MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q3 2023

November 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 Q3 was $152/MWh, a 32% decrease relative to Q3 2022. This decline was largely due to increased wind and solar generation, lower natural gas prices, and less hot weather. In addition, there were fewer high-priced offers submitted by large generators, particularly in September. The margin between pool prices and natural gas input costs averaged $127/MWh in Q3, which is 30% lower than in Q3 2022.

- In Q3, the volume of wind and solar generation that was constrained down increased by a factor of five compared to Q3 2022. The percent of hours where at least 1 MWh of wind or solar generation was constrained down was 46% in Q3. As outlined in this report, the MSA has identified conditions when the pool price may have been set inaccurately during periods of congestion. In some instances, these price inaccuracies resulted from incorrect data on potential wind generation, which meant the AESO inaccurately calculated the volume of constrained down generation. The MSA has identified about 100 hours over a four month period when pool price may have been set inaccurately.

- Increasing amounts of wind and solar generation have expanded ramp requirements for the AESO. For example, because of large and swift generation changes at the Travers solar asset (465 MW) the AESO have activated more standby regulating reserves in recent quarters and began to buy more active regulating reserves on August 25. In September, the received price of active spinning reserves was below the received price of active supplemental reserves for the first time since August 2013. This resulted from changes to the offer behaviour of loads in the supplemental market and competition between hydro and batteries in spinning.

- Monthly forward prices decreased over the quarter as realized pool prices for July, August, and September came in below forward market expectations. The price of Q4 2023 fell by 16% over the quarter while the price of Q1 2024 fell by 25%. Pool prices are expected to be lower in the coming years due to the upcoming addition of the Cascade combined cycle project, the return of HR Milner, the repowering of Genesee 1 and 2 from coal to combined cycle, the development of cogeneration at the Suncor Base Plant, and increasing amounts of wind and solar supply.

- In April 2023, the number of customers that left the Regulated Rate Option (RRO) was 27,000, the highest loss since 2012. Competitive electricity rates were relatively stable over Q3, even though the expected costs of providing these contracts fell. Expected RRO rates for the November 2023 to October 2024 period fell over the quarter, lowering the incentives for RRO customers to switch to fixed rate contracts.

- From July 1 to September 30, 2023, the MSA closed 78 ISO rules compliance matters; 27 matters were addressed with notices of specified penalty. For the same period, the MSA closed 58 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; 23 matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

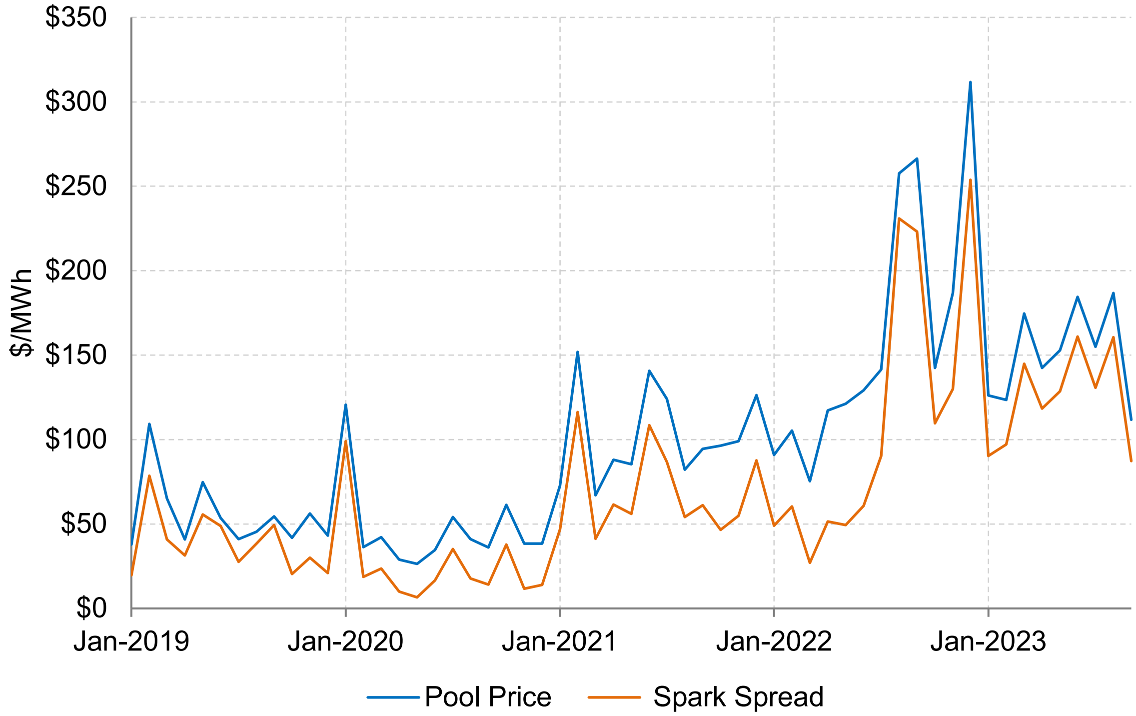
The average pool price in Q3 was $152/MWh, a 32% decrease compared to Q3 2022. The lower pool prices were due to increased wind and solar generation, lower natural gas prices, and lower demand in August and September (Table 1). In addition, there was less exercise of supplier market power year-over-year, particularly in September.

Table 1: Summary market statistics for Q3 and Q3 2022

		2023	2022	Change
Pool price (Avg $/MWh)	July	$155.00	$141.55	9%
	August	$186.80	$257.75	-28%
	September	$111.74	$266.39	-58%
	Q3	**$151.60**	**$221.41**	**-32%**
Demand (AIL) (Avg MW)	July	9,886	9,853	0%
	August	9,739	9,840	-1%
	September	9,314	9,382	-1%
	Q3	**9,650**	**9,695**	**0%**
Gas price AB-NIT (2A) (Avg $/GJ)	July	$2.42	$5.13	-53%
	August	$2.61	$2.68	-3%
	September	$2.44	$4.32	-44%
	Q3	**$2.49**	**$4.04**	**-38%**
Wind generation (Avg MW)	July	761	456	67%
	August	808	523	55%
	September	1,014	638	59%
	Q3	**859**	**538**	**60%**
Solar generation (Avg MW during peak hours)	July	622	386	61%
	August	562	362	55%
	September	454	267	70%
	Q3	**547**	**339**	**61%**
Net imports (+) Net exports (-) (Avg MW)	July	94	691	-86%
	August	108	478	-77%
	September	146	296	-51%
	Q3	**116**	**491**	**-76%**
Available Thermal (Avg MW)	July	8,882	9,154	-3%
	August	8,722	9,045	-4%
	September	8,254	8,414	-2%
	Q3	**8,623**	**8,876**	**-3%**

Figure 1 illustrates monthly average pool prices and spark spreads since January 2019. The spark spread is defined as the margin between pool prices and the cost of natural gas.[1] The average spark spread in Q3 was $127/MWh, a 30% decrease compared to Q3 2022.

Figure 1: Average pool price and spark spread by month (January 2019 to September 2023)



The cost of natural gas is the main element of the variable cost of electricity in Alberta. In Q3, natural gas generation assets set the System Marginal Price (SMP) 90% of the time. Natural gas prices in 2023 have been lower and less volatile than in 2022 (Figure 2). This has put downward pressure on cost-based offers into the energy market and led to lower pool prices in many hours of the quarter (e.g., see Figure 8).

Wind and solar generation continued to increase year-over-year putting downward pressure on pool prices. Figure 3 illustrates duration curves for wind and solar generation in Q3 and Q3 2022. These curves illustrate the percent of hours in which wind and solar generation were below a certain level. For example, in 80% of hours in Q3 wind generation was under 1,447 MW and in 20% of hours solar generation was above this level. In Q3 2022, the 80th percentile of wind generation was 904 MW or 542 MW lower. The marked upward shift in these duration curves illustrates higher wind and solar generation in Q3 this year.

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[1] The spark spread calculations here assume a heat rate of 10 GJ/MWh.

