Report on interim market power mitigation measures

February 27, 2026

Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

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EXECUTIVE SUMMARY

The years 2022 and 2023 saw elevated electricity prices. Steadily increasing demand, retirements, and limited investment in controllable assets created conditions for increased exercise of market power, which contributed to these higher prices.

In August 2023, the Minister of Affordability and Utilities (Minister) issued a letter to the MSA requesting, among other things, the MSA's advice regarding "whether any… legislative or regulatory reforms are required to support more effective competition in our electricity market in order to support affordability and other outcomes in the consumer interest."

The MSA provided the requested advice in December 2023. The MSA made both near-term and long-term recommendations. The near-term recommendation included (i) a monthly secondary offer price cap and (ii) a unit commitment mechanism and start-up cost guarantee. The MSA recommended that these measures expire upon the implementation of a redesigned energy market.

In March 2024, the Minister introduced interim measures to protect the market from the excessive market power that were largely based on the MSA's recommendations. These measures include a secondary offer cap, which limits offer prices from large suppliers when net revenues exceed a certain threshold, as well as a unit commitment mechanism, which requires the AESO to direct certain assets online when supply cushion is low.

These measures are set to expire upon the implementation of the Restructured Energy Market (REM) that has been developed by the Alberta Electric System Operator (AESO).

In this report, the MSA outlines its analysis with respect to these measures for the 18 months from their implementation in July 2024 to the end of 2025.

Following the announcement of these measures, but before they were implemented, electricity prices began to decline, largely due to investment in new generation and lower natural gas prices. After implementation, the interim measures reinforced this effect, and prices have remained low and stable.

The MSA estimates that, absent the interim measures, the average pool price from July 2024 through December 2025 would have been $54.37/MWh – above the observed average of $46.96/MWh, but still well below the 2022 and 2023 average pool prices of $162.46/MWh and $133.63/MWh, respectively. This indicates that the interim measures have been a safeguard against excessive market power, alongside a broader competitive response.

Though the exercise of market power and pool prices have decreased on average, market conditions have become increasingly volatile with greater adoption of intermittent renewable generation. This shift, combined with the consolidation of thermal generation from the merger of two large market participants, resulted in transient increases in market power during tight supply conditions.

With the interim measures in effect, the secondary offer cap was only triggered once, in July 2024 – the first month after implementation. Prices fell with the lower cap in place, though this also coincided with the end of a heat wave, when prices would have declined based on market fundamentals. During the one event with low supply cushion while the secondary offer cap was in place, prices still rose to scarcity levels. While the sample period is small, there is no evidence to suggest that the cap has distorted or impaired market outcomes.

The impact of the secondary offer cap was minimal; however, the unit commitment mechanism was triggered regularly. Over the first 18 months of implementation, the AESO issued 155 unit commitment directives (UCDs), with significant increases towards the end of 2025. This increase was partly driven by increases in constrained down generation (CDG), which resulted in both low supply cushion and low prices. In these circumstances, there was little incentive for assets to self-commit, so the AESO was required to use UCDs to maintain supply cushion above the threshold.

The MSA estimates that 36% of UCDs were issued when self-commitment would have been profitable. This suggests that the UCD supply cushion threshold could be lowered while still mitigating market power effectively. However, the current threshold has been effective in ensuring that sufficient capacity is online to account for unexpected generator outages or drops in intermittent generation, thereby promoting reliability.

Even though UCDs have helped maintain reliability during some events, the AESO's forecast of supply cushion, which underpins commitment decisions, continues to struggle to predict tight supply conditions. For example, when the actual supply cushion ended up under 250 MW, the AESO's forecast 12 hours ahead overestimated the supply cushion by over 1,000 MW on average. These events are often driven by unexpected factors, such as unplanned generator or transmission outages, but also coincide with foreseeable factors such as low intermittent generation and high demand. This reflects the trend of rapidly increasing net demand variability and uncertainty.

Several implementation challenges emerged as the interim measures were applied in a broader set of operating conditions through time. These included issues with the AESO's UCD-related tools, required updates to the ISO rules and information documents, and enforcement issues with UCD response times and asset parameters.

1 BACKGROUND

The years 2022 and 2023 saw elevated electricity prices. Steadily increasing demand, retirements, and limited investment in controllable assets created the conditions for more exercise of market power, which was a driving factor for these higher prices.

Throughout this period, the MSA closely monitored market outcomes and reported publicly on its findings. While long-run market fundamentals created the conditions for increased market power, these factors were compounded by increased net demand variability and the ability for long lead time (LLT) assets to remain offline. The MSA shared its findings and recommendations regarding LLT assets in its Quarterly Report for Q2 2023.[1] Among other findings, the MSA observed a shift in behaviour, in which LLT assets were kept commercially offline for extended periods, and during higher pool prices than in previous years.

1.1 Ministerial direction

In August 2023, the Minister of Affordability and Utilities (Minister), issued a letter to the MSA requesting, among other things, the MSA's advice regarding "whether any… legislative or regulatory reforms are required to support more effective competition in our electricity market in order to support affordability and other outcomes in the consumer interest."

1.2 Advice to the Minister

The MSA delivered its advice to the Minister on December 21, 2023.[2] The MSA noted that changes in the generation fleet led to a marked increase in economic withholding, exacerbated by the ability for LLT assets to be physically withheld. To address this increase in market power and support more effective competition, the MSA made both near-term and long-term recommendations. The near-term recommendation included two components:

i) a Monthly Net Revenue Secondary Offer Price Cap, and

ii) a Unit Commitment Mechanism and Start-up Cost Guarantee Program.

These near-term recommendations were made in recognition of the significant time and investment required to implement larger-scale market reform and were accordingly limited in scope and complexity.

The MSA recommended that these interim measures expire upon the implementation of a redesigned energy market. This is expected to occur upon the implementation of the Restructured Energy Market (REM) that has been developed by the Alberta Electric System Operator (AESO).

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[1] MSA Quarterly Report for Q2 2023 section 1.5, pdf pg. 34.

[2] Advice to support more effective competition in the electricity market: Interim action and an Enhanced Energy Market for Alberta.

1.3 Interim regulations and ISO rules 206.1 and 206.2

In March 2024, the *Market Power Mitigation Regulation* (MPMR) and *Supply Cushion Regulation* (SCR) were enacted. Beginning July 1, 2024, these regulations moderate economic withholding and require the AESO to commit generation capacity in certain circumstances. Both regulations are set to expire on November 30, 2027.

The MPMR is implemented through ISO rule 206.1 and moderates economic withholding by imposing a secondary offer cap once monthly net revenues exceed a certain threshold.

The AESO must calculate the monthly net revenues that would be earned by a reference combined cycle generating unit. This value, called the monthly cumulative settlement interval net revenue (MCSINR), is updated each hour. The AESO must also calculate the annualized unavoidable costs of the reference generating unit, defined as the sum of annualized capital investment costs (ACIC) and annual fixed operating costs.

In any month, if the MCSINR exceeds 1/6 of the annualized unavoidable costs, the secondary offer cap is triggered for the remainder of the month. This limit is the greater of $125/MWh or 25 times the day-ahead natural gas price. The secondary offer cap only applies to market participants with 5% or greater market share offer control and excludes renewable generation and storage. In effect, the limit applies to natural gas-fired generation of large market participants.

The SCR is implemented through ISO rule 206.2 and establishes a unit commitment mechanism for the AESO to direct eligible LLT assets online.

The AESO must perform a forecast of supply cushion, called anticipated supply cushion (ASC), for each settlement interval. If ASC falls below the threshold of 932 MW, the AESO must minimize the supply cushion deficit by issuing unit commitment directives (UCDs) to eligible LLT assets. Eligible LLT assets are assets that require more than one hour to synchronize to the grid. The AESO must determine which asset(s) to direct based on economic merit and physical constraints, which are informed by parameter submissions made by market participants to the AESO.

The AESO uses a tool called Power Optimisation (PowerOp) to determine the least cost UCD or combination of UCDs to minimize ASC deficits over the next 72 hours.

When an asset is directed online, the effect of its generation on the pool price is not reconstituted. The asset is eligible to receive an uplift payment equal to the prudent incremental costs of responding to the UCD up to its minimum stable generation (MSG), net of pool price revenue.

These ISO rules were approved through the expedited process under section 20.6 of the *Electric Utilities Act* (EUA); full approval under section 20.21 of the EUA followed in Alberta Utilities Commission (Commission) Proceedings 29093 and 29940. The final approval granted by the Commission in Proceeding 29093 was subject to a revision in ISO rule 206.2. This revision required the AESO to issue a real-time notification of the start and end of unit commitment directives. The AESO filed this revision, which was approved in Proceeding 29940, resulting in final approval of all subsections effective April 20, 2024.

2 MARKET OUTCOMES

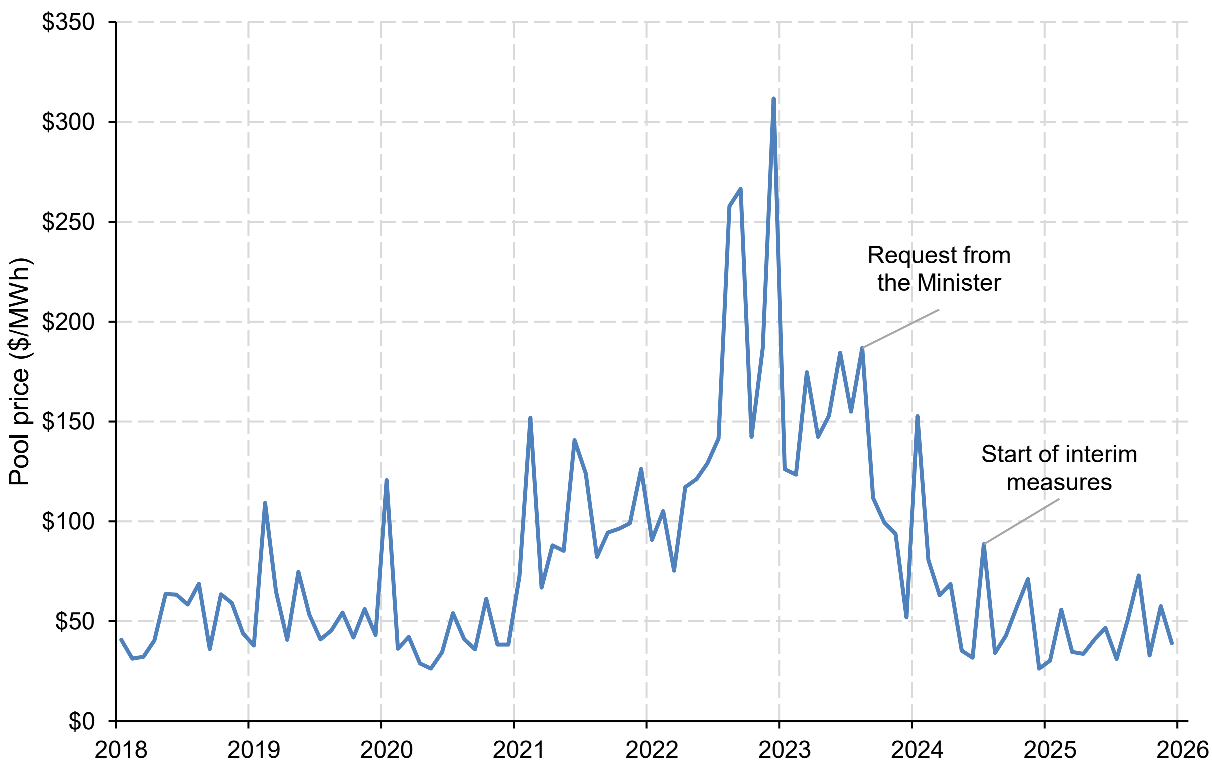
This section sets out general observations of market outcomes under the interim measures. Section 3 contains analysis that adds further context and explanation for these outcomes.

2.1 General market conditions

Prices were generally lower and less volatile since the introduction of the interim measures. While the interim measures contributed to this, wholesale market outcomes are always the result of several factors.

Mild weather, continued expansion of wind and solar generation, and significant gas-fired capacity additions all contributed to higher supply cushion and lower prices. The merger of two large wholesale market participants increased market concentration, but this was offset by downward price pressure from the aforementioned factors, and prices fell as a result.

Figure 1: Monthly average pool price



As shown in Figure 1, even disregarding significant high-price outlier months in the second half of 2022, average pool prices rose steadily starting in 2021. Following the Minister's request for advice in mid-2023, prices dropped sharply, and by the time the interim measures took effect, prices were already in line with pre-2021 levels.

Figure 2, when compared to Figure 1, shows that long-term pool price trends have generally mirrored gas price trends. With the last of the coal generation fleet retired or converted to natural gas, Alberta's electricity system has become increasingly reliant on natural gas, which now fuels over 60% of installed capacity. However, gas prices rose sharply in late 2025, without a corresponding increase in pool prices.

Figure 2: Monthly average AB-NIT (2A) gas price

Figures 3 and 4 show duration curves of pool prices and supply cushion by year. Duration curves are utilized several times in this report and are a tool for visualizing the distribution of a variable. By sorting the observations from largest to smallest, the resulting curve indicates the percentage of observations above a certain level. For example, Figure 3 shows that, in 2024, approximately 10% of pool prices were above $100/MWh.

The duration curves each feature dashed lines indicating relevant levels to the interim measures: the $125/MWh secondary offer cap in the MPMR and the 932 MW supply cushion threshold in the SCR. In 2023, 2024, and 2025, pool price was above $125/MWh approximately 24%, 9%, and 4% of the time, and supply cushion was below 932 MW approximately 11%, 9%, and 4% of the time, respectively.

