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# Wholesale Market Report: Q1 2026

May 7, 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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## **THE QUARTER AT A GLANCE**

### **Mild weather and increased supply drive low prices in Q1**

The average pool price in Q1 was \$32.15/MWh, which is 19% lower than Q1 last year and 25% lower than the prior quarter. The low prices in Q1 were partly caused by mild weather in January and February, which lowered demand and increased wind and solar (intermittent) generation. In addition, lower natural gas prices and reduced exports year-over-year put further downward pressure on prices in February, which averaged \$22.39/MWh. Adjusting for inflation, this is the lowest average price for February on record. Increased capacity at the Base Plant generation asset was also a factor in the lower prices year-over-year; in Q1 the average availability of Base Plant was 780 MW compared with 530 MW in Q1 2025.

### **Natural gas restrictions put upward pressure on pool prices during March events**

There were two events in March where outages on the natural gas network reduced the supply of natural gas to thermal generation assets, both in the Fort McMurray area. From March 7 to 11, the supply of interruptible gas was lowered from 100% to 0%, and the supply of firm gas was lowered from 100% to 42%. As a result, thermal generators in the area had to lower their availability. This combined with other forced thermal generator outages and low intermittent supply during the evening peaks on March 8 and 9 to put upward pressure on pool prices.

Similarly, on March 26, the supply of natural gas in some areas around Fort McMurray was reduced to 0% for interruptible and 72% for firm, lowering the availability of affected thermal generators. This reduction in supply combined with planned thermal generator outages and low intermittent supply during the evening peak and led to a pool price of \$949/MWh in hour ending (HE) 21, the highest in the quarter.

### **Wind outages and a gas generator trip cause low supply cushion on March 25**

On March 25, icing at several wind assets unexpectedly lowered supply. Twenty-four hours ahead, the AESO's forecast for wind generation in HE 12 was 2,650 MW, but actual wind generation in the hour was lower at 1,300 MW. As a result, the AESO did not commit any of the gas-fired steam assets that were commercially offline on long lead time for this event. In addition, at 09:24, the Cascade 1 generation asset tripped offline, reducing available capacity by 466 MW and adding to planned outages at Genesee Repower 1 and Joffre. Consequently, the available capacity left in the supply curve fell to 160 MW during HE 12, the lowest in the quarter.

### **High prices on January 5 due to a Shepard outage and low intermittent generation**

The daily average pool price in Q1 was highest on January 5 at \$363/MWh. The higher prices on this day were caused by a forced outage at the Shepard generation asset, which lowered available capacity by 810 MW. The unexpected nature of the outage at Shepard did not provide the AESO or market participants with enough notice to commit gas-fired steam assets that were commercially offline on long-lead time. In addition, intermittent generation on January 5 was relatively low and below the AESO's forecasts.

### **Alberta provides emergency power to BC during system event on March 8**

Just before 01:00 MST on March 8, there was a major event on the power system in BC which resulted in the generation stations at GM Shrum, Peace Canyon, and Site C becoming separated from the rest of the BC power grid. As a result, the BC grid lost around 2,600 MW of generation and approximately 900 MW of load was shed in BC. In response, exports from Alberta to BC increased automatically and instantaneously, and system frequency in Alberta fell to 59.84 Hz. The AESO subsequently provided emergency energy to BC in response to a request from the Western Power Pool, supplying 425 MW for around 18 minutes.

### **The MSA estimates counterfactual pseudo locational marginal prices from 2021 to 2025**

In recent years, the increase in wind and solar capacity in the south of the province has led to more transmission congestion. As part of the Restructured Energy Market (REM), the AESO will be implementing locational marginal prices (LMP) in the future, allowing prices to vary across Alberta. The MSA's analysis in this report illustrates that LMP in 2025 would have led to lower prices for congested intermittent assets in the southeast, but that prices would have been higher for most assets.

### **Net revenue analysis indicates that the energy market was unprofitable in Q1**

Net revenue analysis estimates the profitability of hypothetical generation assets using pool prices, natural gas prices, carbon prices, and assumed cost parameters. The MSA's net revenue analysis for Q1 indicates that the hypothetical combined cycle, simple cycle, wind, and solar assets were all unprofitable over the quarter due to the low pool prices.

### **Transmission constraint volumes increase year-over-year**

The total volume of constrained intermittent generation reached 561 GWh in Q1, a 250% increase from Q1 last year. At least 1 MWh of intermittent generation was constrained in 58% of hours in the quarter. The constrained and unconstrained SMP differed by \$1/MWh or more in 41% of minutes in the quarter.

### **Battery assets increase competition in off-peak regulating reserves**

Historically, regulating reserves in Alberta have been provided by hydro and thermal assets. However, in recent quarters, batteries have also supplied the product, mostly in the off-peak. Supplying regulating reserves in the off-peak can mean providing energy for eight consecutive hours (from HE 24 one day to HE 07 the next). Therefore, a 20 MWh battery can provide 5 MW of regulating reserves, assuming it supplies 2.5 MWh of energy per hour. Despite relatively small volumes, the participation of batteries has lowered off-peak prices for regulating reserves.

### **Forward prices declined significantly over the quarter**

Pool prices in Q1 came in below forward market expectations. The low pool prices combined with falling natural gas prices and declining power prices in Mid-Columbia to put downward pressure on monthly forward prices. For example, the price of May fell by 28% over the quarter and the price of June fell by 24%. The same factors caused sell-side pressure for annual contracts, which declined significantly. The price of Calendar 2027 (Cal 27) fell by 18% over the quarter to \$47.88/MWh, Cal 28 fell by 20% to \$59.07/MWh, and Cal 29 fell by 18% to \$63.62/MWh.

# 1 THE POWER POOL

## 1.1 Quarterly summary

The average pool price in Q1 was \$32.15/MWh, which is 19% lower than Q1 last year and 25% lower than the prior quarter. The lower prices year-over-year were largely driven by lower prices in February, which averaged \$22.39/MWh, 60% less than in February 2025 (Table 1).

The lower prices in February this year were the result of higher intermittent generation, reduced demand, lower natural gas prices, and less exports.

*Table 1: Summary market statistics for Q1 2025 and 2026*

The average pool price in January was \$39.44/MWh which is 30% higher year-over-year, driven by higher natural gas prices, more thermal outages, and slightly higher demand.

The average pool price in March was \$33.68/MWh, which is comparable to March last year, with higher demand and more thermal outages offset by increased wind generation, lower natural gas prices, and less exports.

Prevailing weather conditions were an important factor in the low prices in Q1. Alberta did not have a major cold period in either January or February this year, which resulted in less demand, higher intermittent generation, and lower natural gas prices.

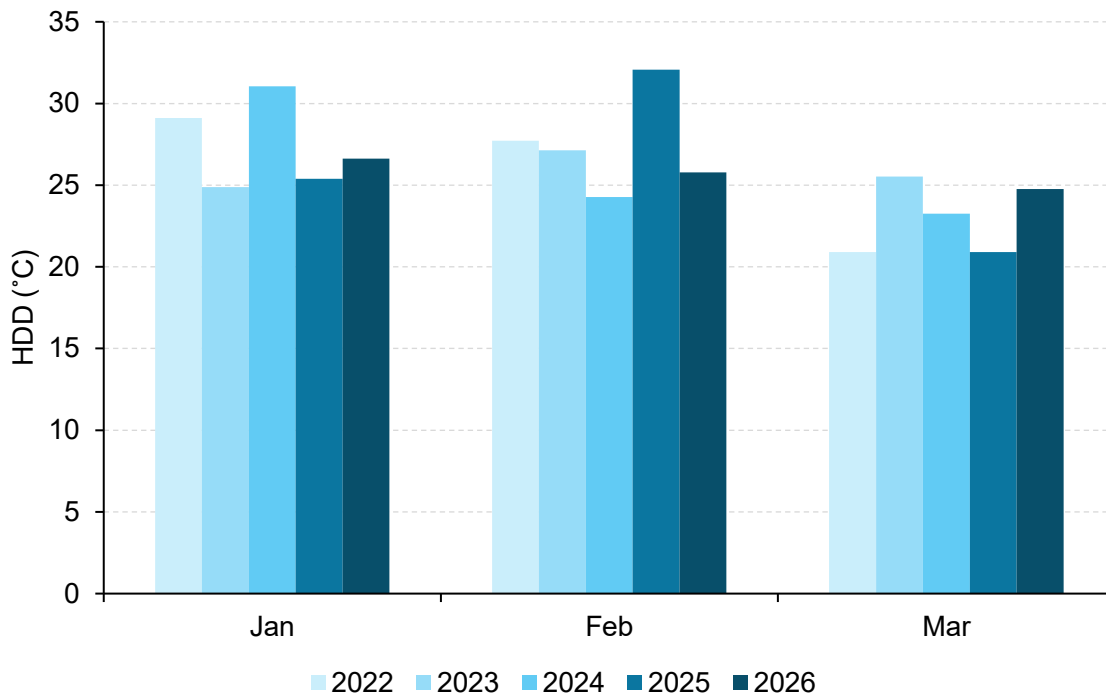
Heating degree days (HDD) measure how much lower temperatures were relative to a base, commonly 18°C, and are used to indicate heating demand. In this report, HDD is

		2025	2026	Change
Pool price (Avg \$/MWh)	Jan	\$30.36	\$39.44	30%
	Feb	\$55.77	\$22.39	-60%
	Mar	\$34.76	\$33.68	-3%
	<b>Q1</b>	<b>\$39.78</b>	<b>\$32.15</b>	<b>-19%</b>
Demand (AIL) (Avg MW)	Jan	10,949	11,126	1.6%
	Feb	11,111	10,954	-1.4%
	Mar	10,431	10,865	4.2%
	<b>Q1</b>	<b>10,824</b>	<b>10,983</b>	<b>1.5%</b>
Gas price AB-NIT (2A) (Avg \$/GJ)	Jan	\$1.74	\$2.30	32%
	Feb	\$2.18	\$1.71	-22%
	Mar	\$2.17	\$1.77	-19%
	<b>Q1</b>	<b>\$2.03</b>	<b>\$1.93</b>	<b>-5%</b>
Available thermal capacity (Avg MW)	Jan	11,668	11,464	-2%
	Feb	11,699	11,312	-3%
	Mar	11,346	10,833	-5%
	<b>Q1</b>	<b>11,568</b>	<b>11,201</b>	<b>-3%</b>
Wind gen. (Avg MW)	Jan	2,150	2,217	3%
	Feb	1,635	2,162	32%
	Mar	1,470	1,909	30%
	<b>Q1</b>	<b>1,754</b>	<b>2,095</b>	<b>19%</b>
Solar gen. (Avg MW during peak hours)	Jan	214	234	9%
	Feb	359	449	25%
	Mar	525	566	8%
	<b>Q1</b>	<b>366</b>	<b>416</b>	<b>14%</b>
Net exports (+) Net imports (-) (Avg MW)	Jan	595	266	-55%
	Feb	456	298	-35%
	Mar	331	-23	-107%
	<b>Q1</b>	<b>461</b>	<b>178</b>	<b>-61%</b>

calculated as the positive difference between 18°C and the average temperature across Calgary, Edmonton, and Fort McMurray.<sup>1</sup>

Figure 1 shows monthly average HDD for January, February, and March over the past five years. In 2024, HDD increased in January and in 2025 HDD increased in February, both reflecting a period of cold weather in these months. However, this year, HDD did not increase notably in either January or February.

Figure 1: Monthly average heating degree days (January, February, and March of 2022 to 2026)



That said, underlying demand in Alberta has increased over time. Figure 2 illustrates that for comparable heating demand levels, Alberta Internal Load (AIL) this quarter was consistently higher than in Q1 of prior years, indicating an increase in underlying demand due to higher oilsands production and population growth.

The mild weather in Q1 increased intermittent generation in Alberta. Intermittent generation hit a record high on March 7 with an average of 5,054 MW in HE 14, beating the prior record of 4,782 MW set in HE 15 of April 25, 2025. In addition, January set a record for monthly average wind generation at 2,217 MW, beating the prior record of 2,172 MW set in December 2023. Figure 3 shows duration curves of hourly wind generation year-over-year. The curves illustrate how often wind generation was above a given level. At the 50% percentile, wind generation in Q1 was 440 MW higher than in Q1 2025.

<sup>1</sup> In hours where the average temperature was above 18°C the HDD is set to 0.

Figure 2: Average AIL by HDD bin (Q1 of 2024 to 2026)<sup>2</sup>

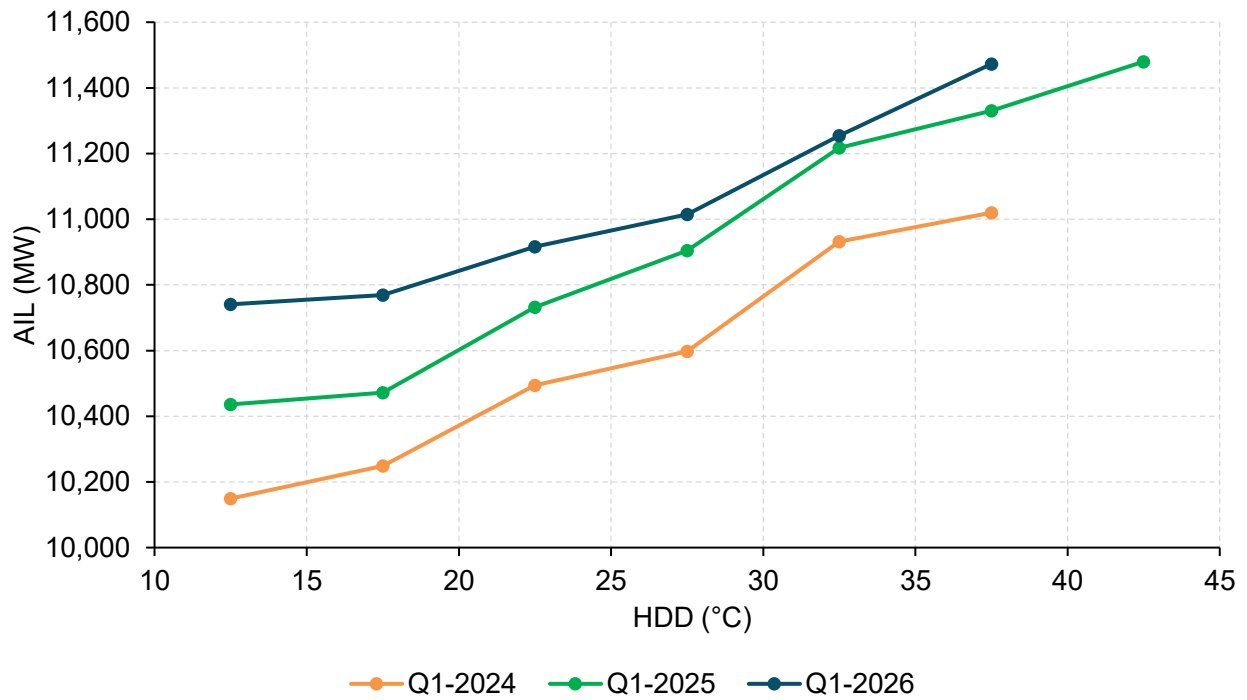
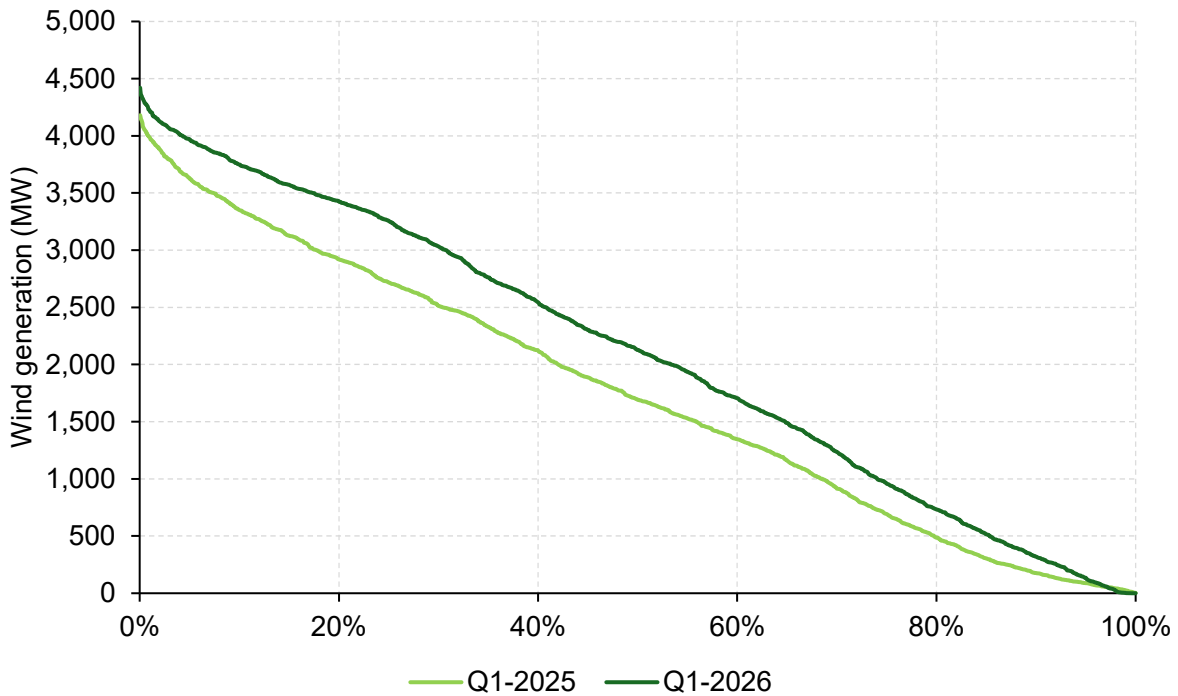


Figure 3: Wind generation duration curve (Q1 2025 and Q1)

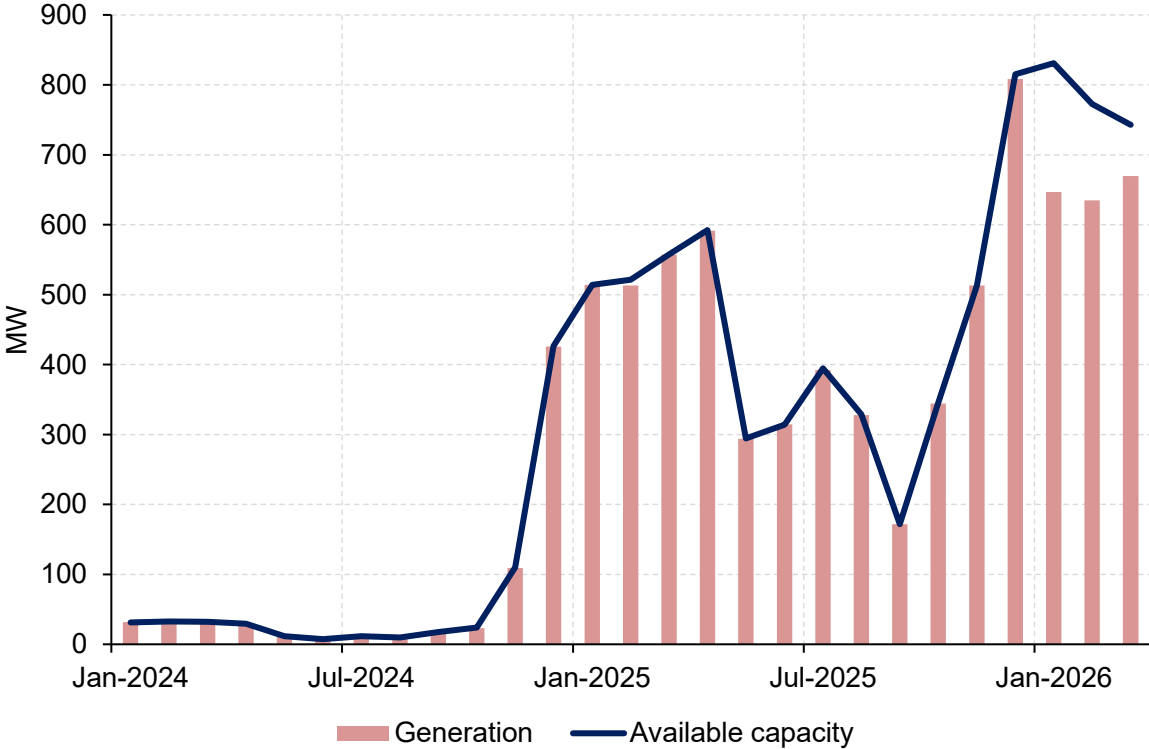


<sup>2</sup> HDD bins are five degrees wide, with each dot representing the bin midpoint. Bins with fewer than five observations are excluded.

Increased supply from Suncor’s Base Plant asset was also a factor in the low pool prices in Q1. Beginning in late 2024, generation at the asset increased as Suncor converted its steam process from coke-fired boilers to cogeneration units, which provide both steam and electricity. This conversion has lowered carbon emissions from the site.

Due to the high steam demands of the oilsands operation, the cogeneration units provide more electricity than the site needs and the excess is exported to the Alberta grid. The cogeneration units were fully commissioned in late 2025 and the asset generated around 800 MW in December 2025 (Figure 4). In Q1, available capacity at Base Plant averaged 780 MW compared to 530 MW in Q1 2025 and 30 MW in Q1 2024.

*Figure 4: Average available capacity and generation at SCR1 by month (January 2024 to March 2026)*



The increase in must-run thermal generation and intermittent supply has led to a rise in the amount of generation offered into the market at \$0/MWh, the price floor. Consequently, the SMP has been set at \$0/MWh more often in recent years, indicating an increasing value for negative pricing to efficiently order dispatch during these periods.

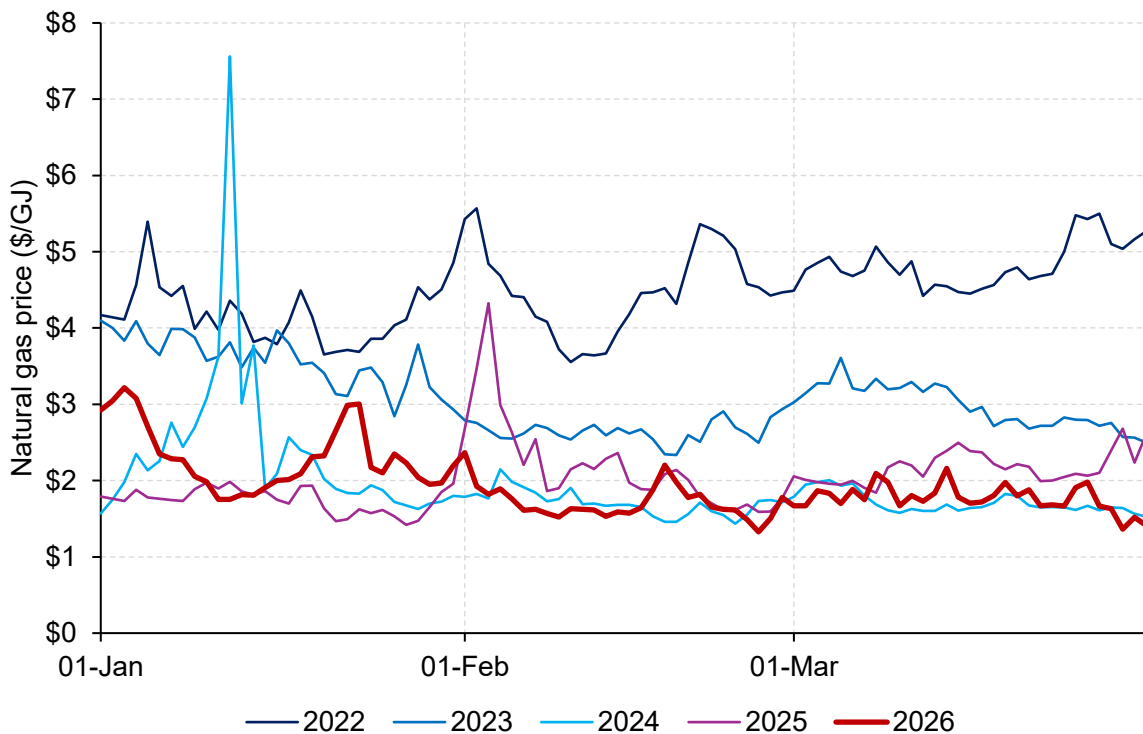
In Q1, the SMP was \$0/MWh 14% of the time, up from 9% in Q1 2025 and 0% in Q1 2024 (Table 2). Year-over-year, the increase in the percent of time the SMP was \$0/MWh was driven by a higher percentage in March. However, the monthly record for the percent of minutes the SMP was \$0/MWh still stands at 21.9% set in October 2025, closely followed by 21.5% in September 2024.

Table 2: Percent of time the SMP was \$0/MWh (Q1 of 2024, 2025, and 2026)

	2024	2025	2026
January	0%	14%	14%
February	0%	12%	12%
March	1%	1%	17%
<b>Q1</b>	<b>0%</b>	<b>9%</b>	<b>14%</b>

Natural gas is the main input cost for Alberta power with gas assets setting the SMP 83% of the time in the quarter. Natural gas prices in Q1 were low and relatively stable, reflecting mild weather and high production levels (Figure 5). In February and March, prices were around 20% lower year-over-year, averaging \$1.71/GJ and \$1.77/GJ, respectively.

Figure 5: Same-day natural gas prices at AB-NIT (Q1 of 2022 to 2026)



## 1.2 Market outcomes and events

The average pool price in Q1 was \$32.15/MWh, 19% lower than in Q1 last year. This decline in average prices reflected lower prices across the distribution. For example, the top 10% of hours averaged \$155/MWh in Q1 compared to \$164/MWh in Q1 2025, and the lowest 50% of hours averaged \$8/MWh in Q1 compared to \$15/MWh in Q1 2025 (Table 3).

As outlined above, the fundamentals driving the lower pool prices in Q1 this year were mild weather, increased intermittent generation, low natural gas prices, and more supply from Base Plant.

*Table 3: The distribution of pool prices (Q1, Q4 2025, and Q1 2026)*

Percentile	Q1 2025 (Avg. \$39.78)		Q1 2026 (Avg. \$32.15)	
	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.
Top 10%	\$164	41%	\$155	48%
10 to 50%	\$40	40%	\$31	39%
Bottom 50%	\$15	19%	\$8	13%

Table 4 shows the distribution of pool prices for the months in Q1. In January and March, the top 10% of hours accounted for around 50% of the average pool price, and it is typical to see a small number of hours account for a relatively high percentage of the average. However, pool price volatility was subdued in February with the top 10% of hours averaging only \$80/MWh and accounting for 37% of the average pool price.

*Table 4: The distribution of pool prices by month (January to March)*

Percentile	January (Avg. \$39.44)		February (Avg. \$22.39)		March (Avg. \$33.68)	
	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.
Top 10%	\$202	52%	\$80	37%	\$165	49%
10 to 50%	\$37	38%	\$24	44%	\$32	38%
Bottom 50%	\$9	11%	\$9	19%	\$8	13%

### **1.2.1 High prices and Shepard outage – January 5**

On January 5, a forced outage at the Shepard Energy Centre combined with low intermittent generation to put upward pressure on prices. As a result, the daily average pool price settled at \$363/MWh, the highest in the quarter (Figure 6).

The Shepard asset tripped offline at around 04:40 on January 5 because of a primary controller switch issue. Prior to the trip, Shepard had been generating 580 MW (Figure 7). The trip occurred in stages as Shepard is comprised of two gas turbines and one steam turbine.

As a result of the Shepard trip, Area Control Error fell to minus 424 MW as Alberta relied on the instantaneous response of the Western Interconnection to maintain supply and demand balance and prevent frequency from declining. On the BC intertie, Alberta was exporting 313 MW less than scheduled because of the Shepard trip (Table 5).

Figure 6: Daily average pool price (Q1 2026)

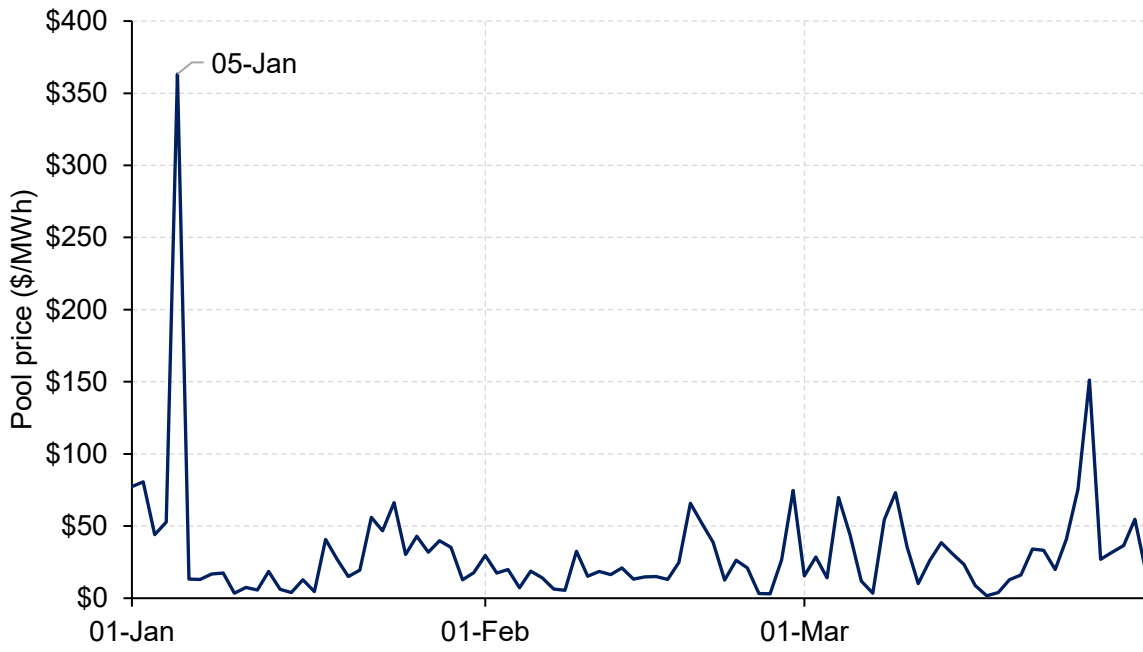
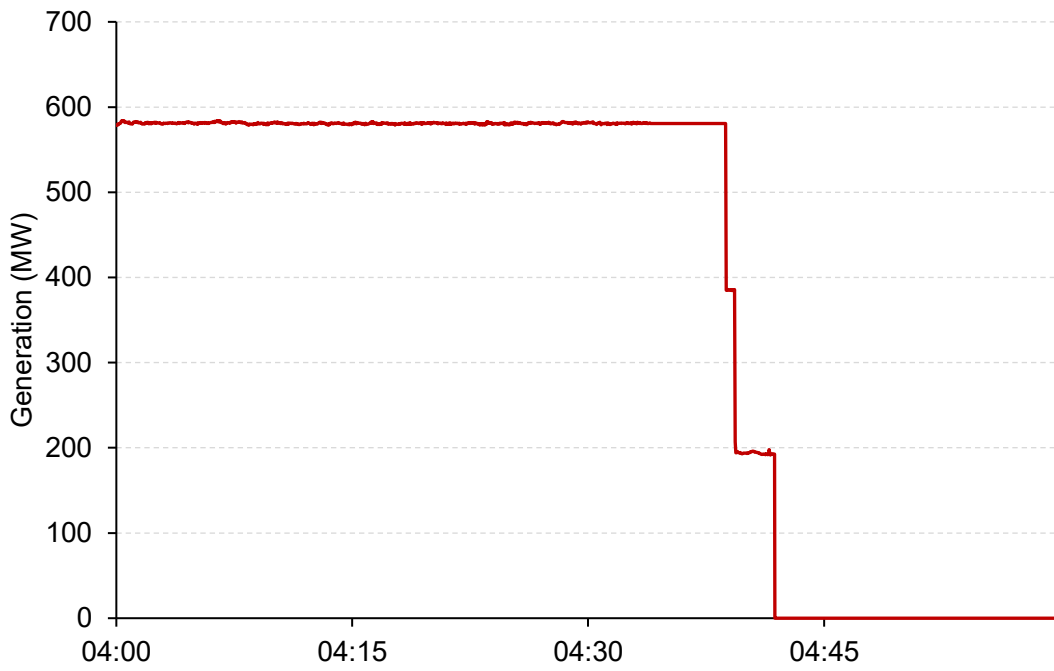


Figure 7: Gross generation at Shepard (January 5)



*Table 5: Actual and scheduled net exports during the Shepard trip*

	Actual net exports	Scheduled net exports	Difference
BC	37	350	-313
MATL	-100	-40	-60

In addition, the AESO directed all 472 MW of available contingency reserves to provide energy in response to the event. The AESO did not have any Fast Frequency Response (FFR)<sup>3</sup> armed at the time of the trip because Alberta was exporting.

The loss of the Shepard asset removed 810 MW of available capacity from the supply curve, putting upward pressure on prices, although there were no other major generator outages on January 5. Because of the potential for low temperatures and high demand in early January, planned outages are not normally scheduled for this time of year.

However, wind and solar generation were relatively low on January 5, and this contributed to the high prices (Figure 8). Between 03:00 and 08:00, wind generation declined from 2,400 MW to 850 MW, and it fell to a low of 170 MW around midday. Solar generation peaked at 450 MW compared to an installed capacity of 1,846 MW, a capacity factor of 24%.

