MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q2 2023

August 15, 2023

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 Q2 was $160/MWh, a 30% increase relative to Q2 2022, despite increased solar generation and lower natural gas prices. The margin between pool prices and natural gas input costs was 152% higher year-over-year. The margins were driven by higher offer behaviour, lower natural gas prices, less imports, and more thermal outages.

- Wind and solar generation set record output levels in Q2 as capacity continues to increase. The increase in wind and solar generation led to more transmission congestion. Wind and solar congestion is concentrated in southern Alberta among a small number of assets. The total cost of these constraints is limited because they occur during periods of lower pool prices.

- Companies were more often pivotal in Q2 compared to Q1 but exercised market power less. Companies withheld more capacity in midday hours during June when they were more often pivotal than prior months despite high wind and solar generation. Some companies continued to take thermal assets offline to exercise market power.

- Monthly forward prices increased over the quarter largely because of higher-than-expected pool prices. For example, the price of September increased by 40% from $157 to $219/MWh. Beginning in October, forward prices are lower due to the expected addition of the Cascade combined cycle project (900 MW) and the expected return of HR Milner (300 MW). As of June 30, the expected average pool price for 2023 was $173/MWh, while the forward price for 2024 was lower at $96/MWh.

- The number of customers that left the Regulated Rate Option (RRO) and Default Rate Tariff (DRT) was lower in Q1 relative to Q4 2022 and Q1 2022. Customers leaving their RRO provider disproportionately signed a contract with their RRO provider's co-branded competitive retailer. Competitive rates were relatively stable over Q2. Expected RRO rates from August 2023 to February 2024 have increased since April, and the incentives for RRO customers to switch to fixed rate contracts continues.

- Micro-generation continued to grow in Alberta at an accelerating pace. In 2022, 3,200 new small micro-generation sites were commissioned, more than double the 1,400 commissioned the previous year. At the end of 2022, there was 103 MW of installed small micro-generation capacity. Most small micro-generation customers are signed with one retailer which paid out and received half of all micro-generation compensation in 2022.

- From April 1 to June 30, 2023, the MSA closed 58 ISO rules compliance matters; 23 matters were addressed with notices of specified penalty. For the same period, the MSA closed 16 Alberta Reliability Standards Operations and Planning compliance matters; three matters were addressed with notices of specified penalty. In addition, the MSA closed 54 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; 26 matters were addressed with notices of specified penalty.

1. THE POWER POOL

1.1 Quarterly summary

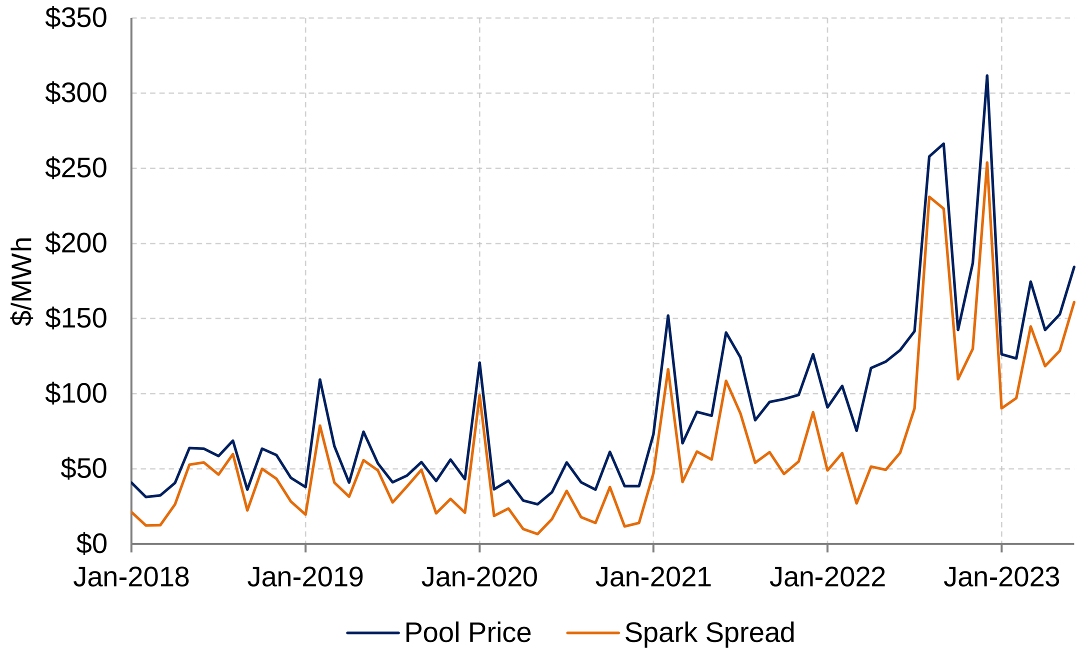
The average pool price in Q2 was $160/MWh, a 30% increase compared to Q2 2022. The higher pool prices were due to offer behaviour, more thermal outages, and lower net imports. These factors offset markedly lower natural gas prices and increased solar generation (Table 1).

Table 1: Summary market statistics for Q2 2023 and Q2 2022

		2023	2022	Change
Pool price (Avg $/MWh)	Apr	$142.34	$117.14	22%
	May	$152.85	$121.24	26%
	Jun	$184.41	$129.08	43%
	Q2	**$159.79**	**$122.47**	**30%**
Demand (AIL) (Avg MW)	Apr	9,387	9,559	-2%
	May	9,053	9,161	-1%
	Jun	9,449	9,265	2%
	Q2	**9,293**	**9,326**	**0%**
Gas price AB-NIT (2A) (Avg $/GJ)	Apr	$2.41	$6.56	-63%
	May	$2.43	$7.19	-66%
	Jun	$2.34	$6.84	-66%
	Q2	**$2.39**	**$6.86**	**-65%**
Wind generation (Avg MW)	Apr	1,166	890	31%
	May	857	907	-5%
	Jun	876	756	16%
	Q2	**965**	**852**	**13%**
Solar generation (Avg MW during peak hours)	Apr	466	150	211%
	May	588	191	208%
	Jun	606	249	143%
	Q2	**554**	**197**	**182%**
Net imports (+) Net exports (-) (Avg MW)	Apr	-40	582	-107%
	May	474	470	1%
	Jun	214	634	-66%
	Q2	**219**	**561**	**-61%**
Thermal outages (Avg MW)	Apr	2,739	2,402	14%
	May	3,418	2,769	23%
	Jun	2,990	2,505	19%
	Q2	**3,053**	**2,561**	**19%**

Figure 1 illustrates monthly average pool prices and spark spreads since January 2018. Spark spreads calculate the difference between pool prices and the input cost of natural gas, which is the main cost driver for Alberta power generation.[1] The average spark spread in Q2 was $136/MWh, a 152% increase compared to Q2 2022. Natural gas prices decreased by 65% as higher natural gas production increased storage inventories.

Figure 1: Average pool price and spark spread by month (January 2018 to June 2023)



The monthly average pool price in June was $184/MWh, the highest so far in 2023. Pool prices in June were increased by hot weather combined with low wind generation and thermal generation outages. The average temperature in June was 17.4°C, which is a 1.9°C increase compared to June 2022. Higher temperatures increase cooling demand for electricity.[2]

Demand in Q2 peaked on June 6 at 11,199 MW in HE 17, which is 522 MW less than the summer record set in June 2021. As shown by Figure 2, pool prices in June were highest in the late afternoon when temperatures were elevated, and in the evening when solar generation declined.

On June 7, the AESO declared an Energy Emergency Alert level 3 (EEA3) from 15:49 to 21:50, indicating that there was not enough generation to reliably meet demand. This EEA3 event lasted 6 hours and 1 minute, which is the longest energy emergency alert event since July 30, 2014, although no firm load was shed. This event resulted from hot weather, low wind generation, and thermal generation outages. This event is discussed further in section 1.2.

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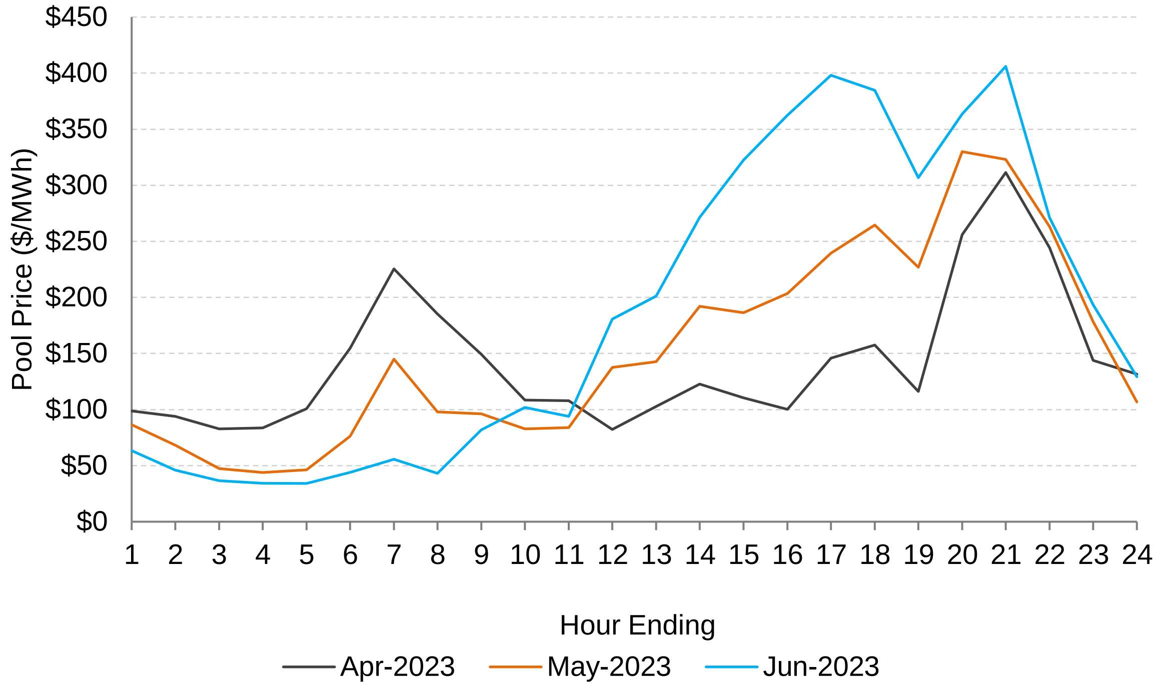
[1] In Q2 2023, natural gas generation assets set the price 89% of the time. The spark spread calculations here assume a heat rate of 10 GJ/MWh, which is comparable to the efficiency of a peaking asset.

[2] The temperature reflects the average across Calgary, Edmonton, and Fort McMurray.

Figure 2: Average pool price by hour and month in Q2 2023



The offer behaviour of some large generators continued to put upward pressure on pool prices in Q2. On average 1,098 MW of available generation capacity was offered at or above $250/MWh in Q2, a 17% increase compared to Q2 2022. Market power and offer behaviour are discussed further in section 1.3.

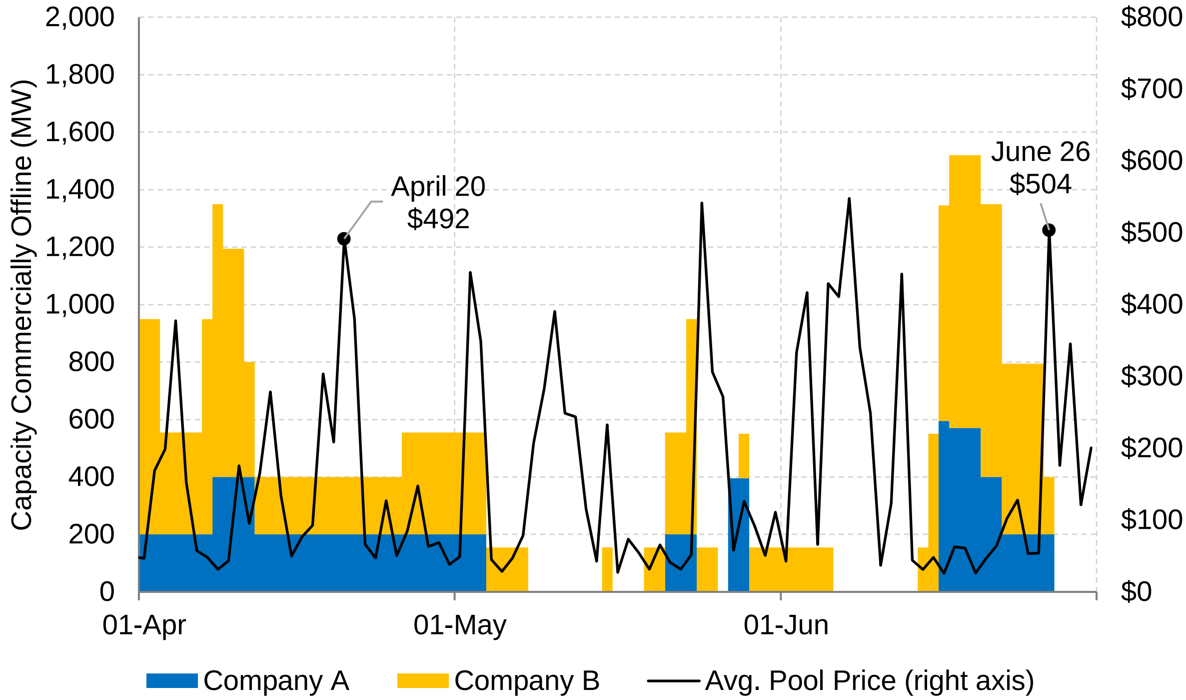
Some larger generators continued to take gas-fired steam assets offline commercially in Q2. Once offline, these assets are placed on long lead time because their start time is more than one hour, and they are not available for dispatch in the energy market. Typically, the start time for these assets ranges from 4 to 24 hours, depending on the asset and how long it has been offline.

Figure 3 illustrates the amount of coal and converted coal capacity that was commercially offline in Q2. In this figure, an asset is shown as commercially offline if it was commercially offline during the highest priced hour of that day. Some gas-fired steam assets were commercially offline on some high-priced days in Q2.

For example, on Thursday, April 20, Sheerness 1 (400 MW) was commercially offline even though pool prices averaged $492/MWh, a 201 GJ/MWh heat rate relative to the price of natural gas. The supply cushion on April 20 was 85 MW in HE 22 indicating very tight supply-demand conditions.

On Monday, June 26, Sheerness 1 was commercially offline even though pool prices averaged $504/MWh, a 206 GJ/MWh heat rate. This high heat rate indicates that pool prices were well above natural gas input costs, and that it was likely economic for the asset to be online. The supply cushion on June 26 fell to 30 MW in HE 18 illustrating very tight supply-demand conditions. Issues associated with long lead time assets are discussed further in section 1.5.

Figure 3: Coal and converted coal capacity that was commercially offline by day and company (April 1 to June 30, 2023)



Intermittent generation in Alberta continued to increase in Q2. On April 8, hourly wind generation set a record at 2,824 MW, up from the pre-Q2 record of 2,496 MW set in January. On May 30 solar generation set a record at 1,121 MW.

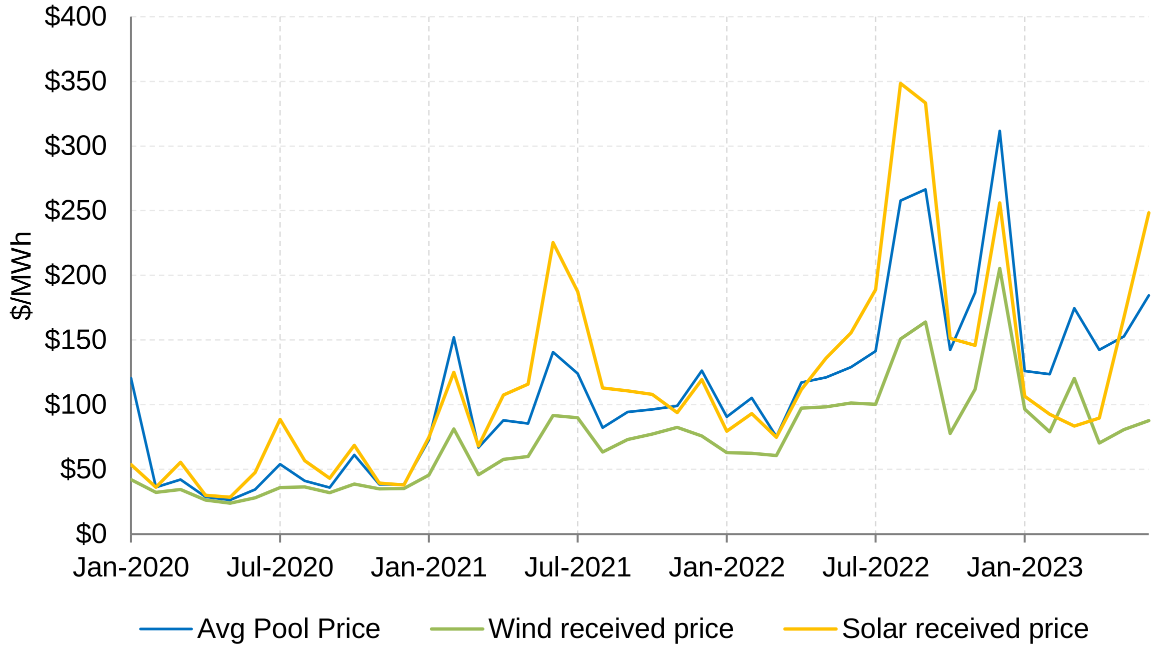
Over the course of June, the average output of wind, solar, and hydro was 1,680 MW or 18% of Alberta Internal Load (AIL),[3] another record. Over Q2, the output of intermittent generation ranged from 0 to 3,460 MW, and this variance in supply was a major driver of pool price volatility. Increasing intermittent generation is causing more constraints on the transmission network, a subject that is analyzed in section 2.1.

Figure 4 illustrates the received price of intermittent generation relative to the average pool price since January 2020. Wind generation has typically received a discount to the average pool price because wind supply is highly correlated across wind assets, and because wind generation tends to be lower during extreme temperatures, when demand is elevated.

The received price of solar generation has often been higher than the average pool price because solar largely generates during peak hours. However, increasing solar supply is putting downward pressure on solar received prices. From November 2022 to April 2023, the received price of solar generation was below the average pool price, and in March the received price of solar was below the received price of wind.

[3] Alberta Internal Load is a measure of total demand.

Figure 4: Average received price of intermittent generation by month (January 2020 to June 2023)



The average amount of thermal capacity on outage was 19% higher in Q2 relative to Q2 2022 (Table 1).[4] Thermal outages reduce the capacity that is competing for dispatch in the energy market and put upward pressure on pool prices, particularly when demand is high, intermittent generation is low, or other assets are on outage. The price impact of a thermal outage will also depend upon whether the unavailable asset is normally highly dispatched. Table 2 lists some of the major thermal outages that took place in Q2.

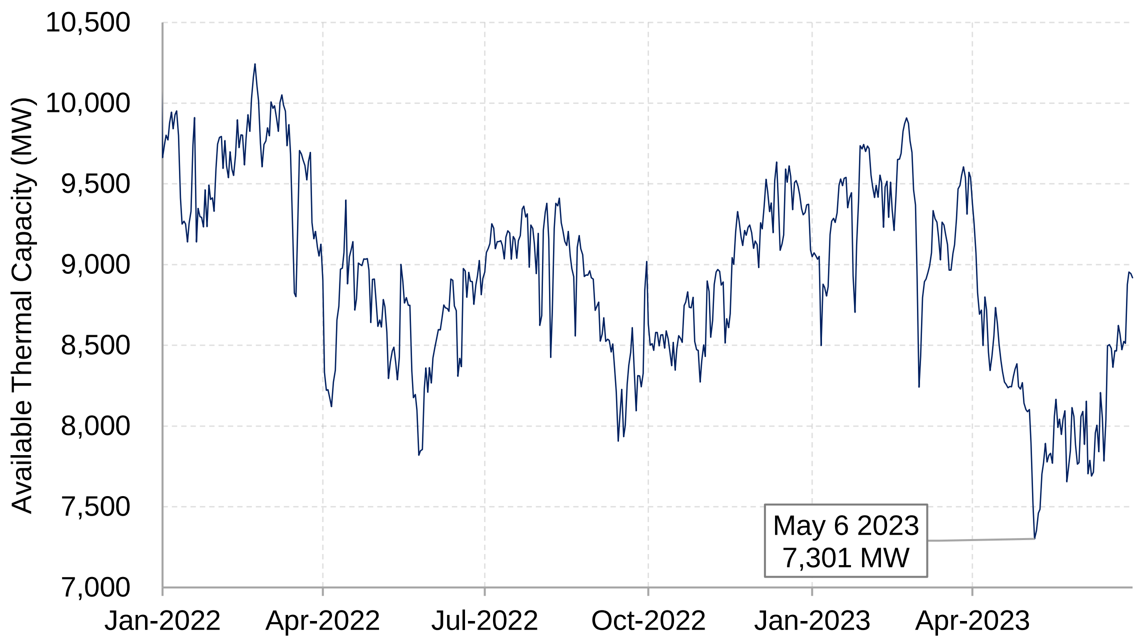
Figure 5 illustrates the average amount of available thermal capacity by day since January 2022. On May 6, average available thermal capacity fell to a low of 7,301 MW in part because of outages at Keephills 3, Sheerness 1, and Genesee 1.

[4] The outage figures reflect the difference between Maximum Capability and Available Capability. The SCL1 asset was not included because it has changed from net to gross reporting.

Table 2: Major thermal outages in Q2

Asset	Capacity (MW)	Start date	End date	Outage length (days)
HR Milner	300	September 1, 2022	*Ongoing*	*348*
Cloverbar 1	48	December 20, 2022	July 9, 2023	202
Cloverbar 3	101	March 21, 2023	June 7, 2023	79
Battle River 4	155	April 9, 2023	April 25, 2023	17
Keephills 3	463	April 18, 2023	May 11, 2023	24
Sheerness 1	400	May 4, 2023	June 15, 2023	43
Genesee 2	420	June 5, 2023	June 10, 2023	6
Joffre	200	June 10, 2023	June 20, 2023	11
Shepard	430	June 13, 2023	June 16, 2023	4
Sundance 6	401	June 20, 2023	June 26, 2023	7

Figure 5: Average available thermal capacity by day (January 1, 2022 to June 30, 2023)

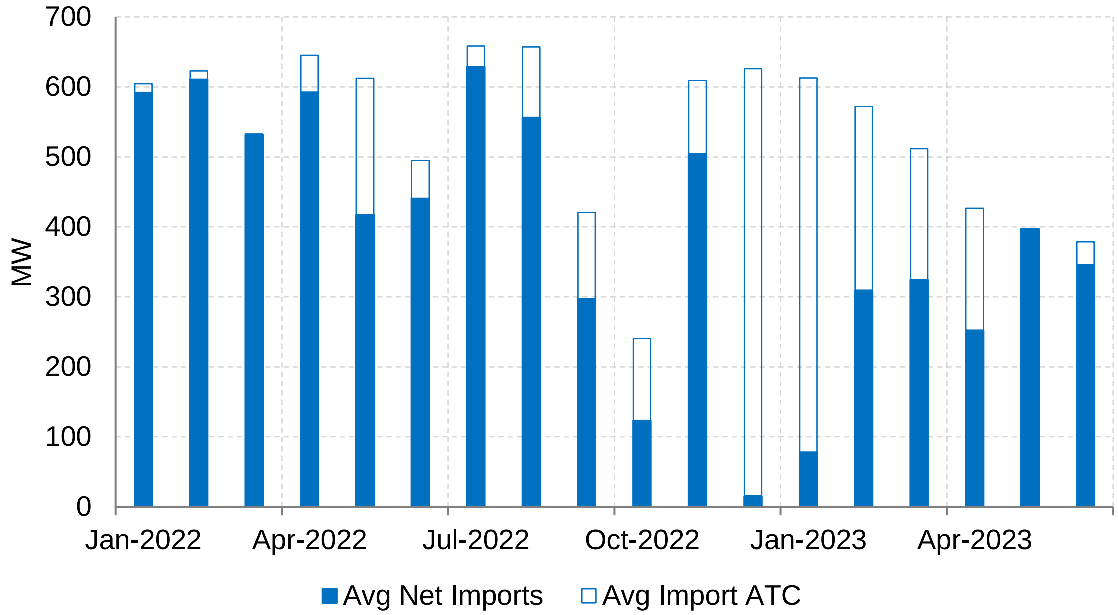


Lower imports to Alberta were a factor in the higher pool prices year-over-year, particularly in April and June. In April, the average flow of power on Alberta's interties was 40 MW of exports, a supply reduction of 621 MW compared to 582 MW of imports in April last year.

In June, 91% of import capacity on BC/MATL was used when the pool price was above $250/MWh (Figure 6). This contrasts with recent months, such as December 2022 and January 2023, when import ATC was only lightly used because of high prices in Mid-Columbia (Mid-C) and California.

The lower imports in Q2 were largely because of reduced import capacity on BC/MATL, resulting from more stringent requirements for Load Shed Service for imports (LSSi)[5] that came into effect on March 15. Imports and exports are discussed further in section 2.2.

Figure 6: Average net imports and import ATC on BC/MATL by month, for hours when pool price was greater than $250/MWh (January 2022 to June 2023)[6]



1.2 Market outcomes

Pool prices were higher on average and more volatile in Q2 compared to Q2 2022. Figure 7 illustrates pool price duration curves for Q2 and Q2 2022. These duration curves illustrate the percentage of hours in which pool price was below a given level.

For example, in 90% of hours in Q2 the pool price was below $560/MWh and in 10% of hours the pool price was above this level. In Q2 2022, the 90th percentile was lower at $218/MWh. The high pool prices in Q2 were often driven by offer behaviour, low intermittent generation, prevailing temperatures, and thermal generation outages.

These high-priced hours have a meaningful impact on average pool prices. In Q2, the highest 10% of hours averaged $779/MWh and contributed 49% to the average pool price for the quarter. In Q2 2022, the highest 10% of hours averaged $350/MWh and contributed 29% to the average pool price. Under the 74th percentile, pool prices were lower in Q2 this year, largely because of

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[5] LSSi is a reliability product that pays certain loads to arm their consumption, such that it will trip automatically in the event of a trip on the BC/MATL intertie. This mitigates the supply loss during a contingency event.

The low import ATC values in September and October 2022 largely reflect transmission line outages and derates.

[6] Net imports are calculated as imports less exports. In this figure net export hours are treated as negative imports.

reduced natural gas prices and higher intermittent generation. For example, the median pool price in Q2 was $52/MWh, whereas it was $94/MWh in Q2 2022.

Figure 7: Pool price duration curves (Q2 2023 and Q2 2022)

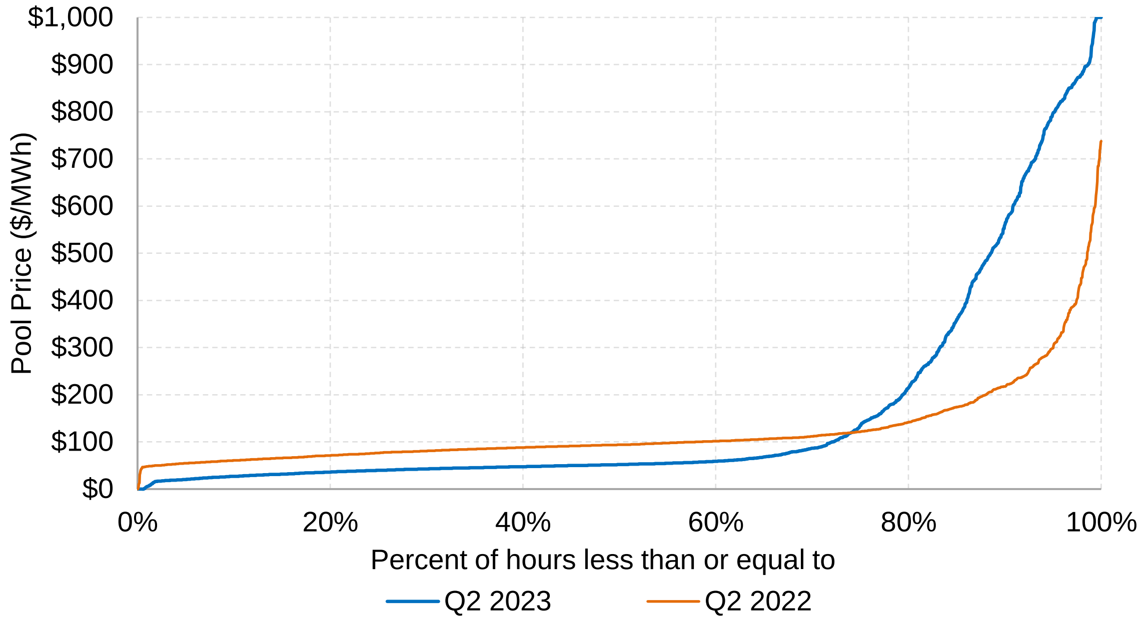


Figure 8 illustrates the price volatility in Q2 as the amount of time in each month the System Marginal Price (SMP) cleared at the offer price floor of $0.00/MWh or the offer price cap of $999.99/MWh. Historically, there have been few instances in which prices were at both the price cap and floor in the same month. In June there were 819 minutes when SMP was at the price cap and 605 minutes when SMP was at the price floor.

In some cases, these extreme price changes happened over a short period of time. For example, around 20:00 on May 15 the SMP peaked at $999.97/MWh, indicating very little remaining supply due to high demand, declining intermittent generation, thermal outages at Sheerness 1 (400 MW) and Keephills 3 (463 MW), and Battle River 4 (155 MW) being commercially offline. The next day (May 16), the SMP was $0.00/MWh from 14:31 to 16:05, indicating a supply surplus event, as intermittent generation was high, demand was lower, less thermal capacity was on outage, and no assets were commercially offline.

Supply surplus events in the afternoon are unusual. Since 2010, less than 1% of the time SMP cleared at $0.00/MWh occurred between 14:00 and 17:00. In contrast, 88% of the time SMP was at $0.00/MWh occurred between 00:00 and 07:00.

Pool prices were also notably volatile in early June, partly because of prevailing temperatures and outages at Genesee 2 (420 MW) and Sheerness 1 (400 MW). Figure 9 illustrates pool prices, system load, and intermittent generation from June 6 to 13. System load measures the amount of electricity demand on the Alberta grid and does not include demand that is met by on-site generation. The net demand line shown illustrates system load less intermittent generation, indicating the amount of generation needed from other sources.

Figure 8: The number of minutes SMP was at the price floor or cap by month (January 2018 to June 2023)

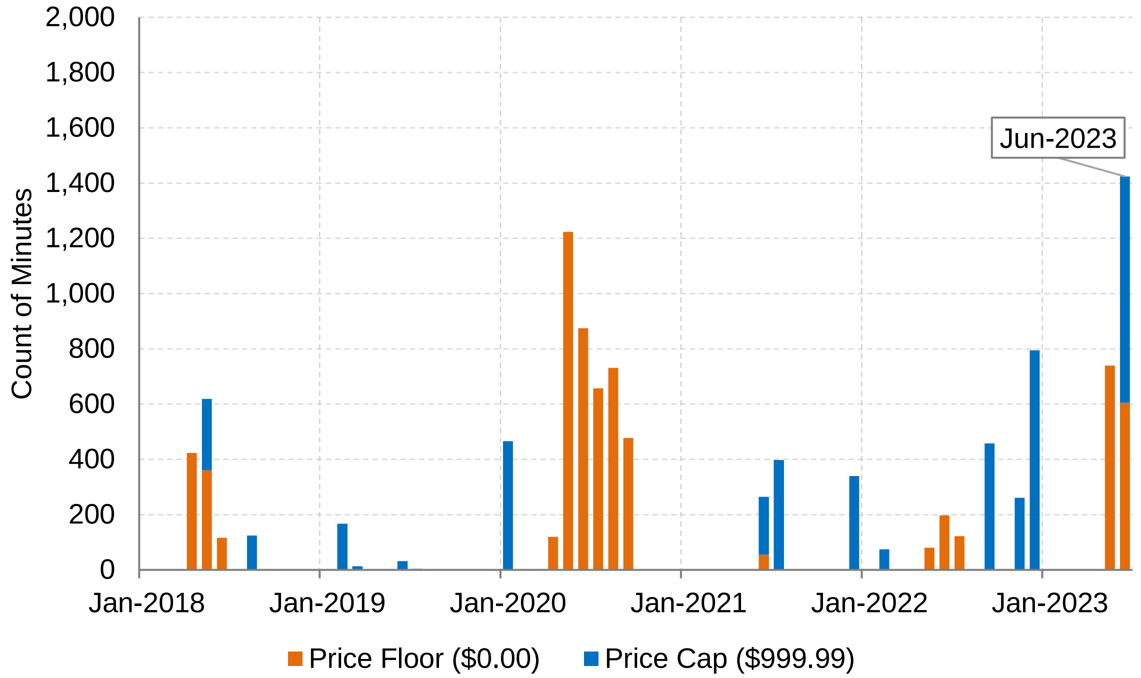
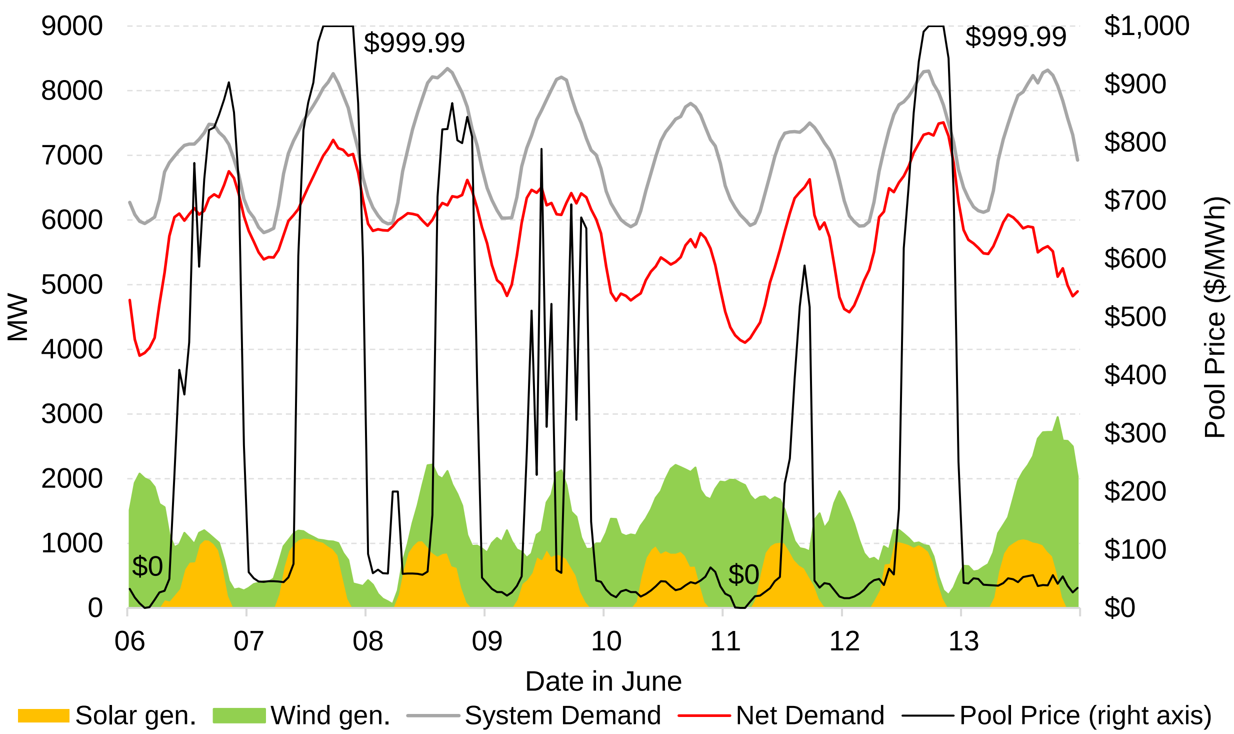


Figure 9: System demand, intermittent generation, net demand, and pool price by hour (June 6 to 13, 2023)



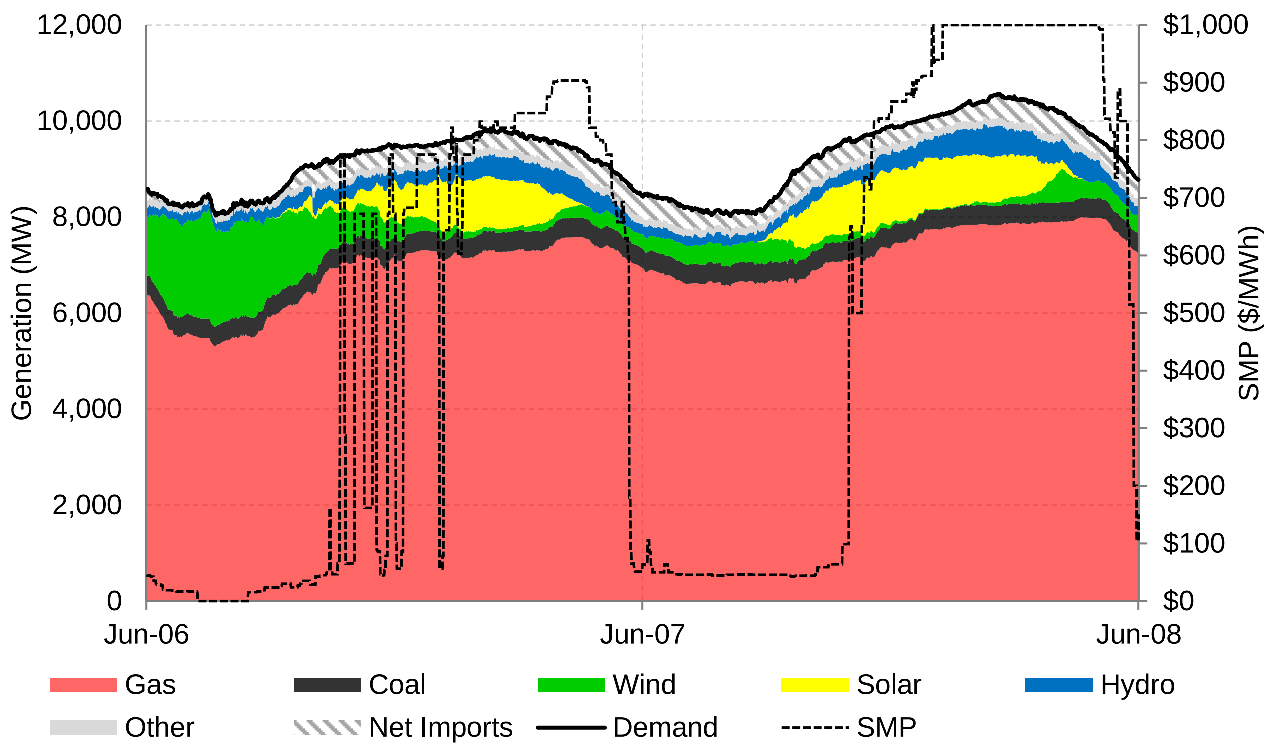
During the early morning of June 6, high levels of wind generation and off-peak demand meant that net demand fell under 4,000 MW and pool price was $0.00/MWh, indicating excess supply. Later that day, wind generation fell, demand increased along with temperatures, and the pool price increased to $904/MWh in HE 20 as solar generation declined.

The following day (June 7), peak demand was higher and wind generation was low, which resulted in a net demand of around 7,000 MW in the late afternoon and evening hours. From 15:49 to 21:50 the AESO declared an EEA3 event, indicating that there was not enough supply to reliably meet demand.

Figure 10 illustrates SMP and generation by fuel type on June 6 and 7. This figure illustrates generation used to meet AIL, which includes demand that is met by on-site generation. During the supply surplus event on the morning of June 6, wind generation supplied up to 27% of AIL.

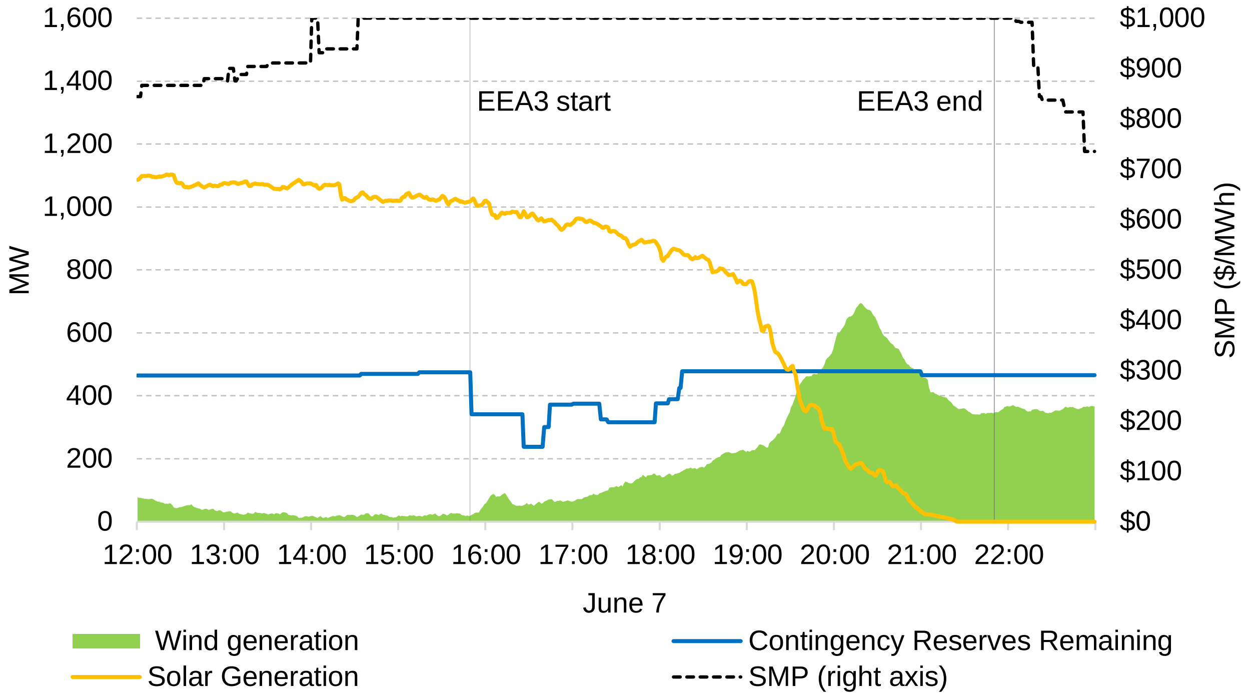
In contrast, in the early stages of the EEA3 event on June 7 wind generation was minimal, while thermal generation supplied around 8,200 MW or 80% of AIL, and solar generation supplied around 1,000 MW or 9% of AIL.

Figure 10: Generation by fuel type and SMP by minute (June 6 to 7, 2023)



Around sunset on June 7, solar generation began to decline at a faster rate. At this time, SMP was at the price cap, indicating that supply from the energy market was exhausted, and the AESO had 478 MW of contingency reserves available. Earlier in the EEA3 event, the AESO had directed contingency reserves to supply energy, as shown in Figure 11.

Figure 11: Wind generation, solar generation, and contingency reserves (June 7, 2023)



As solar generation declined, the supply of wind generation increased, which meant the AESO could avoid shedding load. From 19:51 to 20:57, SMP was at the price cap and the supply of wind generation was more than the volume of contingency reserves available to the AESO. Had wind generation been 0 MW, the AESO would have had to shed load. At one point, wind generation exceeded the available contingency reserves by 208 MW.

1.2.1 Transmission and voltage support directives

For the on-peak hours of May 23, Battle River 5 (395 MW) was scheduled to provide 51 MW of operating reserves and 90 MW of energy (the asset's Minimum Stable Generation).

At 10:24, the AESO issued Battle River 5 a directive to cease providing operating reserves for the rest of the day. The AESO issued this directive to mitigate an N-1 contingency on the transmission line 7L50. To offset this reduction in operating reserves, the AESO conscripted 40 MW of out-of-market reserves. The AESO also dispatched Sundance 6 for 300 MW of Transmission Must Run (TMR) due to an N-1 contingency on 922L.

In HE 12, the energy offers on Battle River 5 were changed such that the asset would be taken commercially offline HE 15. Other units were commercially offline at the time as pool prices were relatively low and had been $0.00/MWh earlier in the day. Battle River 5 went offline at 14:16, at which point the asset had a declared start-up time of 24 hours.

At 20:59, Battle River 5 received a TMR dispatch for 150 MW to assist with voltage stability. The asset continued to have a declared start-up time of 24 hours. Battle River 5 responded to the dispatch in around 3 hours and 20 minutes, as the asset was back online at 00:20 on May 24.

In this situation, the AESO issued TMR dispatches to provide system reliability services that are not incorporated into the AESO's market procurements. The MSA believes that these types of events will increase as intermittent generation growth in Alberta continues. Issues associated with the long-lead time rule are discussed in section 1.5.

1.3 Market power and offer behaviour[7]

In this section the MSA examines:

a) quarterly market outcomes, including the implications of higher intermittent generation;

b) the frequency and extent of pivotality in Q2 and how market prices differed depending on pivotality; and

c) the offer behaviour of companies in Q2 and prior months, and its relationship with pivotality.

The relationship between ISO rule 202.4, *Managing Long Lead Time Assets* (LLT rule) and market power is discussed at length in section 1.5.

The MSA's key findings are:

a) The ability of companies to exercise market power generally increased in Q2, particularly in midday hours despite high intermittent generation volumes, although on average market power was exercised less in periods where companies were pivotal. Periods where companies could exercise market power were generally associated with higher intermittent generation and lower imports than in periods where market power could be exercised in previous quarters. This change in ability to exercise market power was primarily caused by a reduction in import ATC and higher thermal outages in Q2.

b) Companies have responded to this change in midday market power by withholding additional capacity in June 2023.

c) Q2 had a relatively large number of hours with negative market markups (represented by the Lerner Index). This is partly due to higher quarterly intermittent generation but more broadly is due to significant amounts of withholdable capacity that continues to be offered at the price floor. Excluding these hours, market markups were similar quarter-over-quarter.

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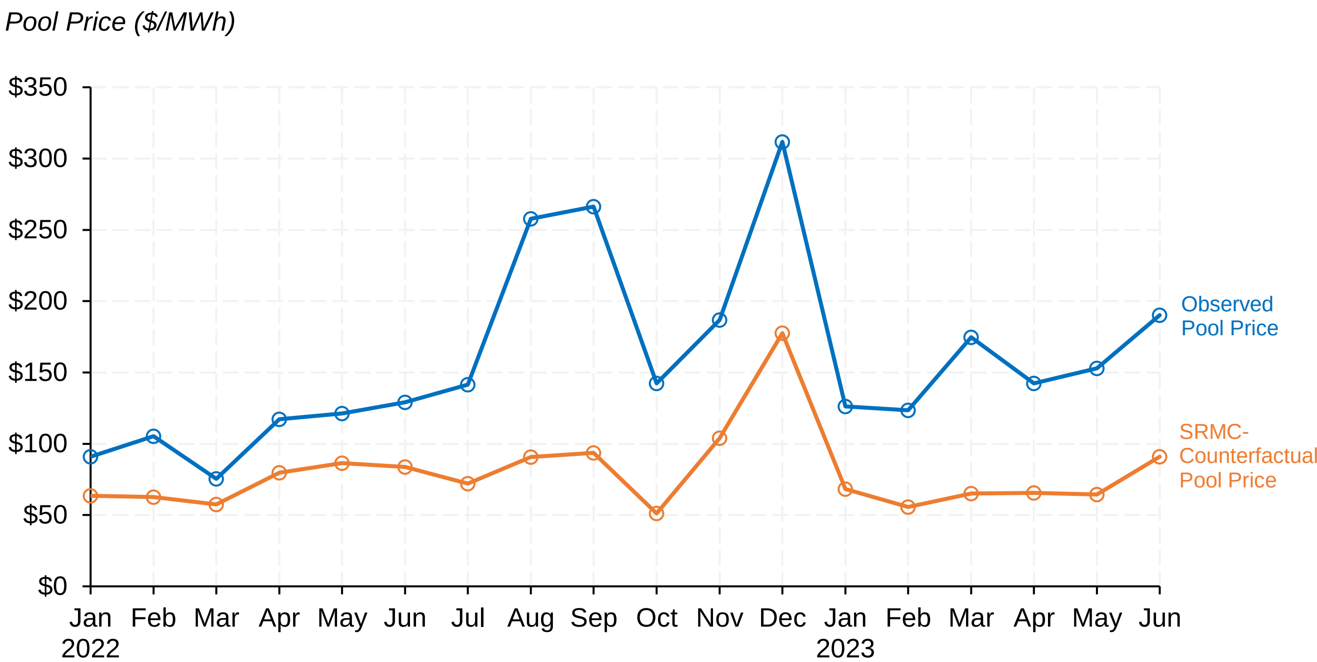
[7] The MSA continuously updates its historical inputs to various estimates described in this section. As a result, historical estimates displayed in this section may differ slightly from those reported in previous Quarterly Reports. Additionally, the MSA has revised its treatment of withholdable capacity offered at $0/MWh in its calculation of the market markup (Lerner Index), SRMC-counterfactual pool prices, and static inefficiencies. The MSA has also revised its calculation of pivotality to reflect the treatment of import ATC as demonstrative of net imports that can be supplied to the Alberta grid. Due to data unavailability, 27 hours are excluded from June 2023 data presented in this section.

1.3.1 Quarterly market outcomes

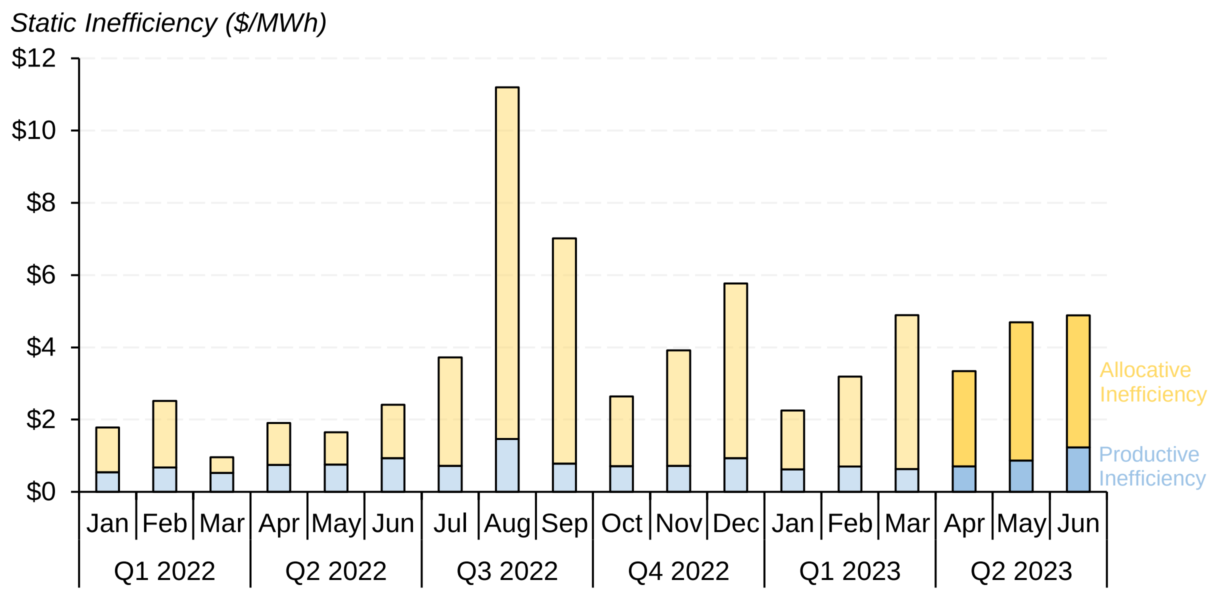
Observed average pool prices rose by $19/MWh, while short-run marginal cost (SRMC) counterfactual prices increased by $10/MWh compared to Q1. Much of this change was the result of an increase in both prices in June 2023, where observed pool prices rose by $37/MWh (Figure 12). SRMC counterfactual pool prices indicate the degree to which changes in pool prices may be a result of changes in generation costs, which can include changes in input costs at a unit-level or changes in costs at a dispatch level.