Figure 3: Duration curve of pool price by year

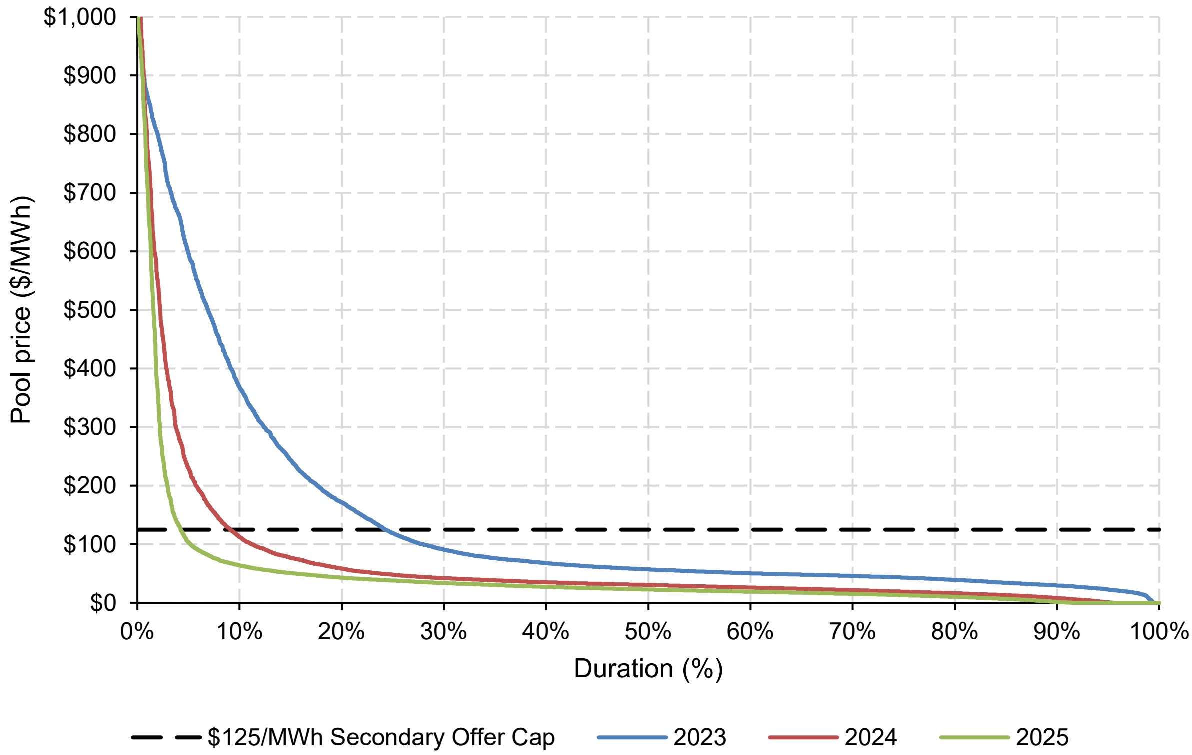
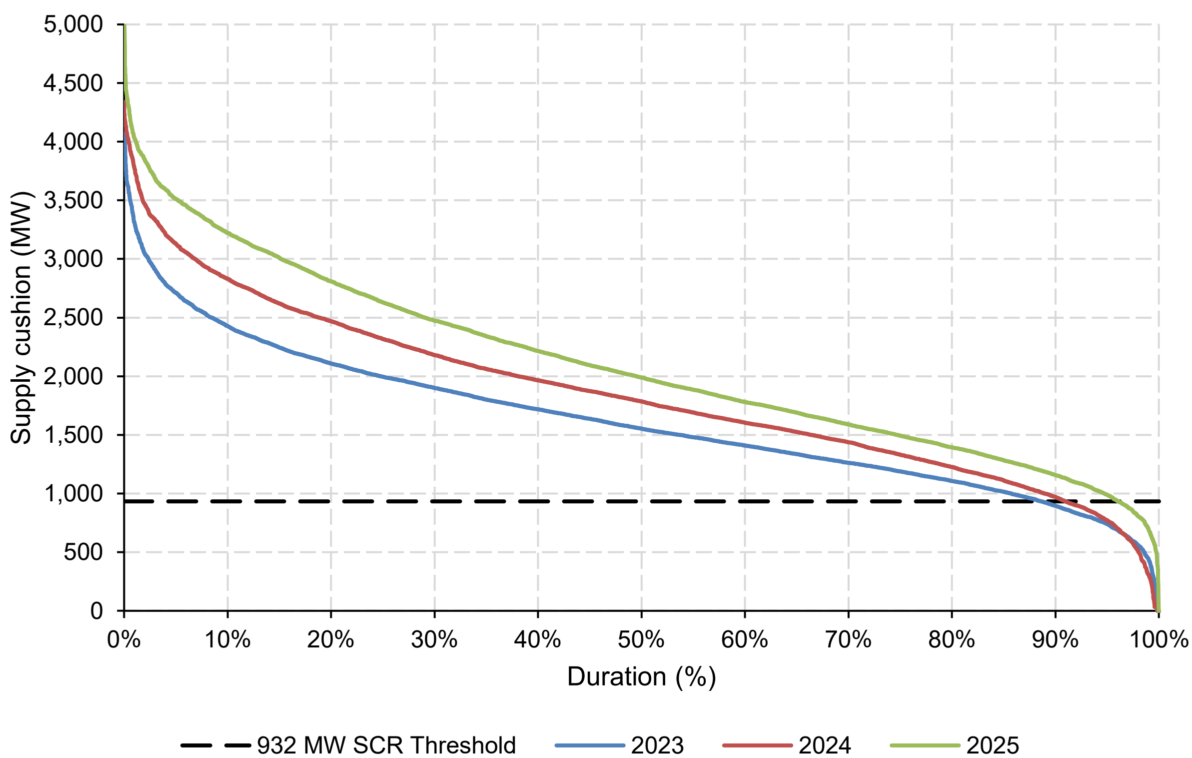


Figure 4: Duration curve of supply cushion by year

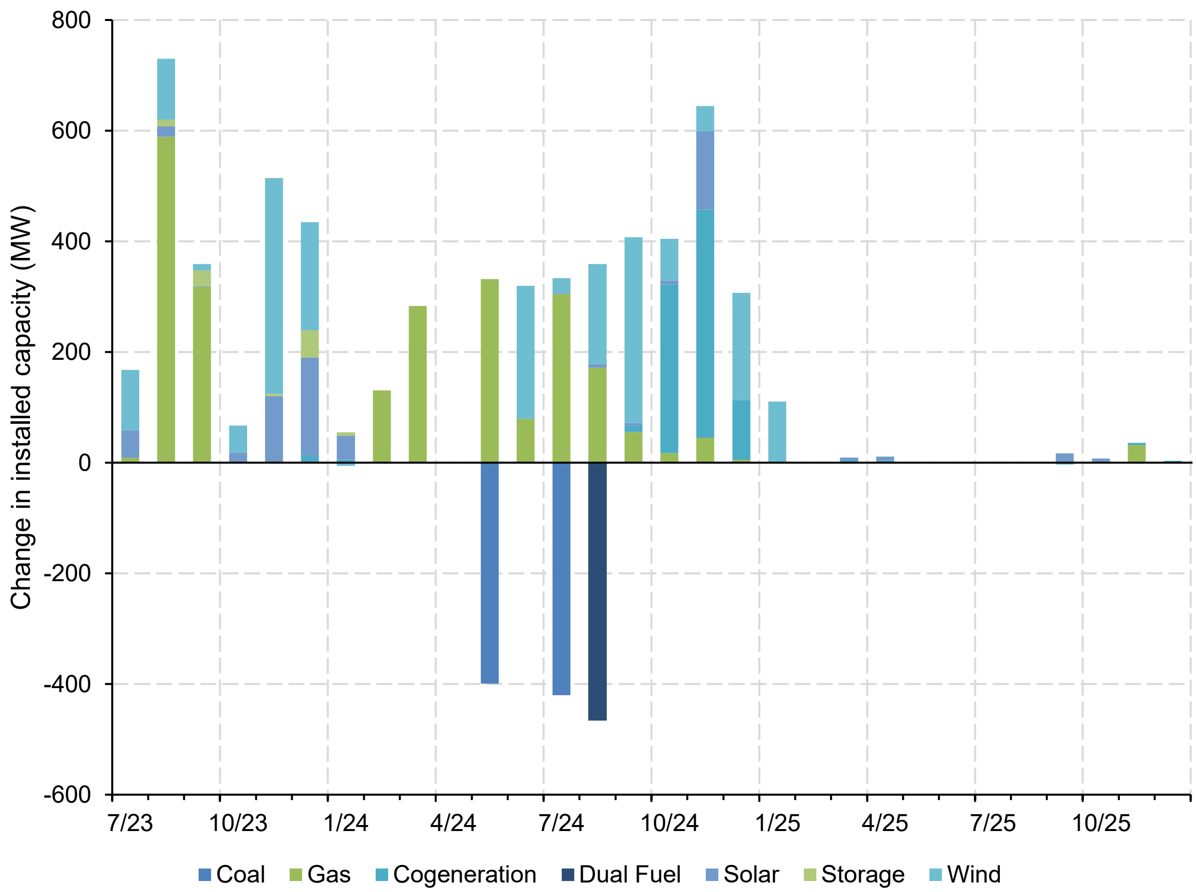


In 2024 and 2025, supply cushion fell below the SCR threshold roughly as often as pool price exceeded the secondary offer cap. This indicates that these thresholds are set at levels that target a similar set of market conditions.

Comparing the supply cushion between 2024 and 2023, the frequency and magnitude of low supply cushion hours were very similar, especially below the threshold of 932 MW. The two diverged more when supply cushion was high, consistent with increased investment in intermittent renewable generation. When these new assets have high output, incumbent renewables also tend to have high output, leading to a significant increase in total renewable generation during high supply cushion hours. Conversely, when the new assets have low output, incumbent renewables also tend to have low output, resulting in the new assets having a smaller impact during low supply cushion hours.

Based on the design of the SCR, it might be reasonable to expect a concentration of supply cushion observations around 932 MW due to UCDs, leaving high supply cushion hours unchanged. However, this was not the case, as supply cushion was consistently higher in 2025, and higher primarily at high supply cushion levels in 2024. This is partly because run time constraints often necessitate committed assets to run in adjacent hours with higher supply cushion. However, it is also because of the broader shift in supply conditions over this period.

Figure 5: Net changes in installed capacity since July 1, 2023



These trends were part of a broader wave of supply-side investment. Around the time of the Minister's request for advice, there were significant additions of controllable and intermittent generation capacity. There were no major retirements during this period, and the Genesee 1 and 2 assets repowered to use natural gas turbines, while Genesee 3 completed its full conversion to natural gas. In total, nearly 5,000 MW of generation capacity was added to the Alberta market in less than two years. In contrast, there were very few changes in the fleet in 2025.[3]

2.1.1 Forward market outcomes

Table 1 sets out annual forward prices as of the day before the announcement of the interim measures, the first day they came into effect, and in six-month intervals thereafter. While forward prices are influenced by many factors, this gives an indication of how the market responded to both the prospect of the measures and their realized impact on market outcomes.

Table 1: Evolution of annual forward prices through the interim period[4]

Product	3/10/2024	7/1/2024	12/31/2024	7/1/2025	12/31/2025
Cal 24	$75.93 (marked)	$67.30 (marked)			
Cal 25	$59.44	$51.26	$48.47	$46.74 (marked)	
Cal 26	$58.50	$51.24	$53.17	$53.75	$50.42
Cal 27	$63.25	$54.75	$60.00	$60.75	$58.19

There was a significant and consistent reduction in price expectations between the announcement of the interim measures and their implementation. During this period, realized prices both for electricity and natural gas came in below forward expectations, adding to the downward pressure for future months.

In contrast, since the interim measures took effect, forward prices have been more stable and have not moved uniformly. By the end of 2025, price expectations for 2026 were lower and for 2027 were higher, compared to the start of the interim period. This suggests that the realized impact of the interim measures was not the primary driver of these changes. The biggest shifts occurred following developments regarding potential data centres, the mothball notifications for Sundance 6 and Sheerness 1, and the Competition Bureau's announcement that it had entered into a consent agreement for the merger of two large market participants.

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[3] The Sundance 6 asset began a mothball outage effective April 1, 2025. Because this is not a retirement it is not depicted in Figure 5, though it did reduce the available supply of generation capacity.

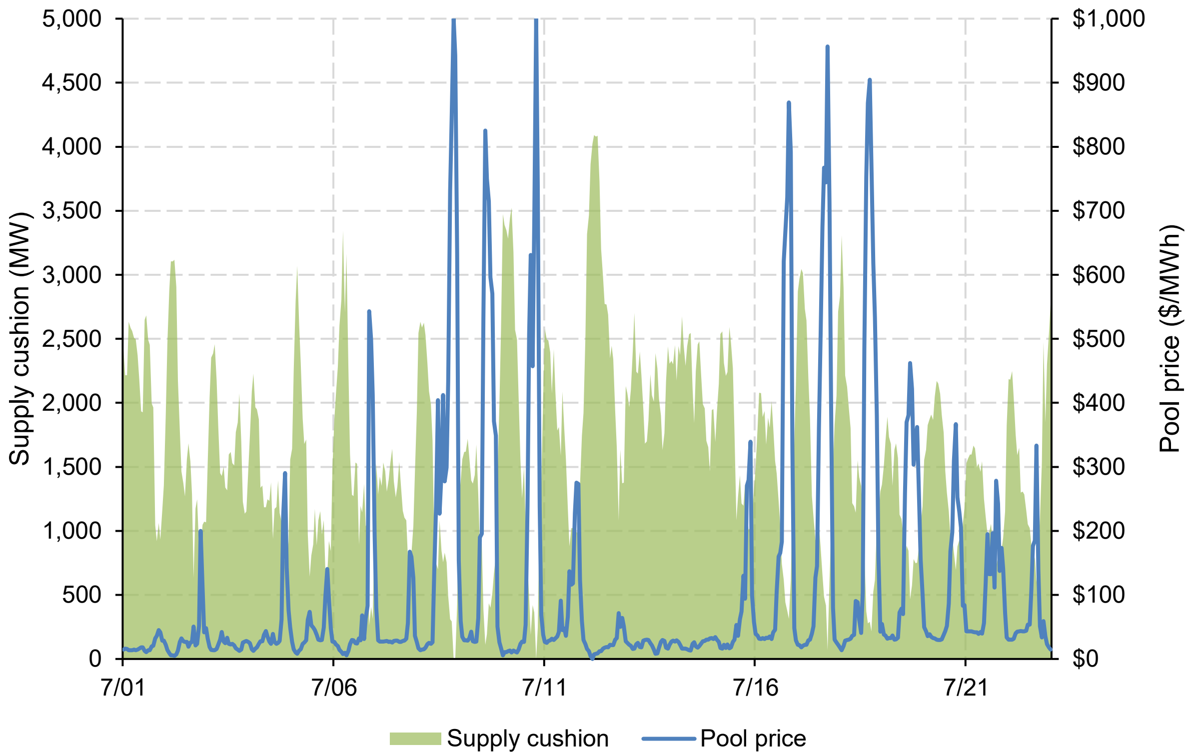
[4] A "marked" price in this context is the updated expected average price for the year, considering historical realized pool prices and forward prices for the balance of the year.

2.2 Market Power Mitigation Regulation and ISO rule 206.1

The interim measures were fully implemented beginning July 1, 2024. Shortly after implementation, the MSA identified that an incorrect inflation rate was used to calculate MCSINR and annualized unavoidable costs. The MSA notified the AESO of this error, following which the AESO issued a notice to stakeholders and corrected the reports on their website. This did not impact market outcomes, as MCSINR did not approach the threshold until later in the month.

The secondary offer cap under the MPMR and ISO rule 206.1 was only imposed in July 2024, as that was the only month in which MCSINR exceeded the threshold. Figure 6 shows pool prices and supply cushion in July 2024, before the secondary offer cap was triggered.

