MARKET SURVEILLANCE ADMINISTRATOR

Wholesale Market Report: Q3 2026

November 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 Q3 due to mild weather and higher intermittent generation

The average pool price in Q3 was $35.52/MWh. This is the lowest price for a Q3 since 2017 and represents a 31% decline from the same quarter last year. The lower prices year over year were driven by increased intermittent (wind and solar) generation, less exports, and mild weather in August and September. July saw record solar generation with a monthly capacity factor of 39%, and that contributed to low prices in that month. In August, there was some significant price volatility during a planned outage on the BC and Montana interties, however the average price still fell by 9% year over year. Mild weather led to high wind generation and reduced demand in September, resulting in the lowest average monthly price in the quarter and a 60% decline year over year.

Prices ranged from the floor to the offer cap on August 26 and September 1

The BC and Montana interties were offline for planned maintenance between August 24 and September 2. This BC/MATL outage combined with large changes in intermittent generation, some major thermal generation outages, and a few assets being commercially offline on long lead time caused major price volatility. For example, on August 26 and September 1, the System Marginal Price was at the floor of $0/MWh in the early morning hours, increased to the offer cap of $999.99/MWh in the evening, and then declined back to the floor towards the end of the day. On both evenings, Sheerness 2 and Battle River 4 (which total 555 MW of gas-fired steam capacity) were commercially offline on long lead time and were not issued unit commitment directives, partly because of large forecast errors in the AESO's wind forecasts.

Congestion declined year over year due to the energization of new transmission lines

In Q3, the MSA estimates that constrained intermittent generation volumes were 243 GWh compared to 269 GWh in Q3 2025, a reduction of 10%. The lower constrained intermittent generation volumes were partly due to the energization of the Central East Transfer Out transmission lines in late June. This led to less congestion and higher intermittent generation, lowering pool prices.

Locational marginal prices would be lower in the southeast due to more congestion

Section 2.3 of this report provides an update on the MSA's analysis of congestion by location and its impact on pseudo locational marginal prices (pLMPs) for different generation assets. The analysis provides an overview of trends in congestion and locational prices ahead of the transition to locational marginal prices (LMP) under the Restructured Energy Market (REM). So far this year, congestion has been highest in May, partly due to a planned outage on the Eastern Alberta Transmission Line. Congestion has mostly occurred at specific wind assets in the southeast, and this has led to pLMPs at these generators being below pool prices. For most other generators, pLMPs have been above pool prices.

On August 18 and 19 there were over-frequency events due to transmission outages in BC

At 11:45 on August 18, the 5L98 transmission line in BC tripped out of service because of wildfire smoke. This outage combined with planned maintenance on 5L91 and caused Southeast BC and Alberta to island together from the rest of the Western Interconnection. At the time of the trip, Southeast BC had excess generation, so the event caused an in-rush of power into Alberta and frequency increased to 60.23 Hz. A similar fact pattern occurred the following day; frequency in Alberta increased to 60.24 Hz due to a trip on 5L98 caused by wildfire smoke. Following both events, the AESO was able to coordinate with external operators, and the interties were restored to normal operations in about an hour.

Net revenue analyses indicate that the energy market remained unprofitable in Q3

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 Q3 indicate that the hypothetical combined cycle, simple cycle, wind, and solar assets were all unprofitable over the quarter due to low pool prices.

Monthly forward prices fell over Q3 due to weather forecasts and declining gas futures

Pool prices came in below market expectations in Q3, putting downward pressure on forward prices for the balance of year and for Calendar 2027 (Cal 27). Forward prices for the upcoming winter were highly correlated with forward prices for natural gas as warm weather forecasts caused both to decline, and because natural gas is the main input cost for Alberta power. Forward prices are increasing into the future as Cal 28, Cal 29, and Cal 30 are trading on expectations for the REM and data centres. For example, the price of Cal 29 increased by 5.3% on the news of a major data centre development in early July. Subsequently, the prices of these long-term annual contracts declined over August because of sell-side pressure amidst low liquidity. In September, prices somewhat recovered due to renewed buy-side interest and higher forward prices in Mid-Columbia.

The MSA starts to report on the primary frequency response of generators

There were three significant frequency events in the quarter. On August 18 and 19, transmission outages in BC led to an in-rush of power into Alberta causing two over-frequency events. For the August 18 event, 34% of units that were online provided a sustained primary frequency response by reducing generation. On August 19, it was 32% of online units. On August 30, there was an under-frequency event as Genesee Repower 2 tripped offline while BC/MATL was out of service. For this event, 33% of online units provided a sustained primary frequency response by increasing generation.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q3 was $35.52/MWh. This is the lowest price for a Q3 since 2017 and represents a 31% decline from the same quarter last year. The lower prices year over year were driven by increased intermittent generation, less exports, and mild weather in August and September. The increase in intermittent generation was partly caused by the energization of the CETO transmission lines at the end of June. Lower pool prices, combined with higher natural gas prices, reduced the spark spread by 48% year over year (Table 1).

Pool prices were low in July, averaging $31.26/MWh, as 711 MW of load growth year over year was offset by more intermittent generation and less exports (Table 2). Average solar generation in July was 1,069 MW during peak hours, and the capacity factor over all hours of the month was 39%, both of which are new records. On July 17, Alberta set a new summer record for hourly demand at 12,390 MW, a 1.4% increase over the prior record.

Table 1: Pool prices, natural gas prices, and spark spreads (Q3 2025 and Q3)

		2025	2026	Change
Pool price (Avg $/MWh)	Jul	$31.19	$31.26	0%
	Aug	$50.35	$45.71	-9%
	Sep	$73.05	$29.40	-60%
	Q3	**$51.29**	**$35.52**	**-31%**
Gas price AB-NIT (2A) (Avg $/GJ)	Jul	$0.75	$1.60	113%
	Aug	$0.80	$1.35	68%
	Sep	$0.33	$1.55	371%
	Q3	**$0.63**	**$1.50**	**138%**
Spark spread (7.5 heat rate) ($/MWh)	Jul	$25.56	$19.28	-25%
	Aug	$44.32	$35.57	-20%
	Sep	$70.59	$17.81	-75%
	Q3	**$46.56**	**$24.29**	**-48%**

Because of underlying load growth, average demand in August was largely unchanged from last year, even though temperatures were lower.

In late August, there was some material price volatility as a planned intertie outage on BC/MATL combined with large changes in intermittent supply, some major thermal generator outages, and a few gas-fired steam assets being on long lead time (LLT).[1]

On August 26 and September 1, the System Marginal Price (SMP) increased from the price floor of $0/MWh in the early morning hours, up to the offer cap of $999.99/MWh in the evening, and back down to the price floor towards the end of the day. Because of this volatility, the monthly

[1] A unit is on long lead time when it is commercially offline and requires more than an hour to supply power to the grid. These are typically gas-fired steam assets that take 12 to 24 hours to start up.

average price in August was $45.71/MWh, the highest in the first three quarters but a 9% decline year over year.

The average pool price in September fell by 60% year over year to $29.40/MWh as mild weather led to low demand and high wind generation. In addition, pool prices in September 2025 were increased by a planned outage on BC/MATL, but the outage this year largely occurred in August.

Table 2: Energy market fundamentals (Q3 2025 and Q3)

		2025	2026	Change (MW)
Demand (AIL) (Avg. MW)	Jul	10,010	10,721	711
	Aug	10,194	10,283	89
	Sep	9,989	9,861	-128
	Q3	**10,065**	**10,293**	**228**
Available thermal capacity (Avg. MW)	Jul	10,410	10,438	28
	Aug	10,262	9,985	-277
	Sep	9,469	9,509	40
	Q3	**10,053**	**9,982**	**-71**
Wind gen. (Avg. MW)	Jul	1,128	1,298	170
	Aug	1,115	1,199	85
	Sep	1,346	1,697	351
	Q3	**1,195**	**1,395**	**200**
Solar gen. (Avg. MW in peak hours)	Jul	865	1,069	204
	Aug	895	839	-56
	Sep	717	635	-82
	Q3	**826**	**850**	**24**
Net imports (+) Net exports (-) (Avg. MW)	Jul	-505	-9	496
	Aug	-364	-176	188
	Sep	-179	-276	-97
	Q3	**-349**	**-153**	**196**

Alberta has seen meaningful load growth so far in 2026. Over the first three quarters, Alberta Internal Load (AIL) has averaged 10,438 MW compared to 10,166 MW in the same period of 2025, an increase of 272 MW or 2.7%.

Alberta set a record for summer demand in hour ending (HE) 17 on Friday, July 17. The prior record of 12,221 MW, set in July 2024, was broken in 15 hours in July. The new record of 12,390 MW is 169 MW or 1.4% higher than the prior record. Temperatures were not abnormally high in

HE 17 on July 17; the average temperature across Calgary, Edmonton, and Fort McMurray was 28.7°C, which is 2.7°C lower than during the prior record (Table 3).

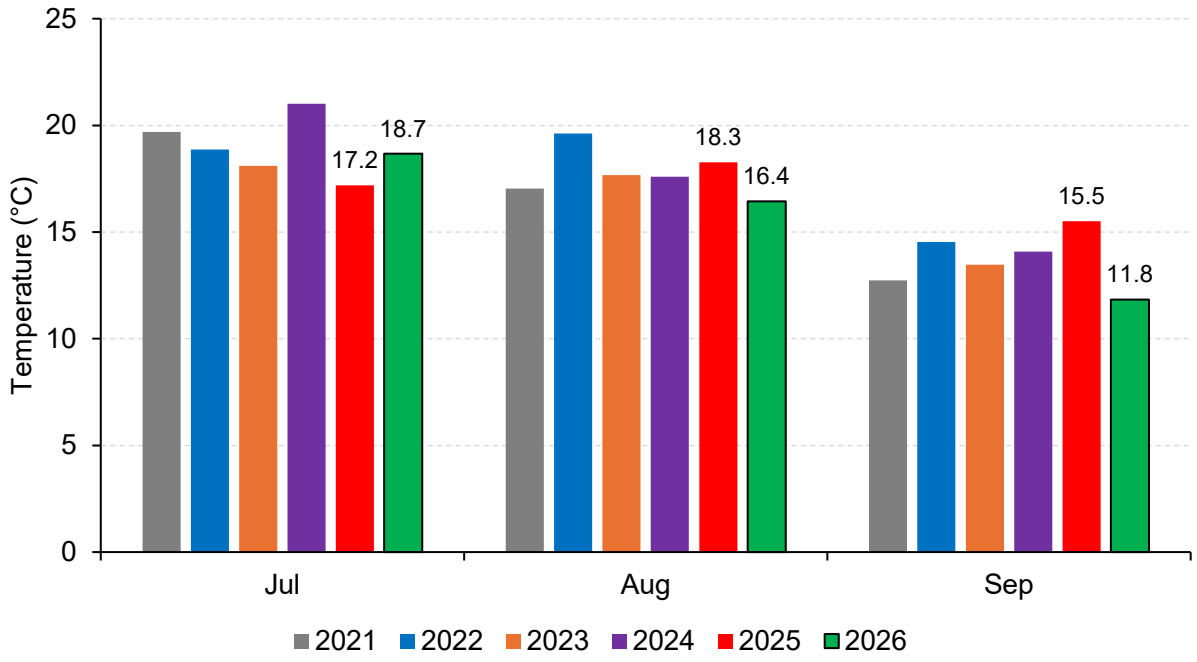
The current winter demand record is 12,785 MW, set on December 11, 2025. Relative to this, the new summer record is 395 MW or 3.1% lower.

Table 3: Demand record summary statistics

	Old demand record	**New demand record**
Date	Jul 22, 2024 (Mon)	Jul 17, 2026 (Fri)
Hour ending	17	17
AIL (MW)	12,221	12,390
Avg. temperature (°C)	31.4	28.7
Pool price ($/MWh)	$333.08	$92.70
Min. supply cushion (MW)	300	970
Wind generation (MW)	591	650
Solar generation (MW)	1,096	974
Net imports (MW)	43	360
Capacity on LLT (MW)	0	0

Mild summer weather was a factor in the low pool prices in Q3. In July, temperatures were in line with the past five years; the average of 18.7°C was 2% lower than the five-year average, but above temperatures last year (Figure 1).

Figure 1: Monthly average temperatures (Q3 of 2021 to 2026)

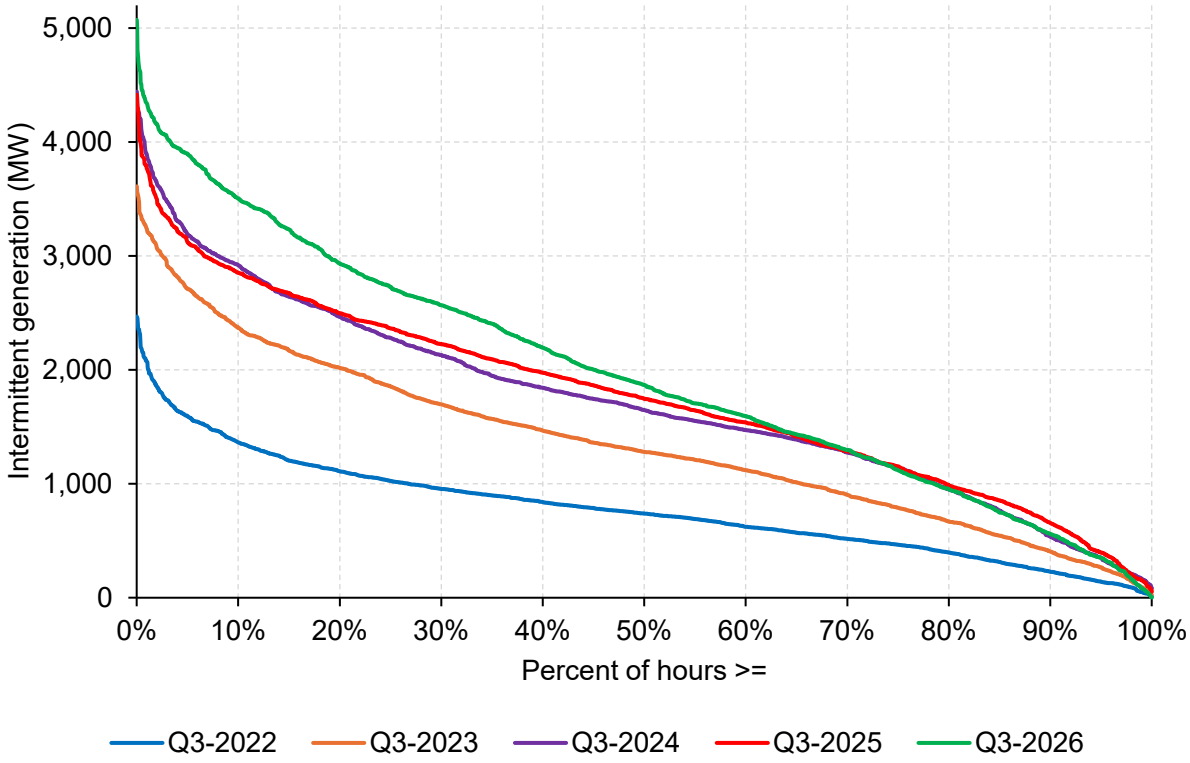


However, temperatures in August and September were relatively low. In August, the average of 16.4°C was 10% less than in 2025 and 9% lower than the five-year average. In September, the average temperature of 11.8°C was 24% less than last year and 16% lower than the five-year average. Mild weather reduced demand through reduced cooling load.

The mild weather also contributed to increased wind generation, particularly in September. Figure 2 illustrates duration curves of intermittent generation in Q3 for the last five years. The lines illustrate how often intermittent generation was above a certain level.

The shift up from Q3 2025 to Q3 on the left-hand side of the figure illustrates more hours of higher intermittent generation. For example, in 20% of hours in Q3 intermittent generation was above 2,930 MW compared to 2,500 MW in 2025, an increase of 430 MW. In 10% of hours in Q3 intermittent generation was above 3,510 MW relative to 2,850 MW in Q3 2025, an increase of 660 MW. The energization of CETO in late June was a factor in reducing congestion and allowing more intermittent generation to supply the market, lowering prices.[2]

Figure 2: Duration curves of intermittent generation (Q3 of 2022 to 2026)

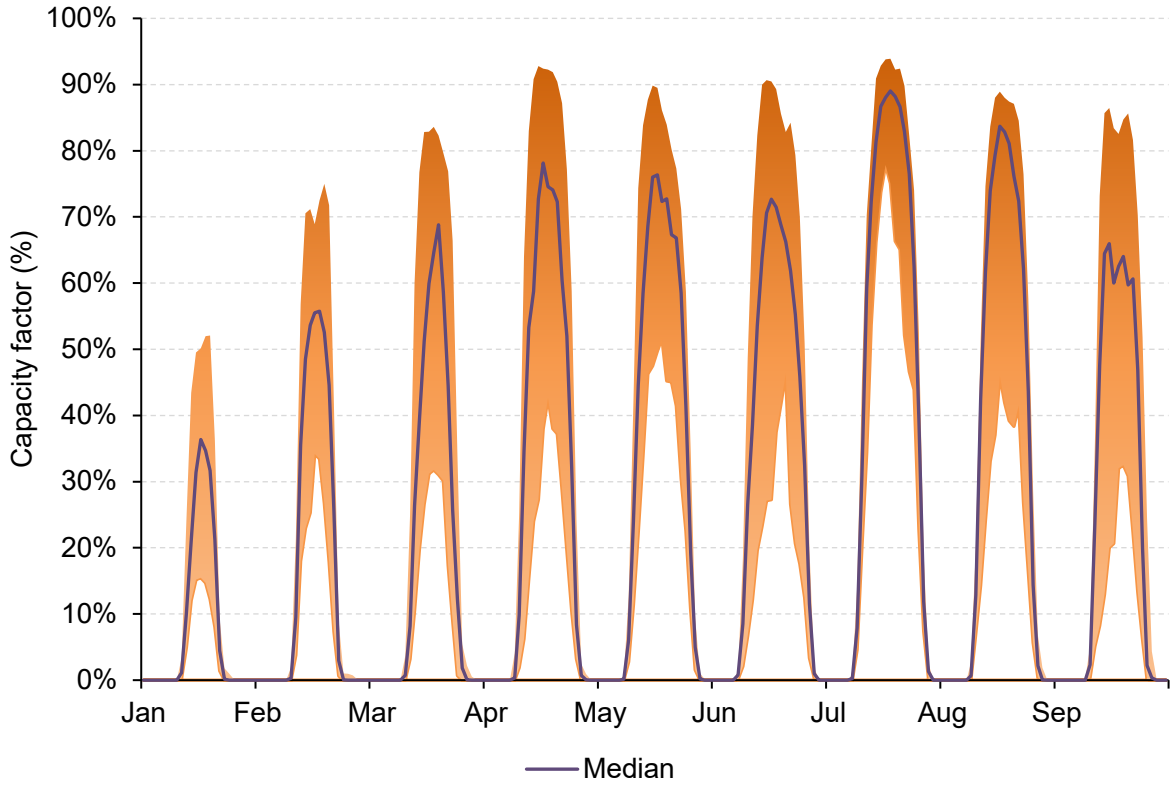


Solar supply increased to a record high in July with total generation of 535 GWh and a capacity factor of 39%. The prior record was set in June 2025 at 462 GWh, a capacity factor of 35%. Figure

[2] Alberta Government, Major projects - CETO transmission development

3 provides the profile of hourly capacity factors for all months so far this year. Solar generation in July was well above other months, with the median capacity factor reaching 89% in HE 14.

Figure 3: Median capacity factor of solar and the 10th to 90th percentile range by month and hour (Q1 to Q3)



There were several major thermal outages in the quarter that reduced available capacity, although average prices remained low. Despite the full commissioning of Base Plant in late 2025, average thermal availability fell slightly year over year, and in August, average thermal availability fell by 277 MW (or 3%) year over year (Table 2).

The decline in thermal availability was partly caused by the mothballing of Sheerness 1 (400 MW) starting on April 1. In addition, there were planned outages at the new cogeneration units at Base Plant: GT12 (403 MW) was offline over August, and GT13 (403 MW) was offline over September (Table 4). There were also extended forced outages at Battle River 5 and Cascade 2 in mid-August. In early September, Keephills 3 was taken offline for a planned outage, and the asset is scheduled to return to service later in November at the time of writing.

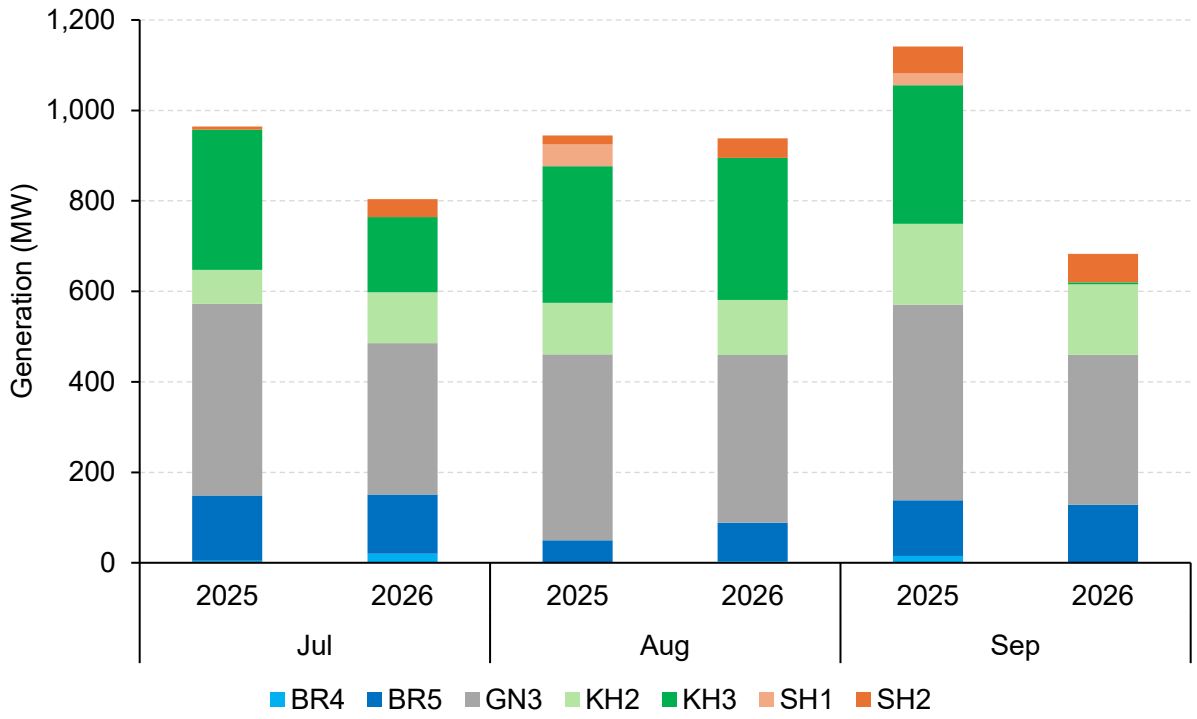
The lower pool prices in Q3 this year caused a decline in gas-fired steam generation, in part because more capacity was on LLT or mothballed. Figure 4 illustrates the monthly average generation of gas-fired steam assets in Q3 year over year. There was a notable decline in supply from gas-fired steam assets in September this year because of the outage at Keephills 3 and as prices declined by 60% year over year.

In September 2025, high temperatures and an outage on BC/MATL increased prices, resulting in more gas-fired steam supply. However, the BC/MATL outage in August this year did not result in a notable increase in gas-fired steam generation. Overall, the capacity factor of gas-fired steam assets was 26% in Q3 compared to 33% in Q3 2025 (these figures include the capacity of the mothballed assets).

Table 4: Major thermal outages in Q3 (200 MW+ for five days or more)

Asset name (ID)	Capacity on outage (MW)	Outage days	Start date	End date
Joffre (CT201)	210	75	07-May	20-Jul
Cascade 1 (CAS1)	466	5	04-Jul	08-Jul
Base Plant GT12 (SCR1)	510	32	31-Jul	31-Aug
Battle River 5 (BR5)	395	12	12-Aug	23-Aug
Cascade 2 (CAS2)	466	14	12-Aug	25-Aug
Syncrude (SCL1)	230	12	23-Aug	03-Sep
Cascade 1 (CAS1)	466	6	31-Aug	05-Sep
Base Plant GT13 (SCR1)	506	30	01-Sep	30-Sep
Keephills 3 (KH3)	466	*TBD*	01-Sep	*TBD*
Mackay River (MKRC)	207	31	08-Sep	08-Oct
Syncrude (SCL1)	210	8	20-Sep	27-Sep

Figure 4: Monthly average generation at gas-fired steam assets (Q3 2025 and Q3)



1.2 Market outcomes and events

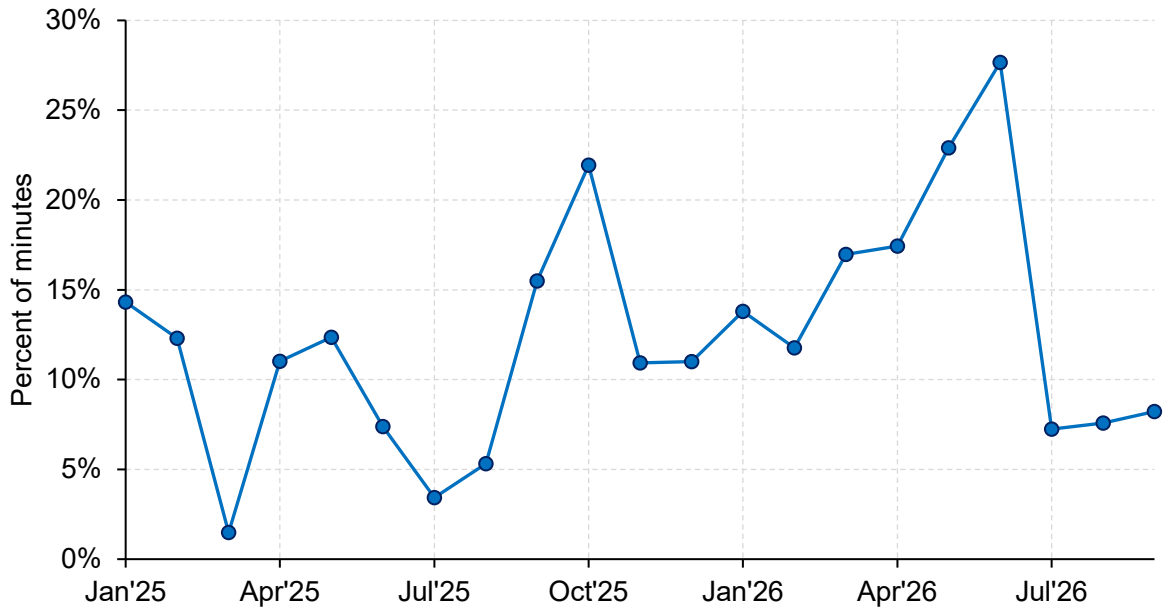
High pool prices in a small number of hours can have an outsized impact on average prices. For example, in Q3 2025, prices averaged $343/MWh in the top 10% of hours and accounted for 67% of the average price (Table 5). In Q3, the average price in the top 10% of hours was lower at $182/MWh and these hours accounted for 51% of the average price. This reduction in high prices at the top of the distribution was the driver of the lower average pool price year over year.

The average pool price increased by 21% from Q2 to Q3 as demand increased, wind generation declined, and net imports fell. These market fundamental changes led to higher prices across the distribution (Table 5). For example, the average price in the 10th to 50th percentile range increased from $22 to $30/MWh, and prices in the bottom 50% increased from $5 to $11/MWh.

Table 5: The distribution of pool prices (Q3 2025, Q2, and Q3)

Percentile	Q3 2025 (Avg. $51.29)		Q2 2026 (Avg. $29.47)		Q3 2026 (Avg. $35.52)	
	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.	Avg. price	Contribution to avg.
Top 10%	$343	67%	$179	61%	$182	51%
10 to 50%	$31	24%	$22	31%	$30	33%
Bottom 50%	$10	9%	$5	9%	$11	15%

Figure 5: Percent of minutes the SMP was $0/MWh by month (January 2025 to September 2026)



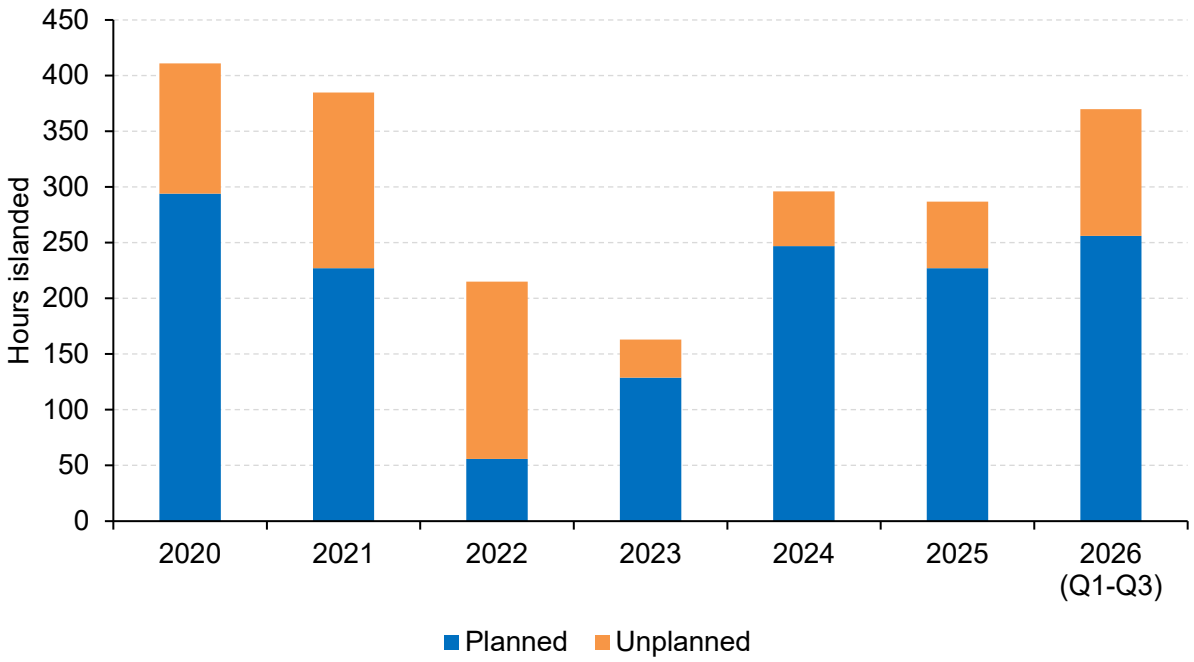
Prices cleared at the price floor less often in Q3 compared to Q2 (Figure 5). In June, the SMP was $0/MWh 28% of the time, but this fell to 7% in July and 8% in August and September. In July

and August this change was driven by higher demand, less wind generation, and fewer imports. In September, demand was slightly less than in June, but a reduction in imports, lower intermittent generation, and less hydro supply led to fewer $0/MWh prices.

1.2.1 Planned BC/MATL intertie outage (August 24 to September 2)

The BC/MATL intertie was on a planned outage from August 24 HE 10 to September 2 HE 01. The outage was taken for maintenance work on 1201L, the 500 kV transmission line running between Alberta and BC. The outage lasted for eight days and 16 hours, bringing the year-to-date total to 15 days and 10 hours, the highest since 2021 (Figure 6). The outage largely ran according to schedule; it was initially scheduled on March 18 to run from August 24 HE 09 to September 1 HE 17.

Figure 6: BC/MATL outage hours by year (2020 to 2026)[3]



The impact of this outage on the energy market was to increase price volatility by reducing imports when pool prices were elevated and lowering exports when pool prices were low. On certain days, the transition between these market conditions occurred quickly. As discussed below, the SMP ranged from the price floor of $0/MWh to the offer cap of $999.99/MWh on August 26 and September 1. On September 1, the SMP was $999.99/MWh at 19:32 but fell to $0/MWh at 22:36, just over three hours later. In addition to the outage on BC/MATL, variable intermittent generation, some large thermal generator outages, and gas-fired steam assets being on LLT were drivers of the volatile pricing.

[3] Outages are categorized as planned when they are scheduled 30 days or more in advance.

