MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q4 2023

February 12, 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

- The average pool price in 2023 was $134/MWh, a 18% decrease relative to 2022 but still 31% higher than 2021. The year-over-year decline was largely due to increased wind and solar generation, lower natural gas prices, and comparatively mild weather in 2023. Relative to prior years, pool prices in 2023 were higher because of greater exercise of market power and less available thermal generation due to coal asset retirements.

- In Q4, the volume of wind and solar generation that was constrained down increased by a factor of over thirteen compared to Q4 2022. The percent of hours where at least 1 MWh of wind or solar generation was constrained down was 69.1% in Q4. Year-over-year the, the total constrained down wind and solar volume for 2023 reached 286 GWh, a 445% increase from 53 GWh in 2022. Dynamic line rating is explored for targeted areas, such as high wind, as a method to increase line capacity.

- Total trade volumes in the forward market during 2023 were low at 42 TWh, a 23% decline relative to 2022 and the lowest total since 2020. Monthly forward prices decreased over the quarter as realized pool prices for October, November, and December came in below forward market expectations. The price of CAL24 increased from $84 to $95/MWh early in the quarter, in part because of a proposed merger announcement, before declining back down due to falling natural gas prices later in the quarter. Pool prices are expected to be lower in the coming years due to the return of HR Milner, the upcoming addition of the Cascade combined cycle project, the repowering of Genesee 1 and 2 from coal to combined cycle, the development of cogeneration at the Suncor Base Plant, and increasing amounts of wind and solar generation supply.

- High Regulated Rate Option (RRO) rates in August and September contributed to the decline in residential RRO customers in Q3. More than 66,000 customers left the RRO, leaving only 470,000 RRO residential customers as of September 30, 2023. Competitive retail customer share (electricity) experienced a sizable increase in all service areas. The average RRO rate in Q4 did not change much year-over-year. However, competitive fixed rates and variable rates for electricity in Q4 were much less than in Q4 2022. Default Rate Tariff (DRT) rates also declined year-over-year in Q4.

- From October 1 to December 31, 2023, the MSA closed 104 ISO rules compliance matters; 28 matters were addressed with notices of specified penalty. For the same period, the MSA closed eight Alberta Reliability Standards Critical Infrastructure Protection compliance matters; four matters were addressed with notices of specified penalty. In addition, the MSA closed 14 Alberta Reliability Standards Operations and Planning compliance matters; five matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Annual summary

The average pool price in 2023 was $134/MWh, a 18% decrease compared to 2022 but still 31% higher than 2021. The price of natural gas in 2023 was 50% lower than in 2022. As a result, the spark spread (the margin between pool prices and natural gas input costs) was 10% lower in 2023 than in 2022 but was higher than prior years (Figure 1).

Figure 1: Spark spread by year (2001 to 2023, inflation adjusted)[1]

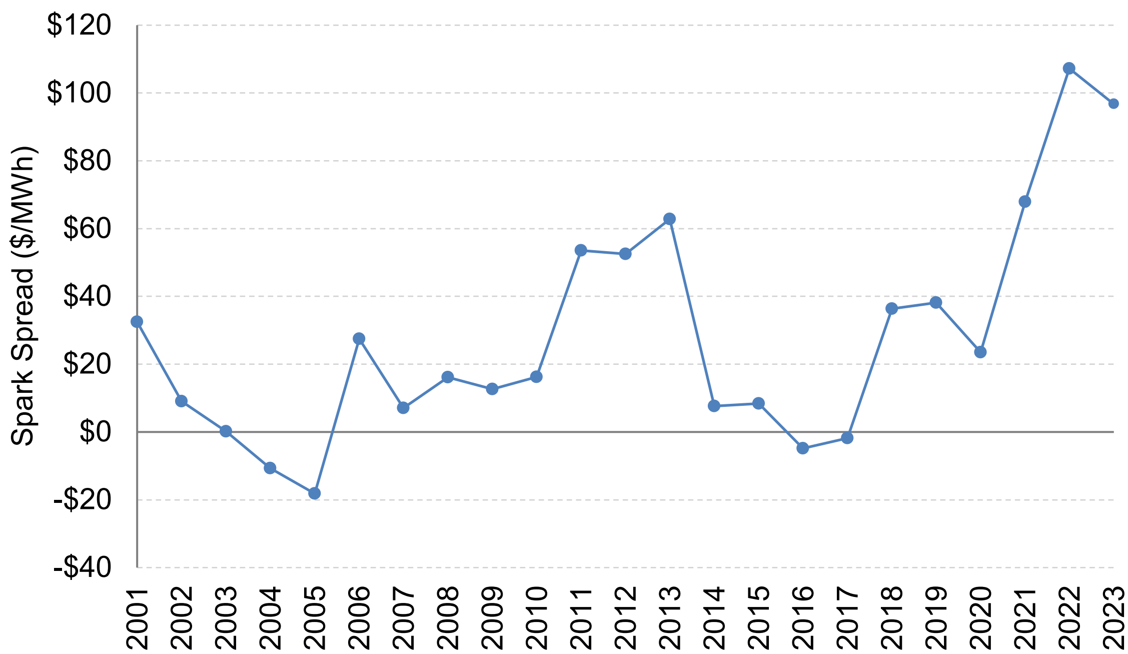


Table 1 provides annual market summary statistics going back to 2018 to provide context for the year-over-year results. Average demand fell from 2022 to 2023 because of milder weather in the summer and winter of 2023. For example, the average temperature was -2°C in December 2023 compared to -15°C in December 2022. Milder temperatures generally result in lower electricity demand because there is less demand for heating or cooling.

The lower Alberta demand for electricity in 2023 was offset by reduced import and increased export volumes. Year-over-year average net import volumes fell from 412 MW to 1 MW, a large reduction of supply. Net import volumes have been less this year because of low hydro conditions in BC and the Pacific Northwest and lower pool prices in Alberta.

Wind and solar (intermittent) generation supply increased from an average of 968 MW in 2022 to 1,435 MW in 2023, a 48% increase. The higher intermittent volume of generation has been a

[1] The spark spread calculation assumes a heat rate of 10 GJ/MWh and considers carbon costs with an emissions intensity of 0.54 tCO_2e/MWh. Adjusted for inflation using the Consumer Price Index, annual average, not seasonally adjusted.

factor in more pool price volatility in recent years. The standard deviation of pool prices increased from $92/MWh in 2020 to $184/MWh in 2023 (Table 1).

Table 1: Annual market summary statistics

	2018	2019	2020	2021	2022	2023
Pool Price Avg ($/MWh)	$50.35	$54.88	$46.72	$101.93	$162.46	$133.63
Pool Price Standard dev. ($/MWh)	$87.22	$90.39	$92.13	$138.96	$199.22	$183.84
Demand (AIL) Avg (MW)	9,741	9,695	9,462	9,728	9,883	9,851
Supply cushion Avg (MW)	1,785	1,605	1,933	1,742	1,540	1,621
Gas Price Avg ($/GJ)	$1.44	$1.68	$2.11	$3.39	$5.08	$2.54
Intermittent gen. Avg (MW)	471	472	702	755	968	1,435
Net Imports Avg (MW)	304	174	440	459	412	1

Larger generators' exercise of market power also increased pool price volatility in recent years. These large generators typically exercise market power though economic withholding but also take assets out of the market on long-lead time. Figure 2 below illustrates trends in economic withholding over time. As shown, the amount of generation priced above $250/MWh in the merit order increased after the remaining PPAs expired at the end of 2020.

Figure 3 illustrates annual pool price duration curves for the years 2020 to 2023. The pool price duration curve for 2023 is shifted slightly to the left of the duration curve for 2022 indicating that prices were lower in 2023 throughout the distribution (Figure 3). Low natural gas prices in 2023 put downward pressure on pool prices for many hours, and at lower price levels 2023 was comparable to 2021. At higher price levels, the 2023 duration curve is to the right of the 2021 duration curve, indicating higher prices which reflects greater exercise of market power.

Figure 2: Average amount of capacity offered above $250/MWh by month (January 2018 to December 2023, peak hours)

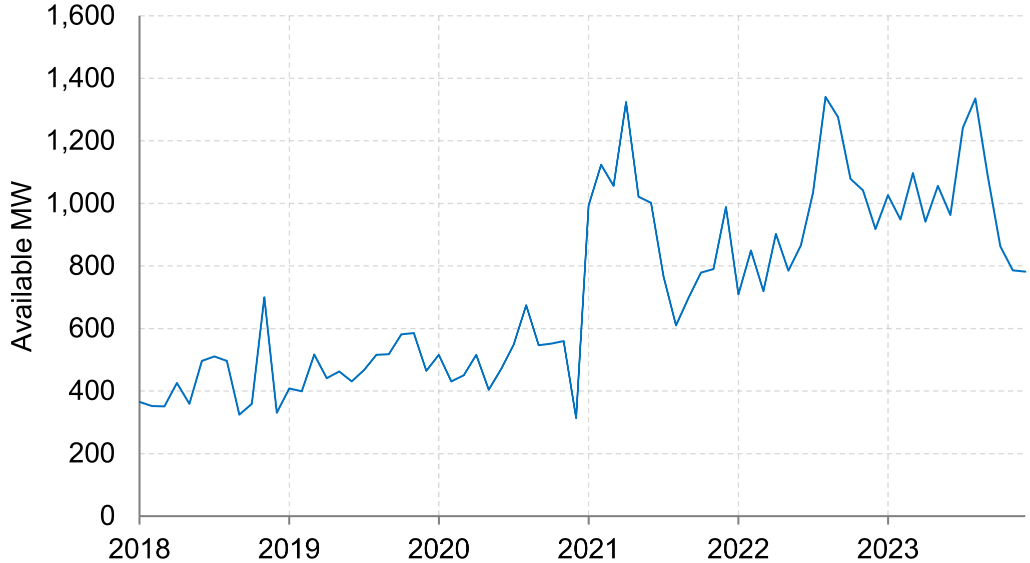
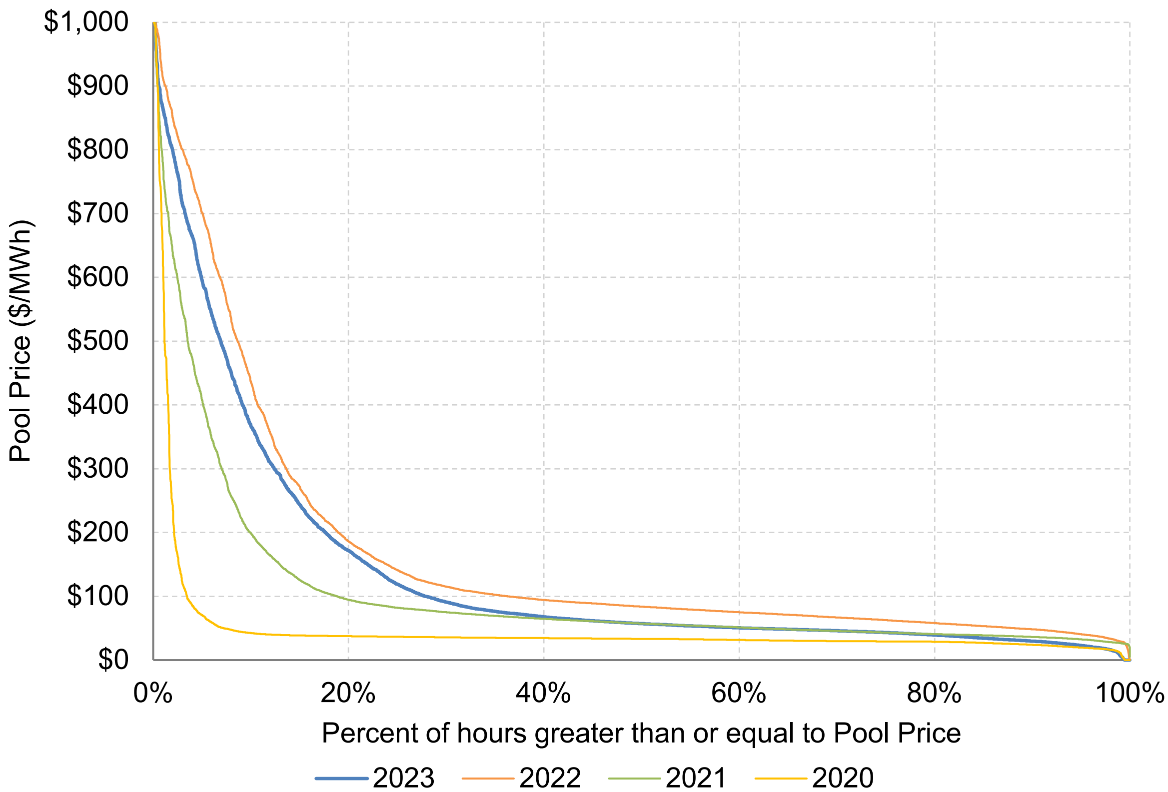


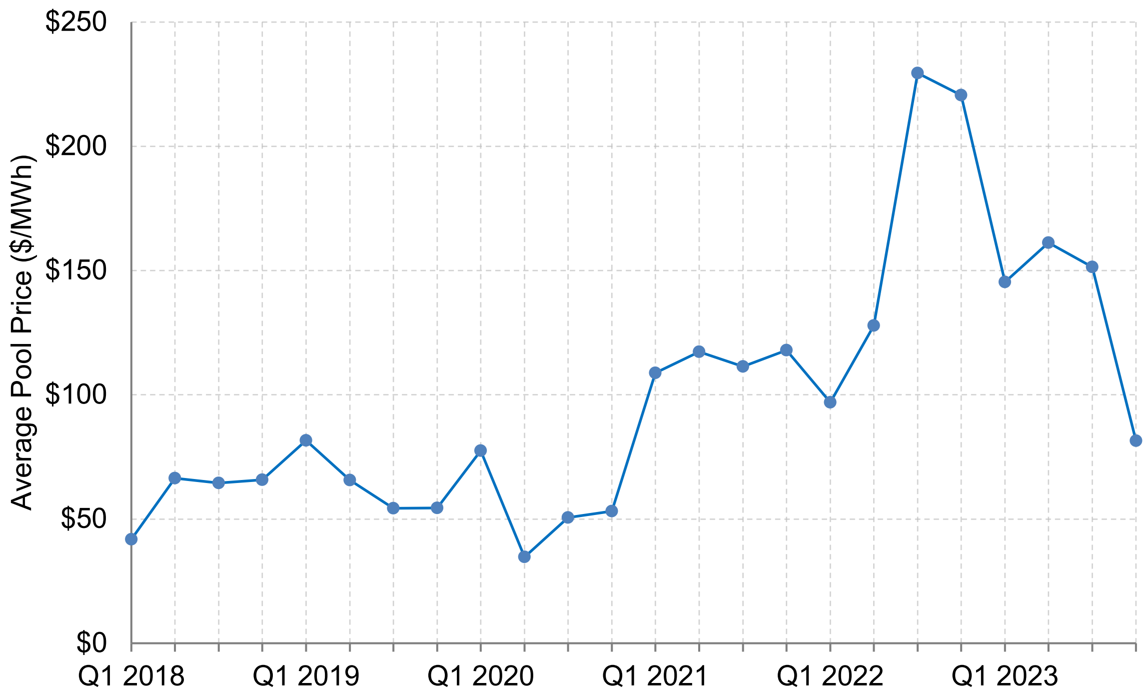
Figure 3: Pool price duration curves by year (2020 to 2023)



1.2 Quarterly summary

The average pool price in Q4 was $82/MWh, a 63% decrease compared to Q4 2022 and the lowest since Q4 2020 (Figure 4). The lower pool prices year-over-year were due to increased wind generation, lower natural gas prices, and lower demand in November and December (Table 2). In addition, suppliers exercised market power less in Q4 as compared to Q4 2022. The lower pool prices combined with low hydro conditions in BC and the Pacific Northwest to result in more exports in Q4 (Table 2).

Figure 4: Average pool price by quarter (Q1 2018 to Q4 2023, inflation adjusted)[2]



Pool prices averaged $52/MWh in December, the lowest monthly average pool price since December 2020. Mild temperatures and strong wind generation were both factors in this outcome. Alberta Internal Load (AIL) averaged 10,518 MW in December which is 232 MW lower than December 2022 (Table 2). Temperatures in December 2023 were higher than December 2022, as shown by Figure 5 and Table 3.

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

Table 2: Summary market statistics for Q4 2023 and Q4 2022

		2022	2023	Change
Pool price (Avg $/MWh)	October	$142.34	$99.34	-30%
	November	$186.84	$93.82	-50%
	December	$311.73	$52.05	-83%
	Q4	**$213.92**	**$81.61**	**-62%**
Demand (AIL) (Avg MW)	October	9,468	9,560	1%
	November	10,336	10,262	-1%
	December	10,750	10,518	-2%
	Q4	**10,183**	**10,111**	**-1%**
Gas price AB-NIT (2A) (Avg $/GJ)	October	$3.27	$2.30	-30%
	November	$5.69	$2.48	-56%
	December	$5.79	$1.80	-69%
	Q4	**$4.91**	**$2.19**	**-55%**
Wind generation (Avg MW)	October	819	1,263	54%
	November	1,128	1,750	55%
	December	908	2,136	135%
	Q4	**950**	**1,716**	**81%**
Solar generation (Avg MW during peak hours)	October	275	254	-8%
	November	161	203	26%
	December	102	155	52%
	Q4	**180**	**204**	**13%**
Net imports (+) Net exports (-) (Avg MW)	October	87	-145	-266%
	November	257	-258	-200%
	December	-168	-561	234%
	Q4	**57**	**-322**	**-669%**
Available Thermal (Avg MW)	October	8,935	9,122	2%
	November	9,363	9,607	3%
	December	9,797	9,964	2%
	Q4	**9,365**	**9,564**	**2%**

Figure 5: Daily average temperatures across Calgary, Edmonton, and Fort McMurray (December 2022 and 2023)

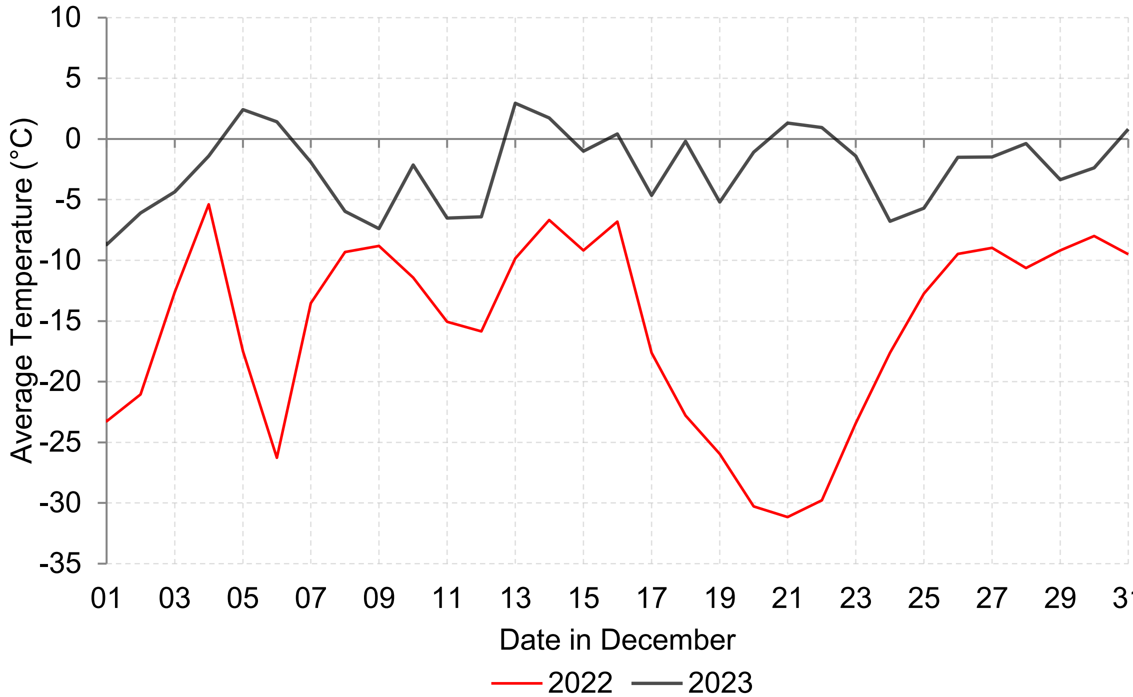


Table 3: Monthly average temperatures across Calgary, Edmonton, and Fort McMurray (Q4 2021, Q4 2022 and Q4 2023)

Month	2021	2022	2023
Oct	4.95	8.09	5.06
Nov	-1.61	-6.37	-0.49
Dec	-16.16	-15.48	-2.39

Wind generation in December averaged 2,136 MW over the month, a record high (Figure 6). This was a function of both a strong wind resource and new wind assets coming online. Since the start of Q3, 667 MW of wind generation capacity has been added to the grid increasing supply (Table 4). In addition, as shown by Table 5, the utilization of available wind capacity was 51% in December, illustrating a strong wind resource in the month.

The average hourly renewable[3] generation in December 2023 was greater than the all-time high. Hourly renewable generation averaged 2,400 MW in December, accounting for 23% of average hourly AIL, a new record. In some hours of Q4, renewables provided 40% of AIL, and in 13% of hours in the quarter renewables accounted for 30% or more of AIL.

As more wind and solar generation are added to the grid there is a larger amount of variance for total intermittent generation. In Q4 the maximum hourly average of intermittent generation was

[3] Wind, solar, and hydro.

4,122 MW and the minimum was 16 MW. The standard deviation of intermittent generation increased from 625 MW in Q4 2022 to 926 MW in Q4, an increase of 48%. An example of the variation in intermittent generation is discussed in section 1.3.

Figure 6: Maximum, average, and minimum of hourly wind generation by month (January 2018 to December 2023)

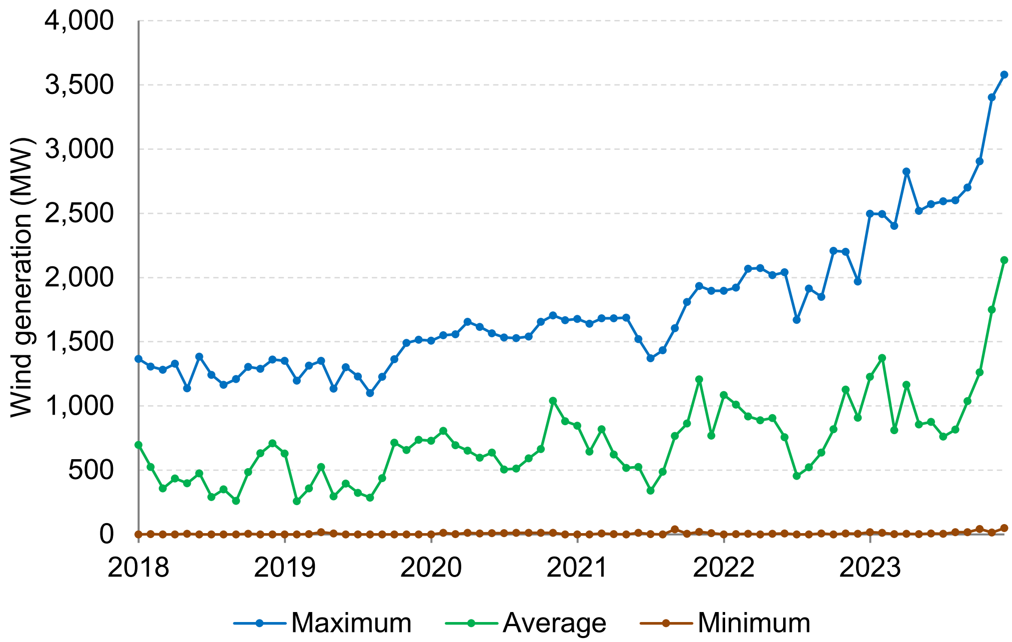


Table 4: Wind assets that started to generate after July 1, 2023

Asset Name	Capacity (MW)	Date of first generation
Jenner 1	122	July 14
Stirling	113	August 2
Sharp Hill	297	October 31
Jenner 2	71	November 4
Buffalo Atlee 1	18	December 2
Buffalo Atlee 2	18	December 5
Buffalo Atlee 3	18	December 5
Buffalo Atlee 4	10	December 13

Table 5: Utilization of available wind capacity (Q4 and Q4 2022)

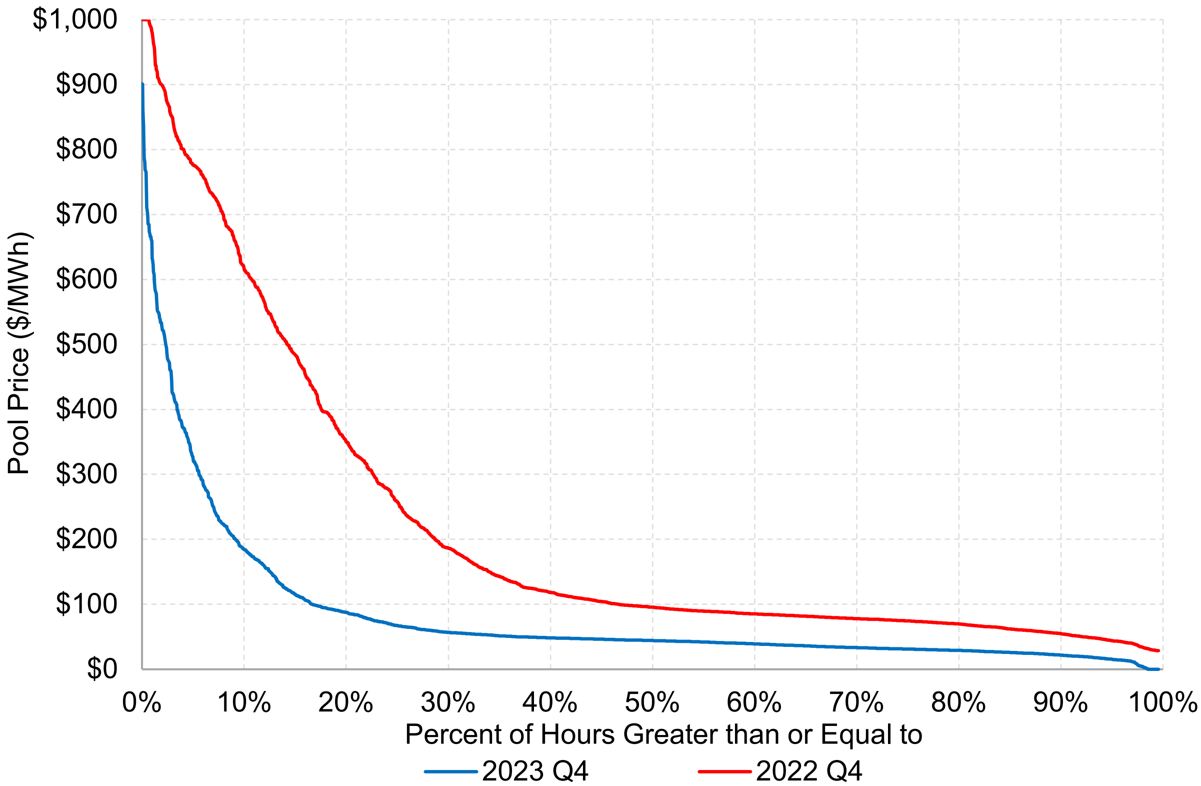
	2022	2023
Oct	35%	34%
Nov	47%	45%
Dec	36%	51%

Lower natural gas prices were also a factor in lower pool prices in Q4. The price of natural gas averaged $2.19/GJ in the quarter, which is 55% lower than prices in Q4 2022 (Table 2). Lower natural gas prices mean lower input costs for gas-fired generators, which set the price 94% of the time in Q4. The lower natural gas prices reflect higher storage volumes, which were up 19% year-over-year.[4]

1.3 Market outcomes and events

Lower year-over-year pool prices in Q4 2023 are indicated by the leftward shift of the pool price duration curve (Figure 7). Pool prices were lower in Q4 because of mild weather, increased wind generation, and lower natural gas prices. Hourly pool prices in Q4 ranged from $0/MWh to $901/MWh.

Figure 7: Pool price duration curves (Q4 2022 and Q4 2023)



The highest daily average pool price in Q4, $392/MWh, occurred on October 25 and resulted from low intermittent generation (Figure 8) and outages at Keephills 2, the Calgary Energy Centre, and a Joffre CT.

December 26 was the lowest priced day in the quarter as pool prices averaged $12/MWh. Consistently high wind generation (Figure 9) led to low prices on this day. The System Marginal

[4] EIA Weekly Natural Gas Storage report – December 29, 2023

Price (SMP) was $0/MWh for a total of 9.3 hours on Boxing Day (Table 6). Supply surplus events are discussed in section 1.3.2.

Figure 8: System demand, wind and solar generation, net demand, and SMP (October 25)

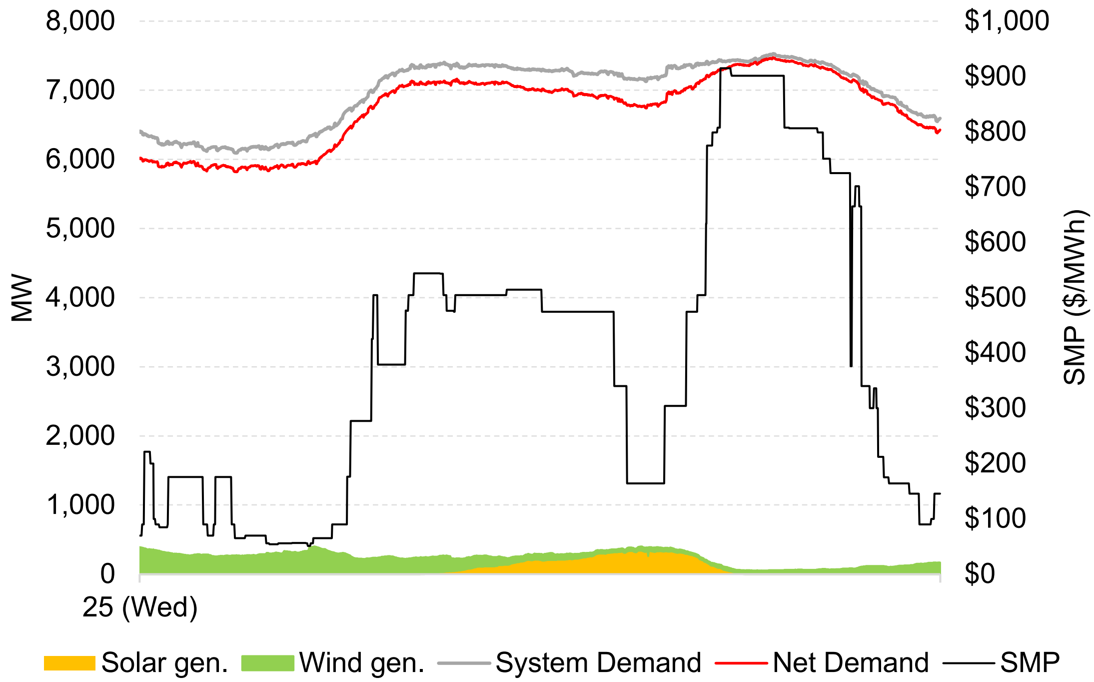


Figure 9: System demand, wind and solar generation, net demand, and SMP (December 26)

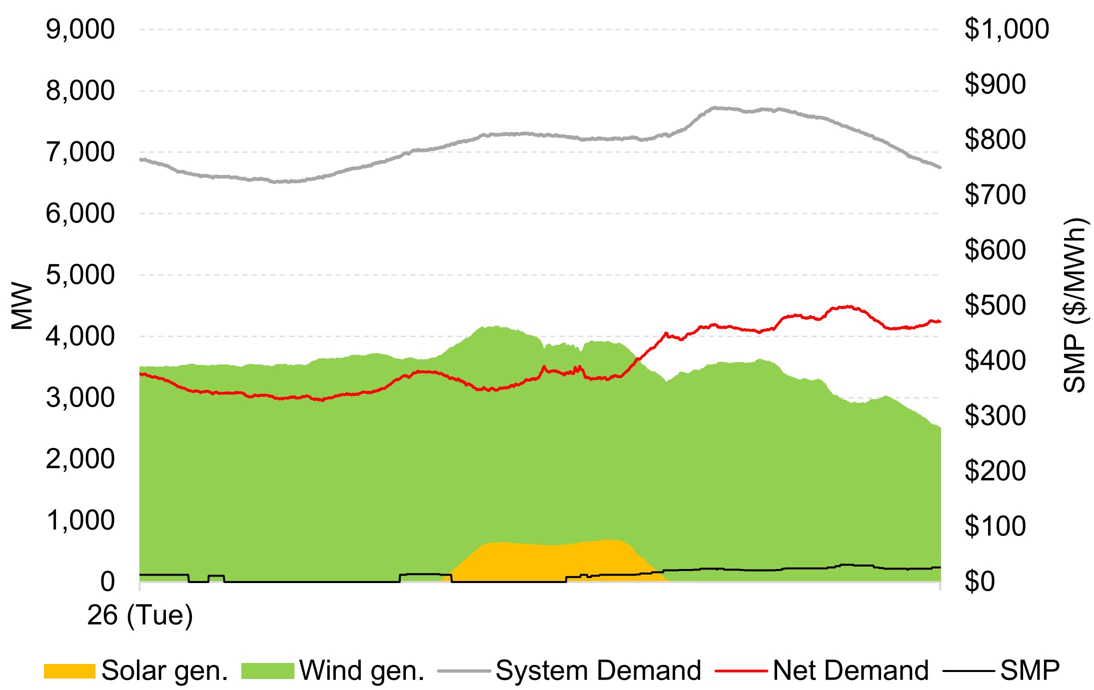


Table 6: Periods of $0/MWh SMP on December 26

From	To	Duration (hours)
01:28	02:04	0.6
02:32	07:48	5.3
09:21	12:47	3.4

1.3.1 Renewable generation variability

While consumers benefit from intermittent generation when it's available, the increasing amount of intermittent generation is raising price volatility in the energy market.

The events of Sunday, November 12, 2023 illustrate price volatility arising from intermittent generation. That day, the SMP ranged from $0/MWh to $999.99/MWh due to variations in intermittent generation. In the morning and early afternoon, prices were low reflecting large amounts of wind generation. The SMP was $0/MWh from 00:09 to 00:14 and from 11:03 to 12:00. In the afternoon, wind and solar generation both declined and total intermittent supply fell from 3,000 MW at 12:00 to 300 MW at 16:30 (Figure 10). The SMP was $999.99/MWh from 17:00 to 17:34, although the AESO did not declare an Energy Emergency Alert.

In addition to intermittent renewable generation, three gas-fired steam assets were commercially offline on November 12: Sheerness 1, Sheerness 2, and Battle River 5. These assets represent approximately 1,200 MW of thermal generation capacity. These assets were commercially offline even though the wind forecast published by the AESO accurately predicted the decline in wind generation eight hours ahead of time (Figure 11).

This example illustrates the unit commitment problem with the current market rules and design, a topic discussed extensively in the MSA's Q2 2023 Quarterly Report.[5]

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[5] MSA Quarterly Report for Q2 2023 section 1.5

Figure 10: System demand, wind and solar generation, net demand, and SMP (November 10 to 13)

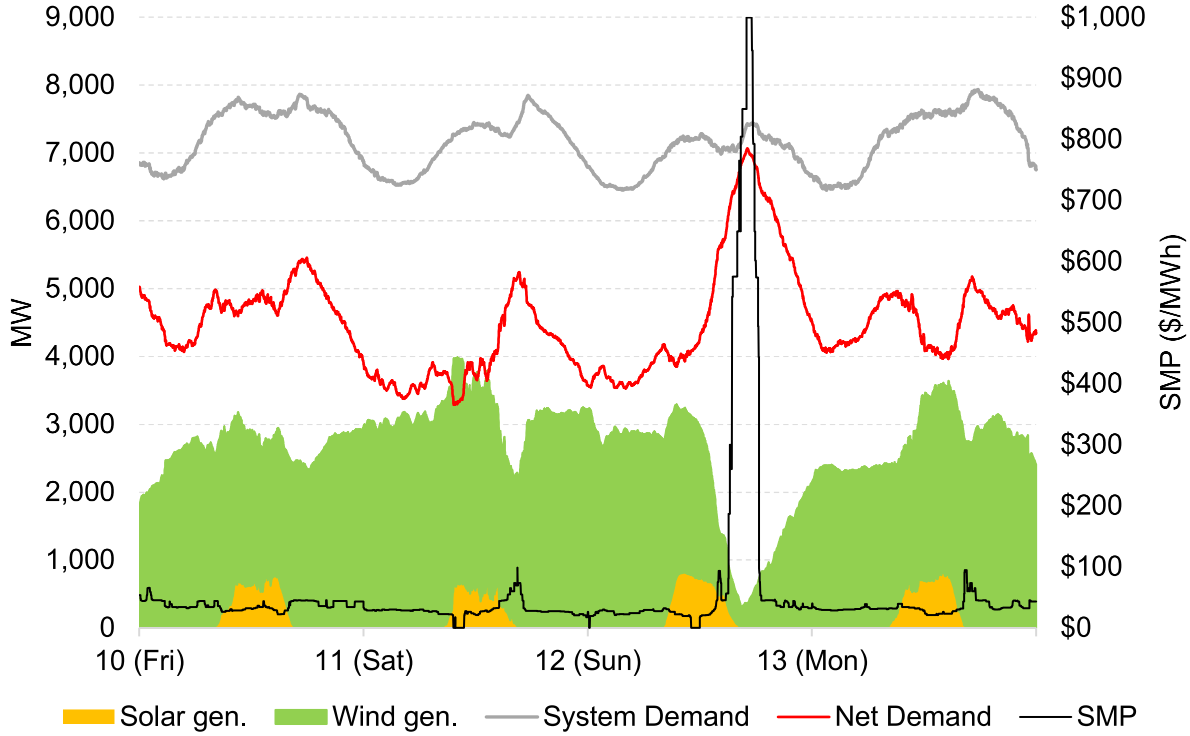
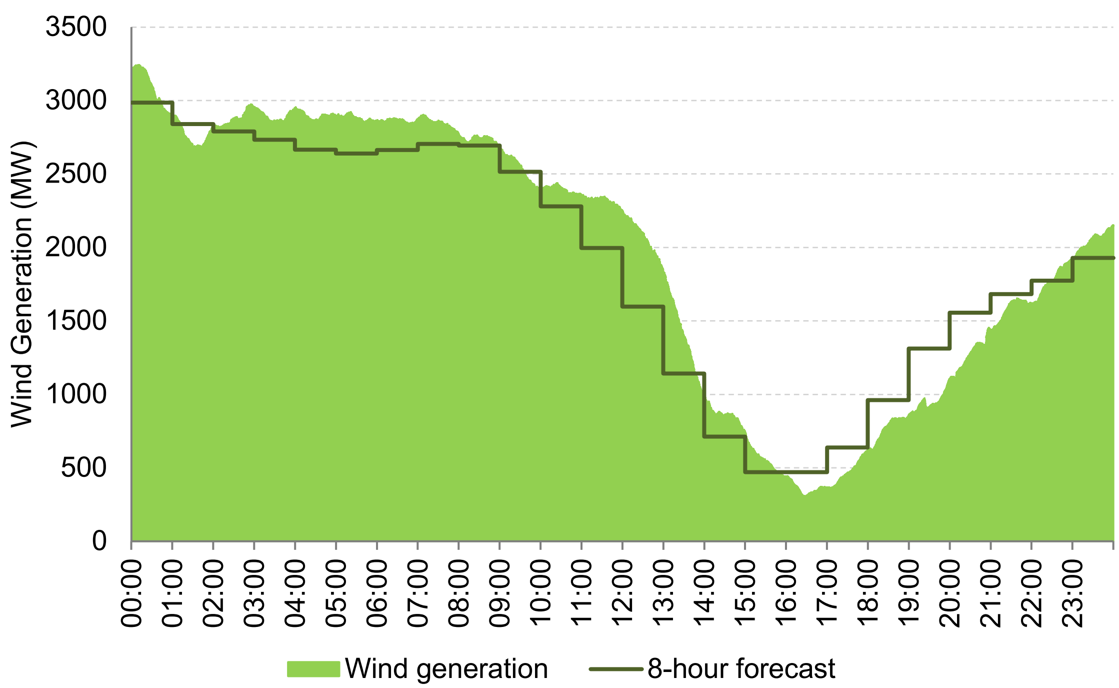


Figure 11: Actual wind generation and the 8-hour forecast (November 12)



1.3.2 Supply surplus events

Supply surplus occurs when system demand is less than the amount of generation offered at $0/MWh. When this occurs, there is too much supply relative to prevailing demand. When the AESO declares a supply surplus it may curtail imports and flexible domestic generation. The AESO declared a supply surplus on seven occasions spanning 14.4 hours in Q4.

On October 4, when Alberta was islanded from WECC, the AESO curtailed 45 MW of imports from Saskatchewan and up to 98 MW of wind generation to resolve the supply surplus event (Table 7). The AESO also curtailed 165 MW of wind generation to resolve the supply surplus event on October 6 when Alberta was again islanded from WECC. On October 20, the supply surplus event was resolved by curtailing 90 MW of imports from Saskatchewan.

