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Wholesale Market Report: Q1 2025

May 14, 2025

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

- **Increased thermal capacity drives decline in average pool prices:**

  The average pool price in Q1 was $39.78/MWh, a decline of 60% relative to Q1 2024 and the lowest average price for the first quarter since 2018. The lower pool prices year-over-year were largely driven by the addition of significant new thermal generation capacity at Cascade and Base Plant.

- **Large wind generation variation events:**

  On the mornings of January 11 and February 27 wind generation dropped quickly by around 700 MW. In both cases, exports from Alberta were reduced to well below the scheduled amount as the interties absorbed the impact of the lower supply. Because the impact of these events was largely absorbed by the interties, there was little impact on system frequency in Alberta. However, had the BC/MATL interties been offline at the time of these events there would have been a notable impact on system frequency.

- **Interim market power mitigation measures had no material effect in Q1:**

  The secondary offer price limit was not triggered in Q1, and the AESO issued only one unit commitment directive in the quarter. This is aligned with the intent of these measures, as significant supply already limited the exercise of market power.

- **Transmission constraints increase in Q1:**

  In Q1, the volume of wind and solar generation that was constrained down was 160 GWh, a 471% increase from Q1 2024. At least 1 MWh of wind and solar generation was constrained down in 42% of hours in Q1. The constrained and unconstrained SMP differed by $1/MWh or more in 18% of hours in Q1, an increase year-over-year (10% in Q1 2024) but a decrease quarter-over-quarter (26% in Q3 2024).

- **Regulating reserve equilibrium prices increase in Q1:**

  In the markets for active operating reserves, including regulating reserves, equilibrium prices are indexed to pool prices to determine the received price for providers. The regulating reserve market has different price caps for the auctions to set equilibrium prices for the on peak, off peak, AM super peak, and PM super peak periods. In recent months these price caps have bound more often as equilibrium prices have increased. The equilibrium prices for regulating reserve were within $0.05/MW of the respective price cap on fifteen occasions in Q1 compared to twice in Q1 2024.

- **Low forward market liquidity continues and forward prices decline:**

  Total trade volumes in Q1 were low at 6.9 TWh, which marks a 13% reduction relative to Q4 2024. Monthly and annual forward prices decreased in Q1 due to the low pricing environment in the energy market. For example, the traded price of Calendar 2026 fell by 15% despite an 11% increase in the forward price of natural gas.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q1 was $39.78/MWh, which is a 60% decrease relative to Q1 2024. This is the lowest average pool price for the first quarter since 2018. The lower pool prices in Q1 this year were largely driven by more available thermal capacity. Compared to Q1 2024 available thermal capacity increased materially, by an average of 1,570 MW (Table 1).

The development of Cascade 1 and 2 has added 900 MW of combined cycle capacity year-over-year and the generation additions at the Base Plant facility have added around 800 MW of cogeneration capacity, although these units were still commissioning in Q1 so not all the capacity was available.

The increase in thermal supply offset higher demand this year, particularly in February. In February average demand increased by 5% (570 MW) year-over-year with cold temperatures being the main driver. Despite this, the average pool price for February fell by 31% because of more thermal supply.

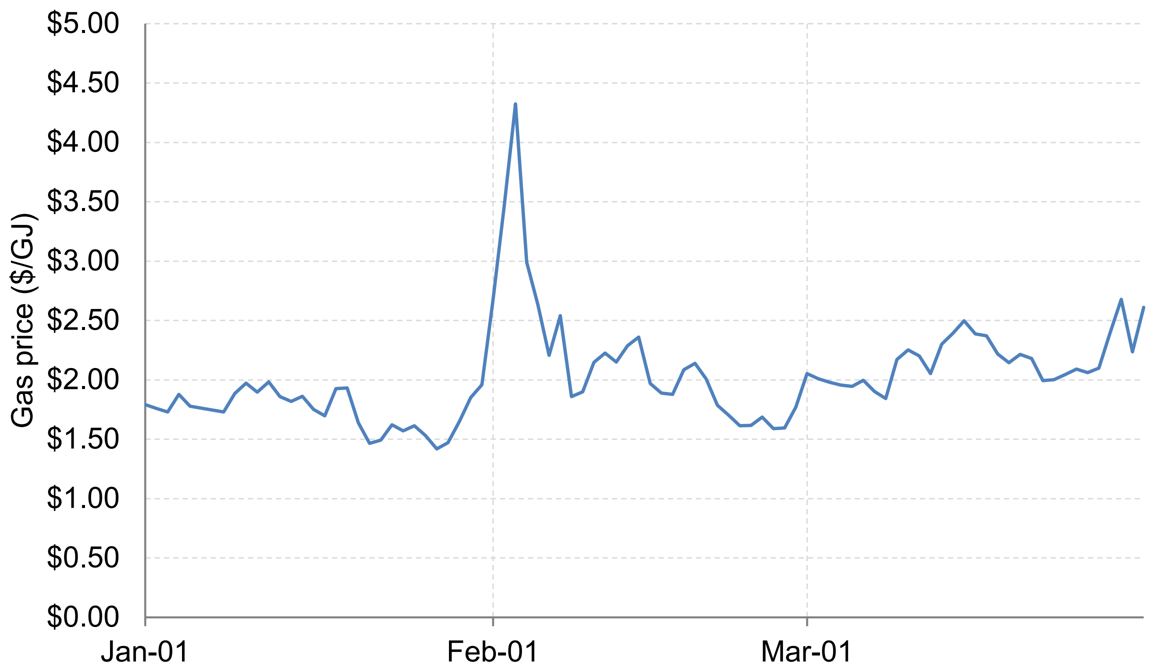
In addition, the supply of wind and solar generation increased year-over-year as more intermittent capacity has been added to the market. Between March 31, 2024 and March 31, 2025 1,207 MW of wind capacity and 163 MW of solar capacity were added. Consequently, average wind generation in the quarter was the highest on record at 1,756 MW.

Table 1: Summary market statistics for Q1 2024 and Q1 2025

		2024	2025	Change
Pool price (Avg $/MWh)	January	$152.78	$30.36	-80%
	February	$80.75	$55.77	-31%
	March	$63.13	$34.76	-45%
	Q1	**$99.30**	**$39.78**	**-60%**
Demand (AIL) (Avg MW)	January	10,871	10,949	1%
	February	10,542	11,111	5%
	March	10,307	10,431	1%
	Q1	**10,574**	**10,821**	**2%**
Gas price AB-NIT (2A) (Avg $/GJ)	January	$2.38	$1.74	-27%
	February	$1.71	$2.18	28%
	March	$1.71	$2.17	27%
	Q1	**$1.94**	**$2.03**	**5%**
Wind gen. (Avg MW)	January	1,398	2,150	54%
	February	1,410	1,635	16%
	March	1,295	1,470	13%
	Q1	**1,367**	**1,756**	**28%**
Solar gen. (Avg MW during peak hours)	January	182	214	18%
	February	353	359	2%
	March	531	525	-1%
	Q1	**355**	**366**	**3%**
Net imports (+) Net exports (-) (Avg MW)	January	-364	-594	63%
	February	-275	-456	66%
	March	-226	-330	46%
	Q1	**-289**	**-461**	**60%**
Available thermal capacity (Avg MW)	January	10,123	11,668	15%
	February	10,065	11,699	16%
	March	9,806	11,346	16%
	Q1	**9,997**	**11,567**	**16%**

Natural gas is the main input cost for Alberta power. Natural gas prices increased in Q1 but continued to remain relatively low averaging $2.03/GJ in the quarter, a 5% increase compared to Q1 last year and a 43% increase compared to Q4 2024. Sameday natural gas prices rose up to $4.32/GJ during a cold period in early February before coming back down to the $2.00/GJ range (Figure 1). As a result, average prices increased from $1.74/GJ in January to $2.18/GJ in February and stayed around this level in March, averaging $2.17/GJ.

Figure 1: Sameday natural gas prices in Q1



The low pool prices in Q1 also motivated record exports from the province, largely to BC. In January average net exports were 594 MW, the highest monthly average for exports on record going back to January 2001.

Figure 2 illustrates average available thermal capacity by month. As shown, available thermal capacity increased by around 1,500 MW year-over-year for all three months of Q1 and this increased supply put downward pressure on pool prices and pool price volatility.

Figure 2: Average available thermal capacity by month (January 2024 to March 2025)

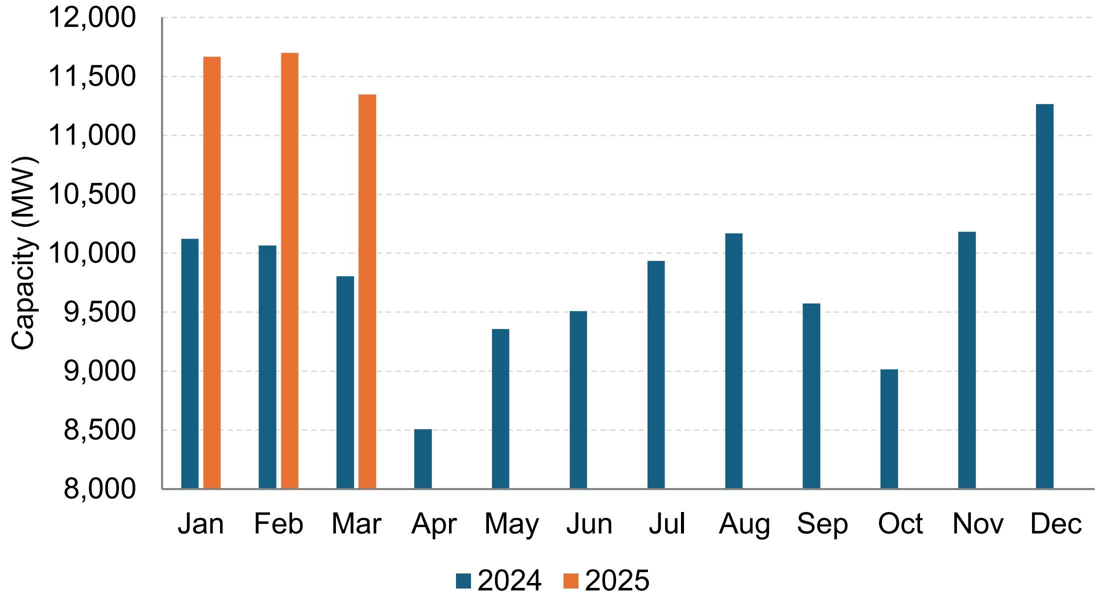


Figure 3 illustrates the quarterly average pool price since Q1 2018. As shown pool prices have been declining since late 2022 and the past four quarters have consistently settled in the $40 to $55/MWh range.

The volatility of pool prices has also been falling since late in 2022 (Figure 4). In Q1 the standard deviation of pool prices was $78/MWh, a 51% reduction year-over-year and the lowest since Q4 2020. The lower volatility of pool prices in recent quarters has largely been driven by increased thermal supply which has offset the impacts of more intermittent generation.

Figure 3: Average pool price by quarter (Q1 2018 to Q1 2025)

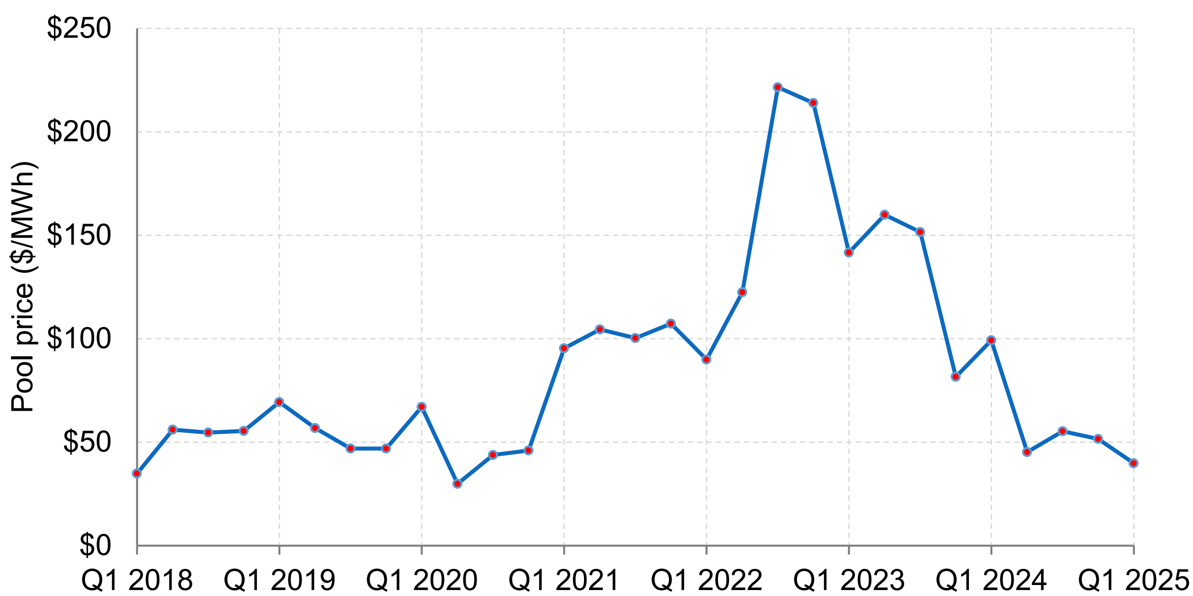
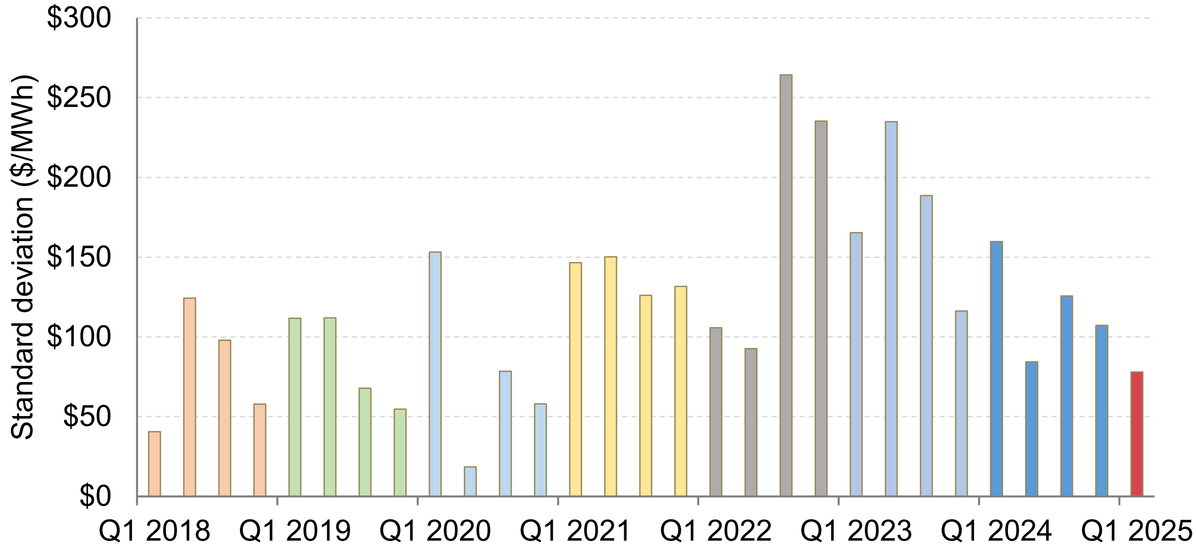


Figure 4: Standard deviation of pool prices by quarter (Q1 2018 to Q1 2025)



As outlined above, the increased thermal supply has come from additional capacity at Cascade and Base Plant. Figure 5 shows the evolution of this supply increase from the beginning of 2024. As shown, Cascade 1 and 2 increased their generation supply from early 2024 into Q3 2024 while Base Plant (SCR1) began increasing generation in late 2024.

In February the total supply from all three assets averaged close to 1,400 MW or 13% of Alberta Internal Load (AIL) as average supply from Cascade 1 and 2 totalled 872 MW and average supply from Base Plant was 513 MW. The supply from Base Plant may increase further in the coming months as commissioning is completed.

Figure 5: Average generation at Cascade 1 and 2 and at Base Plant by month (January 2024 to March 2025)

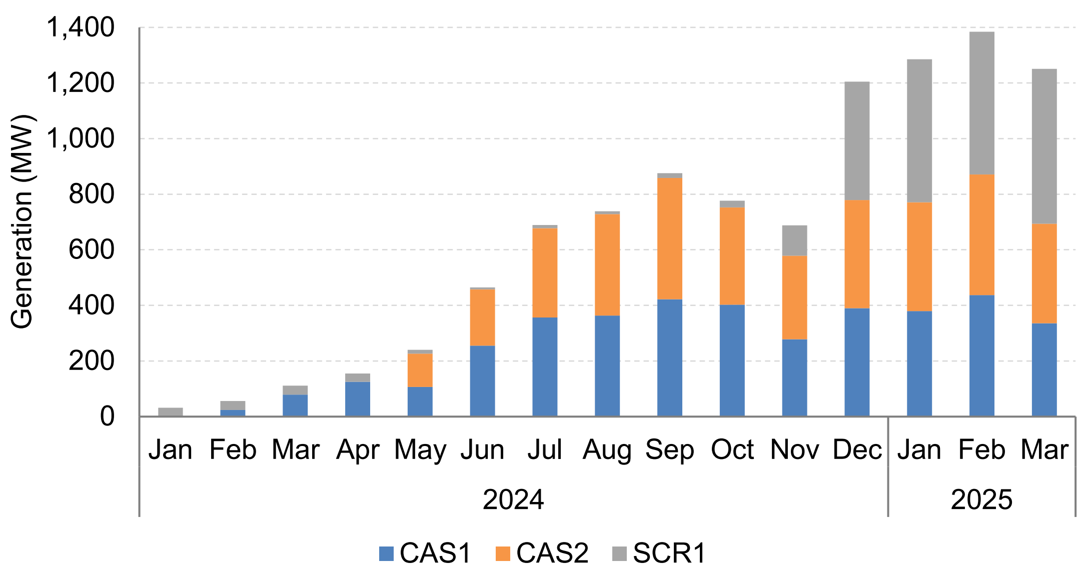
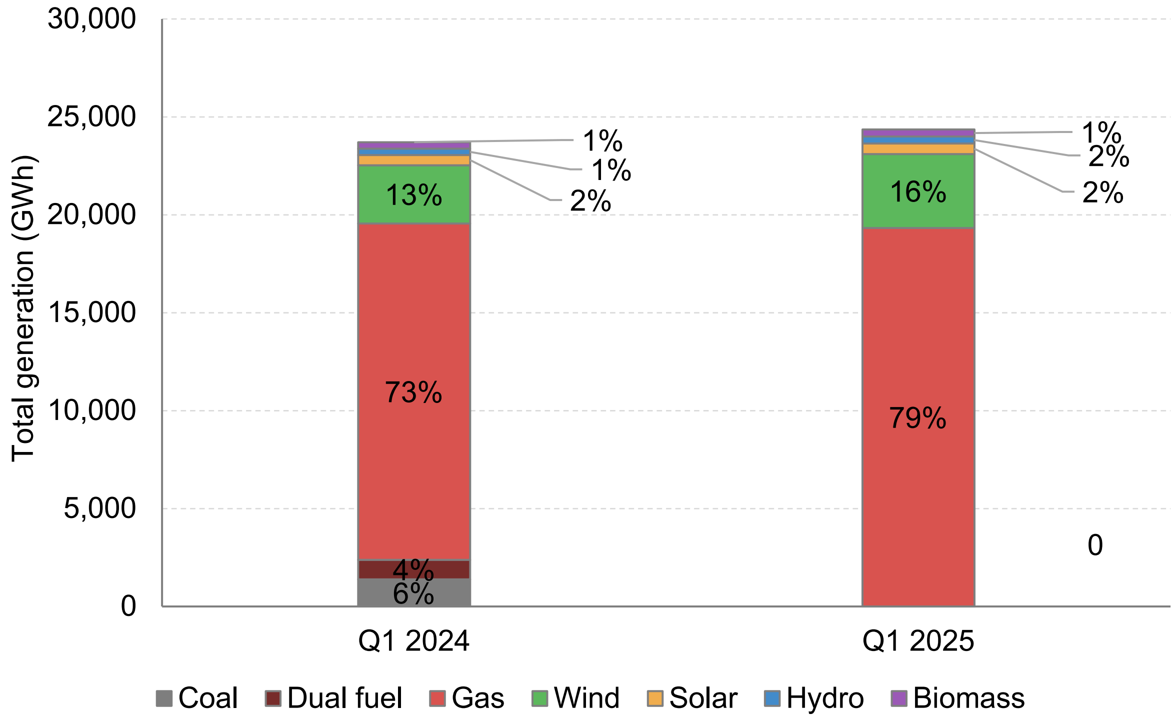


Figure 6 illustrates generation by fuel type year-over-year. This analysis includes generation that was produced and consumed on the same industrial site (behind the fence generation). As shown, Alberta's market is dominated by gas-fired generation with gas providing 79% of electricity supply in Q1, up from 73% in Q1 2024. This increase in gas generation was largely driven by the repowering of Genesee 1 and 2 from coal to combined cycle and the reclassification of Genesee 3 from dual fuel to gas-fired steam. In addition, the increase in wind capacity meant there was more wind supply in Q1 this year with the proportion of wind increasing from 13% to 16%.

Figure 6: Total generation by fuel type (Q1 2024 and Q1 2025)



1.2 Market outcomes and events

Figure 7 plots pool price duration curves for Q1 and Q1 2024. These figures display the distribution of pool prices by showing the percent of hours pool prices cleared at or above a certain level. The duration curve for Q1 is shifted down and to the left of Q1 2024, showing that prices in Q1 were lower throughout the distribution. As discussed above, increased thermal supply has put downward pressure on pool prices year-over-year and this offset slightly higher natural gas prices this year.

In recent quarters pool prices have been clearing at the price floor of $0/MWh more often. In the last three quarters pool prices have cleared at $0/MWh in around 7% of hours, which is a large increase relative to historical values (Figure 8).

Figure 7: Pool price duration curves (Q1 and Q1 2024)

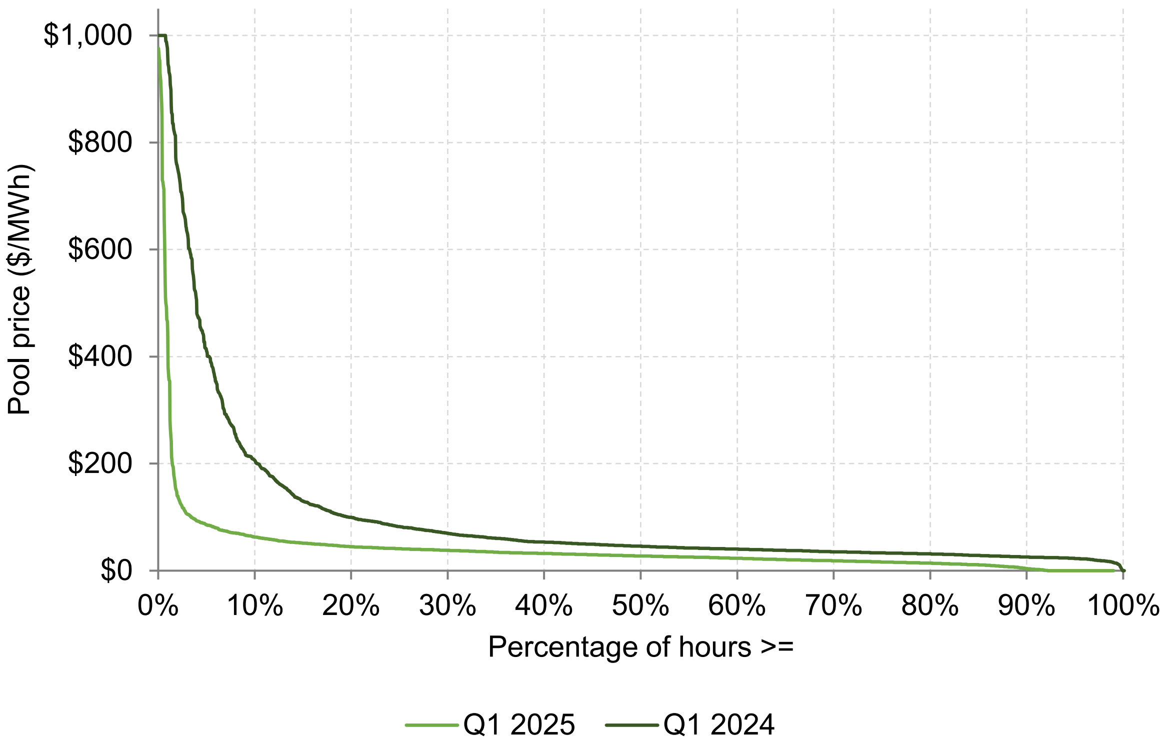
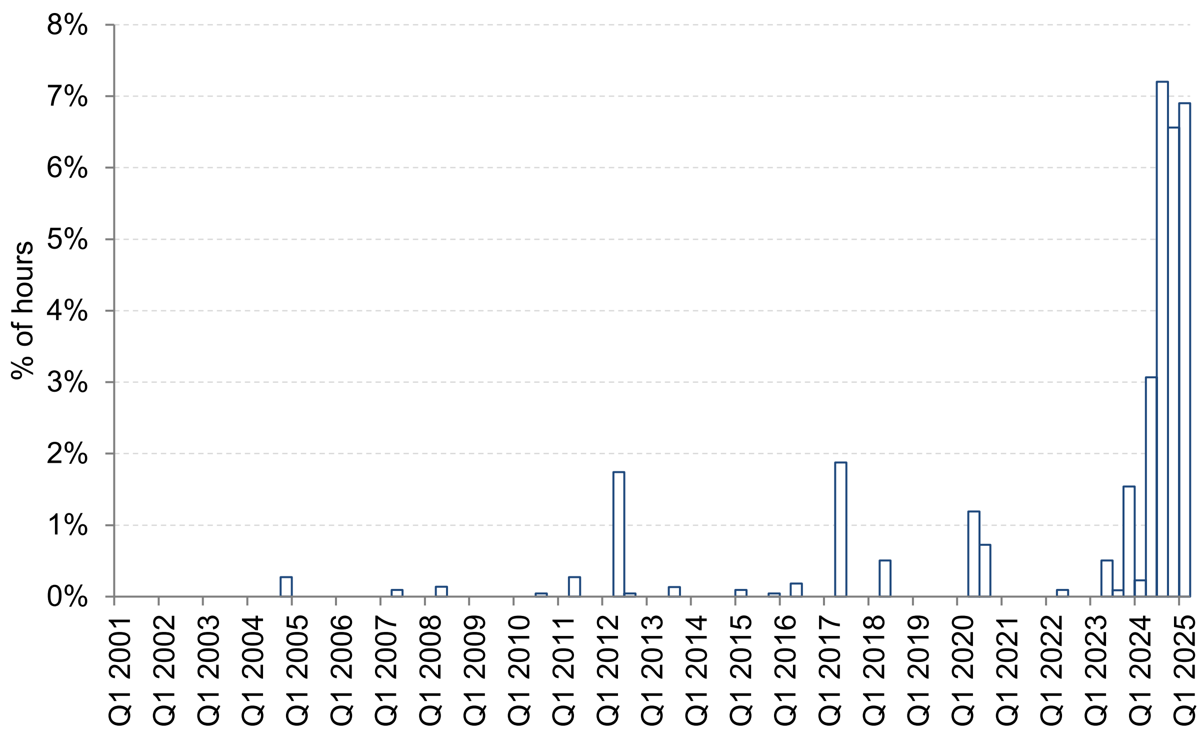


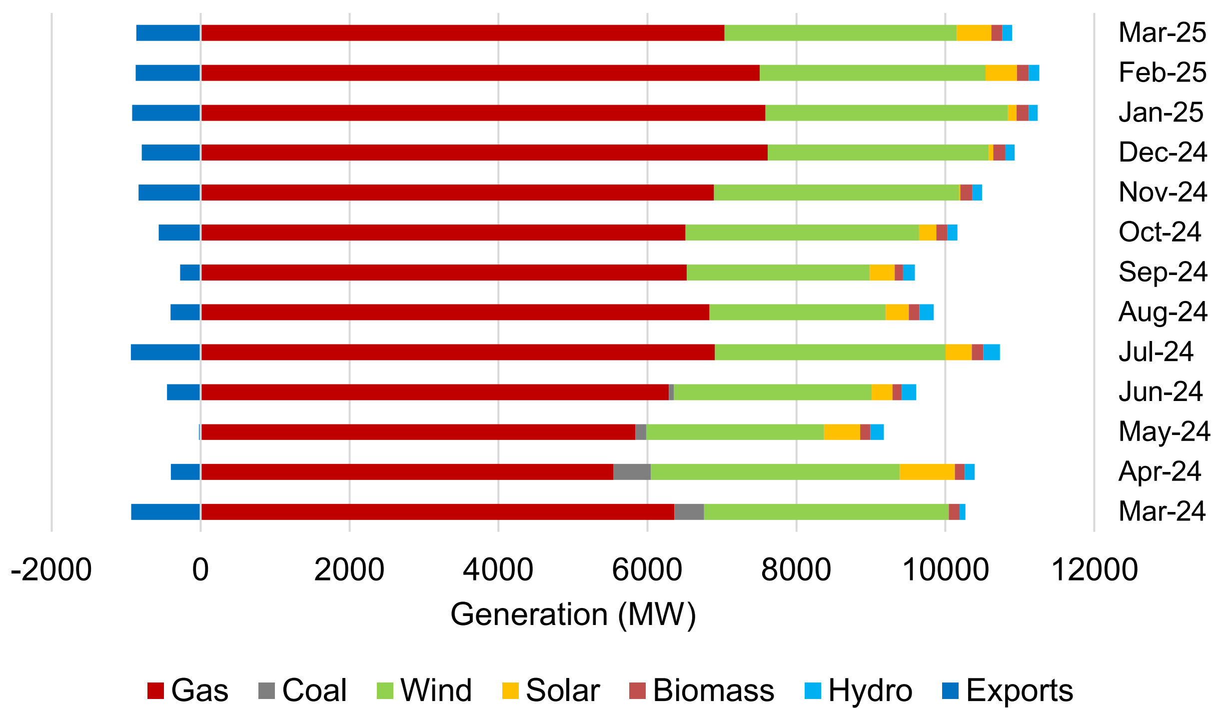
Figure 8: The percent of hours in which the pool price was $0/MWh



Pool prices are clearing at $0/MWh more often because of increased gas and wind supply. Figure 9 illustrates the average generation by fuel type during $0/MWh hours across different months. As shown baseload gas and wind supply a large proportion of the generation when prices are $0/MWh.