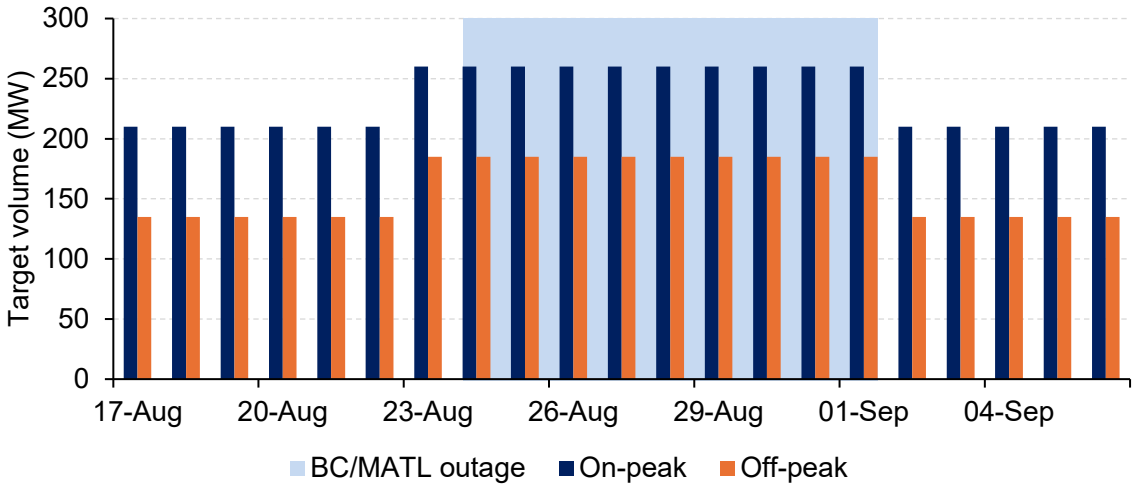
When BC/MATL is out of service Alberta is islanded because the Saskatchewan intertie is high voltage direct current (HVDC) and therefore provides no inertia or frequency response. Consequently, Alberta must deal with large contingency events, such as generator trips, using only domestic resources. Because of this, the AESO procures Islanded Fast Frequency Response (FFR). FFR is an ancillary service provided by batteries and loads, which respond by increasing generation or reducing consumption almost instantaneously when frequency falls below 59.6 Hz (for batteries) or 59.5 Hz (for loads).

During this BC/MATL outage, the AESO generally had around 200 MW of FFR available. Frequency fell to a low of 59.75 Hz on August 30 at 21:27. This frequency drop occurred because of a trip at Genesee Repower 2, which lowered the asset's gross generation from 472 MW to 139 MW instantaneously, before the asset tripped offline completely two minutes later. FFR was not tripped during this event, or at all during the BC/MATL outage, as frequency did not fall below 59.6 Hz.

The AESO also procures additional regulating reserves when BC/MATL is expected to be offline, to deal with more routine variation in frequency. During this BC/MATL outage, the AESO increased their target volumes to 260 MW of regulating reserves for on-peak hours and 185 MW for off-peak hours, both 50 MW more than normal. This is consistent with the procurement volumes during the planned BC/MATL outage in the fall of 2025, although these figures are 10 MW higher than during BC/MATL outages in March and April this year. The AESO procured additional regulating reserves for all nine days of the outage (Figure 7). The AESO also procured more regulating reserves for Sunday, August 23, even though BC/MATL was always scheduled to be in service on that day.

Throughout the BC/MATL outage, Alberta provided around 50 MW of inadvertent energy to BC. These exports were illustrated on the AESO's Current Supply and Demand page and were paid back in accordance with the BAL-004 standard.

Figure 7: Target volumes for on-peak and off-peak regulating reserves (August 17 to September 6)



1.2.2 Volatile prices (August 24 to 26)

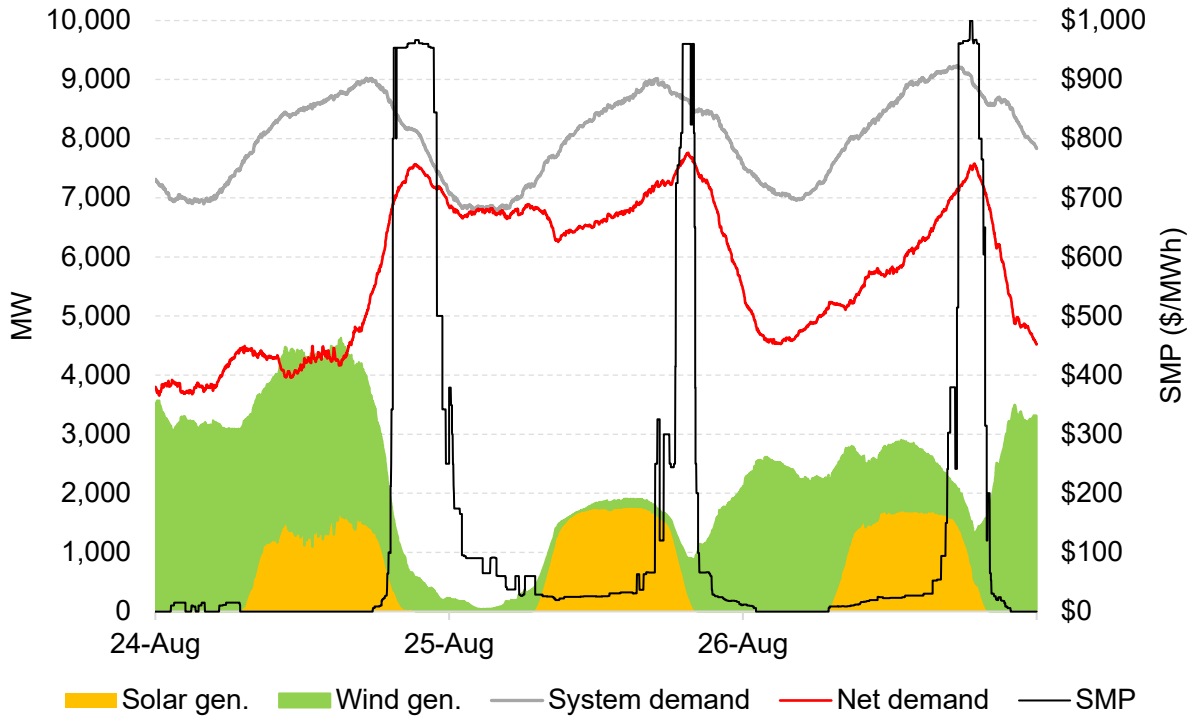
The planned outage on BC/MATL increased pool price volatility because intertie flows could not respond to changing market conditions in Alberta, including changes in intermittent generation. On the first three days of the BC/MATL outage, there was a large amount of price volatility due to substantial changes in intermittent generation (Figure 8).

On the evening of Monday, August 24, intermittent generation fell from 4,000 MW at 17:15 to 400 MW at 22:15, a decline of 3,600 MW over five hours, or 720 MW/hour. Due to the high levels of intermittent generation during the day, the SMP was $0/MWh from 10:29 to 17:29. However, the large decline in intermittent supply caused the SMP to reach $967/MWh three hours and forty-four minutes later, at 21:13, around the net demand peak.

On Wednesday, August 26, the SMP cleared at $0/MWh during the early morning hours, reflecting low demand and around 2,500 MW of wind generation. However, due to higher demand and lower wind generation in the evening, the SMP was $999.99/MWh between 18:33 and 18:45. During this period, wind generation averaged 720 MW and solar generation averaged 800 MW.

The supply cushion fell to a low of 0 MW when the SMP was at the offer cap as the supply curve was fully exhausted. However, the AESO did not declare an Energy Emergency Alert (EEA), no contingency reserves were directed, and no load was shed.

Figure 8: Net demand and SMP (August 24 to 26)



Around three and a half hours later, at 22:09, the SMP fell to $0/MWh because demand had declined and wind generation had increased, illustrating substantial changes to market conditions and prices over a short period of time (Figure 8).

There were some large thermal generator outages that lowered supply and contributed to the price volatility during this event. A planned outage on the GT12 unit at Base Plant was the main cause of the asset being derated by 636 MW. In addition, the Syncrude asset was derated by 230 MW due to outages at G11, G12, and G20. On August 24, the Cascade 2 asset (466 MW) was unavailable due to the extension of a forced outage, but the asset came back online in the early morning hours of August 25.

The tight market conditions on August 26 were also a function of elevated temperatures and higher demand. Temperatures reached 29°C in Calgary, 30°C in Fort McMurray, and 28°C in Edmonton. Consequently, demand peaked at 11,851 MW, 310 MW higher than on August 24 when temperatures reached 23 to 25°C. However, peak demand on August 26 was 539 MW less than the record set on July 17.

Despite the high prices and low supply cushion, Battle River 4 (155 MW) was on LLT for August 24, 25, and 26 as the asset was not committed by TransAlta or the AESO. Sheerness 2 (400 MW) was committed by the AESO for the evenings of August 24 and 25 but was not committed for August 26 (Table 6). Therefore, there was 555 MW of gas-fired steam capacity on LLT when the SMP increased to the offer cap on August 26.

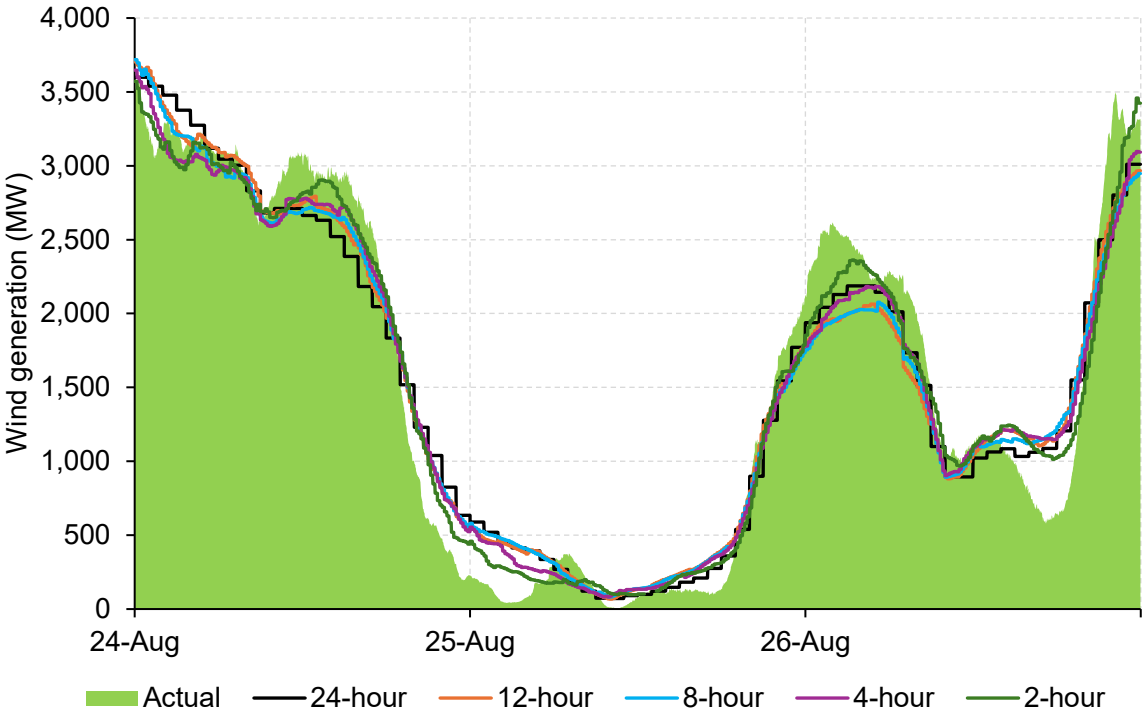
Table 6: AESO unit commitment directives (August 24 to 26)

Asset ID	Issued time	Begin time	Start-up time (hours)	Operation start time	Operation end time
SH2	24-Aug 08:25	24-Aug 09:00	10	24-Aug 19:00	24-Aug 23:00
SH2	25-Aug 07:27	25-Aug 08:00	9	25-Aug 17:00	25-Aug 21:00

Despite the low supply cushion, the assets were not issued unit commitment directives, partly because there was an unexpected drop in wind generation on the evening of August 26 (Figure 9). In HE 19, actual wind generation was 710 MW compared to the forecast 24 hours ahead of 1,210 MW and the forecast 12 hours ahead of 1,260 MW. Therefore, the 24-hour and 12-hour forecasts overpredicted wind generation by 500 MW and 550 MW, respectively. In addition, the committed capacity in the supply cushion forecast 24 hours ahead was 760 MW higher than the committed capacity in real-time.

As outlined above, intertie traders could not respond to the high prices by importing on BC or MATL because of the 1201L outage. However, the Saskatchewan intertie was fully available for 153 MW on the evenings of August 24, 25, and 26. On August 24 and 25, traders fully used this available capacity to import into Alberta. However, on August 26, Alberta was exporting 50 MW to Saskatchewan when the SMP increased to the offer cap, indicating that market conditions were also tight in Saskatchewan.

Figure 9: Wind generation relative to the AESO's "most likely" forecasts (August 24 to 26)



1.2.3 Volatile prices (August 31 to September 1)

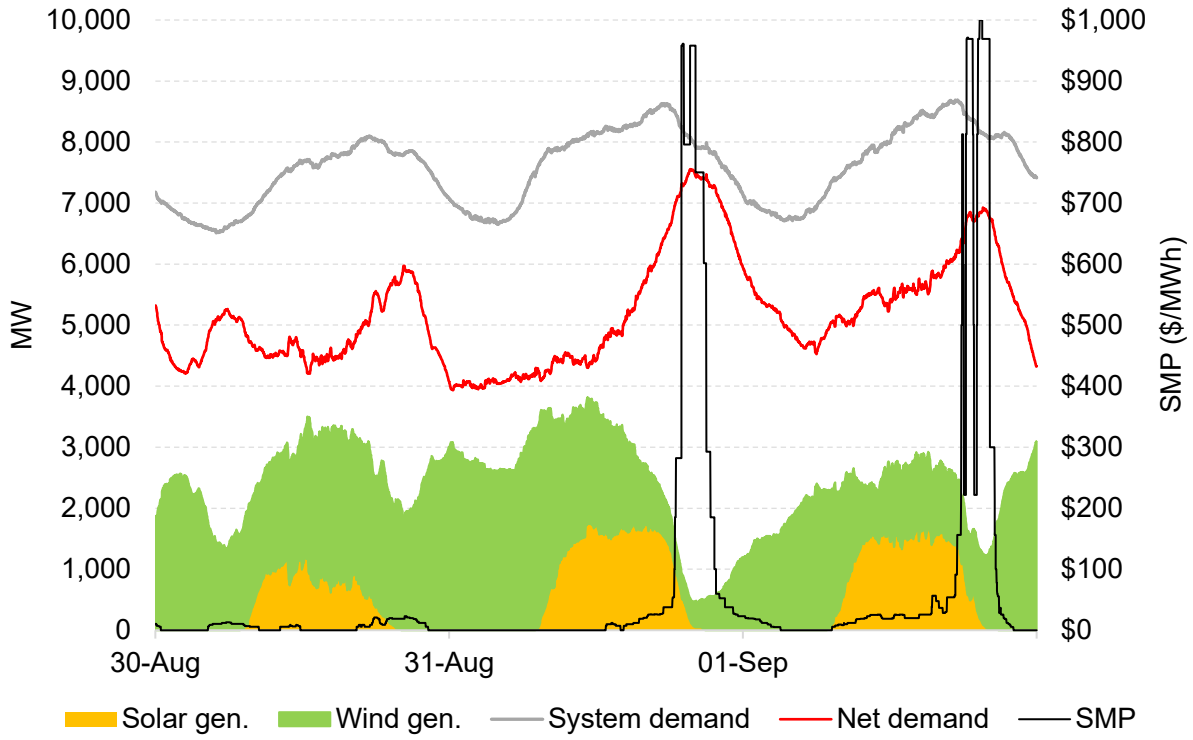
The SMP increased to the offer cap again on Tuesday, September 1. The fundamental drivers were the same: the BC/MATL outage, variable intermittent generation, some major thermal generator outages, and some gas-fired steam assets being on LLT.

The SMP was $999.99/MWh between 19:20 and 19:33. The supply cushion during this period fell to a low of 76 MW, so there was still unused generation capacity in the merit order. Three hours later, at 22:36, the SMP fell to $0/MWh as demand had declined and wind generation had increased (Figure 10). As with the event on August 26, the event on September 1 illustrated substantial changes to market conditions and prices over a short period of time. The SMP had been $0/MWh earlier in the day, between 03:47 and 06:21, due to low demand and high wind generation.

Prices were also volatile on Monday, August 31. The SMP was at the price floor for an extended period, between 22:25 on August 30 and 11:07 on August 31, reflecting high intermittent generation. However, both wind and solar generation declined substantially in the evening, while demand was still elevated, and this drove the SMP to a peak of $961/MWh (Figure 10).

The price volatility on August 31 and September 1 was not driven by elevated demand. Demand on both days was moderate, with peak AIL of around 11,200 MW reflecting temperature highs of 22 to 23°C on August 31 and 26°C on September 1.

Figure 10: Net demand and SMP (August 30 to September 1)



Intermittent generation fell to a low of 450 MW around the net demand peak on August 31 compared to 1,200 MW on September 1 (Figure 10). Despite more intermittent supply, prices were higher on September 1 because:

- Keephills 3 (466 MW) ramped down for a planned outage in HE 15 of September 1,
- Sheerness 2 (400 MW) was committed by the AESO for the evening of August 31 but was not committed for September 1, and
- there were 153 MW of imports on the Saskatchewan intertie for the net demand peak on August 31 compared to 153 MW of exports on September 1.

There were some large thermal generator outages that reduced supply and contributed to the price volatility on August 31 and September 1. At Base Plant, a forced derate on GT13 on the evening of August 31 lowered availability by 400 MW, and a planned outage on GT13 meant the asset's availability was lowered by 500 MW on the evening of September 1. The outages at Syncrude continued and the asset was derated by 230 MW. In addition, Cascade 1 (466 MW) took a forced outage from August 30 to September 5, and Keephills 3 was ramped down for a planned outage in HE 15 of September 1.

Despite the high prices and low supply cushion, Battle River 4 (155 MW) remained on LLT on August 31 and September 1 as the asset was not committed by TransAlta or the AESO. Sheerness 2 (400 MW) was committed by the AESO for the evening of August 31 but was not

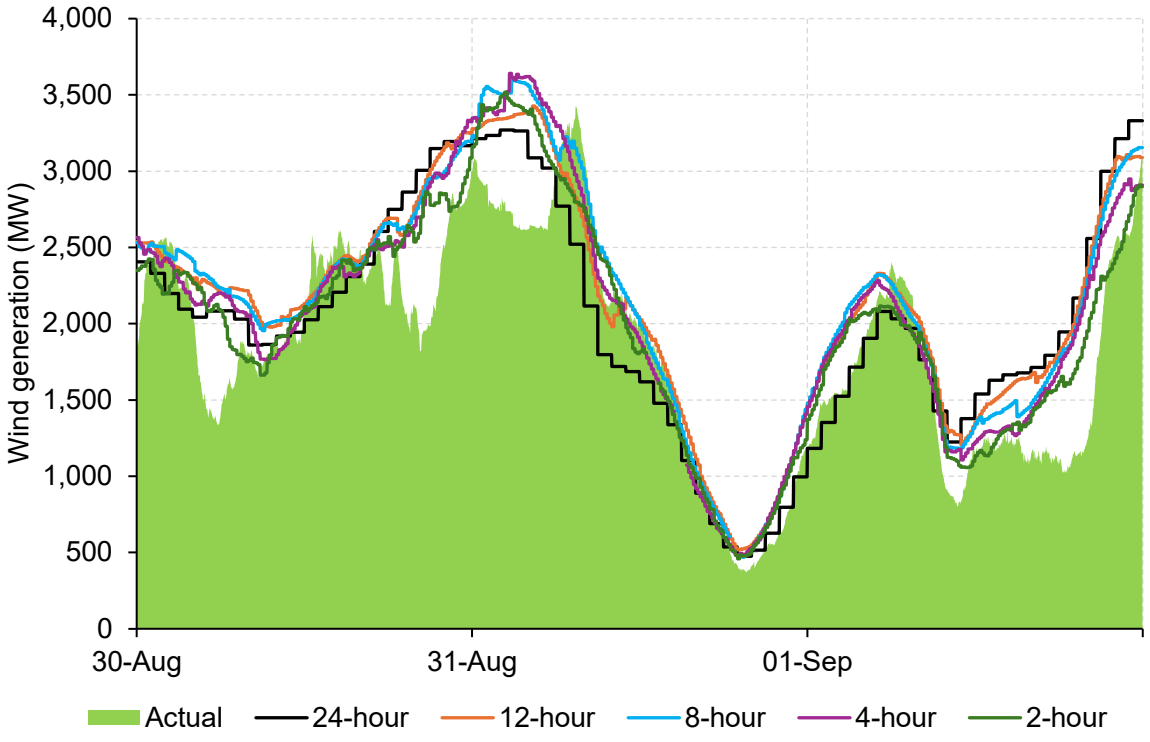
committed for September 1 (Table 7). Therefore, there was 555 MW of gas-fired steam capacity on LLT when the SMP increased to the offer cap on September 1.

Table 7: AESO unit commitment directives (August 30 to September 1)

Asset ID	Issued time	Begin time	Start-up time (hours)	Operation start time	Operation end time
SH2	30-Aug 17:25	30-Aug 18:00	24	31-Aug 18:00	31-Aug 22:00

The Sheerness 2 and Battle River 4 assets were not committed by the AESO for the evening of September 1, partly because wind generation was expected to be significantly higher than it was (Figure 11). In HE 20, when the SMP peaked to the offer cap, actual wind generation averaged 1,160 MW, which is 1,010 MW lower than the forecast 24 hours ahead, and 990 MW lower than the forecast 12 hours ahead.

Figure 11: Wind generation relative to the AESO's "most likely" forecasts (August 30 to September 1)



1.2.4 Over-frequency events (August 18 and 19)

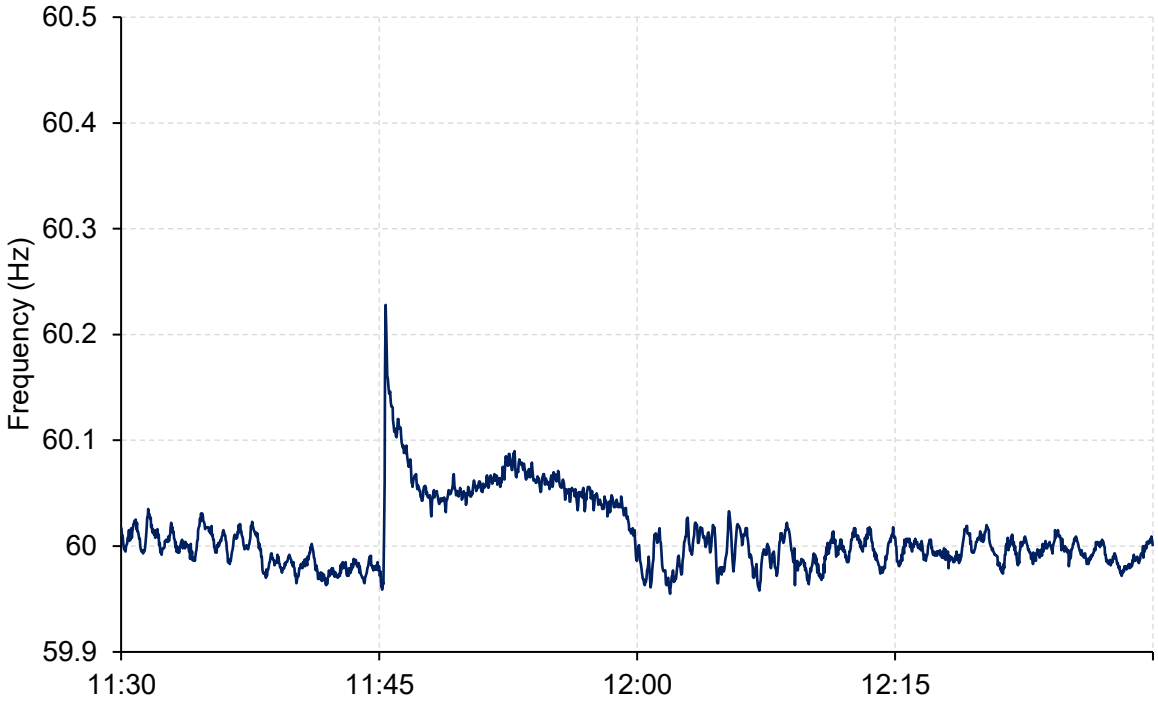
At 11:45 on Tuesday, August 18, an Alberta frequency event occurred because the transmission line 5L98 tripped offline due to wildfire smoke, while the 5L91 line was out of service on planned maintenance. 5L91 and 5L98 are both 500 kV lines internal to BC. The trip on 5L98 caused Southeast BC to island along with Alberta from the Western Interconnection. At the time,

Southeast BC had excess generation relative to its load, so the event caused an in-rush of power into Alberta.

Net imports on the BC intertie increased by around 350 MW: from 205 MW of exports to 147 MW of imports. The excess power also flowed out over MATL, where exports increased before the line tripped. The sudden in-rush of power into Alberta caused frequency to increase to 60.23 Hz (Figure 12).

Following the event, the AESO restated import and export available transmission capacity (ATC) to 0 MW for BC and MATL for HE13, although the BC intertie remained in service. Normal service on the interties resumed around 13:00 as flows were ramped to match the schedule.

Figure 12: System frequency (August 18, 11:30 to 12:30, data increment is 2s)



A similar event occurred at 18:56 the following day. The 5L98 line tripped offline due to wildfire smoke while 5L91 was on a planned outage, which caused Southeast BC to island along with Alberta. The resulting in-rush of power into Alberta caused imports on the BC intertie to increase from 8 to 367 MW, and on MATL exports increased before the line tripped. As a result of the event, frequency in Alberta increased to 60.24 Hz.

Subsequently, for HE 20, the AESO set import and export ATC to 0 MW for BC and MATL, but the BC line remained in service. Normal service on the interties resumed around 20:00.

1.2.5 Genesee Repower 1 and 2 testing

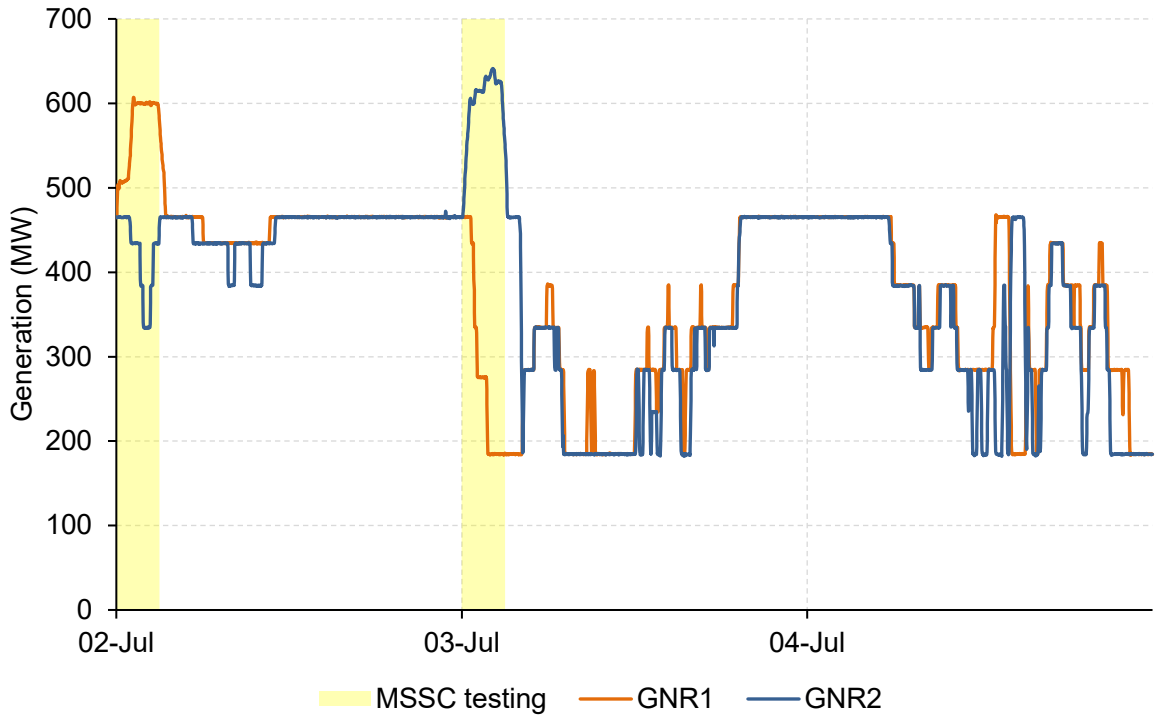
The Genesee Repower 1 (GNR1) and Genesee Repower 2 (GNR2) assets have an installed capacity of 716 MW each. However, due to the AESO's Most Severe Single Contingency (MSSC) limit, each asset is limited to 466 MW of net generation. Efforts to unlock some of this additional capacity continued in Q3, with further MSSC testing carried out at GNR1 and GNR2.

On June 19, the AESO announced that GNR1 and GNR2 would perform MSSC testing.[4] GNR1 testing was scheduled for July 2, 9, 10, and 11 while GNR2 testing was scheduled for July 3 and 4. The AESO noted that the unit being tested would at times operate above the MSSC limit, up to around 716 MW.

Testing began with GNR1 in HE 01 to 03 on July 2, followed by GNR2 in HE 01 to 03 on July 3. The GNR2 testing scheduled for July 4 was cancelled on July 3 at around 22:44.

During the testing on July 2 and 3, generation at GNR1 reached a maximum of 608 MW in HE 02 on July 2, and GNR2 reached a maximum of 642 MW in HE 03 on July 3 (Figure 13).

Figure 13: GNR1 and GNR2 generation (July 2 to 4)



On July 7, the AESO updated the remaining testing schedule and announced that GNR2, instead of GNR1, would perform MSSC testing on July 9, 10, and 11.[5]

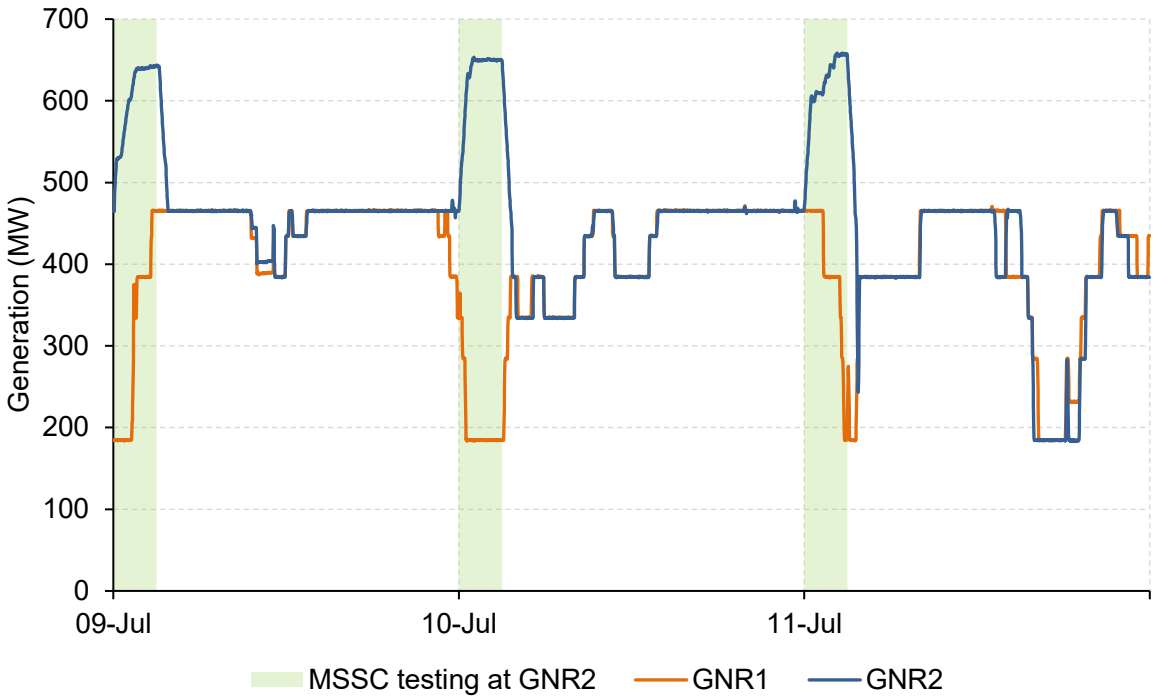
[4] AESO market updates, GNR1 and GNR2 generator testing – June 19, 2026

[5] AESO market updates, GNR1 and GNR2 generator testing update – July 7, 2026

Following the updated schedule, GNR2 was tested in HE 01 to 03 on July 9, 10, and 11 (Figure 14). During these periods, generation generally reached a maximum of around 650 MW. The highest output was observed in HE 03 on July 11 at 659 MW.

