MARKET SURVEILLANCE ADMINISTRATOR

Wholesale Market Report: Q2 2026

August 6, 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

Low pool prices continued in Q2 despite higher demand year-over-year

The average pool price in Q2 was $29.47/MWh, which is 27% lower than Q2 last year and 8% less than the prior quarter. Despite higher demand and more thermal generation outages year-over-year, more imports, increased supply from Base Plant, low natural gas prices, and less high-priced offers led to lower pool prices. Mild weather in June, combined with high wind generation and increased imports, led to an average pool price of $17.36/MWh, which is the lowest monthly average on record after adjusting for inflation.

The AESO declared an Energy Emergency Alert (EEA) on the evening of May 25

Between 19:10 and 21:35 on May 25, the AESO declared an EEA due to a shortfall in supply. The shortfall occurred around the net demand peak as intermittent generation (wind and solar) declined. The event was partly caused by three gas-fired steam assets being commercially offline on long lead time. These assets were not issued unit commitment directives by the AESO because wind generation was expected to be higher than it was. To meet demand, the AESO directed 233 MW of contingency reserves to provide energy, increased imports on the BC/MATL intertie from 440 to 826 MW, and curtailed 50 MW of exports on the Saskatchewan intertie.

An intertie outage and generator trips caused frequency events on April 14 and 17

The BC/MATL intertie was on a scheduled outage from April 13 to 18. When BC/MATL is out of service the AESO need to handle large generator trips without the support of the Western Interconnection. Therefore, the AESO buy additional Fast Frequency Response (FFR). There were three large generator trips during this BC/MATL outage and frequency declined to 59.63, 59.59, and 59.55 Hz. While frequency declined toward the load shed threshold of 59.50 Hz, the AESO had armed FFR that was not tripped in all three events.

The System Marginal Price (SMP) increased from the floor to the offer cap on May 7

Prices on May 7 were volatile. At 15:13, the SMP was at the floor of $0/MWh as intermittent generation was high and temperatures were moderate. However, by 20:46, the SMP had increased to the offer cap of $999.99/MWh as intermittent generation had declined significantly. This price volatility was also a function of several large thermal generator outages. The AESO were able to predict the tight market conditions around the net demand peak and committed Sheerness 2 to be online from 19:00 to 23:00, adding 400 MW of capacity. Without the AESO's commitment of Sheerness 2, the AESO would likely have declared an EEA3 and directed contingency reserves to provide energy in order to meet demand.

The SMP increased to the offer cap on May 28

The daily average pool price on May 28 was $384/MWh, the highest since September 8, 2025. In HE 21, the SMP cleared at the offer cap of $999.99/MWh for the entire hour. The high prices were caused by elevated temperatures, thermal generator outages, and low wind generation. The low wind generation was predicted by the AESO's forecasts, so the AESO committed Battle River 4 to run from 13:00 to the end of the day, increasing capacity by 155 MW during some critical hours.

Without the AESO's commitment of Battle River 4, the AESO would likely have declared an EEA3 and directed contingency reserves to provide energy in order to meet demand.

The daily average pool price cleared at the price floor of $0/MWh on May 14 and 31

For the first time on record, pool prices cleared at $0/MWh for the entire day on Thursday, May 14 and the same occurred on Sunday, May 31. The low prices on these days were driven by high wind generation and low demand. In addition, there is a large amount of must-run gas generation in Alberta that is offered at $0/MWh and is prohibitively expensive to shutdown and start-up. Most cogeneration assets in Alberta are associated with oilsands production, and steam supply at these sites is of primary importance. In addition, combined cycle and gas-fired steam assets have minimum stable generation levels and cannot supply below this amount. There were transmission curtailments in both events, largely at wind assets, so the constrained SMP was higher. On May 14, an issue with the AESO's calculation of anticipated supply cushion resulted in the commitment of certain gas-fired steam units. The AESO identified and addressed the error for go-forward forecasts.

Net revenue analysis indicates that the energy market was unprofitable in Q2

Net revenue analyses estimate the profitability of hypothetical generation assets using pool prices, natural gas prices, carbon prices, and assumed cost parameters. The MSA's net revenue analyses for Q2 indicate that the hypothetical combined cycle, simple cycle, wind, and solar assets were all unprofitable over the quarter due to low pool prices.

MSA analysis estimates net revenues under locational pricing

The market change from pool price to Locational Marginal Prices (LMP) is scheduled to occur under the Restructured Energy Market (REM) in 2028. In the Net revenue analysis by location section of this report, the MSA estimates the impact of locational pricing on historical net revenues for assets of different fuel types located at different points on the grid. The analysis illustrates that assets which were often constrained had lower net revenues under LMP than under pool prices. However, most assets earned higher net revenues under LMP because they were not constrained frequently. In 2025, some wind assets were heavily constrained and would have earned lower net revenues under LMP. In contrast, most wind assets and all solar, simple cycle, and combined cycle assets would have earned higher net revenues under LMP in 2025.

Annual forward prices increased concurrent with data centre developments

Pool prices in Q2 came in below forward market expectations. The low pool prices combined with lower forward prices in Mid-Columbia to put downward pressure on monthly contracts. For example, forward prices for July and September fell by 9% over the quarter, and the expected average pool price for 2026 fell by 7% to $36.91/MWh. Consequently, the price of Calendar 2027 (Cal 27) fell by 3% to $46.55/MWh. However, annual contracts further out are trading based on the REM and the potential for more data centre load. Over the quarter, the price of Cal 28 increased by 7% to $62.95/MWh, Cal 29 increased by 18% to $75.25/MWh, and Cal 30 increased by 25% to $83.00/MWh. The price increases for Cal 29 and Cal 30 were largely driven by data centre developments.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q2 was $29.47/MWh, which is 27% lower than Q2 last year and 8% lower than Q1 (Table 1). The lower prices year-over-year were driven by lower prices in June, which averaged $17.36/MWh. This is 63% less than in June 2025 and is the lowest monthly pool price on record after adjusting for inflation (Table 2).

The lower prices in June were the result of mild weather, high wind generation, and low prices in Mid-Columbia (Mid-C), which led to increased imports (Table 3). These factors offset higher demand year-over-year, lower thermal availability, and higher natural gas prices.

Table 1: Pool prices, natural gas prices, and spark spreads (Q2 2025 and Q2)

		2025	2026	Change
Pool price (Avg $/MWh)	Apr	$33.69	$27.61	-18%
	May	$40.99	$42.98	5%
	Jun	$46.75	$17.36	-63%
	Q2	**$40.48**	**$29.47**	**-27%**
Gas price AB-NIT (2A) (Avg $/GJ)	Apr	$2.24	$1.30	-42%
	May	$1.82	$1.60	-12%
	Jun	$0.85	$1.72	101%
	Q2	**$1.64**	**$1.54**	**-6%**
Spark spread (7.5 heat rate) ($/MWh)	Apr	$16.88	$17.87	6%
	May	$27.32	$30.96	13%
	Jun	$40.34	$4.47	-89%
	Q2	**$28.17**	**$17.91**	**-36%**

The average pool price in April was $33.69/MWh which is 18% lower year-over-year, driven by lower natural gas prices and higher imports.

In May, the average pool price was $42.98/MWh, the highest in the quarter and 5% higher than May last year.

The higher average price in May was driven by elevated prices on a few days later in the month. These higher prices were due to higher temperatures, low wind generation, and some large thermal generator outages.

Table 2: The lowest five monthly average real pool prices (January 2001 to June 2026)

	Pool Price, nominal ($/MWh)	Pool Price, real ($/MWh)
Jun-2026	$17.36	$17.36
Apr-2016	$13.63	$17.96
Mar-2016	$14.79	$19.54
Jun-2016	$15.44	$20.22
May-2016	$15.89	$20.86

On the evening of May 25, the AESO declared an EEA3 due to a supply shortfall. This event was largely caused by wind generation coming in well below the AESO's forecasts. As a result of the forecast errors, 950 MW of gas-fired steam capacity was commercially offline on long-lead time during the EEA3 as the three assets were not committed by TransAlta or the AESO. This event is discussed further in section 1.2.2.

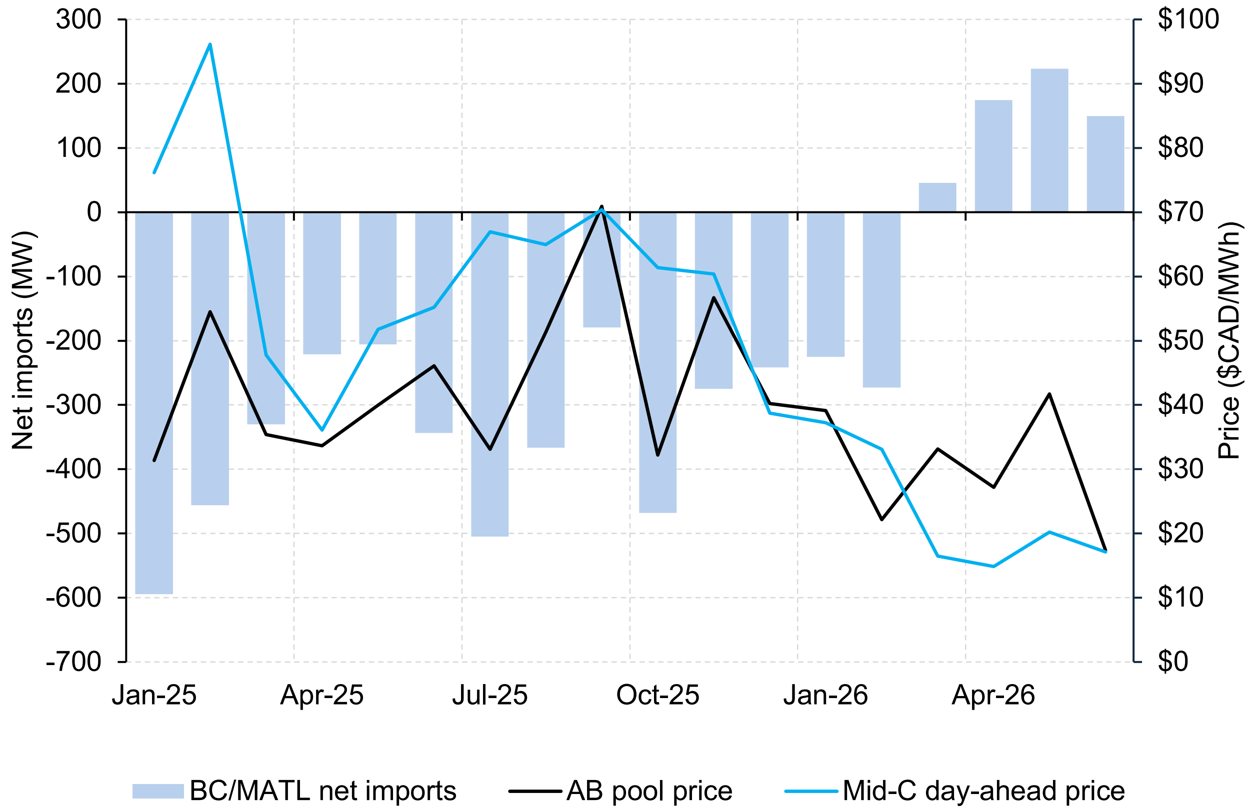
As with April and June, May was characterized by higher demand, lower thermal availability, and more imports year-over-year (Table 3).

Table 3: Energy market fundamentals (Q2 2025 and Q2)

		2025	2026	Change (MW)
Demand (AIL) (Avg MW)	Apr	9,819	10,308	489
	May	9,400	9,866	466
	Jun	9,645	9,969	324
	Q2	**9,619**	**10,046**	**427**
Available thermal capacity (Avg MW)	Apr	10,182	9,567	-615
	May	9,509	8,916	-593
	Jun	9,681	9,387	-294
	Q2	**9,788**	**9,286**	**-502**
Wind gen. (Avg MW)	Apr	1,706	1,694	-12
	May	1,662	1,689	27
	Jun	1,405	1,879	474
	Q2	**1,592**	**1,737**	**145**
Solar gen. (Avg MW in peak hours)	Apr	772	777	5
	May	894	838	-56
	Jun	948	817	-131
	Q2	**872**	**802**	**-70**
Net imports (+) Net exports (-) (Avg MW)	Apr	-222	177	399
	May	-206	250	456
	Jun	-343	174	517
	Q2	**-256**	**201**	**457**

The higher supply from imports was an important factor in the lower pool prices in Q2 this year (Figure 1). Lower prices in Mid-C, caused by increased hydro flows, led to imports increasing by 457 MW compared to Q2 last year, even though pool prices were 27% lower.

Figure 1: Average net imports on BC/MATL and average prices in Alberta and Mid-C (January 2025 to June 2026)



Mild weather was also a factor in the low pool prices, particularly in June. The average temperature in June was 14.2°C, which is the second lowest in the last five years (Figure 2). Despite this, demand increased notably year-over-year in all three months of Q2. On average, demand was 427 MW higher compared to Q2 last year, an increase of 4.4% (Table 3). Figure 3 shows the average load profile in Q2 of 2024, 2025, and 2026, and illustrates a large shift upwards from Q2 2025 to Q2.

In April, the increase in demand was partly a function of low temperatures, with a monthly average of 1.5°C compared to 6.0°C in April last year (Figure 2). As a result, year-over-year demand increased by the most in April at 489 MW.

The increase in demand was also driven by higher oil production. Total oil production in Alberta was 4% higher year-over-year in April, 11% higher in May, and 2% higher in June.[1] In addition, there were load outages in the Northeast in May and June of 2025 that lowered demand by around 100 MW, but there were no such outages in Q2.

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[1] Alberta Energy Regulator: ST3 report – Oil supply and disposition, Total production

Figure 2: Monthly average temperature (April, May, and June of 2022 to 2026)

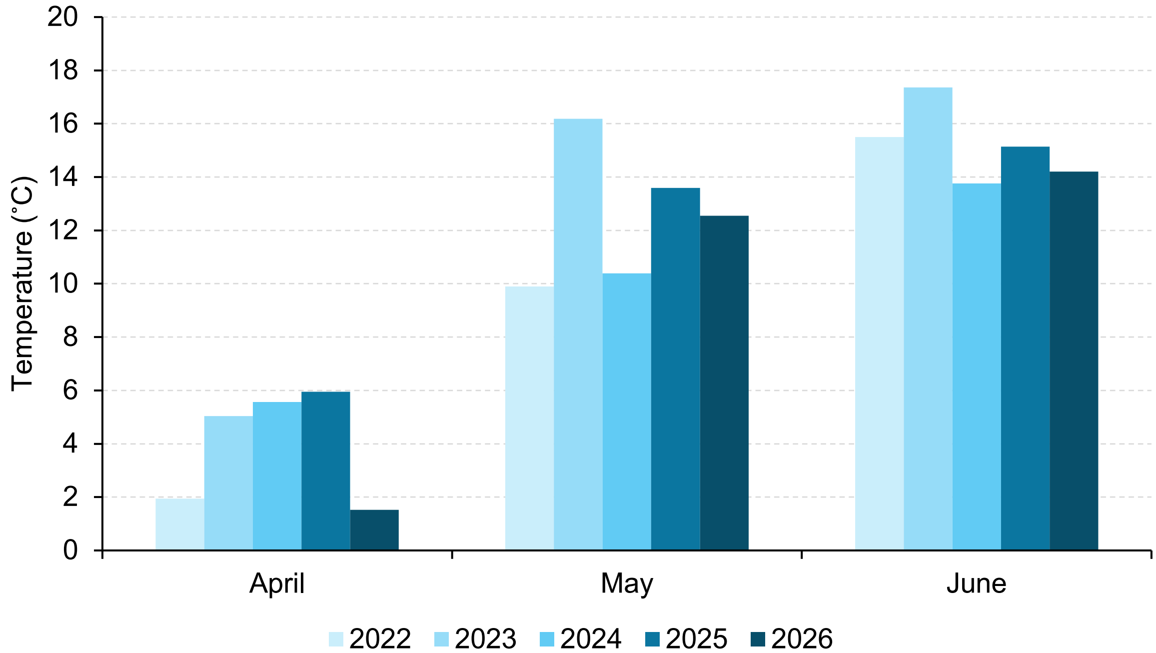
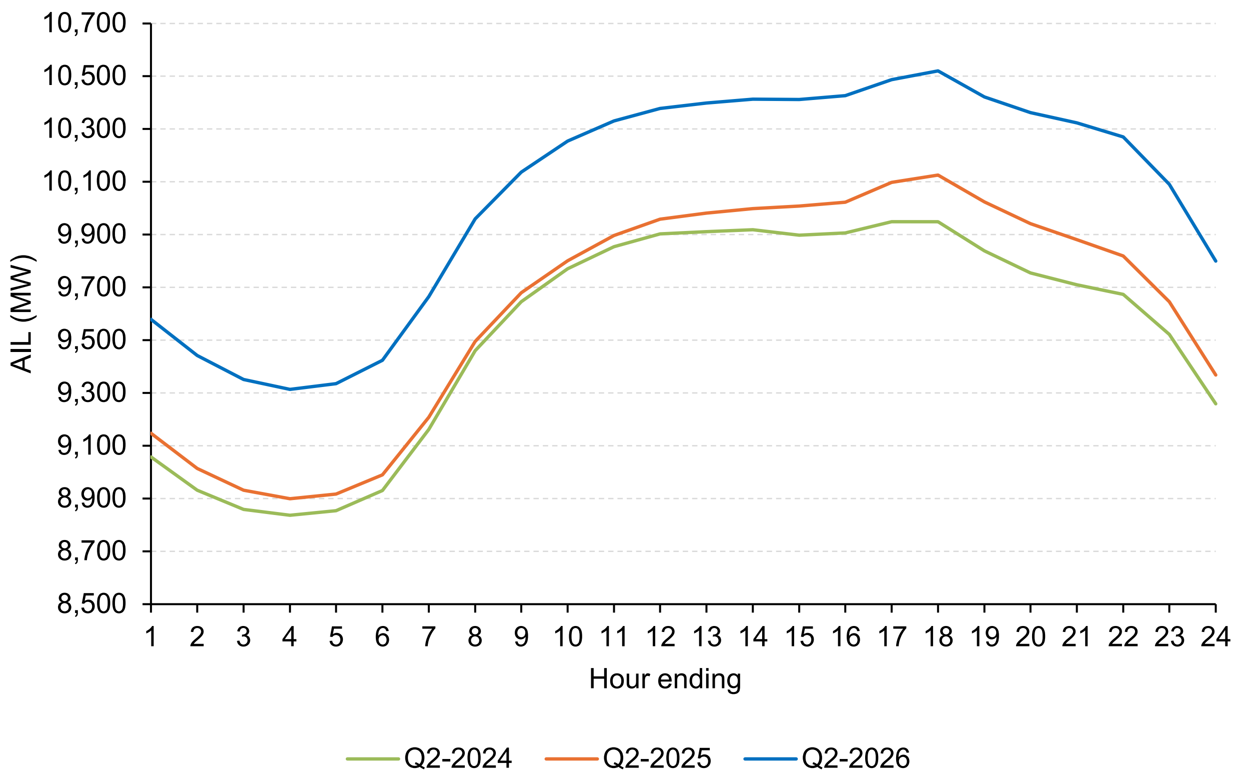


Figure 3: Average demand by hour ending (Q2 of 2024, 2025, and 2026)



Large generation assets are generally taken offline for planned maintenance in the spring and fall, due to lower demand at this time of year. This was the case in Q2 as generators at Shepard, Genesee, Cascade, Keephills, HR Milner, and Joffre were taken offline for planned maintenance (Table 4). These outages, combined with the mothballing of Sheerness 1 starting on April 1, offset increased capacity at Base Plant year-over-year. Consequently, available thermal capacity fell by 502 MW compared to Q2 last year (Table 3).

Table 4: Major thermal outages in Q2 (200 MW+ for more than 5 days)

Asset name (ID)	Capacity on outage (MW)	Days on outage	Start date	End date
Genesee Repower 1 (GNR1)	466	32	Mar 14	Apr 14
Joffre CT201 (JOF1)	210	46	Mar 16	Apr 30
Shepard CT2 (EGC1)	480	42	Apr 3	May 14
Genesee Repower 2 (GNR2)	466	24	Apr 14	May 7
Firebag (SCR6)	355	62	Apr 23	Jun 23
Keephills 3 (KH3)	466	28	Apr 29	May 26
Joffre CT201 (JOF1)	210	75	May 7	Jul 20
HR Milner (HRM)	300	6	May 10	May 15
Cascade 2 (CAS2)	466	21	May 22	Jun 11
Cascade 1 (CAS1)	466	35	May 26	Jun 29

Natural gas is the main input cost for Alberta power with gas assets setting the SMP 78% of the time in the quarter. Natural gas prices in Q2 were low and stable, reflecting mild weather and high production levels (Figure 4). In April and May, prices were 42% and 12% lower year-over-year, averaging $1.30/GJ and $1.60/GJ, respectively. In June, prices were 101% higher year-over-year, averaging $1.72/GJ.

Increased supply from Suncor's Base Plant asset was also a cause of the lower pool prices year-over-year. 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 materially.

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 exported around 800 MW onto the grid in December 2025. In Q2, available capacity at Base Plant averaged 767 MW compared to 400 MW in Q2 2025 and 16 MW in Q2 2024.

The increase in must-run thermal generation, combined with more 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 a higher value for negative pricing to efficiently order dispatch during these periods (Figure 5).

Figure 4: Same-day natural gas prices at AB-NIT (Q2 of 2022 to 2026)

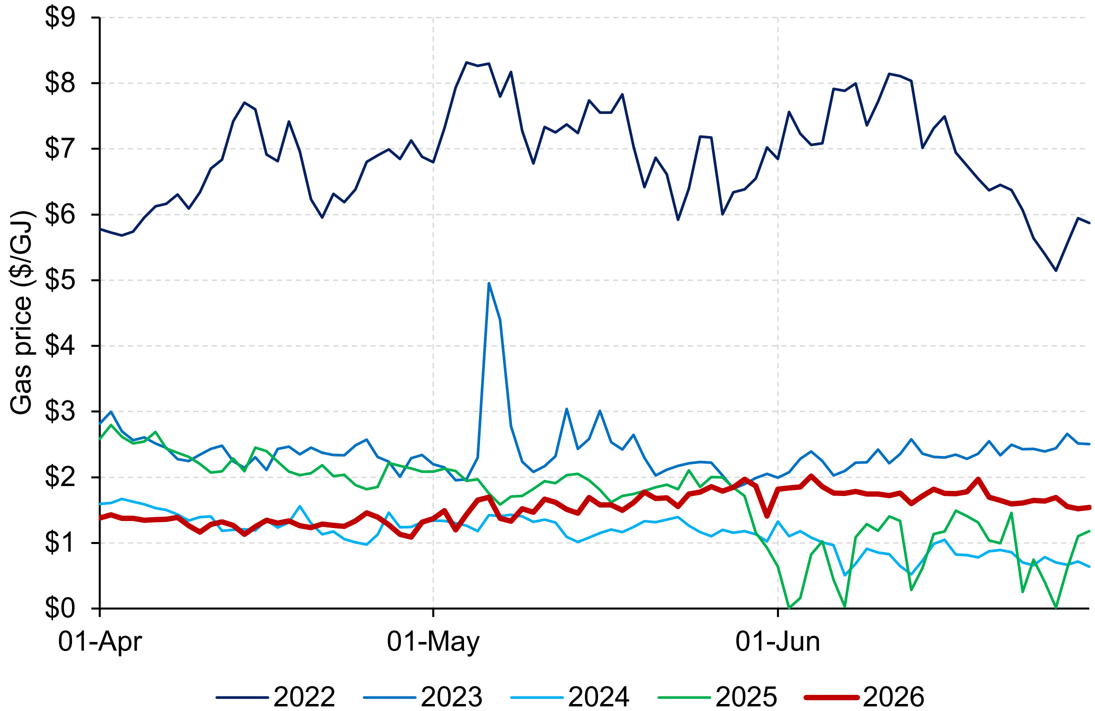
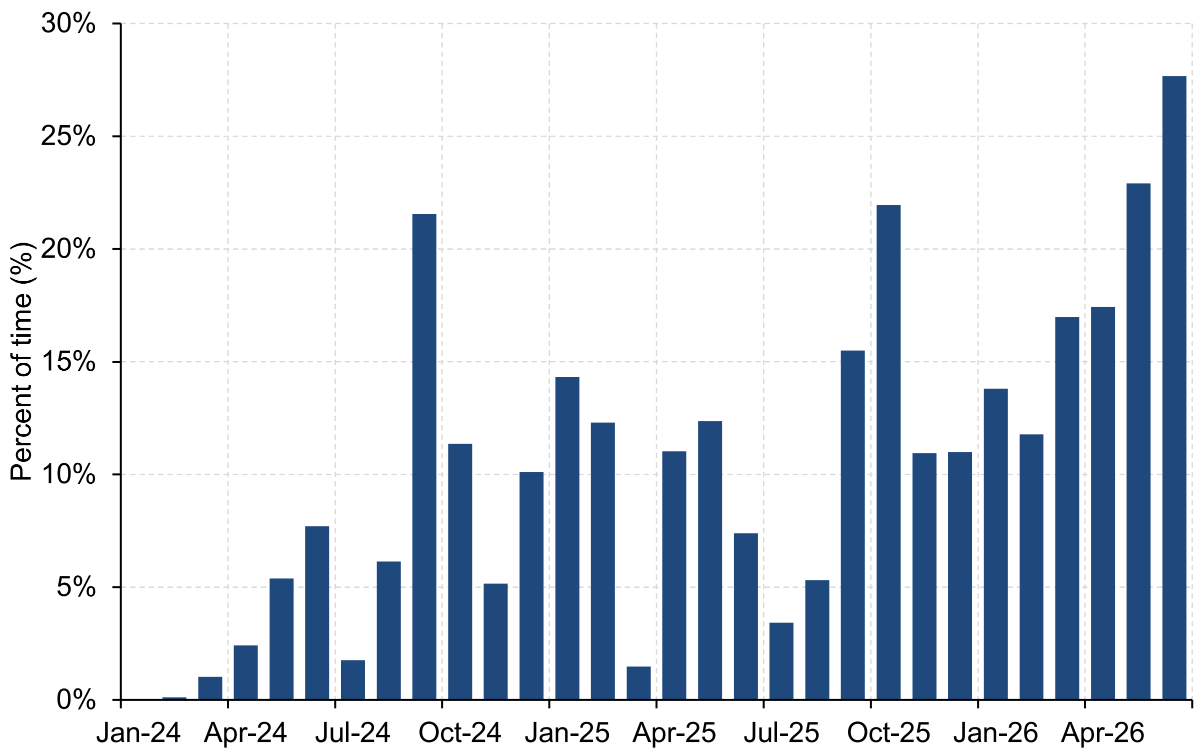


Figure 5: Percent of time the SMP was $0/MWh (January 2024 to June 2026)

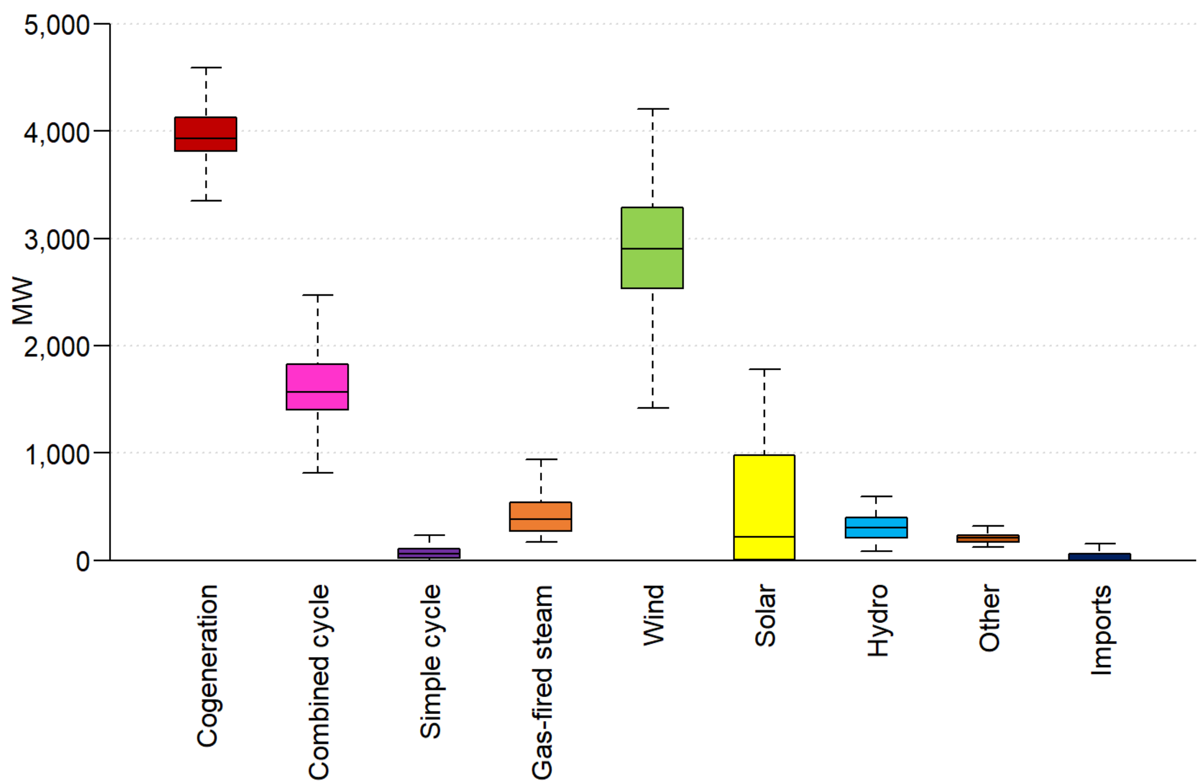


In Q2, the SMP was $0/MWh 23% of the time, a new quarterly record and up from 10% in Q2 2025 and 5% in Q2 2024. The increase in the percent of time the SMP was $0/MWh was driven by higher wind generation and more gas capacity being offered at $0/MWh. The percent of time the SMP was $0/MWh was notably high in May at 23% and June at 28%, as both months surpassed the prior record of 22% in October 2025 (Figure 5).

Figure 6 shows the distribution of generation for different fuel types during minutes of $0/MWh SMP in Q2. As shown, cogeneration assets were often the highest supplier during these periods with a median generation of 3,930 MW. Wind generation was also typically high, with a median generation of 2,910 MW. The median output of combined cycle assets was lower at 1,560 MW. In terms of generation relative to maximum capability, combined cycle was 39% while cogeneration was 64%.

The median generation of solar assets was 213 MW, close to its lower quartile. This illustrates that $0/MWh SMP periods generally occurred at night, when solar output was low. In a smaller number of minutes, solar output was high, creating a right-skewed distribution.

Figure 6: Distributions of generation by fuel type during minutes of $0/MWh SMP (Q2)

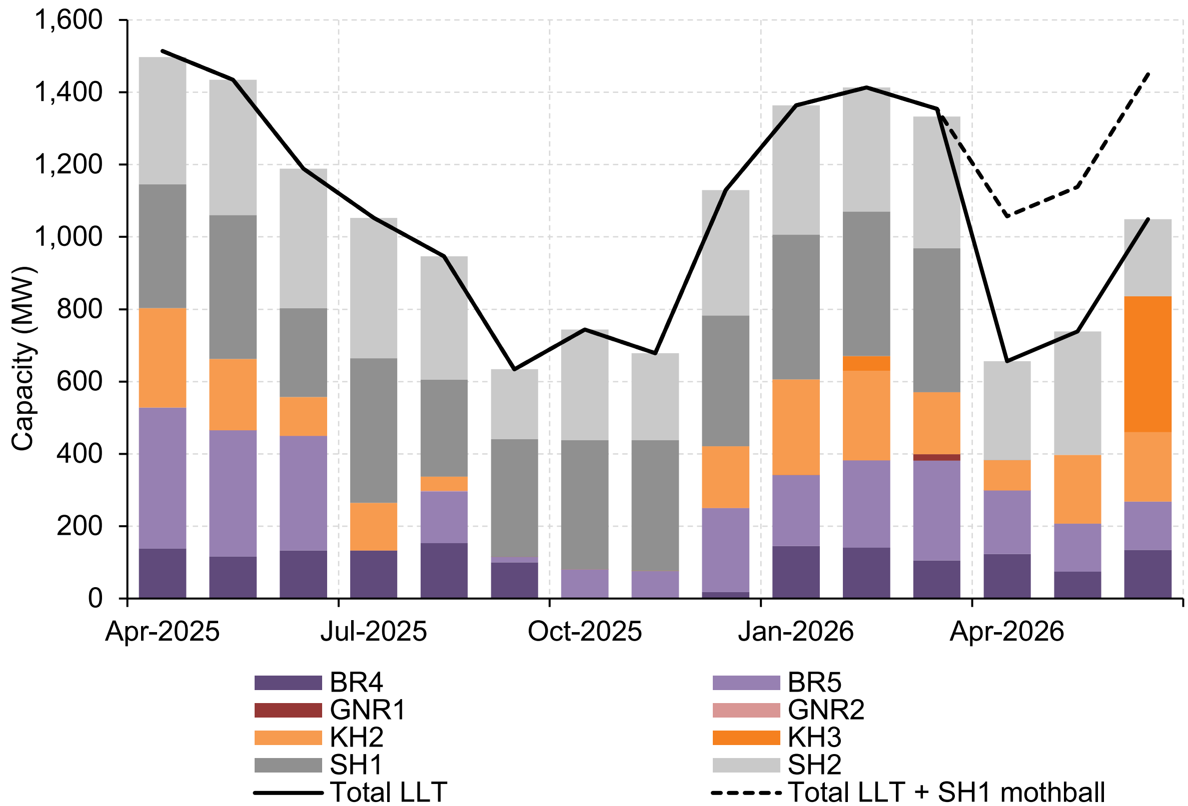


In Q2, less thermal capacity was taken commercially offline on long-lead time (LLT) or mothballed compared to Q2 2025, even though prices were lower. This caused an increase in thermal supply was a factor in the lower pool prices in April and May.

In April, an average of 657 MW of thermal capacity was commercially offline on LLT, meaning the assets required more than an hour to start-up. Assets on LLT are generally gas-fired steam generators that require 12 to 24 hours to start-up. In addition, Sheerness 1 was mothballed for commercial reasons beginning on April 1. In total, an average of 1,057 MW of capacity was on LLT or mothballed in April. In April 2025, this figure was 1,513 MW, 456 MW higher (Figure 7). The reduction in thermal capacity on LLT or mothballed meant more dispatchable supply and was a cause of the lower pool prices year-over-year.

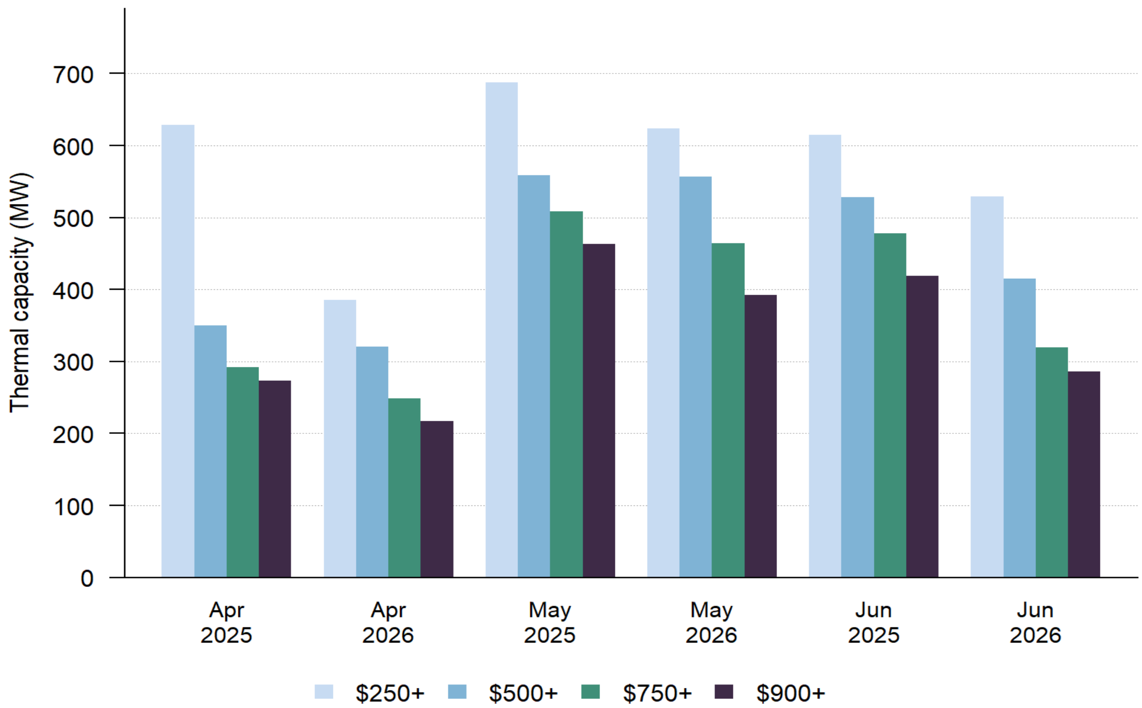
Similarly in May, the amount of thermal capacity on LLT or mothballed fell from 1,434 MW in 2025 to 1,138 MW in 2026, a decline of 296 MW, which put downward pressure on pool prices. In June, mild weather and increased wind supply led to more thermal capacity being on LLT or mothballed; 1,188 MW in 2025 and 1,449 MW in 2026.

Figure 7: Monthly average capacity on long-lead time or mothballed (April 2025 to June 2026)



In addition, there were fewer high-priced offers in Q2 compared to Q2 2025 and this was a factor in the lower pool prices. Figure 8 shows the average amount of thermal capacity offered above different price thresholds during on-peak hours. Across all months in the quarter, the amount of thermal capacity offered above all these thresholds declined compared to Q2 2025.

Figure 8: Average amount of thermal capacity offered above select price thresholds (on-peak hours, Q2 2025 and Q2)



1.2 Market outcomes and events

1.2.1 Distribution of pool prices

The average pool price in Q2 was $29.47/MWh, 27% lower than in Q2 last year. This decline in average prices reflected lower prices across the distribution. For example, the top 10% of hours averaged $179/MWh in Q2 compared to $213/MWh in Q2 2025, and the lowest 50% of hours averaged $5/MWh in Q2 compared to $11/MWh in Q2 2025 (Table 5).

Table 5: The distribution of pool prices (Q2 and Q2 2025)

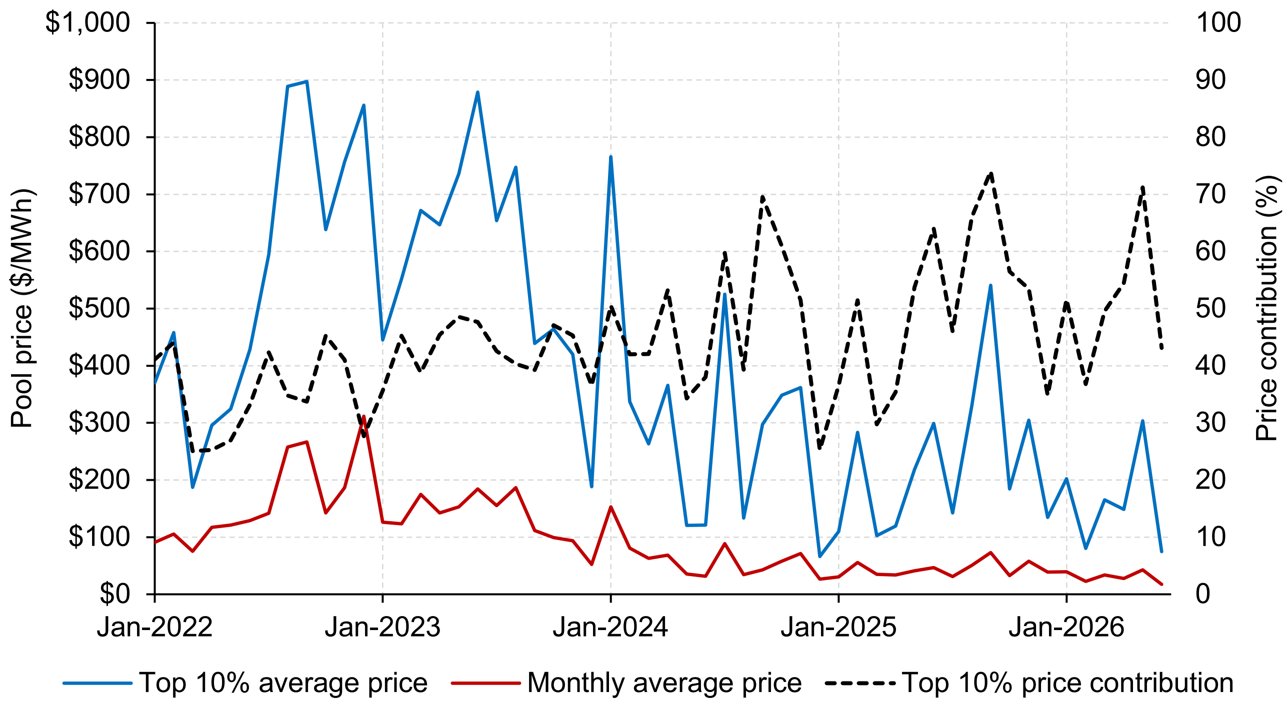
Percentile	Q2 2025 (Avg. $40.48)		Q2 2026 (Avg. $29.47)	
	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.
Top 10%	$213	52%	$179	61%
10 to 50%	$34	34%	$22	30%
Bottom 50%	$11	14%	$5	9%

Table 6 shows the distribution of pool prices for the three months in Q2. In April and June, the top 10% of hours accounted for 54% and 43% of the average pool price, respectively. These values are within the typical historical range, as shown in Figure 9. Pool price volatility in May was higher with the top 10% of hours averaging $304/MWh and accounting for 71% of the average pool price, which has only been higher once, in September 2025, going back to January 2022.