Figure 12: Monthly average observed, SRMC-counterfactual pool prices by month (January 2022 to June 2023)



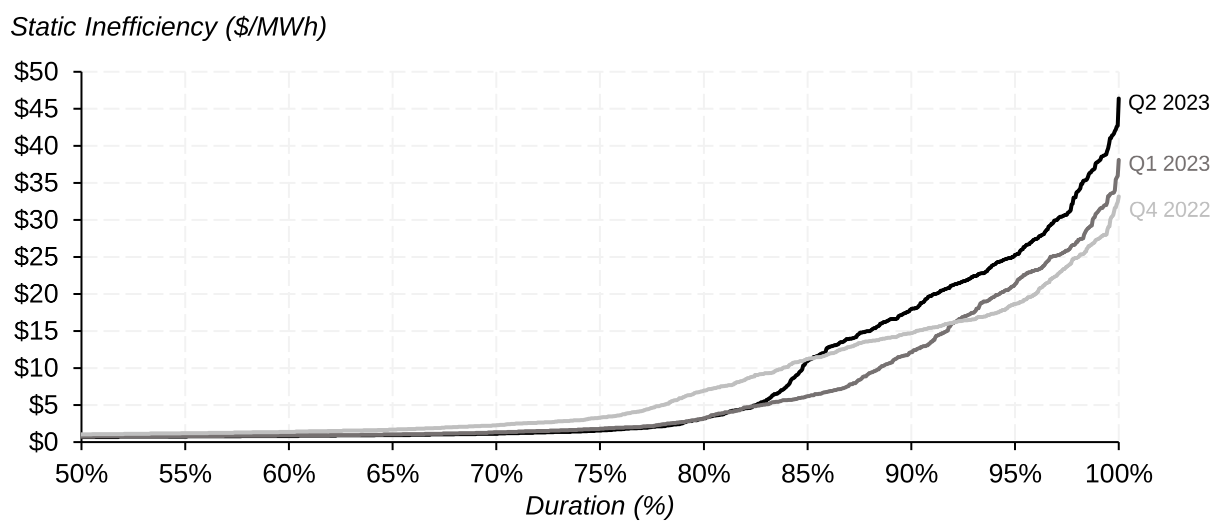
Static inefficiency, which is comprised of allocative and productive inefficiency, rose to $4.29/MWh in Q2, up from $3.42/MWh in Q1, indicative of companies exercising more market power in Q2. Much like the previous two quarters, static inefficiency rose throughout Q2, averaging $4.89/MWh in June 2023 (Figure 13). Static inefficiencies measure societal loss resulting from the exercise of market power by offering capacity at prices above short-run marginal cost. Allocative inefficiency represents the lost value of foregone consumption by consumers and production by generators, while productive inefficiency reflects the excess market-level generation cost that occurs when lower cost generation is withheld.

Figure 13: Monthly average static inefficiency (January 2022 to June 2023)



Although static inefficiency has remained high in recent quarters, most hours have experienced relatively low static inefficiency. Static inefficiency was less than $1.05/MWh in 50% of hours in the previous three quarters (Figure 14). Static inefficiencies in Q2 2023 were similar to those in Q1 2023 in 83% of hours, but averaged about $5/MWh higher in the remaining 17% of hours.

Figure 14: Duration curve of static inefficiency (Q4 2022 to Q2 2023)



Market markups measure the markup of price over the market's marginal cost of generation, expressed as a percentage of the price. Market markups fell from 40% in Q1 to 29% in Q2, largely because of a number of hours with negative markups. Hours with non-negative market markups had similar markups quarter-over-quarter (Figure 15). Q2 had twice as many hours where market markups were negative compared to Q1 and had significantly lower market markups in those hours (Figure 16).

Figure 15: Monthly average market markup, all hours and non-negative hours (January 2022 to June 2023)

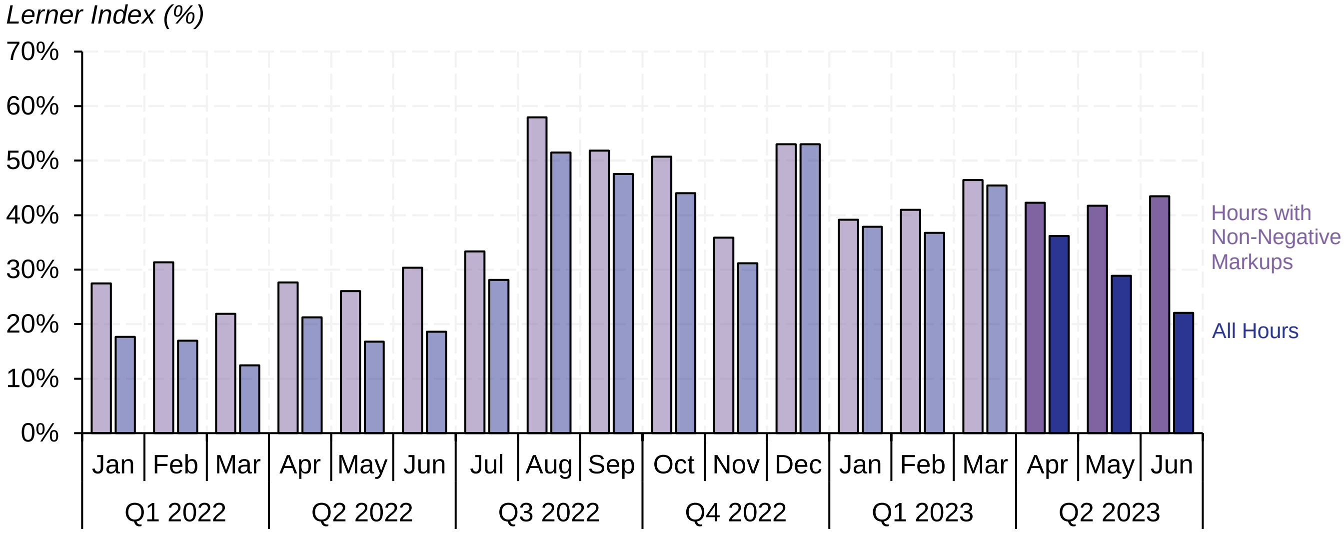
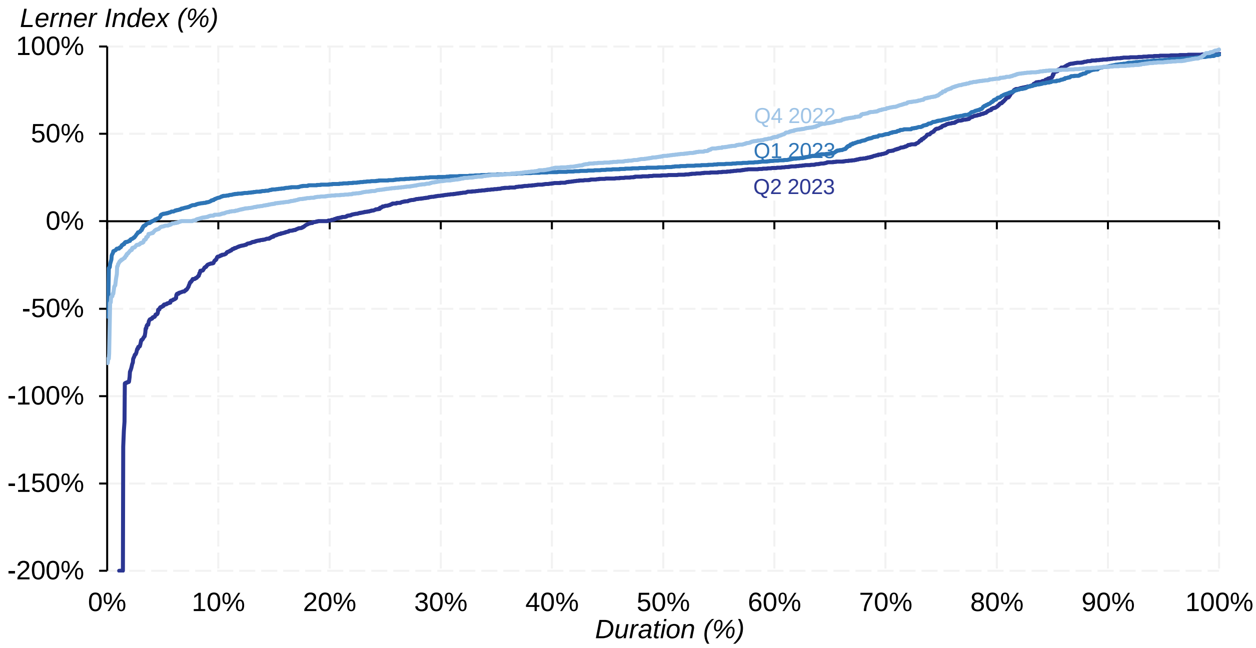


Figure 16: Duration curve of market markup, all hours (Q4 2022 to Q2 2023)[8]

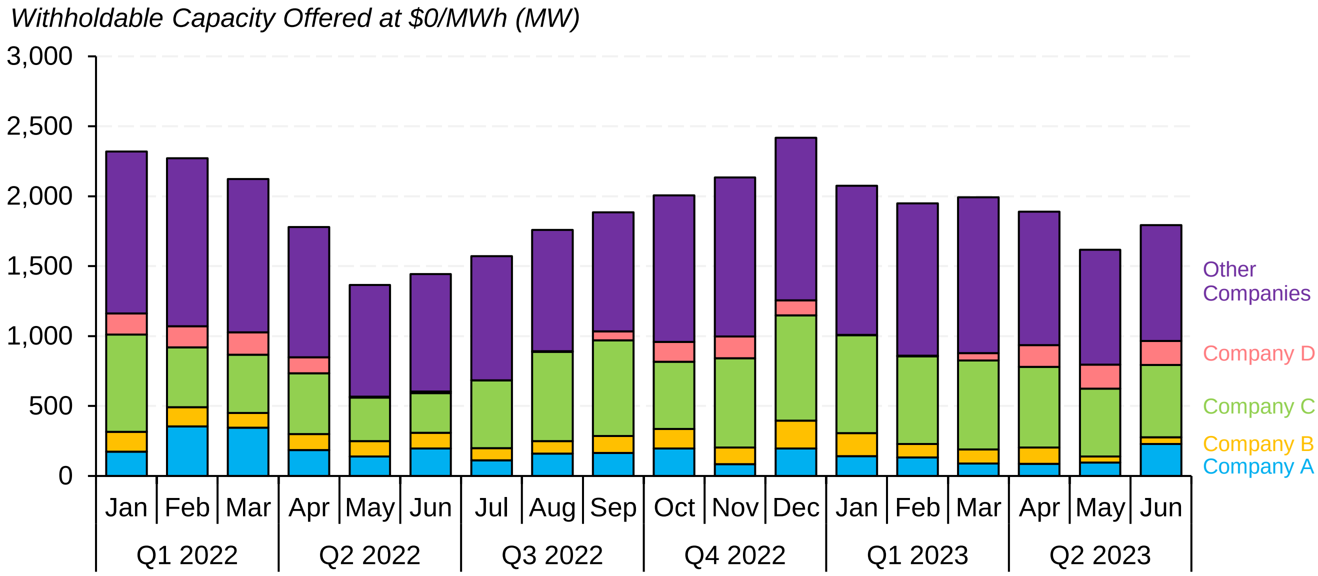


Negative markups occur where the price is less than the market price would have been if generators offered their capacity at marginal cost. This result is primarily due to withholdable capacity being offered at $0/MWh and offer behaviour at low prices, and can be exacerbated by high intermittent generation and low demand.

[8] Lerner index values below -200% have been set at -200%. Hours where the price is $0/MWh have an undefined Lerner index and have been indicated by a gap to the left of the duration curve.

Withholdable capacity consists of capacity that is not minimum stable generation or intermittent generation.[9] Significant amounts of withholdable capacity are routinely offered by generators at $0/MWh (Figure 17). Although withholdable capacity offered at $0/MWh does in most instances have a non-zero short-run marginal cost, generators may choose to offer their capacity in this way to minimize dispatch risk if higher prices are expected or may be beneficial to generators that are net buyers in the energy market who may seek to lower prices.

Figure 17: Monthly average withholdable capacity offered at $0/MWh by company (January 2022 to June 2023)



In hours with negative market markups in Q2 2023, demand net of intermittent generation averaged 6,615 MW, compared to an average of 7,616 MW in all other hours. Among the negative market markup hours below -200% in Q2, the highest pool price was $11.58/MWh, and the most capacity not offered at $0/MWh needed for the market to clear was 73 MW.

Despite higher midday intermittent generation in Q2 2023 compared to Q1, the midday decline in pool prices, inefficiencies, and market markups seen in Q1 did not occur in Q2 2023 (Figure 18, Figure 19).

[9] "Withholdable capacity" has been previously reported-on as "Non-wind-solar-MSG" capacity and "Dispatchable" capacity in the Quarterly Report for Q1 2023 and the Quarterly Report for Q4 2022, respectively.

Figure 18: Wind and solar volumes, pool prices and static inefficiency by hour ending (Q4 2022 to Q2 2023)

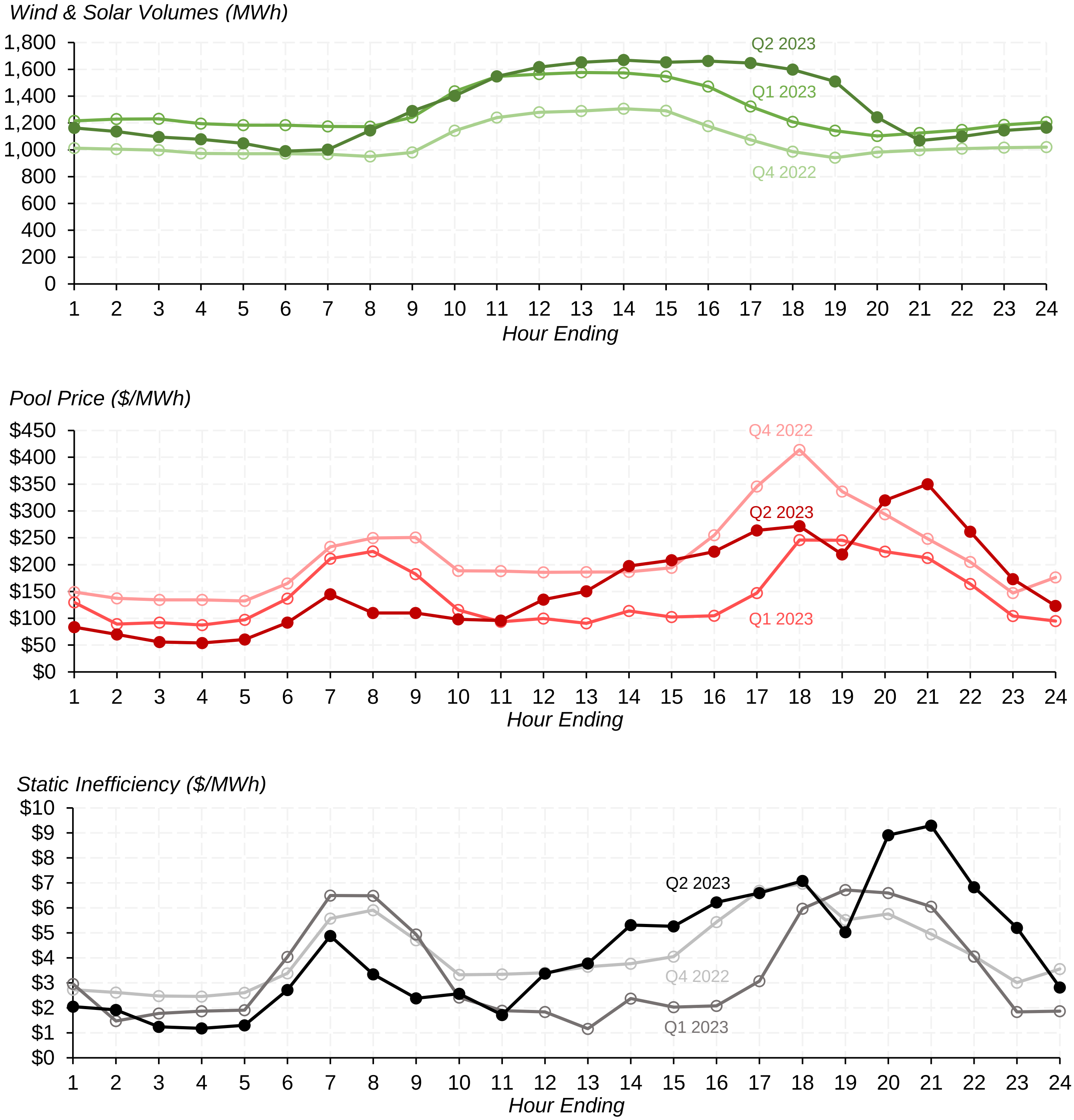
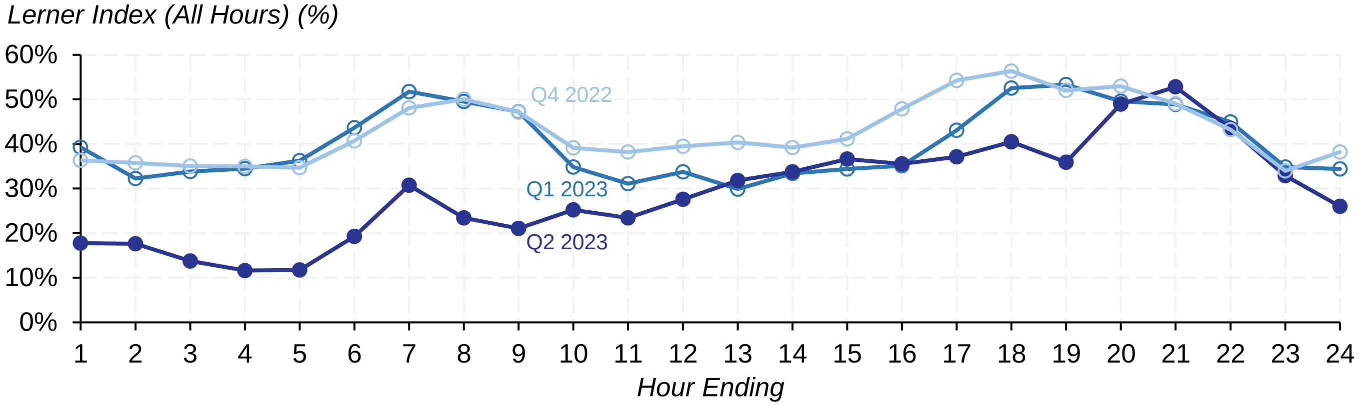
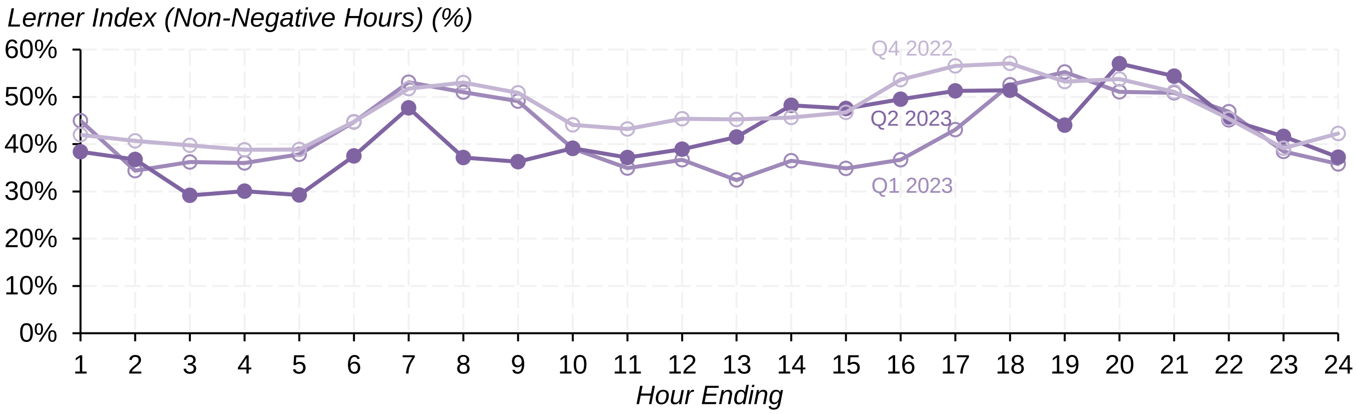


Figure 19: Market markups by hour ending, all hours and non-negative hours (Q4 2022 to Q2 2023)





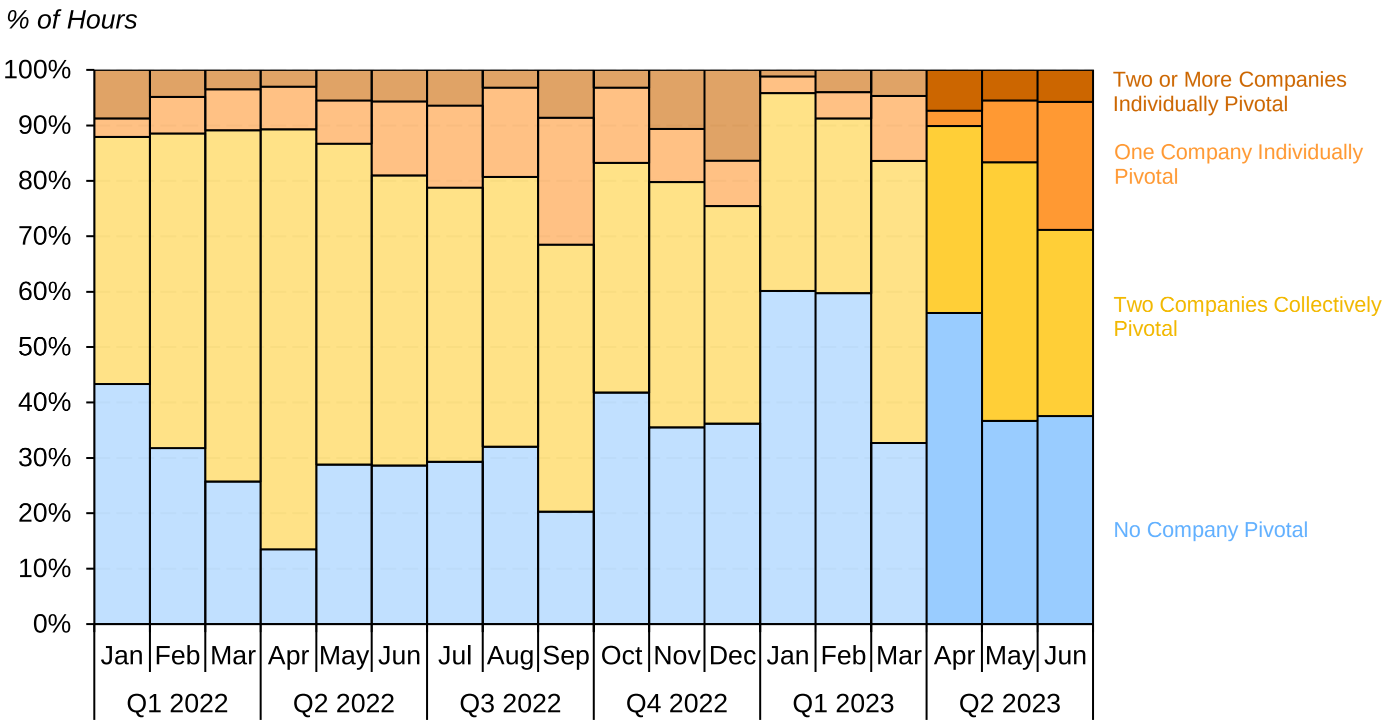
1.3.2 Pivotality

Pivotality is a measure of the ability of companies to exercise market power by economically withholding their capacity. A company[10] is pivotal if demand cannot be supplied without any of that company's withholdable generation capacity, enabling it to offer its capacity in a manner that can guarantee a minimum market price of its choice. Companies are described as being individually pivotal if their own withholdable capacity satisfies this condition, or collectively pivotal with another company if only their combined withholdable capacity is required for market demand to be met. Periods where one or more companies are individually pivotal would generally be expected to be associated with a greater exercise of market power.

Companies were increasingly pivotal throughout Q2 2023 despite generally high intermittent generation in the quarter. This was especially the case in June 2023, where one or more companies were individually pivotal in 29% of hours (Figure 20).

[10] 'Company' has the same meaning as 'Company (Condensed Name / Parent)' in the MSA's Market Share Offer Control.

Figure 20: Market-level pivotality by month (January 2022 to June 2023)



In Q1 2023, pivotality was infrequent in midday hours because of high intermittent generation. While midday intermittent generation increased in Q2, intra-day pivotality did not exhibit the same midday decline as it did in Q1 (Figure 21 and Figure 22).

Figure 21: Market-level pivotality by hour ending (Q1 2023)

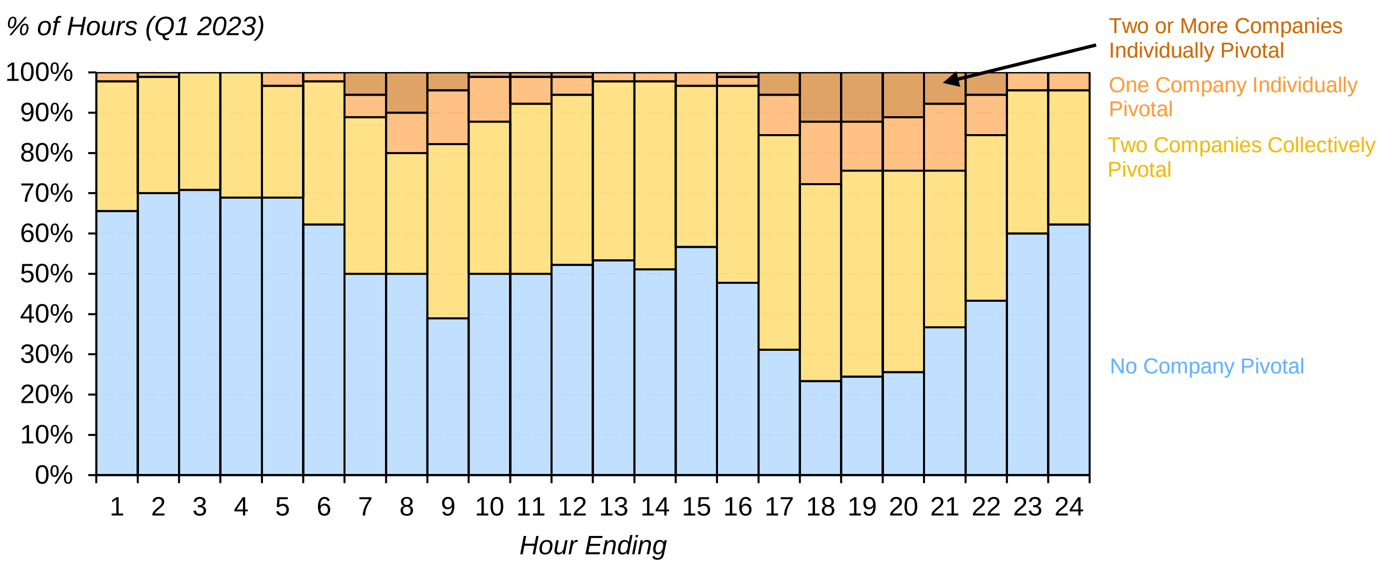
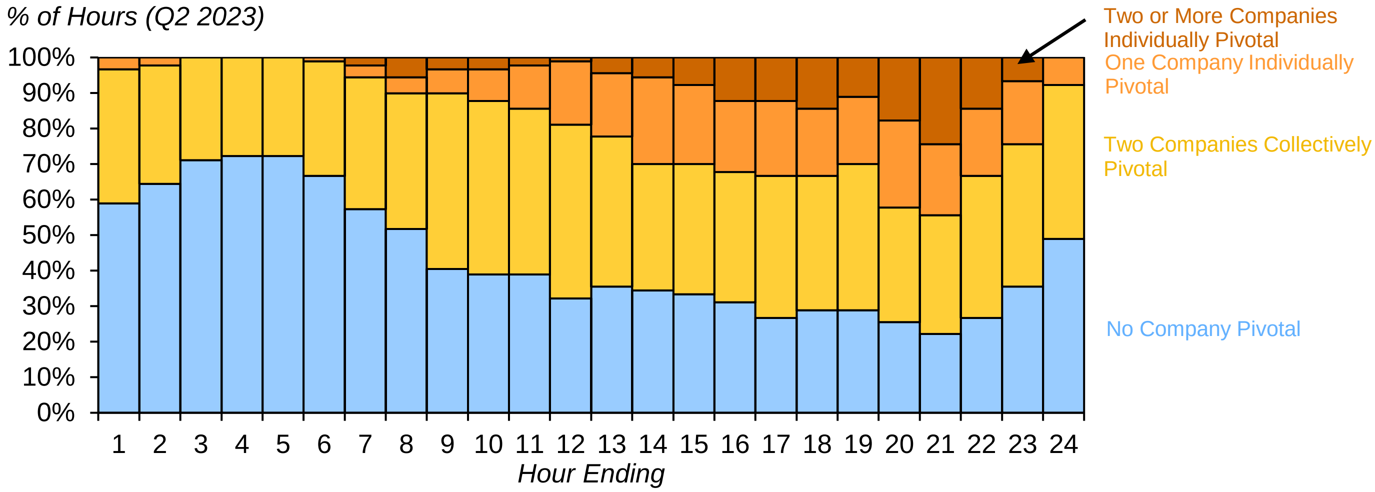


Figure 22: Market-level pivotality by hour ending (Q2 2023)



This change in intra-day pivotality is the result of increased variability of supply cushion in midday hours in Q2 2023 (Figure 23). Lower import ATC and higher thermal outages in Q2 contributed to this increase in the number of midday pivotal hours. The lower import ATC in Q2 was associated with lower import responsiveness in relatively pivotal hours compared to Q4 2022 and Q1 2023 (Figure 24).

Figure 23: Distribution of supply cushion by hour ending (Q1 2023 and Q2 2023)

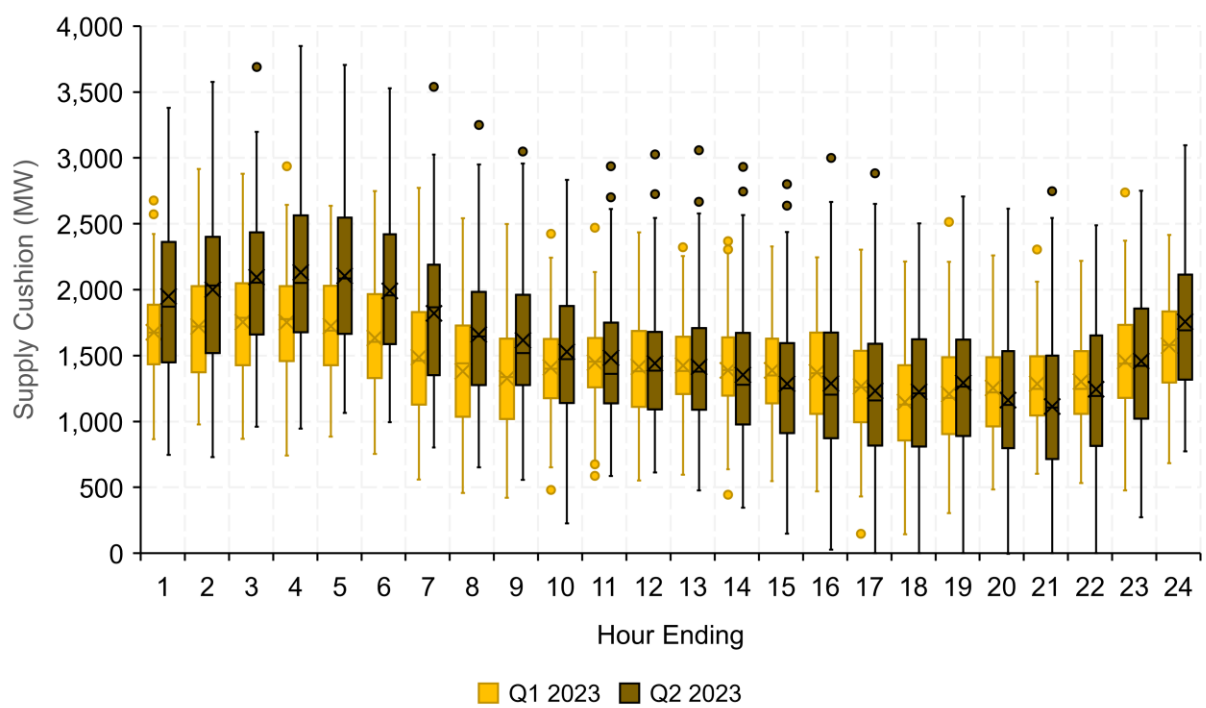
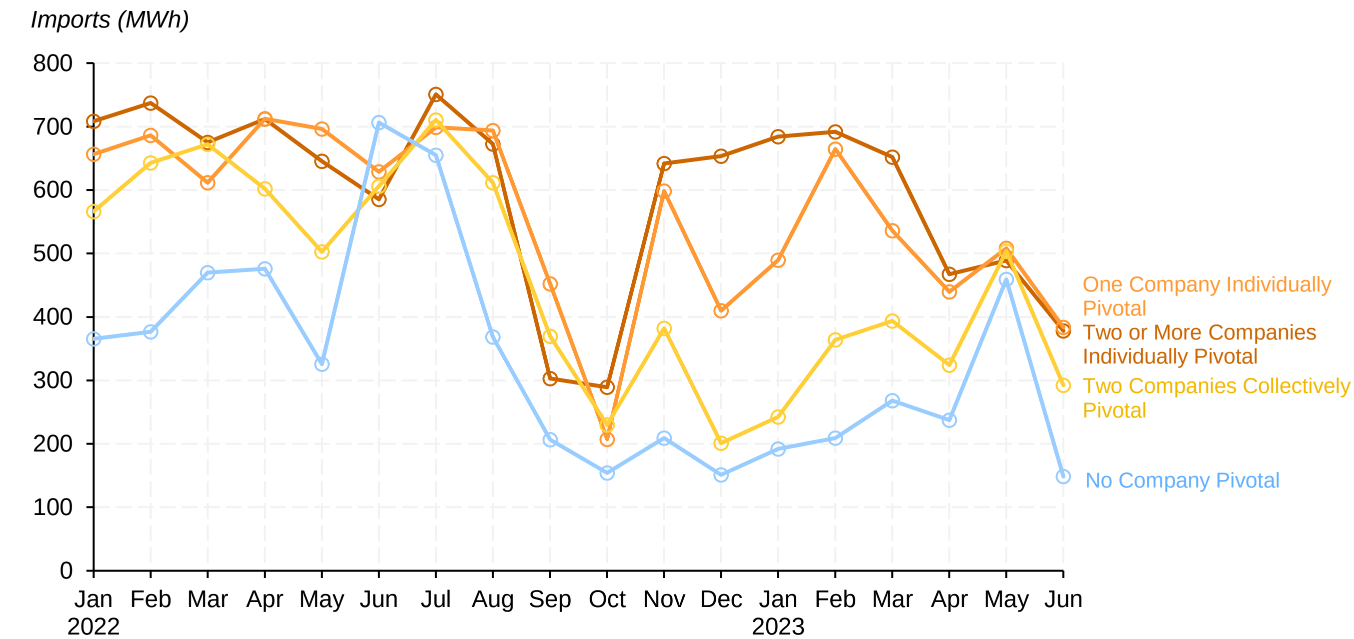
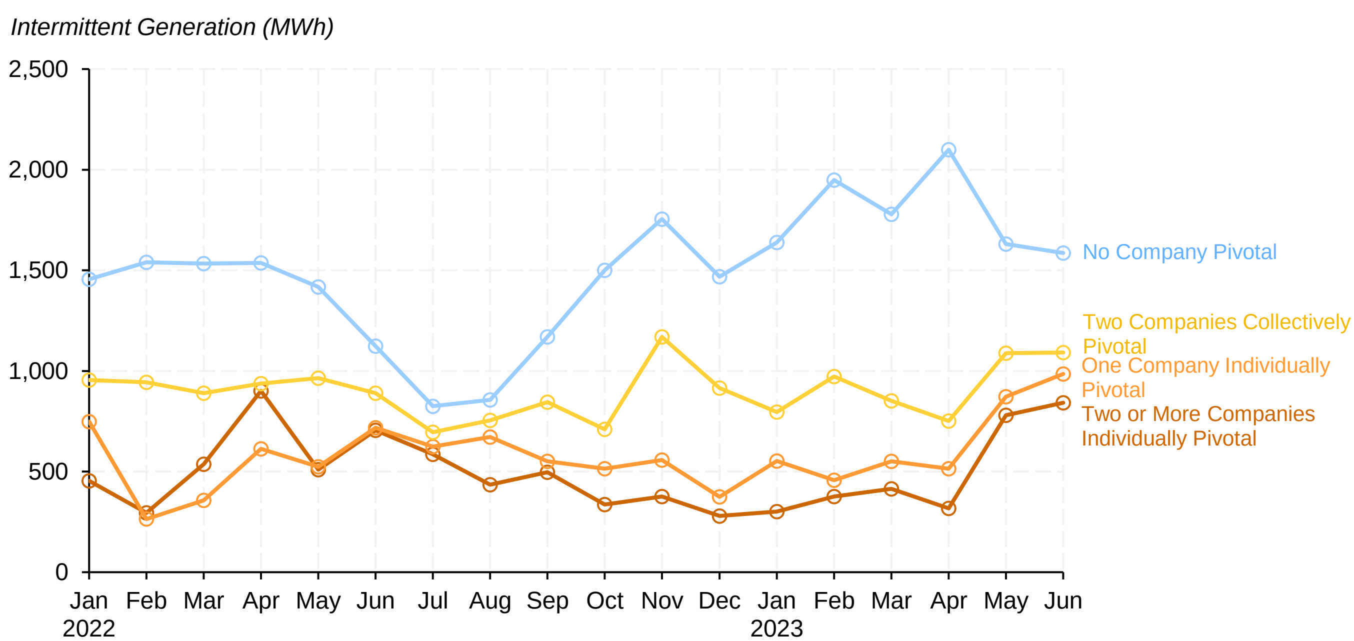


Figure 24: Monthly average imports by pivotality condition (January 2022 to June 2023)



Intermittent generation in hours where companies were collectively or individually pivotal was significantly higher in May and June 2023 than in previous months (Figure 25). This change is primarily due to greater thermal outages and lower import ATC over May and June which resulted in a larger number of pivotal hours where wind and solar generation was not low.

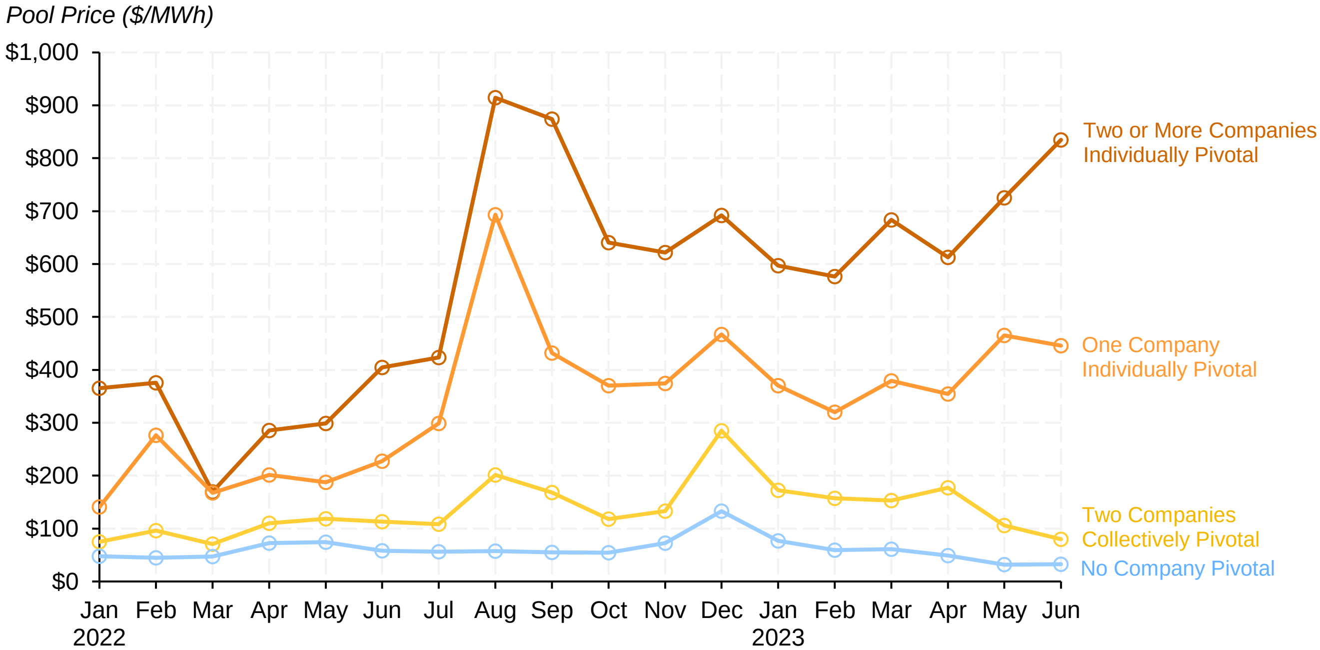
Figure 25: Monthly average intermittent generation by pivotality condition (January 2022 to June 2023)



1.3.3 Outcomes during pivotality conditions

Pool prices were higher in hours where one or more companies were individually pivotal in Q2 compared to Q1 2023 (Figure 26). Average pool prices generally fell in all other hours partly due to the significant number of negative market markup hours in the quarter.

Figure 26: Monthly average pool price by pivotality condition (January 2022 to June 2023)



Overall static inefficiency increased in Q2 2023, and this outcome was primarily driven by an increased number of hours where companies were pivotal. In hours where companies were collectively pivotal average static inefficiency fell by $1.15/MWh compared to Q1 and in hours where multiple companies were individually pivotal it fell by $4.18/MWh. Scarcity conditions in June led to several hours where static inefficiency was $0/MWh when multiple companies were individually pivotal (Figure 27 and Figure 28).

Figure 27: Monthly average static inefficiency by pivotality condition (January 2022 to June 2023)

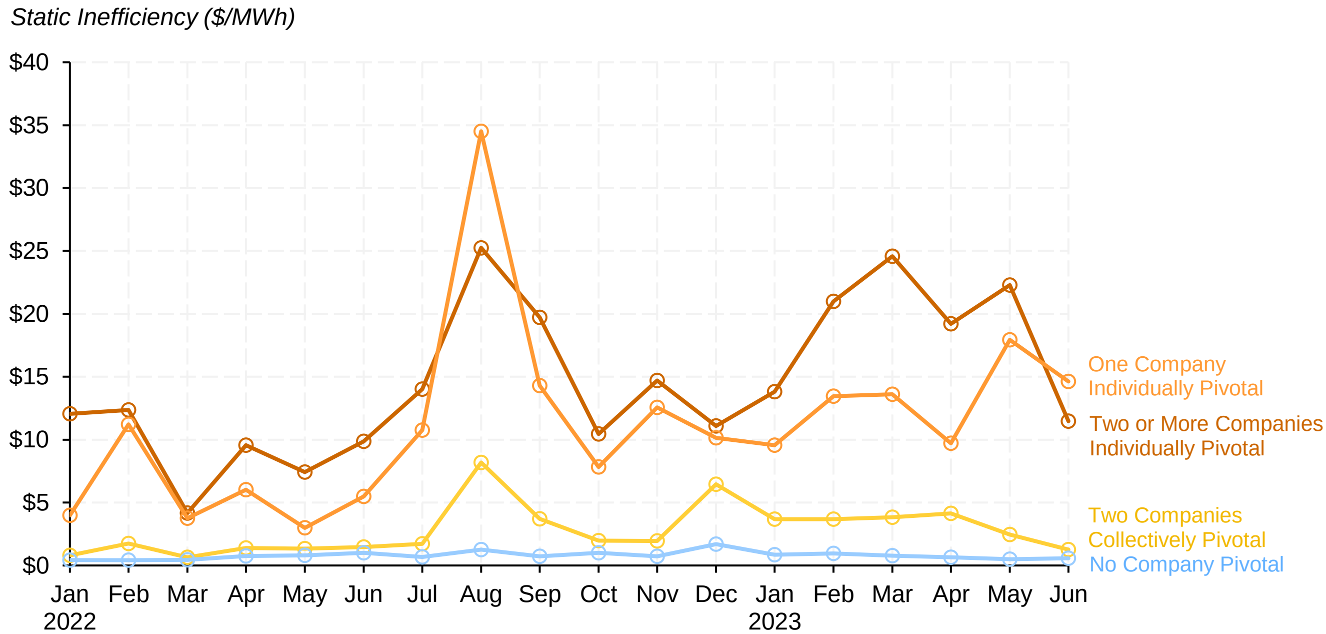
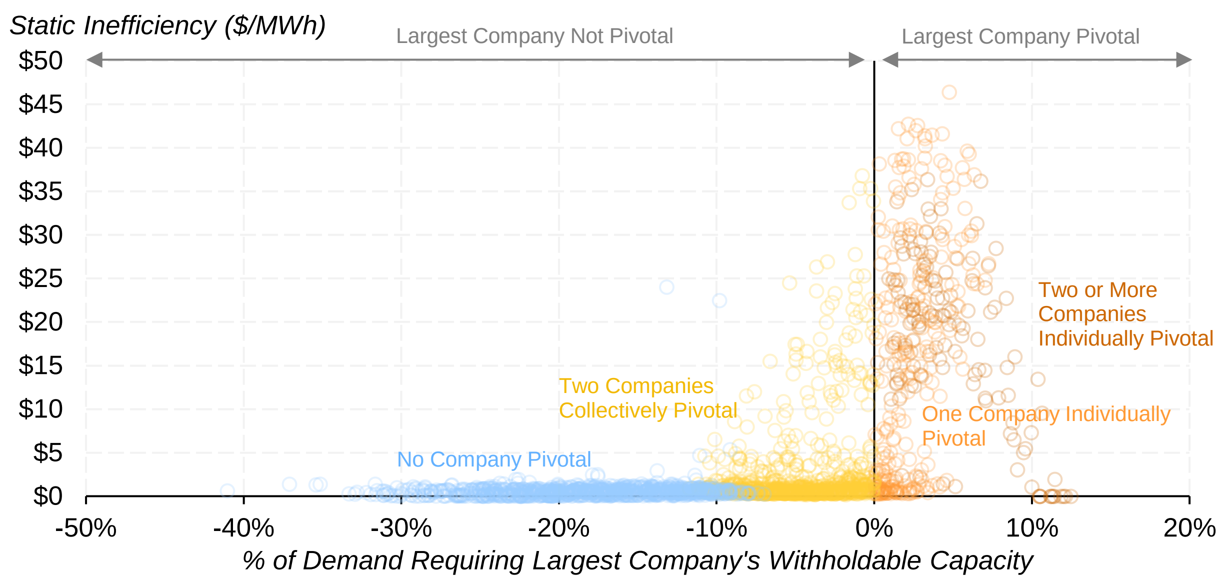
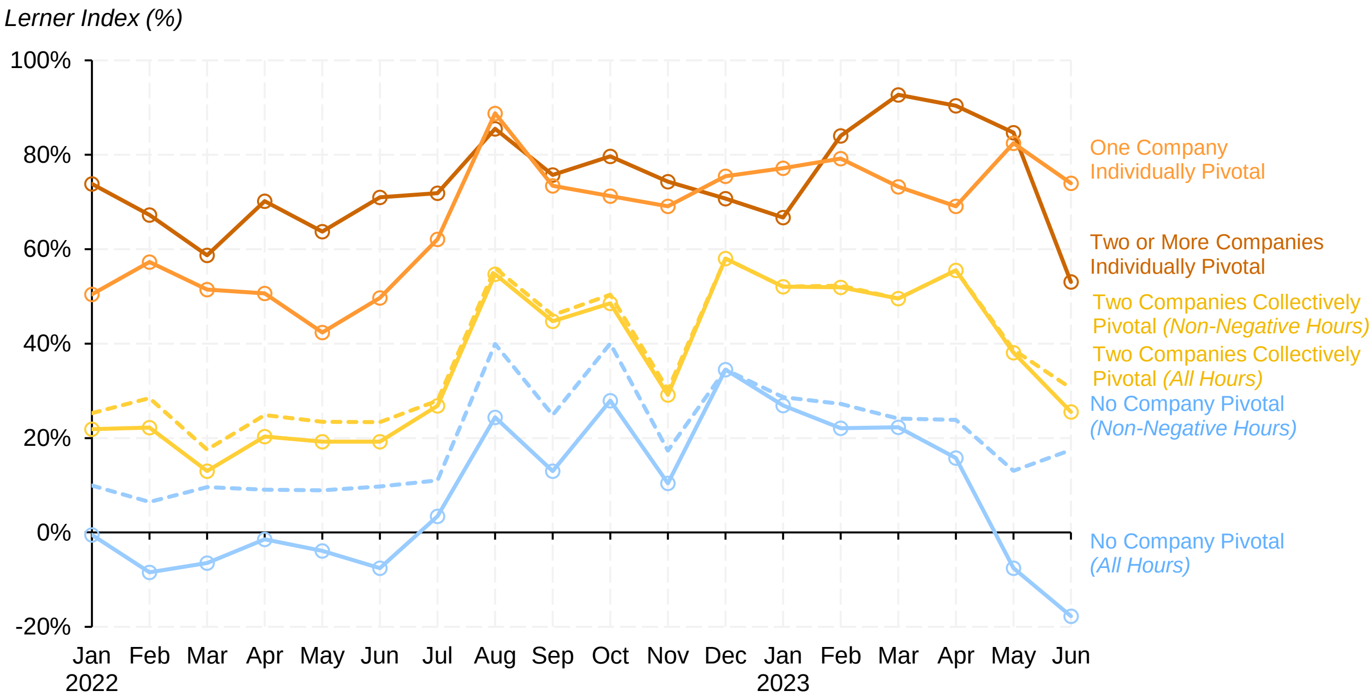


Figure 28: Static inefficiency vs. percent of demand requiring largest company's withholdable capacity by pivotality condition (Q2 2023)



Average market markups fell in all pivotality conditions in Q2 relative to Q1 (Figure 29). Average market markups in hours where no company was pivotal fell below 0% in May and June given the preponderance of hours in those months where demand net of intermittent generation was low, and significant amounts of withholdable capacity were offered at $0/MWh.

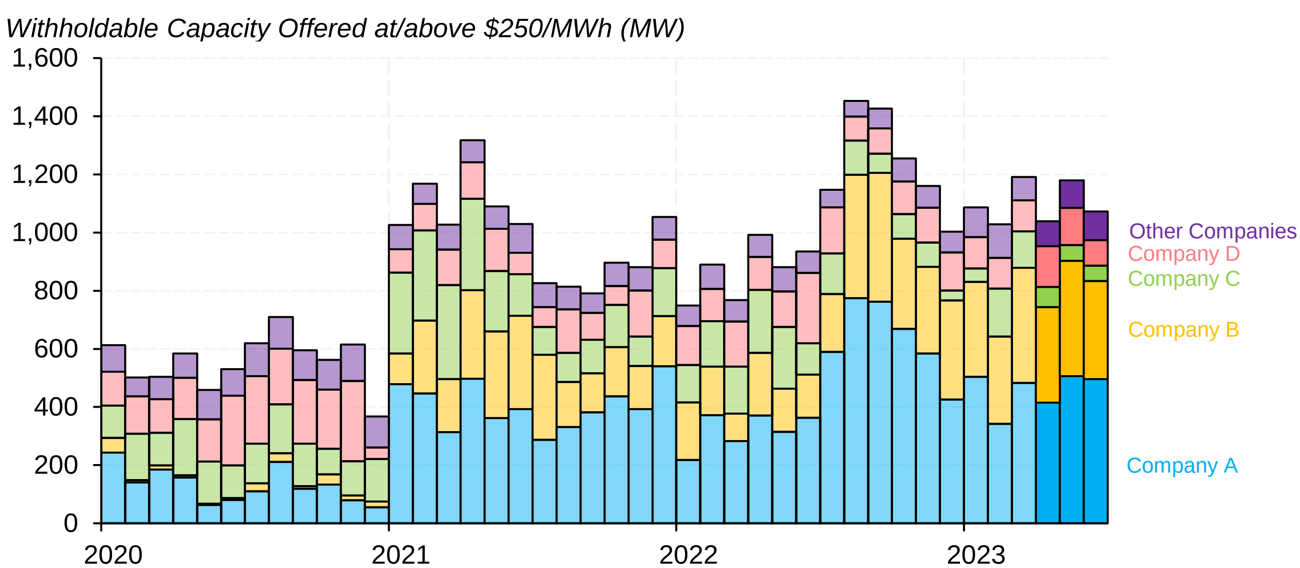
Figure 29: Monthly average market markup by pivotality condition (January 2022 to June 2023)



1.3.4 Offer behaviour

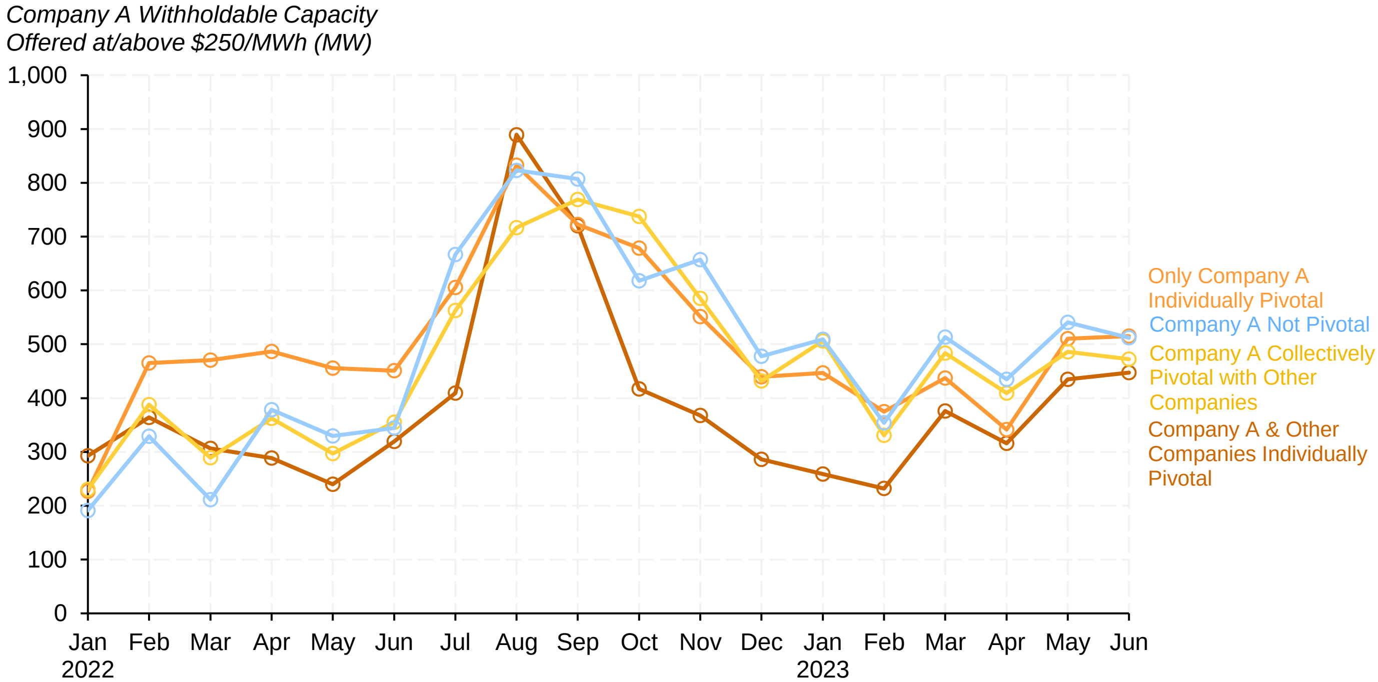
Similar amounts of withholdable capacity were offered at prices above $250/MWh in Q2 (1,098 MW) compared to Q1 (1,105 MW), with Companies A and B continuing to withhold the majority of this capacity as has been the case in previous quarters (Figure 30).