Figure 2: Same-day natural gas prices at AB-NIT (2022 and Q1 to Q3)

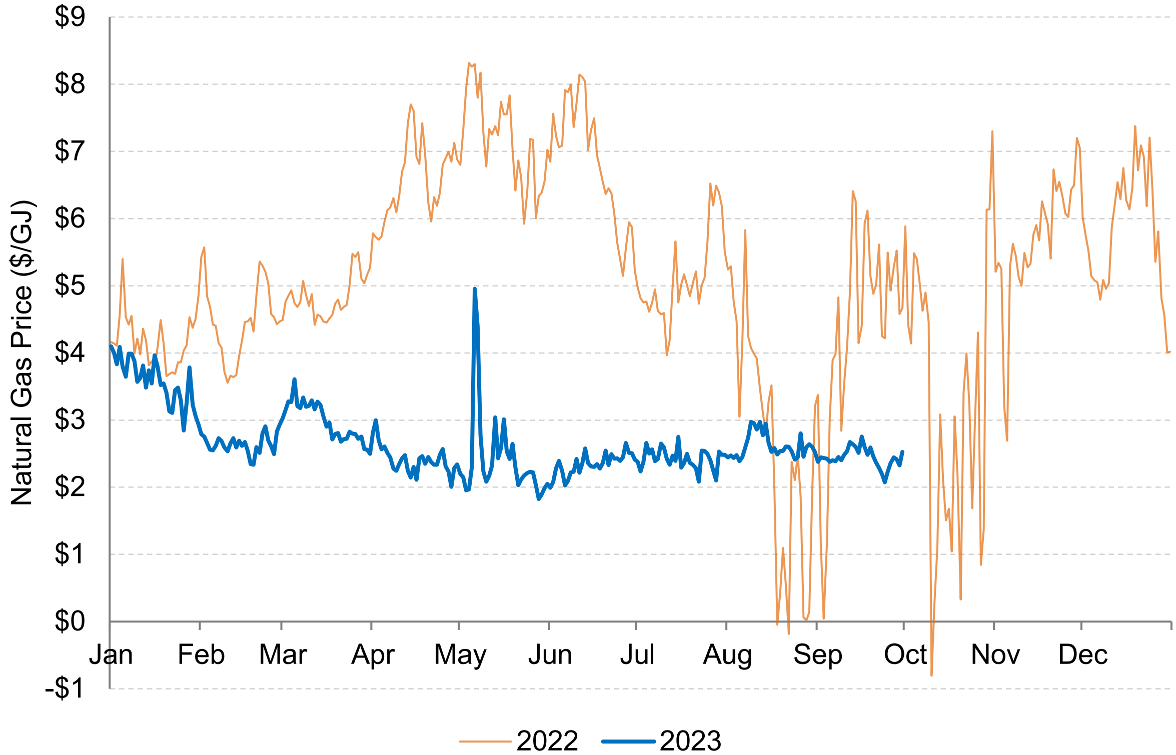
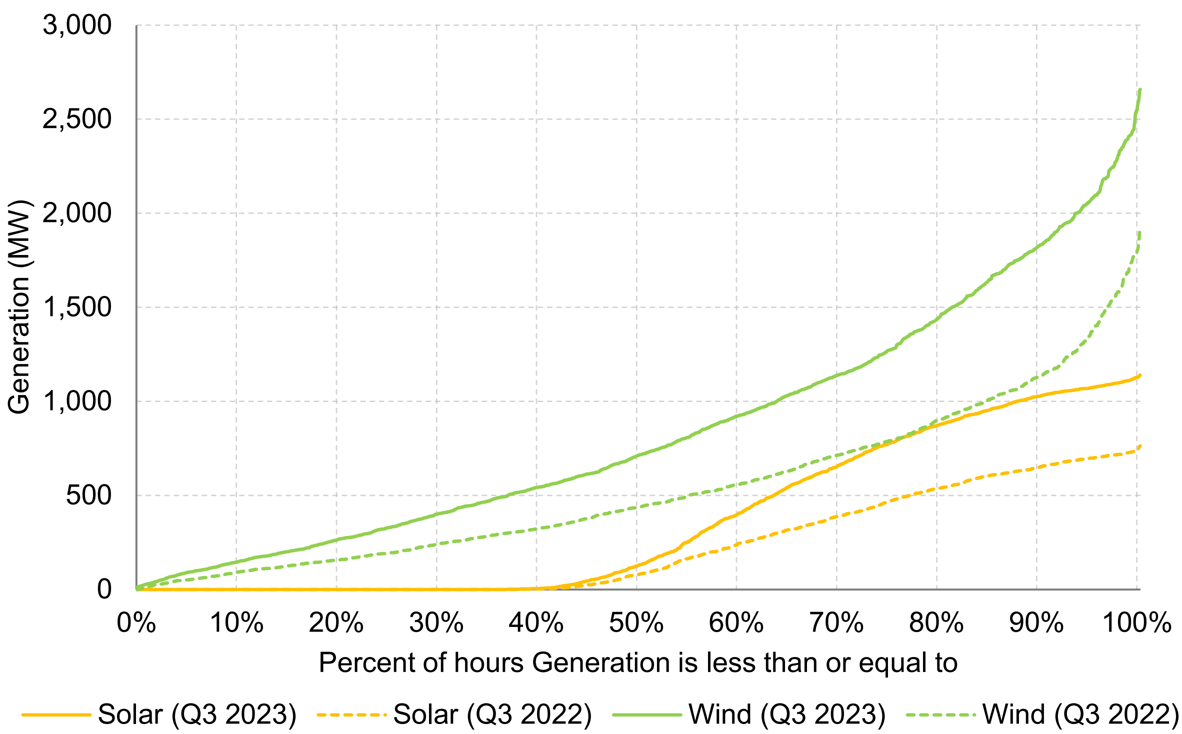
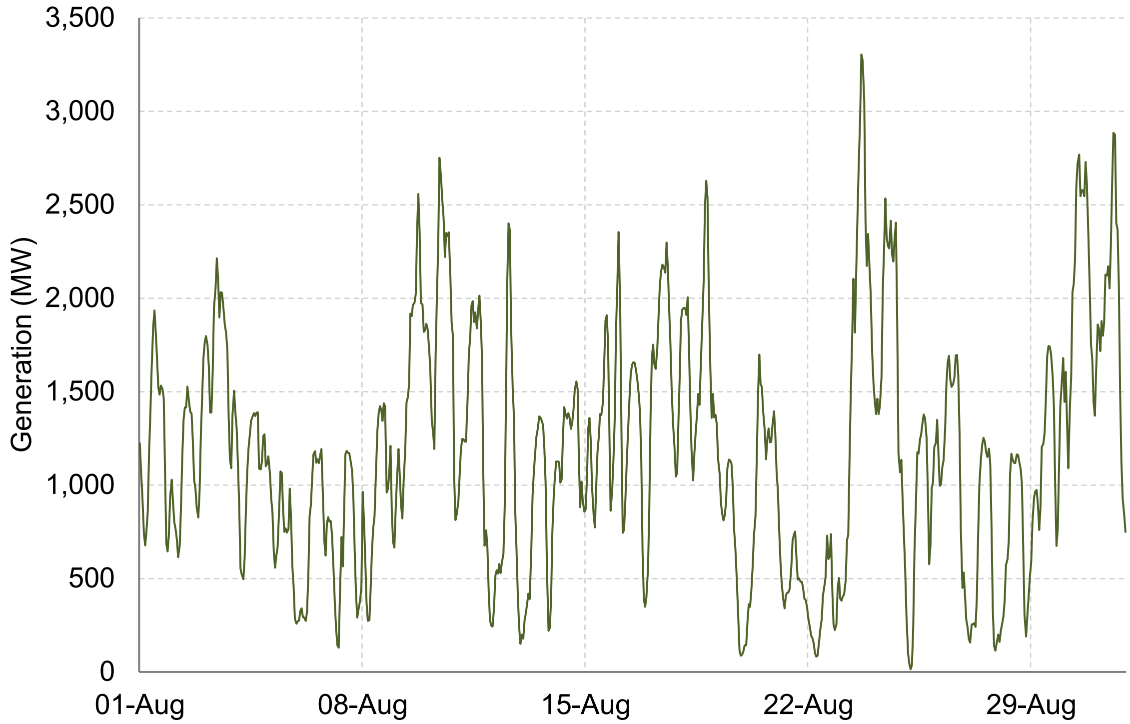


Figure 3: Duration curves for wind and solar generation (Q3 and Q3 2022)



Production from intermittent generators (wind and solar) depends upon prevailing weather conditions which are volatile. For example, Figure 4 illustrates the hourly intermittent generation in August. The addition of more intermittent generation capacity has led to more unpredictable ramping requirements for the AESO and has caused the AESO to procure more regulating reserves, as is discussed in section 3.

