Overview of the Alberta Capacity Market

This section provides an overview of the Comprehensive Market Design 2.0 proposal.

1.1 Overview of the Alberta capacity market

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 the 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.

CMD 2.0 Proposal

The Comprehensive Market Design (CMD) 2 proposal contains red and black text to focus discussions with the working groups and other stakeholders 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 are expected at this time. However, areas of black text may still evolve based on feedback received, stakeholder consultation and continued analysis. The CMD 2 proposal as a whole is expected to continue to evolve based on ongoing AESO analysis and continued engagement with stakeholders.

Overview of Proposed Design

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Eligibility and Prequalification Requirements UCAP Determination	• Minimum sizing requirement will be 1 MW. • Certain prequalification requirements are asset-specific to accommodate different operating characteristics and ensure feasibility of physical delivery. Assets that are eligible to prequalify include thermal, demand response, external, storage, hydro, variable, and aggregated assets. • Existing generation assets located in Alberta with an estimated UCAP of 1 MW or greater will be automatically prequalified for capacity auctions. External capacity assets and demand side assets will be required to prequalify in order to participate in the first transitional auction. • Resources that are the subject of a renewable electricity support agreement in connection with Renewable Electricity Program (REP) Rounds 1, 2 or 3 are not eligible to participate in a capacity auction. • Energy efficiency resources will not be eligible for participation in initial capacity auctions. • Demand response assets will only be eligible to participate on the supply side of

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

Category	High-level Design Choices
	the capacity market. • Storage assets must demonstrate 4 hour continuous discharge capability at its estimated UCAP level. • Refurbished and incremental capacity asset classifications will be introduced. Classification into these categories will be determined utilizing financial and volume thresholds. Refurbished and incremental capacity volumes will be treated as new capacity assets for the purposes of capacity market mitigation measures. The final CMD will include the financial and volume thresholds. The final CM will also clarify that where a capacity market participant that is subject to capacity market power mitigation has an asset satisfying the refurbishment threshold, it will be allowed a one-time option to provide unmitigated offers for the refurbished asset and a mitigated (if applicable) offer for the existing asset. Should the unmitigated offer not clear in the capacity auction, the mitigated offer will be added back into the supply curve and the clearing process for the capacity auction will be run again. This will allow flexibility for participants to offer refurbishment assets as new capacity assets while preventing withholding of capacity from the market. • New capacity assets will be required to post security equal to net-CONE or a minimum dollar amount. The final CMD will be reflect a change to the security requirement for a new capacity asset revised to be based on 5% of CONE multiplied by 1/Capital Recovery Factor for a new capacity asset, incremental capacity asset and refurbished capacity asset. • Prequalified capacity assets will remain prequalified for subsequent auctions subject to certain considerations, including loss of pool participant status, failing to meet development milestones, material changes to the asset, delisting or a change in self-supply designation. • Physical bilateral transactions are not permitted in the Alberta capacity market. However, a site may 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 (including industrial system designations and sites under the Duplication Avoidance Tariff). • Sites with onsite generation that are only net-metered, and sites with onsite generation that are net-metered and cannot physically flow their gross volumes due to system connection limitations must self-supply. • The City of Medicine Hat will be required to self-supply capacity. • 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 four years. The red text above will be changed to black in the final CMD, with the additional provision that changes to the self-supply designation will be permitted prior to four years due to physical operational changes at the self-supply facility.
Delisting	• Capacity assets must temporarily or permanently delist before ceasing participation in the capacity, energy or ancillary service markets. • Delisting requests or notifications will either be permanent delisting notifications (asset