Unlike previous tests, no trips occurred at GNR1 or GNR2. However, a drop in generation at GNR1 was observed when the output of GNR2 was above the MSSC limit, and vice versa (Figure 13 and Figure 14).

Figure 14: GNR1 and GNR2 generation (July 9 to 11)



No additional contingency reserves were procured for the testing, and the BC/MATL import ATC was not reduced to 0 MW during the testing hours. Instead, it was set to 560 MW for the testing hours on July 2 and 3, and to 360 MW for those on July 9 and 10. On July 10, the import ATC for the July 11 testing hours was increased from 360 MW to 560 MW.

1.2.6 Forced BC/MATL intertie outage (July 26)

At 17:54 on Sunday, July 26, the BC intertie was taken offline on a forced outage due to concerns over a grassfire near the 1201L transmission line. 1201L is the main 500 kV line connecting Alberta and BC. The two 138 kV lines connecting Alberta and BC (887L and 786L) were also taken out of service. MATL is not permitted to operate independently of the BC intertie, so it was taken offline at 17:25, ahead of the BC intertie.

Prices in Alberta during this event were low; the pool price for HE 18 was $25.43/MWh. Consequently, at the start of this event, the AESO had no armed FFR because Alberta was exporting over BC/MATL. As outlined above, the AESO normally procure around 200 MW of FFR when BC/MATL is on a planned outage to help deal with large contingency events.

In response to the forced outage on BC/MATL, the AESO issued reliability directives to 112 MW of battery capacity to re-allocate from contingency reserves into FFR, and by 17:52 the AESO had 160 MW of armed FFR. The AESO did not conscript additional contingency reserves to replace the batteries because the reserves requirement fell by 80 MW (from 546 to 466 MW) when BC/MATL came offline due to the reduction in exports.

In addition, the AESO lowered the MSSC limit from 466 to 425 MW. Therefore, generating units supplying more than 425 MW had to lower their generation. Between 18:17 and 18:25, the AESO issued Constrained Down Generation (CDG) directives to eight assets specifying that their generation could not exceed 425 MW, which affected 164 MW of generation (Table 8).

Table 8: Generation assets that were issued CDG directives (July 26)

Asset ID	Gen. prior to CDG directive (MW)	Time of CDG directive	Gen. reduction of CDG directive (MW)	Time CDG directive met
BPW1	118	18:23	0	-
CAS1	402	18:17	0	-
CAS2	449	18:18	24	18:25
GN3	305	18:20	0	-
GNR1	465	18:20	40	18:27
GNR2	465	18:21	40	18:30
KH3	444	18:19	19	18:26
TVS1	466	18:25	41	18:28

The assets responded to the AESO's directives relatively quickly, although average generation at Travers subsequently increased to 430 MW at 18:47 and 19:01. The BC intertie returned to service at 20:56 as the grassfire concerns had been resolved, and MATL came back online at 21:14. The AESO raised the MSSC limit back to 466 MW at 21:05.

1.2.7 Western Power Pool reserve sharing request (July 29)

On the afternoon of Wednesday, July 29, BC experienced multiple generation events associated with transmission line trips due to wildfire smoke.[6] In response to these events, the AESO received a series of reserve sharing requests from the Western Power Pool (WPP) (Table 9).

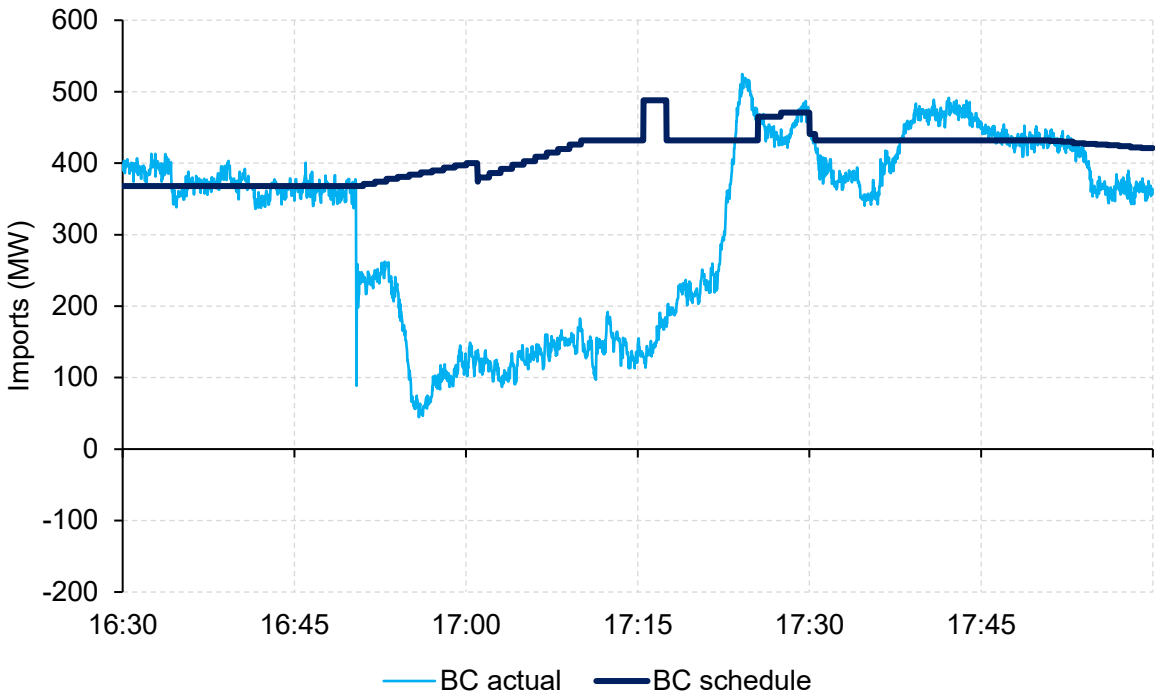
The AESO responded by importing less from BC than was scheduled (Figure 15). The AESO used contingency reserves to meet the additional supply, with available contingency reserves dropping from 546 MW at 16:51 to 0 MW at 16:53. Prices in Alberta were relatively low during this event; the pool prices for HE 17 and 18 were $29.07/MWh and $29.78/MWh, respectively.

[6] CBC news article – July 30, 2026

Table 9: WPP reserve sharing requests (July 29)

Time	Reserve request (MW)
16:52	546
16:54	322
17:03	270
17:20	1
17:23	0

Figure 15: Actual and scheduled imports on the BC intertie (July 29, 16:30 to 18:00)



1.3 Market power mitigation measures

In March 2024, the Market Power Mitigation Regulation (MPMR) and Supply Cushion Regulation (SCR) were enacted. Beginning on July 1, 2024, these regulations moderate economic withholding and require the AESO to commit generation capacity under some circumstances. The MPMR and SCR are implemented through ISO rules 206.1 and 206.2, respectively.

1.3.1 Market Power Mitigation Regulation and ISO rule 206.1

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

The secondary offer price limit was not triggered in Q3. Low pool prices during the quarter led to the reference unit receiving negative hourly net revenue in 48%, 31%, and 40% of hours in July, August, and September, respectively. As a result, the MCSINR stayed below the threshold in all three months.

In July, low pool prices early in the month led to a low MCSINR to start the month. However, some high prices later in the month increased net revenues, and the MCSINR reached a peak of 17% of the threshold by the end of the month.

In August, the MCSINR increased gradually over the month. Later in the month, high prices driven by the planned outage on BC/MATL raised net revenues sharply. The MCSINR reached a peak of 38% of the threshold by the end of the month.

September had the lowest average pool price of the quarter. Consequently, the MCSINR reached a peak of only 14% of the threshold by the end of the month.

1.3.2 Supply Cushion Regulation and ISO rule 206.2

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

In Q3, 27 UCDs were issued by the AESO, a decrease from the 52 UCDs issued in the previous quarter. Within Q3, no UCDs were issued in July, 14 were issued in August, and 13 were issued in September.

As noted in section 1.1, solar generation was elevated in July, exports were lower and thermal availability was higher than in August or September. As a result, the ASC did not fall below the 932 MW threshold in July, so no UCDs were issued. The real-time supply cushion was generally close to the ASC, and July had the highest average supply cushion in Q3, along with the highest amount of capacity offline on LLT.

Despite a similar number of UCDs in August and September, the generation from UCDs in September was almost 5 GWh, compared to 2.1 GWh in August. This was due to most UCDs in August being issued to Battle River 4, which is a smaller asset, along with UCDs being of shorter duration in August.

Table 10 shows the estimated price effect of the UCDs in Q3. Over the quarter, the MSA estimates that the average pool price would have been $2.98/MWh (or 8%) higher without the UCDs.

In Q3, there were no hours in which the supply cushion would have been negative without the AESO's UCDs.

Table 10: Estimated price impact of unit commitment directives in Q3

Time period	Actual average pool price ($/MWh)	Estimated average pool price without unit commitment directives ($/MWh)	Change (%)
Jul	$31.26	$31.26	0%
Aug	$45.71	$50.36	10%
Sep	$29.40	$33.71	15%
Q3	**$35.52**	**$38.50**	**8%**

1.4 Market power, offer behaviour, and net revenues

1.4.1 Market power

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

The MSA has updated its estimates of SRMC to incorporate prevailing carbon prices. Previously, the MSA used the regulated price of carbon to estimate carbon costs for thermal generators. However, the prevailing price of carbon has been below regulated prices, so prior MSA estimates overestimated SRMC and underestimated market power. Figure 16 illustrates the price of carbon over Q2 and Q3. Prices declined gradually over Q3 and averaged $28.35/tCO2e, well below the regulated price of $95/tCO2e.

The MSA has published its updated market power metrics, including counterfactual price estimates, and the data is available on the MSA's data portal.

Figure 17 illustrates actual and counterfactual prices by month in Q3 and Q3 2025. In Q3, the mark-up was highest in August at $23.73/MWh, compared to $13.23/MWh in July and $10.41/MWh in September. The higher mark-up in August was driven by reduced competition later in the month when BC/MATL was taken offline for planned maintenance, there were some major thermal generator outages, and periods of low intermittent generation.

However, the mark-ups in August and September of 2025 were both higher at $34.72/MWh and $53.73/MWh, respectively. The elevated mark-ups in September last year were due to a planned outage on BC/MATL, thermal generation outages, and above-normal temperatures.

Figure 16: The prevailing price of carbon by day (Q2 and Q3)[7]

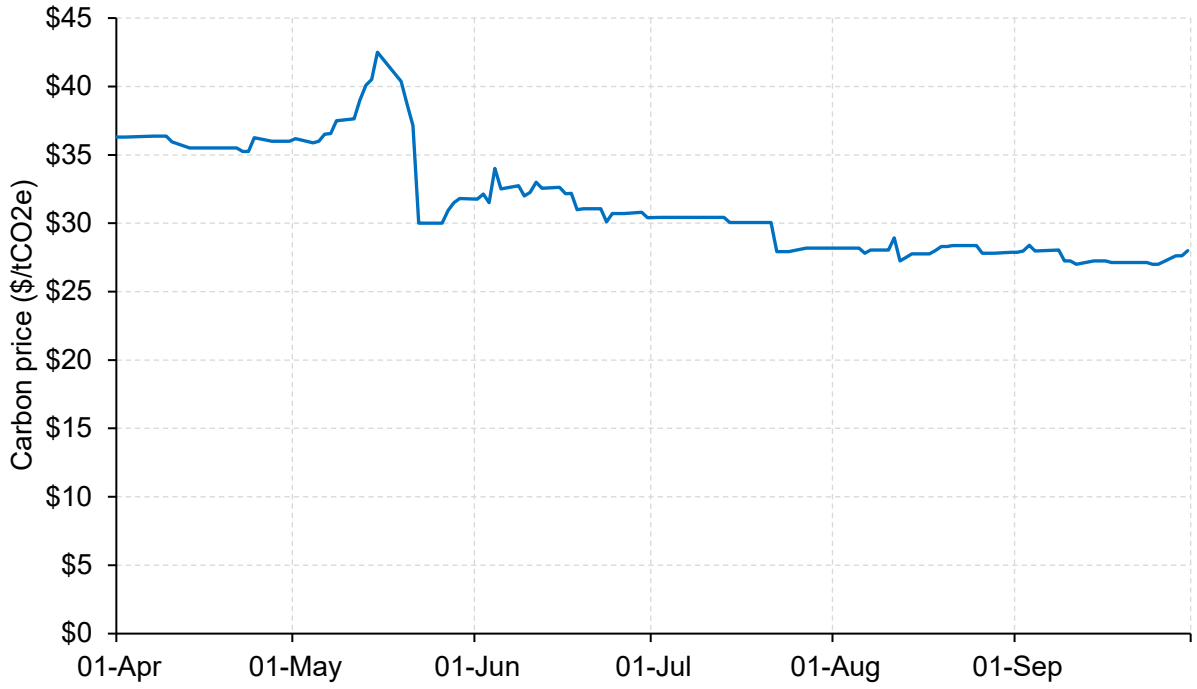
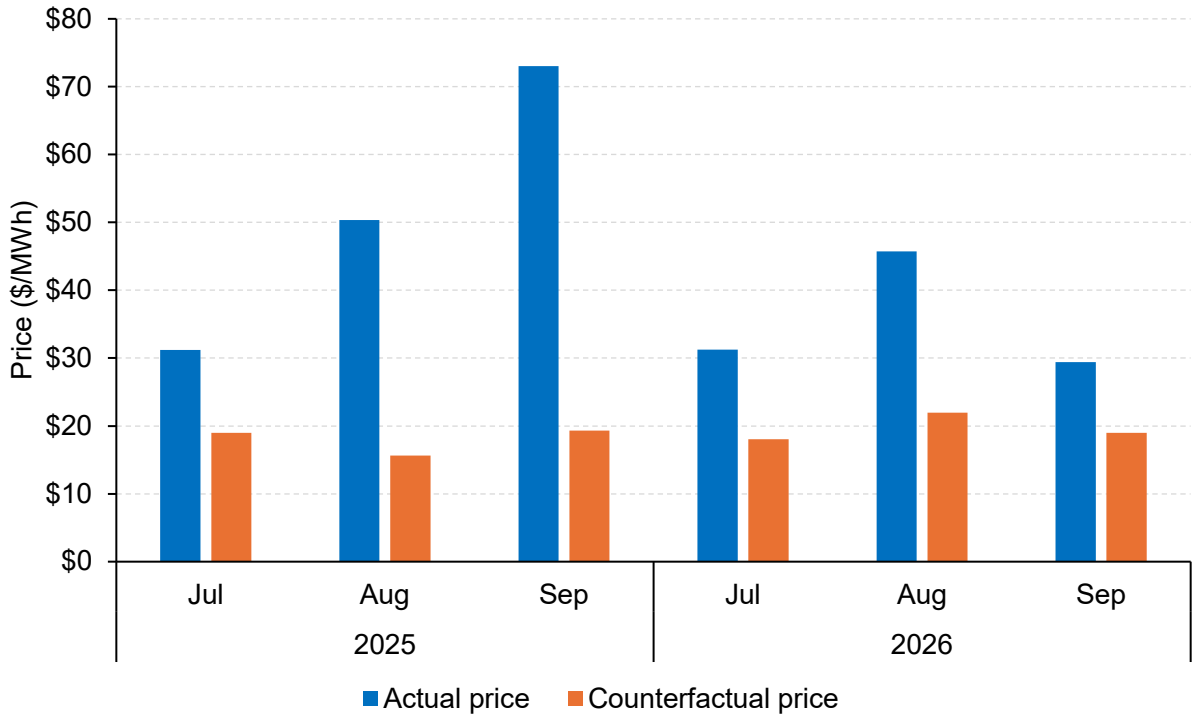


Figure 17: Average actual and counterfactual prices by month (Q3 2025 and Q3)



[7] Carbon prices are sourced from Carbon Assessors

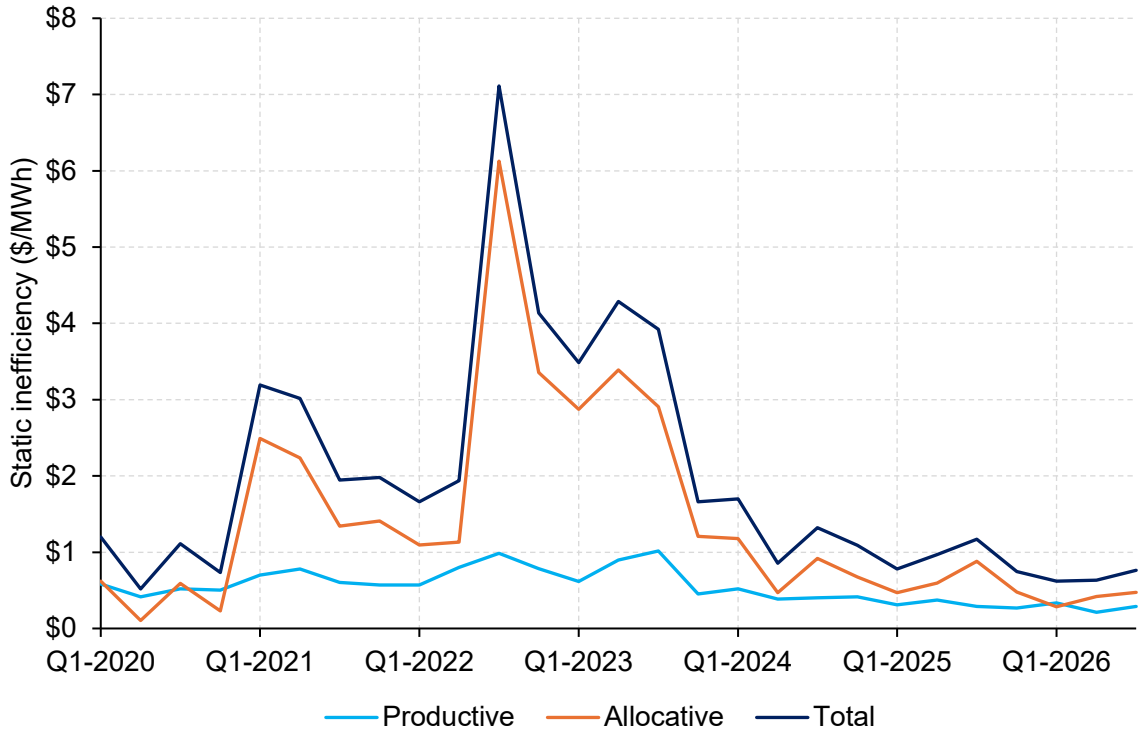
The exercise of market power can lead to static inefficiencies in the short-run, specifically productive and allocative inefficiencies. Productive inefficiencies occur when lower cost generating assets are priced out of the market and higher cost assets supply power instead. Allocative inefficiencies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

In the context of Alberta's energy-only market, these short-run inefficiencies should be weighed against long-run efficiencies, including the supply of new capacity. Short-run inefficiencies are tolerable to the extent that long-run efficiencies are contingent on them.

Static inefficiencies remained relatively low in Q3 because of increased competition and low pool prices (Figure 18). Static inefficiencies over the quarter averaged $0.76/MWh or 2.2% of the average pool price. This is lower than Q3 last year when average static inefficiencies were $1.17/MWh or 2.3% of the average pool price.

Figure 18 provides a long-term perspective. In 2021, 2022, and 2023 static inefficiencies were elevated due to higher levels of market power and more market power being exercised. This exercise of market power led to higher allocative inefficiencies, although productive inefficiencies were less effected. However, the return of HR Milner from an extended forced outage, the addition of Cascade 1 and 2, the addition of cogeneration units at Base Plant, and more intermittent generation have all increased competition in recent years and lowered static inefficiencies.

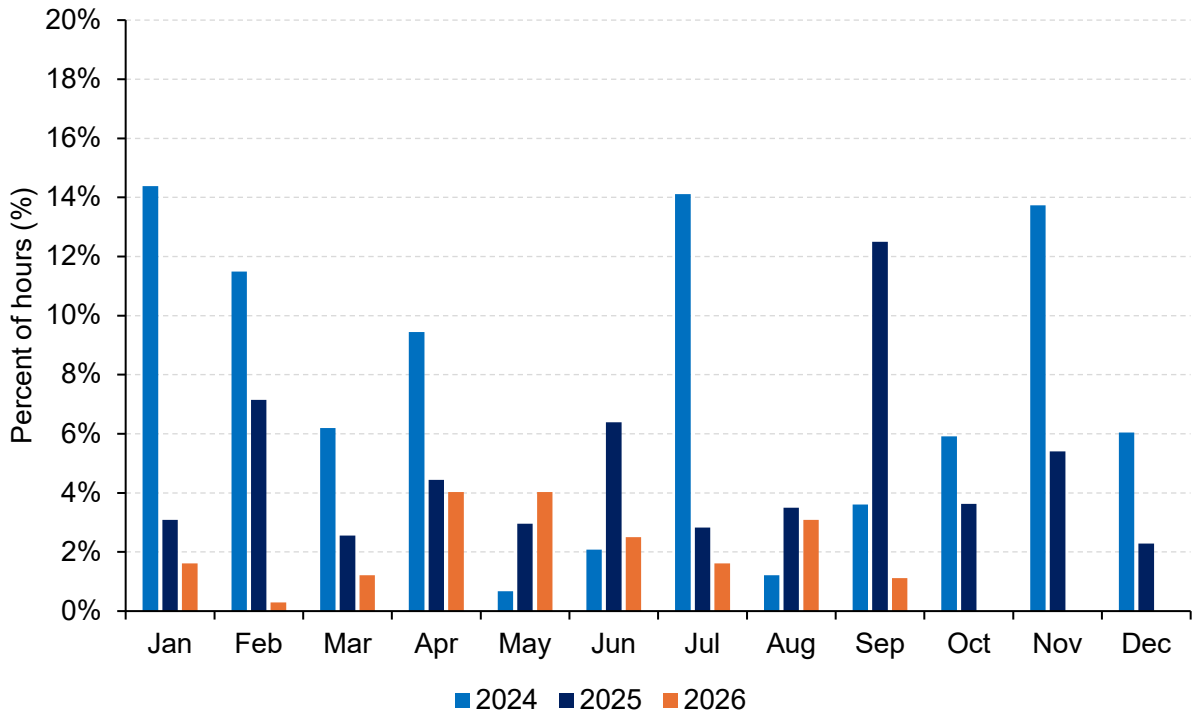
Figure 18: Average static inefficiencies by quarter (Q1 2020 to Q3 2026)



The ability of large firms to exercise market power remained low in Q3. 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[8] is needed for demand to be met.

In Q3, at least one firm was pivotal in 2% of hours, which is down from 4% in Q2 and 6% in Q3 2025. Figure 19 illustrates monthly trends going back to January 2024. The ability of firms to exercise market power has been limited so far in 2026 because of high levels of supply relative to demand. In Q3, market power was highest in August when at least one firm was pivotal in 3% of hours, which is still modest relative to historic data.

Figure 19: Percent of hours in which a firm was pivotal by month (January 2024 to September 2026)



1.4.2 Offer behaviour

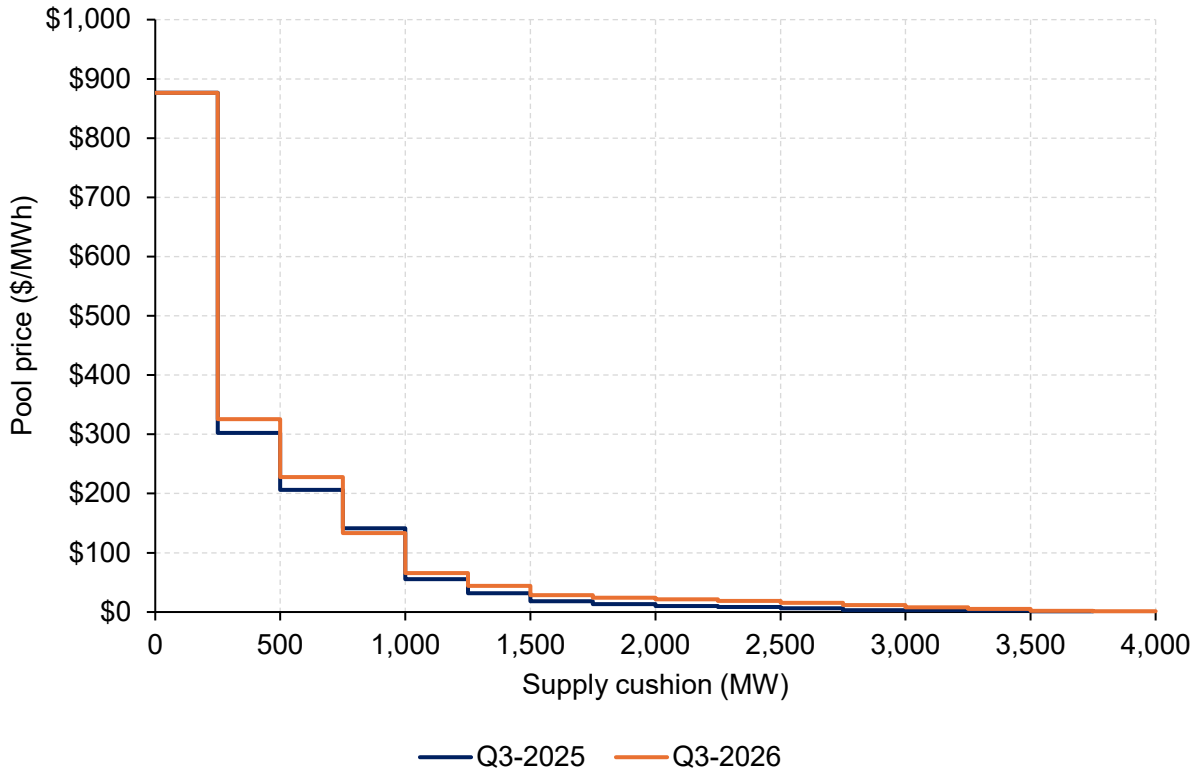
Offer behaviour in Q3 was consistent with Q3 last year. To show this, Figure 20 illustrates the relationship between supply cushion and pool price in Q3 and Q3 2025. Specifically, the figure illustrates the average pool price in 250 MW supply cushion bins for the two quarters. Supply cushion is the amount of generation capacity that was available in the merit order above what was needed to meet demand.[9] As the supply cushion declines, prices increase to reflect tighter

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

[9] 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.

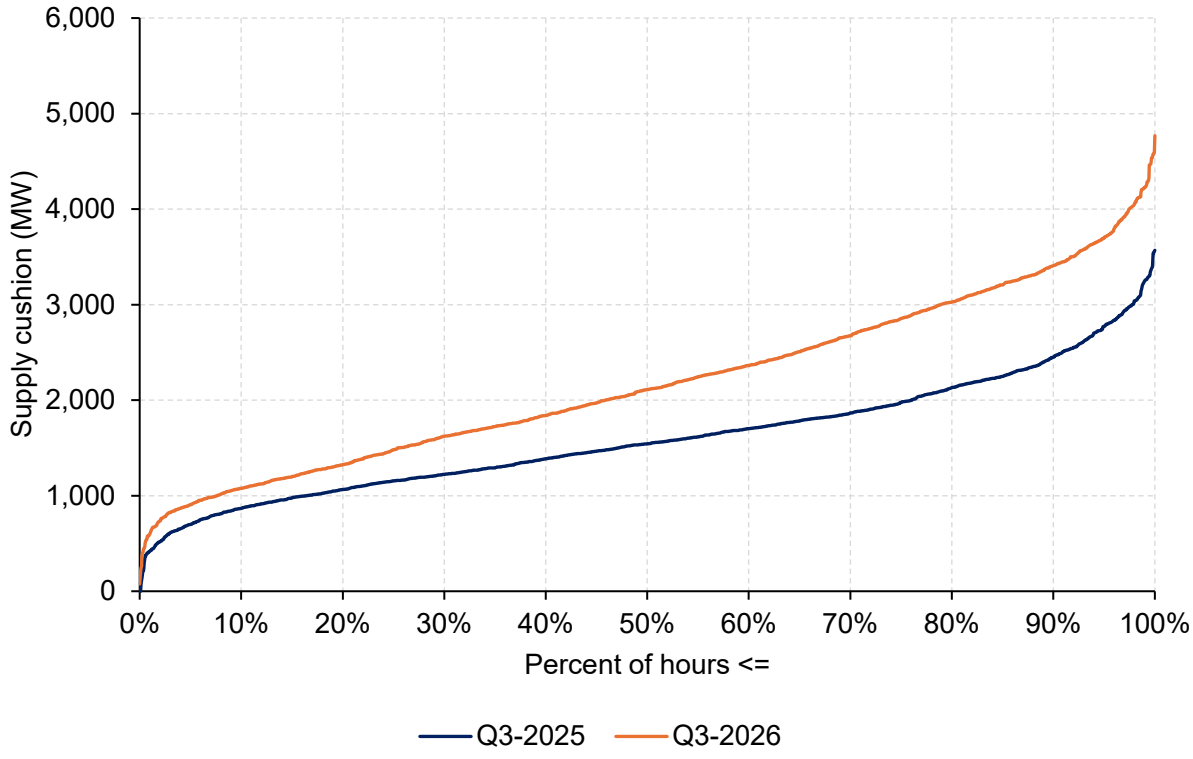
market conditions. The relationship between supply cushion and pool price is comparable across the two quarters, illustrating similar offer behaviour.

Figure 20: Average pool price by supply cushion bin (Q3 2025 and Q3)



As outlined in section 1.1, the decline in pool prices year over year was driven by market fundamentals: mild weather, more intermittent generation, and fewer exports. These changes meant the supply cushion was higher in Q3 this year (Figure 21). At the 5th percentile, the supply cushion was 905 MW in Q3 compared to 700 MW in Q3 2025, an increase of 205 MW. The higher supply cushions at this end of the distribution reduced the number of high-priced events and lowered the average pool price. The median supply cushion in Q3 was 2,110 MW compared to 1,540 MW in Q3 2025, an increase of 570 MW.

Figure 21: Duration curves of supply cushion (Q3 2025 and Q3)



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 Q3 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 11.

Table 12 shows the seasonal capacities and heat rates for the hypothetical natural gas assets. Because Q3 is in 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 Q3. As a result of its lower heat rate, the combined cycle asset incurs lower carbon costs per MWh than 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 $28.35/tCO2e in Q3. The remaining 10% of emissions are covered through payments into the TIER Fund at the regulated carbon price of $95/tCO2e.