For baseload gas assets, must-run constraints often mean it would be costly to reduce generation even when pool prices are $0/MWh. In particular, for cogeneration assets must-run constraints include providing steam and/or power to on-site operations, such as for an oil sands production project. At combined cycle and gas-fired steam assets minimum stable generation (MSG) levels can cause operational constraints because these large assets can't run reliably below a certain level. In addition, some gas generators offer their assets into the market at $0/MWh to reduce ramping costs.

Figure 9: Average generation by fuel type in hours where the pool price was $0/MWh by month (March 2024 to March 2025)



In January and February gas generation averaged around 7,500 MW during hours in which the pool price cleared at $0/MWh, close to the record of 7,600 MW set in December 2024. In March average gas generation during $0/MWh hours dropped down to around 7,000 MW.

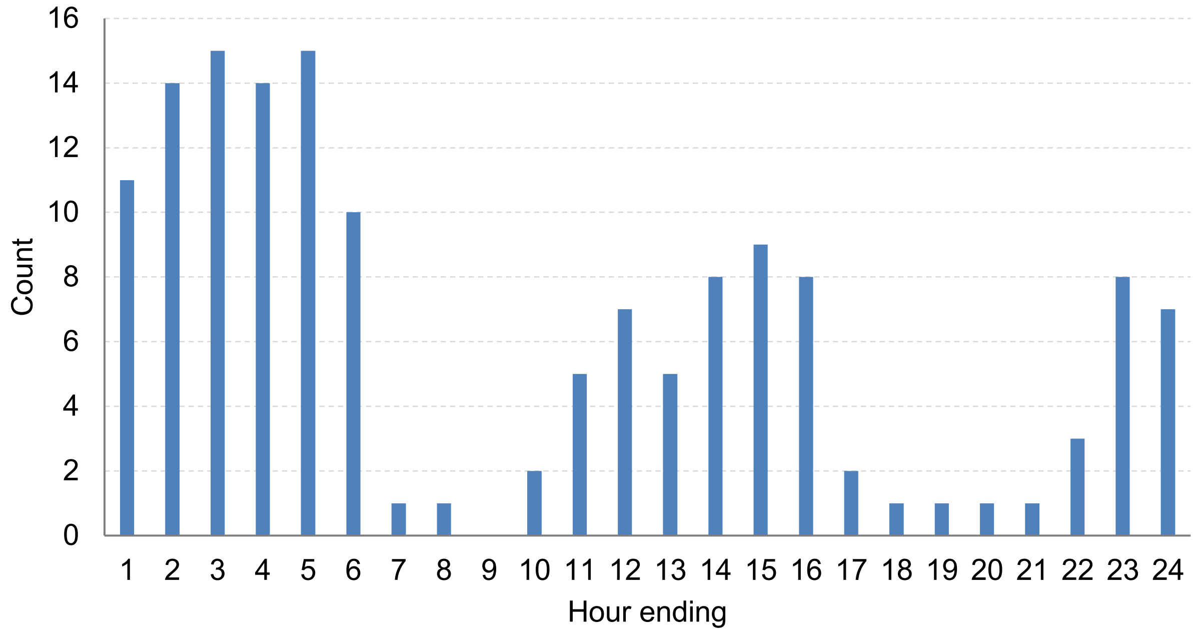
The other main supplier during $0/MWh hours is wind generation (Figure 9). Wind assets in Alberta can claim environmental credits for their generation so they are not incented to reduce generation when prices go to $0/MWh. In Q1 wind generation averaged 3,150 MW during $0/MWh hours.

During some $0/MWh hours solar generation is also a key supplier. Similar to wind assets, solar assets can claim environmental credits for their generation. In Q1 41% of $0/MWh hours occurred during the on-peak period (HE 08 to 23) (Figure 10). Indeed, HE 09 was the only hour that did not see a $0/MWh pool price in Q1. For some $0/MWh hours in February and March solar was supplying upwards of 1,200 MW.

Exports from Alberta can increase demand and counteract the high supply during $0/MWh pool price events (Figure 9). In Q1, exports during $0/MWh hours averaged 900 MW.

During some events, demand was relatively high and yet the pool price was still $0/MWh. For example, on February 12 the pool price for HE 12 was $0/MWh even as AIL was 11,756 MW and exports were 866 MW, meaning total generation in Alberta was 12,622 MW. In this event, gas generation was high averaging 8,990 MW while wind and solar generation were 2,430 MW and 820 MW, respectively.

Figure 10: Count of $0/MWh pool price hours by time of day (Q1 2025)



1.2.1 Large drops in wind generation

On January 11 and February 27 wind generation dropped suddenly and significantly. Figure 11 illustrates the drop in wind generation just before 09:00 on the morning of Saturday, January 11. On this occasion wind generation dropped from around 3,200 MW to under 2,500 MW, a fall of more than 700 MW. This decline occurred in the space of 3 minutes and 30 seconds. Table 2 provides the assets at which there was a generation drop in this case.

Figure 12 illustrates wind assets in Alberta on a map, with the red circles illustrating wind assets that experienced a drop in generation in this event, and the size of the red circle is proportional to the size of the drop. The small blue circles indicate the location of wind assets at which there was no drop in generation. As shown, many of the assets that experienced a drop in generation in this case are in the southeastern part of the province.

Figure 11: Total wind generation (January 11, 2025)

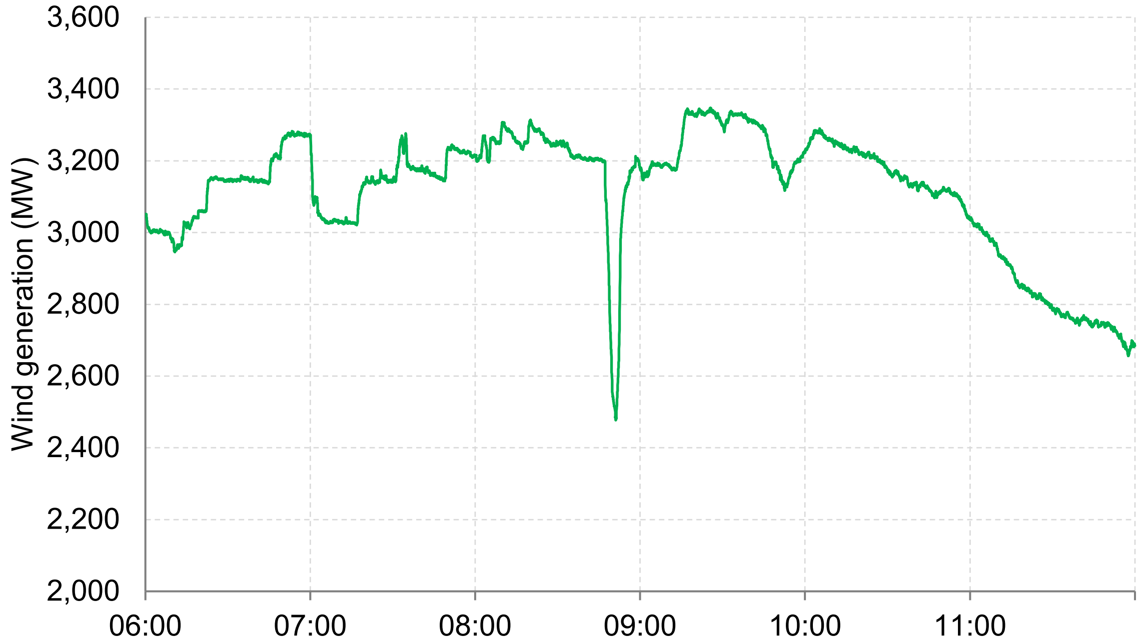
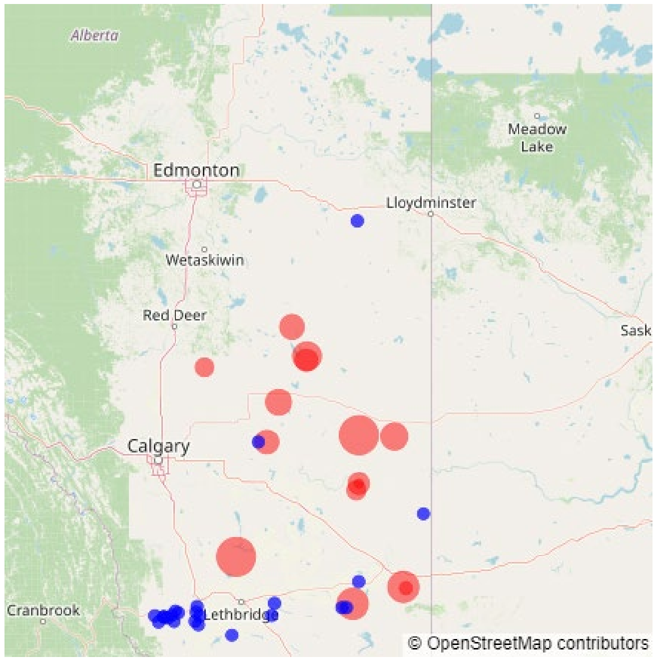


Table 2: Generation drop by wind asset at around 08:51 on January 11, 2025

Asset short name	Generation drop (MW)
SHH1	103
BSR1	102
CYP1	68
FMG1	68
PAW1	58
LAN1	53
HHW1	48
HAL1	44
WHE1	41
GDP1	37
JNR1	35
JNR3	27
NEP1	26
CYP2	15
JNR2	8

Figure 12: A map showing the location of assets where wind generation dropped (January 11, 2025)



As a result of the abrupt decline in wind generation, Area Control Error (ACE) fell to -840 MW, a notably low value (Figure 13). ACE provides an indication of how actual flows on the interties compare with the scheduled volumes.

In this instance the sudden drop in wind generation meant that Alberta was not exporting as much as it was scheduled to. Figure 14 compares the actual flow of power with the schedule on the BC intertie in this case. The drop in wind generation just before 09:00 caused exports to BC to drop down to 130 MW, well below the scheduled amount of 890 MW.

Given the ability of the interties to absorb the sudden drop in wind generation in this event there was little impact on system frequency. However, had the BC/MATL interties been offline when the drop in wind supply occurred there would have been a material impact on the frequency of the Alberta grid.

Figure 13: Area control error (January 11, 2025)

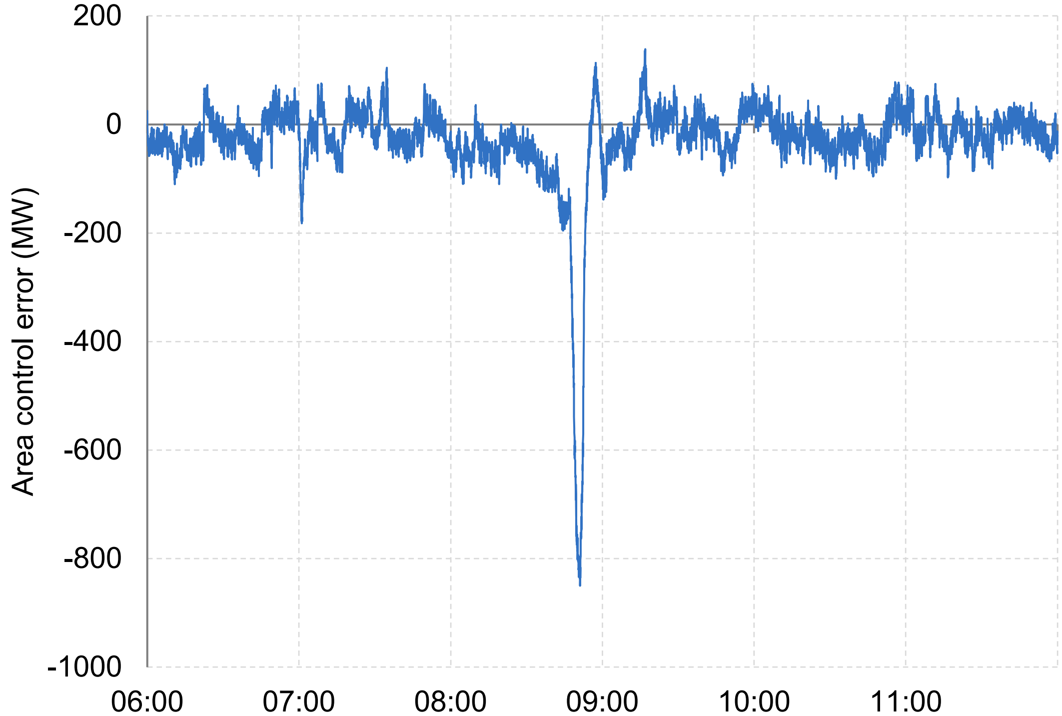
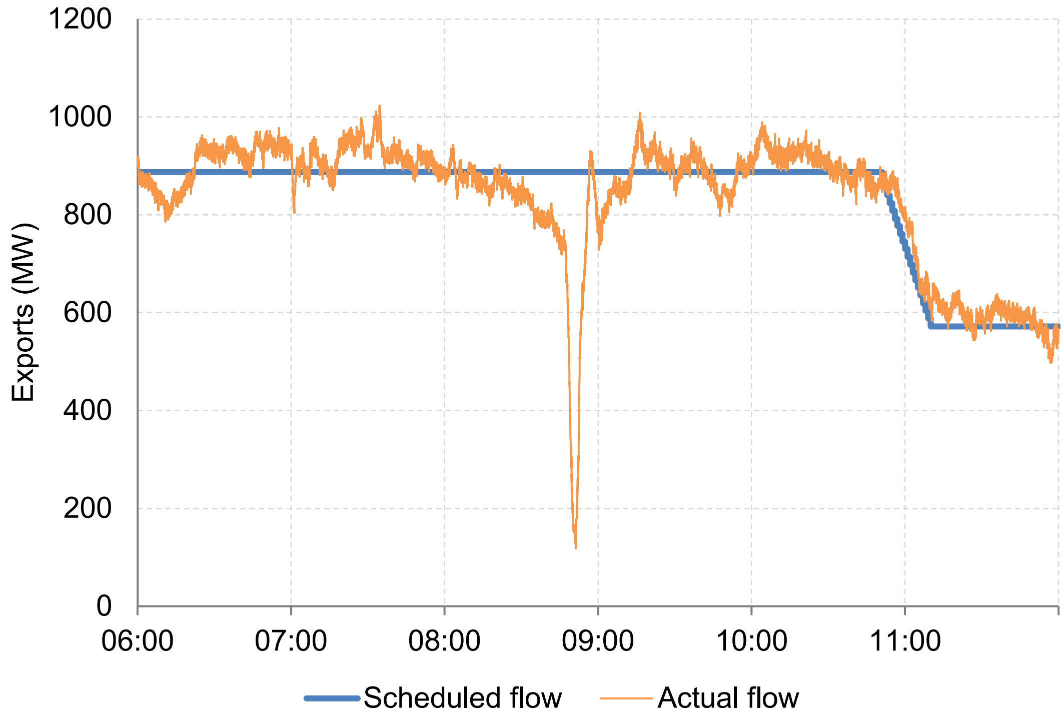


Figure 14: Actual and scheduled exports on the BC intertie (January 11, 2025)



A similar event occurred on the morning of Thursday, February 27. Prevailing wind generation at the time was high at 3,400 MW. However, at around 06:00 total wind generation fell to 2,640 MW, a drop of 760 MW in the space of 3 minutes (Figure 15). Figure 16 provides a map showing the location of wind assets where there was a generation drop in this case (shown by the red circles). In this instance, the wind assets where there was a drop in supply were more scattered across the south of the province. Table 3 lists the assets at which wind generation dropped in this instance.

Figure 15: Total wind generation (February 27, 2025)

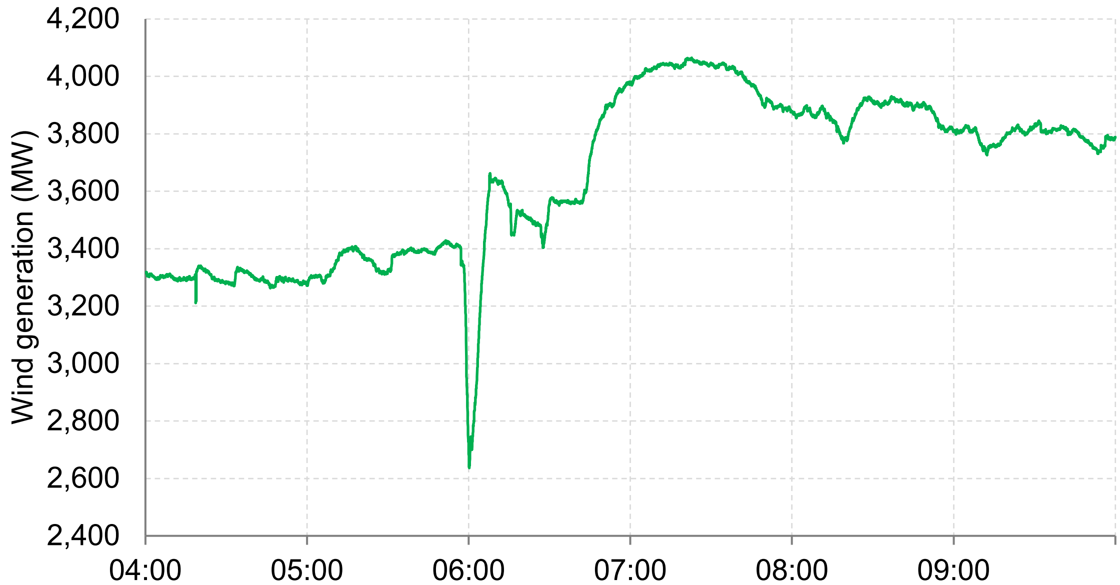


Figure 16: A map showing the location of assets where wind generation dropped (February 27, 2025)

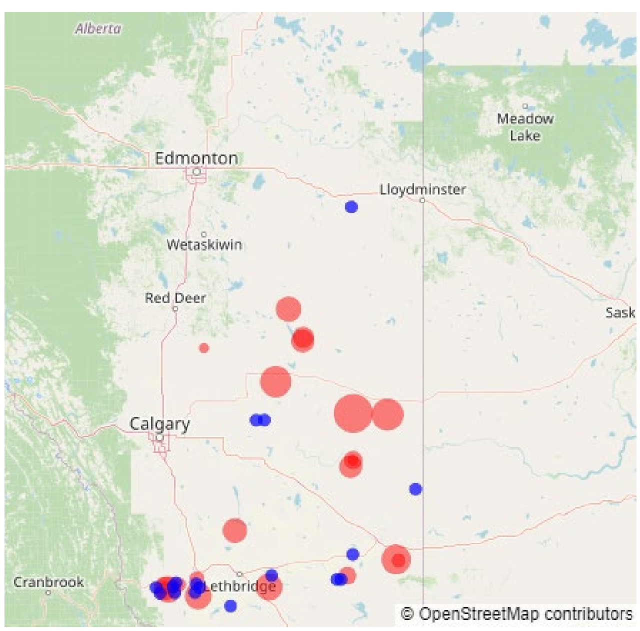


Table 3: Generation drop by wind asset at around 06:02 on February 27, 2025

Asset short name	Generation drop (MW)
SHH1	107
LAN1	74
HHW1	70
CYP1	63
SWP1	53
WRW1	53
RIV1	51
HAL1	48
BSR1	44
CRR1	41
JNR3	39
GDP1	39
PAW1	34
BPW1	31
JNR1	26
FMG1	25
WIR1	17
BTR1	17
CYP2	16
IEW2	15
CRR2	15
JNR2	10
NEP1	9

As a result of the drop in wind generation, ACE fell to a low of -950 MW before increasing to a high of 400 MW (Figure 17). This volatility in ACE reflected changes to the flow of power over the interties.

As shown by Figure 18 the schedule on the BC intertie at the time was for 860 MW of exports to BC. When wind generation dropped the actual flow of power dropped to 130 MW of exports, well below the scheduled amount. When wind generation recovered and increased beyond its previous high, Alberta was exporting around 1,200 MW, well above the schedule.

The volatility of wind generation in this case was largely absorbed by the BC intertie and there was little impact on system frequency. However, had this event occurred when BC/MATL were offline there would have been a material impact on the frequency of the Alberta grid.

Figure 17: Area control error (February 27, 2025)

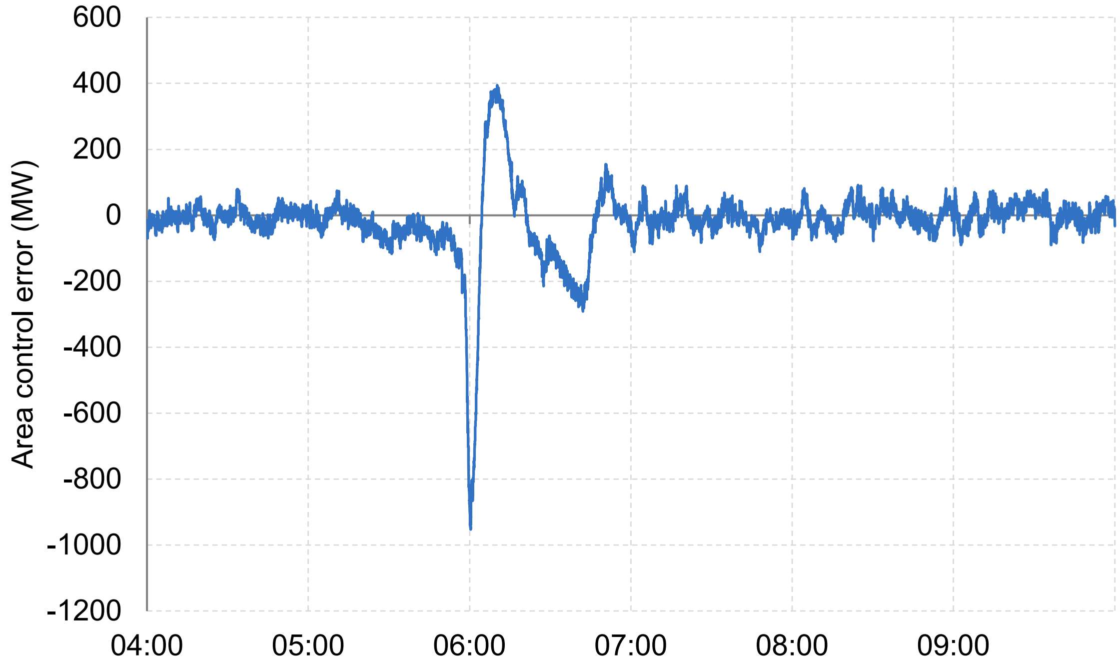
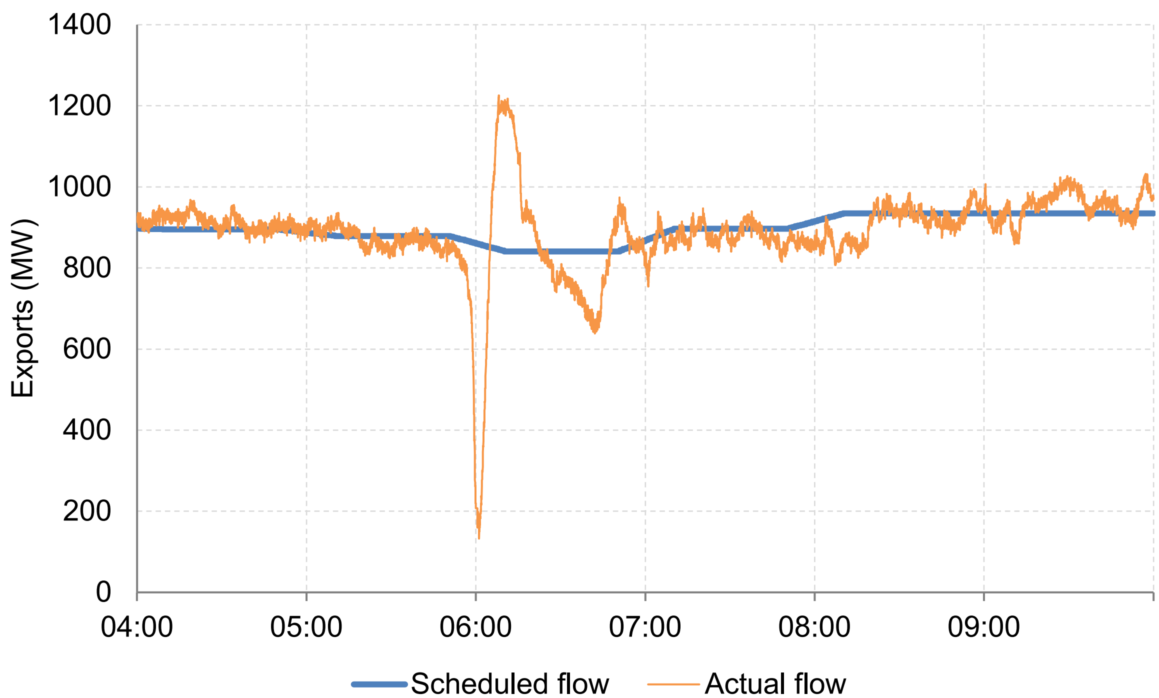


Figure 18: Actual and scheduled exports on the BC intertie (February 27, 2025)



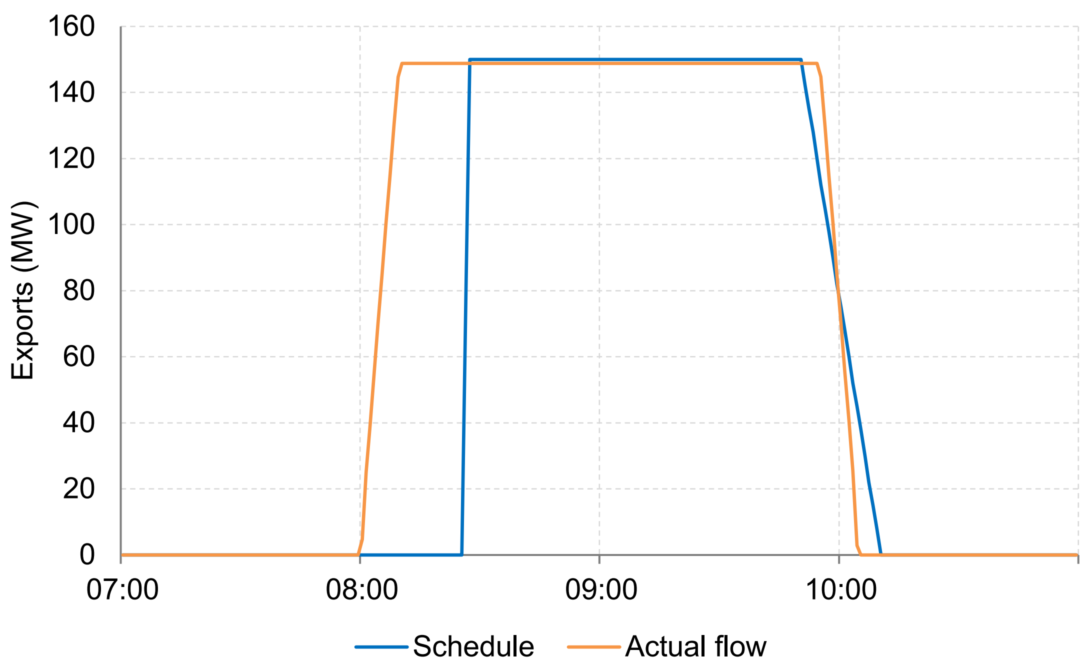
1.2.2 Providing emergency power to Saskatchewan

Due to an operational issue at the McNeil converter station, the Saskatchewan intertie has been unavailable for commercial use since October 4, 2024. Since January 15 the intertie has been offline but available for emergency use. On January 20, Saskatchewan declared a supply shortfall and used the intertie to import emergency power from Alberta.