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	retirement) or temporary delisting requests. Temporary delisting requests may be for physical or economic reasons. • The AESO may conduct a reliability review prior to finalizing its assessment of delisting requests. The red text above will changed to black in the final CMD. • Temporary economic delisting requests will only be allowed for the second rebalancing auction. The red text above will changed to black in the final CMD. If the AESO adopts the market power mitigation model that applies a default offer price cap of net CONE to all existing capacity assets as described in the subsection 7.1. annotation, the AESO will remove the requirement in the final CMD that a temporary economic delisting request may be submitted only before the second rebalancing auction and include a requirement that a temporary economic delisting request may be submitted before any capacity auction. • The legal owner of a capacity asset that is the subject of a temporary economic delisting request must offer the net-going forward costs of such asset into the second rebalancing auction. Costs will be evaluated based on economic justifiability and benefits to the balance of the asset owner's portfolio. The final CMD will include a requirement for a corporate officer to submit an attestation that the submitted costs for a temporary economic delist request or the outage durations for physical delists are accurate. The legal owner of a capacity asset that is the subject of a temporary economic delisting request must offer the net avoidable costs of such asset into the second rebalancing auction. • An asset will only be allowed to temporarily withdraw from the energy and ancillary services markets for the duration of the obligation period if the second rebalancing auction clears at a price less than the temporary economic delist offer price. • A capacity asset may not economically delist for more than two consecutive obligation periods. The red text above will be changed to black in the final CMD with the additional design content below added. A capacity asset may temporarily economically delist from the capacity market but choose to participate in the energy and ancillary services markets for no more than 5 continuous months in the same obligation period. Avoidable costs and EAS offsets will be calculated based on outage dates provided prior to finalization of the second rebalancing auction. • Temporary physical delist requests may be submitted when a capacity asset is expected to be physically unavailable for five continuous months or more during the obligation period. The red text will be changed to black in the final CMD. A capacity asset may temporarily delist from the capacity market but choose to

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	participate in the energy and ancillary services markets for no more than 5 continuous months in the same obligation period. • Permanent delist notifications may only be submitted during the prequalification period associated with the base auction and first rebalancing auction. Requests for the second rebalancing auction are not permitted. The red text above will be changed to black in the final CMD. Clarification will be provided than an asset retirement date need not occur at the start of the obligation period. The legal owner of a capacity asset intending to permanently delist may continue to participate in the energy and ancillary services markets until the physical retirement date through submission of a temporary physical delist request for the relevant portion of the initial retirement year. • No economic test will be conducted on permanent delist notifications.
UCAP Determination	• The AESO will calculate and assign a UCAP value for each prequalified asset. Participants will be allowed to choose a UCAP within a range of the AESO calculated UCAP. The red text above will be changed to black in the final CMD. The ranges for each asset will be calculated based on elimination of the top and bottom 5% of the data set utilized to determine UCAP. A minimum range of either +/- 2% of the calculated capacity or availability factor or +/- 1 MW will be provided if these ranges are wider than those calculated through elimination of 5% of the data. • Five years of historical data will be utilized for asset specific UCAP determination for existing assets. The 100 tightest supply cushion hours in each year will be utilized. The 100 tightest supply cushion hours to calculate an asset's UCAP will change to 250 tightest supply cushion hours and will be turned into black text in the final CMD. • Forced and planned derates and outages, and force majeure events will not be excluded from availability and production data and will act to reduce calculated UCAP values. Transmission system constraints will be excluded and will not reduce calculated UCAP values. • Resources with insufficient historical operating data will have data supplemented by class averages or engineering estimates. The red text above will be changed to black in the final CMD. • With some limited exceptions, an availability or capacity factor methodology will be used to calculate asset-specific UCAPs: o An availability factor will be used when metered generation or load volumes align with energy market dispatches (typically, thermal, storage, large hydro and run-of-river hydro assets). The final CMD will include a requirement that run-of-river hydro UCAP will be based on capacity factor.