Table 11: Cost assumptions used in the net revenue analysis (2026$)[10]

Parameter	Combined cycle	Simple cycle	Wind	Solar
Size (MW)	418	47	100	50
Net overnight capital costs ($/kW)	$1,729	$1,873	$1,192	$1,316
Fixed O&M ($/kW-year)	$22.48	$25.99	$98.68	$30.11
Variable O&M ($/MWh)	$4.06	$7.49	$0.00	$0.00

Table 12: 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 analyses incorporate 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. 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 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 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

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

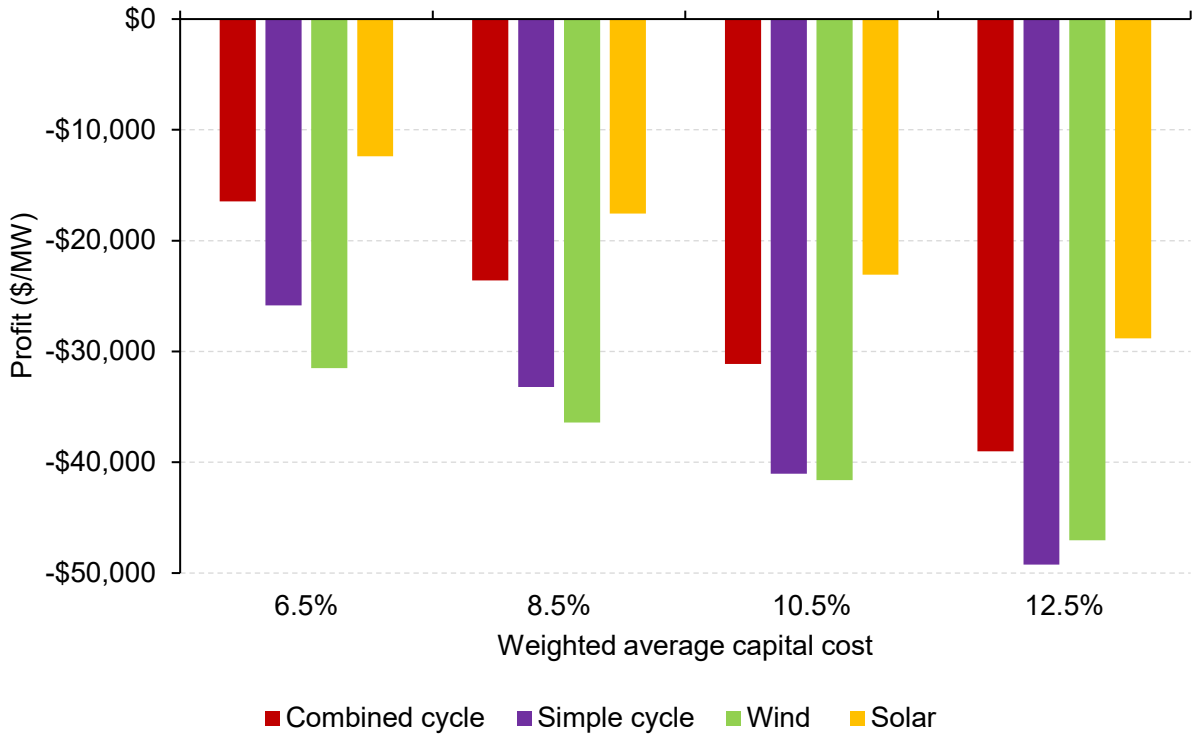
90% are included in the capacity factor calculation. Transmission losses for the hypothetical wind and solar assets are calculated as the generation-weighted average losses of actual wind and solar assets. With respect to dispatch assumptions, both the hypothetical wind and solar assets are assumed to 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 22 illustrates the results of the analysis in dollars per MW.

Pool prices in Q3 were relatively low with an average of $35.52/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. 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 22).

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.

Figure 22: Profits per MW by generation type at different WACC assumptions (Q3)



1.5 Inflexible blocks

Pool participants must submit energy market offers to the power pool for each of their assets in accordance with the ISO Rules.[11] An inflexible block is an operating block in a pool participant's offer that must either be fully dispatched or not dispatched at all by the AESO.[12] In contrast, the AESO may partially dispatch a flexible block when necessary.

Section 2 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation) sets out conduct that does not support the fair, efficient and openly competitive operation of the electricity market.[13] The use of inflexible blocks by a generating asset that is capable of operating flexibly conflicts with section 2(e) of the FEOC Regulation, which prohibits misrepresenting the capability or operating status of an asset.

During periods of supply surplus, the AESO must follow a specific procedure to balance supply and demand.[14] In this procedure, import interchange transactions are first to be curtailed. Following the ability for pool participants to submit interchange transaction bids, offers, and restatements for generation, the fifth action that may be taken to balance supply and demand is to partially dispatch flexible blocks priced at $0/MWh. Only once flexible offer blocks priced at $0/MWh are fully curtailed will the AESO curtail inflexible offer blocks priced at $0/MWh. Therefore, a pool participant could submit offers for their asset as inflexible to avoid curtailment. The use of inflexible blocks to circumvent procedures approved by the Alberta Utilities Commission in section 202.5 of the ISO Rules, *Supply Surplus,* is at odds with section 2(l) of the FEOC Regulation, which prohibits carrying out actions to circumvent an ISO rule.[15]

The MSA has previously reported on intermittent assets offering blocks as inflexible; in its Q1 2025 Wholesale Market Report for example.[16] In addition, the AESO opened a stakeholder engagement on this matter earlier in 2026.[17] Comments submitted in the consultation by the MSA affirmed support for an option that would amend the definition of inflexible block, limiting its use to the management of physical or operational constraints.[18]

Though the proportion of available intermittent capacity being submitted as inflexible fell from a peak of 41% in Q3 2023 to 28% over 2025, the proportion has since increased slightly and remained stable at 31% in Q3 (Figure 23). A greater number of intermittent assets have been submitting offers as inflexible, increasing from 11 assets in 2020 to 35 in 2026. Most intermittent

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

[12] AESO: Consolidated Authoritative Document Glossary, effective March 12, 2026

[13] Fair, Efficient and Open Competition Regulation, AR159/2009, section 2

[14] ISO Rule 202.5 Supply Surplus, effective April 1, 2024

[15] Fair, Efficient and Open Competition Regulation, AR159/2009, section 2(l)

[16] MSA: Wholesale Market Report: Q1 2025, page 34

[17] AESO Engage: Development of Proposed Amended Definition of "inflexible block" in the ISO Rules

[18] MSA comments regarding the proposed amended definition of "inflexible block", August 13, 2026

assets that begin to submit offers as inflexible maintain this behaviour. Only three assets that have submitted offers as inflexible have reverted to submitting flexible blocks (Figure 24).

Figure 23: Percent of available intermittent capacity offered as inflexible (Q1 2020 to Q3 2026)

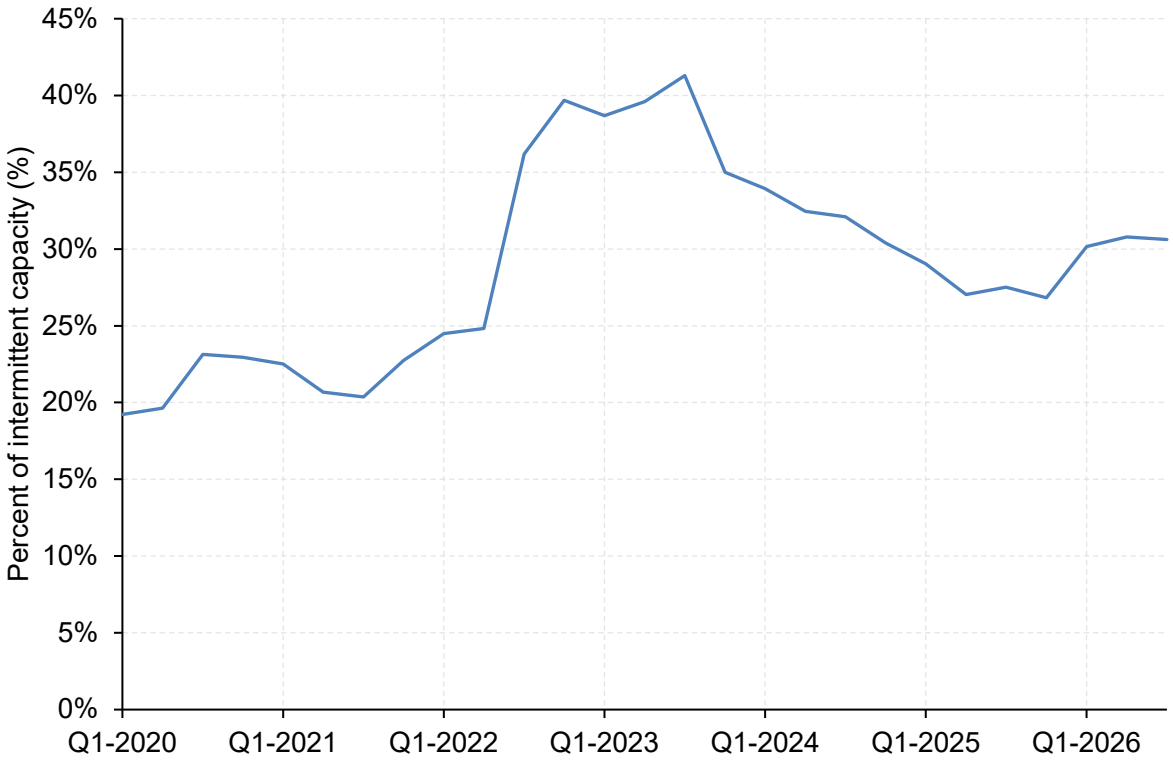
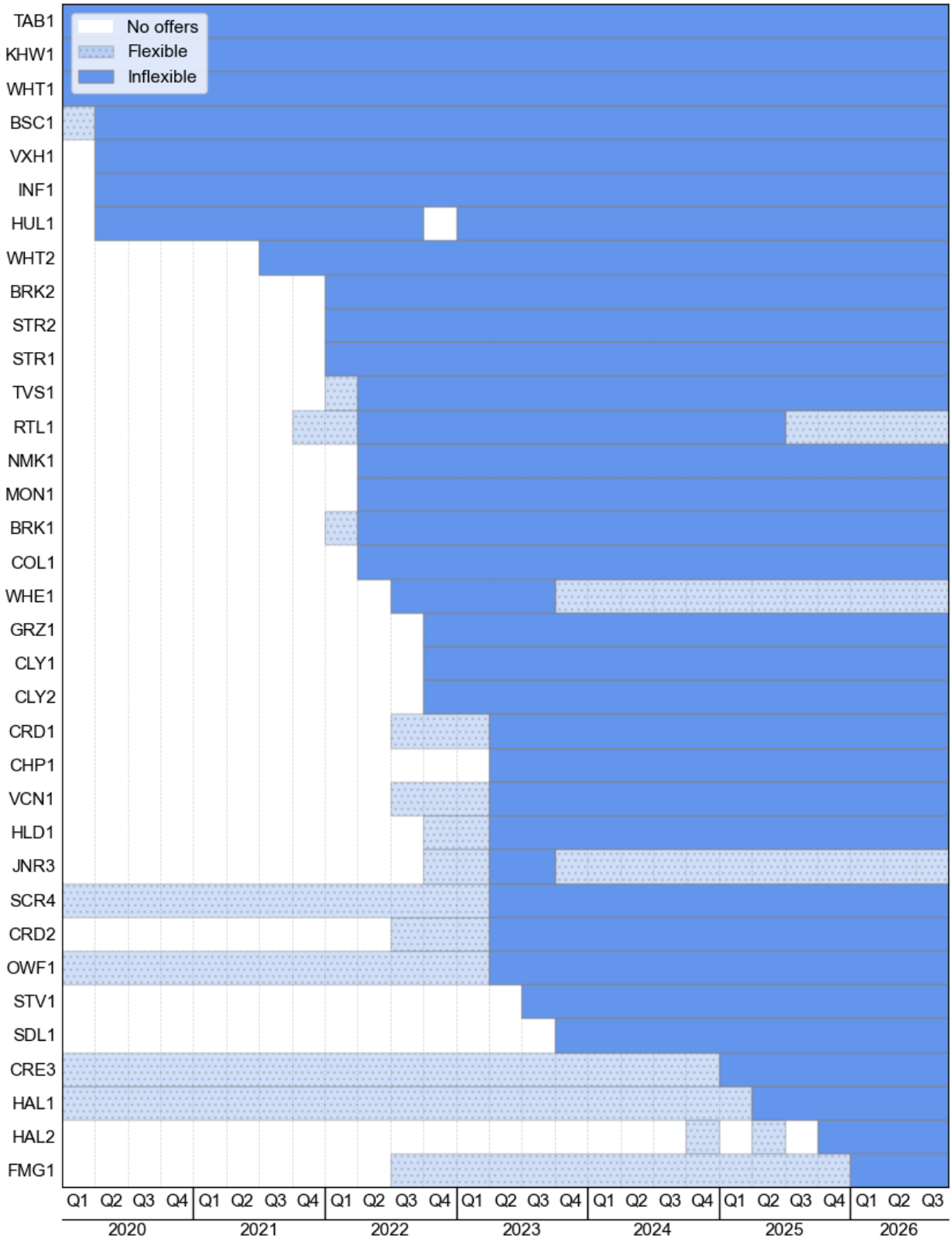


Figure 24: Intermittent assets offering inflexible blocks (Q1 2020 to Q3 2026)



1.6 Primary frequency response

As the balancing authority and reliability coordinator for the Alberta Interconnected Electric System (AIES), the AESO is required to maintain system frequency at 60 Hz under both normal and abnormal grid operating conditions. When the system frequency goes outside of a defined limit for a minimum period of time, automatic relays designed to protect generating equipment from damage will result in generating units tripping off, immediately reducing the amount of electricity supplied to the AIES and potentially leading to a cascading failure and loss of load event. Maintaining system frequency at the required level is therefore critical to the reliable operation of the AIES, a function in which generators play a key role.

System frequency deviations occur because of imbalances between supply and demand. Primary Frequency Response (PFR) arrests frequency deviations by changing real power output to minimize the imbalance between supply and demand. PFR is the immediate proportional increase or decrease in real power output provided by a generating unit in response to a system frequency deviation. This response is in the direction that stabilizes system frequency; if system frequency decreases, a generating unit providing PFR immediately and proportionally increases its real power output, and vice-versa.

A generating unit, when its governor system is configured properly, will automatically provide PFR.[19] The PFR rules also require generators to have a free acting governor, and must respond to system frequency changes.[20] The AESO has developed a set of suspected contravention criteria, including when a generating unit:

- provides no response when it is not constrained by minimum or maximum generation limits,
- responds in the wrong direction, or
- does not sustain its response.

These criteria suggest a potential contravention of the PFR rules, as discussed in the MSA's report on PFR compliance monitoring practices.[21]

When the AIES is islanded from the rest of the Western Interconnection, frequency stability must be maintained using resources internal to Alberta, including PFR provided by generating units in Alberta. Insufficient PFR capabilities contributed to several instances of under-frequency load shedding (UFLS)[22], when system frequency fell to such an extent that load had to be shed in

[19] The analysis in this section does not include generating units with a Maximum Authorized Reactive Power (MARP) of under 10 MW. For intermittent generators, the analysis is carried out at the asset level.

[20] ISO rule 502.5, s. 9(1); ISO rule 502.6, s. 4; ISO rule 503.6, ss. 2(1) and 6.

[21] MSA: Report on AESO Primary Frequency Response Compliance Monitoring Practices

[22] AESO 2023 Reliability Requirements Roadmap, page 24

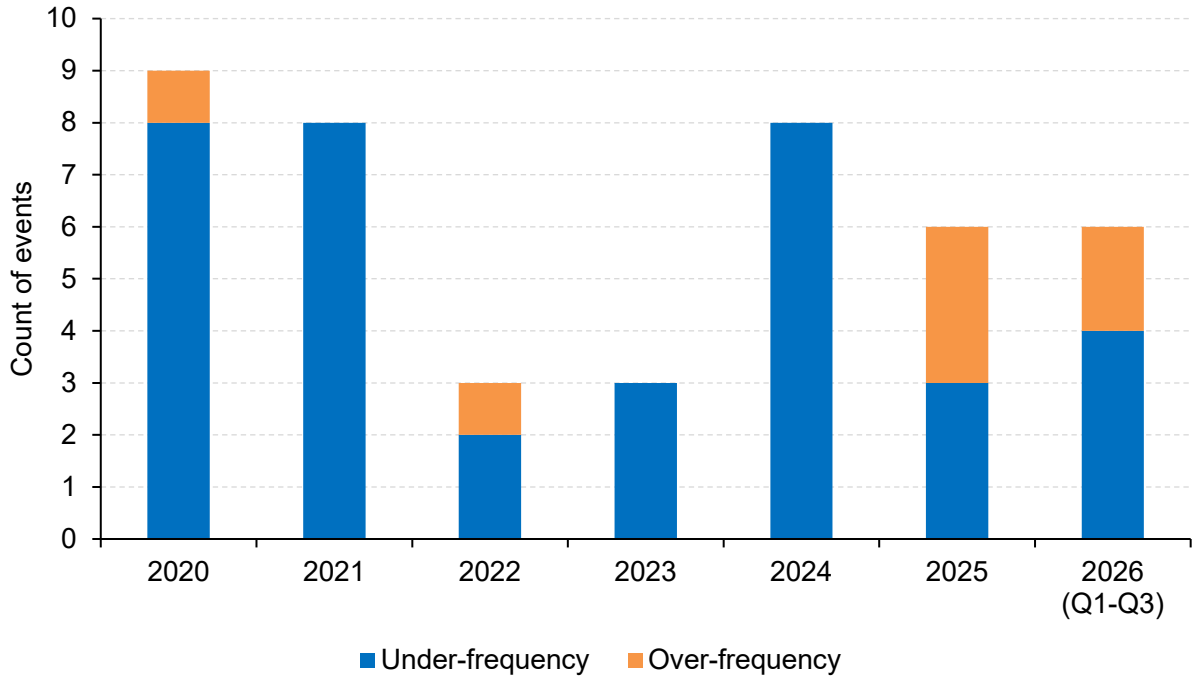
order to return it to a secure state. In the case of the June 7, 2020 event, approximately 235 MW of load was shed, partly due to insufficient PFR, and frequency fell to 59.15 Hz (Table 13).[23]

Table 13: Maximum and minimum values for system frequency (Hz, 2020 to 2026 YTD)

	2020	2021	2022	2023	2024	2025	2026 (Q1-Q3)
Minimum	59.15	59.36	59.73	59.54	59.53	59.66	59.55
Maximum	60.31	60.24	60.31	60.2	60.17	60.49	60.24
Range	1.16	0.88	0.58	0.66	0.64	0.83	0.69

To provide a sense of how often significant frequency events occur, Figure 25 illustrates how many under-frequency and over-frequency events there have been by year since 2020.

Figure 25: Count of frequency events by year (2020 to 2026 YTD)



Beginning in this quarterly report, the MSA will provide aggregated statistics on the PFR of generation units to frequency events, increasing transparency in this important area of system operations.

For this analysis, an excursion starts when frequency leaves the required governor deadband of 59.96 to 60.04 Hz and ends when it returns within that deadband. To identify that a frequency excursion occurred, the MSA uses the following two criteria:

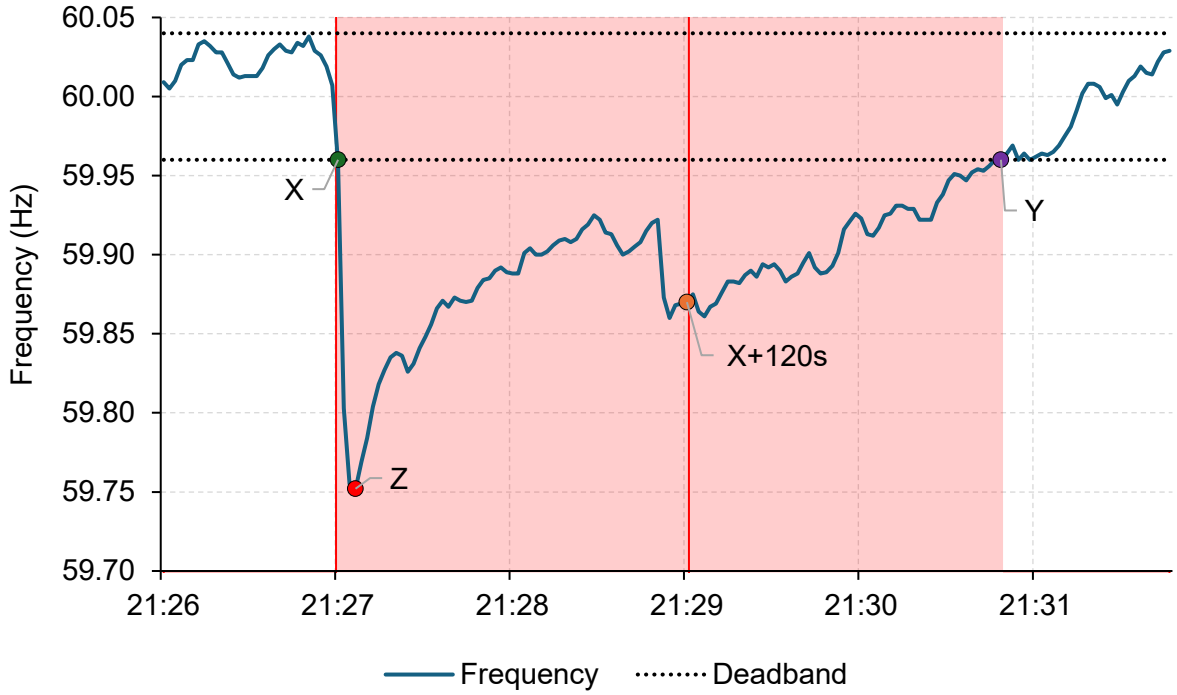
[23] AESO Information Session: Learnings and Actions in Response to Recent System Events (March 9, 2021)

- the excursion lasted more than 30 seconds, and
- frequency fell below 59.8 Hz or increased above 60.2 Hz.

For each frequency excursion, three points are identified (Figure 26 provides an example):

- X: frequency first leaves the deadband
- Y: frequency is last outside the deadband
- Z: frequency reaches its extreme

Figure 26: System frequency (August 30, 21:26 to 21:32, data increment is 2s)



To analyze performance, PFR is assessed in between point X and the lesser of point Y and 120 seconds.

Further, to determine the generation of each unit prior to the event, a baseline generation level is calculated by taking the median generation between X minus 30 seconds and X minus four seconds.

Based on the change in generation around the frequency event, generating units are classified into the following categories:

- **Sustained response:** the unit's output moved at least 0.5 MW in the right direction by X plus 30 seconds and stayed past its baseline for at least 95% of the remaining assessment period.

- **No response and not limited:** the unit's output stayed within 0.5 MW of its baseline for the first 30 seconds, despite not obviously being at a minimum or maximum generation limit.[24]

- **Wrong direction:** at X plus 30 seconds, the unit's output was more than 0.5 MW away from its baseline in the wrong direction.

- **Unsustained response:** the unit's output moved more than 0.5 MW in the right direction within 30 seconds but did not stay past its baseline for the rest of the assessment period.

- **Generation limit:** includes units that did not respond but were constrained by a maximum or minimum generation limit.[25]

- **Other:** includes units that did not fall into the first five groups.

- **Offline**: units that were offline or in synchronous condenser mode (hydro or gas units with negative baseline generation) were excluded from the analysis. However, battery units that were dispatched for spinning or regulating reserves were included.

There were three frequency excursions in Q3. On August 18 and 19, transmission outages in BC led to separate over-frequency events as Alberta islanded from the Western Interconnection along with Southeast BC (as discussed in section 1.2.4). On August 30, there was an under-frequency event as Genesee Repower 2 tripped offline while BC/MATL was on a planned outage (as outlined in section 1.2.1).

Table 14 provides the results of the PFR analysis for the three frequency events in the quarter. For the August 18 event, 34% of generation units provided a sustained decrease in generation. However, 64% of units fell into one of the 'No response and not limited', 'Wrong direction', 'Unsustained response' and 'Other' categories. The figures were similar for the August 19 event: 32% of units provided a sustained response and 64% fell into one of the 'No response and not limited', 'Wrong direction', 'Unsustained response' and 'Other' categories.

For the under-frequency event on August 30, 33% of units provided a sustained increase in generation while 60% of units fell into one of the 'No response and not limited', 'Wrong direction', 'Unsustained response' or 'Other' categories.

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[24] For non-intermittent units, a unit is limited for under-frequency events if the unit's generation was within 0.5 MW of MARP or if the asset's generation was within 0.5 MW of Available Capability (AC). Wind and solar assets were assumed to be limited for under-frequency events if their generation was within 0.5 MW of their potential.

For over-frequency events, assets were assumed to be limited if their generation was within 0.5 MW of the declared Minimum Stable Generation (MSG).

[25] For under-frequency events, cogeneration units are excluded from this group and reported under 'Other'. Based on the data currently available, the MSA is unable to confirm whether these units were limited by a maximum generation constraint.

Table 14: Percent of units in each PFR category for the frequency events in Q3

Category	Aug 18 event (over-frequency)	Aug 19 event (over-frequency)[26]	Aug 30 event (under-frequency)
Sustained response	34%	32%	33%
No response and not limited	37%	42%	19%
Wrong direction	9%	6%	14%
Unsustained response	11%	14%	14%
Generation limit	2%	3%	7%
Other	7%	2%	13%
Count of online units evaluated	215	226	160

1.7 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.[27]

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

1.7.1 Average emission intensity

Hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta electricity grid in each hour. In Q3, hourly average emission intensities continued to decrease with minimum, mean, and maximum values all lower year over year (Table 15).

The lower average carbon emission intensity in Q3 this year was driven by a decrease in the estimated carbon emission intensity of cogeneration assets, in addition to more supply from intermittent generation (Figure 27).

Many cogeneration assets do not report emissions related to their electricity production separately from other industrial operations in the federal Greenhouse Gas Reporting Program (GHGRP), and therefore have estimated carbon emission intensities. Estimated carbon emission intensities are calculated by determining an average from a sample of cogeneration assets that do have

[26] The total does not sum to 100% due to rounding.

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

power generation emissions reported separately under the fossil-fuel electric power generation sector in GHGRP.

Over the last four quarters, hourly average carbon emission intensities have also decreased, though a slight increase in the mean emission intensity was observed in Q3 over Q2 (Table 16).

Table 15: Minimum, mean, and maximum hourly average carbon emission intensities (tCO2e/MWh, Q3 of 2020 to 2026)

Time period	Min	Mean	Max
Q3-2020	0.44	0.59	0.70
Q3-2021	0.43	0.55	0.64
Q3-2022	0.38	0.50	0.58
Q3-2023	0.31	0.45	0.56
Q3-2024	0.25	0.40	0.53
Q3-2025	0.24	0.39	0.51
Q3-2026	0.21	0.35	0.48

Table 16: Minimum, mean, and maximum hourly average carbon emission intensities (tCO2e/MWh, Q4 2025 to Q3)

Time period	Min	Mean	Max
Q4-2025	0.25	0.40	0.57
Q1-2026	0.24	0.39	0.56
Q2-2026	0.20	0.33	0.51
Q3-2026	0.21	0.35	0.48

A leftward shift in the hourly average carbon intensity distributions for Q3 over the past seven years indicates the reduction in carbon emission intensity of the grid (Figure 27). An increase in the variation of average hourly carbon emission intensity has followed this shift with more forms of gas generation replacing coal generation.

Figure 27: Distribution of average carbon emission intensities in Q3 (2020 to 2026)

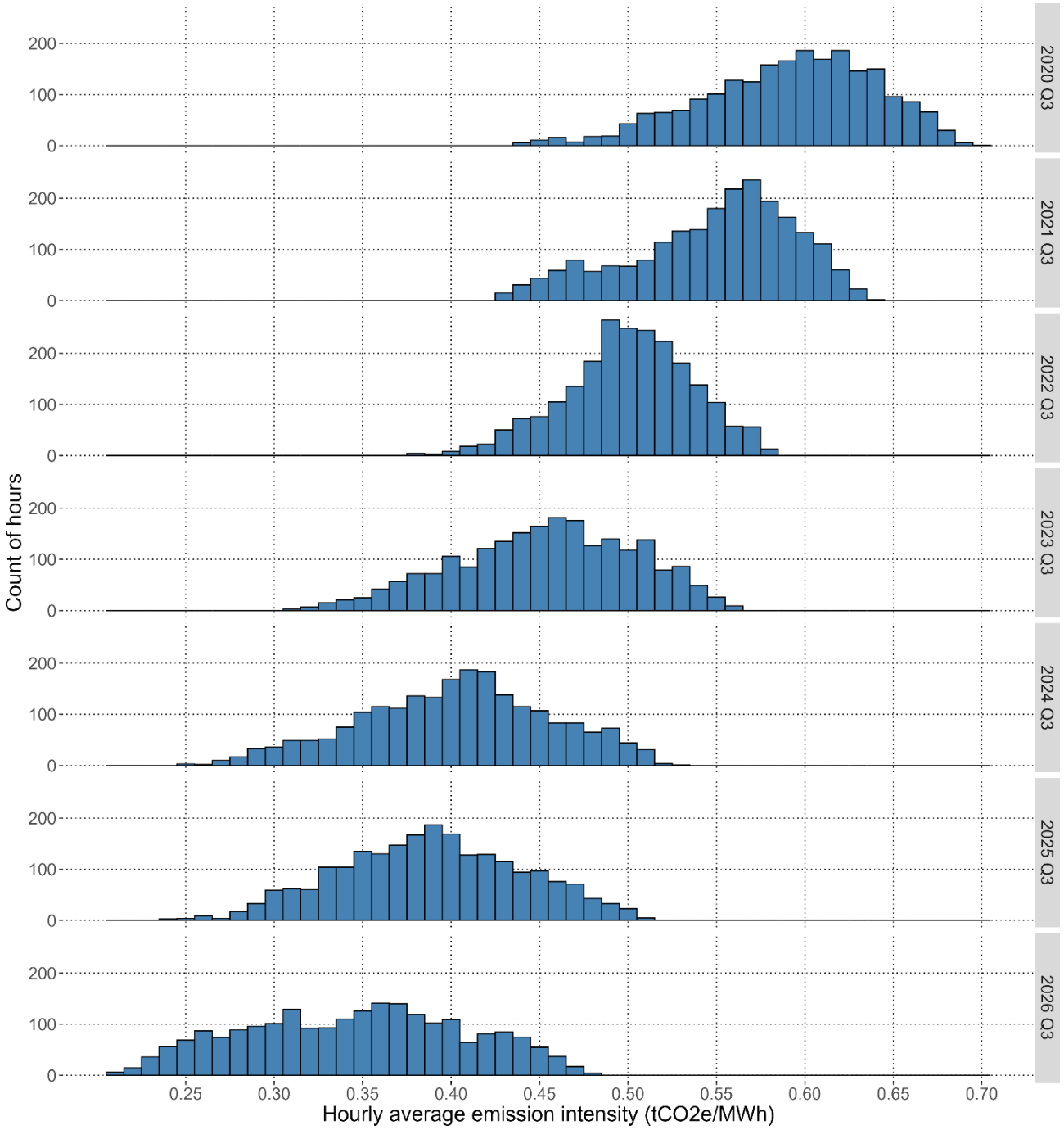
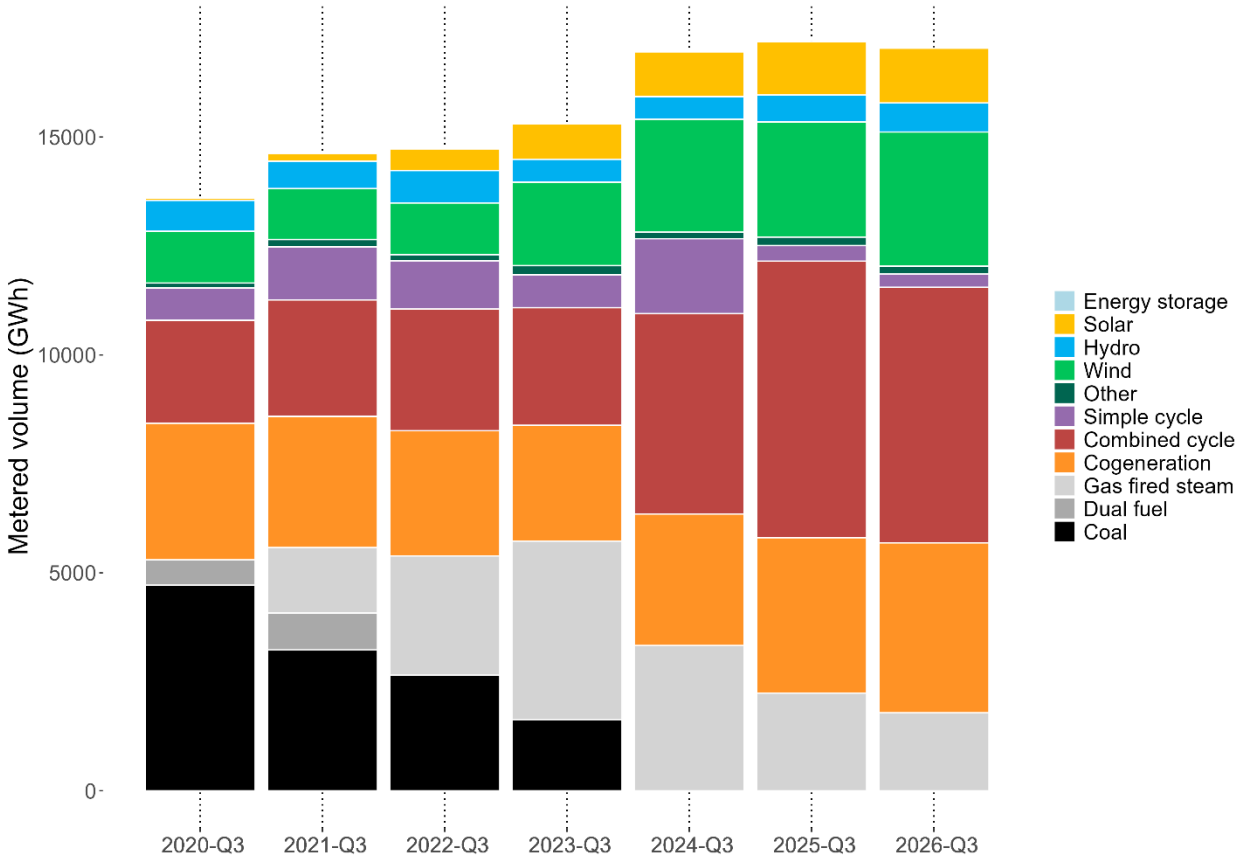