Figure 4: Hourly intermittent generation in August 2023



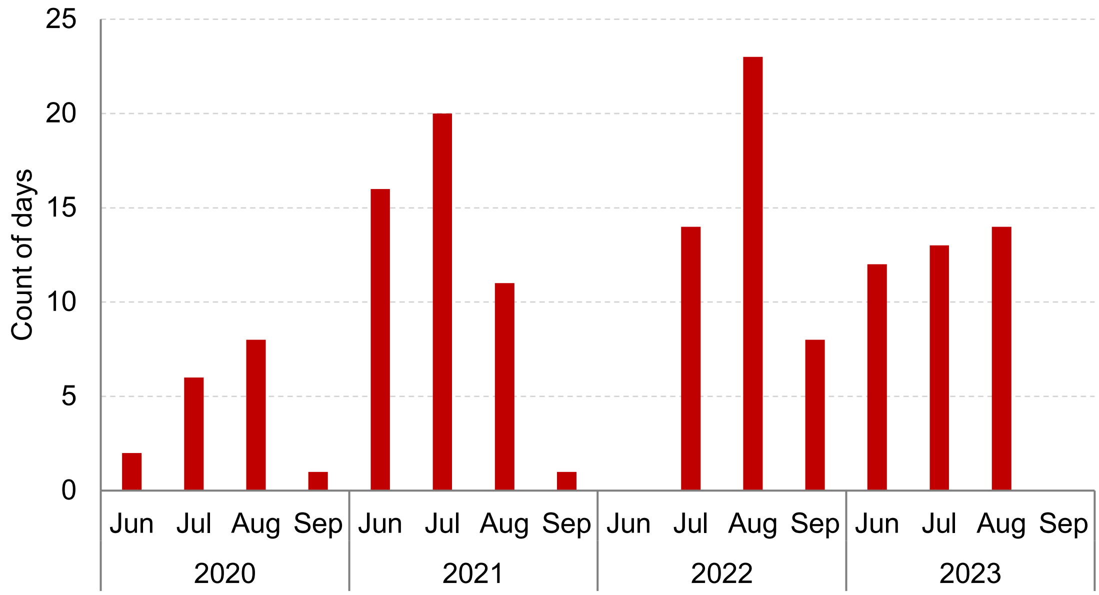
Alberta Internal Load (AIL) in Q3 peaked at 11,522 MW in HE18 of July 24, which is 199 MW less than the summer record set in June 2021.[2] Year-over-year, AIL was lower in August and September because of milder weather. In August this year, there were 14 days in which temperatures peaked above 25°C (averaged across Calgary, Edmonton, and Fort McMurray) compared to 23 such days in August 2022 (Figure 5). In September there were no such days in 2023 compared to eight in 2022. Table 2 provides average summer temperatures by month.

[2] AIL is a measure of total demand in Alberta; it includes generation that was produced and consumed on-site.

Table 2: Average temperatures by month (°C)

	2022	2023	Difference
June	15.5	17.4	1.9
July	18.9	18.1	-0.8
August	19.6	17.7	-1.9
September	14.5	13.5	-1.1

Figure 5: The number of days in which average temperatures peaked above 25°C by month (June to September of 2020, 2021, 2022, and 2023)



Some large suppliers continued to exercise market power in Q3. In the peak hours of August there was 1,335 MW of available generation priced above $250/MWh on average, which is relatively high and comparable with the 1,341 MW in August 2022 (Figure 6). In September there was a decline in the amount of capacity offered above $250/MWh to an average of 1,086 MW during peak hours. This decline was a factor in the lower average pool price of $112/MWh in September, which was a 58% decrease year-over-year and is the lowest monthly pool price since March 2022 (Figure 1). Market power and offer behaviour are discussed in section 1.3.

Figure 6: Monthly average available capacity offered above $250/MWh in peak hours (January 2020 to September 2023)

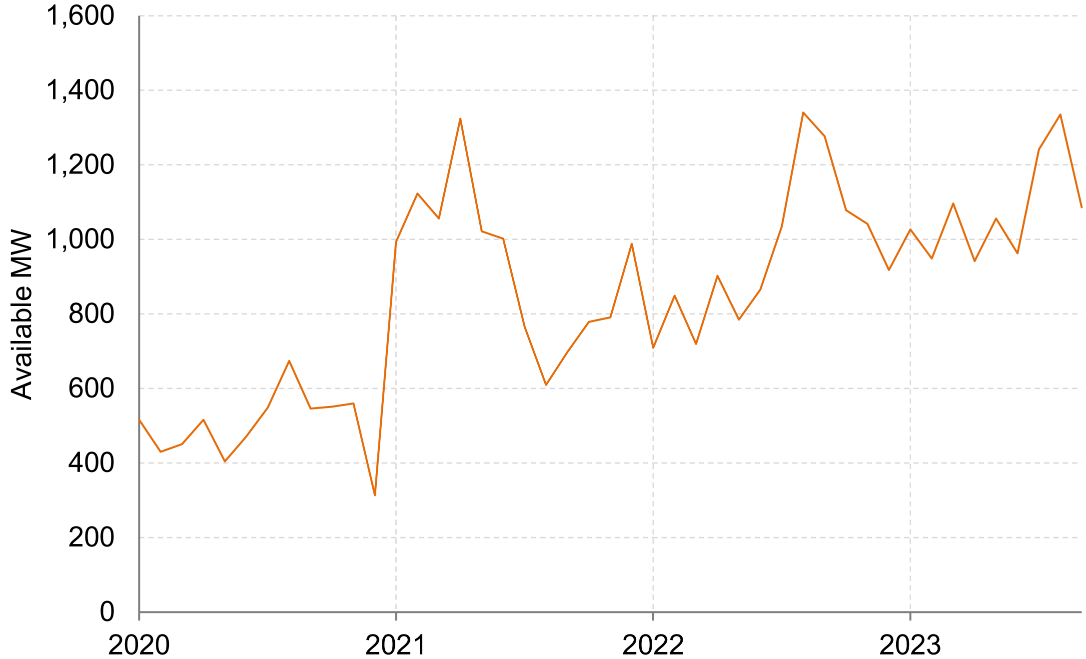
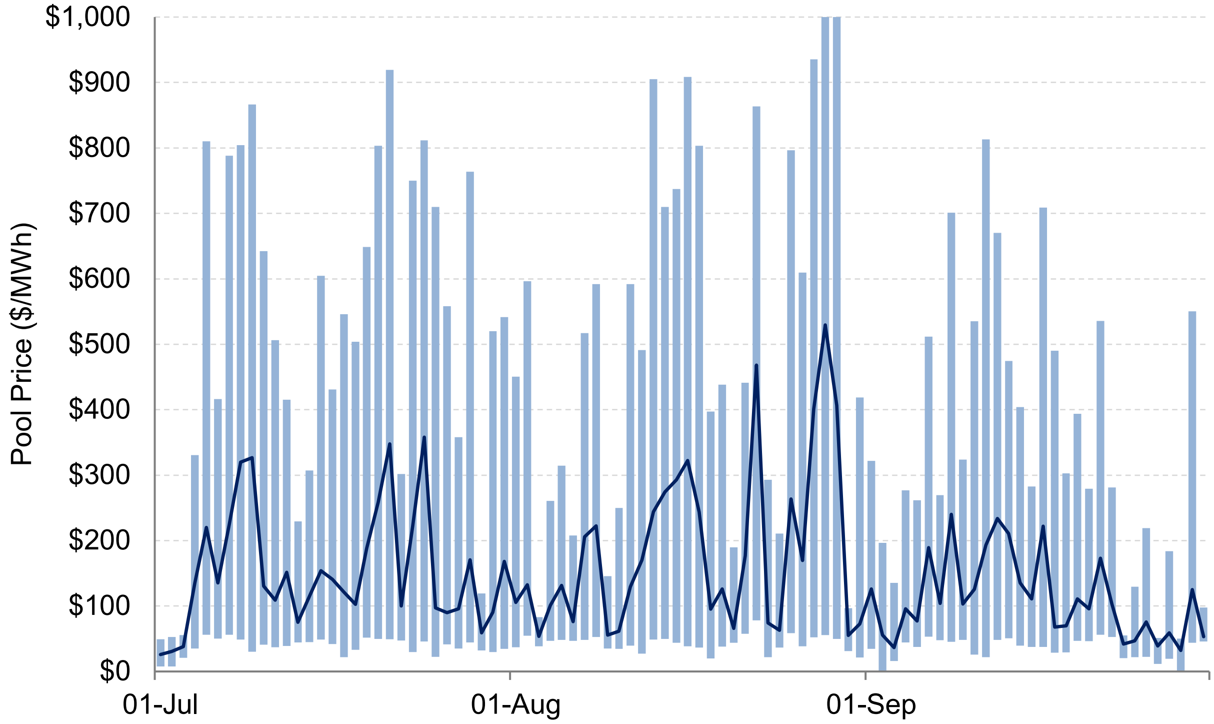


Figure 7 illustrates the daily maximum, minimum, and average pool price over Q3. As shown, there was often a large difference between the highest and lowest pool price. Intraday price volatility often reflects changing demand levels or variations in intermittent generation. In Q3, 40 MW of energy storage assets were connected, bringing the total capacity to 120 MW of grid-scale, standalone batteries operating in Alberta. These assets have typically offered their capacity into the spinning reserves market and have seldom participated in the energy market to arbitrage pool prices.