The remaining supply surplus events in Q4 did not involve the AESO curtailing supply (Table 7).

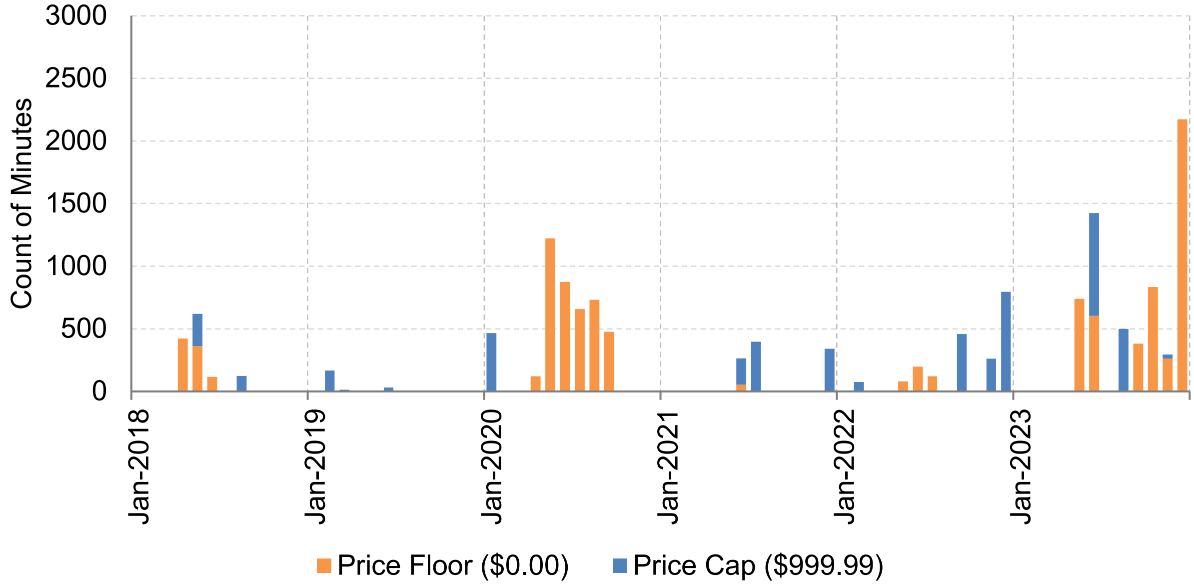
Table 7: Supply surplus events declared by the AESO in Q4

From	To	Length (hours)	Curtailments
Oct-04 03:00	Oct-04 04:37	1.6	SK imports curtailed by 45 MW Wind curtailed by up to 98 MW
Oct-06 23:12	Oct-07 02:32	3.3	Wind curtailed by up to 165 MW
Oct-20 14:03	Oct-20 15:13	1.2	SK imports curtailed by 90 MW
Dec-21 00:16	Dec-21 03:34	3.3	None
Dec-21 04:16	Dec-21 04:53	0.6	None
Dec-23 00:05	Dec-23 01:00	0.9	None
Dec-23 01:47	Dec-23 05:15	3.5	None

The SMP was $0/MWh for 54.5 hours or 2.5% of the time in Q4 with most of these events occurring in December (Figure 12) when wind generation was high and temperatures were mild.

An SMP of $0/MWh does not necessarily indicate a supply surplus event because the SMP is set based on the unconstrained supply curve. This means that if wind generation is curtailed due to transmission constraints that curtailed supply will still be included in the supply curve and influence price which may push the SMP down to $0/MWh. However, the constrained supply would not physically cause supply to exceed demand.

Figure 12: Count of minutes the SMP was at the price floor or price cap by month (January 2018 to December 2023)



1.4 Market power and offer behaviour

Generators have market power when they can profitably offer some of their generation capacity at prices exceeding their short-run marginal cost (SRMC). Comparing pool prices with estimated counterfactual prices based on SRMC offers is a gauge of market power. Pool prices in Q4 2023 were the lowest when contrasted with previous years (Table 8). The average pool price in Q4 was $82/MWh, 95% higher than the MSA's counterfactual price based on SRMC.

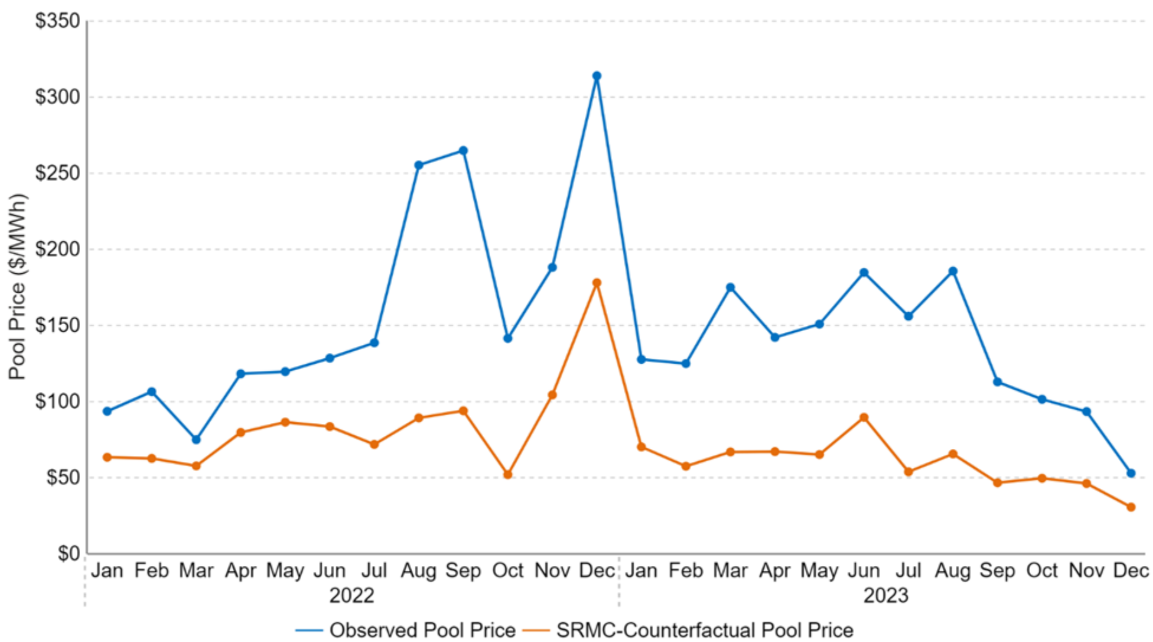
Table 8: Pool prices and SRMC-counterfactual pool prices (Q1 2021 to Q4 2023)

	Observed Pool Price	SRMC-Counterfactual Pool Price	Observed vs. SRMC (%)
Q1 2021	$95	$44	116%
Q2 2021	$105	$52	102%
Q3 2021	$100	$56	79%
Q4 2021	**$107**	**$62**	**73%**
Q1 2022	$90	$61	48%
Q2 2022	$122	$83	47%
Q3 2022	$221	$85	160%
Q4 2022	**$214**	**$111**	**93%**
Q1 2023	$142	$65	118%
Q2 2023	$160	$74	116%

Q3 2023	$152	$55	176%
Q4 2023	**$82**	**$42**	**95%**

Figure 13 shows monthly average pool prices and SRMC-counterfactual pool price estimates since January 2022. The margin between the two prices averaged $50/MWh in October, $48/MWh in November, and fell to $23/MWh in December. December's average margin was the smallest since March 2022. SRMC-counterfactual pool price estimates were lower in Q4 than in recent years due to low natural gas prices and higher levels of intermittent generation.

Figure 13: Monthly observed and SRMC-counterfactual pool prices (January 2022 to December 2023)



The Lerner Index is a measure of market power that measures the markup of price over the market's marginal cost of generation, expressed as a percentage of the price. The market markup in Q4 was 21%, lower than all previous quarters since Q2 2022 (Figure 14). The market markup fell over the quarter, from 23% in October, to 22% in November, and to 18% in December (Figure 15).

Figure 14: Quarterly average market markup (Q1 2020 to Q4 2023)

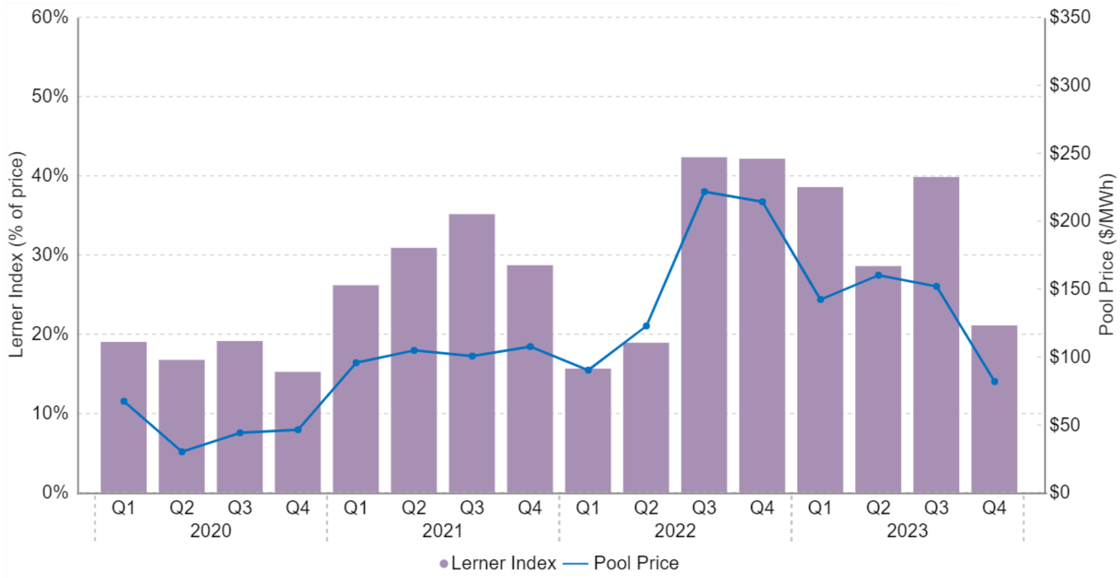
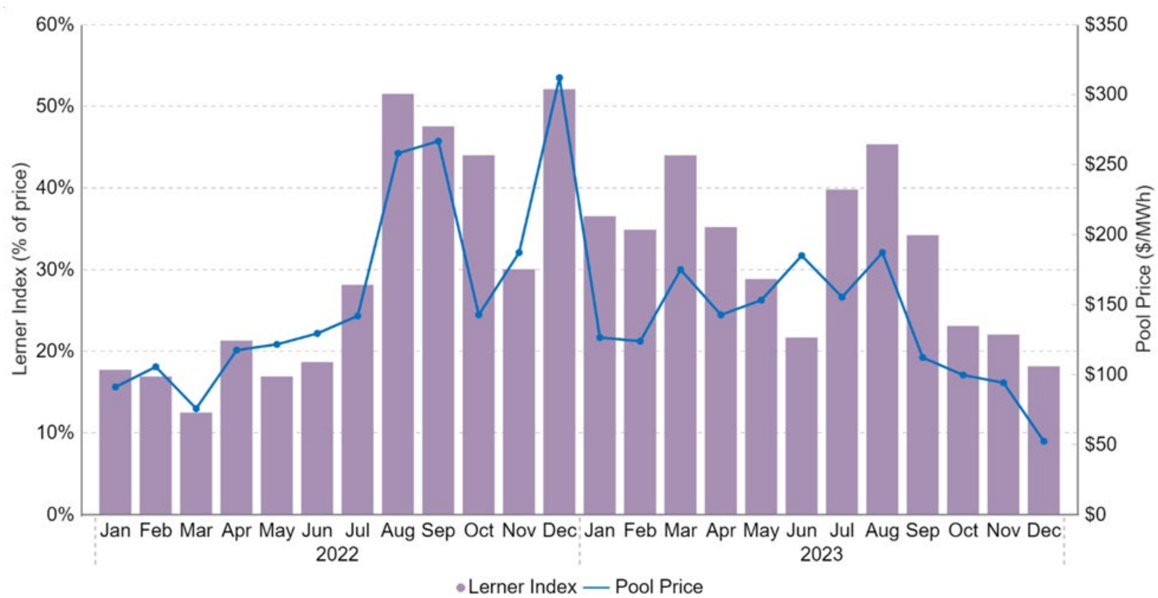


Figure 15: Monthly average market markup (January 2022 to December 2023)



The decline in average market markups in Q4 was significantly influenced by a greater number of hours with negative market markups, which occurred more frequently than other quarters in 2023 (Table 9). Negative market markups can occur in hours where at least some generation capacity is offered below its estimated SRMC and supply cushion is high, and is more common in periods when intermittent generation is high such as Q4. Negative market markups occur most frequently in hours where pool prices are low, which occurred frequently in Q4.

Table 9: Quarterly frequency of negative market markups (Q1 to Q4 2023)

Quarter	Hours with Negative Markups	Percentage of Total Hours
Q1 2023	97	4%
Q2 2023	397	18%
Q3 2023	231	11%
Q4 2023	632	29%

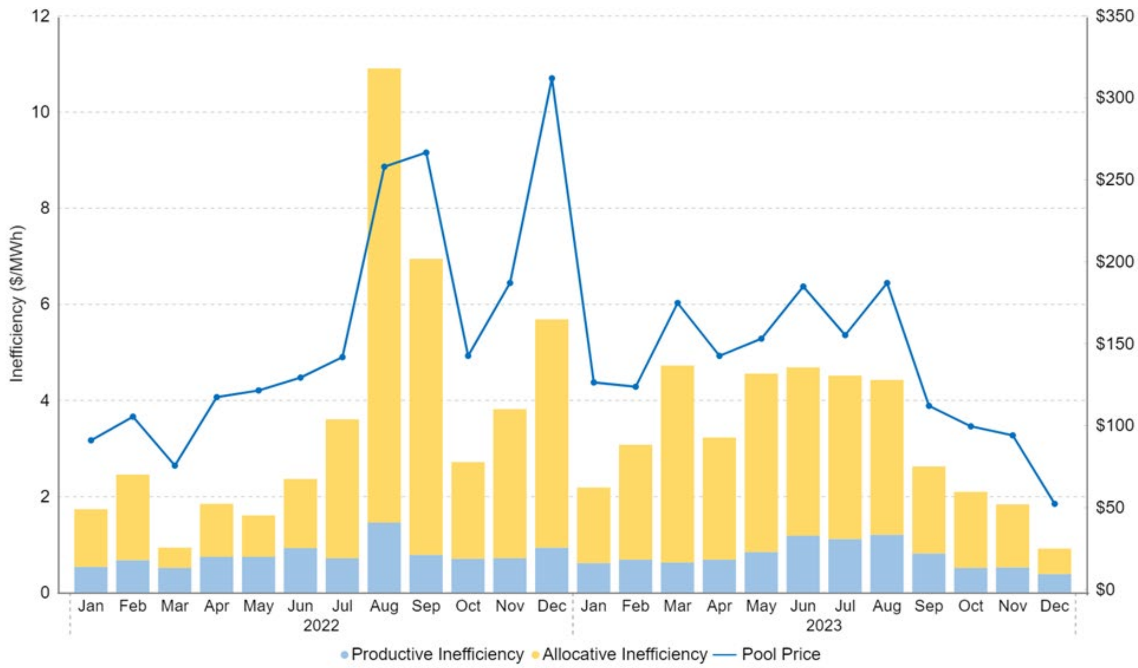
Market power is exercised by generators by offering some generation capacity above SRMC. The exercise of market power results in two distinct types of static inefficiency: allocative inefficiency and productive inefficiency. Together, these two types of inefficiency represent static inefficiency, which the MSA uses as a measure of the exercise of market power.

Allocative inefficiency measures the benefit to consumers and generators from additional production that is not realized due to generators pricing their capacity above SRMC. An electricity market is allocatively efficient if the SRMC of the marginal generator is equal to the marginal benefit to consumers.

Productive inefficiency measures excess generation costs that occur when lower cost generation is economically withheld. An electricity market is productively efficient when only the lowest cost generation in the system is dispatched to meet demand.

In Q4, the average static inefficiency was $1.59/MWh, a 59% decline quarter-over-quarter. Static inefficiency in December was $0.91/MWh, the lowest value since December 2020 and 84% less than December 2022 (Figure 16). Static inefficiencies in October and November were also lower year-over-year, falling by 23% and 52%, respectively.

Figure 16: Monthly average static inefficiency (January 2022 to December 2023)



1.4.1 Pivotality

In Q4 2023, there were fewer hours in which generators were pivotal, which reduced generators' ability to exercise market power. However, in the few hours where generators were pivotal, they exercised market power, leading to higher prices in those hours.

A firm is pivotal in hours when its withholdable capacity[6] is required for the market to clear. In a given hour, one or more firms may be pivotal, or no firms may be pivotal. 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 pivotal collectively with their combined withholdable capacity ("Two Firms Collectively Pivotal"); or
- there may be no firms that are individually or collectively pivotal ("No Firm Pivotal").

If a firm is pivotal, it has the ability to set the pool price by economically withholding its withholdable capacity. Conversely, when a firm is not pivotal its ability to profitably economically withhold is less. In Q4, no firm was pivotal in 71% of hours, the most since Q4 2020 (Figure 17). In October, one or more firms were pivotal in 11% percent of hours, followed by November at 8%, and December at 4% (Figure 18).

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[6] Withholdable capacity includes all capacity that can be economically withheld by generators, except for intermittent generation and minimum stable generation (MSG).

Figure 17: Market-level pivotality by quarter (Q1 2020 to Q4 2023)

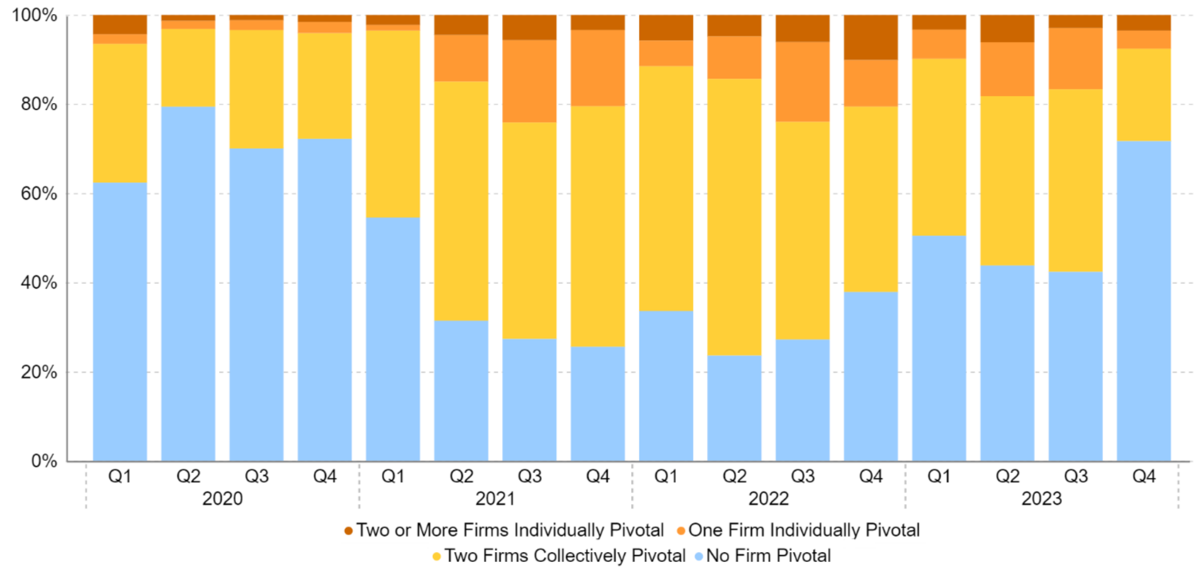
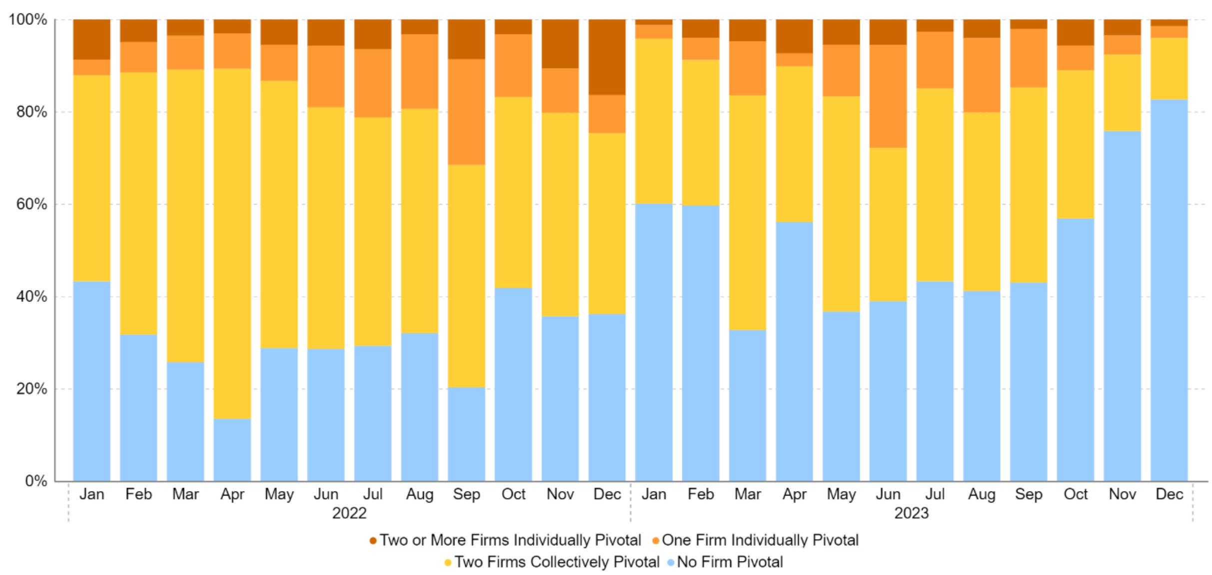


Figure 18: Market-level pivotality by month (January 2022 to December 2023)



Higher intermittent generation in Q4 2023 reduced the number of hours where one or more firms were pivotal. Intermittent generation averaged 1,936 MW across Q4, 55% higher than the previous quarter, and 80% higher than Q4 2022 (Figure 19). Higher levels of intermittent generation occurred in hours where no firm was pivotal in Q4 than in hours with some degree of pivotality (Figure 20). The amount of intermittent generation in hours where no firm is pivotal has increased since 2020, while intermittent generation in hours where some degree of pivotality exists has increased more moderately.

Figure 19: Quarterly average intermittent generation (Q1 2020 to Q4 2023)

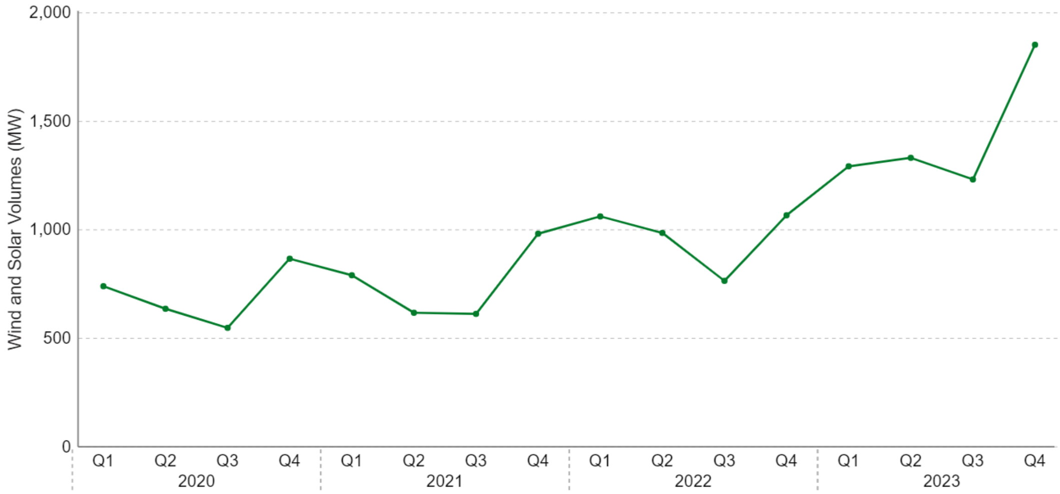
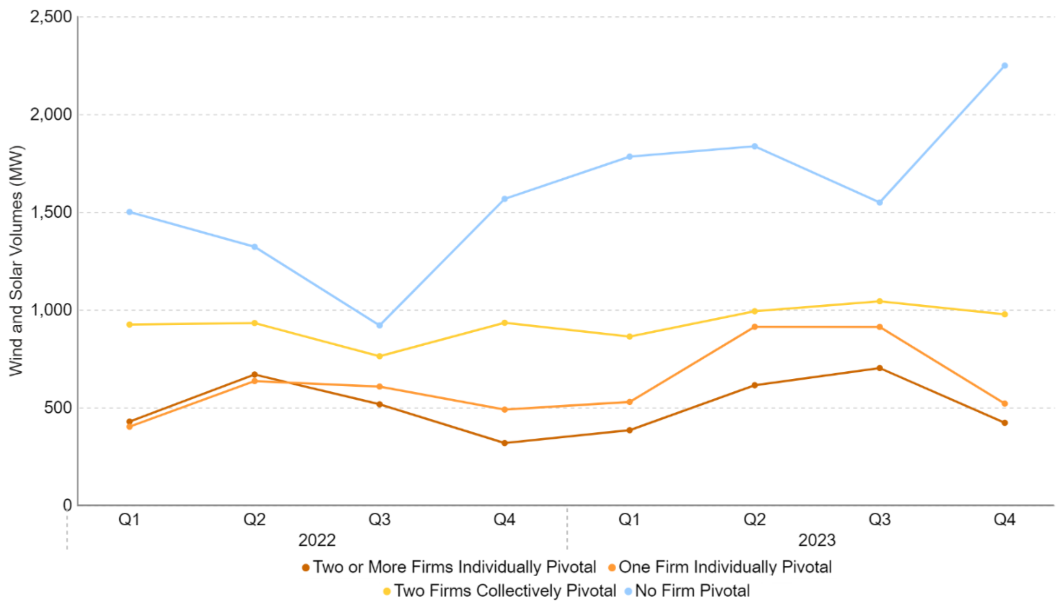
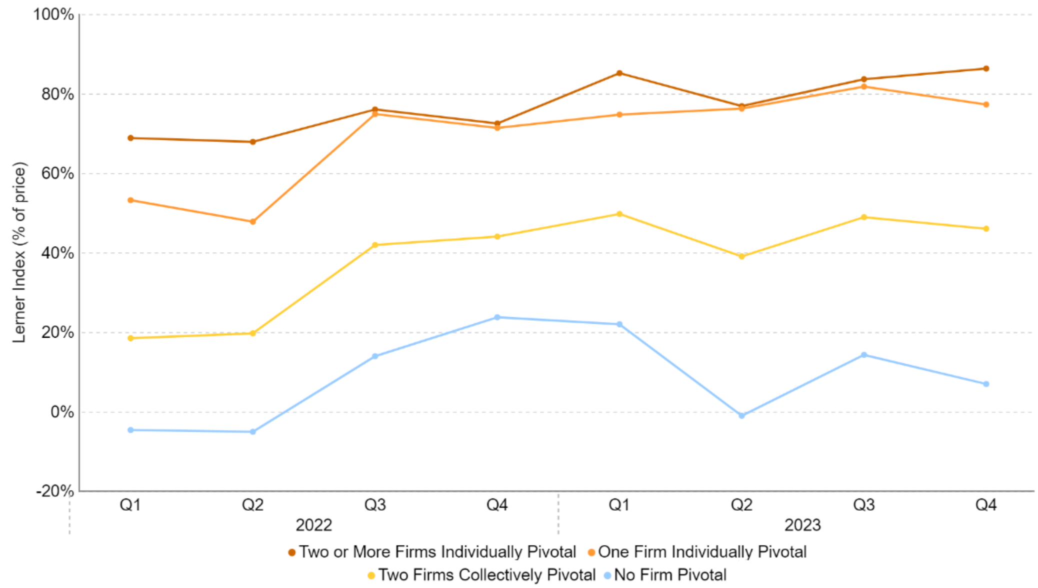


Figure 20: Quarterly average intermittent generation volumes by pivotality condition (Q1 2020 to Q4 2023)



Despite fewer pivotal hours in Q4, firms continued to exercise market power when they were pivotal. Market markups remained high during hours where firms were pivotal (Figure 21). Although this quarter had lower Lerner indices and pool prices overall, this was largely because of the high percentage of hours where no firms were pivotal.

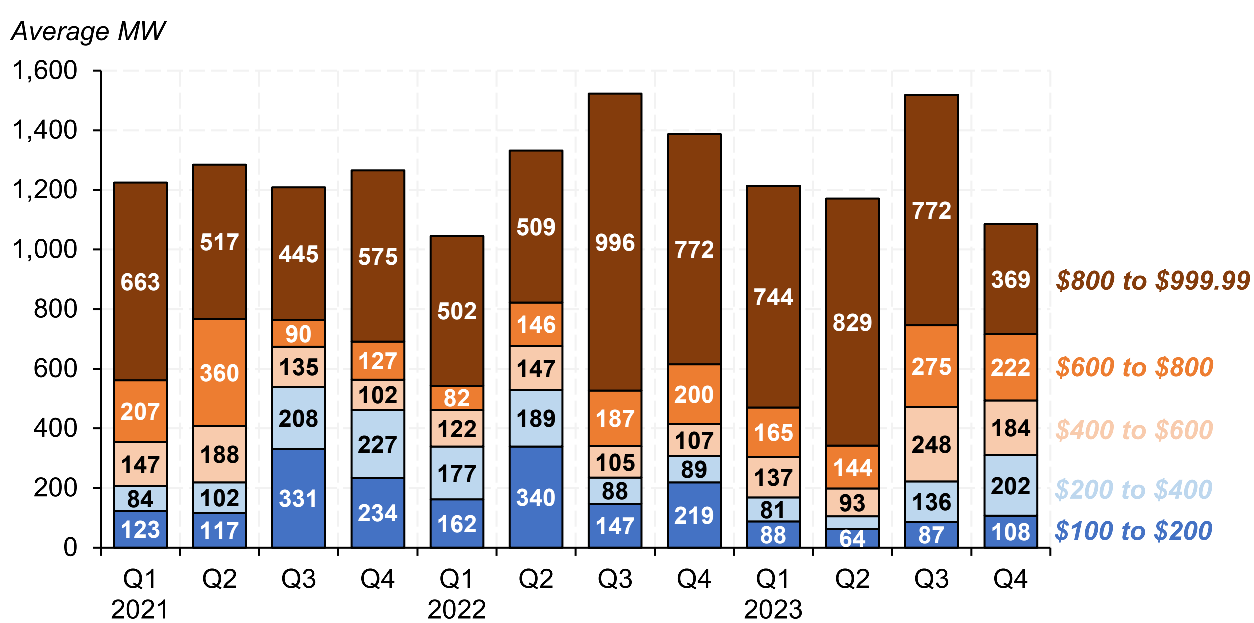
Figure 21: Quarterly average market markup by pivotality condition (Q1 2020 to Q4 2023)



1.4.2 Offer behaviour

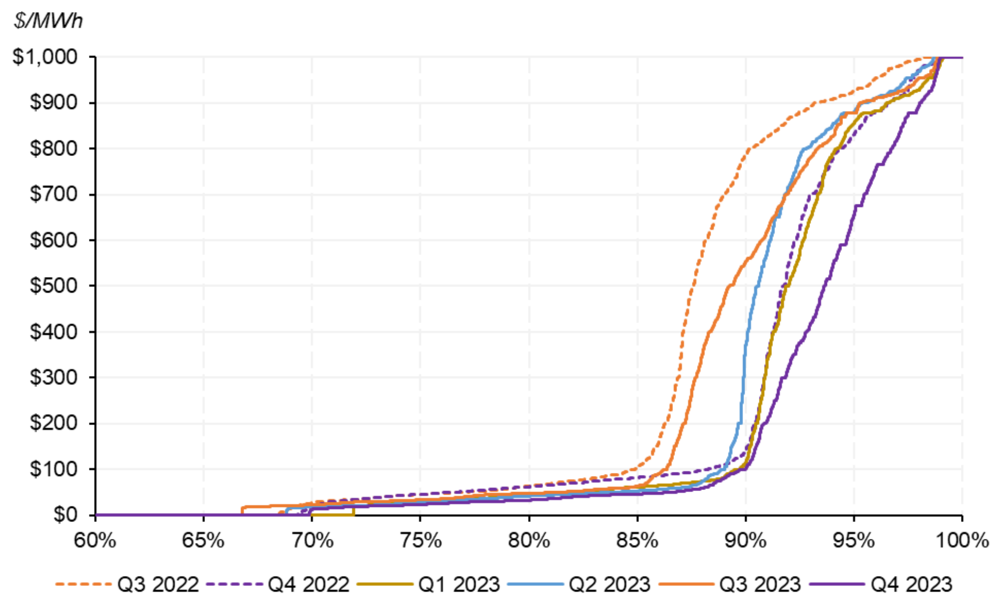
Less capacity was offered above $100/MWh in Q4 and was more evenly distributed at different price levels compared to previous quarters (Figure 22). In particular, less capacity was offered above $800/MWh compared to the previous three years. This change may be attributable to the 426 MW of capacity placed on long lead time on average in Q4, as much of this capacity may have been withheld at relatively high offer prices had it not been put on long lead time.

Figure 22: Average non-hydro capacity offered above $100/MWh (Q1 2021 to Q4 2023)



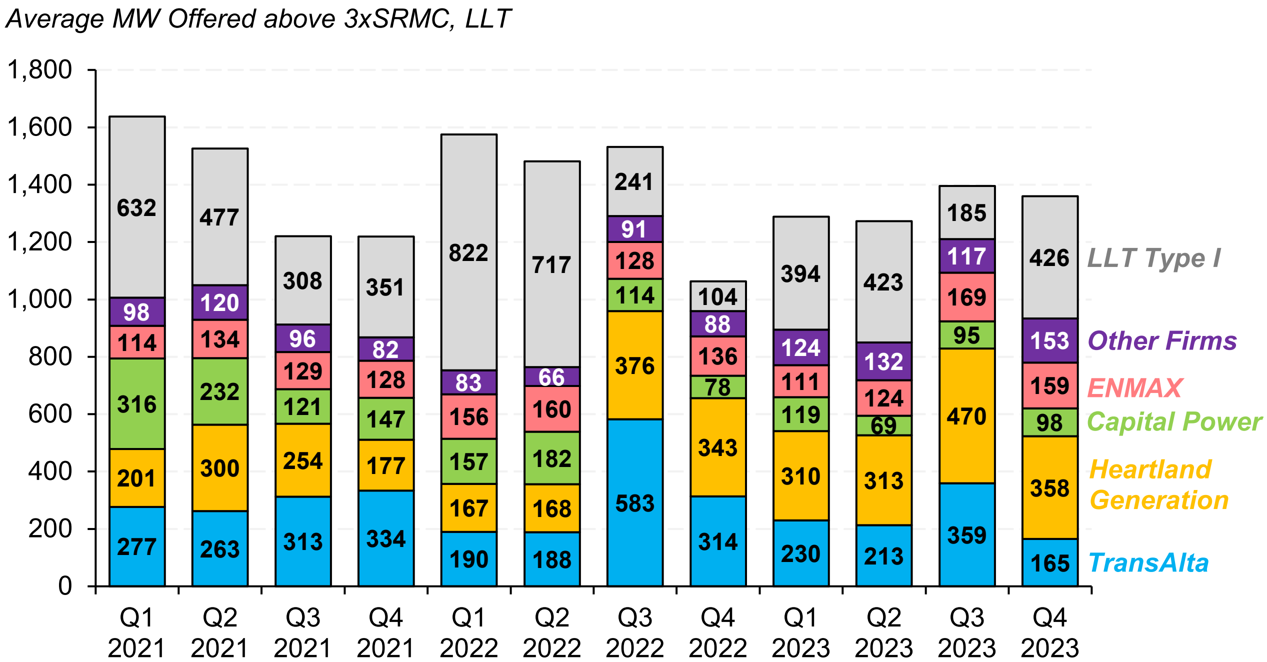
The relatively even dispersion of offers above $100/MWh was reflected in the offer curve of thermal assets in Q4 (Figure 23). The thermal offer curve in previous quarters exhibited a concave “hump” at prices above $100/MWh, reflective of a greater share of offers at higher prices than lower prices, while the Q4 thermal offer curve was significantly more linear. This change in the distribution of thermal offers in Q4 may reflect generators’ more limited ability to influence pool prices in Q4 due to high intermittent generation levels, and suggests generators may have been less certain of their pivotality when attempting to economically withhold.

Figure 23: Average thermal unit offers by quarter (Q3 2022 to Q4 2023)



While generators offered less capacity at prices above three times SRMC in Q4 2023, more capacity was put on long lead time compared to the previous quarter (Figure 24). Capacity put on long lead time in effect constitutes capacity priced out of the merit order. On average, 1,359 MW of non-hydro capacity was offered above three times SRMC or put on long lead time in Q4 2023, somewhat higher than the 1,329 MW average in 2023. The majority of non-hydro capacity offered above three times SRMC was controlled by TransAlta or Heartland Generation.

Figure 24: Average non-hydro capacity offered above 3xSRMC or on long lead time (LLT) (Q1 2021 to Q4 2023)



Since Q2 2022 generators in aggregate have typically offered less capacity above three times SRMC in periods where firms were pivotal than in periods where no firms were pivotal (Figure 25).[7] This result is consistent with competition among generators who attempt to prioritize dispatch in periods during pivotal conditions by offering at lower prices.

Despite less capacity being offered above three times SRMC during pivotal conditions, some of this capacity is often needed for the market to clear when firms are pivotal given the lower supply cushion conditions (Figure 26). This is particularly true when multiple firms are individually pivotal, which most often occurs when the supply cushion is below 1,000 MW.

[7] As a result of the MSA's SRMC estimation assumptions, hydro, cogeneration, and energy storage assets by construction are assumed to always offer at prices equivalent to their SRMC, and as such are omitted from the "three times SRMC" metric by construction.