The AESO's forecasts for wind and solar generation 24 hours ahead overestimated supply. The forecasts for wind generation were almost 1,800 MW above actuals in some hours, and the solar forecast for HE 12 was 280 MW too high.

Demand on January 5 was relatively high, with AIL peaking at 12,238 MW in HE 18 compared to the record of 12,785 MW set on December 11, 2025. The high demand levels on January 5 were a function of prevailing temperatures. Around the evening demand peak, temperatures were minus 15°C in Calgary, minus 16°C in Edmonton, and minus 22°C in Fort McMurray.

The Shepard trip occurred at around 04:40, meaning imports could respond beginning at 07:00 (HE 08). Despite the pool price rising to \$649/MWh in HE 08, while prices in Mid-Columbia were around CAD\$30/MWh, imports did not fully use the available inertia capability for that hour.

This was partly because the AESO's wind forecast two hours ahead overestimated wind generation by 650 MW. Net imports on BC/MATL in HE 08 were 65 MW compared to import capability of 466 MW. However, in subsequent hours, imports did fully use the available inertia capability as pool prices in Alberta remained higher than prices in Mid-C (Figure 9).

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<sup>3</sup> 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.

Figure 8: Net demand and SMP (January 4 to 6)

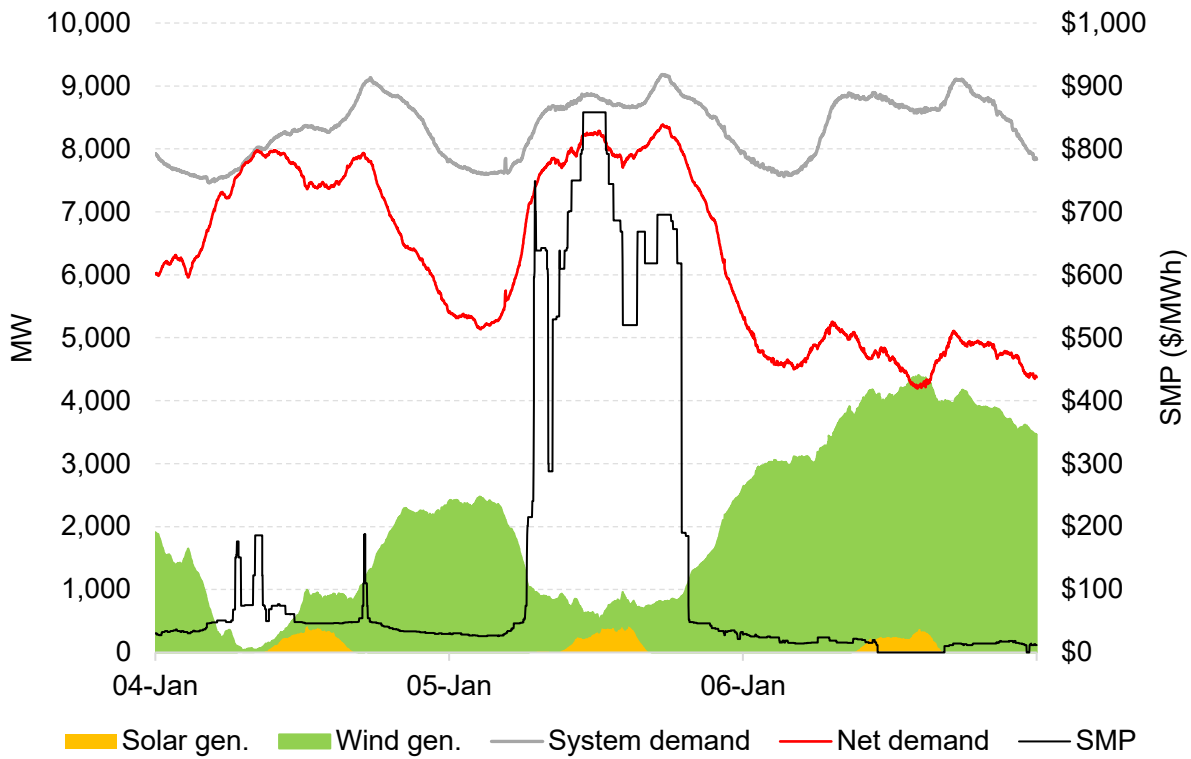
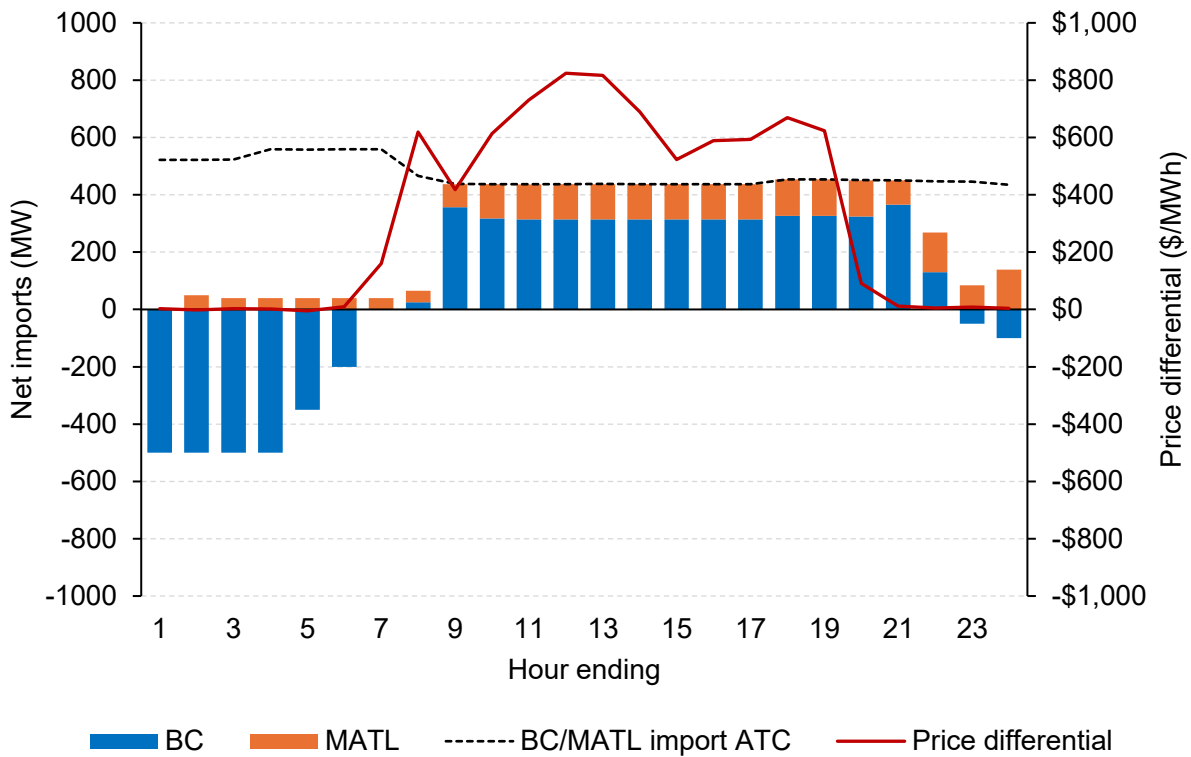


Figure 9: Import and export flows and the AB – Mid-C price differential (January 5)



The supply cushion fell to a low of 272 MW in HE 12 of January 5 indicating tight market conditions.<sup>4</sup> At the time, the Battle River 4, Battle River 5, Sheerness 1, and Sheerness 2 assets were commercially offline on long lead time, totalling 1,245 MW of gas-fired steam capacity. These assets were not self-committed or committed by the AESO because the outage at Shepard was unexpected and did not provide enough lead time for these assets to respond, and because the AESO's forecasts for wind and solar generation overestimated supply. The Battle River 4 asset (155 MW) was committed by the AESO to run between 15:00 and 19:00 on January 5, but this commitment was issued prior to the Shepard trip.

The Shepard asset ramped back online on the evening of January 5 and was fully available again at around 02:00 on January 6. Prices on January 6 were much lower because Shepard was back online, and wind generation was higher (Figure 8).

### **1.2.2 High prices and natural gas restrictions – March 8 and 9**

Beginning on the evening of Saturday, March 7, there was an unplanned outage on the natural gas network near Fort McMurray which reduced the supply of natural gas to some thermal generation assets. The pipeline repair outage had the effect of lowering interruptible gas supply in the area from 100% to 0% and lowering firm gas supply from 100% to 42%.<sup>5</sup>

As a result, the pipeline outage reduced available thermal generation capacity by up to 1,200 MW (Figure 10). This reduction in supply combined with lower intermittent generation during the evening peaks on March 8 and 9 to put upward pressure on prices (Figure 11).

In addition, there were forced outages at Keephills 2 (capacity of 395 MW) and HR Milner (300 MW) during this event that also reduced supply. The pool price peaked at \$782/MWh in HE 21 of March 9 when the supply cushion fell to 950 MW.

The higher prices on these days occurred despite relatively low demand. AIL peaked at 10,592 MW on March 8 and 11,200 MW on March 9. Temperatures around the demand peaks on both days were moderate in Calgary and Edmonton (around minus 4°C), but colder in Fort McMurray (around minus 18 °C). The lower demand on Sunday, March 8 was attributable to weekend load levels.

Importers on BC/MATL were able to predict the higher pool prices on March 8 and 9 and utilized almost all available import capability.

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<sup>4</sup> Supply cushion is the amount of available capacity left in the merit order once demand has been served. This value excludes 203 MW of capacity bid in by load assets.

<sup>5</sup> [TC Energy – Bulletin 3374724602](#)

Figure 10: Available capacity declared by affected generation assets (March 7 to 11)

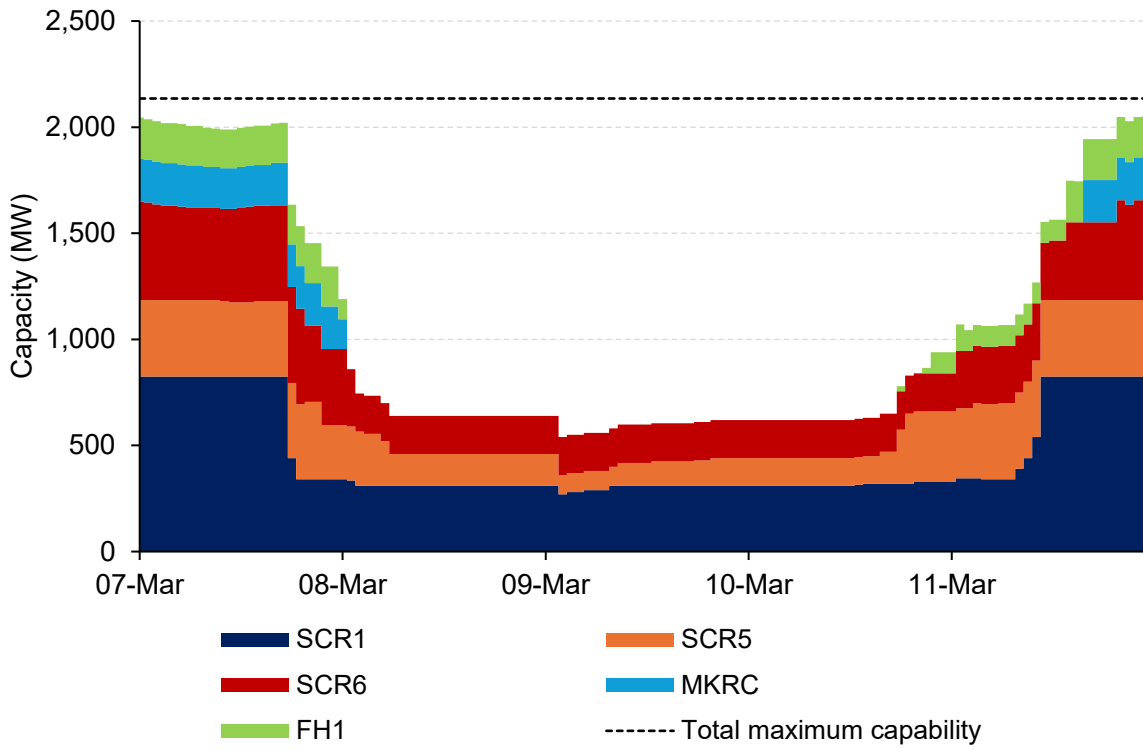
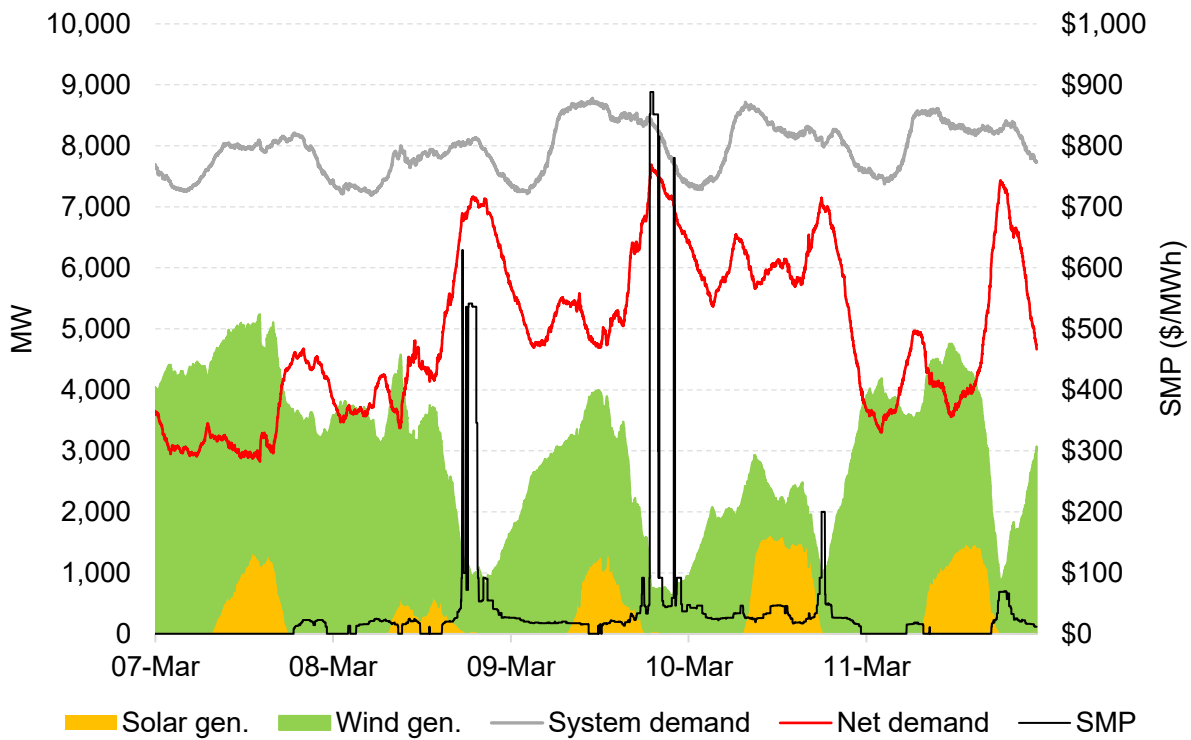


Figure 11: Net demand and SMP (March 7 to 11)



The AESO's wind forecasts 24 hours ahead and 12 hours ahead predicted the declines in wind generation on the evenings of March 8 and 9, and the forecast 12 hours ahead predicted the decline in wind generation on the evening of March 10.

As a result of this, and the reduced availability of thermal assets in Fort McMurray, the AESO's anticipated supply cushion fell below the 932 MW threshold for multiple hours during this event. Therefore, the AESO issued several unit commitment directives (Table 6). In addition, Sheerness 2 was self-committed on the evening of March 8, and Battle River 4 remained online after its unit commitment directive on the evening of March 8.

For March 9, the AESO committed Battle River 5 and Sheerness 1 to run during the evening peak, adding 795 MW of gas-fired steam capacity to the supply curve. However, the Sheerness 1 asset took some time to ramp up, having been offline since December 22, and was only generating around 20 MW when the SMP peaked.

*Table 6: Unit commitment directives (March 8 to 11)*

<b>Asset ID</b>	<b>Capacity (MW)</b>	<b>Issued time</b>	<b>Begin time</b>	<b>Start-up time (hours)</b>	<b>Operation start time</b>	<b>Operation end time</b>
BR4	155	07-Mar 19:59	07-Mar 20:00	24	08-Mar 21:00	09-Mar 01:00
BR5	395	08-Mar 17:25	08-Mar 18:00	24	09-Mar 18:00	09-Mar 23:00
SH1	400	08-Mar 18:45	08-Mar 19:00	24	09-Mar 19:00	09-Mar 23:00
BR5	395	09-Mar 23:25	10-Mar 00:00	4	10-Mar 04:00	10-Mar 08:00
BR5	395	10-Mar 13:28	10-Mar 14:00	4	10-Mar 18:00	10-Mar 22:00

The natural gas pipeline in Fort McMurray came back into service on March 11, increasing the availability of thermal generation assets in the area to normal levels (Figure 10).<sup>6</sup>

### **1.2.3 BC/MATL intertie outage – March 16 to 17**

On March 6, an outage on the BC/MATL intertie was scheduled to run from March 16 HE 10 to March 20 HE 17, for a total of 104 hours. The outage was scheduled due to a transmission line outage on 5L92 in BC. However, the intertie returned earlier than expected and the actual outage ran from March 16 HE 10 to March 17 HE 13, for a total of 28 hours.

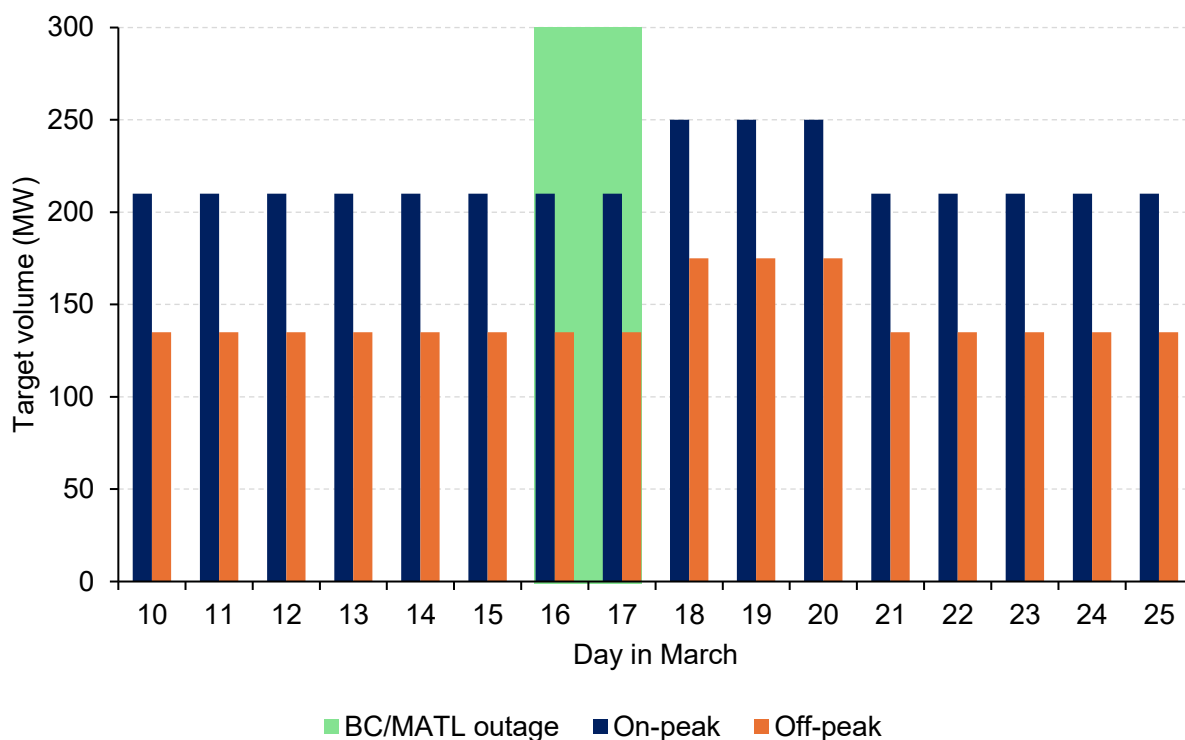
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<sup>6</sup> [TC Energy – Bulletin 3374724614](#)

Outages on BC/MATL mean that Alberta is islanded from other electricity jurisdictions. Therefore, the AESO generally procure more regulating reserves during a BC/MATL outage to deal with higher routine variation in system frequency.

However, in this case, the AESO's target volumes for regulating reserves were the normal level for March 16 and 17, when BC/MATL was offline, and they instead purchased more regulating reserves for March 18, 19, and 20, when the intertie was back in service (Figure 12).

*Figure 12: Target procurement volumes for on-peak and off-peak regulating reserves (March 10 to 25)*



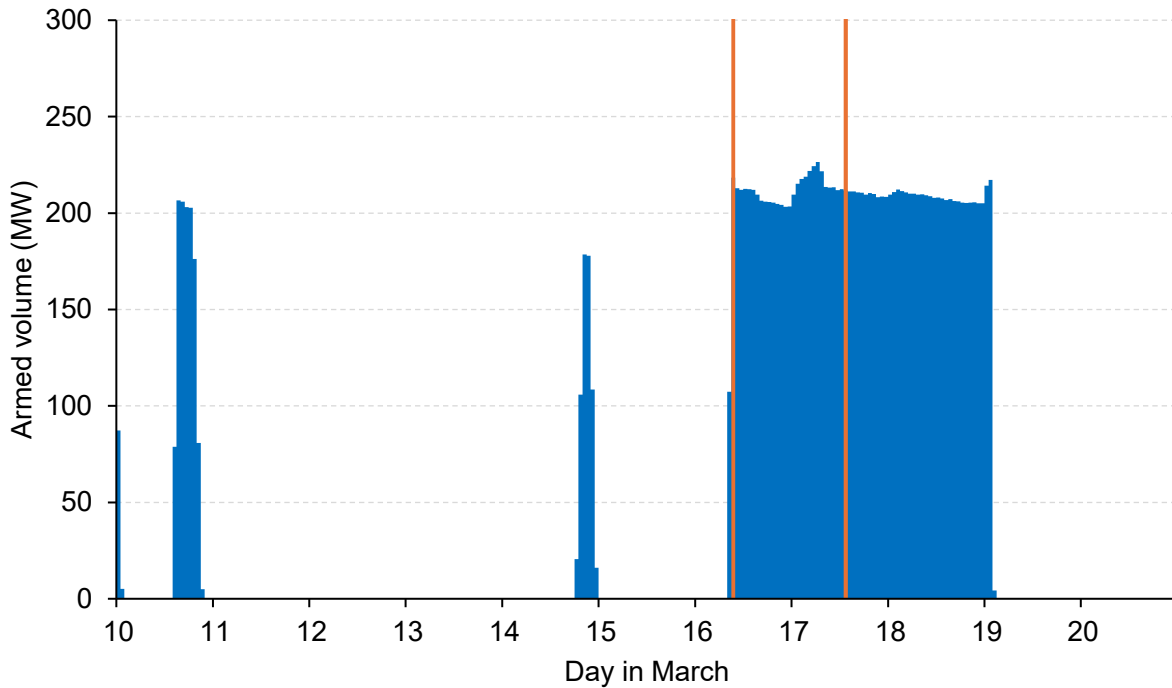
A 5L92 outage in itself does not necessitate the procurement of additional regulating reserves. Therefore, no additional regulating reserves were purchased on March 13 (for March 16) or on March 16 (for March 17). However, real-time changes to the outage occurred on March 16, after ancillary service trading for March 17. Despite 5L92 returning early, additional real-time adjustments to 1201L work on March 18 to 20 necessitated additional regulating reserves.

The AESO armed more FFR during the BC/MATL outage to help deal with the potential for large contingency events. FFR is provided by battery and load assets which respond to a decline in frequency by increasing supply or reducing load almost instantaneously.

Typically, FFR is armed when Alberta is importing on BC/MATL to deal with the potential for a trip on the intertie. However, during the BC/MATL outage, the AESO armed FFR because of the potential for a large generator to trip without the frequency response of the Western Interconnection.

The AESO armed more than 200 MW of FFR during the BC/MATL outage (Figure 13). However, there were no major generation trips during the intertie outage and FFR was not actually deployed. The AESO also armed additional FFR volumes on March 18, which was caused by the day-ahead procurement of FFR and the early return of the BC intertie.

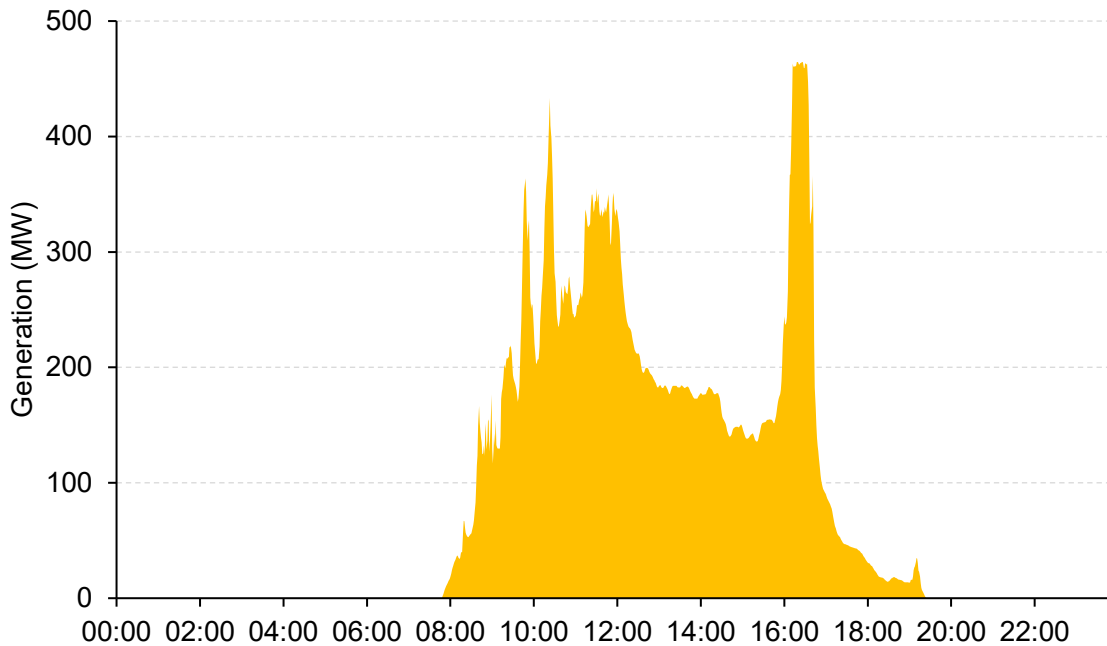
Figure 13: Hourly armed FFR (March 10 to 20)



System frequency during the BC/MATL outage declined to a low of 59.89 Hz at 16:56 and 17:21 on March 16. These falls in frequency were the result of a rapid decline in solar generation at Travers (Figure 14) and falling wind generation, respectively.

The overall price impact of the BC/MATL outage was to put downward pressure on pool prices by preventing exports. Intermittent generation in Alberta was high during the intertie outage, resulting in lower pool prices in Alberta relative to Mid-C.

Figure 14: Generation at the Travers solar asset (March 16)



#### 1.2.4 High prices due to outages and gas restrictions – March 25 and 26

On March 25, the supply cushion fell to 160 MW in HE 12, the lowest in the quarter. The pool price for the hour was \$547.74/MWh and the SMP peaked at \$975.00/MWh (Figure 15). The high prices and low supply cushion were driven by thermal generation outages and gas-fired steam assets being on long lead time, partly due to wind forecast errors caused by the icing of wind turbines.

Due to lower demand at this time of year, large generators often schedule planned outages to occur around this time. This was the case on March 25, as there were planned outages at Genesee Repower 1 and Joffre. In addition to this, there were several forced outages, most notably at Cascade 1 (Table 7). Cascade 1 tripped offline at 09:24 due to excitation system issues and was offline until 12:53.

There were also five gas-fired steam assets commercially offline on long-lead time in HE 12 of March 25, totalling 1,745 MW of capacity. These assets were not committed by the AESO because the anticipated supply cushion did not fall below the 932 MW threshold. The AESO's anticipated supply cushion overestimated the actual supply cushion because of the forced outage at Cascade 1 and because the AESO's wind forecasts overestimated wind generation. For example, the wind forecast 24 hours ahead for HE 12 was 2,650 MW compared to actual wind generation of 1,300 MW, a forecast error of 1,350 MW (Figure 16).

Figure 15: Net demand and SMP (March 25 to 27)

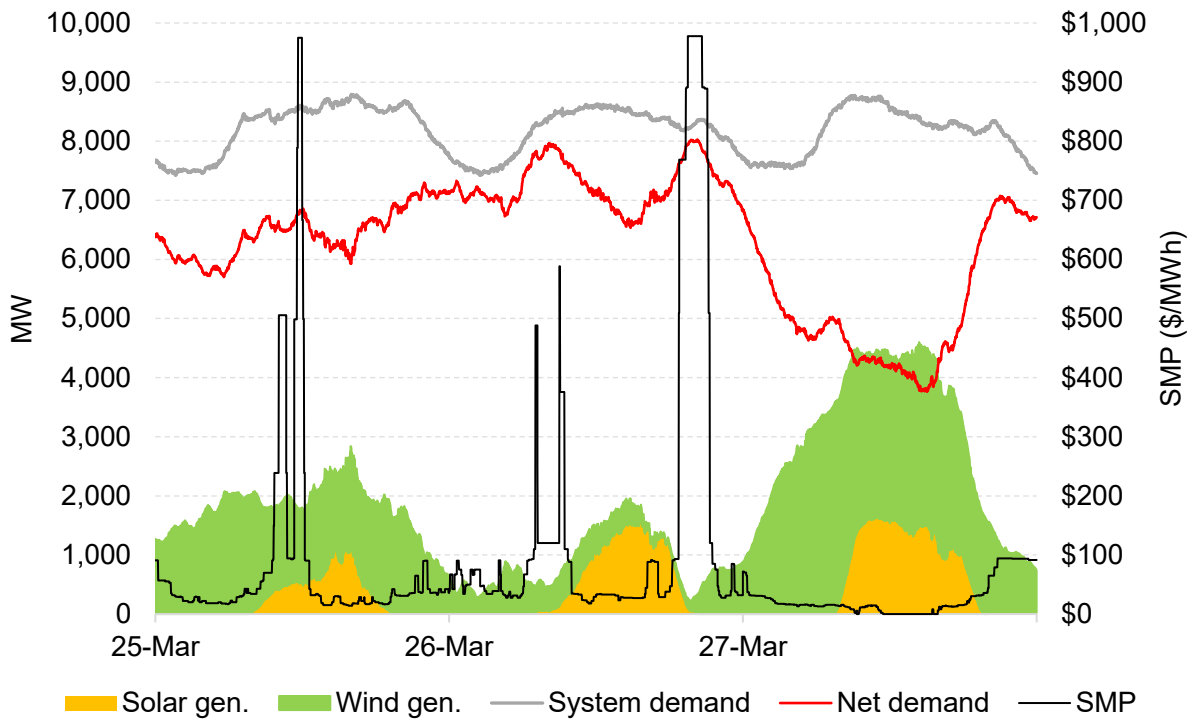


Table 7: Major thermal generation outages (March 25 HE 12)

Asset name	Asset ID	Fuel type	Capacity on outage (MW)
Cascade 1	CAS1	Combined cycle	466
Genesee Repower 1	GNR1	Combined cycle	466
Joffre	JOF1	Cogeneration	210
Cavalier	EC01	Combined cycle	120
Nabiye	IOR2	Cogeneration	113
Genesee 3	GN3	Gas-fired steam	106

The AESO’s overestimation of wind generation on March 25 was partly due to forced outages. In HE 12 of March 25, 1,200 MW of wind capacity was on outage, with a large portion of this due to icing of wind turbines (Figure 17).

Despite the higher pool price in HE 12, imports did not use all available import capability. Scheduled imports on BC/MATL were 115 MW, which were exclusively on MATL, compared to available import capability of 387 MW. On the SK intertie, exports of 153 MW occurred. Intertie traders did not predict the higher prices in time because of the unexpected trip at Cascade 1, which did not provide them with enough notice to schedule imports due to the T-2 offer rules.

