MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q1 2024

May 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

- **Average pool prices decline year-over-year:** The average pool price in Q1 was $99/MWh, 30% less than Q1 2023 but similar to Q1 2022 at $90/MWh. The year-over-year decline occurred despite high prices during the January cold snap and was largely due to increased wind and solar generation, lower natural gas prices, and more available thermal capacity.

- **Renewables contribute to zero-dollar priced hours:** High wind generation and low demand can result in wholesale pool prices at $0/MWh. During the off peak of March 14/15 the price was $0/MWh for approximately 5 hours, and this occurred again on March 15 for a partial hour over the peak. Historically, it has been unusual for prices to clear at the floor during periods of peak demand, but this is becoming more common due to increased solar supply.

- **January 2024 cold snap leads to extended grid emergency advisories:** The AESO declared Energy Emergency Alert (EEA) events on four consecutive days from January 12 to 15 indicating supply shortfalls during certain periods on these dates. Operating reserves, usually held for system contingencies, were used for energy to meet prevailing demand. The MSA will be issuing a separate report covering these events.

- **Historic power system operation without coal-fired assets:** On the morning of February 2, Genesee 1 and 2 tripped offline meaning that Alberta was producing electricity without coal-fired generation for the first time in decades, resulting in substantial unscheduled import flows from BC and Montana. Coal generation is expected to be permanently discontinued in Q2.

- **Renewable operational constraints persist:** In Q1, the volume of wind and solar generation that was constrained down was 27.8 GWh, over double the Q1 2023 volume of 12.7 GWh but less than the Q4 2023 volume of 187.8 GWh. At least 1 MWh of wind or solar generation was constrained down in 25.6% of hours in Q1, a decrease from Q1 2023. The maximum hourly average volume of intermittent generation that was constrained down in Q1 was 370 MWh.

- **Customers continue to switch off the RRO:** High Regulated Rate Option (RRO) rates in August and September contributed to the continued decline in residential RRO customers in Q4 2023. On net, more than 38,000 customers left the RRO in Q4 2023 leaving 430,000 RRO residential customers as of December 31, 2023.

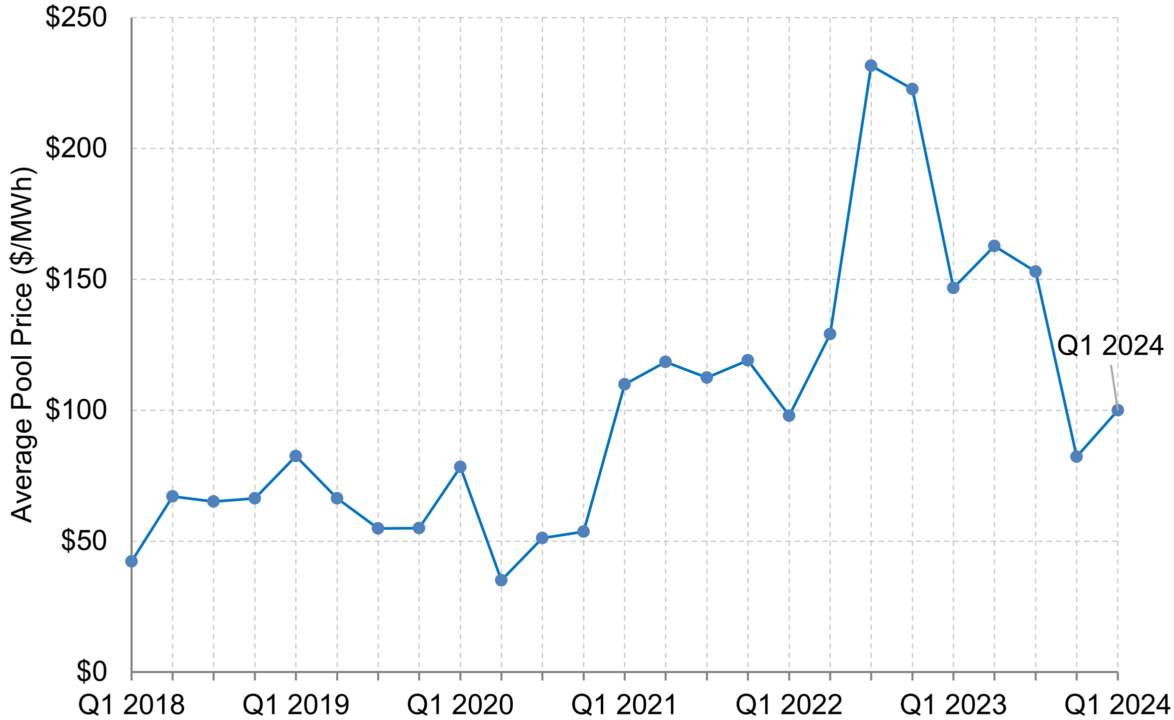
- **MSA compliance matters stable year to year:** From January 1 to March 31, 2024, the MSA closed 181 ISO rules compliance matters; 31 matters were addressed with notices of specified penalty. For the same period, the MSA closed 30 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; no matters were addressed with notices of specified penalty. In addition, the MSA closed 23 Alberta Reliability Standards Operations and Planning compliance matters; four matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average quarterly pool price in Q1 was $99/MWh, a 30% decrease compared to Q1 2023 due to increased wind and solar (intermittent) generation, lower natural gas prices, and more available thermal capacity (Table 1).[1] However, the average pool price in Q1 was a 22% increase compared to last quarter as demand was higher and wind generation was lower in Q1 2024 compared to Q4 2023.

Figure 1: Average pool price by quarter (Q1 2018 to Q1 2024, inflation adjusted)[2]



The monthly average pool price in Q1 was highest in January at $153/MWh. Pool prices in January were elevated during a period of cold weather in the middle of the month when demand was high, intermittent generation was low, and some thermal assets were on outage. During this cold spell, Alberta set a new hourly demand record of 12,384 MW on January 11 in HE 18. Following this, the AESO issued EEAs on four consecutive days from January 12 to 15, indicating that there was insufficient supply to reliably meet demand during certain periods on these days.

[1] Reference to Q1 means Q1 2024, and months or dates refer to months or dates in 2024 unless specified otherwise.

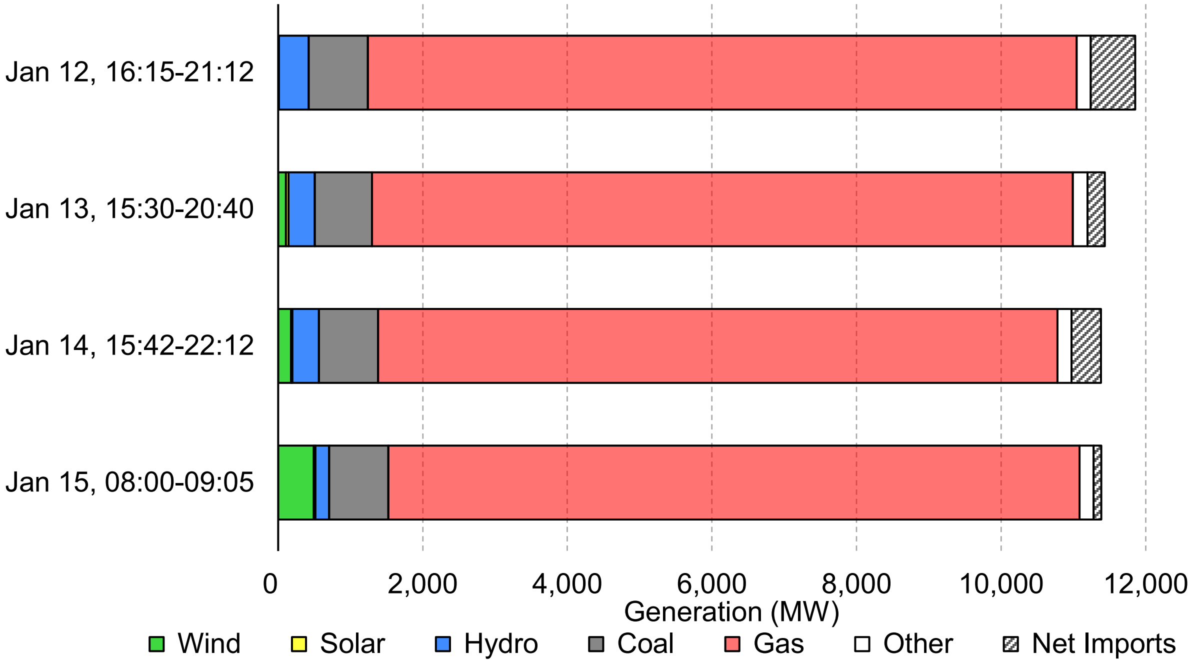
[2] Adjusted for inflation using the Consumer Price Index, monthly, not seasonally adjusted.

Figure 2 illustrates generation by fuel type during these events. As shown, Alberta was largely reliant on thermal generation during the EEA events. While demand varied between these events no load was shed. These events will be discussed in a separate forthcoming MSA report.

Table 1: Summary market statistics for Q1 2023 and Q1 2024

		2023	**2024**	**Change**
Pool price (Avg $/MWh)	January	$126.13	$152.78	21%
	February	$123.50	$80.75	-35%
	March	$174.63	$63.13	-64%
	Q1	**$142.00**	**$99.30**	**-30%**
Demand (AIL) (Avg MW)	January	10,387	10,871	5%
	February	10,458	10,542	1%
	March	10,226	10,307	1%
	Q1	**10,354**	**10,574**	**2%**
Gas price AB-NIT (2A) (Avg $/GJ)	January	$3.58	$2.38	-33%
	February	$2.64	$1.71	-35%
	March	$2.98	$1.71	-43%
	Q1	**$3.08**	**$1.94**	**-37%**
Wind generation (Avg MW)	January	1,227	1,398	14%
	February	1,375	1,410	3%
	March	812	1,295	59%
	Q1	**1,130**	**1,367**	**21%**
Solar generation (Avg MW during peak hours)	January	133	182	37%
	February	213	353	66%
	March	454	531	17%
	Q1	**268**	**355**	**33%**
Net imports (+) Net exports (-) (Avg MW)	January	-256	-364	42%
	February	15	-275	-1819%
	March	221	-225	-202%
	Q1	**-7**	**-288**	**3815%**
Available Thermal Capacity (Avg MW)	January	9,651	10,123	5%
	February	9,944	10,065	1%
	March	9,548	9,806	3%
	Q1	**9,709**	**9,997**	**3%**

Figure 2: Average generation by fuel type during EEA events in Q1



Intermittent generation capacity in Alberta increased year-over-year with 855 MW of wind capacity and 485 MW of solar capacity added between March 31, 2023 and March 31, 2024.[3] Average wind generation increased by 236 MW or 21% year-over-year, while average solar generation during peak hours increased by 84 MW or 31%. As discussed in previous MSA reports, while renewables can put downward pressure on pool price when the fuel is available, the increase in wind and solar capacity can also put upward pressure on pool price volatility as supply from these intermittent generation sources varies depending on prevailing weather conditions.

With the relatively low pool prices in Alberta during Q1, exports from Alberta continued. The average flow of power across all of Alberta's interties was 289 MW of exports in Q1 compared to 7 MW of exports in Q1 2023, an average demand increase of 282 MW (Table 1). Imports and exports are discussed further in section 2.2.

The amount of thermal generation capacity that was available increased from Q1 2023 to Q1 2024 (Table 1) as the HR Milner asset (300 MW) returned from an extended outage in the fall of 2023. This asset was previously offline from early September 2022 to late September 2023. The return of this dispatchable thermal asset has increased competition in the energy market and put downward pressure on prices.

Available thermal capacity in Q1 was also increased slightly by the commissioning activities of the Cascade 1 asset (450 MW). Cascade 1 began generating on January 9 and generated close to 300 MW in certain hours of the quarter, while Cascade 2 (450 MW) did not supply power to the

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[3] An asset's capacity is considered added to the grid when it has supplied more than 1 MW.

grid in Q1. The commissioning of these assets has been delayed and is ongoing. Once commissioned, they will add up to 900 MW of efficient combined cycle capacity to the market which will meaningfully increase competition and put downward pressure on prices.

On February 2, the last remaining coal units in Alberta, Genesee 1 and 2 (800 MW in total) tripped offline in close succession meaning that Alberta's power grid was temporarily coal-free for the first time in decades. The trips at Genesee 1 and 2 also led to an influx of unscheduled imports from BC and Montana to help maintain reliability in Alberta. This event is discussed further in section 1.2.

1.2 Market outcomes and events

Figure 3 illustrates pool price duration curves for Q1 and Q1 2023. These curves illustrate the distribution of pool prices by plotting the percent of hours that were less than or equal to a certain price. The lower natural gas prices year-over-year are evident in the figure as the duration curve for Q1 is slightly lower than the curve for Q1 2023 from the 0% to 70% range.

In Q1 pool prices ranged from the offer price cap at $999.99/MWh to the price floor at $0/MWh. Prices were at the offer price cap in mid-January when cold weather increased demand and reduced wind generation, and some thermal assets were on outage. As a result, the AESO declared EEA events on four consecutive days from January 12 to 15 indicating supply shortfalls during certain periods on these dates. These events will be discussed in a separate MSA report that is forthcoming.

Prices were at the price floor on February 17 and on March 12, 14, 15, and 18. High levels of intermittent generation is often the cause of prices falling to the floor, as the high level of intermittent supply combines with must-run thermal generation to exceed prevailing demand. On March 14/15 prices were at the offer floor for around 5 hours during the off peak as demand was lower overnight and wind generation increased up to 3,400 MW (Figure 4). The System Marginal Price (SMP) also fell to $0/MWh during the peak hours of March 15, from 17:10 to 17:26, as intermittent generation increased up to 3,000 MW and there was a large amount of capacity offered at $0/MWh. Historically, it is unusual for prices to clear at the floor during periods of peak demand but this is becoming more common.

Figure 3: Pool price duration curves (Q1 and Q1-2023)

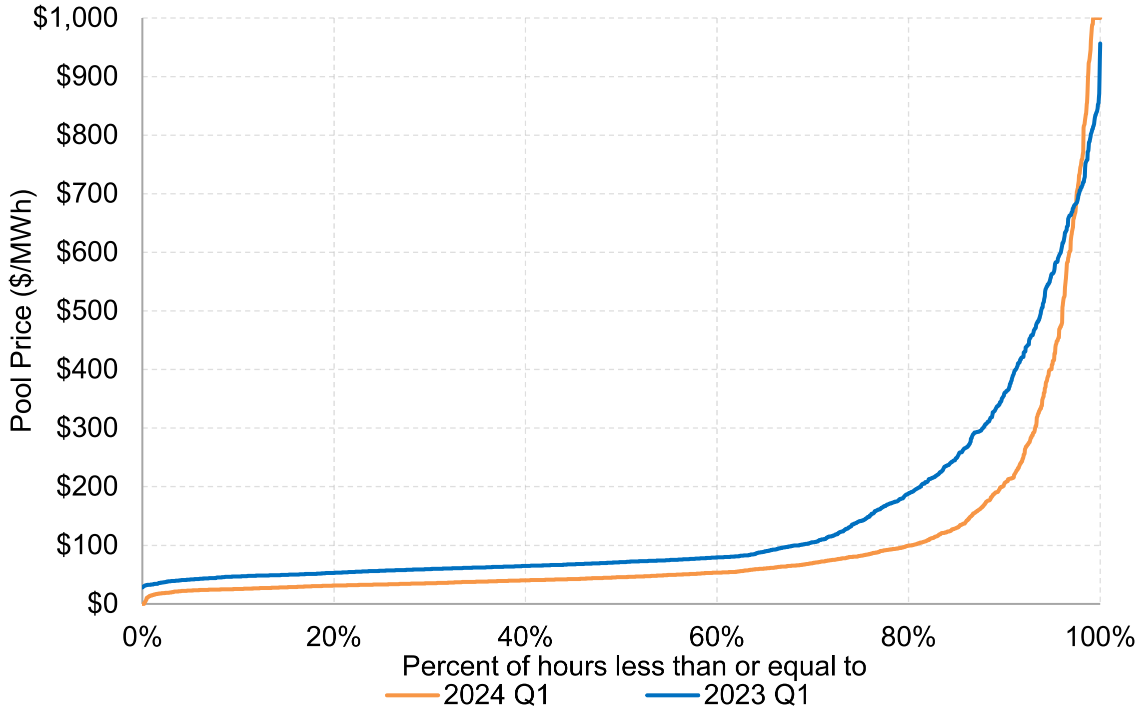
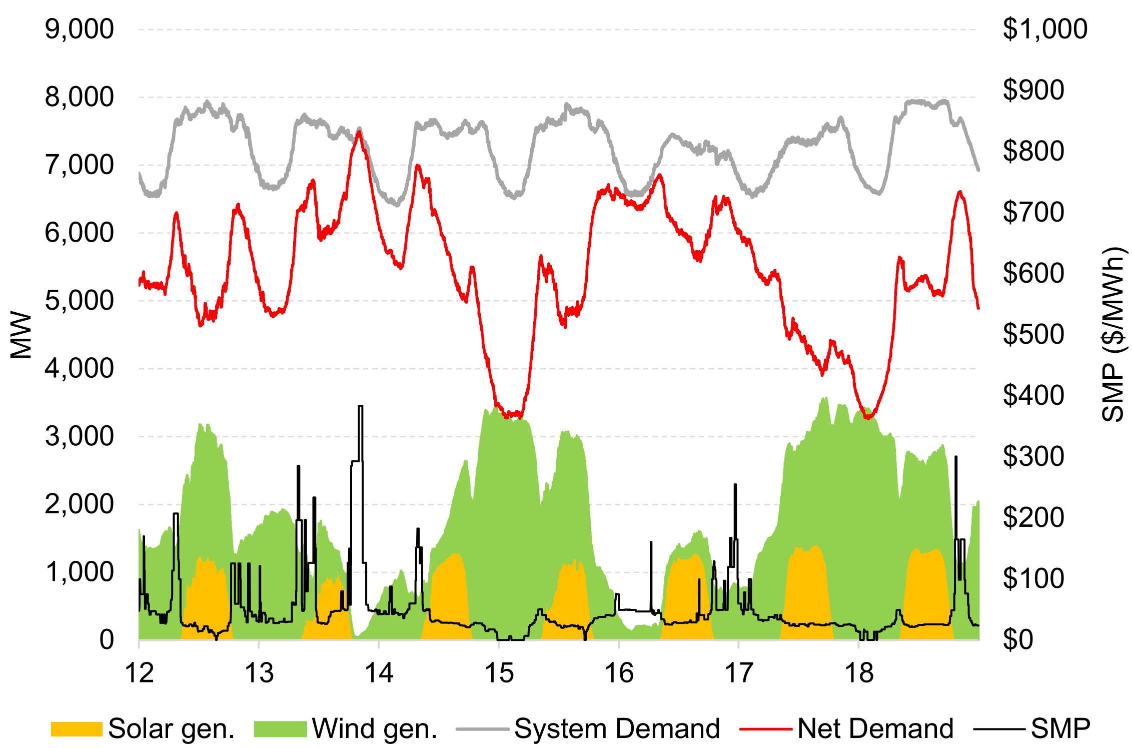


Figure 4: System demand, intermittent generation, net demand and SMP (March 12 to 18)



1.2.1 Genesee 1 and 2 trip

On the morning of February 2, the two remaining coal units in Alberta tripped offline meaning that Alberta's electricity supply was temporarily free of coal the first time in decades.[4] Just before 09:30 Genesee 1 tripped offline and this was subsequently followed by a trip at Genesee 2 (Figure 5).

The assets were offline for around 12 hours in total, accounting for the fact that Genesee 2 attempted to ramp back up between 16:09 and 18:04, before Genesee 1 came back online starting at 00:16 on February 3 (Figure 5).

Figure 5: Trips at Genesee 1 and 2 (February 2 to 3)

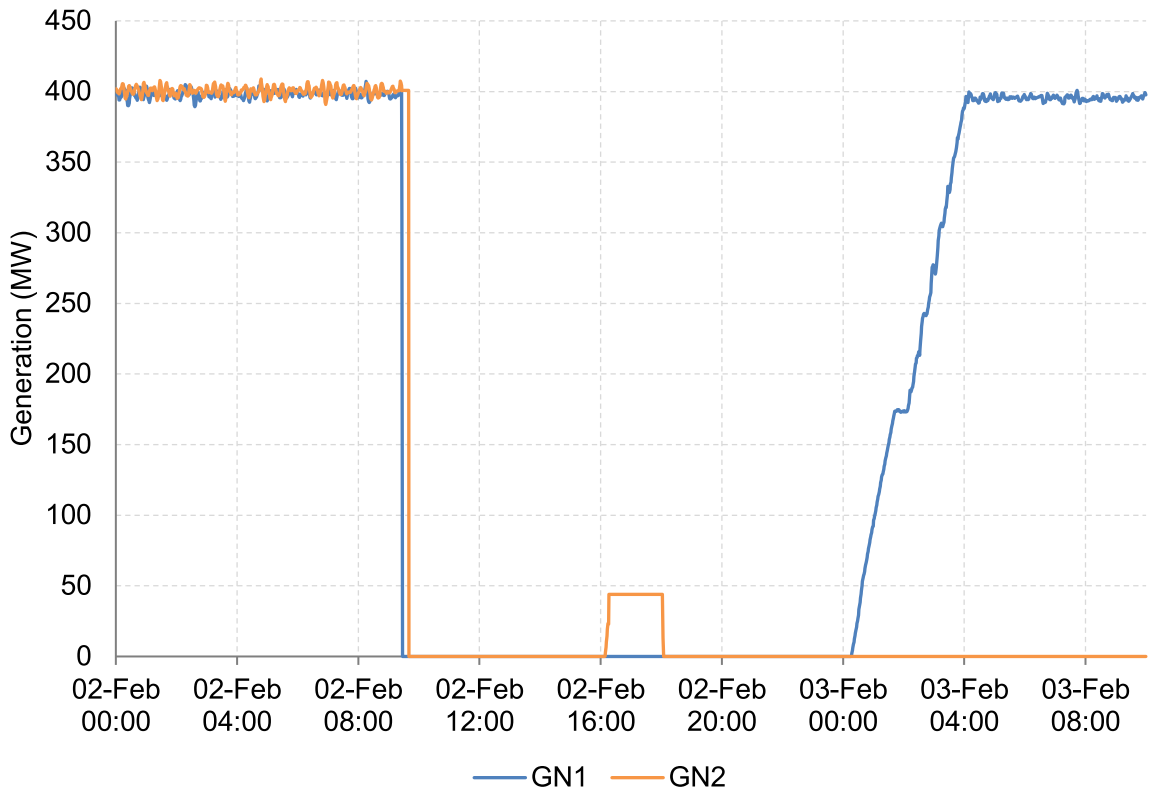


Figure 6 below illustrates generation by fuel type and hour ending on February 2. As shown, coal went to 0 MW in HE 11 and wind generation declined during the day. These declines were offset by increased supply from natural gas, imports, and solar generation. Following the decline of solar in the evening, and for the daily demand peak, increased natural gas generation was the main substitute for the lack of coal.

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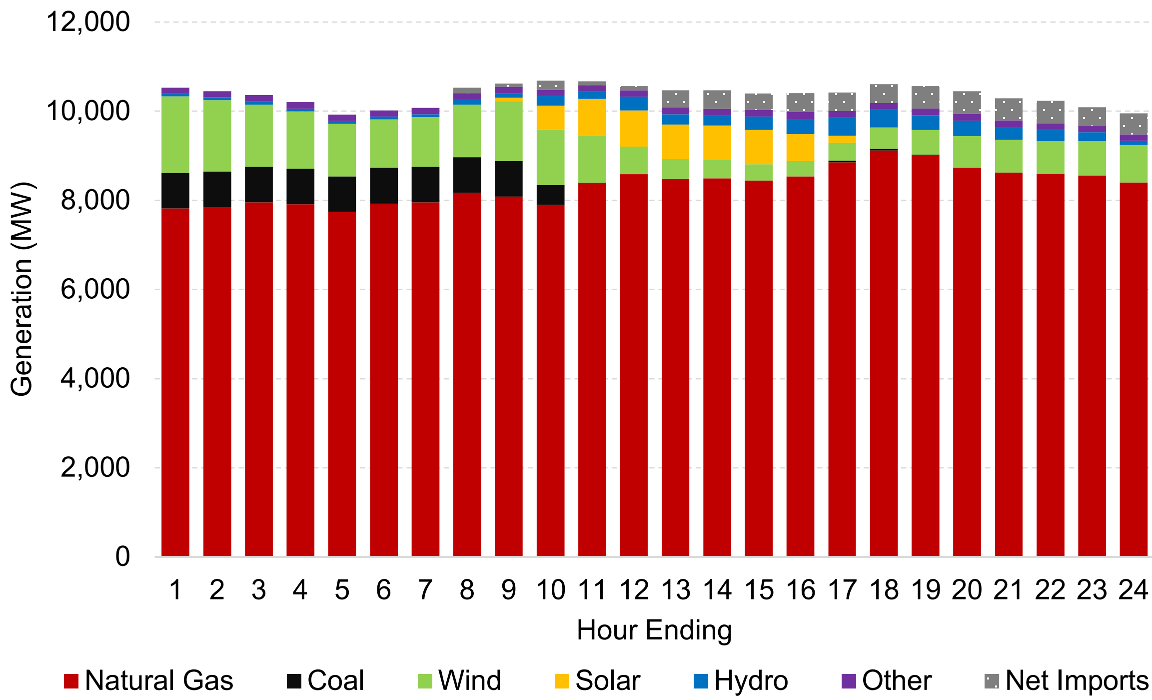
[4] Genesee 3, a dual fuel asset, is assumed to be burning natural gas as per the information on Capital Power's website:

[Genesee Generating Station 3]

[Q3 2022 Results Conference Call transcripts] at page 8-9

Figure 6: Generation by fuel type and HE (February 2)



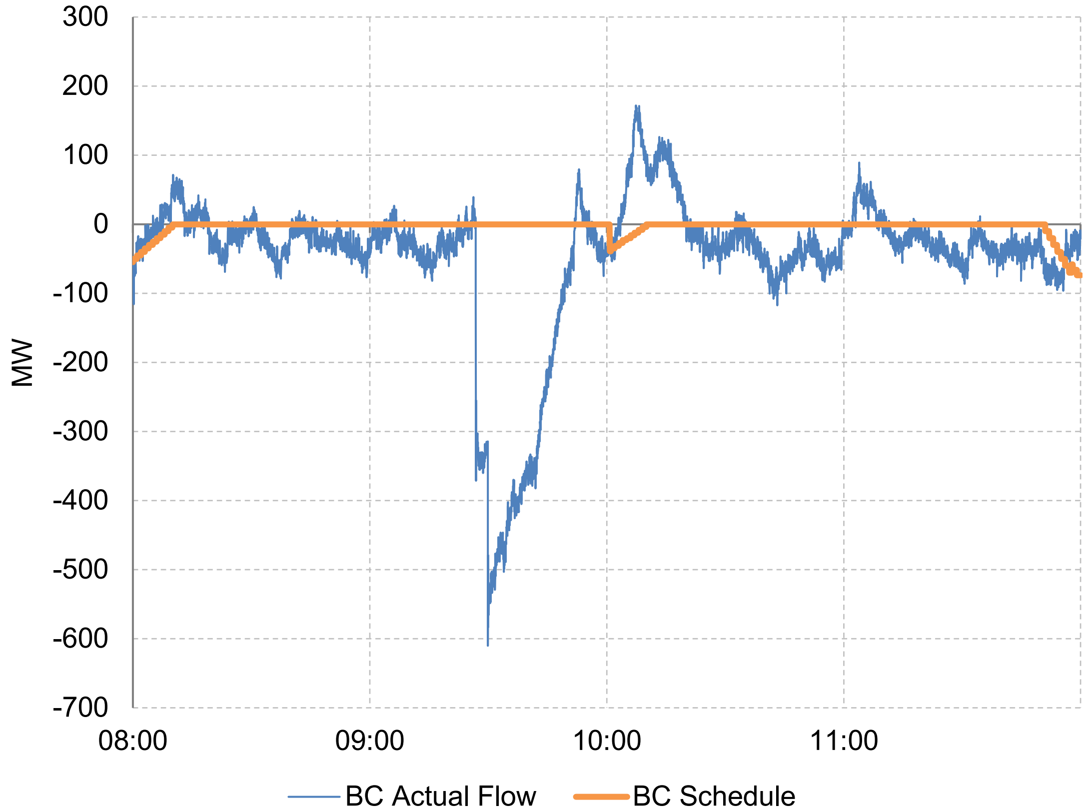
In addition to impacting generation by fuel type, the immediate loss of Genesee 1 and 2 had short-term effects on the flow of power over Alberta's interties. At the time of the Genesee 1 and 2 trips, the BC intertie was scheduled for 0 MW of imports into Alberta. However, because of the Genesee 1 and 2 trips, the actual power flow along the intertie increased to 610 MW of imports. Therefore, at one point the difference between the schedule and flow of imports was close to 610 MW of unscheduled imports (Figure 7).

A similar dynamic was observed on the Montana intertie (MATL). At the time of the Genesee 1 and 2 trips MATL was scheduled for 50 MW of imports. However, because of the trips the line was importing up to 248 MW at one point. Because of the increased supply of power from these interties, system frequency did not fall very far in this instance hitting a low of 59.93 Hz.

Alberta's electricity supply was also free of coal generation in early March when Genesee 1 and 2 were both offline again for around 46 hours. Looking forward, Alberta's electricity supply is expected to be permanently free of coal generation later this year.

Genesee 1 and 2 are being converted from coal to combined cycle natural gas in stages. The Genesee Repower 1 simple cycle asset replaced the Genesee 1 coal asset, which effectively retired in early April. The next phase for the Genesee Repower 1 asset is to add the steam turbine from Genesee 1 to complete the combined cycle conversion. Genesee 2 will undergo a similar conversion process from coal to combined cycle natural gas. The Genesee 2 asset is scheduled to stop using coal later in May and complete Alberta's transition away from coal.

Figure 7: Actual flow and the schedule of the BC intertie (February 2; imports are negative)



1.3 Market power, offer behaviour, and net revenues

Market power refers to the ability of generators to profitably offer their capacity at prices exceeding short-run marginal cost (SRMC). Prices in Q1 2024 were lower than in Q1 2023, with January being the only month where prices increased year-over-year.

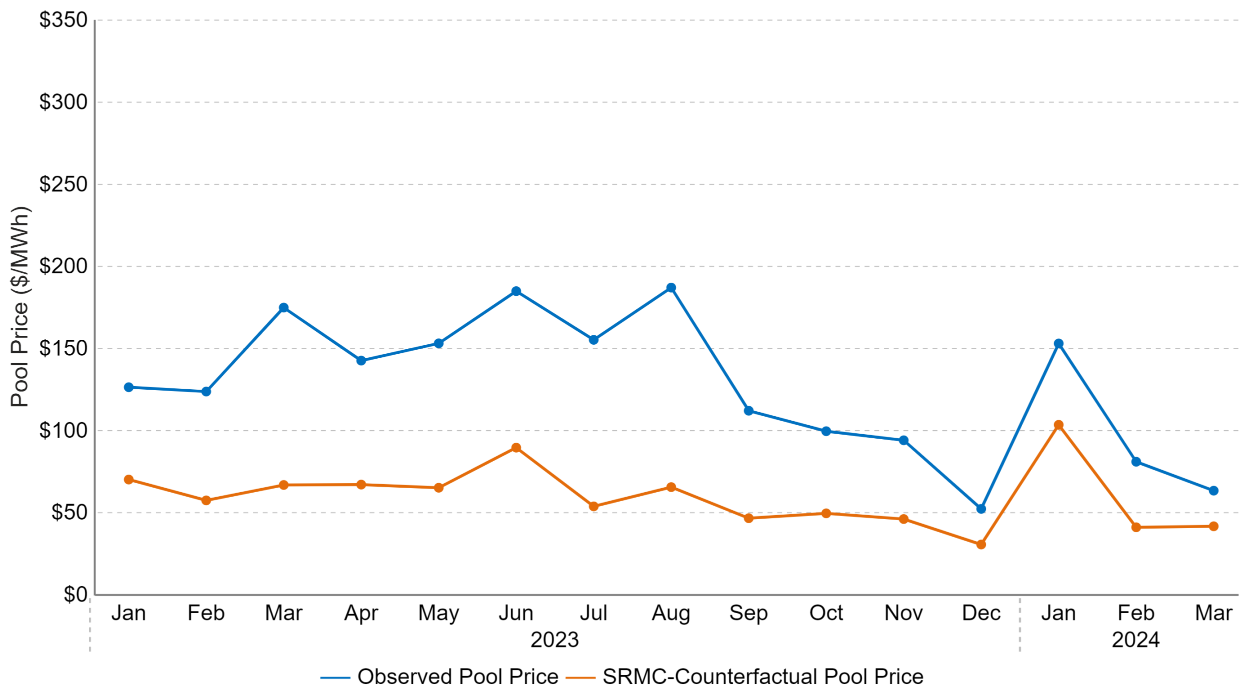
The average pool price in Q1 was $99/MWh, 60% higher than the MSA's SRMC-counterfactual price (Table 2). The MSA estimates SRMC-counterfactual pool prices by adjusting generator's offers to their SRMC and re-dispatching energy market merit orders. SRMC-counterfactual pool prices enable the MSA to assess the degree to which changes in observed pool prices could have been a result of changes in generators' input costs or demand, rather than strategic offer behaviour.

