MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q2 2024

August 13, 2024

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

- **Market fundamentals drive decline in average pool prices:** the average pool price in Q2 was $45.17/MWh, the lowest average pool price since Q3 2020. The low pool prices were largely due to increased wind and solar generation, low natural gas prices, and high thermal availability.

- **The AESO shed load for the first time since 2013:** on the morning of April 5 the AESO shed firm load for 26 minutes due to a large volume of thermal generator outages, which combined with low wind and solar generation to reduce supply. This event is discussed in detail in a separate MSA report titled "Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations".

- **Supply surplus and Energy Emergency Alert (EEA) events declared on the same day:** on April 3 the AESO declared a supply surplus event between 12:04 and 14:11 partly because of high wind and solar generation. Around five hours later, between 19:26 and 20:40, the AESO declared an EEA, indicating insufficient supply to reliably meet demand. The dramatic change in conditions was caused by a decline in wind and solar generation in addition to Genesee 2 being taken offline for a forced outage and Battle River 5 being taken offline commercially.

- **End of coal-fired generation in Alberta:** Q2 saw the retirement of Genesee 1 and 2, the last coal assets in the province. As of May 17, Alberta's electricity supply became permanently free of coal for the first time in many decades. The Genesee assets have been replaced by Genesee Repower 1 and 2 which are simple-cycle natural gas assets. Later this year, these simple-cycle assets are scheduled to connect with the steam turbines at Genesee 1 and 2 to create efficient combined cycle assets. Alberta's electricity supply mix is dominated by natural gas with increasing amounts of wind and solar generation.

- **Extended supply surplus event**: on June 16 pool prices averaged $6.57/MWh, the third lowest on record, due to low demand and high wind and solar generation as the AESO declared a supply surplus event for over 16 hours; from 01:00 to 17:12.

- **Record-setting intermittent generation**: the high amount of wind generation in April meant that intermittent generation combined with hydro accounted for 25% of supply over the month, a new record. Over the quarter, intermittent generation and hydro accounted for at least 30% of supply in 23% of hours.

- **Transmission constraints increase**: in Q2, the volume of intermittent generation that was constrained down reached a record high of 214 GWh, a volume more than five times greater than Q2 2023. At least 1 MWh of intermittent generation was constrained down in 62% of hours in Q2. The constrained and unconstrained SMP differed by $1/MWh or more in 27% of hours in Q2, a marked increase when compared with year-over-year and quarter-over-quarter.

- **Low forward market liquidity:** Total trade volumes in Q2 were low at 5.98 TWh, which is similar to Q1 but represents a 32% reduction compared to Q2 2023. This level of trading is low relative to historic volumes and is comparable with the volumes observed in Q2 and Q3 of 2020 when market liquidity was reduced by uncertainty around the COVID-19 pandemic.

- **Lower expected costs for retail contracts:** declining forward market prices have led to lower expected costs for retailers offering fixed rate contracts. Consequently, some retailers reduced their prices over the quarter; at the end of Q2 the lowest five-year rate was 9.79 c/kWh.

- **Residential RRO customer losses declined:** the net loss in residential RRO customers was only around 10,000 in Q1. The net loss was around 38,000 in Q4 2023 and around 66,000 in Q3 2023. The decline in the number of customers leaving the RRO can be attributed to the relatively low RRO rates in Q1.

- **MSA compliance matters stable year to year:** From April 1 to June 30, 2024, the MSA closed 81 ISO rules compliance matters; 24 matters were addressed with notices of specified penalty. For the same period, the MSA closed 32 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; two matters were addressed with notices of specified penalty. In addition, the MSA closed 43 Alberta Reliability Standards Operations and Planning compliance matters; seven matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q2[1] was $45.17/MWh, a 72% decline compared to Q2 2023 and the lowest average pool price since Q3 2020. Despite a moderate increase in demand, pool prices were substantially lower in Q2 this year because of higher intermittent generation, lower natural gas prices, and more available thermal capacity.

Table 1 provides some summary market statistics for Q2 and Q2 2023. Year-over-year, pool prices were lower in all three months of Q2 with the price in June falling by 83% to $31.85/MWh.

The highest priced month in the quarter was April at $68.61/MWh. Prices in April were increased by a planned outage at the largest generation asset in Alberta: Shepard (868 MW).

In addition, the average price of April was increased by outcomes on April 5, when the AESO declared an EEA event and shed load for 26 minutes. This was the first time the AESO has shed load since July 2, 2013.

Figure 1 illustrates the number of EEA hours by year. As of July 31, there had been 24 EEA hours so far in 2024, a record surpassed only by 2013 which had 28.

Table 1: Summary market statistics for Q2 2023 and Q2 2024

		2023	2024	Change
Pool price (Avg $/MWh)	April	$142.34	$68.61	-52%
	May	$152.85	$35.37	-77%
	June	$184.41	$31.85	-83%
	Q2	**$159.79**	**$45.17**	**-72%**
Demand (AIL) (Avg MW)	April	9,387	9,697	3%
	May	9,053	9,296	3%
	June	9,449	9,585	1%
	Q2	**9,293**	**9,523**	**2%**
Gas price AB-NIT (2A) (Avg $/GJ)	April	$2.41	$1.33	-45%
	May	$2.43	$1.25	-49%
	June	$2.34	$0.83	-64%
	Q2	**$2.39**	**$1.14**	**-52%**
Wind gen. (Avg MW)	April	1,166	1,880	61%
	May	857	1,439	68%
	June	876	1,397	59%
	Q2	**965**	**1,571**	**63%**
Solar gen. (Avg MW during peak hours)	April	466	622	33%
	May	588	619	5%
	June	607	780	29%
	Q2	**554**	**673**	**21%**
Net imports (+) Net exports (-) (Avg MW)	April	-40	-51	30%
	May	474	-10	-102%
	June	214	-132	-162%
	Q2	**219**	**-64**	**-129%**
Available thermal capacity (Avg MW)	April	8,882	8,508	-4%
	May	8,191	9,356	14%
	June	8,666	9,509	10%
	Q2	**8,575**	**9,127**	**6%**

[1] Reference to Q2 means Q2 2024, reference to a month or date means the month or date in 2024.

Despite the high prices on April 5, the average price in April was 52% lower year-over-year as wind generation increased by 61% to average 1,880 MW, and natural gas prices fell by 45% to 1.33/GJ.

Figure 1: EEA hours by year (2010 to July 31, 2024)

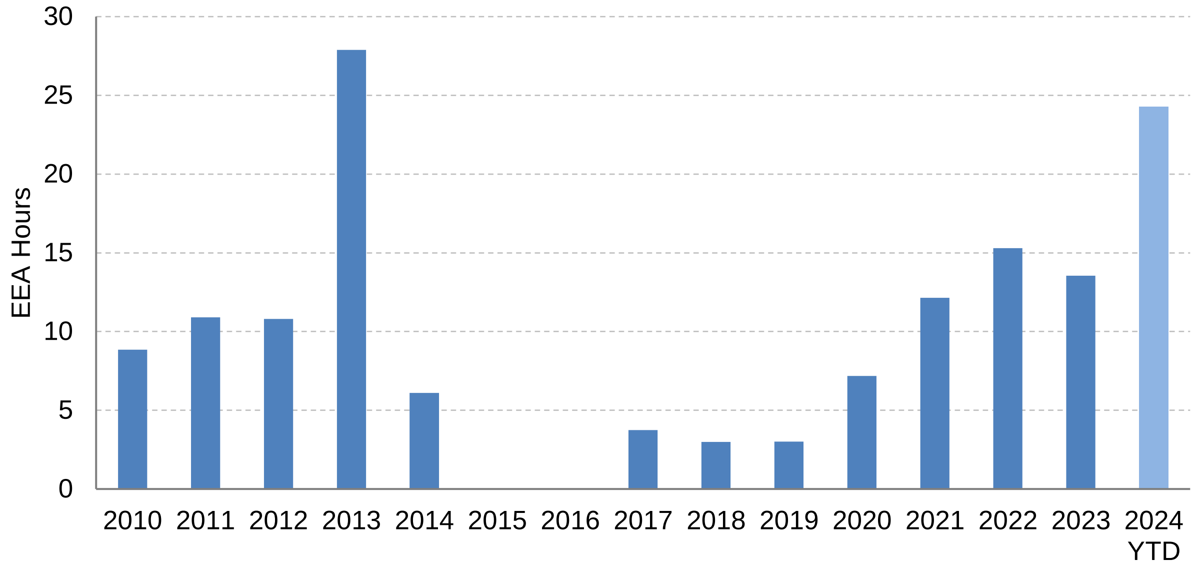
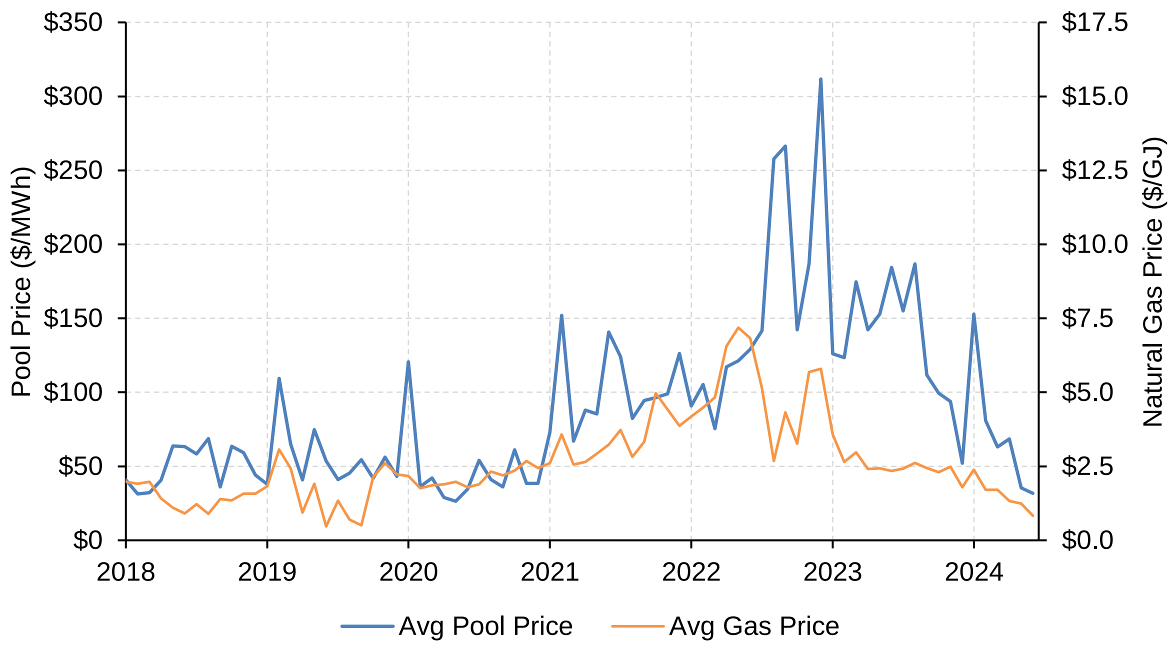


Figure 2 illustrates monthly average power and natural gas prices since 2018. In Q2, pool prices in May and June trended down alongside natural gas prices. The average pool price in June was the lowest since May 2020, and the average natural gas price in June was the lowest since September 2019.

Figure 2: Average pool price and natural gas price by month (January 2018 to June 2024)



Wind generation averaged 1,571 MW in Q2, an increase of 63% relative to Q2 2023. In addition, average solar generation during peak hours increased by 21% to 673 MW. Figure 3 illustrates the distribution of intermittent (wind and solar) generation in Q2 relative to Q2 2023. The upward shift in the duration curve indicates the higher intermittent generation year-over-year. In Q2, intermittent generation supplied between 29 MW and 4,506 MW of generation, a large range considering that average demand was 9,523 MW.

Figure 3: Duration curves of intermittent generation (Q2 2024 and Q2 2023)

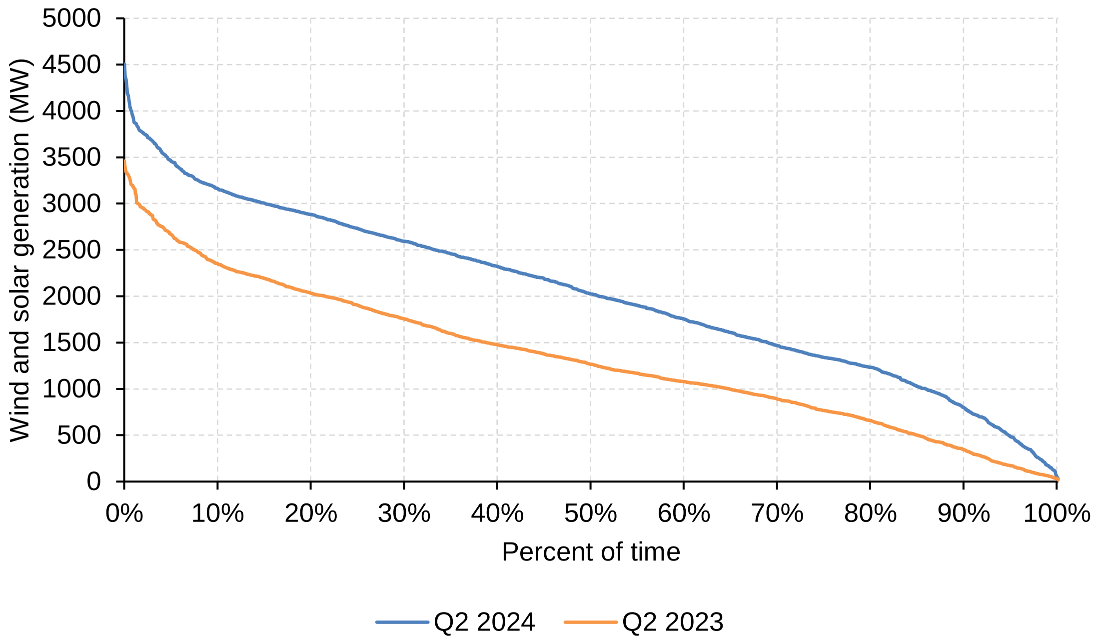
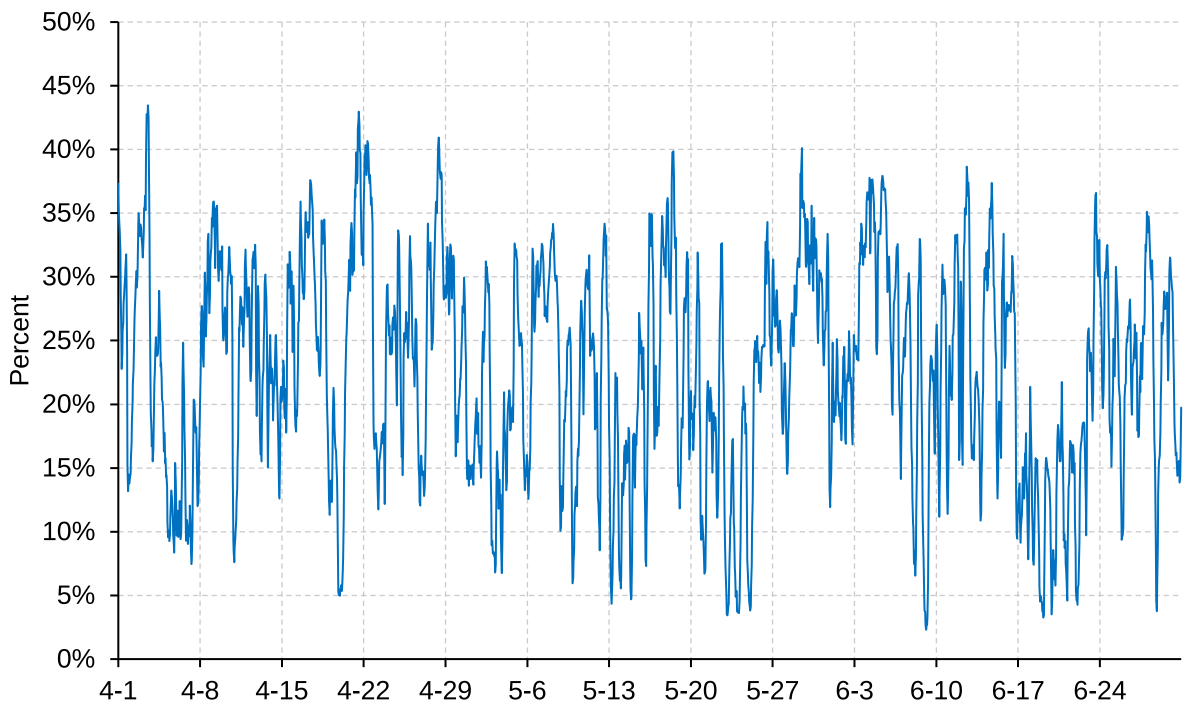


Figure 4 illustrates the combination of intermittent and hydro generation as a percentage of hourly supply over the quarter. This analysis includes generation that was produced and consumed on large industrial sites (behind the fence generation). As shown, the penetration of renewables changed significantly over the quarter as the supply of intermittent generation varied.

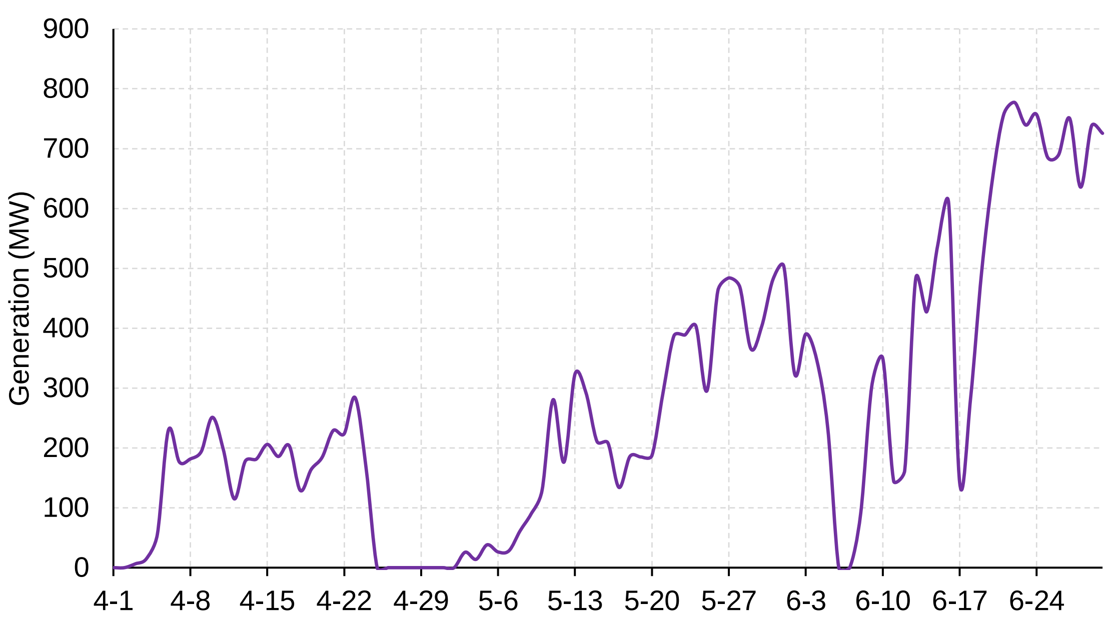
On April 3 in HE 14, the combination of intermittent and hydro generation was 4,660 MW and accounted for 43% of total generation, the highest in the quarter. The high amount of wind generation in April meant that renewables accounted for 25% of total generation over the month, a new record. Renewable generation accounted for 30% of total generation or more in 23% of hours over Q2.

Figure 4: Renewables as a percent of total Alberta generation (Q2 2024)



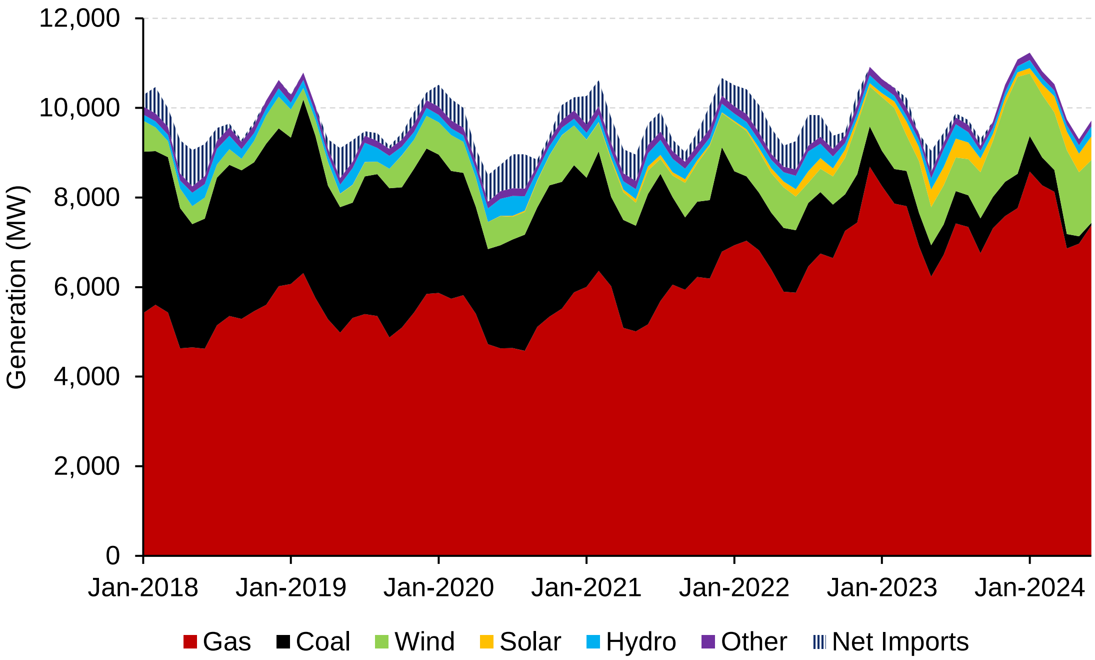
In addition to increasing intermittent supply, thermal availability also increased in May and June relative to last year. One of the main drivers behind the increased thermal availability was the commissioning of Cascade 1 and 2: two large combined cycle assets sized at 450 MW each. Figure 5 provides the combined hourly generation of Cascade 1 and 2 over the quarter. As shown, the assets' generation increased in late May and then rose further in late June.

Figure 5: Hourly generation of Cascade 1 and 2 (Q2 2024)



Q2 also saw the end of coal-fired generation in Alberta as Genesee 1 and Genesee 2 ceased operations on April 7 and June 16, respectively. Genesee 2 stopped using coal on May 17 and after this date was run at a lower generation level using natural gas. As such, the use of coal to generate electricity in Alberta ceased on May 17, 2024. Figure 6 illustrates the decline in coal generation since the start of 2018. Coal generation has largely been replaced by more natural gas; nine coal generators were converted to run on natural gas totalling 3,400 MW of capacity.

Figure 6: Monthly average generation by fuel type (January 2018 to June 2024)



The Genesee 1 and 2 assets are being converted from coal to combined cycle natural gas. In recent months, Genesee Repower 1 and 2 (411 MW each) connected to the grid as simple cycle natural gas generators. Later in the year, the steam turbines at Genesee 1 and 2 will be connected to these simple cycle generators to create two efficient combined cycle assets.

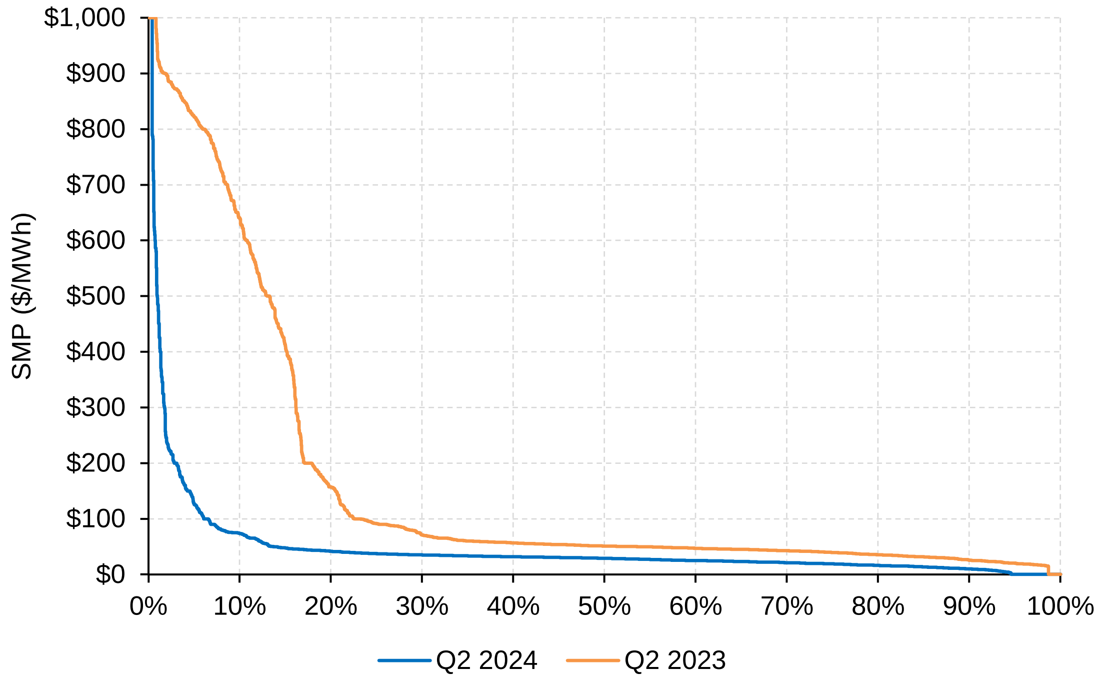
1.2 Market outcomes and events

Figure 7 illustrates the distribution of System Marginal Prices (SMPs) in Q2 and Q2 2023. Prices in Q2 were lower than in Q2 2023 throughout the distribution. In the top 20% of hours prices averaged $132/MWh in Q2 compared to $600/MWh in Q2 2023 as the market saw increased supply and less market power exercised. Prices were also lower at the bottom of the distribution. For example, the bottom 60% of hours in Q2 averaged $19/MWh compared with $40/MWh in Q2 2023. This was largely due to increased intermittent generation and lower natural gas prices.

The SMP cleared at $1,000/MWh for 26 minutes on April 5 as the AESO shed firm load. Prices cleared at the offer price cap of $999.99/MWh on April 3, April 5, and June 25. The events on April 3 and June 25 are discussed here, the April 5 event is discussed in a separate MSA report.

At the other end of the distribution, the SMP cleared at $0/MWh, the offer price floor, 5.2% of the time in Q2 compared to 1.0% of the time in Q2 2023. Increasing amounts of intermittent generation have put downward pressure on prices in the energy market in hours where their fuel is available.

Figure 7: Duration curve of SMPs (Q2 2024 and Q2 2023)



1.2.1 April 3 price volatility

On Wednesday, April 3 the energy market went from a situation of supply surplus to supply shortfall in around five hours. Figure 8 illustrates the SMP on April 3 alongside wind and solar generation. Between 12:04 and 14:11 the AESO declared supply surplus meaning that the supply of generation at $0/MWh exceeded prevailing demand. At this time intermittent generation was supplying around 4,500 MW and the Sheerness 1 and Battle River 4 assets were commercially offline.

However, going into the evening hours intermittent generation declined and thermal availability fell. As shown by Figure 8, intermittent generation declined materially at sunset and as wind speeds fell. Wind generation fell from 3,500 MW at 13:00 to 1,200 MW at 20:00, a decline that was accurately predicted by the AESO's wind forecast (Figure 9). Solar generation declined predictably from 900 MW at 18:00 to 0 MW at 20:00 as the sun set.

Despite the expected decline in intermittent generation, at 14:00 Battle River 5 was taken offline for commercial reasons. In addition to this, at around 17:30 Genesee 2 suffered a forced outage and was offline by 19:00. Between 19:26 and 20:40 the AESO declared an EEA 3 indicating that there was not enough supply to reliably meet demand.

Figure 8: SMP, net demand, and wind and solar generation (April 3, 2024)

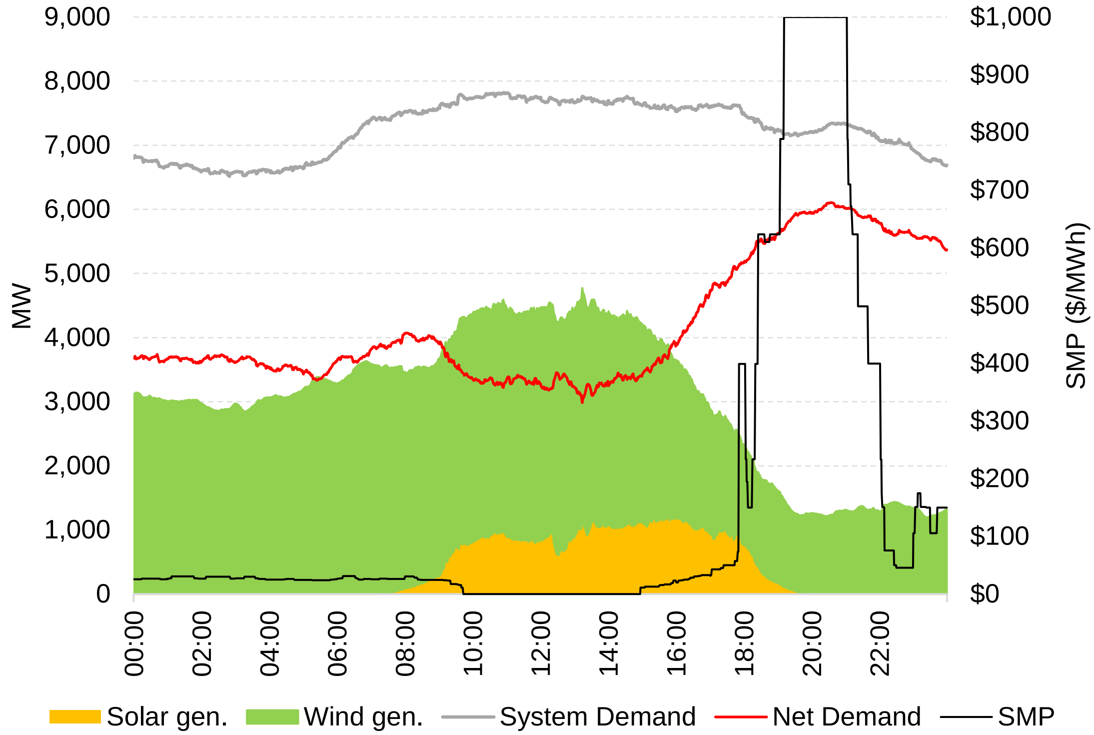
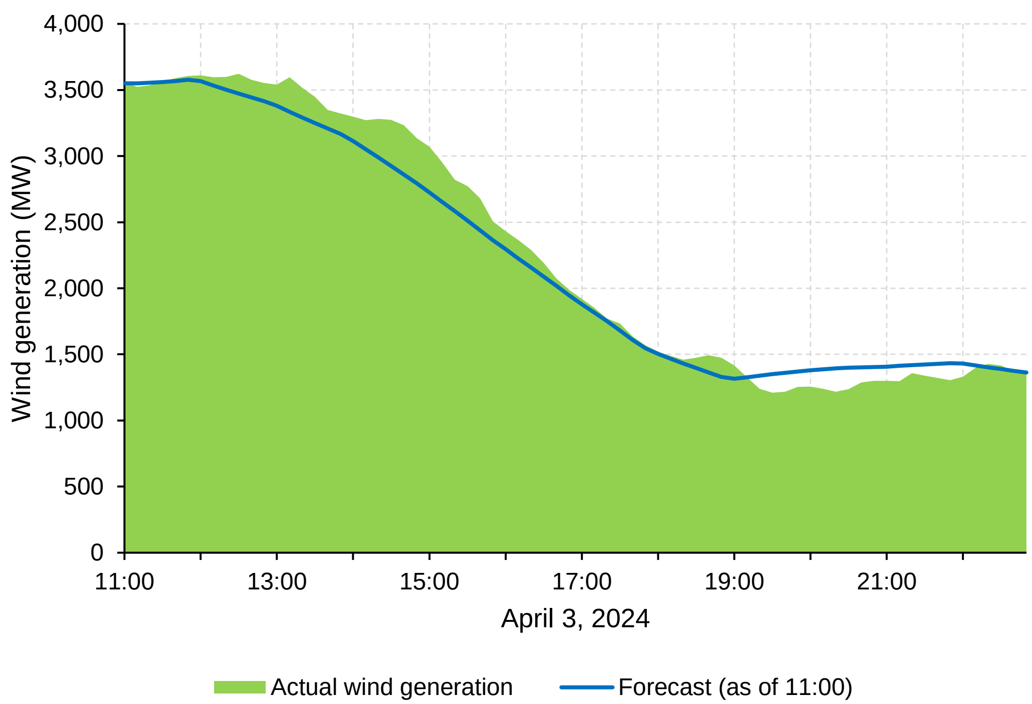


Figure 9: Actual and forecast wind generation (April 3, 2024)



This event highlights the issue of unit commitment with the Sheerness 1 (400 MW), Battle River 4 (155 MW), and Battle River 5 (395 MW) assets being commercially offline during the EEA 3 event despite accurate wind and solar forecasts.

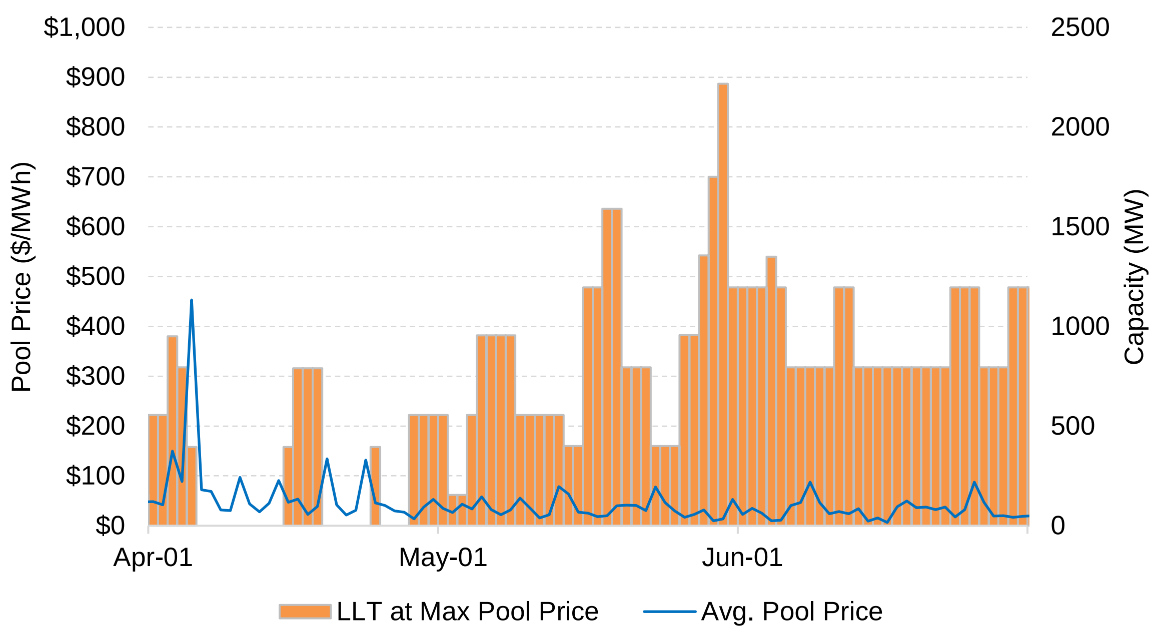
1.2.2 May 30: Six gas-fired steam assets commercially offline

On Thursday, May 30, high intermittent generation and low demand meant prices were low; the daily average pool price was $13.67/MWh. These market fundamentals led to six gas-fired steam assets being commercially offline at the same time. In total, these assets accounted for 2,217 MW of capacity (Table 2). For some assets this was part of an extended absence from the market. For example, Sheerness 2 was commercially offline from May 5 to June 26. Figure 10 illustrates the amount of capacity that was commercially offline (long lead time type I) during the highest pool price hour for each day in Q2.

