Wholesale Market Report: Q2 2025

August 13, 2025

Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

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THE QUARTER AT A GLANCE

- **Increased gas capacity and solar generation drive decline in average prices:**

  The average pool price in Q2 was $40.48/MWh, which is a decline of 10% relative to Q2 2024 but is comparable to the Q1 average of $39.78/MWh. Pool prices were lower in Q2 this year due to more gas capacity and higher solar generation. These fundamentals offset higher demand, higher natural gas prices, a higher carbon price, and some major planned generator outages in May and June.

- **In April off peak prices were higher than peak prices for the first time:**

  Because of high thermal availability and increased solar generation, price volatility in April was minimal; the average pool price settled at $33.69/MWh, the lowest in the quarter. Further to this, off peak prices in April averaged $34.74/MWh, higher than the peak average of $33.17/MWh. This is the first time in the market's history that off peak prices have been higher than peak, and this was largely the result of higher solar generation.

- **GNR1 and GNR2 trip simultaneously and prices increase to the offer price cap:**

  On June 17 at 17:08 the Genesee Repower 1 and 2 assets tripped offline simultaneously, reducing supply by 881 MW. The immediate impact of the trips was absorbed by the Western Interconnection via the BC and Montana interties as import flows increased to compensate for the supply loss. Consequently, system frequency in Alberta only dropped to 59.92 Hz. In response to this event the AESO directed all 501 MW of available contingency reserves to provide energy and requested 450 MW of reserves from the Western Power Pool. The reduction in supply caused prices to increase, with the System Marginal Price (SMP) clearing at the offer price cap of $999.99/MWh from 17:44 to 18:00.

- **Gas generator outages lead to prices at the offer price cap on June 8:**

  On June 8 the SMP cleared at $999.99/MWh from 19:20 to 21:15, illustrating very tight market conditions. For periods of time in HE 20 and HE 21 the energy market supply curve was fully dispatched and supply cushion was 0 MW. However, the AESO did not declare an Energy Emergency Alert and operating reserves were not directed to provide energy. This event was primarily driven by several large gas generator outages occurring at the same time. The AESO directed Battle River 5 to come online over the peak to provide much-needed energy. However, the Battle River 4 and Sheerness 2 assets remained commercially offline for this event. This was largely because of an unexpected outage at Genesee Repower 2, which transpired after the AESO's unit commitment decisions.

- **BC and Montana interties trip four times in Q2 reducing exports:**

  The BC and Montana interties tripped offline simultaneously on four occasions in Q2, all while Alberta was exporting. The AESO operates these interties as a shared flow gate (BC/MATL) because a trip on the BC intertie automatically leads to a transfer trip on the Montana intertie. On May 31 the interties tripped offline while Alberta was exporting 980 MW. Due to this sudden loss of export demand, system frequency in Alberta increased to 60.49 Hz and there was a frequency response from Alberta generators.

- **GNR1 and GNR2 testing with generation above 466 MW:**

  Between June 20 and July 1 Genesee Repower 1 and 2 underwent planned testing which required the assets to generate above the most severe single contingency limit of 466 MW. However, the AESO did not procure additional contingency reserves. On June 21 the AESO had 466 MW of contingency reserves available when Genesee Repower 2 tripped offline from 653 MW and the AESO requested 150 MW of reserves from the Western Power Pool. The AESO relied on support from the BC and Montana interties to manage the contingencies at Genesee Repower 1 and 2 during this testing. In addition, the AESO reduced available import capability on BC/MATL to 0 MW in certain hours to help manage the impact of scheduled trips.

- **The AESO issued 30 unit commitment directives in the quarter:**

  The secondary offer price limit was not triggered in Q2 as monthly average pool prices remained relatively low. However, the AESO issued 30 unit commitment directives in the quarter. These unit commitment directives increased supply cushion during some tight hours, and the MSA estimates they reduced the average pool price for Q2 by $2.86/MWh or 7%.

- **Transmission constraint volumes set record in Q2:**

  The total volume of constrained intermittent generation reached a record high of 310 GWh in Q2, a 44% increase from Q2 2024. At least 1 MWh of wind and solar generation was constrained down in 54% of hours in the quarter. The constrained and unconstrained SMP differed by $1/MWh or more in 28% of hours in Q2. On May 26 and 29 there were significant differences between the constrained and unconstrained SMP, driven by high volumes of constrained intermittent generation and prevailing market fundamentals. A transmission outage on EATL from May 26 to June 8 contributed to the increase in constrained down generation. In HE 15 of May 26 the constrained SMP peaked at $999.96/MWh while the unconstrained SMP was $18.89/MWh, the highest difference in the quarter.

- **Higher prices for regulating reserves:**

  The total cost of operating reserves increased by 14% year-over-year despite the lower pool prices in Q2 this year. The increased cost of operating reserves was driven by higher regulating reserve costs. Following a generation merger in late 2024 there has been reduced competition in the day-ahead auctions for regulating reserves, which may have resulted in higher equilibrium prices. In the market for off peak regulating reserves the equilibrium price was at least $99/MW (within $1/MW of the price cap) on 46% of days in Q2.

- **Forward power prices for future years increased over Q2:**

  Forward power prices for future years increased over the quarter while forward prices for natural gas were flat or declined slightly. The price of power for 2027 increased by 23% over Q2 to $60.75/MWh, while the price of power for 2028 increased by 35% to $75.05/MWh. These price increases were largely driven by a period of heightened buying pressure in early June following the AESO’s discussion of integrating large loads. In addition, a period of higher pool prices in late May put upward pressure on forward prices. Overall liquidity in the forward market remains low with total trade volumes in April being the lowest since May 2007.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q2 was $40.48/MWh, which is a 10% decrease relative to Q2 2024. The lower pool prices in Q2 this year were driven by more gas generation capacity and increased solar generation. These fundamentals offset higher demand, higher natural gas prices, a higher carbon price, and some major planned generator outages in May and June (Table 1).

In April the average pool price was $33.69/MWh, the lowest of the quarter and a 51% decrease year-over-year.

The lower prices in April were largely caused by high thermal availability. Average thermal availability was 10,182 MW in April, an increase of 1,674 MW relative to April 2024.

As a result of the market fundamentals in April the average pool price during peak hours was lower than the average pool price during off peak hours for the first time in the market's history (Figure 1).

The increase in solar generation was a major factor in this outcome. Average solar generation during peak hours was 772 MW in April, a 24% increase year-over-year.

Figure 2 illustrates the hourly profile of solar generation in Q2 of 2024 and 2025. As shown, there was a marked increase in solar supply in Q2 this year. This increase was driven by a combination of more installed capacity and a higher capacity factor.

Table 1: Summary market statistics for Q2 2024 and Q2 2025

		2024	**2025**	**Change**
Pool price (Avg $/MWh)	April	$68.61	$33.69	-51%
	May	$35.37	$40.99	16%
	June	$31.85	$46.75	47%
	Q2	**$45.17**	**$40.48**	**-10%**
Demand (AIL) (Avg MW)	April	9,697	9,819	1%
	May	9,296	9,400	1%
	June	9,585	9,645	1%
	Q2	**9,523**	**9,619**	**1%**
Gas price AB-NIT (2A) (Avg $/GJ)	April	$1.33	$2.24	68%
	May	$1.25	$1.82	46%
	June	$0.83	$0.85	3%
	Q2	**$1.14**	**$1.64**	**44%**
Wind gen. (Avg MW)	April	1,880	1,707	-9%
	May	1,439	1,662	15%
	June	1,408	1,404	0%
	Q2	**1,574**	**1,591**	**1%**
Solar gen. (Avg MW during peak hours)	April	622	772	24%
	May	619	894	44%
	June	781	948	21%
	Q2	**673**	**872**	**29%**
Net imports (+) Net exports (-) (Avg MW)	April	-51	-222	335%
	May	-10	-206	1960%
	June	-132	-343	160%
	Q2	**-64**	**-256**	**302%**
Available thermal capacity (Avg MW)	April	8,508	10,182	20%
	May	9,356	9,509	2%
	June	9,509	9,681	2%
	Q2	**9,127**	**9,788**	**7%**

The total capacity of intermittent generation in Alberta continues to increase. At the end of Q2 total solar capacity was 1,822 MW and total wind capacity was 5,680 MW. Consequently, solar generation set a record of 1,735 MW on June 9 in HE 14, and wind generation set a record of 4,261 MW on April 18 in HE 24.

Figure 1: Average pool prices during peak and off peak hours (January to June)

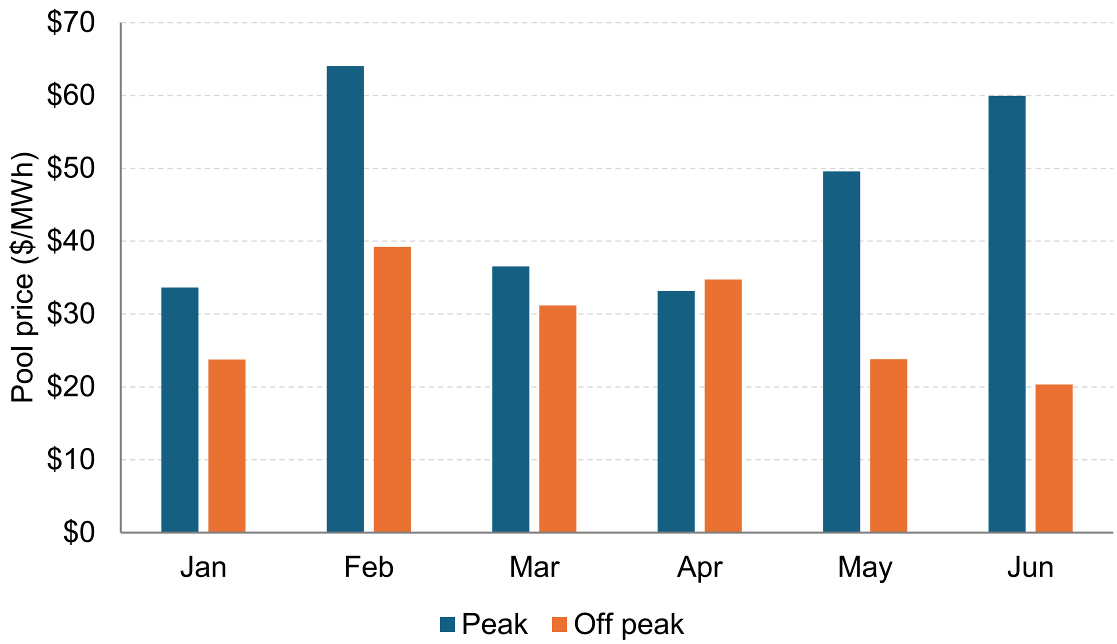
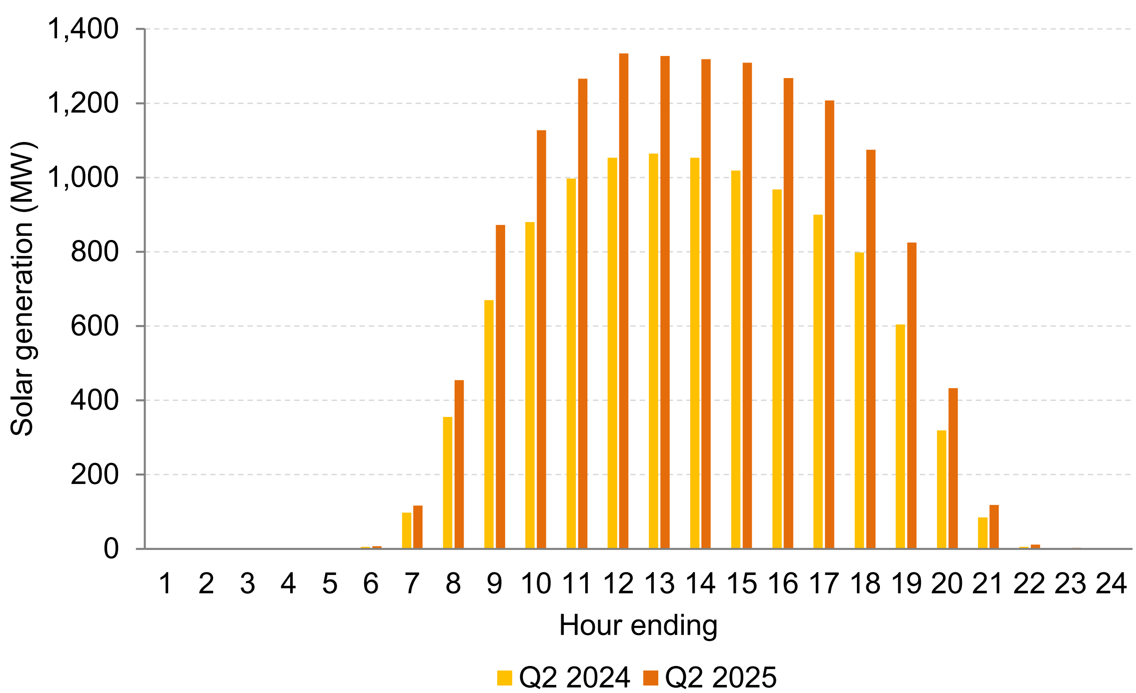


Figure 2: Average solar generation by hour ending (Q2 2024 and Q2 2025)



Average pool prices in May and June were $40.99/MWh and $46.75/MWh, respectively with both representing an increase year-over-year. The higher prices in these months this year were driven by higher demand and more gas generation outages. In a small number of hours these factors combined with low intermittent generation to cause high pool prices and increase the monthly average.

It is normal to see more planned generator outages scheduled for the spring and fall seasons when demand for electricity is lower. Last year outages were higher in April, driven in part by a planned outage at Shepard. This year, outages were higher in May and June driven in part by planned outages at Genesee Repower 1 and 2 in May, and Cascade 1 and 2 in June (Table 2).

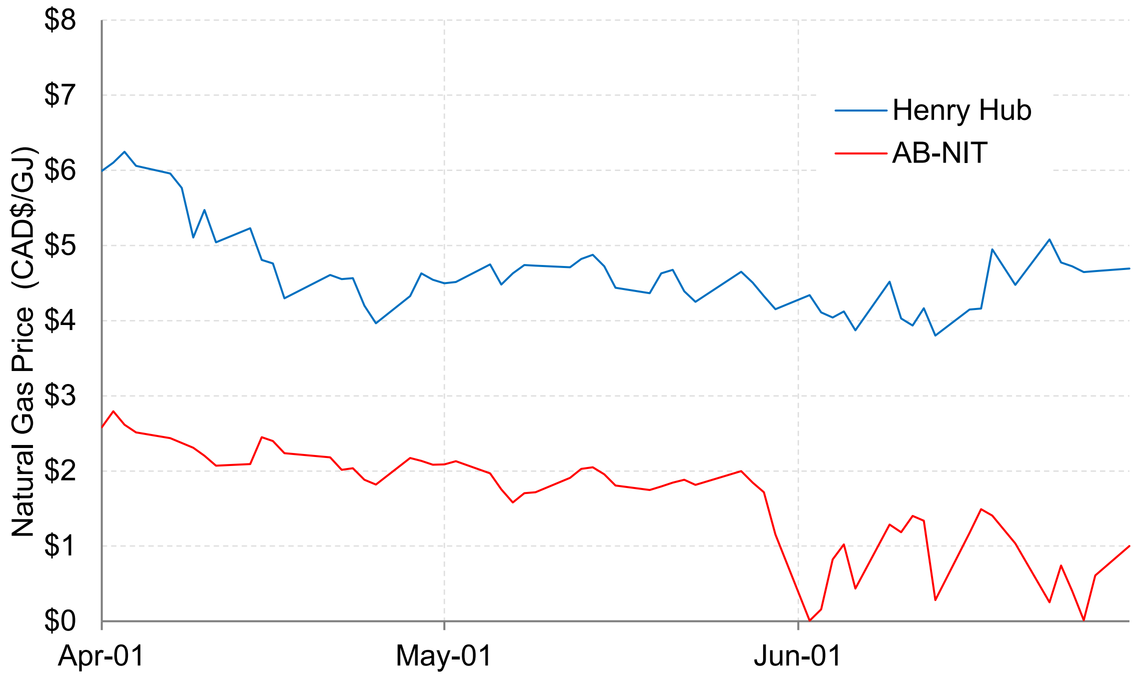
Table 2: Major gas generator outages in Q2

Asset name	Capacity on outage (MW)	Start date	End date	Outage length (days)
Sheerness 2	400	Mar-28	Apr-04	8
Sheerness 1	400	Mar-30	Apr-03	5
HR Milner	300	Apr-09	Apr-12	4
Shepard	480	Apr-17	Apr-21	5
Genesee Repower 1	466	Apr-26	May-16	21
Genesee Repower 2	466	May-09	May-29	21
HR Milner	300	May-24	May-27	4
Keephills 2	395	May-27	May-28	2
Keephills 2	395	Jun-01	Jun-06	6
Cascade 1	450	Jun-01	Jun-17	17
Sheerness 1	400	Jun-05	Jun-16	12
Cascade 2	450	Jun-09	Jun-21	13
Keephills 3	466	Jun-18	Jun-20	3
Keephills 3	466	Jun-23	Jun-28	6

In addition to this, supply from the Base Plant asset declined in June because units were taken offline as the asset continued its commissioning process. Average generation from Base Plant was 294 MW in June compared to 557 MW in April and 591 MW in May.

The price of natural gas is the main input cost for Alberta power. Natural gas prices were relatively stable early in the quarter but declined in late May (Figure 3). Between May 29 and June 2 the price of natural gas at AB-NIT fell from $1.72/GJ to $0.01/GJ while prices at Henry Hub remained stable. This separation of prices occurred because of pipeline constraints which limited the flow of natural gas out of Alberta. As shown by Figure 3 this dynamic played out for much of June, lowering the cost of natural gas for Alberta gas generators.

Figure 3: Daily natural gas prices in Alberta and at Henry Hub (Q2 2025)

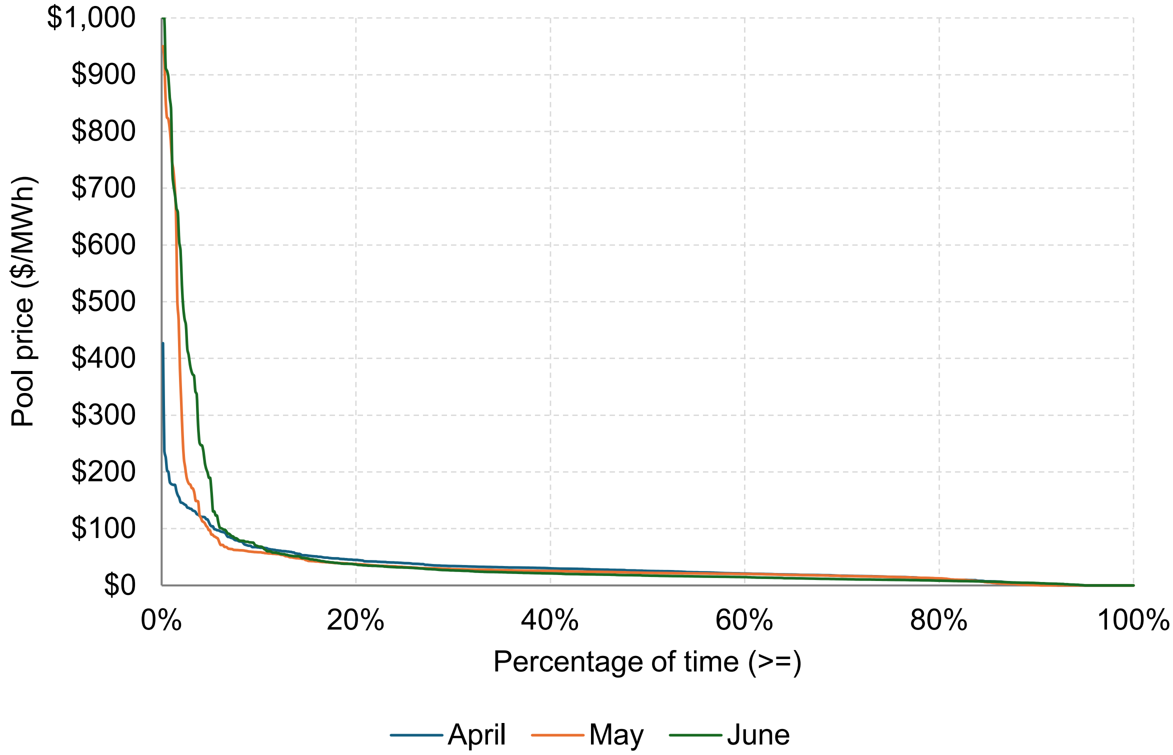


The lower natural gas prices in June put downward pressure on pool prices in hours with a high supply cushion. Nevertheless, the average pool price in June was the highest in Q2, driven by higher pool prices in a small number of hours. Figure 4 illustrates the distribution of pool prices in April, May, and June. As shown, pool prices between these months were comparable for 90% of hours, with prices in the highest 10% of hours driving the difference in average prices.

On June 8 and 17 the SMP cleared at the offer cap of $999.99/MWh during certain times, indicating very tight market conditions. The AESO did not declare an Energy Emergency Alert (EEA) in either event, indicating there were no imminent concerns around a supply shortfall.

As discussed further in section 1.2, these events were partially caused by gas generator outages. In addition, for both events there were gas-fired steam assets that were commercially offline on long-lead time. These assets were not directed to come online by the AESO because some of the fundamentals that led to these events were unexpected and were therefore not incorporated into the AESO's forecast of supply cushion.

Figure 4: Pool price duration curves (April, May, and June)



1.2 Market outcomes and events

Figure 5 illustrates the average pool price by hour ending in Q2. Despite average demand peaking in HE 18, the average pool price was highest in HE 21 at $113/MWh. This occurred because average solar generation was still relatively high during the demand peak in HE 18, averaging 1,092 MW. However, by HE 21 average solar generation had fallen to 114 MW (Figure 6).

Net demand is the demand that is left to be served by other generation types after accounting for wind and solar supply. In Q2 average net demand peaked in HE 21 because solar generation had declined while demand remained relatively high (Figure 7). In this hour of the day more gas generation was needed to meet demand than at any other.

Figure 6 illustrates average generation supply by fuel type and hour ending in Q2. As shown, electricity generation in Alberta is dominated by natural gas. At the net demand peak in HE 21 natural gas generation supplied an average of 7,744 MW or 78% of total generation.

Figure 5: Average pool price by hour ending (Q2 2025)

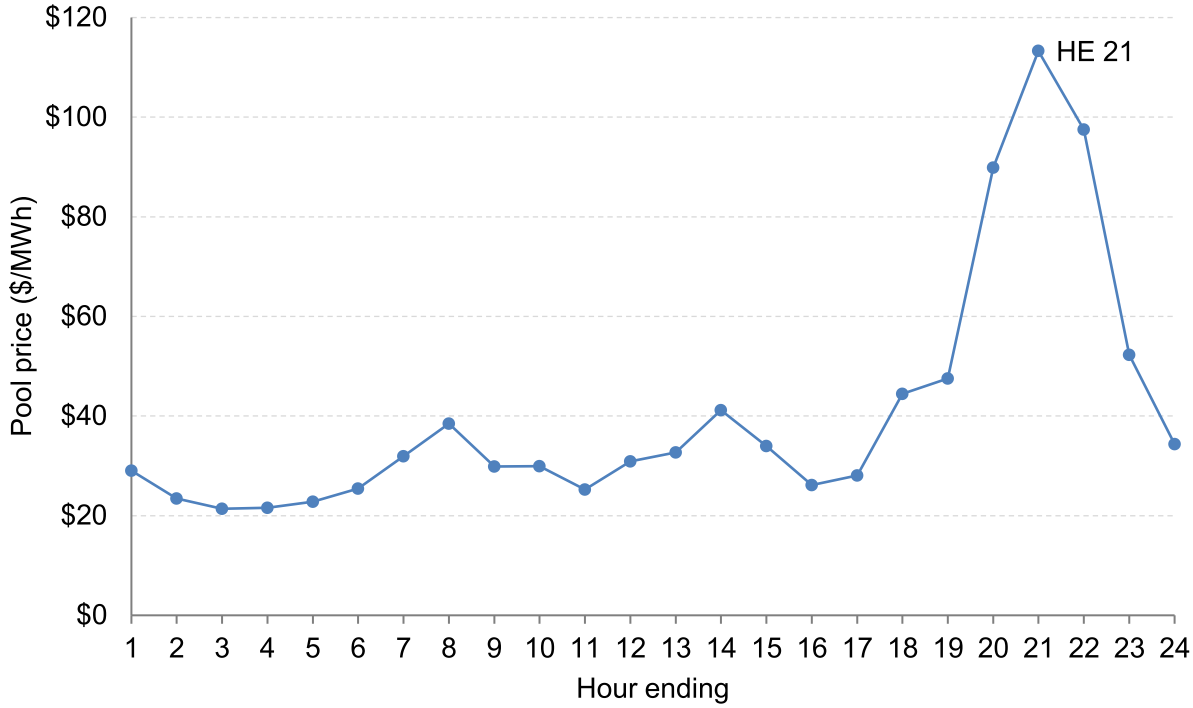


Figure 6: Average generation by fuel type and hour ending (Q2 2025)

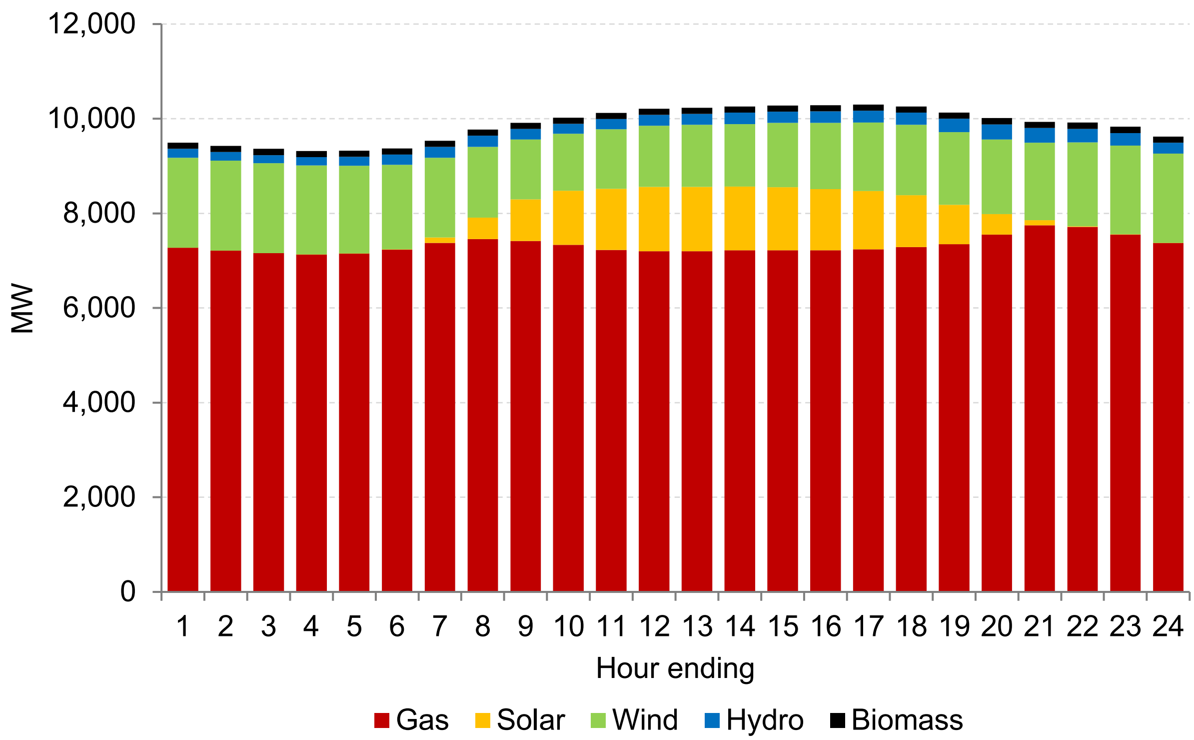
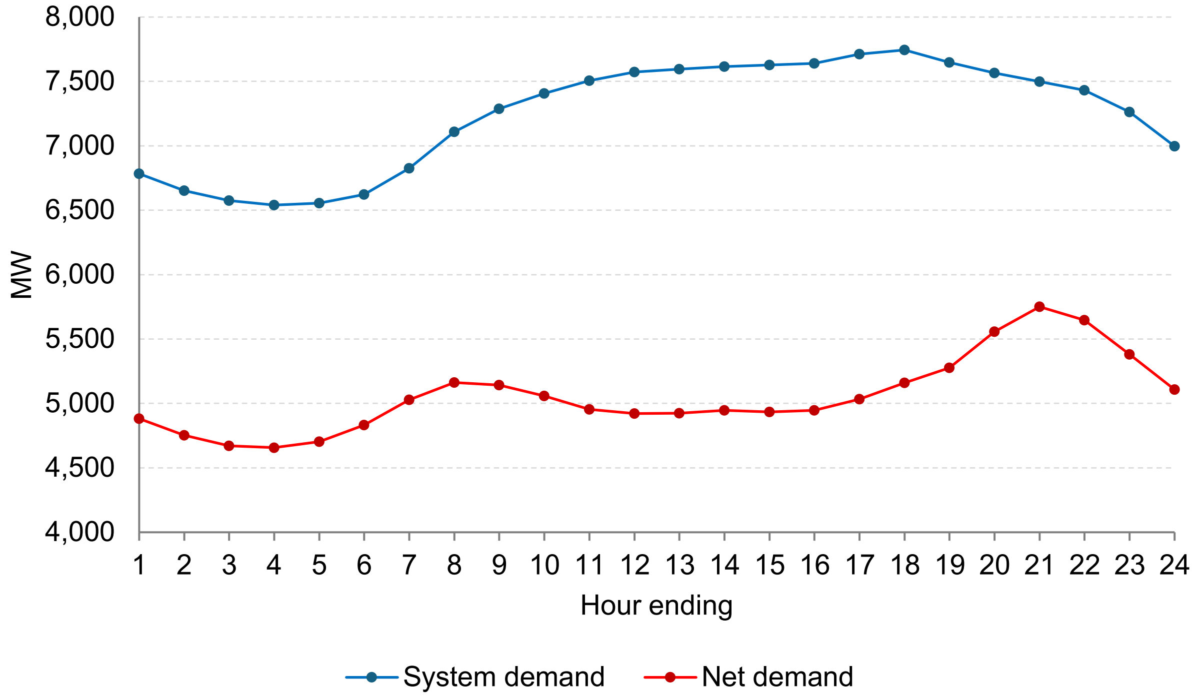


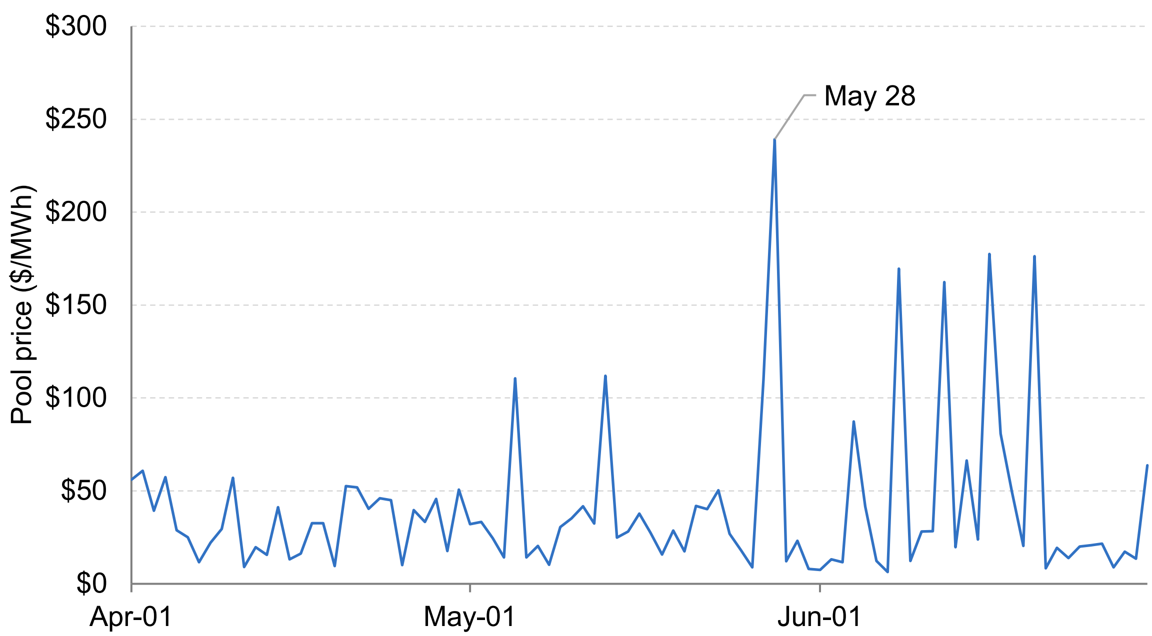
Figure 7: Average system demand and net demand by hour ending (Q2 2025)



1.2.1 Volatile prices, from $999.94 to $0.00/MWh

The daily average pool price on Wednesday, May 28 was $239/MWh, the highest in the quarter (Figure 8). The SMP peaked at $999.94/MWh in HE 20 as the supply cushion fell to 59 MW.