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	○ A capacity factor will be used when metered generation or load volumes do not align with energy market dispatches (typically, wind and solar assets) • UCAP for self-supply sites and aggregated capacity assets may use an availability or capacity factor methodology, depending on the asset. The final CMD will clarify that UCAP will be determined based on an availability factor methodology for assets for which metered volumes do not match energy market dispatches but have a correlation of 80% or greater between metered volumes and dispatch levels. • Demand side resources will be classified as either firm consumption level (FCL) or guaranteed load reduction (GLR): ○ UCAP for FCL assets will be established as 90% of the difference between an estimated baseline consumption level and the FCL of the asset. An availability factor methodology will be utilized once sufficient historical performance data is available. ○ UCAP for GLR assets will be established as 90% of the GLR level provided during prequalification. The 90% value will be changed to 91% in the final CMD. For FCL assets, the use of an availability factor methodology will be removed from the final CMD. • UCAP for external capacity assets will be based on firm transmission volume held in the external jurisdiction and demonstration that the supply source is a non-recallable resource of sufficient size. This volume will then be derated to reflect the frequency of time during historical supply cushion hours that the respective intertie was out of service with 0 ATC. The reference to named and utility system resources will be removed and red text will be changed to black in the final CMD. • UCAP for mothballed or temporarily delisted assets with data available for 250 or more tight supply cushion hours will utilize available data to calculate UCAP. Assets with less than 250 hours of data available will have available data supplemented with class average data such that a total of 250 data points is obtained. The red text will be changed to black in the final CMD. • A UCAP dispute resolution process will be established for disputes exceeding a materiality threshold. The AESO is continuing to evaluate a dispute resolution process for all capacity market disputes as described in Section 5 and anticipates this subsection will be removed in the final CMD.

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Calculation of Demand Curve Parameters	• The demand curve will be developed in order to satisfy the resource adequacy standard specified by the Government of Alberta. • The AESO will use a forward-looking probabilistic resource adequacy model (RAM) to determine capacity volume requirements. The RAM will consider factors that impact the supply demand balance in Alberta such Alberta gross load, supply availability, forced and planned outages for thermal assets, onsite generation, variable generation profiles, hydroelectric generation profiles, and imports. • Outputs of the RAM will be translated into fleet-wide UCAP values using a formula to align with asset-specific UCAP calculations. The red text will be changed to black in the final CMD. The final CMD is expected to contain a description of the processes and methodologies associated with adjustments to the fleet-wide unforced capacity value to account for demand and supply shocks that are not captured in the RAM. • System UCAP requirements will be adjusted to account for self-supplied volumes, unqualified import volumes, and ineligible resources (including successful Renewable Electricity Program (REP) Round 1, 2 and 3 projects). The reference to unqualified import volumes in red text will be removed in the final CMD. Interties will be treated in a similar fashion to other capacity resources by utilizing calculated eligible UCAP to align procurement volumes from the RAM. • The reference technology used for determining gross-CONE and net-CONE will be a natural gas-fired technology and selected through detailed cost screening. The AESO anticipates that an F-class turbine will be black in the final CMD and will be evaluated in addition to an aeroderivative simple-cycle gas turbine (two LM6000 units) and combined-cycle frame turbine (one H-class gas turbine and one steam turbine). • A comprehensive gross-CONE estimate will be completed by an independent consultant at regular intervals. Annual interim adjustments will be made using cost indices. • The energy and ancillary services offset for the reference technology will be determined on a forward looking basis via a revenue certainty methodology utilizing forward market electricity and natural gas prices. The AESO continues to evaluate and consult on this, however the revenue certainty approach remains the preferred option. • The demand curve for the Alberta capacity market will be a downward-sloping, convex demand curve. Current working assumptions are as follows: o The price cap at the maximum of 1.75 x net-CONE or 0.5 x gross-CONE; o The minimum quantity will be set at a value of capacity commensurate with the minimum resource adequacy standard of 0.0011% Expected Unserved Energy (EUE) in one year (modelled as 800 MWh currently) o Target quantity has been set based on 400 MWh EUE; o The inflection point is set at 0.875 x net-CONE, at a quantity 4 % above the target quantity;