Figure 25: MW offered above three times SRMC by pivotality condition (Q1 2021 to Q4 2023)

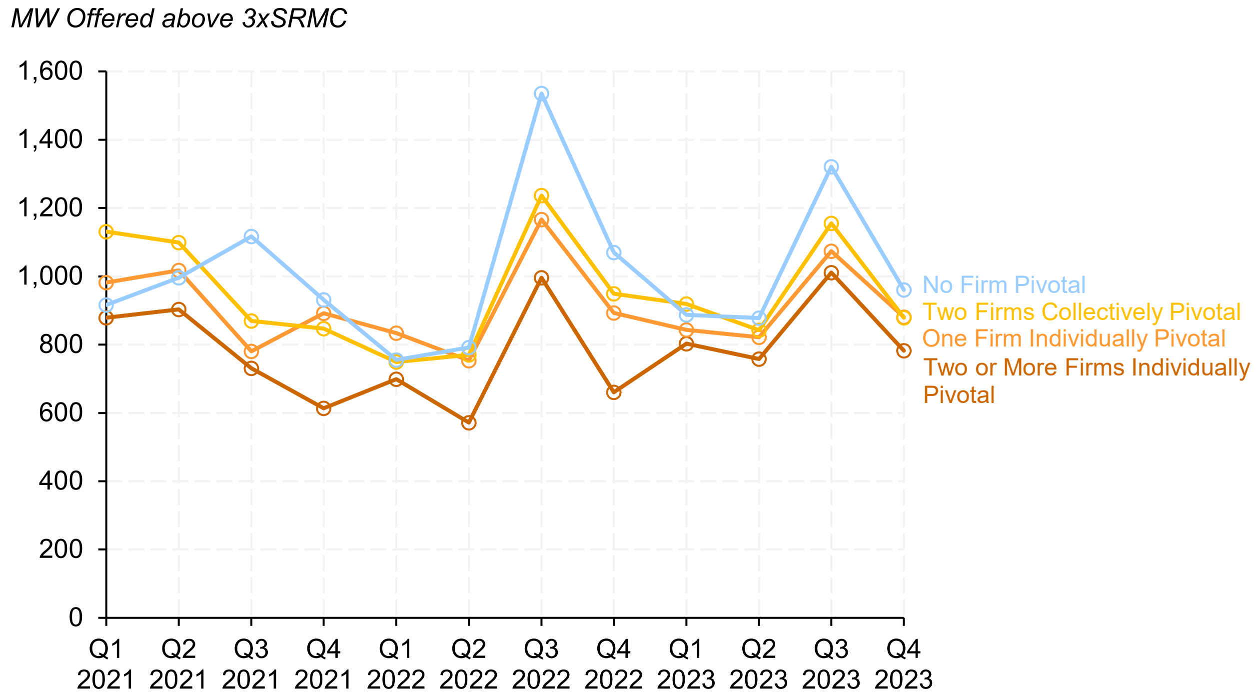
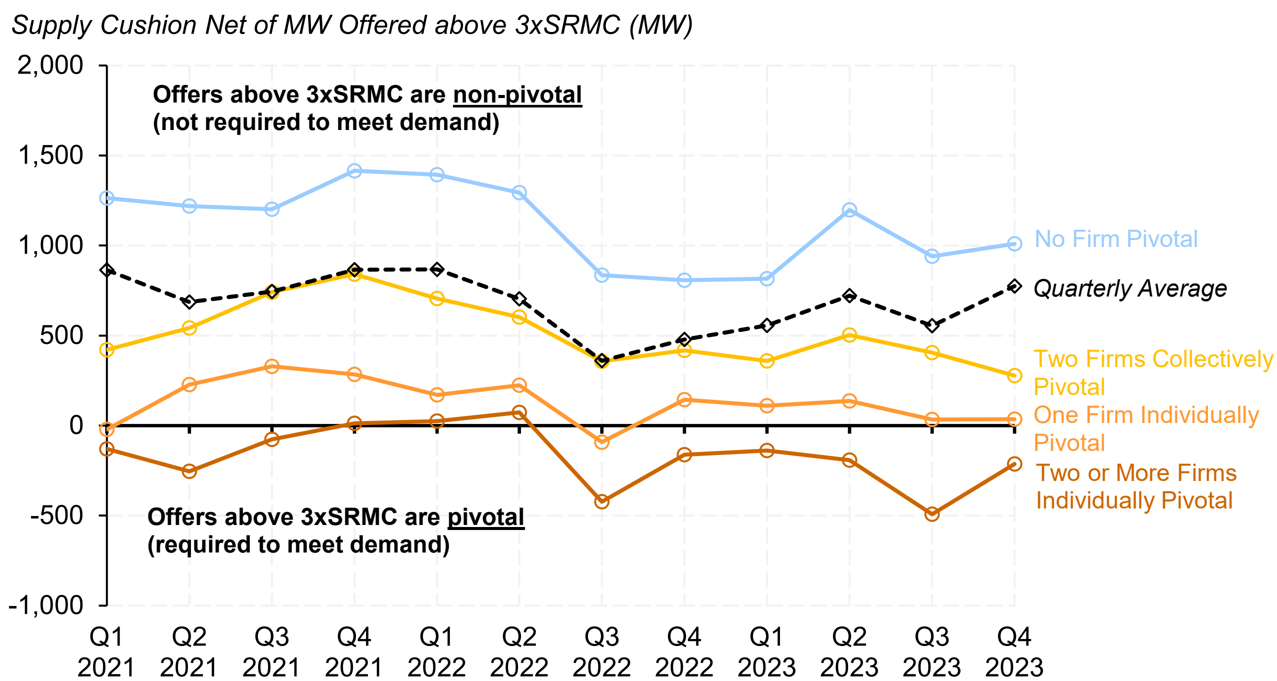
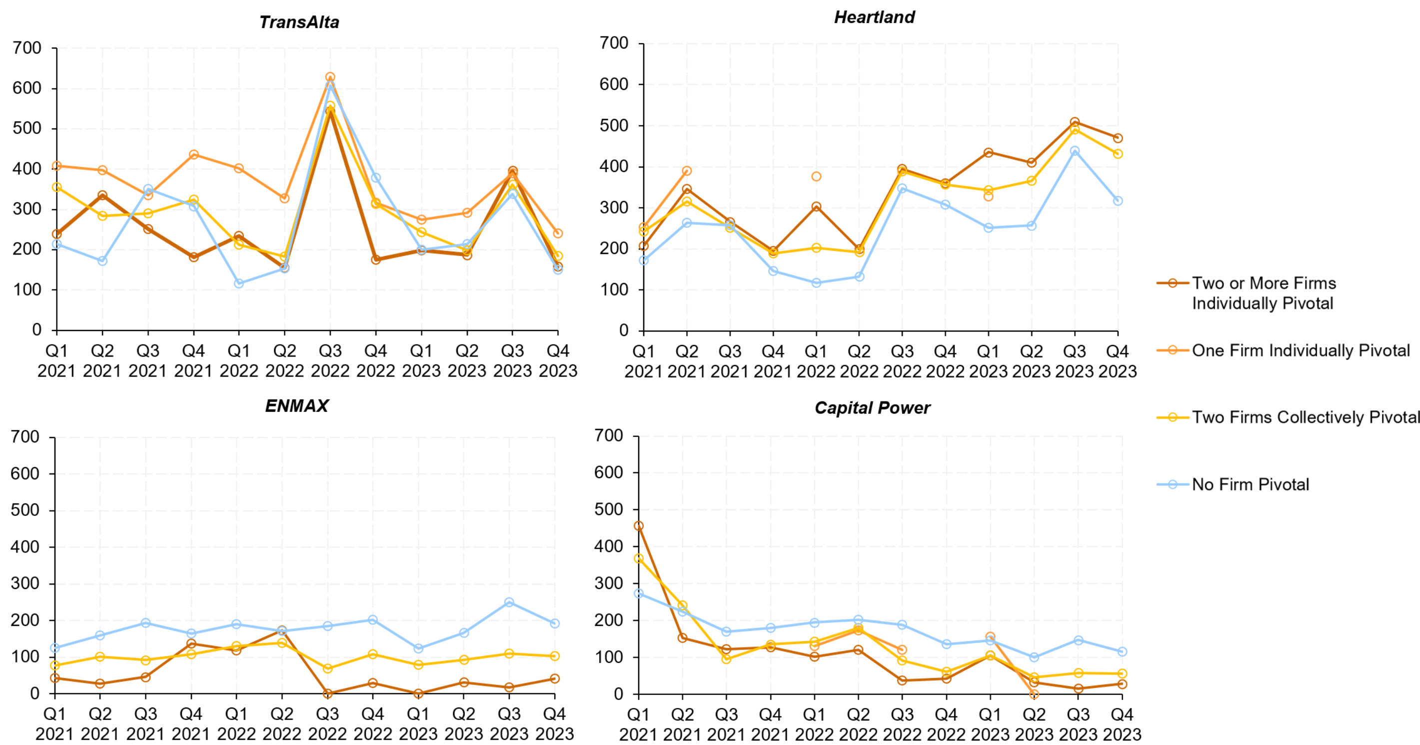


Figure 26: Supply cushion net of MW offered above 3x SRMC (Q1 2021 to Q4 2023)



The largest four generators generally offered lower amounts of capacity at prices above three times SRMC in Q4 compared to Q3 2023 (Figure 27). TransAlta and Heartland Generation continued to offer more capacity at these higher prices in periods where they were pivotal, while ENMAX and Capital Power continued to offer less capacity at higher prices in periods where they were pivotal.

Figure 27: MW offers above 3xSRMC by firm, pivotality condition (Q1 2021 to Q4 2023)



1.5 Carbon emission intensity

Carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The MSA has published analysis 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.[8]

1.5.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in each hour. Table 10 shows the minimum, mean, and maximum hourly average emission for Q4 over the past seven years, and Table 11 shows the same information for the past four quarters. The max carbon intensity has remained relatively the same since Q4 2022; however the minimum and mean emission intensity have seen more pronounced decreases. Notably, the maximum hourly average carbon emission intensity this quarter was lower than the minimum hourly average carbon emission intensity in Q4 2017.

Table 10: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2017 Q4	0.62	0.75	0.89
2018 Q4	0.56	0.68	0.79
2019 Q4	0.52	0.63	0.75
2020 Q4	0.47	0.59	0.72
2021 Q4	0.41	0.52	0.63
2022 Q4	0.37	0.48	0.57
2023 Q4	0.30	0.43	0.57

Table 11: Quarter over quarter min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2023 Q1	0.36	0.47	0.57
2023 Q2	0.28	0.44	0.57
2023 Q3	0.31	0.45	0.56
2023 Q4	0.30	0.43	0.57

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

Figure 28 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q4 for the past seven years. Figure 29 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 28 and Figure 29.

Figure 28: The distribution of average carbon emission intensities in Q4 (2017 to 2023)

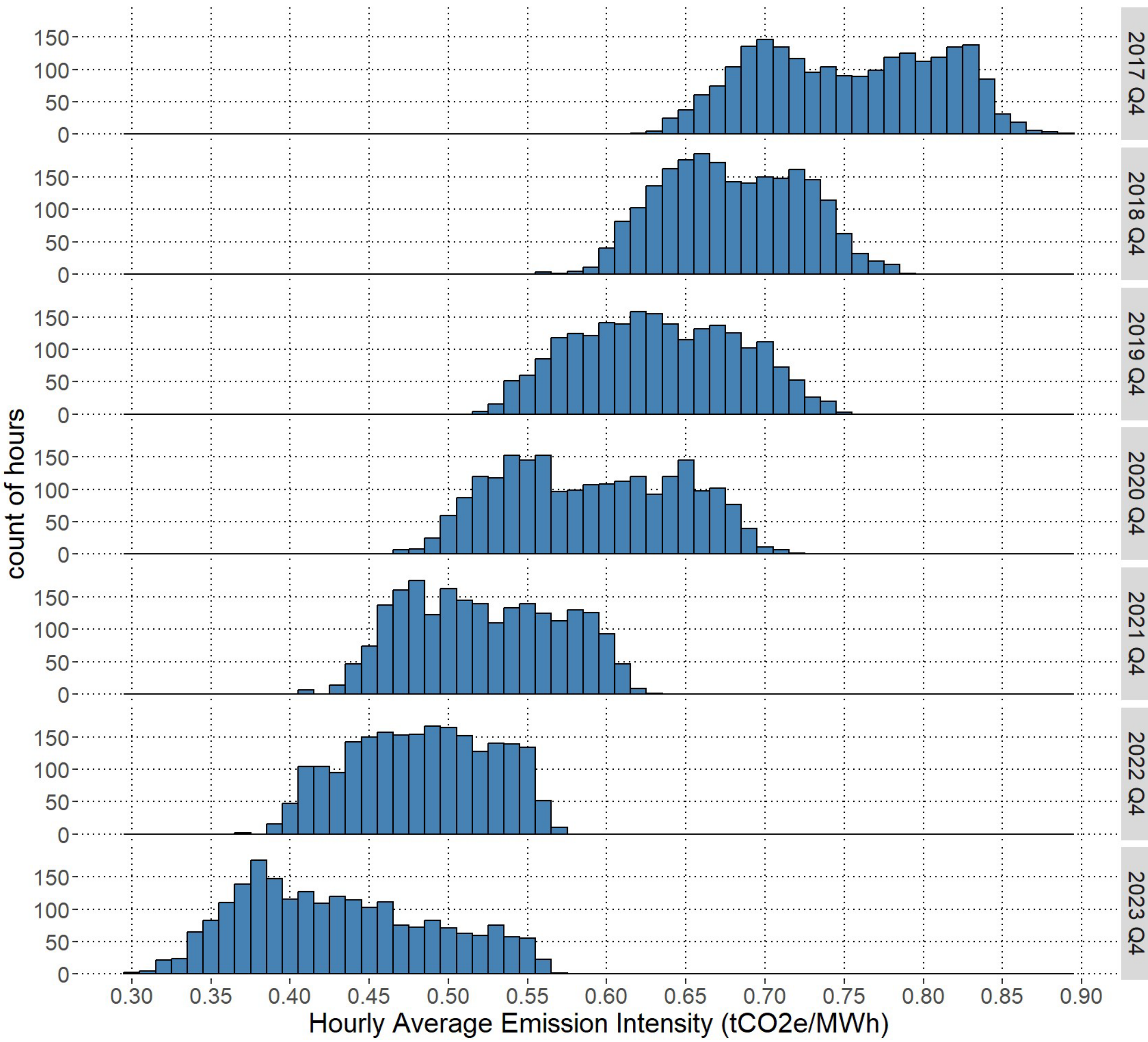
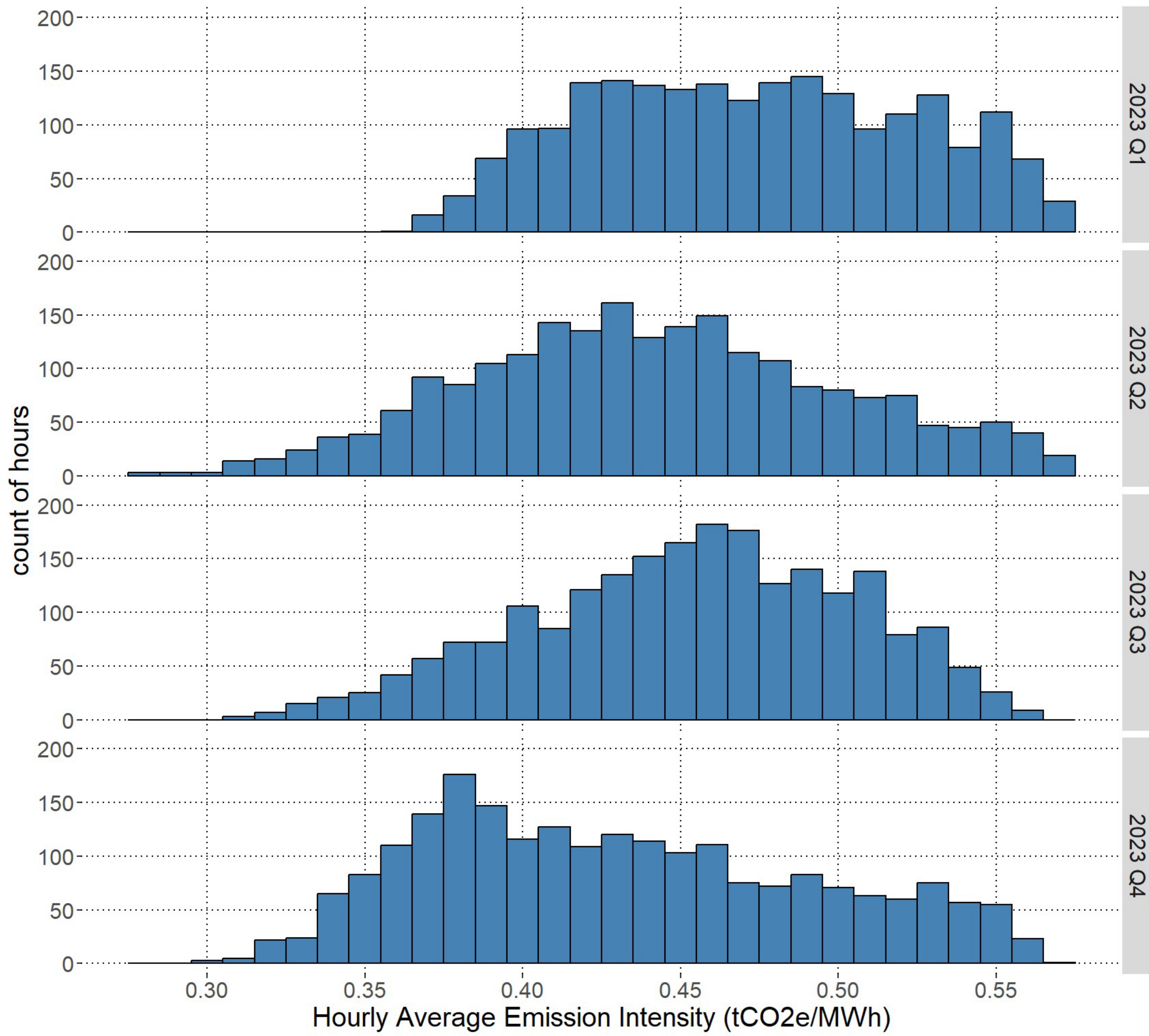
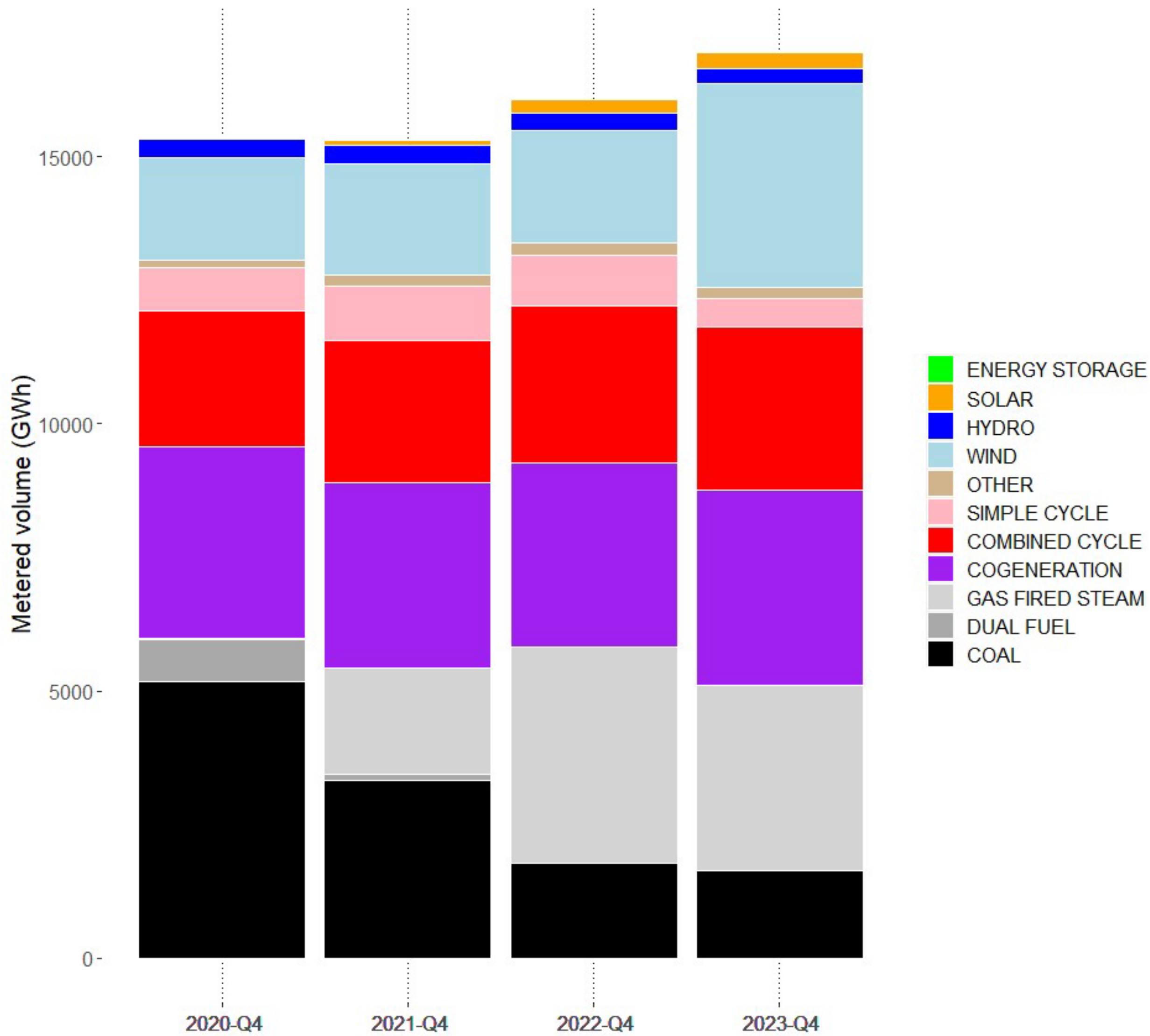


Figure 29: The distribution of average carbon emission intensities in the past four quarters



The general trends observed in the above distribution figures can be traced in Figure 30, 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 since 2020.

Figure 30: Quarterly total net-to-grid generation volumes by fuel type for Q4 (2020 to 2023)

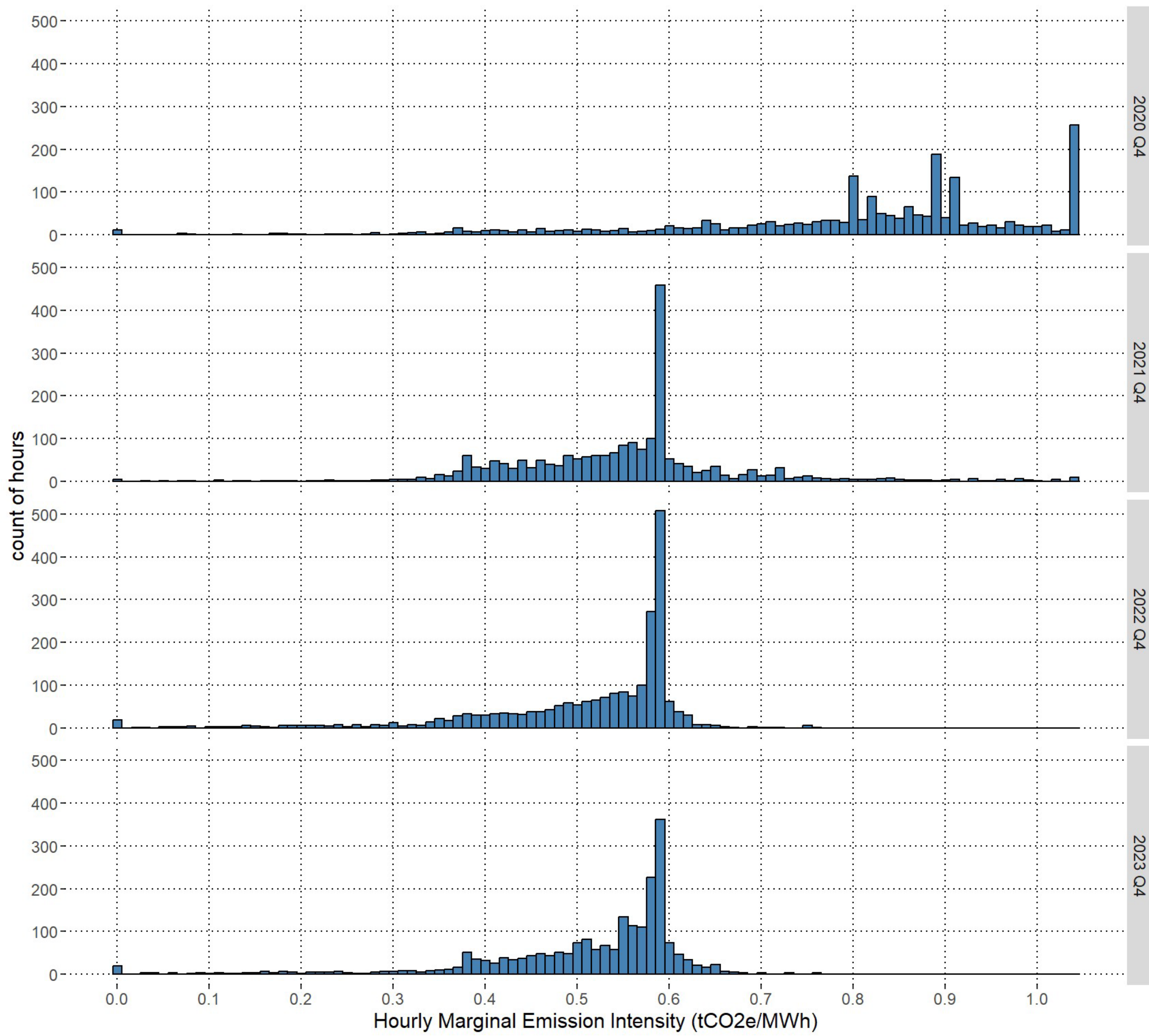


1.5.2 Hourly marginal emission intensity

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

Figure 31 shows the distribution of the hourly marginal emission intensity of the grid in Q4 for the past four years. Converted coal assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO2e/MWh from 2021 Q4 onwards.

Figure 31: The distribution of marginal carbon emission intensities in Q4 (2020 to 2023)



1.6 Energy storage analysis

As of January 2024, there is 190 MW of grid-scale energy storage in Alberta. These storage assets have primarily participated in the operating reserves market, although some assets engaged in arbitrage in the energy market. As of January 2024, there is over 1,700 MW of transmission-connected energy storage capacity not co-located with other generation assets in early stages of the AESO connection project list, which may or may not ultimately be developed.

Given substantial potential investment, the MSA has sought to understand:

- the viability of a transmission-connected energy storage asset that exclusively participates in the energy market,

- the impact of energy storage participation in the energy market on market outcomes, and

- the impact of existing tariff policies on energy storage that treat storage as both a load and supplier.

The AESO is currently engaging with industry stakeholders on tariff issues related to energy storage development.[9]

The MSA has concluded the following from its analysis:

- Energy storage assets exclusively participating in the energy market may be able to recover their capital costs, but this may require a) perfect foresight over market conditions, b) sustained periods of highly variable pool prices, and c) the removal of the load treatment of energy storage from the AESO tariff.

- Absent the treatment of energy storage assets as loads for tariff purposes, energy storage asset viability in the long run may still require significant price volatility over the lifespan of the asset and perfect price foresight. While one energy storage asset participating in the energy market may be able to achieve this outcome, the incremental development of energy storage assets may result in cannibalizing one another's revenues by reducing price volatility.

- Volatile/opportunistic offer behaviour may be a more viable offer strategy for energy storage assets participating in the energy market than a more regimented hour-based approach.

- Energy storage participation in the energy market is efficiency-enhancing, but may have little impact on average prices, or may even be price-increasing if small amounts of energy storage participate.

To arrive at these conclusions, the MSA conducted two analyses assessing storage viability using various configurations of hypothetical energy storage assets. The MSA constructed a "marginal analysis" to assess the viability of storage under the assumption that such an asset would be small enough that its charging and discharging would not impact pool prices or the interval of the monthly coincident metered demand. In this marginal analysis, various storage asset charging and discharging behaviour ("cycling behaviour") was prescribed for certain periods of each day.

The MSA also constructed an "incremental analysis" which relaxed the assumption that storage cycling behaviour would not impact pool prices. The MSA assessed storage assets with capacities of 10, 50, and 100 MW. Strict cycling behaviour assumptions used in the marginal analysis were also relaxed; storage assets were assumed to forecast pool prices with perfect foresight at the outset of a day and schedule charge and discharge periods accordingly to maximize quasi-rents.

[9] AESO Engage Demand Opportunity Service (DOS) formerly the Energy Storage Tariff Working Group.

Both analyses examined energy storage viability over the period of January to June 2023 for 2-hour and 4-hour energy storage configurations. This period was selected given the high volatility of pool prices during that period relative to previous quarters.

Both the marginal and incremental analyses assumed a storage asset would have the costs and technical characteristics of a lithium-ion battery storage technology. All analyses and scenarios assumed an energy storage unit would begin and end each day with a state of charge of zero.

This section describes the results and key assumptions of the MSA's analyses.

1.6.1 Marginal analysis

The purpose of the marginal analysis is to assess the viability of cycling strategies for energy storage assets assumed to be sufficiently small as to never impact pool price by their offer behaviour. The MSA tested five combinations of storage configurations and cycling strategies (Table 12).

Table 12: Marginal analyses scenarios

Scenario	Storage Configuration	Charging Strategy	Discharging Strategy
Simple Schedule	2-hour	Always charge in HE 3 & 4	Always discharge in HE 20 & 21
2-hour Cycle Limit	2-hour	Conditionally charge in two hours of HE 1 – 19 if Price < \$100 and price is not higher than the following two hours. Must reach full state-of-charge before discharging (cannot "partially cycle").	Conditionally discharge in two hours of: i) HE 1 – 19 if Price > \$250 and price is not lower than the following two hours, or ii) HE 20 – 24
2-hour No Limit	2-hour	*Identical to 2-hour Cycle Limit without \$100 limit price, and can partially cycle.*	*Identical to 2-hour Cycle Limit without \$250 limit price, and can partially cycle.*
4-hour Cycle Limit	4-hour	Conditionally charge in four hours of HE 1 – 19 if Price < \$100 and price is not higher than the following two hours. Must reach full state-of-charge before discharging.	Conditionally discharge in four hours of: i) HE 1 – 19 if Price > \$250 and price is not lower than the following two hours, or ii) HE 20 – 24

4-hour No Limit	4-hour	*Identical to 4-hour Cycle Limit without $100 limit price, and can partially cycle.*	*Identical to 4-hour Cycle Limit without $250 limit price, and can partially cycle.*

In Alberta, while average prices exhibit a daily profile, market conditions can lead to high or low prices at any time of day. This made the Simple Schedule strategy, in which the storage asset charged and discharged in prescribed hours, least profitable out of the modeled scenarios (Table 13).

Table 13: Results of the marginal energy storage analysis

Scenario	**Internal Rate of Return**	
	Not Subject to Tariff	**Subject to Tariff**
Simple Schedule	3.4%	-0.4%
2-hour Cycle Limit	9.1%	7.0%
2-hour No Limit	14.6%	12.6%
4-hour Cycle Limit	7.7%	6.2%
4-hour No Limit	10.0%	8.1%

2-hour storage assets were generally found to be more profitable than 4-hour storage assets, while the use of limit pricing decreased profitability. Energy storage assets subject to the AESO STS and DTS tariff rates were less profitable than those modelled as not subject to the AESO tariff.

1.6.2 Incremental analysis

The MSA's incremental analysis assumed energy storage assets could impact the pool price by charging (increasing load) or discharging (increasing supply). Because storage charging increases load in this analysis, the interval of the monthly coincident demand was allowed to vary from the observed interval accordingly.

The MSA assessed 6 configurations of energy storage assets of varying capacities and energy durations under 3 different tariff assumptions and 3 cycling behaviour assumptions, totalling 54 scenarios representing combinations of the above.

Six configurations of energy storage assets comprised of 2-hour and 4-hour durations with capacities of 10, 50, and 100 MW were modelled. Three tariff assumptions were used to evaluate the incremental impact of coincident metered demand charges and other charges related to the DTS tariff (Table 14).

Table 14: Incremental analysis DTS tariff assumptions

Tariff Assumption	**Storage Asset subject to DTS Tariff Charges**	**Storage Asset Anticipates & Avoids DTS Coincident Metered Demand Charge**
No DTS	No	N/A
DTS & No CMD Avoidance	Yes	No
CMD-Avoidant	Yes	Yes

Energy storage assets were assumed to cycle either once per day, twice per day, or partially cycle throughout the day (Table 15). As capital cost assumptions were premised on a storage asset cycling once per day, capital costs under other cycling behaviour assumptions were scaled to reflect the presumed decrease in asset lifespan proportional to the number of realized cycles per day.

Table 15: Incremental analysis cycling behaviour assumptions

Cycling Behaviour Assumption	**Description**
1 Cycle/Day	An X-hour storage asset: charges over at most X hours, and subsequently discharges over at most X hours in a single day. Charge/discharge hours are determined based on the single daily combination with the highest quasi-rent (accounting for DTS Coincident Metered Demand charges, when applicable), accounting for incremental price impact.
2 Cycle/Day	The asset follows the 1 Cycle/Day cycling behaviour at most twice (sequentially). Charge/discharge hours are determined based on the two daily combinations with the highest quasi-rent (accounting for DTS Coincident Metered Demand charges, when applicable), accounting for incremental price impact.
Partial Cycling	The asset charges and discharges in any combinations of hours in the day, provided its state of charge is between 0 and its energy capacity. Charge/discharge hours are chosen based on the combinations of hours that yield the highest daily quasi-rent (accounting for DTS Coincident Metered Demand charges, when applicable), accounting for incremental price impact.

Market conditions observed in the first six months of 2023 were assumed to persist over the lifespan of the asset by annualizing net revenues over the six months for each of the 54 scenarios. A weighted-average cost of capital of 12.5% was assumed to estimate annualized capital costs.

Most energy storage configurations earned an insufficient amount of net revenues to recover their capital costs when subject to the DTS tariff (Figure 32). Although assets with perfect foresight of monthly coincident metered demand intervals were able to earn higher net revenues than assets that did not have this foresight, all scenarios tested earned insufficient net revenues when subject to the DTS tariff except the partially cycling 4-hour storage asset of either 50 MW or 100 MW capacity. Storage assets that cycled once per day generally had the lowest rate of return above capital cost, while assets that utilized a partial cycling strategy had the highest rate of return (Figure 33).

These results pertain to the introduction of a single hypothetical storage asset. If additional storage assets were to enter the market, the net revenues and rate of return of these assets would be lower than presented in the following two figures, as new storage assets would incrementally erode arbitrage opportunities in periods with the largest differentials in charge-discharge prices or would elect to charge and discharge in different periods altogether with lower price differentials.

Figure 32: Annualized net revenues, capital costs ($000's/MW) by energy storage asset, DTS tariff treatment, cycling treatment

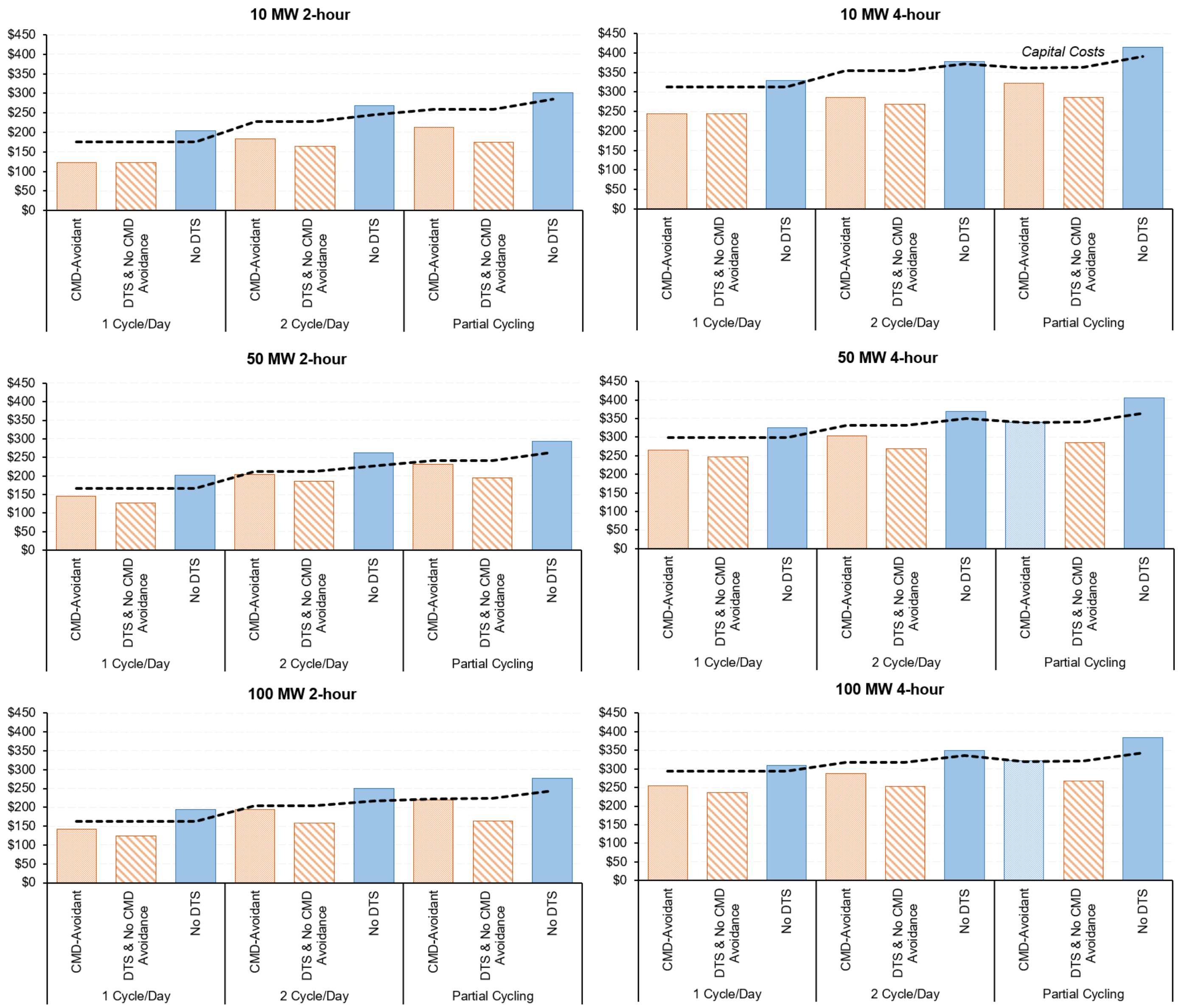
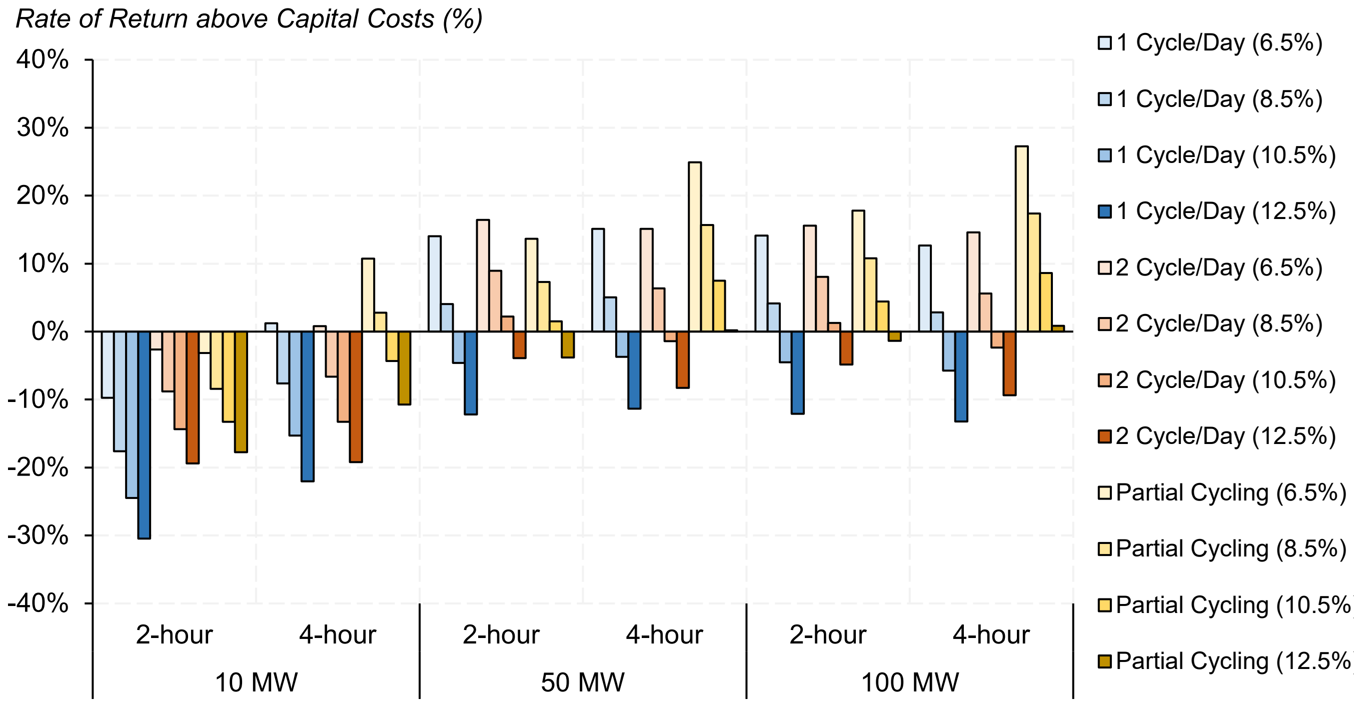


Figure 33: Annualized rate of return above capital costs by energy storage asset, cycling treatment, weighted average cost of capital (WACC) (CMD-Avoidant case)



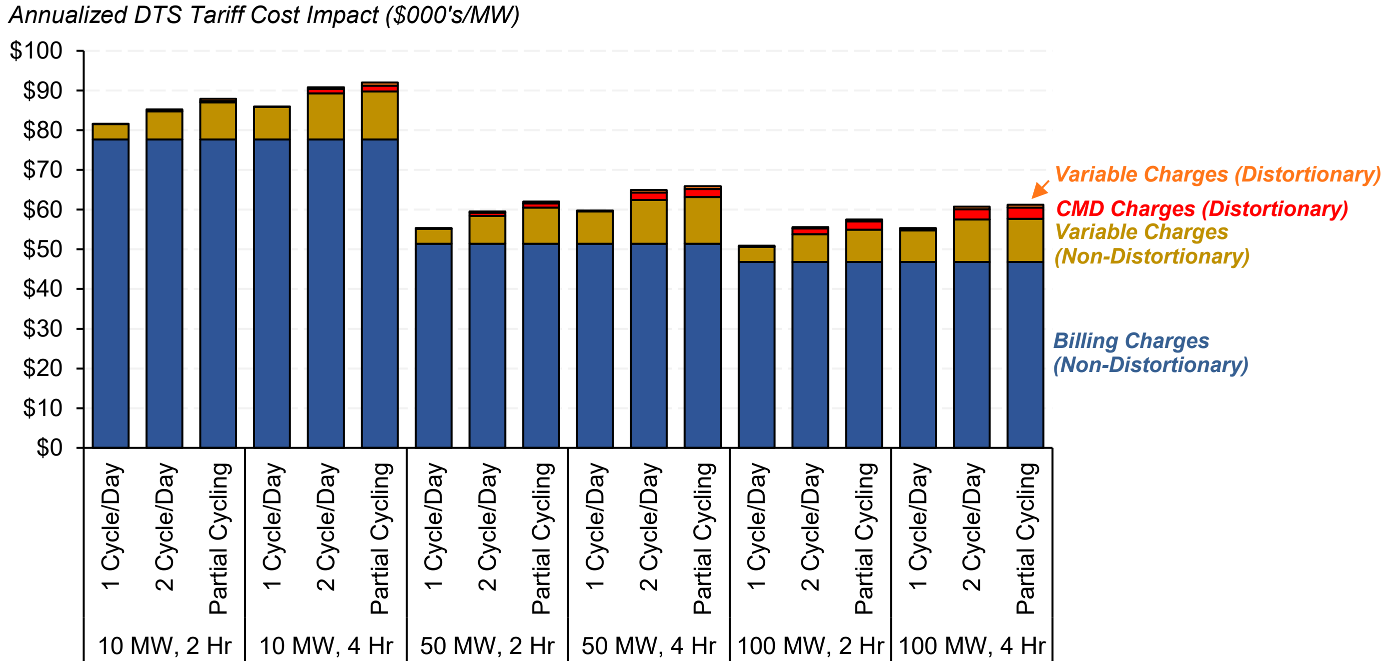
Given the rigidity of the perfect price foresight assumption and the assumption that Q1 and Q2 2023 prices would persist over an energy storage unit's lifespan, it is unclear if energy storage assets participating exclusively in the energy market would be able to recover their capital costs if they were not subject to the DTS tariff. However, it is evident that storage units subject to the DTS tariff face significant costs as a result.