Figure 16: Wind generation forecasts and actual wind generation (March 25 to 27)

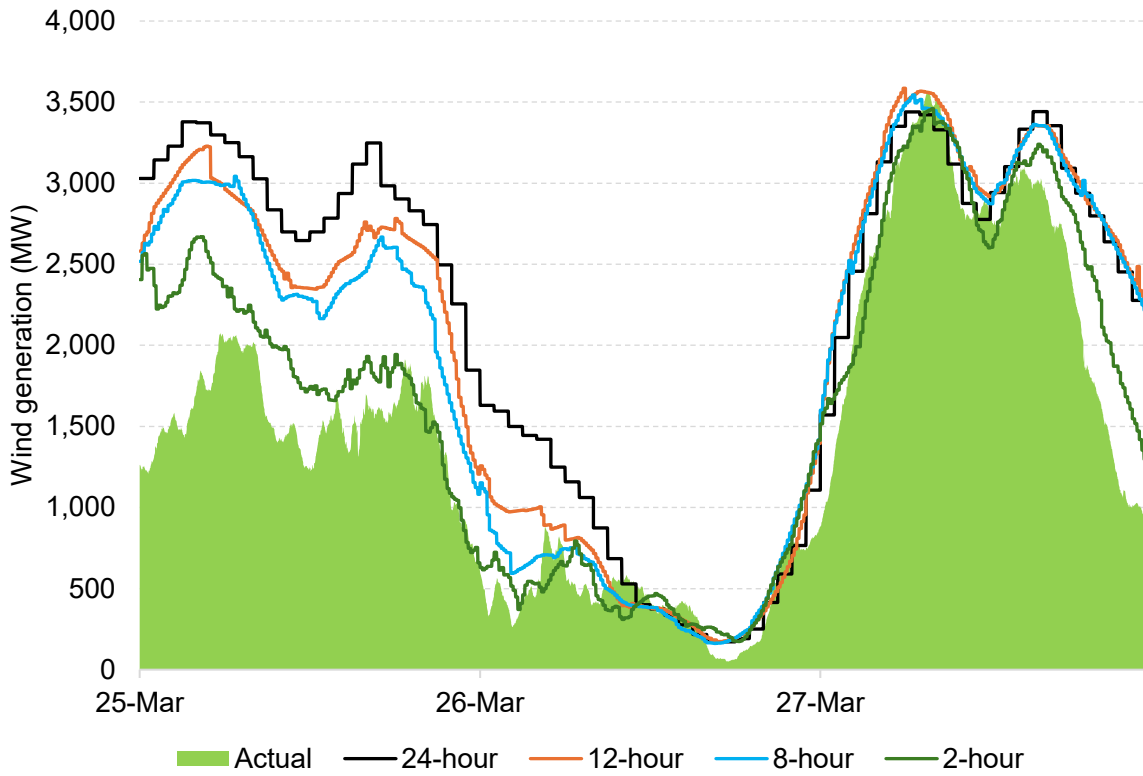
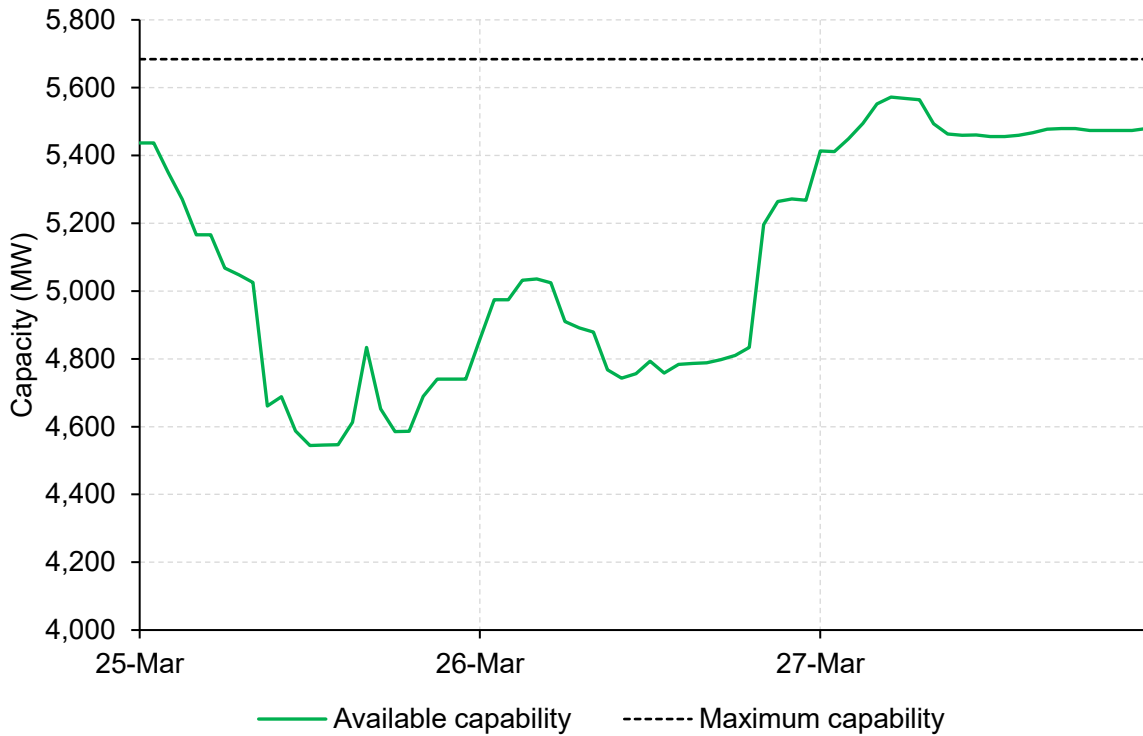


Figure 17: Total available capacity of wind assets (March 25 to 27)



On the evening of March 26, the pool price increased to \$948.63/MWh, the highest in the quarter. The SMP peaked at \$977.94/MWh and the supply cushion fell to a low of 570 MW. The higher prices were caused by low intermittent generation and an outage on the natural gas network which reduced the available capacity of some large thermal generators.

The low wind generation on the evening of March 26 was predicted by the AESO in advance (Figure 16). This allowed the AESO to commit the Battle River 4 asset (155 MW) to run from 20:00 to midnight. In addition to this, Battle River 5 (395 MW) was self-committed on the afternoon of March 25 and Keephills 2 (395 MW) was self-committed in the early morning hours of March 26, so both assets were online for the evening peak on March 26. Consequently, Sheerness 1 and 2 (400 MW each) were the only assets that were commercially offline on long lead time.

Due to unplanned maintenance at a compressor station on the natural gas network near Fort McMurray, natural gas supply in some areas was reduced from 100% interruptible and 100% firm supply to 0% interruptible and 72% firm.<sup>7</sup> As a result, available capacity at Base Plant, Firebag, and Nexen 2 was meaningfully reduced (Table 8).

*Table 8: Major thermal generation outages (March 26 HE 21)*

<b>Asset name</b>	<b>Asset ID</b>	<b>Fuel type</b>	<b>Capacity on outage (MW)</b>
Genesee Repower 1	GNR1	Combined cycle	466
Base Plant	SCR1	Cogeneration	406
Joffre	JOF1	Cogeneration	210
Firebag	SCR6	Cogeneration	142
Nexen Inc #2	NX02	Cogeneration	110

In contrast with the higher prices on March 25, intertie traders were able to predict the higher prices on the evening of March 26. Consequently, importers used all available transmission capability during the high-priced hours around the net demand peak. It is also worth noting that import capability dropped from 514 MW in HE 20 to 404 MW in HE 21 due to an FFR restatement.

Elevated demand levels were a factor in the higher prices on March 25 and 26. AIL peaked at 11,663 MW on March 25 (the tenth highest hour in the month) and at 11,584 MW on March 26. These demand levels reflected relatively low temperatures in Fort McMurray and Edmonton, with prevailing temperatures at the demand peaks provided in Table 9.

*Table 9: Prevailing temperatures (°C) at the demand peak (March 25 and 26)*

<b>Date time</b>	<b>Calgary</b>	<b>Edmonton</b>	<b>Fort McMurray</b>
25-Mar 16:00	-6	-12	-15
26-Mar 11:00	-12	-13	-18

<sup>7</sup> [TC Energy – Bulletin 3374724655](#) and [TC Energy – Bulletin 3374724663](#)

### **1.2.5 Genesee Repower 1 and 2 testing**

The Genesee Repower 1 (GNR1) and Genesee Repower 2 (GNR2) assets have an installed capacity of 716 MW each. However, these assets cannot supply more than 466 MW each due to the AESO's Most Severe Single Contingency (MSSC) limit.

On February 2, the AESO announced that GNR1 and GNR2 would undergo further MSSC testing from February 15 to 21.<sup>8</sup> This testing was part of Capital Power's engineering efforts to unlock some of the additional capacity at GNR1 and GNR2 by the end of 2026.<sup>9</sup>

Specifically, 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.<sup>10</sup> This testing was a continuation of the testing conducted in December 2025, which was suspended before completion due to a forced trip at GNR2 during the testing period.

During the February 15 to 21 testing window the Genesee assets were permitted to generate up to 600 MW. As with prior testing, the AESO did not procure more contingency reserves to mitigate the risk of a larger trip but instead relied on the frequency response from the BC and Montana interties. However, unlike earlier testing where import capability on BC/MATL was reduced to 0 MW, the AESO lowered import capability to 200 MW during testing this time.

The testing commenced on February 15 at both assets. As the testing progressed, planned trips occurred at GNR1 on February 16 and at GNR2 on February 17 (Figure 18).

The GNR1 trip on February 16 occurred at 00:00. At this time, generation at GNR1 dropped from 530 MW to about 180 MW, an instantaneous decrease of 350 MW. Following this, generation declined gradually and reached 0 MW after 6 minutes. During this gradual decrease phase, generation at GNR2 increased in response to the trip (Figure 19). Generation at GNR2 reached a maximum of 618 MW during the GNR1 trip.

The GNR2 trip on February 17 occurred at 02:13. Similar to the GNR1 trip, generation at GNR2 dropped from 530 MW to 160 MW and declined gradually thereafter. By 02:20, 7 minutes after the instantaneous drop, generation at GNR2 reached 0 MW. During the gradual decrease phase, generation at GNR1 increased in response to the trip. Generation at GNR1 reached a maximum of 623 MW during the GNR2 trip.

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<sup>8</sup> [AESO market updates](#), Genesee Repower 1 and Genesee Repower 2 generator testing – February 2, 2026

<sup>9</sup> [Capital Power – Reporting](#), Q4 2025 webcast

<sup>10</sup> [Capital Power – Reporting](#), Q3 2025 webcast

Figure 18: GNR1 and GNR2 generation (February 15 to 21)

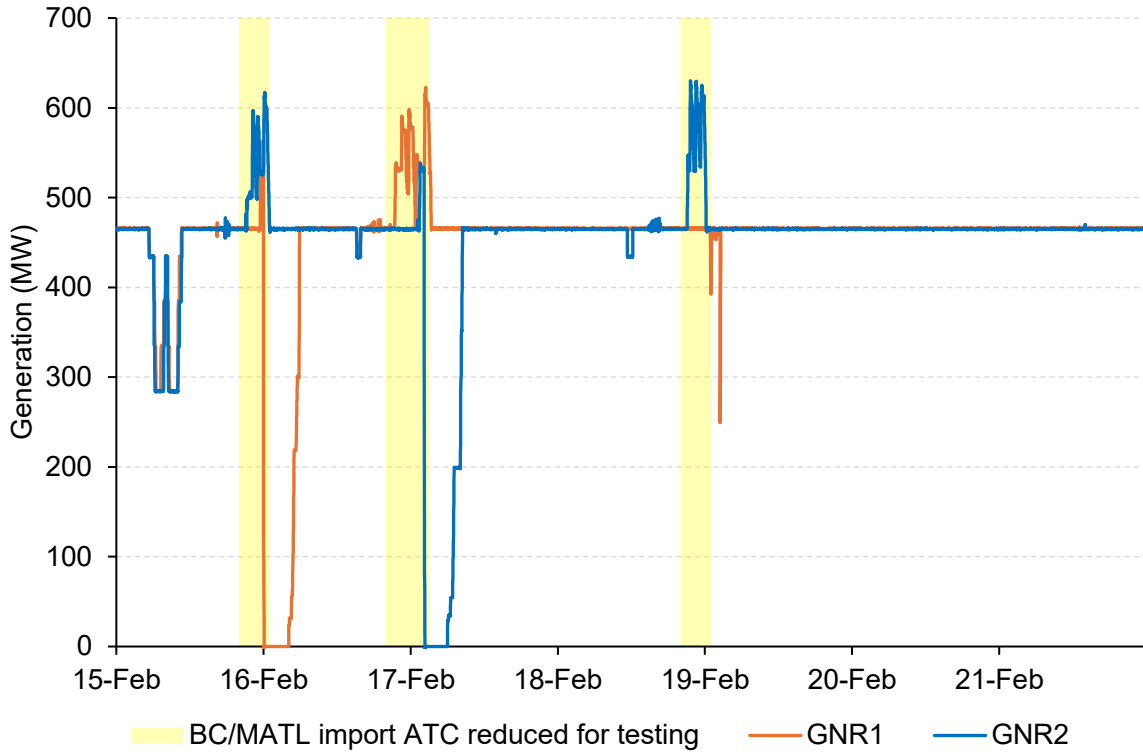
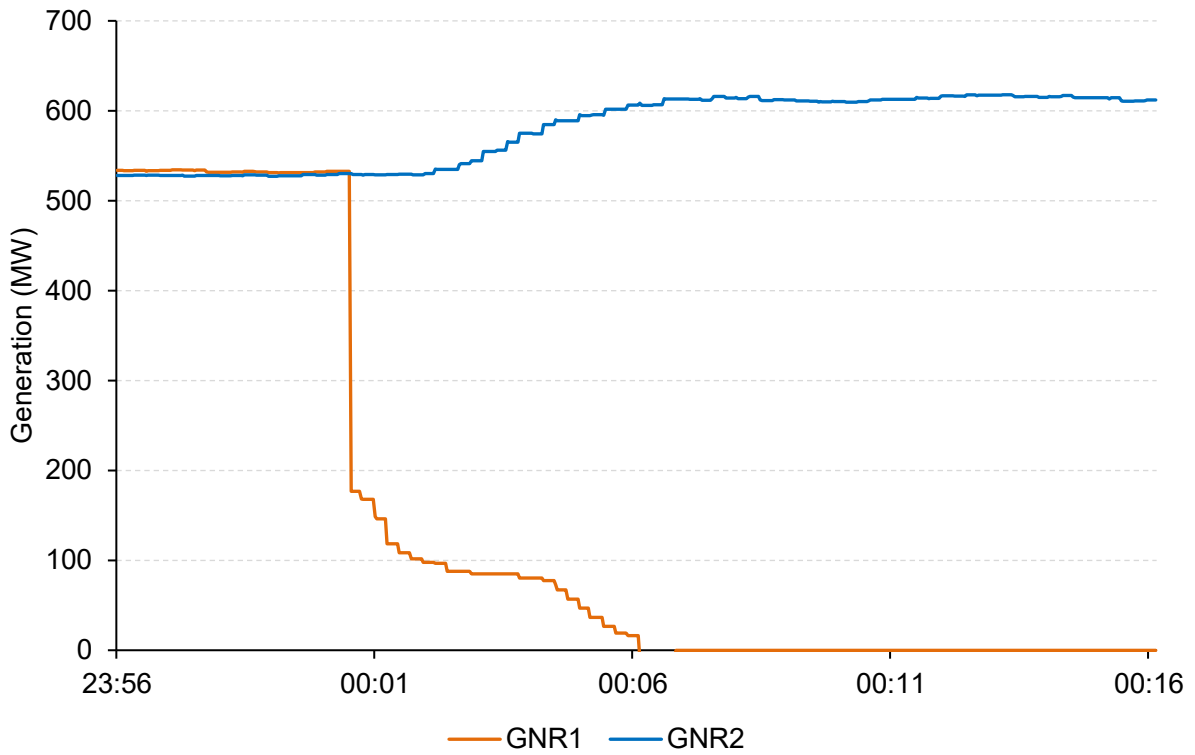


Figure 19: GNR1 and GNR2 generation (February 15 to 16)



Although no planned trips occurred on February 18, the import capability on the BC/MATL intertie was limited to 200 MW from February 18 HE 21 to February 19 HE 01. On this day, generation reached a maximum of 631 MW at GNR2 in HE 22, while GNR1 generated a constant 466 MW.

While testing was scheduled to conclude on February 21, no testing occurred on February 19, 20, or 21 due to low wind generation in Alberta. Low wind generation tends to drive imports into the province, which are not favourable for the MSSC testing. Higher imports mean there is less room on the interties for a frequency response to a generator trip.

With low wind conditions and the testing cancelled, the import capability restrictions were lifted. The import capability on BC/MATL, which was earlier limited to 200 MW for February 19 HE 02 to HE 04 and from February 19 HE 21 to February 20 HE 01, was lifted on the afternoon of February 18. Similarly, the import capability limitation of 200 MW that had been set for February 20 HE 20 to February 21 HE 01 was lifted on the afternoon of February 17.

On February 20, the AESO announced further testing at GNR1 and GNR2. According to the new schedule, GNR1 would perform testing on March 13 and GNR2 would perform testing on April 9. During this testing, the assets were allowed to generate up to 520 MW.

As with the prior testing, the AESO did not procure any additional contingency reserves. However, unlike earlier testing events, the import capability on BC/MATL was not lowered.

On March 13, MSSC testing for GNR1 commenced in HE 22. Generation reached a maximum of 520 MW within the same hour and continued into the next hour. However, due to fluctuations in combustor pressure, the test was bypassed, and at 22:14, the generation at GNR1 dropped to about 350 MW from 520 MW. Generation remained in this range for the remainder of the hour. The GNR1 asset was subsequently taken offline for a combustor inspection.

The testing scheduled for April 9 at GNR2 was cancelled on April 7 due to the low wind forecast.

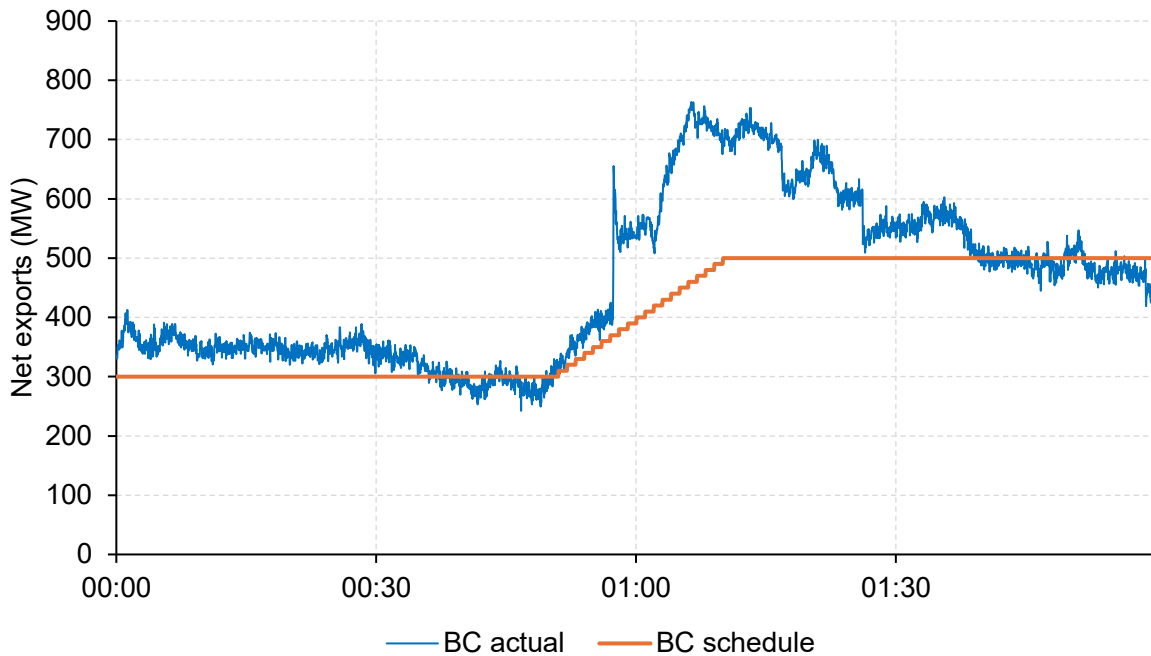
### **1.2.6 Transmission trips in BC – March 8**

Just before 01:00 MST on March 8 there was a major event on the power system in BC. Due to a fault at a 500 kV bus at GM Shrum the transmission lines 5L1, 5L2, 5L3, and 5L4 tripped. This resulted in the generation stations at GM Shrum, Peace Canyon, and Site C becoming separated from the rest of the BC power grid.

Consequently, the BC grid lost around 2,600 MW of generation and approximately 900 MW of load was shed in BC. In response, exports from Alberta to BC increased automatically and instantaneously from 400 to 660 MW (Figure 20). As a result, frequency in Alberta fell to 59.84 Hz at 00:57.

A few minutes later, the AESO received a reserve sharing request from the Western Power Pool to provide 425 MW, which lasted for around 18 minutes. The AESO responded by directing 435 MW of contingency reserves to supply power.

Figure 20: Actual and scheduled power flows on the BC intertie (March 8)



### 1.3 Market power mitigation measures

In March 2024, the Market Power Mitigation Regulation (MPMR) and Supply Cushion Regulation (SCR) were enacted. Beginning on 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.

#### 1.3.1 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 Q1. In January, the MCSINR increased early in the month as high pool prices, driven by an outage at Shepard and low intermittent generation, pushed it to a monthly peak of 22% of the threshold in HE 01 of January 6. However, low pool prices for the remainder of the month lowered the MCSINR, which ended January at 20% of the threshold.

In February, low pool prices resulted in hourly net revenues that were frequently negative, lowering the MCSINR. As a result, the MCSINR reached a maximum of only 2% of the threshold during the month.

In March, the MCSINR increased in response to high-price events caused by the combination of natural gas restrictions and low intermittent generation. However, despite some price volatility from these events, the MCSINR only reached a monthly maximum of 20% of the threshold.

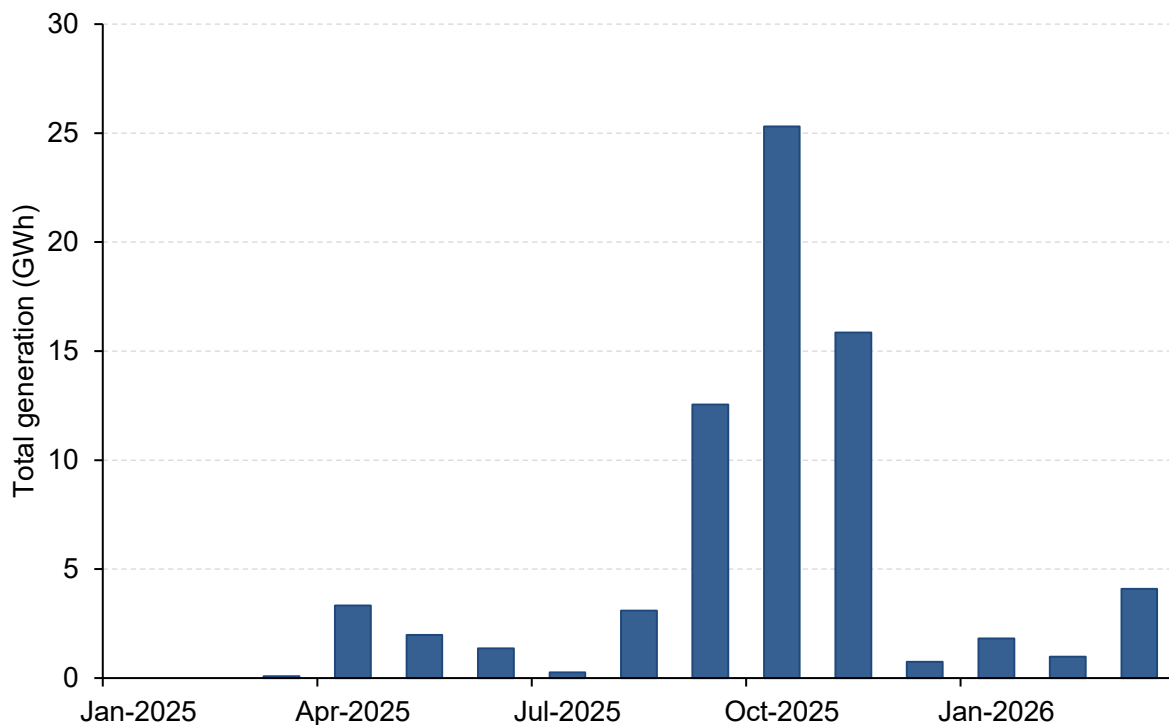
### 1.3.2 Supply Cushion Regulation and ISO rule 206.2

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 assets to direct based on economic merit and physical constraints.

In Q1, 23 UCDs were issued by the AESO, a decrease from the 61 UCDs issued in the previous quarter. Within Q1, six UCDs were issued in January, two in February, and 14 in March. The higher number of UCDs in March was driven by higher demand year-over-year and more thermal generator outages, as discussed in section 1.

Figure 21 illustrates the total volume of generation provided by assets under UCDs by month. In Q1, a total volume of 7 GWh was provided through UCDs, with over 4 GWh provided in March.

Figure 21: Total generation from unit commitment directives (January 2025 to March 2026)



The MSA undertook an analysis to estimate the price effect of the UCDs in Q1, an analysis which it has done in prior quarters since the introduction of the SCR. This analysis assumes that the LLT assets under UCD would have remained commercially offline on LLT absent the UCD. The observed merit order is used, with the committed offer blocks removed to create a counterfactual merit order, while holding all other offers constant.

Beginning at the highest dispatched block, the analysis moves up the counterfactual merit order by the amount of dispatched MW committed through ISO rule 206.2 to determine an initial counterfactual price, which is used as a placeholder. This process considers block flexibility (i.e., it does not partially dispatch an inflexible block).

Additionally, the analysis factors in Transmission Constraint Rebalancing (TCR) volumes. Once the initial counterfactual price has been calculated, the analysis moves back down the counterfactual merit order by the TCR volumes for the respective period. The prevailing offer price of that block is then used to determine the final counterfactual price. This analysis is conducted at the SMP level using merit order snapshots at different points in the hour.

Table 10 shows the estimated price effect of the UCDs in Q1. Over the quarter, the MSA estimates that the average pool price was lowered by \$2.44/MWh or 8% because of the UCDs.

In Q1, there were no hours where the supply cushion would have been negative without the UCDs issued by the AESO.

*Table 10: Estimated price impact of unit commitment directive in Q1*

Time period	Actual average pool price (\$/MWh)	Estimated average pool price without unit commitment directives (\$/MWh)	Percentage change (%)
January	\$39.44	\$42.54	-8%
February	\$22.39	\$22.66	-1%
March	\$33.68	\$37.42	-11%
<b>Q1</b>	<b>\$32.15</b>	<b>\$34.59</b>	<b>-8%</b>

## 1.4 Market power, offer behaviour, and net revenues

### 1.4.1 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.

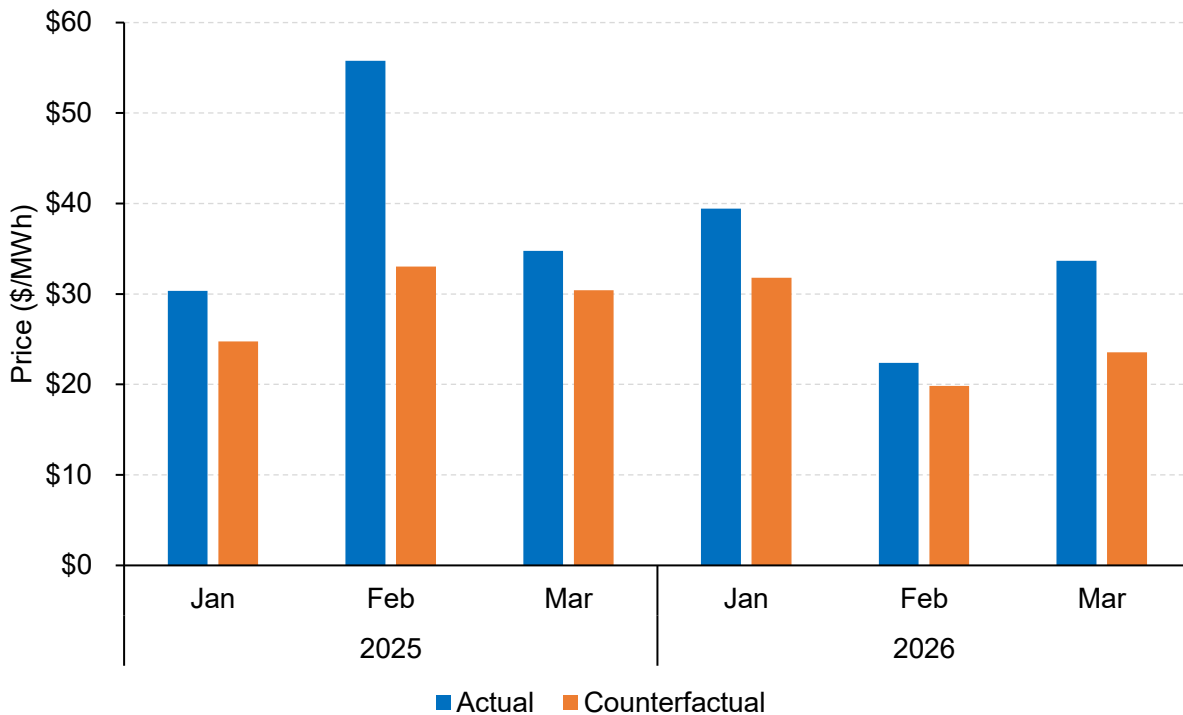
The MSA now publishes its counterfactual price estimates, and other market power metrics, on its [data portal](#).

The average pool price in Q1 was \$32.15/MWh which is a premium of \$6.91/MWh or 27% over counterfactual prices based on SRMC. In Q1 last year the premium was higher at 36%, largely driven by higher prices in February (Figure 22).

In early February 2025, a period of cold weather increased demand and lowered intermittent generation, which increased the ability of larger suppliers to exercise market power and raise mark-ups. The average pool price in February 2025 was a 69% premium to counterfactual prices.

Mild weather, high intermittent generation, and increased supply from Base Plant increased competition in January and February this year, resulting in mark-ups of 24% and 13%, respectively. The highest mark-up in Q1 was in March at 43%, which reflected more generator outages and increased demand year-over-year.

Figure 22: Monthly average pool prices and counterfactual prices (Q1 of 2025 and 2026)



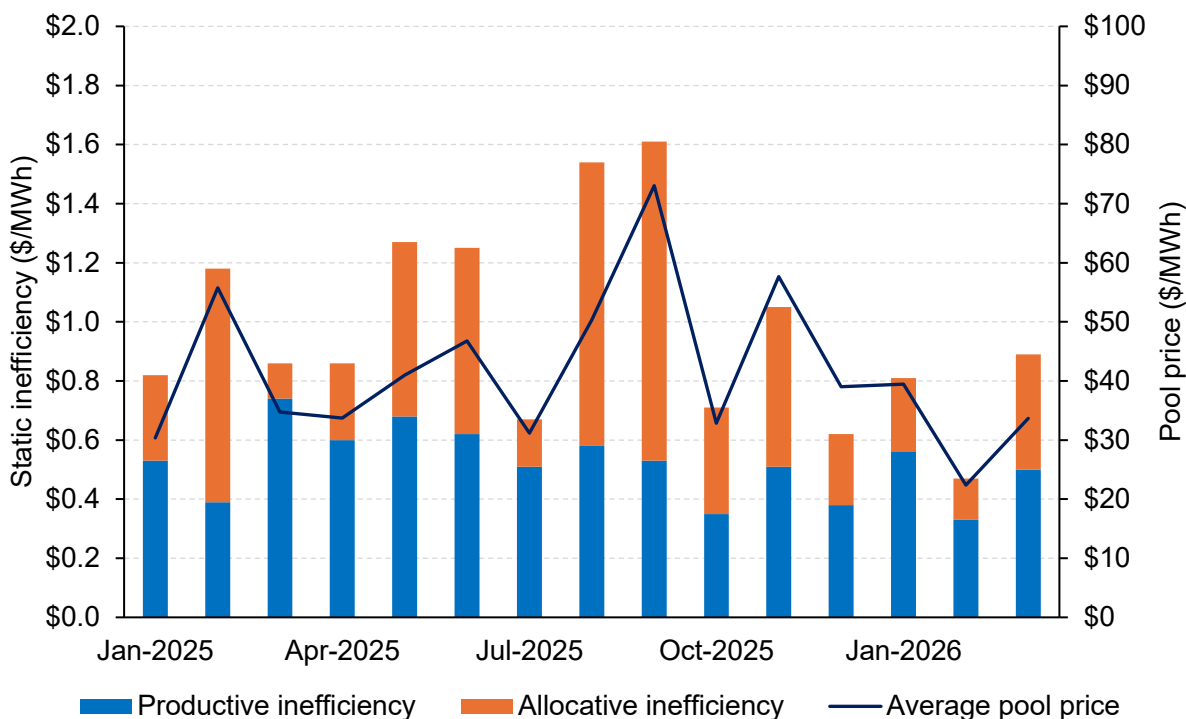
The exercise of market power can lead to static inefficiencies in the short-run, specifically productive and allocative inefficiencies. Productive inefficiencies occur when lower cost generating assets are priced out of the market and higher cost assets supply power instead. Allocative inefficiencies 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.

Static inefficiencies in Q1 were relatively low because of increased competition and low pool prices (Figure 23). Over the quarter, productive inefficiencies averaged \$0.47/MWh and allocative inefficiencies averaged \$0.26/MWh, yielding static inefficiencies of \$0.73/MWh or 2.3% of the

average pool price. In Q1 last year static inefficiencies were higher at \$0.95/MWh but were a similar percentage of the average pool price at 2.4%.

*Figure 23: Average static inefficiencies and average pool price by month (January 2025 to March 2026)*



The ability of larger suppliers to exercise market power was limited in Q1. One way to analyze the ability of firms to exercise market power is to calculate how often they are pivotal. A firm is pivotal in an hour when its withholdable capacity<sup>11</sup> is needed for demand to be met.