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	○ The foot is 13 per cent above the target capacity volume and at a price of 0. The AESO continues to evaluate and consult on the Gross CONE, Net CONE estimate, and shape of the demand curve. • The rebalancing demand curve will have the same shape as the base auction demand curve. Procurement volumes will be updated prior to each rebalancing auction.
Forward Capacity Auction	• Three-year forward period. • One-year obligation period, running November 1 – October 31. One-year payment term for all capacity committed assets, corresponding with obligation period. • No option for seasonal capacity commitments (annual obligations only). • REP Round 1, 2 and 3 resources with a Renewable Electricity Support Agreement will be ineligible. No other adjustments for out-of-market payments will be made for the initial auction. • Uniform price, sealed bid, single round auction. • Alberta will clear as a single capacity region with one capacity price set at the unconstrained price level established without consideration of expected transmission constraints. The red text will be changed to black in the final CMD. • After considering volumes limited due to expected transmission constraints, any capacity asset volumes required to satisfy the capacity purchase volume determined through unconstrained market clearing that are priced above the market clearing price will receive uplift payments equal to the difference between their offer price and the market clearing price. The red text will be changed to black in the final CMD. • External capacity asset offers and any transmission-constrained offers exceeding transmission delivery limits will be cleared based on offered capacity price in supply curve, then by the offer maximizing social surplus, then by pro rata allocation. Cleared assets will receive the market clearing price. The red text will be changed to black in the final CMD. • The capacity market auction clearing mechanism will maximize social surplus and minimize deadweight loss. Offers will consist of one up to seven price quantity pairs with limitation as to which blocks may be inflexible.
Rebalancing Auctions	• After a transitionary period, two rebalancing auctions will be held at 18 and 3 months before the obligation period. • During the transitionary period, ending after auctions for the 2023/24 obligation period, one rebalancing auction will be held three months before the obligation period. • Capacity suppliers may offer buy-out bids and incremental sell offers into the rebalancing auction. • Capacity suppliers who are required to buy-out in a rebalancing auction due to failure to meet development milestones or UCAP reductions will be priced marginally above the

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	market price cap to ensure they clear in the market. The final CMD will clarify that assets choosing to buy back an obligation for reasons other than UCAP reduction in the final rebalancing auction or missing milestones will not have the ability to submit a price above the price cap. • The rebalancing auction may clear with a net purchase or sale from the AESO, consistent with an updated administrative demand curve. • The shape of the demand curve will stay the same in the rebalancing auction. • Rebalancing auctions will clear using the same mechanics as the base auction. • Rebalancing auctions will reflect updated assessments of any anticipated transmission constraints. Previously cleared capacity committed assets which are no longer able to deliver all or a portion of their committed capacity volume will not be subject to reduced capacity payments. Offers will consist of one up to seven price quantity pairs with limitation as to which blocks may be inflexible.
Monitoring and Mitigation	• A must-offer requirement will apply to all qualified capacity assets unless they are permanently delisted or temporarily physically delisted. • The AESO will conduct an ex-ante market power screen prior to each base auction to identify firms who will be subject to capacity market offer price mitigation based on their portfolio size. Rebalancing auctions will not be subject to offer mitigation. In addition to an ex-ante market power screen option, the AESO is proposing an alternative option for market power mitigation where all existing capacity assets would be subject to a default offer price cap of net CONE and no asset specific offer caps would be allowed. • Firms subject to market power mitigation will be identified utilizing the demand curve. A market power screen will be applied to identify firms that have the ability to profitably increase the clearing price of an auction by 10% or more, measured both above and below the inflection point of the demand curve, by economically withholding capacity from a base auction. If the final market power mitigation approach includes a market power screen, the red text above will be changed to black in the final CMD. The market power screen will be based on a firm's capacity offer control of UCAP, regardless of resource type. • Firms that fail the market power screen will be required to offer all existing capacity assets at or below the default offer price cap of 0.5 x net-CONE. Assets may be allowed to offer at higher prices subject to demonstrating higher net going-forward costs. If the final market power mitigation approach includes a market power screen, the AESO will increase the default offer price cap from 0.5 x net-CONE to 0.8 x net-CONE in the final CMD. The final CMD will clarify that the net going forward cost will be equal to avoidable costs minus the energy and ancillary service margin. Guiding principles will be included to inform acceptable avoidable costs. Opportunity costs, major incremental capital expenditures and net decommissioning costs will be removed from the list of

