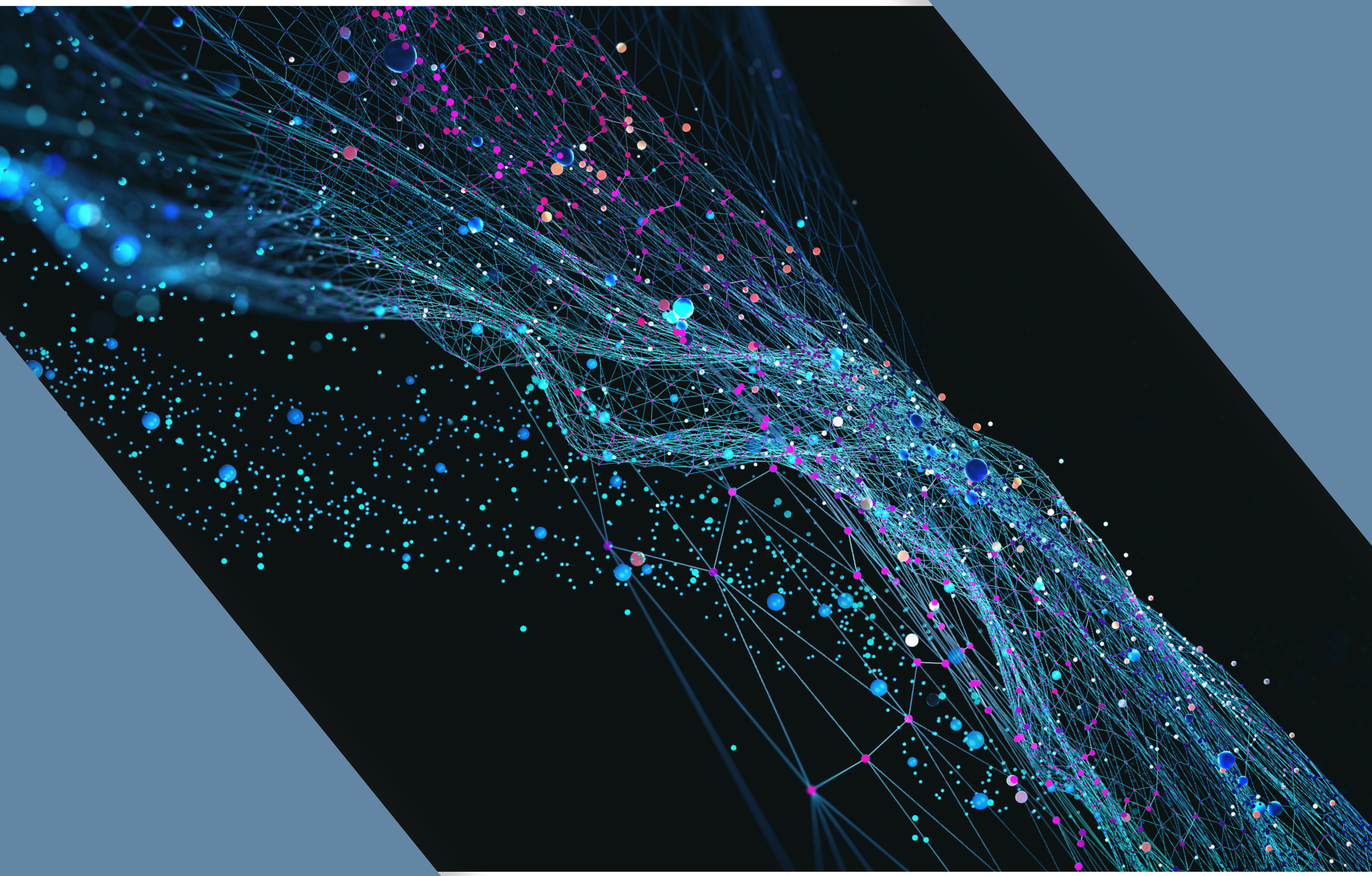


Restructured Energy Market
High-Level Design Update

MAY 22, 2025

Contents

1. Overview

The Alberta Electric System Operator (AESO) has been working extensively with industry stakeholders and market participants, partner agencies and government to ensure the Restructured Energy Market (REM) design provides a strong foundation for the Alberta electricity system, ensuring it is affordable, reliable, investable and sustainable for generations to come.

This document outlines the near-final elements of the high-level market design and invites further feedback from stakeholders.

REM Design Recent Updates

Since releasing the High-Level Design in December 2024, the AESO has removed the day-ahead energy market and the day-ahead commitment (DAC) product in response to significant industry feedback. We heard stakeholder concerns over the scope of change being progressed and that the success of the REM would be better served if we narrowed its scope and focused on the key market changes. These components can be removed from the market design while still achieving the reliability and affordability we need from Alberta's grid. The existing day-ahead market for reliability products will be retained and enhanced.

Discussions with stakeholders around congestion management have also led to changes on a market-based mechanism to manage congestion with the removal of the congestion avoidance market (CAM). We heard stakeholder concerns on the complexity of the CAM and that the CAM design had not been tested in any other markets. Locational marginal pricing (LMP) has been widely tested to handle congestion pricing and send locational signals. It is a common approach in North American markets, which makes it easier for investors to understand. This REM high-level market design considers LMP as the pricing mechanism in the market for producers. Consumers will continue to settle at a uniform price but may opt-in to settle at their LMP.

The overall framework will also consider a transition mechanism for incumbents, which will provide a degree of financial protection from the transition away from the current planning standard to an Optimal Transmission Planning (OTP) standard. These details are not considered within this document. The AESO will progress the discussion and consultation on this transition mechanism with stakeholders, in coordination with the OTP consultation.

2. Revised REM Design Highlights

We are updating the high-level design released in December 2024 to provide a comprehensive overview of the key components of the design. We invite stakeholders to share their feedback on the revised elements of the design. Upcoming engagements will aid in finalizing the design, developing corresponding Independent System Operator (ISO) rules and identifying the associated information system requirements.

The key design features include market-based congestion management, updated pricing parameters, consumer guardrails, enhancements to the day-ahead reliability market, a new ramp product and updated reliability unit commitment process.

- **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 may opt-in 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 firms in constrained areas to set their own price when there is limited competition due to limits on the transmission system. The AESO has proposed parameters for local market power mitigation that are compatible with the investment signals in an energy-only market with strategic bidding, by ensuring that units subject to mitigation still allow for full cost recovery.
  - The reliance on LMP to manage congestion provides the opportunity to consider locational losses in the pricing. Including locational losses improves the efficiency of the price signal.
- **Updated pricing:** The energy market offer cap will increase to $1,500/megawatt hour (MWh) and then will increase further to $2,000/MWh in 2032 after nearly five years of market operation. The increase in the offer cap is to provide an additional price signal for investment, given that DAC is no longer proposed. Staging it gives the market time to adjust. The energy price cap will be set at $3,000/MWh. The price floor will remain at $0/MWh initially but will decrease to negative $100/MWh in 2032, after nearly five years of market operation to promote additional flexibility in the market. The scarcity pricing curve will reflect the value of the ramping product to set the price between the energy offer cap and the price cap when ramp capability is limited.
- **Appropriate guardrails:** The 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 of $400/MWh will apply only to firms with five per cent or greater market share offer control (MSOC).
- **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 ensure more competitive outcomes for the products needed to meet reliability. Key changes to this market include shifting from block to hourly procurement, co-clearing all operating reserves and using simplified price-setting rules to set the clearing price at the marginal offer. The day-ahead reliability market will continue to use indexed pricing to align with market conditions and incentivize participation in the operating reserve market.
- **New ancillary service:** Introduction of a real-time ramping product will help manage the need to dispatch resources to better meet the needs for system flexibility by compensating resources for the ramping capability that they can provide, while simplifying the scarcity pricing and ramping product design. A single ramp product, R30, will simplify the offers, price setting and scheduling for the ramping products relative to the R10 and R60 products. The cost of R30 will be allocated based on cost causation principles.

- **Reliability unit commitment:** An updated unit commitment process to ensure reliability, given that dispatchable supply is no longer committed through the day-ahead market. This process will still rely primarily on the self-commitment model. The unit commitment process will be based on a supply cushion threshold, factoring in forecasted ramp volumes in each hour; commitments will occur if the forecasted supply cushion is insufficient to meet demand, operating reserves and ramp requirements. The supply cushion trigger balances the need for controllable supply in a future hour while minimizing distortions to commercial decisions. This reliability backstop will enable the AESO to issue unit commitment directives to turn resources online to meet future needs.
- The impact of *Transmission Regulation* (T-Reg) changes on incumbents will be limited through temporary financial transmission rights for those who made investments in assets under the current market framework; this temporary transition mechanism will be phased out over time.

These REM market design changes will support a reliable, affordable electricity system that supports future investment in assets delivering the reliability attributes needed through competitive market-based mechanisms.

Under the REM Design:

- Firm generation is compensated for its flexibility through a ramping reserve product and higher energy pricing during scarcity conditions
- The AESO has better tools to manage an increasingly complex and more congested grid with an improved market management IT system incorporating security-constrained economic dispatch (SCED)
- Alberta's competitive electricity market continues to be supported with consumer protection guardrails, including a secondary offer cap
- The REM market design aligns with government policy, allowing energy prices to be set through strategic offers of market participants, while ensuring that there are appropriate guardrails for consumers to limit the potential for excessive exercise of market power

3. REM Design 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. The AESO strives to minimize negative impacts on existing asset investment during REM implementation.

