MARKET SURVEILLANCE ADMINISTRATOR

Wholesale Market Report: Q4 2025

February 13, 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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TABLE OF CONTENTS

THE REPORT AT A GLANCE

Increased gas capacity and more wind and solar supply drive lower prices in 2025

The average pool price in 2025 was $43.68/MWh, which is 30% less than in 2024 and is the lowest annual pool price since 2017. The lower pool prices in 2025 were driven by increased gas generation from Cascade and Base Plant, in addition to more wind and solar (intermittent) generation. This additional supply offset higher demand, more exports, a higher carbon price, and higher natural gas prices year-over-year.

Lower carbon emissions from electricity generation continue

In 2025, the average carbon emissions intensity was 0.39 tCO2e/MWh, a decline of 5% compared to 2024 and 52% lower than in 2015. Carbon emissions from electricity generation have fallen significantly in recent years as coal assets have been retired or converted to run on natural gas, and intermittent generation has increased.

Alberta sets record demand for electricity

Demand for electricity increased by 2% from 2024 to 2025, driven by higher oilsands production and population growth. In hour ending 18 of December 11, Alberta set a record for hourly demand at 12,785 MW, which is 401 MW higher than the prior record. Demand in December was notably high due to increased oilsands production and cold weather. The prior record for hourly demand was surpassed 35 times in December, even during relatively mild weather conditions.

Base Plant increases supply and completes commissioning

The high demand in December was offset by high wind generation and increased supply from Suncor's Base Plant asset. Consequently, the average pool price for the month was relatively low at $39.00/MWh. In late November, more cogeneration capacity was brought online, increasing the supply of Base Plant from 430 MW to 840 MW. Beginning on December 1, portions of the asset's capacity were offered above $0.00/MWh, indicating the end of the commissioning period.

Alberta exported record volumes in 2025

In 2025, Alberta exported a record 348 MW on average, compared to exports of 212 MW in 2024. Historically, Alberta has been an importer of power, with higher prices than in other jurisdictions. This has shifted in recent years. In 2025, pool prices in Alberta were below real-time prices in Northern California 77% of the time.

Unit commitment directives lower prices and maintain reliability

Gas-fired steam assets provided over 65 GWh of supply while under unit commitment directives in 2025. These unit commitment directives lowered pool prices significantly in some months. MSA estimates provide that average pool prices in October and November were lowered by 47% and 32%, respectively because of unit commitment directives. In addition, the directives have played an important role in maintaining reliability. For example, there were sixteen hours in 2025 where the supply cushion would have been negative without the capacity provided by unit commitment directives.

There were two system frequency events in Q4

On the afternoon of November 13, frequency in Alberta declined to 59.73 Hz due to a major disturbance in Wyoming where two 500 kV transmission lines tripped offline and led to the loss of around 4,000 MW of generation in that area.

The BC intertie is made up of one 500 kV transmission line and two 138 kV lines. On the afternoon of December 17, the 500 kV line to BC was inadvertently tripped by contractors, and this caused the loss of the Montana intertie as well. A few minutes later, there was a sudden 400 MW drop in wind generation caused by a fault at the Elkwater substation. As a result, frequency fell to 59.80 Hz and subsequently the two 138 kV lines of the BC intertie tripped offline.

Increased transmission congestion drives higher price differentials

The total volume of constrained intermittent generation increased to 1,468 GWh in 2025, a 189% increase from 2024. In Q4, we saw the highest volume of constrained intermittent generation yet at 729 GWh, a 421% increase year-over-year and more than double the previous record. The increased congestion drove larger differences between constrained and unconstrained prices. For example, on October 29, the constrained price was at the offer cap of $999.99/MWh while the unconstrained price was at the floor of $0.00/MWh.

Market power declined in 2025 despite a large acquisition

In late 2024, TransAlta completed the purchase of Heartland Generation, acquiring an additional 2,141 MW of offer control over natural gas generation capacity and increasing market concentration. Despite this, the ability of larger firms to exercise market power declined in 2025 due to the increased supply from Cascade and Base Plant, in addition to more intermittent generation. The largest firm was pivotal to the market clearing in 5% of hours in 2025 compared to 8% of hours in 2024. MSA net revenue calculations indicate that prevailing pool prices, carbon prices, and natural gas prices meant that hypothetical combined cycle natural gas, simple cycle natural gas, wind, and solar assets were all uneconomic in 2025 as net revenues from the energy market were not sufficient to cover fixed and capital costs.

The MSA recommends changes to the AESO's pool price forecast

The AESO provide pool price forecasts beginning two hours prior to the start of each hour. However, these pool price forecasts assume wind and solar generation will remain at current levels and do not incorporate wind and solar forecasts. This can lead to systematic errors in the pool price forecasts, particularly around sunrise and sunset due to the large amount of solar capacity now installed in Alberta. The MSA recommends that the AESO's pool price forecast be modified to reflect expected changes in wind and solar supply.

The price of regulating reserves increased in 2025 due to higher market concentration

The received price of regulating reserves increased slightly from 2024 to 2025 despite lower pool prices and similar volumes year-over-year. In contrast, the received prices for spinning and supplemental reserves declined by 36% and 35%, respectively. The increased price of regulating reserves was largely driven by higher market concentration. The largest supplier of regulating reserves provided 73% of dispatched volumes in 2025 compared with 68% in 2024.

1 THE POWER POOL

1.1 Annual summary

The average pool price in 2025 was $43.68/MWh, which is a 30% decline relative to 2024 and is the lowest annual pool price since 2017. The lower pool prices in 2025 were driven by increased gas capacity and more intermittent generation. This additional supply offset higher demand, more exports, a higher carbon price, and higher natural gas prices year-over-year (Table 1).

Table 1: Annual market summary statistics (2020 to 2025)

Year	2020	2021	2022	2023	2024	2025
Pool Price Avg ($/MWh)	$46.72	$101.93	$162.46	$133.63	$62.78	$43.68
Gas Price Avg ($/GJ)	$2.11	$3.39	$5.08	$2.54	$1.29	$1.61
Carbon price ($/tCO2e)	$30	$40	$50	$65	$80	$95
Demand (AIL) Avg (MW)	9,462	9,728	9,883	9,851	10,112	10,316
Thermal capacity Avg available (MW)	9,575	9,315	9,201	9,217	9,795	10,415
Intermittent gen. Avg (MW)	702	755	968	1,438	1,785	2,037
Net Imports Avg (MW)	440	459	412	1	-212	-348

1.1.1 Increased gas and intermittent supply lowers prices

Figure 1 illustrates average pool prices and spark spreads[1] by year since 2018. As shown, pool prices and spark spreads in 2024 and 2025 were broadly comparable with those seen in 2018, 2019, and 2020 after a period of higher prices in 2021, 2022, and 2023. The reduction of pool prices in recent years has been caused by the addition of more gas and intermittent capacity, which has increased competition in the energy market.

The increase in natural gas capacity has largely come from the developments at Cascade and Base Plant. The Cascade 1 and 2 assets are efficient combined cycle units with a total capacity of 932 MW. These assets came online in early 2024 and completed their commissioning later the same year. The additional supply from these assets was an important driver of the lower pool prices in 2025 (Figure 2).

At Suncor's Base Plant oilsands site, operators have replaced coke-fired boilers with natural gas cogeneration units to provide both steam and electricity, lowering carbon emissions. Due to the

[1] Spark spread is the margin between pool price and the input cost of natural gas for a combined cycle asset, assuming a heat rate of 7.5 GJ/MWh.

high steam demands of their oilsands operations, Suncor produces more electricity than they need and export the balance to the Alberta grid. The increased supply from Base Plant has put downward pressure on pool prices since late 2024 (Figure 2). However, the cogeneration assets only became fully operational in late 2025 with the asset exporting more than 800 MW.

Figure 1: Average pool price and spark spread (2018 to 2025)

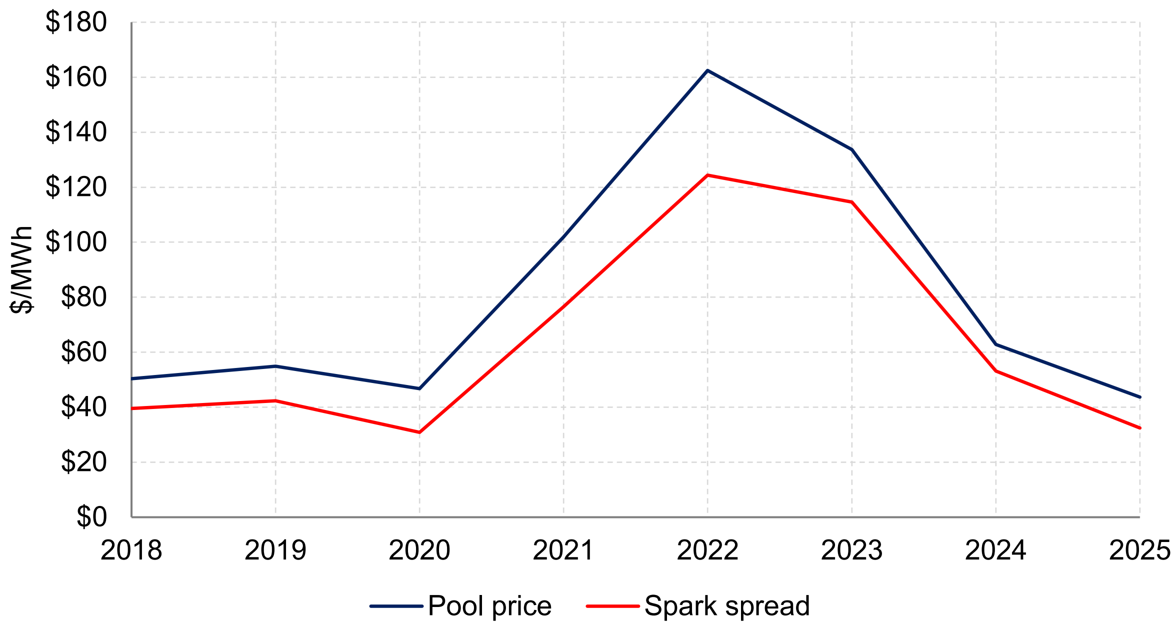
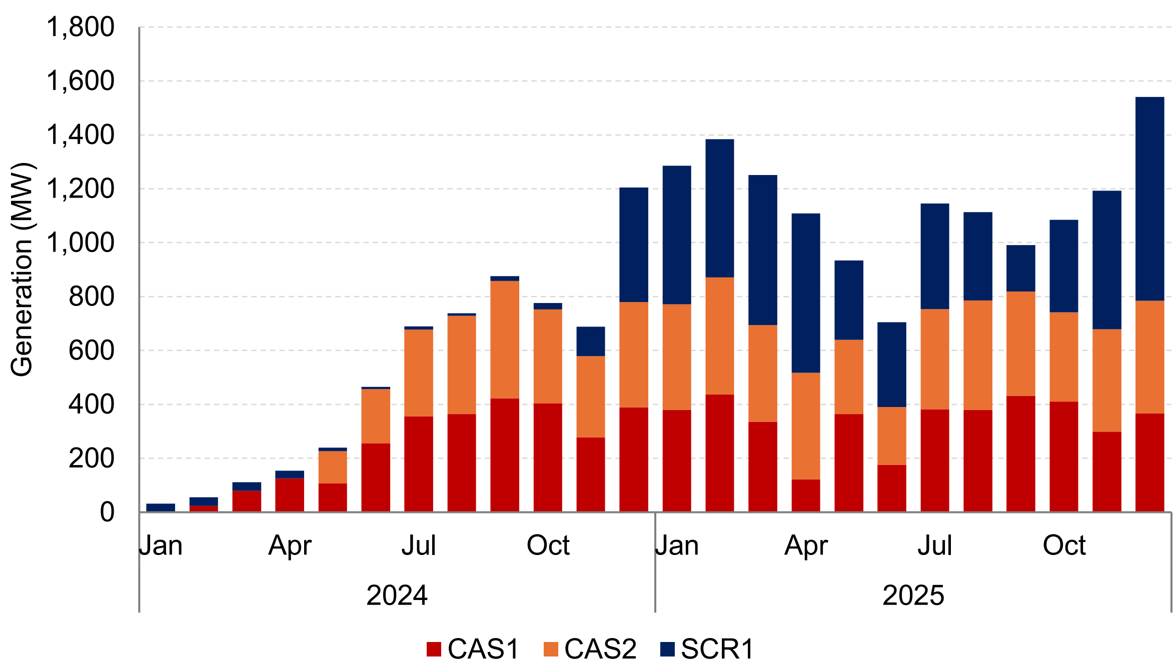


Figure 2: Average generation of Cascade 1, Cascade 2, and Base Plant (January 2024 to December 2025)



In 2025, intermittent generation averaged 2,037 MW, a 14% increase compared to 2024. This increase was driven by more capacity being added in late 2024 and early 2025. At the end of 2025, wind capacity totalled 5,684 MW and solar capacity totalled 1,850 MW (Table 2). The increase in intermittent capacity has put downward pressure on pool prices; when intermittent supply is elevated pool prices are generally low.

Table 2: Installed capacity by fuel type (December 31, 2025)

Fuel type	Capacity (MW)	Percent
Gas	14,140	61%
Wind	5,684	24%
Solar	1,850	8%
Hydro	899	4%
Energy storage	190	1%
Other	479	2%
TOTAL	**23,242**	**100%**

1.1.2 Significant reduction in carbon emissions

Figure 3 illustrates annual generation by fuel type since 2015. The phase out of coal generation was completed in mid-2024 after all coal assets had been retired or converted to run on natural gas. This phase out occurred quickly, given that as recently as 2015 coal assets accounted for 50% of generation.

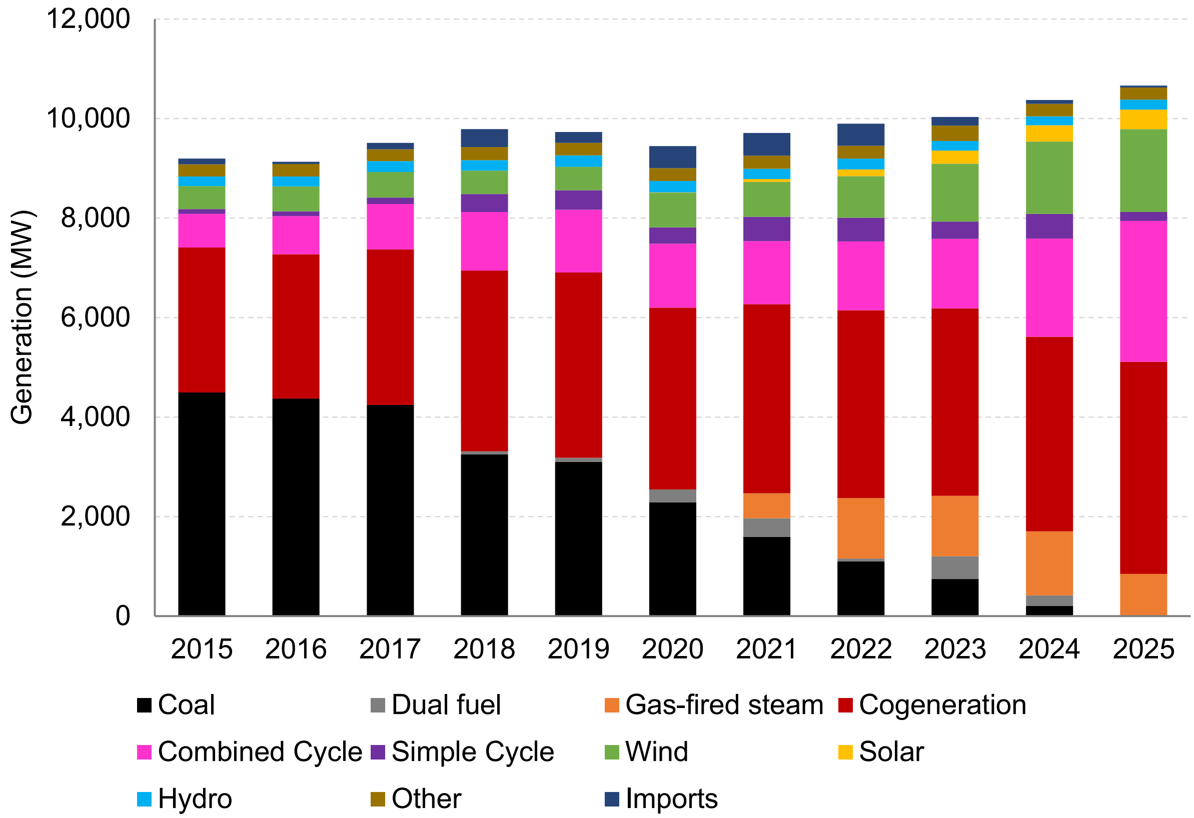
In 2025, cogeneration assets saw their share of generation increase slightly to 40% due to the additional supply from Base Plant. Combined cycle assets also increased their share of generation in 2025, suppling 27%. This is up from 19% in 2024 because of the additional supply from Cascade 1 and 2. Overall, generation from gas assets supplied 76% of Alberta's electricity in 2025, up from 53% in 2018.

In recent years Alberta has seen significant growth in intermittent supply. Wind generation averaged 1,642 MW in 2025 compared to 469 MW in 2018, and solar generation averaged 395 MW in 2025 compared to 3 MW in 2018. Overall, intermittent generation supplied 19% of total generation in 2025 compared to 5% in 2018. Hydro assets supplied 2% of total generation in 2025, bringing renewable generation to 21% of total supply.

It is important to note that the supply of intermittent generation varies significantly depending on prevailing weather conditions. In 2025, intermittent generation provided between 0% and 44% of total supply on an hourly basis, while gas generation provided between 54% and 98%.

The change from coal to natural gas and the increase in intermittent supply means Alberta has seen a material decline in carbon emissions from electricity generation in recent years. The MSA estimates that the average carbon emission intensity was 0.39 tCO2e/MWh in 2025 compared to 0.81 tCO2e/MWh in 2015, a decline of 52%. Section 1.6 provides further analysis of carbon emissions intensity.

Figure 3: Average generation by fuel type (2015 to 2025)[2]



1.1.3 Demand increases and sets a record peak

Demand for electricity increased in 2025 as Alberta Internal Load (AIL) rose by 2.0% compared to 2024. The higher demand in 2025 was driven by higher oilsands production, population growth, and weather conditions in February, September, and December when year-over-year demand increased by 5.4%, 5.9%, and 5.9% respectively (Figure 4).

August and October 2025 saw very little change in their average temperatures year-over-year, yet demand still increased by 2.5% and 2.3%, respectively. Only in July did year-over-year demand decline, which was caused by milder weather conditions in July 2025.

In hour ending (HE) 18 of December 11, Alberta set a demand record of 12,785 MW, which is 3.2% higher than the prior record set in January 2024 (Table 3). The prior record was surpassed during 35 hours in December, even during periods of relatively mild weather. When the new record was set, the average temperature across Calgary, Edmonton, and Fort McMurray was minus 22°C, compared to minus 32°C when the previous one was set (Table 3).

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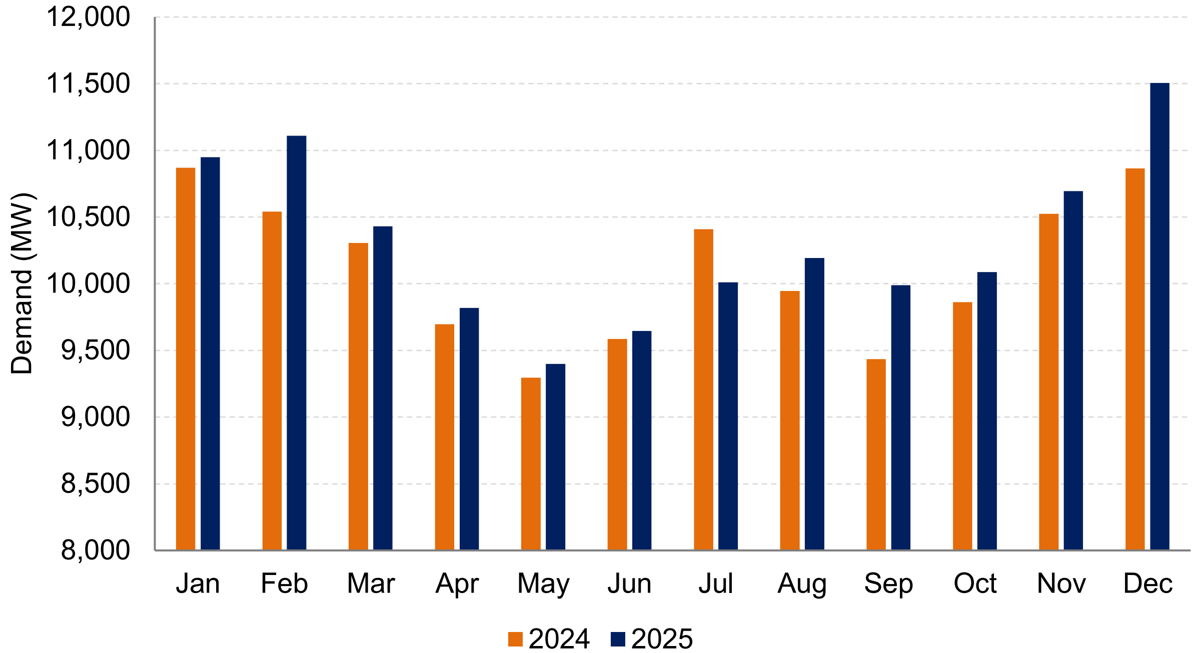
[2] This figure includes generation that was produced and consumed on the same industrial site (behind-the-fence generation).

Figure 4: Average AIL by month (2024 and 2025)



The pool price during the new demand record was low, at $44.20/MWh. This is because the availability of gas generation was high and wind generation averaged 2,016 MW. As a result, the supply cushion was relatively high at 1,471 MW, and this does not include the 1,090 MW of gas-fired steam capacity that was commercially offline on long-lead time.

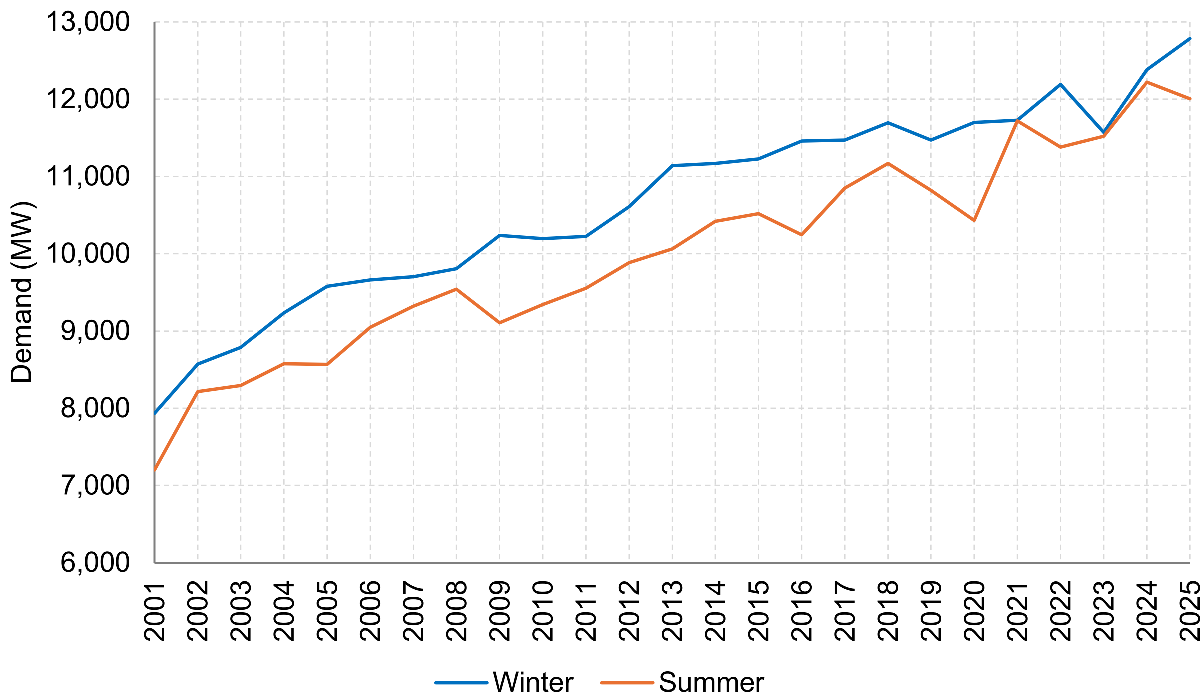
Table 3: Demand record summary statistics

Date	Jan 11, 2024 (Thu)	Dec 11, 2025 (Thu)
AIL (MW)	12,384	12,785
Hour ending	18	18
Avg. temperature (°C)	-32.3	-22.1
Pool price ($/MWh)	$629.01	$44.20
Supply cushion (MW)	322	1,471
Wind generation (MW)	1,111	2,016
Solar generation (MW)	0	0
Net imports (MW)	425	165
Long lead time vol. (MW)	0	1,090

Alberta’s peak demand occurs in winter and has increased significantly since the beginning of the market in 2001 as the population has grown and the oilsands and broader economy have expanded (Figure 5). On average, peak demand has increased by 202 MW per year over this time. Relative to the peak demand in 2018, the current demand record is 9.3% higher.

Peak demand in the summer has also increased with the population and economy, as maximum temperatures have risen, and more consumers have installed air conditioning. The current record for summer demand was set in July 2024 at 12,221 MW, which is 9.4% higher than the summer peak in 2018.

Figure 5: Peak demand in winter and summer (2001 to 2025)



1.1.4 Alberta exports a record amount in 2025

Alberta is interconnected to other jurisdictions via three interties: BC, Montana, and Saskatchewan. Through its interconnections with BC and Montana, Alberta is indirectly connected with large electricity markets in Mid-Columbia and California.

Historically, prices in Alberta have been higher than in these other markets and Alberta has been an importer of power (Figure 6). However, in 2024 and 2025, prices in Alberta were often lower which caused exports. In 2025, the Alberta pool price was below real-time prices in Northern California (NP15) in 77% of hours, and this drove record exports of 348 MW on average.

In terms of capacity, the intertie to BC is the largest, with total transmission capacity of 800 MW for imports and 1,000 MW for exports (Table 4). However, the available capacity for imports is currently well below these limits.

For contingency reasons, the AESO treat the BC and MATL[3] interties as one flow gate (BC/MATL) because a trip on the BC intertie also causes MATL to trip offline. From a reliability perspective,

[3] Montana Alberta Tie Line.

the AESO must be prepared so that a trip on BC/MATL while Alberta is importing does not cause frequency to decline too far. In 2025, the AESO limited imports on BC/MATL to an average of 390 MW when BC/MATL was import constrained. This availability is well below the total combined import capacity of the two interties (Table 4).

Figure 6: Average net imports (2001 to 2025)

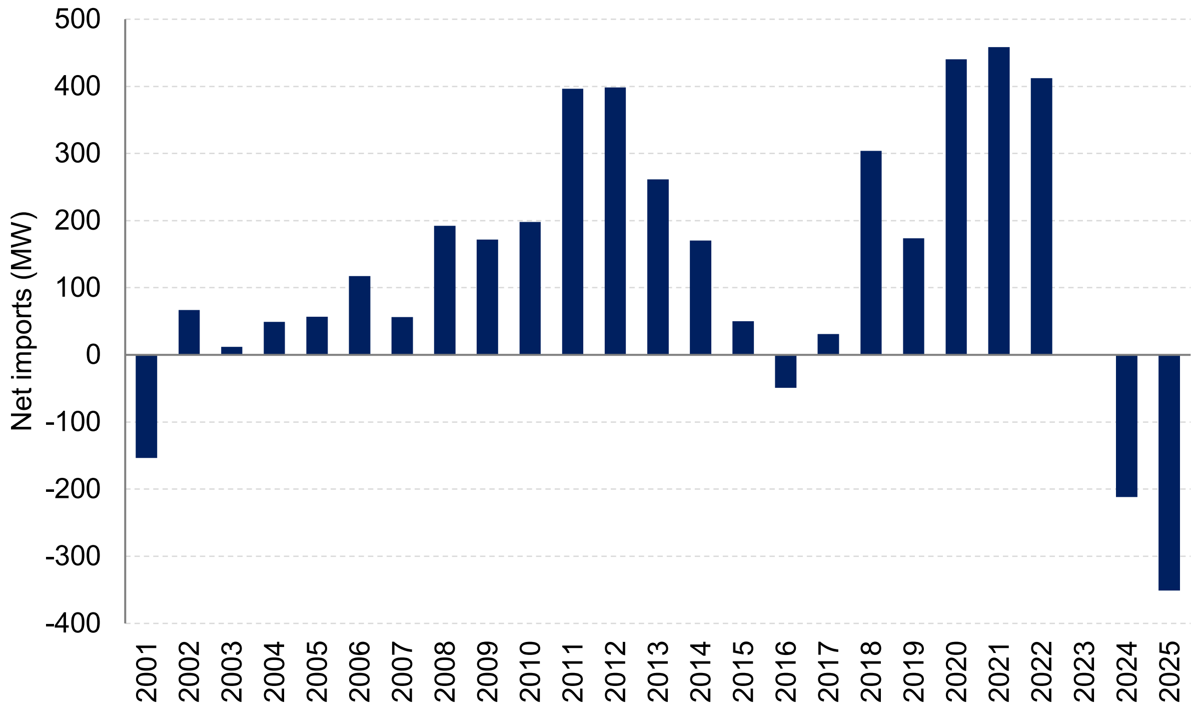


Table 4: Total transmission capacity by intertie

Intertie	Import (MW)	Export (MW)
BC	800	1,000
MATL	310	315
SK	153	153

In 2025, the Government of Alberta directed the AESO to take all reasonable efforts to restore the availability of the BC intertie to 800 MW of imports and the Montana intertie to 300 MW of imports by 2029. In response, the AESO have started a process to procure up to 750 MW of Fast Frequency Response plus (FFR+). FFR+ will be provided by battery or load assets which are available to increase supply or reduce load almost instantaneously in response to a decline in system frequency.[4] By using FFR+, the AESO can increase import flows on the BC and Montana interties because if the interties trip the response of the FFR+ assets will help arrest the frequency decline.

[4] AESO Engage - FFR+

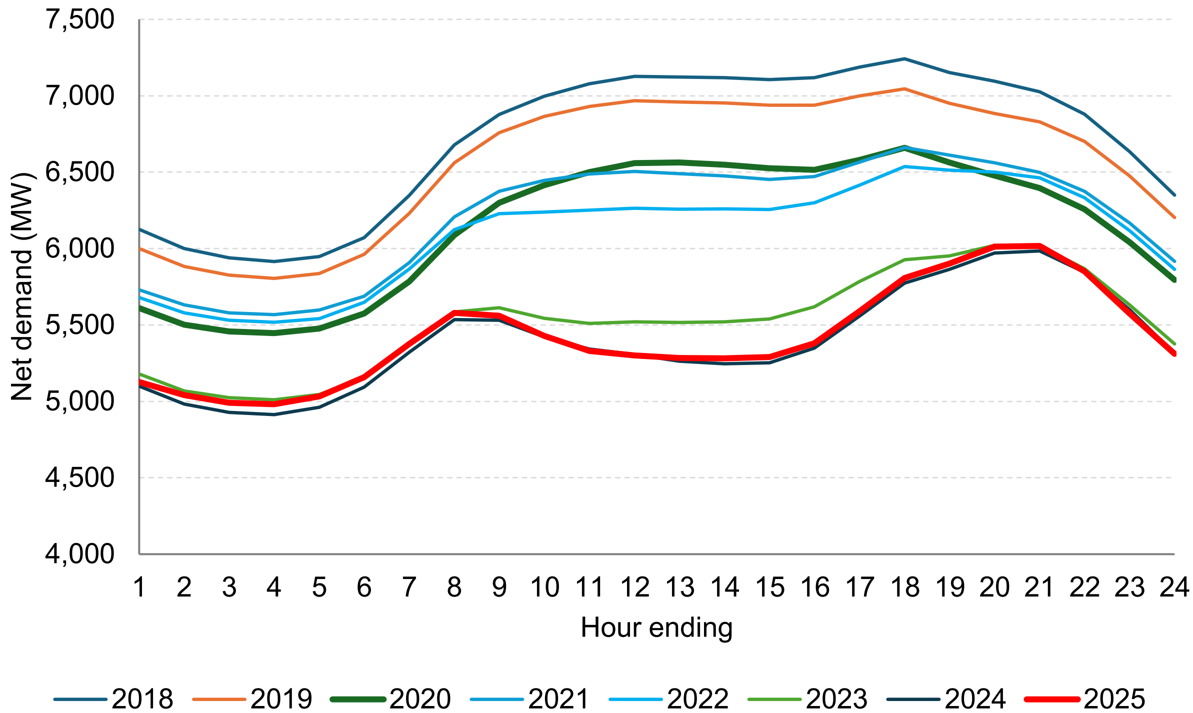
1.1.5 Net demand becomes more variable

AIL can be broken down into system load and behind-the-fence generation. System load is demand that is served by the transmission grid, plus losses, and represents around 72% of AIL.

Net demand is the amount of system load that is left for other generation to serve after subtracting intermittent supply. In recent years, average net demand has fallen because the increases in system load have been more than offset by the increases in intermittent generation.

From 2024 to 2025, average net demand was largely unchanged as increases in system load were offset by more intermittent generation (Figure 7).

Figure 7: Average net demand by hour ending (2018 to 2025)



In 2025, hourly net demand was volatile ranging from 2,635 MW to 9,079 MW, a difference of 6,444 MW (Figure 8). This difference has increased in recent years as the minimum net demand has fallen due to more intermittent supply. The annual peak value of net demand has been less affected because the supply of intermittent generation is generally low in the hours of highest system load.

Increases in wind and solar capacity have increased the variability of net demand. For example, the average absolute change in net demand was 201 MW per hour in 2025, a 44% increase compared to 2018 (Table 5). In 2025, the largest increase in net demand from one hour to the next was 1,368 MW, a record that is almost double the largest net demand increase in 2018. The increased variability of net demand puts upward pressure on the AESO's requirements for regulating reserves and increases the ramping and cycling requirements of some thermal assets.