Table 6: The distribution of pool prices by month (April to June)

Percentile	April (Avg. $27.61)		May (Avg. $42.98)		June (Avg. $17.36)	
	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.
Top 10%	$148	54%	$304	71%	$75	43%
10 to 50%	$23	33%	$25	23%	$20	47%
Bottom 50%	$7	13%	$5	6%	$3	10%

Figure 9: Average pool prices and the contribution of the top 10% of hours (January 2022 to June 2026)



1.2.2 Energy Emergency Alert (May 25)

On the evening of Monday, May 25, the AESO declared an EEA from 19:10 to 21:35 due to a shortfall in supply. During this event, the AESO declared different levels of EEA and used their new communications protocol for the first time during an emergency event (Table 7).

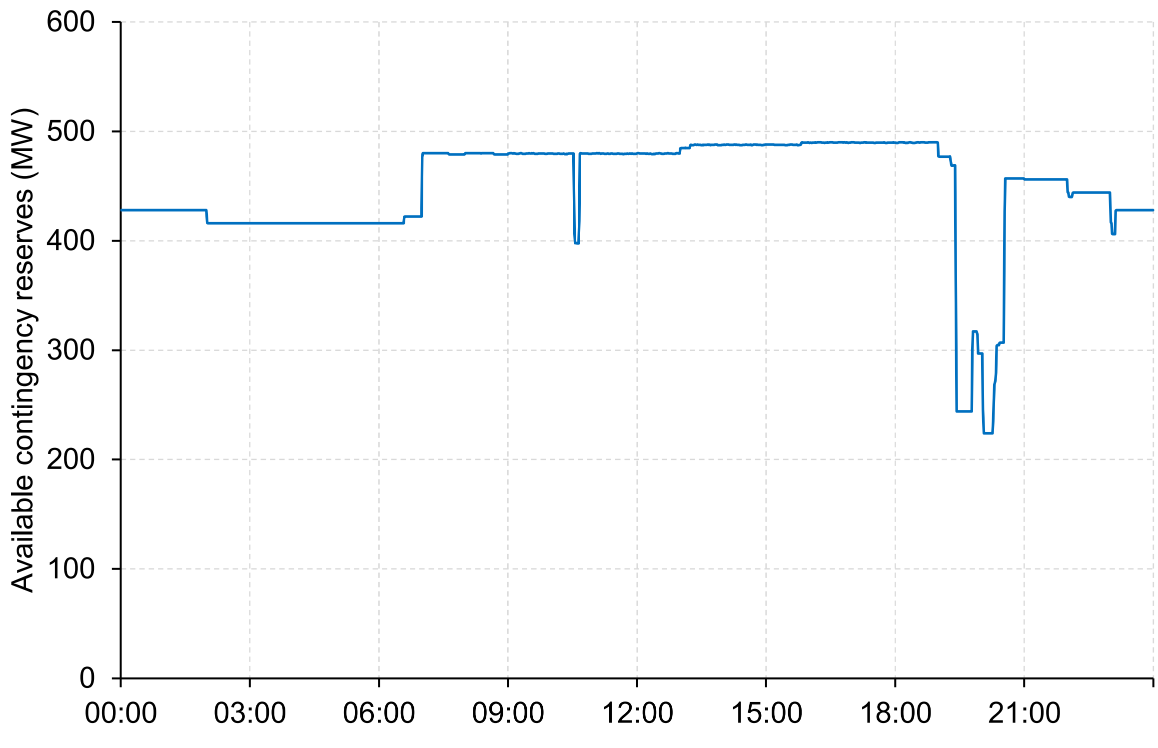
Table 7: EEA levels and AESO grid conditions (May 25)

Time	Event	AESO grid condition
19:10	EEA1	Watch
19:20	EEA2	
19:22	EEA3	Attention
20:35	EEA2	Watch
21:35	EEA0	Normal

The AESO declared an EEA1 at 19:10 to indicate that the supply curve had been exhausted. Between 19:22 and 20:35, an EEA3 was declared as the AESO were directing contingency reserves to provide energy in order to meet demand.

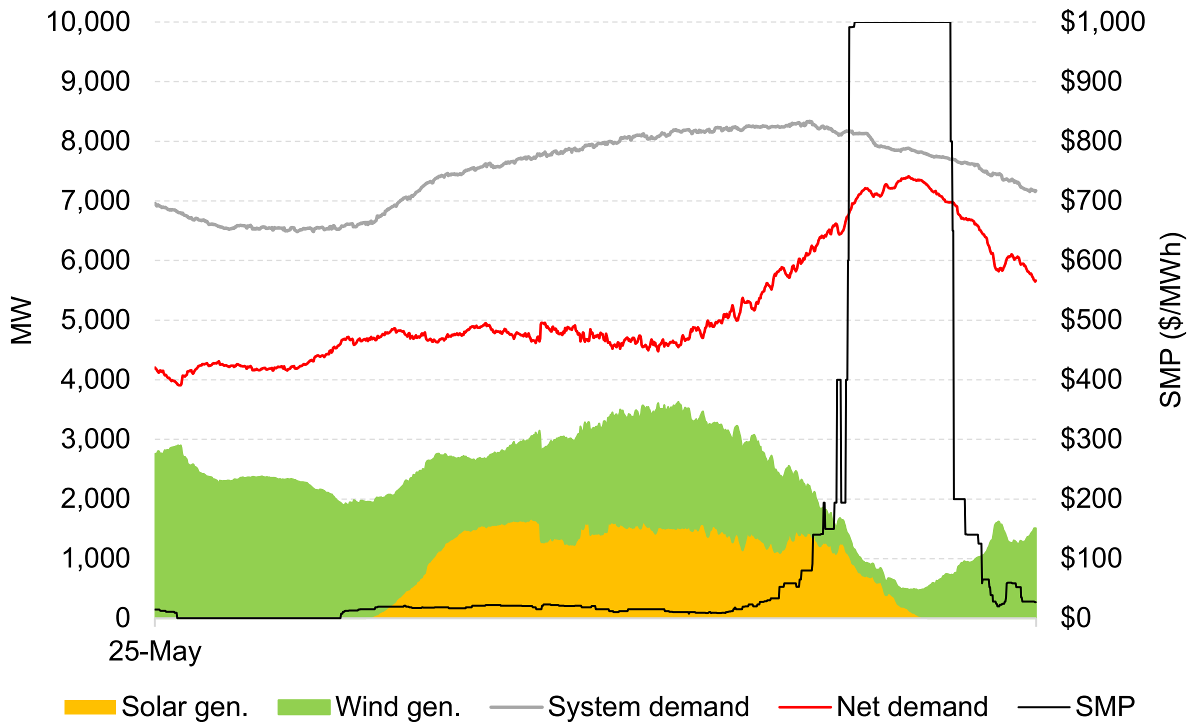
Leading into this event, the AESO had 490 MW of available contingency reserves, but this fell to a low of 224 MW due to a reduction in available reserves and because up to 233 MW of reserves were used to provide energy (Figure 10). The AESO were not required to shed firm load during this event.

Figure 10: Available contingency reserves (May 25)



The EEA event on May 25 occurred around the net demand peak, as intermittent generation declined into the evening, but demand remained elevated (Figure 11).

Figure 11: Net demand and SMP (May 25)



The supply shortfall was partly caused by Battle River 4, Battle River 5, and Sheerness 2 being commercially offline on LLT. These three gas-fired steam assets accounted for 950 MW of available capacity.

These assets were not committed by the AESO because wind generation was expected to be higher than it was (Figure 12). For instance, the AESO's "most likely" wind generation forecast for HE 21 was 1,380 MW 24 hours ahead and 1,240 MW 12 hours ahead, but actual wind generation was 350 MW.

In addition, there were ongoing outages at Cascade 2, Keephills 3, Firebag, and Joffre which further reduced supply. Major thermal generator outages totalled 2,400 MW for this event (Table 8).

Demand on May 25 was not notably high. AIL peaked at 10,725 MW in HE 18 compared to a summer record of 12,221 MW, and a peak of 11,491 MW in May. Prevailing temperatures on the day reached a high of 24°C in Calgary, 27°C in Edmonton, and 23°C in Fort McMurray.

Figure 12: AESO forecasts compared to actual wind generation (May 25)

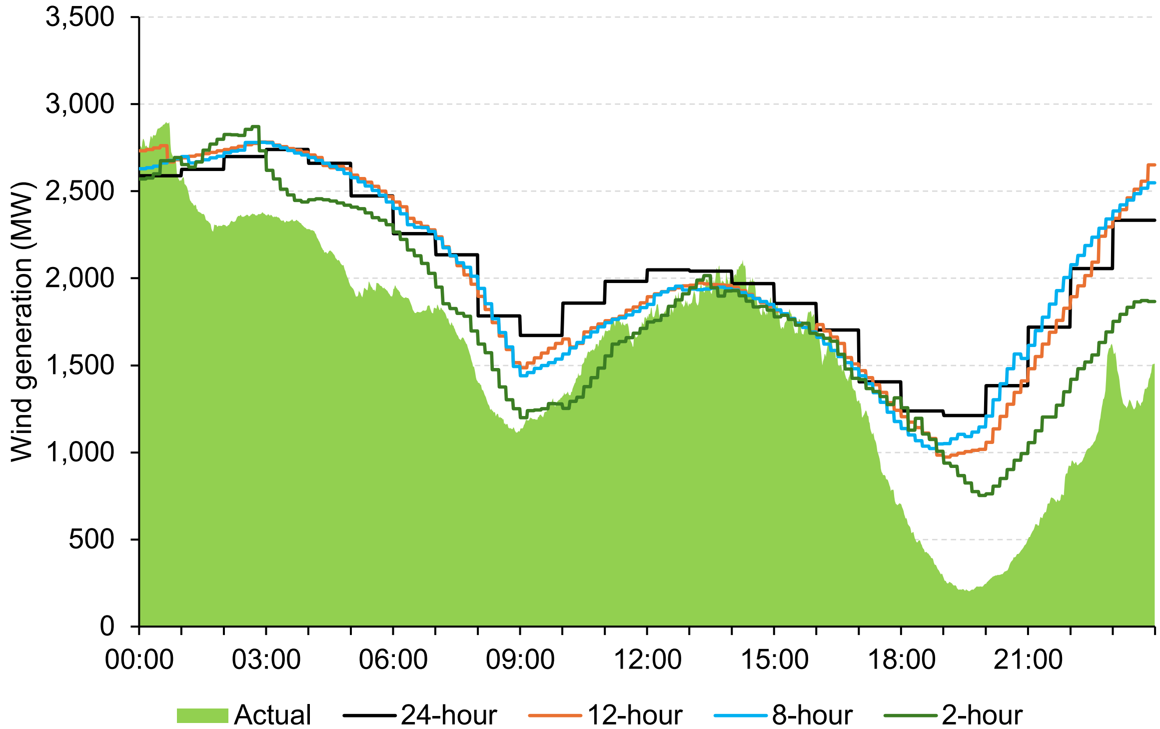


Table 8: Major generator outages (May 25, HE 21)

Asset name	Asset ID	Fuel type	Capacity on outage (MW)
Cascade 2	CAS2	Combined cycle	466
Keephills 3	KH3	Gas-fired steam	466
Firebag	SCR6	Cogeneration	417
Joffre CT201	JOF1	Cogeneration	210
Poplar Creek	SCR5	Cogeneration	156
Base Plant	SCR1	Cogeneration	136
Nexen 2	NX02	Cogeneration	135
Muskeg River	MKR1	Cogeneration	125
Nexen 1	NX01	Combined cycle	120
Dow Hydrocarbon	DOWG	Cogeneration	105
Syncrude	SCL1	Cogeneration	100

Imports on the BC/MATL intertie made full use of the available transmission capability (ATC) during this event, as prices in Mid-C were lower, in the CAD$30/MWh range. In HE 19, import ATC was 450 MW and import offers totalled 800 MW, and in HE 20 import ATC was 441 MW and import offers totalled 1,115 MW.

At 19:48, the AESO increased import ATC on BC/MATL for HE 21 to 530 MW to help meet expected demand. At 20:19, import ATC was increased further to 730 MW, and at 20:42 it was increased to 826 MW. Import offers for HE 21 totalled 1,115 MW so importers were able to use the additional capacity. Subsequently, the AESO lowered import ATC down to 730 MW at 21:00, to 480 MW at 21:09, and to 406 MW at 21:16.

On the Saskatchewan intertie, Alberta was scheduled to export 50 MW in HE 19 and HE 20 despite the high pool prices, but these volumes were curtailed. These exports were also scheduled for HE 21, but at 19:33, the AESO curtailed the exports for HE 21 and set export ATC for the hour to 0 MW. The AESO increased export ATC on the Saskatchewan intertie to normal levels at 21:00.

1.2.3 BC/MATL outage and frequency events (April 13 to 18)

The BC/MATL intertie was out of service for five days in mid-April (from April 13 HE 10 to April 18 HE 15). The intertie was offline due to a scheduled outage on the transmission line 1201L. The outage was initially scheduled on March 13 to run from April 13 HE 10 to April 17 HE 17, but it was later extended.

When BC/MATL is out of service Alberta is reliant on domestic inertia and frequency response to handle contingency events, such as a large generator trip. Therefore, to increase Alberta's frequency response, the AESO procure additional Fast Frequency Response (FFR) when BC/MATL is offline.

FFR is an ancillary service supplied by batteries and loads. When armed, these assets are set to increase supply or reduce consumption almost instantaneously if frequency falls to 59.70 or 59.50 Hz.

For context, the AESO's Under Frequency Load Shedding (UFLS) is set to trip firm loads if frequency falls below 59.50 Hz. During this BC/MATL outage, the AESO generally had more than 200 MW of FFR armed, although this value fell to 140 MW between 21:11 and 23:36 on April 16.

There were three large generator trips during the BC/MATL outage (Table 9). At 14:19 on April 14, Genesee Repower 1 tripped offline from 383 MW causing frequency to fall to 59.63 Hz. During this event, the AESO had 209 MW of armed FFR and 151 MW of this tripped.

Table 9: Major frequency events during the BC/MATL outage

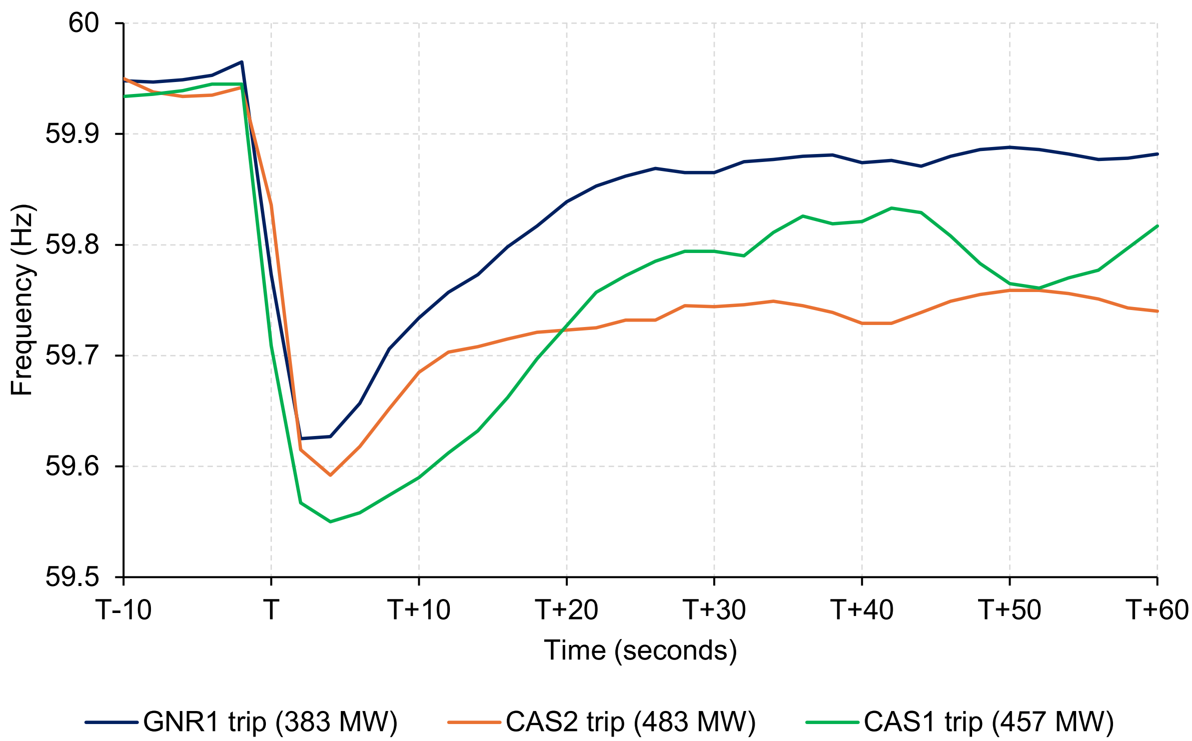
Date time	Asset ID	Gross generation loss (MW)	Frequency low (Hz)	Armed FFR (MW)	Tripped FFR (MW)
14-Apr 14:19	GNR1	383	59.625	209	151
17-Apr 19:42	CAS2	483	59.592	216	163
17-Apr 20:39	CAS1	457	59.550	314	131

On the evening of April 17, there were two large generator trips at Cascade, about an hour apart. At 19:42, Cascade 2 tripped offline from 483 MW causing frequency to fall to 59.59 Hz. At the time, the AESO had 216 MW of armed FFR and 163 MW of this tripped.

At 20:39, Cascade 1 tripped offline from 457 MW and frequency fell to 59.55 Hz. Because of the loss of Cascade 2 earlier, the AESO had 314 MW of FFR armed for this event and 131 MW of this tripped.

The evolution of system frequency around these large trips is shown in Figure 13. In all three events, frequency declined toward the UFLS threshold of 59.50 Hz. However, it is worth noting that the AESO had additional armed FFR that was not tripped in all three events.

Figure 13: System frequency around the large trip events



The unexpected loss of Cascade 1 and 2 while BC/MATL was offline on the evening of April 17 combined with low intermittent generation and planned thermal outages at Shepard CT2, Genesee Repower 2, and Joffre CT201 to lower supply. As a result, the SMP increased to $988.62/MWh at the start of HE 22 and the supply cushion fell to 38 MW with no assets commercially offline on LLT.

Outages on BC/MATL also increase routine variation in system frequency. To deal with this, the AESO procure additional regulating reserves. For most days of the BC/MATL outage, the AESO increased its target volumes for regulating reserves to 250 MW for the on-peak and 175 MW for the off-peak, both 40 MW more than normal.

However, for Thursday, April 16 the AESO's target volumes were normal at 210 MW and 135 MW. This occurred because BC/MATL was scheduled to return to service on April 15 HE 18 when the AESO were procuring regulating reserves for April 16 on the morning of April 15.

1.2.4 SMP at the floor and offer cap (May 7)

Between 20:46 and 20:59 on May 7, the SMP increased to the offer cap of $999.99/MWh. The supply cushion fell to a low of 76 MW, illustrating tight market conditions. However, the AESO were not required to direct contingency reserves to provide energy during this event.

The tight market conditions on Thursday, May 7 occurred despite mild temperatures and relatively low demand. AIL peaked at 10,396 MW compared to a high of 11,491 MW in May. When the SMP increased to the offer cap, temperatures were 17°C in Calgary, 15°C in Edmonton, and 14°C in Fort McMurray.

Thermal generator outages and low intermittent generation were the main drivers of the tight market conditions on the evening of May 7. As shown by Table 10, there was over 3,200 MW of thermal generation capacity on outage in HE 21, including planned outages at Shepard CT2 and Genesee Repower 2.

Table 10: Major generator outages (May 7, HE 21)

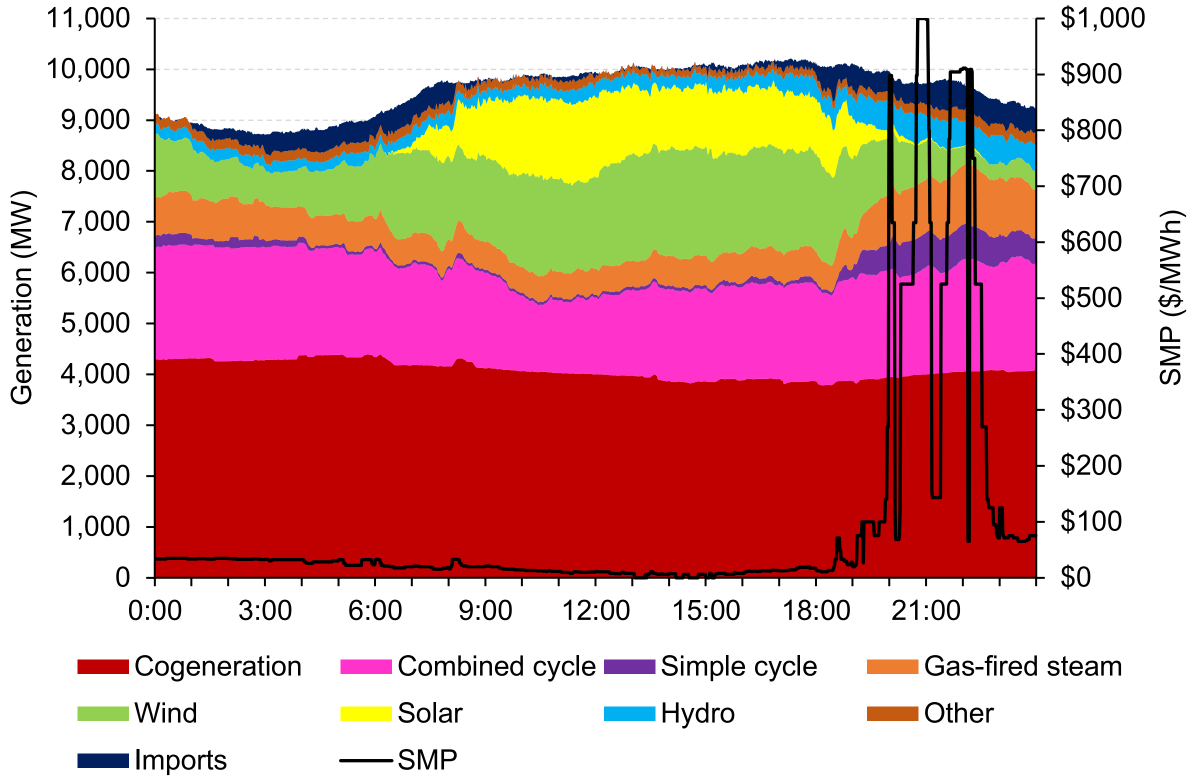
Asset name	Asset ID	Fuel type	Capacity on outage (MW)
Shepard CT2	EGC1	Combined cycle	488
Genesee Repower 2	GNR2	Combined cycle	466
Keephills 3	KH3	Gas-fired steam	466
Firebag	SCR6	Cogeneration	417
Keephills 2	KH2	Gas-fired steam	395
Calgary Energy Centre	CAL1	Combined cycle	215
Joffre CT201	JOF1	Cogeneration	210
Nexen 1	NX01	Combined cycle	120
Fort Hills	FH1	Cogeneration	119
Mahkeses	IOR1	Cogeneration	113
City of Medicine Hat	CMH1	Combined cycle	109
Christina Lake	MEG1	Cogeneration	85

The SMP on May 7 was highest around the net demand peak; when demand was still elevated but solar generation had declined (Figure 14). Wind generation was also relatively low at the time. During the SMP peak, wind generation averaged 760 MW and solar generation averaged 40 MW, so total intermittent generation was 800 MW.

Intermittent generation was higher earlier in the day, supplying up to 3,600 MW (Figure 14). As a result, prices were much lower. Indeed, the SMP cleared at the price floor of $0/MWh from 14:32 to 14:41 and from 15:10 to 15:13.

Over the course of 5 hours and 33 minutes (from 15:13 to 20:46), the SMP increased from the floor to the offer cap as intermittent generation declined. In response to the higher prices, gas generators, hydro assets, and imports increased supply (Figure 14).

Figure 14: Generation by fuel type and SMP (May 7)



The AESO's forecasts for wind and solar generation predicted the low levels of intermittent supply on the evening of May 7. For example, the AESO's "most likely" wind forecast for HE 21 24 hours ahead was 980 MW compared actual wind generation of 910 MW. Consequently, the AESO's anticipated supply cushion fell below the 932 MW threshold and the AESO committed Sheerness 2 to be online from 19:00 to 23:00.

As a result of this unit commitment directive, Sheerness 2 came online and added 400 MW of capacity to the supply curve in HE 21. The supply cushion during this hour fell to a low of 76 MW. Without the AESO's commitment of Sheerness 2, the AESO would likely have declared an EEA3 and directed contingency reserves to provide energy. Because of the unit commitment directive for Sheerness 2, there were no assets commercially offline on long lead time for this event.

Importers on BC/MATL made full use of the ATC during on the evening of May 7. In HE 21, import ATC on BC/MATL was around 400 MW and import offers totalled 1,095 MW. However, on the Saskatchewan intertie, there were no imports or exports scheduled for HE 21 despite 153 MW of ATC.

The SMP declined from the offer cap at 20:59, and prices fell further later in the evening as demand declined and Genesee Repower 2 returned from a planned outage. Between 22:15 and 22:55, the SMP fell from $905/MWh to $75/MWh.

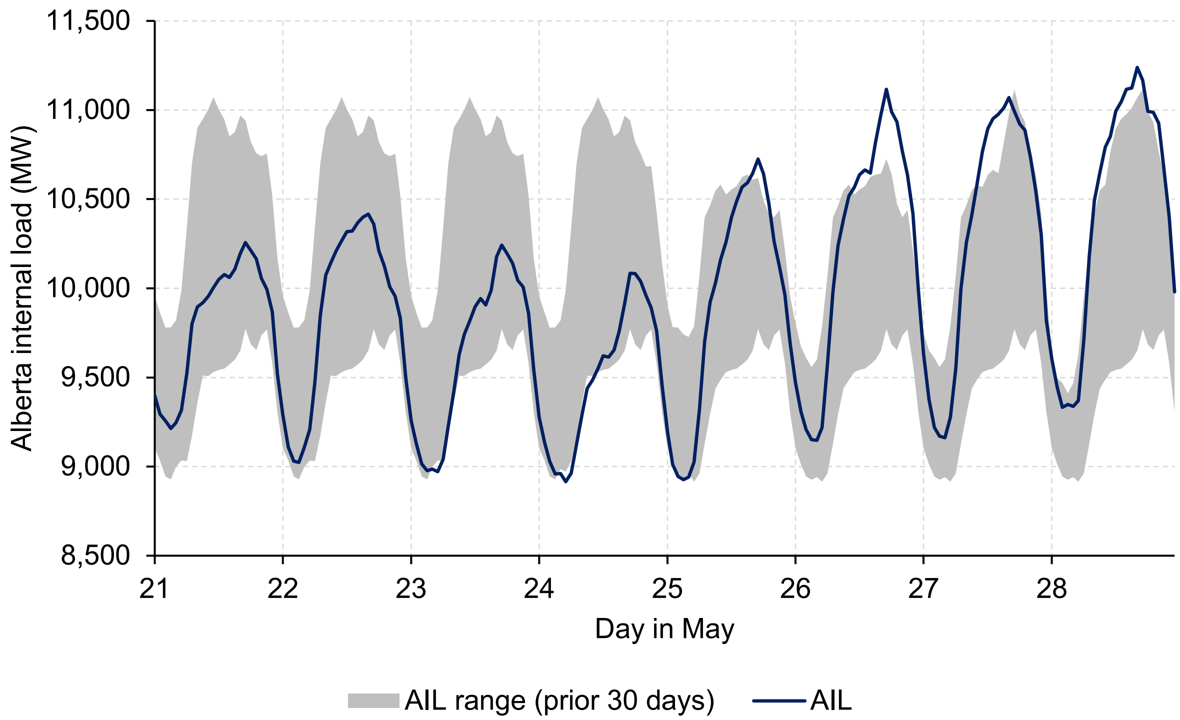
1.2.5 SMP at the offer cap (May 28)

The daily average pool price on Thursday, May 28 was $384/MWh, the highest in the quarter and the highest since September 8, 2025. The pool price cleared above $980/MWh for eight consecutive hours: from HE 16 to 23. Prices were also elevated on May 27, with the daily average pool price settling at $270/MWh.

Prices on both days were highest around the net demand peak. In HE 21 on May 28, the pool price cleared at $999.99/MWh as the SMP was at the offer cap for the entire hour. In HE 20, the pool price was only slightly lower at $999.48/MWh.

The high prices on these days were partly the result of elevated demand as temperatures were high across the province (Figure 15). On May 28, temperatures peaked at 26°C in Calgary and 29°C in Edmonton and Fort McMurray. As a result, AIL reached 11,239 MW, which is high for this time of year.

Figure 15: Hourly AIL (May 21 to 28)



Wind generation was low for most of the day (Figure 16). In the late afternoon, wind generation was notably low, supplying under 100 MW in HE 17. However, wind generation increased later as solar generation declined. In HE 21, wind generation averaged 570 MW and in HE 22 it averaged 970 MW.

In addition, supply on May 28 was lowered by thermal generation outages. Cascade 1 and 2 were both offline for planned maintenance, and there were outages at Firebag and Joffre. Overall, major thermal outages totalled 2,500 MW for this event (Table 11).

Figure 16: Net demand and SMP (May 26 to 29)

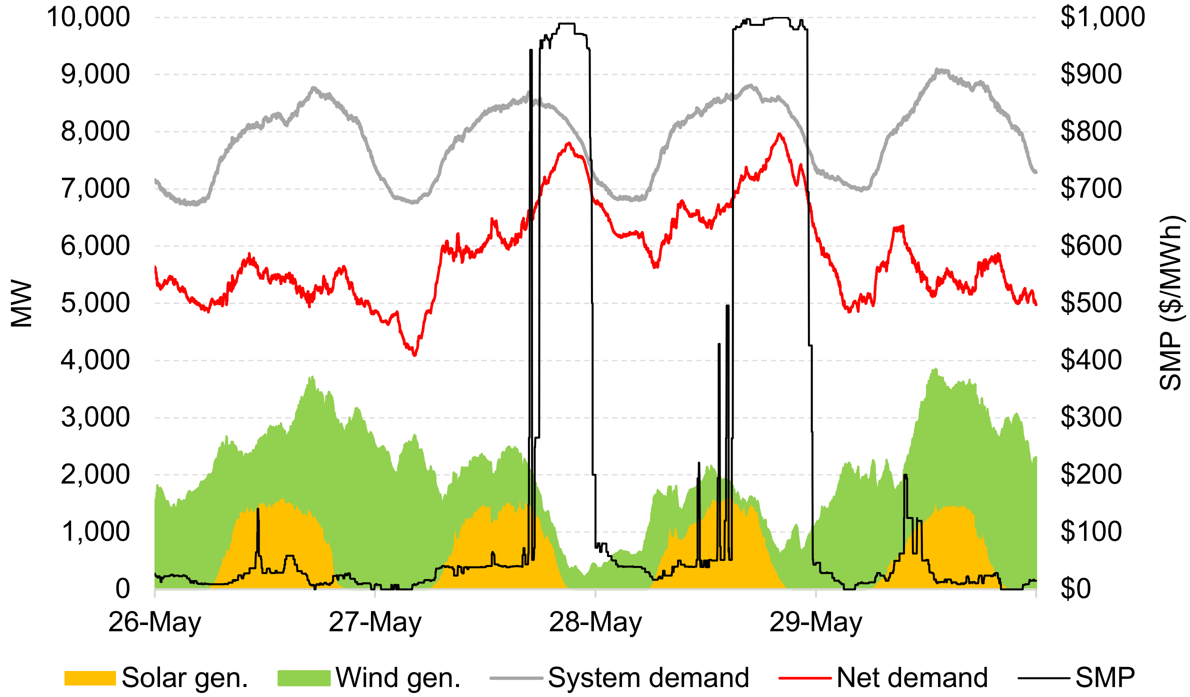


Table 11: Major generator outages (May 28, HE 21)

Asset name	Asset ID	Fuel type	Capacity on outage (MW)
Cascade 1	CAS1	Combined cycle	466
Cascade 2	CAS2	Combined cycle	466
Firebag	SCR6	Cogeneration	420
Joffre CT201	JOF1	Cogeneration	210
Base Plant	SCR1	Cogeneration	146
Nexen 2	NX02	Cogeneration	140
Muskeg River	MKR1	Cogeneration	127
Nexen 1	NX01	Combined cycle	120
Syncrude	SCL1	Cogeneration	120
Dow Hydrocarbon	DOWG	Cogeneration	105
Cloverbar 2	ENC2	Simple cycle	101
Christina Lake	MEG1	Cogeneration	90

The low wind generation on May 28 was predicted by the AESO's forecasts. As a result, the anticipated supply cushion fell below the 932 MW threshold for multiple hours. Therefore, the AESO committed Battle River 4 to run from 13:00 until the end of the day.

The AESO's commitment of Battle River 4 increased available capacity by 155 MW for some critical hours. The supply cushion on May 28 fell to a low of 38 MW in HE 21. Consequently, without the additional supply of Battle River 4, the AESO would likely have declared an EEA3 and directed contingency reserves to provide energy.

Importers on BC/MATL responded to the high pool prices and used all the import ATC. Over the net demand peak, import ATC was around 440 MW and import offers were over 1,100 MW. On the Saskatchewan intertie, 135 MW of imports were scheduled relative to ATC of 153 MW.

1.2.6 Daily average pool price of $0 (May 31)

A few days after the pool price cleared at the offer cap on the evening of May 28, pool prices fell to the floor of $0/MWh for 34 consecutive hours: from May 31 HE 01 to June 1 HE 10. Therefore, on Sunday, May 31, the daily average pool price was $0/MWh for the second time in the quarter.

The significant decline in prices was caused by a change in weather conditions. On May 28, temperatures were elevated, with Edmonton and Fort McMurray peaking at 29°C (Table 12). However, by May 31, temperature highs in these cities had dropped to 15°C and 19°C, respectively, and the temperature in Calgary peaked at 10°C.

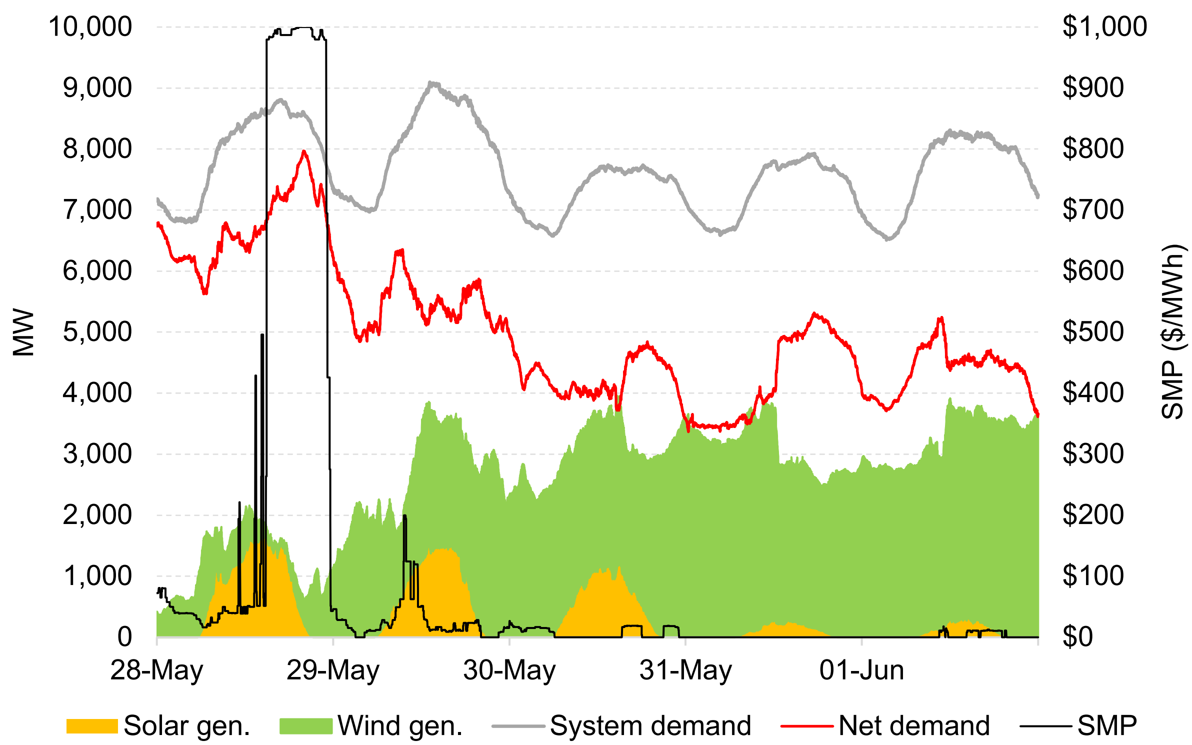
Table 12: Daily temperature highs across Alberta (°C) (May 27 to 31)

Date	Calgary	Edmonton	Fort McMurray
27-May (Wed)	26	26	23
28-May (Thu)	26	29	29
29-May (Fri)	28	30	33
30-May (Sat)	17	22	23
31-May (Sun)	10	15	19

In addition to the temperature changes, demand for electricity is lower on Sundays, largely due to less commercial and industrial activity. Overall, peak AIL fell from 11,239 MW on May 28 to 10,264 MW on May 31, a decline of around 1,000 MW.

Further to this, wind generation was higher on May 31 (Figure 17). During peak hours on May 28, wind generation averaged 480 MW, but this increased to 2,900 MW during peak hours on May 31, an increase of 2,420 MW. Wind and solar assets offer into the market at the price floor of $0/MWh because it is economic for them to supply when prices are $0/MWh due to carbon revenues.

Figure 17: Net demand and SMP (May 28 to Jun 1)



The low pool prices on May 31 were also a function of transmission congestion. Just before 13:00, there was a forced outage on EATL due to excessive rainwater pooling in the valve hall. As a result of this transmission outage, the AESO curtailed around 900 MW of wind generation (Figure 17). This increase in congestion drove the constrained SMP from $17.99/MWh to $27.95/MWh while the unconstrained SMP remained at $0/MWh (Figure 18).

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 the hourly pool price. Offer blocks that are dispatched above the unconstrained SMP are paid their offer price.

Despite the low pool prices on May 31, gas generators continued to provide large amounts of supply (Figure 19). Cogeneration assets supplied an average of 3,700 MW (38% of total supply), combined cycle assets supplied 1,530 MW (16% of total supply), and gas-fired steam assets supplied 600 MW (6% of total supply).