Figure 28: Total net-to-grid generation by fuel type for Q3 (2020 to 2026)



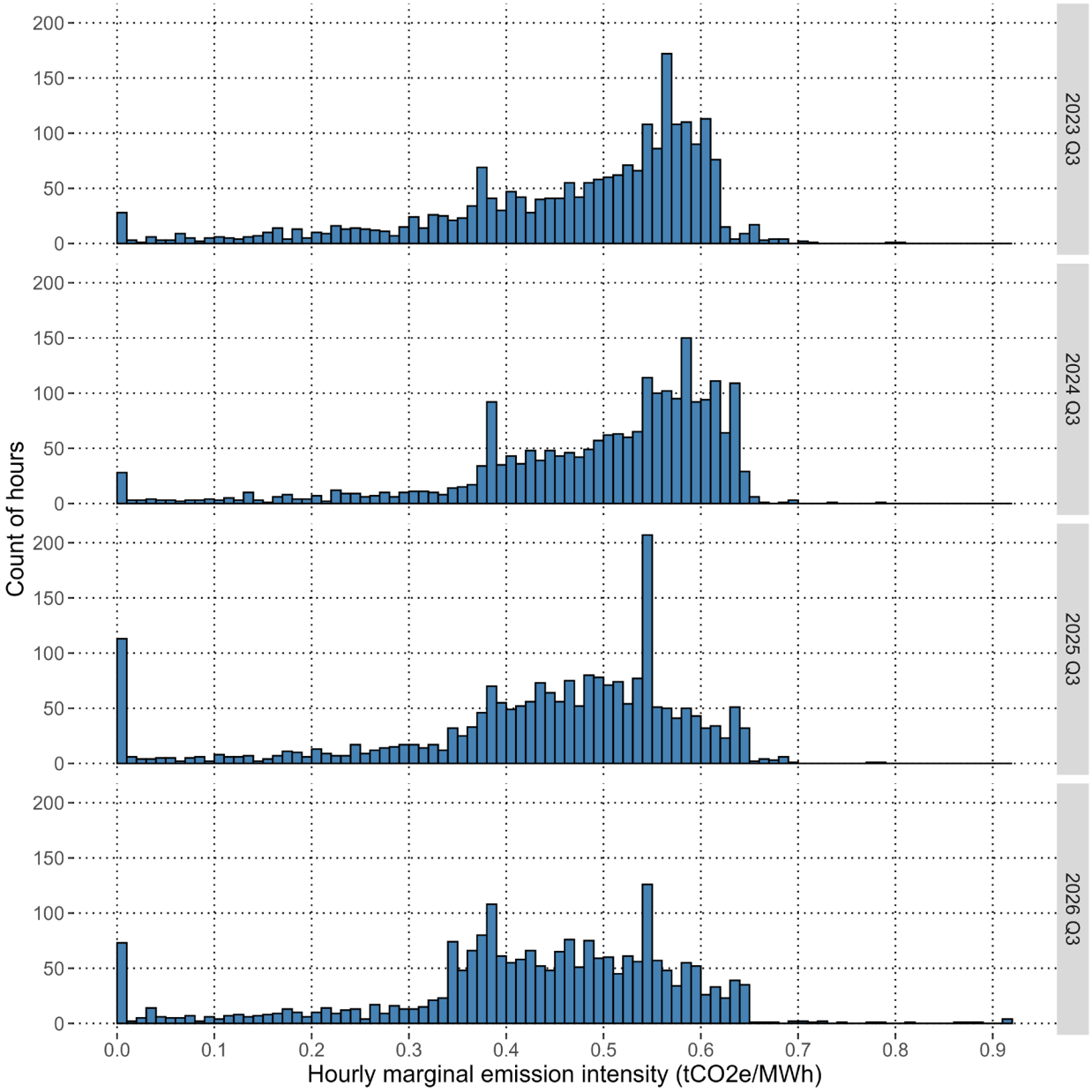
1.7.2 Marginal emission intensity

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 marginal assets, a time-weighted average of the carbon emission intensities of those assets is used.

For Q3 of the past three years, gas-fired steam assets were frequently setting the price, indicated by a high frequency of observations around 0.54 to 0.60 tCO2e/MWh. However, Q3 2026 saw a greater proportion of hours with combined cycle assets being marginal, indicated by a higher frequency of observations around 0.35 to 0.40 tCO2e/MWh (Figure 29).

In Q3, combined cycle assets were marginal 42% of the time while gas-fired steam assets were marginal 25% of the time. Assets considered to have 0.0 tCO2e/MWh were marginal 12% of the time in Q3.

Figure 29: Distribution of marginal carbon emission intensities in Q3 (2023 to 2026)



2 THE POWER SYSTEM

2.1 Amended Constrained Intermittent Generation

An asset can be curtailed to mitigate a transmission constraint, as detailed in ISO Rule 302.1 (TCM Rule).[28] Since Q2 2023, the MSA has published aggregated constrained intermittent generation (CIG) volumes, which reflect the MSA's estimation of curtailed volumes for intermittent assets under the TCM Rule.[29] The CIG volumes focus only on the transmission constraint volumes of intermittent assets and provide insight into the transmission system, congestion, and asset or locational specific information. The CIG calculation uses data on curtailment limits, available capability, potential real power capability, and energy dispatch.

There are known issues with intermittent asset data for real potential power, which is a required input for the calculation of CIG.[30] The MSA is now reporting on amended CIG, which uses a methodology that attempts to moderate the potential power data issues and present a more accurate value of constrained volumes for intermittent generation.

2.1.1 Real Potential Power Data Issues

Most wind and solar assets are required to have meteorological equipment on site to calculate their potential real power capability, an estimate of how much power the site could provide absent any constraints.[31] ISO Rule 503.16 states that a wind or solar asset must meet the supervisory control and data acquisition (SCADA) requirements, including those for real potential power.

When a wind or solar asset is constrained down, the counterfactual generation which the asset could have provided is not directly observable. Instead, potential real power capability is used to calculate the volume of energy that was constrained down. If an asset reports incorrect potential real power data and is transmission constrained, the AESO may incorrectly calculate the volume of constrained down generation (CDG). If CDG is inaccurate, there may be further implications for pool price and operating reserve prices, as reserve prices are indexed to the pool price. Inaccurate potential power can also lead to misallocated dispatches during certain system events, such as supply surplus or inaccurate pro rata curtailments during transmission constraint events.[32]

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[28] ISO Rule 302.1 Real Time Constraint Transmission Constraint Management, effective February 6, 2025

[29] MSA Q2 2023 Quarterly Report, Transmission congestion and pool price formation, page 50. CIG was previously referenced as constrained down volumes.

[30] The MSA first reported on this issue in the MSA Quarterly Report Q3 2023, Section 2.2 Pool price inaccuracies caused by inaccurate price reconstitution

[31] ISO Rule 304.9 Wind and Solar Aggregated Generation Facility Forecasting

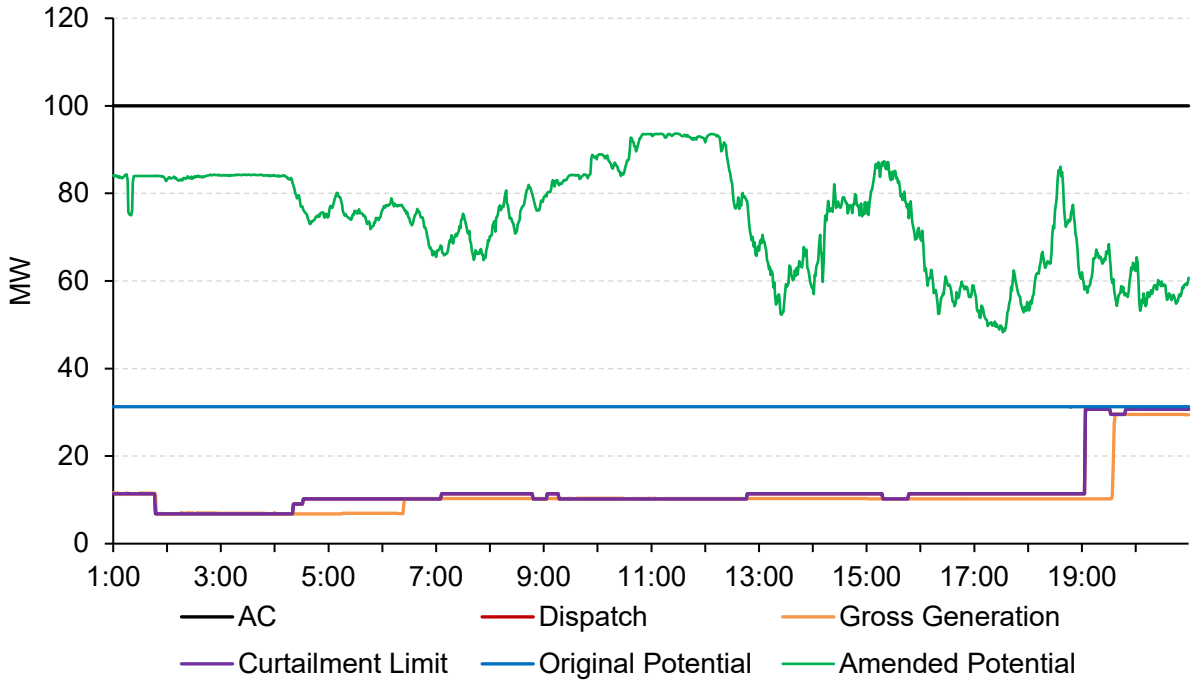
[32] ISO Rule 202.5 Supply Surplus, Effective April 1, 2024

2.1.2 Amended Potential Power Data

When instances of poor data quality for real potential power are identified, the inaccurate potential power data is replaced. The inaccurate potential power is replaced with the potential power data for a nearby asset of the same fuel type, to provide a more accurate real potential power, accounting for differences in maximum capability.[33] The CIG is then recalculated every minute and aggregated by hour for each asset. This is then used to determine the total amended CIG for all intermittent assets for each hour. The new CIG volumes, which attempt to moderate the potential power data issues, are called amended CIG.[34]

For example, on November 17, 2024, a sample asset's potential power was stale. Using the methodology for amended CIG, the MSA reconstructed the sample asset's potential power, as shown in Figure 30. Using the amended potential power over this period, the MSA can calculate the amended CIG for the asset to obtain a value that is a more accurate reflection of congestion.

Figure 30: Available capability, gross generation, curtailment limit, and potential data of a sample asset (November 17, 2024)



[33] The instance of potential power issue is measured per minute and must exceed 1,440 consecutive minutes.

[34] The amended CIG is based on a quarterly identification of real potential power issues. Although the issues may be fluid and carry over between each quarter, the evaluation is limited to a quarterly view, and each asset will need to be reidentified each quarter.

The MSA identified 19 assets in 2025 with real potential power data issues (Table 17). Each of these assets may have had multiple periods over the year, anywhere from one day to an entire quarter, in which they were identified to have potential power data issues.

Table 17: Number of assets identified for real potential power replacement (2023 to 2026 YTD)

Year	Number of affected assets	Total number of wind and solar assets
2023	32	88
2024	24	95
2025	19	97
2026 (Q1 to Q3)	15	98

2.1.3 Amended CIG

An asset's CIG volumes are not always changed when the potential power of the asset is amended. For a change to the CIG volumes to occur, the asset must not only be identified as having real potential power data issues, but the issues must occur over a period where the asset was curtailed to mitigate a transmission constraint.

Table 18 shows the amended CIG volume by quarter, and the difference between CIG volumes and amended CIG volumes. A positive value for the difference shows an increase from the calculated CIG values to the amended CIG. The absolute value by hour was also assessed to determine if the absolute magnitude was greater, where directional changes between the CIG volumes would not cancel out volumes, but the values remained substantially consistent.

The difference, due to the alignment of potential power issues and curtailment, has not led to a large difference in the measured volumes for CIG. In Q1 2025, the amended CIG was 341 MWh less than the original CIG, which is the largest difference measured over a quarter. This difference is equivalent to 0.34% of the CIG volumes for the quarter. Although there were six different assets identified with periods of potential power data issues over the period, the only change to the CIG value arose from a single asset. This asset only experienced an issue with potential power data over two periods during the quarter, accounting for a total of approximately six days. This pattern, where multiple assets are identified as having potential power issues, but few contribute to a difference in CIG, is common due to the required alignment of potential power issues and curtailment.

The number of assets identified with issues has decreased over time, but the difference between the volumes has generally increased, demonstrating the increasing implications of potential power issues on the value of CIG. To the extent that curtailments become more common through time, it is likely that potential power errors will become more consequential for CIG, CDG volumes, and pool prices.

Table 18: Amended CIG volumes and difference from CIG to amended CIG by quarter (Q1 2023 to Q3 2026)

	Amended CIG (GWh)	Difference (%)
Q1-2023	18	0.00%
Q2-2023	42	0.05%
Q3-2023	44	0.02%
Q4-2023	187	0.01%
Q1-2024	26	0.00%
Q2-2024	211	0.00%
Q3-2024	126	0.04%
Q4-2024	141	0.04%
Q1-2025	161	-0.34%
Q2-2025	310	0.15%
Q3-2025	269	0.00%
Q4-2025	729	0.00%
Q1-2026	562	0.01%
Q2-2026	642	0.18%
Q3-2026	243	-0.11%

2.1.4 Issues arising from inaccurate real potential power data

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.

To determine the unconstrained SMP, the AESO calculates the transmission constrained rebalancing volume (TCRv) by determining the volume of generation that has been constrained down.[35] The AESO then uses the TCRv to read down the merit order from the constrained SMP to determine the unconstrained SMP. The unconstrained SMP is averaged over the hour to determine the pool price. Therefore, any inaccuracies in the CDG volume are passed on to the TCRv and will affect the pool price.

If the difference between CIG and amended CIG is assessed on a minute-by-minute basis, the difference can be used to inform whether the pool price was set accurately. If the difference is negative, as in Q1 2025, the curtailed volumes were higher than the volumes used to calculate CIG, the CIG value was set lower than it ought to have been. Therefore, the value used to read down the merit order was too low. This means that the pool price may have been, depending on the size of the marginal block, reconstituted to a higher price than it ought to have been.

[35] AESO ID#2015-006R, Calculation of Pool Price and Transmission Constraint Rebalancing Costs During a Constraint Event.

The TCRv also includes CDG from imports and transmission must-run.

Conversely, when the original CIG value was higher than the amended CIG, the pool price may have been set too low.[36]

Identifying assets with potential power data issues and recalculating the amended CIG value provides a more accurate reflection of the estimated congestion for intermittent assets. It is the requirement of the owner of the intermittent asset to ensure that the potential power data is accurate. Given that there are instances of known issues with potential power which may likely have resulted in changes to the CIG and CDG volumes, there are possible cascading effects into the calculation of pool price. Ensuring that potential power data issues are identified and fixed is an important issue for not only understanding the congestion of the transmission system, but also in the reconstitution of pool price.

2.1.5 MSA Reporting

The MSA has published CIG data in its quarterly reports since Q2 2023. MSA Quarterly Reports from Q2 2023 to Q2 2026 rely on the original CIG data. All data, including the historical comparisons, from Q3 2026 onwards will rely on amended CIG data as the amended CIG is an improved reflection of the state of congestion on the transmission system.

2.2 Congestion

Transmission elements may impose limitations on the transfer of electric energy from one location on the transmission system to another. The AESO may mitigate these limitations in real time by curtailing generation.[37]

The MSA measures 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 capability, potential real power capability, and energy dispatch.[38]

There are known issues with data for real potential power, which is a required input for the calculation of CIG.[39] The MSA now uses amended CIG values for reporting purposes, where when instances of poor data quality for real potential power are identified, the inaccurate potential power is replaced. The inaccurate potential power is substituted with the potential power data of a nearby asset of the same fuel type to provide a more accurate real potential power, accounting for differences in maximum capability. CIG is then recalculated every minute, aggregated by hour

[36] See MSA Quarterly Report for Q3 2023 for further discussion.

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

[38] 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).

[39] The MSA first reported on this issue in the MSA Quarterly Report Q3 2023, Section 2.2 Pool price inaccuracies caused by inaccurate price reconstitution

for each asset, and used to determine the total amended CIG for all intermittent assets for each hour.

The magnitude of CIG decreased year-over-year. The MSA estimates that CIG volumes were 243 GWh in Q3 compared to 269 GWh in Q3 2025, a 10% decrease. Quarter-over-quarter, CIG volumes fell by 62%.

The highest hourly average volume of CIG in Q3 was 2,209 MW on August 31 in HE 05. This is a decrease from the Q3 2025 maximum of 2,334 MW (Figure 31 and Figure 33). The highest hourly average volume of CIG in Q3 was also lower than the maximum value in Q2 of 2,423 MWh (Figure 32).

Figure 31: Maximum hourly constrained intermittent generation (Q2 2025)

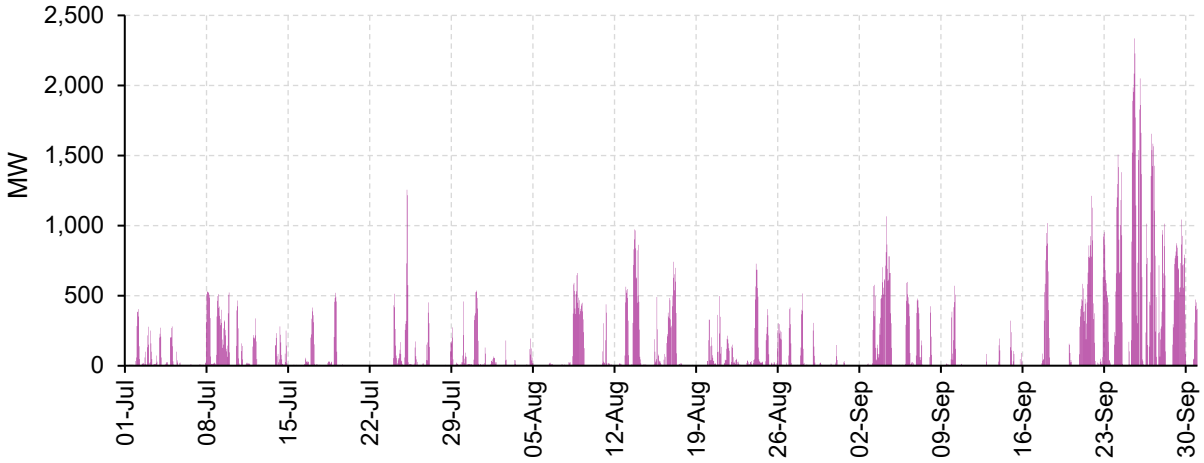


Figure 32: Maximum hourly constrained intermittent generation (Q2)

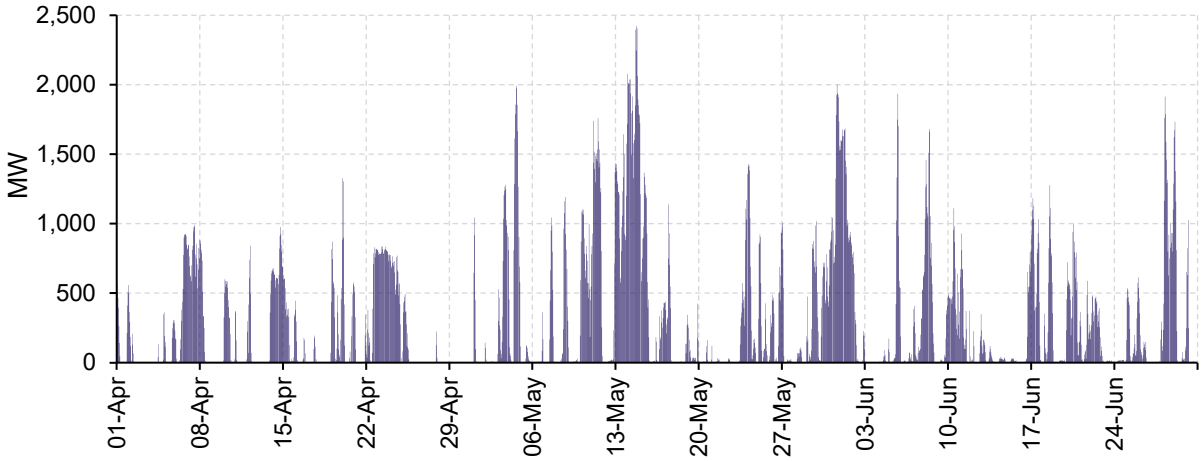
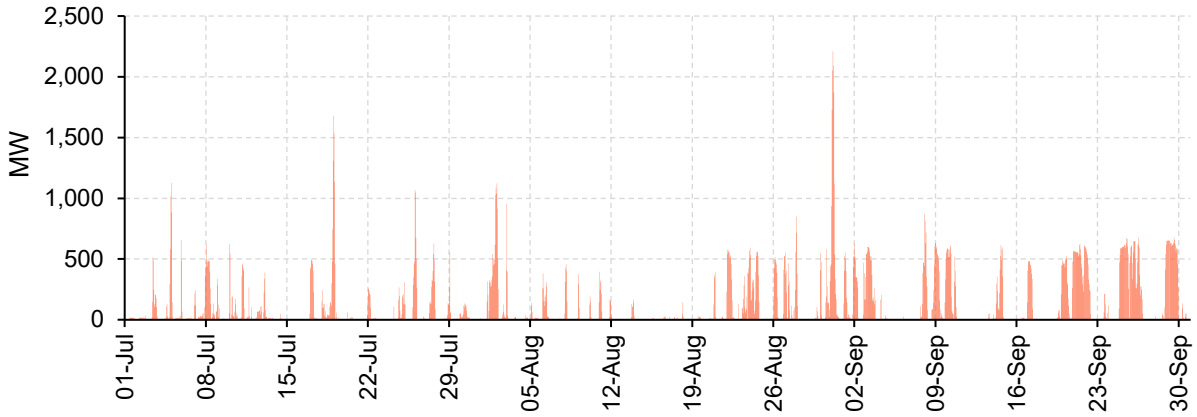


Figure 33: Maximum hourly constrained intermittent generation (Q3)



The lower CIG volumes year-over-year occurred despite more intermittent generation. The energization of the CETO transmission lines in late June was an important factor in the decline of CIG volumes. Higher CIG volumes generally align with periods of high intermittent generation or supply surplus events (Figure 34).

There were around 317 AESO System Controller shift log events for CDG in Q3. Increased CIG volumes can be caused by persistent or frequent limitations to certain transmission elements and may affect one or more generation assets. The most persistent constraint was 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 240 kV lines."[40]

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

Figure 34: A scatterplot of CIG and potential intermittent generation (Q3)

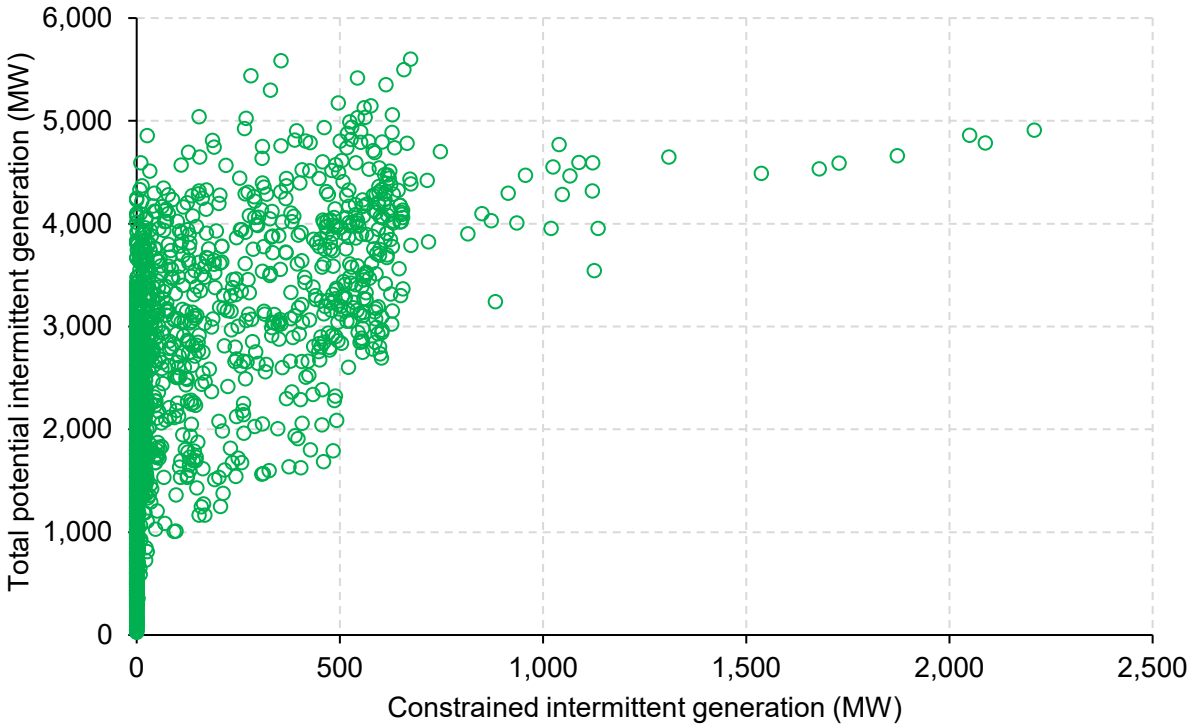


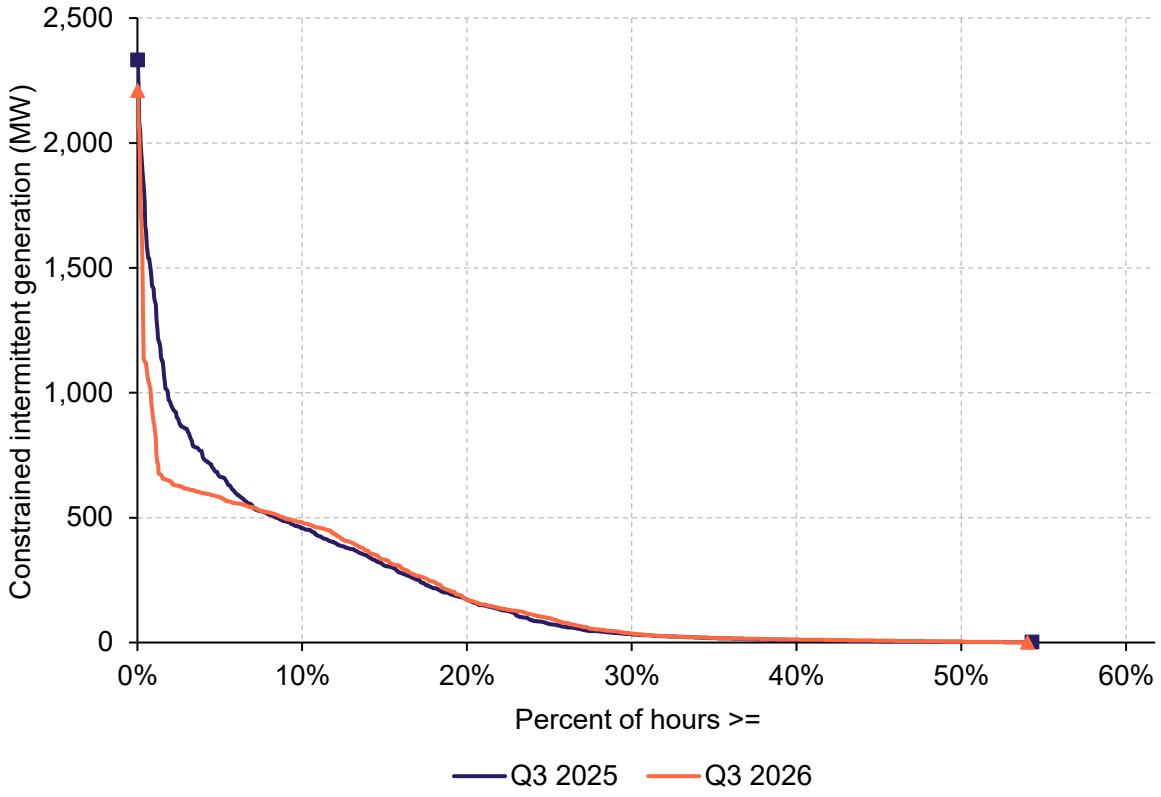
Figure 35 illustrates duration curves of CIG year-over-year. The shift downwards from Q3 2025 to Q3 illustrates lower CIG volumes. The length of the tails on the right of the duration curves show that the frequency of CIG events remained relatively constant. There were 1,189 hours of CIG volumes greater than 1 MW in Q3, which is 54% of hours in the quarter. Similarly, Q3 2025 experienced more than 1 MW of CIG in 54% of hours (1,198 hours).

Transmission constraint volumes had frequent fluctuations throughout Q3. September experienced the highest CIG volumes (119 GWh) although the highest peak occurred in August (2,209 MW). Total CIG volumes in September accounted for 49% of all Q3 volumes.

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. The unconstrained SMP is an estimate of what price would have been in the absence of transmission congestion.

Figure 35: Duration curves of CIG (Q3 2025 and Q3)



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 Q3, the average constrained SMP was $36.87/MWh, or 4% higher than the average unconstrained SMP (Table 19). This compares to a difference of 6% in Q3 2025 and 23% in Q2. The higher premium in Q2 was driven by outcomes in May when the constrained SMP was 34% higher than the unconstrained SMP.

Table 19: Average constrained and unconstrained SMP by month (Q3)

	Constrained SMP ($/MWh)	Unconstrained SMP ($/MWh)	Difference	
			($/MWh)	(%)
Jul	$32.22	$31.26	$0.95	3%
Aug	$46.68	$45.71	$0.97	2%
Sep	$31.56	$29.40	$2.17	7%
Q3	**$36.87**	**$35.52**	**$1.37**	**4%**

The constrained and unconstrained SMP differed by $1/MWh or more in 18% of minutes in Q3. In comparison, Q3 2025 had 20% of minutes with a variance of $1/MWh or more, and Q2 had the difference in 31% of minutes.

In Q3, the largest difference between the constrained SMP and unconstrained SMP was $345/MWh, which occurred in HE 18 of July 16. The largest difference was higher in Q3 2025 at $893/MWh, and in Q2 at $959/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 CIG volumes in Q3, there was often only a small difference between the constrained and unconstrained SMP.