Figure 8: Daily average pool prices (Q2 2025)



In terms of demand, Alberta Internal Load (AIL) on May 28 was highest at 10,879 MW in HE 18 as temperatures increased to 28°C in Edmonton and 30°C in Fort McMurray (Table 3).

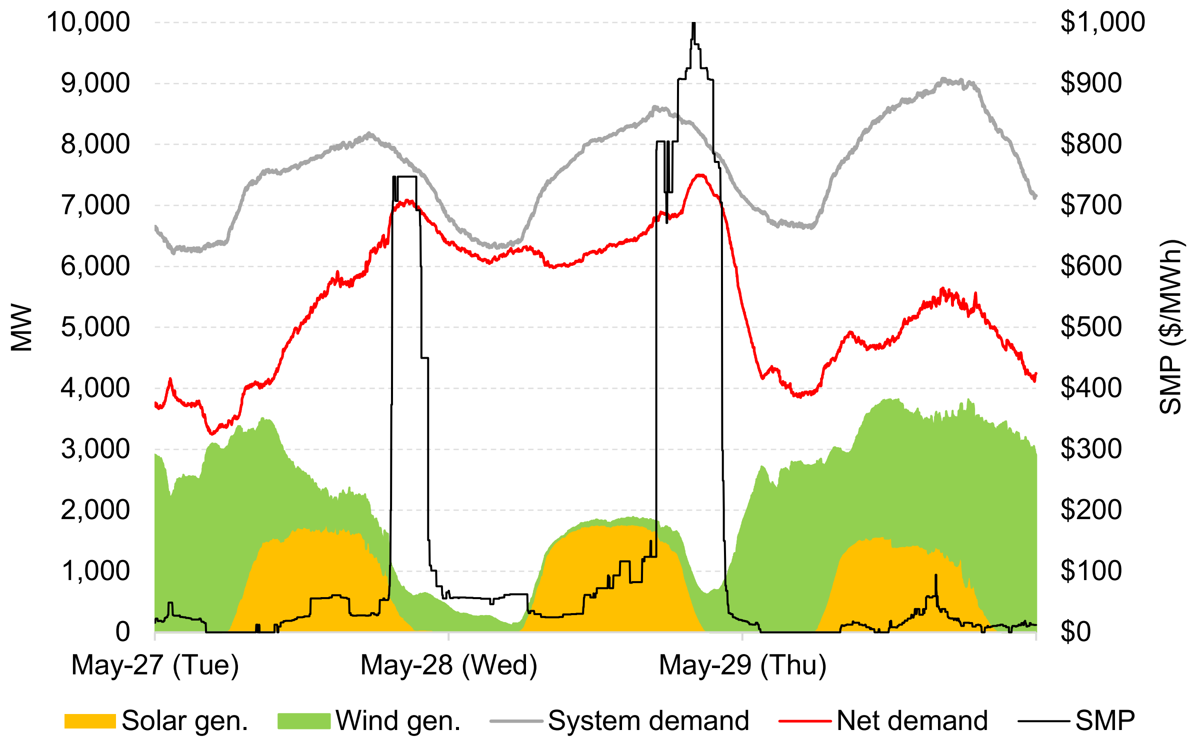
On May 29 AIL was higher still, peaking at 11,362 MW, the highest in the quarter. Despite the higher demand, prices were lower on May 29 than on May 28 because wind generation was higher (Figure 9).

Table 3: Peak hourly temperatures (May 28, 2025)

Location	Temperature (°C)
Calgary	26.3
Edmonton	28.2
Fort McMurray	29.8

Net demand peaked at 7,500 MW on the evening of May 28 before declining to under 4,000 MW in the early hours of May 29 as wind generation increased and demand fell. Because of these changes, the SMP declined from $999.94/MWh at 20:00 on May 28 to $0.00/MWh at 01:31 on May 29 (Figure 9).

Figure 9: Net demand and SMP (May 27 to 29, 2025)



The highest prices on May 28 occurred around the net demand peak as solar generation was declining but demand remained high. When the SMP peaked at $999.94/MWh between 19:56 and 19:59 solar generation averaged 470 MW and wind generation averaged 450 MW.

Generator outages were also a factor in the high prices on the evening of May 28. There were several outages on the evening of May 28, with the major outages being at Base Plant and Genesee Repower 2 (Table 4). The Keephills 2 asset (395 MW) returned from an outage shortly before the event, coming online at 17:35, and was supplying 372 MW when the SMP peaked.

Table 4: Generator outages greater than 100 MW (HE 20 of May 28, 2025)

Asset name	Fuel type	Capacity on outage (MW)
Base Plant	Cogeneration	586
Genesee Repower 2	Combined cycle	466
Poplar Creek	Cogeneration	216
Scotford Upgrader	Cogeneration	195
Syncrude	Cogeneration	170
MEG1 Christina Lake	Cogeneration	157
Dow Hydrocarbon	Cogeneration	145
Bighorn	Hydro	120
Firebag	Cogeneration	112
Cloverbar 2	Simple cycle	101
Cascade 2	Combined cycle	100

In terms of intertie flows on May 28, imports on BC/MATL fully used the 400 MW of import capability during the higher priced hours.

On the Saskatchewan line, in HE 19 and HE 20 the AESO provided 153 MW of emergency exports because Saskatchewan had declared an EEA2. The AESO supplied this power from the Alberta energy market rather than by directing contingency reserves to provide the energy. This contrasts with the approach taken during a similar event on January 20.

The Battle River 4 asset (155 MW) was self-committed by TransAlta for the higher prices on May 28. In particular, the asset came online at 19:35 and was in the process of ramping up when the SMP was highest, supplying around 20 MW.

Despite the high prices and low supply cushion on the evening of May 28, Battle River 5 (395 MW) and Sheerness 1 (400 MW) were commercially offline on long lead time for this event. These assets were not committed by the AESO because of unexpected events occurring well after their start-up window. In this example, the actual supply cushion for HE 21 was lower than forecast due to a generator trip, increased demand, and a reduction in expected intermittent supply.

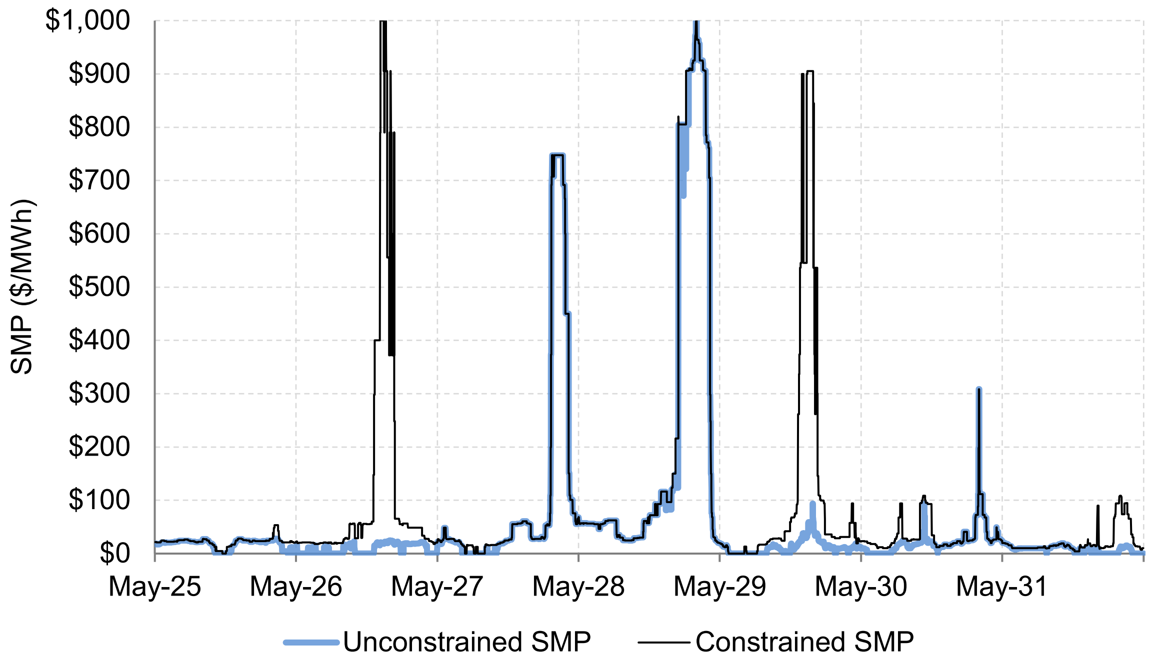
1.2.2 Large difference between constrained and unconstrained prices

The constrained SMP is set by the intersection of demand and the constrained supply curve, where the constrained supply curve excludes supply that is unavailable due to transmission constraints. The unconstrained SMP is calculated by including the supply that is unavailable due to transmission constraints, and the price is set based on the intersection of demand and the unconstrained supply curve. Therefore, when transmission constraints occur the constrained SMP is normally higher than the unconstrained SMP. It is the unconstrained price that sets SMP and pool price in Alberta.

On Monday, May 26 and Thursday, May 29 there were major differences between the constrained and unconstrained SMP (Figure 10). On May 26, the constrained SMP averaged $122.98/MWh while the unconstrained SMP averaged $8.93/MWh. The constrained SMP peaked at $999.96/MWh during HE 15 and HE 16 while the unconstrained SMP remained in the $20/MWh range. The difference between the constrained and unconstrained SMP peaked at $981.07/MWh, the highest in the quarter.

On May 29, the constrained SMP averaged $117.14/MWh while the unconstrained SMP averaged $12.17/MWh. The constrained SMP peaked at $905.45/MWh during HE 16. Between 13:56 and 13:59, the constrained SMP was $900/MWh while the unconstrained SMP was $23.77/MWh, resulting in a price difference of $876.23/MWh, the largest of the day.

Figure 10: Unconstrained SMP and constrained SMP (May 25 to 30, 2025)

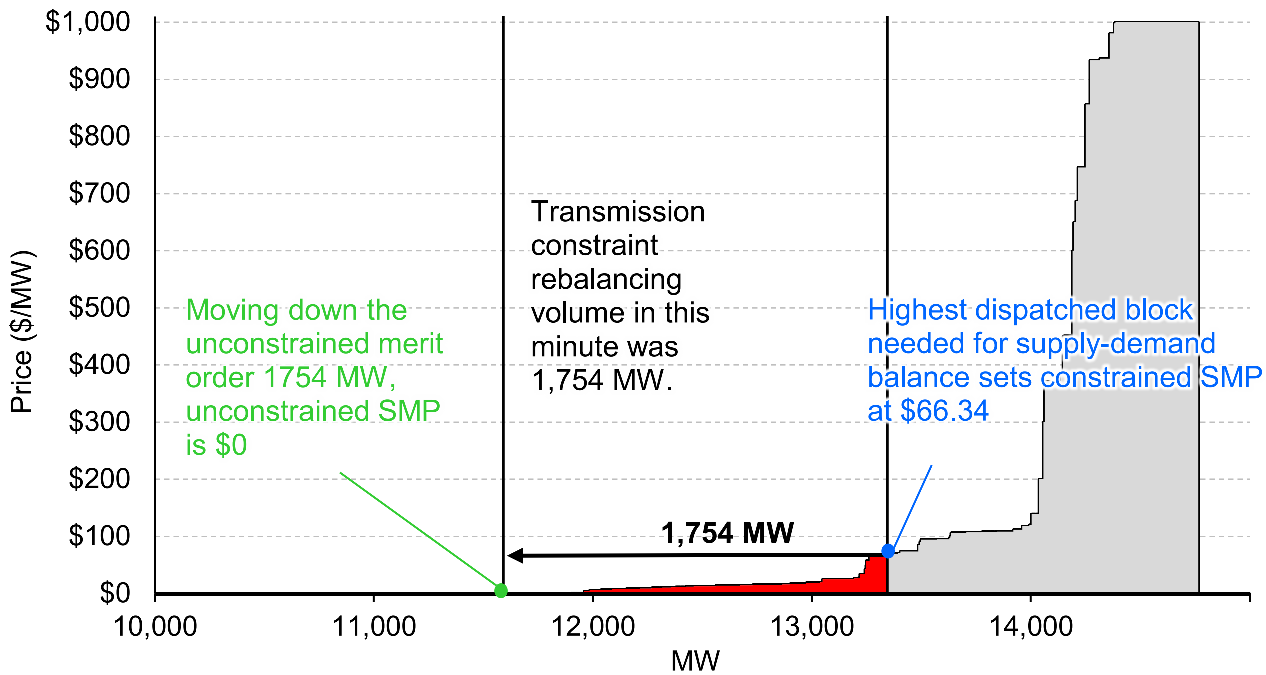


These large differences between the constrained and unconstrained SMP were driven in part by a high volume of transmission constraints, which in turn were influenced by a transmission outage at EATL. The MSA estimates that total constrained intermittent generation (CIG) reached 26 GWh on May 26 and 22 GWh on May 29. Together, these two days accounted for around 15% of the total CIG in Q2.

Periods of high CIG volumes tend to align with high levels of intermittent generation. On May 26 and 29, average wind generation was 2,738 MW and 2,485 MW, respectively - both well above the Q2 average of 1,591 MW. During peak hours, solar generation averaged 834 MW on May 26 and 1,003 MW on May 29, compared to the Q2 average of 872 MW. Overall, wind generation was high on both days, contributing to the high volumes of CIG.

High CIG volumes were not the only driver of the large differences between the constrained and unconstrained SMP on May 26 and 29. For example, the highest hourly volume of CIG in Q2 occurred in HE 19 of May 31 at 1,686 MW. Despite the high volume of CIG in this hour, the highest constrained SMP was just $66.34/MWh while the unconstrained SMP remained at $0/MWh. The prevailing market fundamentals on May 31 meant that prices were clearing low down on the supply curve, where it is relatively flat (Figure 11).

Figure 11: Unconstrained energy market supply curve (May 31 18:56)



In contrast, during some hours on May 26 and 29 the prevailing market fundamentals meant that prices were clearing higher up the supply curve, where it is steeper (Figure 12 and Figure 13). In particular, demand was higher and there were more gas assets on outage on May 26 and 29 relative to May 31.

When intermittent generation is high the unconstrained SMP is normally low as the large volume of intermittent generation supplies the market at $0/MWh. When large volumes of intermittent generation are constrained, higher-priced generation must be dispatched instead, pushing the constrained SMP higher up the supply curve.

On May 26 and 29 this dynamic occurred alongside gas outages and higher market demand, so the constrained SMP rose high up the supply curve. This led to a higher constrained SMP and a significant difference between the constrained and unconstrained prices.

Figure 12: Unconstrained energy market supply curve (May 26 at 14:30)

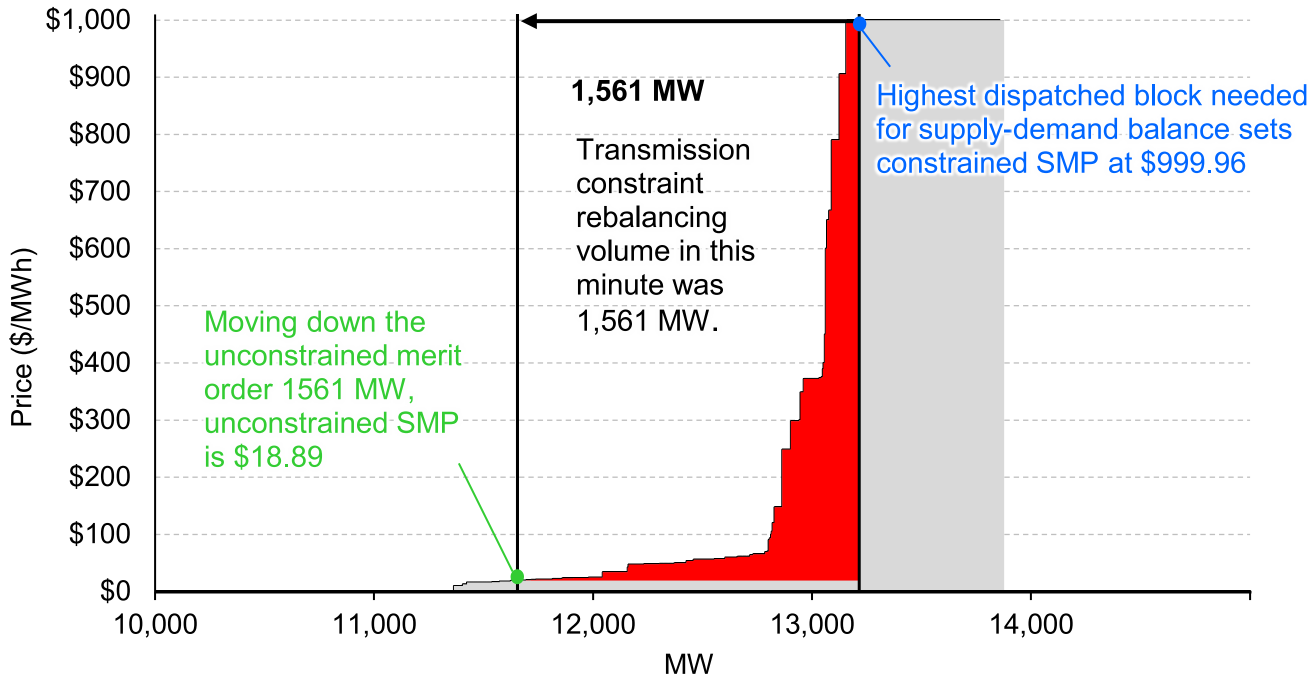
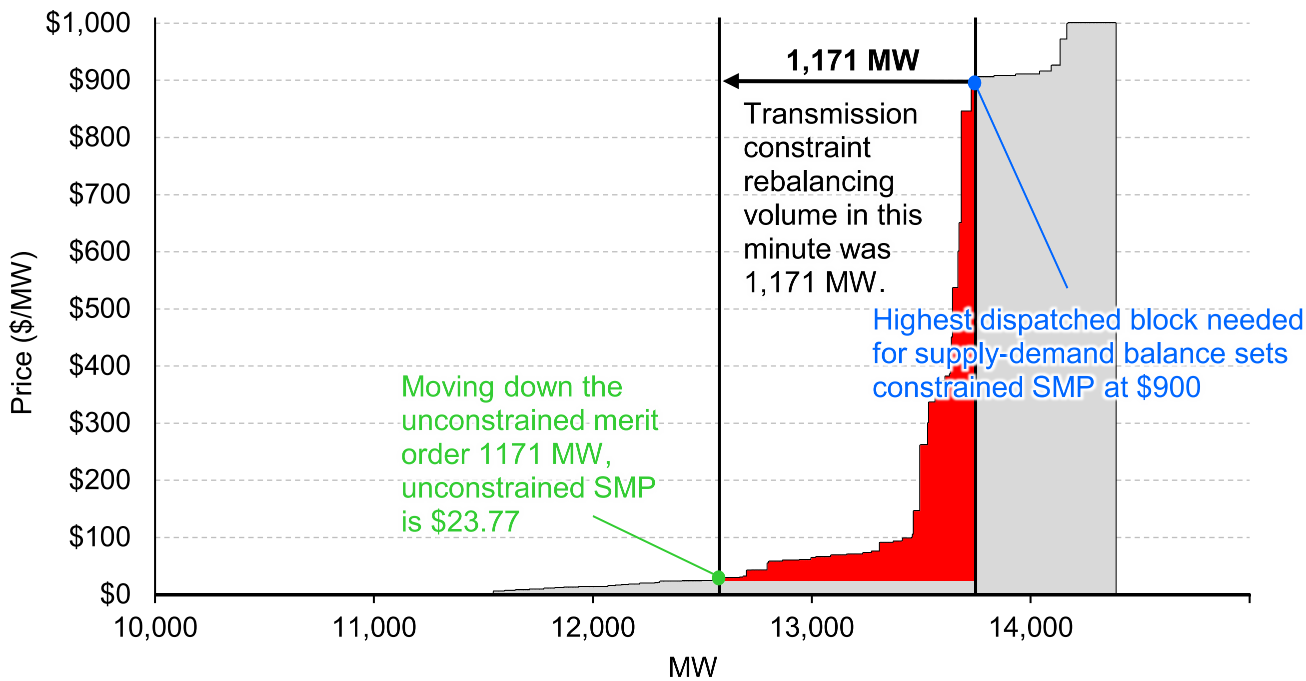


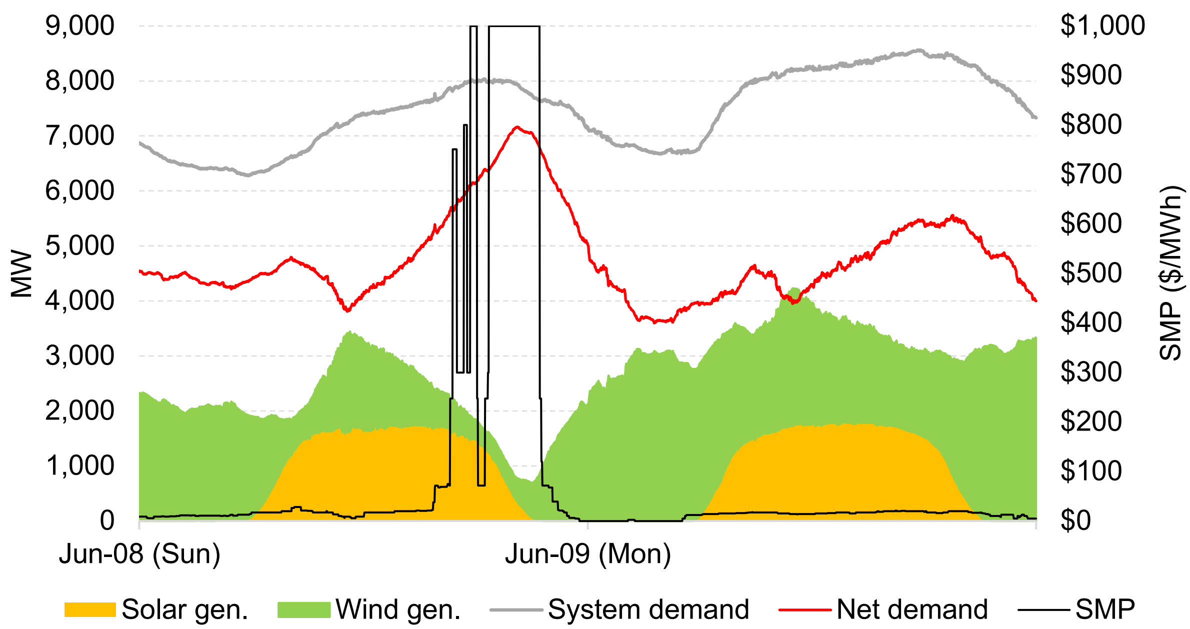
Figure 13: Unconstrained energy market supply curve (May 29 at 13:57)



1.2.3 *SMP at offer price cap on June 8*

From 19:20 to 21:15 on Sunday, June 8 the SMP cleared at the offer price cap of $999.99/MWh indicating very tight market conditions (Figure 14). For periods of time in HE 20 and HE 21 the energy market supply curve was fully dispatched and the supply cushion was 0 MW. However, the AESO did not declare an EEA during this event and operating reserves were not directed to provide energy.

Figure 14: Net demand and SMP (June 8 to 9, 2025)



The tight market conditions on June 8 were driven by several large gas generation outages and low intermittent supply, rather than by increased demand. Moderate temperatures (Table 5) and weekend load levels meant that demand peaked at 10,272 MW in HE 18, which is well below the summer peak of 12,221 MW.

Table 5: Peak hourly temperatures (June 8, 2025)

Location	Temperature (°C)
Calgary	25.7
Edmonton	27
Fort McMurray	22

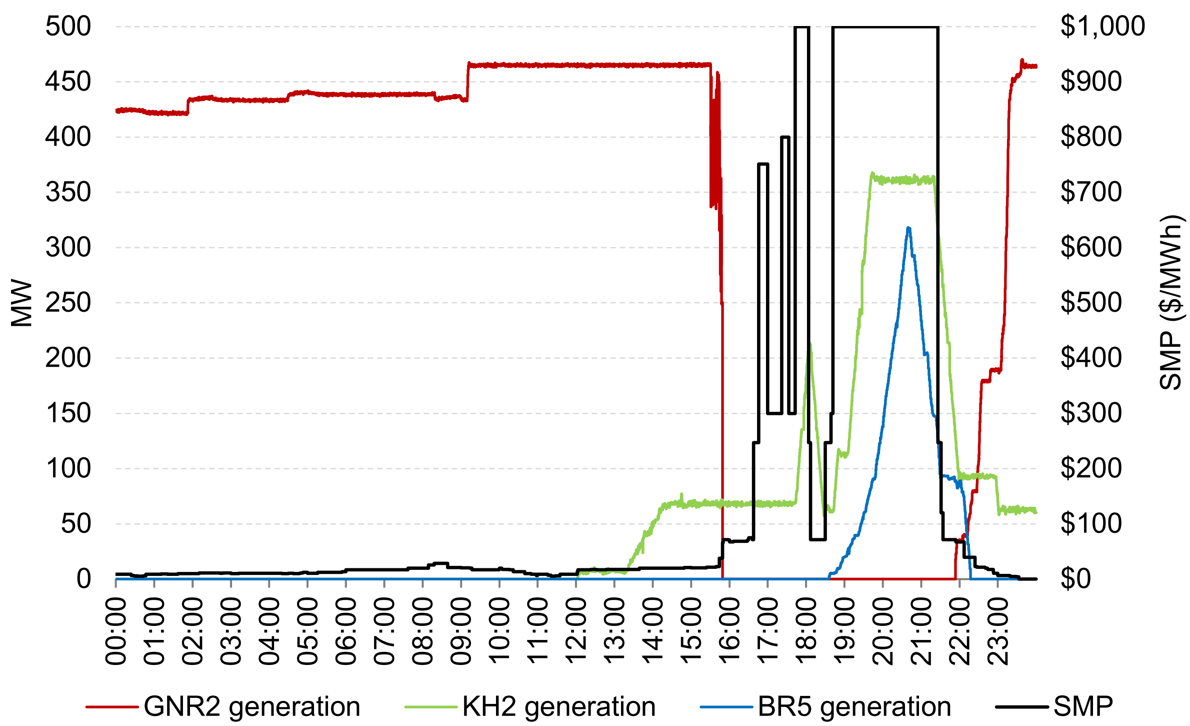
Table 6 provides a list of the large generators that were on outage or heavily derated for the event on June 8. As shown, the major outages were at Baseplant, Genesee Repower 2, and Cascade 1. Base Plant had multiple generation units offline, Genesee Repower 2 tripped offline on a forced outage earlier in the day (Figure 15), and Cascade 1 was offline on a planned outage.

In addition to the capacity on outage, Battle River 4 (155 MW) and Sheerness 2 (400 MW) were commercially offline on long lead time for this event and were unavailable to the AESO for dispatch. These assets were not committed earlier by the AESO because of unexpected markets events, including the trip at Genesee Repower 2. These unexpected events were not considered in the forecast of supply cushion used to determine unit commitment decisions, resulting in the actual supply cushion being lower.

Table 6: Generator outages greater than 100 MW (HE 21 of June 8, 2025)

Asset name	Fuel type	Capacity on outage (MW)
Base Plant	Cogeneration	596
Genesee Repower 2	Combined cycle	466
Cascade 1	Combined cycle	450
Sheerness 1	Gas-fired steam	400
Dow Hydrocarbon	Cogeneration	235
Poplar Creek	Cogeneration	211
MEG1 Christina Lake	Cogeneration	202
Scotford Upgrader	Cogeneration	120
Cascade 2	Combined cycle	105
Cloverbar 2	Simple cycle	101
Christina Lake	Cogeneration	100

Figure 15: SMP and generation of GNR2, KH2 and BR5 (June 8, 2025)



However, the forecast of supply cushion was sufficiently low to trigger an AESO unit commitment for Battle River 5 (395 MW). Battle River 5 was committed by the AESO at 22:41 on Saturday, June 7 for the period of 18:00 to 22:00 on Sunday, June 8. In addition to this, Keephills 2 (395 MW) was self-committed to the market by TransAlta, with the asset coming online in HE 13 (Figure 15).

In terms of intertie flows, the BC/MATL intertie was fully used for imports during this event. However, its capability was derated to around 300 MW due to a line outage on 1L274 and a restatement by a Fast Frequency Response (FFR) provider.

As shown by Figure 14 solar generation was declining over the June 8 event while wind generation was increasing. Between 19:20 and 21:14, when the SMP cleared at the offer price cap, solar generation fell from 900 MW to 27 MW while wind generation increased from 370 MW to 730 MW.

After the event, wind generation continued to increase reaching 2,040 MW by 23:30 (Figure 14). At the same time demand declined, with AIL falling from 9,924 MW at 21:15 to 9,517 MW at 23:30. In addition to this, Genesee Repower 2 returned to the market at 21:53 and ramped to full capacity by 23:36.

These fundamental changes led to a steep decline in the SMP: from $999.99/MWh at 21:14 to $0.00/MWh at 23:33. At 00:33 on June 9 the AESO declared a supply surplus event. This series of events illustrates how volatile the Alberta energy market can be.

1.2.4 Genesee Repower 1 and 2 trip offline simultaneously

The AESO has established a Most Severe Single Contingency (MSSC) limit in Alberta of 466 MW. This is the maximum amount of supply loss the Alberta grid can reliably withstand. Therefore, generators are restricted from supplying more than 466 MW from a single unit contingency because it risks the reliability of the Alberta grid.

It is important to note that the MSSC limit applies at a unit level. Generation assets such as Shepard are still able to generate more than 466 MW because of their configuration. For example, the Shepard asset has a total capacity of 868 MW and is made up of two gas turbines combined with one steam turbine. The largest single contingency at Shepard is the tripping of a gas turbine which would cause the loss of generation from the gas turbine plus the loss of some generation from the steam turbine.

Genesee Repower 1 and 2 are both configured as a single gas turbine combined with a single steam turbine. Therefore, the largest single contingency at each of these assets is the tripping of a gas turbine which would cause the loss of all generation from the asset. Consequently, the AESO have limited the output for each of these assets to 466 MW although each asset has an installed capacity of around 700 MW.

On June 17 at 17:08:54 Genesee Repower 1 and 2 tripped offline simultaneously due to low gas pressure. At the time of the trips unit 1 was generating 449 MW and unit 2 was generating 432 MW for a total supply loss of 881 MW (Table 7).