Figure 30: Monthly average withholdable capacity offered at/above $250/MWh by company (January 2020 to June 2023)



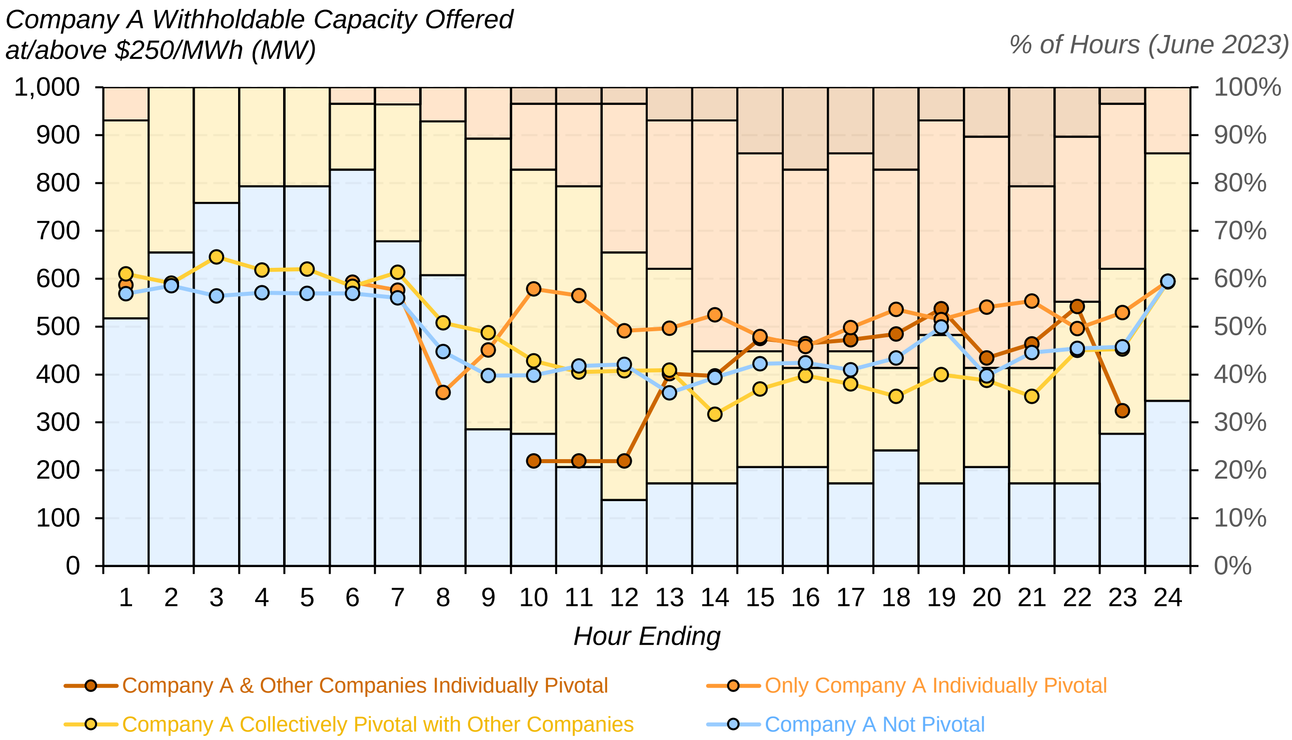
In its Q1 2023 report, the MSA described the offer behaviour of Company A and B during periods where they were individually pivotal, collectively pivotal, and not pivotal. Since the autumn of 2022, Company A has withheld less of its withholdable capacity in periods where it is individually pivotal and in hours when it and other companies are each individually pivotal, compared to periods where it is not pivotal or only collectively pivotal with another company (Figure 31).

Figure 31: Monthly average withholdable capacity offered by Company A at/above $250/MWh by pivotality condition (January 2022 to June 2023)



In June 2023, Company A began to withhold more of its capacity in on-peak hours, possibly in response to the greater likelihood of it being individually pivotal in those hours compared to prior months (Figure 32).

Figure 32: Monthly average withholdable capacity offered by Company A at/above $250/MWh by pivotality condition and hour ending (June 2023)



In Q2, Company B generally maintained its Q1 offer strategy by withholding additional capacity in hours where it is individually pivotal (Figure 33, Figure 34).

Figure 33: Monthly average withholdable capacity offered by Company B at/above $250/MWh by pivotality condition (January 2022 to June 2023)

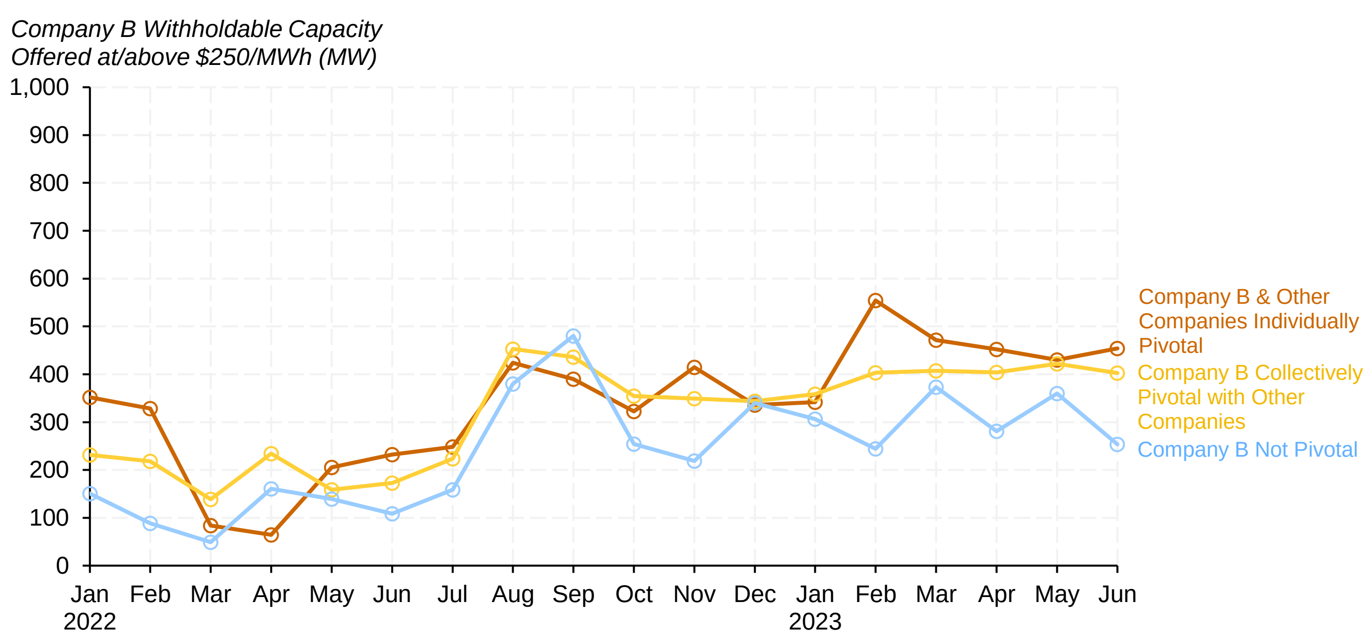
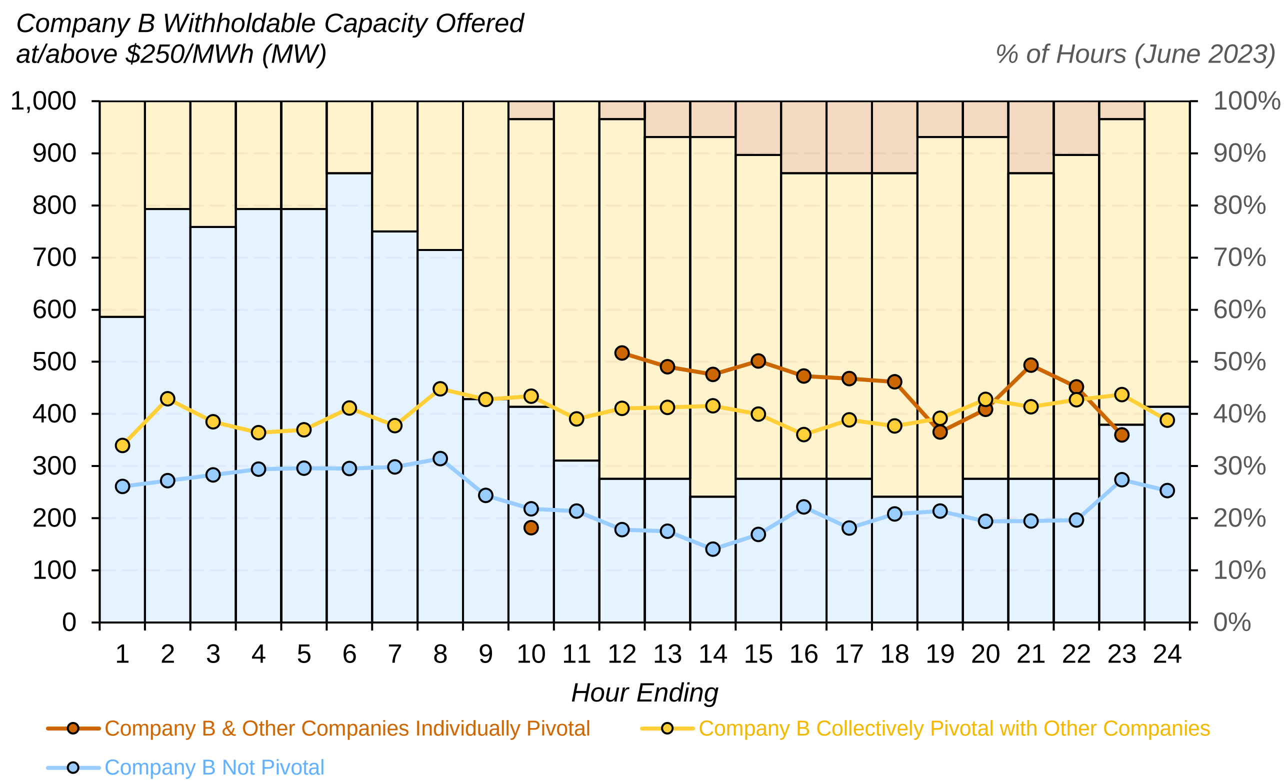


Figure 34: Monthly average withholdable capacity offered by Company B at/above $250/MWh by pivotality condition and hour ending (June 2023)



1.4 Carbon emission intensity

Carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The MSA has published analysis of the carbon emission intensity of the Alberta electricity grid in its quarterly reports since Q4 2021. The MSA's analysis is indicative only, as the MSA has not collected the precise carbon emission intensities of assets from market participants but relied on information that is publicly available. The results reported here do not include imported generation.[11]

1.4.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in a given hour. Figure 35 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q2 for the past four years.

The leftward shift shown in Figure 35 indicates a decline in carbon emission intensity over time, with the lowest hourly average carbon emission intensity in Q2 2019 higher than the mean hourly average carbon emission intensity in Q2 2023.[12] The conversion of coal-fired generation to natural

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

[12] Quarterly Report for Q3 2022, p. 40

gas in addition to increased intermittent generation drove this decline in carbon emission intensity. Mean hourly average emission intensities are reported in Table 3, showing year-over-year and quarter-over-quarter comparisons.

Table 3: The mean of hourly average emission intensities (tCO2e/MWh)

Time period	Mean
2020 Q2	0.58
2021 Q2	0.58
2022 Q2	0.49
2023 Q2	0.48

Time period	Mean
2022 Q3	0.50
2022 Q4	0.48
2023 Q1	0.47
2023 Q2	0.48

Figure 35: The distribution of average carbon emission intensities in Q2 (2019 to 2023)

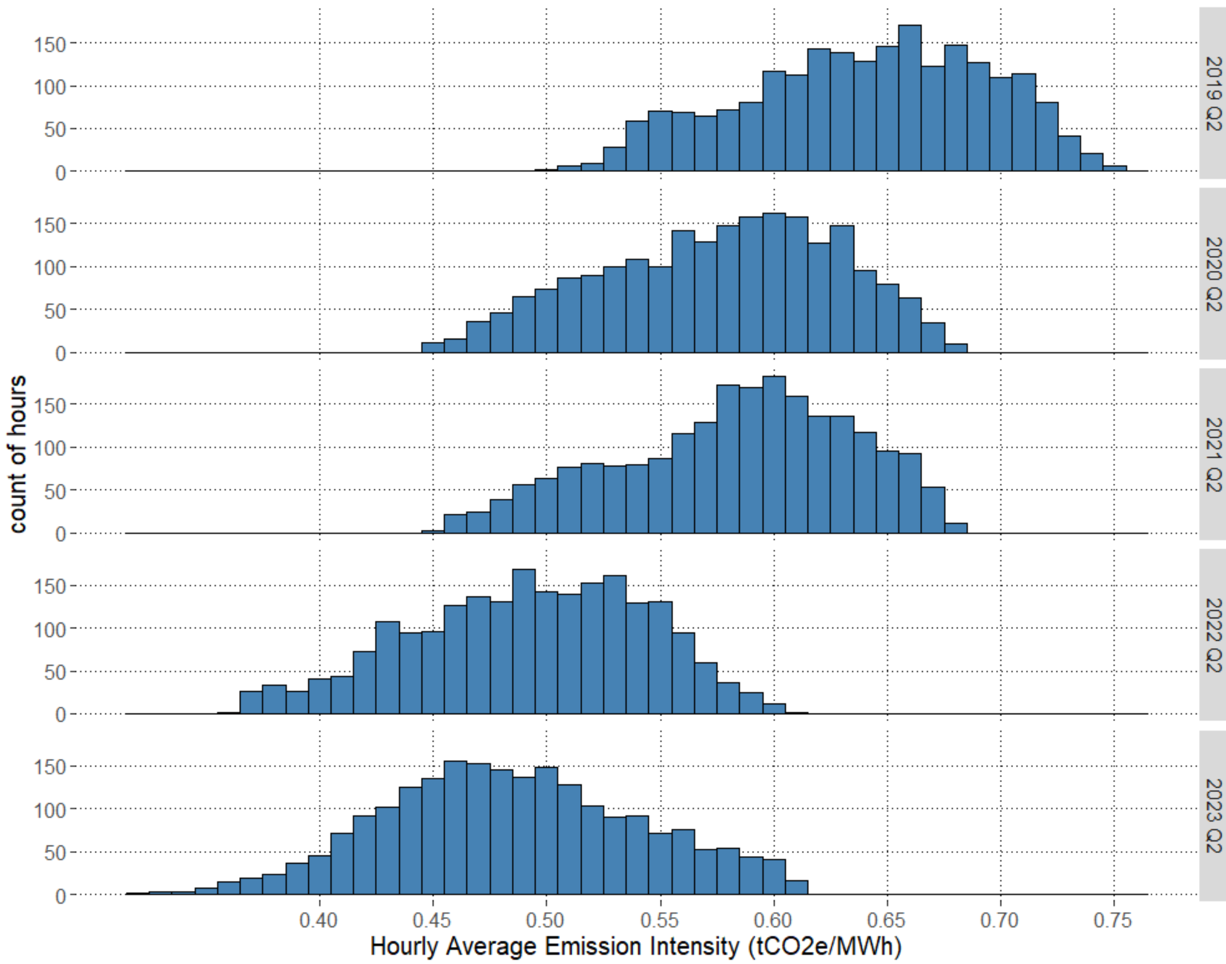


Figure 36 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The mean of the distribution has remained relatively stable since 2022 Q4 (see right of Table 3).

The general trends observed in the above distribution figures can be traced in Figure 37, 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 dual fuel and 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 36: The distribution of average carbon emission intensities in the past five quarters

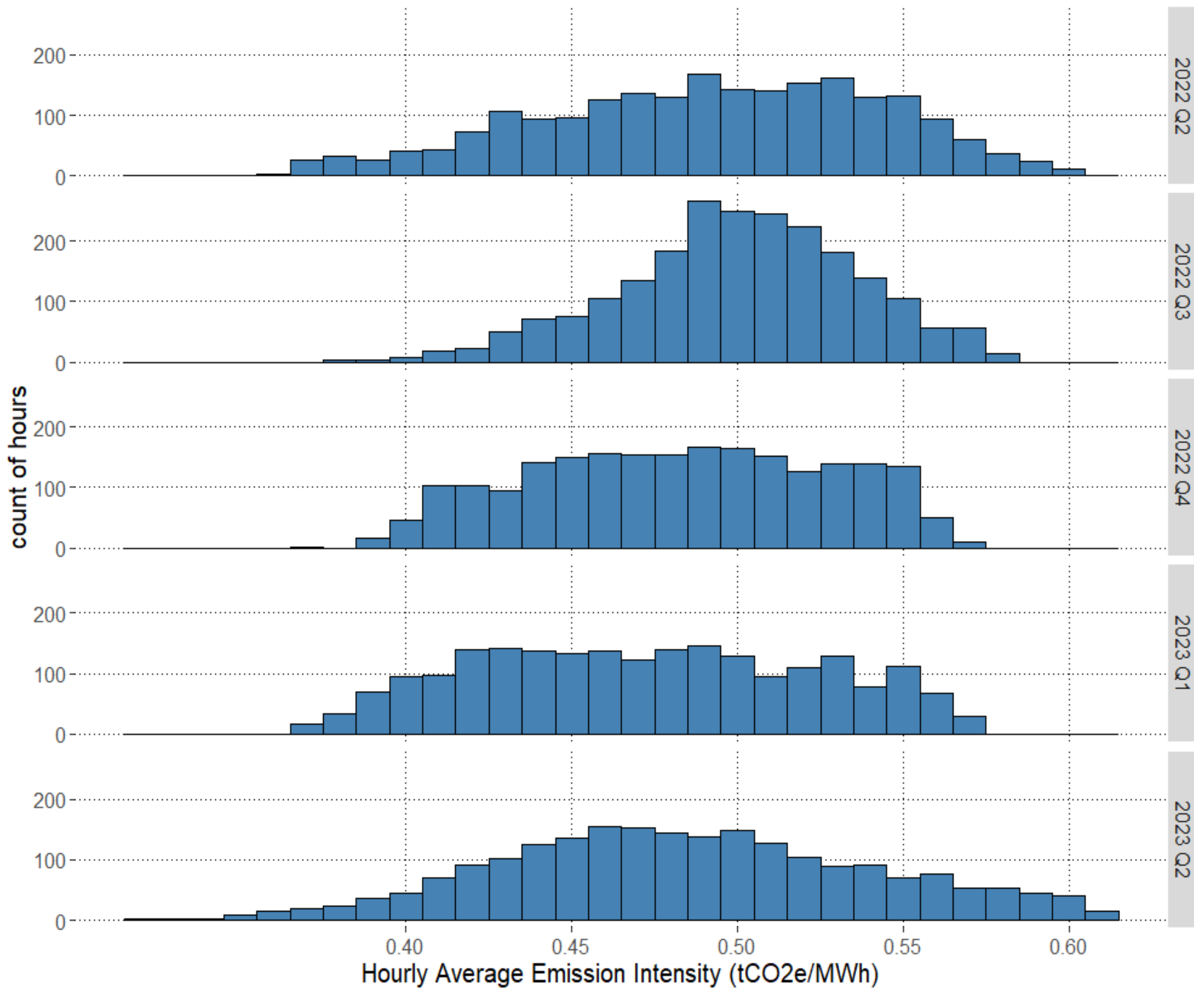
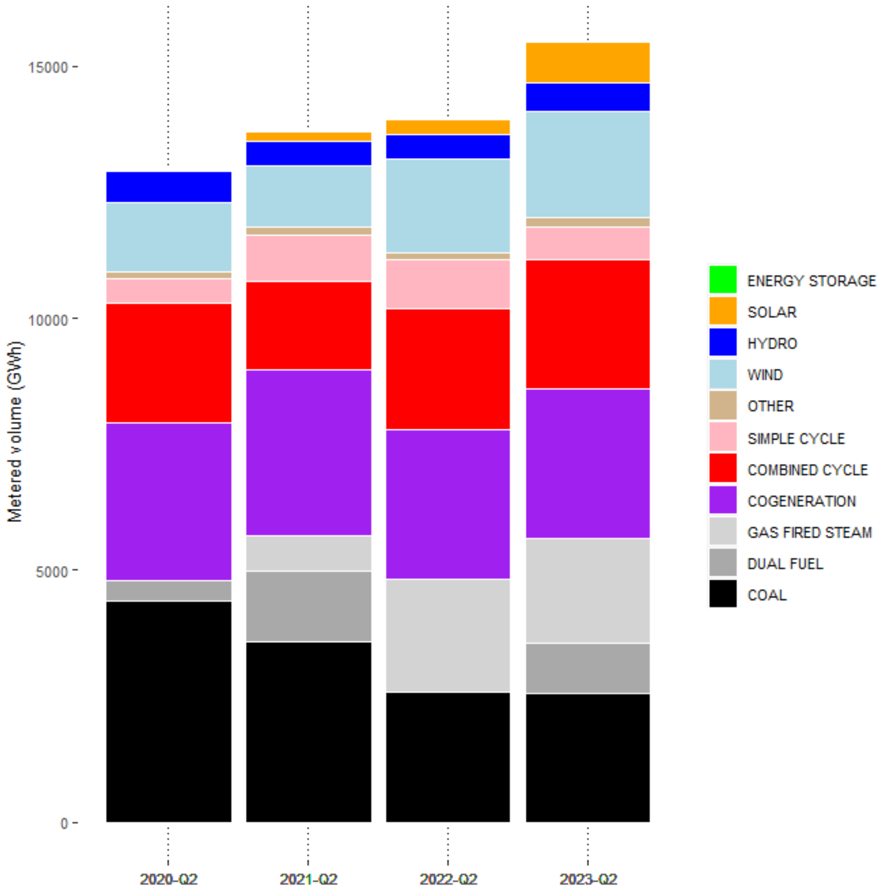


Figure 37: Quarterly total net-to-grid generation volumes by fuel type for Q2 (2020 to 2023)

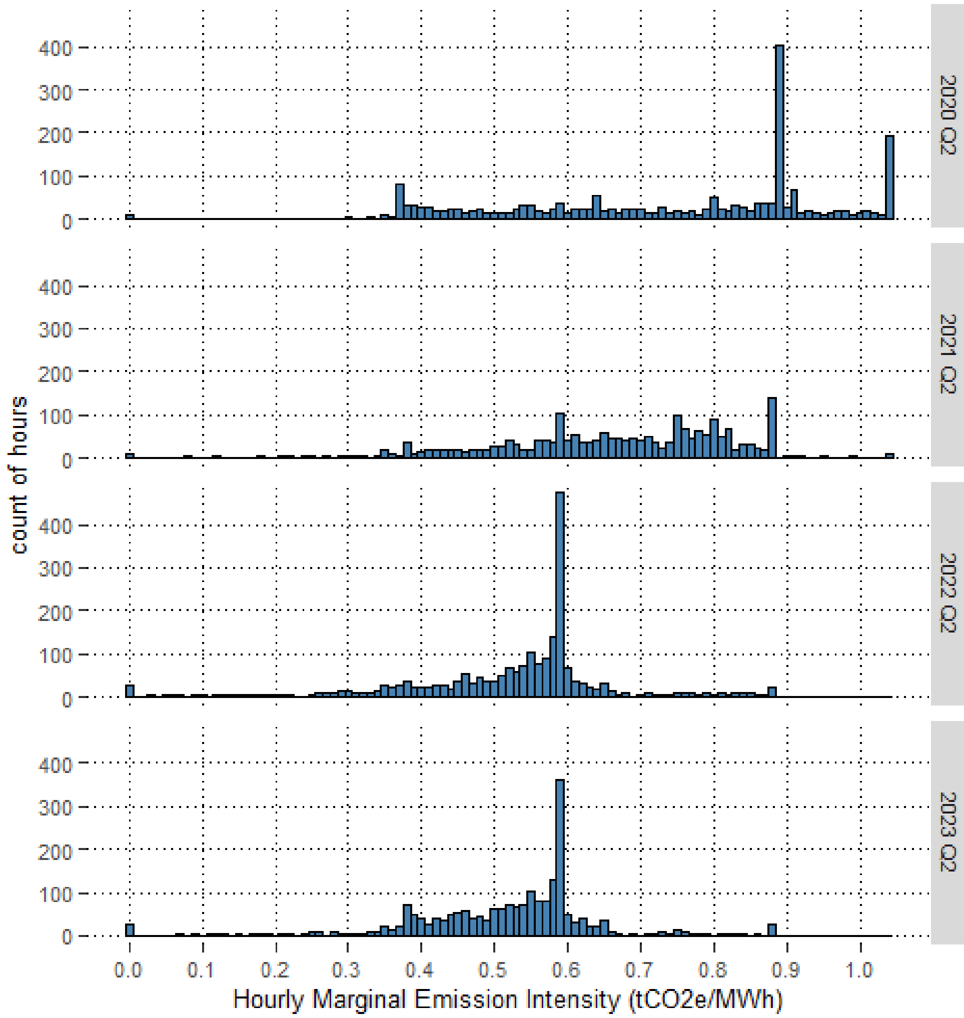


1.4.2 Hourly marginal emission intensity

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

Figure 38 shows the distribution of the hourly marginal emission intensity of the grid in Q2 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 tCO2/MWh in the latter two histograms.

Figure 38: The distribution of marginal carbon emission intensities in Q2 (2020 to 2023)



1.5 Long lead time: MSA analysis and recommendations

In Alberta's electricity market, market participants decide independently whether to commit or decommit (i.e., turn on or turn off) their generation capacity. This section examines the behaviour of long lead time (LLT) assets and the framework for their participation in Alberta's electricity market.[13] A LLT asset is defined as a source asset that:

(i) requires more than one (1) hour to synchronize to the system under normal operating conditions; or

(ii) is synchronized but has varying start-up times for distinct portions of its MW and which requires more than one (1) hour to deliver such additional portions of its MW; and

[13] The MSA has commented on LLT assets in previous reports, including section 1.2.4 of the Quarterly Report for Q1 2023.

which is not delivering all of its energy for reasons other than an outage.[14]

ISO rule 202.4, *Managing Long Lead Time Assets* (LLT rule), contains requirements for how LLT assets participate in the energy market.[15] These include requirements for the pool participant to "enter a start-up time of no greater than thirty-six (36) hours in the Energy Trading System" and "if it wishes to have a long lead time asset that is not synchronized participate in the energy market, enter a start time for the long lead time asset prior to two (2) hours before the start of the settlement interval", which may be restated. LLT assets must still submit available capability (AC) equal to their maximum capability (MC) unless they have an acceptable operational reason (AOR), even when not synchronized to the system.[16]

The MSA recognizes that unit commitment decisions often reflect expected market fundamentals, with assets typically offline when intermittent generation is expected to be high and pool prices are expected to be low. However, uncertainty and variability of generation over the time horizon of unit commitment decisions are increasing, resulting in more instances of assets being commercially offline when price and supply indicators are signalling the need for generation.

The MSA has also observed a shift in behaviour recently, with assets remaining commercially offline for extended periods with seemingly no regard for price or supply conditions. Supply adequacy communications do not appear to always be sufficient to incentivize commercially offline assets to start. While LLT assets have not yet resulted in significant reliability events, the data suggest the current framework is unsustainable, with many events within a single generator trip from supply shortfall or mitigated by over-performing intermittent generation. These examples highlight the divergence between public and private tolerance of supply shortfall risk that has emerged with the changing composition of supply and market participant behaviour.

The market must be structured to maintain reliability and provide for a competitive power pool so that an efficient electricity market based on fair and open competition can develop. As intermittent generation increases, market participants can make independently reasonable commitment decisions that are not efficient in aggregate. Therefore, the AESO must implement mechanisms to coordinate the commitment of sufficient capacity to meet demand while accounting for uncertainty.

The MSA is of the view that incremental changes to the current market framework will not result in a satisfactory solution to the unit commitment problem in the long run. Instead, significant structural market design changes will be necessary to enable the market to manage increased uncertainty and net demand variability. These changes should be explored and progressed in the AESO's Market Pathways initiative.[17] While the current LLT rule is focused on the delivery of

[14] AESO Consolidated Authoritative Document Glossary

[15] ISO rule 202.4, *Managing Long Lead Time Assets*

[16] These and other elements of the rule are important from the perspective of compliance with section 2(g) of the *Fair, Efficient and Open Competition Regulation*.

[17] AESO Market Pathways

energy, this process should also consider how unit commitment mechanisms can contribute to adequacy of other grid services.[18]

The MSA anticipates that the AESO may be required to exercise its directive-issuing authority to maintain reliability during the interim period before structural market changes can be implemented. The MSA makes the following recommendations in relation to this issue:

- the AESO's public short-term adequacy metrics should align with its directive issuing authority and obligations under the existing ISO rules related to the reliable operation of the power system (section 1.5.1),
- the AESO should provide public guidance indicating when and how it will issue and revoke directives under the existing ISO rules (section 1.5.1),
- the AESO should reconsider the threshold at which it will issue directives, in particular for LLT assets, to ensure they support an efficient allocation of resources (section 1.5.2), and
- the predictive quality of the AESO's forward-looking supply adequacy metrics is poor and should be improved (section 1.5.3).

In addition to these recommendations, which are discussed in detail below, the MSA is also of the view that:

- the AC submission requirement for LLT assets does not accurately represent their physical capability to produce energy, and
- start-up time submissions by market participants may not be frequent enough to accurately represent the physical condition of the LLT assets they control.

The MSA's analysis concludes with an analysis of commitment decisions and supply metrics (section 1.5.4), discussion of a selection of specific example events (section 1.5.5), and extensive analysis of LLT and the exercise of market power (section 1.5.6).

1.5.1 The AESO's public short-term adequacy metrics should align with its directive issuing authority and obligations under the existing ISO rules related to the reliable operation of the power system & the AESO should provide public guidance indicating when and how it will issue and revoke directives under the existing ISO rules

The AESO's Supply Adequacy Report, commonly referred to as the short-term adequacy (STA) report, is particularly important with respect to its issuance of directives. The STA report publishes a numerical rating for each hour of the current day and the following six days. These codes update every five minutes for future hours in the current day and every hour for the following six days.

[18] As highlighted in the AESO Reliability Requirements Roadmap, relevant grid services may include frequency response capability, inertia, voltage support, and flexibility.

The STA codes are determined using forecasts of several adequacy indicators outlined in the associated Information Document,[19] including demand (accounting for behind the fence load and price responsive load), available capability, intermittent output, and import ATC.

Figure 39 shows the definition of each STA code. In particular, the lowest STA code of 0 is triggered when all offers in the merit order are forecast to have been dispatched and there is not enough forecast supply available to maintain 3% operating reserve requirements. If shedding firm load is expected to be required to maintain regulating reserves, the STA code will still be 0 and therefore the STA report does not distinguish these most severe forecast circumstances.

Figure 39: AESO Supply Adequacy Report code definitions

4	= greater than 400 MW of supply available in the merit order
3	= 200 to 400 MW of supply available in the merit order
2	= 0 to 200 MW of supply available in the merit order
1	= not enough supply available to maintain 6% reserve requirements
0	= not enough supply available to maintain 3% reserve requirements.

The STA report is critical for operation of LLT assets, not only because of the forward-looking adequacy assessment it provides to the market, but because it forms the basis for the AESO's directive-issuing authority as set out in ISO rule 202.2, *Short-Term Adequacy and Supply Shortfall*. The AESO must take action to manage a state of supply shortfall, including issuing directives to LLT assets, once the STA report indicates insufficient supply to serve firm load and maintain regulating reserves (but not contingency reserves). As indicated above, these most severe forecast circumstances are grouped with slightly less severe forecast circumstances into the lowest STA code of 0. This means that the STA report, as currently structured, does not—and cannot—clearly indicate publicly when directives under ISO rule 202.2 are forecast to be needed.

The MSA is of the view that (some version of) the AESO's public short-term adequacy metrics should align with its directive issuing authority and obligations related to the reliable operation of the power system. This is particularly important as the likelihood of directives grows as a result of the changing composition of supply and the power system's evolving system support needs.

Related to this, the MSA is of the view that the AESO should provide public guidance indicating when and how it will issue and revoke directives under the existing ISO rules, including what information will be made public about the frequency of directives and relevant costs.

The MSA understands that the AESO may be hesitant to clearly indicate when it will issue certain directives to minimize the ability and incentive of market participants to act strategically in relation to this information. However, it is the MSA's view that those incentives are better addressed through other mechanisms in the short-term (such as enforcement) and in the long-term through

[19] ID #2012-006R, *Adequacy, Supply Shortfall and Energy Emergency Alerts*

the development of market-based improvements to the current market design through its Market Pathways initiative.

While the focus of this section is on improvements related to LLT assets, the MSA is of the view that these improvements would provide broader benefits in the form of better information about the near-term future state of the electricity system.

1.5.2 The AESO should reconsider the threshold at which it will issue directives, in particular to LLT assets, to ensure they support an efficient allocation of resources

While the recommendation above would result in alignment of the AESO's public reporting and directive issuing authority and obligations, as well as greater clarity about how it would carry out these activities, it does not necessarily follow that the conditions set out in ISO rule 202.2 are appropriate for the coordination of unit commitment decisions related to LLT assets. In particular, in addition to any applicable reliability considerations, it may not be economically efficient to wait until the STA report indicates insufficient supply to serve firm load and maintain regulating reserves to issue a unit commitment directive to a LLT asset, if there are any LLT assets at the time or in the near-term forecast.

For example, it may be reasonable to commit an LLT asset if, from the day-ahead perspective, it is expected to be able to recover its incremental generation costs, including cycling costs, in light of reasonable expectations of demand and intermittent supply, among other things. In jurisdictions with day-ahead unit commitment mechanisms, including day-ahead markets, unit commitment decisions embody greater risk aversion on the part of the system operator or are explicitly made on an economic basis, which achieves the same result. In most other electricity markets, the system operator implements a coordinated process, usually on a day-ahead basis for the entire following day, to ensure that sufficient generation (in conjunction with transmission assets) is committed to meet demand for electricity, as well as to provide sufficient supply of system support services needed to manage the power system, including accounting for where on the transmission grid the supply is located. The MSA understands that in the past unit commitment may not have been an issue in Alberta, or at least that a centralized approach would not have improved market outcomes. However, as elsewhere, the changing composition of supply and the power system's evolving system support needs are changing this.

Notably, at a point in time there may be multiple LLT assets available to choose from. Market mechanisms are better suited to select among these in cases where not all of the assets need to be committed. Some of the information needed to most efficiently allocate resources is not currently collected in Alberta.

The MSA is of the view that the AESO should explicitly – and publicly – reconsider the threshold at which it will issue directives, in particular unit commitment directives to LLT assets, to ensure they support an efficient allocation of resources going forward. While near-term patches may be required, it is the MSA's view that it is unlikely the arbitrary intervention will efficiently allocate resources over time and better, market-based solutions should be sought as long as there are LLT assets in Alberta's market.

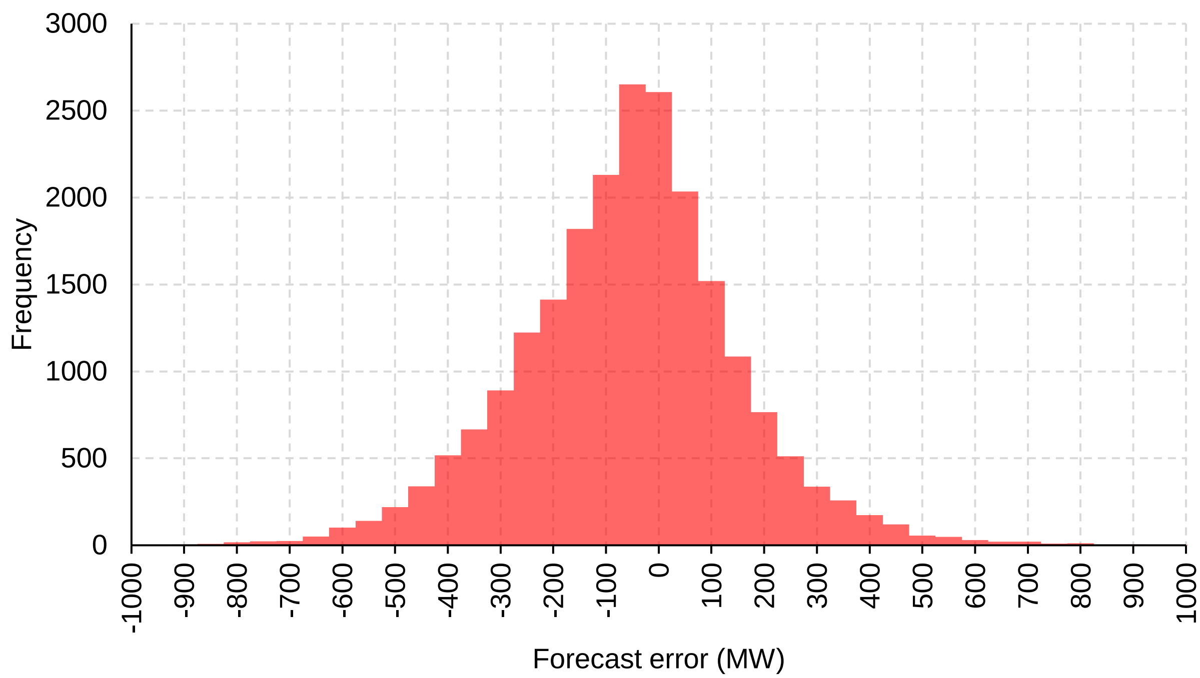
1.5.3 The predictive quality of the AESO's forward-looking supply metrics is poor and should be improved

With the increasing level of intermittent generation in Alberta, near-term forecasts (hours / days ahead) of wind and solar output have become an important factor in unit commitment decisions. An understanding of the available wind and solar forecasts can help explain the observed behaviour of LLT assets. The MSA has previously reported on implications of increased intermittent generation in the Alberta electricity market.[20]

The focus in this section is on the 12-hour wind and solar forecasts published by the AESO. A 12-hour forecast period was chosen to represent an approximate cold start-up time for some LLT assets, recognizing that actual start-up times will vary between assets. While these forecasts are published separately, they are aggregated into a combined wind and solar forecast for the purpose of this section.

Figure 40 shows the realized forecast error in the 12-hour intermittent generation forecast for the period of January 1, 2021 through June 30, 2023. For reference, as of July 2023, the combined installed capacity of wind and solar in Alberta is approximately 5,000 MW. The forecast error is defined as the forecast generation minus actual generation, so a positive value indicates that the forecast over-predicted the amount of intermittent generation.

Figure 40: Distribution of 12-hour intermittent generation forecast errors (January 1, 2021 to June 30, 2023)



[20] For example, see section 1.2 of the Quarterly Report for Q1 2023.

Table 4: Summary statistics of 12-hour intermittent generation forecast errors (January 1, 2021 to June 30, 2023)

Minimum	-983 MW
Maximum	1,091 MW
Mean	-33 MW
Mean Absolute Error (MAE)	158 MW

Table 4 shows summary statistics for the 12-hour intermittent generation forecast error. As shown, the forecast error averages negative 33 MW, indicating that intermittent generation was slightly under-forecast on average by the AESO. While the mean absolute error was 158 MW, significant forecast errors do occur, with both under- and over-forecasts of approximately 1,000 MW observed in the sample period.

As the installed capacity of intermittent generation increases, high forecast errors are becoming more frequent and more significant. For example, absolute forecast errors of 600 MW or higher occur in approximately 1% of hours and can have an impact on the market, especially with large thermal assets going commercially offline.

Table 5 shows the number of hours assigned each STA code and Energy Emergency Alert (EEA) level, both for STA codes published 5 minutes ahead of the hour and 12 hours ahead. This gives an indication of how accurately the STA report predicts real time supply adequacy conditions. When comparing the two metrics it is important to remember that supply adequacy is worsening with higher EEA levels (i.e., EEA 3 is the least adequate), while supply adequacy improves with higher STA codes (i.e., STA code 0 is the least adequate).

Table 5: Count of forecast supply adequacy code vs realized Energy Emergency Alert level (January 1, 2022 to June 30, 2023)

		EEA level			
Lead time	**STA code**	**0**	**1**	**2**	**3**
5-minute	**4**	12,919	0	0	2
	3	90	0	1	3
	2	35	0	1	12
	1	10	0	0	9
	0	2	0	0	3
12-hour	**4**	12,874	0	2	18
	3	115	0	0	2
	2	42	0	0	3
	1	9	0	0	6
	0	0	0	0	0

As set out in Alberta Reliability Standard EOP-011-AB-1, *Emergency Operations*, EEA 3 is declared when the ISO is unable to meet minimum contingency reserve requirements. Therefore, an STA code of 1 or 0 most closely aligns with forecasting an EEA 3 event. Prior to January 1, 2022, EEA levels were defined differently, so for clarity the table only includes observations since the definitions were changed.

During the study period there are 29 hours in which an EEA 3 event occurred, a number that is clearly not dependent on the forecast lead time.

Looking first at the 5-minute ahead observations, an STA code of 1 or 0 was assigned in 12 (9 + 3, in red in the top part of the table) of these 29 hours. This means that, even 5 minutes ahead, the STA report correctly predicted EEA 3 events in only 41% of instances, though this is too short a time period for the forecast supply issue to be mitigated with a directive to a LLT asset. In two events (green in the top part of the table), the STA report assigned the highest adequacy code 5 minutes ahead that materialized as an EEA 3 event. An STA code of 0 or 1 was assigned in a different 12 hours (10 + 2, in blue in the top part of the table) where there was no EEA event at all (i.e., observed EEA 0, normal operating conditions).

Looking 12 hours ahead, the STA report predicted EEA 3 in only 6 (6 + 0, in red in the bottom part of the table) of 29 hours. This means that, 12 hours ahead, the STA report correctly predicted EEA 3 in only 21% of instances. In 18 (green in the bottom part of the table) of 29 hours, the 12-hour outlook of the STA report assigned the highest adequacy code of 4 to an hour that materialized with an EEA 3 event. In 9 hours (9 + 0, in blue in the bottom part of the table), the 12-hour ahead STA code predicted an EEA 3 event when there was no realized EEA event. This can potentially be explained both by forecast error and by the market responding to the supply outlook to improve adequacy. The 12 hours in which the 5-minute STA code incorrectly predicted EEA 3 suggest that forecast error is a significant factor.

While indicative of the increased uncertainty and variability on the system that will reduce forecast accuracy, in the MSA's view, these observations highlight that the predictive quality of the AESO's forward-looking supply metrics is poor and should be improved.

1.5.4 Analysis of commitment decisions and supply metrics

The following figures compare LLT volumes against the pool price, STA codes, and supply cushion to observe the circumstances surrounding LLT commitment decisions. The LLT volumes in this analysis exclude assets that are synchronized according to definition (ii) above, which are sometimes called "type 2." LLT decisions and pool prices are affected by the same market fundamentals, so these relationships are shown for context and not to make causal conclusions.

Figure 41 shows a wide variety of LLT volume at different price levels. There are a few possible explanations for this:

- the LLT assets in this analysis are inflexible and therefore brief high prices are not sufficient to incentivize a full commitment cycle,

- market participants do not have perfect foresight, and many factors can lead to high prices within the time frame in which the asset is not capable of starting up, and
- for market participants with large portfolios, keeping an asset offline may be profitable if they capture higher pool prices on their remaining assets.

There are many observations concentrated at 0 MW of LLT volume, indicating that the assets frequently run at all price levels.

Figure 41: LLT volume vs pool price (January 1, 2021 to June 30, 2023)

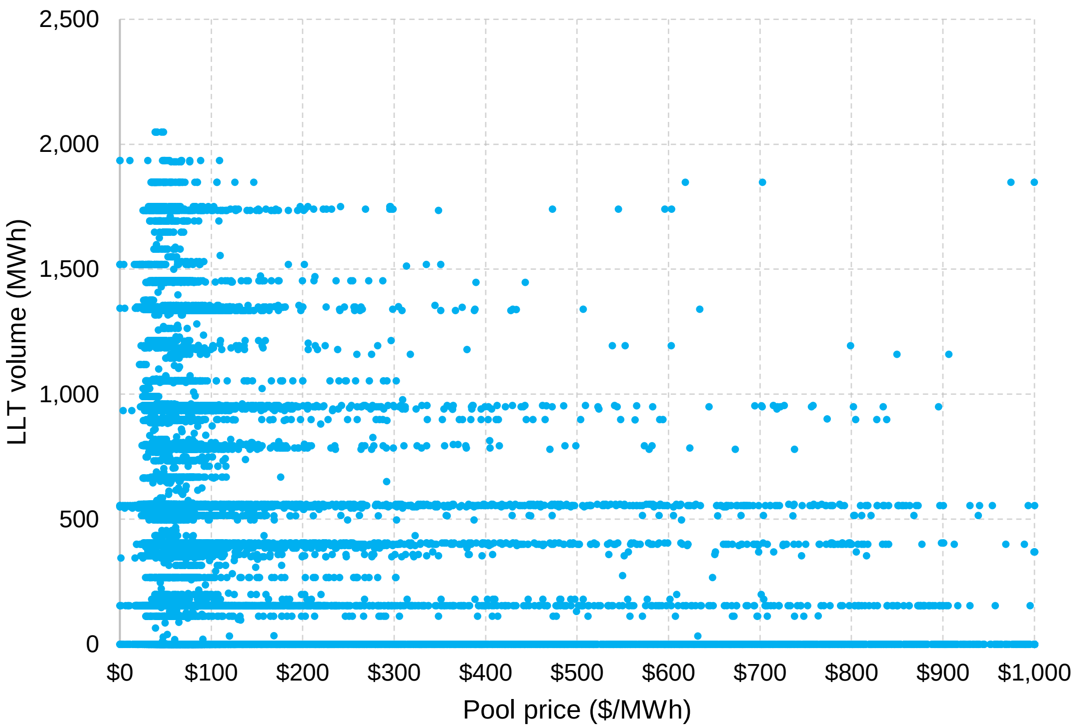


Figure 42 shows the relationship between LLT volumes and the STA code 12 hours ahead of real time. Observations of significant LLT volume at low STA codes indicate that LLT assets do not always respond to scarcity signals sent by the STA report. As discussed in the previous section, there is an imperfect correlation between STA codes and EEA levels. There was only one instance of an asset commercially offline during an EEA event, which occurred on July 7, 2021.

Figure 43 shows the relationship between LLT volumes and supply cushion. Large LLT volumes appear to be reduced below approximately 500 MW, with even fewer below 250 MW, but these instances are rare to begin with. Further, there are several notable exceptions, including a small number of significant LLT volumes at 0 MW supply cushion.

Figure 42: LLT volume vs 12-hour-ahead supply adequacy code (January 1, 2021 to June 30, 2023)

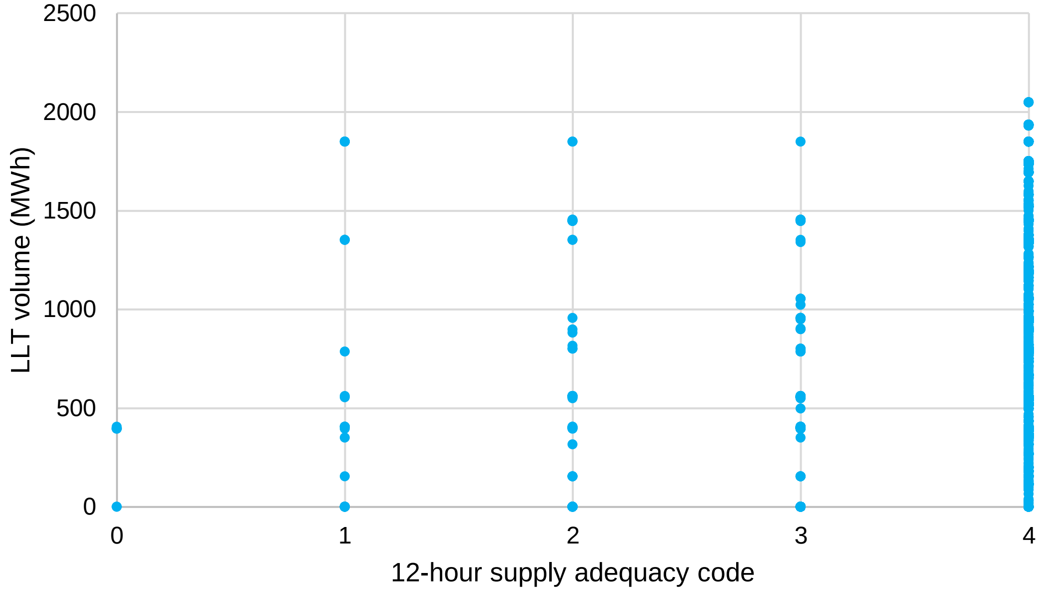
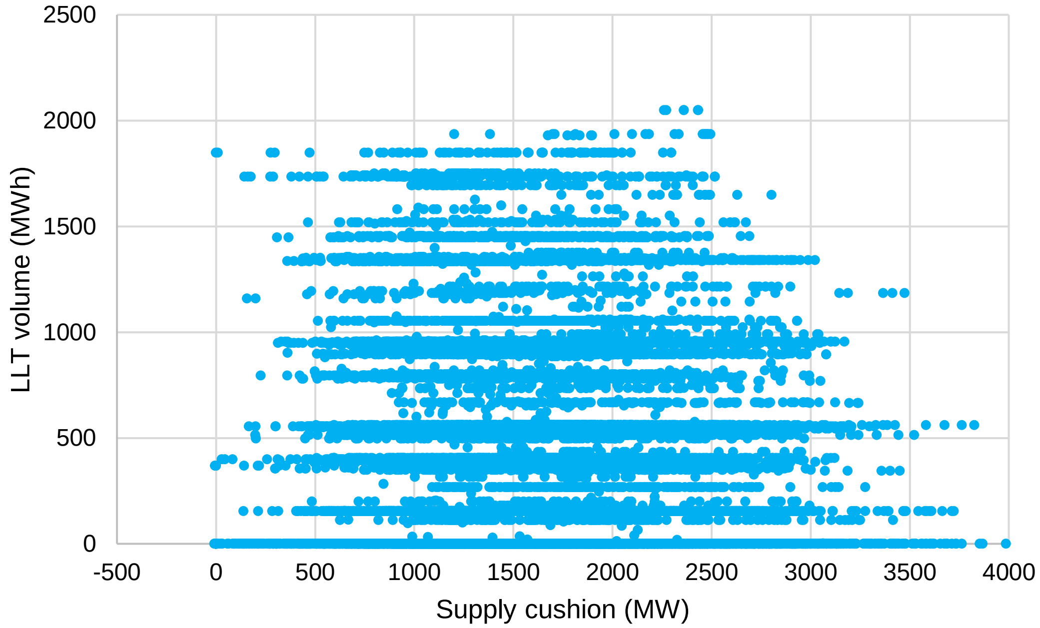


Figure 43: LLT volume vs supply cushion (January 1, 2021 to June 30, 2023)

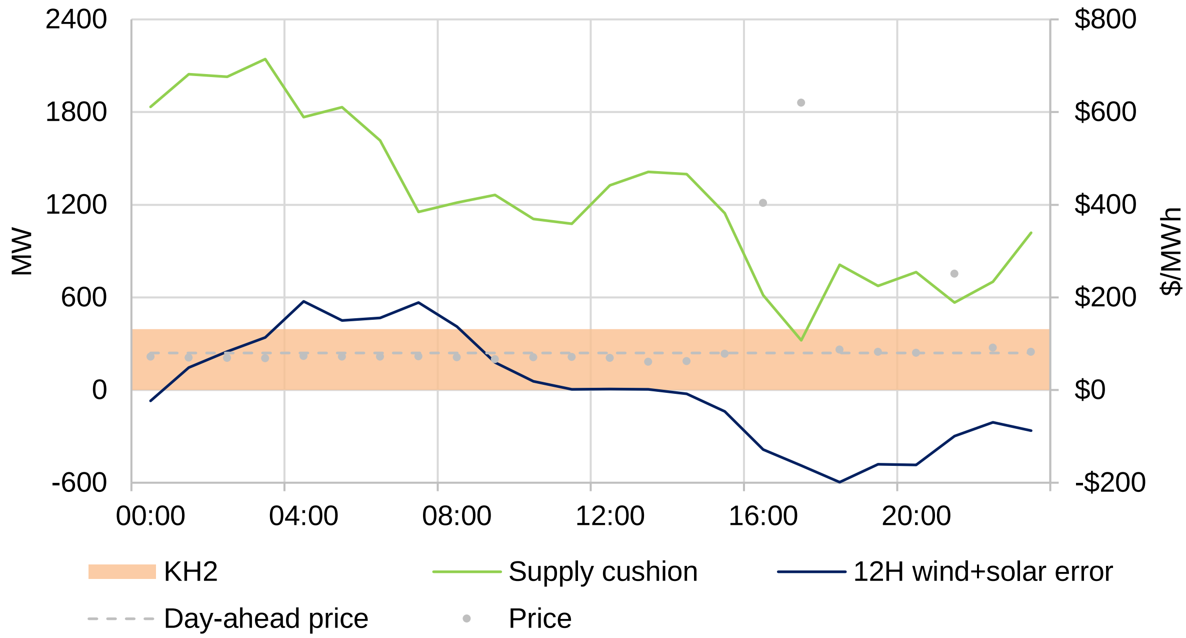


1.5.5 A selection of specific LLT example events

This section analyzes a few instances of assets on LLT identified from the figures in the previous section. Instances were flagged based on several factors, including low supply cushion, high prices, and low STA codes.