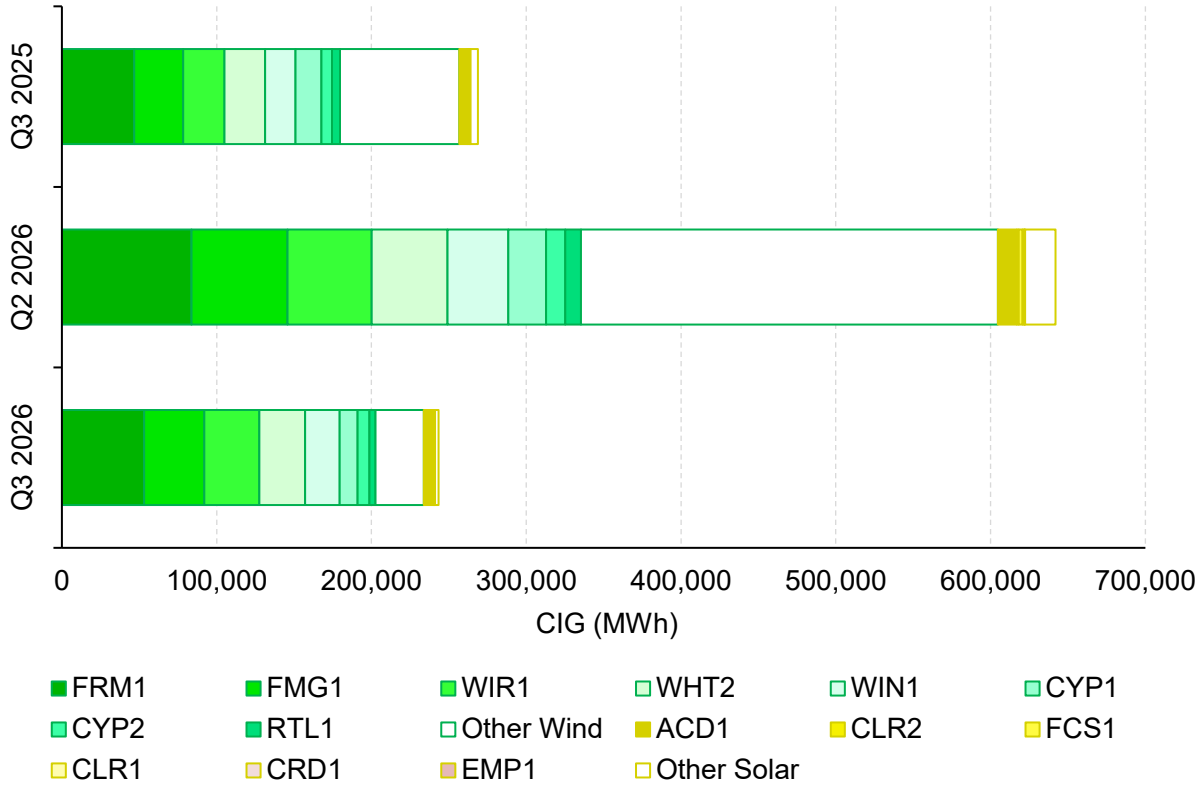
This occurred because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity have a small impact on price. Only 0.02% of minutes in Q3 experienced a difference of greater than $100/MWh between the constrained and unconstrained SMP.

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 Q3, the eight most constrained wind assets accounted for 87% of the total CIG volume but only 23% of total installed wind capacity. Forty Mile Bow Island, Forty Mile Granlea, and Wild Rose continued to be the most constrained wind assets in Q3 (Figure 36). These three assets represent 12% of Alberta's installed wind capacity, however they accounted for 55% of the wind CIG volume in Q3. 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 Q3, with a total of 5,579 MWh constrained, or 5% of its potential generation. This asset was constrained for a variety of reasons, most of which relate to contingency mitigation relating to 760L. The six most constrained solar assets have an aggregate maximum capability of 415 MW and were constrained by 7,316 MWh in Q3. These assets accounted for 77% of solar CIG volumes in Q3 but only 22% of total solar capacity. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

Figure 36: Wind and solar CIG volumes by asset (Q3 2025, Q2, Q3)



2.3 Prices by location

Alberta's current uniform pool price is expected to be replaced by LMPs in 2028 as part of the implementation of the REM. Over time, LMPs will guide investment toward higher value locations on the transmission system, reducing the cost of building additional transmission infrastructure for consumers.[41]

This section continues the MSA's analysis of pseudo locational marginal prices (pLMPs) presented in the Q1 2026 quarterly report, extending it to cover the period from Q1 to the end of Q3. The methodology used to calculate pLMPs is described in the MSA's Q1 2026 report.[42] For clarity, the actual LMPs implemented as part of the REM will be calculated by solving a security-constrained economic dispatch problem.

Figure 37 illustrates curtailed generation as a percent of total potential for May and Figure 38 to Figure 40 show the same analysis for July, August, and September. Darker areas of the maps indicate higher levels of congestion. In areas of the figures where there are no nodes, the heat map determines the shading using an inverse relationship to the distance to the nearest nodes, so a closer node has a greater impact on the prevailing shade.

[41] AESO: Restructured Energy Market Final Design

[42] MSA: Quarterly Report for Q1 2026, page 46

During the first three quarters of 2026, May experienced the highest level of congestion, with nine wind assets having more than 30% of their potential generation curtailed, as EATL was offline on a planned outage from May 4 to 15. In Q3, congestion was lower. No assets exceeded the 30% level in July or August; the highest monthly curtailment at any asset was 20% of potential in July and 27% in August. In September, six wind assets exceeded the 30% level due to high wind generation.

Figure 41 shows the pLMP across Alberta for HE 10 on May 13, and Figure 42 shows the curtailed generation as a percentage of potential for the same hour. In this hour, the average unconstrained SMP (the pool price) was $62.45/MWh, indicated by the dashed red line on the legend, and the average constrained SMP was $999.98/MWh. During this hour, transmission constraints affected certain intermittent generators in the southeast of the province. This congestion was partly due to EATL being out of service. As a result of the congestion, pseudo nodes unaffected by congestion had pLMPs near the constrained SMP while constrained assets in the southeast had pLMPs below the pool price.

While congestion is most often concentrated in the southeast, other patterns can occur. Figure 43 and Figure 44 show the pLMP and curtailed generation as a percentage of potential for HE 17 of January 26. In this hour, the average unconstrained SMP (the pool price) was $150/MWh and the average constrained SMP was $688.91/MWh. Congestion in this hour was at MacKay River and Baseplant assets due to an outage on 9L57. As a result, the pLMPs at these generation assets were below the pool price.

Hourly pLMPs can be averaged over time. Figure 45 to Figure 48 illustrate the average pLMP for May, July, August, and September. In all these months, most pseudo nodes were generally unconstrained and had an average pLMP that was above the average pool price, but some constrained assets had pLMPs that were below the average pool price.

The variation in prices was largest in May, as congestion occurred more often and was more widespread. However, in all these months, some intermittent assets in the southeast had an average pLMP that was consistently below the average pool price due to persistent transmission constraints. Overall, during the first three quarters of 2026, some generation assets in the southeast had pLMPs below the pool price, while most other assets had pLMPs above it.

Figure 37: Curtailed generation as a percentage of total potential (May)

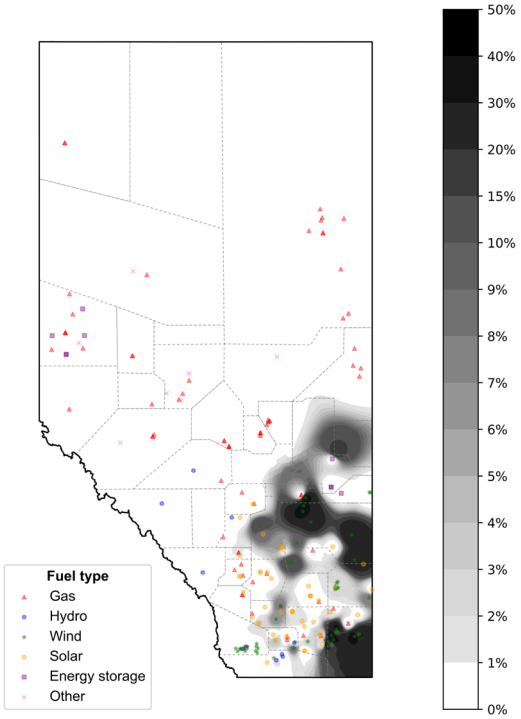


Figure 38: Curtailed generation as a percentage of total potential (Jul)

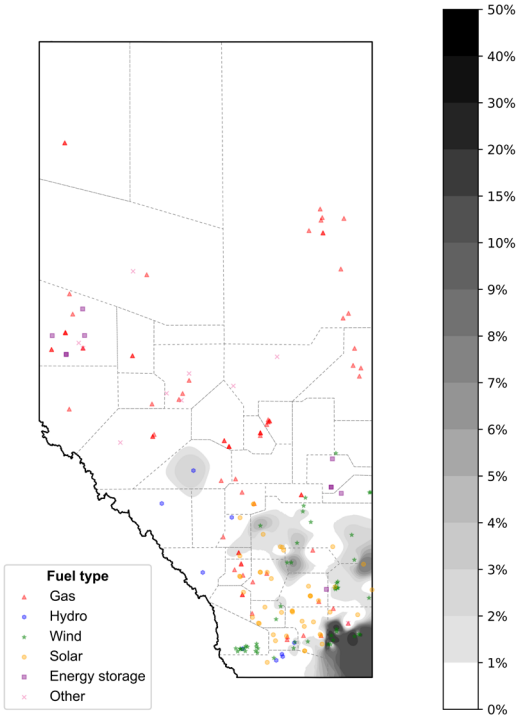


Figure 39: Curtailed generation as a percentage of total potential (Aug)

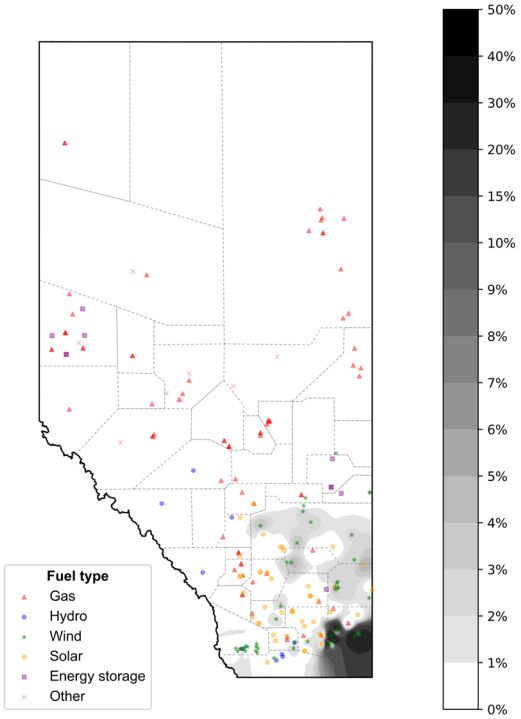


Figure 40: Curtailed generation as a percentage of total potential (Sep)

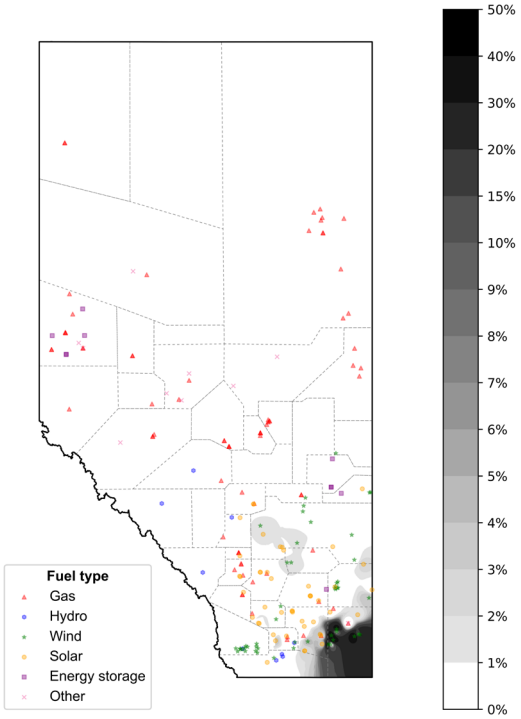


Figure 41: Alberta pLMP (May 13, HE 10)

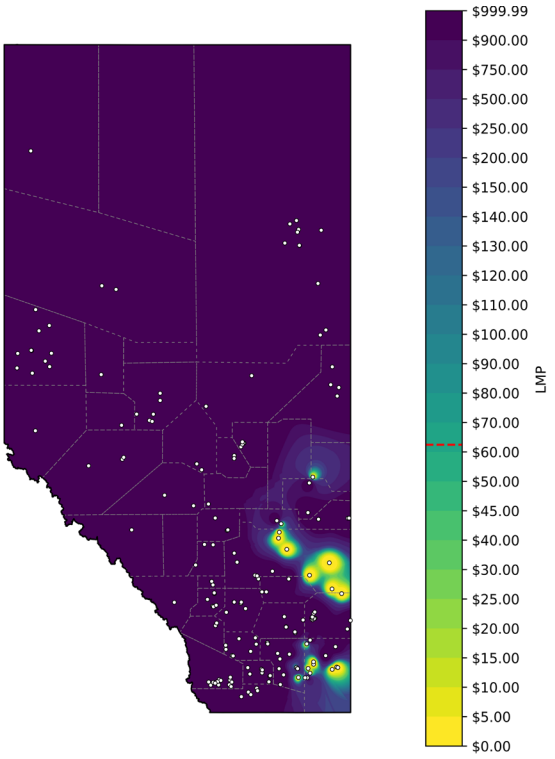


Figure 42: Curtailed generation as a percentage of potential (May 13, HE 10)

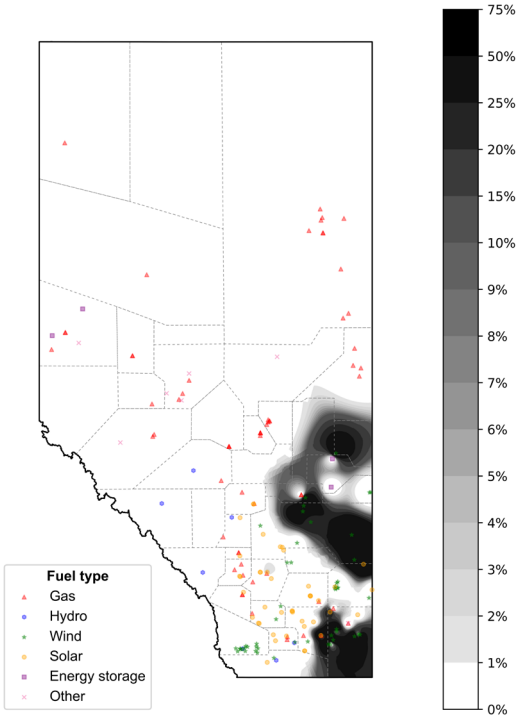


Figure 43: Alberta pLMP (Jan 26, HE 17)

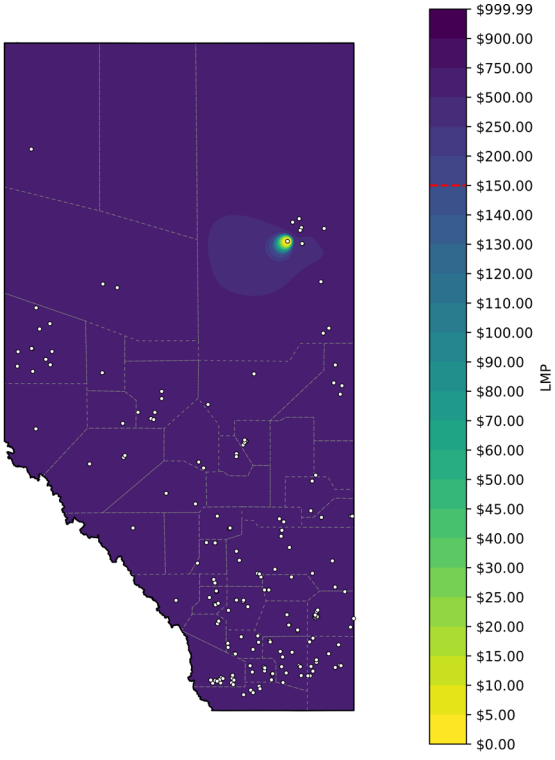


Figure 44: Curtailed generation as a percentage of potential (Jan 26, HE 17)

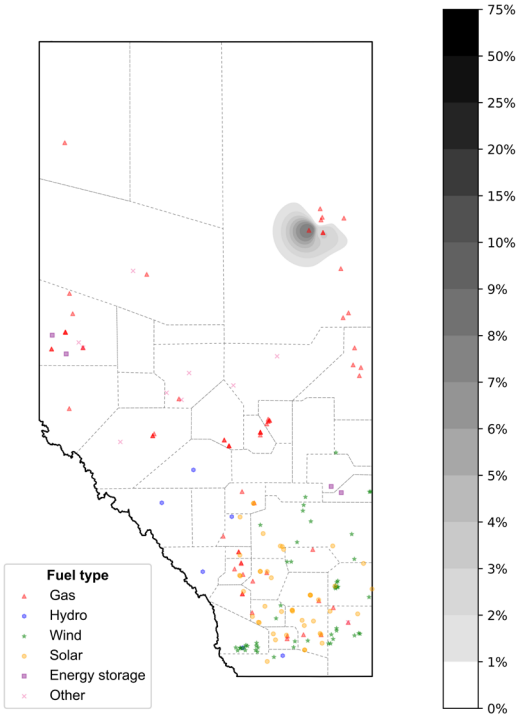


Figure 45: Alberta pLMP (May)

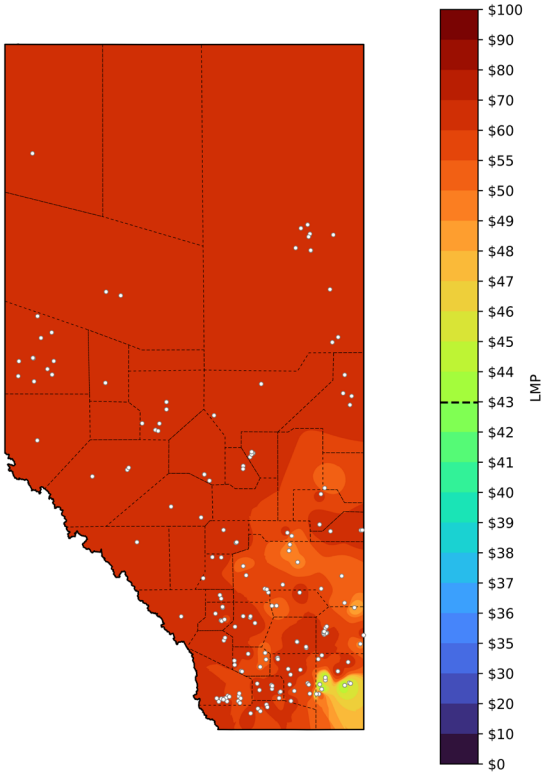


Figure 46: Alberta pLMP (Jul)

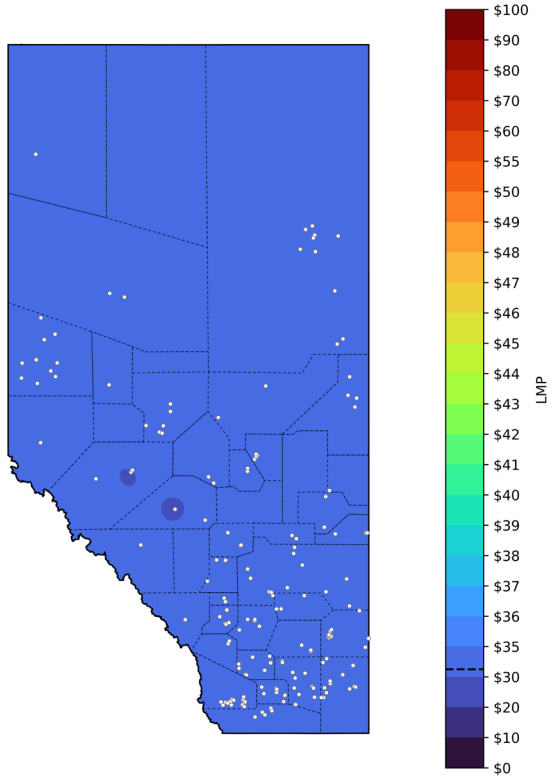


Figure 47: Alberta pLMP (Aug)

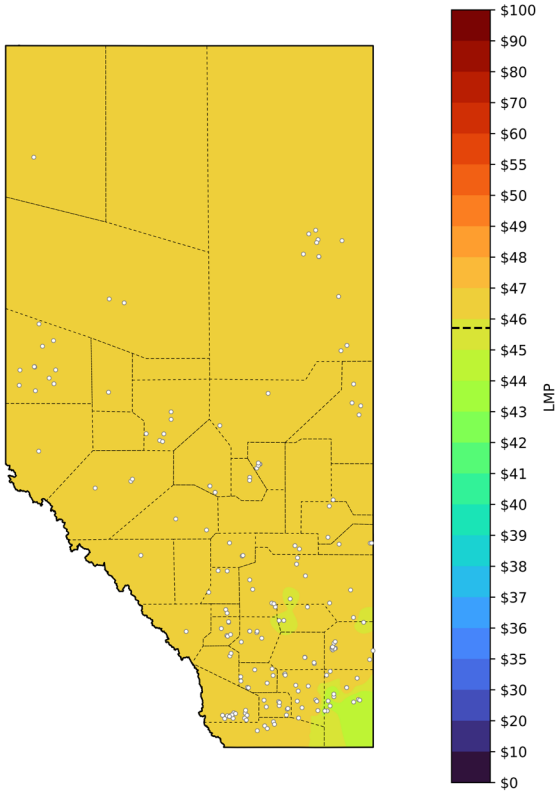
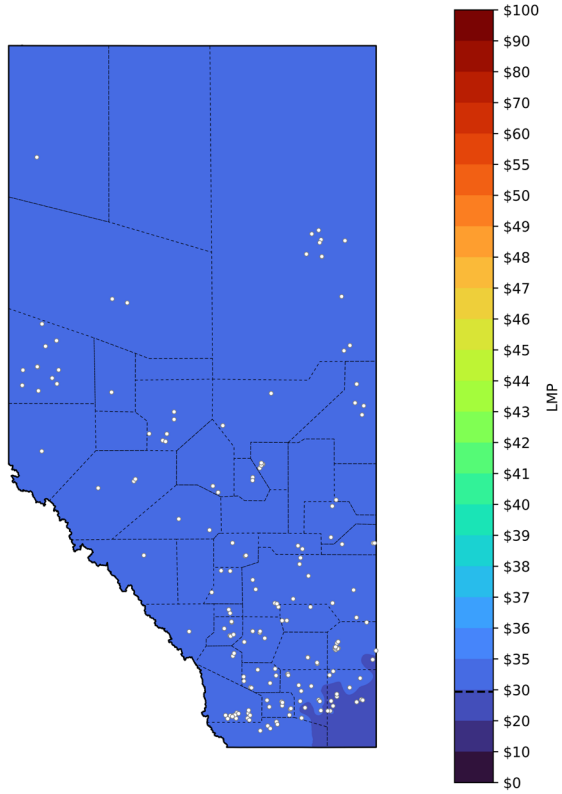


Figure 48: Alberta pLMP (Sep)

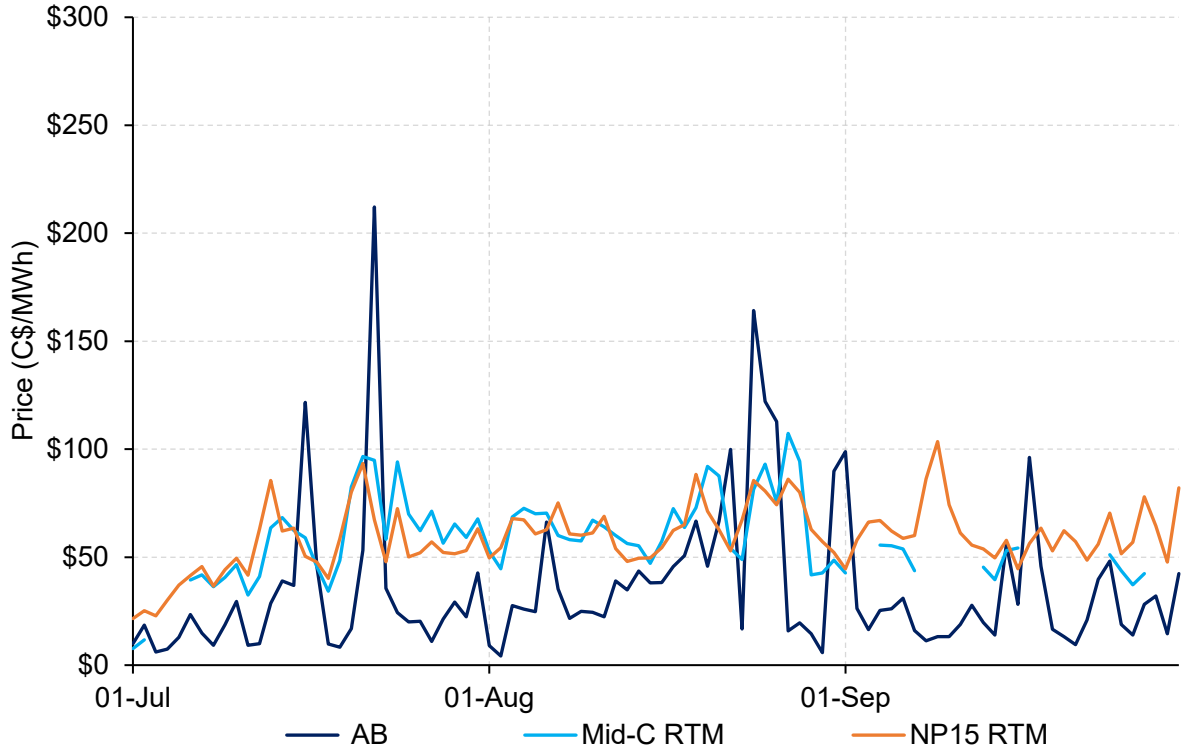


2.4 Interties

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.

Daily average prices in Alberta were generally lower than prices in Mid-C and NP15 during Q3 (Figure 49). Alberta prices averaged $35.52/MWh over the quarter while real-time prices in NP15 averaged $59.25/MWh, and day-ahead prices in Mid-C averaged $70.61/MWh. Prices in NP15 were higher than the pool price in 90% hours over the quarter, driving exports from Alberta.

Figure 49: Daily average prices in Alberta, Mid-C, and NP15 in California (Q3)[43]



In July, despite a low average pool price of $31.26/MWh and higher prices in Mid-C, imports from BC averaged 95 MW. Real-time prices in Mid-C averaged $57.22/MWh and prices in NP15 averaged $51.83/MWh. The imports on BC were offset by exports on MATL and the Saskatchewan intertie, resulting in average net exports of 9 MW over the month. Year-over-year, net exports fell by 496 MW in July (Table 20).

[43] Data for real-time Mid-C prices is unavailable for certain periods over the quarter. Data on monthly settlement prices for the day-ahead Mid-C index is still available.

In August, pool prices increased to $45.71/MWh on average, while real-time prices in Mid-C and NP15 averaged $65.77/MWh and $64.29/MWh, respectively. Prices in NP15 were higher in 87% of hours, contributing to exports over BC/MATL, which averaged 209 MW.

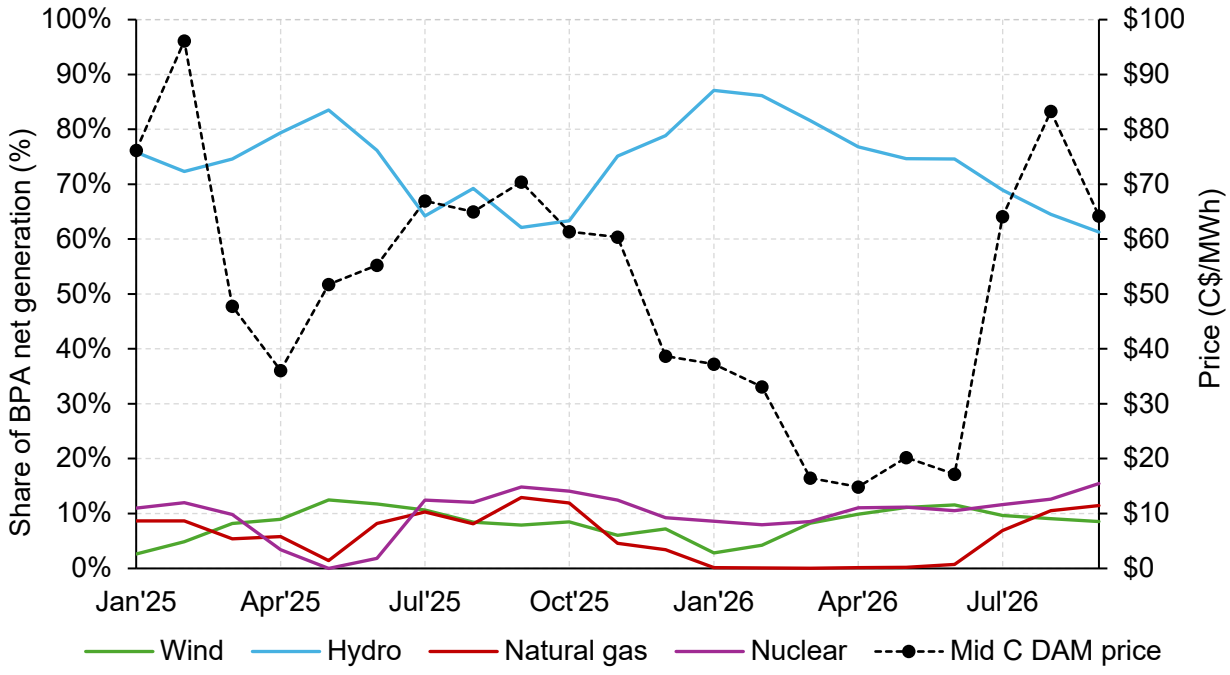
Pool prices were low in September, averaging $29.40/MWh. Real-time prices in NP15 remained comparatively high, averaging $61.70/MWh while day-ahead prices in Mid-C settled at $64.23/MWh. Prices in NP15 were above the pool price in 93% of hours which contributed to net exports of 261 MW on BC/MATL over the month.

Table 20: Monthly average net imports (Q3 2025 and Q3)

	2025				2026			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
Jul	-409	-96	0	-505	95	-77	-27	-9
Aug	-275	-89	0	-364	-143	-66	34	-176
Sep	-150	-29	0	-179	-216	-45	-14	-276
Q3	-278	-71	0	-349	-88	-63	-2	-153

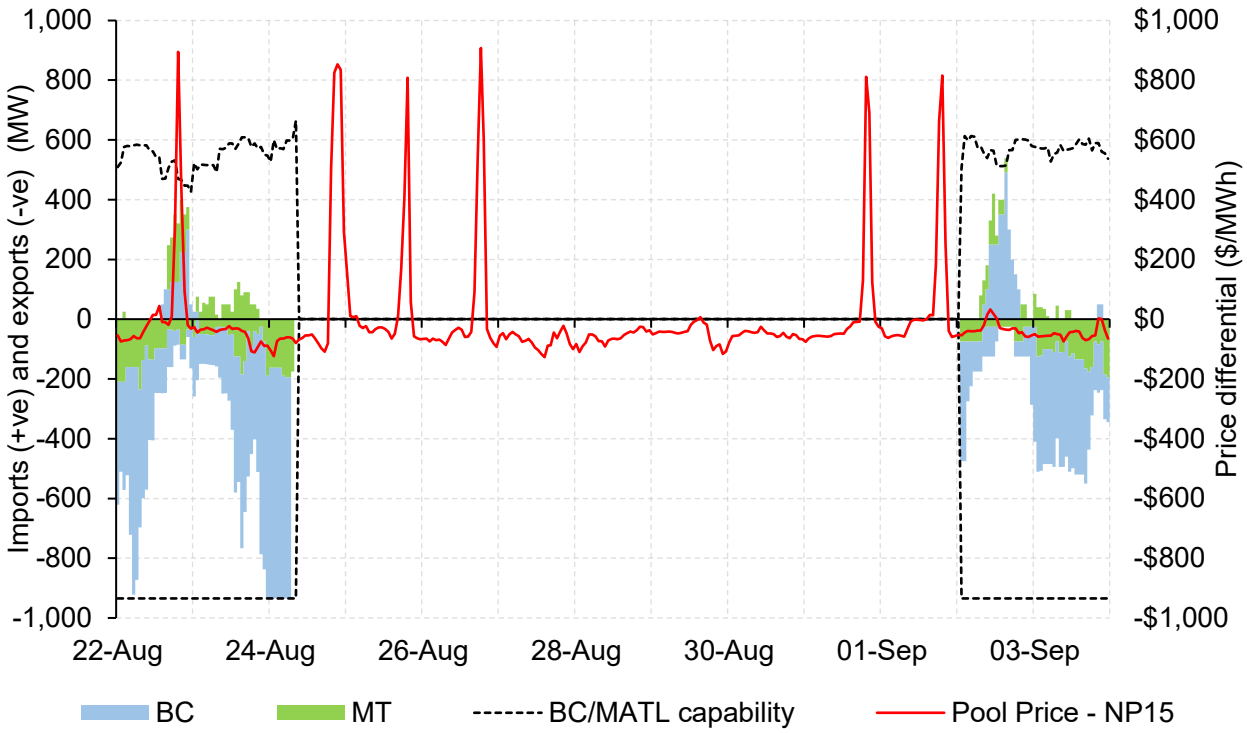
Bonneville Power Administration (BPA) operate one of the largest balancing authorities in the Pacific Northwest, and conditions in the hydro-dominated system are often closely linked to prices in Mid-C and California. In Q3, the share of BPA's generation from hydro declined to 61%, down from 75% in Q2. Natural gas was the primary generation type that compensated for this decrease (Figure 50). Lower hydro supply and more gas generation led to higher prices in the region and contributed to Alberta's position as a net exporter over the quarter.