Figure 8: Daily average net demand (January 1 to December 31, 2025)

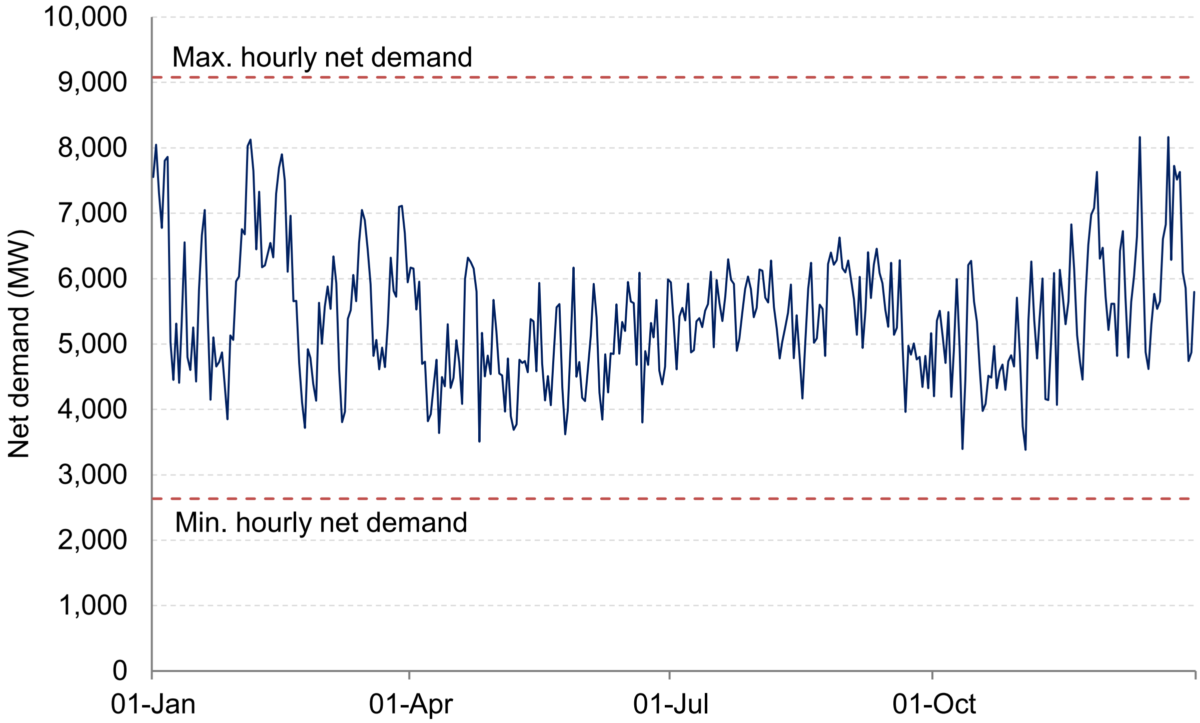


Table 5: Net demand statistics (2018 to 2025)

Year	Avg. absolute hourly change (MW)	Standard deviation (MW)	Maximum hourly increase (MW)	Minimum hourly decrease (MW)
2018	140	712	720	-605
2019	133	728	736	-618
2020	135	787	793	-630
2021	130	793	781	-603
2022	136	764	733	-825
2023	163	853	1,220	-782
2024	190	1,148	1,166	-986
2025	201	1,170	1,368	-1,111

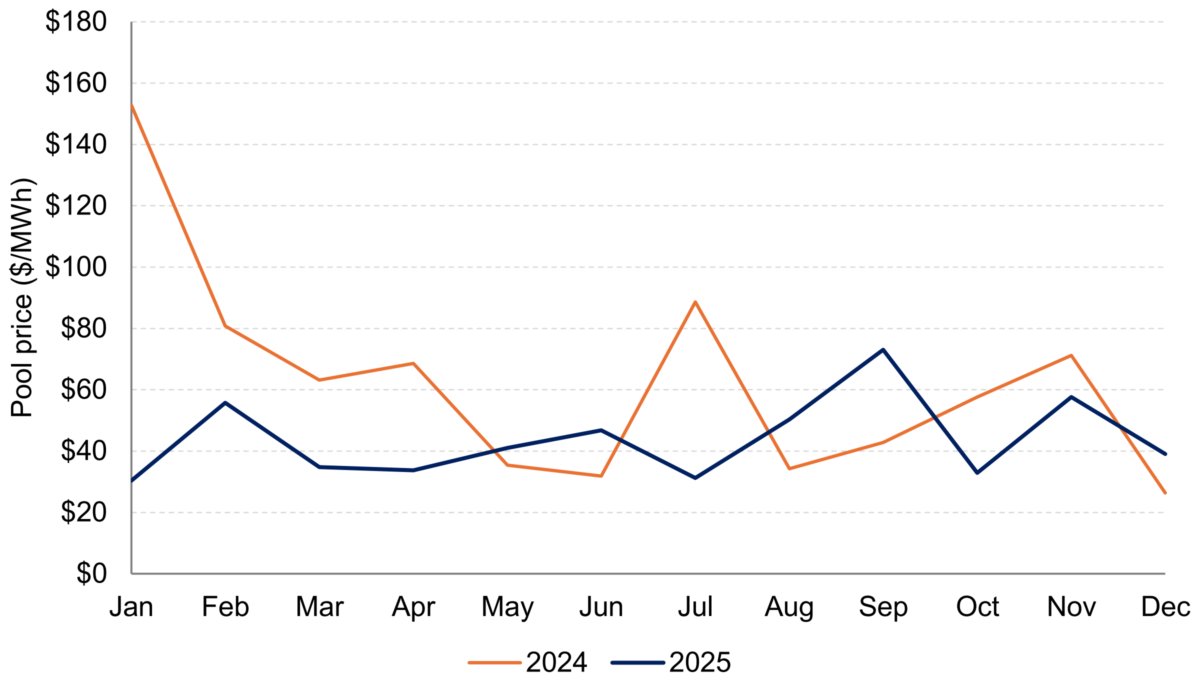
1.1.6 Despite lower average prices some price volatility remains

Figure 9 illustrates monthly average pool prices year-over-year. The average pool price in 2024 was increased by prices in January, which averaged $152.78/MWh. The higher prices in this month were driven by a period of cold weather which increased demand, lowered wind generation, and raised power prices in Mid-Columbia. This period of cold weather was prior to the addition of Cascade 1 and 2, and during this cold spell Alberta set a demand record and the AESO declared Energy Emergency Alerts (EEAs) on multiple days.

In January 2025, the average pool price was 80% lower at $30.36/MWh, the lowest monthly average price in 2025. The low prices in January 2025 were due to high thermal availability, mild weather, and increased wind generation.

In 2025, the monthly average pool price was highest in September at $73.05/MWh. The higher prices in this month were driven by higher demand year-over-year, some planned gas generator outages, and a planned BC/MATL intertie outage later in the month.

Figure 9: Monthly average pool price (2024 and 2025)



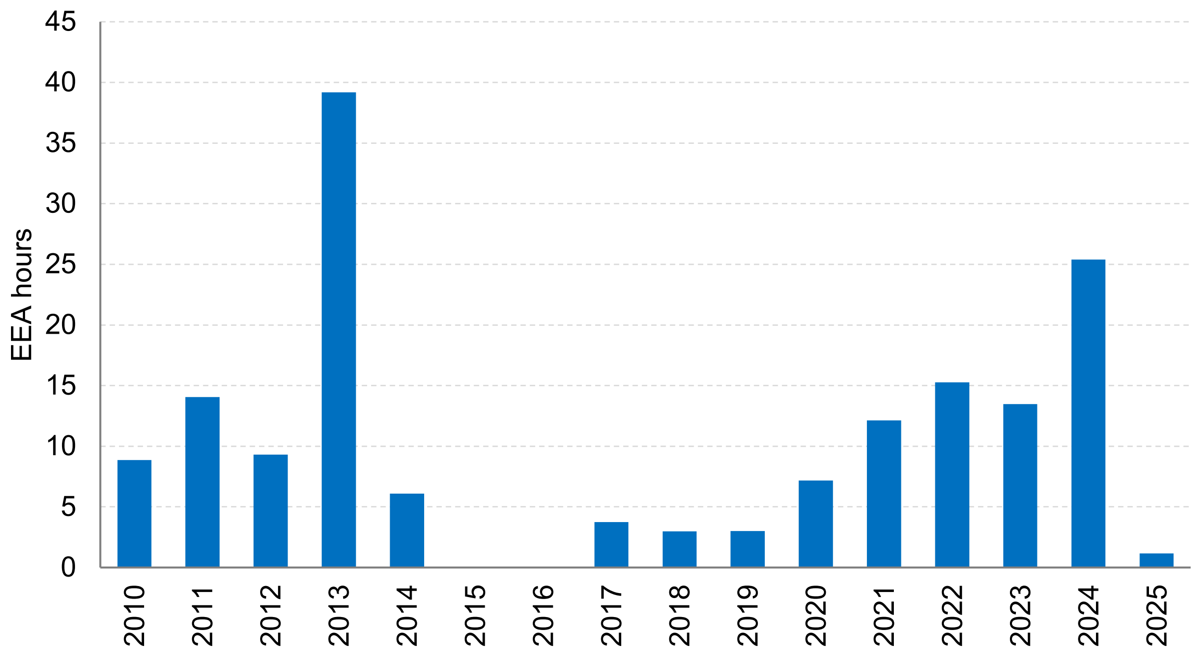
While average pool prices in 2025 were relatively low, there continued to be a fair amount of price variation. For example, the daily average pool price ranged from $0.75/MWh on September 21 to $409.93/MWh on September 8. The lower priced days were normally caused by high intermittent supply and low demand, while the higher priced days were often driven by low intermittent supply, elevated demand, gas generator outages, and offer behaviour.

On some days there was a large variation in prices intraday, generally driven by large changes in intermittent supply. For example, on June 8, the System Marginal Price (SMP) was at the offer cap of $999.99/MWh at 21:15 as intermittent supply was 775 MW and Genesee Repower 2 was on outage. However, the SMP fell to $0.00/MWh just over two hours later when intermittent generation was 2,100 MW and Genesee Repower 2 was back online.

Similarly, on September 8, the SMP cleared at the floor of $0.00/MWh at 02:00 driven by high wind generation and low overnight demand. However, conditions were different later in the day as wind generation declined and demand increased. In addition, there were several gas generator outages and constraints on the supply of imports. As a result, between 18:54 and 20:04 the AESO declared an EEA3 as the supply curve had been exhausted and the AESO were using contingency reserves to help meet demand.

The EEA3 on September 8 lasted 1 hour and 10 minutes and was the only EEA event in 2025. In 2024, the AESO declared an EEA3 on eight separate days, with the events totalling 25 hours and 24 minutes (Figure 10). The low number of EEAs in 2025 was driven by increased gas generation capacity and the AESO's unit commitment directives.

Figure 10: Total EEA hours (2010 to 2025)



Prior to declaring an EEA3 on September 8, the AESO dispatched three load bids that were priced at the top of the merit order. These three load assets began bidding into the energy market in July 2025 (Table 6), bidding a portion of their energy consumption in accordance with the Demand Opportunity Service (DOS) rate of the AESO's tariff. These bids are novel as loads have not bid into the energy market in the past. The DOS rate became an option for loads beginning on February 1, 2025.

Table 6: Load assets bidding into the energy market

Company	Asset ID	Capacity (MW)	Start date
Alberta Newsprint	ANCD	83	July 1, 2025
Millar Western	MWFD	65	July 24, 2025
Millar Western	MWAD	55	July 24, 2025

In addition to the EEA3 event on September 8, prices also cleared at the offer cap on four other days in 2025: June 8, June 17, July 12, and September 16. In total, prices were at the offer cap for 8 hours and 4 minutes, or 0.1% of the time over the year. This is a reduction from 2024 when prices cleared at the offer cap for 39 hours and 29 minutes, or 0.4% of the time (Table 7).

Prices cleared at the floor of $0.00/MWh for 10.6% of the time in 2025. This is an increase from 6.1% in 2024 and is much higher than prior years (Table 7). This increase was caused by more must-run gas generation and higher intermittent supply. Must-run gas generation occurs because of steam requirements at cogeneration assets and because gas-fired steam and combined cycle assets have minimum stable generation levels that they cannot run below.

Table 7: Percent of time the SMP was at the floor or the offer cap (2018 to 2025)

Year	SMP at $0.00/MWh	SMP at or above $999.99/MWh
2018	0.17%	0.07%
2019	0.00%	0.04%
2020	0.77%	0.09%
2021	0.01%	0.18%
2022	0.08%	0.30%
2023	0.95%	0.26%
2024	6.06%	0.45%
2025	10.56%	0.09%

1.1.7 Unit commitment directives lowered pool prices and maintained reliability

In March 2024, the *Market Power Mitigation Regulation* and *Supply Cushion Regulation* were enacted. Since July 1, 2024, these regulations have moderated economic withholding and required the AESO, under some circumstances, to commit generation capacity that is commercially offline on long lead time. The impacts of these interim market power measures will be analyzed in detail in a forthcoming standalone MSA report.

The *Market Power Mitigation Regulation* moderates economic withholding by imposing a secondary offer cap once monthly net revenues exceed a certain threshold. In 2025, monthly net revenues were never sufficient to trigger the secondary offer cap. Net revenues were highest in September when they reached 86% of the threshold.

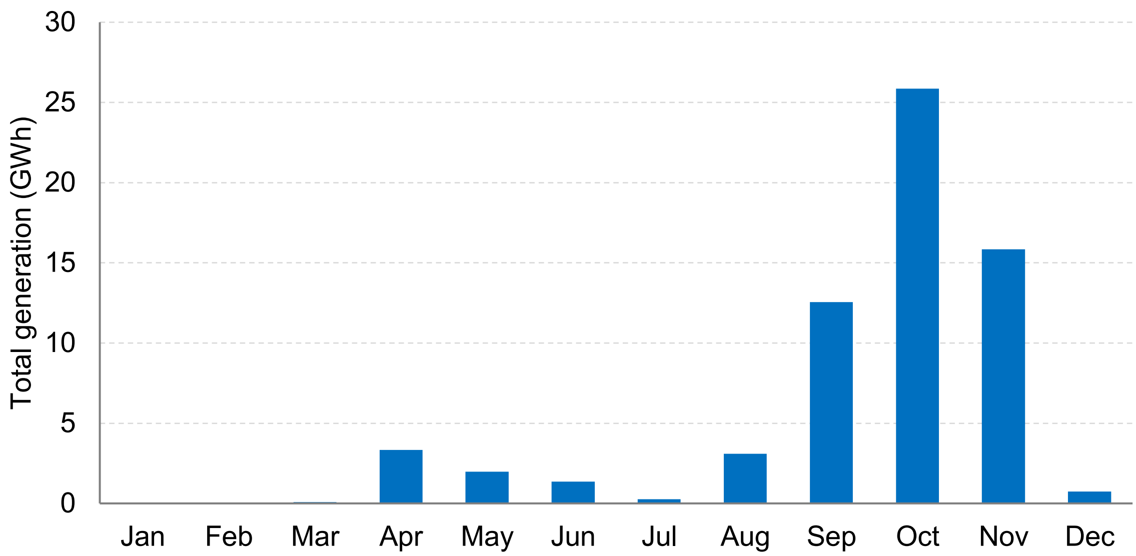
The *Supply Cushion Regulation* requires the AESO to commit generation assets that are commercially offline on long lead time when the AESO forecast that supply cushion will fall under 932 MW. The AESO issued 135 unit commitment directives in 2025, although three of these the relevant market participant was later instructed to disregard. The unit commitment directives had a notable impact on pool prices in some months. For example, our estimates show that average pool prices in October were 47% lower because of unit commitment directives.

Figure 11 illustrates the monthly volume of generation provided by assets that were under unit commitment directives. As shown, unit commitment directives were most prevalent in October when they supplied a total of 26 GWh. The large volume of unit commitments in October was driven by high amounts of constrained wind generation and several large gas assets being on outage. The high volume of constrained down generation meant pool prices were low despite supply cushion being relatively tight, leading to a high number of unit commitment directives.

In addition to lowering pool prices, the unit commitment directives played a critical role in maintaining reliability. In 2025, there were sixteen hours in which the supply cushion would have been below 0 MW without the unit commitment directives. These sixteen hours were spread over six days: June 8, September 8, September 16, October 29, November 3, and November 4.

During the EEA3 event on September 8, three assets were committed by the AESO adding 950 MW of supply. Given that the merit order was exhausted and the AESO were using contingency reserves to provide energy, it is clear that without the unit commitment directives the AESO would have been required to shed firm load in this event.

Figure 11: Total generation from unit commitment directives (January to December, 2025)



1.1.8 Increased transmission congestion drives higher price differentials

The MSA estimates that total constrained intermittent generation was 1,468 GWh in 2025, a 189% increase compared to 508 GWh in 2024. In recent years, more intermittent generation has been constrained as additional intermittent capacity has been installed in the South of the province. The higher amount of constrained intermittent generation has caused a larger differential between the constrained and unconstrained SMP over time (Table 8).

The constrained SMP is determined based on the offer price of the marginal block that is required for supply to meet demand. The constrained SMP accounts for the fact that some generation may be unavailable due to transmission congestion.

The unconstrained SMP is calculated by moving down the merit order from the constrained SMP by the volume of constrained generation. The unconstrained SMP is an estimate of what price would have been in the absence of transmission congestion. It is the unconstrained SMP that sets the published SMP and determines pool price. However, blocks that are dispatched above the unconstrained SMP are paid their offer price.

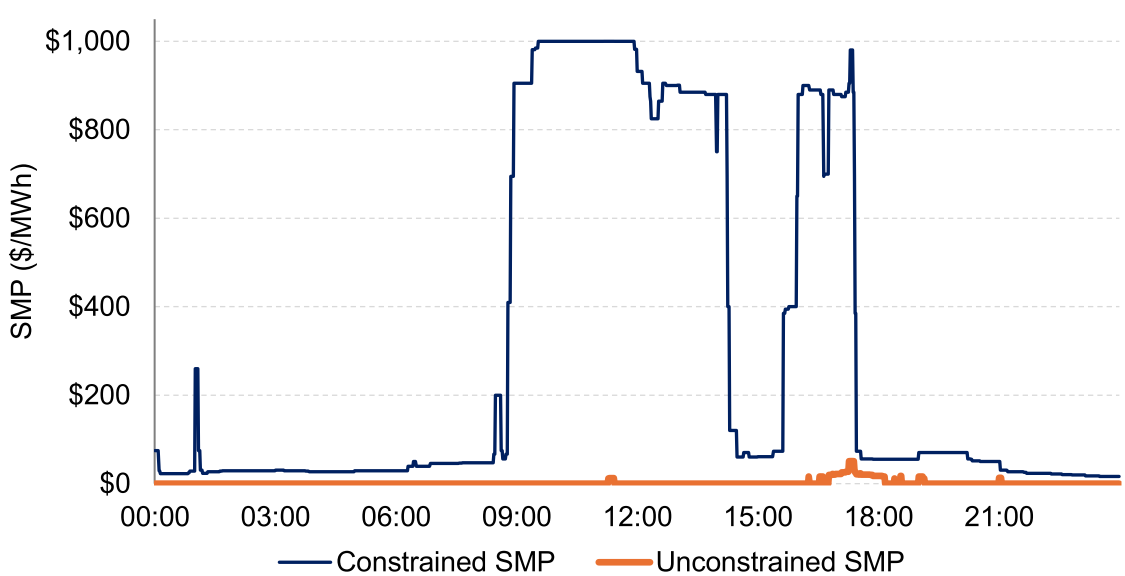
Table 8: Average constrained and unconstrained SMP (2018 to 2025)

Year	Constrained SMP ($/MWh)	Unconstrained SMP ($/MWh)	Difference ($/MWh)	Difference (%)
2018	$50.39	$50.35	$0.04	0%
2019	$55.06	$54.88	$0.18	0%
2020	$47.30	$46.72	$0.58	1%
2021	$104.58	$101.93	$2.64	3%
2022	$164.49	$162.46	$2.03	1%
2023	$137.71	$133.63	$4.08	3%
2024	$65.71	$62.78	$2.92	5%
2025	$49.83	$43.68	$6.15	14%

On certain days in 2025 there was a notable difference between the constrained and unconstrained SMP. For example, on October 29, the constrained SMP was at the offer cap of $999.99/MWh while the unconstrained SMP was at the floor of $0.00/MWh (Figure 12).

As a result, gas-fired steam assets were operating in accordance with unit commitment directives and the supply curve was almost exhausted, all while the published SMP was $0.00/MWh and Alberta was exporting 515 MW. As discussed further in section 1.3.1, this event was driven by a large amount of wind generation being constrained in addition to some large gas generators being on outage. This event illustrates the value of bringing locational marginal prices to Alberta.

Figure 12: The constrained and unconstrained SMP (October 29, 2025)



1.1.9 *Market power declines despite large acquisition*

On December 4, 2024, TransAlta completed the purchase of Heartland Generation and acquired an additional 2,141 MW of offer control for gas generation capacity in Alberta. As a result of the purchase, the MSA's annual market share offer control calculations showed that TransAlta's market share increased from 15% in early 2024 to 23% in early 2025.

On August 1, 2025, as part of its agreement with the Canadian Competition Bureau, TransAlta sold the Poplar Hill (48 MW) asset to Dynasty Power, and on October 2, 2025, TransAlta sold its 50% share of the Rainbow Lake 1 (47 MW) and Rainbow 5 (50 MW) assets to Cenovus Energy.

Despite the increase in market concentration in late 2024, the ability of large firms to exercise market power declined in 2025. One way to analyze the ability of firms to exercise market power is to calculate how often they are pivotal. A firm is pivotal when its withholdable capacity[5] is needed for demand to be met.

In 2025, the largest firm was pivotal in 5% of hours, which is a decline from 8% in 2024 (Figure 13). The ability of firms to exercise market power has declined in recent years due to the addition of Cascade 1 and 2, Base Plant, and more intermittent supply.

Figure 13: The percentage of hours in which the largest firm was pivotal (2020 to 2025)

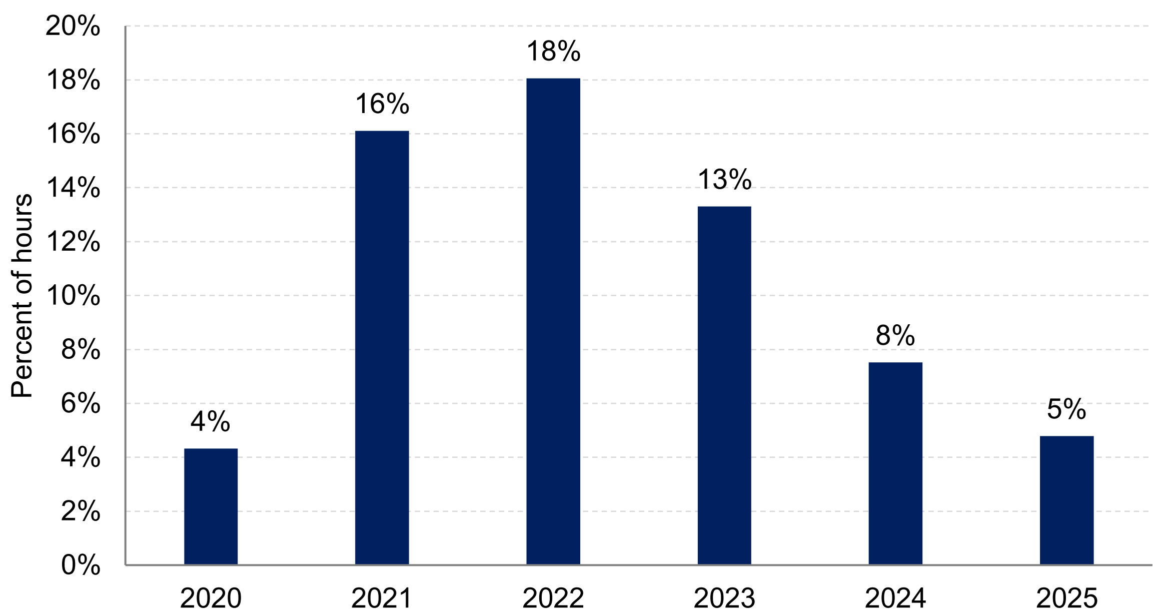
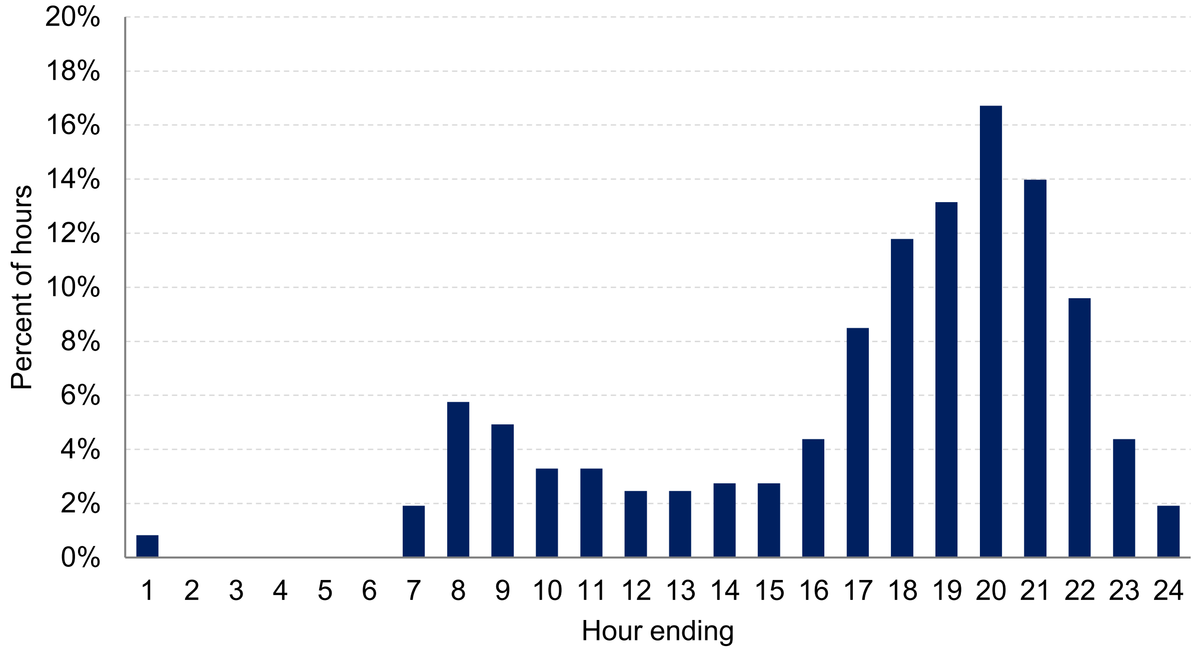


Figure 14 illustrates how often the largest firm was pivotal by hour ending in 2025. While demand for electricity generally peaks in HE 18, the ability of firms to exercise market power is often later. In 2025, the ability of firms to exercise market power was highest in HE 20 when the largest firm was pivotal 17% of the time, followed by HE 21 at 14% of the time. The ability of firms to exercise

[5] Withholdable capacity is all capacity except for minimum stable generation and intermittent capacity.

market power is highest after the demand peak due to the reduced supply of solar generation. Apart from the winter months, the net demand peak occurs in HE 20 or 21 because solar supply is still relatively strong during the demand peak.

Figure 14: The percentage of hours in which the largest firm was pivotal by hour ending (2025)



1.1.10 Wind and solar received prices decline

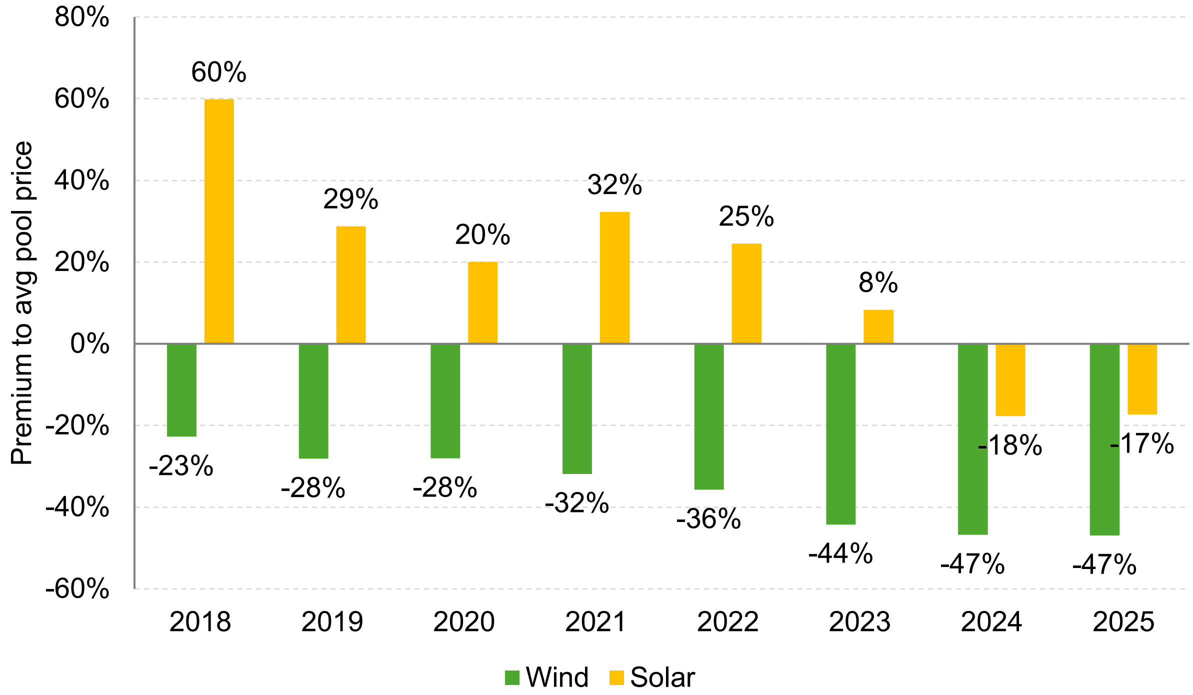
Different generation assets receive different average prices depending on how much they generate when pool prices are high or low. An asset that supplies more when pool prices are elevated will receive a higher average price compared to an asset that generates more when prices are lower.

The received prices for wind and solar assets were below the average pool price in 2025. The received price of total wind generation in 2025 was $23.18/MWh, a 47% discount to the average pool price (Figure 15). Wind assets receive a discount to the average pool price because:

- the output of wind generators across Alberta is highly correlated; when wind generation is high at one wind asset, it is likely to be high at other wind assets as well which lowers prices, and

- wind generation is often higher during periods of mild weather and overnight when demand is lower.

Figure 15: Received price of wind and solar relative to the average pool price (2018 to 2025)



The received price of total solar generation in 2025 was $36.12/MWh, an 17% discount to the average pool price. As with wind generation, the received price of solar assets has been lowered by the correlation of supply across assets. In prior years, solar generation received a premium to the average pool price because solar supply often occurred during hours of higher pool prices. However, this premium has been eroded as more solar capacity has been developed and solar supply has increased (Figure 15).

1.1.11 Transmission must-run volumes increase

Transmission must-run (TMR) is an out of market ancillary service used by the AESO to provide supplementary sources of supply to help maintain grid stability. Generally, the AESO use TMR when demand in a region of the province's electricity system cannot be served by dispatched generation due to transmission constraints.

Consequently, the AESO issues TMR directives that require local generation to operate at specific levels to ensure demand in the area is met. Further to this, on occasion, the AESO uses TMR to maintain grid stability for other reasons, such as voltage support.

Total TMR volumes increased from 82 GWh in 2024 to 340 GWh in 2025, an increase of 317%. The higher TMR volumes in 2025 were largely caused by more TMR directives to assets in the Grande Prairie region due to higher load in that area. TMR is discussed further in section 2.3.

1.1.12 Operational trends in system frequency and area control error

The AESO operates the Alberta electricity grid at a frequency of 60 Hz, the standard frequency level across North America. However, system frequency can deviate from this level due to imbalances between supply and demand.

When there is insufficient supply relative to demand, frequency can fall. This may occur because of an unexpected trip at a generation asset, a sudden decline in intermittent generation, or a trip on an intertie while Alberta is importing. On the other hand, if supply exceeds demand, frequency can rise. This may occur when there is a sudden reduction in demand due to a large load tripping offline, or an intertie tripping while Alberta is exporting.

In 2025, system frequency in Alberta ranged from 59.66 to 60.49 Hz. This is a similar range to 2021 but is above the range in 2022, 2023, and 2024 (Table 9). For context, the AESO's under frequency load shed (UFLS) service is set to start tripping loads if frequency falls below 59.5 Hz.

Table 9: System frequency statistics (2020 to 2025)

	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Minimum (Hz)	59.17	59.36	59.73	59.54	59.53	59.66
Maximum (Hz)	60.31	60.24	60.31	60.20	60.17	60.49
Range (Hz)	1.15	0.88	0.59	0.66	0.64	0.83

Table 10 provides a summary of the six events in which system frequency has fallen below 59.5 Hz since January 1, 2020. The lowest value of system frequency during this time was 59.17 Hz and was due to a trip of the BC and Montana interties on the afternoon of June 7, 2020. A lightning strike on transmission line 5L92 was the cause of the trips. Alberta was importing 651 MW from BC and 264 MW from Montana at the time. Due to the sudden loss of 915 MW of imports, frequency fell to 59.17 Hz even though the AESO tripped 200 MW of Fast Frequency Response (FFR)[6] and 235 MW of UFLS.

The lowest value of system frequency in 2025 occurred on the evening of June 23 due to a trip at the Keephills 3 asset while Alberta was islanded. Keephills 3 was only generating 253 MW at the time of the trip, but inertia and primary frequency response in Alberta were insufficient to avoid the decline in frequency.

The highest value of system frequency in 2025 occurred on the afternoon of May 31 and was caused by a trip on the BC transmission line 5L92, which caused the BC and Montana interties

[6] FFR is a service provided by batteries and loads which increase supply or reduce consumption almost instantaneously once frequency falls below 59.7 or 59.5 Hz. Previously, a similar service was provided exclusively by loads and was called Load Shed Service for imports (LSSi).

to trip offline. Alberta was exporting 980 MW to BC at the time, so the trip caused a large and sudden loss in export demand and this increased frequency.

Table 10: Events in which system frequency fell below 59.5 Hz (January 1, 2020 to December 31, 2025)

Datetime	Min. frequency (Hz)	Event description	Generation loss (MW)	FFR tripped (MW)	UFLS tripped (MW)
Jun 07, 2020 14:50	59.17	BC/MATL trip	915	200	235
Jun 03, 2021 14:43	59.36	BC/MATL trip	707	94	177
Feb 21, 2021 21:13	59.44	BC/MATL trip	444	0	125
Feb 22, 2021 18:22	59.49	BC/MATL trip	468	235	0
Oct 23, 2021 17:29	59.49	KH2 trip while islanded	395	0	0
Nov 30, 2021 21:24	59.49	BC/MATL trip	523	0	0

Area Control Error (ACE) illustrates the instantaneous difference between the actual flow of power on BC/MATL and the scheduled flow of power on BC/MATL, taking into account frequency bias and metering error. When ACE is positive this illustrates that Alberta is exporting more than scheduled. In contrast, a negative ACE indicates Alberta is importing more than scheduled. A larger absolute value of ACE indicates a larger difference between actual flows and the schedule.

Figure 16 illustrates how often the 1-minute average of ACE was above 200 MW and how often the 1-minute average was below negative 200 MW. In recent years, ACE has more frequently been below the negative 200 MW threshold, indicating that Alberta has more frequently imported more than was scheduled. This trend has been driven by more generation trips in Alberta in recent years and by an increased proportion of supply coming from intermittent generation.

The largest contingency event in 2025 occurred on June 17 when Genesee Repower 1 and 2 tripped offline simultaneously. This event removed 927 MW of supply instantaneously and lowered ACE below negative 1,000 MW. However, because the BC and Montana interties were in service at the time, the supply shock was largely absorbed by the Western Interconnection and frequency in Alberta was not significantly affected (Table 11).

In Q1 2025, there were two large contingency events involving drops in wind generation. On the morning of January 11, 2025, wind generation dropped quickly by approximately 730 MW, a change that is well above the AESO's Most Severe Single Contingency (MSSC) limit of 466 MW. Similarly, on February 27, 2025, wind generation dropped by approximately 770 MW. In both cases, Alberta was interconnected with the Western Interconnection via the BC and Montana interties so there was little impact on system frequency. However, if wind generation declined by this magnitude while Alberta was islanded, there would be a notable impact.

Figure 16: The percent of time ACE was above or below certain thresholds (2020 to 2025)

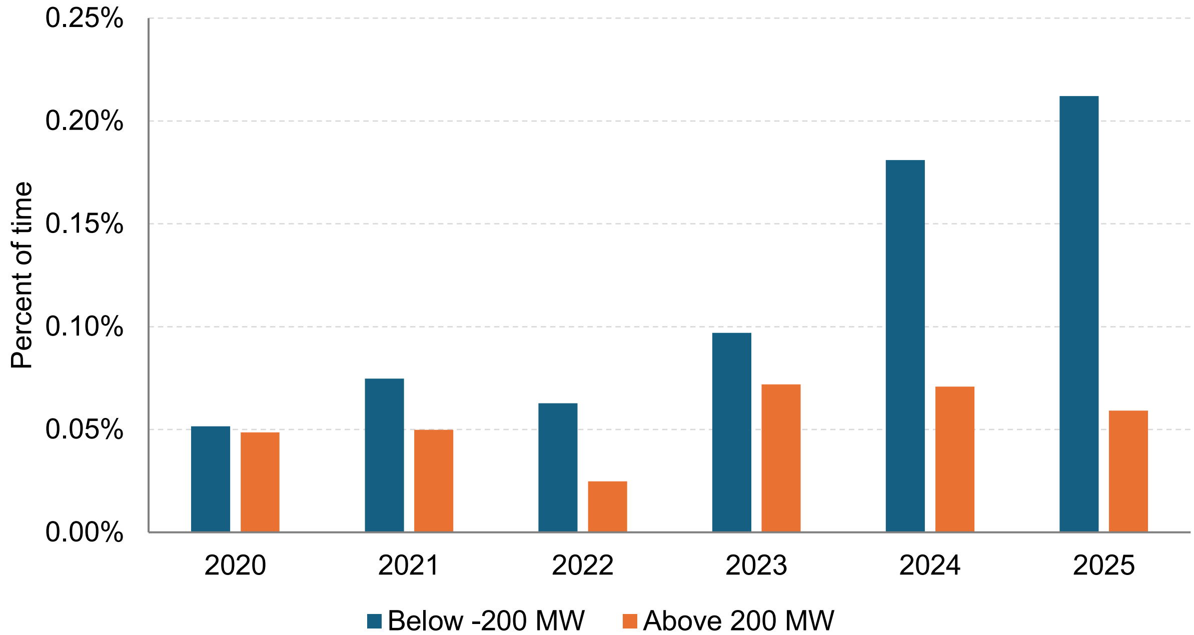


Table 11: The five events with the lowest ACE value in 2025

Datetime	Event description	Gen. loss (MW)	Min. ACE (MW)	Min. frequency (Hz)	Interconnected with WECC?	Intermittent gen. (MW)
Jun 17 17:08	GNR1,GNR2 trip	927	-1,034	59.92	Yes	1,720
Feb 27 06:00	Wind drop	770	-952	59.95	Yes	3,430
Jan 11 08:51	Wind drop	730	-850	59.96	Yes	3,210
Oct 18 12:56	GNR1 trip	558	-687	59.94	Yes	3,600
Jun 21 12:34	GNR1 trip	632	-647	59.93	Yes	3,340

The Genesee Repower 1 and 2 assets are large combined cycle units with an installed capacity of around 700 MW each. However, due to their configuration[7] and the AESO's MSSC limit, the output of each asset is currently restricted to 466 MW.