Table 2: Pool prices and SRMC-counterfactual pool prices (Q1 2023 and Q1 2024)

		2023	2024	Change vs. 2023
Observed Pool Price (Avg $/MWh)	Jan	$126	$153	21%
	Feb	$124	$81	-35%
	Mar	$175	$63	-64%
	Q1	$142	$99	-30%
SRMC-Counterfactual Pool Price (Avg $/MWh)	Jan	$70	$103	48%
	Feb	$57	$41	-29%
	Mar	$67	$41	-38%
	Q1	$65	$62	-5%

Figure 8 illustrates how monthly average pool prices have generally declined since January 2023 despite only moderate declines in SRMC-counterfactual pool price estimates over the same period, suggesting declines in the exercise of market power. The margin between the two prices averaged $50/MWh in January 2024, $40/MWh in February, and fell to $22/MWh in March, compared to margins of $56/MWh, $67/MWh, and $108/MWh in the first three months of 2023, respectively.

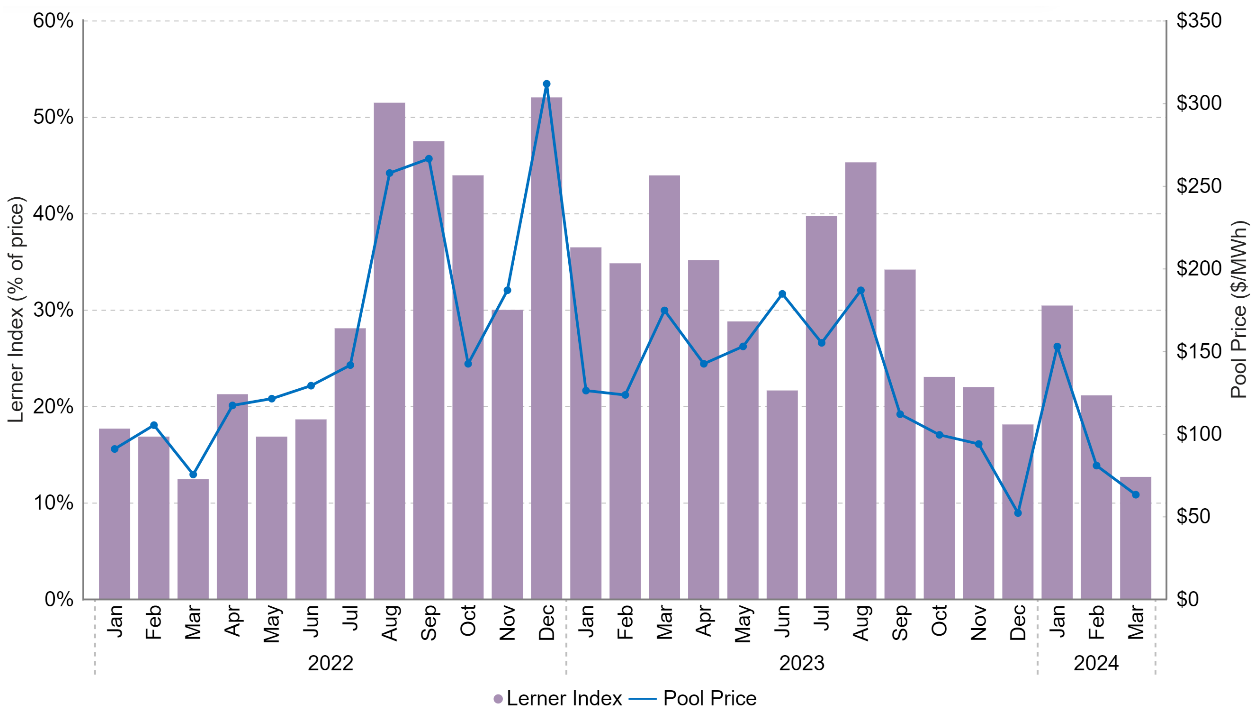
Figure 8: Quarterly observed and SRMC-counterfactual pool prices (Q1 2023 to Q1 2024)



The Lerner Index measures the markup of price over the market's marginal cost of generation, expressed as a percentage of the price. Following the pool price trend, the Lerner Index dropped throughout the quarter, from 30% in January, to 21% in February, and to 13% in March (Figure 9). The quarterly average was 21%, only 0.4% percentage points greater than in Q4 2023.

Consistent with observations in the previous quarter, Q1 was marked by a considerable number of hours with negative markups. Of all the hours in the quarter, 32% had negative Lerner index values. This happens when some generation capacity is offered below its estimated SRMC and occurs more frequently in hours where pool prices are low.

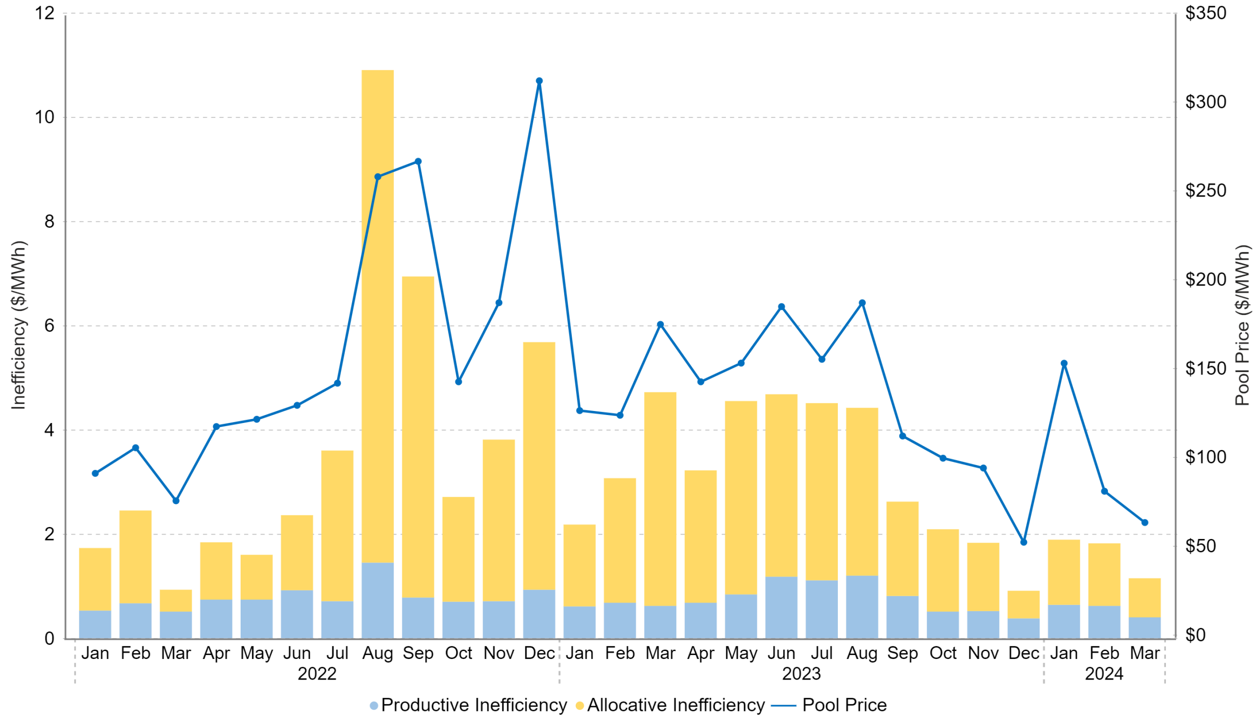
Figure 9: Monthly average market markup (January 2022 to March 2024)



Another measure of the exercise of market power used by the MSA is static inefficiency, which is the sum of allocative and productive inefficiencies. When generators offer their capacity above SRMC, some consumers may reduce their consumption or forgo consuming entirely in response to the higher price. Allocative inefficiency measures the unrealized benefits to consumers and generators resulting from this loss of consumption (and production). Productive inefficiency measures excess generation costs that occur when lower cost generation is economically withheld. An electricity market is productively efficient if only the lowest cost generation in the system is dispatched to meet demand.

In Q1, the average static inefficiency was $1.62/MWh, a 2% increase compared to Q4 2023. Static inefficiencies were lower compared to Q1 2023, with $1.89/MWh in January, $1.82/MWh in February, and $1.13/MWh in March, for year-over-year declines of 13%, 41%, and 76%, respectively (Figure 10).

Figure 10: Monthly average static inefficiency (January 2022 to March 2024)



1.3.1 Pivotality

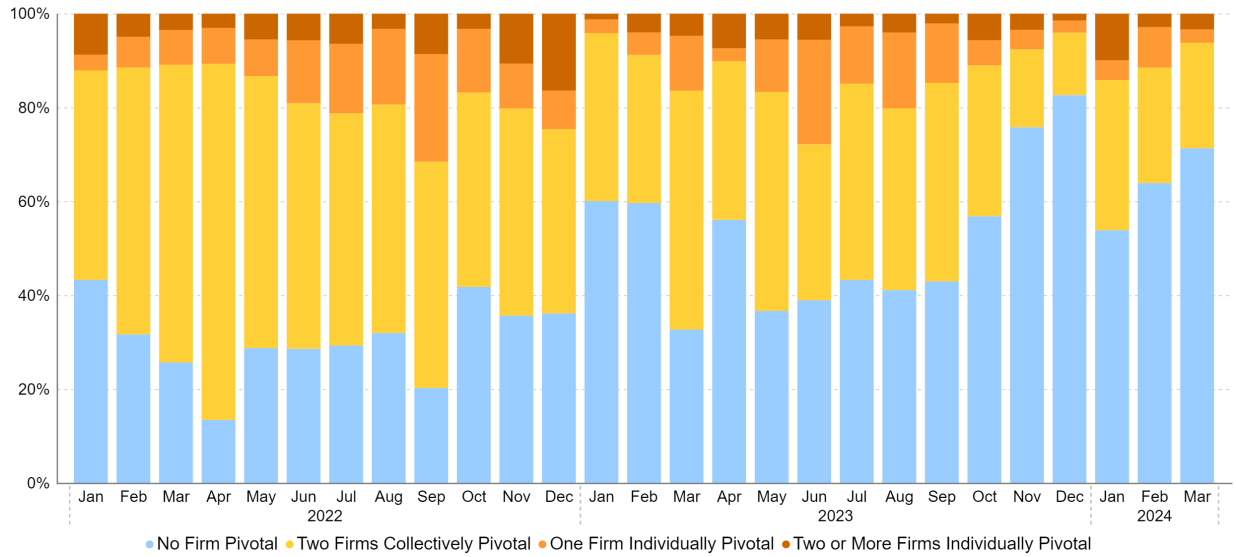
A firm is considered pivotal in hours when its withholdable capacity is required for the market to clear. The MSA's current definition of withholdable capacity includes all capacity that can be economically withheld by generators, except for intermittent generation and minimum stable generation (MSG).

There are different degrees to which a firm may be pivotal:

- multiple firms may each be pivotal at the same time ("Two or More Firms Individually Pivotal");
- only one firm may be pivotal ("One Firm Individually Pivotal");
- two firms may only be collectively pivotal with their combined withholdable capacity ("Two Companies Collectively Pivotal"); or
- there may be no firms that are individually or collectively pivotal ("No Company Pivotal").

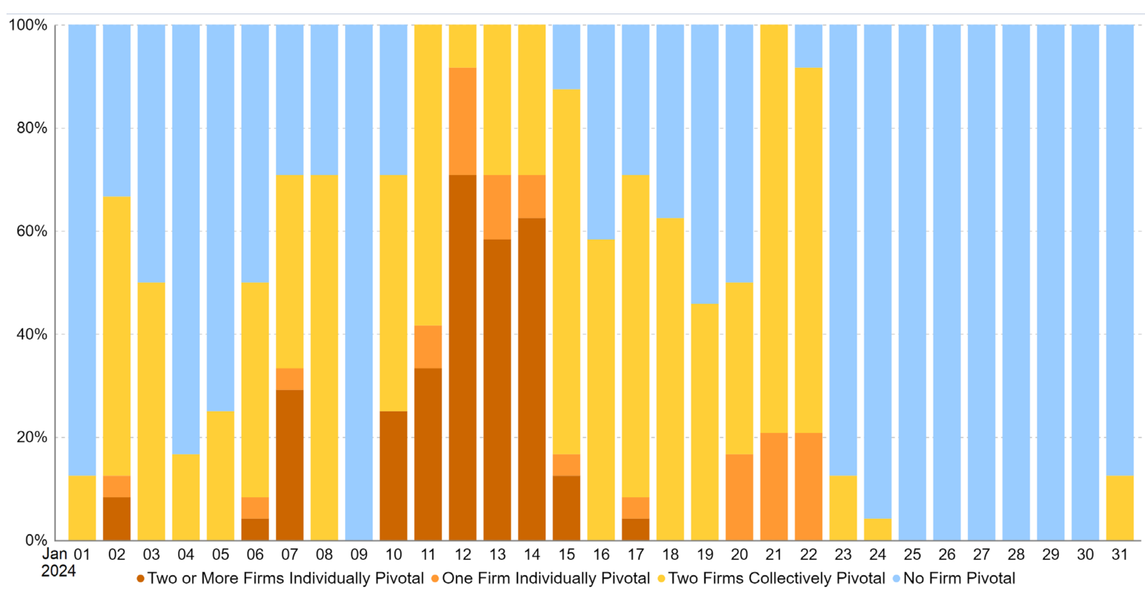
When a firm is pivotal, it may have market power as it can set the pool price by economically withholding its withholdable capacity. Conversely, when a firm is not pivotal, its ability to economically withhold profitably is lower. In Q1 2024, firms were most frequently pivotal in January, with at least one firm being individually pivotal in 14% of hours in that month, compared to 12% of hours in February, and 6% in March (Figure 11).

Figure 11: Market-level pivotality by month (January 2022 to March 2024)



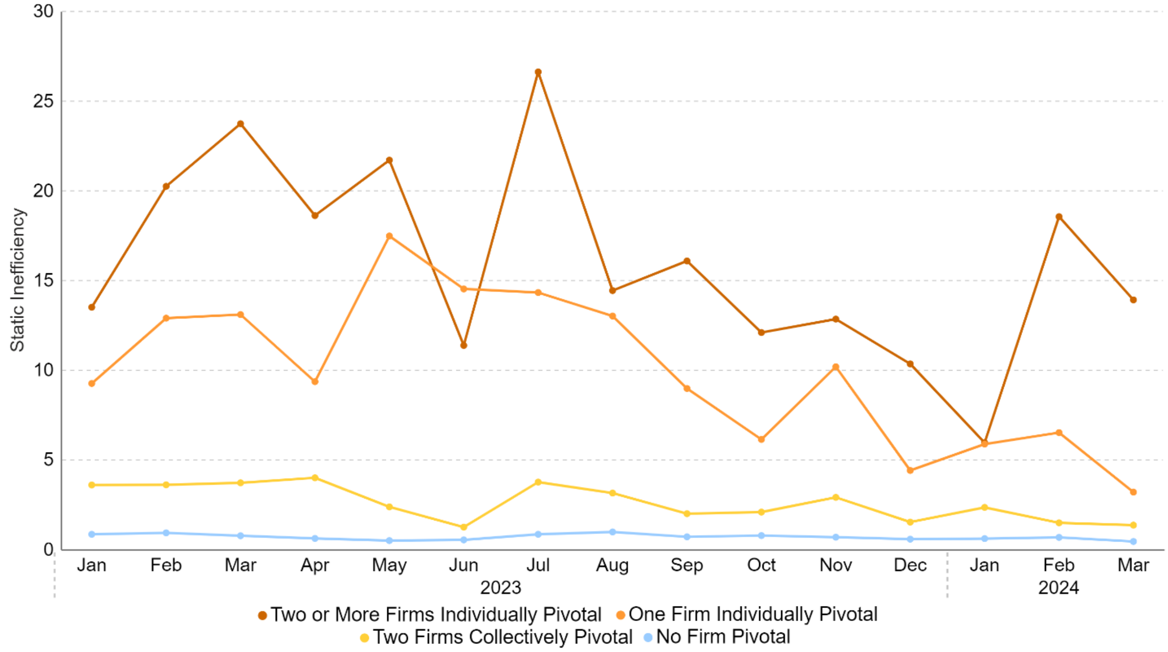
Firms were more frequently pivotal in January than other Q1 months, driven not only by higher demand but also significantly affected by the energy emergency alerts that occurred between January 12 to 15. In hours where an energy emergency alert occurs, virtually all firms are individually pivotal as all generation capacity in the merit order is needed for the market to clear (Figure 12).

Figure 12: Market-level pivotality by day (January 1 to 31)



Quarter-over-quarter, static inefficiency decreased by \$0.03/MWh in hours with no pivotality, by \$0.18/MWh in hours of collective pivotality, and by \$1.04/MWh in hours with one firm pivotality (Figure 13). When two or more firms were individually pivotal, the static inefficiency fell by \$3.60/MWh. Excluding the 4-day period when emergency alerts occurred in January, the average static inefficiency when two or more firms were pivotal in January was \$7.42/MWh, 25% higher than the result including those dates. This indicates that the supply cushion in these critical days was low, and the market could not support any additional demand that would have resulted from SRMC offers, decreasing the static inefficiency impact resulting from the exercise of market power.

Figure 13: Monthly average static inefficiency by pivotality condition (Jan. 2023 to Mar. 2024)



No firm was pivotal in 63% of hours in Q1, a higher rate of non-pivotality compared to the first quarter of previous years (Figure 14). This can be attributed in part to a rise in intermittent generation, averaging 1,519 MW, marking an 18% increase over Q1 2023 (Figure 15).

Figure 14: Market-level pivotality by quarter (Q1 2021 to Q1 2024)

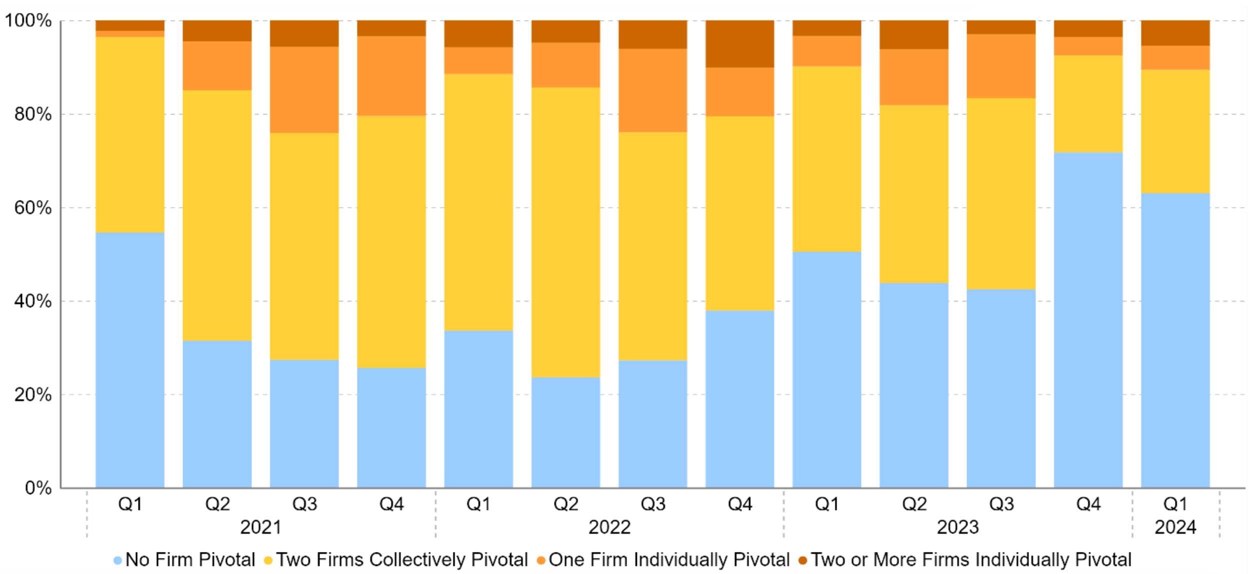
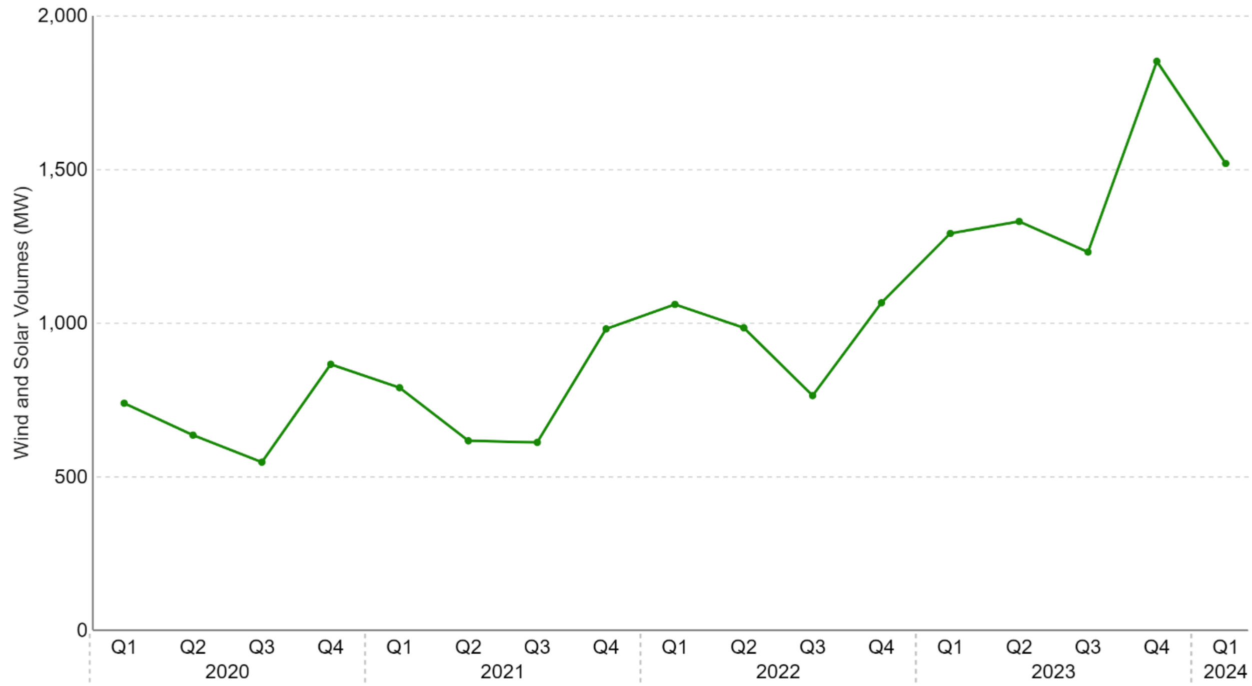


Figure 15: Quarterly average intermittent generation (Q1 2020 to Q1 2024)

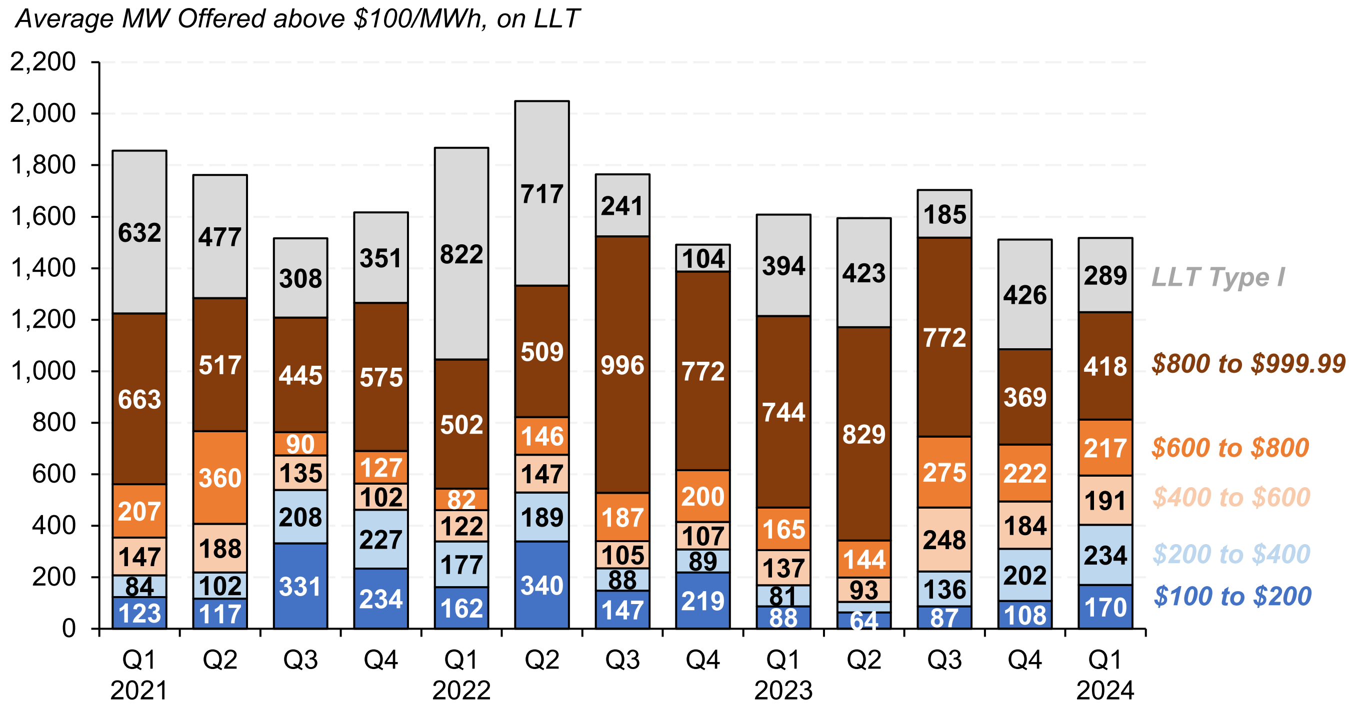


1.3.2 Offer behaviour

More capacity was offered above $100/MWh in Q1 2024 both year-over-year and quarter-over-quarter, although this coincided with less capacity being placed on long lead time (LLT)[5] (Figure 16). In Q1, an average of 1,229 MW was offered into the merit order above $100/MWh, compared to 1,085 MW in Q4 2023 and 1,214 MW in Q1 2023. However, 289 MW was placed on LLT in Q1, a decline from the 426 MW of capacity on LLT in Q4 2023 and 394 MW in Q1 2023. The MSA considers capacity on LLT to be capacity that is withheld, as it is effectively priced out of the merit order. Much like Q4, offers above $100/MWh in the merit order in Q1 were more evenly distributed at various price ranges compared to the Q3 2022 to Q3 2023 period.

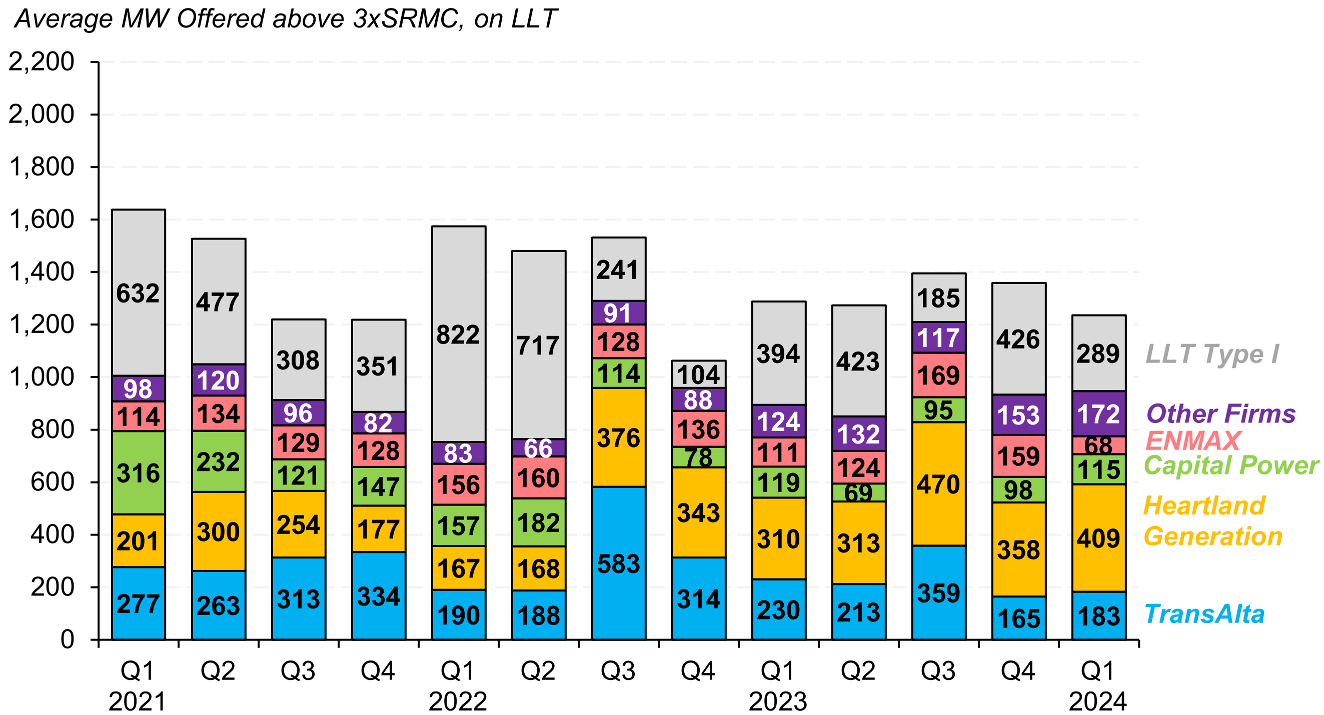
[5] In this section, the MSA refers to capacity "on long lead time", or alternatively "LLT Type I" to refer to source assets whose capacity is: not synchronized to the system, requires more than one hour to synchronize to the system, and is not in the merit order for reasons other than an outage, in accordance with the AESO's definition (i) of a "long lead time asset" described in the *Consolidated Authoritative Document Glossary*.

Figure 16: Average non-hydro capacity offered above $100/MWh or on long lead time (LLT) (Q1 2021 to Q1 2024)



Firms economically withhold by offering generation capacity above SRMC or placing units on LLT to raise pool prices. Although merit order capacity offered above $100/MWh increased quarter-over-quarter, less capacity was put on LLT and similar levels of capacity were offered considerably in excess of SRMC (Figure 17). On average, 1,236 MW were offered above three times SRMC or placed on LLT in Q1 2024, compared to 1,359 MW in Q4 2023 and 1,288 MW in Q1 2023.

Figure 17: Average non-hydro capacity offered above 3xSRMC or on long lead time (LLT) (Q1 2021 to Q1 2024)



Thermal offers were slightly lower in Q1 compared to the previous quarter (Figure 18), with the highest 10% of available MW offered at an average price of $583.40/MWh in Q1 compared to $614.13/MWh in Q4 2023. Thermal offers were relatively uniformly distributed above $100/MWh, which is reflected in a relatively linear duration curve above $100/MWh. This result was similar to the distribution of thermal offers in Q4 2023, but contrasts with thermal offers in Q1 2023, where relatively few thermal offers were made at prices between $100 and $800/MWh (Table 3).

