Restructured Energy Market

Final Design

AUGUST 2025

Contents

1. Executive Summary

This document outlines the Restructured Energy Market (REM) Design, developed through collaboration between the Alberta Electric System Operator (AESO) and industry stakeholders in alignment with government policy and overall objectives. It complements other key materials released during the consultation process, marking the transition from finalizing the High-Level REM Design to initiating engagement on the ISO rules required for REM implementation.

The next engagement will focus on ensuring the REM ISO rules are aligned with the REM Design and are technically sufficient. We will not be revising the final design.

1.1 Policy Direction Alignment

This document explains how the REM Design was shaped by and meets the policy directions received over the past several years, including:

- Market prices driven by competitive offers to guide long-term investments and ensure cost recovery
- Market power mitigation to protect consumers from excessive exercise of market power
- A market and transmission policy that allows for congestion on the transmission system and a market-based mechanism to manage congestion
- Co-optimization, security-constrained economic dispatch (SCED) and shorter settlement intervals

On July 14, 2025, the Minister of Affordability and Utilities provided additional guidance, including:

- Maintaining a uniform pricing framework for loads while adopting locational marginal pricing (LMP) for generators and transmission-connected loads who wish to settle wholesale market transactions at their respective LMP
- Recovering line loss costs through LMP
- The direction letter provides information on how the transition mechanism to protect incumbents is intended to work within the context of REM and optimal transmission planning (OTP). This document does not provide additional information on the incumbent treatment or on the long-term congestion management options that we will continue to progress through the OTP and transmission reinforcement payment (TRP) engagements.

1.2 REM Stakeholder Consultation Process

The REM design reflects over 18 months of detailed consultation with industry stakeholders. From spring 2024 to mid-2025, we conducted a multi-phased engagement process, including virtual information sessions, written feedback cycles and in-person/virtual meetings. This feedback played a key role in shaping the REM design.

Significant design changes:

- Removed the day-ahead commitment (DAC) product

- Reduced the day-ahead market (DAM) scope from a day-ahead market for energy and operating reserves to a day-ahead reliability market for operating reserves only
- Simplified the congestion avoidance market (CAM) into locational marginal pricing to manage congestion

Refinements and adjustments:

- Simplified the ramp product from two products (R10/R60) to one (R30)
- Adjusted parameters for the secondary offer cap
- Increased the offer cap in stages to allow the market time to transition
- Lowered the price floor five years after REM launch
- Refined the reliability unit commitment (RUC) triggering threshold

No changes in some areas: After extensive discussion, some elements remained unchanged to preserve REM objectives, such as R30 offer caps, the broad market power mitigation framework, and real-time co-optimization of energy and R30 including a scarcity pricing curve.

This extensive consultation has resulted in a well-debated and robust REM Design. A detailed summary of the stakeholder engagement process is available in Appendix 3: REM Engagement and Progression Summary.

1.3 Guiding Objectives

The REM design is structured to meet four objectives:

- **Reliability:** Market incentives and design support reliable power delivery
  - A sufficient range of reliability attributes and supply technologies are available to keep the lights on during the various system conditions
- **Affordability:** Achieve the lowest overall delivered cost of electricity by promoting competitive and efficient outcomes, creating safeguards from excessive use of market power and incentivizing optimal use of the existing infrastructure
- **Decarbonization by 2050:** Better market integration of technology and innovation that facilitates decarbonization to reach the goal of net-zero emissions by 2050
- **Reasonable implementation:** Implemented expeditiously to minimize investment and reliability risks
  - We strive to minimize negative impacts on existing asset investment during REM implementation

1.4 Key Features of the REM Design

1.4.1 Market-Based Congestion Management

LMP for energy produced in areas where transmission constraints are binding will allow the price of energy to vary based on the value of energy production at different locations. This will encourage efficient use of the transmission system by aligning the incentive to produce energy with the capability of the transmission system. Over time, this market signal will guide investment to relatively higher value locations on the transmission system, reducing the cost of building additional transmission infrastructure for consumers. Loads will continue to settle at a uniform price, but eligible loads have a one-time option to elect to settle at their nodal price.

- To protect consumers from the excessive exercise of market power, local market power mitigation rules will limit the ability for units in constrained areas to set their own price when there is limited competition due to limits on the transmission system
  - The parameters for local market power mitigation are compatible with the investment signals in an energy-only market with strategic bidding, while also ensuring that units subject to local market power mitigation can still recover their full cost
- LMP will include locational losses, which improves the efficiency of the price signal by reflecting the appropriate cost of losses with the real-time system conditions at each location

1.4.2 Updated Pricing

The energy market offer cap will increase to $1,500/megawatt-hour (MWh), rising to $2,000/MWh in 2032, with a price cap of $3,000/MWh. These increases strengthen investment signals, while staging allows market adjustment.

- The price floor will initially remain at $0/MWh but will decrease to -$100/MWh in 2032
- The increase to the price cap and eventual decrease to the price floor attracts additional supply/demand response and promotes flexibility in the market
- Scarcity pricing will reflect the value of the ramping product to set prices between the energy offer cap and the price cap at times when ramp capability is limited

1.4.3 Appropriate Guardrails

The broad market power mitigation framework will continue to track the revenues of a hypothetical unit to trigger a secondary offer cap when two times the annual unavoidable costs have been recovered in the energy market. When triggered, the secondary offer cap will apply only to firms with five per cent or greater market share offer control (MSOC).

1.4.4 Day-Ahead Reliability Market

The current day-ahead market for operating reserves (regulating reserves [RR], spinning reserves [SR], supplemental reserves [SUP]) will be enhanced to promote more competition for the products needed to meet reliability. Key changes to this market include introducing hourly procurement, co-clearing all operating reserves and clearing prices at the marginal offer for active reserve. The day-ahead reliability market will continue to use indexed pricing to align with real-time market conditions and incentivize participation.

1.4.5 New Real-Time Co-optimized Ancillary Service

A single real-time ramping product (R30) will improve system flexibility by compensating resources for ramping capability. The 30-minute ramping reserve demand curve (R30DC) will determine procurement volumes and reflect the scarcity value of the ramping product, up to $3,000/MWh. Co-optimization of energy and R30 allows a trade-off between them such that the relative tightness of R30 allows the energy price to be set above the offer cap. Costs will be allocated based on cost causation principles.

1.4.6 Reliability Unit Commitment

An updated unit commitment process provides a backstop to ensure reliability. The market continues to rely primarily on self-commitment of generation. The unit commitment process will be based on a supply cushion threshold of zero or below; the commitment process will be triggered if the anticipated available supply is insufficient to meet forecasted demand and reserve requirements. The supply cushion trigger balances the need for controllable supply in a future hour while minimizing distortions to commercial decisions.

1.4.7 Transition Mechanism for Incumbents

Temporary financial transmission rights will limit the impact of changes to congestion management in the *Transmission Regulation* (T-Reg) for incumbents who invested under the current framework. This mechanism will phase out over time.

Details on incumbent treatment and long-term congestion management are not included in this document.

1.5 REM ISO Rule Engagement

This document transitions the REM from the high-level design phase to engagement on the REM ISO rules. The REM design elements in this document support this transition and fall into two categories:

- **Consulted Design Elements:** These were the focus of the REM design consultations and are included within this document
- **Unchanged Design Elements:** There are changes to the REM ISO rules that are associated with these design elements; these were not a focus of the REM design consultations

We are drafting the REM ISO rules to align with the REM Design. These rules, which will be submitted for approval by the Minister under Section 20.01 of the *Electric Utilities Act* (as amended by Bill 52), will outline the requirements for market participants in the REM. To ensure alignment with the finalized REM Design and to ensure that the REM ISO rules are technically sufficient, we will engage stakeholders before submitting the rules for approval.

The REM ISO rules engagement process will allow stakeholders to:

1. Understand the organization and layout of the REM ISO rules

2. Review and provide feedback on rule alignment with the REM design
3. Review and provide feedback on the technical sufficiency (including clarity and completeness) of the REM ISO rules
4. Understand the process for initial approval of the REM ISO rules, as well as for further consultation and amendment of the REM ISO rules to address implementation requirements

The AESO intends to submit the REM ISO rules for approval by the Minister before the end of 2025. Following initial approval, we will continue to work with stakeholders to revise the REM ISO rules, as necessary, to support successful implementation of the REM.

1.6 REM Design Independent Assessments

1.6.1 Assessment of Capital Provider Perspectives

We are committed to ensuring the REM supports private investment, which is essential for Alberta's energy sector. To support this, we engaged Morrison Park Advisors (MPA) to consult with financial institutions and gather their perspectives on how the REM impacts investment.

We are encouraged by MPA's findings, which indicate that no financial institution suggests that the REM introduces barriers to future investment. The key takeaway from the MPA report is that investment depends on:

- Clear opportunities and risks
- Certainty in the regulatory framework
- Confidence in forecastable, predictable cash flows

We remain dedicated to incorporating feedback from the financial sector and ensuring the timely implementation of the REM to strengthen confidence in Alberta's energy market. The MPA report summarizes its discussions with debt capital providers in Alberta's power sector.[1]

1.6.2 REM Design Reasonableness Assessment

To ensure the REM reflects market design best practices while addressing Alberta-specific needs, including the key objectives of reliability, affordability, decarbonization by 2050 and reasonable implementation, we engaged ECCO International to review and evaluate the reasonableness of the REM market design.

ECCO International confirmed that the REM design is reasonable and represents a more complete design architecture based on best practices. ECCO International also provided recommendations for future consideration. We have incorporated several of these recommendations into the final REM design and set aside others for potential future consideration. We decided not to revisit some recommendations that were already addressed during the REM development process. The ECCO report summarizes its evaluation of the REM design.[2]

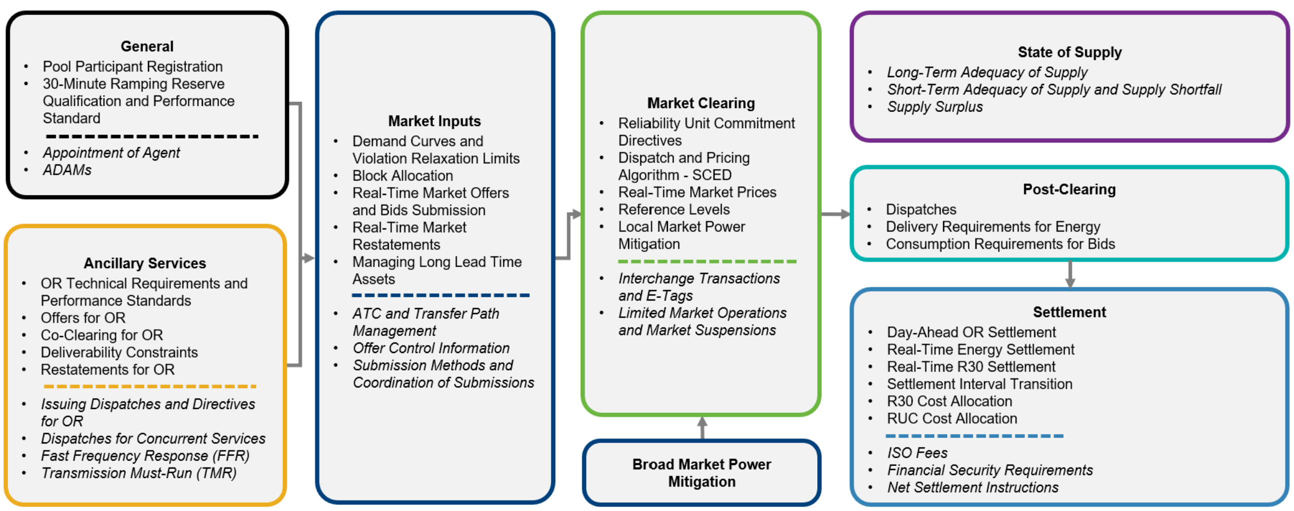
[1] MPA Report | REM Technical Design | AESO Engage
[2] ECCO Report | REM Technical Design | AESO Engage

2. REM Design Summary

This section details the key components of the overall REM design, building on the information previously released through the stakeholder consultation process. To aid the transition from high-level market design to ISO REM rules, the key design components are grouped together in the following categories:

- General
- Ancillary services
- Market inputs
- Market clearing
- Broad market power mitigation
- Post-clearing
- Settlement
- State of supply

Figure 1: REM Components



A complete list of the materials shared throughout the consultation process is provided in Appendix 2: Detailed Stakeholder Engagement Activities and Materials.