On August 28 and 29 pool prices cleared at the offer price cap of $999.99/MWh and the AESO declared Energy Emergency Alerts (EEAs), indicating that there was not enough supply to reliably meet demand. These events were caused by high demand due to high temperatures, low wind generation, some thermal generation outages, and a transmission outage affecting the supply of imports; they are discussed further in section 1.2.

Figure 7: Maximum, minimum, and average pool prices by day in Q3



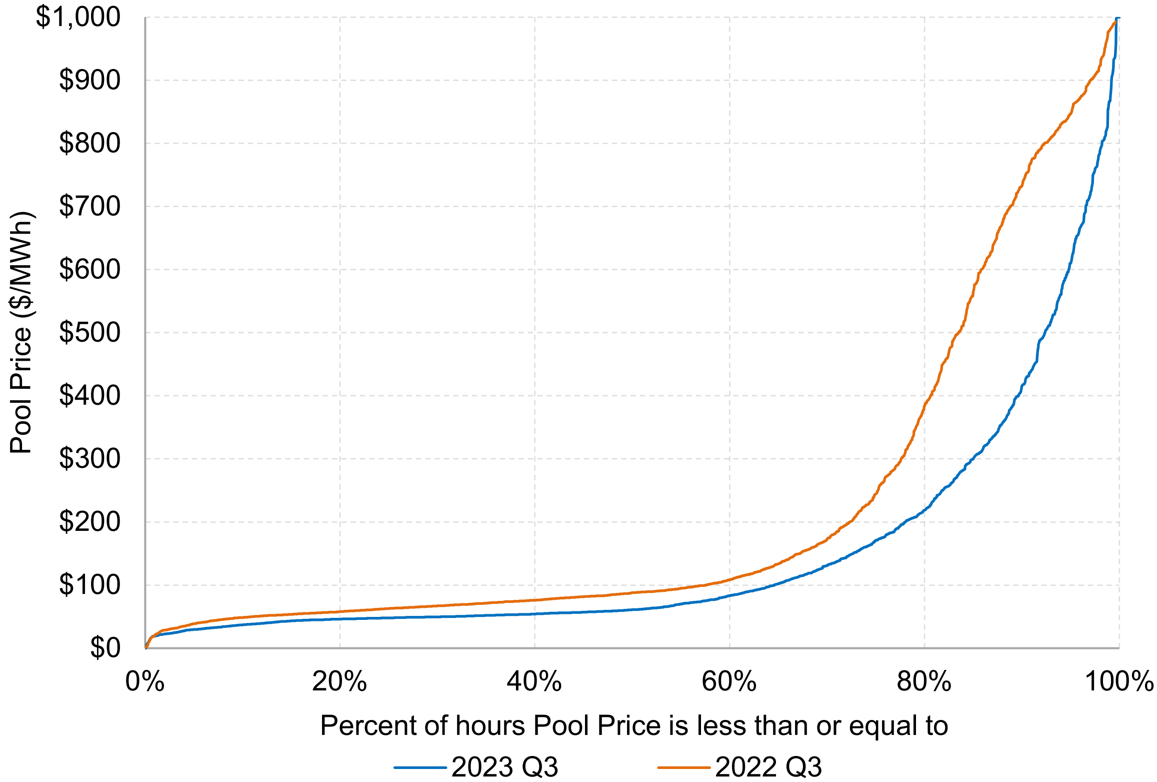
The constrained SMP was at $999.96/MWh on September 11, indicating that almost all generation offered into the energy market, which was not congested by transmission constraints, was being used to meet demand. Section 2.1 of this report analyzes transmission congestion in Q3 and section 2.2 looks at instances in which incorrect transmission constraint volumes led to incorrect pool prices.

Import volumes fell year-over-year in response to lower pool prices, low water levels in BC, higher prices in the Mid-Columbia (Mid-C) region, and because of reduced import capacity. In March, the AESO increased the required amount of Load Shed Service for imports (LSSi) which had the impact of lowering import capacity and reducing import supply, particularly during periods of higher pool prices. In Q3 2022, the median BC/MATL import capability was 644 MW in hours when the pool price was above $250/MWh. In Q3, this figure fell to 413 MW, a reduction of 231 MW or 36%. Imports and exports in Q3 are discussed further in section 2.3.

1.2 Market outcomes and events

Figure 8 illustrates pool prices duration curves for Q3 and Q3 2022. These curves show the distribution of pool prices by plotting the percent of hours in which pool prices were at or below a certain level. For example, the 90th percentile in Q3 was $416/MWh compared to $733/MWh in Q3 2022. Year-over-year, pool prices were lower throughout the distribution which reflects higher intermittent generation, a reduction in the exercise of market power, and lower natural gas prices.

Figure 8: Pool price duration curves (Q2 2023 and Q2 2022)



1.2.1 EEA events

The AESO declared two EEA events in Q3, one from 15:08 to 20:03 on August 28, and one from 17:25 to 20:02 on August 29. In addition to the event on June 7, these events bring the total number of EEA hours to 13.5 so far in 2023. The frequency of EEA events has increased in recent years but remains below the number of EEA hours observed in 2013 (Figure 9).

Prevailing weather conditions were a factor in the EEA events on August 28 and 29, with temperatures reaching 31°C in Calgary (Table 3). These weather conditions increased cooling demand, reduced the supply of thermal generation assets, and lowered wind generation. Further to this, there was a transmission outage in BC that reduced import supply.

Figure 9: EEA hours by year (2010 to Q3 2023)

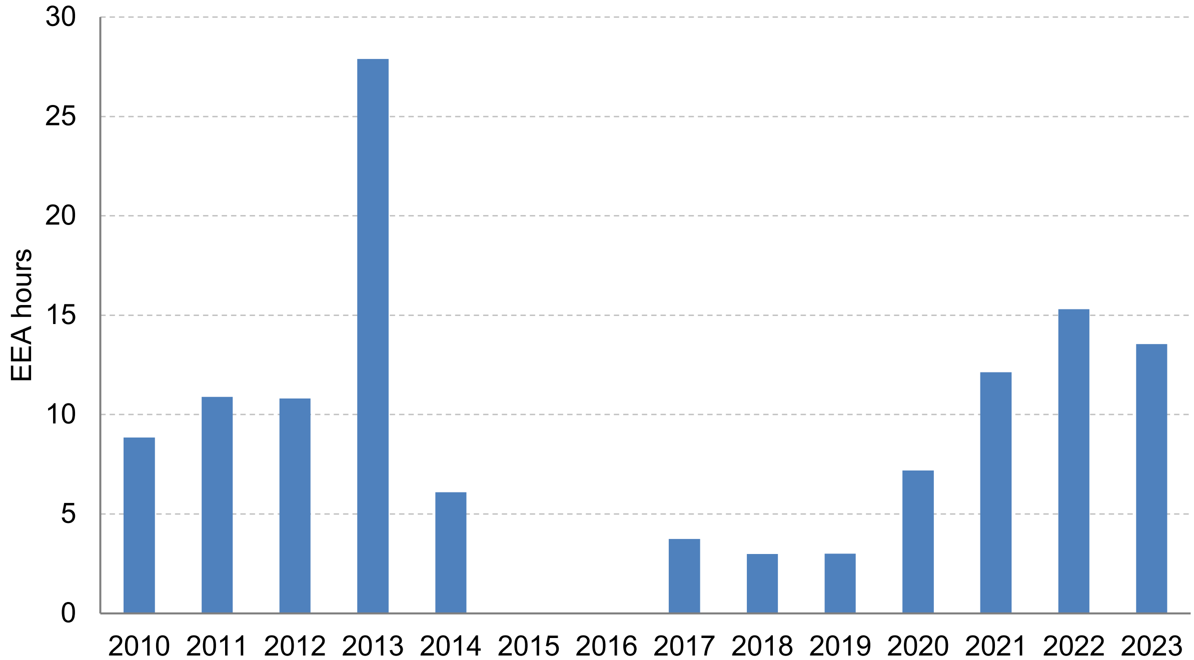
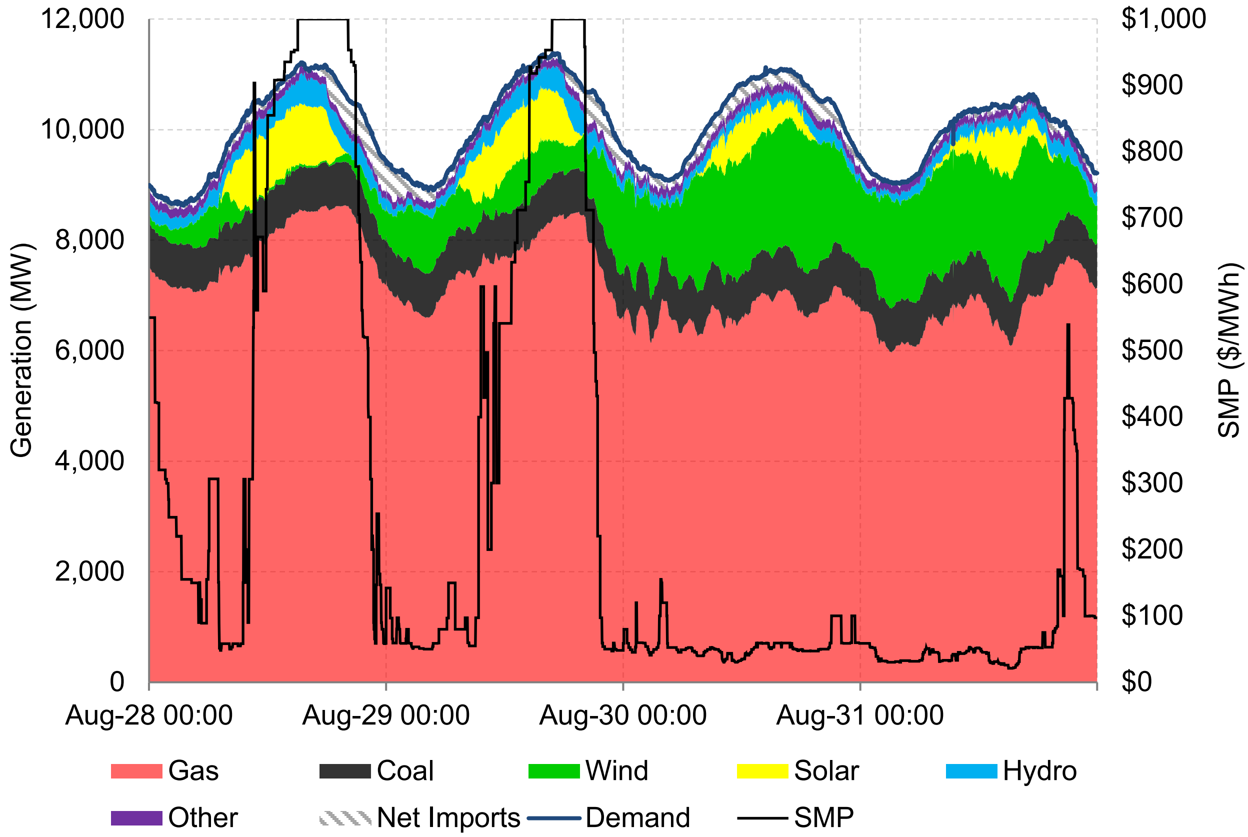