Storage assets subject to the DTS tariff face charges that can be grouped as follows:

- Variable charges: Charges based on energy consumption ($/MWh).
- Billing charges: Charges based on monthly demand ($/MW/month) or monthly fixed charges ($/month).
- Coincident metered demand (CMD) charges: Charges based on demand during the monthly 15-minute coincident metered demand interval.

A storage asset that can successfully avoid coincident metered demand charges still faces significant DTS charges, although the DTS tariff will have a limited distortionary effect on its cycling behaviour (Figure 34). Assuming it charges to its MW capacity at least once a month it will face identical billing charges regardless of its cycling behaviour. Variable charges will vary depending on an asset's consumption over the month and impart a small distortionary effect whereby an asset subject to the DTS tariff may elect not to cycle (or partially cycle) if the expected value of the arbitrage is less than the sum of DTS variable charges it would incur for its charging in that cycle. Similarly, even if an asset has perfect foresight into CMD intervals and avoids charging in those hours it may face a small distortionary opportunity cost associated with not charging in those hours.

Figure 34: Annualized DTS tariff cost impact ($000's/MW) by DTS cost component, energy storage asset, cycling behaviour (CMD-Avoidant case)



Energy storage assets had varying price impacts that depended both on the size of the asset and whether it was charging or discharging. An energy storage asset that charges acts to increase load, and therefore increases the pool price. Similarly, an asset that discharges increases generation supply and may depress the pool price, depending on the offer behaviour of other firms. Over the six-month period, smaller energy storage assets tended to increase the average price, while the larger 100 MW units decreased the average price (Figure 35). This result largely reflects the offer behaviour of other firms and the resulting distribution of offers in Q1 and Q2 2023. All assets increased the average price in periods where they charged and decreased the average price in periods where they discharged (Figure 36).

Figure 35: Average price impact by energy storage asset, cycling behaviour (CMD-Avoidant case)

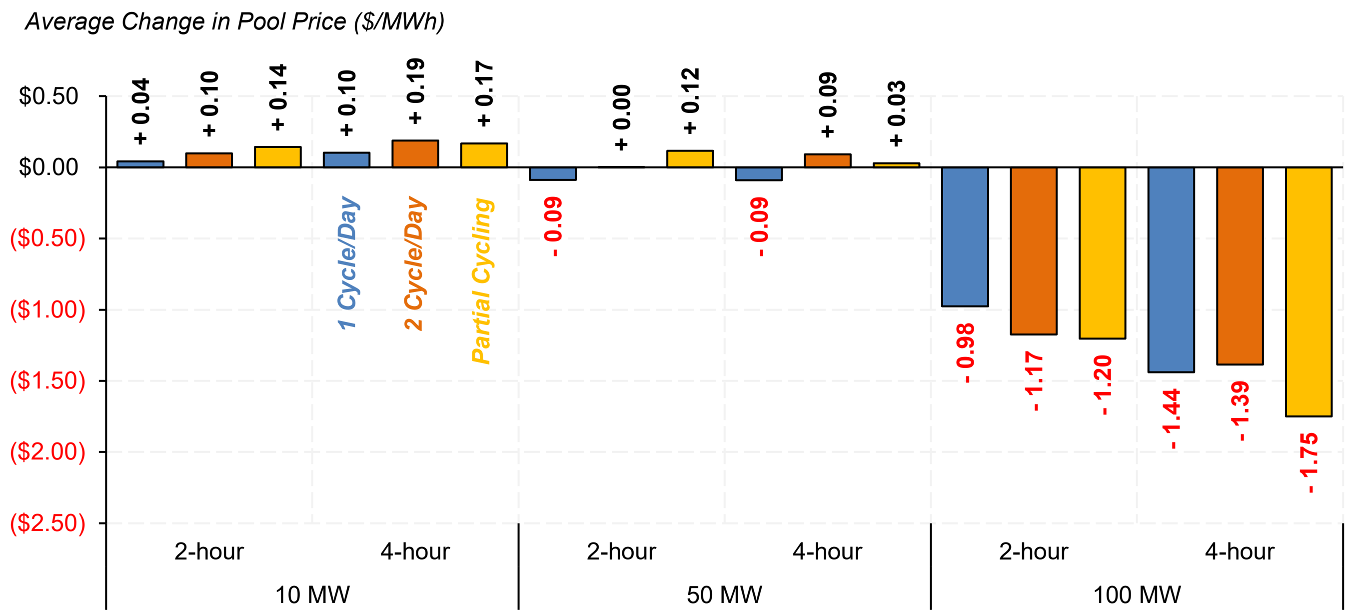
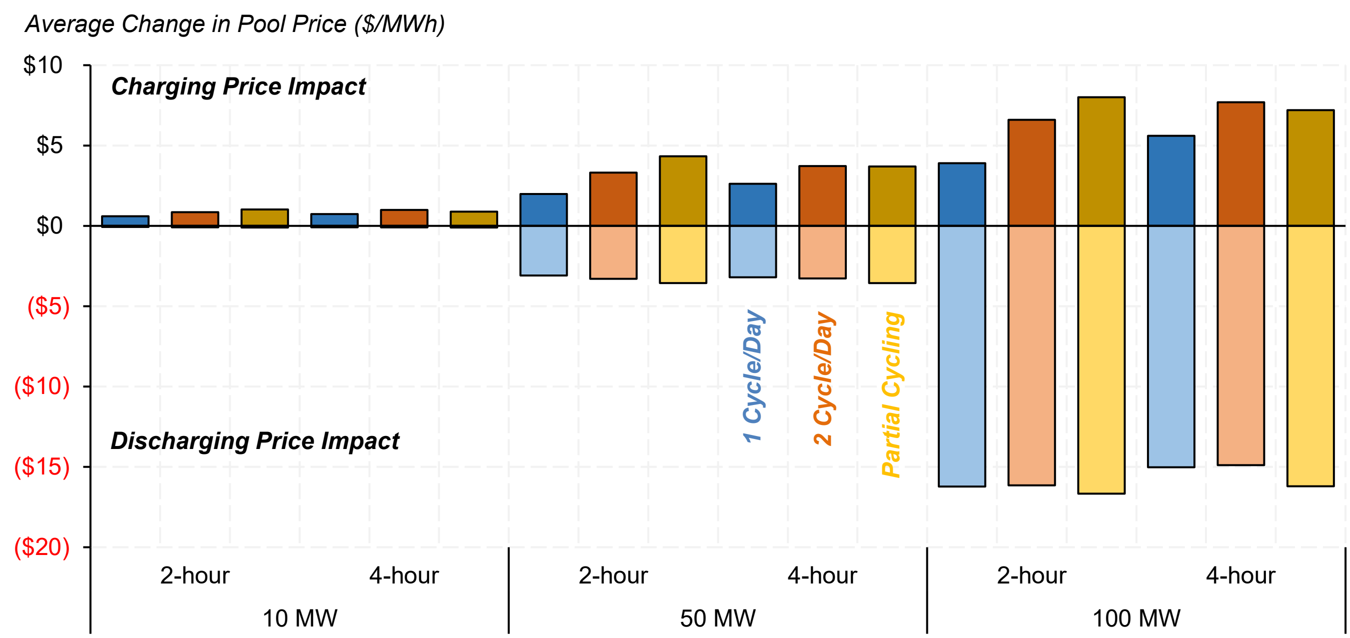


Figure 36: Average charging, discharging price impact ($/MWh) by energy storage asset, cycling behaviour (CMD-Avoidant case)



All storage assets modelled were found to have increased market efficiency, with the larger 100 MW storage asset increasing efficiency by the most in absolute terms (Figure 37). Gains in market efficiencies can be earned by generators and/or consumers, represented as changes in producer or consumer surplus, respectively. The MSA found that the introduction of smaller 10 MW and 50 MW storage assets led to a slight reduction in consumer surplus given they generally increased average prices, while the 100 MW storage asset increased consumer surplus in all scenarios (Figure 38).

Figure 37: Average efficiency gain ($/MWh of demand net of import supply, export demand) by energy storage asset, cycling treatment (CMD-Avoidant case)

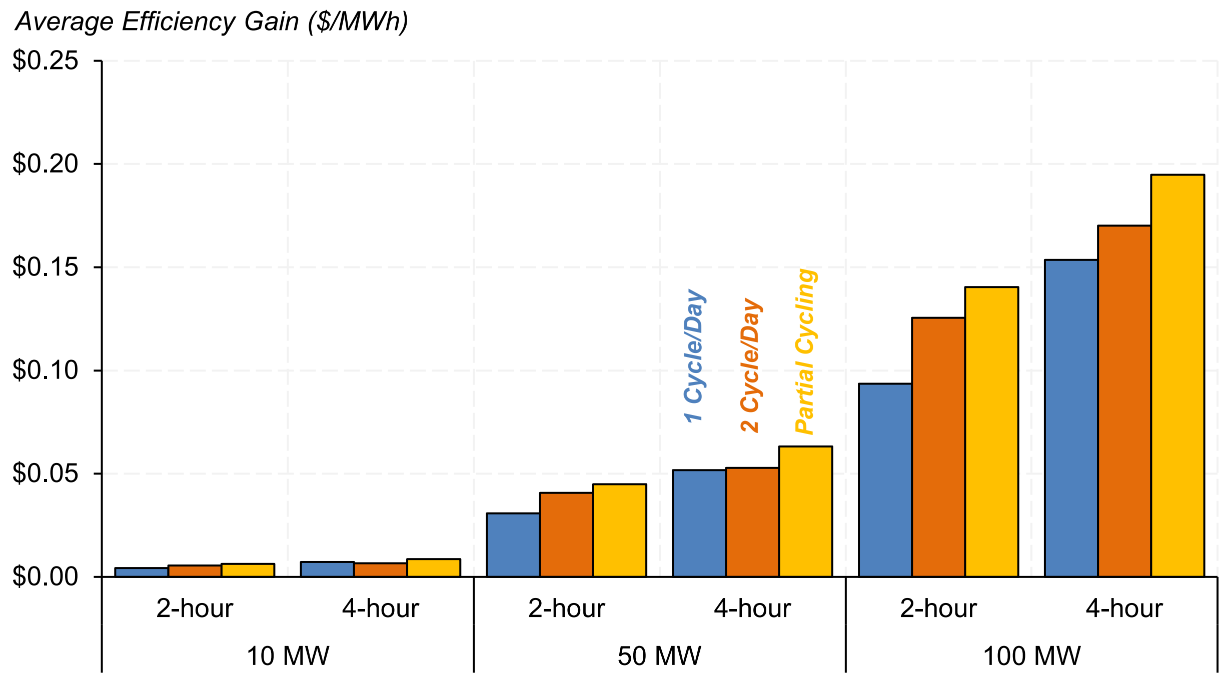
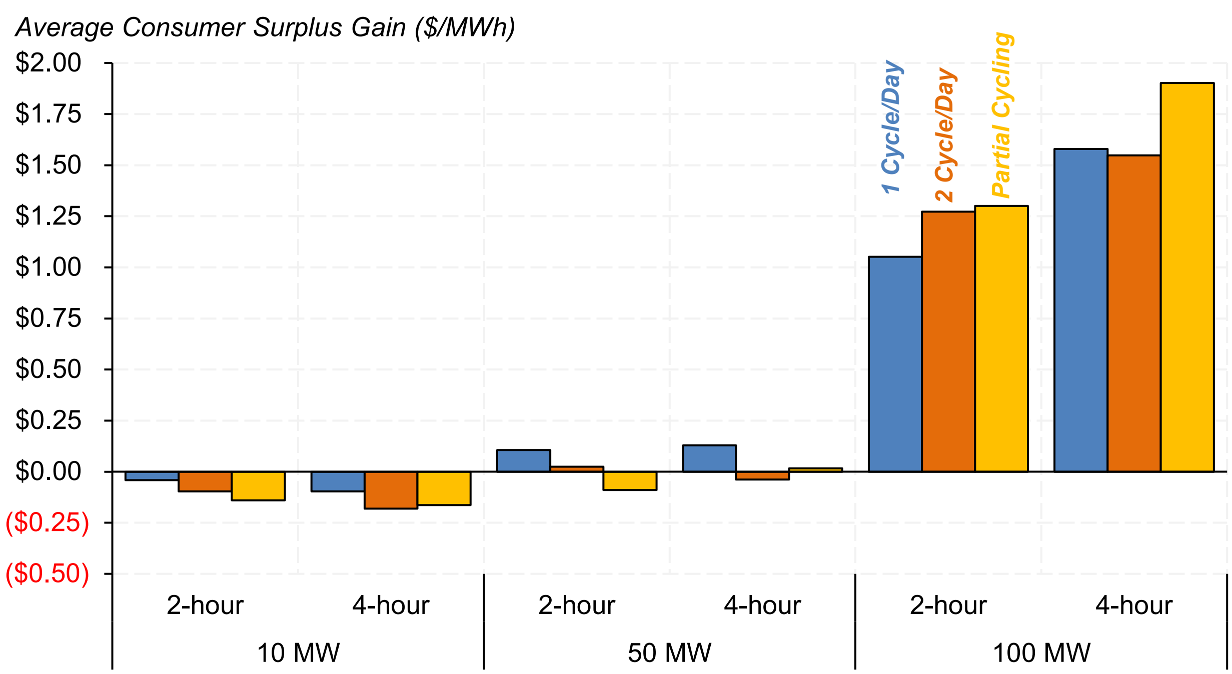


Figure 38: Average consumer surplus gain ($/MWh of demand net of import supply, export demand) by energy storage asset, cycling treatment (CMD-Avoidant case)



Altogether, the MSA's analyses indicate that the AESO's treatment of storage assets as a load may act as a barrier to their exclusive participation in the energy market, although storage assets would require sustained periods of variable prices and be able to predict prices with a high degree of accuracy in order to be able to recoup their investment. Storage assets that are sufficiently large could be expected to lower average prices as a result of their arbitrage behaviour. While the introduction of storage assets of any size is welfare-enhancing, consumers may only be net beneficiaries of this effect if this storage is sufficiently large.

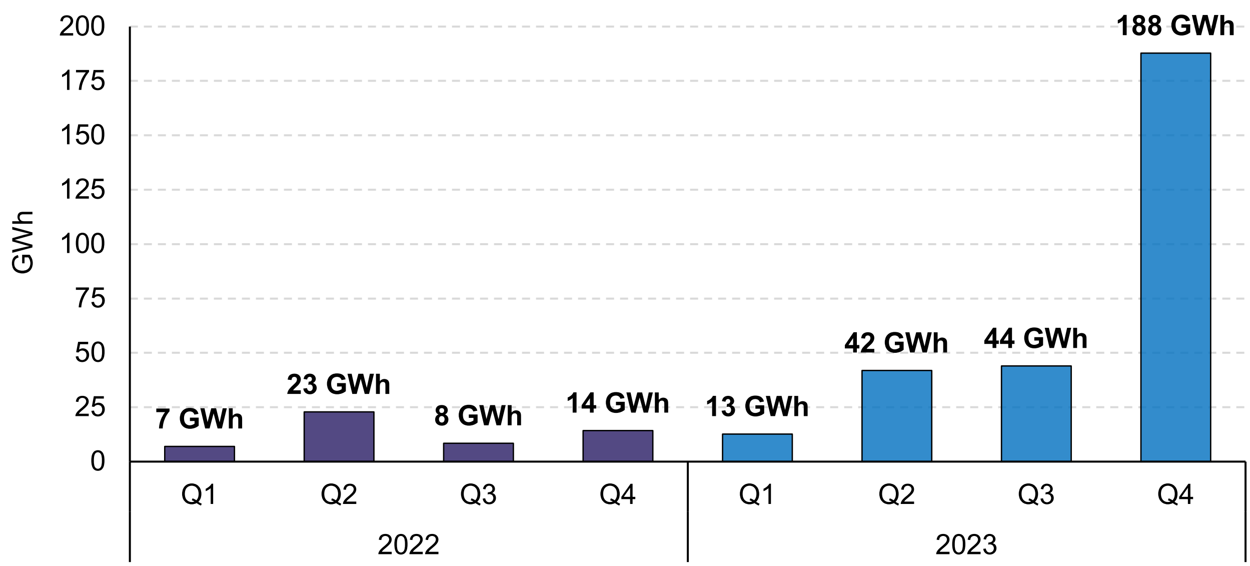
2 THE POWER SYSTEM

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 volume of intermittent generation that was constrained down increased through the year. Each quarter experienced more constrained intermittent volumes, increasing from 13 GWh in Q1 to 42 GWh in Q2, 44 GWh in Q3, and 188 GWh in Q4 (Figure 39).[10,11] The total constrained down intermittent volume for 2023 reached 286 GWh, a 445% increase from 53 GWh in 2022.

Figure 39: Quarterly total constrained volumes for wind and solar generation (2022 and 2023)



The maximum hourly average volume of intermittent generation constrained down in 2022 reached 193 MW (Figure 40). The 2023 maximum hourly average volume of intermittent generation constrained down of 840 MW was reached on December 13 (Figure 41). The 2023 peak was 337% higher than 2022. There were 4,107 hours of intermittent constrained down generation greater than 1 MWh in 2023. This is equivalent to approximately 171 days, or 47%, of

[10] For more information on how the MSA calculates the constrained down volume for wind and solar assets, see [Quarterly Report for Q2 2023](#).

[11] The AESO's ETS Estimated Cost of Constraint Report calculate TCR volumes using a different methodology than the MSA's estimate of constrained down generation.

the year. In contrast, 2022 only experienced 2,320 hours of intermittent constrained down generation greater than 1 MWh, or approximately 97 days.

Figure 40: Maximum hourly transmission constrained wind and solar generation (2022)

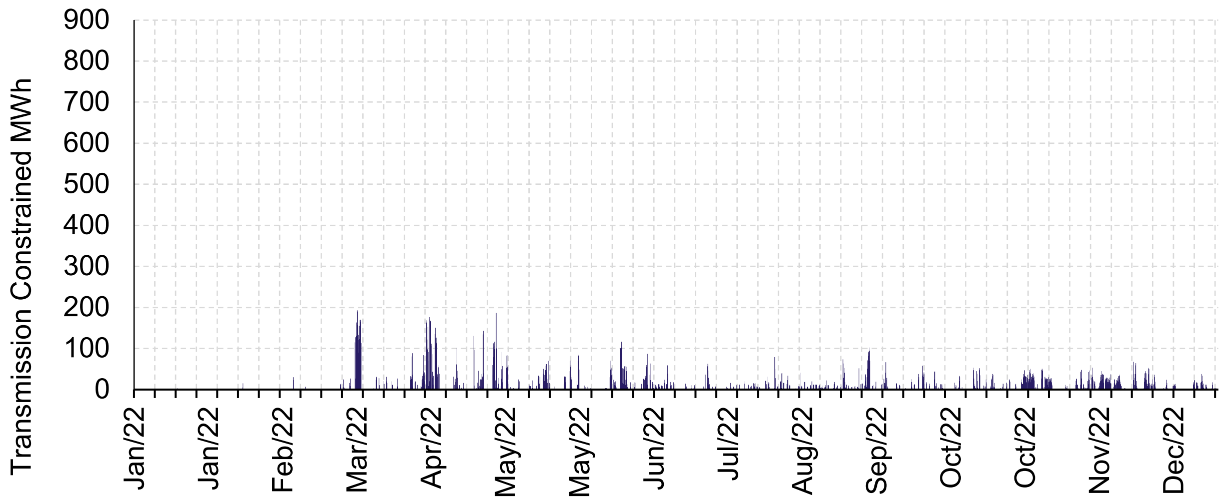
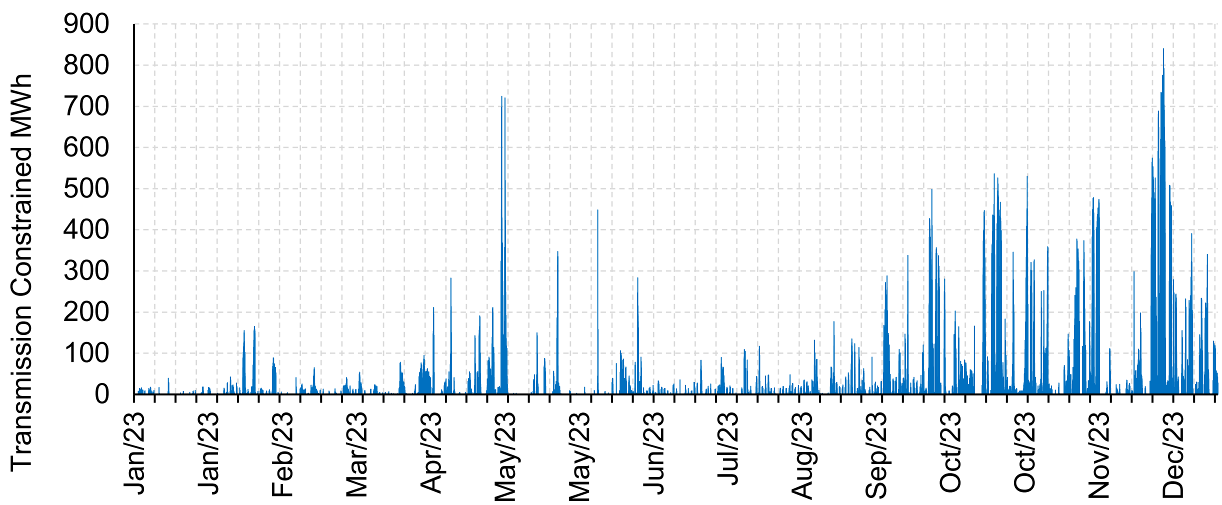


Figure 41: Maximum hourly transmission constrained wind and solar generation (2023)



The frequency and significance of intermittent constrained down generation directives increased from Q4 2022 to Q4. [12] The MSA estimates that intermittent constrained down generation volumes were 14 GWh in Q4 2022 and 188 GWh in Q4.[13] This represents an increase of 1,213%, year-over-year. The quarter-over-quarter increase, from 44 GWh in Q3 to 188 GWh in Q4, was also

[12] There were multiple planned transmission outages (unlisted in Outages Report) that contributed to congestion. I.e., 1034L/1035L (impacting CYP1&2, FGM1, WHT1&2).

[13] 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.

significant at 327%. Although the total installed capacity of wind and solar generators increased year-over-year, the increase in constrained down volume from Q4 2022 to Q4 grew at a faster rate. While total installed intermittent capacity increased by 45%, average hourly constrained down volumes, expressed as a percent of installed intermittent capacity, increased from 0.16% in Q4 2022 to 0.83% in Q4, an increase of more than five times. The growth of constrained down volume outpaced the growth in installed capacity.

The maximum hourly average volume of intermittent generation constrained down in Q4 was 840 MWh, over 12 times the maximum of 67 MWh in Q4 2022 (Figure 42 to Figure 44). The Q4 maximum hourly average volume of intermittent constrained also exceeded the maximum value of Q3 2023, which was 498 MWh (Figure 43). The next highest maximum hourly average volume of intermittent constrained of 725 MWh occurred in Q2 2023. The increase in total constrained down volumes and the higher maximum hourly average peak both occurred in Q4, a marked increase from other quarters in 2023.

Transmission constraints had frequent and substantial fluctuations throughout all months, however December experienced the most change and highest peak. The intermittent constrained down volume in the month of December accounted for 47% of all Q4 intermittent constrained volumes. In 76% of December hours there was at least 1 MWh of intermittent constrained down volume.

Figure 42: Maximum hourly transmission constrained wind and solar generation (Q4 2022)

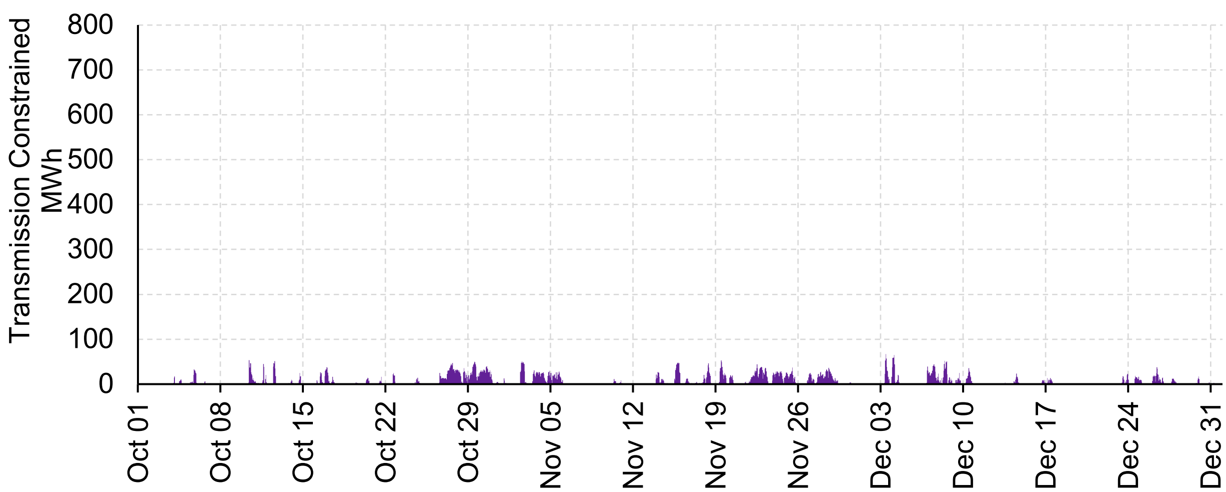


Figure 43: Maximum hourly transmission constrained wind and solar generation (Q3 2023)

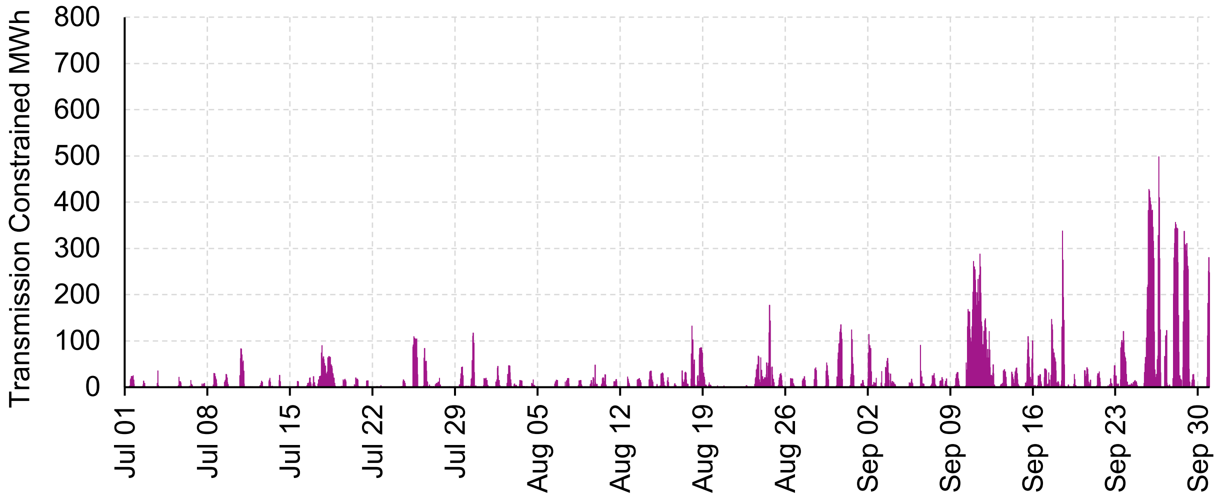
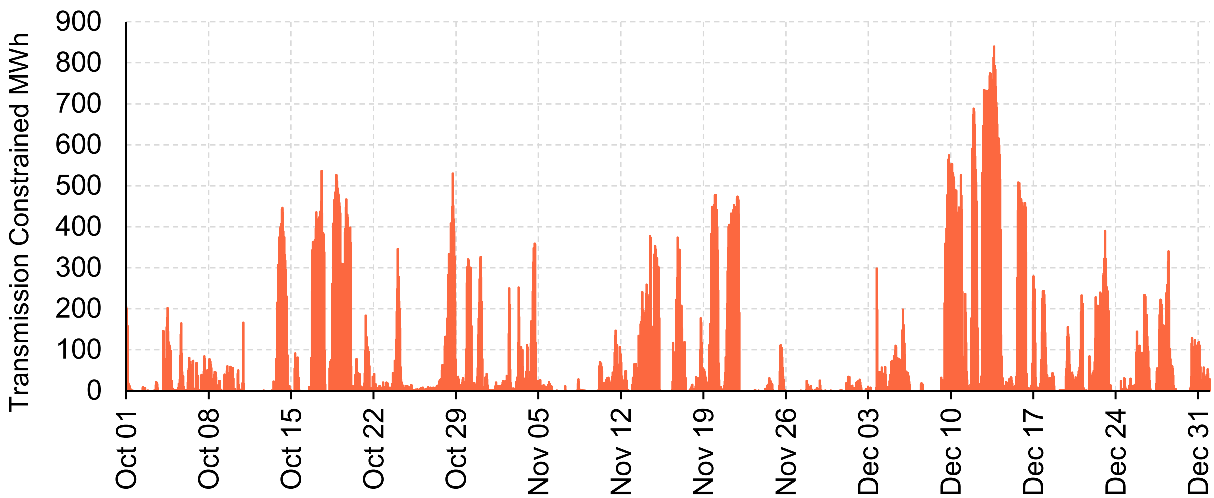
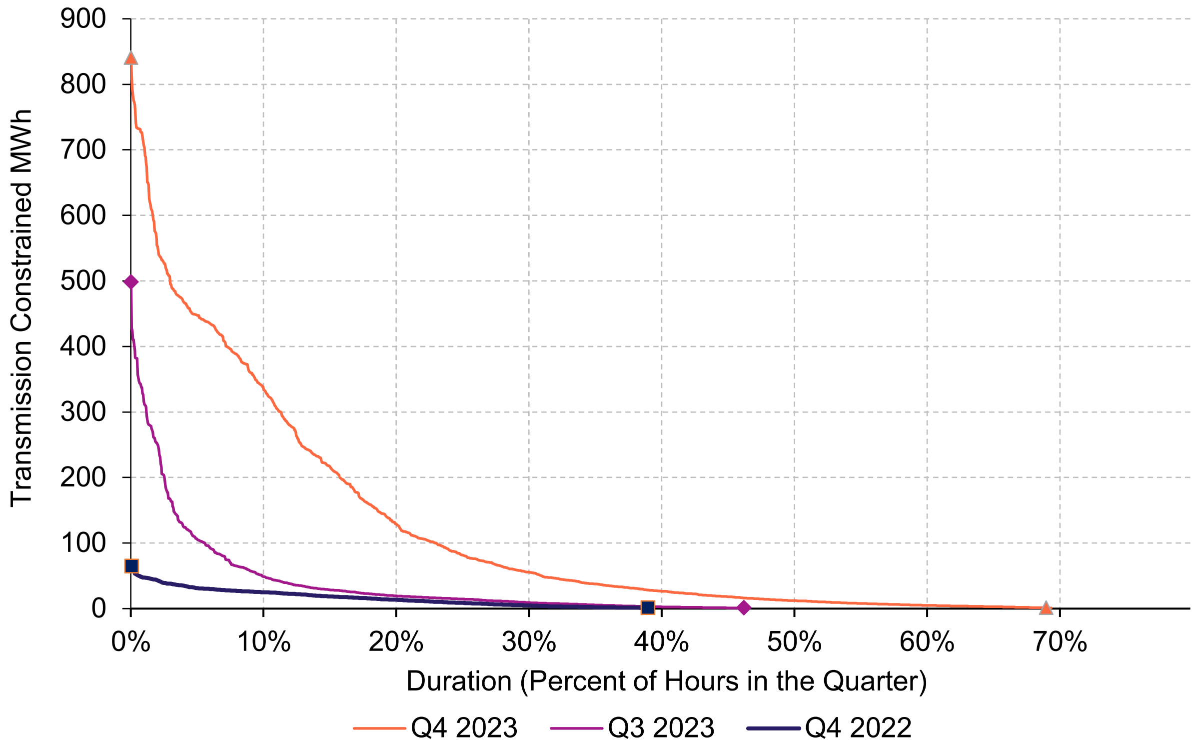


Figure 44: Maximum hourly transmission constrained wind and solar generation in Q4



Increased intermittent constraints resulted in over five times the constrained volume year-over-year (Figure 45).[24] To understand the increasing magnitude of congestion, note that 27% of hours in Q4 had more congestion than the single most congested hour in Q4 2022. The length of the tails of the duration curves to the right show that the frequency of intermittent constrained down events increased. The percent of hours where at least 1 MWh of intermittent generation was constrained down was 69% in Q4.

Figure 45: Duration of wind and solar constraint volume (Q4 2022, Q3 2023 and Q4)



Examining the peak congestion event in December more closely, the most constrained down generation occurred on December 13. The peak congestion event in Q4 occurred on December 13 in hour ending 17. The event most significantly impacted Cypress 1 (118 MW of 196 MW maximum capability) and Whitla 1 (121 MW of 202 MW maximum capability). The constraint began on December 8 for WHT1&2 and CYP1&2 and remained in place for 10 days. FMG1 was added on December 10. The zone was created based on the 964L outage, where 964L is a 240 kV double circuit line with 983L, located in the Medicine Hat region. The total constrained down volume for all assets was 64 GWh or 34% of total constrained down volumes in Q4. Whitla 1 was the most constrained over this period, being curtailed by 14.1 GWh, and Cypress 1 was second with 13.2 GWh.

Over the period of December 8 to 18, the constrained SMP was not substantially different to the posted SMP, when compared to previous constrained down events. This is indicative of the volume of generation available at low prices and is likely a result of the high wind conditions for December, as discussed in other sections of the report. The price difference was only above $100 for 9 minutes during this constrained event. The largest difference between constrained and unconstrained price was $121/MWh on December 12.

Figure 46: Wind and solar transmission constrained MW (December 8 to 16, 2023)

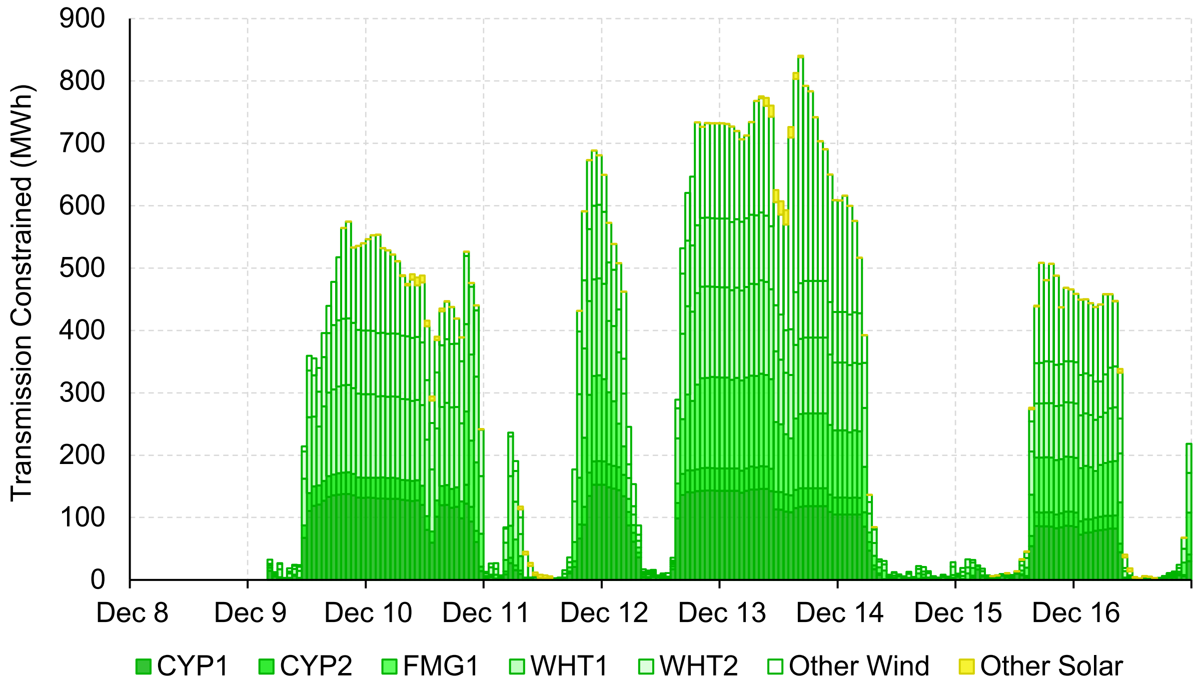
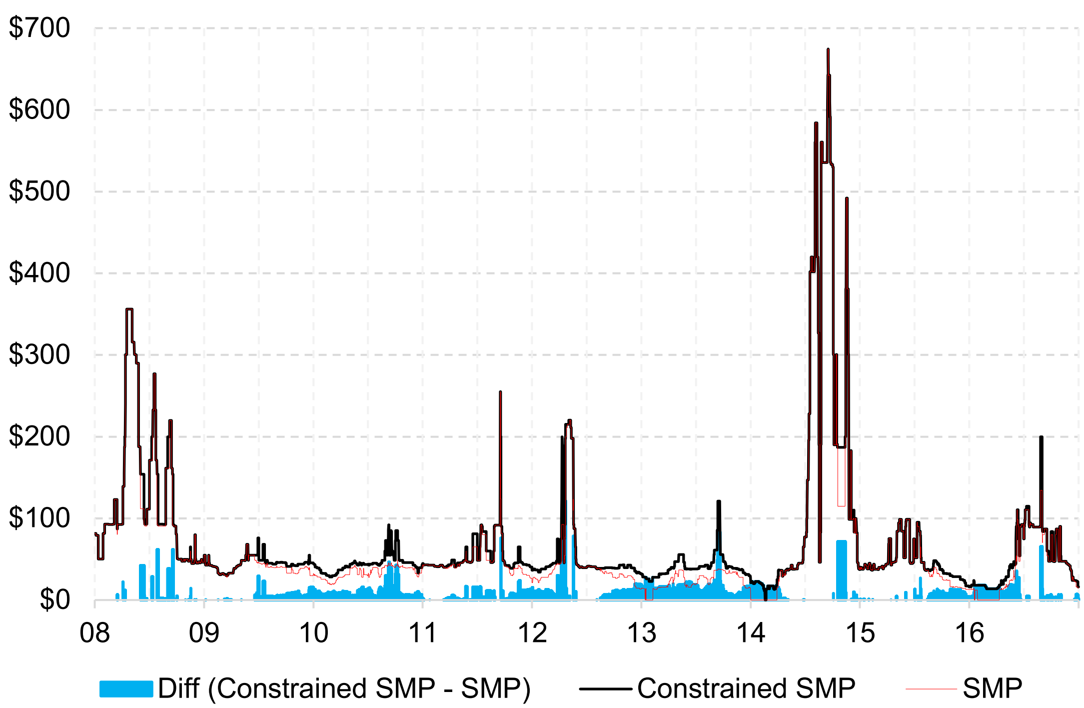


Figure 47: Constrained SMP vs. SMP (December 8 to 16, 2023)

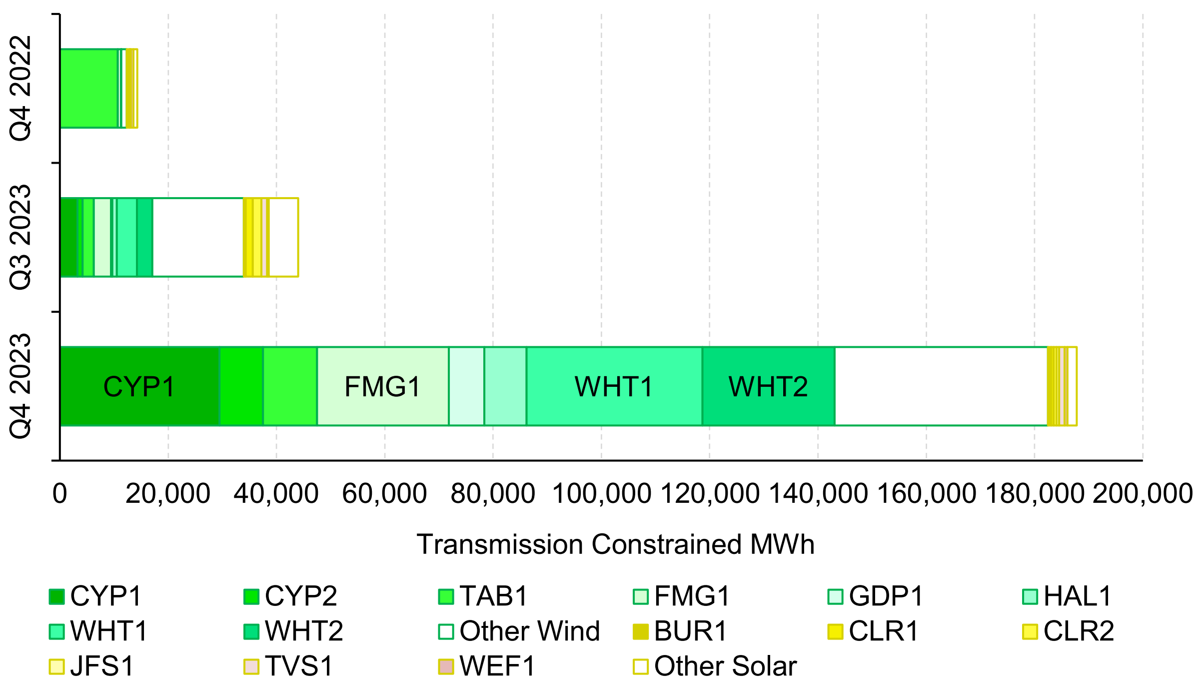


Line 610L is a located within the Vauxhall region and was reviewed for the recent Vauxhall Area Transmission application with the Alberta Utilities Commission. The Commission approved the Needs Identification Document including Section 15(2) of the *Transmission Regulation* for line 610L (and 879L) for a temporary exception to the 100-95 requirement.[14] The exception will apply until the Preferred Transmission Development is fully energized (expected in Q3 2024).