Table 7: Generation of GNR1 and GNR2 (June 17, 2025)

Time	GNR1 generation	GNR2 generation
17:08:50	449	432
17:08:52	449	432
17:08:54	-1	0
17:08:56	-1	0

The specific sequence of events that caused the simultaneous trips at Genesee Repower 1 and 2 is outlined below:

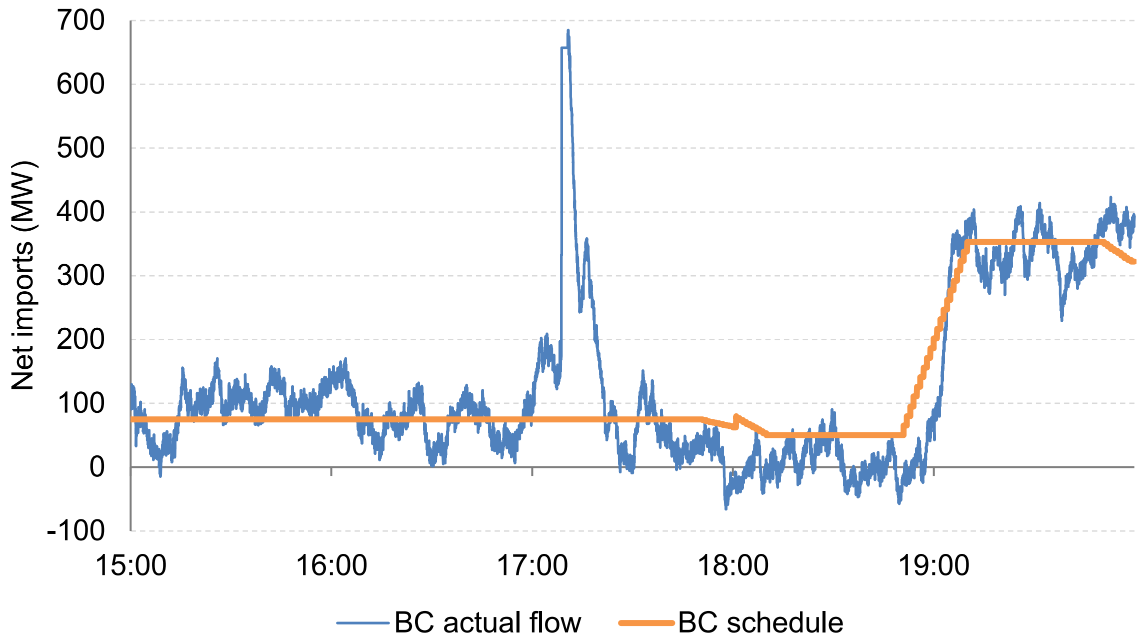
- The event started with a unit 2 steam turbine left hand intermediate pressure turbine governor valve servo failure.
- The servo failure resulted in the turbine governor valve cycling open and closed repeatedly, causing a 50 to 60 MW swing on the output of unit 2.
- The gas turbines on both Genesee Repower 1 and 2 saw the disturbance on the grid (resulting from the swing of unit 2) and responded by cycling 5 MW in what appears to have been a frequency response.
- The control system for each gas turbine provides a MW demand signal to its dedicated fuel gas compressor. As the gas turbines cycled up and down, so did the MW demand signals to the fuel gas compressors.
- The fuel gas compressors saw the cycling MW demand signal and misinterpreted it as a gas turbine runback. This caused the fuel gas conditioning inlet valve to close incrementally with each cycle.
- As the inlet valves closed more and more during each cycle, the fuel gas supply to the gas turbines was reduced until it resulted in a low fuel gas trip condition.

The sudden loss of 881 MW resulted in the Area Control Error (ACE) dropping to negative 1,034 MW. This notably low value indicates that Alberta was importing more than scheduled following the trips. As outlined below, the impact of these trips was largely absorbed by Western Interconnection via the BC and Montana interties.

- On the BC intertie the schedule for the hour was 75 MW of imports but after the Genesee Repower 1 and 2 trips actual imports increased up to 685 MW (Figure 16).

- On the Montana intertie the scheduled flow was for 50 MW of imports but after the trips imports increased up to 266 MW.

Figure 16: Actual and scheduled import volumes on the BC intertie (June 17, 2025)



Because the impact of these trips was absorbed by the Western Interconnection via the BC and Montana interties, system frequency in Alberta did not decline by much, reaching a low of 59.92 Hz.

In response to the Genesee Repower 1 and 2 trips the AESO directed all 501 MW of available contingency reserves to produce energy to normalize flows on the interties (Figure 17). This included directing 271 MW of hydro and 118 MW of battery reserves. In addition to this, the AESO requested 450 MW of reserves from the Western Power Pool for 4.8 minutes beginning around 17:12.

The loss of generation from Genesee Repower 1 and 2 quickly put upward pressure on prices (Figure 18). From 17:44 to 18:00 the SMP cleared at the offer price cap of $999.99/MWh, indicating very tight market conditions although the supply cushion did not fall to 0 MW. The AESO did not declare an EEA and no new directives to contingency reserve providers were issued during this period (Figure 17).

The sudden and unexpected loss of Genesee Repower 1 and 2 did not provide market participants or the AESO with any notice to consider unit commitments for this event. Therefore, there were gas-fired steam assets that were commercially offline and on long lead time. Specifically, Battle River 4 (155 MW), Battle River 5 (395 MW), Sheerness 1 (400 MW), and Sheerness 2 (400 MW) were all commercially offline when the SMP cleared at $999.99/MWh, totalling 1,350 MW in capacity.

Figure 17: Available contingency reserves (June 17, 2025)

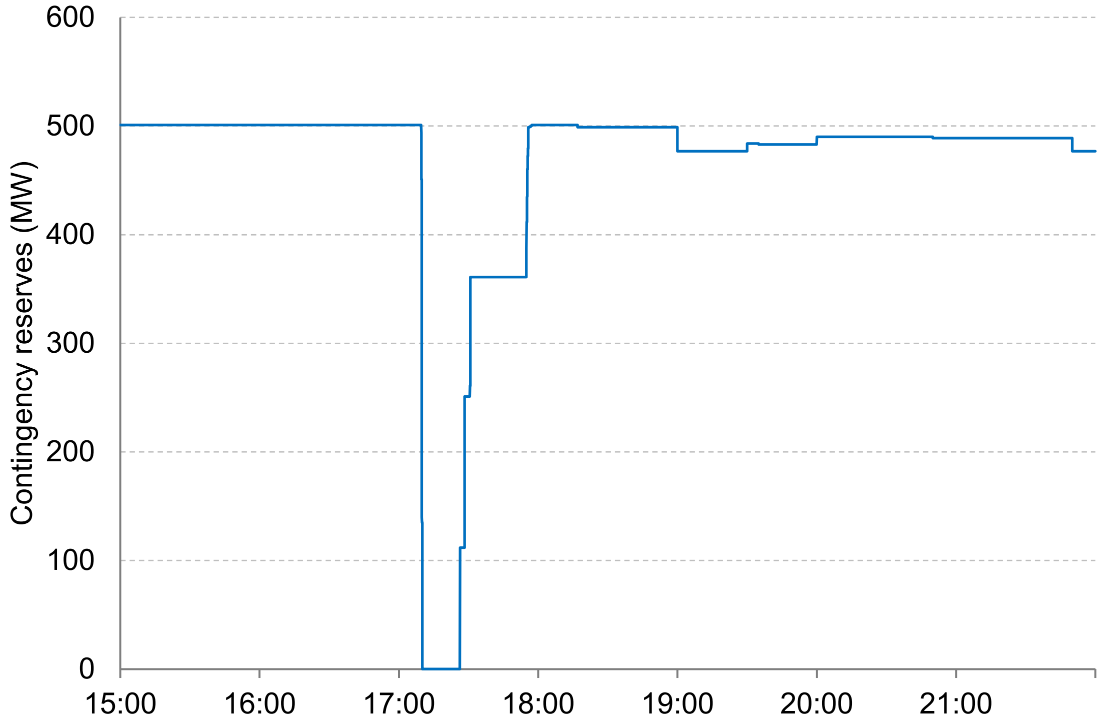
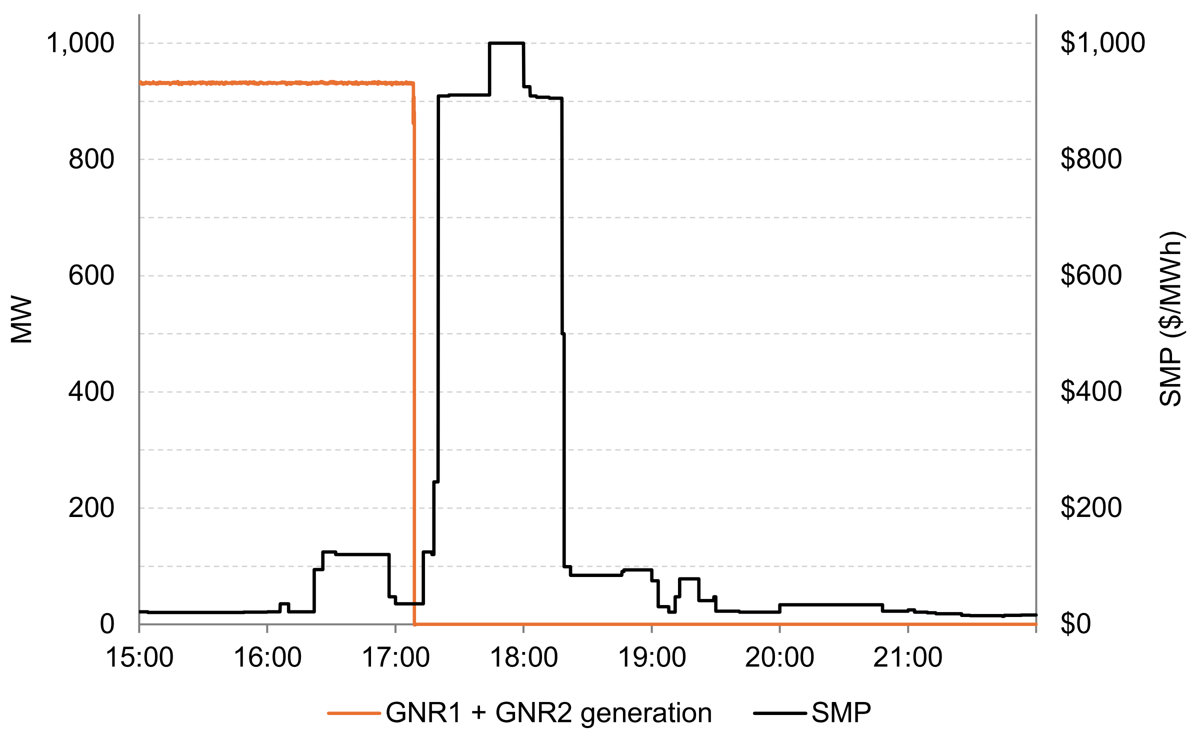


Figure 18: SMP and GNR1 plus GNR2 generation (June 17, 2025)



In addition to this, there were several large gas assets on outage for this event. As shown by Table 8, the major prevailing outages were at Base Plant and Cascade 2.

Table 8: Generator outages greater than 100 MW (HE 18 of June 17, 2025)

Asset name	Fuel type	Capacity on outage (MW)
Base Plant	Cogeneration	596
Genesee Repower 1	Combined cycle	466
Genesee Repower 2	Combined cycle	466
Cascade 2	Combined cycle	450
Poplar Creek	Cogeneration	209
Dow Hydrocarbon	Cogeneration	138
Scotford Upgrader	Cogeneration	120
Firebag	Cogeneration	112
Cloverbar 2	Simple cycle	101

When the SMP was $999.99/MWh wind generation averaged 837 MW and reached a high of 855 MW. During the same period, solar output averaged 912 MW and reached a high of 970 MW. Given the tight market conditions during this event, it is evident that supply adequacy was contingent on the output of intermittent generation.

At the time of the Genesee Repower 1 and 2 trips the schedule on BC/MATL was for 125 MW of imports. Due to the rules around offers on intertie capacity, import flows could not respond to the event immediately. However, scheduled flows on BC/MATL fully used the available import capability of 395 MW beginning in HE 20. When the SMP cleared at the offer price cap in HE 18 import flows on BC/MATL were scheduled for 125 MW.

As shown by Figure 18 prices declined relatively quickly following the event. Between 18:00 and 18:19 the SMP fell by 89% from $925.06/MWh to $99.44/MWh. This decline was the result of wind generation rising, demand decreasing, and the Battle River 4 asset coming online.

Table 9 puts the trips at Genesee Repower 1 and 2 into context by summarizing other large contingency events in recent years. In terms of generation loss, the trips at Genesee Repower 1 and 2 on June 17 were comparable to the trips at Genesee Repower 1 and 2 on November 30, 2024, although there was a sixteen second gap between the trips on that occasion.

Despite the loss of almost 900 MW, the Genesee Repower 1 and 2 trips did not cause a large impact on system frequency. As discussed above, this is because the BC and Montana interties were in service and the Western Interconnection absorbed much of the impact. On June 7, 2020, the BC/MATL intertie tripped offline causing a supply loss of 915 MW and frequency fell much further to 59.17 Hz. The contrast between these events illustrates the importance of the BC/MATL interties for Alberta in managing large contingency events and providing frequency support.

Table 9: Some large contingency events since January 1, 2018 (ordered by generation loss)

Trip event	Date	Generation loss (MW)	Min. ACE (MW)	Min. frequency (Hz)
GNR2 then GNR1	Nov 30, 2024	924	-972	59.91
BC/MATL	Jun 7, 2020	915	-974	59.17
GNR1 and GNR2	Jun 17, 2025	881	-1,034	59.92
Wind generation	Sep 7, 2024	834	-917	59.94
GN1 then GN2	Feb 2, 2024	800	-880	59.93
EGC1	Jul 25, 2023	745	-860	59.93
BC/MATL	Jun 3, 2021	707	-909	59.36
BC/MATL	Jun 22, 2018	689	-939	59.31
SH1 and SH2	Apr 4, 2021	668	-711	59.93

1.2.5 GNR1 and GNR2 testing

On June 2 the AESO announced that Genesee Repower 1 (GNR1) and Genesee Repower 2 (GNR2) would undergo duct firing testing and tuning from June 20 to July 1. As part of this testing both units were expected to operate above the MSSC limit of 466 MW for certain periods, with generation at each unit scheduled to reach up to around 680 MW.[1] Scheduled trip testing of both units also occurred during this time.

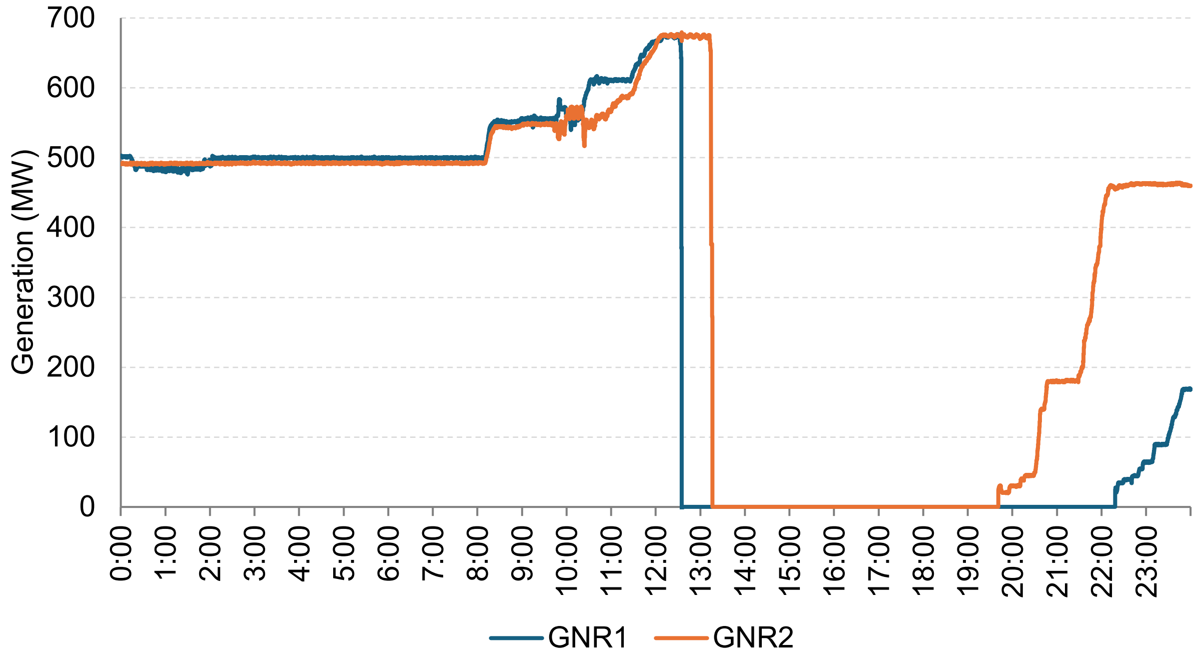
Testing began as scheduled in HE 22 on Sunday, June 20. GNR1 ramped above the MSSC limit within the hour and maintained an output of around 500 MW until HE 08 on June 21. The unit continued ramping up through the morning, reaching a peak output of 677 MW at 12:30, its highest value during the testing period. Four minutes later, GNR1 tripped offline due to a high drum level, with output dropping sharply from 649 MW to 0 MW within a minute (Figure 19).

GNR2 exceeded the MSSC limit during HE 24 on June 20 and held a stable output of around 490 MW through HE 08 on June 21. The unit then ramped up further, reaching its maximum generation of 680 MW at 12:34. At 13:15, GNR2 tripped offline due to a high drum level, with generation falling from 653 MW to 0 MW between 13:14 and 13:16 (Figure 19).

These two trip events caused large deviations in ACE. Following the GNR1 trip, ACE dropped to negative 647 MW at 13:35, prompting the AESO to direct all 477 MW of available contingency reserves to provide energy. Shortly after, the GNR2 trip pushed ACE down to negative 637 MW at 13:16, resulting in the deployment of all 466 MW of contingency reserves. In addition, a 150 MW reserve sharing request was issued to the Western Power Pool and was used for 4.4 minutes.

[1] AESO market updates: Genesee Repower 1 and Genesee Repower 2 generator testing – June 2, 2025

Figure 19: GNR1 and GNR2 generation (June 21, 2025)



Despite the deviations in ACE, system frequency remained stable during these events because of support from the BC and Montana interties. Alberta was heavily exporting to BC during the trip events and export volumes reduced in response (Table 10). This lowered the demand for electricity in Alberta and offset the generation loss. On MATL, export flows were low at the time of these events and Alberta imported power in response to the trips (Table 10).

Table 10: Net imports on the BC and MATL interties at the time of the GNR1 and GNR2 trips (June 21, 2025)

Intertie	GNR1 trip at 12:34		GNR2 trip at 13:15	
	Scheduled net imports (MW)	Actual net imports at trip (MW)	Scheduled net imports (MW)	Actual net imports at trip (MW)
BC	-911	-491	-934	-521
MATL	-24	123	-1	136

Wind generation was high on June 21. In HE 13, average wind generation reached 3,300 MW, increasing to 3,610 MW in HE 14. This helped maintain a large supply cushion and minimized the impact of the unit trips on market prices. Pool prices remained low at $2.73/MWh in HE 13 and $11.58/MWh in HE 14.

Despite the scheduled testing at GNR1 and GNR2 the AESO only procured 466 MW of active contingency reserves for the peak hours of June 21. The AESO's reserve procurement volume did not change materially throughout the testing window, even though both units regularly operated above the MSSC limit.

Figure 20 compares the daily maximum generation from GNR1 and GNR2 during peak hours alongside the contingency reserves procured by the AESO for the peak. On several days during the testing window the maximum generation from GNR1 and GNR2 was higher than the volume of contingency reserves procured.

Figure 20: Maximum generation at GNR1 and GNR2 and on peak contingency reserve volumes (June 20 to July 1, 2025)

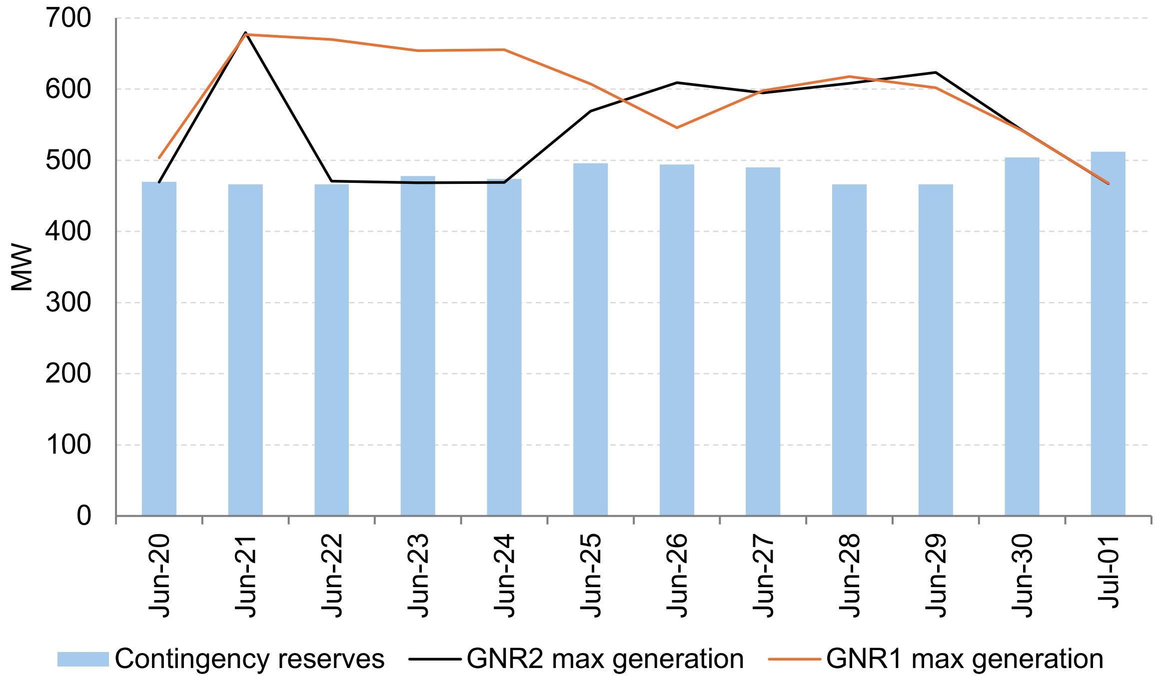


Table 11: GNR1 and GNR2 trips during testing (June 20 to July 1, 2025)

Trip date time	**Asset**	**Generation prior to trip (MW)**	**ACE (MW)**
June 21 12:34	GNR1	649	-647
June 21 13:15	GNR2	653	-637
June 27 01:00	GNR2	523	-430
June 27 22:10	GNR2	523	-473
June 28 22:00	GNR2	532	-271
June 29 12:02	GNR1	523	-430
June 29 22:51	GNR2	531	-438
June 30 23:11	GNR2	526	-46

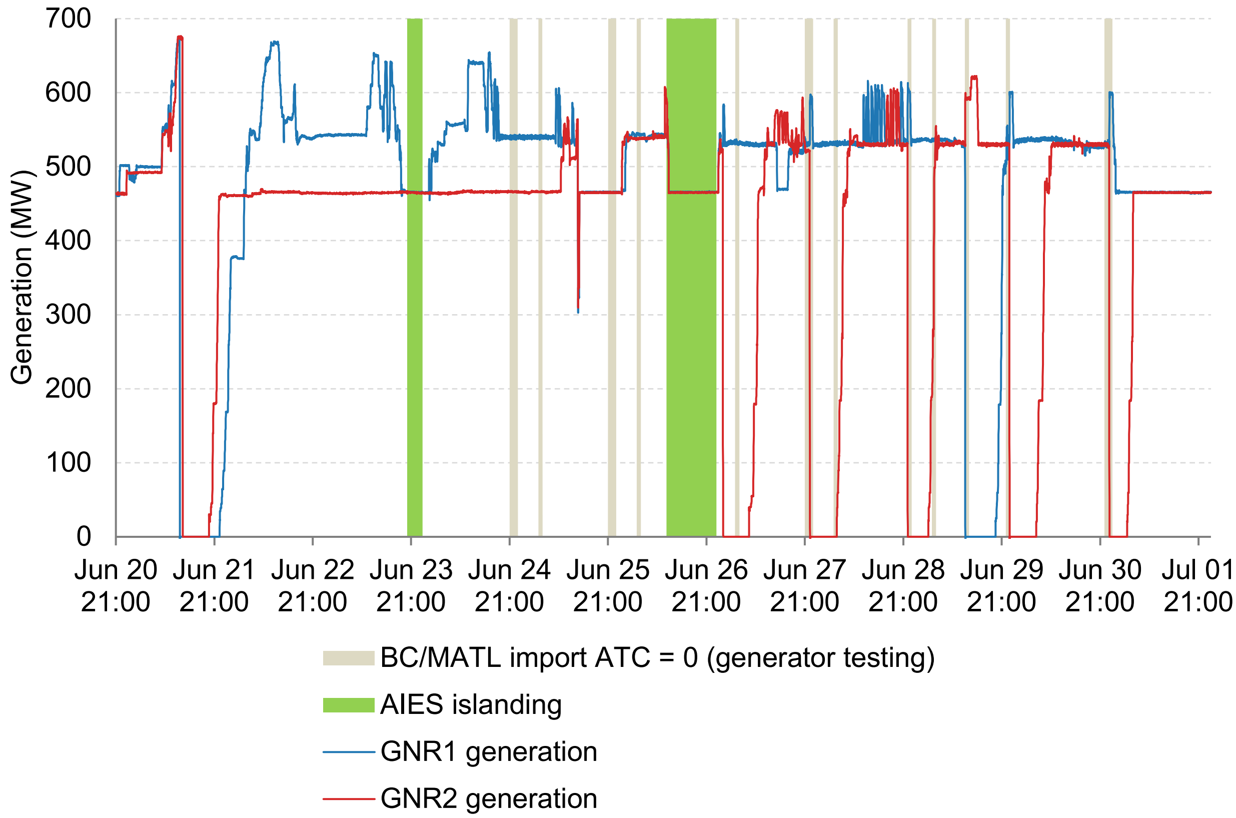
Testing concluded in HE 02 of July 1 for GNR1 and in HE 05 of July 1 for GNR2. Multiple trips were recorded during the testing window, particularly at GNR2. These trip events are summarized in Table 11.

Apart from the trips on June 21, the other trips occurred during scheduled testing hours when the import capability on BC/MATL was set to 0 MW. Figure 21 illustrates how import capability was held at 0 MW for the generator trip events. The figure also highlights two periods when the Alberta grid was islanded during the generator testing. During these islanding events, GNR1 and GNR2 were instructed to lower generation to 466 MW in accordance with the MSSC limit.

Table 12: Hours where BC/MATL import capability was set to 0 MW due to generator testing

Date	HE
June 24	22, 23
June 25	5, 22, 23
June 26	5, 22, 23
June 27	5, 22, 23
June 28	5, 23
June 29	5, 13, 23
June 30	23, 24

Figure 21: GNR1 and GNR2 generation (June 20 to July 1, 2025)



1.2.6 BC/MATL trips affecting export flows

In Q2 there were four trips on the BC and Montana interties, which were initially triggered by trips on the BC intertie. The AESO operates these lines as a shared flow gate (BC/MATL) because a trip on the BC intertie automatically leads to a transfer trip on MATL. When such events occur, the Alberta grid becomes islanded, increasing the risk of system frequency fluctuations following large contingency events, such as a generator trip. During the islanding events in Q2 the AESO maintained an MSSC limit of 466 MW.

On May 31 at 16:20 both the BC and Montana interties went out of service due to a line reactor trip on the BC line 5L92 (Figure 22). At the time of the event, Alberta was exporting 980 MW to BC, just below the export limit of 1,000 MW on that intertie. Following the line trip, system frequency in Alberta increased to 60.49 Hz (Figure 23) and ACE increased to 846 MW (Figure 24).