2.1 General

This section covers the following design elements:

- Pool participant registration
- 30-minute ramping reserve qualification and performance standard

Features that will remain largely unchanged:

- Appointment of agent
- Automated Dispatch and Messaging System (ADaMS)

2.1.1 Pool Participant Registration

Description

- Pool participants, with assets of 5 MW maximum capability (MC) or greater must register as a pool asset to exchange energy and ancillary services (AS)
  - Pool participants with assets greater than or equal to 1 MW but less than 5 MW MC may register as a pool asset and must indicate if they will participate in the energy market
- All controllable sink assets and all source assets are subject to LMP
- Non-controllable sink assets will settle based on the Alberta Load Price (ALP), unless they choose LMP
- This choice is limited to a one-time election, as outlined during REM Design Finalization Session Week 4. For existing assets, this election must be made within the first year of REM onset
  - New non-controllable sink assets connecting after REM has been implemented must choose between ALP and LMP during registration

Rationale

- Must-offer must-comply requirements:
  - All registered source assets with 5 MW MC or greater must offer and comply with energy dispatches, consistent with current rules
  - Registered source assets that are greater than or equal to 1 MW, but less than 5 MW MC must offer and comply with energy dispatches if they are qualified to provide OR or if they opt into the energy market
    - This approach supports participation of smaller generators in the AS market while avoiding unnecessary obligations for non-controllable or passive generators
  - Registered sink assets have the option to submit bids and must comply with energy dispatches if they opt to participate, ensuring the integrity of energy dispatches
- ALP vs. LMP election for non-controllable sink assets:
  - Allowing non-controllable sink assets to choose between ALP and LMP aligns with the July 15, 2025, Minister Direction Letter

- This promotes price responsiveness and demand-side participation

– Limiting the election to a one-time choice within the first year of REM implementation balances load choice flexibility with market certainty for consumers

– Stakeholders raised concerns about potential gaming if sink assets could switch pricing options

  - There were noted concerns with how non-controllable sink assets could impact the forward markets and use the ALP as a shield in the short term as not all sink assets may be able to select LMP
  - Limiting the choice to one direction (ALP to LMP) within the first year of REM implementation mitigates this risk

– Some participants proposed that giving non-controllable sink assets this option would result in an increasing ALP, as sink assets with lower LMPs would select LMP

  - However, removing the choice from sink assets with low LMPs in an attempt to lower the ALP results in inefficient outcomes and cross-subsidization

– Requiring all non-controllable sink assets to be on ALP may seem more equitable but could disadvantage price-responsive loads

  - This would include loads that do not respond directly to market dispatches but do respond to aggregate market signals over longer time periods
  - Allowing LMP selection encourages demand-side flexibility and efficient market outcomes

- Controllable loads are settled at LMP to ensure efficient market signals and consistent treatment with other dispatchable resources

2.1.2 30-Minute Ramping Reserve (R30) Qualification and Performance Standard

Description

- All dispatchable source assets including energy storage must qualify for R30
- R30 qualification for sink assets is tied to their capability to submit a bid in the energy market
  - Any bid from a sink asset qualifies it to provide energy and R30
- Qualification is binary
  - The real-time energy dispatch determines the available R30 headroom for clearing
- Additional technical requirements for providing R30 while offline: the asset must be able to provide dispatchable energy within 10 minutes
- Intertie participants are not eligible to provide R30

Rationale

- The mandatory qualification requirement for R30 for all source assets matches the must-offer requirement in the energy market
  - Since R30 providers only need to follow energy dispatches, any dispatchable source asset qualified for energy should also qualify for R30

- Sink assets are not required to be dispatchable at all times, so R30 qualification remains optional for sink assets
- Qualification is binary because the volume an asset can offer into R30 changes interval-to-interval based on energy dispatch and therefore is better defined in real time
- The requirement for offline units to be able to start in 10 minutes, ensures we can access R30 providers ramp capability sufficiently close to real time
- Fast-start units are dispatched for energy when their LMP meets or exceeds their energy offer
  - A fast-start unit will be dispatched for energy based on its energy offers regardless of its R30 offer and if they had previously cleared in R30
  - Once dispatched for energy from an offline state, fast-start units are responsible for adjusting their energy offer to ensure that their minimum up-time is respected
  - Intertie participants will not qualify to provide R30 because of challenges in co-optimizing between R30 and energy over hourly scheduling intervals
    - Further, enabling R30 on the interties could result in fewer transmission service rights (TSRs) from being released to other market participants who are willing to compete in the energy market

2.2 Ancillary Services

This section covers the following design elements:

- Operating reserves (OR) technical requirements and performance standards
- Offers for OR
- Co-clearing for OR
- Deliverability constraints
- Restatements for OR

Features that will remain largely unchanged:

- Issuing dispatches and directives for OR
- Dispatches for concurrent services
- Fast frequency response (FFR)
- Transmission must-run (TMR)[3]

[3] The design element for transmission must-run has largely been superseded by the use of local market power mitigation. What remains is the capability of the market clearing process to issue instructions to contracted services, including TMR.

2.2.1 OR Technical Requirements and Performance Standards

Description

- The minimum qualification levels for regulating reserve (RR), spinning reserve (SR) and supplemental reserve (SUP) will be reduced to 1 MW

Rationale

- Lowering the minimum qualification level reduces barriers to entry and enables more competition through broadening market access for existing and new assets

2.2.2 Offers for OR

Description

- Active offer caps, indexed:
  - +$150/MW for RR
  - +$50/MW for SR
  - +$25/MW for SUP
- Standby premium offer caps:
  - $99/MW
- Hourly and multi-hour blocks:
  - Participants will be able to offer both flexible and inflexible hourly blocks
  - Participants will also be able to offer inflexible blocks of 1, 2 or 3 consecutive hours
- Each price-quantity pair must correspond to a qualified asset.
  - Virtual assets will no longer be allowed

Rationale

- RR offer caps are indexed based on a methodology that reflects recovery of start-up and variable costs for a simple-cycle gas facility operating at minimum stable generation during periods when LMPs are near the price floor
  - This technology was chosen as it represents a higher-cost marginal provider, which may set price during periods when lower-cost providers are unavailable
- SR and SUP offer caps are less directly tied to simple-cycle technology due to the wide range of qualified resource types
  - However, we considered the cost recovery needs of higher cost thermal assets when reviewing contingency reserve (CR) offer caps
- Offer caps for RR and CR will continue to be reviewed and updated as needed based on market outcomes and changes to input costs, such as start-up, fuel and emissions costs
- Standby premium offer caps remained unchanged and we will continue to review the cap based on market outcomes

- Hourly blocks enable technologies that have shorter delivery intervals to provide OR
- Inflexible blocks spanning up to three hours address stakeholder concerns that some assets cannot recover costs within a single hour under current offer caps
- Clearing offers for virtual assets is inconsistent with the dynamic deliverability constraints outlined in subsequent sections

2.2.3 Co-Clearing for OR

Description

- Auction Timing:
  - Auction for active OR at 9:00 a.m.
  - Standby OR at 10:00 a.m.
- Hourly co-clearing:
  - An optimization algorithm will determine the lowest cost combination of offers across all three products: RR, SR, SUP
- Deliverability Assessment:
  - Deliverability will be assessed based on seasonal transmission line ratings, planned transmission outages and expected net power outflows from regions prone to transmission congestion
  - When clearing day-ahead OR, constraints will limit offered volumes from assets located behind expected outflow congestion

Rationale

- Co-clearing simultaneously clears RR, SR and SUP products at the lowest overall cost, subject to the volume requirements of each, as well as deliverability constraints
  - This integrated approach improves price fidelity by enabling OR providers to compete in a unified market structure
- Moving from a block-based procurement model (on/off/super-peak) to hourly clearing aligns reserve volumes with hourly needs
  - This eliminates the inefficiency of procuring higher volumes across multiple hours to cover peak-hour requirements
- OR providers must be capable of injecting energy in response to real-time system needs, such as changes in regulating setpoints or CR directives
  - Clearing OR subject to an assessment of deliverability maintains the reliability value of reserves while improving price fidelity for deliverable OR

2.2.4 Deliverability Constraints

Description

- In the Design Finalization Session (DFS4)[4], we introduced deliverability assessments for day-ahead OR
  - We will publish the results of the assessments prior to the daily auction
- Participants may still submit OR offers for resources within geographic regions of forecasted congestion; however, a clearing constraint will be applied to limit the volumes cleared day-ahead to what is expected to be deliverable from all the resource providers within the region

Rationale

- Deliverability assessments are a reliability safeguard that promote the value of OR being provided from resources that are not behind outflow transmission congestion, thereby maintaining their ability to respond to regulating setpoints and CR directives
- Publishing these assessments as forward-looking transmission capability forecasts provides participants with day-ahead expectations regarding deliverability

2.2.5 Restatements for OR

Description

- While providing OR, participants must restate an asset's OR volume to reflect any changes in resource capability
- Participants can substitute OR volume to other qualified assets no later than one hour before the start of the delivery hour

Rationale

- Restatements will continue to inform protocols for activating standby OR, ensuring the replacement of previously cleared OR volumes that become undeliverable during the operating day
- Continuing to permit substitution of OR volumes provides participants the flexibility to deliver OR as their asset availability may change between day-ahead and real-time delivery
- Keeping the substitution deadline of T-1 unchanged provides sufficient lead time for assets to be dispatched in energy, R30 and OR
  - The T-1 lockdown aligns with offer restatements in energy and R30 as outlined in the Market Inputs section below

[4] See DFS4 slides 169-170 on OR deliverability assessments.

2.3 Market Inputs

This section covers the following design elements:

- Demand curves and violation relaxation limits
- Block allocation
- Real-time market offers and bids submission
- Real-time market restatements and timing requirement for ATC allocation
- Managing long lead time assets

Features that will remain largely unchanged:

- Available transfer capability (ATC) and transfer path management
- Offer control information
- Submission methods and coordination of submissions

2.3.1 Demand Curves and Violation Relaxation Limits

Description

- We developed the R30 Demand Curve (R30DC), which is comprised of an expected ramping volume and an uncertainty ramping volume
- Each point on the resulting R30DC reflects the reliability value derived from an additional MW of R30, based on reducing the likelihood of a net load increase causing a supply shortfall event
  - Expected ramping volume methodology:
    - Calculate the volume requirement over the expected ramp lookout period using the expected net demand forecast[5]
  - Uncertainty ramping volume is comprised of two calculations:
    - Reliability value of operating reserves: the R30 value of lost operating reserves ($3,000/MWh) multiplied by the probability of losing operating reserves
    - Reliability value of lost load (VOLL): the R30 VOLL ($32,000/MWh)[6] multiplied by the probability of lost load
- These two calculations are added together and capped at the R30 price cap of $3,000/MWh to create the final R30DC
  - If the expected ramping volume is negative (e.g., during a down-ramping event), the negative value will reduce the uncertainty ramping volume of the R30DC by that same amount
- Historic Data Usage:
  - The uncertainty portion of the R30DC uses 12 months of historic net demand forecast data

[5] For further information on the expected volume methodology, see DFS4 slides 91-103.
[6] See VOLL study.