This 138kV line was, and still is, experiencing real time congestion. Looking back on 2023, there were 215 original events logged relating to curtailing generation due to overloads on 610L. Of these, 61 events occurred in Q4, effecting six different wind and solar assets.

Wind and solar assets are not constrained uniformly throughout the province. In Q4, the eight most constrained wind assets accounted for 78% of the total constrained down volume (Figure 48). Cypress 1, Forty Mile Granlea, Whilta 1, and Whitla 2 were the most constrained wind assets. These four assets represent 18% of Alberta's installed wind capacity, however they accounted for approximately 78% of the wind constrained volume in Q4. Travers (465 MW) was the most-constrained solar asset in Q4, with a total of 1,010 MWh constrained. The following five most constrained solar assets have an aggregate maximum capability of 197 MW and were constrained by 2,567 MWh in Q4. This illustrates the uneven concentration of constraints within Alberta.

Figure 48: Wind and solar transmission constrained MWh by asset (Q4 2022, Q3 2023 and Q4)



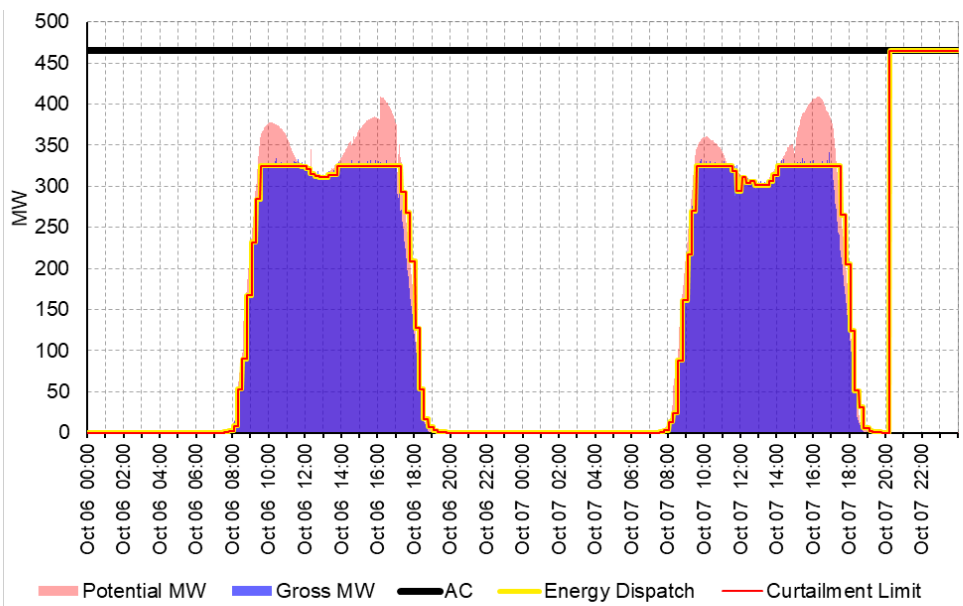
[14] Transmission Regulation Alta Reg 86/2007 Section 15

The AESO uses constrained down generation to manage outflow transmission constraints.[15] When this occurs, the electricity price is set as if, notionally, the system is not transmission constrained. This report refers to this price adjustment process as price reconstitution. Specifically, the highest pool asset marginal price is set ignoring MW dispatched for transmission constraint rebalancing. Pool asset marginal price is used to calculate SMP and pool price.[16] The MSA discussed how the AESO sets pool price during periods with transmission constraint rebalancing in section 2.1 of the Q2 2023 report.[17]

On October 6 and 7, Travers 1 was placed on constraint due to reliability risks during the scheduled 1201L outage (BC/MATL). The directive constrained Travers down by 340 MWh over the period (Figure 49). When islanded (1201L outage), the AESO arms LSS and FFR to enable the Most Severe Single Contingency (MSSC) limit to stay at 466 MW. These services are there to restore frequency to 60 Hz in the event that a large generator trips offline suddenly. During this time, the AIES was islanded due to the scheduled outage on BC/MATL. Genesee 3 was generating at 466 MW, indicating that the MSSC was not reduced to a lower islanded value.

Travers is a variable asset as it can quickly ramp down. It was constrained by the AESO to reduce variability, to manage the risk of an under-frequency event, which may be triggered due to sudden ramps down. If this occurred, the AESO would no longer be able to support MSSC for other large generators and the AESO would then have to lower the MSSC limit. Travers was the only intermittent asset constrained for reliability risk.

Figure 49: Travers Constrained down generation (October 6 and 7, 2023)



[15] ID 2015-006R Calculation of Pool Price and TCR Costs (aeso.ca)

[16] Section 201.6 - Pricing » AESO

[17] Alberta MSA Quarterly Report for Q2 2023

2.2 Dynamic line rating

The Alberta electricity transmission line rating is the maximum limit that power can flow through the line, which can be varied by season, as appropriate. The static line ratings are fixed at a certain threshold and referred to as the line capacity. Two seasonal ratings are applied to adjust the line rating, one in the winter months (November 1 to April 30)[18] and one in the summer months (May 1 to October 31). The seasonal shifts from four sampled regions varied greatly from 0% to an increase of 36% (or 0 MW to 142 MW) in 2022, depending on the line.

As the transmission system is built with a zero-congestion policy,[19] there is relatively low congestion compared to generation and congestion generally only occurs in large volumes during line outages or high wind events. However, in regions of increasing congestion, such as areas with multiple wind assets, the returns to using non-wire solutions are high. Even small changes in line ratings in discrete areas or specific lines can create a valuable opportunity for increased flows.

Dynamic line rating (DLR) is a non-wires method to vary an overhead transmission line's thermal rating limit in response to environmental and weather conditions.[20] Conditions, such as lower temperatures or increased wind speeds, can have cooling effects on the line, reducing sag and increasing the potential safe operating rating. As a result, wind generation and line rating are naturally correlated. DLR is a supporting relief to congested areas, offering additional capacity to lines where the area would have been otherwise constrained, adding to the efficient operation of the electricity grid and market.

There are multiple parameters and conditions that are considered when calculating the real time DLR. The weather factors can include wind speed, direction and angle, solar radiation, ambient temperature, humidity, and more. The physical considerations include line current, sag and tension, material, and construction of the physical line and insulation. Although there are different tools and methods, the more comprehensive the evaluation, the less risky and the more accurate the result.

DLR pilots have led to promising results, ranging from a 20% to 177% increase in line ratings and are currently implemented in Germany, Belgium, the United Kingdom, New York, PJM, and Texas. A 2017 study within a PJM region on a 22-mile, 345 kV line with 3 DLR monitored sections, was estimated to cost $500,000 USD. However, the study also notes that the net congestion savings was over $4 million USD over one year. There are many considerations when implementing DLR including safety, information quality and speed, increased physical monitoring of equipment, and data integration. Using a cost benefit approach could help determine the optimal implementation plan.

[18] AESO Alberta Reliability Standard Facility Ratings FAC-008-AB-3

[19] Transmission Regulation, Alta Reg 86/2007, Section 15

[20] Dynamic Line Rating: Innovation Landscape Brief (irena.org)

2.2.1 *Alberta*

DLR was previously tested in Alberta from June to December of 2015, when AltaLink conducted a DLR study on four segments of a 138 kV line.[21] The site was of interest as the majority of the power in the test area was from wind generation. The tested lines include both east-west and north-south components in an L-shape, which was chosen to assess the impact of wind direction on line cooling.

The results included a mean increase in over 75% of the study period (June to December 2015). The increase in mean transmission line rating ranged from 22% to 72%, depending on the line. Of note, during certain instances the dynamic rating was lower than the original static rating. The report theorizes that this was due to the wind reaching the generators before the lines, where the increased flow from generation was heating the line before the wind was able to cool it. Although no major issues were reported in this study, AltaLink stated in 2022 that the province's harsh climate has previously caused different DLR devices to stop working, go out of calibration, or be blown from the line.[22]

Since this time, the AESO has begun to explore using DLR for real time operations in the South and Central regions (AltaLink and ATCO TFO regions, respectively). During the 2023 grid reliability session,[23] the new pilots were discussed, and the in-service date for DLR was updated to 2025. The proposal includes the 240 kV double circuit lines 924L and 927L as well as the 138kV line 7L128. There have been previous mentions of DLR in AESO's 2021 technology forward publication[24] and in the 2022 year in review[25] where the AESO states that DLR would be implemented where feasible in 2023.

2.2.2 *Theoretical DLR Example*

Line 610L is a 138 kV line located in the Vauxhall region and runs between Fincastle and Taber. The seasonal shift in thermal line rating is approximately 6%.

On November 15, 2022, the AESO filed a development NID which will include a new line and the removal of the current 610L. The line is frequently overloaded in real time and, consequently, multiple solar and wind farms are constrained down. The proximity to wind generation assets,

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[21] Bhattarai B.P et al., Transmission line ampacity improvements of AltaLink wind plant overhead tie-lines using weather-based dynamic line rating, 2017.

[22] Exploring Dynamic Line Ratings: Increasing the Capacity of the Grid, Electricity Canada

[23] AESO Grid Reliability Update, Information Session Nov. 23, 2023

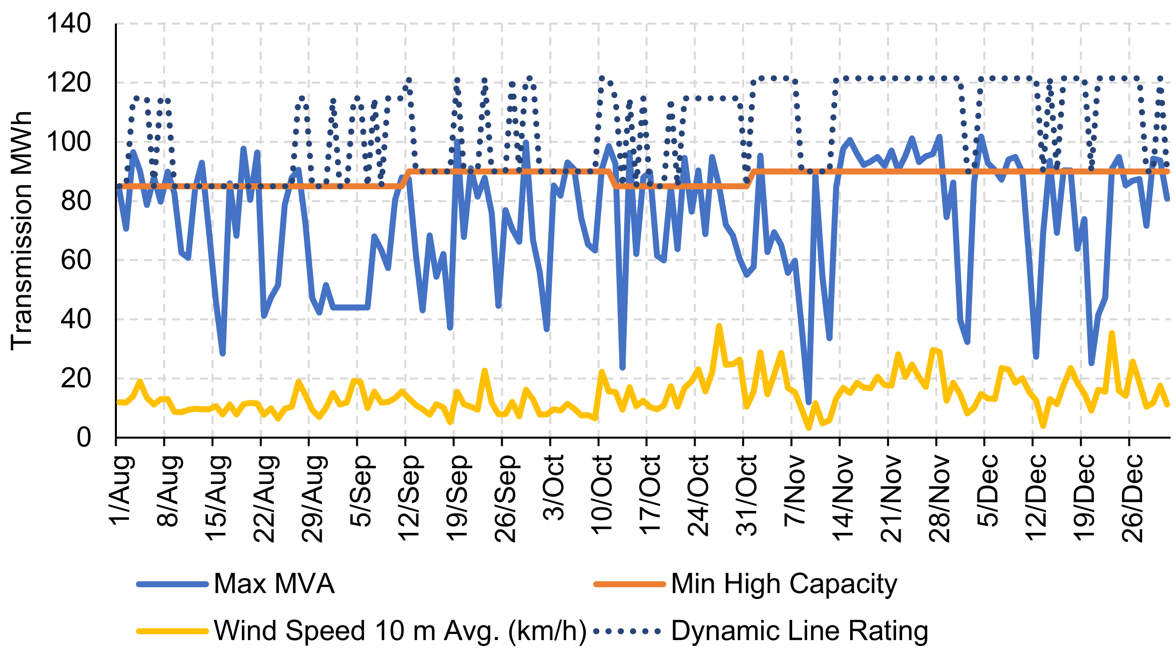
[24] AESO 2021 Technology Forward Publication

[25] AESO 2022 Year in Review

length and congestion makes 610L a candidate for DLR. The data from the 610L is outlined below as a simplified example of the potential increase in capacity from wind generation.[26]

A previous study by the Idaho National Laboratory[27] estimated that a 12 km/h wind speed can increase the dynamic line rating by 35%[28] in a conservative scenario. Using this metric, the dashed line represents the dynamic line rating, where the line rating is increased by 35% when wind speeds met or exceeded 12 km/h.[29] The yellow line represents the wind speed in km/h, the orange is the current seasonal line ratings employed by the AESO,[30] and the blue line shows actual flow in MVA.[31]

Figure 50: 610L Real capacity and theoretical DLR capacity comparison (August 1 to December 31, 2022)



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[26] The actual measurement of the wind effect is calculated by computer software that more accurately predicts the wind effect on the temperature of the transmission line. An operationally safe change to capacity based on weather data requires more data (such as line material, wind direction, ambient temperature, etc.) and processing. This is a simplified example and made for illustrative purposes.

[27] Idaho National Laboratory (INL) is a U.S. Department of Energy National Laboratory. INL previously published a study for dynamic line ratings in Alberta (2017) and received the corresponding data for the previous study analysis. Bhattarai B.P et al., Transmission line ampacity improvements of AltaLink wind plant overhead tie-lines using weather-based dynamic line rating, 2017.

[28] Gentle J et al., Concurrent Wind Cooling in Power Transmission Lines, 2012.

[29] Wind speed data was collected from the Alberta Climate Information Service at the Fincastle Station.

[30] In the actual application of DLR there are many other considerations that would be included in the calculations for the DLR based capacity (as mentioned above). This graph represents a simplified example for illustrative purposes.

[31] 610L is currently using a Remedial Action Scheme (Overload Mitigation Scheme).

The overall modelling trends demonstrate the overlapping pattern of wind speed and increased flow. The actual real flow on 610L is frequently above the seasonal line rating, as shown where the solid blue line exceeds the orange. When capacity is modeled with the increase in line rating from increased wind speeds, the line would not have been overloaded (in most of situations that occurred). An example is from November 14 to 28, 2022, where actual flow exceeded the line rating, but was below the DLR theoretical limit. 610L is a demonstration of how DLR could help increase the line rating and flow, reduce congestion, and contribute to efficient use of the existing transmission system.

The MSA recommends that the AESO continue to study and implement DLR in Alberta in targeted areas, such a high wind or frequently constrained areas. More tangible deadlines with near term implementation could facilitate optimal planning and use of the transmission system. Understanding DLR's role in operations is an opportunity to incorporate this method into the future grid.

2.3 Line losses

Line losses, also known as transmission line losses, is the electrical energy lost from the transmission line during the transfer of electricity from the generator to the destination. The electrical energy is lost in the form of heat, primarily due to the resistance of the transmission lines to the flow of current. Other factors such as distance, generation dispatch levels, temperature, and weather can also impact line losses. The AESO recovers the cost of transmission losses from generating facilities by determining a percentage loss factor, for each generating facility, that reflects its location and contribution to transmission losses. A lower loss factor indicates less transmission line losses.

The requirements for determining loss factors are set out in ISO rule 501.10.[32] The AESO posted the 2024 loss factors on October 2, 2023 and updated them on December 19, 2023.[33] Based on the AESO's procedure to determine transmission loss and loss factor[34], line losses on the transmission system are expected to be 2,021 GWh for 2024 and the average loss factor for the transmission system is estimated to be 3.26% for 2024. Losses on the transmission system were 1,914 GWh for 2023 and the average loss factor for the transmission system was 3.12% for 2023.[35]

The heat map (Figure 51) shows the distribution and density of loss factor associated with the generating facilities in Alberta. Red areas in the heat map show areas of high loss factor and blue areas show areas of low or zero loss factor. The loss factor is higher in the southern part of the province (Medicine Hat, Lethbridge), given the large amount of renewable generation and the

[32]Transmission Loss Factors

[33]2024 Loss Factors Effective 1 Jan 2024

[34]Procedure to Determine Transmission System Losses for Loss Factor Calculations

[35]AESO Website – Loss Factors

longer transmission distance to meet higher demand in the central (Calgary) and northern part (Edmonton) of the province.

The wind and solar assets in Alberta are predominantly situated in the southern region. Their location optimizes renewable energy generation but results in higher losses because of the long transmission distance and the high utilization of the transmission lines in that region. The loss factors for gas and hydro assets are lower, attributed to their location within the province where energy transmission is more efficient (Figure 52). Biomass facilities are generally wood-fueled heating systems and are usually sited as near as possible to the heating end-user. They are designed to meet the needs of local consumers, providing high efficiency and avoiding transmission losses. For 2024, the highest loss factor for a generating facility was 12%, while the lowest was -9%.

Figure 51: Loss Factor intensity in Alberta for 2024

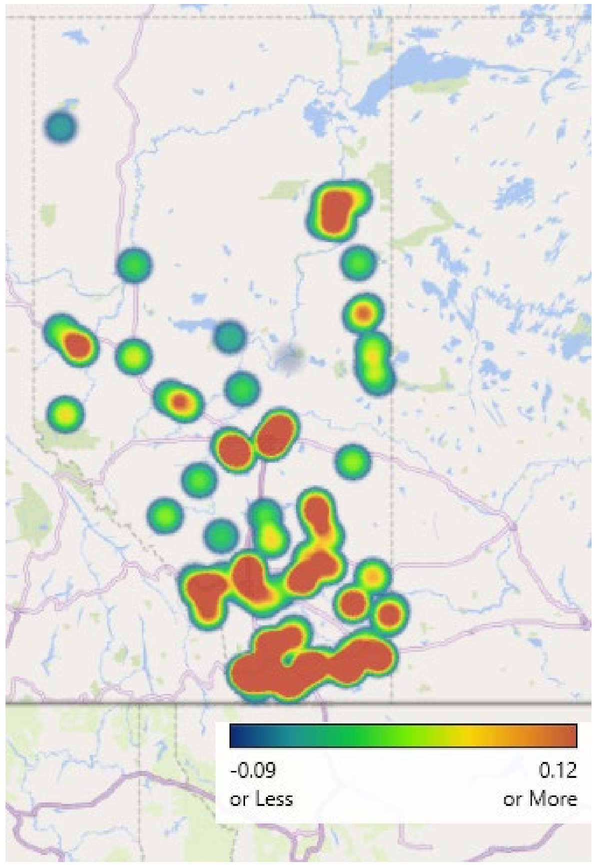
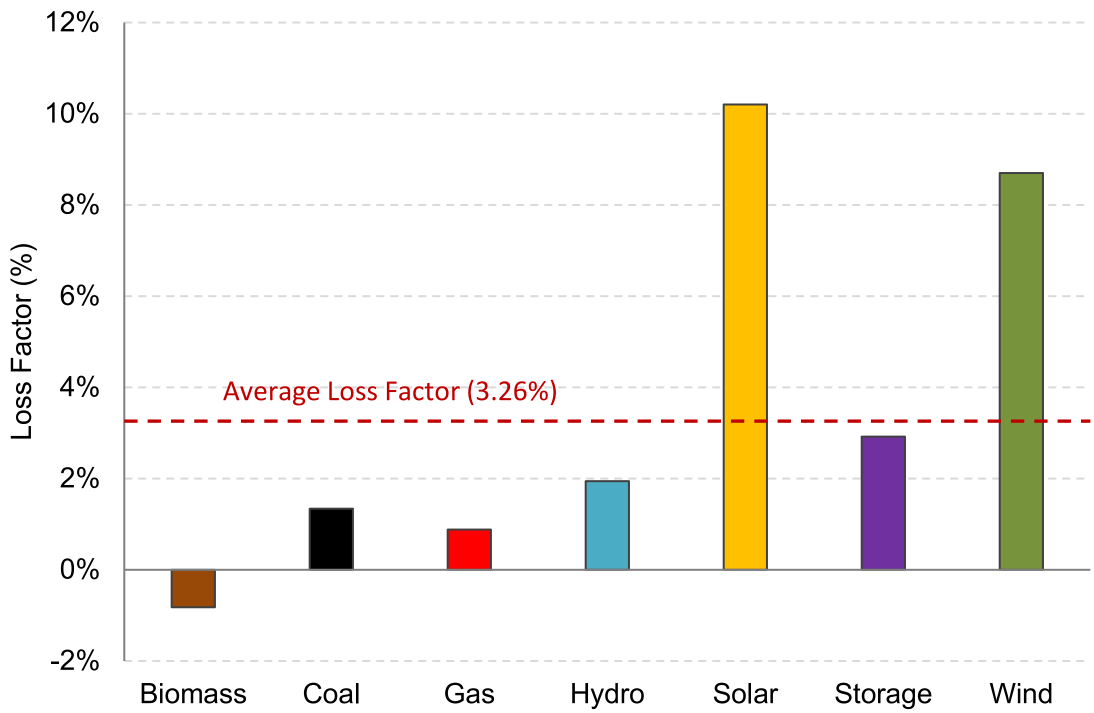


Figure 52: Average Loss Factor by fuel type

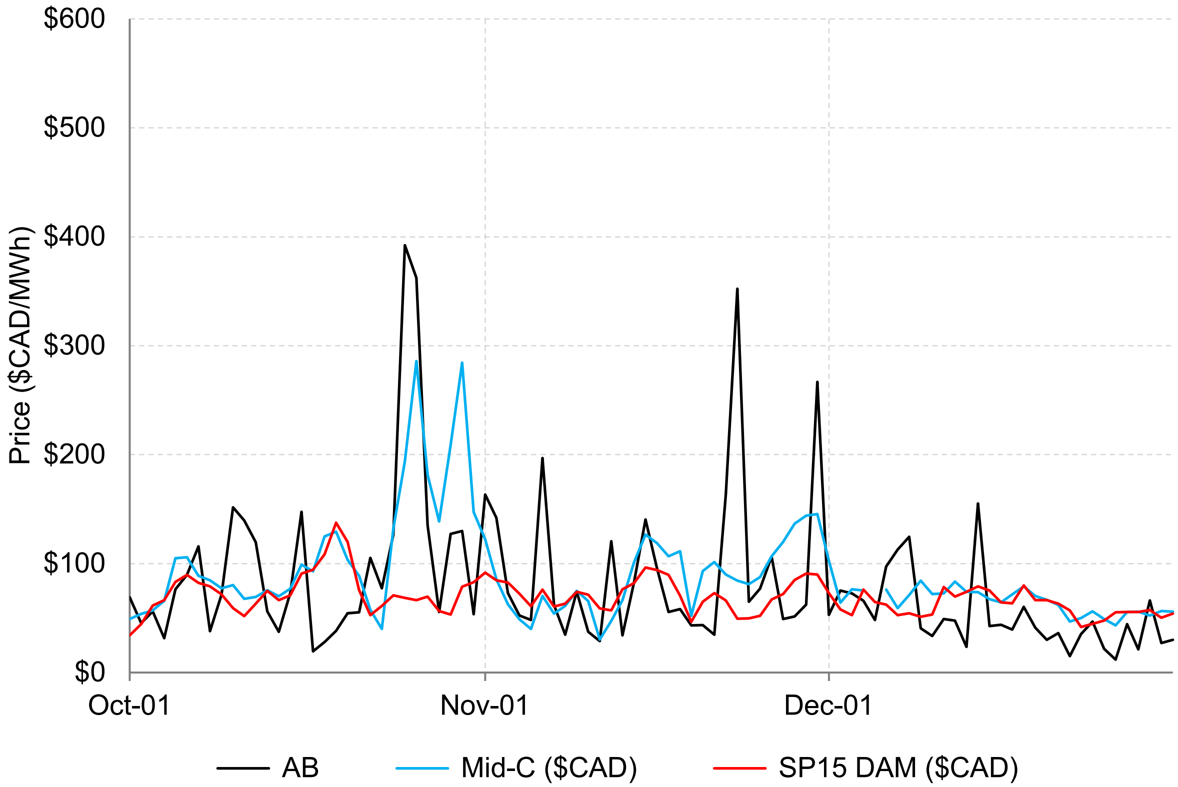


2.4 Imports and exports

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 operates BC and MATL as one intertie (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.

Figure 53 illustrates the daily average power prices in Alberta, Mid-C, and SP-15 over Q4. As observed, prices in Alberta were more volatile than Mid-C and SP-15; however, Mid-C averaged higher prices in October and December with comparable prices in November. The Mid-C price spikes in late October were caused by early winter storms in the US Northwest.

Figure 53: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q4)



Price differentials between Alberta and other markets drive intertie flows. Figure 54 illustrates the daily average price differential between Alberta and Mid-C, the daily average import and export volumes on the BC and MATL interties, and the intertie capacity on BC/MATL. Notably, BC/MATL capability was at 0 MW from October 2 to 7, 2023 for a scheduled outage. Over this period up to

320 MW of Load Shed Service (LSS)[36] and Fast Frequency Response (FFR)[37] were armed and the Most Severe Single Contingency (MSSC) limit in Alberta was not reduced. At approximately 07:13 on October 2, MATL was taken out of service, followed by the BC intertie at 09:07. At approximately 18:51 on October 7, the BC intertie returned to service followed by MATL at 19:05.

Figure 54 shows daily average intertie volumes for BC/MATL. Over the quarter, flows on the BC intertie averaged 394 MW of exports, with the highest net exports in December averaging 601 MW. In Q4 2022, the BC intertie averaged 81 MW of exports, with the highest level of net exports observed in December averaging 243 MW. The higher level of exports to BC in Q4 this year can be attributed to a lower water resource year and higher Mid-C prices. Most hydro capacity in BC lies in the Columbia (southeast) and Peace (northeast) regions, which have been affected by drought.

Flows on MATL averaged 56 MW of imports, the highest net imports were observed in November with an average of 78 MW. In Q4 2022, MATL averaged 74 MW of imports, with the highest net imports observed in November averaging 143 MW. Approximately 21 GWh of imports through MATL were wheeled[38] to BC, as shown in Figure 54.

In total, net exports on BC/MATL averaged 339 MW, a 470% increase relative to average net exports of 7 MW in Q4 2022. As indicated above, this increase was because of the large export volumes to BC.

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[36] 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.

[37] FFR is a reliability product developed to mitigate the impact of under frequency excursions caused by the sudden loss of imports or internal generation and is contracted between the AESO and eligible providers.

[38] The transportation of electricity from one system to another over transmission facilities of interconnecting systems. In this context, the transportation of electricity from Montana to BC through Alberta.

Figure 54: Daily average import (+ve) and export (-ve) volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q4)

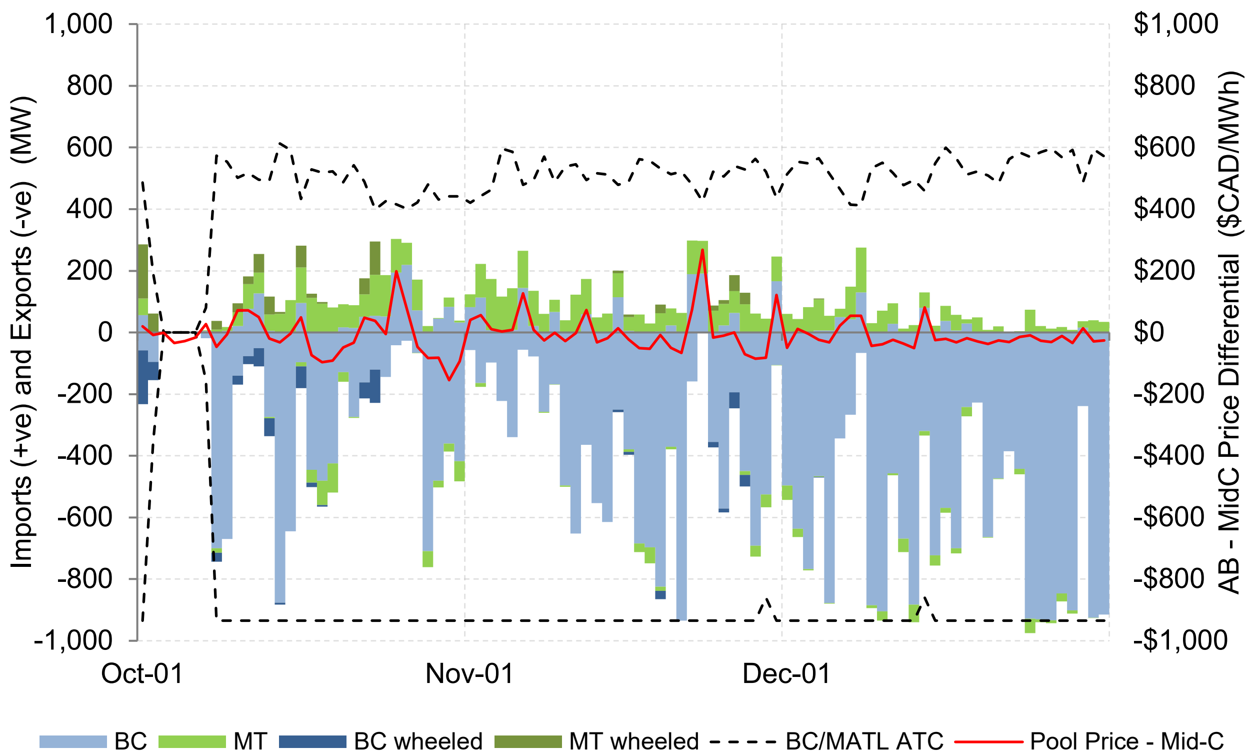


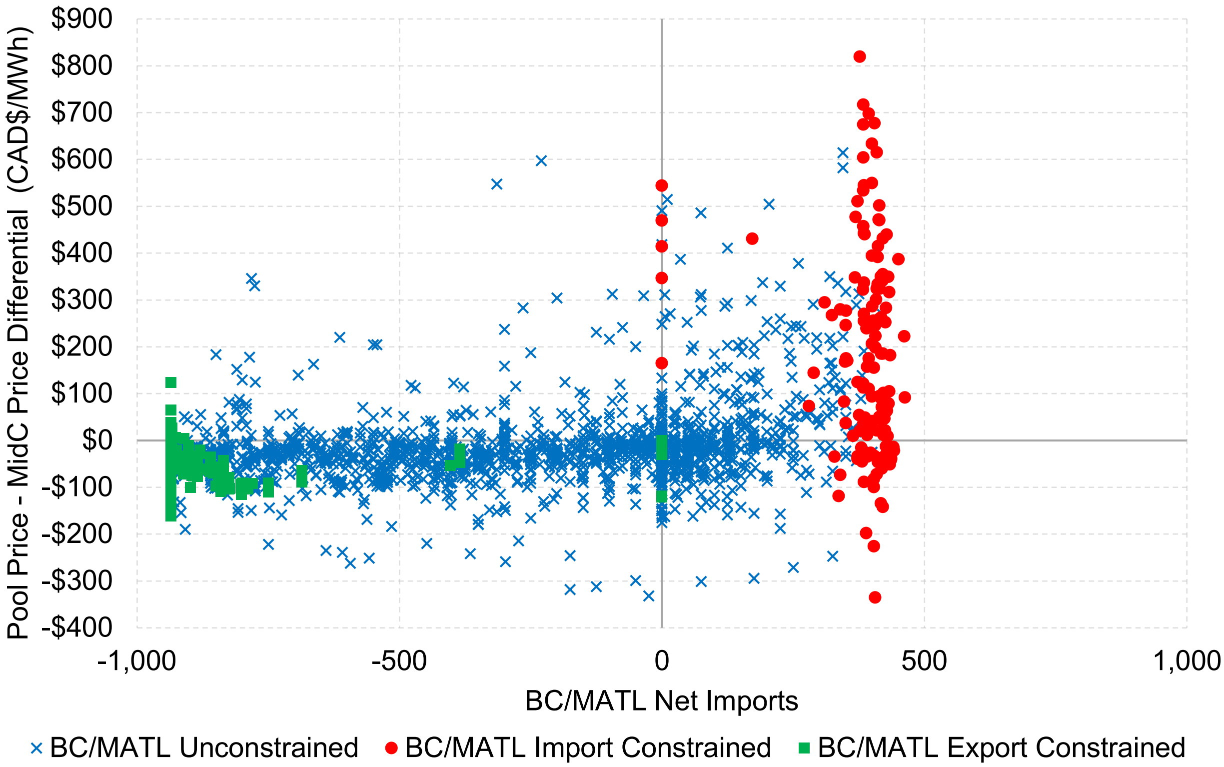
Figure 55 shows a scatterplot of the price differential between Alberta and Mid-C against the net flow on BC/MATL for each hour in Q4. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors).

In certain hours the net import offers on BC/MATL were at or above available import capacity, meaning the interties were import constrained (shown in red). There were generally two clusters of import constraints over the quarter; near 0 MW and around 400 MW. The 0 MW segment reflects derates and outages on BC/MATL during early October, while the segment in the range of 400 MW represents the normal operation of the interties. The import capability on BC/MATL was lowered in March 2023 when the AESO increased the amount of LSSi required.

BC/MATL was import constrained in 6% of hours in Q4, and the average price differential between Alberta and Mid-C during these hours was $184/MWh. The average import capability on BC/MATL during these constrained hours was 393 MW.

BC/MATL was export constrained in 12% of hours in Q4, and the average price differential between Alberta and Mid-C during these hours was -$52/MWh. The average export capability on BC/MATL during these constrained hours was 907 MW.

Figure 55: Alberta and Mid-C price differential and net BC/MATL flows (Q4)



In hours when the pool price was more than CAD$100/MWh higher than prices in Mid-C, the utilization of import capacity was 58%. Similarly, in hours where the pool price was more than CAD$100/MWh lower than prices in Mid-C, the utilization of export capability was 45%. Price volatility observed over the quarter and the timing requirements of interchange scheduling can impact overall intertie utilization.

For some hours in Q4, heavy intertie flows occurred despite pool price settling in the opposite direction. For example, on October 26 in HE 14 to HE 16 net imports through BC/MATL were 389 MW, 406 MW, and 404 MW, although the differential between Alberta and Mid-C in these hours was -$197/MWh, -$335/MWh, and -$225/MWh, respectively. The decrease in pool price over these hours was caused by an increase in supply cushion. In the preceding eight hours, the differential averaged $205/MWh.

Additionally, on October 29 during HE 01 net exports through BC/MATL were 782 MW, although the differential between Alberta and Mid-C was $346/MWh. During HE 01 pool price reached $486/MWh due to lower supply cushion caused by a drop in wind generation and an increase in exports. In the preceding 36 hours the differential averaged -$99/MWh.

Figure 56: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q4)[39]

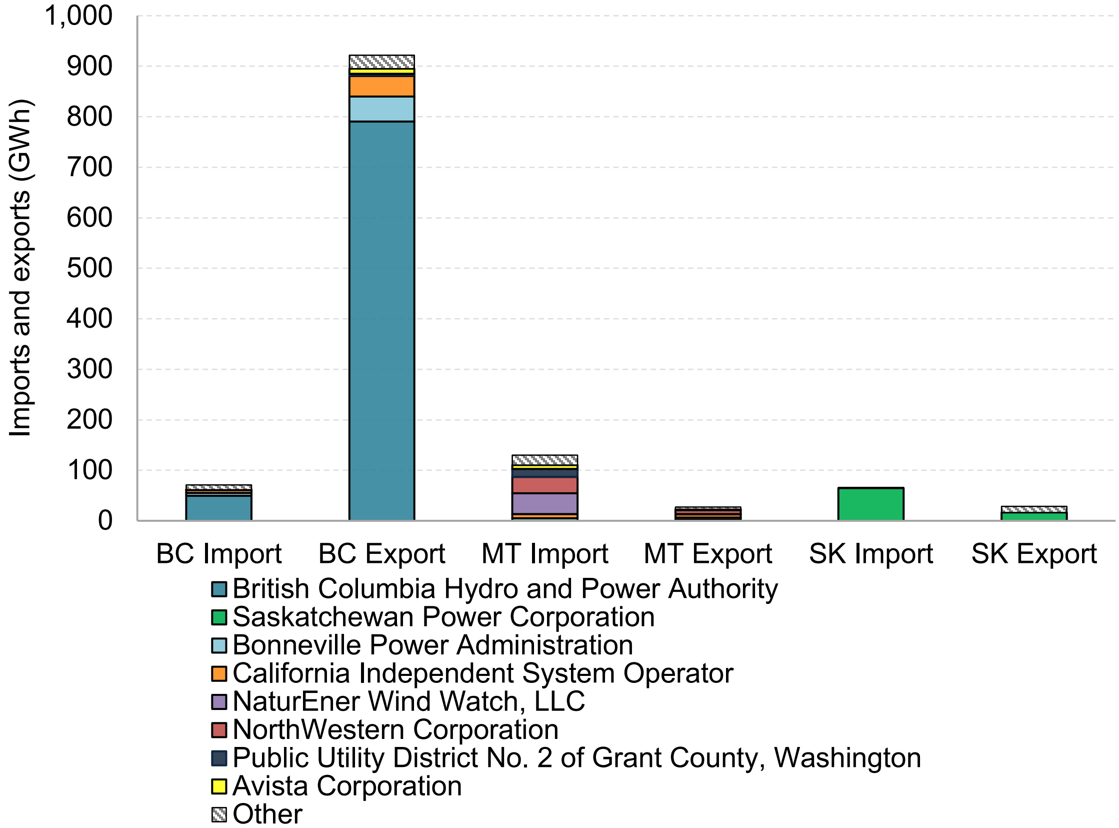


Figure 56 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD). The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered 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 70% originated from BC, 21% from the US Northwest, and 8% from California. For exports on the BC intertie, 86% was delivered to BC, 10% to the US Northwest, and 4% to California.

For imports through MATL, 93% originated from the US Northwest and 6% from California. For exports on MATL 69% was delivered to the US Northwest and 24% was delivered to California.

For imports through the SK intertie, 98% originated from Saskatchewan. For exports through the SK intertie, 58% was delivered to Saskatchewan, 13% was delivered to the Southwest Power Pool, and 14% was delivered to Ontario.

[39] This includes the highest eight Balancing Authorities by volume. Wheeled volumes are not included in Figure 56, these volumes represent 21 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 Annual summary

Total operating costs in 2023 were $378 million, a decrease of $123 million (-24%) relative to 2022 costs (Figure 57). Operating reserve (OR) costs include active and standby costs for regulating, spinning, and supplemental reserves.

This decline in total OR costs was largely due to a decrease in active OR costs. Active costs decreased by 28% to $334 million relative to 2022 levels partly because of lower pool prices. Annual costs for active spinning and supplemental reserves declined by 39% and 55% primarily due to a decrease in pool price, while active regulating reserve costs increased by 22%. The costs of active regulating reserves rose due to an increase in procured active volumes by the AESO. Likewise, standby OR costs increased by 27% to $44 million relative to 2022 costs due to higher volumes.

Load Shed Service for imports (LSSi) is a product provided by load customers who willingly commit to have their power source swiftly disconnected in the event of an unexpected loss of imports through the BC/MATL intertie. Figure 58 captures annual LSSi costs and volumes from 2019 to 2023. LSSi costs reached a 5-year high in 2021 at $28 million and have since gradually declined to $19 million in 2023. LSSi volumes have steadily declined since 2020.