Table 3: Peak temperatures by date and location (August 25 to 31)

	Calgary	**Edmonton**	**Fort McMurray**
Aug 25 (Fri)	22.6	22.4	23.3
Aug 26 (Sat)	27.1	25.6	27
Aug 27 (Sun)	27.2	26.9	25.2
Aug 28 (Mon)	**30.5**	**29.7**	**26.3**
Aug 29 (Tue)	**30.5**	**32.1**	**28.1**
Aug 30 (Wed)	23	27.2	29.8
Aug 31 (Thu)	18.9	22.2	26.5

AIL demand peaked at 11,188 MW on August 28 and 11,332 MW on August 29. While these demand levels were elevated, they were not the highest in Q3 (peak demand occurred on July 24) and they were less than the summer record of 11,721 MW set in June 2021. Lower demand due to moderating temperatures and increased wind generation resulted in much lower prices on subsequent days (Figure 10).

Figure 10: Generation by fuel type (August 28 to 31)[3]



The high temperatures on August 28 and 29 lowered the efficiency of thermal generation capacity, meaning thermal assets that were online and generating could supply less. In addition, there were some thermal generation outages which lowered supply, including at Joffre (200 MW), HR Milner (300 MW), and Nabiye (185 MW).

The availability of the BC/MATL intertie was also reduced for portions of the EEA events. Following an inspection of the transmission line 5L92 on August 22, BC Hydro took the line out of service for maintenance work that was scheduled to take until September 1. As a result, import capacity on the BC/MATL intertie was significantly reduced.

Following the EEA declaration on August 28, the AESO requested that BC Hydro put the transmission line back in service to enable more import supply. The AESO made a similar request for August 29, and on both days the line was put back in service and imports into Alberta were increased during the EEA events (Figure 11).

The blue line in Figure 11 illustrates the volume of contingency reserves available to the AESO over time. At 15:07 on August 28, just prior to the EEA event, the AESO had 512 MW of contingency reserves available. By 15:42, 34 minutes into the EEA event, the AESO had directed

[3] Includes generation that was produced and consumed on-site at large cogeneration facilities.

250 MW of these contingency reserves to provide energy, leaving 262 MW of available contingency reserves. Subsequently, import supply increased and allowed the AESO to end these directives and increase the volume of contingency reserves available. A similar chain of events occurred again on August 29 when the AESO directed up to 265 MW of contingency reserves and had 265 MW of contingency reserves remaining before import supply increased. No firm load was shed during either of these EEA events.

Figure 11: BC/MATL imports, wind generation, solar generation, and contingency reserves (August 28 and 29)

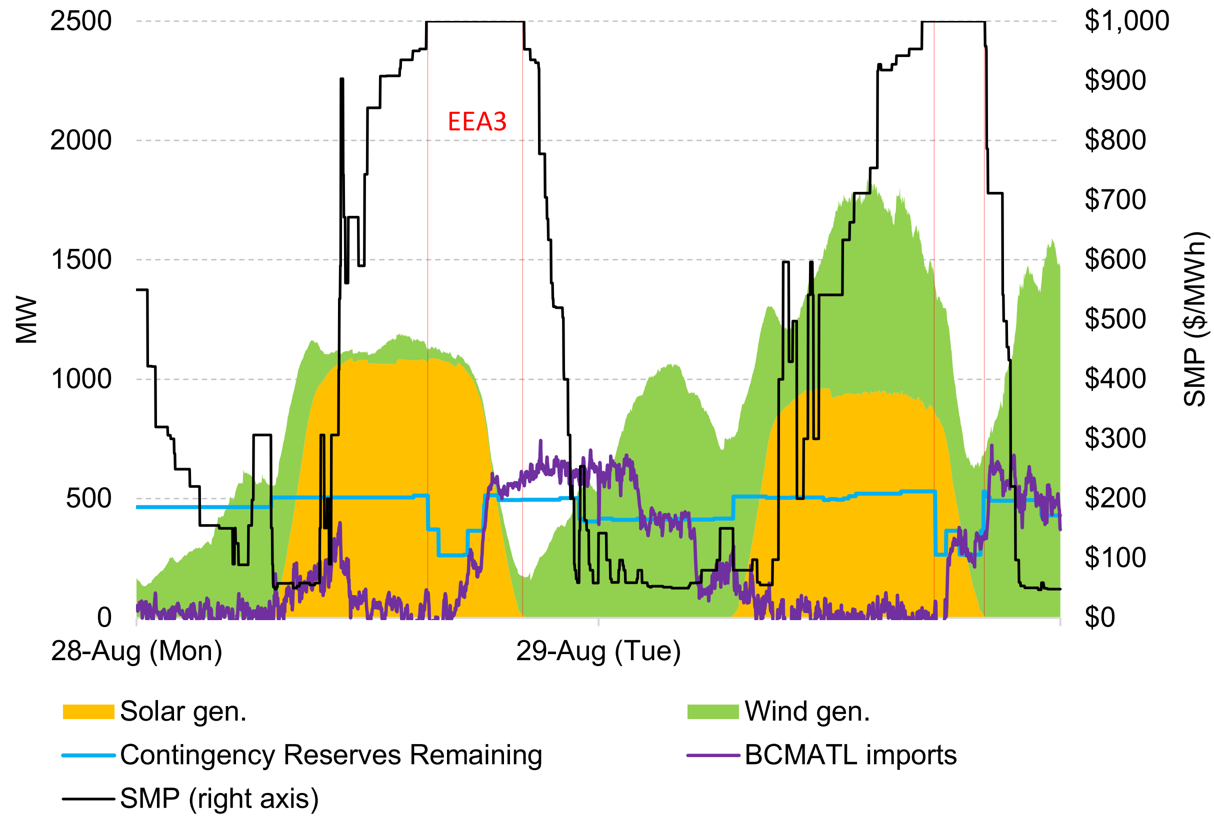
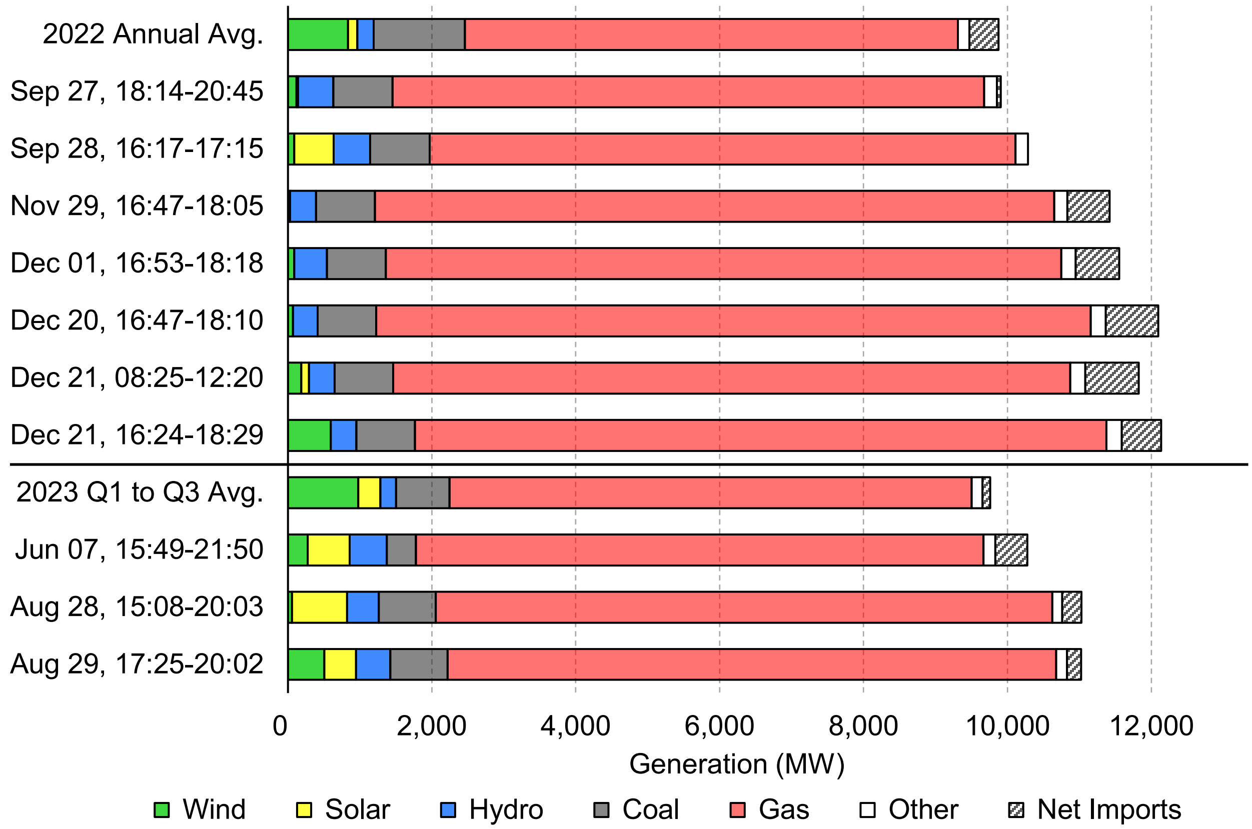