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	acceptable avoidable costs in the final CMD. • There will be no minimum offer price requirements for capacity suppliers due to net-short capacity positions or out-of-market payments.
Supply Obligations and Performance Assessments	• Prior to the commencement of an obligation period, a capacity supplier will be required to meet development milestones: ○ A new capacity committed asset will be required to meet development milestones tracked by the AESO. If, prior to the first rebalancing auction, major milestones have not been met by more than eight months, or, prior to the second rebalancing auction, if a new capacity asset is more than five months delayed in its project schedule, then the new capacity asset will be required to buy out its capacity commitment in the rebalancing auction up to the market price cap. The red text above will be changed to black in the final CMD, subject to confirmation via further research. ○ A capacity committed asset with a UCAP that has decreased below its capacity commitment volume by a threshold will be required to buy back the difference in the second rebalancing auction up to the market price cap. • During an obligation period, the AESO will assess a capacity committed asset on both an availability and performance basis: ○ The availability of a capacity committed asset will be assessed during the 100 tightest supply cushion hours. The AESO will perform a supply cushion analysis at the end of each obligation period to identify the 100 tightest supply cushion hours. The red text above will be changed to black in the final CMD. ○ The AESO will apply an unavailability payment adjustment to capacity suppliers with a negative availability volume throughout an obligation period. The unavailability payment adjustment will be based on a $/MWh rate of 40 % of 1.3 multiplied by the asset specific weighted average capacity revenue per MW across all auctions for the delivery year divided by 100. – For a guaranteed load reduction (GLR) asset, its stated available capability (AC) volume will be adjusted for armed LSSi volumes. For a firm consumption level asset, availability will be measured by the difference between a “look-back baseline” (established using actual data from the immediately preceding 10 days) less the firm consumption level. – Long lead time energy resources will need to be online and ready to receive a dispatch to be deemed available. For the final CMD, the AESO intends to clarify that a 10 of 10 day average baseline and an “in-day” adjustment factor will be used to assess the performance of a guaranteed load reduction (GLR) asset. Provision of armed LSSi volumes will be counted as performance volume. ○ A capacity committed asset with a positive availability volume throughout an obligation period will be eligible to receive an over-availability payment adjustment, to be wholly funded from the unavailability payment adjustments received from capacity committed assets with negative availability volumes. The over-availability payment adjustment will be based on a $/MWh rate determined by dividing the total unavailability payment adjustments collected in an obligation period ($) by the total over-availability volume (MWh).

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	The red text above will be changed to black in the final CMD.
	○ The performance of a capacity committed asset relative to its capacity commitment adjusted by a balancing ratio (energy and reserves produced by all capacity committed assets during a performance assessment period divided by total capacity purchased) will be assessed during EEA events (levels 1 through 3) using actual energy production, level of consumption and/or provision of reserves.
	External assets will be considered meeting performance requirements for the first two hours of a performance event if they have an offer in the merit order but are not dispatched because the available transfer capability is fully utilized.
	○ The AESO will apply a non-performance payment adjustment for a capacity committed asset with a negative performance volume. The non-performance payment adjustment will be based on a $/MWh rate of 60 per % all auctions for the delivery year divided by the maximum of (Expected EEA hours, 20). The non-performance payment adjustment rate will then be multiplied by the performance volume to determine the non-performance payment adjustment for the performance event for the capacity committed asset. Armed LSSi volumes will be considered as meeting performance requirements for demand side resources. A GLR asset will be measured relative to a baseline consumption level established using actual data from the 10 days preceding the event.
	The red text above will be changed to black in the final CMD, subject to the following clarification: • The actual availability volume for a firm consumption level (FCL) asset will be measured as follows: Actual Availability Volume = Qualifying Baseline calculated for the purposes of bidding into the auction - Qualifying Baseline calculated during the delivery year.
	○ Long lead time energy (LLTE) capacity asset performance will be measured based on its availability to provide energy in response to a dispatch during a performance assessment period. An LLTE asset that has at any point received a directive covering the performance period will be considered non-performing.
	The above requirements will be modified in the final CMD to clarify that a LLTE asset that is directed to start but enters a start time within 10 minutes of receiving the directive will be eligible to be considered performing during a performance assessment period based on production volume.
	○ In the event availability and performance assessment periods overlap, both forms of payment adjustments will be applicable.
	○ The AESO will cap the combined payment adjustment exposure to unavailability and non-performance payment adjustments for each capacity committed asset. Monthly non-performance payment adjustments for a capacity committed asset will be capped at 300% of the monthly capacity revenue based on the capacity committed asset's obligation price per MW. The cumulative annual unavailability and non-performance payment adjustments for a capacity committed asset will be capped at 130% of the annual capacity revenue based on the obligation price per MW.
	The red text above will be changed to black in the final CMD.

