWh expected unserved energy (EUE) resource adequacy level. For subsequent years, the demand curve shape was held constant, but indexed to load growth to reflect the expansion of the market over time. The SAM 3.0 process tested the performance of three demand curves, capped at 1.9 x net-CONE, 1.75 x net-CONE, and 1.6 x net-CONE. For the purpose of this illustrative analysis, the 1.75 x net-CONE curve was selected, with an inflection point at 0.875 x net-CONE. Feedback from stakeholders included concerns regarding the width of curves which perform to the 100 MWh EUE level. The initial 100 MWh curve presented to stakeholders in the SAM 3.0 process for the year 2021 was 3,163 MW wide, from foot to cap, whereas the 400 MWh EUE curve was 1,924 MW wide.

Figure 9: Comparison of Capacity Market Demand Curves for 2021



1.4.5 Cost of New Entry

As a modelling input, the gross cost of new entry (gross-CONE) was modelled based on the development cost of a new simple-cycle gas turbine reference plant, with a Jan. 1, 2021 commissioning date. The estimated 2017 overnight capital cost for this facility was $1,250/kW. A net operating heat rate of 10.5 GJ/MWh is expected for this facility with $18/kW-yr fixed costs and $4/MWh variable costs, based on a two-LM6000 simple-cycle facility. The emissions intensity of the unit was 0.59 t/MWh. A 2 per cent annual price escalation was assumed for all capital and operating costs throughout the analysis.

Using an after-tax weighted average cost of capital (ATWACC) of 8.2 per cent, 45 per cent debt / 55 per cent equity leverage ratio, and a 25-year asset useful life, the overnight gross-CONE was determined to be $148/kW-yr in 2021.

In 2021, the estimated net electricity revenue for the reference unit was $66/kW-yr, leaving the net-CONE calculation at $82/kW-yr.

While these values are considered valid and reasonable for this analysis, they do not represent the net-CONE calculation that will be used for the actual demand curve development. The net-CONE values to be used in the demand curve are being developed with the support of a third party expert and through the ongoing stakeholder engagement process.

1.4.6 Generator Revenue Sufficiency

Through this analysis, revenues between Alberta's energy and capacity markets have demonstrated sufficient returns to generators, slightly above the forecast weighted-average cost of capital for a new entrant. Since the capacity market is indexed to the net cost of new entry, shortfalls from annual energy and ancillary service revenue markets are expected to be recovered in the capacity market. When energy and ancillary services revenues are relatively high, the capacity market is generally small, and when energy and ancillary services revenues are relatively low, the capacity market is generally large. Hence, the capacity market acts as a buffer against low energy and ancillary service revenues, providing long-term electricity market price stability.

Generator net revenue was calculated as the sum of energy and capacity market revenues, less capital costs, fixed operating costs, and variable operating costs. Using the stream of cash flows, the internal rate of return and payback period for the generator were determined.

Combined-cycle Economics

The combined-cycle power plant was simulated as a 455 MW 1-on-1 natural gas-fired facility with a net operational heat rate of 7.20 GJ/MWh. The corresponding emissions rate for this facility was 0.40 t/MWh. A three-year construction cycle was required to initiate operations in 2021, and the capital costs of $1,867/kW-yr were evenly spread over this three-year period.

The power plant was projected to operate at an average 60 per cent capacity factor, dispatching when energy market revenues exceed variable costs. The variable costs include natural gas ($2.84/GJ in 2021), variable O&M ($8.66/MWh in 2021), and carbon costs (estimated at $30/tonne for all emissions above a 0.37 GJ/MWh baseline).

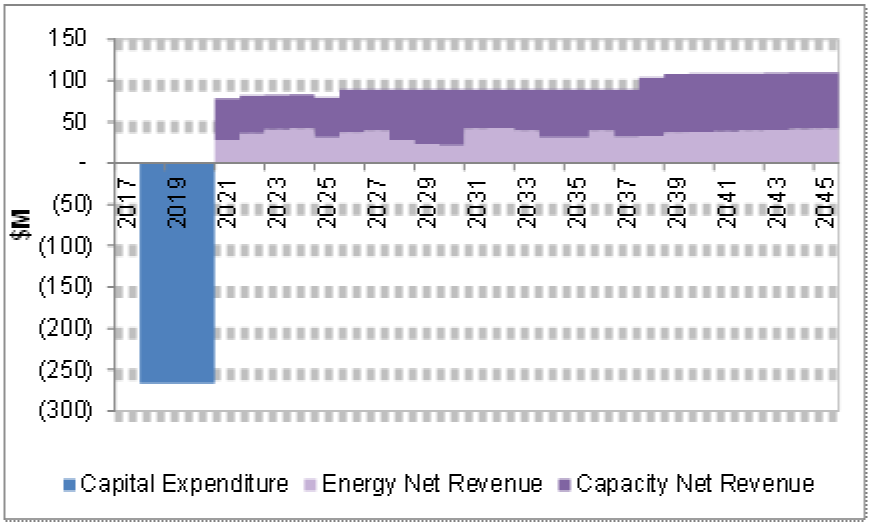
Facility fixed costs include fixed O&M of $29.23/kW-yr in 2021. Estimated fixed O&M costs were extracted from the *AESO 2017 Long-term Outlook* for combined-cycle plants, and escalated at 2 per cent per annum to 2021.