At various times in 2025, the AESO permitted testing at the Genesee Repower 1 and 2 assets. During this testing, the AESO allowed the assets to generate more than 466 MW when Alberta

[7] Genesee Repower 1 and 2 are both configured as one gas turbine to one steam turbine. Therefore, a trip on the gas turbine will remove the generation of the entire asset.

was interconnected. On June 21 and October 18, the Genesee Repower 1 asset tripped offline during such testing, reducing supply by 558 MW and 632 MW, respectively (Table 11).

Alberta's system inertia and primary frequency response are lower when intermittent supply is high. Therefore, the sudden loss of generation has a higher impact on ACE when intermittent supply is elevated. For these Genesee Repower 1 trips, intermittent generation was high at the time raising the impact of the trips on ACE (Table 11).

1.2 Quarterly summary

The average pool price in Q4 was $43.03/MWh, which is 16% lower than in Q4 2024 and Q3 2025. The lower pool prices in Q4 were due to higher wind generation and higher availability of natural gas assets. These fundamentals offset increased demand, more exports, and higher natural gas prices (Table 12).

Despite cold weather and high demand in December, the average pool price for the month was relatively low at $39.00/MWh. This price was reflective of high wind generation and increased supply from Suncor's Base Plant asset (Figure 17).

Figure 17: Daily average generation of Base Plant (January 1, 2024 to December 31, 2025)

Beginning in late November, the supply of Base Plant increased as more cogeneration capacity was brought online. Between November 20 and 28 generation at the site increased from 430 MW to 840 MW and generally remained high for the duration of the quarter. On December 1, Suncor began to offer parts of the asset into the market at a positive price, indicating the end of the commissioning period.

Wind generation was exceptionally high in Q4, averaging 2,032 MW. This is the first time the quarterly average has been above 1,800 MW, with all three months averaging around 2,000 MW (Table 12). In December, the capacity factor of wind generation was 38%, the highest since January.

December also saw record high demand levels due to cold temperatures and high oilsands production. On average, AIL was 11,505 MW over the month marking a 6% increase year-over-year.

In HE 18 of December 11, Alberta set a record for hourly demand at 12,785 MW, which is 401 MW higher than the prior record set in January 2024.

Indeed, the prior demand record was broken in 35 hours in December, including during relatively mild weather. On December 9, demand peaked at 12,424 MW, a new record at the time, even though temperatures in Calgary were only minus 12°C.

The low pool prices in Q4 occurred despite some large gas generator outages in October and November.

For example, Keephills 3 was offline for 44 days starting in late September, Genesee 3 was offline for 21 days beginning in late October, and the Calgary Energy Centre was offline for 25 days beginning on November 6 (Table 13). In addition, Cascade 1 and 2 took outages in late October and early November.

Table 12: Summary market statistics for Q4 2024 and 2025

		2024	2025	Change
Pool price (Avg $/MWh)	Oct	$57.62	$32.88	-43%
	Nov	$71.20	$57.64	-19%
	Dec	$26.35	$39.00	48%
	Q4	**$51.52**	**$43.03**	**-16%**
Demand (AIL) (Avg MW)	Oct	9,861	10,087	2.3%
	Nov	10,525	10,695	1.6%
	Dec	10,864	11,505	5.9%
	Q4	**10,416**	**10,763**	**3.3%**
Gas price AB-NIT (2A) (Avg $/GJ)	Oct	$1.13	$1.33	18%
	Nov	$1.36	$2.25	65%
	Dec	$1.76	$2.87	63%
	Q4	**$1.42**	**$2.15**	**52%**
Available thermal capacity (Avg MW)	Oct	9,016	9,389	4%
	Nov	10,183	9,875	-3%
	Dec	11,265	11,532	2%
	Q4	**10,154**	**10,269**	**1%**
Wind gen. (Avg MW)	Oct	1,783	2,034	14%
	Nov	1,469	1,929	31%
	Dec	1,886	2,130	13%
	Q4	**1,715**	**2,032**	**18%**
Solar gen. (Avg MW during peak hours)	Oct	409	501	22%
	Nov	153	235	54%
	Dec	144	146	1%
	Q4	**236**	**294**	**25%**
Net imports (+) Net exports (-) (Avg MW)	Oct	-159	-466	193%
	Nov	-60	-250	317%
	Dec	-418	-258	-38%
	Q4	**-214**	**-325**	**52%**

Table 13: Major gas generator outages (Q4 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
Cloverbar 3	101	22 Sep	27 Sep	6
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
Cascade 1	466	03 Nov	09 Nov	7
ENMAX Calgary Energy Centre	330	06 Nov	30 Nov	25
Battle River 5	395	13 Nov	27 Nov	15
Keephills 2	395	16 Nov	30 Nov	15

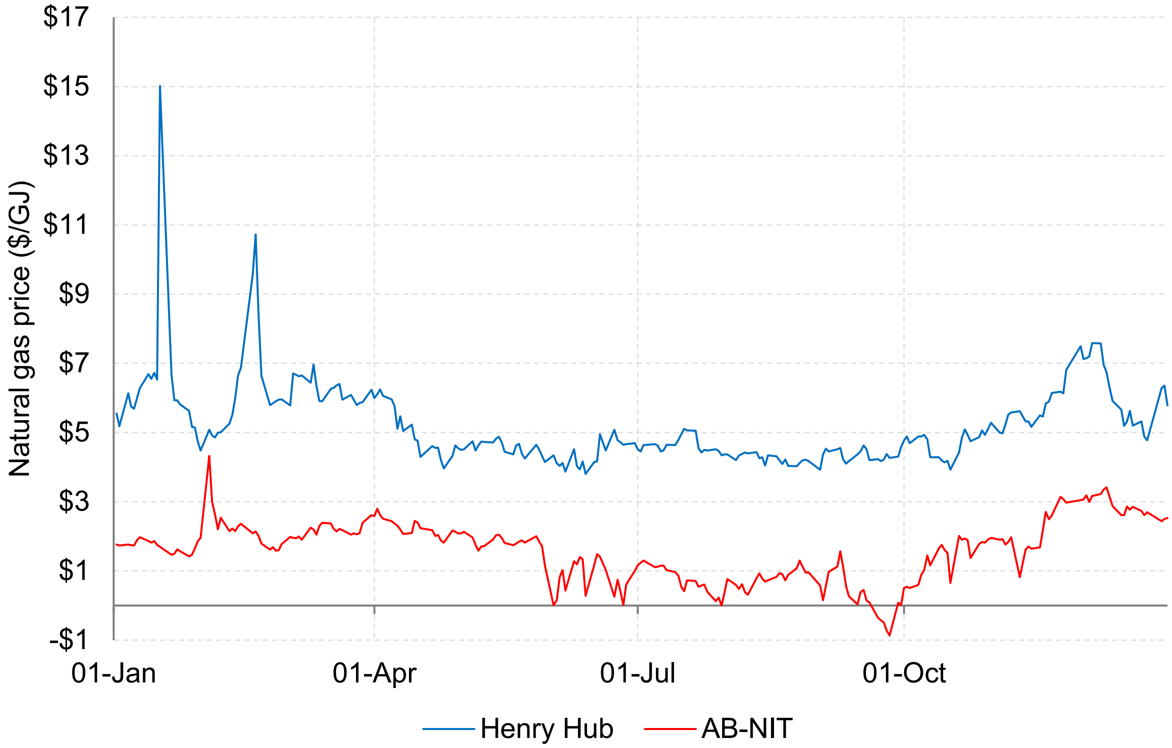
Generator outages contributed to pool price volatility on November 3 and 4, and to a notable difference between the constrained and unconstrained SMP on October 29. These events are discussed further in section 1.3. It is normal to see planned generator outages scheduled for the spring and fall when demand is lower. In Q4, thermal availability was highest in December averaging 11,532 MW compared with 9,875 MW in November, and 9,389 MW in October.

Natural gas is the main input cost for Alberta power. In most hours, the supply cushion is relatively high and offers into the energy market are generally reflective of variable costs. In these hours, natural gas prices are a major factor in determining the pool price.

Figure 18 illustrates daily spot prices for natural gas in Alberta and at Henry Hub. Henry Hub is a major natural gas distribution centre located in Erath, Louisiana. Natural gas prices at Henry Hub are used as the benchmark for North America. Natural gas prices at Henry Hub trade at a premium to prices in Alberta due to pipeline constraints getting natural gas out of Alberta. In Q4, the average spread between the two was $3.37/GJ, which is higher than it has been historically.

Natural gas prices in Q4 increased on the back of export demand and cold weather. The average price of natural gas in Alberta was $2.15/MWh in Q4, which is an increase of 240% relative to Q3 and is 52% higher than Q4 2024. Despite the higher natural gas prices, average pool prices declined as there were fewer elevated pool prices in the quarter.

Figure 18: Daily natural gas prices at Henry Hub and AB-NIT (2025)



1.3 Market outcomes and events

The average pool price in Q4 was $43.03/MWh, a 16% decline compared to Q3 2025 and Q4 2024. The lower average price in Q4 was largely driven by fewer high-priced hours. In the highest 10% of hours in Q4 pool prices averaged $211/MWh and contributed 49% to the average quarterly price (Table 14).

In Q3, the top 10% of hours had a higher average pool price at $343/MWh and contributed more to the quarterly average at 67%. As shown by the figures below, the higher pool prices in a small number of hours are a major driver of average pool prices.

Table 14: The distribution of pool prices (Q4, Q3, and Q4 2024)

Percentile	Q4 2025 (Avg. $43.03)		Q3 2025 (Avg. $51.29)		Q4 2024 (Avg. $51.52)	
	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.
Top 10%	$211	49%	$343	67%	$278	54%
10 to 50%	$40	37%	$31	24%	$42	33%
Bottom 50%	$12	14%	$10	9%	$14	13%

1.3.1 October 29: large difference between the constrained and unconstrained SMP

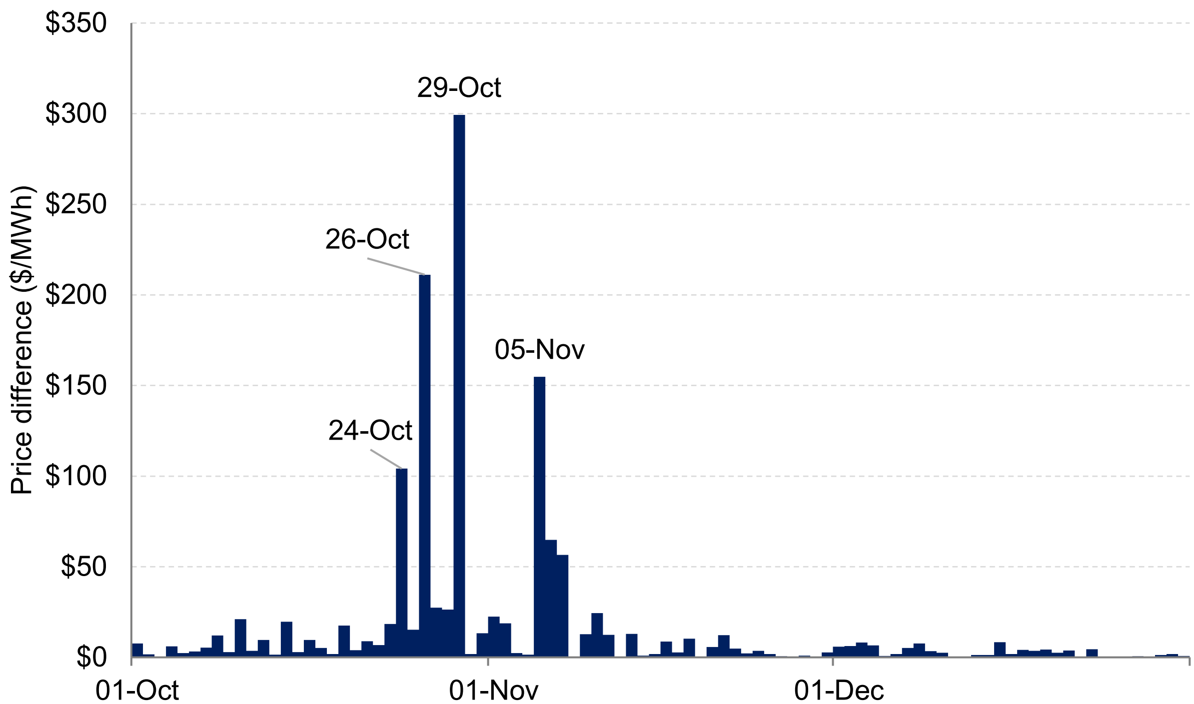
The difference between the constrained and unconstrained SMP continued to increase in Q4. In October, the monthly average constrained price was $28/MWh higher than the unconstrained price, and in November the difference was $15/MWh (Table 15). For both months, the difference was above the prior record of $14/MWh set in February 2021.

Table 15: Monthly average constrained and unconstrained SMP (Q4 2025)

	Constrained SMP ($/MWh)	Unconstrained SMP ($/MWh)	Difference ($/MWh)	Difference (%)
Oct	$60.95	$32.88	$28.07	85%
Nov	$72.44	$57.64	$14.80	26%
Dec	$41.86	$39.00	$2.86	7%
Q4	**$58.27**	**$43.03**	**$15.24**	**35%**

The monthly price differentials in October and November were driven by large price differentials on a few days (Figure 19). On October 29, the price differential was close to $300/MWh as the average constrained price was $301.10/MWh and the unconstrained price was $1.71/MWh.

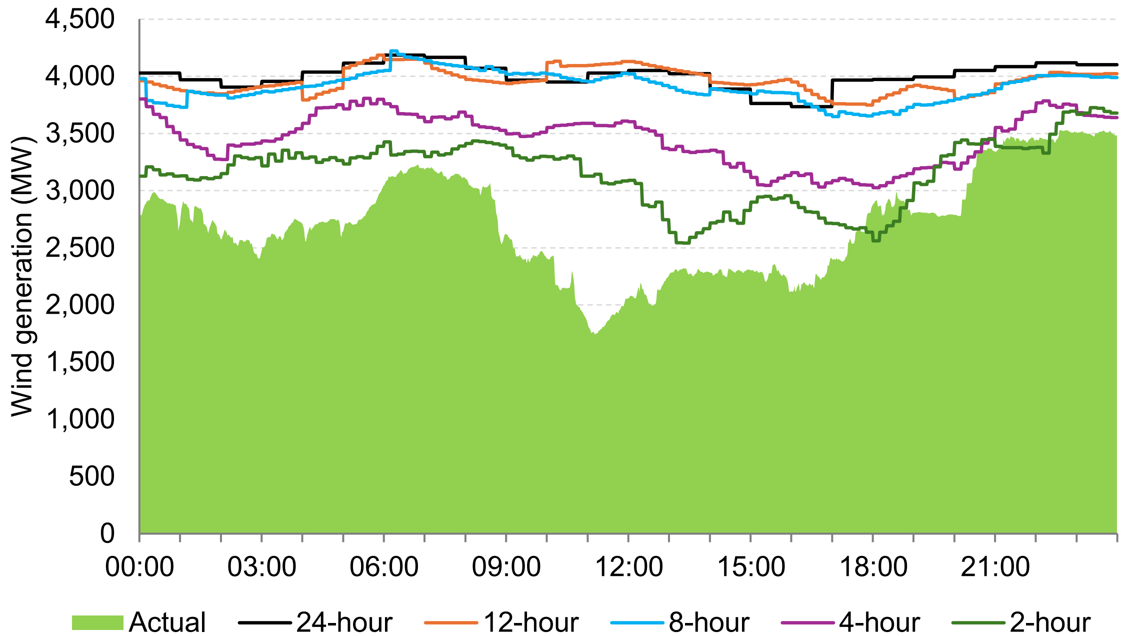
Figure 19: Daily average differential between the constrained and unconstrained SMP (Q4 2025)



The large price differential on October 29 was caused by a significant amount of wind generation being constrained in addition to some large gas generators being on outage. Potential wind generation over the course of October 29 was exceptionally high, averaging 4,470 MW. However, due to constraints on the transmission system, actual wind generation was lower averaging 2,710 MW.

The large amounts of transmission congestion also impacted the accuracy of the AESO's wind forecast. The forecasts that were 24 hours, 12 hours, and 8 hours ahead all forecast average wind generation of around 4,000 MW for the day based on an uncongested transmission system (Figure 20). The forecast only started to account for transmission congestion closer to real-time because it began to incorporate current wind generation levels.

Figure 20: Actual wind generation and wind generation forecasts (October 29, 2025)

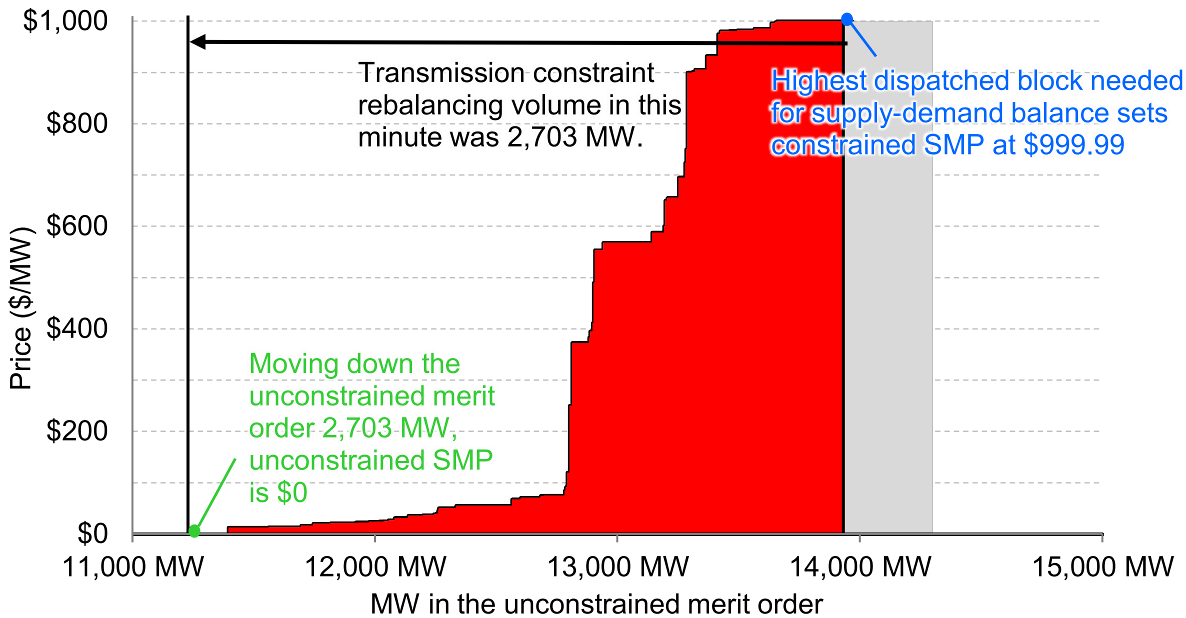


Because there was a large volume of wind generation that was constrained, there was a large shift down the merit order from the constrained SMP to the unconstrained SMP (Figure 21). In addition, the amount of capacity in the merit order was lowered by some major generator outages. As shown in Table 16, there was more than 3,100 MW of generation capacity on outage in HE 12. This made the merit order thinner and meant that the shift down by the constrained volume had a larger impact on price.

Due to the combination of generation outages and the high volume of constrained down generation, between 11:10 and 11:17 the constrained SMP cleared at the cap of $999.99/MWh while the unconstrained SMP cleared at the floor of $0/MWh. Because of the low unconstrained prices, Alberta was exporting 515 MW at the time.

In response to the anticipated supply cushion being below 932 MW, the AESO issued unit commitment directives to Sheerness 2 to run from 06:00 to 23:00, and Battle River 5 to run from 08:00 to 22:00. The AESO did not commit Sheerness 1, which remained commercially offline on long lead time all day.

Figure 21: The unconstrained energy market supply curve (October 29 11:15)



The commitments of Sheerness 2 and Battle River 5 added 690 MW of capacity to the merit order in HE 12 when the supply cushion fell to 330 MW, the lowest of the day. Without the capacity provided by these assets subject to unit commitments, the AESO would have been directing contingency reserves to provide energy to meet demand, and the AESO may have had to shed load.

Table 16: Major generation outages (October 29 HE 12)

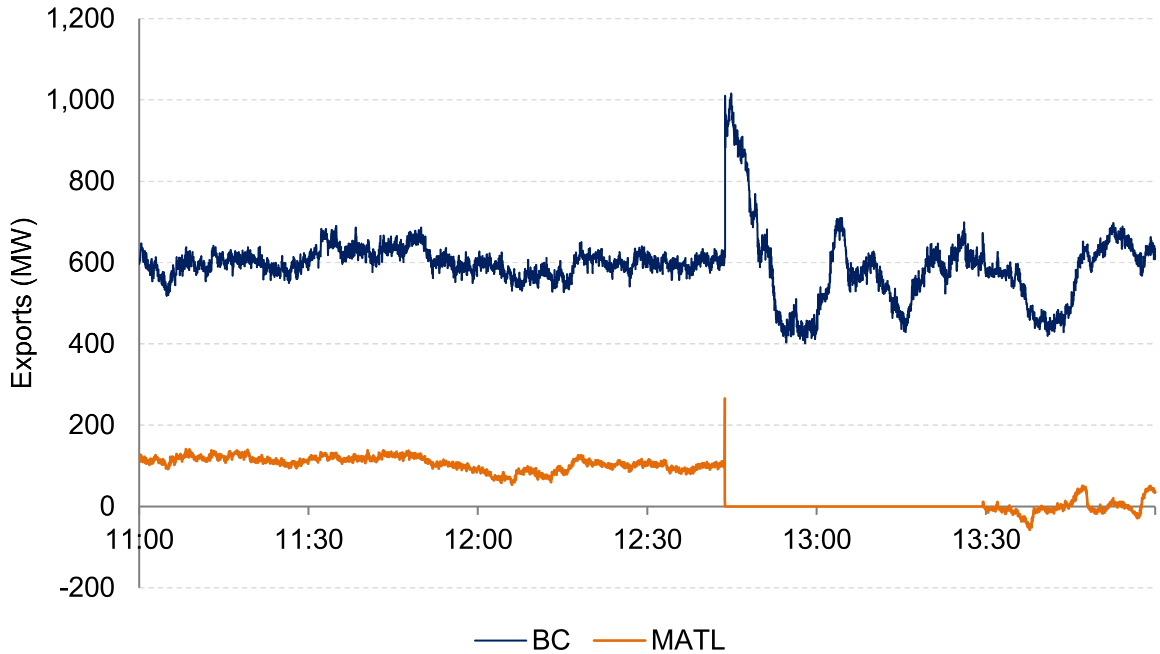
Asset name	Fuel type	Capacity on outage
Genesee 3	Gas-fired steam	466
Keephills 3	Gas-fired steam	466
Cascade 2	Combined cycle	450
Base plant	Cogeneration	436
HR Milner	Combined cycle	300
Genesee Repower 2	Combined cycle	266
Brazeau	Hydro	190
Nabiye	Cogeneration	185
Scotford	Cogeneration	160
Firebag	Cogeneration	149
Battle River 5	Gas-fired steam	105
TOTAL		**3,173**

1.3.2 November 13: system frequency event

On November 13 at 12:43, there was a major disturbance on the electricity grid in Wyoming. Specifically, two 500 kV transmission lines tripped offline causing voltage issues and the loss of around 4,000 MW of generation. The power outages impacted nearly 93,000 customers in Wyoming.[8]

In response to the event, exports on the BC and Montana interties increased sharply. On the BC intertie, exports increased from 630 MW to 1,010 MW. These flows exceeded the export available transmission capacity of the BC intertie, which was 950 MW. However, following the spike, exports on the BC line gradually declined (Figure 22).

Figure 22: Exports on the BC and Montana interties (November 13, 2025)

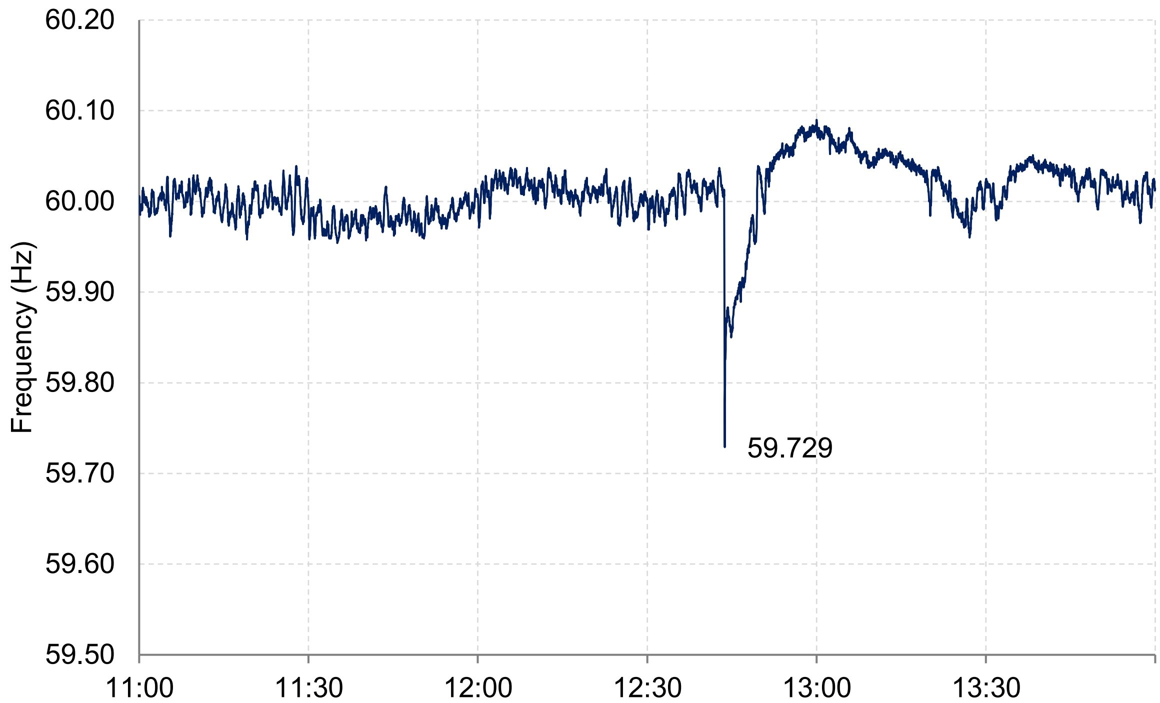


On the Montana intertie, exports increased from 100 MW to 265 MW before the line tripped offline (Figure 22).

The sudden increase in exports led to a material drop in Alberta's system frequency. At 12:43:42 frequency fell to 59.729 Hz (Figure 23). Wind generation at the time of this event was high at 3,600 MW and solar generation was 500 MW. This high level of intermittent generation lowered Alberta's inertia and primary frequency response. In addition, no Fast Frequency Response (FFR) was armed by the AESO because Alberta was exporting.

[8] Cowboy State Daily (November 13, 2025)

Figure 23: System frequency (November 13, 2025)



Subsequently, between 13:01 and 13:10, the AESO provided 170 MW of reserve-sharing energy as requested by the Western Power Pool.

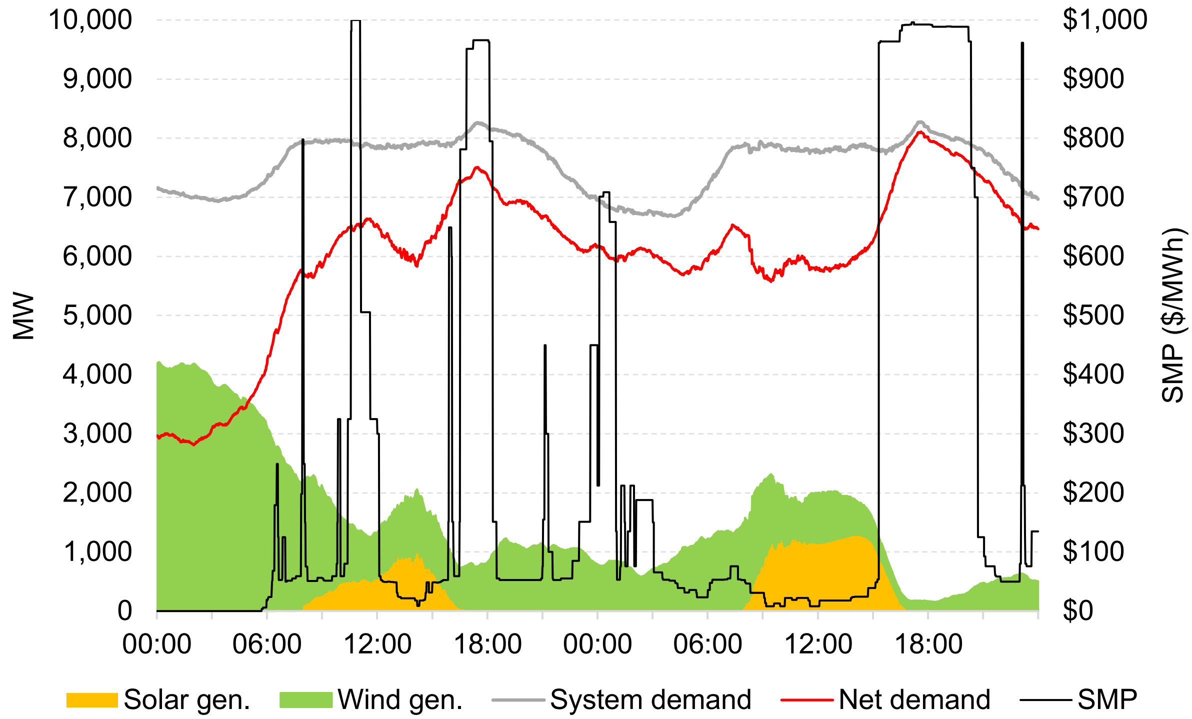
Despite being notable, the low frequency value of this event was not reported to the AESO's AIES Event Log.

1.3.3 November 3: prices at $999.96/MWh

Pool prices on November 3 and 4 were elevated; the daily averages were $165/MWh and $289/MWh, respectively, the highest two days in the quarter. The high prices were driven by gas generator outages and low intermittent generation. Between 10:36 and 10:43 on November 3, the SMP peaked at $999.96/MWh, indicating very tight market conditions. Only five hours earlier, the SMP had been at the price floor of $0/MWh.

The drastic change in market conditions on the morning of November 3 was caused by changes in wind generation and demand. As demand ramped up wind generation declined, resulting in a large change in net demand. As shown by Figure 24, net demand increased from 3,000 MW in the early morning hours to around 6,500 MW when the SMP peaked.

Figure 24: Net demand and SMP (November 3 and 4, 2025)



While wind generation had declined, it still contributed 930 MW to supply when the SMP cleared at $999.96/MWh, and solar generation supplied 530 MW. In total, intermittent generation was 1,460 MW relative to a supply cushion of 380 MW.

There were several major outages at gas generation assets on the morning of November 3. Cascade 2, Genesee 3, Keephills 3, and HR Milner were all on scheduled outages and Battle River 5 and Cascade 1 were both derated (Table 17). Genesee Repower 2 (466 MW) had just returned from a forced outage and was generating 465 MW when the SMP peaked.

Table 17: Major generation outages (November 3 HE 11)

Asset name	Fuel type	Capacity on outage
Cascade 2	Combined cycle	466
Genesee 3	Gas-fired steam	466
Keephills 3	Gas-fired steam	466
Base Plant	Cogeneration	461
HR Milner	Combined cycle	300
Bow River	Hydro	137
Cascade 1	Combined cycle	126
Nexen Inc. 1	Combined cycle	120
Battle River 5	Gas-fired steam	105
TOTAL		**2,647**

Demand levels on November 3 and 4 were not particularly high. AIL peaked at 10,968 MW on November 3 and at 10,983 MW on November 4, compared with an average daily peak of 11,380 MW in November. The modest demand levels were the result of moderate temperatures across Alberta (Table 18).

Table 18: Hourly temperatures at peak demand (November 3 and 4)

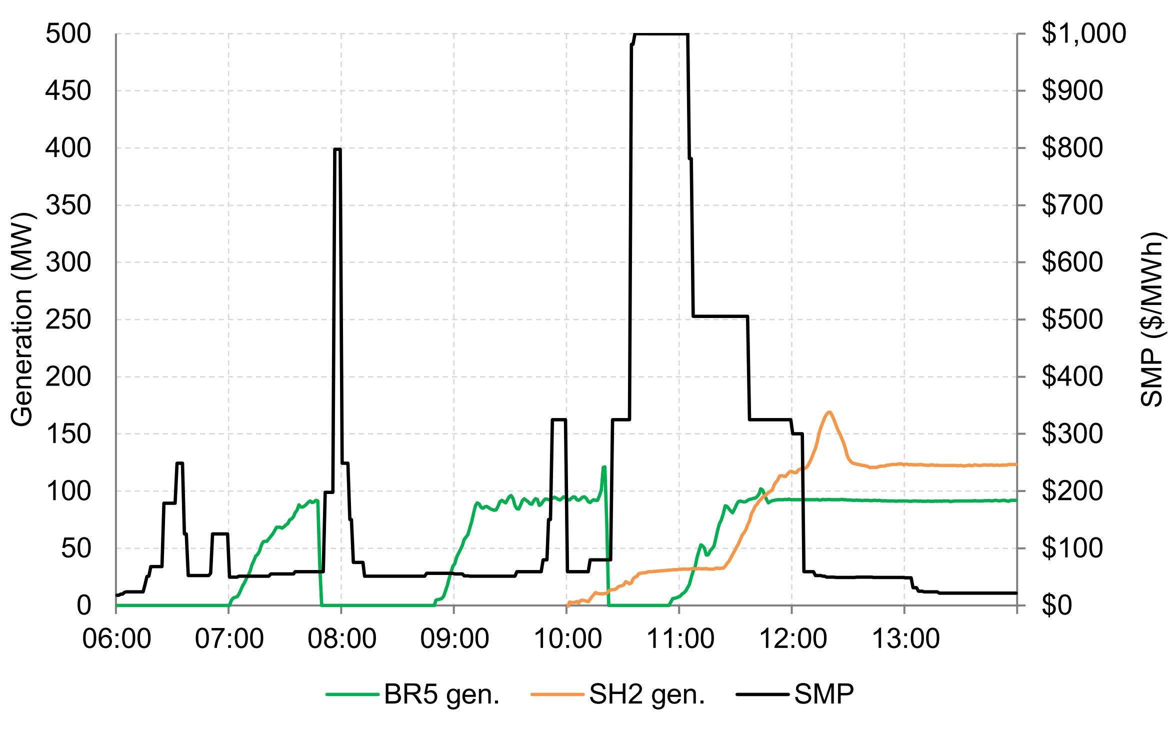
	Calgary	Edmonton	Fort McMurray
Nov 3 17:00	5.1	2.9	3.8
Nov 4 17:00	3.7	3.8	-0.9

As a result of the generator outages and the forecasted decline in wind generation, the AESO's anticipated supply cushion fell below the 932 MW threshold for multiple hours on November 3. Therefore, the AESO initially committed Battle River 5 (available capacity of 290 MW) to be online from 07:00 to 11:00 and Sheerness 2 (400 MW) to be online from 10:00 to midnight. The AESO did not commit Sheerness 1 (400 MW), which remained commercially offline on long lead time.

However, Battler River 5 tripped offline twice on start-up and was unavailable when the SMP peaked to $999.96/MWh. Sheerness 2 started on time at 10:00 but was generating under 30 MW when the SMP peaked (Figure 25).

Subsequently, at around 11:00, Battle River 5 came online and ramped up to 90 MW. In addition, the generation from Sheerness 2 increased beginning at around 11:30 (Figure 25). These supply increases combined with a rise in intermittent generation to put downward pressure on the SMP.

Figure 25: SMP and the generation of BR5 and SH2 (November 3, 2025)



Imports did not fully use the available transmission capacity for this event because the operational issues at Battle River 5 were unexpected and the AESO's wind forecast two hours ahead overestimated wind generation by 190 MW.

On the BC/MATL intertie, imports were 271 MW while the available import capacity was 453 MW. On the Saskatchewan intertie, imports were 75 MW while the available import capacity was 153 MW. Overall, there was 260 MW of available import capacity that was unused when the SMP cleared at $999.96/MWh.

1.3.4 December 17: system frequency event

On the afternoon of December 17, system frequency in Alberta declined to 59.80 Hz due to a sudden fall in wind generation. The event started at 16:39 when the 500 kV transmission line between Alberta and BC (1201L) was inadvertently opened by a contractor performing planned work on the substation 520s Benett. The loss of 1201L also caused the Montana intertie to trip offline on Remedial Action Scheme (RAS) operations (Figure 26).