Figure 12 illustrates generation by fuel type for EEA events that occurred between January 1, 2022 and September 30, 2023. The figure illustrates that Alberta relies on thermal generation, particularly natural gas, during EEA events. During the EEA events on August 28 and 29, natural gas and coal generation supplied 85% and 84% of AIL demand, respectively. For the EEA events in the fall and winter of 2022, natural gas and coal generation supplied between 86% and 91% of AIL demand.

Wind generation is normally relatively low during EEA events because these events tend to occur during periods of very high or low temperatures, and these prevailing weather patterns usually cause low wind speeds. Solar generation can provide a source of supply during EEA events in the daylight hours (as shown in Figure 11), but often the EEA events will extend beyond, or occur following, sunset.

Figure 12: Generation by fuel type during EEA events in 2022 and 2023



1.2.2 Supply surplus events

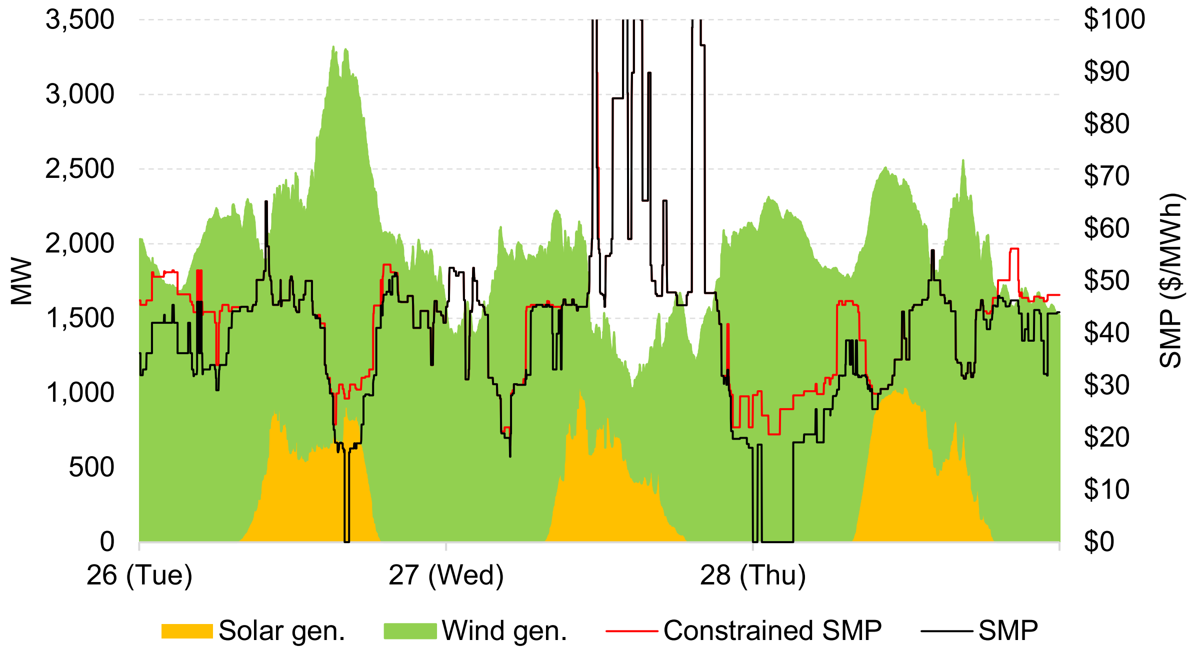
A few days after the EEA events, in the early morning hours of September 2, the SMP cleared at \$0/MWh, indicating a supply surplus event during which a reduction of the SMP to reduce supply is not possible. A supply surplus event occurs when demand is less than supply even though SMP is at the price floor of \$0/MWh.

The supply surplus event on September 2 was caused by low demand levels, high wind generation, and large amounts of thermal generation offered at \$0/MWh. At 04:14 on September 2 the SMP increased from \$0 to \$91.20/MWh and then back down to \$0/MWh at 04:18. The price change up to \$91.20/MWh for four minutes was due to a volume miscalculation at the AESO.

On September 3 and 26 there were brief periods where the SMP was \$0/MWh during peak hours because of high intermittent generation. The SMP is the unconstrained SMP and will include constrained down generation in supply when setting price. On September 26 at around 16:00 intermittent generation increased above 3,300 MW and a further 498 MW was constrained down by transmission limits. Consequently, while the unconstrained price was \$0/MWh but the constrained SMP was higher at \$27.50/MWh (Figure 13), because the constrained SMP does not include the supply of constrained down generation.

September 2 was the only event in Q3 where the constrained SMP cleared at $0/MWh, and it did so for a total of 121 minutes. To deal with this supply surplus situation, 50 MW of imports were curtailed down to 0 MW in HE 05 and HE 06.

Figure 13: System demand, wind and solar generation, and net demand (September 27 to 28, SMP shown up to $100/MWh)



1.2.3 Wind and solar ramps

Intermittent generation capacity continues to grow in Alberta. Over the course of Q3, the hourly generation of intermittent generators ranged from 14 MW to 3,305 MW. The increase in intermittent capacity means there are more ramping requirements for the AESO. For example, on the evening of July 17 intermittent generation decreased from 3,000 MW at 18:30 to 1,300 MW at 20:34, a decline of 1,700 MW (Figure 14). This decline in intermittent generation caused the SMP to increase from $33 to $801/MWh and a comparable decline in intermittent generation occurred the following evening on July 18 (Figure 14).

In addition to the ramp up of solar generation in the morning and the ramp down of solar generation in the evening there have also been substantial changes to solar generation during day light hours. These changes may be caused by cloud cover or strong gusts of wind (strong winds can necessitate the need to pivot the solar panels to a different angle).

On the morning of July 17, for example, solar generation at Travers decreased by 214 MW over 3 minutes. These changes in solar output are challenging to predict, and this event resulted in a decline in Area Control Error (ACE) to negative 271 MW (Figure 15). ACE indicates the deviation between actual and scheduled flows over the interties.