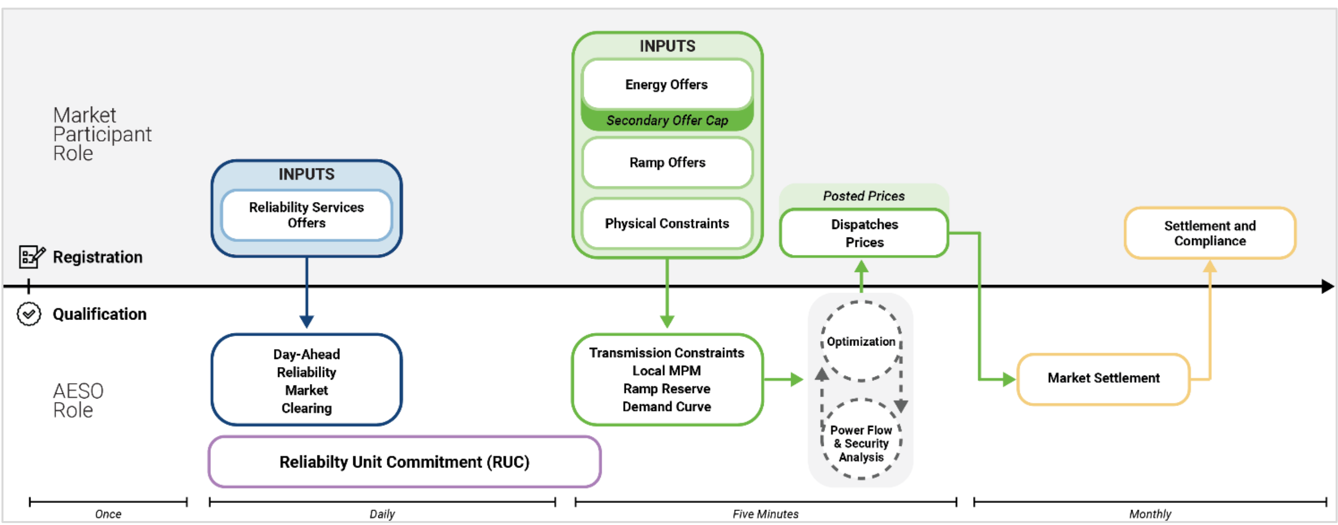
4. High-Level Design Purpose

This document shares the near-final high-level market design. It will guide the development of a complete and thoughtful design that is fit for purpose and meets REM objectives.

The layout of the high-level design reflects the relevant time periods for the REM. Below is a visual overview of the sequence of processes covered in the main sections of this document.

- Pre-market (Once)
- Day-ahead reliability market (Daily)
- Real-time market (Five minutes)
- Post-market (Monthly)

Figure 1: REM Process Overview



The AESO will seek feedback and work with stakeholders to finalize the REM design, building on the feedback and design decisions already made.

5. Registration/Eligibility

5.1 Purpose

The registration process is a requirement to participate in the Alberta wholesale electricity market. Registration comprises two key elements: participation eligibility and qualification for various products. The registration process will adopt and improve on existing processes to facilitate participation in REM.[1] These processes define the criteria for assessing eligibility on a product-by-product basis.

5.2 Detailed Design

Market participants must register with the AESO to exchange electric energy or provide ancillary services.

- Pool Participant Registration
  - The registration process for market participants is expected to remain largely unchanged from the current process.
- Asset Registration
  - Assets must register with the AESO by specifying whether they are a source or sink asset, providing their operating characteristics, ancillary service participation details and any other information required by the AESO to incorporate the asset into the market[2]
    - The asset registration process and required information will remain largely unchanged
  - Sink assets must choose to settle at either their LMP or the Alberta Load Price (ALP)
    - Non-controllable sink assets must elect ALP or LMP and can only change their election once every 12 months
    - Controllable sink assets will be settled on LMP
- Linking Pool Participants with Assets
  - Each asset will be linked to a pool participant and published on the pool participant list
    - This process remains unchanged from today
  - Participants seeking to engage in intertie transactions will receive an Asset ID to submit offers or bids

Rationale for Design Changes

The registration process will be modified to align with locational pricing, the introduction of ramping reserve and any new procedures and information required to implement REM.

[1] ISO Rule Section 201.1, *Pool Participant Registration*.
[2] Connecting to the Grid | aeso.ca

5.2.1 Operating Reserve Products Eligibility and Qualification

The current day-ahead market for operating reserves (OR)[3] will be enhanced to ensure more competitive outcomes; this includes procurement of RR, SR and SUP. The AESO procures these OR products to meet reliability standards.

Detailed Design

Controllable assets seeking to qualify for RR, SR and SUP must meet the eligibility requirements for each product. These requirements will remain largely unchanged from the current market, with a lower minimum qualification size of one megawatt (MW) for each product. This change promotes greater competition in the market. The current technical requirements for RR,[4] SR[5] and SUP[6] will continue to apply with updates, if required, to ensure applicability for assets smaller than five MW. OR will continue to be procured in the day-ahead timeframe.

Rationale for Design Changes

Given the overall market design changes, the AESO reviewed the suite of OR products and considered alternative procurement methods. The AESO has concluded that minor changes to the OR market will best advance REM objectives, particularly with respect to reasonable implementation, while ensuring that the objectives of reliability and affordability are still achieved through design efficiencies.

5.2.2 Ramping Product Eligibility and Qualification

The ramping product will help ensure there is sufficient ramping capability to meet net demand in real-time. The AESO does this by procuring ramping capability that matches the expected ramping need, with an additional volume to account for uncertainty. Given updates to the overall market design, the AESO reassessed which ramping design best meets ramping needs within the revised market design. As a result, the ramping products have been simplified from the previous R10 and R60[7] to a single R30 product. The change to R30 is further described in the Ramp Reserve Demand Curve section.

Detailed Design

R30 qualification for controllable source assets is mandatory. Controllable source assets will automatically qualify for R30 during the energy registration process for the amount of ramp-up capacity they can provide within 30 minutes.

R30 qualification for controllable sink assets is voluntary. Controllable sink assets will be eligible to qualify, but will not automatically qualify, up to the amount of ramping capacity they can provide within 30 minutes.

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[3] ISO Information Document 2013-005R
[4] ISO Rule 205.4, *Regulating Reserve Technical Requirements and Performance Standards*.
[5] ISO Rule 205.5, *Spinning Reserve Technical Requirements and Performance Standards*.
[6] ISO Rule 205.6, *Supplemental Reserve Technical Requirements and Performance Standards*.
[7] For more information on R10 and R60, see REM High Level Design, updated on AESO Engage December 16, 2024.

6. Day-Ahead Reliability Market for Operating Reserves

6.1 Purpose

The day-ahead reliability market will allow participants with qualified assets to sell OR ahead of the operating day. By securing OR commitments in advance, participants have enough time to position their asset(s) for real-time delivery. In addition, cleared OR prices provide a forward-looking scarcity signal to all market participants, which can inform their operational and commercial decisions as real-time approaches.

Rationale for Design Changes

While the current Active and Standby OR markets[8] meet reliability objectives and provide a form of day-ahead price signalling, several enhancements are proposed to unlock procurement efficiencies and support broader REM objectives:

Shorter Procurement Blocks:

The current long, fixed procurement blocks (e.g., HE 1–7 plus HE 24 for off-peak and HE 8–23 for on-peak) will shift to shorter-duration blocks, such as hourly. Shorter procurement windows will enhance competition by enabling participation from assets that may not be uniformly available or economic across the full 16 on-peak or eight off-peak hours, especially when those off-peak hours are separated by a 16-hour gap.

Co-clearing of Reserves:

The current AESO-set bid price for Active OR will be replaced with a co-clearing mechanism where the marginal offer for each product sets price. Co-clearing for all Active OR products ensures required volumes are procured at the lowest combined cost. This addresses inefficiencies in the current sequential auction design, where less flexible products (e.g., SUP) can clear at a premium over superior products (e.g., SR) due to reduced competition in later auctions.

OR Marginal Price Indexing to Reference Bus Price:

While REM introduces LMP for energy, Active OR payments will not be tied to each participant's LMP. Instead, OR settlements will be indexed to the Reference Bus Price. This simplifies settlement and ensures reporting consistency by avoiding unintended price discrepancies amongst participants providing the same product. Given that most OR providers are located outside of in-flow constrained areas, the Reference Bus Price they are offering in reference to will typically equal or exceed their local LMP. For the few providers located within in-flow constrained areas, higher opportunity costs can still be reflected in their offers.

[8] ISO Information Document 2013-005R

6.2 Detailed Design

6.2.1 Participation

Market participants with qualified source or sinks assets can register to provide OR products, including RR, SR and SUP. Once registered, participants can submit hourly offers into the day-ahead reliability market, up to their asset's qualified volume, for any or all qualified products.

Participants providing Active OR will submit offer prices indexed to the Reference Bus Price. Offer price caps will apply to each OR product. The maximum positive basis price for RR will be +$100 per MW, consistent with the current maximum AESO bid price for off-peak RR. This cap reflects the estimated revenue required to recover energy production costs from an online thermal asset during periods of low energy market revenue. The maximum offer price for SR and SUP reserves will be +$40 per MW, consistent with the current maximum AESO bid price for SR and on-peak SUP. This cap is based on the estimated cost of a thermal asset operating at its minimum economic output during periods of low energy market revenue.

For Standby OR products, participants will submit single-part offers comprising a per MW premium price only. Participants will no longer submit two-part offers which include an activation price. Instead, activation prices will be set equal to the cleared price from the Active OR auction. The value of OR is the same whether it is cleared as standby or active; only the premium price differs between standby and active products.

Rationale for Design Changes

The High-Level Design, posted in December 2024, outlined a day-ahead financial OR market alongside a real-time OR market where reserves would be co-optimized with energy. That design required participants to meet must-offer obligations for both OR and energy.

In response to stakeholder feedback and revised direction on the day-ahead market, the AESO will maintain a voluntary day-ahead OR market, similar to today. This approach provides greater flexibility to market participants, allowing participants to retain the option to offer into OR once qualified. In contrast, a must-offer obligation would restrict participants' ability to opt out of day-ahead OR in favour of providing real-time energy.

Another change from the prior High-Level Design is setting Active OR prices based on an index to the reference bus price for energy, rather than a non-indexed price for each product.

A retained feature from the prior High-Level Design is the ability to clear smaller block volumes. Combined with a lower qualification requirement, this reduces barriers to entry and increases efficiencies in reserve clearing. Additionally, shorter block durations allow procurement volumes to better align with the reserve needs of each operating hour.

6.2.2 Clearing of Operating Reserve Products

The Active OR auction will close at 10:00 a.m. prior to the operating day. The auction will simultaneously co-clear all three products; RR, SR and SUP. Clearing will be subject to the constraint that no single asset can provide more than its qualified volume across all products for any given hour. Clearing will also be subject to daily reliability studies, which provide an assessment of deliverability, ensuring sufficient reserves are procured in unconstrained zones. If a limited amount of transmission capability is expected in a given area, then the volume of reserves that can clear in that zone may be limited to what can be delivered to maintain reliability. The marginal offer price cleared for each product will set the indexed price for that product in every hour.