- The historic data will not be scaled, unlike previous versions
    - An updated spreadsheet reflecting these changes has been published
  - We have standardized the mean of the distribution of net demand forecast error to zero based on observations that the mean of net demand forecast error is close to zero in historic data
- Governance: The REM ISO rules will include the key input parameters that determine the shape of the R30DC
  - Any change to these input parameters will require appropriate approval
- The R30DC allows security-constrained economic dispatch (SCED) to set a price when there is not enough supply for R30 offers to intersect with the ramping requirement
  - There are additional requirements, like physical constraints, that the SCED algorithm needs to respect in solving dispatch
  - Violation relaxation limits are used by SCED to respect physical constraints on the grid
- Violation relaxation limits provide a relative priority to the SCED for respecting constraints
  - These limits do not affect the energy and R30 market prices
  - Examples of violation relaxation limits include:
    - Energy shortfall evaluated at $30,000/MWh
    - Energy surplus evaluated at $30,000/MWh
    - System operating limit evaluated at $90,000/MWh

Rationale

- Adding the expected ramping requirement and the uncertainty ramping requirement reflects the total value of holding R30 to avoid shortages in operating reserves and energy market supply
- The R30 reliability value of lost operating reserves is set to $3,000/MWh
  - This reflects the energy price during an Energy Emergency Alert (EEA) when we must use contingency reserve to serve load
  - Including this calculation in the uncertainty portion of the R30DC incorporates the risk of running so low of R30 that contingency reserves are needed to serve energy
- The reliability VOLL is included to incorporate the risk of running so low of R30 and operating reserves that we may have to shed load to reliably maintain supply and demand balance
- The R30DC is capped at $3,000/MWh to align with the R30 price cap
  - The R30 price cap matches the energy market price cap, allowing the R30 price to reflect the equivalent value of energy and ramp products before load shedding occurs
- Using 12 months of non-scaled historic data, updated quarterly, is based on AESO analysis indicating that this timeframe accurately reflects current ramping needs
  - Standardizing the mean of the net demand forecast error to zero creates a more stable distribution while still reflecting historic data

- Violation relaxation limits are used in the market clearing process to communicate the high cost of violating certain operational constraints, without affecting the settlement prices
  - We are employing violation relaxation limits to ensure that operating limits, such as preventing overloading a transmission line, are respected in the market clearing process

2.3.2 Block Allocation

Description

- Energy offers will include 10 price quantity (PQ) blocks
- R30 offers will include 1 price (P) block

Rationale

- The 10 PQ blocks provide greater flexibility to reflect costs across an asset's full capability
  - Many ISOs across North America, such as the Electric Reliability Council of Texas (ERCOT), California Independent System Operator (CAISO) and Southwest Power Pool (SPP), allow up to 10 PQ blocks or segments in their energy markets
- A single price block for R30 allows participants to communicate start costs for the asset and enables strategic offers to set the R30 price

2.3.3 Real-Time Market Offers and Bids Submission

Description

- Participation in Energy:
  - Must offer for source assets with a MC greater than or equal to 5 MW
  - Source assets with a MC greater than or equal to 1 MW but less than 5 MW, must offer and comply with energy dispatches if they are qualified to provide AS or if they have indicated they will participate in the energy market
  - Sink assets may submit a bid but must comply with energy dispatches
  - Participants can choose between "smoothed" or "stepped" offers
- Participation in Ramping:
  - Source assets must submit offers
  - Linked participation for sink assets
    - Sink assets that offer in energy or R30, must offer in both
  - Energy storage assets are only cleared for R30 using the associated source asset
- Offer cap:
  - Energy offers capped at $1,500/MWh at market inception, increasing to $2,000/MWh after five years
  - Ramping offers are capped at $100/MWh

- Offer floor:
  - Energy and ramping offers have a floor of $0/MWh at market inception
    - After five years, the energy offer floor will decrease to negative $100/MWh

Rationale

- The REM design maintains the energy participation obligations from the current market
  - R30 participation obligations extend from these as R30 is tied to energy through available capability and ramping capability
- Smooth or stepped offers allow for more flexibility in how participants choose to offer
- Differences in must-offer obligations between source assets and sink assets are based on the differences that exist in the current market
- Limiting ramping participation for energy storage assets to their source asset aligns with treatment of energy storage in the current OR market
- Increasing the offer caps supports strategic offering as the primary driver to recover investment costs in the energy market
- Staging the increase in offer caps and the decrease in the price floor allows the market time to adjust while balancing affordability objectives
- Decreasing the price floor enables electricity prices to better reflect its value under certain conditions
  - Negative pricing increases incentives for flexibility from market participants

2.3.4 Real-Time Market Restatements

Description

- Restatements are allowed up to T-1 (one hour before the delivery hour)

Rationale

- Reducing the offer restatement lockdown window to T-1 (from the current T-2 lockdown) gives participants more flexibility to update offers based on recent information
- A lockdown is still necessary to ensure reliable market operation
- Allowing last-minute changes to offers or bids make balancing supply and demand more difficult, impacting reliability

2.3.5 Managing Long Lead Time Assets

Description

- Participants must submit an initial start-up time no greater than 36 hours
- A long lead-time (LLT) resource is any asset or portion of an asset that has a start time greater than 1 hour

  - An LLT asset is a source asset that contains a LLT resource
- When submitting a start time for an LLT asset, that start time can be no later than the time of the submission plus the initial start-up time for that LLT asset
- This process allows participants to voluntarily self-commit their LLT asset

Rationale

- The definition of "LLT asset" is largely unchanged: assets (type i) or portions of an asset (type ii) that take longer than one hour to synchronize and deliver energy to the grid
- Self-commitment remains the primary mechanism for unit commitment
  - Having a LLT asset does not alleviate a participant from "must offer, must comply" obligations for that asset
    - This promotes a level-playing field with non-LLT assets while recognizing LLT assets unique physical constraints
- Start time submissions obligations work with self-commitments and the supply cushion forecasting to improve the reliability of the energy market and better inform RUC directives, if necessary

2.4 Market Clearing

This section covers the following design elements:

- Reliability unit commitment (RUC) directives
- Dispatch and pricing algorithm - SCED
- Real-time market prices
- Reference levels
- Local market power mitigation

Features that will remain largely unchanged:

- Interchange transactions and E-tags
- Limited market operations and market suspension

2.4.1 RUC Directives

Description

- The anticipated supply cushion forecast is an ongoing report with an hourly granularity for the next 48 hours. The main components include:
  - Anticipated supply cushion: available capability from all assets with less than 1 hour start time or a start time submitted for prior to the assessed period, estimated output from wind/solar, estimated on-site generation that is behind-the-fence, forecasted ATC of the intertie
  - Offset by:

- Alberta Internal Load forecast
- Reserve requirements: including half the forecast regulating reserve (to represent the ramp-up capability), forecast contingency reserve and a measure of uncertainty to account for forecast error (similar in concept to the uncertainty ramping volume)

- All LLT assets must submit energy cost parameters in the specified form and have those costs accepted by the AESO
  - Participants must maintain the accuracy of these energy cost parameters for their long lead time asset
- An anticipated supply cushion forecast of 0 MWs or less triggers the unit commitment directive process
- Once triggered, the unit commitment process assesses and potentially issues a directive based on relative economic merit of available LLT assets
  - The submitted energy cost parameters inform the relative economic merit when issuing unit commitment directives
  - These directives are issued "just in time" to fully allow market participants to self-commit
- When accepting a directive, a participant is faced with the decision to accept as a cost guarantee (forfeiting all associated market revenues under the cost guarantee) or opt-out of the cost guarantee and self-commit for at least the length of the directive
  - Regardless of participant choice, market price reconstitution will not apply
- RUC directive reporting: Tracks when unit commitment directives are issued and their duration, a continuation of current reporting practices

Rationale

- As a reliability metric, we will determine the RUC supply cushion forecast methodology
  - The change from forecast net interchange to ATC of the interties, allows the RUC supply cushion forecast to better reflect the reliability conditions intended to trigger a directive
  - The inclusion of reserve requirements allows the RUC supply cushion forecast to make a unit commitment directive in anticipation of needing to serve both anticipated energy demand and reserves demand in a future period
- Self-commitment remains the primary unit commitment mechanism, supporting strategic offering
- The current RUC design does not include price reconstitution:
  - The difference between the price cap ($3,000/MWh) and the offer cap ($1,500/MWh), increases the incentive and potential harm from physical withholding
  - RUC is intended to be an infrequent backstop to self-commitment based on a reliability trigger
    - Based on this design, price reconstitution is not necessary and, in the cases where it prevents physical withholding, would be inappropriate

2.4.2 Dispatch and Pricing Algorithm - SCED

Description

- The real-time market-clearing process simultaneously clears energy and R30 to maximize net benefit
  - It minimizes the sum of offer-based dispatch costs while respecting constraints
  - The relative importance of constraints and the manner in which they are relaxed under certain conditions is facilitated using violation relaxation limits where appropriate. The security constraints used are:
    - Power balance constraint
    - Asset capacity constraints
    - Asset-level ramping constraints
    - Ramping reserve demand requirement
    - System-wide maximum ramp share by resource type constraint
    - Operating reserve requirement constraint
    - Transmission constraints within the Alberta Interconnected Electricity System (AIES)
    - ATC of interconnections
- Dispatches and prices are optimally determined for each individual interval
- The market-clearing process operates the SCED
  - Market-clearing solutions will meet the energy and R30 needs of the system while respecting constraints
    - "Security Constrained" refers to the reliability and operational limits that constrain the dispatch solution
    - "Economic Dispatch" refers to the goal to maximize total surplus or minimize the total dispatch cost
- Co-optimization calculates energy and R30 schedules simultaneously (not via sequential clearing), selecting the lowest cost assets to meet energy and R30 needs
- The SCED will dispatch assets for energy and R30 in a way that minimizes offer-based dispatch costs while respecting constraints
  - When there is no tradeoff between serving energy needs and meeting R30 needs, the R30DC does not impact the LMP
- If the SCED cannot meet both energy and R30 requirements, it runs short of the R30 requirement to continue to serve load in the current interval
  - This tradeoff is reflected in the LMP because the cost of serving energy includes an implicit cost of running short of R30
- When R30 is not scarce, the co-optimization process will result in an R30 price that is the intersection of the R30DC and the R30 offer curve plus lost opportunity cost, if applicable

- The lost opportunity cost, its interaction with strategic offers and the exercise of market power is further explained in the DFS4 pre-read[7]
- During R30 scarcity, when there is no intersection between the R30DC and supply of R30 in the market, the R30 price is set at the R30 price for the cleared volumes on the demand curve

- The market clearing solutions will consider the effect of line losses
  - The real-time cost of marginal losses at a location is used by SCED in dispatch solutions
- The pricing impact of losses is reflected in the losses component of LMP
- SCED evaluates differentiated price offers alongside individual congestion and losses costs to arrive at the lowest cost dispatch solution
  - During outflow congestion, when upstream generators have equally priced offers, assets are curtailed in a manner that considers differences between their constraint effective factors and losses
    - This implies that assets that are more effective in mitigating a constraint, based on constraint effective factors, will be curtailed before assets that are less effective, all else being equal
    - This will result in a lower curtailed volume
- SCED compares the total cost of assets when deciding which ones to dispatch, including the cost of congestion and losses
  - When considering all three components of costs—offered-in cost, congestion, and losses—SCED may treat generators differently than what offers alone would suggest
  - In other words, economic merit also considers congestion and losses
  - SCED may view an asset that has offered at the floor and reduces system losses as being very efficient to dispatch, as if its relative cost was below the price floor for the purpose of dispatch
    - However, LMPs always fall between the price floor and price cap
- When the reference bus price is zero, system-wide supply surplus occurs and all LMPs are $0/MWh
  - When this occurs, the market clearing process will first initiate curtailment of import interchange transactions similar to today
    - If more curtailment is required, assets will be dispatched down in a pro-rata manner determined by the ISO, respecting operating constraints such as minimum stable generation

[7] REM DFS4 Pre-read Strategic Offers

- The Supply Surplus rule will require updates given the changes to congestion management leading up to surplus conditions and the nature of dispatch with the new market clearing process[8]

Rationale

- Market clearing constraints ensure reliable system operation
- Including line losses in dispatch and pricing improves efficiency and provides better locational price signals
- A single-interval market clearing process supports reasonable implementation
- The R30DC impacts LMP when energy and R30 tradeoffs occur
  - This design approach is preferred as the tradeoffs indicate changes in the energy supply directly impact the supply of R30, and having the energy price reflect the R30 price can incent energy market assets to provide R30

2.4.3 Real-Time Market Prices

Description

- LMP is calculated at every pricing node on the system and represents the cost to deliver power to that location
  - LMP is comprised of three components:
    - Reference Bus Price – reflecting the cost of last the increment of energy delivered to the load-weighted average of all load nodes[9]
      - This value is the same for all LMPs as the specific congestion and losses components will adjust this value to calculate LMPs
    - Congestion component – reflecting the cost of binding constraints associated with a specific pricing node and power flows
    - Losses component – reflecting the marginal cost of losses at a specific pricing node
      - Pricing nodes represent where source or sink assets connect to the transmission system
- The Alberta Load Price (ALP) will be the load-weighted average of LMPs at pricing nodes, excluding nodes for sink assets that have opted into LMP
- The R30 price is a single, Alberta-wide price
- We will continue to report on market prices to improve transparency and the competitive function of the market:
  - LMP: Published for each node and interval, including its components: reference bus price, congestion component and losses component

[8] The Supply Surplus process as a design feature is mostly unchanged, as indicated in the System and Reliability Operations section below.
[9] The Reference Bus chosen for the REM is a distributed load bus, based on the load-weighted average of all load nodes.