Table 2: Assets that were commercially offline on May 30

Asset	Capacity (MW)	Commercially offline since	Commercially offline to
Sheerness 2	400	May 05 12:00	Jun 26 00:00
Battle River 4	155	May 25 12:00	May 31 16:00
Sundance 6	401	May 26 02:00	May 31 17:00
Sheerness 1	400	May 28 14:00	Jun 06 16:00
Battle River 5	395	May 29 01:00	Jul 07 13:00
Keephills 3	466	May 29 23:00	May 31 08:00
Total	**2,217**	-	-

Figure 10: Capacity commercially offline and daily average pool price (Q2 2024)



When several large thermal generators are offline and the market is more reliant on intermittent generation to meet demand, system inertia will be reduced and the ability of the system to react to unexpected shocks (i.e., primary frequency response) will be lower.

1.2.3 June 16: Extended supply surplus

On Sunday, June 16, the SMP cleared at $0/MWh from 00:16 to 12:47 and from 12:49 to 17:04. The low prices were caused by high amounts of wind generation and low weekend demand due to moderate temperatures (Figure 11). The daily average pool price settled at $6.57/MWh, which is the third lowest on record going back to January 1, 2001 (Table 3).

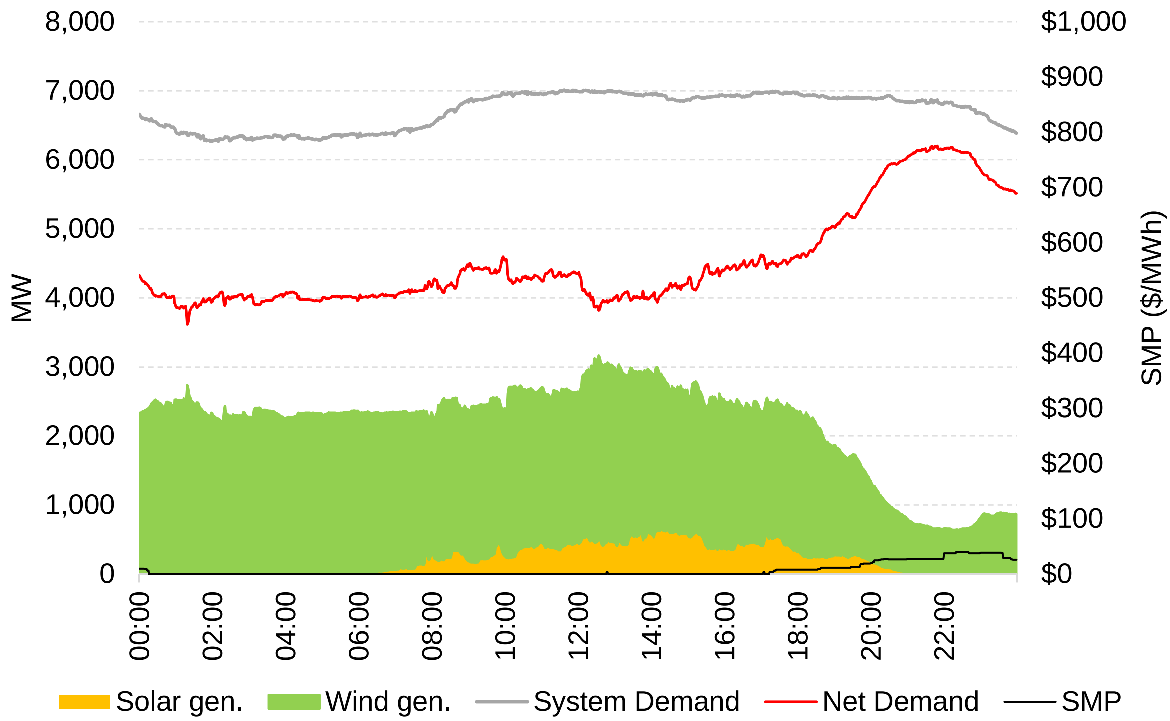
Table 3: The lowest daily average pool prices (January 1, 2001 to June 30, 2024)

Date	Average pool price ($/MWh)
June 9, 2012	$5.61
June 30, 2002	$6.46
June 16, 2024	**$6.57**
June 10, 2012	$6.71
December 19, 2004	$7.13

The AESO declared a supply surplus event for more than sixteen hours; from 01:00 to 17:12. The AESO dealt with the supply surplus in this event by curtailing imports on the MATL line. In HE 03, the AESO curtailed 125 MW of imports from MATL, the highest volume of imports curtailed on the day.

This event, and the frequency with which prices are clearing at $0/MWh, underline the ongoing need for negative pricing in the power pool to support efficient generation dispatch.

Figure 11: SMP, net demand, and intermittent generation (June 16)



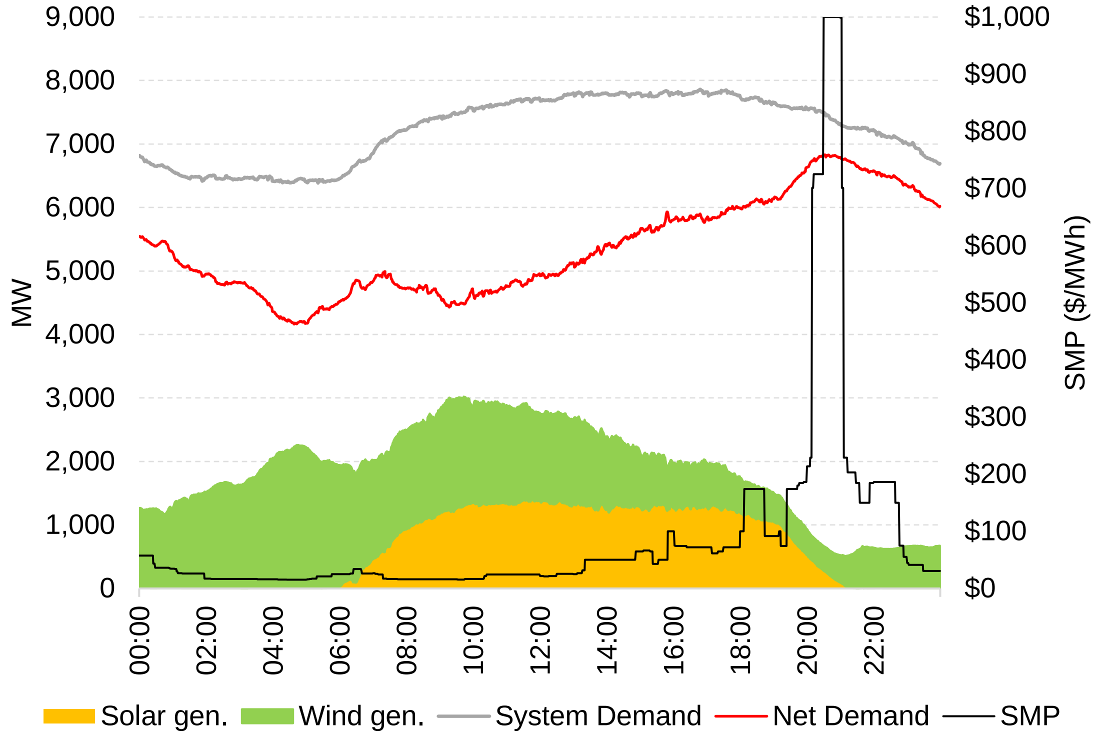
1.2.4 June 25: Price at the cap

On Tuesday, June 25, the SMP increased to $999.99/MWh from 20:30 to 21:00 but no EEA event was declared by the AESO. Prices earlier in the day had been relatively low with the average pool price from HE 01 to HE 18 being $32.78/MWh (Figure 12). Solar generation declined from 1,190 MW at 18:00 to 280 MW at 20:30 while wind generation declined from 560 MW to 400 MW over the same time period.

In addition to the decline in intermittent generation, there were a number of outages at thermal generation assets including Genesee 3 (466 MW), Keephills 2 (395 MW), Joffre (474 MW), and Sheerness 1 (400 MW). Sheerness 1 was on outage from HE 09 to HE 20, before going commercially offline in HE 21. In addition, Battle River 5 (395 MW) and Sheerness 2 (400 MW) were commercially offline for this event, further reducing supply.

This event underlines unit commitment as an issue given that three gas-fired steam assets were commercially offline when the SMP cleared at the cap.

Figure 12: SMP, net demand, and intermittent generation (June 25)



1.3 Market power and offer behaviour

1.3.1 Market power

Figure 13 compares observed pool prices with a short-run marginal cost (SRMC) counterfactual. The SRMC counterfactual estimates what prices would have been if all assets in the market were offered in at SRMC. The difference between observed prices and the SRMC counterfactual is indicative of market power, with a larger difference indicating greater exercise of market power.

The difference between observed pool prices and counterfactual SRMC prices was relatively small in Q2, indicating less exercise of market power. The average pool price in Q2 was $45/MWh compared to a SRMC average of $32/MWh. The ability of firms to exercise market power in Q2 was lowered by more available thermal capacity and increased intermittent generation.

Figure 13: Observed monthly average pool prices and SRMC counterfactual prices (January 2022 to June 2024)

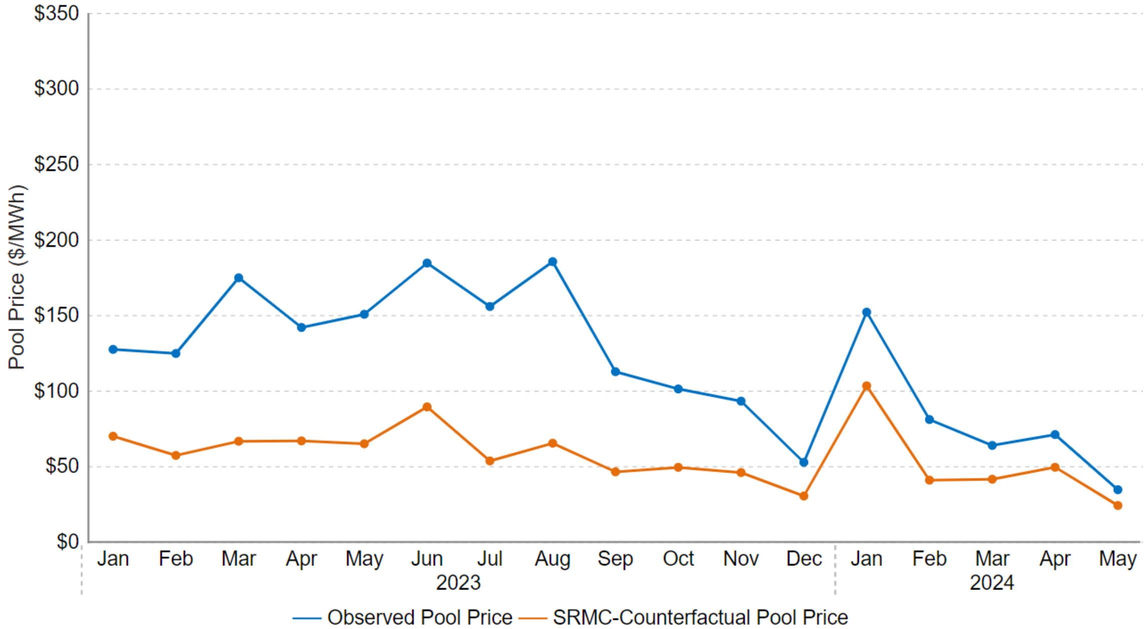


Figure 14 illustrates market-level pivotality by quarter going back to Q1 2020. A firm is pivotal when its withholdable generation capacity is needed for the market to clear.[2] The extent to which firms are pivotal in the market provides an indication of their ability to exercise market power. The levels of pivotality are as follows, in descending order:

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

In Q2 no firm was pivotal or collectively pivotal in 81% of hours and firms were only collectively pivotal in 15% of hours. At least one firm was pivotal in the remaining 4% of hours in Q2, compared to 11% of hours in Q1, and 18% of hours in Q2 2023. This fall in the ability of firms to exercise market power was largely driven by increased wind and solar generation and the commissioning of Cascade 1 and 2.

Figure 15 provides the average pool price by pivotality condition over time. As shown, pool prices tend to be relatively low when no firm is pivotal or when firms are only collectively pivotal.

[2] Witholdable generation capacity is all capacity except for Minimum Stable Generation and wind and solar.

Therefore, pool prices in Q2 were low in part because increased supply reduced the ability of larger firms to exercise market power.

Figure 14: Market level pivotality by quarter (Q1 2020 to Q2 2024)

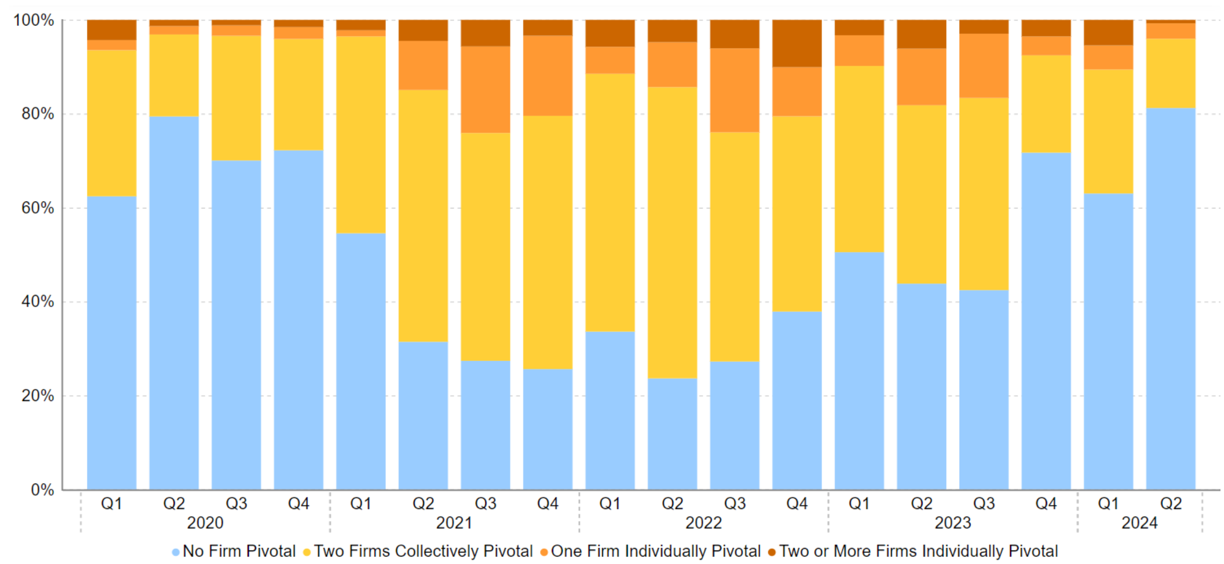
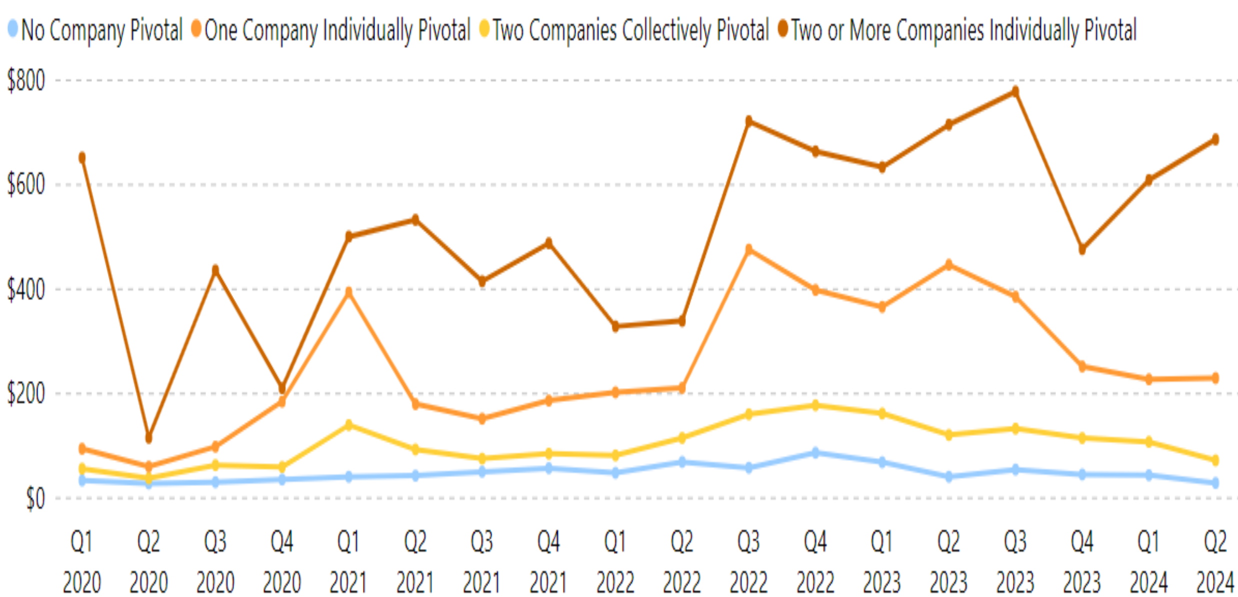


Figure 15: Quarterly average pool price by pivotality condition (Q1 2020 to Q2 2024)



The Lerner index is a measure of mark-up between observed prices and SRMC. The Lerner index indicates what percentage of price can be attributed to mark-up. A lower Lerner index indicates less exercise of market power. The average Lerner index in Q2 was low at 12%, a decline from 22% in Q1, and 29% in Q2 2023 (Figure 16).

Static inefficiencies were also low in Q2, again indicating less exercise of market power. Static inefficiencies arise when higher cost generation is dispatched instead of lower cost generation (productive inefficiency) or when some consumption is lost because prices are elevated by the exercise of market power (allocative inefficiency). Total static inefficiency losses averaged $0.94/MWh in Q2, the lowest value since Q4 2020 (Figure 17).

Figure 16: Average Lerner index by quarter (Q1 2020 to Q2 2024)

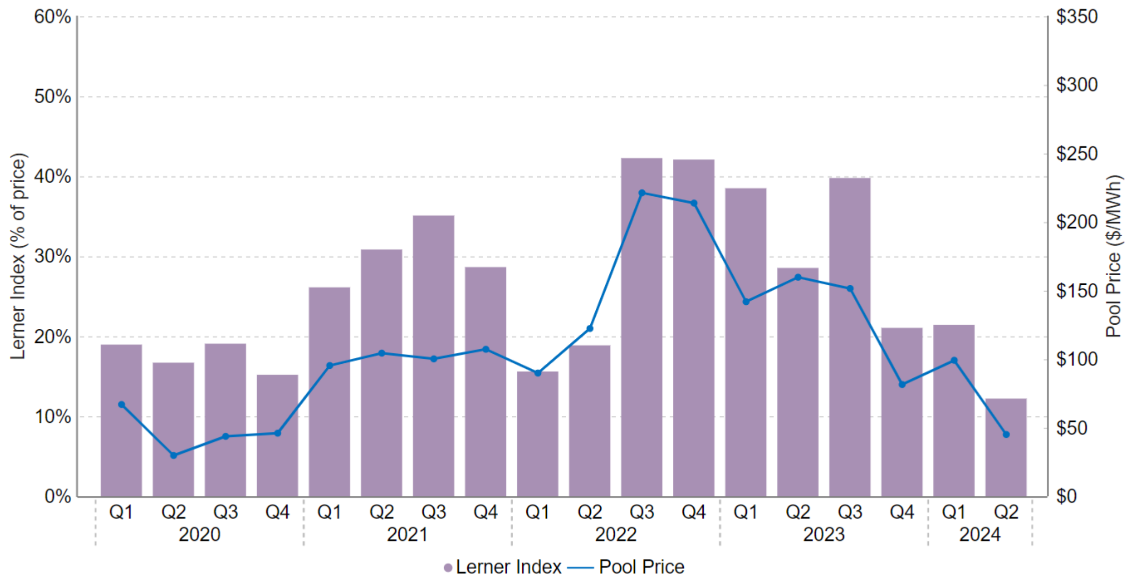
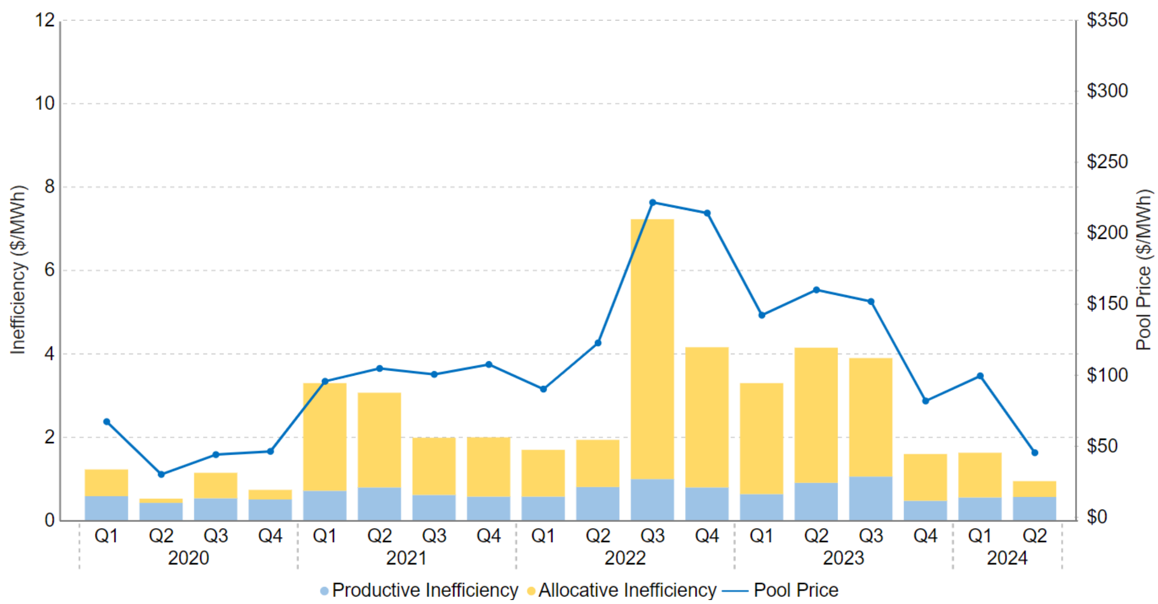


Figure 17: Average static inefficiencies and pool price by quarter (Q1 2020 to Q2 2024)



1.3.2 Offer behaviour

Figure 18 illustrates the average amount of non-hydro capacity that was offered above $100/MWh by quarter. The figure also breaks these offers down into price bins. On average in Q2 there was 416 MW priced between $800 and $999.99/MWh, a reduction of 50% compared to Q2 2023. Since Q4 2023 there has been relatively few offers above $800/MWh.

Figure 18: Average non-hydro capacity offered above $100/MWh (Q1 2021 to Q2 2024)

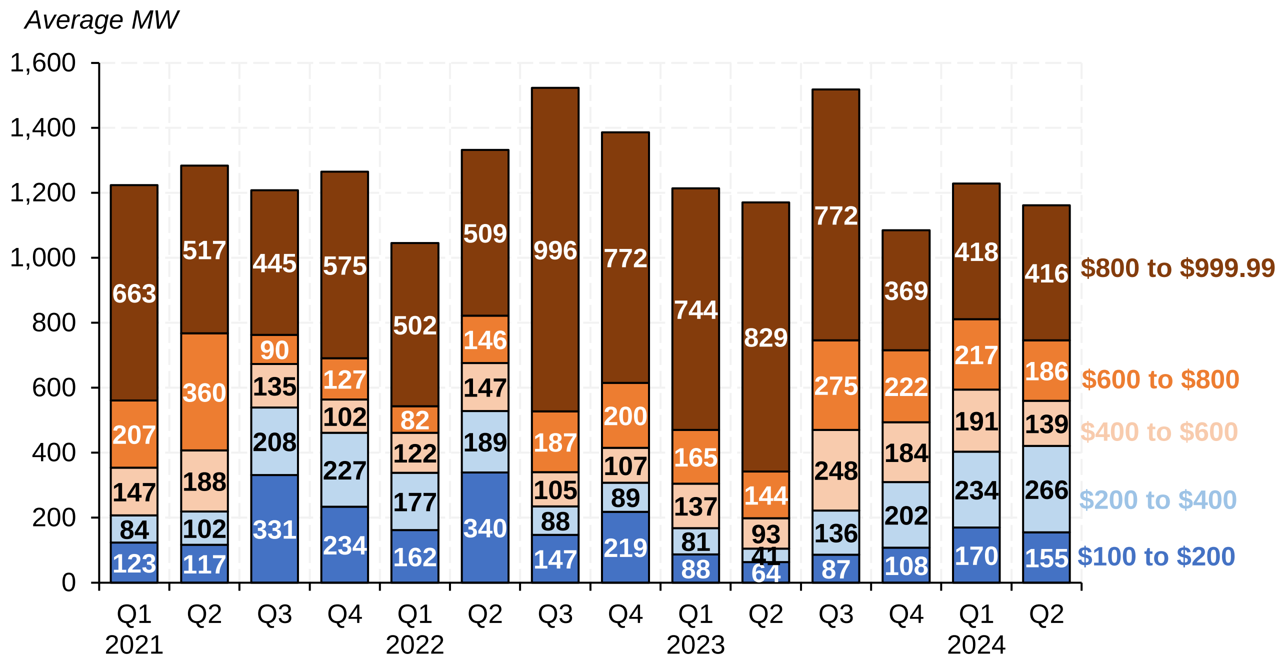


Figure 19 below illustrates offer behaviour by firm. Specifically, the figure illustrates the average amount of capacity that was offered above three times SRMC by firm and by quarter. Compared to Q1 2024 and Q2 2023, TransAlta and Heartland both offered less capacity above three times SRMC in Q2.

Figure 19 also illustrates the average amount of capacity that was commercially offline (i.e., on long-lead time). In Q2, the average amount of capacity that was on long lead time was 693 MW, the highest since Q2 2022. In Q2, assets were often taken offline on long-lead time during periods of low prices.

Larger suppliers exercised less market power in Q2 compared to Q2 2023. For example, in hours in which TransAlta was pivotal on its own the amount of non-hydro capacity that TransAlta offered above three times SRMC fell from 295 MW in Q2 2023 to 210 MW in Q2 (Figure 20). Likewise, for hours in which Heartland was pivotal along with at least one other company the average amount of capacity that Heartland offered above three times SRMC fell from 411 MW in Q2 2023 to 274 MW in Q2 (Figure 20).

Figure 19: Average non-hydro capacity offered above 3xSRMC or on long lead time (LLT) (Q1 2021 to Q2 2024)

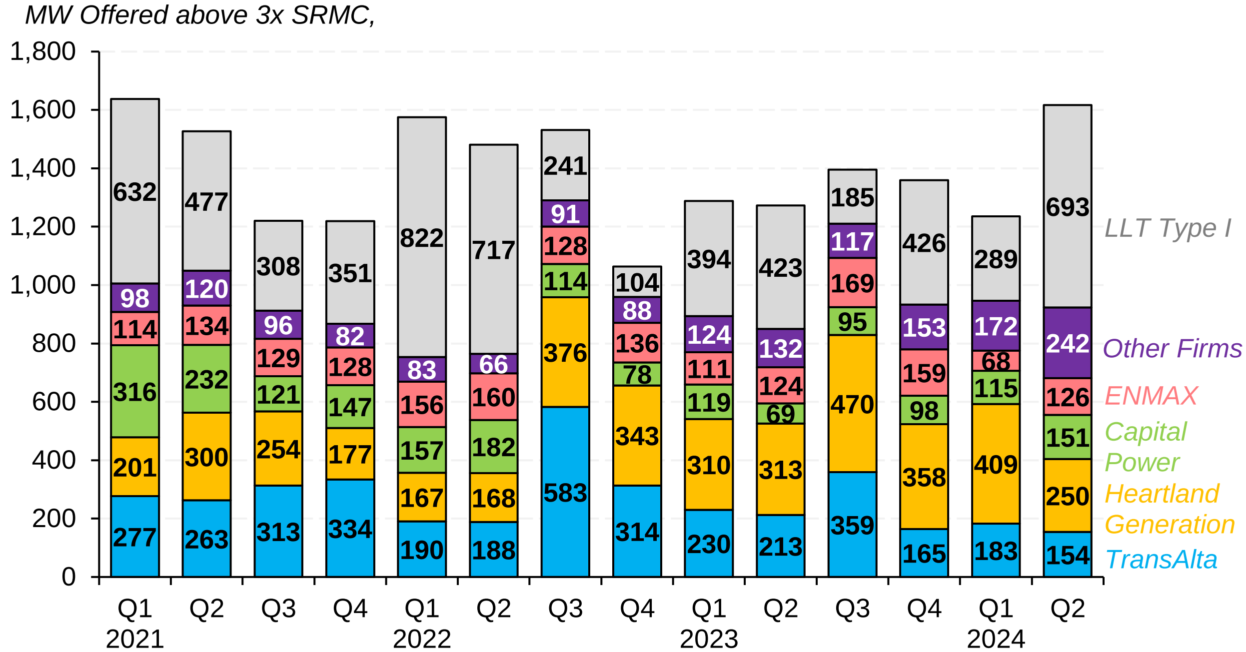
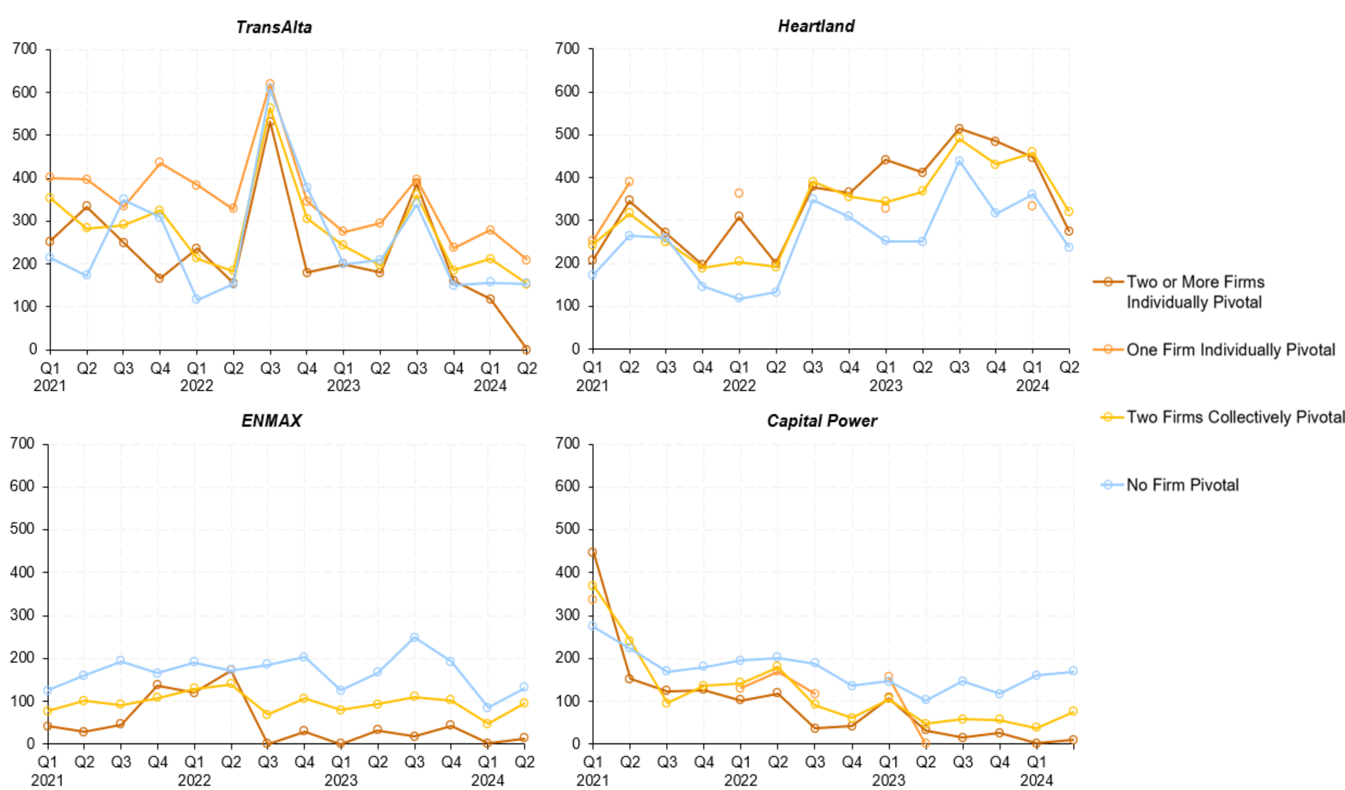


Figure 20: MW offers above 3xSRMC by firm, pivotality condition (Q1 2021 to Q1 2024)



1.4 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 of the carbon emission intensity of the Alberta electricity grid in its quarterly reports since Q4 2021. The MSA's analysis is indicative only, as the MSA has not collected the precise carbon emission intensities of assets from market participants but relied on information that is publicly available. The results reported here do not include imported generation.[3]

1.4.1 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 4 shows the minimum, mean, and maximum hourly average emission for Q2 over the past seven years.

Table 5 shows the same information for the past four quarters. The minimum and mean carbon emission intensity have seen decreases since Q3 2023, with a stable max emission intensity. Figure 21 and Figure 22 highlight the distributions of average carbon emission intensities for the time periods utilized in Table 4 and Table 5.

The average hourly carbon emission intensity fell from 0.45 tCO2e/MWh in Q1 to 0.39 tCO2e/MWh in Q2, a decline of 13%. These recent declines have been driven by high levels of intermittent generation and the commissioning of new thermal assets. Cascade 1 and 2 and Genesee Repower 1 and 2 are thermal assets that all commissioned in recent months. Cascade 1 and 2 are efficient combined cycle natural gas assets with a relatively low carbon emission intensity of 0.34 tCO2e/MWh; these assets are displacing less efficient thermal generation. In addition, the simple cycle assets at Genesee Repower 1 and 2 have largely replaced the coal generation from Genesee 1 and 2, reducing the carbon emission intensity from 0.85 to 0.46 tCO2e/MWh.