Figure 22: Net exports on the BC and MATL interties (May 31, 2025)

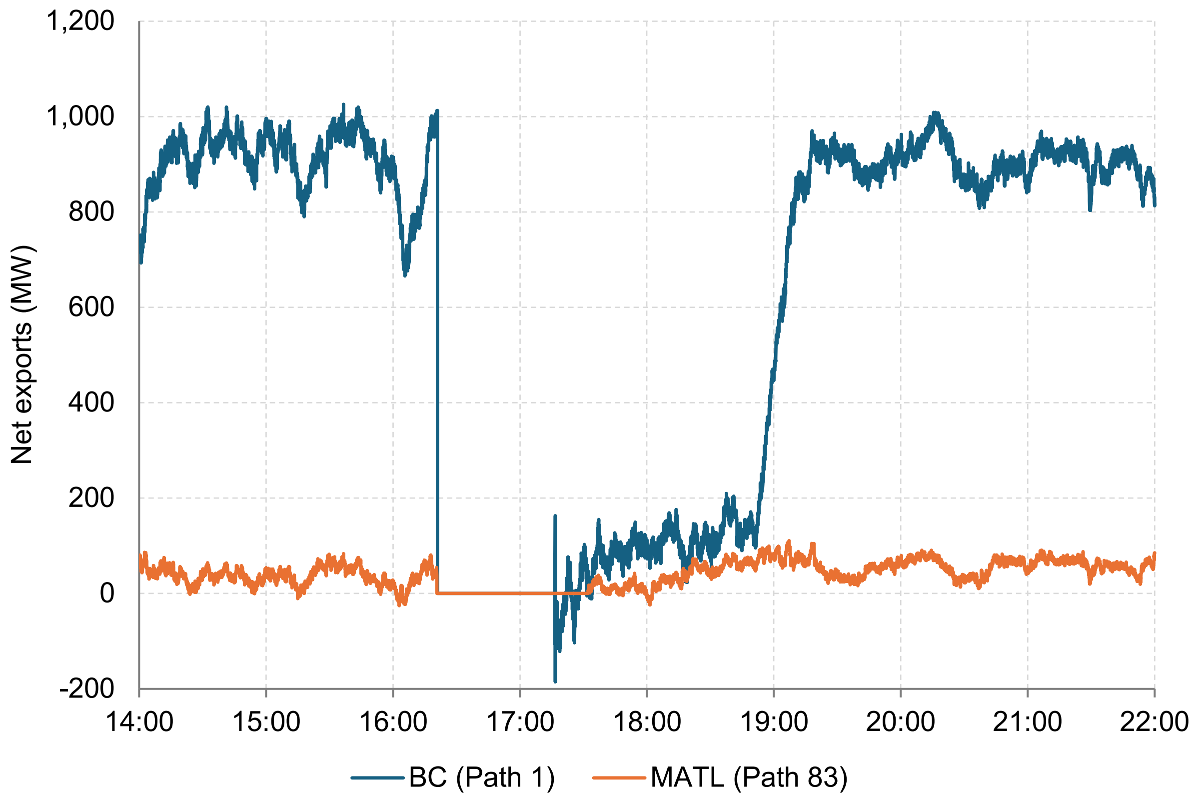


Figure 23: System frequency (May 31, 2025)

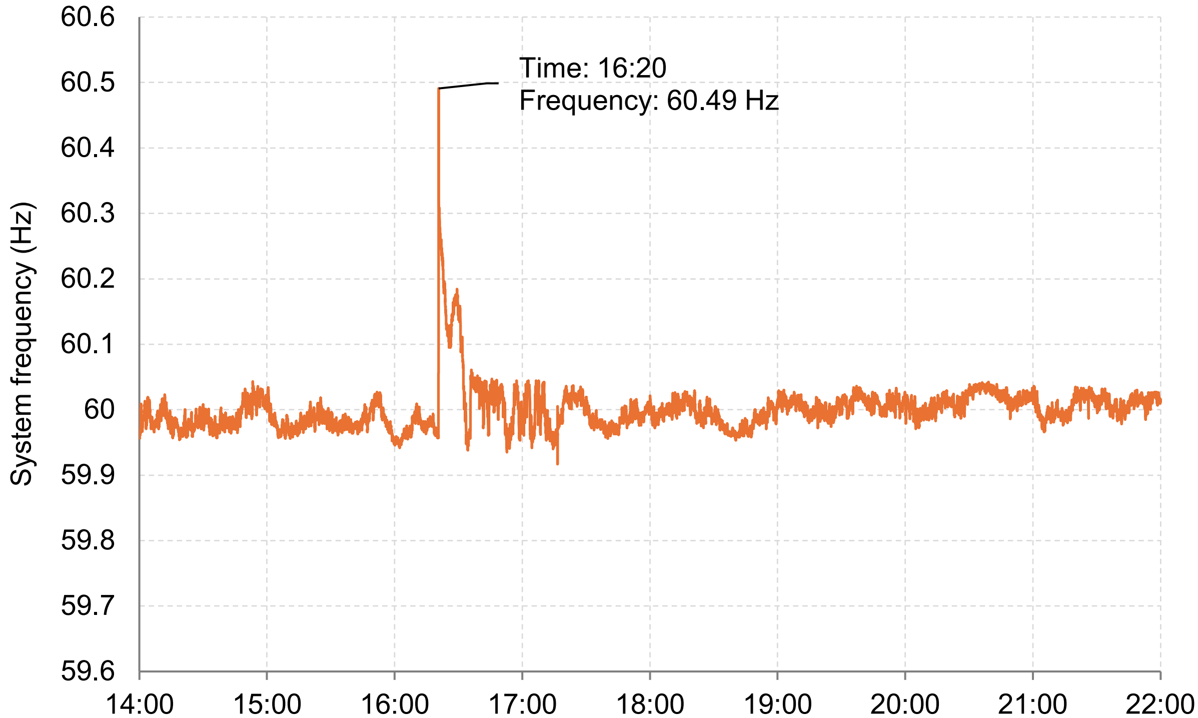
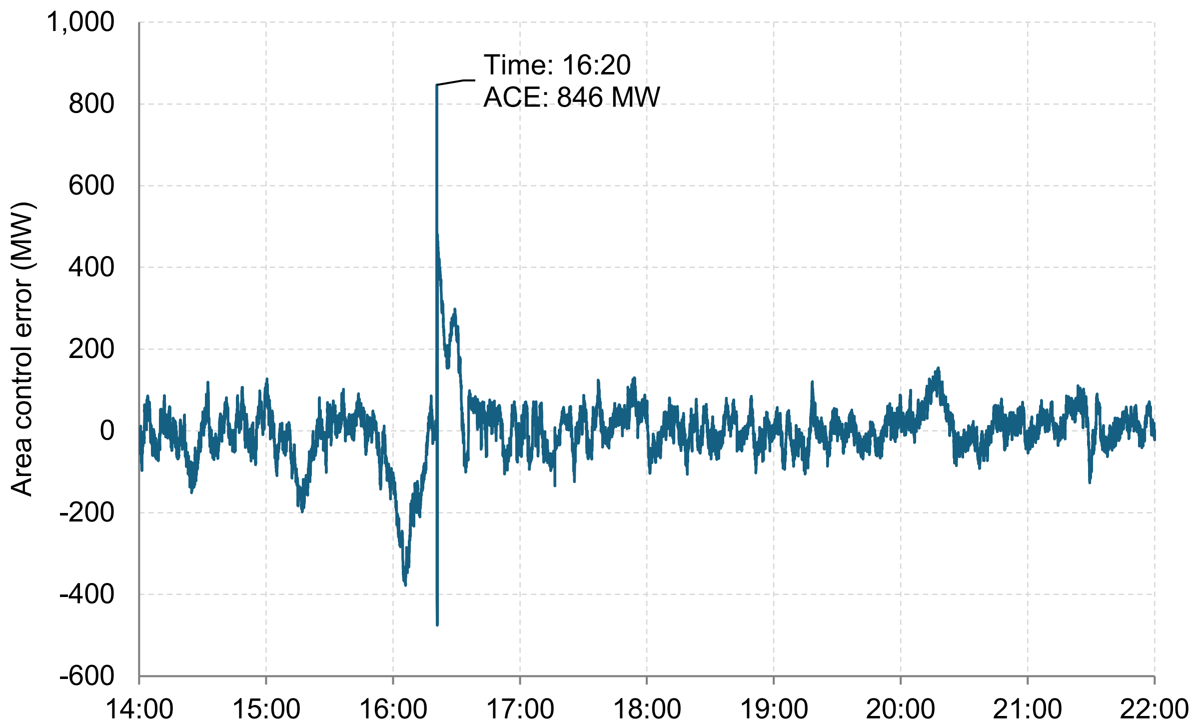


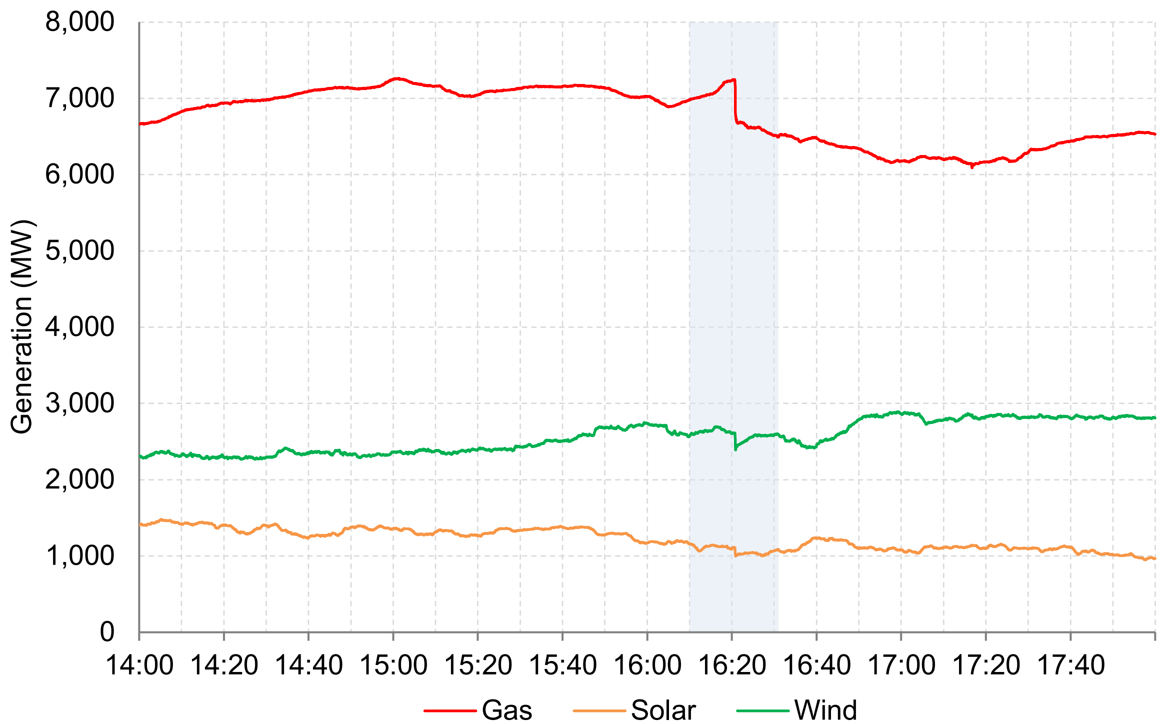
Figure 24: Area control error (May 31, 2025)



Immediately following the BC/MATL trip, generation declined at several gas assets and intermittent supply also declined. For example, at 16:20 Base Plant tripped offline from 260 MW. The drops in generation at the time of the BC/MATL trip are illustrated by fuel type in Figure 25.

The BC and Montana interties were quick to return to service, with BC coming back online at 17:16 and MATL returning at 17:27. The SMP averaged just $0.48/MWh during this islanding event, reflecting the lower demand due to the loss of exports. In addition, wind generation averaged 2,680 MW and solar generation averaged 1,110 MW.

Figure 25: Generation by fuel type (May 31, 2025)



Other BC/MATL trip events occurred later in Q2, specifically on June 23, 25, and 26. Each of these islanding incidents affected system frequency and ACE, as summarized in Table 13. Apart from the event on June 23, the BC/MATL trips each increased system frequency and ACE because Alberta was exporting at the time.

On June 23, Alberta was only exporting 14 MW at the time of the BC/MATL trip, resulting in no immediate system impact. However, 36 minutes later, at 20:38, Keephills 3 tripped offline from 253 MW leading to a decline in ACE and system frequency. ACE dropped to negative 548 MW and frequency fell to 59.66 Hz as the Alberta grid remained islanded.

To help stabilize frequency following contingency events during this period the AESO had armed 49 MW of FFR. This FFR capacity was fully directed following the trip at Keephills 3 and the AESO also directed 250 MW of contingency reserves.

Table 13: BC/MATL trips in Q2

Trip date time	Return to service date time (BC)	Reason	Net exports at trip (MW)	Frequency at trip (Hz)	ACE at trip (MW)
May 31 16:20	May 31 17:16	BC 5L92 trip	980	60.49	846
June 23 20:02	June 23 23:48	BC 5L92 trip	14	60.02	-32
June 25 13:30	June 25 19:43	1201L trip	569	60.31	481
June 26 11:15	June 26 23:25	1201L trip	497	60.33	566

This event highlights the important role of interties in maintaining system stability in Alberta. During normal operations, when the Alberta grid is not islanded, the primary impacts of such generator trips are absorbed by the Western Interconnection via the BC and Montana interties and there is minimal impact on system frequency. However, in this case, with Alberta islanded and no intertie support available, the impact of a small generator trip was a decline in system frequency.

1.3 Market power mitigation measures

In March 2024, the *Market Power Mitigation Regulation* (MPMR) and *Supply Cushion Regulation* (SCR) were enacted. Beginning July 1, 2024, these regulations moderate economic withholding and require the AESO to commit generation capacity under some circumstances.

The MPMR and SCR are implemented through ISO rules 206.1 and 206.2, respectively. On April 20, ISO rule 206.2 was amended following approval in AUC Proceeding 29940. This amendment requires the AESO to post information about unit commitment directives (UCDs) on the AESO website, including issued time, operation start time, and operation end time.[2]

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 Q2, as the MCSINR reached only 14%, 29%, and 45% of the threshold in April, May, and June, respectively. As described in section 1.1, relatively low prices in Q2 were driven by increased gas generation capacity and higher solar generation.

[2] See the current and historical "Unit Commitment Directives" reports on ets.aeso.ca.

The MCSINR being highest in June was primarily the result of more high price outlier events. During most hours of Q2, pool prices were near the theoretical variable cost of the reference combined cycle unit, leading to negligible net revenues. Even in June, net revenues were below 0.1% of the threshold in approximately 89% of hours and were negative in 37% of hours. However, net revenues accumulate quickly during high pool price events. For example, during the June 8 price cap event described in section 1.2.3, the MCSINR accumulated over 6% towards the threshold between HE 17 and HE 21, while average pool price was $631.84/MWh.

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

In previous quarterly reports, the MSA included a table listing each UCD. With this data now available on the AESO website, the MSA will omit this table going forward.

In Q2, 32 UCDs were issued; however, as described below, two of these UCDs were due to a UCD process error and did not result in assets being committed. Therefore, in effect, there were 30 UCDs in Q2. This is a significant increase compared to the 13, 10, and 1 UCDs issued in Q3 2024, Q4 2024, and Q1 2025, respectively.

While this quarter was the first Q2 subject to the interim measures, it is not unusual for the second quarter to periodically experience low supply cushion, as market participants schedule outages to take advantage of mild weather and spring run-off conditions. Therefore, when higher demand or unexpected outages occur, there is often less available capacity compared to other times of the year.

Table 14 shows the estimated price effect of the 30 UCDs in Q2. Over the quarter the MSA estimates that the average pool price was lowered by $2.86/MWh or 7% because of the UCDs.

Table 14: Estimated price impact of unit commitment directives in Q2 2025

Time period	**Actual average pool price ($/MWh)**	**Estimated average pool price without unit commitment directives ($/MWh)**	**Percentage change (%)**
April 2025	$33.69	$37.61	-10%
May 2025	$40.99	$43.21	-5%
June 2025	$46.75	$49.22	-5%
Q2 2025	**$40.48**	**$43.34**	**-7%**

UCDs are triggered to increase available supply in hours of low anticipated supply cushion, and therefore they can lower pool prices. However, in Q2 there were still hours of low supply cushion and high pool prices that occurred while gas-fired steam assets were on long lead time. Some of these events are outlined in section 1.2. Generally, these events occurred when actual generator outages, demand, or intermittent supply were significantly different than forecast.

1.3.2.1 Unit commitment directives issued on April 3, 2025

As reported on the AESO website, the AESO issued three UCDs on April 3: two to Battle River 4 (BR4), and one to Battle River 5 (BR5). The first UCD, issued at 19:45, required BR4 to operate from 06:00 to 10:00 on April 4. At 19:46, a second UCD was issued to BR5 for the same period as the first UCD, and a third UCD was issued to BR4 to operate from 20:00 on April 3 to 00:00 to April 4.

The second UCD to BR5 occurred because the UCD process did not update to consider the UCD already issued to BR4. The third UCD to BR4 to start immediately occurred because the UCD process mistakenly considered BR4 to be already online. Ultimately, the system controller instructed the market participant to respond only with BR5 and disregard the two UCDs to BR4.

On May 1, the AESO enhanced the UCD process to correct the issue that led to BR4 incorrectly being considered online.

1.4 Market power, offer behaviour, and net revenues

1.4.1 Market power

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

Table 15 provides average actual and counterfactual prices by month in Q2 of 2024 and 2025. In Q2 2025 average mark-ups were highest in June at $20.37/MWh and lowest in April at $6.55/MWh. While the cost-based counterfactual prices remained comparable across the months in Q2, actual prices were highest in June and lowest in April. In April, increased competition was driven by higher thermal availability while the higher mark-ups in June were driven by gas generator outages and lower wind generation. The average mark-up in Q2 was $13.97/MWh which is comparable to the average mark-up of $13.43/MWh in Q2 2024.

Table 15: Average actual and counterfactual prices by month (Q2 2024 and Q2 2025)

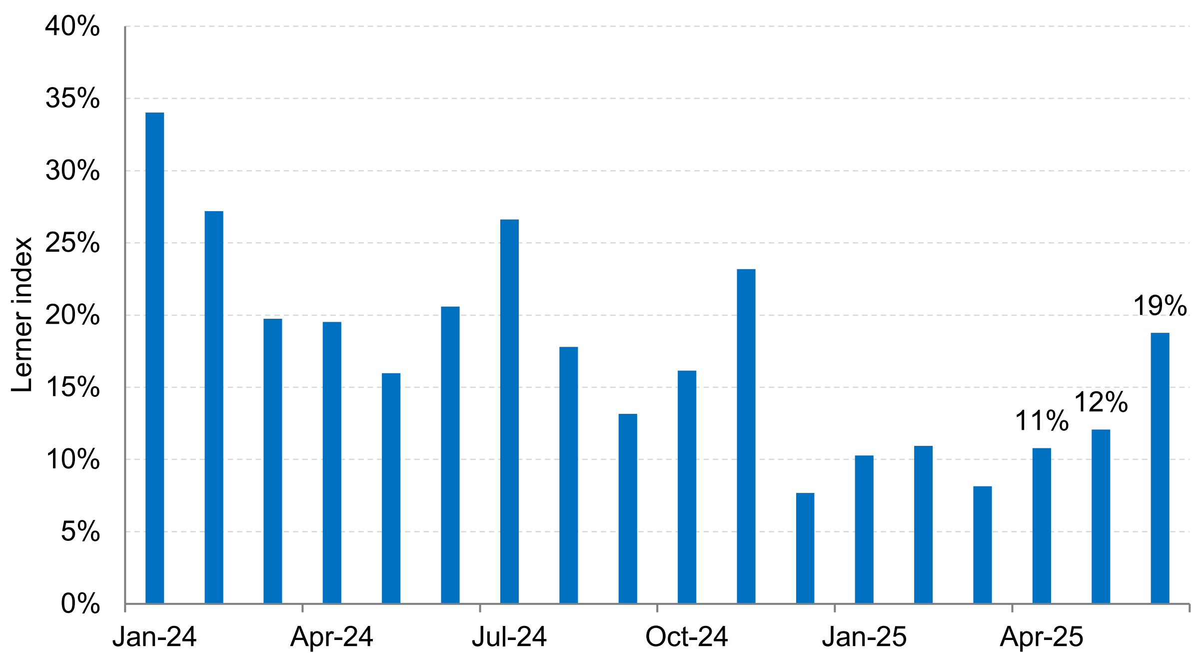
	2024			2025		
	Actual	**Counterfactual**	**Difference**	**Actual**	**Counterfactual**	**Difference**
April	$68.61	$49.00	$19.61	$33.69	$27.14	$6.55
May	$35.37	$23.78	$11.59	$40.99	$26.04	$14.95
June	$31.85	$22.69	$9.16	$46.75	$26.38	$20.37
Q2	**$45.17**	**$31.73**	**$13.43**	**$40.48**	**$26.51**	**$13.97**

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

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

Figure 26 illustrates the monthly average Lerner index going back to January 2024. In this analysis the Lerner index is set to zero in hours where the actual price is less than the counterfactual price, meaning there is no market power assumed in these hours. In Q2 the average Lerner index was 14% which is slightly lower than the 19% observed in Q2 2024.

Figure 26: Average Lerner index by month (January 2024 to June 2025)

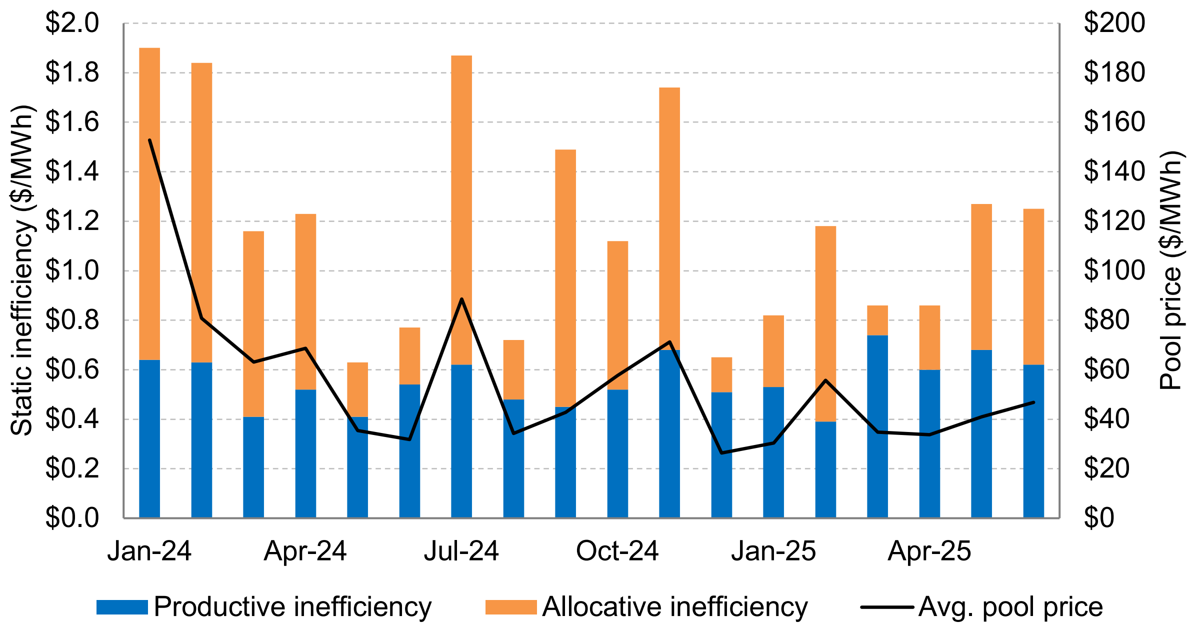


The exercise of market power can lead to static inefficiencies in the short-run, specifically productive and allocative inefficiencies. Productive inefficiencies occur when lower cost generating assets are priced out of the market and higher cost assets supply power instead.

Allocative inefficiencies occur when the exercise of market power leads to prices above SRMC and demand is lowered as a result. In the context of Alberta's energy only market these short-run inefficiencies should be weighed against long-run efficiencies, including the supply of new capacity. Short-run inefficiencies are tolerable to the extent that long-run efficiencies are contingent on them.

Total static inefficiencies averaged $1.13/MWh in Q2 compared to $0.87/MWh in Q2 2024. The higher static inefficiencies this year were caused by higher allocative inefficiencies in May and June (Figure 27). In turn, the higher allocative inefficiencies in May and June were driven by higher prices in a relatively small number of hours when suppliers exercised market power.

Figure 27: Average productive and allocative inefficiencies by month (January 2024 to June 2025)



One way to analyze the ability of firms to exercise market power is to calculate the extent to which they are pivotal to the clearing of the energy market. A firm is said to be pivotal when its withholdable capacity is needed for demand to be met.[3]

In recent years the ability of firms to exercise market power has declined as new gas capacity has come online and additional intermittent capacity has been developed. For example, in June of 2023 at least one firm was pivotal in 28% of hours compared to 2% of hours in June 2024 and 6% of hours in June 2025 (Table 16).

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

In Q2 the ability of firms to exercise market power was highest in June. Across the quarter at least one firm was pivotal in 5% of hours which is comparable with Q2 2024 when at least one firm was pivotal in 4% of hours (Table 16).

Table 16: The percent of time where at least one firm was pivotal (Q2 2023, Q2 2024, and Q2 2025)

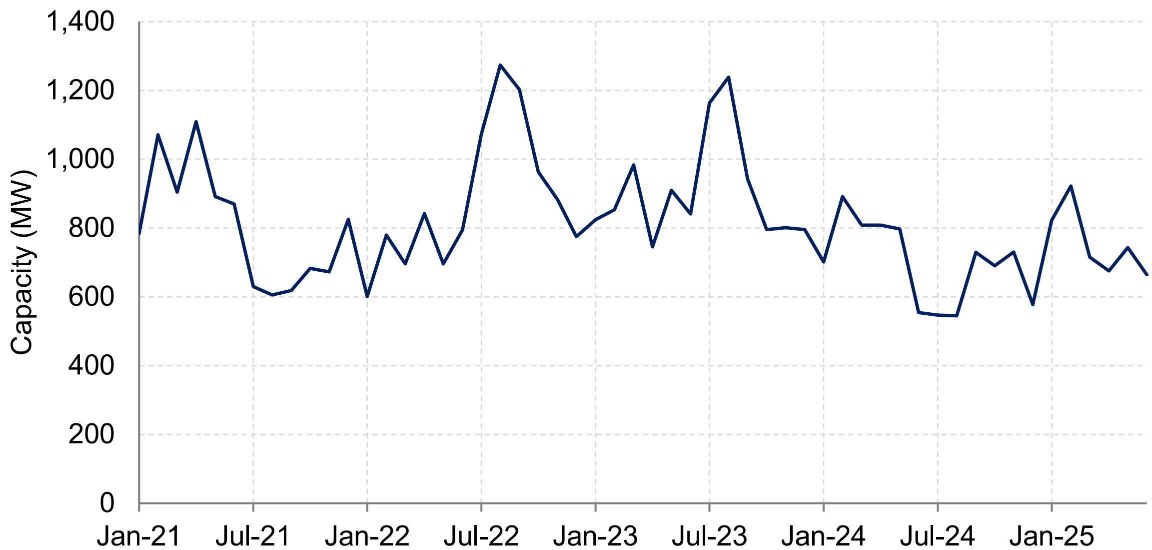
	2023	**2024**	**2025**
April	10%	9%	4%
May	16%	1%	3%
June	28%	2%	6%
Q2	**18%**	**4%**	**5%**

1.4.2 Offer behaviour

Economic withholding by a market participant is an offer strategy in which available capacity is offered into the power pool at a price sufficiently in excess of its SRMC and opportunity cost such that it is not dispatched and the pool price is raised as a result.

The amount of economic withholding in the energy market has declined in recent years as competition has increased due to the addition of new gas and intermittent generation capacity. Figure 28 illustrates the average amount of non-hydro capacity that was offered above $250/MWh by month since January 2021. In August and September of 2022 this average increased above 1,200 MW and there were similar highs in the summer of 2023. Since then, the average amount of non-hydro capacity offered above $250/MWh has rarely increased above 800 MW, and in Q2 the average was 695 MW.

Figure 28: Average amount of non-hydro capacity offered above $250/MWh by month (January 2021 to June 2025)



However, in a relatively small number of hours in the market supply-demand balance is sufficiently tight, and some large suppliers continue to exercise market power. This typically occurs in the evening hours around the net demand peak.

In Q2 the amount of capacity offered above $250/MWh was highest in early May at around 1,300 MW (Figure 29). During this period the entire capacity of Cascade 2 (450 MW) was offered at the price cap as the asset was taken commercially offline due to low demand and high levels of intermittent supply; as a result pool prices were relatively low.

In late May and on several days in early June the offer behaviour of larger suppliers increased pool prices. As an example, Figure 30 illustrates the supply curve for HE 21 of May 28.

Figure 29: The amount of non-hydro capacity offered above $250/MWh during the highest priced hour of the day (Q2 2025)

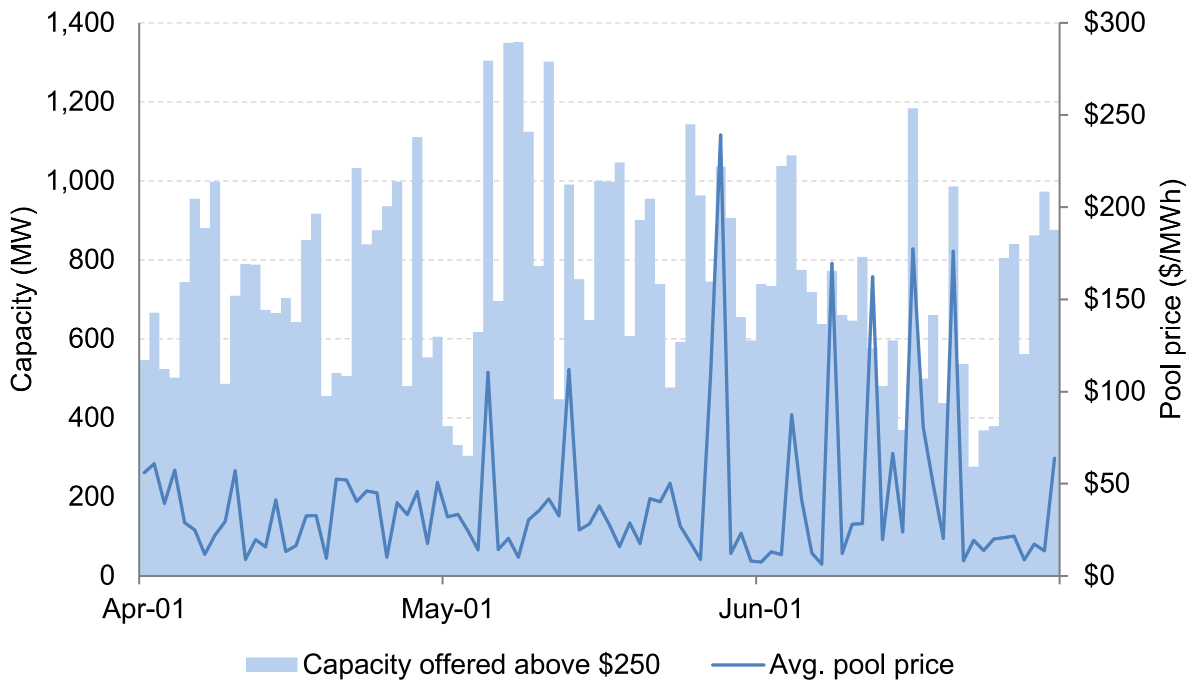
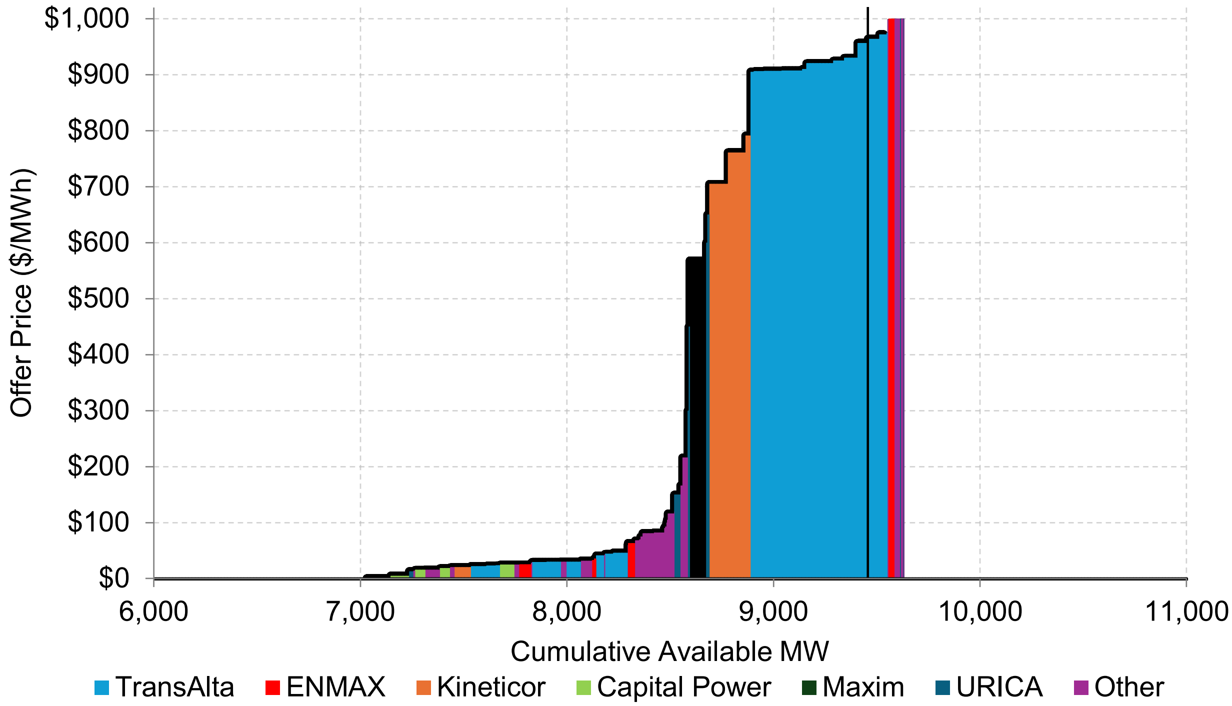


Figure 30: Energy market supply curve (HE 21 of May 28, 2025)



1.4.3 Net revenues

Net revenue analyses add context to observed pool prices because they compare prices to a set of assumed costs for hypothetical assets to examine the profitability of the energy market for different asset types. The net revenue analysis presented here looks at four generation types that are present in the Alberta energy market: simple cycle, combined cycle, wind, and solar. Table 17 provides the cost assumptions used in the analysis. These cost assumptions are taken from the AESO's 2024 Long Term Outlook and are adjusted for inflation using the Consumer Price Index.[4]

Table 17: Cost assumptions used in the net revenue analysis (2025$)

Parameter	Simple cycle	Combined cycle	Wind	Solar
Size (MW)	47	418	100	50
Net overnight capital costs ($/kW)	$1,709	$1,577	$1,088	$1,200
Fixed O&M ($/kW-year)	$23.71	$20.51	$90.03	$27.47
Variable O&M ($/MWh)	$6.83	$3.71	$0.00	$0.00

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

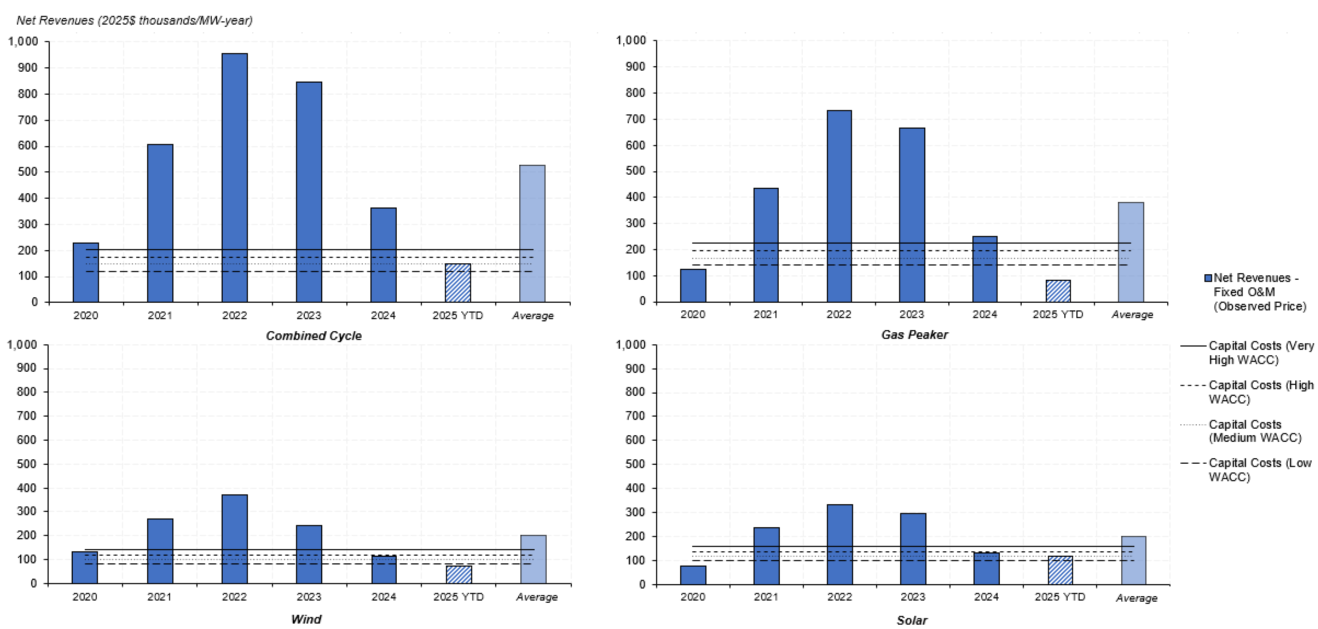
Net revenues calculate the revenues different generating technologies could have earned in the energy market based on observed pool prices less their variable costs of production. For a detailed description of the calculation methodology used to calculate net revenues for the different asset types see Appendix A of the MSA's Q2 2022 report.[5] Generators incur fixed operating and maintenance (O&M) costs on an annual basis, and these are subtracted from the net revenues to be compared with annual capital costs.