There were several high price periods with assets commercially offline during the sample period. However, a significant portion of these events had a relatively high supply cushion, with high prices driven by economic withholding. These examples are focused on periods when LLT assets were a contributor to supply tightness, with high prices often coinciding. Even within this category, there were several examples within the sample period. However, in most events intermittent generation forecast errors were a major factor. The examples here focus on events when the wind and solar forecast errors were not sufficient to explain the observed behaviour. These examples are not exhaustive and were selected to illustrate the patterns of behaviour.

Figure 44 : LLT assets and market indicators (November 13, 2021)



On November 13, 2021, Keephills 2 (395 MW) was commercially offline (Figure 44). In HE 08, the AESO communicated a forecast shortfall for HE 17. The Shepard unit experienced a forced outage in HE 16 and supply cushion dropped to 322 MW in HE 18 while intermittent generation was over-performing the 12-hour forecast by 600 MW. Similar but less severe events occurred through the remainder of November 2021 while Keephills 2 remained offline.

On August 5, 2022, five assets were commercially offline, totalling 1,736 MW: Sheerness 1, Battle River 4, Battle River 5, Keephills 2, and Sundance 6 (Figure 45). In HE 21, the supply cushion reached a low of 144 MW. The day-ahead price was $130/MWh and the daily average pool price was $106/MWh.

From April 18 to 21, Sheerness 1 (400 MW) was offline (Figure 46). The average pool price over this period was $346/MWh, while the day-ahead prices ranged from $150/MWh to $310/MWh. On April 20, in HE 22, supply cushion reached a low of 85 MW after Genesee 1 tripped in HE 20.

On June 26, both Sheerness 1 and Battle River 5 were initially commercially offline, totalling 795 MW (Figure 47). Battle River 5 came online in HE 10. In HE 17, the supply cushion hit a low of 30

MW while the AESO reduced import capacity due to severe weather operation of the BC/MATL interties. The day-ahead price was $200/MWh and the daily average pool price was $504/MWh.

Figure 45: LLT assets and market indicators (August 5, 2022)

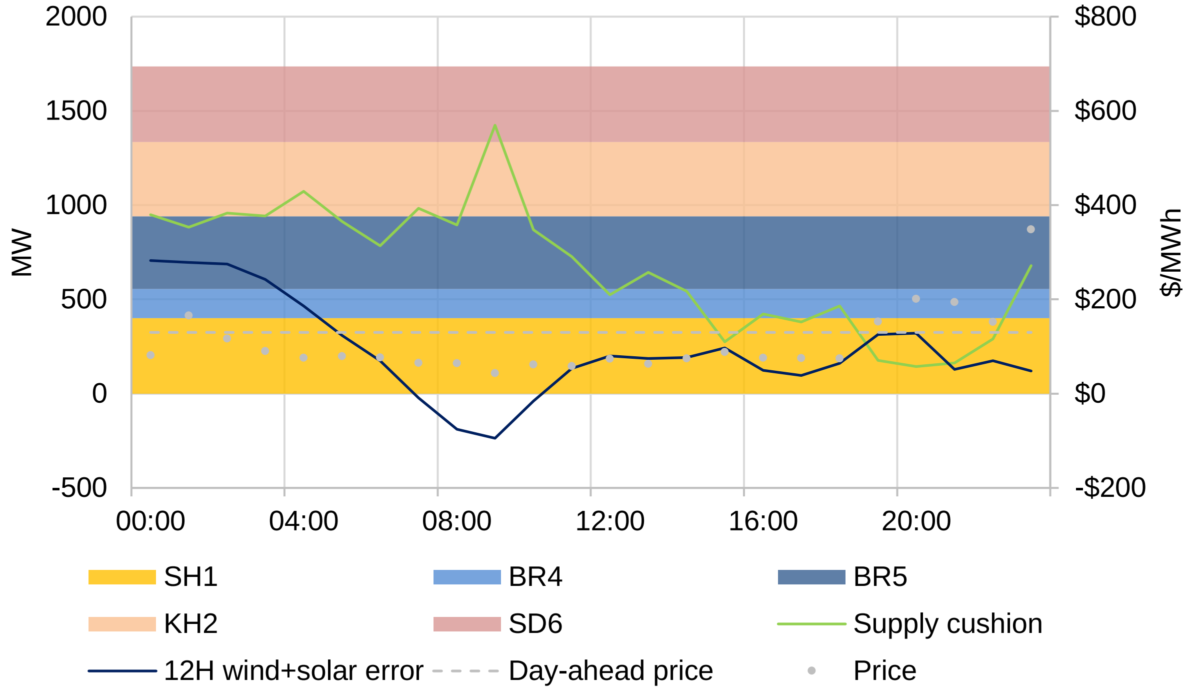


Figure 46: LLT assets and market indicators (April 18 to 21, 2023)

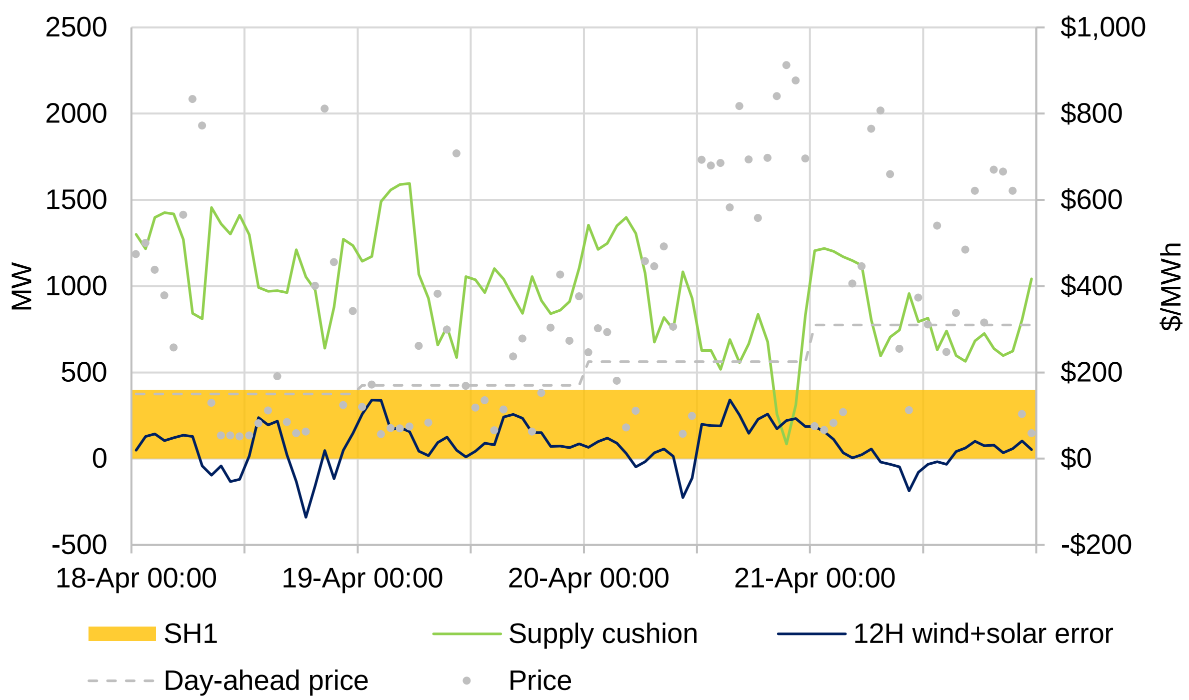
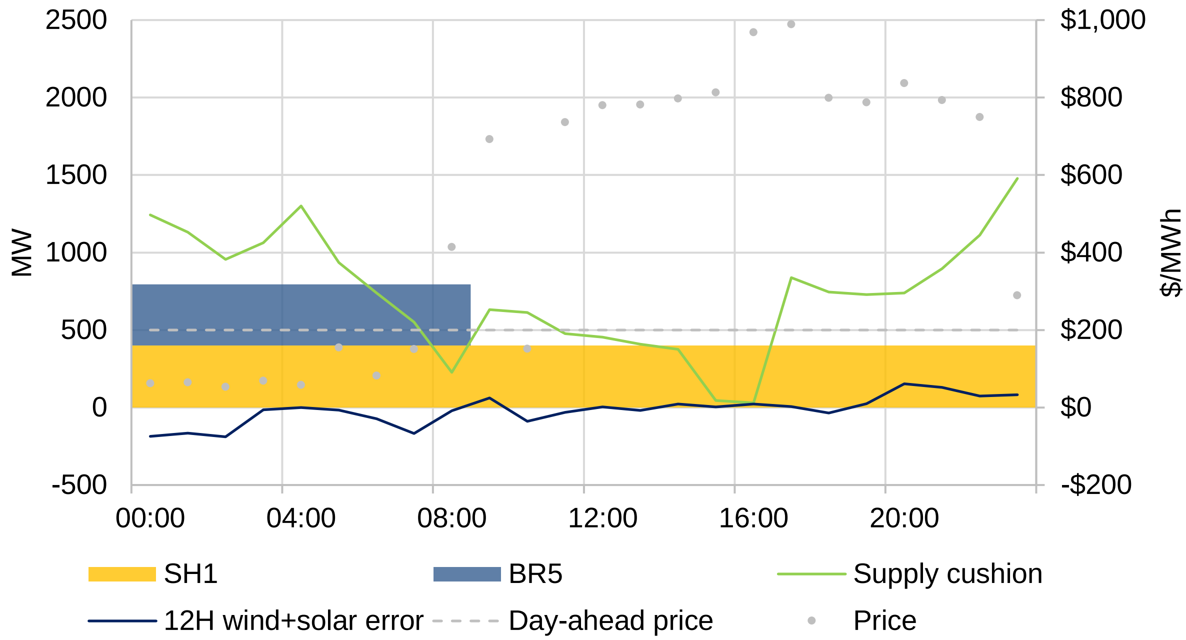


Figure 47: LLT assets and market indicators (June 26, 2023)



1.5.6 LLT and the exercise of market power across sequences of hours

The MSA has traditionally considered economic withholding through offers to be the primary means by which market participants exercise market power. However, market participants can exercise market power in other ways, including taking an LLT asset offline. Unlike economic withholding, where non-minimum stable generation offers are raised to very high offer prices, putting an asset on LLT removes these offers from the market altogether and the minimum stable generation block that would otherwise be offered at $0/MWh with them.

In Alberta's electricity market, where the production capacity of various market participants is well-understood, taking offline an asset that is known to require a substantial number of hours to start can be seen as a credible and public commitment to exercise market power in future hours. This commitment may not be feasible through economic withholding alone.

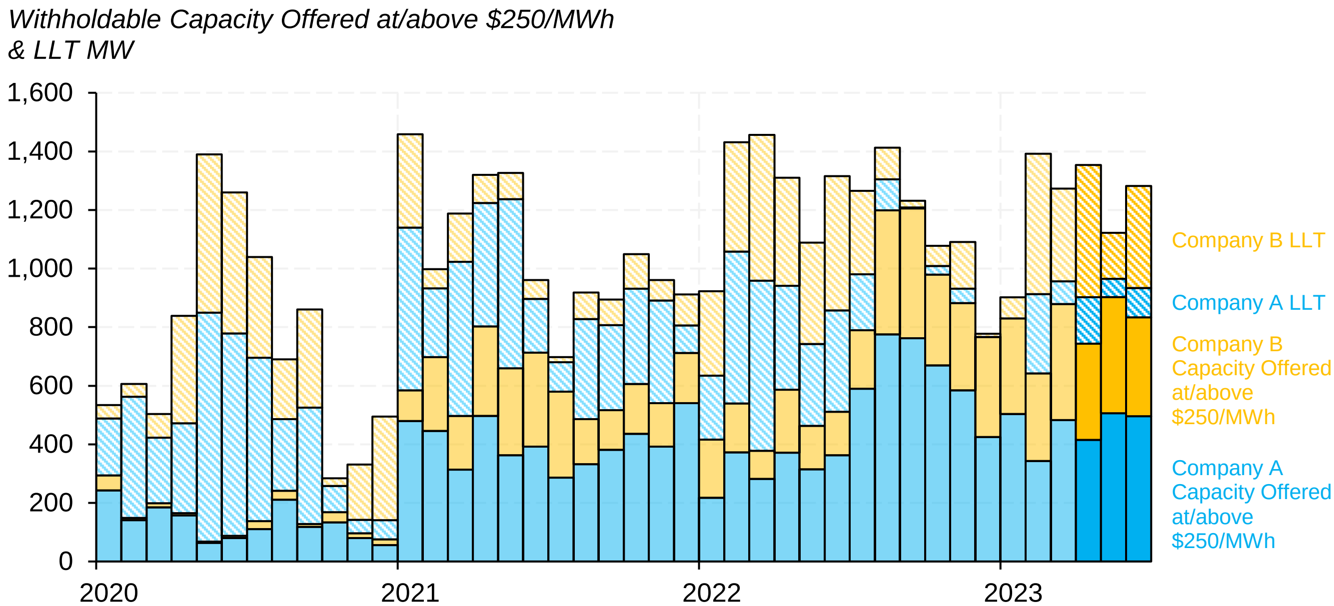
A market participant may also put a unit on LLT if it expects that unit would generate at a loss over a period. This could occur if a unit with minimum stable generation had a short-run marginal cost greater than the expected pool price. Placing such a unit on LLT could enhance efficiency by lowering the overall cost of generation.

An overwhelming majority (99.6%) of the capacity that has been put on LLT (type 1)[21] since 2020 was offered by market participants A and B. Combined, both market participants withheld an

[21] A LLT (type 1) asset refers to a full asset that requires more than one (1) hour to synchronize to the system under normal operating conditions per AESO Information Document # 2012-007R.

average of at least 1,200 MW of capacity using a combination of offers and LLT in most months since February 2022 (Figure 48).

Figure 48: Monthly average market participant A and B withholdable capacity offered at/above $250/MWh and LLT type I MW (January 2020 to June 2023)



The MSA estimated unit and market participant level profitability of LLT events[22] from January 2020 to June 2023 and categorized them as exercise of market power or unit-loss avoidance. The profitability was calculated by comparing market outcomes to a counterfactual scenario where all LLT units were offered into the merit order with all non-minimum stable generation at the price cap. Demand, imports, and export levels were not fixed and instead were allowed to vary according to their respective estimation functions. LLT counterfactuals were constructed under the same assumptions used for the MSA's short-run marginal cost counterfactual.[23]

The MSA's estimates suggest LLT events in 2020 generally resulted in losses being avoided rather than (solely) an increase in market participant profitability (Figure 49). This is consistent with periods of relatively low pool prices in that year. However, since 2021 the MSA's modelling indicates that the majority of LLT events have not been unit-loss avoiding and have instead resulted in higher profits for the market participants placing units on LLT. This is consistent with market participants putting assets on LLT to exercise market power.

In some instances, the MSA's modelling suggests the placement of units on LLT led to reduced market participant profits, particularly in 2021 and early 2022. This could reflect periods where

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[22] A LLT "event" refers to a continuous period of time that a unit is on LLT type 1.

[23] The assumptions used in the MSA's short-run marginal cost counterfactual are discussed in Appendix A of the Quarterly Report for Q2 2022.

market participants may have over-forecast the amount of surplus generation in the market and placed units on LLT to avoid expected unit losses or to attempt to exercise market power. LLT events that led to estimated declines in market participant profits were 55% as long in duration as the other two categories of LLT events (Table 7).

Figure 49: Monthly average capacity on LLT type I by category (January 2020 to June 2023)[24]

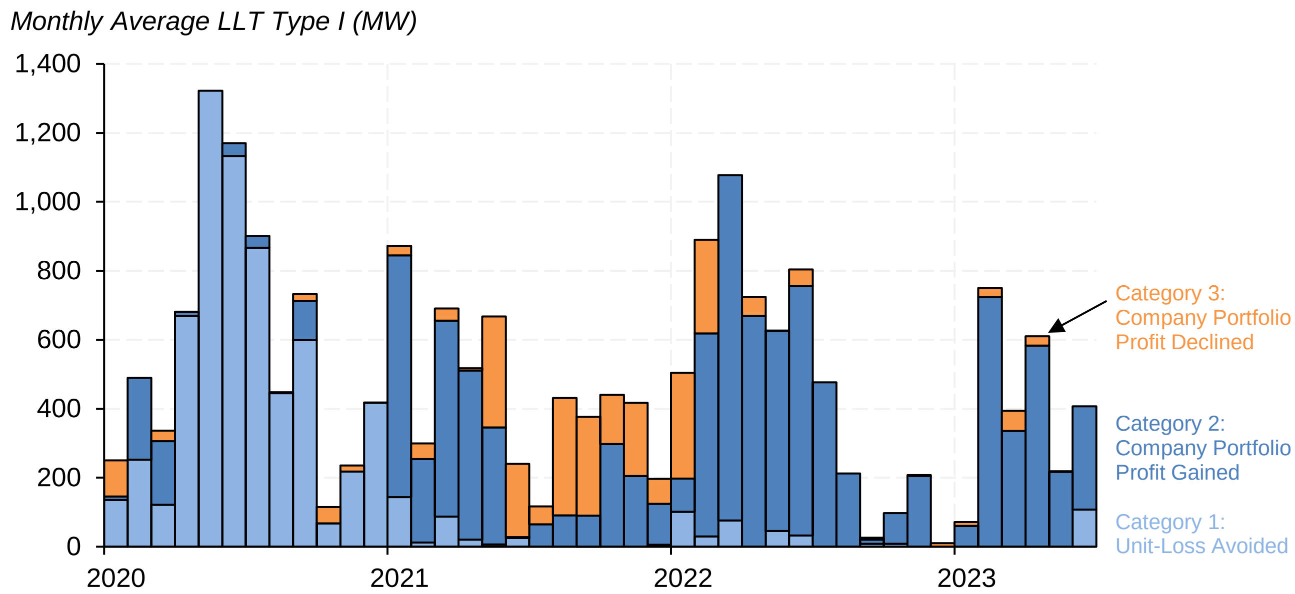


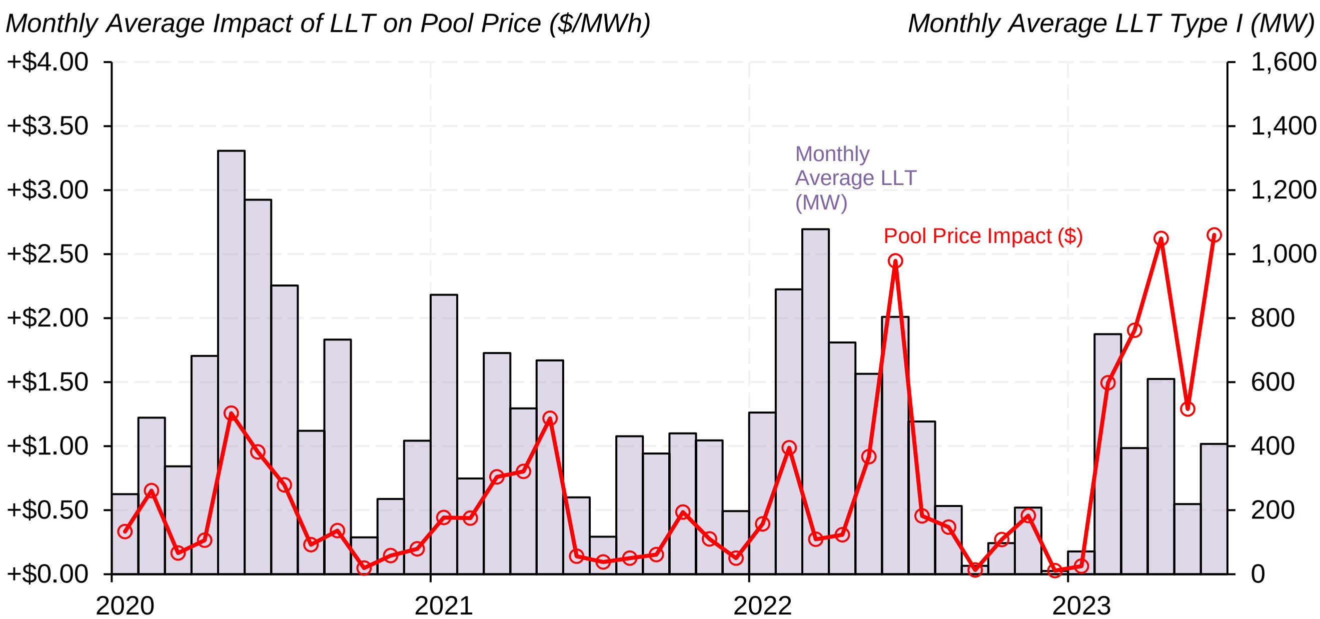
Table 6: Summary of LLT type I modelling results by category

LLT event category	Number of events	Average event length (days)	Estimated average hourly unit loss (profit) avoided using LLT	Estimated average hourly market participant profit (loss) from LLT
Category 1: Unit-loss avoided	117	6.07	$396.30	$2,327.76
Category 2: Company portfolio profit gained	178	6.06	($2,498.24)	$3,488.90
Category 3: Company portfolio profit declined	83	3.34	($2,206.46)	($2,875.97)
Total (average)	378	5.46	($1,463.78)	$2,236.46

Although the LLT rule has led to an increase in market power, it has not substantially increased average monthly pool prices (Figure 50), with the greatest monthly impacts since 2020 occurring in June 2022 (+$2.45/MWh), April 2023 (+$2.62/MWh), and June 2023 (+$2.65/MWh).

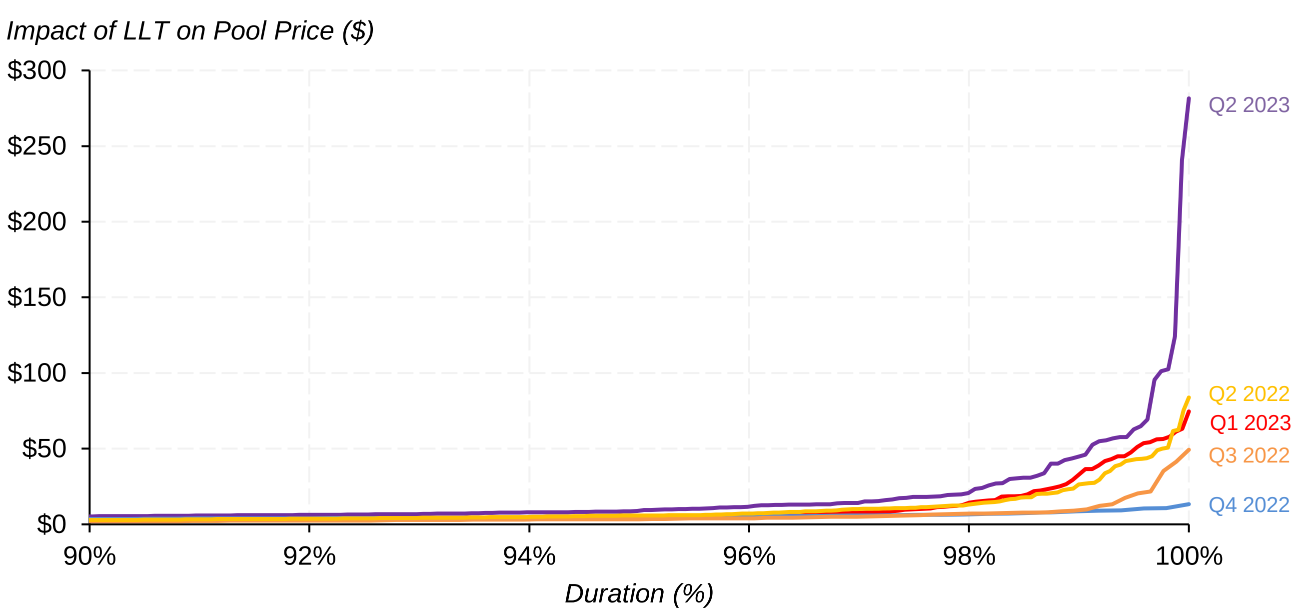
[24] In all instances where a LLT event could be characterized as belonging to both Category 1 (unit-loss avoided) and Category 2 (company portfolio profit gained), the event is labelled as Category 1.

Figure 50: Monthly average pool price impact from LLT type I (January 2020 to June 2023)



In at least 90% of hours where units have been on LLT between Q2 2022 and Q2 2023, the average impact of LLT capacity on pool price has been less than $6/MWh (Figure 51). However, in a few hours the placement of assets on LLT can have a significant effect on pool price. For example, in Q2 2023 units on LLT caused the pool price to be at least $50/MWh higher than it would have been if that capacity had been economically withheld in the merit order in 1% of such hours (15 hours).

Figure 51: Duration curve of hourly LLT pool price impact in hours where units are on LLT (Q2 2022 to Q2 2023)



2. THE POWER SYSTEM

2.1 Transmission congestion and pool price formation

The frequency of transmission constraints binding has increased with the increase of wind and solar generation capacity at locations away from the core of the existing transmission system. In this section, the MSA examines transmission constraints with a focus on:

- the increase in the frequency and size of wind and solar constrained down generation volumes,
- the geographic concentration of transmission constraints, and
- the relationships between hours with higher constraints and lower pool prices.

Transmission constraints can cause generation capacity to be constrained off. Transmission constraints can be either inflow constraints or outflow constraints. An outflow constraint occurs when there is insufficient transmission capability 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. To meet demand, the AESO dispatches the amount of capacity that is needed at that point in time, accounting for the fact that some generation is constrained.

At all times, the SMP and pool price are set as if there is no congestion (i.e., no constrained down generation). Specifically, the AESO calculates the transmission constraint rebalancing (TCR) volume in that minute and reads down the merit order by that amount to calculate the SMP.

The transmission constraint rebalancing volume is calculated based on:[25]

- the volume of in-merit energy that was constrained down;
- for the first hour of a constraint event, the volume of imports constrained down as a result of the intra-Alberta constraint event; and
- the amount of transmission must-run energy dispatched when SMP is less than or equal to the reference price.

The volume of in-merit energy that is constrained down is calculated differently for wind and solar assets than thermal and hydro assets because output from wind and solar assets is intermittent and varies with weather conditions. The volume of constrained wind and solar energy is based on a counterfactual volume of generation that would have been delivered to the grid had there been no constraint. Calculating this requires a measure of the potential generation for each asset based on prevailing conditions at that site during the constraint. Wind and solar assets are

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

required to have meteorological equipment on site that can be used to calculate their potential real power capability, an estimate of how much power the site could provide.[26]

Wind and solar assets generally offer their capacity at $0/MWh and, under normal conditions, are dispatched for their full available capability.[27] The actual generation from wind and solar assets varies with the weather. Because of this, the energy dispatch for wind and solar assets is almost always above their actual generation. However, an asset's potential real power capability, based on meteorological conditions on-site, is generally an accurate predictor of an asset's generation when it is not constrained.

When a wind or solar asset receives a transmission constraint directive, its energy dispatch level is reduced, and set equal to the curtailment limit determined by the AESO. This curtailment limit is set for applicable assets in the area based on a pro-rata methodology.[28] The volume of energy curtailed is calculated based on the difference between the asset's potential real power capability and the curtailment limit applied to the asset. The MSA estimates constrained down volumes for wind and solar assets as set out in the following graphic.[29]

Estimation of constrained down volume for wind and solar assets

If $\text{Curtailment\_limit}_t < \text{Potential\_MW}_t$ **AND** $\text{Energy\_Dispatch}_t < \text{AC}_t$**:**

$\text{T\_constraint\_volume}_t = \mathbf{MAX(}0,\ \mathbf{MIN(}\text{AC}_t, \text{Potential\_MW}_t\mathbf{)} - \text{Energy\_Dispatch}_t\mathbf{)}$

else:

$\text{T\_constraint\_volume}_t = 0$

Where subscript t denotes time, at a minute-level

As an example, Figure 52 shows the wind generation from Blackspring Ridge (300 MW) on May 4 and 5. The asset's generation closely matched its potential capability in HE 10 to HE 12 of May 4; the asset was fully dispatched and was not constrained.

From 12:25 until 01:14 the next day, the asset received a transmission constraint directive that reduced its energy dispatch down to the curtailment limit, which was binding. Over that period,

[26] ISO rule 304.9, *Wind and Solar Aggregated Generating Facility Forecasting*

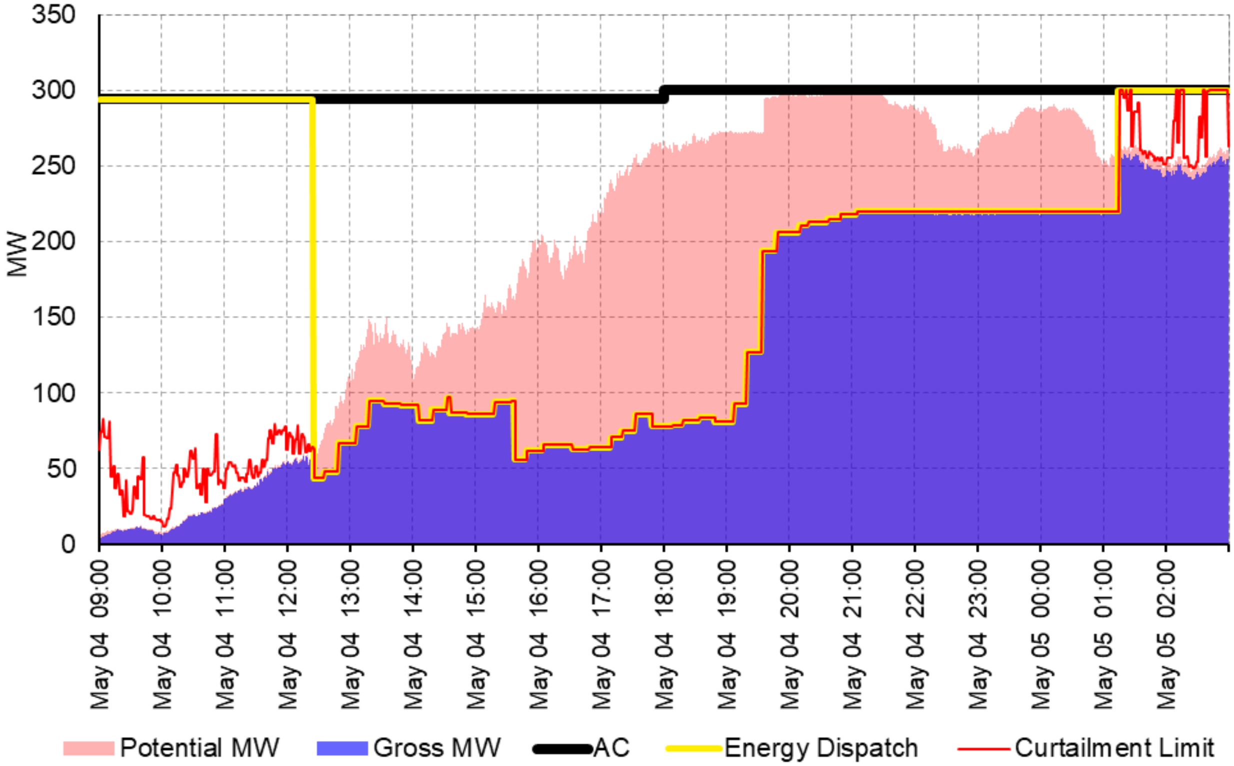
[27] Wind and solar generators are not required to offer at $0/MWh, but generally do so to ensure they are dispatched on as wind or sunlight become available.

[28] ISO rule 302.1, *Real Time Transmission Constraint Management*

[29] The *If* condition requires energy dispatch to be less than AC. MSA staff's current understanding is that transmission constraint directives to wind and solar assets manifest as energy dispatch instructions to a level of output below AC, while ramping constraints manifest as the curtailment limit declining below potential capability, while the asset remains fully dispatched.

the volume of constrained down generation is the difference between the asset's potential capability and its curtailment limit.

Figure 52: Constrained down generation for BSR1 Blackspring Ridge



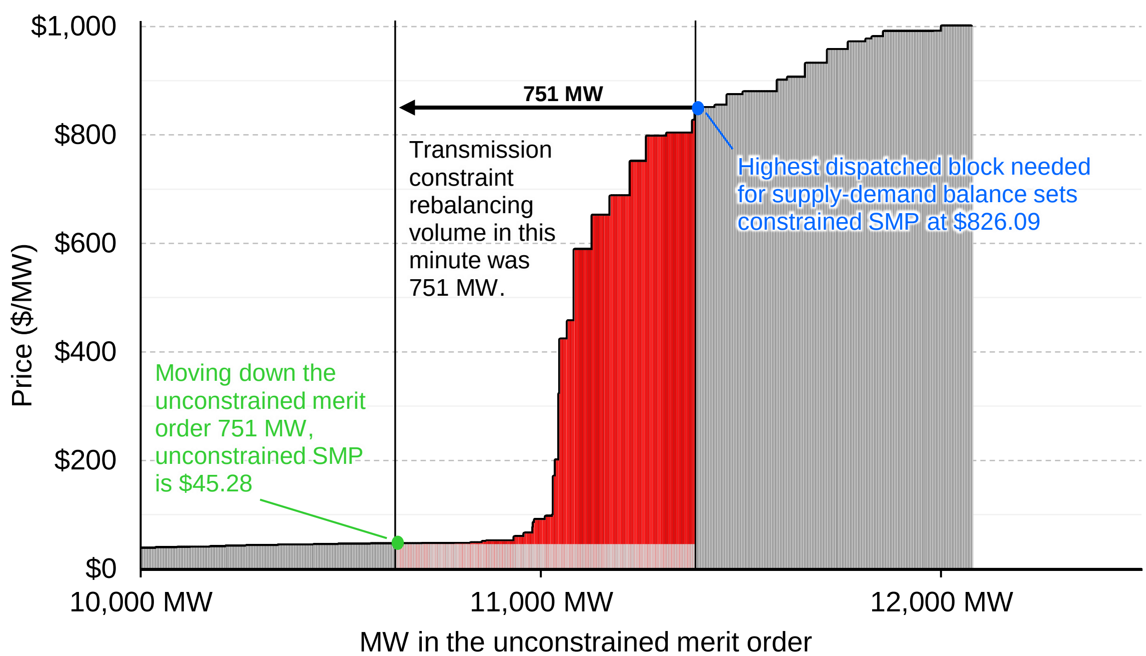
A snapshot of the merit order at 18:05:30 shows an $826.09/MWh offer price for the highest dispatched block. This block set the constrained SMP (Figure 53). In this minute, 13 assets were constrained down totalling 751 MW; 24 MW of this constrained volume was at a thermal asset and the remaining 727 MW (97%) was at wind or solar assets (Table 7).

Moving down the merit order by 751 MW yields the block that set actual SMP as if there had there been no constraints at $45.28/MWh (Figure 53). This unconstrained SMP is used to determine pool price.

Table 7: Constrained down volume at May 4, 2023, 18:05:30

Asset ID	Fuel Type	MC	Constrained down volume (MW*minute)
TVS1	Solar	465	323
BSR1	Wind	300	185
WHE1	Wind	120	77
SCR4	Wind	88	64
NEP1	Wind	82	43
EC01	Combined Cycle	120	24
STR2	Solar	23	10
STR1	Solar	18	9
NMK1	Solar	20	7
BUR1	Solar	20	4
CRD1	Solar	23	2
RTL1	Wind	130	2
TAB1	Wind	81	1
			Total: 751

Figure 53: Unconstrained energy market merit order snapshot at 2023-05-04 18:05:30



Generators dispatched above the unconstrained SMP are paid a TCR payment in addition to pool price for energy they delivered. These generators are paid TCR payments according to their respective offer prices on these blocks. An illustrative approximation of TCR payments is shown as the red shaded area in Figure 53.

2.2 Wind and solar constrained down generation

The frequency and significance of wind and solar constrained down generation directives increased from Q2 2022 to Q2 2023. The AESO reported 25 GWh of total TCR volume in Q2 2022, and 44 GWh in Q2 2023. The MSA estimates that wind and solar constrained down volumes were 23 GWh in Q2 2022 and 42 GWh in Q2 2023.

The maximum hourly average volume of wind and solar generation constrained was 725 MWh in Q2 2023, triple the maximum of 187 MWh in Q2 2022 (Figure 54 and Figure 55). Transmission constraints were more variable in Q2 2023, in some instances rapidly changing from zero, or almost no constraints, to over 400 MW. Examples of this occurred on May 4 and 5, and June 6, 2023. The percent of hours where at least 1 MWh of wind or solar was transmission constrained increased from 32% in Q2 2022, up to 39% in Q2 2023.

Figure 54: Hourly transmission constrained wind and solar generation (Q2 2022)

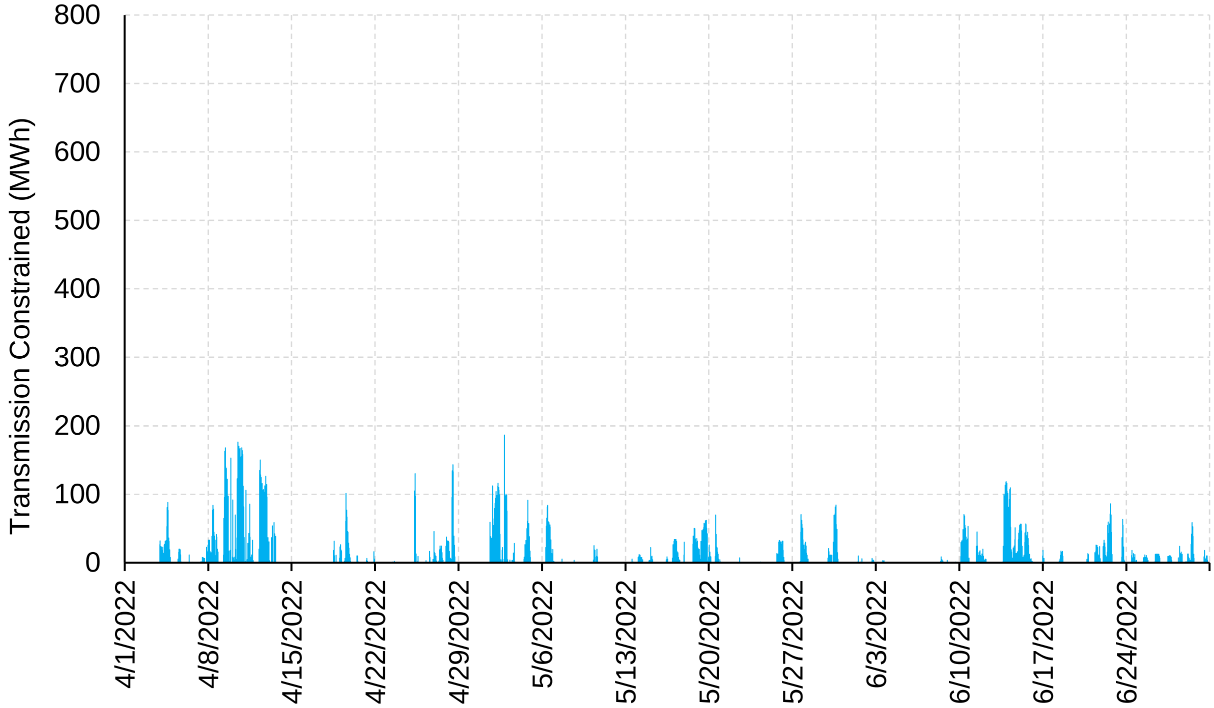
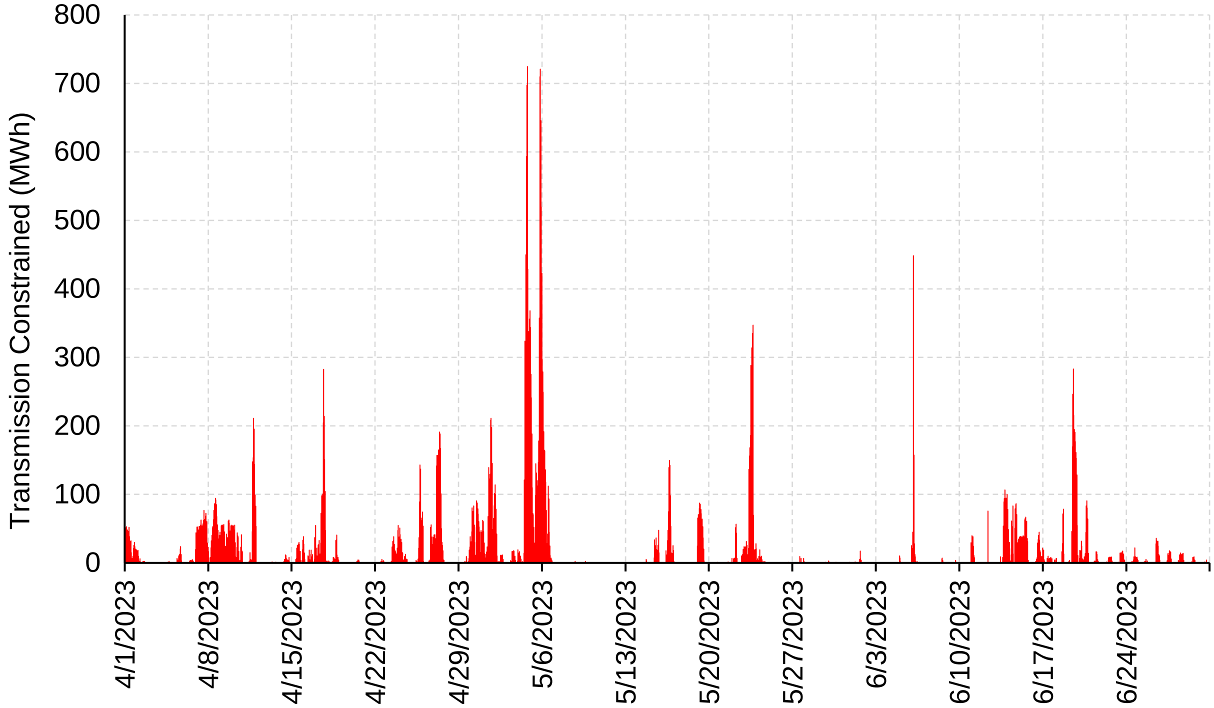
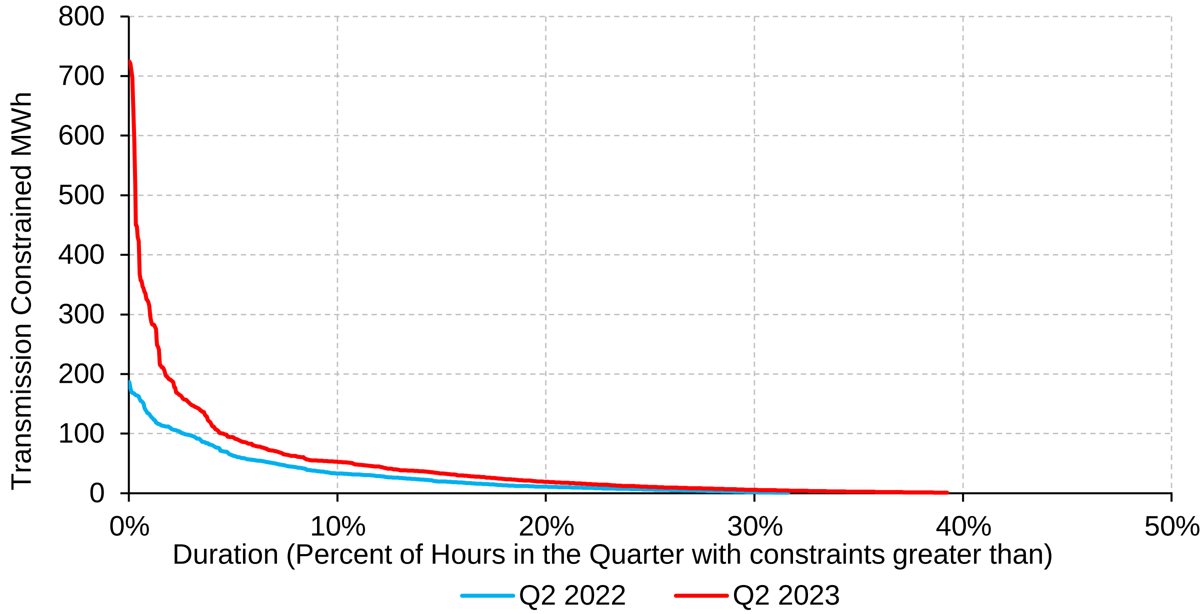


Figure 55: Hourly transmission constrained wind and solar generation (Q2 2023)



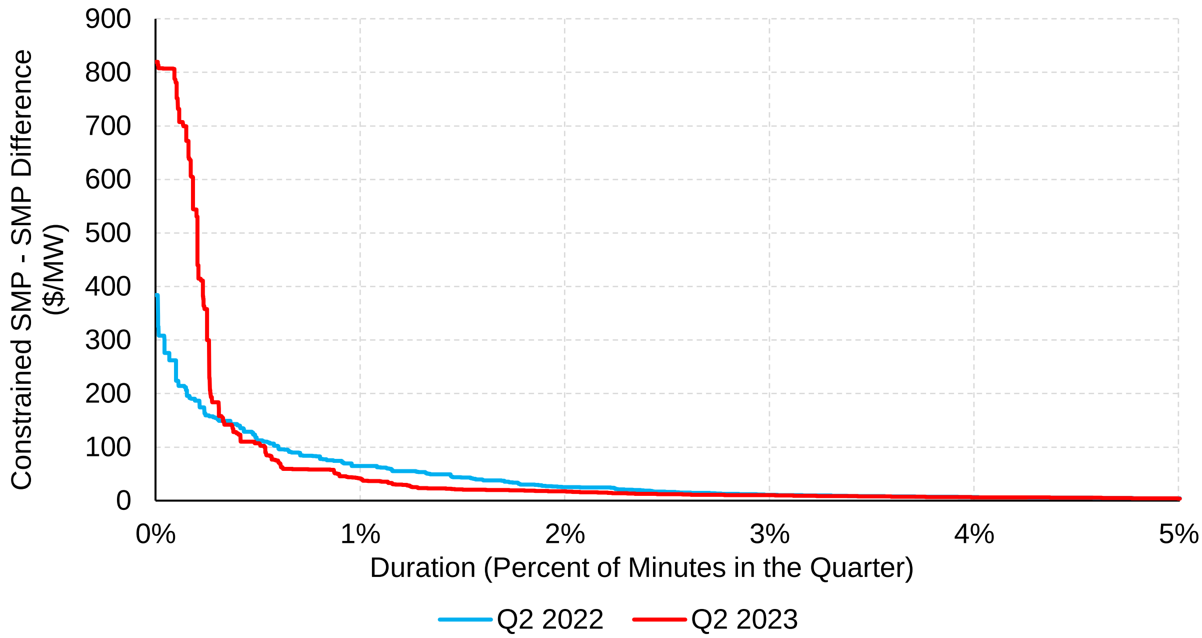
Increased wind and solar constraints resulted in almost twice the constrained volume year-over-year (Figure 56). The divergence of the duration curves to the left shows that the increase in constrained volume was driven more by larger, infrequent events, while the frequency of mid-sized events only increased modestly. Although the top 1% most constrained hour had twice the constrained volume in 2023, the top 25% most constrained hour had only 4 MWh more constraints in 2023.

Figure 56: Duration of wind and solar constraint volume (Q2 2022 and Q2 2023)



When the transmission constraint rebalancing volume is sufficiently large, the unconstrained SMP, which is used to determine pool price, can be less than constrained SMP, which is set by the offer price of the highest dispatched block. Constrained and unconstrained SMPs differed by $1/MW or more in 8% of minutes in Q2 2022, increasing to 10% of minutes in Q2 2023. Over that period, the maximum minutely differences between SMPs doubled from $384/MW to $820/MW, reflecting larger constraints (Figure 57).

Figure 57: Duration of constrained and unconstrained SMP difference (Q2 2022 and Q2 2023)



The hourly distribution of wind and solar constraints varied across more hours of the day in Q2 2023, becoming more concentrated during the evening demand peak. The maximum volume of constraints by hour (Figure 58) and the median volume of constraints by hour (Figure 59) were both greatest during the evening peak in Q2 2023, while this shape was less pronounced in Q2 2022. These hours coincided with periods of daily peak demand.

In Q2 2022, constraints were more evenly spread across hours of the day, suggesting that constraints more often resulted from stochastic system conditions. The occurrence of large and more frequent evening constraints in 2023 indicates a pattern of insufficient transmission during the daily peak demand. Put another way, insufficient transmission capacity is more likely to bind during hours of high system load.