Table 4: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2018 Q2	0.50	0.67	0.79
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

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

Table 5: Quarter over quarter min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2023 Q3	0.31	0.45	0.56
2023 Q4	0.30	0.43	0.57
2024 Q1	0.27	0.45	0.58
2024 Q2	0.26	0.39	0.56

Figure 21: The distribution of average carbon emission intensities in Q2 (2018 to 2024)

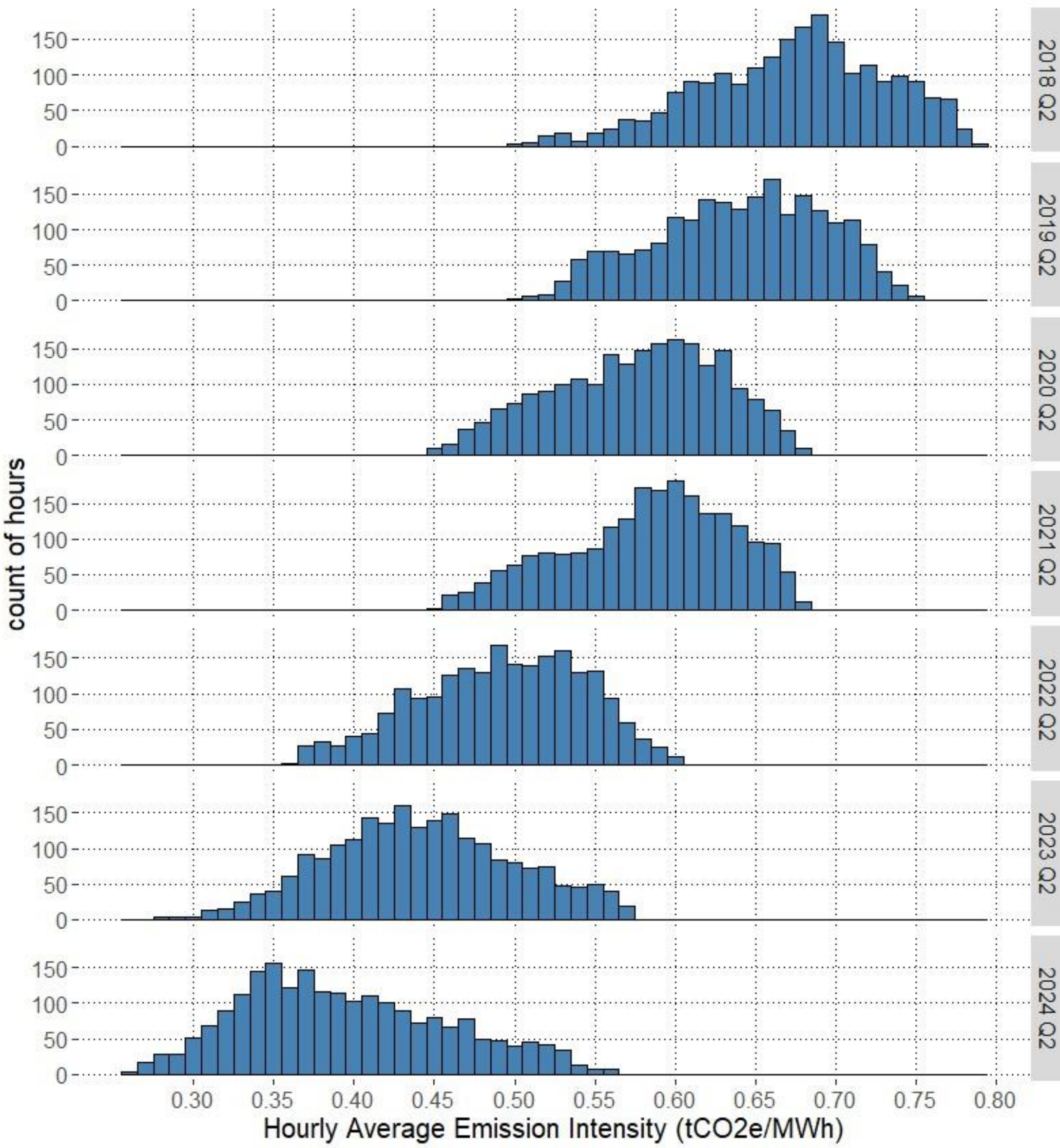
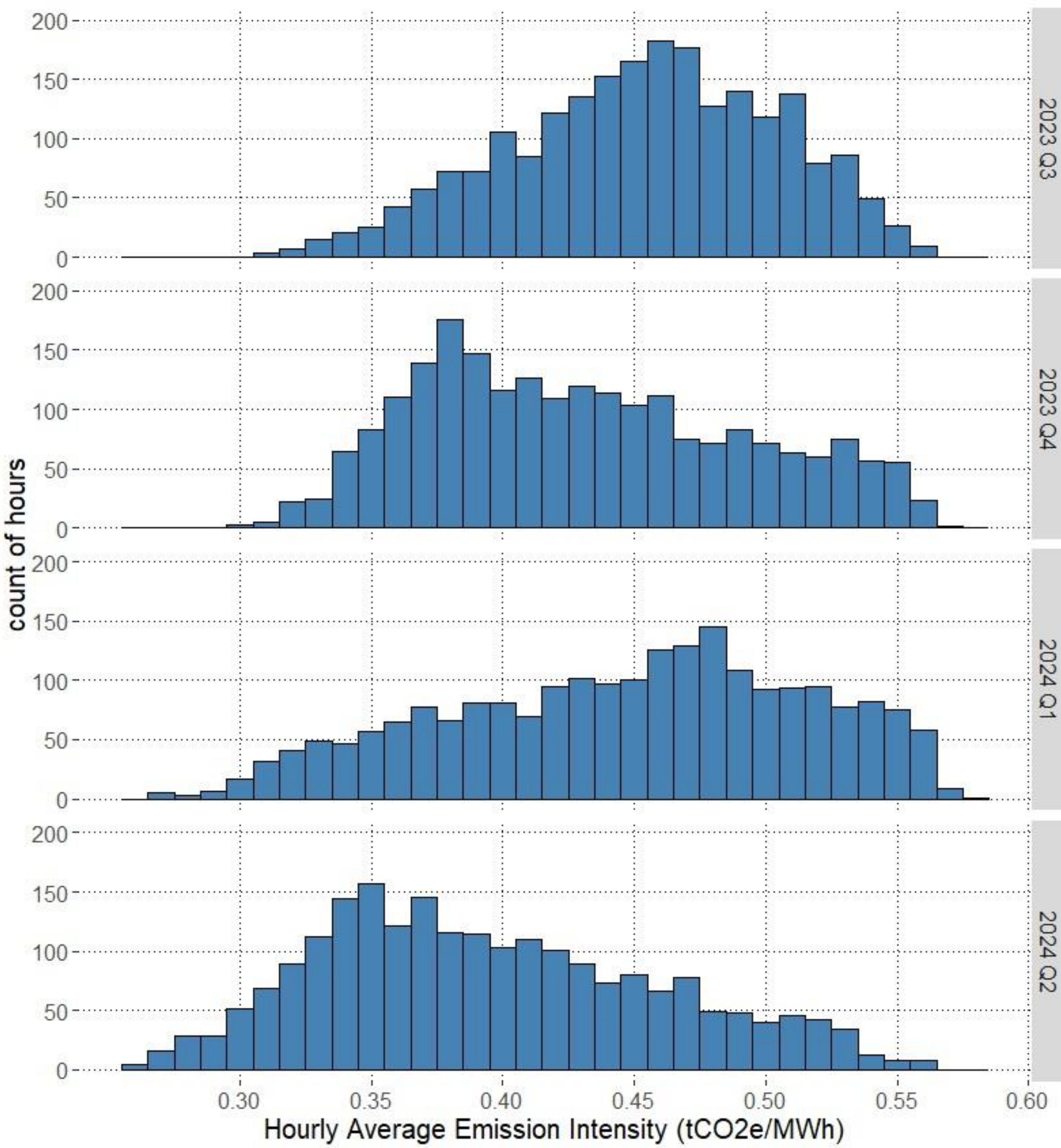
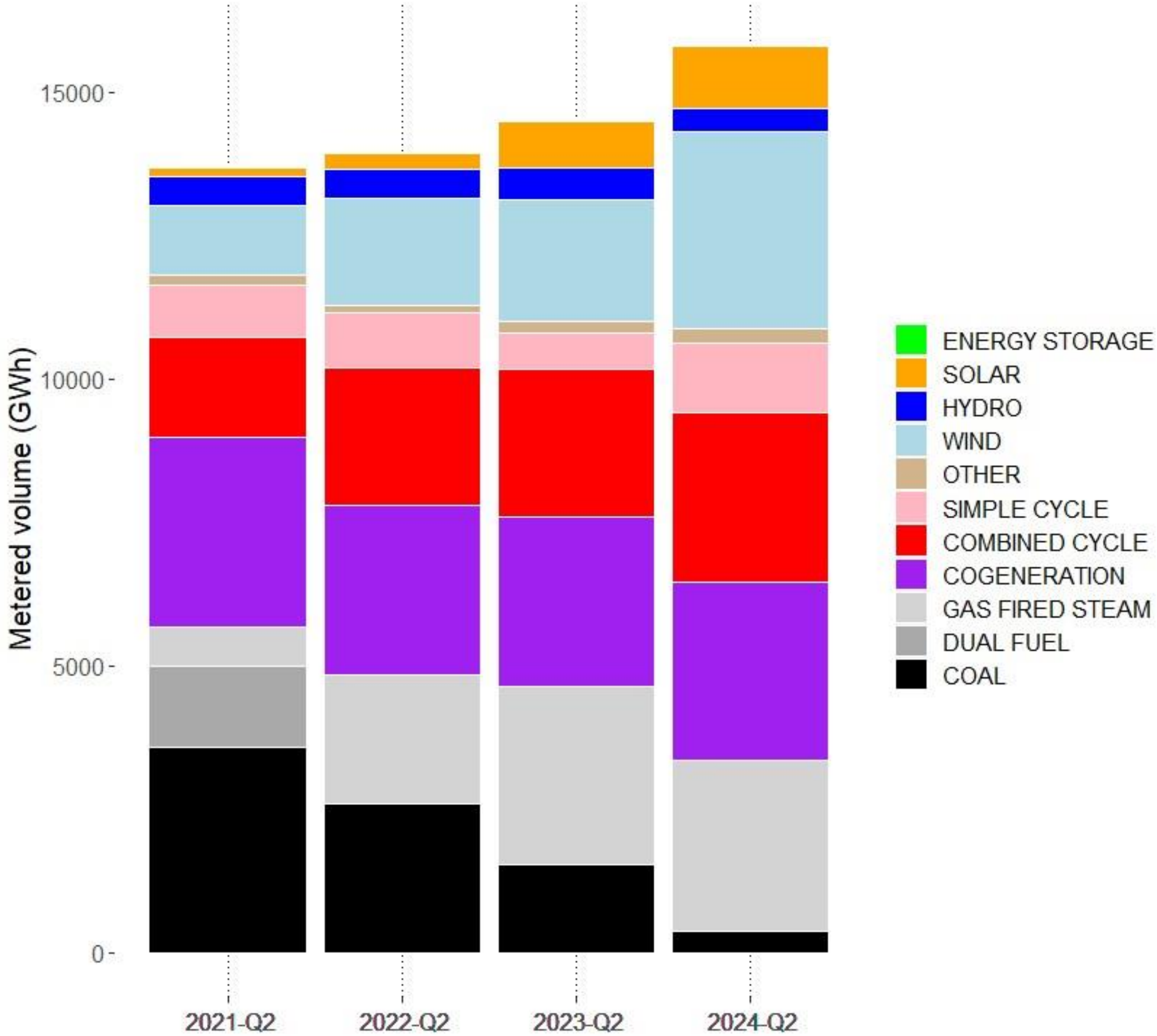


Figure 22: The distribution of average carbon emission intensities in the past four quarters



The general trends observed in the above distribution figures can be traced in which shows net-to-grid generation volumes by fuel type. Since 2021, there has been a decline in the volume of coal-fired generation, with generation from gas-fired steam assets replacing it (Figure 23). The increase in intermittent generation driven by growing capacity has also contributed to the displacement of coal-fired generation.

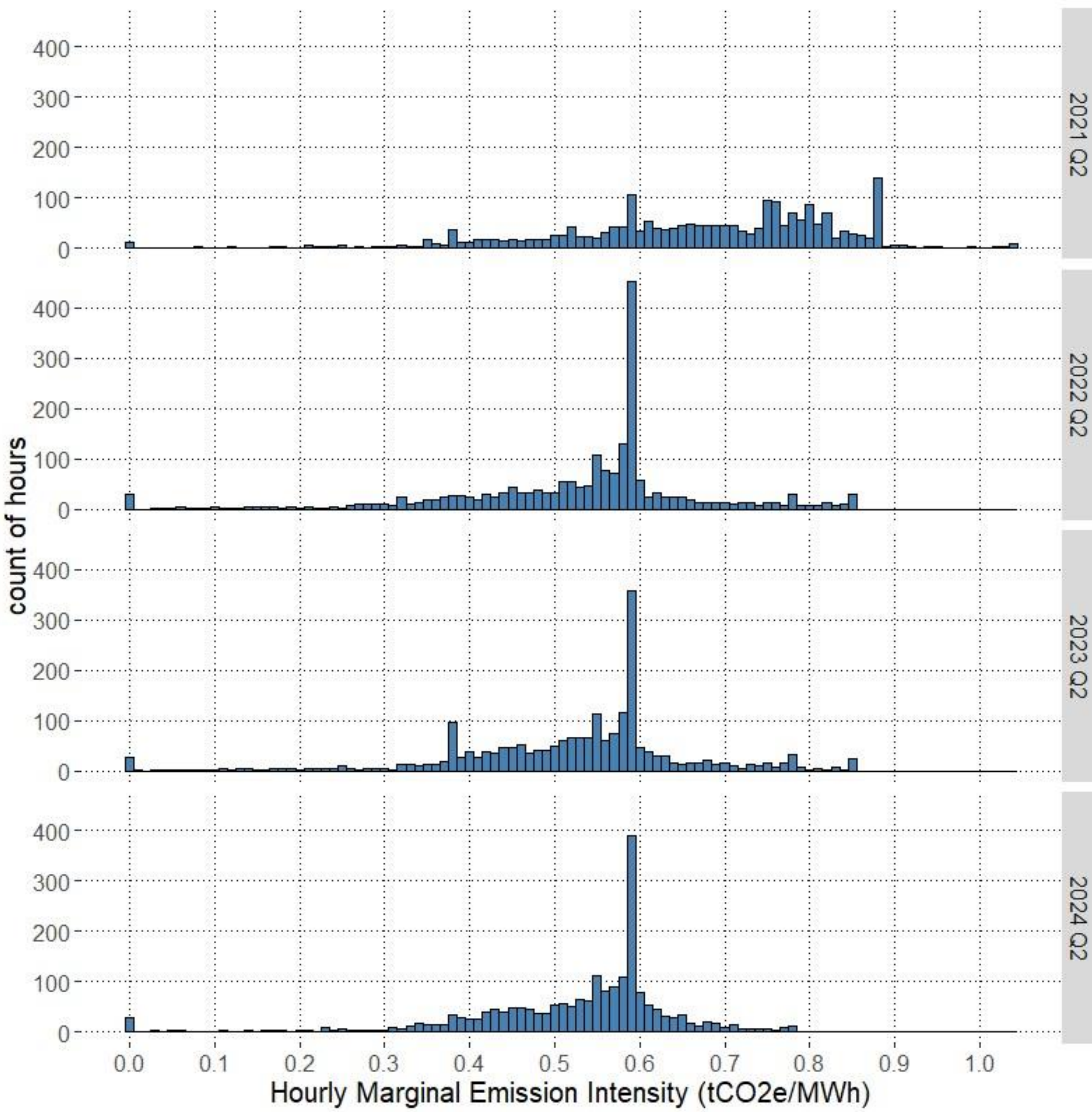
Figure 23: Quarterly total net-to-grid generation volumes by fuel type for Q2 (2021 to 2024)



1.4.2 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 24 shows the distribution of the hourly marginal emission intensity of the grid in Q2 for the past four years. Gas-fired steam assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO2e/MWh from Q1 2022 onwards.

Figure 24: The distribution of marginal carbon emission intensities in Q1 (2021 to 2024)



2 THE POWER SYSTEM

2.1 Trends in transmission congestion

Transmission constraints can cause generation to be curtailed. Transmission constraints can be either inflow constraints or outflow constraints. An outflow constraint occurs when there is insufficient transmission capacity to permit all generators to deliver the full amount of their in-merit energy to the grid. When this occurs, the AESO directs constrained generators to reduce their output to manage the constraint; this is constrained down generation. In this section, the MSA examines trends in intermittent constrained down generation.

The frequency and significance of intermittent constrained down generation directives increased from Q2 2023 to Q2.[4] The MSA estimates that intermittent constrained down generation volumes were 42 GWh in Q2 2023 and 214 GWh in Q2. This represents an increase by a factor of five year-over-year. Quarter-over-quarter, the intermittent constrained down generation volumes increased by 186 GWh. The intermittent constrained down volume of 214 GWh in Q2 is the highest recorded quarter, exceeding the second highest quarter (188 GWh in Q4 2023) by 26 GWh. The maximum hourly average volume of intermittent generation constrained down in Q2 was 1,665 MW, over double the maximum of 725 MW in Q2 2023 (Figure 27 to Figure *29*). The Q2 maximum hourly average volume of intermittent constrained was substantially higher than the previous quarters maximum value of 370 MWh (Figure 28). The maximum hourly average volume of intermittent generation constrained down in Q2 was 1,665 MW, over double the maximum of 725 MW in Q2 2023 (Figure 27 to Figure 29) The Q2 maximum hourly average volume of intermittent constrained was substantially higher than the previous quarters maximum value of 370 MWh (Figure 28).

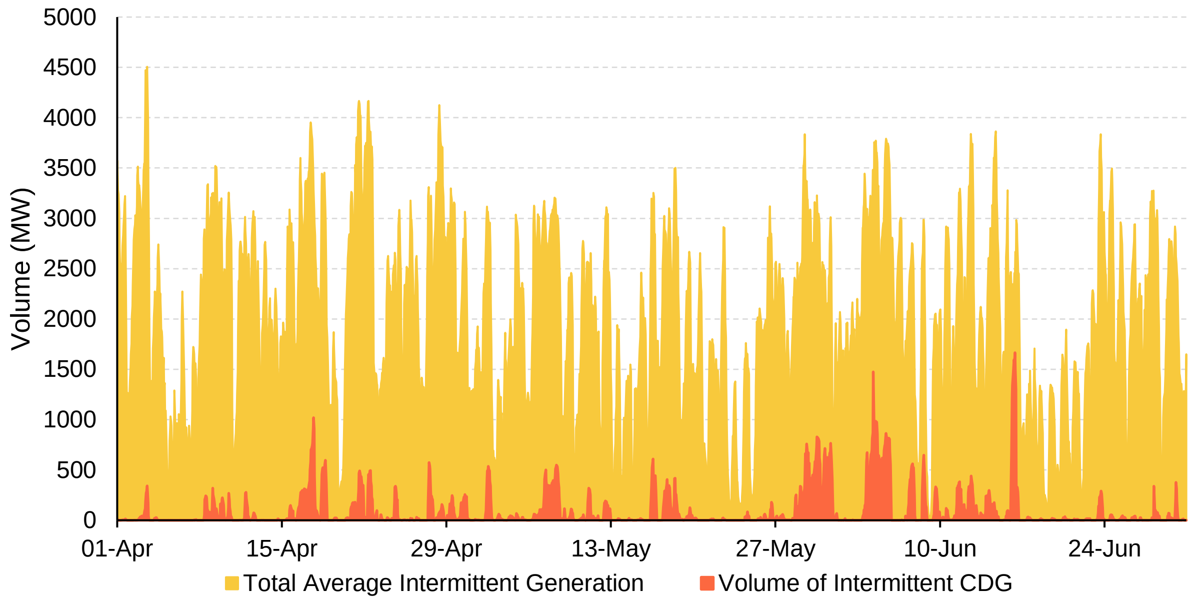
The increased constrained volumes in Q2 are likely due to increased intermittent capacity and high intermittent generation, as detailed in Section 1 and demonstrated in Figure 3. Generally, higher intermittent constrained down volumes align with periods of high intermittent generation or supply surplus events when supply is often high (Figure 25).

There were over 340 shift log events for constrained down generation in Q2. Increased constrained down generation volumes may also be due to persistent or frequent congestion on certain transmission lines and may affect one or more generation assets. One example of a frequently constrained transmission line is 610L, which is the subject of the Vauxhall Area Transmission Development. An additional example that demonstrates congestion is the constraint of Travers due to real time overload on 1005L, which occurred often throughout the quarter.

---

[4] The AESO's ETS Estimated Cost of Constraint Report calculate TCR volumes using a different methodology than the MSA's estimate of constrained down generation. The MSA's [Q2 2023 Quarterly Report] discusses how the MSA calculates the constrained down volumes.

Figure 25: Average hourly intermittent generation and constrained down volumes for Q2



The increase in intermittent constrained down volume from Q2 2023 to Q2 occurred at a higher rate than the installation of intermittent generation capacity. While total installed intermittent capacity increased by 34%, average hourly constrained down volumes, expressed as a percent of installed intermittent capacity, increased from 0.40% in Q2 2023 to 1.53% in Q2 (Figure 26).

Figure 26: Volume of intermittent CDG compared to total potential intermittent generation in Q2

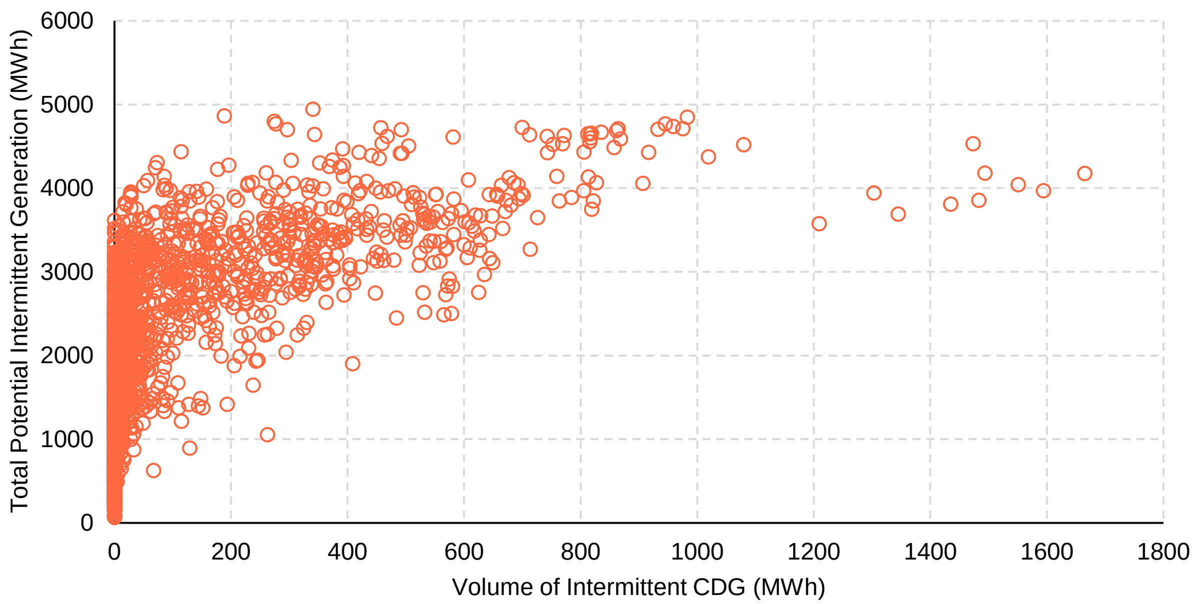


Figure 27: Maximum hourly transmission constrained wind and solar generation (Q2 2023)

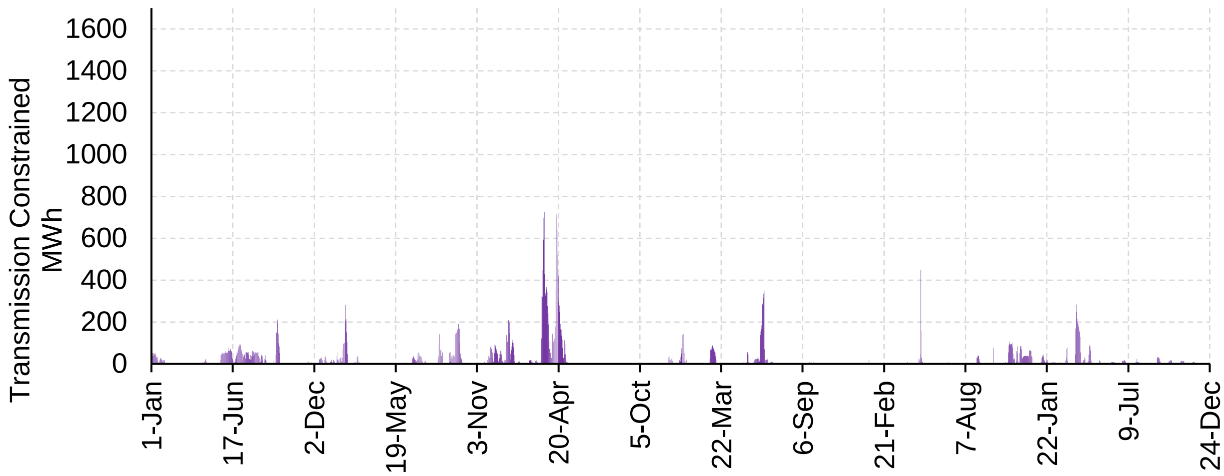


Figure 28: Maximum hourly transmission constrained wind and solar generation (Q1 2024)

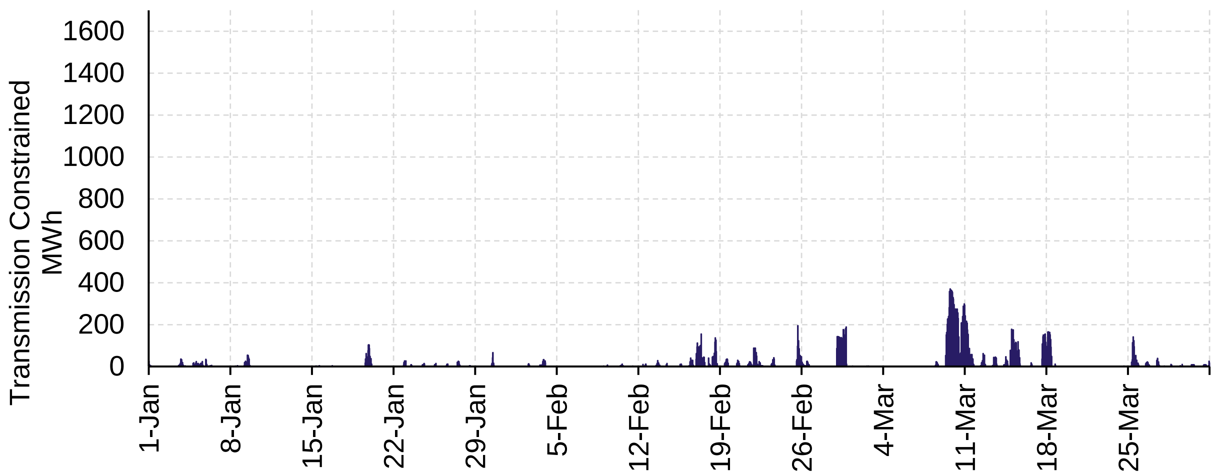


Figure 29: Maximum hourly transmission constrained wind and solar generation (Q2 2024)

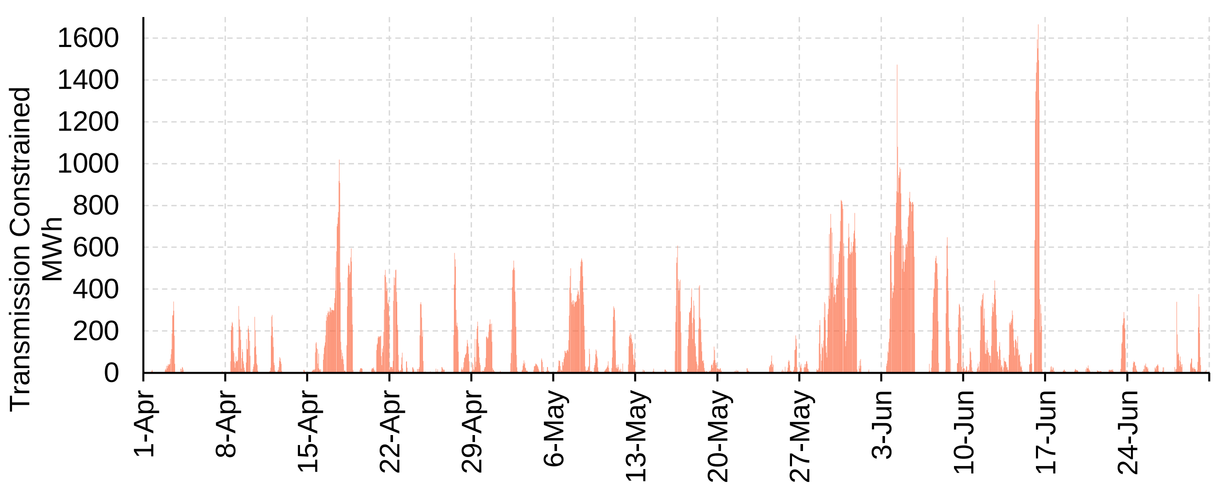
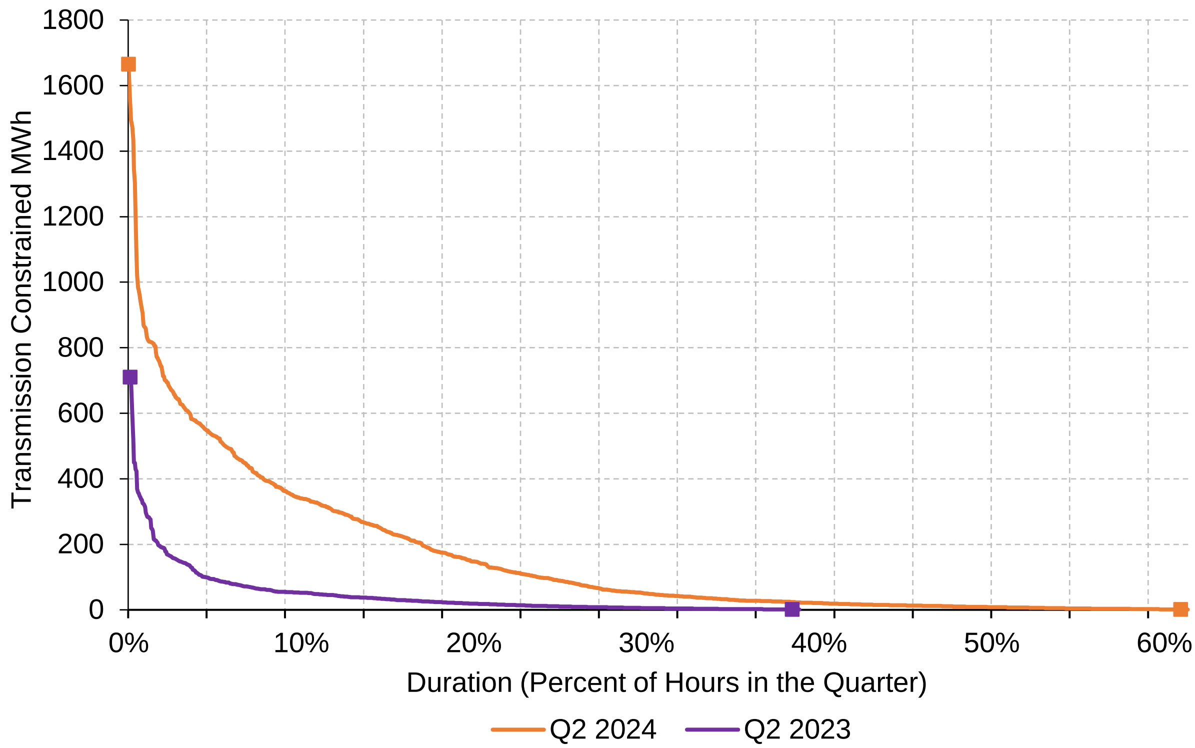


Figure 30 illustrates duration curves of constrained intermittent generation year-over-year. The length of the tails to the right of the duration curves show that the frequency of intermittent constrained down events increased. There were 1,351 hours of intermittent constrained down generation greater than 1 MWh in Q2. This is equivalent to just over 56 days, or 62% of Q2. In contrast, Q2 2023 experienced 856 hours of intermittent constrained down generation greater than 1 MWh, or over 35 days or 39% of Q2 2023.

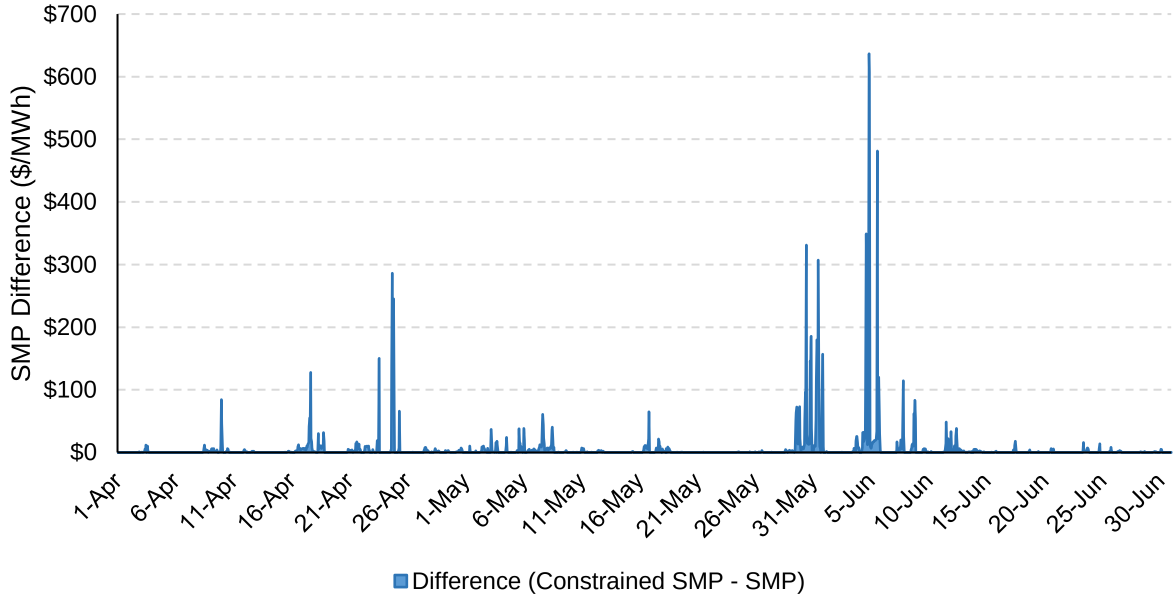
Figure 30: Duration of wind and solar constraint volume (Q2 2023 and Q2)



Transmission constraints had frequent fluctuations throughout all months, however June experienced the most change and the highest peak. The intermittent constrained down volume in the month of June accounted for 40% of all Q2 volumes. In 60% of June hours there was at least 1 MWh of intermittent constrained down volume.