Figure 6: Pool prices and supply cushion during the unmitigated period in July 2024



There were several low supply cushion periods during July 2024, including an Energy Emergency Alert, during which high prices caused net revenues to rise quickly. During eight distinct events, supply cushion fell below 500 MW, with corresponding pool prices ranging from $412.35/MWh to $999.99/MWh. These events coincided with high temperatures and increased demand.

2.2.1 July 2024 secondary offer cap event

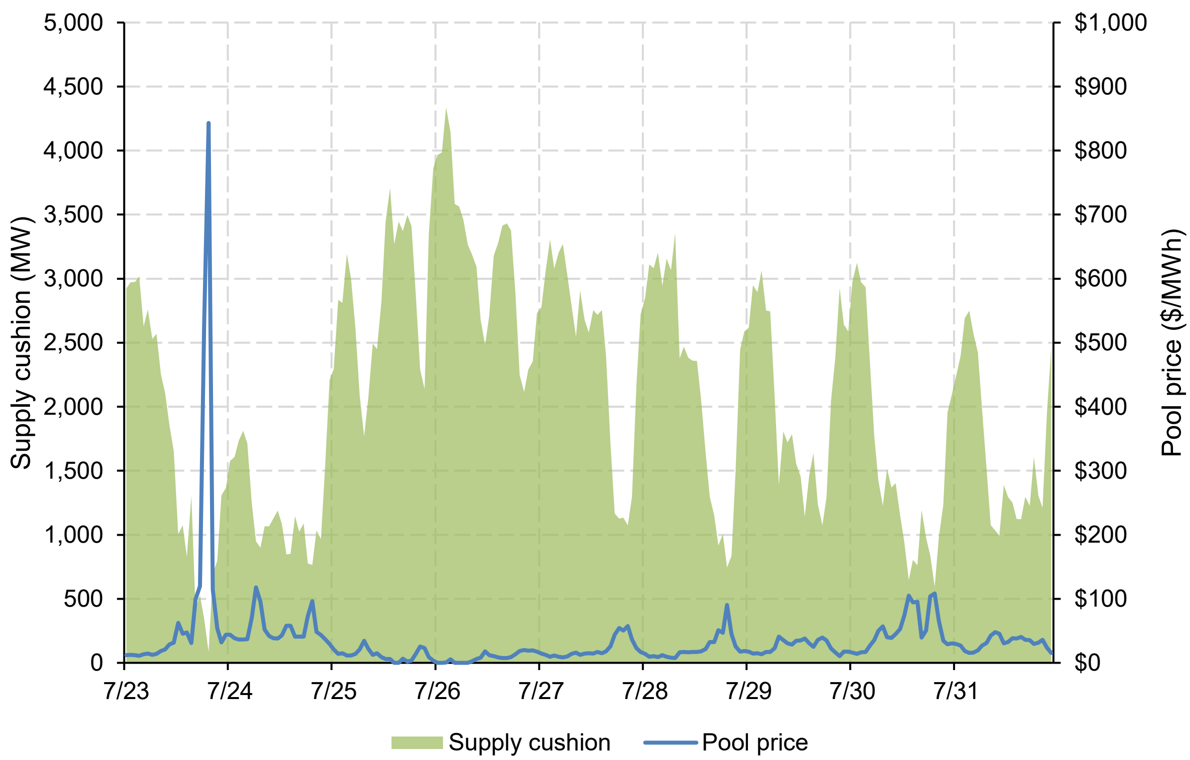
The MCSINR calculated for hour ending (HE) 21 on July 22, 2024, exceeded 1/6 of the annualized unavoidable costs of the reference generating unit. In this event, the AESO is required to calculate the secondary offer cap and notify pool participants in accordance with the MPMR and ISO rule 206.1.

ISO rule 206.1 requires the AESO to issue notification of the secondary offer cap at least two hours prior to the time it becomes effective. Had the MCSINR been updated promptly, a notification during HE 22 would have imposed the secondary offer cap beginning in HE 01 on July 23. However, notification was delayed until HE 23. Therefore, the secondary offer cap did not come into effect until HE 02 on July 23.

The AESO continued to report the secondary offer cap and effective period through the end of July. This information was reported during HE 17 the day before it was effective, except for days where the effective period included Sunday or Monday, which was then reported the Friday before. The day-ahead natural gas price did not exceed $5/GJ, so the secondary offer cap remained at $125/MWh through the end of July.

Figure 7 shows pool prices and supply cushion in July 2024 after the secondary offer cap was imposed. Shortly thereafter, the hot weather subsided, and demand returned to typical levels.

Figure 7: Pool prices and supply cushion during the mitigated period in July 2024

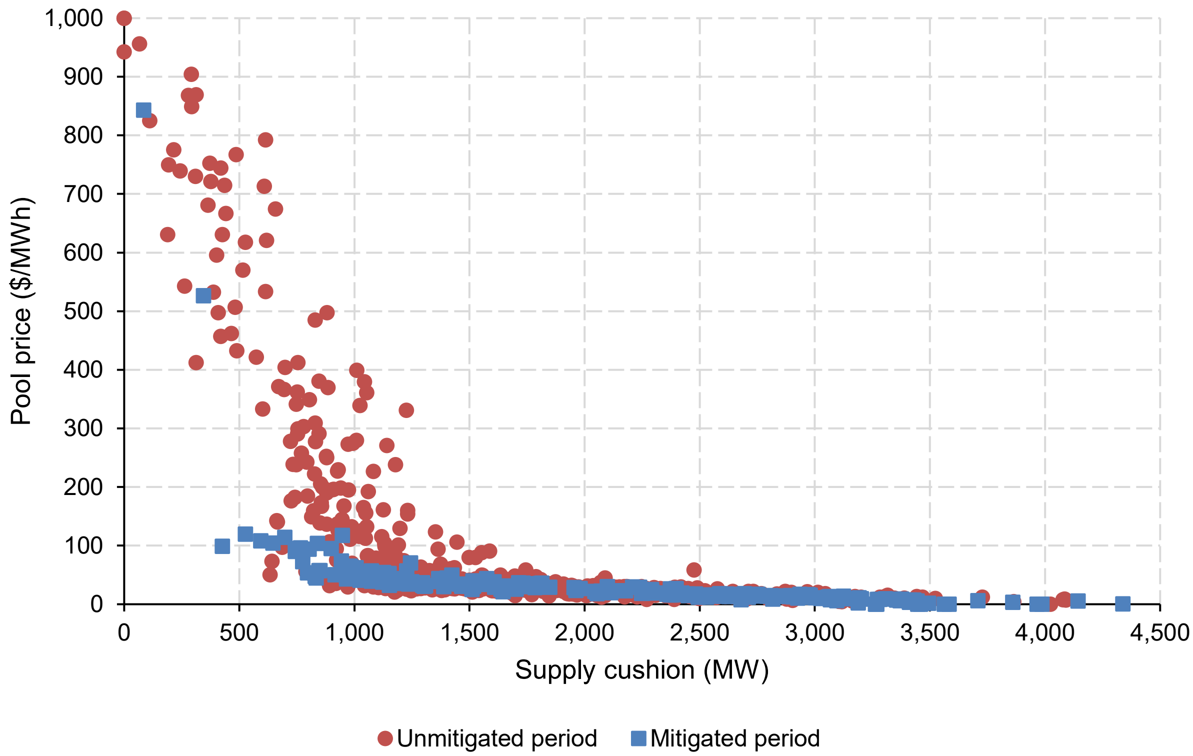


In contrast with the rest of July, during the mitigated period, there was only one event with supply cushion under 500 MW, in which pool price reached $843.15/MWh. This difference in underlying conditions naturally led to different market outcomes, independent of the secondary offer cap.

The most significant difference in price formation between the two periods was when supply cushion was between 500 and 1,000 MW. During the unmitigated period, average pool price in these hours was $238.73/MWh, compared to $78.46/MWh in the corresponding hours during the mitigated period. However, 20% of these hours in the unmitigated period had prices below the mitigated average, indicating that relatively low prices occur in these hours even without mitigation. Figure 8 shows the relationship between supply cushion and pool price during the mitigated and unmitigated periods of July 2024, highlighting this effect.

This is consistent with the expected function of the secondary offer cap. During moderate scarcity, large suppliers have more market power; however, their ability to exercise market power is constrained by the secondary offer cap. During significant scarcity, prices may be set by unmitigated offers above the secondary offer cap and, therefore, still approach the unmitigated offer cap.

Figure 8: Pool prices and supply cushion in July 2024



There were no UCDs during the mitigated period.[5] This was due to both fewer low supply cushion events, but also fewer assets commercially offline. This affirms that market participants did not circumvent the limitation on economic withholding by taking assets offline.

While the secondary offer cap did not appear to impede scarcity price signals during July 2024, this sample period is small, and changing weather was also a major driver for the shift in market conditions. There has not yet been a period where the secondary offer cap was imposed during

[5] Sheerness 2 was commercially offline during the one event when supply cushion fell below 932 MW. However, this event was not anticipated in time to direct Sheerness 2 online, primarily because Cascade 2 tripped offline unexpectedly.

significant or prolonged scarcity conditions. Should the secondary offer cap bind again, the MSA will continue its monitoring to ensure the secondary offer cap does not impede efficient price formation.

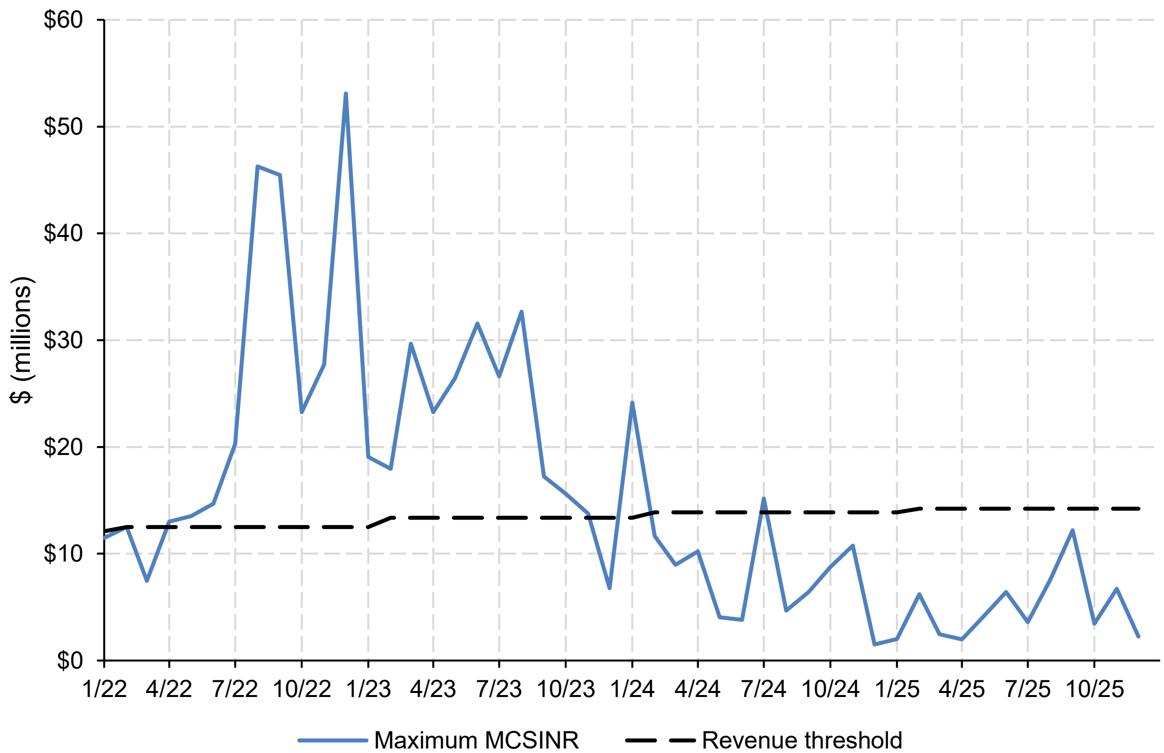
2.2.2 Monthly cumulative settlement interval net revenues

While the net revenue threshold was only exceeded in July 2024, the MSA calculated MCSINR and the net revenue threshold going back to the beginning of 2022, using the methodology as set out in the MPMR and ISO rule 206.1.

Had the interim measures been in place, the secondary offer cap would have been imposed in every month from April 2022 through November 2023. In February 2022, while the MCSINR did exceed the revenue threshold, it did so in the last hour of the month. After accounting for the AESO's notification period, this means the secondary offer cap would not have been imposed.

Following November 2023, the secondary offer cap would also have been imposed in January 2024, and then in July 2024, when it did bind while the MPMR was in effect.

Figure 9: MCSINR and the net revenue threshold beginning January 1, 2022



As shown in Table 2, net revenues were significant in 2022 and 2023. In 2024, the net revenues of the reference unit totalled roughly 133% of its annualized unavoidable costs, still indicating the opportunity for cost recovery. With lower prices and escalating costs in 2025, the reference unit would have recovered only 68% of its annualized costs. [6]

Table 2: Cost recovery of the reference generating unit

Year	Annualized unavoidable costs ($million)	Net revenues ($million)	Cost recovery (%)
2022	74.9	288.8	386%
2023	79.8	260.6	327%
2024	83.0	110.2	133%
2025	85.2	58.3	68%

The MSA notes that stakeholders have raised concerns about the parameters of the reference generating unit,[7] and that the AESO has committed to undertaking a cost of new entry (CONE) study.[8] Nonetheless, the result reinforces that market signals shifted from scarcity to adequate supply as new supply came online during this period, as outlined in section 2.1, above.

2.3 Supply Cushion Regulation and ISO rule 206.2

Through the end of 2025, the AESO issued a total of 155 UCDs under the interim measures.[9] As shown in Figure 10, these were not distributed uniformly across time, with the number of UCDs increasing significantly in the second half of 2025. In October 2025 alone, more UCDs were issued than in the first 10 months of the interim measures.

In addition to distribution over time, Figure 11 shows the distribution of UCDs by asset. While the distribution is not uniform, no single asset received notably more UCDs than the others. Given that the AESO must issue UCDs according to relative economic merit, this indicates that the most economic asset will depend on the circumstances of the event, including the length of the UCD, magnitude of the supply cushion deficit, and set of assets available to respond.

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[6] These estimates rely upon all the assumptions of the reference generation unit, as outlined in the MPMR, including that the unit is fully exposed to pool prices, natural gas prices, and carbon prices. The results differ from net revenue analysis in MSA quarterly reports due to key assumption differences. Most significantly, the MSA calculates taxes based on annual net revenues, not monthly, and incorporates the ability to reduce emissions exposure by purchasing offset credits at prevailing prices.