The Standby OR auction will close after the Active OR auction and will also co-clear all three products, subject to qualified volume constraints and reliability assessments. The AESO proposes that Standby OR premiums continue to be paid as offered rather than having the marginal offer set price. If activated, Standby OR providers will be paid the Active OR clearing price. This clearing process differs from the current process, where Standby OR is cleared based on a calculated blended price.[9]

Rationale for Design Changes

OR will be co-cleared to enhance affordability without compromising other REM objectives. The clearing process will determine the least-cost combination of cleared offers to achieve the lowest total procurement cost for all product volumes. Co-clearing reserves selects the least-cost combination of all reserves to meet requirements.

7. Ramp Reserve Demand Curve

7.1 Purpose

A demand curve represents willingness to pay. The Ramp Reserve Demand Curve (R30DC) represents willingness to pay for improved reliability through the purchase of additional reserves (R30).[10] The R30DC enables the market-clearing process to reflect the reliability benefits from incurring additional costs to meet ramping needs.[11] The R30DC is critical to the reliability and affordability objectives of REM. Previously, the “scarcity pricing curves” were demand curves calculated for R10, R60 and DAC. The same concept refers to the ramping reserve demand curve or R30DC.

The R30DC informs the volume of R30 scheduled in the ramp market. The R30DC is calculated prior to the real-time market and adjusts to the expected ramping needs in that interval as part of the real-time market-clearing process.

[9] Section 5.2 of ISO Information Document 2013-005R

[10] Reminder: The R30 product is an evaluation of an asset’s ramping capability in 30 minutes. The eligibility and qualification criteria above are reflected in the Ramping Product Eligibility and Qualification section.

[11] The term reliability in the context of scarcity curves refers to meeting the grid's flexibility and supply adequacy needs.

The R30DC includes two components: the expected ramping requirement (the horizontal part of the demand curve) and the unexpected ramping requirement (the downward sloping portion). The expected ramping requirement adjusts based on a rolling two-hour forecast of ramping. The unexpected ramping requirement will be more static, calculated and published prior to the real-time market.[12]

In the short term, the R30DC enables efficient pricing to tradeoff between the cost of clearing additional ramping volume and the implied reduction in load shed risk. These signals allow market participants to respond to system conditions by signalling when energy is approaching tight conditions or when ramping capability becomes scarce.

Longer term, the demand curve supports investment by signalling acceptable supply adequacy (reliability) levels through the market prices for ramp. The demand curve reflects the reliability value associated with additional ramp capability, influencing the long-term market price to help attract investment in resources capable of meeting the ramping requirements.

Rationale for Design Changes

With the increase in the energy market offer cap, the ramping products were reviewed to ensure they still align with the objectives of the REM. A single R30 ramp product provides a pricing signal for flexibility while simplifying the ramping market. Three factors led to the change to a single ramp product:

- **Price signal for flexibility**
  - A primary goal of ramping products is to provide a price signal for flexible ramping capability to meet real-time and forecasted needs over two hours. In the previous design, the R10 and R60 products provided these signals for quicker response (R10) and a longer duration product (R60). However, in the revised design with the removal of DAC and increased energy market offer cap, a longer-term product like R60 is not warranted to the same degree. The increased energy offer cap, combined with a shorter ramping product like R10 or R30 strengthens the required investment signal for real time flexibility.
- **Ensuring real-time ramping requirements are met**
  - The real-time ramping requirement is based on the expected variability and ramping need over a two-hour forecast. The ramping product duration should be related to the length of the forecast period (two hours); for example, an extremely short ramping product like one minute is not reasonable when forecasting the ramping need for the next two hours. However, the ramping product duration should also be able to meet more extreme ramping events. Since R10 has the most restrictive qualification parameters (volume of capability within 10 minutes), the resulting qualified volume is too restrictive to provide sufficient capability over two hours. The less restrictive qualification of R30 allows for more supply to provide ramp over the two-hour lookout period relative to R10.

[12] The AESO is still determining if this will be one static curve regardless of time of day/year, or if there will be several static curves based on different assumed conditions.

- **Complexity of ramping product market structure**
  - An additional consideration on defining the ramping products is the complexity introduced from having multiple ramping products compared to a single ramping product. Other jurisdictions procure multiple ramping products based on opportunity costs alone. However, Alberta's proposed design allows participants to offer to provide ramp at an offer price. Having differentiated offers for multiple ramping products is more challenging for market participants and introduces additional complexity in the market-clearing process.

7.2 Detailed Design

The demand curve[13] represents willingness to pay for R30 through a probability-weighted value of avoiding supply shortfall events by procuring additional reserves.[14] The R30DC will be used to determine the R30 procurement volume and schedules in the real-time clearing process.

As outlined in the previous High-Level Design document,[15] the demand curve is developed in three steps:

1. Estimate net load forecast error within relevant timeframes (e.g., the uncertainty which reserves are protecting against)
2. Determine the $/MWh value of avoiding Energy Emergency Alerts (EEA) and load shed events and the trigger conditions for these events
3. Calculate the probability-weighted reliability value of holding more reserves

These three steps are used to determine the $/MW value of each level of R30. A point on the R30DC curve reflects the value derived from an additional one MW of R30, based on reducing the likelihood of a net load increase causing a supply shortfall event. This value is calculated by multiplying the avoided supply shortfall events (MWh/MW) by the cost of these events ($/MWh), resulting in a price for incremental reserves ($/MW).

Accurately determining the cost of supply shortfall events requires an estimate of the value of lost load (VOLL). VOLL represents the costs to consumers of shedding load. A more detailed explanation of the process to determine the width, height and shape of the demand curve is covered in the presentation from Sprint 6.[16] VOLL is used to set the cost of load shed, even though the resulting demand curve will be capped at $3,000/MWh.

To procure the appropriate amount of R30, both a measure for expected and unexpected ramping requirements will be used:

- Expected ramp: This is the portion of the procurement volume informed by expectation of ramp over the next two-hour period.

[13] The R30 demand curve terminology better aligns with a single product rather than previous scarcity pricing curves, which were calculated for R10, R60 and DAC. The same underlying concepts apply to both curves.
[14] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 36-45.
[15] REM High Level Design, updated on AESO Engage December 16, 2024.
[16] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 36-45.

- Unexpected/Uncertain ramp: The portion of the procurement volume that is informed by the sloped R30DC as calculated from forecast errors. The process to calculate the uncertainty portion and the R30DC is detailed further below.

The expected ramp is based on the ramping need over the next two hours. This allows the AESO to prepare for ramping-up events two hours in advance by scheduling resources to provide R30. The AESO can revisit this two-hour requirement as the generation fleet becomes more flexible and the need to prepare two hours in advance for ramping is reduced.

The unexpected portion of the R30DC ramp procurement is based on the same methodology previously described for R10 and R60. The 10-minute and 60-minute net demand forecast errors that were used for R10 and R60 will be updated with the 30-minute net demand forecast error to calculate R30DC uncertainty portion for R30 procurement.

The ramp reserve demand curves for the uncertainty portion of volumes are shown in the graph below for the previous R10 and R60 products as well as the new R30 product. The *Operating Reserves Demand Curve (ORDC) Workbook - R60-R10-R30*[17] used to calculate the curves has also been released. Key assumptions in the spreadsheet include:

- Historic data is scaled to better represent the current or forecasted installed capacity of renewables
- The unexpected portion of the R30DC is not adjusted for the hour of the day or the forecast for renewable output for a given hour (e.g., demand curve for uncertainty volume remains static in each hour)
- Input data for load, solar and wind is measured over 10-minute intervals

Scaling Process for Historic Data

The AESO has developed a scaling process to convert the historic net demand data to better represent the current and forecasted installed capacity of renewables. This process is not yet final but provides an example of how to modify historic data to match the current and forecasted installed capacity of renewable generation.

Static Uncertainty Volume Curve

The ramp reserve demand curve for the uncertainty volume will remain static across all hours, regardless of the level of output or the time of day. In contrast, the expected ramp volume will be updated in real-time based on the expected ramp over the next two hours.

When choosing how to set the ramping volume in real-time, the AESO is balancing meeting ramping requirements and minimizing costs of doing so with stability from a forecasting and price perspective. A static curve for the uncertainty portion provides stability from a ramping and energy pricing perspective and the dynamic expected ramp volume ensures adequate ramping reserves are procured with changing conditions.

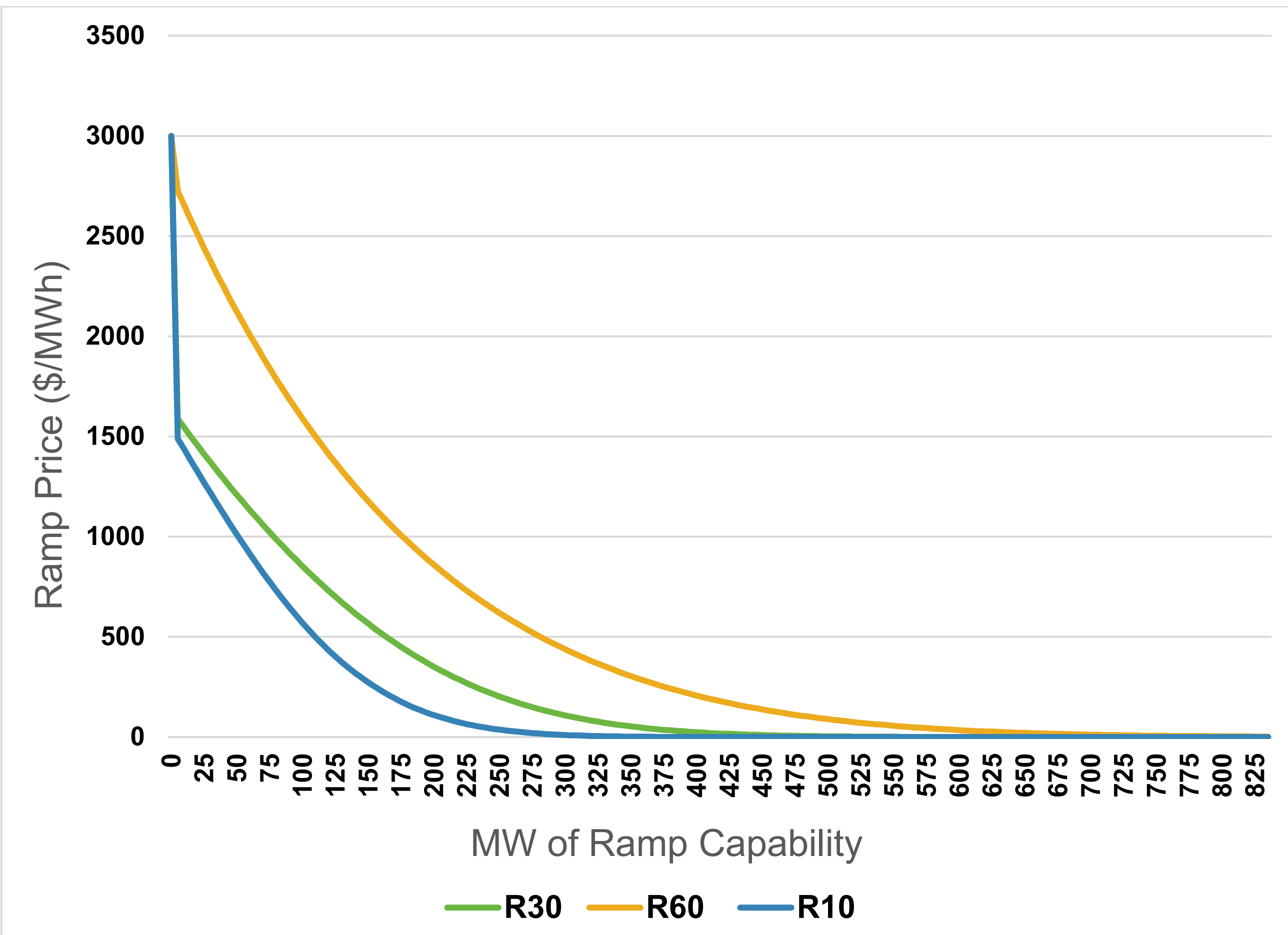
[17] *ORDC Workbook - R60-R10-R30*

The AESO continues to evaluate different conditions like time of day/year and/or level of output from variable supply that would result in significant differences in the demand curves.