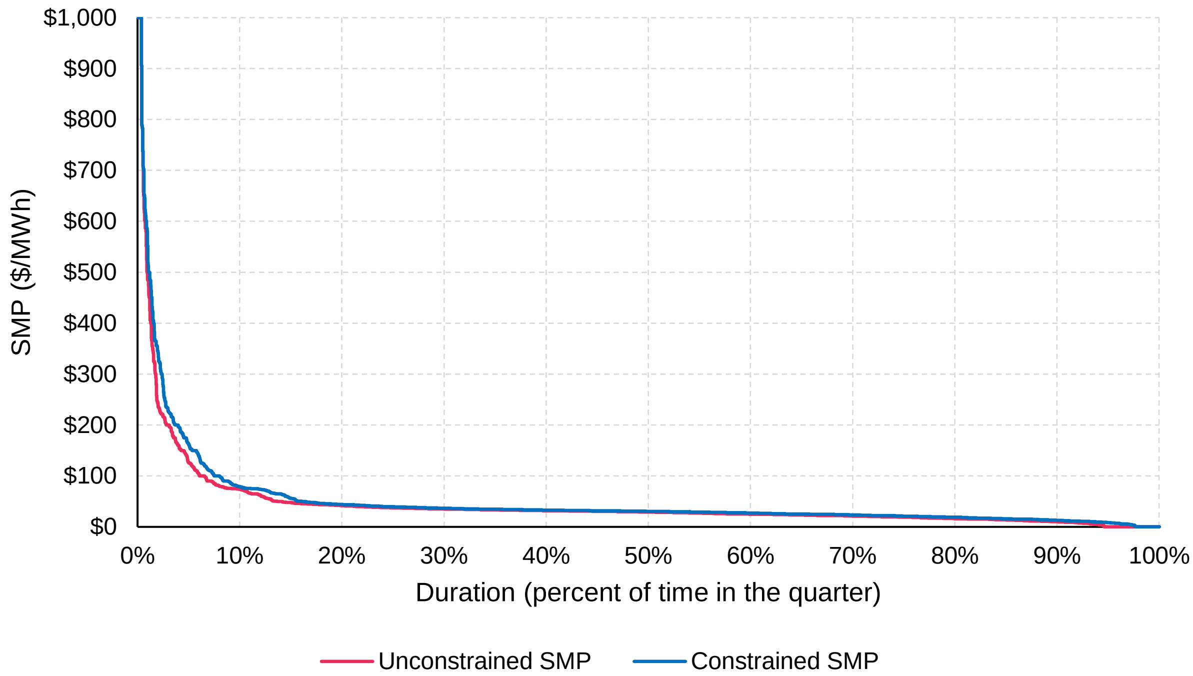
The constrained and unconstrained SMP differed by $1/MWh or more in 27% of hours in Q2 (Figure 31). In comparison, Q2 2023 only experienced 12% of hours with a variance of $1/MWh or more in the constrained SMP and unconstrained SMP, and Q1 2024 only experienced the difference in 10% of hours. The largest difference between constrained SMP and SMP in Q2 was $637/MWh, which occurred in HE22 of June 4. Despite the frequency and significance of the intermittent constrained down generation in Q2, the largest difference in unconstrained and constrained price was higher in Q2 2023 at $807/MWh. The largest difference in Q1 2024 occurred on February 24 and only reached $213/MWh, close to one-third of the Q2 peak.

Figure 31: Difference of Constrained SMP and SMP in Q2



The periods that experience high volumes of intermittent constraints 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 constrained volumes in Q2, there was often only a small difference between the unconstrained SMP and the constrained SMP (Figure 32). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity may have a relatively small impact on prices.

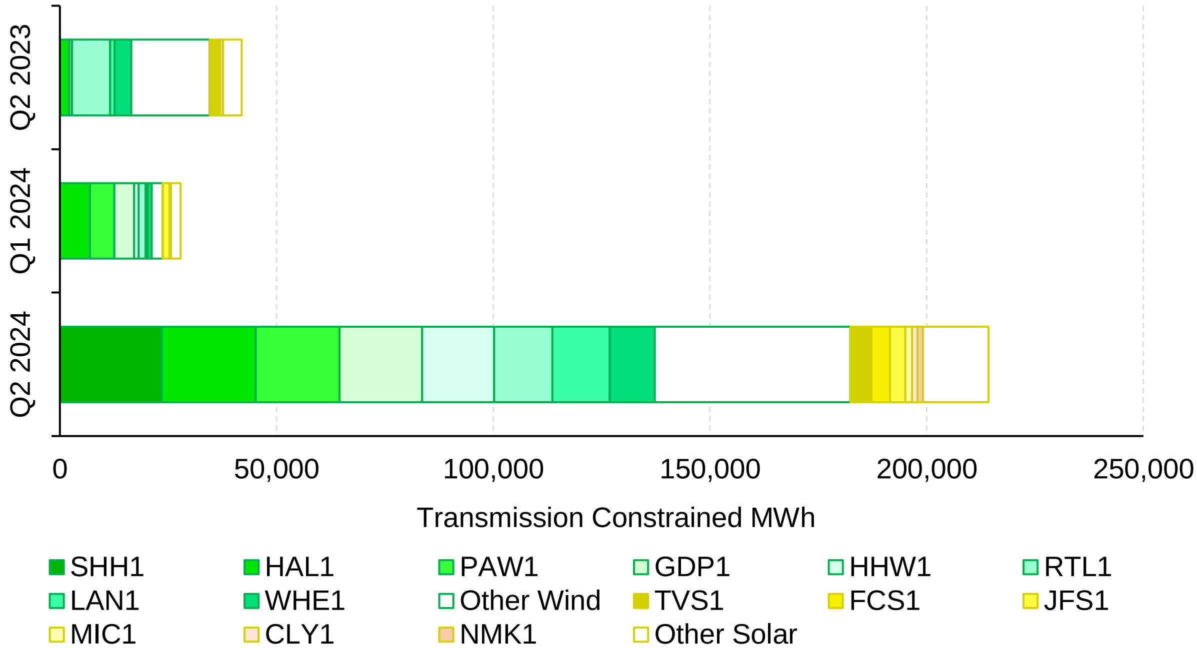
Figure 32: Duration of SMP and constrained SMP for Q2



Transmission capability varies throughout the province, and certain regions may experience more congestion than others, often leading to local constraints (Figure 33). Often, wind and solar assets are not constrained uniformly throughout the province. In Q2, the eight most constrained wind assets accounted for 75% of the total constrained down volume but only 28% of total installed wind generation. Sharp Hill Wind, Halkirk Wind Power Facility, and Paintearth Wind Project were the most constrained wind assets in Q2. These 3 assets represent 14% of Alberta's installed wind capacity, however they accounted for approximately 35% of the wind constrained volume in Q2.

Travers (465 MW) was the most-constrained solar asset in Q2, with a total of 4,889 MWh constrained. The asset was most commonly constrained due to overloads of 1005L. The following five most constrained solar assets have an aggregate maximum capability of 186 MW and were constrained by 11,815 MWh in Q2. The top 6 constrained solar assets account for 39% of the maximum capability of the market but accounted for 52% of solar constrained volumes in Q2. This illustrates the uneven concentration of constraints between assets within Alberta.

Figure 33: Wind and solar transmission constrained MWh by asset (Q2 2023, Q1 2024 and Q2)

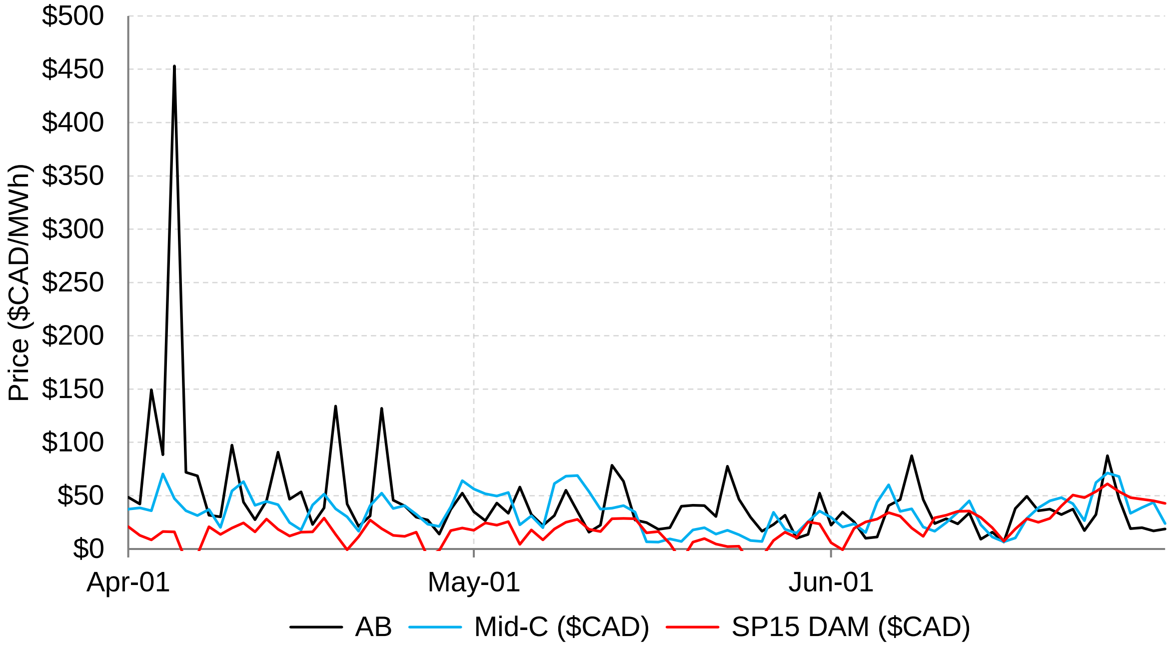


2.2 Imports and exports

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

Figure 34 provides the daily average power prices in Alberta, Mid-C, and California (SP-15) over Q2 (shown in Canadian currency). Alberta prices were volatile in April, with prices being more comparable over May and June.

Figure 34: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q2)



Alberta was a net exporter of electricity over the quarter, largely driven by export volumes to BC. In Q2, scheduled volumes on the BC intertie averaged 164 MW of exports, with the highest monthly average export volumes occurring in April at 238 MW (Table 6). In Q2 2023, the BC intertie averaged 41 MW of imports, driven by large import volumes in May. In May 2023, the average net volume on the BC intertie was 280 MW of imports, compared to 66 MW of exports this May (Table 6). Higher imports in May 2023 were caused by higher pool prices, along with more snowpack and rapid melt brought on by record high temperatures in BC over the month.

BC's largest hydro facilities are in the Peace (Northeast) and Columbia (Southeast) Regions and are supplied primarily through snow melt. Given the below normal snowpack this year, net exports to BC are expected to continue.

*Table 6: Average net import (+ve) and export (-ve) volumes for Q*2 2023 and Q2 2024

	2023				2024			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
April	-247	103	104	-40	-238	113	74	-51
May	280	122	73	474	-66	55	1	-10
June	82	113	19	214	-192	38	23	-132
Q1	**41**	**113**	**65**	**219**	**-164**	**69**	**32**	**-63**

Scheduled volumes on MATL averaged 69 MW of imports over Q2 with the highest monthly average net imports of 113 MW occurring in April. In Q2 2023, scheduled volumes averaged 113 MW, with the highest monthly average net imports of 122 MW occurring in May (Table 6). Over the quarter, approximately 8.5 GWh of imports from MATL were wheeled to BC, which all occurred in April, as shown in Figure 35.

As observed in Figure 35, the capability of BC/MATL fell to 0 MW in early May. On May 10 during HE 20 the capability of BC and BC/MATL decreased to 0 MW due to fire under 1201L near Claresholm. Alberta was islanded until May 12 in HE 13 when the BC intertie returned to service, followed by MATL in HE 17.

Figure 35: Daily average import (+ve) and export (-ve) scheduled *volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q2)*

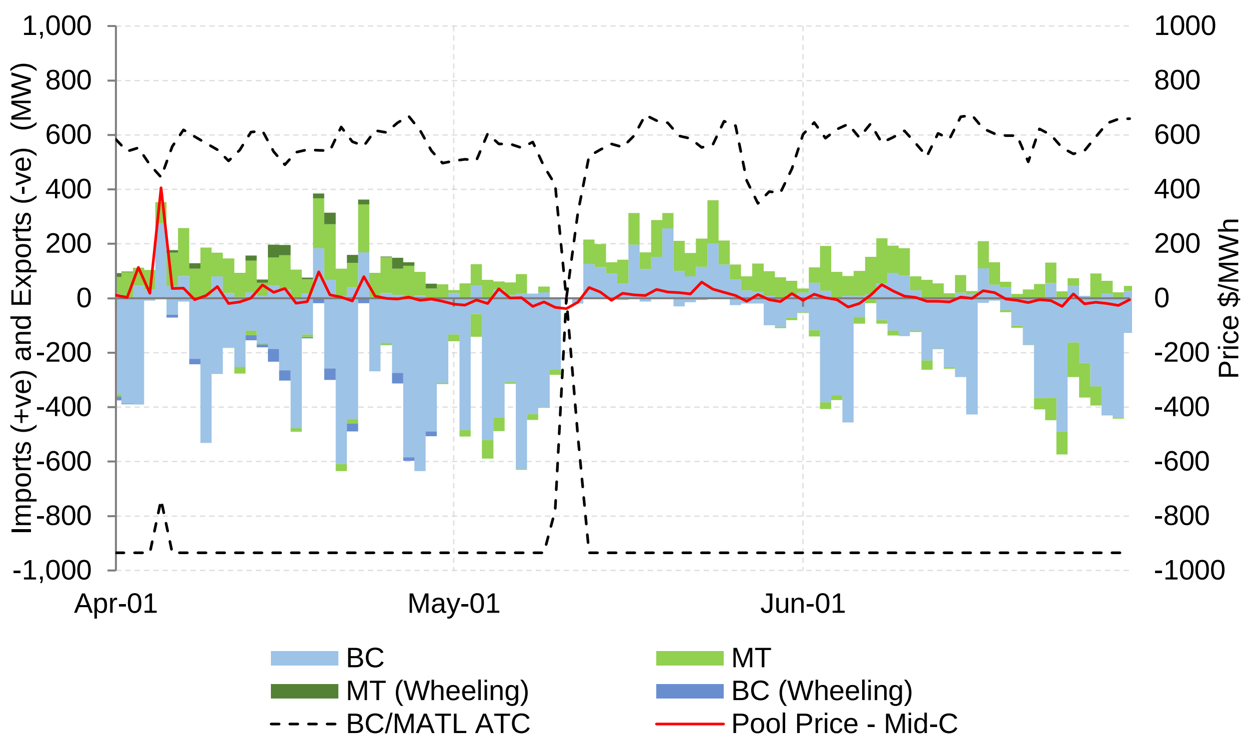


Figure 36 shows the daily average scheduled interties volumes for Saskatchewan. Over the quarter, scheduled volumes averaged 69 MW of imports. In Q2 2023, the scheduled volumes averaged 113 MW of imports, while ATC was often derated, averaging 105 MW. The lower import volumes this year are partly the result of lower pool prices.

Figure 36: Daily average import (+ve) and export (-ve) scheduled *volumes on SK and pool price (Q2)*

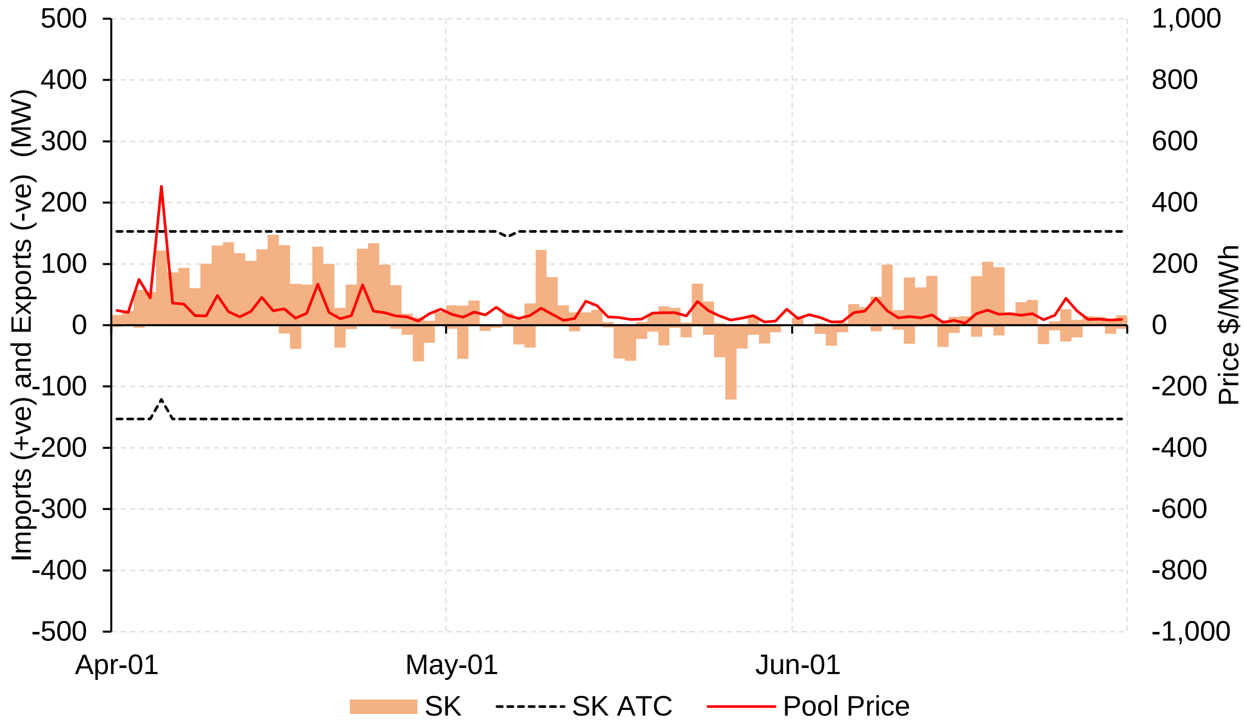
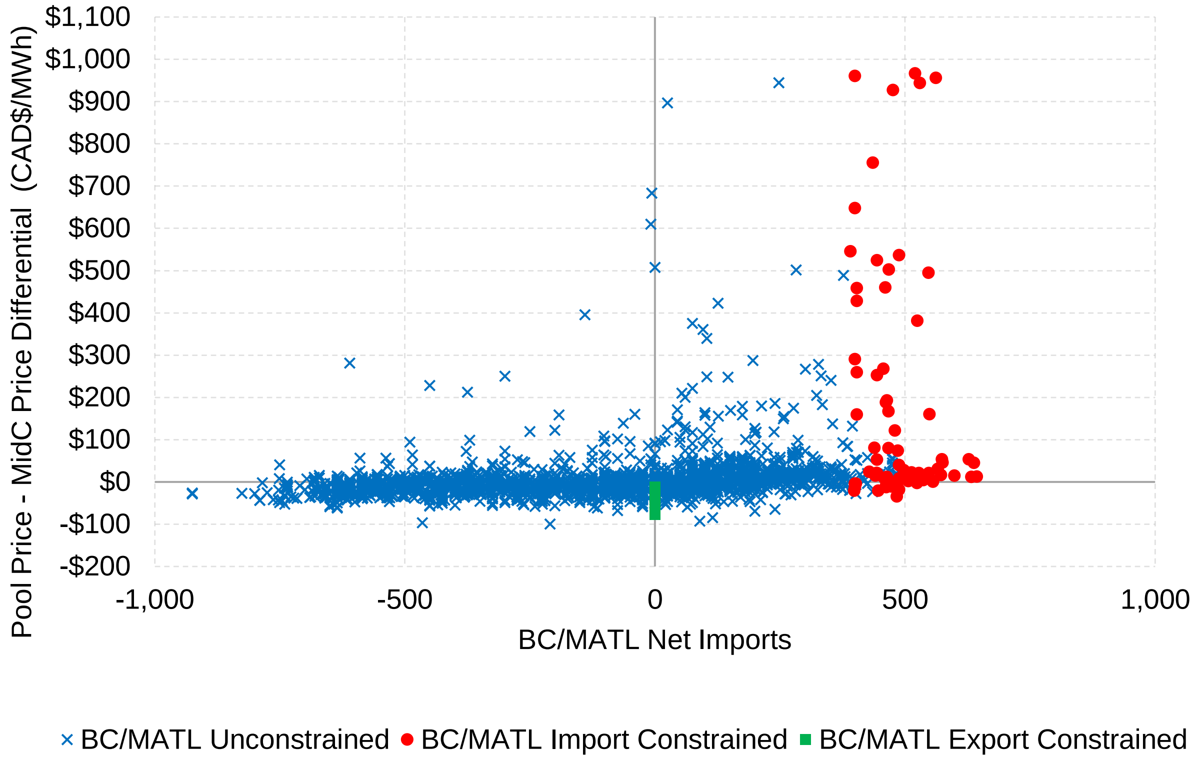


Figure 37 shows a scatterplot of the price differential between Alberta and Mid-C against the net scheduled flows on BC/MATL for each hour over the quarter. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors).

In certain hours the net import offers or schedule volumes on BC/MATL were at or above import capability, meaning that BC/MATL was import constrained (shown in red). BC/MATL imports were constrained for 70 hours in Q2 or 3% of the time. While import constrained, the price differential between Alberta and Mid-C averaged $189/MWh and import capability averaged 497 MW.

There were also hours where net export bids or scheduled volumes were at or above export capability, meaning that BC/MATL was export constrained (shown in green). Constrained values at 0 MW are associated with the BC/MATL outage between May 10 to 12. BC/MATL exports were constrained for 22 hours or 1% of the time in Q2. While export constrained, the differential between Alberta and Mid-C averaged -$43/MWh.

Figure 37: Alberta and Mid-C price differential and net BC/MATL flows (Q2)



For some hours in Q2, heavy scheduled volume occurred despite prices settling in the opposite direction. For example, on May 5, 2024 during HE 17 and HE 18 net exports to BC were 635 MW and 400 MW, although the Alberta and Mid-C price differential in these hours was $282/MWh and $213/MWh, respectively. In the preceding hours of May 5, 2024, the price differential averaged $5/MWh. For HE 17 and HE 18, BC was also receiving imports from the intertie connected to Bonneville Power Authority.

Figure 38 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[5] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

For imports on the BC intertie, approximately 43% originated from BC, 45% from the US Northwest, and 11% from California. For exports on the BC intertie, 98% was delivered to BC, and 2% to the US Northwest.

For imports through MATL, 85% originated from the US Northwest, 14% from California, and 1% from Southwest Power Pool. For exports on MATL 93% was delivered to the US Northwest, 5% to BC, and 1% to Southwest Power Pool.

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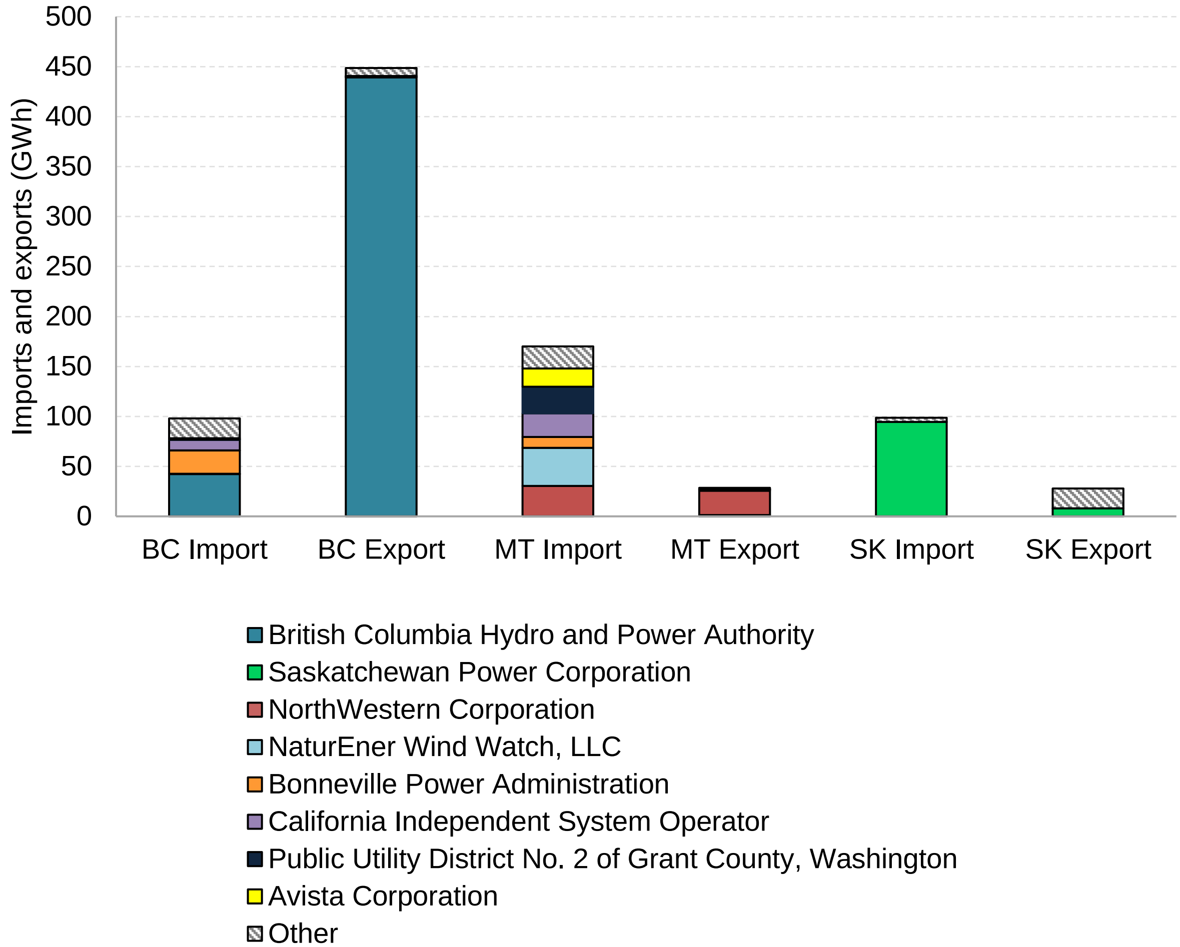
[5] The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered to.

For imports through the SK intertie, 96% originated from Saskatchewan, 2% from the Midcontinent Independent System Operator, and 2% from Southwest Power Pool. For exports through the SK intertie, 38% was delivered to the Midcontinent Independent System Operator, 29% to Saskatchewan, 27% to Southwest Power Pool, and 5% to Ontario.

Figure 38: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q2)[6]



[6] This includes the highest eight Balancing Authorities by volume. Wheeled volumes are not included in the figure, these volumes represent 8.5 GWh from Montana to BC.

2.3 Analysis of BAL-001-AB-2, *Real Power Balancing Control Performance*

Compliance with the Alberta Reliability Standards (ARS) is necessary to ensure the reliable operation of the Alberta interconnected electric system. BAL-001-AB-2, *Real Power Balancing Control Performance* (BAL-001)[7], is a reliability standard that is applicable only to the ISO which has the purpose to control interconnection frequency within defined limits. This section reports an MSA analysis of the ISO's performance in respect of the requirements and measures set out in BAL-001 for the period of January 1, 2017, to June 30, 2024 (assessment period).

BAL-001 applies to the ISO except when:

(i) the ISO is receiving overlap regulation service;

(ii) the ISO is a member of a regulation reserve sharing group and remains in active status under the applicable agreement or the governing rules for the regulation reserve sharing group; or

(iii) the interconnected electric system is not synchronously connected to the Interconnection.

Aside from Alberta being occasionally islanded, there were no other exemptions applicable to the ISO during the assessment period.

BAL-001 contains two requirements and two corresponding measures:

> R1: The ISO must operate such that the control performance standard 1 is greater than or equal to 100% for each preceding 12 consecutive month period, evaluated monthly.
>
> MR1: Evidence of operating such that the control performance standard 1 is greater than or equal to 100% as required in requirement R1 exists. Evidence may include dated calculation output from spreadsheets, system logs, or other equivalent evidence.
>
> R2: The ISO must operate such that its clock-minute average of reporting area control error does not exceed the clock-minute area control error limit of the balancing authority for more than 30 consecutive clock-minutes.
>
> MR2: Evidence of operating such that the clock-minute average of reporting area control error does not exceed the clock-minute area control error limit of the balancing authority for more than 30 consecutive clock-minutes as required in requirement R2 exists. Evidence may include dated calculation output from spreadsheets, system logs, or other equivalent evidence.

[7] BAL-001-AB-2 *Real Power Balancing Control Performance,* July 1, 2019

R2 replaced the previously effective control performance standard 2 (CPS2) when BAL-001 became effective on July 1, 2019. For this reason, the assessment of R2 begins on July 1, 2019.

2.3.1 Assessing R1: Control Performance Standard 1 (CPS1)

CPS1 is based on one-minute averages of reporting area control error (ACE), frequency error, and frequency bias settings and measures it against a 100% threshold. CPS1 expresses the relationship between ACE and system frequency deviations relative to the targeted frequency bound for the western interconnection that is assessed and adjusted as needed by the North American Electric Reliability Corporation (NERC). CPS1 allocates a portion of the responsibility for maintaining steady-state interconnection frequency to each balancing authority (BA), which is the AESO in Alberta. The amount of responsibility is determined by the frequency bias of that BA.[8] CPS1 measures a BA's contribution to the interconnection's frequency volatility relative to an acceptable standard. CPS1 can be represented by the following formulas:

Threshold:

$$CPS1 \geq 100$$

CPS1 calculation:

$$CPS1 = (2 - CF) * 100$$

$$CF = \frac{CF_{12-month}}{\epsilon_1^2}$$

$$ACE = (NI_A - NI_S) - 10B(F_A - F_S) - I_{ME}$$

$$CF_{clock-minute} = \left(\frac{ACE}{-10B}\right)_{clock-minute} * (F_A - F_S)_{clock-minute}$$

Table *7* provides a list of the defined terms used in the CPS1 calculation.

[8] NERC, Balancing and Frequency Control, 2021.

Table 7: Variables used in CPS1 calculation

CF	Compliance factor.
ϵ	Western interconnection targeted frequency bound. This represents a benchmark for frequency volatility on the grid. The value of this constant is different for each interconnection in North America.
NI_A	Actual net interchange flows on all tie lines.
NI_S	Actual scheduled interchange flows on all tie lines.
B	Frequency bias setting (MW/0.1 Hz). Used in the area control error algorithm of a balancing authority and allows the balancing authority to contribute its frequency response to the Interconnection.
F_A	Actual frequency.
F_S	Scheduled frequency.
I_{ME}	Meter error correction factor.

The clock-minute product of ACE and frequency deviations are divided by the square of the targeted frequency bound to yield CF which is then utilized in the CPS1 calculation. All else equal, if movements in a BA's ACE are proportional to NERC's constant, CPS1 will be equal to 100%, the threshold value.[9] When actual frequency is equal to scheduled frequency (or ACE = 0), CPS1 will be equal to 200%.

When there is more supply than demand, ACE becomes positive and applies upward pressure on interconnection frequency.[10] Conversely, a negative ACE can cause interconnection frequency to decline. Frequency error calculates the difference between the actual and scheduled frequency. In North America, the scheduled frequency of the electrical grid is 60 Hz. When demand is more than supply, system frequency will decrease below 60 Hz and when supply exceeds demand, system frequency will rise above 60 Hz.

The effects of ACE on frequency error are linked to the correlation between the two variables. Over-frequency errors can be exaggerated when ACE reflects situations in which generation exceeds demand, and reduced when ACE reflects market conditions where demand exceeds supply. Conversely, under-frequency errors can be increased when ACE < 0, and be further diminished when ACE > 0.[11] BAs achieve a more positive CPS1 score when their ACE responds in a way which corrects for the frequency error.[12] Events which have significant impacts on ACE or frequency error will have the largest effect on CPS1. As previously noted by the AESO,

[9] NERC, Balancing and Frequency Control, 2021.

[10] NERC, Balancing and Frequency Control, 2021.

[11] NERC, Balancing and Frequency Control, 2021.

[12] For example, if actual frequency is less than scheduled frequency and ACE is positive (representing over-generation), the BA will get a higher CPS1 score.

increasing variable generation on the electric system will cause net demand variability and forecast uncertainty to grow, making ACE more difficult to manage.[13]

Figure 39 illustrates the monthly average CPS1 from January 2017 to June 2024. While the AESO has maintained CPS1 above the 100% threshold as required by R1, the 12-month rolling average CPS1 exhibits gradual deterioration over the assessment period. Despite a modest increase from mid-2021 to late-2022, the rolling 12-month average CPS1 has declined over time, dropping from 189% in Q1 2018 to 180% at the end of Q2 2024. A notable decline in CPS1 occurred in Q2 2024, from 186% in March 2024 to 173% in May 2024.