The vertical bars in Figure 31 illustrate the estimated annual net revenues less fixed O&M costs. For 2025, the net revenues up to June 30 are doubled so they can be compared with the annual fixed O&M costs and reported as a year-to-date figure. The dashed lines in Figure 31 illustrate simple estimates of the annualized capital cost of generation capacity, including a return on and of capital for different weighted average costs of capital (WACC).[6]

Pool prices have been relatively low so far in 2025 with an average price of $40.14/MWh over Q1 and Q2. As shown by Figure 31, the low pool prices so far this year have meant that some generation types have not earned sufficient net revenues to cover their capital costs.

Specifically, based on doubling net revenue estimates so far in 2025, the hypothetical simple cycle asset has covered 49% of its annual capital costs assuming a WACC of 8.5%, and the hypothetical wind asset has covered 72% of its annual capital costs so far in 2025. The hypothetical combined cycle and solar assets fared better and are both estimated to have covered 101% of their annual capital costs based on doubling net revenues so far in 2025.

Figure 31: Net revenues by year (2020 to 2025 YTD)

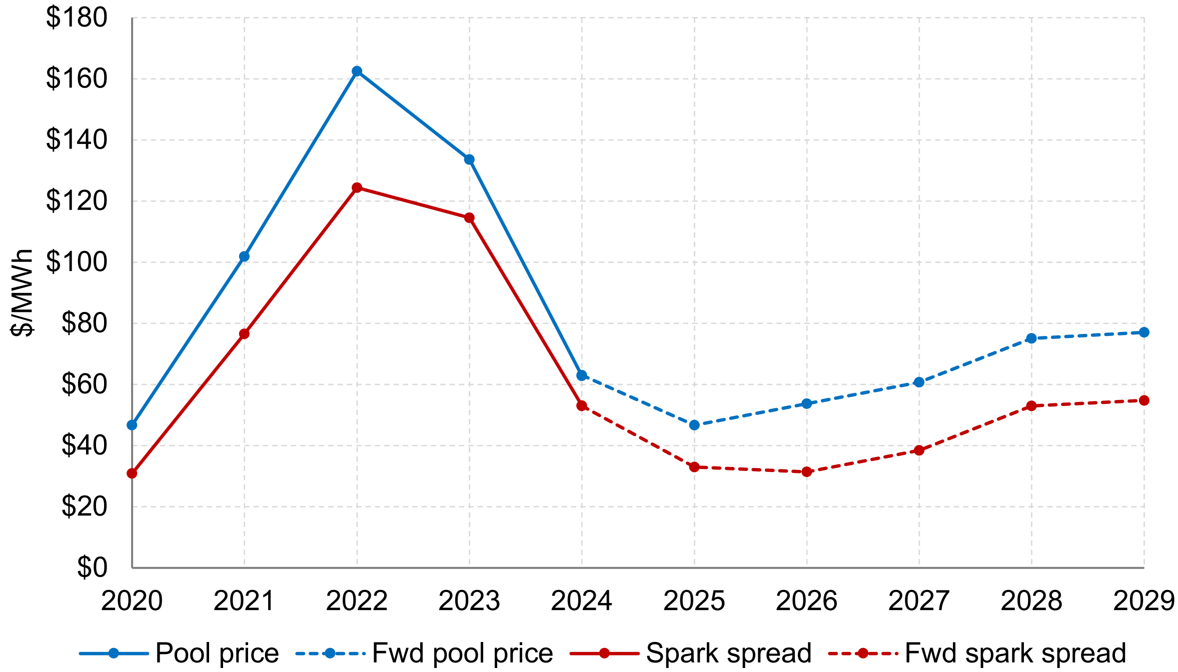


[5] MSA Quarterly Report for Q2 2022 at page 69

[6] Low is 6.5%, medium is 8.5%, high is 10.5%, and very high is 12.5%

While current pool prices are quite low, prices have been higher in recent years and they are expected to rise again in the coming years, although not to the same levels seen historically (Figure 32). As of June 30, the average pool price for 2026 was priced at $53.75/MWh in the forward market, while 2027 was priced at $60.75/MWh, and 2028 was priced at $75.05/MWh.

Figure 32: Pool price and spark spread by year, forward prices as of June 30 (2020 to 2029)



1.5 Carbon emission intensity

Carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The MSA has published analysis on the carbon emission intensity of the Alberta electricity grid in its quarterly reports since Q4 2021. The MSA's analysis is indicative only, as the MSA has not collected the precise carbon emission intensities of assets from market participants but has relied on information that is publicly available. The results reported here do not include imported generation.[7]

1.5.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in each hour. Table 18 shows the minimum, mean, and maximum hourly average emission for Q2 over the past seven years. Notably, the mean hourly average emission intensity for Q2 2025 (0.37 tCO2e/MWh) was close to the minimum hourly average emission intensity for Q2 2022 (0.36 tCO2e/MWh). Table 19 shows the same summary

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

statistics for the past four quarters, demonstrating stability in the hourly average emission intensity.

Table 18: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2019 Q2	0.50	0.64	0.76
2020 Q2	0.45	0.58	0.68
2021 Q2	0.45	0.58	0.68
2022 Q2	0.36	0.49	0.61
2023 Q2	0.28	0.44	0.57
2024 Q2	0.26	0.39	0.56
2025 Q2	0.24	0.37	0.54

Table 19: Quarter over quarter min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2024 Q3	0.25	0.40	0.53
2024 Q4	0.25	0.40	0.54
2025 Q1	0.27	0.40	0.54
2025 Q2	0.24	0.37	0.54

Figure 33 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q2 over the past seven years. Figure 34 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The conversion of coal-fired generation to natural gas, in addition to increased intermittent generation, has driven a decline in carbon emission intensity. This decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions as shown in Figure 33.

Figure 33: The distribution of average carbon emission intensities in Q2 (2019 to 2025)

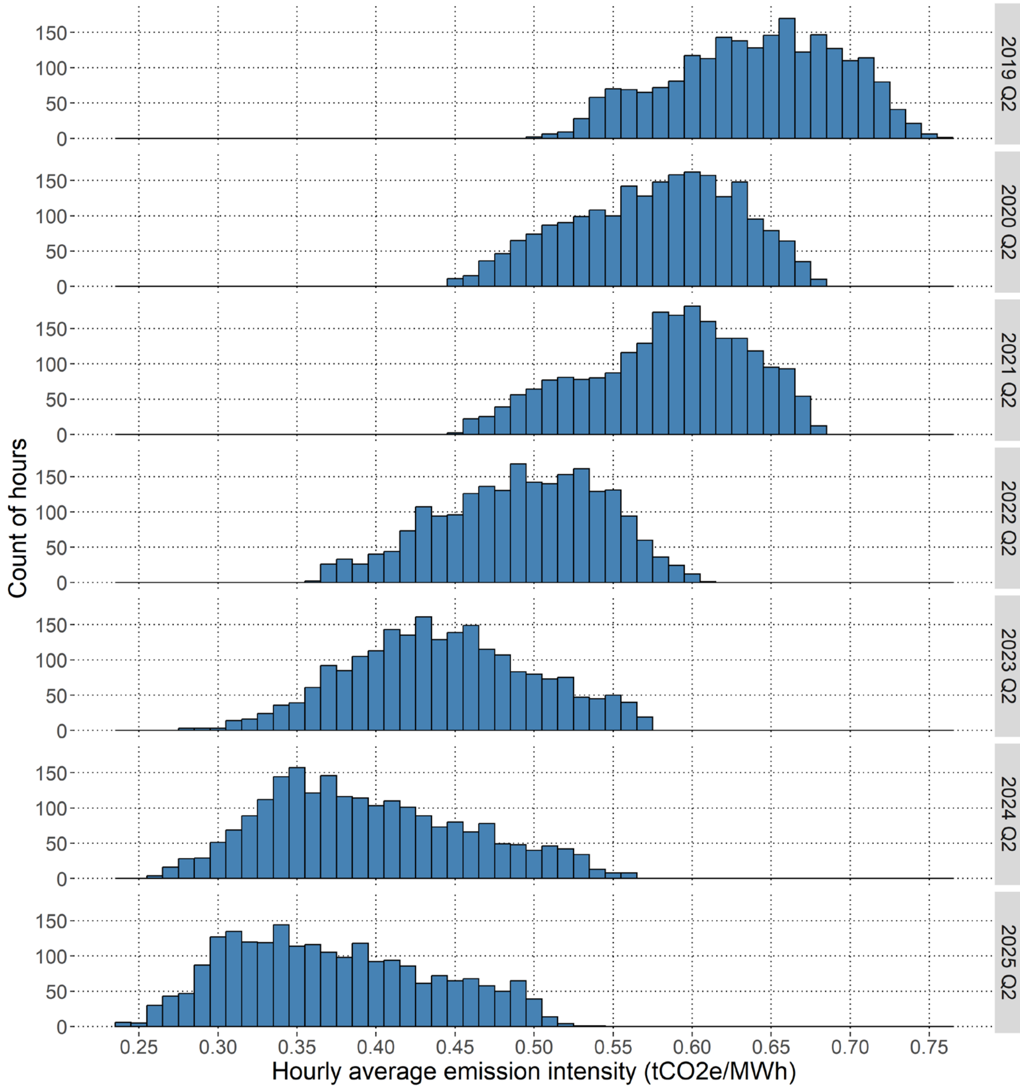
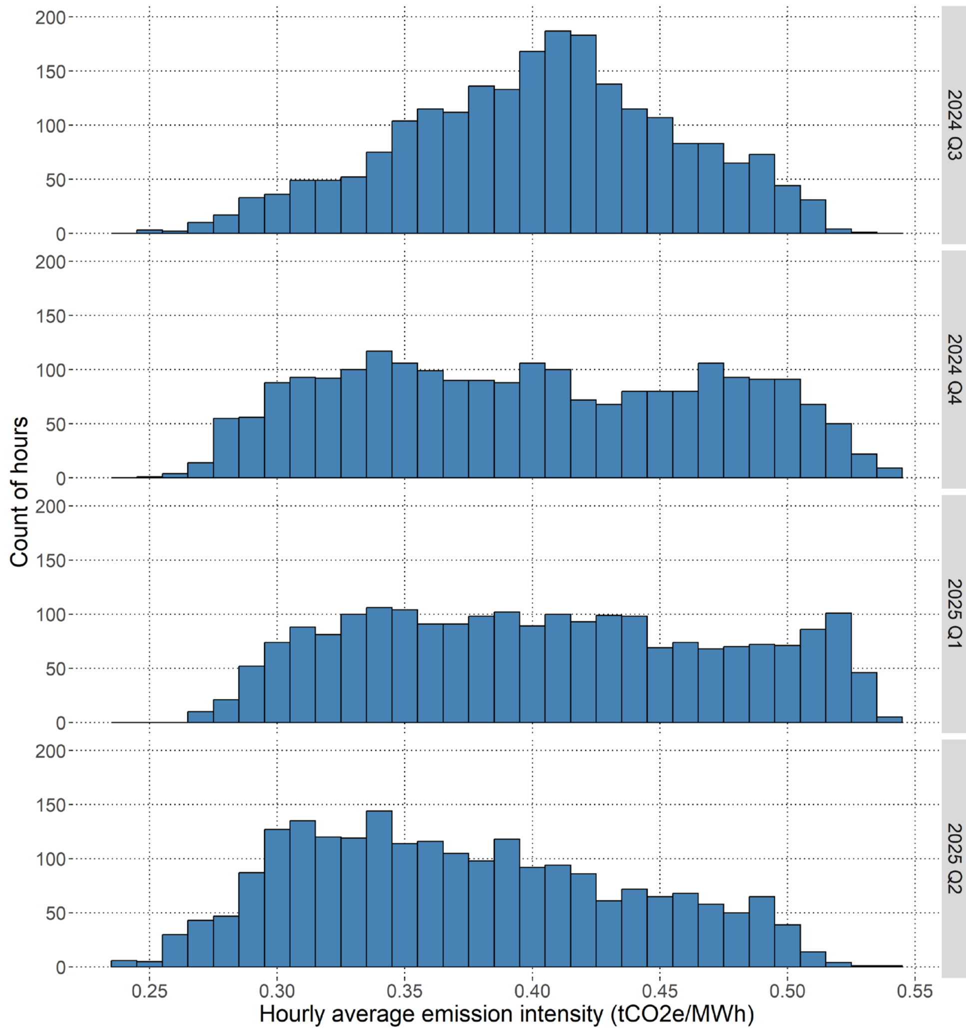
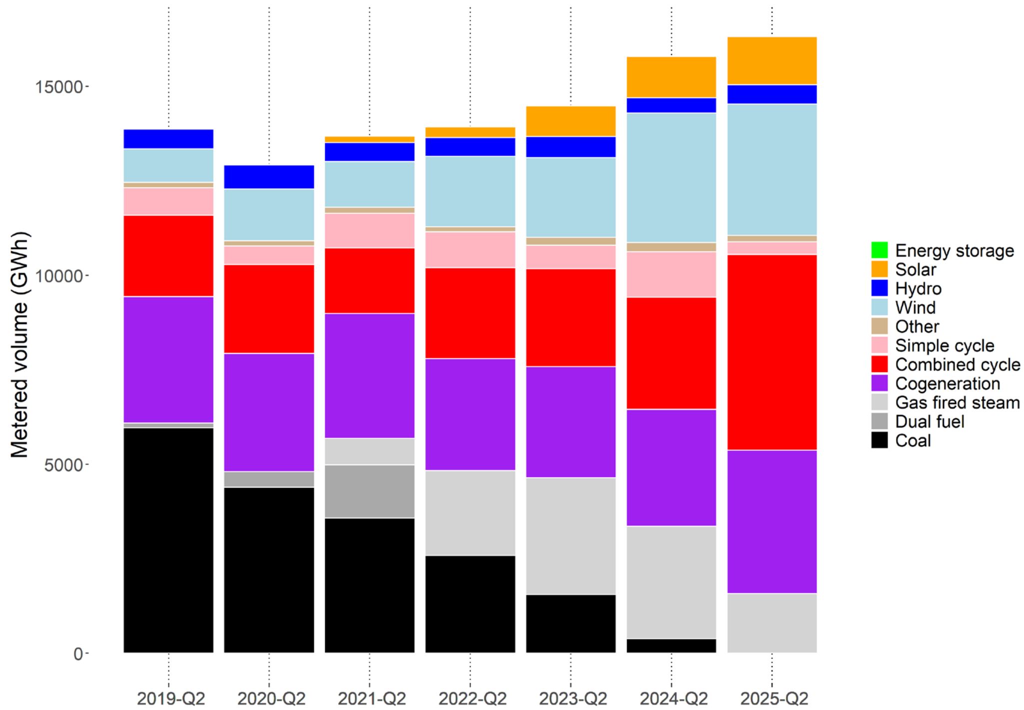


Figure 34: The distribution of average carbon emission intensities in the past four quarters



The leftward shifts of the distributions in Figure 33 can be traced to Figure 35, which shows the net-to-grid generation volumes by fuel type. Since 2019, there has been a material decline in the volume of coal-fired generation due to retirements and coal-to-gas conversions. In addition, the continuous increase in intermittent generation driven by growing capacity has also contributed to the displacement of coal-fired generation. Increased generation from efficient gas assets, including Cascade 1 and 2 and Genesee Repower 1 and 2, has put downward pressure on average carbon intensity more recently.

Figure 35: Quarterly total net-to-grid generation volumes by fuel type for Q2 (2019 to 2025)

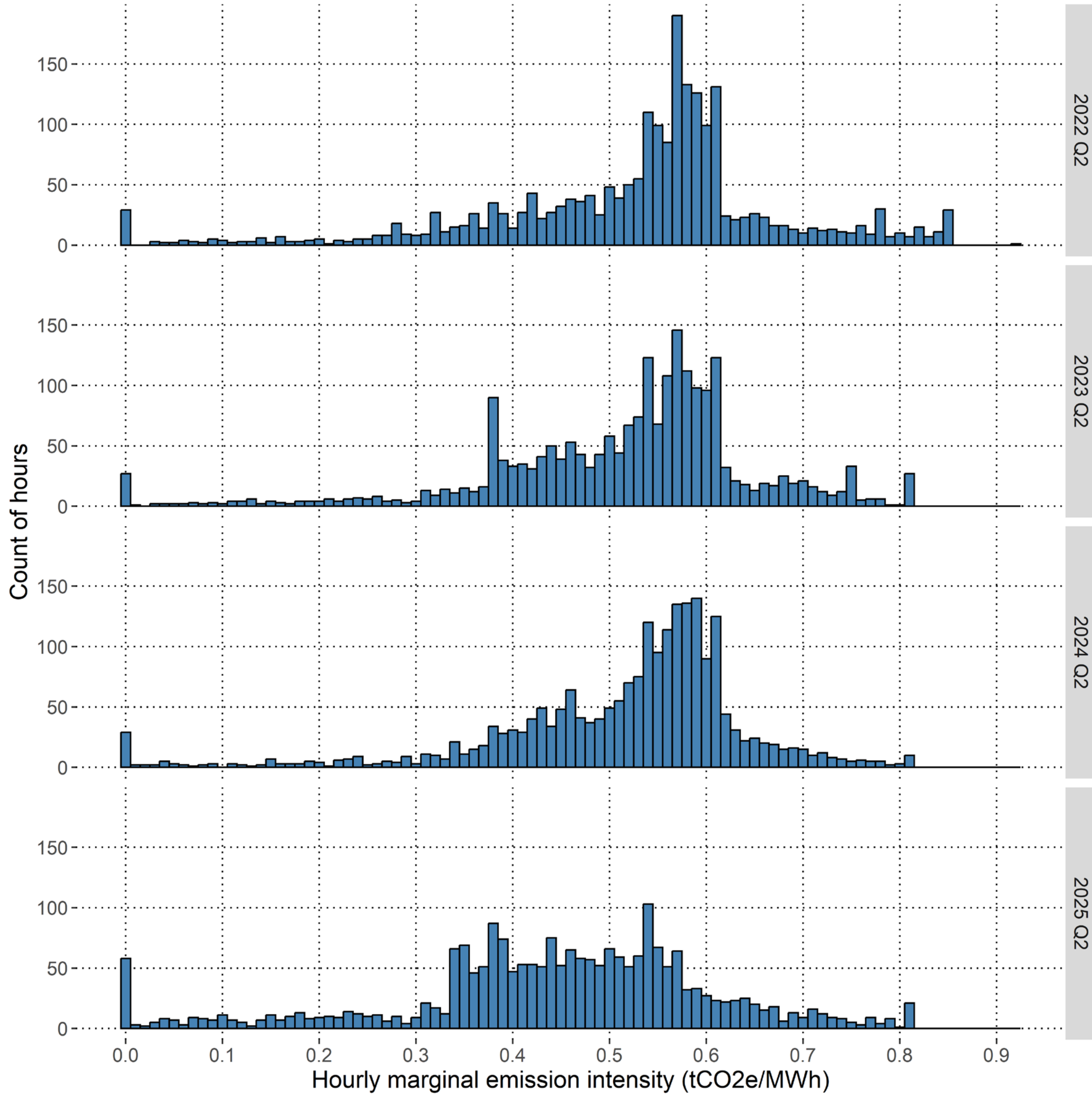


1.5.2 Hourly marginal emission intensity

The hourly marginal emission intensity of the grid is the carbon emission intensity of the asset setting the SMP in an hour. In hours where there were multiple SMPs and multiple marginal assets, a time-weighted average of the carbon emission intensities of those assets is used. Figure 36 shows the distribution of the hourly marginal emission intensity of the grid in Q2 for the past four years. From Q2 2022 through Q2 2024 gas-fired steam assets were setting the price quite often, which was a factor in higher observations around 0.54 to 0.60 tCO2e/MWh.

In Q2, combined cycle assets were setting the price more often than gas-fired steam assets, resulting in a noticeable decline of the 0.54 to 0.60 tCO2e/MWh observations. There was a 63% decline in the amount of time that gas-fired steam assets were setting the price in Q2 compared to Q2 2024. Additionally, there was a 99% increase year-over-year in the amount of time 0.0 tCO2e/MWh assets were setting the price. The smaller spike towards the higher end of the distribution this quarter can be attributed to cogeneration assets setting the price more often than in Q2 of the prior year.

Figure 36: The distribution of marginal carbon emission intensities in Q2 (2022 to 2025)



2 THE POWER SYSTEM

2.1 Congestion

Transmission elements may impose limitations to the transfer of electric energy from one location on the transmission system to another. The AESO mitigates these limitations in real time by curtailing generation.[8]

The MSA measures constrained intermittent generation (CIG) volumes, an estimate of the potential generation of an intermittent asset that is curtailed due to a transmission constraint. The CIG calculation uses data on curtailment limits, available capacity, potential real power capability, and energy dispatch.[9]

The frequency and significance of CIG directives increased from Q2 2024 to Q2, largely due to the EATL outage from May 26 to June 8. The MSA estimates that CIG volumes were 214 GWh in Q2 2024 and 310 GWh in Q2, a 45% increase year-over-year. Quarter-over-quarter, the CIG volumes increased by 150 GWh. The CIG volume of 310 GWh reached in Q2 is a new record high; the previous record occurred in Q2 2024.

The maximum hourly average volume of CIG in Q2 was 1,686 MW, almost equivalent to the Q2 2024 maximum of 1,665 MW (Figure 37 to Figure 39). The Q2 maximum hourly average volume of CIG was higher than the previous quarters maximum value of 1,076 MWh (Figure 38).

The increased CIG volumes in Q2 were likely due to increased intermittent capacity and high intermittent generation. Generally, higher CIG volumes align with periods of high intermittent generation or supply surplus events (Figure 40).

There were over 413 shift log events for constrained down generation in Q2. Increased constrained intermittent generation volumes may also be due to persistent or frequent limitations to certain transmission elements and may affect one or more generation assets. In Q2 there was a wide variety of events that occurred over many different transmission elements. Q2 experienced two peak events where the difference between the constrained and unconstrainted SMP was large, which are further discussed below and in section 1.2.

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

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

Figure 37: Maximum hourly transmission constrained intermittent generation (Q2 2024)

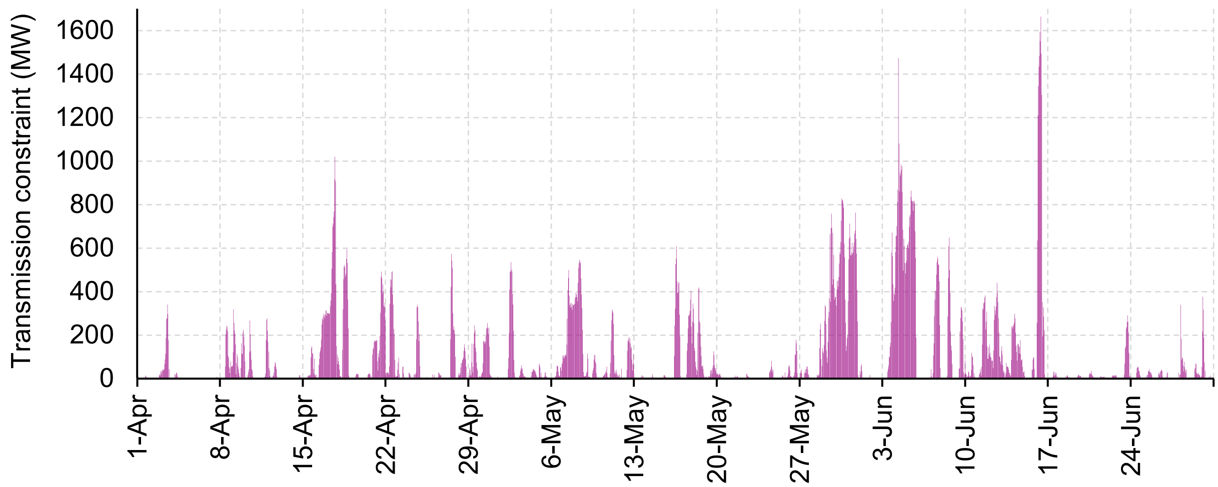


Figure 38: Maximum hourly transmission constrained intermittent generation (Q1 2025)

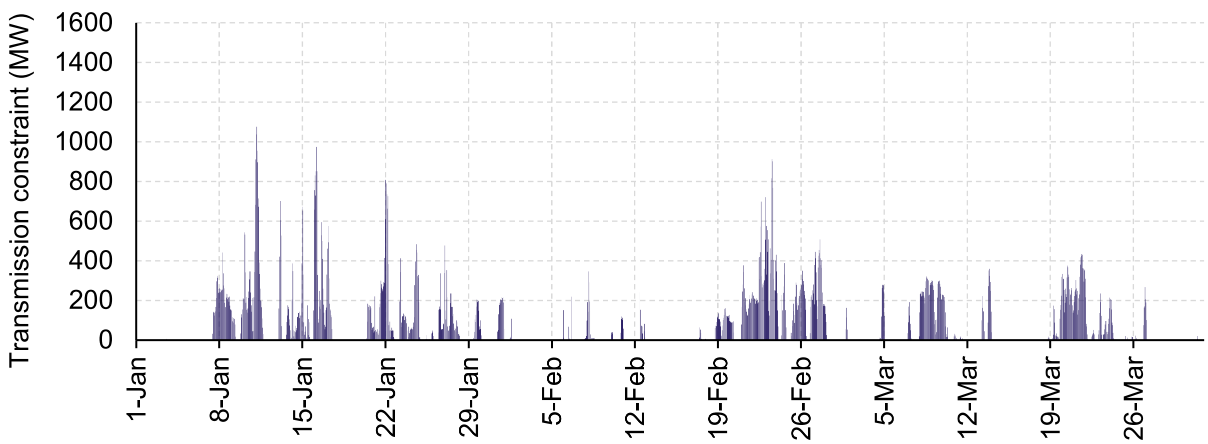


Figure 39: Maximum hourly transmission constrained intermittent generation (Q2 2025)

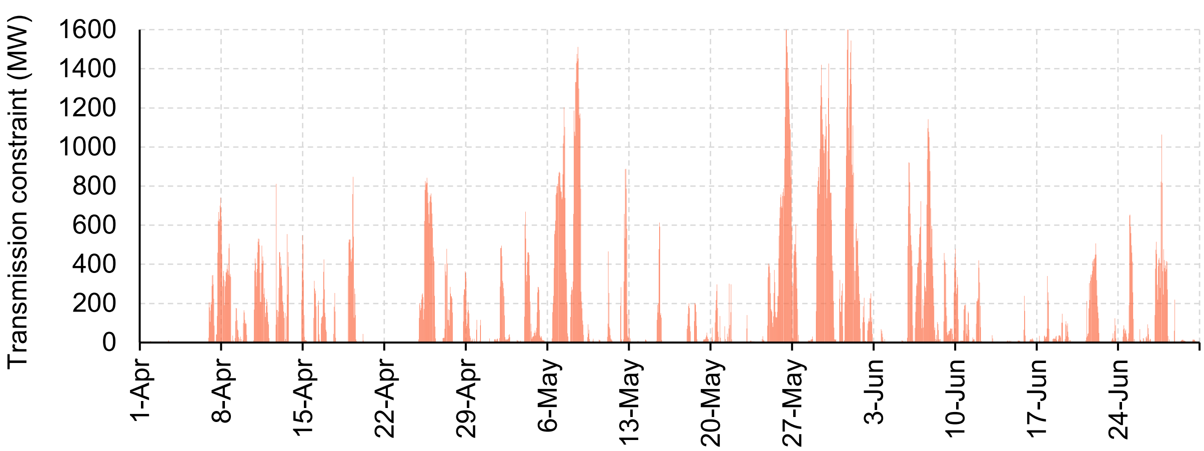
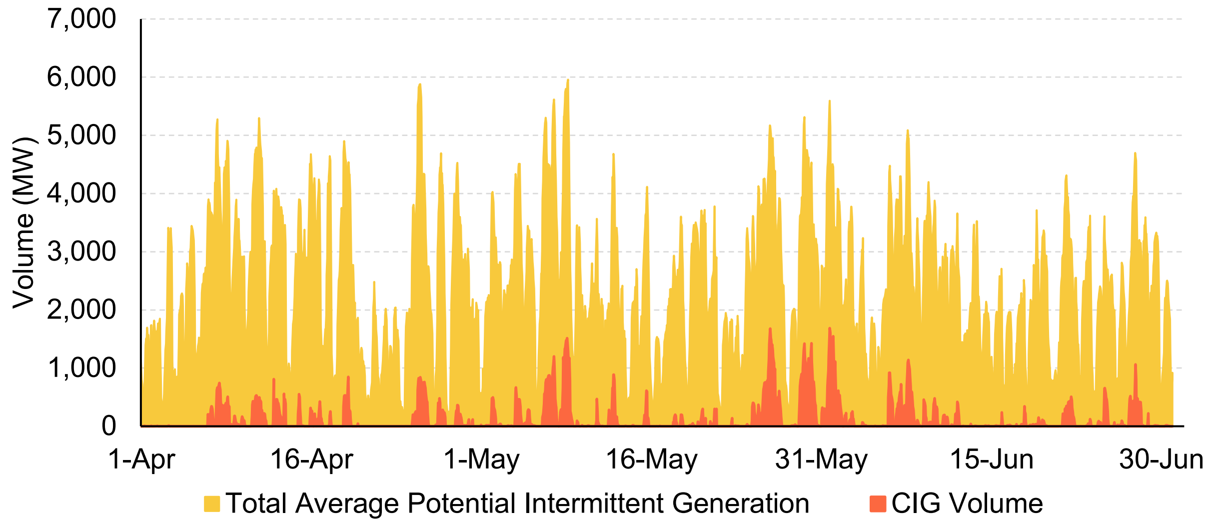


Figure 40: Average hourly intermittent generation and constrained intermittent generation (Q2)



The increase in CIG volume from Q2 2024 to Q2 occurred at a higher rate than the installation of intermittent generation capacity. While total installed intermittent capacity increased by 17%, average hourly CIG volumes, expressed as a percent of installed intermittent capacity, increased from 1.5% in Q2 2024 to 1.9% in Q2 (Figure 41).