Figure 58 : Hourly maximum wind and solar constraints (Q2 2022 and Q2 2023)

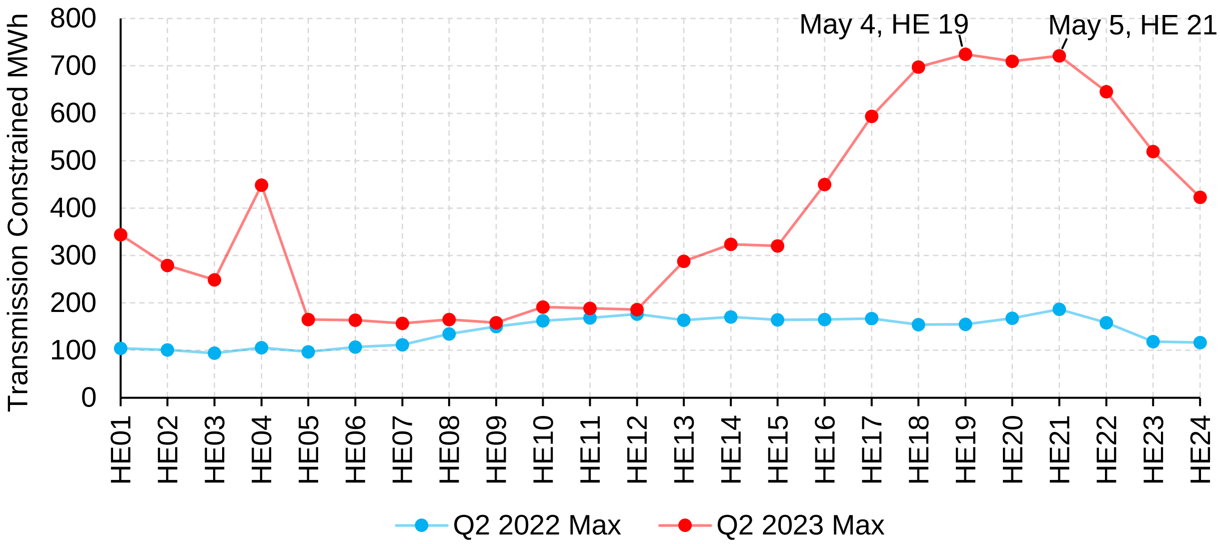
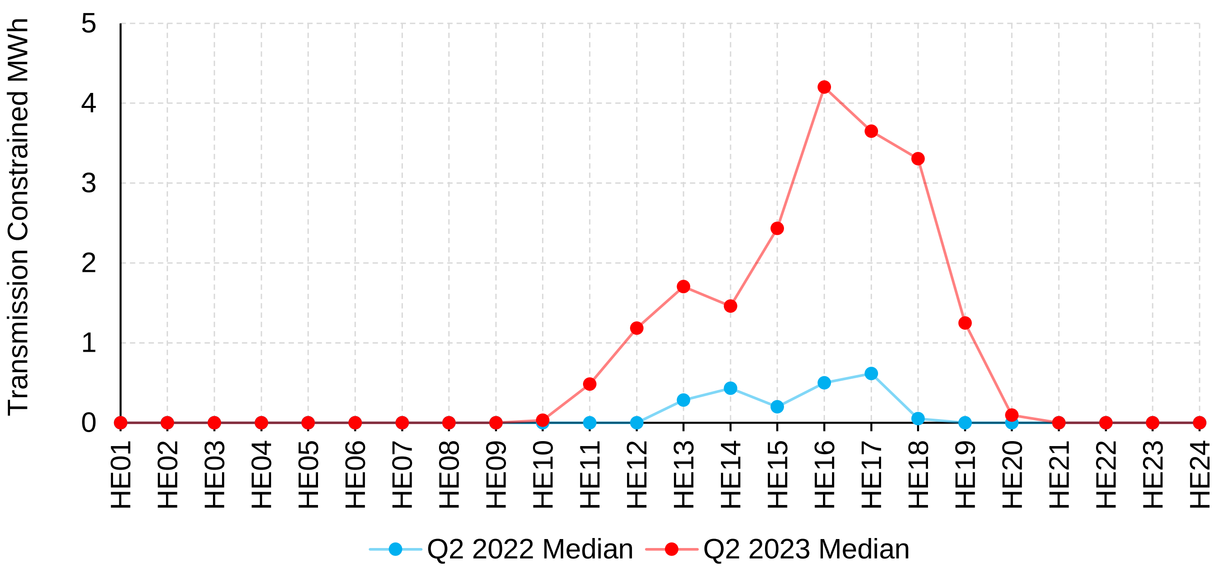


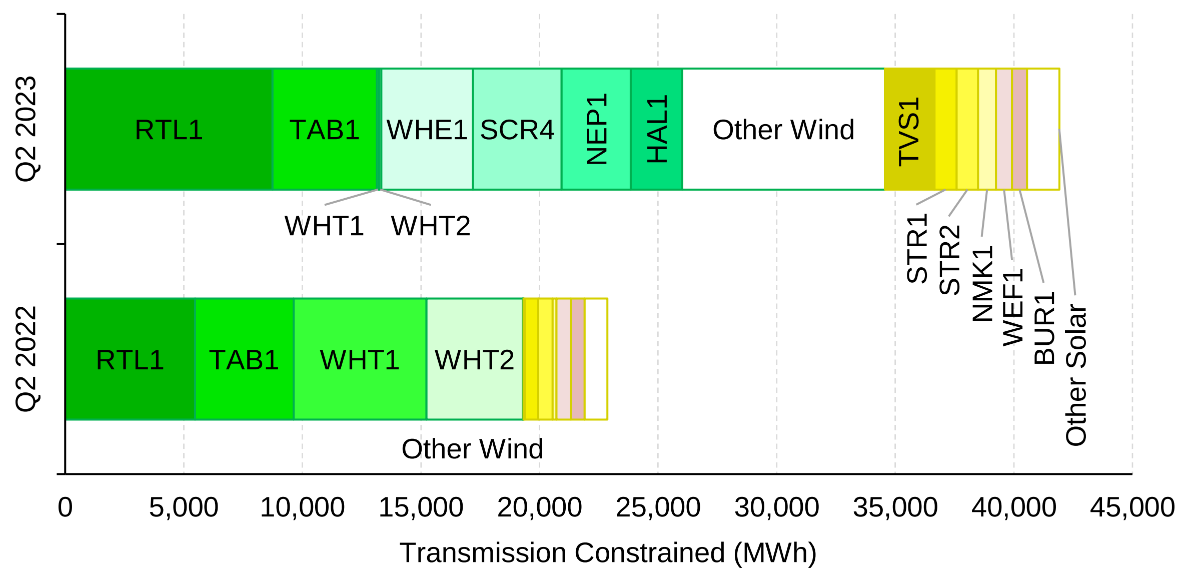
Figure 59: Hourly median wind and solar constraints (Q2 2022 and Q2 2023)



Wind and solar assets are not constrained uniformly throughout the province; rather, assets located in transmission constrained areas face the greatest constraints. In Q2 2022 transmission constraints at four wind assets accounted for almost all wind transmission constrained volume. In Q2 2023, the overall volume of constraints increased and a greater number of assets were impacted (Figure 60).

The two most-constrained wind assets, Rattlesnake Ridge and Taber, are approximately 6% of Alberta's installed wind capacity but were constrained for approximately 38% of the wind constrained volume in Q2 2023.

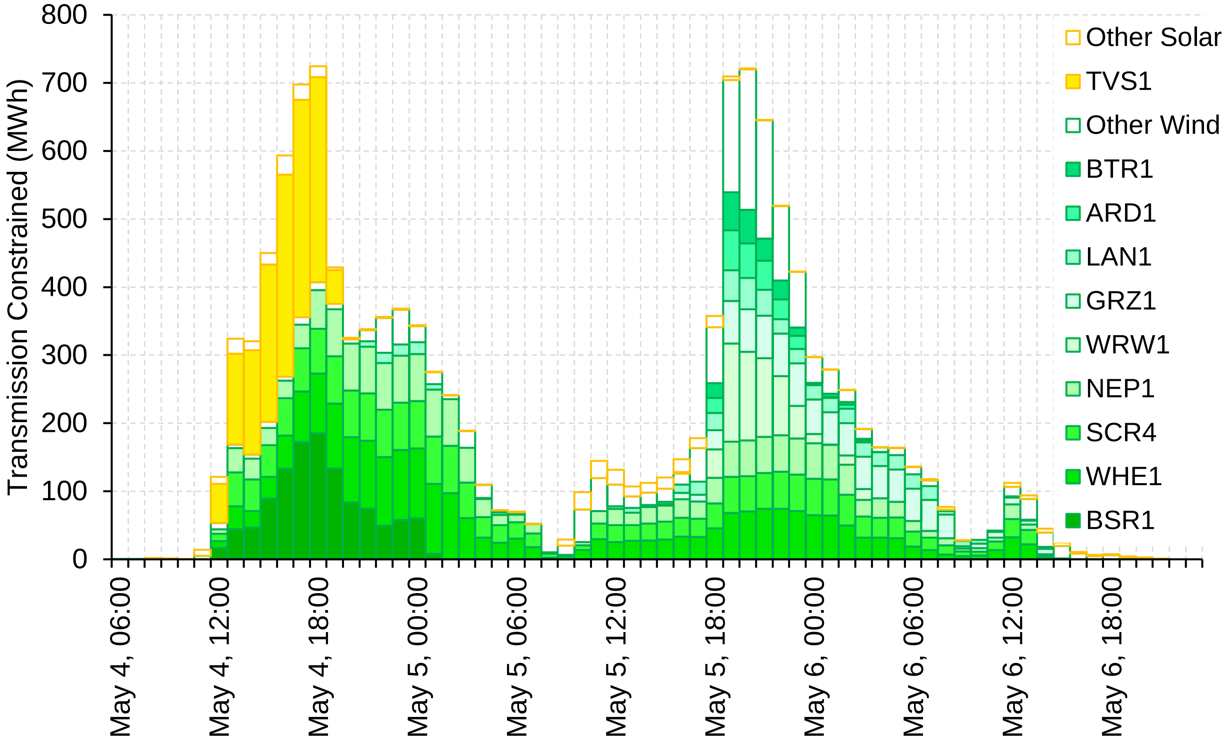
Figure 60: Wind and solar transmission constrained MWh by asset (Q2 2022 and Q2 2023)



Travers, with a maximum capability of 465 MW, was the most-constrained solar asset in Q2 2023. The second, third, and fourth most constrained solar assets have an aggregate maximum capability of 61 MW. These three assets are all located near Strathmore, and, in aggregate, were constrained down more than Travers. This illustrates the uneven concentration of constraints. The most heavily constrained wind and solar assets are concentrated near Whitla, Taber, Drumheller, Strathmore, and Vulcan.

The impact of these constraints was concentrated across a small number of wind and solar assets (Figure 61). System conditions on these days were impacted by rapid wind and solar ramping, wildfires, and WATL tripping out of service on May 4. Additionally, the AESO's Dispatch Tool failed from HE 12 to HE 13 on May 4, resulting in Limited Market Operations. Although Limited Market Operations ended before the greatest volume of wind and solar constraints that day, the event likely added to the complexity of the system conditions.

Figure 61: Wind and solar transmission constrained MW (May 4, 2023 to May 6, 2023)



Wind and solar constraints occur most often when wind and solar generation is high. This is often when pool price is relatively low. Although pool price in Q2 2023 was 30% higher than in Q2 2022, the median pool price when least 1 MWh of wind or solar was constrained fell by about half from $89/MWh in Q2 2022 to $47/MWh in Q2 2023.

Figure 62 and Figure 63 illustrate a $42/MWh decrease in median Q2 pool price, from 2022 to 2023, for hours with at least 1 MWh of transmission constraint. The growth in wind and solar generation drove greater transmission congestion, which increases constraints, and lower pool prices during windy and sunny hours. Therefore, the market cost of congestion for these hours is often low because the power market is well supplied. As an example, on June 6, 2023, HE 04, about 750 MWh were constrained down, of which 450 MWh were wind and solar. Over this hour SMP and constrained SMP were $0/MWh. As a result, the AESO did not report any TCR costs associated with this hour.

Figure 62: Wind and solar constrained volume vs. pool price (Q2 2022 and Q2 2023)

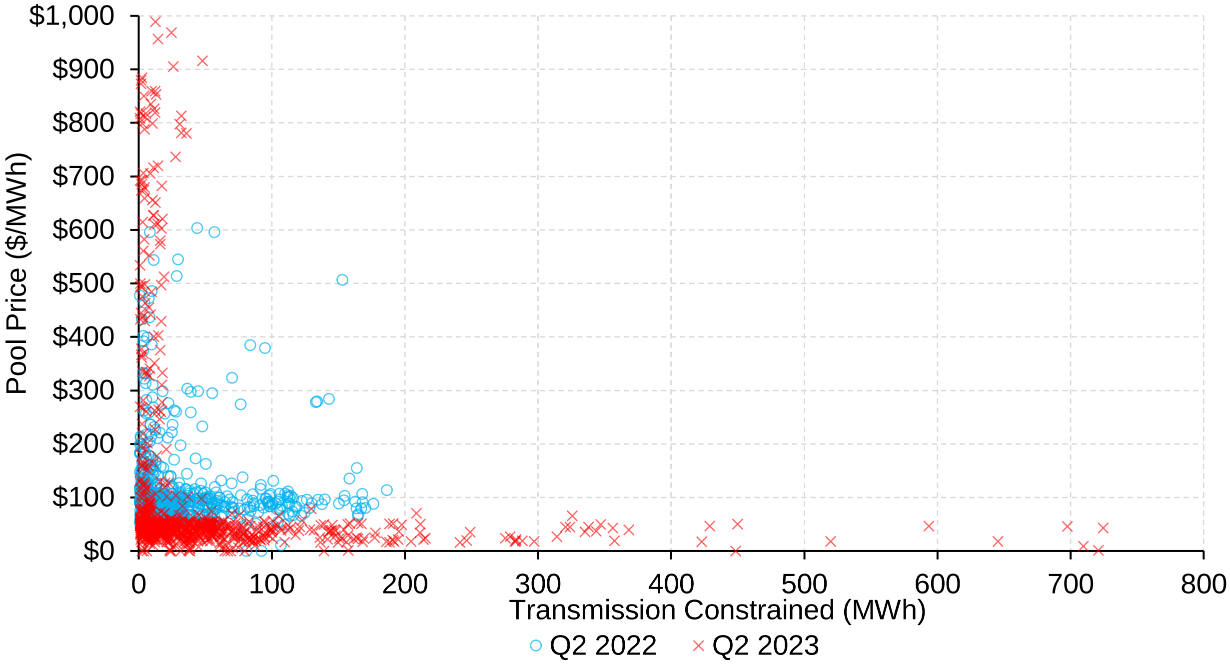
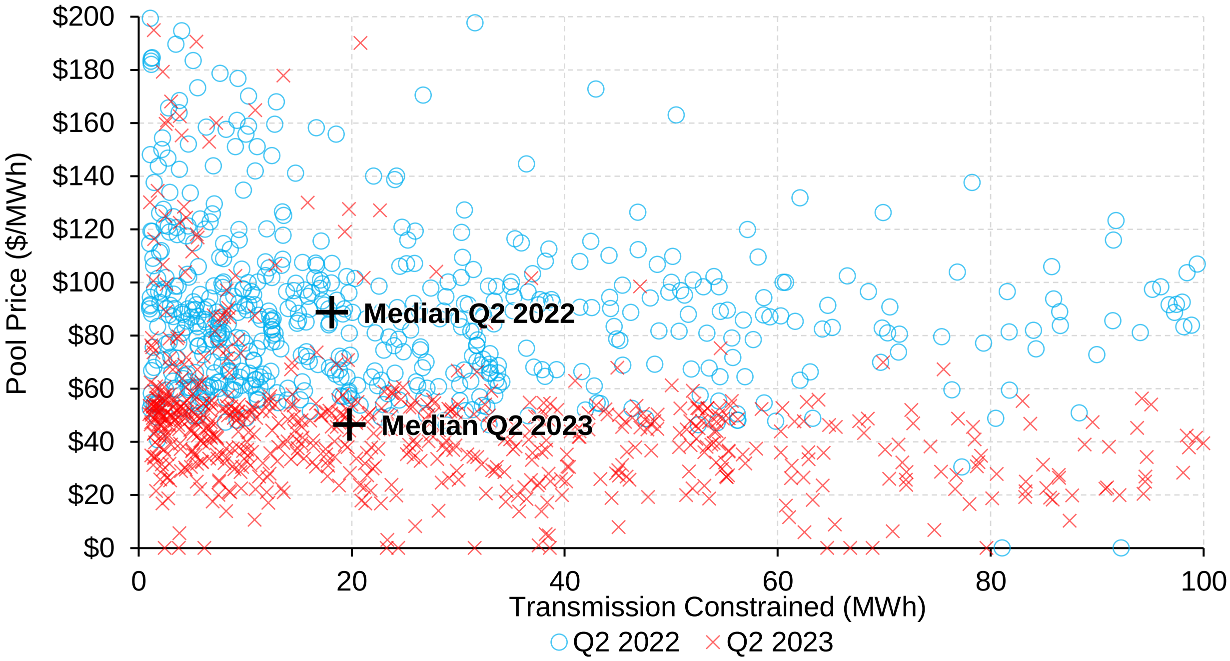


Figure 63: Wind and solar constrained volume vs. pool price, between 0 MW – 100 MW and $0 - $200, (Q2 2022 and Q2 2023)

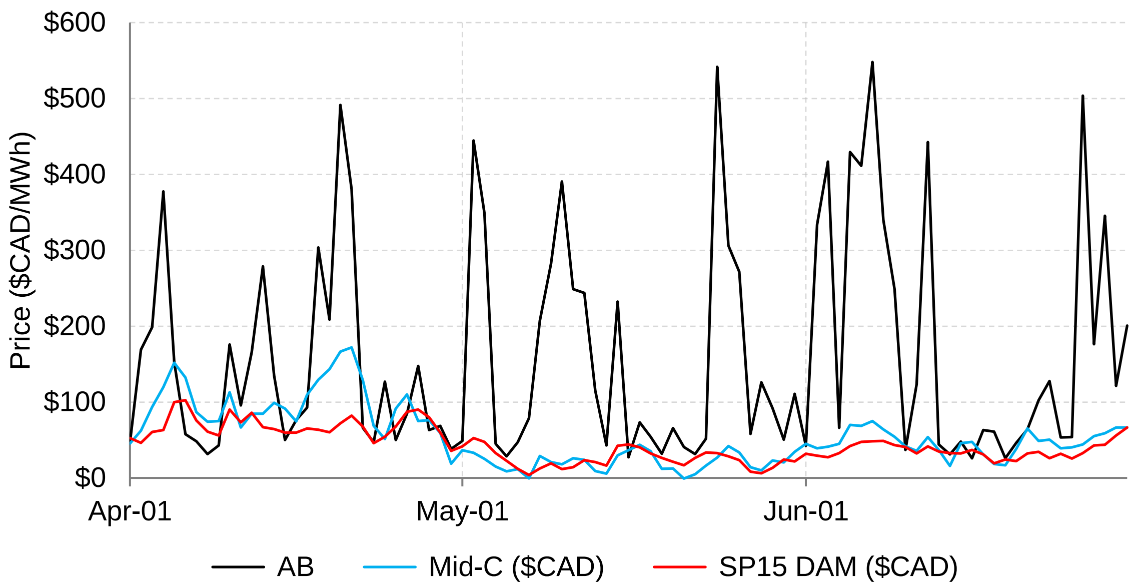


2.3 Imports and exports

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. For reliability purposes, the AESO treats BC and MATL as one intertie (BC/MATL) because any trip on the BC intertie causes MATL to trip offline. These interties indirectly link Alberta's electricity market to markets in Mid-C and California.

Figure 64 illustrates Q2 daily average power prices in Alberta, Mid-C, and California.[30] As shown, prices in Alberta were generally higher and more volatile than prices observed in California and Mid-C. The monthly average price differential between Alberta and Mid-C was the lowest in April at $47/MWh. Low water supply in the US Northwest in April contributed to periods of elevated Mid-C prices in that month. In early May, hydro supply in the US Northwest increased, lowering Mid-C prices.

Figure 64: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q2 2023)



Price differentials between Alberta and other markets drive intertie flows. Figure 65 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 joint capability on BC/MATL.

As shown, export flows were elevated for periods of April due to periods when prices were higher in Mid-C than Alberta. In May and June more import volumes occurred due to higher pool prices in Alberta and increased hydro supplies in Mid-C. In May, import flows often used all available import capacity, and the BC/MATL lines were often import constrained. Import volumes on BC/MATL used 93% of the available import capacity in May.

[30] Mid-C and California prices have been converted from USD to CAD using the Bank of Canada's daily exchange rate.

Figure 65: Daily average import (+ve) and export (-ve) volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q2 2023)

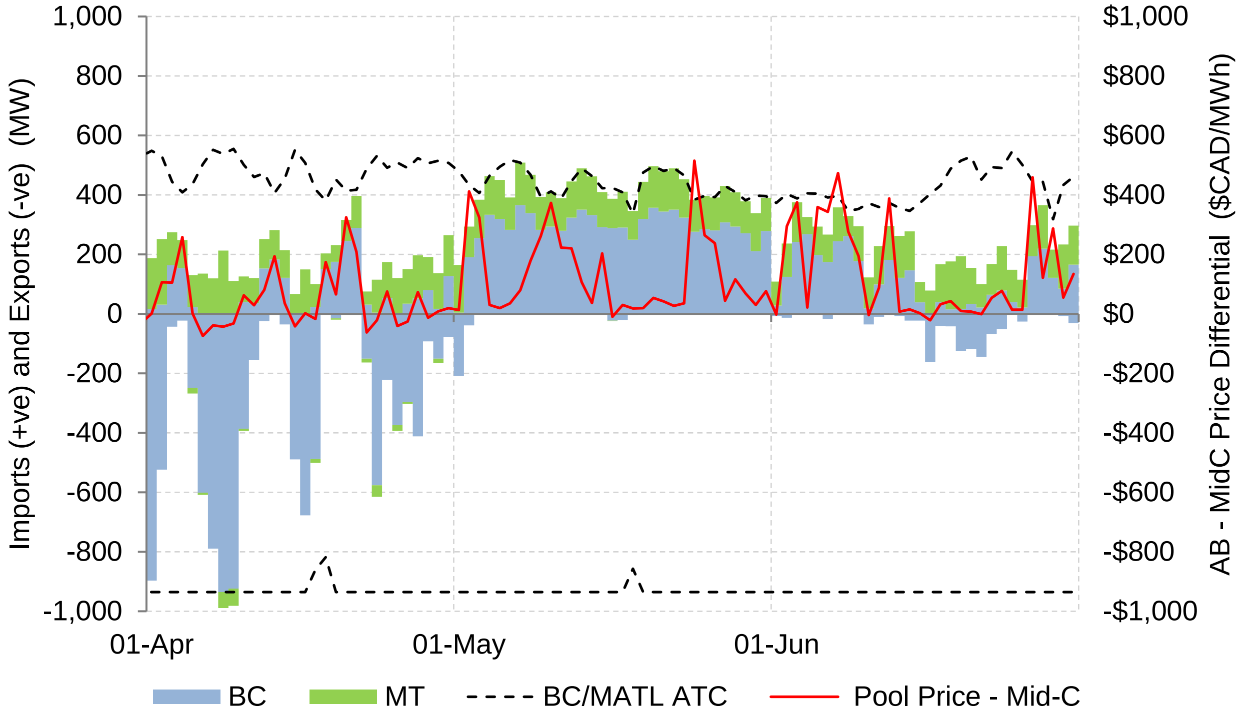


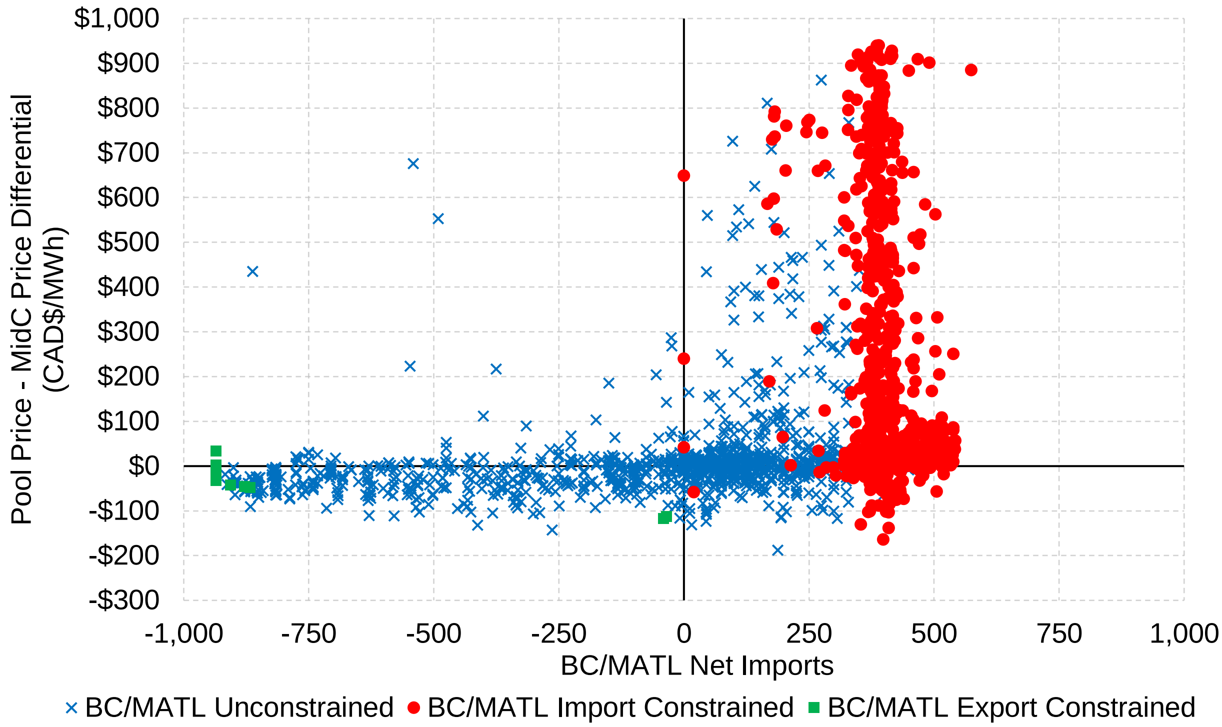
Figure 66 is a scatterplot of the price differential between Alberta and Mid-C against the net flow on BC/MATL for each hour in Q2. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors).

In certain hours the net import offers on BC/MATL were at or above import capability, meaning the interties were import constrained (shown in red). In other hours, the net export bids were at or above export capability, meaning the interties were export constrained (shown in green). There was more variability in flows during hours of import constraints relative to hours of export constraints, as the import capability on BC/MATL is derated by the AESO for reliability reasons whereas the export capacity is more reflective of transmission capacity.

In Q2, BC/MATL was import constrained in 48% of hours and the average price differential between Alberta and Mid-C during these hours was $200/MWh. The average import capacity on BC/MATL during these constraints was 417 MW, which is down from 615 MW during constrained hours in January and February.[31] BC/MATL was export constrained less than 1% of the time in Q2, which is a result of relatively modest price differentials for exports, in addition to the BC/MATL export capability normally being much higher at 935 MW.

[31] The months preceding the changes to the minimum amount of LSSi required for BC/MATL import ATC (effective March 15, 2023).

Figure 66: Alberta and Mid-C differential and net BC/MATL flows (Q2 2023)



There were instances of constrained hours where realized flows were low or close to zero despite pool prices being relatively high. These occurred due to planned and unplanned outages on the BC intertie, which also causes unavailability on MATL.

For example, on April 17 there was a planned outage on the BC intertie during HE 09 and HE 10, and as a result MATL was also on outage. The following day, on April 18, the BC intertie tripped offline at around 17:56, which also tripped the MATL intertie offline. At the time of the trips, the lines were flowing a combined 70 MW of net imports although the schedule for the hour was 158 MW of net imports. No frequency issues or load shed occurred, and the lines returned to service for HE 22. For these events, the AESO did not lower the market's Most Severe Single Contingency (MSSC) by reducing the generation supply of large thermal assets. As a result, MSSC was 466 MW while the BC and MATL interties were offline for several hours.

For some hours in Q2, heavy export flows occurred despite pool price settling well above Mid-C price. For example, on April 5 in HE 20 and HE 21, net exports through BC/MATL were 491 MW and 541 MW, although Alberta pool prices increased to $692/MWh and $828/MWh, much higher than in Mid-C. In the preceding 12 hours, Mid-C prices were $82/MWh higher, on average. Higher pool prices for HE 20 and 21 were largely caused by a change in offer behaviour in combination with prevailing thermal outages, solar generation dropping to zero as the sun set, a coincidental reduction in wind generation, and large export volumes.

Figure 67 illustrates the difference between actual and scheduled flows on the BC intertie from HE 13 to HE 24 on June 27. There were periods where actual net interchange was significantly less than scheduled net interchange, which means that actual imports were higher than scheduled.[32] The steep ramp down of solar generation is met with increased energy dispatches and positioning of regulating reserve. However, because these actions do not entirely balance supply and demand, actual interchange flows increase to balance the system. This exemplifies the challenges associated with intermittent generation resources.

Figure 67: BC actual vs scheduled net interchange on June 27, 2023

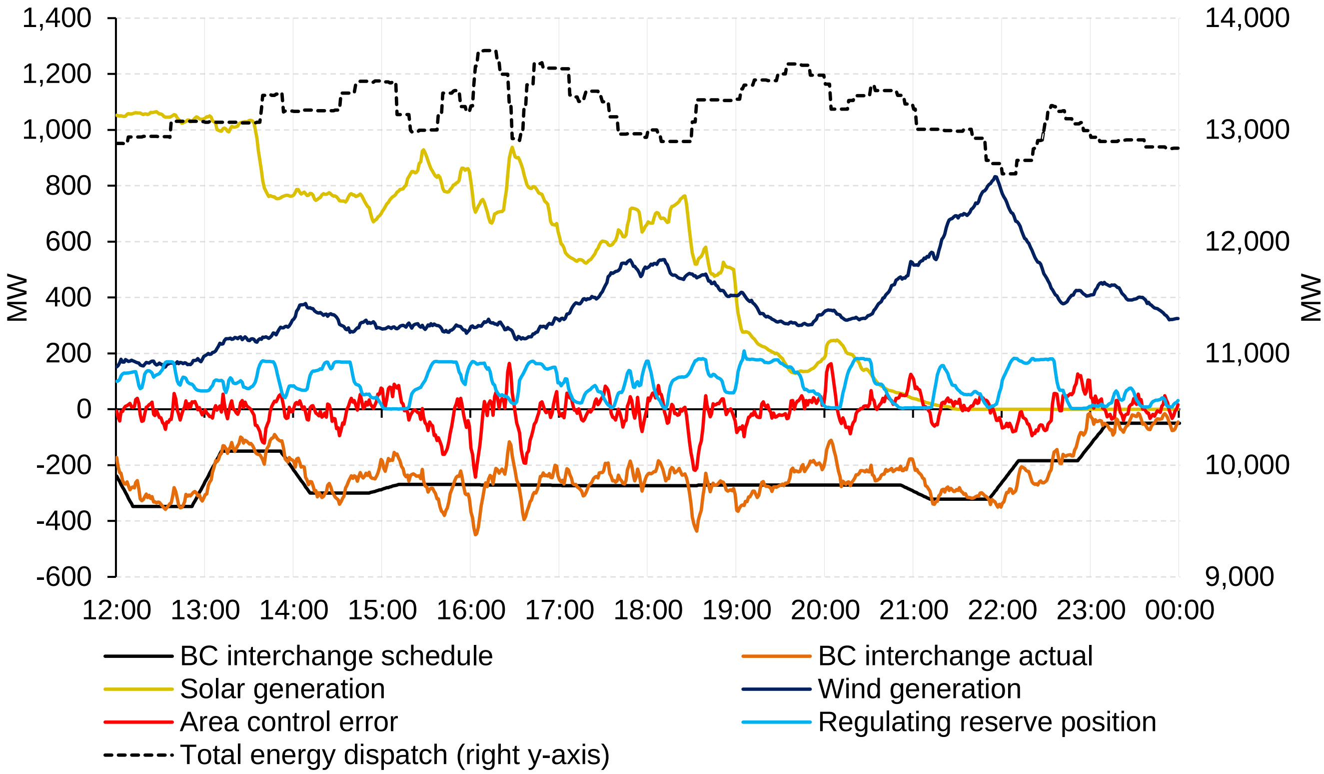


Figure 68 illustrates total import and export volumes in Q2 by intertie and market participant. As shown, the highest import volume across Q2 was scheduled on BC, followed by exports to BC and imports on MATL. However, on a net basis, the Saskatchewan intertie delivered the highest volume of imports. Total imports were 759 GWh, and total exports were 280 GWh, for a total net import of 479 GWh over the quarter. Flows on all three interties were largely scheduled by market participants that hold long-term firm transmission service.

Figure 69 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[33] 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 POD for imports and POR for exports is Alberta.

[32] Imports denoted as negative in Figure 67.

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

Figure 68: Total import and export volumes by intertie and market participant (Q2 2023)

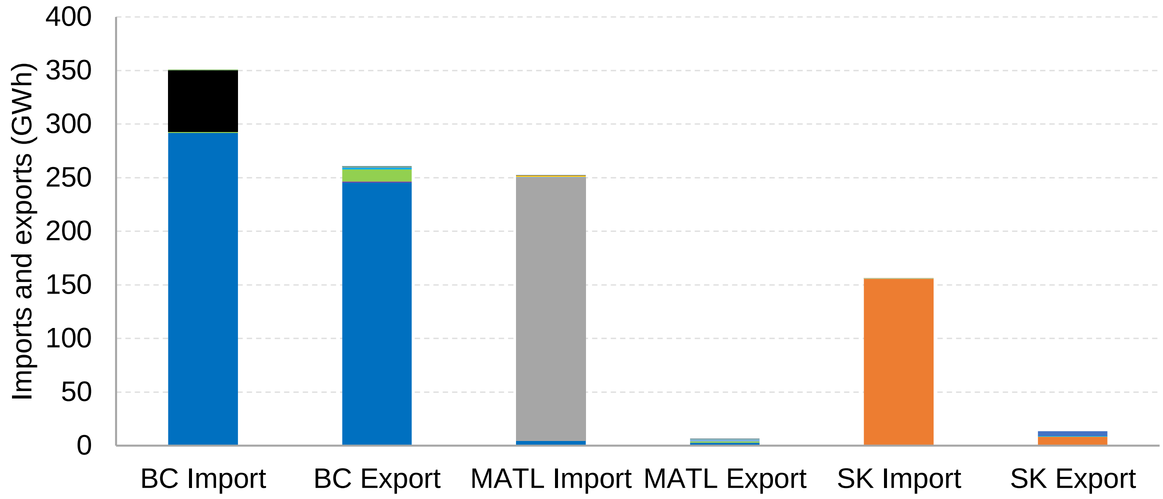
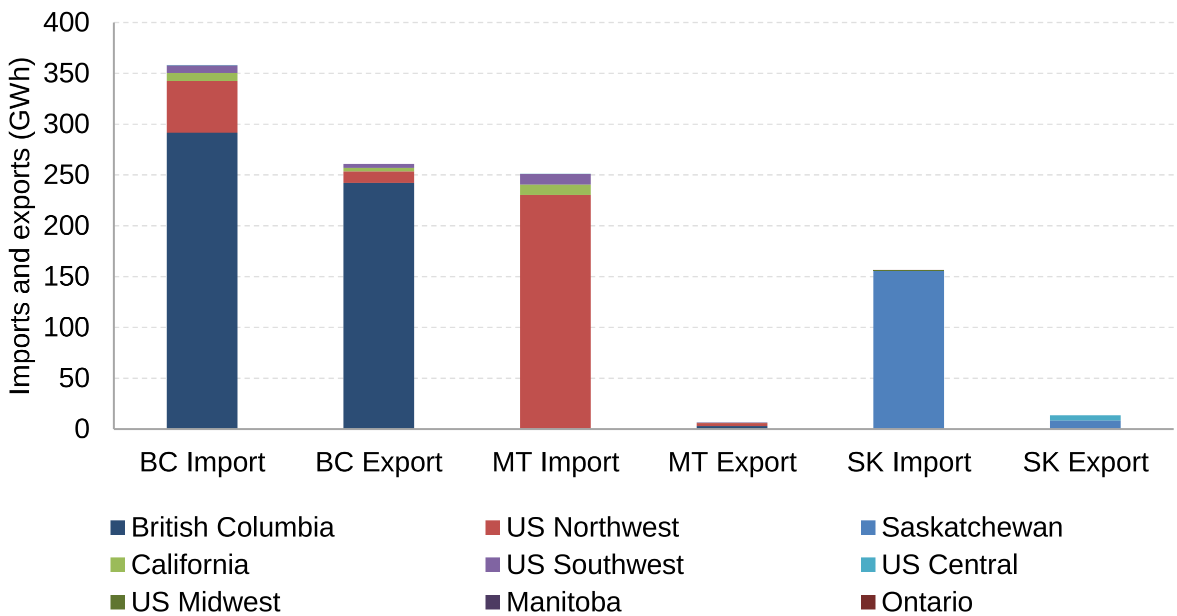


Figure 69: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes (Q2 2023)[34]



The balancing authority regions directly connected with Alberta have a high share of import and export flows. For imports on the BC intertie, approximately 83% originated from BC, 14% from US Northwest, and 3% from California. For exports on the BC intertie, 94% were delivered to BC and 5% to the US Northwest, and 1% to California.

For imports through Montana, approximately 58% originated from the US Northwest excluding Montana, 34% from Montana, and 4% from California.

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[34] Wheel-through volumes are not included in figure, though represent a small amount of total volume (3,500 MWh).

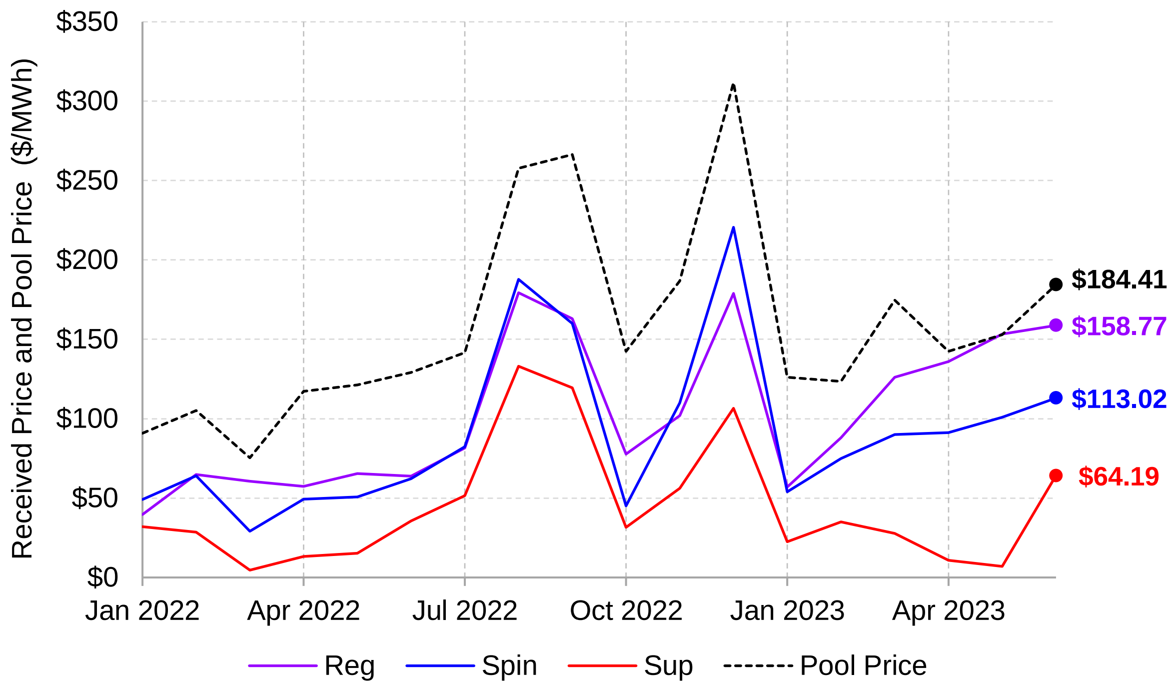
3. OPERATING RESERVE MARKETS

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.

Figure 70 shows the average received price for active regulating, spinning, and supplemental reserves by month since January 2022. The average received price for each month depends on hourly pool prices and the equilibrium prices set in the OR auctions; these calculations cover all hours in the month.

In general, received prices for active regulating reserve have been higher than for spinning reserve, and spinning reserve prices have in turn been higher than prices for supplemental reserve. This is in line with the technical requirements for each product, which are most stringent for regulating reserve, followed by spinning reserve, and least stringent for supplemental reserve. In some months with higher pool prices the received price of spinning reserve has exceeded regulating reserve, which is likely due to competition for the additional pool price revenues that accrue when providing energy for regulating reserve.

Figure 70: *Average received price for active spinning, supplemental, and regulating reserve (January 2022 to June 2023)*



In early 2023, the received price of supplemental reserve fell in contrast to the upward trends in pool prices and the received prices for spinning and regulating reserve. The decline in prices for supplemental reserve reflected increased competition in this market, including from load providers which are not eligible to provide spinning or regulating reserve.

On Tuesday, April 4, the equilibrium price for on-peak active supplemental reserve cleared at negative $900/MWh, a new low. Equilibrium prices are indexed to pool price, so at negative $900/MWh supplemental reserve providers would only receive revenue if the pool price was above $900/MWh.

The average received price for supplemental reserve increased from $6.98/MWh in May to $64.19/MWh in June, in part due the absence of a large hydro unit in late June. This reduced supply and contributed to increasing equilibrium prices for supplemental reserve (Figure 71).

Figure 71: Daily active on-peak equilibrium prices for spinning, supplemental, and regulating reserve (Q2 2023)

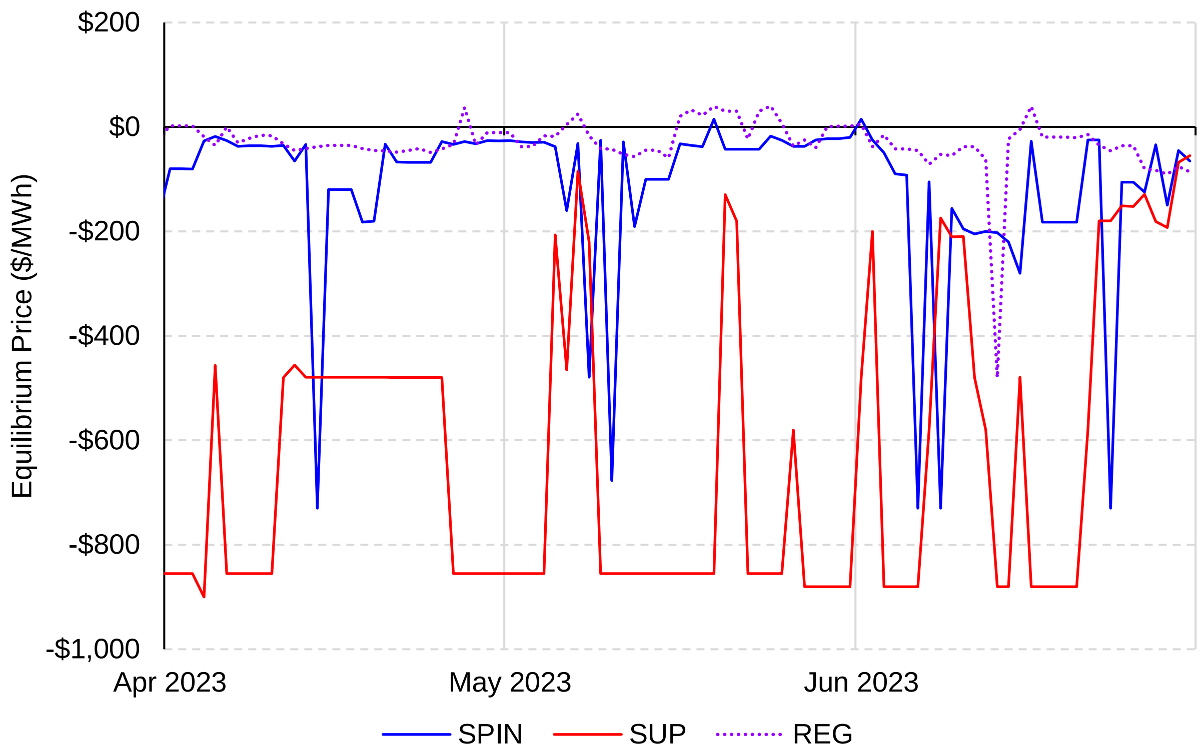
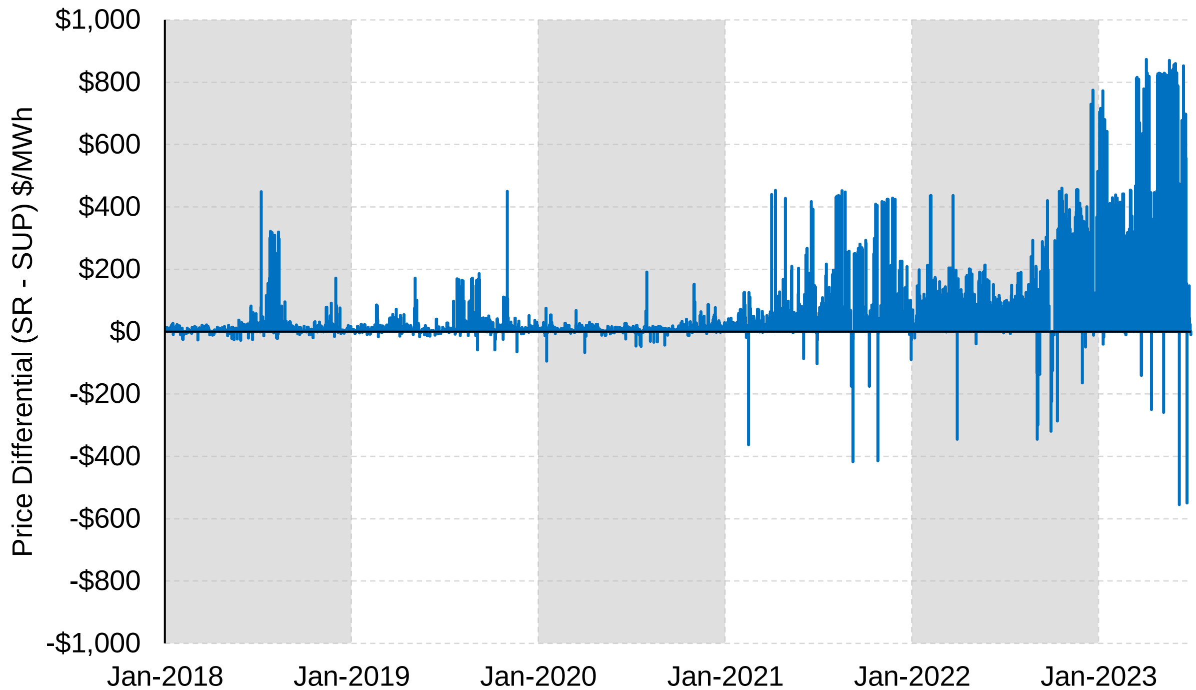


Figure 72 illustrates the daily price differential between the received price for active spinning and active supplemental during on-peak hours. The price differential increased in 2021 and increased further in 2023. The ability of loads to provide supplemental reserve increases competition in this market and puts downward pressure on supplemental reserve prices relative to spinning reserve.

On some days, the price for spinning reserve clears below the price of supplemental even though all providers of spinning reserve can provide supplemental, but not visa versa. This can occur because the OR auctions happen sequentially, with the auctions for active spinning occurring prior to the auctions for active supplemental. Before 2021, these events happened more often but the price differentials were relatively modest; since 2021, these events have been less frequent but the price differences have been larger (Figure 72).

Figure 72: Daily equilibrium price difference between active spinning and supplemental reserve (on-peak, January 2018 to June 2023)



As discussed above, April 4 set a record low equilibrium price for on-peak active supplemental reserve at negative $900/MWh. In addition, the equilibrium price for supplemental was negative $880/MWh for 16 days over Q2, making it the most frequently observed equilibrium price.

Figure 73 and Figure 74 illustrate the supply curves for supplemental and spinning reserve for April 4. As shown, a relatively large volume of load and hydro offers at low offer prices was the main driver of the low equilibrium price for supplemental. The equilibrium price for on-peak spinning reserve was higher at negative $26.67/MWh on April 4, and the average on-peak pool price was $439/MWh. The highest priced on-peak hour that day was $900.48/MWh and the lowest priced on-peak hour was $58.14/MWh. As a result, supplemental reserve providers earned little revenues on this day, while spinning reserve providers earned positive revenues in all hours.

Figure 73: Offers for active on-peak supplemental reserve (April 4, 2023)

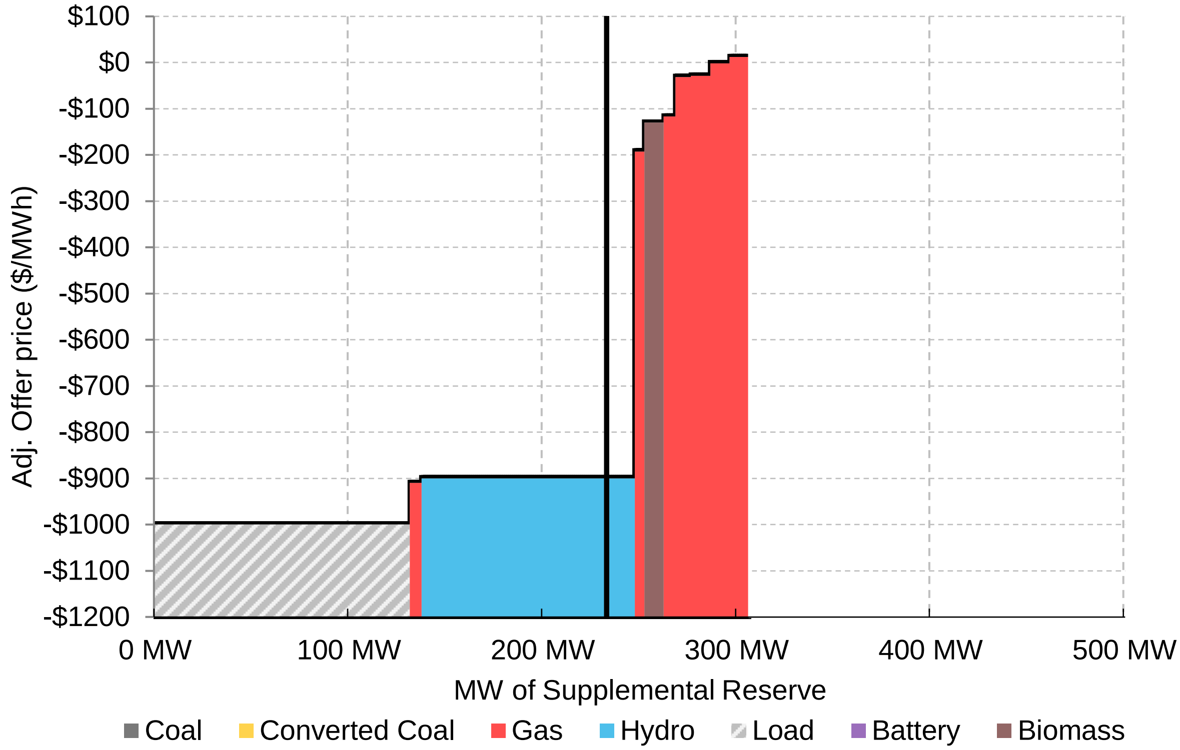


Figure 74: Offers for active on-peak spinning reserve (April 4, 2023)

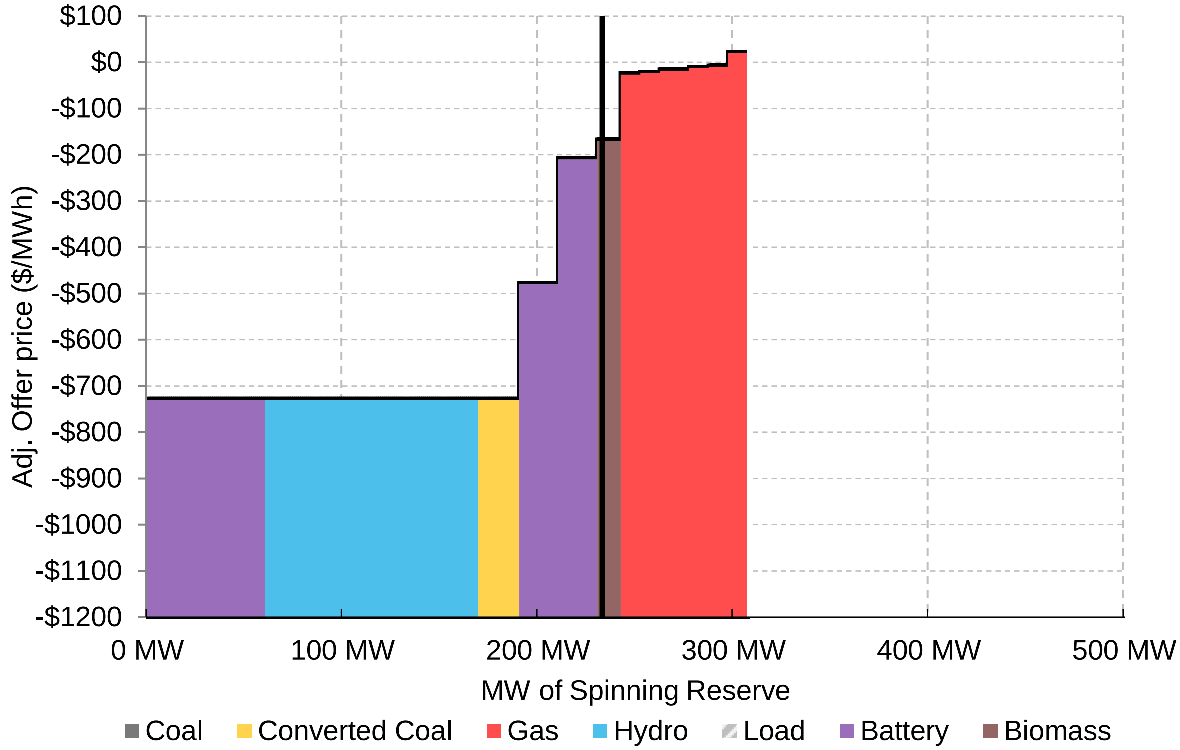


Figure 75 illustrates the total dispatch of supplemental reserve by month and market participant. The dispatched volumes include active reserves and activated standby volumes. Since January, the largest supplemental provider supplied between 43% and 48% of dispatched volumes by month, and the largest three providers combined supplied between 80% and 94%.