Figure 14: Wind generation, solar generation, and SMP (July 15 to 19)

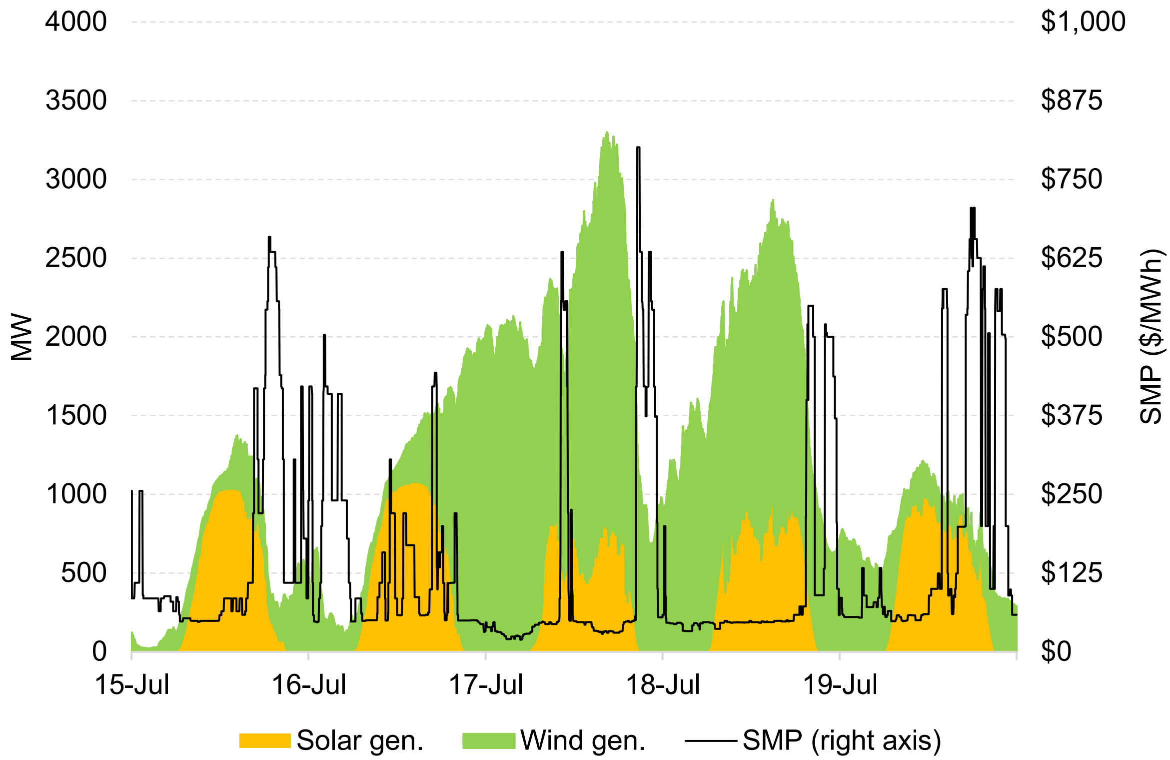
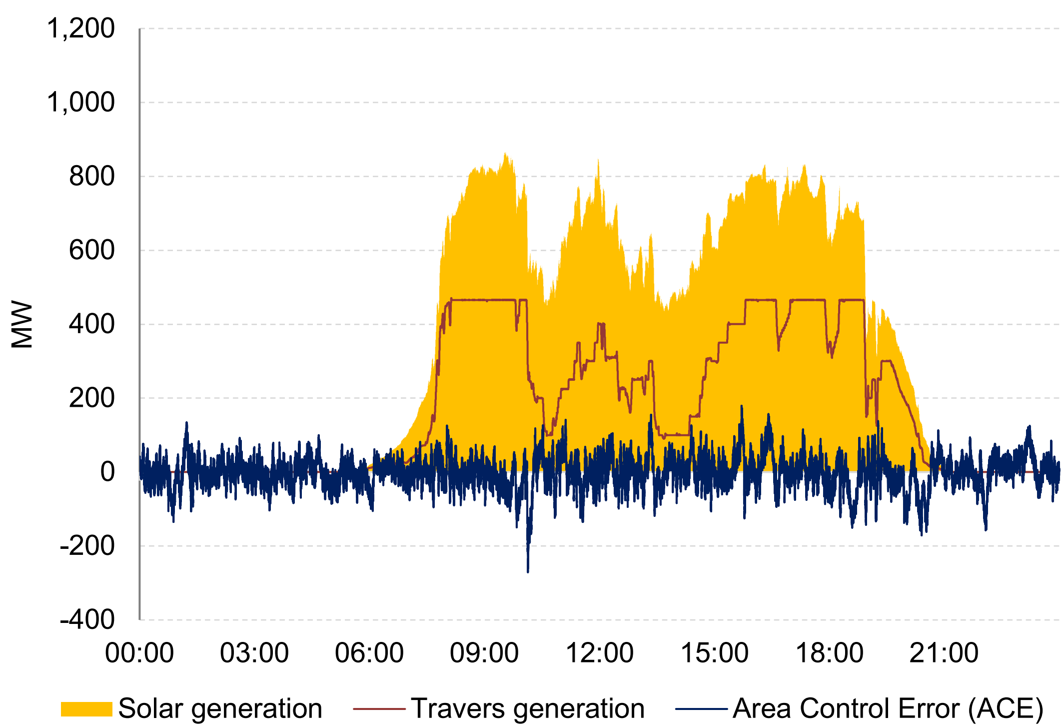


Figure 15: Total solar generation, Travers solar generation, and Area Control Error (July 17)



On August 2 there were two large declines in solar generation due to reductions at the Travers asset (Figure 16). A decline of 380 MW over 74 seconds occurred around 10:42 and another decline of 380 MW over 78 seconds occurred at 16:22. In both instances, the decline was unexpected and resulted in a large decline in ACE. In the first instance, the ACE fell as low as negative 358 MW (Figure 16).

Figure 16: Total solar generation, Travers solar generation, and Area Control Error (August 2)

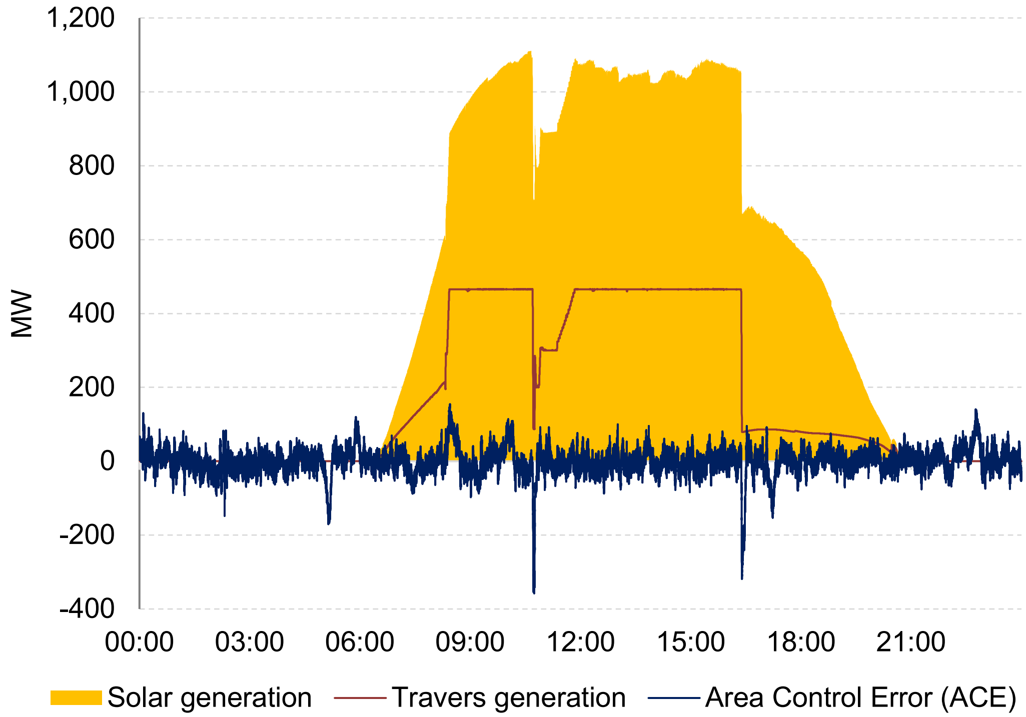


Table 4 provides a broader analysis of wind and solar ramps over Q3. The table provides the number of instances in which solar or wind generation changed by more than a certain threshold. There were seven instances in Q3 when solar generation declined by more than 250 MW in two minutes, and in five of those instances the decline was more than 350 MW.