  - ALP: published for each interval
  - R30 clearing price: published for each interval

Rationale

- LMP is a more efficient price signal than a uniform energy price
  - It enables price to vary across locations, signaling the value of energy under different conditions
  - A locational price signal is more important in a system with optimal transmission planning (OTP) and potentially increased congestion
  - LMP provides a locational signal that differentiates investment locations by signalling where energy is most valuable, supporting optimal use of the transmission system
- Non-controllable loads have the option to consume energy at the ALP, or opt into LMP[10]
  - The ability to opt-into LMP provides loads with an incentive to site and consume in response to the locational value of energy
  - This supports the best use of the transmission system by reducing costs for those customers and by reducing congestion for generators in those locations
- A global R30 price aligns with system-wide ramping needs and is consistent with OR pricing, which is indexed to the reference bus price

2.4.4 Reference Levels

Description

- We will create reference level costs for all standard technology types registered as pool assets within Alberta
- These costs will be entered into the market IT system using the associated reference unit which matches most closely with the asset
  - The majority of asset types will have reference level costs based on variable costs
    - Energy storage and hydro assets will have reference level costs based on opportunity costs
  - Reference level costs will apply to local market power mitigation for all pool assets except for energy storage and hydro, where the reference level determined will apply to both local and broad market power mitigation
- Participants may submit alternative cost information if the reference cost does not accurately reflect their asset
  - If accepted by the AESO, this information will be used instead of AESO determined reference level costs for the purposes of local market power mitigation testing and replacement offers

Rationale

[10] More detail on this choice for non-controllable loads is provided in the Participant Registration section above.

- Reference level costs ensure all assets have values that reflect their technology type to be used by the local market power mitigation process
- Allowing participants to submit alternative cost information allows for the more accurate reflection of an asset's characteristics

2.4.5 Local Market Power Mitigation

Description

- AESO assessment of local constrained areas:
  - We will determine local constrained areas where local generation is needed to meet reliability criteria
  - We will identify assets that are located within these areas
- Conduct Test: when assets within local constrained areas have a positive congestion component to their LMP, they will be subject to the conduct test:
  - If a hydro or energy storage asset has an offer greater than their reference level cost the conduct test will be considered failed
  - If an asset of any other technology type has an offer greater than four times their reference level cost the conduct test will be considered failed
- Impact Test: If the conduct test has been failed, the asset will undergo the impact test:
  - The impact test first simulates a LMP by using the mitigated offers for all assets that had failed the conduct test
    - This simulated LMP is then compared to an LMP where the offers remain unmitigated
  - If the unmitigated LMP is higher than the mitigated LMP, the offer is replaced with a mitigated offer
  - The mitigated offer is equal to four times the assets reference level cost or for hydro and energy storage assets the reference level cost
    - An assets reference level cost is determined by either our specified reference level, or by participant submissions
- Treatment of different technology types
  - Local market power mitigation will be applied to all technology types
- Mitigated offers are based upon a multiple of variable costs for the majority of technology types
  - Mitigated offers are based upon opportunity cost for energy storage and hydro

Rationale

- Applying mitigation to only assets in a local constrained area with a positive congestion component prevents inadvertent application of local market power mitigation
- The replacement offer level for failure of the conduct and impact test was chosen as it still maintains recovery of costs while promoting investment signals in these areas

- Using opportunity cost for hydro and energy storage resources better reflects the true value of their energy, which is not possible using a formula based on strictly variable cost

2.5 Broad Market Power Mitigation

Description

- Broad market power mitigation applies to thermal, hydro and energy storage assets, and resources owned by market participants with more than five per cent Market Share Offer Control (MSOC) as determined by the Market Surveillance Administrator (MSA)
- Mitigation Period: An annual period beginning April 1 and ending March 31
  - The cumulative revenue of the reference unit starts on April 1
    - If this value exceeds 2x annualized unavoidable costs, then the secondary offer cap comes into effect
  - Once in effect, the secondary offer cap remains in effect until March 31
- At the end of the mitigation period, the cumulative revenue calculation resets, regardless of whether the cap was triggered
- When in effect, the secondary offer cap is:
  - for thermal assets, the greater of $400/MWh or 25x the gas price referenced in the ICE NGX AB-NIT Day Ahead Index
  - for hydro and energy storage assets, based on opportunity costs
- In the case of hybrid assets, portions of the asset must follow the secondary offer cap as applicable to the underlying resource
- The value used for the secondary offer cap is determined daily
- The reference generating unit parameters determine when the secondary offer cap comes into effect:
  - The reference generating unit is a natural gas fired technology
  - The AESO determines the parameters of the reference generating unit used to calculate Annualized Unavoidable Costs and determine the cumulative revenue, informed by an initial cost of new entry (CONE) study

Rationale

- Applying the secondary offer cap only to thermal, hydro and energy storage assets of large firms ensures a targeted approach to broad market power mitigation
- An annual mitigation application period provides certainty and predictability
- Other alternatives with shorter durations or rolling periods provided either less certainty, more administrative burden or increased the risk of over-mitigation, and were not aligned with the purpose of broad market power mitigation

- A secondary offer cap level of $400/MWh was chosen for thermal assets as AESO analysis determined this value best addresses affordability concerns while still promoting investability allowing cost recovery over the duration of an asset's lifecycle
  - The 25x gas multiple allows for the continued use of the secondary offer cap in extreme high gas price situations
  - Based upon AESO and E3 analysis, the secondary offer cap comes into effect during simulated tight supply conditions, such as extreme weather years
- A secondary offer cap level based on opportunity costs was chosen for hydro and energy storage assets as these assets have unique characteristics (i.e., energy limited) and a $400 SOC is not an appropriate mitigation level
- We will develop a methodology to calculate the opportunity costs of Energy Storage and Hydro assets to set their secondary offer cap
  - Details of the methodology will be provided in an information document and as part of the reference level costs for those technology types
- The reference generating unit is based on a natural gas fired technology informed by the initial cost of new entry (CONE) study, which assesses project economics, historic builds and potential projects embedded in the AESO's project list
- We will finalize the parameters of the reference generating unit closer to the beginning of the REM to align with updated information
  - These parameters are used to calculate Annualized Unavoidable Costs and determine the cumulative revenue
    - This includes a CONE study specific to Alberta to best determine these values
    - The parameters previously presented by the AESO will largely change as the result of this study
- The technology type and parameters of the reference generating unit will be reviewed every five years to ensure they reflect Alberta's investment environment
- We will continuously assess the impacts of market power to determine if any components of the broad market power framework should be adjusted

2.6 Post-Clearing

This section covers the following design elements:

- Dispatches
- Delivery requirements for energy
- Consumption requirements for bids

There are no identified design features within this component section that will remain largely unchanged from a design perspective.

2.6.1 Dispatches

Description

- Dispatches will be issued every 5 minutes, aligning with 5-minute price intervals

Rationale

- The dispatch interval aligns with the market clearing process, which runs every 5 minutes
  - Under normal operation, the market clearing process will run for each 5-minute interval, dispatch instructions will be sent every 5 minutes, and pricing will be created for each 5-minute interval
- A 5-minute dispatch interval is standard in other markets that use SCED

2.6.2 Delivery Requirements for Energy

Description

- The allowable dispatch variance (ADV) will be modified to a percentage variance based on the MC:
  - 5 per cent of MC, to a maximum of 10 MW
- Pool assets must comply with dispatches within the ADV requirements at any point in time
  - The variance is a percentage from the linear interpolation between dispatch levels, for each 5-minute interval
  - For non-controllable resources, the variance is measured from potential real-power capability, when potential real-power capability is less than dispatch
  - R30 will only be dispatched to provide energy through the energy market and thus will not have a separate ADV

Rationale

- Changes to the market clearing process and shortening of the dispatch interval to 5 minutes requires updates to the ADV rule
- The new ADV requirements ensure it is no less rigid than current limits
- This approach to ADV balances AESO reliability goals with market participant compliance concerns
  - The treatment of operational deviation and modification of exceptions to non-compliance, will be updated to facilitate the design

2.6.3 Consumption Requirements for Bids

Description

- Sink assets that submit bids, must consume electricity in such a way to be available for dispatch within ADV obligations

Rationale

- Sink assets qualified to bid have a "may offer" obligation to participate in the energy market
- Once a bid is submitted, the asset must comply with the associated dispatch, including consuming electricity at the appropriate level to respond effectively

2.7 Settlement

This section covers the following design elements:

- Day-ahead OR settlement
- Real-time energy settlement
- Real-time R30 settlement
- Settlement interval transition
- R30 cost allocation
- RUC cost allocation

Features that will remain largely unchanged:

- ISO fees
- Financial security requirements
- Net settlement Instructions

2.7.1 Day-Ahead OR Settlement

Description

- Settlement and compliance will remain largely unchanged
- Settlement will be based on cleared index to the reference bus price
- The OR penalty framework, which includes liquidated damages and clawback of payment for OR non performance, will remain largely unchanged
- Non-compliance with ISO rules will be referred to MSA

Rationale

- Indexing OR to the reference bus price:
  - Facilitates co-clearing, resulting in the lowest procurement cost
    - Providers submit offers indexed to the same reference price, keeping all offers comparable rather than indexing to local prices
  - Ensures consistent reporting of cleared OR prices over time by avoiding price discrepancies for participants providing the same product in different locations

2.7.2 Real-Time Energy Settlement

Description

- Source assets and controllable sink assets will be subject to LMP
- As further explained in the participant registration section, non-controllable sink assets may be subject to either to ALP or LMP based on choices made by the participant at registration; some exceptions may apply

Rationale

- The settlement systems will require the flexibility to apply different energy pricing options:
  - ALP for non-controllable sink assets
  - LMP for source assets
  - LMP for controllable sink assets
  - Potentially LMP for non-controllable sink assets

2.7.3 Real-Time R30 Settlement

Description

- R30 will settle in each 5-minute interval
- Participants will be paid the R30 price multiplied by their cleared R30 volume
- The cleared R30 volume and price will be determined through co-optimization of energy and R30 which would incorporate energy/R30 offers and the R30DC
- Participants will be paid the R30 price multiplied by their cleared R30 volume
  - Payments will only apply to headroom delivered
    - R30 revenue will be clawed back if headroom is not provided
  - Headroom is defined as available capability minus energy provided during the settlement interval with a limit that ensures headroom can provide energy in 30 minutes

Rationale

- We addressed stakeholder concerns about co-optimizing energy and R30 and its impact on strategic offering and opportunity cost representation in a document on how strategic offering works with co-optimization [11]
  - Alternative approaches were not appropriate because they unnecessarily increased the risk for the excessive exercise of market power to inflate the cost of R30 or energy

[11] REM DFS4 Pre-read Strategic Offers.

2.7.4 Settlement Interval Transition

Description

- The settlement interval will be 5 minutes to align with the dispatch interval
- Current metering infrastructure misaligns the metering interval, frequency of meter reading (e.g., 15 minutes, 1 hour), with the settlement interval
- Transmission-connected generators and loads, and the interties will align their settlement and metering interval to 5 minutes by 2032
- All market participants must align their settlement and metering interval to 5 minutes by 2040
- Until then, metering intervals collected less frequently (e.g., 15 minutes or 1 hour) will be transformed and any settlement residuals will be allocated to all loads

Rationale

- A 5-minute settlement interval aligns energy market transactions with real-time dispatch intervals, incentivizing flexible responses from generators and loads
- During the settlement transition the metering interval may vary among participants
  - Keeping dispatch and settlement intervals consistent and allowing the metering interval to be specific, based on technological capability, ensures the settlement language reflects the intended future state of the market
- The need for a settlement residual or true-up mechanism to account for differences that are created because of different settlement and metering intervals was discussed during Sprint Session 2
- Further implementation details on transforming metering intervals will be developed in consultation with other agencies and with industry[12]

2.7.5 R30 Cost Allocation

Description

- The total cost of R30 in the interval will be allocated to loads, solar and wind resources based on cost causation
- Cost allocation methodology will use the same inputs that are used to set procurement volumes, namely the ramping forecast and produce a different cost allocation in each interval
- Costs will be shared based on each group's relative contribution to the ramping requirement
  - Wind and solar assets: Allocated costs based on individual ramping forecasts
  - Load sink assets: Allocated costs based on metered volumes during the interval

[12] As indicated in the December 10, 2024, Direction Letter, "The AESO will collaborate in an Alberta Utilities Commission-led initiative to implement 5-minute settlement for transmission-connected loads, generators and interties by 2032 and for all loads by 2040."