Figure 39: Monthly average CPS1 (January 2017 to June 2024)

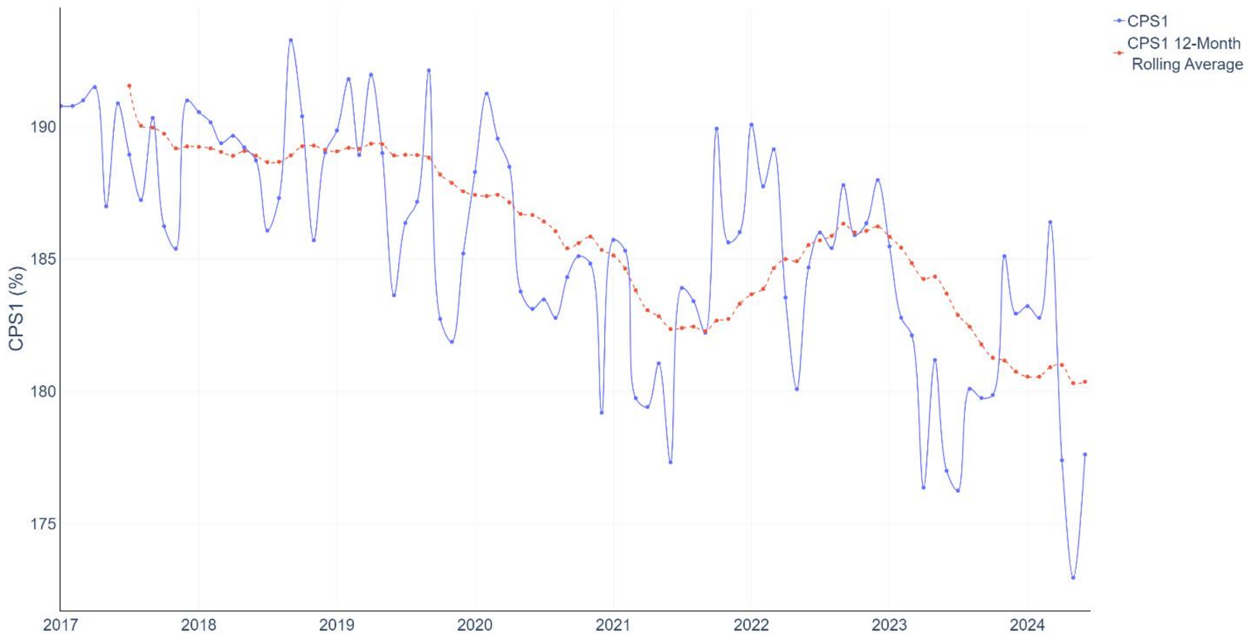
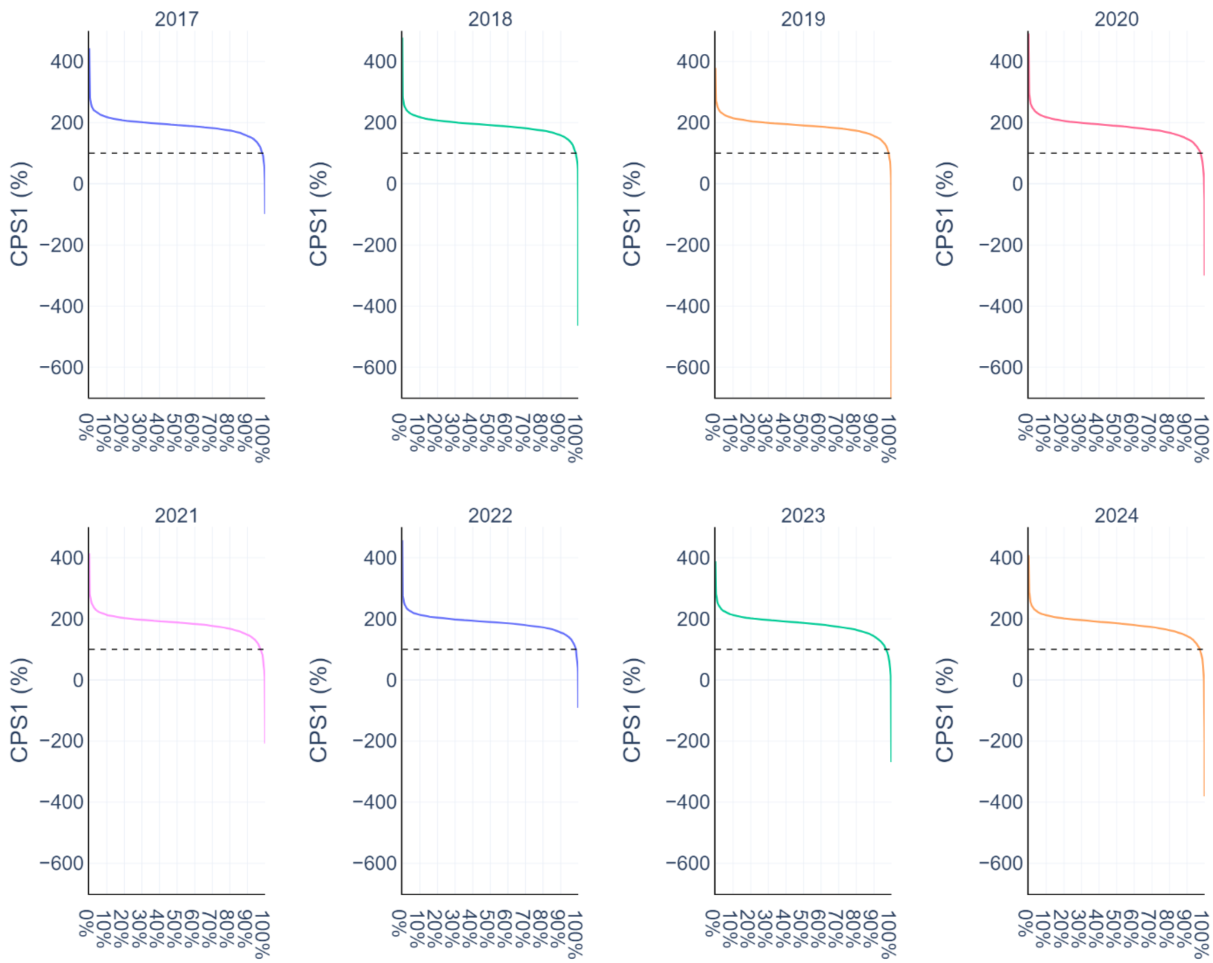


Figure 40 provides duration curves of the average hourly CPS1 for the assessment period. On average, CPS1 exceeds the 100% threshold in 98% of hours. In the first half of 2024, 97% of hours exceed the 100% threshold.

[13] AESO, Reliability Requirements Roadmap, 2023.

Figure 40: Hourly CPS1 duration curves by year (2017 to 2024)



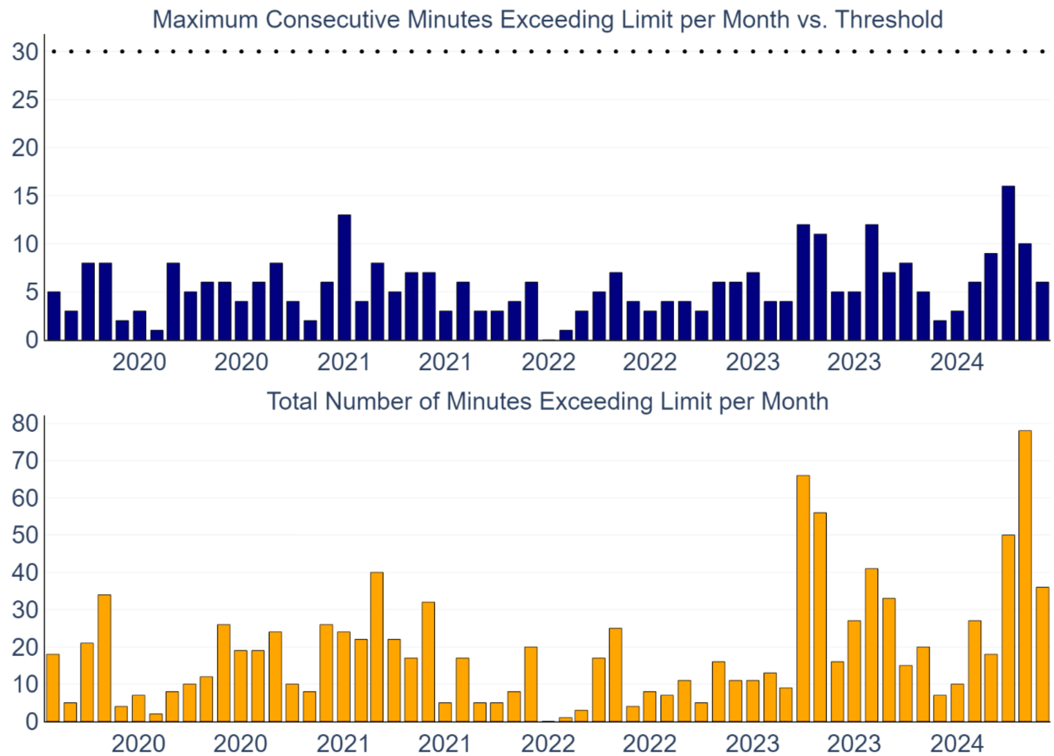
2.3.2 Assessing R2: Balancing Area ACE Limits (BAAL)

ACE is a power system metric that is inherently volatile. The thresholds $BAAL_{Low}$ and $BAAL_{High}$ are used to establish bounds on ACE for every clock-minute. BAL-001 requires that ACE not ever exceed these bounds, below or above, respectively, for more than 30 consecutive clock-minutes. BAL-001 does not specify an upper limit on the total number of exceedances in a month, or any other time period. When actual frequency is less than 60 Hz, $BAAL_{Low}$ is used as the lower boundary, and when actual frequency is greater than 60 Hz, $BAAL_{High}$ is used as the upper boundary. When actual frequency is equal to scheduled frequency, $BAAL_{Low}$ and $BAAL_{High}$ do not apply.

The top panel in Figure 41 details the total number of clock-minute exceedances per month, as well as the 30 clock-minute threshold. The bottom panel illustrates the total number of BAAL exceedances for each month. While the number of consecutive clock-minutes in excess of the applicable BAAL has remained relatively low, it was exceeded for 16 consecutive clock-minutes in April 2024. This event occurred on the evening of April 10 in response to a rapid and concurrent decline in generation from wind and solar. Additionally, ACE surpassed the BAAL limits on April 5, the same day the AESO shed load, for 12 consecutive minutes following the trip at Keephills 2. Both events will be further discussed in Section 2.3.3.

The bottom panel in Figure 41 suggests a slight upward trend in the monthly total number of minutes exceeding the BAAL over the assessment period. The largest observed total was 78 minutes in May 2024 – the same month CPS1 reached its minimum.

Figure 41: Monthly ACE limit exceedances (July 2019 to June 2024)



2.3.3 Event analysis

As noted above, for the AESO to be in contravention of BAL-001 R1 (CPS1), the 12-consecutive month clock-minute average of CPS1 must drop below the 100% threshold.

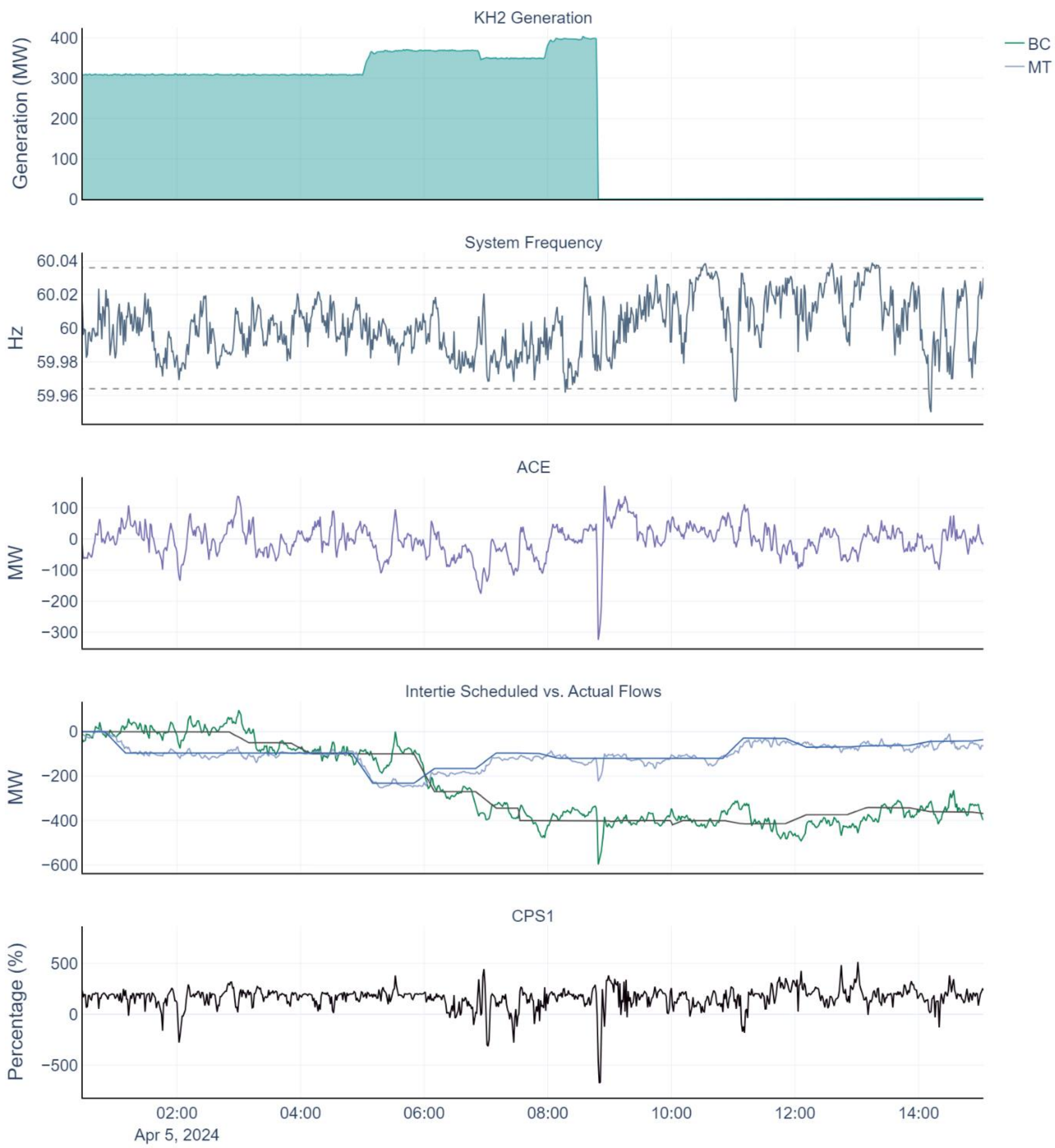
The events detailed below did not result in a violation of BAL-001. However, they illustrate the types of events which can and do occur in the power system and lead to deviations in CPS1 below its threshold. If the number of these events increase, so too will the decline of the monthly average CPS1, and the 12-month rolling average as it follows.

2.3.3.1 April 5, 2024

On April 5 at 8:48, the AESO had declared an EEA 3 when Keephills 2 tripped offline, causing the grid to abruptly lose 395 MW of generation. During this time, Alberta was a net importer. The sudden loss of Keephills 2 led to an in-rush of imports onto the grid in excess of scheduled import volumes, causing ACE to plummet from 49 MW to -350 MW in 2 minutes.

Subsequently, CPS1 went from 290% at 8:46 to -675% at 8:50, before rebounding back above the 100% threshold to 248% at 8:53. During this time, wind and solar output was low. For HE 9, wind generation averaged 254 MW and solar averaged 28 MW. At 8:53, shortly after Keephills 2 tripped offline, the AESO began to shed load. Figure 42 highlights the Keephills 2 trip and the corresponding impacts it had on system frequency, ACE, imports and CPS1. The MSA undertook a detailed analysis of this load shed event in a report titled “Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations”.

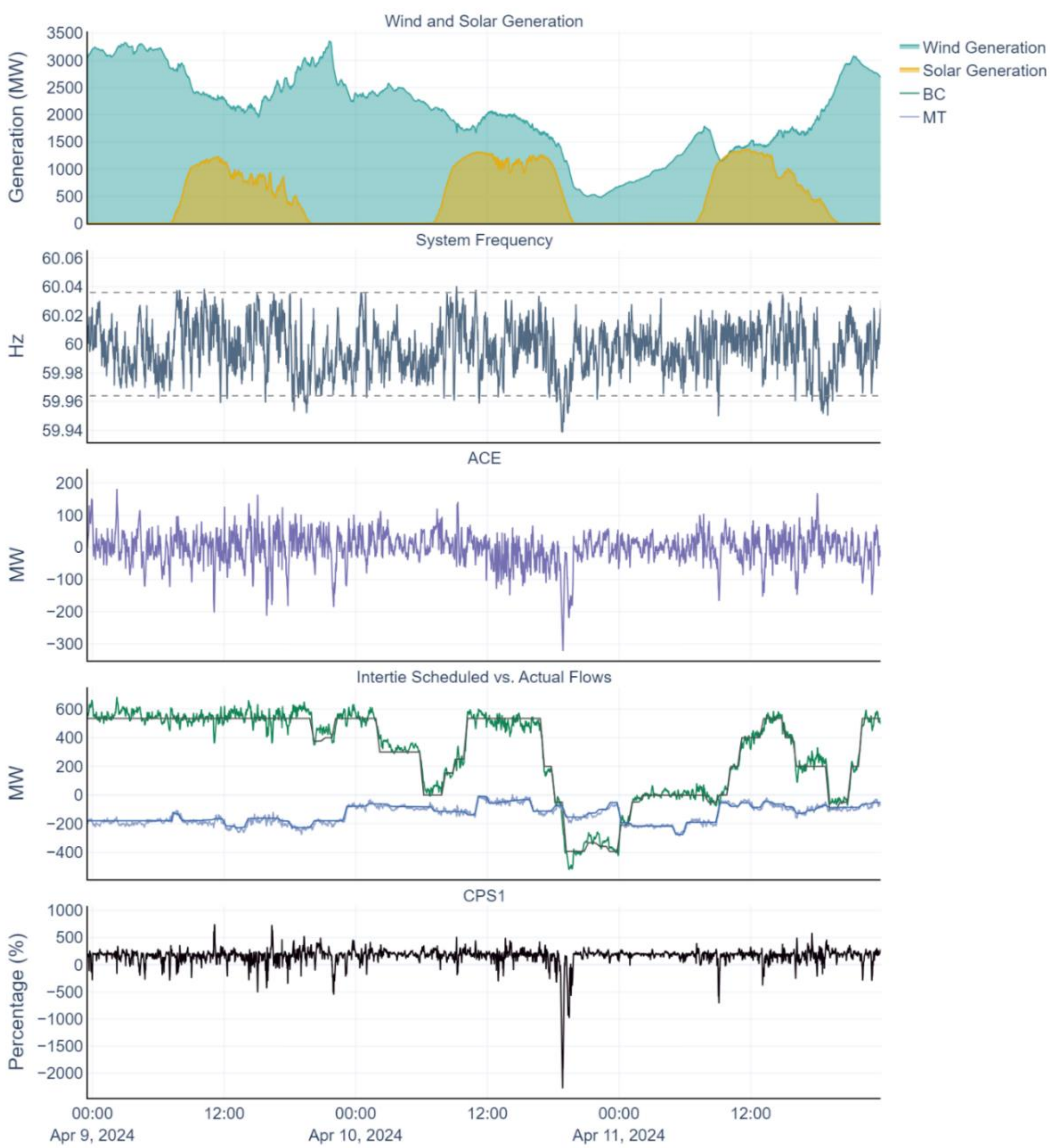
Figure 42: CPS1 decline on April 5, 2024



2.3.3.2 April 10, 2024

For most nights during the week of April 8 to 14, the reduction in supply as solar generation ramped down around sunset was offset by an increase in wind generation. However, on April 10 this did not occur. On April 10, solar reached its daily peak of 1,263 MW at 16:54 and subsequently began declining as it entered its evening ramp. On the same day, wind generation reached its peak of 2,023 MW at 14:29 and continued to decline steadily until 22:22. During this time, Alberta was importing from British Columbia and Montana. The rapid decrease in intermittent supply resulted an inrush of imports compared to the schedule. This caused a decrease in ACE and system frequency causing CPS1 to rapidly decline. CPS1 began to decline at 18:39, dropping from -3.74% to -2,278% at 18:52. Figure 43 illustrates renewable generation, system frequency, ACE, intertie activity and CPS1 from April 9 to 11.

Figure 43: CPS1 decline on April 10, 2024



2.3.3.3 May 18, 2024

On May 18, 2024, from 11:45 to 11:50 a period of 5 minutes, wind generation fell by 220 MW and solar generation declined by 74 MW. The greatest decline in wind generation was at the Sharp Hill Wind asset, which saw a decrease of 106 MW in generation. During this time, Alberta was importing from British Columbia and Montana. The abrupt decline in intermittent generation led to an increase in actual imports flowed from BC, resulting in an additional 456 MW of imports above what was scheduled. This caused a swift decline in ACE and a decrease in CPS1. CPS1 declined from 124% at 11:44, to -2,000% at 11:48 (Figure 44).

Intermittent generation remained relatively high throughout the day, and the grid entered a supply surplus event from 10:15 to 11:45. The high, consistent penetration of renewables at the time likely resulted in lower levels of inertia on the grid, which in turn caused this event to have a larger impact on frequency and ACE than would have otherwise been experienced had there been additional spinning mass on the grid. This is due to the fact that higher inertia will provide additional resistance to drops in frequency and give the grid more time to rebalance supply and demand.[14]

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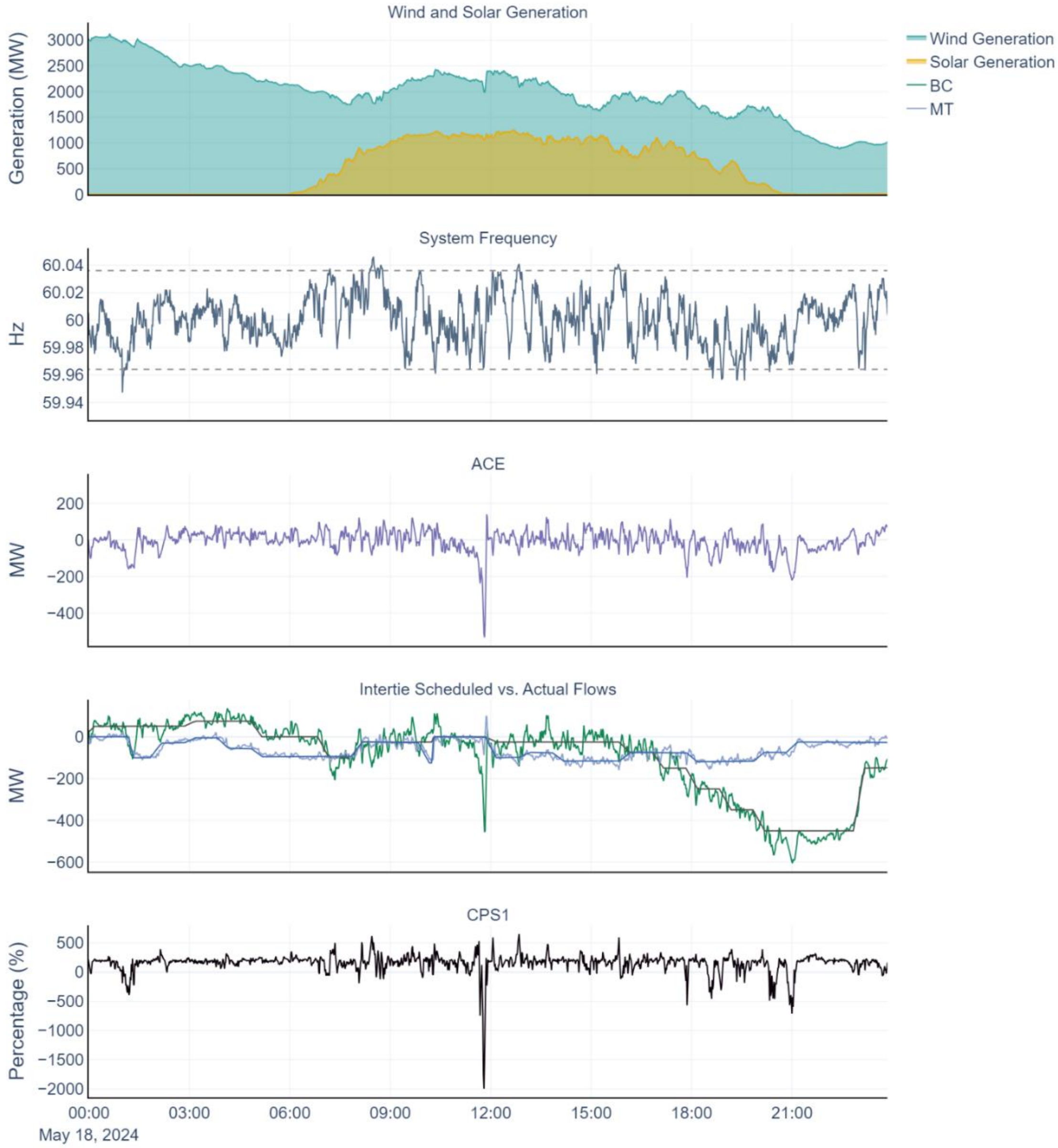
[14] NREL, Inertia and the Power Grid: A Guide Without the Spin, 2020.

Figure 44: CPS1 decline on May 18, 2024



3 OPERATING RESERVE MARKETS

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

3.1 Received prices

Received prices for operating reserves (OR) are calculated by indexing pool prices with the equilibrium prices set in OR auctions. Figure 45 illustrates monthly average received prices for active OR products over time. Year-over-year, the quarterly received prices for regulating, spinning, and supplemental reserves decreased by \$85/MWh, \$76/MWh, and \$17/MWh, respectively, which was driven by a decrease in the average pool price of \$115/MWh (Table 8).

Figure 45: Average received price for active spinning, supplemental, and regulating reserves (January 2023 to June 2024)

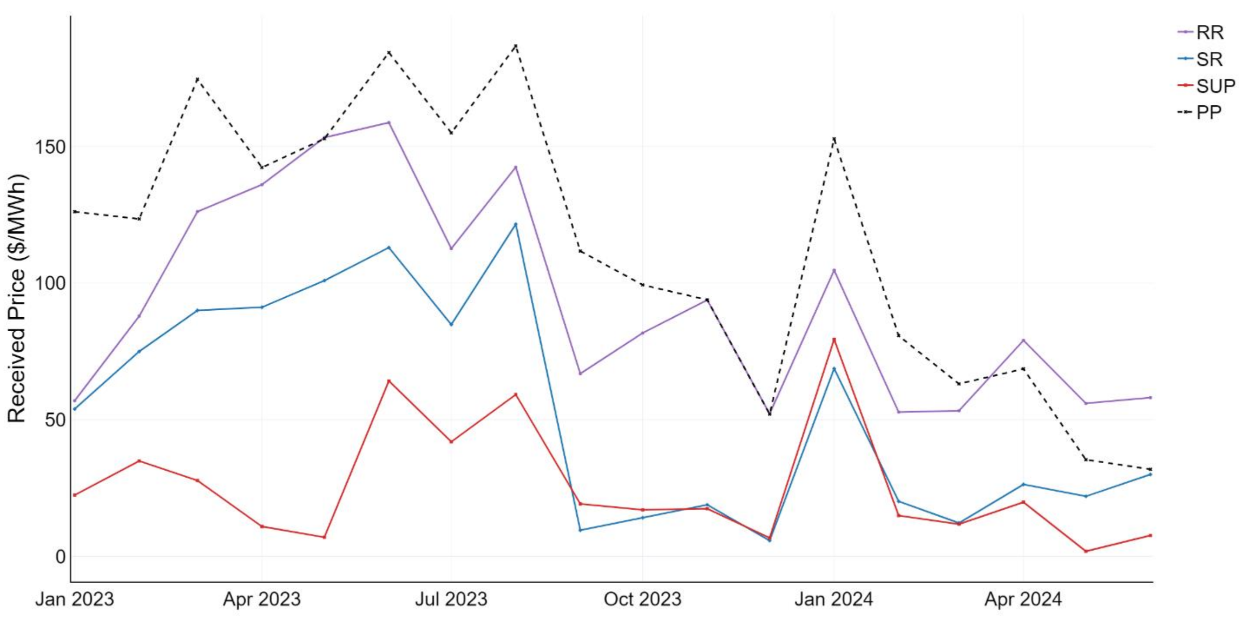
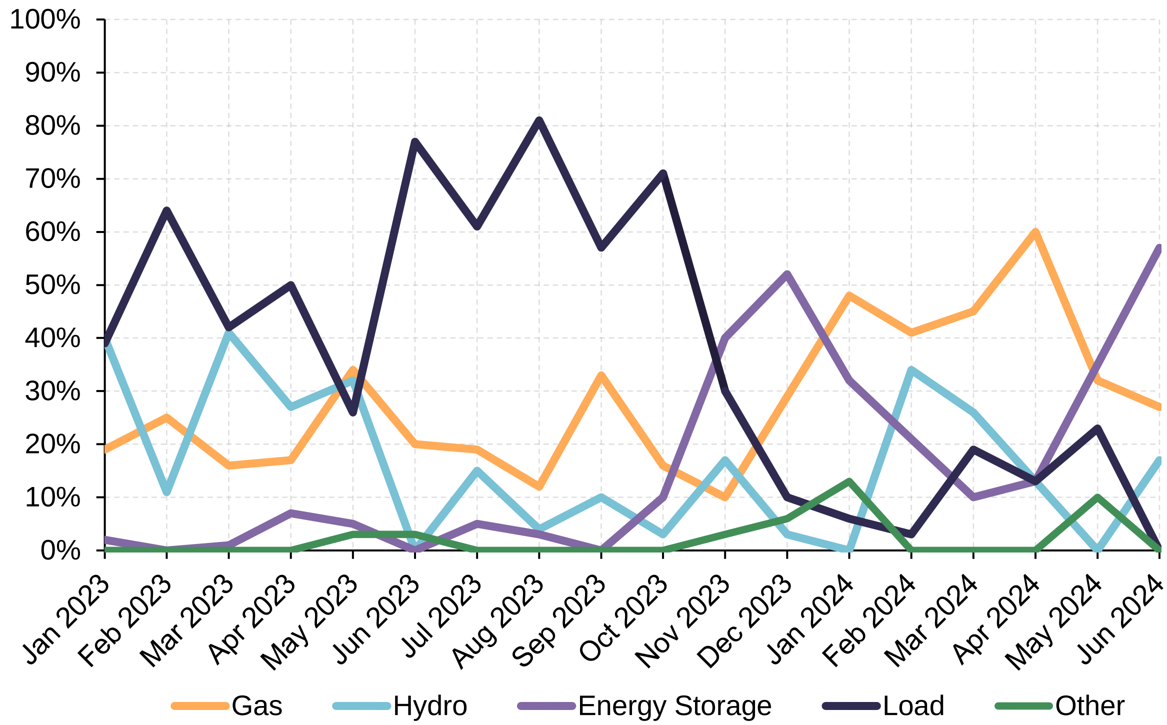


Table 8: Average received price for active regulating, spinning and supplemental reserves (Q2 2023 and Q2 2024)

Qtr Year	Regulating Reserves	Spinning Reserves	Supplemental Reserves	Pool Price
Q2 2023	$149	$102	$27	$160
Q2 2024	$64	$26	$10	$45
Difference	*($85)*	*($76)*	*($17)*	*($115)*

The fact that the decrease in received prices was less than the fall in pool price indicates that the equilibrium prices of the three products increased. The lower decline in supplemental reserve received prices year-over-year compared to regulating and spinning means that the supplemental equilibrium price had the greatest increase. This was partly attributable to less load participation in supplemental reserves, which was the marginal fuel type the majority of the time in Q2 2023 (Figure 46), and generally priced at high discounts to pool price. In Q2 2024, natural gas and energy storage were often the clearing fuel types for supplemental and were priced at lower discounts.

Figure 46: Monthly percentage of marginal fuel type for on-peak supplemental reserve (January 2023 to June 2024)



Quarter-over-quarter, the average received prices for regulating decreased by $6/MWh, spinning decreased by $8/MWh, and supplemental decreased by $26/MWh, while the average pool price decreased by $54/MWh (Table 9). Since the price decline for regulating and spinning was much lower than the pool price decline, that means the equilibrium prices for these products increased.

For regulating reserves, the increase in equilibrium price was driven by lower offered volume and higher cleared offer prices by natural gas-fired generation, which is generally the marginal fuel type for regulating reserve (Figure 47). For spinning reserves, the increase in equilibrium price was driven by a significant decline in energy storage participation, which was replaced with natural gas-fired generation mainly acting as the marginal fuel type and clearing at lower discounts (Figure 48).

Table 9: Average received price for active regulating, spinning and supplemental reserve (Q1 2024 and Q2 2024)

Qtr Year	Regulating Reserves	Spinning Reserves	Supplemental Reserves	Pool Price
Q1 2024	$71	$34	$36	$99
Q2 2024	$64	$26	$10	$45
Difference	*($6)*	*($8)*	*($26)*	*($54)*

Figure 47: Monthly percentage of marginal fuel type for on-peak regulating reserve (January 2023 to June 2024)

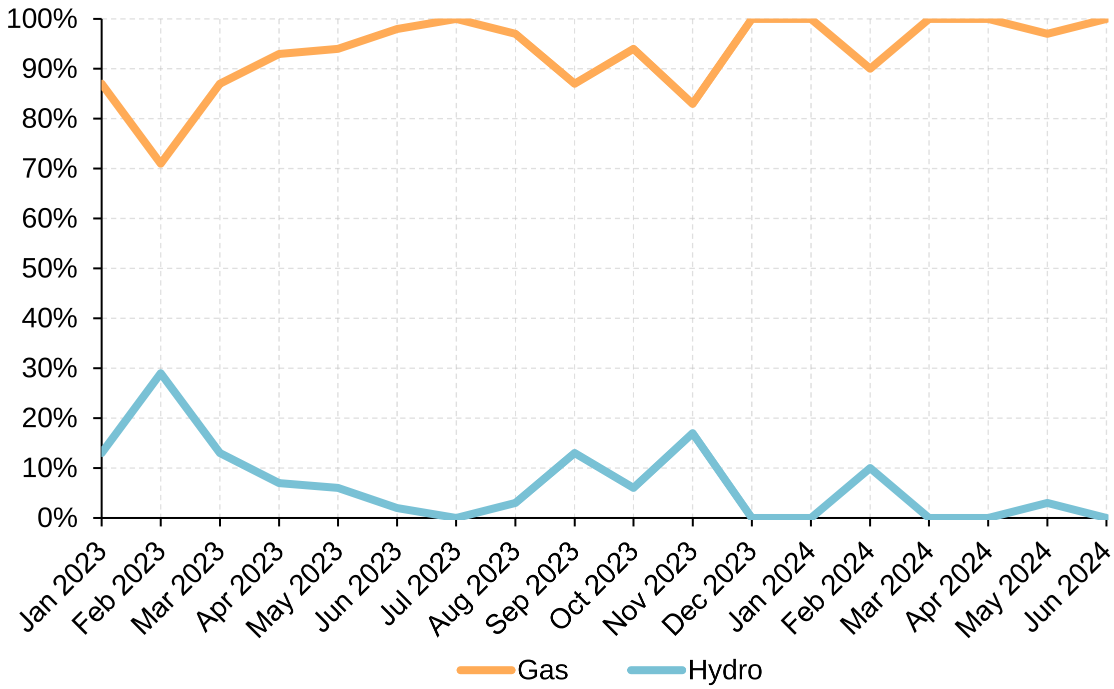
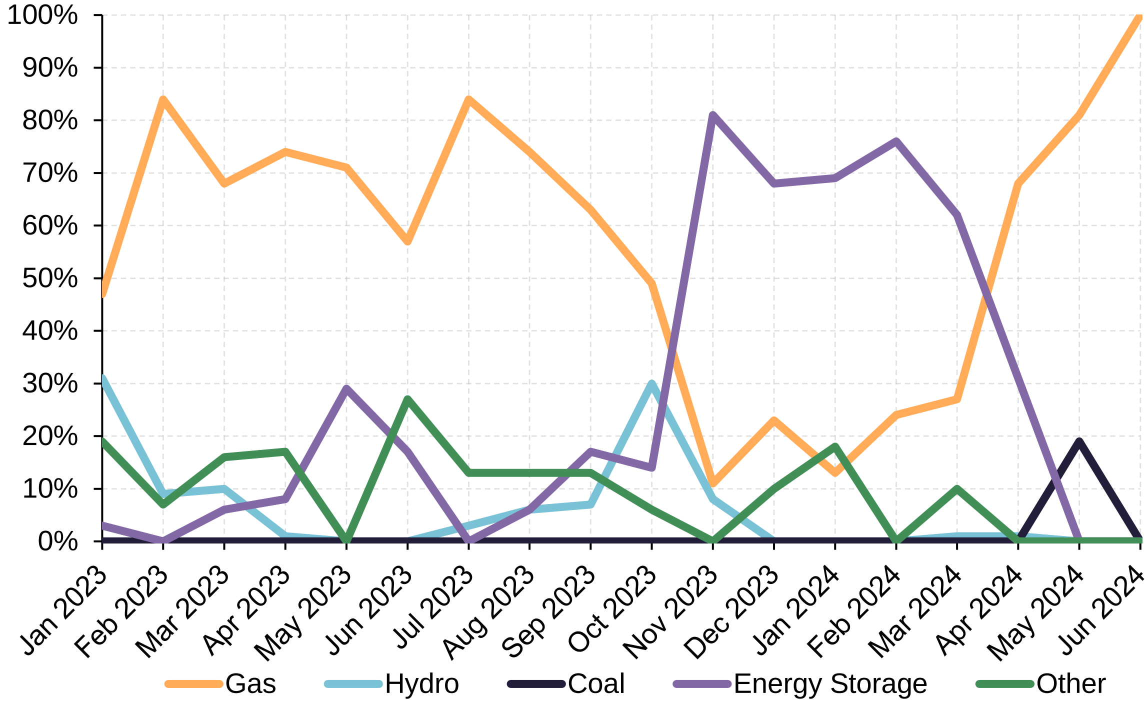


Figure 48: Monthly percentage of marginal fuel type for on-peak spinning reserve (January 2023 to June 2024)



Offered volumes for on-peak regulating reserves for Q2 2024 increased drastically in comparison to Q2 2023 in response two increases in AESO bid volumes throughout the year (Figure 49). Mean offered volumes declined versus the previous quarter, with several instances where offered volumes and the AESO bid volume converged.