Figure 57: Annual operating reserve costs ($ millions) and pool price ($/MWh) (2019 to 2023)

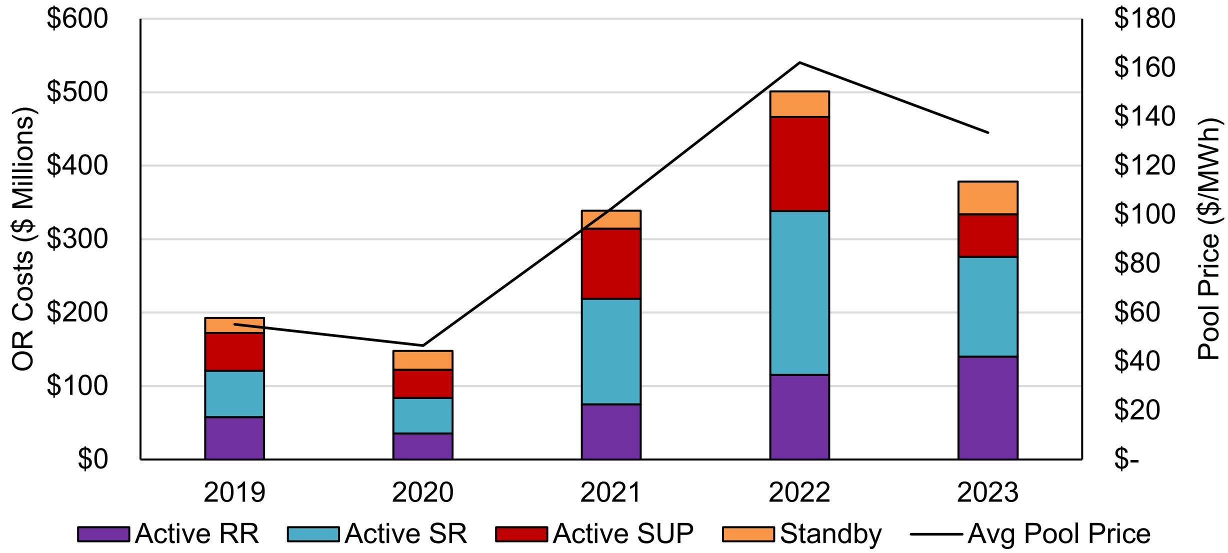
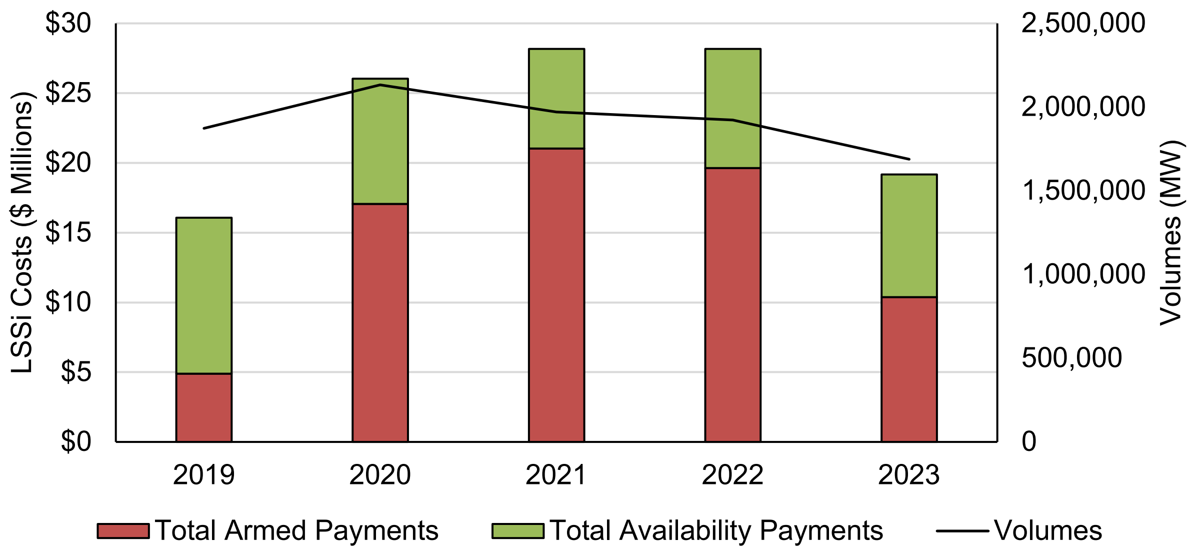


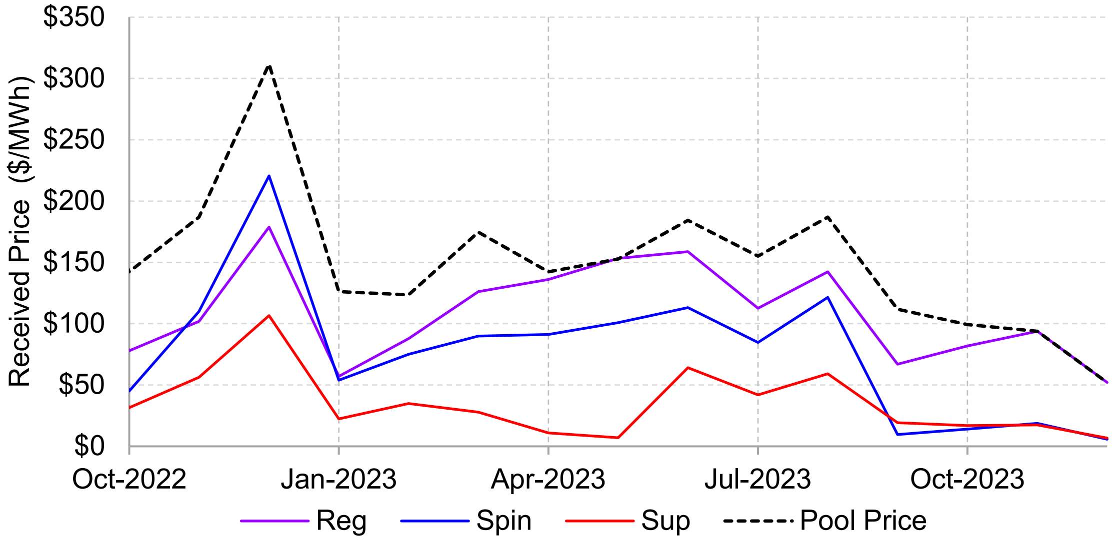
Figure 58: Annual LSSi cost and volumes (2019 to 2023)



3.2 Operating reserve received prices

Figure 59 shows the average received price for active regulating, spinning, and supplemental reserves by month since October 2022. The average received price is indexed to hourly pool prices using the equilibrium prices set in OR auctions.

Figure 59: Monthly average received prices for active regulating, spinning and supplemental reserves ($/MWh, all hours)



Despite a decline in the annual average pool price of 18%, the annual average received price for regulating reserves increased from $95/MWh in 2022 to $106/MWh in 2023. This increase can be partially attributed to the increase in procured on-peak active regulating reserves in October from 170 MW to 210 MW. This came following an initial increase on August 25 from 130 MW to 170 MW in response to increasing amounts of wind and solar generation. The importance of reserves, particularly active reserves, grows as the number of renewable generation projects climbs, and the magnitude of these projects rise. In 2023, the received prices for spinning and supplemental reserves fell broadly in line with the decrease in pool price (Table 16).

Table 16: Annual OR received prices (2022 to 2023)

	2022 ($/MWh)	**2023 ($/MWh)**	**Change ($/MWh)**
Regulating Reserves	$95	$106	$11
Spinning Reserves	$93	$65	-$28
Supplemental Reserves	$52	$27	-$25
Pool Price	$162	$134	-$29

In Q4, the received price of supplemental reserves ($13.74/MWh) exceeded the received price of spinning reserves ($12.92/MWh). An inversion between spinning reserve and supplemental reserve prices was observed in September 2023, however this trend did not result in an inversion of the quarterly average received price. This trend has now been persistent enough to impact the quarterly received prices in Q4 (Table 17). This price inversion is the result of competition between batteries and hydro assets for market share in the spinning market.

This price inversion does not align with the technical requirements for these products, which are more stringent for spinning reserves. To provide spinning reserves requires that an asset can provide a frequency response in addition to the requirements for supplemental reserves. Spinning reserve is an inherently more valuable product for the grid, and a price inversion between spinning and supplemental reserves does not reflect this value, nor does it reflect the shortage of frequency products identified by the AESO. Therefore, the price inversion of spinning and supplemental reserves in Q4 is not intuitive, particularly given the urgency placed around the procurement of fast ramping products.

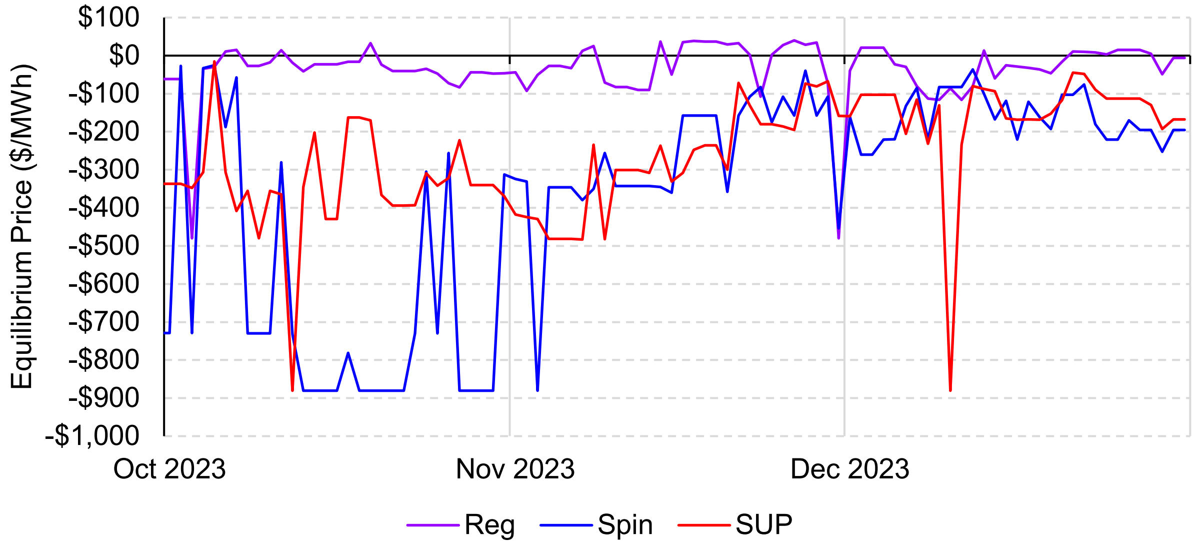
Table 17: Quarterly OR received prices (Q4 2022 and Q4 2023)

	Q4 2022 ($/MWh)	**Q4 2023 ($/MWh)**	**Change ($/MWh)**
Regulating Reserves	$120	$76	-$44
Spinning Reserves	$125	$13	-$112
Supplemental Reserves	$65	$14	-$51
Pool Price	$214	$82	-$132

Figure 60 illustrates equilibrium prices for each operating reserve product from October 1 to December 31, 2023. Equilibrium prices for spinning reserve in Q4 saw a 179% decrease relative to prices in Q4 2022, while supplemental reserves and regulating reserves saw equilibrium prices increase by 34% and 79%, respectively. The market for spinning reserves has become more competitive due to the addition of new battery storage assets. The on-peak price of active spinning reserves was below the price of supplemental reserves on 60% of days in Q4, up from 27% of days in Q3.

In September 2023, spinning reserve equilibrium prices were negative $554/MWh and were negative $631/MWh in October, in comparison to its annual average equilibrium price of negative $213/MWh. Spinning reserve equilibrium prices increased in November and December, which was largely due to a change in the offer behavior of market participants.

Figure 60: Daily active on-peak equilibrium prices (Q4 2023)



Supplemental reserve equilibrium prices increased as the year went on, with a Q4 average of negative $258/MWh relative to an average of negative $489/MWh for the first three quarters of the year. Q4 saw a decrease in the number of supplemental load providers as some load providers stopped participating in the market.

Average equilibrium prices for active spinning and supplemental reserves declined in 2023 relative to their annual averages in 2022 (Table 18). In contrast, equilibrium prices for regulating reserves increased from negative $114/MWh in 2022 to negative $58/MWh in 2023. Increased demand for active regulating reserves, including an increase from 170 MW to 210 MW in October, contributed to this increase in price as it effectively shifted the demand curve for active regulating reserves to the right. Table 18

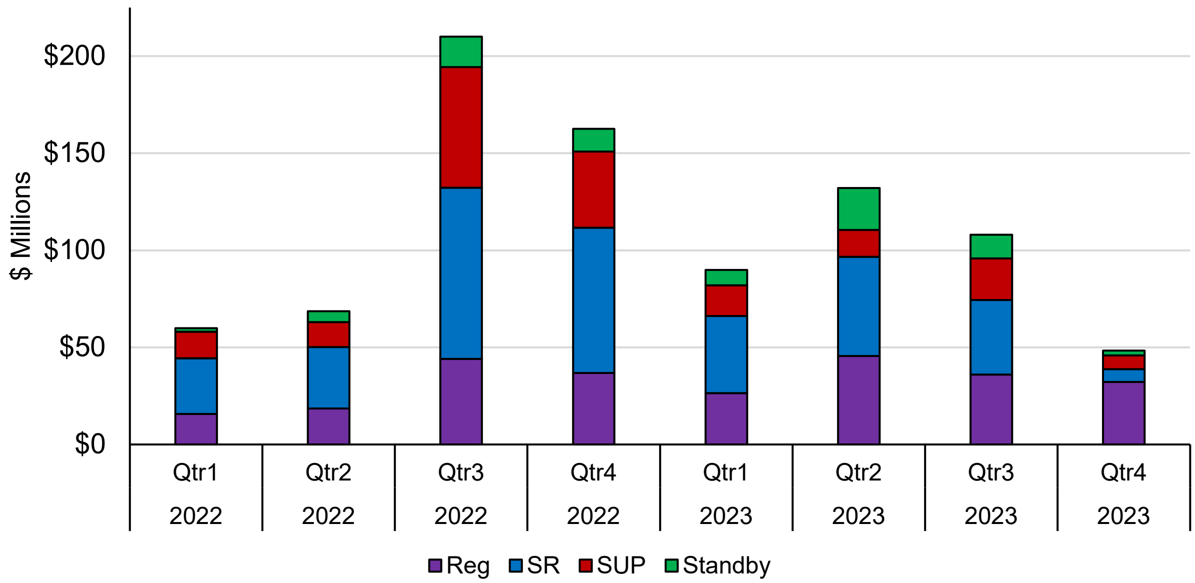
Table 18: Average active OR equilibrium prices (2022 to 2023)

	2022 ($/MWh)	**2023 ($/MWh)**	**Change ($/MWh)**
Regulating Reserve	-$114	-$58	$56
Spinning Reserve	-$93	-$213	-$120
Supplemental Reserve	-$239	-$431	-$192
Pool Price	$162	$134	-$29

3.3 Operating reserve costs and volumes

In Q4, total operating reserve costs declined in by 55% in comparison to Q3 2023, largely due to a reduction in the average pool price, which fell by $70/MWh. Of the three OR products, spinning reserves experienced the largest decrease in costs, with spinning costs falling 83% from $38 million to $7 million.

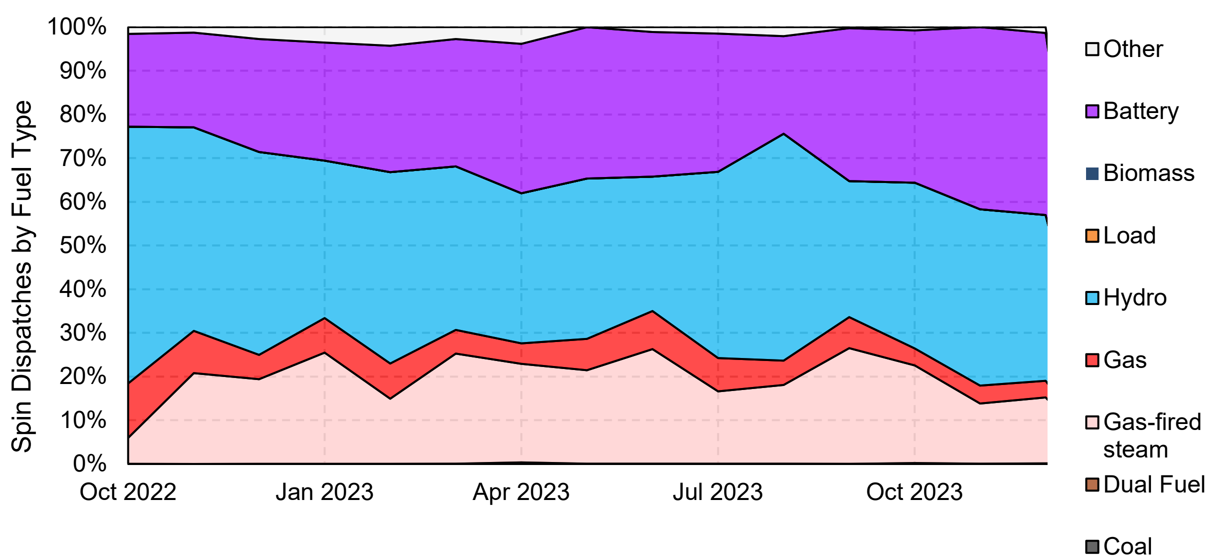
Figure 61: Total OR costs by quarter (2022 to 2023)



3.4 Dispatches by fuel type

Figure 62 captures dispatches by fuel type for spinning reserves from October 2022 to December 2023. The composition of dispatched spinning reserves made up by battery assets increased from 30% in Q3 to 40% in Q4.

Figure 62: Dispatched spinning reserves by fuel type (October 2022 to December 2023)



3.5 Standby activations

Standby OR are used to provide volumes to the OR market when all active reserves have been dispatched, and additional reserves are required.

The standby market follows a pay-as-bid structure and uses a blended price formula to rank standby offers for market clearing.[40] Market participants receive the premium price for contracted standby volumes, the activation price for dispatched active volumes, and pool price for directed volumes.

The activation percentages in the blended price formula are determined by the AESO and are intended to reflect historical activation rates for on and off peak hours. Table 19 compares the AESOs activation rates to annual average activation rates over the past two years. While the AESOs on peak activation rates for spinning and supplemental reserves are similar to the annual averages, this is not the case for the regulating reserves.

Annual standby activations for regulating reserves (both on and off peak) showed the greatest divergence from AESO activation values. In 2023, on peak regulating reserve activations were 36 percentage points greater than the AESOs activation percentage used to calculate the blended price formula. Off peak activation rates for regulating reserves were 35 percentage points greater than the AESOs respective activation percentage.

Table 19: Standby activation rates (2022 - 2023)

Product	***Block***	***AESO Activation %***	***Annualized Activation % (2022)***	***Annualized Activation % (2023)***
On Peak	Regulating Reserves	1%	24%	37%
	Spinning Reserves	10%	11%	10%
	Supplemental Reserves	10%	12%	9%
Off Peak	Regulating Reserves	3%	22%	38%
	Spinning Reserves	10%	20%	14%
	Supplemental Reserves	10%	21%	15%

The activation percentages in the blended price formula should be reflective of actual historic activation rates for on and off peak standby products. The existence of an outdated, administratively set activation rate in the blended price formula results in an inefficient weighting between premium and activation prices. This causes market participants to try and account for this in their offer behaviour, which can result in less clear price signals.

Figure 63 illustrates that average monthly activations rates for spinning and supplemental reserves increased markedly in Q4 relative to Q3. Activation rates for supplemental reserves

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

increased from 7% in Q3 to 21% in Q4, while standby activation rates for spinning reserves increased from 8% to 20%. Standby activations for regulating reserves continued to decline from its Q3 average, decreasing by 27 percentage points. This decline can be largely attributed to the increase in the AESOs procurement of active regulating reserves.

It is expected that standby activation rates for regulating reserves will continue to decline in the future. Figure 64 highlights an increase in on peak active regulating reserves in early Q4 from 170 MW to 210 MW, following on from a 40 MW increase in Q3.

Figure 63: Standby activation rates for regulating, spinning and supplemental reserves (October 2022 to December 2023)

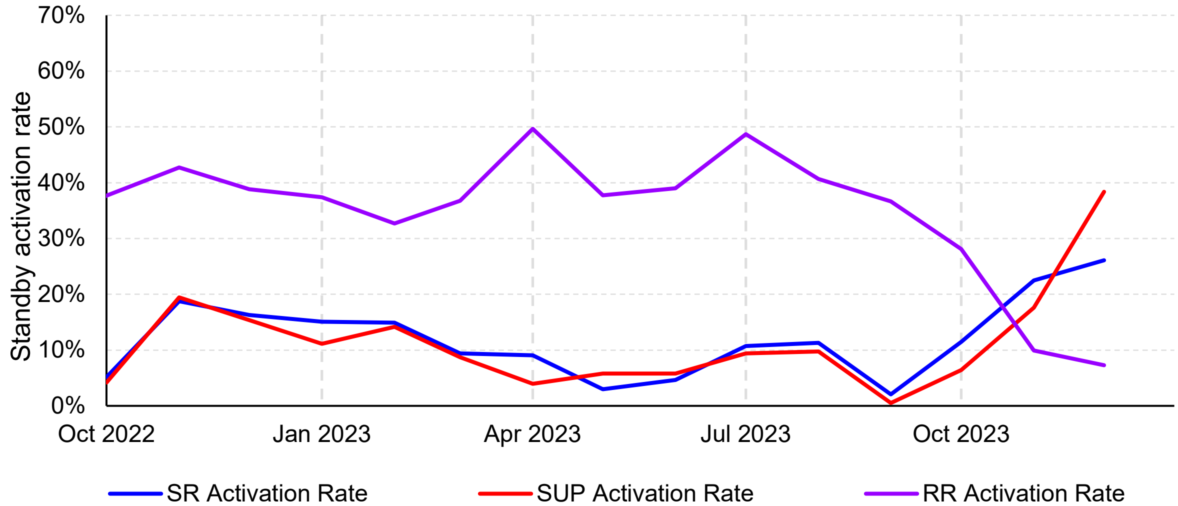
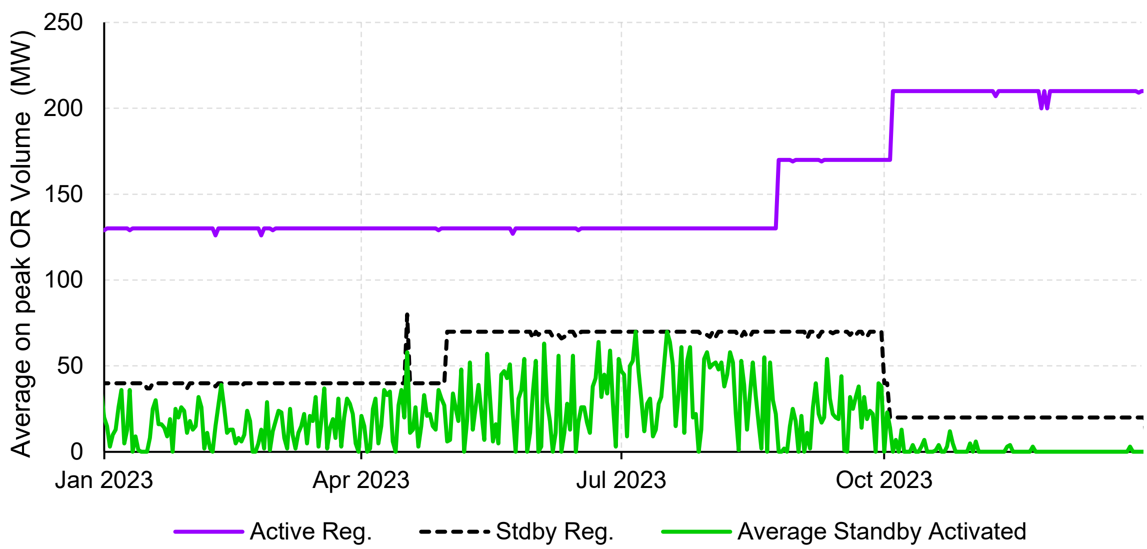


Figure 64: Active, standby, and activated standby volumes for on-peak regulating (October 2022 to December 2023)



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.[41]

4.1 Forward market volumes

Figure 65 illustrates total volumes by trade year since 2013. These figures include direct bilateral trades up to a trade date of December 31, 2023. Total trade volumes have been lower in recent years compared to prior years. This trend continued in 2023 as the total volume of trading was 41.6 TWh, a 23% decline relative to 2022 and the lowest year aside from 2020 when trading volumes were affected by the pandemic. The total volume of direct bilateral trades in 2023 was 6.5 TWh or 16% of total volumes.

Figure 65: Total volume by trade year (2013 to 2023)

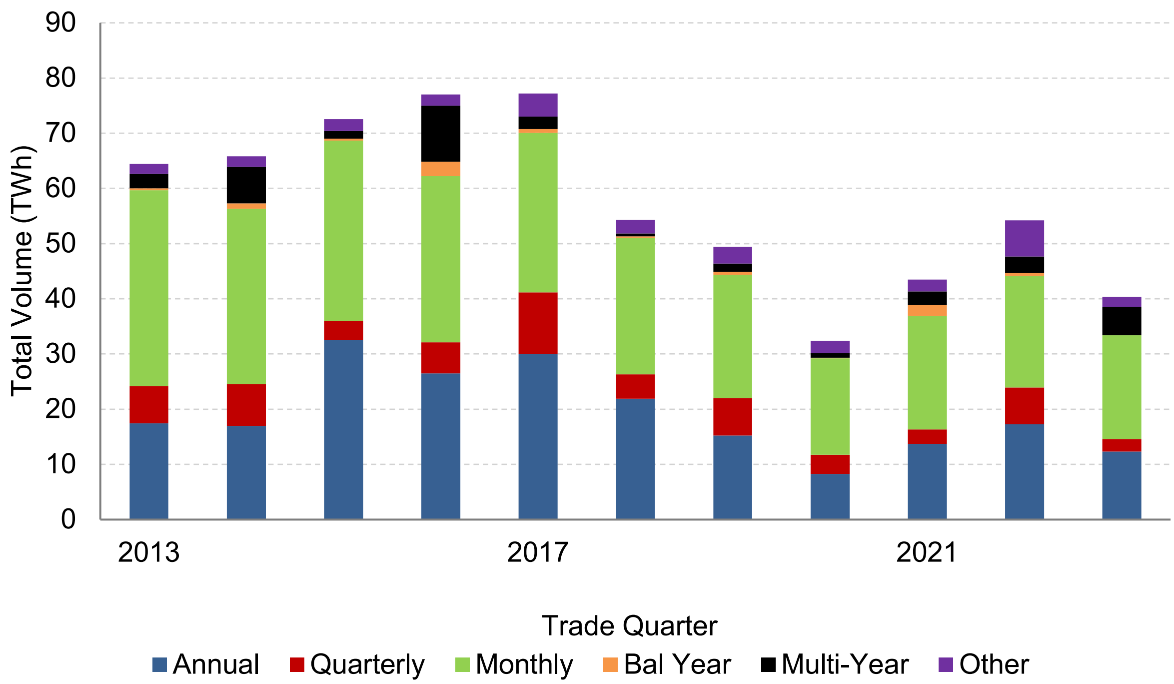
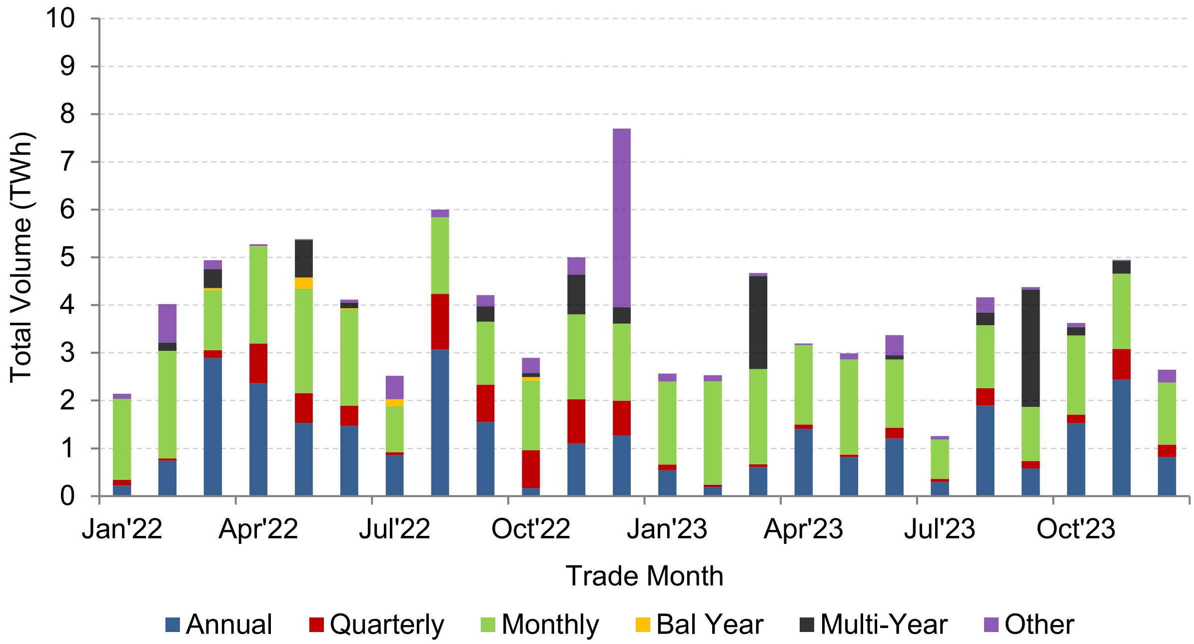


Figure 66 shows total volumes by trade month in 2022 and 2023. In 2023, volumes were highest in November and March, with March being increased by a few large multi-year trades. Total trade

[41] 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.

volumes were lowest in July. Year-over-year, trade volumes in each month were generally lower in 2023 relative to 2022.

Figure 66: Total trade volumes by trade month (January 2022 to December 2023)



4.2 Open interest

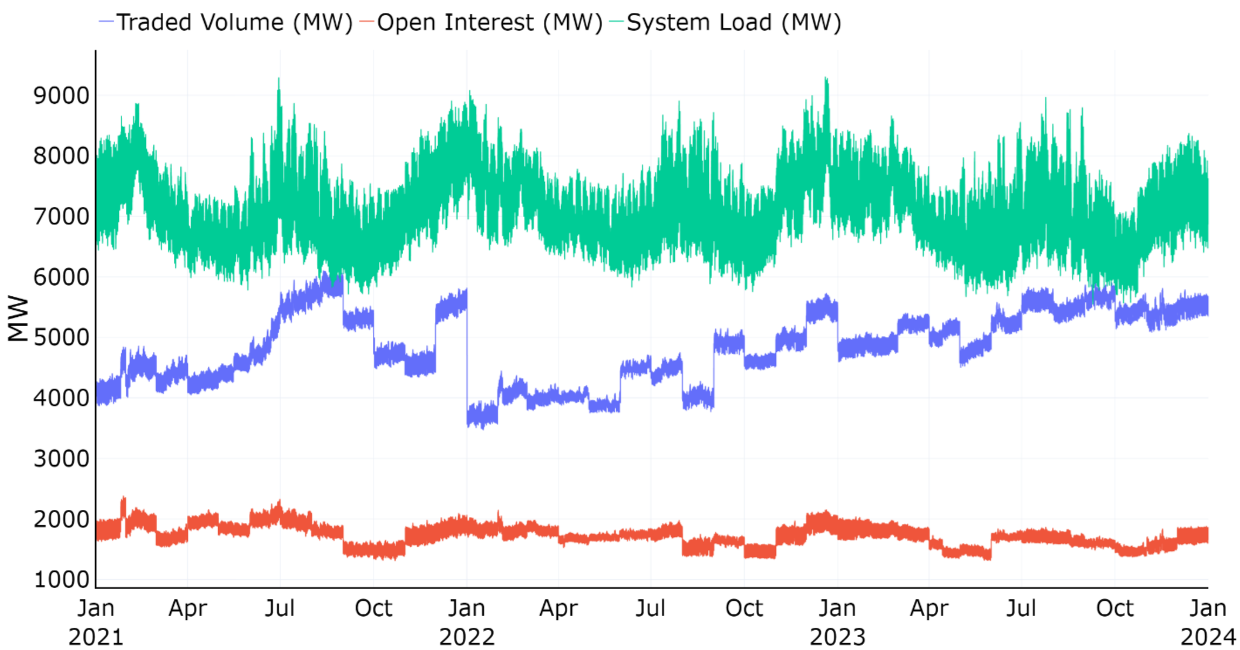
Another metric relevant to forward market liquidity is open interest. Open interest is the amount of trading volume that has not been settled and is left open to the pool price. In the context of Alberta's electricity market, open interest refers to the volume of electricity purchased or sold via forward market contracts. When new buyers and sellers negotiate futures contracts, open interest increases. Conversely, as incumbent buyers and sellers offset their trades and close positions, open interest declines. Higher open interest is indicative of greater market liquidity.

Open interest is calculated by looking at forward contracts traded on ICE NGX, OTC brokers, or bilaterally, and transposing the results to be represented on an hourly basis. The net position of each company is calculated by summing traded volumes across all forward contracts for all products in a given hour. Positive volumes are then aggregated across all companies and summed to produce the market net position for the hour. When calculating open interest, only net positions greater than 0 MW are summed to calculate the buy position of contracts that have not yet closed.

Figure 67 below illustrates open interest relative to system load and traded volumes. Open interest has averaged 1,756 MW since the start of 2021 which accounts for 24% of system load.

Relative to the traded volumes open interest is relatively stable. Following a decline in average traded volumes in 2022, volumes increased above 5,000 MW in 2023. Although traded volumes have increased for 2023, open interest volumes have declined from an annual average of 1,749 MW in 2022 to 1,680 MW in 2023. On average open interest is around 37% of the traded volume, illustrating that 37% of trades are left open to pool price on average. While traded volumes for January 2022 were substantially lower than volumes traded in January of 2021 and 2023, open interest volumes remained relatively unchanged. This reduction in traded volumes was a result of a decrease in monthly trades.

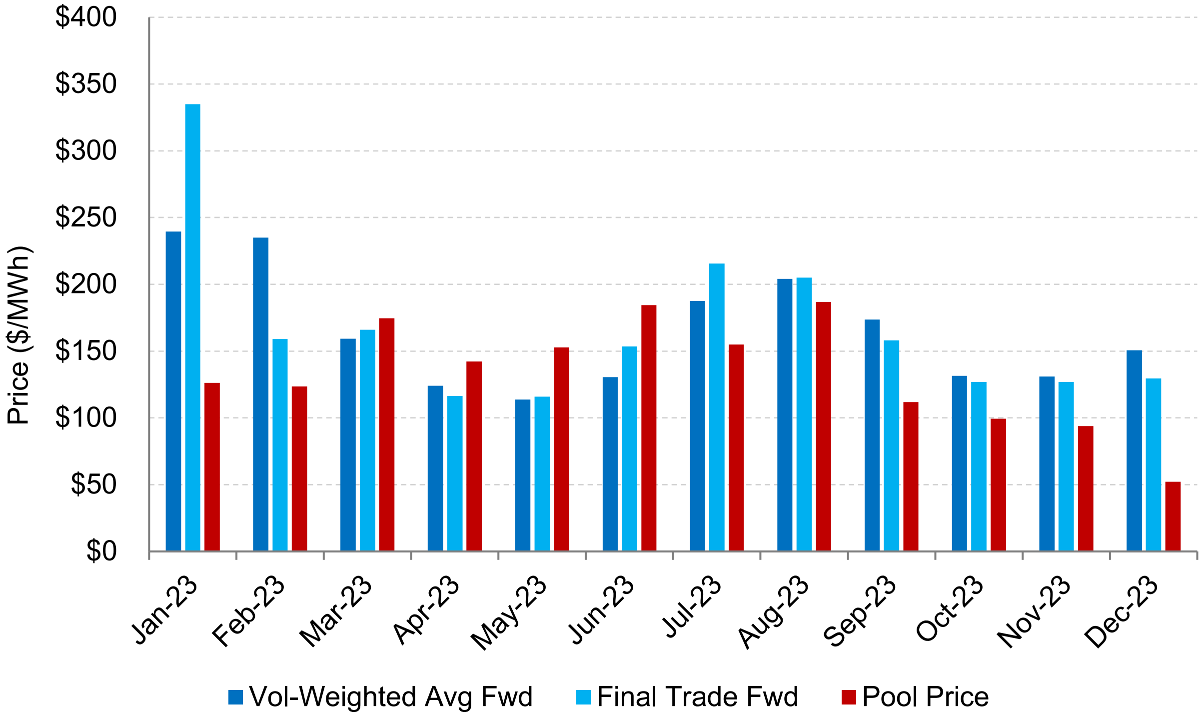
Figure 67: Traded volume, open interest and system load by hour (2021 to 2023)



4.3 Trading of monthly products

Figure 68 below illustrates volume-weighted average forward prices and final-trade forward prices relative to the monthly average pool price. For all three months in Q4, forward prices traded at a premium to the realized pool price. In December, the volume-weighted average forward price was $98/MWh higher than the pool price, a premium of 189% relative to the realized pool price. This is the highest percent premium on record going back to 2013.

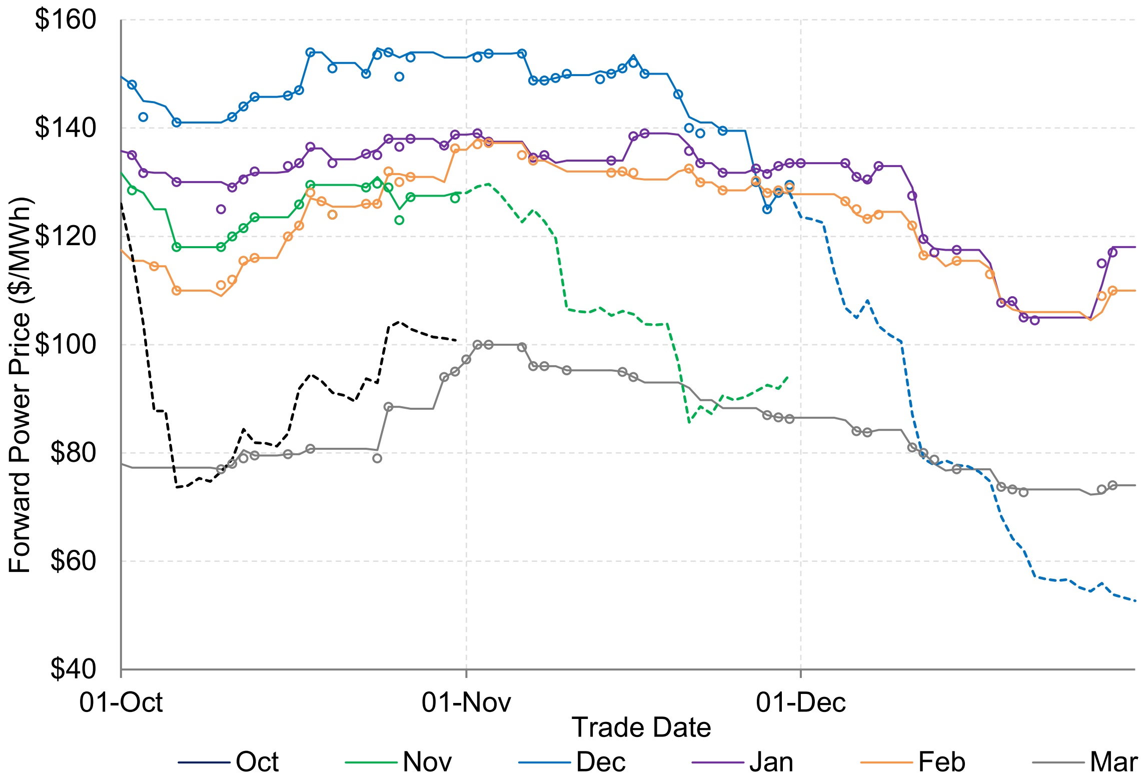
Figure 68: Monthly forward prices compared to average pool prices (January to December 2023)



The lower-than-expected pool prices put some downward pressure on forward prices over Q4 as shown by Figure 69. Figure 69 illustrates the evolution of select monthly forward prices over Q4. The markers illustrate the price of the final trade on that that day while the dashed lines illustrate marked prices (the expected average price for these months as the months unfold).

As shown by the marked prices for October, November, and December pool prices in these months came in below prior forward market expectations and this put some downward pressure on prevailing forward prices for other contracts. However, this downward pressure was somewhat offset by other factors such as delays to the commissioning of the Cascade combined cycle assets and weather forecasts.

Figure 69: Select monthly forward prices over Q4 (October 2023 to March 2024)



4.4 Trading of annual products

Figure 70 illustrates volume-weighted average and final-trade forward prices for annual contracts relative to average pool prices. Since 2021 volume-weighted average forward prices have been lower than realized pool prices. The volume weighted forward price for Calendar 2023 (CAL23) was $78/MWh, a forward discount of $56/MWh or 42% relative to the average pool price. However, unlike for CAL21 and CAL22, the final forward trade price for CAL23 of $163/MWh was above the realized pool price of $134/MWh.