Rationale

- Using the individual ramping forecasts of wind and solar source assets to apportion R30 costs is appropriate given that these forecasts are then aggregated and added to the system-wide load ramping forecast in the determination of R30 volumes
  - The R30 amount procured in the interval is a direct reflection of the anticipated ramping requirements and costs
- Metered volumes for sink assets are used because individual ramping forecasts for these assets are not available
- A concern was raised that the cost allocation approach did not consider the asset-specific attributes and behaviours of energy storage and hybrid assets
  - Standalone energy storage assets:
    - When adding energy onto the system, they are seen as controllable source assets that does not contribute to system ramping and are not allocated R30 costs on the source side
    - When consuming energy on the system they are seen as sink assets and are allocated costs based on the metered volume they consume in the interval
  - Hybrid assets:
    - Co-located energy storage firming renewable output does not contribute to system ramping as a sink asset and will not be allocated costs as a sink asset
    - When they consume energy from the grid, co-located energy storage is seen as a sink asset and will be allocated costs based on their metered volume in the interval
    - Hybrid sites that behave as a renewable source asset contributing to system ramp will be allocated costs based on ramping forecast
  - We are exploring enhancements to both internally generated and externally provided forecasts
  - Because load is not forecast at an asset level, sink assets will be allocated cost based on their metered volumes
    - An exemption process could be introduced for sink assets if they can demonstrate they do not contribute to the system need for R30

2.7.6 RUC Cost Allocation

Description

- 100 per cent of RUC costs will be allocated to loads with metered volumes during the interval(s) when the RUC was in place
- Cost recovery will occur through an ISO fee

Rationale

- As only LLT assets that accept a cost guarantee will need to be paid for it, it is appropriate to determine the cost allocation for RUC costs incurred

- RUC costs are minimal and the primary purpose is to serve load during periods of foreseeable supply adequacy concerns, making load customers the appropriate group for cost recovery

2.8 State of Supply

Features within this component section will remain largely unchanged from a design perspective, but are still listed here as there are changes to the associated rules as an indirect result of the REM design:

- Long-term adequacy of supply
- Short-term adequacy and supply shortfall
- Supply surplus[13]

[13] There is some additional detail about how the supply surplus design feature interacts with the Dispatch and Pricing Algorithm - SCED section above.

Appendix 1: Reference Materials

- July 15, 2025, Direction Letter from Minister
- December 10, 2024, Direction Letter from Minister
- July 3, 2024, Direction Letter from Minister (Posted: July 11, 2024)
- March 11, 2024, Direction Letter from Minister
- AESO REM Recommendation Report (Posted: March 11, 2024)

Appendix 2: Detailed Stakeholder Engagement Activities and Materials

2025 Activities & Materials

July 29, 2025 | Part B: REM Modelling Workshop presentation and recording

July 15, 2025 | Minister Direction Letter posted

July 8, 2025 | Corrected R30 Expected Ramp Volume 2024-2025

July 4, 2025 | REM Design Finalization Session Week 4 Summary

June 27, 2025 | Stakeholder Update

June 26, 2025 | Materials posted:

- Explanation of forecast data in the expected R30 volume calculation
- Forecast data for R30 expected ramp calculation

June 17 - 20, 2025 | REM Design Finalization Session Week 4 Presentation

June 12, 2025 | REM DFS4 pre-read materials:

- Strategic Offers
- Brattle FTR Memo

June 11, 2025 | REM Design Finalization Session Week 4 Agenda

June 9, 2025 | Consolidated Stakeholder Feedback on REM High-Level Design Update

June 6, 2025 | E3 Revised REM Design Scenarios *(including workshop materials)*

June 3, 2025 | Part A: REM Modelling Workshop

June 2, 2025 | Materials posted:

- Updated E3 Revised REM Design Scenarios
- E3 Data File and Instructions

May 30, 2025 | Discussion Board for REM Modelling Workshop closes and Eligibility Determination for Funding for Participation in REM Engagements

May 29, 2025 | Stakeholder Information Session Presentation and Recording

May 26, 2025 | Application Deadline - Funding for Participation in REM Engagements

May 22, 2025 | Materials posted:

- REM High-Level Design Update
- REM High-Level Design Update - Stakeholder Feedback form

- ORDC Workbook and Instructions
- E3 Revised REM Design Scenarios

April 30, 2025 | Stakeholder Update

April 23, 2025 | REM Design Finalization Week 3 Summary

April 10, 2025 | REM Design Finalization Week 3 Agenda and Presentation

April 4, 2025 | Stakeholder Update

March 24, 2025 | REM Design Finalization Week 1 | Consolidated Written Feedback

March 18, 2025 | REM Design Finalization Week 2 Presentation

March 14, 2025 | Materials posted:

- REM Design Finalization Week 2 Updated Agenda
- REM Design Finalization Week 2 Pre-reads
  - Generation Participation
  - Load Participation
  - Storage Participation
  - E3 Assessment of Market Outcomes & Efficiency of the Proposed REM Design
  - E3 Assessment Data File

March 7, 2025 | Materials posted:

- REM Design Finalization Week 1 Summary
- REM Design Finalization Week 1 Written Feedback Form

March 5, 2025 | Materials posted:

- REM Design Finalization Week 2 Agenda
- REM Technical Design 2025 Engagement Schedule

February 28, 2025 | Updated REM Design Finalization Week 1 Presentation

February 19, 2025 | REM Design Finalization Week 1 Agenda

February 11, 2025 | Issue Prioritization Session

January 29, 2025 | Materials posted:

- Save the Dates - REM Design Finalization Sessions
  - Week 1 | February 24 - 28
  - Week 2 | March 17 - 21
  - Week 3 | April 7 - 11

- Week 4 | April 21 - 25

January 22, 2025 | REM High-Level Design Consolidated Stakeholder Feedback posted

January 8, 2025 | AESO CAM Overview for CANRea

2024 Activities & Materials

December 16, 2024 | Updated E3 REM Preliminary Report

December 13, 2024 | Stakeholder Update and materials posted:

- REM High-Level Design and associated Stakeholder Feedback Form
- Updated E3 Restructured Energy Market Preliminary Report and AESO REM Modelling Results and Instructions

December 12, 2024 | Stakeholder Information Session Presentation and Recording

December 11, 2024 | Design Sprint 6 Summary

December 10, 2024 | Minister Direction Letter

November 26, 2024 | Materials posted:

- Sprint 6 Presentation
- Updated Sprint 6 Agenda
- Revised 2024 REM Engagement Schedule

November 22, 2024 | AESO Quantitative Review and E3 REM Preliminary Report

November 20, 2024 | Reserve Offer Cap Calculations

November 18, 2024 | Materials posted:

- Sprint 6 Agenda
- Sprints 4 & 5 Summary
- Sprint 5 Stakeholder Presentation Day

November 15, 2024 | Materials posted:

- Data:
  - Smooth Scarcity Pricing Curve
  - 24-Hour Forecast and Actual Wind, Solar and Load
- 2018 Capacity Market Consultation Documents:
  - Capacity Markets CMD Consolidated Final Proposal
  - Section 206.3 Uniform Capacity Value Determination
  - Capacity Markets CMD Consolidated Rational

– Capacity Markets Presentation on Demand Response Participation

November 7, 2024 | Sprint 5 Presentation

November 1, 2024 | Sprint 4 Presentation

October 30, 2024 | Sprint 5 Agenda

October 28, 2025 Information Session | Presentation and Recording

October 25, 2024 | Stakeholder Update and Revised REM Engagement Schedule

October 22, 2025 | Cooptimization Tool Demo Recording

October 17, 2024 | Co-optimization Tool and Instructions

October 16, 2024 | Materials posted:

- Sprint 4 Agenda
- Sprint 3 Summary

October 4, 2024 | Sprint 3 Presentation

October 3, 2024 | Revised Sprint 3 Agenda

September 27, 2024 | Sprints 1 & 2 Summary

September 20, 2024 | Sprint 2 Presentation

September 17, 2024 | Revised Sprint 2 Agenda

September 13, 2024 | Sprint 1 Presentation

September 6, 2024 | Feedback due on four workstream options papers

August 28, 2024 | Question Board comments due

August 16, 2024 | Materials posted:

- Shorter Settlement stakeholder feedback
- Intertie Participation stakeholder feedback
- Agendas for REM Design Sprints 1 & 2
- Comparison REM Starting Points with Current Marker Overview Chart
- Brattle - Value of Lost Load
- Co-optimization Information Document
- Initial Revenue Sufficiency Analysis
- Workstream Options Papers:
  - Market Clearing
  - Pricing and Reserve Market

- Market Power Mitigation
- Day-Ahead Market

August 9, 2024

- Feedback due Shorter Settlement
- Feedback due Intertie Participation

August 6, 2024 | Intent to Register for fall engagement

July 24, 2024 | Agreement to Participate in fall engagement sessions

July 19, 2024 | Stakeholder Update

July 18, 2024 | Materials posted:

- Stakeholder Information Session Recording
- Engagement Timeline
- Shorter Settlement page
- Intertie Participation Options page

July 11, 2024

- Stakeholder Update
- Minister Direction Letter posted
- Comments Due: REM Shorter Settlement Cost Estimates

May 22, 2024 |

- Stakeholder Update
- CEO Meeting: Pricing and Mitigation Options and ORDC Technical Primer

May 17, 2024 | REM Shorter Settlement Cost Settlement Comment Matrix

May 9, 2024 | REM Stakeholder Survey Responses

May 1, 2024 | AESO REM Recommendation & Design Elements Comments Due

April 23 - May 1, 2024 | REM Recommendation & Design Elements Survey Period

April 22 - 23, 2024 | EWG Session

Appendix 3: Stakeholder Engagement & Progression Summary

The following provides an overview of the discussions with stakeholders and iterations on various design elements over the course of the REM engagement. The document is intended to summarize, at a high level, stakeholder perspectives shared through the REM Sprints and Design Finalization Sessions (DFS), and how this feedback impacted the design's evolutions.

General Topics

Throughout the consultation we requested feedback on specific areas of the REM design. Participants also provided feedback on more general overarching aspects of the REM, including objectives and investability. This section provides a high-level overview of key themes in the feedback on these general topics.

Feedback on REM Objectives

Affordability

As an outcome of the REM, we committed to pursuing efficient market outcomes that would minimize the delivered cost of energy. Affordability was a continuous theme throughout the consultation. Main themes included:

- Participants questioned whether the REM design met the affordability objective, given that costs were projected to increase from today
  - Explored the balance between minimizing costs to consumers while maintaining strong investment signals to ensure reliability throughout all topics in the consultation
- Stakeholders acknowledged they had differing definitions of affordability
  - They requested clearer definitions of affordability and discussed over the course of the engagement
- Given the ties between efficient market outcomes and lower total delivered costs to consumers, participants requested simplifying the design and especially administrative requirements, to add investor certainty and decrease overall long-term costs
  - They also requested cost-benefit analysis, sensitivity scenarios and other analysis as the to support various design elements

Reliability

Ensuring that the right resources are available to meet reliability needs while maintaining the balance of supply and demand was a primary objective of the REM. Participants were largely aligned on the need to ensure reliability but had concerns with over procurement. Main themes included:

- Largely supported targeted reliability products, which could strengthen supply adequacy if used only when appropriate through reasonable trigger thresholds and procurement volumes

- The balance between lowering the overall costs to consumers and delivering on reliability requirements were often explored to ensure that the balance was met
- Requested greater forecasting tools for loads and generators, alongside transparent data sharing, as it would allow participants to plan and hedge effectively and to react to reliability needs

Decarbonization by 2050

A primary objective was to ensure that the design supported the transformation to a low-carbon future and the increasing need for flexible resources. While participants broadly supported this objective, many challenged where and how it was embedded in the design. Main themes included:

- From the earliest Sprints, participants agreed on decarbonization as a core objective, but struggled to see its links in the design as clearly as other objectives
- While many supported technology-neutral rules across the design, others argued that the unique characteristics of renewables, storage and hybrids should be explicitly accommodated to encourage investments in these technologies

Reasonable Implementation

The reasonable implementation objective was intended to ensure the transition to a new market design was as simple and timely as possible, subject to meeting the other objectives. Stakeholders urged for the overall simplification of the design to help in this ambition. Main themes included:

- Many flagging the initial design as overly complex, with multiple new products, layered mitigations and significant rule changes
  - Asked for simplifications to the design to reduce scope and improve implementation
- In some cases, participants recommended a phased implementation or push back the implementation deadline
  - This derived from concerns that other jurisdictions implemented similar large-scale transformations over longer periods of time and that the phasing of the design could allow additional time for implementation
- Generally, they stressed that the final design decisions should consider the readiness of different operational processes, software and physical infrastructure (such as metering)

Feedback on Investability

During the REM engagement, some stakeholders requested that investability should be a stand alone objective, consistent with perspectives raised during the prior Executive Working Group (EWG) Engagement. We viewed that the key themes around investability as a standalone objective were included within the other four REM objectives and did not create a separate investability objective. Investability was included as a topic of discussion over the course of the engagement sessions across multiple topics. Main themes included:

- Participants consistently linked investability with clear, durable market signals, particularly price signals, that reflect actual system needs and are not distorted by overlapping mitigation measures
  - Warned that over-mitigation could suppress revenues to a level that undermines long-term investment
- Participants emphasized that investors need confidence in how the market will operate over time, with transparent forecasting, a clear congestion management framework and clarity on design parameters
  - Uncertainty was identified early as a barrier to investment
- Many noted that investability is shaped not only by the market design changes but also by policy direction (e.g., transmission planning, net-zero targets)
  - They stressed the need for coordination so that REM design choices complement evolving policy, avoiding sudden changes that disrupt planning
- Stakeholders maintained that complex or highly bespoke design elements were seen as adding investment risk and were to be avoided

In addition to the four REM objectives, stakeholders also suggested other goals and objectives we should consider, which included maintaining a fair, efficient and openly competitive (FEOC) market, market simplicity, and maintaining strong investment signals.