On April 22 and May 27 all the offered active regulating reserve cleared, and on June 15 offered volumes were short of the AESOs target bid volume by 6 MW. On all three days, on-peak regulating reserve reached the price cap of $40/MWh. The shortfall in offered volumes on June 15 came largely in response to a reduction in participation by Cavalier.

Bid volumes for on-peak spinning and supplemental reserves stabilized this quarter relative to Q1 2024, which exhibited some seasonal volatility around the cold temperatures (Figure 50 and Figure 51). In Q2 offered volumes for spinning reserves steadily declined due to a decrease in participation by energy storage assets.

On June 13 on-peak offered volumes for active spinning reserve were short of the AESO bid volume by 5 MW. This came on the heels of a decline in offered volumes from 311 MW on June 8 to 227 MW on June 13. The decrease in offered volume corresponded to the highest equilibrium price for on-peak spinning reserves in Q2. However, due to lower pool prices it only ranks as the sixth highest on-peak received price for spinning reserves in the quarter. This outcome was the result of a reduction in offered volumes from several assets in the spinning reserve market including Battle River 4, Bow River Hydro, Brazeau, and Keephills 2.

Offered volumes for on-peak supplemental reserves declined in comparison to the previous quarter, however a reduction in the average AESO bid volumes for this same time period caused the spread between offered volumes and bid volumes to remain relatively constant.

Figure 49: AESO bid and participant offered volume for regulating reserve (January 2023 to June 2024)

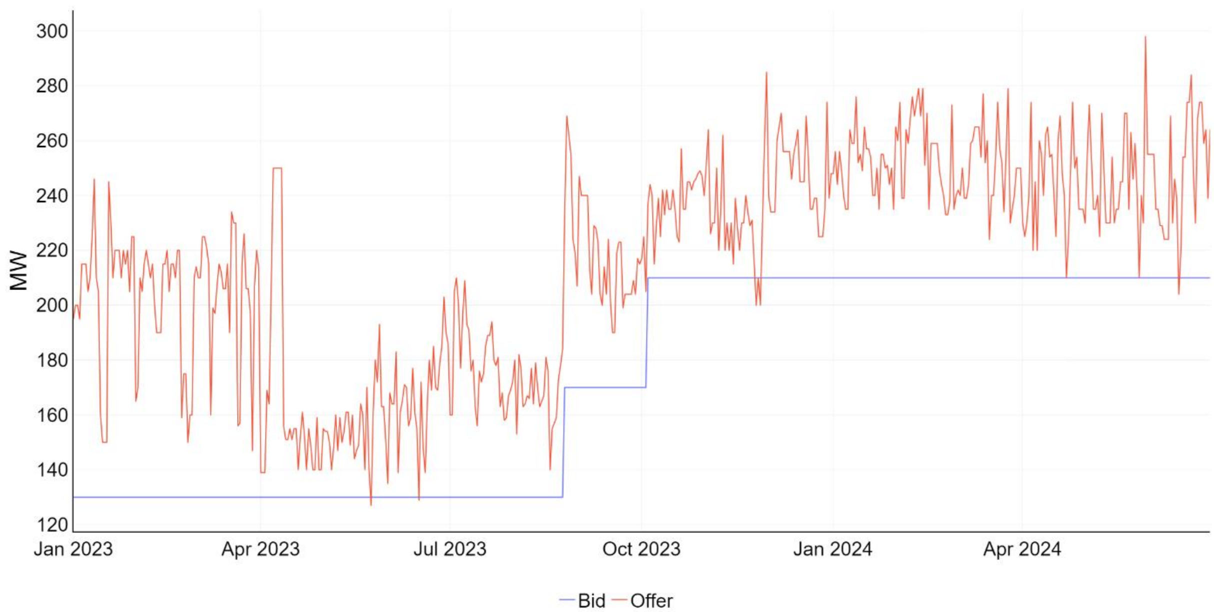


Figure 50: AESO bid and participant offered volume for spinning reserve (January 2023 to June 2024)

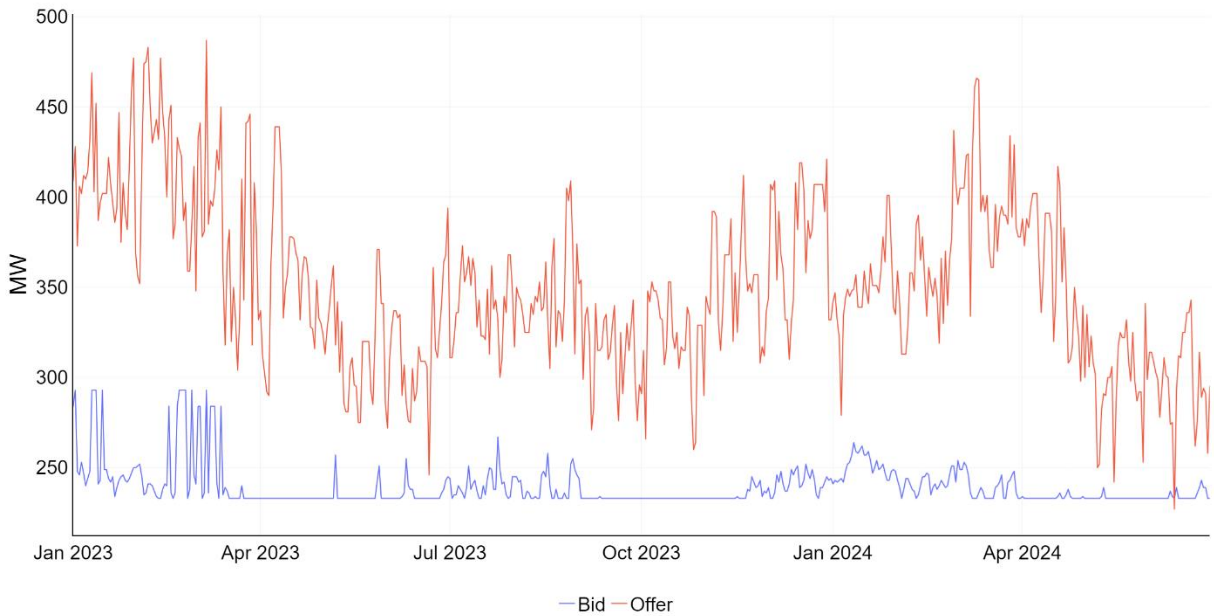
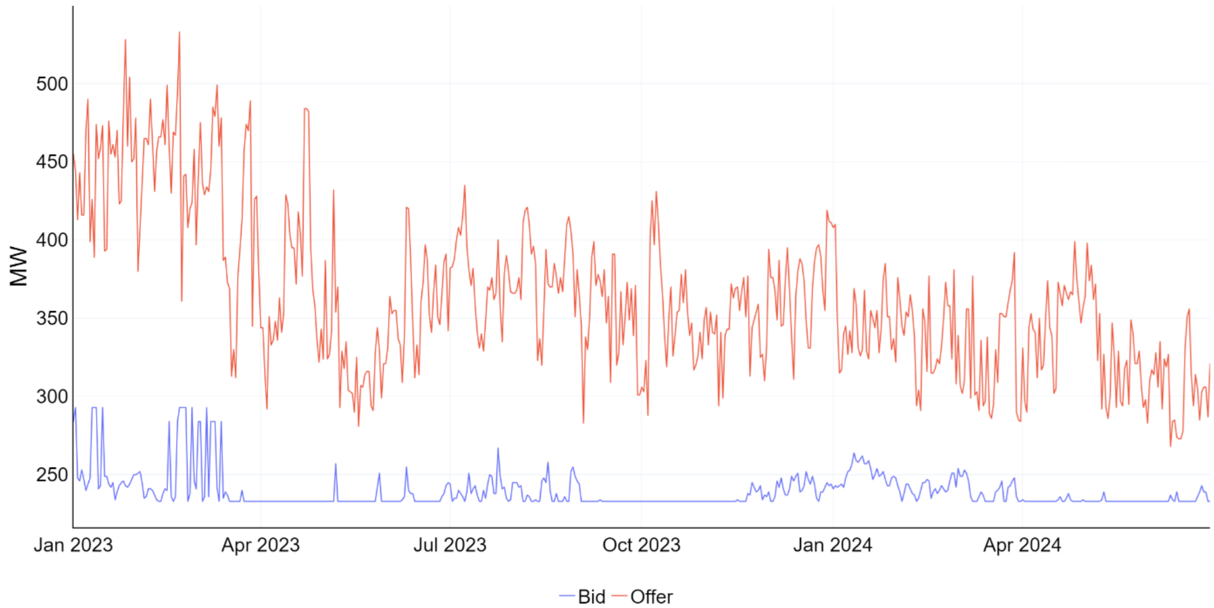


Figure 51: AESO bid and participant offered volume for supplemental reserve (January 2023 to June 2024)

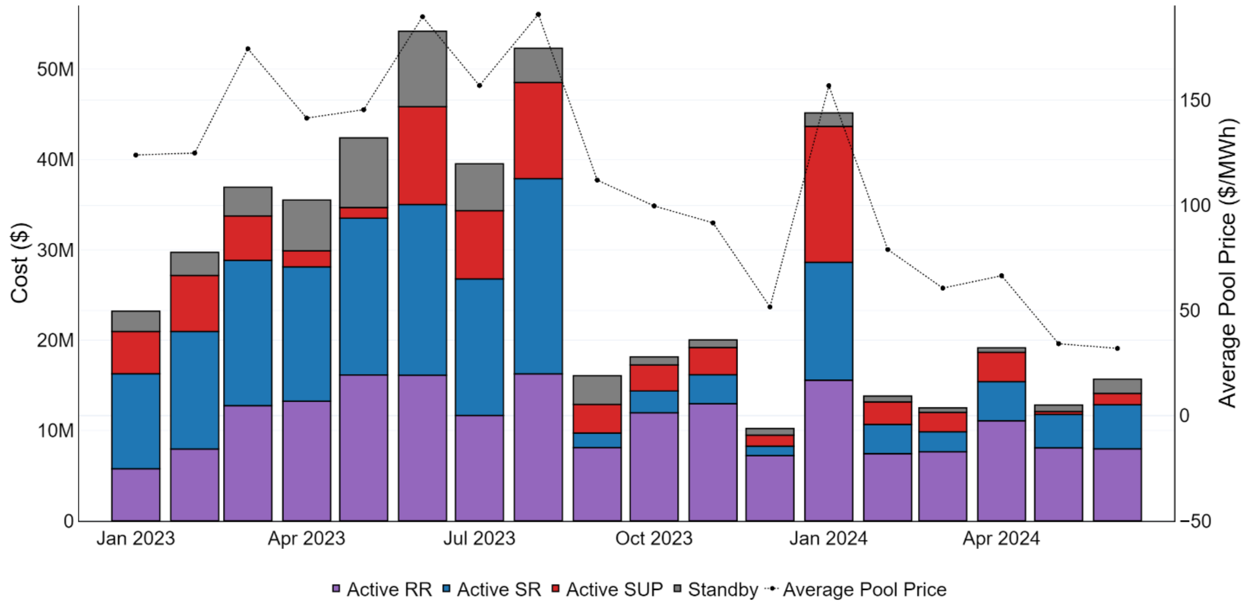


3.2 Total operating reserve costs

Total operating reserve costs in Q2 decreased by 33% relative to Q1, largely due to lower pool prices and a reduction in the costs of active supplemental reserves. Standby costs increased by 7% and will be further discussed in Section 3.4 below.

In comparison to Q2 2023, there was a 64% decrease operating reserve costs. This decrease was linked to a reduction in pool price, and a decrease in standby costs driven by fewer standby reserve volumes being procured for regulating reserves. Figure 52 captures changes in monthly OR costs from January 2023 to June 2024.

Figure 52: Total cost of operating reserves by month (January 2023 to June 2024)



3.3 Operating reserve directives

Table 10 captures the number of events requiring contingency reserve directives by month in Q2 2024. In addition, the table shows the average directive response by providers of spinning reserves and supplemental reserves – with supplemental broken down by load and generation.

In total there were 26 events that required the AESO to direct contingency reserves. Throughout the quarter the newer thermal assets Cascade 1 and 2 and Genesee Repowering 1 and 2, tripped offline multiple times resulting in contingency reserve directives. The longest duration event of the quarter lasted for 201 minutes on April 5 spanning from 6:53 to 10:13. The MSA undertook a detailed analysis of this load shed event in a report titled “Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations”.

Table 10: Monthly contingency reserve directives (Q2 2024)

Month	Number of Events	Average SR Directed (MW)	Average SUPL Directed (MW)	Average SUPG Directed (MW)
April	8	118	69	117
May	7	125	52	95
June	11	122	49	75

3.4 Standby changes

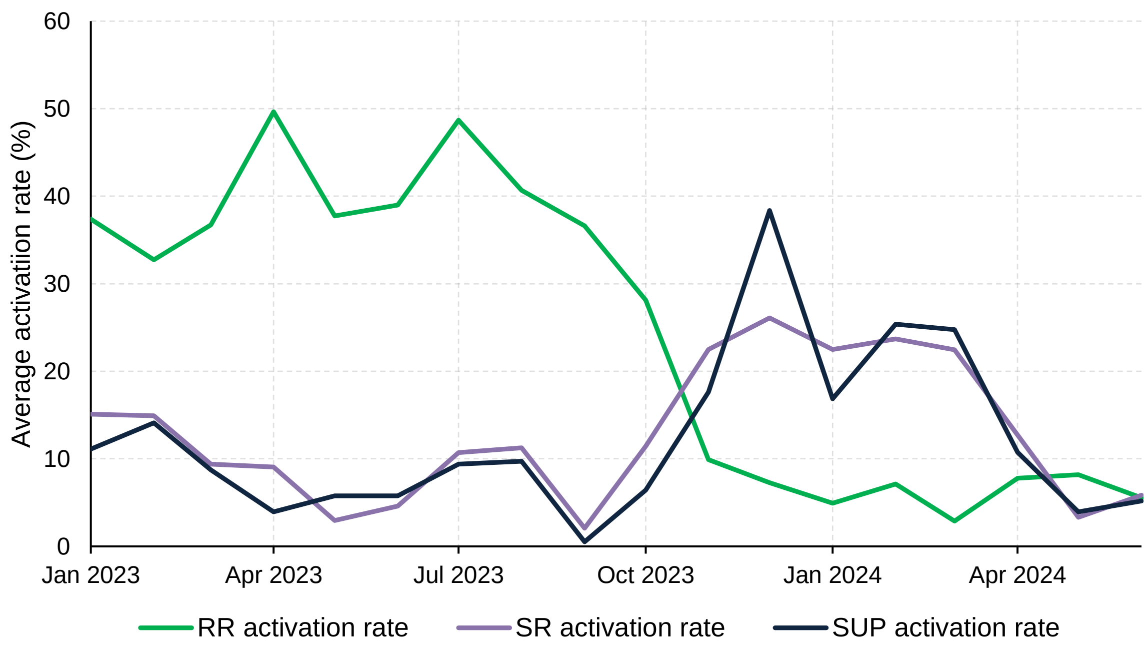
Standby reserves are activated to supply additional volumes to the OR market when more reserves are required. Figure 53 shows the combined on and off-peak activation rates for regulating reserve, spinning reserve, and supplemental reserve. This quarter, the activation rates for all three products averaged 7%. In Q1 2024, the activation rates averaged 5%, 23% and 22%, for regulating, spinning and supplemental, respectively.

In combination with less activated volume, the decline in the activation rate for spinning from 23% to 7% can be partly attributed to approximately 20 MW more standby volume being procured beginning on May 1, 2024. This increase occurs on a seasonal basis.

As shown in Figure 53, the activation rates for spinning and supplemental are in line with Q2 2023 rates. However, the activation rate for regulating reserves in Q2 was much lower than in Q2 2023. This is because the AESO now procure 80 MW more active regulating reserves during on-peak periods and 20 MW more during off-peak periods, so less standby volumes are being activated.

Notably, June had the lowest on-peak activation rate for regulating reserve in Q2 at 1%, while having the highest off-peak activation rate for regulating reserve at 15%.

Figure 53: Activation rates for regulating, spinning, and supplemental reserve (January 2023 to June 2024)



The standby market follows a pay-as-bid structure and uses a blended price formula to rank standby offers for market clearing.[15] Market participants receive the premium price for contracted

[15] Blended Price = Premium Price + (Activation Percentage * Activation Price)

standby volumes, the activation price for activated standby volumes, and the pool price for directed volumes.

The activation percentages in the blended price formula are determined by the AESO and are intended to reflect historical activation rates for on and off-peak hours. Effective April 15, 2024, the AESO updated the activation percentages for the first time in many years (Table 11). As a result, this has had an impact on the offer prices for the premium and activation products in the standby market.

Table 11: Blended price methodology activation percentage changes

Period	Product	Activation Percentage (Before April 15, 2024)	Activation Percentage (Effective April 15, 2024)
On-Peak	RR	1%	37%
	SR	10%	10%
	SUP	10%	9%
Off-Peak	RR	3%	38%
	SR	10%	14%
	SUP	10%	15%

Figure 54 shows the monthly average on-peak premium price for standby regulating, spinning, and supplemental reserves. There has been an increase in premium prices for both on and off-peak operating reserve products since the change to the activation percentage of the blended price formula. The most significant change was in the on-peak premium price for regulating reserves, which averaged $39/MWh in June, compared to an average of $0.2/MWh from January 2023 to April 15, 2024 (the date of the activation percentage change).

Figure 54: Average on-peak premium price (January 2023 to June 2024)

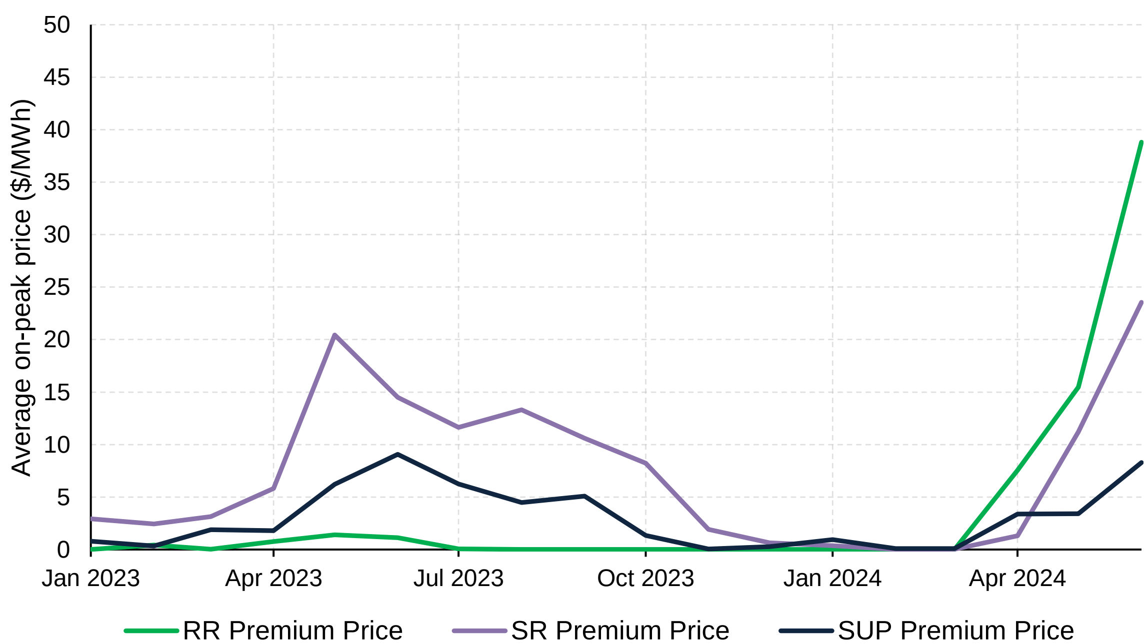
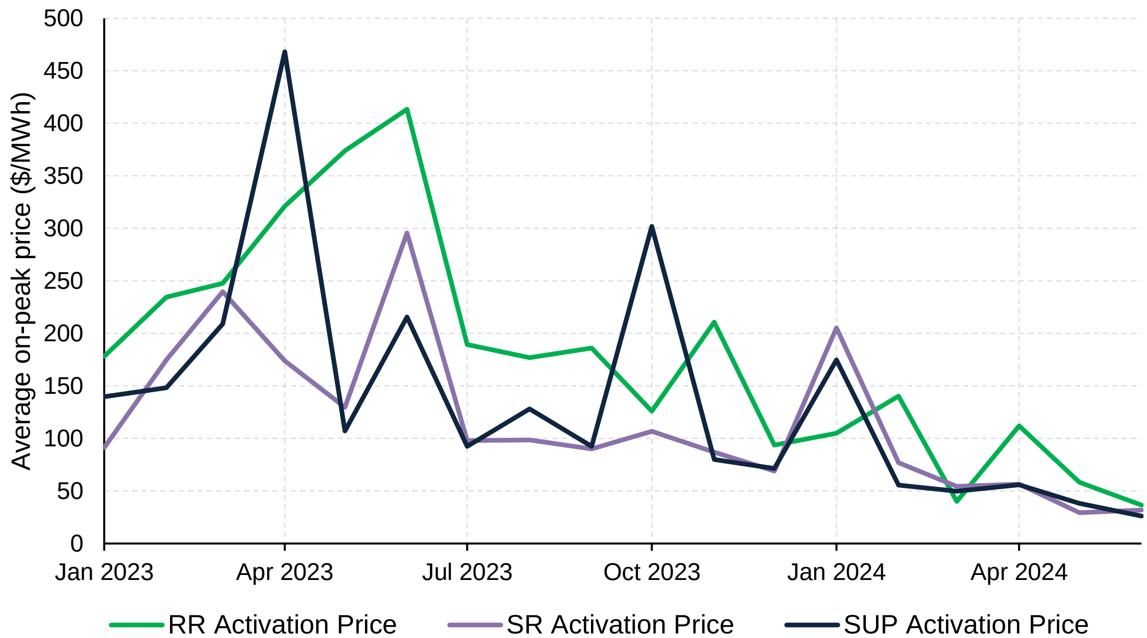


Figure 55 shows the monthly average activation price for standby regulating, spinning and supplemental. Since the change to the activation percentage of the blended price formula, there has been a decrease in activation prices for both on and off-peak products. This fall in activation prices reflects lower pool prices and the higher weighting of the activation price in the blended price formula. As shown, on and off-peak activation prices are at the lowest levels going back to January 2023.

Figure 55: Average on-peak activation price (January 2023 to June 2024)



4 THE FORWARD MARKET

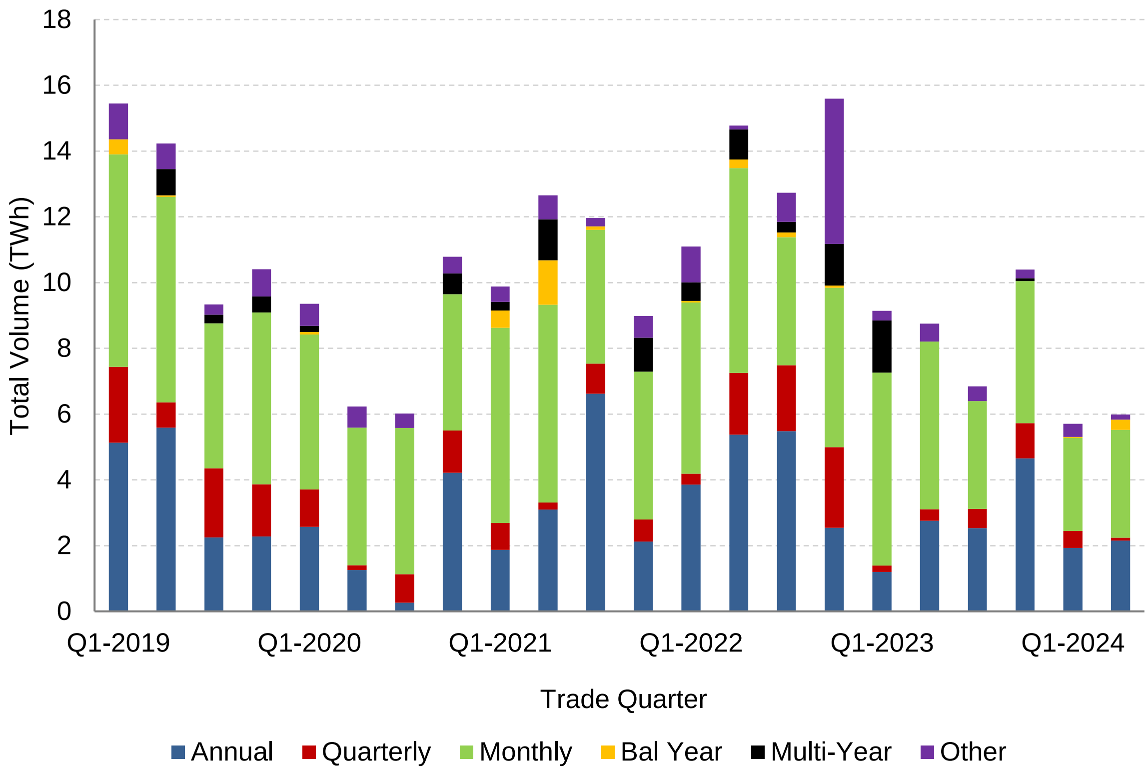
Alberta's financial forward market for electricity is an important component of the market because it allows for generators and larger loads to hedge against pool price volatility, and it enables retailers to reduce price risk by hedging sales to retail customers.[16]

4.1 Forward market volumes

Liquidity in the forward market continued to be low in Q2. Total trade volumes on ICE NGX and via brokers was 5.98 TWh, a slight increase on Q1 but a 32% decrease compared to Q2 2023. Total trade volumes in Q2 were comparable with Q2 and Q3 of 2020 when trade volumes were lowered by uncertainty around the COVID-19 pandemic (Figure 56).

The largest decline year-over-year was in monthly trade volumes. Total monthly volumes on ICE NGX and via brokers was 5.10 TWh in Q2 2023 but this fell by 1.82 TWh to 3.28 TWh in Q2. Annual volumes also fell, by 0.60 TWh from 2.76 TWh to 2.16 TWh.

Figure 56: Total volumes by trade quarter and product term (Q1 2019 to Q2 2024)



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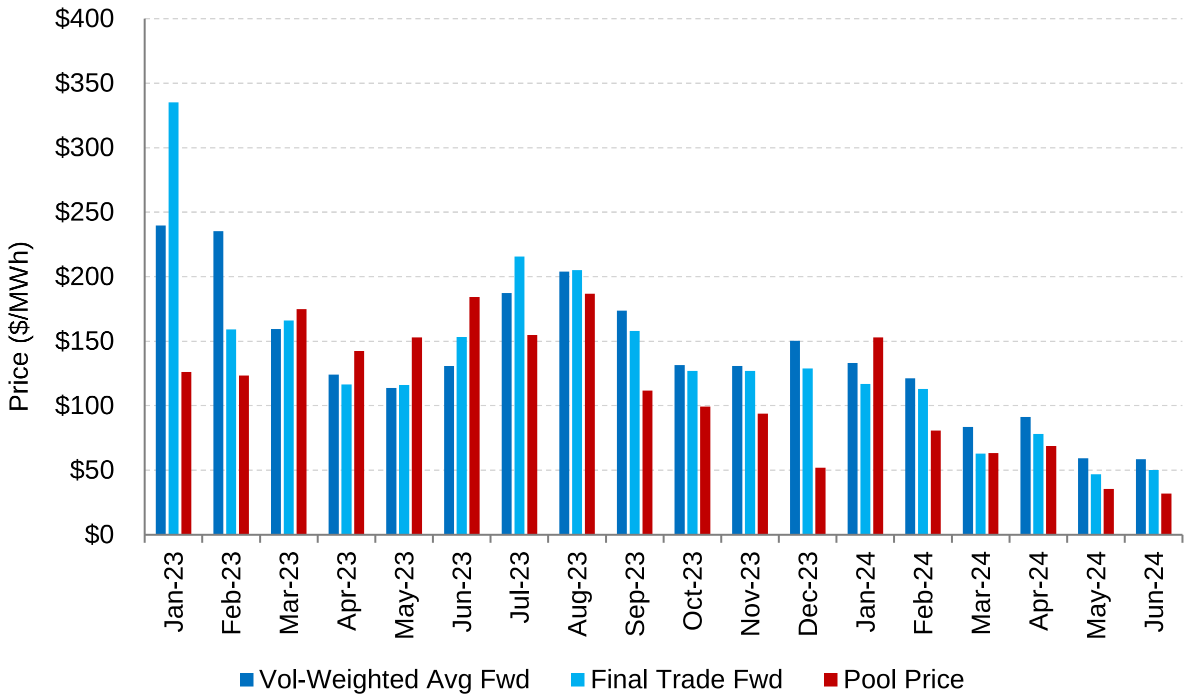
16 The MSA's analysis in this section incorporates trade data from ICE NGX and two over the counter (OTC) brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2023 are also included. Direct bilateral trades occur directly between two trading parties, not via ICE NGX or through a broker, and the MSA generally collects information on these transactions once a year.

4.2 Trading of monthly products

Figure 57 illustrates monthly forward prices compared to realized pool prices since January 2023. Forward prices and pool prices in recent months have been below prices last year because of increased supply in the energy market. For example, the volume-weighted average forward price for June 2024 was $58.41/MWh compared to $130.47/MWh for June 2023, and the realized pool price fell from $184.41/MWh in June 2023 to $31.85/MWh in June 2024.

For each month in Q2 there was a forward premium relative to realized pool prices. In April the forward premium was $22.59/MWh, in May the forward premium was $23.77/MWh, and in June the forward premium was $26.56/MWh.[17]

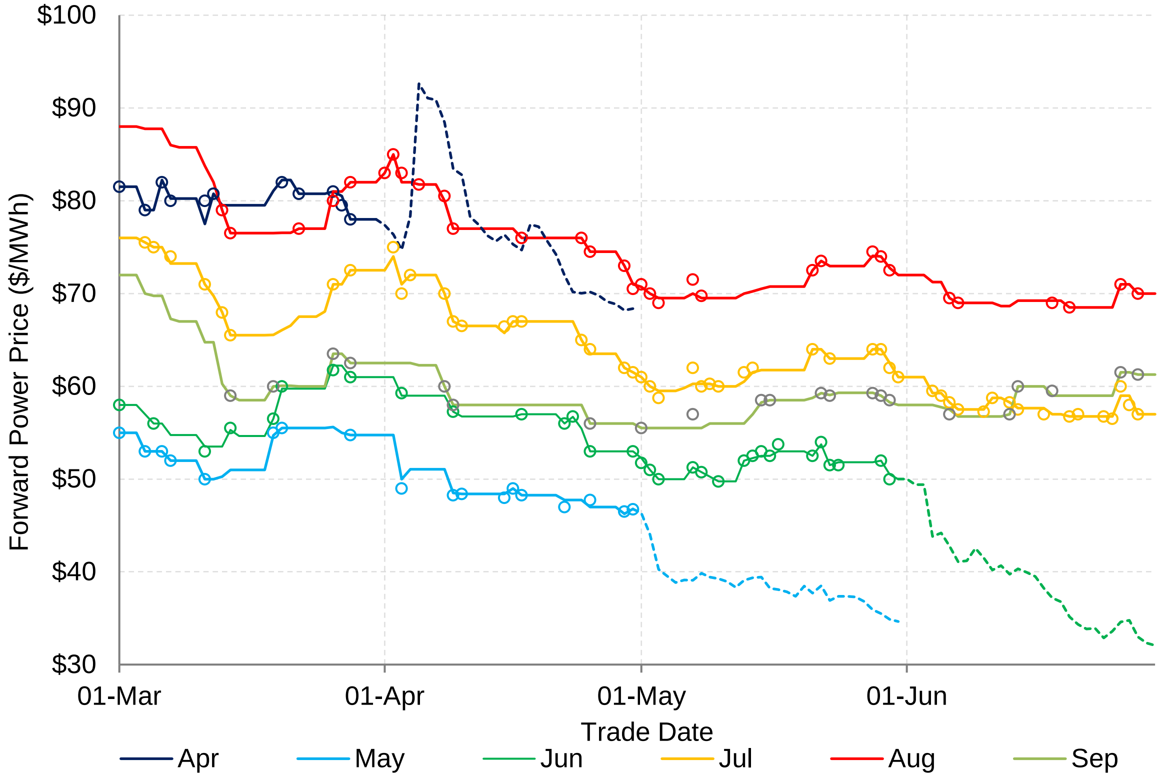
Figure 57: Monthly forward prices compared to realized pool prices (January 2023 to June 2024)



The fact that pool prices came in under forward market expectations in Q2 put downward pressure on forward prices for the coming months (Figure 58). For example, the price of July declined by 21% over the quarter and the price of August fell by 15%. In addition, natural gas prices declined over Q2. The forward natural gas price for July fell by 60% from $1.65/GJ to $0.65/GJ and the price of August also fell by 60%. Natural gas is the main input cost for Alberta power so declining forward prices for natural gas can put downward pressure on forward prices for electricity.

[17] These figures compare the volume-weighted average forward price with realized pool prices.

Figure 58: Select monthly forward prices (March 1 to June 30)



4.3 Trading of annual products

Figure 59 illustrates the evolution of forward prices for annual contracts since the start of the year. The dashed green line illustrates the marked price of Calendar 2024 (CAL24), which shows the expected average pool price for the year based on realized and forward prices.

The marked price of CAL24 fell by 10% over the quarter as pool prices came in under expectations and this put downward pressure on future months. In addition, natural gas prices fell with the expected average natural gas price for 2024 falling by 25% over Q2.

The lower-than-expected pool prices in Q2 and declining natural gas prices also put downward pressure on power prices for CAL25, CAL26, and CAL27 (Table 12). However, the price of CAL28 increased by 2% over the quarter, largely due to a rally in early May. The price of CAL28 increased from $59.80/MWh on May 1 to $63.75/MWh on May 16 before trading at $64.00/MWh on May 24. The CAL28 contract was priced at a $7.00/MWh premium to CAL27 as of June 30.