Figure 70: Volume-weighted average and final trade forward prices for annual contracts relative to realized pool prices (2013 to 2023)

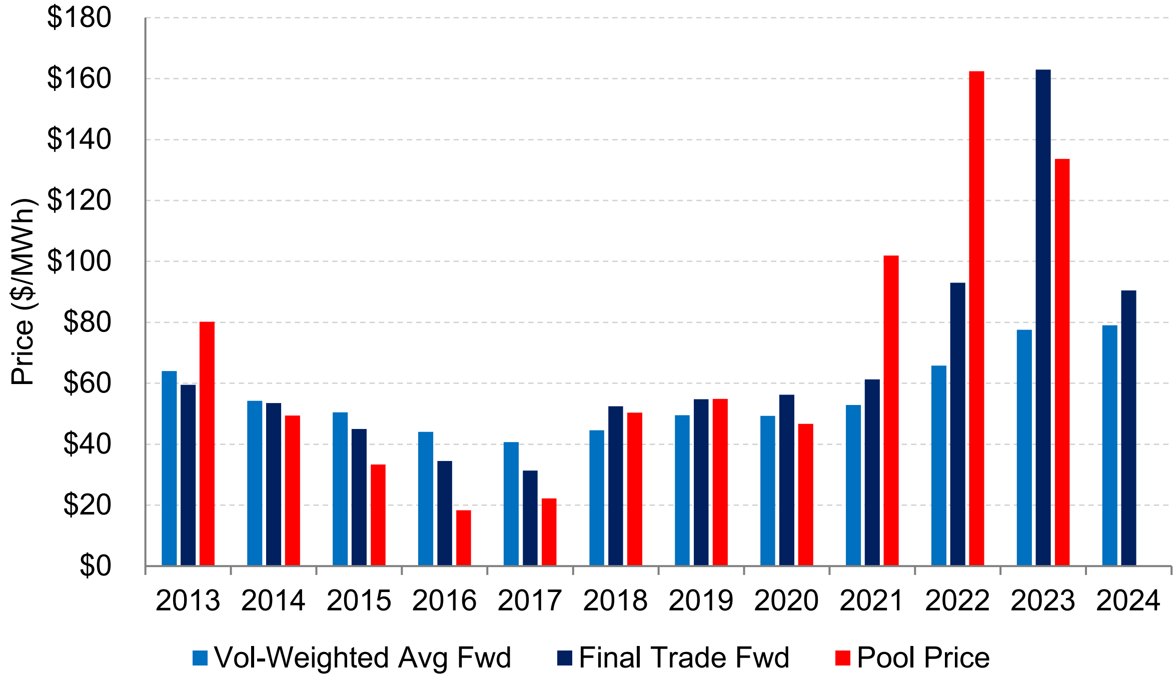


Figure 71 illustrates the evolution of the marked price of CAL23 alongside forward power prices for CAL24, CAL25, and CAL26. The price of CAL24 increased by 6% from $89.53/MWh on November 1 to $94.75/MWh on November 2 as TransAlta announced the proposed acquisition of Heartland Generation.[42] This acquisition would increase the market concentration of generation assets in the province, assuming no new entry, and may put upward pressure on prices. Over Q4, the price of CAL24 increased from $84 to $95/MWh and then fell back down to end the quarter largely unchanged.

Declining natural gas prices were a factor in the falling price of CAL24 later in the quarter. The price of natural gas for CAL24 fell by 31% over the quarter with the declines largely occurring between mid-November and mid-December. The price of power did come down over this period, but not to the same extent as the declines in natural gas. As a result, the spark spread for CAL24 increased by 20% over the quarter (Table 20).

The price of contracts for CAL24 to CAL28 are lower than the price of CAL23. This reflects the expectation of increased thermal capacity in addition to increasing amounts of intermittent generation. The major thermal projects coming online include the Cascade combined cycle project, the repowering of Genesee 1 and 2 from coal to combined cycle, and the Suncor Base plant cogeneration project.

[42] TransAlta to acquire Heartland Generation – November 2, 2023

Figure 71: Annual forward prices since January 1 (CAL23 to CAL26)

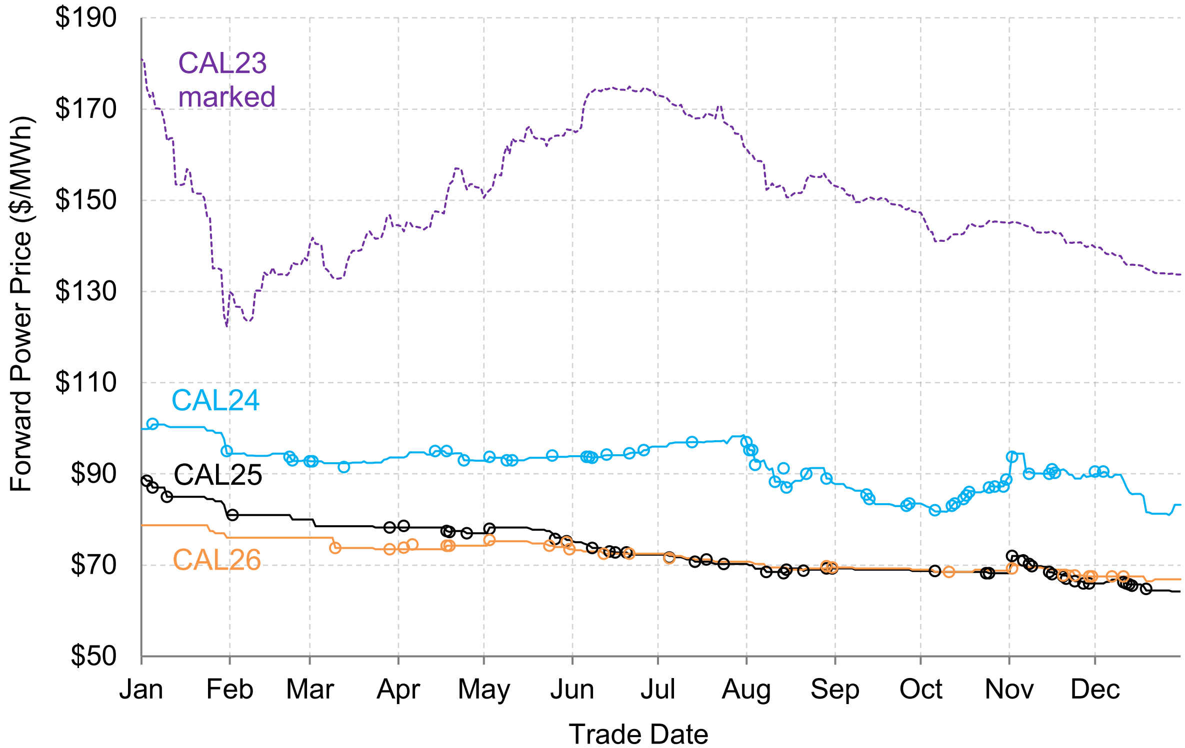


Table 20: Forward power and natural gas price changes over Q4[43]

Contract	**Power price ($/MWh)**			**Gas price ($/GJ)**			**Spark spread ($/MWh)**		
	Sep 30	**Dec 31**	**% Chg**	**Sep 30**	**Dec 31**	**% Chg**	**Sep 30**	**Dec 31**	**$ Chg**
CAL23 (marked)	$147	$134	-9%	$2.64	$2.54	-4%	$109	$97	-12%
CAL24	$84	$83	0%	$2.79	$1.92	-31%	$41	$49	20%
CAL25	$69	$64	-7%	$3.50	$2.99	-15%	$16	$16	4%
CAL26	$69	$67	-3%	$3.74	$3.43	-8%	$10	$11	10%
CAL27	$69	$68	-1%	$3.66	$3.42	-7%	$7	$8	22%
CAL28	$69	$69	-1%	$3.67	$3.34	-9%	$3	$5	110%

[43] The spark spread figures assume a heat rate of 10 GJ/MWh and consider the carbon costs associated with an emissions intensity of 0.54 tCO_2e/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 rates in October and November 2023 were 5% and 9% higher than last year. However, the RRO rate in December 2023 was 11% lower than last year, keeping the average RRO rate in Q4 largely unchanged year-over-year (Table 21). The RRO rates shown in Table 21 include the collection rates.[44] The collection rates increased the RRO rates in Q4 by around 2.2 ¢/kWh.

Table 21: Retail market summary statistics

		2022	2023	Change
RRO (Avg ¢/kWh)	Oct	18.72	19.63	5%
	Nov	17.73	19.32	9%
	Dec	22.99	20.37	-11%
	Q4	**19.84**	**19.78**	**-0.3%**
DRT (Avg $/GJ)	Oct	5.11	2.50	-51%
	Nov	5.51	2.78	-49%
	Dec	6.15	2.83	-54%
	Q4	**5.59**	**2.70**	**-52%**
Competitive Variable Electricity Rate (Avg. ¢/kWh)	Oct	15.88	11.46	-28%
	Nov	20.70	10.83	-48%
	Dec	33.54	6.42	-81%
	Q4	**23.40**	**9.56**	**-59%**
Competitive Variable Natural Gas Rate (Avg. $/GJ)	Oct	4.27	3.30	-23%
	Nov	6.69	3.48	-48%
	Dec	6.79	2.80	-59%
	Q4	**5.91**	**3.19**	**-46%**
Expected Cost, 3-Year Electricity Contract (Avg. ¢/kWh)	Oct	10.60	8.21	-23%
	Nov	11.33	8.32	-27%
	Dec	12.82	7.65	-40%
	Q4	**11.58**	**8.06**	**-30%**
Expected Cost, 3-Year Natural Gas Contract (Avg. $/GJ)	Oct	4.74	3.50	-26%
	Nov	4.58	3.50	-24%
	Dec	4.47	2.95	-34%
	Q4	**4.60**	**3.31**	**-28%**

The average residential Default Rate Tariff (DRT) rate in Q4 was 52% lower than last year (Table 21). The year-over-year decline in DRT rate is because of lower natural gas prices. The DRT rate was lowest in October and highest in December during Q4.

The average competitive variable electricity and natural gas rate faced by residential customers experienced a notable 59% decrease year-over-year. The low variable electricity rate was related to the lower pool prices, especially in December. The variable electricity rate in December 2023 was 6.42 ¢/kWh, 27¢/kWh less than December 2022. Competitive variable natural gas rates also showed a year-over-year decline, decreasing by $2.72/GJ.

[44] 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

In Q4, retailers' expected cost of providing 3-year fixed rate electricity contracts was 30% lower year-over-year and 14% lower than in Q3. The expected cost of providing 3-year fixed rate natural gas contracts also dropped by 28% year-over-year and 6% lower relative to Q3.

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 Q3 2023.

5.2.1 Regulated retailer customer losses

In Q3 2023, the total number of residential RRO customers fell by around 66,000, making the most substantial net reduction in any quarter since 2012 (Figure 72). While the RRO customer loss in July was relatively modest, the large migration of residential customers in August and September from the RRO to other providers contributed to the substantial drop in Q3 (Figure 73). The number of residential customers that left the RRO in August and September was over 42,000 and 38,000, respectively (Figure 73). The cumulative RRO customer gain throughout the months in Q3 were relatively similar year-over-year (Figure 73). The decline in residential RRO customers may be attributed to the high RRO rates in August and September. For example, the August RRO rates in ENMAX service area was 32 ¢/kWh and at the same time the lowest 5-Year fixed rate offering for electricity was available at 12.49 ¢/kWh, 62% less.

Figure 72: RRO customer net losses, residential customers (Q1 2021 to Q3 2023)

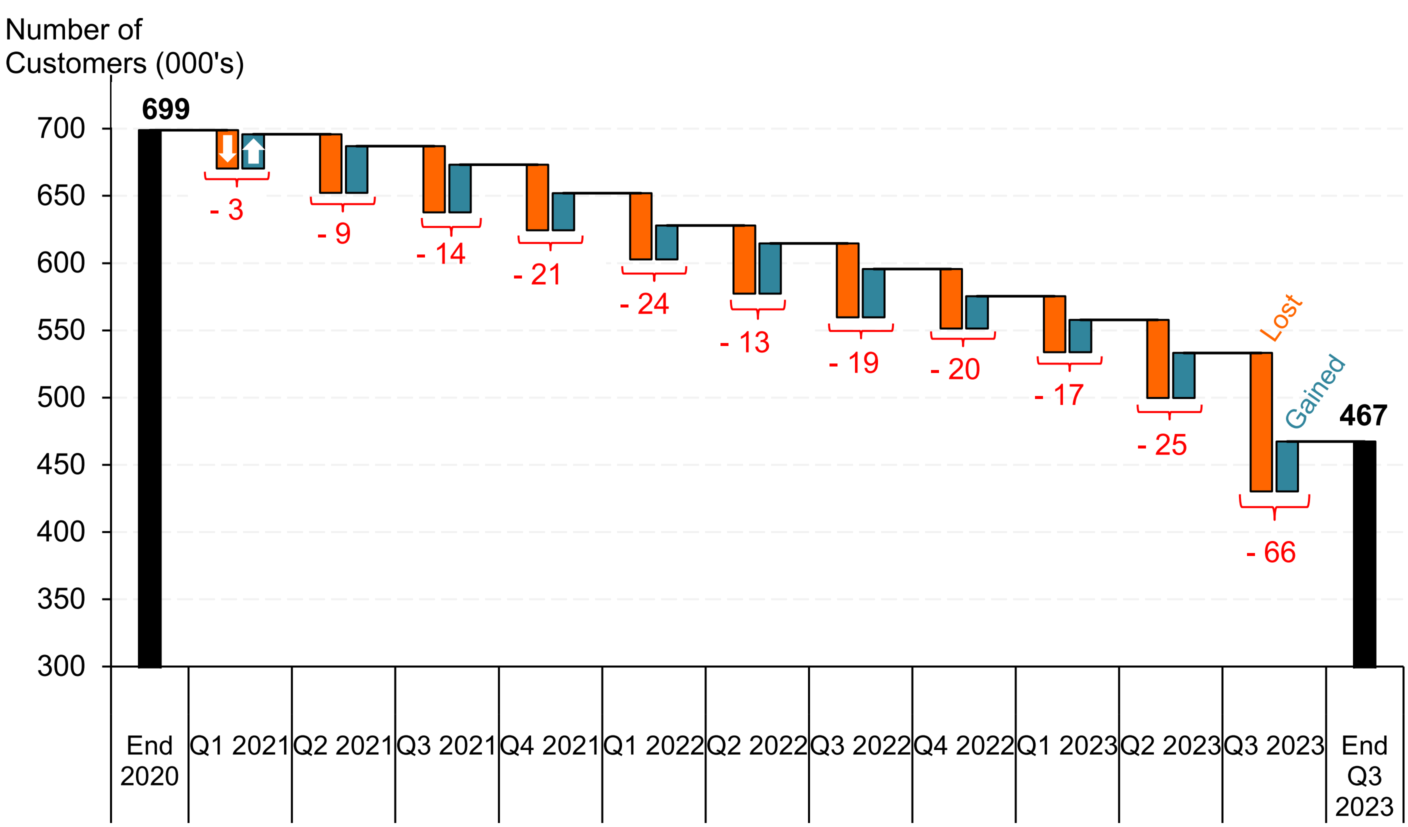
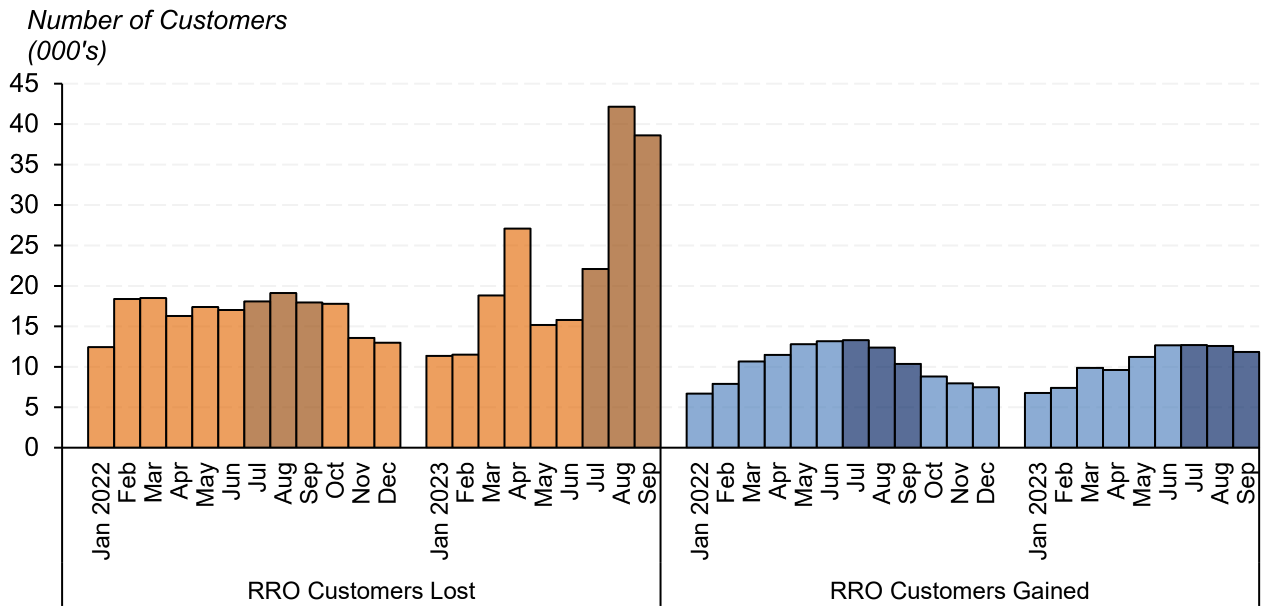
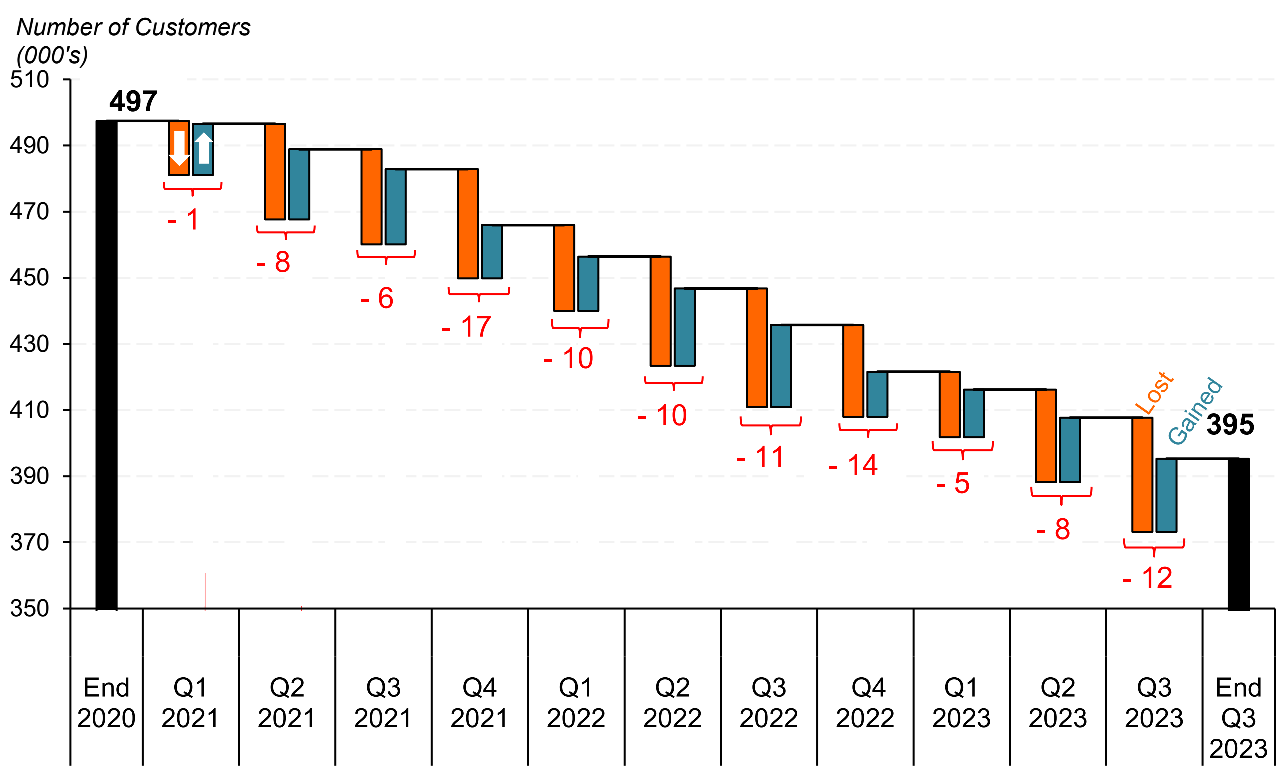


Figure 73: RRO customer losses and gains, residential customers (January 2022 to September 2023)



The total number of residential DRT customers fell by around 12,000 in Q3 2023 (Figure 74). While around 34,500 residential customers left the DRT, around 22,100 residential customers joined DRT in Q3. DRT rates were often less than prevailing competitive natural gas rates in Q3, keeping the net loss for DRT customers much less than the RRO.

Figure 74: DRT customer net losses, residential customers (Q1 2020 to Q3 2023)



5.2.2 Dynamics of retail switching

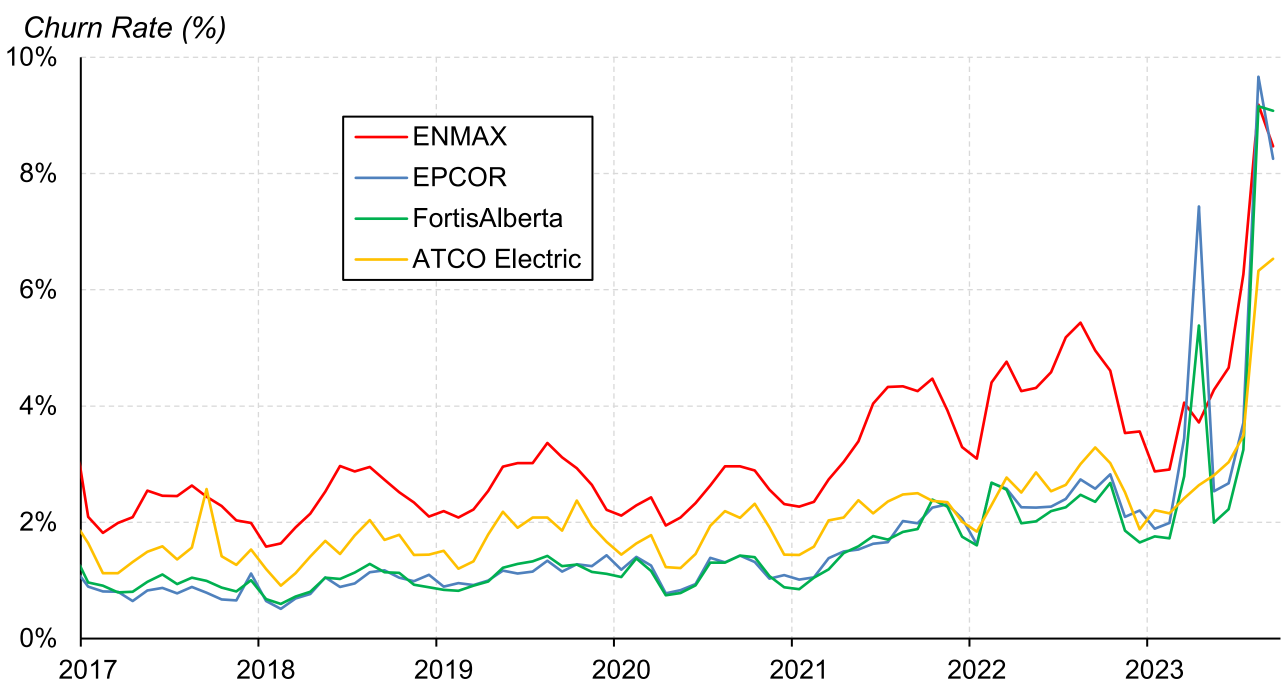
Churn rates are the percentage of a retailer's customer base that switches to another provider in each period. Since 2021, churn rates have been lower among competitive customers relative to RRO customers, indicating that RRO customers are switching competitive retailers at greater rates.

The RRO churn rate in all the service areas was high in August and September, which resulted in the large net loss of RRO customers in Q3. Among the four service areas, EPCOR had the highest churn rate of 9.67% in August followed by ENMAX and FortisAlberta with churn rates of 9.19% and 9.16% respectively. The ATCO service area experienced the least amount of RRO customer switching in August with a churn rate of 6.33%. High churn rates continued in September with an average of 8.08% of RRO customers switching to a different provider across all service areas.

Since 2018, residential RRO churn rates in the ENMAX service area have exceeded that of other service areas, while churn rates in the EPCOR and FortisAlberta service areas were generally the lowest among the four (Figure 75). In recent months, however, the churn rates in the EPCOR and FortisAlberta service areas have been higher than in the ENMAX service area, including in August.

From April 2023 onwards the residential RRO rate includes the collection rates resulting from the deferred revenue associated with the rate ceiling set on RRO rates for January, February, and March 2023. The collection rates will increase as more customers leave the RRO.

Figure 75: RRO retailer churn rates by service area, residential customers (January 2017 to September 2023)



5.2.3 Competitive retailer market share

Concurrent with the drop in residential RRO customer count, the competitive retail customer share for electricity increased across all the service areas in Q3. The overall customer contract shares for electricity increased from 66.9% in June to 71.2% by the end of September (Figure 76). The increase in market share was highest in the EPCOR service area at 5.9%, followed by FortisAlberta at 5.6% (Table 22). Market share increased by 2.3% and 2.6% in the ENMAX and ATCO service areas, respectively. The market share increase in Q3 was substantial relative to previous quarters due to the sizeable drop in RRO customer shares.

The retail market share of competitive natural gas contracts increased by 1.5% in Q3 to reach 69.5% (Figure 77). For the first time since 2012, the competitive retail market share for electricity surpassed natural gas. The natural gas retail market share increased by 2.1% in Apex service area and 1.5% in Atco Gas North (Table 23).

Figure 76: Competitive retail customer share (electricity) by service area, residential customers (January 2012 to September 2023)

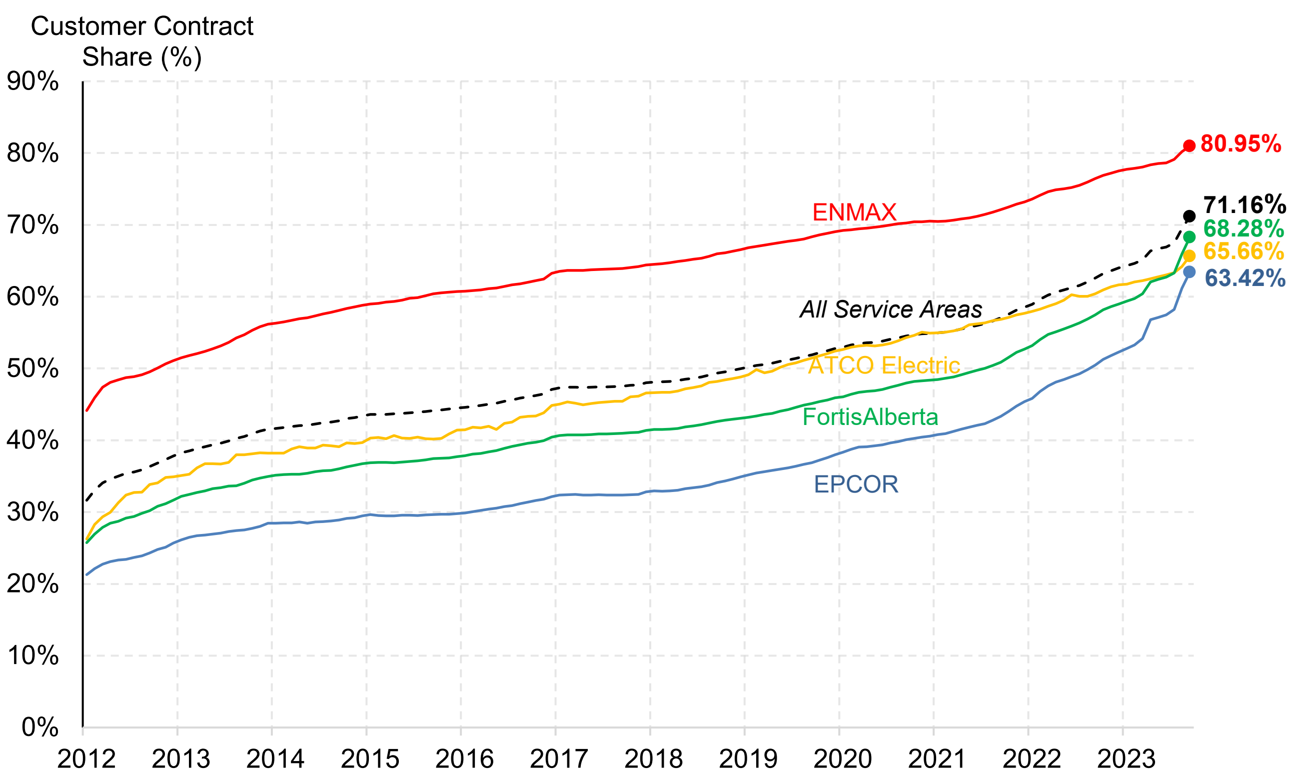


Table 22: Change in retail competitive shares (electricity) by service area, residential customers

	ENMAX	EPCOR	FortisAlberta	ATCO
Change (Q2 - 2023)	0.6%	3.3%	2.3%	0.8%
Change (Q3 - 2023)	2.3%	5.9%	5.6%	2.6%
Competitive Share (Sep 2023)	81.0%	63.4%	68.3%	65.7%

Figure 77: Competitive retail customer share (natural gas) by service area, residential customers (January 2012 to September 2023)

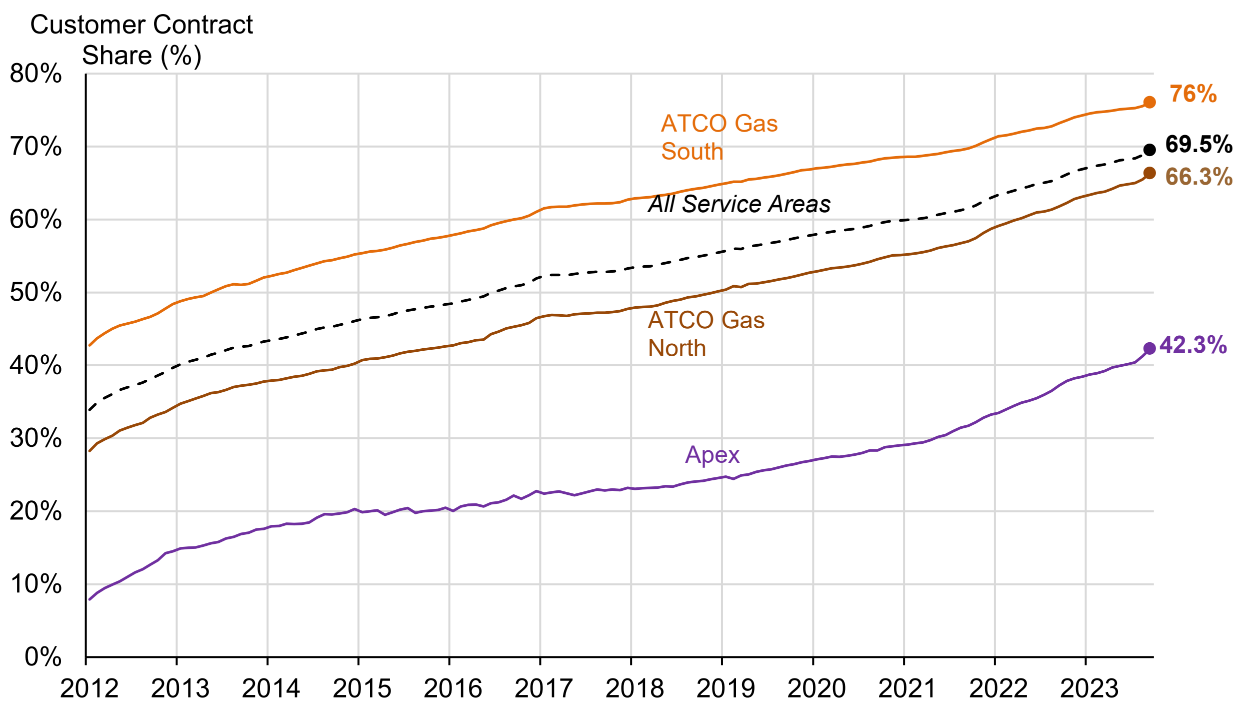


Table 23: Change in retail competitive shares (natural gas) by service area, residential customers

	ATCO Gas North	ATCO Gas South	Apex
Change (Q2 - 2023)	1.0%	0.4%	0.9%
Change (Q3 - 2023)	1.5%	0.8%	2.1%
Competitive Share (Sep 2023)	66.3%	76.0%	42.3%

5.3 Competitive retail rates

5.3.1 Fixed rates

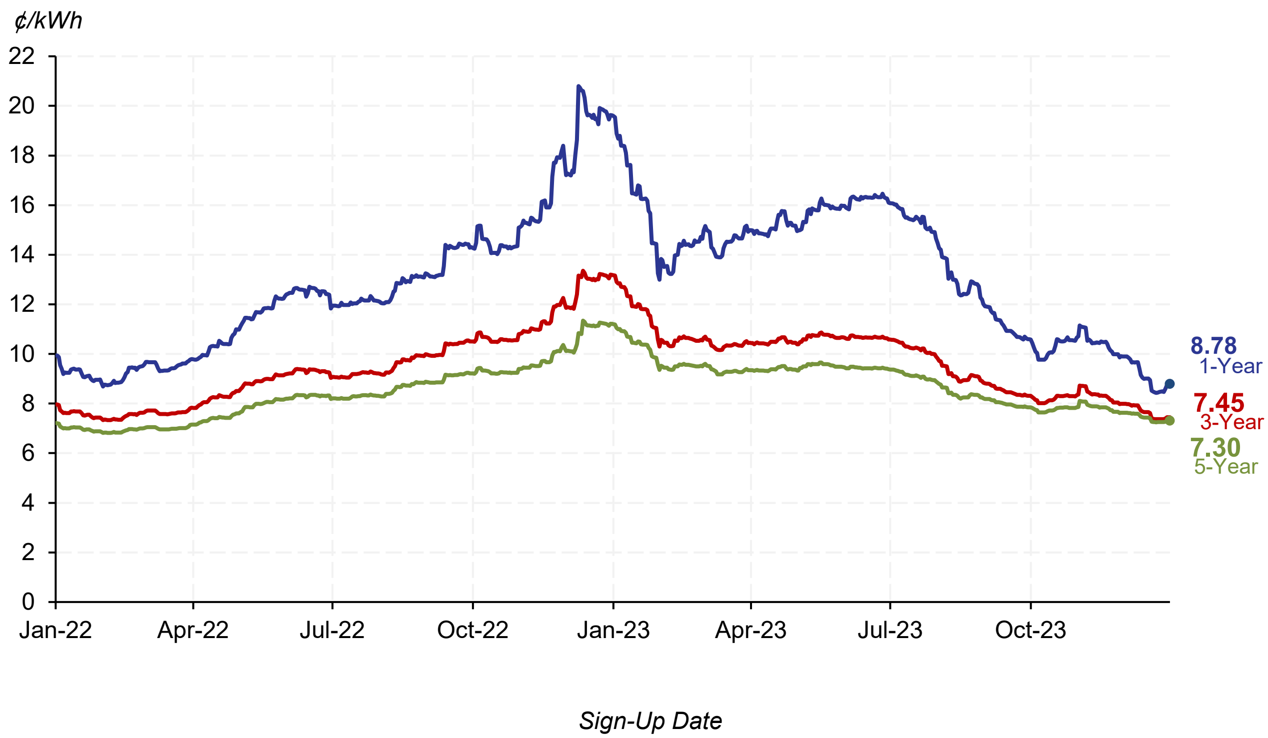
Most retail customers can choose to sign a contract with a competitive retailer instead of remaining on the RRO. Competitive retailers typically offer fixed and variable energy rates. Fixed rates are fixed over a defined contract term; usually one, three or five years. Variable rates are energy rates 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 increased marginally in October and then decreased over the rest of Q4 as near term and longer-term forward prices for electricity dropped.

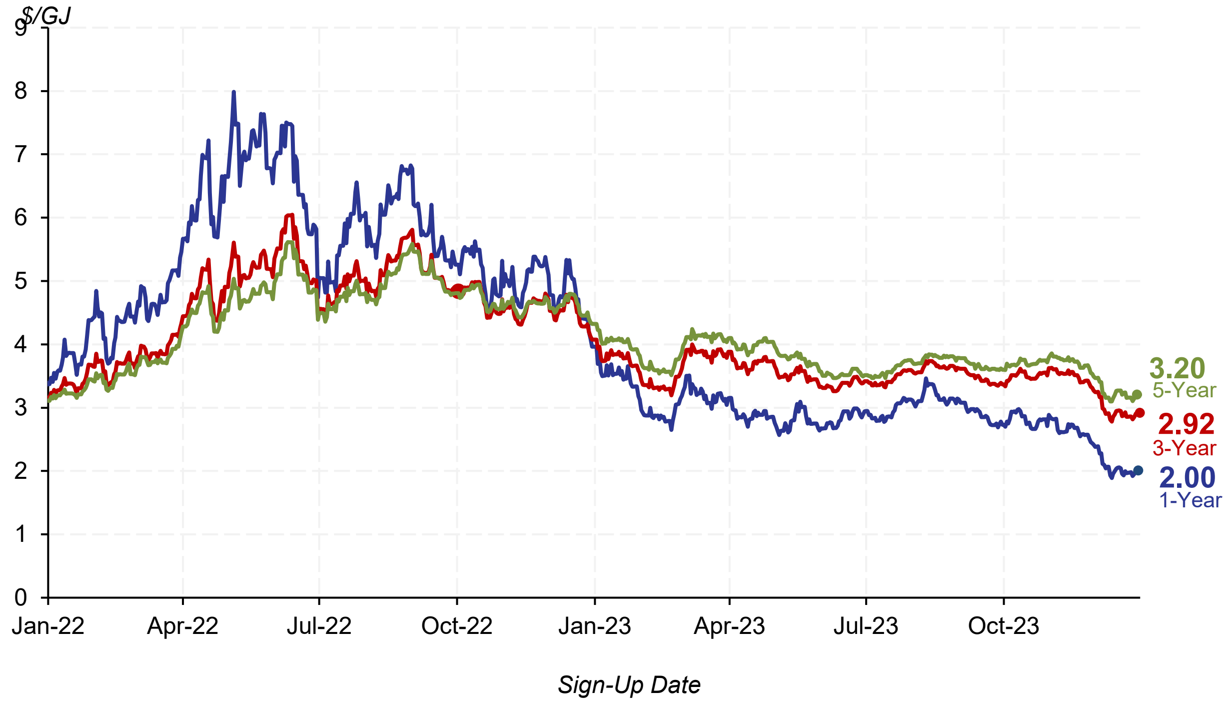
The expected cost for 1-, 3-, and 5-year fixed rate contracts decreased by 17%, 10%, and 7% respectively over Q4 (Figure 78). The expected cost for longer term contracts is lower than the 1-year contract as prices for annual forward contracts such as CAL25 and CAL26 are lower than prices for near term forward monthly prices. On December 31, the expected cost for 1-, 3-, and 5-year fixed rate electricity contracts are at 8.78 ¢/kWh, 7.45 ¢/kWh and 7.30 ¢/kWh respectively.

Figure 78: Expected cost, fixed rate electricity contract, residential customer (January 1, 2022 to December 31, 2023)



The expected cost for fixed rate natural gas contracts decreased in Q4, largely in November (Figure 79). Unlike electricity contracts, the expected costs for natural gas contracts are higher for longer term contracts, and have been since January 2023. On December 31, the expected cost for 1-, 3-, and 5-year fixed rate natural gas contracts are at $2.00/GJ, $2.92GJ and $3.20/GJ respectively, which represent declines of 26%, 13%, and 11% relative to the cost on September 30. The expected cost for natural gas contracts throughout 2023 were much lower than they were in 2022 (Figure 79).

Figure 79: Expected cost, fixed rate natural gas contract, residential customer (January 1, 2022, to December 31, 2023)



Most of the competitive electricity retailers in Alberta reduced their fixed rate offerings in Q4 (Figure 80). However, in Q4 all the fixed rate electricity contracts were offered above the respective expected costs.

Six main retailers provide competitive fixed price offers for Alberta residential customers (Figure 80). Retailer A reduced its 1-year fixed rates from 19.59 ¢/kWh to 15.99 ¢/kWh, matching the rates of Retailer C. Retailer A also reduced its 3-year and 5-year rates by 1 ¢/kWh each. Despite its reduction in rates, Retailer A remains the highest-rate provider in each of the three fixed rate electricity contracts (Figure 80).