Figure 18: Thermal unit offers by quarter (Q1 2023 to Q1 2024)

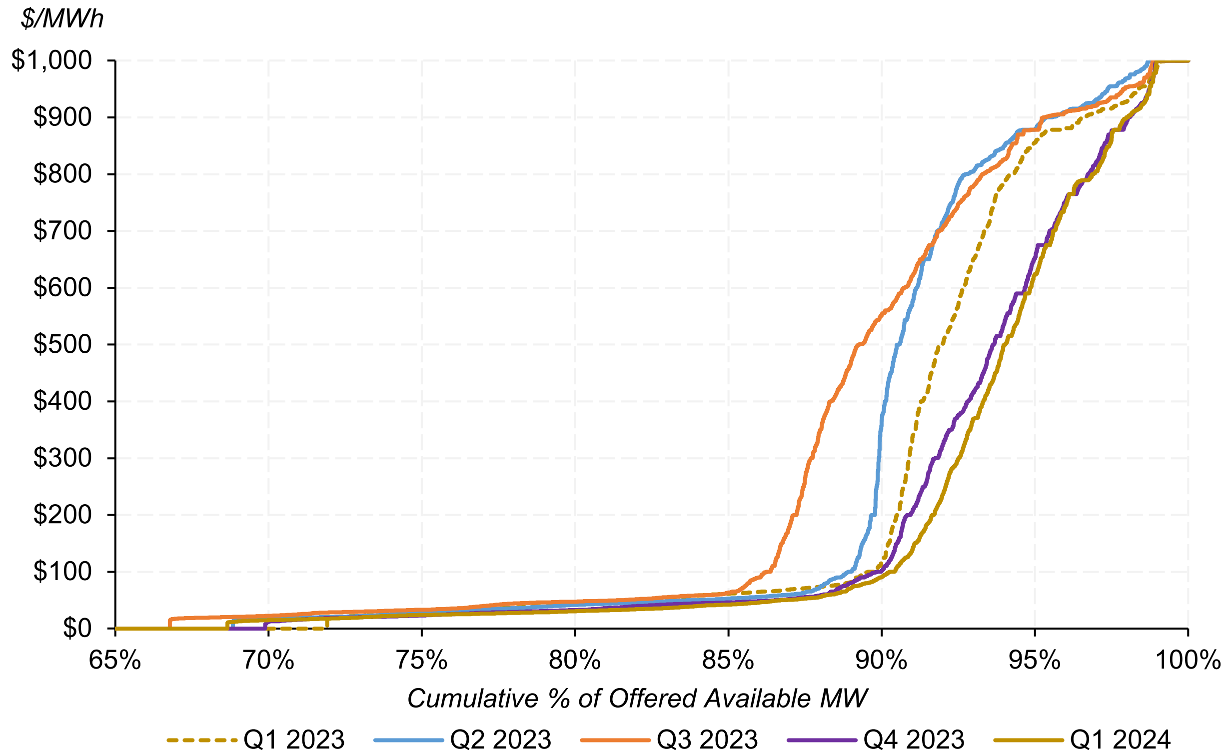
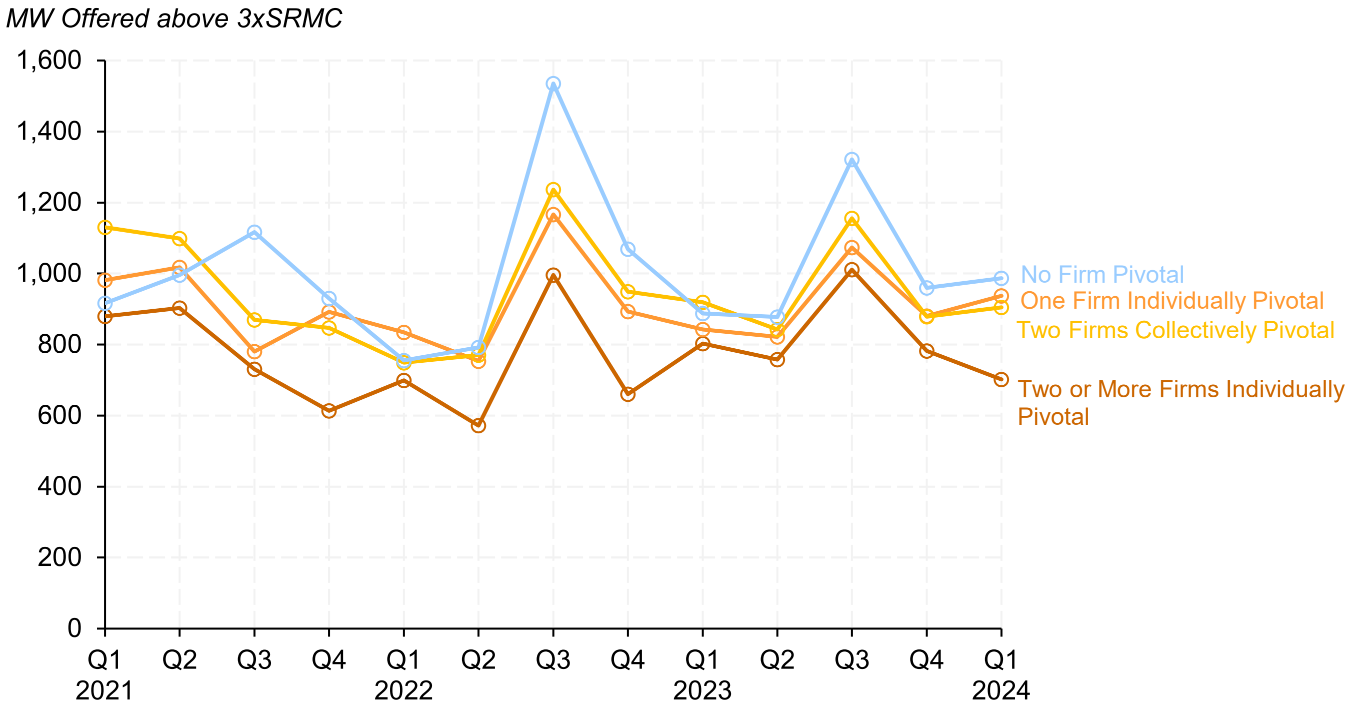


Table 3: Quarterly share of thermal offers above $100/MWh

	% of Available MW Offered between $100 and $800	% of Available MW Offered between $800 and $999.99	% of Available MW Offered At/Above $100
Q1 2023	4.6%	5.8%	**10.4%**
Q2 2023	3.8%	7.3%	**11.1%**
Q3 2023	7.0%	6.7%	**13.8%**
Q4 2023	6.9%	3.3%	**10.1%**
Q1 2024	6.6%	3.1%	**9.7%**

Firms offered slightly more capacity above three times SRMC in all hours except those where multiple firms were individually pivotal in Q1 compared to Q4 2023 (Figure 19). In the past two years, the MSA has observed firms in aggregate attempting to economically withhold less capacity in hours where they are pivotal, compared to periods where they are non-pivotal.

Figure 19: MW offered above 3xSRMC by pivotality condition, all firms (Q1 2021 to Q1 2024)

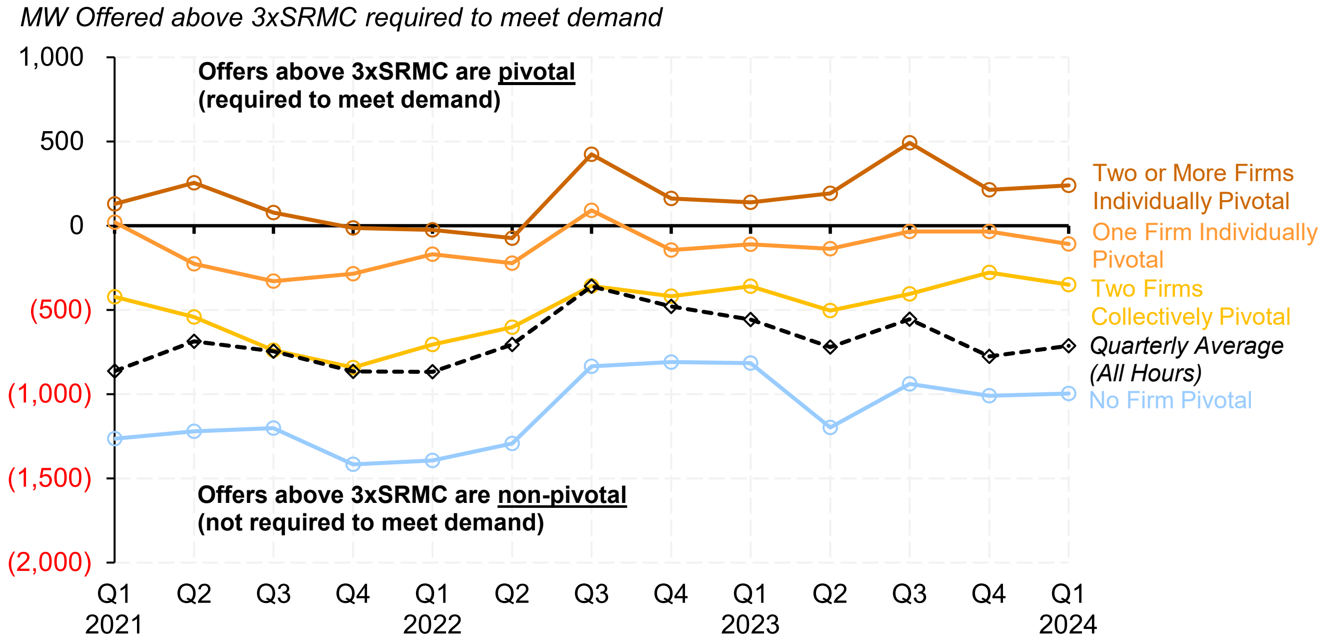


This result is in part due to differences in supply cushion within pivotal hours between quarters. By offering capacity above SRMC, firms forego potential revenues earned from this capacity if it goes un-dispatched, but may be able to increase the pool price received for any remaining capacity that is not withheld. Competing capacity from other firms (or low demand) disciplines this exercise of market power by increasing the risk that less of a firm's non-withheld capacity may be dispatched. When supply cushion is lower, a pivotal firm has greater ability to exercise market power by economically withholding and may find it profit-maximizing to offer less of its capacity above SRMC given its attempt to exercise market power is less disciplined by demand. Therefore, the degree to which market power is exercised by firms' offering their capacity above SRMC is best contextualized by accounting for the impact of supply cushion.

For example, capacity offered above three times SRMC in Q1 hours where two or more firms were individually pivotal declined by 80 MW relative to similar hours in Q4 2023. However, supply cushion in these most pivotal hours declined by 107 MW over the same period. As a result, these offers above three times SRMC were more pivotal in Q1 compared to Q4 2023 in hours where two or more firms were individually pivotal: 213 MW of capacity offered above three times SRMC was needed in-merit to meet demand in these Q4 2023 hours, while 240 MW of this capacity was needed in-merit to meet demand in similar Q1 hours (Figure 20).

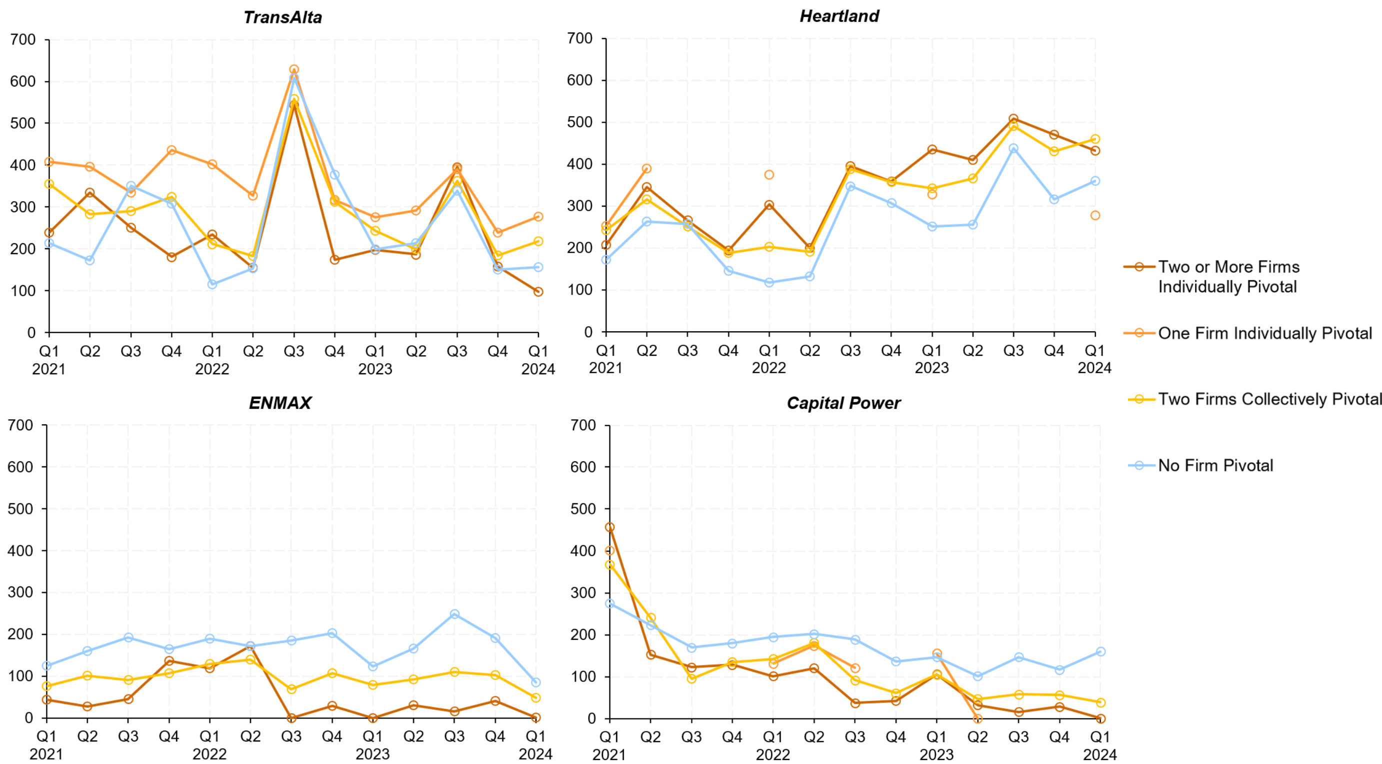
This suggests slightly more market power was exercised in Q1 compared to Q4 2023 in hours where two or more firms were individually pivotal, given the decline in capacity withheld was lower than the decline in supply cushion. Among other hours where only one firm was pivotal or two firms were collectively pivotal, supply cushion increased sufficiently in Q1 relative to Q4 2023 to more than offset the increase in capacity offered above three times SRMC observed in Q1.

Figure 20: MW offered above 3xSRMC less supply cushion by pivotality condition, all firms (Q1 2021 to Q1 2024)



In Q1, ENMAX and Capital Power generally offered less capacity at prices above three times SRMC in hours when they were at least collectively pivotal compared to similar hours in the previous quarter (Figure 21). In contrast, TransAlta and Heartland offered more of their capacity at these above-cost prices when they were at least collectively pivotal in Q1 compared to Q4 2023.

Figure 21: MW offers above 3xSRMC by firm, pivotality condition (Q1 2021 to Q1 2024)



1.3.3 Net revenues

Between 2013 and Q1 2024, hypothetical combined cycle and gas peaker generators received sufficient net revenues in the energy market to cover their annualized capital costs at various weighted-average cost of capital (WACC) levels (Figure 22).[6] Over the same period of time, hypothetical wind and solar generators have received lower net revenues from the energy market, including the out-of-market payments received for their environmental attributes.

This difference in capital cost recovery is in part a result of differences in received pool prices between different types of generators. Since 2018, the average quarterly pool price received by wind generators while generating was 70% of the hourly average pool price over the same period (Figure 23). While solar generators have averaged a higher received price over the same period – 112% relative to the hourly average pool price – this received price has declined since 2022 as more solar capacity has come online.

[6] The MSA has modeled annualized capital costs at four WACC levels: 6.5%, 8.5%, 10.5%, and 12.5%, referred to as "Low", "Medium", "High", and "Very High" WACC levels, respectively.

Figure 22: Annual observed, SRMC counterfactual net revenues by hypothetical generator (2024$ thousands/MW-year) (2013 to Q1 2024)

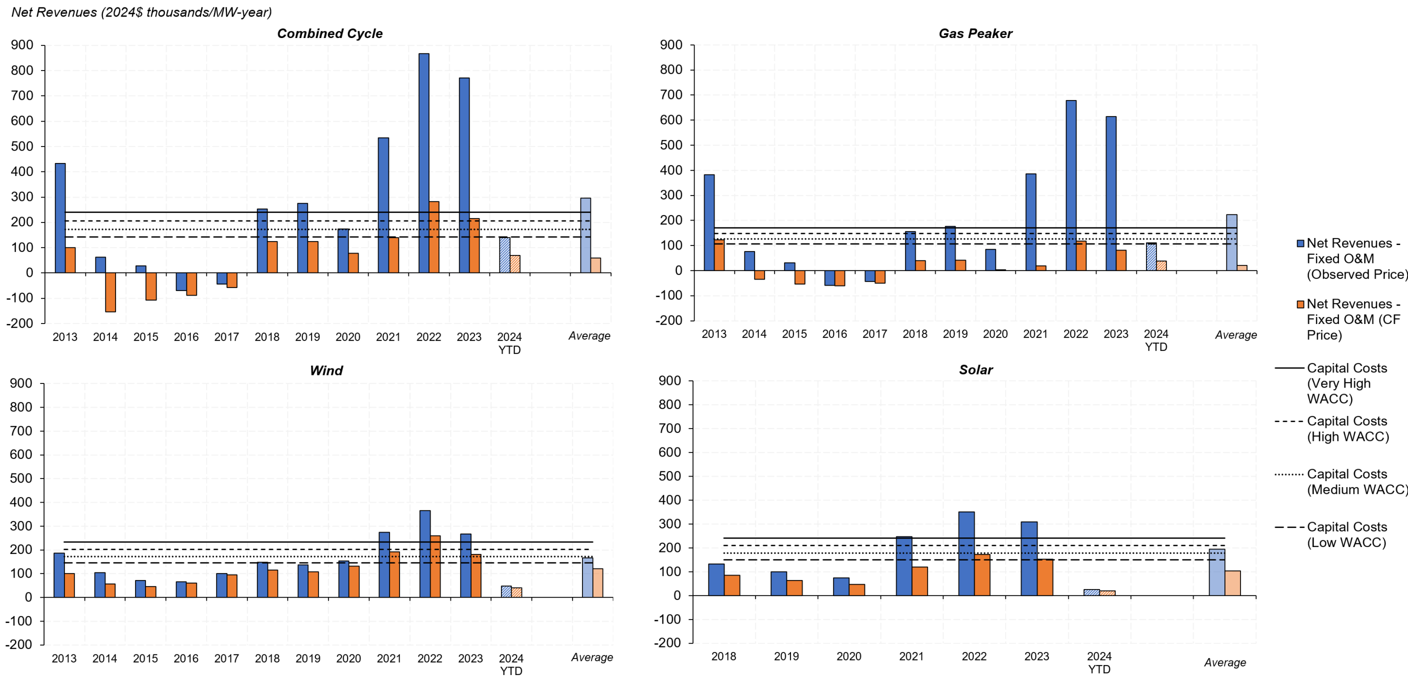
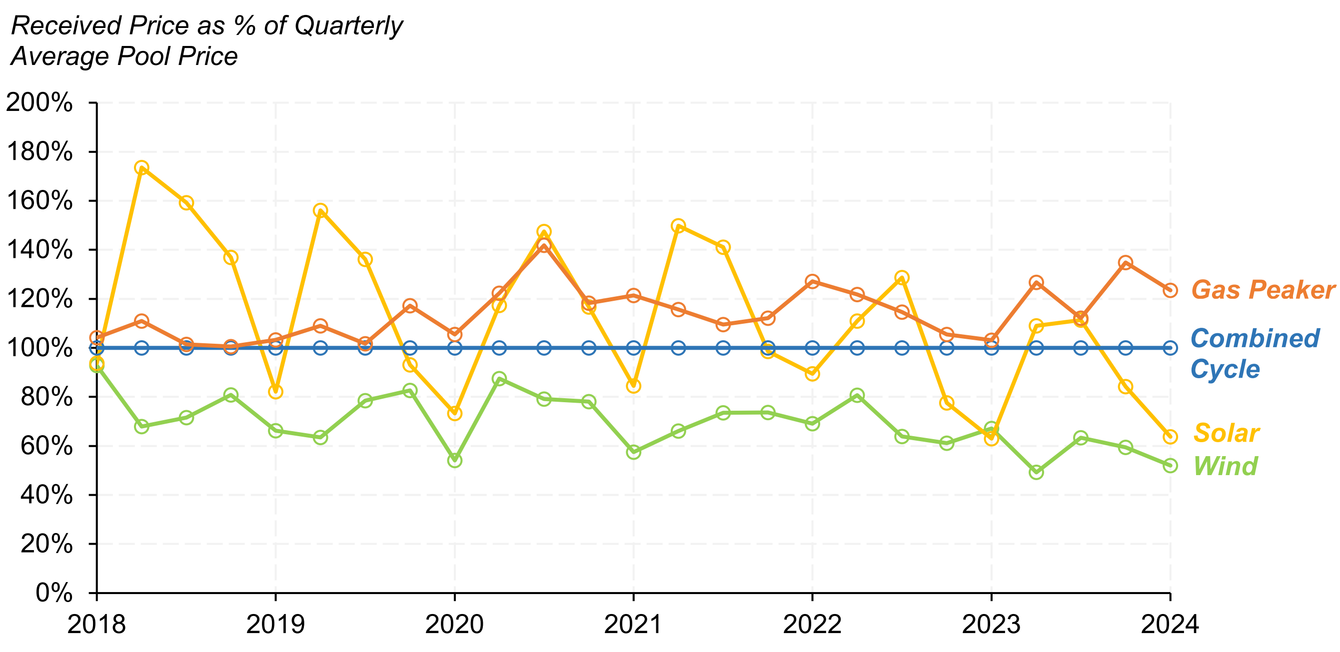


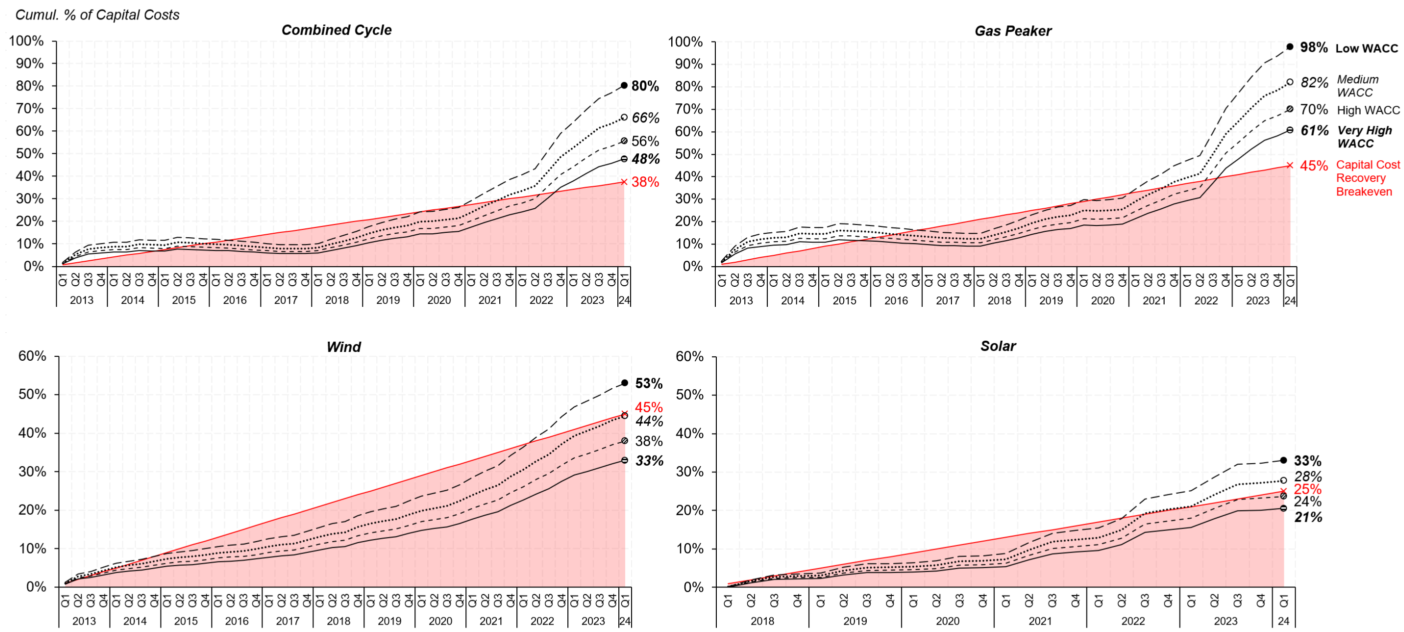
Figure 23: Quarterly received price relative to quarterly average pool price for hypothetical generators (Q1 2018 to Q1 2024)



Capital cost recovery takes place over many years, and requires a stream of net revenues over the lifespan of the generating asset. A hypothetical combined cycle or gas peaker generator built in 2013 would have received total net revenues that outpaced its capital financing costs by 2021 or 2022, depending on the assumed cost of capital (Figure 24).

By the end of Q1 2024 a combined cycle generator financed with a low WACC would have recovered 80% of its capital costs over the preceding 11 years, well in advance of its 30-year unit life, while a gas peaker generator financed with a low WACC would have recovered 98% of its capital costs almost halfway into its 25-year unit life. This suggests that pool prices observed since 2013 have generated sufficient incentives for investment in natural gas generation, and peaking generation in particular.

Figure 24: Quarterly cumulative capital cost recovery by hypothetical generator (Q1 2013 to Q1 2024) (observed net revenues)



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.[7]

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 Q4 2023 over the past seven years, and Table 5 shows

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

the same information for the past four quarters. The max carbon intensity has remained relatively the same since Q1 2022; however, the minimum and mean emission intensity have seen pronounced decreases (Table 4). The maximum hourly average carbon emission intensity this quarter was comparable to the minimum hourly average carbon emission intensity in Q1 2018.

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

Time period	Min	Mean	Max
2018 Q1	0.58	0.70	0.80
2019 Q1	0.53	0.67	0.75
2020 Q1	0.47	0.61	0.70
2021 Q1	0.43	0.56	0.68
2022 Q1	0.39	0.50	0.60
2023 Q1	0.36	0.47	0.57
2024 Q1	0.27	0.45	0.58

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

Time period	Min	Mean	Max
2023 Q2	0.28	0.44	0.57
2023 Q3	0.31	0.45	0.56
2023 Q4	0.30	0.43	0.57
2024 Q1	0.27	0.45	0.58

Figure 25 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q1 for the past seven years. Figure 26 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The conversion of coal-fired generation to natural gas in addition to increased intermittent generation has driven a decline in carbon emission intensity. This decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions as shown in Figure 25.

Figure 25: The distribution of average carbon emission intensities in Q1 (2018 to 2024)

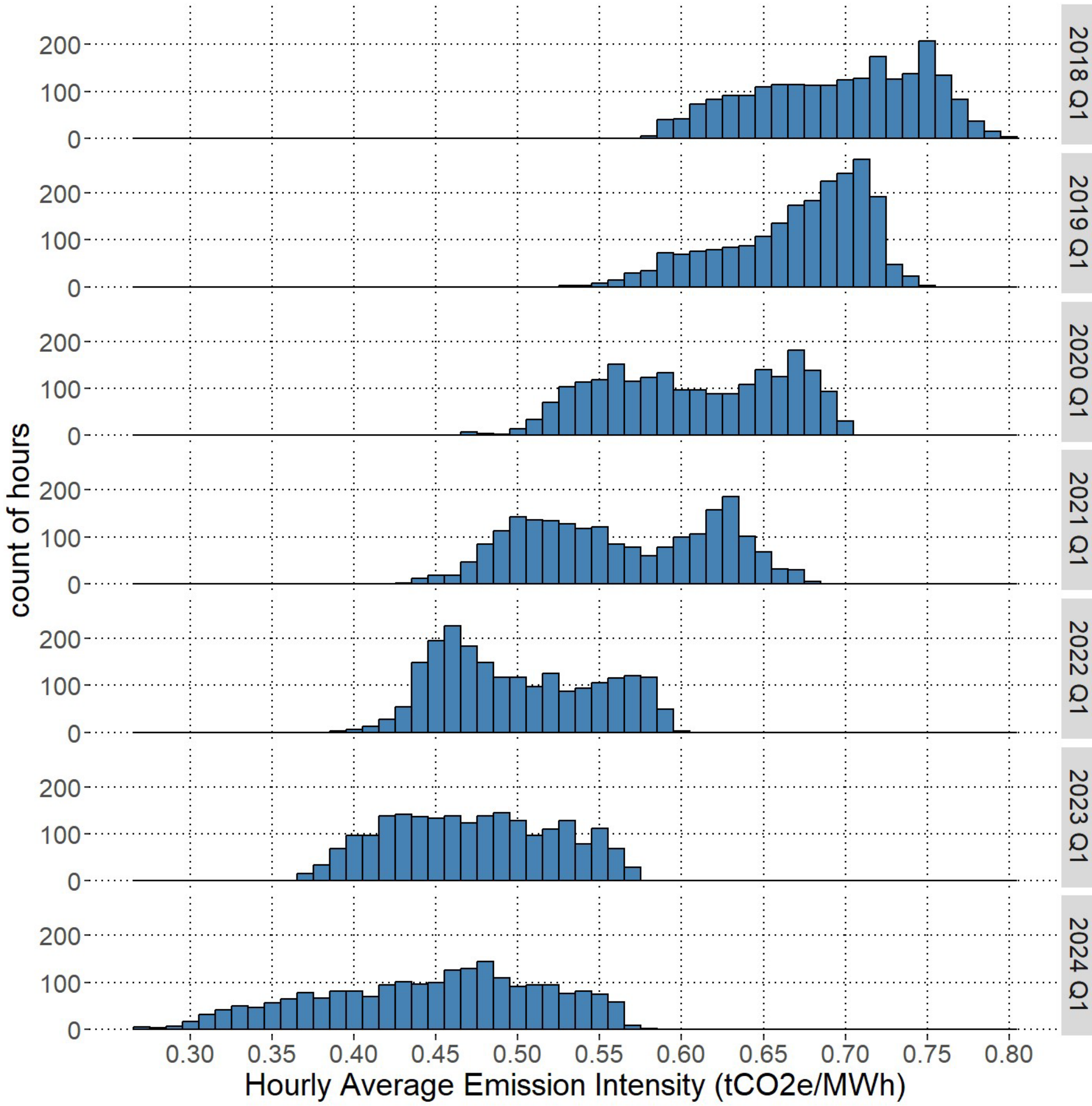
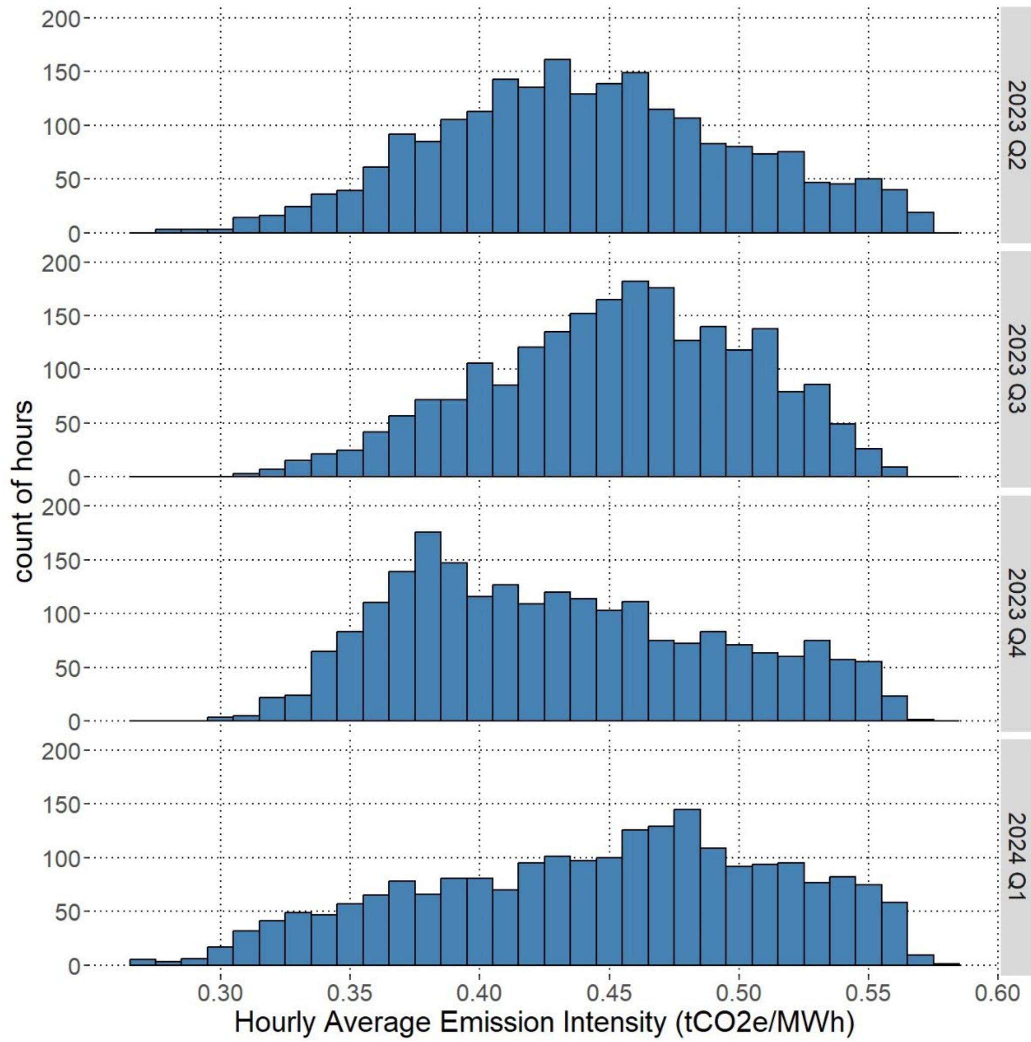


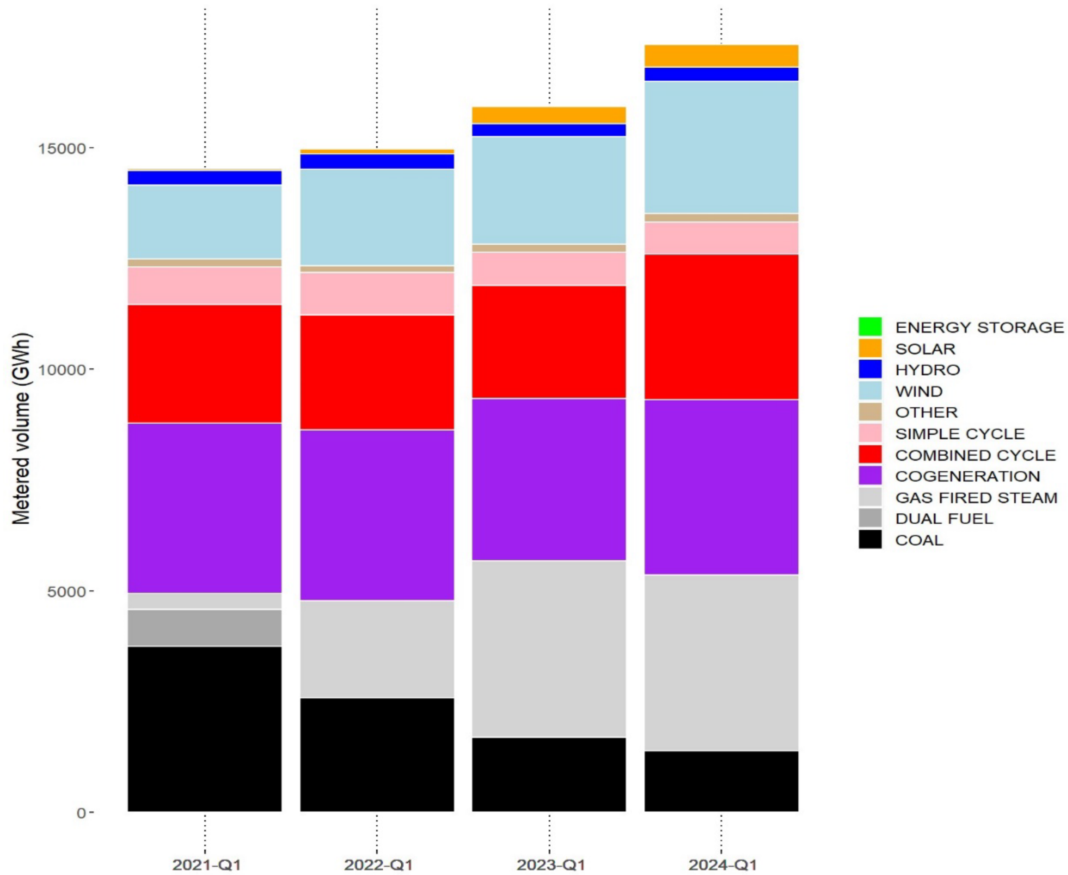
Figure 26: The distribution of average carbon emission intensities in the past four quarters



The general trends observed in the above distribution figures can be traced in Figure 27 which shows net-to-grid generation volumes by fuel type. Since 2020, there has been a decline in the volume of coal-fired generation, with generation from gas-fired steam assets replacing it. The increase in intermittent generation driven by growing capacity has also contributed to the displacement of coal-fired generation.