Underlying 10-minute Forecast Intervals

The last assumption in the ramp reserve calculation is the granularity of the data used to calculate net demand forecast errors. For the R30 product, the actual and forecast data measures net demand (Alberta Internal Load [AIL] minus solar generation minus wind generation) over 10-minute intervals. The forecast for net demand is the forecast over a 10-minute interval, 30 minutes into the future. The AESO may update the renewable forecasts to forecast net demand over 5-minute intervals if the data is available. The ramp reserve demand curve would also then be updated to use forecast errors from a 30-minute ahead forecast using 5-minute intervals of wind, solar and load.

Figure 2: Ramp Reserve Demand Curves for Uncertainty for 9 GW of Renewables



The R60 demand curve has been updated since the earlier version released in the REM process due to changes in the actual and forecasting data used. The original R60 curve relied on data that averaged load, wind and solar over a one-hour period, whereas the updated curve relies on data that is averaged over 10 minutes. The 10-minute data provides a more precise view of net demand for a particular point in time compared to the average hourly data.

The price cap for the R30 ramp product will be $3,000/MWh, as reflected in the R30 ramp reserve demand curve that reaches a maximum at this value. A $3,000/MWh price cap for R30 is appropriate for the following reasons:

- **Reflecting Opportunity Costs:** The opportunity cost of providing ramp can be as high as the energy market offer cap. A $3,000/MWh price cap allows the market-clearing process to incorporate high opportunity costs of energy when ramping reserve is scarce.
- **Signalling Ramp Shortages:** In situations where there is adequate supply of energy, but the market is ramp-constrained, the ramp price will rise even if there is undispatched energy in the market. In these situations, a $3,000/MWh price cap for ramp signals the shortage of ramp, which will provide greater incentive for more resources to provide ramp (and for energy market resources to provide more energy to help to alleviate the ramp shortage).

8. Reliability Unit Commitment

8.1 Purpose

Self-commitment remains the primary commitment mechanism. The reliability unit commitment (RUC) process will determine when there are periods with foreseeable reliability needs and will commit additional supply that was not expected to be available in the real-time market.

The primary objective of RUC is to backstop reliability needs that may not be met by the self-commitment process.

Rationale for Design Changes

The previous intra-day unit commitment process was designed to commit units only under extreme circumstances, as determined by a short-term supply adequacy assessment. This design relied on the day-ahead process with day-ahead energy and DAC products to inform appropriate commitments.

Without the additional certainty provided by the day-ahead process, the RUC will ensure adequate supply levels are available based on the expectation of the real-time market. To achieve this, all reserve products will be included in the supply cushion forecast, which will inform unit commitment decisions. The triggering threshold will shift from a fixed capacity measure of 932 MW to a threshold that reflects anticipated reserve requirements (operating reserves and ramping reserves). The reserve requirements will act as an offset in the supply cushion forecast, such that the triggering condition is a forecast supply cushion of zero or less. This change is represented in the simple formula below:

Supply Cushion = **Capability of Source Assets** − **Forecast Alberta Internal Load** − **Expected Reserves Requirement**

This change allows market participants every opportunity to self-commit while ensuring anticipated reliability needs are met. RUC upholds the competitive market signals while providing a reasonable backstop for the commitment of long-lead time (LLT) assets considering supply adequacy needs.

8.2 Detailed Design

At a high level, the RUC process will follow these steps:

- **Participation:** All LLT assets are pre-qualified and eligible to receive directives through the RUC process.
- **Supply Cushion Forecast:** The AESO will have a continuous supply cushion forecast looking out 48 hours to determine the anticipated remaining supply over that period. A unit commitment is triggered when the supply cushion equals zero, factoring in estimated reserve requirements.
- **Commitment Process:** If the triggering conditions are met, AESO operations are notified and can issue a unit commitment directive based on the cost information of available LLT assets.
- **Participant Accepts the Directive:** As part of accepting the unit commitment directive, the asset owner must also elect to either treat the start as a self-commitment or with a cost guarantee.
- **Cost Guarantee Recovery (if necessary):** For asset owners that accept the commitment directive as a cost guarantee, the recovery of start costs and potentially foregone market revenues will be calculated. Asset owners will not be paid the foregone market revenues if they accept the cost guarantee.

8.2.1 Participation

Only LLT assets are eligible to participate in the RUC. LLT assets are those not able to synchronize and provide energy within one hour. These assets are automatically qualified and included in the RUC mechanism for consideration. The AESO will use reference unit cost information for LLT assets, specifically the asset's start-up, no-load and energy costs.[18] If a participant disagrees with the use of the published reference unit cost data for their asset, they can submit their cost information for AESO verification and approval.[19] The reference unit cost data will also be applied to assets that accept the cost guarantee directive option (explained further below).

8.2.2 Supply Cushion Forecast

The RUC process relies on a supply cushion forecast that will run every five minutes, projecting ahead for the next 48 hours. If the supply cushion forecast indicates a supply cushion equal to or below 0 MW and there is an LLT asset offline with just enough time to turn online, the commitment process will be triggered.

The supply cushion forecast will adapt the current calculation used in ISO Rule 206.2, *Interim Supply Cushion Directives*. However, the changes in ancillary services and removal of DAC

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[18] For LLT assets that are currently obligated to submit costs under ISO Rule 206.2 *Interim Supply Cushion Directives*, the AESO will work with participants to convert the previously submitted cost data into cost information for RUC. These individual cost parameters will be used in place of the publicly reported reference unit costs.

[19] These reference unit costs are the same as those used in the Local Market Power Mitigation section and submission of own costs for verification/approval is also the same.

increases the importance of evaluating anticipated reserve requirements for a future period; specifically, improving the estimation of operating reserves and ramping reserves for inclusion in the supply cushion forecast. The estimated reserve requirement will include expected and unexpected reserve requirements over the forecast period, accounting for planned ramping and uncertainty.[20]

8.2.3 Commitment Process

An LLT asset will be committed through the RUC process when the supply cushion forecast indicates that committing an additional unit is required to maintain reliability. The action is triggered when the supply cushion is zero MW or less, indicating that only reserves remain available for that interval. Unit commitment decisions would occur as close to real-time as possible, respecting asset constraints, like ramp-up time to minimum stable generation.

The resource will be committed based on the relative economic merit of the asset. The AESO will evaluate economic merit using reference unit cost information, including startup, no-load and energy costs.

The AESO will issue a commitment directive based on the supply cushion forecast and the assessment of relative economic merit.[21] When accepting this directive, a participant must enter a start time for the chosen asset for the interval indicated by the supply cushion forecast. The participant must also make a decision regarding cost recovery:

- The asset accepts the directive as a self-commitment; or
- The asset accepts the directive with a cost guarantee.

Self-Commitment

When a market participant chooses the self-commitment option, they forgo a cost guarantee but will receive all market revenues. The market participant will be required to comply with the submitted start time and ensure the asset's capability is available for dispatch. To meet this requirement, the minimum stable generation block of the LLT asset must be offered at the price floor. However, as with all self-commitments, the participant has the ability to offer its flexible generation blocks where it sees fit between the price floor and the offer cap. Aside from the initial directive issued to the market participant, this option will appear identical to a self-commitment. It introduces little to no distortion to the competitive market. Market participants will adapt to a self-commitment as a result of a unit commitment directive in the same way as any other self-commitment, making price reconstitution unnecessary.

Cost Guarantee

When a market participant accepts a cost guarantee, they forego all additional market revenue. The cost guarantee is limited to the reference unit costs for startup, no-load and energy. To comply with

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[20] These are the same two portions, expected and unexpected, that are used in R30DC to inform the R30 procurement volume based on a two-hour lookahead period (see Ramp Reserve Demand Curve section). This will be a similar process used by the supply cushion forecast to determine the anticipated reserve requirement with a multi-hour lookout.

[21] In some circumstances, the information from the supply cushion forecast may result in multiple unit commitment directives.

the submitted start time, the market participant must offer the minimum stable generation at the price floor. The remaining offers associated with flexible generation blocks will be entered at the offer cap. This approach serves to limit the potential distortion to the market from the cost guarantee commitment option. The RUC mechanism is only triggered when there is a foreseeable risk of reserve depletion, as shown by the forecasted supply cushion. Under these conditions, the market price should reflect supply tightness, making the flexible generation at the offer cap less distortive to competitive outcomes. As a result, price reconstitution is unnecessary.

The appropriate offer cap depends on the asset being directed and whether the secondary offer cap applies to that asset. For example, if the secondary offer cap is binding, flexible generation must be offered at the secondary offer cap instead of the broad offer cap of $1,500/MWh (or $2,000/MWh). This is to prevent an LLT asset owner from having an added benefit to accepting the cost guarantee when the secondary offer cap is in place.

8.2.4 Cost Recovery

An asset that chooses to self-commit after receiving a directive from the AESO will forego the cost guarantee but retain all market revenues. This option does not require cost recovery.