Figure 59: Annual forward prices (January 1 to June 30)

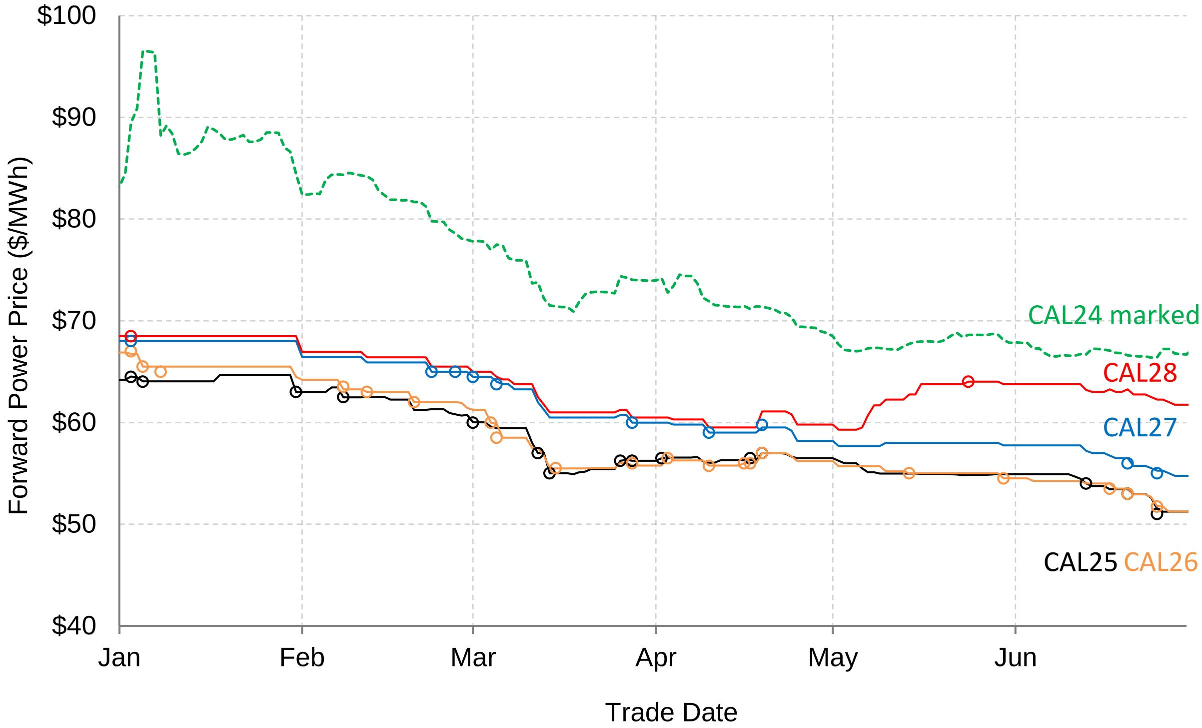


Table 12: Forward power and natural gas price changes over Q1

Contract	Power price ($/MWh)			Natural gas price ($/GJ)			Operating margin[18] ($/MWh)		
	Mar 31	**Jun 30**	**% Chg**	**Mar 31**	**Jun 30**	**% Chg**	**Mar 31**	**Jun 30**	**% Chg**
CAL24 (marked)	$73.95	$66.70	-10%	$1.94	$1.46	-25%	$58	$55	-6%
CAL25	$56.24	$51.24	-9%	$3.11	$2.78	-11%	$31	$28	-8%
CAL26	$55.76	$51.24	-8%	$3.51	$3.17	-10%	$26	$24	-8%
CAL27	$60.00	$54.75	-9%	$3.51	$3.24	-8%	$29	$26	-11%
CAL28	$60.50	$61.75	2%	$3.41	$3.28	-4%	$29	$31	8%

[18] The operating margin figures assume a heat rate of 7.5 GJ/MWh and consider the carbon costs associated with an emissions intensity of 0.37 tCO2e/MWh.

5 THE RETAIL MARKET

5.1 Quarterly summary

Residential retail customers can choose from several retail energy rates. By default, retail customers are on the regulated rate option (RRO). RRO prices vary monthly and by distribution service area.

Alternatively, customers can sign with a competitive retailer. Competitive retailers typically offer both fixed and variable energy rates. Fixed energy rates are typically set for a period of between one and five years, while competitive variable energy rates vary monthly.

The residential RRO rate in Q2 2024 was 33% lower than last year (Table 13), and 28% lower than Q1 2024. The RRO rates shown in Table 13 include the collection rates.[19] The collection rates increased the RRO rates in April, May, and June by around 3.4 ¢/kWh.

The average residential Default Rate Tariff (DRT) rate in Q2 was 49% lower than last year (Table 13) and 42% lower relative to Q1 2024. In Q2, the DRT rate was lowest in June and highest in April.

Table 13: Monthly retail market summary for Q2 (Residential customers)

		2023	2024	Change
RRO (Avg ¢/kWh)	Apr	18.27	14.17	*-22%*
	May	16.56	10.55	*-36%*
	Jun	18.43	11.27	*-39%*
	Q2	**17.74**	**11.98**	***-33%***
DRT (Avg $/GJ)	Apr	3.57	1.95	*-45%*
	May	2.25	1.60	*-29%*
	Jun	3.36	1.15	*-66%*
	Q2	**3.05**	**1.57**	***-49%***
Competitive variable electricity rate (Avg. ¢/kWh)	Apr	15.56	8.09	*-48%*
	May	17.56	4.59	*-74%*
	Jun	21.96	4.28	*-81%*
	Q2	**18.35**	**5.64**	***-69%***
Competitive variable natural gas rate (Avg. $/GJ)	Apr	3.41	2.33	*-32%*
	May	3.43	2.25	*-34%*
	Jun	3.34	1.83	*-45%*
	Q2	**3.39**	**2.14**	***-37%***
Expected cost, 3-year electricity contract (Avg. ¢/kWh)	Apr	10.49	6.00	*-43%*
	May	10.68	5.82	*-46%*
	Jun	10.66	5.71	*-46%*
	Q2	**10.61**	**5.85**	***-45%***
Expected cost, 3-year natural gas contract (Avg. $/GJ)	Apr	3.71	3.38	*-9%*
	May	3.51	3.26	*-7%*
	Jun	3.37	3.09	*-8%*
	Q2	**3.53**	**3.24**	***-8%***

The average competitive variable electricity rate faced by residential customers was 69% lower year-over-year. Variable electricity rates in May and June experienced 74% and 81% declines respectively, contributing to a high year-over-year decline in the quarter (Table 13). Again, the variable electricity rate in Q2 was 50% lower than the rates in Q1 2024. Competitive variable natural gas rates declined by 37% year-over-year and by 27% relative to Q1 2024.

Retailers' expected cost of providing 3-year fixed rate electricity contracts in Q2 was 45% lower year-over-year and 14% lower than in Q1 2024, reflecting lower forward prices for electricity. The

[19] Collection rates result from the deferred revenue associated with the rate ceiling set on RRO rates for January, February, and March 2023. The deferred revenue is being recovered from the RRO customers from April 2023 until December 2024

expected cost of providing 3-year fixed rate natural gas contracts dropped by 8% year-over-year but increased by 3% relative to Q1 2024.

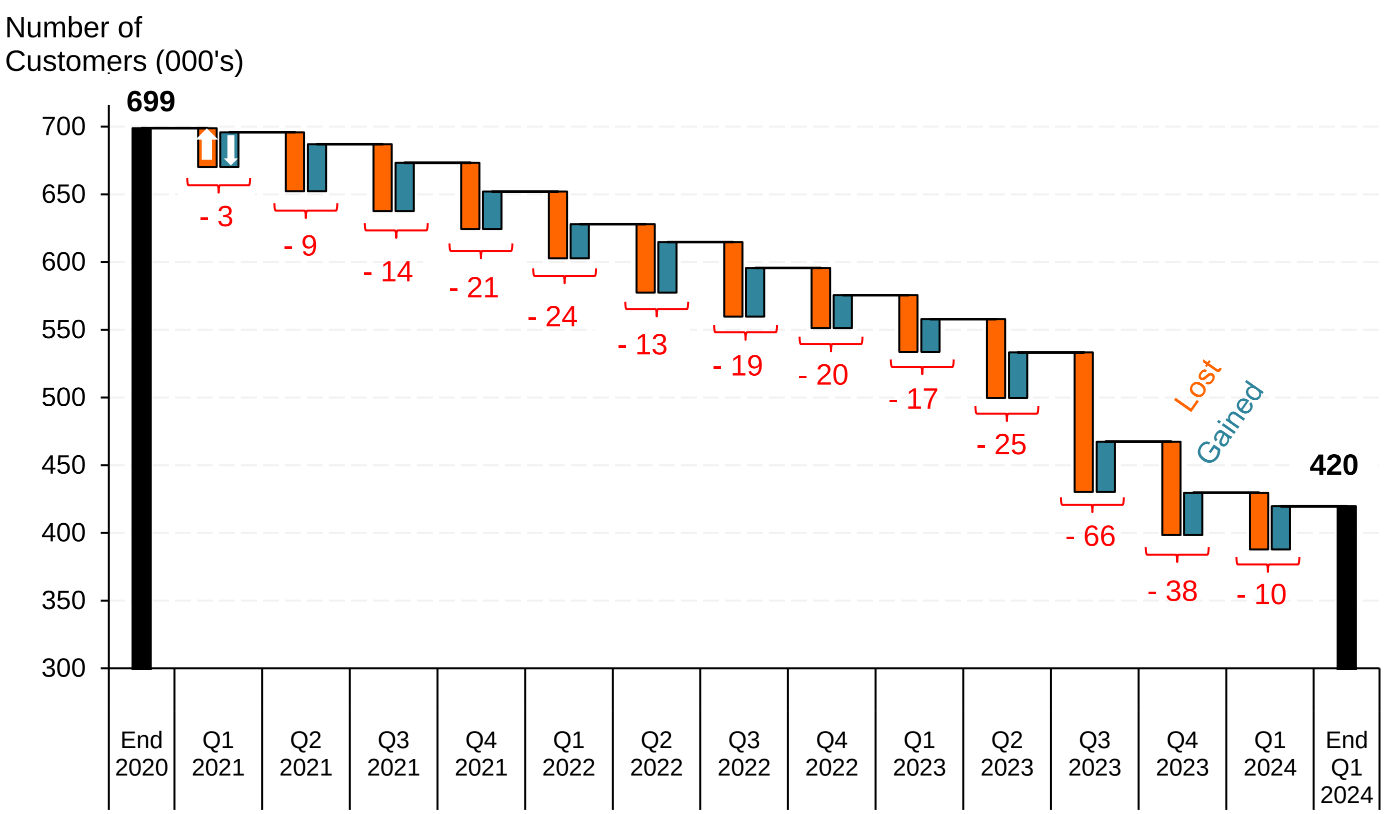
5.2 Retail customer movements

The MSA collects and tracks retail switching data on a one-quarter lagged basis. As such, the discussion in this section focuses on retail switching in and prior to Q1 2024.

5.2.1 Regulated retailer customer losses

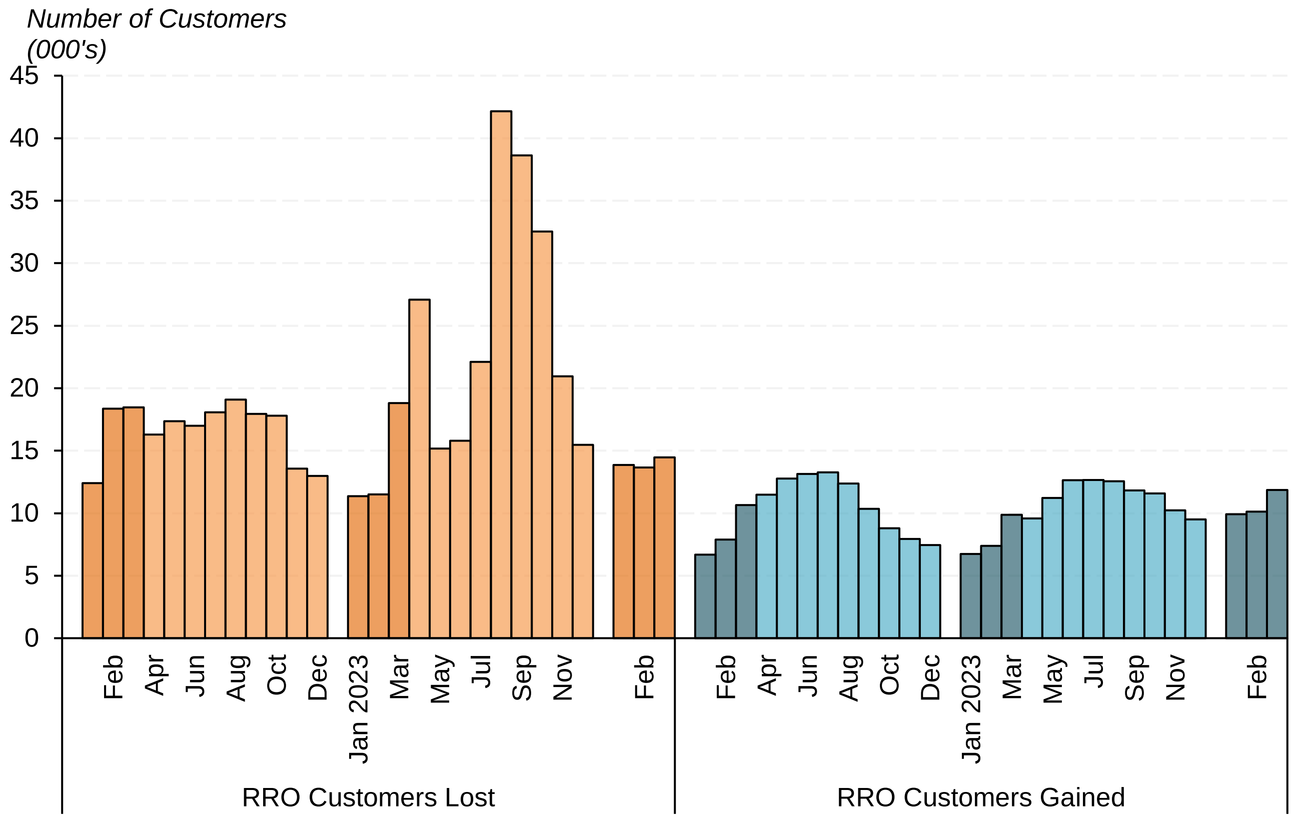
In Q1 2024, the net residential RRO customer loss was around 10,000 customers, the lowest since Q2 2021 (Figure 60). During this quarter, approximately 42,000 residential customers left RRO, while 32,000 new customers joined. The low RRO rates observed in Q1 contributed to the decline in net loss. RRO rates in Q1 were 15% lower than in Q4 2023 and 43% lower than in Q3 2023. As of March 2024, there are around 420,000 residential customers on RRO.

Figure 60: RRO customer net losses, residential customers (Q1 2021 to Q1 2024)



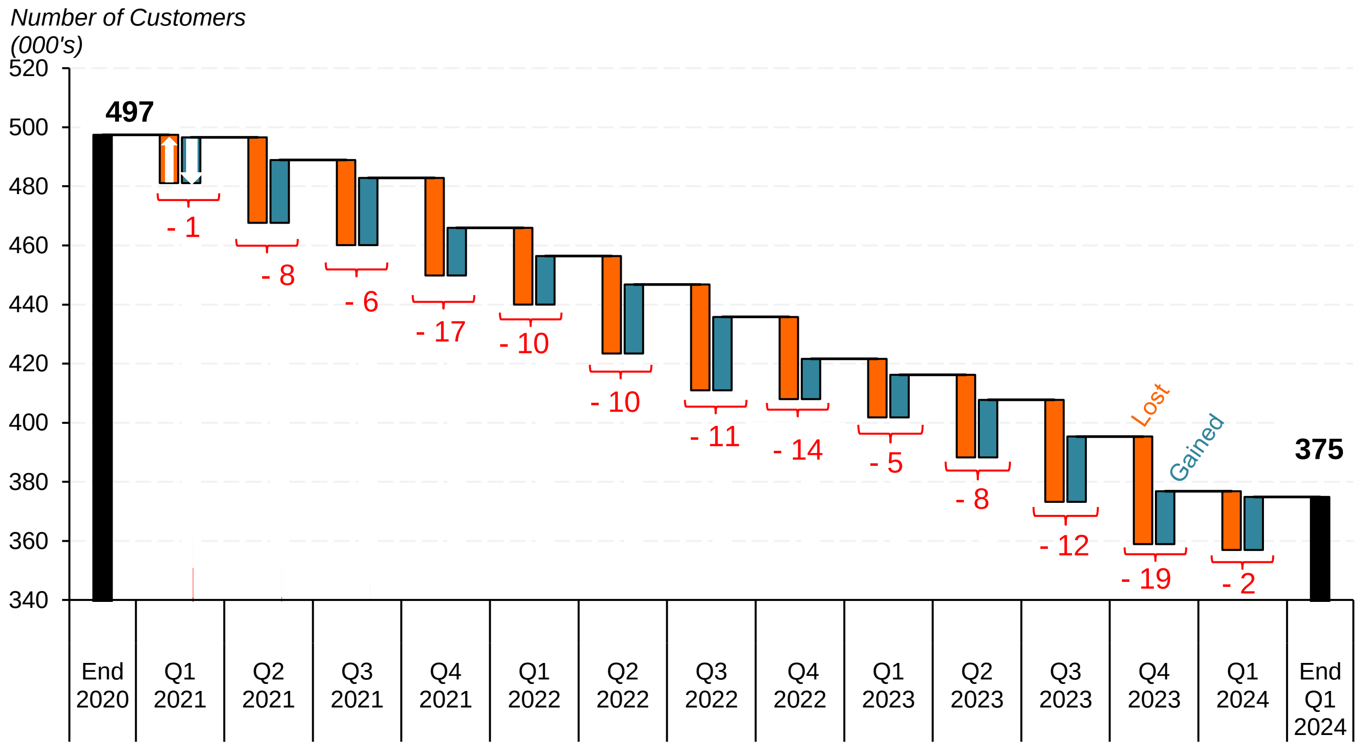
In Q1, the gain in residential RRO customers was highest in March at around 12,000. The gains in January and February were around 10,000 each (Figure 61).

Figure 61: RRO customer losses and gains, residential customers (January 2022 to March 2024)



Like the RRO, the residential DRT customer net loss in Q1 2024 was low at around 2,000, marking the lowest net loss observed since Q1 2021 (Figure 62). Around 20,000 customers left the DRT in Q1 and around 18,000 new customers joined. The DRT rates in Q1 were significantly lower than all available competitive fixed-rate options for natural gas in the market. As of March 2024, there are around 375,000 residential customers on DRT.

Figure 62: DRT customer net losses, residential customers (Q1 2021 to Q1 2024)

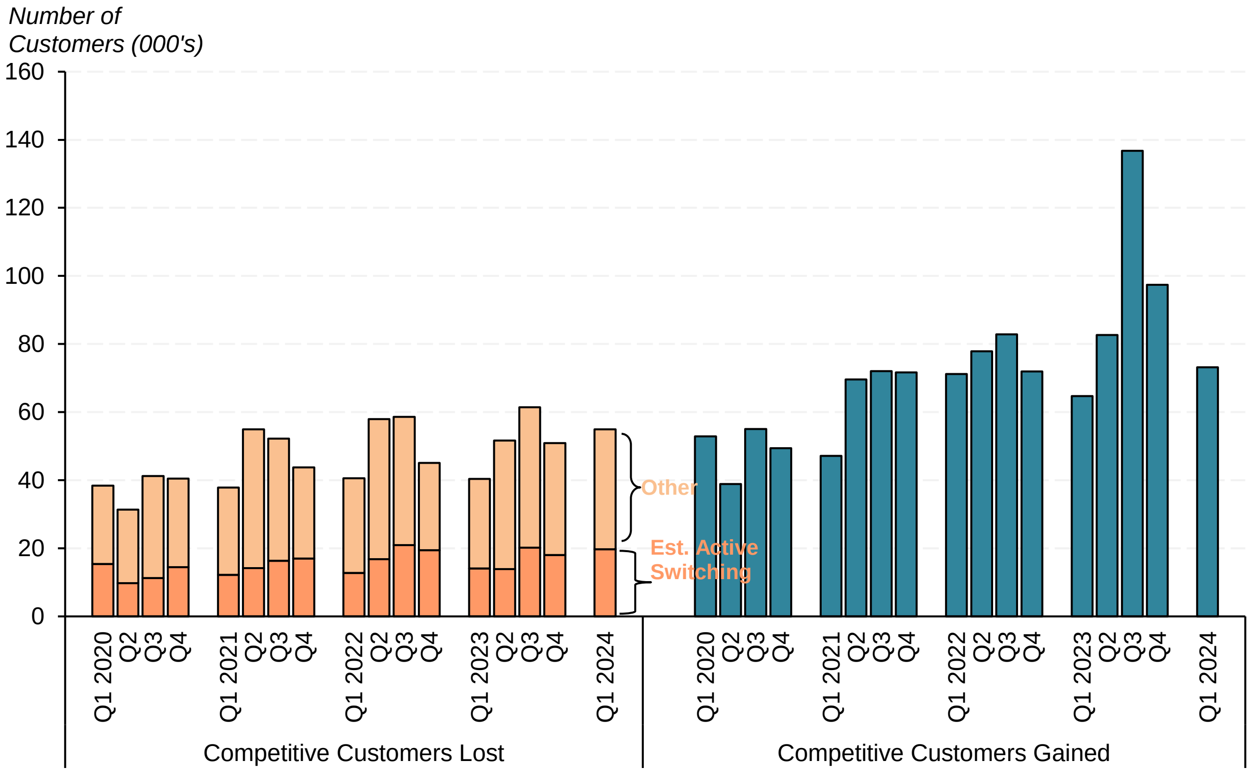


5.2.2 Competitive retailer customer gains

As the number of customers leaving RRO decreased in Q1, the number of customers gained by the competitive market also declined. The competitive market gained approximately 73,000 customers in Q1, the lowest since Q1 2023 (Figure 63). The competitive customer gain was around 100,000 in Q4 2023 and over 136,000 in Q3 2023.

The number of customers leaving the competitive market in Q1 was slightly higher than in Q4 2023. The competitive customer loss in Q1 was 55,000, while it was under 51,000 in Q4 2023 (Figure 63). Out of the 55,000 competitive customers lost in Q1, the MSA estimates around 20,000 residential customers left their competitive retailer for reasons unrelated to a move or as a result of being dropped by their retailer. The MSA counts such a switch as an 'Active Switching', as the decision to leave for these customers may be motivated by economic factors, such as a decision to change retailers to take advantage of a competing rate offering.

Figure 63: Competitive electricity customer losses and gains, residential customers (Q1 2020 to Q1 2024)



5.2.3 Competitive retailer market share

Unlike Q3 and Q4 of 2023, in Q1 2024, the competitive retail customer share (electricity) did not increase substantially in any service areas, as the RRO switching rate was low. The overall competitive market share for electricity increased by only 0.74% from 73.64% in December 2023 to 74.39% by the end of March 2024 (Figure 64).

The increase in market share (electricity) was highest in the EPCOR service area at 1.1%, followed by FortisAlberta and ATCO at 0.9% and 0.7% respectively (Table 14). The market share increase (electricity) was lowest in the ENMAX service area at 0.4%. However, as of March 2024, the ENMAX service area had the highest customer contract share in the competitive market at 83%, followed by Fortis Alberta (72%), ATCO (69%), and EPCOR (68%).

Figure 64: Competitive retail customer share (electricity) by service area, residential customers (January 2012 to March 2024)

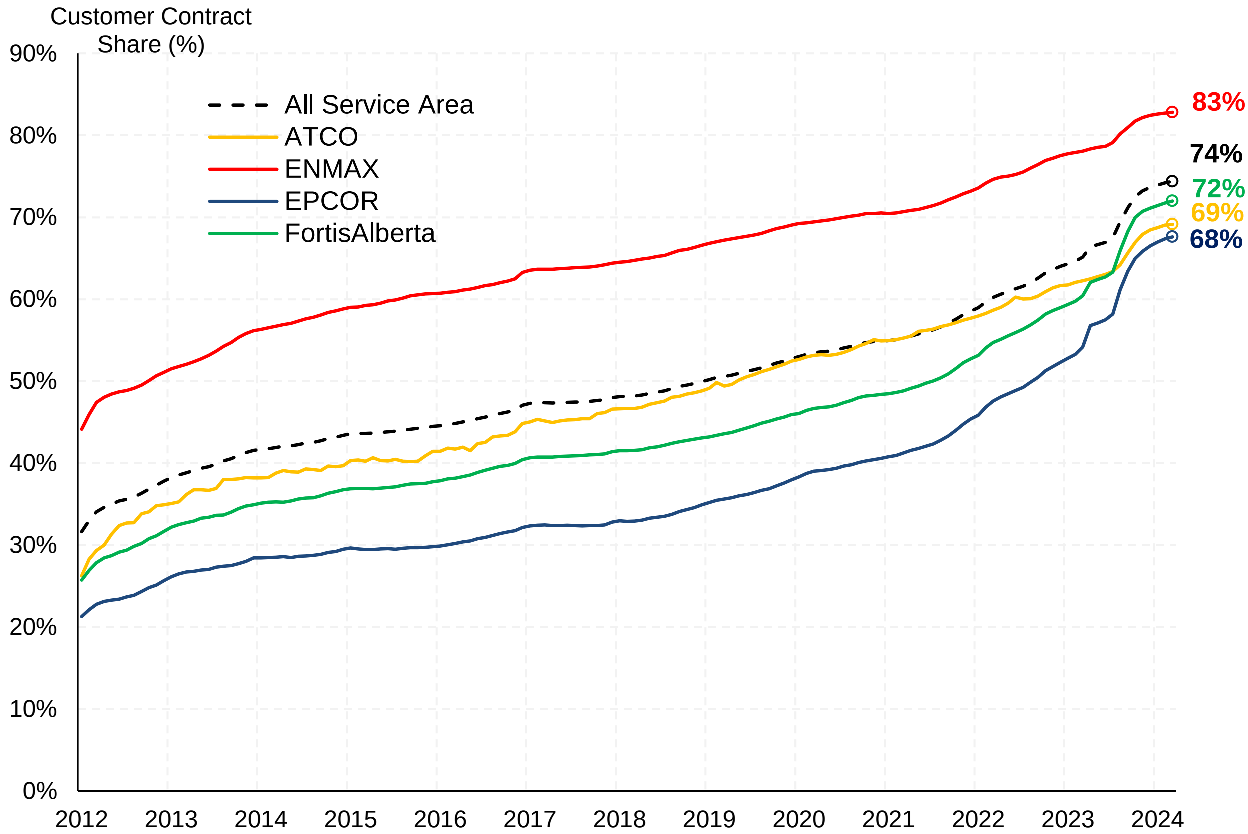


Table 14: Change in retail competitive shares (electricity) by service area, residential customers

	ENMAX	EPCOR	FortisAlberta	ATCO
Change (Q4 - 2023)	1.5%	3.1%	2.8%	2.8%
Change (Q1 - 2024)	0.4%	1.1%	0.9%	0.7%
Competitive share (March 2024)	82.8%	67.6%	72.0%	69.1%

Competitive shares in the retail natural gas market increased marginally by 0.3% in Q4 to reach 71% (Figure 65). At the end of Q1 2024, ATCO Gas South had the highest market share of 77%, followed by ATCO Gas North (68%) and Apex (44%) (Figure 65). The highest change in retail competitive share was seen Atco Gas North service area and the lowest was in Apex (Table 15).

Figure 65: Competitive retail customer share (natural gas) by service area, residential customers (January 2012 to March 2024)

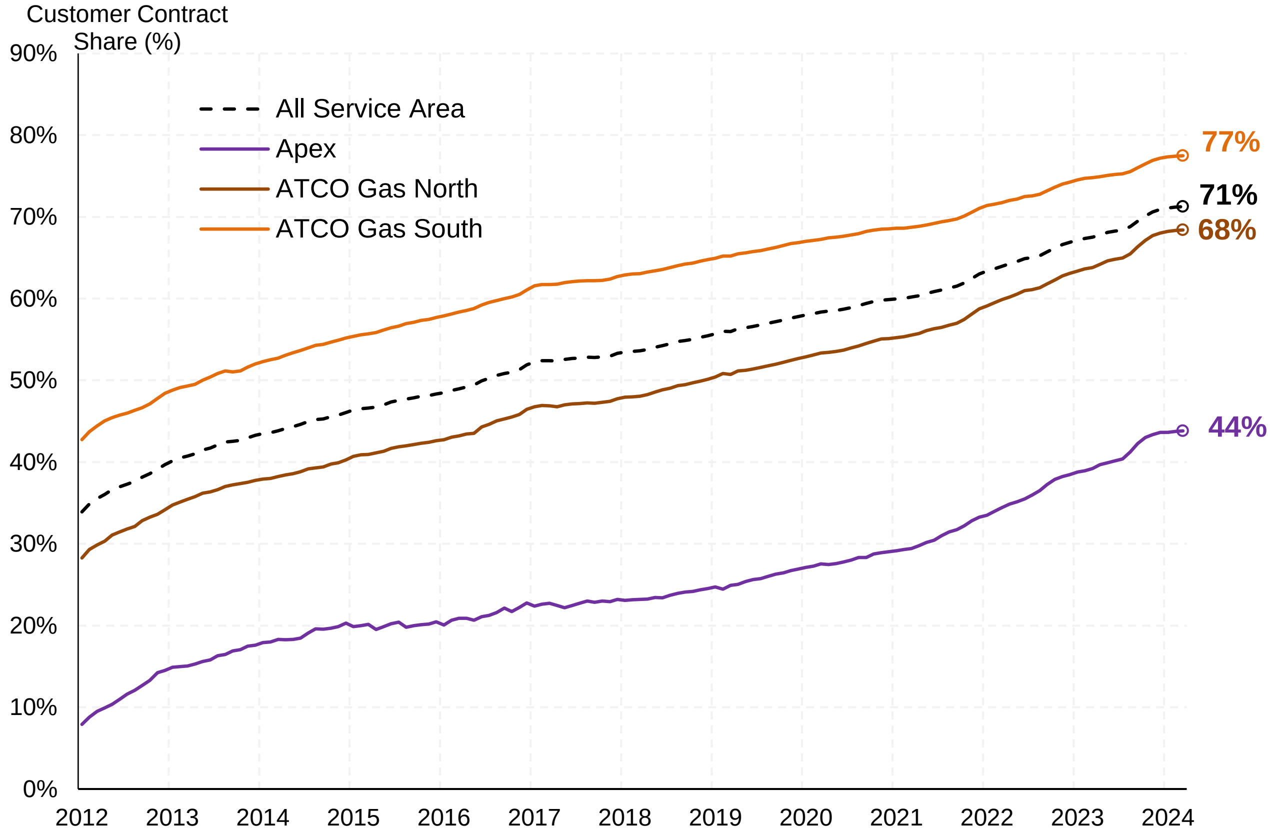


Table 15: Change in retail competitive shares (natural gas) by service area, residential customers

	ATCO Gas North	ATCO Gas South	Apex
Change (Q4 - 2023)	1.7%	1.2%	1.4%
Change (Q1 - 2024)	0.4%	0.3%	0.2%
Competitive share (March 2024)	68.4%	77.5%	43.8%

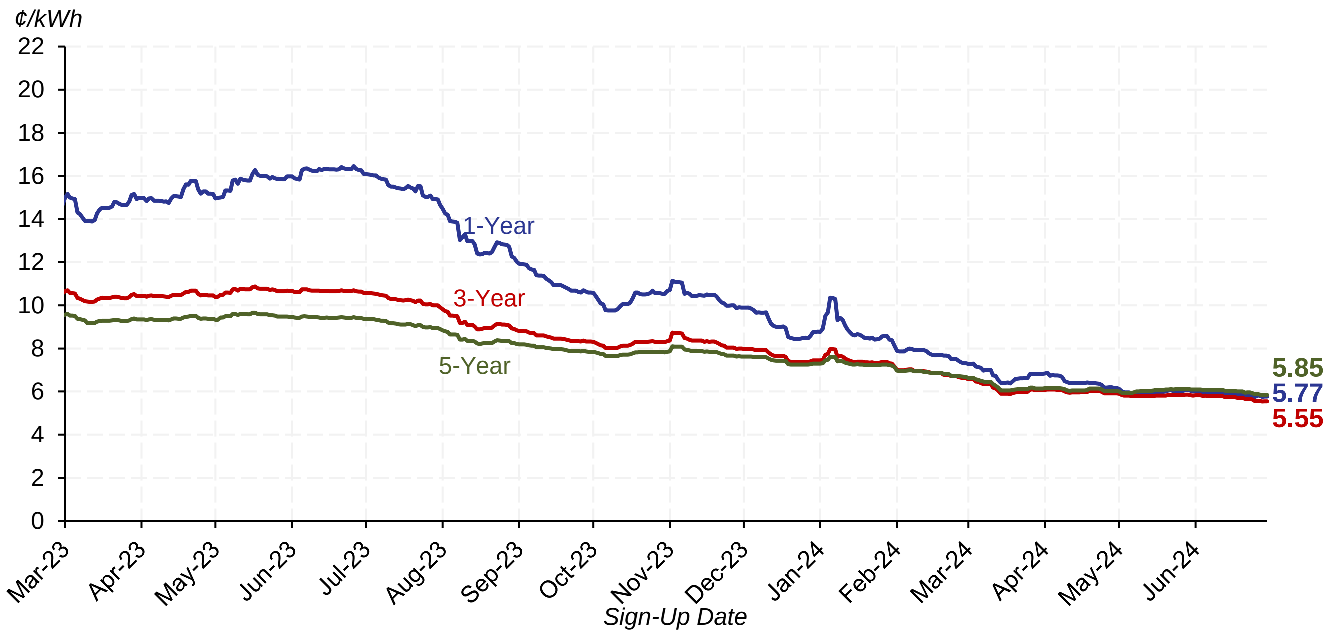
5.3 Competitive fixed retail rates

Most retail customers can choose to sign a contract with a competitive retailer instead of remaining on regulated rates. Competitive retailers typically offer fixed and variable energy rates. Fixed rates are fixed over a defined contract term; usually one, three or five years. Variable rates are energy rates that vary by month and can be tied to pool prices or regulated rates.

Retailers offering fixed rates to customers face energy costs associated with that customer's consumption over the length of the contract term. The MSA refers to these energy costs as expected costs. In the long-run, competitive retailers may adjust the fixed rates offered to new customers in response to changes in the expected cost of fixed rate contracts as retailers compete for customers.