[7] See, for example, stakeholder comments on the REM HLD Update, pdf pgs. 21, 55, 124.

[8] REM Final Design pdf pg. 29.

[9] This excludes two UCDs in April 2025 and one in September 2025, which the participant was instructed to disregard. See section 4.5.

Figure 10: Number of unit commitment directives by month

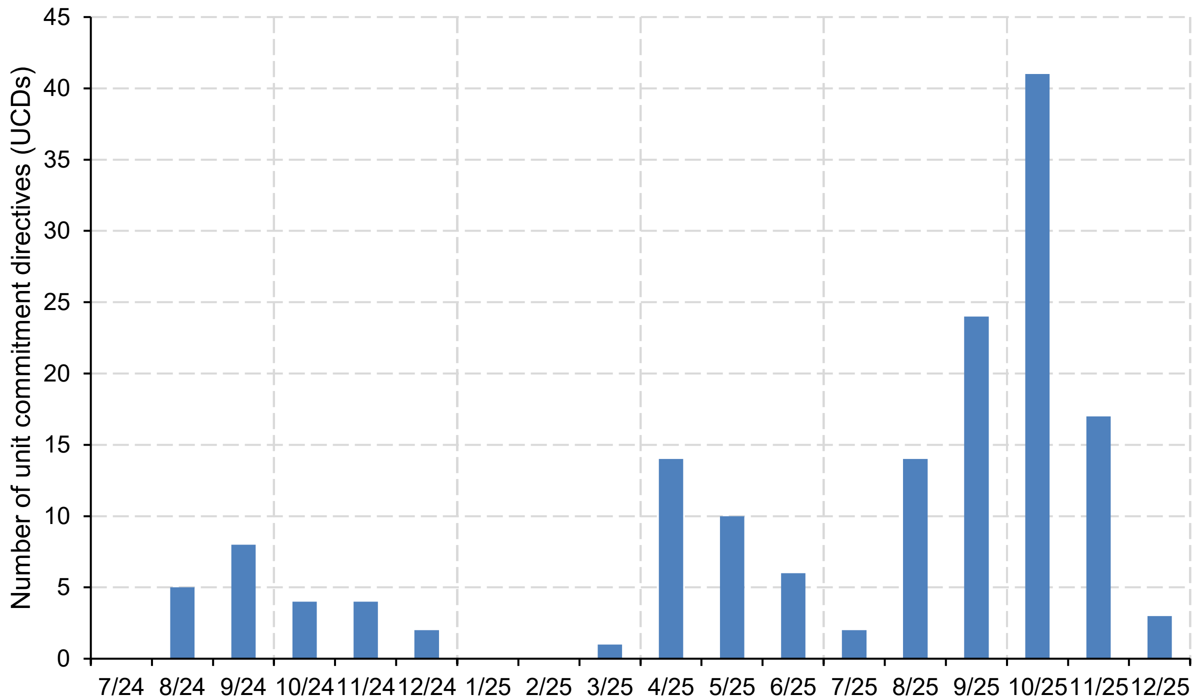
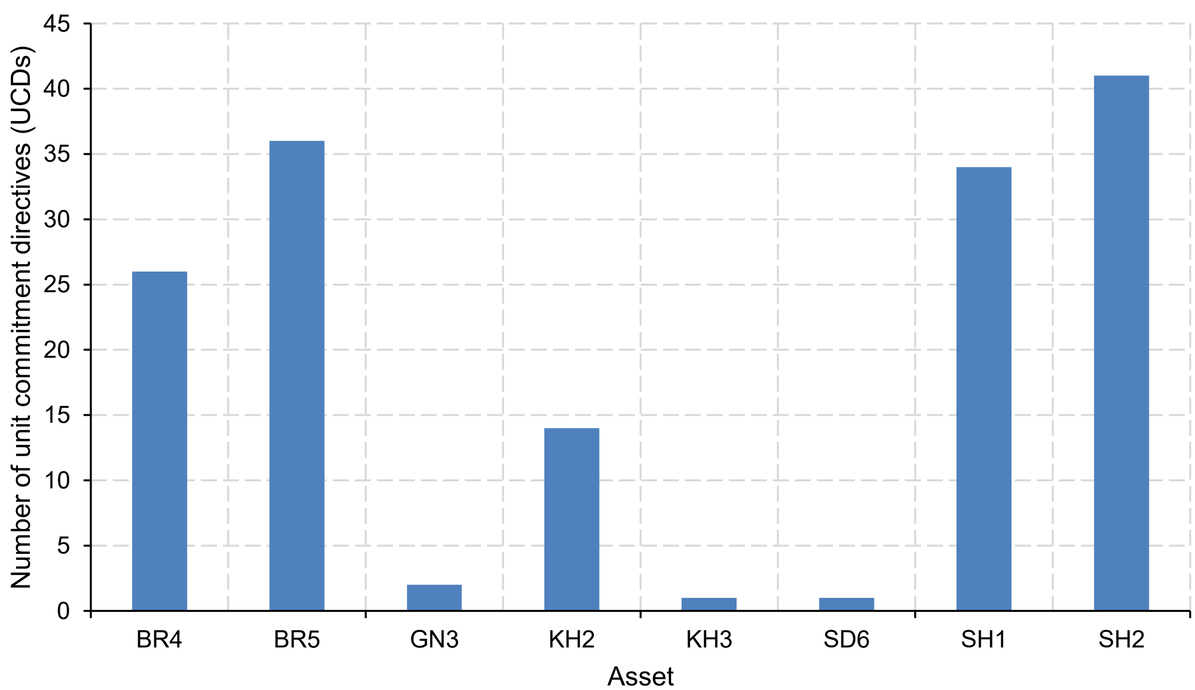


Figure 11: Number of unit commitment directives by asset[10]



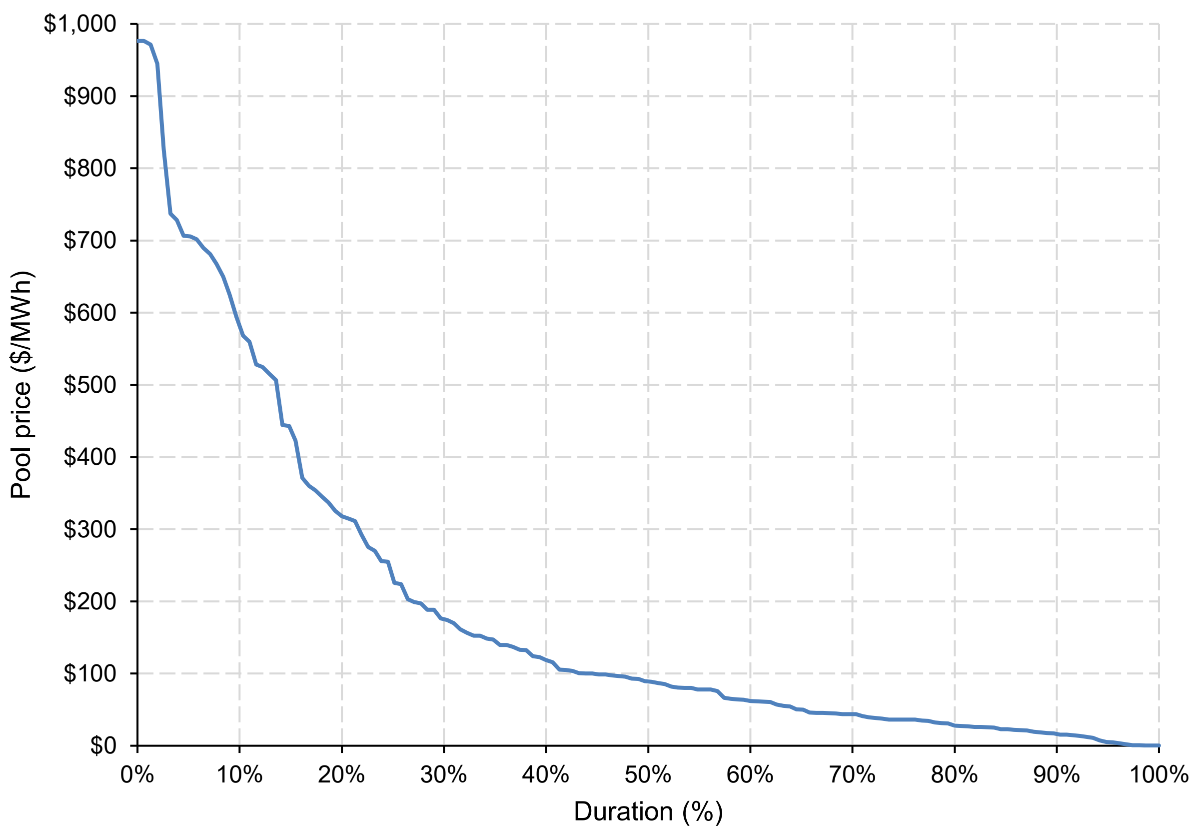
[10] Sundance 6 was mothballed effective April 1, 2025.

The supply cushion threshold below which the AESO must issue UCDs is 932 MW. At or below this level, the average pool price was $443.99, $310.10, and $260.52/MWh in 2023, 2024, and 2025, respectively. However, these prices do not reflect the received price of assets under UCD, as run time constraints often require assets under UCD to remain on for hours adjacent to those with a supply cushion deficit. Further, assets will often be self-committed for periods when low supply cushion and high prices are relatively certain.

The average received price of UCDs was $170.63/MWh, though it ranged from $0.31/MWh to $976.43/MWh, as shown in Figure 12.

55% of UCDs had a received price of under $100/MWh. While the cost of responding to a UCD will depend on several factors, including the asset, warmth state, fuel prices, and length of the UCD, the MSA anticipates that these received prices will result in several claims under the cost guarantee. Up to the publication of this report, the MSA is not aware of any claims made thus far. The AESO included projected unit commitment costs in its budgetary process, and estimated that approximately 45% of UCDs may result in a cost claim, resulting in roughly $600,000 of total costs over 2025.[11]

Figure 12: Duration curve of received price of unit commitment directives



[11] AESO 2026 Budget Development Process Stakeholder Presentation pdf pgs. 51-53 and 70.

3 ANALYSIS

This section sets out further analysis to contextualize the market outcomes described in section 2.

3.1 Market power and efficiency

As described above, several factors have resulted in lower average pool prices following the introduction of the interim measures. To better understand the role of market power, further analysis is needed to characterize the ability of suppliers to influence prices and how their exercise of that ability has changed over time.

Market power is the ability to profitably raise the market clearing price. In an electricity market, this means offering generation capacity in such a way that higher cost generation must be dispatched to meet demand, raising the price for all suppliers. The strategy of raising offer prices above marginal cost to achieve this result is called economic withholding.

To examine changes in market power over time, the following three figures depict a series of conditional analysis, in which one aspect of the energy market is compared across years while controlling for another.

The first two figures incorporate the Residual Supply Index (RSI), which is a metric used to assess the ability of large suppliers to influence prices. In this context, the RSI measures the proportion of energy demand that can be served without using the capacity of the largest supplier. An RSI of exactly one implies that, removing the capacity of the largest supplier, the remaining generation from other suppliers would exactly serve demand without any remaining supply cushion. An RSI less than one indicates that at least some capacity of the largest supplier is required to meet demand.

A supplier with an RSI less than one is pivotal, which means some of their capacity must be dispatched, regardless of its offer price. Importantly, while this may give them the ability to significantly increase prices, doing so may leave much of their capacity undispatched, and thereby not benefiting from this higher price. The most profitable offer strategy will involve a balance between setting high prices and receiving a high dispatch volume. While the RSI does not reflect this trade off, it remains a strong indicator of the ability for large suppliers to influence prices.

Figure 13 shows the average RSI across years while controlling for supply cushion. It shows that, in 2025, RSI increased at high supply cushion, indicating lower pivotality, but decreased at low supply cushion, indicating higher pivotality. The effect at high supply cushion is consistent with investment in intermittent generation from smaller suppliers. When supply cushion is high, intermittent generation tends to be high, and offer control is distributed between more suppliers. The opposite effect at low supply cushion is primarily driven by the merger of two large suppliers, which increased concentration of thermal generation. The impact of this merger is more pronounced when intermittent generation is low, which typically coincides with low supply cushion.