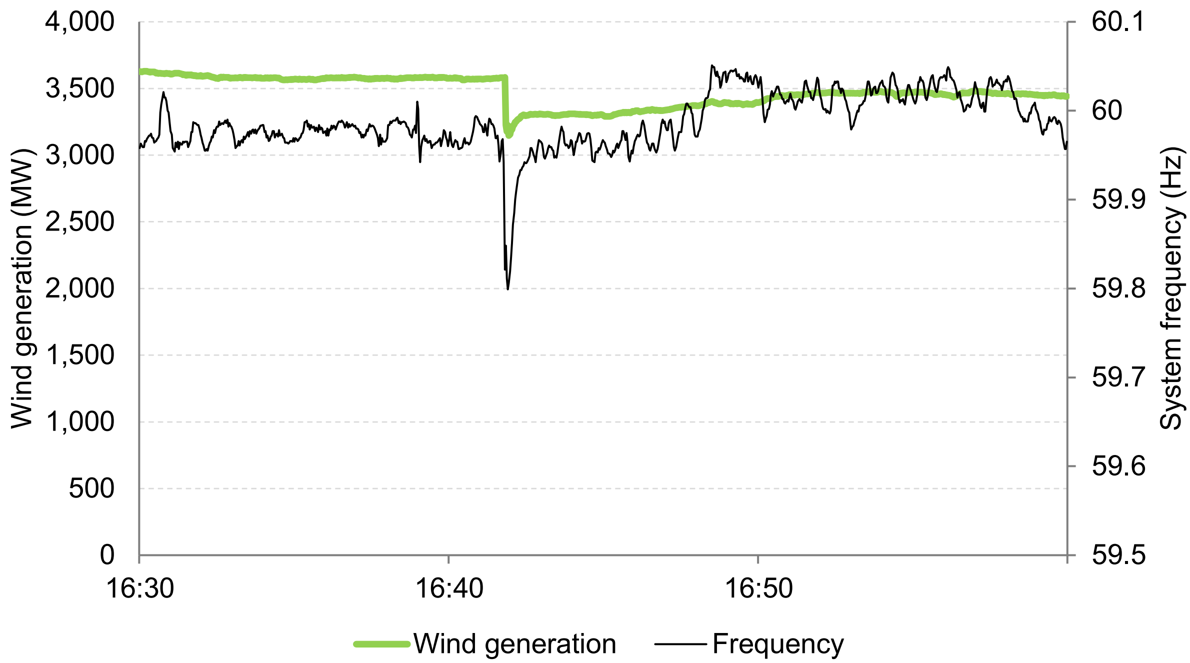
Figure 26: Exports on BC and MATL interties (December 17, 2025)

A few minutes later at 16:42, there was a sudden decline in wind generation as some wind assets around the City of Medicine Hat tripped offline due to a fault at the Elkwater substation, which subsequently triggered RAS 164. Total wind generation fell by 405 MW in four seconds. This decline occurred as the Forty Mile Bow Island asset tripped offline from 115 MW, the Wild Rose asset tripped offline from 96 MW, the Whitla 2 asset tripped offline from 73 MW, and generation at the Cypress 1 asset fell from 160 MW to 70 MW. This decline in wind generation combined with the outages on 1201L and MATL and caused frequency to fall to 59.80 Hz (Figure 27).

Subsequently, the remaining two 138 kV lines of the BC intertie also tripped offline, and the cause of these trips is still under investigation. At the time of the trips, Alberta was exporting 150 MW to BC (Figure 26).

The AESO did not have any FFR armed for this event because Alberta was exporting to BC prior to the trip. The AESO did have 575 MW of contingency reserves available, however they were not directed to provide energy.

Figure 27: System frequency and wind generation (December 17, 2025)



The islanding condition ended at 18:01 when the BC intertie returned to service, followed by MATL at 19:23. In total, Alberta was islanded for one hour and 20 minutes. This event underscores the importance of interconnections for maintaining frequency in Alberta and highlights the increased exposure to disturbances in their absence.

1.3.5 Price forecast methodology

The AESO provide a pool price forecast beginning two hours ahead of the start of an hour. For example, beginning at around 08:00 the AESO provide the market with their price forecast for HE 11.[9] The price forecast is subsequently updated every five minutes.

The price forecast is relatively simple as it takes the current dispatch level and uses the merit order for the relevant hour to estimate where the dispatch will be in the future based on forecast changes to AIL, scheduled changes to intertie flows, and adjustments for the regulating reserve

[9] The forecast is publicly available on the AESO's ETS page under Current, Actual Forecast

range.[10] No adjustments are made for expected wind and solar generation changes; the price forecast assumes they will remain at current levels.

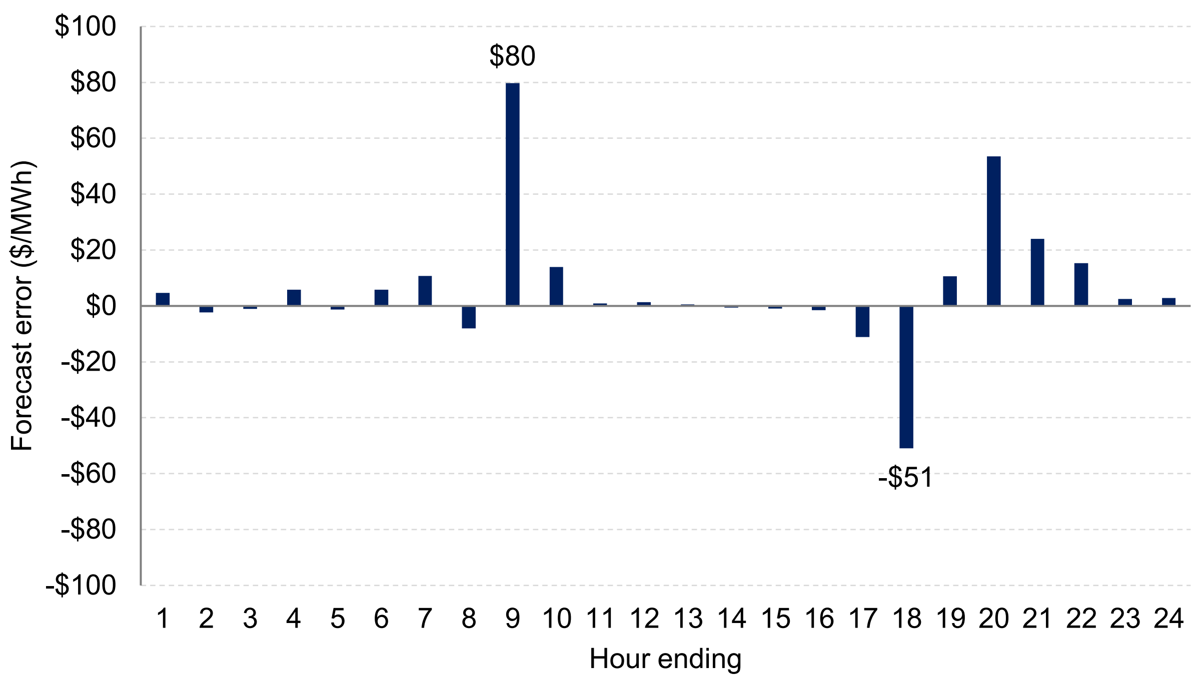
In recent years there has been a large amount of solar capacity developed in Alberta. At the beginning of Q4 there was 1,850 MW of solar capacity. As a result, the increase in supply from solar generation can have a meaningful impact on pool prices. Given the AESO's price forecast methodology, solar generation can lead to systematic errors in the price forecast.

For example, Figure 28 provides the average price forecast error by hour ending in October 2025. The price forecast error is the difference between the AESO's forecast an hour ahead and the realized pool price. In HE 09, the average price forecast error was $80/MWh in part because the price forecast assumed solar generation would remain low, so it overestimated the pool price.

In the evening, the opposite occurred; the AESO's price forecast assumed solar generation would remain high so the price forecast underestimated the pool price. For HE 18, the average price forecast error was negative $51/MWh.

The MSA believes that the AESO's price forecast should be, to the extent possible, an unbiased estimate of future pool prices so that market participants can make informed decisions. Therefore, the MSA encourages the AESO to adjust the methodology of its price forecast so that expected changes to wind and solar generation are incorporated.

Figure 28: Average pool price forecast error by hour ending (October 2025)



[10] AESO – Pool Price Forecast Calculation Methodology (March 8, 2011)

1.3.6 *Genesee Repower 1 and 2 testing*

The Genesee Repower 1 (GNR1) and Genesee Repower 2 (GNR2) assets have an installed capacity of around 700 MW each. However, due to their configuration of one gas turbine to one steam turbine, each asset's output is restricted to the MSSC limit of 466 MW.

In 2025, the AESO issued four market announcements related to planned generator testing at GNR1 and GNR2 (Table 19).[11] In its investor reporting, Capital Power stated that some of these tests were undertaken to unlock the additional capacity at the Genesee assets.[12] Specifically, some of the testing was intended to support the development of a technical solution, in coordination with the AESO, to allow an increase in generation up to 566 MW while maintaining the potential sudden loss of generation at the MSSC limit of 466 MW.

Table 19: AESO announcements related to GNR1 and GNR2 testing (2025)

Announcement date	Announced test period	Assets	Type of testing
March 31	April 11 to 13	GNR1 & GNR2	Duct firing
June 2	June 20 to July 1	GNR1 & GNR2	Duct firing and tuning
October 15	October 16 to 26	GNR1	Performance tuning
	October 27 to November 5	GNR2	
November 24	December 1 to 15	GNR1 & GNR2	Testing MSSC

As part of the tests, the AESO permitted the Genesee units to generate above the MSSC limit during certain defined periods. During these testing periods, the AESO did not buy additional contingency reserves to cover the risks of a larger trip, but instead relied on the frequency response of the BC and Montana interties.

Unlike the other tests conducted during the year, the testing announced on October 15 featured separate schedules for GNR1 and GNR2. GNR1 testing occurred from October 16 to 26, followed by GNR2 testing from October 27 to November 5 (Table 19).

During the GNR1 testing window, the asset tripped offline from 558 MW at 12:56 on October 18 due to the loss of duct burners during a ramp, which caused an intermediate pressure drum level trip on the heat recovery steam generator. Following the trip, ACE declined to negative 687 MW.

At the time of the trip, exports on the BC and Montana interties were relatively high as demand was low and intermittent generation was elevated. Consequently, the impact of the GNR1 trip was absorbed through a reduction in exports on the BC and Montana interties (Table 20). Therefore,

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[11] AESO - market updates

[12] Capital Power - reporting, Q3 2025 webcast – October 29, 2025

there was no impact on system frequency. In response to the event, the AESO directed 485 MW of contingency reserves and requested up to 200 MW of reserves from the Western Power Pool.

During this testing period, GNR1 reached a maximum output of 621 MW at 10:29 on October 19.

Table 20: Net exports on the BC and Montana interties (12:56 on October 18, 2025)

Intertie	Scheduled net exports (MW)	Actual net exports at trip (MW)
BC	873	467
MATL	62	-98

During the GNR2 testing period, the asset tripped once on November 1. Leading up to the event, the output of GNR2 fluctuated around the 466 MW threshold before tripping at 18:38 from 158 MW due to turbine smoke. Given the relatively low level of generation prior to the trip, ACE declined modestly to negative 256 MW. In response, the AESO directed 200 MW of contingency reserves.

During the testing, GNR2 reached a peak output of 627 MW at 12:10 on October 31. Although only GNR2 was scheduled for testing during this period, GNR1 also exceeded the MSSC limit on November 5, reaching a maximum output of 557 MW at 16:13.

While the earlier tests were focused on operational refinement and performance tuning, the testing announced on November 24 was to evaluate whether the GNR1 and GNR2 assets can supply more than the MSSC limit. The testing was scheduled for GNR1 and GNR2 to operate above 466 MW at times between December 1 and December 15. However, this testing was paused on December 9 due to unplanned trips at the Genesee assets.

During this shortened testing window, GNR1 reached a peak output of 617 MW at 22:12 on December 4, and GNR2 reached a peak output of 628 MW at 20:27 on December 5. The GNR2 asset tripped multiple times during the testing period (Table 21).

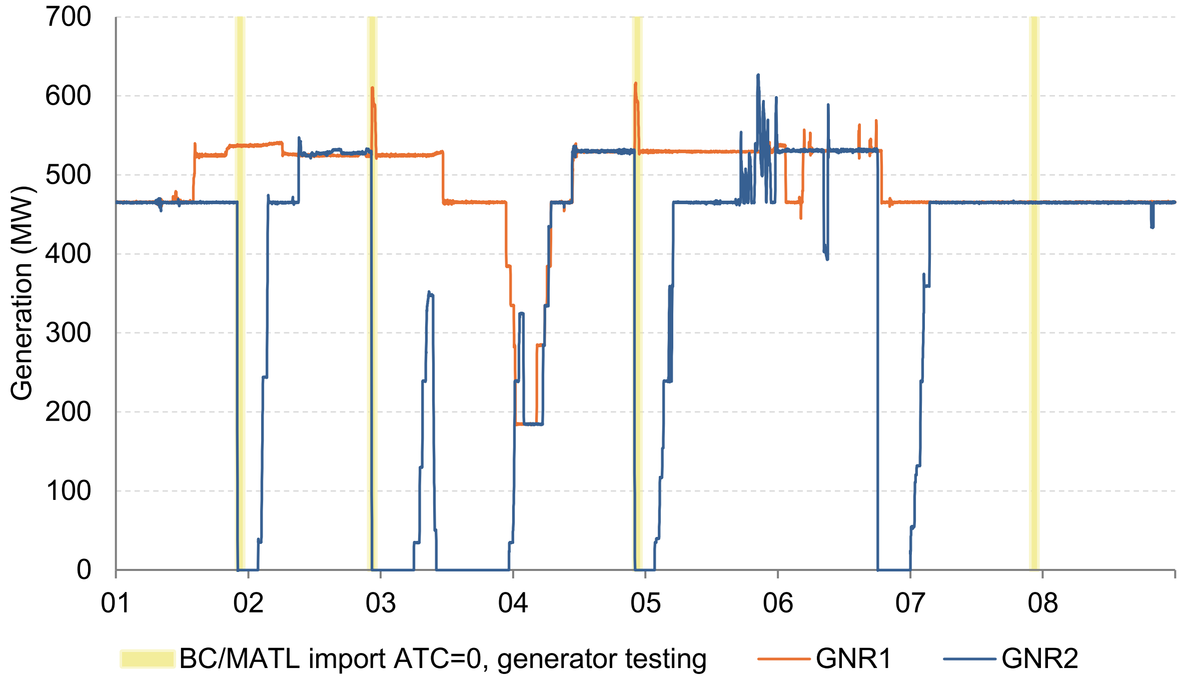
Table 21: GNR2 trips during testing (December 1 to December 15, 2025)

Trip datetime	Generation loss (MW)	Min. ACE (MW)
December 1 22:00	465	-299
December 2 22:20	528	-239
December 4 22:00	531	-299
December 6 18:04	532	-597

The GNR2 trips on December 1, 2, and 4 were planned and conducted around HE 23 to assess the response of GNR1. During these hours, the import capability on the BC and Montana interties was reduced to 0 MW to allow for a large frequency response from the interties (Figure 29).

In contrast, the trip on December 6 was unplanned. Despite ACE declining to negative 597 MW following this event, system frequency was not affected as the impact was absorbed through the Western Interconnection via the BC and Montana interties.

Figure 29: GNR1 and GNR2 generation (December 1 to 8, 2025)



1.3.7 Data issues on November 4

On the morning of November 4, there were issues with some of the PI data being displayed on the AESO's *Current Supply and Demand* page. Specifically, the total net generation and/or the dispatched contingency reserve figures for some generation assets were incorrectly showing as 240 MW. These data errors also led to issues with aggregated figures. For example, AIL was erroneously showing as more than 20,000 MW.

These data issues lasted for around an hour; from approximately 10:32 to 11:23. The issues were caused by two activities occurring simultaneously: PI patching and PI production tag deployment. These concurrent changes led to connectivity issues, resulting in invalid tag data being sent to applications. The issue was addressed relatively quickly and the data available to the AESO System Controllers was not affected.

1.4 Market power mitigation measures

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 under some circumstances. The MPMR and SCR are implemented through ISO rules 206.1 and 206.2, respectively.

This section provides updates to the metrics shown in previous MSA quarterly reports since the introduction of the interim measures. Following the end of 2025, the MSA completed a comprehensive review of the interim measures, which will be published separately in a forthcoming standalone report.

1.4.1 Market Power Mitigation Regulation and ISO rule 206.1

Under ISO rule 206.1, a secondary offer price limit equal to the greater of either $125/MWh or 25 times the day-ahead natural gas price is triggered when the Monthly Cumulative Settlement Interval Net Revenue (MCSINR) exceeds 1/6 of the annualized avoidable costs of a reference combined cycle generating unit.

The secondary offer price limit was not triggered in Q4, as the MCSINR reached only 24%, 47%, and 15% of the threshold in October, November, and December, respectively.

1.4.2 Supply Cushion Regulation and ISO rule 206.2

Under ISO rule 206.2, the AESO must perform a forecast of supply cushion, called anticipated supply cushion (ASC), and issue unit commitment directives (UCD) to eligible long lead time (LLT) assets when the ASC falls below 932 MW. The AESO must choose which eligible LLT assets to direct based on economic merit and physical constraints.

In Q4, 61 UCDs were issued by the AESO, continuing the trend of increasing UCDs quarter-over-quarter. This was especially the case in October, when the AESO issued 41 UCDs – the same number as in all of Q3.

Table 22 shows the estimated price effect of the 61 UCDs in Q4.[13] Over the quarter, the MSA estimates that the average pool price was lowered by $19.18/MWh or 31% because of the UCDs. This estimate assumes that the LLT assets under UCD would have remained commercially offline absent the UCD.

[13] The methodology for measuring the price impact of UCDs was described in section 1.3.2.2 of the MSA Quarterly Report for Q3 2024.

Table 22: Estimated price impact of unit commitment directives in Q4

Time period	Actual average pool price ($/MWh)	Estimated average pool price without unit commitment directives ($/MWh)	Percentage change (%)
October	$32.88	$61.84	-47%
November	$57.64	$84.78	-32%
December	$39.00	$40.73	-4%
Q4	**$43.03**	**$62.21**	**-31%**

As discussed in section 2.1, Q4 saw unprecedented levels of constrained down generation, especially in October and November. Constrained generation reduces pool price due to the effect of reconstitution, but higher priced generation must still be dispatched to meet demand. This allowed the supply cushion to frequently drop below the threshold of 932 MW while unconstrained pool prices were still low, reducing the incentives for self-commitment, and requiring the AESO to issue UCDs.

Of the 41 UCDs issued in October, 22 had received prices of under $30/MWh, and the lowest received price was only $0.31/MWh. These market conditions created a greater reliance on UCDs compared to self-commitment, which also led to the greater estimated price impact when these UCDs were removed in the MSA's analysis.

1.5 Market power, offer behaviour, and net revenues

1.5.1 Market power

As part of our market monitoring, the MSA calculates counterfactual prices based on short-run marginal costs (SRMC). These counterfactual prices can then be compared against actual prices to calculate mark-ups. The mark-up between actual and counterfactual prices is indicative of market power, with a higher mark-up indicating more market power.

The MSA now publishes its counterfactual price estimates and other market power metrics on its data portal.

Table 23 provides monthly average actual and counterfactual prices year-over-year. The average counterfactual prices in Q4 and Q4 2024 were comparable at $31.15/MWh and $33.36/MWh, respectively. However, actual pool prices were 16% lower year-over-year resulting in a lower average mark-up in Q4.

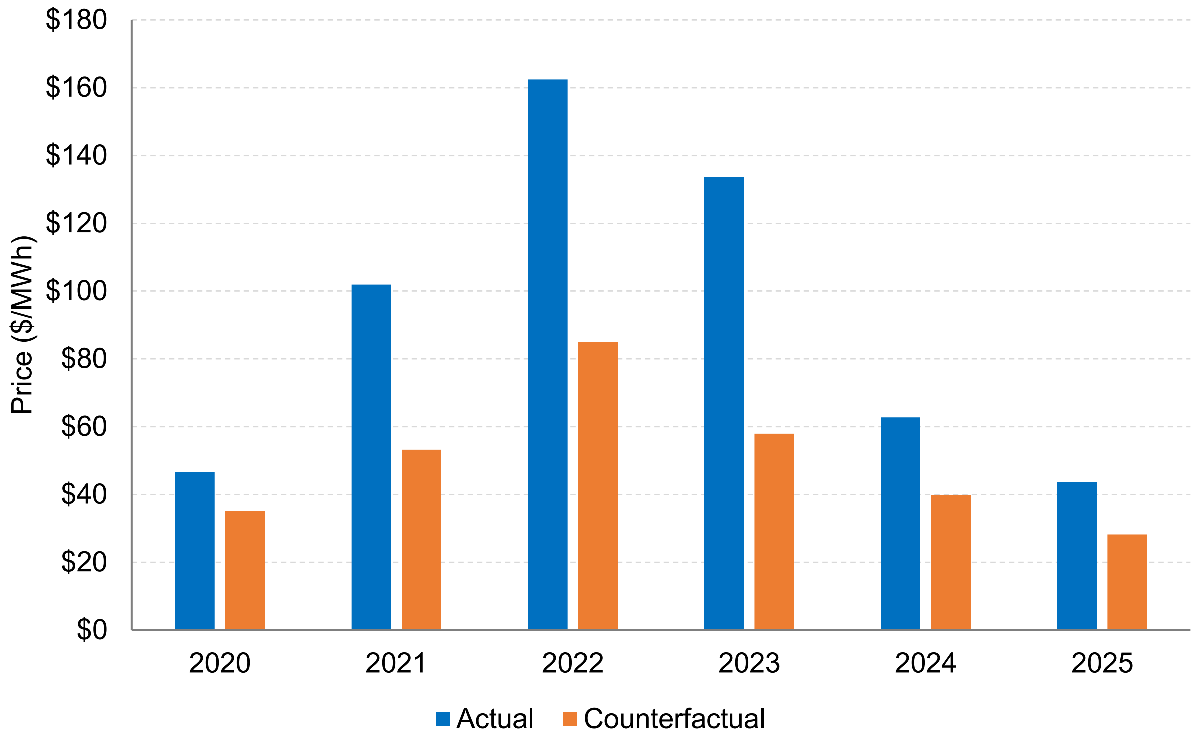
Markups in Q4 were highest in November; the average pool price was $20.77/MWh above the average counterfactual price. The higher mark-up in November was driven by high pool prices on November 3 and 4 when low wind generation combined with gas generator outages to reduce supply (as discussed in section 1.3.3).

Table 23: Actual and counterfactual monthly average prices (Q4 and Q4 2024)

	2024			2025		
	Actual	**Counterfactual**	**Difference**	**Actual**	**Counterfactual**	**Difference**
Oct	$57.62	$39.23	$18.40	$32.88	$22.17	$10.71
Nov	$71.20	$35.71	$35.49	$57.64	$36.88	$20.77
Dec	$26.35	$25.22	$1.13	$39.00	$34.57	$4.43
Q4	**$51.52**	**$33.36**	**$18.16**	**$43.03**	**$31.15**	**$11.88**

The average pool price in 2025 was $43.68/MWh which is a mark up of $15.46/MWh above counterfactual prices based on SRMC (Figure 30). This is the lowest annual mark-up since 2020 and compares to a mark-up of $22.99/MWh in 2024. The lower mark-up in 2025 was driven by more competition from Cascade 1 and 2, Baseplant, and additional intermittent generation.

Figure 30: Annual average pool prices and counterfactual prices (2020 to 2025)



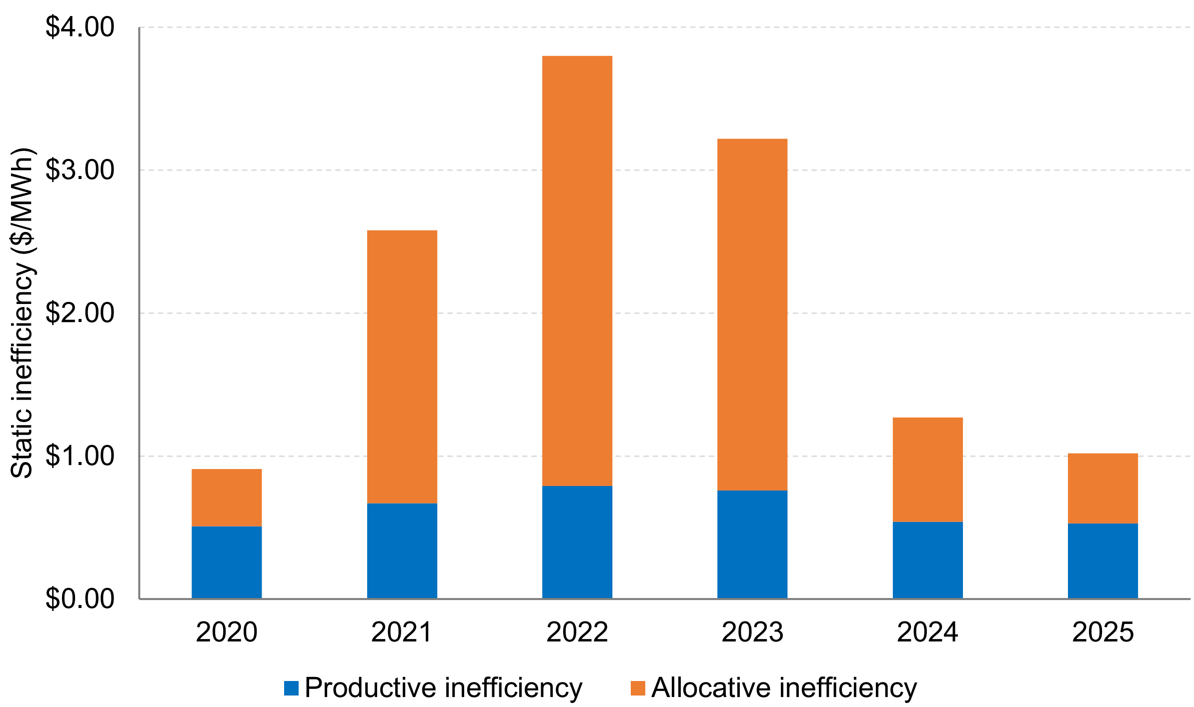
The exercise of market power can lead to static inefficiencies in the short-run, specifically productive and allocative inefficiencies. Productive inefficiencies occur when lower cost generating assets are priced out of the market and higher cost assets supply power instead. Allocative inefficiencies occur when the exercise of market power leads to prices above SRMC and demand is lowered as a result.

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. Short-run inefficiencies are tolerable to the extent that long-run efficiencies are contingent on them.

In 2025, productive inefficiencies averaged $0.53/MWh and allocative inefficiencies averaged $0.49/MWh, resulting in total static inefficiencies of $1.02/MWh (or 2.3% of the average pool price). Static inefficiencies in 2025 were 20% lower than in 2024 and were the lowest since 2020 when they averaged $0.91/MWh (Figure 31).

The lower static inefficiencies in recent years have been driven by less market power being exercised, which has resulted in lower allocative inefficiencies. Increased competition from additional gas and intermittent supply has reduced the ability of larger firms to exercise market power.

Figure 31: Average static inefficiencies by year (2020 to 2025)



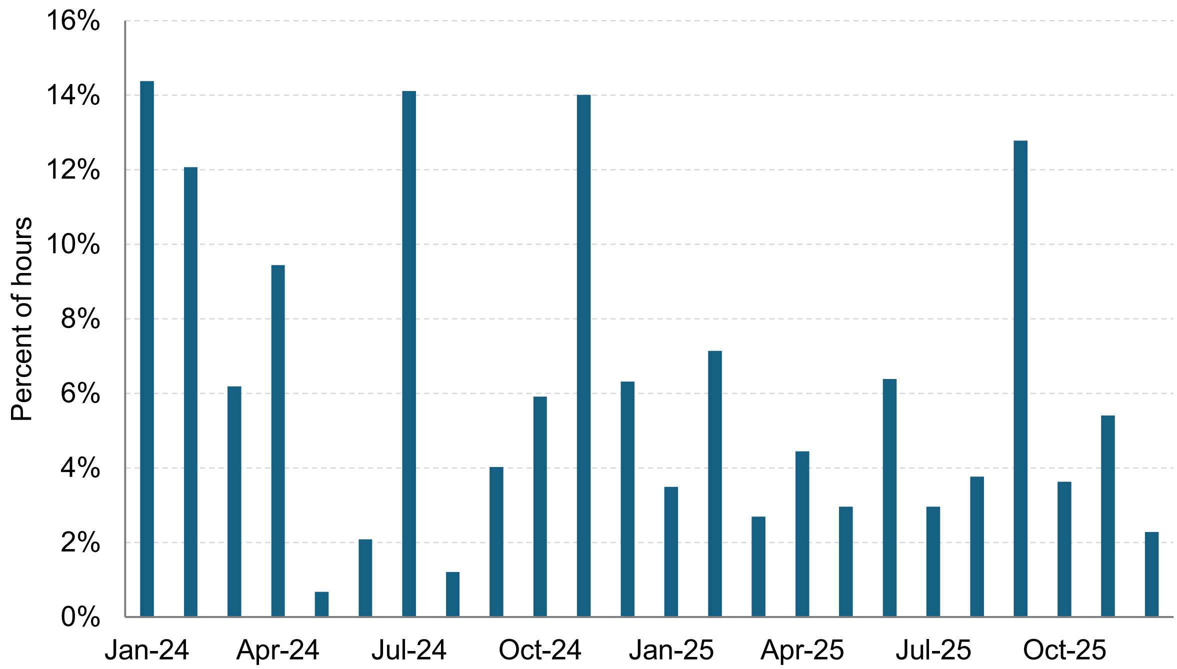
One way to measure the ability of firms to exercise market power is to calculate how often they are pivotal. A firm is pivotal to the market when its withholdable capacity[14] is needed for the market to clear. In 2025, the largest firm was pivotal in 5% of hours compared to 8% in 2024 and 13% in 2023.

Figure 32 shows the percent of hours in which the largest firm was pivotal by month since January 2024. In Q4, the ability of firms to exercise market power was relatively low with the largest supplier being pivotal 4% of the time in October, 5% of the time in November, and 2% of the time

[14] A firm's withholdable capacity includes all capacity except for intermittent capacity and minimum stable generation.

in December. Despite cold weather and record demand in December, the ability of firms to exercise market power was reduced by additional supply from Base Plant and high wind generation.

Figure 32: The percent of hours in which the largest firm was pivotal (January 2024 to December 2025)



1.5.2 Offer behaviour

Larger firms exercised less market power in 2024 and 2025 relative to 2023. Figure 33 illustrates the average amount of thermal capacity offered above $250/MWh by month in 2023, 2024, and 2025.

In July and August of 2023, there was a large amount of thermal capacity priced high in the merit order, averaging 1,160 MW and 1,240 MW, respectively. Pool prices in these months were high; July averaged $155/MWh and August $187/MWh. This amount of economic withholding did not occur in 2024 or 2025.

Figure 34 illustrates the relationship between pool price and supply cushion for the last three years. Higher pool prices are expected at lower values of supply cushion to reflect the tighter supply-demand fundamentals.

In 2024 and 2025, the relationship between pool price and supply cushion was very comparable. However, in 2023 pool prices were higher in the 250 to 1,500 MW supply cushion range. These outcomes were largely the result of more economic withholding in 2023 but also reflect higher natural gas prices that year.

Figure 33: Average amount of thermal capacity offered above $250/MWh by month (2023, 2024, and 2025)

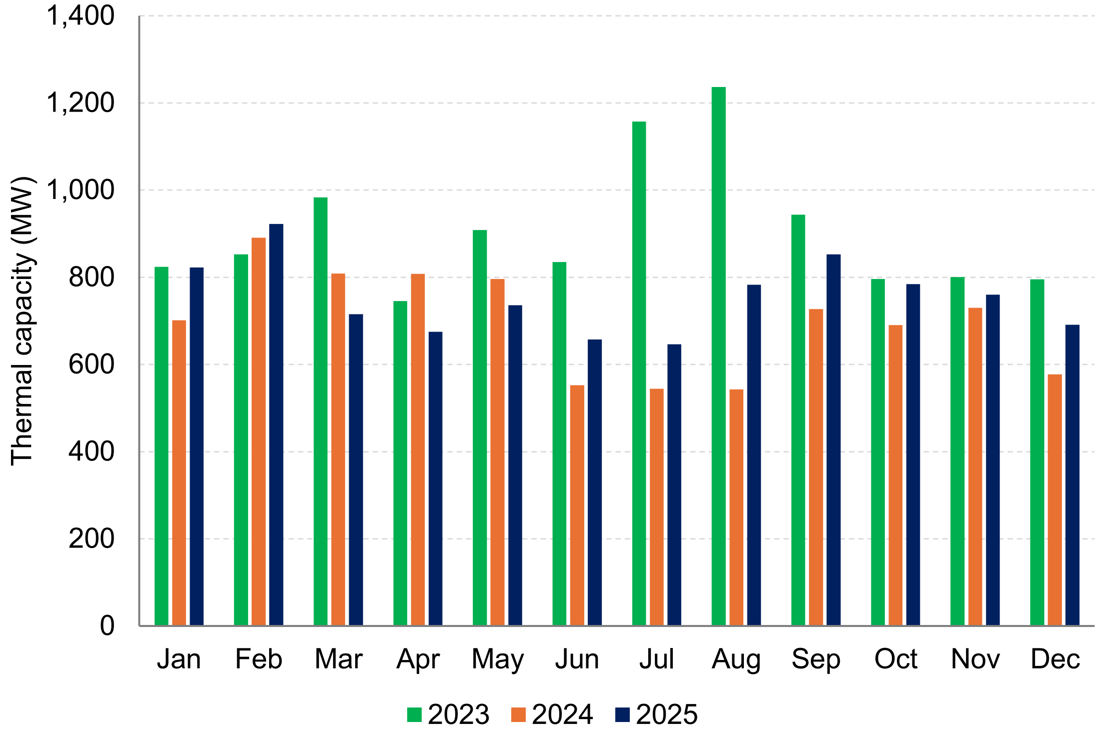
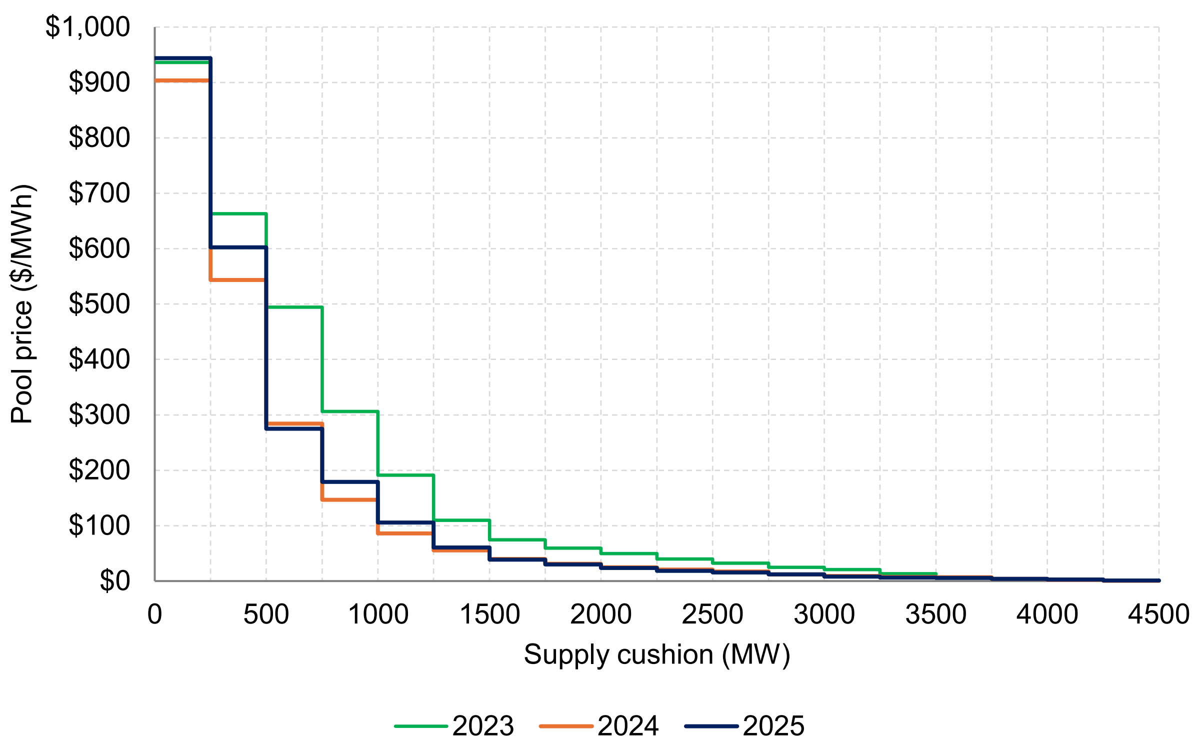


Figure 34: Average pool price by supply cushion bins (2023, 2024, and 2025)



1.5.3 Net revenues

Net revenue analysis provides insight into how observed pool prices compare against a set of assumed costs for different generation technologies. This section presents the 2025 net revenues for hypothetical combined cycle, simple cycle, wind, and solar assets. These net revenues are then compared with fixed and capital costs to assess profitability.