At around 08:00 on the morning of January 20 the AESO were contacted by Saskatchewan to request emergency power as Saskatchewan was in Energy Emergency Alert level 2 (EEA2). The declaration of EEA2 indicated that Saskatchewan did not have enough power to reliably meet their demand and that load management procedures had been put into effect.

The AESO responded by directing 150 MW of contingency reserves for two hours and exporting this amount to Saskatchewan (Figure 19). Shortly after this event, at 10:12, the McNeil converter station tripped out of service and became unavailable.

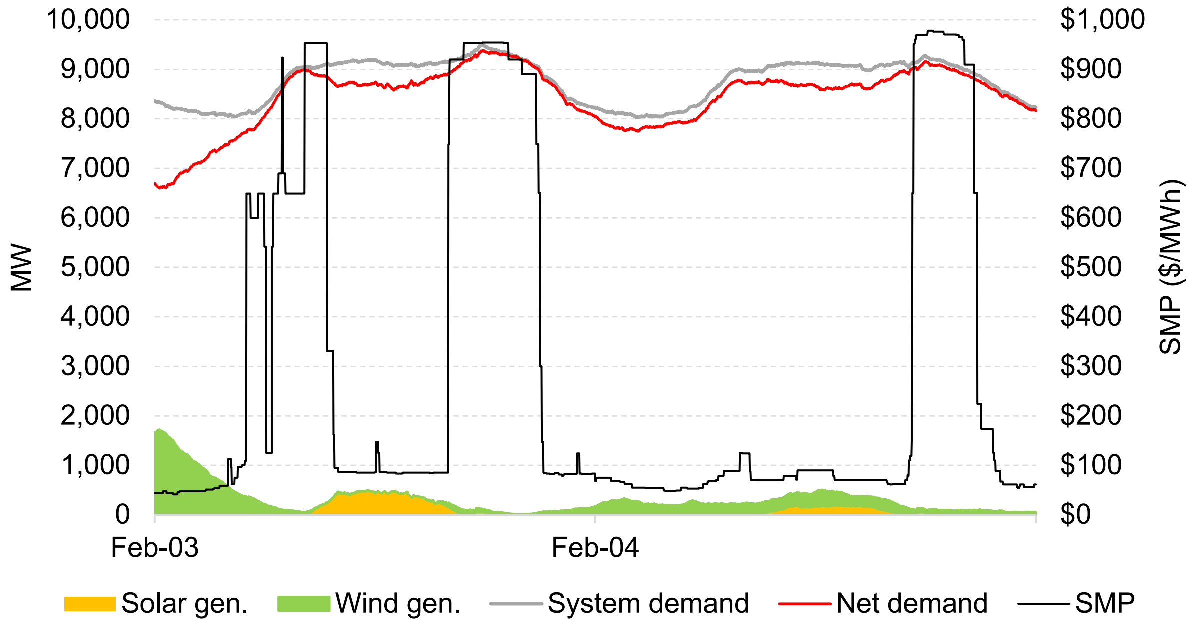
Figure 19: Actual and scheduled power flows on the SK intertie (January 20, 2025)



1.2.3 High prices and Cascade 1 and 2 outages

Prices on Monday, February 3 averaged $370/MWh, the highest in the quarter. Prices on this day were increased by cold weather, low intermittent generation, and thermal outages at Sheerness 2 and HR Milner. In addition, Sheerness 1 was commercially offline on long lead time (LLT).

Figure 20: System demand, intermittent generation and SMP (February 3 to 4, 2025)



Prices increased up to $649/MWh on the morning of February 3 as wind generation declined and demand began to increase (Figure 20). As demand rose further, the SMP increased up to $953/MWh as of 08:10. However, solar supply increased and put downward pressure on prices, bringing the SMP down to $95/MWh as of 09:47. In part because of solar supply, prices remained relatively low throughout the day, before increasing again when solar declined around the evening demand peak.

Prices increased to $954/MWh in the evening although the supply cushion did not fall below 893 MW. The high pool price combined with the relatively high supply cushion indicates there was a large amount of economic withholding in this case. Figure 21 illustrates the merit order for HE19.

Despite the continuation of low intermittent supply, prices were lower in the morning and during the day of February 4 because Sheerness 2 returned from outage and Sheerness 1 came online. However, prices increased during the evening peak due to forced outages at Cascade 1 and 2.

As shown by Figure 22 Cascade 2 tripped offline at 16:47 and then Cascade 1 tripped offline at 17:48 on February 4. These outages reduced supply by around 900 MW right before the evening peak in demand on a cold winter day. As a result, the supply cushion fell to 846 MW and pool price increased to $976/MWh in HE 19.

Figure 21: Energy market merit order for February 3 HE19

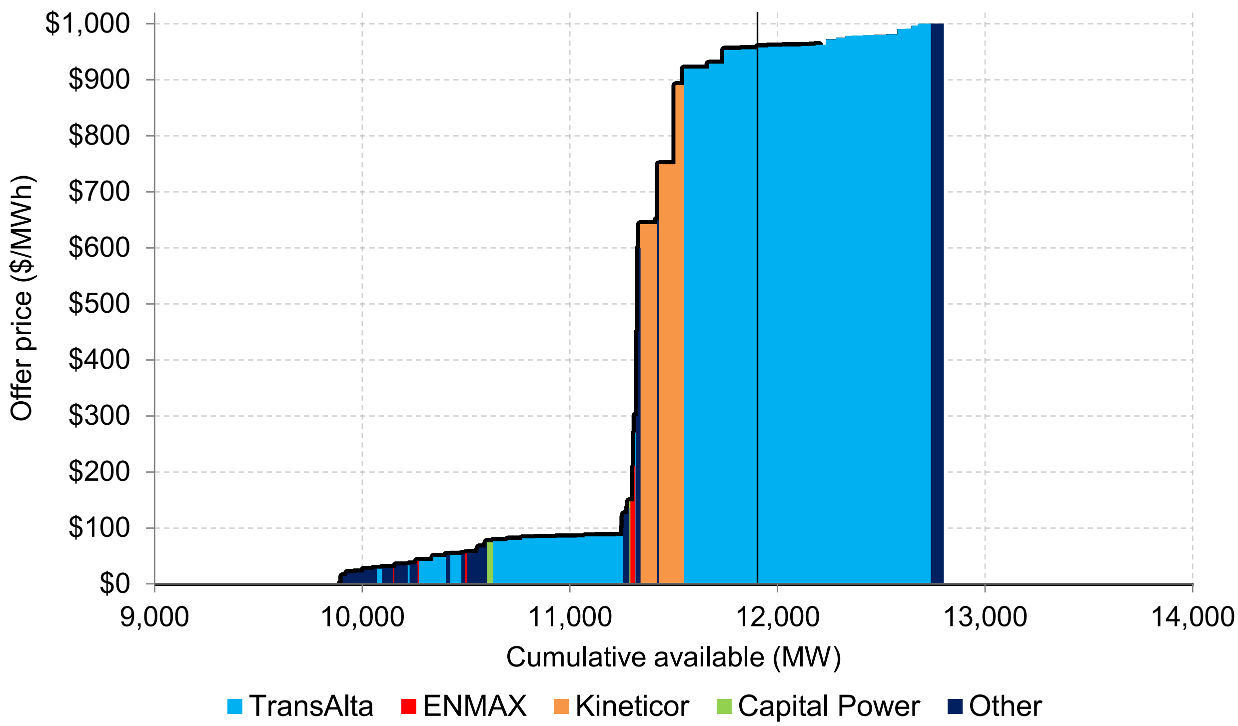
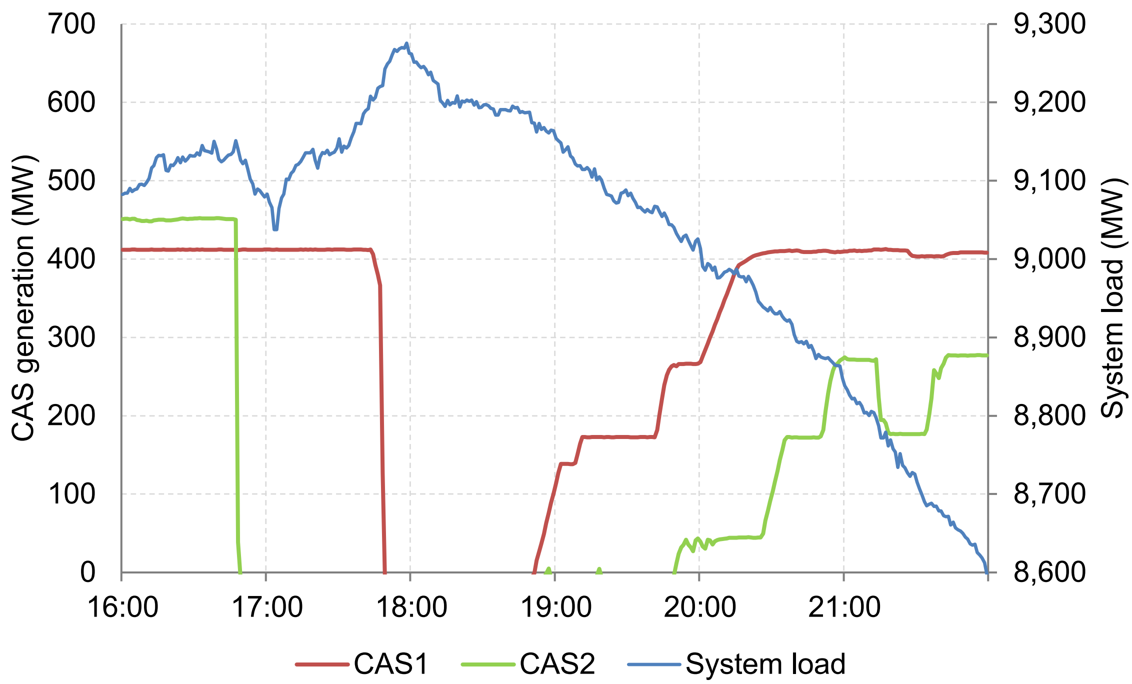


Figure 22: System demand and generation of Cascade 1 and Cascade 2 (February 4, 2025)



1.2.4 Low prices

The supply of intermittent generation was high in Q1 as the market continued to add wind and solar capacity. Q1 saw the second highest supply of intermittent generation on record at an average of 2,000 MW, just behind Q2 2024 (Table 4).

As outlined above, Q1 recorded the highest ever supply of wind generation, averaging 1,756 MW. The high level of wind generation in Q1 was largely driven by the addition of new wind capacity and moderate temperatures in the quarter. As shown in Table 5, four of the top five wind generation days on record occurred in Q1.

Table 4: Top five Quarters with highest intermittent generation

Quarter	Average wind generation (MW)	Average solar generation (MW)	Average intermittent generation (MW)
Q2 2024	1,574	453	2,027
Q1 2025	**1,756**	**244**	**2,000**
Q4 2024	1,715	157	1,872
Q4 2023	1,728	136	1,864
Q3 2024	1,172	465	1,637

Table 5: Top five days with highest average wind generation

Date	Average wind generation (MW)
January 21, 2025	3,743
January 27, 2025	3,734
February 23, 2025	**3,436**
January 10, 2025	3,390
December 26, 2023	3,381

On Sunday, February 23 a combination of high intermittent generation and low demand meant the daily average price was the lowest in the quarter (Figure 23). During HE 20, wind generation peaked at 4,178 MW, the highest hourly value on record. Prices on February 23 averaged $1.45/MWh, making it the third lowest day ever, with the SMP at the price floor for 82% of the day (Table 6).

Figure 23: System demand, intermittent generation, and SMP (February 23, 2025)

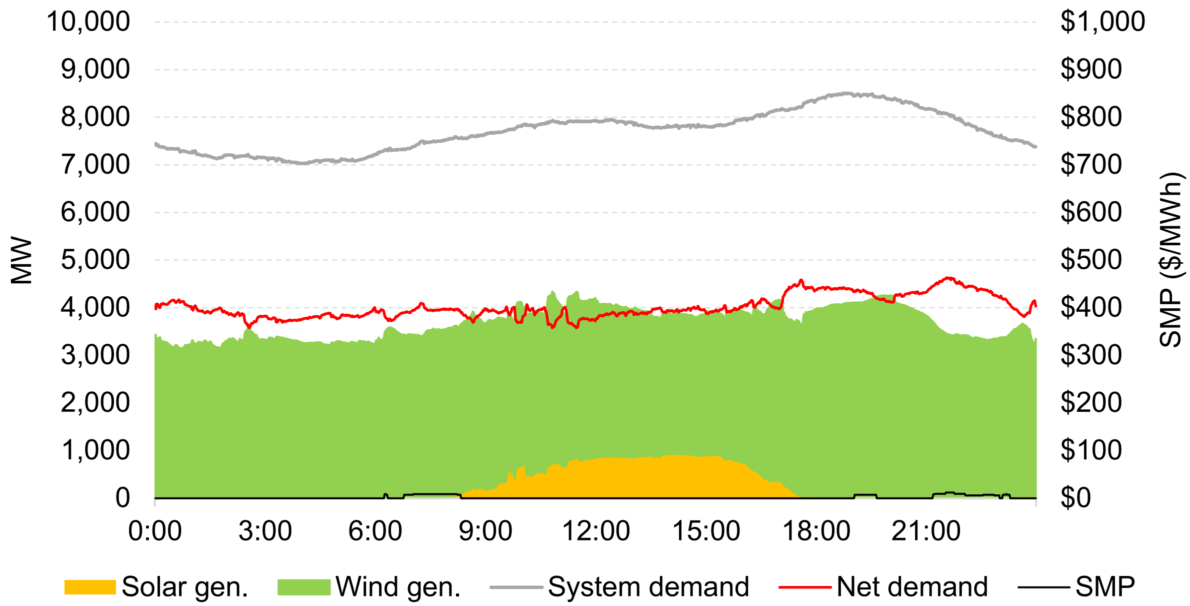


Table 6: Top five days with lowest daily average pool price

Date	Avg pool price	Percent of time SMP at floor	Avg wind generation (MW)	Avg solar generation (MW)	Avg AIL demand (MW)
Aug. 24 2024	$0.79	88%	2,501	379	9,651
Sep. 29, 2024	$1.33	73%	2,314	178	9,283
Feb. 23, 2025	**$1.45**	**82%**	**3,436**	**255**	**10,207**
Sep. 27, 2024	$2.53	77%	2,531	367	9,632
Sep. 25, 2024	$3.28	58%	2,749	407	9,915

1.3 Market power mitigation measures

In March 2024, the *Market Power Mitigation Regulation* (MPMR) and *Supply Cushion Regulation* (SCR) were enacted. Beginning July 1, 2024, these regulations moderate economic withholding and require the AESO to commit generation capacity under some circumstances. These regulations were informed by advice that the Minister requested from the MSA.[1]

The MPMR and SCR are implemented through ISO rules 206.1 and 206.2, respectively. These rules were originally in force in their expedited form but received final approval in Alberta Utilities Commission Proceeding 29093 on February 19, subject to a revision in rule 206.2. This revision required the AESO to issue a real-time notification of the start and end of unit commitment

[1] See the Advice from the MSA

directives. The AESO filed this revision, which was approved in Proceeding 29940, resulting in final approval of all subsections effective April 20.

The MSA first reported on these measures in section 1.3 of its Quarterly Report for Q3 2024, which provides a more comprehensive description of the underlying mechanisms and the MSA's analytical methods.

With generally low prices and high supply cushion through Q1, the interim measures had little effect, which is consistent with their intended purpose. The MSA estimates that, without the single unit commitment directive in Q1, average pool prices would have been $39.82/MWh. Compared to the observed average pool price of $39.78/MWh, this means the measures are estimated to have reduced the average Q1 pool price by just $0.04/MWh, or effectively 0%. This is a significant change from the 10% and 11% reductions estimated in Q3 and Q4 2024, 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, as the MCSINR reached only 15%, 44%, and 17% of the threshold in January, February, and March, respectively. As described in section 1, lower prices in Q1 were primarily driven by more available thermal capacity.

The maximum MCSINR in February was reached in HE 22 on February 20. Due to milder weather during the remainder of February, pool prices were lower and hourly net revenues were often negative, reducing the MCSINR.

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 (UCDs) to eligible LLT assets when the ASC falls below 932 MW. The AESO must choose which eligible LLT assets to direct based on economic merit and physical constraints, for which it uses a tool called Power Optimisation (PowerOp).

In Q1, there was only one UCD, as shown in Table 7. The ASC deficit was small, and actual supply cushion was higher than anticipated primarily due to the UCD itself and due to the early return of CAL1 from an outage.

Table 7: Unit commitment directives in Q1 2025

Asset ID	Commitment start time	Commitment end time	Minimum anticipated supply cushion	Minimum actual supply cushion
BR4	Mar 29 18:00	Mar 29 22:00	915 MW	1,319 MW

Table 8 shows the estimated price effect of the single UCD in Q1. While the UCD is estimated to have reduced average pool price by 23% during its four-hour duration, this had a negligible impact on average pool price over March or Q1.

Table 8: Estimated price impact of unit commitment directives in Q1 2025

Time period	Actual average pool price ($/MWh)	Estimated average pool price without unit commitment directives ($/MWh)	Percentage change (%)
UCD period	$64.10	$82.89	-23%
March 2025	$34.76	$34.86	0%
Q1 2025	$39.78	$39.82	0%

1.4 Market power and offer behaviour

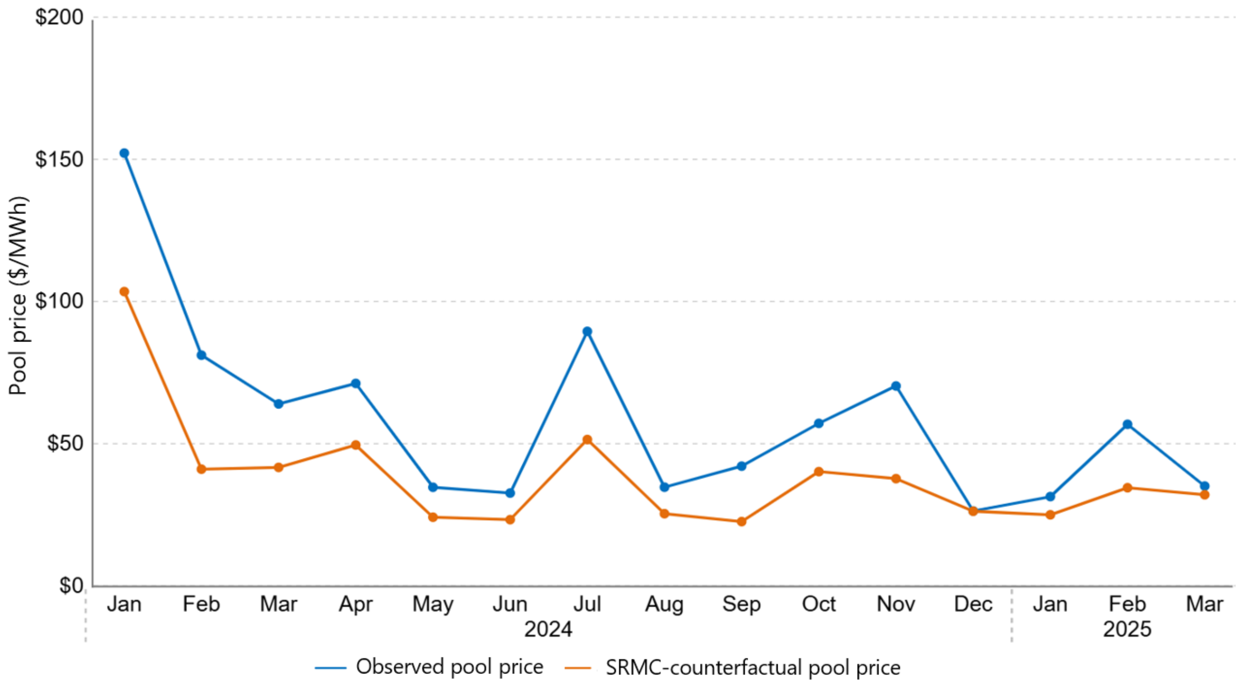
1.4.1 Market power

As part of our market monitoring the MSA analyzes the difference between observed prices and counterfactual prices which are estimated based on offers being submitted at short-run marginal cost. The mark-up between observed prices and counterfactual prices based on short-run marginal cost is indicative of market power, with a higher mark-up indicating more market power.

Figure 24 illustrates monthly average pool prices and monthly average counterfactual prices going back to January 2024. In Q1 the mark-up was highest in February as cold weather early in the month increased demand, reduced wind generation, and raised market power. The average mark-up in February was $26/MWh compared to $6/MWh in January and $3/MWh in March.

Year-over-year there was a decline in the mark-up of prices over short-run marginal cost. In Q1 the average mark-up was $9/MWh compared with an average mark-up of $37/MWh in Q1 2024, a reduction of 76%. This reduction in the mark-up was largely driven by increased thermal capacity year-over-year. As discussed in section 1, developments at Cascade and Base Plant have increased thermal capacity significantly since Q1 2024. In addition, Q1 saw a record amount of wind generation, and this was also a factor in the lower levels of market power in Q1 this year.

Figure 24: Average observed and counterfactual pool prices (January 2024 to March 2025)



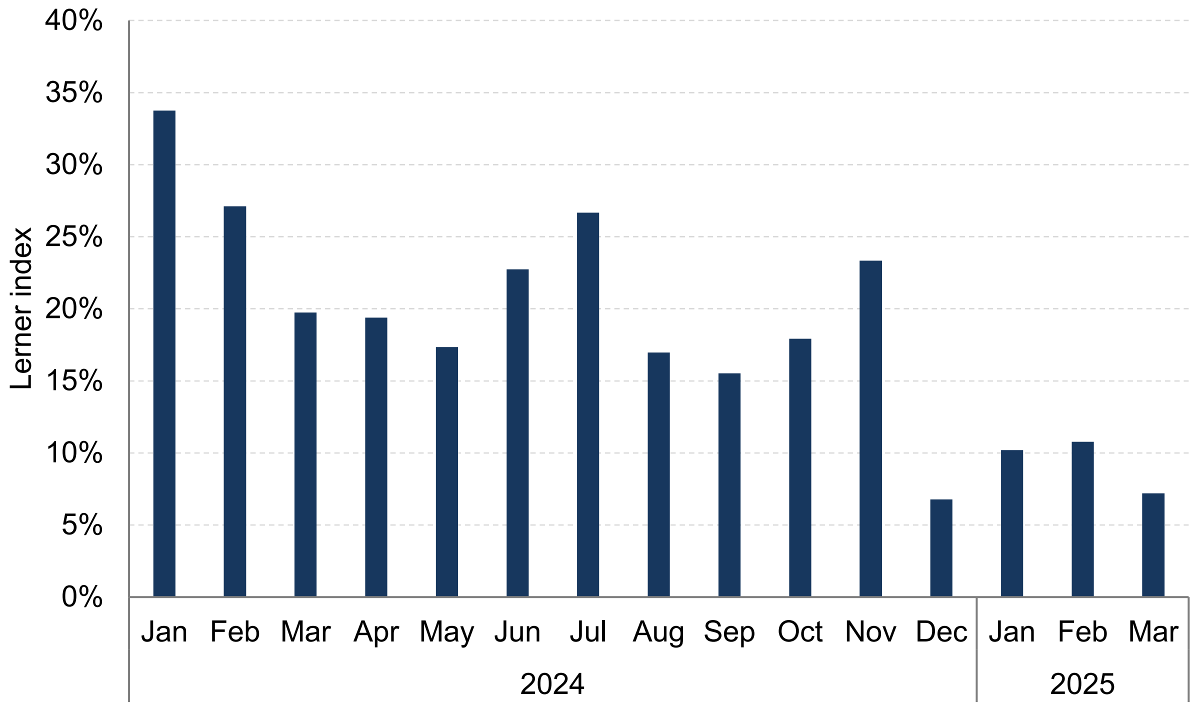
The Lerner index is a measure of market power that calculates what percentage of the observed price is attributable to mark-up (see equation below). Therefore, a higher Lerner index indicates more market power.

$$Lerner\ Index = \frac{(Price(Obs) - Price(SRMC))}{Price(Obs)}$$

Figure 25 illustrates the monthly average Lerner index going back to January 2024. In this analysis the Lerner index is set to zero in hours where the observed price is less than the counterfactual price, meaning we assume no market power in these hours. This is different to how these hours have been treated in prior MSA quarterly reports where negative values were included.

As shown, the average Lerner index has been declining over the last year as thermal supply to the market has increased. In Q1 the average Lerner index was 9% compared to 27% in Q1 2024.

Figure 25: Average Lerner index by month (January 2024 to March 2025)



One way to analyze the ability of firms to exercise market power is to calculate the extent to which they are pivotal to the energy market clearing. A firm is said to be pivotal when its withholdable capacity is needed for demand to be met.[2]

The ability of firms to exercise market power declined year-over-year. In Q1 at least one firm was pivotal in 4% of hours compared to 11% of hours in Q1 2024 (Table 9). Firms were pivotal less often in Q1 this year largely because of increased thermal capacity.

Table 9: The percent of time at least one firm was pivotal (Q1 2024 and Q1 2025)

	2024	**2025**
Jan	14%	3%
Feb	11%	7%
Mar	6%	2%
Q1	11%	4%

[2] A firm's withholdable capacity includes all capacity except for must-run capacity reflected as minimum stable generation (MSG) and wind and solar capacity.

1.4.2 Offer behaviour

The extent to which firms are pivotal in the energy market will change over time as market fundamentals and the supply controlled by firms changes. The different classifications of pivotality used here are as follows:

- Two or more firms are individually pivotal at the same time ("two or more firms individually pivotal")
- One firm by itself is pivotal ("one firm individually pivotal")
- Two firms are collectively pivotal with their combined withholdable capacity ("two firms collectively pivotal"), and
- No firm is pivotal or collectively pivotal ("no firm pivotal")

Figure 26 illustrates average pool prices by month and pivotality classification. In Q1 there were only seventeen hours in March in which two or more firms were individually pivotal and the average price in these hours was relatively low at an average of $120/MWh.

In February there was an increase in the average price of hours in which firms were individually pivotal up to $340/MWh as large firms exercised market power in these hours, especially early in the month.

Prices remained relatively low in hours where no firm was individually pivotal, as has been the case historically.