Figure 13: Average Residual Supply Index conditional on supply cushion by year

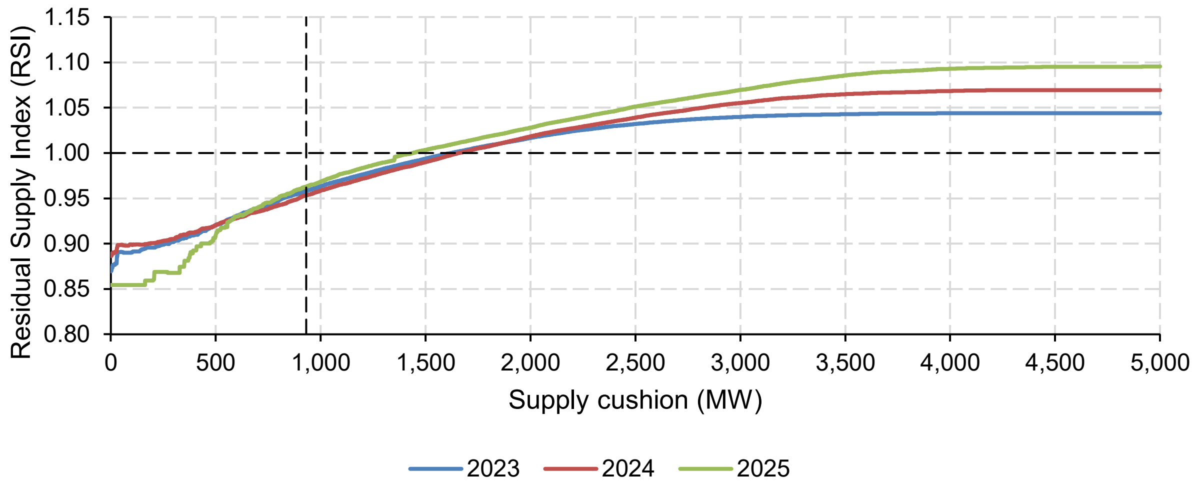


Figure 14: Average pool price conditional on Residual Supply Index by year

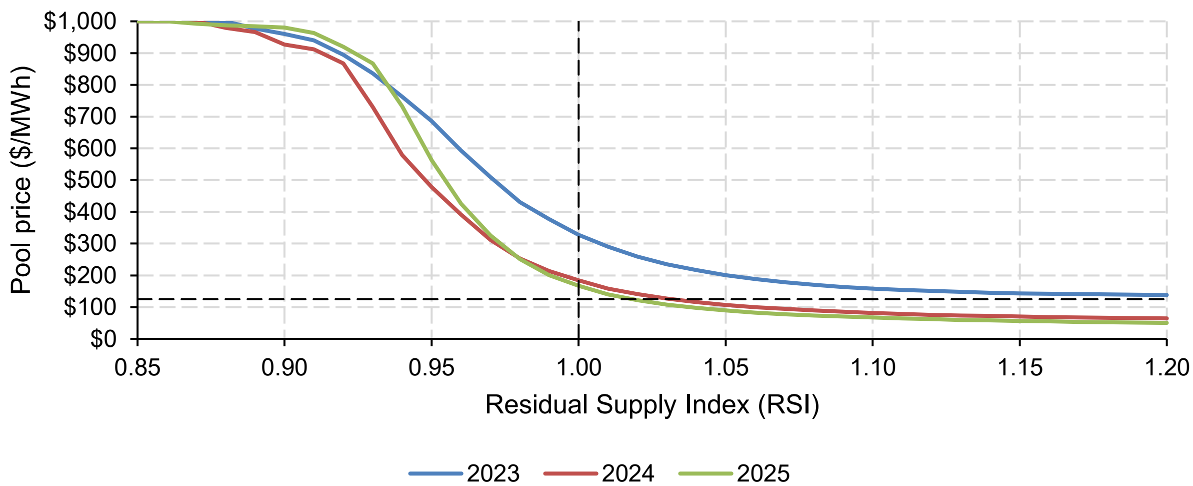


Figure 15: Average pool price conditional on supply cushion by year

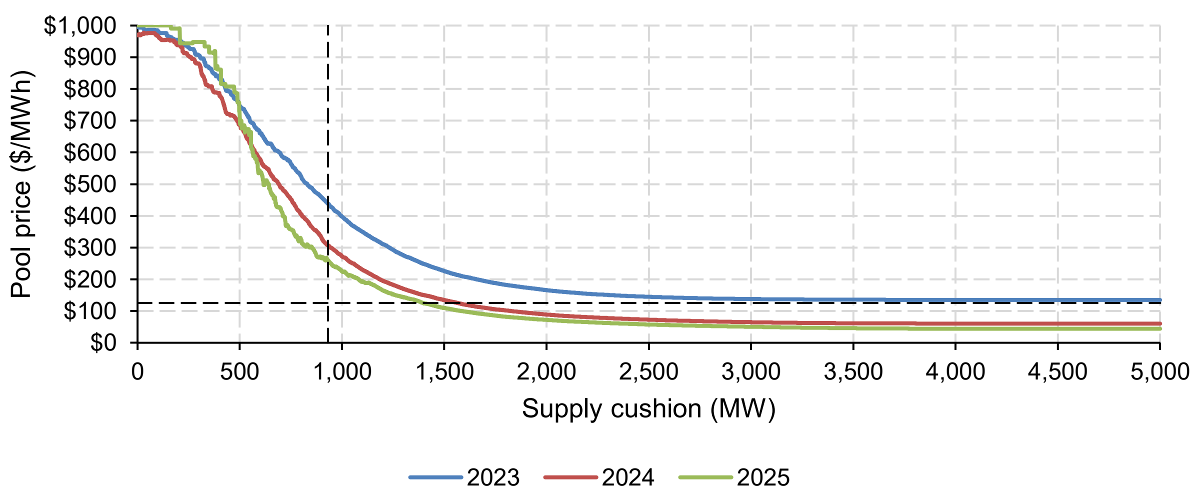


Figure 14 shows that, for a given level of pivotality, prices have generally decreased since the introduction of the interim measures. The exception is at low RSI, where prices have remained similar to 2023. This suggests that when suppliers had moderate market power, they exercised it less. However, when suppliers had significant market power, it was exercised similarly.

As described above, RSI alone is not sufficient to explain market outcomes. Many factors could explain this shift, including the following:

- reduced predictability of scarcity conditions driven by increased net demand variability,
- increased competition between suppliers apart from the largest supplier,
- shorter forward positions, reducing exposure to real-time pool prices,
- efforts to reduce costs associated with cycling and ramping, and
- shifts in corporate strategy and risk tolerance.

Together, Figures 13 and 14 show that at high supply cushion, suppliers both had less market power and exercised it less, while market power was similar or even higher at low supply cushion. Figure 15 is consistent with the net effect of these fundamental shifts on prices, with lower pool prices under the interim measures when supply cushion was above 500 MW, but similar prices below this level. This result is also consistent with the general market conditions described in section 2.1.

While the exercise of market power can raise prices, the economic harm arises when this causes a loss in static efficiency. Static efficiency measures the short-run net benefits realized in the electricity market, which can be reduced when market power causes the dispatch of higher cost generation or reduced demand.

In the context of Alberta's energy-only market, these short-run inefficiencies should be weighed against long-run efficiencies, including the supply of new capacity. To the extent that market power enables fixed cost recovery and thereby facilitates new entry, the long-run efficiencies may outweigh the short-run inefficiencies caused by the exercise of market power. This trade-off is fundamental to the sustainability of an energy-only market framework.

Figure 16 shows that pool prices and static efficiency have remained highly correlated, and that static efficiency losses have decreased since the introduction of the interim measures. The biggest divergence was in January 2024, when average price was high while static inefficiencies remained low. This occurred because extreme cold temperatures were the driver of high prices in this month, not the exercise of market power, and the resulting high prices were efficient.

As shown in section 2.1, the period of high prices in 2022 and 2023 was followed by significant additions of both intermittent and controllable generation. This is a strong indication that timely entry has disciplined the exercise of market power and is promoting long-run efficiency.

Figure 16: Monthly average pool price and static efficiency loss

3.2 Change in offer behaviour

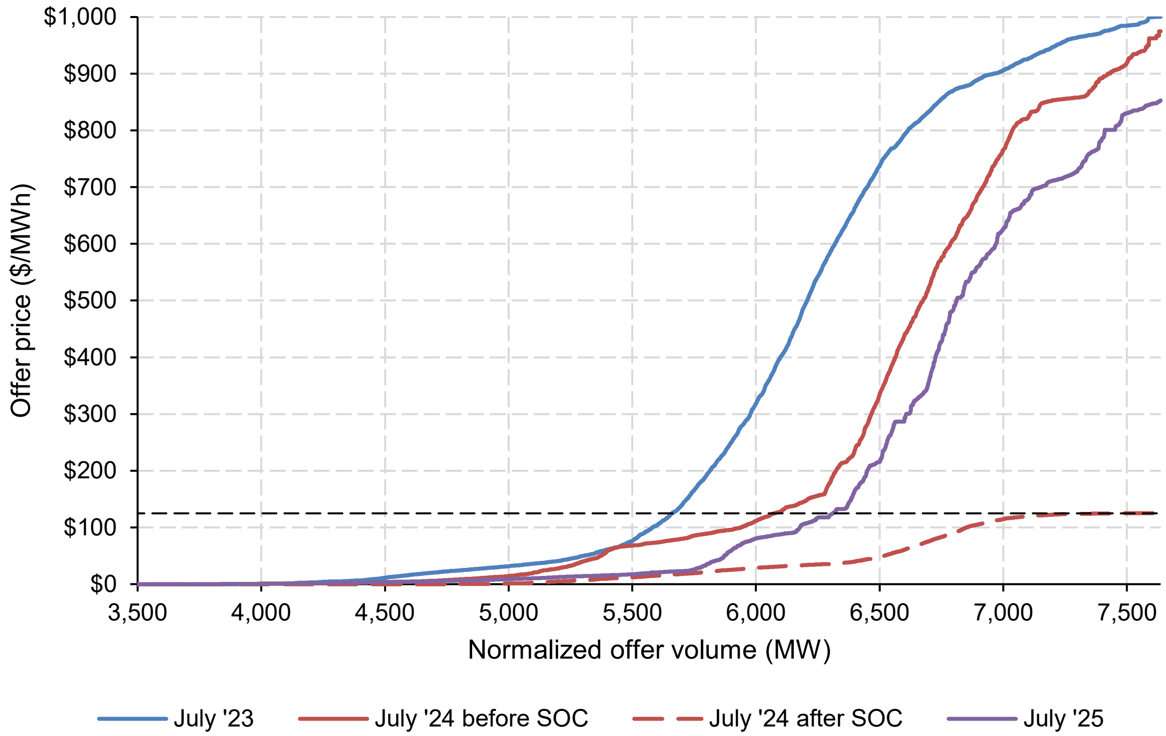
This section analyzes how the $125/MWh secondary offer cap affected offer behaviour when it was imposed in July 2024. While assets bound by the secondary offer cap had explicit restrictions on their offer prices, unmitigated assets may have also changed their offer strategy, stemming from the overall change in competitive dynamics. This includes both how suppliers subject to mitigation may have altered the strategy of their unmitigated portfolio, and also the response from unmitigated suppliers.

The following sections examine the average offer curve by asset category in July 2023, July 2024 both before and after the secondary offer cap was imposed, and July 2025 – when the interim measures were in place but offer price mitigation was not triggered. These curves are derived by measuring the average offer price of each incremental MW of supply over the relevant period. When the total volume of offers was different between sample periods, the volume is normalized to aid in comparison by adding additional MW at $0/MWh. Note that the x-axis of each figure is truncated to exclude significant volumes at or near the price floor, highlighting the differences in positively priced offers.

3.2.1 Change in offer behaviour of mitigated assets

As shown in Figure 17, offers in July 2024 were already below those in July 2023, even before the secondary offer cap was imposed. Then, under the secondary offer cap there was a significant shift in offers from mitigated assets. While the reduction in offers that were previously above the cap is unsurprising, the secondary offer cap did not just truncate prices at $125/MWh. Rather, competition also put downward pressure on offer prices below the secondary offer cap, leading to a significant reduction in all non-zero offer prices, on average.

Figure 17: Average offer curves for mitigated assets



3.2.2 Change in offer behaviour of unmitigated assets

Because not all asset types are subject to the secondary offer cap, suppliers with mitigated assets may still have a portfolio of unmitigated assets. The offer strategy for these assets may have adapted in response to the limitation on offers from those suppliers' mitigated portfolios.

Figure 18 shows that the response from these assets was not uniform. Notably, the change in offer prices differed below and above the secondary offer cap, even though the cap did not directly apply to these assets. Above the secondary offer cap, prices increased on average, while below the cap, prices decreased on average. However, all average offer prices in July 2024 were still below those in July 2023.

This is likely the result of how mitigated assets responded at different points in the merit order. As shown above, mitigated assets both reallocated their high-price volumes to comply with the secondary offer cap and decreased their existing offer prices below the cap. These factors compounded to increase competitive pressure at low price levels. Conversely, with significantly less volume priced above the secondary offer cap, this created the opportunity for unmitigated assets to further raise their high offer prices, though the effect was moderate.

Figure 18: Average offer curves from mitigated suppliers for unmitigated assets

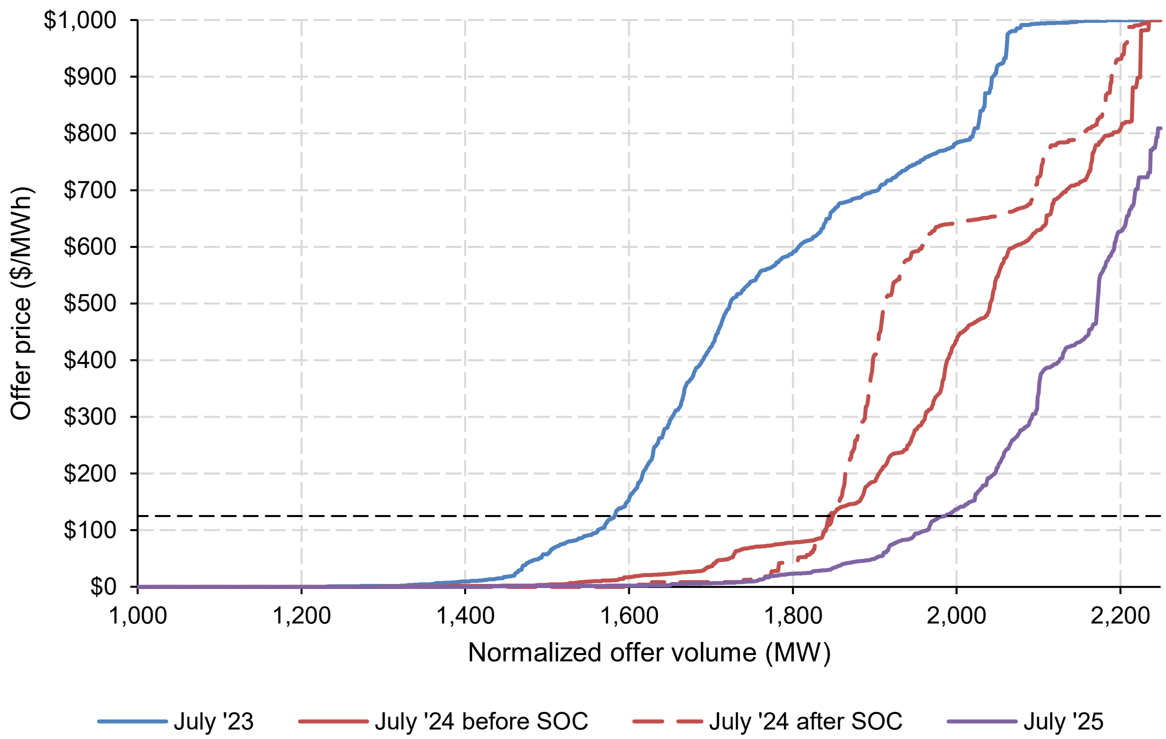
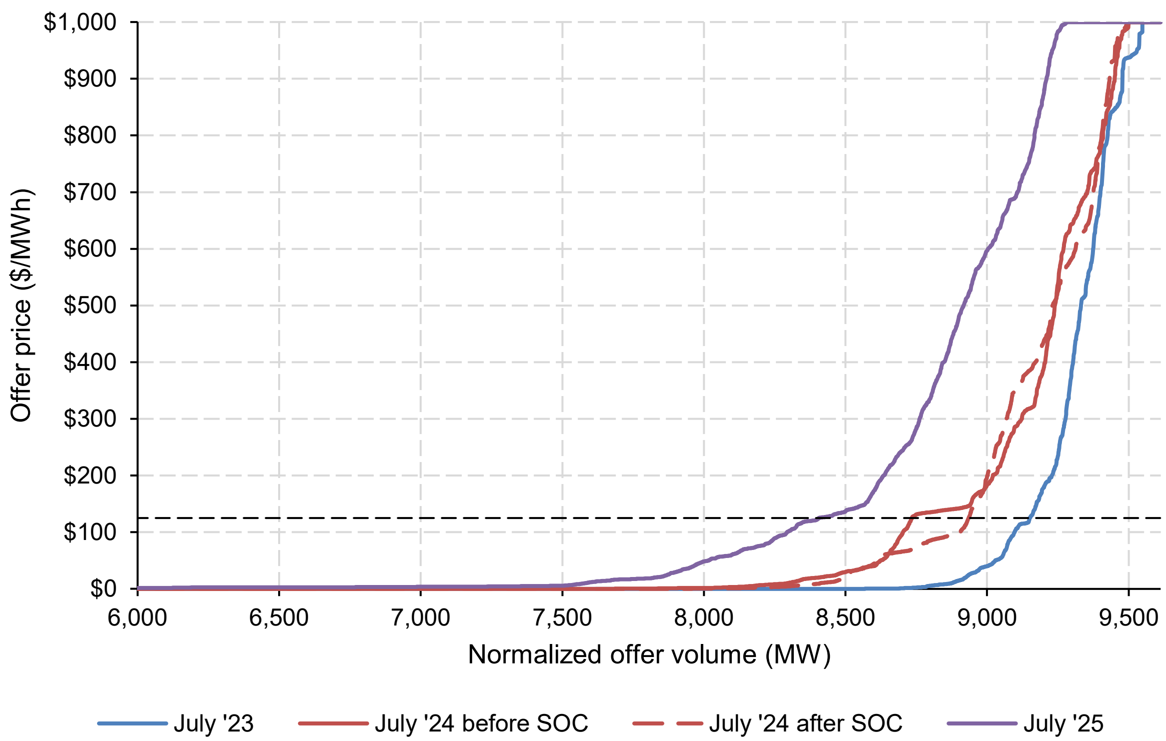


Figure 19 shows that unmitigated assets from unmitigated suppliers saw very little change, which is expected since most of these assets are intermittent renewables priced at $0/MWh. Generally, July 2024 saw somewhat higher offer prices from these assets than July 2023, but offers were still below those in July 2025, and there was no significant change before and after the secondary offer cap was triggered.