The net revenues for the hypothetical assets are calculated using cost estimates published in the AESO's 2024 Long Term Outlook and are adjusted for inflation using the Consumer Price Index.[15] The resulting costs are reported in Table 24.

Table 24: Cost assumptions used in the net revenue analysis (2025$)

Parameter	Combined cycle	Simple cycle	Wind	Solar
Size (MW)	418	47	100	50
Net overnight capital costs ($/kW)	$1,653	$1,791	$1,097	$1,211
Fixed O&M ($/kW-year)	$21.50	$24.85	$90.79	$27.70
Variable O&M ($/MWh)	$3.88	$7.16	$0.00	$0.00

For the hypothetical natural gas assets, the combined cycle asset is more efficient with an assumed heat rate of approximately 7 GJ/MWh, compared with a heat rate of approximately 10 GJ/MWh for the simple cycle asset. As a result of its lower heat rate, the combined cycle asset incurs lower carbon costs per MWh. The emissions intensity of natural gas is assumed to be 0.0561 tCO_2e/GJ.

For both the natural gas assets, carbon costs are calculated assuming that 80% of the emissions obligation is met through the purchase of emission performance credits (EPCs). The prevailing price of EPCs is sourced from data available on ICE NGX with an average price of $29.82/tCO2e in 2025.[16] The remaining 20% of emissions are covered through payments into the TIER Fund at the regulated carbon price of $95/tCO2e.[17]

In addition to carbon costs, the net revenue analysis incorporates several cost components for the natural gas assets. Fuel costs are calculated using the same-day AB-NIT 2A natural gas price in combination with the assumed heat rate, and the natural gas commodity fuel charge is also included. Hourly variable costs are then calculated as the sum of fuel costs, carbon costs, variable

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[15] AESO Long Term Outlook 2024 see Data file sheet New Resource Inputs

[16] ICE NGX Alberta Emission Performance Credit vintage 2025 futures (January 2026 contract)

[17] TIER – Technology Innovation and Emissions Reduction Regulation

operating and maintenance (O&M) costs, and the AESO trading charge. For transmission losses, both natural gas assets are assumed to be in Fort Saskatchewan.

With respect to dispatch assumptions, the simple cycle gas asset is assumed to offer into the energy market at its variable cost plus $10/MWh and to generate whenever the pool price, net of transmission losses, exceeds this amount. In contrast, given its higher efficiency, the combined cycle asset is assumed to generate at capacity in all hours, regardless of prevailing pool prices. In addition, both the hypothetical simple cycle and combined cycle assets are assumed to have an outage rate of 14%.

For the hypothetical wind and solar assets, revenues are derived not only from the energy market but also from the sale of carbon emission offsets. Carbon credit revenues are calculated based on the grid displacement factor and the prevailing price of offsets. The price of offsets is sourced from data available on ICE NGX with an average of $29.87/tCO2e in 2025.[18] The assets are assumed to fully utilize all carbon emission offsets generated.

Hourly capacity factors for wind and solar assets are estimated using historical generation data. For wind, all assets that historically achieved a capacity factor greater than 30% are included in the capacity factor calculation. For solar, all assets that have achieved a capacity factor greater than 90% are included in the capacity factor calculation. Transmission losses for the hypothetical wind and solar assets are calculated as the volume-weighted average losses of actual wind and solar assets.

With respect to dispatch assumptions, both the hypothetical wind and solar assets are assumed to offer into the energy market at $0/MWh and to act as price takers, such that all available generation is supplied and receives the prevailing pool price.

Finally, for all generation technologies, fixed O&M costs incurred on an annual basis are deducted from the net revenues earned by each hypothetical asset. If the net revenues are greater than the fixed O&M costs, the difference is taxed at an assumed rate of 23%.

Table 25 provides the resulting net revenues less fixed O&M for the hypothetical assets. As shown, the combined cycle, simple cycle, and solar assets all earned enough net revenues to sufficiently cover their fixed O&M costs, whereas the wind asset did not.

Table 25: Net revenues less fixed O&M per MW by technology (post tax, 2025$)

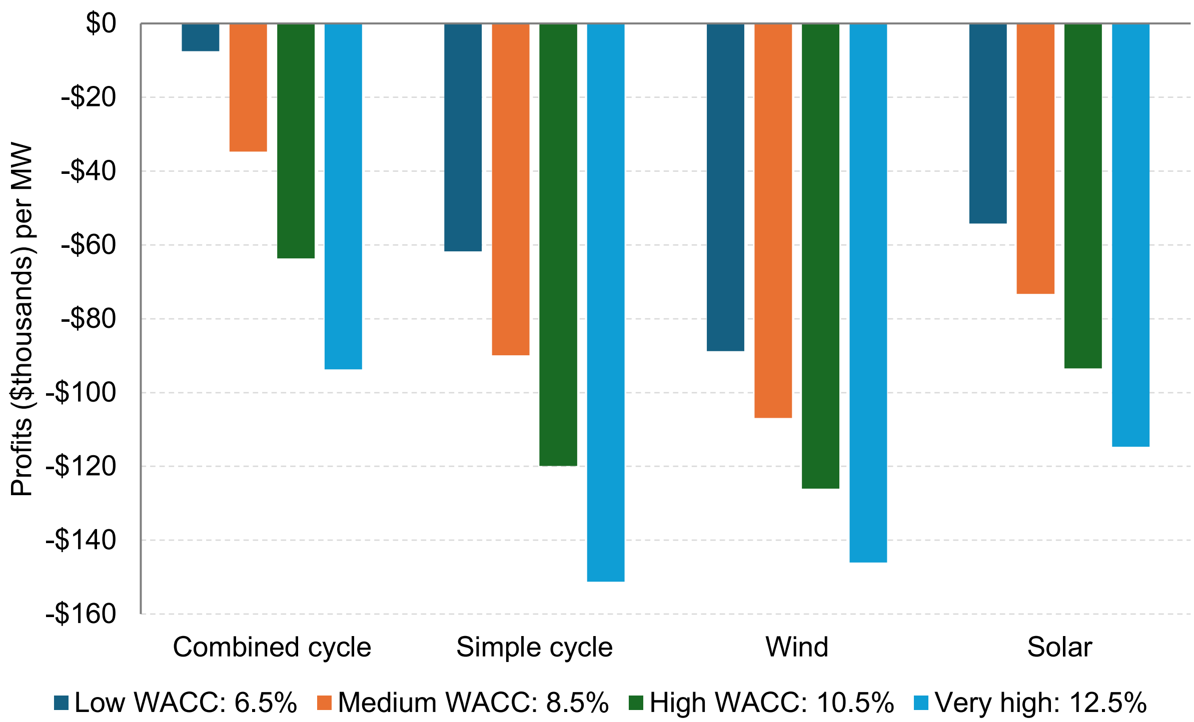
Fuel type	Net revenue less fixed O&M per MW
Combined cycle	$119,088
Simple cycle	$85,098
Wind	- $4,795
Solar	$45,045

[18] ICE NGX Alberta Emission Offset vintage 2025 futures (January 2026 contract)

Pool prices in 2025 were relatively low with an average of $43.68/MWh. These low prices meant that none of the hypothetical generation assets earned sufficient net revenues to fully recover their annual fixed and capital costs.

This net revenue analysis assumes that generators finance the overnight capital cost of assets through payments amortized over the asset's lifetime, with capital cost repayments made on an annual basis. This simplifying assumption does not address economic returns being recovered over an economic cycle and is indicative of the single year contribution to lifecycle economic returns. When the net revenues less fixed O&M figures in Table 25 are compared with annual capital costs, all assets report a loss in 2025. This outcome is true across a range of weighted average cost of capital (WACC) assumptions (Figure 35).

Figure 35: Profits per MW at different WACC levels (2025$)



1.6 Carbon emissions intensity

Carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The MSA has published analysis on the carbon emission intensity of the Alberta electricity grid in its quarterly reports since Q4 2021. The MSA's analysis is indicative only, as the MSA has not collected the precise carbon emission intensities of assets from market participants but has relied on information that is publicly available. The results reported here do not include imported generation.[19]

[19] For more details on the methodology, see the MSA's Quarterly Report for Q4 2021.

The hourly data on the MSA's carbon emission estimates are now available on our data portal.

1.6.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in each hour. Table 26 shows the minimum, mean, and maximum hourly average emission intensity for Q4 over the past seven years.

Average emission intensity has fallen significantly over recent years driven primarily by the removal of coal from the system; some coal assets have been converted to natural gas while others have been retired. In addition, there has been a material increase in the supply of intermittent generation.

Table 26: Minimum, mean, and maximum hourly average carbon emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2019 Q4	0.52	0.63	0.75
2020 Q4	0.47	0.59	0.72
2021 Q4	0.41	0.52	0.63
2022 Q4	0.37	0.48	0.57
2023 Q4	0.30	0.43	0.57
2024 Q4	0.25	0.40	0.54
2025 Q4	0.25	0.40	0.57

Figure 36 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q4 over the past seven years. The decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions.

Figure 36: The distribution of average carbon emission intensities in Q4 (2019 to 2025)

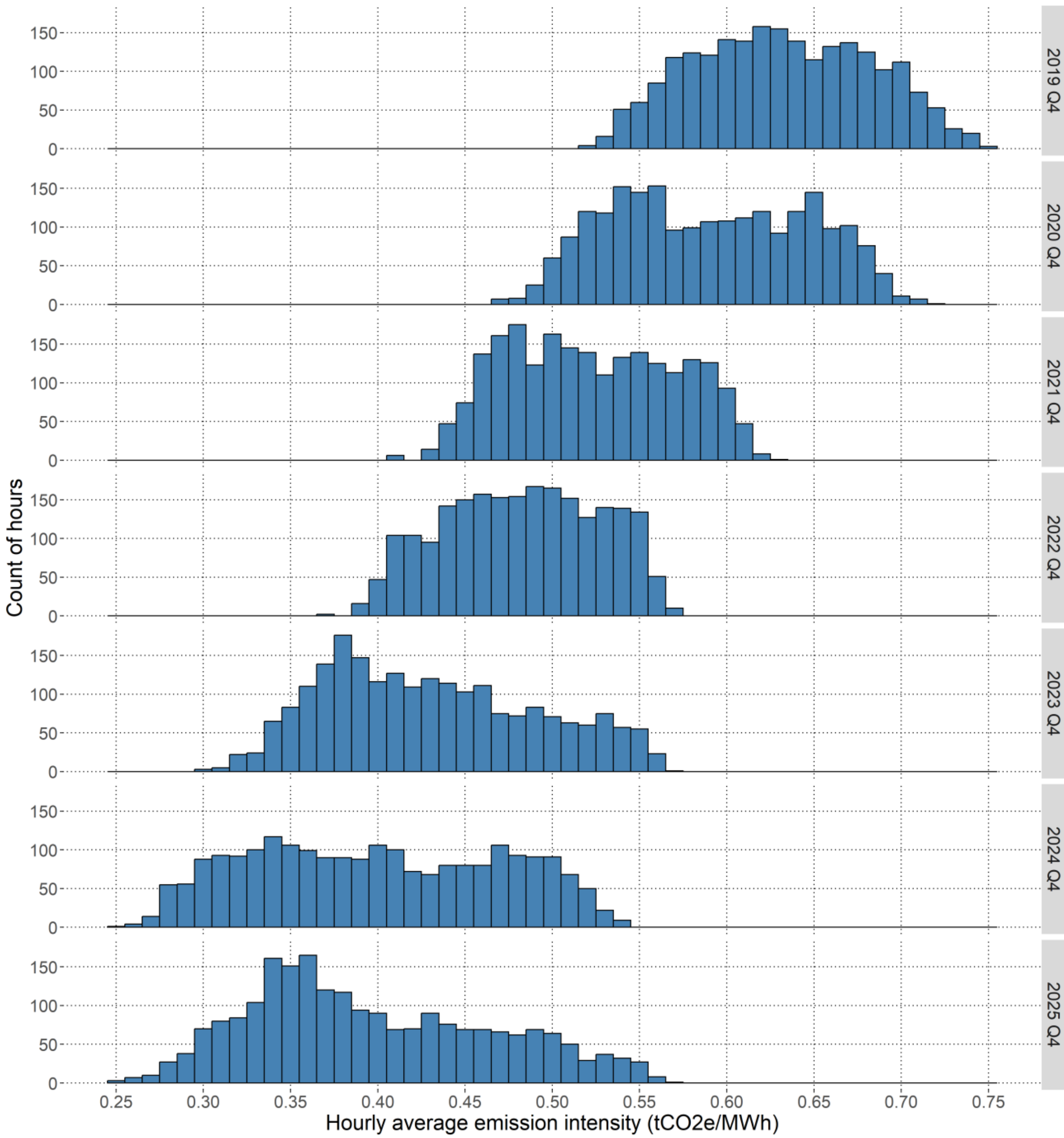
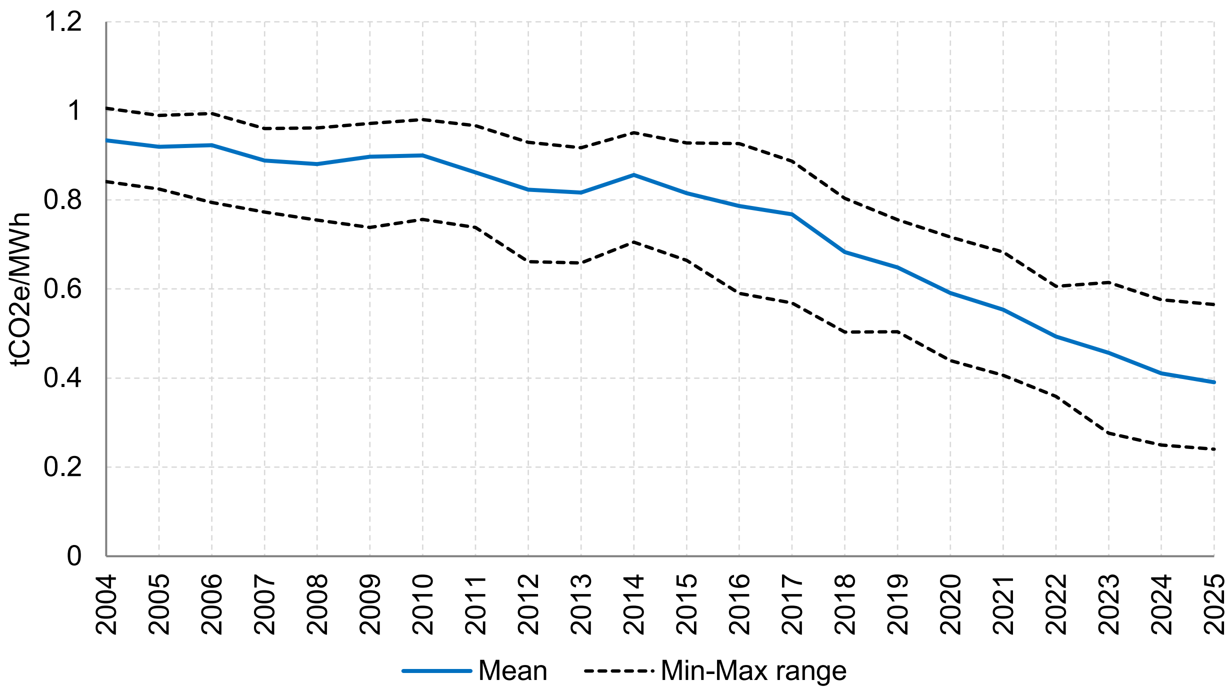


Figure 37 shows the trends in average carbon emissions over a longer time horizon. Since 2015, Alberta has seen a significant decline in the average carbon emission intensity of its electricity generation.

In 2025, the average carbon emissions intensity was 0.39 tCO2e/MWh compared to 0.81 tCO2e/MWh in 2015, a decline of 52%. Relative 2020, the average carbon emission intensity has fallen from 0.59 tCO2e/MWh, a decline of 34%.

Figure 37: Average hourly carbon emission intensity by year (2004 to 2025)



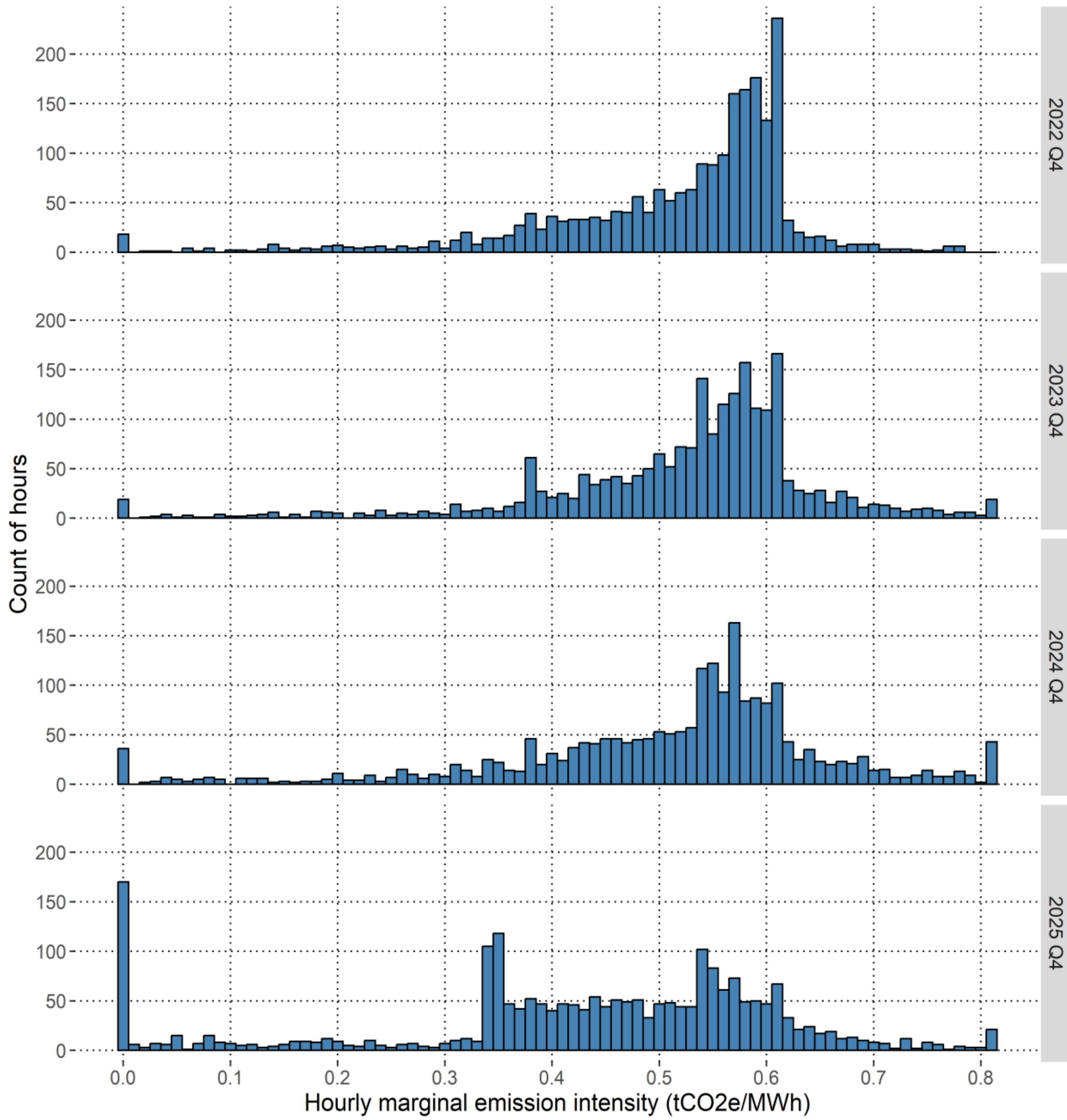
1.6.2 Hourly marginal emission intensity

The hourly marginal emission intensity of the grid is the carbon emission intensity of the asset setting the SMP in an hour. In hours where there were multiple SMPs and multiple marginal assets, a time-weighted average of the carbon emission intensities of those assets is used.

Figure 38 shows the distribution of the hourly marginal emission intensity of the grid in Q4 for the past four years. Gas-fired steam assets were setting the price quite often for these quarters, as demonstrated by the higher observations around 0.54 to 0.60 tCO2e/MWh.

In Q4, combined cycle assets were marginal most often at 40% of the time, followed by gas-fired steam assets at 25%. Assets that are considered having a 0.0 tCO2e/MWh emission intensity were marginal 15% of the time.

Figure 38: The distribution of marginal carbon emission intensities in Q4 (2022 to 2025)



2 THE POWER SYSTEM

2.1 Congestion

Transmission elements may impose limitations to the transfer of electric energy from one location on the transmission system to another. The AESO mitigates these limitations in real time by curtailing generation.[20]

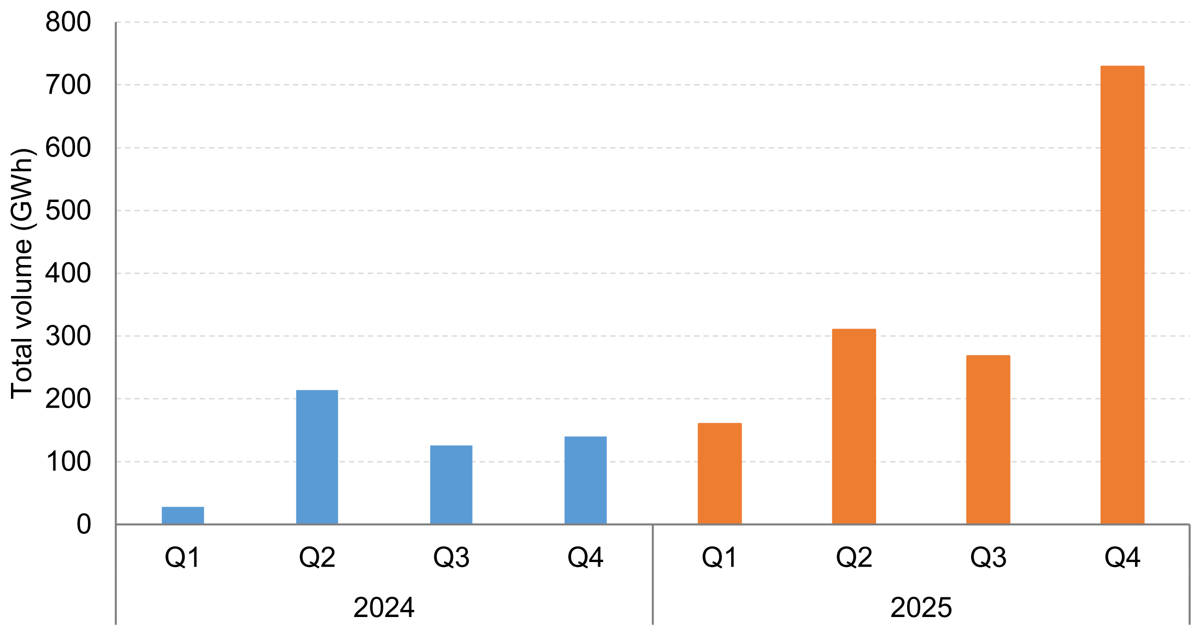
The MSA measures constrained intermittent generation (CIG) volumes, an estimate of the potential generation of an intermittent asset that is curtailed due to a transmission constraint. The CIG calculation uses data on curtailment limits, available capacity, potential real power capability, and energy dispatch.[21]

2.1.1 Annual summary

The total volume of CIG in 2025 was 1,468 GWh, a 189% increase from 508 GWh in 2024. The higher CIG volumes in 2025 were largely driven by higher volumes in Q4 (Figure 39).

The 2025 maximum hourly average CIG volume of 2,699 MW was reached in HE 11 of October 29 (Figure 41). This 2025 peak is 62% higher than the peak in 2024 (Figure 40).

Figure 39: Quarterly total CIG volumes (2024 and 2025)



[20] This is known as constrained down generation. See ISO Rule 302.1 Transmission Constraint Management.

[21] The AESO's ETS Estimated Cost of Constraint Report calculate TCR volumes using a different methodology than the MSA's estimate of constrained intermittent generation. The MSA's Quarterly Report for Q2 2023 discusses how the MSA calculates the CIG volumes (previously referenced as constrained down volumes).

Figure 40: Maximum hourly transmission constrained intermittent generation (2024)

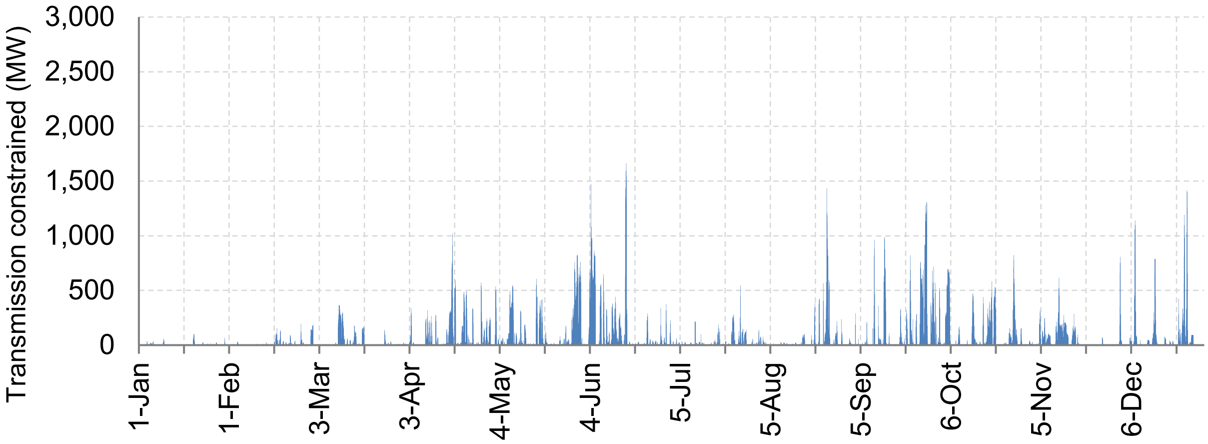
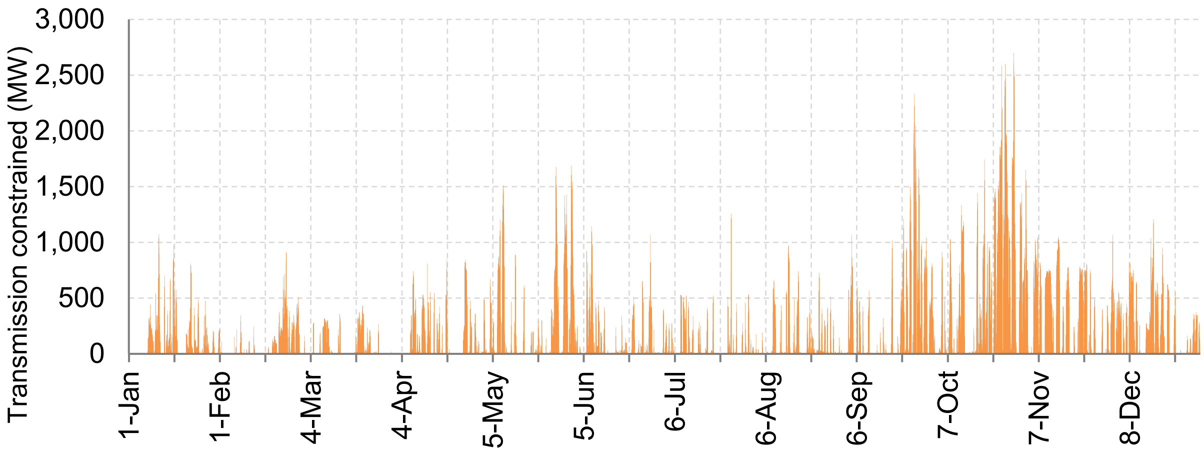


Figure 41: Maximum hourly transmission constrained intermittent generation (2025)



In 2025, there were 4,741 hours in which CIG was greater than 1 MWh, which is equivalent to 198 days or 54% of hours. To understand the increasing magnitude of congestion, note that 62 hours in 2025 had more CIG than the most constrained hour in 2024 (1,665 MW).

Transmission capability and contingencies vary through the province and over time, and certain assets experience more congestion than others. In 2025, the ten most constrained intermittent assets (of 97) accounted for 69% of all CIG volumes (Table 27).

The asset that experienced the highest volume of constrained generation in 2025 was Forty Mile Bow Island (FRM1). FRM1 was almost solely constrained for Remedial Action Scheme (RAS) 164, which is discussed further in section 2.1.2. The six most constrained assets were also often included in the RAS 164 constraint.

Table 27: Top 10 CIG assets by total CIG volume (2025)

Asset name	Asset ID	Total volume (MWh)	Percent of total
Forty Mile Bow Island	FRM1	202,680	14%
Forty Mile Granlea	FMG1	170,139	12%
Whitla 2	WHT2	152,836	10%
Wild Rose	WIR1	119,108	8%
Winnifred Wind	WIN1	93,881	6%
Cypress 1	CYP1	68,527	5%
Paintearth Wind	PAW1	62,859	4%
Sharp Hill Wind	SHH1	60,754	4%
Halkirk Wind Power Facility	HAL1	43,383	3%
Buffalo Plains	BPW1	42,015	3%

The most constrained asset, measured using CIG as a percentage of total potential generation, had 30% of its potential generation constrained in 2025 (Table 28). The maximum reached in 2024 was 12%.

Although most assets are in both Table 27 and Table 28, the ordering varies between measurement. For example, WIR1 ranks as the most constrained intermittent asset using percentage of potential generation, but the asset has a moderate amount of total potential generation when compared to other intermittent assets (23rd of 97) so is lower on the list of total CIG volumes.

Table 28: Top 10 CIG assets by CIG volume as percentage of potential generation (2025)

Asset name	Asset ID	CIG volume as share of potential generation (%)
Wild Rose	WIR1	30%
Forty Mile Bow Island	FRM1	29%
Winnifred Wind	WIN1	29%
Whitla 2	WHT2	27%
Forty Mile Granlea	FMG1	25%
Cypress 2	CYP2	23%
Cypress 1	CYP1	11%
Paintearth Wind	PAW1	11%
Rattlesnake Ridge Wind	RTL1	9%
Wheatland Wind	WHE1	9%

The share of total CIG value by company is determined using a simplified calculation where the pool price is used to establish the estimated value, which is then multiplied by the associated hours constrained volume. Each company is then given a share based on the total value (Table 29).

Table 29: Top 10 companies by CIG cost (2025)[22]

Company (assets)	Cost ($)	Share of total CIG cost (%)
Capital Power (CLY1, CLY2, HAL1, HAL2, STR1, STR2, WHT1, WHT2)	$2,745,959	20%
Acciona (FRM1, SCR2, SCR3)	$2,176,939	16%
ATCO (BLS1, DFT1, EMP1, FMG1)	$1,797,434	13%
Capstone Infrastructure (BFL1, BFL2, BFL3, BFL4, CLR1, CLR2, MIC1, TRH1, WIR1)	$1,237,868	9%
EDF Power Solutions (BSR1, CYP1, CYP2)	$1,116,675	8%
Atlantica (WIN1)	$934,070	7%
CWP Energy Inc. (JNR1, JNR2, JNR3, PAW1, SWP1, WHE1)	$864,355	6%
EDP Renewables (SHH1)	$414,387	3%
BHE Canada Limited (RTL1)	$362,612	3%
Pattern Energy Group (LAN1)	$299,997	2%

2.1.2 Q4 results

The frequency and significance of CIG directives increased from Q4 2024 to Q4. The MSA estimates that CIG volumes were 140 GWh in Q4 2024 and 729 GWh in Q4, a 421% increase year-over-year. Quarter-over-quarter, CIG volumes increased by 172%.

The maximum hourly average volume of CIG in Q4 was 2,699 MW, nearly double the Q4 2024 maximum of 1,417 MW (Figure 42 and Figure 44). The Q4 maximum hourly average volume of CIG was also higher than the maximum value of 2,332 MWh in Q3 (Figure 43).

[22] Company market share was assessed using the February 12, 2025, MSA Market Share Offer Control data. For each Company, all assets as of February 12, 2025, are listed. However, not all assets listed contributed to the total constrained down cost.

Figure 42: Maximum hourly transmission constrained intermittent generation (Q4 2024)

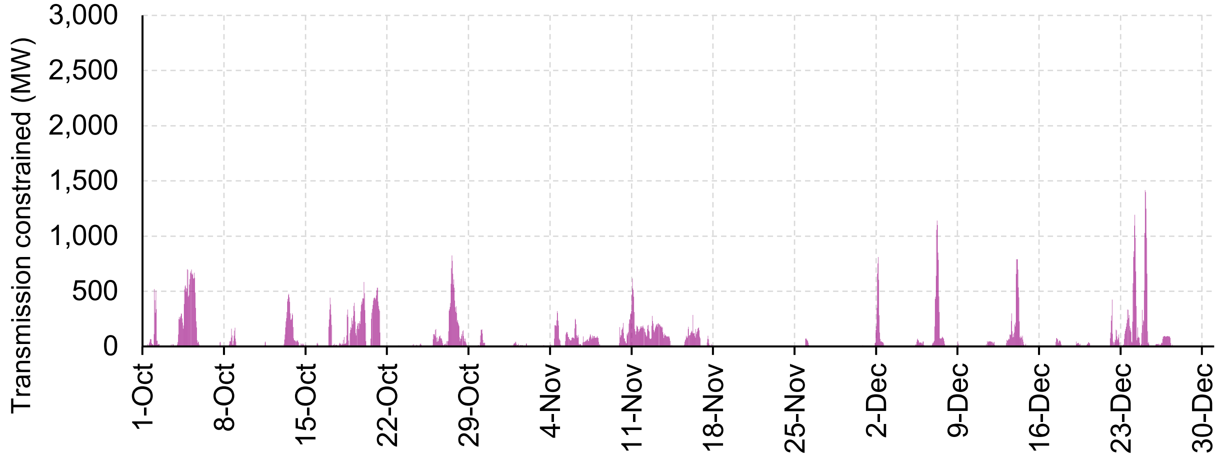


Figure 43: Maximum hourly transmission constrained intermittent generation (Q3 2025)

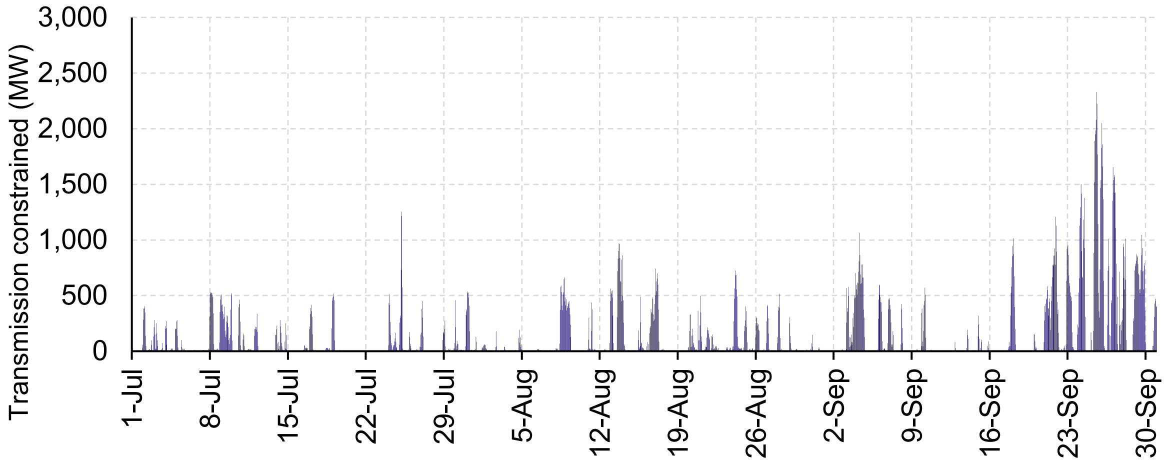
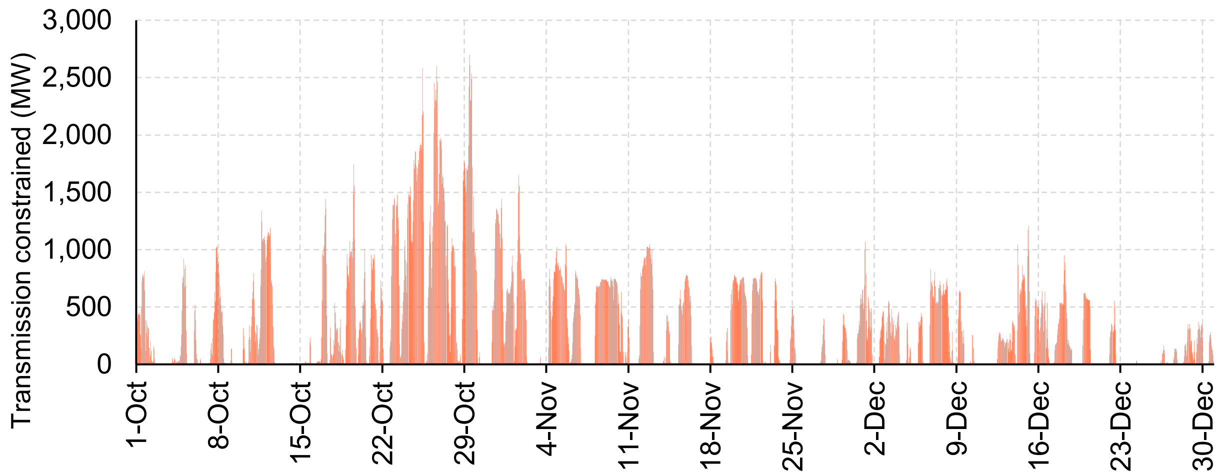


Figure 44: Maximum hourly transmission constrained intermittent generation (Q4 2025)



The increased CIG volumes in Q4 were due to increased intermittent capacity and higher intermittent generation. Higher CIG volumes generally align with periods of high intermittent generation or supply surplus events (Figure 45 and Figure 46).