Figure 26: Average pool price by pivotality classification and month (January 2024 to March 2025)

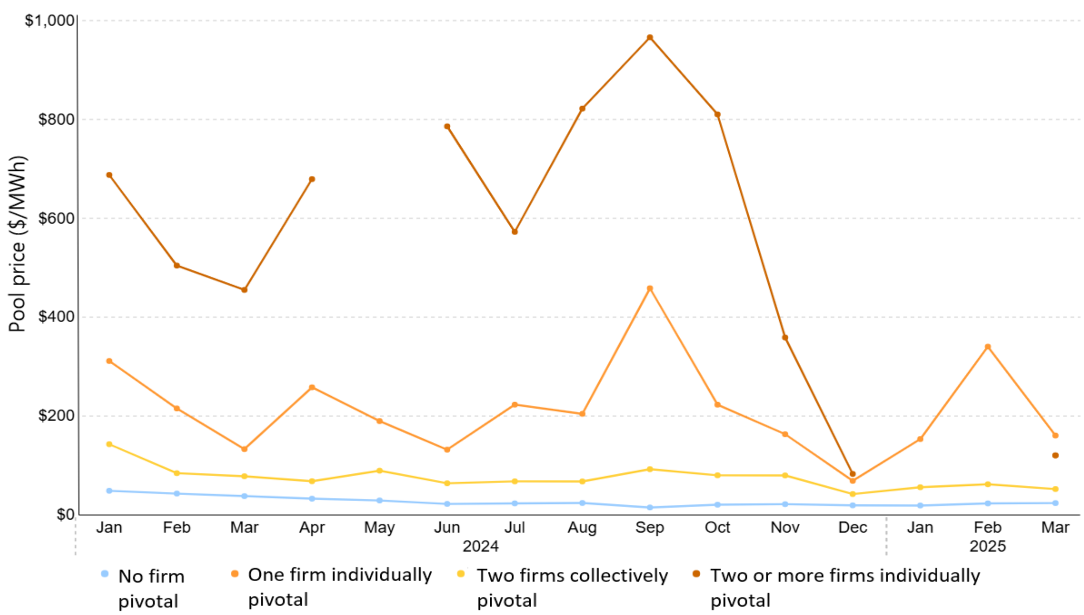


Figure 27 illustrates the amount of non-hydro capacity offered above $250/MWh in the highest priced hour of each day in Q1. As shown, the exercise of market power was most prevalent in early January and early February when cold temperatures and low intermittent generation combined to tighten the market.

In HE 09 of February 7 1,875 MW of non-hydro capacity was offered above $250/MWh, the highest in the quarter. However, the pool price in this case was relatively low at $117/MWh which illustrates the impact the new thermal supply has had on the market. Pool prices in the quarter peaked in HE 19 of February 3 when 1,450 MW were offered above $250/MWh (see Figure 21).

Figure 27: Non-hydro capacity offered above $250/MWh in the highest price hour of the day (January 1 to March 31, 2025)

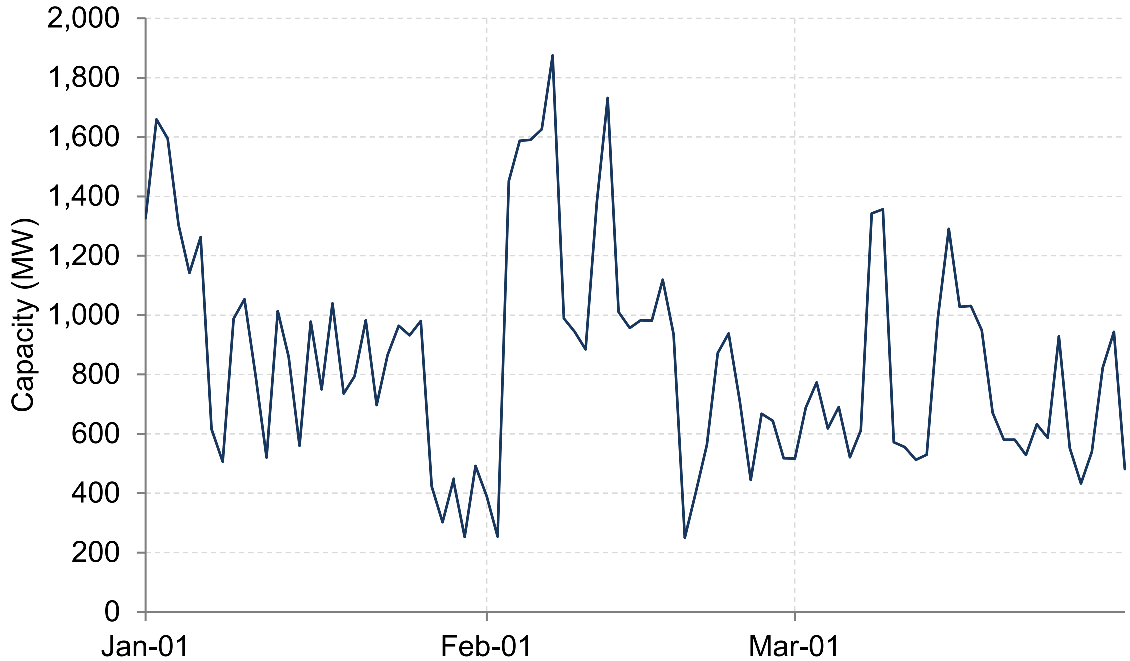
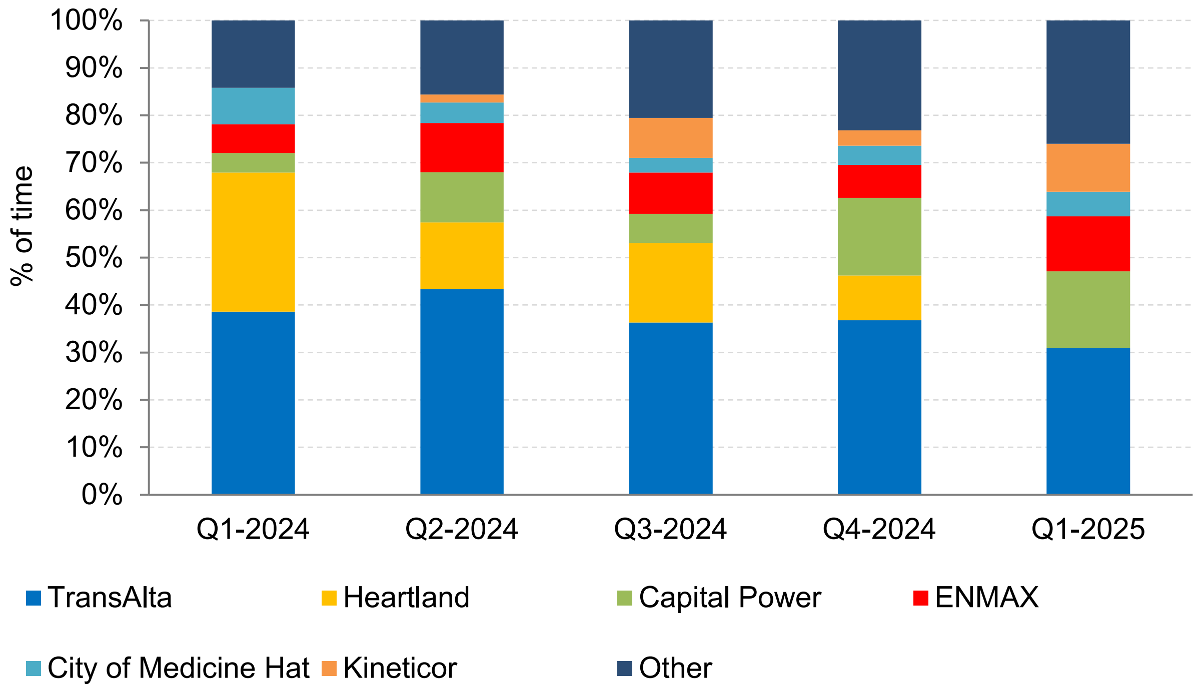


Figure 28 illustrates the amount of time in each quarter that different companies set the SMP. As shown the percent of time that TransAlta set the SMP has fallen in recent quarters despite TransAlta's acquisition of Heartland on December 4, 2024.

In Q1 a TransAlta asset set the SMP 31% of the time whereas in Q1 2024 TransAlta and Heartland together set the SMP almost 70% of the time. The decrease in TransAlta's time setting price has largely occurred because of the thermal additions at Cascade and Base Plant. These assets have increased supply and moved the SMP lower down the merit order. In addition, TransAlta's gas-fired steam assets have been commercially offline on LLT more often in recent quarters.

Figure 28: Percent of time firms set the SMP by quarter (Q1 2024 to Q1 2025)



1.5 Carbon emission 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 relied on information that is publicly available. The results reported here do not include imported generation.[3]

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 10 shows the minimum, mean, and maximum hourly average emission for Q1 over the past seven years. Notably, the maximum hourly average emission intensity for Q1 2025 (0.54 tCO2e/MWh) was close to the minimum hourly average emission intensity for Q1 2019 (0.53 tCO2e/MWh). Table 11 shows the same summary statistics for the past four quarters, demonstrating stability in the hourly average emission intensity.

[3] For more details on the methodology, see Quarterly Report for Q4 2021.

Table 10: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2019 Q1	0.53	0.67	0.75
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

Table 11: Quarter over quarter min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2024 Q2	0.26	0.39	0.56
2024 Q3	0.25	0.40	0.53
2024 Q4	0.25	0.40	0.54
2025 Q1	0.27	0.40	0.54

Figure 29 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q1 over the past seven years. Figure 30 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The conversion of coal-fired generation to natural gas, in addition to increased intermittent generation, has driven a decline in carbon emission intensity. This decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions as shown in Figure 29.

Figure 29: The distribution of average carbon emission intensities in Q1 (2019 to 2025)

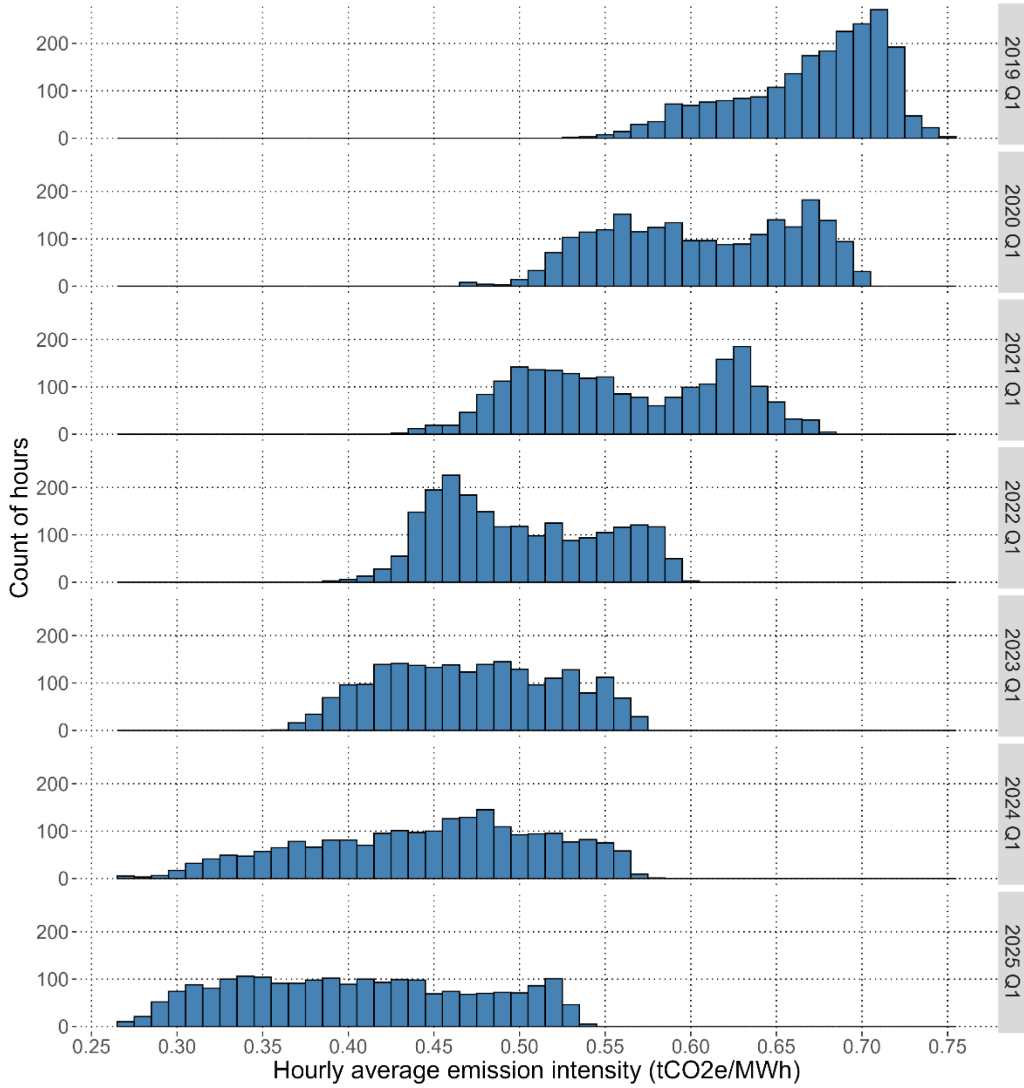
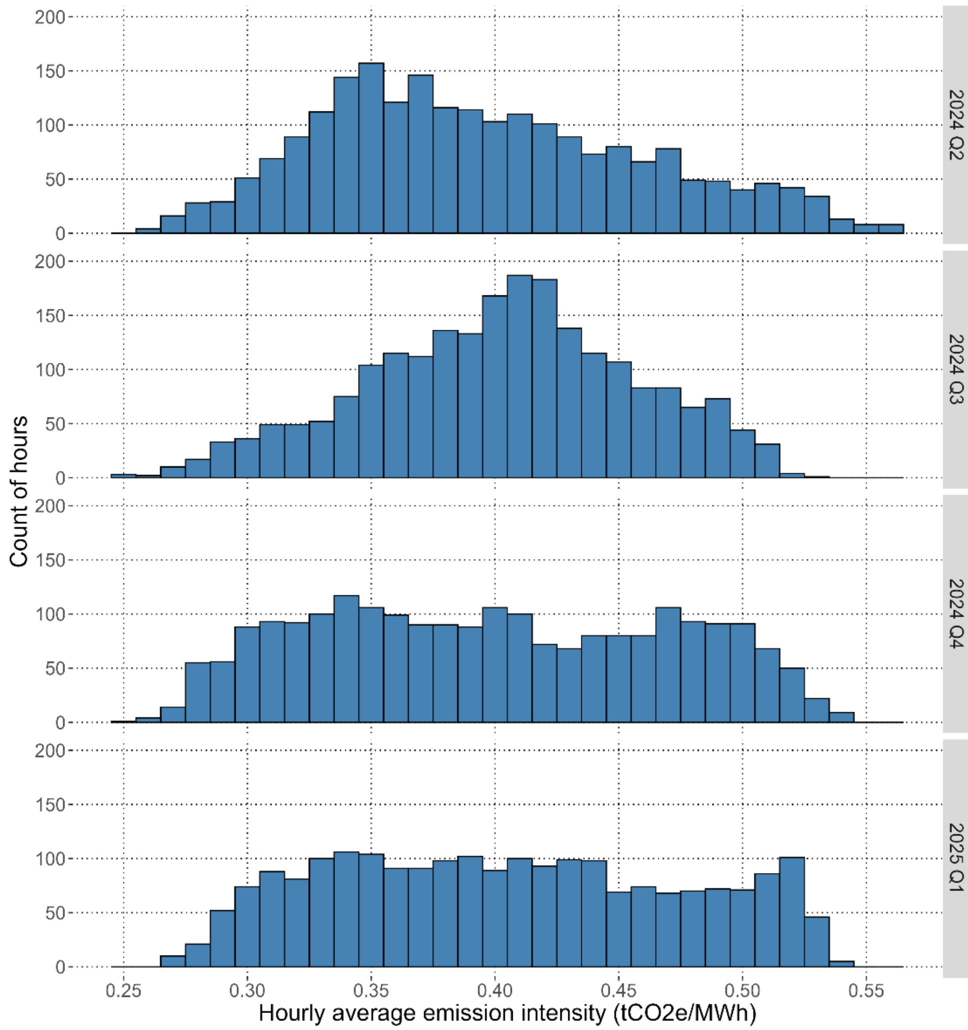
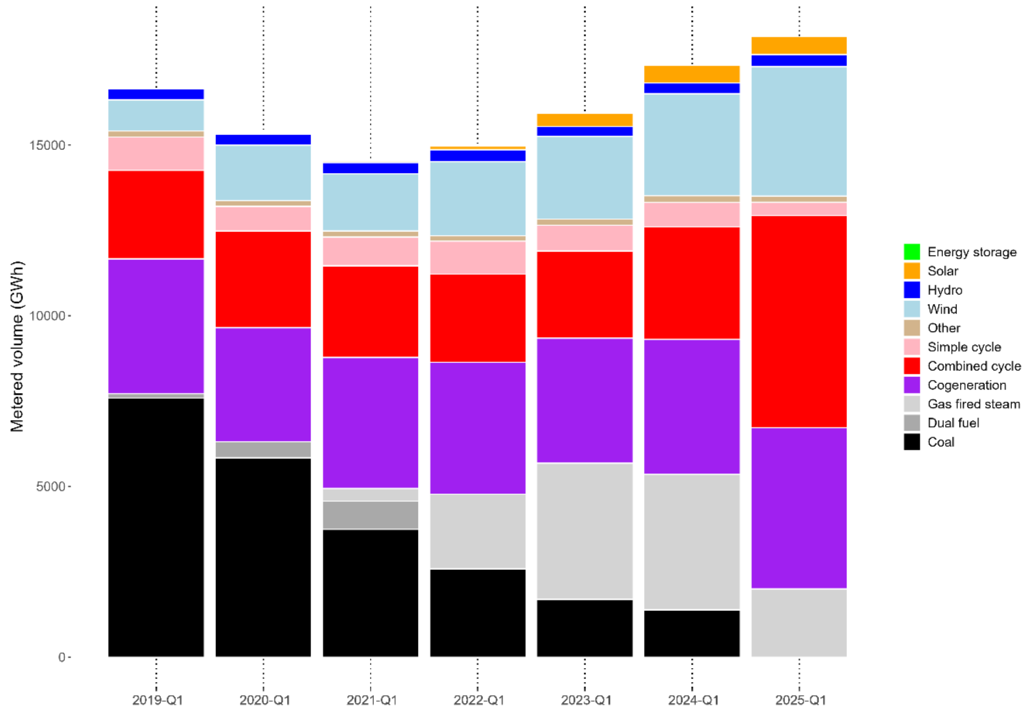


Figure 30: The distribution of average carbon emission intensities in the past four quarters



The leftward shifts of the distributions in Figure 29 can be traced to Figure 31, which shows the net-to-grid generation volumes by fuel type. Since 2019, there has been a material decline in the volume of coal-fired generation due to retirements and coal-to-gas conversions. In addition, the continuous increase in intermittent generation driven by growing capacity has also contributed to the displacement of coal-fired generation. Increased generation from efficient gas assets, including Cascade 1 and 2 and Genesee Repower 1 and 2, have put downwards pressure on average carbon intensity more recently.

Figure 31: Quarterly total net-to-grid generation volumes by fuel type for Q1 (2019 to 2025)

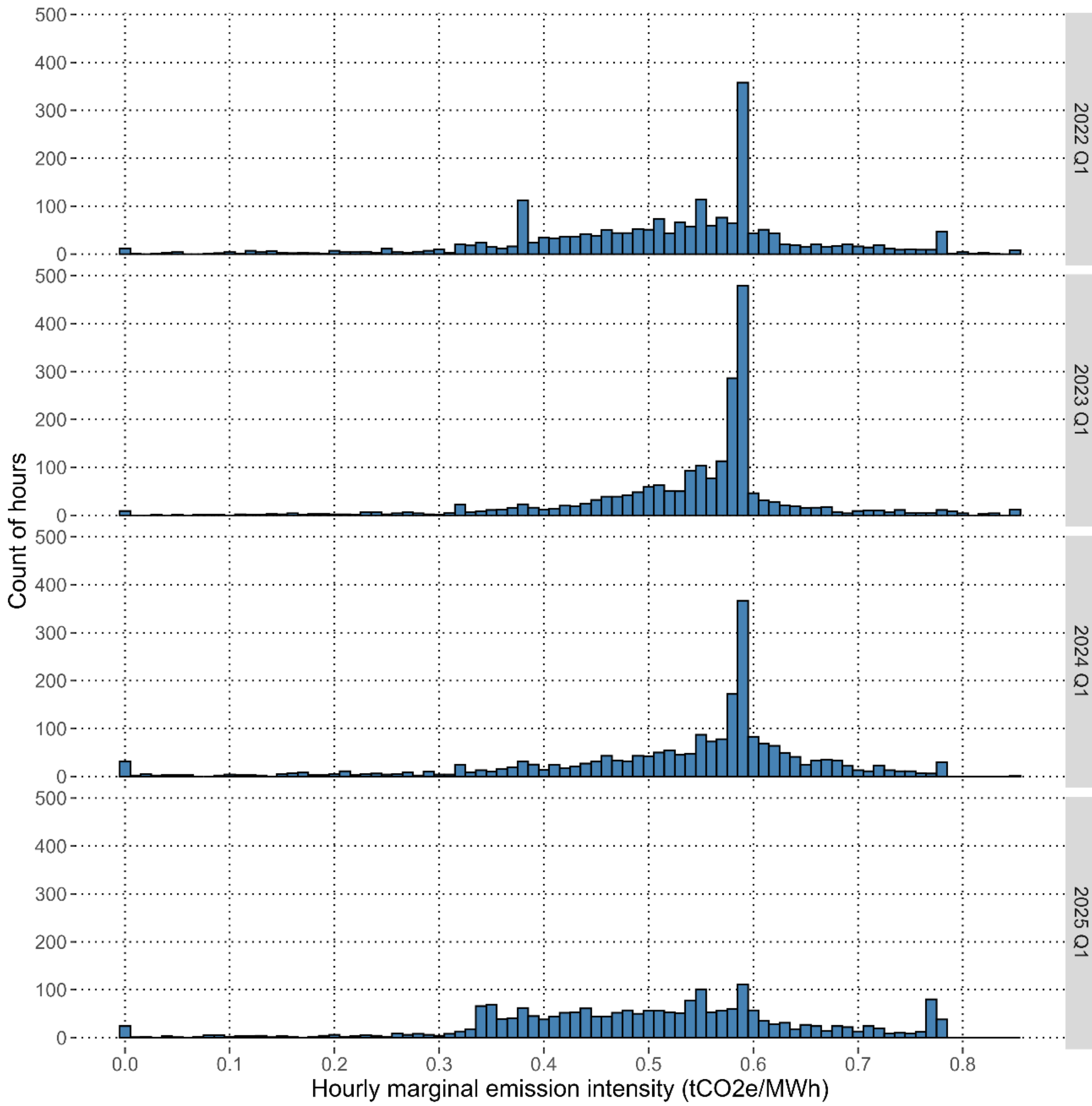


1.5.2 Hourly marginal emission intensity

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 32 shows the distribution of the hourly marginal emission intensity of the grid in Q1 for the past four years. From Q1 2021 through Q4 2024 gas-fired steam assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO2e/MWh.

In Q1, combined cycle assets were setting the price more often than gas-fired steam assets, resulting in a noticeable decline of the 0.59 tCO2e/MWh spike. There was a 54% decline in the amount of time that gas-fired steam assets were setting the price in Q1 compared to Q1 2024. The smaller spike towards the higher end of the distribution this quarter can be attributed to cogeneration and simple cycle assets setting the price more often than in Q1 of the prior year.

Figure 32: The distribution of marginal carbon emission intensities in Q1 (2022 to 2025)



1.6 Inflexible energy market offers

Pool participants must submit energy market offers to the power pool for each asset, as detailed in ISO Rule 203.1 Offers and Bids for Energy.[4] For each operating block in an offer, the pool participant must include an offer price, a quantity, and an indication of whether the block is flexible or inflexible. The asset's minimum stable generation (MSG) must also be declared. An inflexible block is an operating block that can only be dispatched for the full amount or not be dispatched at all, whereas the AESO may partially dispatch a flexible block.[5]

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[4] ISO Rule 203.1 Offers and Bids for Energy, effective July 1, 2024

[5] AESO Consolidated Authoritative Document Glossary, effective February 1, 2025

The AESO updated the Information Document for ISO Rule 203.1 in April 2024 to clarify that an "inflexible block is used to indicate when, due to an operating constraint, only the full amount of MW in the operating block can be dispatched."[6] In other words, the Information Document suggests that an operating block should only be declared inflexible if there is an operational reason that it cannot be partially dispatched.

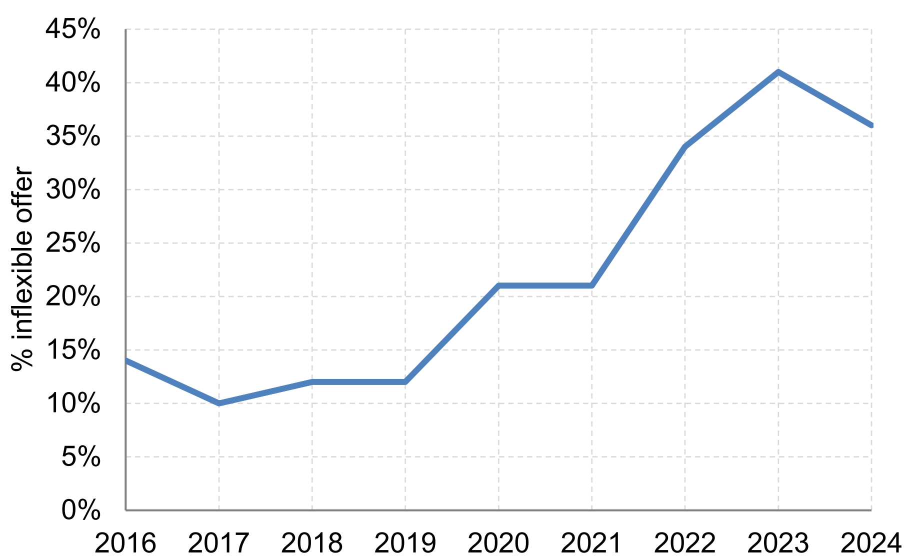
The MSA has reviewed the offer behaviour of pool participants with respect to flexible and inflexible blocks. There are two offer behaviours that are discussed:

- intermittent assets offering inflexible blocks, and
- assets with a positive MSG declaring the lowest-price offer block (zero block) to be flexible.

1.6.1 Inflexible offers

The AESO treats an operating block that is declared to be inflexible as though there is an operational reason that it cannot be partially dispatched and either dispatches it for the full amount or not at all. The first instance of an intermittent asset offering an inflexible block occurred in 2015. In that year, 7% of intermittent offers were declared inflexible.[7] However, through time more intermittent assets began declaring inflexible blocks, reaching a peak in 2023 when 41% of intermittent offers were submitted in inflexible operating blocks (Figure 33). The share of inflexible offers remained high in 2024 at 36%.

Figure 33: Intermittent inflexible offers as a percentage of intermittent available capability by year (2016 to 2024)



[6] AESO Information Document, Energy Offers and Bids, ID #2012-008R, August 22, 2024, page 2

[7] Inflexible offers as a percentage of available capability.