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	○ Over-availability and over-performance payment adjustments will also be capped at a capacity committed asset's total annual obligation price per MW. ○ A capacity committed asset that is constrained down due to limits on the Alberta internal transmission system will be exempt from unavailability payment adjustments and non-performance payment adjustments on that volume of its obligation. Availability and performance assessments will not be conducted during periods when a state of market suspension is in effect. ○ No other exemptions to the assessment of unavailability payment adjustments or non-performance payment adjustments will be permitted (including for on-site and/or distribution system constraints, or transmission outages that result in the asset being electrically disconnected from the transmission system). The red text above will be changed to black in the final CMD based on rationale developed for section 3. ○ A capacity supplier will have the option of *ex ante* asset substitution, or *ex post* volume reallocation to avoid or decrease non-performance payment adjustments associated with a failure to deliver on its obligation volume during a performance assessment period.
Settlements and Credit Requirements	The Section will be renamed "Settlement and Financial Security Requirements". • Payments will not be made to capacity suppliers prior to the start of the obligation 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. • Capacity payment adjustments due to non-availability and non-performance will be deducted from monthly capacity payments. Remaining payment adjustment balances will be carried over to subsequent months until the total payment adjustment is collected. • Costs of procuring capacity will be allocated to customers according to the approved capacity cost allocation methodology. • No net settlement instructions for capacity will be enabled. • Capacity assets looking to buy back in rebalancing auctions, as well as new capacity assets, will need to demonstrate sufficient credit and may have to provide security. • 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. The final CMD will clarify that new capacity assets that have not reached commercial operation before the start of the settlement period will not be paid the monthly capacity payment in that settlement period. The monthly capacity payment for that settlement period will be held by the AESO until all penalties for the delivery year are assessed and thereafter will be applied towards the payment adjustment balance. The final CMD will also clarify that financial security is not required for existing capacity assets during the obligation period provided the asset maintains an obligation and is eligible for a capacity payment for the following obligation period.

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Roadmap for Changes in the Energy and Ancillary Services Markets	• Current aspects of the energy and ancillary services markets will continue, including, without limitation: ○ Current self-commitment rules. ○ Current must-offer requirement will continue to apply to a generation asset, regardless of whether or not it has a capacity commitment (available capability must be offered). ○ A load asset that does not have a capacity commitment (demand response and price-responsive load) may offer or may continue to self-dispatch. ○ A generation asset, regardless of whether or not it has a capacity commitment, must submit information related to asset outages in accordance with current requirements (no outage approval). ○ All offers may be between the price cap ($999) and floor ($0), unless mitigated (further explained below). ○ The current market structure for ancillary services will remain the same. ○ *Ex post* monitoring and mitigation of the market will continue. • New requirements to facilitate implementation of the capacity market and market power mitigation include: ○ Offer control information must be submitted. ○ Section 306.7 of the ISO rules, Mothball Outage Reporting will be replaced by capacity market delist process. Market participants must offer energy in the delivery period unless delisted. The red text above will be changed to black in the final CMD. ○ Minor changes to the supply adequacy or supply shortfall rules to include assets with capacity commitments. ○ A load asset with a capacity commitment must offer (similar to generation assets), and comply with dispatch requirements. In the event of equal priced offers throughout the merit order, including at the offer cap ($999.99), a load asset with a capacity commitment will be the last dispatched assets. The final CMD will clarify that a load or an aggregated load asset with a capacity commitment less than 5 MW but greater than 1 MW may participate in the energy market by submitting an offer (not a bid). A load or an aggregated load asset that has a capacity commitment of 5 MW or more must submit an offer (not a bid). A load or aggregated load that has not cleared in a capacity auction will not have a must offer requirement. ○ An import or export asset will be provided the option to submit offers in price quantity pairs upon request of a new priced asset, in which case they will be dispatched during the settlement period, and may set system marginal price. The red text above will be changed to black in the final CMD. The final CMD will clarify that an import asset with a capacity commitment will not have priority dispatch and bump a non-capacity committed import asset.