Figure 45: Average hourly potential intermittent generation and CIG (Q4)

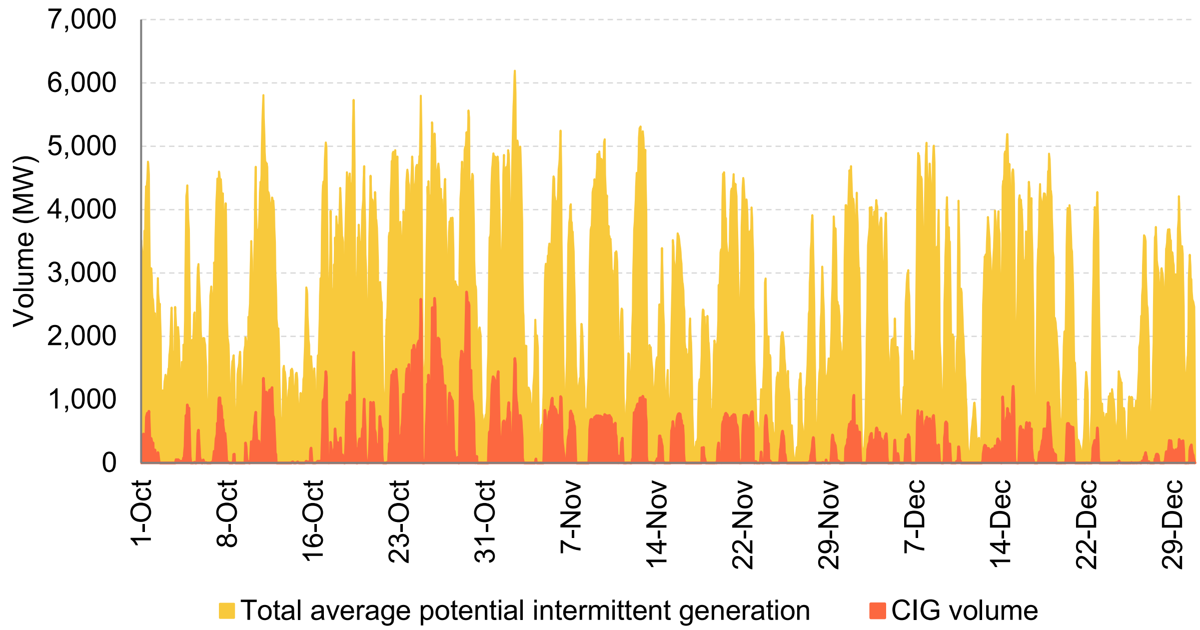
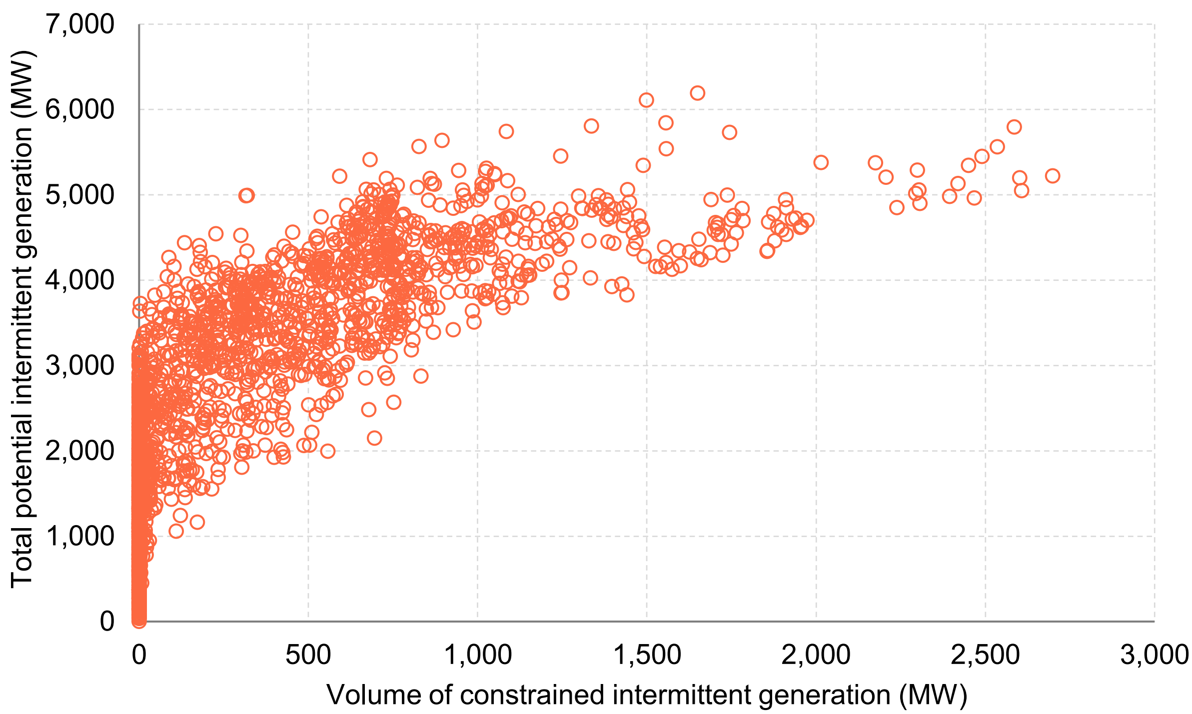


Figure 46: Volume of CIG compared to total potential intermittent generation (Q4)



There were over 344 shift log events for constrained down generation in Q4. Increased constrained intermittent generation volumes may also be due to persistent or frequent limitations to certain transmission elements and may affect one or more generation assets.

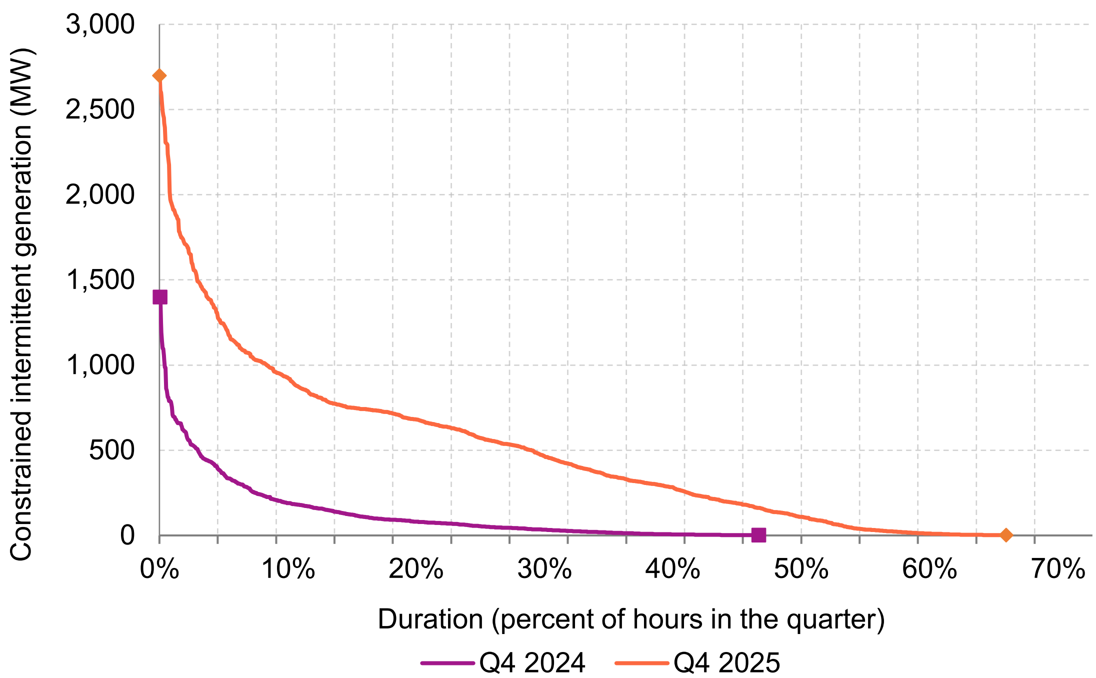
In Q4, there were a wide variety of events that occurred over many different transmission elements. Q4 saw frequent curtailments related to RAS associated pre-contingency curtailment to manage the MSSC limit, specifically 164 in the Cassils-Bowmanton-Whitla (CBW) area which "protects local area system against the loss of various 240kV lines."[23]

Two other common constraints include 9L16, which was overloaded, and 879L, which was overloaded due to the loss of 1053L. In late October and early November, approximately 45 assets were constrained due to the contingency risk of losing EATL and overloading 927L.

The increase in CIG volumes from Q4 2024 to Q4 occurred at a higher rate than the installation of intermittent generation capacity. While total installed intermittent capacity increased by only 0.4%, average hourly CIG volumes, expressed as a percent of installed intermittent capacity, increased from 0.9% in Q4 2024 to 4.4% in Q4.

Figure 47 illustrates duration curves of CIG year-over-year. The length of the tails to the right of the duration curves show that the frequency of CIG events increased year-over-year. There were 1,458 hours of CIG volumes greater than 1 MWh in Q4 which is 66% of hours in the quarter. In contrast, Q4 2024 experienced 1,028 hours of CIG volumes greater than 1 MWh, or 47% hours.

Figure 47: Duration curves of CIG volume (Q4 2024 and Q4)



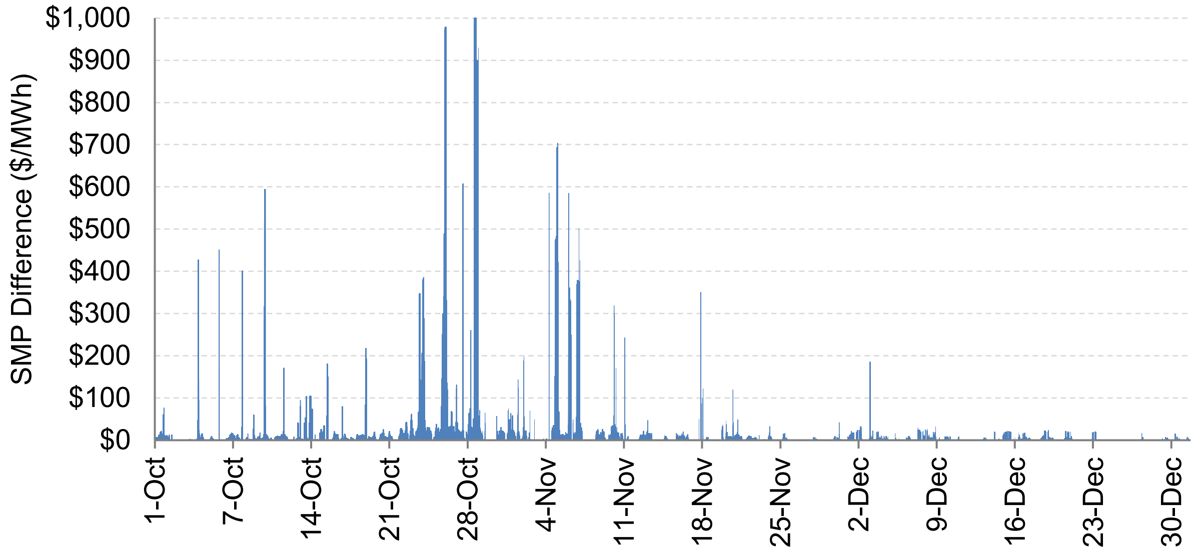
[23] AESO Alberta Remedial Action Schemes, page 2 (updated October 15, 2025)

Transmission constraint volumes had frequent fluctuations throughout all months of Q4, however October experienced the most volume of CIG and the highest peak. The CIG volume in the month of October accounted for 50% of all Q4 volumes. In 76% of hours in October there was at least 1 MWh of CIG. The CIG volumes in the month of October were 365 GWh, exceeding the previous record for highest CIG volume over a quarter (previously Q2 2025 with 310 GWh).

The constrained and unconstrained SMP differed by $1/MWh or more in 46% of minutes in Q4. In comparison, Q4 2024 had 22% of minutes with a variance of $1/MWh or more, and Q3 2025 had the difference in 20% of minutes.

The largest difference between the constrained SMP and unconstrained SMP in Q4 was $999.99/MWh, which occurred in HE 12 of October 29 (Figure 48). The largest difference was lower in Q4 2024 at $813/MWh, and in Q3 2025 the largest difference occurred on September 3 at $893/MWh.

Figure 48: Difference of constrained SMP and unconstrained SMP (Q4)

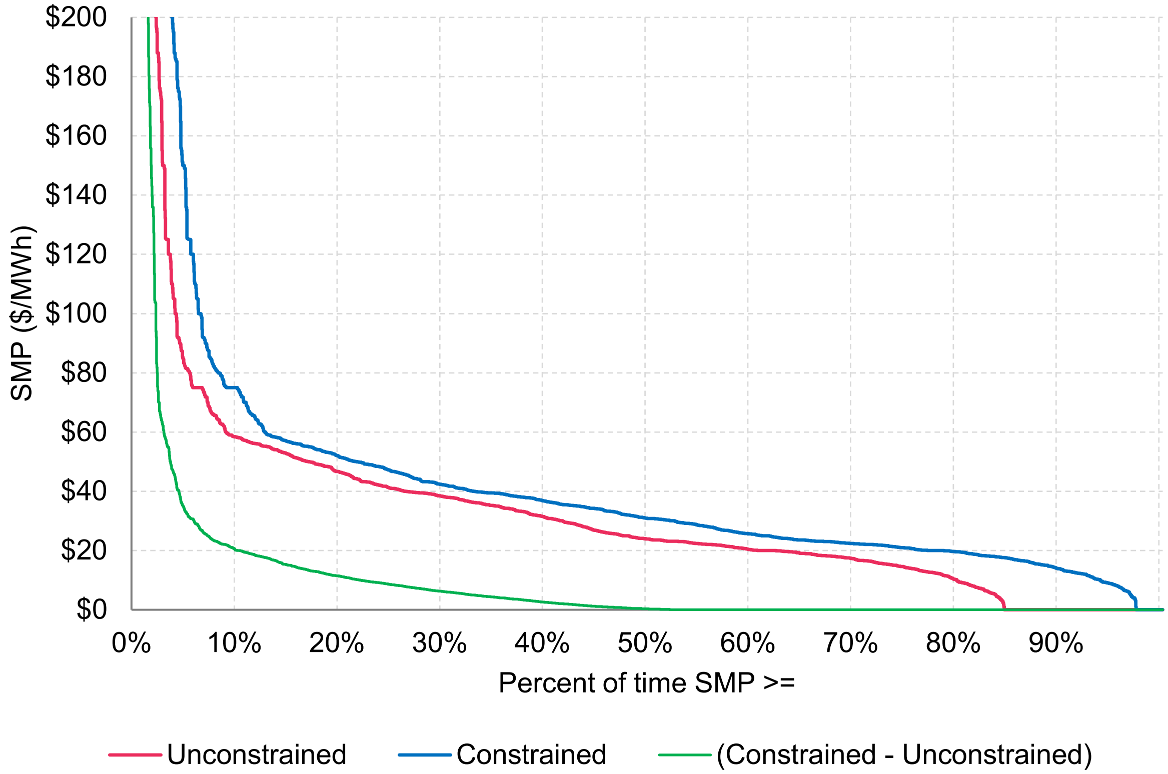


The periods that experience high volumes of CIG often occur when potential generation from intermittent resources is high. Given the offer behaviour of these resources, when intermittent generation is higher, the SMP is lower as higher priced generation is displaced.

Therefore, despite the high amount of CIG volumes in Q4, there was often only a small difference between the constrained SMP and the unconstrained SMP (Figure 49). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity have a relatively small impact on prices.

Only 2.4% of minutes in Q4 experienced a difference of greater than $100/MWh between the constrained and unconstrained SMP. However, Q4 experienced more large divergences between the constrained and unconstrainted SMP. For example, a notable event occurred on October 29 when the constrained SMP was at the offer cap of $999.99/MWh and the unconstrained SMP was at the floor of $0.00/MWh. This event is discussed further in section 1.3.1.

Figure 49: Duration of unconstrained SMP, constrained SMP, and the difference between the constrained and unconstrained SMP (Q4)

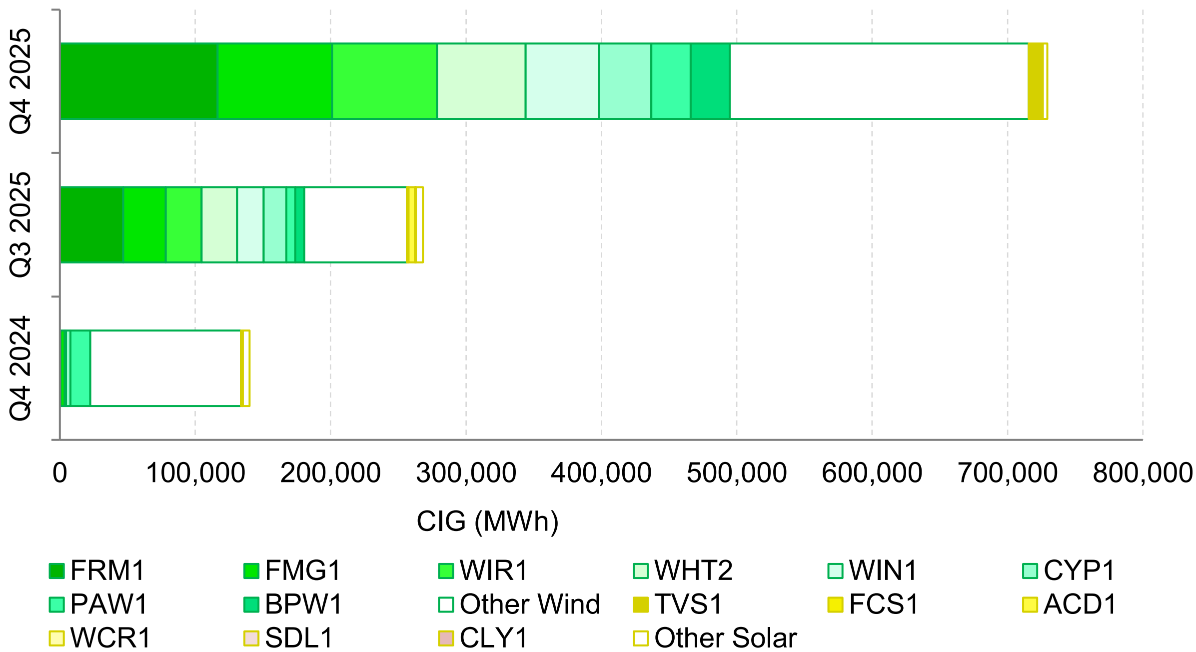


Transmission capability varies throughout the province, and certain regions experience more congestion than others, often leading to local constraints. Often, wind and solar assets are not constrained uniformly throughout the province. In Q4, the eight most constrained wind assets accounted for 69% of the total CIG volume but only 32% of total installed wind capacity. Forty Mile Bow Island, Forty Mile Granlea, and Wild Rose were the most constrained wind assets in Q4 (Figure 50). These three assets represent 12% of Alberta's installed wind capacity, however they accounted for 39% of the wind CIG volume in Q4.

Travers (466 MW) was the most constrained solar asset in Q4, with a total of 7,476 MWh constrained. The asset was constrained for multiple reasons, the most common being for the potential or real-time overload of 927L.

The following five most constrained solar assets have an aggregate maximum capability of 392 MW and were constrained by 2,896 MWh in Q4. The top six constrained solar assets accounted for 46% of total solar capacity but accounted for 76% of solar CIG volumes in Q4. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

Figure 50: Wind and solar CIG by asset (Q4 2024, Q3 2025, Q4)



2.2 Interties

Interties connect Alberta's electricity grid directly to those in BC, Saskatchewan, and Montana, with the intertie to BC being the largest. The AESO manages the BC and Montana interties as one shared flow gate (BC/MATL) because any trip on the BC intertie results in a direct transfer trip on MATL. These interties indirectly link Alberta's electricity market to markets in Mid-Columbia (Mid-C) and California.

Figure 51 shows the highest hourly values for net imports and net exports by year since 2018. As shown, there has been a declining trend in the maximum value of net imports; from 1,154 MW in 2019 to 677 MW in 2025, a decline of 42%. Maximum import flows have been lower in recent years largely because the AESO have reduced import capability on BC/MATL due to a reduction in Alberta's inertia and primary frequency response.

Conversely, the maximum values for net exports have been increasing since 2020, and in 2025 reached the system export limit of 1,088 MW (935 MW on BC/MATL and 153 MW on the Saskatchewan intertie). In Q4, the system export limit was reached in 40 hours.

Figure 51: Maximum values for net imports and net exports by year (2018 to 2025)

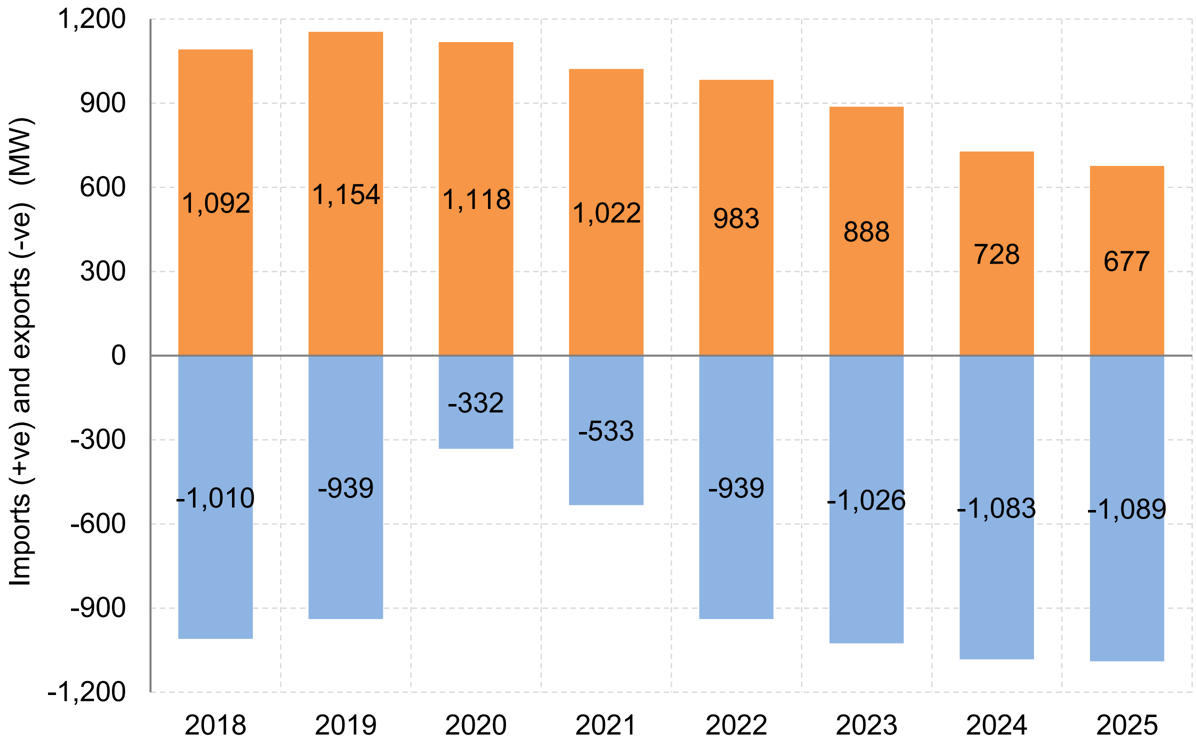


Figure 52 shows daily average power prices over Q4 in Alberta, Mid-C, and at NP15 and SP15 in California (all shown in CAD). Over the quarter, Alberta pool prices averaged $43.03/MWh while Mid-C, NP15, and SP15 were all higher at $51.89/MWh, $61.44/MWh, and $50.25/MWh, respectively.

In October, Mid-C prices exceeded Alberta pool prices by an average of $24/MWh, and Mid-C prices were higher in 93% of hours. In November, average prices were comparable even though Mid-C prices were higher in 84% of hours, as higher pool prices in a few hours increased the Alberta average price. In December, Mid-C prices exceeded Alberta pool prices by an average of $2/MWh, and Mid-C prices were higher in 60% of hours over the month.

Over the quarter, Alberta pool prices were lower than prices in Mid-C in 79% of hours. Consequently, Alberta continued to be a strong exporter in Q4 (Table 30). Exports were highest in October averaging 465 MW (668 MW during off-peak hours and 365 MW during peak hours). Alberta was exporting in 70% of hours over the quarter and importing in 24% of hours.

The Saskatchewan intertie returned to the market on October 29, having been unavailable for commercial operations since October 4, 2024.

Figure 52: Daily average power prices in Alberta, Mid-C, and NP15/SP15 in California (Q4)

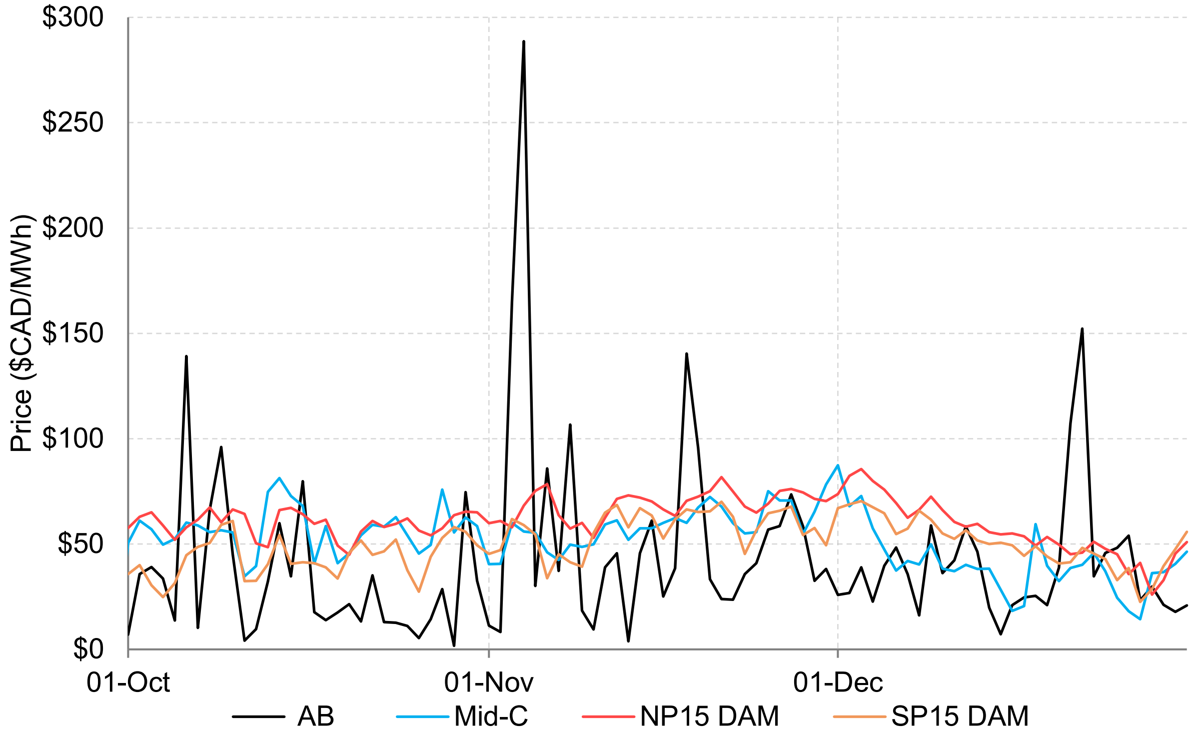


Table 30: Average net imports (Q4 and Q4 2024)

	2024				2025			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
Oct	-177	14	5	-158	-413	-55	2	-465
Nov	-114	55	0	-59	-257	-18	23	-251
Dec	-367	-50	0	-417	-258	17	-17	-258
Q4	**-221**	**6**	**2**	**-213**	**-309**	**-19**	**3**	**-326**

Figure 53 shows the monthly average net schedule for the BC and Montana interties against the proportion of time that pool price was greater than prices at NP15 in California. As shown, there is a strong correlation between the variables as prevailing prices are the major determinant of intertie flows. Over the past two years, months with the strongest net exports over BC/MATL occurred when NP15 prices exceeded Alberta pool prices in more than 90% of hours.

Figure 53: Monthly average net schedule for BC and MATL and the proportion of time the pool price was greater than prices at NP15 (January 2024 to December 2025)

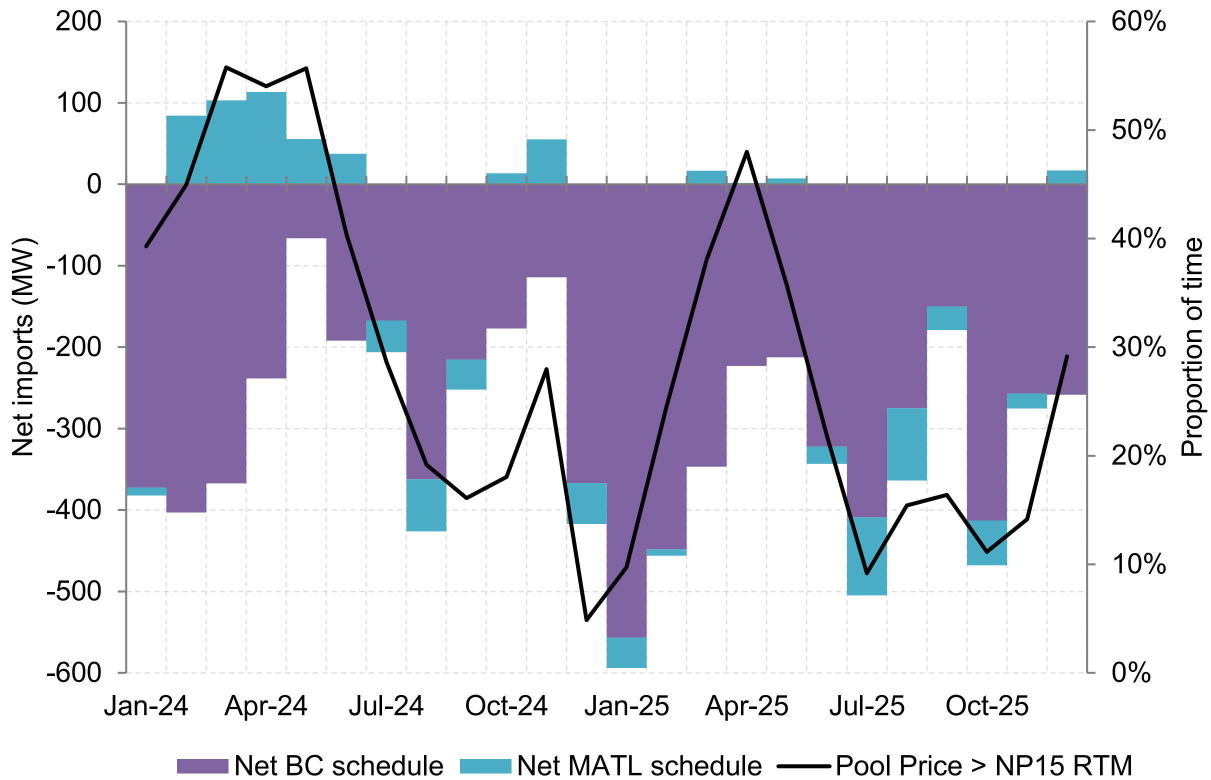


Figure 54 and Figure 55 show monthly average imports and exports on BC and MATL over 2025 by the five most active participants. On the BC intertie, the main participant was exporting to serve domestic load, while the other participants were largely exporting to US utilities or market hubs. On MATL, exports were generally serving US utilities or industrial loads, while imports typically came from wind assets.