An asset that accepts the cost guarantee will only be compensated for startup, no-load and energy costs. All market revenues that would have been received during the period of time considered in the directive instruction are foregone by the asset.

9. Broad Market Power Mitigation

9.1 Purpose

To achieve reliability, affordability and ensure strong investment signals in an energy-only market with strategic bidding, a balance between the risk of high prices set by excessive exercise of market power and the risk of over-mitigation leading to low prices, less investment and decreased reliability is required. The market will primarily achieve these objectives by fostering and maximizing competition. This includes enabling all resource types, encouraging increased participation of sellers and buyers and enabling entry.

The market power mitigation framework will:

- Establish guardrails to limit the potential for excessive exercise of market power, while allowing the price of energy to reflect strategic offers that attract and recover investment
- Encourage competitive entry to discipline the excessive exercise of market power
- Provide guardrails to protect consumers only in specific situations when the competitive response is ineffective or insufficient
- Adapt to changes over time

9.2 Detailed Design

9.2.1 Broad Market Power Mitigation Overview

The broad market power mitigation process has multiple components, the first of which is a real-time energy market offer cap which is always in effect and applies to all market participants.

A second component involves a secondary offer cap (SOC). It involves tracking the energy market revenue of a theoretical reference unit whose parameters and behaviour have been predetermined by the AESO. When the cumulative revenue of this reference unit reaches two times the calculated annualized unavoidable costs, the SOC will come into effect. This SOC is set to $400/MWh and will remain in effect for the remainder of the evaluation period and is only applicable to thermal assets owned by market participants with greater than five per cent MSOC.

9.2.2 Real-Time Energy Market Offer Cap

At the onset of REM, the real-time energy market offer cap will be set at $1,500/MWh. In 2032, after nearly five years of market operation, this cap will increase to $2,000/MWh. These levels were selected to update the current $999.99/MWh cap and to reaffirm that strategic bidding remains the primary driver to recover investment costs in the energy market. The transition with an initial energy market offer cap of $1,500/MWh will bridge the current offer cap and the future, giving the market time to adjust to the increased ability to strategically bid. The future $2,000/MWh energy market offer cap will be implemented in 2032, after nearly five years of market operation, to coincide with the introduction of a negative $100/MWh energy market price floor.

9.2.3 Real-Time Energy Market Applicability

The mitigation framework will apply MSOC to determine which firms are subject to mitigation.[22]

- When in effect, the SOC will apply to firms with an MSOC of five per cent or higher
- Firms with an MSOC below five per cent are exempt from the SOC. The MSOC for all firms will be calculated and updated at least annually based on values provided by the Market Surveillance Administrator (MSA) per Section 5 of the *Fair, Efficient and Open Competition Regulation*.

Net Revenue Calculation

The net revenue calculation, which determines when the SOC is triggered, is based on the costs and operational assumptions of a reference unit.

The reference unit is a combined-cycle generator.[23] To calculate the reference unit revenue, the reference unit is assumed to operate as described below. The reference unit is subject to assumed

[22] As found in the REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slide 18.
[23] As shown in REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 15-27, the AESO's analysis evaluated the secondary offer cap using several generation types. The combined-cycle reference unit is the most representative unit in the Alberta market. The analysis found that it provides more appropriate guardrails to protect consumers from the excessive exercise of market power (compared to a peaker unit). The analysis also

physical constraints, will not be subject to locational constraints and will be paid the Reference Bus Price (see Real-Time Market section for an explanation of the Reference Bus Price).

The net revenue calculation assumes that the combined-cycle reference unit operates at different output levels depending on the price relative to its variable cost:

- If the Reference Bus Price exceeds its variable cost, the unit operates at maximum capability multiplied by its capacity factor
- If the Reference Bus Price is equal to or below its variable cost, the unit operates at its minimum stable generation

The reference unit's unavoidable costs will be calculated using the methodology outlined in the ISO rules, which may adopt components from Section 3 of the *Market Power Mitigation Regulation*.[24] The AESO proposes the following cost parameters for the combined-cycle reference unit.

Table 1: Combined-Cycle Reference Unit Cost Parameters

Variables	Combined-Cycle Reference Unit Parameters
Source	EIA Annual Energy Outlook 2025
Reference generating unit type	Natural gas-fired combined-cycle
Configuration	H-class combustion turbine; single shaft configuration
Net capacity	627 MW
Overnight capital cost	$1,378.17/kW
Construction financing factor	1.12
Fixed operations and maintenance cost	$23.22/kW-year
Variable operations and maintenance cost	$4.99/MWh
Useful life	40 years
Availability factor	86%

considered a combined-cycle unit with carbon capture, utilization and storage (CCUS), but the assumptions required to apply mitigation based on a reference unit that is not currently operating in Alberta make it a less appropriate benchmark. The reference unit can be reviewed as the generation fleet changes.

[24] Market Power Mitigation Regulation, Section 3.

Variables	Combined-Cycle Reference Unit Parameters
Minimum stable generation	30%
Emissions intensity	0.05035 tonnes/gigajoule (t/GJ)
Heat rate	7.554 GJ/MWh
Natural gas price	ICE NGX AB NIT DAY-AHEAD
Fuel delivery costs	$25.58/kW-year
Pre-tax weighted average cost of capital (WACC)	10.50%
Loss factor	3%
Tax rate	23%

Ancillary services revenues are not included in the revenues received by the reference unit.

Secondary Offer Cap

The SOC is triggered when the reference unit recovers twice its unavoidable costs over a fixed 12-month evaluation period (starting April 1 and ending March 31), as determined by the net revenue calculation. Once triggered, the SOC applies to firms with MSOC greater than or equal to five per cent for the remainder of the 12-month evaluation period.

The SOC will be set at $400/MWh, a level the AESO has determined is sufficient to cover the costs of providing energy for assets subject to the SOC. Initially, the AESO proposed including considerations for verified cost if higher than the SOC of $250/MWh. However, with the increased SOC to $400/MWh, this process is no longer necessary. The original proposal aimed to cover the costs of providing incremental energy through duct firing. However, the AESO expects these costs will now be covered under the higher SOC.[25]

Treatment of Reserves (Including Operating Reserves, R30)

Product-specific offer caps apply to each ancillary service.[26] The secondary offer cap does not apply to ancillary service offers.

[25] The expected heat rate of duct firing capabilities is 12 times the price of natural gas. With a SOC of $400/MWh, the cost of natural gas must be greater than $33/GJ for the cost of operating the natural gas asset to exceed the SOC.
[26] See Day-Ahead Reliability Market for Operating Reserves - Participation and Real-time Market – Participation in Ramping Product sections.

9.2.4 Technology-Specific Broad Market Power Mitigation Rules

The following requirements apply to specific asset types:

- **Hydro and energy storage (including batteries):** Firms with five per cent or higher MSOC must enter into a negotiated compliance plan
- **Wind, solar, intertie transactions and demand response:** Secondary offer cap does not apply
- **Hybrid assets:** Portions of the asset will be subject to the requirements specific to the associated technology type. For example, for a hybrid asset that is comprised of a solar resource and a thermal resource, only the thermal resource may be held to the secondary offer cap when in effect.

9.2.5 Periodic Review

Market power mitigation parameters are subject to review every five years. This will include the SOC, reference unit, SOC triggering thresholds and applicability. The review process will consider whether the mitigation framework continues to balance the ability to attract and retain supply to support reliability while protecting customers from the potential for excessive exercise of market power.

Other inputs used in this process are updated in accordance with predetermined methods and more frequently to provide increased accuracy. These include the price of natural gas (updated daily), the capital cost, fixed operating cost, variable operating cost and trading charge (updated annually for inflation).

10. Real-Time Market

10.1 Purpose

The ISO will operate the real-time market for the exchange of real-time energy and the ramping product. The market will clear products to maximize total social surplus, ensuring the lowest cost power, while respecting system constraints.[27] This means minimizing the sum of offer-based dispatch costs. Market-clearing includes both dispatches and price formation. The real-time market will co-optimize energy and R30, clearing simultaneously to make trade-offs between the two products to reduce the combined cost.

The market-clearing process will produce real-time energy prices that may vary by location and province-wide ramping reserve prices. Nodal LMPs will reflect the value of energy at each generator's location (node). Generators will receive the LMP for energy produced at their node. Unless a load elects to be exposed to its nodal load LMP, loads will pay the province-wide ALP, that is the load-weighted average of all load nodes that have not opted into LMP. Province-wide R30 prices will reflect the value of ramp-up capability in the system.

[27] For further explanation, see the *Co-optimization Information Document*, posted on AESO Engage August 16, 2024

LMPs will consist of multiple components. A province-wide energy price component (referred to as the Reference Bus Price, see below) and a location-specific congestion price component. In other jurisdictions, location-specific marginal losses are calculated as part of the market-clearing process in real-time. In those markets, LMP includes a loss price component. The components are discussed further in the Energy and Ramp Pricing section, but in summary:

- The Reference Bus Price component is the total cost of the last increment of energy delivered to the load-weighted average of all load nodes
  - This cost is based on dispatched energy offers and could include the lost opportunity of foregoing the sale of R30, based on R30 offers and the R30DC, when applicable
- The location-specific congestion price component, which may vary by asset, is a price of all the transmission constraints associated with the asset's location and power flows
- In other markets, a location-specific loss price component, which may vary by asset, is the price of losses associated with the asset's location and power flows
  - The loss price is part of LMP and is the efficient signal for the cost of losses
  - With the incorporation of LMP into the Alberta market, there is an opportunity to include the location-specific loss price in the LMP

Operating reserves volumes are cleared day-ahead and typically remain unchanged in real-time. Reserve schedules can change in real-time to manage real-time system conditions. For example, regulating reserves setpoints can change in real-time based on system conditions. Standby reserves may be activated in real-time, causing that capacity to be converted into active reserves. The changes to OR schedules in real-time will not be co-optimized with energy because the OR indexed prices are set in the day-ahead market.

10.2 Detailed Design

10.2.1 Participation in Energy

Offering Energy Into the Real-Time Market

Energy offers are submitted as single-part ($/MWh) offers through price-quantity pairs, or operating blocks. Real-time energy offers have an offer cap of $1,500/MWh (transitioning to $2,000/MWh in 2032, after nearly five years of market operation), energy bids to consume have a cap of $3,000/MWh (consistent with the energy price cap). Both energy offers and bids have an offer/price floor of $0/MWh (transitioning to -$100/MWh in 2032, after nearly five years of market operation). Energy offers must be monotonically increasing for source assets and monotonically decreasing for sink assets.