Figure 50: Monthly average day-ahead Mid-C prices and BPA generation percentages



From August 24 HE 10 to September 2 HE 01, Alberta was islanded from the Western Interconnection due to a planned Path 1 outage (Figure 51). Alberta was export constrained heading into the outage as pool prices were low. Pool price volatility increased during the outage, though pool prices in most hours remained below real-time prices in NP15. Due to the outage, importers were unable to respond to periods of high pool prices towards the beginning and end of the outage.

Figure 51: Hourly imports and exports on BC/MATL, joint capability, and the Alberta - NP15 price differential (August 22 to September 3)



Over the quarter, Alberta was net exporting on BC/MATL in 67% of hours and net importing in 23% of hours. In the remaining 10% of hours the net interchange on BC/MATL was flat, which can primarily be attributed to the planned BC/MATL outage (Figure 52).

There were several hours in Q3 where export bids or scheduled volumes were at or above the export capability of BC/MATL which indicates that it was export constrained (Figure 53, shown in green). Exports on BC/MATL were constrained for 46 hours or 2% of the quarter, down from 10% of hours in Q3 2025. While export constrained, the price differential between Alberta and NP15 averaged negative $47/MWh and export ATC averaged 918 MW.

Figure 52: Daily average import and export volumes on BC/MATL, joint capability, and the Alberta - NP15 RTM price differential (Q3)

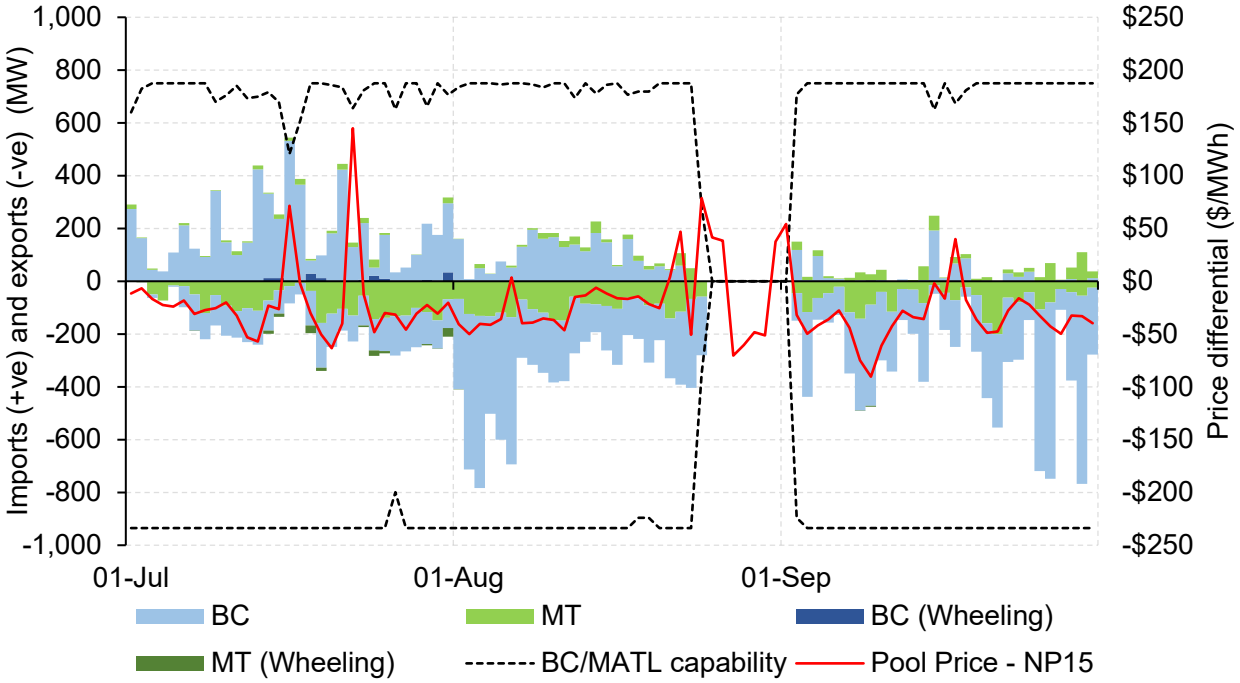
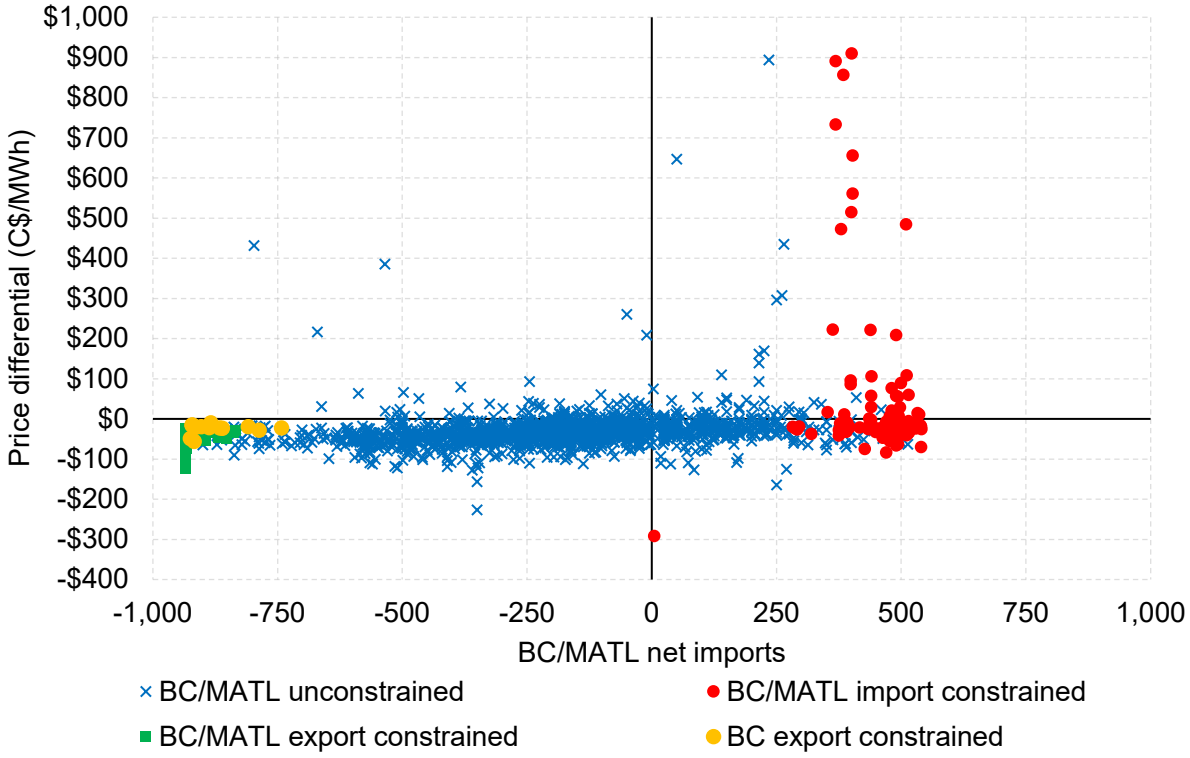


Figure 53: Alberta - NP15 RTM price differential and net imports on BC/MATL (Q3, excludes hours where BC/MATL was offline)



Year over year, there were slightly more hours where BC/MATL was import constrained; from 104 hours in Q3 2025 to 120 hours in Q3 (Figure 53, shown in red). BC/MATL imports are considered constrained in hours where net import offers, or scheduled volumes, were at or above import capability. While import constrained, the differential between Alberta and NP15 averaged $42/MWh and import ATC averaged 459 MW.

The sources and destinations of flows over the interties may be evaluated by the point of receipt (POR) for imports and the point of delivery (POD) for exports. Balancing authority regions directly connected with Alberta frequently have the highest share of import and export flows.

For imports on the BC intertie, approximately 97% of volumes originated from BC, 2.7% from the US Northwest, and 0.3% from California (Figure 54). Exports on the BC intertie were primarily delivered to the US Northwest, accounting for 70% of volumes, followed by BC at 23% and California at 7%. Exports to the US Northwest were primarily delivered to public utilities and Mid-C hubs.

For imports on MATL, 97% of volumes originated from the US Northwest with the remaining 3% originating from California. Exports on MATL were delivered primarily to the US Northwest at 96%, followed by 2.6% to California, 1% to SPP and the remainder to the US Southwest and Mexico.

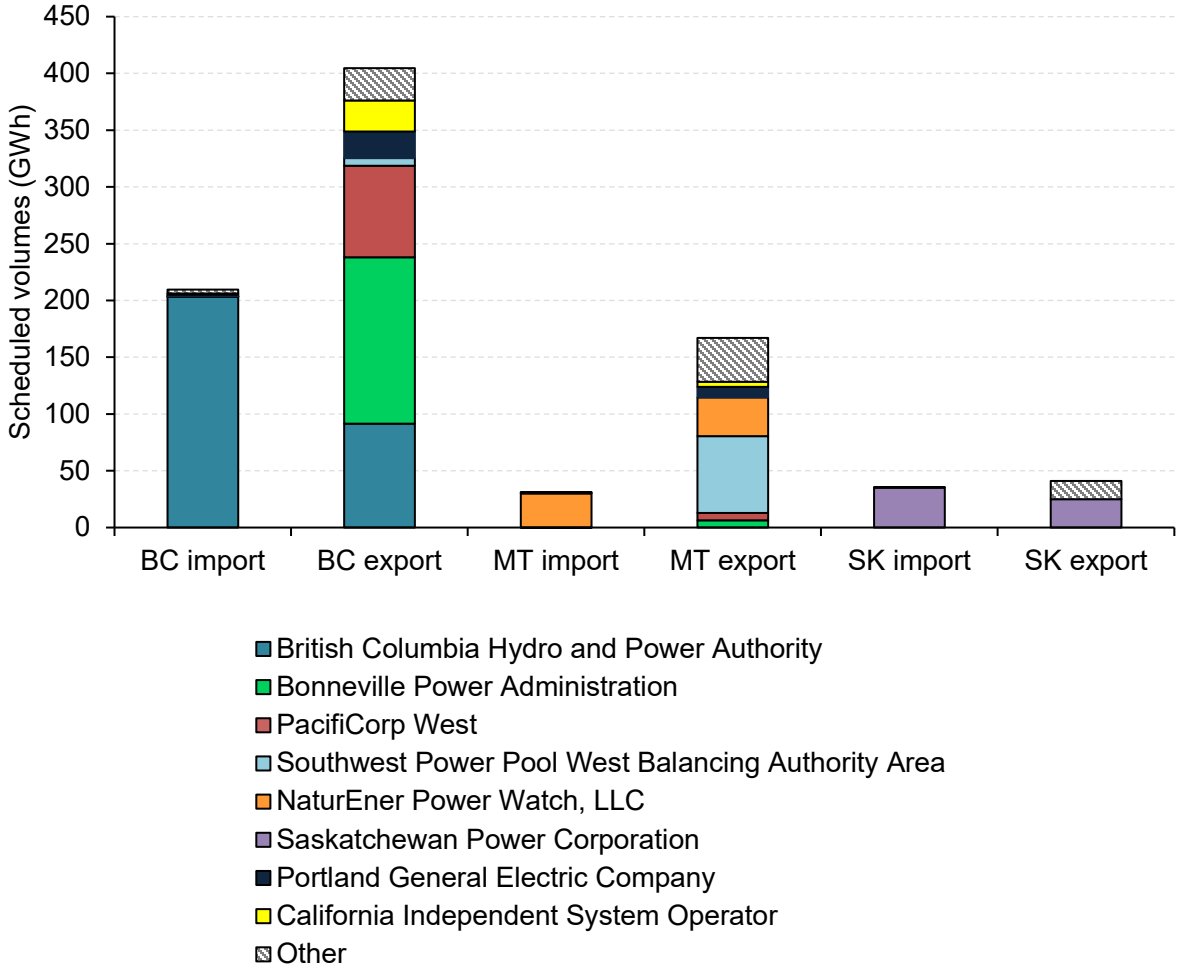
For imports on the Saskatchewan intertie, 98% of volumes originated from Saskatchewan, 1.3% from MISO, and the remainder from Ontario. For exports on the Saskatchewan intertie, 61% of volumes were delivered to Saskatchewan, 37% to MISO, and the remainder to SPP and Ontario.

Marginal congestion rent estimates the incremental value of 1 MW of additional intertie capacity. It is calculated as the sum of price differentials across the interties in hours when flows were constrained. Accrual of marginal congestion rent occurs when the capacity limit of an intertie binds and prices on the two sides of the intertie differ. Monthly marginal congestion rents are shown in Figure 55. Constrained observations are identified in the same manner as in Figure 53; 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. The analysis does not account for transmission costs.

External prices are proxied using real-time prices at nodes in the Western Energy Imbalance Market (WEIM). The Sumas node on the BC-US border is used to proxy pricing in BC, while the Rainbow node near Great Falls, Montana is used for MATL as it is near the intertie's termination point.[44] Prices as these nodes may differ from broader prices in Mid-C and California due to congestion within the WEIM.

[44] The Sumas node refers to WEIM locational marginal pricing node SMS_GNODEGEN2, and the Rainbow node refers to locational marginal pricing node RBOW_GEN1_RBOWGNODE.

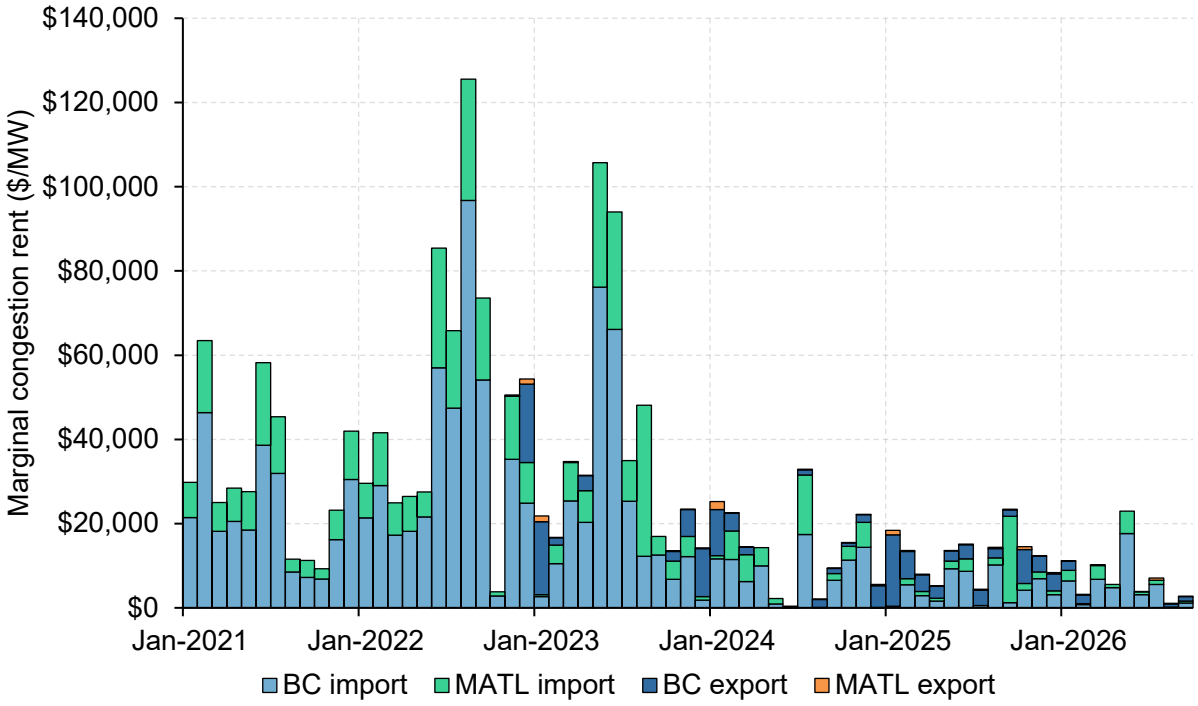
Figure 54: Intertie volumes by source of imports and destination of exports (Q3)



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. Hours in which BC and MATL were jointly constrained have the marginal congestion rent allocated between the two interties based on the relative share of scheduled flow. Results are aggregated monthly by intertie and direction to create a measure that reflects the marginal value of intertie capacity over time.

In Q3, marginal congestion rents on BC and MATL were lower both year over year and quarter over quarter. Price differentials were lower this quarter which, along with relatively few constrained hours, resulted in low marginal congestion rent.

Figure 55: Marginal congestion rent on BC and MATL (January 2021 to September 2026)



2.5 Transmission must-run

Transmission must-run (TMR) is an out-of-market ancillary service used by the AESO to provide supplementary sources of supply to help maintain grid stability. Generally, the AESO use TMR when demand in a region of the province's electricity system cannot be served by dispatched generation due to transmission constraints. Consequently, the AESO issue TMR directives that require local generation to operate at specific levels to ensure demand in the area is met. On occasion, the AESO use TMR to maintain grid stability for other reasons, such as voltage support.

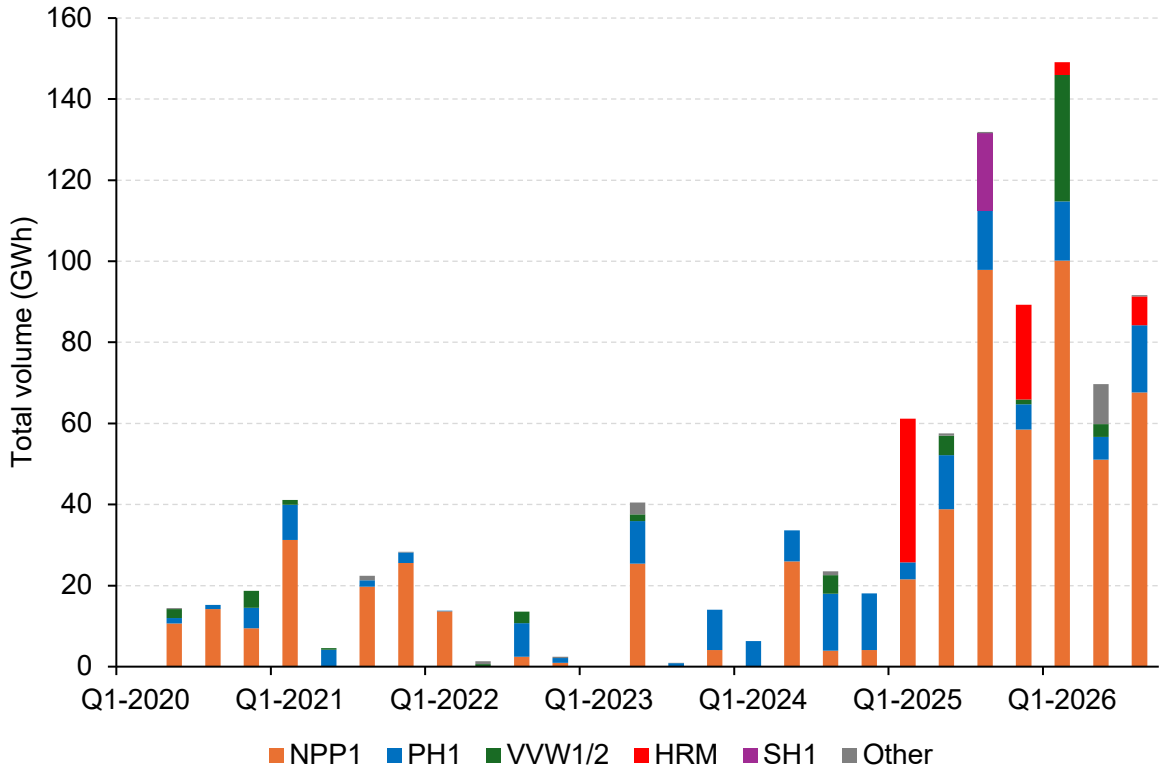
The total cost of TMR in Q3 was $5.0 million.[45] TMR volumes in the quarter totalled 91.6 GWh which is a 30% decline year over year, but a 32% increase compared to Q2. In Q1, the AESO directed a record amount of TMR at 149 GWh (Figure 56).

Northern Prairie Power Project (NPP1) is a major provider of TMR. Between September 7 and 23, the asset was offline on a planned outage and the AESO issued more TMR directives to Poplar Hill (PH1) and HR Milner (HRM), which are also located around Grande Prairie.

The highest daily volume of TMR in Q3 was 3.6 GWh, which occurred on September 9 and 10, as the AESO issued TMR directives to PH1 and HRM. On these days, HRM was directed for 120 MW of TMR due voltage concerns arising from an outage on transmission line 7L228, and later because of N-1 contingencies on 7L199.

[45] These cost figures do not include GST. The TMR cost figures listed in previous MSA reports include GST.

Figure 56: Total TMR volumes by quarter and asset (Q1 2020 to Q3)



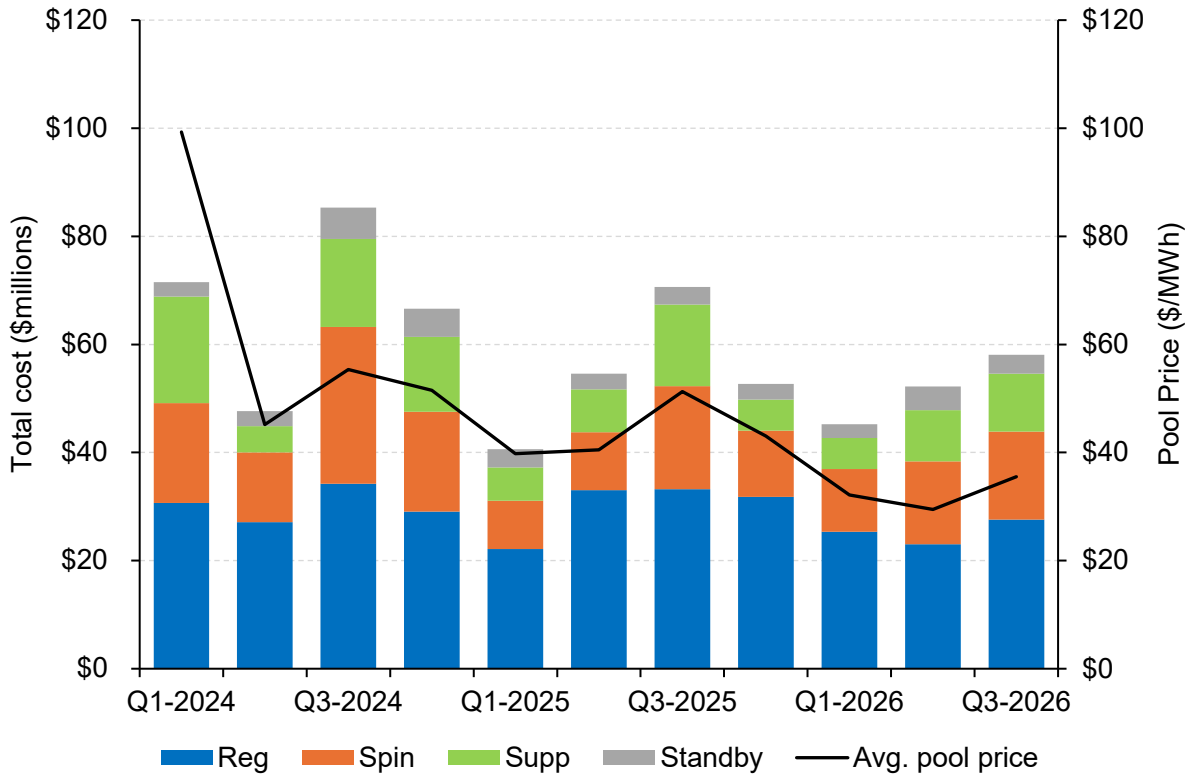
3 OPERATING RESERVES

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 in Q3 was $58 million which is a year-over-year decline of 18%. The lower OR costs in Q3 this year were driven by lower pool prices, which fell by 31%. Lower pool prices directly impact OR costs because payments for active reserves are calculated by indexing equilibrium prices, which are set in OR auctions, to pool prices. Compared to Q2, total OR costs were 11% higher as the average pool price increased by 21% (Figure 57).

Figure 57: Total OR costs by product and quarter (Q1 2024 to Q3)



3.2 Active reserves

Received prices for OR products are calculated by indexing equilibrium prices to hourly pool prices, as shown by the equation below. Table 21 provides average received prices for the different OR products in Q3 2025 and Q3.

$$Received\ price = \max(0, Pool\ price + Equilibrium\ price)$$

The average pool price fell by $15.77/MWh year over year and the received price for regulating reserves fell by a similar amount. This illustrates that overall equilibrium prices for regulating reserves were comparable year over year.

In Q3, equilibrium prices for off-peak regulating reserves were lower than Q3 last year because of participation from Raymond Reservoir (RYMD), which started in August 2025, and from Enfinite, which started in February 2026, and because of more supply from the NPP1 asset. Offsetting this, equilibrium prices for on-peak regulating reserves increased year over year, largely due to less supply from ENMAX and the Air Liquide Scotford (ALS1) asset.

Table 21: Average received price by OR product (Q3 2025 and Q3)

	Q3 2025	Q3 2026	Change
Reg	$72.36	$59.11	-$13.25
Spin	$34.84	$29.69	-$5.14
Supp	$27.55	$19.47	-$8.08
Pool price	$51.29	$35.52	-$15.77

The received prices for spinning and supplemental reserves fell by less than the average pool price because equilibrium prices for these products increased year over year. Figure 58 illustrates how often equilibrium prices for spinning reserves were above different thresholds in Q3 2025, Q2, and Q3. As shown, equilibrium prices were often higher in Q3 than in Q3 2025. The higher equilibrium prices for spinning reserves were caused by lower pool prices and less supply from TransAlta and Suncor.

Equilibrium prices for supplemental reserves also increased year over year, despite more supply from the AB Newsprint (ANC1) generation asset and the RODN load asset. Equilibrium prices for supplemental reserves increased because of lower pool prices, less supply from other load assets, and reduced supply from TransAlta in the off-peak market.

Figure 58: Duration curves of equilibrium prices for spinning reserves (Q3 2025, Q2 2026, and Q3 2026)

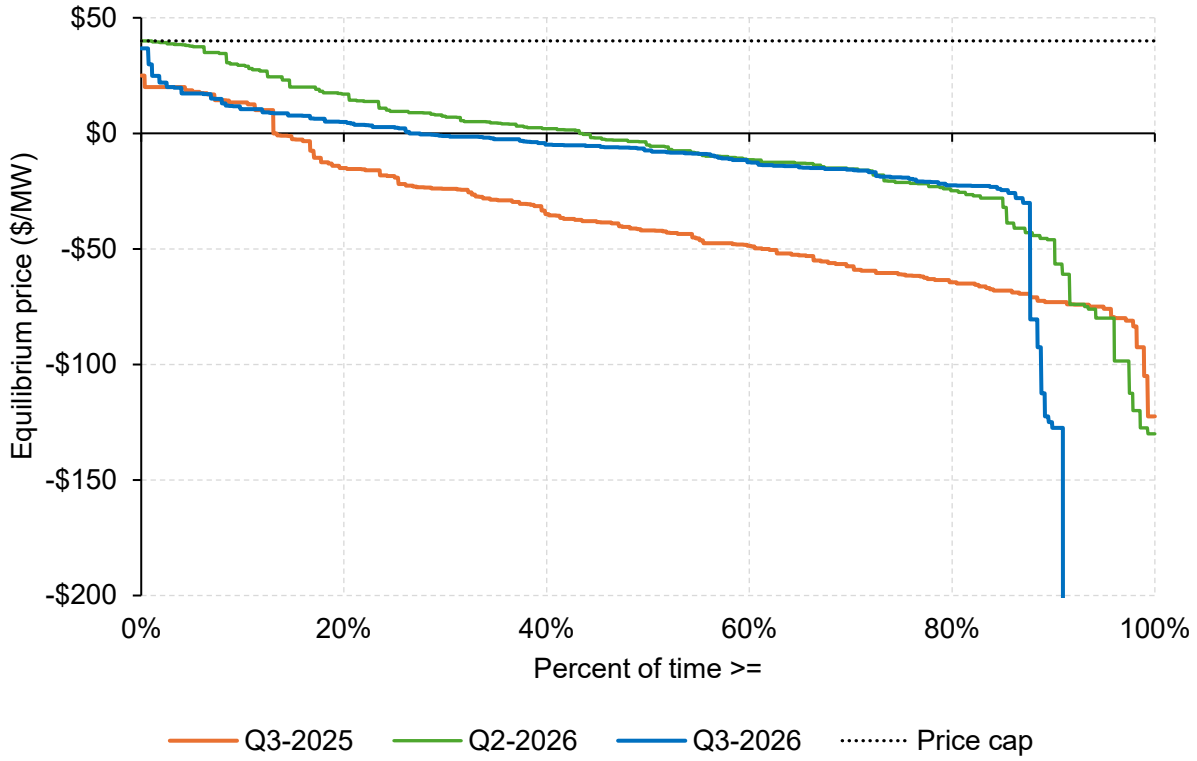


Table 22 provides received prices quarter over quarter. For regulating reserves, the increase in received prices was comparable with the increase in pool prices as on-peak and off-peak equilibrium prices were largely unchanged.

For spinning and supplemental reserves, received prices increased by less than the pool price as increased competition lowered equilibrium prices. For spinning reserves, this was caused by more supply from TransAlta and Enfinite. For supplemental reserves, the increased competition was due to more offered capacity from Enfinite and ANC1.

Table 22: Average received price by OR product (Q2 and Q3)

	Q2 2026	Q3 2026	Change
Reg	$51.68	$59.11	$7.43
Spin	$29.46	$29.69	$0.23
Supp	$17.86	$19.47	$1.61
Pool price	$29.47	$35.52	$6.06

Equilibrium prices for spinning reserves were above $0/MW in 26% of hours in the quarter. This is down from the record of 43% in Q2, as there were fewer $0/MWh pool prices in Q3. Figure 59 illustrates equilibrium prices for spinning reserves over Q3.

In September, equilibrium prices for spinning reserves were volatile; on-peak prices cleared at negative $880.50/MW for seven days and off-peak prices cleared at this level for 11 days. The lower equilibrium prices were driven by a high amount of capacity being offered at low prices by TransAlta and Enfinite. Table 23 shows the offers of dispatched assets for on-peak spinning reserves on September 2, the day BC/MATL returned to service, and the first day prices cleared at negative $880.50/MW in Q3.