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- An import asset with a capacity commitment must offer its obligation volume into the energy market.
- A load asset with a capacity commitment must submit outage information, similar to the existing requirements for generation assets (no outage approval).
- Changes for enhanced dispatch certainty, including continued evaluation of ramp rates.

  The AESO anticipates that a proposal for submission of an asset's ramp capability during an asset's operational state (dispatch table) will be included in the final CMD as black, and will be subject to ongoing consultation. The consultation will determine a model for monitoring dispatch compliance and how to trigger potential changes to the Section 203.4 of the ISO rules, as required. Further changes including the ramp product and ramp by block and are currently in the market roadmap for future consideration.

- An *ex ante* market power screen will be adopted in the energy market, based on an hourly residual supplier index (RSI) structural screen set at an RSI of 1.0. The market power screen will not be conducted when the energy market is forecast to be in scarcity situations such that the supply cushion is forecast to be less than 500 MW. The RSI calculation will incorporate a voluntary submission of physical supply obligations, which will be netted off the firm's portfolio.

  The red text above will be changed to black in the final CMD, subject to further evaluation of the 500 MW threshold.

  The final CMD will clarify that, in additional to physical supply obligations, financial obligations will also be considered in the calculation of obligations to be netted off in the calculation of the residual supplier index.

- A firm that fails the market power screen will have its offers or bids mitigated to an asset-specific reference price, calculated as:
  - For thermal assets, 3 x marginal cost, defined as heat rate x fuel price + variable O&M + carbon cost; or
  - For other assets, including an import asset or a non-thermal, energy-limited asset, a formula that captures the concept of opportunity cost.

  The final CMD will clarify that while firms are identified during the market power screen, it is the offers above the reference price for a firm that has been identified as having market power that fail the three part test.

  The red text above will turn to black in the final CMD, subject to replacing "carbon cost" with "carbon price$_t$ x Asset-specific Carbon Efficiency Factor$_j$".

- An asset may submit to the AESO an exception request for the asset-specific reference price, and in doing so must submit its actual short-run marginal cost.

- The following design changes are included in the market roadmap (i.e., not included as part of the capacity market implementation for 2021) and will be reviewed and implemented as part of the ongoing evaluation of the market and day to day operations:
  - Energy market pricing methodology, including those that may be required to

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	ensure efficient dispatch and pricing during shortage and surplus events in the future: – raising the offer cap above $999.99; – negative pricing; and – shortage pricing. ○ Dispatch and flexibility: – dispatch certainty through tightened dispatch tolerance and ramp by block; – introduction of a ramp product; and – shorter settlement. • The following design changes will not be included as part of the capacity market implementation or market roadmap, although they may be considered as part of a separate evaluation at another time should the need arise: ○ locational marginal pricing (LMP); ○ security constrained unit commitment (SCUC); ○ security constrained economic dispatch (SCED); ○ intertie dynamic scheduling; ○ co-optimization of the energy and ancillary services markets; and ○ day-ahead market (DAM).

1.2 Auction Timelines and Transitionary Period

Each capacity auction process is expected to take approximately eight months, starting from the prequalification process through to market clearing and posting of auction results. In the transition to the final capacity market structure, auctions will be conducted on a compressed forward period and with a reduced number of rebalancing auctions. The initial base auction process for the 2021/2022 obligation period will start in November 2019 and is anticipated to run through to approximately the end of June 2020. During the transitionary period, base auctions will be held approximately every six months until the full three-year forward period is achieved with the completion in October 2021 of the base auction process for the 2024/2025 obligation period. Please see Sections 5 and 6 for additional detail.

The red text above will turn to black in the final CMD, with the clarification that auction process timelines may be adjusted based on further analysis.