Figure 54: Monthly average scheduled interchange on the BC intertie by top five participants (January to December 2025)

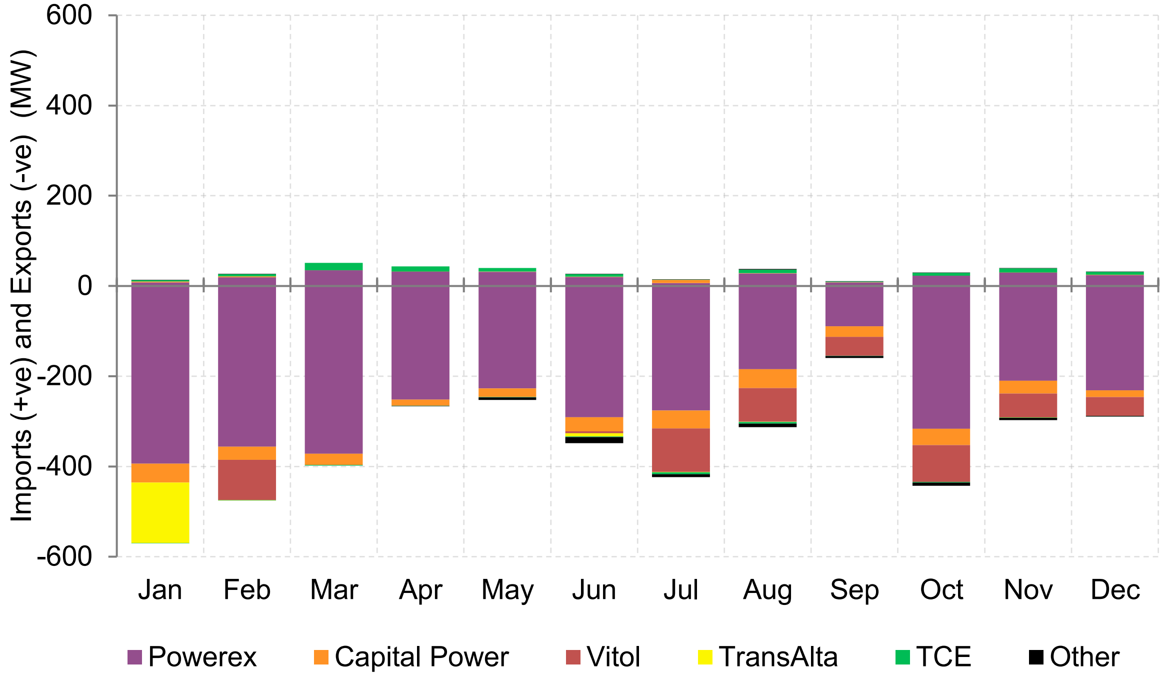


Figure 55: Monthly average scheduled interchange on MATL by top five participants (January to December 2025)

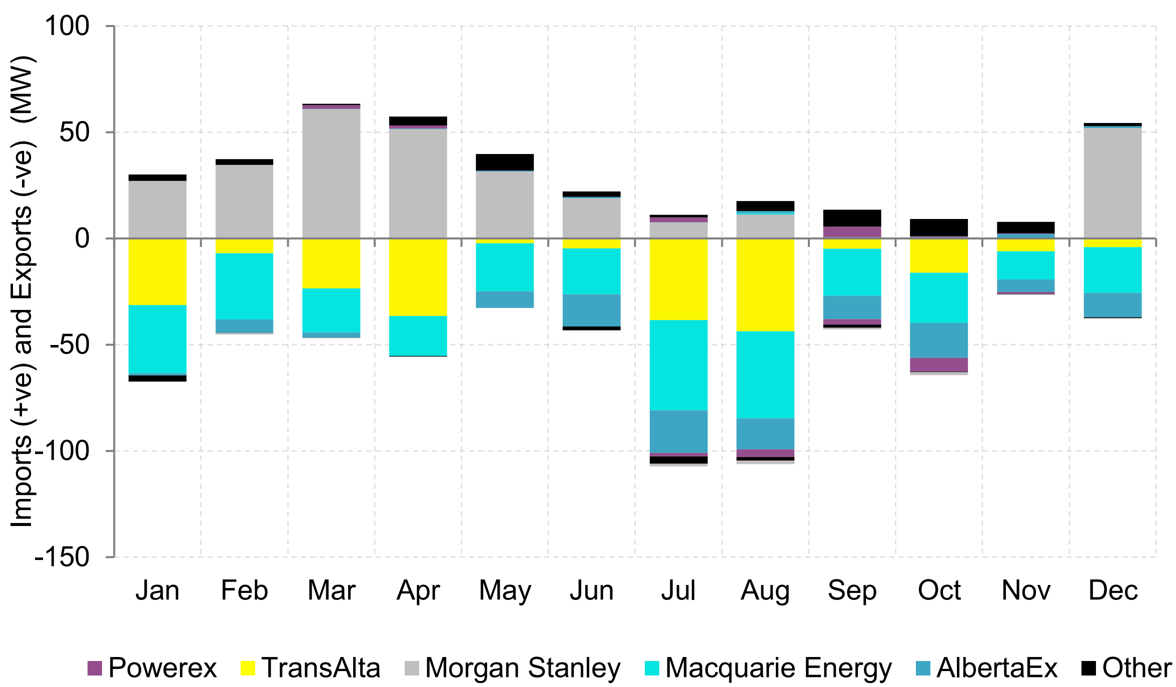
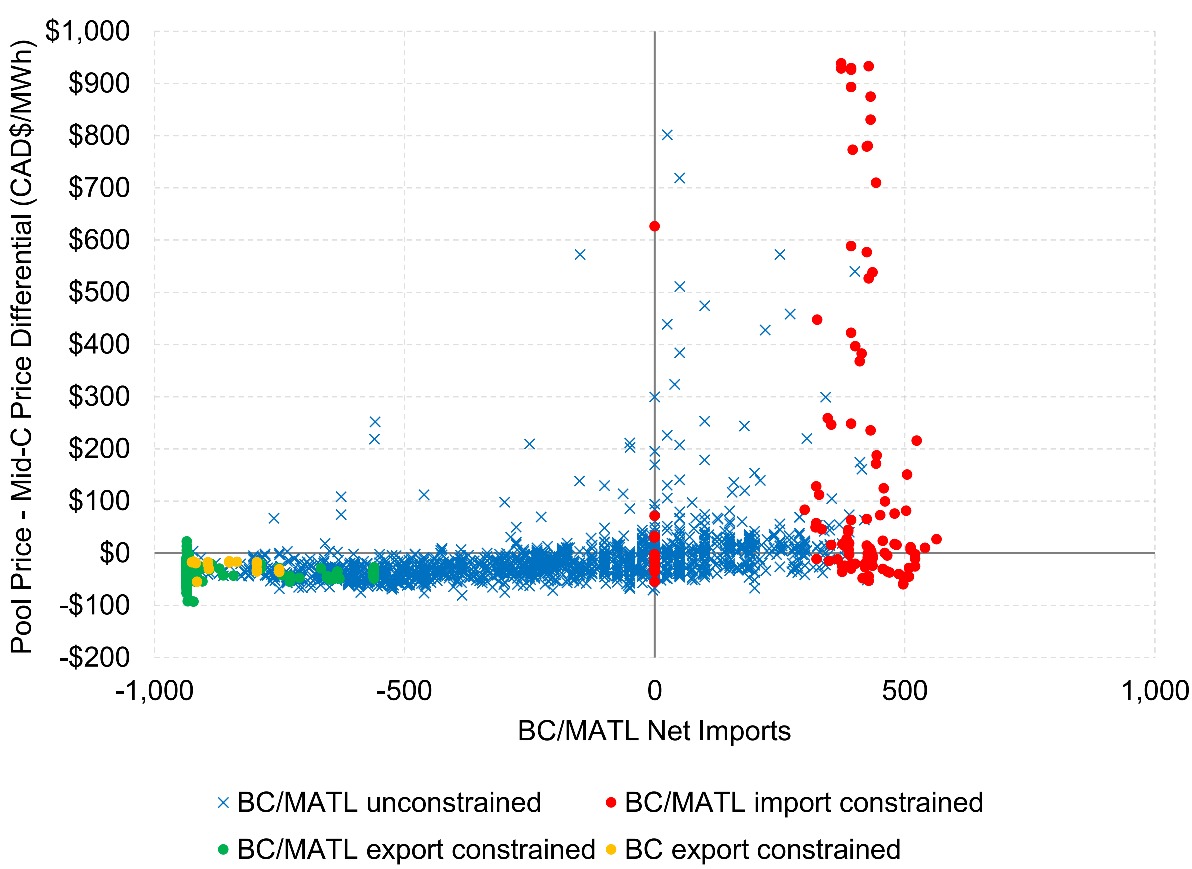


Figure 56 shows a scatterplot of the Alberta and Mid-C price differential against net imports on BC/MATL for each hour of the quarter. Over Q4, there were many hours where export bids or scheduled volumes were at or above BC/MATL export capability, meaning that BC/MATL was export constrained (shown in green). BC/MATL exports were constrained for 20% of the time over the quarter.

While BC/MATL was export constrained, the price differential between Alberta and Mid-C averaged negative $40/MWh and joint export capability averaged 935 MW. Export constrained observations generally lie on the left-hand side of the figure. Reasons for this not being the case include insufficient transmission capacity and curtailments.

In addition, there were hours where BC net export bids were at or above BC export capability, with net imports on MATL, meaning that only the BC intertie was export constrained (shown in yellow). Over the quarter, BC exports were constrained 1% of the time. While BC was export constrained, the price differential averaged negative $24/MWh and BC/MATL export capability averaged 935 MW.

Figure 56: Alberta and Mid-C price differential and net BC/MATL schedule (Q4)



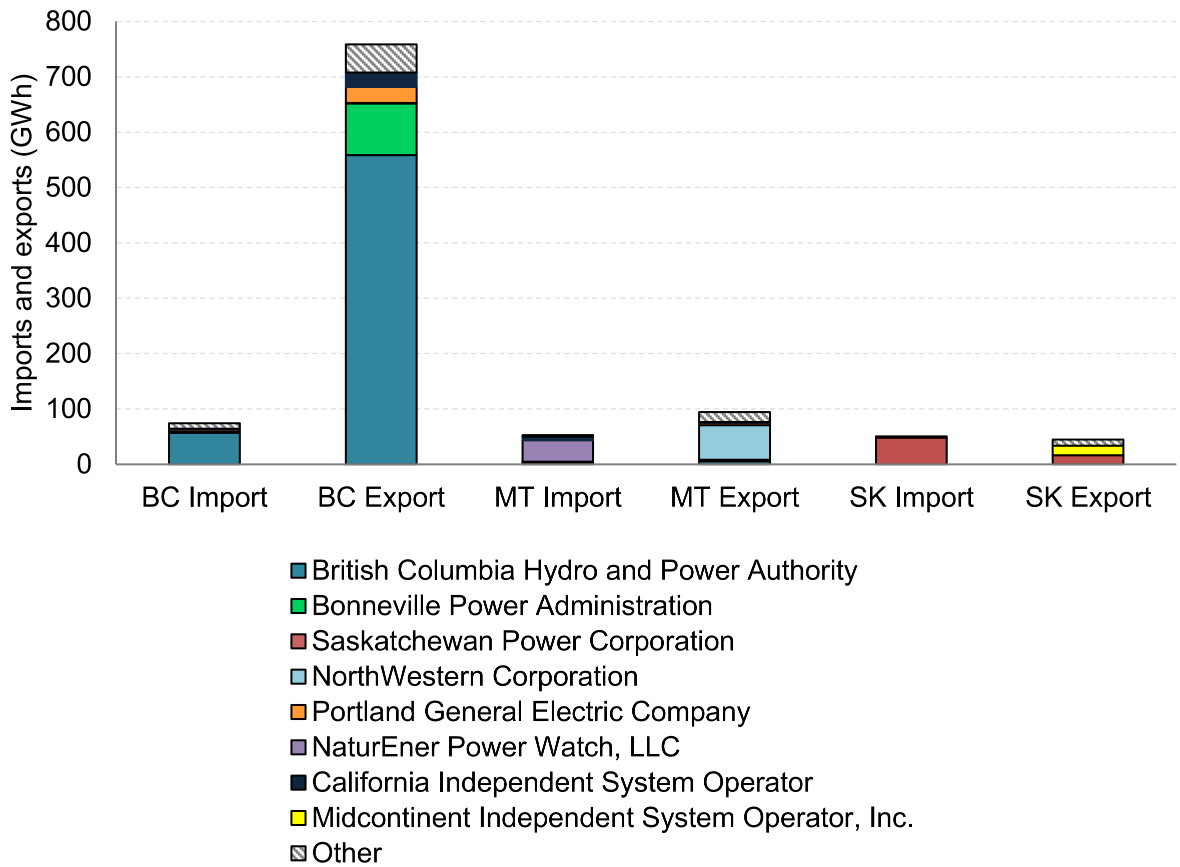
There were also hours where net import offers or scheduled volumes on BC/MATL were at or above import capability, meaning that BC/MATL was import constrained (shown in red). BC/MATL imports were constrained for 5% of the time over the quarter.

While import constrained, the price differential between Alberta and Mid-C averaged $145/MWh and import capability averaged 372 MW. Most of the hours where imports were constrained at 0 MW occurred on November 4, when BC/MATL import capability was reduced to mitigate the risk of losing Genesee Repower 1 and 2 during an emergency outage on the Genesee 500 kV bus #1. The sudden loss of these assets could have could have resulted in a trip of the interties.

During HE 17 and 18 of November 18, there were exports on the Saskatchewan intertie when pool prices were around $200/MWh as participants exported to the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO) even though prices were lower in these markets.

Figure 57 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[24] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

Figure 57: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q4)[25]



[24] The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered to.

[25] This includes the highest eight Balancing Authorities by volume.

For imports on the BC intertie, approximately 77% originated from BC, 22% from the US Northwest, and 1% from California. For exports on the BC intertie, 74% was delivered to BC, 23% to the US Northwest, and 3% to California.

For imports on MATL, 86% originated from the US Northwest, 13% from California, 1% from BC, and 1% from US Central. For exports on MATL, 89% was delivered to the US Northwest, 6% to BC, 3% US Central, and 2% to California.

For imports on the Saskatchewan intertie, 95% originated from Saskatchewan, and 5% from US Central. For exports on the Saskatchewan intertie, 39% was delivered to the US Midwest, 37% to Saskatchewan, 12% to US Central, 9% to Ontario, and 2% to Manitoba.

2.3 Transmission must-run

TMR is an out of market ancillary service used by the AESO to provide supplementary sources of supply to help maintain grid stability. Generally, the AESO uses TMR when demand in a region of the province's electricity system cannot be served by dispatched generation due to transmission constraints.

Some TMR can be foreseen by the AESO based on expected operating conditions and planned transmission outages. For this foreseeable TMR, the AESO may enter into contracts with the appliable generating asset owner, and these contracts determine the payment structure. However, some TMR is unforeseen and for these events the AESO conscripts a generating unit to provide supply. In the case of conscripted TMR, the market participant is compensated based on the asset's fixed and variable costs in accordance with the ISO tariff.[26]

At present, the AESO has one TMR contract with a generating asset to provide energy in the Grande Prairie region. This contract started on July 1, 2025 and runs for a minimum of three years.[27]

The volume of TMR used by the AESO increased from 82 GWh in 2024 to 340 GWh in 2025 (Figure 58). This year-over-year increase was largely driven by TMR directives to the Northern Prairie Power Project (NPP1), Poplar Hill (PH1), and HR Milner (HRM) assets, which are all located in the Grande Prairie area. The additional TMR volumes required in Grande Prairie during 2025 were largely caused by load growth in the area.

[26] AESO ISO Tariff – section 8.6 (October 17, 2025)

[27] AESO Engage: Transmission Must-Run Services

Figure 58: Total TMR volumes by generating asset (2018 to 2025)

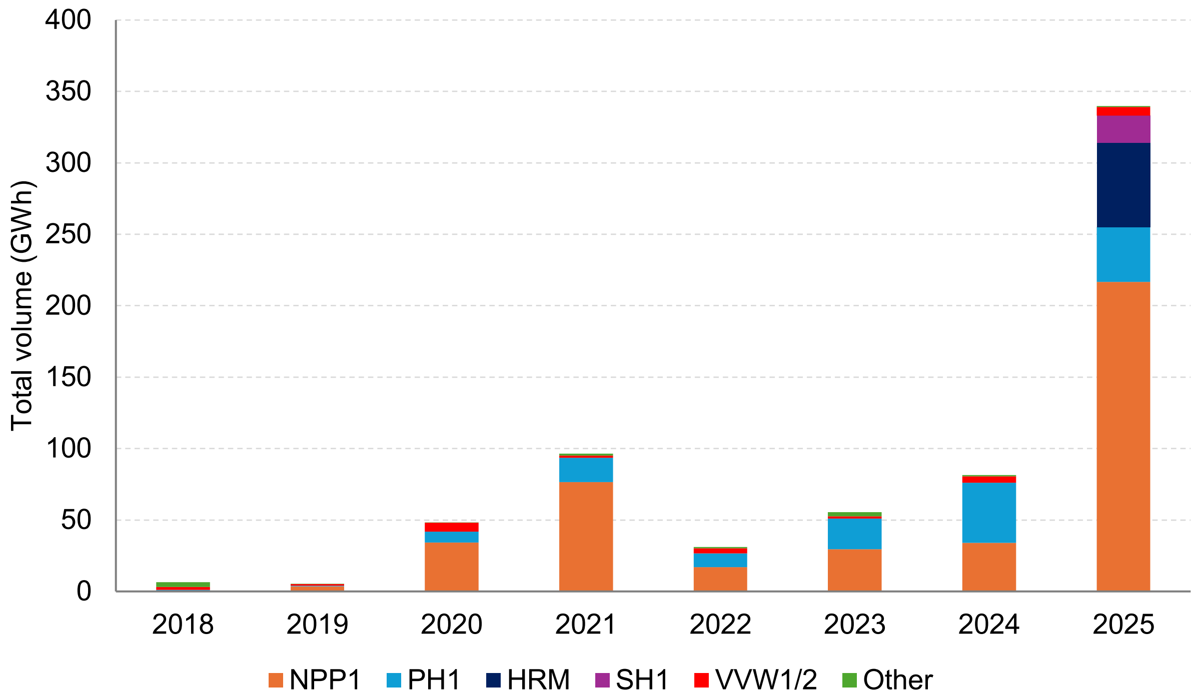
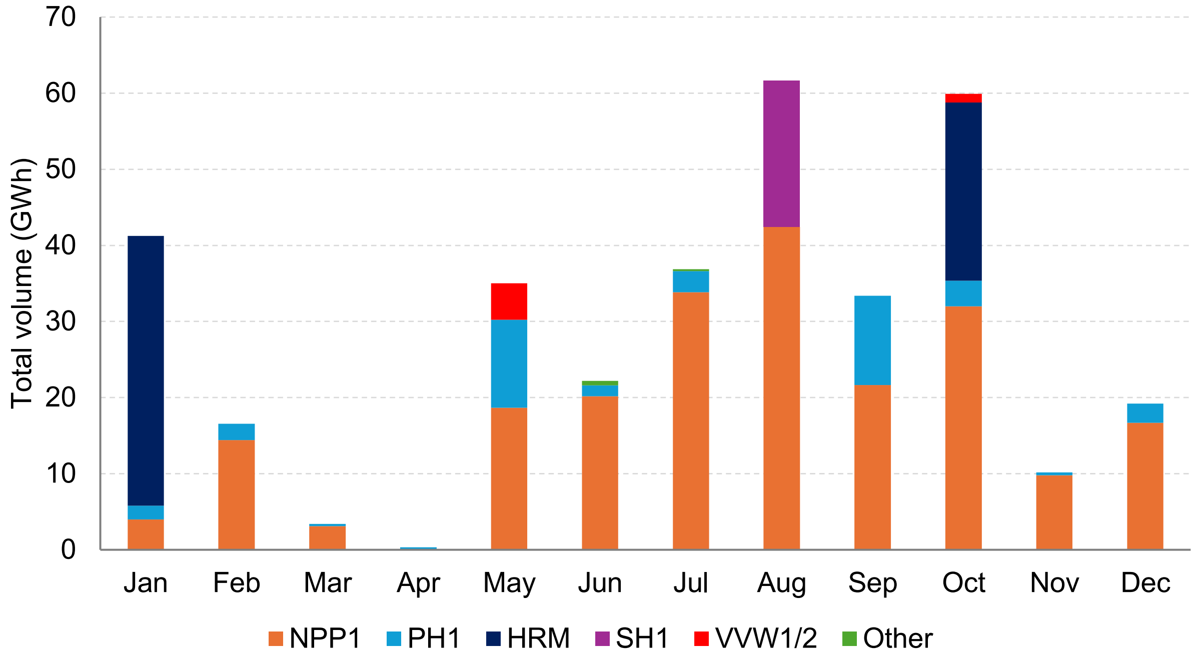


Figure 59 illustrates the volume of TMR directives issued by month and generating asset in 2025. TMR volumes for NPP1 and PH1 occurred in most months and were generally issued to provide energy into the Grande Prairie area because of transmission constraints.

In January 2025, the HRM asset was directed to provide TMR from January 21 to 29 due to a transmission line outage on 9L10. In October 2025, the HRM asset was directed to provide TMR between October 7 and 15 due to a transmission line outage on 7L228, which caused voltage concerns in the area.

In August 2025, the Sheerness 1 (SH1) asset was directed to come online and supply TMR from August 23 to 29 to provide dynamic stability in the southeast region.

Figure 59: Total TMR volumes by generating asset (January to December 2025)



The use of TMR increases supply and puts downward pressure on pool prices. Because TMR is out of market supply, the AESO uses a product called Dispatch Down Service (DDS) to offset TMR volumes. Through DDS, the AESO pays generators to reduce their supply up to the amount of TMR. Suppliers compete to provide DDS by submitting offers that provide the discount to pool price they are willing to accept to reduce their generation.

The AESO only uses DDS when prices are below the TMR reference price and there are offered volumes in the DDS market. The TMR reference price is determined monthly based on a forward natural gas price and an assumed heat rate of 12.5 GJ/MWh.[28]

DDS volumes have been much smaller than TMR volumes in recent years (Table 31). This has occurred because prices have frequently been above the TMR reference price and because there were often no offers to provide DDS.

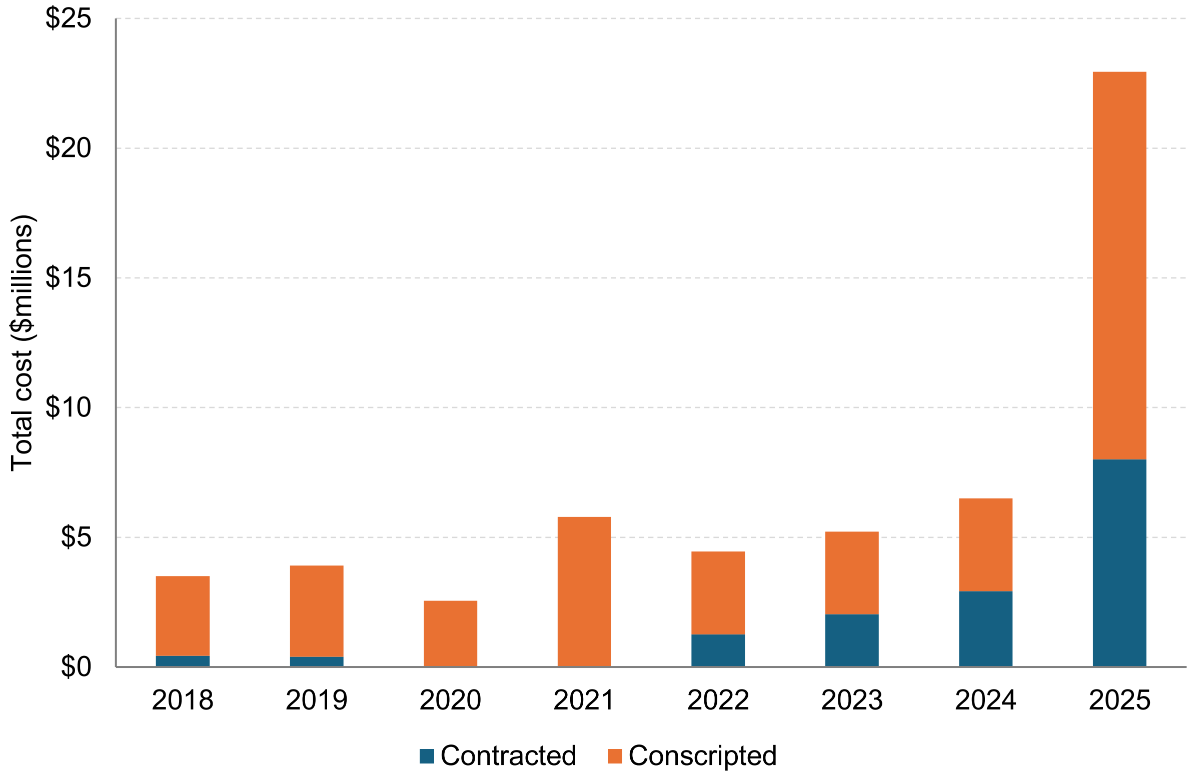
The total costs of TMR produced in 2025 are estimated at $23 million, which is a 250% increase compared to 2024 (Figure 60). These costs are estimates because the costs for some conscripted TMR have not yet been finalized. In 2025, 65% of TMR costs were due to conscripted volumes and 35% were due to contracted volumes. The assets located in the Grande Prairie area accounted for around 90% of TMR costs in 2025.

[28] ISO Rule 201.6

Table 31: Total TMR and DDS (2018 to 2025)

	Total TMR (GWh)	Total DDS (GWh)	DDS as a portion of TMR
2018	6.6	0.1	1.6%
2019	5.4	0.4	7.0%
2020	48.4	8.5	17.5%
2021	96.4	0.0	0.0%
2022	31.1	0.0	0.0%
2023	55.5	0.0	0.0%
2024	81.5	0.0	0.0%
2025	339.9	0.9	0.3%

Figure 60: Total TMR costs by production year (2018 to 2025)



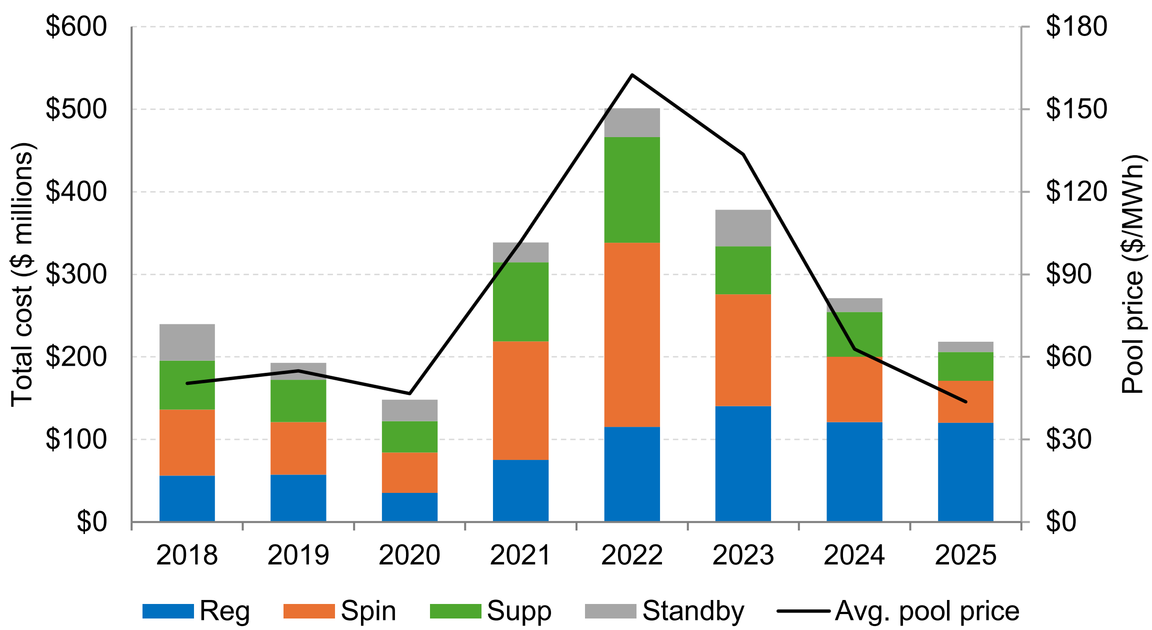
3 OPERATING RESERVES

The AESO use three types of operating reserves to maintain system reliability: regulating, spinning, and supplemental. The AESO use regulating reserves to automatically address small imbalances between supply and demand. Spinning and supplemental reserves are used to bring supply and demand back into balance following large contingency events, such as the sudden loss of a generator. Spinning and supplemental reserves must quickly respond to the AESO's directives to increase supply or reduce load. The provision of spinning reserves also requires a primary frequency response. The AESO procure operating reserves through day-ahead auctions on Wattex.

3.1 Annual summary

The total cost of operating reserves in 2025 was $218 million, 19% lower than in 2024. This reduction was driven by lower pool prices. The total cost of regulating reserves was largely unchanged year-over-year at $120 million. In contrast, the total cost of spinning reserves declined by 36% to $51 million, and the total cost of supplemental reserves declined by 36% to $35 million.

Figure 61: Total cost of operating reserves (2018 to 2025)



Equilibrium prices for active operating reserves are set based on supply and demand in day-ahead auctions. These equilibrium prices are indexed to pool prices to determine the received prices providers are paid for operating reserves. Table 32 provides the average received prices in 2024 and 2025.

The received price for spinning reserves fell by $13.05/MW year-over-year and the received price for supplemental reserves fell by $8.78/MW. The received price of both products fell because of lower pool prices in 2025.

Table 32: Received prices for active operating reserves (2024 and 2025)

	2024	2025	Difference
Reg	$69.79	$70.71	$0.92
Spin	$36.54	$23.50	-$13.05
Supp	$24.95	$16.17	-$8.78
Pool price	$62.78	$43.68	-$19.11

Despite the lower pool prices, the received price of regulating reserves increased by $0.92/MW year-over-year. The received price of regulating reserves increased because of higher equilibrium prices in the day-ahead auctions.

The markets for regulating reserves were more concentrated in 2025 due to a large acquisition which was finalized in December 2024. Consequently, the equilibrium prices for regulating reserves were higher and closer to the price caps more often in 2025.

The current caps on equilibrium prices for on-peak and off-peak regulating reserves are $40/MW and $100/MW, respectively. Figure 62 illustrates how often equilibrium prices for on-peak and off-peak regulating reserves were within $5/MW of these caps. As shown, there was a marked increase in how often equilibrium prices cleared close to the caps from 2024 to 2025. In October 2025, equilibrium prices in the on-peak market were above $35/MW 65% of the time, and equilibrium prices in the off-peak market were above $95/MW 61% of the time.

Figure 62: The percentage of time in which equilibrium prices for regulating reserves were within $5/MW of the price cap (January 2024 to December 2025)

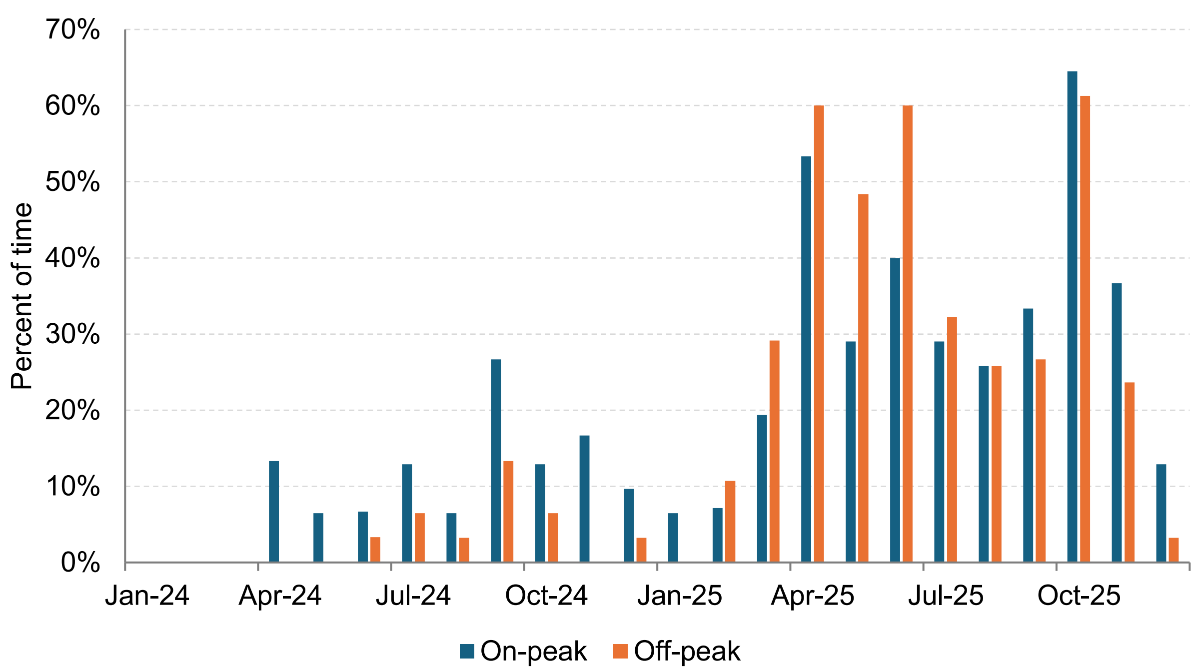


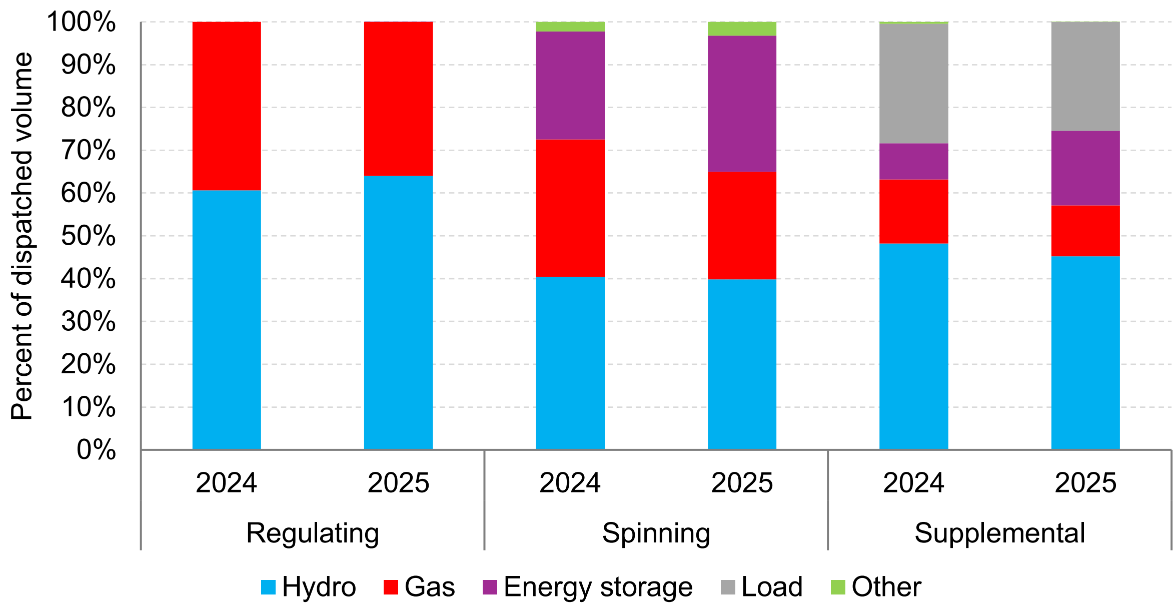
Figure 63 illustrates the provision of operating reserves by fuel type in 2024 and 2025. Regulating reserves in Alberta are provided by hydro and natural gas assets. In 2025, hydro assets accounted for 64% of dispatched volumes and natural gas assets accounted for 36%.

Hydro assets are also the largest provider of spinning and supplemental reserves. In 2025, hydro assets accounted for 40% of spinning reserves and 45% of supplemental reserves. Hydro assets are a natural provider of operating reserves because they allow the assets to earn revenues without using up limited water resources.

Similarly, batteries have become an important provider of spinning and supplemental reserves in recent years. In 2025, batteries accounted for 32% of spinning reserves and 17% of supplemental reserves, both of which are an increase year-over-year.

Load assets can provide supplemental but not spinning reserves (load assets can't provide the frequency response required for spinning reserves). In 2025, load assets remained an important provider of supplemental reserves at 25%, although this is down slightly from 28% in 2024.

Figure 63: Percentage of dispatched operating reserves by fuel type (2024 and 2025)



3.2 Total costs

The total cost of operating reserves in Q4 was $53 million, which is 21% lower than in Q4 2024. The lower cost of operating reserves year-over-year was driven by lower pool prices and increased competition in the markets for spinning and supplemental reserves.

Average pool prices in Q4 fell by 16% year-over-year putting downward pressure on operating reserve costs. However, the total cost of spinning reserves fell by 34% year-over-year and the total cost of supplemental reserves fell by 58%. In contrast, the total cost of regulating reserves increased by 9%.

Table 33 provides the average received prices for active operating reserves in Q4 and Q4 2024. The average pool price fell by $8.50/MWh year-over-year but the received prices for spinning and supplemental reserves fell by $12.04/MW and $15.14/MW, respectively. The larger price fall in the spinning and supplemental markets occurred because of lower equilibrium prices in the day-ahead auctions. Increased competition in these auctions has put downward pressure on equilibrium prices.

For regulating reserves, the received price increased by $7.01/MW year-over-year despite the lower pool prices. This increase occurred because of higher equilibrium prices in the day-ahead auctions. The higher prices in these auctions were largely the result of less competition; the markets for regulating reserves were more concentrated in Q4 compared to Q4 2024.

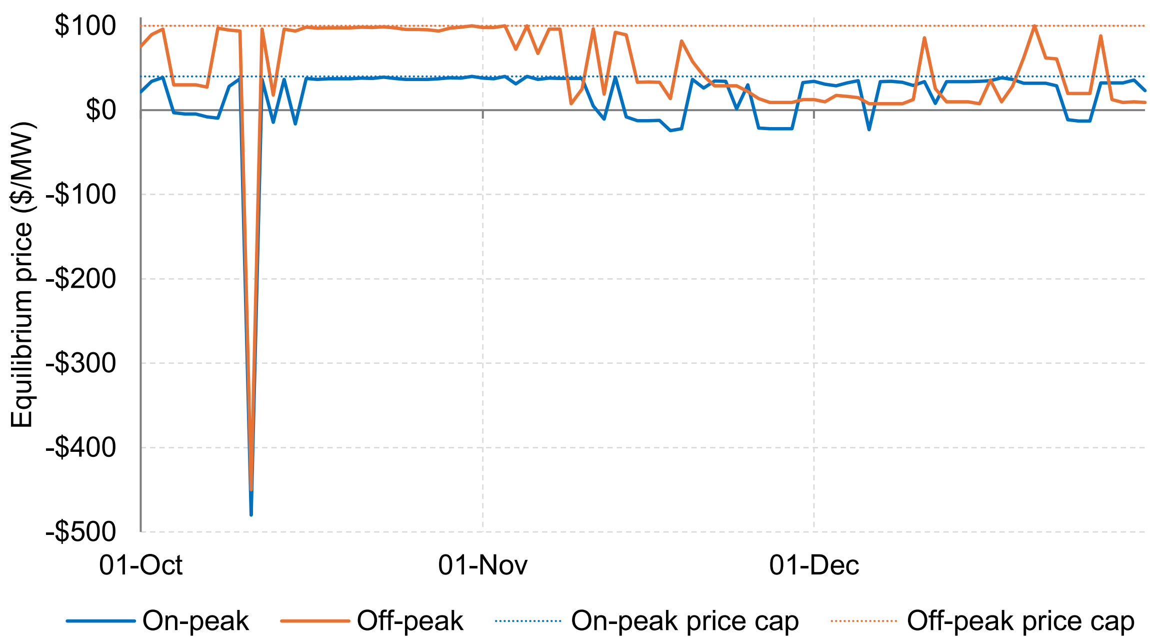
Table 33: Received prices for active operating reserves (Q4 and Q4 2024)

	Q4 2024	Q4 2025	Difference
Reg	$67.67	$74.68	$7.01
Spin	$34.33	$22.28	-$12.04
Supp	$25.77	$10.63	-$15.14
Pool price	$51.52	$43.03	-$8.50

3.3 Active reserves

Figure 64 illustrates the evolution of equilibrium prices for on-peak and off-peak regulating reserves over the quarter. On October 11, the prices for on-peak and off-peak regulating reserves were notably low at negative $479.99/MW and negative $449.99/MW, respectively.