Day-Ahead Market

Starting Point

We introduced the day-ahead market (DAM) as a forward market designed to ensure resource availability in the real-time and therefore ensure greater certainty and price stability.

We considered two options, both required mandatory participation for supply resources:

- A two-sided Financial DAM: financially binding market that would clear based on the bids and offers from load and supply resources, with demand-side participants opting-in by submitting bids for energy
- A two-sided Physical DAM: physically-binding and required supply resources to provide energy they sold day-ahead in real-time
  - The market cleared based on offers from supply resources and the demand curve, which consisted of voluntary demand-side bids and forecast of demand

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2 and 3: Which DAM to Pursue

- During the initial Sprints, discussions with stakeholders were on the intent of the DAM and whether the Financial DAM or Physical DAM with firm delivery obligations was preferable

- Stakeholders preferred the financial DAM due to its flexibility and reduced risk for suppliers taking on day-ahead positions
- Load participants supported a DAM as a tool to hedge price risk but preferred an opt-in model
  - Other stakeholders believed an opt-out model would ensure greater participation
- Some stakeholders identified concerns about penalties for renewables and the exclusion of virtual participation in the DAM creating additional risk for participation that would in turn raise costs
- Generators, especially renewable generators, shared concerns about the mandatory participation for suppliers without a greater knowledge of the penalties for non-performance
- Some stakeholders proposed implementing the day-ahead commitment (DAC) product without a full DAM to reduce complexity

Sprints 4, 5 and 6: Fleshing out the Financial DAM

- The discussions in the later Sprints focused on moving forward with a fully financial day ahead market without a physical delivery obligation, but with a DAC product to ensure reliability needs would be met
- Support generally continued from demand-side participants on an opt-in model for load participation
- Stakeholders suggested we move forward with no additional penalties beyond real-time re-settlement obligations
- Further details were established related to the DAC, which ensure reliability while allowing the DAM to be a tool for price discovery and hedging
- In response to stakeholder feedback regarding day-ahead to real-time risk, we increased the DAM offer cap to equal the price cap to address price risk between day-ahead and real-time for generators
  - Load had the ability to manage risk because day-ahead price settled only based on the demand that showed up in the DAM

Design Finalization Sessions 1, 2 and 3: Removal of the DAM

- In response to stakeholder feedback regarding the complexity of the REM and the overall critical feedback on DAC costs, participation and potential complexity with congestion management, we removed the DAM and DAC from the REM
  - The day-ahead market for reserves would remain with key enhancements, including the real-time market that continued to support the objectives of reliability, affordability and short- and long-term investment signals
- Stakeholders were generally supportive of the responsiveness and the focus on design simplification
- Some requested that elements of the DAM be visited in the future as voluntary market features

Updated High-Level Design and Corresponding Feedback from DFS 4

- The updated High-Level Design included the following elements to ensure that the reliability needs would be met through the real-time energy market without the DAC and DAM:
  - The day-ahead reliability market to ensure that our reliability requirements for operating reserves would be met
  - Reliability unit commitment (RUC) process, as a backstop reliability mechanism to ensure that resources could be committed in times of scarcity
- The proposed DA reliability market would be voluntary, similar to the current operating reserve market structure
- Stakeholders were generally supportive of this proposal and requested more information on how DA OR would be priced with the change to LMP for energy
- Stakeholders identified concerns with the current level of reserve offer caps
  - We were open to reassessing offer caps for OR products, especially in the context of an added negative price floor

Reserves Market

Starting Point

We proposed changes to the reserves market as part of the REM design. This included existing operating reserves and new reserve products to ensure greater system reliability. New reserve products introduced:

- R10 and R60, ramping reserves used to meet requirements for expected ramp in real-time, which includes forecast ramping events plus additional capability for unexpected ramping events
  - R10 was designed to meet near-immediate ramping needs, whereas R60 was designed to meet ramping needs further out
- The DAC product was a signal for dispatch availability that worked in tandem with the DAM
  - The DAC was designed to meet expected net demand forecast and demand uncertainty in the DAM

Our starting point for the consultation included procurement of all reserves (DAC, OR and R10/R60) in the DAM through co-optimization with energy. The subsequent real-time market would co-optimize OR, ramp products and energy. Scarcity pricing would also be applied to the DAM and real-time market (discussed separately below).

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2 and 3: Introduction of New Reserve Products

- Initial Sprints served to explore and introduce the new products (R10/R60 and DAC), including discussions on their volumes, eligibility, must-offer requirements and offer caps

- Stakeholders agreed that the new products could help improve reliability, but shared some concerns on the design starting point, including:
  - The risk of day-ahead over-procurement which could distort energy price signals, resulting in increased costs
  - Low offer caps for the various products, which stakeholders deemed to be too low to reflect opportunity costs and would undermine strategic bidding
  - Whether participation in all products needed to be mandatory, there could be voluntary participation in the reserves, or additional flexibility for some participants (such as load and cogeneration)
- Participants shared concerns about DAC that the product may lead to higher overall costs and whether it was strictly necessary
- Stakeholders had some concerns with penalties for non-delivery of reserves, given the "buy-back" between the day-ahead and real-time market

Sprints 4, 5 and 6: Details of the Reserve Market

- In response to stakeholder requests for simplicity in the market and concerns with the value of separate ramp products with DAC, the ramping products (R10 and R60) were moved into the real-time, with DAC providers expected to meet the anticipated need for ramping through the day-ahead procurement
- We spent significant time with participants discussing the details of the reserves design, including between mandatory and voluntary participation by asset types
  - Many generators called for symmetry in load and generation treatment in the market, while storage and renewables participants wanted eligibility rules adjusted to reflect their technical capabilities
- In response to stakeholder feedback, we proposed a qualification process for assets to supply reserves to address concerns regarding mandatory participation in reserves
  - A qualified asset would be required to participate, but participants could voluntarily choose to not qualify
- There was general support for increasing the offer caps to reflect opportunity costs and adequately recover costs
  - While some participants had concerns about the lack of market power mitigation in the reserves market, others had concerns about the potential for over-mitigation from the combination of the must-offer requirements, the offer caps and scarcity pricing curve
  - We provided additional information to support the calculation of the offer caps for the reserve products, noting that the scarcity pricing signal would provide the appropriate price signals to reflect tightness
- While there was general alignment on the purpose of DAC to ensure reliability, there were growing concerns on the cost allocation and recovery by load and renewables
  - In response to stakeholder feedback we adjusted DAC parameters, such as decreasing the price cap to $600 from the previous $1000, refining participation requirements for different

types of resources, providing more flexible DAC offer structures and providing additional information on the qualified DAC volumes relative to demand

- DAC participation was a key topic of discussion
  - Renewables participants wanted to participate in the DAC given that renewable generation was considered in determining the DAC's volumes
  - We asserted that the DAC being an AS meant that the asset had to meet specific technical requirements like the ability to be available when called on, which renewables may not be able to meet

Design Finalization Sessions 1, 2 and 3: Removal of the DAC

- Given the requests for further discussion on DAC and AS products, further information was shared on DAC participation, DAC offers and price setting, settlement and volumes
- Further discussion on cost allocation for DAC, R10 and R60
- Participants had concerns with the fairness of cost allocation between loads and renewables
  - Concerns about limiting participation in DAC to only controllable assets and excluding the anticipated contributions from renewables, like wind and solar
- Overall asks from participants for a simplification of the reserves market design
  - Participants had concerns that the inclusion of the new products and co-optimization in the DAM was more complicated than warranted by the perceived efficiency gain

Updated High-Level Design and Corresponding Feedback from DFS 4

- Following the removal of DAM and DAC from the REM design, the DAM would only apply to operating reserves
  - This leverages the current structure for the operating reserves market with some key enhancements, which were raised during previous consultations
- Participants were generally favourable to this change, for several reasons:
  - Indexed pricing for operating reserves, rather than co-optimization, was seen as more compatible with strategic offers in the energy market
    - Indexed pricing would also remove the need for a two-settlement system between day-ahead and real-time clearing
  - Voluntary participation in reserves would allow for greater participant flexibility to manage on-site operations
  - The simplicity of the current day-ahead reserves market structure in combination with the real-time energy market reduced the overall scope and complexity of the REM changes
- In response to stakeholder feedback regarding complexity of the market for a ramp product we replaced the two ramping product design (R10 and R60) with a single ramping product design (R30)
  - This change reflected a move towards greater simplicity for offers and price setting for ramp, while continuing to meet the reliability needs of the system

- Similar concerns remained on the R30 as were shared with the R10 and R60, notably concerns on the risk of over procurement, the impacts of co-optimization with strategic bidding for energy and cost recovery of offline units eligible to provide R30

Intraday / Reliability Unit Commitment

Starting Point

Intraday unit commitment (IUC) was introduced as part of the AESO's December High Level Design document. It was further discussed during Design Finalization Session (DFS) 2.

IUC provides an additional mechanism, working with the DAM and DAC products, to ensure reliability in moments of scarcity that emerge between the day-ahead and real-time markets. These commitments would provide an emergency backstop under exceptional reliability needs.

The starting point for the intraday process built on the current Interim Supply Cushion Directives, with updates to the financial compensation available under the cost-guarantee and updated supply cushion trigger. Under the directive the IUC would maintain the lack of price reconstitution for commitment directives.

IUC was intended as complimentary to the primary commitment mechanism of DAC and self-commitment. It was not intended to duplicate or replace DAC.

Feedback Received Throughout the Sprints and DFS

Written Feedback, Design Finalization Sessions 2 and 3: Exploring the IUC

- Stakeholders and the AESO agreed the mechanism should be considered only as a last-resort reliability mechanism and that the supply cushion trigger should be set such that the commitment directives are not routinely used
  - Stakeholders had concerns that the product would be frequent and result in distorted market price signals
  - They requested transparency through various analysis and reports being released whenever the IUC process issues directives
    - This would increase AESO accountability for the issued IUC directives
- Stakeholders strongly requested price reconstitution exist for any IUC directives, such that prices would properly reflect reliability events and would not be distorted by out-of-market commitment decisions
- Some stakeholders encouraged us to consider an opt-in decommitment option when short-term oversupply or a lower need for the IUC occurs
  - These comments were primarily in the context of the decommitment of DAC and how that would interact with IUC

Updated High-Level Design and Corresponding Feedback from DFS 4

- Following the decision to remove the DAC and DAM from the REM, the IUC process evolved into the RUC mechanism
  - The RUC process shared all the key features of the intraday concept that was previously discussed, as a reliability backstop in response to critical conditions
  - The primary mechanism for commitment would remain the self-commitment model in response to energy market price signals
- Feedback emphasized that frequent use of the IUC or DAC would distort price signals
  - Stakeholders called for high triggering thresholds and additional transparency
  - The RUC was intended to reflect stakeholder perspectives that the product should be treated as a reliability-use only, not a daily operational tool for commitment
- Stakeholders highlighted the need for price reconstitution to reflect commitment decisions
  - Some believed that the lack of price reconstitution would result in unfair pricing and distorted market outcomes

Real-Time Market and Market Pricing

Starting Point

The real-time market determines dispatches and prices in real-time, incorporating physical system constraints. The real-time market incorporates the other design elements, like scarcity pricing and congestion management.