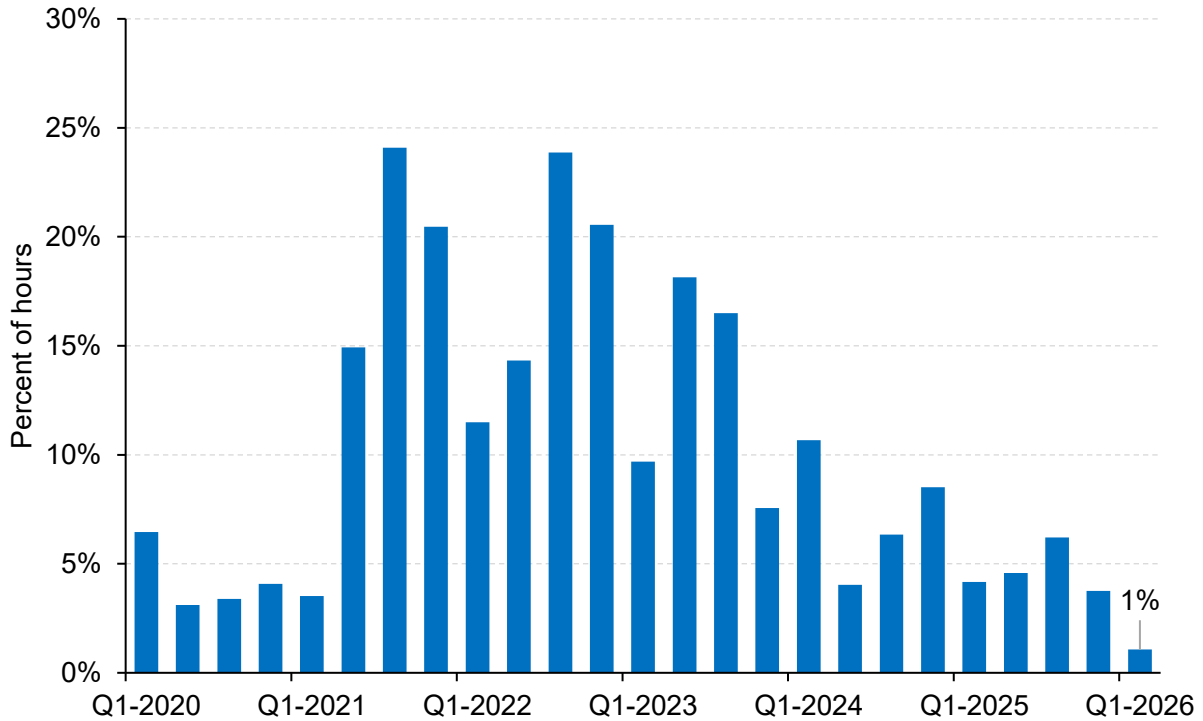
In Q1, the largest firm was pivotal in 1% of hours, the lowest quarterly value going back to 2020 (Figure 24). Mild weather in January and February, high intermittent generation, and increased availability at Base Plant combined to lower market power in Q1.

The ability of firms to exercise market power in Q1 was highest in January, however the largest firm was only pivotal in 1.6% of hours in the month. The largest supplier was pivotal in 0.3% of hours in February and in 1.2% of hours in March.

As shown by Figure 24, the ability of larger suppliers to exercise market power has fallen considerably in recent years, largely due to increased supply from Cascade and Base Plant, in addition to more intermittent generation.

<sup>11</sup> Withholdable capacity is all capacity except for minimum stable generation and intermittent capacity.

Figure 24: The percent of hours in which the largest firm was pivotal by quarter (Q1 2020 to Q1 2026)



### 1.4.2 Offer behaviour

Figure 25 illustrates the relationship between supply cushion and pool price in Q1 of 2024, 2025, and 2026. Specifically, the figure illustrates the average pool price for 250 MW supply cushion bins during the three quarters. Supply cushion is the amount of generation capacity that is available in the merit order above what was needed to serve demand.<sup>12</sup>

The relationship between supply cushion and pool price is as expected in all three quarters. During hours of low supply cushion pool prices are higher, and during hours of high supply cushion pool prices are lower.

The figure also provides information about offer behaviour, particularly in hours of low supply cushion. For example, the average pool price in Q1 was \$618/MWh for hours when the supply cushion was between 250 and 500 MW. In Q1 2024, the average pool price was lower at \$528/MWh when the supply cushion was in this range. This indicates that during hours of similar supply cushion more capacity was offered high in the merit order in Q1 relative to Q1 2024. In Q1 2025, there were no hours where the supply cushion was under 500 MW.

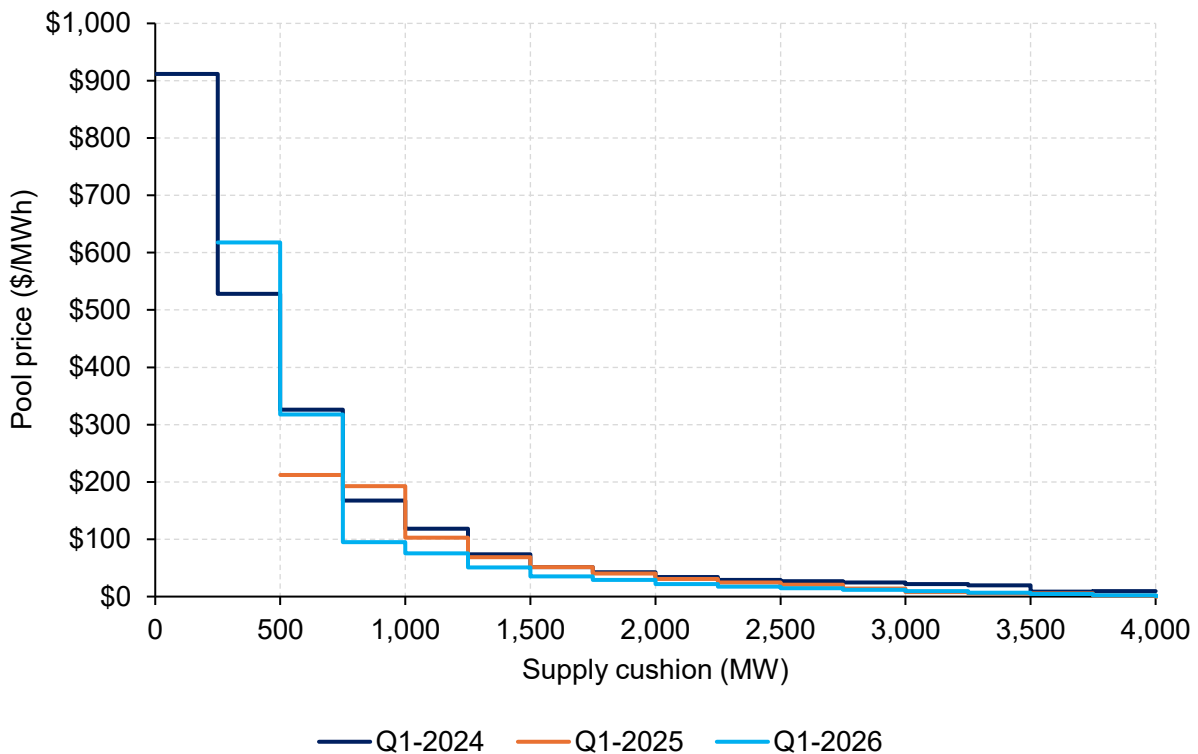
<sup>12</sup> In this analysis, the supply cushion is calculated as the difference between available MW and dispatched MW for offer blocks priced above \$0/MWh in the merit order. The analysis uses an hourly snapshot around the 30<sup>th</sup> minute and load assets bidding into the market are excluded.

Similarly, for hours with a supply cushion of between 500 and 750 MW there was an increase in the average pool price year-over-year: from \$212/MWh in Q1 2025 to \$318/MWh in Q1.

However, at higher supply cushion levels prices were generally lower in Q1 (Figure 25). For example, for hours with a supply cushion of between 750 and 1,000 MW the average pool price fell by \$98/MWh year-over-year.

In addition, for hours with a supply cushion of between 1,000 and 2,000 MW average pool prices were systematically lower in Q1 relative to Q1 2024 and Q1 2025. In addition to more competition for dispatch during these hours, lower natural gas prices year-over-year were also a factor.

Figure 25: Supply cushion and pool prices (Q1 of 2024, 2025, and 2026)



### 1.4.3 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 Q1 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, which are adjusted for inflation using the Consumer Price Index.<sup>13</sup> The resulting costs are reported in Table 11.

*Table 11: Cost assumptions used in the net revenue analysis (2026\$)*

<b>Parameter</b>	<b>Combined cycle</b>	<b>Simple cycle</b>	<b>Wind</b>	<b>Solar</b>
Size (MW)	418	47	100	50
Net overnight capital costs (\$/kW)	\$1,706	\$1,849	\$1,177	\$1,298
Fixed O&M (\$/kW-year)	\$22.19	\$25.65	\$97.39	\$29.72
Variable O&M (\$/MWh)	\$4.01	\$7.39	\$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<sub>2</sub>e/GJ.

For both the natural gas assets, carbon costs are calculated assuming that 90% of the emissions obligations are met through the purchase of emission performance credits (EPCs). The prevailing price of EPCs is estimated using data available on ICE NGX with an average price of \$35.39/tCO<sub>2</sub>e in Q1.<sup>14</sup> The remaining 10% of emissions are covered through payments into the TIER Fund at the regulated carbon price of \$95/tCO<sub>2</sub>e.

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 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%.

<sup>13</sup> AESO [Long Term Outlook 2024](#) see Data file sheet New Resource Inputs

<sup>14</sup> ICE NGX [Alberta Emission Performance Credit vintage 2025 futures](#) (May 2026 contract)

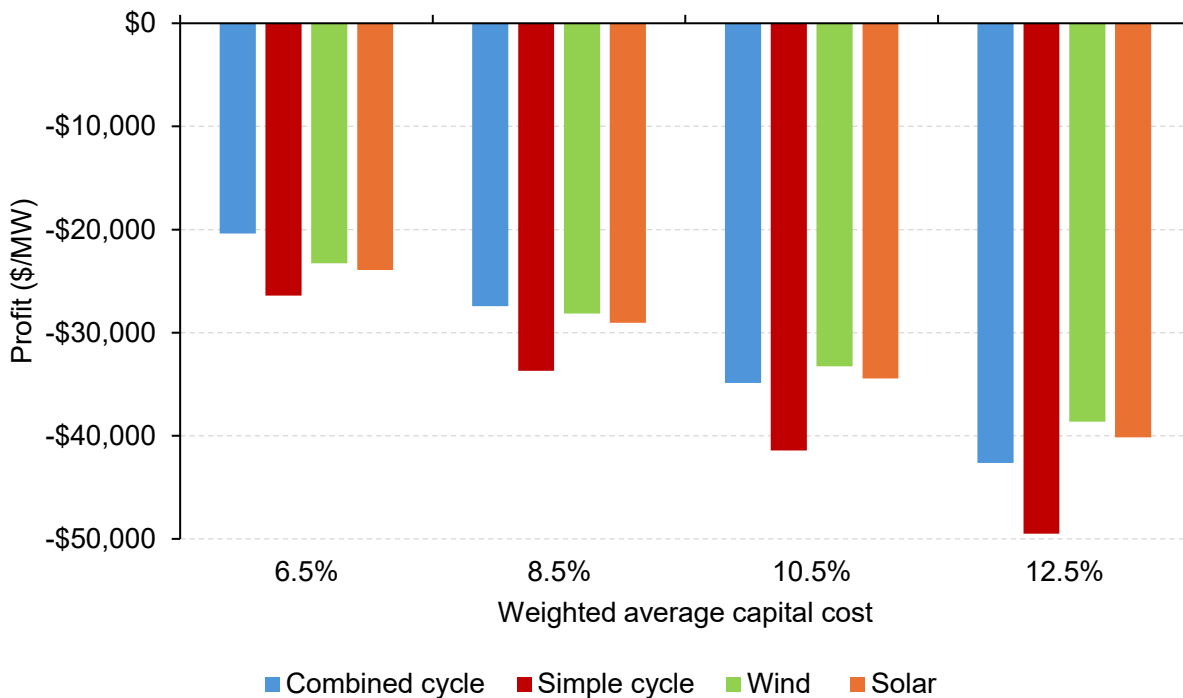
For the hypothetical wind and solar assets, revenues are derived not only from the energy market but also from the sale of carbon emission offsets. Carbon credit revenues are calculated based on the grid displacement factor and the prevailing price of offsets. The price of offsets is estimated using data available on ICE NGX with an average of \$35.39/tCO<sub>2</sub>e in Q1.<sup>15</sup> 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 have 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.

For all generation technologies, 25% of annual fixed O&M costs are deducted from the net revenues earned. If the net revenues are greater than the fixed O&M costs, the difference is taxed at an assumed rate of 23%. This after-tax amount is then compared to 25% of annual capital costs, for a range of weighted-average cost of capital (WACC) assumptions. Figure 26 illustrates the results of the analysis in dollars per MW.

Figure 26: Profits per MW by generation type at different WACC assumptions (Q1)



<sup>15</sup> ICE NGX [Alberta Emission Offset vintage 2025 futures](#) (May 2026 contract)

Pool prices in Q1 were relatively low with an average of \$32.15/MWh. These low prices meant that none of the hypothetical generation assets earned sufficient net revenues to fully recover 25% of their annual fixed and capital costs in Q1. The estimated net revenues resulted in a loss for all the hypothetical assets, and this outcome is true across a range of WACC assumptions (Figure 26).

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 quarter contribution to lifecycle economic returns.

## **1.5 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.<sup>16</sup>

Hourly data on the MSA's carbon emission estimates are now available on our [data portal](#).

### **1.5.1 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 12 shows the minimum, mean, and maximum hourly average emission intensity for Q1 over the past seven years.

Average emission intensity has fallen significantly over recent years driven 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. Increased generation from efficient gas assets, including Cascade 1 and 2 and Genesee Repower 1 and 2, has put downward pressure on average carbon intensity more recently.

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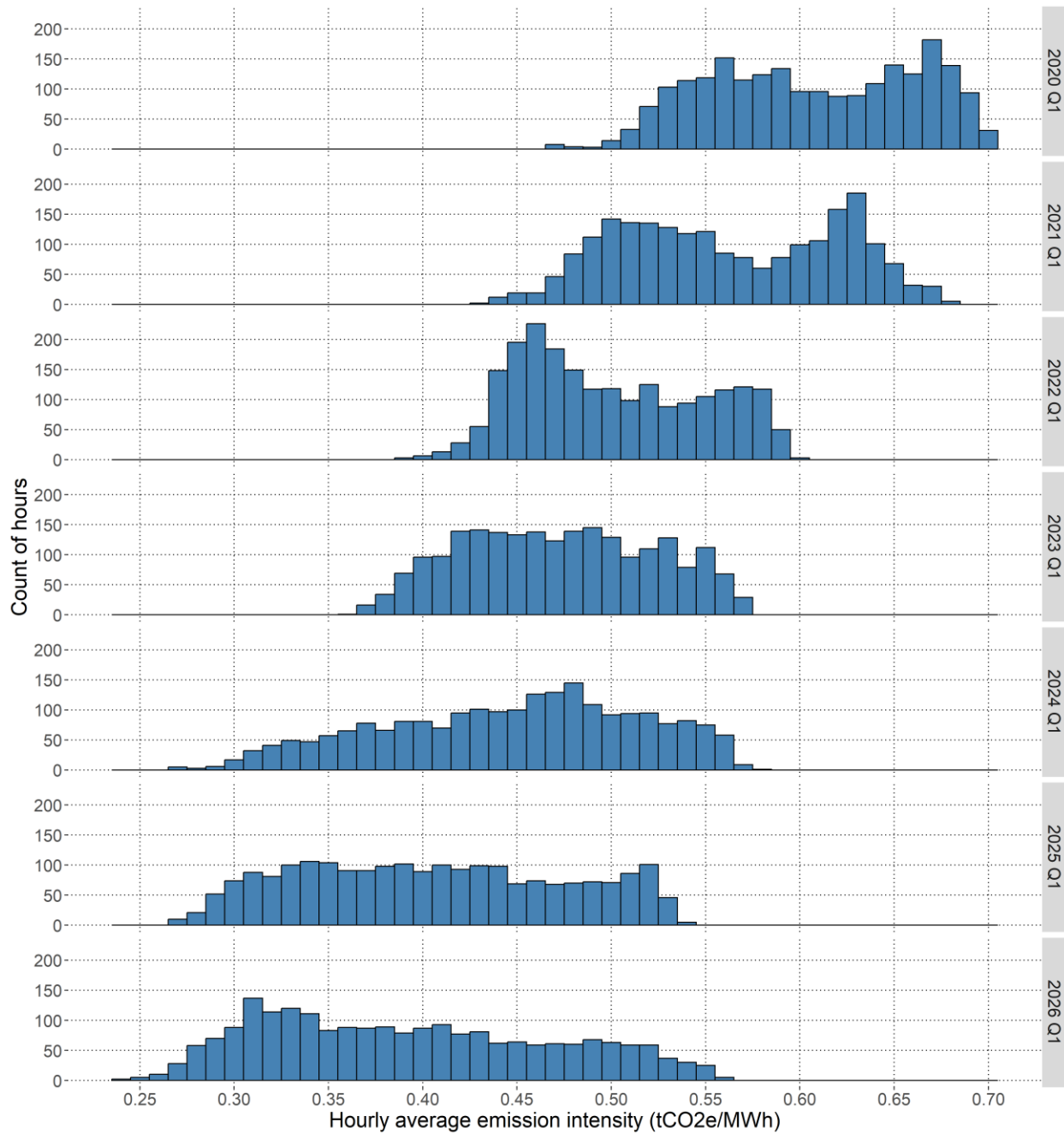
<sup>16</sup> For more details on the methodology, see the MSA's [Quarterly Report for Q4 2021](#).

Table 12: Minimum, mean, and maximum hourly average carbon emission intensities (tCO<sub>2</sub>e/MWh)

<b>Time period</b>	<b>Min</b>	<b>Mean</b>	<b>Max</b>
2020 Q1	0.47	0.61	0.70
2021 Q1	0.43	0.56	0.68
2022 Q1	0.39	0.50	0.60
2023 Q1	0.36	0.47	0.57
2024 Q1	0.27	0.45	0.58
2025 Q1	0.27	0.40	0.54
2026 Q1	0.24	0.39	0.56

Figure 27 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q1 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 27: The distribution of average carbon emission intensities in Q1 (2020 to 2026)



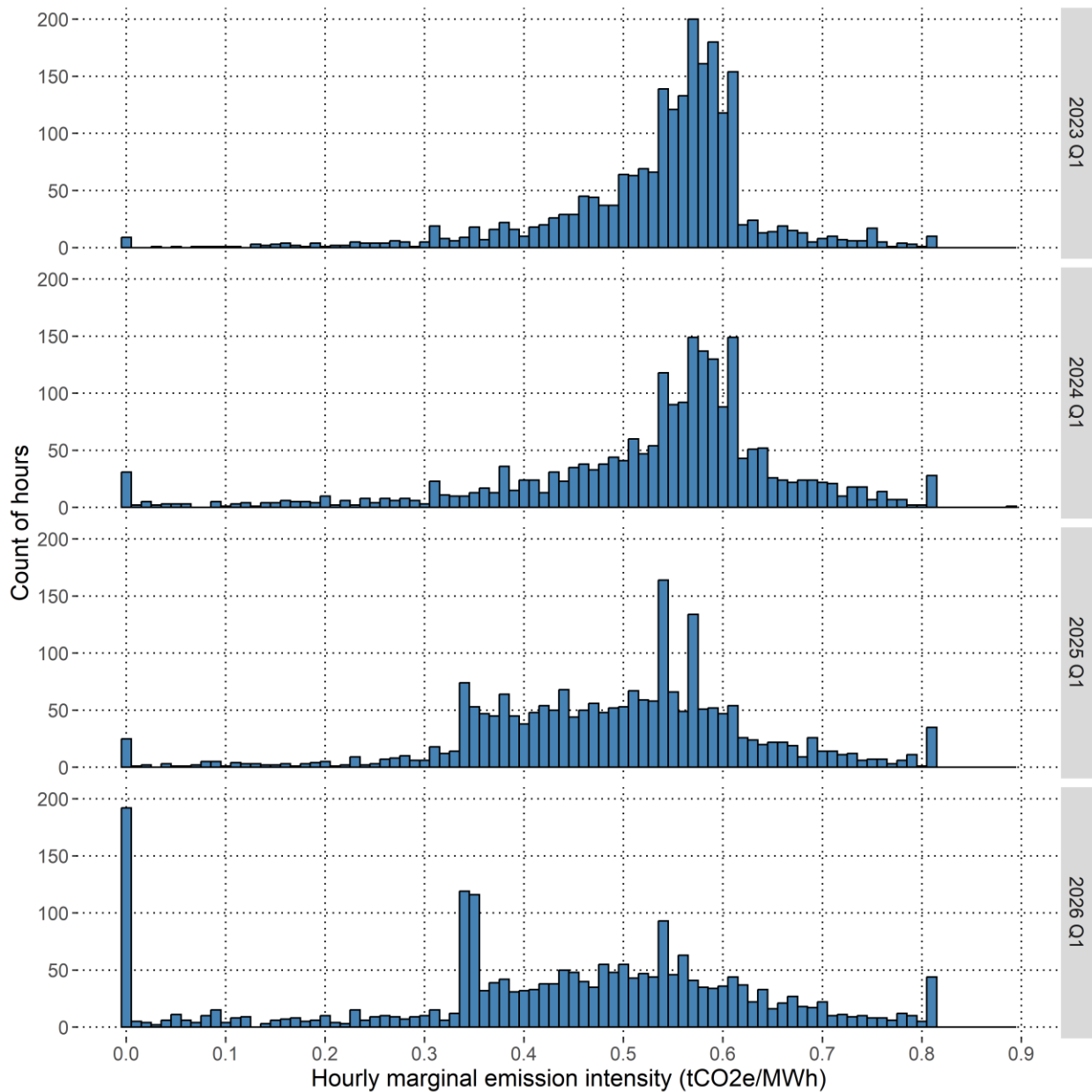
### 1.5.2 Hourly marginal emission intensity

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 28 shows the distribution of the hourly marginal emission intensity of the grid in Q1 for the past four years. Gas-fired steam assets were setting the price quite often historically, as demonstrated by the higher observations around 0.54 to 0.60 tCO<sub>2</sub>e/MWh.

In Q1, combined cycle assets were marginal most often at 41% of the time, followed by cogeneration assets at 20%. Assets that are considered to have a 0.0 tCO<sub>2</sub>e/MWh emission intensity were marginal 16% of the time, indicating an increase in the amount of time the SMP was \$0/MWh.

Figure 28: The distribution of marginal carbon emission intensities in Q1 (2023 to 2026)



## 2 THE POWER SYSTEM

### 2.1 Congestion

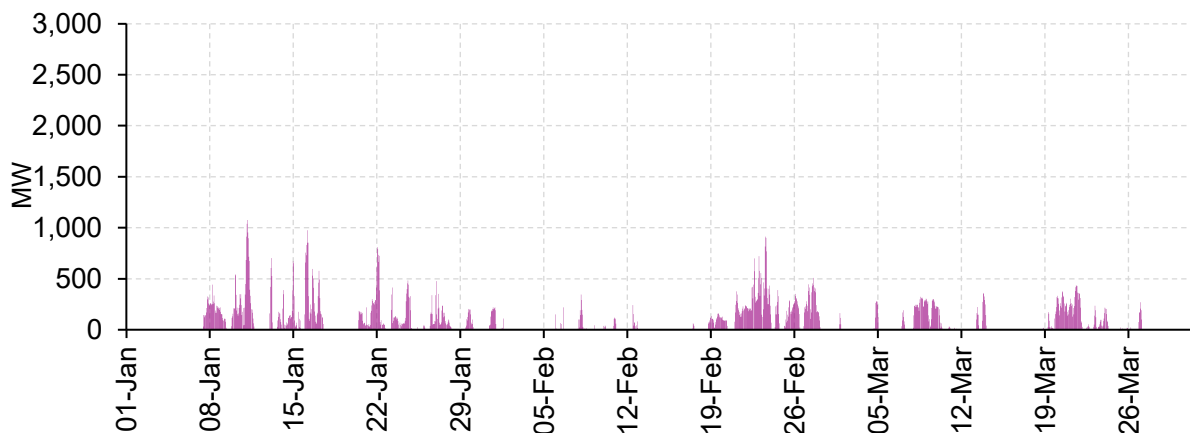
Transmission elements may impose limitations on the transfer of electric energy from one location on the transmission system to another. The AESO mitigates these limitations in real time by curtailing generation.<sup>17</sup>

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.<sup>18</sup>

The frequency and significance of CIG directives increased year-over-year. The MSA estimates that CIG volumes were 160 GWh in Q1 2025 and 561 GWh in Q1, a 250% increase. Quarter-over-quarter, CIG volumes decreased by 23%.

The highest hourly average volume of CIG in Q1 was 1,588 MW, an increase from the Q1 2025 maximum of 1,076 MW (Figure 29 and Figure 31). However, the highest hourly average volume of CIG in Q1 was lower than the maximum value of 2,699 MWh in Q4 2025 (Figure 30).

*Figure 29: Maximum hourly transmission constrained intermittent generation (Q1 2025)*



<sup>17</sup> This is known as constrained down generation. See [ISO Rule 302.1 Transmission Constraint Management](#).

<sup>18</sup> 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 30: Maximum hourly transmission constrained intermittent generation (Q4 2025)

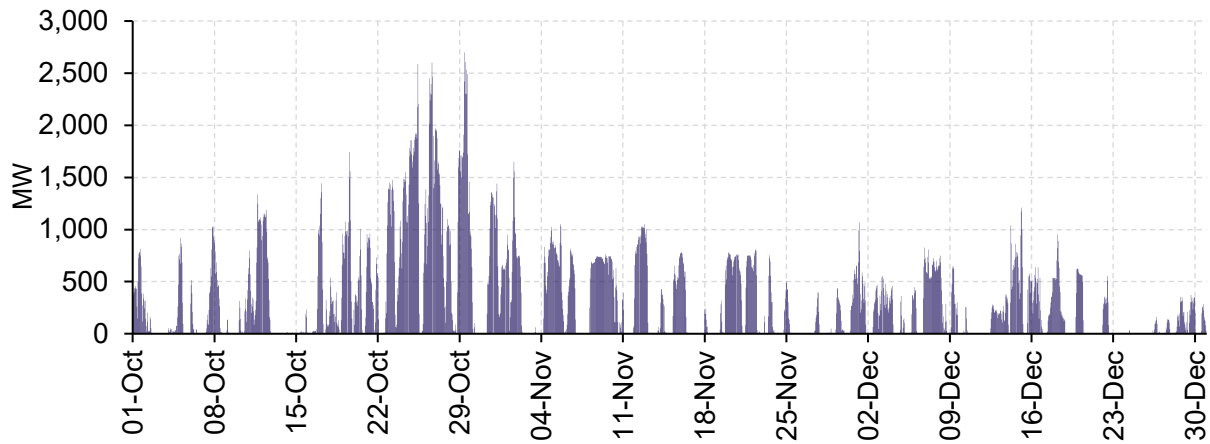
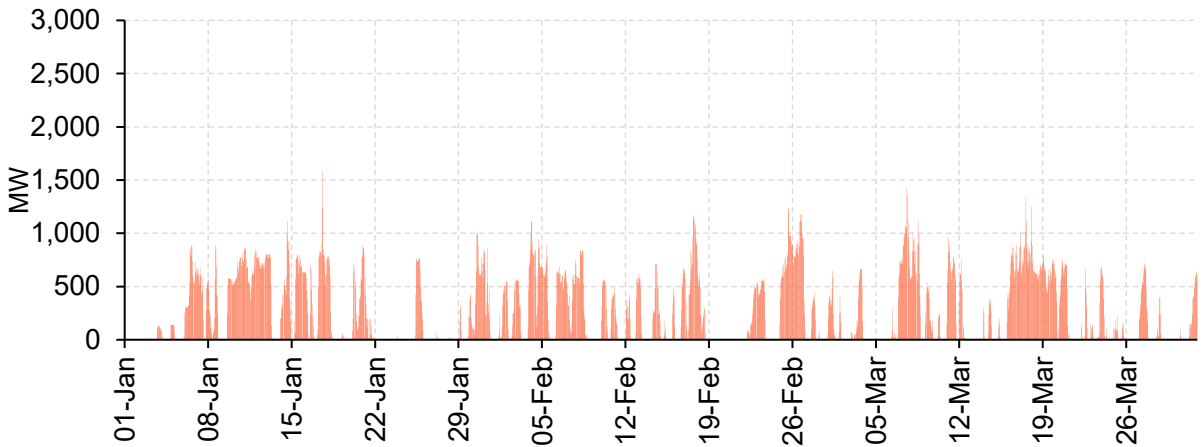


Figure 31: Maximum hourly transmission constrained intermittent generation (Q1 2026)



The increased CIG volumes year-over-year were due to higher intermittent generation. Higher CIG volumes generally align with periods of high intermittent generation or supply surplus events (Figure 32 and Figure 33).

Figure 32: Average hourly potential intermittent generation and CIG (Q1)

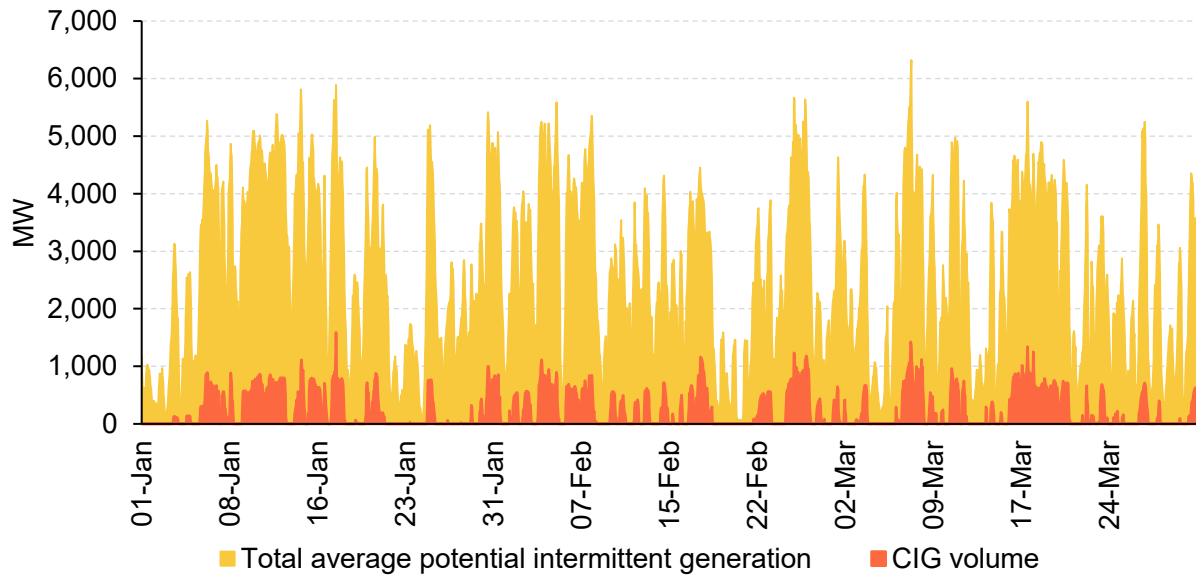
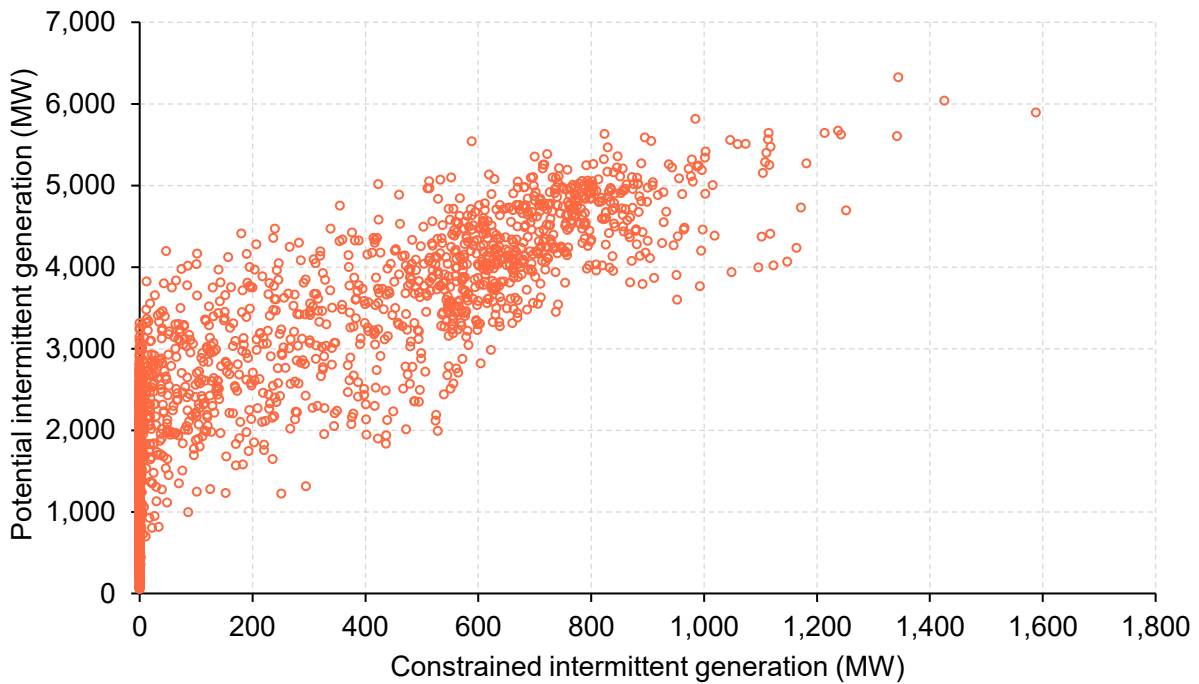


Figure 33: CIG compared to total potential intermittent generation (Q1)



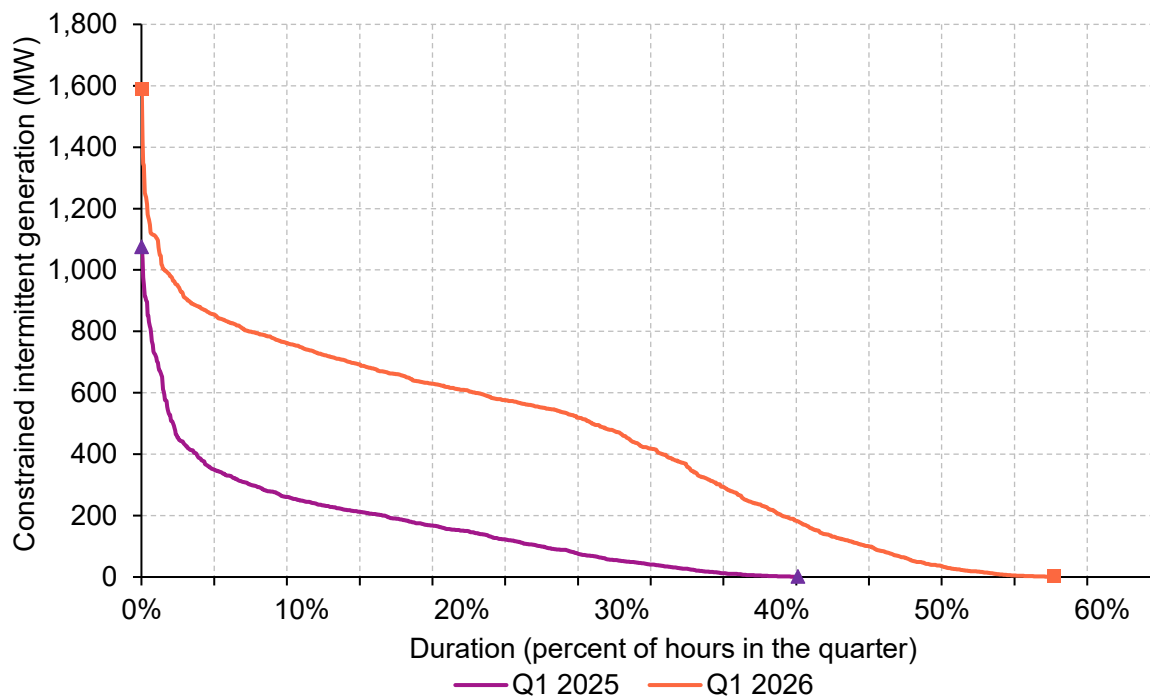
There were over 285 AESO System Controller shift log events for constrained down generation in Q1. Increased CIG volumes may also be due to persistent or frequent limitations to certain transmission elements and may affect one or more generation assets.