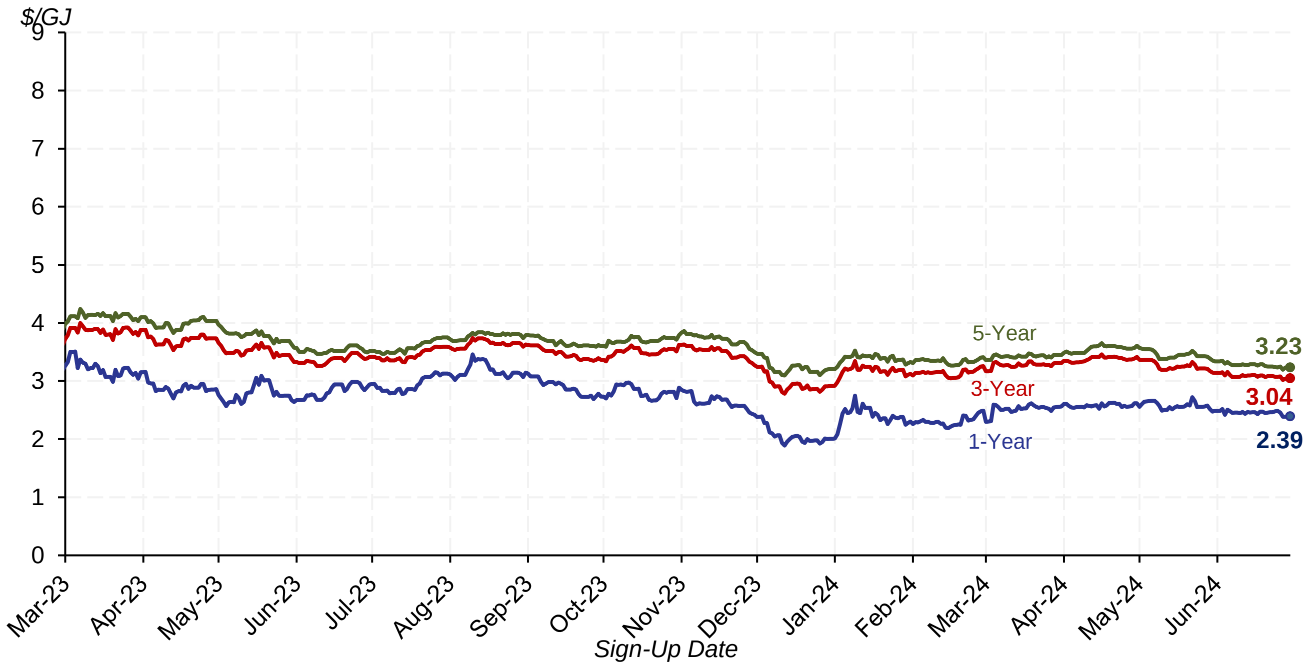
Historically, the expected costs for 1, 3, and 5-year electricity contracts have varied significantly, with 1-year contracts typically being the highest and 5-year contracts the lowest. However, since the beginning of this year, the gap between these expected costs has narrowed considerably (Figure 66). This change has been caused by the reduced disparity in the pricing of the upcoming five forward annual electricity contracts. The expected cost for 1-, 3-, and 5-year fixed rate electricity contracts decreased in Q2. Expected cost dropped by 15%, 9%, and 5% for 1-, 3-, and 5-year contracts, respectively. On June 30, the expected cost for 1-, 3-, and 5-year fixed rate electricity contracts were 5.77 ¢/kWh, 5.55 ¢/kWh, and 5.85 ¢/kWh, respectively (Figure 66).

Figure 66: Expected cost, fixed rate electricity contract, residential customer (March 1, 2023 to June 30, 2024)



During Q2, the expected costs for 1-, 3-, and 5-year natural gas contracts declined by 7%, 8%, and 6%. On June 30, the expected cost for 1-, 3-, and 5-year fixed rate natural gas contracts were $2.39/GJ, $3.04/GJ, and $3.23/GJ, respectively (Figure 67).

Figure 67: Expected cost, fixed rate natural gas contract, residential customer (March 1, 2023, to June 30, 2024)



With the 15% decline of expected cost for one-year electricity contracts, all major retailers reduced their 1-year fixed rates in Q2 (Figure 68). With the exception of Retailer F, all other providers of 3-year fixed rates also lowered their rates in Q2. Retailer F, previously the lowest-cost provider for three-year fixed rates, raised their rates twice in Q2 (each in April and May) but implemented a rate reduction in June. None of the five-year fixed rate providers increased their rates in Q2.

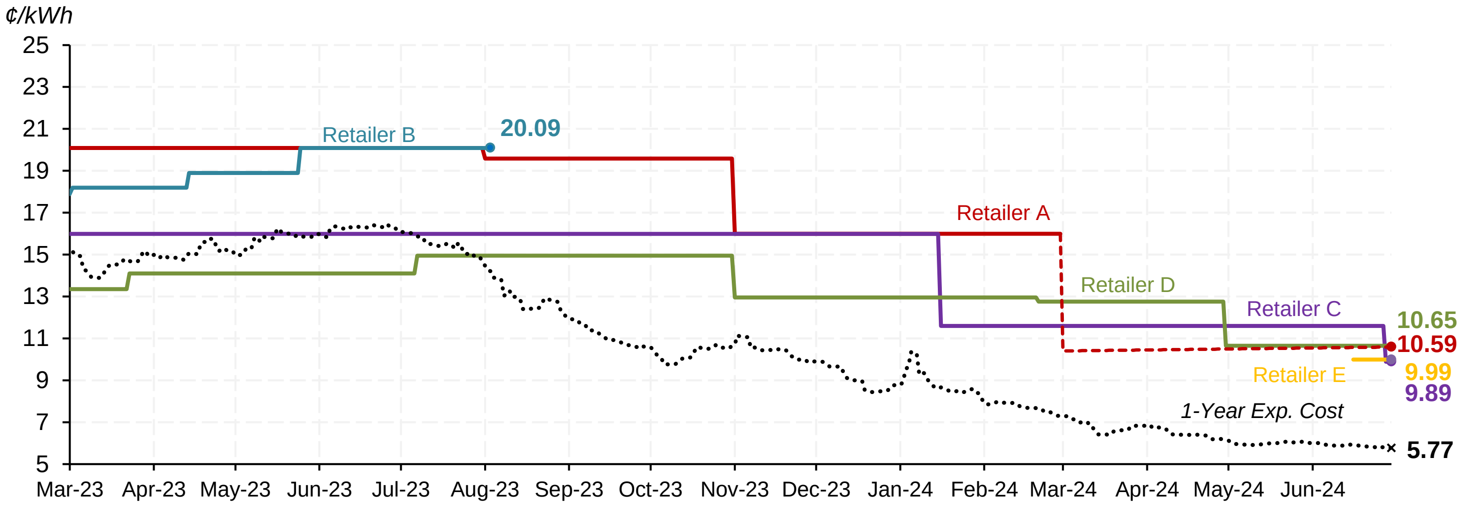
Retailer E, which previously offered only five-year fixed rate contracts, began offering one- and three-year contracts to customers starting on June 16 (Figure 68). The rates for Retailer A shown in Figure 68 is a weighted average rate, as they offered a rate of 7.77 ¢/kWh until July 31, followed by a rate of 10.59 ¢/kWh for the remainder of the contract. Retailer A started this limited time offer on March 1 and stopped it on June 30.

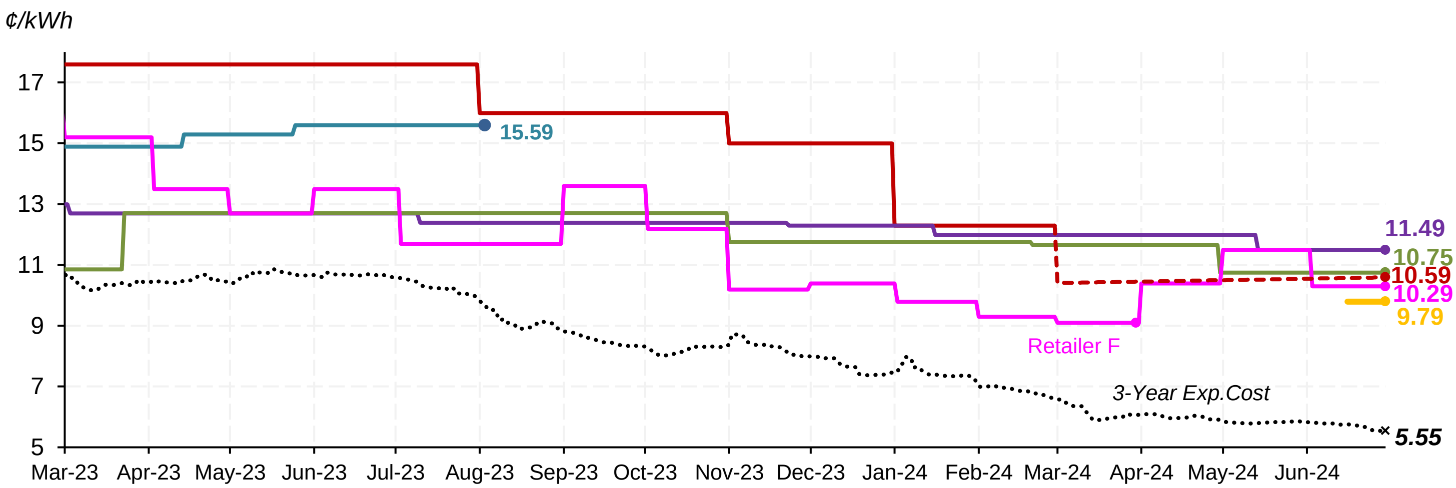
As of June 30, Retailer C offered the lowest one-year fixed rate electricity contracts at 9.89 ¢/kWh, Retailer E provided the lowest three-year fixed rate electricity contracts at 9.79 ¢/kWh, while Retailer G offered the lowest five-year fixed rates at 9.79 ¢/kWh (Figure 68).

In Q2 2024, most retailers kept their 1-, 3-, and 5-year fixed-rate natural gas contract rates unchanged (Figure 69). However, a few retailers increased their rates. Retailer F raised their 3-year rates from $3.69/GJ to $4.69/GJ on March 31, an increase of 27%. Retailer E also raised their 5-year rates by $0.20/GJ. Like their electricity offerings, Retailer E began providing 1-year and 3-year fixed-rate natural gas contracts to customers starting on June 16.

As of June 30, Retailer C offered the lowest one-year fixed rate natural gas contracts at 3.99 $/GJ, Retailer E provided the lowest three-year fixed rate natural gas contracts at 4.59 $/GJ, while Retailer G offered the lowest five-year fixed rates at 4.79 $/GJ (Figure 69).

Figure 68: 1-, 3-, and 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (March 1, 2023 to June 30, 2024)





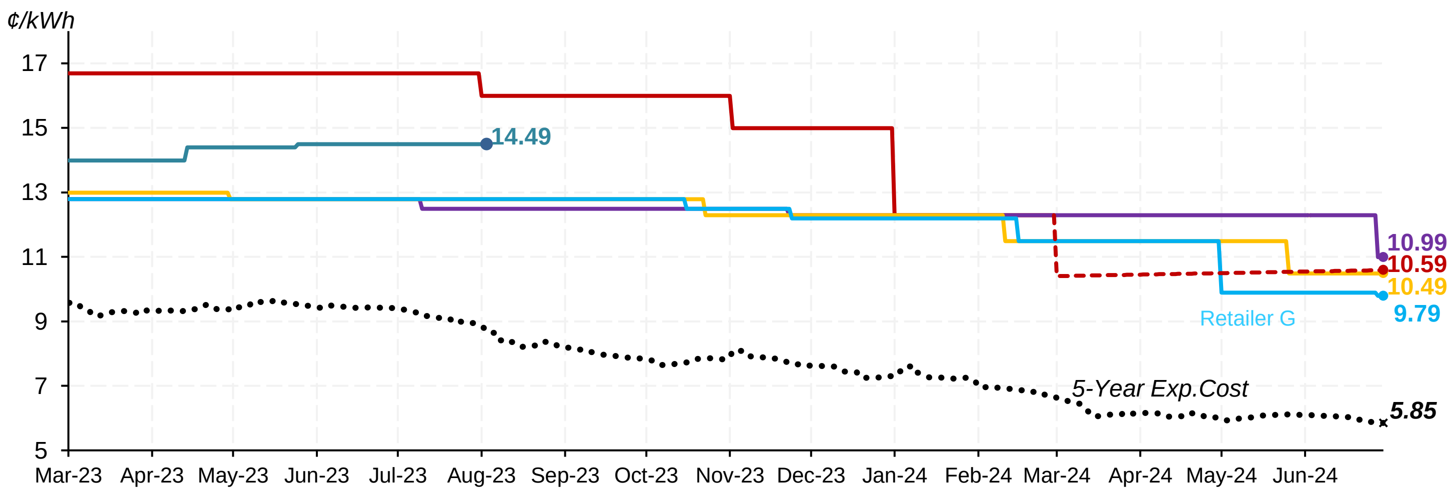
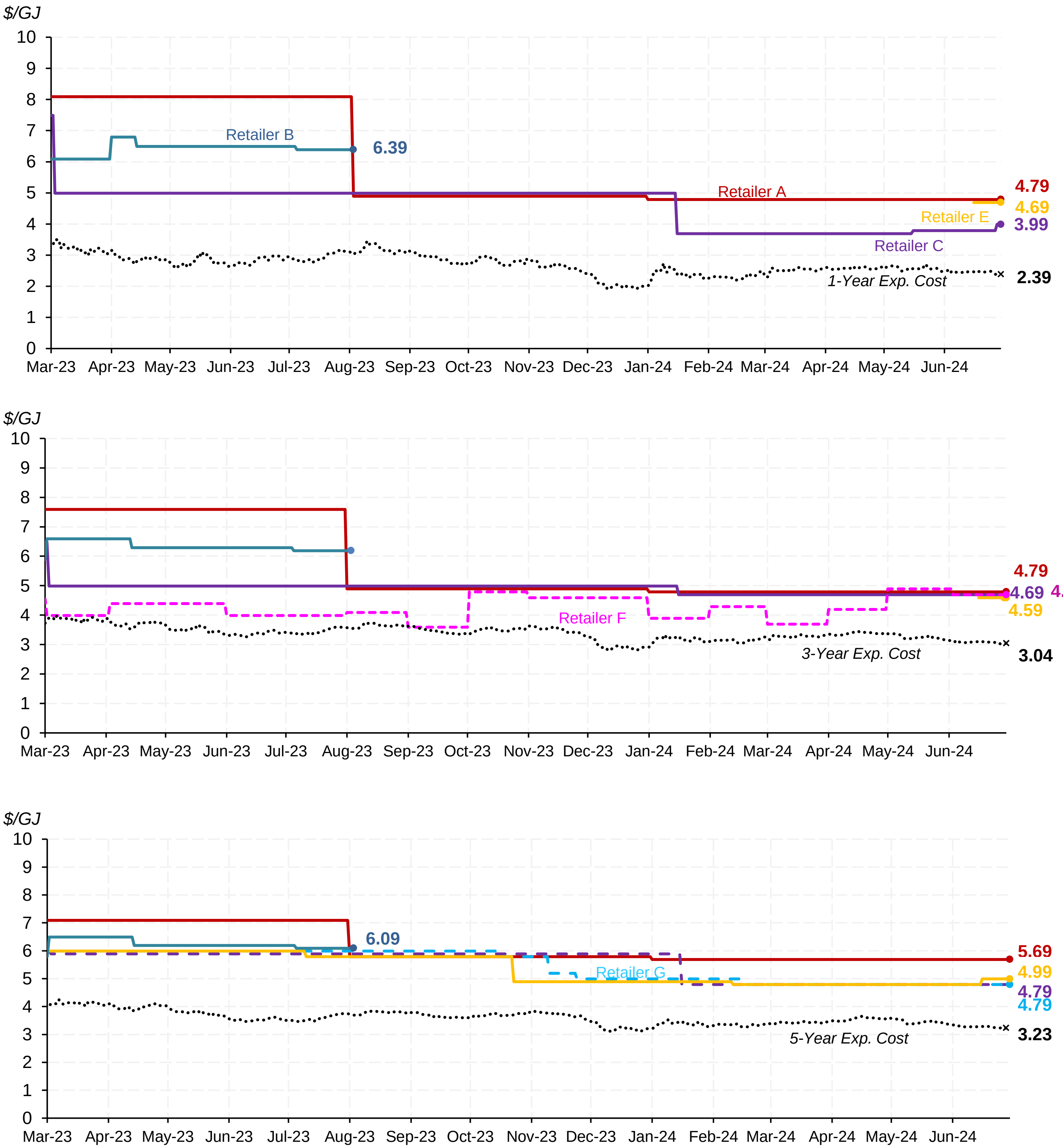


Figure 69: 1-, 3-, and 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (March 1, 2023 to June 30, 2024)

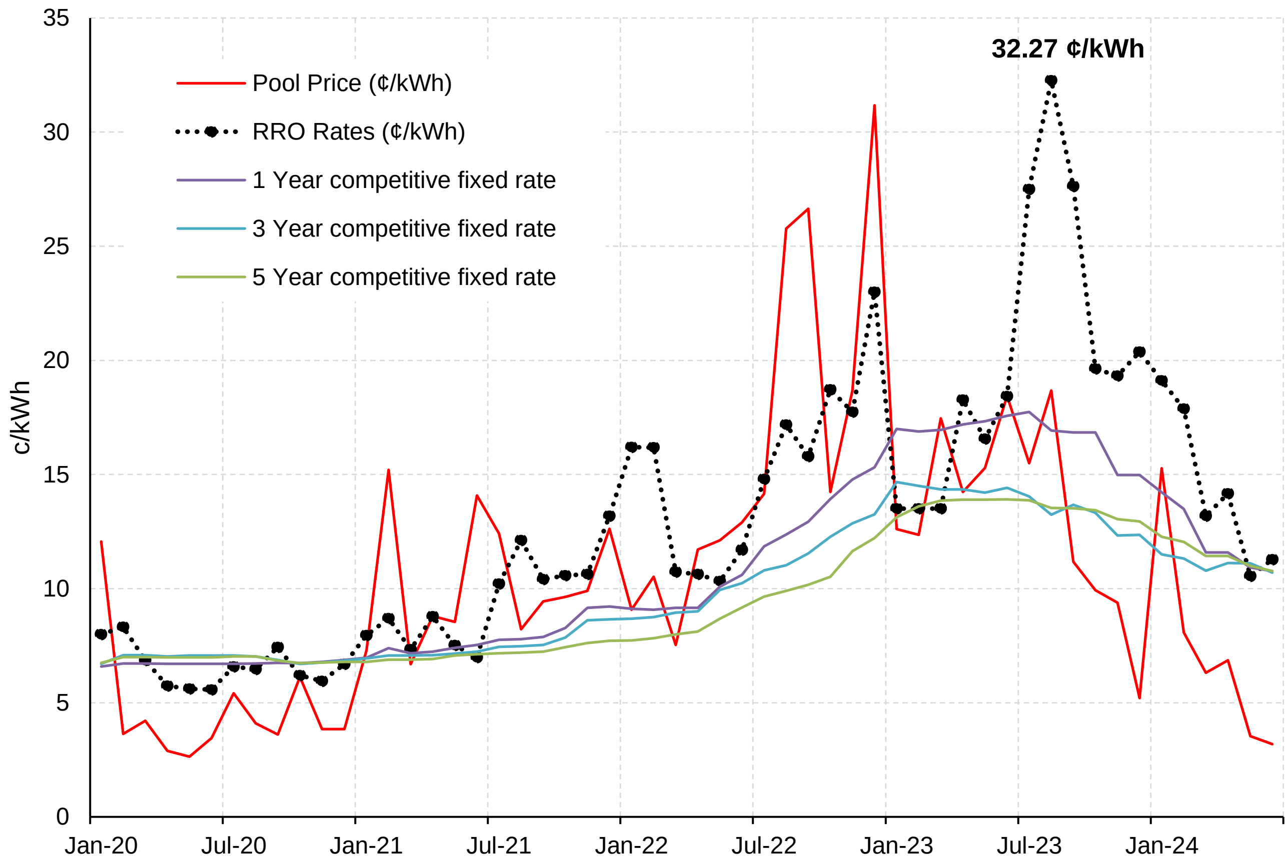


5.4 Retail regulations and legislations

5.4.1 Electricity regulated rate – Rate of Last Resort (RoLR)

In recent years, the monthly default electricity rates, known as the Regulated Rate Option (RRO), have been volatile. Notably, 2023 experienced record-breaking RRO rates in July, August, and September. These rates were markedly higher than both the prevailing fixed-rate options and the real-time electricity rates in Alberta (Figure 70).

Figure 70: RRO vs. competitive rates (January 2020 to June 2024)[20]



In April 2024, the Government of Alberta announced that the RRO would be renamed the as the Rate of Last Resort (RoLR) and that the rate would be fixed for two-year periods, the first one beginning on January 1, 2025. Further detail is expected to become public in Q3 2024.

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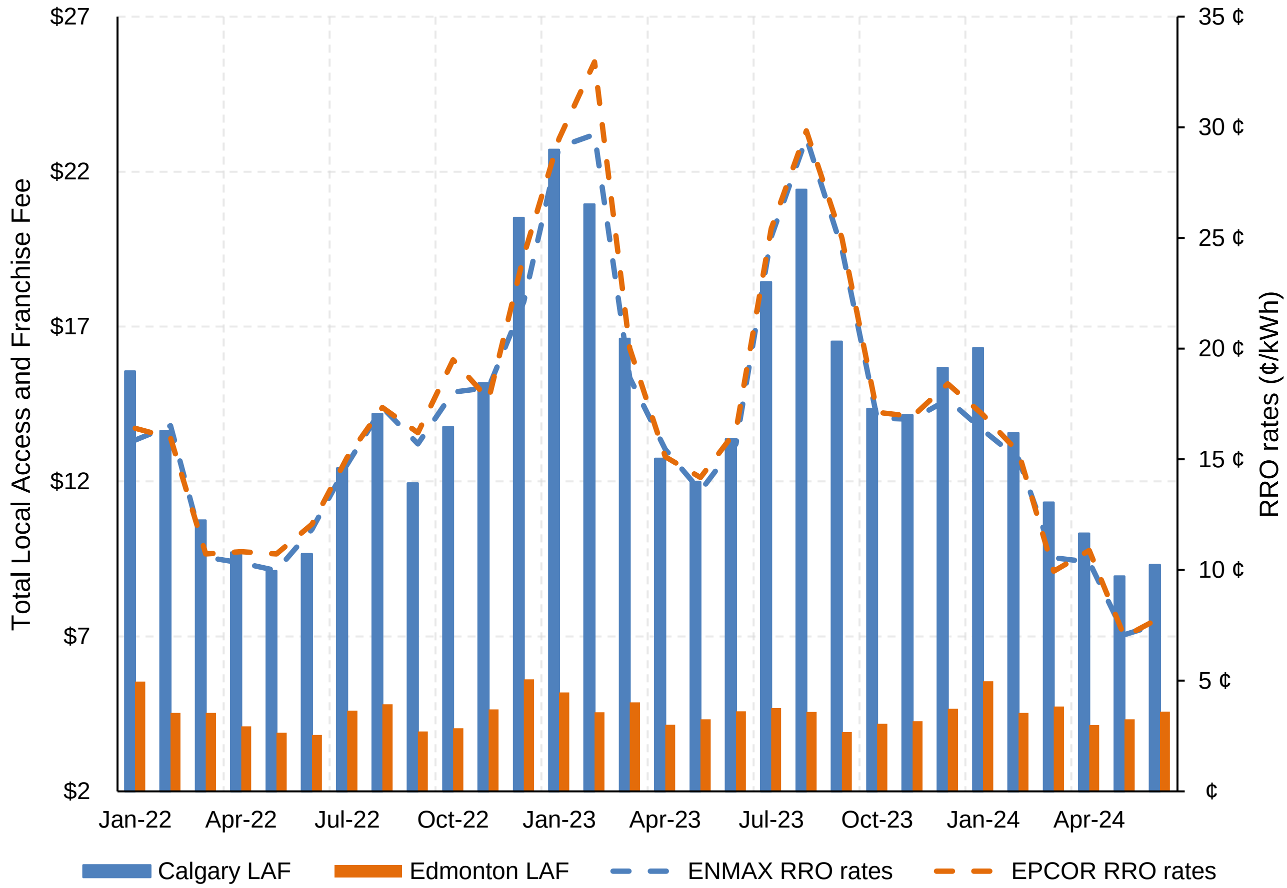
[20] The RRO rate in January, February and March 2023 was capped at 13.5 ¢/kWh and the rates from April 2023 to June 2024 indicate the base RRO rate plus the collection rate resulted from the deferred revenue associated with the rate ceiling.

5.4.2 Changes in local access and franchise fee calculation.

Figure 71 shows the Local Access and Franchise Fee (LAF) paid by RRO residential customers in the ENMAX (Calgary) and EPCOR (Edmonton) service areas. As illustrated in the figure, the access fees paid by Calgary residents have been significantly higher than those paid by Edmonton residents. This discrepancy arises because Calgary includes variable energy rates in the LAF calculation, whereas Edmonton does not. Consequently, when RRO rates increase, there is a substantial rise in the total LAF fees paid by Calgary residents that is not observed in Edmonton.

*Figure 71: Local Access and Franchise Fee, ENMAX and EPCOR service areas (*January 2022 to June 2024*)*[21]



In April 2024, the Government of Alberta announced legislation to eliminate the use of variable rates when setting local access fees for electricity and natural gas service distribution. Changes to local access fees were approved on June 20, 2024.

[21] The RRO rates shown in this figure are the uncapped rates and without including the collection rates. See the previous footnote.

6 REGULATORY AND ENFORCEMENT MATTERS

6.1 AESO publication of forecast pool prices

In August 2023, the MSA issued a Notice of Investigation to the AESO and requested that the AESO immediately stop publishing forecast pool prices for hours outside the T-2 offer lockdown window set out in ISO Rule 203.3 (T-6 Forecast). The AESO promptly ceased publication of the T-6 Forecast and fully co-operated with the MSA during the investigation.

The MSA was concerned that the T-6 Forecast prices, which were available through the AESO's Data Portal Dashboard[22] and Pool Price API,[23] could be used by market participants to enhance their market power. Specifically, market participants could make successive restatements and observe the impact on the forecast price to gain information about their competitors' offers and facilitate economic withholding with greater precision. If it were to occur, this conduct may be inconsistent with sections 6(1) and 16(1) of the *Electric Utilities Act*, which require market participants and the AESO, respectively, to conduct themselves in a manner that supports the fair, efficient, and openly competitive operation of the electricity market.

Following its investigation, the MSA did not find evidence that any market participant misused the T-6 Forecast contrary to the fair, efficient, and openly competitive operation of the electricity market.

Despite finding no evidence of misuse of the T-6 Forecast in this instance, the MSA is of the view that the T-6 Forecast could have been used by market participants to enhance market power. The MSA has requested that the AESO implement a more robust process to assess the potential competitive implications of its public-facing reporting.

6.2 MSA comments on draft interim ISO rules

On May 31, 2024, the MSA provided comments on three topics relating to ISO Rules 206.1 (Interim Secondary Offer Cap) and 206.2 (Interim Supply Cushion Directives).[24] For ISO Rule 206.1, the MSA identified concerns about aligning the timing of secondary offer cap notifications and ensuring that pool participants have a reasonable opportunity to restate their offers. This concern was addressed in a later version of the rule.

For ISO Rule 206.2, the MSA noted the lack of detail in how relative economic merit will be determined when determining the order of unit commitment directives. Further, the MSA proposed that ISO Rule 206.2 include explicit requirements that the ISO, prior to making a cost guarantee payment, exercise due diligence and be satisfied that the cost information is true, accurate, and

[22] https://aeso-portal.powerappsportals.com/data-portal-dashboard/

[23] https://api.aeso.ca/web/api/ets

[24] Alberta MSA Comments regarding proposed ISO rules (May 31, 2024)

complete, the costs submitted are truly incremental, and the costs submitted were prudently incurred.

6.3 Secondary offer cap calculation errors

On July 5, 2024, the MSA notified the AESO of apparent errors in the calculation of monthly cumulative settlement interval net revenue (MCSINR) and annualized unavoidable costs (AUAC) as required by the *Market Power Mitigation Regulation* and ISO Rule 206.1 (Interim Secondary Offer Cap). By using an incorrect inflation rate, the calculated values of MCSINR were lower and the calculated values of AUAC were higher than had the correct inflation rate been used. Accordingly, the threshold for the secondary offer cap taking effect was higher than if the calculations had been correct. The AESO corrected these errors on July 10, prior to the secondary offer cap taking effect later in the month.[25]

6.4 MSA comments on draft pilot project ISO rule and related amendments

On July 15, 2024, the MSA submitted comments regarding draft ISO Rule 103.14 (Pilot Projects) and amendments to ISO Rule 103.12 (Compliance Monitoring).[26] The MSA recognized the ongoing value of pilot projects in determining technical feasibility and identifying unintended consequences. However, the MSA also identified concerns about the necessity of the changes in light of the existing process whereby the AESO seeks forbearance from the MSA in advance of any pilot projects, whether the changes would provide certainty to market participants, and how the changes would be compatible with the respective jurisdictions set out in the scheme of the *Electric Utilities Act*.

[25] AESO – Market Updates, Energy Trading System – Changes to public reports – MCSINR Calculation (July 9, 2024)

[26] Alberta MSA Comments on AESO Draft Pilot Rules (July 15, 2024)

7 ISO RULES COMPLIANCE

The ISO rules promote orderly and predictable actions by market participants and facilitate the operation of the Alberta Interconnected Electric System (AIES). The MSA enforces the ISO rules and endeavours to promote a culture of compliance and accountability among market participants, thereby contributing to the reliability and competitiveness of the Alberta electric system. If the MSA is satisfied a contravention has occurred and determines that a notice of specified penalty (NSP) is appropriate, then AUC Rule 019 guides the MSA on how to issue an NSP.

From January 1 to June 30, 2024, the MSA closed 262 ISO rules compliance matters, as reported in Table 16.[27] An additional 286 matters were carried forward to the next quarter. During this period 55 matters were addressed with NSPs, totalling $836,500 in financial penalties, with details provided in Table 17.

Table 16: ISO rules compliance outcomes from January 1 to June 30, 2024

ISO rule	Forbearance	Notice of specified penalty	No contravention
201.1	1	-	-
201.3	1	2	-
201.7	12	7	-
203.1	3	-	-
203.3	64	2	4
203.4	56	5	3
203.6	6	-	-
205.3	-	2	-
205.4	2	-	-
205.5	3	1	1
205.6	5	20	2
301.2	2	-	-
304.3	1	-	-
304.4	1	-	-
304.9	2	-	-
306.4	3	2	-
306.5	6	5	-
502.1	-	1	-
502.4	6	6	-
502.6	2	1	-
502.8	4	-	-
502.14	-	1	-
502.15	3	-	-
502.16	3	-	-
Total	197	55	10

[27] An ISO rules compliance matter is considered to be closed once a disposition has been issued.

Table 17: Specified penalties issued between January 1 and June 30, 2024 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)															Total ($)	Matters
	201.3	201.7	203.3	203.4	203.6	205.3	205.5	205.6	306.4	306.5	502.1	502.4	502.6	502.8	502.14		
Air Liquide Canada Inc.						2,000										2,000	2
AltaGas Ltd.				1,500												1,500	1
ATCO DB Solar GP Services Ltd.		250														250	1
ATCO Electric Ltd.									250							250	1
Canadian Hydro Developers, Inc.							678,500								250	678,750	2
Capital Power (CBEC) L.P.						500										500	1
Castle Rock Ridge LP			500													500	1
Concord Monarch Partnership			500													500	1
Concord Vulcan Partnership														500		500	1
Cypress 2 Renewable Energy Centre Limited Partnership		13,750										1,250				15,000	4
Cypress Renewable Energy Centre Limited Partnership	250	13,750								500		1,250				15,750	6
Enel X Canada Ltd.								57,500								57,500	12
Enel X Canada Ltd.								5,000								5,000	1
Forty Mile Granlea Wind GP Inc.		23,750		1,000					250							25,000	5
Grande Prairie Generation Inc.										500						500	1
Halkirk I Wind Project LP				250									250			500	2
Hays Solar LP			500													500	1
Heartland Generation Ltd.								250								250	1
Kneehill Solar LP										500		500				1,000	2
Lanfine Wind 1 LP										500						500	1
MEG Energy Corp.				250												250	1
Michichi Solar LP										500		500				1,000	2
Morgan Stanley Capital Group Inc.					10,000											10,000	1
Pincher Creek Limited Partnership			500													500	1
Signalta Resources Limited	250															250	1
Taber Solar 1 Inc.			500													500	1
Voltus Energy Canada Ltd.								30,000								30,000	6
Wheatland Wind Project LP				500												500	1
Total	500	51,500	2,500	3,500	10,000	2,500	678,500	92,750	500	2,500	250	3,500	250	500	250	836,500	62

The ISO rules listed in Table 16 and Table 17 fall into the following categories:

201	General (Markets)
203	Energy Market
205	Ancillary Services Market
301	General (System Reliability and Operations)
304	Routine Operations
306	Outages and Disturbances
502	Technical Requirements
504	Legal Owners of Transmission Facilities and Load Facilities
505	Legal Owners of Generating Facilities

8 ARS COMPLIANCE

The MSA assesses market participant compliance with Alberta Reliability Standards (ARS) and issues NSPs where appropriate.

The ARS ensure the various entities involved in grid operation have practices in place, including procedures, communications, coordination, training, and maintenance to support the reliability of the AIES.[28] ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach to compliance with ARS focuses on promoting awareness of obligations and a proactive compliance stance. The MSA's process, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

In accordance with AUC Rule 027, NSPs for CIP ARS contraventions are not made public, as well as any information related to the nonpayment or dispute of a CIP ARS NSP. CIP matters often deal with cyber security issues and there is concern that granular public reporting may itself create a security risk. As such, the MSA only reports aggregated statistics regarding CIP ARS outcomes.

From January 1 to June 30, 2024, the MSA addressed 67 O&P ARS compliance matters (Table 18).[29] 31 O&P ARS matters were carried forward to the next quarter. During this period, 11 matters were addressed with NSPs, totalling $36,000 in financial penalties (Table 19). For the same period, the MSA addressed 62 CIP ARS compliance matters, as reported in Table 20, two matters were addressed with NSPs, totalling $7,500. 105 CIP ARS matters were carried forward to next quarter.

[28] Entities subject to ARS include legal owners and operators of generators, transmission facilities, distribution systems, as well as the independent system operator.

[29] An ARS compliance matter is considered closed once a disposition has been issued.

Table 18: O&P ARS compliance outcomes from January 1 to June 30, 2024

Reliability standard	Forbearance	Notice of specified penalty	No contravention
COM-001	2	-	1
EOP-005	-	1	-
EOP-008	5	1	-
EOP-011	1	-	-
FAC-008	11	1	-
IRO-008	1	-	-
PER-006	3	-	-
PRC-001	2	-	-
PRC-002	3	-	-
PRC-005	11	4	2
PRC-018	1	-	-
PRC-019	5	2	-
VAR-002	6	2	2
Total	51	11	5

Table 19: Specified penalties issued between January 1 and June 30, 2024 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)						Total ($)	Matters
	EOP-005	EOP-008	FAC-008	PRC-005	PRC-019	VAR-002		
City of Lethbridge			2,250	3,750			6000	2
City of Medicine Hat		5,000					5000	1
City of Red Deer				3,750			3750	1
MEG Energy Corp.				2,500			2500	1
TA Alberta Hydro LP	3,750			5,000	2,500		11250	4
Windrise Wind LP						7,500	7500	2
Total	3,750	5,000	2,250	15,000	2,500	7,500	36,000	11

The ARS outcomes listed in Table 18 and Table 19 are contained within the following categories:

COM Communications
EOP Emergency Preparedness and Operations
FAC Facilities Design, Connections, and Maintenance
IRO Interconnection Reliability Operations and Coordination
PER Personnel Performance, Training, and Qualifications
PRC Protection and Control
VAR Voltage and Reactive

Table 20: CIP ARS compliance outcomes from January 1 to June 30, 2024

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	4	1	-
CIP-003	8	-	-
CIP-004	14	-	-
CIP-005	3	-	-
CIP-006	6	-	-
CIP-007	8	-	-
CIP-009	1	-	-
CIP-010	11	-	-
CIP-011	4	1	-
CIP-012	1	-	-
Total	60	2	-

The ARS outcomes listed in Table 20 are contained within the following categories:

CIP-002	BES Cyber System Categorization
CIP-003	Security Measurement Controls
CIP-004	Personnel & Training
CIP-005	Electronic Security Perimeter(s)
CIP-006	Physical Security of BES Cyber Systems
CIP-007	System Security Management
CIP-009	Recovery Plans for BES Cyber Systems
CIP-010	Configuration Change Management and Vulnerability Assessments
CIP-011	Information Protection
CIP-012	Communications between Control Centres