Several patterns emerge when the percentage of inflexible blocks is considered by asset. In 2024, all assets that offered an inflexible block offered no flexible blocks throughout the year, as shown in Table 12. In 2024, there were 28 intermittent assets (of 87 total) with 11 parent companies, that offered any inflexible blocks, all these assets consistently offered inflexible offers over the year. Generally, once an intermittent asset begins offering inflexible blocks, it does not switch back to flexible offers, as shown in Figure 34.[8]

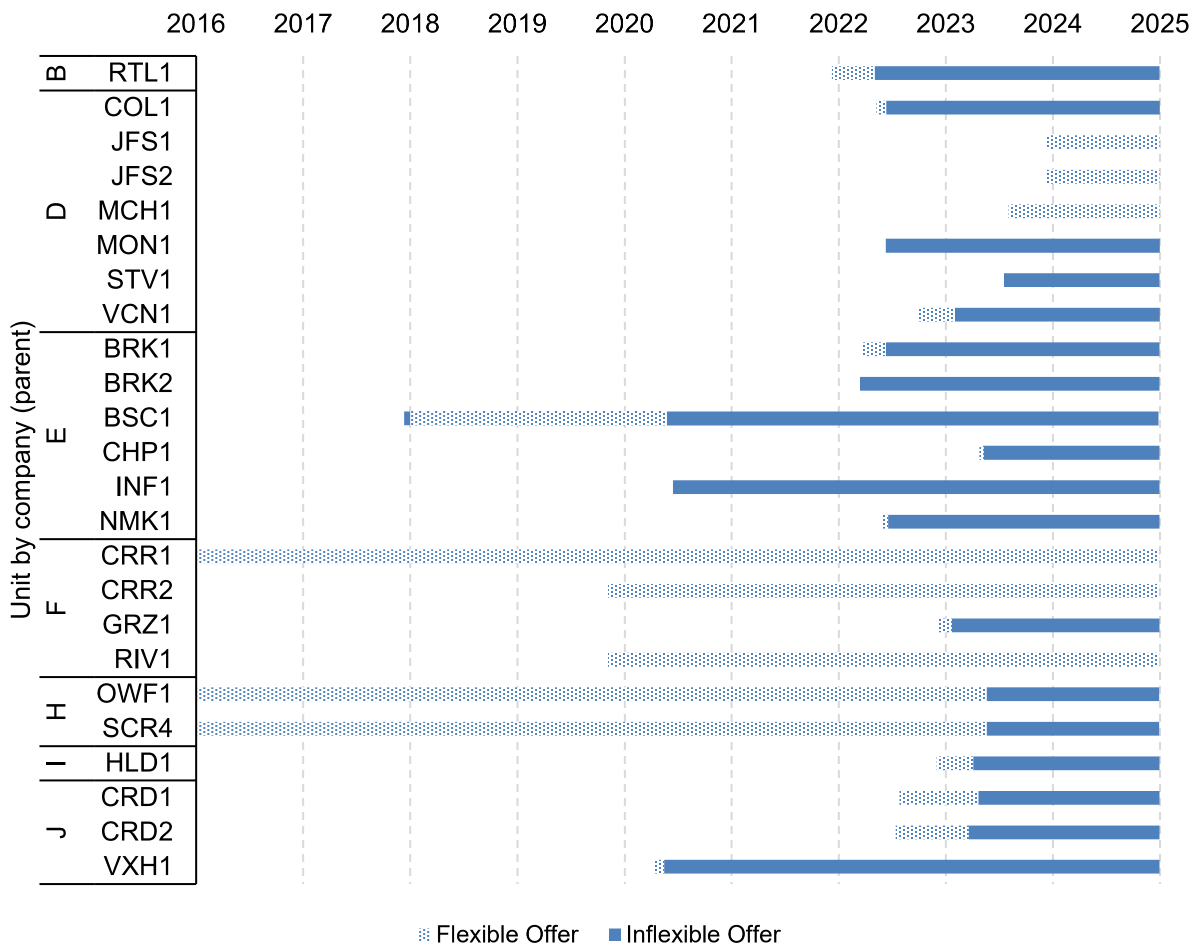
Table 12: Intermittent assets by company with 100% inflexible offers in 2024

Company (parent)[9]	**Unit(s)**
Company A	TVS1
Company B	RTL1
Company C	CLY1, CLY2, STR1, STR2, WHT1, WHT2
Company D	COL1, MON1, STV1, VCN1
Company E	BRK1, BRK2, BSC1, CHP1, INF1, NMK1
Company F	GRZ1
Company G	KHW1, TAB1
Company H	OWF1, SCR4
Company I	HLD1
Company J	CRD1, CRD2, VXH1
Company K	SDL1

[8] Only in five instances has an intermittent asset changed offer behaviour from offering inflexible to offering flexible blocks since 2016.

[9] The company (parent) data are based on the MSA Market Share Offer Control Data, February 12, 2025.

Figure 34: Intermittent assets by company with inflexible offer behaviour changes over time



1.6.2 Flexible offers

In addition to declaring an offer block as flexible or inflexible, the pool participant must include the asset's MSG. The MSG represents the minimum generation level at which an asset can be continuously operated without becoming unstable. If an asset has a positive MSG and the asset also declares a flexible zero block, this creates an operational challenge, as the asset may be issued a dispatch below its MSG value. In this case, the asset is likely unable to comply with a dispatch below MSG due to risk of damage to the asset or for other operational reasons, as set out in ISO Rule 201.7 Dispatches.[10] The most common situation where a zero block will be partially dispatched is during ISO Rule 202.5 Supply Surplus when the AESO issues pro rata dispatches for partial volumes of flexible blocks.[11] This is further discussed in Section .

There are three different flexible zero blocks that are reviewed:

[10] ISO Rule 201.7 Dispatches, Effective May 31, 2024

[11] ISO Rule 202.5 Supply Surplus, section 2(2)(e), Effective April 1, 2024

1. zero blocks with available capability less than the stated MSG,
2. zero blocks with available capability equal to the stated MSG, and
3. zero blocks with available capability that exceeds the stated MSG.

1.6.2.1 Flexible zero blocks with available capability less than MSG

Of the flexible offers for zero blocks (for assets with positive MSG), 1% had available capability values less than the stated MSG. ISO Rule 203.1 requires that the MSG submitted not exceed the MW of the lowest price operating block. These offers may therefore contravene ISO Rule 203.1.

1.6.2.2 Flexible zero blocks with available capability equal to MSG

Of the flexible offers for zero blocks (for assets with positive MSG), 12% had available capability values equal to the stated MSG. However, if only the dispatched flexible zero blocks with positive MSG are included, the value drops to 5% of flexible offers. If the asset receives any partial dispatch, as allowed through the flexible offer, the asset will be dispatched for lower than the stated MSG.

1.6.2.3 Flexible zero blocks with available capability greater than MSG

Of the flexible offers for zero blocks (for assets with positive MSG), 87% had available capability values greater than the stated MSG. However, if only the dispatched flexible zero blocks with positive MSG are included, the value increases to 94% of flexible offers. If the asset receives any partial dispatch that is below the stated MSG, as allowed through the flexible offer, the asset will be dispatched for lower than the stated MSG.

Given that the offer exceeds the stated MSG, there are some MW available for patrial dispatch. However, the MSA has identified that the AESO may issue dispatches below the stated MSG when the zero block is labelled as flexible.

1.6.2.4 2024 offer behaviour

In 2024, 71% of zero block offers were inflexible and 29% were flexible, where the offering asset had a positive MSG. Comparatively, in 2023, 57% of zero block offers were inflexible and 43% were flexible, where the offering asset had a positive MSG.

In 2024, 43 assets with a positive MSG offered zero blocks as flexible, ranging from 1% of offers to 100%. As shown in Table 13, 24 parent companies had offer control of these assets.

Table 13: Assets (by company) offering flexible zero blocks with MSG greater than 0

Company - Parent[12]	Unit	Flexible
Company L	FRM1	100%
	SCR2	100%
Company M	ALS1	5%
Company N	ANC1	100%
Company O	HMT1	100%
Company P	EMP1	100%
Company Q	GPEC	100%
Company R	CCMH	1%
Company S	BFL2	100%
Company T	CL01	60%
	EC04	51%
Company U	CYP1	100%
	CYP2	100%
Company V	SET1	100%
Company W	IOR2	29%
Company X	HRM	6%
Company Y	MEG1	57%
Company Z	DAI1	100%
Company AA	NPC2	100%
	NPC3	100%
Company AB	LAN1	100%
Company AC	TLM2	100%
Company AD	ALP1	100%
	ALP2	100%
Company AE	FNG1	95%
Company AF	FH1	2%
	SCR1	2%
	SCR5	2%
	SCR6	1%
Company AG	MUL1	100%
	SDH1	100%
Company AH	BIG	11%
	BOW1	12%
	BRA	13%
	KH3	42%
	KH2	44%
	SD6	42%
	SH1	4%
	SH2	7%
Company AI	GEN5	100%
	GEN6	100%
	PH1	6%
	RL1	1%

[12] The Company (Parent) data are based on the MSA Market Share Offer Control Data, February 12, 2025.

1.6.3 Event on October 4, 2023

On October 4, 2023, the AESO declared a supply surplus event in HE 04. During this event, the AESO, following ISO Rule 202.5 Supply Surplus, issued pro-rata dispatches pertaining to flexible energy offers. Several circumstances during this event appear to have materially increased the complexity for system controllers. During this time, multiple assets with positive MSG values received a pro-rata dispatch for its zero block as they were offered as flexible. For two of these assets, the zero block was equal to its MSG. Each of these units communicated to the AESO that they were unable to comply with the dispatch.

Dispatch during this hour was also complicated in part due to the offer behaviour of other assets. Multiple intermittent generation assets offered inflexible blocks, thereby not receiving the pro-rata dispatch. Accordingly, the various offer behaviours which altered the asset dispatches, combined with additional system factors, led to challenging conditions for the system controllers.

1.6.4 Recommendations

Recommendation 1: The specification that inflexible energy market offers should be used to indicate operational constraints is only set out in an Information Document. The MSA recommends that the AESO change the definition “inflexible block” in the Consolidated Authoritative Document Glossary, or otherwise amend the ISO rules, to clarify that an operating block may only be declared to be inflexible if there is an operational reason that it cannot be partially dispatched.

Recommendation 2: The MSA recommends that the AESO refine its tools and practices to ensure that units are not dispatched to a fraction of their MSG. This would prevent operational issues like the ones observed on October 4, 2023. The MSA understands that the AESO has completed IT updates effective April 29 to address this issue.

2 THE POWER SYSTEM

2.1 Trends in transmission congestion

Transmission constraints can cause generation to be curtailed. When this occurs, the AESO directs constrained generators to reduce output to manage the constraint.[13] The MSA estimates constrained intermittent generation (CIG) volumes using curtailment limits, available capacity, potential real power capability, and energy dispatch.[14]

The frequency and significance of CIG directives increased from Q1 2024 to Q1. The MSA estimates that CIG volumes were 28 GWh in Q1 2024 and 160 GWh in Q1, a greater than five times increase year-over-year. Quarter-over-quarter, the CIG volumes increased by 20 GWh.

The maximum hourly average volume of CIG in Q1 was 1,076 MW, almost triple the maximum of 370 MW in Q1 2024 (Figure 37 to Figure 39). The Q1 maximum hourly average volume of CIG was lower than the previous quarters maximum value of 1,417 MWh (Figure 38).

The increased CIG volumes in Q1 are likely due to increased intermittent capacity and high intermittent generation. Generally, higher CIG volumes align with periods of high intermittent generation or supply surplus events (Figure 35).

There were over 382 shift log events for constrained down generation in Q1. Increased constrained down generation volumes may also be due to persistent or frequent congestion on certain transmission lines and may affect one or more generation assets. One example of a frequently constrained transmission line is 610L, which is the subject of the Vauxhall Area Transmission Development. However, this quarter saw a wide variety of constraints and zones. An example of a path over this quarter that experienced frequent CIG events was the Cassils – Bowmanton – Whitla path. The issues included voltage oscillations, outages, and Most Severe Single Contingency in combination with of Remedial Action Scheme 164 (protection of local system from loss of various 240kV lines).[15,16]

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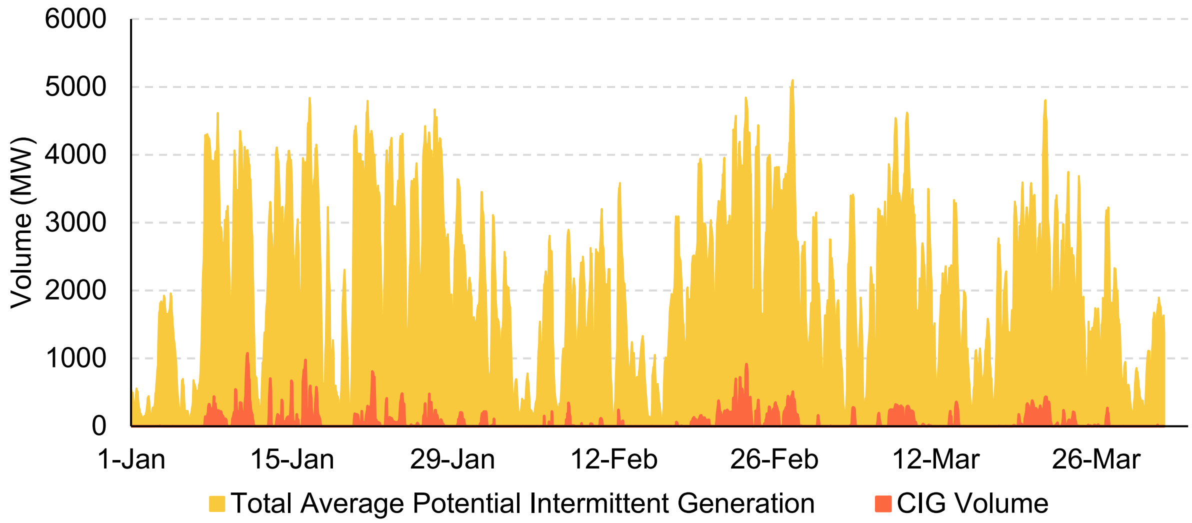
[13] This is known as constrained down generation. See ISO Rule 302.1 Transmission Constraint Management.

[14] 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).

[15] AESO Alberta Remedial Action Schemes, January 24, 2025

[16] AESO Paths 1 & 83 Total Transfer Capability Review, February 2023

Figure 35: Average hourly intermittent generation and constrained intermittent generation in Q1



The increase in CIG volume from Q1 2024 to Q1 occurred at a higher rate than the installation of intermittent generation capacity. While total installed intermittent capacity increased by 23%, average hourly CIG volumes, expressed as a percent of installed intermittent capacity, increased from 0.21% in Q1 2024 to 0.99% in Q1 (Figure 36).

Figure 36: Volume of CIG compared to total potential intermittent generation in Q1

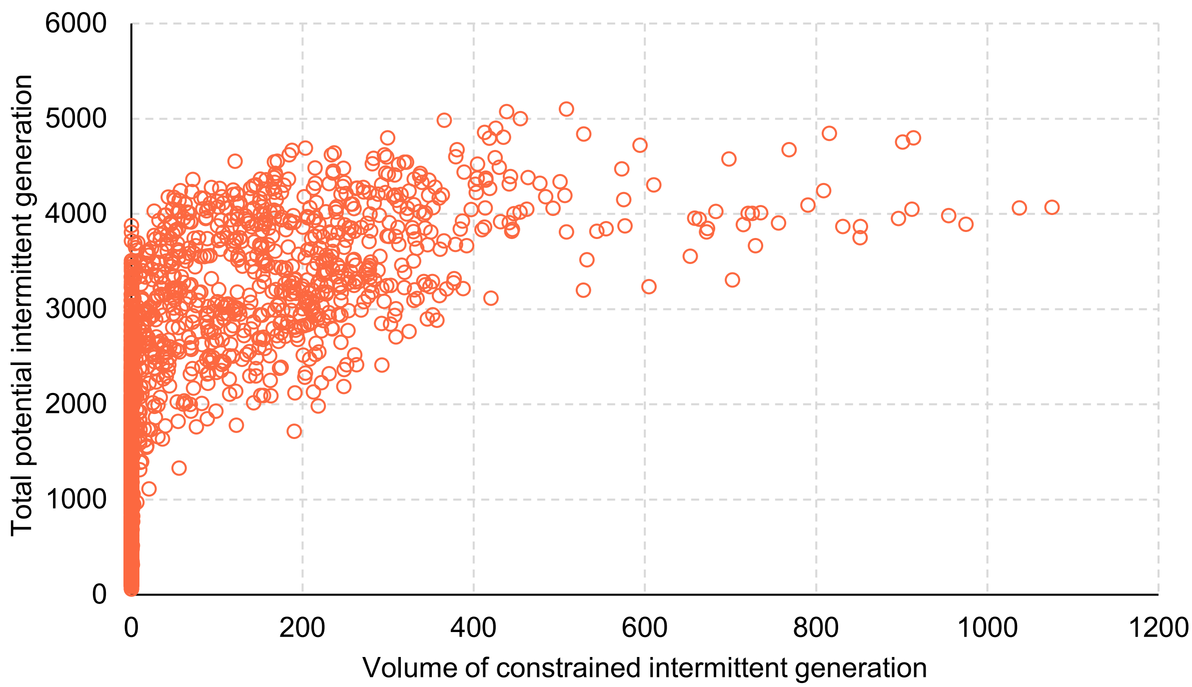


Figure 37: Maximum hourly transmission constrained intermittent generation (Q1 2024)

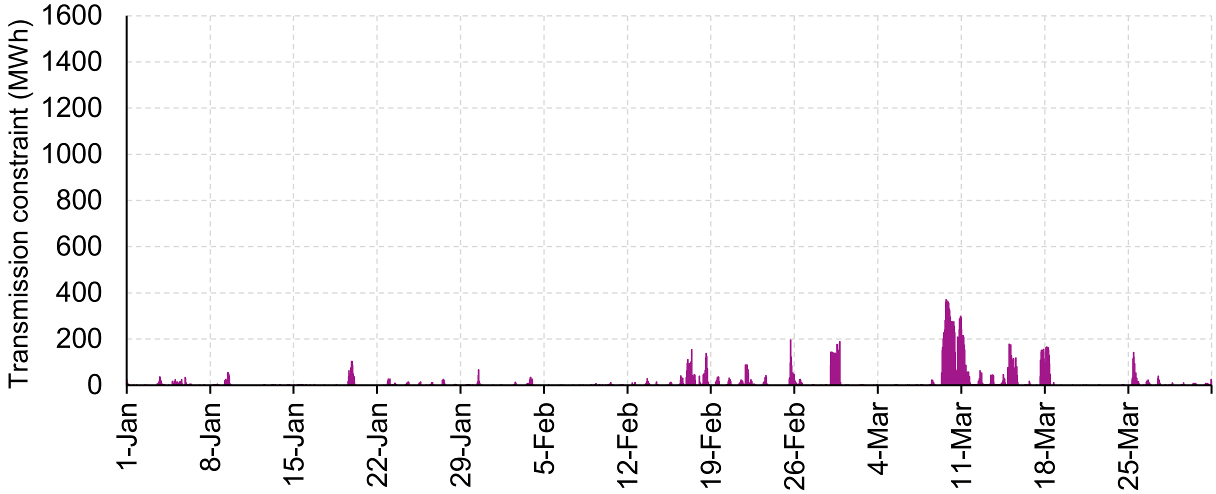


Figure 38: Maximum hourly transmission constrained intermittent generation (Q4 2024)

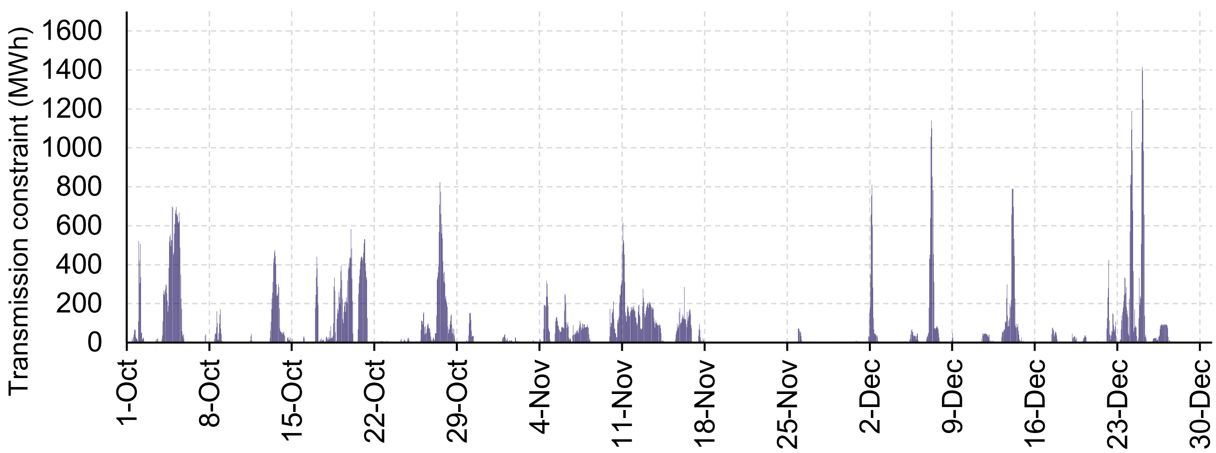


Figure 39: Maximum hourly transmission constrained intermittent generation (Q1 2025)

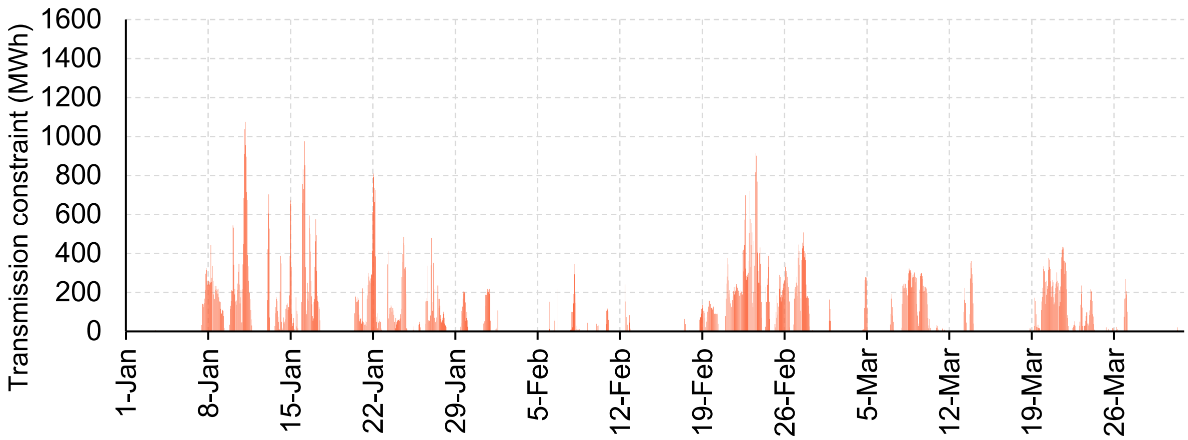
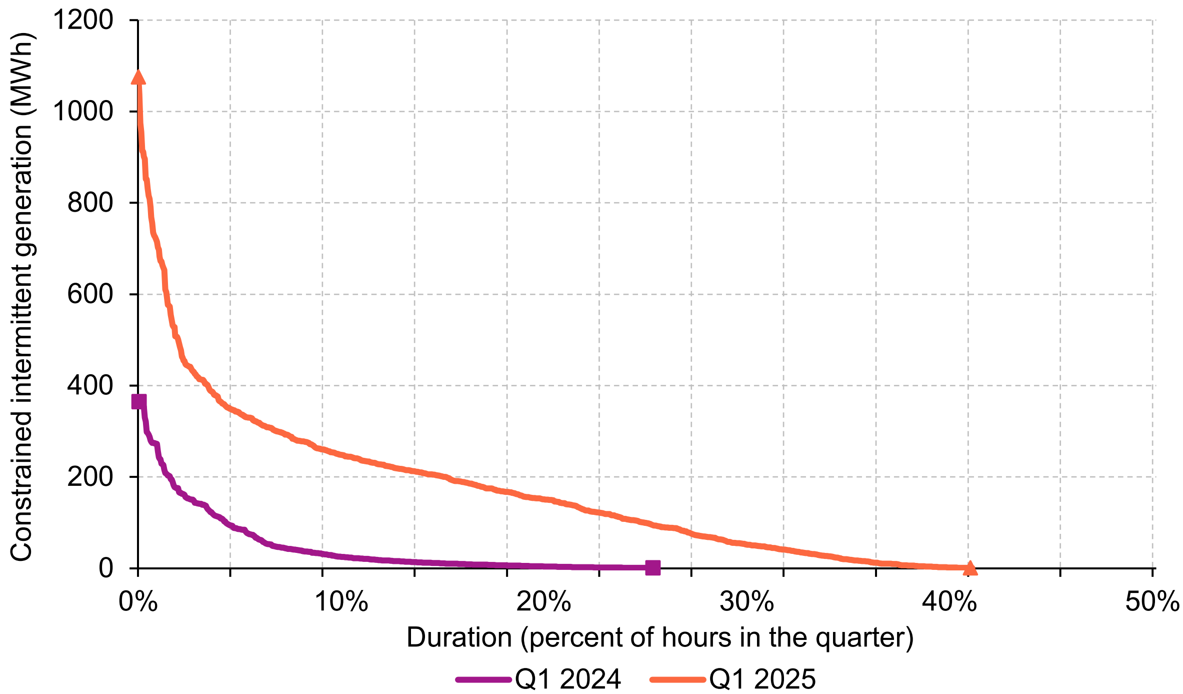


Figure 40 illustrates duration curves of CIG year-over-year. The length of the tails to the right of the duration curves show that the frequency of CIG events increased. There were 906 hours of CIG volumes greater than 1 MWh in Q1. This is equivalent to just under 38 days, or 42% of Q1. In contrast, Q1 2024 experienced 561 hours of CIG volumes greater than 1 MWh, or over 23 days or 26% of Q1 2024.

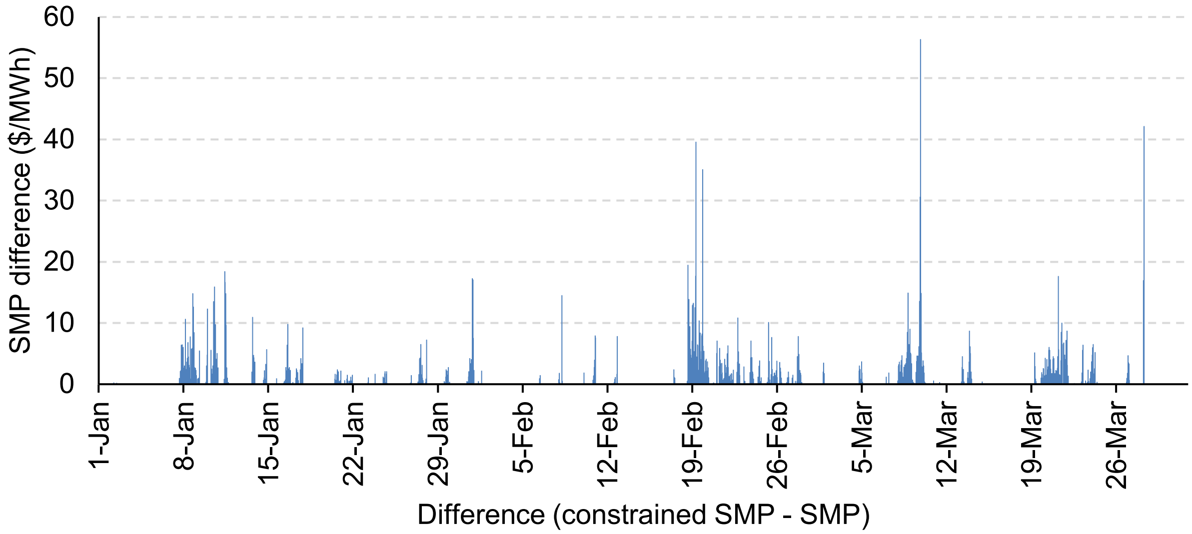
Figure 40: Duration curves of CIG volume (Q1 2024 and Q1)



Transmission constraints had frequent fluctuations throughout all months of Q1, however January experienced the most volume of CIG and highest peak. The CIG volume in the month of January accounted for 46% of all Q1 volumes. In 51% of January hours there was at least 1 MWh of CIG volume.

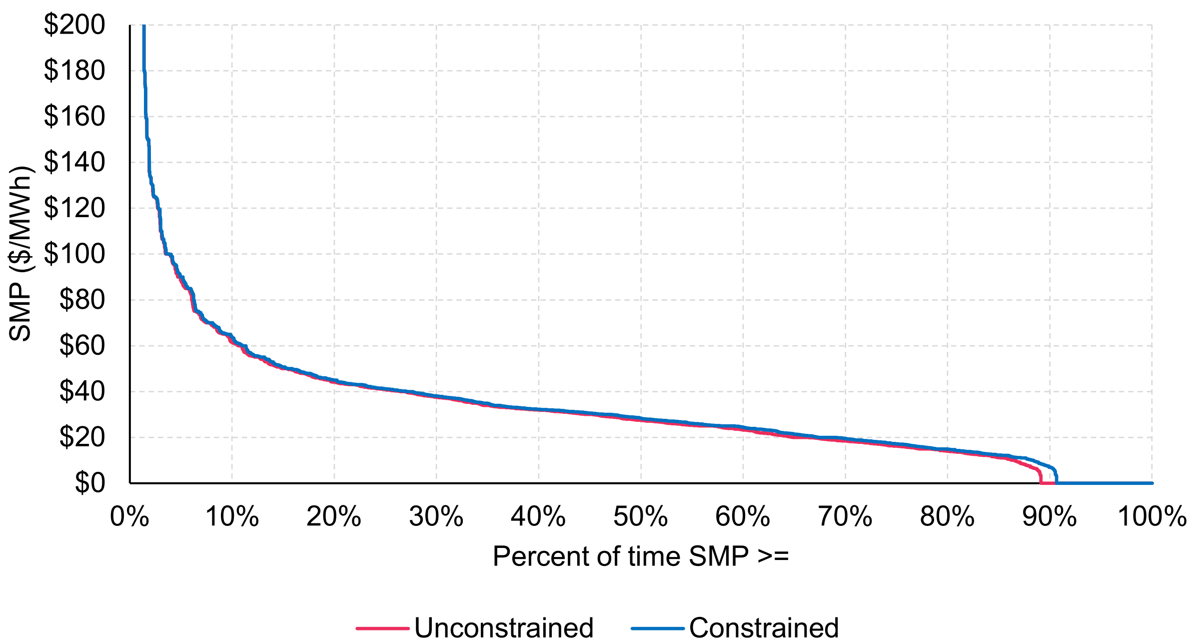
The constrained and unconstrained SMP differed by $1/MWh or more in 18% of hours in Q1 (Figure 41). In comparison, Q1 2024 experienced 10% of hours with a variance of $1/MWh or more in the constrained SMP and unconstrained SMP, and Q4 2024 experienced the difference in 26% of hours. The largest difference between constrained SMP and SMP in Q1 was $56/MWh, which occurred in HE22 of March 9. Despite the frequency and significance of the CIG in Q1, the largest difference in unconstrained and constrained price was higher in Q1 2024 at $213/MWh. The largest difference in Q4 2024 occurred on December 16 and reached $268/MWh, almost five times the Q1 peak.