In Q1, there were a wide variety of events that occurred over many different transmission elements. Similar to Q4 2025, Q1 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.”<sup>19</sup>

The increase in CIG volumes from Q1 2025 to Q1 occurred at a higher rate than the installation of intermittent generation capacity. While total installed intermittent capacity increased by only 0.3%, average hourly CIG volumes, expressed as a percent of installed intermittent capacity, increased from 0.99% in Q1 2025 to 3.45% in Q1.

Figure 34 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. There were 1,259 hours of CIG volumes greater than 1 MWh in Q1, which is 58% of hours in the quarter. In contrast, Q1 2025 experienced 905 hours of CIG volumes greater than 1 MWh, or 42% of hours.

Figure 34: Duration curves of CIG volume (Q1 2025 and Q1)



Transmission constraint volumes had frequent fluctuations throughout all months of Q1, and each month’s CIG volume was similar with January, February, and March experiencing 191 GWh, 186 GWh, and 185 GWh, respectively. January had the most volume of CIG and the highest peak. The CIG volume in the month of January accounted for 34% of all Q1 volumes. In 56% of hours in January there was at least 1 MWh of CIG.

<sup>19</sup> AESO [Alberta Remedial Action Schemes](#), page 2 (updated October 15, 2025)

In every minute, the AESO determines the constrained SMP using the offer price of the marginal block that is dispatched for supply to meet demand. The constrained SMP accounts for the fact that some generation may be unavailable due to transmission constraints.

The unconstrained SMP is calculated by moving down the merit order from the constrained SMP by the transmission constraint rebalancing volume, which is largely determined by the volume of in-merit generation that was constrained down.<sup>20</sup> 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 hourly pool price. Offer blocks that are dispatched above the unconstrained SMP are paid their offer price.

In Q1, the average constrained SMP was \$4.66/MWh or 14% higher than the average unconstrained SMP (Table 13). This compares to a difference of 2% in Q1 2025 and 35% in Q4 2025. The lower premium in Q1 2025 reflects less CIG in Q1 last year. The higher premium in Q4 2025 was the result of more CIG, particularly in October.

*Table 13: Average constrained and unconstrained SMP by month (Q1)*

	Constrained SMP (\$/MWh)	Unconstrained SMP (\$/MWh)	Difference	
			(\$/MWh)	(%)
Jan	\$45.74	\$39.44	\$6.31	16%
Feb	\$26.08	\$22.39	\$3.69	16%
Mar	\$37.56	\$33.68	\$3.88	12%
<b>Q1</b>	<b>\$36.81</b>	<b>\$32.15</b>	<b>\$4.66</b>	<b>14%</b>

The constrained and unconstrained SMP differed by \$1/MWh or more in 41% of minutes in Q1. In comparison, Q1 2025 had 15% of minutes with a variance of \$1/MWh or more, and Q4 2025 had the difference in 46% of minutes.

In Q1, the largest difference between the constrained SMP and unconstrained SMP was \$560/MWh, which occurred in HE 17 of January 26 (Figure 35). The largest difference was lower in Q1 2025 at \$231/MWh, but in Q4 2025 the largest difference occurred on October 29 at \$999.99/MWh.

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 elevated, the SMP is lower as higher priced generation is displaced. Therefore, despite the high amount of CIG volumes in Q1, there was often only a small difference between the constrained and unconstrained SMP (Figure 36). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity have a small

<sup>20</sup> The transmission constraint rebalancing volume includes the volume of in-merit energy which has been constrained down, but also the reduced import interchange transactions in the first hour of a constraint event, and dispatched transmission must-run energy. See [ID#2015-006R](#) Calculation of Pool Price and Transmission Constraint Rebalancing Costs during a Constraint Event for more information.

impact on price. Only 0.3% of minutes in Q1 experienced a difference of greater than \$100/MWh between the constrained and unconstrained SMP.

Figure 35: The difference between the constrained SMP and the unconstrained SMP (Q1)

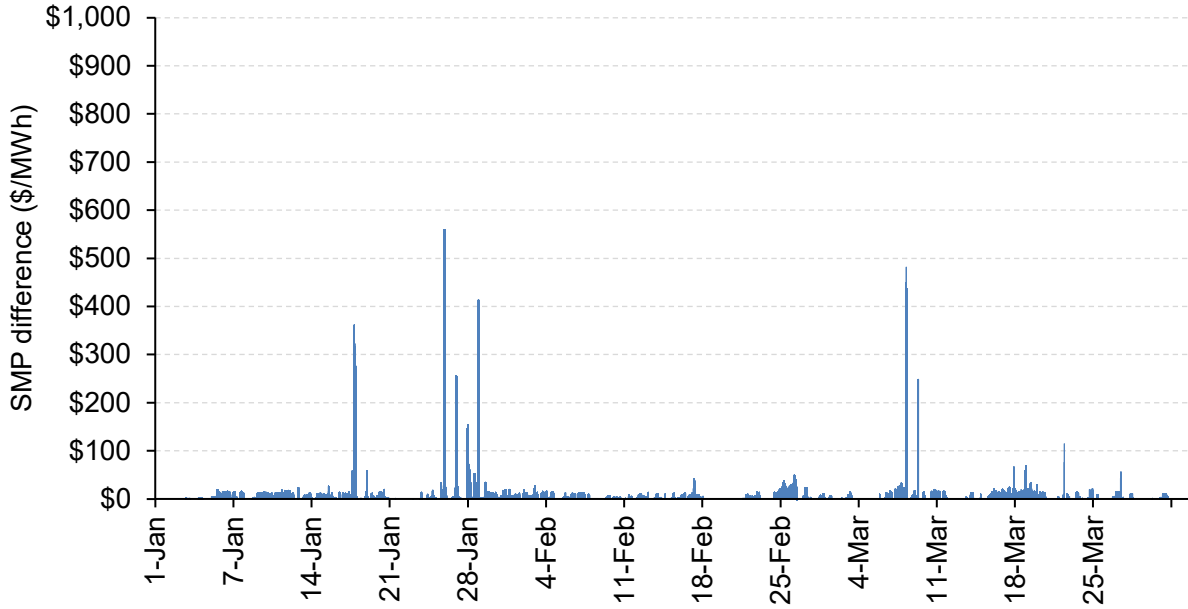
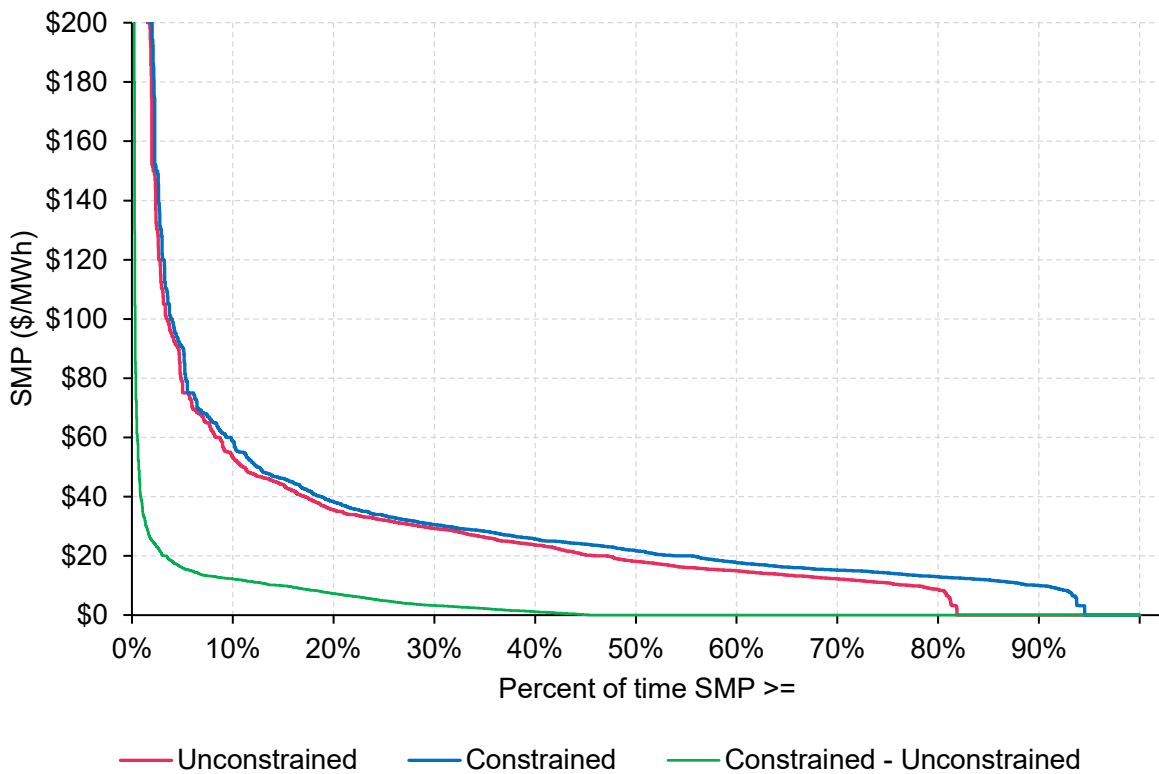


Figure 36: Duration of unconstrained SMP, constrained SMP, and the difference between the constrained and unconstrained SMP (Q1)

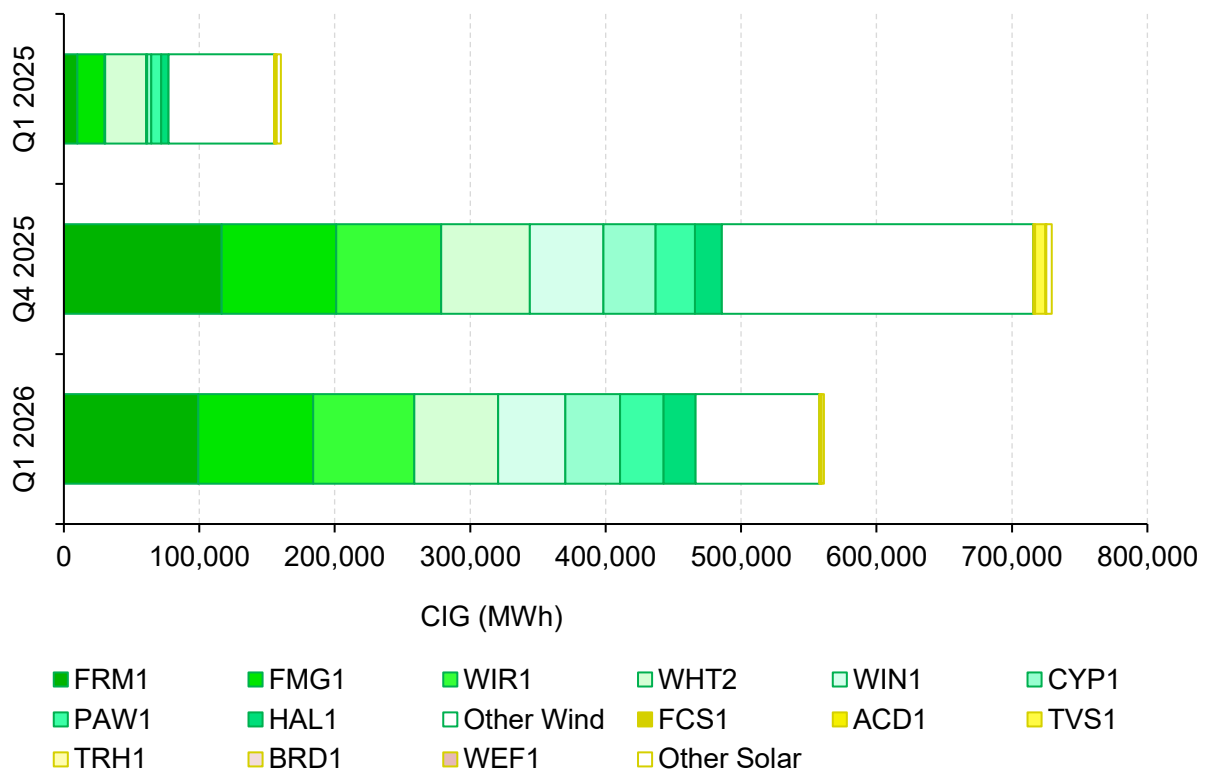


Transmission capability varies throughout the province, and certain regions experience more congestion than others, often leading to local constraints. Often, wind and solar assets are not constrained uniformly throughout the province.

In Q1, the eight most constrained wind assets accounted for 84% of the total CIG volume but only 27% of total installed wind capacity. Forty Mile Bow Island, Forty Mile Granlea, and Wild Rose were the most constrained wind assets in Q1 (Figure 37). These three assets represent 12% of Alberta’s installed wind capacity, however they accounted for 46% of the wind CIG volume in Q1. These three assets were all constrained under the RAS 164 constraint, which is discussed above.

Fox Coulee Solar (80 MW) was the most constrained solar asset in Q1, with a total of 352 MWh constrained. This asset was constrained for a variety of reasons; most of which relate to contingencies overloading 801s 901T.<sup>21</sup> The top six most constrained solar assets have an aggregate maximum capability of 740 MW and were constrained by 1,660 MWh in Q1. The top six constrained solar assets accounted for 40% of total solar capacity but accounted for 50% of solar CIG volumes in Q1. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

Figure 37: Wind and solar CIG by asset (Q1 2025, Q4 2025, Q1)

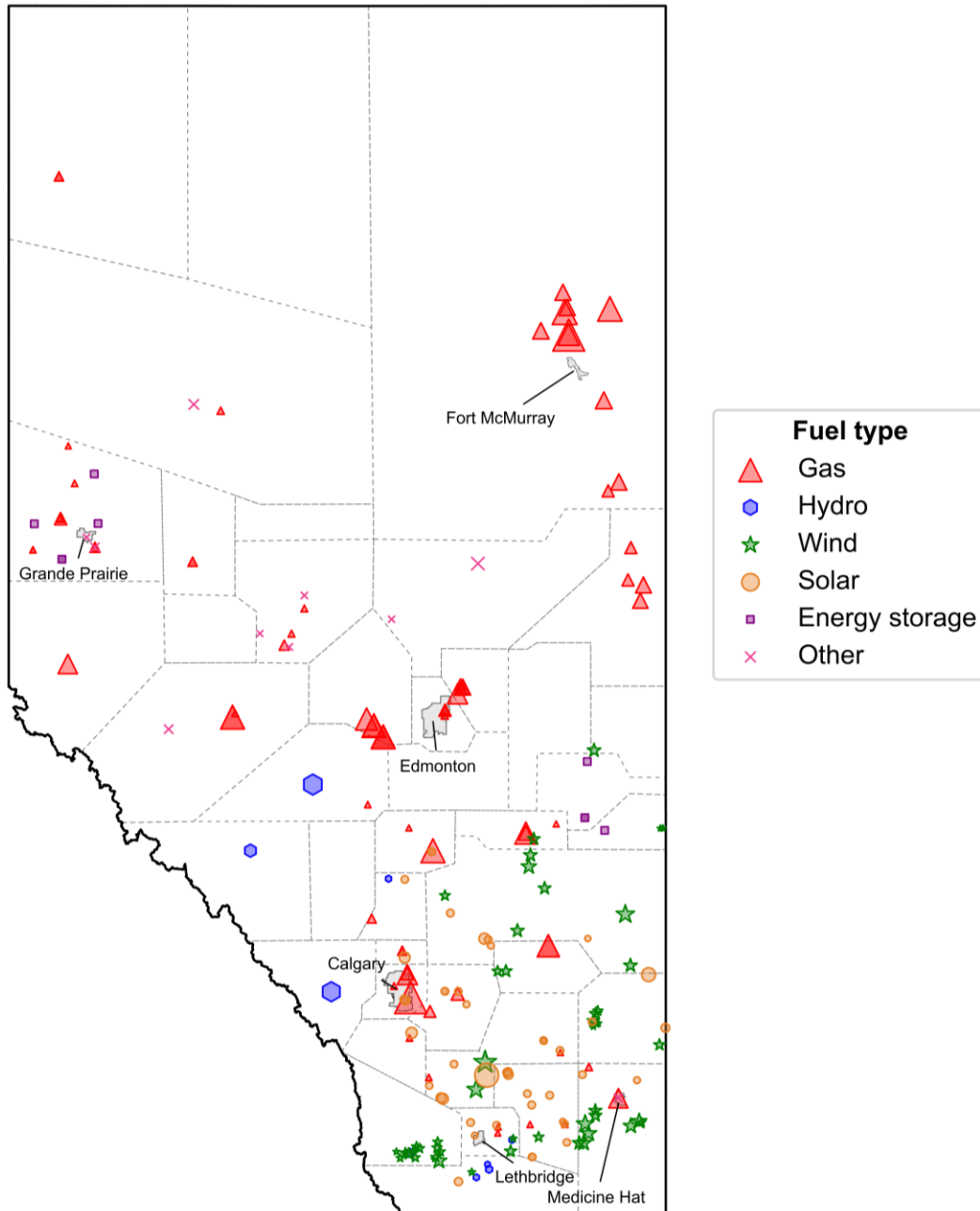


<sup>21</sup> RAS 200 is not mentioned in the log; however, it is related to mitigation actions relating to 801s 901T. RAS 200 901T-801S Anderson Overload Mitigation mitigates potential overload and other reliability concerns in the area. AESO [Alberta Remedial Action Schemes](#), page 3 (updated October 15, 2025)

## 2.2 Prices by location

Figure 38 illustrates the location of generation assets, by fuel type, across Alberta. The dashed lines on the figure indicate the boundaries of transmission planning areas. While thermal assets are generally located near load centres throughout the province, intermittent assets (wind and solar) have generally been developed in south and central areas.

Figure 38: Location of generators in Alberta by fuel type and size (December 31, 2025)



In recent years there has been a significant increase in intermittent capacity in Alberta. Wind capacity increased from 1,800 MW at the beginning of 2021 to 5,600 MW by the end of 2025, while solar capacity increased from 100 MW to 1,850 MW over the same period. Most of this additional capacity was developed in the south of the province.

Figure 39 and Figure 40 provide heat maps of generation curtailments as a percentage of potential generation. The nodes on the map indicate generation assets rather than transmission buses. For each generation asset, the annual figures are calculated by taking the ratio of total generation curtailed to total potential generation over the year.

To calculate the curtailed volumes for intermittent assets, the MSA used its calculation of constrained intermittent generation (CIG), as discussed in section 2.1. CIG is calculated using potential power capability data to estimate the counterfactual amount of intermittent generation that could have been delivered to the grid had there been no transmission constraint. A detailed outline of this calculation is provided in the MSA's Quarterly Report for Q2 2023.<sup>22</sup>

For thermal, hydro, and other generator types, the MSA used energy merit order snapshot data to estimate curtailed volumes. Specifically, curtailed volumes were estimated by taking the difference between available MW and dispatched MW for offer blocks that were dispatched and offered below the constrained SMP. Hours where the constrained SMP was equal to \$0/MWh were excluded because the difference may have been caused by curtailments due to supply surplus. For thermal, hydro, and other generator types, the declared available capability was used to calculate potential generation.

As illustrated by the legends on Figure 39 and Figure 40, darker areas of the map indicate higher levels of congestion. In areas of the figures where there are no nodes, the heat map determines the shading gradient using an algorithm which uses an inverse relationship of the distance to the nearest nodes, so a closer node has a greater impact on the prevailing shade.

The figures illustrate the following areas of congestion:

- In 2021, HR Milner (which is in the central west) had 1.3% of its available capacity constrained largely due to 7L228 and 7L20 outages in January and February.
- In 2023 and 2024, Rainbow 5 (which is in the northwest) had 3.5% and 5.2% of its available capacity constrained, respectively, due to real time overloads on the Rainbow export cutplane from October 2023 to February 2024.
- In the southeast of the province, congestion at intermittent assets has increased over time as more installed intermittent capacity has led to higher generation in the area.

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<sup>22</sup> [MSA Quarterly Report for Q2 2023](#) – starting at page 50.

Figure 39: Curtailed generation as a percent of total potential (2021 to 2024)

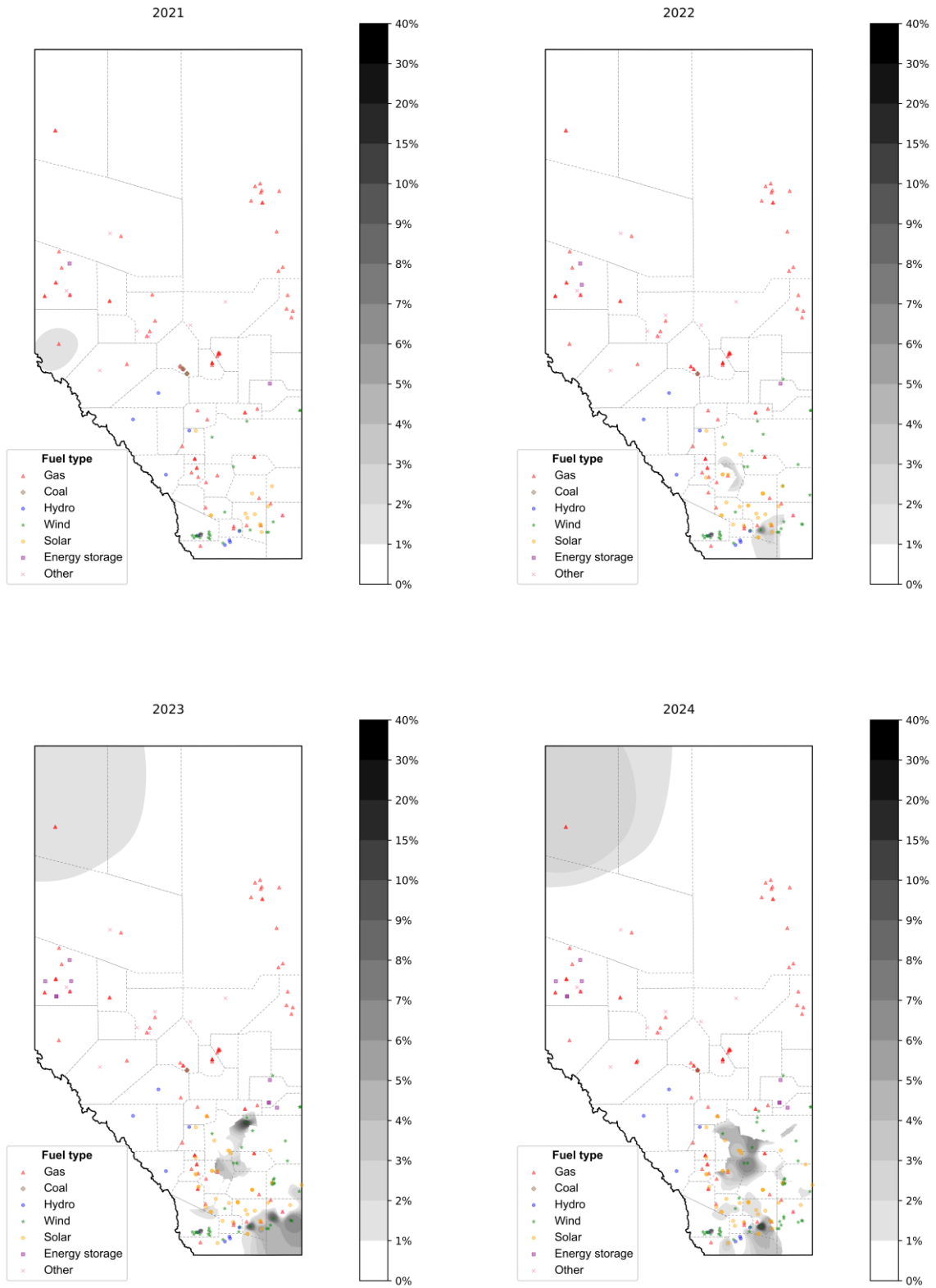
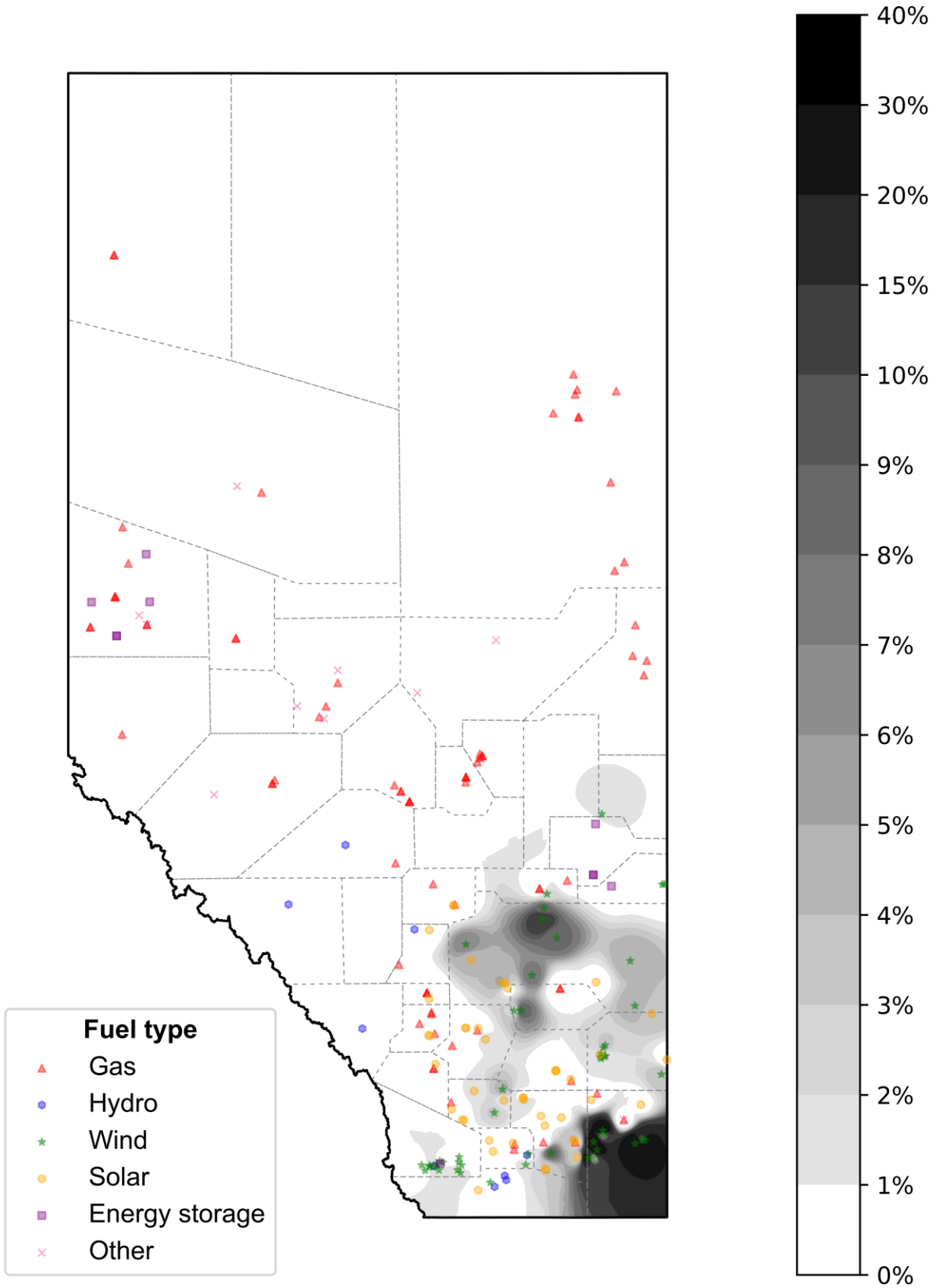


Figure 40: Curtailed generation as a percent of total potential (2025)



Alberta's current uniform pool price is expected to be replaced by locational marginal prices (LMP) in 2028 as part of the implementation of the Restructured Energy Market (REM).

To illustrate the potential impact of LMP, the MSA has estimated counterfactual pseudo locational marginal prices (pLMP) for the period from January 1, 2021 to December 31, 2025. For the purposes of this analysis, each generation asset is treated as a separate pseudo node, even where two or more assets share the same bus in the physical transmission network. The analysis does not consider loads that are directly connected to the transmission network. The pLMP were calculated at each pseudo node.

Understanding the methodology used to calculate the pLMP requires an understanding of how constrained and unconstrained SMPs are currently calculated. In each minute:

- The constrained SMP is determined by the offer price of the marginal block that is dispatched for supply to meet demand. The constrained SMP accounts for the fact that some generation may be unavailable due to transmission constraints.
- The unconstrained SMP is calculated by moving down the merit order from the constrained SMP by the transmission constraint rebalancing volume, where the largest component is generally the volume of in-merit energy that has been constrained down. 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. Offer blocks that are dispatched above the unconstrained SMP are paid their offer price.