Figure 59: Equilibrium prices for spinning reserves (Q3)

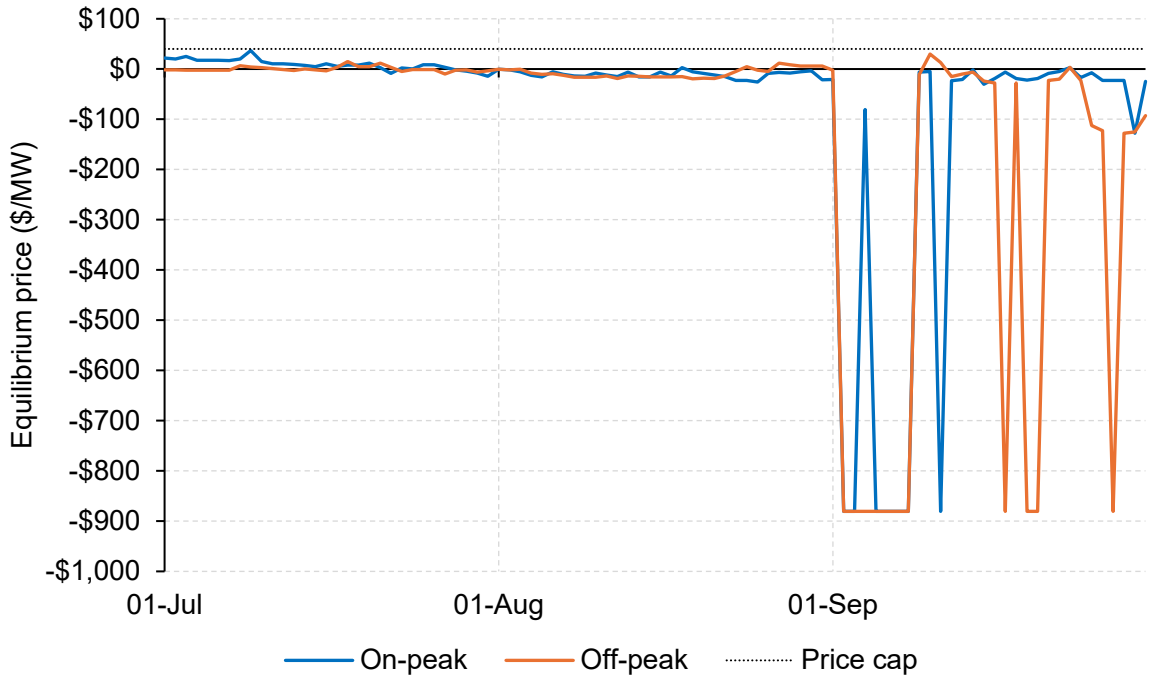


Table 23: Dispatched offers for on-peak spinning reserves (September 2 delivery)

Asset	Fuel type	Offer price ($/MW)	Offer volume (MW)	Cumulative volume (MW)
ERV1	Battery	-$930.00	20	20
ERV2	Battery	-$930.00	20	40
ERV3	Battery	-$930.00	20	60
ERV4	Battery	-$930.00	20	80
BOW1	Hydro	-$880.50	29	109
BIG	Hydro	-$880.50	27	136
BRA	Hydro	-$880.50	80	216
KH2	**Gas**	**-$880.50**	**35**	**251**

During the BC/MATL outage, Enfinite reduced the amount of battery capacity they offered into spinning and supplemental reserves because the capacity was required for FFR. This put some upward pressure on equilibrium prices for spinning and supplemental reserves.

Equilibrium prices for supplemental reserves were volatile in early September, driven by increased competition at lower offer prices. On September 3, the on-peak price was negative $480/MW, and the off-peak price was negative $898/MW. Table 24 provides the offers of dispatched assets for the off-peak.

Figure 60: Equilibrium prices for supplemental reserves (Q3)

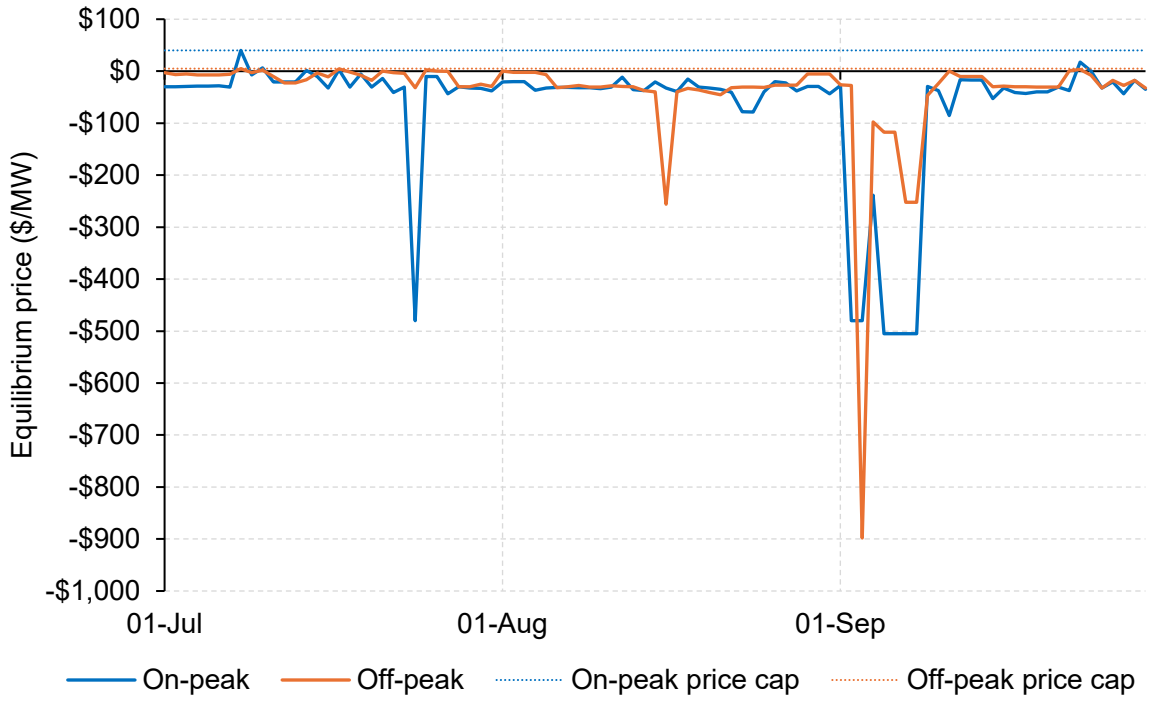


Table 24: Dispatched offers for off-peak supplemental reserves (September 3 delivery)

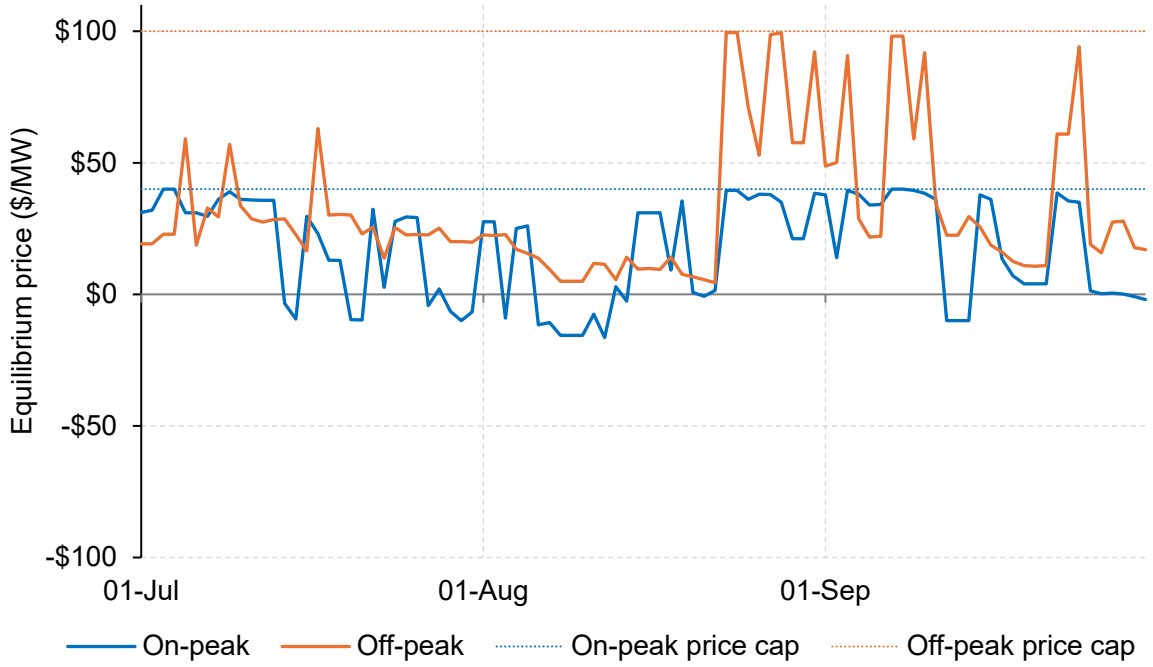
Asset	Fuel type	Offer price ($/MW)	Offer volume (MW)	Cumulative volume (MW)
VOCG	Load	-$1,017.50	8	8
VOED	Load	-$1,017.50	8	16
VONW	Load	-$1,017.50	20	36
ERV7	Battery	-$947.50	20	56
ERV8	Battery	-$947.50	20	76
BOW1	Hydro	-$898.00	77	153
BRA	Hydro	-$898.00	5	158
KH2	Gas	-$898.00	6	164
VVW1	Gas	-$898.00	27	191
VVW2	Gas	-$898.00	27	218
KH2	**Gas**	**-$898.00**	**3**	**221**

On July 8, prices for supplemental reserves cleared close to the caps as reduced supply led to insufficient offers. The on-peak price cleared at $39.99/MW as offers totalled 259 MW compared to the AESO's target volume of 262 MW. For the off-peak, offers totalled 216 MW compared to the target volume of 224 MW, and price cleared at $4.99/MW. The reduced supply was caused by lower offer volumes from TransAlta due to an outage at Brazeau unit 1, and because ANC1 was not offered into the on-peak or off-peak markets.

Figure 61 illustrates equilibrium prices for on-peak and off-peak regulating reserves over the quarter. Equilibrium prices for the on-peak cleared within $5/MW of the $40/MW cap on 30% of days in Q3 compared with 29% in Q3 2025. For the off-peak, prices were within $5/MW of the $100/MW cap for 7% of days in Q3 compared with 28% in Q3 last year. The increased competition in the off-peak market has been driven by the participation of RYMD and Enfinite battery assets.

The AESO increased their target volumes for on-peak and off-peak regulating reserves during the BC/MATL outage, from August 23 to September 1, which led to higher equilibrium prices (Figure 61). The on-peak target was increased from 210 to 260 MW, and the off-peak target was increased from 135 to 185 MW.

Figure 61: Equilibrium prices for on-peak and off-peak regulating reserves (Q3)



On September 3 and 22, there was insufficient capacity offered into on-peak regulating reserves to meet the AESO's target volume of 210 MW. Total offered capacity was 196 MW and 201 MW, respectively, as NPP1 and ALS1 were absent, and ENMAX offered less volume than normal. Prices for on-peak and off-peak regulating reserves were also high on September 7 and 8 due to the absence of NPP1 and ALS1 from both markets, and the absence of RYMD from the on-peak.

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 forecasted).

The total cost of standby reserves in Q3 was $3.5 million, representing 6% of total OR costs for the quarter. Total standby costs were 8% higher year over year due to higher premium prices for spinning and supplemental reserves.

Table 25 provides the AESO's target volumes for standby reserves over Q3. From May to July each year, the AESO procure more standby spinning reserves because import volumes are often higher during the hydro run-offs in BC and Mid-C. In addition, from August 23 to September 1, the AESO procured an additional 30 MW of off-peak spinning and supplemental reserves due to the planned BC/MATL outage. The AESO added these volumes because historically there has been a higher volume of out-of-market conscription for standby spinning and supplemental reserves during off-peak hours when BC/MATL was offline.

Table 25: AESO target volumes for standby reserves (MW, July to September)

Month	Reg		Spin		Supp	
	On-peak	Off-peak	On-peak	Off-peak	On-peak	Off-peak
Jul	20	20	65	55	15	15
Aug	20	20	45	35 to 65	15	15 to 45
Sep	20	20	45	35 to 65	15	15 to 45

Activation rates for standby reserves in Q3 were comparable with Q2 (Table 26). The activation rate for regulating reserves remained low at 1%, while 13% of spinning reserves were activated and 16% of supplemental reserves.

Table 26: Activation rates for standby reserves (Q1 2025 to Q3)

	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%
Q3-2026	**1%**	**13%**	**16%**

Table 27 compares activation prices with pool prices at the time of the activations. Consistent with Q2, the activation premium for standby regulating reserves grew year over year, although regulating reserves were not activated often. Activation prices for standby spinning and supplemental reserves remained at a discount to prevailing pool prices.

Table 27: Activation prices compared to prevailing pool prices (Q3 2025 and Q3)

		Q3-2025	Q3-2026
Reg	Activation price	$83.11	$106.36
	Prevailing pool price	$34.15	$12.51
	Standby premium	143%	750%
Spin	Activation price	$45.06	$26.78
	Prevailing pool price	$52.87	$33.74
	Standby premium	-15%	-21%
Supp	Activation price	$39.81	$23.36
	Prevailing pool price	$56.83	$30.59
	Standby premium	-30%	-24%

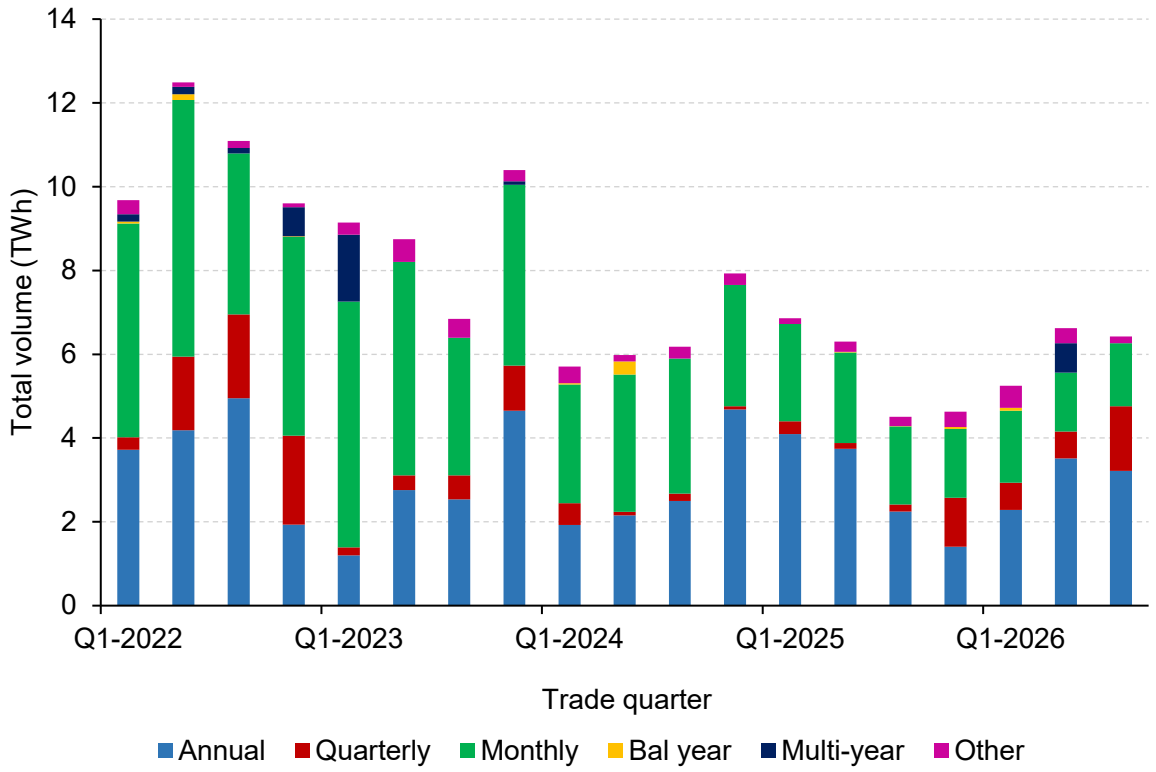
4 THE FORWARD MARKET

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.[46]

4.1 Forward market volumes

Liquidity in the forward market remained low in Q3, although total trade volumes were 43% higher than the same quarter last year. Total volumes over ICE NGX and the brokers were 6.43 TWh in Q3 compared to 4.51 TWh in Q3 2025 (Figure 62). The year-over-year increase was driven by more annual and quarterly volumes, which were up 0.97 TWh and 1.37 TWh, respectively.

Figure 62: Total trade volumes by quarter and term
(Q1 2022 to Q3 2026, excludes direct bilateral trades)



4.2 Trading of monthly products

Pool prices came in below forward market expectations for July and September (Figure 63). The volume-weighted average forward price for July was $44.11/MWh, a 41% premium to the pool

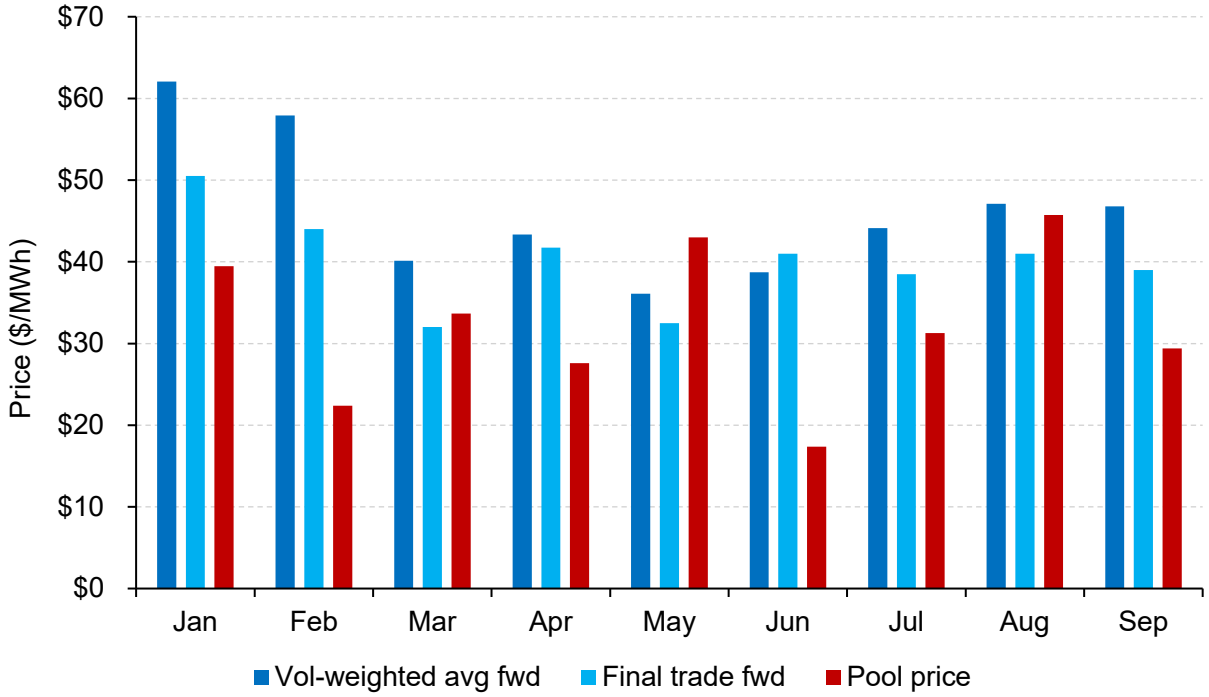
[46] The analysis in this section incorporates trade data from ICE NGX and two over-the-counter brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring. Data on direct bilateral trades up to a trade date of December 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.

price, and the final trade price was $38.50/MWh, a 23% premium. Despite significant year-over-year load growth, pool prices were low in July because of strong solar generation, reduced exports, and few thermal outages.

In August, the average pool price of $45.71/MWh was slightly below the volume-weighted average forward price of $47.10/MWh, but above the final trade price of $41.00/MWh. As outlined in sections 1.1 and 1.2, pool prices in August were increased by volatility during the BC/MATL outage late in the month. Going into the intertie outage, August was marked at $38.84/MWh.

Forward prices were at a premium to the average pool price in September. The volume-weighted average forward price was $46.77/MWh, a 59% premium, and the final trade price was $39.00/MWh, a 33% premium. Low pool prices in September were caused by mild weather, which increased wind generation and lowered demand.

Figure 63: Monthly forward prices relative to pool prices (January to September)



Monthly forward prices were highly correlated with natural gas prices over Q3, as both declined in response to mild weather forecasts for the winter, and because natural gas is the main input cost for Alberta power. Over Q3, the correlation coefficients between daily power and natural gas prices were 0.9 for the November to March contracts, indicating tight relationships.

Natural gas prices fell significantly from late July to late August as the market reacted to forecasts for a super El Nino, high production and storage levels, and pipeline bottlenecks constraining exports. Between July 23 and August 31, the price of natural gas for December fell by 22%. The weather forecasts, and associated declines in natural gas prices, were a major driver of lower power prices over Q3; the price of the December contract fell by 7% (Table 28).

Table 28: Monthly forward price changes over Q3 (October 2026 to June 2027 contracts)

Contract	Price on Jun 30 ($/MWh)	Price on Sep 30 ($/MWh)	Change	
			($/MWh)	(%)
Oct'26	$36.00	$35.00	-$1.00	-3%
Nov'26	$43.00	$38.75	-$4.25	-10%
Dec'26	$49.00	$45.50	-$3.50	-7%
Jan'27	$54.75	$50.70	-$4.05	-7%
Feb'27	$52.50	$49.50	-$3.00	-6%
Mar'27	$42.00	$36.70	-$5.30	-13%
Apr'27	$40.25	$41.20	$0.95	2%
May'27	$38.75	$40.20	$1.45	4%
Jun'27	$37.00	$36.20	-$0.80	-2%

The March contract fell by $5.30/MWh or 13% over the quarter. Despite lower natural gas prices, this decline caused the spark spread for March to fall by 10% to $21.64/MWh. This fall occurred in the face of higher power prices in Mid-C, which increased by 30% to C$55.09/MWh. The March decline was partly in response to a gas-fired steam outage being moved from February/March to June on July 6, although the March contract did not trade in Q3.

Prices for April and May increased slightly over Q3 as these contracts were less affected by the weather forecasts and price declines for natural gas. In addition, there is a large amount of combined cycle capacity scheduled to be on outage in April and May, and Mid-C prices for these months increased over Q3. For example, the Mid-C price for April increased by 46% to C$57.11/MWh.

4.3 Trading of annual products

The expected average pool price for 2026 fell by 7% to $34.27/MWh over Q3 as pool prices came in below market expectations and forward prices for the balance of year fell. Similarly, the price of Cal 27 fell by 6% to $43.80/MWh because of low pool prices and declining natural gas futures (Table 29). The price of Cal 27 was strongly correlated with the price of natural gas over Q3, with a correlation coefficient of 0.9.

The price changes for contracts further out were mixed; Cal 28 fell by 3%, Cal 29 increased by 2%, and Cal 30 was unchanged (Table 29). However, it is worth noting that larger price changes occurred within the quarter (Figure 64).

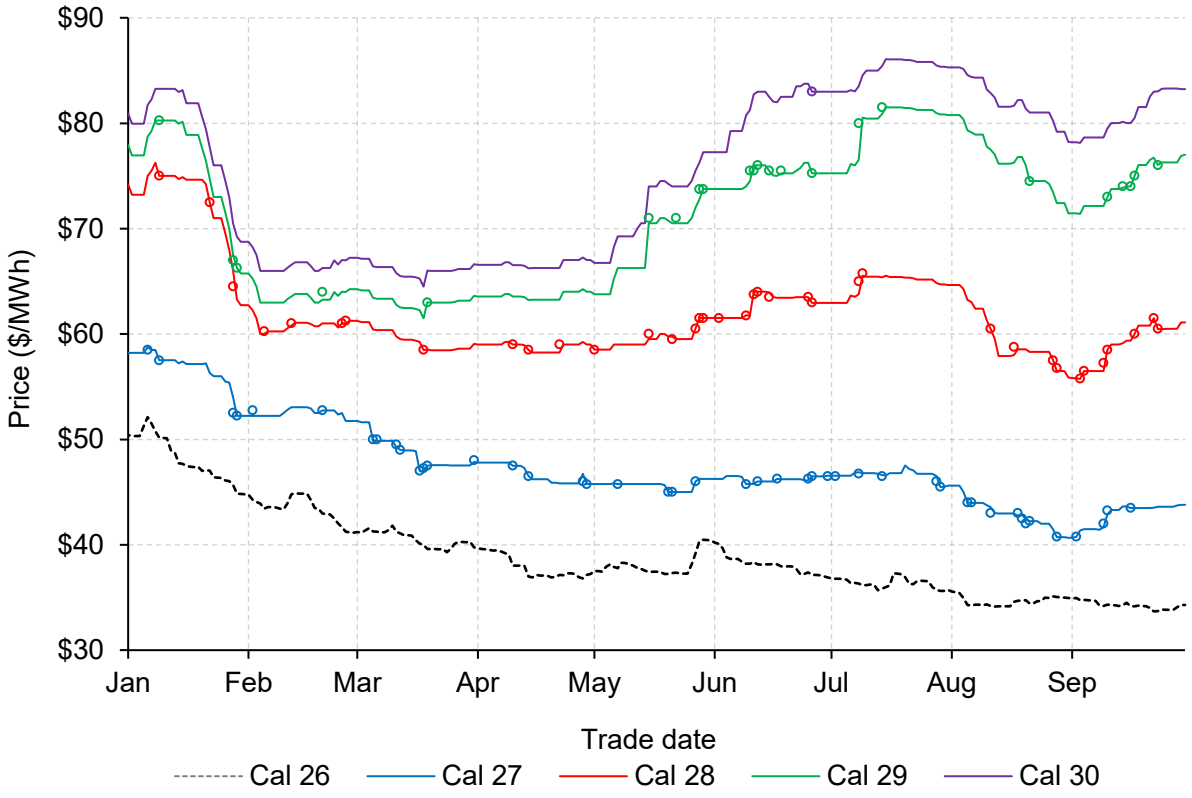
In early July, the prices of Cal 28 and 29 increased on the back of a major data centre announcement. On July 8, it was announced that a large data centre is expected to come online in the second half of 2028, in accordance with the AESO's Large Load Phase 1. The associated

Greenlight combined cycle asset (932 MW) is scheduled to begin operations in the second half of 2030.[47]

Table 29: Changes to annual power and natural gas prices over Q3

Contract	Power price ($/MWh)			Natural gas price ($/GJ)			Spark spread ($/MWh)		
	Jun 30	Sep 30	Change	Jun 30	Sep 30	Change	Jun 30	Sep 30	Change
Cal 26 (marked)	$36.91	$34.27	-7%	$1.78	$1.74	-3%	$23.56	$21.25	-10%
Cal 27	$46.55	$43.80	-6%	$2.28	$2.13	-7%	$29.48	$27.86	-5%
Cal 28	$62.95	$61.10	-3%	$2.45	$2.48	1%	$44.60	$42.49	-5%
Cal 29	$75.25	$77.00	2%	$2.44	$2.54	4%	$56.96	$57.94	2%
Cal 30	$83.00	$83.25	0%	$2.44	$2.61	7%	$64.71	$63.69	-2%

Figure 64: Annual power prices (January 1 to September 30)[48]



[47] Pembina Pipelines Announces FID on Greenlight Electricity Centre – July 2, 2026

Capital Power Enters Long-Term Energy Supply Agreement with Meta in Alberta – July 8, 2026

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

[48] Markers in the figure illustrate the price of the last trade on that day.

The data centre news increased prices for the back half of 2028 by 5.5%, raising the overall price of Cal 28 by 2.8%. The price of Cal 29 increased by 5.3% following the news while the price of Cal 30 was less affected, rising by 1.2%.

Annual prices remained relatively stable for the rest of July. However, prices declined over August: Cal 28 fell by 14% to $55.87/MWh and Cal 29 fell by 12% to $71.47/MWh. The price declines in August were driven by sell-side pressure amidst a general lack of liquidity. Cal 28 traded five times in August and Cal 29 traded once.

This sell-side pressure came on the back of continued low pool prices in the energy market. As outlined above, summer pool prices came in below forward market expectations, and mild weather forecasts and declining natural gas prices put downward pressure on the prices of upcoming winter contracts. In August, pool prices averaged $45.71/MWh despite some major forced generator outages and a planned outage on BC/MATL.

In addition, the Cal 28 contract came under pressure because traders began to question whether the REM would begin on schedule in 2028. The transition to the REM may put upward pressure on prices in the energy market because of the higher price cap, the procurement of the R30 ramp product, and the move to LMPs.

Over September, annual forward prices increased, partially erasing the August declines (Figure 64). Cal 28 rose by 9% over the month to $61.10/MWh and Cal 29 rose by 8% to $77.00/MWh. The increases came on the back on renewed buying pressure in the context of the lower annual prices.

In addition, prices in Mid-C increased meaningfully because of an expectation of lower hydro flows in the future due to a drier climate and fish remediation. Figure 65 illustrates the evolution of prices for Cal 28 in Alberta, Mid-C, NP15, and SP15 since the start of the year. There was also more trading activity for Cal 28 and 29 in September, with both contracts trading 13 times.

Figure 66 illustrates annual prices in Alberta relative to these other markets at the end of the quarter. For Cal 27 and 28, Alberta prices are the lowest of the markets shown, and prices are expected to be well below prices in Mid-C, indicating Alberta is forecast to be a strong exporter of power. For Cal 29 and 30, prices in Alberta are more comparable with prices in Mid-C.

Figure 65: The price of Cal 28 in Alberta relative to other markets (January 1 to September 30)

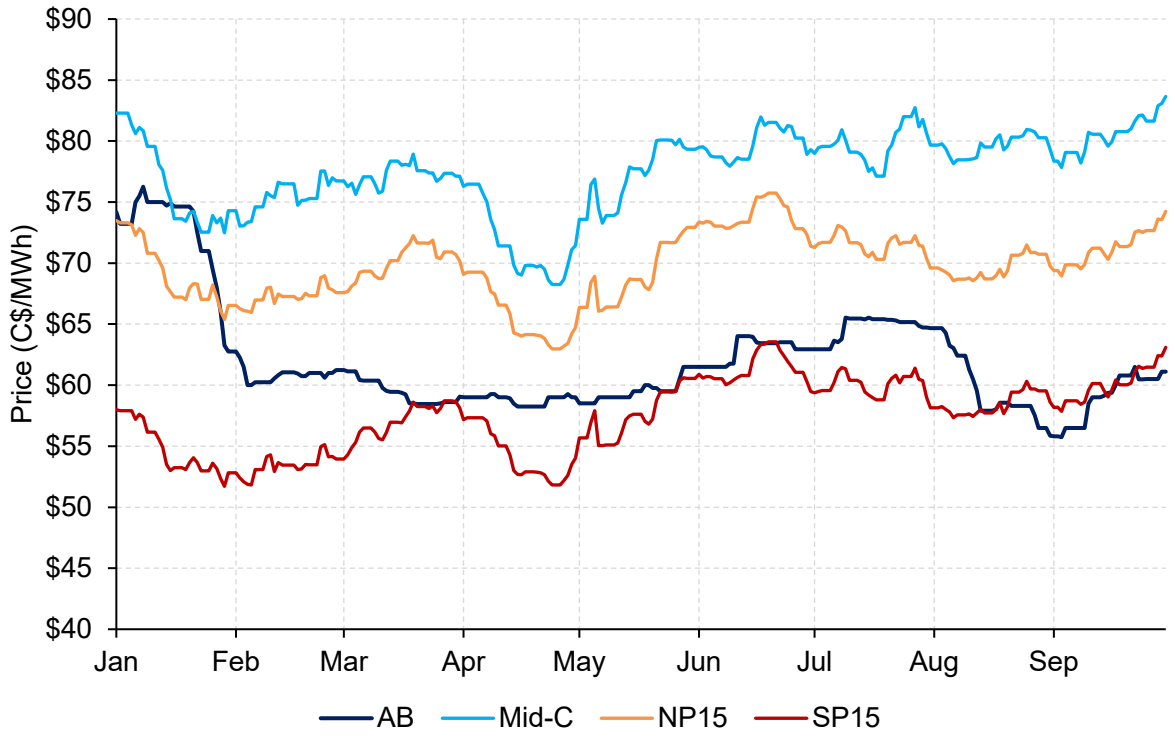


Figure 66: Annual prices in Alberta relative to other markets (as of September 30)