Figure 41: Difference of constrained SMP and SMP in Q1



The periods that experience high volumes of CIG often occur when generation from intermittent resources is high. Given the offer behaviour of these resources, when intermittent generation is higher, 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 unconstrained SMP and the constrained SMP (Figure 42). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity will have a relatively small impact on prices.

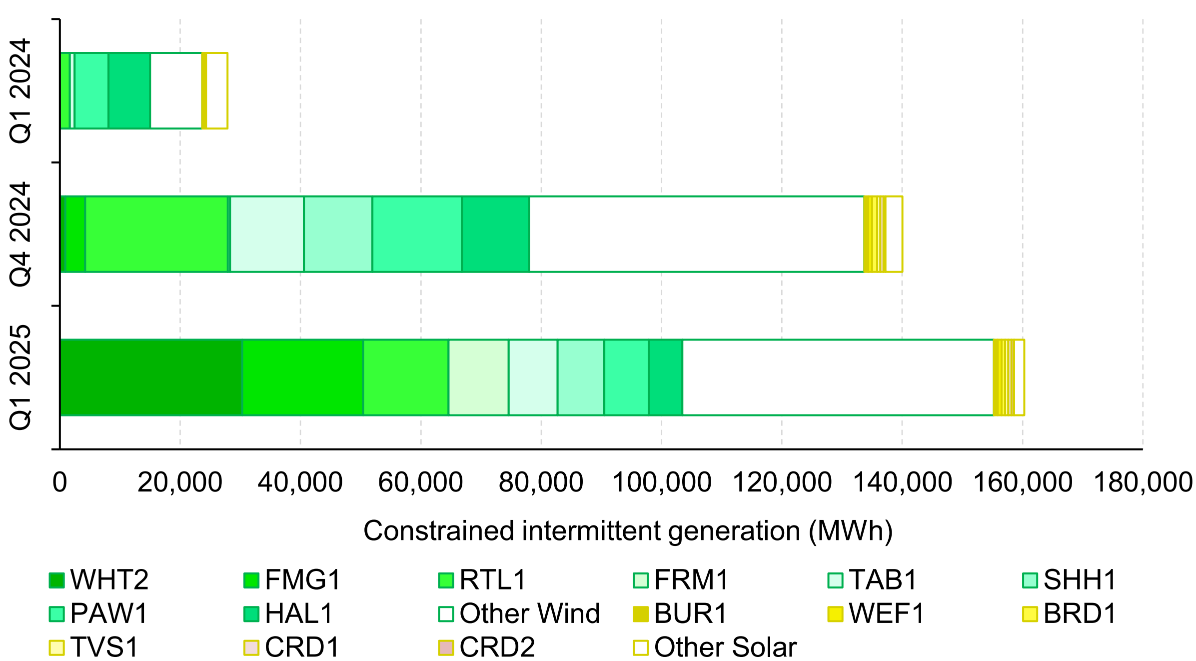
Figure 42: Duration of SMP and constrained SMP for Q1



Transmission capability varies throughout the province, and certain regions experience more congestion than others, often leading to local constraints (Figure 43). Often, wind and solar assets are not constrained uniformly throughout the province. In Q1, the eight most constrained wind assets accounted for 67% of the total CIG volume but only 27% of total installed wind generation. Whitla 2, Forty Mile Granlea, and Rattlesnake Ridge Wind were the most constrained wind assets in Q1. These 3 assets represent 10% of Alberta's installed wind capacity, however they accounted for approximately 42% of the wind CIG volume in Q1.

BUR1 Burdett (20 MW) was the most-constrained solar asset in Q1, with a total of 623 MWh constrained. The asset was constrained due to two different reasons over the quarter, to mitigate real time overload on 879L and to mitigate real time overload on 610L. The following five most constrained solar assets have an aggregate maximum capability of 536 MW (71 MW excluding Travers) and were constrained by 2,701 MWh (2,145 MWh excluding Travers) in Q1. The top 6 constrained solar assets account for 30% of the maximum capability of the market and accounted for 66% of solar CIG volumes in Q1. Excluding Travers capability and congestion, the top constrained assets account for 7% of the maximum capability of the market and accounted for 61% of solar CIG volumes in Q1. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

Figure 43: Wind and solar transmission CIG by asset (Q1 2024, Q4 2024, Q1)

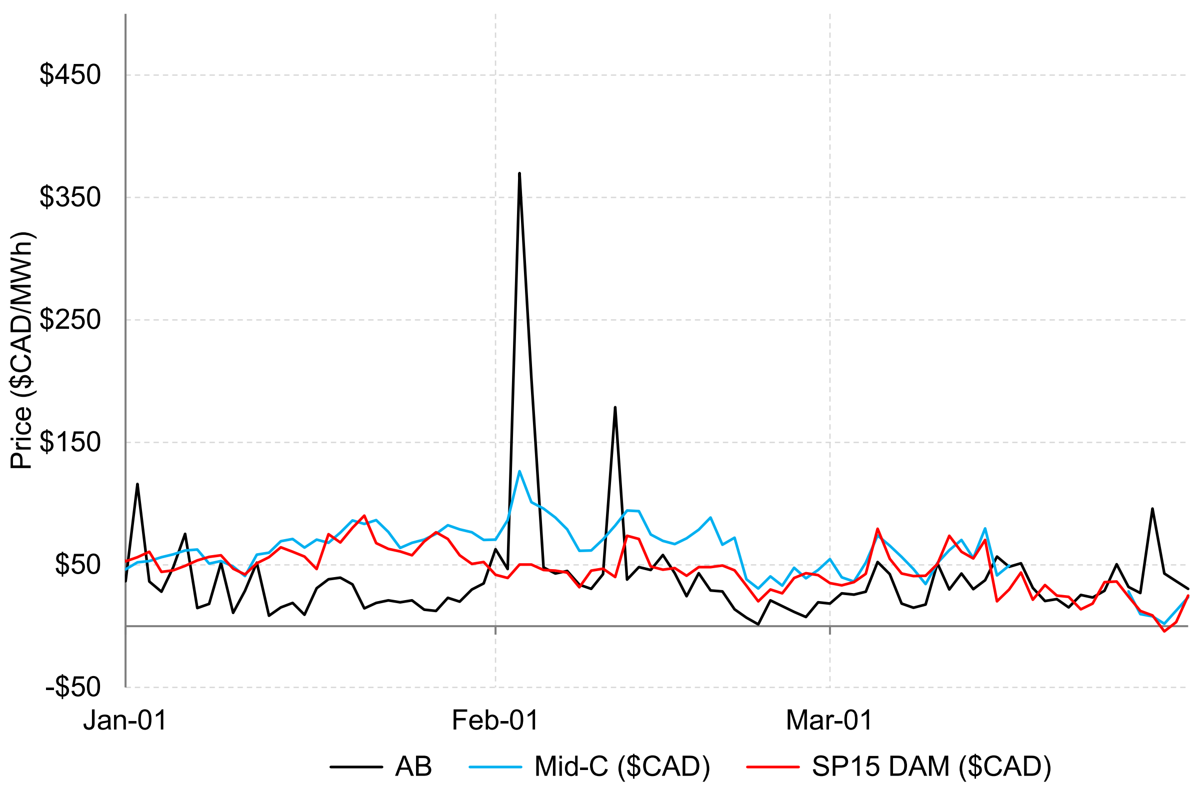


2.2 Imports and exports

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

Figure 44 shows daily average power prices in Alberta, Mid-C, and California (SP-15) over Q1 (shown in Canadian currency). Over the quarter, Alberta prices averaged $39.78/MWh, while Mid-C and California averaged $61.62/MWh and $46.34/MWh, respectively.[17] As shown, Alberta prices were often lower than Mid-C and SP-15, with periods of volatility bringing up average prices in Alberta. In 86% of hours over the quarter, Mid-C prices were higher than Alberta. As a result, Alberta was a net exporter across the quarter, with record monthly exports in January (Figure 45).

Figure 44: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q1)



[17] Mid-C price data is not available for the March 16 to 26 period.

Figure 45: Daily average import (+ve) and export (-ve) volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q1)

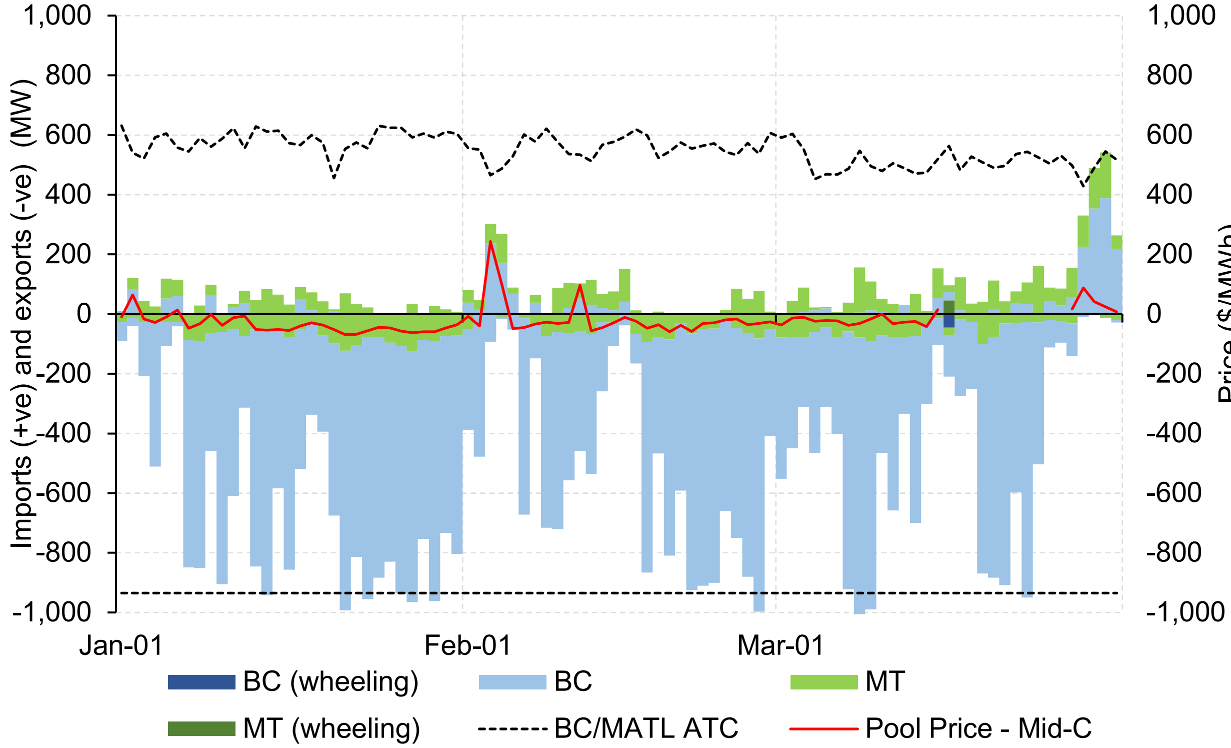


Table 14: Average net import (+ve) and export (-ve) volumes for Q1 2024 and Q1 2025

	2024				2025			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
January	-372	-10	18	-364	-557	-37	0	-594
February	-403	84	44	-275	-448	-8	0	-456
March	-367	103	39	-226	-347	17	0	-330
Q1	**-381**	**59**	**33**	**-289**	**-451**	**-10**	**0**	**-461**

Exports from Alberta in Q1 were largely driven by export volumes to BC. During Q1, the scheduled flow of power over the BC intertie averaged 451 MW of exports. The highest monthly average, 557 MW, occurred in January, consisting of 648 MW during off peak hours and 511 MW during on peak hours. There were net exports on the BC intertie in 87% of hours over January, corresponding to a weighted average pool price of $18/MWh for the exports.

The scheduled flow of power on MATL averaged 10 MW of exports, compared to 59 MW of imports in Q1 2024. The increase in exports can be partly explained by lower pool prices in Alberta, especially over January, with net exports during 80% of hours in the month, corresponding to a weighted average pool price of $21/MWh for the exports.

Overall, the total scheduled flow averaged 594 MW of exports in January, which is the highest monthly average net exports recorded in Alberta (Figure 46).

The SK intertie resumed operation on an emergency basis as of January 15, which was exercised on January 20 when Saskatchewan requested emergency imports due to an EEA2. As of April 23, the intertie is set to return for commercial operation beginning December 23, 2025, having been offline since October 4, 2024.

Figure 46: Monthly average total import (+ve) and export (-ve) volumes (January 2001 to March 2025)

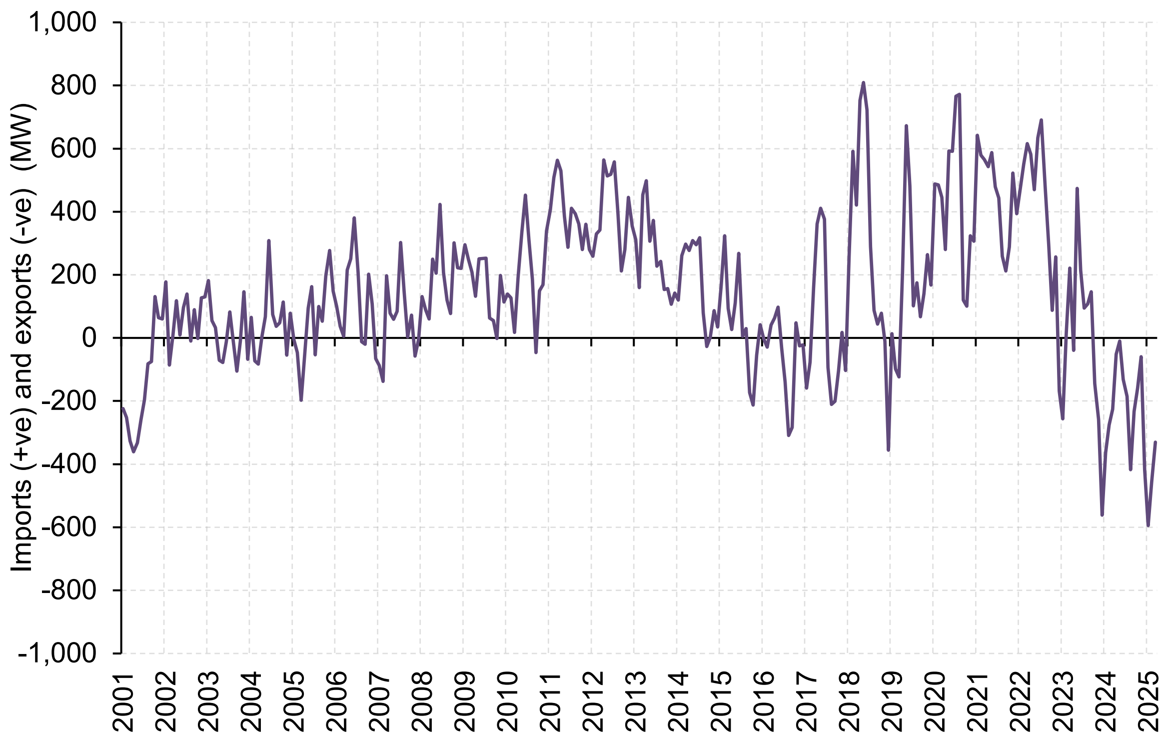


Figure 47 shows a scatterplot of the price differential between Alberta and Mid-C against the net scheduled flows on BC/MATL for each hour over the quarter. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors).

Over Q1 there were many hours where net 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 603 hours or 28% of the time. While BC/MATL was export constrained, the price differential between Alberta and Mid-C averaged -$48/MWh and export capability averaged 935 MW. Additionally, there were hours where net export bids were at or above BC export capability, with net import offers on MATL, meaning that only the BC intertie was export constrained (shown in yellow). Over the quarter, BC exports were constrained for 172 hours or 8% of the time. While BC was export constrained, the differential averaged -$38/MWh and export ATC averaged 935 MW.

There were also hours where net import offers or schedule 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 108 hours in Q1 or 5% of the time. While import constrained, the price differential between Alberta and Mid-C averaged $93/MWh and import capability averaged 470 MW. Import constrained observations with a negative price differential are generally associated with the conclusion of periods of pool price volatility.

For some hours in Q1, scheduled volumes occurred in one direction despite prices settling in the opposite direction. For example, on February 3 in HE 06 the net interchange schedule averaged 184 MW exports while the price differential averaged $542/MWh. However, in the preceding 24 hours the price differential averaged -$42/MWh.

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

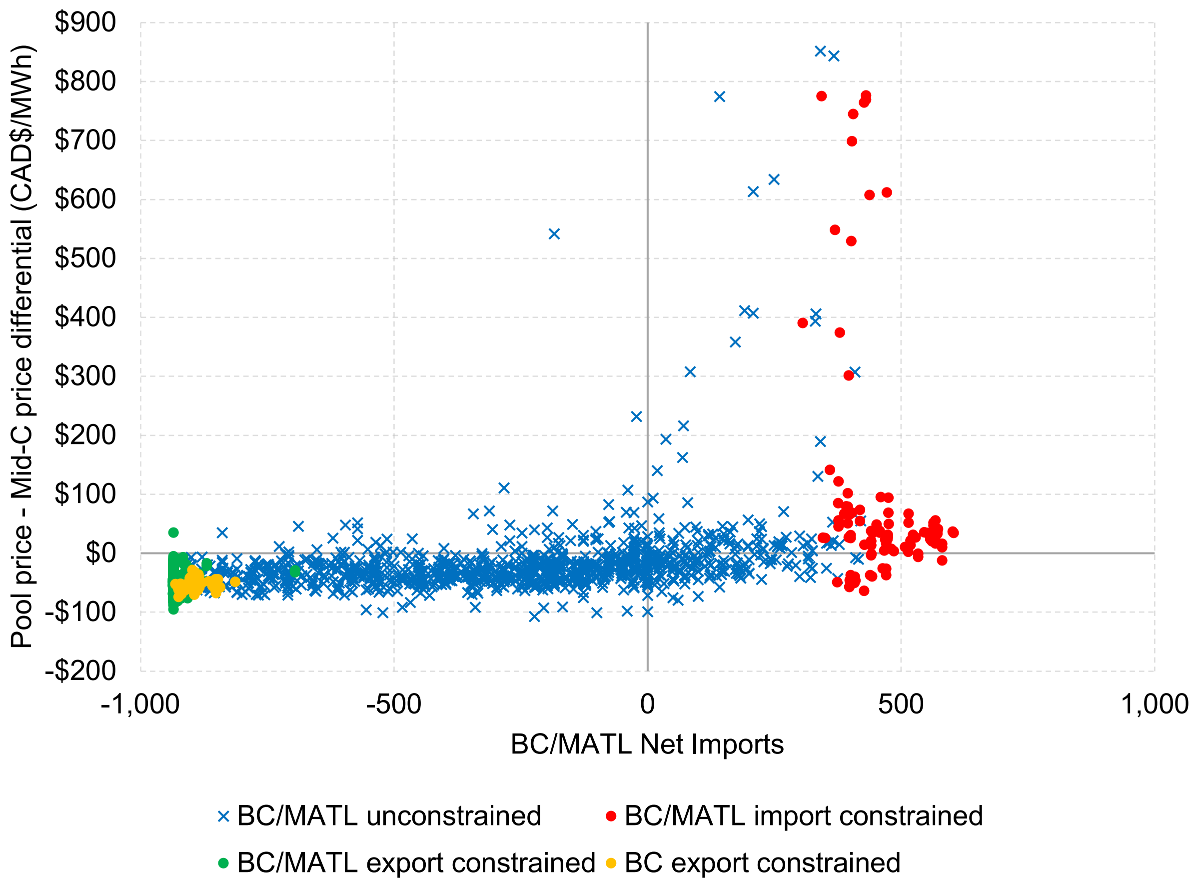
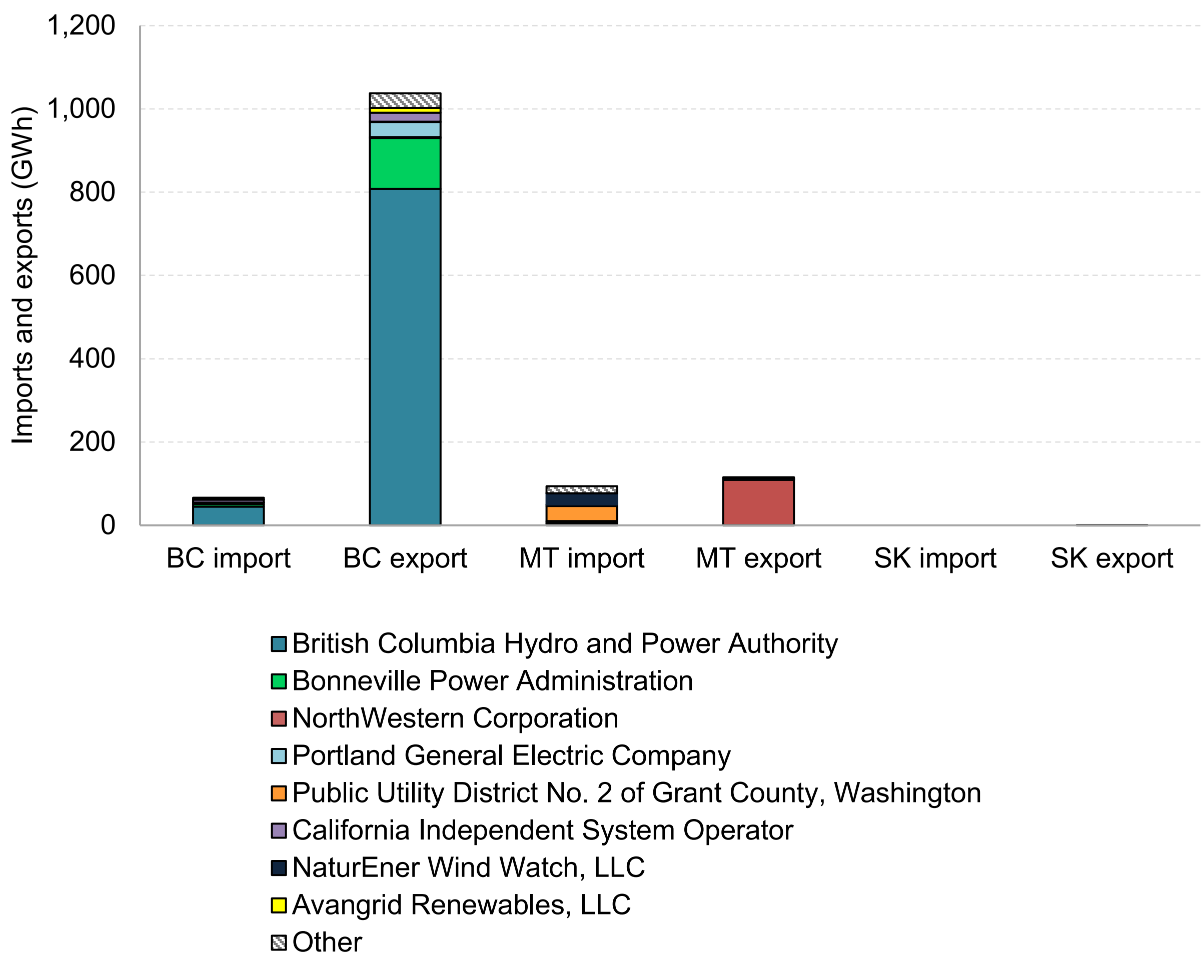


Figure 48 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[18] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

For imports on the BC intertie, approximately 68% originated from BC, 21% from the US Northwest, and 11% from California. For exports on the BC intertie, 78% was delivered to BC, 20% to the US Northwest, and 2% to California.

For imports through MATL, 96% originated from the US Northwest and 4% from California. For exports on MATL 97% was delivered to the US Northwest, 2% to California, and 1% to Southwest Power Pool.

Figure 48: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q1)[19]



[18] 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.

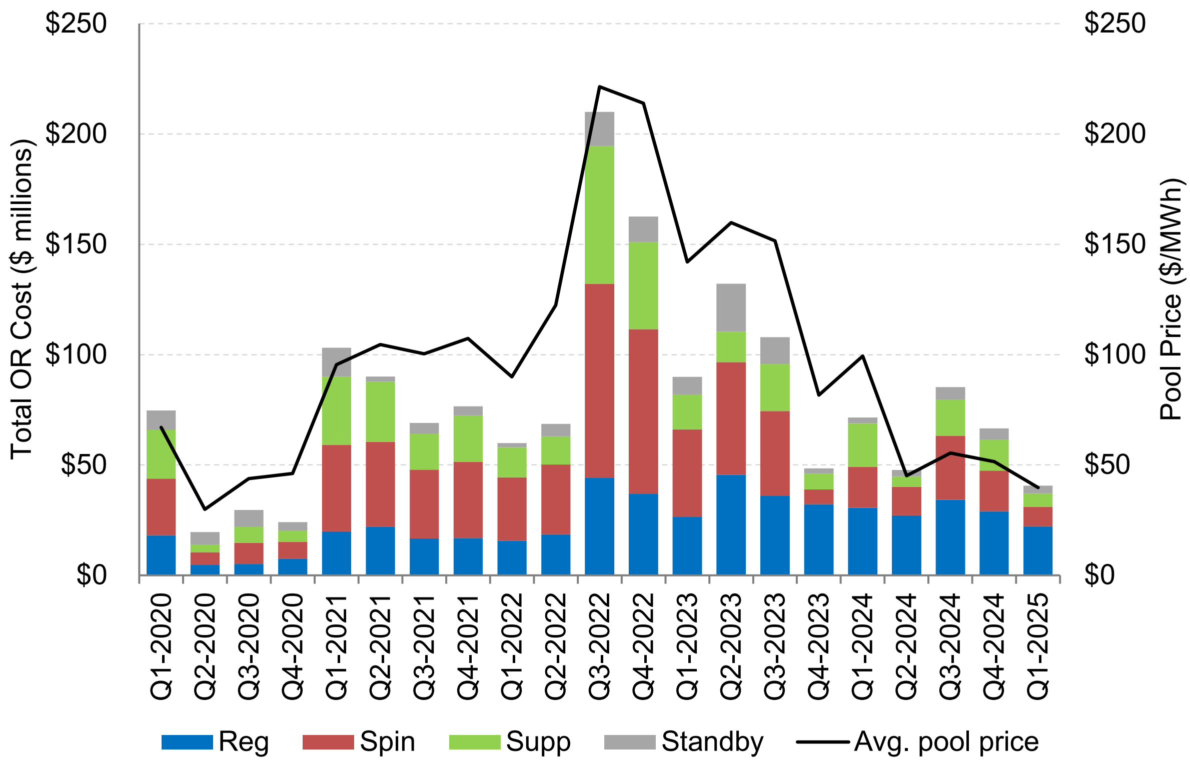
[19] This includes the highest eight Balancing Authorities by volume.

3 OPERATING RESERVES

AESO system controllers call upon three types of operating reserve (OR) to address unexpected imbalances or lagged responses between supply and demand: regulating reserve, spinning reserve, and supplemental reserve. Regulating reserve provides an instantaneous response to an imbalance of supply and demand. Spinning reserve is synchronized to the grid and provides capacity that the system controller can direct quickly when there is a sudden drop in supply. Supplemental reserve is not required to be synchronized but must be able to respond quickly if directed by the system controller. The AESO buys operating reserves through day-ahead auctions.

The total cost of OR in Q1 was $40.6 million, the lowest since Q4 2020. Relative to Q4 2024 total OR costs in Q1 were 39% lower, and relative to Q1 2024 total costs were 43% less. The lower costs for OR in Q1 were largely driven by the reduction in pool prices (Figure 49). The total cost of operating reserves is highly correlated with average pool prices because active reserve costs are directly indexed to pool prices.