Figure 18: The constrained and unconstrained SMP (May 31)

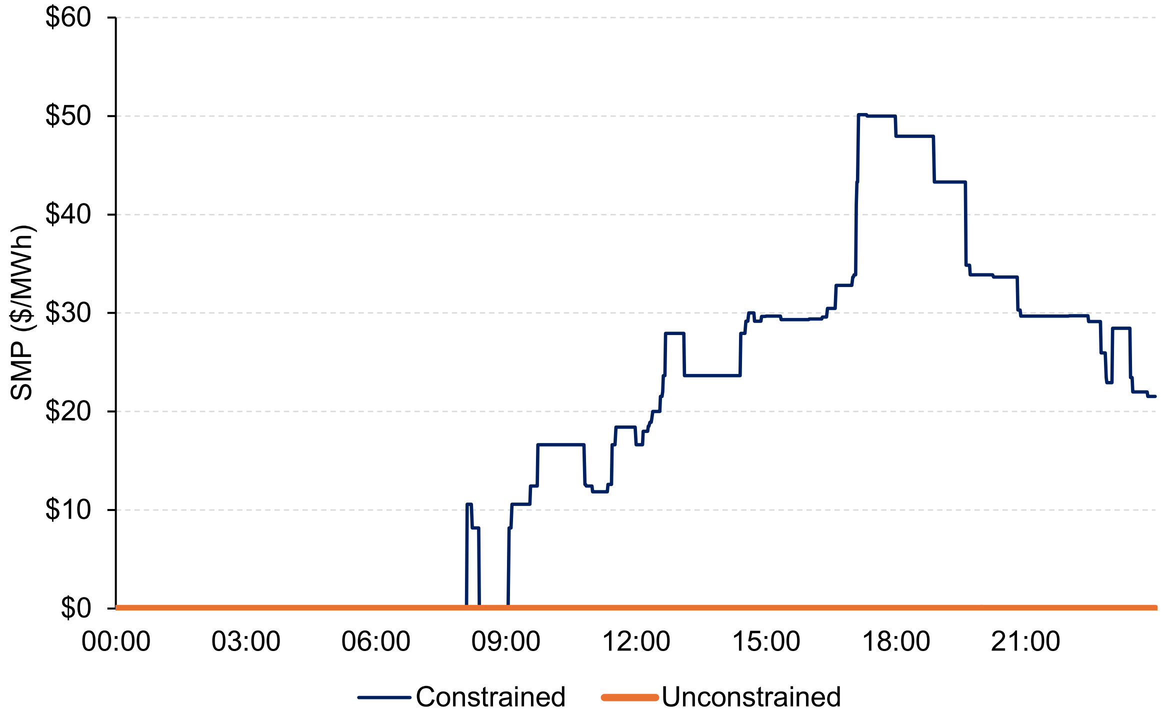
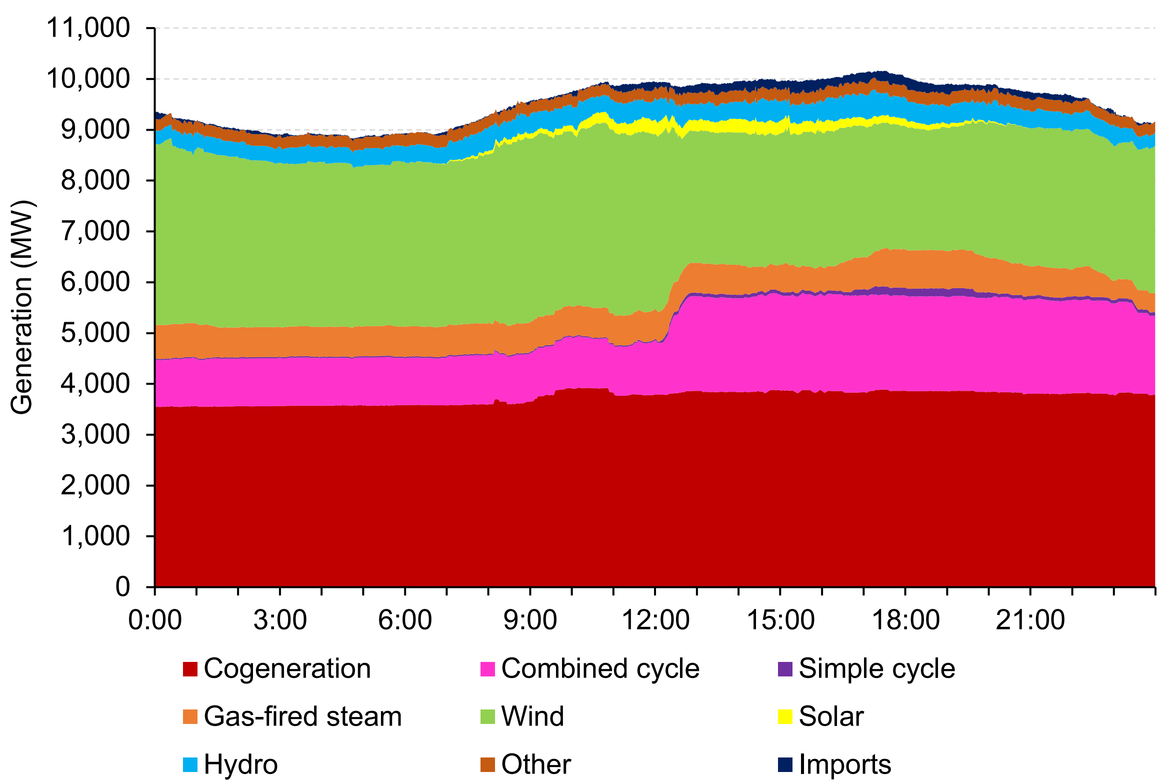


Figure 19: Generation by fuel type (May 31)



For most cogeneration assets in Alberta, electricity is a biproduct of oil production and its generation is necessary to ensure steam supply. Combined cycle and gas-fired steam assets have minimum stable generation levels and cannot be run below this amount. Start-up and shutdown costs for these assets can be prohibitively expensive relative to the losses incurred by generating when prices are $0/MWh. This is why gas assets often continue to operate when pool prices are $0/MWh.

Power prices were also low in other jurisdictions on May 31. In California, real-time prices in NP15 and SP15 were around negative CAD$15/MWh for much of the day, reflecting solar generation. In addition, high hydro flows in the Pacific Northwest and BC led to low prices in Mid-C. As a result, Alberta was an importer of power despite the $0/MWh pool prices. Specifically, there were more than 100 MW of imports from HE 12 to 22, with the power largely coming across MATL.

Between 00:23 and 08:04, the AESO declared supply surplus, indicating that demand for electricity was below the amount of generation offered at $0/MWh. Due to the supply surplus conditions, the AESO curtailed imports on MATL from 200 to 0 MW during HE 01, and from 140 to 0 MW for HE 02.

1.2.7 The constrained SMP at $999.98/MWh (May 13)

Between 08:49 and 09:07 on Wednesday, May 13, the constrained SMP increased to $999.98/MWh, reflecting tight market conditions. The unconstrained SMP at the time was lower, ranging from $61.24/MWh to $63.59/MWh (Figure 20).

The large difference between the constrained and unconstrained SMP was driven by transmission congestion. The MSA estimates that there was around 900 MW of constrained intermittent generation when the constrained SMP peaked, most of it being wind generation.

This transmission congestion was largely due to EATL being out of service. EATL was on outage from May 4 to 15 for annual planned maintenance, with the outage initially approved by the AESO in late January.

The high constrained prices on May 13 were not a function of elevated demand. AIL peaked at 10,638 MW in HE 16 and was only 10,186 MW in HE 10. These demand levels reflected mild weather; temperatures peaked at 23°C in Calgary, 20°C in Edmonton, and 25°C in Fort McMurray.

The high constrained prices on May 13 were not the result of low intermittent generation (Figure 21). When the constrained SMP peaked to $999.98/MWh around 09:00, wind generation was 1,650 MW and solar generation was 530 MW. In total, intermittent generation was 2,180 MW despite the large volume of curtailments.

Figure 20: Constrained and unconstrained SMP (May 13 and 14)

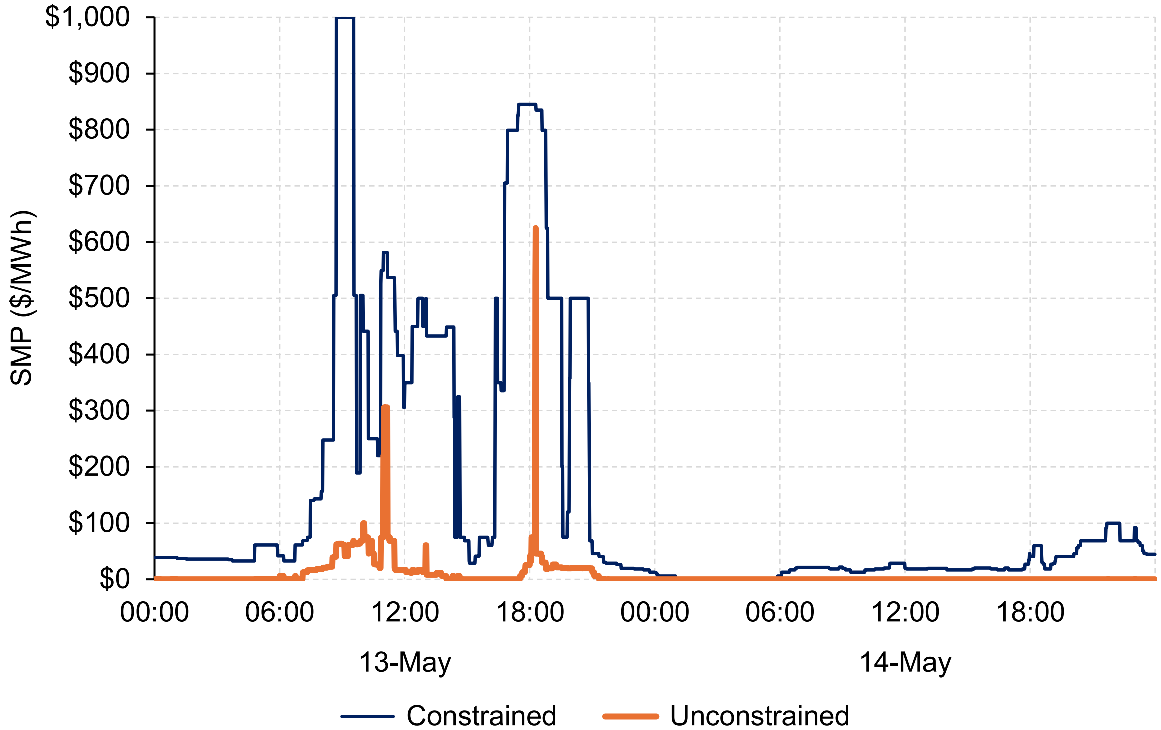
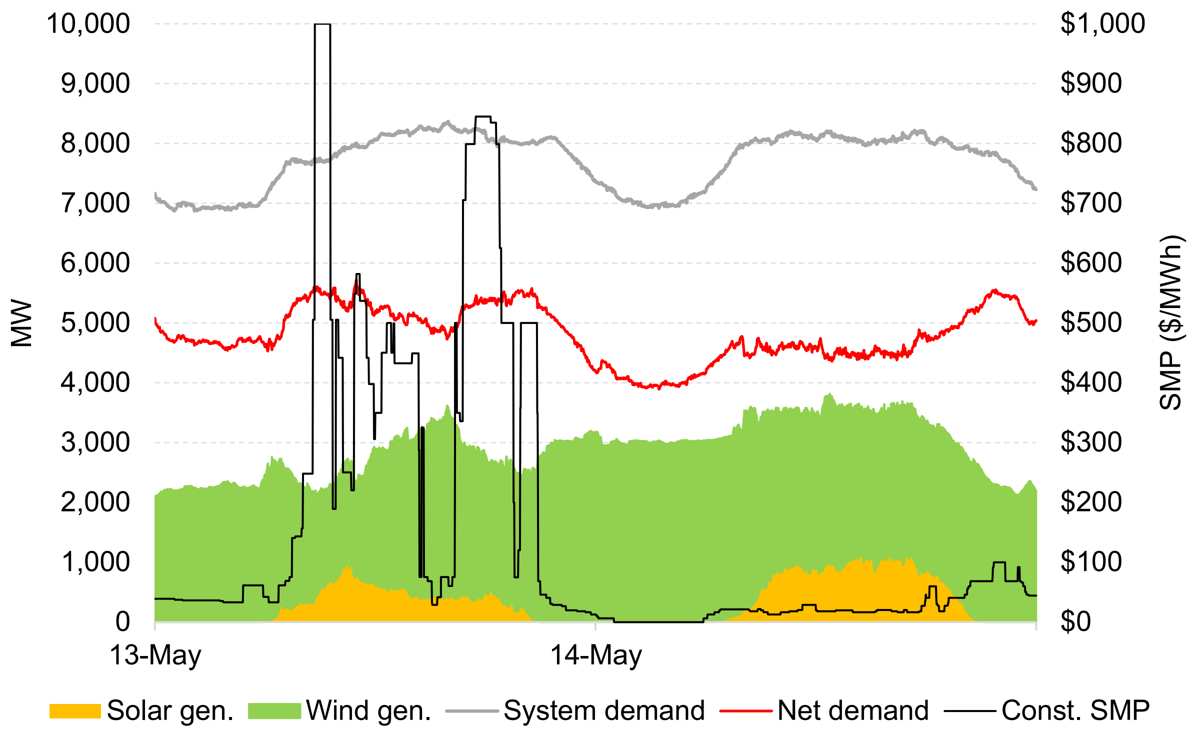


Figure 21: Net demand and the constrained SMP (May 12 to 15)



The high constrained prices on May 13 were partly driven by generator outages (Table 13). The Shepard asset was heavily derated due to a planned outage on CT2. In addition, there was an extended forced outage on Keephills 3, HR Milner was offline for planned maintenance, gas units 8 to 11 were unavailable at Firebag, and Joffre CT201 was offline for an extended forced outage. In total, more than 2,400 MW of thermal capacity was on outage in HE 10.

Table 13: Major generator outages (May 13, HE 10)

Asset name	Asset ID	Fuel type	Capacity on outage (MW)
Shepard CT2	EGC1	Combined cycle	528
Keephills 3	KH3	Gas-fired steam	466
Firebag	SCR6	Cogeneration	415
HR Milner	HRM	Combined cycle	300
Joffre CT201	JOF1	Cogeneration	210
Muskeg River	MKR1	Cogeneration	121
Nexen 1	NX01	Combined cycle	120
Fort Hills	FH1	Cogeneration	116
Northern Prairie Power Project	NPP1	Simple cycle	105

Further to this, due to high wind generation forecasts, Battle River 4 (available capacity of 155 MW), Battle River 5 (395 MW), Keephills 2 (395 MW), and Sheerness 2 (400 MW) were all scheduled to be commercially offline on LLT time on May 13. In total these assets accounted for 1,345 MW of available gas-fired steam capacity.

In addition, Cascade 2 (466 MW) was taken commercially offline in the early morning hours as the asset's entire capacity was offered at $999.99/MWh. Although it went offline, the asset did not go on LLT time because it's able to start in under an hour.

The AESO's wind forecasts for May 13 were elevated and based on an uncongested transmission system (Figure 22). The forecast for HE 10 24 hours ahead was 2,520 MW, and the forecast 12 hours ahead was 2,280 MW. Actual wind generation in HE 10 was lower at 1,600 MW. These forecast errors were largely driven by the transmission congestion. Closer to real-time, the AESO's wind forecasts were more reflective of actual generation because these forecasts consider prevailing wind generation.

However, when analyzing the need for unit commitments, the AESO calculate the anticipated supply cushion by factoring in expected transmission congestion. As a result, the anticipated supply cushion fell below the 932 MW threshold for multiple hours on May 13. Therefore, the AESO issued unit commitment directives to Battle River 4 and 5 (Figure 23).

Both Battle River 4 and 5 were committed by the AESO starting in HE 10 on May 13, adding 550 MW of capacity, although the generation was not available immediately. When the constrained SMP peaked to $999.98/MWh around 09:00, the supply cushion fell to a low of 662 MW (which does not include the capacity of Battle River 4 and 5).

Figure 22: AESO wind forecasts versus actual wind generation (May 13 and 14)

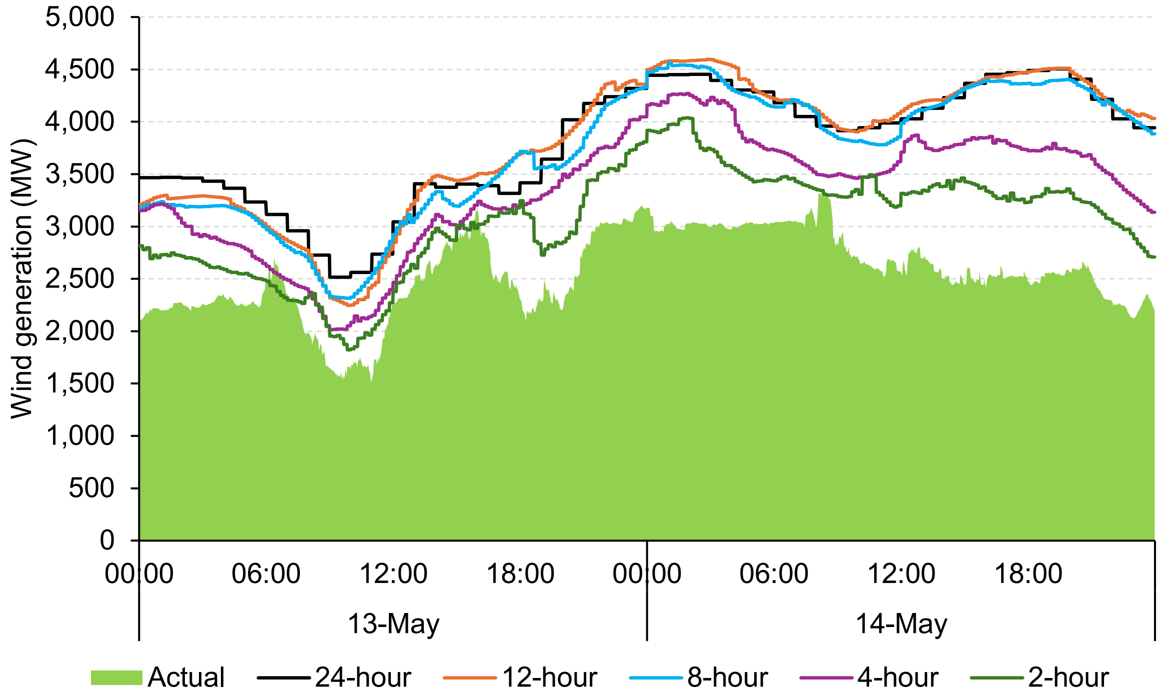
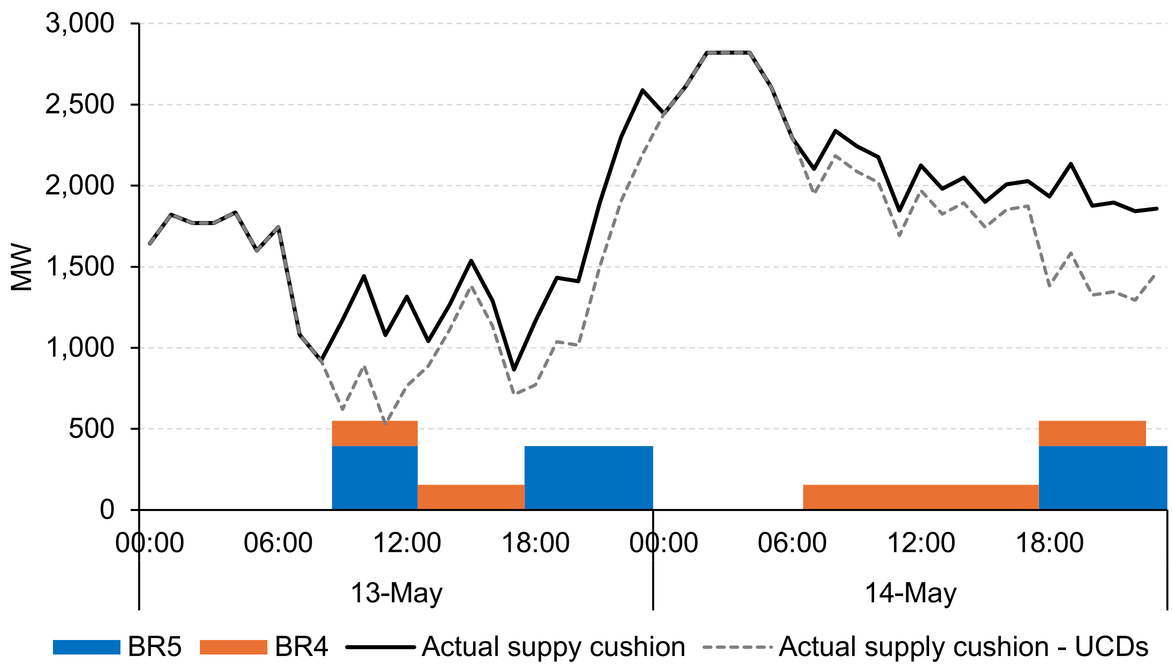


Figure 23: Unit commitment directives and actual supply cushion[2] (May 13 and 14)



[2] Actual supply cushion is the available capacity that was priced at or above the constrained SMP and was not dispatched. The calculation subtracts applicable TMR volumes and excludes load bids and capacity offered at $0/MWh.

Imports into Alberta are compensated based on prevailing pool prices. Therefore, importers had less incentive to flow into Alberta for this event. Although the constrained SMP peaked at $999.98/MWh, the pool price for HE 10 was $59.96/MWh. While prices in Mid-C were lower at CAD$7.71/MWh, Alberta was exporting 40 MW on MATL in HE 10, and there were no offers to import or export on the BC or Saskatchewan interties.

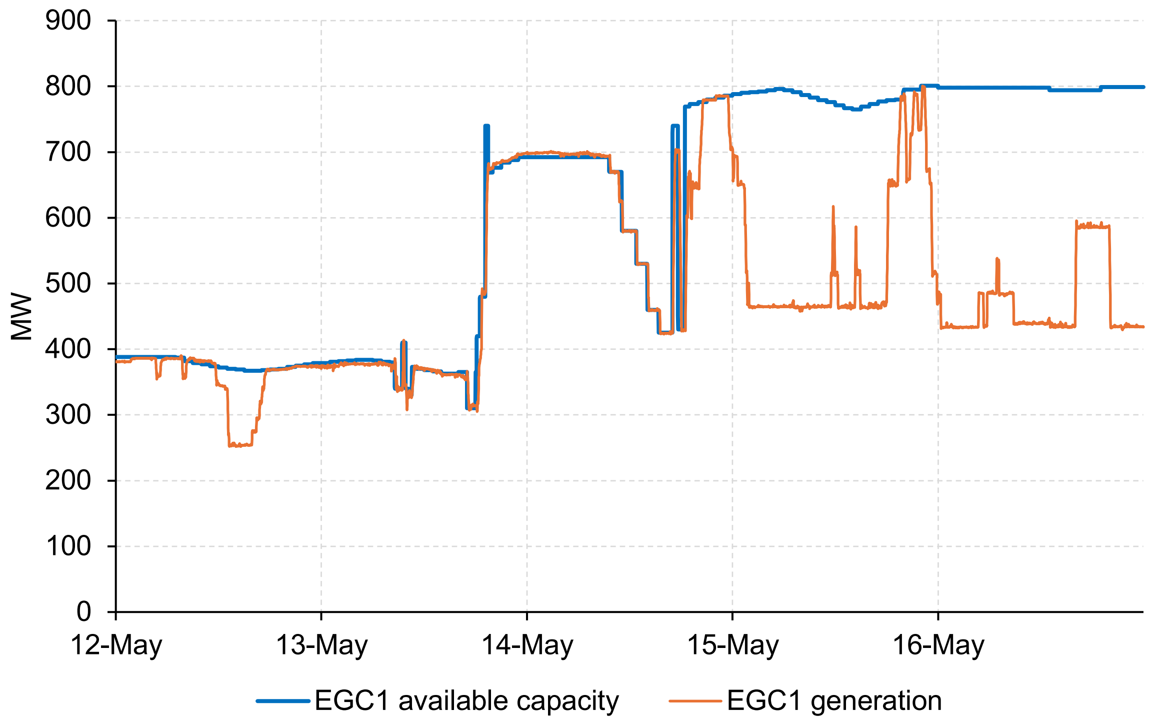
1.2.8 The first daily average pool price of $0/MWh (May 14)

The following day, on Thursday, May 14, the pool price was $0/MWh in every hour for the first time in market history. The low pool prices reflected high wind generation, large amounts of transmission congestion, and high volumes of must-run gas generation.

In addition, demand on May 14 was relatively low with AIL peaking at 10,619 MW in HE 18 as temperatures peaked at 19°C in Calgary, 15°C in Edmonton, and 13°C in Fort McMurray.

The CT2 generator at Shepard returned to service on the evening of May 13, having been offline since April 3. As a result, supply from the Shepard asset increased from 360 to 700 MW and its supply remained elevated for much of May 14 (Figure 24).

Figure 24: Available capacity and generation at Shepard (May 12 to 16)



Further to this, wind generation on May 14 was high, averaging 2,720 MW (335 MW higher than the day before). This elevated level of wind generation occurred despite large amounts of it being curtailed due to the EATL outage. The MSA estimates that constrained intermittent generation averaged 1,930 MW over the day and increased up to 2,420 MW.

As a result of this congestion, the constrained SMP was higher than the unconstrained SMP all day. This included a period in the early morning hours when the constrained SMP was $0.01/MWh and the unconstrained SMP was $0/MWh. The price differential between the two peaked at $99.81/MWh from 21:47 to 22:19 (Figure 20).

The actual supply cushion on May 14 was elevated, remaining above 2,000 MW for the duration of the day (Figure 23). However, the AESO committed Battle River 4 and 5 to run for many of the peak hours (Figure 23). The AESO issued unit commitments to these assets in advance and close to real-time, despite the large supply cushion.

These unit commitments resulted from issues with the AESO's calculation of anticipated supply cushion. Some of the AESO's anticipated supply cushion calculations subtracted congestion volumes from wind and solar forecasts that already included congestion impacts. Therefore, for anticipated supply cushion estimates within 12 hours of real-time, congestion was effectively being double counted. Due to the high volumes of congestion on May 14, this materially lowered the AESO's supply cushion estimates and led to some unit commitments that should not have been issued. The MSA understands that the AESO has since addressed this matter.

The low pool prices on May 14 were also a function of low prices in other markets. Despite pool prices being $0/MWh, Alberta did not see large volumes of exports. On the BC intertie there were no imports or exports over the day. While prices in Mid-C were higher than in Alberta, averaging CAD$8.05/MWh, they were not high enough to justify the costs of transmission to export. Prices at NP15 in California were negative for much of the day, although they did rise to around CAD$40/MWh in the evening and so there were some exports on MATL during this period (up to 150 MW).

As outlined above, large amounts of must-run gas generation are a major cause of $0/MWh pool prices. Cogeneration supply is needed to ensure steam for oilsands operations, while combined cycle and gas-fired steam assets are expensive to shut down and start back up and cannot be run below minimum stable generation levels. Consequently, despite pool prices being $0/MWh all day, cogeneration assets supplied an average of 3,800 MW, combined cycle assets supplied 2,000 MW, and gas-fired steam assets supplied 320 MW. Overall, gas generation accounted for 63% of total supply over the day.

1.2.9 Frequency declined to 59.80 Hz (April 27)

At 11:30 on April 27, system frequency in Alberta fell to 59.80 Hz due to an external power system event. Preliminary analysis indicates that a 500 kV line was taken out of service in Arizona because of protection issues. This resulted in oscillations occurring on the system, so additional 500 kV switching was initiated and caused the open ending of a large area of renewable generation in Arizona, around 1,600 MW. This event led to imports on the BC intertie instantaneously falling to 352 MW compared to a schedule of 495 MW. On MATL, exports increased to 45 MW compared to a schedule of 0 MW.

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 unavoidable costs of a reference combined cycle generating unit.

The secondary offer price limit was not triggered in Q2. Pool prices remained low for most of the quarter, resulting in negative hourly net revenues in a large share of hours (Table 14). Consequently, the MCSINR stayed below the threshold in all three months.

Table 14: Share of hours in which the reference combined cycle generator earned negative revenue (Q2)

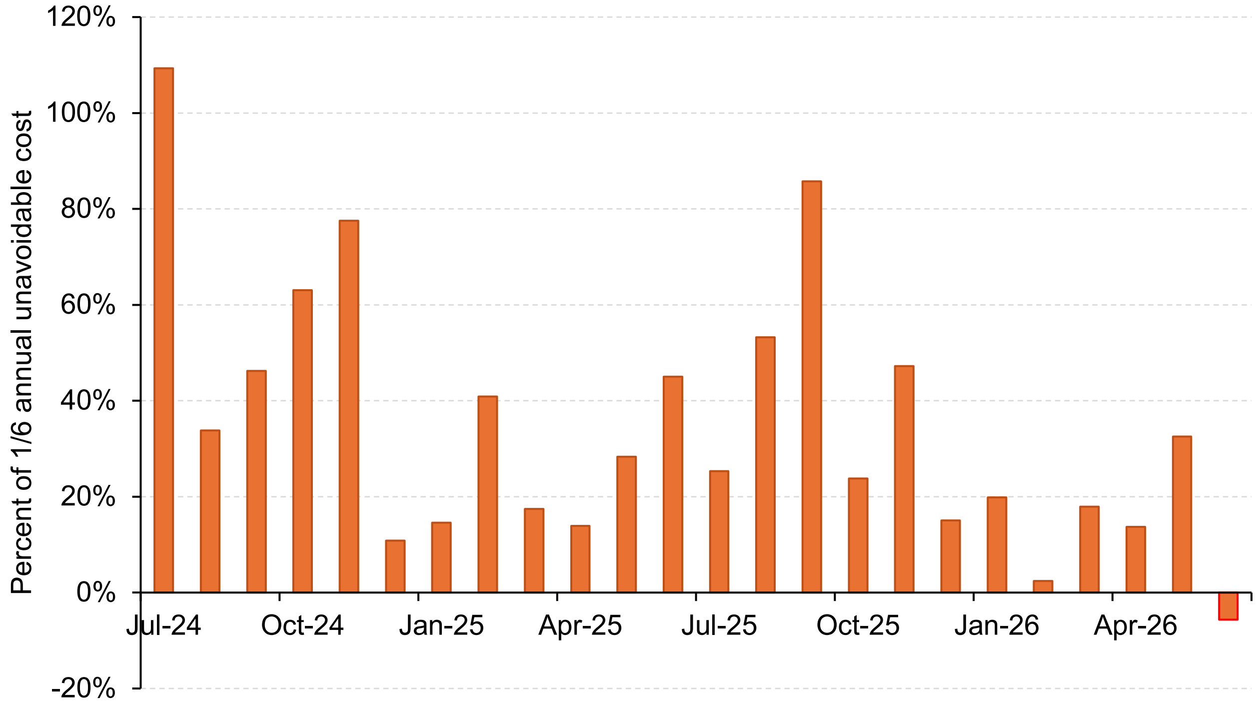
Month	Percentage
April	58%
May	60%
June	69%

In April, low pool prices early in the month held the MCSINR down. However, some high prices later in the month pushed it upward, and the MCSINR reached a peak of 14% of the threshold by the end of the month.

May followed a similar pattern. Low pool prices early in the month kept the MCSINR low, while higher prices later in the month, as discussed in section 1.2, raised it sharply. The MCSINR peaked at 34% of the threshold on May 29 HE 13. Low pool prices over the remainder of the month pushed it down slightly, and May closed at 33% of the threshold.

As noted in section 1.1, June recorded the lowest average pool price on record after adjusting for inflation. Table 14 shows that 69% of hours in June returned negative hourly revenue, and revenue in the remaining hours was modest. As a result, June became the first month in which the MCSINR closed below zero, ending at negative 6% of the threshold (Figure 25). A negative MCSINR means the reference unit's losses in negative revenue hours outweighed its earnings in positive revenue hours. The reference unit lost money over the month and was far from the revenue needed to reach the threshold.

Figure 25: Month-end MCSINR (July 2024 to June 2026)



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 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 Q2, 52 UCDs were issued by the AESO, an increase from the 23 UCDs issued in the previous quarter. This is the second highest quarterly total behind only Q4 2025, during which 61 UCDs were issued. Within Q2, nine UCDs were issued in April, 35 in May, and eight in June. The higher number of UCDs in May was driven by higher demand, low wind generation, and several large thermal generator outages, as discussed in section 1.1.

On May 14, the first day with an average pool price of $0/MWh, the AESO issued ten UCDs, the highest daily count on record. As noted in section 1.2, these UCDs were issued to Battle River 4 and 5 to run for many of the peak hours. These unit commitments resulted from an issue with the AESO's calculation of ASC.

Specifically, some of the AESO's ASC calculations subtracted congestion volumes from wind and solar forecasts that already accounted for congestion impacts. Therefore, for ASC estimates within 12 hours of real-time, congestion was effectively being double counted. Because of the high volumes of congestion on May 14, this materially lowered the AESO's ASC estimates and led the AESO to issue some unit commitments that should not have been issued.

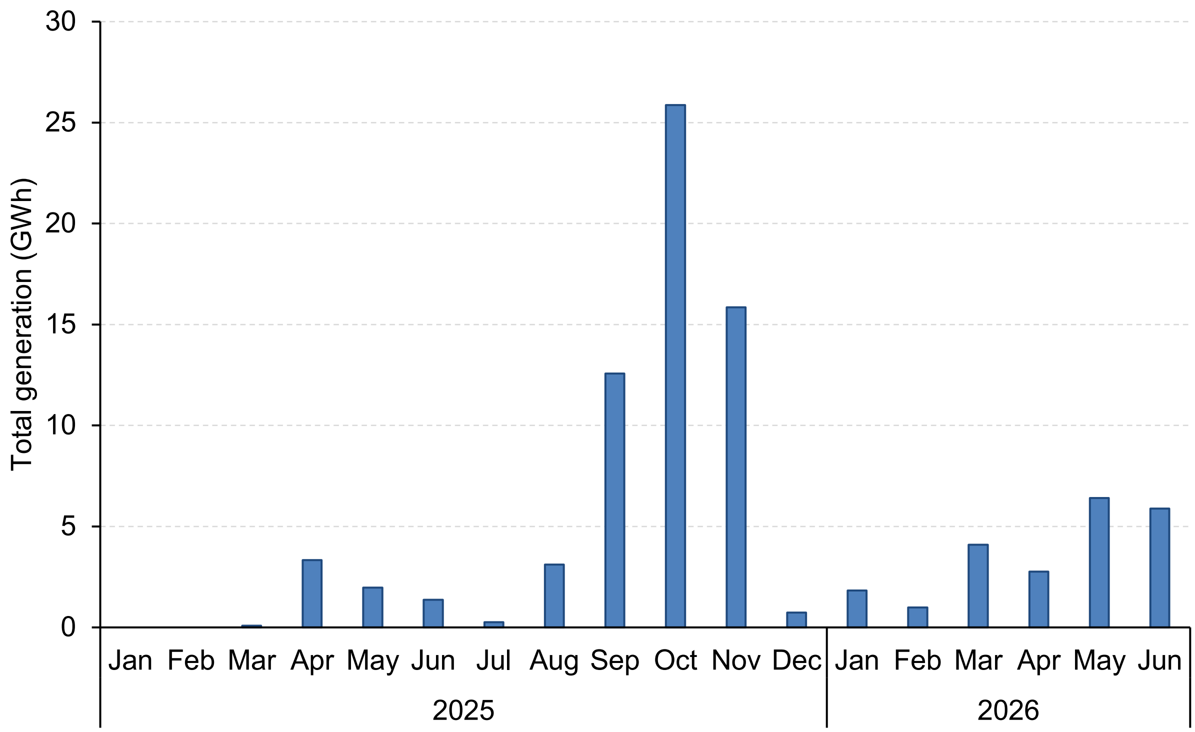
Table 15 shows the estimated price effect of the UCDs in Q2. Over the quarter, the MSA estimates that the average pool price was lowered by $5.10/MWh or 17 % because of the UCDs.

Table 15: Estimated price impact of unit commitment directives in Q2

Time period	Actual average pool price ($/MWh)	Estimated average pool price without unit commitment directives ($/MWh)	Percentage change (%)
April	$27.61	$31.05	-12%
May	$42.98	$48.96	-14%
June	$17.36	$23.23	-34%
Q2	**$29.47**	**$34.57**	**-17%**

Figure 26 illustrates the monthly total volume of generation provided by assets under UCDs. In Q2, a total volume of 15 GWh was provided through UCDs, with over 6 GWh provided in May.

Figure 26: Total generation from unit commitment directives (January 2025 to June 2026)



In Q2, there were five hours in which the supply cushion would have been negative without the AESO's UCDs: HE 21 and 22 on May 7, HE 21 on May 27, and HE 20 and 21 on May 28.

1.4 Market power, offer behaviour, and net revenues

1.4.1 Market power

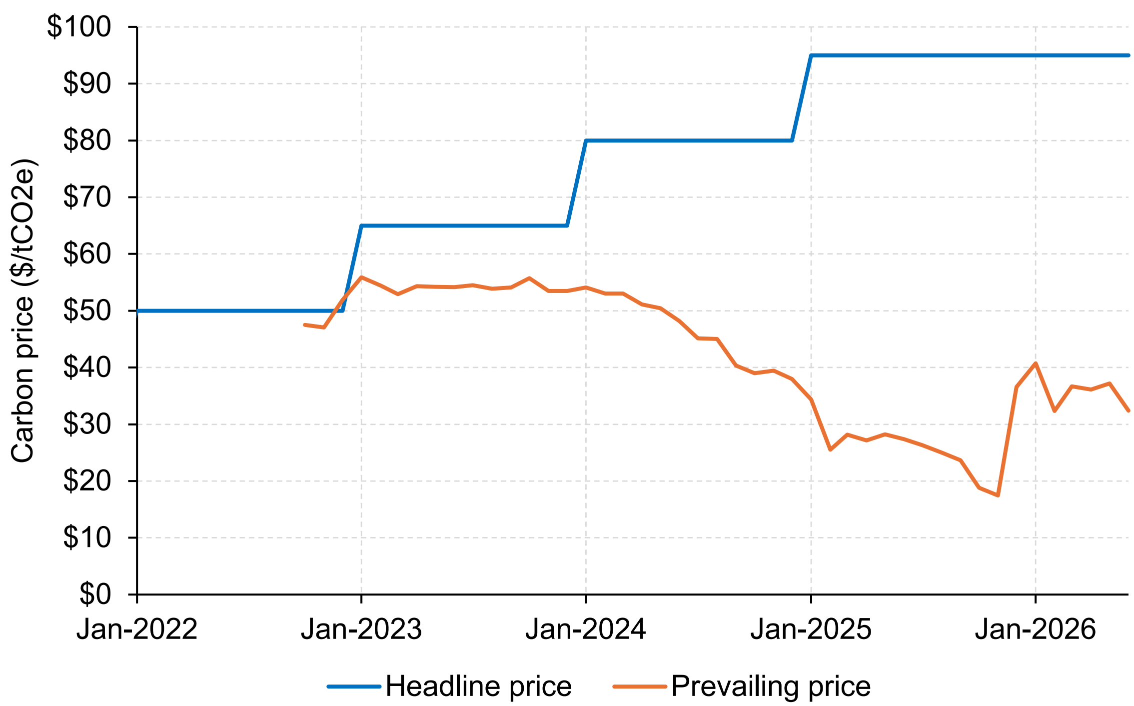
The MSA currently uses the headline price of carbon in its estimates of short-run marginal cost (SRMC) for thermal generators. These SRMC estimates underpin many of the market power measures used by the MSA. However, in recent years, the prevailing price of carbon in Alberta has fallen below headline prices (Figure 27). Therefore, the MSA's current measures will overestimate SRMC and understate market power.

The MSA is in the process of updating its models to incorporate accurate carbon costs for market power measures including:

- mark-ups using counterfactual prices based on SRMC,
- the Lerner index, and
- static inefficiencies.

These measures will be updated in the MSA's Q3 2026 Wholesale Market report, and the corresponding data will be updated in the MSA's data portal at that time.

Figure 27: Carbon prices (January 2022 to June 2026)[3]



[3] The prevailing price of carbon is sourced from Carbon Assessors.

The ability of large firms to exercise market power remained low in Q2. 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[4] is needed for demand to be met.

In Q2, the largest firm in any given hour was pivotal 4% of the time. This is an increase from 1% in Q1 and is slightly less than the 5% in Q2 2025. Figure 28 illustrates long-term trends going back to Q1 2020. In recent years, the ability of larger firms to exercise market power has declined because of increased competition from Cascade, Base Plant, and more intermittent generation.