As a starting point to the REM consultation, we introduced the following components:

- The real-time market clears at 5-minute intervals
- The real-time market will integrate other design elements, like the co-optimization of energy and reserves, scarcity pricing and congestion management

We put forward the following starting points for the price cap and floor:

- Price cap of $3,000/MWh
- Price floor of negative $100/MWh

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2 and 3: Core Real-Time Market Foundations

- Together we explored how the new pricing framework and new products may impact the market and how real-time prices would respond to supply scarcity
- Negative pricing received mixed support with advocates liking the flexibility incentives
  - Renewables participants broadly saw negative pricing as unfair and disproportionately impacting them

- Sprint 3 focused on how the real-time market interacts with the DAC and the other reserve products
  - Questions were raised on whether over-procuring reserves in the day-ahead market might mute real-time price signals

Sprints 4, 5 and 6: Furter Real-Time Implications and Price Formation

- Later Sprints continued to explore the impacts of the REM design on the real-time market and market clearing
  - Specific topics included how the real-time market would integrate with the potential congestion management frameworks, how these would impact price formation, and the implications of both broad and local market power mitigation on the real-time market
- Participants were concerned that pricing in the real-time market may be overly complex
  - Congestion management planned to introduce locational elements and could increase price volatility for some regions
  - The concerns were that this may impact overall market investability
- Stakeholders were generally worried about over-mitigation suppressing prices in the real-time through a combination of offer caps, scarcity curves, market power mitigation mechanisms and over-procurement of DAC transferring money from real-time to the day-ahead markets
- Demand-side participants wanted additional clarity on how they could capture value in the real-time market and eligibility of demand response to provide various products
- Offer cap values were revisited, with requests to us to ensure that opportunity costs are be fully reflected
- Stakeholders requested that the AESO set explicit convergence rules between congestion pricing and the pool price, so importers and exporters are not exposed to double price risk
- Outcome: We confirmed the real-time market would continue to use real-time security-constrained economic dispatch (SCED) with scarcity pricing and market power mitigation guardrails; over-mitigation concerns were flagged for further evaluation through the DFS
  - We reviewed the offer cap values in the context of strategic offering and real-time market opportunity costs

Design Finalization Sessions 1, 2 and 3: The Simplification of the Real-Time Market

- With the removal of the DAC and DAM, the real-time market became the primary energy market, with operating reserves, R30 and RUC to support reliability
  - With the removal, stakeholders expressed support in the simplification of the market
- They supported the continued adjustments to the price cap and floor, with renewables stakeholders continuing to challenge negative pricing
- Outcome: We confirmed that the real-time market would remain the core energy market and that it would continue to review elements for simplification, like the scarcity pricing curves and market power mitigation parameters

Updated High-Level Design and Corresponding Feedback from DFS 4

- Following the REM High-Level Design Update, discussions focused on how the real-time market would interact with the new R30 reserve product and the RUC
- Hearing stakeholders' cautions against the existing mechanisms potentially suppressing real-time prices, we confirmed the real-time market as the core energy market and further simplified price-formation elements
- Alongside changes to the congestion management framework, we introduced two load pricing options—the Alberta Load Price (ALP) and a locational marginal pricing (LMP) election
  - Some load participants wanted increased flexibility in choosing between ALP and LMP, while others worried about increased ALP volatility if too much flexibility was allowed
- We confirmed that the final REM design would maintain higher energy price caps and a negative price floor
  - All source assets and controllable sink assets would settle on their respective LMP
- The ALP is an aggregate, province-wide price calculated as the weighted-average of all load nodes that did not elect LMP
- Some participants expressed concerns that flexibility in the ability to choose between ALP and LMP would negatively impact the ALP price
  - The ALP would become unpredictable and create unhedgeable risk for ALP customers
- Some load participants supported increased flexibility to choose between ALP and LMP
- We proposed in the final DFS that loads would only be able to choose to move from the ALP to the LMP once, to limit the unpredictability that would come from moving back and forth from LMP to ALP

Congestion Management

Starting Point

Government policy indicated a shift away from Alberta's zero-congestion framework. The transition towards a market with congestion would address affordability challenges with the zero-congestion policy and would guide long-term investment in generation to locations with transmission capability. The market framework would need to adapt to reflect this shift to include congestion as part of the market clearing and dispatch process.

The *Market Clearing Options Paper* introduced the challenges of energy price setting and dispatch during congestion. We introduced three options for managing dispatch to reflect congestion:

- Reverse merit order for offers and then pro-rata curtailment: this would align with the current zero-congestion market design but would not provide incentives to efficiently manage congestion
  - Participants would disorderly bid to manage curtailment risk
- Curtail based on verified cost: use a pre-determined cost order to determine appropriate curtailment during congestion

- Constrained down market (CDM), later evolved into the congestion avoidance market (CAM): allow for market-based offers to determine the dispatch during congestion

We introduced three options for setting the energy price in a market with congestion. In the initial design, these were options for a uniform energy price:

- Constrained pricing: set the energy price based on the highest cost resource that is dispatched
- Reference Bus pricing: the price of the last MWh dispatched to serve demand at a reference bus, an actual physical location
- Unconstrained pricing: reflect the current model and would not appropriately value the cost of dispatching to manage congestion

We also discussed constrained-on and constrained down payments. The starting point for consultation was that assets behind congestion would be curtailed based on verified costs, that the price would be set at a defined location, the reference bus and that generators dispatched out of merit would receive constrained-on payments. The starting point did not include constrained down payments.

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2 and 3: Initial Congestion Approaches

- Stakeholders viewed unconstrained pricing as a simpler option but noted that it failed to send efficient siting signals
- The Reference Bus price was seen as an appropriate middle ground, with some preferring its simplicity, but others worrying that it may mask congestion costs in certain areas
- The constrained down market curtailment option was recognized for sending efficient signals
  - Stakeholders requested that the AESO explore how a market-based mechanism to manage congestion could work, including how energy storage and loads participation could manage congestion
- Other stakeholders identified that a simpler approach would be preferred, such as Last-In First-Out (LIFO) or simple pro-rata curtailment

Sprints 4, 5 and 6: Details of Congestion Management

- In response to stakeholder requests for more details on the market-based congestion mechanism, we introduced a CAM option to the discussion
- We presented the mechanics of the CAM and how the resulting prices would provide appropriate incentives to manage dispatch efficiency
- Many stakeholders viewed the CAM as complex and worried that its complexity would deter investment
- Some stakeholders argued that the CAM market would not meet the direction to have a uniform energy price and would result in outcomes similar to LMP

- Stakeholders also flagged concerns on fairness related to the CAM, depending on how congestion costs would be allocated
  - As designed, there were concerns that new entrants may face disproportionate risks and therefore be dissuaded from entering the market
- There was a stakeholder preference to explore alternatives to CAM
  - We identified that LMP was a tested alternative market-based mechanism to manage congestion
  - Stakeholders noted that an LMP model would still represent a significant departure from the current uniform price model and that little information had been shared on LMP, but LMP was preferred as a market-based congestion management option relative to the CAM
- Participants presented alternatives to the CAM for consideration by the AESO
- The interactions between the transmission planning process, the cost to connect and the real-time dispatch process were highlighted as elements that all need to work together
- Stakeholders requested additional clarity in relation to the conversation around transmission rights and to incumbent investments that were made under the current policy, as priority topics to be explored prior to the discussion on market-based dispatch efficiency
- The December High-Level Design provided further examples and clarifications on CAM and how it could apply to both the day-ahead and real-time markets to manage congestion with a market-based mechanism

Design Finalization Sessions 1, 2 and 3: Introduction of Rights and LMP

- Stakeholders viewed CAM as overly complex and bespoke, creating new risks that would be difficult or impossible for participants to manage
  - All these factors would undermine efficient investment in REM
- In the context of transmission rights, we asked whether there would be a better market-based mechanism to manage congestion; specifically, would LMP be preferred over the CAM
- Overall, the dispatch mechanism of LMP was seen as more widely understood than the CAM and result in similar outcomes
  - For these reasons, the replacement of CAM with LMP as the dispatch and price setting mechanism was seen in a favourable light
- In response to stakeholder feedback on the relationship between congestion management and system planning, we introduced the topic of transmission rights
  - The discussion was separated between transmission rights that exist over the long term and rights that could be used to manage the transition from a zero-congestion planning standard to an optimal transmission planning standard (OTP) for incumbents
- We presented a number of key questions on rights that would need to be answered and introduced a starting point for the financial transmission rights (FTR) conversation
  - incumbents could receive congestion revenue rights for a transitional period and in the long term the congestion rents would be used to offset transmission costs

- Stakeholders supported financial rights to manage the risk during the system planning shift to OTP
  - Some requested that rights be available for a longer time period or available to participants on a go forward basis
  - They discussed whether new entrants would receive rights through payment of the transmission reinforcement payment (TRP)
- Transitional rights to incumbents were requested to ensure fairness and transparency
  - Different versions of FTRs were discussed with participants
  - Many participants favoured FTRs over congestion revenue rights (CRRs) to manage congestion risk, but asked for more detail on term length, MW volume and allocation method

Updated High-Level Design and Corresponding Feedback from DFS 4

- We put forward additional details on the LMP design, including load pricing considerations
  - This included the introduction of the non-controllable sink assets having a choice between ALP and LMP
- Stakeholders were concerned about investments in the market without FTRs as a tool to manage long term congestion risk
  - We agreed that there is a close connection between overall congestion risk, market-based congestion management, transmission planning and the TRP and that close coordination of these consultations is required
- We noted concerns with FTRs frameworks in other jurisdictions and presented options that could be considered in Alberta
  - Further discussion on the congestion framework, which included incumbency treatment for the transition between the current policy to OTP and whether there was a role for FTRs in the future was further discussed in the OTP sprint sessions

Market Power Mitigation

Starting Point

Market power mitigation provides guardrails to limit the potential for excessive exercise of market power while allowing strategic offers to set prices and provide long term investment signals.

The market power mitigation starting point explored three options:

- A secondary offer cap (SOC), which would adjust bid caps for market participants with significant offer control
- An SOC that caps overall market prices under certain conditions
- Lower offer cap, which would create lower cap on offers

Local market power mitigation was introduced as a mechanism to ensure that in-flow transmission constraints that create or enhance market power do not lead to excessive costs.

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2: Exploring Initial Market Power Mitigation Options

- Initial discussions on market power mitigation questioned how to balance consumer protection without hindering strong investment signals in the context of the energy-only market
- Some stakeholders agreed that some form of consumer protection is required to prevent excessive prices, mainly in prolonged scarcity or constrained situations
- Many stakeholders agreed that the principles of market power mitigation are covered by the principles of a FEOC market
  - They argued that the market signals for entry would address high prices naturally
- A robust market power mitigation framework, rather than just relying on ex-post enforcement analysis, was preferred by many stakeholders as a way to prevent sudden, future government intervention
- There were concerns that some of the mitigation options, like the SOC, were too blunt and would dampen investment signals and undermine market confidence
- An early preference emerged for a targeted SOC as opposed to broad price caps or lower offer caps

Sprint 3: Refining the SOC

- We presented a refined SOC with potential parameters, including an evaluation period, applicability threshold, offer cap levels and reference units
- Stakeholders proposed phasing-in the SOC and reviewing it on a fixed schedule to limit policy shocks as the market evolves
- Stakeholders provided feedback on the parameters and assumptions underlying the SOC, including:
  - A preference for longer evaluation periods for stability or the potential to have a rolling evaluation period
  - Some preference towards using a peaker unit as the reference unit instead of a combined-cycle unit, as the peaker would better reflect marginal supply costs
- Participants asked for consistency in approach between local market power mitigation and market power mitigation
  - The discussion on local market power mitigation was deferred until there was further clarity on the market-based congestion management options
- Participants supported a mitigation framework that would focus on repeated and excessive uses of market power rather than single-instance events

Sprints 4, 5 and 6: The Details of the SOC

- Sprints 4 and 5 continued to explore the parameters for the SOC and its interaction with the DAC and other reserve products
- In Sprint 6, historical analysis was provided to support the selection of SOC parameters
  - Six different sets of parameters were compared over the same historical period
  - This assessment was intended to inform which mitigation parameters would best address the trade-off between consumer protection and maintaining strong investment signals
- Stakeholders voiced concerns at potentially overlapping mitigation tools: DAC penalties, scarcity pricing curves and offer caps including SOC
- Further discussed and refined the SOC parameters, with participants suggesting:
  - Larger market share thresholds (>5 per cent)
  - For the SOC level to increase, as previously proposed levels were too low or would require numerous exceptions, causing an administrative burden
  - For reference unit cost assumptions to be updated with a more recent Cost of New Entry (CONE) study
  - To consider a rolling evaluation period rather than static window
  - To move away from complex metrics and to more intuitive indicators like reserve margin or supply cushion thresholds
- There were further discussions on whether or not local market power mitigation was required, or if its triggers could be further aligned with broad mitigation