The carbon emission intensity of Alberta's grid should continue to decline with the addition of Cascade, an efficient combined cycle asset, the repowering of Genesee 1 and 2 from coal to combined cycle, and the upcoming addition of Suncor's Base plant cogeneration project. In addition, there are many wind and solar assets that are scheduled to be developed in Alberta.

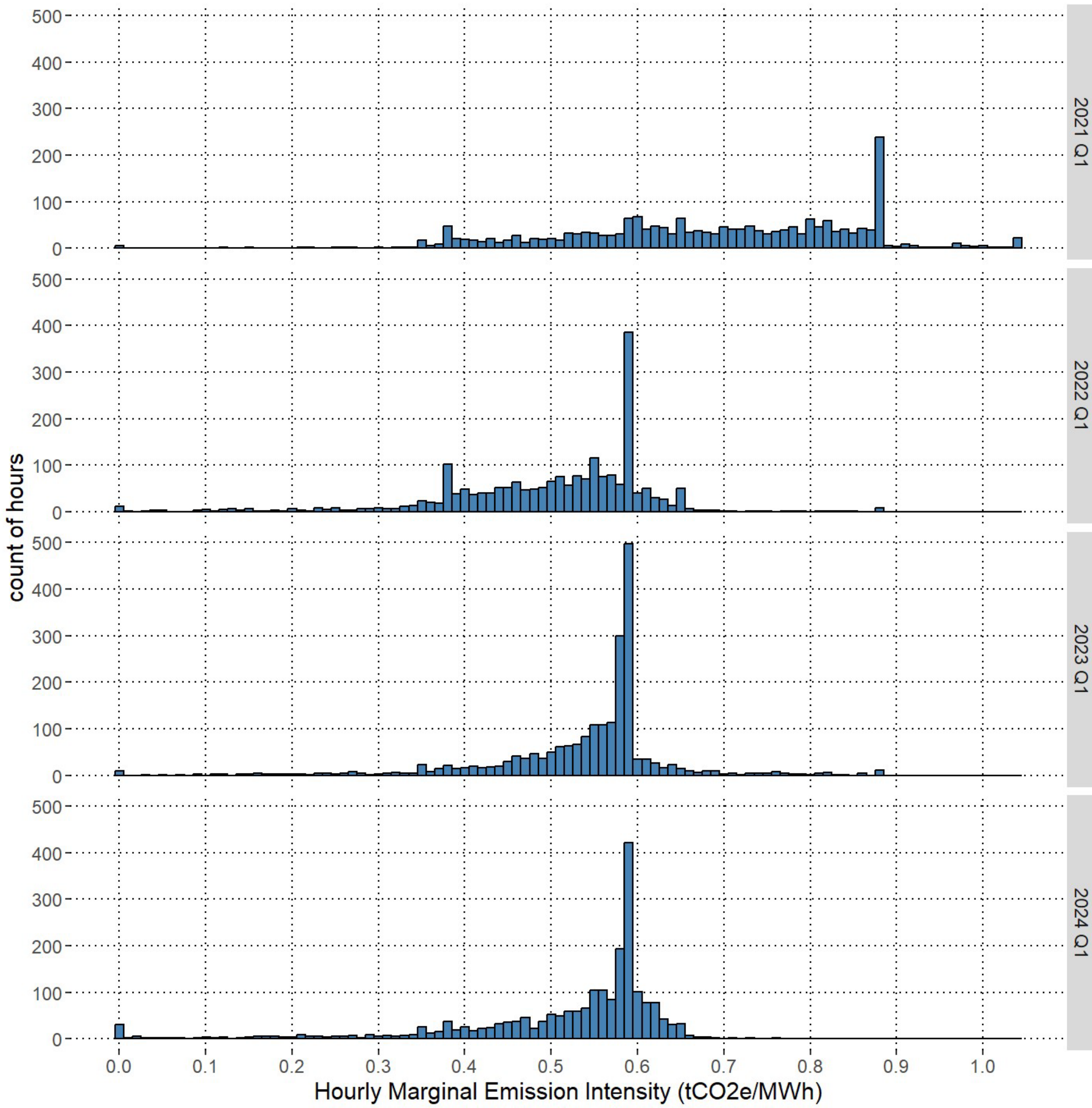
Figure 27: Quarterly total net-to-grid generation volumes by fuel type for Q1 (2021 to 2024)



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 28 shows the distribution of the hourly marginal emission intensity of the grid in Q1 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 28: The distribution of marginal carbon emission intensities in Q1 (2020 to 2023)



1.5 Fast Frequency Response

Frequency stability refers to the ability of the electrical system to maintain an acceptable level of frequency and promptly recover from imbalances between supply and demand caused by unforeseen events in a timely manner.[8] The system's ability to address such imbalances is heavily influenced by factors such as the composition of its generation fleet, the strength of connections to neighboring jurisdictions, and the availability of reliability support services. Fast Frequency Response (FFR) is a product aimed at swiftly addressing and stabilizing drops in frequency below a predefined threshold.[9] It reacts much faster than primary frequency response, with response

[8] AESO, Reliability Requirements Roadmap, PDF page 2

[9] AESO, Reliability Requirements Roadmap, PDF page 21

times measured in thousandths of seconds. When the system frequency falls below the set threshold, FFR promptly releases additional power or reduces load to restore balance.

With a changing supply mix, the Alberta Interconnected Electric System has experienced declining frequency response which has resulted in a reduction of market access for interties. The implementation of an FFR product that is activated when there is an outage on the intertie allows for the grid to maintain a frequency of close to the nominal value of 60 Hz. The AESO is in the process of designing two discrete FFR products, one for when the grid is interconnected and another for islanded conditions. These new FFR products are substitutes for the previous Load Shed Service (LSS)[10] product. The AESO has stated that sufficient frequency response is required to meet reliability compliance obligations, allow market access for interties, and ensure market access for internal generation when the system is islanded.[11]

In March 2023, the AESO released its Reliability Requirements Roadmap,[12] which detailed that it needed to, "urgently implement mitigation measures to lower the current risk of under frequency load shed (UFLS) activation due to supply loss."[13] The LSSi arming table[14] was updated in the same month, and this reduced base import ATC on BC/MATL without LSSi from 466 MW to 325 MW.

Moving forward, the use of dynamic FFR arming will allow for the addition of 50 MW of import ATC on average. Dynamic FFR arming will replace the use of static look up tables and leverage simulations to determine required volumes 1 or 2 hours in advance, dependent on system conditions.[15] Dependent on cost, the AESO has stated that it may procure 670 MW of FFR or greater to allow for the max ATC of 1,045 MW.[16] Procurement is currently underway for the interconnected FFR product, with procurement for islanded FFR to commence in mid-2024.[17]

The FFR product currently being procured requires a discrete response by providers. This product will enable import transfer capability in support of the AESO's obligation to restore the intertie without compromising system reliability and protect against sudden frequency deviations from intertie trips when importing. Assets providing the discrete interconnected FFR product must be able to provide a response in 0.5 seconds or less and maintain their response for up to 60 minutes.

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[10] LSS is a reliability product developed to mitigate the impact of under frequency excursions and is contracted between the AESO and load providers who agree to instantaneously shed consumption in the case of a sudden loss of imports or internal generation. Load Shed Service for imports (LSSi) refers to the specific case of using LSS for the purposes of increasing import capability.

[11] AESO, Frequency Response Program Stakeholder Session, PDF Slide 10

[12] AESO, Reliability Requirements Roadmap

[13] AESO, Reliability Requirements Roadmap, PDF page 3

[14] AESO, Information Document Available Transfer Capability and Transfer Path Management ID #2011-001R, PDF page 9

[15] AESO, Frequency Response Program Stakeholder Session Audio, 33:45

[16] AESO, Frequency Response Program Q&A, PDF Slide 12

[17] AESO, Fast Frequency Response Interconnected Service Procurement

The initial design of the FFR product is similar to the current LSS product, and what was evaluated in the FFR pilot. This means that the FFR product would provide a discrete response and disallow the simultaneous offering of capacity into the contingency reserves (CR) and FFR market. The AESO plans to use short-term commercial agreements until outcomes from Market Pathways are to be implemented. A stackable FFR product with a proportional response is being explored and would require ISO rule revisions. This product would allow for the concurrent selling of FFR and CR with management during delivery.

Participation in this market is voluntary, and compensation will be provided using a three-part price. This will include an hourly availability payment, an hourly arming payment (pay-as-bid), and an event-based response payment. An FFR merit order will be constructed to ensure that reliability requirements are met at least cost, given the eligible providers.

Interconnected FFR contracts will be awarded in May 2024, with the earliest service term commencing July 2, 2024. The AESO's procurement of an islanded FFR product will begin in mid-2024, with an anticipated service term of January 1, 2025. The AESO has stated that by early 2026, a new interconnected FFR service term will commence. Subject to ISO rule revisions, eligible market participants may be able to provide proportional responses and submit stackable offers before 2026.

Presently, the AESO has 90 MW of FFR, with contracts beginning in 2023. The AESO uses this FFR to increase imports and to increase the ability of large internal generators to supply power during islanded conditions. Figure 29 compares hourly import ATC and net import flows from BC/MATL against hourly armed FFR volumes from February 21 to March 15, 2024. A total of 934 MW of FFR was armed on March 5, 2024, with an additional 580 MW armed the following day. On February 21, 2024 1201L went offline, however due to the fact that Alberta was a net exporter at this time, no FFR was used. FFR is currently being utilized in hours when the grid is net importing from BC/MATL, as seen in Figure 29. FFR was armed on several occasions throughout the quarter when net imports were high.

Figure 29: Hourly BC/MATL import ATC, net imports and armed fast frequency response MW (February 21, 2024 to March 15, 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 wind and solar (intermittent) constrained down generation.

The significance of intermittent constrained down generation directives increased from Q1 2023 to Q1[18]. The MSA estimates that intermittent constrained down generation volumes were 12.7 GWh in Q1 2023 and 27.8 GWh in Q1. This represents an increase by a factor of two year-over-year. Quarter-over-quarter, the intermittent constrained down generation volumes decreased substantially from 187.8 GWh in Q4 2023 to 27.8 GWh in Q1.

The maximum hourly average volume of intermittent generation constrained down in Q1 was 370 MWh, over double the maximum of 166 MWh in Q1 2023 (Figure 30 and Figure 32). However, the Q1 maximum hourly average volume of intermittent constrained was substantially lower than the previous quarters maximum value of 840 MWh (Figure 31).

Although the total installed capacity of wind and solar generators increased year-over-year, the increase in constrained down volume from Q1 2023 to Q1 grew at a faster rate. While total installed intermittent capacity increased by 28.4%, average hourly constrained down volumes, expressed as a percent of installed intermittent capacity, increased from 0.12% in Q1 2023 to 0.21% in Q1, an increase of 75%. The growth of constrained down volume outpaced the growth in installed capacity year over year.

[18] 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.

Figure 30: Maximum hourly transmission constrained wind and solar generation (Q1 2023)

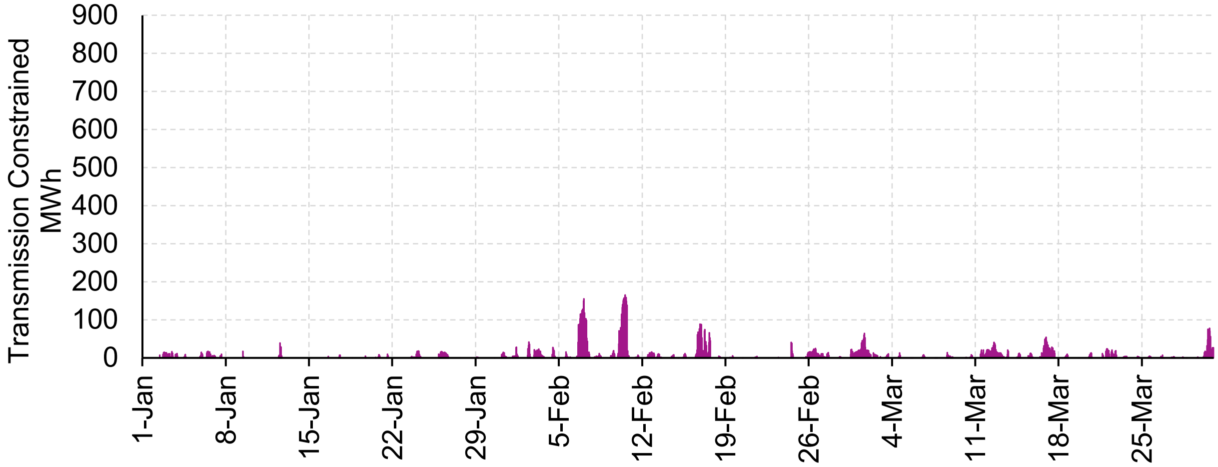


Figure 31: Maximum hourly transmission constrained wind and solar generation (Q4 2023)

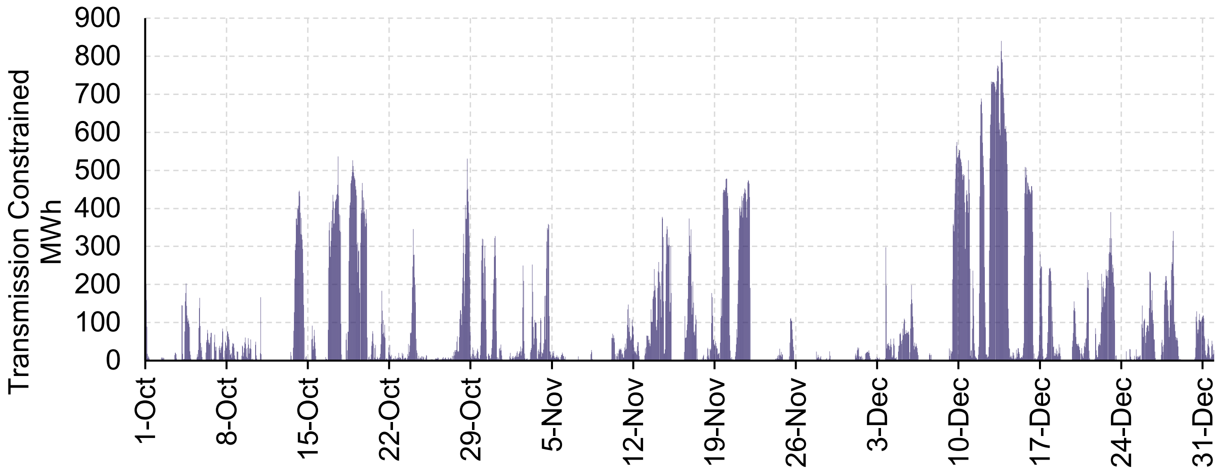


Figure 32: Maximum hourly transmission constrained wind and solar generation (Q1 2024)

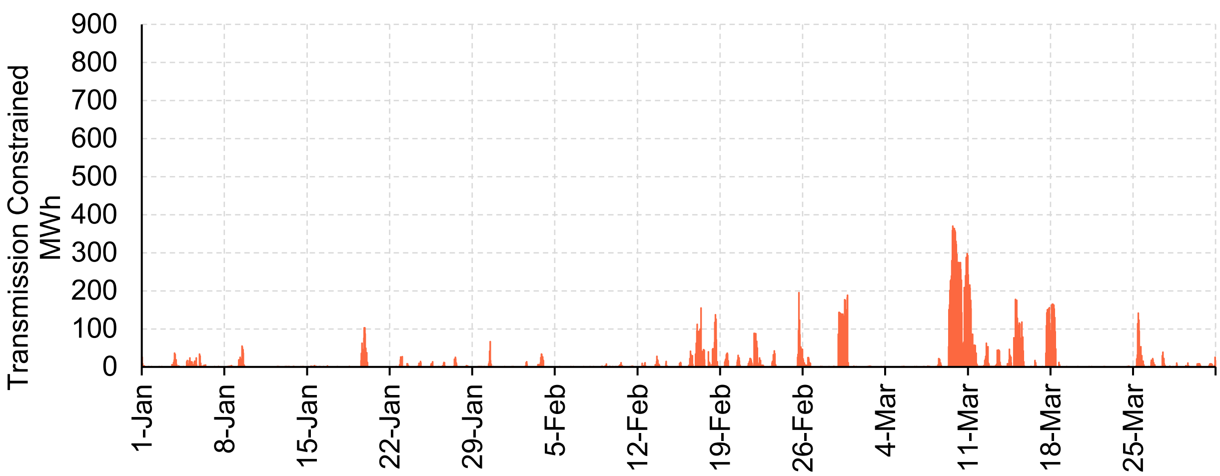
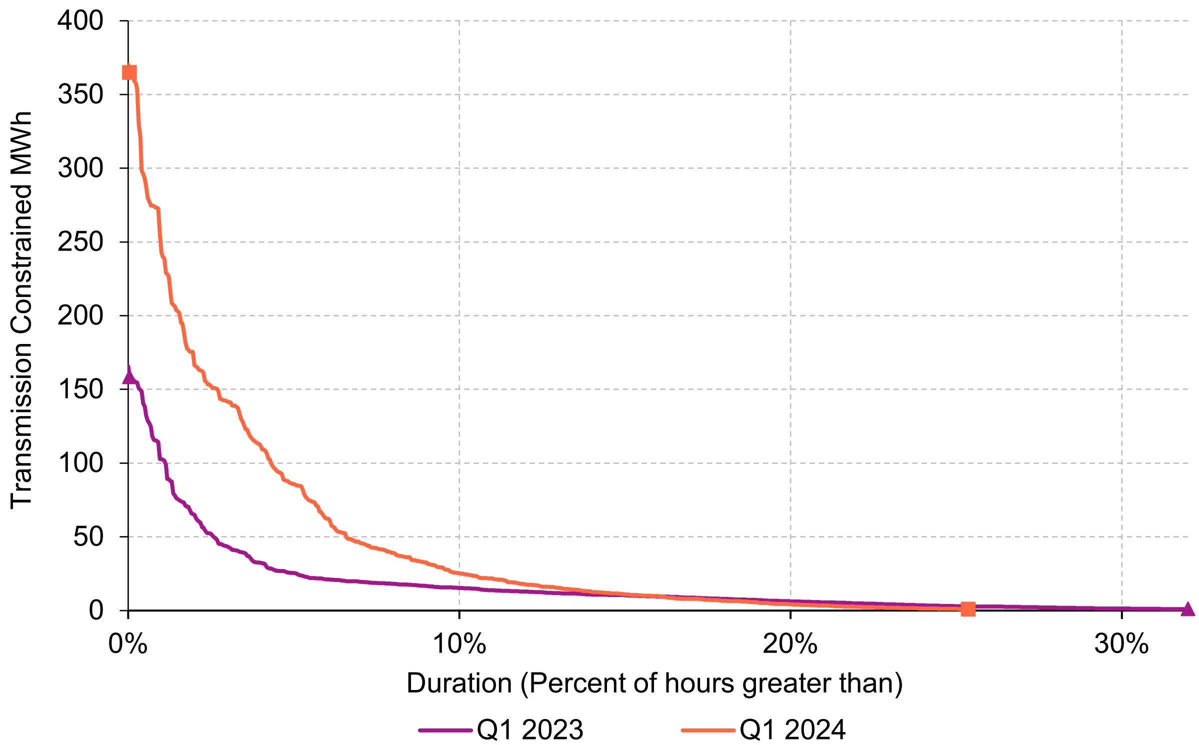


Figure 33 illustrates duration curves of constrained intermittent generation year-over-year. The length of the tails to the right of the duration curves show that the frequency of intermittent constrained down events decreased. There were 560 hours of intermittent constrained down generation greater than 1 MWh in Q1. This is equivalent to just over 23 days, or 25.6% of Q1. In contrast, Q1 2023 experienced 705 hours of intermittent constrained down generation greater than 1 MWh, or approximately a over 29 days or 32.6% of Q1 2023.

The Q1 maximum hourly average volume of intermittent generation constrained down was 370 MW and was reached on March 9th (Figure 32). The Q1 peak was 124% higher than Q1 2023, which was 165 MW. To understand the increasing magnitude of congestion, note that 2% of hours in Q1 had more congestion than the single most congested hour in Q1 2023. The peak event in Q1 2024 was higher, but intermittent constrained down generation over 1 MW occurred more often in Q1 2023.

Figure 33: Duration of wind and solar constraint volume (Q1 2023 and Q1)



Transmission constraints had frequent fluctuations throughout all months, however March experienced the most change and the highest peak. The intermittent constrained down volume in the month of March accounted for 65% of all Q1 volumes. In 29% of March hours there was at least 1 MWh of intermittent constrained down volume.

Examining the peak congestion event in March more closely, the most constrained down generation event occurred on March 9, hour ending 18. At this time, the potential wind generation was over 3,500 MW, indicating a period of high wind (Figure 34). The event most significantly impacted Paintearth Wind Project 1 (108 MW of 198 MW maximum capability constrained), Halkirk Wind Power Facility (90 MW of 150 MW maximum capability constrained) and Garden Plain 1 (77 MW of 130 MW maximum capability constrained). The operation zone was created to mitigate the N-1 loss of 9L46 and contingency overloading on 9L16. These assets were constrained 16 times over the quarter due to this issue or the loss of EATL with contingency overloading on 9L16.

The total constrained down volume for these assets was 17 GWh or 62% of total constrained down volumes in Q1. Halkirk Wind Power Facility 1 was the most constrained over this period, being curtailed by 6.9 GWh, and Paintearth Wind Project 1 was second with 5.6 GWh. Although the peak event occurred on March 9, March 10 also experienced 5.0 GWh of constrained down intermittent generation. There were multiple constrained down generation directives, however these same assets experienced the largest volume of constraints.

Over the period of March 8 to 9 the difference between the constrained SMP and the SMP reached a high of $164/MWh for 4 minutes, which occurred on March 9 at HE 16. However, the subsequent event on March 10 led to larger price differences of over $256/MWh for 19 minutes (over $100/MWh for 113 minutes) (Figure 36).

Figure 34: Potential Wind Generation MW (March 8 to 10, 2024)

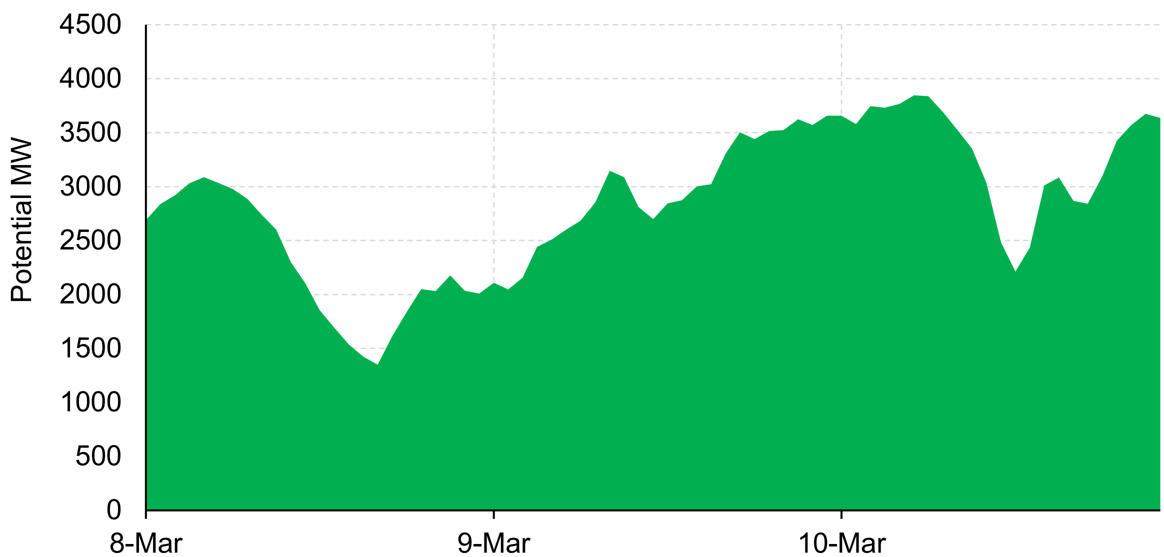


Figure 35: Wind and solar transmission constrained MW (March 8 to 10, 2024)

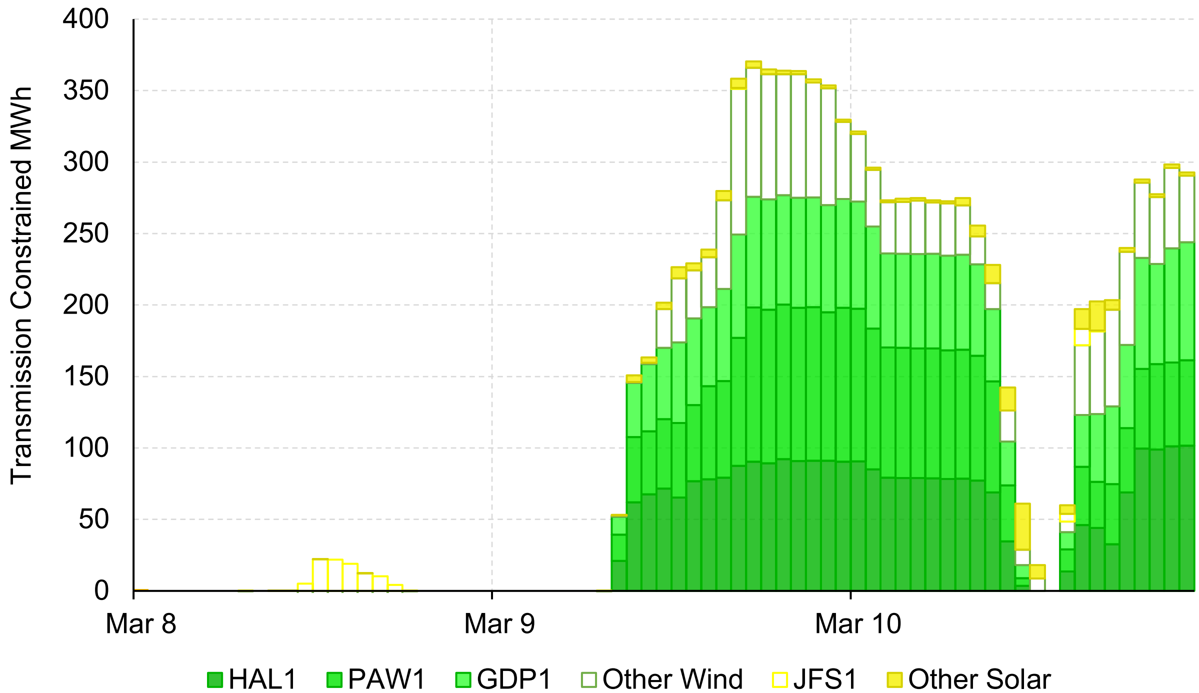
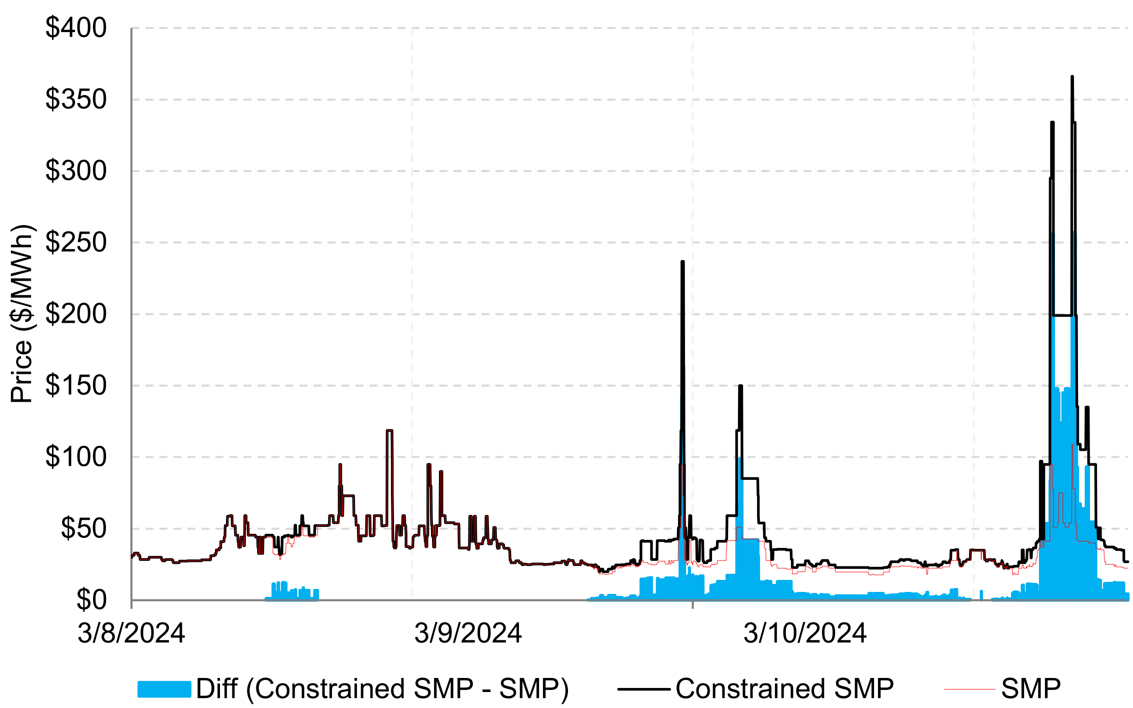


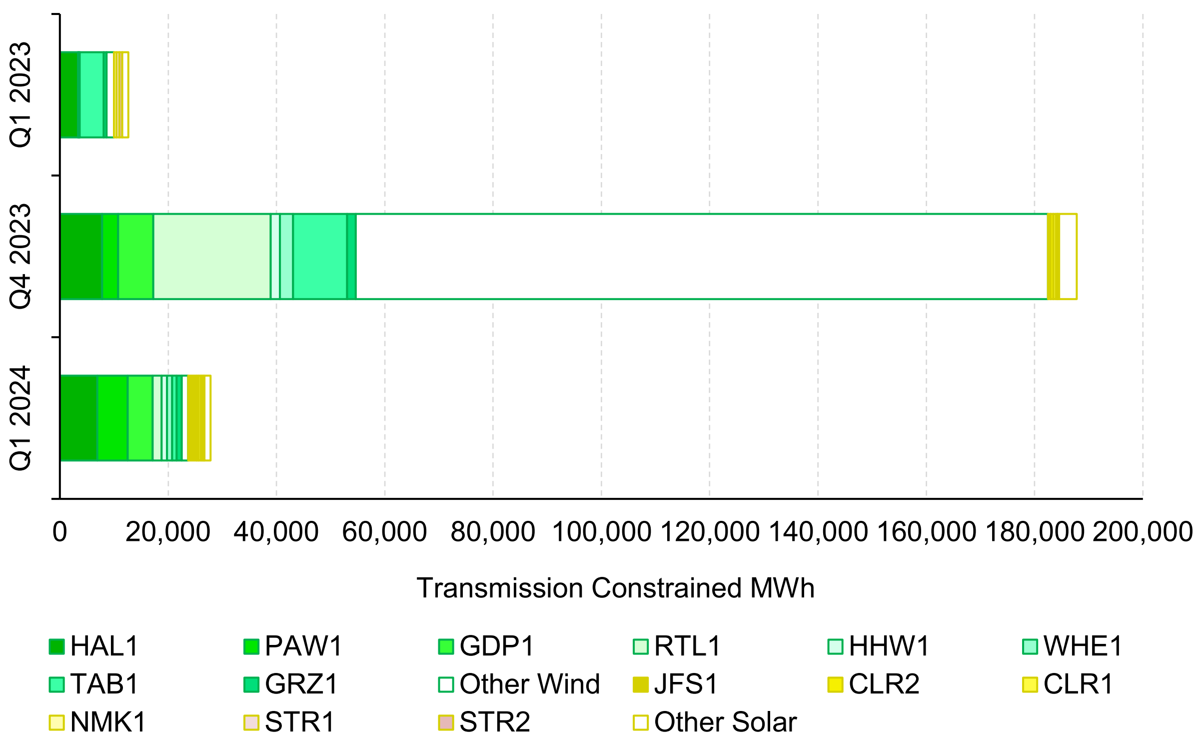
Figure 36: Constrained SMP vs. SMP (March 8 to 10, 2024)



Transmission capability varies throughout the province, and certain regions may experience more congestion than others, often leading to local constraints. Often, wind and solar assets are not constrained uniformly throughout the province. In Q1, the eight most constrained wind assets accounted for 95% of the total constrained down volume but only 25% of total installed wind generation.[19] Halkirk Wind Power Facility, Paintearth Wind Project 1, and Garden Plain 1 were the most constrained wind assets in Q1. These 3 assets represent 11% of Alberta's installed wind capacity, however they accounted for approximately 62% of the wind constrained volume in Q1.