Figure 28: The percent of hours in which the largest firm was pivotal (Q1 2020 to Q2 2026)

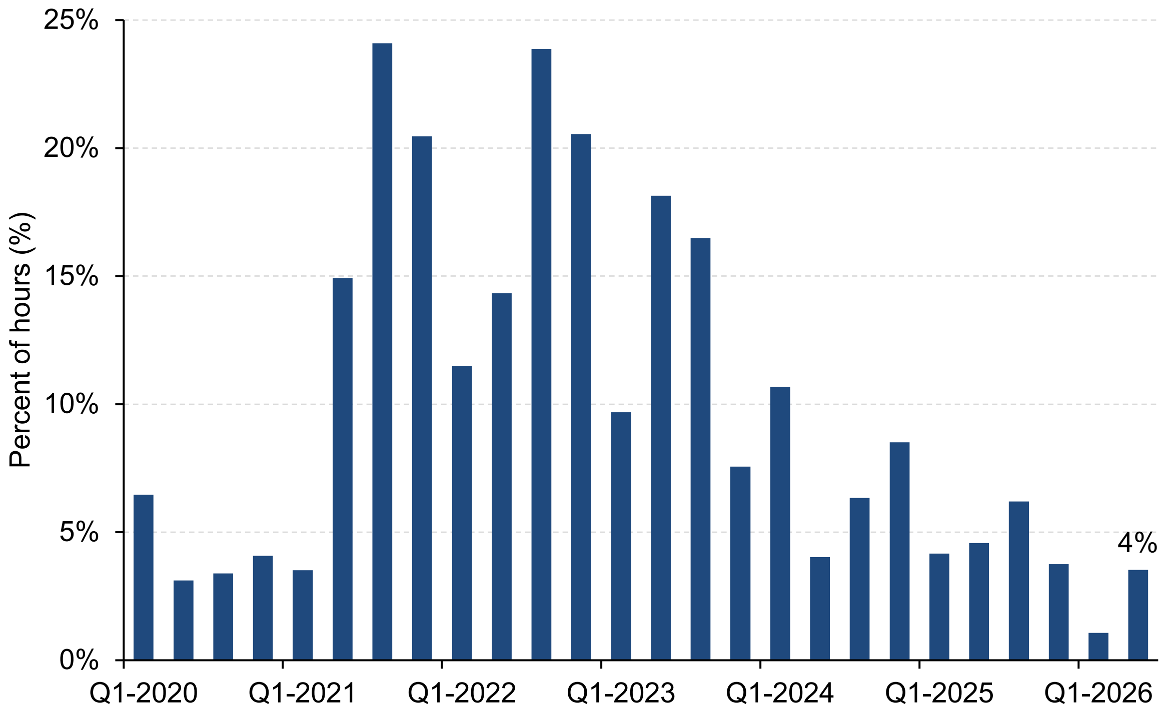
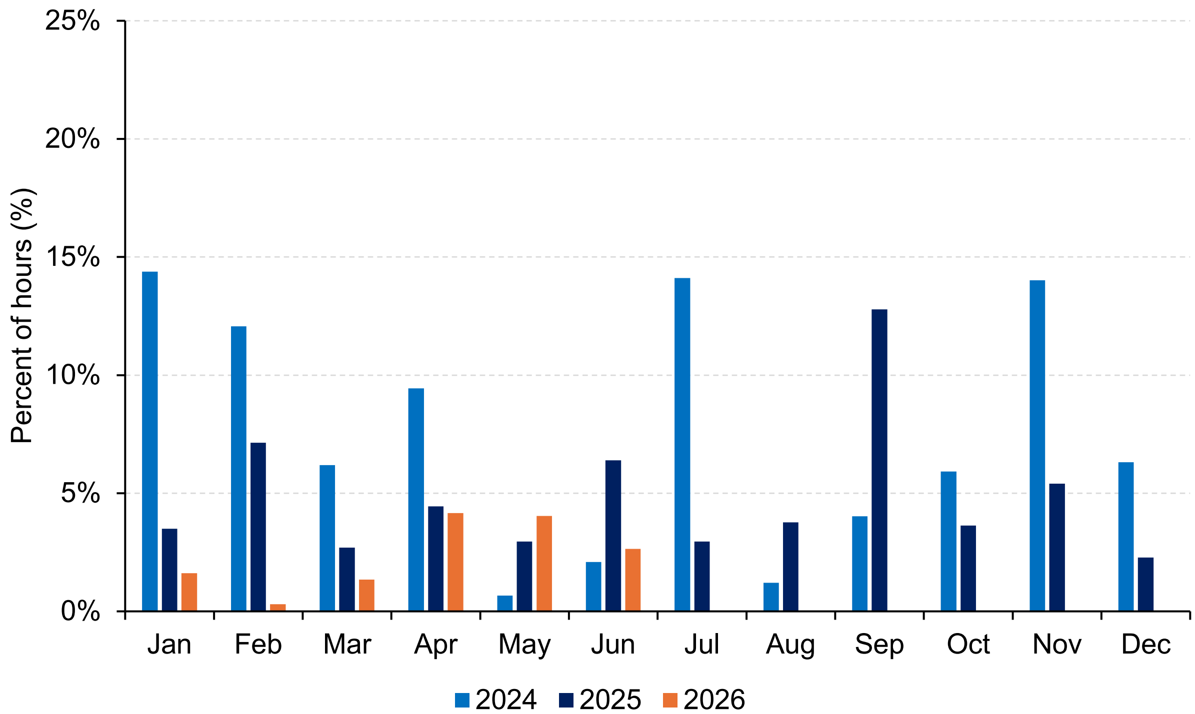


Figure 29 provides the same analysis by month since January 2024. As shown, market power has been limited so far in 2026 as the largest firm has been pivotal under 5% of the time in every month.

In Q2, market power was low despite higher demand year-over-year, the mothballing of Sheerness 1, and some major planned generator outages. Higher import volumes, less capacity going commercially offline on LLT, and higher wind generation in June all acted to increase competition.

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

Figure 29: The percent of hours in which the largest firm was pivotal (January 2024 to June 2026)



1.4.2 Offer behaviour

Figure 30 illustrates the relationship between supply cushion and pool price in Q2 2025 and Q2. Specifically, the figure illustrates the average pool price in 250 MW supply cushion bins during the two quarters. Supply cushion is the amount of generation capacity that was available in the merit order above what was needed to serve demand.[5] The overall relationship between supply cushion and pool price was as expected in both quarters; during hours of low supply cushion average pool prices were higher, and during hours of high supply cushion average pool prices were lower.

Less thermal capacity was offered into the energy market at higher prices in Q2 compared to Q2 2025. This resulted in lower pool prices when the supply cushion was relatively low. For example, when the supply cushion was between 0 and 250 MW the average pool price was $790/MWh in Q2 whereas in Q2 2025 the average pool price was $902/MWh. However, these hours were relatively rare, accounting for 0.3% of hours in Q2 and 0.2% of hours in Q2 2025.

[5] The supply cushion is calculated as the available capacity of offer blocks that were priced at or above the constrained SMP and were not dispatched. The analysis uses an hourly snapshot at the 30th minute. Load assets bidding into the market were excluded and applicable TMR volumes were subtracted.

Hours with a supply cushion of between 250 and 500 MW were more prevalent, occurring 1% of the time in Q2. The average pool price in these hours was also lower year-over-year: $377/MWh in Q2 compared to $559/MWh in Q2 2025.

Importantly, hours with a supply cushion of between 750 and 1,000 MW accounted for 5% of the hours in Q2 and the average pool price in this range fell by $40/MWh or 33% year-over-year. Similarly, the average pool price fell by $32/MWh or 42% in hours where the supply cushion was between 1,000 and 1,250 MW, which accounted for 7% of hours in Q2, indicating more competition for dispatch.

Figure 30: Supply cushion and average pool prices (Q2 2025 and Q2)

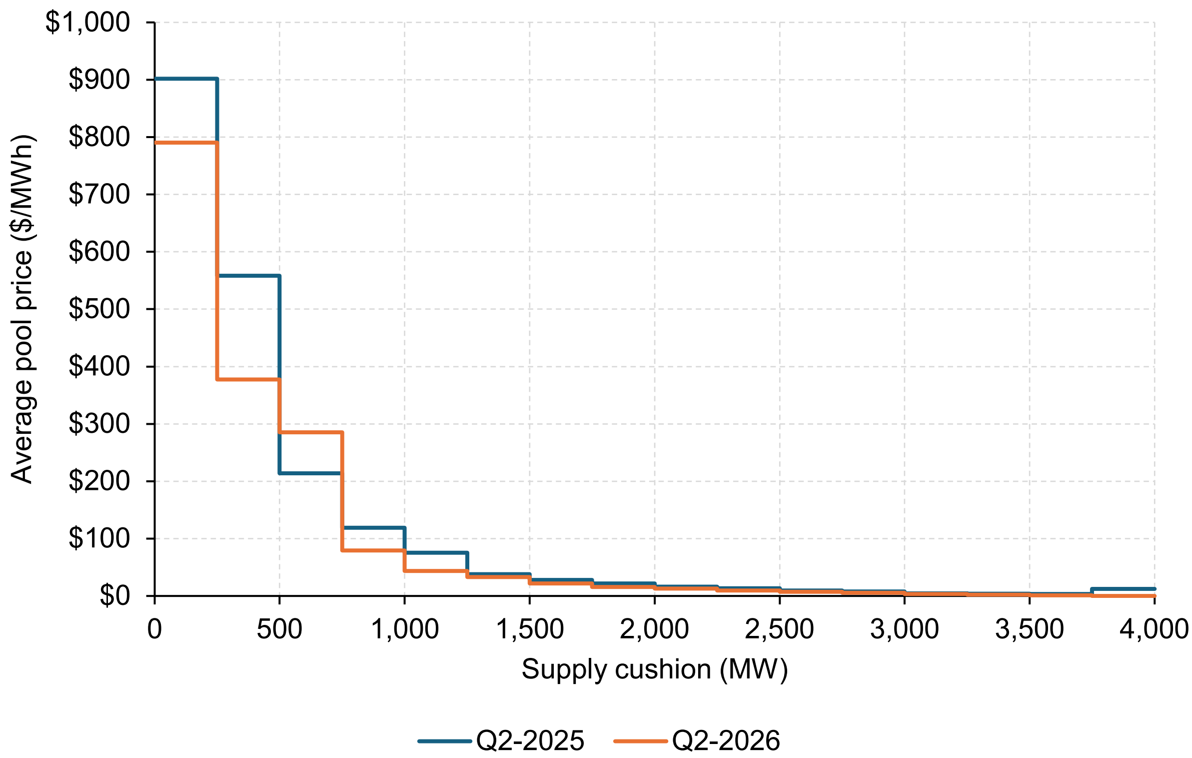


Figure 31 provides a scatterplot of supply cushion and pool price in Q2. There were four hours in the quarter when the pool price cleared above $999/MWh:

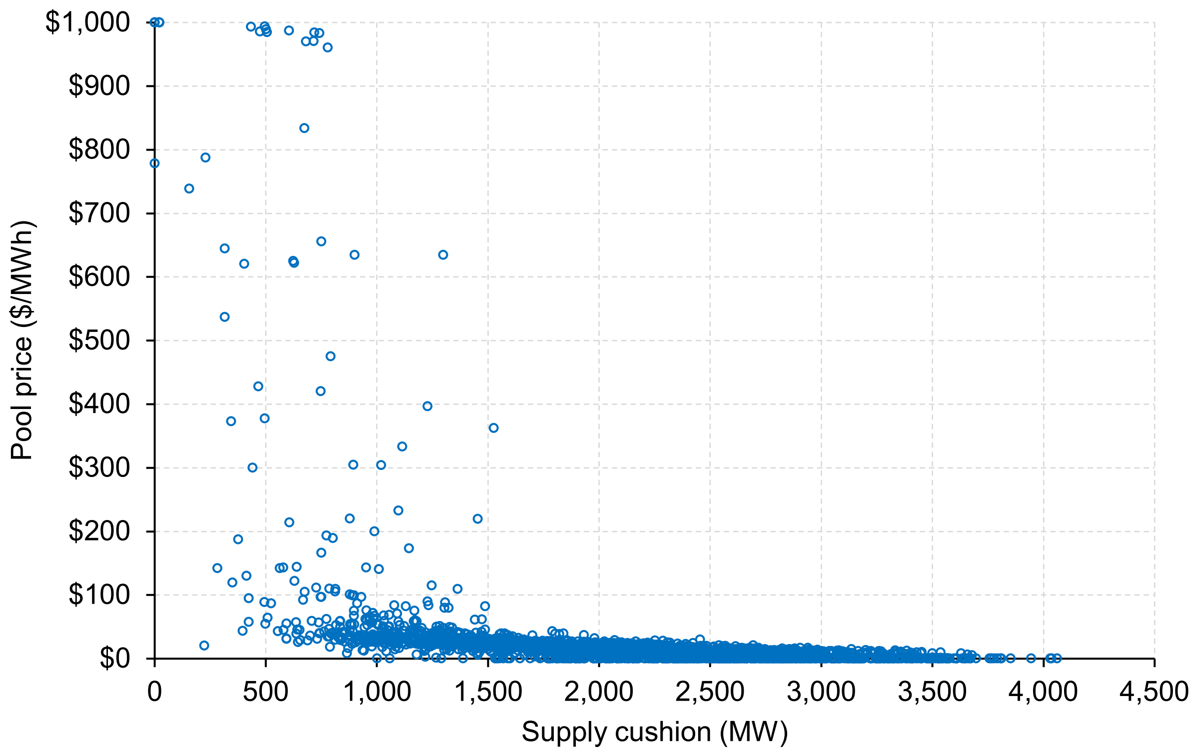
- May 25 HE 20 and 21 (the EEA3 event), and
- May 28 HE 20 and 21.

In HE 22 of May 25, the supply cushion was 0 MW for the first 35 minutes of the hour, but the SMP fell quickly thereafter, and the pool price settled at $778/MWh.

There were hours in the quarter where the pool price was elevated given the supply cushion. For example, on in HE 24 of May 27 the pool price cleared at $635/MWh even though supply cushion was 1,300 MW.

Conversely, there were some notable anomalies at the price floor of $0/MWh. For example, in HE 16 of May 11, the pool price cleared at $0/MWh when the supply cushion was only 1,001 MW. Similarly, in HE 17 of May 13 the pool price was $0/MWh when the supply cushion was 1,290 MW. On May 31 from HE 18 to 20, the supply cushion was around 1,550 MW and the pool price for the three hours settled at $0/MWh.

Figure 31: Scatterplot of supply cushion and pool price (Q2)



1.4.3 Net revenues

Net revenue analyses provide insight into how observed pool prices compare against a set of assumed costs for different generation technologies. This section presents the Q2 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. The resulting costs are reported in Table 16.

Table 17 shows the seasonal capacities and heat rates for the hypothetical natural gas assets. Because Q2 falls within the summer season, the summer capacities and heat rates shown in the table were applied when calculating net revenues for the natural gas assets in Q2. As a result of its lower heat rate, the combined cycle asset incurs lower carbon costs per MWh compared to the simple cycle asset. The emissions intensity of natural gas is assumed to be 0.0561 tCO_2e/GJ.

For both the natural gas assets, carbon costs are calculated assuming that 90% of the emissions obligations are met through the purchase of Emission Performance Credits (EPCs). The carbon prices are sourced from Carbon Assessors with an average price of $34.62/tCO2e in Q2. The remaining 10% of emissions are covered through payments into the TIER Fund at the regulated carbon price of $95/tCO2e.

Table 16: Cost assumptions used in the net revenue analysis (2026$)[6]

Parameter	Combined cycle	Simple cycle	Wind	Solar
Size (MW)	418	47	100	50
Net overnight capital costs ($/kW)	$1,720	$1,864	$1,186	$1,309
Fixed O&M ($/kW-year)	$22.38	$25.87	$98.21	$29.97
Variable O&M ($/MWh)	$4.04	$7.46	$0.00	$0.00

Table 17: Seasonal capacities and heat rates used in the net revenue analysis

	Season	Capacity (MW)	Heat rate (GJ/MWh)
Combined cycle	Winter	418	6.79
	Summer	382	7.43
Simple cycle	Winter	47	9.53
	Summer	40	11.20

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 natural gas price (AB-NIT 2A) 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%.

For the hypothetical wind and solar assets, revenues are derived from the energy market and from the sale of carbon emission offsets. Carbon revenues are calculated based on the grid

[6] AESO: 2024 Long-Term Outlook – Data file (XLSX), New Resource Inputs

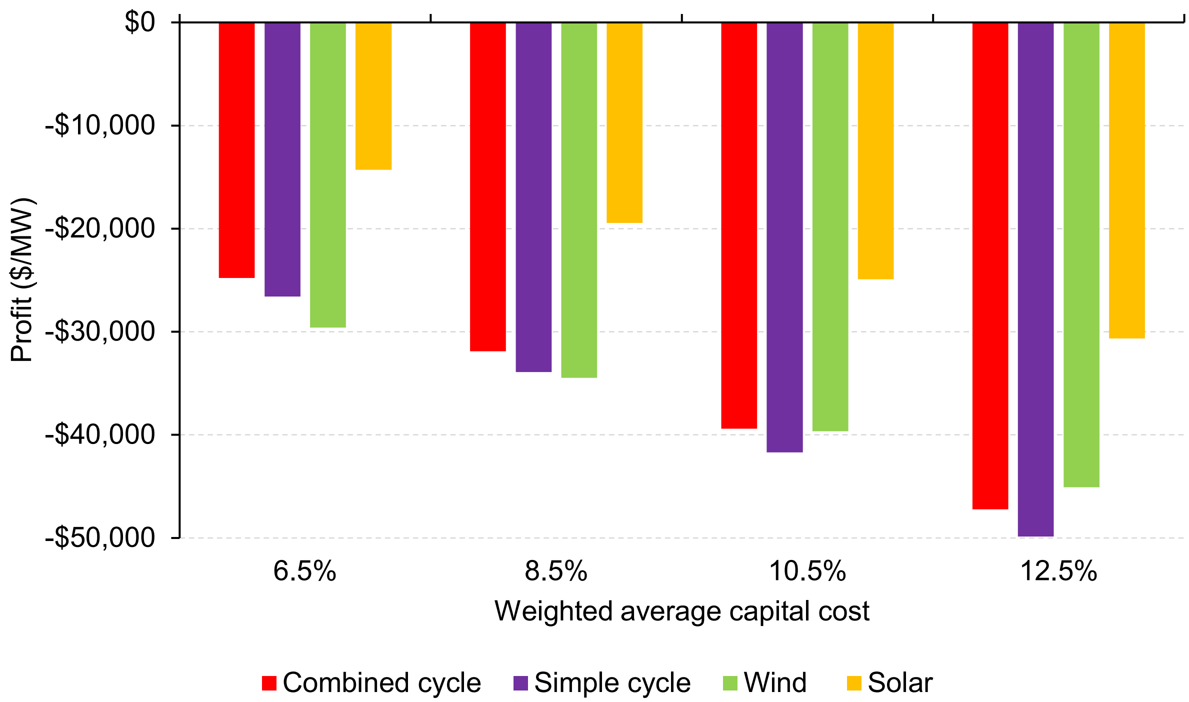
displacement factor and the prevailing price of carbon. The assets are assumed to fully utilize all carbon emission offsets generated.

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 70% 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 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 32 illustrates the results of the analysis in dollars per MW.

Figure 32: Profits per MW by generation type at different WACC assumptions (Q2)



Pool prices in Q2 were relatively low with an average of $29.47/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 Q2. 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 32).

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 Market share offer control

The MSA began publishing market share offer control (MSOC) metrics in its quarterly report in 2021. The MSA also includes a data file on its website with offer control data, along with tables and charts of interest. Certain tables that were included in previous market share offer control reports can be found in the data file. The data file for market share offer control can be found in the MSA Market Share Offer Control Data file located on the MSA's website under Documents & Reporting > Reports > MSOC.

1.5.1 Requirement to publish offer control report and associated process

The MSA's assessment of MSOC information is required by subsection 5(3) of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation). Subsection 5(3) states:

> (3) The MSA shall at least annually make available to the public an offer control report that
>
> a) shall include the names and the percentage of offer control held by electricity market participants, where the percentage of offer control is greater than 5%, and
>
> b) may include the names and the percentage of offer control held by electricity market participants, where the percentage of offer control is 5% or less.

Details of the process to collect and publish information on offer control to meet the requirements of subsection 5(3) are set out in the MSA's Annual Market Share Offer Control Process (MSOC Process).[7]

1.5.2 Assessment of offer control

In accordance with the MSOC Process, the MSA calculated offer control with data obtained from the AESO for HE 18 of June 25, 2026. The MSA requested confirmation of offer control from market participants whose total offer control was calculated as greater than five percent, or for joint ventures that required further clarification. As per section 5(2) of FEOC Regulation, an electricity market participant's total offer control is measured as the ratio of generation capacity under its offer control to the sum of maximum capability of all generating units in Alberta.

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[7] MSA: Market Share Offer Control Process – April 30, 2013

Generating units are included in the offer control of an electricity market participant (and the denominator) if they are registered with the AESO as active assets during the reference hour. Generating units registered as active assets are still required to make offers even if they are not available or are mothballed, and their lack of availability is included in outage data published by the AESO. The total non-dispatchable capacity consists of the total maximum capability of generating units that do not submit offers into the power pool, such as generating units with a maximum capability less than 5 MW.

The maximum capability of assets used to calculate the denominator may not correspond to the name plate maximum capability that is published on the AESO's Current Supply Demand report. Instead, the denominator uses maximum capability as it is registered with the AESO for the purpose of submitting price-quantity offer pairs.

Market shares for participants with more than 5% of total offer control were largely unchanged compared to MSOC 2025 (Table 18). Total offer control for these four participants fell slightly: from 11,740 MW to 11,736 MW. This represented a market share decrease from 51.4% in 2025 to 50.8% in 2026.

Generation retirements, additions, and maximum capability changes are discussed further in section 1.7.3.

Table 18: Market share offer control of market participants with greater than 5% offer control (MSOC 2025 and 2026)

	January 1, 2025		**June 25, 2026**	
Company	**Control (MW)**	**%**	**Control (MW)**	**%**
TransAlta	5,303	23.2%	5,303	23.0%
Capital Power	2,610	11.4%	2,606	11.3%
Suncor	2,438	10.7%	2,438	10.6%
ENMAX	1,389	6.1%	1,389	6.0%
Other	10,754	47.1%	10,965	47.5%
Total Dispatchable	22,494	98.4%	22,701	98.3%
Total Non-dispatchable	362	1.6%	384	1.7%
Grand Total	**22,856**	**100%**	**23,085**	**100%**

Figure 33: Dispatchable MW by fuel type (MSOC 2025 and 2026)

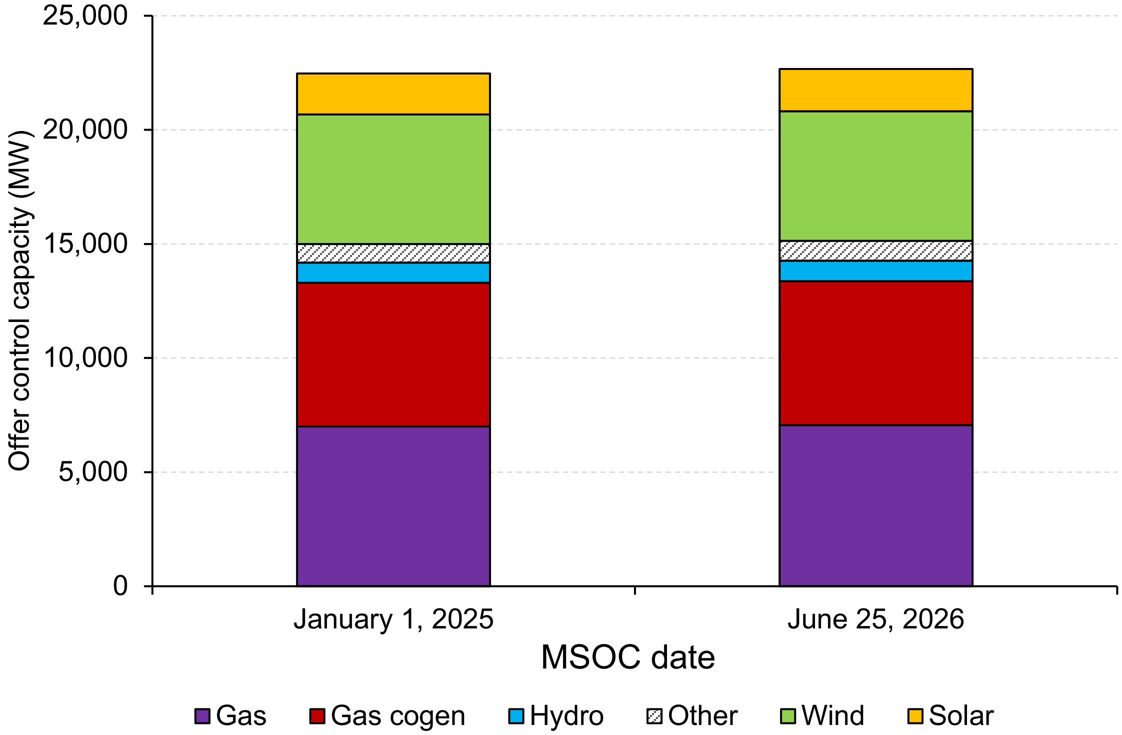
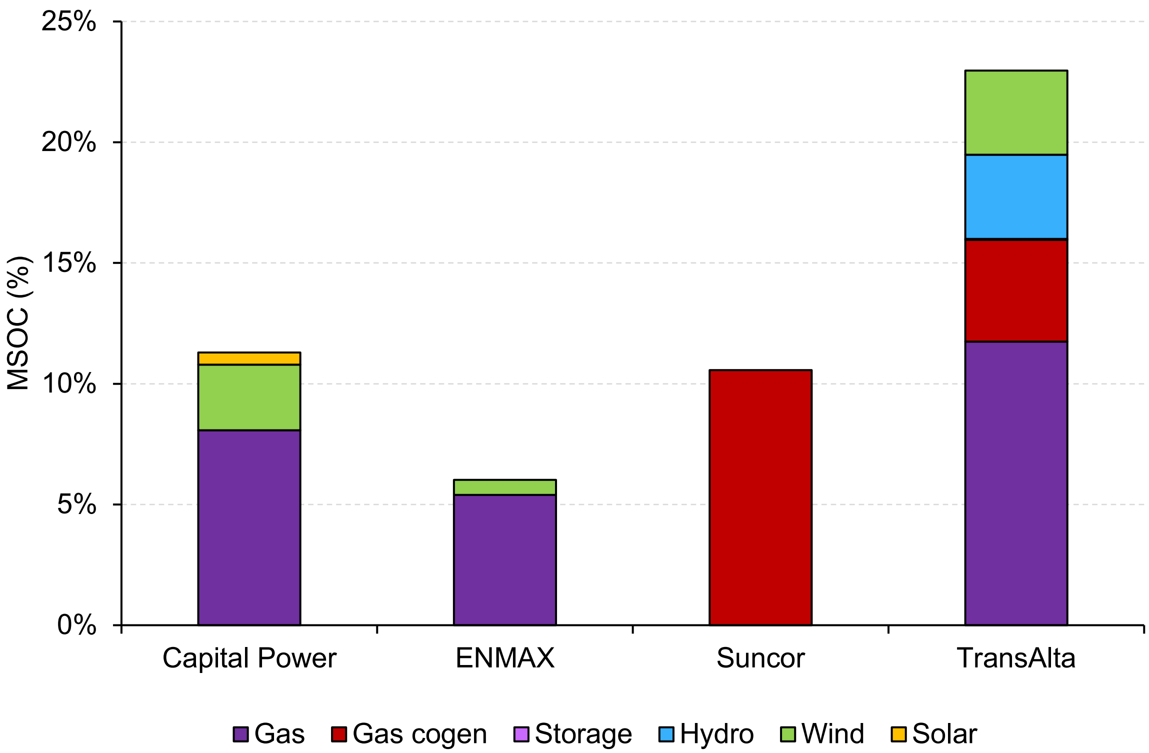


Figure 34: MSOC by fuel type for market participants with more than 5% offer control (2026)



1.5.3 Generation additions, retirements, and maximum capability changes

Since the last MSOC assessment on January 1, 2025:

- 177 MW of dispatchable capacity was added; and
- existing assets' capacity increased by 30 MW.

Overall, these changes resulted in Alberta's total capacity increasing by 229 MW. Generation additions were comprised of gas, gas cogeneration, solar, and storage assets. A total of 177 MW of dispatchable generation capacity was added, of which 80 MW (45%) was storage generation, 58 MW (33%) was solar generation, 25 MW (14%) was gas cogeneration, and 14 MW (8%) was gas generation.

For the purposes of MSOC, a dispatchable generator is one that submits offers into the power pool. The largest change in existing assets' capacity was from Cascade 1 and 2, which increased their maximum capability from 450 MW each to 466 MW each on November 11, 2025. Specific changes by asset are included in Table 19.

Table 19: Capacity changes between MSOC 2025 and 2026

Asset ID	Fuel Type	2025 (MW)	2026 (MW)	Diff	Date of Change
DUS1	Solar	--	20	20	January 15, 2026
GLE1	Solar	--	14	14	March 14, 2025
KAS1	Gas cogen	--	25	25	January 15, 2026
RIM1	Gas	--	14	14	March 6, 2026
RPT2	Storage	--	80	80	April 24, 2026
TLE1	Solar	--	24	24	September 10, 2025
Units Added (Units >=5 MW)			**177**	**177**	
CAS1	Gas	450	466	16	November 11, 2025
CAS2	Gas	450	466	16	November 11, 2025
CHIN	Hydro	15	12	-3	May 12, 2026
HAL2	Wind	126	122	-4	September 3, 2025
RYMD	Hydro	21	26	5	April 4, 2025
MC Changes (Units >=5 MW)		**1,062**	**1,092**	**30**	
Units <5 MW		225	247	22	
Unchanged Units >=5 MW		21,568	21,568	0	
TOTAL (MW)		**22,856**	**23,085**	**229**	

1.6 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 has relied on information that is publicly available. The results reported here do not include imported generation.[8]

Hourly data on the MSA's carbon emission intensity estimates are available on our data portal.

1.6.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in each hour. Table 20 shows the minimum, mean, and maximum hourly average emission intensity for Q2 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 meaningful 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 lowered average carbon emission intensity more recently.

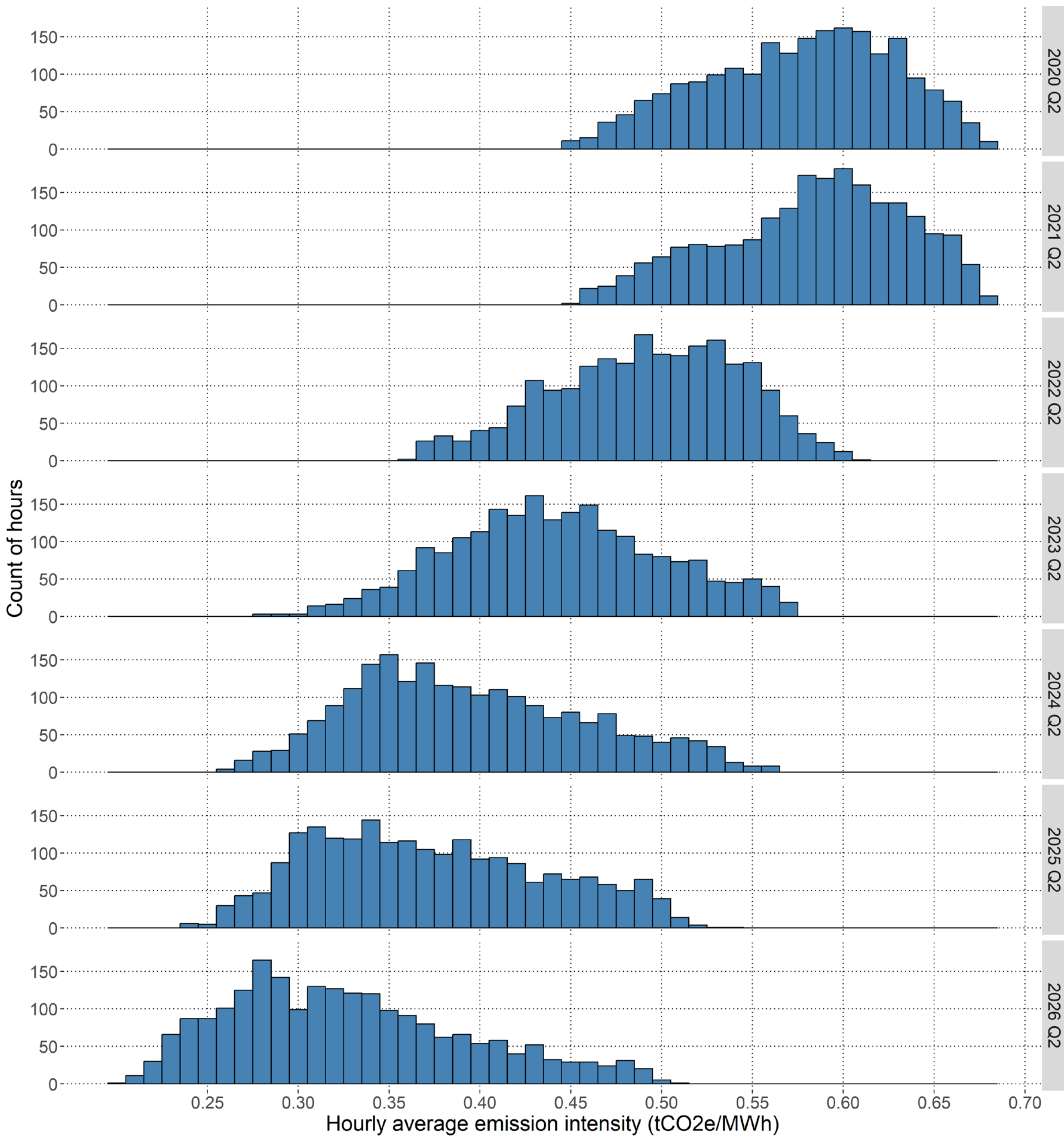
Table 20: Minimum, mean, and maximum hourly average carbon emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2020 Q2	0.45	0.58	0.68
2021 Q2	0.45	0.58	0.68
2022 Q2	0.36	0.49	0.61
2023 Q2	0.28	0.44	0.57
2024 Q2	0.26	0.39	0.56
2025 Q2	0.24	0.37	0.54
2026 Q2	0.20	0.33	0.51

Figure 35 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.

[8] For more details on the methodology, see MSA: Quarterly Report for Q4 2021 at page 25

Figure 35: The distribution of average carbon emission intensities in Q2 (2020 to 2026)



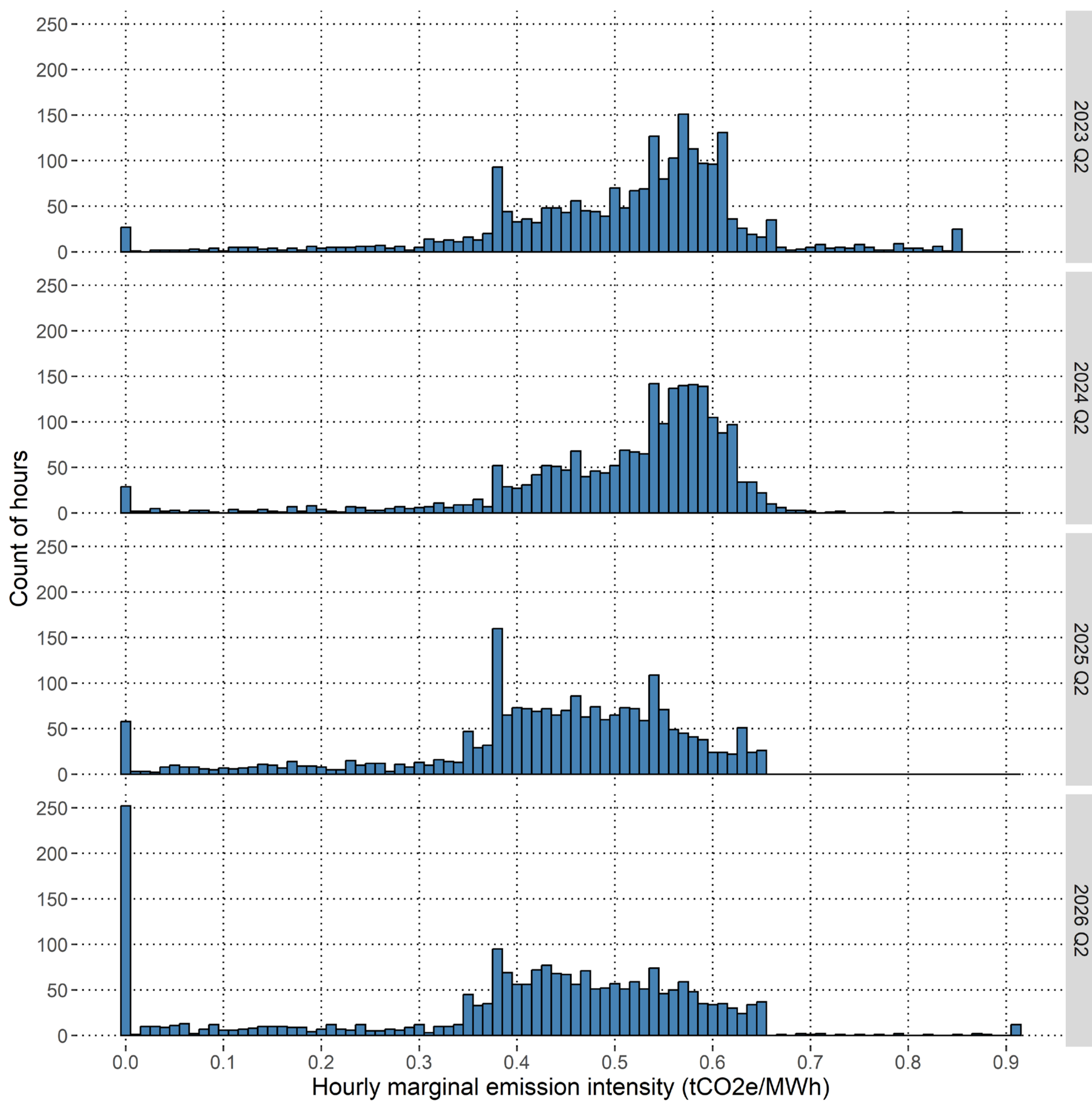
1.6.2 Hourly marginal emission intensity

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

Figure 36 shows the distribution of the hourly marginal emission intensity of the grid in Q2 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 tCO2e/MWh.

In Q2, combined cycle assets were marginal most often at 37% of the time, followed by assets that are considered to have a 0 tCO2e/MWh emission intensity, which were marginal 22% of the time. Gas-fired steam assets were marginal 19% of the time, cogeneration 15% of the time, and simple cycle 7% of the time in Q2.

Figure 36: The distribution of marginal carbon emission intensities in Q2 (2023 to 2026)



2 THE POWER SYSTEM

2.1 Congestion

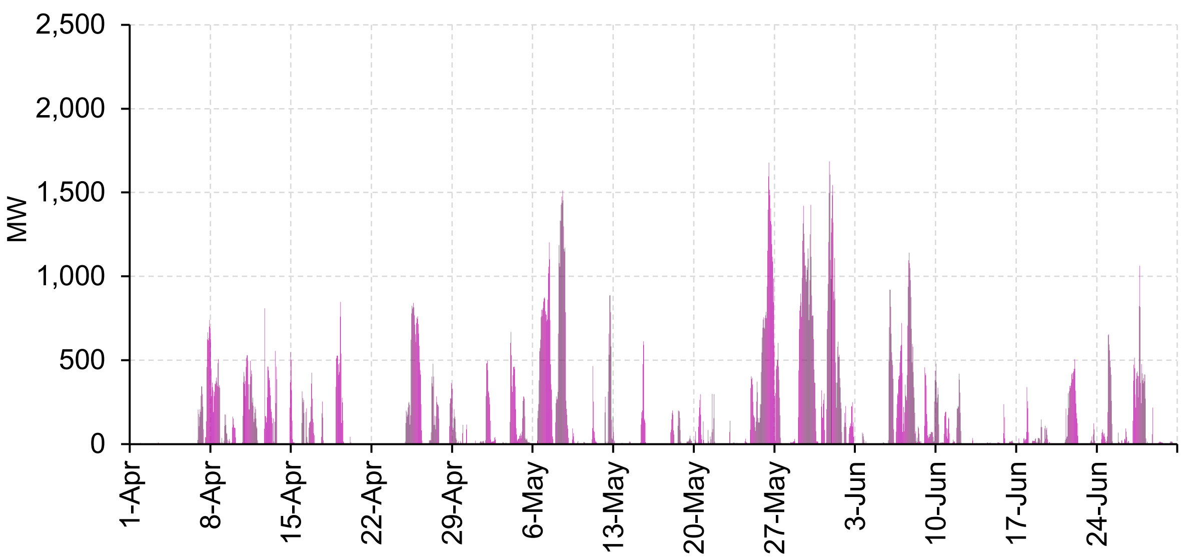
Transmission elements may impose limitations on the transfer of electric energy from one location on the transmission system to another. The AESO mitigates these limitations in real time by curtailing generation.[9]

The MSA measures constrained intermittent generation (CIG), which is an estimate of the potential generation of an intermittent asset that was curtailed due to a transmission constraint. The CIG calculation uses data on curtailment limits, available capacity, potential real power capability, and energy dispatch.[10]

The frequency and significance of CIG directives increased year-over-year. The MSA estimates that CIG volumes were 642 GWh in Q2 compared to 310 GWh in Q2 2025, a 107% increase. Quarter-over-quarter, CIG volumes increased by 14%.

The highest hourly average volume of CIG in Q2 was 2,424 MW on May 14 in HE 19. This is an increase from the Q2 2025 maximum of 1,686 MW (Figure 37 and Figure 39). The highest hourly average volume of CIG in Q2 was also higher than the maximum value in Q1 of 1,588 MWh (Figure 38).

Figure 37: Maximum hourly constrained intermittent generation (Q2 2025)



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

[10] 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 CIG volumes (previously referenced as constrained down volumes).