The unlevered cash flows from the combined-cycle plant operation include energy market net revenue, capacity market revenue, and capital costs. These cash flows produce internal rates of return between 8.9 per cent and 9.6 per cent (depending on the energy and capacity market price forecasts) with a 12 to 13 year payback period, suggesting that combined-cycle economics support sufficient revenue to incent development.

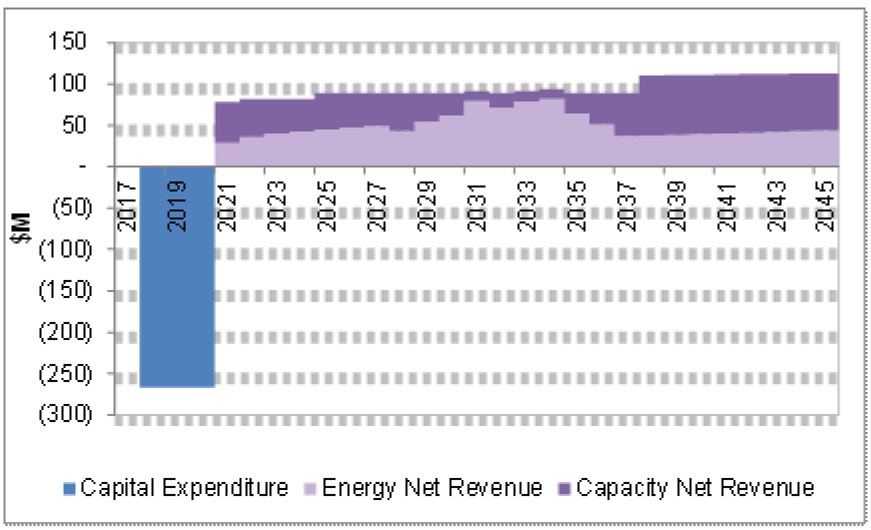
The combined-cycle facility received a large portion of its revenue from the energy market, as the facility operated at a relatively high capacity factor. The low reserve margin scenario derived most of the combined-cycle revenue from the energy market, leaving a smaller capacity market, while the reference case had more “missing money” in the energy market, which was compensated by a larger capacity market.

Figure 10: Generator Cash Flow – Combined-cycle

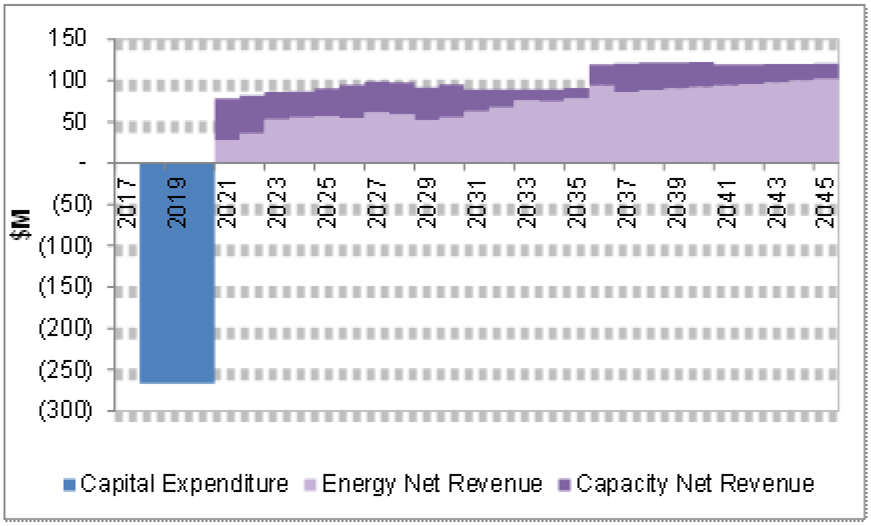
Reference Case Scenario



High Coal-to-gas Conversion Scenario



Low Reserve Margin Scenario



1.4.7 Simple-cycle Economics

The forecast simple-cycle power plant was a 100 MW two-turbine, open-cycle, natural gas-fired facility with a net operational heat rate of 10.5 GJ/MWh. The corresponding emissions rate for this facility was 0.59 t/MWh. A two-year construction cycle was required to initiate operations in 2021, and the capital costs were evenly spread over this two-year period.