Figure 41: Volume of CIG compared to total potential intermittent generation (Q2)

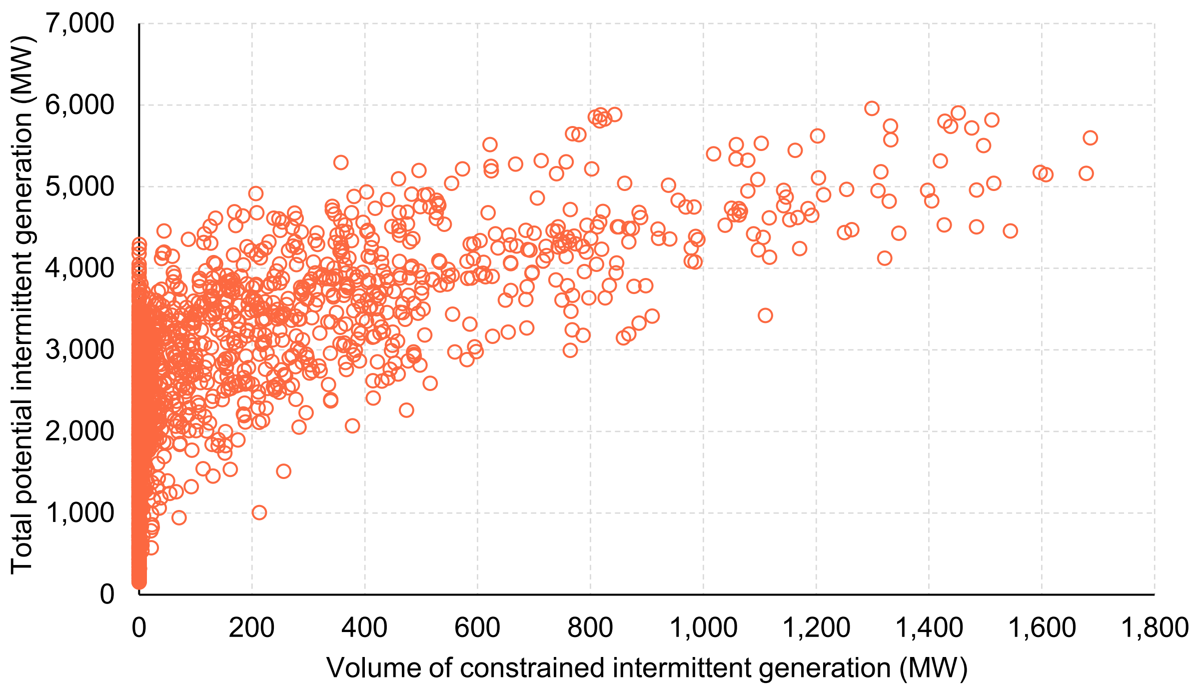
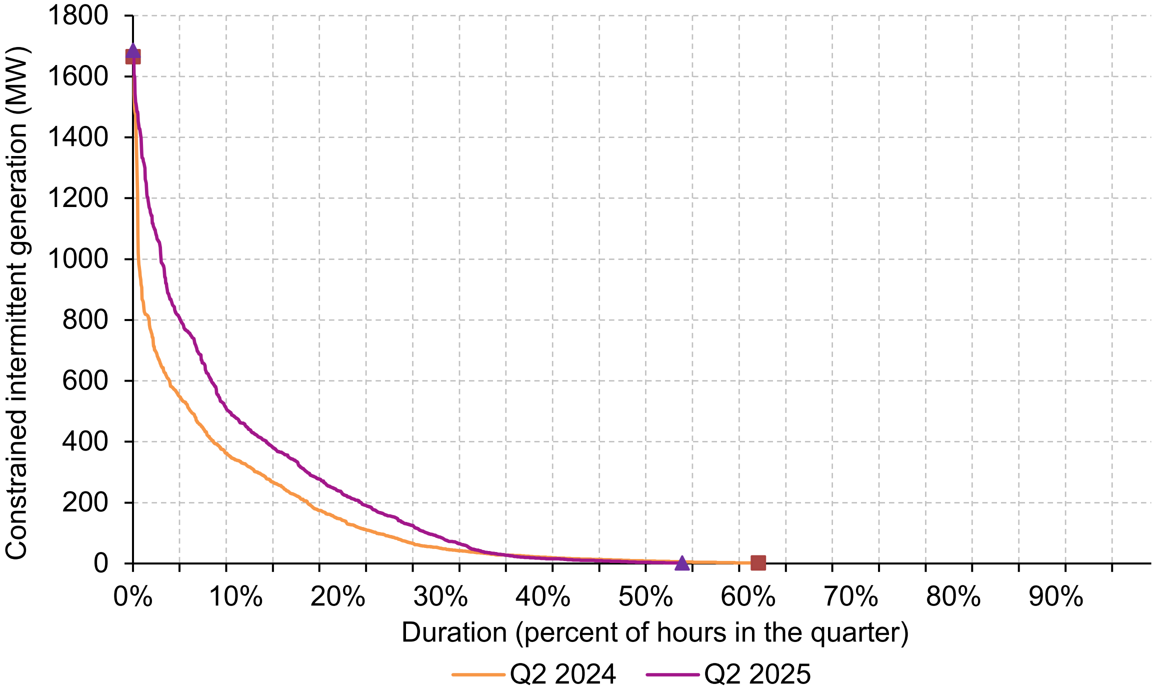


Figure 42 illustrates duration curves of CIG year-over-year. The length of the tails to the right of the duration curves show that the frequency of CIG events decreased year-over-year. There were 1,181 hours of CIG volumes greater than 1 MWh in Q2. This is equivalent to just over 49 days, or 54% of Q2. In contrast, Q2 2024 experienced 1,351 hours of CIG volumes greater than 1 MWh, or over 56 days or 62% of Q2 2024.

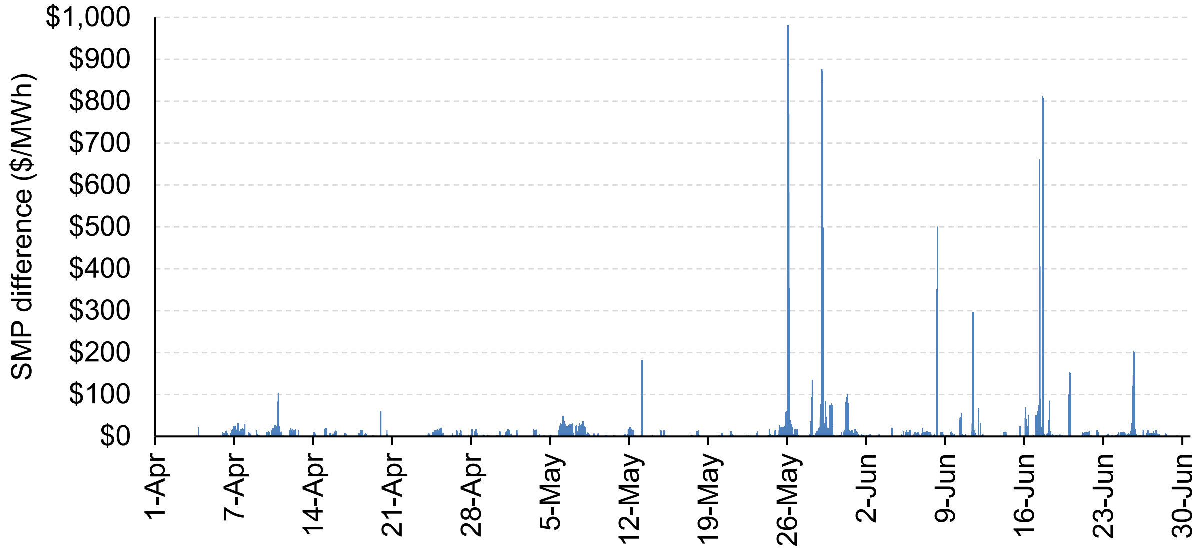
Figure 42: Duration curves of CIG volume (Q2 2024 and Q2)



Transmission constraint volumes had frequent fluctuations throughout all months of Q2, however May experienced the most volume of CIG and the highest peak. The CIG volume in the month of May accounted for 50% of all Q2 volumes. In 58% of May hours there was at least 1 MWh of CIG.

The constrained and unconstrained SMP differed by $1/MWh or more in 25% of minutes in Q2 (Figure 43). In comparison, Q2 2024 experienced 24% of minutes with a variance of $1/MWh or more in the constrained SMP and unconstrained SMP, and Q1 2025 experienced the difference in 15% of minutes. The largest difference between the constrained SMP and unconstrained SMP in Q2 was $981/MWh, which occurred in HE15 of May 26. The largest difference in unconstrained and constrained price was lower in Q2 2024 at $659/MWh. The largest difference in Q1 2025 occurred on March 8 and reached $231/MWh.

Figure 43: Difference of constrained SMP and unconstrained SMP (Q2)

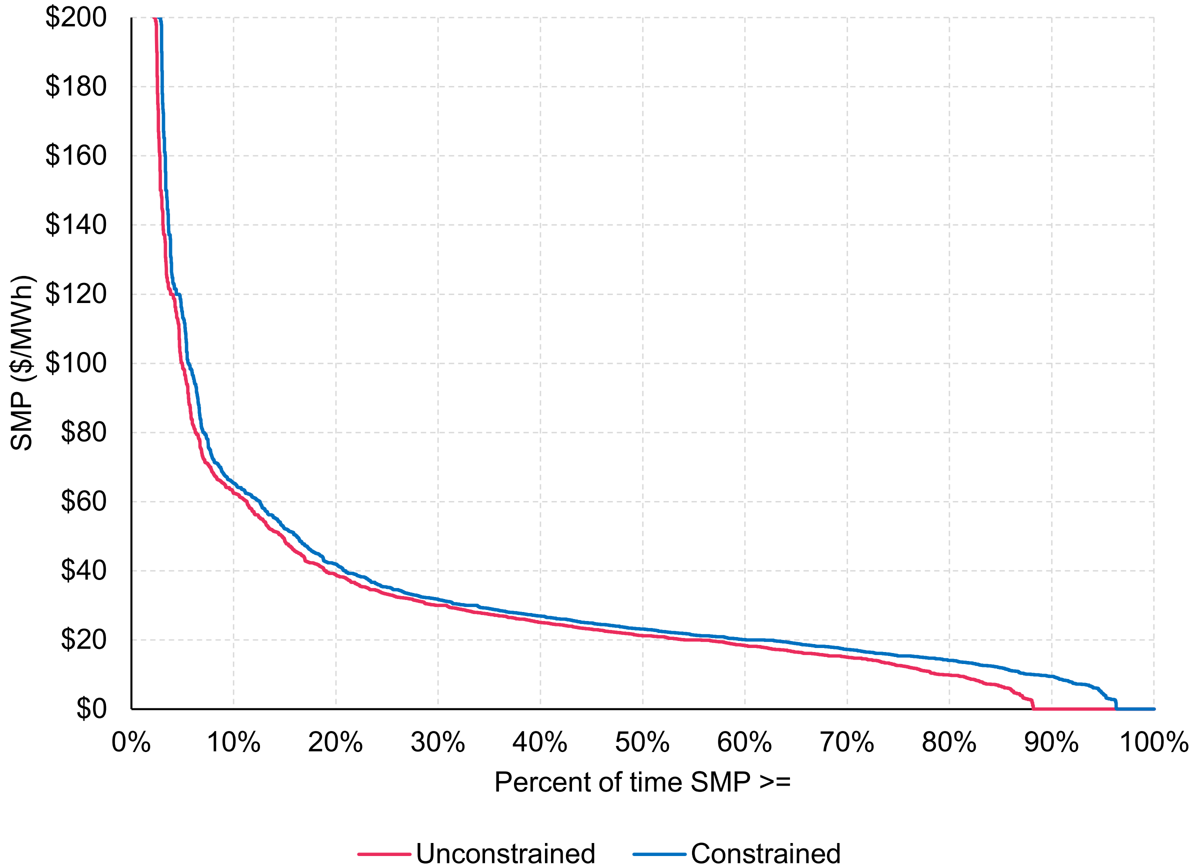


The periods that experience high volumes of CIG often occur when generation from intermittent resources is high. Given the offer behaviour of these resources, when intermittent generation is higher, SMP is lower as higher priced generation is displaced. Therefore, despite the high amount of CIG volumes in Q2, there was often only a small difference between the constrained SMP and the unconstrained SMP (Figure 44). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity will have a relatively small impact on prices.

The two spikes in the difference between the constrained and unconstrained SMP occurred on May 26 and May 29. These two days accounted for 48 GWh or 15% constrained intermittent generation for Q2. There were 22 different logged transmission constraint events that occurred over May 26. These events related to a wide variety of transmission constraints and applied to 40 intermittent assets over the day. Forty Mile Granlea (2,409 MWh CIG volume on May 26) was the most constrained asset, followed by Sharp Hill Wind (2,002 MWh CIG volume on May 26) and Travers (1,885 MWh CIG volume on May 26). Each of these assets were constrained for different reasons, further illustrating the variety of constraints present over the period.

On May 29, there were 20 logged transmission constraint related events and 40 intermittent assets constrained over the period. The most constrained asset was Paintearth Wind Project (2,032 MWh CIG volume on May 29), followed by Forty Mile Bow Island (1,830 MWh CIG volume on May 29) and Forty Mile Granlea (1,609 MWh CIG volume on May 29). There were multiple constraints that were applied to these assets over May 29 at different points during the day.

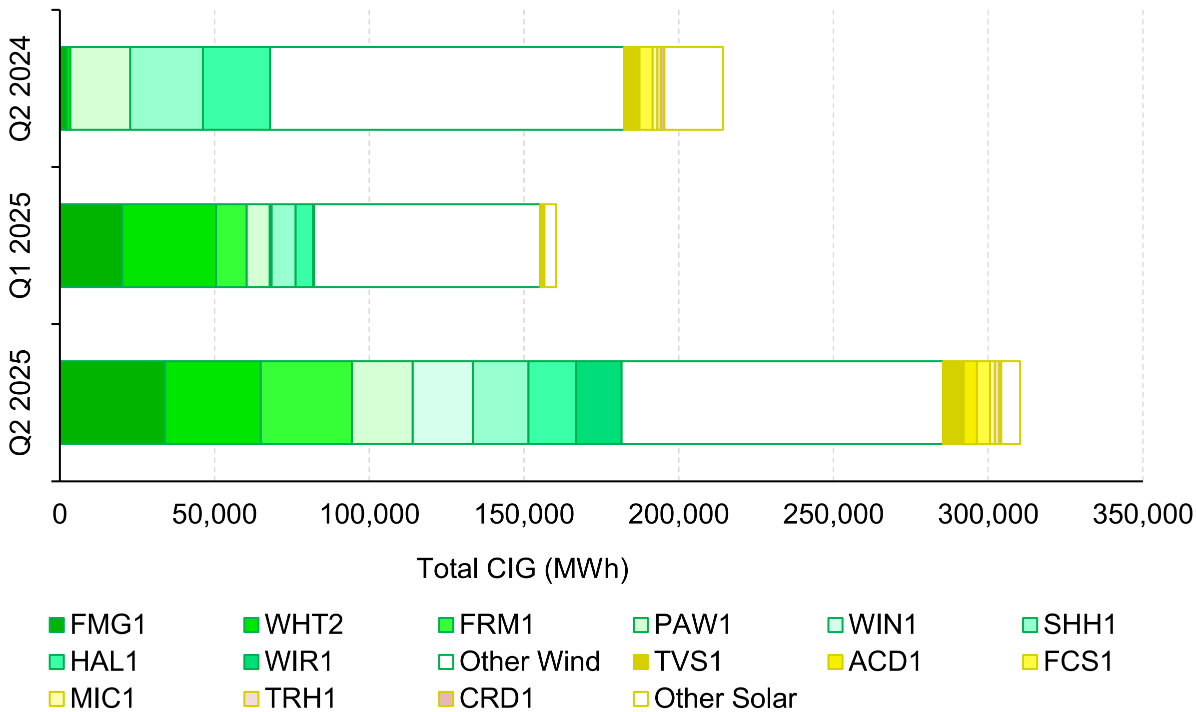
Figure 44: Duration of unconstrained SMP and constrained SMP for Q2



Transmission capability varies throughout the province, and certain regions experience more congestion than others, often leading to local constraints (Figure 45). Often, wind and solar assets are not constrained uniformly throughout the province. In Q2, the eight most constrained wind assets accounted for 64% of the total CIG volume but only 28% of total installed wind generation. Forty Mile Granlea, Whitla 2, and Forty Mile Bow Island were the most constrained wind assets in Q2. These 3 assets represent 11% of Alberta's installed wind capacity, however they accounted for approximately 33% of the wind CIG volume in Q2.

Travers (465 MW) was the most-constrained solar asset in Q2, with a total of 6,714 MWh constrained. The asset was constrained due a variety on constraints over the quarter with most constraints related to transmission lines 927L, 924L, and 1005L. The following five most constrained solar assets have an aggregate maximum capability of 293 MW and were constrained by 12,125 MWh in Q2. The top 6 constrained solar assets account for 42% of the maximum capability of the market and accounted for 76% of solar CIG volumes in Q2. The uneven distribution of congestion volumes to intermittent assets continues within Alberta.

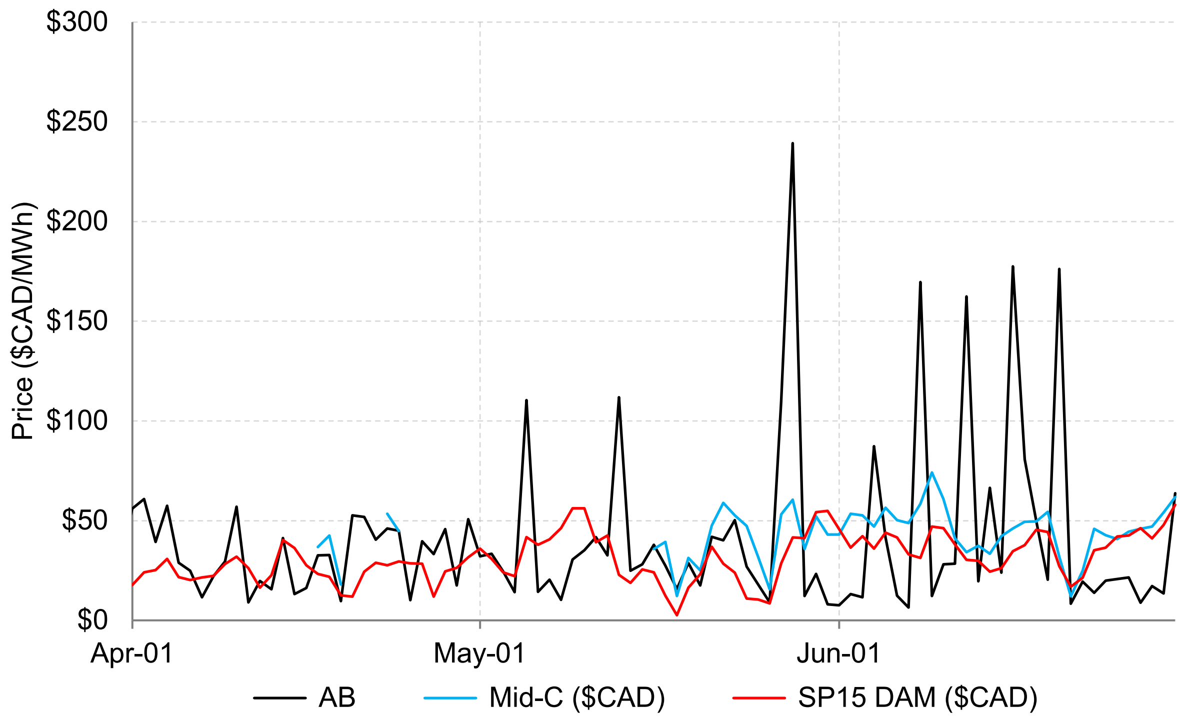
Figure 45: Wind and solar CIG by asset (Q2 2024, Q1 2025, Q2)



2.2 Interties

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

Figure 46: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q2)[10]



Alberta remained an exporter of power in Q2. On average, Alberta exported 256 MW over the quarter, with the highest monthly average occurring in June at 343 MW of exports (Table 20). Overall, Alberta was a net exporter during 69% of hours in Q2 and a net importer in 27% of hours.

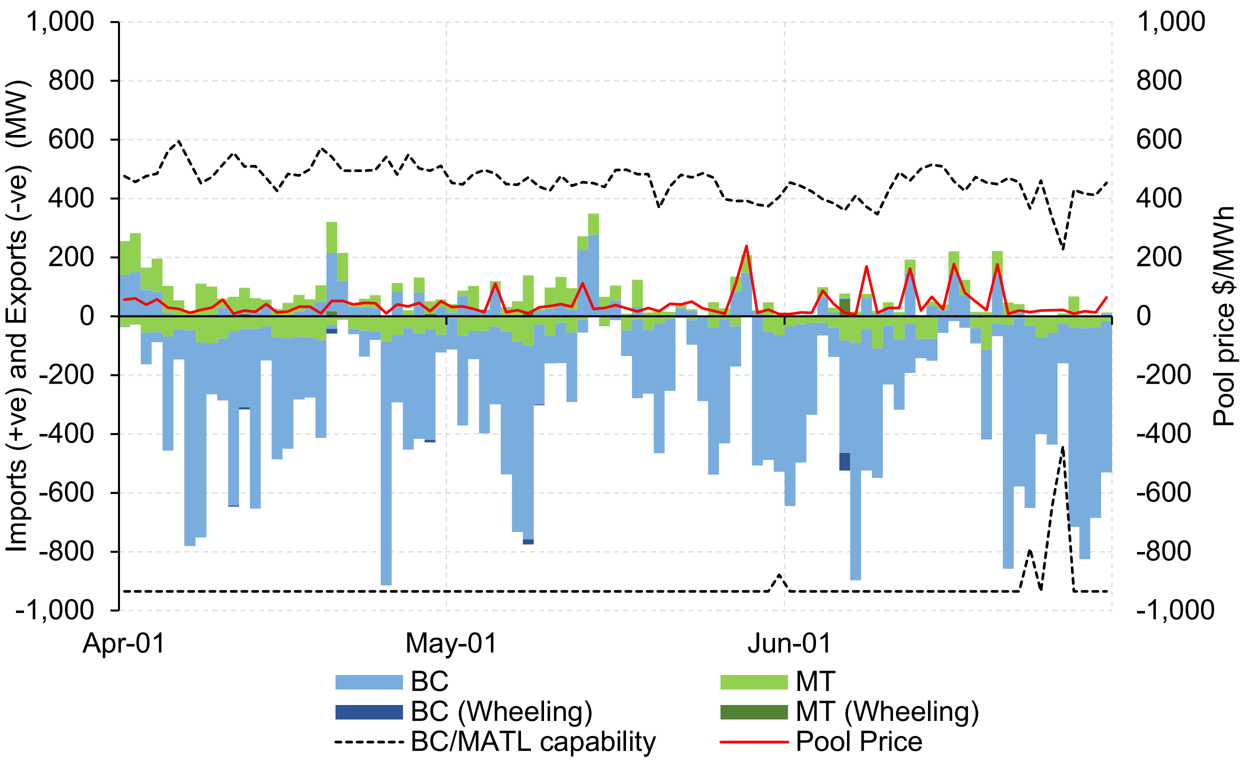
In comparison to Q2 2024, there were more exports to BC, more exports and less imports along MATL, and no imports from Saskatchewan as the intertie continued to be on outage. Over the quarter BC/MATL import capability averaged 459 MW, and export capability averaged 924 MW. Figure 47 shows the daily average scheduled volumes along BC/MATL along with joint capability and pool price.

[10] Mid-C price data is unavailable for much of April and May; therefore, the analysis will primarily reference pool price in relation to intertie measures.

Table 20: Average net import (+ve) and export (-ve) volumes for Q2 2024 and Q2 2025

	2024				2025			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
April	-238	113	74	-51	-223	2	0	-221
May	-66	55	1	-10	-213	7	0	-206
June	-192	38	23	-132	-322	-21	0	-343
Q2	**-164**	**69**	**32**	**-63**	**-252**	**-4**	**0**	**-256**

Figure 47: Daily average import (+ve) and export (-ve) scheduled volumes on BC/MATL, joint capability, and pool price (Q2)



The volume-weighted average price paid by exports on the BC intertie was $13/MWh over the quarter and the volume-weighted average price received by imports was $148/MWh. During periods of net imports on the BC intertie in June, the volume-weighted received pool price averaged $242/MWh, spanning 16% of hours over the month.

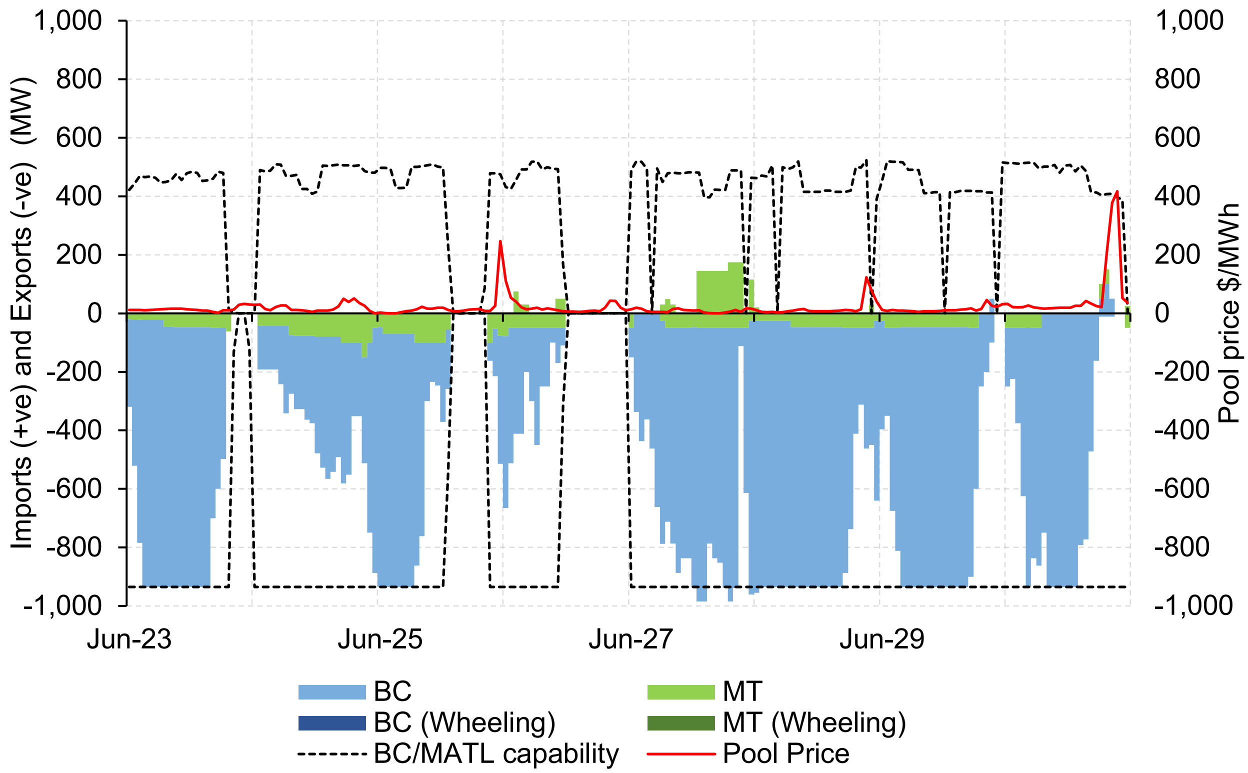
The volume-weighted average price paid by exports on MATL intertie was $23/MWh over the quarter and the volume-weighted average price received by imports was $75/MWh. During periods of net imports on MATL in June, the volume-weighted received pool price averaged $158/MWh, spanning 19% of hours over the month.

On April 23, the return to commercial operation for the SK intertie was revised from June 30 to December 23. The timeline was updated to reflect the receipt of replacement parts from vendors and associated installation and testing. The intertie has been available for emergency operation and during HE 19 and HE 20 on May 28 the AESO provided 153 MW of emergency exports due to an EEA2 in Saskatchewan, as described in section 1.2.

Over the course of the quarter there were multiple outages affecting BC/MATL, as outlined below:

- May 29: Planned outage on MATL during HE 08 through HE 17.
- May 31: Forced outage on BC/MATL over HE 17 and HE 18 caused by a trip on 5L92 (BC).
- June 3 to 10: Planned outage on 1L274 (BC), which lowered BC/MATL import capability.
- June 5: Forced outage on MATL between HE 17 and HE 23 due to debris on 941L.
- June 23: Forced outage on BC/MATL between HE 21 and HE 24. This outage and the following June outages are shown in Figure 48.
- June 25: Forced outage on BC/MATL between HE 14 and HE 22, work was being performed on 1201L (BC) at the time of the trip.
- June 26 to 27: Forced outage on BC/MATL between HE 12 and HE 01, work was being performed on 1201L (BC) at the time of the trip.
- June 27 through 30: BC/MATL import capability at 0 MW for various hours associated with the Genesee Repower 1 and 2 testing.

Figure 48: Hourly import (+ve) and export (-ve) scheduled volumes on BC/MATL, joint capability, and pool price (June 23 to 29, 2025)



Over the course of the quarter there were a few instances of the AESO receiving or providing power as part of the Western Power Pool (WPP), as described below:

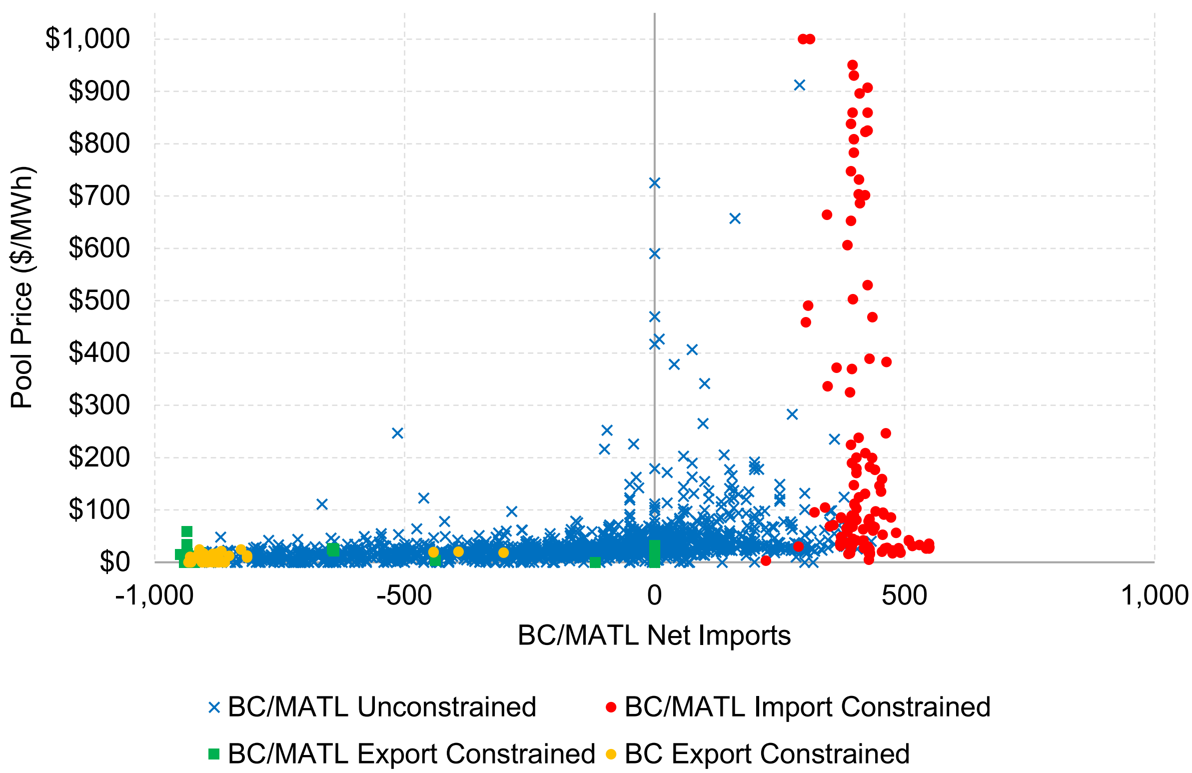
- On June 12 during HE 17 the AESO responded to a WPP request for 215 MW due to loss of generation within BC and 44 MWh of energy was provided.
- On June 17 during HE 18 the AESO requested 450 MW from the WPP due to GNR1 and GNR2 trips and 36 MWh of energy was received.
- On June 21 during HE 14 the AESO requested 150 MW from the WPP due to a GNR2 trip and 11 MWh of energy was received.