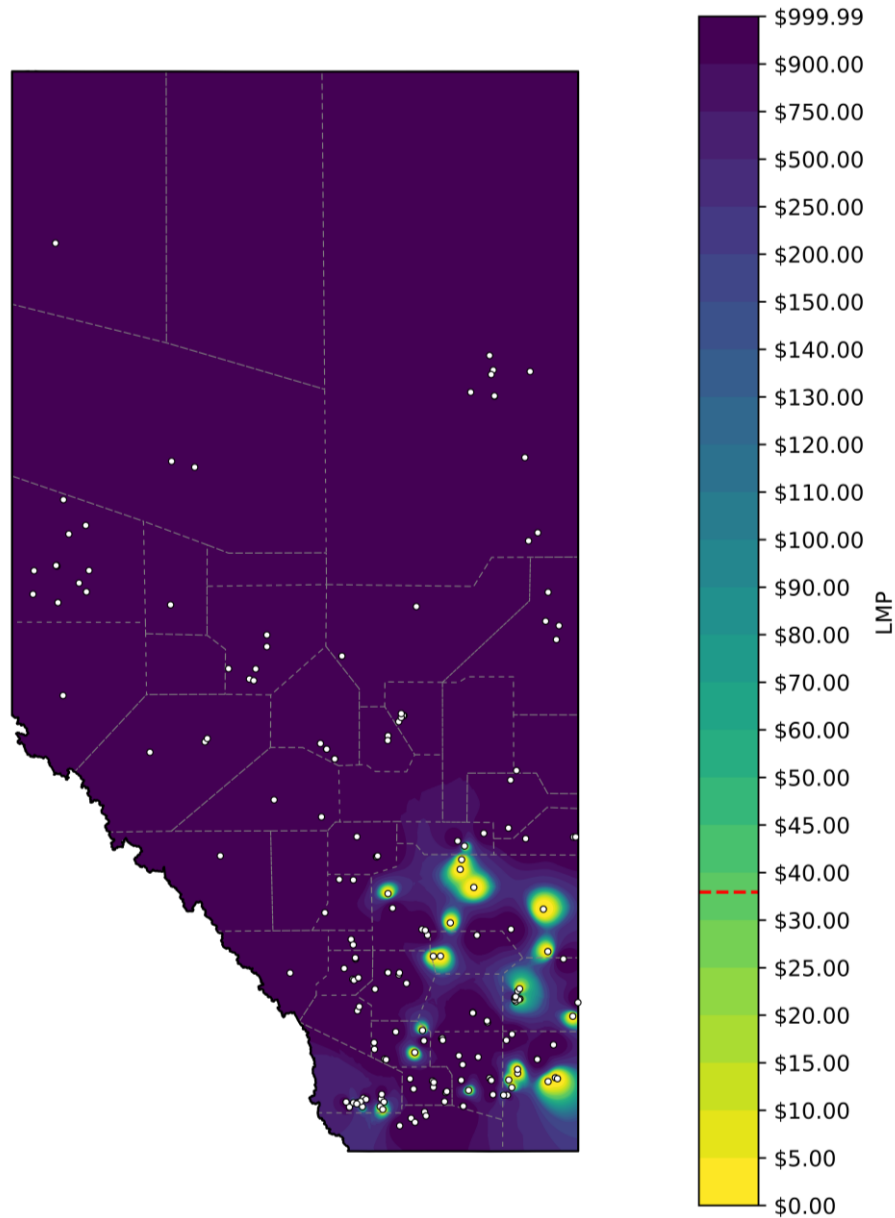
To calculate the pLMP in an hour, the average constrained SMP is compared with the average unconstrained SMP in that hour:

- If the average constrained SMP is equal to the average unconstrained SMP, the pLMP at each generator is set equal to average unconstrained SMP (the pool price). In such an hour, there was either no congestion or insufficient congestion to cause a price impact.
- If the average constrained SMP was higher than the average unconstrained SMP, then:
  - For generation assets that were determined to be curtailed for a transmission constraint, the pLMP is set equal to the offer price of the asset's highest dispatched block.
  - For generators that were unconstrained, the pLMP is set equal to the average constrained SMP.
- By construction, the average constrained SMP cannot be below the average unconstrained SMP.

The MSA may alter this methodology in future analyses. For clarity, real LMP that will be implemented as part of the REM will be calculated by solving a constrained optimization problem.

Figure 41 illustrates the pLMP across Alberta for HE 20 of October 26, 2025. In this hour, the average unconstrained SMP (the pool price) was \$35.88/MWh, which is indicated by the dashed red line on the legend, and the average constrained SMP was \$999.98/MWh.<sup>23</sup> During this hour, binding transmission constraints affected certain intermittent generators in the south of the province. As a result, the pLMP at the pseudo nodes connecting these generators were \$0/MWh, which is the highest offer price offered by these assets.

Figure 41: Alberta pLMP (October 26, 2025, HE 20)



<sup>23</sup> In some areas between nodes the heat map displays a shade of green although there were no pLMPs at this price level in this hour. The colours away from the nodes are filled in by an algorithm which uses an inverse relationship of the distance to the nearest nodes, so a closer node has a greater impact on the prevailing colour.

At unconstrained generators, the pLMP was set equal to the average constrained SMP over the hour: \$999.98/MWh. This resulted in large price disparities which are illustrated. At most generators, the pLMP was set at the constrained price, which was much higher than the pool price and was almost at the offer cap. However, at the constrained intermittent generators pLMP were set at the price floor of \$0/MWh.

Hourly pLMP can be averaged over time. When doing so, pseudo nodes are excluded if the associated asset was not on the Current Supply and Demand page at the beginning and end of the period or had no offers in the merit order during the period. The reason for this approach is to prevent higher or lower pLMP for portions of the period from erroneously suggesting the existence of congestion when there may have been none.

For assets that were not in the merit order for some hours of the month, the pLMP at nearby assets of the same fuel type were used to fill in the gaps.

Figure 42: Alberta pLMP (October 2025)

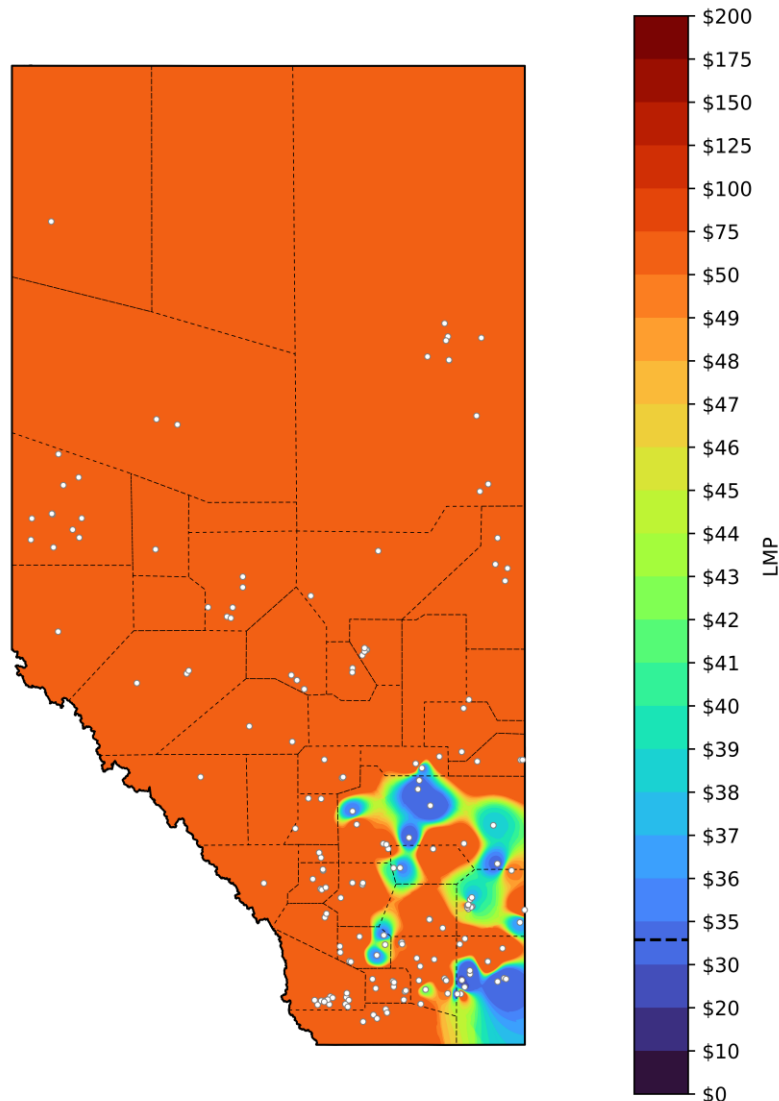


Figure 42 illustrates the pLMP for October 2025. Importantly, the pattern of congestion implied by Figure 41 and Figure 42 are different because the nature of congestion in October 2025 varied throughout the month. For some intermittent assets in the southeast of the province, transmission constraints meant that the average pLMP at the associated pseudo nodes were below the monthly average pool price (which was \$32.88/MWh and is again indicated by the dashed line on the legend).

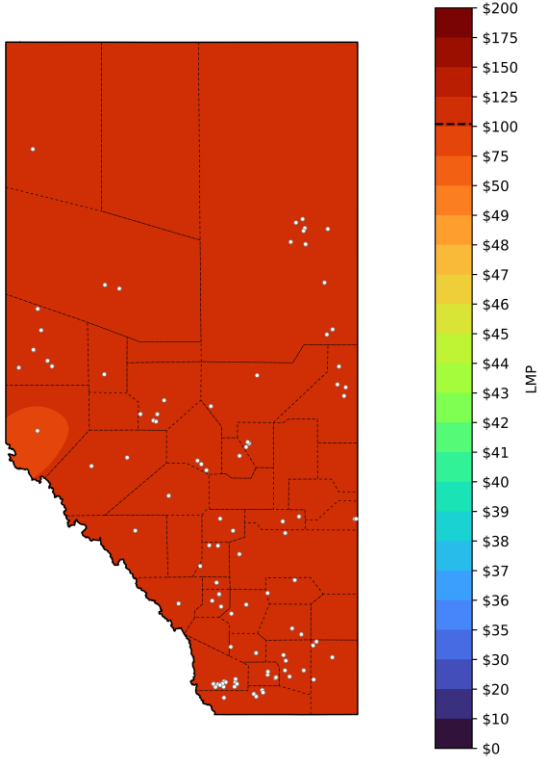
Most pseudo nodes were generally unconstrained during October 2025 and had pLMP of approximately \$60/MWh. While the same shade of orange is predominant in Figure 42, this does not mean that the average pLMP in October 2025 were exactly the same at most pseudo nodes. Of note, the average pLMP at most pseudo nodes were higher than the average pool price, driven by high constrained prices in a small number of hours.

Figure 43 and Figure 44 illustrate average pLMP for the years from 2021 to 2025. The figures show the following:

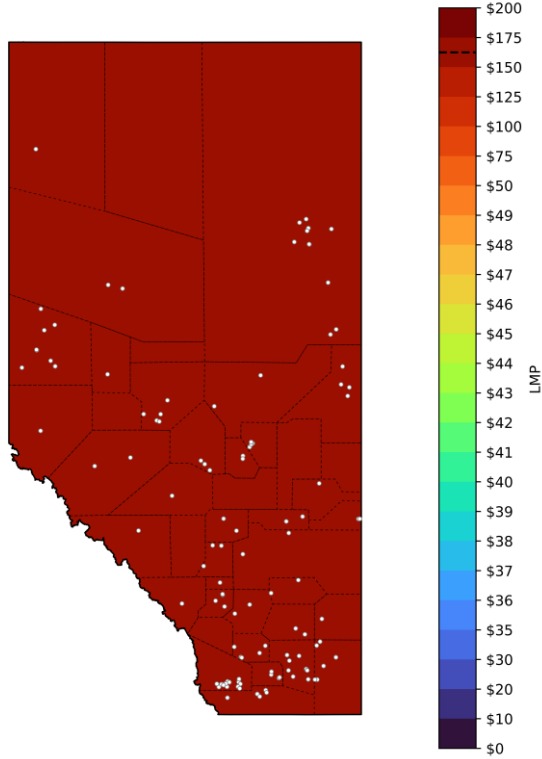
- In 2021, the pLMP at HR Milner was lower than the average pool price due to the congestion outlined above and displayed in Figure 39.
- The pLMP in 2022, 2023, and 2024 are shown to be uniform across the province despite some congestion in the southeast (Figure 39). The pLMP in these years were not sufficiently different to fall into different bins of the colour scale.
- Some congestion at HR Milner in October of 2025 (8.9% of potential for the month) occurred due to real-time overload of 7L80, which led to the pLMP being lower than in surrounding areas.
- As outlined above, in 2025, there was more congestion at intermittent assets in the southeast of the province (Figure 40). This led to more divergence of pLMP in that year (Figure 44). At intermittent assets that were often constrained, the average pLMP were below the average annual pool price. On the other hand, for generation assets that were generally unconstrained, the average pLMP were higher than the average annual pool price due to high constrained prices in a small number of hours.

Figure 43: Alberta pLMP (2021 to 2024)

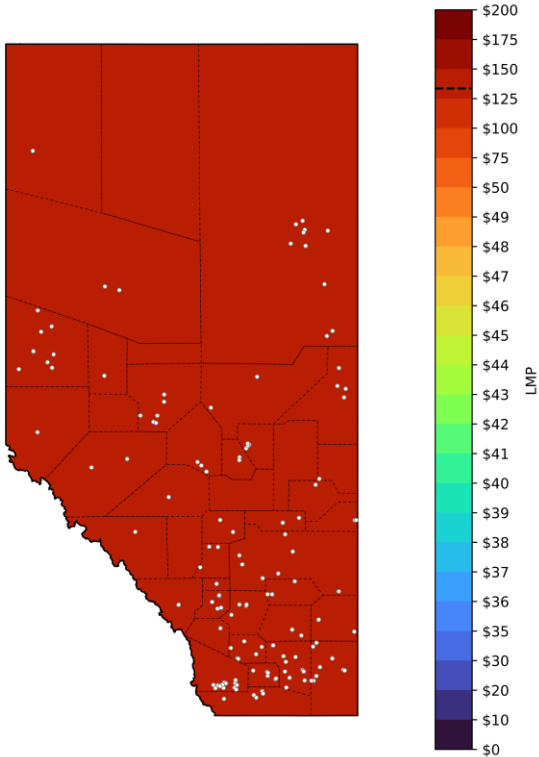
2021 - Average pool price: \$101.93/MWh



2022 - Average pool price: \$162.46/MWh



2023 - Average pool price: \$133.63/MWh



2024 - Average pool price: \$62.78/MWh

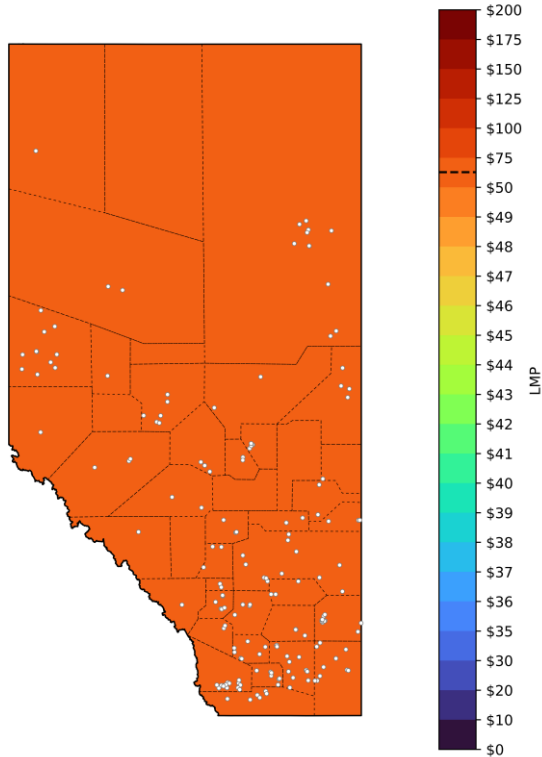
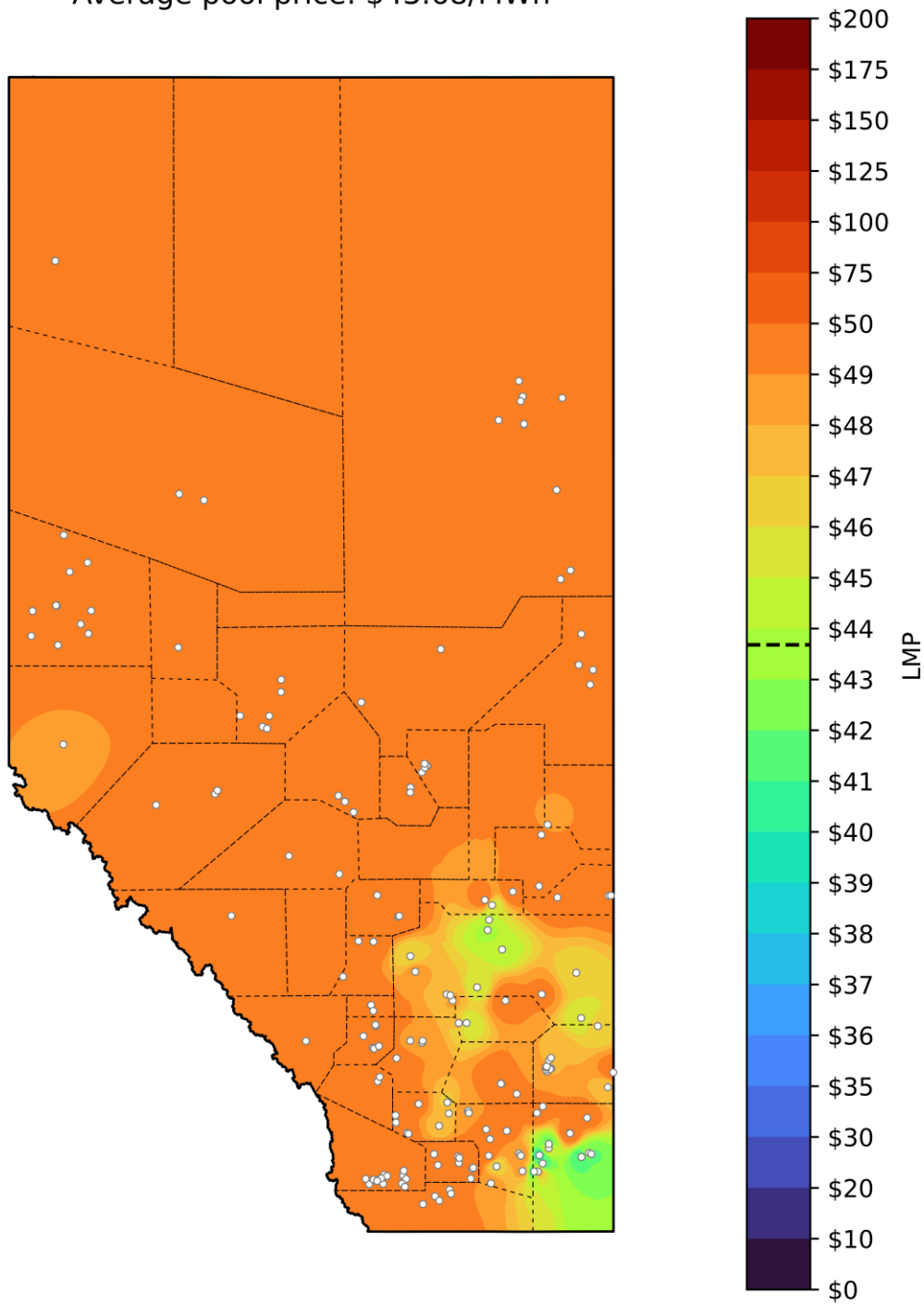


Figure 44: Alberta pLMP (2025)

Average pool price: \$43.68/MWh



Assuming all wholesale market consumers in Alberta pay a common price in each hour, a generation-weighted pLMP can be calculated that would equal the price consumers would have to pay to fund all generation settlement costs in that hour. This hourly price can then be averaged over time to obtain an average of the total payments to generation.

The annual averages of generation-weighted pLMP are reported in Table 14, along with averages of unconstrained SMP. Generation-weighted pLMP are higher than unconstrained SMP in all years, ranging from less than 1% higher in 2022 to 11% higher in 2025. This analysis provides an indication of how settlement based on LMP in the future may impact the overall cost to consumers of generation.

*Table 14: Average unconstrained SMP and generation-weighted pLMP (2021 to 2025)*

<b>Year</b>	<b>Unconstrained SMP (\$/MWh)</b>	<b>Generation-weighted pLMP (\$/MWh)</b>
2021	\$101.93	\$104.24
2022	\$162.46	\$163.71
2023	\$133.63	\$136.86
2024	\$62.78	\$64.75
2025	\$43.68	\$48.57

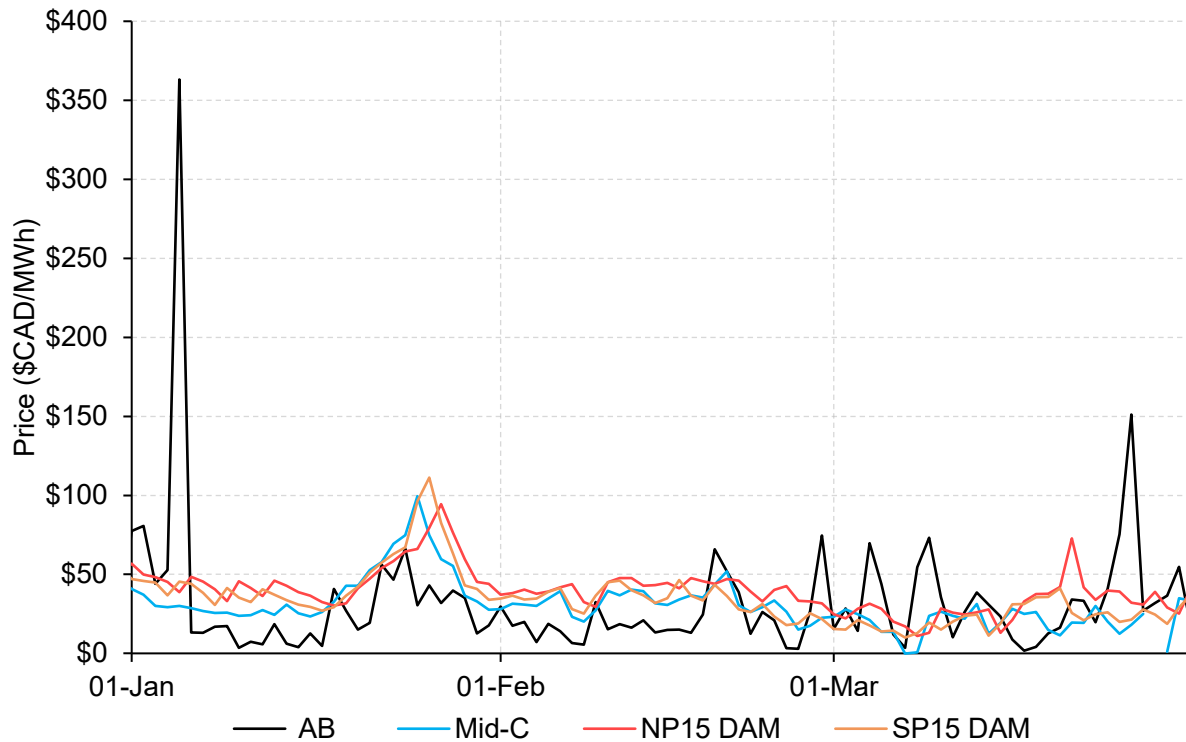
### **2.3 Interties**

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 45 shows daily average power prices over Q1 in Alberta, Mid-C, and at NP15 and SP15 in California (all shown in CAD). Over the quarter, Alberta pool prices averaged \$32.15/MWh while prices in Mid-C averaged \$30.67/MWh, and prices at NP15 and SP15 averaged \$39.78/MWh and \$34.40/MWh, respectively.

The higher average price in Alberta relative to Mid-C was driven by higher pool prices in a small number of hours. Over the quarter, Alberta pool prices were lower than prices in Mid-C in 70% of hours leading to net exports on average.

Figure 45: Daily average power prices in Alberta, Mid-C, and NP15/SP15 in California (Q1)<sup>24</sup>



In January, Mid-C prices averaged \$39.95/MWh compared to \$39.44/MWh in Alberta. However, Mid-C prices were higher in 77% of hours over the month driving net exports of 266 MW on average. In February, Mid-C prices averaged \$31.62/MWh while Alberta averaged \$22.39/MWh, and Alberta prices were lower in 81% of hours, so exports from Alberta continued.

However, in March, Mid-C prices declined to average \$20.16/MWh compared to \$33.68/MWh in Alberta, and prices in Alberta were higher in 50% of hours. This was a driver of net imports into Alberta over the month, which has not occurred since September 2023. Imports on MATL offset slight export volumes on the BC and Saskatchewan interties, leading to net imports of 23 MW on average.

Overall, Alberta continued to be a net exporter of power in Q1, and exports were highest in February (Table 15). Alberta exported in 59% of hours over the quarter and imported in 35% of hours.

<sup>24</sup> Mid-C price data is unavailable for most of March 28, the associated hours are removed from applicable calculations.

Table 15: Average net imports (Q1 and Q1 2025)

	2025				2026			
	BC	MATL	SK	Total	BC	MATL	SK	Total
Jan	-557	-37	-	-594	-241	16	-41	-266
Feb	-448	-8	-	-456	-263	-10	-24	-297
Mar	-347	17	-	-330	-17	62	-22	23
<b>Q1</b>	<b>-451</b>	<b>-10</b>	<b>-</b>	<b>-461</b>	<b>-170</b>	<b>24</b>	<b>-29</b>	<b>-176</b>

A planned outage, which was scheduled on March 6, resulted in BC/MATL coming offline beginning on March 16 in HE 10. The BC intertie returned to service earlier than expected on March 17 during HE 14, and MATL returned on March 18 during HE 19.

Figure 46: Daily average import and export volumes on BC/MATL, joint capability, and the Alberta - Mid-C price differential (Q1)

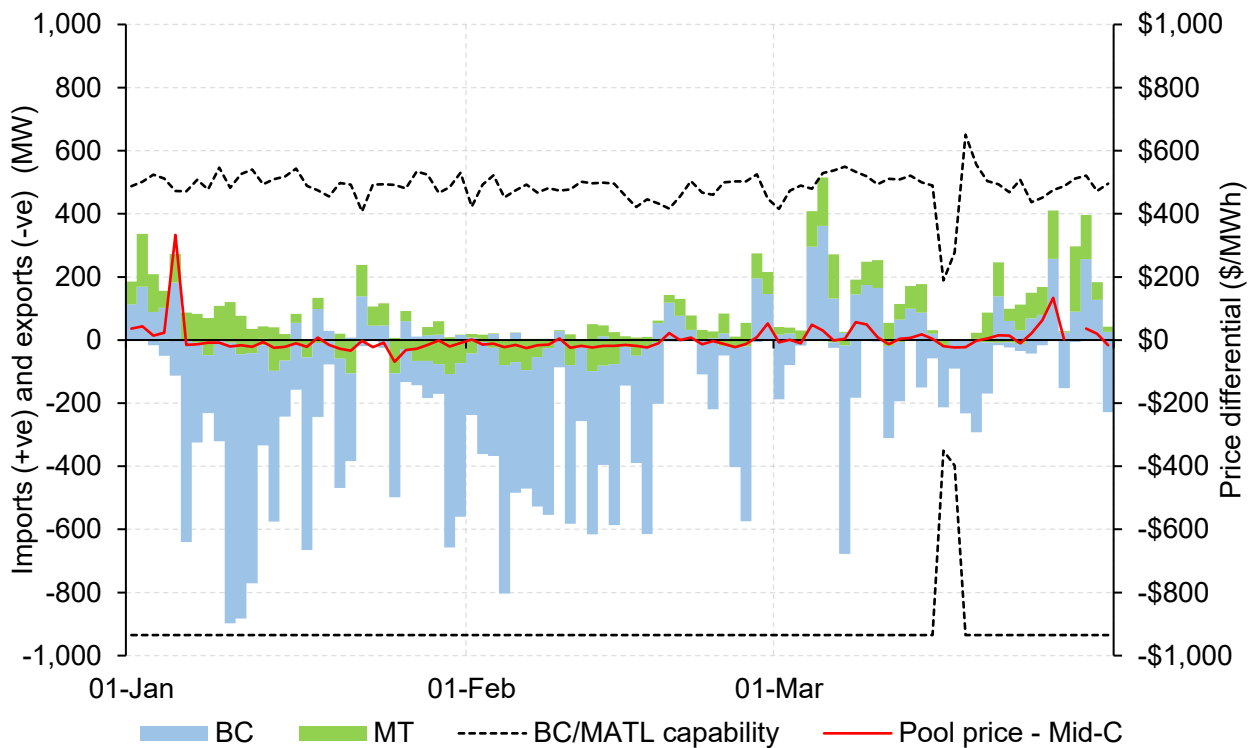
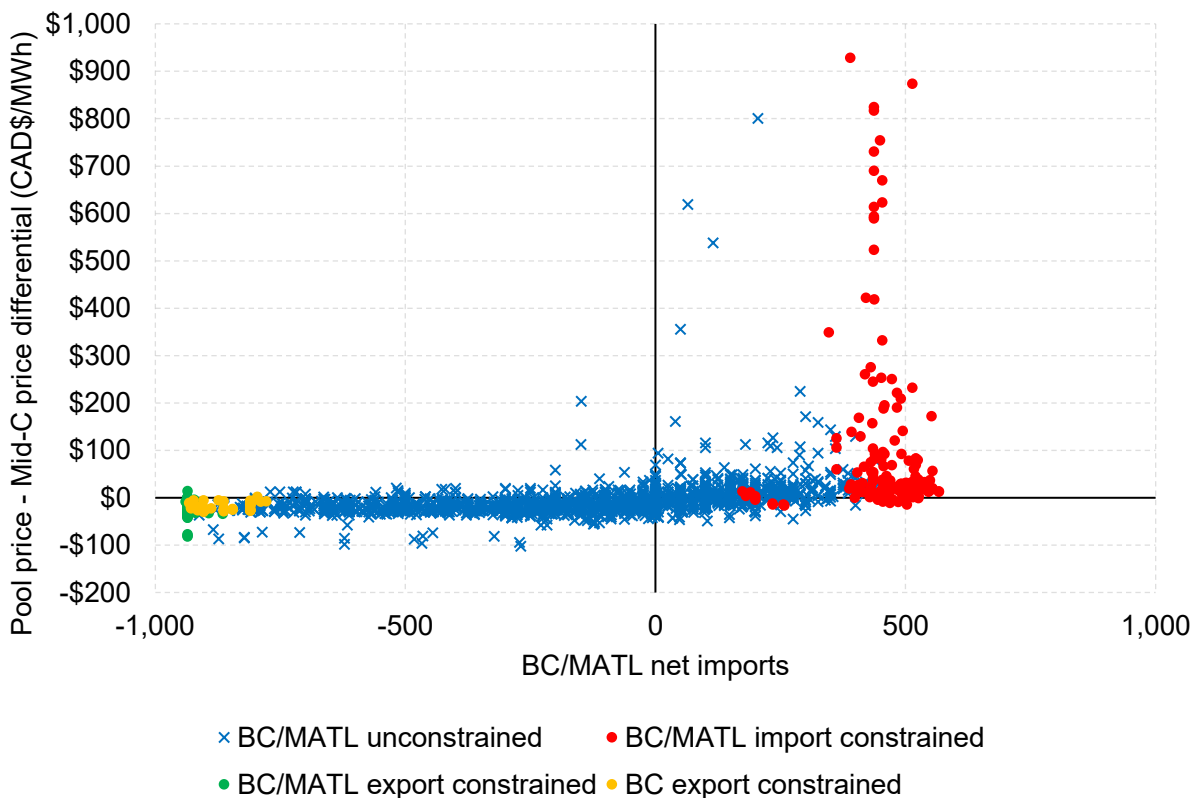


Figure 47 shows a scatterplot of the Alberta and Mid-C price differential against net imports on BC/MATL for each hour of the quarter. Over Q1, there were some hours where export bids or scheduled volumes were at or above BC/MATL export capability, meaning that BC/MATL was export constrained (shown in green). BC/MATL exports were constrained for 8% of the time over the quarter.

While BC/MATL was export constrained, the price differential between Alberta and Mid-C averaged negative \$22/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 export bids binding but subsequently transmission capacity being reduced.

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 2% of the time.

Figure 47: Alberta and Mid-C price differential and net imports on BC/MATL (Q1)



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 8% of the time over the quarter. While import constrained, the price differential between Alberta and Mid-C averaged \$104/MWh and import capability averaged 464 MW.

There were a few observations where the price differential was high, but imports did not make full use of the available capability. For example, on January 5 in HE 08 the price differential was \$619/MWh, but net imports were only 65 MW while import capability was 466 MW. As discussed in section 1.2.1, the high prices during this hour were the result of a forced outage at Shepard, cold weather, and low intermittent generation. However, due to a higher wind forecast, imports did not fully use available intertie capability.

In addition, on Saturday, February 28 in HE 09 the price differential was \$800/MWh, but net imports were only 205 MW while import capability was 453 MW. The high pool price in this hour was driven by low intermittent generation, and outages at Genesee 3 and a Shepard CT, in addition to derates at Base Plant, Firebag, and Syncrude. Importers did not predict the high pool price for this hour because of a prolonged period of relatively low pool prices and because the AESO's wind forecast overestimated wind generation by 320 MW.

Figure 48 illustrates marginal congestion rents for intertie capacity between Alberta and external markets connected via the BC intertie and MATL from 2021 to Q1 2026. The marginal congestion rent provides the incremental value of 1 MW of additional intertie capacity. It is calculated as the sum of the price differentials across the interties in hours when flows were constrained.

The marginal congestion rent accrues when the intertie's capacity limit binds and prices on the two sides of the intertie differ. Constrained observations are identified in the same manner as in Figure 47; an intertie is constrained when scheduled flow is at line capability or when offers/bids meet or exceed line capability. Only positive contributions are included, reflecting economic transfers, and the analysis does not account for transmission costs.

External prices are proxied using real-time locational marginal prices (LMP) at nodes in the Western Energy Imbalance Market (WEIM). The Sumas node<sup>25</sup> on the BC-US border is used to proxy pricing in BC, and the Rainbow node<sup>26</sup> near Great Falls, Montana is used for MATL as it's near the intertie's termination point. Prices at these nodes may differ from broader prices in Mid-C and California due to congestion within the WEIM.

Congestion rent is calculated on an hourly basis for import and export constrained conditions and is attributed to each intertie based on the price differential. For hours in which BC and MATL were jointly constrained, the marginal value was allocated between the two interties based on their relative share of scheduled flow.

These results are aggregated monthly by intertie and direction, providing insight into the relative contribution of BC and MATL and the extent to which value is driven by imports during periods of higher pool prices or exports during periods of lower pool prices. The resulting measure reflects the marginal value of intertie capability over time.