Figure 38: Maximum hourly constrained intermittent generation (Q1)

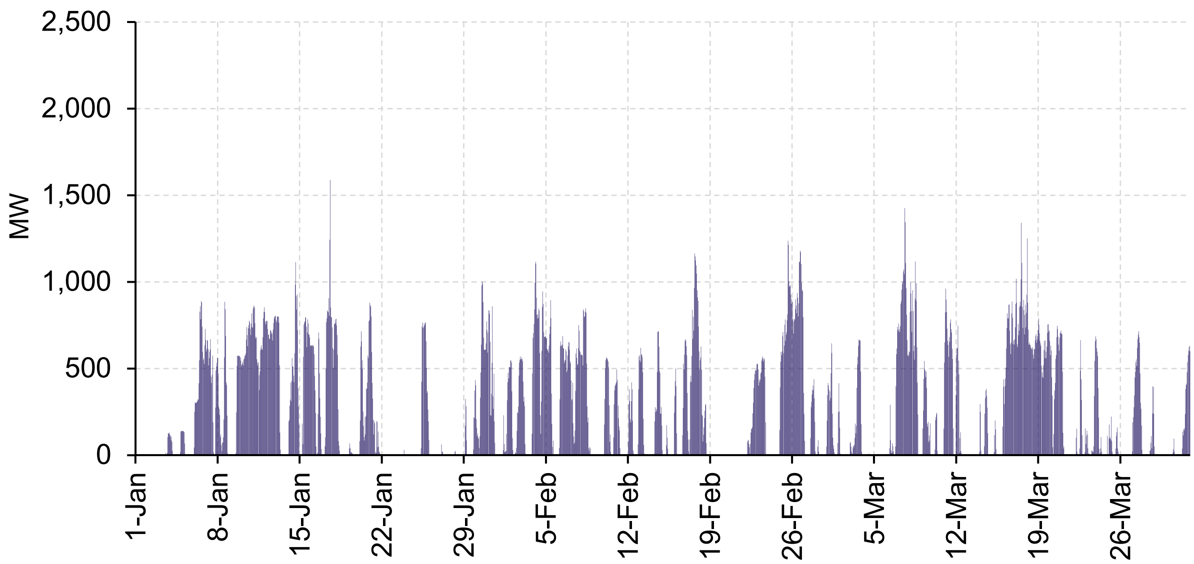
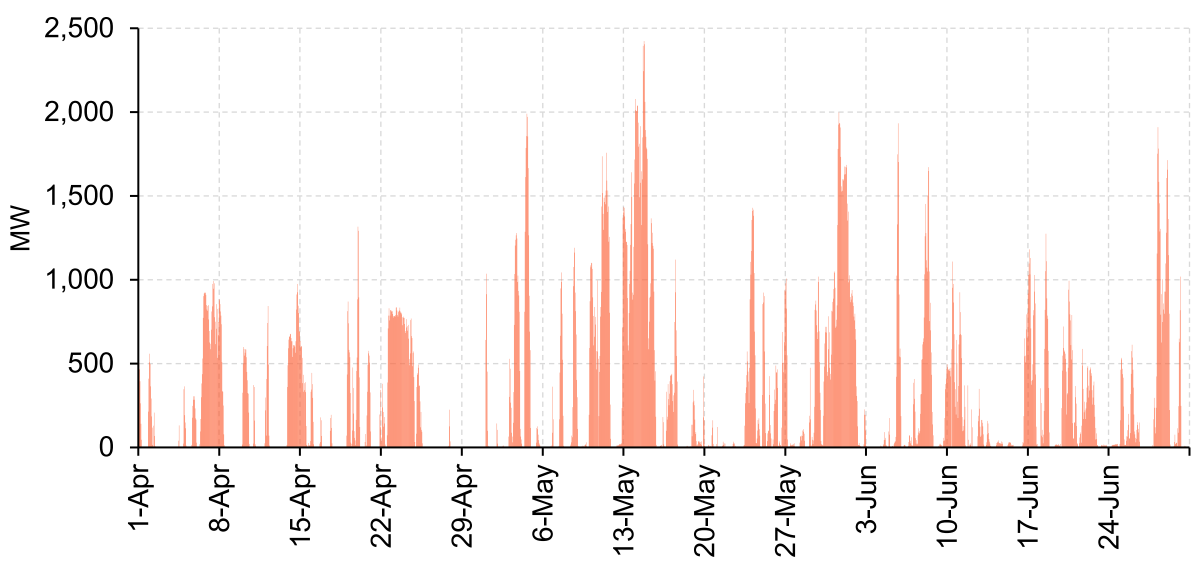


Figure 39: Maximum hourly constrained intermittent generation (Q2)



The increased CIG volumes year-over-year were partly due to higher intermittent generation. Higher CIG volumes generally align with periods of high intermittent generation or supply surplus events (Figure 40 and Figure 41).

Figure 40: Average hourly potential intermittent generation and CIG (Q2)

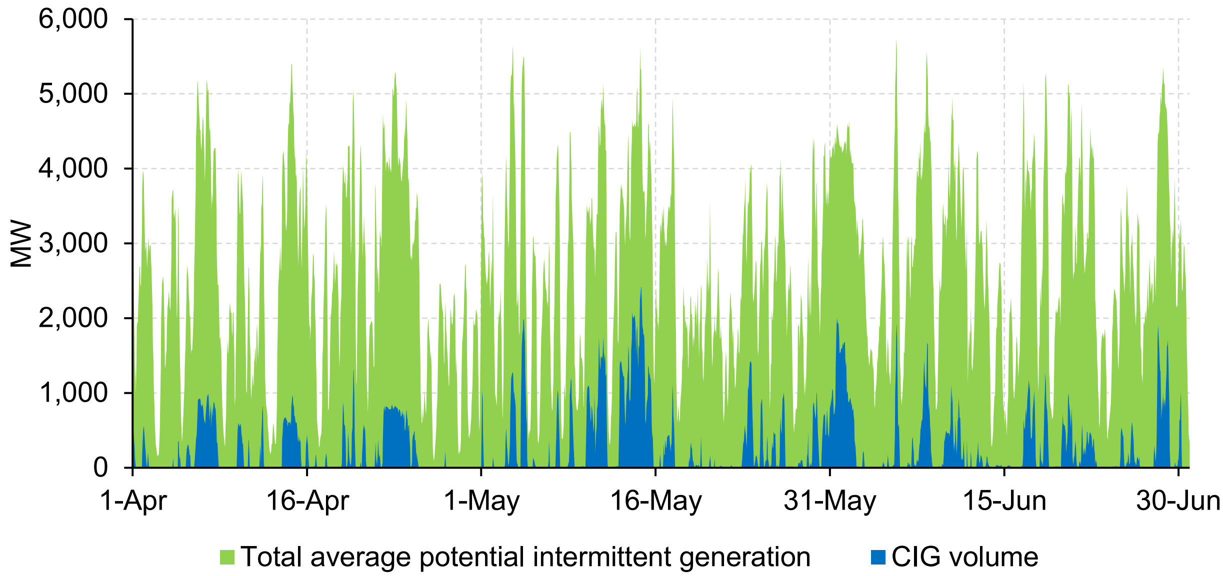
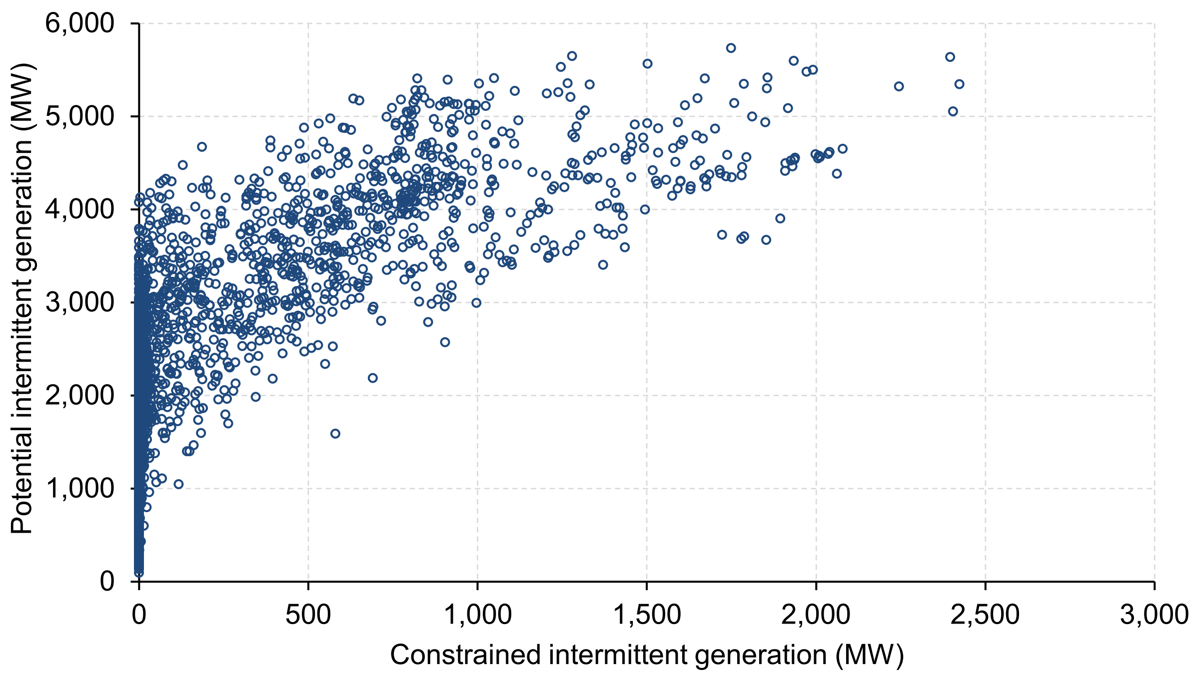


Figure 41: A scatterplot of CIG and potential intermittent generation (Q2)



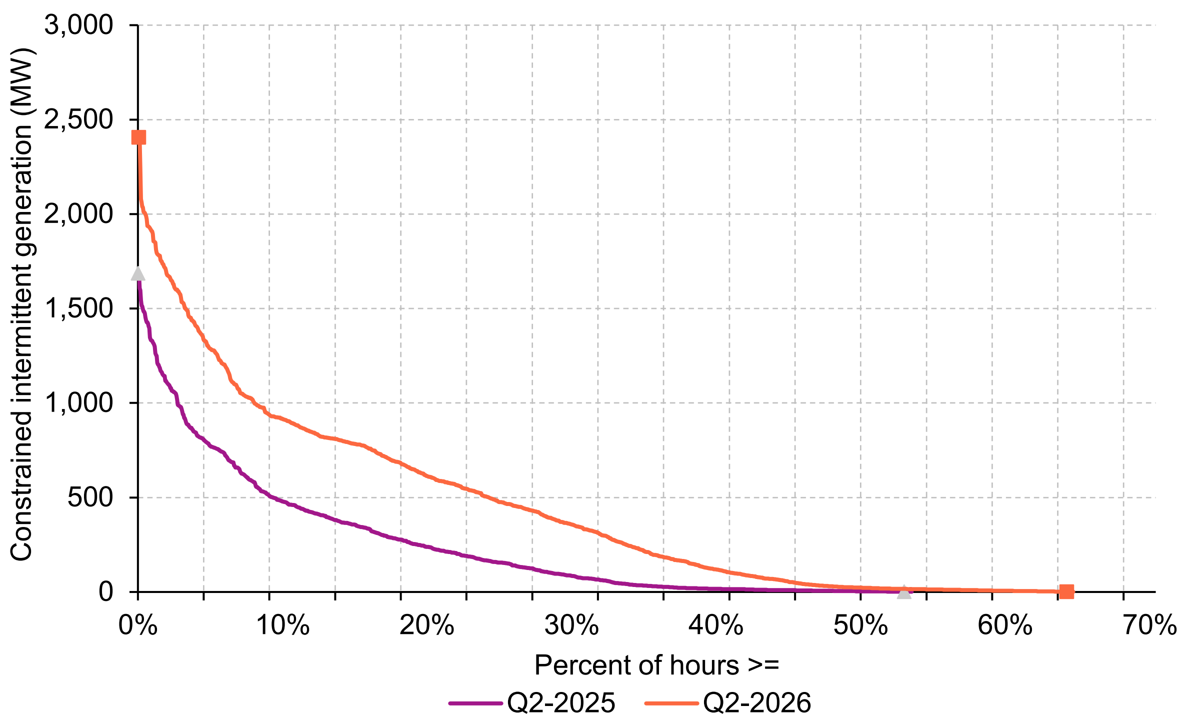
There were around 450 AESO System Controller shift log events for constrained down generation in Q2. Increased CIG volumes can be caused by persistent or frequent limitations to certain transmission elements and may affect one or more generation assets. A notable transmission outage in Q2 was the planned outage on EATL, which ran from May 4 to 15. Consequently, May experienced the most curtailment events in the quarter; 47% of the event logs related to generation curtailments for transmission constraints occurred in May.

Following the trends in Q1, Q2 also 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."[11]

The increase in CIG volumes from Q2 2025 to Q2 occurred at a higher rate than the installation of intermittent capacity. While total installed intermittent capacity increased by only 1.7%, average hourly CIG volumes, expressed as a percent of installed intermittent capacity, increased from 1.89% in Q2 2025 to 3.84% in Q2.

Figure 42 illustrates duration curves of CIG year-over-year. The shift upwards from Q2 2025 to Q2 illustrates higher CIG volumes this year. The length of the tails on the right of the duration curves show that the frequency of CIG events increased. There were 1,424 hours of CIG volumes greater than 1 MW in Q2, which is 65% of hours in the quarter. In contrast, Q2 2025 experienced more than 1 MW of CIG in 54% of hours.

Figure 42: Duration curves of CIG (Q2 2025 and Q2)



Transmission constraint volumes had frequent fluctuations throughout Q2 but May experienced the highest CIG volumes (299 GWh) and the highest peak (2,424 MW). Total CIG volumes in May accounted for 47% of all Q2 volumes. In 73% of hours in May there was at least 1 MW of CIG.

[11] 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.[12] 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 Q2, the average constrained SMP was $36.11/MWh or 23% higher than the average unconstrained SMP (Table 21). This compares to a difference of 13% in Q2 2025 and 14% in Q1. The higher premium in Q2 was driven by outcomes in May when the constrained SMP was 34% higher than the unconstrained SMP.

Table 21: Average constrained and unconstrained SMP by month (Q2)

	Constrained SMP ($/MWh)	Unconstrained SMP ($/MWh)	Difference	
			($/MWh)	(%)
Apr	$30.71	$27.61	$3.11	11%
May	$57.51	$42.98	$14.54	34%
Jun	$19.40	$17.36	$2.03	12%
Q1	**$36.11**	**$29.47**	**$6.65**	**23%**

The constrained and unconstrained SMP differed by $1/MWh or more in 31% of minutes in Q2. In comparison, Q2 2025 had 25% of minutes with a variance of $1/MWh or more, and Q1 had the difference in 41% of minutes.

In Q2, the largest difference between the constrained SMP and unconstrained SMP was $959/MWh, which occurred in HE 10 of May 13 (Figure 43). The price differential was more pronounced in May than in April and June due to the EATL outage and higher CIG volumes. The largest difference was higher in Q2 2025 at $981/MWh, but lower in Q1 at $600/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 Q2, there was often only a small difference between the constrained and unconstrained SMP (Figure 44).

[12] 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.

This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity have a small impact on price. Only 0.75% of minutes in Q2 experienced a difference of greater than $100/MWh between the constrained and unconstrained SMP.

Figure 43: The difference between the constrained SMP and the unconstrained SMP (Q2)

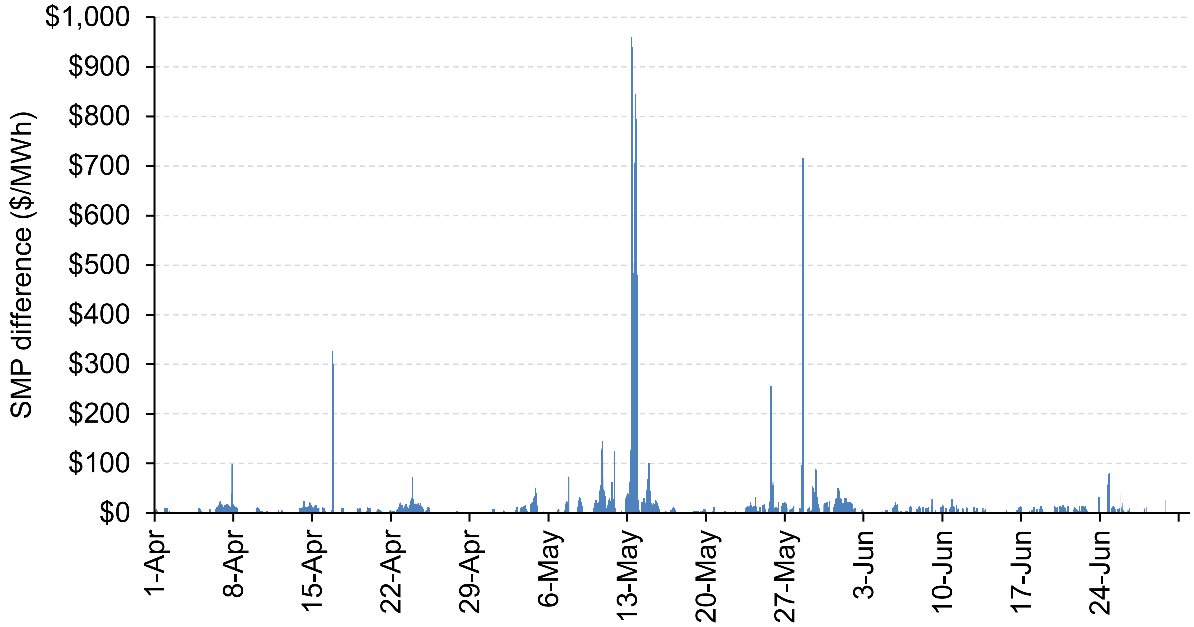
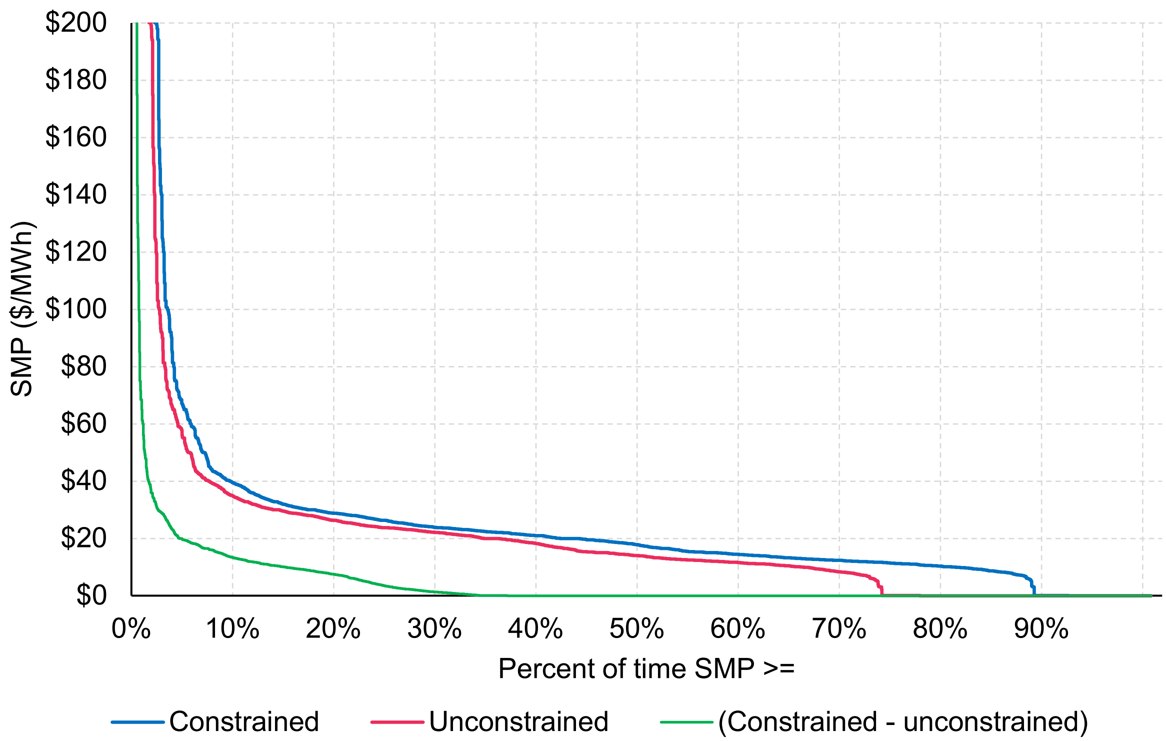


Figure 44: Duration curves of constrained SMP and unconstrained SMP (Q2)

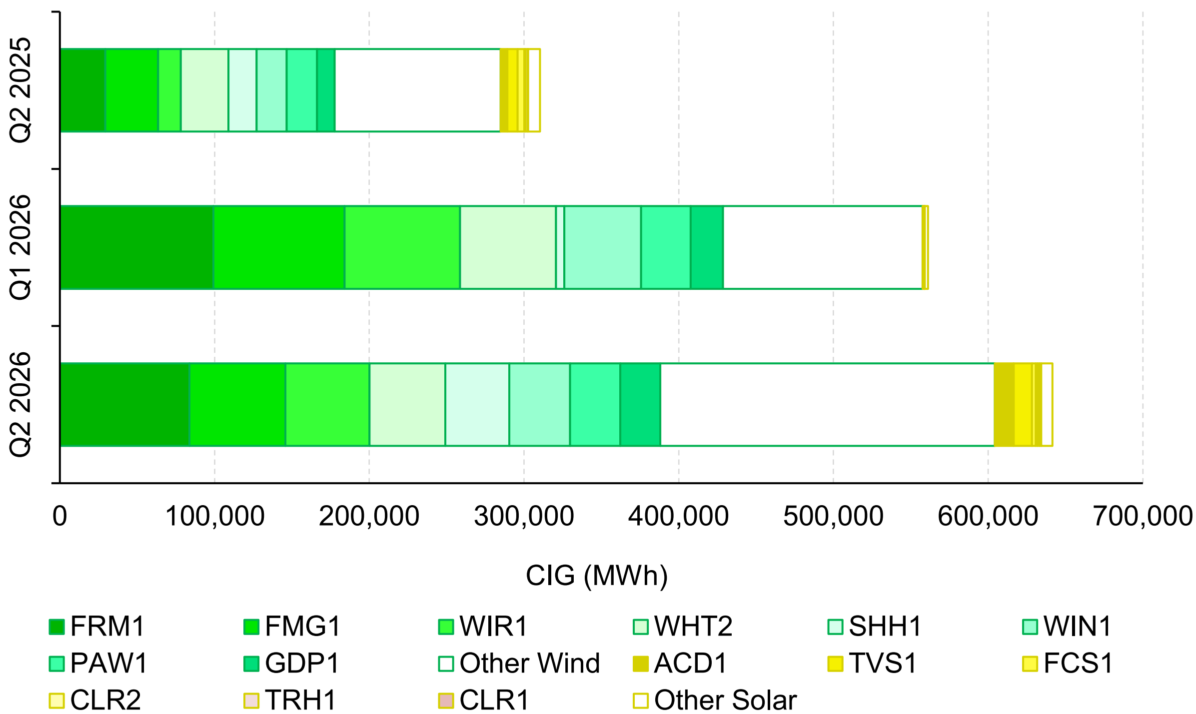


Transmission capability varies throughout the province, and certain regions experience more congestion than others, often leading to local constraints. Consequently, wind and solar assets are not constrained uniformly throughout the province.

In Q2, the eight most constrained wind assets accounted for 64% of the total CIG volume but only 28% of total installed wind capacity. Forty Mile Bow Island, Forty Mile Granlea, and Wild Rose continued to be the most constrained wind assets in Q2 (Figure 45). These three assets represent 12% of Alberta's installed wind capacity, however they accounted for 33% of the wind CIG volume in Q2. These three assets were all constrained under the RAS 164 constraint, which is discussed above.

Big Sky Solar (140 MW) was the most constrained solar asset in Q2, with a total of 12,264 MWh constrained, or 12% of its potential generation. This asset was constrained for a variety of reasons, most of which relate to contingency mitigation relating to 760L. The top six most constrained solar assets have an aggregate maximum capability of 678 MW and were constrained by 30,039 MWh in Q2. The top six constrained solar assets accounted for 81% of solar CIG volumes in Q2 but only 45% of total solar capacity. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

Figure 45: Wind and solar CIG volumes by asset (Q2 2025, Q1, Q2)



2.2 Net revenue analysis by location

As part of the Restructured Energy Market (REM), the AESO will incorporate locational marginal prices (LMP) into the Alberta wholesale electricity market. This change is scheduled to occur in 2028.

Currently, Alberta has a single pool price that covers generation across the province. When congestion occurs, generation assets are dispatched to meet demand, accounting for the fact that there is congestion, and the constrained SMP is set at this equilibrium. The unconstrained SMP is calculated by moving down the supply curve from the constrained SMP by the amount of congested generation.

Pool prices are set using the unconstrained SMP, which is an estimate of what the price would have been in the absence of congestion. Offer blocks that are dispatched above the unconstrained SMP are paid their offer price.

In our Q1 2026 report, the MSA provided analysis that estimated pseudo locational marginal prices (pLMP) from January 1, 2021 to December 31, 2025.[13] In these calculations, each generator in the province was considered a node and pLMP were calculated at each node.

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

- If the average constrained SMP was equal to the average unconstrained SMP, the pLMP at each generator was set equal to the average unconstrained SMP (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 was set equal to the offer price of the asset's highest dispatched block.
    - For generators that were unconstrained, the pLMP was set equal to the average constrained SMP.
- By construction, the average constrained SMP cannot be below the average unconstrained SMP.

In this section, we further this analysis by using the pLMP to estimate net revenues for different generation assets. The net revenues using pLMP are then compared to net revenues using pool price. The purpose of the analysis is to quantify the impact of moving from pool prices to pLMP for assets of different fuel types and at different locations on the grid. The analysis is undertaken for combined cycle, simple cycle, wind, and solar assets.

Net revenue analyses assess profitability by looking at how observed pool prices or estimated pLMP compared against a set of assumed costs for different generators. The net revenue calculations used here generally follow the methodology outlined in section 1.4.3.

[13] MSA: Wholesale Market report for Q1 2026 at page 46

The net revenues for the generation assets are estimated using cost figures published in the AESO's 2024 Long Term Outlook, which are adjusted for inflation using the Consumer Price Index (Table 22).[14]

Table 22: Cost assumptions used in the net revenue analysis (2026$)

Parameter	Combined cycle	Simple cycle	Wind	Solar
Useful life (years)	30	25	30	25
Capital costs ($/kW)	$1,720	$1,864	$1,186	$1,309
Fixed O&M ($/kW-year)	$22.38	$25.87	$98.21	$29.97
Variable O&M ($/MWh)	$4.04	$7.46	$0.00	$0.00

For the natural gas assets, actual heat rates were used in calculating fuel costs and carbon costs for different assets. The heat rates for different generators were sourced from public information, generally AUC hearings.

Carbon costs for the natural gas assets were estimated assuming an emissions intensity of 0.0561 tCO_2e/GJ. Data on the prevailing price of carbon was sourced from Carbon Assessors starting in October 2022, prior to that the regulated price of carbon was used.

The net revenue analysis incorporates several cost components for the natural gas assets. Fuel costs were estimated using the asset heat rate, the same-day price of natural gas (AB-NIT 2A), and the natural gas commodity fuel charge. Hourly generation for the natural gas assets was based on observed metered volumes.

Hourly variable costs were then calculated as the sum of fuel costs, carbon costs, variable operating and maintenance (O&M) costs, and the AESO trading charge. Transmission losses were applied to each asset in accordance with the loss factors published by the AESO as per the equations below for asset (i) in hour (h).

$$Pool\,price: \quad Revenue_{i,h} = \left(Pool\,price_h * \left(1 - Losses_{i,h}\right)\right) * MWh_{i,h}$$

$$pLMP: \quad Revenue_{i,h} = \left(pLMP_{i,h} - \left(Pool\,price_h * Losses_{i,h}\right)\right) * MWh_{i,h}$$

For wind and solar assets, revenues are derived from the energy market and from the sale of carbon emission offsets. Carbon revenues were estimated based on the grid displacement factor

[14] AESO: 2024 Long-Term Outlook – Data file (XLSX), New Resource Inputs

for that year and the prevailing price of carbon. Data on hourly metered volumes were used for the generation of different wind and solar assets.

Wind assets were only included in the analysis if they had reached an hourly capacity factor of 70% before the start of the year, and solar assets were included if they had achieved a 90% capacity factor. Transmission losses were applied to each asset in accordance with the loss factors published by the AESO as per the equations above. For distribution-connected assets, the loss factors listed for the relevant point of delivery were used.

For all generation technologies, a Weighted Average Cost of Capital (WACC) of 10.5% was assumed and was used to derive an estimated annual capital cost. The net revenue figures in this analysis do not incorporate taxes. The resulting net revenues, based on pool prices and pLMP, were compared to the estimated annual fixed and capital costs for each asset and year.

Figure 46 illustrates net revenues based on pool price as a percentage of fixed and capital costs for wind assets in 2025. A figure of 100% in this analysis indicates break-even; net revenues were just sufficient to cover annual fixed and capital costs. As shown, wind assets located to the northeast of the other wind farms received higher net revenues in 2025. This occurred because their generation was less correlated to overall wind supply.

Figure 47 provides the same analysis for net revenues under pLMP. As shown, some assets earned higher net revenues under pLMP while other assets earned less. Figure 48 illustrates the differences, providing pLMP net revenue less pool price net revenue.

In 2025, there was a large amount of congestion for some wind assets located in the southeast, particularly at Cypress 2, Whitla 2, and Forty Mile Granlea which all had more than 20% of their potential generation curtailed.[15] Further north, there was also notable congestion at assets such as Paintearth Wind, which had 12% of its potential generation curtailed, and Garden Plain, which had 8% of its potential generation curtailed. Due to the high level of congestion, these assets all had lower net revenues under pLMP than under pool prices.

In contrast, some wind assets fared better under pLMP. These assets were generally not curtailed in 2025, and included Bull Creek 2, which is northeast of the other wind farms, and Castle Rock Ridge 2, which is in southwest Alberta.

Figure 50 provides the same analysis for solar assets; it illustrates the difference in net revenues between pLMP and pool prices. In 2025, no solar asset earned sufficient net revenues to cover fixed and capital costs under either pricing regime. Net revenues under pool price ranged from 32% to 60% of annual fixed and capital costs, and under pLMP the range was from 37% to 65%.

[15] There was also high congestion at some newer wind assets in the southeast, but these were not included in the analysis because they hadn't previously achieved a capacity factor of 70%, indicating they weren't fully commissioned.

Figure 46: Net revenues for wind assets based on pool price (2025)

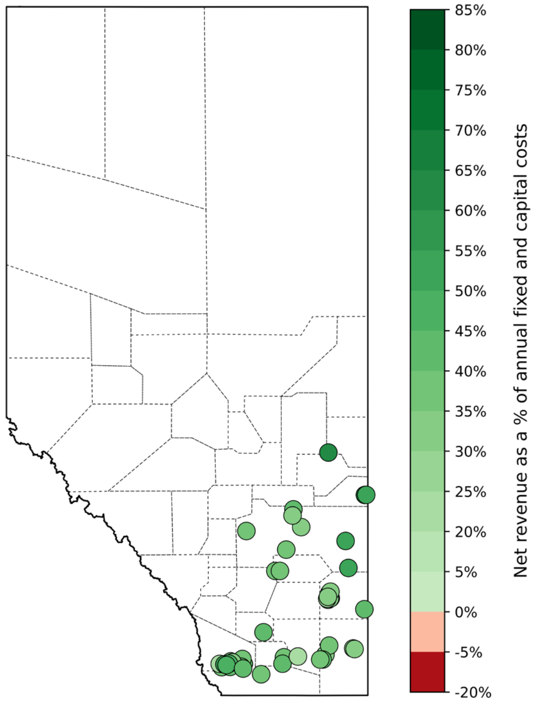


Figure 47: net revenues for wind assets based on pLMP (2025)

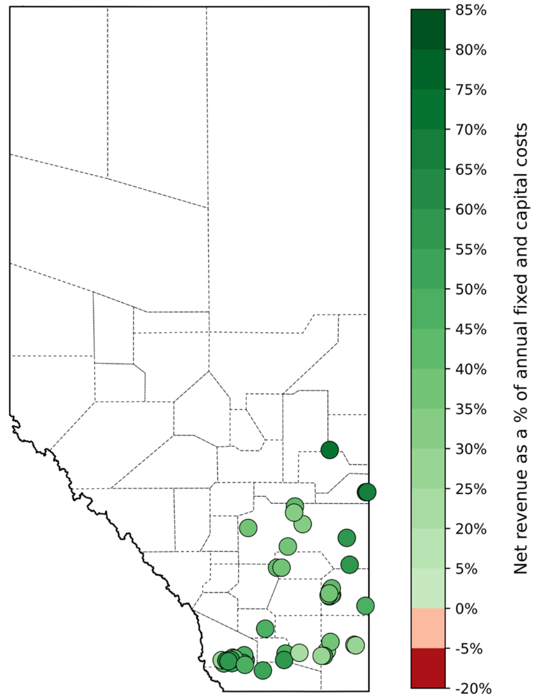


Figure 48: Net revenue difference for wind assets (pLMP – pool price, 2025)

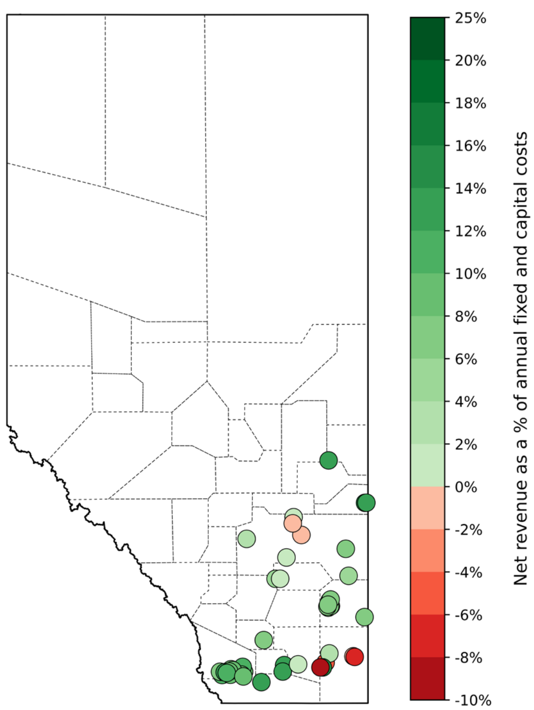


Figure 49: Congestion as a percentage of potential for wind assets (2025)

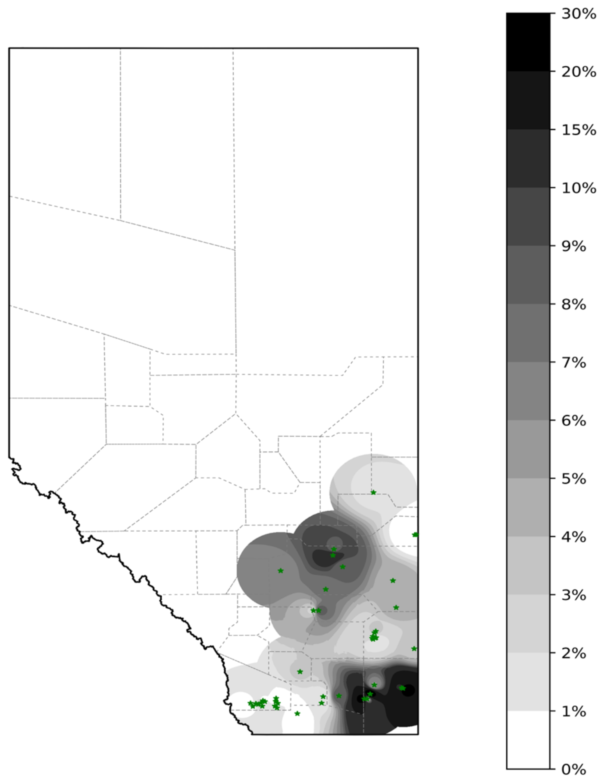


Figure 50: Net revenue difference for solar assets (pLMP – pool price, 2025)

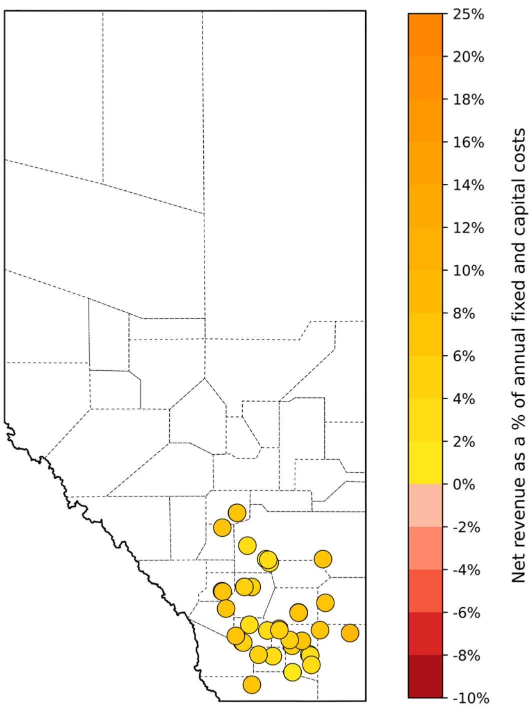
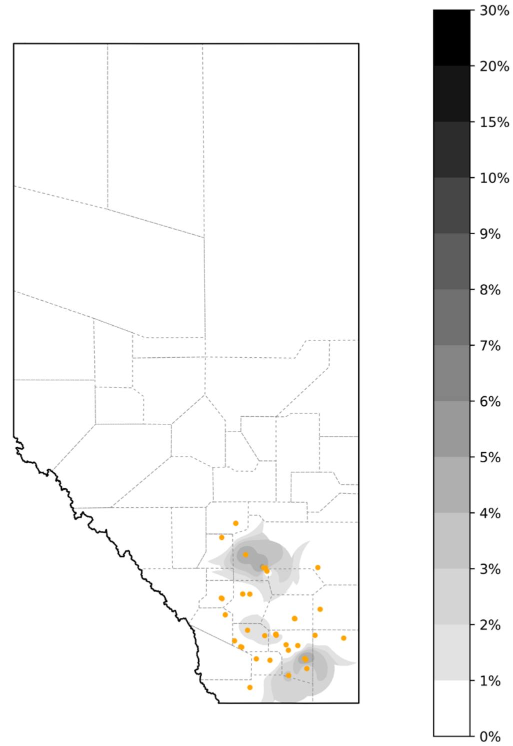


Figure 51: Congestion as a percentage of potential for solar assets (2025)



In 2025, all solar assets earned higher net revenues under pLMP as they were less congested than some wind generators. The Burdett (BUR1) asset was the most congested solar asset in 2025 with 5% of its potential generation curtailed (Figure 51).

However, in prior years some solar assets earned lower net revenues under pLMP. For example, in 2023 and 2024 the East Strathmore Namaka, Strathmore 1 and 2, and Claresholm 1 and 2 solar assets all earned lower net revenues under pLMP due to congestion.

Figure 52 and Figure 54 illustrate the same analysis for simple cycle and combined cycle assets, respectively. In 2025, all these natural gas assets would have earned higher net revenues under pLMP as there was minimal congestion for these generators (Figure 53 and Figure 55). However, even under pLMP, no simple cycle or combined cycle asset earned sufficient net revenues in 2025 to cover annual fixed and capital costs (Table 23).