The absence of a significant response from unmitigated suppliers supports their exemption from the secondary offer cap, as their offer behaviour is driven primarily from exogenous factors and not the exercise of market power. However, this same rationale would also apply to unmitigated assets from mitigated suppliers, which did exhibit a response. This indicates that there is some opportunity to offer unmitigated asset types in a strategic manner, though the extent is somewhat limited, as evidenced by the magnitude of the response. The difference in response from unmitigated assets between mitigated and unmitigated suppliers also suggests that the increased pivotality and informational advantage of mitigated suppliers contributes to their offer strategy.

In summary, the secondary offer cap prompted a significant change in offer behaviour for mitigated assets, with offers both above and below the cap reduced substantially. While mitigated suppliers did respond strategically with their unmitigated assets, the effect was moderate, and the same asset types owned by unmitigated suppliers exhibited no material response, which is indicative of the external factors that typically underpin the operational strategy for these assets.

Figure 19: Average offer curves from unmitigated suppliers for unmitigated assets



3.3 Anticipated supply cushion

To determine when UCDs may be required, the AESO must perform a forecast of supply cushion, called anticipated supply cushion (ASC). The AESO does so according to a prescribed methodology, outlined in Information Document #2024-005, *Interim Supply Cushion Directives* (UCD ID).[12]

While the components of the ASC formula are set out clearly, several of these components involve an underlying forecast before being combined to estimate the ASC, such as wind and solar output, Alberta Internal Load (AIL), and net imports. These underlying forecasts are described at a high level in the UCD ID. Other components, such as committed available capability (AC), are derived from market participant submissions. This means the ASC forecast depends on the ASC formula, the underlying forecast methodologies, and on the accuracy of data submitted by market participants.

Figure 20 shows that the distribution of ASC forecast errors is biased to over-estimate supply cushion and that this bias increases as the time-horizon lengthens. This results in fewer UCDs. For instance, underestimates of supply cushion exceeding 1,000 MW are rare, whereas it is not uncommon for supply cushion to be overestimated by 1,000 MW or more, particularly 12 or more hours ahead of real time.

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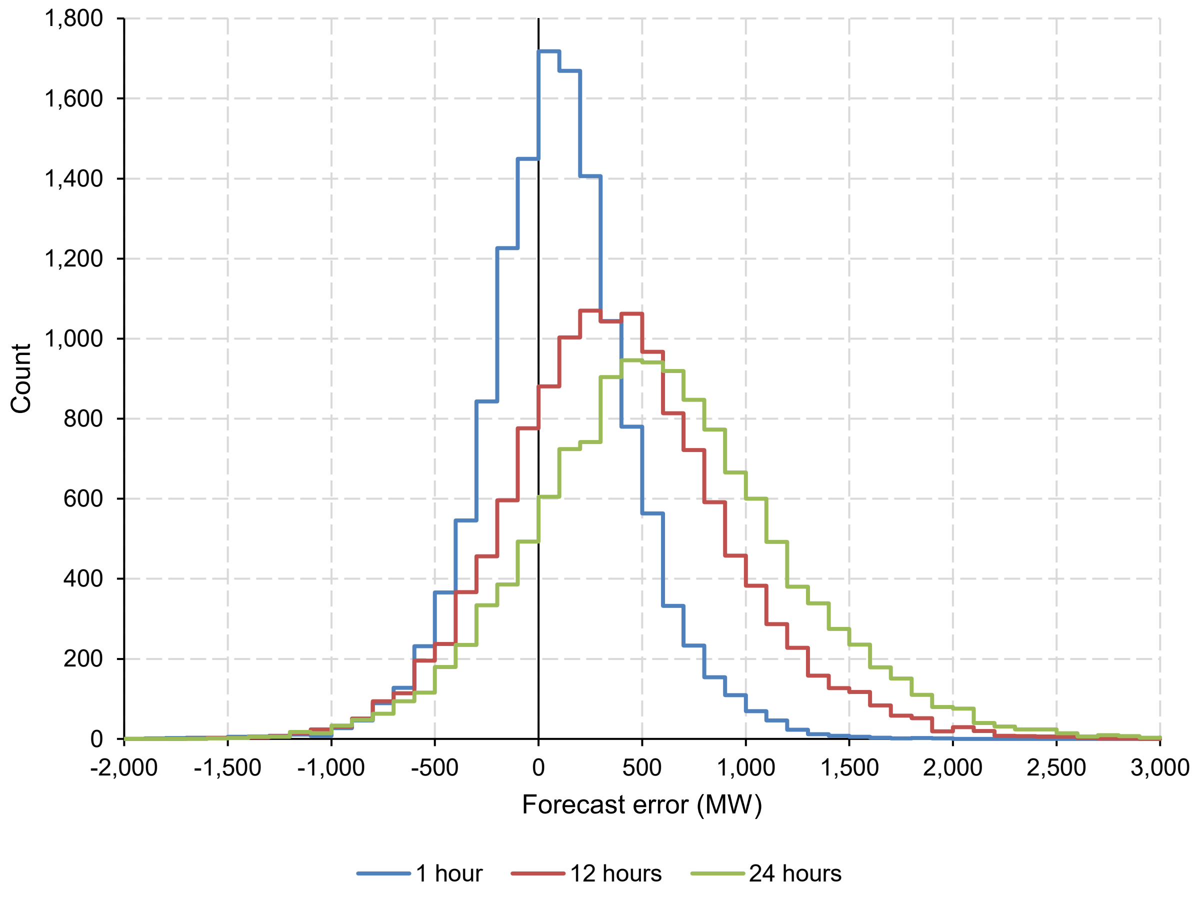
[12] Information Document #2024-005, *Interim Supply Cushion Directives* Appendix 1, pdf pg. 9.

One definition of supply cushion is the available MW remaining in the merit order for dispatch; however, the ASC methodology differs from this approach. Most significantly, ASC includes regulating reserves volume and generation used to supply net exports, while excluding CDG volumes. Additionally, because the ASC forecast is used to determine whether to issue UCDs, the addition of generation capacity under UCD should not be considered an error in the ASC forecast, but rather a result of the process.

To measure forecast error, the MSA estimated a realized version of the ASC. Supply cushion was first calculated from the merit order, then reduced by CDG volumes and the projected AC of assets under UCDs that were issued following the forecast run time, and increased by the volume of scheduled net exports and half of the capacity used to supply regulating reserves.[13]

Figure 20: Distribution of ASC forecast errors 1 hour, 12 hours, and 24 hours ahead



Narrowing down only to events with realized supply cushion less than 250 MW, on average, the ASC forecast overestimated supply cushion by 581 MW, 1,041 MW, and 1,093 MW for 1-hour, 12-hour, and 24-hour horizons, respectively. Realized supply cushion was only underestimated

[13] This assumes that, on average, the dispatch of the merit order reflects the point that keeps regulating reserve resources in the middle of their regulating range.

in one such hour, and only by 6 MW in the 1-hour forecast horizon. This is indicative of the bias of unexpected events tending to reduce rather than increase supply cushion.

However, this average tendency is not only the result of outlier tail events caused by unexpected contingencies. For example, 27% of all 24-hour forecasts overestimate supply cushion by 200 – 600 MW, while only 17% were within 200 MW of the realized value.

3.4 Self-commitment

The interim measures introduced a centralized unit commitment mechanism, backstopped by a cost guarantee. While some form of guarantee is needed when the system operator directs an asset online, this has the potential to significantly alter the incentives for LLT assets to choose to self-commit, because self-commitments have no such guarantee that cycling costs will be recovered through market revenues. However, the mechanism was designed with features to limit interference with the market signals for self-commitment – for example, UCDs must only be issued immediately prior to when the asset must begin start-up procedures, reducing the potential for assets to be directed online when they otherwise would have self-committed.

Figures 21 and 22 show the general change in average generation and commitment of LLT assets by hour ending and across years. There was little shift between 2023 and 2024; however, in 2025, both the number of LLT assets committed and the average generation significantly fell. While Sundance 6 was mothballed effective April 1, 2025, this does not fully explain the shift, as shown by the 2024 values with Sundance 6 excluded.

In addition to the general tendency for self-commitment, there may also have been shifts in the timing and distribution of those commitments, particularly given the operational characteristics of LLT assets. Through the end of 2025, UCDs were only issued to gas-fired steam assets. These assets historically operated as coal-fired generation to serve base load; however, as the fleet evolved, many of these assets were mothballed or retired. Those that remained were converted to use natural gas. While they are now natural gas-fired, in most respects, the fundamental characteristics of the assets are still more closely aligned with their history as coal-fired steam generators, as compared to generators that use natural gas-fired turbines.

The year-over-year decrease of LLT generation and committed LLT assets is consistent with the new entry of combined cycle and cogeneration assets to serve base load and continued increases in intermittent renewables.

Notably, both trends show a uniform shift throughout the day. This indicates that, as a class of assets, the operation of LLT assets has remained very similar since the introduction of the interim measures.

Figure 21: Average generation from LLT assets by hour ending

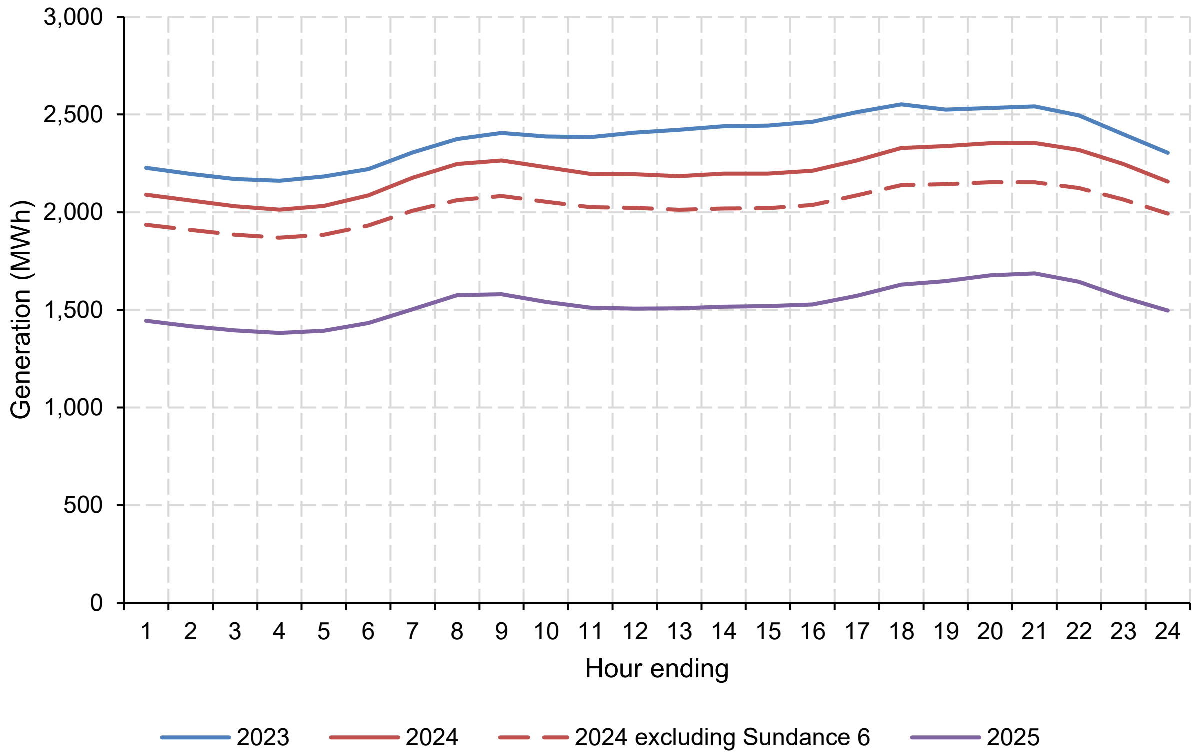
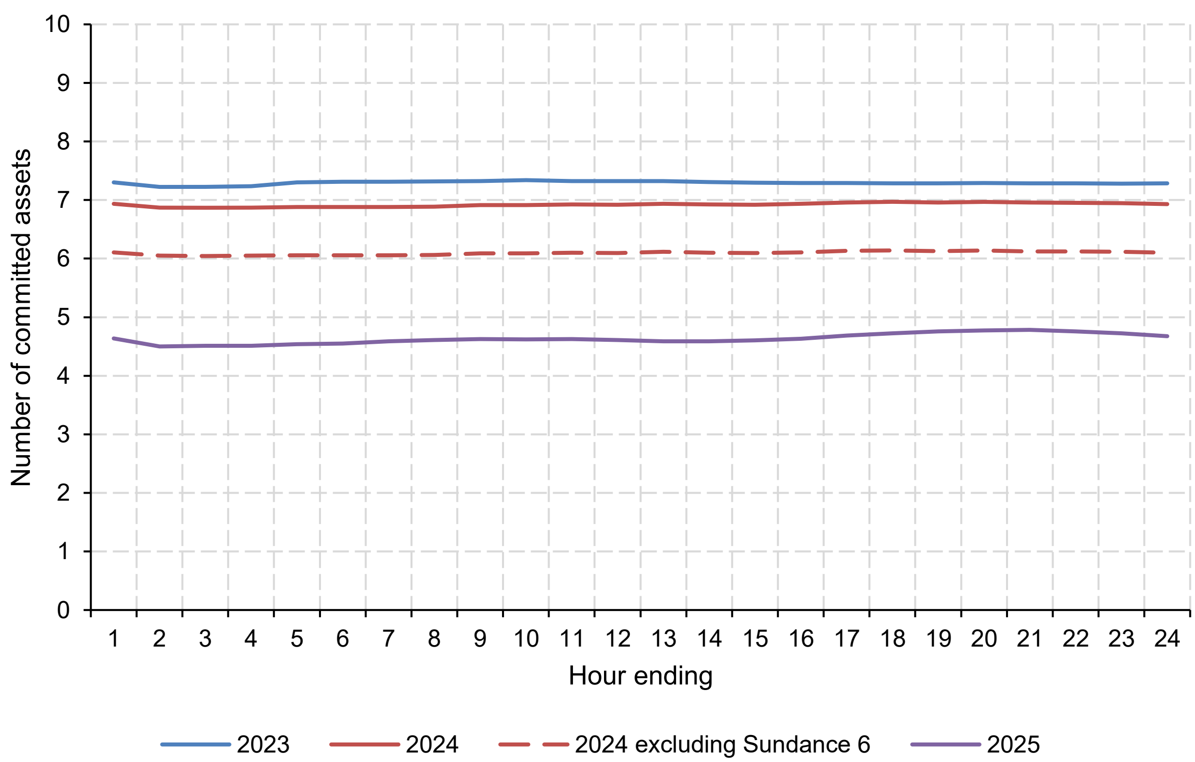