In 2021, 2022, and for much of 2023, pool prices were higher than prices in external markets and imports were the drivers of congestion rent (Figure 48). Congestion rents were highest in August 2022 when pool prices in Alberta were well above external prices, and the BC intertie and MATL were import constrained in over 50% of hours (Figure 49). The high import volumes combined with elevated price differentials to drive the marginal congestion rent for the month to \$126,000.

In recent years, the price differentials have moderated, and marginal congestion rents have lowered as a result. For much of 2024 and 2025, pool prices have been lower than prices in

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<sup>25</sup> Sumas node refers to the WEIM locational marginal pricing node SMS\_GNODEGEN2

<sup>26</sup> Rainbow node refers to the WEIM locational marginal pricing node RBOW\_GEN\_1\_RBOWGNODE (prior to June 16, 2021, Mid-C prices are used due to data availability).

external markets and this has driven congestion rents from exports. However, due to the lower absolute price differentials, the congestion rents have been less than in prior years.

Figure 48: Marginal congestion rent on BC and MATL (January 2021 to March 2026)

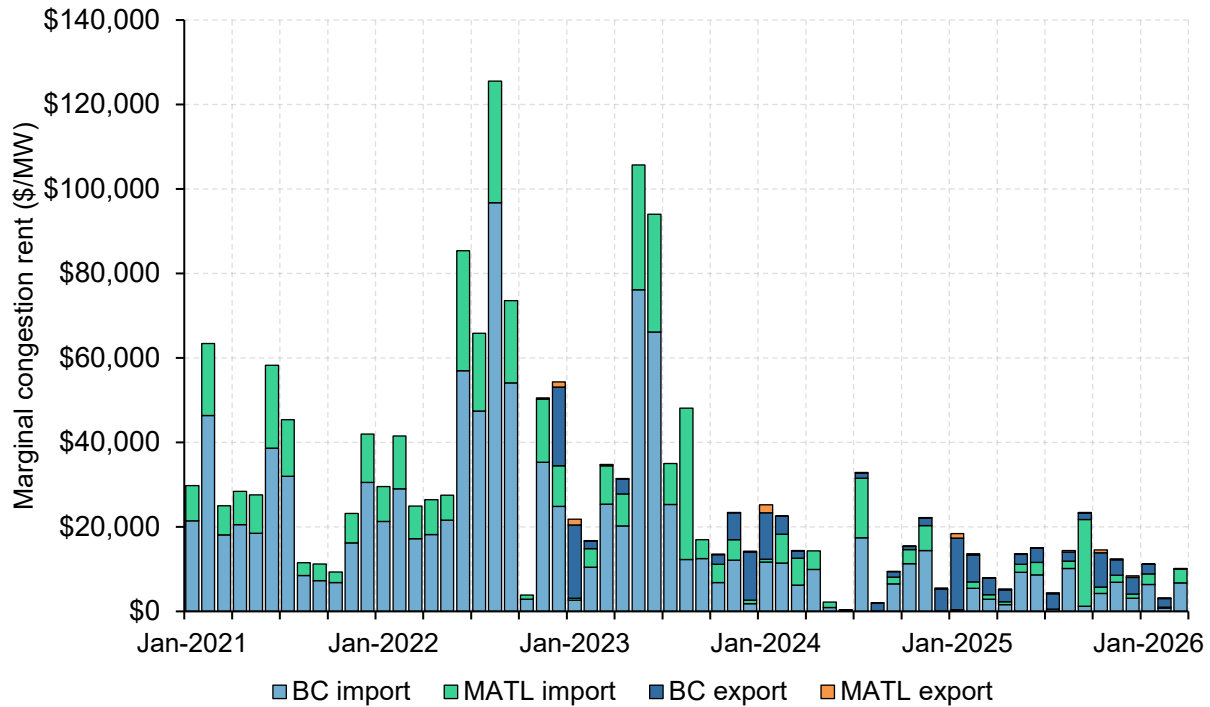


Figure 49: Percent of hours constrained by inertia and direction (January 2021 to March 2026)

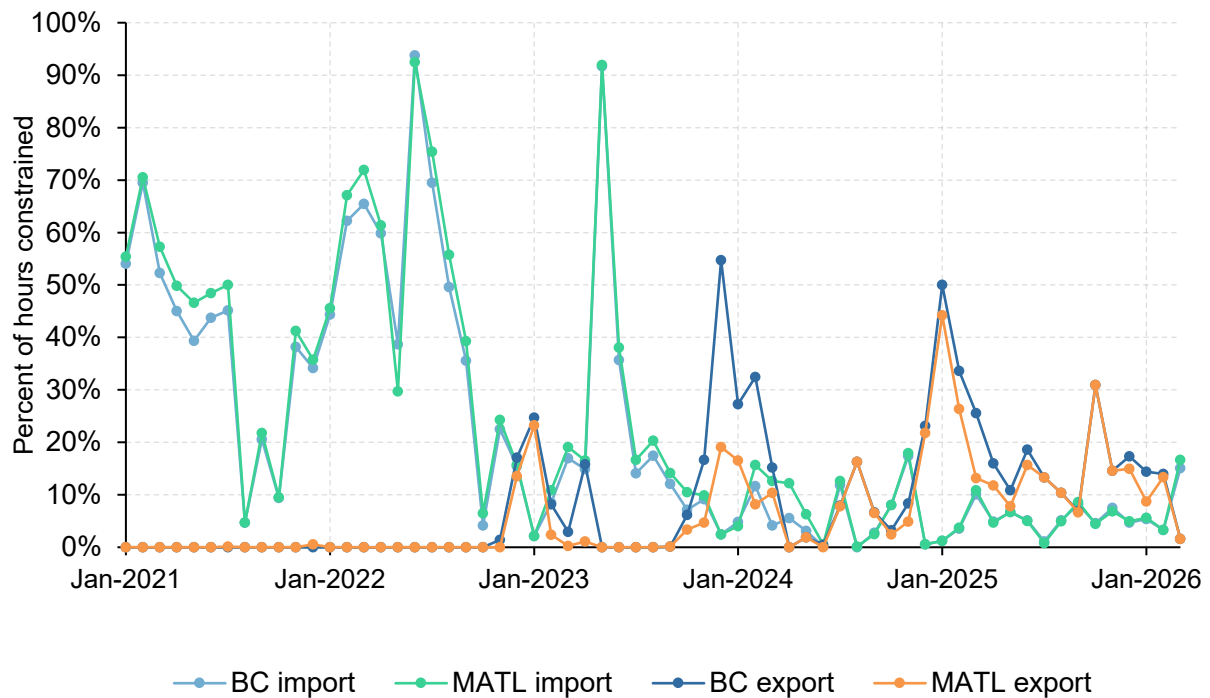


Table 16, Table 17, and Table 18 provide some context for the direction of intertie flows and their overall value from 2015 to 2025. The total volumes of imports and exports are calculated using metered volumes data, which are publicly available. The estimated value of intertie flows is then derived by multiplying the import and export volumes by the prevailing pool price to illustrate general trends.

On the BC intertie and MATL, import volumes were elevated in 2020, 2021, and 2022. In 2021 and 2022, these higher flows combined with elevated pool prices and increased the estimated value of imports.

In 2024 and 2025, Alberta was a net exporter of power, driven by exports on the BC intertie. As a result, on the BC intertie the estimated value of exports were slightly higher than the value of imports in these years, despite higher pool prices during hours of imports.

*Table 16: The estimated total value of imports and exports on the BC intertie (2015 to 2025)*

<b>Year</b>	<b>Total imports (GWh)</b>	<b>Total value of imports (\$millions)</b>	<b>Total exports (GWh)</b>	<b>Total value of exports (\$millions)</b>
2015	732	\$59.4	460	\$8.3
2016	283	\$6.8	556	\$9.4
2017	1,038	\$23.2	580	\$12.7
2018	2,184	\$128.4	542	\$23.9
2019	1,058	\$87.3	498	\$28.9
2020	2,454	\$133.5	44	\$1.7
2021	2,286	\$271.5	60	\$8.0
2022	2,469	\$428.3	473	\$65.9
2023	728	\$180.8	1,960	\$113.9
2024	359	\$70.8	2,585	\$80.4
2025	266	\$39.7	3,093	\$57.6
<b>Total</b>	<b>13,857</b>	<b>\$1,429.5</b>	<b>10,851</b>	<b>\$410.7</b>

Table 17: The estimated total value of imports and exports on MATL (2015 to 2025)

Year	Total imports (GWh)	Total value of imports (\$millions)	Total exports (GWh)	Total value of exports (\$millions)
2015	296	\$22.7	89	\$2.06
2016	138	\$2.6	110	\$2.34
2017	222	\$4.3	285	\$7.20
2018	958	\$49.2	44	\$1.79
2019	823	\$50.6	70	\$4.93
2020	1,130	\$55.8	31	\$2.19
2021	1,186	\$120.6	55	\$6.72
2022	1,256	\$189.2	136	\$35.95
2023	801	\$110.6	145	\$15.30
2024	536	\$42.1	352	\$21.49
2025	265	\$17.9	497	\$12.17
<b>Total</b>	<b>7,611</b>	<b>\$665.5</b>	<b>1,813</b>	<b>\$112.2</b>

Table 18: The estimated total value of imports and exports on the SK intertie (2015 to 2025)

Year	Total imports (GWh)	Total import value (\$millions)	Total exports (GWh)	Total export value (\$millions)
2015	63	\$7.5	102	\$3.0
2016	14	\$0.3	201	\$4.3
2017	34	\$1.1	158	\$3.7
2018	252	\$17.4	145	\$7.5
2019	250	\$22.4	43	\$2.1
2020	381	\$22.0	23	\$1.6
2021	677	\$85.0	16	\$1.9
2022	517	\$89.9	22	\$3.3
2023	647	\$95.1	65	\$7.8
2024	263	\$27.7	80	\$3.4
2025	51	\$5.3	44	\$1.4
<b>Total</b>	<b>3,148</b>	<b>\$373.6</b>	<b>898</b>	<b>\$40.0</b>

Figure 50 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).<sup>27</sup> The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

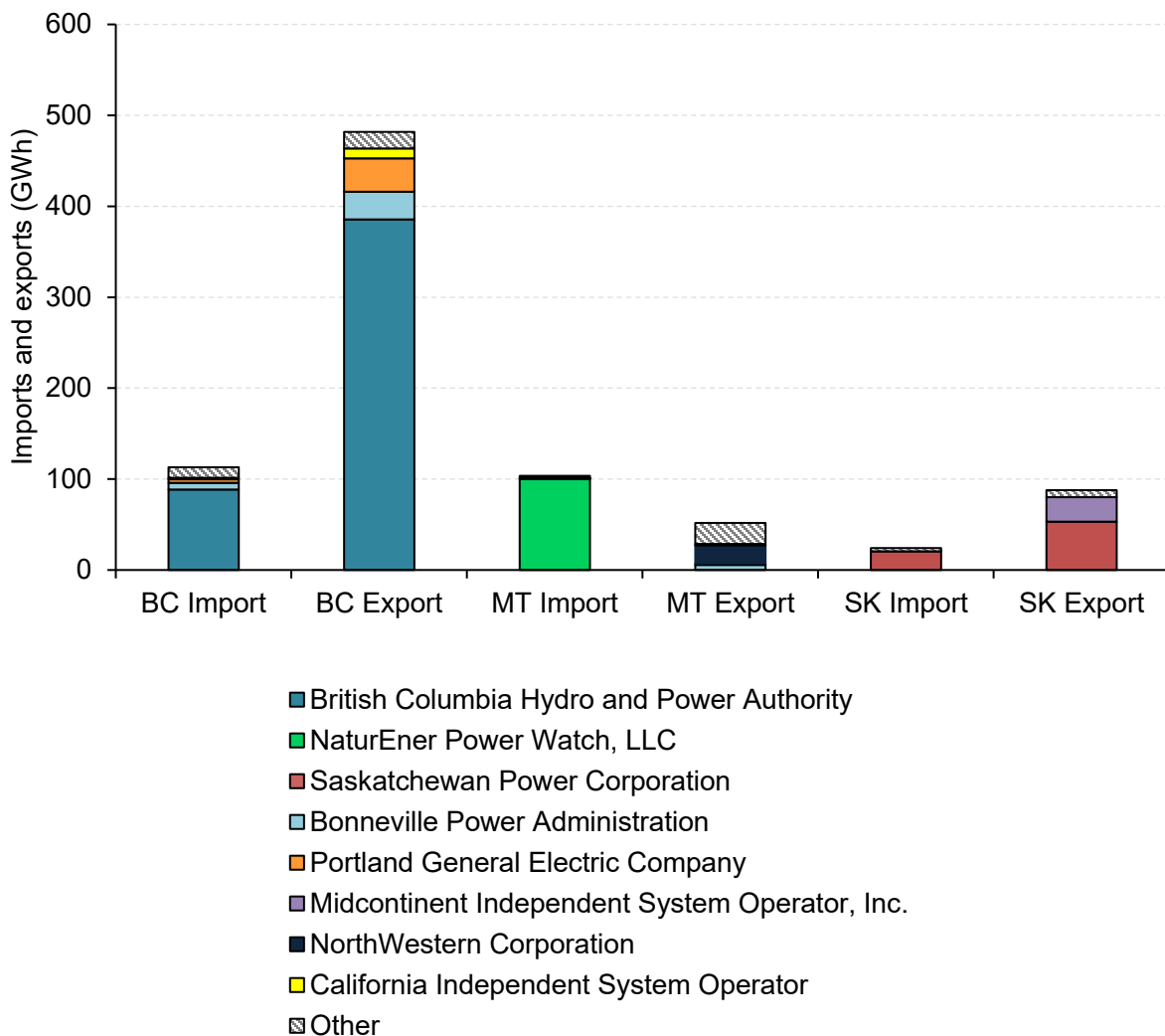
<sup>27</sup> The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered to.

For imports on the BC intertie, 78% originated from BC, 21% from the US Northwest, and 1% from California. For exports on the BC intertie, 80% was delivered to BC, 17% to the US Northwest, and 3% to California.

For imports on MATL, 99% originated from the US Northwest, and 1% originated from the SPP. For exports on MATL, 83% was delivered to the US Northwest, 14% to SPP, and 4% to California.

For imports on the Saskatchewan intertie, 85% originated from Saskatchewan, and 15% from SPP. For exports on the Saskatchewan intertie, 61% was delivered to Saskatchewan, 31% to MISO, 6% to Ontario, 1% to SPP, and 1% to PJM.

Figure 50: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q1)<sup>28</sup>



<sup>28</sup> This includes the highest eight Balancing Authorities by volume.

## 2.4 Transmission must-run

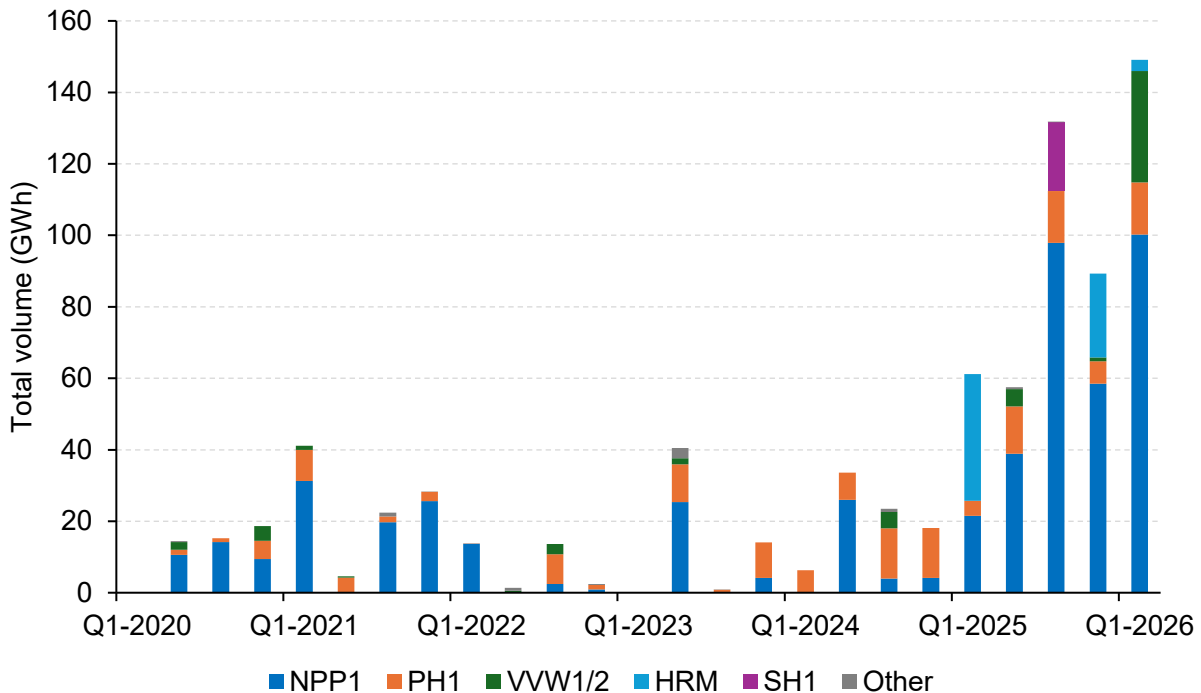
Transmission must-run (TMR) is an out of market ancillary service used by the AESO to provide supplementary sources of supply to help maintain grid stability. Generally, the AESO use TMR when demand in a region of the province’s electricity system cannot be served by dispatched generation due to transmission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

Consequently, the AESO issue 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 use TMR to maintain grid stability for other reasons, such as voltage support.

The total volume of TMR in the quarter was 149 GWh, a record high (Figure 51). TMR volumes in Q1 were exclusively directed in and around the Grande Prairie area with the Northern Prairie Power Project (NPP1), Poplar Hill (PH1), Valley View (VW1/2), and HR Milner (HRM) assets accounting for all the volume.

On an hourly basis, TMR directives in the quarter hit a high of 215 MW on January 8 from HE 20 to HE 24. This is less than the record of 355 MW set on May 23, 2023, in HE 13 and HE 14. The total cost of TMR for Q1 is estimated at \$9.1 million.

Figure 51: Total TMR volumes by asset and quarter (Q1 2020 to Q1)



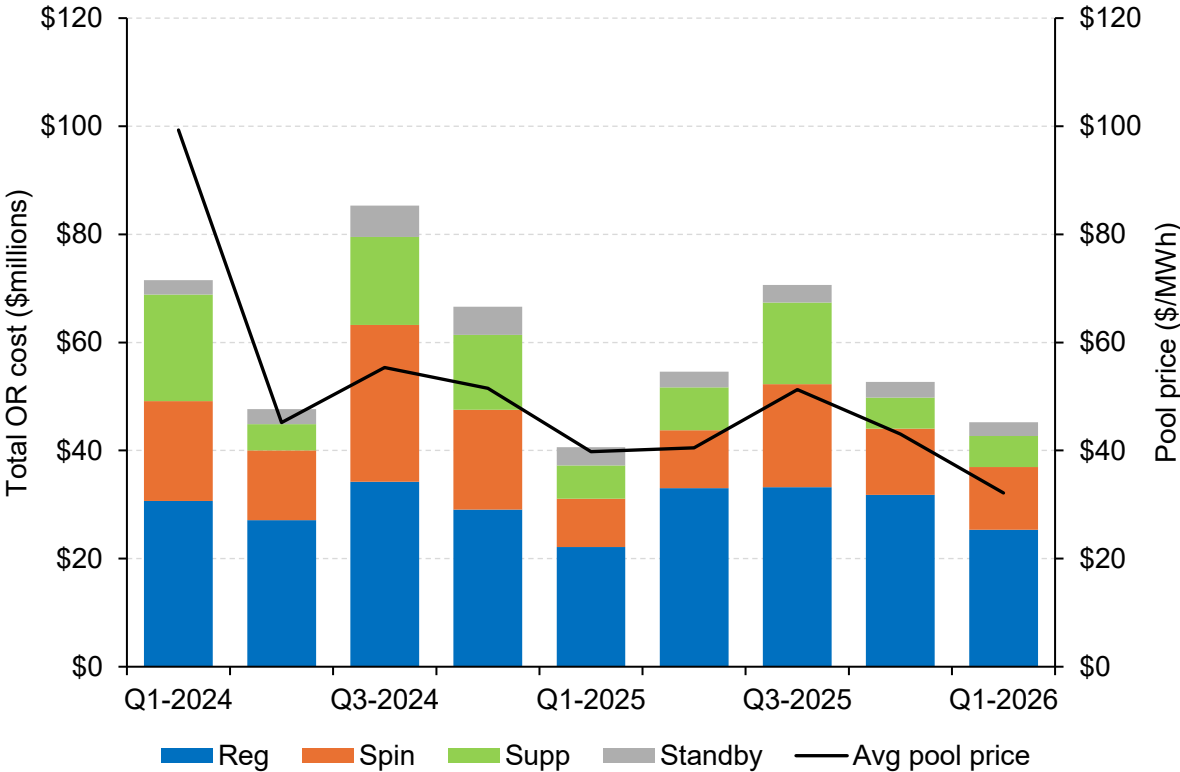
### 3 OPERATING RESERVES

The AESO use three types of operating reserves (OR) to maintain system reliability: regulating, spinning, and supplemental. Regulating reserves are used 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 OR through day-ahead auctions on Wattex.

#### 3.1 Total costs

The total cost of OR in Q1 was \$45 million, representing an 11% increase compared to Q1 2025, but a 14% decrease compared to the previous quarter (Figure 52). The year-over-year increase in total cost occurred despite lower pool prices in Q1 this year and was driven by higher equilibrium prices in the regulating and spinning reserves markets. The quarter-over-quarter decrease in total OR cost was driven by the decline in pool prices.

Figure 52: Total cost of operating reserves (Q1 2024 to Q1)



Regulating reserves in Alberta have historically been provided by hydro and thermal assets. However, in recent quarters battery assets have also supplied regulating reserves. Q4 2025 saw

battery assets provide 0.3% of dispatched regulating reserves. In Q1, hydro assets accounted for 55.7% of dispatched volumes, natural gas assets accounted for 43.5%, and batteries for 0.8%.<sup>29</sup>

### 3.2 Active reserves

Received prices for operating reserves are calculated by indexing equilibrium prices set in day-ahead auctions to the hourly pool price. Table 19 provides average received prices by OR product for Q1 and Q1 2025.

The average pool price fell by \$7.63/MWh year-over-year, while the average received price for regulating reserves increased by \$4.05/MW. This increase was driven by higher equilibrium prices in the day-ahead auctions, which reflected less participation from assets such as Cloverbar 3 and Northern Prairie Power Project.

However, a different dynamic was observed quarter-over-quarter. The average pool price fell by \$10.88/MWh from Q4 2025 to Q1 but the average received price for regulating reserves decreased by \$14.92/MW (Table 20). This outcome was largely driven by more competition in the off-peak regulating reserves market because of increased participation by battery assets.

*Table 19: Average received price by OR product (Q1 2025 and Q1)*

	<b>Q1 2025</b>	<b>Q1 2026</b>	<b>Difference</b>
<b>Reg</b>	\$55.70	\$59.76	\$4.05
<b>Spin</b>	\$15.96	\$20.94	\$4.98
<b>Supp</b>	\$11.05	\$9.83	<b>-\$1.22</b>
<b>Pool price</b>	\$39.78	\$32.15	<b>-\$7.63</b>

*Table 20: Average received price by OR product (Q4 2025 and Q1)*

	<b>Q4 2025</b>	<b>Q1 2026</b>	<b>Difference</b>
<b>Reg</b>	\$74.68	\$59.76	<b>-\$14.92</b>
<b>Spin</b>	\$22.28	\$20.94	<b>-\$1.34</b>
<b>Supp</b>	\$10.63	\$9.83	<b>-\$0.80</b>
<b>Pool price</b>	\$43.03	\$32.15	<b>-\$10.88</b>

The market for regulating reserves is split into four procurement periods: on-peak, off-peak, AM super-peak, and PM super-peak. Each procurement period applies to different hours of the day, and each has a cap on equilibrium prices (Table 21).

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<sup>29</sup> These figures assume the Raymond Reservoir asset was using its battery unit to provide regulating reserves.

Table 21: Applicable hours and equilibrium price caps for regulating reserve products

Procurement period	Applicable hours	Equilibrium price cap (\$/MW)
On-peak	HE 8 - 23	\$40
Off-peak	HE 1 - 7 and HE 24	\$100
AM super-peak	HE 6 - 8	\$100
PM super-peak	HE 17 - 24 (Nov, Dec, Jan) HE 18 - 24 (other months)	\$30

In Q1, battery assets generally participated in the off-peak regulating reserves market. As a result of the increased competition, prices in the off-peak market were close to the cap less often in Q1 compared to Q4 2025 (Figure 53).

However, prices in the on-peak regulating reserves market were close to the cap more often in Q1 (Figure 53). This was due to less competition in the on-peak market, although the effect of the higher equilibrium prices was offset by a decline in on-peak pool prices quarter-over-quarter.

Figure 53: Percent of days where equilibrium prices in the regulating reserve markets cleared within \$5.00/MW of the price cap (Q4 2025 and Q1)

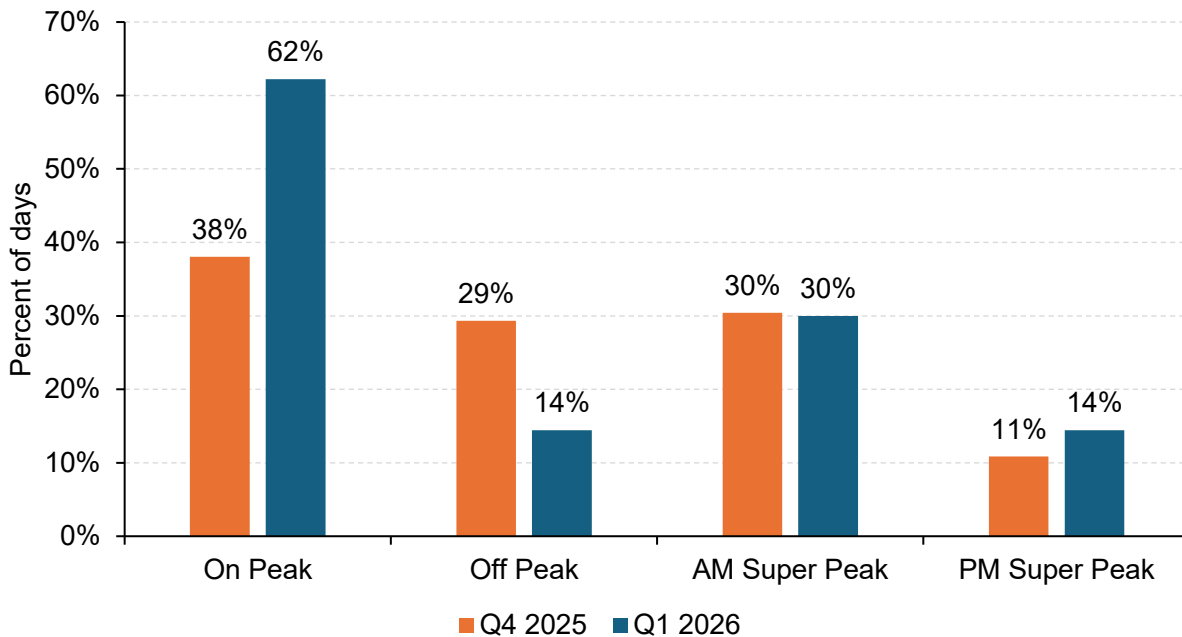
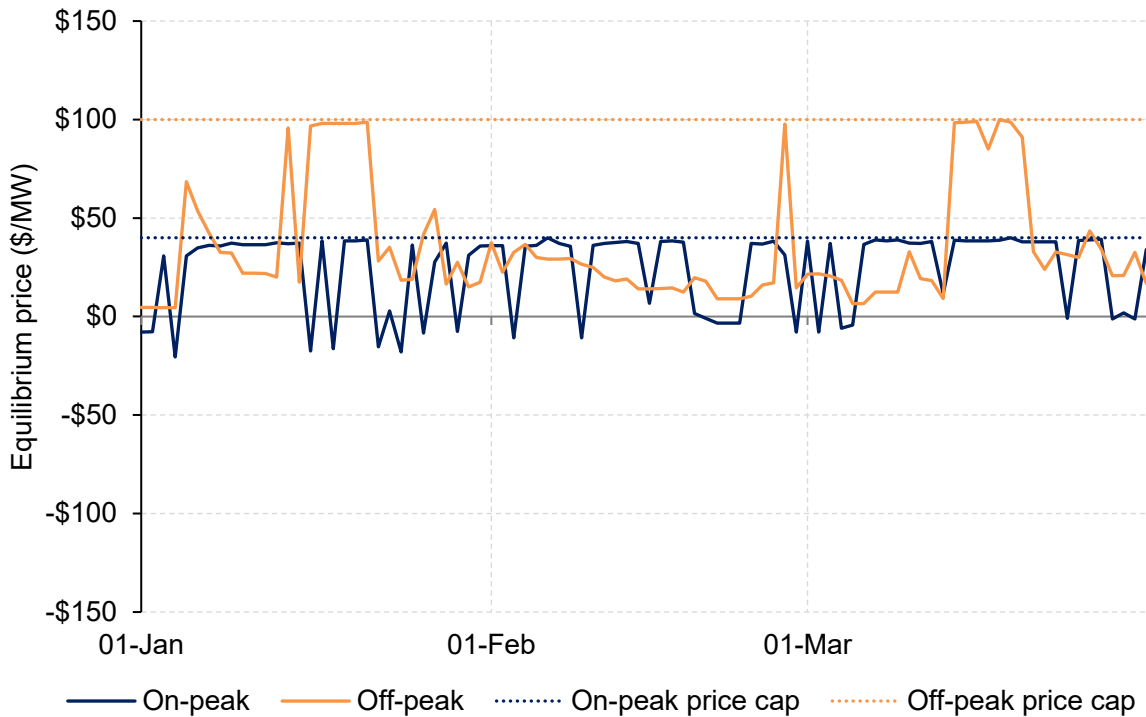


Figure 54 illustrates the evolution of equilibrium prices for on-peak and off-peak regulating reserves over the quarter. As shown, prices in the on-peak market were volatile, with prices either below \$0/MW or close to the cap at \$40/MW most of the time. This volatility was driven by limited participation in the on-peak market. In contrast, prices in the off-peak regulating reserves market were generally more consistent, reflecting more competition.

Figure 54: Equilibrium prices for on-peak and off-peak regulating reserves (Q1)



Enfinite began offering capacity from its battery assets into the off-peak regulating reserves market more consistently starting on February 10. In addition, Irrican offered volumes from its battery unit into the off-peak market throughout the quarter. Irrican offers into the regulating reserves market through its Raymond Reservoir asset, a hydro facility that includes energy storage. The characteristics of the current battery assets in Alberta are better suited to the off-peak market given its shorter duration relative to the on-peak.

High equilibrium prices in the regulating reserves market are typically associated with the absence of certain market participants or lower offered volumes. However, the high prices observed on March 18, 19, and 20 were driven by higher target volumes from the AESO, associated with work on the BC/MATL intertie (Figure 55). The AESO's target procurement levels on these days were 250 MW for the on-peak and 175 MW for the off-peak, both 40 MW more than normal.

The AESO were able to procure the higher target volumes on March 18 and 20; however, they were unable to meet the on-peak target on March 19. This was driven by lower offered volumes from TransAlta compared to the other two days.

The BC/MATL intertie was offline on March 16 and 17, but the AESO's target procurement volumes for these days were normal at 210 MW for the on-peak and 135 MW for the off-peak. However, due to reduced offer volumes from Air Liquide and ENMAX, the AESO were only able to procure 200 MW of regulating reserves for the on-peak and 125 MW for the off-peak of March 16. The merit order for the on-peak is shown below in Table 22.