Figure 64: Equilibrium prices for on-peak and off-peak regulating reserves (Q4)



These outliers were caused by the participation of the Cascade 2 asset. More specifically, Kineticor offered 25 MW from Cascade 2 into the on-peak and off-peak markets for October 11 (Table 34 provides the offers for the on-peak). This additional volume was enough to significantly lower equilibrium prices. The AESO procures 210 MW of regulating reserves for the on-peak, so the market cleared on the 44 MW block offered at negative $479.99/MW by ENMAX.

Table 34: Offers for on-peak regulating reserves (for October 11, 2025)

Asset ID	Fuel type	Offer price ($/MW)	Offer volume (MW)	Cumulative offer volume (MW)	Company
BIG	Hydro	-$730.00	80	80	TransAlta
BRA	Hydro	-$730.00	5	85	TransAlta
KH2	Gas	-$730.00	40	125	TransAlta
BR4	Gas	-$730.00	30	155	TransAlta
CAS2	Gas	-$479.99	25	180	Kineticor
CAL1	**Gas**	**-$479.99**	**44**	**224**	**ENMAX**
ALS1	Gas	-$22.50	10	234	Air Liquide
CAL1	Gas	$36.60	1	235	ENMAX
KH2	Gas	$37.92	1	236	TransAlta
CAL1	Gas	$39.56	4	240	ENMAX
CAL1	Gas	$39.99	5	245	ENMAX

From mid to late October, the equilibrium prices for on-peak and off-peak regulating reserves were high, often clearing close the caps (Figure 64). The high prices during this period were caused by reduced competition for dispatch as the Northern Prairie Power Project (NPP1) and Raymond Reservoir (RYMD) assets rarely offered into the auctions.

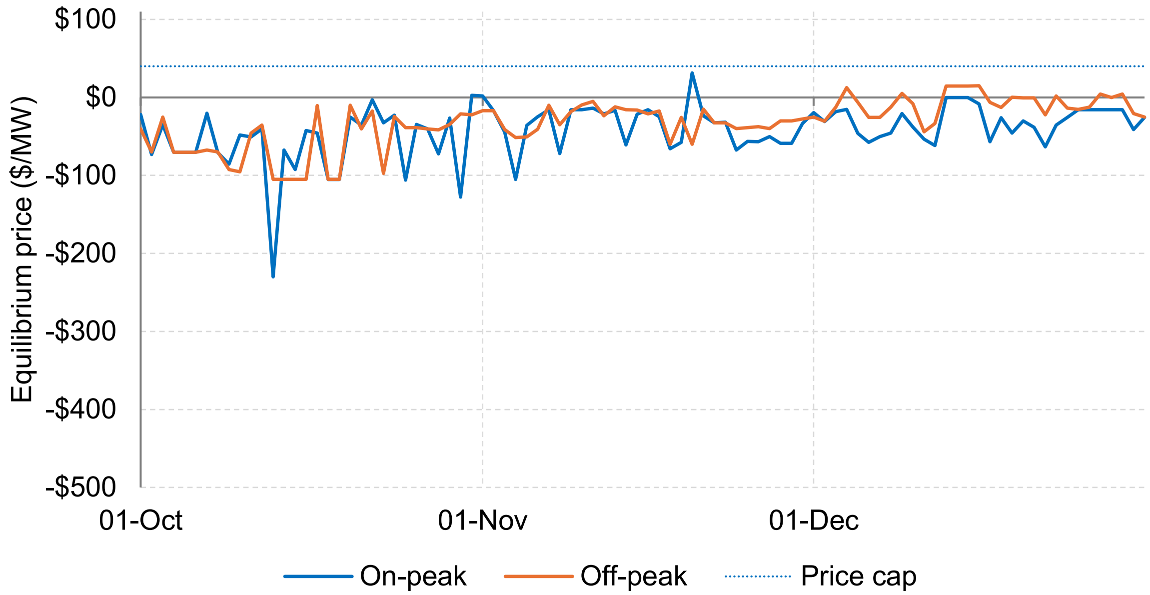
Beginning in early November and for the duration of the quarter, these assets participated more often in the auctions for on-peak and off-peak regulating reserves. This increased competition and lowered equilibrium prices (Figure 64).

The equilibrium prices for spinning reserves over Q4 are illustrated by Figure 65. On October 13, the price of on-peak spinning reserves cleared at negative $230/MW. This lower price was caused by a low AESO procurement volume and reduced offer prices at the margin.

There were also some high equilibrium prices for spinning reserves over the quarter. For example, the equilibrium price for November 20 was $31.45/MW. It is unusual to see equilibrium prices for spinning reserves clear above $0/MW because this means they are paid a premium to energy. The outlier on November 20 was caused by reduced offer volumes from TransAlta. TransAlta only offered 10 MW into the market compared with 145 MW the day before.

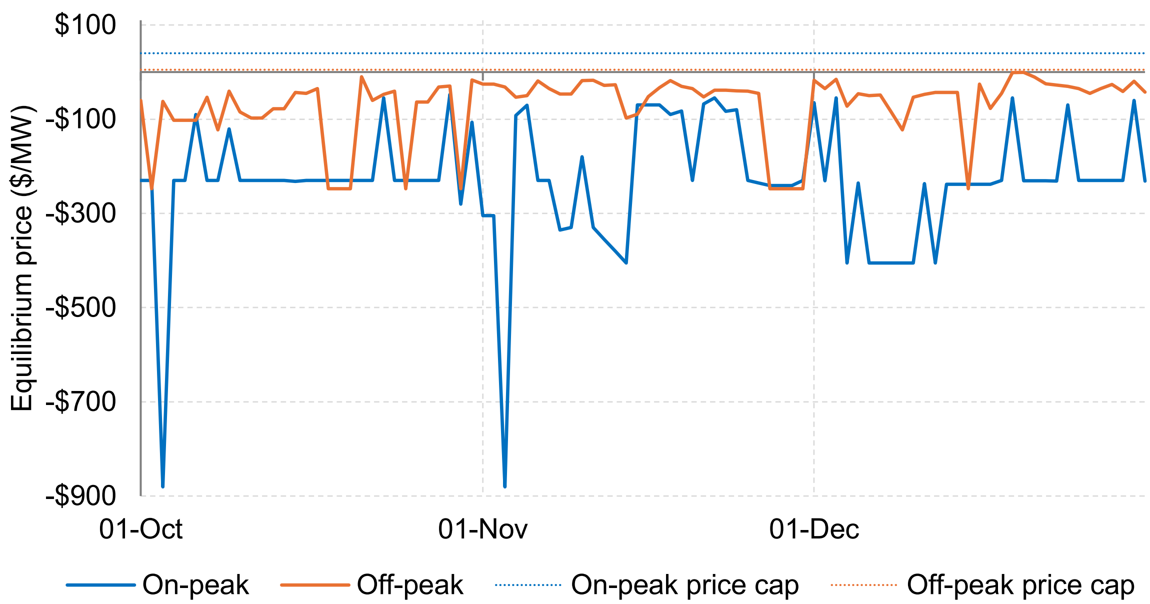
There were also some positive outliers in December with equilibrium prices for off-peak spinning reserves clearing above $0/MW on ten days. These events were caused by suppliers offering less capacity than normal into the auctions. For example, from December 13 to 16 the equilibrium price for off-peak spinning reserves cleared at $15/MW as Enfinite only offered 20 MW at negative $970/MW, 40 MW less than normal.

Figure 65: Equilibrium prices for on-peak and off-peak spinning reserves (Q4)



The markets for supplemental reserves continued to be competitive in Q4 with loads, batteries, and hydro offering at low prices. Consequently, the equilibrium prices for supplemental reserves were frequently low (Figure 66). The on-peak market was particularly competitive because Voltus offered more load capacity into the on-peak market.

Figure 66: Equilibrium prices for on-peak and off-peak supplemental reserves (Q4)



The on-peak prices for supplemental reserves for October 3 and November 3 cleared at negative $880.50/MW. This equilibrium price meant that providers would only receive revenues if the pool price rose above $880.50/MWh.

Table 35 provides the offers for dispatched assets in the on-peak supplemental market for October 3. On this day, the AESO had a target procurement volume of 241 MW. Due to the high volume of offers at low prices, the AESO's procurement volume was met at an equilibrium price of negative $880.50/MW.

Table 35: Offers of dispatched assets for on-peak supplemental reserves (for October 3, 2025)

Asset ID	Fuel type	Offer price ($/MW)	Offer volume (MW)	Cumulative offer volume (MW)	Company
MKR1	Gas	-$1,000	6	6	TransAlta
VOED	Load	-$1,000	9	15	Voltus
VOCG	Load	-$1,000	30	45	Voltus
VONW	Load	-$1,000	53	98	Voltus
ERV7	Energy storage	-$930.00	20	118	Enfinite
ERV8	Energy storage	-$930.00	20	138	Enfinite
BOW1	Hydro	-$880.50	54	192	TransAlta
BRA	**Hydro**	**-$880.50**	**70**	**262**	**TransAlta**

3.4 Standby reserves

The AESO procure standby reserves as backup to ensure enough active reserves are available. Providers of standby reserves are paid a premium for being on standby and an activation payment when they are called on to supply active reserves. Standby reserves may be activated because of an outage or constraint at an asset providing active reserves, or if more active reserves are needed than were expected day-ahead (for example if realized demand is higher than forecast).

The total cost of standby reserves was $12 million in 2025, which is 25% lower than in 2024. This year-over-year decline was due to lower average costs for premiums and activations. The lower pool prices in 2025 put downward pressure on the prices for both.

Total standby activation costs have fallen significantly in recent years because the AESO started to procure more active contingency reserves day-ahead in anticipation of high imports, instead of responding to high imports in real-time by activating standby reserves. This change reduced the overall demand for standby reserves.

In addition, the AESO adjusted the activation rates used in the selection process for standby reserves so that offers with a higher activation price would be selected less frequently. As a result of these changes, total activation costs were $4 million in 2025 compared to $41 million in 2023 (Figure 67).

Figure 67: Total costs of standby premiums and activations (2018 to 2025)

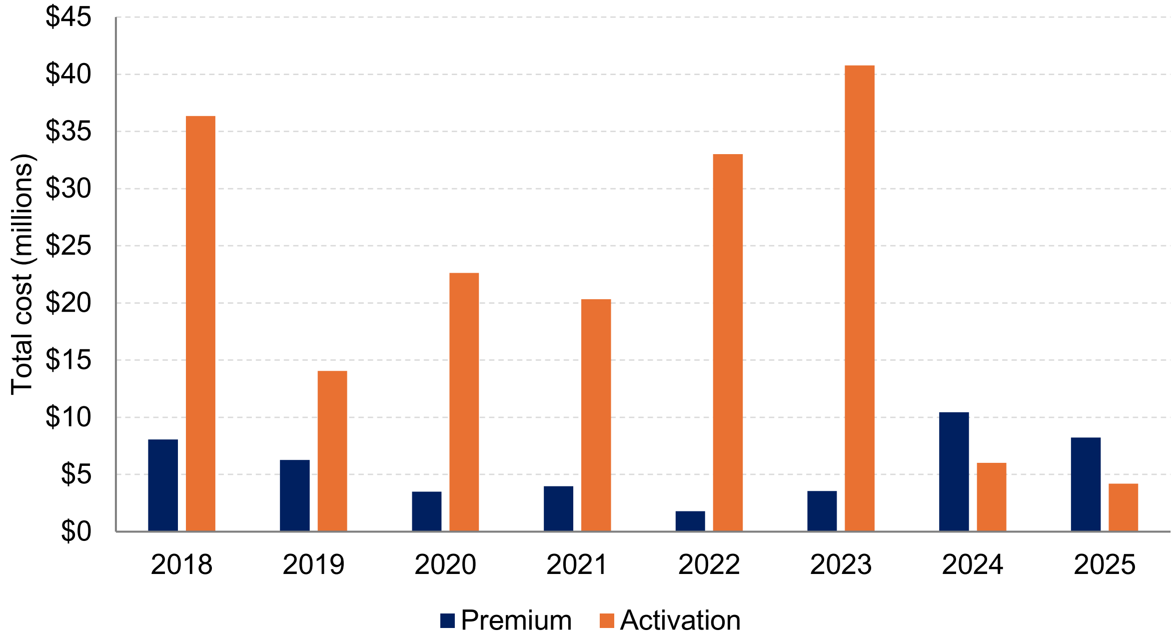


Table 36 compares activation prices with prevailing pool prices for the different operating reserve products over the last three years. For regulating reserves, there was a high premium of activation prices over prevailing pool prices in 2025. The volume-weighted average activation price for standby regulating reserves in 2025 was $76/MW which is a 200% premium compared to pool prices at the time of the activations.

In contrast, activation prices for standby supplemental reserves continued to be discounted to prevailing pool prices. In 2025, the volume-weighted average activation price was $12/MW, which is 66% lower than prevailing pool prices of $34/MWh.

Table 36: Activation prices compared with prevailing pool prices (2023 to 2025)

		2023	**2024**	**2025**
Reg	Activation price ($/MW)	$225.36	$76.95	$75.70
	Pool price ($/MWh)	$136.96	$32.15	$25.35
	Standby premium (%)	65%	139%	199%
Spin	Activation price ($/MW)	$96.24	$70.87	$35.18
	Pool price ($/MWh)	$139.53	$63.63	$36.65
	Standby premium (%)	-31%	11%	-4%
Sup	Activation price ($/MW)	$28.26	$19.55	$11.53
	Pool price ($/MWh)	$131.33	$60.23	$33.62
	Standby premium (%)	-78%	-68%	-66%

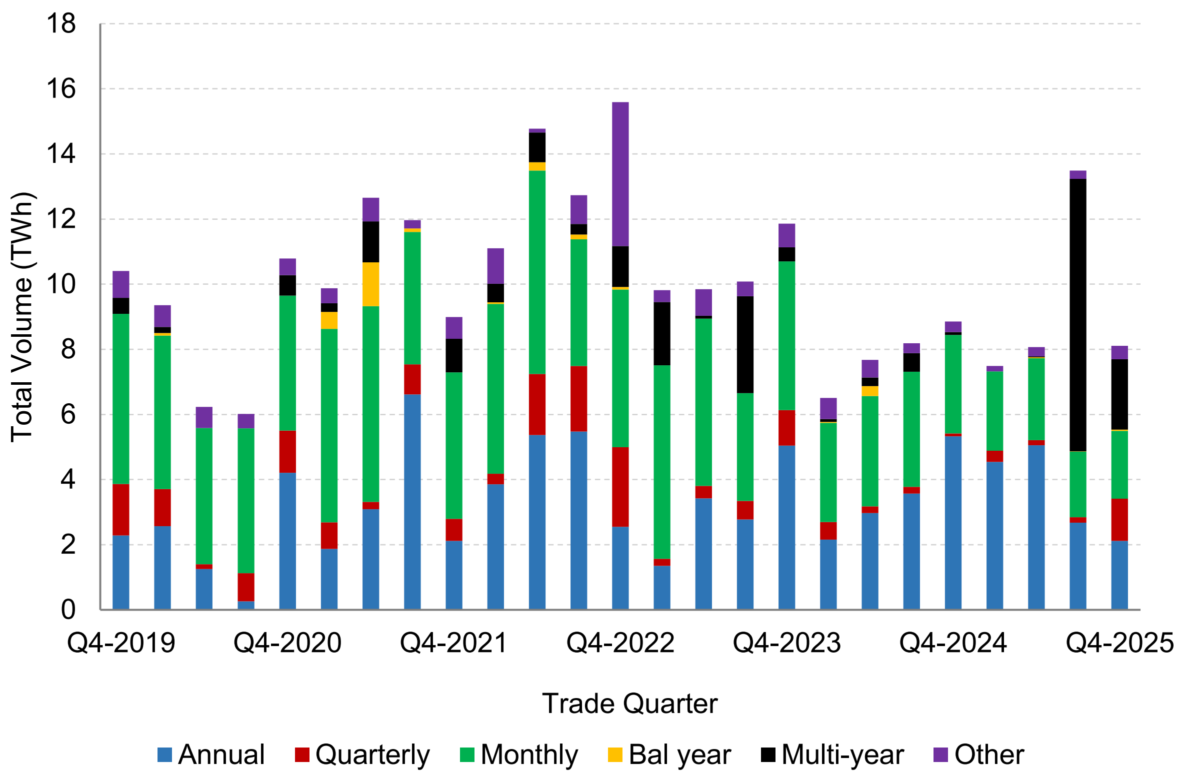
4 THE FORWARD MARKET

4.1 Forward market volumes

Low liquidity in the forward market continued in Q4 with 4.6 TWh traded on ICE NGX or through brokers, a decline of 42% from Q4 2024. Total trade volumes have been relatively low since Q1 2024. However, there were 1.2 TWh of quarterly trades in Q4, which marked the largest quarterly volume since Q4 2022.

In 2025, bilateral trades that took place directly between two parties totaled 14.8 TWh compared to 5.4 TWh in 2024. The increase in bilateral volumes was largely driven by some multi-year trades in Q3 2025. For example, on September 23, a 24 MW trade out to the end of 2044 was priced at $53.00/MWh and added 4.1 TWh of total volume.

Figure 68: Total trade volumes by term and quarter (Q4 2019 to Q4 2025, includes bilateral trades)



4.2 Trading of monthly products

Pool prices came in below forward market expectations in October and December, with pool prices settling lower than the volume-weighted average forward price and the final trade price leading into these months (Figure 69). In November, real time volatility pushed average pool prices higher than forward market expectations.

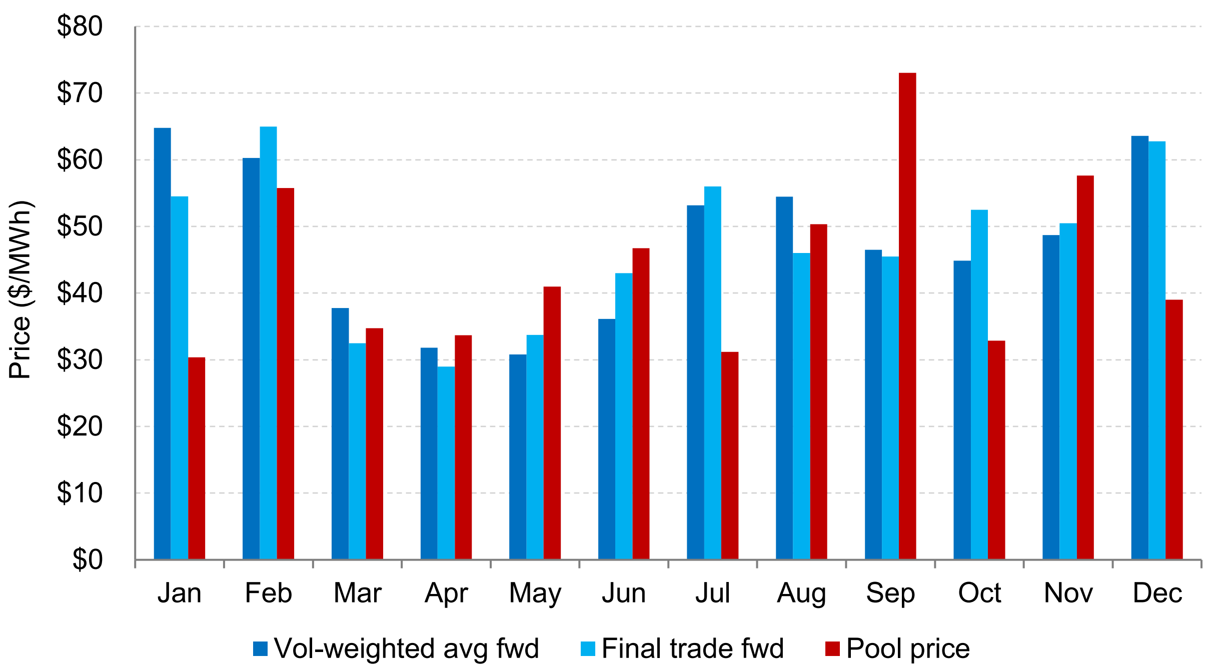
The pool price in October averaged $32.88/MWh compared to a volume-weighted average forward price of $44.85/MWh, and a final trade price of $52.50/MWh. The marked price[29] of October fell throughout the month as the energy market was characterized by low pool prices and limited volatility.

The pool price in November averaged $57.64/MWh relative to a volume-weighted average forward price of $48.69/MWh and a final trade price of $50.50/MWh. The marked price of November rose to $66/MWh as of November 17 but fell through the back half of the month as the supply of Base Plant increased.

In December, the pool price averaged $39.00/MWh compared to a volume-weighted average forward price of $63.59/MWh and a final trade price of $62.75/MWh. The marked price of December declined to $54/MWh on December 1 but recovered to $62/MWh on December 3. Subsequently, the marked price fell to $42/MWh by December 15 due to low pool prices during cold weather and high demand.

Overall, in 2025 monthly forward prices traded at a 9% premium to pool prices with a volume-weighted average forward price of $47.71/MWh. This monthly forward premium for the year was driven by outcomes in January, July, and December (Figure 69).

Figure 69: Monthly flat forward prices and realized average pool prices (January to December 2025)



[29] Marked prices combine realized pool prices and forward prices for the balance-of-month to calculate the expected average pool price for a month as of a certain date.

The evolution of monthly forward prices over the course of Q4 is shown in Figure 70. The dashed lines in the figure illustrate the marked prices for October, November, and December. In Q4, forward price changes often occurred alongside changes to the prevailing marked price, as forward prices responded to events and outcomes in the energy market. For example, the lower pool prices in December put downward pressure on the forward prices for January and February.

The December contract was the most volatile in Q4 (Figure 70). In mid-November, the price of December increased on the back of cold weather forecasts and higher forward prices in Mid-C. On November 10, December was priced at $65.75/MWh, but this increased by 18% to $77.50/MWh on November 13.

However, the price of December later declined as Base Plant moved up its commissioning dates on November 17, which also put downward pressure on the monthly contracts for Q1 2026. In late November, Base Plant increased its supply above 800 MW and the price of December fell further. Overall, the price of December closed at $62.74/MWh on November 28, a decline of 19% relative to its peak on November 13.

Figure 70: Monthly flat forward prices (September 1 to December 31, 2025)

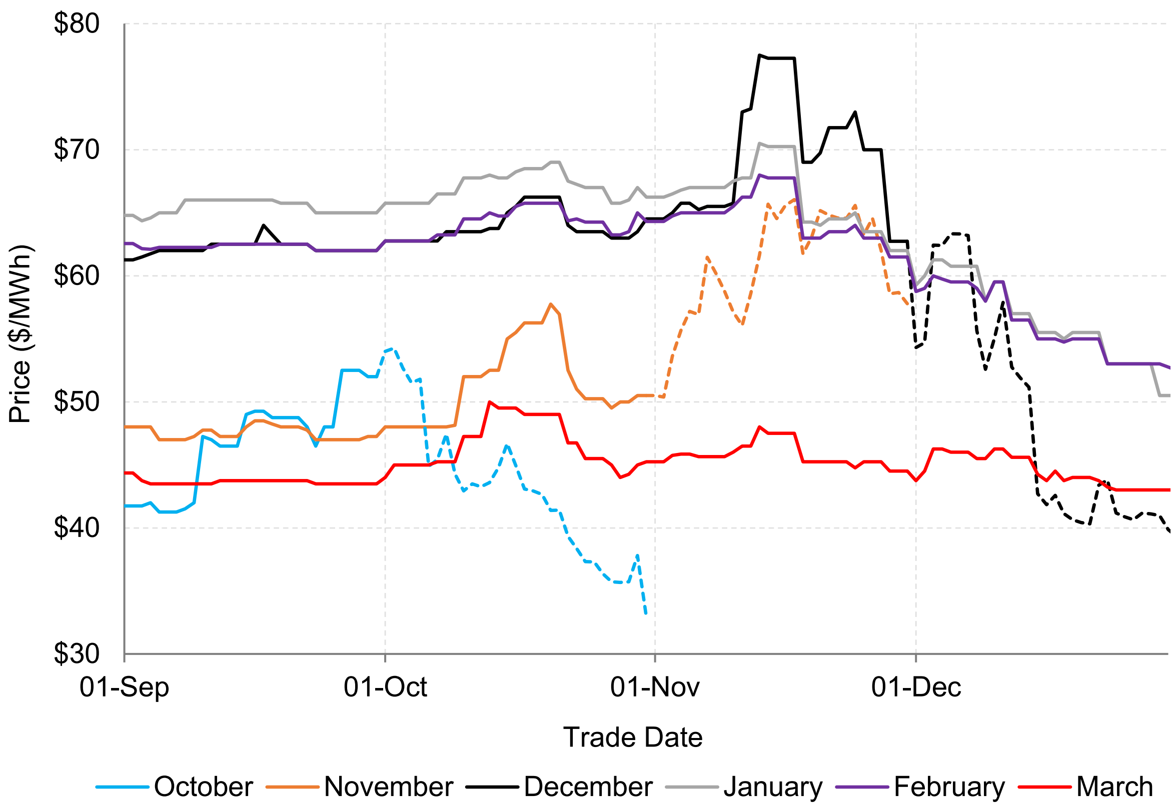
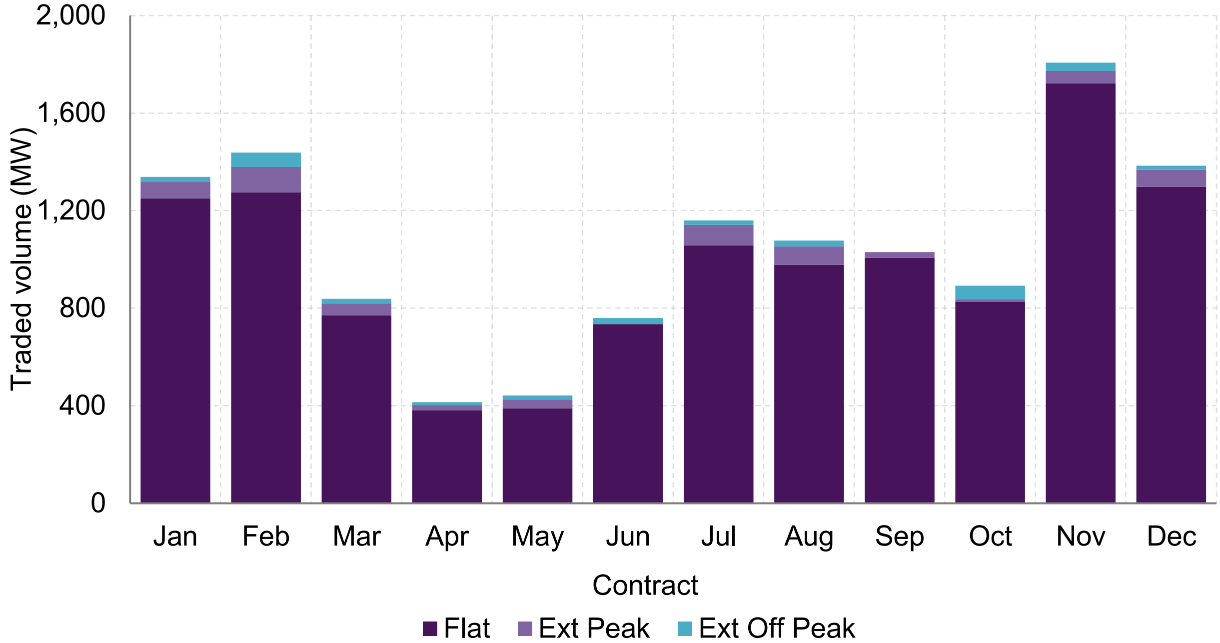


Figure 71 shows the distribution of traded volumes for the monthly contracts in 2025. As shown, traded volumes were higher for the winter months with November the most actively traded followed by January, December, and February. Traded volumes for the November contract were above other contracts with 1,720 MW of the flat trading compared to 1,300 MW for December.

Figure 71: Traded volume for monthly contracts in 2025[30]



4.3 Trading of annual products

As with 2024, pool prices in 2025 came in below forward market expectations (Figure 72). Cal 25 traded for a volume-weighted average price of $63.00/MWh, which is a 44% premium to the average pool price. The final trade price for the year was lower at $49.50/MWh but was still a 13% premium to the pool price.

Figure 73 shows the evolution of annual forward prices since July 1, 2025. Annual price changes were variable over Q4 with Cal 26 remaining flat and Cal 27 and Cal 28 both declining by 5%. The marked price for Cal 25 declined by 6% over the quarter to $43.68/MWh as pool prices for October and December came in below forward market expectations.

The price of Cal 26 was flat over the quarter despite lower-than-expected pool prices, a 12% decrease in the forward price of natural gas, and a 26% decline in the forward power price for Mid-C.

However, the prices for Cal 27 and Cal 28 did respond to these changes; both declined by 5% over the quarter. Natural gas prices for Cal 27 declined by 8% over Q4 and natural gas prices for Cal 28 declined by 6%. In addition, forward power prices in Mid-C fell by 12% for Cal 27 and 9% for Cal 28, indicating Alberta will receive more imports.

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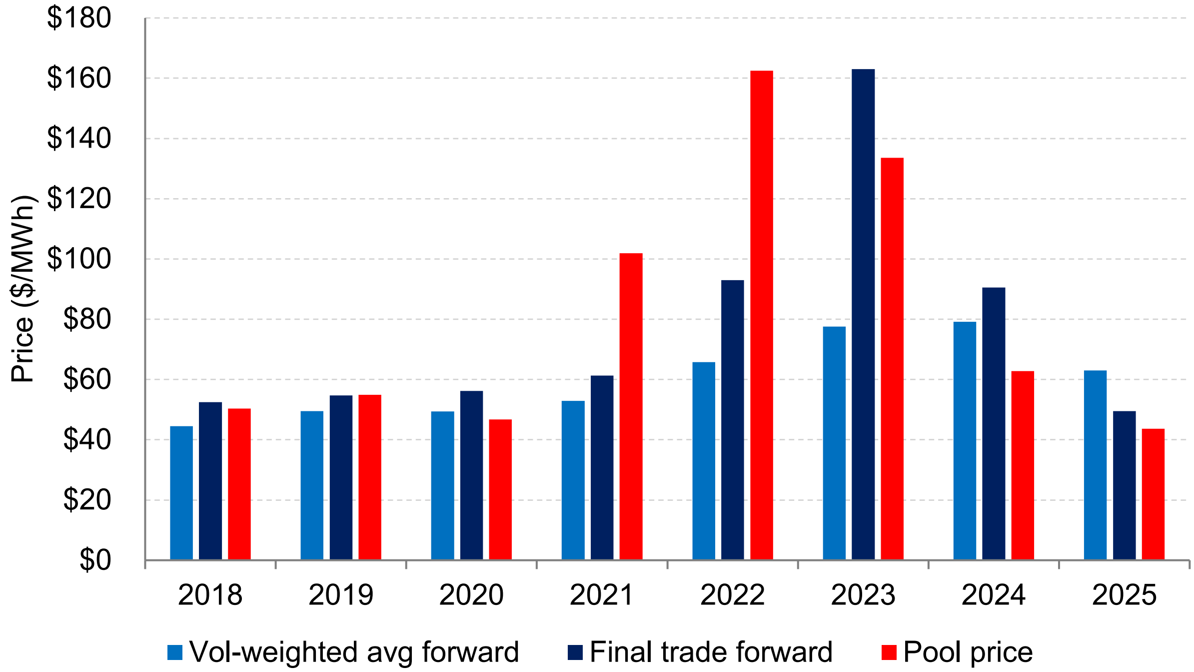
[30] Extended peak and extended off-peak volumes weighted accordingly.

Figure 72: Annual flat forward prices and realized average pool prices (2018 to 2025)



In early October, the price of Cal 28 increased by 5% to $82.00/MWh partly on the back of data centre interest. On October 6, there was an update regarding the Greenlight Energy Centre.[31] This project is set to combine large data centre load with around 1,800 MW of combined cycle capacity. The update provided that the partners had secured allocation for the data centre project under the AESO's large load allocation phase 1, and that they had entered a demand transmission service (DTS) agreement with the AESO to start as early as 2027.

On November 27, 2025, a Memorandum of Understanding between the Government of Canada and the Government of Alberta was announced. This agreement committed to suspend the application of the *Clean Electricity Regulation* to Alberta and committed to a minimum effective carbon price of $130/tCO2e. This new agreement is to be negotiated on or before April 1, 2026.[32] There were no major price movements in the forward market on the days following this announcement.

On December 18, 2025, TransAlta provided notice to the AESO that Sheerness 1 would be temporarily mothballed effective April 1, 2026 for a period of up to two years.[33] In response to this announcement, the forward prices of annual contracts increased by around 3% the following day.

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[31] Pembina Pipeline provides update on Greenlight Electricity Centre (October 6, 2025)

[32] Canada-Alberta Memorandum of Understanding (November 27, 2025)

[33] TransAlta provides notice to mothball Sheerness unit 1 (December 18, 2025)

Figure 73: Annual flat forward prices (July 1 to December 31, 2025)

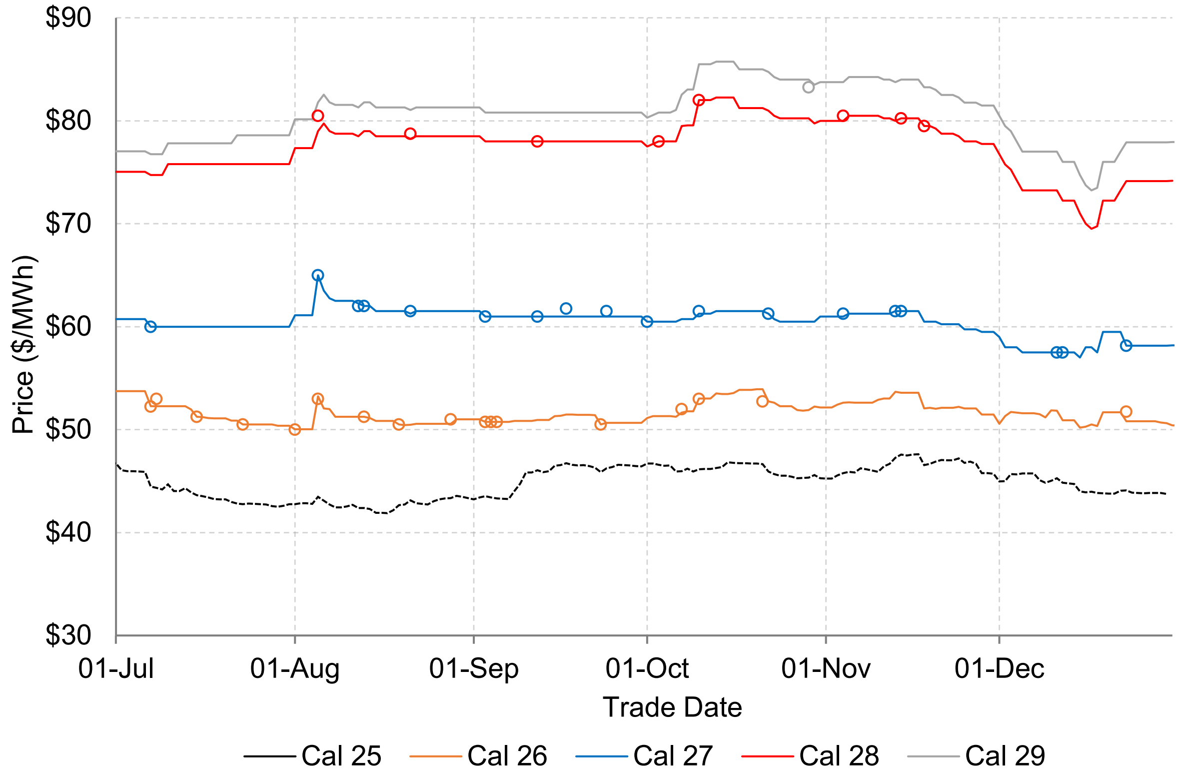

Table 37: Annual power and natural gas price changes over Q4

Contract	Power price ($/MWh)			Gas price ($/GJ)			Spark spread[34] ($/MWh)		
	Sep 30	**Dec 31**	**Chng**	**Sep 30**	**Dec 31**	**Chng**	**Sep 30**	**Dec 31**	**Chng**
Cal 25 marked	$46.44	$43.68	-6%	$1.56	$1.61	3%	$34.75	$31.61	-9%
Cal 26	$50.65	$50.42	0%	$2.84	$2.51	-12%	$29.35	$31.58	8%
Cal 27	$61.00	$58.19	-5%	$3.07	$2.82	-8%	$37.95	$37.05	-2%
Cal 28	$78.00	$74.19	-5%	$2.99	$2.80	-6%	$55.59	$53.21	-4%
Cal 29	$80.80	$77.94	-4%	$2.94	$2.74	-7%	$58.75	$57.36	-2%

[34] Spark spreads assume a heat rate of 7.5 GJ/MWh.