Figure 22: Average number of committed LLT assets by hour ending



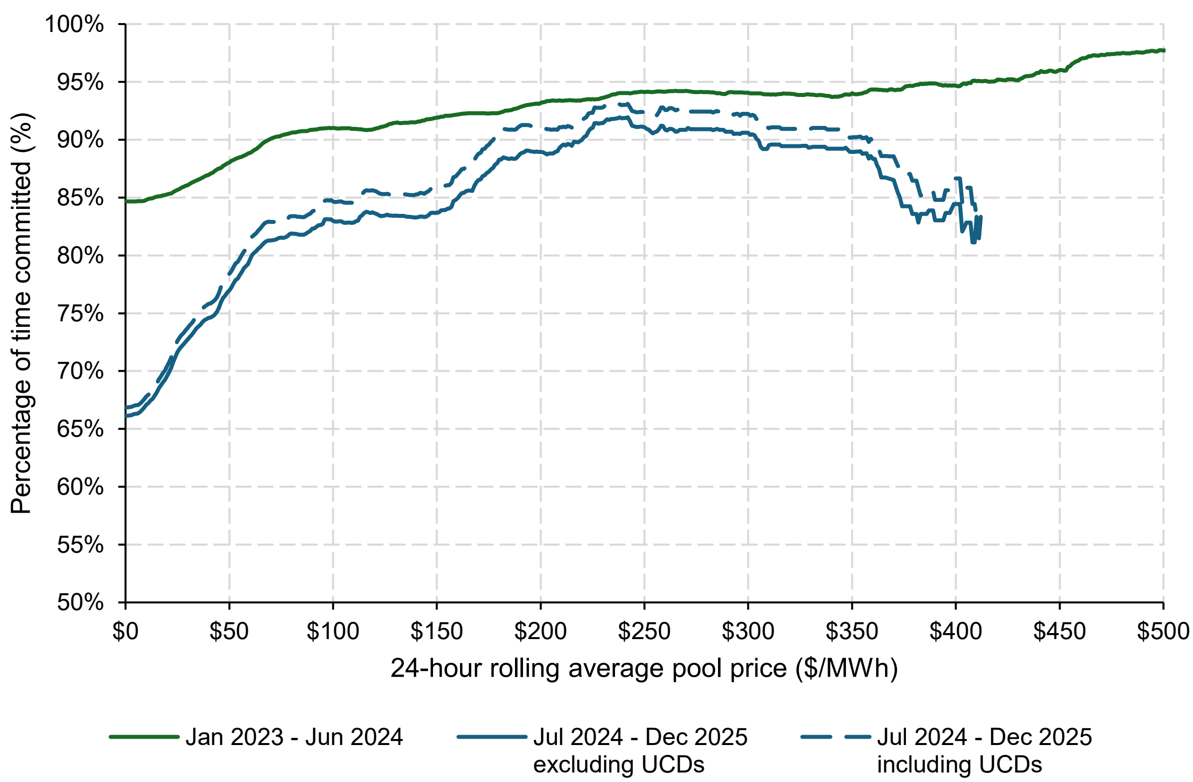
To further assess changes in self-commitment behaviour, the MSA analyzed whether LLT assets were self-committed at different pool price levels. Specifically, Figure 23 shows the average percentage of time that LLT assets were committed when pool price was at or above a certain level, in the 18 months prior to and following the introduction of the interim measures.

The data underlying the figure measures how many hours a LLT asset was committed each period, divided by the number of hours the asset was available (i.e. not on outage), conditional on pool prices being at or above a certain level. Because commitment decisions are made based on expected prices over a full commitment cycle, the 24-hour rolling average pool price is used instead of hourly pool price. To construct the curves depicted in the figure, the simple average of this asset-level metric is taken across all LLT assets.

LLT assets were less likely to self-commit following the introduction of the interim measures; however, the effect was most significant at price extremes. The drivers for this change are likely different at low versus high price levels. At low price levels, new entry of base load generation has displaced the LLT fleet, whereas very high prices are usually the result of unexpected events and increased net demand variability, making high prices more difficult to predict and resulting in fewer commitments during these times.

The dashed line incorporates all unit commitments, including both UCDs and self-commitments. The result is similar, indicating that UCDs did not replace the reduction in self-commitment, and LLT assets were generally committed less under the interim measures.

Figure 23: LLT asset commitment conditional on 24-hour rolling average pool price



Self-commitment was lower overall, but especially so in October 2025, when the AESO issued 41 UCDs. Supply cushion in October 2025 was reduced by significant thermal generation outages, as shown below in Table 3.

Table 3: Major gas generator outages in October 2025

Asset name	Capacity on outage (MW)	Begin date	End date	Length (days)
Cloverbar 2	101	24 May	27 Oct	157
Mackay River	207	03 Sep	21 Oct	49
Nexen Inc #2	90	08 Sep	16 Oct	39
Northern Prairie Power Project	105	15 Sep	04 Oct	20
HR Milner	300	19 Sep	06 Oct	18
Nexen Inc #1	120	24 Sep	17 Dec	85
Fort Hills	115	25 Sep	05 Oct	11
Keephills 3	466	30 Sep	12 Nov	44
Genesee Repower 2	466	04 Oct	09 Oct	6
Primrose	100	15 Oct	20 Oct	6
Shepard	490	20 Oct	23 Oct	4
HR Milner	300	22 Oct	07 Nov	17
Genesee 3	466	24 Oct	13 Nov	21
Cascade 2	466	25 Oct	04 Nov	11

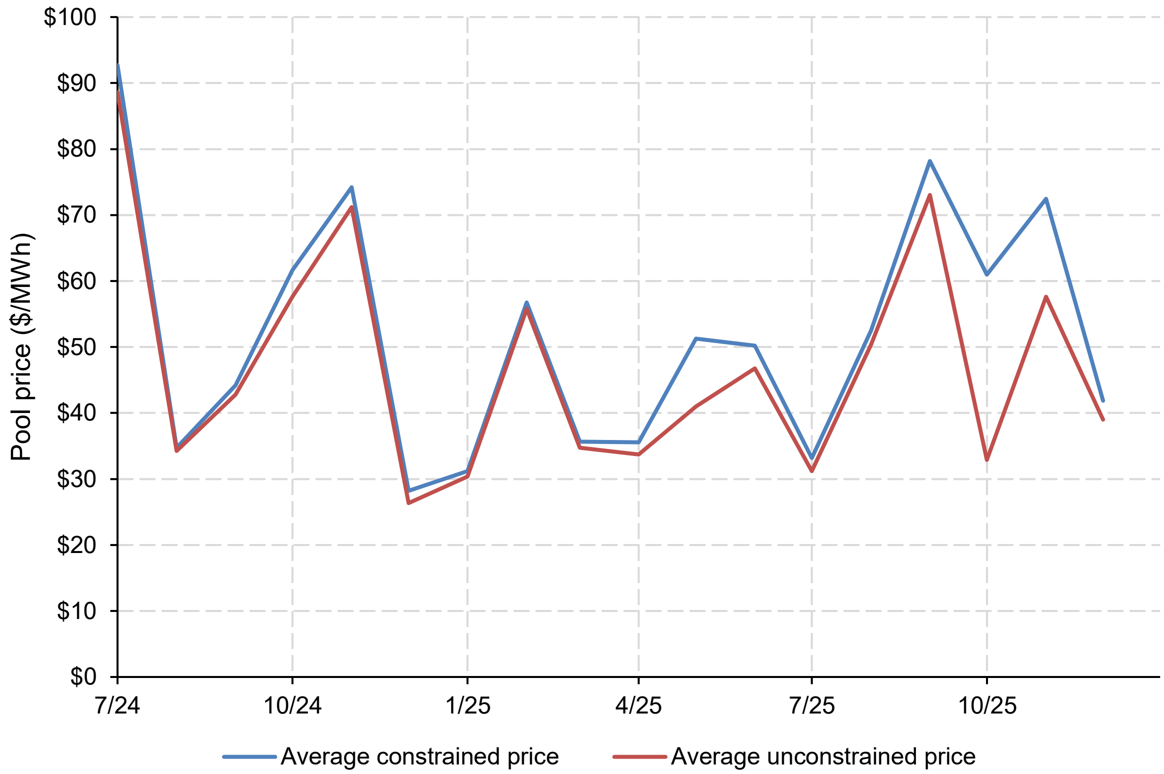
Although thermal generation was reduced due to outages, intermittent renewable generation was high; however, much of this potential generation was constrained off due to transmission congestion, resulting in significant constrained down generation volumes. The pool price is reconstituted to the level it would have been if all in-merit generation was deliverable, creating a large difference between the constrained and unconstrained prices, as shown below in Figure 24.

This effect peaked in HE 12 on October 29, 2025, when constrained down generation was so significant that the unconstrained price was at the floor of $0/MWh while the constrained price was at the offer cap of $999.99/MWh.

While higher priced generation was dispatched to meet demand as supply cushion fell in October 2025, these prices were subsequently lowered due to transmission constraint rebalancing, resulting in unusually low pool prices given the tightness of supply. This led to low self-commitment rates, but also the need for more generation online to maintain the supply cushion threshold, thereby requiring the AESO to issue an unprecedented number of UCDs.

While the cost guarantee likely contributed to the incentive to stay offline, the average received price of UCDs in October 2025 was only $71.34/MWh, and 22 UCDs had received prices of under $30/MWh. Self-commitment decisions are ultimately based on price, not supply cushion, so when low supply cushion is not signalled by high prices, there is little incentive to self-commit.

Figure 24: Monthly average constrained and unconstrained prices under the interim measures



3.5 Price impact of the interim measures

The MSA estimated pool price with and without the effect of the interim measures and has included these estimates in its quarterly reports. Two models are used: one to estimate the impact of the secondary offer cap, and one to estimate the impact of UCDs.

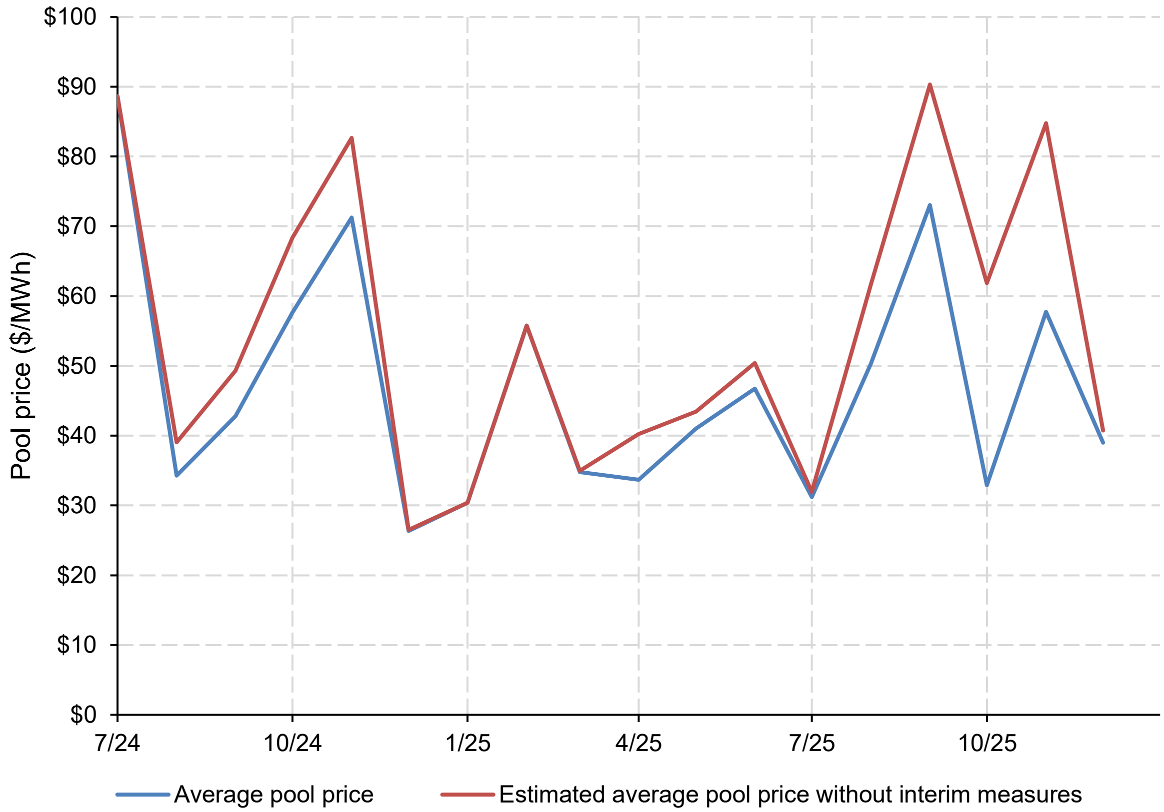
The secondary offer cap model matches each mitigated hour with an unmitigated reference hour in which market fundamentals such as demand, intermittent renewable generation, and availability of large market participants' portfolios were similar. Offer behaviour in the unmitigated reference hour is used to reconstitute the offer prices of assets subject to the secondary offer cap. In July 2024, market participants also appeared to adjust their offers below the secondary offer cap, so all offers from mitigated assets are reconstituted – not only the offers at the cap. A new system marginal price is determined using these reconstituted offers.