Joffre Solar 1 (25 MW) was the most-constrained solar asset in Q1, with a total of 1,571 MWh constrained. The following five most constrained solar assets have an aggregate maximum capability of 219 MW and were constrained by 1,442 MWh in Q1. The top 6 constrained solar assets account for 13% of the maximum capability of the market but accounted for 72% of solar constrained volumes in Q1. This illustrates the uneven concentration of constraints between assets within Alberta.

Figure 37: Wind and solar transmission constrained MWh by asset (Q1 2023, Q4 2023 and Q1)



[19] 'Other Wind' appears substantially larger for Q4 2023 as compared to the Q4 2023 report due to the change in most congested assets, which are based on the current quarter.

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 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-C and California. Over the quarter, Alberta was a net exporter, primarily driven by large export volumes to BC.

Figure 38 provides the daily average power prices in Alberta, Mid-C, and California (SP-15) over Q1 (shown in Canadian currency). Notably, there were periods of higher pricing in Mid-C and Alberta in mid January, caused by extreme winter storms. The remainder of the quarter saw much less volatility.

Figure 38: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q1)

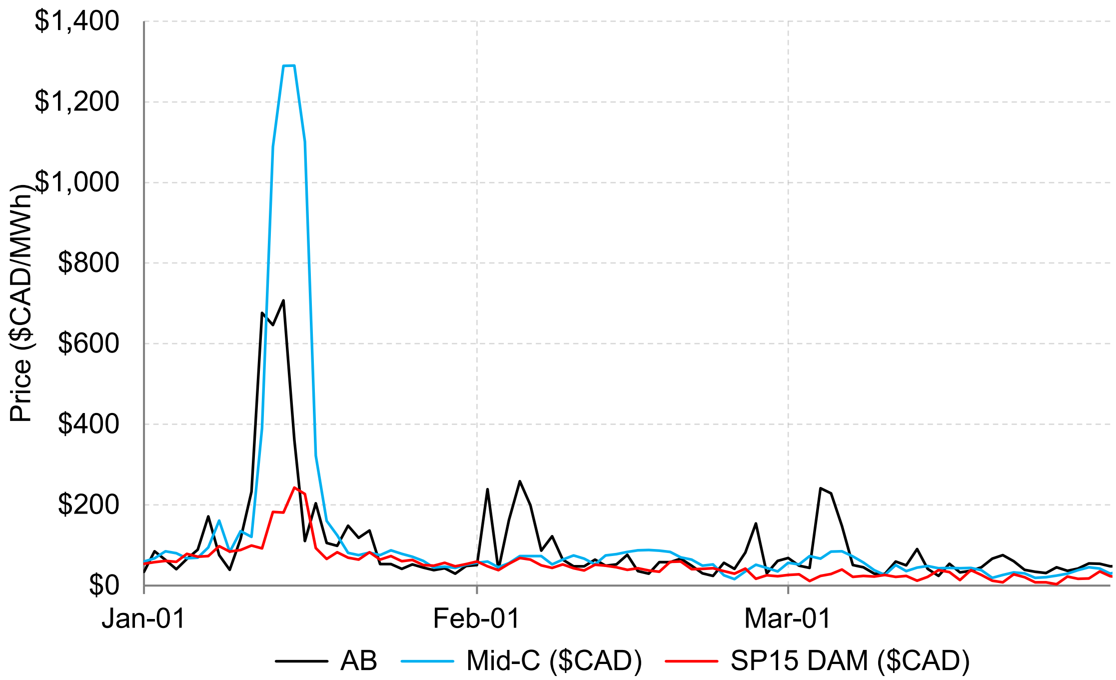
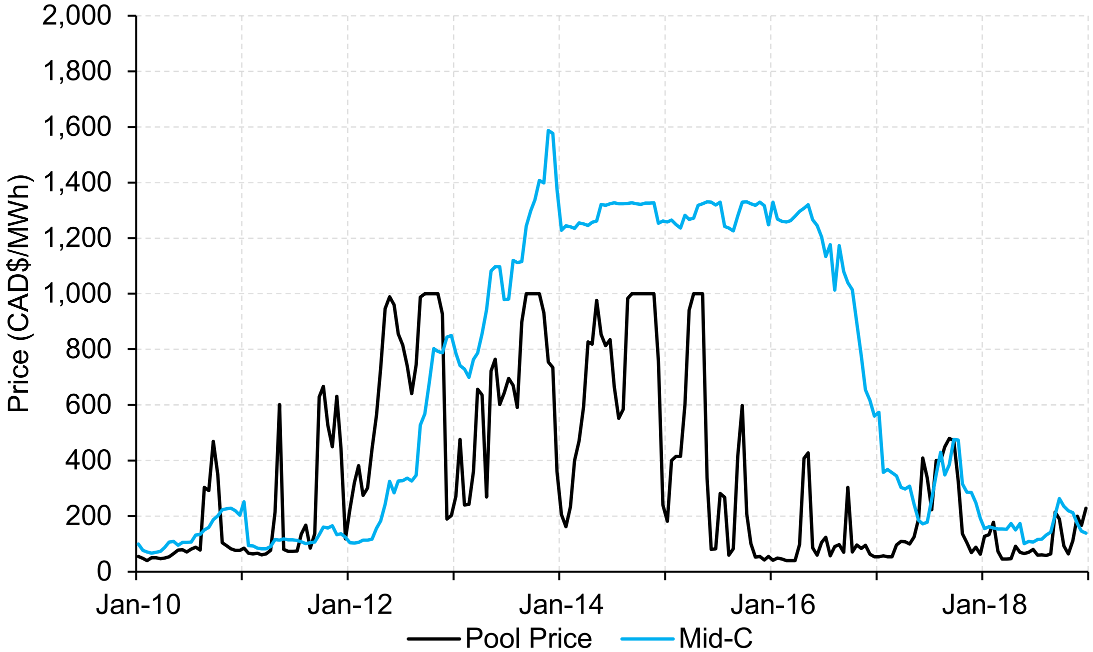


Figure 39 shows hourly power prices in Alberta and Mid-C over January 10 to 18, 2024. Notably, Mid-C prices rose significantly on January 12, approaching a maximum of CAD$1,600/MWh on January 13, with sustained high prices through January 16. Balancing Authorities[20] (BAs) in the US Northwest experienced drastically low temperatures which led to record high demand in certain jurisdictions as well as ensuing reliability issues. Over the period of January 13 to 15, EEA events occurred in four BAs across the US Northwest.[21]

[20] Balancing authorities are the responsible entities that integrate resource plans ahead of time, maintain demand and resource balance within a Balancing Authority Area, and support interconnection frequency in real time (NERC).

[21] WRAP: Assessment of January 2024 Cold Weather Event

Figure 39: Hourly power prices in Alberta and Mid-C (January 10 to 18, 2024)



Alberta had significant exports over the BC line and on average across the interties in total. Figure 40 shows daily average intertie volumes for BC/MATL. Over the quarter, flows on the BC intertie averaged 380 MW of exports, with the highest net exports in February averaging 403 MW. In Q1 2023, the BC intertie averaged 199 MW of exports, with the highest level of net exports observed in January averaging 362 MW (Table 6). BC continues to export from Alberta due to the low water year and the relatively low pool prices in Alberta.

Flows on MATL averaged 59 MW of imports over Q1 with the highest net imports observed in March at an average of 103 MW (Table 6).

Approximately 24 GWh of imports from MATL were wheeled to BC, as shown in Figure 40. In total, net exports on BC/MATL averaged 322 MW in Q1, a 113% increase relative to average net exports of 151 MW in Q1 2023.

Table 6: Average net import (+ve) and export (-ve) volumes for Q1 2023 and Q1 2024

	2023				2024			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
January	-362	-31	137	-256	-372	-10	18	-364
February	-192	63	145	15	-403	84	44	-275
March	-41	114	148	221	-367	103	39	-226
Q1	**-199**	**48**	**143**	**-7**	**-380**	**59**	**33**	**-288**

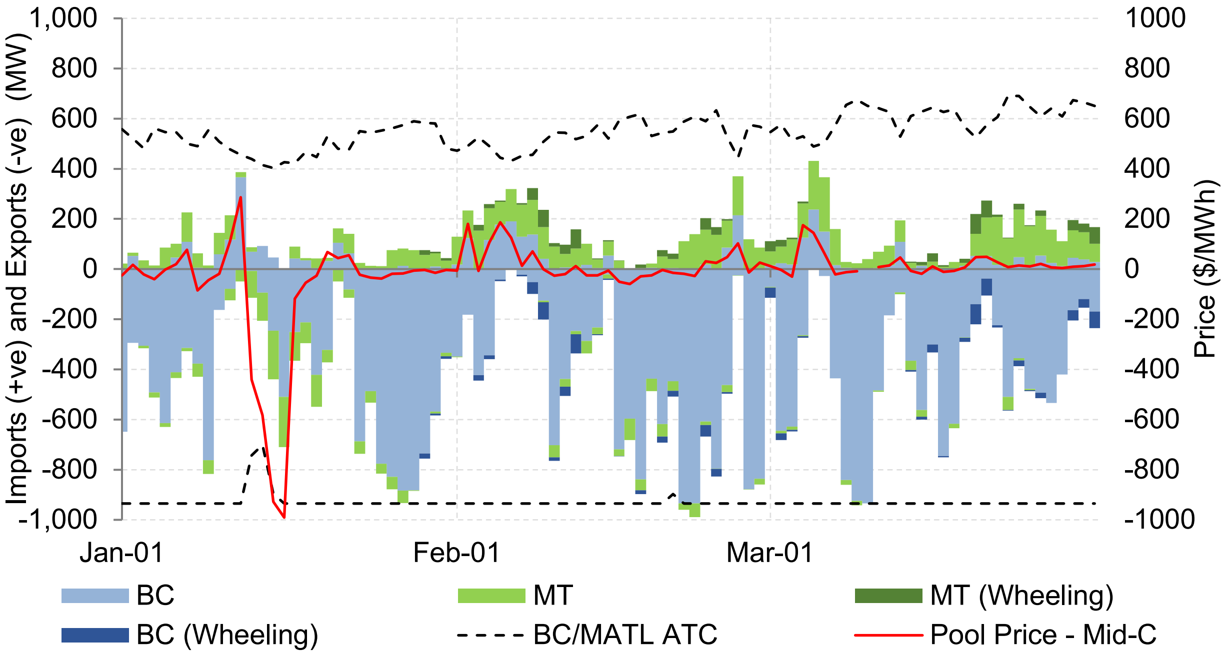


Figure 41 shows the daily average intertie volumes for Saskatchewan. Over the quarter, flows on the SK intertie averaged 33 MW of imports to Alberta. In Q1 2023, the SK intertie averaged 143 MW of imports (Table 6). On February 5, 2024, the capability of the SK intertie returned to 153 MW; it has been largely derated to 90 MW since April 12, 2023.

Figure 41: Daily average import (+ve) and export (-ve) volumes on SK, and the average pool price (Q1)

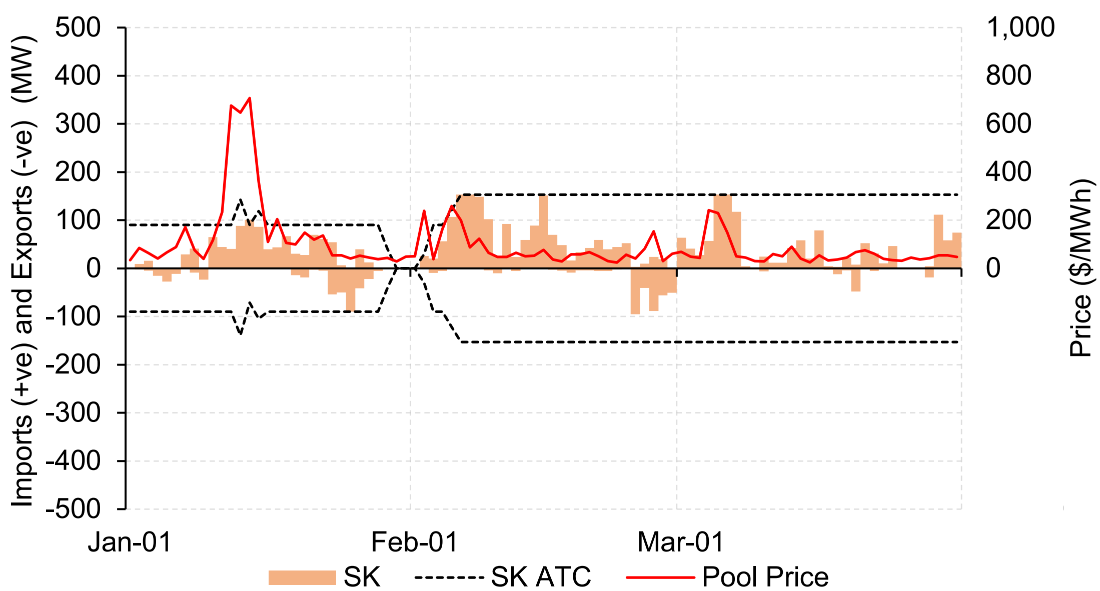


Figure 42 and Figure 43 show emergency imports[22] that were observed during the January 12 to 15 EEA events. The cumulative energy denoted as emergency transactions totaled 965 MWh from BC and 454 MWh from Saskatchewan.

Figure 42: BC/MATL emergency imports (January 12 to 15)

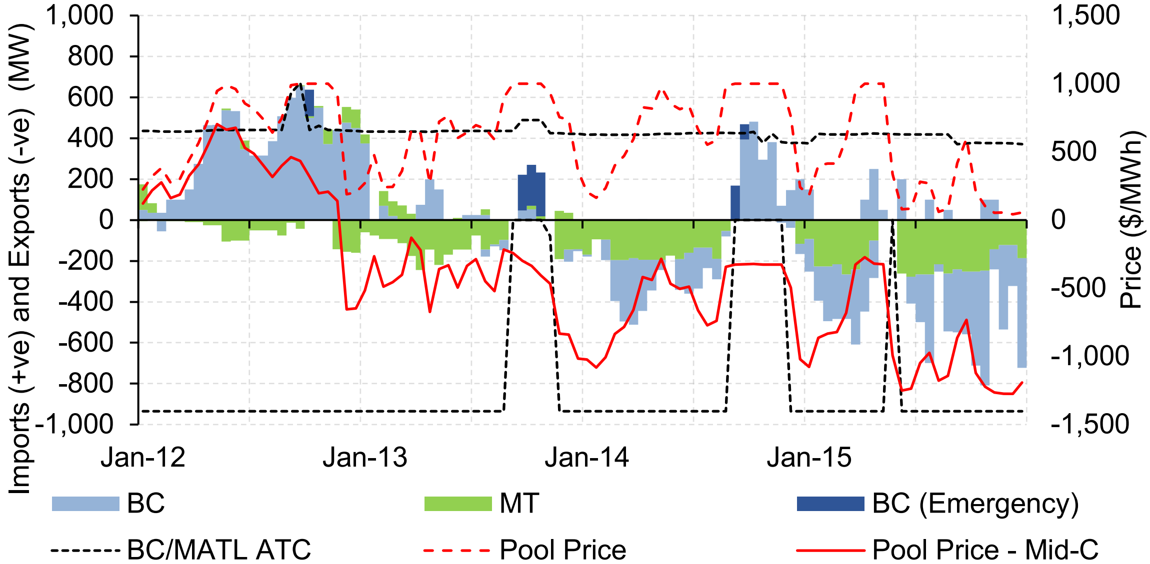
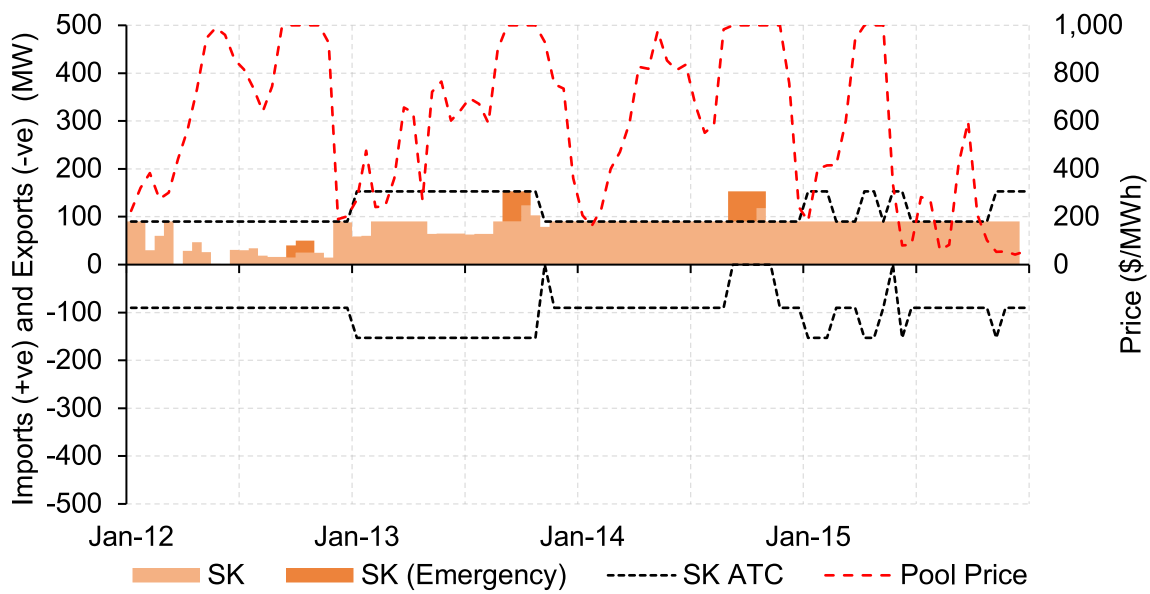


Figure 43: SK emergency imports (January 12 to 15)



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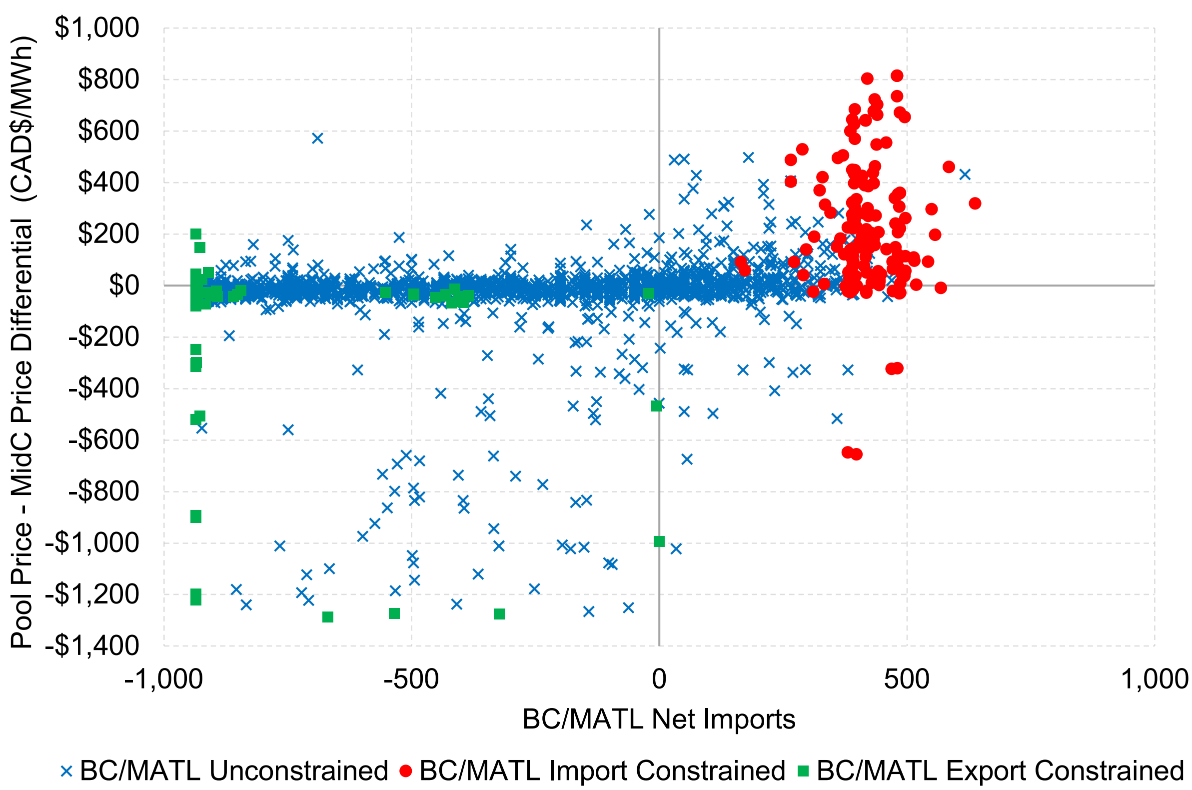
[22] Supply that is directed by the System Controller to meet an emergency event.

Figure 44 shows a scatterplot of the price differential between Alberta and Mid-C against the net flow on BC/MATL for each hour in Q1. 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 on BC/MATL were at or above import capability, meaning that BC/MATL was import constrained (shown in red). Constrained observations around the 400 MW range represent the normal operation of the interties. Values below this range are generally the result of reliability curtailments. The import capability on BC/MATL was lowered in March 2023 when the AESO increased the amount of LSSi required. BC/MATL imports were constrained for 156 hours in Q1 or 7% of the time. While import constrained, the price differential between Alberta and Mid-C averaged $215/MWh and import capability averaged 441 MW.

There were also hours where net export bids were at or above export capability, meaning that BC/MATL was export constrained (shown in green). There is a cluster of constrained observations at -935 MW, which is the normal BC/MATL export capability. Values lower than this are generally the result of reliability curtailments. Constrained values at or near-zero are curtailments associated with the EEA events on January 13 and 15, as well as a BC/MATL outage on February 21. BC/MATL exports were constrained for 266 hours or 12% of the time in Q1. While export constrained, the differential between Alberta and Mid-C averaged -$83/MWh and export ATC averaged 925 MW.

Figure 44: Alberta and Mid-C price differential and net BC/MATL flows (Q1)



For some hours in Q1, heavy intertie flows occurred despite prices settling in the opposite direction. For example, on January 12 in HE 23 and HE 24 net imports through BC/MATL were 398 MW and 381 MW, although the differential between Alberta and Mid-C in these hours was -$655/MWh and -$648/MWh, respectively. In the preceding hours of that day the differential averaged $372/MWh. For HE 23 pool price fell to $190/MWh from $921/MWh in HE 22 due to falling demand and increases in imports.

Additionally, on February 29 in HE 20 and HE 21 net exports through BC/MATL were 820 MW and 690 MW, although the differential between Alberta and Mid-C in these hours was $160/MWh and $573/MWh, respectively. The increase in pool price over these hours was caused by a drop off in wind generation. In the preceding 36 hours the price differential averaged -$7/MWh.

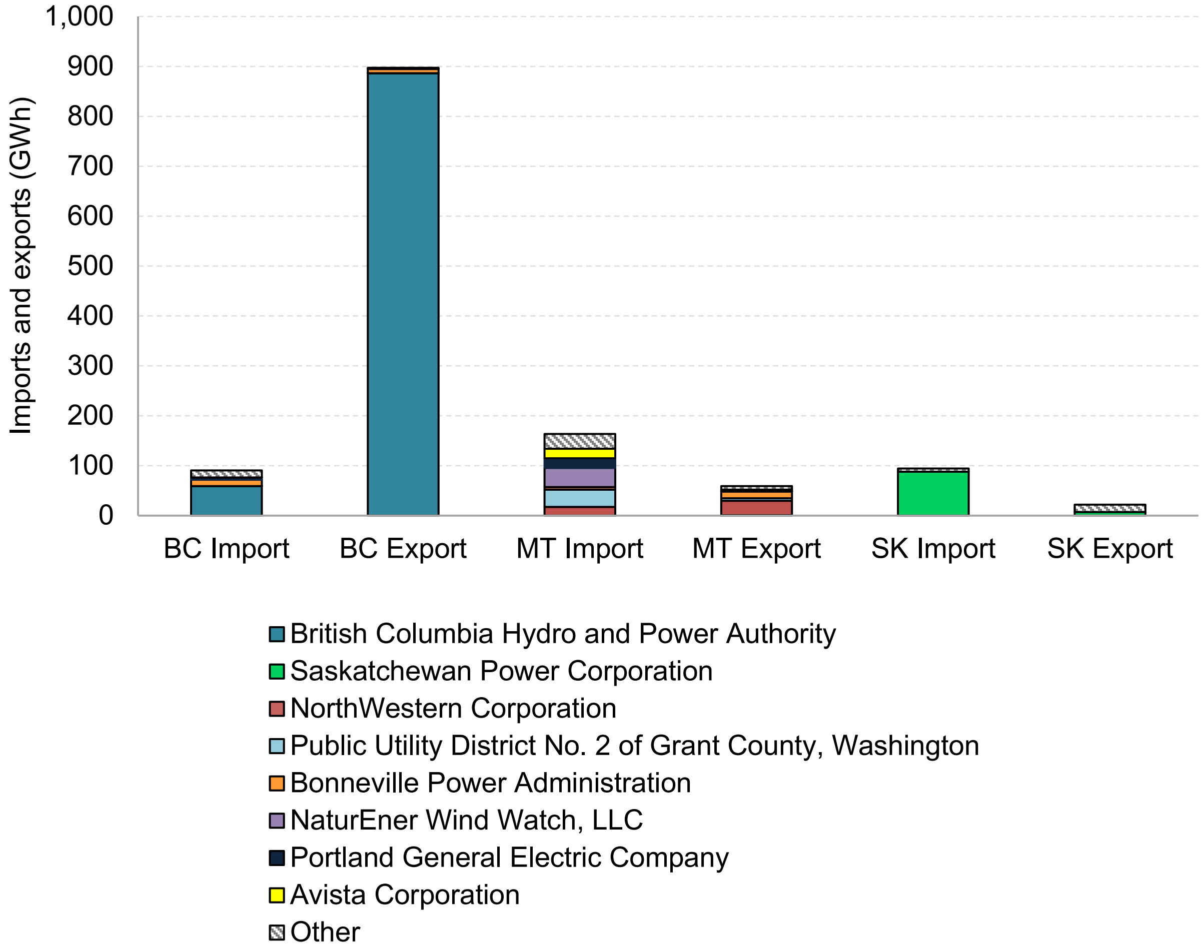
Figure 45 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD). The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered to.

The Balancing Authority regions directly connected with Alberta have a high share of import and export flows. For imports on the BC intertie, approximately 65% originated from BC, 30% from the US Northwest, and 5% from California. For exports on the BC intertie, 99% was delivered to BC, and 1% to the US Northwest.

For imports through MATL, 90% originated from the US Northwest and 9% from California. For exports on MATL 96% was delivered to the US Northwest, 3% to California, and 1% to BC.

For imports through the SK intertie, 93% originated from Saskatchewan, 5% from the Midcontinent Independent System Operator, and 1% from Ontario. For exports through the SK intertie, 41% was delivered to the Midcontinent Independent System Operator, 34% to Saskatchewan, 24% to the Southwest Power Pool, and 1% to Manitoba.

Figure 45: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q1)[23]



[23] This includes the highest eight Balancing Authorities by volume. Wheeled volumes are not included in the figure, these volumes represent 24 GWh from Montana to BC.

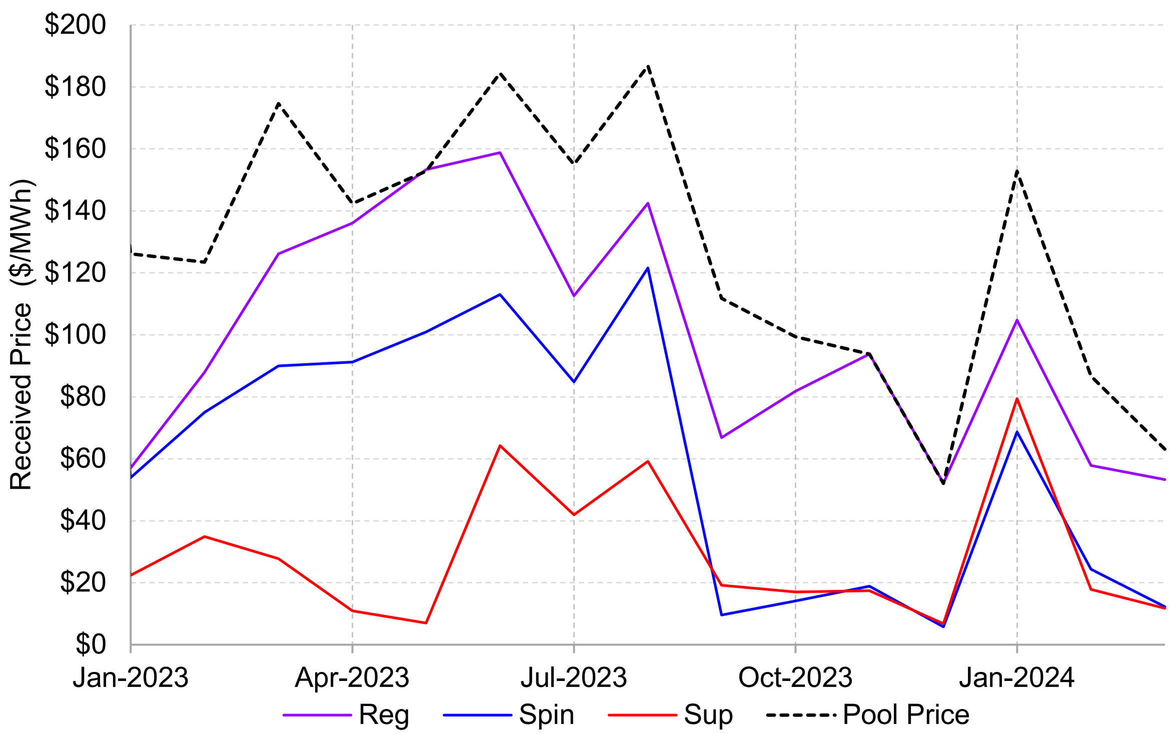
3 OPERATING RESERVE MARKETS

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 Operating reserve received prices

Received prices for operating reserves (OR) are calculated by indexing pool prices with the equilibrium prices set in OR auctions. Figure 46 illustrates monthly average received prices by OR product. Year-over-year, received prices for regulating reserves and spinning reserves decreased alongside pool prices, while the received price for supplemental reserves increased (Table 7). The increase in supplemental received prices year-over-year was due to a decrease in participation by loads and an increase in offer prices by the marginal units in the supplemental market.

Figure 46: Average received price for active spinning, supplemental, and regulating reserves (January 2023 to March 2024)



Quarter-over-quarter, the average received prices for supplemental and spinning reserves increased by $22/MWh, which was in-line with the increase in average pool price (Table 8). For regulating reserves, however, received prices decreased from $76/MWh to $72/MWh relative to Q4 2023 despite the higher pool prices. This decline in received prices for regulating reserves was driven by below average monthly received prices in February and March. While procured volumes for all regulating reserve products remained relatively constant, the average cleared offer prices declined indicating more competition, resulting in lower prices.