Energy offers will be submitted via ten price-quantity pairs. Market participants can elect to have their price-quantity pairs interpreted by the market-clearing process as either "blocks" or "slopes". Block submission interprets price-quantity pairs like a staircase. The height of each step is set by submitted price; the width of each step is set by the additional quantity in excess of the previous price-quantity pair. Slope submission interprets price-quantity pairs as segments of a curve. The offer segments are drawn by linearly interpolating the points between price-quantity pairs.

Based on applicability, offers are subject to the secondary offer cap when market power mitigation is binding (see the Broad Market Power Mitigation section). Subject to applicability, offers may be replaced when local market power mitigation is binding (see Local Market Power Mitigation section).

The real-time offer lockdown will be revised to one hour to provide greater offer flexibility. The real-time offer lockdown period is when offers cannot be restated without an Acceptable Operational Reason (AOR). The T-1 lockdown period allows greater flexibility of offers in reflecting market changes closer to real-time.

Intertie Transactions in the Real-Time Market

Intertie transactions will continue to be scheduled as price takers in real-time, with participation on a voluntary, may-offer basis. Under this design, offers to import energy are submitted at the price floor, while bids to export energy are submitted at the price cap, with volume to be fixed over the hour. To schedule physical power flows across interconnections, participants must secure approved eTags no later than T-20 minutes. The eTag volumes must match the offered or bid quantities and the point of delivery must match the intertie price node offered into or bid out of by the participant.

10.2.2 Participation in Ramping Product

R30 Offer Cap

The offer cap for the R30 product will remain $100/MWh with a must-offer obligation in real-time. This cap is based on two factors:

- Cycling cost of a simple cycle generator
- Ability to economically price providing ramp with an upper limit to mitigate market power in the ramping product market

The AESO used estimates of the start cost of a simple cycle generator to inform the $100/MWh offer cap. This cap allows a simple cycle generator to recover its estimated start-up costs in five minutes. The start-up cost of a simple cycle generator was chosen to allow an offline unit of this type to offer into R30, provided they can meet a certain start-up time (e.g., can start within 10 minutes). The AESO intends to clear the ramp and energy market every five minutes, so the minimum amount of time that a generator could clear in the ramp product would be five minutes (after five minutes, they may be scheduled to provide energy or no longer clear in ramp). If a generator expects to only clear in the ramp product for five minutes, the $100/MWh offer cap would allow the generator to recover its start-up costs. The AESO used the cold start cost plus the cold start fuel amount[28], assuming a nine GJ/MWh[29] heat rate and a $3/GJ gas price[30] for a 51 MW simple cycle aeroderivative unit, to calculate the offer cap.

The R30 offer cap is a reasonable limit on market power within the ramping product. The design of the R30 product is complimentary to the energy market, providing the primary investment signal. This design intention is, in part, reflected through the increased energy market offer cap of

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[28] See National Renewable Energy Laboratory - Power Plant Cycling Costs (table 1-3, page 30)
[29] GE Vernova - LM6000 Aeroderivative Gas Turbine
[30] Cal 2027 forward natural gas price on April 29, 2025

$1,500/MWh (to $2,000/MWh). Assets that provide ramping capability are the same assets that receive the energy market price. R30 provides an additional signal when approaching scarcity and at times of supply tightness. The $3,000/MWh price cap is reasonable for R30 for energy and ramping to reflect the value of additional energy and ramp capability at times of scarcity. The offer cap in R30 is not intended to allow the same degree of strategic bidding as the energy market, given the relatively small size of the R30 market. The offer caps in energy and R30 work together to balance the recovery of costs while limiting the exercise of market power.

Offering R30 into the Real-Time Market

Source assets are subject to energy offer and delivery requirements, referred to as *must offer, must comply.* Ramping reserves are provided by un-dispatched headroom; the need to comply with ramping obligations are met by complying with energy dispatch requirements. For this reason, there is a *must offer* requirement for source assets that have qualified for R30. Sink assets have a may offer requirement in energy and consequently have a may offer requirement for R30.

Assets will have different qualified volumes for ramp based on having an offline or online status. For online units, ramp volume is calculated in real-time based on the amount of MW's an asset can ramp in 30 minutes. For offline units, only those units that can start up in 10 minutes are eligible to provide ramp, with limits on the total volume from offline units that can clear to provide ramp. The limit on the total volume of offline units providing ramp will provide a more consistent linear ramp from all the assets cleared in R30 so that enough capability is available for energy dispatch in the subsequent interval.

Assets will submit one flexible block and offer price into the R30 market. The market-clearing process will calculate the size of the block in real-time based on the assets ramping capability over thirty minutes. A single block for ramp will allow participants to economically price themselves out of ramp if desired, while maintaining a simple design.

10.2.3 Price Cap and Floor

The real-time energy market price cap is $3,000/MWh. The price floor at the start of REM will be $0/MWh and will transition to -$100/MWh in 2032, after nearly five years of market operation, coinciding with an increased energy market offer cap of $2,000/MWh.

The price cap for R30 will be $3,000/MWh.

In both energy and ramping, prices exceeding the offer cap are determined by the R30DC and the implied opportunity cost calculation from co-optimization.[31]

[31] See Real-Time Market-Clearing Process section for how real-time market-clearing results in pricing or the *Co-optimization Information Document*, posted on AESO Engage August 16, 2024, for further information on how co-optimization relates to opportunity costs.

10.2.4 Market-Clearing Engine Real-Time Constraints

The market-clearing process clears energy and R30 to minimize the sum of dispatched offers subject to constraints. Constraints refer to the limitations that must be respected to ensure the market-clearing solution is feasible. The major constraints are broadly captured by the following:

- **Power balance constraint:** Supply must equal demand
- **Asset capacity constraints:** Assets can only be dispatched within their available physical capacity, what would be called today available capability (AC).
- **Asset-level ramping constraints**: Assets can only ramp up or down within their design limits
- **Ramping reserve requirement constraint:** Ramping reserve supply should be greater than or equal to the requirement specified by the R30DC.[32]
- **System-wide maximum ramp share by resource type constraint:** The maximum share of system-wide ramp that can be provided by certain provider types over an interval. For example, sink resources could be capped at a maximum share.
- **Operating Reserve requirement constraint:** Contingency reserve and regulating reserve supply must meet the requirements specified per reliability standards.
- **Transmission constraints within the Alberta Interconnected Electricity System (AIES):** Dispatches must respect security constraints; this refers to limits on the flow of energy for a number of reasons. These include limits informed by thermal transmission line limits, N-1 operating limits and others, within the AIES.
- **Available Transfer Capability (ATC) of interconnections:** Real-time schedules for intertie transactions must not exceed the ATC of the relevant intertie and/or flow gate.

10.2.5 Local Market Power Mitigation

The market-clearing process will identify inflow constraints and the congestion component of the LMP (Energy and Ramp Pricing section that describes the components of LMP). Assets with a positive congestion component at their LMP will be subject to the conduct impact test to determine if the extent they are exercising local market power in that area exceeds an allowable amount.[33]

When setting the parameters of local market power mitigation, it is essential to strike a balance between protection against the excessive ability of market participants to exercise market power under certain local conditions while still maintaining the investment and cost recovery signals consistent with the energy-only market.

Conduct and Impact Test

The conduct and impact test is a multistage process that evaluates an asset's offers and impact on LMP to determine if mitigation is applied. The table below the stages of the conduct and impact test.

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[32] Normally the R30 price is set by the intersection of R30 offers and the R30DC. Under times of R30 scarcity (no intersection possible), the price is the determined by the R30DC for the available quantity of R30.
[33] See Energy and Ramp Pricing section for explanation of the congestion price component of LMP.

Table 2: Conduct and Impact Test

Stage	Action	Threshold
First Stage: Conduct Test	If an asset in a node subject to an inflow constraint its offer is evaluated for whether it exceeds the threshold	If an asset in a node subject to an inflow constraint submits an offer that exceeds four times the variable cost, the asset's offer fails the conduct test
Second Stage: Impact Test	If the asset's offer fails the conduct test, an impact test determines if the asset's LMP was increased by the threshold	If the offer increases the LMP by more than four times, the offer is replaced with a mitigated offer
Third Stage: Offer Replacement	If the asset's LMP was increased above the threshold amount the mitigated offer replaces the asset's offer	The asset's original offer will be set equal to four times the applicable variable cost

The variable cost used for each asset throughout the conduct and impact test will be a multiple of a default reference unit's variable cost calculated by the AESO, unless an updated value is submitted by the market participant and accepted by the AESO.

Using the new offers, the market-clearing process will determine the price in the relevant nodes to be the marginal price of the highest-cost asset that has been dispatched.

An offer limit of four times variable cost is appropriate as it is high enough to recover investment for all technology types that may be subject to local market power mitigation. The table below provides analysis supporting the appropriate multiplier of variable cost that allows the example resources to recover their levelized cost of electricity through an offer that is a multiple of their calculated variable cost. A multiple of four times allows all reference technologies to recover their levelized cost of electricity (LCOE), allowing the local price in those areas to be set at a level that can support new investment in those areas.

Using the new offers, the market-clearing process will determine which assets to dispatch and the price in the relevant nodes will be set at the marginal price of the highest-cost asset that has been dispatched.

Table 3: Variable Cost and Levelized Cost of Electricity Comparison

	Simple Cycle Frame	Simple Cycle Aero	Combined Cycle	Simple Cycle Aero (only provides during inflow constraints)
Capacity Factor	33%	38%	75%	20%
Variable Cost	$72.41/MWh	$83.92/MWh	$42.03/MWh	$83.93/MWh
Levelized Cost of Electricity	$149.84/MWh	$186.93/MWh	$77.57/MWh	$279.62/MWh
Implied Multiplier of Variable Cost	2.0	2.2	1.8	3.3

10.2.6 Real-Time Market-Clearing Process

The real-time market-clearing process simultaneously clears energy and R30 to maximize net benefit. It will minimize the sum of offer-based dispatch costs subject to constraints.

Dispatches and prices are determined in 5-minute intervals. Each dispatch interval is solved optimally by minimizing total dispatch cost for that interval. Information within the next two-hour period will be included in the solution for the current interval to ensure the system can meet forecasted net demand and ramp over the subsequent two-hour period.