Figure 75: Total volume of dispatched supplemental reserve by month and market participant (anonymized, January to June 2023)

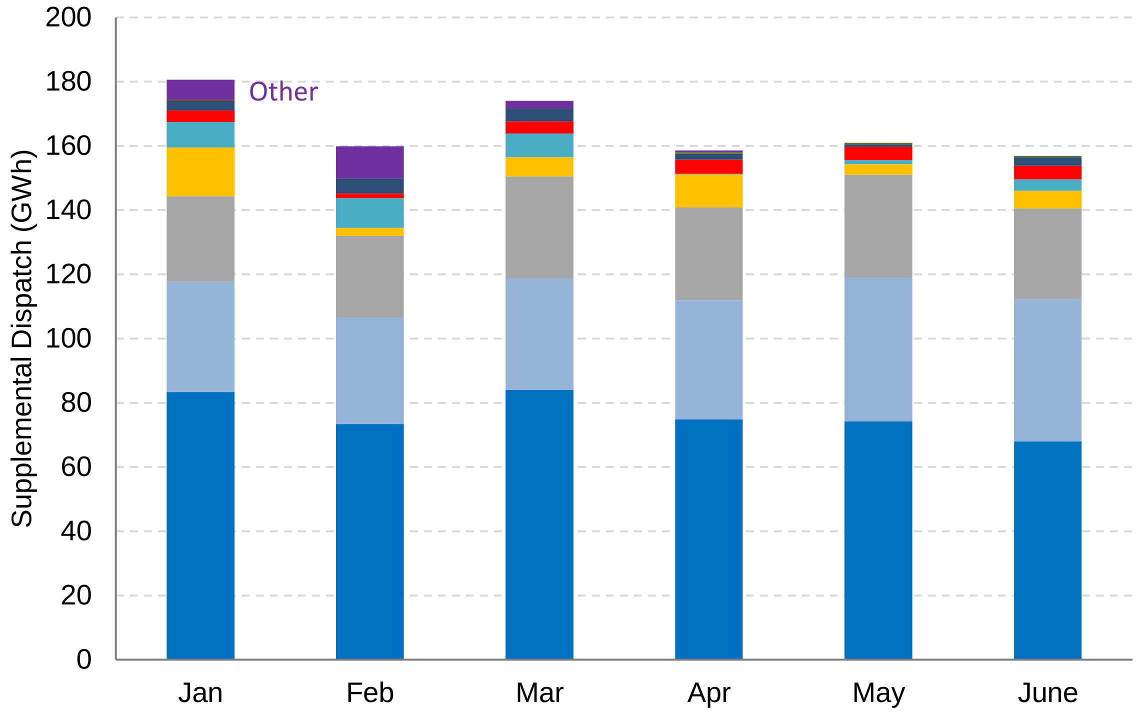


Figure 76 illustrates the same analysis for spinning reserve. The largest provider is the same in both markets but there are different other competitors with loads participating in supplemental and battery storage assets competing mainly in spinning. Since January, the largest spinning provider supplied between 53% and 59% of dispatched volumes, and the largest three providers combined supplied between 86% and 93%.

Figure 76: Total volume of dispatched spinning reserve by month and market participant (anonymized, January to June 2023)

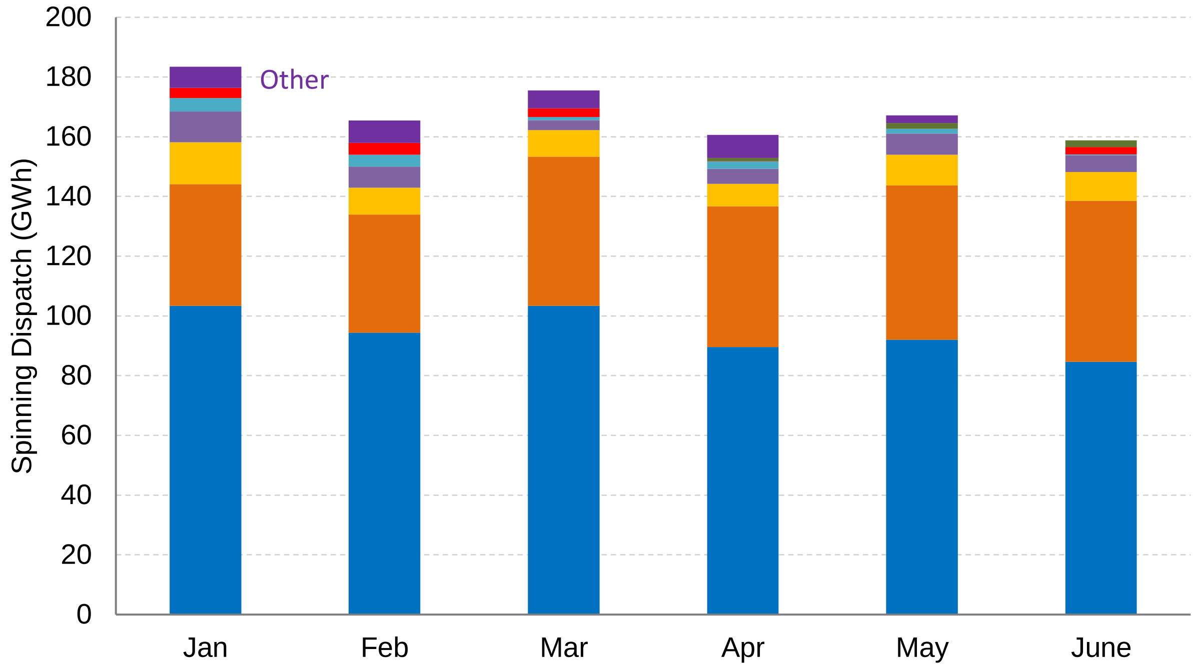


Figure 77 shows the percent of dispatched contingency reserve that was directed to provide energy by fuel type.[35] Historically, hydro and coal assets have been most heavily directed in peak directive months due to their size, reliability, and responsiveness during contingencies.

In response to market participant concerns over the fairness of directives, on March 29, the AESO updated its directive issuance practice to rank providers based on the time elapsed since their last directive. The directive rates appear to be converging and the MSA will continue to monitor this matter.

Figure 78 provides the same directive rate analysis for the size of the block dispatched.[36] Historically, larger resources were directed more frequently than smaller resources, though rates began to converge in recent months. To accurately assess the impact of the new directive procedure will require additional time to pass.

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[35] The method of calculating directive percentages is as follows: the sum of directive volume (i.e., the numerator) is the sum of directed MW for each instance of a spinning directive instruction. This is not measured in MWh but rather MW*instructions. The sum of spinning reserve dispatches (i.e., the denominator) is the sum of dispatched active and standby, which is sold on a per hour basis and hence expressed in MWh.

This method of counting means that if a resource is directed for 10 MW, whether for 10 minutes or 30 minutes, it will be counted as a single 10 MW directive. If a directive spans multiple settlement intervals, it is still counted as a single directive. The count of directives is determined by instances of instructions directing a resource to turn on.

[36] Dispatch and directive size are not directly related to asset size. For example, if a 100 MW asset is dispatched for 5 MW of reserves and subsequently directed for 5 MW, that would be counted in the "small" category.

Figure 77: Dispatched contingency reserve directed by fuel type (January 2021 to June 2023)

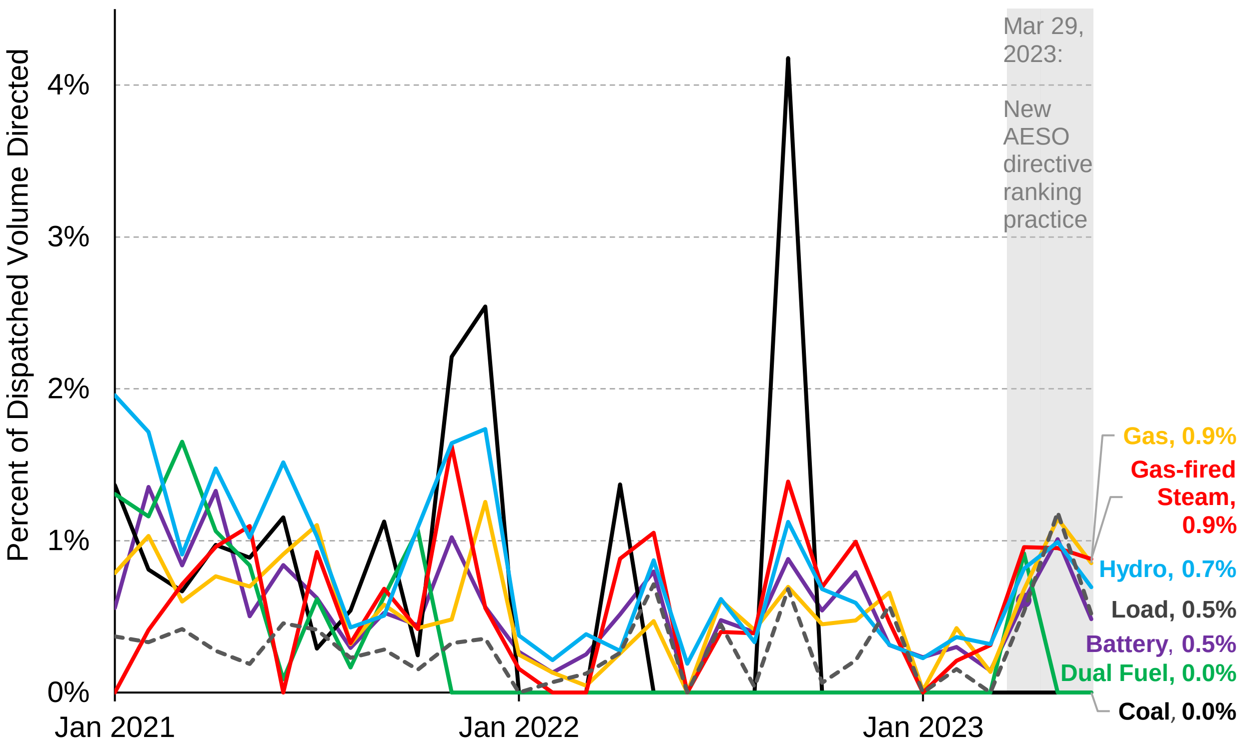
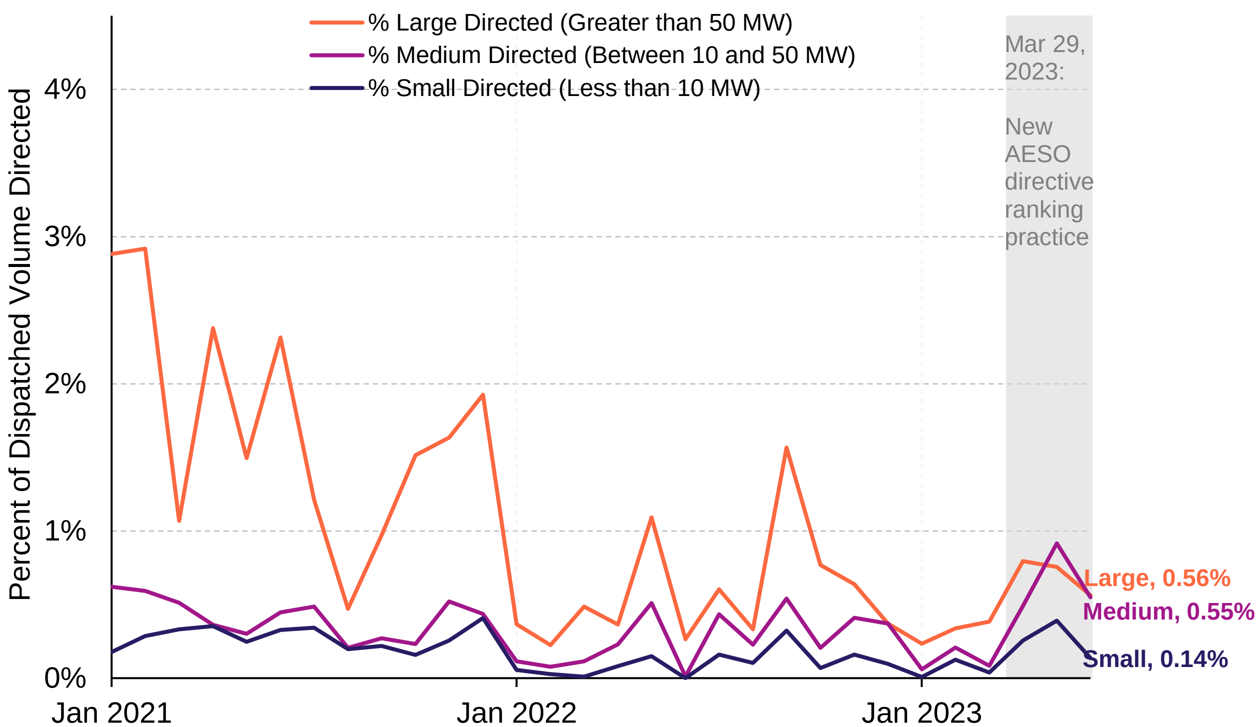


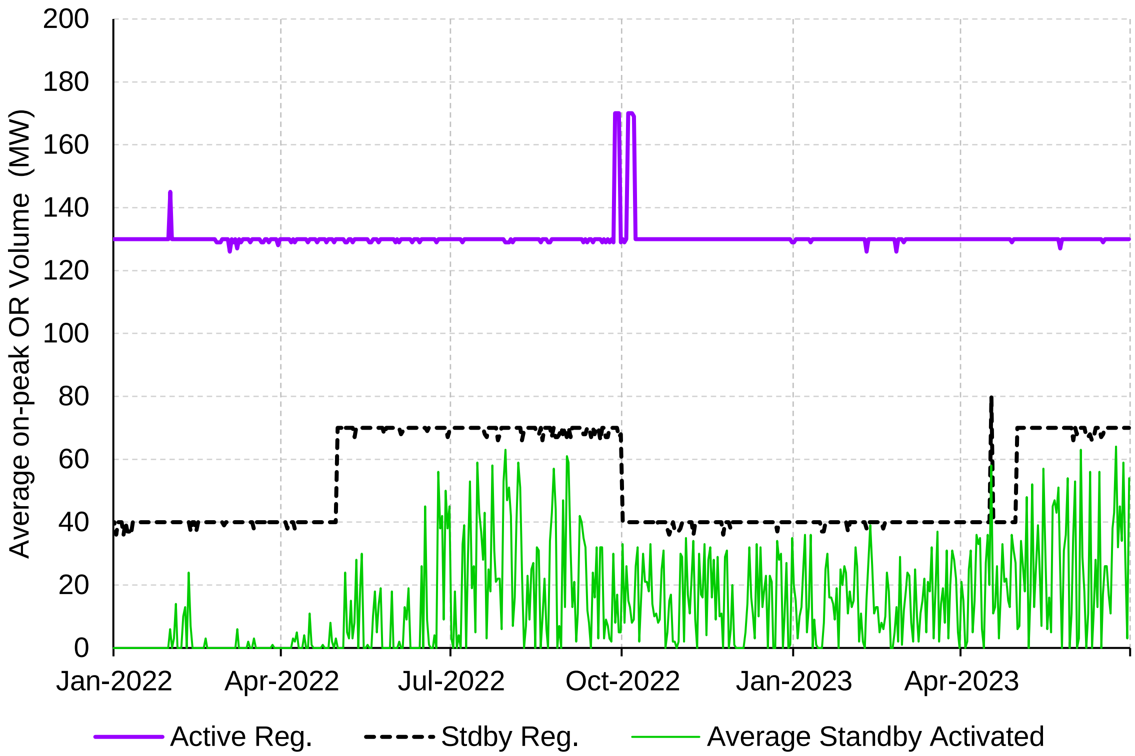
Figure 78: Dispatched contingency reserve directed by asset size (January 2021 to June 2023)



Total volumes of spinning and supplemental reserve declined year-over-year because of lower import volumes. Beginning on March 15, the LSSi requirements for import capacity increased, which lowered import supply. In Q2 2023, the average volume of active spinning and supplemental reserve was 468 MW, a 13% decrease from 536 MW in Q2 2022.

Figure 79 illustrates regulating reserve volumes by day since January 2022. On May 1, the AESO increased the procured volume of standby regulating reserve from 40 to 70 MW, an annual adjustment made each spring. Intermittent generation, particularly unpredictable declines in solar generation, led the AESO to use the additional standby volumes. Compared with 11% in Q2 2022, the activation rate of standby regulating reserve in Q2 2023 was 41%. The AESO assumes a standby activation percentage of 1% to establish the merit order for the procurement of standby regulating reserve for on-peak.

Figure 79: Average active and standby regulating reserve procured and activated (January 2022 to June 2023)



4. THE FORWARD MARKET

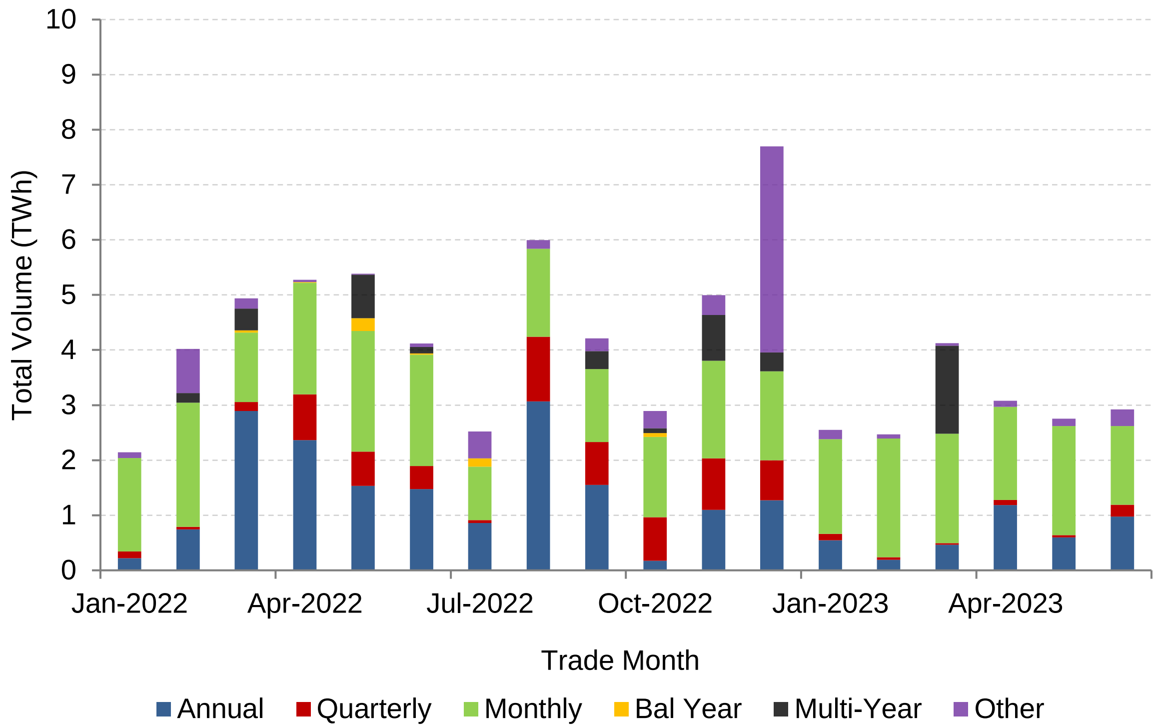
Alberta's financial forward market for electricity allows generators and larger loads to hedge against pool price volatility and enables retailers to reduce price risk by hedging sales to retail customers.[37]

4.1 Forward market volumes

Total volume is the total amount of power traded financially over the duration of a contract. In Q2, 8.8 TWh of total volume traded on ICE NGX or through a broker. This is a 4% decrease from Q1, and a 30% decrease compared to Q2 2022. Figure 80 illustrates total volumes by trade month and product term, including direct bilateral trades up to December 31, 2022.

The decline in liquidity year-over-year was largely caused by less trading of annual products. In Q2 2022 the Calendar 2023 (CAL23) contract traded more than CAL24 did in Q2 this year (Table 8). CAL26 was the most actively traded contract in Q2, with 1.12 TWh of total volume.

Figure 80: Total volumes by trade month and term



[37] 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, 2022 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.

Table 8: Total volumes of annual contracts by delivery year (TWh)
(Q2 and Q2 2022; volumes on ICE NGX and brokers)

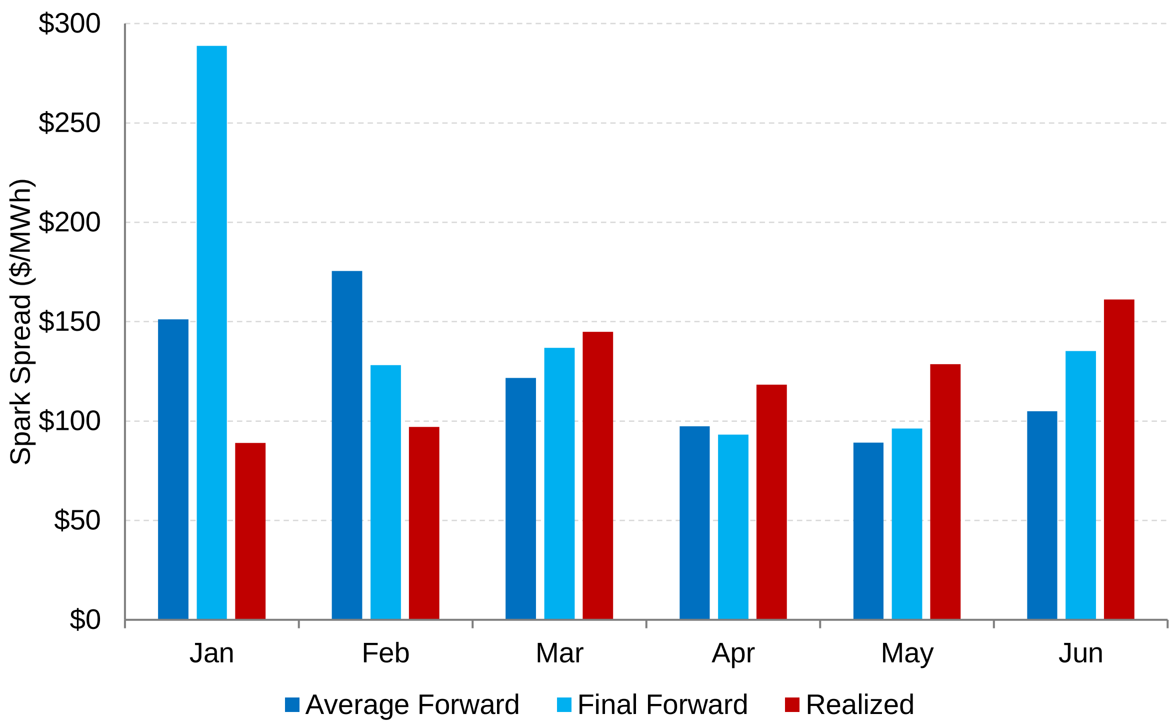
	Q2 2022	**Q2 2023**
CAL23	3.35	-
CAL24	0.66	0.94
CAL25	0.18	0.70
CAL26	-	1.12
CAL27	-	-
Total	**4.18**	**2.76**

4.2 Trading of monthly products

Figure 81 below compares the forward and realized spark spreads by month. Spark spread provides an indication of the margin between pool prices and the input cost of natural gas; these figures assume a heat rate of 10 GJ/MWh.

In Q2, the realized spark spreads for April, May, and June came in above forward market expectations as pool prices were higher than predicted by the forward market. For June, the volume-weighted average forward price was $130/MWh, a 29% discount to the average pool price of $184/MWh.

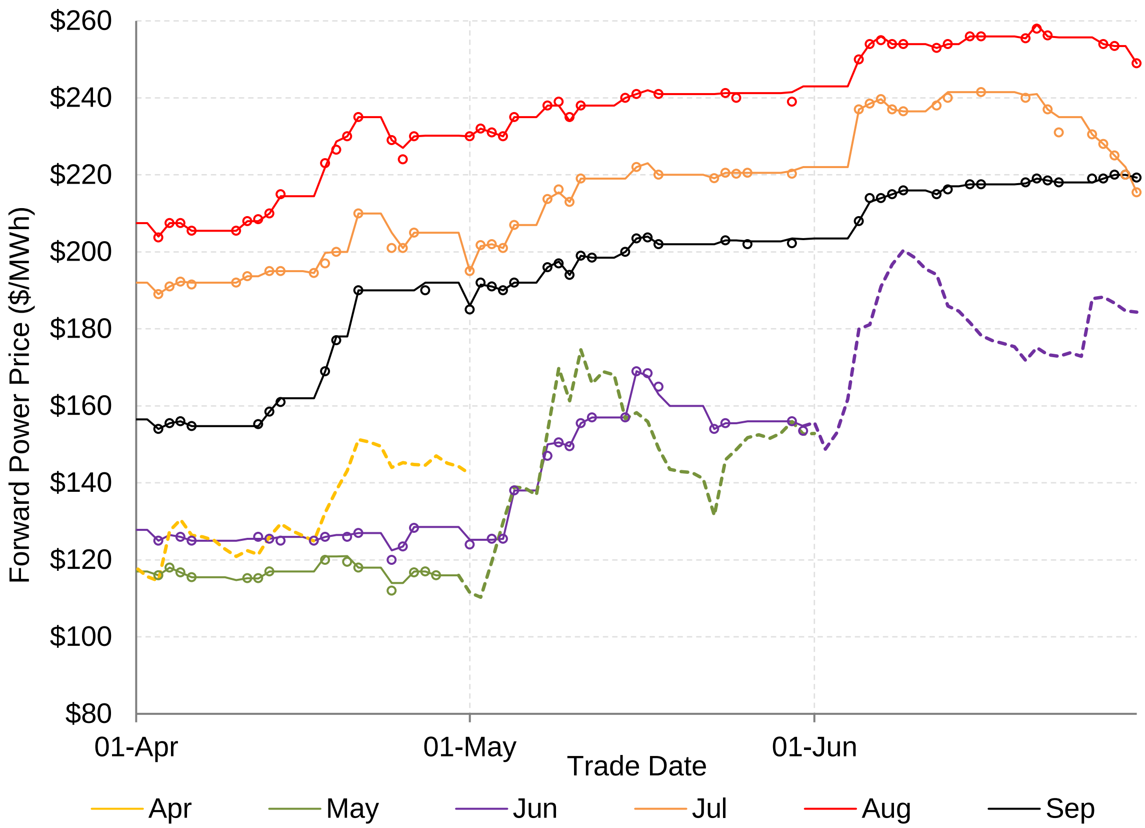
Figure 81: Forward versus realized spark spread by month (January to June)



Forward prices increased in Q2 in response to higher-than-expected pool prices. Figure 82 shows monthly forward prices for May through September during Q2. The dashed lines in the figure illustrate the marked prices for April, May, and June. These prices show the expected average pool price as pool prices were realized and balance-of-month forward prices changed. In late April, early May, and early June forward prices increased on the back of events in the energy market and higher-than-expected pool prices.

In late June, the price of the July contract declined from $240/MWh to $216/MWh in response to weather forecasts and the price of the June contract settling at $184/MWh.

Figure 82: Monthly forward prices for May to September over Q2



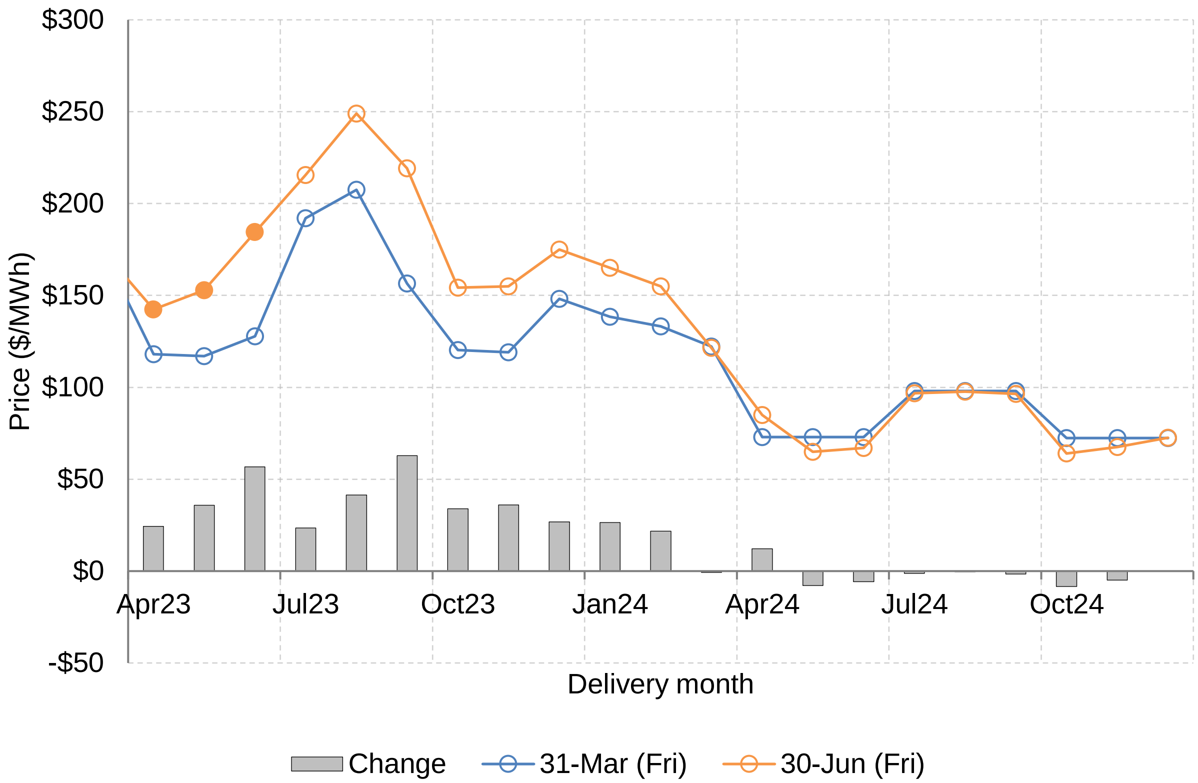
The price of the September contract increased by $63/MWh over the quarter, from $157/MWh to $219/MWh, with a large portion of the increase occurring in mid-April. Figure 83 illustrates the changes to the monthly forward curve over the quarter. Forward prices out to February 2024 increased over Q2, but prices beyond that were more stable.

Forward prices for October 2023 onwards are lower, partly because the Cascade combined cycle project (900 MW) and the return of HR Milner (300 MW) are expected to increase supply.[38] Forward prices decline further later in 2024, in part because Genesee 1 and 2 are expected to

[38] AESO Long Term Adequacy Metrics

add 512 MW of incremental capacity when they are repowered to combined cycle.[39] As of June 30, the price of Q3 2024 was 47% less than Q3 2023, and the price of Q4 2024 was 44% less than Q4 2023.

Figure 83: The monthly forward curve as of March 31 and June 30, 2023



4.3 Trading of annual products

The increase in monthly prices over Q2 increased the expected pool price for 2023 by 20% to $173/MWh on June 30. The expected spark spread for 2023 started the year at $144/MWh before declining to $93/MWh at the end of January (Figure 84). Since early February the expected spark spread for 2023 has generally increased and ended the quarter at $147/MWh. By comparison, the spark spreads for CAL24, CAL25, and CAL26 have been lower and more stable. The spark spread for CAL26 increased by 19% to $37/MWh as the price of natural gas declined by 16% over Q2 while the price of power fell by 1% (Table 9).

[39] Capital Power Investor Presentation at slides 4, 17 and 18 – July 2023

Figure 84: Annual spark spreads for CAL23 to CAL26 (from January 1 to June 30, 2023)

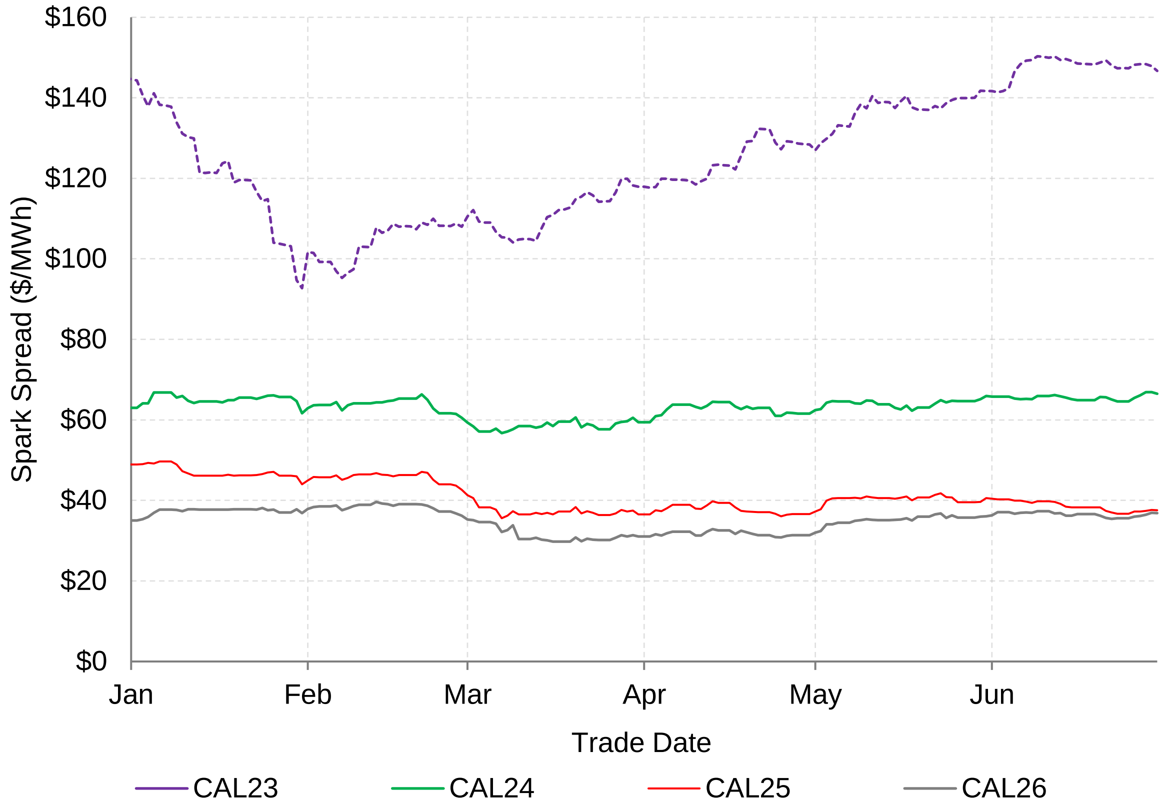


Table 9: Forward power and natural gas price changes over Q2

Contract	**Power price ($/MWh)**			**Gas price ($/GJ)**			**Spark spread ($/MWh)**		
	Mar 31	**Jun 30**	**% chg**	**Mar 31**	**Jun 30**	**% chg**	**Mar 31**	**Jun 30**	**% chg**
CAL23 (marked)	$145	$173	20%	$2.66	$2.63	-1%	$118	$147	24%
CAL24	$94	$96	3%	$3.42	$2.95	-14%	$59	$67	12%
CAL25	$78	$72	-8%	$4.17	$3.47	-17%	$37	$38	3%
CAL26	$74	$73	-1%	$4.25	$3.57	-16%	$31	$37	19%

5. THE RETAIL MARKET

5.1 Quarterly summary

Residential retail customers can choose from several retail energy rates. By default, retail customers are on regulated energy rates, which vary monthly and by distribution service area.

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

The Regulated Rate Option Stability Act (RROSA) placed a ceiling on regulated electricity rates at a maximum of 13.5 ¢/kWh for the months of January, February, and March 2023. The deferred revenue that resulted from this rate ceiling will be recovered from the RRO customers over the period of April 2023 to December 2024. This additional cost incurred by the RRO customers is referred to as collection rates. As a result of the imposed collection rates over the monthly base RRO rates, the regulated electricity rates in Q2 2023 were around 2.5 ¢/kWh higher than usual.

Table 10: Monthly retail market summary for Q2 (Residential customers)

		2023	2022	Change
RRO (Avg ¢/kWh)	Apr	18.27	10.63	72%
	May	16.56	10.32	60%
	Jun	18.43	11.70	58%
	Q2	**17.74**	**10.88**	**63%**
DRT (Avg $/GJ)	Apr	3.57	4.59	-22%
	May	2.25	6.44	-65%
	Jun	3.36	8.70	-61%
	Q2	**3.05**	**6.58**	**-54%**
Competitive variable electricity rate (Avg. ¢/kWh)	Apr	15.56	12.79	22%
	May	17.56	13.56	29%
	Jun	21.96	14.62	50%
	Q2	**18.35**	**13.66**	**34%**
Competitive variable Natural Gas rate (Avg. $/GJ)	Apr	3.41	7.56	-55%
	May	3.43	8.19	-58%
	Jun	3.34	7.84	-57%
	Q2	**3.39**	**7.86**	**-57%**
Expected cost, 3-year electricity contract (Avg. ¢/kWh)	Apr	10.49	8.19	28%
	May	10.68	8.93	20%
	Jun	10.66	9.30	15%
	Q2	**10.61**	**8.80**	**21%**
Expected cost, 3-year natural gas contract (Avg. $/GJ)	Apr	3.71	4.76	-22%
	May	3.51	5.22	-33%
	Jun	3.37	5.44	-38%
	Q2	**3.53**	**5.14**	**-31%**

Higher forward prices also put upward pressure on regulated rates in Q2 2023. The average regulated rate in Q2 2023 was 17.74 ¢/kWh, a 63% increase year-over-year. On average, competitive variable electricity rates for residential consumers increased by 34% compared to the previous year driven by changes in pool prices.

The average residential Default Rate Tariff (DRT) rates decreased by over 50% from $6.58/GJ in Q2 2022 to $3.05/GJ in Q2 (Table 10). Competitive variable natural gas rates were also lower year-over-year and were slightly above the prevailing DRT.

Retailers' expected cost of providing 3-year fixed rate electricity contracts was 21% higher year-over-year but was largely unchanged compared to Q1. The expected cost of providing 3-year fixed rate natural gas contracts dropped by 31% year-over-year but only changed slightly relative to Q1 2023.

5.2 Retail customer movements

The MSA collects and tracks retail switching data on a one-quarter lagged basis. As such, the discussion in this section focuses on retail switching in and prior to Q1 2023.

5.2.1 Regulated retailer customer losses

The total number of residential RRO customers fell by around 16,000 in Q1 2023, the lowest net loss since Q2 2022 (Figure 85). Over 11,000 residential customers left the RRO in January and a further 11,500 left in February, while 17,500 residential customers left the RRO in March (Figure 86). The RRO rate ceiling in effect over Q1 2023 may have reduced the incentive for RRO customers to switch to competitive retailers.

Figure 85: RRO customer net losses, residential customers (Q1 2020 to Q1 2023)

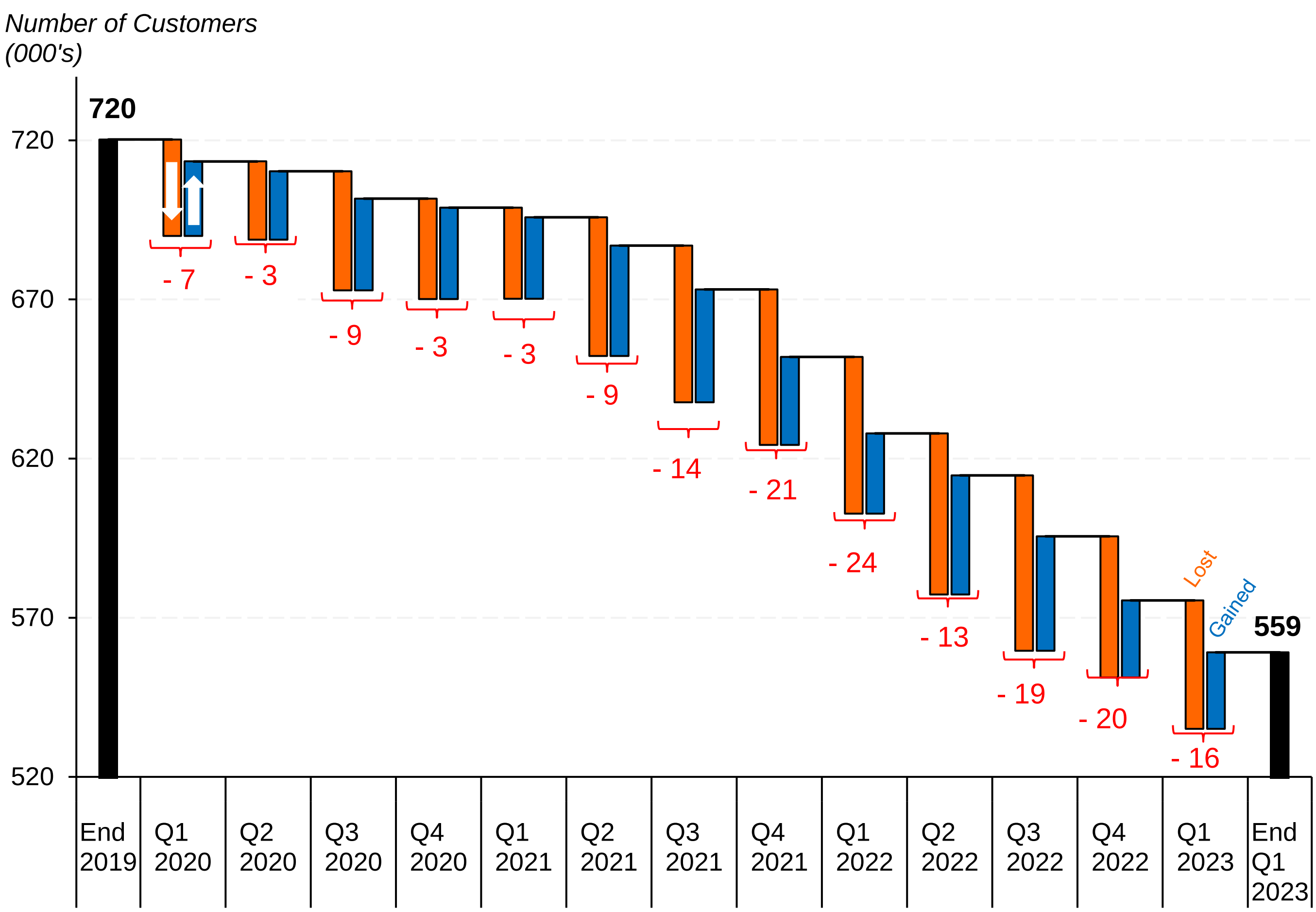
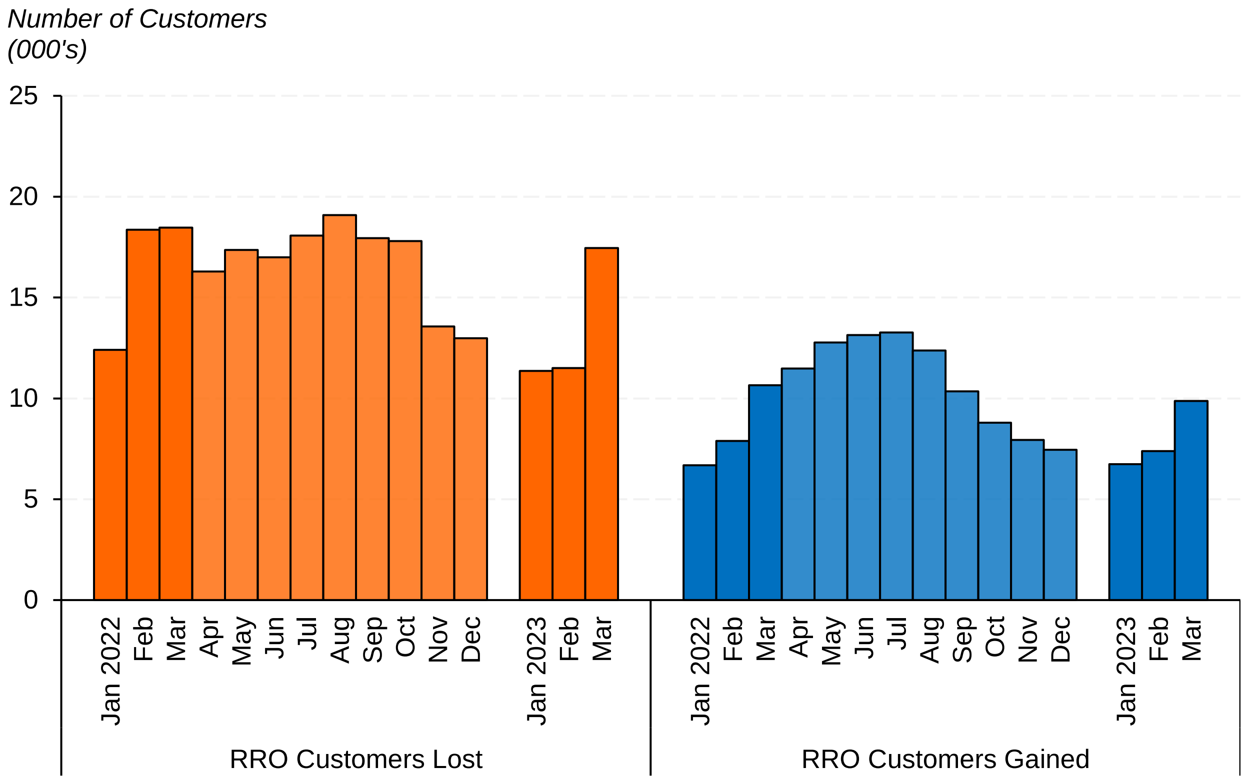
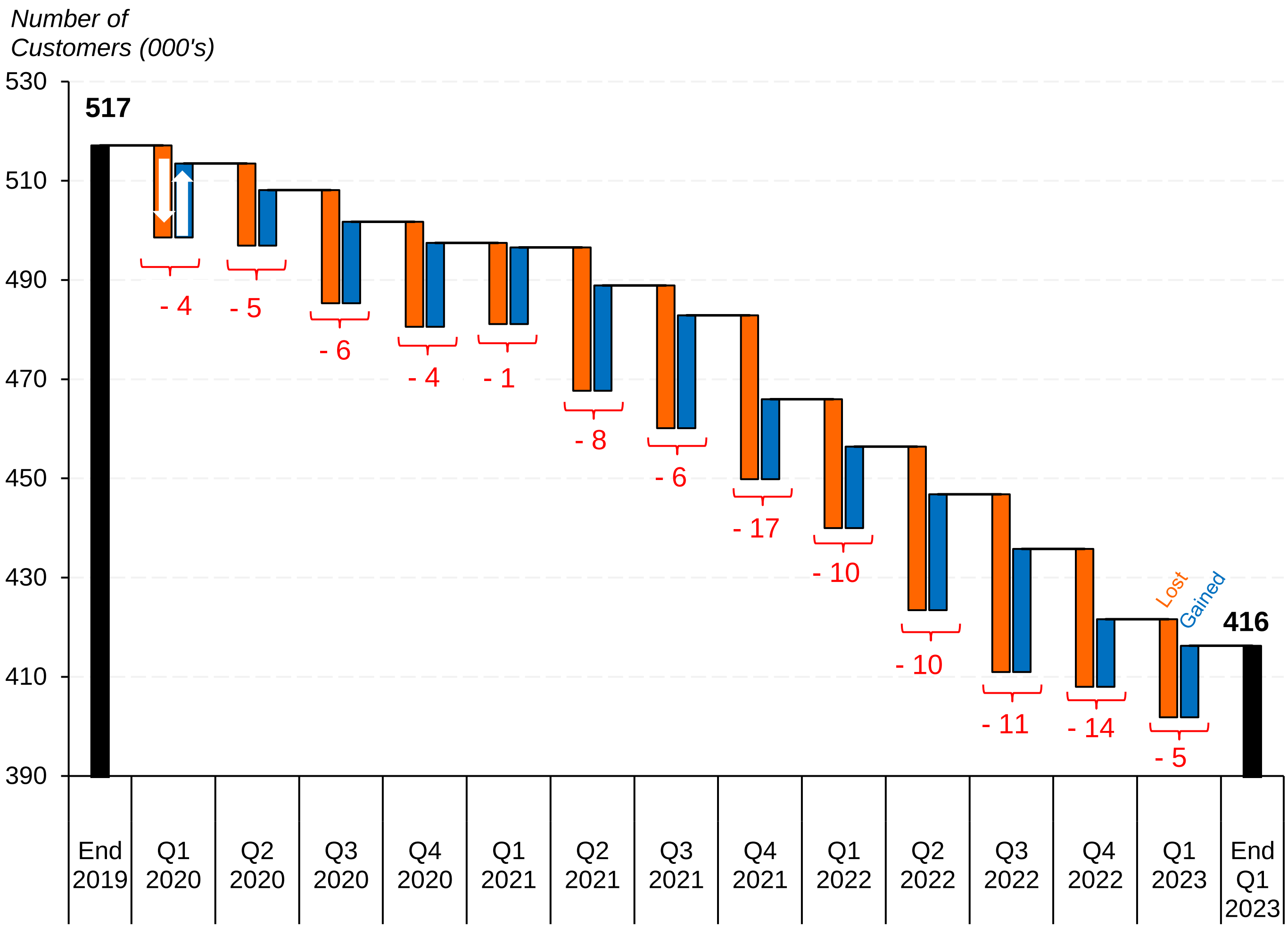


Figure 86: RRO customer losses and gains, residential customers (January 2022 to March 2023)



The total number of residential DRT customers fell by around 5,300 in Q1 2023, the smallest decline in two years (Figure 87). Only 20,000 residential customers left the DRT in Q1, compared to 28,000 DRT customer losses in Q4 2022 and 26,000 in Q1 2022.

Figure 87: DRT customer net losses, residential customers (Q1 2020 to Q4 2022)

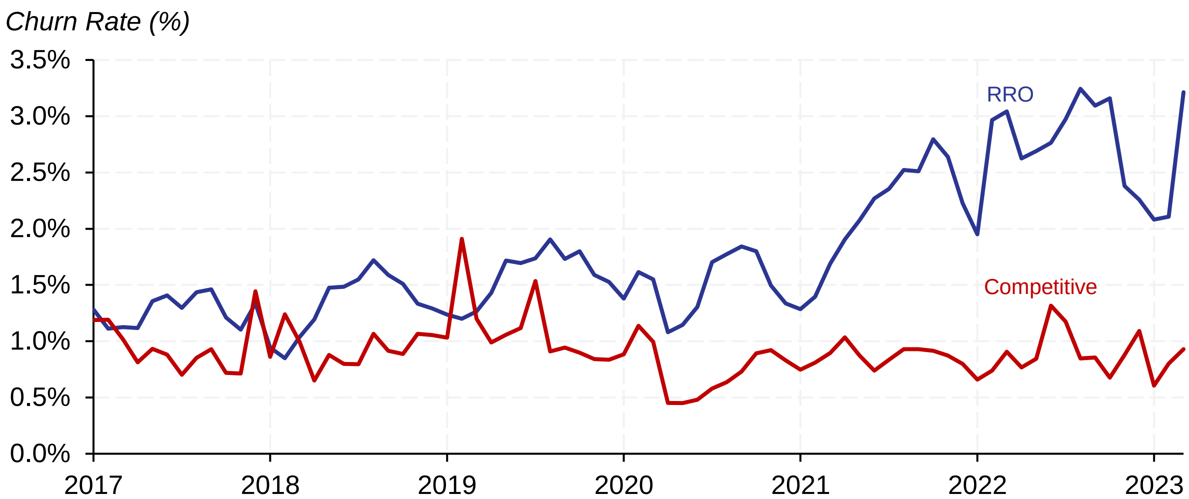


5.2.2 Dynamics of retail switching

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 customer churn, indicating RRO customers are switching retailers at greater rates than competitive customers, and consistent with a growth in competitive retailer market shares among residential customers (Figure 88).

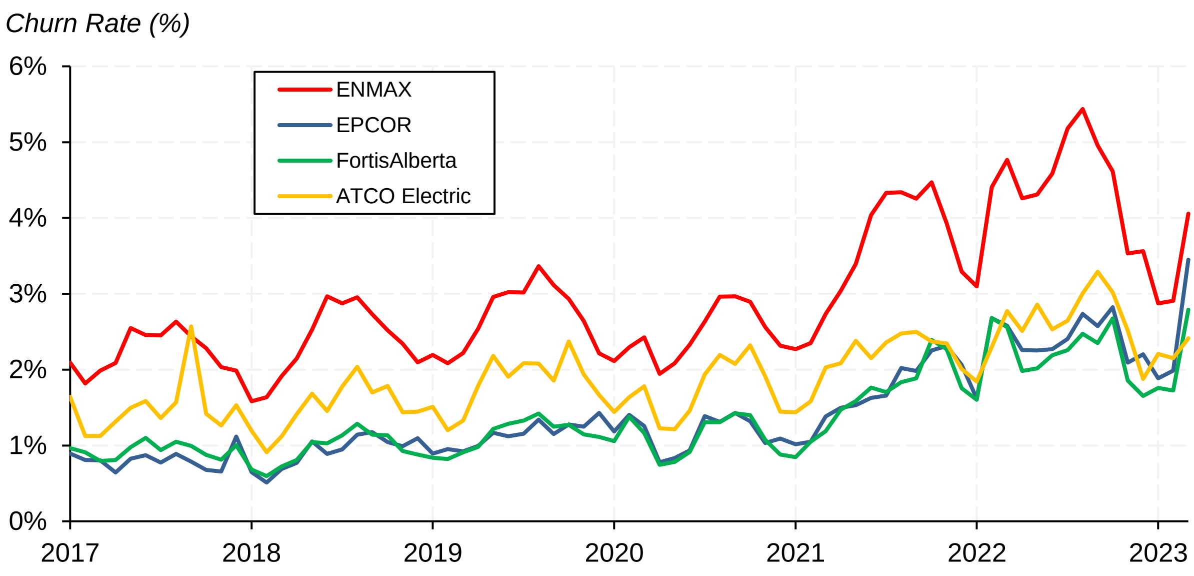
Residential RRO churn rates increased by 1.1% in March 2023, the largest month-over-month change recorded by the MSA. The well-publicized end of the 13.5 ¢/kWh RRO rate ceiling in March and customer expectations of higher RRO rates in the following months may have driven this increase.