Table 7: Average received price for active regulating, spinning and supplemental reserves (Q1 2023 and Q1 2024)

	Regulating Reserves	**Spinning Reserves**	**Supplemental Reserves**	**Pool Price**
Q1 2023	$90	$73	$28	$141
Q1 2024	$72	$35	$36	$101
Difference	*($18)*	*($38)*	*$8*	*($40)*

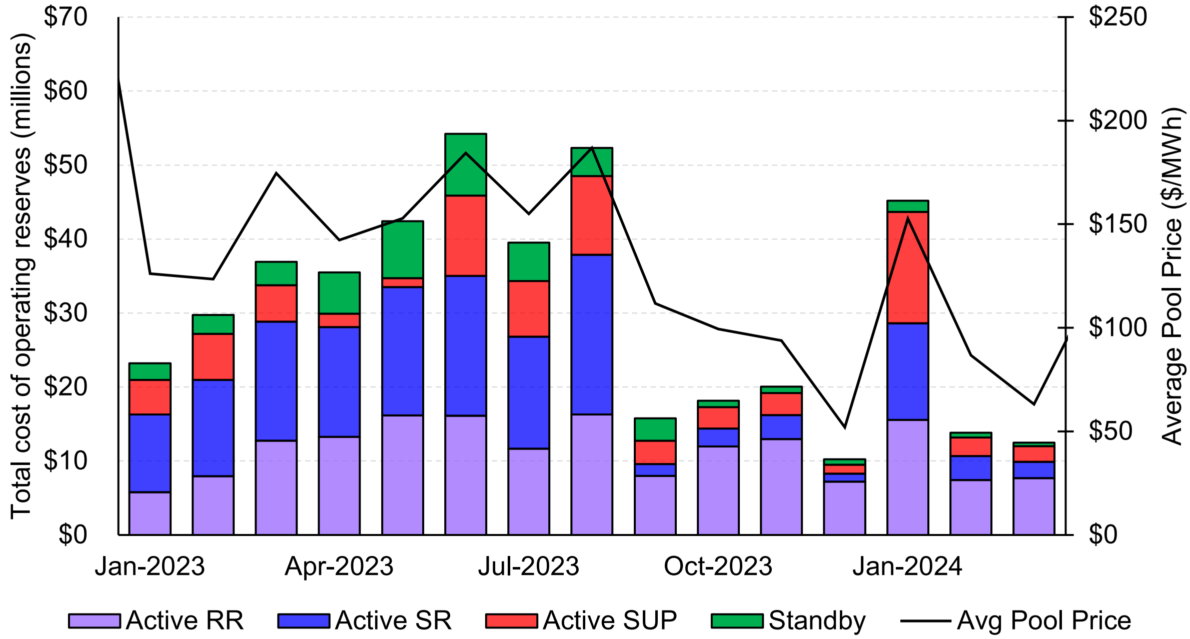
Table 8: Average received price for active regulating, spinning and supplemental reserves (Q4 2023 and Q1 2024)

	Regulating Reserves	**Spinning Reserves**	**Supplemental Reserves**	**Pool Price**
Q4 2023	$76	$13	$14	$82
Q1 2024	$72	$35	$36	$101
Difference	*($4)*	*$22*	*$22*	*$19*

3.2 Total operating reserve costs

Total operating reserve costs increased by 48% following a mild Q4 2023, with most of this increase being attributed to active costs (Figure 47). While there was a steep increase in operating reserve costs due to the January cold snap, year-over-year costs decreased by 20%, as we saw a decline in both active and standby reserve costs, largely due to lower pool prices. 63% of all Q1 2024 operating reserve costs were incurred in January. The volume of active operating reserves utilized throughout Q1 remained relatively consistent when compared to the previous quarter.

Figure 47: Total cost of operating reserves by month (January 2023 to March 2024)



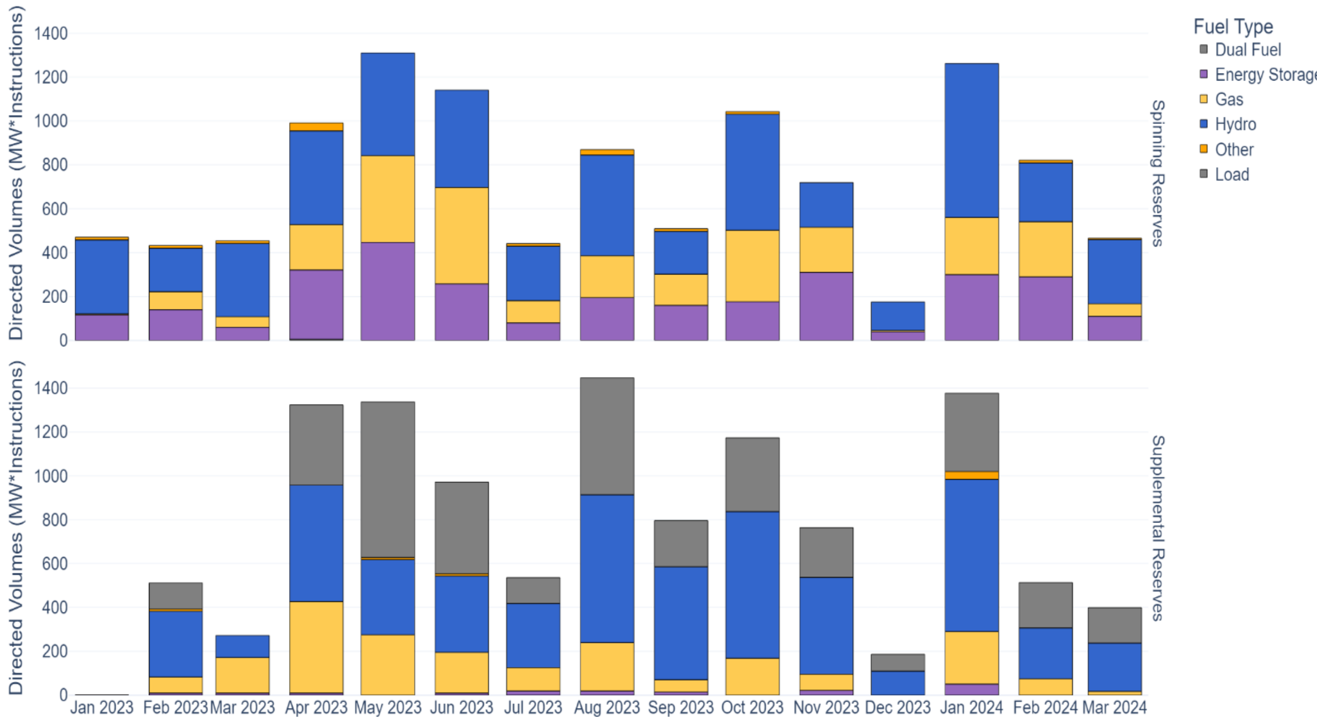
3.3 Operating reserve directives

The combination of low temperatures, insufficient levels of intermittent generation, and thermal asset outages resulted in several EEA events in mid-January. As a result, the system saw an increase in the directed volumes of operating reserves by the AESO (Figure 48). A more detailed look at these events will be addressed in a future report by the MSA.

In Q1 the AESO directed on 2,549 MW of spinning reserve to provide energy, with roughly 50% of all directives occurring in January. Half of all directives in Q1 were issued to hydro assets, with an additional 27% being issued to energy storage assets, and the remainder issued largely to natural gas.

Approximately 60% of all directed supplemental reserve volumes in Q1 (2,290 MWs) were directed in January. Supplemental reserves continue to be largely provided by hydro and loads. Throughout Q1, 50% of supplemental reserve directives were issued to hydro, 32% to loads, 14% to gas, and the remaining 4% were issued to energy storage and assets with fuel types classified as other.

Figure 48: Monthly directed volumes of spinning and supplemental reserves (January 2023 to March 2024)



3.4 Standby activations

Compared to Q4 2023, on-peak spinning and supplemental reserves both saw an increase in the use of active volumes in Q1, with the largest increase occurring in January (Figure 49 and Figure 50). The average procured volume of active spinning and supplemental reserves for on-peak was 250 MW for the month of January. This was an increase from 242 MW in December, but a slight decrease from the January 2023 average of 253 MW.

Active regulating reserve volumes remained constant throughout Q1 (Figure 51). Standby regulating reserves were activated on six days in Q1 as activation rates for regulating reserves averaged 5%, a decrease from 15% in the previous quarter.

Activation rates for spinning and supplemental reserves both increased quarter-over-quarter, with spinning reserve activations climbing by 3 percentage points to 23%, and supplemental reserves increasing from an activation rate of 22% to 23%.

Figure 49: Active, standby, and activated standby volumes for on-peak spinning reserves

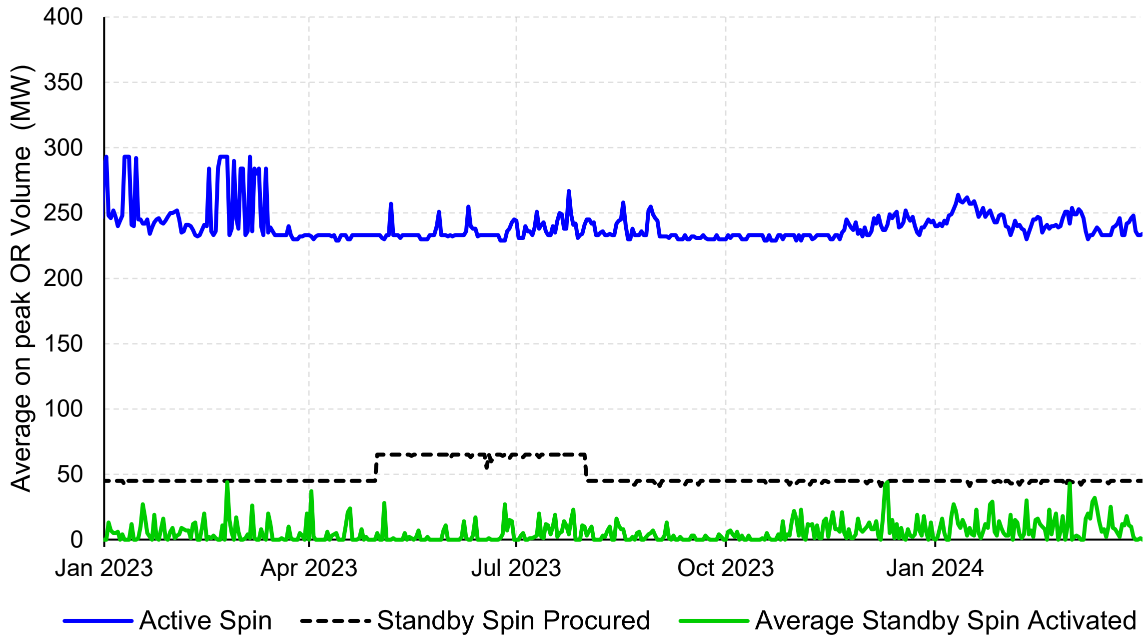


Figure 50: Active, standby, and activated standby volumes for on-peak supplemental reserves

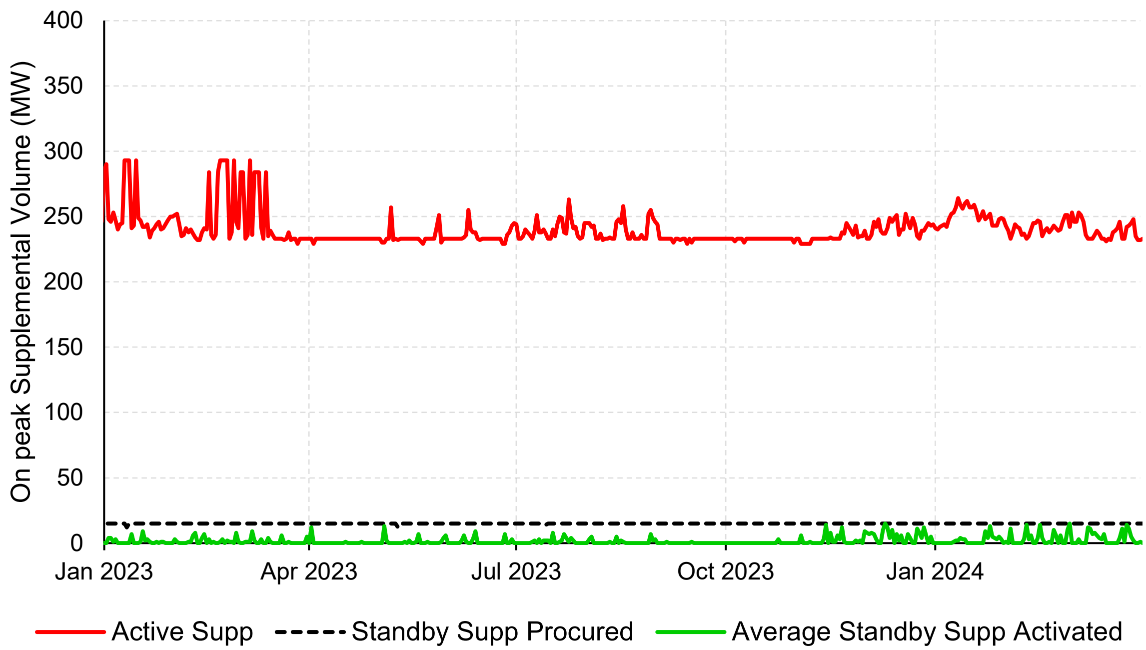
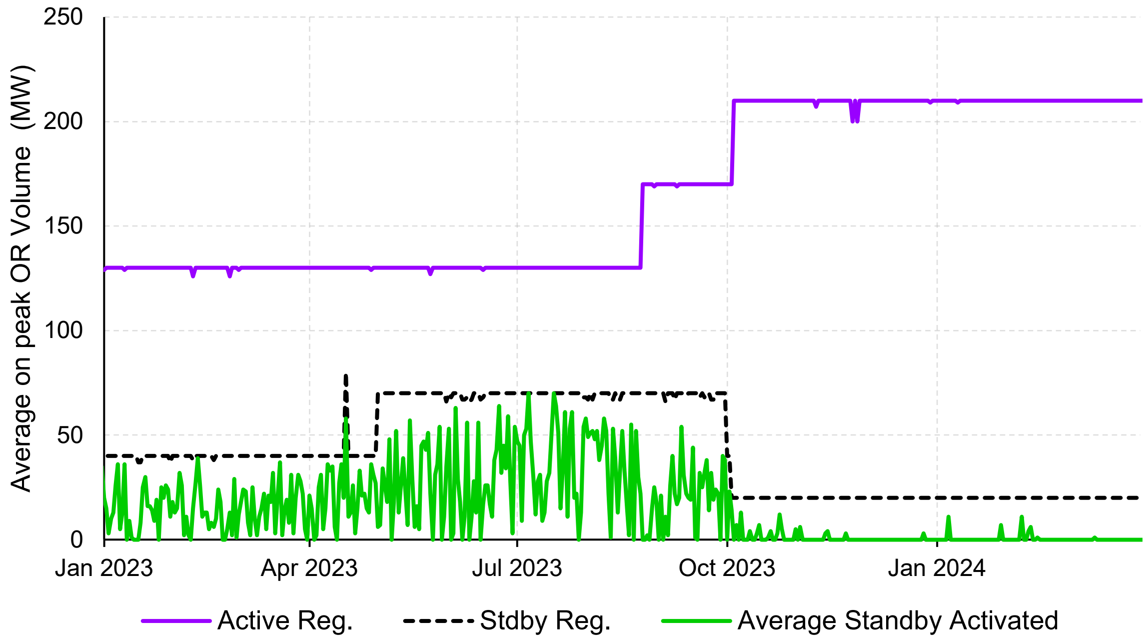


Figure 51: Active, standby, and activated volumes for on-peak regulating reserves



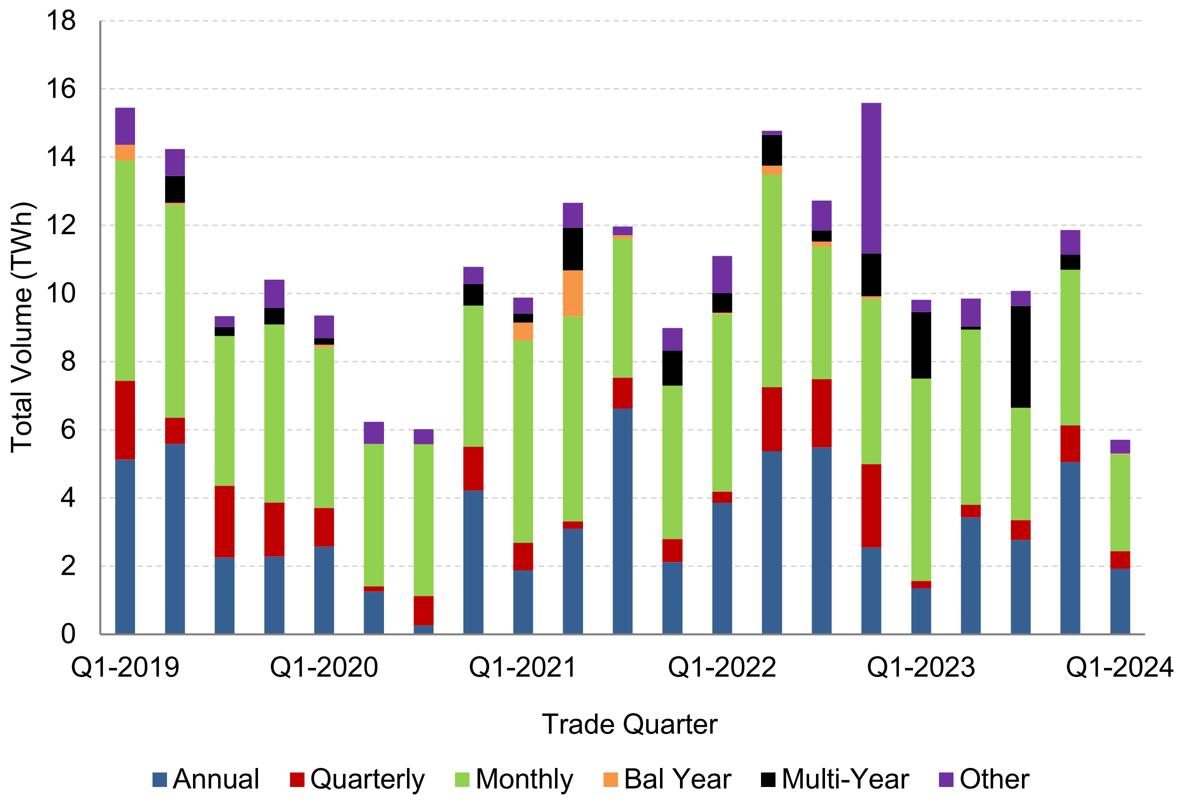
4 THE FORWARD MARKET

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.[24]

4.1 Forward market volumes

Figure 52 illustrates the total volume of power traded by quarter since Q1 2019. Total volume is the total amount of power traded over the duration of a financial contract. The total volume traded on ICE NGX or via brokers was relatively low in Q1 at 5.71 TWh. Total volumes over a quarter have not been this low since Q2 and Q3 of 2020 when volumes on ICE NGX and brokers were 5.25 TWh and 5.39 TWh, respectively. Trade volumes in Q2 and Q3 of 2020 were lowered by uncertainty around the COVID-19 pandemic.

Figure 52: Total trade volumes by term and trade quarter (Q1 2019 to Q1 2024)



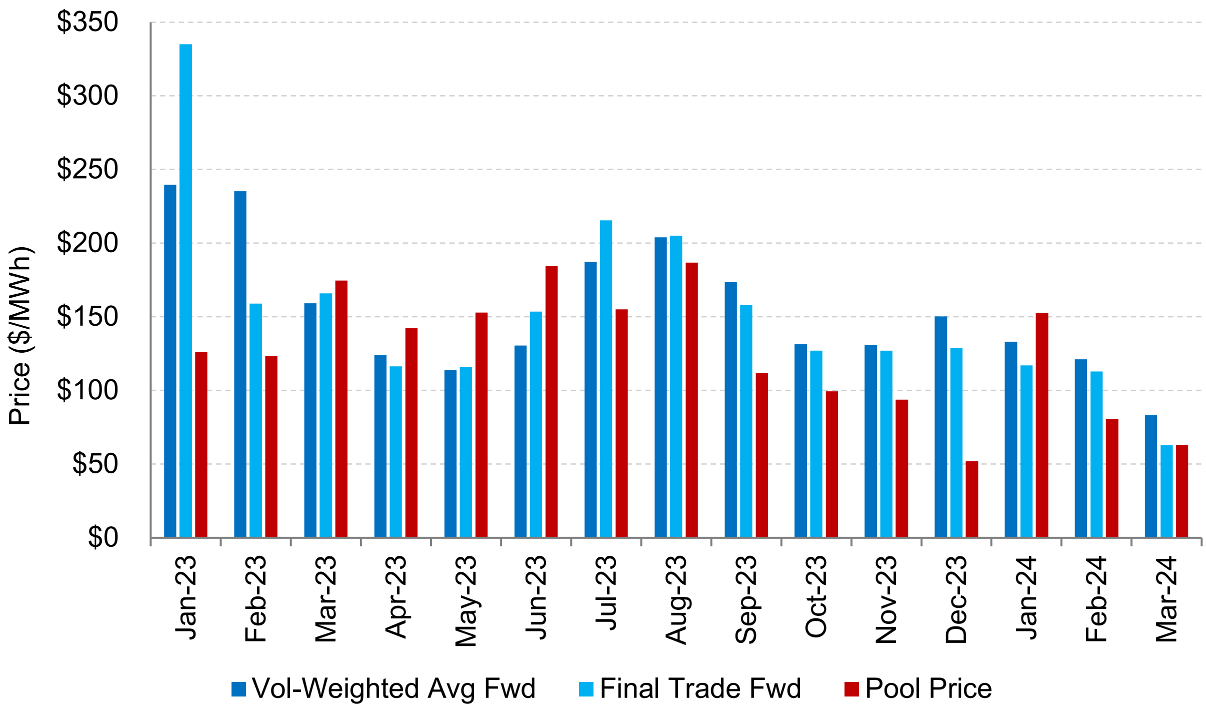
[24] The MSA's analysis in this section incorporates trade data from ICE NGX and two over the counter (OTC) brokers: Canax and Velocity Capital. Data from these trade platforms are routinely collected by the MSA as part of its surveillance and monitoring functions. Data on direct bilateral trades up 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 53 compares monthly forward prices with realized pool prices since January 2023. Forward prices for January and February were lower this year relative to 2023. For example, the volume-weighted average forward price for January this year was $133/MWh compared with $240/MWh for January 2023. Forward prices were lower this year because of increased supply, lower prices in neighbouring jurisdictions, and less exercise of market power.

The pool price for January came in at $153/MWh, slightly higher than forward market expectations. This was largely due to the cold-weather event in mid-January which increased demand and lowered wind generation, causing higher pool prices. In February and March, pool prices came in below the volume-weighted average forward prices in part because of relatively mild weather conditions.

Figure 53: Monthly forward prices compared to realized pool prices (January 2023 to March 2024)



4.3 Trading of annual products

Natural gas prices increased slightly over the quarter, putting upward pressure on the input costs for power generators (Table 9). The declining power prices and increasing natural gas costs meant that annual operating margins declined over the quarter. For example, using a 10 heat rate and including carbon costs, the operating margin for CAL25 declined from $16 to $7/MWh and the operating margin for CAL26 declined from $11 to -$1/MWh (Table 9).

Figure 54: Annual power prices over time (October 1, 2023 to March 31, 2024)

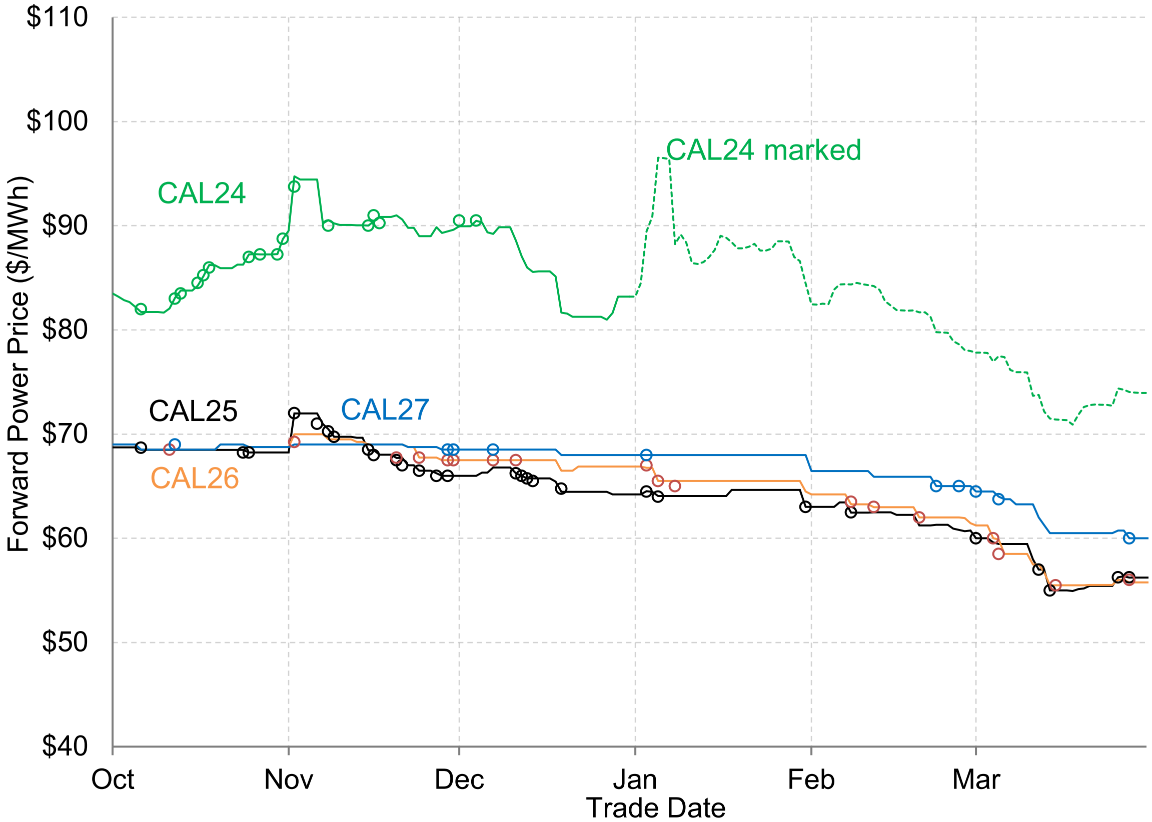


Table 9: Forward power and natural gas price changes over Q1[25]

Contract	Power price ($/MWh)			Gas price ($/GJ)			Operating margin ($/MWh)		
	Dec 31	**Mar 31**	**% Chg**	**Dec 31**	**Mar 31**	**% Chg**	**Dec 31**	**Mar 31**	**% Chg**
CAL24 (marked)	$83	$74	-11%	$1.92	$1.94	1%	$49	$40	-19%
CAL25	$64	$56	-12%	$2.99	$3.11	4%	$16	$7	-57%
CAL26	$67	$56	-17%	$3.43	$3.51	2%	$11	($1)	-111%
CAL27	$68	$60	-12%	$3.42	$3.51	3%	$8	($1)	-110%
CAL28	$69	$61	-12%	$3.34	$3.41	2%	$5	($3)	-162%

[25] The operating margin figures assume a heat rate of 10 GJ/MWh and consider the carbon costs associated with an emissions intensity of 0.54 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 Q1 was 24% higher than last year, due to the Rate Cap of 13.50 ¢/kWh on RRO rates during Q1 last year. While RRO rates in January and February showed a year-over-year increase of 42% and 32% respectively, RRO rates in March were 2% lower than last year's capped March rate (Table 10). The uncapped RRO rates in Q1 2023 were 60% higher than this year on average. The RRO rates shown in Table 10 include the collection rates.[26] The collection rates increased the RRO rates in January, February, and March by around 2.2 ¢/kWh, 2.6 ¢/kWh, and 2.8 ¢/kWh respectively.

Table 10: Monthly retail market summary for Q1 (Residential customers)

		2023	2024	Change
RRO (Avg ¢/kWh)	Jan	13.50	19.11	42%
	Feb	13.50	17.89	32%
	Mar	13.50	13.19	-2%
	Q1	**13.50**	**16.70**	**24%**
DRT (Avg $/GJ)	Jan	6.43	2.11	-67%
	Feb	3.45	4.25	23%
	Mar	2.54	1.77	-30%
	Q1	**4.16**	**2.68**	**-36%**
Competitive Variable Electricity Rate (Avg. ¢/kWh)	Jan	14.23	17.00	19%
	Feb	13.94	9.49	-32%
	Mar	18.77	7.52	-60%
	Q1	**15.70**	**11.38**	**-28%**
Competitive Variable Natural Gas Rate (Avg. $/GJ)	Jan	4.58	3.38	-26%
	Feb	3.64	2.71	-26%
	Mar	3.98	2.71	-32%
	Q1	**4.08**	**2.94**	**-28%**
Expected Cost, 3-Year Electricity Contract (Avg. ¢/kWh)	Jan	11.98	7.48	-38%
	Feb	10.54	6.86	-35%
	Mar	10.37	6.15	-41%
	Q1	**10.98**	**6.83**	**-38%**
Expected Cost, 3-Year Natural Gas Contract (Avg. $/GJ)	Jan	3.80	3.12	-18%
	Feb	3.36	3.09	-8%
	Mar	3.86	3.25	-16%
	Q1	**3.68**	**3.15**	**-14%**

The average residential Default Rate Tariff (DRT) rate in Q1 was 36% lower than last year (Table 10) due to declining natural gas prices. During Q1, the DRT rate was lowest in March and highest in February. The average DRT rate in Q1 did not change notably relative to Q4 2023.

The competitive variable electricity rates faced by residential customers were 28% lower year-over-year on average. The variable electricity rate in January 2024 was 17.00 ¢/kWh, 19% higher than January 2023. However, lower variable rates in February and March reduced the quarterly

[26] 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

average (Table 10). Competitive variable natural gas rates declined by 28% year-over-year and by 8% relative to Q4 2023.

Retailers' expected cost of providing 3-year fixed rate electricity contracts in Q1 was 38% lower year-over-year and 15% lower than in Q4 2024 as forward power prices declined. The expected cost of providing 3-year fixed rate natural gas contracts fell by 14% year-over-year and 5% relative to Q4 2023.

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 Q4 2023.

5.2.1 Regulated retailer customer losses

Q4 2023 experienced yet another significant decline of RRO residential customers after a record decline in Q3 2023. The total number of residential RRO customers fell by around 38,000 in Q4 2023 (Figure 55). In continuation of the trends observed in August and September, October witnessed a relatively high amount of RRO customer loss. Around 32,500 residential customers left the RRO in October while 11,600 customers joined (Figure 56). However, the magnitude of the customer losses declined in November and December when 21,000 and 15,000 customers left the RRO, respectively. The total RRO customer loss in Q4 2023 was 68,950 while the RRO customer gains were around 31,000, which is around 6,000 less than customer gains in Q3 2023 (Figure 56).