Figure 49 shows a scatterplot of pool prices and the net scheduled volume on BC/MATL for each hour over the quarter. Over Q2 there were many hours where export bids or scheduled volumes were at or above BC/MATL export capability, meaning that BC/MATL was export constrained (shown in green). BC/MATL exports were constrained for 272 hours or 12% of the time. While BC/MATL was export constrained, pool price averaged $9/MWh and joint export capability averaged 878 MW.

Additionally, there were hours when net export bids for BC were at or above the joint export capability, while there were net import offers on MATL, meaning that only the BC intertie was export constrained (shown in yellow). Over the quarter, BC exports were constrained for 74 hours or 3% of the time. While BC was export constrained, pool price averaged $7/MWh, and joint export capability averaged 927 MW.

Export constrained observations generally lie on the left-hand side of Figure 49, however, this is not always the case. Reasons for this include intertie outages, insufficient transmission, and curtailments.

Figure 49: Pool price and net BC/MATL schedule (Q2 2025)



There were also hours when net import offers or schedule volumes on BC/MATL were at or above joint import capability, meaning that BC/MATL was import constrained (shown in red). BC/MATL imports were constrained for 121 hours in Q2 or 6% of the time. While import constrained, pool price averaged $233/MWh and import capability averaged 417 MW.

Import constrained observations generally lie on the right-hand side of the figure; however as shown in Figure 49, this is not always the case. The anomalous observations were generally the result of intertie outages, participant error, and curtailments.

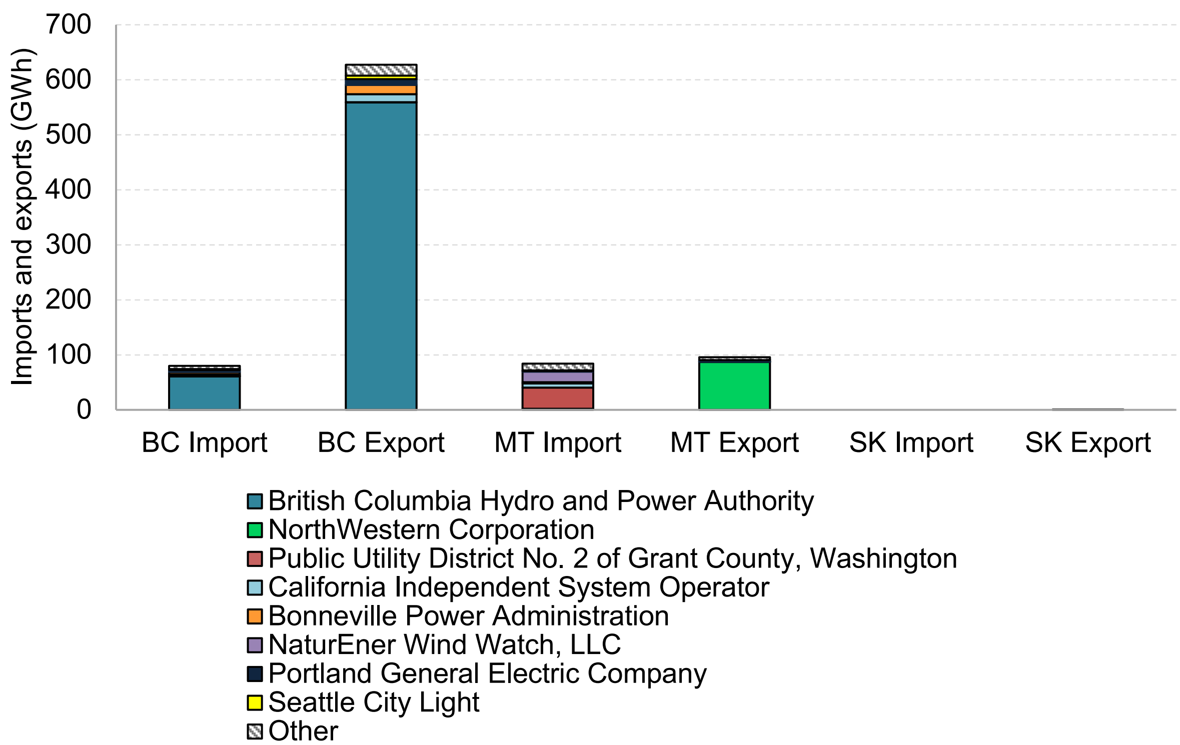
There were certain high-priced hours where the net scheduled flow on BC/MATL was 0 MW or less. This is often the result of unexpected pool price volatility. For example, on June 8 during HE 17 pool price was $252.28/MWh, and Alberta was net exporting 95 MW. However, in the prior 48 hours pool prices averaged $9.52/MWh and Alberta was export constrained on BC/MATL 42% of the time. During HE 18 prices rose to $589.97/MWh and the scheduled flow was 0 MW. Over HE 19 through HE 24 prices ranged between $458.42/MWh and $999.99/MWh and Alberta was BC/MATL import constrained for the duration of this period.

Figure 50 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[11] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

For imports on the BC intertie, approximately 76% originated from BC, 19% from the US Northwest, and 4% from California. For exports on the BC intertie, 89% was delivered to BC, 8% to the US Northwest, and 2% to California.

For imports through MATL, 90% originated from the US Northwest and 10% from California. For exports on MATL 99% was delivered to the US Northwest and 1% to the Southwest Power Pool.

Figure 50: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q2)[12]



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

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

3 OPERATING RESERVES

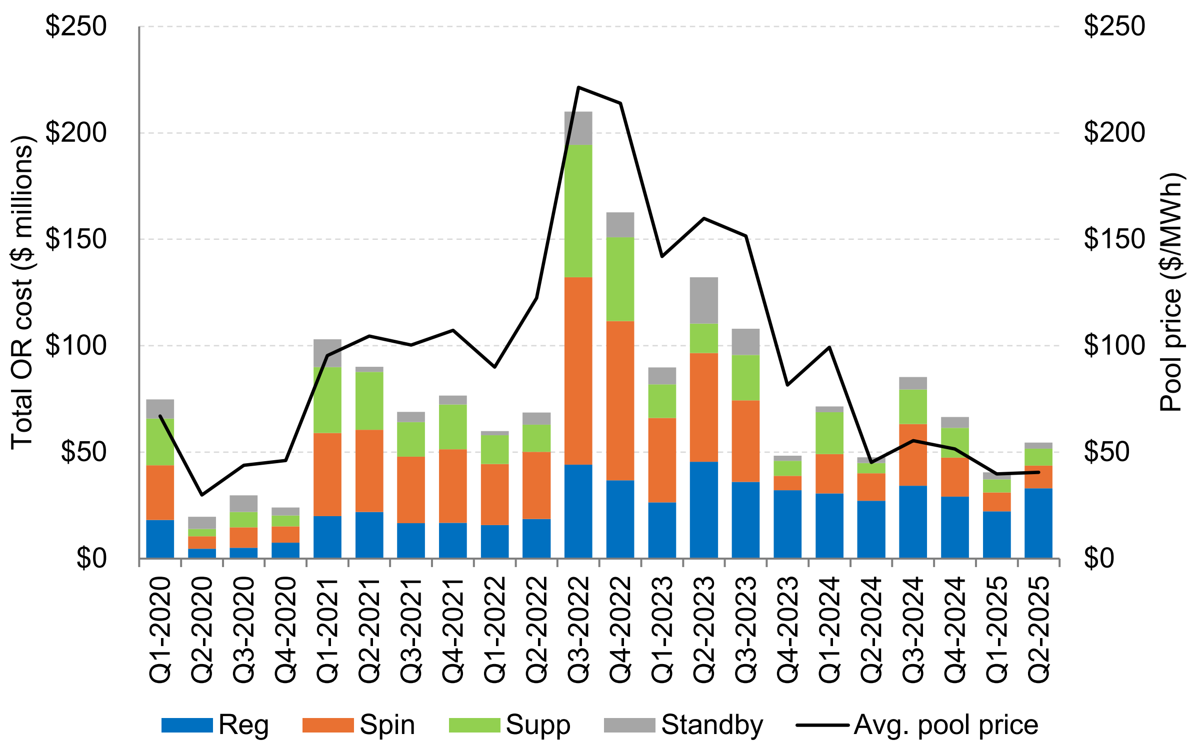
AESO system controllers call upon three types of operating reserve (OR) to address unexpected imbalances or lagged responses between supply and demand: regulating reserve, spinning reserve, and supplemental reserve. Regulating reserve provides an automatic and instantaneous response to small imbalances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

3.1 Total costs

The total cost of OR in Q2 was $54.6 million, which is a 14% increase year-over-year, and a 34% increase compared to Q1. The higher OR costs in Q2 occurred despite lower average pool prices year-over-year and similar average pool prices quarter-over-quarter.

The higher OR costs were primarily driven by higher costs of regulating reserves (Figure 51). The total cost of regulating reserves in Q2 was $33 million, an increase of $5.9 million year-over-year, and an increase of $10.9 million compared to Q1. The higher costs of regulating reserve were driven by higher prices rather than by more volume.

Figure 51: Total OR costs by quarter and OR product (Q1 2020 to Q2 2025)



3.2 Active reserves

Equilibrium prices for active OR products are set based on market clearing prices in day-ahead auctions. These equilibrium prices are subsequently indexed to hourly pool prices to yield the received price for providing active reserves (see equation below).

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

Table 21 presents average received prices by OR product for Q2 2024 and Q2 2025. The average pool price fell by $4.69/MWh year-over-year, but the average received price for regulating reserves increased by $15.58/MW. This occurred because there was an increase in equilibrium prices for regulating reserves.

A similar dynamic is observed quarter-over-quarter. The average pool price was stable, increasing by only $0.70/MWh, but the average received price for regulating reserves increased by $24.16/MW (Table 22).

Table 21: Average received price by OR product (Q2 2024 and Q2 2025)

	Q2 2024	Q2 2025	Difference
Reg	$64.28	$79.87	$15.58
Spin	$26.04	$20.71	-$5.33
Supp	$9.68	$15.35	$5.67
Pool Price	$45.17	$40.48	-$4.69

Table 22: Average received price by OR product (Q1 2025 and Q2 2025)

	Q1 2025	Q2 2025	Difference
Reg	$55.70	$79.87	$24.16
Spin	$15.96	$20.71	$4.76
Supp	$11.05	$15.35	$4.30
Pool Price	$39.78	$40.48	$0.70

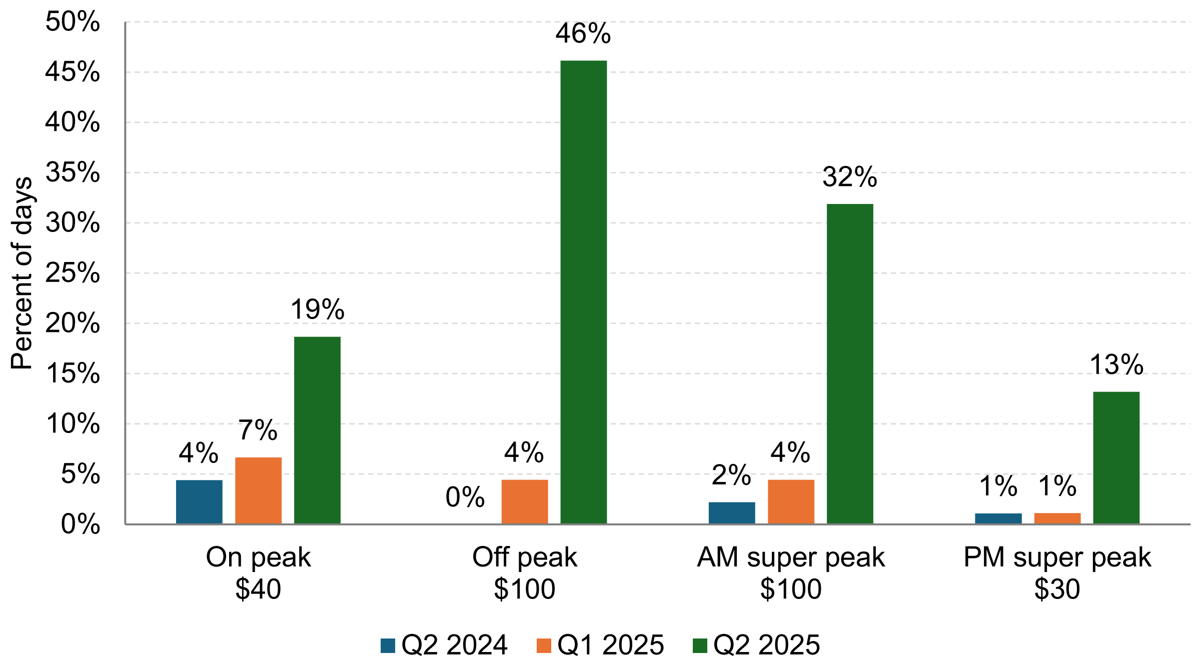
The market for regulating reserves is split into four procurement periods: on peak, off peak, AM super peak, and PM super peak. Each procurement period applies to different hours of the day and each has a cap on equilibrium prices (Table 23). The off peak and AM super peak products have the highest equilibrium price caps at $100/MW because pool prices are usually lower during these periods.

The higher equilibrium prices for regulating reserves have meant prices clearing closer to the caps more often (Figure 52). This has been particularly notable in the off peak and AM super peak markets. On 46% of the days in Q2 the equilibrium price for off peak regulating reserves was at least $99.00/MW. This is up from 4% of days in Q1 2025, and from 0% of days in Q2 2024.

Table 23: The different procurement periods for regulating reserves

	Applicable HEs	Equilibrium price cap ($/MW)
On peak	8 – 23	$40
Off peak	1 – 7, 24	$100
AM super peak	6 – 8	$100
PM super peak	17 – 24 (Nov – Jan) 18 – 24 (other months)	$30

Figure 52: Percent of days where equilibrium prices in the regulating reserve markets cleared within $1.00/MW of the price cap (Q2 2024, Q1 2025 and Q2 2025)



The higher equilibrium prices for regulating reserve may be the result of increased supplier concentration. Specifically, a generation merger in late 2024 reduced the number of participants competing for dispatch in the regulating reserves market and may have lowered competition.

As shown by Figure 53, following the merger two large incumbents have seen higher dispatch shares in regulating reserves. TransAlta's share of dispatches increased from 66% in Q2 2024 to 73% in Q2, while ENMAX's share increased from 16% to 21%.

In general equilibrium prices for regulating reserves were higher in Q2. However, there were also some exceptionally low equilibrium prices for regulating reserves in the quarter (Figure 54):

- for May 10, 11, and 12 the off peak equilibrium prices cleared at negative $700/MW, and
- for May 15 the on peak equilibrium price cleared at negative $480/MW.

Figure 53: Percent of dispatch for regulating reserves by firm (Q2 2024 and Q2 2025)

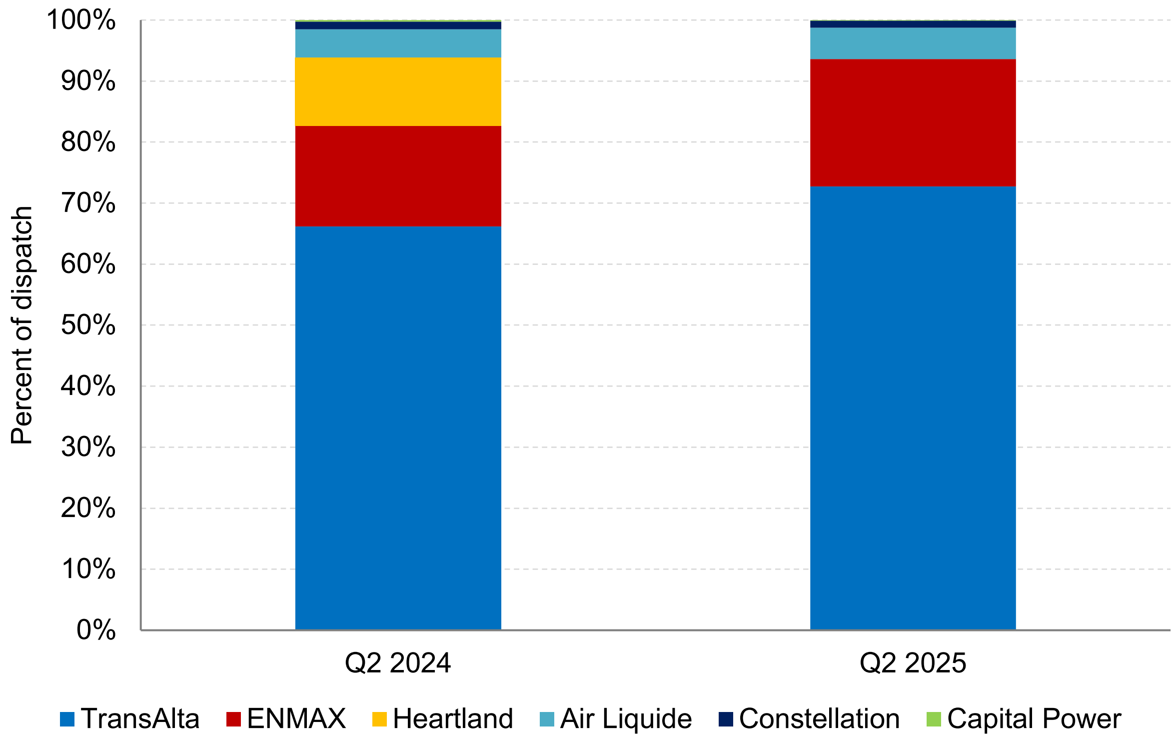
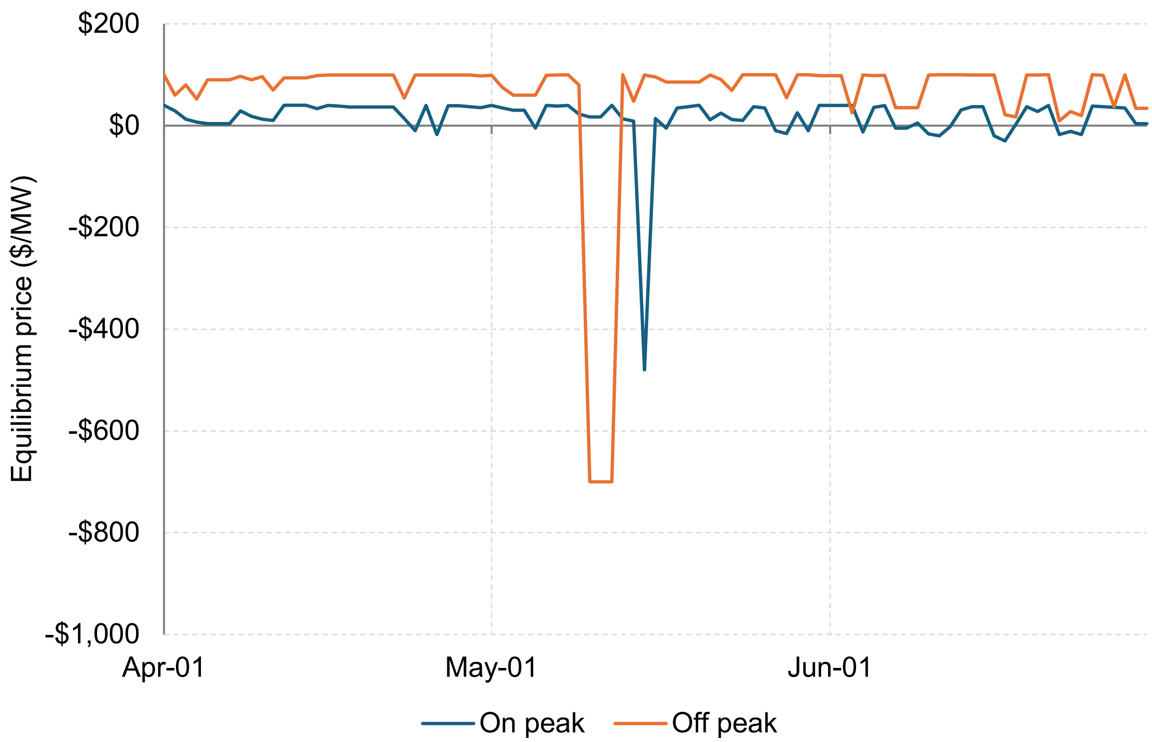


Figure 54: Equilibrium prices for on peak and off peak regulating reserves (Q2 2025)



The lower equilibrium prices for off peak regulating reserves on May 10, 11, and 12 resulted from increased supply in the auctions on Friday, May 9. As shown by Figure 53, TransAlta is the main provider of regulating reserves. In the off peak regulating reserves market TransAlta typically offers 98 MW at negative $700/MW. However, for the three auctions on May 9, TransAlta offered an additional 80 MW at negative $850.50/MW. Therefore, TransAlta offered a total of 178 MW into the market at low prices. The AESO procures 135 MW of regulating reserves for the off peak period, so TransAlta's offers cleared the market at negative $700/MW for the three days.

On May 15 the on peak equilibrium price cleared at negative $480/MW, which is considered abnormally low. This outcome appears to be influenced by offers into the market at negative $705/MW (Table 24). Additional supply may have contributed to downward pressure on the equilibrium price.

Table 24: The supply curve for on peak regulating reserves (May 15, 2025)

Asset ID	Firm	Volume (MW)	Cumulative volume (MW)	Offer price ($/MW)
BIG	TransAlta	76	76	-$730.00
BOW1	TransAlta	61	137	-$730.00
BRA	TransAlta	18	155	-$730.00
ENC3	Capital Power	20	175	-$705.00
CAL1	**ENMAX**	**40**	**215**	**-$479.99**
CAL1	ENMAX	4	219	-$11.61
ALS1	Air Liquide	10	229	$7.50
BRA	TransAlta	20	249	$20.00
CAL1	ENMAX	1	250	$30.13
CAL1	ENMAX	1	251	$39.98
CAL1	ENMAX	1	252	$39.98
CAL1	ENMAX	1	253	$39.99
CAL1	ENMAX	1	254	$39.99
CAL1	ENMAX	6	260	$40.00

In the markets for spinning and supplemental reserves on peak procurement volumes above the MSSC limit of 466 MW were generally driven by expectations of higher demand. The highest procurement volume for spinning and supplemental reserves in the quarter was a total of 510 MW for Monday, June 9.

The markets for spinning and supplemental reserves also saw some outliers in the quarter:

- For Monday, May 5 the off peak supplemental reserve market settled at negative $898/MW, an unusually low price. This occurred because TransAlta offered 155 MW into the auction at negative $898/MW, compared to 125 MW at negative $898/MW in the auction for May 4. The resulting equilibrium price basically guaranteed that providers of off peak supplemental reserves would not receive revenues for May 5.

- For Tuesday, May 20 the on peak spinning reserves market cleared at $37.71/MW, an unusually high price and one which is close to the price cap of $40/MW. Equilibrium prices for spinning and supplemental reserves are typically negative, meaning received prices clear at a discount to pool prices, because the provision of these reserves requires available capacity rather than energy. However, in the auction for May 20 TransAlta reduced the supply it offered at negative $880.50/MW to only 19 MW, compared to 142 MW in the auction for May 19. TransAlta's reduced offer volumes put upward pressure on the equilibrium price and was the main driver of this outlier.

- For Thursday, June 26 the equilibrium price for off peak spinning reserves cleared at negative $480/MW, which is unusually low. This low price basically guaranteed that off peak spinning reserve providers would not receive revenues for June 26. The lower equilibrium price in this instance was the result of higher offer volumes by TransAlta. For June 26 TransAlta offered 149 MW at negative $880.50/MW and 21 MW at negative $480/MW, for a total of 170 MW offered at low prices. For comparison, in the auction for June 25 TransAlta offered 125 MW at negative $880.50/MW.

3.3 Standby reserves

The AESO procure standby reserves as backup to ensure enough active reserves are available. Standby reserves are activated because of an outage or constraint at an asset providing active reserves or if more active reserves are needed than were expected day-ahead, for example if realized demand is higher than the forecast.

In Q2 the AESO procured 195 GWh of standby reserves, with the majority being spinning reserves. The total volume of standby reserves procured in Q2 was similar to the amount procured in Q2 2024 (Figure 55). However, the AESO procured more standby spinning reserves in Q2 compared to Q1.

This occurred because each year the volume of standby spinning reserves procured by the AESO increases by 20 MW between May 1 and July 31. On peak volumes increase from 45 MW to 65 MW and off peak volumes increase from 35 MW to 55 MW.

Historically, the AESO have procured more standby spinning reserves from May through July because import volumes can be higher during the hydro run-off. Higher import flows can increase the demand for spinning reserves as the supply of imports on BC/MATL may increase above 466 MW and become the MSSC.

However, in Q2 Alberta was generally a net exporter of power. In addition, during hours of net imports, the import capability on BC/MATL often constrained import flows to around 400 MW, below the MSSC limit of 466 MW. Therefore, there was little room for import flows to increase standby spinning activations in Q2. The MSA understands that the AESO evaluates adjustments to standby volumes based on historical data on the frequency and volume of standby reserve activations.

Figure 55: Total standby volumes by quarter and product (Q1 2024 to Q2 2025)

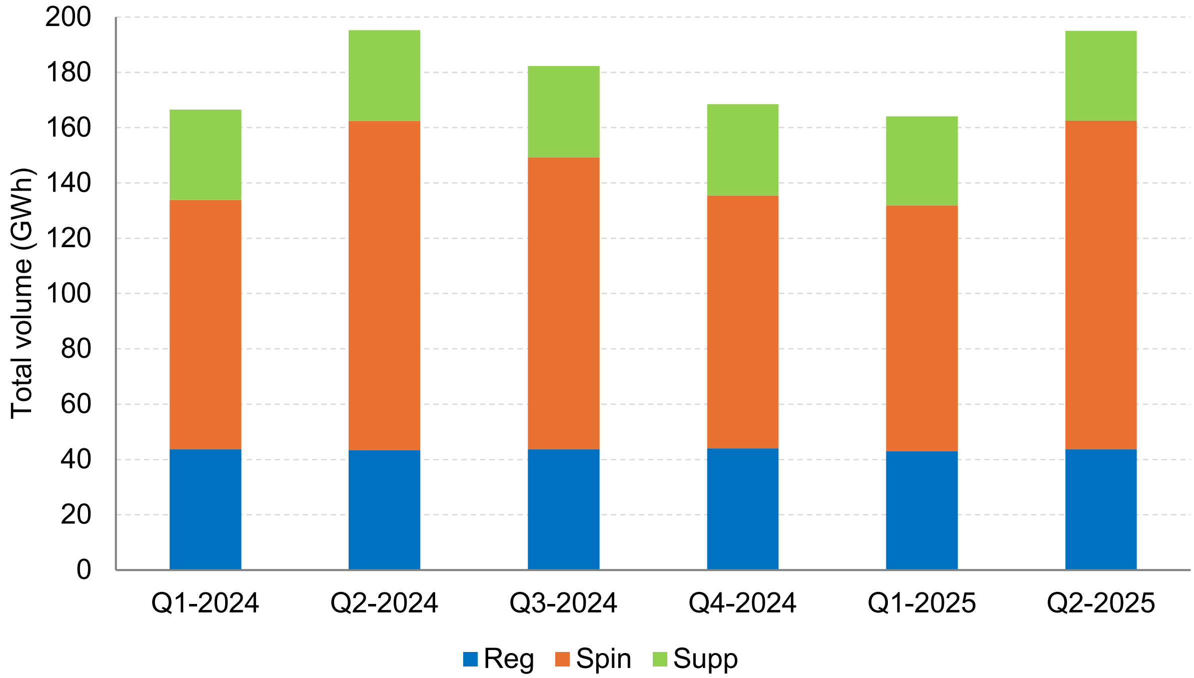


Table 25 provides activation rates by product since Q1 2024. The activation rates for regulating reserves were relatively low and stable over this period, ranging from 5% to 9%. However, the activation rates for spinning and supplemental reserves were more volatile. In Q1, the activation rates for spinning and supplemental reserves were 28% and 31%, respectively, compared to 11% and 19% in Q2. Activations for standby spinning and supplemental reserves in recent quarters were often caused by export volumes increasing demand.

Table 25: Activation rates by quarter and product (Q1 2024 to Q2 2025)

	Reg	**Spin**	**Supp**
Q1-2024	5%	23%	22%
Q2-2024	7%	7%	7%
Q3-2024	5%	12%	13%
Q4-2024	9%	17%	15%
Q1-2025	7%	28%	31%
Q2-2025	7%	11%	19%

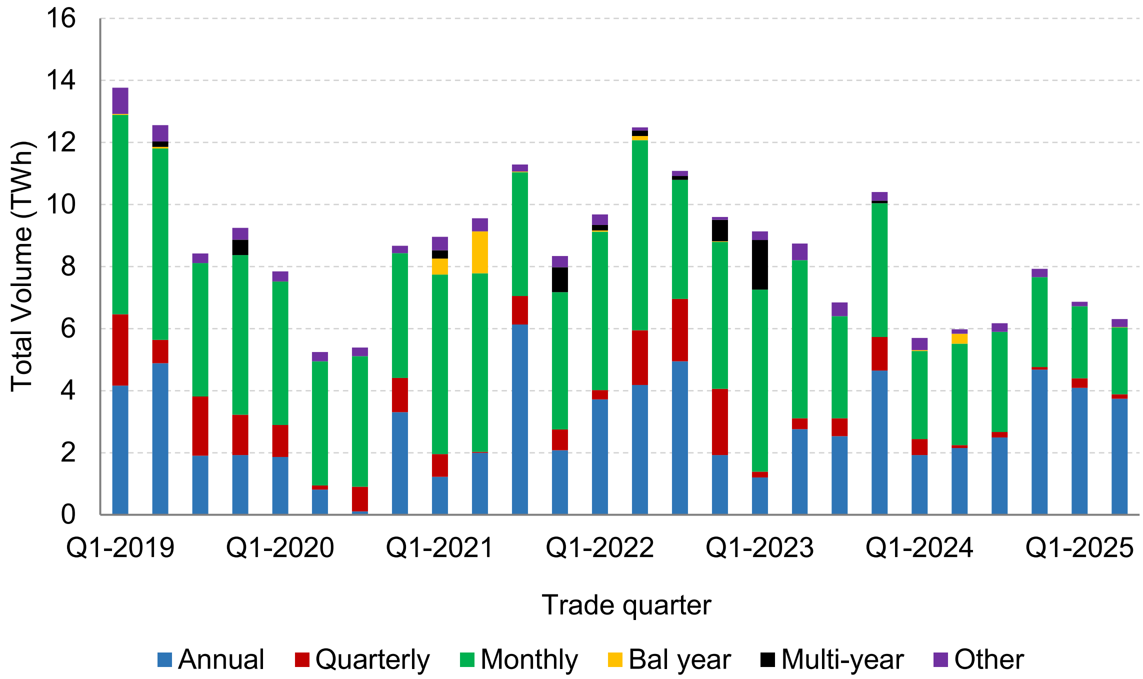
4 THE FORWARD MARKET

Alberta's financial forward market for electricity is an important component of the market because it allows for generators and larger loads to hedge against pool price volatility, and it enables retailers to reduce their price risk by hedging sales to retail customers.[13]

4.1 Forward market volumes

Low liquidity in the forward market continued in Q2 (Figure 56). The total trade volume on ICE NGX or through brokers was 6.3 TWh in Q2, which represents a decline of 8% from the previous quarter, but an increase of 5% from Q2 2024. As shown in Figure 56, total trade volumes have been relatively low over the past year.