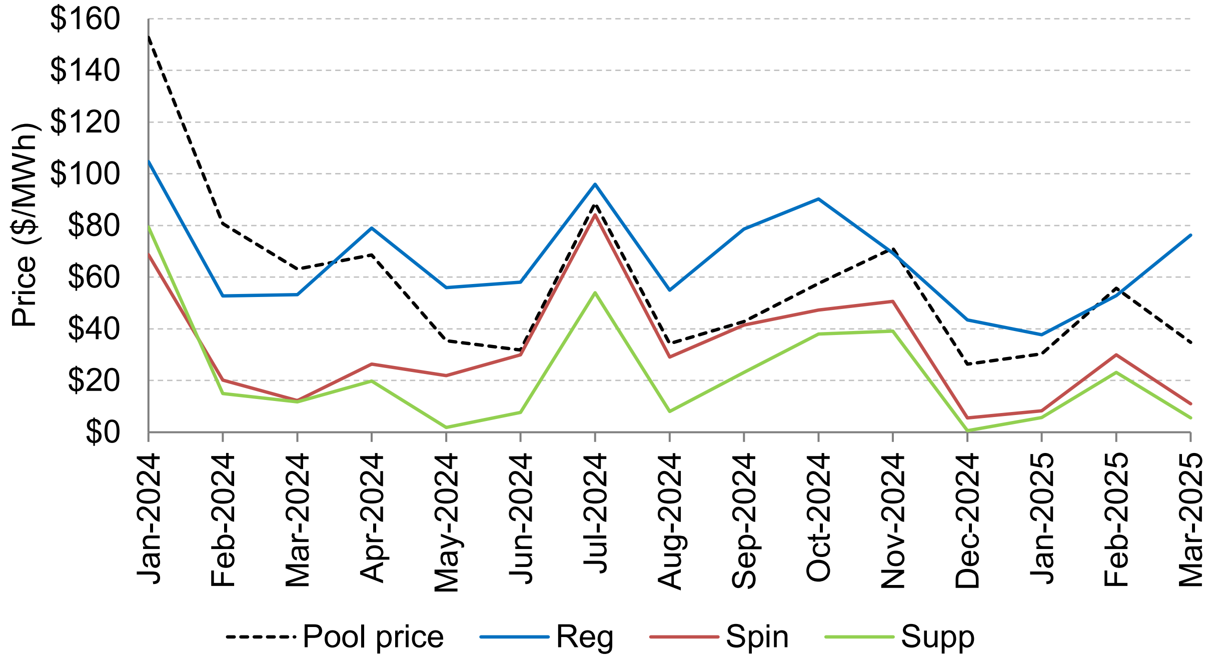
Figure 49: Total cost of operating reserves and the average pool price (Q1 2020 to Q1 2025)



3.1 Active reserves

Figure 50 illustrates monthly average received prices for active OR products alongside the average pool price. The received price is the price received by the seller after the equilibrium price set in an OR auction has been indexed to pool prices. As one would expect, received prices are positively correlated to pool prices over time. However, from February to March the received price of regulating reserves increased even as average pool prices fell.

Figure 50: Average received prices for active OR products by month (January 2024 to March 2025)



The received price for regulating reserves increased from February to March because of higher equilibrium prices set in the OR auctions. Figure 51 and Figure 52 plot the equilibrium prices set over Q1 for on peak and off peak regulating reserves, respectively. As shown equilibrium prices for both on peak and off peak regulating reserves increased in late February and stayed relatively high for much of March. The higher equilibrium prices for regulating reserves in March were reflective of lower pool prices and less gas capacity being offered into the auctions.

On several occasions in Q1 the equilibrium prices for regulating reserves were close to binding at the respective price cap. The price caps for different regulating reserve products are reported in Table 15.

Table 15: Price caps for the equilibrium prices of different regulating reserve products

Regulating Product	Price cap ($/MW)
On peak	$40
Off peak	$100
AM Super Peak	$100
PM Super Peak	$30

Figure 51: The equilibrium price for on peak regulating reserves (January 1 to March 31)

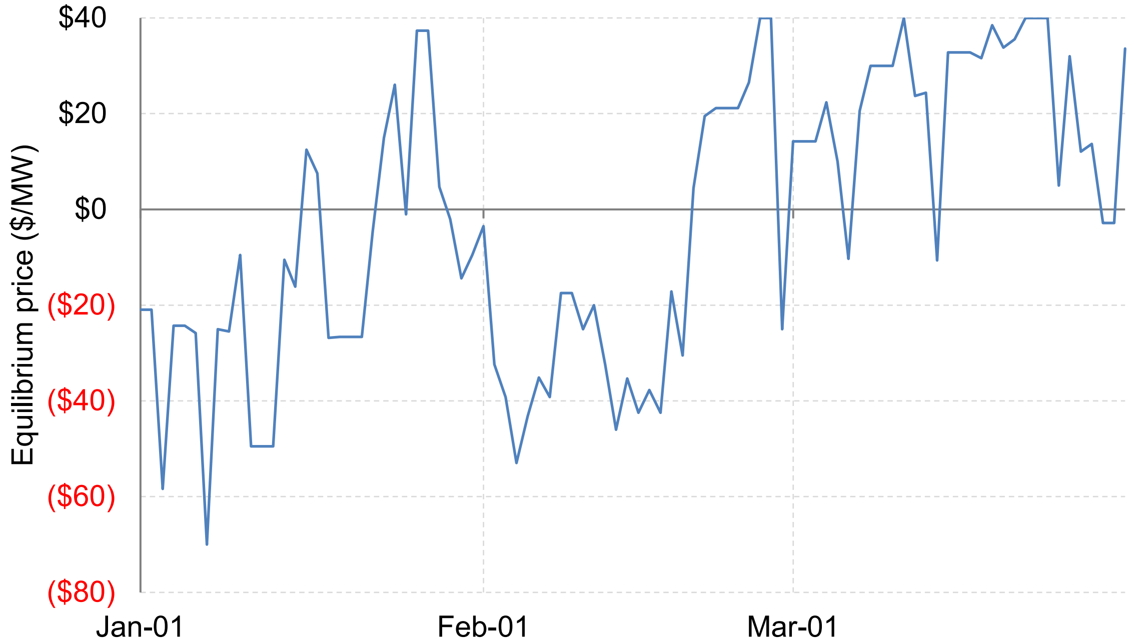


Figure 52: The equilibrium price for off peak regulating reserves (January 1 to March 31)

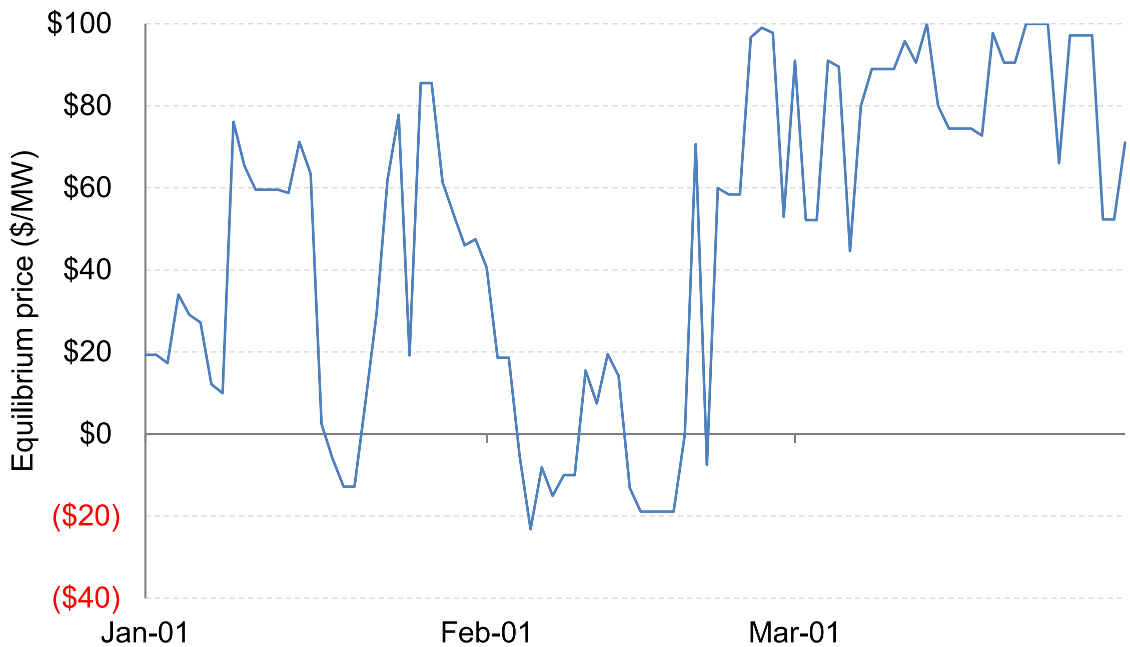


Figure 53 illustrates the number of times the equilibrium price for regulating reserves has been within $0.05/MW of the respective price cap by quarter. As shown, in recent quarters there has been an increasing trend of equilibrium prices for regulating reserves being set close to the respective price cap. In Q1 the equilibrium price was close to the price cap on fifteen occasions: six in the on peak, four in the off peak, four in the AM super peak, and one in the PM super peak.

Figure 53: Count of times the equilibrium price for regulating reserves has been within $0.05/MW of the price cap (Q1 2018 to Q1 2025)

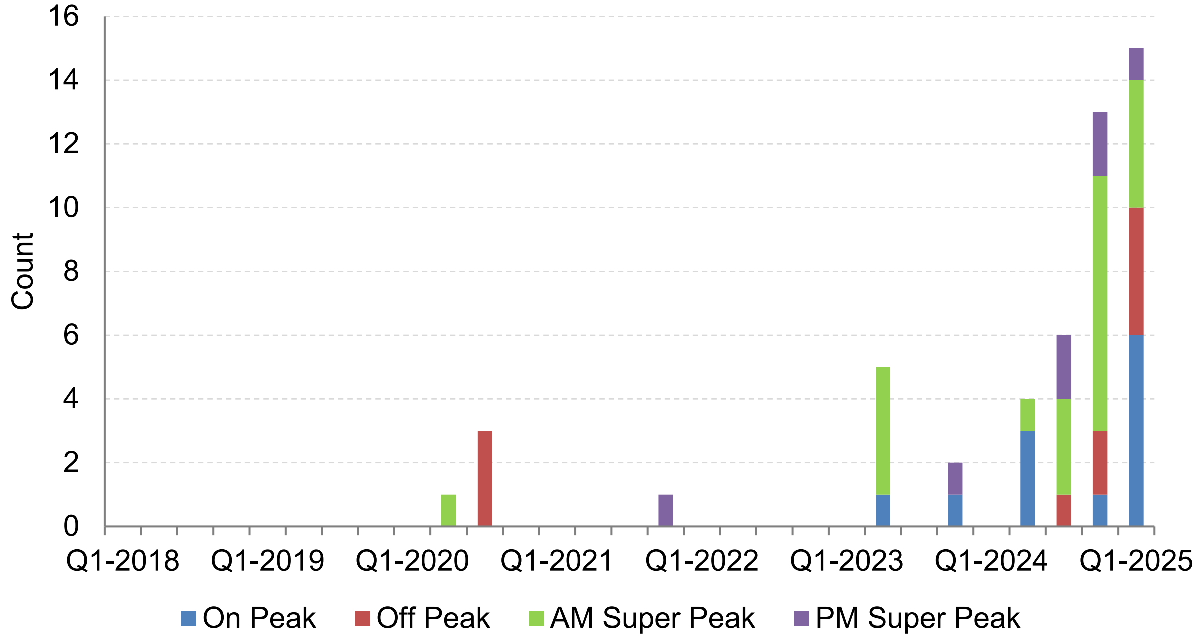
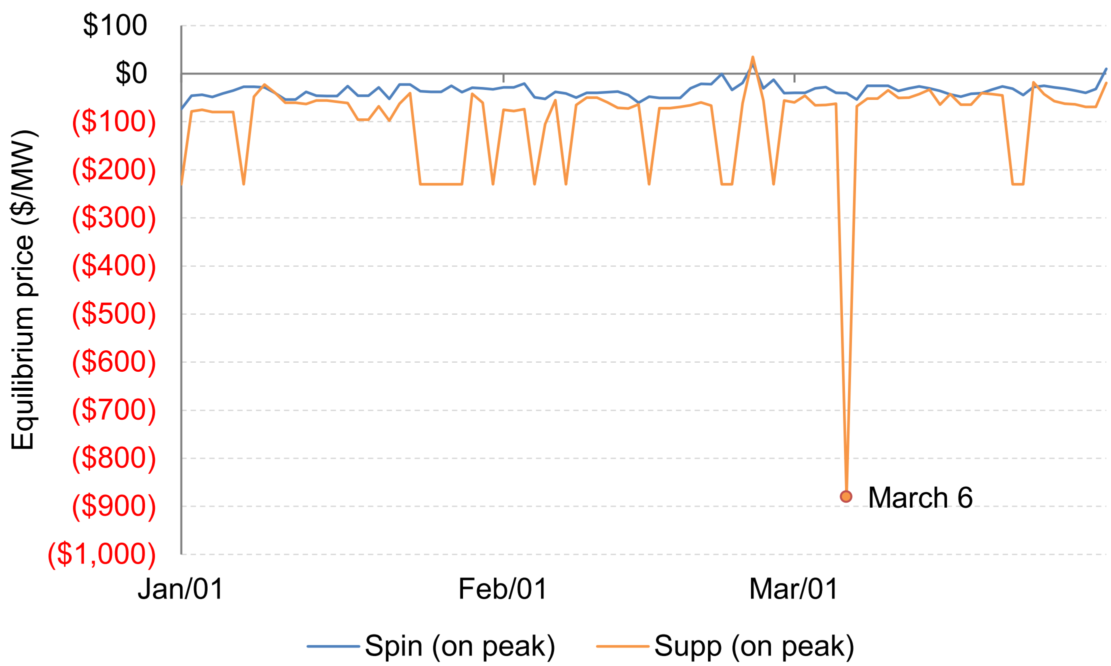


Figure 54 illustrates the evolution of equilibrium prices for on peak spinning and supplemental reserves over Q1. The price of spinning reserves was higher than the price of supplemental reserves for most of the quarter, which is intuitive given that spinning reserves must provide frequency response whereas supplemental reserves are not required to.

Figure 54: Equilibrium prices for on peak spinning and supplemental (Q1 2025)



On March 6 there was an outlier in the on peak supplemental market as the equilibrium price cleared at negative $880.50/MWh. This outlier basically guaranteed no payments for on peak supplemental reserves on that day and was driven by an increase in the supply of hydro. Specifically, on March 6 the total volume of hydro offered for on peak supplemental was 160 MW compared to 110 MW on March 5 and 115 MW on March 7 when the equilibrium prices cleared at negative $62.50/MWh and negative $67.90/MWh, respectively.

Table 16 provides average received prices for active OR products year-over-year alongside the average pool price. The average pool price declined by $59.52/MWh year-over-year and the received prices for regulating, spinning and supplemental all declined as well, but declined by less than the pool price. This indicates that the equilibrium prices for active OR products all increased year-over-year, in part to compensate for the lower pool prices. Received prices for regulating reserves declined by only $15/MWh year-over-year and traded at a $16/MWh premium to pool price in Q1.

Table 16: Average received prices for active OR (Q1 2024 and Q1 2025)

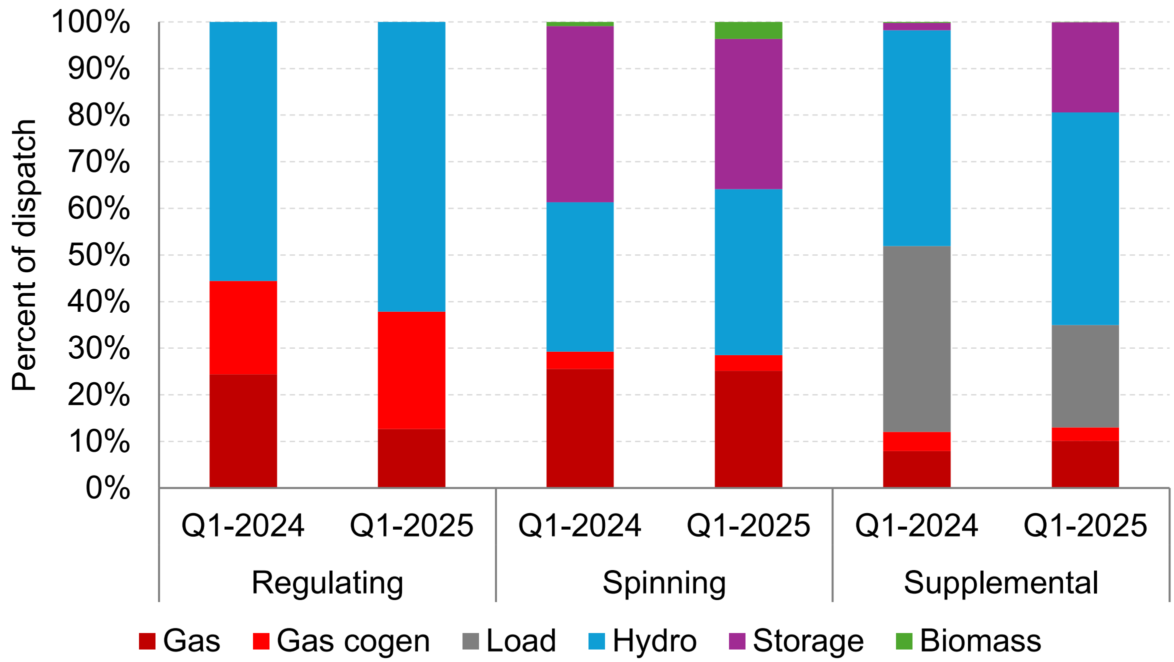
	Q1 2024	Q1 2025	Difference
Pool price	$99.30	$39.78	-$59.52
Reg	$70.65	$55.70	-$14.94
Spin	$33.99	$15.96	-$18.04
Supp	$35.84	$11.05	-$24.79

Figure 55 illustrates the percent of dispatched volumes by fuel type for the different OR markets year-over-year. In the regulating reserves market, there were some small changes to the dispatch percentages of different fuel types. Specifically, the dispatched percentage of hydro increased from 56% to 62%, cogeneration volumes increased from 20% to 25%, while gas volumes fell from 24% to 13%.

The make up of dispatch percentages in the spinning reserve market was largely unchanged year-over-year as storage fell from 38% to 32%, hydro increased from 32% to 36%, and biomass increased from 1% to 4%.

The market for supplemental reserves saw the largest change year-over-year. The dispatch percentage of load assets fell from 40% to 22% while storage volumes increased from 2% to 19%. This transition from less load assets being dispatched to more storage assets being dispatched put upward pressure on equilibrium prices for supplemental reserves.

Figure 55: Percent of dispatch by fuel type for active OR products (Q1 2024 and Q1 2025)



On December 4, 2024 TransAlta completed the acquisition of Heartland Generation. Prior to the acquisition, TransAlta and Heartland both competed for dispatch in the OR markets. A supplier can be dispatched for reserves by selling active reserves or by being activated through standby.

Figure 56 illustrates the share of dispatches for TransAlta and Heartland in the regulating reserve market since Q1 2024. In Q1 2024 TransAlta's assets accounted for 67% of the dispatches in the regulating reserve market and Heartland's assets accounted for 12%. In total, the two companies combined accounted for 79% of regulating reserve dispatches. In Q1 2025, after the acquisition, TransAlta maintained a large share of the regulating reserves market with the combined assets accounting for 75% of dispatches.

Figure 57 and Figure 58 provide the same analysis for spinning reserves and supplemental reserves, respectively. As shown, in both markets TransAlta's share of dispatches after the acquisition is comparable with the combined share of TransAlta and Heartland prior to the acquisition.

Figure 56: TransAlta and Heartland share of regulating reserve dispatches by quarter (Q1 2024 to Q1 2025)

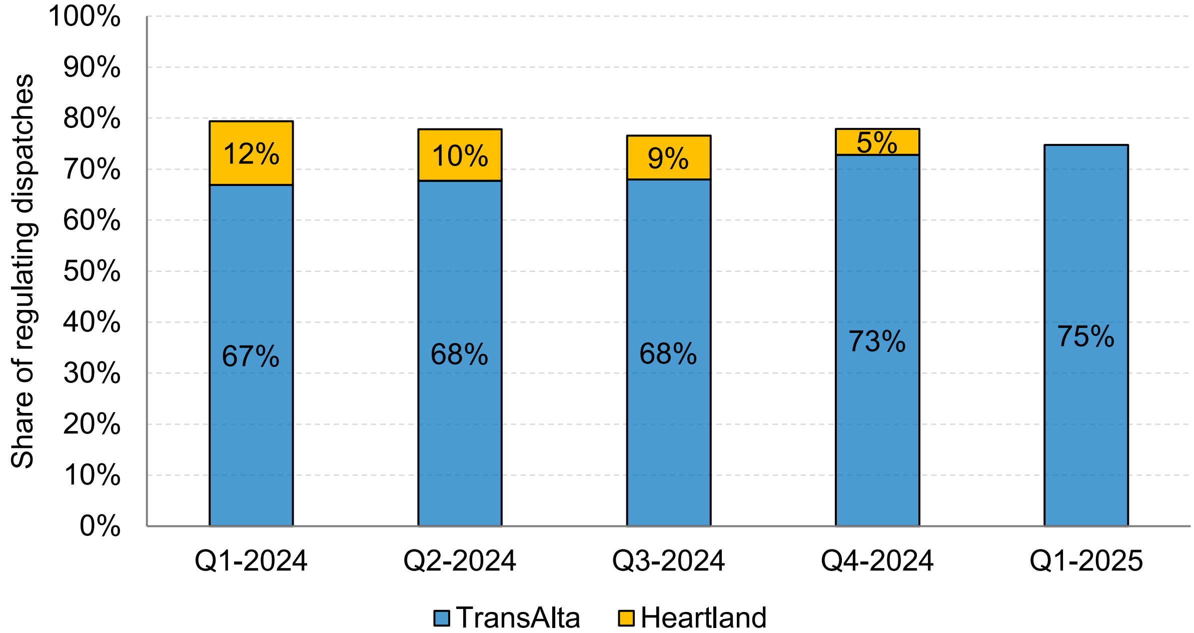


Figure 57: TransAlta and Heartland share of spinning reserve dispatches by quarter (Q1 2024 to Q1 2025)

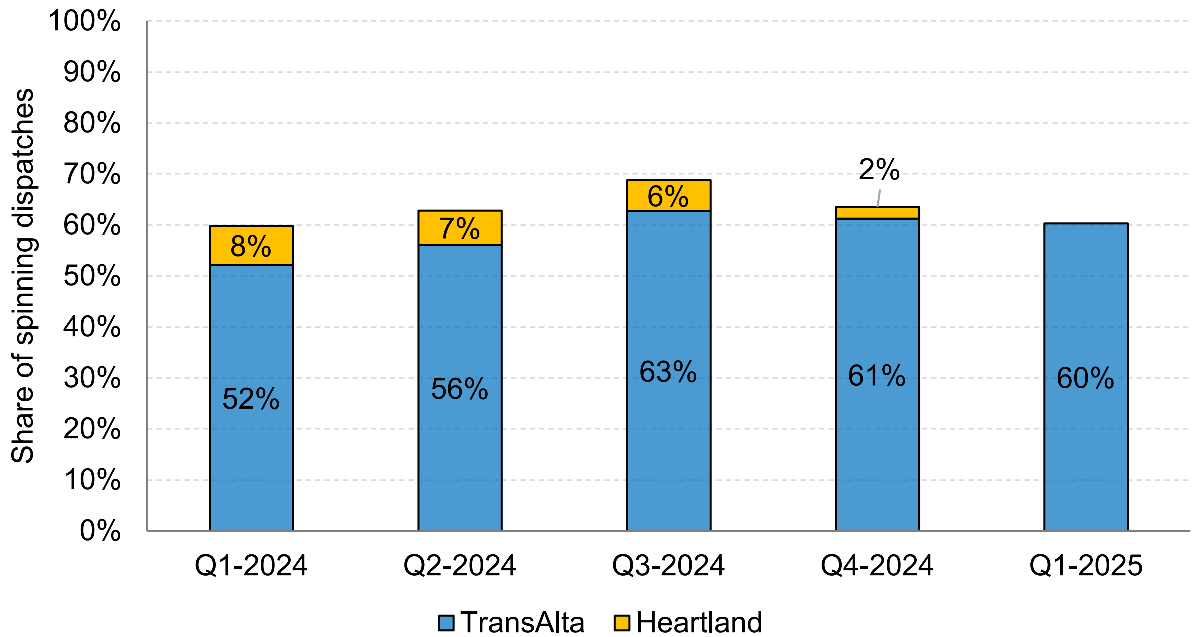
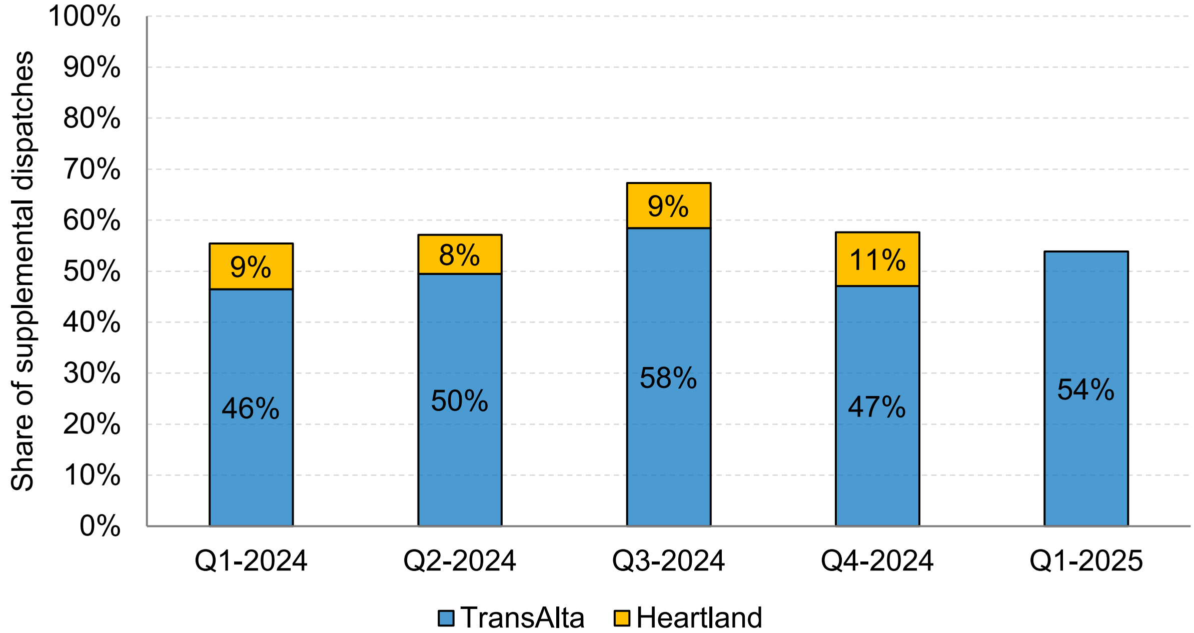


Figure 58: TransAlta and Heartland share of supplemental reserve dispatches by quarter (Q1 2024 to Q1 2025)



3.2 Standby reserves

Standby reserves are procured day-ahead as back up in case the AESO need more active reserves in real time. Table 17 illustrates the typical volume of standby reserves procured by the AESO. Standby activations occur because:

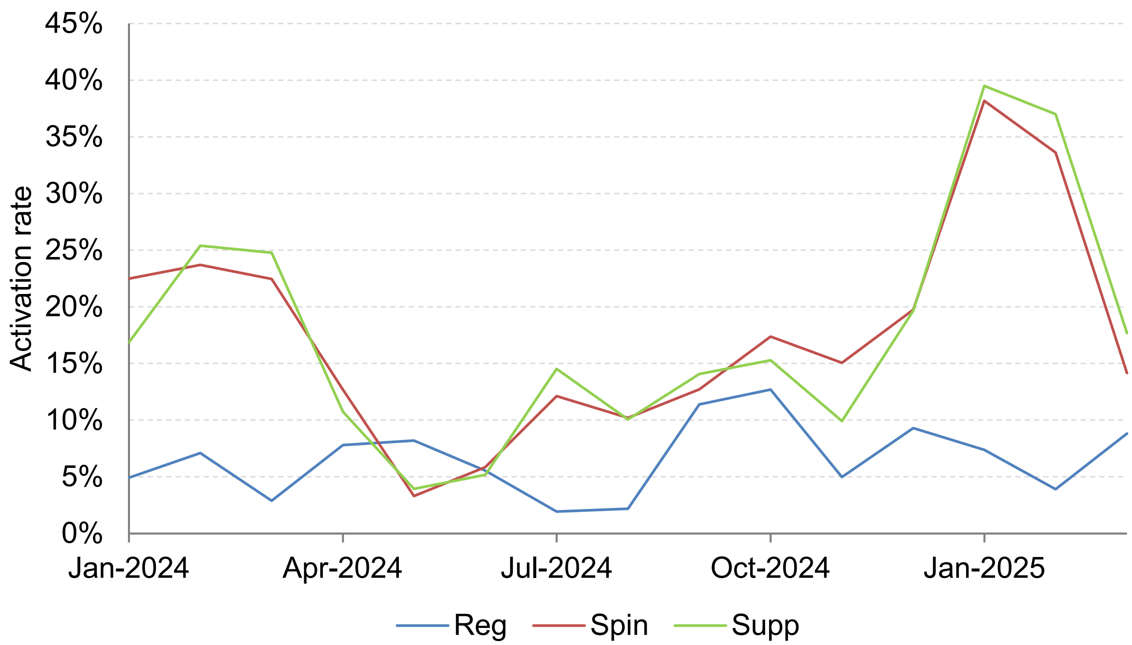
- an outage or constraint at an asset providing active reserves means the asset can no longer provide the service, or
- system conditions in real time necessitate the need for more active reserves than those forecasted day ahead.