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

A key feature of SCED is co-optimization of energy and reserves. Co-optimization means calculating energy and reserve schedules simultaneously (not via sequential clearing), selecting the lowest cost assets to meet energy and reserve needs. The process will co-optimize energy and ramping reserves (R30), producing energy and R30 schedules for each asset and each interval. For more information on the mechanics of SCED and co-optimization refer to the *Co-optimization Information Document*.[34]

[34] Co-optimization Information Document, posted on AESO Engage August 16, 2024. Note that the previous market designs included real-time co-optimization of energy, ramping reserves and real-time operating reserves.

10.2.7 Energy and Ramp Pricing

The real-time market-clearing process will use SCED to determine LMPs, a Reference Bus Price and an ALP. Each LMP is calculated at individual nodes. These nodes refer to an asset's specific location on the system. LMP reflects the value of the marginal unit of energy at that location. LMPs will be comprised of multiple components. A province-wide energy price component and a location-specific congestion price component. A loss price component can be included to reflect the marginal impact of losses by location.

- The province-wide energy price component is the Reference Bus Price. Two components make up the reference bus price. The offer-based cost to deliver one more increment of energy to the reference bus is the marginal energy offer plus, when applicable, the lost opportunity cost of not providing R30 (including any R30DC scarcity adder). The reference bus is the load-weighted average of all prices at load nodes in the province.
- The location-specific congestion price component reflects all the transmission constraints for which a generator was effective. This is informed by each asset's constraint effective factor, calculated in real-time based on the binding transmission system limits. The congestion price reflects the re-dispatch cost associated with curtailing generation upstream and dispatching higher-priced generation downstream. The congestion component is calculated automatically as an output from SCED and can be posted as a separate value for each node. When there is no congestion, the congestion component of LMP will be zero.
- In other markets, the cost of marginal losses forms a third component of LMP. Including losses in LMPs improves the efficiency of the price signal. Should losses be recovered on a system average basis, the market clearing prices and dispatches will not consider individual, asset-specific loss factors, and generator LMPs will not contain a loss price component. The system will dispatch a greater nominal volume of energy than what is consumed by load to account for losses.

Supply/source assets will receive the LMP at that asset's node. Loads that have elected to be subject to LMP will pay the LMP for consumption at that asset's load node. All other loads, those that have not elected or are not able to elect, will be subject to the ALP.

Table 4: Alberta Electricity Prices Summary

Price	Description	Applicability
LMP	The locational marginal pricing for an asset's specific node. Comprised of multiple components: Reference Bus Price, location-specific congestion price, (potentially) cost of marginal losses.	All source assets All qualified, controllable sink assets Sink assets that have nominated to receive their LMP
ALP	The ALP is the load-weighted average price of all remaining load nodes, after removal of all the load nodes that receive their LMP. This is the default load rate if the sink asset is not qualified or not able to access their LMP.	All sink assets that have not elected to receive their LMP
Reference Bus Price	The Reference Bus Price is the load-weighted average energy component of all load buses. This price is used to calculate prices for other products.	The province-wide energy component used in calculating LMPs Day-ahead OR products are indexed to the Reference Bus Price

Ramp Clearing

The R30DC represents the system's demand curve for ramping reserves. The R30 supply curve is constructed by ordering all available R30 offers, from lowest to highest price. When there are sufficient offers to provide all the required R30 volume, the intersection of the R30DC and the R30 supply curve determines the market-clearing price and quantity of R30. More specifically, the R30 market and energy market are co-optimized, meaning they are simultaneously cleared. The real-time market-clearing process will result in a price for ramp and energy prices for each 5-minute interval. The ramp product will have a single Alberta-wide price.

Intertie Clearing

The clearing of physical flows across interties will be based on ATC, with the scheduled flow being the net of both import and export schedules. Fixed-volume schedules within the ATC limit will clear prior to the top of hour and volumes will remain constant across all five-minute intervals within the hour unless real-time ATC changes.

10.2.8 Special Conditions

Dispatch Tie Breaking During Transmission Constraints

When upstream generators have equally priced offers (for example, offered energy at the price floor) and transmission constraints bind, resources will not be dispatched based on their offers and will follow a pre-determined method. The AESO has two tie-breaking options for curtailing affected generators upstream of a transmission constraint with equal offers.

- **Option A:**
  - Curtail affected assets according to constraint effective factors, in a manner that minimizes cost and curtailment
  - This approach results in the most economically efficient dispatch
- **Option B:**
  - Curtail affected assets pro-rata as a less efficient but more equitable approach

11. Market Settlement

11.1 Purpose

This section describes how market participants are compensated or charged for energy and ancillary services provided through the day-ahead and real-time markets. It includes the settlement intervals in both markets and performance assessments for unacceptable deviations from dispatches.

Day-ahead market prices are settled on an hourly basis. The real-time market will settle on a 5-minute interval to align energy market transactions with dispatch requirements to ensure that prices reflect the real-time flexibility requirements of the system. Aligning settlement and dispatch intervals will result in an improvement to energy market signals. The current hourly real-time settlement will continue until the transition to 5-minute settlement is implemented in 2032.

11.2 Detailed Design

Settlements for market products involve two key components:

- Settlement of the products: Energy, OR and ramp
- Performance assessment associated with not providing the products

11.2.1 Day-Ahead OR Settlement

The AESO will continue to settle day-ahead (DA) OR using today's process. Active OR prices paid will be no less than $0/MW at settlement to ensure that market participants are not paying the AESO to provide OR, which would deter participation in the OR market.

DA OR settlement:

- **Active OR:** Calculated by multiplying the quantity cleared by the calculated price (indexed clearing price plus Reference Bus Price) for each relevant product
- **Standby OR:** Multiplying the quantity cleared by the standby premium price for each relevant product
- **Activated standby OR:** Calculated by multiplying the quantity activated by the respective active OR product calculated price (indexed clearing price plus Reference Bus Price)

The DA OR price will be indexed to the Reference Bus Price. While the Reference Bus Price is calculated every five minutes, DA OR will clear on an hourly basis. For settlement, the hourly indexed price will be applied to each five-minute interval within the hour.

Active OR

$$(Q_{POR}^{RT}) \times P_{OR}^{DA}$$

Where:

Q_{POR}^{RT} is the lesser of real-time quantity of provided OR or day-ahead quantity of cleared OR for each relevant OR product

P_{OR}^{DA} is the calculated OR price (indexed clearing price plus reference bus price) for each relevant OR product

Standby OR

$$(Q_{SBOR}^{RT}) \times P_{SBOR}^{DA}$$

Where:

Q_{SBOR}^{RT} is the lesser of real-time quantity of provided standby OR or day-ahead quantity of cleared standby OR for each relevant OR product

P_{SBOR}^{DA} is the standby premium price for each relevant OR product

Activated Standby OR

$$(Q_{AOR}^{RT}) \times P_{OR}^{DA}$$

Where:

Q_{AOR}^{RT} is the quantity of activated standby OR for each relevant OR product

P_{SBOR}^{DA} is the respective active OR product calculated price (indexed clearing price plus Reference Bus Price.)

Performance Assessment for OR

The performance assessment for OR (RR, SR and SUP) will remain largely unchanged as it is based on technical requirements that will continue to remain. The technical requirements, such as maintaining headroom, operating within RR range and responding to dispatch and directives, etc., are not affected by REM and will continue to apply.[35] The remedies for non-performance will continue to include the following:

- Claw back of payment to the pool participant for the operating reserve during the hour in question
- Assessment of liquidated damages
- Pursuit of the event as a potential ISO rule contravention

11.2.2 Real-Time Energy Settlement

Real-time energy settlement is calculated by multiplying the quantity dispatched (energy) by the relevant price. Energy will be settled at the applicable LMP or ALP.

LMP Settlement (Generators and Participating Loads) for Energy

Settlement at the LMP price will occur for all generation/source assets and those sink assets that have nominated and qualified for LMP.

$$(Q_{PE}^{RT}) \times P_E^{LMP}$$

Where:

Q_{PE}^{RT} is the real-time quantity of provided energy for source assets and consumed for sink assets. This is determined using metered volumes of energy.

P_E^{LMP} is the real-time LMP for energy at the applicable node.

Performance Assessment for Energy

The REM design will transition from the current 10-minute clock periods for assessing Generating Asset Steady State[36] to align with the new 5-minute dispatch intervals. This will include updates to ramping compliance for all assets, including dispatches for renewable assets based on the physical capabilities of the grid in each 5-minute interval.

The AESO evaluates non-compliance by determining whether an asset's real-time provided energy deviates from its real-time dispatched energy by more than the allowable dispatch variance (ADV). The AESO will refer these non-compliance events to the MSA.

$$|Q_{PE}^{RT} - Q_{DE}^{RT}| > ADV$$

[35] ISO Rule 205.4, *Regulating Reserve Technical Requirements and Performance Standards*, ISO Rule 205.5, *Spinning Reserve Technical Requirements and Performance Standards*, ISO Rule 205.6, *Supplemental Reserve Technical Requirements and Performance Standards*.
[36] ISO Rule 203.4, *Delivery Requirements for Energy.*

Where:

Q_{PE}^{RT} is the real-time quantity of provided energy determined using metered volumes of energy or supervisory control and data acquisition (SCADA) data for energy.

Q_{DE}^{RT} is the real-time quantity of energy based on energy dispatch in real-time.

Performance assessments for energy apply only to those assets that receive and must comply with real-time dispatches through the market-clearing engine. This includes source assets that submit energy offers and sink assets that submit energy bids. Sink assets that have opted for the LMP price but do not submit energy bids will not be subject to performance assessments for energy.

Load Settlement (Alberta Load Price)

Settlement at the ALP will apply to all sink assets that did not nominate or are not qualified to receive their LMP.

$$(Q_{CE}^{RT}) \times P_{E}^{ALP}$$

Where:

Q_{CE}^{RT} is the real-time quantity of consumed energy for sink assets determined by using metered volumes of energy.

P_{E}^{ALP} is the real-time ALP as the load-weighted average of load LMPs from the remaining loads (ones not exposed to LMP).

Performance assessments for energy are not applicable to sink assets that are subject to ALP as they are non-controllable and do not follow real-time dispatches.

LMP Settlement for Energy Transacted Over Interties

For fixed-volume transactions, schedules will remain constant across each five-minute interval within the hour. Participants will be compensated based on the time-weighted average LMP for the hour, multiplied by the scheduled quantity. In the event of intra-hour curtailments due to special conditions within AESO or in adjacent regions, participants will be paid the weighted average LMP, using the curtailed quantities as weights.

11.2.3 Real-Time Ramping Product Settlement

Ramping settlement will be calculated by multiplying the cleared ramp volume by the relevant price. Ramping products will be settled at the relevant single market clearing price for each interval.