Figure 56: Total trade volumes by term and quarter (Q1 2019 to Q2 2025, excludes direct bilateral trades)



Over the quarter, total volumes were lower in April and May and higher in June (Figure 57). In April, a total of 1.07 TWh was traded which marks the lowest monthly volume since May 2007.

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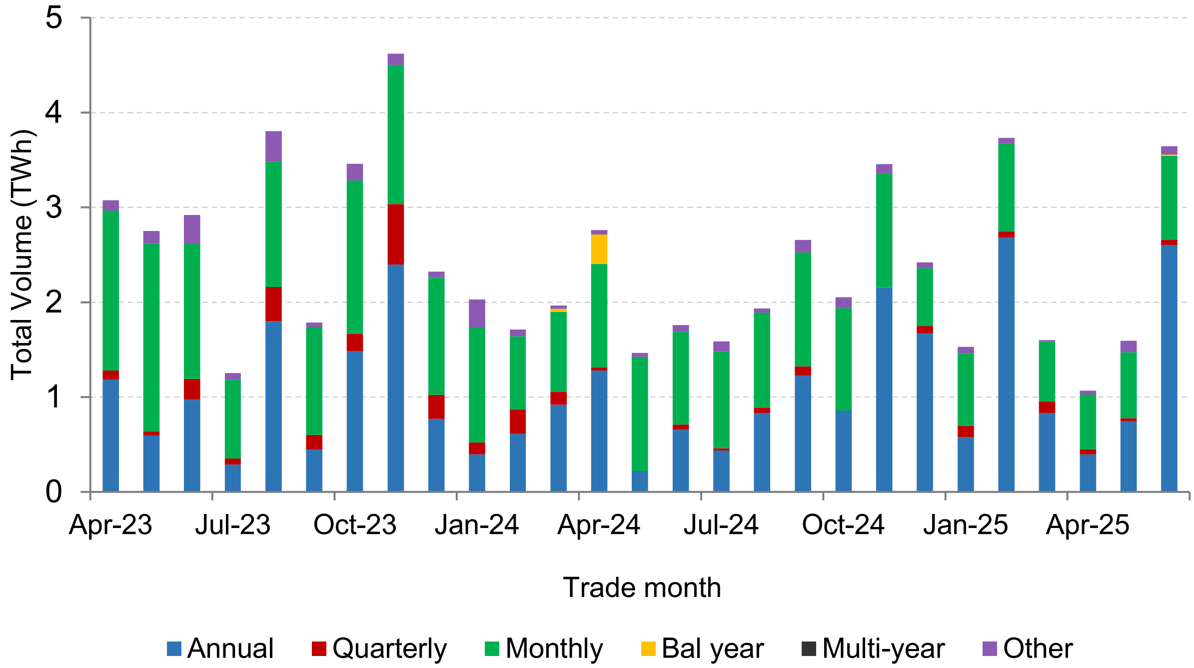
[13] The MSA's analysis in this section incorporates trade data from ICE NGX and two over the counter (OTC) brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2024 are also included 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.

Figure 57: Total trade volumes by term and month
(April 2023 to June 2025, excludes direct bilateral trades)



4.2 Trading of monthly products

Pool prices came in above forward market expectations in Q2, with pool prices settling slightly higher than the volume-weighted average forward price and the final trade price leading into the month (Figure 58).

The average pool price in April was $33.69/MWh, with a volume-weighted average forward price of $31.84/MWh, and a final trade price of $29.00/MWh. The marked price[14] of April reached a minimum of $27.51/MWh on April 9 but increased to $32.32/MWh by April 11.

The average pool price in May was $40.99/MWh, with a volume-weighted average forward price of $30.83/MWh, and a final trade price of $33.75/MWh. The marked price of May was only $34.93/MWh as of May 27, but this increased over the last few days of the month due to pool price volatility during the evening hours of May 27 and 28.

The average pool price in June was $46.75/MWh, with a volume-weighted average forward price of $36.13/MWh, and a final trade price of $43.00/MWh. The marked price of June reached a maximum of $53.84/MWh on June 22 as pool prices exceeded $900/MWh in select hours on the few days prior. However, marked prices fell throughout the remainder of the month as pool prices averaged $22.44/MWh from June 23 onwards.

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

Figure 58: Monthly flat forward prices and realized average pool prices by month (April 2024 to June 2025)

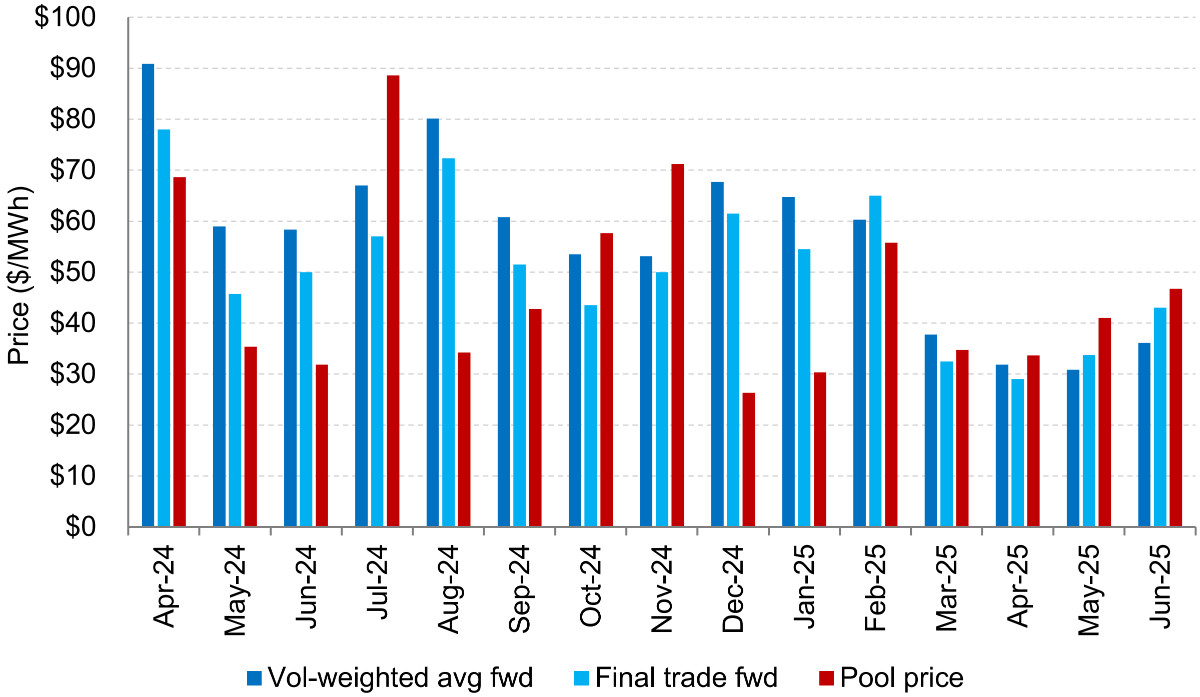
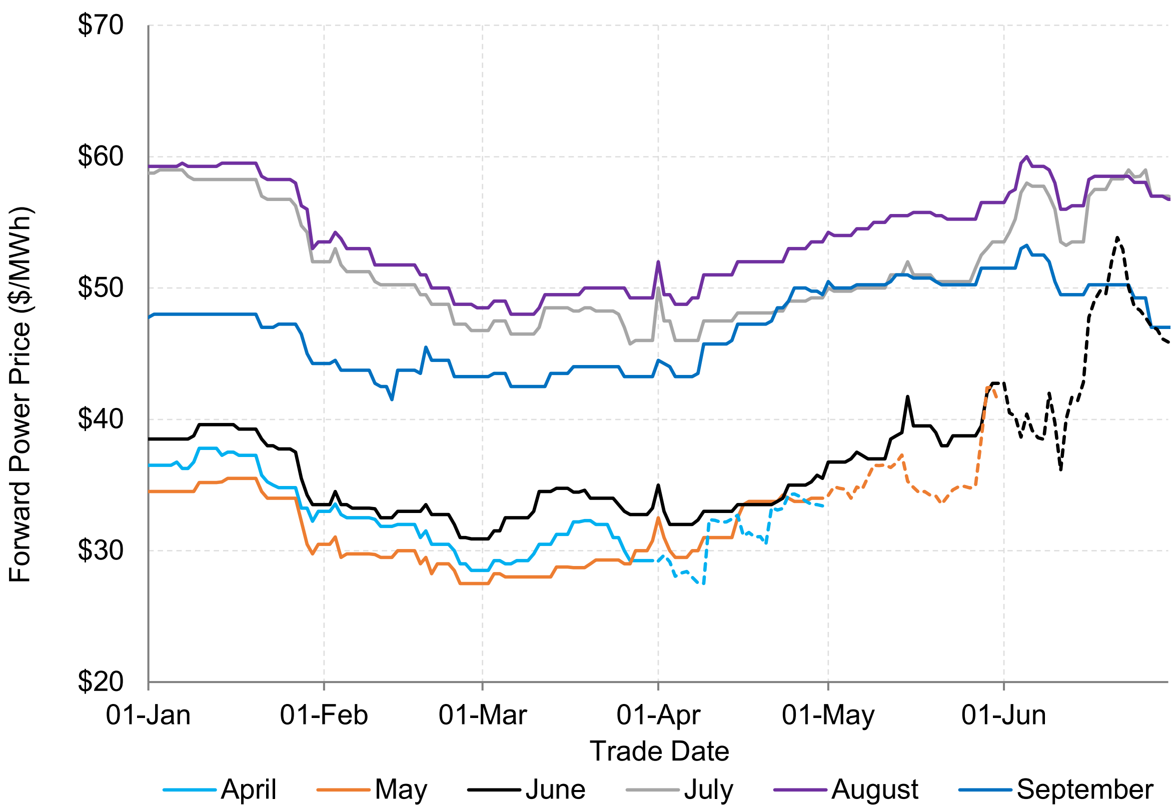


Figure 59: The evolution of select monthly flat forward prices (January 1 to June 30)

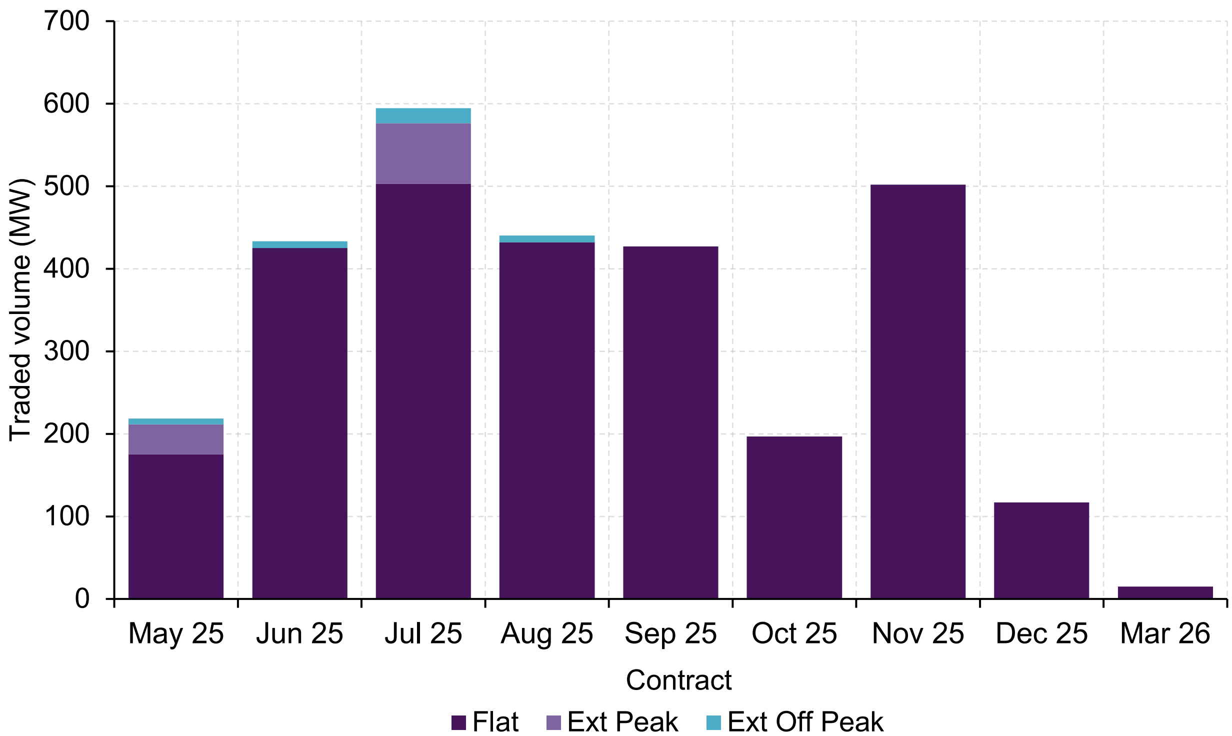


The evolution of select monthly forward prices over the course of Q2 is shown in Figure 59. The dashed lines in the figure illustrate the marked prices for April, May, and June. In Q2, forward price changes often occurred alongside changes to the prevailing marked price, as forward prices responded to events and outcomes in the energy market. Despite declining natural gas forwards, forward power prices increased over the quarter as pool prices came in above prior forward market expectations.

Figure 60 shows the distribution of traded volume by monthly product over Q2, and Figure 61 shows the distribution of traded volume by monthly product up to and including Q2. Over the quarter the highest traded monthly volume was for July followed by November.

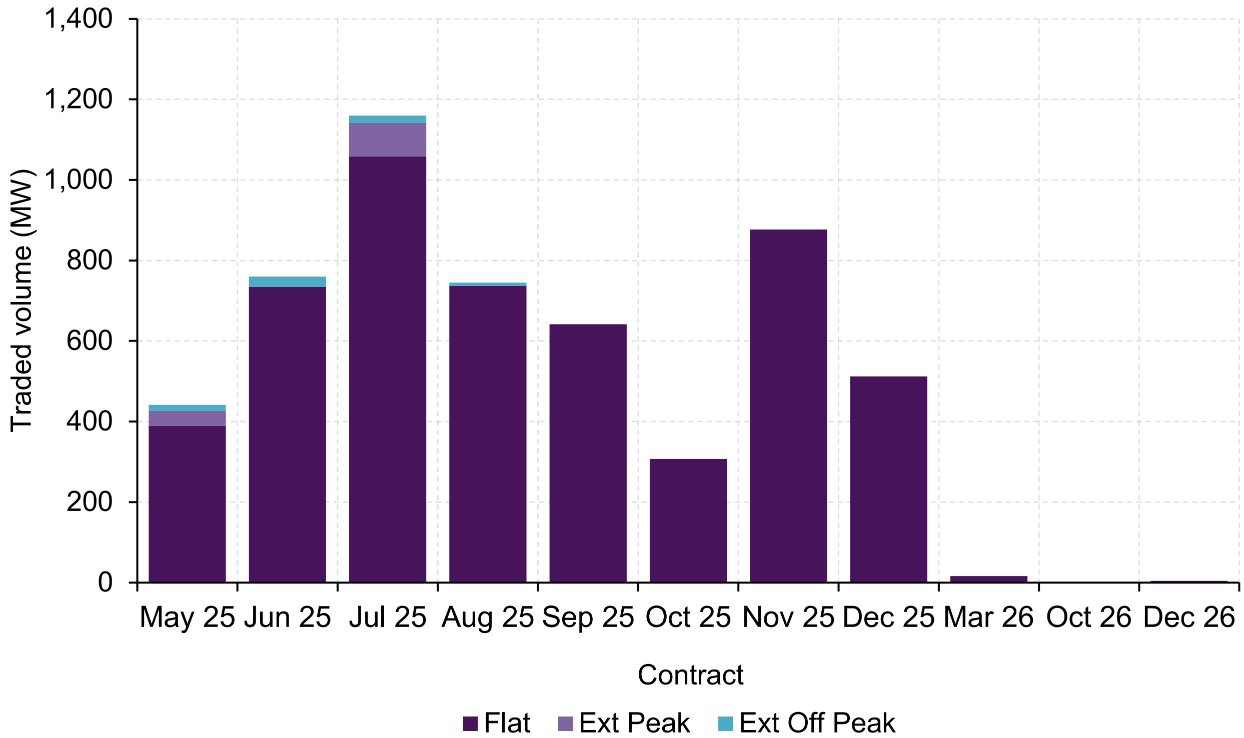
As shown in Figure 61, the volume traded so far for July outpaces other months by a significant margin. Additionally, the highest volume of extended peak products was traded for July.

Figure 60: Distribution of monthly trades in Q2 2025[15]



[15] Extended peak and extended off peak products weighted accordingly

Figure 61: Distribution of monthly trades up to and including Q2 2025[16]



4.3 Trading of annual products

Figure 62 shows the evolution of annual forward power prices since October 1, 2024. Annual power prices increased over Q2 with Cal 26 increasing by 19%, Cal 27 increasing by 23%, and Cal 28 increasing by 35%. The higher annual prices over the quarter were mainly driven by price increases in late May and early June (Figure 62).

The power price increases over the quarter occurred despite falling or relatively stable natural gas prices (Table 26). This combination led to spark spread increases of between 45% and 59%.

The marked price of Cal 25 increased by 11% over the quarter as pool prices came in above forward market expectations. The expected average price of natural gas for 2025 fell by 25% to $1.86/GJ.

Annual power prices saw a 2 to 3% increase over the first few days in April with Cal 27, Cal 28, and Cal 29 remaining relatively flat for the remainder of the month. On May 7, Cal 27, Cal 28, and Cal 29 increased by 3% following data centre news, with increases of 1 to 2% also seen on subsequent days.

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[16] Extended peak and extended off peak products weighted accordingly

Figure 62: The evolution of annual flat forward prices (October 1, 2024 to June 30, 2025)

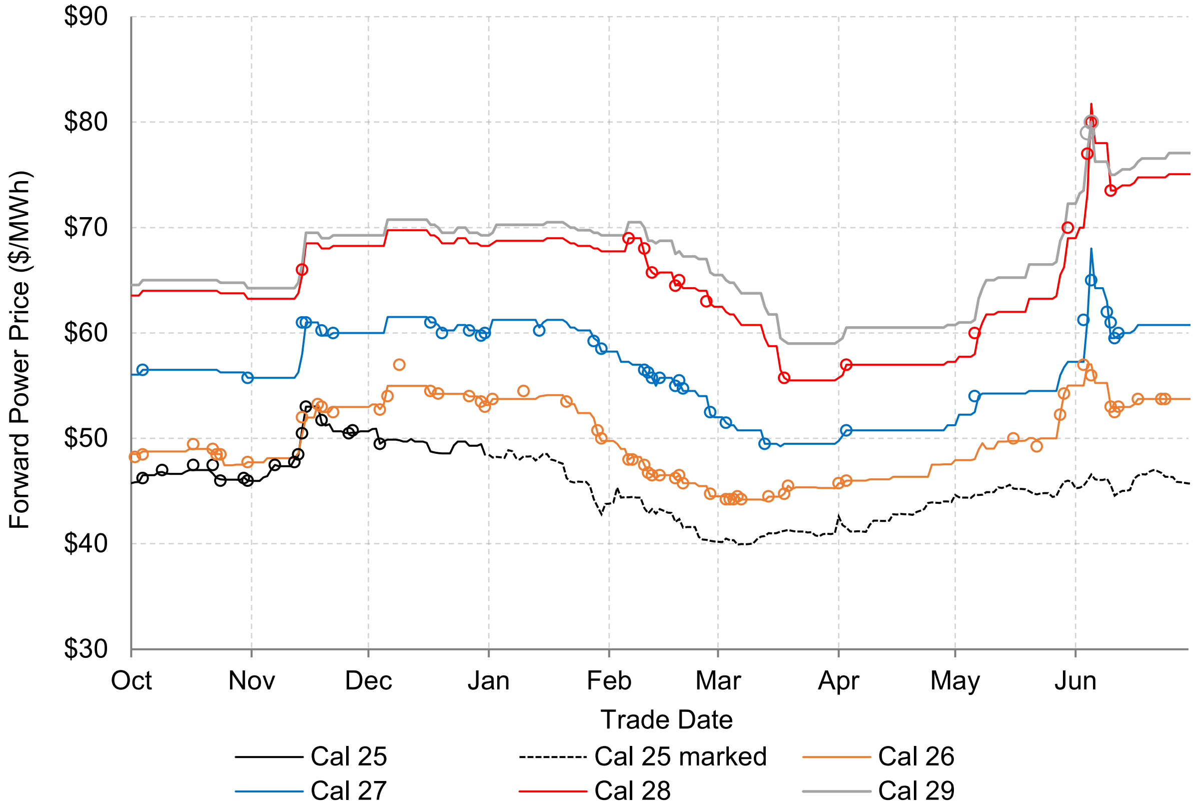

Table 26: Annual power and natural gas price changes over Q2 2025

Contract	Power price ($/MWh)			Gas price ($/GJ)			Spark spread[17] ($/MWh)		
	Mar 31	**Jun 30**	**% Chng**	**Mar 31**	**Jun 30**	**% Chng**	**Mar 31**	**Jun 30**	**% Chng**
Cal 25 Marked	$41.02	$45.73	11%	$2.47	$1.86	-25%	$22	$32	45%
Cal 26	$45.27	$53.75	19%	$3.20	$2.98	-7%	$21	$31	48%
Cal 27	$49.50	$60.75	23%	$3.07	$2.98	-3%	$26	$38	45%
Cal 28	$55.50	$75.05	35%	$2.96	$2.94	0%	$33	$53	59%
Cal 29	$59.00	$77.05	31%	$2.92	$2.96	1%	$37	$55	48%

From May 27 to 30, pool price volatility and buy-side pressure pushed up the price of calendar products by between 5 and 10% (Table 27). Over this period 45 MW of Cal 26 and 5 MW of Cal 28 traded.

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

Table 27: Annual contract prices (May 26 to 30, 2025)

	Cal 26	Cal 27	Cal 28	Cal 29
May 26 (Mon)	$49.99	$54.50	$63.25	$66.50
May 27 (Tue)	$49.99	$54.50	$63.50	$66.75
May 28 (Wed)	$52.24	$56.00	$65.60	$68.75
May 29 (Thu)	$54.23	$56.75	$66.25	$69.50
May 30 (Fri)	$55.00	$57.25	$69.00	$72.25
% change	**10%**	**5%**	**9%**	**9%**

The price of annual products continued to rise the following week (Table 28). For example, the price of Cal 27 increased by $10.75/MWh from June 3 to 5 and the price of Cal 28 increased by $11.75/MWh. Buying pressure following the AESO's discussion of integrating large loads was the principal driver of these price increases.[18]

Table 28: Annual contract prices (June 2 to 6, 2025)

	Cal 26	Cal 27	Cal 28	Cal 29
June 2 (Mon)	$55.00	$57.25	$70.00	$73.25
June 3 (Tue)	$55.00	$57.25	$70.00	$73.50
June 4 (Wed)	$57.01	$61.25	$73.25	$77.25
June 5 (Thu)	$57.01	$68.00	$81.75	$80.00
June 6 (Fri)	$55.25	$64.25	$78.00	$76.25
% change	**0%**	**12%**	**11%**	**4%**

Figure 63 shows the highest bid price and lowest offer price on ICE NGX for Cal 27 during the trading day of Thursday, June 5. Figure 64 shows the same analysis for Cal 28. The figures also show the time and price of trades executed on ICE NGX or via over the counter (OTC) brokers.

As shown in Figure 63, just prior to 10:00 there was an increase in the bid price for Cal 27 as it came up to meet the offer and the product traded for $65.00/MWh. Subsequently, the bid and offer prices for Cal 27 both increased and there was a flurry of trading activity. During this period, the traded price of Cal 27 increased from $65.00/MWh to $69.00/MWh, and for 82% of the ICE NGX trades the buyer lifted the offer of the seller, indicating buying pressure.

The price of Cal 27 declined later in the day as the buying pressure abated, with the product trading for $65.00/MWh at 14:40 and 16:46. Prices came down further on Friday, June 6 (Table 28) although no trades were executed (Figure 65). Prices continued to fall early in the following week; as of close on Tuesday, June 10 Cal 27 was priced at $59.50/MWh and Cal 28 was priced at $73.50/MWh.

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

Figure 63: Trading of Cal 27 (June 5, 2025)

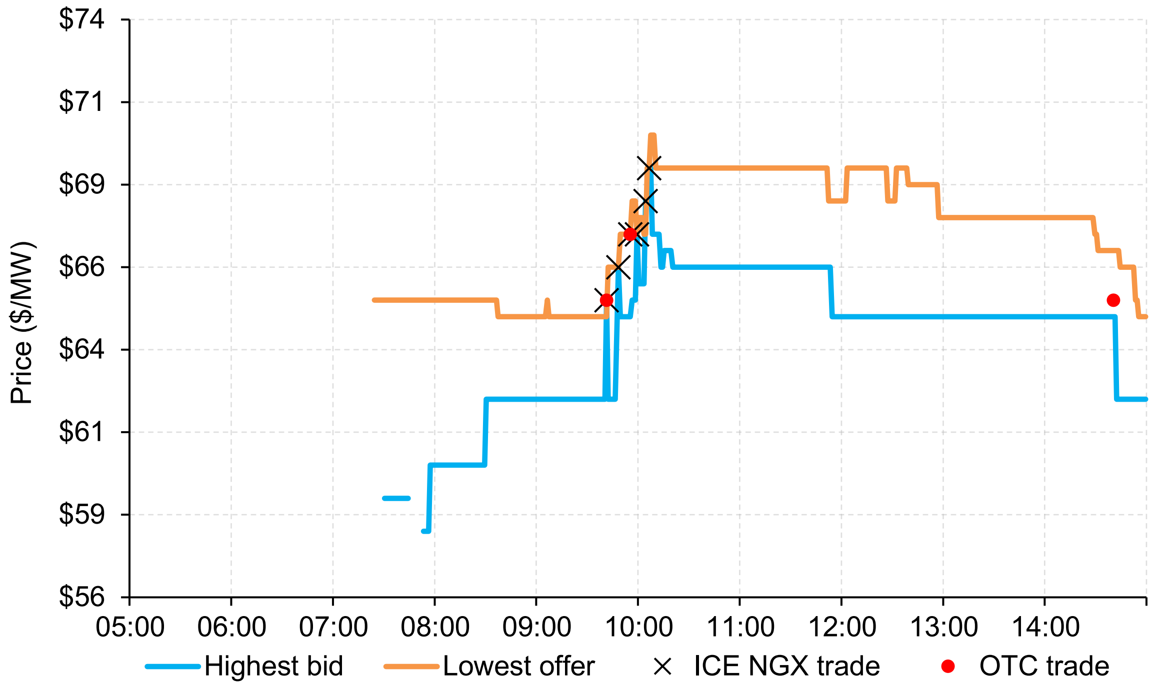

Figure 64: Trading of Cal 28 (June 5, 2025)

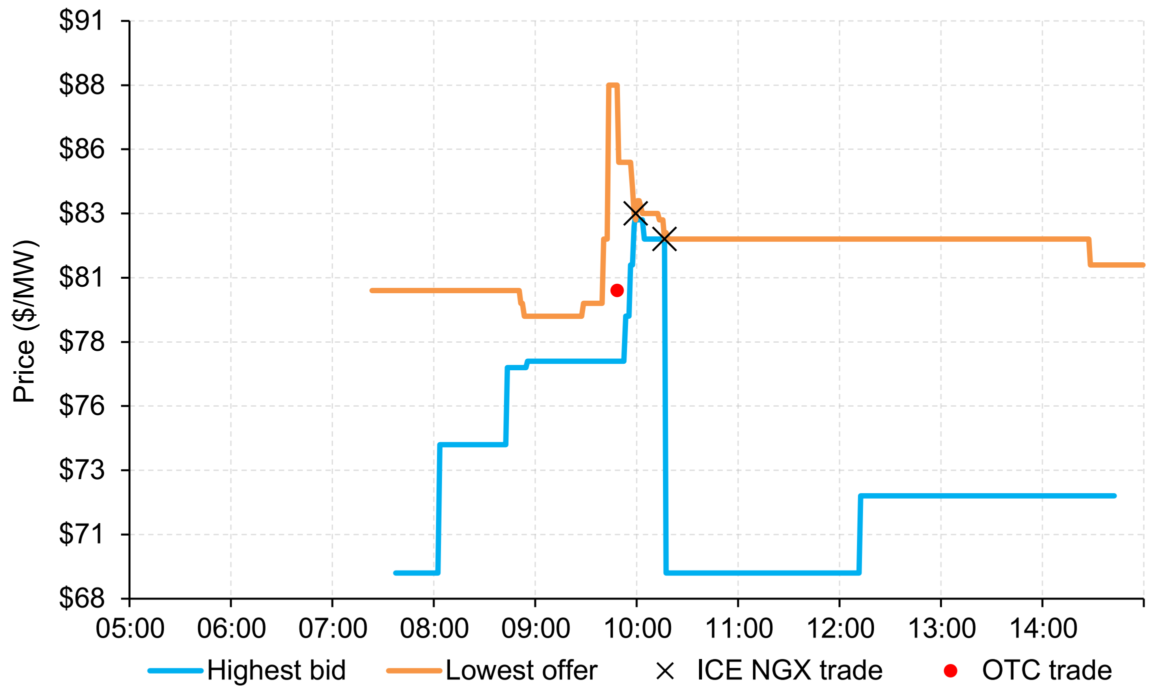

Figure 65: Traded volumes of annual products (June 2 to 6, 2025)

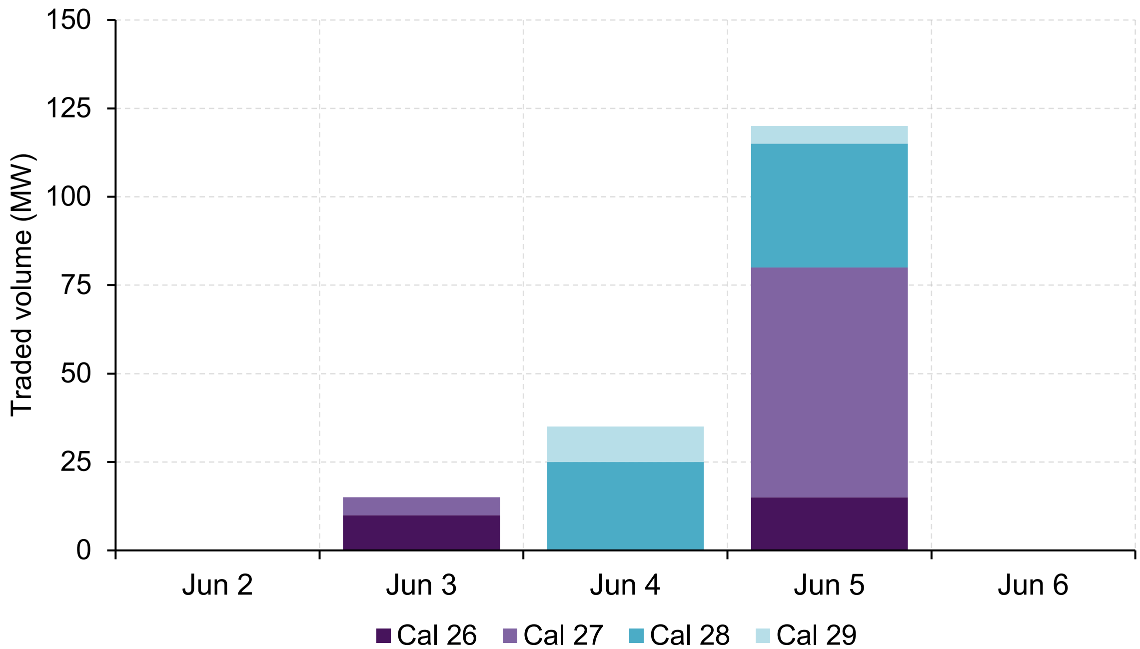

Figure 66 shows the distribution of traded volume by calendar product over Q2. As expected, the prompt year recorded the highest traded volume, with declining activity along the forward curve.

Figure 66: Distribution of annual trades (Q2 2025)