Table 17: Typical standby volumes purchased by the AESO (MW)

	On peak	Off peak
Regulating	20	
Spinning	45	35
Supplemental	15	

Standby activation rates for spinning and supplemental reserves were high in January and February (Figure 59). In January the activation rates for standby spinning and supplemental were close to 40% which is well above historic values and those assumed in the AESO's blended price formula.[20] These high activation rates were driven by higher-than-expected export volumes which increased demand and the need for active contingency reserves.

Figure 59: Standby activation rates by month (January 2024 to March 2025)



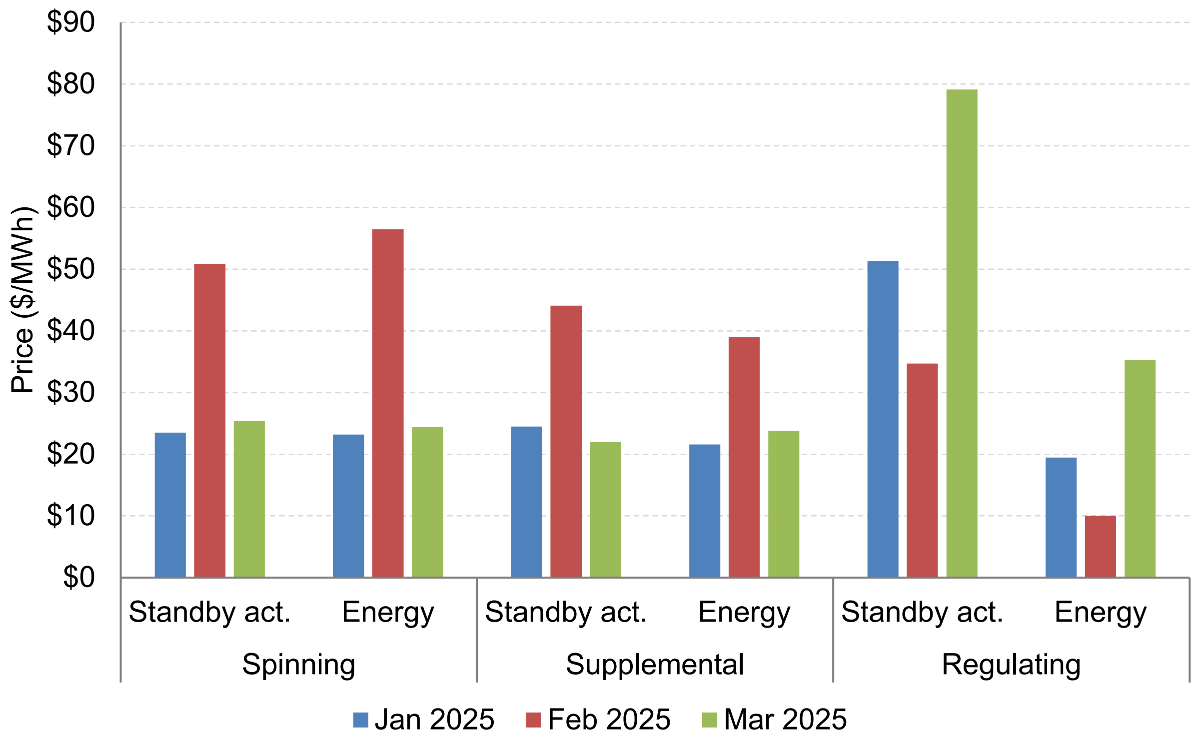
The activation prices offered by suppliers are set day-ahead based in part on pool price expectations for the next day. Standby activation prices are not indexed directly to pool prices as with prices for active reserves.

Figure 60 compares standby activation prices with prevailing pool prices across the three months in Q1. As shown, the activation prices for standby spinning and supplemental reserves were generally comparable with prevailing pool prices at the time of the activations. However, for regulating reserves standby activation prices were well above prevailing pool prices. This is consistent with outcomes in the market for active regulating reserves where we have seen regulating reserves trade at a premium to energy.

[20] The AESO uses a blended price formula to rank standby offers for market clearing:

Blended Price = Premium Price + (Activation Price * Assumed Activation Rate)

Figure 60: Standby activation prices compared with prevailing pool prices by month (Q1 2025)



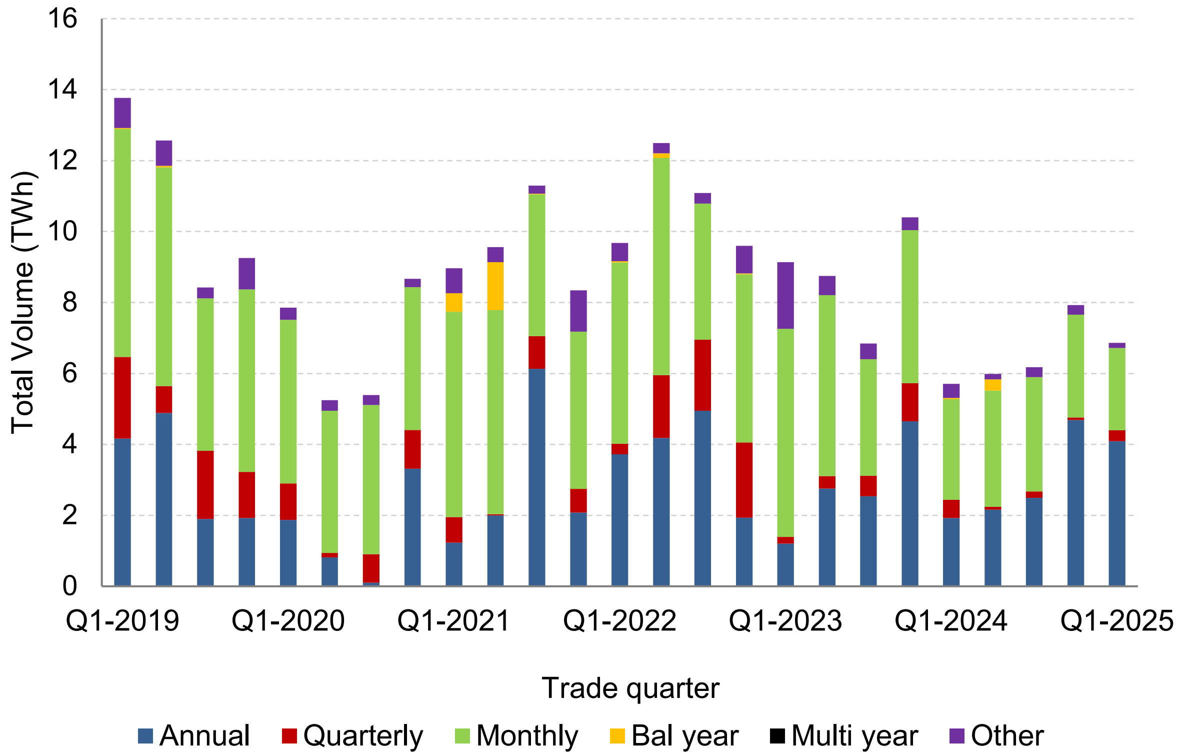
4 THE FORWARD MARKET

Alberta's financial forward market for electricity is an important component of the market because it allows for generators and larger loads to hedge against pool price volatility, and it enables retailers to reduce price risk by hedging sales to retail customers.[21]

4.1 Forward market volumes

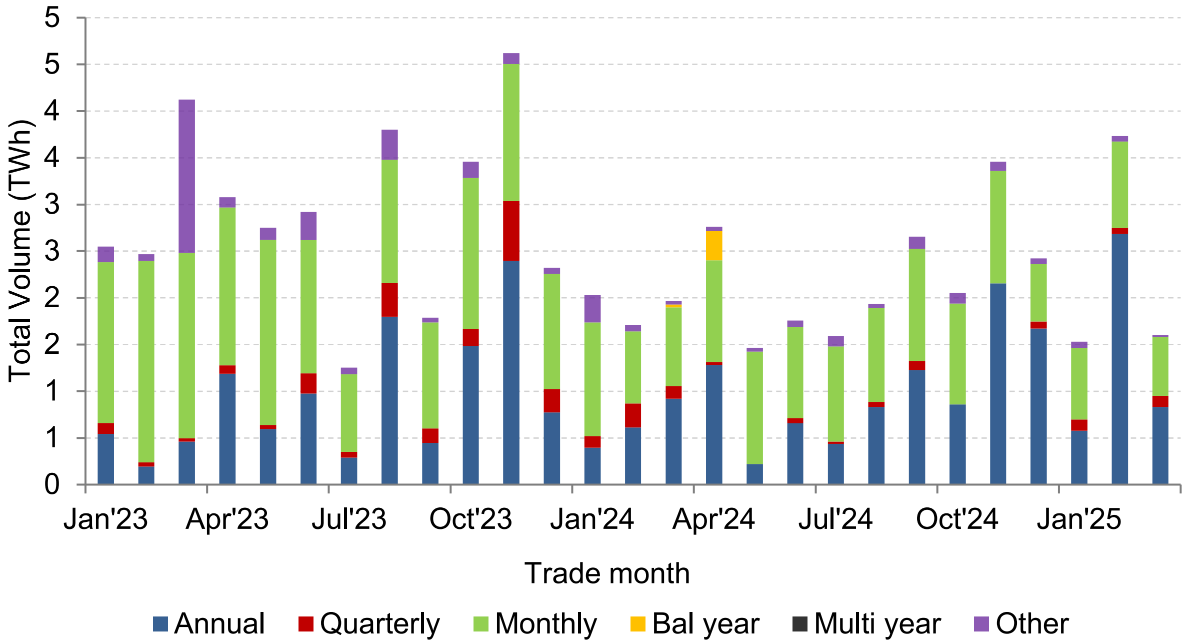
Low liquidity in the forward market continued in Q1 (Figure 61). The total trade volume on ICE NGX or through brokers was 6.9 TWh, which represents a decline of 13% from the previous quarter, but an increase of 20% from Q1 2024. As shown in Figure 61, traded volumes have been low over the past year. In Q1 traded volume was highest in February and lower in January and March, which are among the lowest traded months since July 2023 (Figure 62).

Figure 61: Total trade volumes by term and quarter (Q1 2019 to Q1 2025, excludes direct bilateral trades)



[21] 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, 2024 are also included. 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.

Figure 62: Total trade volumes by term and month
(2023 to 2025, excludes direct bilateral trades)



4.2 Trading of monthly products

Pool prices came in below forward market expectations in January and near expectations for February and March (Figure 63). In January the average pool price settled 53% below the volume-weighted average forward price of $64.76/MWh. As shown in Figure 63 the forward-spot pricing dynamic for January was similar to December as pool prices in both months came in well under forward market expectations. This dynamic is in contrast to January last year, when pool prices settled 15% higher than the volume-weighted forward price.

Despite cold weather in early February the average pool price for the month settled at 7% below the volume-weighted average price of $60.28/MWh. For March pool prices settled 8% below the volume-weighted average price of $37.76/MWh, but 7% above the final trade price leading into the month ($32.50/MWh).

Figure 64 shows the distribution of traded volume by monthly product over Q1. As expected, the traded volume was concentrated in the prompt months throughout the quarter (February, March, and April), along with more trades spanning the winter and summer season.

Figure 63: Monthly flat forward prices and realized average pool prices by month (January 2024 to March 2025)

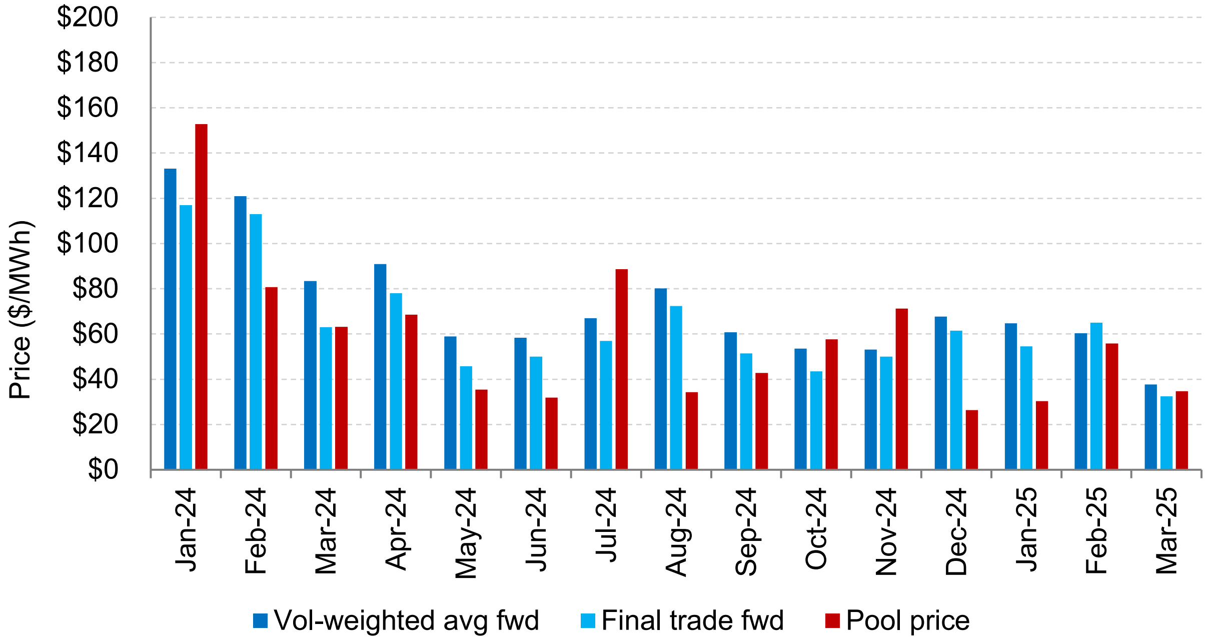
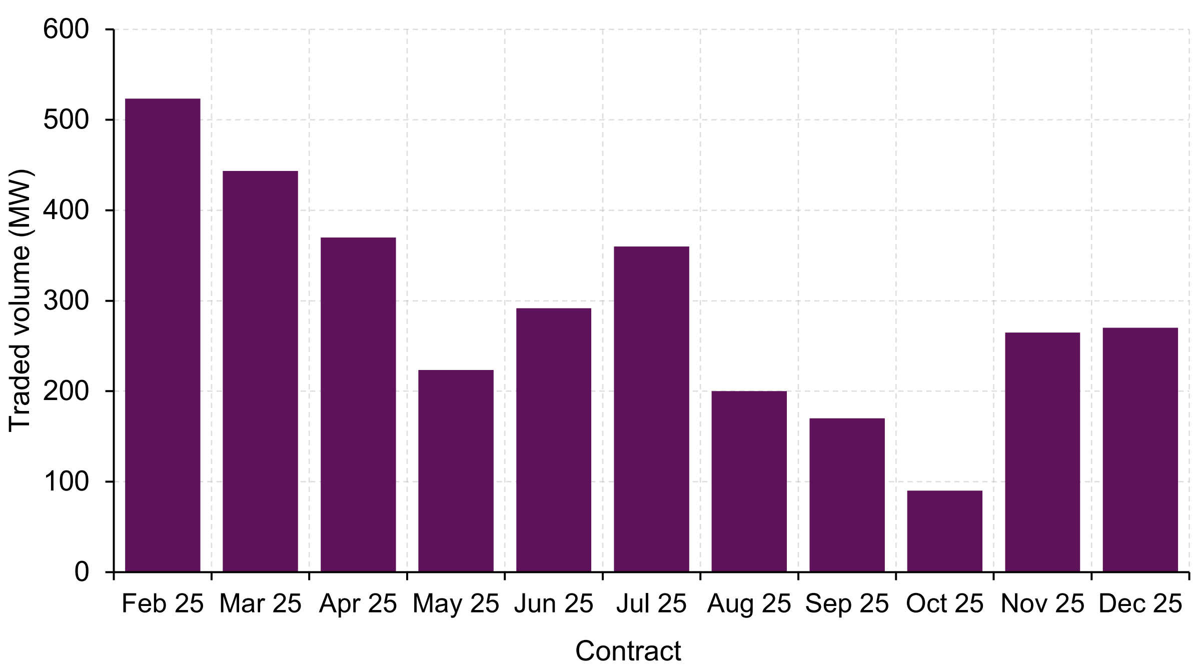


Figure 64: Distribution of monthly trades in Q1 2025[22]



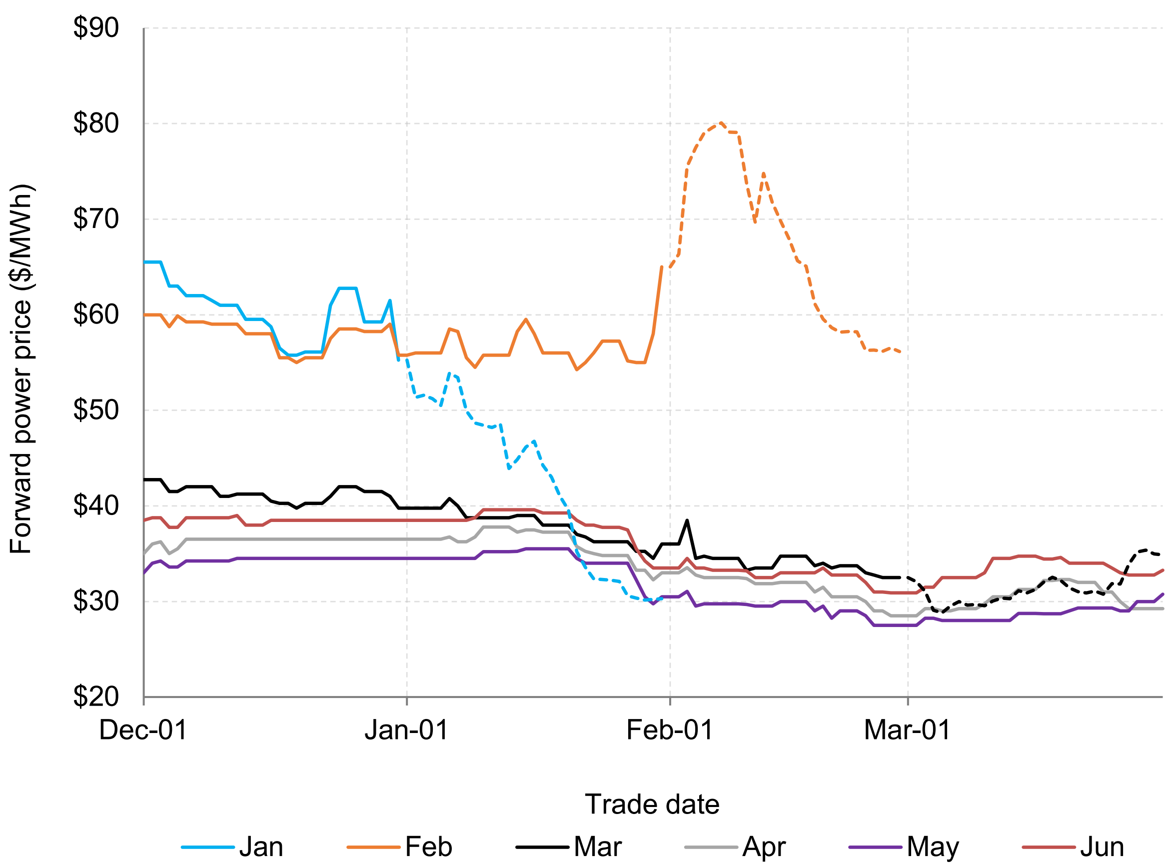
[22] On/off peak products weighted accordingly

The evolution of select monthly forward prices over the course of Q1 is shown in Figure 65. The dashed lines in the figure illustrate the marked prices for January, February, and March. These marked prices combine realized prices and forward prices for balance-of-month to calculate the expected average price for a month as of a certain date.

Rising Mid-C prices combined with colder temperatures in Alberta toward the end of January to put upward pressure on February forward prices, which observed an increase of $10/MWh over the course of January 29 to January 31, with a final trade price of $65/MWh. The marked price of February reached a maximum of $80/MWh early in the month due to pool price volatility on February 3 and 4. However, low pricing for the back half of February caused the marked price to fall to $56/MWh by the end of the month.

Forward prices for April, May, and June generally declined together throughout the quarter due to the low pricing environment in the energy market. These prices reached a minimum at the end of February, though rose slightly through March due to upwards pressure from real-time pricing and increases in gas forwards.

Figure 65: The evolution of select monthly flat forward prices (December 1 to March 31)



4.3 Trading of annual products

Figure 66 illustrates the evolution of annual forward prices over the course of Q1. Calendar products slid throughout the quarter, with declines of 15% to 19% observed across CAL26 through CAL29.

CAL26 experienced a decline of 15% despite an 11% increase in the forward gas price, which equates to a 33% decline in the spark spread (**Error! Reference source not found.**). For most annual power trades over the quarter the seller was the aggressor, indicating sell side pressure.

Figure 66: The evolution of annual flat forward prices (December 1 to March 31)

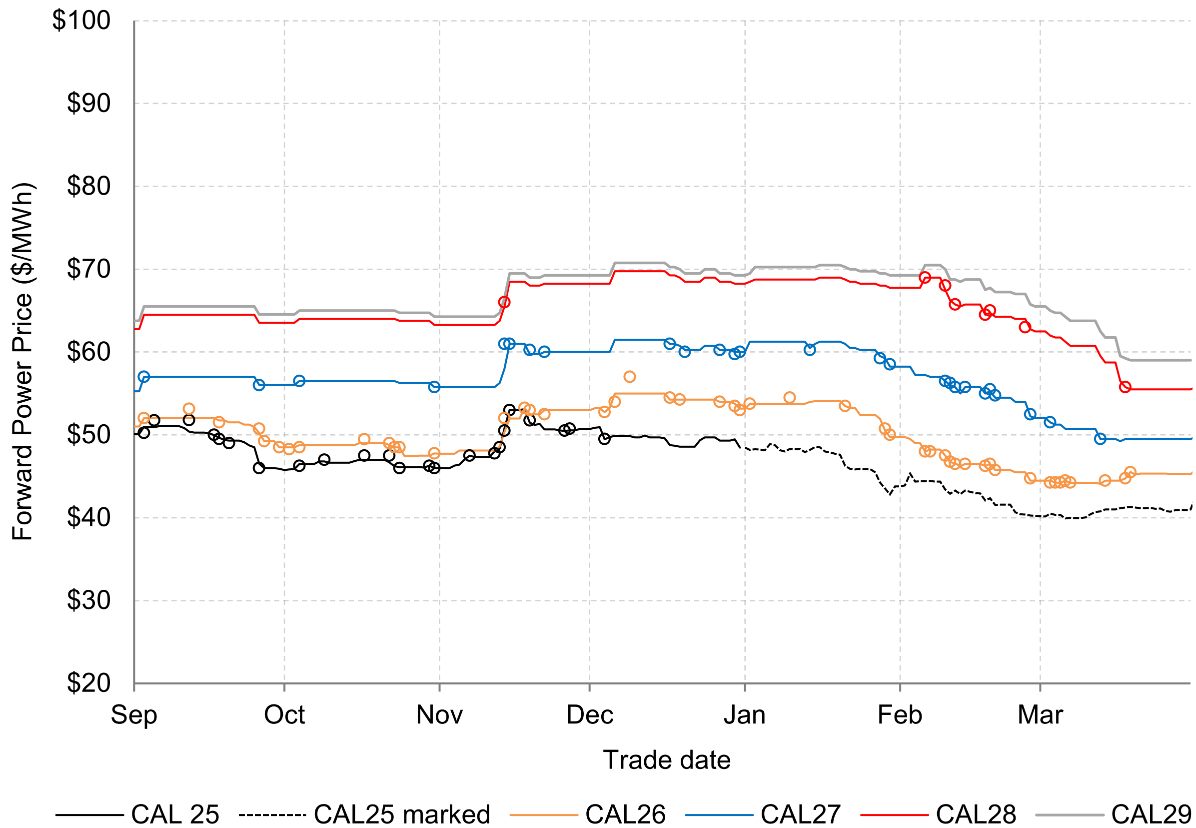
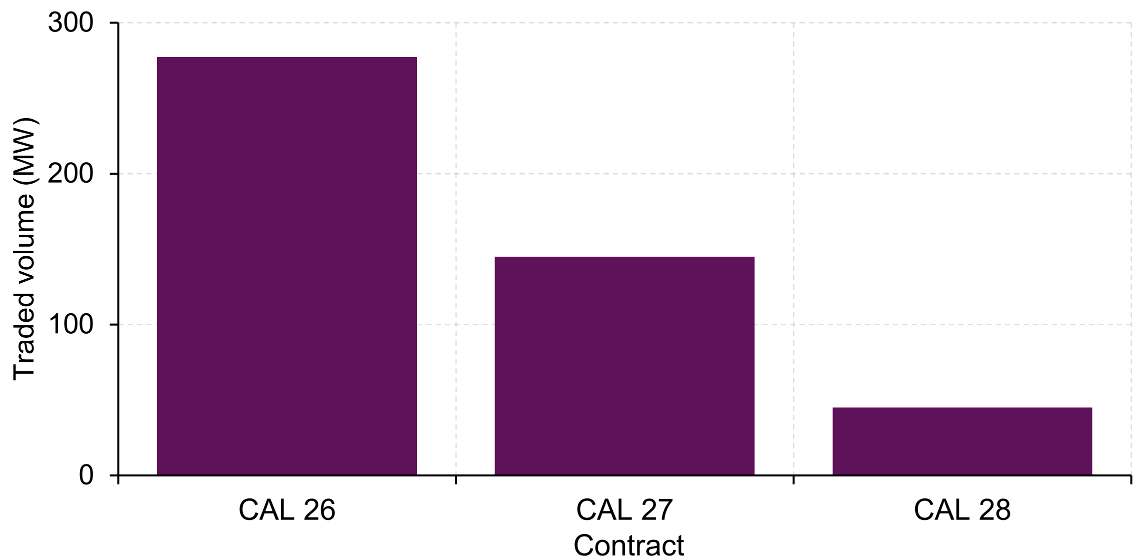


Table 18: Annual power and natural gas price changes over Q4 2024

Contract	Power price ($/MWh)			Gas price ($/GJ)			Spark spread[23] ($/MWh)		
	Dec 31	**Mar 31**	**% Chng**	**Dec 31**	**Mar 31**	**% Chng**	**Dec 31**	**Mar 31**	**% Chng**
CAL25 Marked	$48.47	41.02	-15%	2.01	2.47	23%	$33	$22	-33%
CAL26	$53.17	$45.27	-15%	$2.87	$3.20	11%	$32	$21	-33%
CAL27	$60.00	$49.50	-18%	$2.99	$3.07	3%	$38	$26	-30%
CAL28	$68.25	$55.50	-19%	$3.07	$2.96	-4%	$45	$33	-26%
CAL29	$69.25	$59.00	-15%	$3.17	$2.92	-8%	$45	$37	-18%

Figure 67 shows the distribution of traded volume by calendar product over Q1. As expected, the prompt year (CAL26) recorded the highest traded volume, with declining activity along the forward curve and no trades for CAL29.

Figure 67: Distribution of annual trades in Q1 2025



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