Figure 88: RRO and competitive electricity retailer churn rates, residential customers (January 2017 to March 2023)



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 89). In March 2023 churn rates in the EPCOR, FortisAlberta, and ENMAX service areas increased by at least 1%, while churn rates in the ATCO Electric service area increased by less than 0.3%.

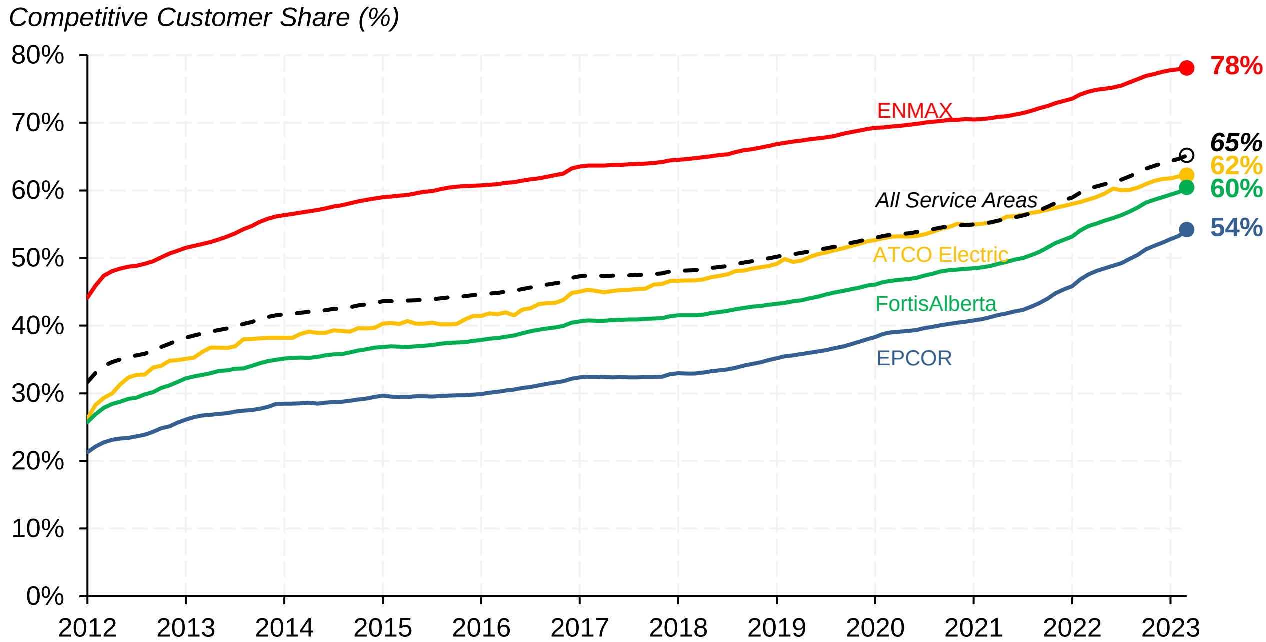
Figure 89: RRO retailer churn rates by service area, residential customers (January 2017 to March 2023)



5.2.3 Competitive retailer market share

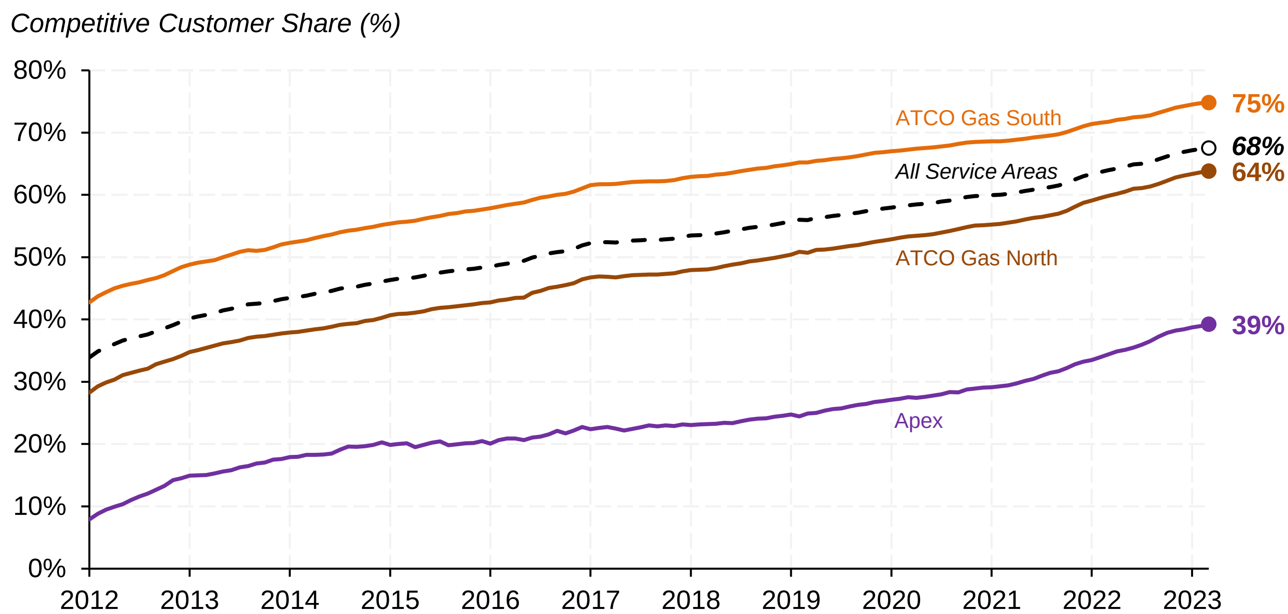
The percent of residential customers on a competitive retail contract for electricity increased by 1% to 65% in Q1 2023 (Figure 90). The market share increase was highest in the EPCOR service area at 2% quarter-over-quarter.

Figure 90: Competitive retail customer share (electricity) by service area, residential customers (January 2012 to March 2023)



The percent of residential customers on a competitive retail contract for natural gas increased by 1% in Q1 2023 (Figure 91).

Figure 91: Competitive retail customer share (natural gas) by service area, residential customers (January 2012 to December 2022)



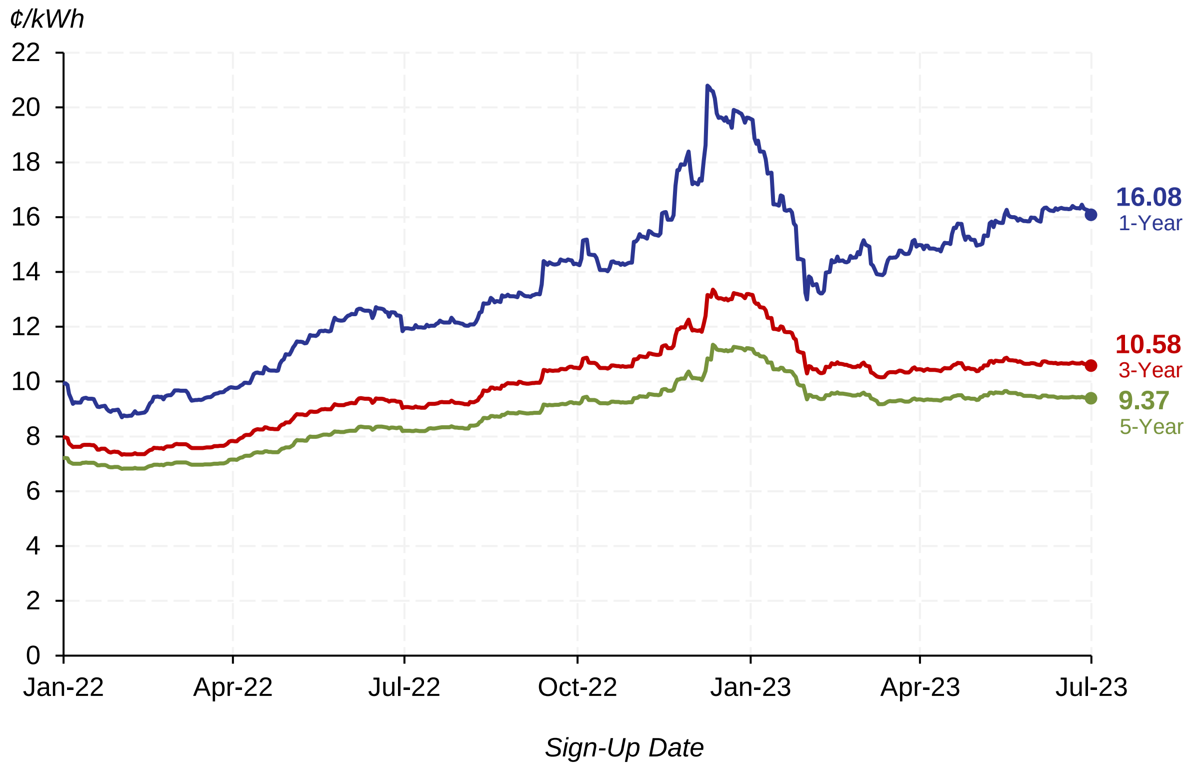
5.3 Competitive fixed retail rates

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

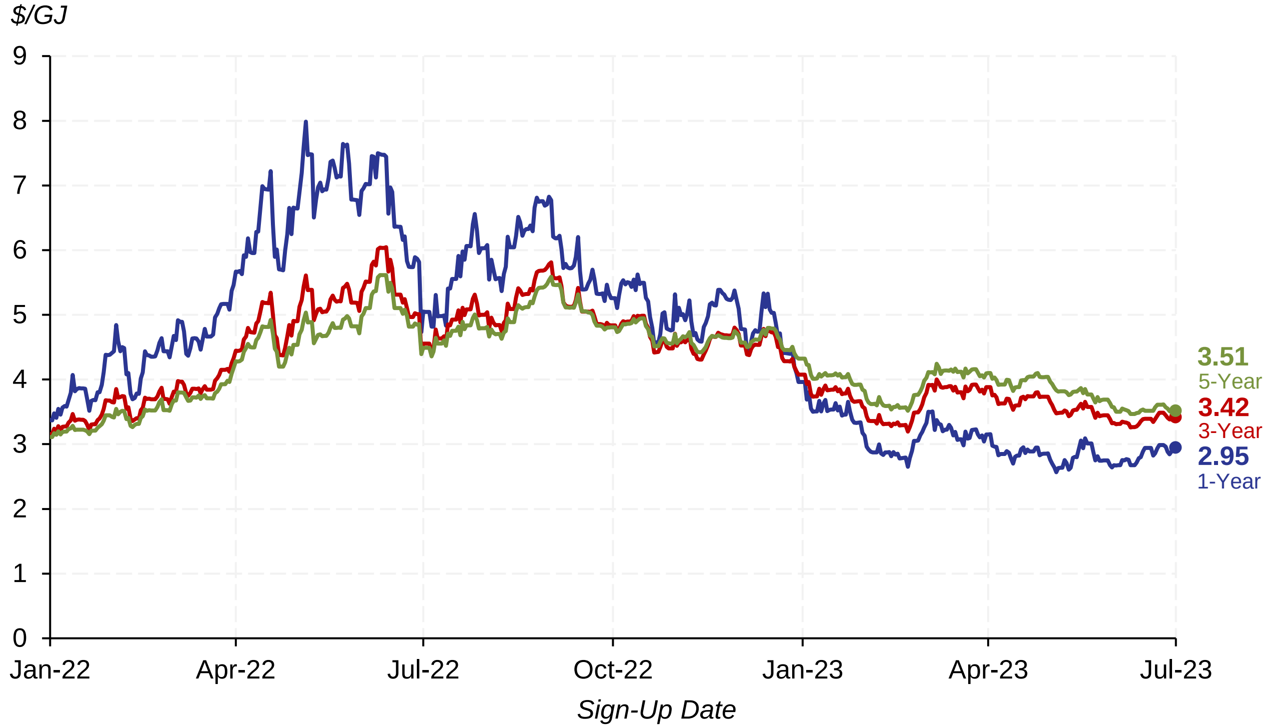
The expected cost for 1-year fixed rate electricity contracts increased in Q2 while the expected cost for 3- and 5-year fixed rate contracts were largely unchanged. As discussed in the forward market section, this is because forward prices for annual electricity contracts, such as CAL24 and CAL25 were relatively stable over Q2 but near term forward monthly prices increased and were more volatile. The expected cost for 1-, 3-, and 5-year fixed rate contracts increased by 7.3%, 1.2%, and 0.7% respectively in Q2 2023 (Figure 92).

Figure 92: Expected cost, fixed rate electricity contract, residential customer (January 1, 2022 to July 1, 2023)



The expected cost for fixed rate natural gas contracts dropped in Q2 with the decline in near-term and long-term forward natural gas prices. Unlike expected costs for electricity contracts, expected costs for natural gas contracts are higher for longer term contracts (Figure 93). The expected cost of 1-, 3-, and 5-year natural gas fixed rate contracts decreased by 7%, 12%, and 14% respectively in Q2 2023 and were lower year-over-year.

Figure 93: Expected cost, fixed rate natural gas contract, residential customer (January 1, 2022, to July 1, 2023)



Competitive fixed rates for electricity were relatively stable over Q2, reflecting the stability in underlying expected costs. The majority of 1-, 3-, and 5-year fixed rate offerings did not change throughout the quarter (Figure 94). Most fixed rate contracts were offered above their respective expected costs over Q2.

The MSA has observed competitive dynamics between select retailers that suggest they may be trying to compete for new customers by lowering their fixed rate prices in response to changes in expected costs. Retailer E had the highest 3-year fixed rates at the beginning of 2023, however, beginning in February, Retailer E began to reduce their 3-year fixed rate price and by June had become one of the lowest-priced providers of the 3-year. Retailers C, F, and G offered the lowest 5-year fixed rate at 12.79 ¢/kWh in Q2. Retailer F had previously offered a 5-year fixed rate at 12.99 ¢/kWh in Q1 but reduced it in Q2.

Competitive fixed natural gas rates were also largely unchanged in Q2 (Figure 95). Retailer C dropped their 1-year rate from $7.49/GJ to $4.99/GJ in March and continued to offer that rate in Q2. All fixed rates offered by major natural gas retailers in Q2 exceeded expected costs.

Figure 94: 1-, 3-, and 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (May 1, 2022 to July 1, 2023)

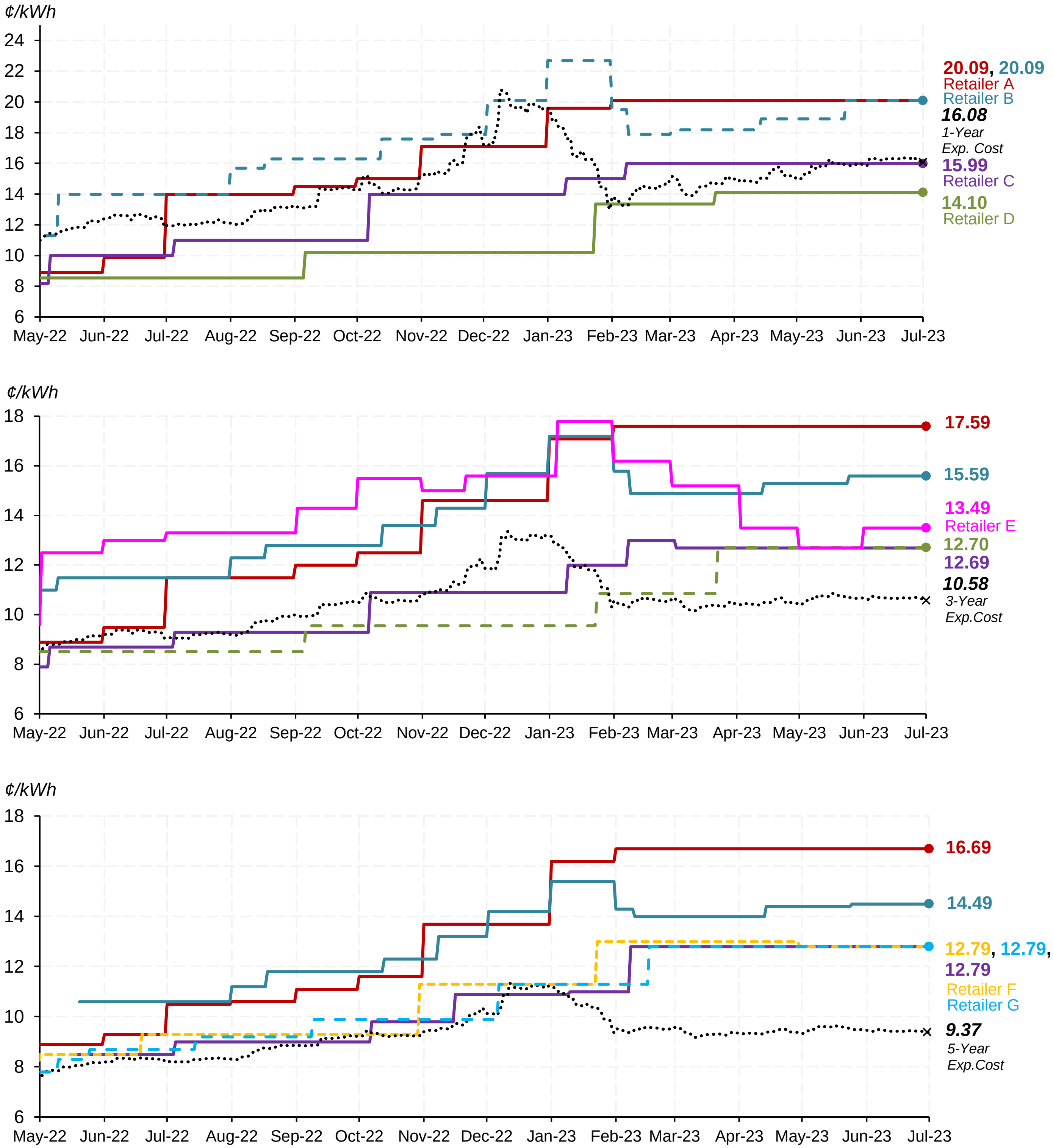
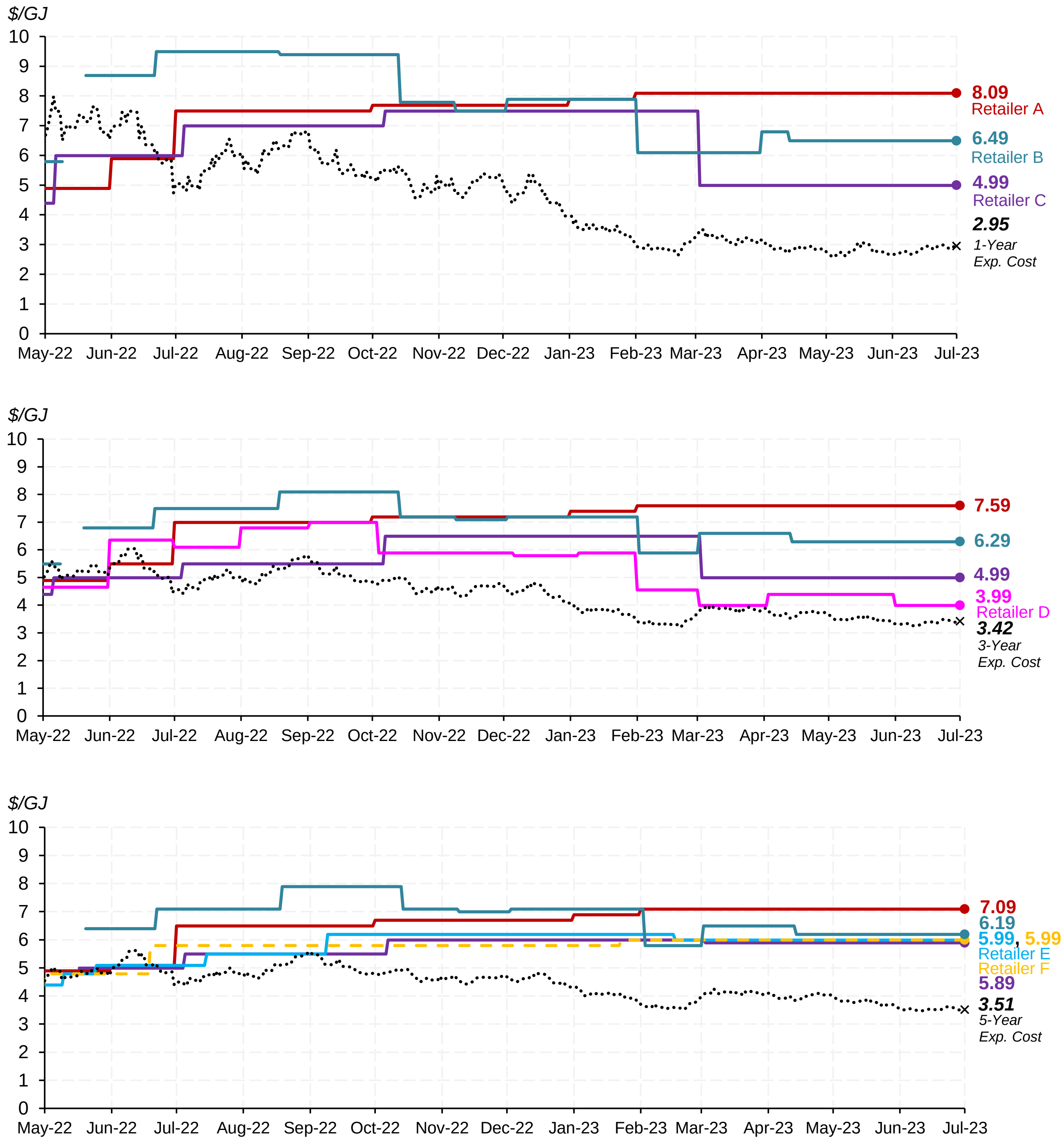


Figure 95: 1-, 3-, and 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (May 1, 2022 to July 1, 2023)

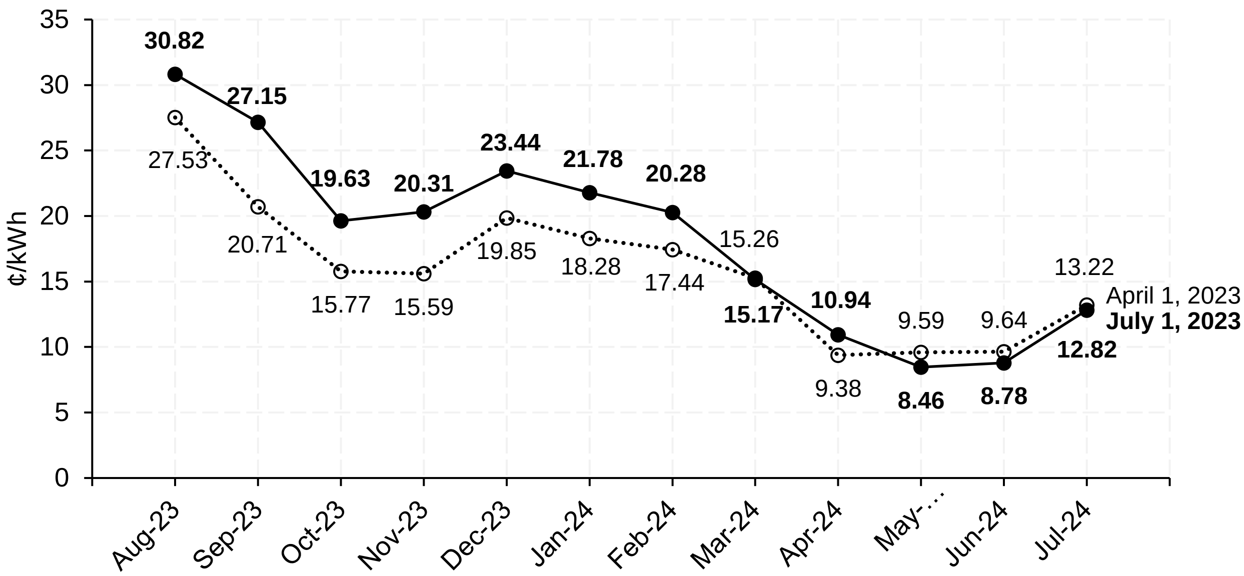


5.4 Regulated retail rate estimates

5.4.1 Electricity regulated rate estimates

Expected residential RRO monthly rates over the August 2023 to February 2024 period have increased since April 1, while rates expected between March 2024 and July 2024 have not significantly changed since the last quarter (Figure 96). On average, RRO rates for the remaining months of 2023 increased by around 4 ¢/kWh in the EPCOR service area, while expected RRO rates for January and February 2024 increased by 3.5 ¢/kWh and 2.8 ¢/kWh respectively.

Figure 96: August 2023 to July 2024 residential RRO monthly rate estimates, EPCOR service area (as of April 1, 2023 vs. July 1, 2023)

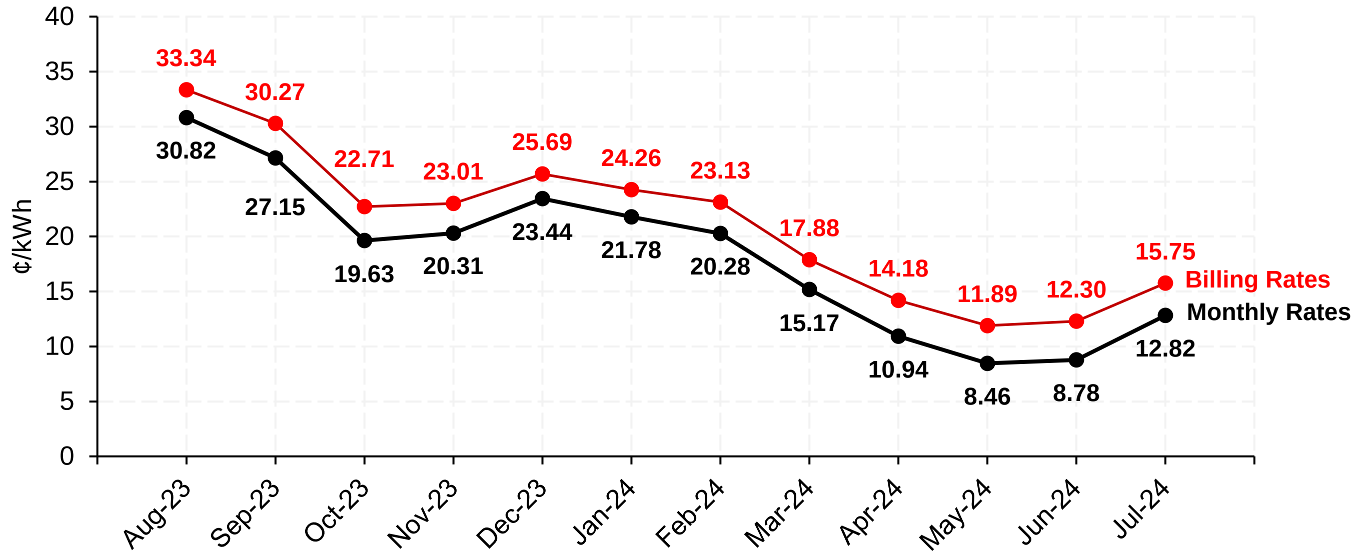


RRO customers paid 13.5 ¢/kWh in Q1 due to the rate ceiling applied on the regulated rates. The underlying RRO cost was much higher, averaging 26.87 ¢/kWh across all service areas over Q1.

In Q2, RRO providers started collecting the deferred revenue that resulted from the Q1 regulated rate ceiling. The deferred revenue will be recovered from RRO customers over the recovery period spanning April 2023 to December 2024 using “collection rates” added to the RRO monthly rates, resulting in the billing rates paid by RRO customers. If customers leave the RRO over the recovery period, the deferred revenue will be recovered over a smaller pool of RRO customers, which could increase collection rates over time.

The MSA's forecast of residential collection rates increased for all service areas except ATCO. The model uses RRO site counts as of Q1 2023, monthly recovery amounts, and historical seasonal changes in residential RRO customer site counts to derive expected collection rates. Expected collection rates in the EPCOR service area have increased by 0.25 ¢/kWh relative to the April 1 forecast and are expected to exceed 3 ¢/kWh in fall 2023 and spring 2024 (Figure 97). Residential collection rates between April and July 2023 were below 3 ¢/kWh in all service areas.

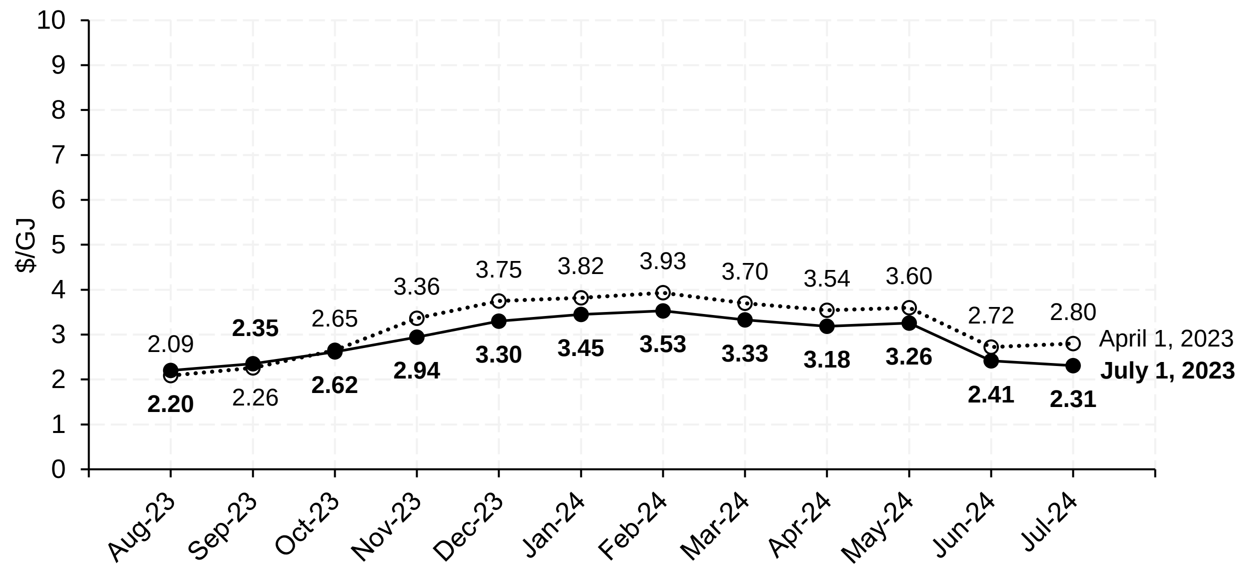
Figure 97: August 2023 to July 2024 estimated residential RRO monthly rates and billing rates, EPCOR service area (as of July 1, 2023)



5.4.2 Natural gas regulated rate estimates

Expected DRT rates for the August 2023 to July 2024 period have decreased by an average of $0.35/GJ since the MSA's April 1 forecast (Figure 98). Declines in natural gas prices since the beginning of 2023 have driven this decline in residential DRT expectations. The forecasted rates remain below the $6.50/GJ threshold for natural gas rebates by the Government of Alberta.

Figure 98: August 2023 to July 2024 residential DRT estimates, ATCO Gas service areas (as of April 1, 2023 vs. July 1, 2023)



5.4.3 Variable charge transparency in electricity bills

In recent years, electricity bills for the residential customers have increased (Table 11). For example, in 2016 the average RRO residential customer in the ATCO service area paid $142 for electricity. Their bills have increased since 2016 and as of the first half of 2023 an RRO residential customer in the ATCO service area paid a monthly bill of $265. A similar increase in RRO bills has been observed in other service areas as well. While customers on competitive fixed rates have been more insulated from these bill increases, competitive rate offerings have also increased since 2016, as have service area-level charges that all customers are exposed to.

Table 11: Average monthly residential RRO bills in ATCO service area (Excluding bill rebates from July 2022 to April 2023)

Year	Average monthly bill	% change (Relative to 2016)
2016	$141.57	
2017	$153.57	**+8%**
2018	$172.37	**+22%**
2019	$185.90	**+31%**
2020	$182.68	**+29%**
2021	$203.30	**+44%**
2022	**$262.46**	**+85%**
2023	**$264.92**[40]	**+87%**

With broad electrification expected in Alberta in the coming years as part of ongoing environmental efforts, it is increasingly important that retail customers can accurately assess the price of their energy consumption. The price of energy consumption can impact customers' decision making in the short-term through conservation efforts, and in the longer-term via investment in energy efficiency. A price signal lower than the price of energy consumption they actually face may lead customers to consume more than they would have had they known the actual price of their consumption, which could lead to customers facing higher than expected bills without a proper understanding on how to reduce their bills.

Fixed charges are charged to customers based on the length of a customer's billing cycle, and are typically charged on a per-day or per-month basis. Variable charges are charged to customers based on their electricity consumption and so are often charged on a ¢/kWh or $/kWh basis.

Many non-energy cost components in the Alberta market are charged to customers using both fixed and variable charges, further compounding this price signal problem as in the case of transmission and distribution these variable charges do not reflect the marginal cost of transmission and distribution. This could lead to inefficient levels of consumption, though here

[40] Average monthly bill over January to June 2023, excluding GOA Utility Commodity Rebates.

this would manifest as customers under-consuming relative to an efficient level of consumption if they were aware of the actual price of their energy consumption.

Residential customers' retail electricity bills are dependent on their area of residence, energy retailer and energy rate, consumption, length of a customer's billing cycle, and GST. In some cases, these factors can affect both the fixed and variable charges on customers' bills (Table 12).

Table 12: Factors impacting fixed and variable components of electricity bills

Factor	Fixed charges	Variable charges	Explanation
Service area	✓	✓	Non-energy rates (transmission, distribution, riders) vary by service area and in many instances can include fixed and/or variable charges.
Municipality	✓	✓	Municipalities charge access fees and franchise fees to distributors, which are passed on to consumers. These fees are often fixed percentages of rates set for the service area, and so increase fixed and variable charges on bills.
Energy retailer	✓	✓	Most energy retailers charge a fixed daily or monthly administration fee (a fixed charge) and an energy rate (a variable charge).
Consumption		✓	Billed values for all variable charges are determined based on the rate itself and the customer's energy consumption.
Length of billing cycle	✓		Fixed charges are affected by the number of days in a billing cycle and are often charged as $/month or ¢/day rates.
GST	✓	✓	GST is applied to all billing components, increasing both fixed and variable charges.

Most energy bills do not delineate between the fixed charges and variable charges associated with all factors described in Table 12 nor do most bills provide a summary of the total or average fixed and variable charges associated with the customer's billing cycle and consumption.[41] Instead, most energy bills indicate the fixed and variable charges related to the administration fee and energy charge associated with a customer's energy retailer, while non-retailer charges relating to a customer's service area and municipality are listed as totals per line item (in $). Customers unfamiliar with the details of service area and municipality-level charges may not understand that some of these charges are impacted by their consumption. This could lead to customers consuming more than they would if they knew the actual variable charges they face.

[41] "Total" fixed and variable costs are measured in dollars ($), while "average" fixed and variable costs could be measured in $/day and ¢/kWh respectively.

Variable charges faced by residential RRO customers have increased significantly in recent years and can vary significantly depending on what service area and municipality a customer resides in. While RRO energy rates (and competitive rate offerings) are similar in different service areas, non-retailer variable charges from transmission, distribution, and riders are typically higher in rural service areas like FortisAlberta or ATCO Electric (Figure 99) when compared to relatively urban service areas like EPCOR or ENMAX (Figure 100).

Figure 99: Breakdown of variable components of RRO bills (¢/kWh) in ATCO service area (City of Grande Prairie access and franchise fees), from January 2020 to June 2023

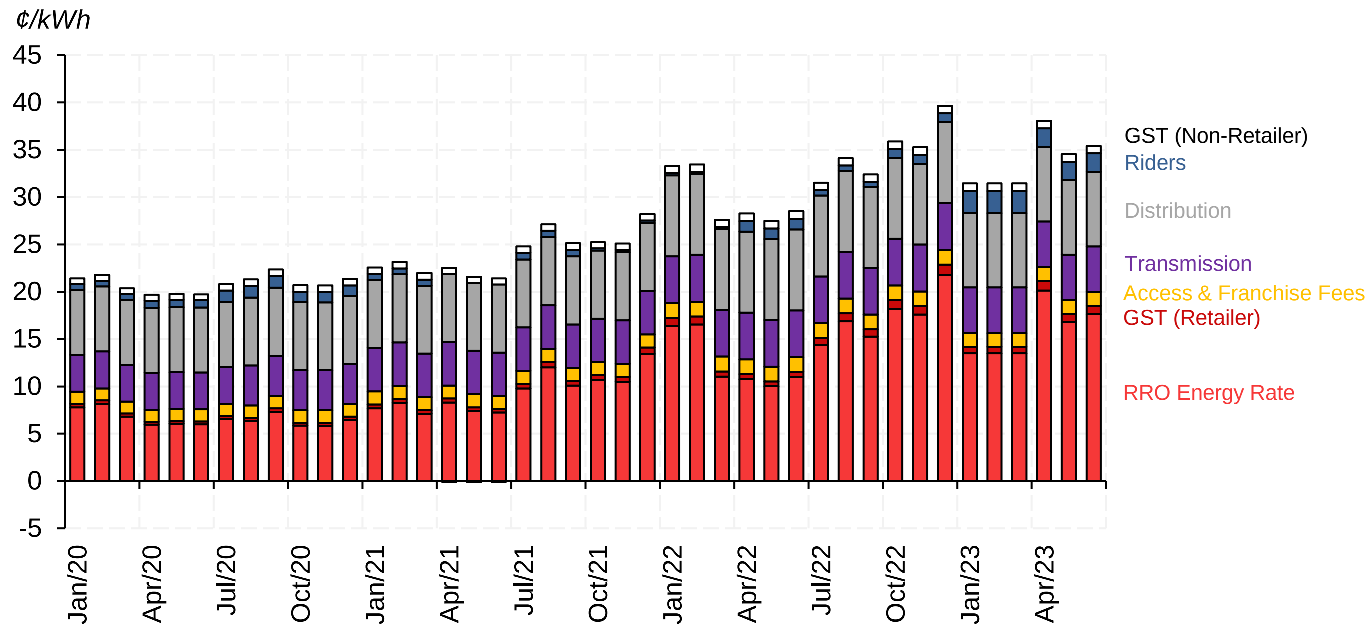
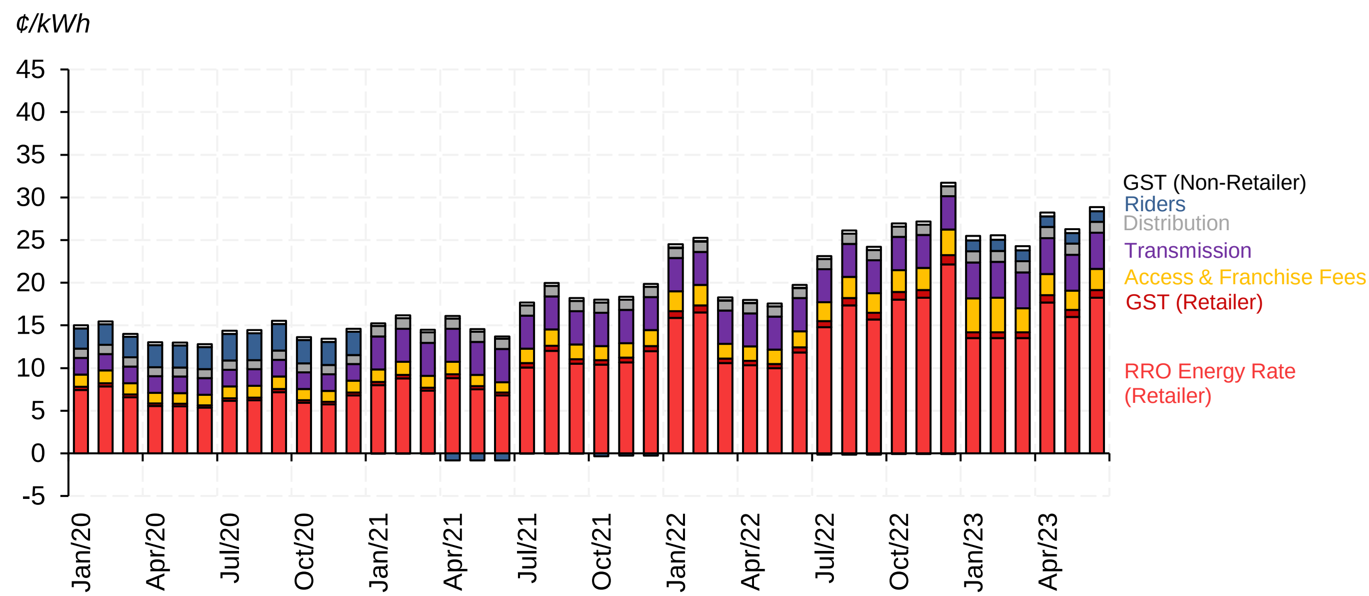
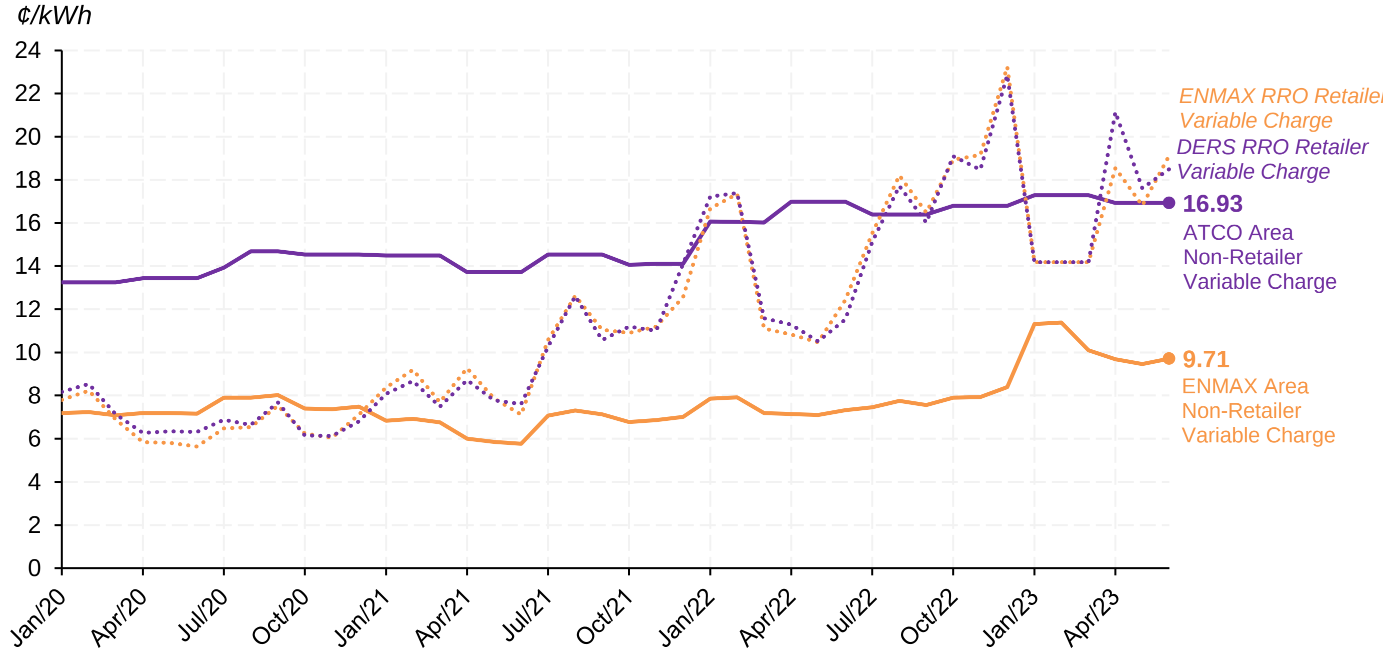


Figure 100: Breakdown of variable components of RRO bills (¢/kWh) in ENMAX service area (City of Calgary access and franchise fees), from January 2020 to June 2023



Non-retailer variable charges are often not elucidated in customer bills, and unlike energy rates are the same for all residential customers in a given service area and municipality regardless of retailer choice. In June 2023 all residential customers in the ENMAX service area faced non-retailer variable charges of 9.71 ¢/kWh (Figure 101). While this non-retailer variable charge constituted 34% of the total variable charge faced by an ENMAX RRO customer (28.9 ¢/kWh), only a 19.14 ¢/kWh variable charge may have been visible to RRO customers based on information available to them in bills (reflecting their RRO energy rate and applicable GST).

Figure 101: RRO energy variable, non-energy variable charges in ENMAX and ATCO service areas



Fixed charges have also risen since 2020. In the ATCO service area, total fixed charges for a residential RRO customer increased from approximately $58/month in January 2020 to $79/month by June 2023 (Figure 102) while ENMAX RRO customers experienced a smaller increase from $25/month to $33/month over the same period (Figure 103).

Residential RRO customers in the ATCO service area pay significantly greater fixed charges at both a retailer and non-retailer level as compared to customers in the ENMAX service area. Between July 2022 and April 2023, the Government of Alberta provided Utility Commodity Rebates to most residential Alberta electricity customers. These rebates were significant enough to reduce the total fixed charge faced by residential ENMAX RRO customers to a net rebate over July through February, while residential ATCO RRO customers only had a net rebate on fixed charges in January and February 2023 given the significantly higher fixed charges in that service area.

Figure 102: Breakdown of fixed components of RRO bills ($) in ATCO service area (City of Grande Prairie access and franchise fees), from January 2020 to June 2023

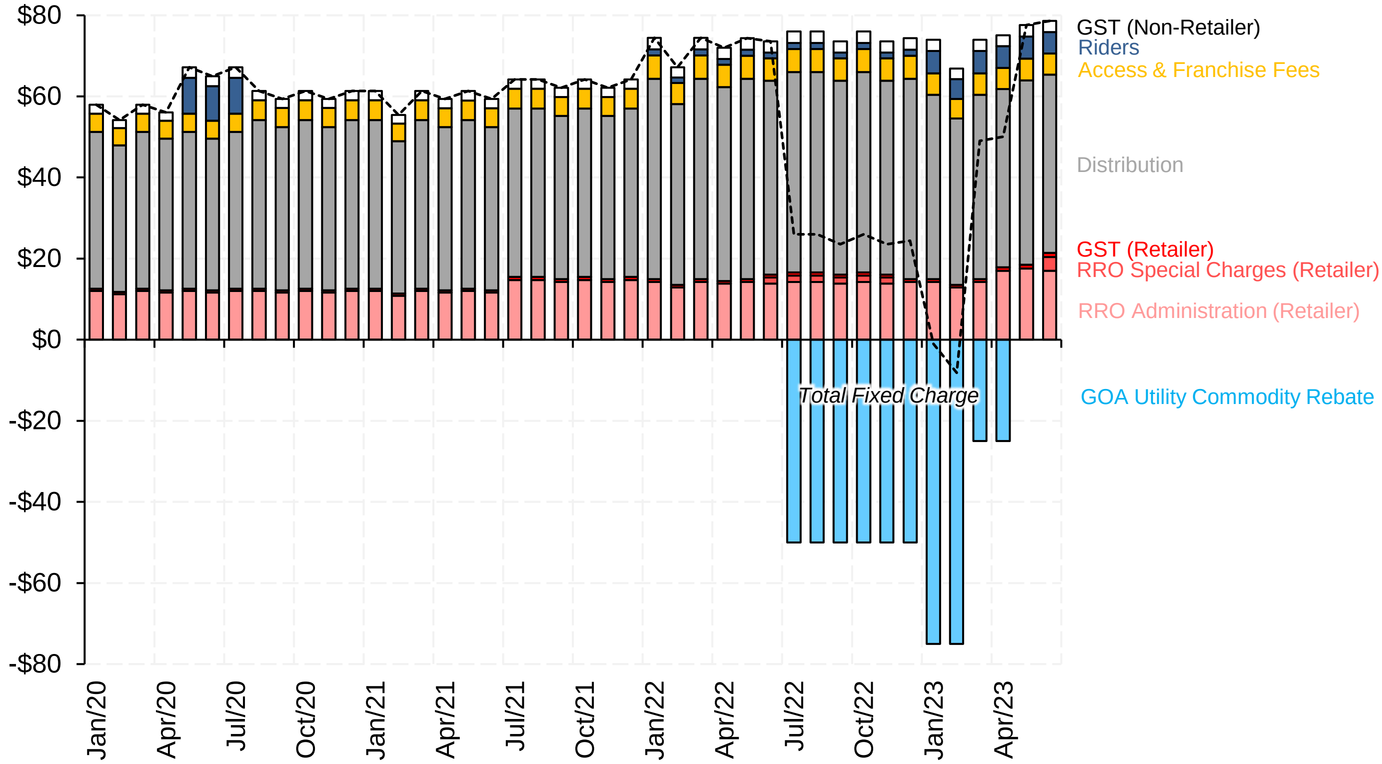
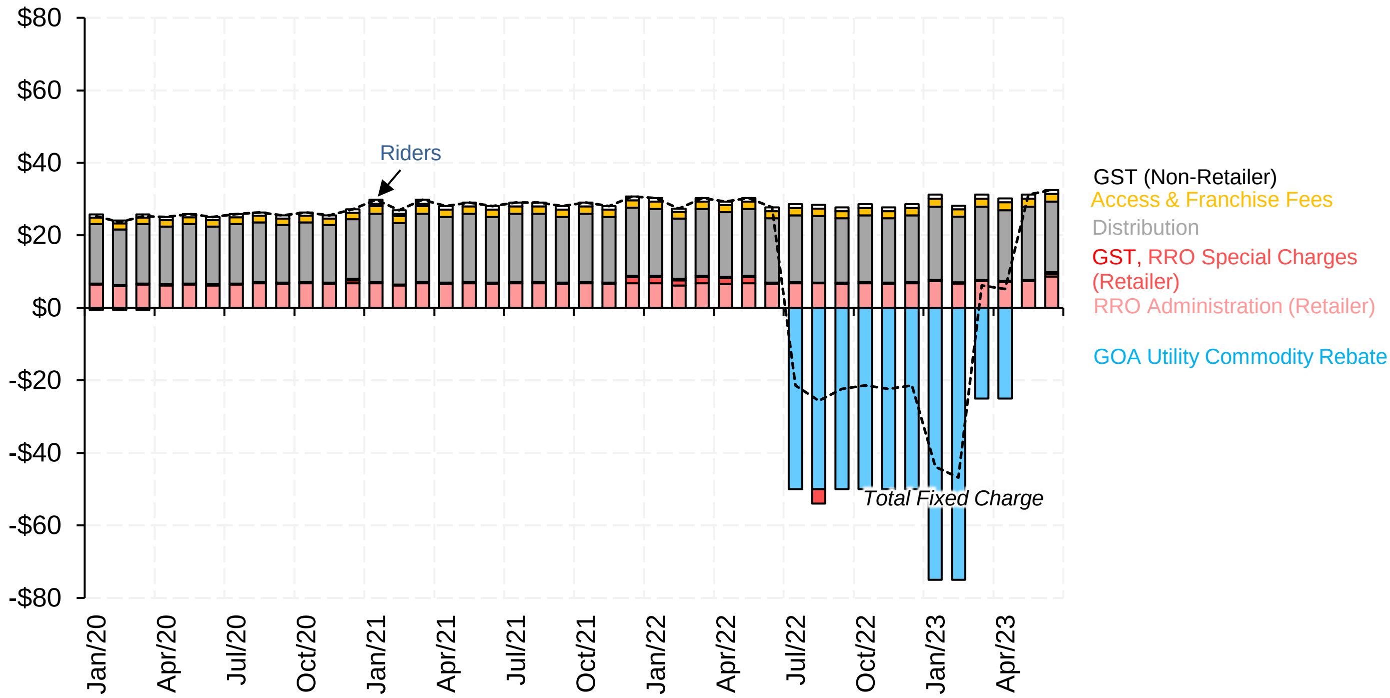


Figure 103: Breakdown of fixed components of RRO bills ($) in ENMAX service area, from January 2020 to June 2023



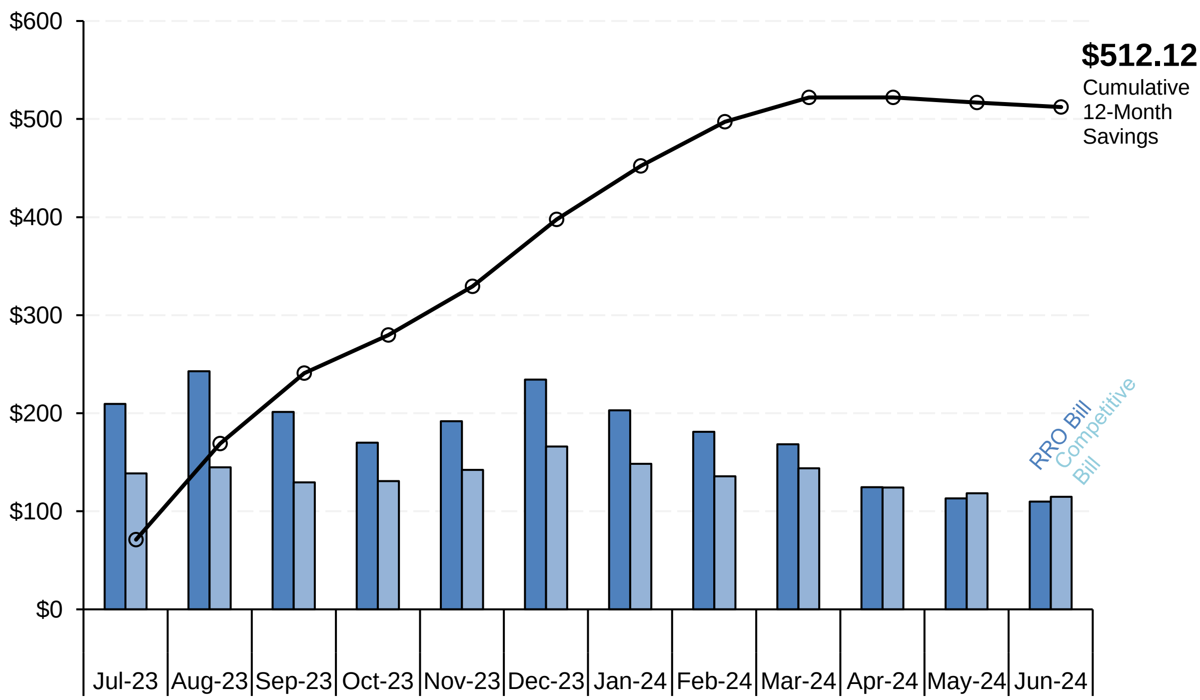
5.4.4 *Fixed rate switching incentives*

Residential RRO customers continue to have strong financial incentives to switch to competitive fixed electricity rates given RRO rate expectations for the July 2023 to June 2024 period (Figure 104). An average residential RRO customer in the ENMAX service area could expect to save over $512 over 12 months if they switched to the lowest priced 3-year fixed rate electricity contract among contracts available on July 1, 2023 (displayed in Figure 104).