Figure 55: RRO customer net losses, residential customers (Q1 2021 to Q4 2023)

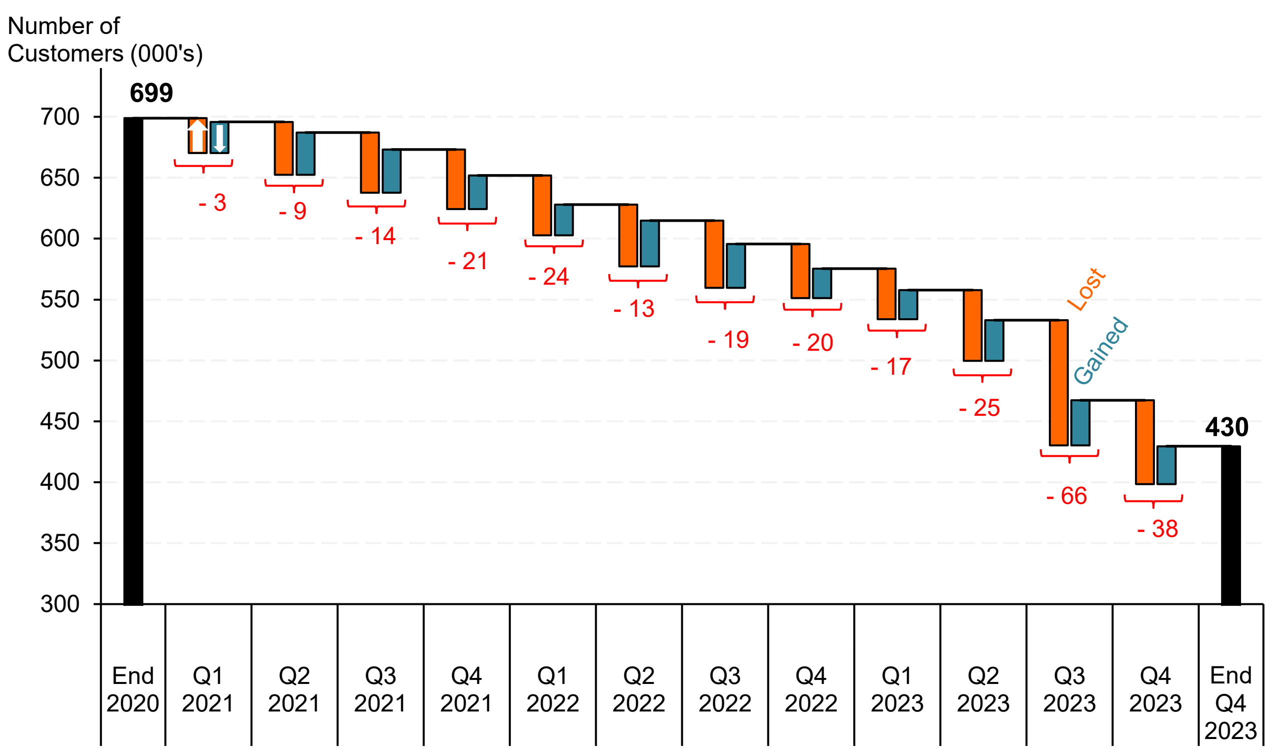
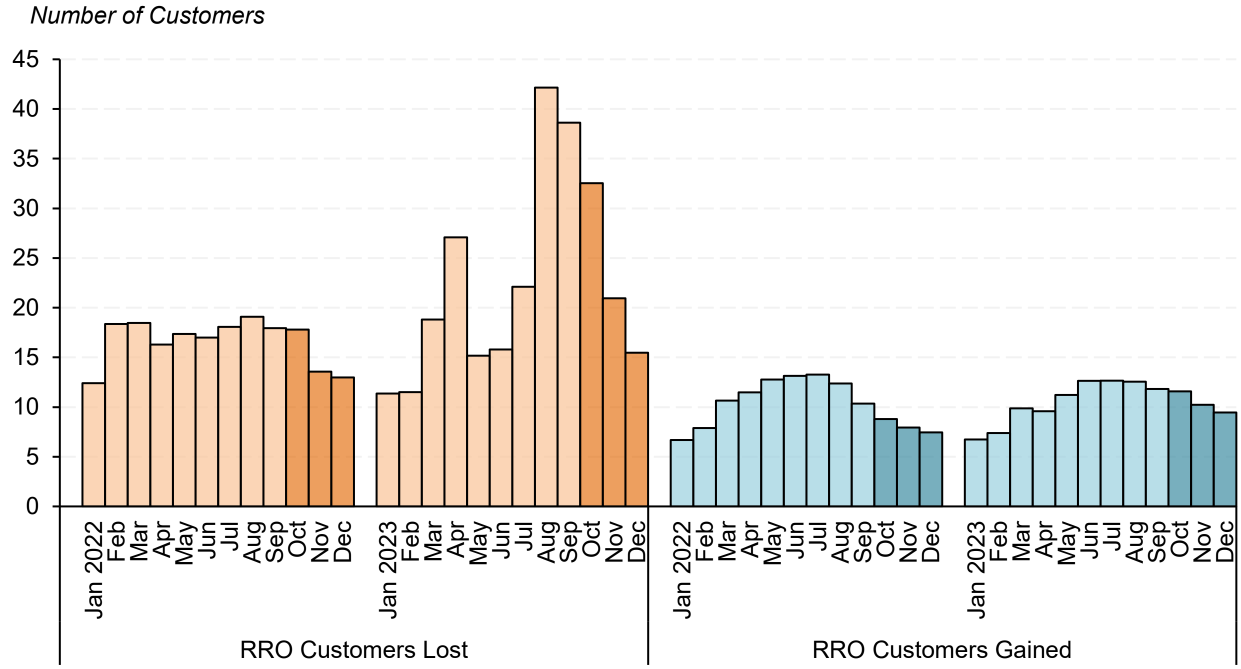
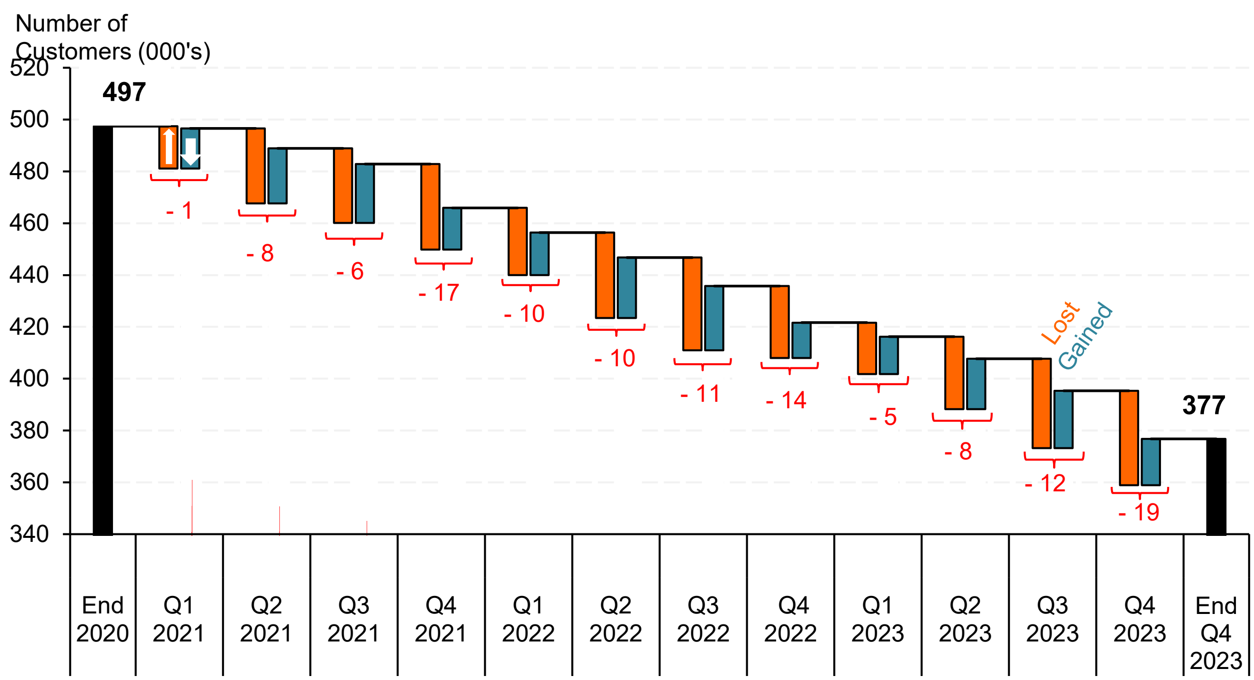


Figure 56: RRO customer losses and gains, residential customers (January 2022 to December 2023)



The DRT also continued to lose more customers in Q4 2023. The total number of residential DRT customers fell by around 19,000 in Q4 2023 (Figure 57). While around 36,500 residential customers left the DRT, around 18,100 residential customers joined the DRT in Q4 2023 (Figure 57). The DRT rates in Q4 2023 were lower than the prevailing competitive natural gas rates and therefore, there was less incentive to leave the DRT as compared with the RRO.

Figure 57: DRT customer net losses, residential customers (Q1 2021 to Q4 2023)

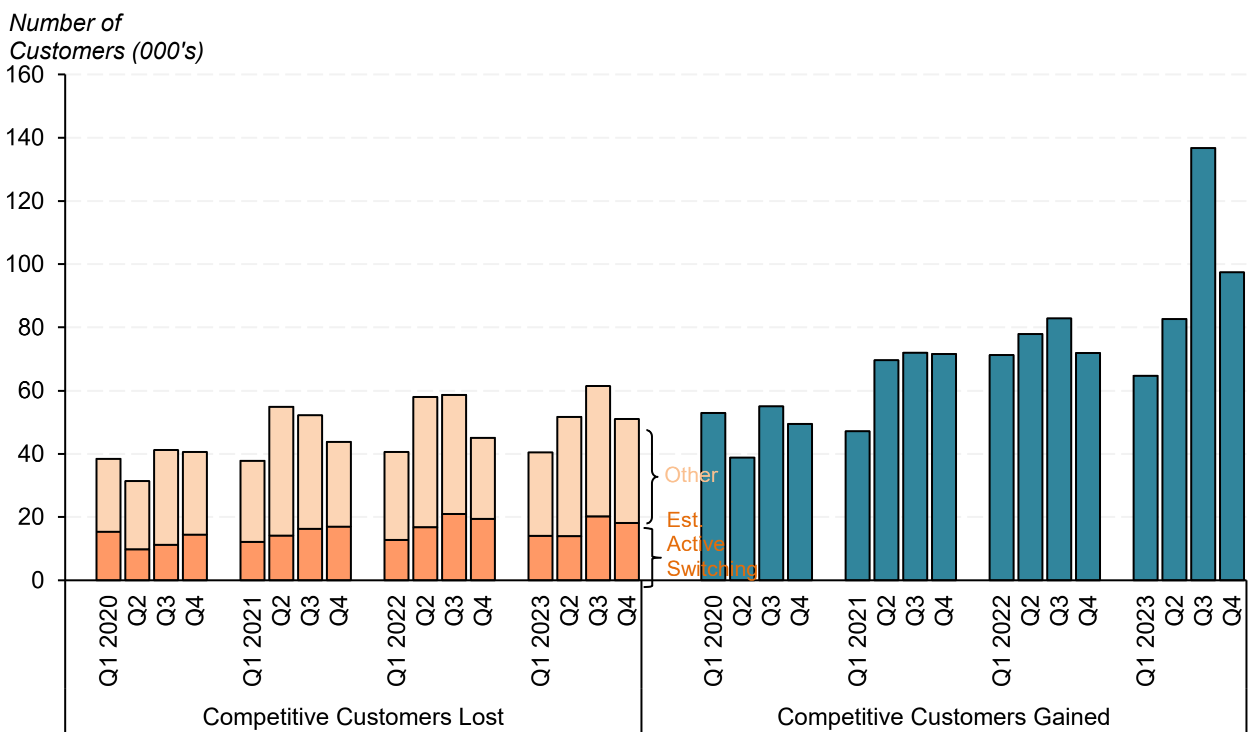


5.2.2 *Competitive retailer customer gains*

Concurrently, as the RRO customer count decreased, there was a discernible rise in competitive customers gained in Q3 2023 and Q4 2023. The customers gained by the competitive market in Q3 2023 was a all time high at 136,800, followed by another high increment of 97,400 in Q4 2023 (Figure 58). The number of customers leaving the competitive market in Q4 2023 was lower than in Q3 2023. The competitive customer loss in Q4 2023 was 51,000, while it was over 61,000 in Q3 2023 (Figure 58).

Out of the 51,000 competitive customers lost in Q4 2023, the MSA estimates around 18,000 residential customers left their competitive retailer for reasons unrelated to a move or being dropped by their retailer (Figure 58). The MSA counts such a switch as an 'Active Switch', 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 58: Competitive electricity customer losses & gains, Q1 2020 to Q1 2024 (residential customers)



5.2.3 *Dynamics of retail switching*

Churn rates are the percentage of a retailer's customer base that switches to another provider in each period. Since 2021, churn rates have been lower among competitive customers relative to RRO customers, indicating that RRO customers are switching retailers at greater rates. In Q4 2023, residential RRO churn rate was highest in October (7.4%) and lowest in December (3.6%).

Even though RRO churn rates were lower in Q4 2023 relative to Q3 2023, these numbers are still relatively high (Figure 59). In contrast, the competitive churn rates were as low as 0.80% in Q4 2023.

Figure 59: RRO and competitive electricity retailer churn rates, residential customers (January 2018 to December 2023)

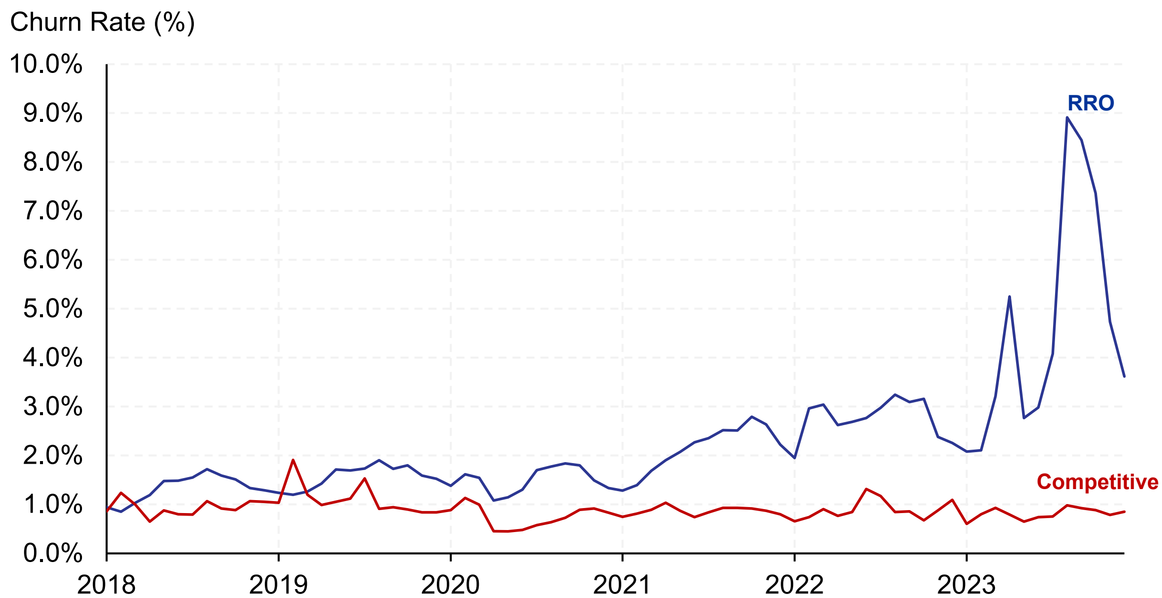


Figure 60: RRO retailer churn rates by service area, residential customers (January 2017 to December 2023)

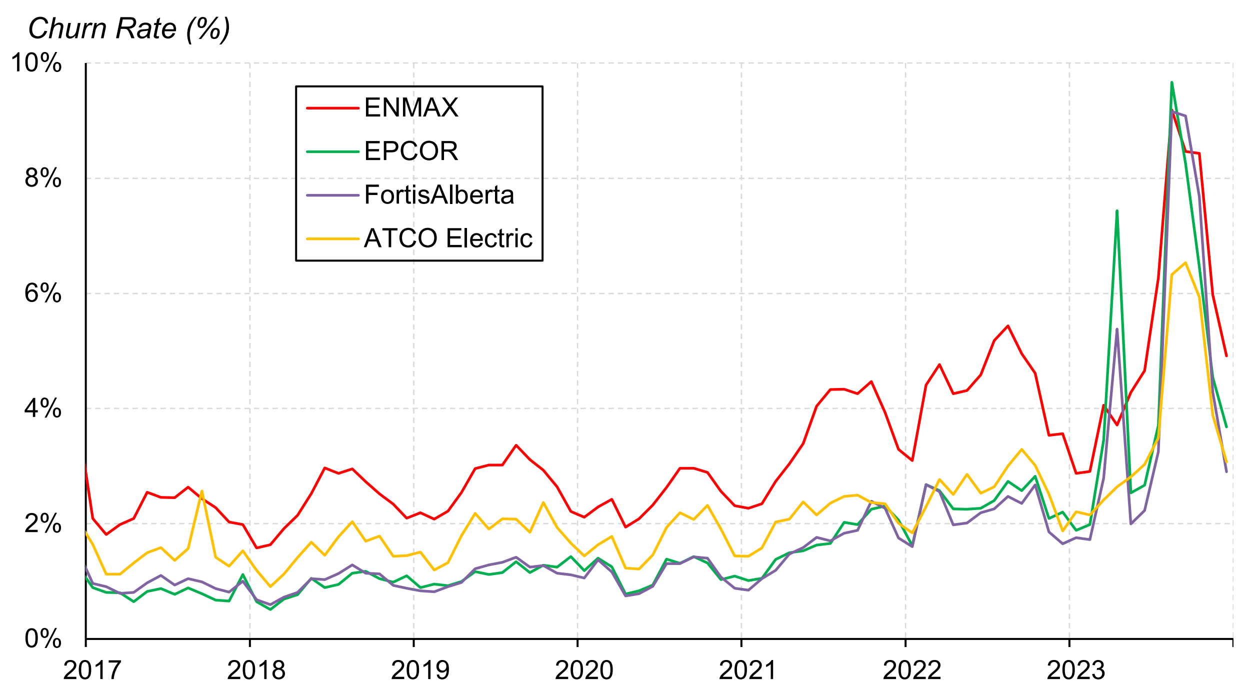


Figure 60 shows the residential RRO churn rates by month and service area. In Q4 2023 the RRO churn rate was highest in October and lowest in December in all four service areas. The churn rate was highest in the ENMAX service area in October (8.43%), November (5.98%) and December (4.92%). ATCO service area exhibited the lowest churn rates in October (5.94%) and November (3.88%), while Fortis Alberta had the lowest residential RRO churn rate in December (2.90%) (Figure 60). Even though the RRO rates were higher in December than October, the high churn rates in October relative to December can be attributed to the preceding trends in August and September, where a significant number of residential RRO customers switched to another provider due to high RRO rates.

5.2.4 Competitive retailer market share

The competitive retail customer share in electricity increased across all service areas in Q4 2023. The overall competitive market share for electricity increased by 3% from 71% in September to 74% by the end of December (Figure 61). As with Q3 2023, the increase in market share was highest in the EPCOR service area at 3.1%, followed by FortisAlberta and ATCO at 2.8% each (Table 11). Market share increased by 1.5% in the ENMAX service area. Although the increase in competitive market share was substantial in Q4 2023, it was low relative to the percentage increase observed in Q3 2023. As of December 2024, the ENMAX service area had the highest customer contract share (82%) in the competitive market, followed by Fortis Alberta (71%), ATCO (68%) and EPCOR (67%).

Figure 61: Competitive retail customer share (electricity) by service area, residential customers (January 2012 to December 2023)

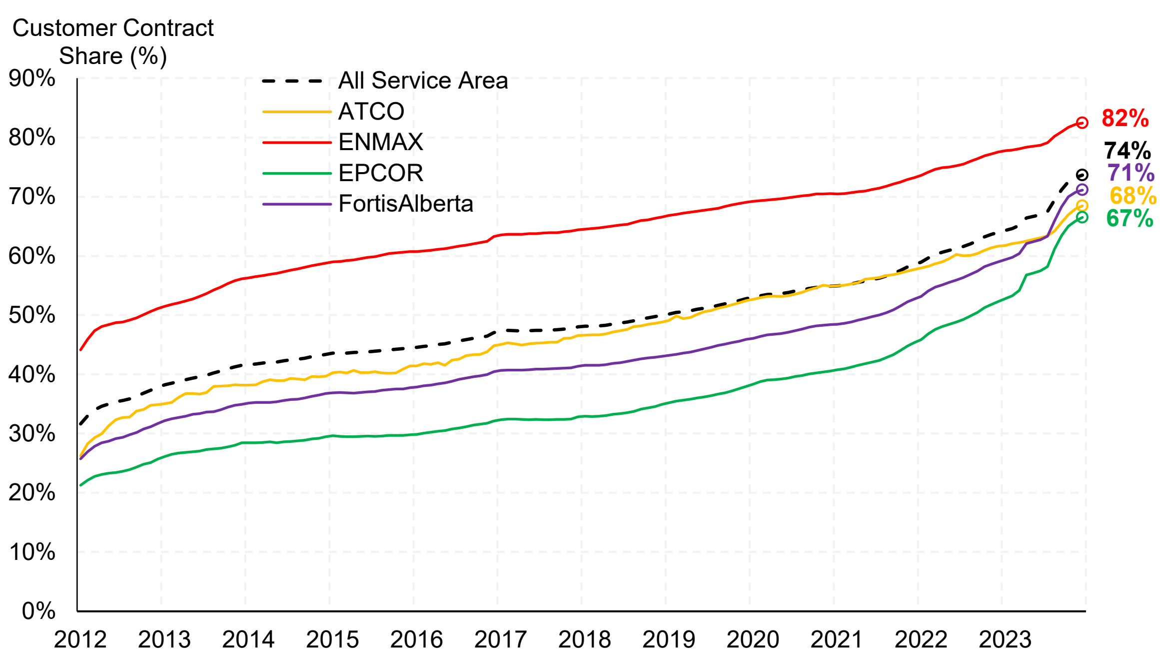


Table 11: Change in retail competitive shares (electricity) by service area, residential customers

	ENMAX	EPCOR	FortisAlberta	ATCO
Change (Q3 - 2023)	2.3%	5.9%	5.6%	2.6%
Change (Q4 - 2023)	1.5%	3.1%	2.8%	2.8%
Competitive Share (Dec 2023)	82.4%	66.5%	71.1%	68.4%

Looking back since January 2012, the split of market shares between RRO and competitive retailers have undergone substantial changes (Figure 62 and Figure 63). Over this period, competitive retailers exhibited a consistent upward trend in market share, while the RRO has experienced a corresponding decline in all service areas.

In January 2012, the RRO market share in the EPCOR service area was 79%, and the remaining 21% were with competitive retailers (Figure 62). Over the years there was a steady erosion in RRO market share and a corresponding modest growth in the competitive market share. Since Q1 2023, however, the magnitude of the decline in customers on the RRO and the growth in the competitive market share respectively has become significant in the EPCOR service area. The market share of the RRO declined from 47% in January 2023 to 33% in December 2023, a decline of 14% in 1 year. On the other side, the market share of competitive retailers increased by 14% in 2023 (Figure 62). As shown by Figure 62, even though the uncapped RRO rate for January was around 30 ¢/kWh, the Regulated Rate Option Stability Act (RROSA) capped the rates at 13.5 ¢/kWh for Q1 2023. Therefore, the change in market share was not that significant in Q1 2023.

Compared to the EPCOR service area, the competitive and RRO market shares in the ENMAX service area were closer to one another in January 2012; the RRO market share accounted for 56% in 2012 and the competitive market share was 44% (Figure 63). The decline in the market share of the RRO and the growth in the market share of the competitive was more uniform throughout the 2012 to 2023 period in the ENMAX service area, including 2023. As of Q4 2023, the market share of the RRO was 18% and the market share of competitive retailers was 82% in the ENMAX service area.

Figure 62: Retail market share (electricity) in EPCOR service area, residential customers (January 2012 to December 2023)

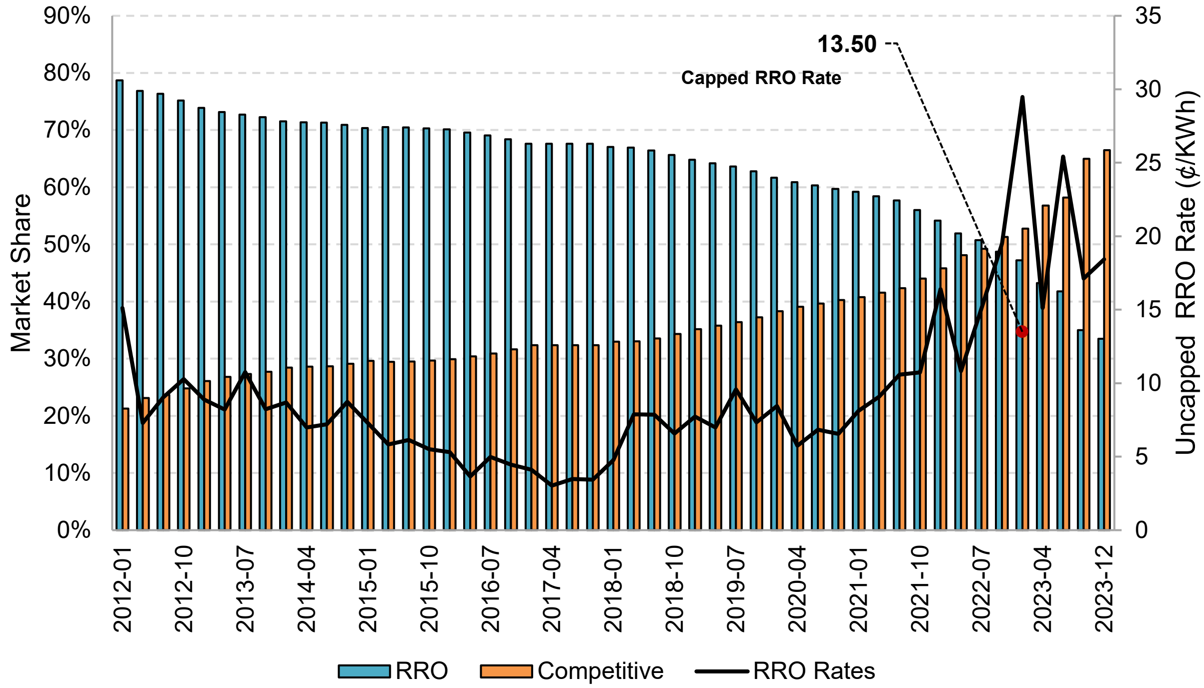
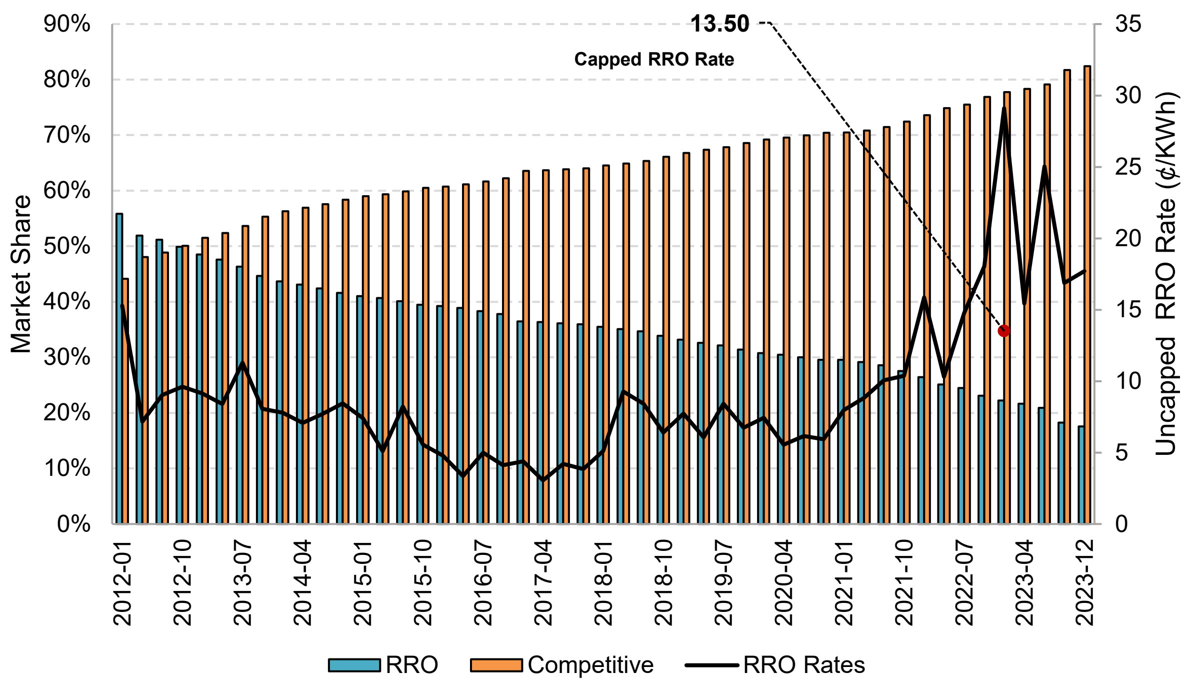


Figure 63: Retail market share (electricity) in ENMAX service area, residential customers (January 2012 to December 2023)



The market share of competitive retailers in the natural gas market increased by 1.4% in Q4 2023 to reach 71% (Figure 64). At the end of Q4 2023, ATCO Gas South had the highest retail market share at 77%, followed by ATCO Gas North (68%) and Apex (44%) (Figure 64). Over Q4 2023, the highest change in retail competitive share was seen in ATCO Gas North service area and the lowest was in ATCO Gas South (Table 12).

Figure 64: Competitive retail customer share (natural gas) by service area, residential customers (January 2012 to December 2023)

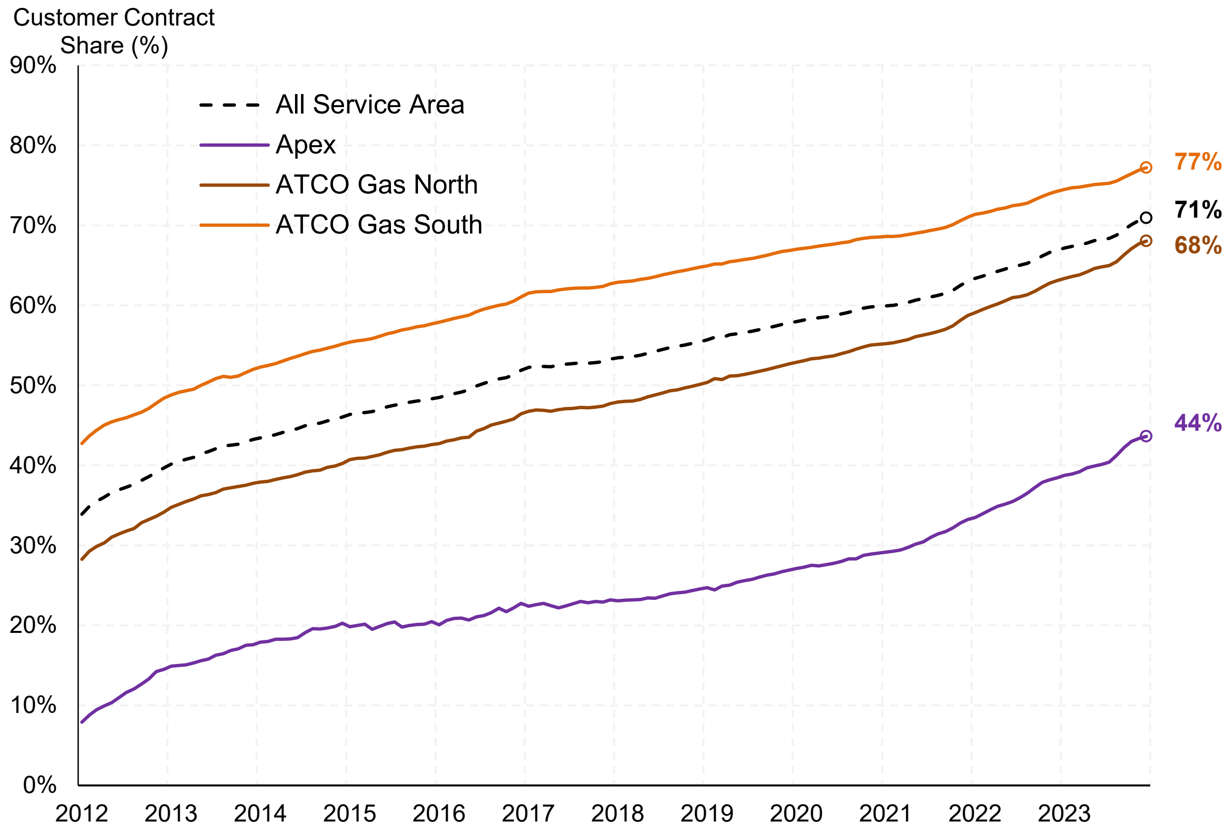


Table 12: Change in retail competitive shares (natural gas) by service area, residential customers

	ATCO Gas North	ATCO Gas South	Apex
Change (Q3 - 2023)	1.5%	0.8%	2.1%
Change (Q4 - 2023)	1.7%	1.2%	1.4%
Competitive Share (Dec 2023)	68.0%	77.2%	43.6%

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.

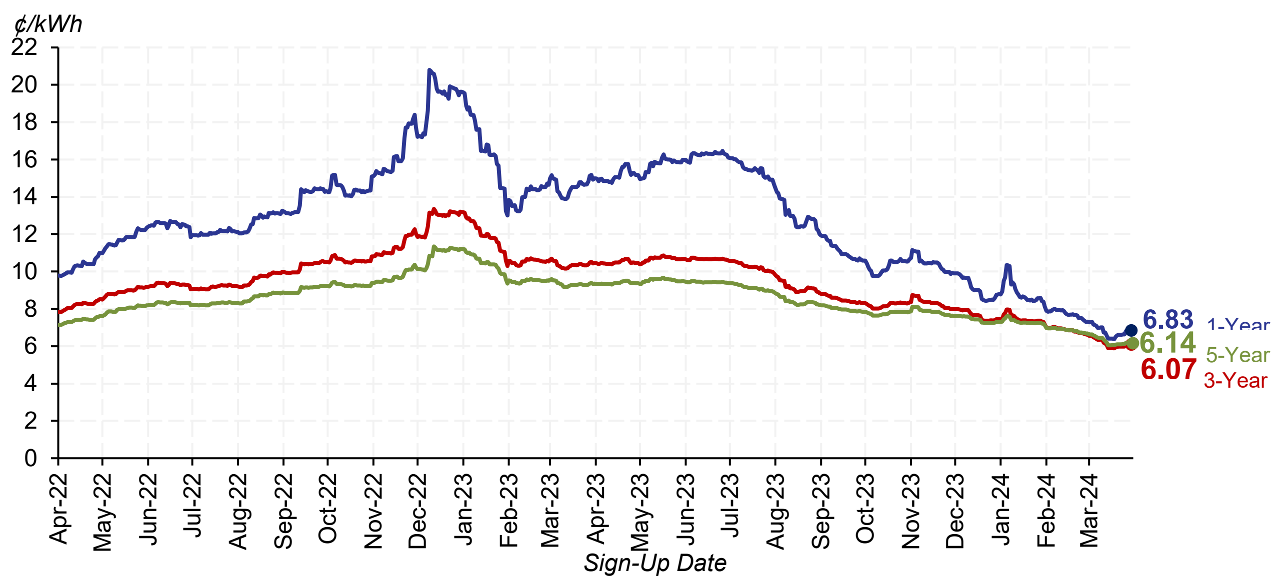
Fixed rates are fixed over a defined contract term; usually one, three or five years. Variable rates are energy rates that vary by month and can be tied to pool prices or regulated rates.