The power plant was projected to operate at an average 38 per cent capacity factor, dispatching when energy market revenues exceed variable costs. The variable costs include natural gas ($2.84/GJ in 2021), variable O&M ($4.33/MWh in 2021), and carbon costs (estimated at $30/tonne for all emissions above a 0.37 GJ/MWh baseline).

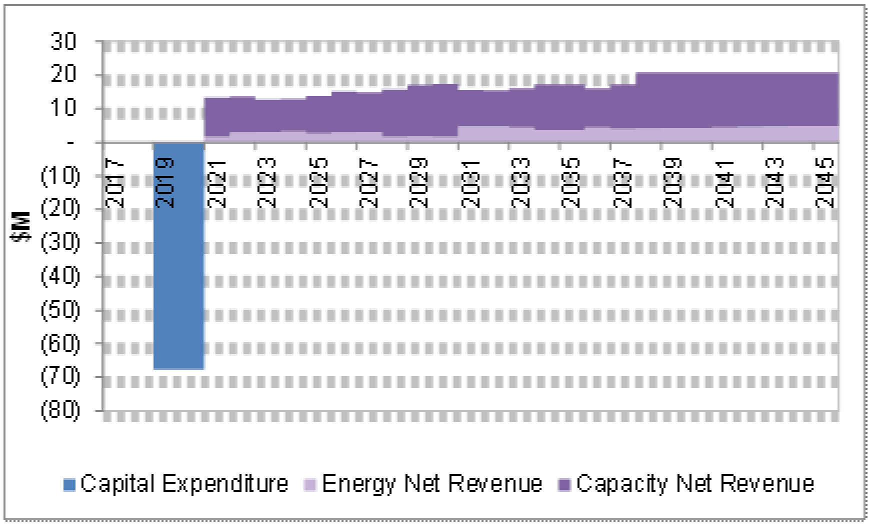
Facility fixed costs included fixed O&M of $19.48/kW-yr in 2021, escalated at 2 per cent per annum from the AESO's *2017 Long-term Outlook* estimate. The capital cost of the facility was $1,353/kW-yr in 2021.

The unlevered cash flows from the simple-cycle plant operation include energy market net revenue, capacity market revenue, and capital costs. These cash flows produce a 9.3 per cent to 9.8 per cent internal rate of return with a 13 year payback period, suggesting that simple-cycle economics support sufficient revenue to incent development of these assets.

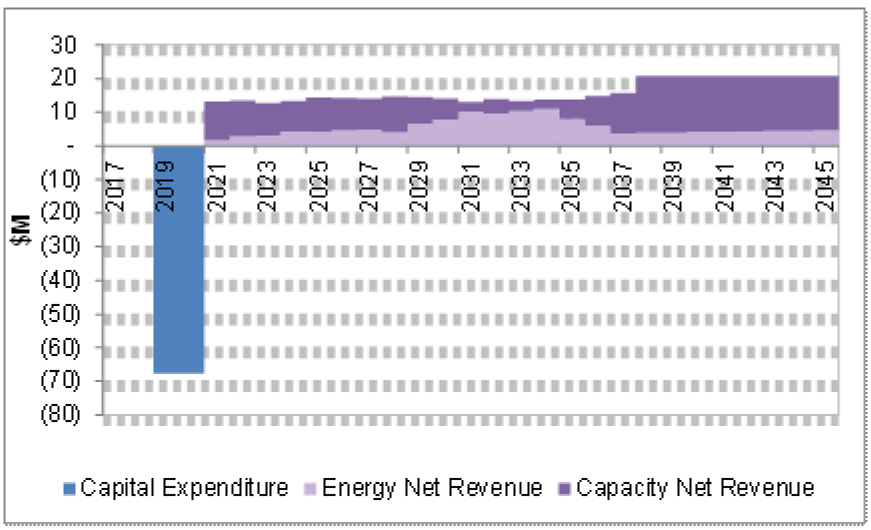
Simple-cycle cash flows were generally more dependent on capacity market revenues than combined-cycle plants, as the facilities operate less frequently in the energy market. The scenarios presented a wide range in the breakdown of capacity and energy market revenues, but in all three energy market scenarios, the simple-cycle cash flows supported development of the reference unit.