Table 23: Net revenue estimates as a percent of fixed and capital costs (2025)

		Lowest	**Highest**
Simple cycle	Pool price	-16%	75%
	pLMP	-2%	85%
Combined cycle	Pool price	9%	46%
	pLMP	11%	69%

Figure 52: Net revenue difference for simple cycle assets (pLMP – pool price, 2025)

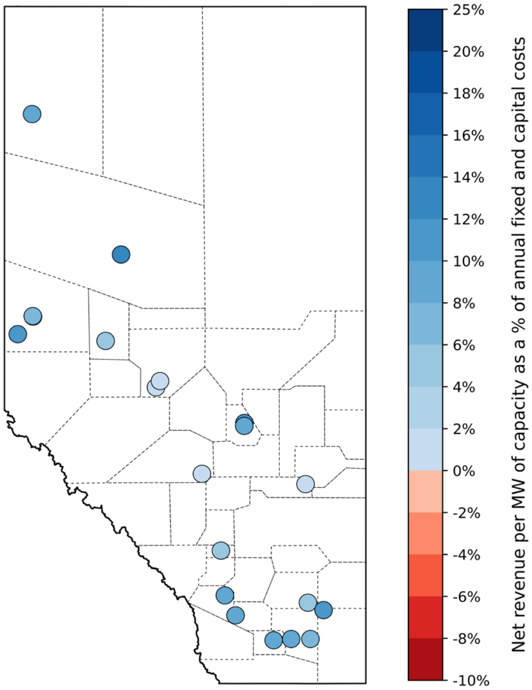


Figure 53: Congestion as a percentage of potential for simple cycle assets (2025)

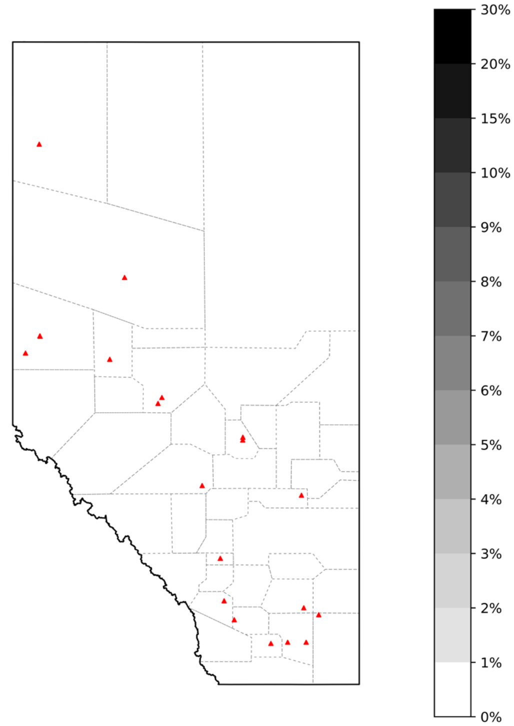


Figure 54: Net revenue difference for combined cycle assets (pLMP – pool price, 2025)

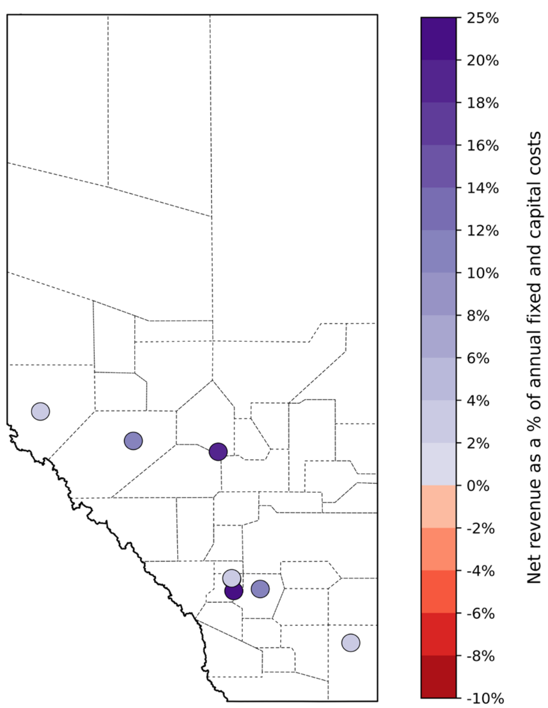
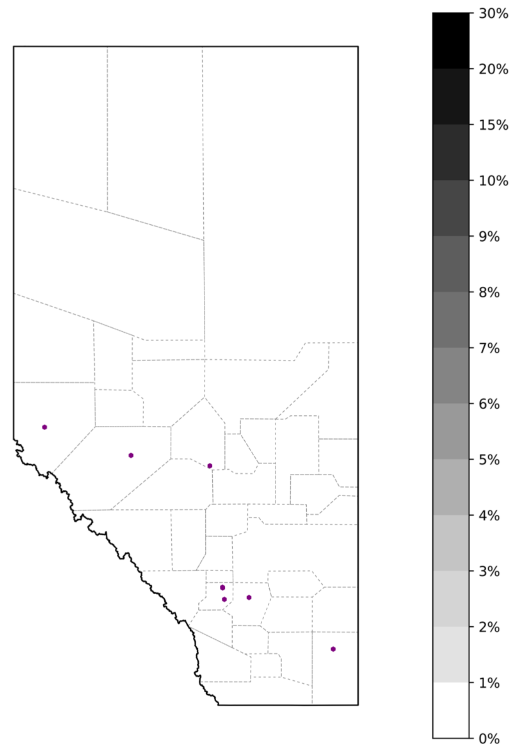


Figure 55: Congestion as a percentage of potential for combined cycle assets (2025)



While all the simple cycle and combined cycle assets would have earned higher net revenues under pLMP in 2025, this was not the case in earlier years, as several assets experienced congestion:

- In 2021, HR Milner had 1.3% of its available capacity constrained, largely due to 7L228 and 7L20 outages in January and February.
- In 2022, 2023, and 2024, Rainbow 5 had 0.6%, 3.5%, and 5.2% of its available capacity constrained, respectively, resulting from real-time overloads on the Rainbow export cutplane.
- In 2022, 2023, and 2024, Cavalier had 0.8%, 1.5%, and 1.1% of its capacity constrained, respectively, due to overloads on the 691L, 765L, and 733L transmission lines.
- In 2024, Cascade 1 and 2 had 0.9% and 1.0% of their available capacity constrained, respectively, due to overloads on the 202L, 720L, 671L, and 890L transmission lines.

As a result of the congestion during these periods, the pLMP at these assets were often lower than the pool price. Consequently, these assets earned lower net revenues under pLMP than under pool price in those years.

Overall, the analysis illustrates that the move from pool price to locational pricing will amplify the negative impact of congestion on net revenues for certain generation assets. Under both pricing regimes, the quantity assets in congested areas can sell is limited, but under locational pricing, the prices received by these assets are lower as well. This provides investors with a stronger incentive to locate generators where there is surplus transmission capacity, and congestion is less likely. By doing so, locational pricing should reduce the need for further transmission capacity in the future. Therefore, the change to locational pricing should lower the costs of transmission compared to carrying on with a market of uniform pricing.

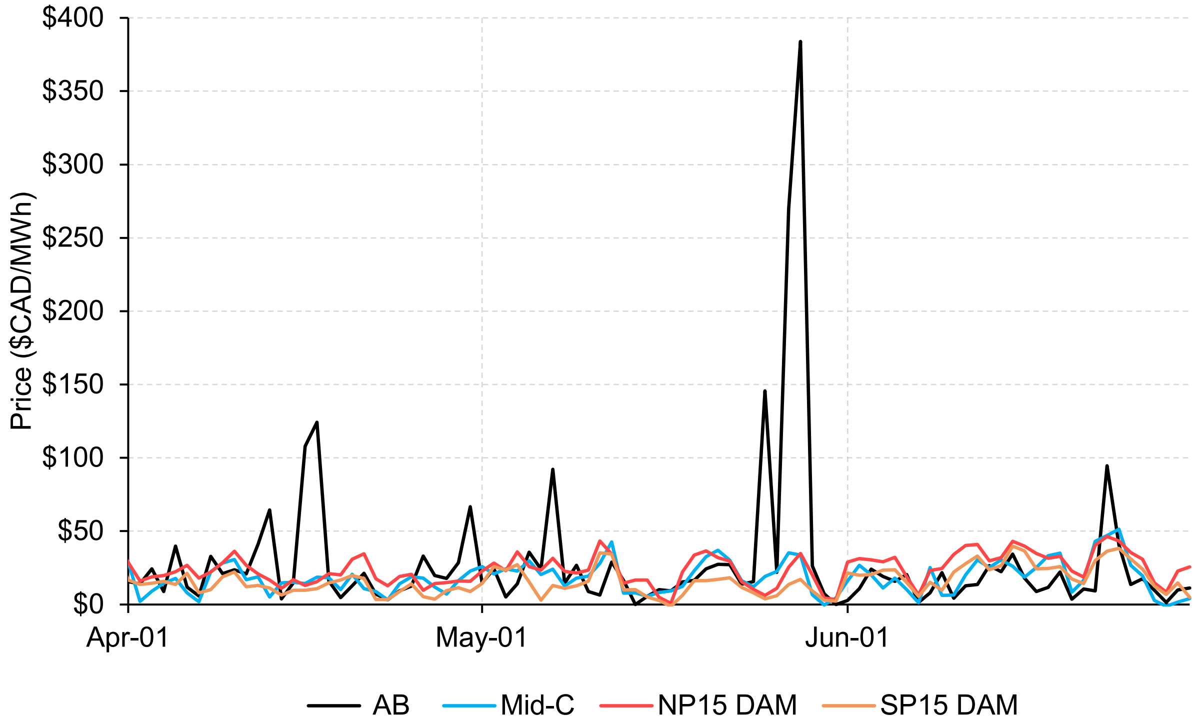
2.3 Interties

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-C and California.

Figure 56 shows daily average power prices over Q2 in Alberta, Mid-C, and at NP15 and SP15 in California (all shown in CAD). Over the quarter, Alberta pool prices averaged $29.47MWh while prices in Mid-C averaged $18.32/MWh, although Mid-C prices were higher in 54% of hours.

Day-ahead prices at NP15 and SP15 averaged $23.92/MWh and $15.86MWh, respectively, over the quarter. Alberta was a net importer over Q2 (Table 24), which hasn't occurred since Q3 2023. Alberta was a net importer in 69% of hours in Q2, a net exporter in 19% of hours, with no net flows in 13% of hours.

Figure 56: Daily average power prices in Alberta, Mid-C, and NP15/SP15 in California (Q2)



In April, Mid-C prices averaged $14.95/MWh compared to $27.61/MWh in Alberta, with Alberta prices being higher in 56% of hours, leading to net imports of 174 MW over BC/MATL. In May, Mid-C prices averaged $19.77/MWh while Alberta averaged $42.98/MWh. However, Mid-C prices were higher in 57% of hours. Given the price differential, net imports on BC/MATL averaged 223 MW over the month.

In June, Alberta prices declined to an average of $17.36/MWh compared to $20.20/MWh in Mid-C, and prices in Mid-C were higher in 63% of hours. Despite this, an average of 150 MW of net imports were scheduled over BC/MATL.

Bonneville Power Administration (BPA) operates one of the largest balancing authorities in the Pacific Northwest, and conditions within its hydro-dominated system are closely linked to Mid-C prices. Figure 57 shows that monthly average Mid-C prices declined as BPA's generation mix became increasingly hydro-dominated.

During Q2, hydro accounted for at least 75% of net generation and wind approximately 10%, while natural-gas generation was near zero. Greater hydro availability, supplemented by wind generation, was the main driver of lower prices in Mid-C. This increase in hydro generation contributed to the shift from Alberta being a net exporter to a net importer.

Figure 57: Monthly average Mid-C day-ahead price and BPA net generation percentages

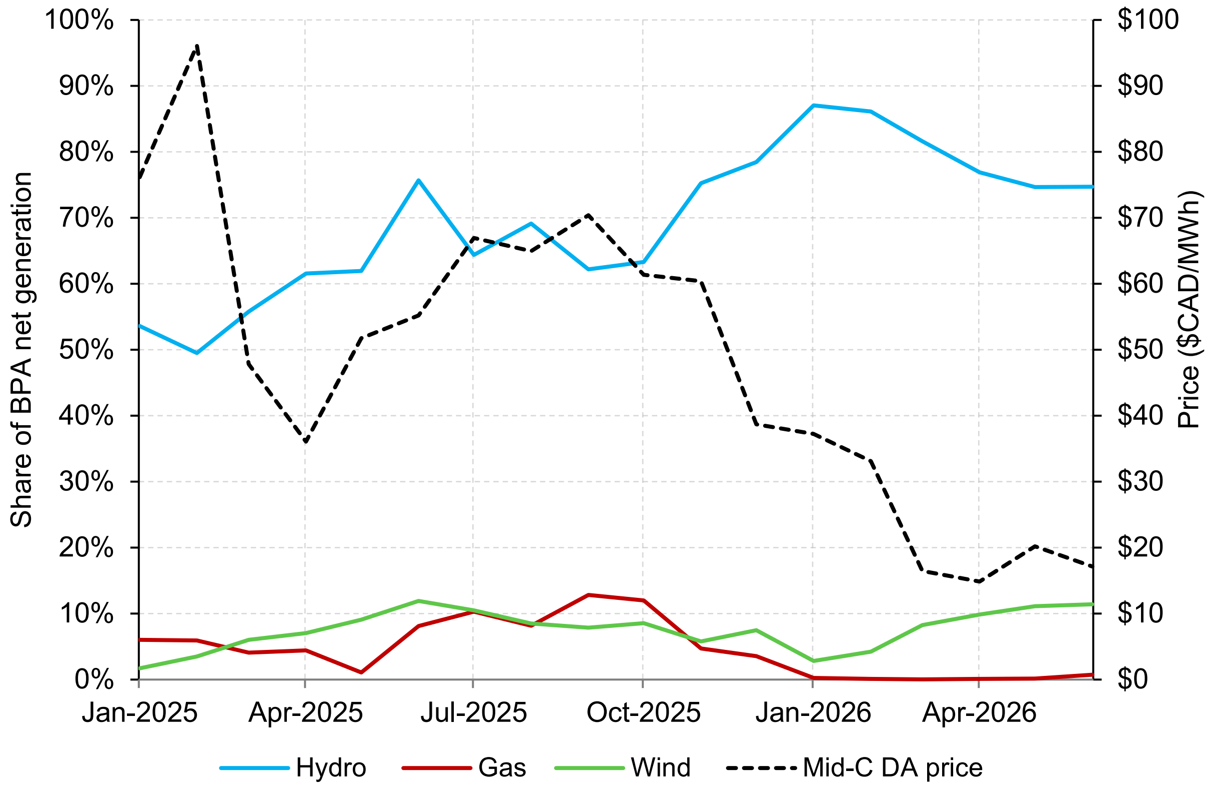


Table 24: Average net imports (Q2 2025 and Q2)

	2025				2026			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
Apr	-223	1	0	-222	156	18	2	177
May	-213	7	0	-206	198	24	27	250
June	-322	-21	0	-343	140	10	24	174
Q2	**-252**	**-4**	**0**	**-256**	**165**	**17**	**18**	**201**

Between April 13 HE 10 and April 18 HE 15, Alberta was islanded due to a scheduled Path 1 outage (Figure 58). Heading into the outage, Alberta was import constrained on BC/MATL due to periods of higher pool prices. Due to the intertie outage, pool price volatility that occurred on April 16 and 17 could not be captured by importers.

BC/MATL import capability was also reduced between June 10 and 25, and fell below 200 MW in certain hours, because of an outage on 2L294, which is a 230 kV transmission line in southeast BC (Figure 59).

Figure 58: Hourly import and export volumes on BC/MATL, joint capability, and the Alberta - Mid-C price differential (April 12 to April 19)

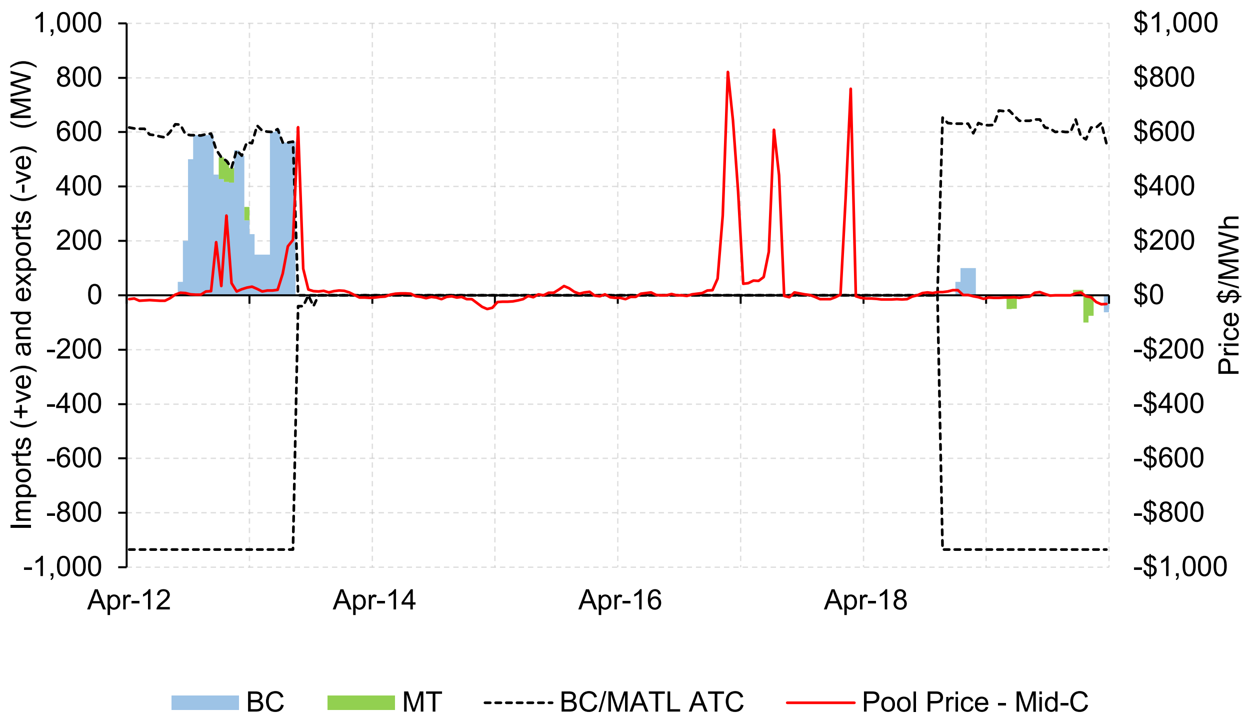


Figure 59: Daily average import and export volumes on BC/MATL, joint capability, and the Alberta - Mid-C price differential (Q2)

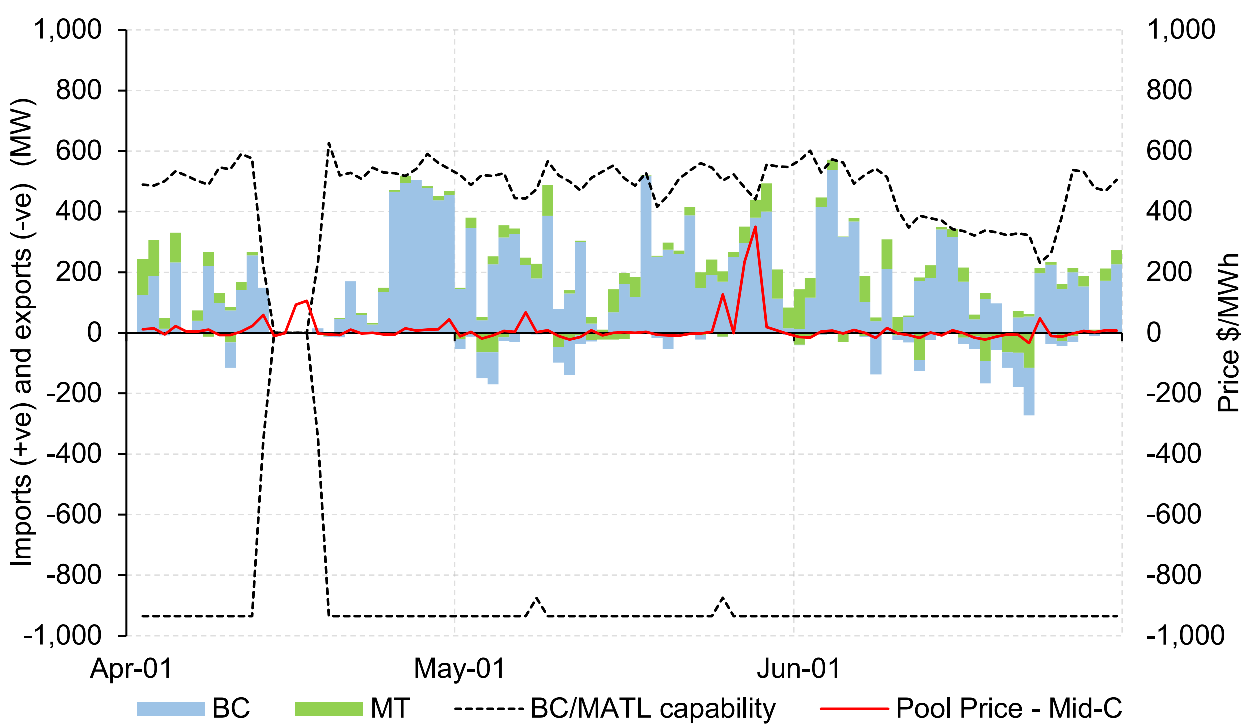


Figure 60 to Figure 62 show the monthly average scheduled volumes for the main participants on the BC, Montana, and Saskatchewan interties. Most of the import volume on the BC intertie is originated by Powerex as they have 635 MW of firm import transmission, with TCE also holding 100 MW of firm import transmission.

Import volumes on MATL from Morgan Stanley ceased at the end of April because the power purchase agreements for the control of the Glacier 1, Glacier 2, and Rim Rock wind farms in Montana expired and have returned to AlbertaEx. This is demonstrated by their import volume in May and June. AlbertaEx holds the entire 300 MW of firm import transmission capacity on MATL.

Most of the import volume on the Saskatchewan intertie originates from Northpoint, who hold the entire 153 MW of firm import transmission capacity.

Figure 60: Monthly average scheduled interchange on the BC intertie by top participants (January to June 2026)

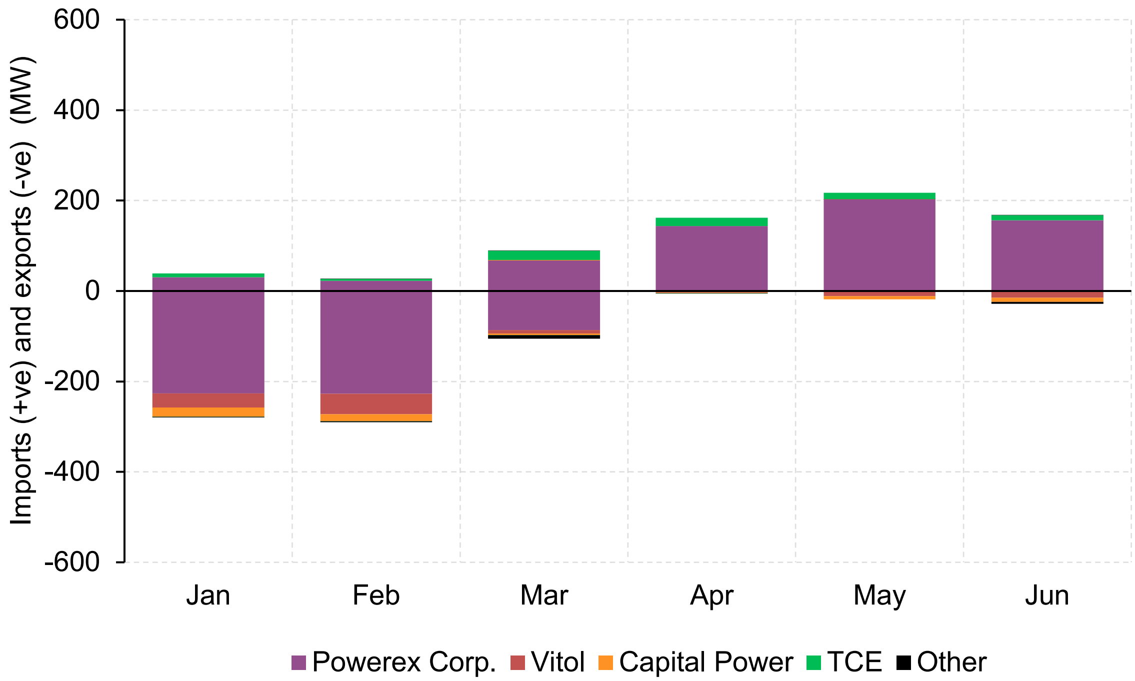


Figure 61: Monthly average scheduled interchange on MATL by top participants (January to June 2026)

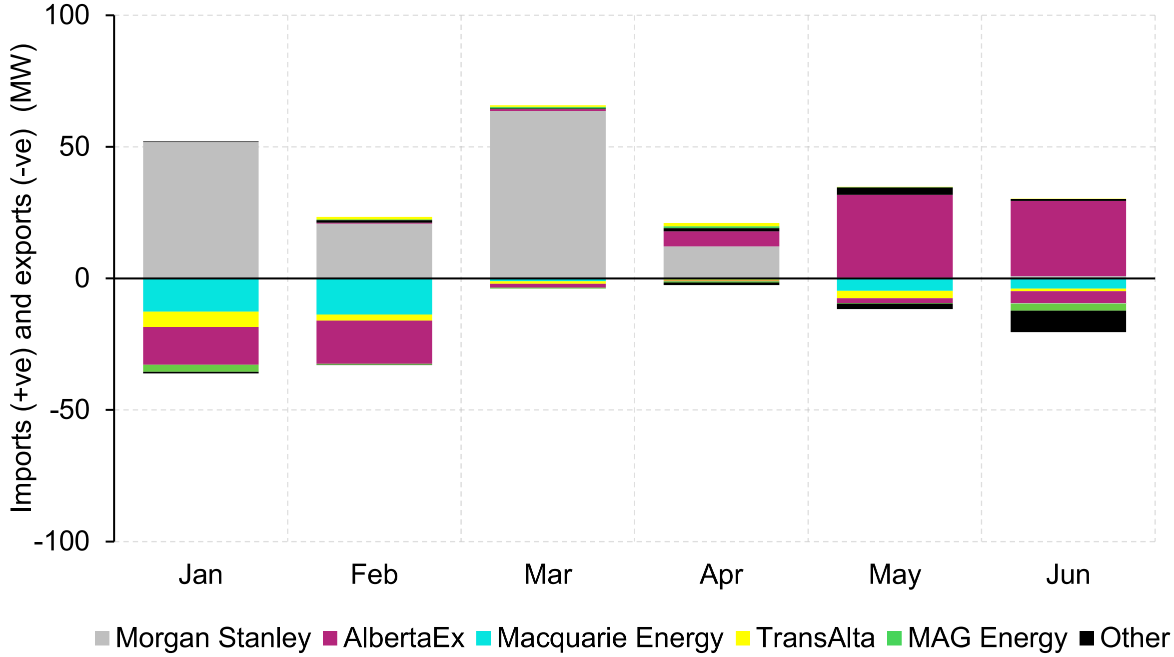


Figure 62: Monthly average scheduled interchange on the Saskatchewan intertie by top participants (January to June 2026)

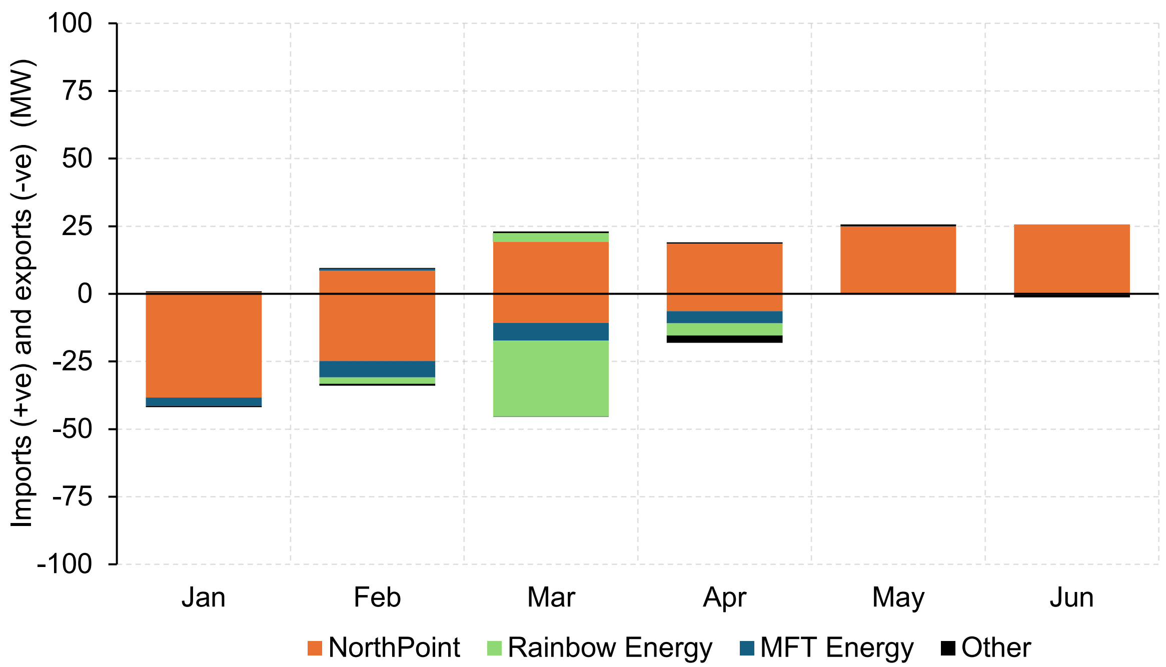


Figure 63 shows a scatterplot of the Alberta and Mid-C price differential against net imports on BC/MATL for each hour of the quarter. Over Q2, there were some hours where import offers or scheduled volumes were at or above BC/MATL import capability, meaning that BC/MATL was import constrained (shown in red). BC/MATL imports were constrained 27% of the time over the quarter. While import constrained, the price differential between Alberta and Mid-C averaged $44/MWh and import capability averaged 462 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, the observations of zero net imports with high prices coincide with the BC/MATL outage from April 13 to 18. In addition, the constrained observations under 250 MW are associated with hours between June 10 to 25, when import capability was reduced because of the outage on 2L294.

In HE 21 of May 25, the AESO increased import capability from 440 MW to 826 MW because of the EEA3 event, as shown by the constrained observation in the top right.

Figure 63: Alberta and Mid-C price differential and net imports on BC/MATL (Q2)

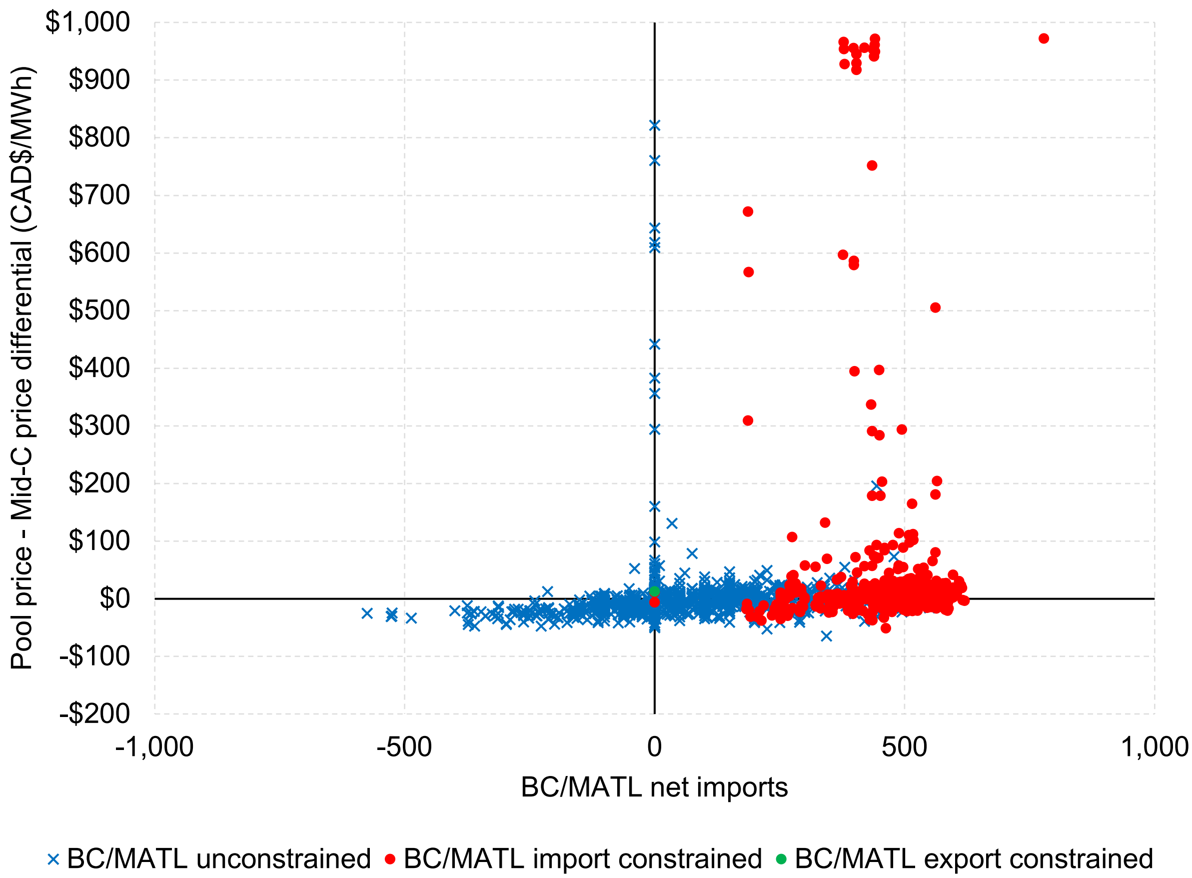
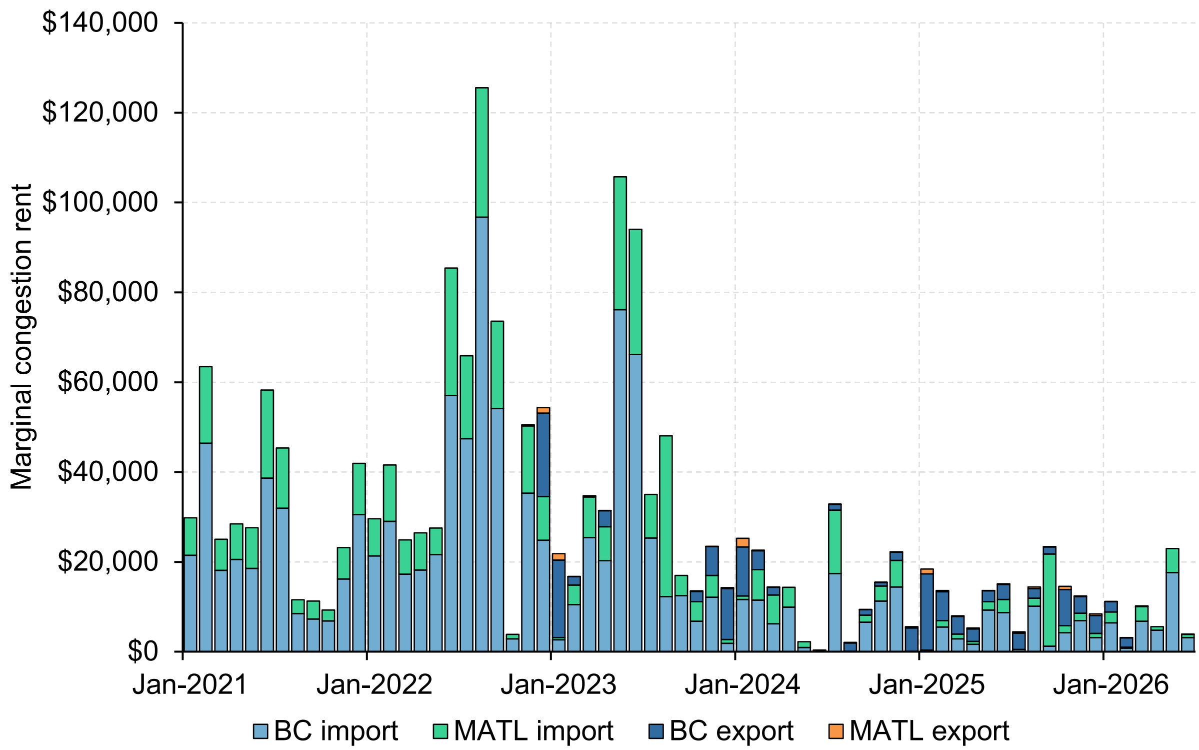


Figure 64 illustrates total monthly marginal congestion rents for the BC and Montana interties from January 2021 to June 2026. The marginal congestion rent estimates the incremental value of 1 MW of additional intertie capacity. It is calculated as the sum of the price differentials across the interties in hours when flows were constrained.

The marginal congestion rent accrues when an 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 63; 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 LMP at nodes in the Western Energy Imbalance Market (WEIM). The Sumas node[16] on the BC-US border is used to proxy pricing in BC, and the Rainbow node[17] near Great Falls, Montana is used for MATL as it is 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.

Figure 64: Marginal congestion rent on BC and MATL (January 2025 to June 2026)



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.

[16] Sumas node refers to the WEIM locational marginal pricing node SMS_GNODEGEN2

[17] Rainbow node refers to the WEIM locational marginal pricing node RBOW_GEN_1_RBOWGNODE

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 capacity over time.

In Q2, marginal congestion rents on BC and MATL accrued from imports due to higher Alberta pricing. However, due to the lower absolute price differentials, the congestion rents were less than in prior years.

Figure 65 shows how often the BC and Montana interties were constrained in each month. The frequency of import constrained periods on BC and MATL increased in Q2, with May having the highest proportion of import constrained hours since June 2023.

Figure 65: Percent of hours constrained by intertie and direction (January 2021 to June 2026)

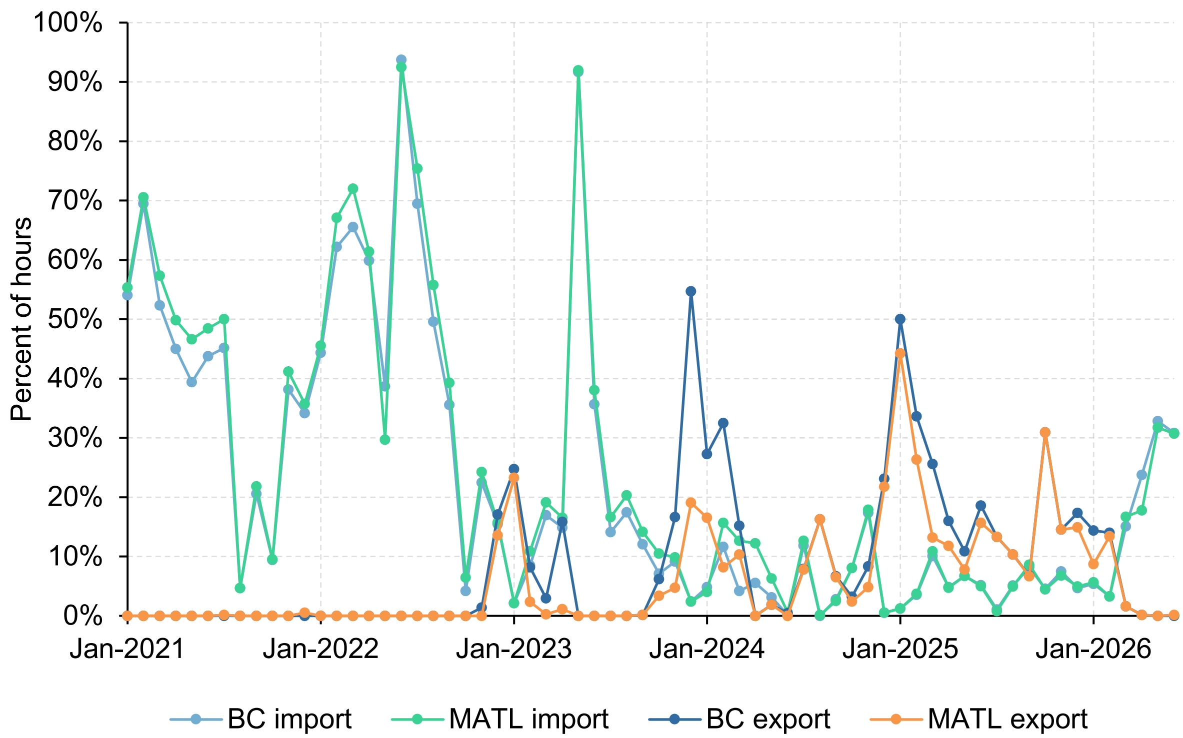


Figure 66 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[18] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

For imports on the BC intertie, 92% originated from BC and 8% from the US Northwest. For exports on the BC intertie, 87% were delivered to US Northwest, 4% to BC, 4% to California, 4% to US Southwest, and 1% to SPP.

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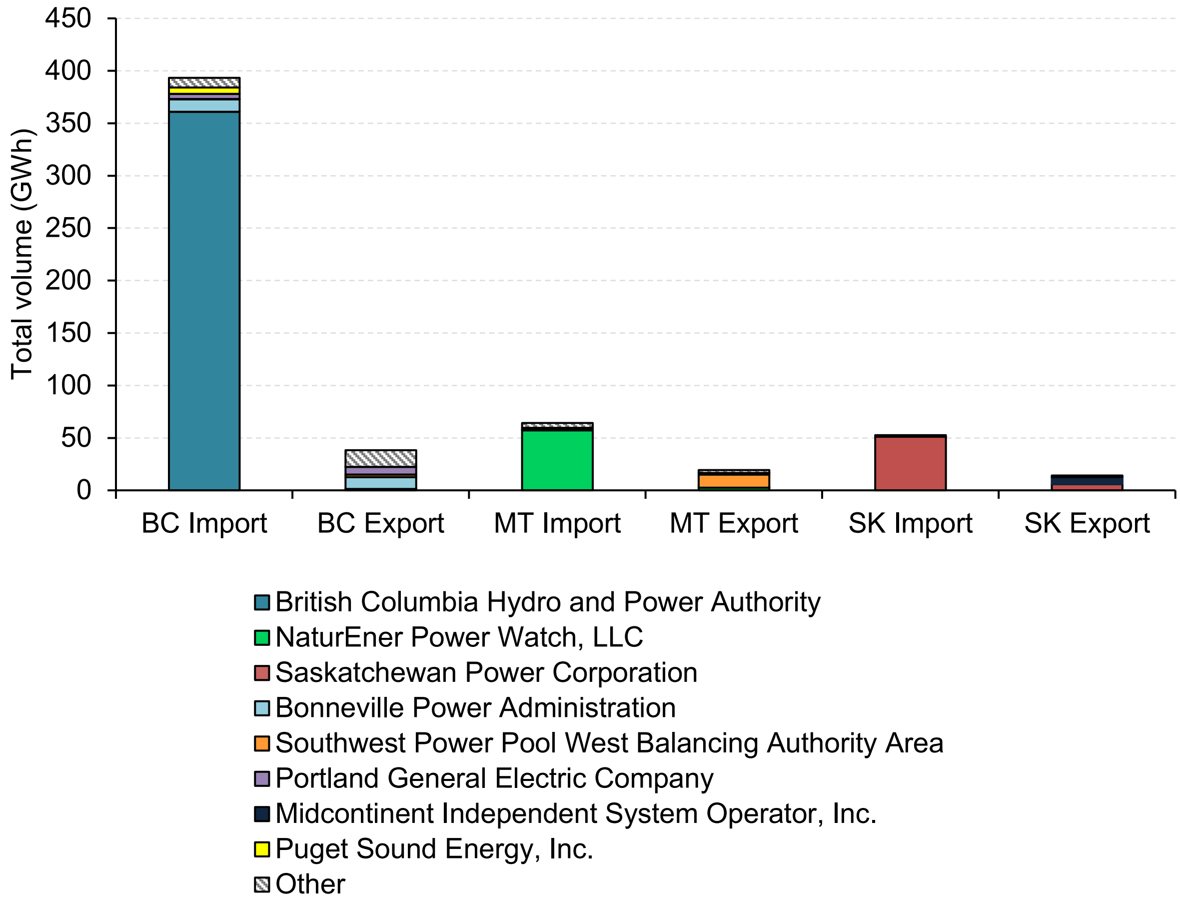
[18] The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered to.