Retailer D reduced its 1-, 3- year fixed rates by 2 ¢/kWh and 1 ¢/kWh respectively. Retailer E, who provided 3-year fixed rate electricity for 17.79 ¢/kWh in January 2023, reduced its rate to 10.39 ¢/kWh as of Dec 31, to become the lowest provider of 3-year fixed rate electricity. Retailer F and Retailer G only provide 5-year electricity contracts and didn't alter their rates notably in Q4 (Figure 80).

Only Retailer D, Retailer F, and Retailer G changed their fixed rate natural gas rates in Q4 (Figure 81). When Retailer D increased its 3-year fixed rate natural gas contract prices from $3.44/GJ to $4.34/GJ, Retailer F and Retailer G reduced their 5-year fixed rates by $1/GJ and $0.90/GJ respectively in Q4 (Figure 81). All the fixed rate natural gas contracts were offered above their respective expected costs over Q4.

Figure 80: 1-, 3-, and 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (September 1, 2022 to December 31, 2023)

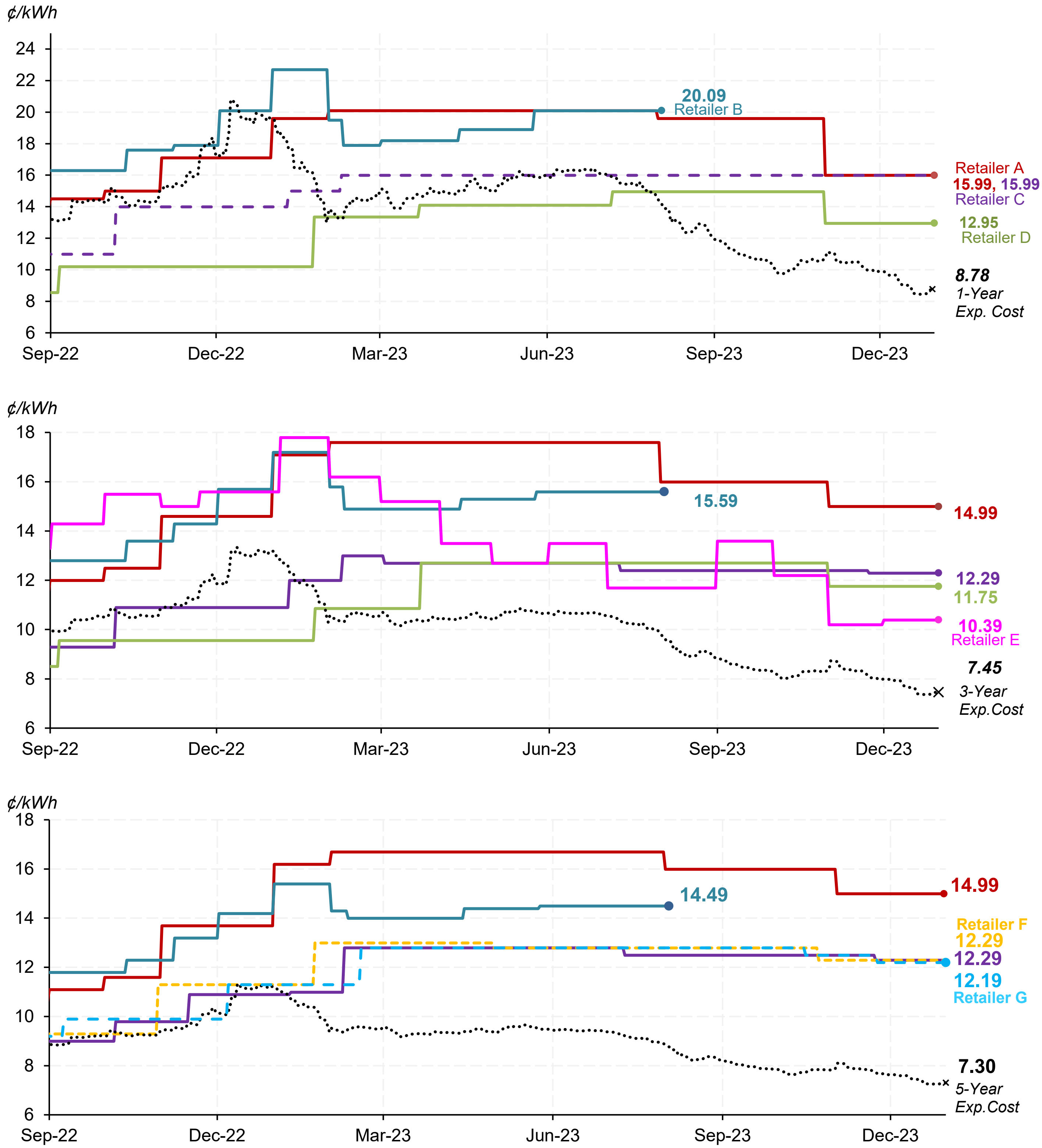
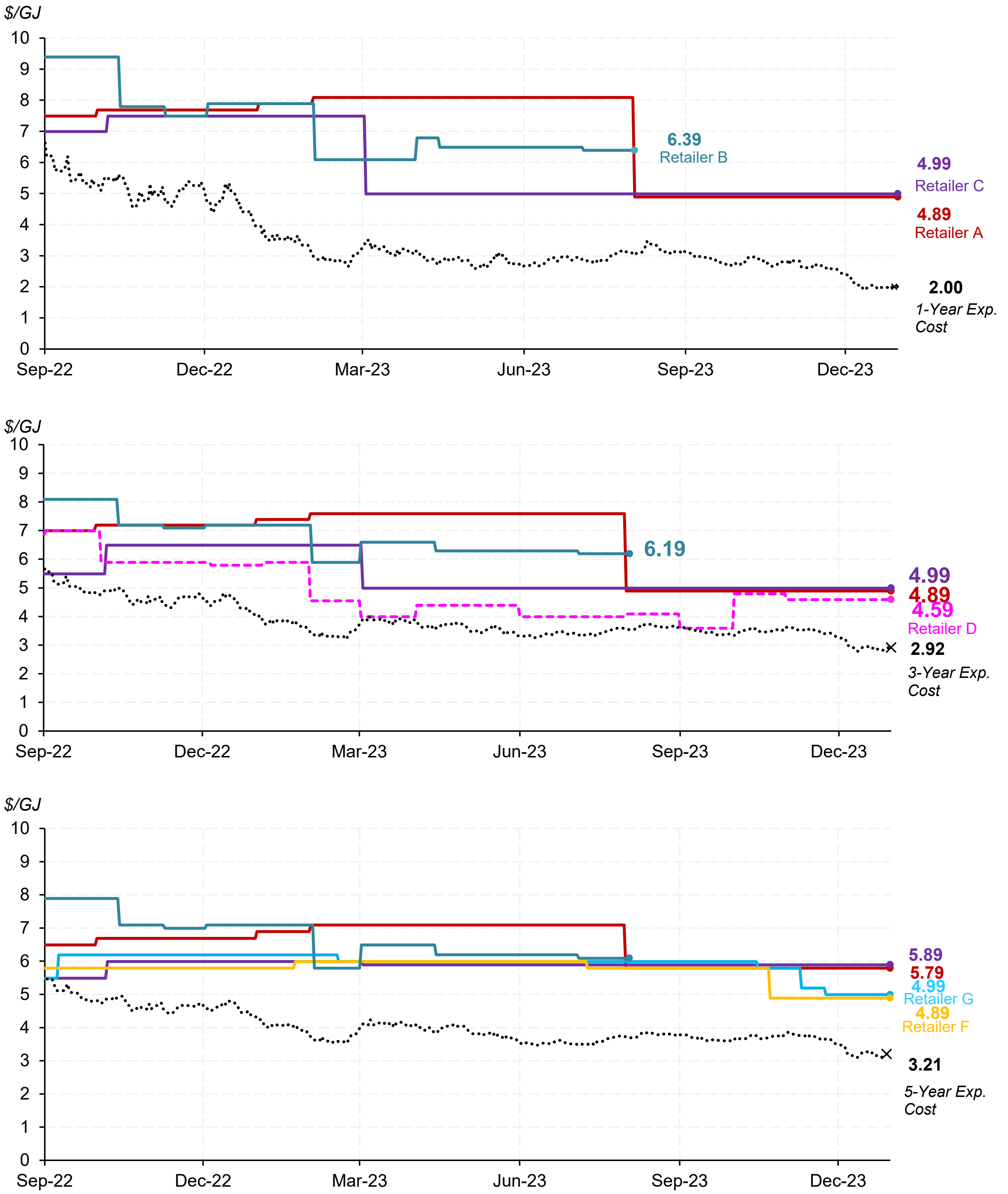


Figure 81: 1-, 3-, and 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (September 1, 2022 to December 31, 2023)



5.3.2 Variable Rate

Variable rates refer to competitive rates that vary monthly and are tied to pool prices. It often includes an adder to the energy rate, around 1 ¢/kWh. Competitive variable rates faced by residential customer dropped in Q4 and were the lowest in 2023 as the pool prices were moderate compared to the rest of 2023. The variable rates in October, November and December were 39%, 42% and 67% less than the RRO rates in these months respectively (Figure 82). Pool Price decreased in December, leading to decline in variable rates tied to pool price. In December, variable electricity was 6.4 ¢/kWh, the lowest since 2021 and was also around 4 ¢/kWh less than the cheapest fixed rate electricity contract in December.

Even though there wasn't a significant difference between default rate tariff (DRT) rates and variable natural gas rates in Q4, variable natural gas rates were higher in October and November, but slightly less than the DRT rates in December (Figure 83).

Figure 82: Estimated competitive variable electricity rates vs. RRO, residential customers,ENMAX service area (Q1 2021 to Q4 2023)

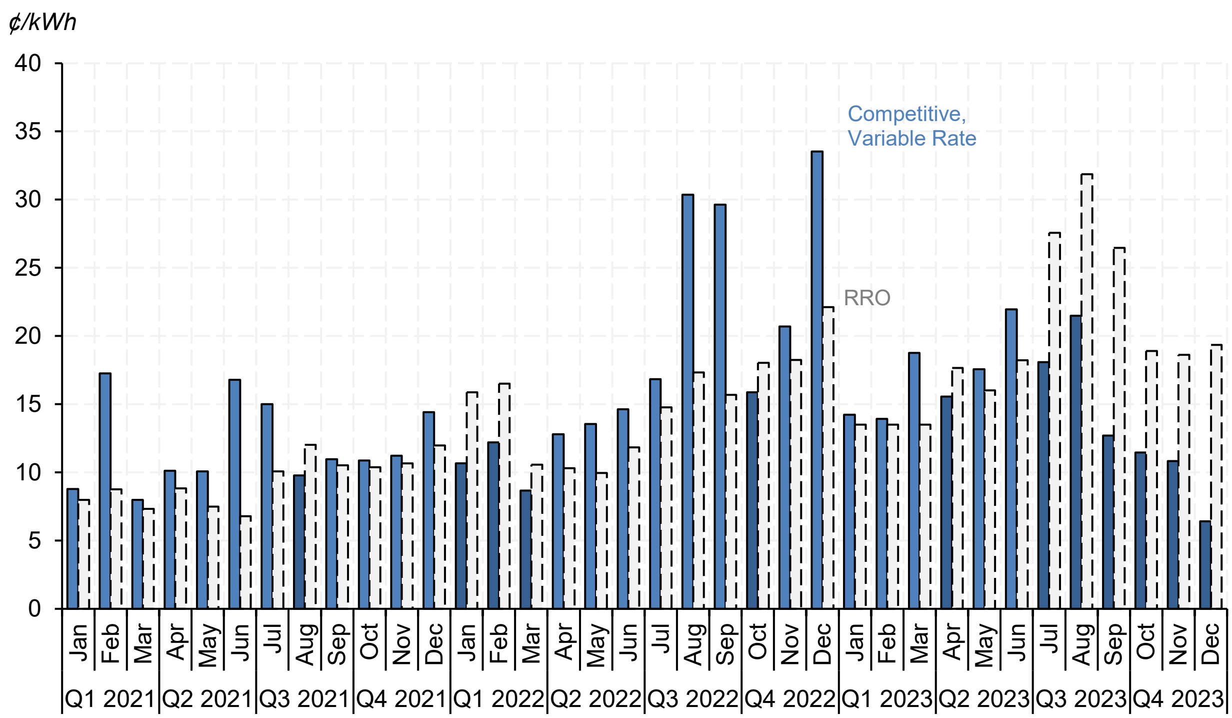
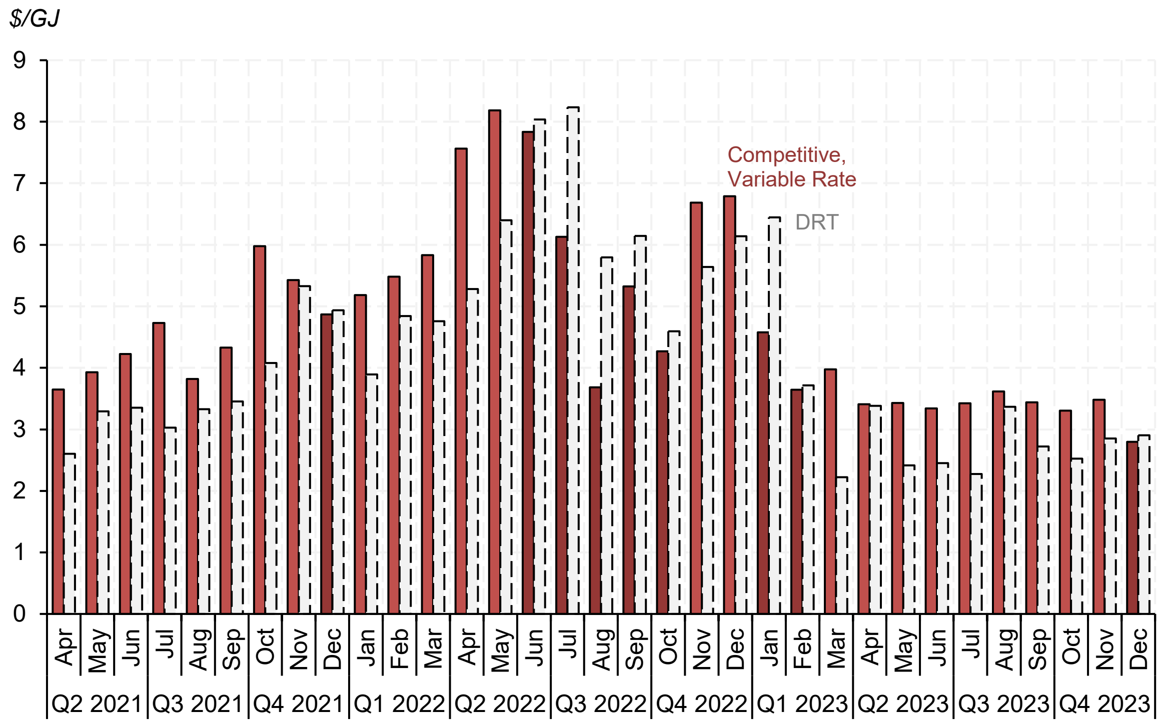


Figure 83: Estimated competitive variable natural gas rates vs. DRT, residential customers, ATCO Gas South service area (Q1 2021 to Q4 2023)[45]



5.4 Regulated retail rate estimates

5.4.1 Electricity regulated rate estimates

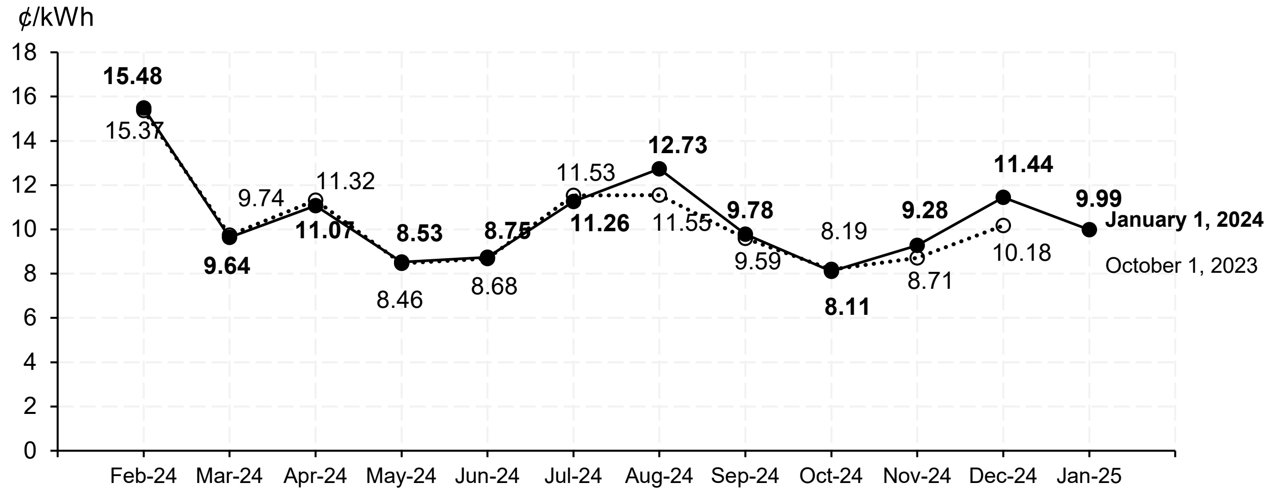
The expected residential RRO rate estimates calculated in this section make use of prevailing forward prices for electricity. While indicative of current market expectations, it should be noted that forward prices can be subject to material changes over time.

Figure 84 shows the expected residential RRO monthly rates in the EPCOR service area for the February 2024 to January 2025 period as of January 1, 2024, and October 1, 2023. The expected rates have not changed much since October 1, 2023 (Figure 84). However, a decline of over 1 ¢/kWh was observed for the months of August 2024 and December 2024.

The forecast did not change significantly because the forward prices for monthly and annual contracts that fall in this period have been relatively stable since October 1. In Q4, RRO providers continued collecting the deferred revenue that resulted from the rate ceiling in first quarter of 2023 through collection rates. These collection rates are added on top of the monthly base RRO rates to give the billing rates paid by RRO customers (Figure 85).

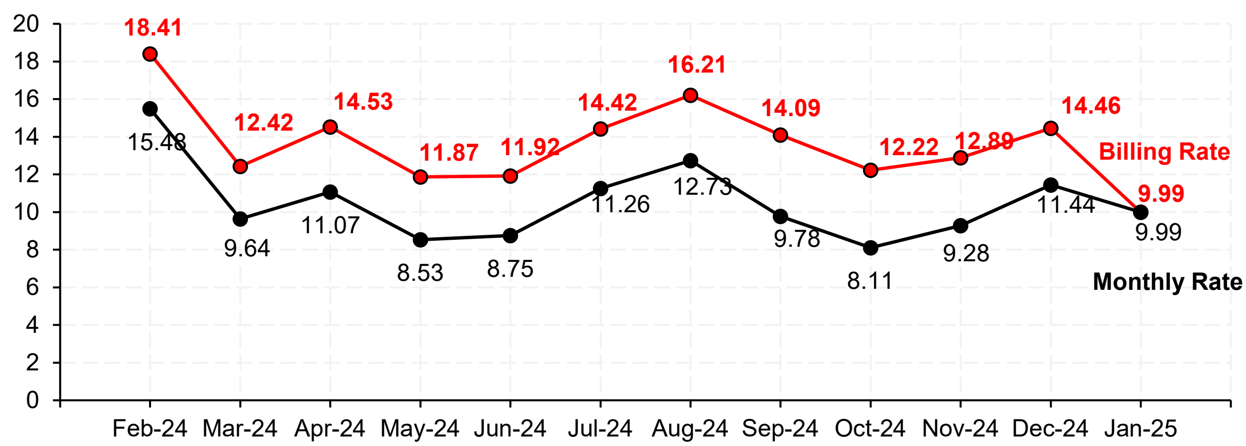
[45] Competitive variable natural gas rates calculated using the daily gas index; includes a $1/GJ adder.

Figure 84: February 2024 to January 2025 residential RRO monthly rate estimates, EPCOR service area (as of January 1, 2024 vs. October 1, 2023)



The MSA has forecasted residential collection rates using RRO site counts as of Q3 2023, monthly recovery amounts, and historical seasonal changes in residential RRO customer site count. As of January 1, 2024, the expected collection rate in the EPCOR service area averaged 3.4 ¢/kWh over the period of February 2024 to December 2024 (Figure 85). This average has increased since October 1, mainly due to the drop in RRO site counts in the EPCOR service area. The expected collection rates averaged 2.20 ¢/kWh, 3.31 ¢/kWh, and 3.07 ¢/kWh in the ENMAX, FortisAlberta, and ATCO service areas, respectively for the same period.

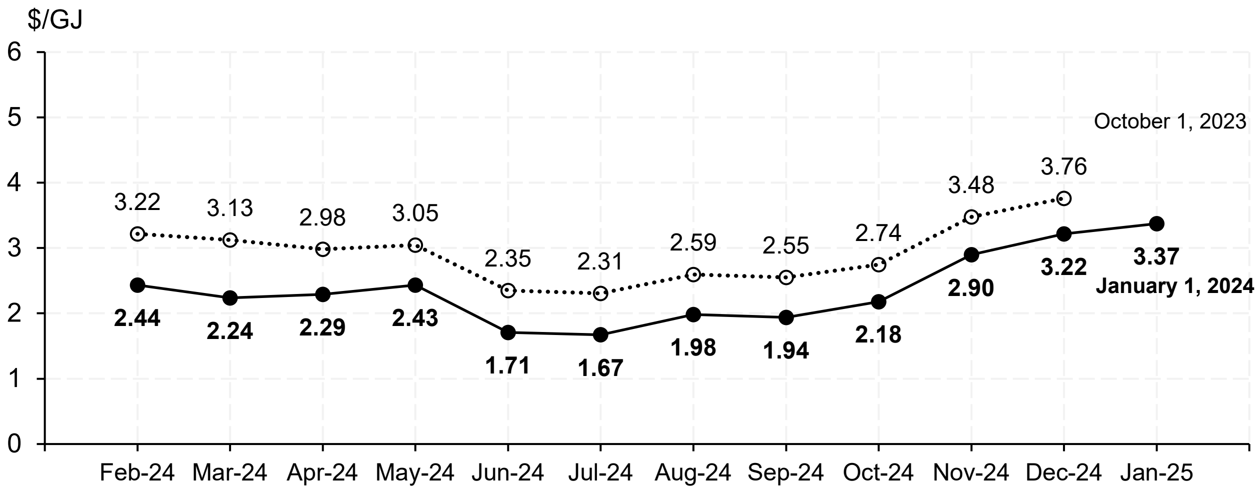
Figure 85: February 2024 to January 2025 estimated residential RRO monthly rates and billing rates, EPCOR service area (as of January 1, 2024)



5.4.2 Natural gas regulated rate estimates

Expected DRT rates for the February 2024 to January 2025 period have decreased since the MSA's estimates on October 1 (Figure 86). The estimated DRT rates experienced an average reduction of $0.56/GJ over this period in the ATCO Gas service area. A similar level of decline in DRT rates was forecasted in the Apex service area as well. The forecasted DRT rates have come down due to the downward trend in forward natural gas prices in Q4 2024. The forecasted rates remain well below the $6.50/GJ threshold for natural gas rebates by the Government of Alberta.

Figure 86: February 2024 to January 2025 residential DRT estimates, ATCO Gas service areas (as of January 1, 2024 vs. October 1, 2023)

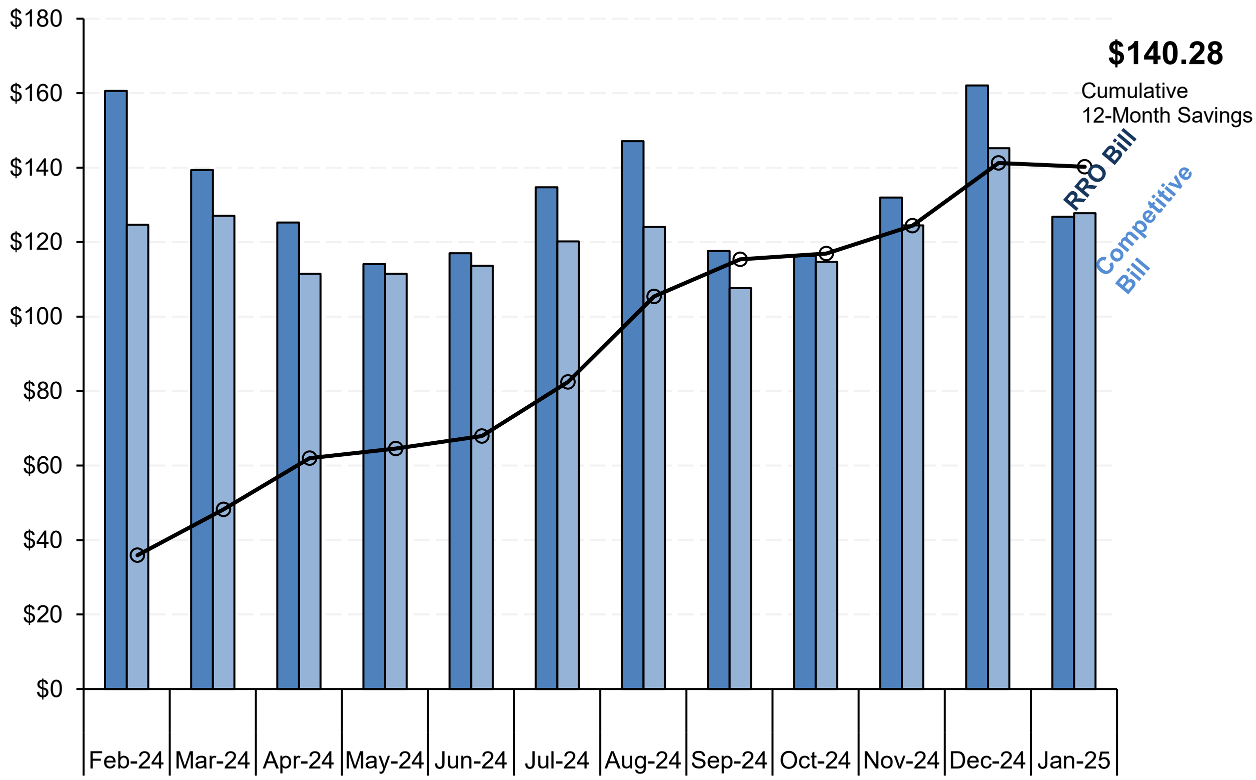


5.5 Fixed rate switching incentives

The financial incentive to switch to a fixed-rate competitive electricity contract for residential RRO customers has increased based on the RRO rate expectations for the February 2024 to January 2025 period as of January 1, 2024 (Figure 87). Even though the forecasted RRO rates have not changed significantly in the last three months, the decline in fixed rate electricity contract offerings increased the incentive. The lowest 3-year fixed rate offer was at 12.39 ¢/kWh in October, but this has gone down to 10.39 ¢/kWh as of January 1, 2024 (displayed in Figure 80).

An average residential RRO customer in the ENMAX service area could expect to save around $140 over the next 12 months if they switched to the lowest priced 3-year fixed rate electricity contract on or before January 1, 2024. This incentive to switch from the RRO to a competitive electricity fixed rate was lower at $111 on October 1, 2023.

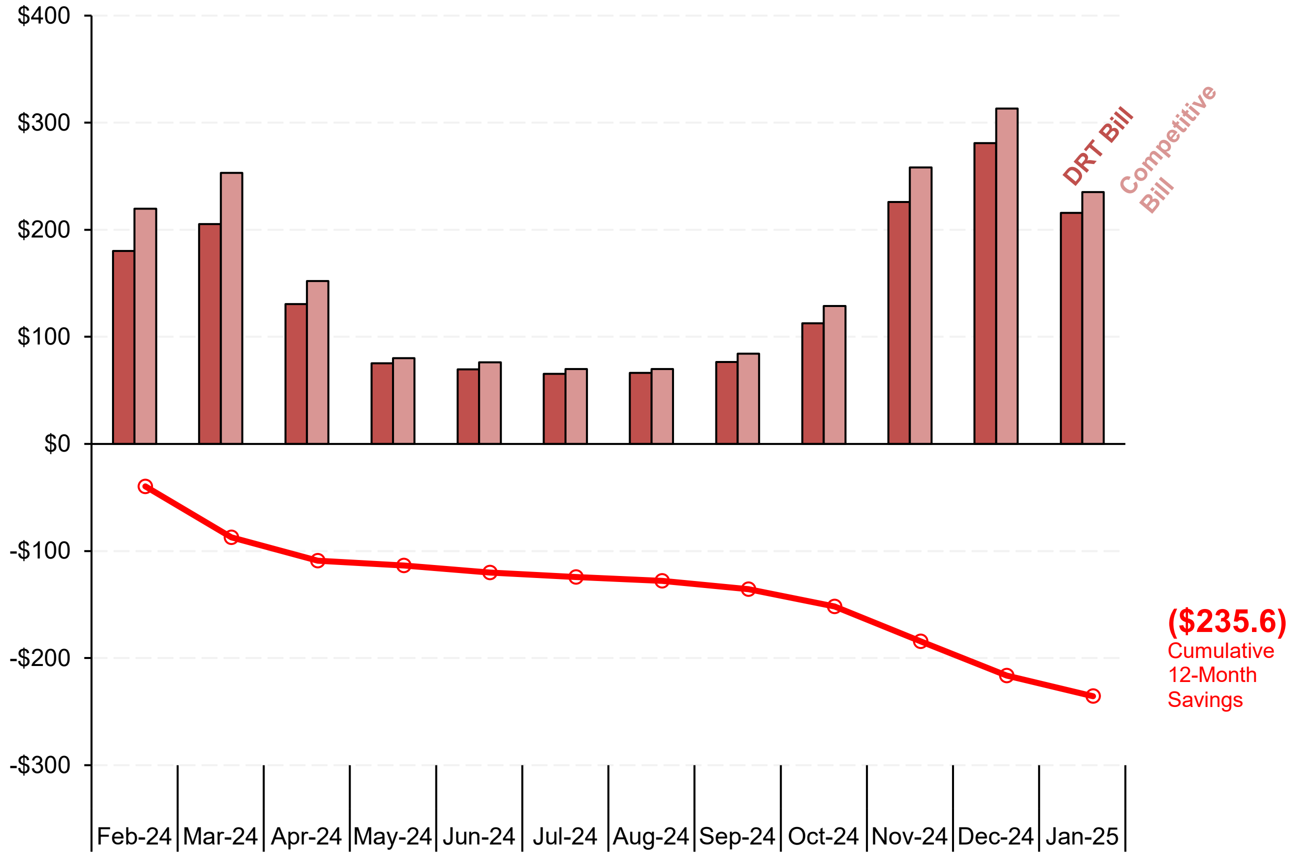
Figure 87: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at 10.39 ¢/kWh, $6.85/month)[46]



Residential DRT customers are not financially incentivized to switch onto competitive rates at present. If an average residential DRT customer had switched to the lowest priced 3-year fixed natural gas contract on or before January 1, 2024, they could expect to pay around $235 more in the next 12 months that followed (Figure 88). This incentive to remain on the DRT rather than switch to a competitive natural gas fixed rate was only $38 on October 1, 2023. This increase in incentive to remain on the DRT can be attributed to the slow decline in fixed rate natural gas rates even after the decline of forward natural gas prices.

[46] Estimated bills for a residential customer in the ENMAX service area over February 2024 to January 2025 period.

Figure 88: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at $4.59/GJ, $6.85/month)[47]



[47] Estimated bills for a residential customer in the ATCO Gas South service area over the February 2024 to January 2025 period.

6 REGULATORY AND ENFORCEMENT MATTERS

6.1 HR Milner outage reporting

Following an investigation, the MSA was satisfied that Milner Power II Limited Partnership, by its General Partner Milner Power II Inc. (Milner) contravened ISO Rule 306.5 Generation Outage Reporting and Coordination (ISO Rule 306.5), section 6 of the Electric Utilities Act SA 2003 c E-5.1 (EUA), and subsections 2(d), 2(e), and 4(2) of the Fair Efficient and Open Competition Regulation AR 159/2009 (FEOC Reg) (collectively, the Contraventions).

The MSA also investigated possible contraventions of the FEOC Reg by Maxim Power Corp. (Maxim), and concluded that Maxim and its trading staff did not improperly trade forward market products and, at all times, acted in good faith and for no improper purposes with respect to their trades of forward market products.

Subsection 4(2) of the FEOC Reg requires electricity market participants to provide outage records to the AESO as soon as reasonably practicable in a form and manner and containing the contents required by the AESO. ISO Rule 306.5 prescribes the requirements for the submission of outages to the AESO, and requires pool participants to submit: (i) the dates, times, durations, and impact to the affected asset's MW capability of planned outages through ETS; and (ii) any revisions to planned outages to the AESO as soon as reasonably practicable.

In breach of ISO Rule 306.5 and FEOC Reg subsection 4(2), Milner unintentionally did not remove an outage that was planned for October 2021 as soon as reasonably practicable. In breach of ISO Rule 306.5 and FEOC Reg subsection 4(2), Milner did not submit an outage planned for November 2021 as soon as reasonably practicable. By its conduct and omissions, Milner breached subsections 2(d) and 2(e) of the FEOC Reg and, in doing so, breached its obligation under section 6 of the EUA.

Maxim Power Corp. (Maxim) and Milner fully co-operated with the MSA's investigation. After they received the MSA's summary of facts and findings in its investigation, Maxim and Milner took remedial steps to prevent a recurrence of the contraventions. The MSA, Maxim, and Milner reached a comprehensive settlement agreement which provided for:

a) Milner's payment of an administrative penalty of $20,000, and

b) Milner's of the MSA's costs in the amount of $20,000.

The Commission approved the settlement agreement in Decision 28589-D01-2023 Market Surveillance Administrator - Application for Approval of a Settlement Agreement with Maxim Power Corp. and Milner Power II Limited Partnership, a copy of which is available here.

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 December 31, 2023, the MSA closed 298 ISO rules compliance matters, as reported in Table 24.[48] An additional 323 matters were carried forward to the next year. During this period 100 matters were addressed with NSPs, totalling $173,250 in financial penalties, with details provided in Table 25.

Table 24: ISO rules compliance outcomes from January 1 to December 31, 2023

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.12	1	-	-
201.4	-	10	-
201.7	19	8	1
203.1	-	1	-
203.3	60	17	-
203.4	47	11	8
203.6	19	22	-
205.3	1	1	-
205.4	1	-	-
205.5	3	-	1
205.6	5	5	6
301.2	5	4	-
304.3	2	-	-
304.7	1	-	-
304.9	2	-	-
306.4	1	-	-
306.5	2	5	-
502.4	-	1	-
502.5	3	-	-
502.6	5	1	-
502.8	1	11	-
502.9	1	-	-
502.16	2	-	-
505.3	-	3	-
505.4	1	-	-
Total	**182**	**100**	**16**

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

Table 25: Specified penalties issued between January 1 and December 31, 2023 for contraventions of the ISO rules

Market participant	**Total specified penalty amounts by ISO rule ($)**														**Total ($)**	**Matters**
	201.4	**201.7**	**203.1**	**203.3**	**203.4**	**203.6**	**205.3**	**205.6**	**301.2**	**306.5**	**502.4**	**502.6**	**502.8**	**505.3**		
Air Liquide Canada Inc.		500													500	1
Alberta Pacific Forest Industries Inc.					1,000										1,000	2
Alberta Power (2000) Ltd.				250											250	1
Alberta Solar One, Inc.													500		500	1
British Columbia Hydro and Power Authority													500		500	1
Canadian Hydro Developers, Inc.	57,000			500											57,500	11
Claresholm Solar LP													1,000		1,000	2
Conrad Solar Inc.									4,000				1,000	1,000	6,000	8
DAPP Power L.P.				500											500	1
East Strathmore Solar Project Inc.														500	500	1
Enel X Canada Ltd.		500						10,000							10,500	4
Enfinite Generation Corporation				500											500	1
ENMAX Generation Portfolio Inc.				250											250	1
ENMAX Kettles Hill Inc.		500													500	1
EPCOR Distribution & Transmission Inc.											250				250	1
Evolugen Trading and Marketing LP						17,000									17,000	4
Ghost Pine Windfarm, LP				500											500	1
Grande Prairie Generation Inc.				7,000											7,000	3
Hays Solar LP					250								500		750	2
Heartland Generation Ltd.						250									250	1
MAG Energy Solutions Inc.						3,750									3,750	4
MEG Energy Corp.										500					500	1
Mercer Peace River Pulp Ltd.		250													250	1
Morgan Stanley Capital Group Inc.						7,000									7,000	3
NRGreen Power Limited Partnership										500					500	1
Powerex Corp.						9,250									9,250	5
Riverview Limited Partnership				500											500	1

Table 25: Specified penalties issued between January 1 and December 31, 2023 for contraventions of the ISO rules (continued)

Market participant	Total specified penalty amounts by ISO rule ($)														Total ($)	Matters
	201.4	201.7	203.1	203.3	203.4	203.6	205.3	205.6	301.2	306.5	502.4	502.6	502.8	505.3		
Syncrude Canada Ltd.					250							250			500	2
TA Alberta Hydro LP							250								250	1
TransAlta Corporation				500									5,000		5,500	6
TransAlta Energy Marketing Corp.						250									250	1
TransAlta Generation Partnership					5,000										5,000	5
TransCanada Energy Ltd.				500											500	1
TransCanada Energy Sales Ltd.						10,000									10,000	2
Vitol Inc.						750									750	2
Voltus Energy Canada Ltd.								12,500							12,500	3
West Fraser Mills Ltd.		2,000		4,500											6,500	6
Wild Run LP		500	500							2,000					3,000	4
Windrise Wind LP										500					500	1
Yellow Lake & Burdett Solar LP					500										500	2
Total	57,000	4,250	500	15,500	7,000	48,250	250	22,500	4,000	3,500	250	250	8,500	1,500	173,250	100

The ISO rules listed in Table 24 and Table 25 fall into the following categories:

103	Administration
201	General (Markets)
203	Energy Market
205	Ancillary Services Market
301	General (System Reliability and Operations)
304	Routine Operations
306	Outages and Disturbances
502	Technical Requirements
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.[49] 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 December 31, 2023, the MSA addressed 56 O&P ARS compliance matters (Table 26).[50] 44 O&P ARS matters were carried forward to the next year. During this period, 16 matters were addressed with NSPs, totalling $55,000 in financial penalties (Table 27). For the same period, the MSA addressed 162 CIP ARS compliance matters,[51] as reported in Table 28, and 57 matters were addressed with NSPs, totalling $162,000 in financial penalties. 107 CIP ARS matters were carried forward to next quarter.

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

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

[51] Of the 162 matters, one matter was rejected.

Table 26: O&P ARS compliance outcomes from January 1 to December 31, 2023

Reliability standard	Forbearance	Notice of specified penalty	No contravention
COM-002	2	-	-
EOP-001	1	-	-
EOP-008	1	-	-
EOP-011	2	1	-
FAC-008	13	2	-
IRO-008	1	-	-
PRC-001	-	1	-
PRC-002	3	-	-
PRC-005	11	7	1
PRC-018	-	-	1
PRC-019	1	3	1
VAR-002	2	-	-
Total	37	16	3

Table 27: Specified penalties issued between January 1 and December 31, 2023 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)					Total ($)	Matters
	FAC-008	PRC-001	PRC-005	PRC-019	EOP-011		
Air Liquide Canada Inc.			2,250			2,250	1
Alberta-Pacific Forest Industries Inc.			2,250			2,250	1
AltaLink L.P., by its general partner, AltaLink Management Ltd.		2,500				2,500	1
Canadian Natural Resources Limited			3,750	3,750		7,500	2
Castle Rock Ridge, LP	2,250					2,250	2
Cenovus Energy Inc.			2,500			2,500	1
City of Medicine Hat			7,500		12,500	20,000	3
CNOOC Petroleum North America ULC			3,750			3,750	1
International Paper Canada Pulp Holding ULC				3,750		3,750	1
MEG Energy Corp.				3,750		3,750	1
Milner Power Limited Partnership by its General Partner Milner Power Inc.	2,250		2,250			4,500	2
Total	4,500	2,500	24,250	11,250	12,500	55,000	16

The ARS outcomes listed in Table 26 and Table 27 are contained within the following categories:

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

Table 28: CIP ARS compliance outcomes from January 1 to December 31, 2023

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	3	4	1
CIP-003	13	3	-
CIP-004	19	6	-
CIP-005	7	5	-
CIP-006	8	5	-
CIP-007	24	18	1
CIP-008	1	-	-
CIP-009	2	3	-
CIP-010	18	12	-
CIP-011	7	1	-
Total	102	57	2

The ARS outcomes listed in Table 28 are contained within the following categories:

CIP-002	BES Cyber System Categorization
CIP-003	Security Measurement Controls
CIP-004	Personnel & Training
CIP-005	Electronic Security Perimeter(s)
CIP-006	Physical Security of BES Cyber Systems
CIP-007	System Security Management
CIP-008	Incident Reporting and Response
CIP-009	Recovery Plans for BES Cyber Systems
CIP-010	Configuration Change Management and Vulnerability Assessments
CIP-011	Information Protection