Design Finalization Sessions 1, 2 and 3: Providing more clarity

- In the removal of the DAC and DAM, we confirmed that the SOC would remain the guardrail for broad market power
- As an evolved starting point, the SOC was set at $400/MWh, triggered when a reference unit recovers twice its annual unavoidable costs over a 12-month period
- The increased SOC level was considered as there was some discussion with stakeholders that the previous level of $250/MWh would require exceptions for verifiable costs
  - Further, E3 and the AESO analysis presented during the design sprints outlined that there was little difference in annual average energy prices between the previous level of $250/MWh and $400/MWh
- There were mixed perspectives on the proposed SOC of $400, with some believing it may not be high enough, while others questioned whether $400 was too high
- We concluded that the $400/MWh provided an appropriate balance between affordability and consumer guardrails and ensuring that the mitigation levels didn’t hinder investment signals
- Broad market power mitigation would apply to firms with a market share offer control (MSOC) of 5 per cent or higher and local market power mitigation would address inflow constraints using cost-based uplifts or transmission must-run (TMR) payments

- Stakeholders supported different treatment for hydro and energy storage assets to address unique characteristics, such as negotiated compliance plans or broader exceptions from market power mitigation mechanisms

Updated High-Level Design and Corresponding Feedback from DFS 4

- Stakeholders reiterated the market power mitigation should only bind in exceptional conditions, protecting both consumer outcomes and investment signals
- Stakeholders expressed some concern that the broad market power mitigation framework may hinder strategic bidding or otherwise lead to poor price signals and urged us to consider this in its design
- Stakeholders had some mixed support for local market power mitigation, with a general preference to align or minimize separate local market power mitigation frameworks
  - Some stakeholders suggested targeted out-of-market mechanisms like TMR contracts
- Participants requested that any future SOC changes follow a clear governance and consultation path, with parameter updates filed to the Alberta Utilities Commission (AUC) to preserve regulatory certainty
- Participants continued to suggest updates to the SOC parameters, including adjustments to the SOC value to reflect gas price
  - We agreed to update the SOC parameters to reflect gas price, and to consider a CONE study closer to the beginning of REM for the reference unit used in the triggering threshold

Scarcity Pricing Curve

Starting Point

The scarcity pricing curve is a mechanism to provide a signal for scarcity in advance of running short of reserves. The scarcity pricing curve would be used to set prices between the offer cap and the price cap, to ensure that prices appropriately reflected scarcity conditions.

We put forward two options for the scarcity pricing curve in the *Reserves Market Options Paper*:

- A stepped scarcity pricing curve, wherein a fixed quantity of each reserve product would be procured with various “stepped” prices to indicate when there is insufficient supply available
- A smooth scarcity pricing curve, which procures more reserves at a lower cost when the system value of the reserves is lower and smoothly increases the price as supply becomes insufficient

Both options would be used to procure the existing and new reserves including DAC, R10 and R60. Both the day-ahead and the real-time markets would rely on scarcity pricing curves to set prices during times of insufficient supply.

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2 and 3: Initial Review of the Scarcity Pricing Frameworks

- Initial Sprints introduced the scarcity pricing curves, assessed their purpose, benefit and impact alongside the price caps, price floors
- Stakeholders were supportive of scarcity pricing to incent investment and operational flexibility, but had concerns with potential for additional volatility
- There were different perspectives between the smooth curve, which stakeholders believed offered greater predictability and a stepped curve which was simpler to understand and model
- Some stakeholders were concerned that scarcity pricing, combined with other mechanisms like the DAC and lower offer caps, would suppress real-time price signals
- Some stakeholders also raised concerns that overlapping products, like the DAC and the reserve products, may dampen the scarcity price outcomes
- Renewables participants supported strong scarcity pricing signals, but worried about exposure, while loads wanted assurance that consumer costs would remain manageable as scarcity conditions come into effect
- Stakeholders called for transparent and predictable review processes for the curves, as well as the publication of data to support the triggers and volumes

Sprints 4, 5 and 6: The Impacts of Scarcity Pricing

- Later Sprints continued to explore details of the pricing curve and how it interacts with the DAC and the reserves, as well as examples of how it would function
- We provided additional information on the underlying data that is used to calculate the scarcity pricing curves
- We also provided information on how the scarcity pricing curve would be used to make commitment decisions and set the price for DAC when dealing with a multi-hour commitment decision
- The scarcity curve was recognized as one of the potential drivers of investment; however, the energy market price was the primary investment signal
- In terms of governance, suggestions were made to update the curves infrequently for stability, but adjusted when significant market fundamentals change
- Using real event back-casts, we demonstrated how scarcity pricing would have set prices during challenging grid operations
  - Stakeholders agreed that scarcity pricing would have improved operational and investment signals

Design Finalization Sessions 1, 2 and 3: A Focus on Governance

- The governance of the scarcity pricing curves became a focus area after we removed the DAC and DAM

- The scarcity pricing curves would continue to apply to the ramping products in the real-time market
- A broad acceptance of the scarcity price signal as a reliability price signal at times of scarcity remained
- Stakeholders continued to emphasize the need for clear, transparent processes to review and adjust the scarcity curve parameters
- With DAC removed from the design, stakeholders believed the scarcity signals in the real-time energy market would be clearer
  - Discussions focused on the intersection between mitigation and scarcity pricing, with stakeholders flagging that mitigation could undermine scarcity signals

Updated High-Level Design and Corresponding Feedback from DFS 4

- We confirmed the scarcity pricing curve design would apply to the R30 market and would send scarcity prices through the real-time energy price via co-optimization
- Scarcity pricing was positioned as a balanced solution to provide investment signals while managing consumer risk

Settlement

Starting Point

As part of the REM initiative, we released options to move to a shorter settlement interval in the electricity market. The transition would better align the settlement interval and the dispatch interval and would provide more accurate information to reflect system conditions. We put forward four options for a shorter settlement interval:

- A 15-minute settlement interval for transmission and distribution connected generators and intertie transactions/hourly settlement interval for load
- A 5-minute settlement interval for transmission and distribution connected generators and intertie transactions/hourly settlement interval for load
- A 15-minute settlement interval for all generators, intertie transactions and loads
- A 5-minute settlement interval for all generators, intertie transactions and loads

We also introduced the two-settlement process to settle the day-ahead and the real-time markets for energy and reserves and introduced concepts for performance penalties in the event of non-delivery.

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2 and 3: Exploring Interval Options

- There was general alignment that the Alberta market should move towards a shorter settlement to better reflect actual operations and align Alberta with other markets

- Participants sought clarity on the long-term goal for the settlement interval, but also requested a reasonable time frame to carry out the implementation
- Initially, stakeholders held split perspectives on whether to go directly to a 5-minute settlement or first to a 15-minute settlement interval
- Regardless of the selected interval, participants wanted a clear long-term target so investment in metering and infrastructure would not have to be repeated during the life of an asset
- Some participants flagged that their organizations are already in the process of implementing meters equipped for shorter settlements and that they could align the remainder of the investment with shorter intervals
  - On the other hand, participants highlighted sunk costs for metering that is already in place and that would need to be replaced mid-life
- Loads requested flexibility in how it adopts shorter settlements to avoid unnecessary or excessive costs
- Some participants requested more information on the two-settlement process for the day-ahead and real-time markets
- We prepared additional examples on the two-settlement process, for different types of resources including generation and load that is participating in the market
- We provided additional detail on how cost allocation would work for loads that did not bid in the day-ahead market
- Participants requested additional information on the cost allocation for the new AS products, including DAC, R10 and R60

Sprints 4, 5 and 6: Continued Discussions

- We proposed a 5-minute settlement by 2040, and a 15-minute settlement by 2032, with transmission-connected load and generators as early adopters
- Some agreed that a staged approach was more realistic and allowed for cost recovery for existing metering investments
- Other challenged whether Alberta's small market scale would see the additional benefits of a 5-minute settlement as opposed to a 15-minute settlement
- We provided additional information on settlement imbalance and penalties for non-delivery of DAC, OR and ramping reserves
- Participants requested further consideration of the implications of penalties on participation in various markets and DAC clawback
- We presented options for cost allocation for the new AS products including DAC, R10 and R60
- Participants had concerns about the cost allocation of new reserve products based on different types of resources

Design Finalization Sessions 1, 2 and 3: Confirmed Direction

- The December 10, 2024, direction letter communicated that the REM design changes would include the move to a 5-minute settlement interval, with a phased approach led through an AUC initiative
- Many accepted the settlement changes as long-term modernization, separate from the REM core implementation
  - Others worried the transition as defined may result in duplicative investment costs or complications
- The cost allocation for DAC, R10 and R60 continued to be a concern for participants
- Following the removal of the DAM, DAC, the simplification of the ramp products into a single R30 product and the enhancements to the day-ahead reliability market, settlement complexity was considerably reduced
  - We proposed that the current settlement process would continue to apply in the energy market and the reserves market
- We provided additional information on the cost allocation for the single R30 product, based on the different types of resources that contribute to the need for ramp

Intertie Participation

Starting Point

With the introduction of new regional market frameworks (EDAM and Markets+) alongside the REM market design, we considered the treatment, obligations, and expectations of Alberta's energy importers and exporters. The following high-level options were introduced for discussion in the initial options paper:

- Option 1 - Status quo: intertie participants would self-schedule and be price takers for offers and bids
- Option 2 - Priced interties: intertie participants would submit priced bids and offers, scheduling would be based on economic merit
- Option 3 - Optimize intertie scheduling between jurisdictions, jurisdictions would coordinate intertie offers/bids/schedules to increase economic trade
- Option 4 - Join a Regional Market: we would join a broader western market like EDAM (CAISO) or Markets+ (SPP)

Feedback Received Throughout the Sprints and DFS

Written Feedback, Sprints 1, 2 and 3: Intertie Options are Introduced

- Initial discussions explored the various possibilities for intertie participation in the new REM products, such as the DAM and DAC

- Regardless of the selected option, intertie participants emphasized the need for the AESO's market design to respect and not de-value existing out of province firm transmission rights

- There was support for enabling intertie offers in the REM design
  - For practical reason, some stakeholders preferred priced intertie offers in the DAM to promote cross-jurisdiction hedging and price discovery
- Across participant groups, there were mixed views on whether intertie participants should or could have a must-offer requirement equivalent to those proposed for domestic source assets. Some stakeholders preferred an exception for intertie participants
- Stakeholders stressed the need for equivalent treatment relative to internal market participants, especially around DAC participation and how expected net interchange flows impact the DAC volume requirement

There were several uncertainties related to DAC such as whether interties could be reliably scheduled or called upon within DAC timeframes. We committed to defining clear intertie participation rules and considering how intertie volume contributes to system adequacy.

Sprints 4, 5 and 6: Reliability, Access and Participation Clarity

- Intertie participants favored priced markets like the DAM, however, there was a concern with the ability for intertie participants to be priced in real-time
  - There continued to be stakeholder concerns regarding an equivalent must-offer obligation for intertie participants; some voicing that absent equivalent obligations, interties should not be allowed equal participation
- Intertie participants expressed a preference for interties to be eligible to capture the uniform pool price instead of a separate intertie pricing node, introduced to reflect the value of electricity from outside Alberta
  - Intertie participants viewed this as a limitation to competitive outcomes
- Some participants supported pursuing a formal seams agreement for fairness and coordination
  - Other participants disagreed and preferred an in-market solution that would not need to rely on bilateral negotiation
- Intertie participants emphasized the need to recognize transmission rights outside of Alberta, within Albertan market frameworks
  - They indicate that those transmission rights provided more certainty in physical supply and should therefore be preferred during market clearing

In response to stakeholder feedback we confirmed that interties would have access to participate in REM products where feasible and committed to clarifying participation requirements/obligations in the final design rules.

Design Finalization Sessions 1, 2 and 3: Simplification

- Following the removal of the DAC and DAM, intertie participation discussions shifted focus to the real-time market for energy and R30

- Intertie participants were generally supportive of the simplified design that leveraged existing market frameworks
- We confirmed that interties would participate primarily as price-takers in real-time energy, with expanded participation considerations deferred but not ruled out for future enhancements outside of REM

Updated High-Level Design and Feedback from DFS 4

- The introduction of LMPs required confirmation of the location and application of LMP to intertie participants
  - Price setting and curtailment of intertie schedules were a particular focus
  - Some stakeholders had specific suggestions for intertie curtailment order during supply surplus conditions.
  - Due to the lack of intertie transmission rights, stakeholders supported the proposal that the intertie node be located within Alberta so that congestion on the intertie does not impact the price received by imports
- Some intertie participants questioned if transmission rights, or congestion rents would be made available to intertie participants either during the transitional phase or in the long run
- Given feedback from participants, we clarified that there would be no must-offer obligation for interties and that intertie participation would remain as price takers and have similar obligations to the current market

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