For imports on MATL, 97% originated from the US Northwest, and 3% from California. For exports on MATL, 92% were delivered to the US Northwest, 5% to SPP, and 3% to California.

For imports on the Saskatchewan intertie, 98% originated from Saskatchewan and 2% from SPP. For exports on the Saskatchewan intertie, 48% were delivered to MISO, 41% to Saskatchewan, 6% to Ontario, 4% to SPP, and 1% to Manitoba.

Figure 66: Interchange POR (imports) and POD (exports) for interchange volumes by Balancing Authority (Q2)[19]



2.4 Transmission must-run

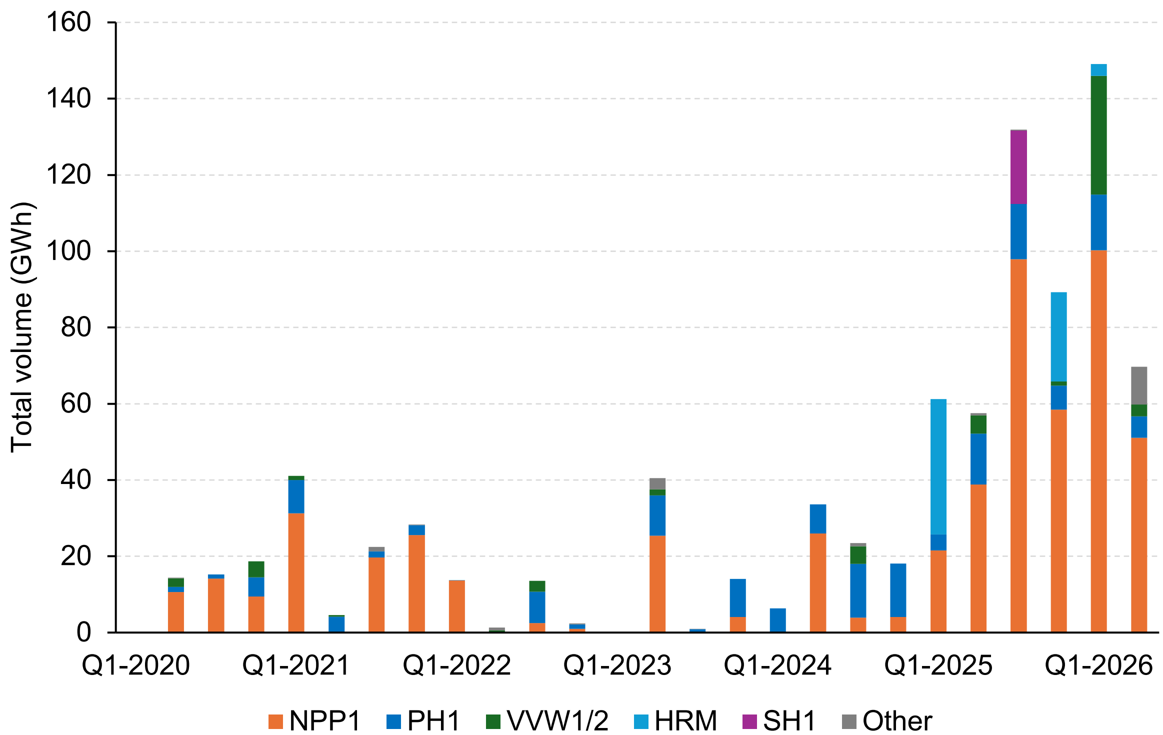
Transmission must-run (TMR) is an out-of-market ancillary service used by the AESO to provide supplementary sources of supply to help maintain grid stability. Generally, the AESO use TMR when demand in a region of the province's electricity system cannot be served by dispatched generation due to transmission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

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

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.

Total TMR volumes in Q2 were 70 GWh, down 53% from the record in Q1, but a 21% increase compared to Q2 last year (Figure 67). Total TMR costs in Q2 were $5.6 million. As with prior quarters, TMR volumes in Q2 were almost exclusively directed in the Northwest region, generally around Grande Prairie. The Northern Prairie Power Project generation asset accounted for 73% of TMR volumes in the quarter.

Figure 67: Total TMR volumes by quarter and asset (Q1 2020 to Q2)



On May 12, the AESO directed a total of 9,891 MWh of TMR, a new daily record by some margin (the prior record was 4,800 MWh). The large volume of TMR on May 12 was mainly caused by two emergency transmission line outages on 919L and 989L (both at 240 kV), which forms one of the main transmission corridors from Central to Northwest Alberta. The outages were taken due to forest fires in the area and reduced the power transfer capability into the Northwest. As a result, TMR was directed in the region to maintain grid reliability.

The AESO directed more than 300 MW of generation to provide TMR from HE 12 to 19 on May 12. Table 25 provides the generators that were directed to provide TMR in HE 17, when total TMR was 336 MW.

In addition, the AESO directed some Demand Opportunity Service (DOS) loads to provide Transmission Must Reduce by reducing consumption (Table 26). The AESO did this for the first time during the evening peak on May 11.

Table 25: Generation assets directed to provide TMR (May 12, HE 17)

Asset name	Asset ID	Fuel type	Location	Volume (MW)
Northern Prairie Power Project	NPP1	Simple cycle	Grande Prairie, NW	76
AB Newsprint	ANC1	Simple cycle	Swan Hills, NW	50
Rainbow 5	RB5	Simple cycle	Rainbow Lake, NW	46
Valleyview 2	VVW2	Simple cycle	Valleyview, NW	43
Valleyview 1	VVW1	Simple cycle	Valleyview, NW	43
Poplar Hill 1	PH1	Simple cycle	Grande Prairie, NW	33
Swan Hills Geothermal	SRL1	Other	Swan Hills, NW	13
Carson Creek	GEN5	Simple cycle	Swan Hills, NW	12
Saddle Hills	SDH1	Simple cycle	Grande Prairie, NW	10
Judy Creek	GEN6	Simple cycle	Swan Hills, NW	10

Table 26: DOS load assets directed to provide Transmission Must Reduce (May 12, HE 17)

Asset name	Asset ID	Type	Location	Volume (MW)
ANCD AB Newsprint DOS	ANCD	Load	Swan Hills, NW	83
MWFD Millar Western DOS	MWFD	Load	Swan Hills, NW	65
MWAD Millar Western DOS	MWAD	Load	Swan Hills, NW	55

2.5 BAL compliance

Compliance with the Alberta Reliability Standards (ARS) is essential to the reliable operation of the Alberta Interconnected Electric System (AIES). Six BAL (Resource and Demand Balancing) reliability standards currently apply to the AESO:

- BAL-001-AB-2 *Real Power Balancing Control Performance*
- BAL-002-AB-3 *Contingency Reserve for Recovery from a Balancing Contingency Event*
- BAL-002-WECC-AB1-2 *Contingency Reserve*
- BAL-003-AB1-1.1 *Frequency Response and Frequency Bias Setting*
- BAL-004-WECC-AB-2 *Automatic Time Error Calculation*
- BAL-005-AB-1 *Balancing Authority Control*

This section reports the MSA's assessment of the AESO's performance against the specific requirements of BAL-002-AB-3, BAL-002-WECC-AB1-2, BAL-003-AB1-1.1, BAL-004-WECC-AB-2, and BAL-005-AB-1 for the period from January 1, 2023 to September 1, 2025 based on the period covered by Information Requests sent to the AESO.

This section also covers BAL-001-AB-2, continuing the MSA's reporting on that standard from the Q4 2024 report.[20] In this case, the MSA's analysis of the AESO's performance against the requirements set out in BAL-001 covers the period from January 1, 2017 to December 31, 2025.

The requirements for each standard can be found in the respective standard documents on the AESO's website.[21]

2.5.1 BAL-001-AB-2 Real Power Balancing Control Performance

The purpose of this reliability standard is to control interconnection frequency within defined limits.

This standard applies to the ISO, except when:

(i) the ISO is receiving overlap regulation service
(ii) the ISO is a member of a regulation reserve sharing group and remains in active status under the applicable agreement or the governing rules for the regulation reserve sharing group; or
(iii) the interconnected electric system is not synchronously connected to the interconnection.

The AESO does not receive overlap regulation service and is not a member of a regulation reserve sharing group.

Requirement R1 - Control Performance Standard 1 (CPS1) measures the relationship between Area Control Error (ACE) and system frequency deviations, relative to the targeted frequency bound for the Western Interconnection as determined by the North American Electric Reliability Corporation (NERC). The specifics of the CPS1 calculation are set out in the MSA's Q2 2024 report.[22] The average CPS1 for 2025 was 181%, a year-over-year increase of 1%. CPS1 exceeded the 100% threshold in 97% of hours in 2025.

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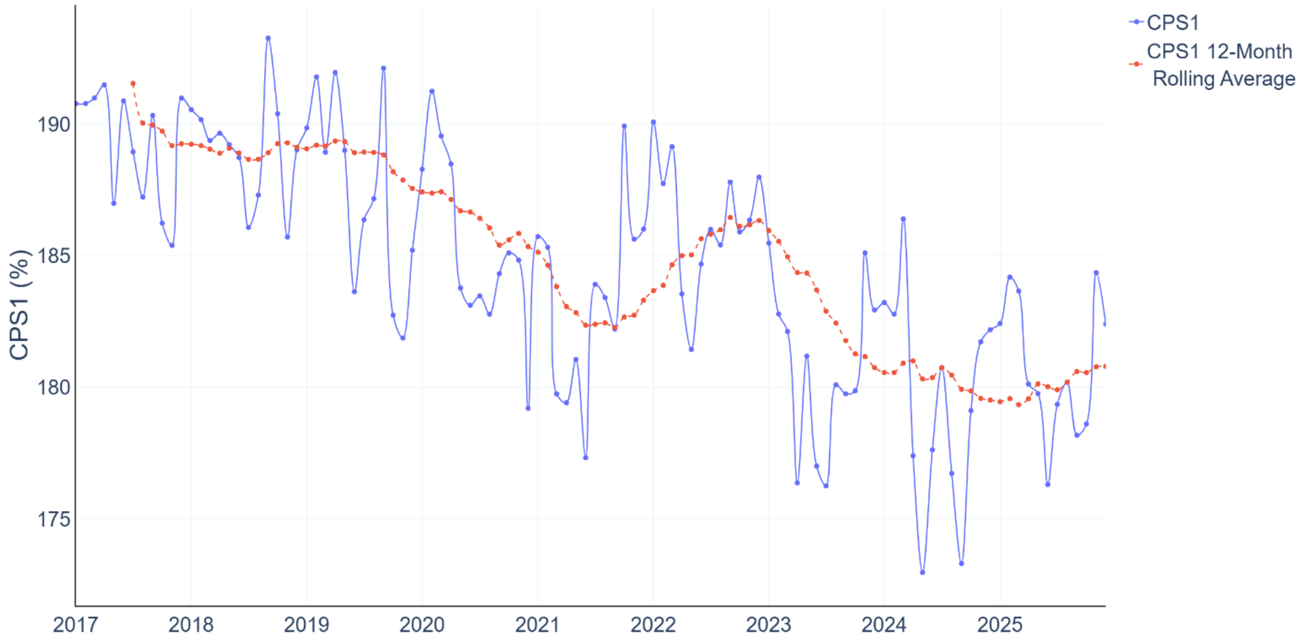
[20] MSA: Quarterly Report for Q4 2024 at page 74

[21] AESO: Alberta Reliability Standards

[22] MSA: Quarterly Report for Q2 2024 at page 38

Figure 68: Monthly average CPS1 (Jan 2017 to Dec 2025)

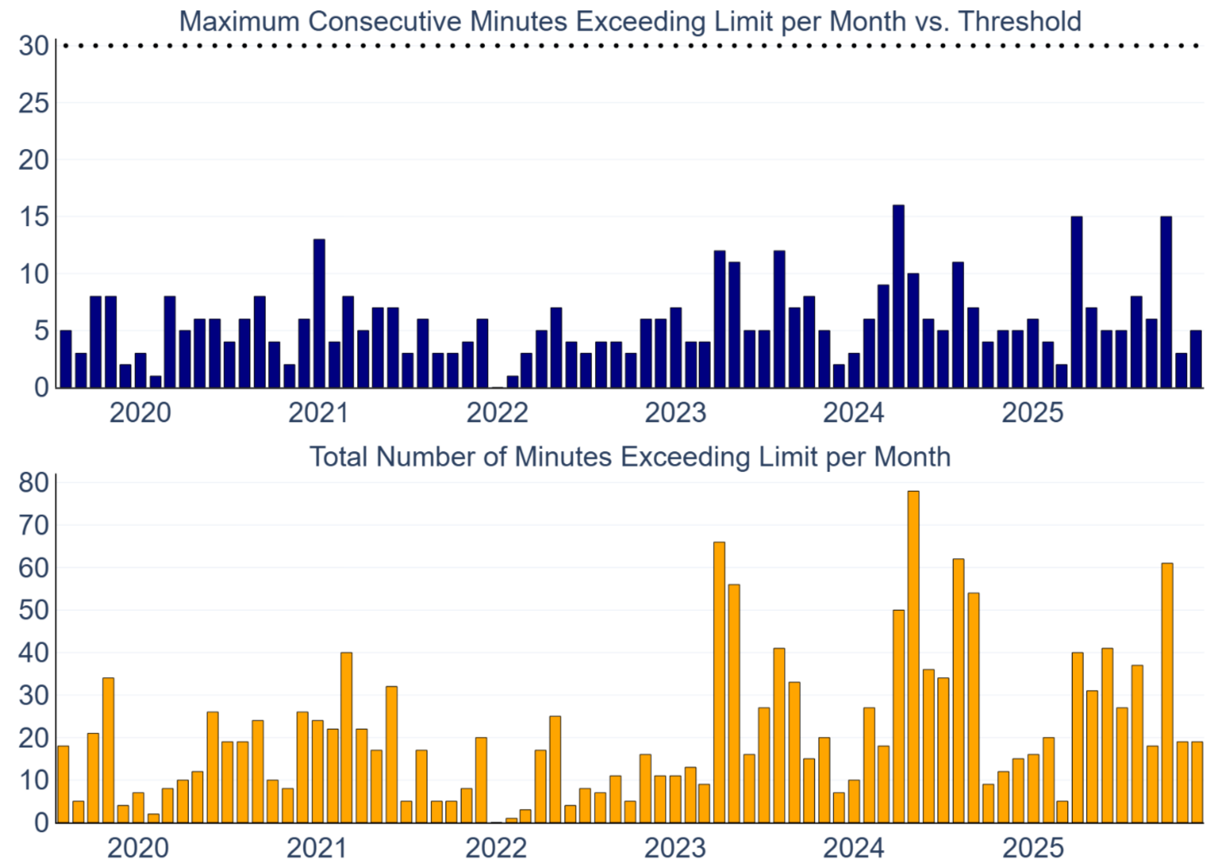


Requirement R2 - ACE is a power system metric that is inherently volatile. The thresholds BAALLow and BAALHigh establish bounds on ACE for each clock-minute. BAL-001 requires that ACE not exceed these bounds, above or below, for more than 30 consecutive clock-minutes. The standard does not set an upper limit on the total number of exceedances in a month or any other period.

BAALLow applies as the lower boundary when actual frequency is below 60 Hz, and BAALHigh applies as the upper boundary when actual frequency is above 60 Hz. Neither applies when actual frequency is exactly 60 Hz.

Figure 69 is presented in two panels. The upper panel shows the maximum number of consecutive minutes in which the bounds were exceeded; the lower panel shows the total number of minutes in exceedance. The longest run of consecutive ACE exceedances in 2025 occurred on April 9 and October 5 with ACE exceeding the limits in 15 consecutive clock-minutes, driven by rapid loss in output from wind and solar assets combined with a high amount of gas outages. October recorded the greatest total number of minutes in exceedance of BAAL in 2025 at 61 minutes.

Figure 69: Monthly ACE limit exceedances (July 2019 to December 2025)



2.5.2 *BAL-002-AB-3 Contingency Reserve for Recovery from a Balancing Contingency Event*

The purpose of this reliability standard is to ensure the ISO balances resources and demand and returns the ACE to defined values, subject to applicable limits, following a reportable balancing contingency event.

This reliability standard applies to the ISO, only in the periods during which the ISO is not in active status under a reserve sharing group (RSG) agreement or governing rules for a RSG. The AESO is a member of the Western Power Pool (WPP) RSG program.[23]

The MSA's assessment determined that the AESO maintained active status in the WWP RSG program throughout the assessment period and therefore the requirements of BAL-002-AB-3 were not applicable to the AESO during this period.

[23] Western Power Pool: Reserve Sharing Program Documentation

2.5.3 BAL-002-WECC-AB1-2 Contingency Reserve

The purpose of this reliability standard is to specify the quantity and types of contingency reserve required to ensure reliability under normal and abnormal conditions.

The ISO may meet the requirements of this reliability standard through participation in a RSG program that the ISO has designated it as its agent.

The MSA's assessment determined that the AESO maintained active status in the WWP RSG Program and therefore the AESO satisfied its compliance obligations under BAL-002-WECC-AB1-2 during the assessment period. The MSA did not assess the AESO’s compliance with the terms of the Reserve Sharing Group Agreement.

2.5.4 BAL-003-AB1-1.1 Frequency Response and Frequency Bias Setting

The purpose of this reliability standard is to:

a. require sufficient frequency response from the ISO to maintain interconnection frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value, and
b. provide consistent methods for measuring frequency response and determining the frequency bias setting.

This standard applies to the ISO, unless the interconnected electric system is not synchronously connected to the Interconnection.

The MSA's assessment of Requirement R1 determined that the AESO complies by designating the WPP SRG as its agent. Table 27 sets out the AESO's annual frequency response (including purchased transferred frequency response) and its corresponding frequency response obligation for 2023 and 2024.

Table 27: AESO annual frequency response and frequency response obligation (2023-2024)

Year	Frequency response measure (MW/0.1Hz)	Frequency response obligation (MW/0.1 Hz)
2023	-107.83	-105.3
2024	-113.52	-98.2

The MSA's assessment of Requirement R2 determined that the AESO complies with the requirement to implement the frequency bias setting. The setting is validated by the Electric Reliability Organization (ERO) and then incorporated into the Automatic Generation Control (AGC) application within the AESO's Energy Management System (EMS).

As the AESO does not utilize a variable frequency bias setting or perform overlap regulations, Requirements R3 and R4 do not apply.

2.5.5 BAL-004-WECC-AB-2 Automatic Time Error Correction

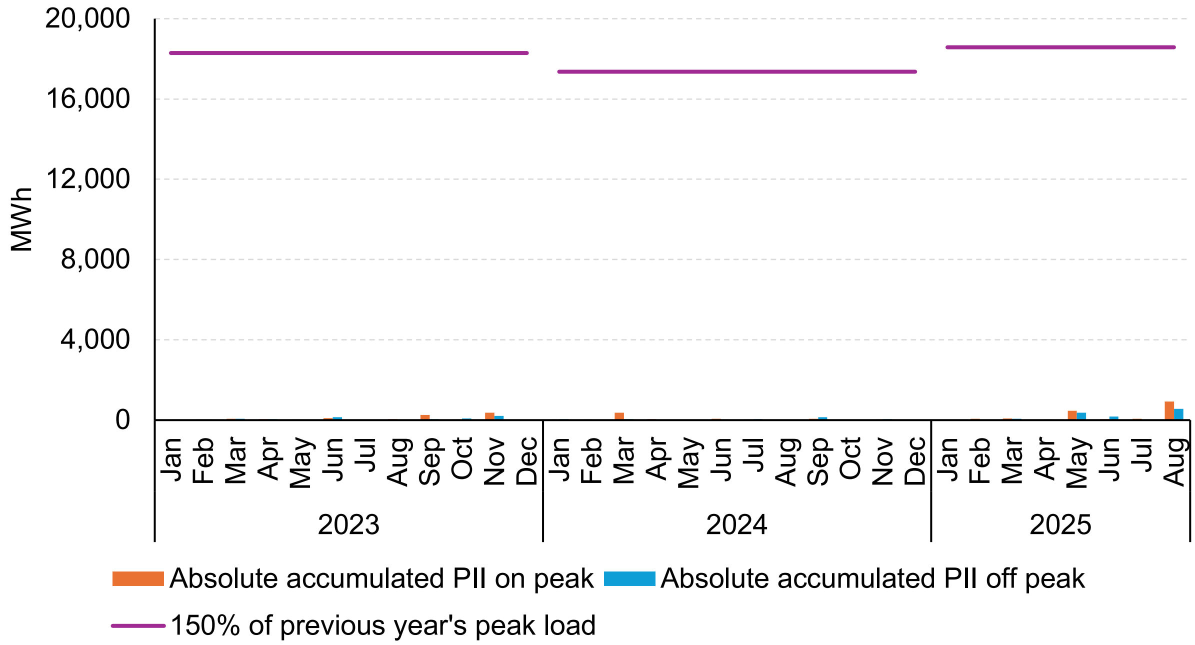
The purpose of this reliability standard is to maintain the frequency of the Western Interconnection and to ensure that time error corrections and primary inadvertent interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Western Interconnection.

This standard applies to the ISO.

The MSA assessed Requirements R1 through R4 of this standard.

For Requirement R1, the MSA assessed the AESO as compliant throughout the assessment period, as the monthly absolute accumulated PII for both on-peak and off-peak periods remained below the applicable threshold of 150% of the previous calendar year's peak demand (Figure 70).

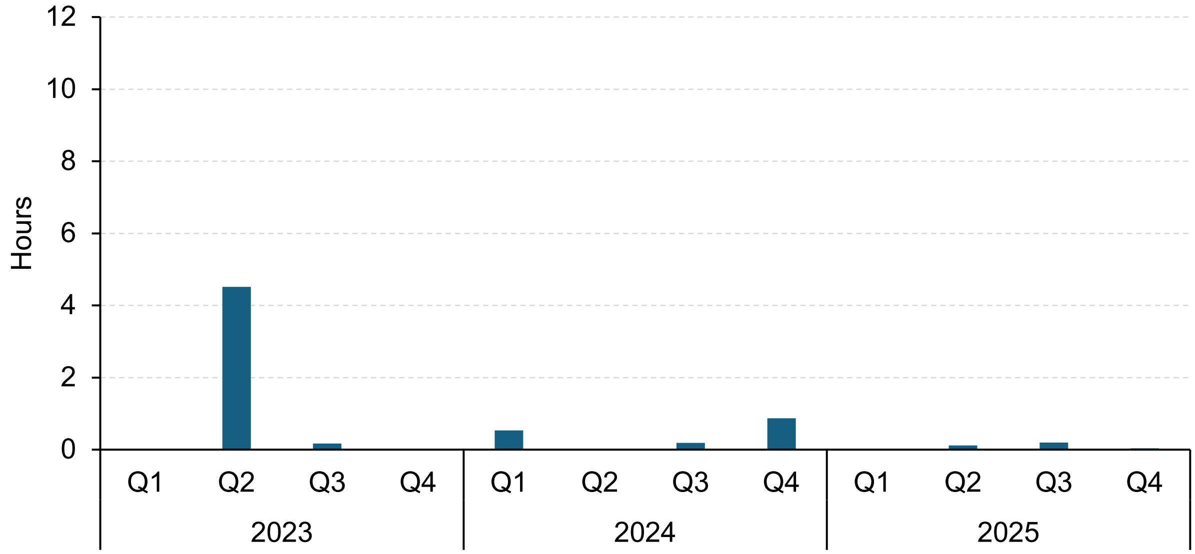
Figure 70: Monthly on-peak and off-peak absolute accumulated PII against the 150% prior year peak demand (2023 to 2025)



For Requirement R2, the MSA's assessment concluded that the AESO was compliant, as adjustments are automated between Alberta and the adjacent balancing authority in Montana and are confirmed and agreed upon monthly between Alberta and the adjacent balancing authority in British Columbia.

For requirement R3 - The MSA's assessment concluded that the AESO was compliant. The automatic time error correction (ATEC) was offline for less than a cumulative total of 24 hours in each calendar quarter (Figure 71).

Figure 71: Cumulative ATEC offline by calendar quarter (2023 to 2025)



For Requirement R4 - The MSA's assessment concluded that the AESO was compliant as the Hourly PII, the accumulated PII, and the ATEC are computed by the 50th minute of each hour.

2.5.6 BAL-005-AB-1 Balancing authority control

The purpose of this reliability standard is to establish requirements for acquiring data necessary to calculate reporting ACE and specify a minimum periodicity, accuracy, and availability requirement for acquisition of the data.

This reliability standard applies to the ISO.

The MSA assessed Requirements R3 and R5 of this standard.

For requirement R3 - The MSA is satisfied that the frequency metering equipment the AESO uses to calculate reporting ACE operates with a minimum accuracy of 0.001 Hz. The MSA further determined that this equipment met the minimum availability of 99.95% in 2024 and in 2025. In 2023, however, availability was 99.83%, below the required minimum. The AESO self-reported this contravention prior to the MSA's assessment.

For requirement R5 - The AESO's calculations indicate that the system it uses to calculate reporting ACE was available for at least 99.5% of each year in 2023, 2024, and 2025. In reviewing the methodology and calculations used by the AESO, the MSA identified that the documented methodology applied and provided to the MSA was not aligned with industry norms. On June 11, the MSA recommended the AESO review its methodology. On July 29, the AESO provided a letter to the MSA indicating that they had previously given an inaccurate description of their methodology. The AESO has clarified that the methodology used to calculate reporting ACE aligns with industry norms and that they are updating their compliance narrative to accurately reflect the methodology.

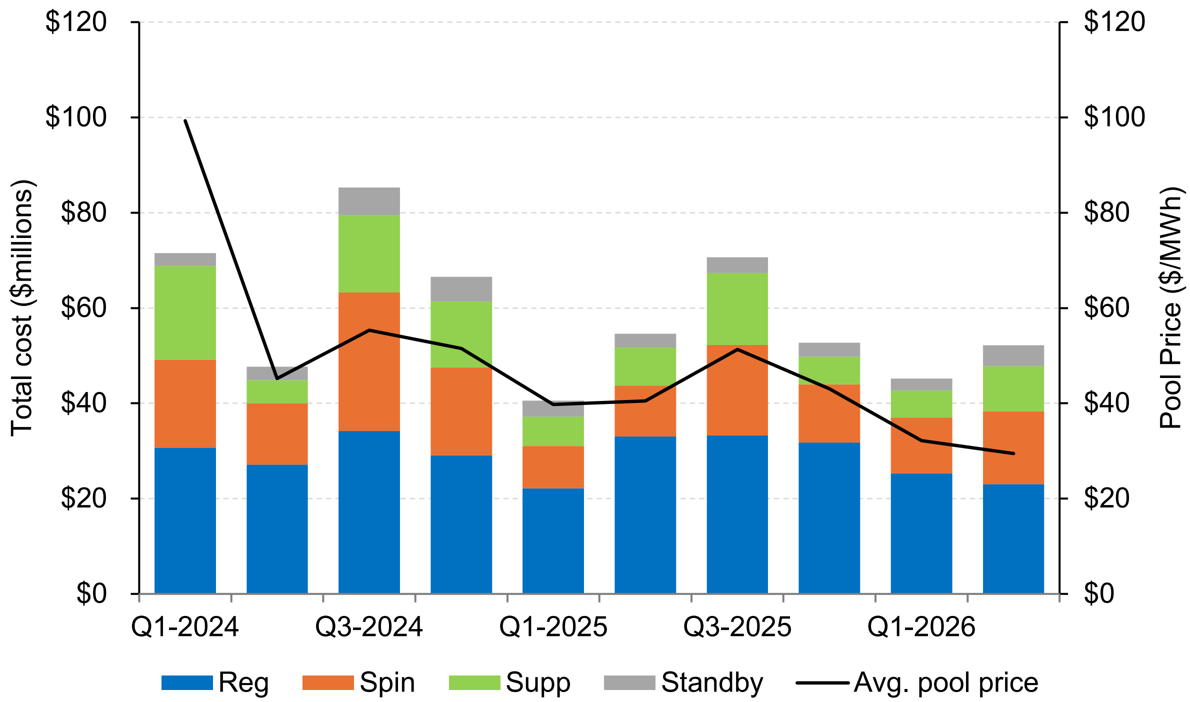
3 OPERATING RESERVES

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 trip of a generator. Spinning and supplemental reserves must respond quickly to AESO 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 fell by 4% year-over-year to $52 million while the average pool price fell by 27% (Figure 72). The decline in OR costs was less than the decline in pool prices because of higher prices for spinning and supplemental reserves. Despite the lower pool prices, the total cost of active spinning reserves increased by 43% year-over-year and the cost of active supplemental reserves increased by 19%, although demand for these products was largely unchanged.

Figure 72: Total OR costs by quarter and product (Q1 2024 to Q2)



Compared to Q1, total OR costs increased by 15% while the average pool price fell by 8%. The increase in OR costs, despite lower pool prices, was driven by higher prices for spinning and supplemental reserves. The total cost of active spinning reserves increased by 32% quarter-over-quarter and the cost of active supplemental reserves increased by 66%, even though demand for both products fell by 7%.

3.2 Active reserves

Received prices for OR products are calculated by indexing equilibrium prices set in day-ahead auctions to the hourly pool price. Table 28 provides received prices by OR product in Q2 2025 and Q2.

The average pool price fell by $11.02/MWh year-over-year but the received price for regulating reserves fell by more, declining by $28.18/MWh. This larger decline was the result of lower equilibrium prices in the day-ahead auctions. In contrast, the received prices for spinning and supplemental reserves were higher in Q2 this year, even as pool prices declined, because of higher equilibrium prices.

Table 28: Average received price by OR product (Q2 2025 and Q2)

	Q2 2025	Q2 2026	Change
Reg	$79.87	$51.68	-$28.18
Spin	$20.71	$29.46	$8.75
Supp	$15.35	$17.86	$2.51
Pool price	$40.48	$29.47	-$11.02

The overall trends were the same quarter-over-quarter; Table 29 shows received prices in Q1 and Q2. For regulating reserves, lower equilibrium prices caused the received price to fall by more than the average pool price. However, in the markets for spinning and supplemental reserves, higher equilibrium prices meant that received prices increased by around $8/MW, despite the average pool price falling by $2.68/MWh.

Table 29: Average received price by OR product (Q1 and Q2)

	Q1 2026	Q2 2026	Change
Reg	$59.76	$51.68	-$8.08
Spin	$20.94	$29.46	$8.52
Supp	$9.83	$17.86	$8.03
Pool price	$32.15	$29.47	-$2.68

Year-over-year, the lower equilibrium prices for regulating reserves were driven by lower off-peak prices. Figure 73 illustrates duration curves of equilibrium prices for off-peak regulating reserves. The lines in the figure illustrate how often equilibrium prices were at or above a given level. The large shift down from Q2 2025 to Q1 and Q2 illustrates lower equilibrium prices, which were largely caused by the entry of batteries. Figure 74 illustrates an example of the change in generation for a battery asset providing off-peak regulating reserves in early June. The asset supplied regulating reserves by consuming and producing power.

Figure 73: Duration curves of equilibrium prices for off-peak regulating reserves (Q2 2025, Q1 2026 and Q2 2026)

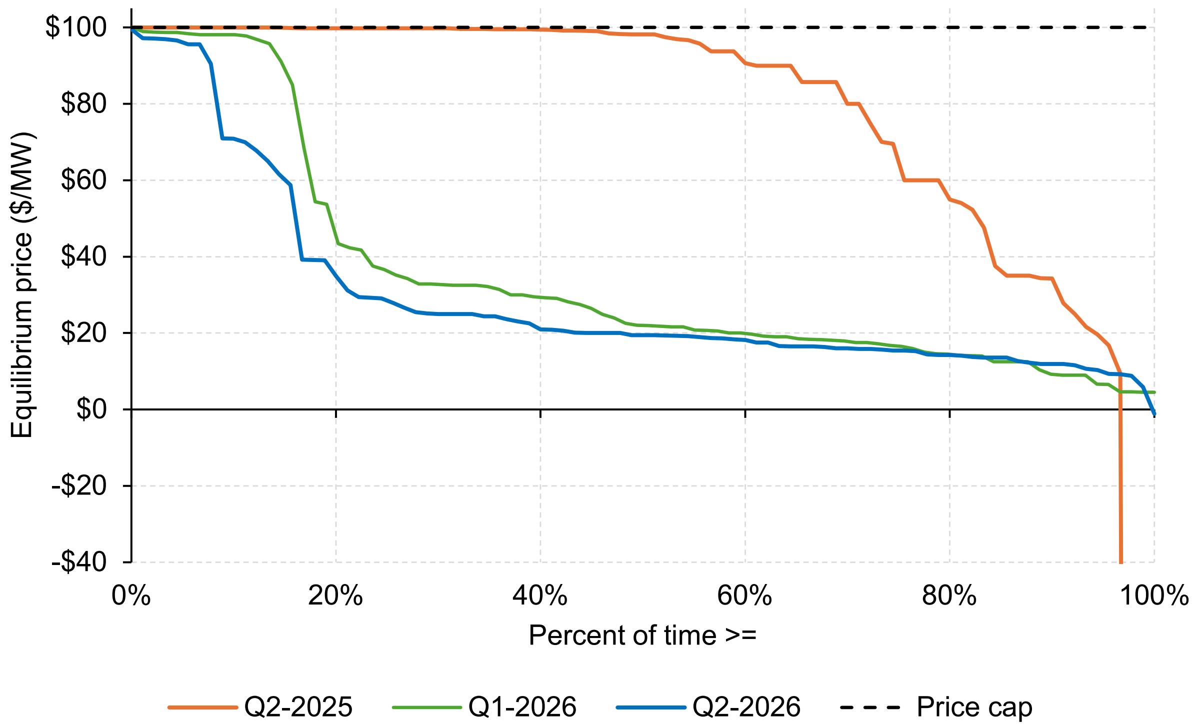
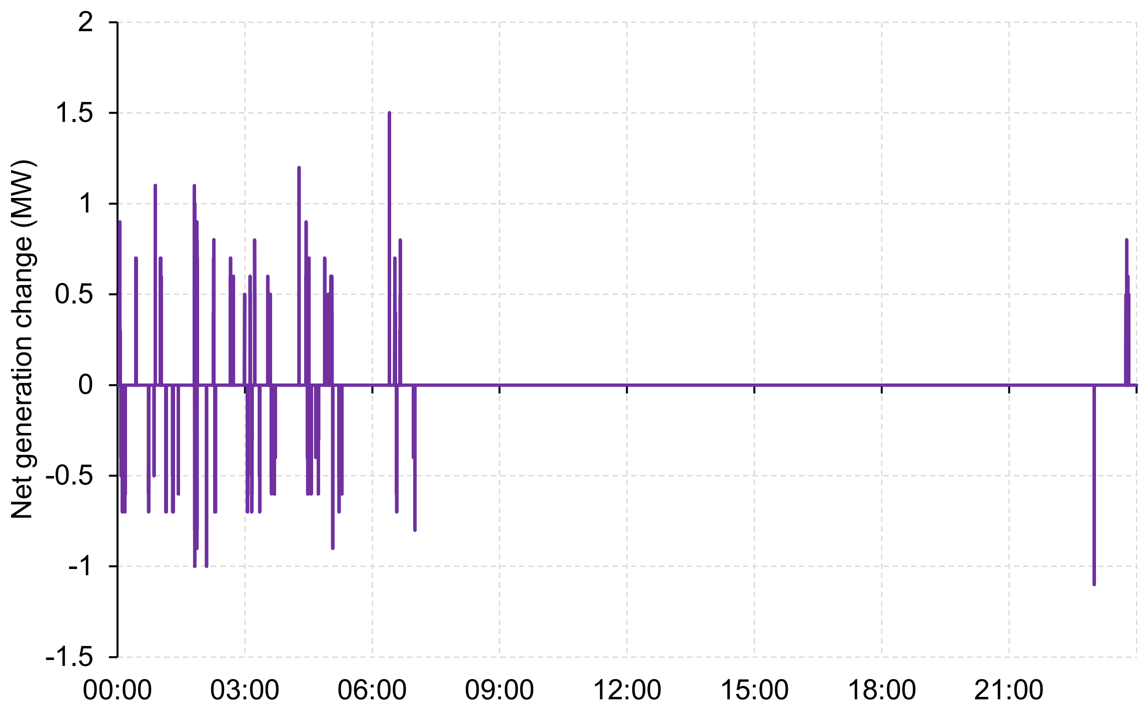


Figure 74: A battery providing off-peak regulating reserves (June 4, data increment is two seconds)



Quarter-over-quarter, the decline in equilibrium prices for regulating reserves was largely due to lower on-peak prices. However, battery assets have not typically been offered into the on-peak market. The decline in on-peak prices quarter-over-quarter was largely caused by increased offer volumes.

Offers for regulating reserve from the Raymond Reservoir asset (RYMD), which has an onsite battery, began in August 2025. Over the following winter, the battery unit was often offered into off-peak regulating reserves, but neither the hydro generator nor the battery unit were offered into the on-peak market. The hydro asset was not offered because of reduced water flows. In early May 2026, as water flows increased, offers for on-peak regulating reserves began again. This increase in supply was a cause of the lower on-peak equilibrium prices in Q2 compared to Q1.

The equilibrium prices for on-peak and off-peak spinning reserves were higher in Q2 compared to Q2 2025 (Figure 75 shows on-peak prices). The higher equilibrium prices were partly a reflection of lower pool prices and reduced offer volumes from Suncor's Firebag asset and the City of Medicine Hat asset. For example, in the on-peak spinning reserves market, the average offered volume from Firebag declined from 11 MW to 1 MW year-over-year and the average volume offered from the City of Medicine Hat fell from 20 MW to 9 MW.

In addition, the BC/MATL intertie outage was out of service in mid April, and this led to higher equilibrium prices for spinning reserves from April 13 to 19. The higher prices during this period were largely the result of less capacity being offered from Enfinite's battery assets, as some batteries were deployed for FFR instead. There was no scheduled intertie outage in Q2 2025.

Further to this, high water flows and a bearing outage on Brazeau unit 1 caused TransAlta to lower its offer volumes into on-peak and off-peak spinning reserves in late June. In the on-peak market, TransAlta's offers fell from around 150 MW to 61 MW on some days. This caused a period of higher equilibrium prices for spinning reserves in the second half of June.

Equilibrium prices for supplemental reserves were also higher year-over-year (Figure 76 illustrates on-peak prices). This was partly a reflection of the lower pool prices in Q2. In addition, Enfinite and the City of Medicine Hat both lowered their offer volumes. In the on-peak market, Enfinite lowered their average offer volumes from 94 to 61 MW year-over-year, and the City of Medicine Hat reduced their offer volumes from 19 MW to 11 MW.

Starting in early May, and for the duration of Q2, there was a decrease in the number of very low equilibrium prices for on-peak and off-peak supplemental reserves (Figure 76 shows on-peak prices). This was partly the result of TransAlta offering less volume at low prices.