This incentive to switch from the RRO to a competitive electricity fixed rate was $410 as of April 1, 2023. The increase in the switching incentive is largely because of higher forward prices, which has increased RRO billing rates.

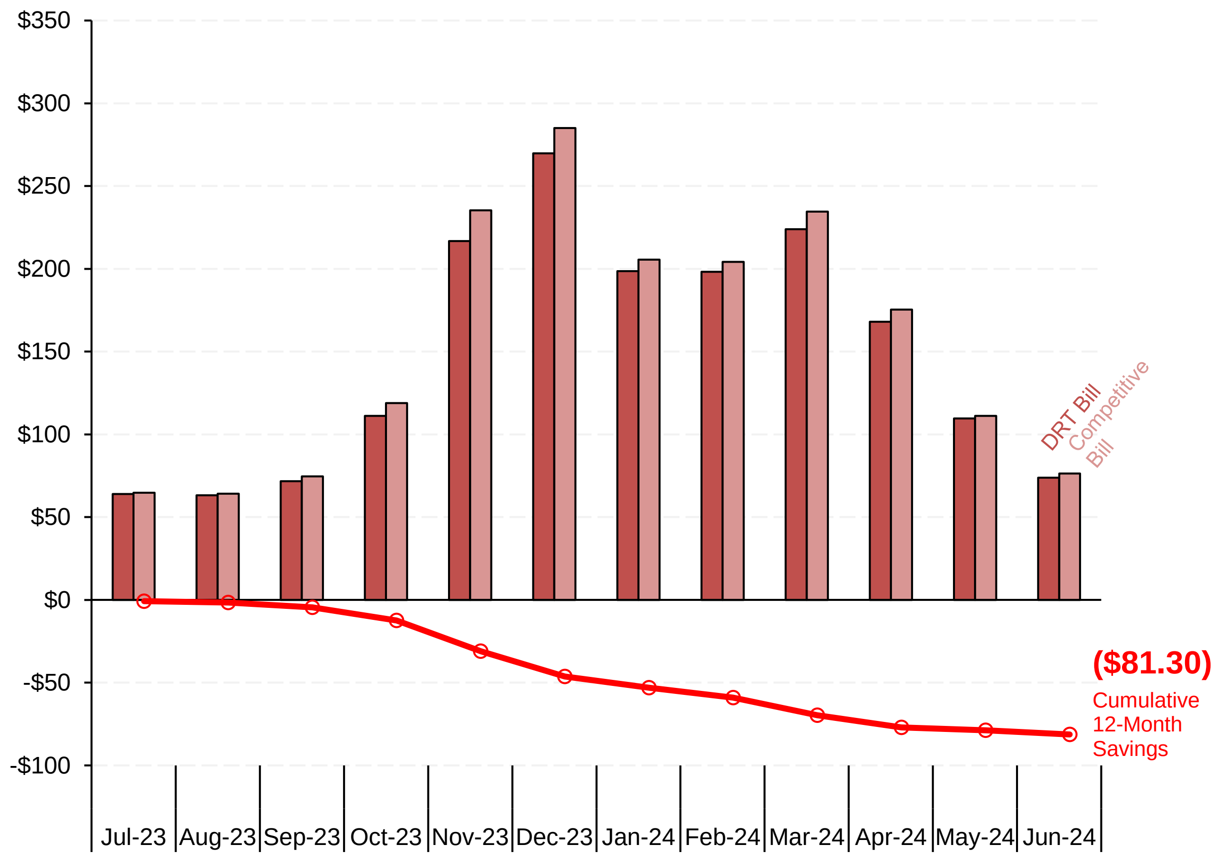
Unlike RRO customers, residential DRT customers are not financially incentivized to switch onto competitive rates at this time. If an average residential DRT customer had switched to the lowest priced 3-year fixed natural gas contract on July 1, 2023, they could expect to pay around $81 more in the 12 months that followed (Figure 105).

Figure 104: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at 12.69 ¢/kWh, $8.99/month)[42]



[42] Estimated bills for a residential customer in the ENMAX service area over July 2023 to June 2024 period.

Figure 105: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at $3.99/GJ, $6.85/month)[43]



5.5 Residential electricity consumption in Edmonton

Increasingly intermittent supply is resulting in more volatile pool prices. This creates the potential for cost savings and increases in economic efficiency for consumer responsiveness – by themselves or, more importantly, through retailers – to market price signals. Concurrently, new consumer technologies and real-time information exchange have made possible immediate consumer responsiveness to market signals — most importantly, coordinated by retailers.

In Alberta, in accordance with AUC Rule 021, *Settlement System Code Rules*, residential sites are settled based on standard load profiles for classes of consumers (e.g., residential sites in a given city) and cumulative meter readings. Many residential sites only have cumulative meters. However, many residential sites have interval meters that record actual hourly consumption information even though the hourly data are not used for settlement. This includes almost 400,000 residential sites in Edmonton.

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[43] Estimated bills for a residential customer in the ATCO Gas South service area over the July 2023 to June 2024 period.

To begin to develop a better understanding of site-level consumer behaviour, the MSA has collected an anonymous, confidential, random sample of about 1,600 residential sites in Edmonton. Sites with micro-generation were excluded; some apartment complexes that are not sub-metered are included. For these sites, hourly consumption data were collected for the 43,824-hour period from January 1, 2018 to December 31, 2022. Other information that was collected for these sites included whether the site was served by the RRO or a competitive retailer.

Table 13 provides information about average consumption in each year in the sample. Mean consumption was about 0.7 kW, which is equivalent to about 510 kWh of consumption per month, with little average variation across the years. The distribution of site-level average consumption for each of the five years is illustrated in Figure 106.[44] It is clear that there is a long right-tail to these distributions: most sites consume close to the average level but there is an increasing small number of sites with higher levels of consumption. As with the average, there is little variation of these distributions across the years in the sample.

Table 13: Residential site consumption in Edmonton

Year	Number of sites	Median (kW)	Mean (kW)
2018	1,584	0.47	0.71
2019	1,607	0.46	0.69
2020	1,631	0.48	0.72
2021	1,656	0.48	0.72
2022	1,677	0.47	0.71

[44] Only residential sites with consumption less than 2.5 kW are illustrated. In each year, these sites comprise approximately 96% of all sites in the sample. The largest of the sites that are not illustrated are apartment buildings without sub-metering.

Figure 106: Distribution of residential site consumption in Edmonton (less than 2.5 kW)

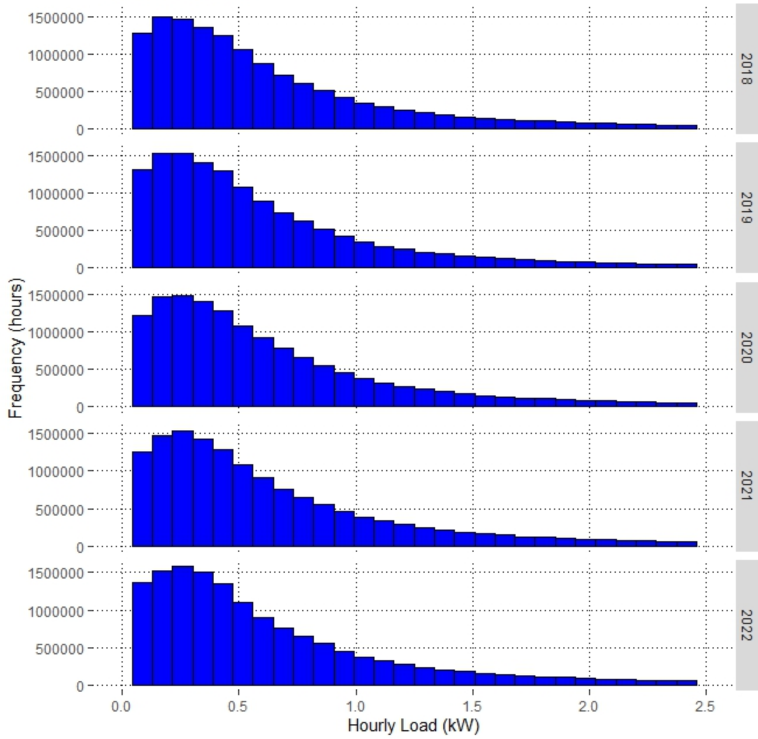


Figure 107 illustrates the average pattern of residential consumption over the months of the year, where sites are distinguished by being served by the RRO or a competitive retailer. The patterns of consumption over the course of the year are similar, but sites served by the RRO consume less electricity on average in each month than sites served by competitive retailers (non-RRO). This relationship is consistent across the years of the sample. In other words, larger residential consumers are more likely on average to have signed a competitive retail contract. Figure 108 illustrates a similar result but for average monthly consumption by hour.

In future reporting, the MSA will explore these data in greater detail, including consideration of the within-city location of the sites and related characteristics, the evolution of site-level retail contract choices, the variation of site-level consumption differences, and the characteristics of residential sites with micro-generation (which were excluded from the sample discussed above).

Figure 107: Monthly consumption profile for RRO and competitive residential sites

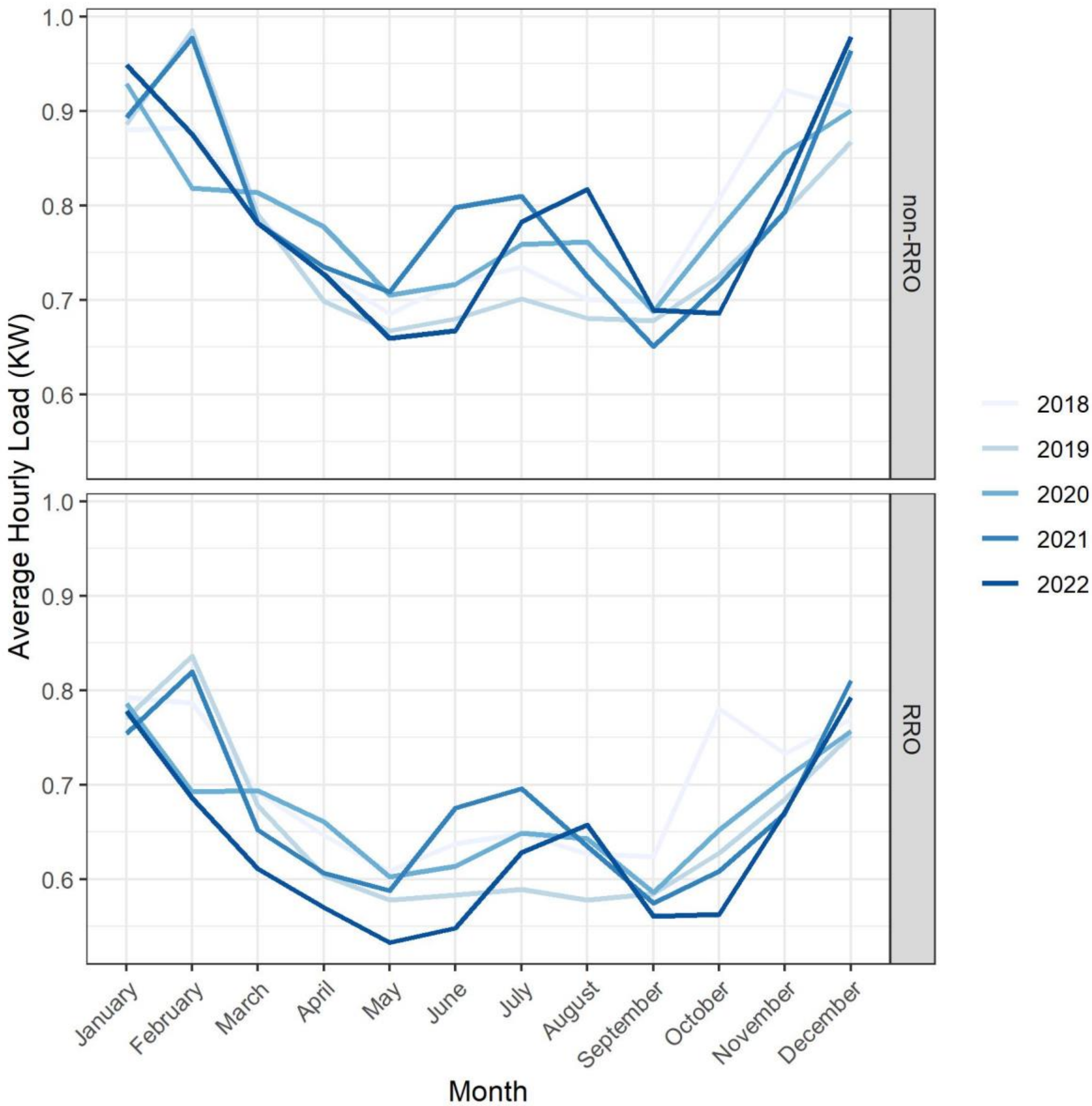
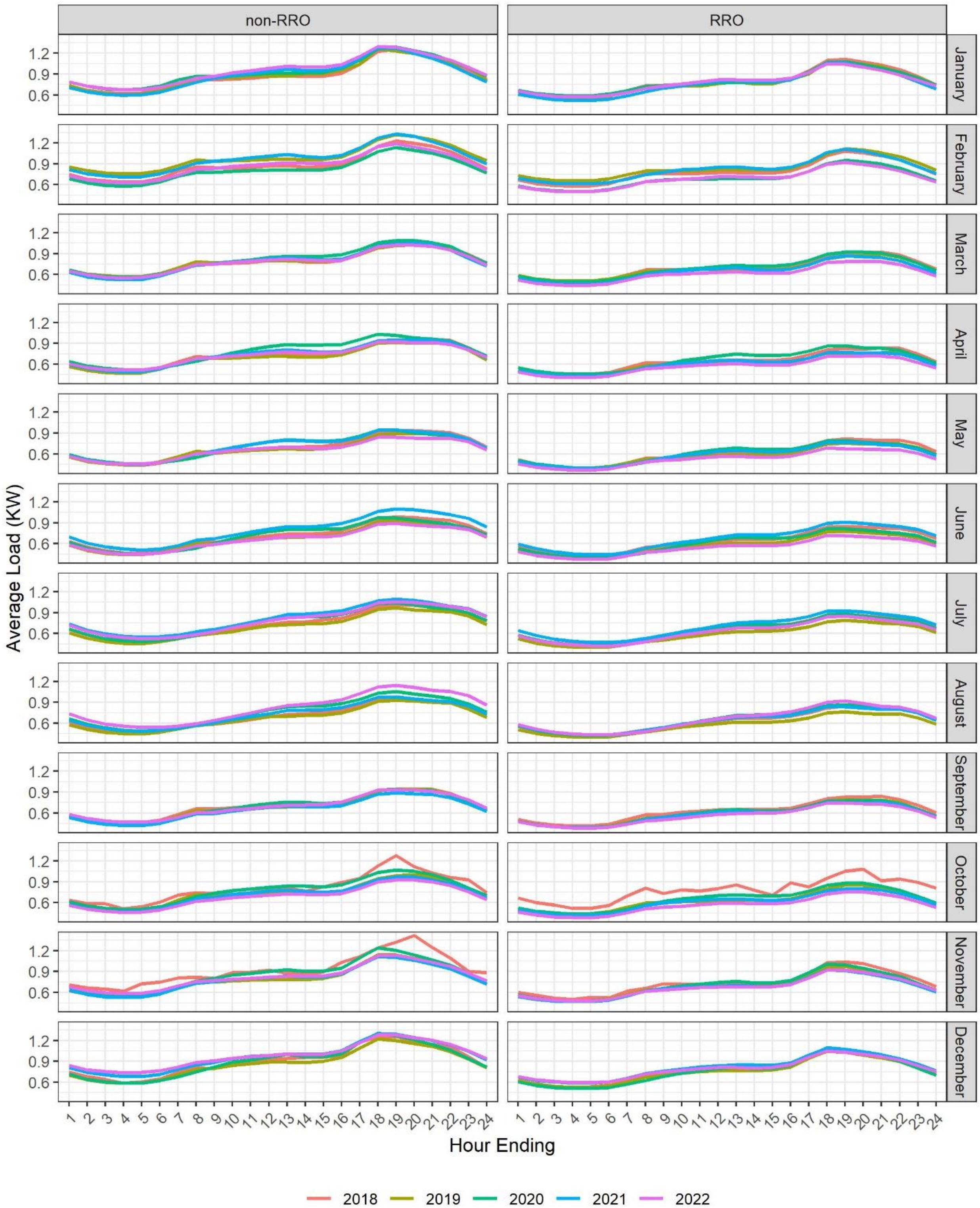


Figure 108: Monthly consumption profile by hour for RRO and competitive residential sites



6. REGULATORY AND ENFORCEMENT MATTERS

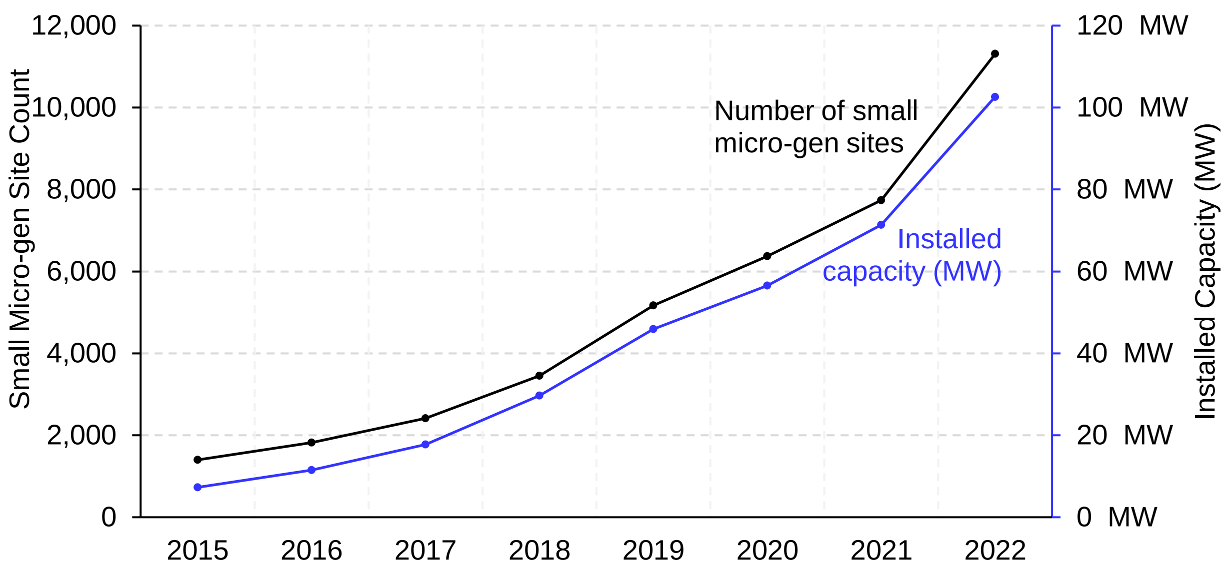
6.1 Micro-generation update

The *Micro-generation Regulation* (MGR) sets out a framework allowing electricity consumers to connect renewable or alternative energy generation to the grid. The MGR outlines how micro-generation (micro-gen) units are qualified, sized, and compensated. The MSA previously discussed micro-gen topics in its Q1 2021 and Q2 2022 reports.[45]

A micro-gen unit exclusively uses renewable or alternative energy sources to generate electricity. A small micro-gen unit must be less than 150 kW of installed capacity and have a bi-directional cumulative meter. Bi-directional cumulative meters measure the net flow of energy imported into the site (when consumption is greater than generation) and exported to the grid (when generation is greater than consumption).

The number of small micro-gen sites continues to increase, and at an accelerating pace (Figure 109). In 2022, 3,200 new small micro-gen sites were commissioned, more than double the 1,400 commissioned the previous year. 11,300 small micro-gen sites, totaling about 103 MW of installed capacity, were connected to the grid as at the end of 2022.

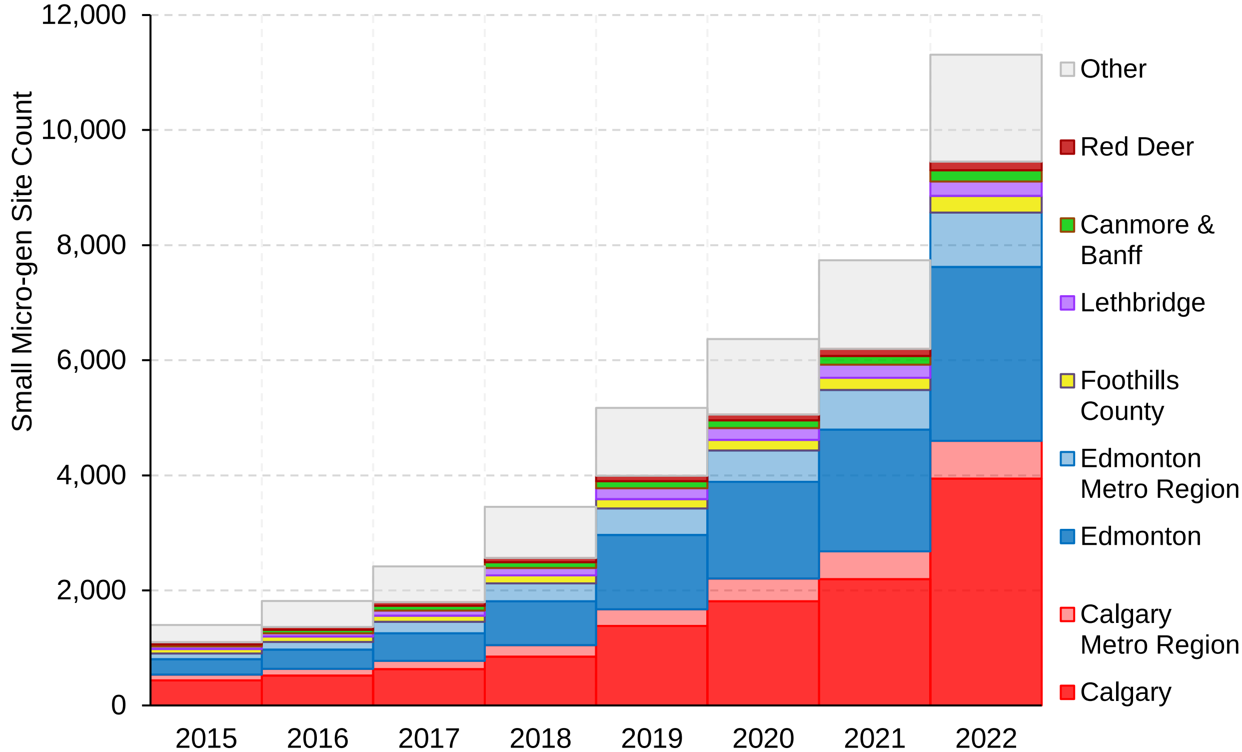
Figure 109: Number of small micro-gen sites and installed capacity (December 31, 2015 to December 31, 2022)



At the end of 2022, 76% of small micro-gen sites were in Calgary and Edmonton and the surrounding metropolitan regions (Figure 110). Year-over-year growth was most significant in Calgary.

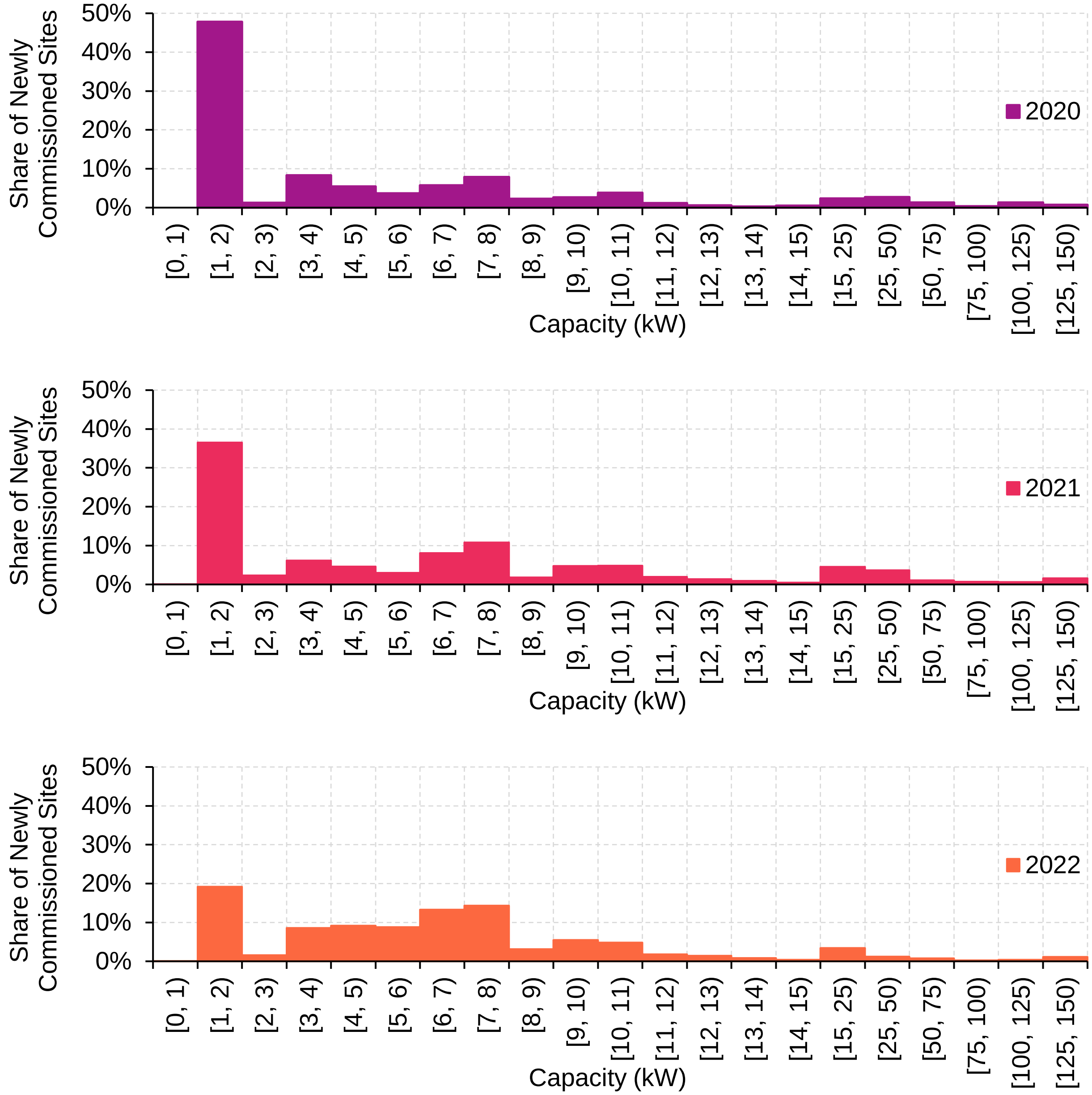
[45] Quarterly Report for Q1 2021; Quarterly Report for Q2 2022.

Figure 110: Number of small micro-gen sites by municipality (December 31, 2015 to December 31, 2022)



The average size of a newly commissioned small micro-gen site fell from 11 kW in 2021 to 9 kW in 2022. In 2022, a lower share of new sites were commissioned between 25 kW and 149 kW compared to 2021. This size is more typical of small commercial or farm sites. In 2022, a greater share of sites under 8 kW were commissioned compared to 2021, a size more typical for residential rooftop installations (Figure 111). This reflects the rapid growth of micro-gen in Calgary and Edmonton, most of which is residential rooftop solar.

Figure 111: Distribution of size of newly installed small micro-gen sites by year (2020 to 2022)



When an electricity customer with a small micro-gen unit imports energy into their site, they are charged a retail rate based on an agreement with an energy retailer. Conversely, the retailer must compensate the customer for the exported energy at the same retail rate the customer pays to import energy. The AESO reimburses the retailer for the amount the retailer paid to the small micro-gen customer and recovers the compensation cost through the ISO tariff as part of the line loss charges or credits, and associated Rider E calibration factor adjustments.

The total compensation paid to small micro-gen increased by 80% from 2021 to 2022, while total exported small micro-gen energy increased by 51% in the same period (Table 14). The larger growth in compensation, which outpaced the growth in exported energy, was driven by higher retail rates in 2022 (Figure 112).

Table 14: Annual exports to the grid and compensation paid to small micro-gen[46]

Year	Exports (MWh)	Small micro-gen compensation	Value of exports
2018	12,000	$820,000	$970,000
2019	21,000	$1,650,000	$1,480,000
2020	29,000	$2,580,000	$1,630,000
2021	37,000	$4,900,000	$4,980,000
2022	56,000	$8,970,000	$10,130,000

Figure 112 shows site-level small micro-gen exports and compensation in 2022; each site is plotted as a blue cross. Retail rates are shown as rays from the origin at different slopes. For example, sites compensated at 26 ¢/kWh are plotted along the steep solid black line representing that rate. Sites below the solid line were compensated at less than 26 ¢/kWh. As shown, compensation and exports varied significantly from site to site.

As shown, one outlier (labeled "A") received approximately $280,000 in compensation in 2022 and produced 1,052 MWh. The next highest provider (labeled "B") received approximately $61,000 and produced 327 MWh; a third of the volume of A. Sites B and A are combined heat and power (CHP) micro-gen sites. Another outlier (labeled "C") was compensated at a rate of approximately 17,500 ¢/kWh; it received almost $17,000 for the export of less than 100 kWh. This residential rooftop solar site has a 3.5 kW capacity.

Figure 113 shows site-level small micro-gen exports up to 10 MWh and compensation up to $1,000 in 2022, which captures 80% of sites. The median site exported 2.5 MWh in 2022. Most sites were compensated at a rate between 6¢/kWh and 26¢/kWh.

[46] The estimated value of micro-gen exports is based on the received price of utility scale solar assets, which weighs pool prices by the hourly capacity factor of generation from the following solar assets: BSC1, VXH1, HUL1, INF1, and SUF1.

Figure 112: Site-level small micro-gen exports and compensation in 2022

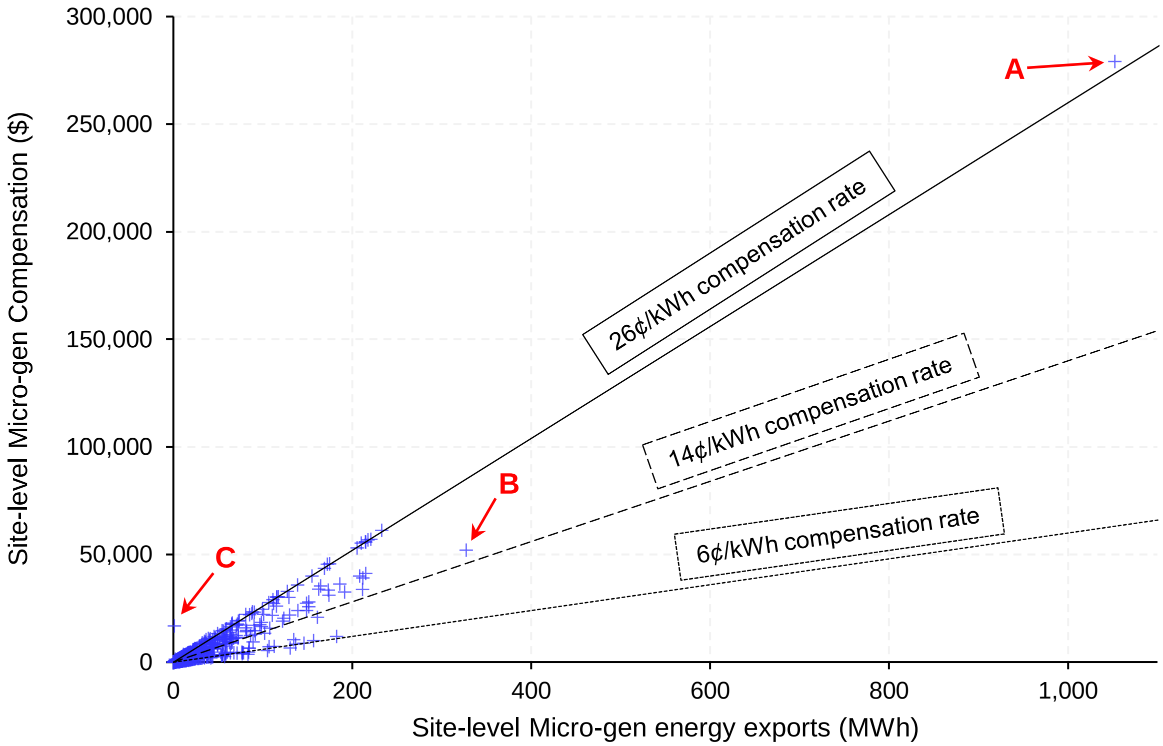
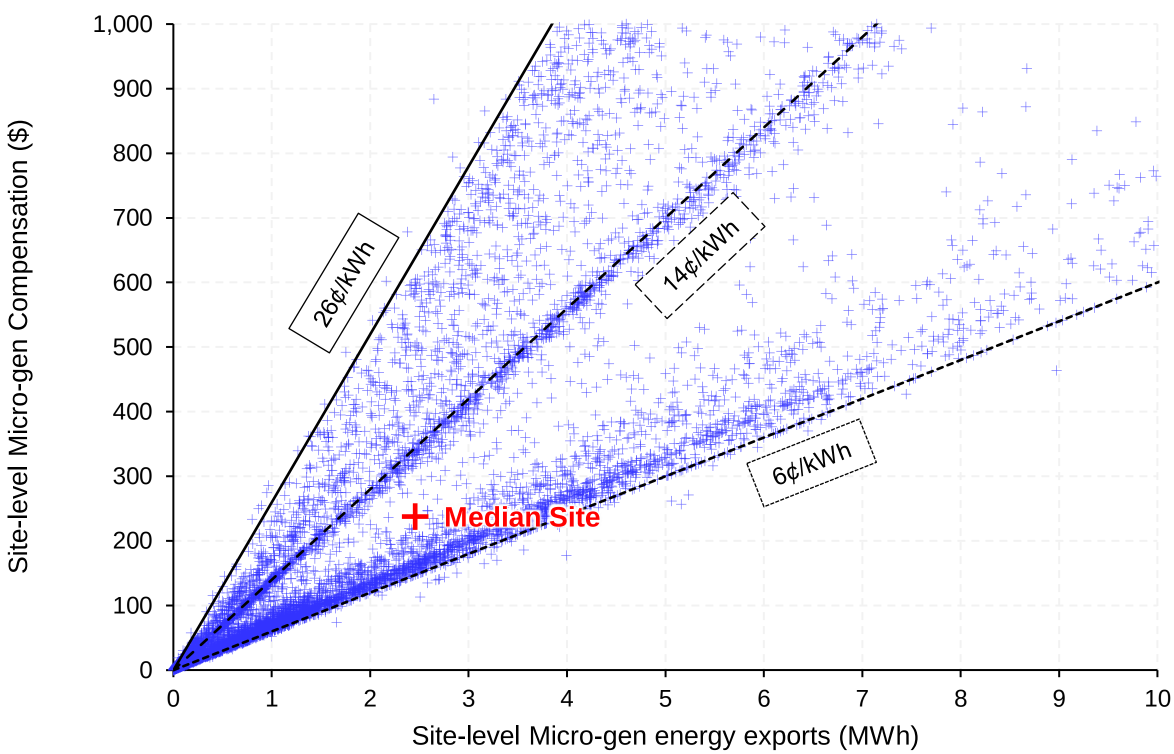


Figure 113: Site-level small micro-gen exports and compensation in 2022 up to 10 MWh and $1,000



Most small micro-gen export volumes were produced by customers who have signed retail contracts with one of four retailers. Figure 114 shows the percentage of small micro-gen exports corresponding to those four retailers. Retailer A's export volume share has increased and averaged 40% in 2022 (shown in light blue). Retailer D's share declined the most, with its average annual share falling from 16% in 2021 to 12% in 2022. This was likely driven by large differences in retail rates.

Figure 114: Percent of small micro-gen exports submitted by retailer, by month (January 2018 to March 2023)

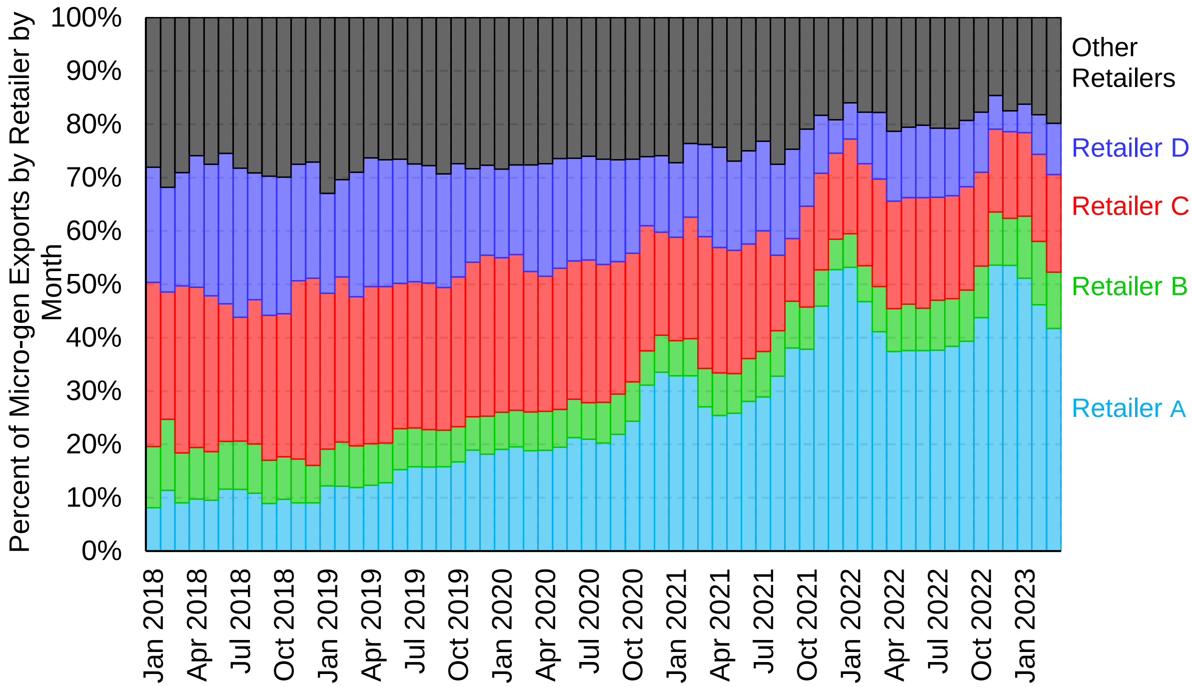


Figure 115 shows the amount of small micro-gen compensation retailers paid to their customers, for which the retailers were reimbursed by the AESO. Retailer A paid and received significantly more compensation than any other retailer in recent years. In 2022, Retailer A paid and received 53% of all compensation, up from 49% the year prior. This is about 4.3 times more than the next highest retailer. Retailer B, shown in green, paid and received more than Retailer C, despite its customers producing less than half the export volume than the customers of Retailer C. The differences in the levels of compensation and export volumes for retailers were driven by different retail rates.

Figure 115: Small micro-gen compensation by retailer, by month (January 2018 to March 2023)

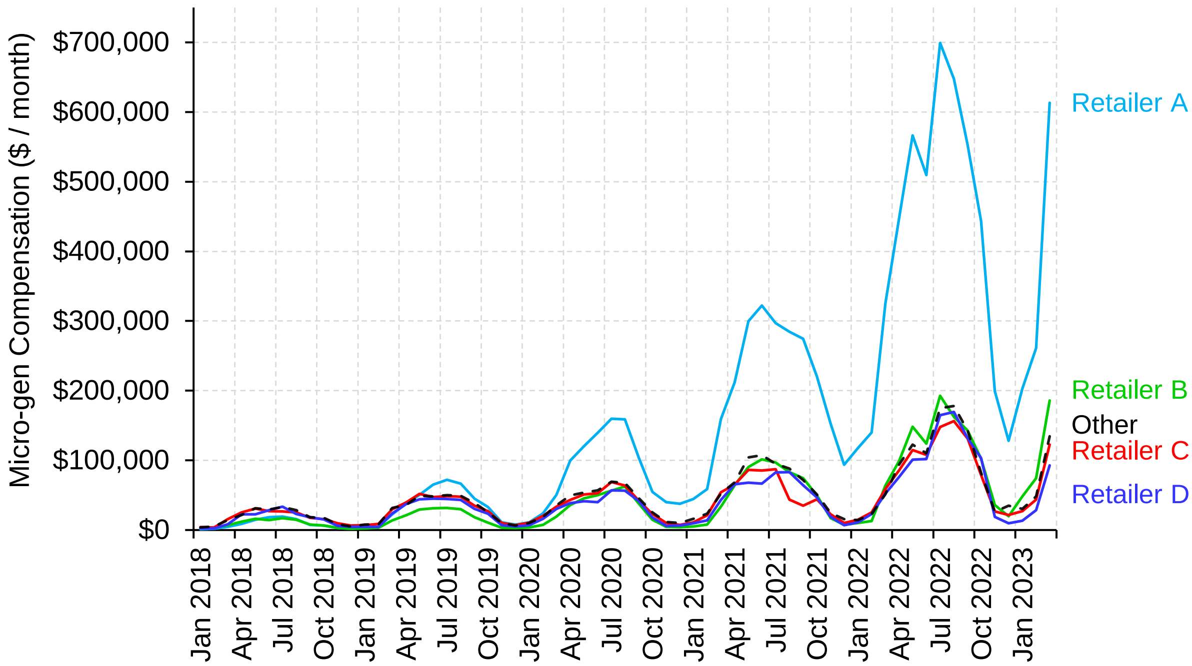
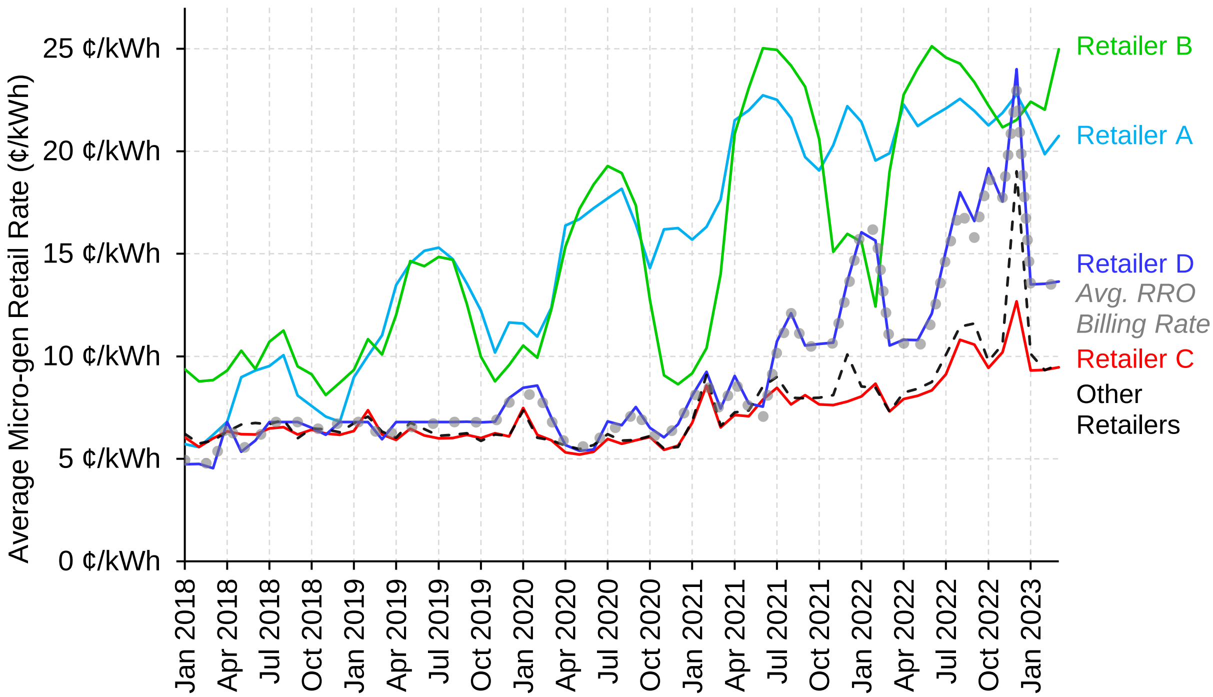


Figure 116 shows the volume-weighted average micro-gen retail rate charged and paid by retailers. Also plotted in grey dots is the average residential RRO billing rate for the four RRO zones. On average, micro-gen rates across retailers have increased, but the magnitude of change varies from retailer to retailer. The average rates of Retailer A and B remain higher than other retailers in most months: The rates for retailers A and B averaged over 20¢/kWh, while Retailer C and D's rates averaged under 10¢/kWh.

The rates for retailers A and B exhibited strong seasonality from 2019 through 2021. The seasonal variation in average rates reflects the fact that these retailers provide their small micro-gen customers the option to switch between high and low rates. Typically, a customer would choose a higher rate in the summer when, on average, their micro-gen site is a net-exporter of energy, resulting in a larger payment. A customer could choose a lower rate in the winter, when solar energy production is lower, and their site is a net importer of energy, resulting in a lower energy bill. In 2022, the rates of Retailers A and B showed less seasonal variation and remained at higher levels. This reflects increasing retail rates generally, as well as customers not changing to the lower winter rate. This could be because customers with sufficient micro-gen capacity to enable their site to net export year-round prefer to stay on the higher retail rate.

The average micro-gen rates of retailers other than Retailer A and B also increased from 2018 to 2022 but generally remained at levels similar to or below the RRO or other competitive retail contracts. The large difference in micro-gen retail rates between retailers drove the disproportionately large compensation paid and received by Retailers A and B versus their competitors.

Figure 116: Volume-weighted average small micro-gen retail rate by retailer, by month (January 2018 to March 2023)



6.2 Fast frequency response pilot

Between Q1 2022 and Q1 2023, two service providers participated in the AESO's Fast Frequency Response (FFR) Pilot. On June 26, 2023, the AESO published a report on lessons learned from that pilot.[47] The report noted "potential opportunities and challenges associated with service providers offering FFR services while also participating in operating reserves and the energy market."[48] The MSA reviewed several events where a service provider offered volumes of operating reserves and FFR, such that the total offered volume exceeded the asset's maximum capability and the asset would not have been able to comply with all dispatches related to those submissions.[49] Following its review, the MSA issued ten Notices of Specified Penalty totalling $57,000 for contraventions of ISO rule 201.4.

[47] Fast Frequency Response Pilot Lessons Learned (June 26, 2023)

[48] Fast Frequency Response Pilot Lessons Learned (June 26, 2023), page 8

[49] ISO rule 201.4

7. ISO RULES COMPLIANCE

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

From January 1 to June 30, 2023, the MSA closed 116 ISO rules compliance matters, as reported in Table 15.[50] An additional 234 matters were carried forward to next quarter. During this period 45 matters were addressed with NSPs, totalling $107,750 in financial penalties, with details provided in Table 16.

Table 15: ISO rules compliance outcomes from January 1 to June 30, 2023

ISO rule	Forbearance	Notice of specified penalty	No contravention
201.4	-	10	-
201.7	1	5	-
203.3	32	6	-
203.4	12	1	1
203.6	7	10	-
205.3	1	-	-
205.6	2	5	4
301.2	1	-	-
304.3	2	-	-
304.9	1	-	-
306.4	1	-	-
306.5	1	2	-
502.5	1	-	-
502.6	2	1	-
502.8	-	5	-
502.9	1	-	-
505.4	1	-	-
Total	**66**	**45**	**5**

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

Table 16: Specified penalties issued between January 1 and June 30, 2023 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)									Total ($)	Matters
	201.4	201.7	203.3	203.4	203.6	205.6	306.5	502.6	502.8		
Air Liquide Canada Inc.		500								500	1
British Columbia Hydro and Power Authority									500	500	1
Canadian Hydro Developers, Inc.	57,000									57,000	10
DAPP Power L.P.			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
Grande Prairie Generation Inc.			2,000							2,000	2
Heartland Generation Ltd.					250					250	1
MEG Energy Corp.							500			500	1
Mercer Peace River Pulp Ltd.		250								250	1
Morgan Stanley Capital Group Inc.					500					500	1
Powerex Corp.					9,250					9,250	5
Syncrude Canada Ltd.				250				250		500	2
TransAlta Corporation									5,000	5,000	4
TransAlta Energy Marketing Corp.					250					250	1
TransCanada Energy Ltd.			500							500	1
TransCanada Energy Sales Ltd.					5,000					5,000	1
Vitol Inc.					500					500	1
Voltus Energy Canada Ltd.						12,500				12,500	3
Windrise Wind LP							500			500	1
Total	57,000	1,750	3,750	250	15,750	22,500	1,000	250	5,500	107,750	45

The ISO rules listed in Table 15 and Table 16 fall into the following categories:

201 General (Markets)
203 Energy Market
205 Ancillary Services Market
301 General (System Reliability and Operations)
304 Routine Operations
306 Outages and Disturbances
502 Technical Requirements
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.[51] ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach to compliance with ARS focuses on promoting awareness of obligations and a proactive compliance stance. The MSA's process, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

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

From January 1 to June 30, 2023, the MSA addressed 41 O&P ARS compliance matters (Table 17).[52] 17 O&P ARS matters were carried forward to next quarter. During this period, 11 matters were addressed with NSPs, totalling $27,500 in financial penalties (Table 18). For the same period, the MSA addressed 96 CIP ARS compliance matters, as reported in Table 19, and 30 matters were addressed with NSPs, totalling $104,125 in financial penalties. 85 CIP ARS matters were carried forward to next quarter.

Table 17: O&P ARS compliance outcomes from January 1 to June 30, 2023

Reliability standard	Forbearance	Notice of specified penalty	No contravention
EOP-001	1	-	-
EOP-011	1	-	-
FAC-008	10	3	-
IRO-008	1	-	-
PRC-001	-	1	-
PRC-002	2	-	-
PRC-005	10	5	1
PRC-018	-	-	1
PRC-019	1	2	-
VAR-002	2	-	-
Total	28	11	2

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

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

Table 18: Specified penalties issued between January 1 and June 30, 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		
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
Castle Rock Ridge, LP	2,250				2,250	2
Cenovus Energy Inc.			2,500		2,500	1
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	13,000	7,500	27,500	11

The ARS outcomes listed in Table 17 and Table 18 are contained within the following categories:

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 19: CIP ARS compliance outcomes from January 1 to June 30, 2023

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	3	2	1
CIP-003	12	1	-
CIP-004	11	4	-
CIP-005	4	3	-
CIP-006	5	2	-
CIP-007	11	7	1
CIP-008	1	-	-
CIP-009	-	2	-
CIP-010	12	8	-
CIP-011	5	1	-
Total	64	30	2

The ARS outcomes listed in Table 19 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