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.

The expected cost for 1-, 3-, and 5-year fixed rate electricity contracts decreased in Q1. Expected cost dropped by 22%, 19% and 16% for 1-, 3-, and 5-year contracts, respectively. The quarter started with an increase in expected cost for all the contracts. During the January 1 to 7 period, the expected cost of 1-year contracts increased by 1.52 ¢/kWh, an increase of 17%, due to the upward trend in near-term forward power prices. During the same time 3- and 5-year contracts increased by a smaller margin of 7% and 4%, respectively.

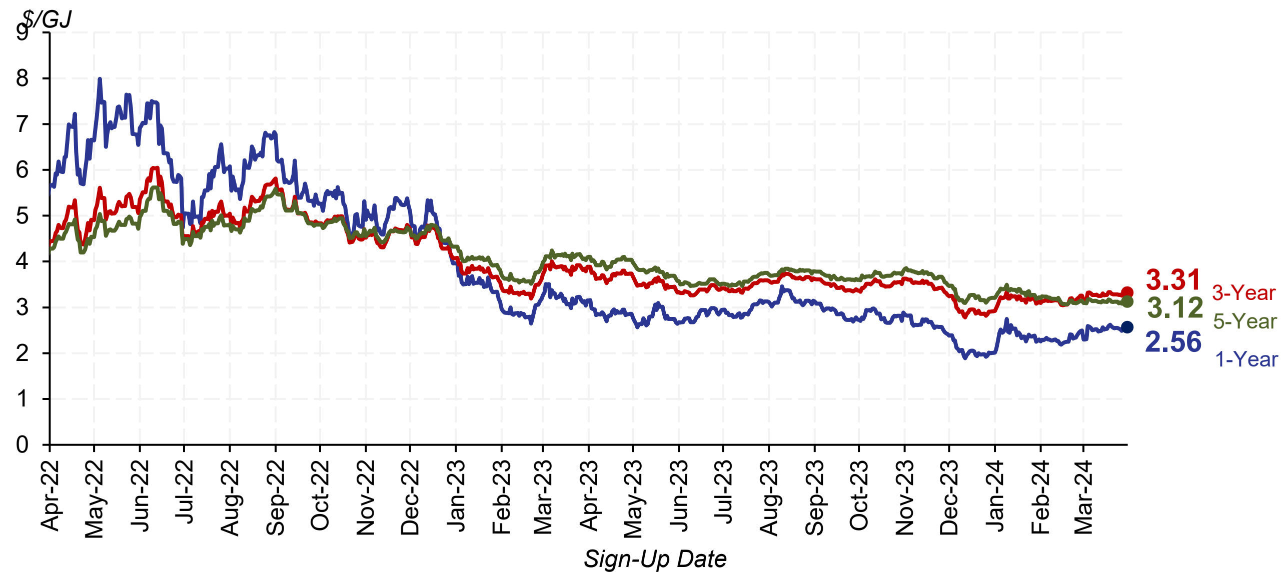
After January 7, expected costs declined steadily until March 13 as near-term and long-term forward power prices came down. During the January 7 to March 13 period expected cost for 1-, 3-, and 5-year contracts dropped by 36%, 24%, and 19% respectively. After March 13, the expected cost increased slightly for all the three fixed rate contract types. As of March 31, the expected cost for 1-, 3-, and 5-year fixed rate electricity contracts were at 6.83 ¢/kWh, 6.07 ¢/kWh, and 6.14 ¢/kWh respectively.

Figure 65: Expected cost, fixed rate electricity contract, residential customer (April 1, 2022 to March 31, 2024)



In Q1, the expected cost for 1- and 3-year fixed rate natural gas contracts increased by 27% and 14% respectively but the expected cost for 5-year contracts decreased by 3% (Figure 66). Unlike electricity contracts, the expected costs for natural gas contracts have been higher for longer term contracts since January 2023. As of March 31, the expected cost for 1-, 3-, and 5-year fixed rate natural gas contracts were at \$2.56/GJ, \$3.31/GJ and \$3.12/GJ, respectively (Figure 66).

Figure 66: Expected cost, fixed rate natural gas contract, residential customer (April 1, 2022, to March 31, 2024)



Most of the competitive retailers in Alberta reduced their fixed rate electricity offerings in Q1, in line with the drop in expected cost (Figure 65). However, all the fixed rate electricity contracts were offered well above the respective expected costs.

There are six main retailers who provide competitive fixed price electricity offers for Alberta residential customers (Figure 67). In March, Retailer A unveiled their limited time offer of 1-, 3- and 5-year fixed electricity at 7.77 ¢/kWh until July 31, 2024, followed by a rate of 10.59 ¢/kWh. A rate of 7.77 ¢/kWh indicates a reduction of Retailer A's 1-year rate by 51%, and 3- , and 5-year rate by 37%. A rate of 10.59 ¢/kWh post July 31 indicates a reduction of Retailer A's 1-year rate by 34%, and 3- and 5-year rate by 14%, relative to their February rates. If no other retailer reduces their rates in response, Retailer A will remain the lowest 1-,3- and 5-year fixed rate provider in the province until July 31.

In addition to Retailer A's rate reduction, Retailer C reduced its 1- year fixed rates by 4.4 ¢/kWh in January. Retailer F and Retailer G reduced their 5-year fixed rates by 0.7 ¢/kWh and 0.8 ¢/kWh, respectively to become the second lowest rate providers of 5-year fixed rate electricity in Alberta (Figure 67). None of the retailers increased their electricity rates in Q1 2024.

While Retailer A has decreased electricity rates, there hasn't been a parallel reduction in their natural gas rates in Q1 (Figure 68). Retailer C, similar to what they did for electricity, reduced 1-year fixed rate natural gas rates by \$1.3/GJ in January. Retailer E increased their 3-year fixed rate natural gas rates in January by \$0.4/GJ in February, but then reduced the rate by \$0.6/GJ in March. Retailer C, F, and G are providing 5-year fixed rate natural gas at the same rate of \$4.79/GJ as of March 31 (Figure 68).

Figure 67: 1-, 3-, and 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (January 1, 2023 to March 31, 2024)

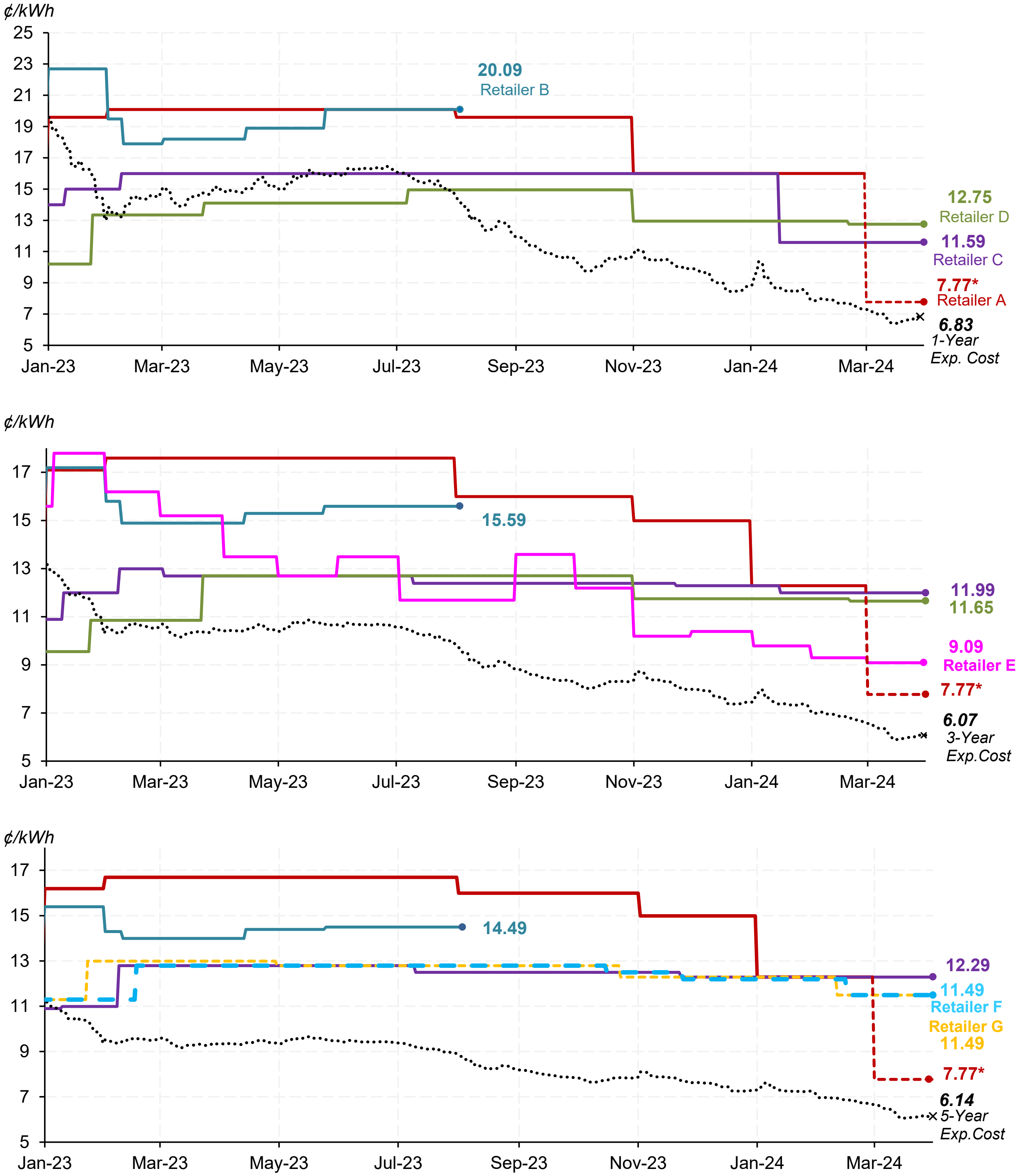
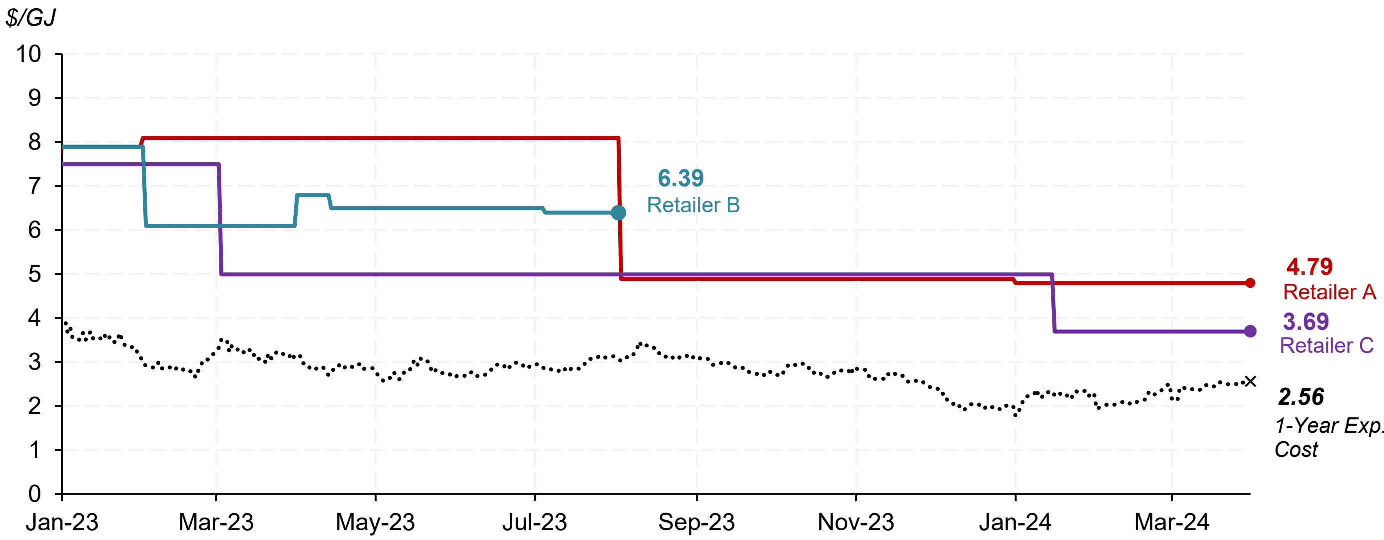
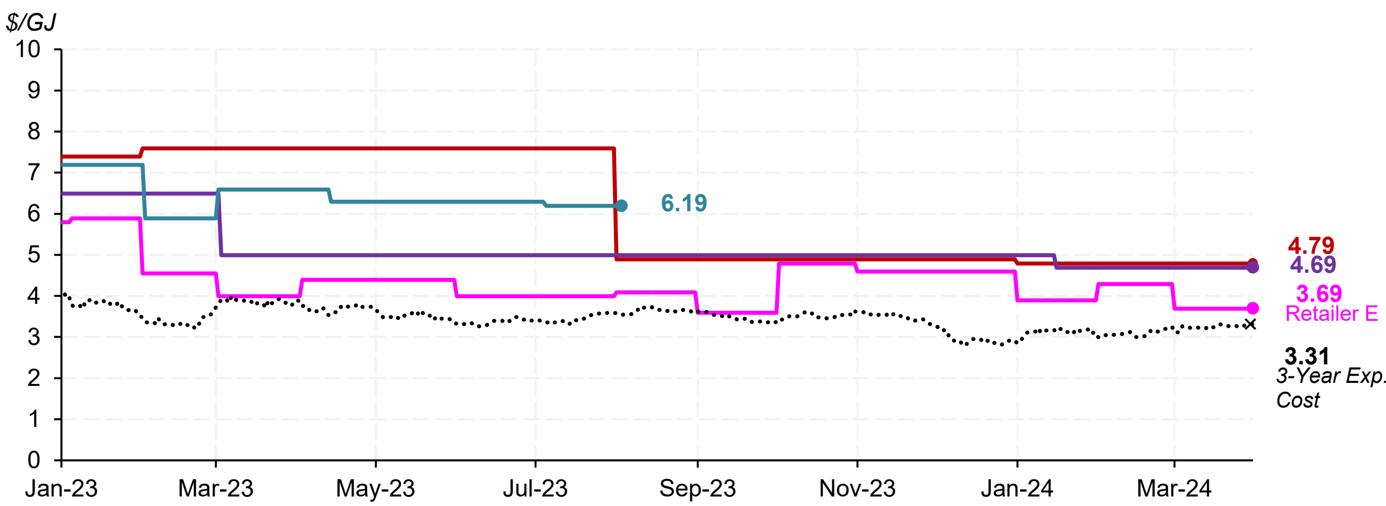
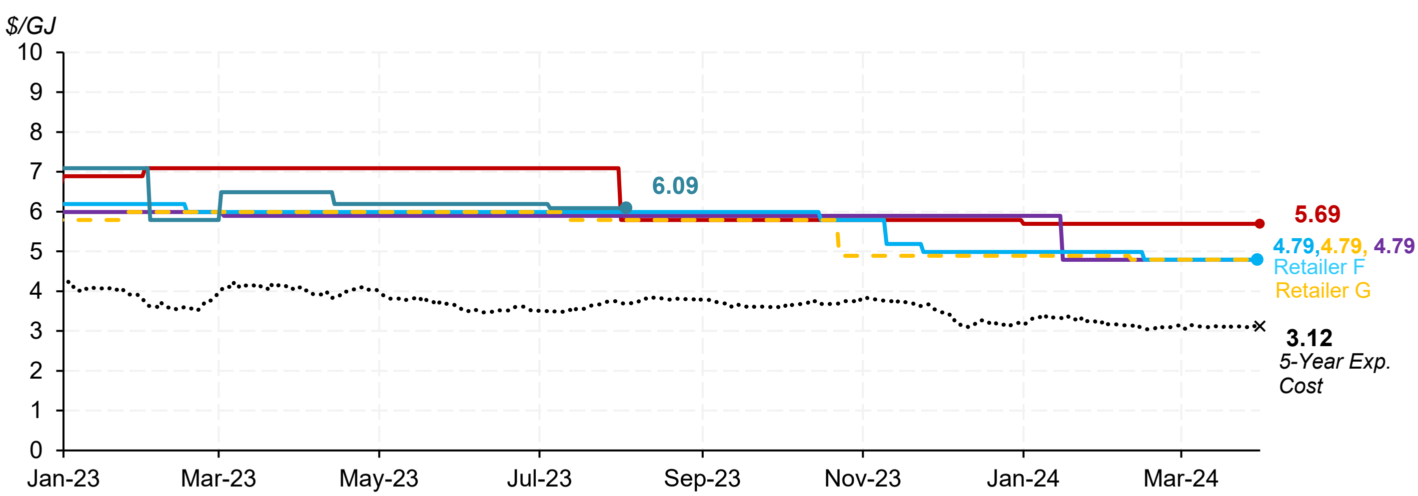


Figure 68: 1-, 3-, and 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (January 1, 2023 to March 31, 2024)







5.4 Regulated retail rate

5.4.1 Electricity regulated rate – Historical rates and forecast

The average annual residential RRO rates in all service areas have been increasing since 2017. In 2017, the RRO rates across all the months averaged 3.73 ¢/kWh in the ENMAX service area, the lowest since 2012. However, the yearly average increased in 2018 by 3.07 ¢/kWh to 6.80 ¢/kWh. RRO rates increased to 7.15 ¢/kWh in 2019 and then had a marginal reduction in 2020. After 2020, RRO rates increased further, especially during the summer months of July and August and in the winter months of December, January, and February. The yearly average RRO rates in 2021 was 9.40 ¢/kWh and in 2022 reached 15.11 ¢/kWh.

2023 witnessed the highest ever RRO rates in July, August, and September, bringing the yearly average to 18 ¢/kWh. Figure 69 shows the evolution of monthly RRO rates in the ENMAX service area since January 2022. Q1 2023 had a rate cap (13.5 ¢/kWh) over the RRO rates, which kept the yearly average as low as 18 ¢/kWh. In the absence of this rate cap, the yearly average would have gone over 21 ¢/kWh in 2023.

The MSA's regulated rate estimates indicate that RRO rates will be lower in 2024, correlating with the lower forward prices. The average RRO rate in the ENMAX service area for the period May 2024 to March 2025 is expected to be around 10 ¢/kWh, including the collection rates.[27]

Figure 70 shows the forecasted residential RRO monthly rates and billing rates (monthly base rates plus collection rates) from May 2024 until April 2025. The collection rates are in place until December 2024 and therefore after December the RRO monthly base rate and billing rate will be the same. The MSA has forecasted the collection rates using RRO site counts as of Q4 2023, monthly recovery amounts, and historical seasonal changes in residential RRO customer site count. The expected collection rate in the ENMAX service area averaged 2.3 ¢/kWh over the period of May 2024 to December 2024, as of April 1, 2024 (Figure 70). This average is slightly higher in EPCOR and Fortis Alberta service area at around 3.6 ¢/kWh.

[27] Collection rates are added on top of the monthly base RRO rates to give the billing rates paid by RRO customers.

Figure 69: Historical and Forecasted RRO billing rates, residential customers ENMAX service area (January 2022 to March 2025)

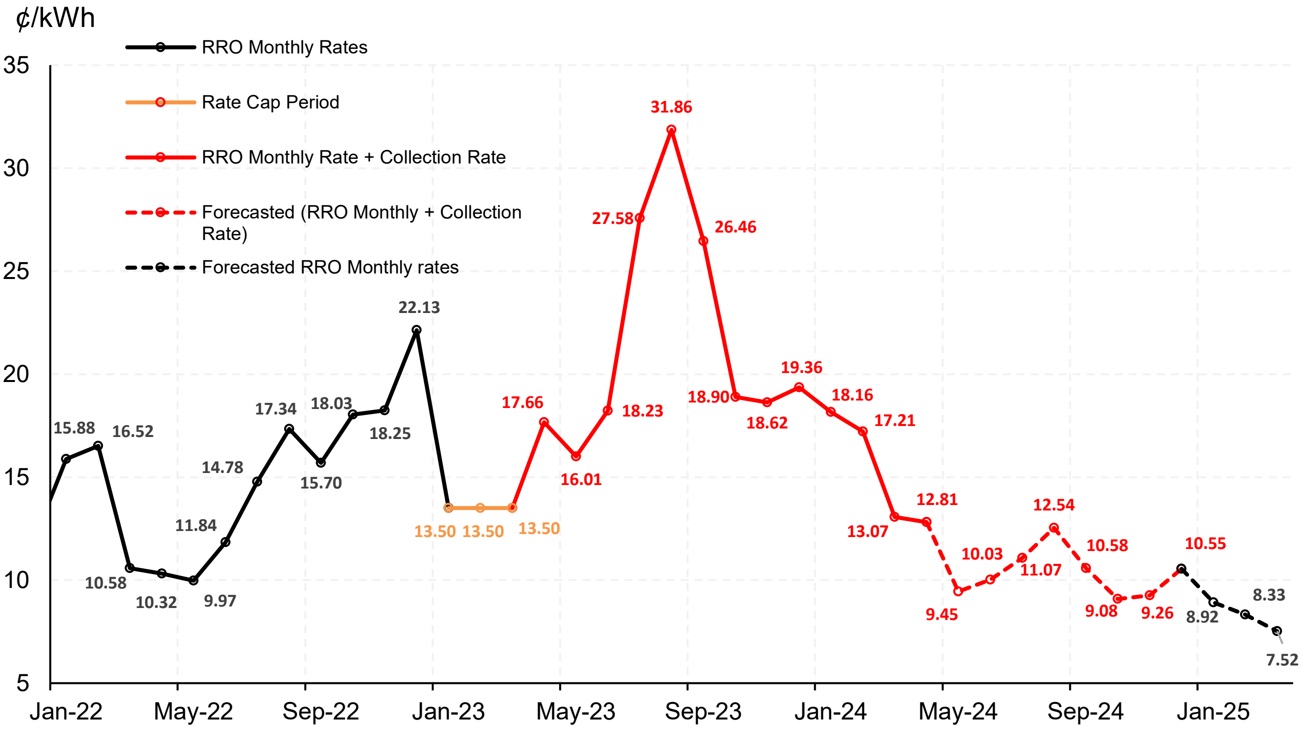
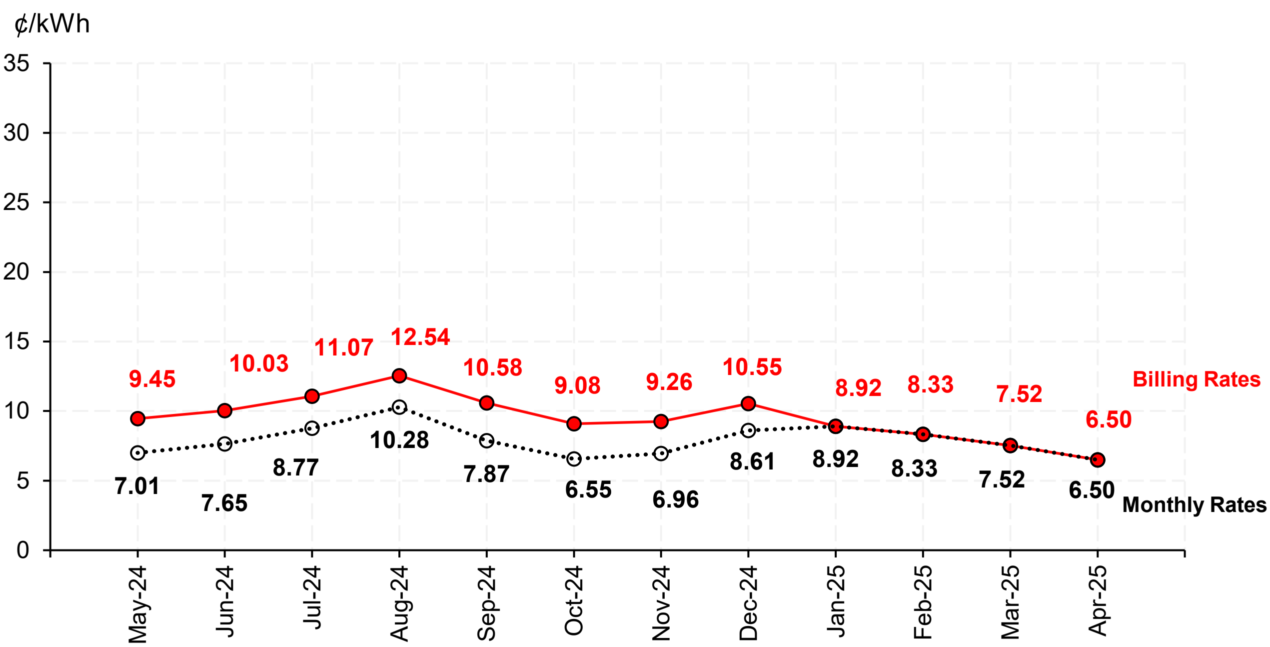


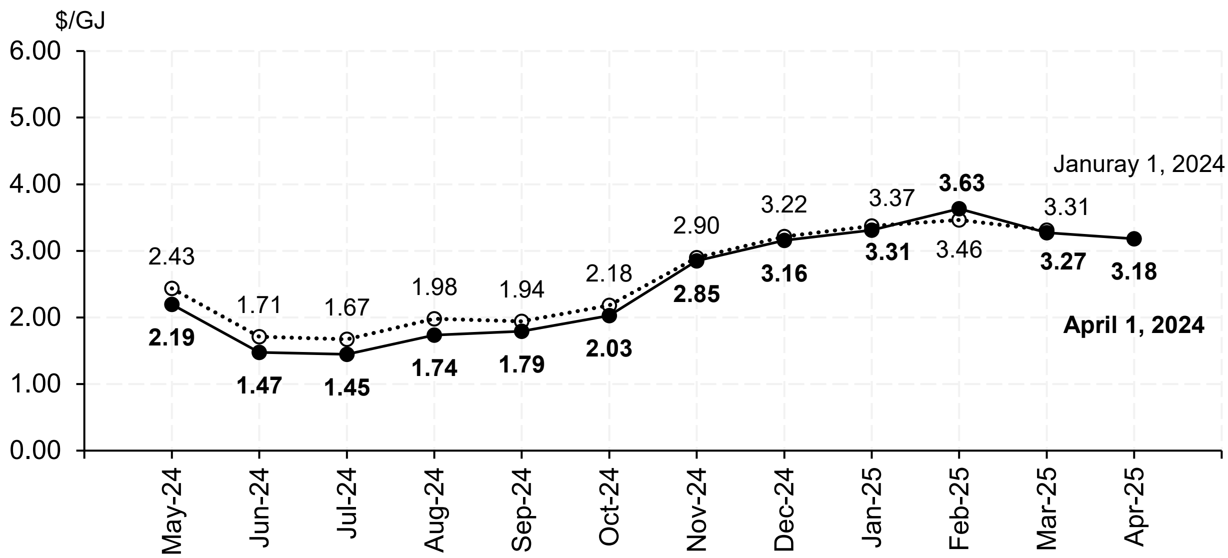
Figure 70: February 2024 to January 2025 estimated residential RRO monthly rates and billing rates, ENMAX service area (as of April 1, 2024)



5.4.2 *Natural gas regulated rate estimates*

Expected DRT rates for the May 2024 to April 2025 period have decreased slightly since the MSA's estimates on January 1 (Figure 71). The slight decline in the estimates were observed for the months of May to October. The estimates did not change notably for the rest of the months in the period under observation, relative to the previous forecast. The forecasted rates remain well below the $6.50/GJ threshold for natural gas rebates by the Government of Alberta.

Figure 71: May 2024 to April 2025 residential DRT estimates, ATCO Gas service areas (as of April 1, 2024 vs. January 1, 2024)



6 REGULATORY AND ENFORCEMENT MATTERS

6.1 SUM1 Notices of Specified Penalties

On June 23, 2023, Canadian Hydro Developers, Inc. (Canadian Hydro) self-reported contraventions of section 205.5 of the ISO rules to the MSA. After assessing the self-report, on February 22, 2024, the MSA issued 138 Notices of Specified Penalty (NSP) totaling $678,500 to Canadian Hydro for contraventions of section 205.5 of the ISO rules between August 20, 2022 and May 22, 2023. One NSP was issued for each day the Summerview1 battery storage asset (SUM1) was under dispatch to provide spinning reserve but did not provide frequency response when the system frequency dropped below the deadband set out in subsection 3(1)(b)(ii) of section 205.5 of the ISO rules.

> Section 205.5 of the ISO rules states, in part:
>
> (2) A pool participant must ensure that, while its pool asset is under dispatch to provide spinning reserve, the change in real power of each spinning reserve resource being used to provide spinning reserve is:
>
> > (a) continuously proportional to the measured frequency;
> >
> > (b) in accordance with the droop setting set out in subsection 3(1)(b)(iii); and
> >
> > (c) limited to the maximum real power capability of the spinning reserve resource that is available at the time of the frequency event
>
> for any change in frequency where the frequency goes outside the deadband set out in subsection 3(1)(b)(ii).

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 March 31, 2024, the MSA closed 181 ISO rules compliance matters, as reported in Table 13.[28] An additional 259 matters were carried forward to the next quarter. During this period 31 matters were addressed with NSPs, totalling $776,750 in financial penalties, with details provided in Table 14.

Table 13: ISO rules compliance outcomes from January 1 to March 31, 2024

ISO rule	Forbearance	Notice of specified penalty	No contravention
201.3	1	-	-
201.7	8	-	-
203.3	56	1	4
203.4	48	2	2
205.5	-	1	-
205.6	4	19	1
306.4	-	1	-
306.5	-	4	-
502.4	4	2	-
502.6	2	-	-
502.8	4	-	-
502.14	-	1	-
502.15	3	-	-
502.16	2	-	-
Total	**143**	**31**	**7**

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

Table 14: Specified penalties issued between January 1 and March 31, 2024 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)								Total ($)	Matters
	203.3	203.4	205.5	205.6	306.4	306.5	502.4	502.14		
AltaGas Ltd.		1,500							1,500	1
ATCO Electric Ltd.					250				250	2
Canadian Hydro Developers, Inc.			678,500					250	678,750	1
Enel X Canada Ltd.				62,250					62,250	13
Grande Prairie Generation Inc.						500			5,000	1
Kneehill Solar LP						500	500		500	2
Lanfine Wind 1 LP						500			1,000	1
MEG Energy Corp.		250							500	1
Michichi Solar LP						500	500		250	2
Taber Solar 1 Inc.	500								1,000	1
Voltus Energy Canada Ltd.				30,000					500	6
Total	500	1,750	678,500	92,500	250	2,000	1,000	250	776,750	31

The ISO rules listed in Table 13 and Table 14 fall into the following categories:

201 General (Markets)
203 Energy Market
205 Ancillary Services Market
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.[29] 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 March 31, 2024, the MSA addressed 23 O&P ARS compliance matters (Table 15).[30] 68 O&P ARS matters were carried forward to the next year. During this period, four matters were addressed with NSPs, totalling $14,750 in financial penalties (Table 16). For the same period, the MSA addressed 30 CIP ARS compliance matters, as reported in Table 17, and no matters were addressed with NSPs. 95 CIP ARS matters were carried forward to next quarter.

Table 15: O&P ARS compliance outcomes from January 1 to March 31, 2024

Reliability standard	Forbearance	Notice of specified penalty	No contravention
EOP-008	5	1	-
EOP-011	1	-	-
FAC-008	6	1	-
PRC-005	2	2	2
PRC-019	1	-	-
VAR-002	-	-	2
Total	15	4	4

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

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

Table 16: Specified penalties issued between January 1 and March 31, 2024 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)			Total ($)	Matters
	EOP-008	FAC-008	PRC-005		
City of Lethbridge		2,250	3,750	6,000	2
City of Medicine Hat	5,000			5,000	1
City of Red Deer			3,750	3,750	1
Total	5,000	2,250	7,500	14,750	4

The ARS outcomes listed in Table 15 and Table 16 are contained within the following categories:

EOP Emergency Preparedness and Operations
FAC Facilities Design, Connections, and Maintenance
PRC Protection and Control
VAR Voltage and Reactive

Table 17: CIP ARS compliance outcomes from January 1 to March 31, 2024

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-003	3	-	-
CIP-004	8	-	-
CIP-005	1	-	-
CIP-006	4	-	-
CIP-007	5	-	-
CIP-010	6	-	-
CIP-011	3	-	-
Total	30	-	-

The ARS outcomes listed in Table 17 are contained within the following categories:

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-010 Configuration Change Management and Vulnerability Assessments
CIP-011 Information Protection