Figure 11: Generator Cash Flow – Simple-cycle

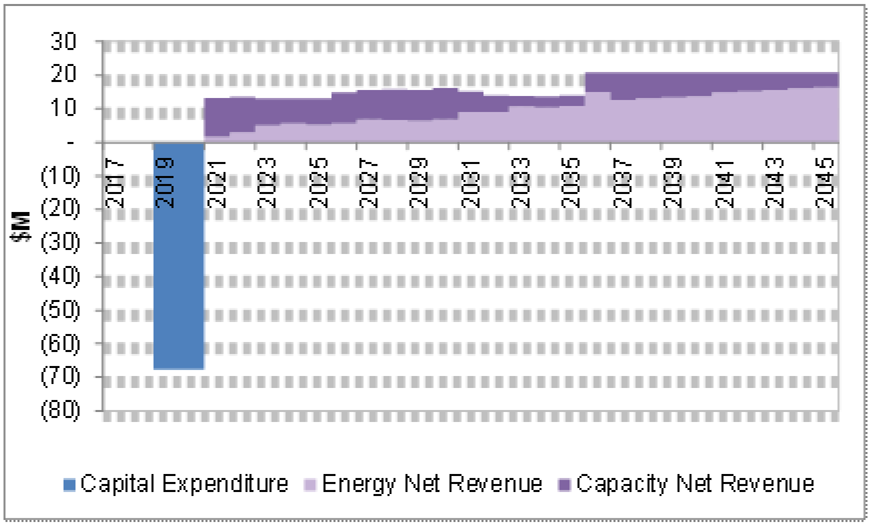
Reference Case Scenario



High Coal-to-Gas Scenario



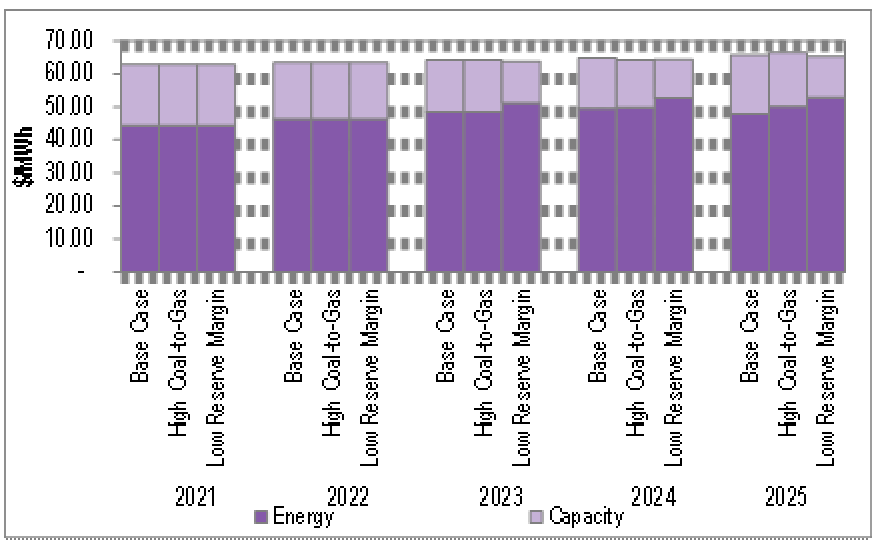
Low Reserve Margin Scenario



1.4.8 Consumer Prices

Although a tariff for capacity market payments has yet to be designed for system users, the revenues paid to generators will ultimately be paid by system users. On aggregate, the estimated capacity costs for consumers range between $12/MWh and $19/MWh in the 2021–2025 timeframe. Generally, these capacity market consumer costs will change inversely to the energy market prices, creating a more stable pricing environment for consumers than an energy-only market.

Figure12: Simulated Consumer Capacity & Energy Prices



1.4.9 Market Price Volatility

The revenue sufficiency analysis indicated that consumer market prices will be generally more stable under capacity market conditions than under Alberta's energy-only market. While the energy-only market exhibited a relatively large standard deviation of prices, the standard deviation of combined capacity and energy market price volatility is expected to be lower. This result reflects that the capacity market price tends to provide the "missing money" associated with the reference unit, and therefore acts a buffer in times of low energy market prices. Although the average price for the historical energy only was $62.04 / MWh, the market exhibited high volatility with a range of prices from $133.21 / MWh in 2001 to $18.28 / MWh in 2016.

Table 2: Energy & Capacity Price Volatility

Scenario	Standard Deviation of Annual Consumer Prices, $/MWh	Average Consumer Energy Plus Capacity Prices, $/MWh
High Coal-to-gas (2021-2031)	$2.42	$66.24
Reference Case	$3.81	$67.46
Low Reserve Margin	$2.91	$66.85
Historical Energy Only Market (2000-2017)	$23.51	$62.04

[1],2 Source: EPIS AURORA Help Information Document

[3] https://www.bv.com/docs/reports-studies/nrel-cost-report.pdf

[4] http://wind.nrel.gov/public/wwis/aptechfinalv2.pdf