Ramping Product Settlement

$$Q_{R30}^{RT} \times P_{R30}^{RT}$$

Where:

Q_{R30}^{RT} is the lesser of real-time quantity of provided ramping reserve or real-time quantity of cleared ramping reserve.

P_{R30}^{RT} is the real-time price of ramping reserves.

Performance Assessment for Ramping Reserves (R30)

The AESO assesses non-compliance by determining if an asset's real-time provided R30 quantity is less than its real-time cleared R30 quantity. The AESO will refer these non-compliance events to the MSA.

$$If\ (Q_{PR30}^{RT} - Q_{CR30}^{RT}) < 0$$

Where:

Q_{PR30}^{RT} is the real-time quantity of provided ramping reserves.

Q_{CR30}^{RT} is the real-time quantity of cleared ramping reserves.

P_{R30}^{RT} is the real-time price of ramping reserves.

The assessment for real-time quantity of provided ramping reserves (R30) is determined by the available headroom:

- For source assets: (asset capability – energy measured[37] - OR volume sold) ≥ R30 cleared quantity
- For sink assets that are controllable (submits bids): Consumption level (measured volume) must be larger than the combined R30 volume cleared and OR volume cleared

11.2.4 Settlement Interval Transition

REM will introduce a 5-minute settlement interval in the real-time market for transmission-connected generators and loads and the interties by 2032. All market participants will need to be able to settle to a 5-minute settlement interval by 2040.

A shorter settlement interval better aligns energy market transactions with the dispatch interval in the real-time market of five minutes, so that prices reflect the system's real-time flexibility requirements to incentivize more flexible response to market conditions from generators and loads. Further implementation details relating to introducing 5-minute settlement will be developed in consultation with other agencies and with industry.

[37] Energy measurement from SCADA or metered volumes.

12. Ancillary Services Cost Allocation

12.1 Purpose

The cost for all ancillary services will be recovered based on cost causation principles[38] and in accordance with the legislative framework.[39] Each ancillary service product's costs will be primarily allocated based on the factors driving the need for the product.

The cost allocation for the R30 ramping product is outlined below. The AESO will engage further on cost allocation for all other ancillary services, including existing OR products, in Q3 2025.[40]

12.2 Detailed Design

12.2.1 R30 Cost Allocation

Ramping products were introduced through the REM to address increasing net demand variability. Net demand variability and the increase of wind and solar generation cause grid imbalance, voltage and frequency issues and a mismatch between supply and demand. Since R30 provides dispatchable flexibility to manage changes in net demand variability, it is reasonable to allocate R30 costs to those contributing to this variability. Increasing net demand variability in recent years has largely been driven by increases in wind and solar generation on the AIES. As a result, R30 costs will be allocated to wind, solar and load.

The AESO determines the expected ramping requirement volume for each upcoming interval based on ramping and power forecasts for load, wind and solar. As detailed in the Detailed Design and Energy and Ramp Pricing sections, the market-clearing mechanism will determine the volume and price for R30 in each interval, which is procured for both the expected and unexpected ramping requirements. Once known, the total cost for R30 for an interval can be allocated to individual wind, solar and load assets for that interval using the following high-level steps:

1. Split the total R30 costs[41] into total wind, solar and load shares. The AESO will determine each share using the separate wind and solar ramping forecasts for the applicable interval. Since wind and solar generation ramp differently, the AESO will allocate R30 costs based on the AESO's ramping forecasts for each technology type. This dynamic allocation will result in different shares of the total R30 costs being attributed to wind vs solar for each interval (for example, at night when there is no solar generation and therefore no ramping due to solar generation is expected, the share of R30 costs for solar will be zero).

Currently, the AESO's ramping forecasts are based on total wind and total solar generation and not individual assets.[42] In the future, if ramping forecasts are available for individual wind and solar

[38] Minister of Affordability and Utilities (MAU) Direction Letter - July 3, 2024.
[39] *Electric Utilities Act*, Section 30(4)
[40] For more details, see Ancillary Services Cost Allocation | AESO Engage
[41] Total R30 costs include both expected and uncertainty costs
[42] AESO currently publishes wind and solar forecasts at 10-minute granularity. See Wind and Solar Power Forecasting | aeso.ca

assets, R30 costs can be directly allocated to each asset based on its specific contribution to the ramping requirement.

After splitting costs into wind, solar and load shares, each share will be allocated to the individual wind/solar source assets or load sink assets based on the applicable billing determinant.

2. **Allocate load share to sink assets.** Since loads drive the demand that contributes to the ramping requirement in each interval, it is appropriate to allocate ramping costs to load based on a MWh billing determinant that reflects each load's share of demand during that interval. The load share of R30 costs will be allocated to all pool participants registered as sink assets, including retailers and loads participating in the market on their own behalf.

The load share of R30 costs (calculated in Step 1 above) will be distributed over each load sink asset based on their share of total metered volume consumption for that interval. For example, if a sink asset consumed four per cent of all metered volumes in an interval, it will pay four per cent of the total R30 costs allocated to load. The rate will be on a $/MWh basis and loads that consumed more in that interval will pay more than those that consumed less.

While loads currently have limited ability to adjust their consumption to reduce their R30 costs, controllable sink assets can qualify to provide and be paid for R30.

3. **Allocate wind and solar shares to applicable source assets.** The allocation of wind and solar shares to individual source assets follows the same process, but for simplicity, this section focuses on wind generation. The wind share of R30 costs for an interval will be allocated to all pool participants that are registered as a source asset with wind generation. Similarly, the solar share of R30 costs will be allocated to all source assets with solar generation. The AESO is still exploring cost allocation for hybrids (for example, wind or solar with energy storage) but believes that hybrid assets that do not contribute to the need for R30 should not be allocated R30 costs.

Ramping costs for each wind asset is allocated based on a $/MW billing determinant that reflects that source asset's maximum capability (MC). A billing determinant based on MC is more indicative of how that wind asset impacted the *forecasted* wind generation (and therefore, the need for R30) rather than a billing determinant that reflects their *actual* generation in that interval.[43]

The wind share of R30 costs (calculated in Step 1 above) will be allocated over each wind source asset based on individual asset MC relative to the total amount of wind MC. Each wind asset's share of total wind costs will be the same as the asset's share of total wind MC.

Wind and solar assets can mitigate their R30 costs by controlling their ramp. For example, adding a battery could enable a solar or wind source asset to manage its ramp. Assets that mitigate their contribution to R30 costs through controllable ramping will not be allocated R30 costs.

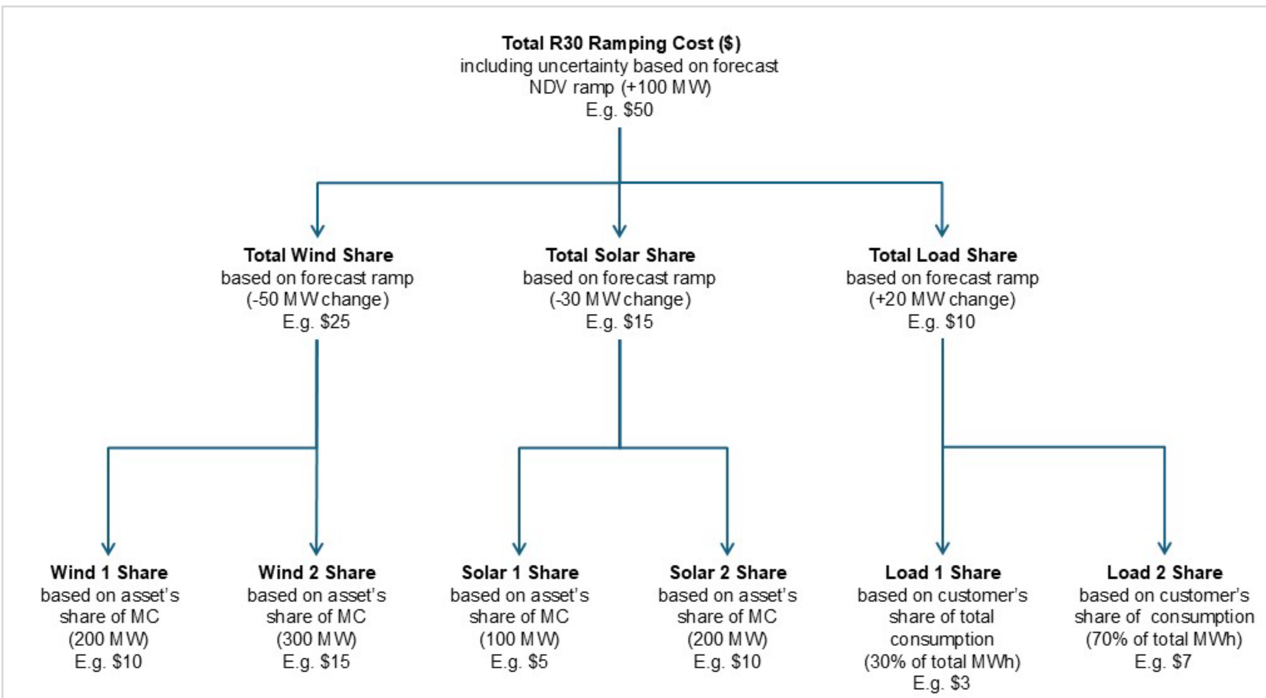
The figure below illustrates a simplified example of the R30 cost allocation framework. In this example, 100 MW of expected ramp is forecast due to a forecast of wind (ramping down 50 MW), solar (ramping down 30 MW) and load (ramping up 20 MW). Depending on offers and volume with the associated ramp demand curve, the R30 procured volume may include a portion to account for

[43] As noted above, in the future, if ramping forecasts are available at an asset level and used to determine the ramping requirements, then R30 costs can be allocated based on each wind or solar asset's forecasted contribution to the ramping requirement for an interval.

uncertainty. However, splitting the total R30 costs into total wind, solar and load shares will be based on their contribution to the *expected* ramp (i.e., the contribution of wind, solar and load to expected ramp will be used to split the R30 costs for both the expected and uncertainty volumes).

In this example, the total R30 cost is $50, which includes the portion of costs related to uncertainty. Wind, solar and load each contribute differently to the need for the product and therefore are allocated a share of the total cost, based on how much each technology contributes to the forecast need (Step 1 above). Then each technology's share is allocated to individual source or sink assets based on Steps 2 & 3 described above.

Figure 3: Simplified R30 Cost Allocation Framework Example



Note: This example is illustrative and does not represent an expectation of which technologies will pay more or less.

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05/25