The UCD model removes assets under a UCD from the merit order and determines the new system marginal price. In instances when an asset came online early or remained online following a UCD, it is not removed from the merit order, as the asset was not compelled to be online at that time.

There are other factors that influence market outcomes that are not included in these models, such as response from load or interchange, which would tend to decrease the estimated impact, and changes in offer strategy, which would tend to increase the estimated impact.

Using this approach, the interim measures are estimated to have reduced the average pool price from July 2024 through December 2025 from $54.37/MWh to $46.96/MWh, or by approximately 14%.

Figure 25: Monthly average pool price with and without the interim measures



3.6 Profitability of self-commitment

In the MSA's Advice to the Minister, the recommendation for a unit commitment mechanism was made to address physical withholding. Physical withholding occurs when assets are individually profitable but kept commercially offline to exercise market power to the benefit of a portfolio.

LLT assets have significant startup costs and therefore need sufficient revenues through a commitment cycle to recover both these costs and their hourly operating costs. In many other jurisdictions, this is achieved through uplift payments; however, in Alberta, these revenues must come from the sale of energy or ancillary services. Accordingly, there are times that LLT assets are unprofitable, and it is efficient for them to remain offline. To distinguish between this behaviour and physical withholding, a measure of their profitability is required.

While the MSA recommended an economic test as the basis for the unit commitment mechanism, the design ultimately used a supply cushion threshold as a proxy. Supply cushion and pool price are highly correlated, but even when controlling for supply cushion, pool prices still vary significantly based on other market fundamentals. Therefore, the statutory design will inevitably result in some UCDs directing profitable assets online and some UCDs that direct unprofitable assets online, which may help to maintain reliability but are not required for market power mitigation.

The MSA estimated the percentage of UCDs that were profitable using the following methodology. This approach has the benefit of perfect foresight and therefore does not necessarily identify physical withholding, as assets may have remained offline due to uncertainty about market outcomes and not to exercise market power.

Many UCDs are of short duration; however, these are driven by the statutory requirements and not the economic characteristics of LLT assets. The MSA used the submitted parameters from LLT assets to estimate their levelized cost over commitment cycles of 12 hours, 24 hours, 48 hours, and 72 hours. These time frames were chosen to represent a range of commitment durations that may be commercially viable, thereby giving the best comparison of whether a self-commitment may have been profitable.

These levelized costs are compared to the average pool price in the representative number of hours surrounding each UCD. For example, if a UCD was issued for 14:00 – 16:00, the 12-hour assessment would compare 12-hour levelized costs to the average pool price from 09:00 – 21:00. The results of this comparison are shown below in Table 4.

Table 4: Percentage of UCDs issued when self-commitment was profitable

Self-commitment duration assumption	Percentage of UCDs issued when self-commitment was profitable
12 hours	36%
24 hours	36%
48 hours	34%
72 hours	28%

The results show that, choosing the best case for self-commitment of a 12- or 24-hour cycle, 36% of UCDs were issued when a self-commitment would have been profitable. Because this assumes perfect foresight, the number of UCDs that committed assets when they were exercising market power would be even lower.

Given that pool prices conditional on supply cushion have dropped considerably under the interim measures, as shown above in Figure 15, the threshold of 932 MW could likely be reduced without compromising the ability of the unit commitment mechanism to address market power. However, as shown in section 3.3, forecast errors above 932 MW occur regularly, especially when realized supply cushion is low. Accordingly, the 932 MW threshold has helped to maintain reliability. The MSA outlined several such events in the Wholesale Market Report for Q4 2025.[14]

[14] MSA Wholesale Market Report: Q4 2025 section 1.1.7, pdf pgs. 16-17.

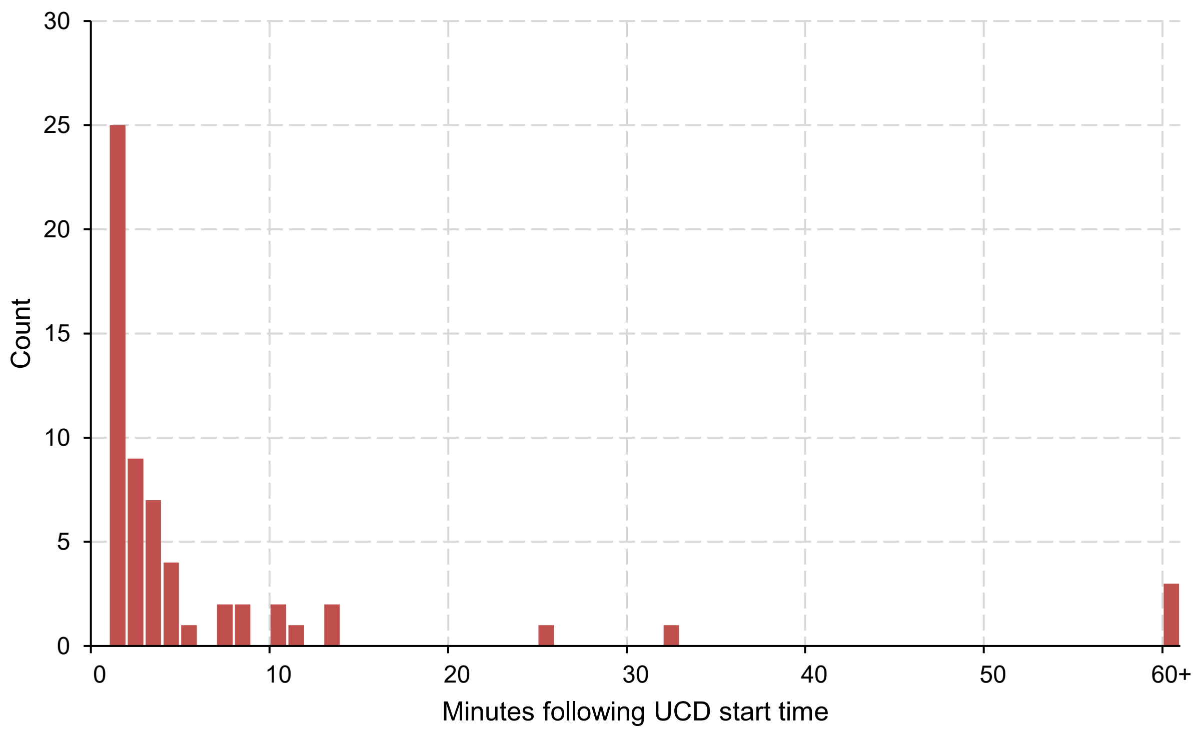
4 IMPLEMENTATION

This section outlines issues and observations relating to the implementation and enforcement of the interim measures.

4.1 Response to unit commitment directives

ISO rule 206.2 requires that an asset under UCD must "synchronize by the time specified by the ISO."[15] Given the data available to the MSA, the closest measure of synchronization time is the moment when the gross production of the asset becomes positive. Of the 155 UCDs issued up to the end of 2025, the asset responded at or before the UCD start time in 94 instances, and for one UCD, the asset experienced an outage before the UCD start time. The response time of the remaining 60 UCDs is shown below in Figure 26. While many assets responded after one or two minutes, there were 10 UCDs for which the asset synchronized 10 or more minutes late, and three UCDs for which the asset was more than an hour late.

Figure 26: Number of minutes following UCD start time before energy was delivered



Even when an asset does synchronize at the UCD start time, some take an hour or more to ramp up to their MSG. Therefore, while the ASC forecast may predict a supply cushion deficit beginning at the UCD start time, the asset's full MSG is typically not available until much later, resulting in a window for potentially increased market power and supply shortfall risk.

[15] ISO rule 206.2, *Interim Supply Cushion Directives* subsection 5(5)(a)(i).

4.2 The UCD process

The AESO employs a tool called PowerOp to determine the order of issuance for UCDs. PowerOp is integrated with other data pipelines and AESO systems, including the ASC forecast and the Dispatch Tool (DT), which taken together constitute the process for issuing UCDs (the "UCD Process"). The UCD Process produces recommendations, which must be manually accepted by an AESO system operator for a UCD to be issued to a pool participant.

The UCD Process has undergone several changes since being first implemented alongside the interim measures – the MSA is aware of at least five such changes. Given the complex nature of power system operations and the multitude of factors that factor into UCD decisions, many of these changes resulted from operational edge cases in which the UCD process performed in an unintended manner.

While updates to the UCD Process have refined its functionality, in some cases, process and/or human errors were material enough to result in the AESO not meeting the requirements of ISO rule 206.2. In two such cases, the MSA issued Notices of Specified Penalty (NSPs) to the AESO, as outlined in the MSA's Regulatory and Enforcement Activities Report for Q3 2025.[16]

4.3 Unit commitment parameters

The SCR requires the AESO to "determine the order of unit commitment directives according to relative economic merit and physical constraint parameters."[17] To enable the AESO's determination, both the SCR and ISO rule 206.2 place obligations on pool participants to submit parameters to the AESO that outline the characteristics of their LLT assets, and then maintain these submissions through time. These submissions are further described in the UCD ID,[18] which includes a submission template as Appendix 2.[19] The parameter definitions are divided across the *Consolidated Authoritative Document Glossary*[20] (CADG) and the UCD ID. Because the parameters are used to determine the eligibility and order of issuance for UCDs, they are consequential to energy market outcomes.

Following the introduction of the interim measures, the MSA obtained and reviewed the parameter submissions made to the AESO. This initial review raised potential concerns, and accordingly, the MSA opened investigations into pool participant conduct under the SCR and ISO rule 206.2.

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[16] MSA Regulatory and Enforcement Activities Report: Q3 2025 section 1.5, pdf pgs. 7-8.

[17] *Supply Cushion Regulation* AR 42/2024 section 5(1)(b).

[18] Information Document #2024-005, *Interim Supply Cushion Directives*.

[19] Appendix 2 – Estimated Cost Parameters and Physical Constraints Template.

[20] *Consolidated Authoritative Document Glossary*.

The investigations revealed that the submissions contained several errors, including misinterpretations of parameter definitions, outdated or otherwise inaccurate data or assumptions, inappropriate methodologies, and clerical errors.

As a result of the investigations, pool participants made substantive updates to their parameters and implemented processes to promote ongoing compliance.

In the MSA's view, insufficient care was taken both in establishing the parameter definitions and Template Appendix by the AESO, and by pool participants in developing their estimates and completing their submissions. This issue was foreseeable, as there was uncertainty about parameter definitions going back to the outset of stakeholder consultation in May 2024.[21] Following their introduction, the MSA is aware of at least five versions of the UCD ID and four versions of the Template Appendix, and while these updates made directional improvements, the frequent changes contributed to stakeholder confusion.

The collection of this type of information, while new in Alberta, is common practice in other jurisdictions. Similarly, these jurisdictions have established mechanisms to ensure that inputs to the market clearing processes are accurate and justifiable. With further reliance on asset-level data expected in the future, robust data validation and oversight will be required to ensure the fidelity of market outcomes.

4.4 Offer restatements within T-2

Under ISO rule 203.3, *Energy Restatements*, pool participants cannot modify their offer prices within 2 hours before the start of the corresponding settlement interval. Pool participants can modify their offer volumes within 2 hours, but only with an acceptable operational reason or when required due to an operational deviation.

When a market participant wishes to cycle their LLT asset offline, they do so by pricing the lowest price offer block, which must contain the MSG of the asset, out of merit.

The AESO issues two types of UCDs: start-up UCDs and stay-on UCDs. Start-up UCDs require a LLT asset to synchronize and operate from an offline state. Stay-on UCDs require an online asset that would otherwise cycle offline to continue operating.

The AESO will only issue stay-on UCDs to eligible LLT assets that have received an advance dispatch offline. LLT assets only receive an advance dispatch offline when they have priced their MSG out of merit, as described above.

Because stay-on UCDs, by their nature, are issued minutes before the relevant settlement interval, the pool participant cannot adjust their offer price. Therefore, to comply with the UCD, they must operate the LLT asset at its MSG without a dispatch for energy. Additionally, the original offer containing the asset's MSG remains in the merit order. Should the energy market dispatch change, it is possible for this block to be dispatched and set price. This occurred on September

[21] See, for example, the survey response report containing stakeholder comments on the proposed template.

1, 2025, as described in the MSA's Wholesale Market Report for Q3 2025.[22] The dispatch of this block has no effect on the supply of energy, since the asset is already operating at its MSG generation.

In the MSA's view, because these offer blocks do not correspond to an incremental volume of energy and were priced with the intent of cycling offline, it is inappropriate for them to set the energy price. The MSA notes that the AESO has addressed this issue in the REM ISO Rules by requiring the pool participant to restate the MSG offer block to the price floor.[23]

4.5 Disregarded UCDs

As reported on the AESO website, the AESO issued three UCDs on April 3, 2025: two to Battle River 4 (BR4), and one to Battle River 5 (BR5). The first UCD, issued at 19:45, required BR4 to operate from 06:00 to 10:00 on April 4. At 19:46, a second UCD was issued to BR5 for the same period as the first UCD, and a third UCD was issued to BR4 to start immediately.

The second UCD to BR5 occurred because the UCD tool did not update to consider the UCD already issued to BR4. The third UCD to BR4 to start immediately occurred because the UCD tool erroneously considered BR4 to be already online. Ultimately, the system controller requested that the market participant respond only with BR5 and disregard the two UCDs to BR4.

A similar event occurred after the AESO issued a UCD to BR4 at 19:25 on September 18, 2025, which required BR4 to operate from 19:00 to 23:00 on September 19. In this case, BR4 was on a forced outage and was not capable of starting up in time to meet the UCD, so the AESO instructed the pool participant for BR4 to disregard the UCD.

In Proceeding 29093, the Commission directed the AESO to publicly report on UCD issuance in real time, stating that if the AESO fails to do so, "then a market participant who receives a UCD has more information than others who didn't receive one" and that "this information asymmetry has the potential to affect the FEOC operation of the market."[24]

In the MSA's view, these UCDs resulted in persisting asymmetry between the UCDs reported on the AESO website and the information available to market participants who received UCDs. While publishing these UCDs is consistent with the Commissions' direction, the MSA has recommended that the AESO consider adding additional information to its public report to indicate when it has instructed a pool participant to disregard a UCD.[25]

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[22] MSA Wholesale Market Report: Q3 2025 section 1.2.5, pdf pg. 29.

[23] Proposed REM ISO Rules Section 214.1, *Reliability Unit Commitment*, subsection 8(1), pdf pg. 103.

[24] Commission Decision 29093-D02-2025 paras. 78 and 79.

[25] MSA Wholesale Market Report: Q3 2025 section 1.3.2.1, pdf pg. 36.