Figure 75: Equilibrium prices for on-peak spinning reserves (Q2 of 2025 and 2026)

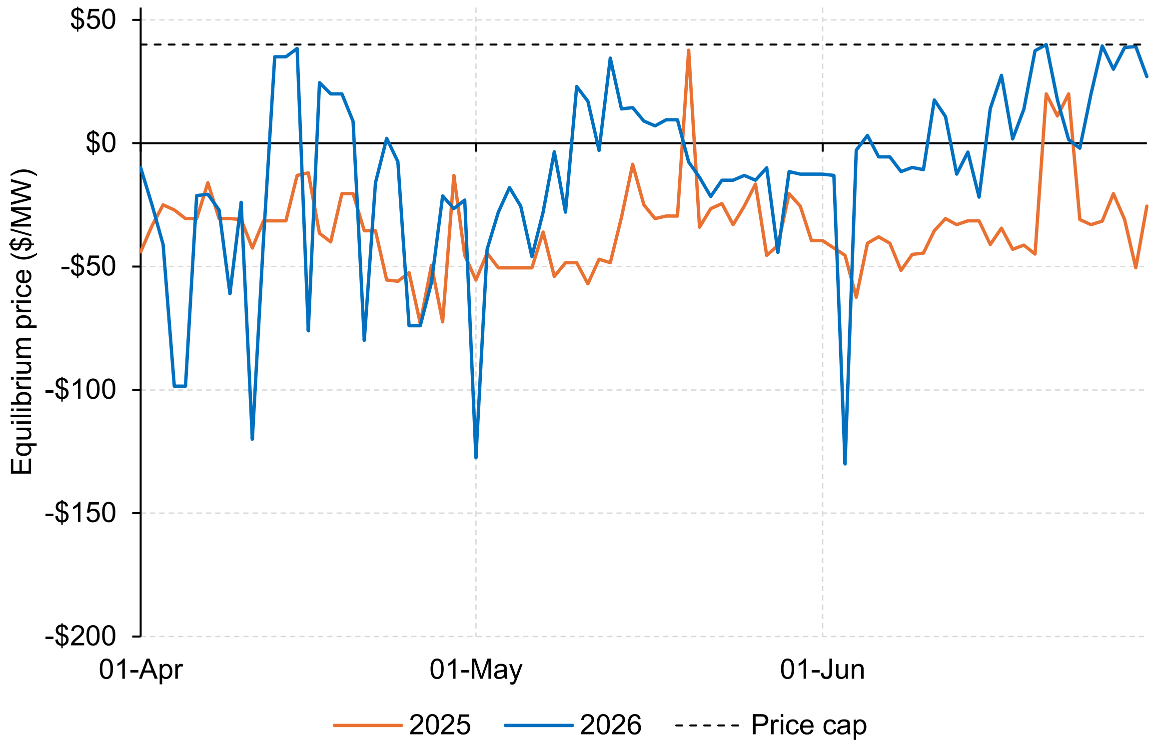
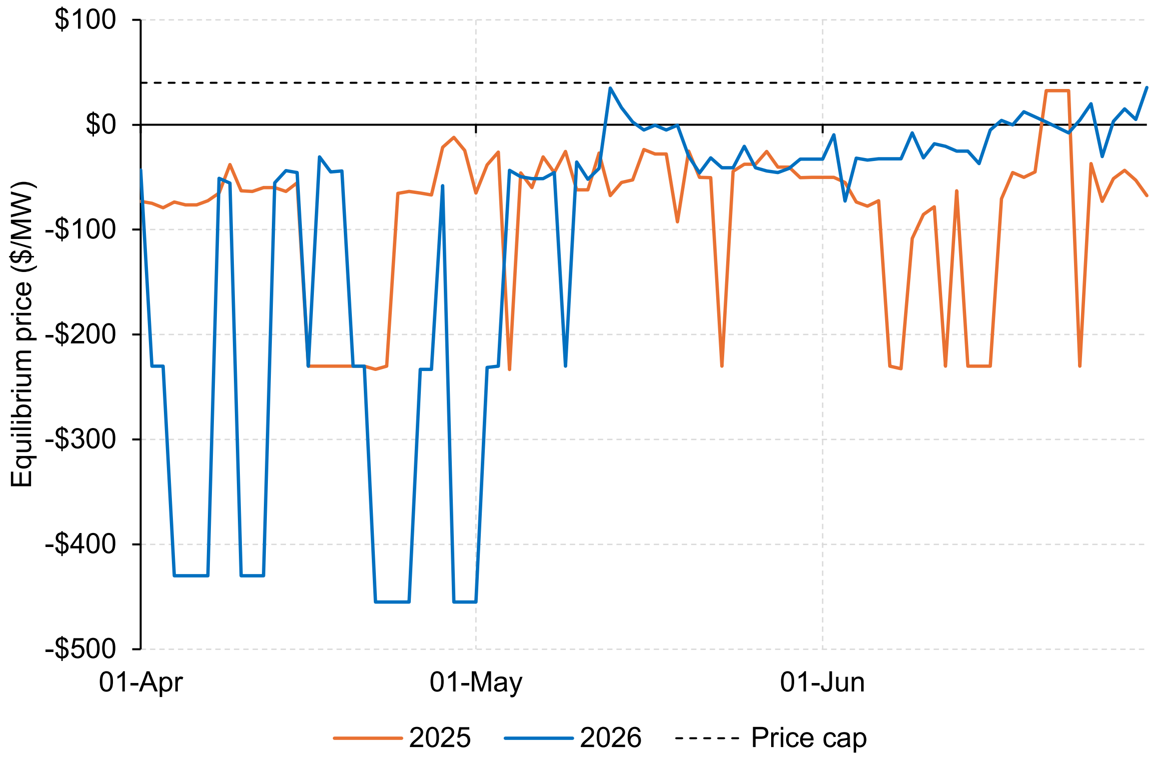


Figure 76: Equilibrium prices for on-peak supplemental reserves (Q2 of 2025 and 2026)



As with the markets for spinning reserve, the BC/MATL intertie outage in mid April impacted the supplemental markets. Enfinite reduced their offer volumes into on-peak and off-peak supplemental reserves because some of their batteries were providing FFR. For example, in the on-peak supplemental market Enfinite lowered their offer volumes from 80 MW on April 12 to 15 MW on April 13, the first day of the BC/MATL outage.

In the off-peak market, the equilibrium prices for supplemental reserves were elevated during the BC/MATL outage, generally clearing around $4/MW compared to the price cap of $5/MW. However, the price fell from $4.06/MW on April 19 to negative $898/MW on April 20. The price fell to this level four times in April as load, battery, and hydro assets competed for dispatch by offering at low prices. Table 30 provides the offer prices of assets that were dispatched for off-peak supplemental reserves on April 20.

Table 30: Offer prices for off-peak supplemental reserves (dispatched assets, April 20 delivery)

Asset ID	Type	Offer price ($/MW)	Volume (MW)	Cumulative volume (MW)
VOCG	Load	-$1,017.50	15	15
VOED	Load	-$1,017.50	9	24
ERV7	Battery	-$947.50	20	44
ERV8	Battery	-$947.50	20	64
BRA	Hydro	-$898.00	80	144
BOW1	Hydro	-$898.00	80	224

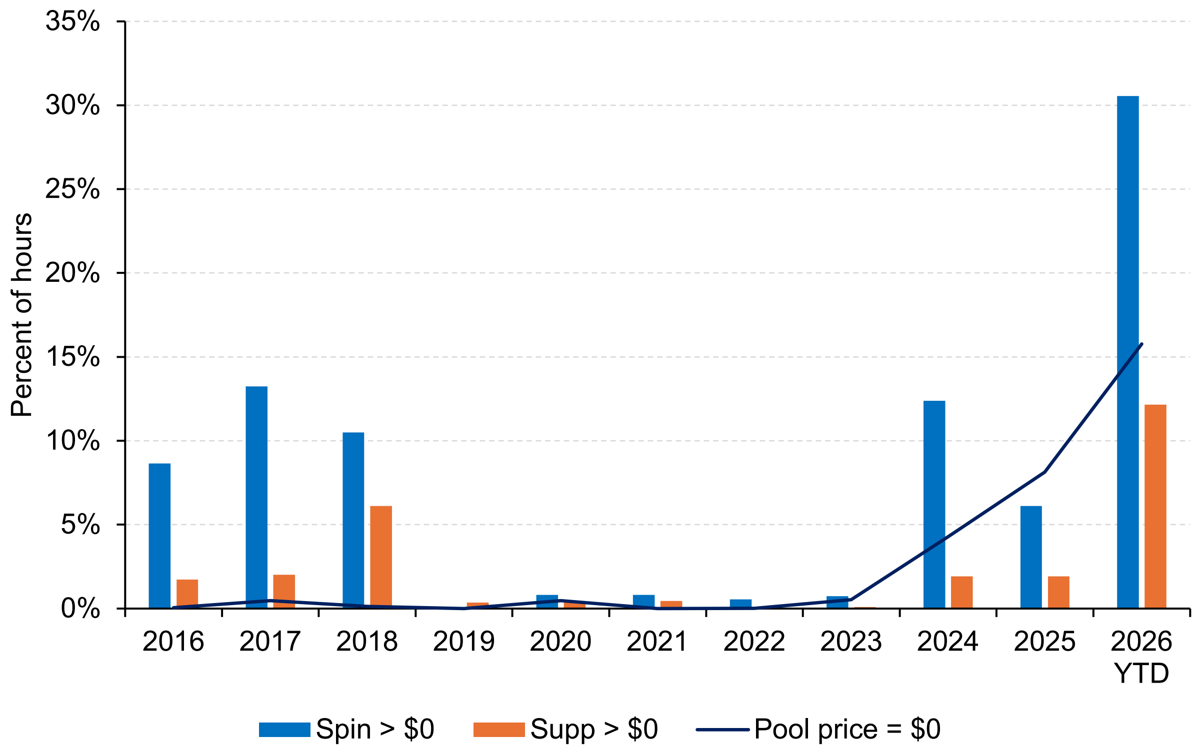
The high number of $0/MWh pool prices so far in 2026 has increased equilibrium prices for spinning and supplemental reserves. In prior years, it was relatively unusual to see equilibrium prices for spinning and supplemental reserves clear above $0/MW, as this means contingency reserves are paid a premium to energy. However, in Q2, equilibrium prices for spinning reserves were above $0/MW on 37% of days for the on-peak and on 55% of days for the off-peak (Table 31).

Overall, so far in 2026, equilibrium prices have been above $0/MW in 31% of hours for spinning reserves and in 12% of hours for supplemental, both high compared to historical values (Figure 77). These outcomes were partly driven by pool prices clearing at the floor of $0/MWh more often.

Table 31: Percent of days where equilibrium prices were above $0/MW (Q1 2024 to Q2)

	Spinning		Supplemental	
	On-peak	Off-peak	On-peak	Off-peak
Q1 2024	0%	0%	0%	0%
Q2 2024	13%	12%	0%	0%
Q3 2024	27%	15%	1%	3%
Q4 2024	15%	10%	7%	4%
Q1 2025	2%	0%	1%	0%
Q2 2025	4%	3%	3%	3%
Q3 2025	14%	11%	2%	7%
Q4 2025	3%	11%	0%	0%
Q1 2026	9%	36%	2%	7%
Q2 2026	**37%**	**55%**	**14%**	**33%**

Figure 77: Percent of hours where equilibrium prices were above $0/MW (2016 to 2026)



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 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).

Table 32 provides the AESO's target volumes for standby reserves by product and month in Q2. Standby volumes for regulating and supplemental reserves were consistent over the quarter. For spinning reserves, standby volumes increased in May and June because of the hydro run-off in BC and Mid-C, which can lead to higher import volumes.

Table 32: AESO target volumes for standby reserves (April to June)

	Reg		**Spin**		**Supp**	
	On-peak	**Off-peak**	**On-peak**	**Off-peak**	**On-peak**	**Off-peak**
April	20	20	45	35	15	15
May	20	20	65	55	15	15
June	20	20	65	55	15	15

The total cost of standby reserves in Q2 was $4.4 million, a 53% increase year-over-year and a 72% increase compared to Q1. The higher standby costs were driven by higher premium costs, which increased by 90% year-over-year while activation costs declined by 30%. Premiums accounted for 86% of total standby costs in Q2, which is relatively high.

Activation rates for standby regulating reserves remained low in Q2 at 2%, down from 7% in Q2 last year (Table 33). Activation rates for spinning and supplemental reserves were 12% and 15%, respectively, which are comparable with Q2 2025.

Table 33: Activation rates for standby products (Q1 2025 to Q2)

	Reg.	**Spin.**	**Supp.**
Q1 2025	7%	28%	31%
Q2 2025	7%	11%	19%
Q3 2025	6%	14%	14%
Q4 2025	5%	21%	19%
Q1 2026	3%	18%	22%
Q2 2026	**2%**	**12%**	**15%**

Table 34 compares volume-weighted average activation prices with prevailing pool prices at the time of activations (pool prices are weighted by standby activation volumes). For standby regulating reserves, there was a large premium for standby activations relative to prevailing pool prices; the premium increased from 305% in Q2 2025 to 510% in Q2, although regulating reserves were not activated often.

For spinning reserves, the volume-weighted average activation price was $26.29/MW in Q2, a 13% discount to prevailing pool prices. For supplemental reserves, the volume-weighted average activation price was $27.28/MW, a 7% premium to prevailing pool prices.

Table 34: Activation prices compared to prevailing pool prices (Q2 2025 and Q2)

		Q2 2025	**Q2 2026**
Regulating	Activation price	$85.01	$104.26
	Prevailing pool price	$21.01	$17.08
	Standby premium	305%	510%
Spinning	Activation price	$33.12	$26.29
	Prevailing pool price	$34.35	$30.19
	Standby premium	-4%	-13%
Supplemental	Activation price	$27.86	$27.28
	Prevailing pool price	$32.20	$25.44
	Standby premium	-13%	7%

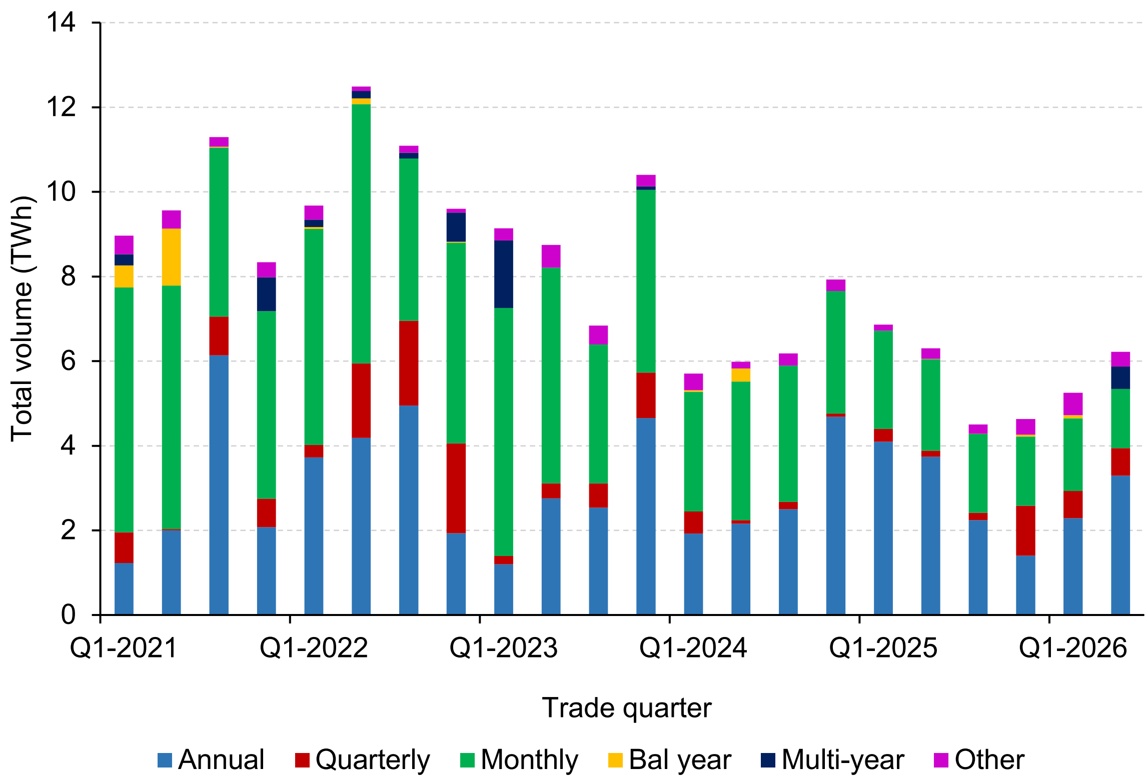
4 THE FORWARD MARKET

Alberta's financial forward market for electricity is an important component of the overall market because it allows generators, retailers, and larger loads to hedge against pool price volatility.[24]

4.1 Forward market volumes

In Q2, total trade volumes remained low relative to historical values (Figure 78). Trade volumes on ICE NGX and the brokers totalled 6.6 TWh which is 5% higher than Q2 last year and 26% higher than in Q1. The increase in volumes relative to Q1 was driven by more annual trading and by five multi-year trades which totalled 0.7 TWh (Table 35).

Figure 78: Total trade volumes by quarter and term
(Q1 2021 to Q2 2026, excludes direct bilateral trades)



[24] The analysis in this section incorporates trade data from ICE NGX and two over-the-counter brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring. 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.

Table 35: Multi-year trades in Q2

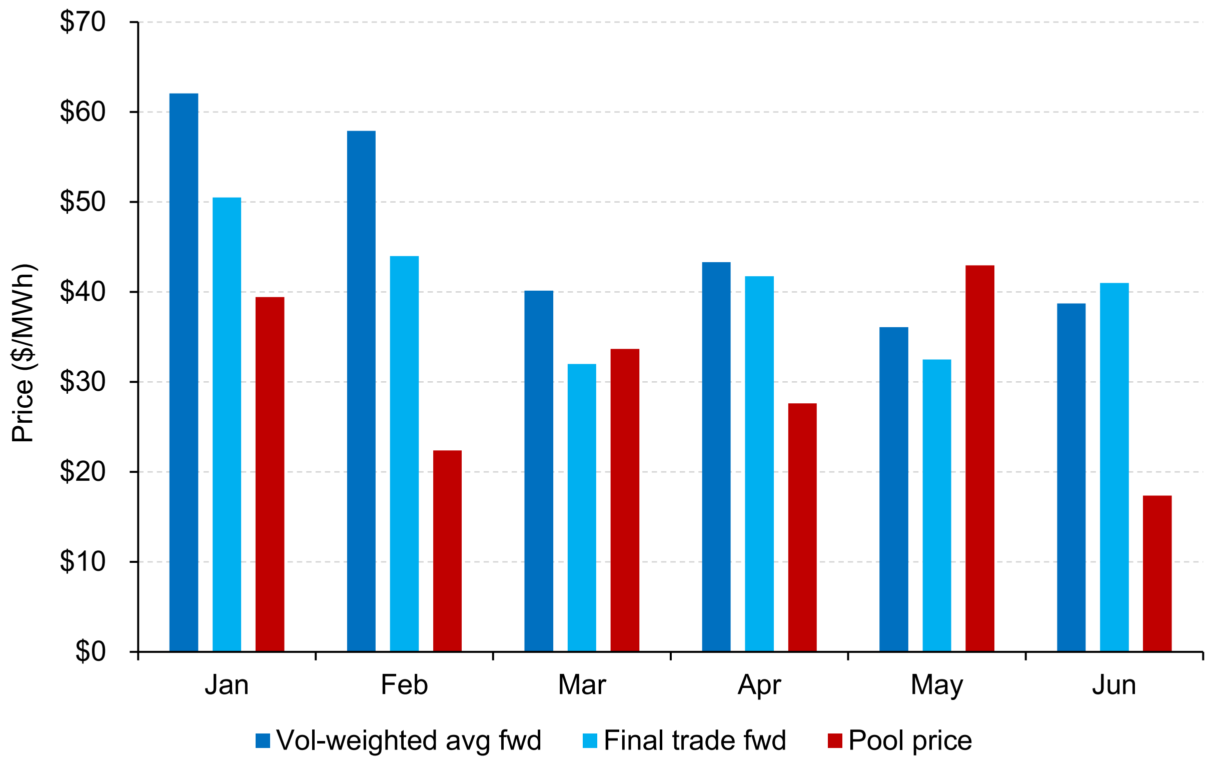
Trade date	Contract	Shape	Traded Volume (MW)	Total Volume (MWh)	Price ($/MWh)
May 27 10:05	Cal 27-29	Flat	5	131,520	$59.25
Jun 4 09:06	Cal 27-29	Flat	10	263,040	$60.50
Jun 4 09:09	Cal 27-29	Flat	5	131,520	$60.50
Jun 9 11:11	Cal 27-28	Flat	5	87,720	$53.75
Jun 9 14:12	Cal 27-28	Flat	5	87,720	$53.75

4.2 Trading of monthly products

Pool prices in April and June came in below market expectations (Figure 79). For April, the volume-weighted average forward price was $43.33/MWh, a 57% premium compared to the average pool price of $27.61/MWh. For June, the volume-weighted average forward price was $38.71/MWh, a premium of 123% compared to the average pool price of $17.36/MWh.

In May, pool prices came in slightly above forward market expectations due to pool price volatility late in the month. The volume-weighted average forward price for May was $36.09/MWh, a 16% discount relative to the average pool price of $42.98/MWh.

Figure 79: Forward prices compared to pool prices (January to June)



The lower-than-expected pool prices in Q2 put downward pressure on forward prices for the balance of year (Table 36). The price of July and September fell by 9% over the quarter and the price of December fell by 8%. The expected average pool price for Cal 26 fell by 7% to $36.91/MWh.

Table 36: Monthly forward price changes over Q2 (July to December)

Contract	Price on Mar 31 ($/MWh)	Price on June 30 ($/MWh)	Change	
			($)	(%)
July	$42.25	$38.50	-$3.75	-9%
Aug	$48.00	$47.00	-$1.00	-2%
Sep	$48.00	$43.75	-$4.25	-9%
Oct	$37.25	$36.00	-$1.25	-3%
Nov	$43.00	$43.00	$0.00	0%
Dec	$53.00	$49.00	-$4.00	-8%
Cal 26	$39.72	$36.91	-$2.81	-7%

Figure 80 illustrates how monthly forward prices evolved over Q2. The solid lines illustrate forward prices while the dashed lines show marked prices.[25]

In early April, the expected average pool price for April declined from $40 to $30/MWh as pool prices came in below expectations. The low pool prices combined with falling prices in Mid-C to put downward pressure on monthly forward prices. In late April and early May, higher forward prices in Mid-C and increasing natural gas futures increased forward prices.

Pool prices were low for much of May, and this lowered the price of June. However, pool price volatility on May 25, 27, and 28 caused a notable increase in the marked price of May and put upward pressure on forward prices. The marked price of May increased from $22.05/MWh on May 25 to $42.98/MWh at the end of the month, an increase of 95%. As a result, the price of June increased by 11% and the price of July increased by 10%.

In early June the opposite occurred. The expected price of June fell from $40.00/MWh at the end of May to $26.13/MWh on June 5, a decline of 35%. This put downward pressure on forward prices, with July falling by 3% and September falling by 4%.

The price of July fell further towards the end of June. July was priced at $45.50/MWh on June 19, but this fell by 15% to $38.50/MWh on June 30. With the end of trading for July approaching, the decline was due to sell-side pressure caused by low pool prices, mild weather forecasts, and declining prices in Mid-C.

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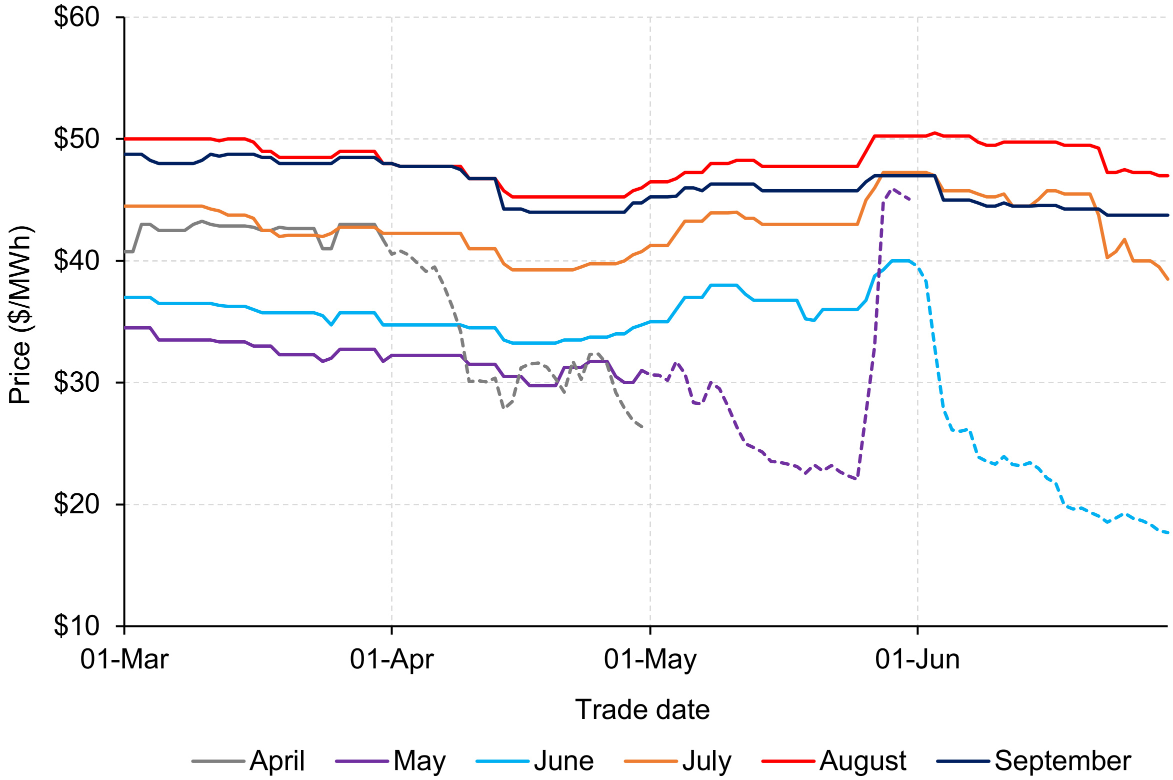
[25] A marked price is the expected average pool price for a contract on a given day within that contract. It is calculated using realized pool prices and forward prices for the balance of the contract.

Figure 80: Monthly forward prices for Q2 and Q3 (March 1 to June 30)



4.3 Trading of annual products

As outlined above, the marked price of Cal 26 declined by 7% over the quarter as pool prices came in below expectations. This, combined with lower natural gas prices, put downward pressure on the price of Cal 27, which declined by 3% over the quarter (Table 37).

However, the prices of other annual contracts increased. The price of Cal 28 increased by 8% over the quarter, while Cal 29 increased by 18% and Cal 30 increased by 25%. The price increases for Cal 29 and Cal 30 were largely driven by optimism around data centre developments.

Table 37: Changes in annual power and natural gas prices over Q2

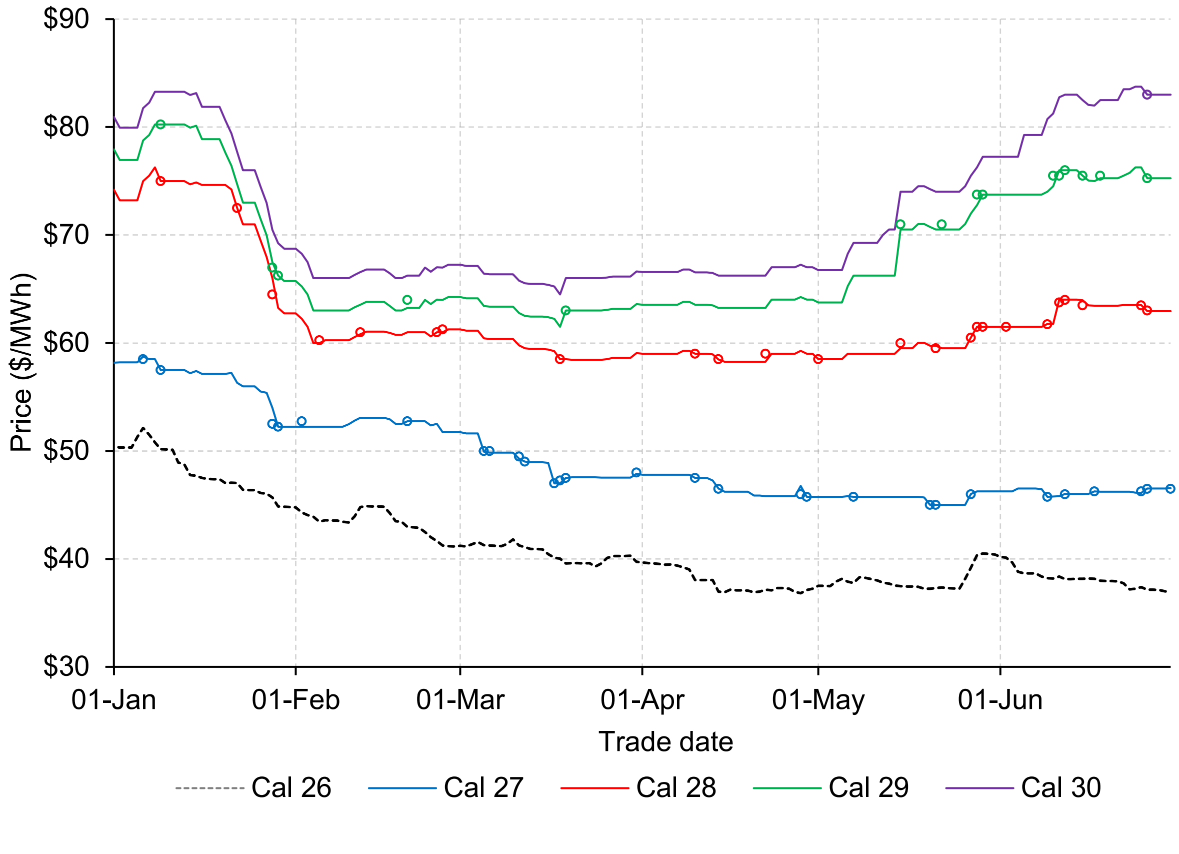
Contract	Power Price ($/MWh)			Gas Price ($/GJ)			Spark Spread ($/MWh)		
	Mar 31	Jun 30	Change	Mar 31	Jun 30	Change	Mar 31	Jun 30	Change
Cal 26 (marked)	$39.74	$36.91	-7%	$1.76	$1.78	1%	$26.55	$23.56	-11%
Cal 27	$47.88	$46.55	-3%	$2.42	$2.28	-6%	$29.70	$29.48	-1%
Cal 28	$59.07	$62.95	7%	$2.57	$2.45	-5%	$39.82	$44.60	12%
Cal 29	$63.62	$75.25	18%	$2.59	$2.44	-6%	$44.23	$56.96	29%
Cal 30	$66.62	$83.00	25%	$2.62	$2.44	-7%	$46.99	$64.71	38%

Figure 81 illustrates the evolution of annual prices since the start of the year. The lines on the figure depict settlement prices and the markers illustrate the latest trade price on a given day. As shown, the price of Cal 27 has declined so far this year along with the marked price of Cal 26.

However, the prices of Cal 28, Cal 29, and Cal 30 have been independent of Cal 26 and more volatile. This is largely due to the potential for data centre load in future years and because of the Restructured Energy Market (REM), which is scheduled to be implemented in 2028. In mid January, the prices of these contracts were elevated; Cal 28 was priced at $75.00/MWh, Cal 29 at $80.25/MWh, and Cal 30 at $83.25/MWh.

However, in late January and into early February the prices of these contracts declined by around 20% due to low pool prices, falling natural gas futures, and lower power prices in Mid-C. In addition, there was sell-side pressure, potentially caused by pessimism around future data centre load. A lack of market liquidity, combined with the sell-side pressure, amplified the decline in prices.

Figure 81: Annual power prices (January 1 to June 30)



Between early February and early May, the prices of Cal 28, Cal 29, and Cal 30 were largely unchanged (Figure 81). Starting in early May, the prices of Cal 29 and Cal 30 increased up and away from the price of Cal 28.

On May 15, the Alberta government and the Government of Canada announced the implementation of the Memorandum of Understanding (MOU) outlined on November 27, 2025.[26] Included in the MOU was the abeyance of the *Clean Electricity Regulations* (CER) to Alberta in addition to a headline price of carbon and a price floor for carbon (Table 38).

Table 38: The headline carbon price and the carbon price floor (2026 to 2032)

Year	Headline carbon price ($/tCO2e)	Carbon price floor ($/tCO2e)
2026	$95	
2027	$100	
2028	$100	
2029	$100	
2030	$115	$60
2031	$118	$63
2032	$121	$67

The $60/tCO2e price floor on carbon starting in 2030 combines with a lower performance benchmark and a headline price of $115/tCO2e to increase carbon costs for combined cycle assets by around $1.90/MWh and for simple cycle assets by around $5.20/MWh, relative to carbon costs on May 14, 2026. This increase in costs may have been a factor in the higher prices for Cal 29 and Cal 30. For example, on May 15, the price of Cal 29 increased by 6% to $70.50/MWh, up by $4.25/MWh from the day before.

However, it is important to note that the prevailing price of carbon declined following the MOU announcement on May 15.[27] On May 14, the price of carbon was $40.50/tCO2e and increased to $42.50/tCO2e on May 15 before falling to $30.00/tCO2e on May 22.[28] For the duration of Q2, the price of carbon was between $30 and $35/tCO2e, below the levels prior to May 15 (Figure 82).

By putting the application of the CER to Alberta into abeyance, the MOU between the governments of Alberta and Canada increased the likelihood that companies will develop data centre load in the province alongside dedicated natural gas generation capacity. However, data centres can be developed faster than natural gas generation capacity.

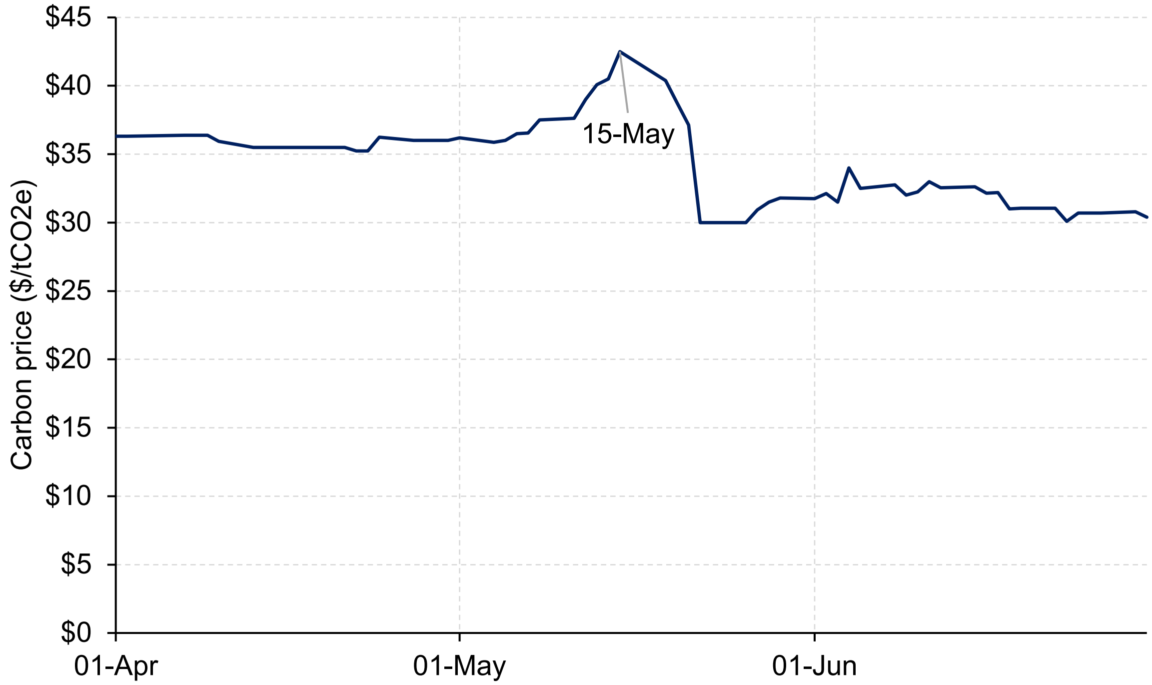
[26] Implementation Agreement for the Canada-Alberta MOU of November 27, 2025 – May 15, 2026

[27] The price of carbon is not meaningfully different across different vintages or between EPCs and offsets.

[28] Data on the price of carbon is sourced from Carbon Assessors.

In recognition of this, the AESO's large load integration phase 2A proposed a 1,600 MW bridge, which would allow some data centre loads to consume power from the grid ahead of their generation capacity coming into service.[29]

Figure 82: The prevailing price of carbon (April 1 to June 30)



On June 19, the AUC approved the development of the Greenlight Electricity Centre, a large combined cycle asset and data centre project which is scheduled to be built northeast of Edmonton in Sturgeon County.[30] In early July, Pembina Pipeline announced confirmation of the final investment decision for the project.[31] In terms of generation capacity, the Greenlight project will begin with 932 MW of generation capacity, which is anticipated to come into service in the second half of 2030.

In phase 1 of the large load integration, the AESO announced that the Alberta grid could reliably serve an incremental 1,200 MW of large load in 2027 and 2028.[32] On the back of this news, the price of Cal 28 increased by 11% (from $70.00/MWh on June 3, 2025 to $78.00/MWh on June 6, 2025). On November 5, 2025, the AESO provided the allocation of this 1,200 MW, with the Greenlight project securing 970 MW and the Keephills project 230 MW.[33]

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[29] AESO: Large Load Integration Phase 2A – June 24, 2026

[30] AUC: Decision 30261-D01-2026 – June 19, 2026

[31] Pembina Pipeline Announces Positive Final Investment Decision on the Greenlight Electricity Centre – July 2, 2026

[32] AESO: Large Load Integration Phase I – June 4, 2025

[33] AESO: Large Load Projects website

On July 8, 2026 it was announced that a 1 GW data centre is being developed alongside the Greenlight project, with the data centre load expected to be in service in the back half of 2028.[34] In response, forward prices for the second half of 2028 increased by 5%, and the price of Cal 29 increased by 5% to $80.55/MWh. The price of Cal 30 increased by 1% to $84.55/MWh, implying that the data centre load was already considered for that year.

The pool price volatility in late May also increased annual forward prices. As shown by Figure 83, pool prices were elevated on May 25, 27, and 28 because of low intermittent supply, thermal generation outages, and elevated temperatures. The average pool price on May 28 was $384/MWh, the highest since September 8, 2025. This pool price volatility put upward pressure on forward prices; Cal 28 increased by 3% and Cal 29 by 5% (Table 39).

Figure 83: Daily average pool price (April 1 to June 30)

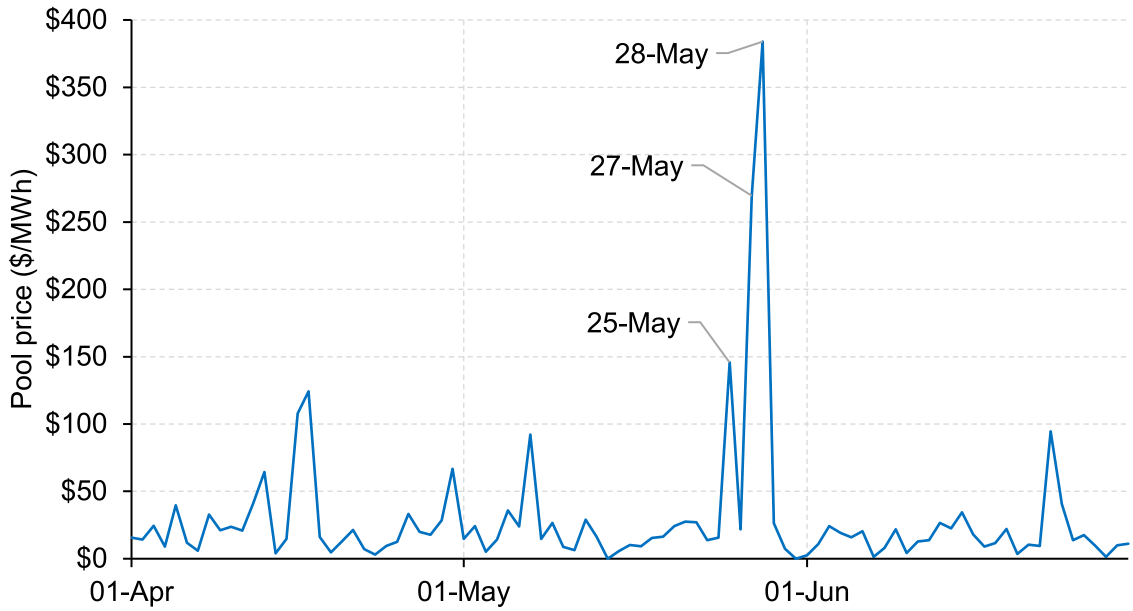

Table 39: Change in annual prices (May 25 to 29)

Contract	Price on May 25 ($/MWh)	Price on May 29 ($/MWh)	Change
Cal 27	$45.00	$46.25	3%
Cal 28	$59.50	$61.50	3%
Cal 29	$70.50	$73.75	5%
Cal 30	$74.00	$77.25	4%

[34] Calgary Herald: Varcoe: Meta unveils massive $13B, gigawatt scale development in Alberta, Canada's largest data centre – July 8, 2026

Capital Power: Capital Power enters long-term energy supply agreement with Meta in Alberta – July 8, 2026

It is worth noting that Cal 30 traded for the first time on June 26. The trade occurred on the Velocity Capital broker and cleared on ICE NGX. The price of the trade was $83.00/MWh, which was broadly in line with settlement prices (the contract was marked at $83.76/MWh the day before).

Figure 84 illustrates the price of Cal 29 in Alberta alongside prices in Mid-C and California. Prices in Mid-C, NP15, and SP15 declined in early April but increased starting in late April and this continued for much of May and June. The increasing prices in other markets were a small factor in the higher price of Cal 29 in Alberta. At the end of the quarter, the price of Cal 29 in Alberta was comparable with NP15, $7.71/MWh lower than the price in Mid-C, and $13.09/MWh higher than the price in SP15.

Figure 84: The price of Cal 29 in Alberta and other markets (January 1 to June 30)