Figure 55: Procured volume of regulating reserves (Q1)

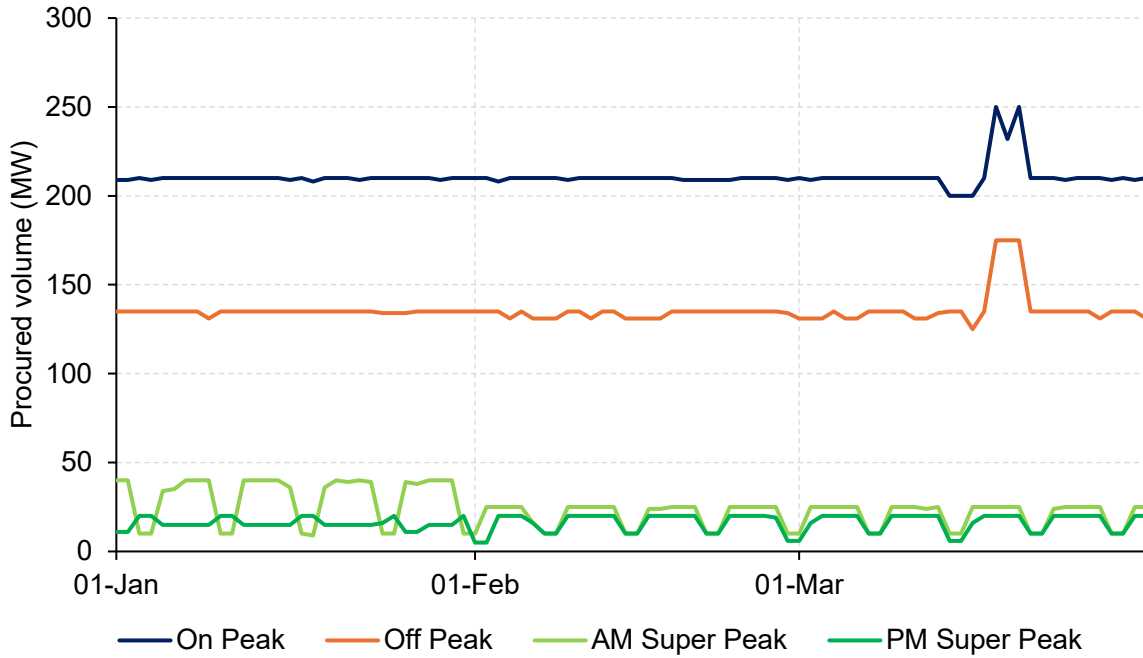


Table 22: The merit order for on-peak regulating reserves (for March 16)

Offer price (\$/MW)	Volume (MW)	Cumulative volume (MW)	Asset ID	Fuel type	Company
-\$730.00	44	44	CAL1	Gas	ENMAX
-\$730.00	69	113	BOW1	Hydro	TransAlta
-\$730.00	18	131	BIG	Hydro	TransAlta
-\$730.00	47	178	BRA	Hydro	TransAlta
-\$730.00	21	199	KH3	Gas	TransAlta
<b>\$38.47</b>	<b>1</b>	<b>200</b>	<b>KH3</b>	<b>Gas</b>	<b>TransAlta</b>

The equilibrium prices for spinning reserves over Q1 are illustrated in Figure 56. During the quarter, equilibrium prices in the spinning reserves market cleared above \$0/MW on 10% of days for the on-peak and on 37% for the off-peak, both representing an increase over prior quarters (Table 23).

It is somewhat unusual for equilibrium prices for spinning reserves to clear above \$0/MW because this means the reserves are paid a premium to energy. These outcomes were largely driven by reduced participation in the spinning reserves markets due to low expected pool prices.

Figure 56: Equilibrium prices for on-peak and off-peak spinning reserves (Q1)

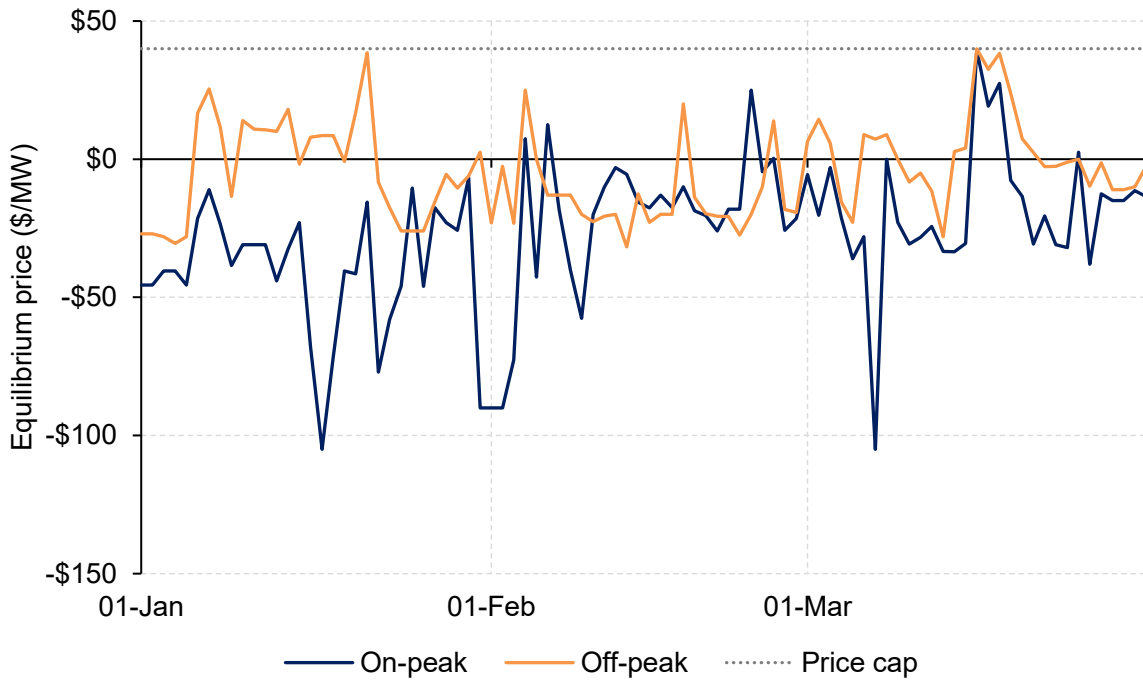


Table 23: Percent of days where equilibrium prices for spinning reserves were above \$0/MW

	<b>On-peak</b>	<b>Off-peak</b>
Q1 2025	2%	0%
Q2 2025	4%	3%
Q3 2025	14%	12%
Q4 2025	7%	12%
<b>Q1 2026</b>	<b>10%</b>	<b>37%</b>

In early to mid January, equilibrium prices in the off-peak market were mostly above \$0/MW, and higher than prices in the on-peak market. This was largely driven by reduced offered volumes from TransAlta. For January 21 delivery, the off-peak spinning reserves market cleared at \$38.50/MW, close to the cap at \$40/MW. This high price was driven by reduced offered volumes from TransAlta, Fengate, Enfinite, and Mercer Peace. Consequently, the AESO were only able to procure 225 MW, below their target of 234 MW.

In February, prices in the on-peak and off-peak spinning reserves markets were generally comparable, and prices in both markets cleared above \$0/MW on several days due to low expected pool prices.

In March, off-peak spinning reserve prices were generally higher than on-peak prices. During the month, elevated prices were observed in the on-peak and off-peak markets from March 16 to 18. These high prices were driven by reduced offered volumes from Enfinite’s battery assets. As noted in section 1.2.3, a BC/MATL intertie outage was scheduled from March 16 to March 20 and

additional FFR was procured by the AESO. With increased FFR requirements, Enfinite reduced its participation in the operating reserves markets.

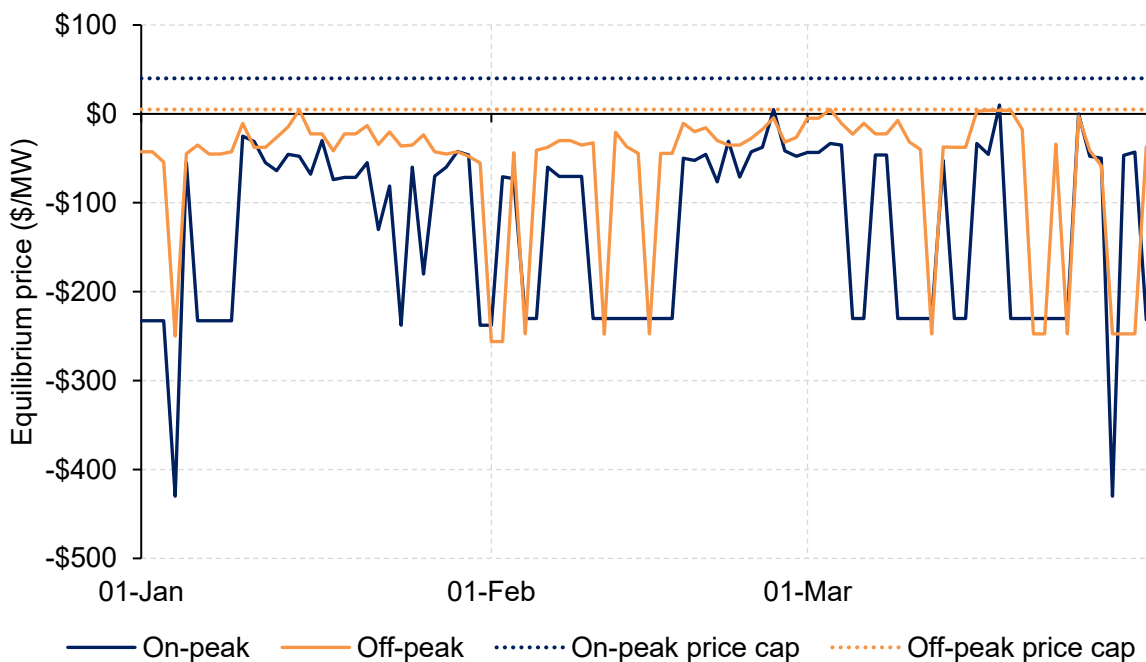
Similar to the spinning reserves market, prices for off-peak supplemental reserves were generally higher than on-peak prices over the quarter (Figure 57). This was driven by increased load participation in the on-peak market. The supplemental reserves markets generally remained competitive over Q1 with load, battery, and hydro assets offering at low prices.

However, off-peak supplemental prices cleared close to the cap of \$5.00/MW on several days:

- For January 15, the off-peak supplemental price cleared at \$4.50/MW. This outcome was driven by reduced offered volume from TransAlta. The average off-peak pool price on this day was low at \$3.22/MWh.
- For March 3, the off-peak supplemental price cleared at \$4.99/MW. This outcome was largely driven by lower offered volumes from TransAlta and Enfinite. The average off-peak pool price was \$20.57/MWh.
- For March 16 to 19, off-peak supplemental prices cleared above \$0/MW, driven by reduced offered volumes from Enfinite. As noted above, this was due to increased FFR requirements because of a BC/MATL intertie outage.

In Q1, providers of supplemental reserves did not receive revenues in 84% of hours because the pool price was not sufficiently high relative to the equilibrium price. This is comparable to 90% of hours in Q4 2025 and 83% of hours in Q1 2025.

Figure 57: Equilibrium prices for on-peak and off-peak supplemental reserves (Q1)



### 3.3 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).

Standby volumes remained largely consistent throughout the quarter, with the AESO procuring the regular 20 MW of regulating reserves, 45 MW of on-peak spinning reserves, 35 MW of off-peak spinning reserves, and 15 MW of supplemental reserves.

In Q1, the total cost of standby reserves was \$2.5 million, of which 32% was attributable to activation costs. This share was unchanged from the previous quarter, but lower than the 40% observed in Q1 2025. The year-over-year decrease was driven by reduced activation rates in Q1.

Table 24 summarizes activation rates since Q1 2024. In Q1, the activation rate for regulating reserves reached its lowest level over this period at 3%. Activation rates for contingency reserves declined on a year-over-year basis but remained relatively stable compared to the previous quarter.

*Table 24: Activation rates by OR product and quarter (Q1 2024 to Q1)*

	<b>Reg</b>	<b>Spin</b>	<b>Supp</b>
Q1 2024	5%	23%	22%
Q2 2024	7%	7%	7%
Q3 2024	5%	12%	13%
Q4 2024	9%	17%	15%
Q1 2025	7%	28%	31%
Q2 2025	7%	11%	19%
Q3 2025	6%	14%	14%
Q4 2025	5%	21%	19%
<b>Q1 2026</b>	<b>3%</b>	<b>18%</b>	<b>22%</b>

Table 25 compares activation prices with prevailing pool prices across different standby reserve products for Q1 2025, Q4 2025, and Q1.

In Q1, the volume-weighted average activation price for standby regulating reserves was \$46.98/MW. Although this is lower than the activation prices observed in Q1 2025 and Q4 2025, it represents a 241% premium compared to pool prices at the time of the activations.

Similarly, the standby contingency reserves markets recorded higher premiums in Q1 compared to the previous quarter and Q1 last year. Despite similar activation prices, the drop in prevailing pool prices in Q1 resulted in higher activation premiums for contingency reserves.

Table 25: Activation prices compared with prevailing pool prices (Q1 2025, Q4 2025, and Q1)

		<b>Q1 2025</b>	<b>Q4 2025</b>	<b>Q1 2026</b>
<b>Reg</b>	Activation price (\$/MW)	\$60.66	\$74.67	\$46.98
	Pool price (\$/MWh)	\$24.77	\$22.27	\$13.77
	Standby premium (%)	145%	235%	241%
<b>Spin</b>	Activation price (\$/MW)	\$33.91	\$30.88	\$33.75
	Pool price (\$/MWh)	\$35.68	\$27.42	\$16.01
	Standby premium (%)	-5%	13%	111%
<b>Supp</b>	Activation price (\$/MW)	\$31.19	\$27.58	\$28.97
	Pool price (\$/MWh)	\$28.41	\$26.41	\$14.08
	Standby premium (%)	10%	4%	106%

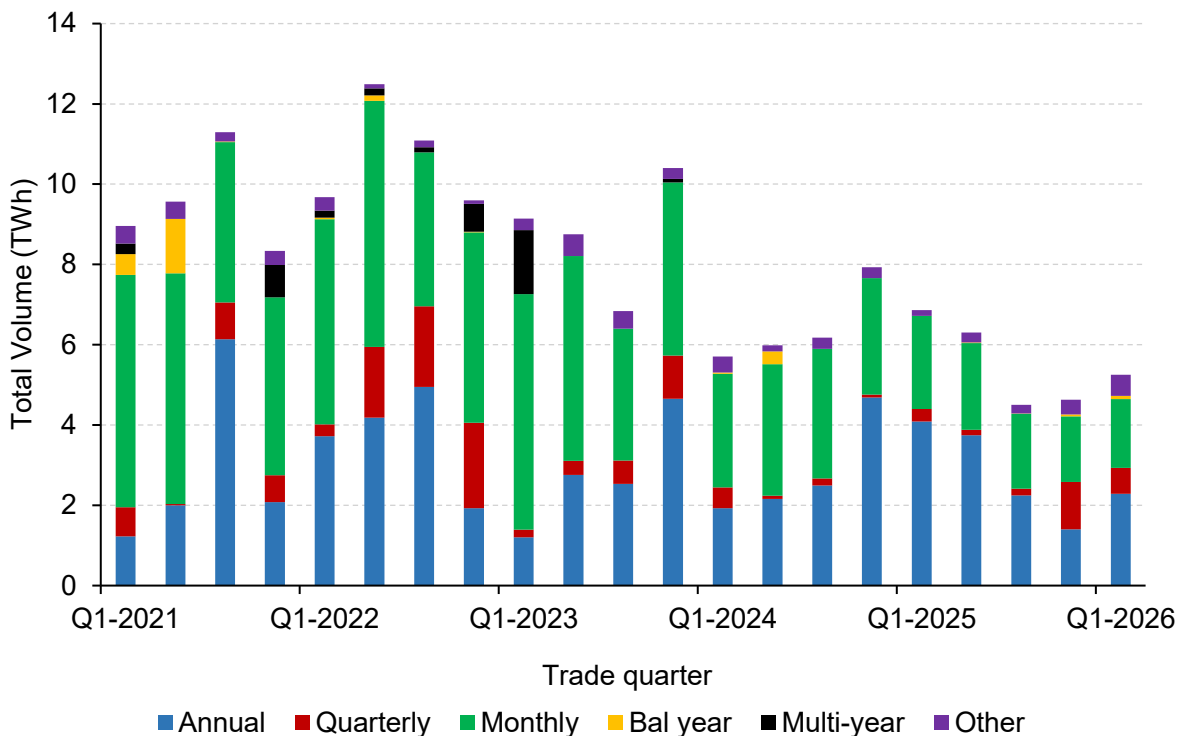
## 4 THE FORWARD MARKET

Alberta's financial forward market for electricity is an important component of the overall market because it allows for generators, retailers, and larger loads to hedge against pool price volatility.<sup>30</sup>

### 4.1 Forward market volumes

Total trade volumes in Q1 remained low, with 5.25 TWh trading on ICE NGX or through the brokers (Figure 58). This is a 24% decline compared to Q1 2025, driven by lower monthly and annual volumes. Compared to Q4 2025, volumes increased slightly due to more annual trades.

Figure 58: Total trade volumes by term and quarter (Q1 2021 to Q1)



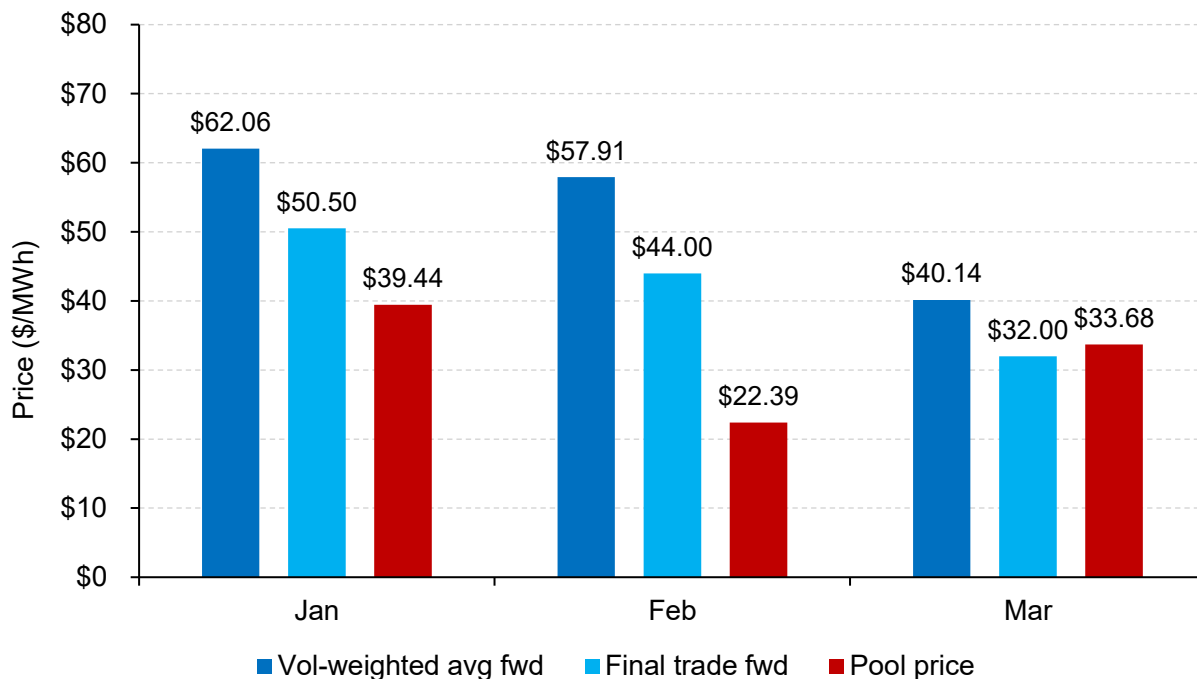
### 4.2 Trading of monthly products

Pool prices came in below forward market expectations for all three months in Q1. In January the volume-weighted average forward price was 57% higher than the average pool price, and the same forward premium was 159% in February and 19% in March (Figure 59). Mild weather

<sup>30</sup> The MSA's analysis in this section incorporates trade data from ICE NGX and two over the counter (OTC) brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2025, are also included unless stated otherwise. Direct bilateral trades occur directly between two trading parties, not via ICE NGX or through a broker, and the MSA generally collects information on these transactions once a year.

conditions in January and February lowered pool prices by reducing demand, increasing intermittent generation, and lowering natural gas prices.

Figure 59: Forward prices compared with pool prices for monthly contracts (January to March)



The low pool prices put downward pressure on monthly forward prices for the balance of year (Table 26). For some months, forward prices declined by more than 20% over the quarter. For example, the price of May declined by 28% and the price of June fell by 24%.

Table 26: Monthly contract price changes over Q1 for the balance of year

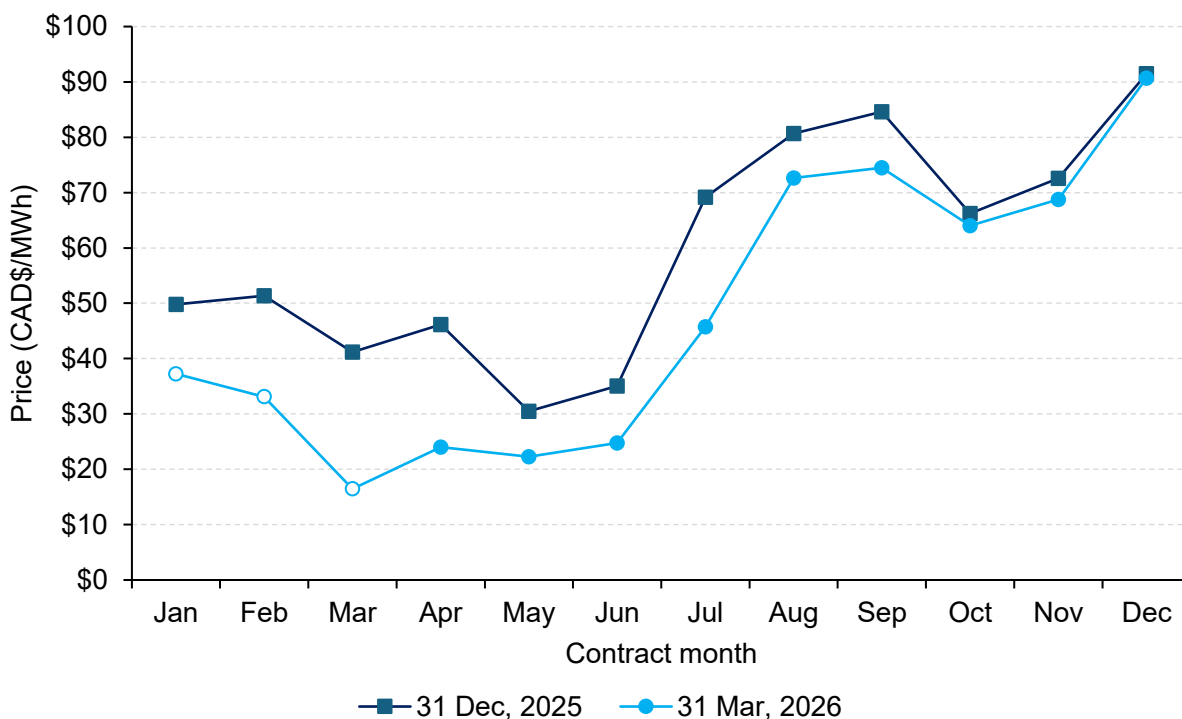
Contract	Dec. 31, 2025 (\$/MWh)	Mar. 31, 2026 (\$/MWh)	Change	
			(\$/MWh)	(%)
Apr-26	48.25	41.75	-6.50	-13%
May-26	44.35	31.75	-12.60	-28%
Jun-26	46.00	34.75	-11.25	-24%
Jul-26	49.75	42.25	-7.50	-15%
Aug-26	56.50	48.00	-8.50	-15%
Sep-26	52.00	48.00	-4.00	-8%
Oct-26	47.00	37.25	-9.75	-21%
Nov-26	52.75	43.00	-9.75	-18%
Dec-26	62.50	53.00	-9.50	-15%
<b>Cal 26</b>	<b>50.42</b>	<b>39.72</b>	<b>-10.69</b>	<b>-21%</b>

In addition to the low pool prices in Q1, falling natural gas prices and lower power prices in Mid-C also put downward pressure on forward prices. Lower forward prices for natural gas means lower input costs for thermal generation assets, and lower forward power prices in Mid-C indicate that Alberta will receive more imports and provide less exports in the future.

The forward curve for natural gas fell materially in Q1. The price of natural gas for April fell by 38% from \$2.30/GJ to \$1.43/GJ, and similar declines were seen for all months out to October. Natural gas prices for November and December declined by 19%. Overall, the price of natural gas for the balance of 2026 fell by 32% over the quarter.

In Mid-C, prices in Q1 came in below forward market expectations at the end of 2025, largely due to increased hydro supply. The price of March was particularly affected settling around CAD\$16.50/MWh (Figure 60). As a result, near term forward prices in Mid-C fell notably over Q1, with April declining by 48% and July declining by 34%.

Figure 60: Mid-C monthly forward curve (flat, January to December)



As a result of these factors, the expected average pool price for 2026 fell by 21% over the quarter; from \$50.42/MWh to \$39.72/MWh. This decline took the expected average pool price for 2026 below the realized average pool price in 2025 (\$43.68/MWh).

#### 4.2.1 Genesee outage changes – January 15

Leading into this event, there was a planned outage at Genesee Repower 2 scheduled to run from March 13 HE 24 to April 10 HE 23. This outage was for a low-pressure turbine spring

replacement and had been scheduled since October 9, 2025. The forward price for March had last traded for \$40.00/MWh at 12:22 on January 14.

At 12:56 on January 15, an additional planned outage for a combustor inspection at Genesee Repower 1 was entered into the AESO's Energy Trading System (ETS). The outage was scheduled to run from March 13 HE 24 to April 3 HE 23. This change had the effect of increasing outages in March and was reflected in the AESO's Daily and Monthly Outage reports at 13:00:44.

Shortly thereafter, the price of March increased from \$40.00/MWh to \$41.00/MWh. Between 13:01:30 and 13:21:49, 15 MW of the March contract traded at \$41.00/MWh. These three trades all occurred on ICE NGX.

Subsequently, at 14:37, the initial outage at Genesee Repower 2 was moved to April 6 HE 24 to April 30 HE 23 and the asset was declared to be fully available from March 13 HE 24 to April 6 HE 23. This change had the effect of lowering outages in March and was reflected in the AESO's Monthly and Daily outage reports at 15:00:43.

The price of March traded for \$42.00/MWh on the Velocity broker at 15:01:42. Subsequently, the price of March contract fell, and next traded for \$38.25/MWh at 09:10 on January 21. The April contract was not traded on January 15.

### 4.3 Trading of annual products

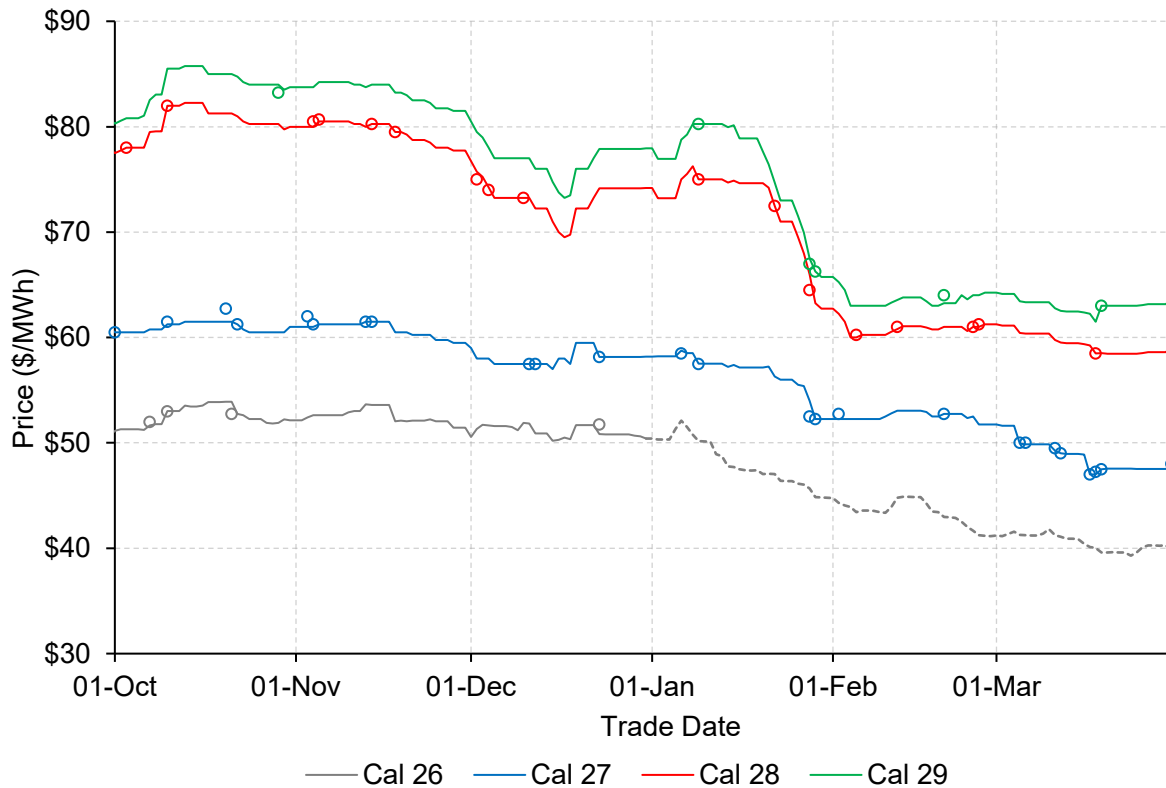
Low pool prices, falling natural gas futures, and declining power prices in Mid-C also put downward pressure on the forward prices for annual contracts in Q1. Over the quarter, the price of Calendar 2027 (Cal 27) fell by 18%, the price of Cal 28 fell by 20%, and the price of Cal 29 fell by 18% (Table 27). As a result, spark spreads declined by between 20% and 25%.

Table 27: Changes to annual power and natural gas prices over Q1

Contract	Power Price (\$/MWh)			Gas Price (\$/GJ)			Spark Spread (\$/MWh)		
	Dec 31	Mar 31	Change	Dec 31	Mar 31	Change	Dec 31	Mar 31	Change
CAL26 (marked)	50.42	39.72	-21%	2.51	1.76	-30%	31.58	26.53	-16%
CAL27	58.19	47.88	-18%	2.82	2.42	-14%	37.05	29.70	-20%
CAL28	74.19	59.07	-20%	2.80	2.57	-8%	53.21	39.82	-25%
CAL29	77.94	63.62	-18%	2.74	2.59	-6%	57.36	44.23	-23%

Figure 61 illustrates annual forward prices from October 1 to March 31. As shown, the prices for Cal 28 and Cal 29 declined notably in late January. For example, the price of Cal 28 fell from \$74.23/MWh on January 21 to \$60.00/MWh on February 4, a decline of 19%. Similarly, the price of Cal 29 declined by 18% over the same period.

Figure 61: Annual forward prices (October 1, 2025 to March 31, 2026)



In addition to the market fundamentals outlined above, low market liquidity and sell-side pressure were factors in the price declines for Cal 28 and Cal 29. Over a number of days in late January, the bids and offers for Cal 28 and Cal 29 were submitted by the same market participant. This market participant lowered its bid and offer prices for these products until there was buy-side interest from others.

Figure 62 provides some context for the price of Cal 28 in Alberta by illustrating forward prices for Cal 28 in Mid-C and California. In early January, the forward prices for Cal 28 in other markets declined while the price in Alberta remained relatively consistent at around \$75.00/MWh.

In late January the converse occurred, the price of Cal 28 in Alberta declined while prices in other markets were generally consistent. As a result, the price of Cal 28 in Alberta fell below prices in Mid-C and NP15. Although not shown here, the same analysis for Cal 29 illustrates similar trends.

For Cal 27, the forward price in Alberta was the lowest of the four jurisdictions at the end of the quarter (Figure 63). This indicates that Alberta is set to remain a strong exporter of power next year.

Figure 62: The price of Cal 28 in Alberta and other jurisdictions  
(December 1, 2025 to March 31, 2026)

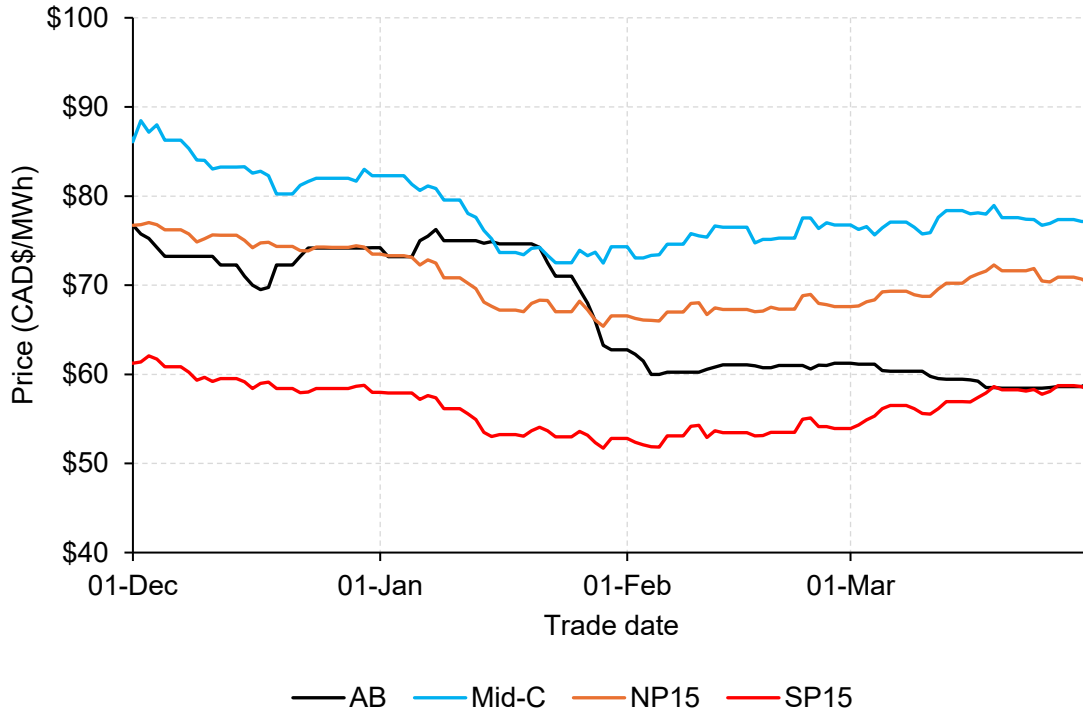


Figure 63: The price of Cal 27 in Alberta and other jurisdictions  
(December 1, 2025 to March 31, 2026)