There were more large declines in solar generation in Q3 than there were large declines in wind generation. This result occurred even though total wind capacity was roughly three times total solar capacity. As discussed in section 3 on operating reserves, the AESO have started procuring more regulating reserves, in part due to this volatility of solar generation.

The ramps of increasing wind or solar generation are lower in magnitude than the declines. This is partly because these ramp-ups are actively managed by the AESO through the wind and solar power ramp-up management.

Table 4: Count of ramp changes for wind and solar generation in 2 minutes (Q3)

MW decline in 2 mins	Down ramps	
	Solar	Wind
-100	78	18
-150	18	5
-200	8	0
-250	7	0
-300	5	0
-350	5	0
-400	0	0

MW increase in 2 mins	Up ramps	
	Solar	Wind
100	41	28
150	3	2
200	0	0
250	0	0
300	0	0
350	0	0
400	0	0

1.2.4 Large generator trip

The Most Severe Single Contingency (MSSC) limit is the maximum amount of supply loss the Alberta grid can reliably withstand and is currently set at 466 MW, although it may be lower during islanded conditions when Alberta is separated from BC and Montana.[4]

Shepard is a large combined cycle natural gas asset located in Calgary which consists of two 268 MW gas turbines and one 332 MW steam turbine. The largest contingency considered to be credible for this asset is one natural gas turbine tripping offline, which would also reduce the output of the steam turbine by around 50%, for a total reduction of around 434 MW, which is less than the interconnected MSSC limit. Notwithstanding this, on the afternoon of July 25 the Shepard generation asset tripped offline, reducing supply by 745 MW instantaneously (Figure 17). This is not the first large trip at this asset that has resulted in near instantaneous generation losses well in excess of the MSSC limit since it was commissioned in 2015 (Table 5). The MSA has observed at least three instances in the last eight years when this asset's production has fallen by more than 550 MW in less than four seconds.[5]

Table 5: Large trips at the Shepard asset

Date time	Trip time (seconds)	Generation (MW)		
		From	To	Difference
Jul. 25, 2023 14:25	< 2	745	0	745
Sep. 1, 2022 20:30	< 2	774	223	551
Nov. 30, 2015 08:30	< 4	818	0	818

[4] AESO Frequency Response Program, Stakeholder Session Q&A, bottom of page 12 (October 25, 2023)

[5] The highest granularity of the real-time PI SCADA data used for this analysis is 2 seconds.

Figure 17: The Shepard trip at 14:25:32 on July 25 (data increment is 2 seconds)

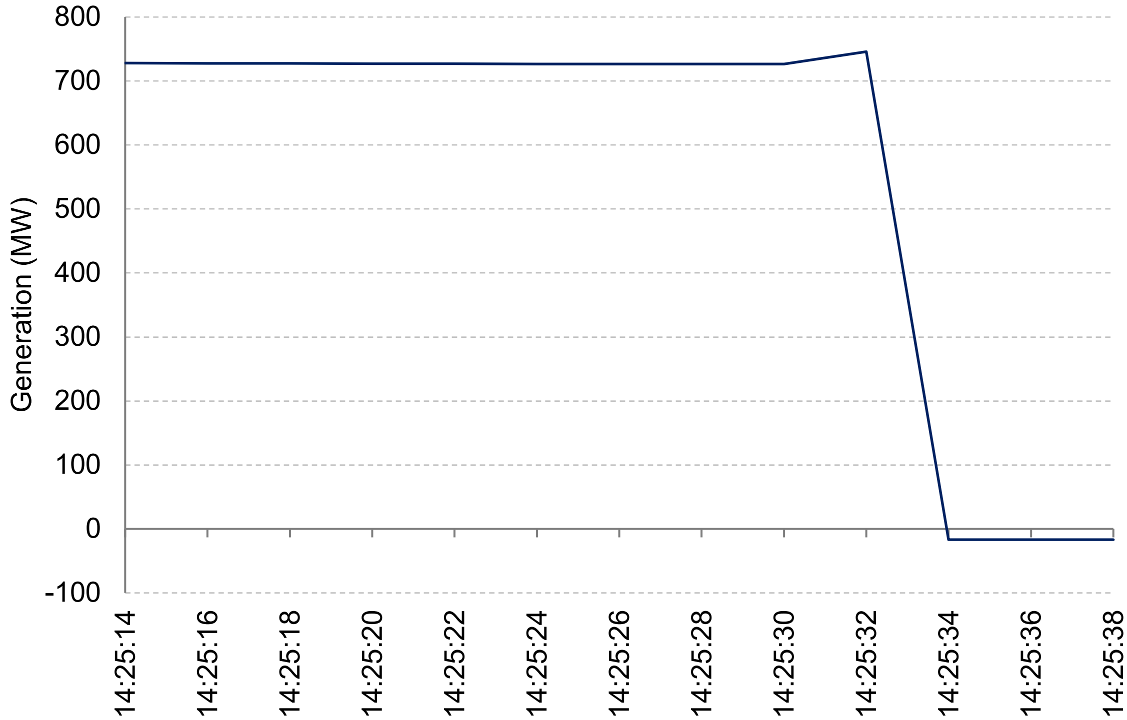
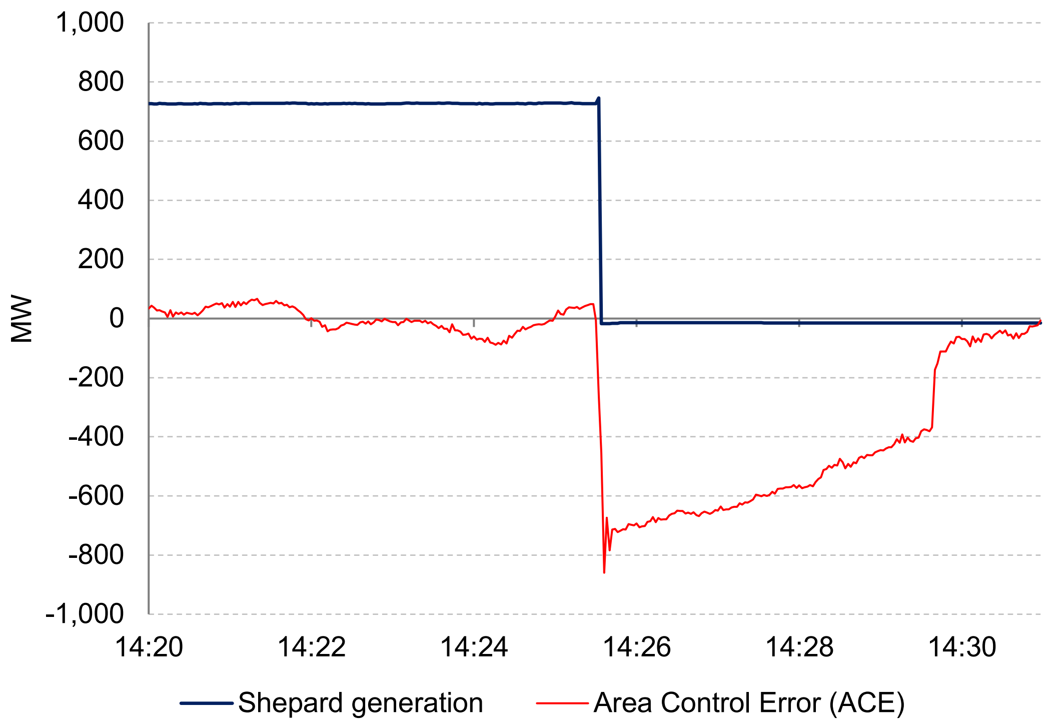


Figure 18: Shepard generation and Area Control Error (July 25 from 14:20 to 14:31)



The Shepard trip had a large and immediate effect on flows over the BC and MATL interties, as indicated by the drop in Alberta's ACE from above 0 to negative 860 MW (Figure 18). At the time of the Shepard trip, intermittent generation in Alberta was high and prices were low at $49/MWh. As a result of these market conditions, Alberta was scheduled to export 501 MW to BC in HE15. However, the Shepard trip resulted in a large deviation from this schedule and Alberta was importing 250 MW from BC following the trip (Figure 19).

Given the magnitude of the trip, including it being well in excess of the MSSC limit, Alberta was fortunate to be both operating interconnected with BC/MATL and a large net exporter at the time. Because of the in-rush of power from BC, the event had relatively little impact on system frequency in Alberta, with frequency dropping down to 59.93 Hz. Had the BC/MATL intertie been offline or heavily importing, the Shepard trip may have been more consequential.

Table 6 provides some context for the Shepard trip by providing ACE and frequency figures for some large contingency events since 2018. These events highlight that market contingencies tend to have a larger impact on reducing frequency in Alberta when an automatic in-rush of power from BC/MATL is not available because Alberta was islanded or because BC/MATL itself tripped. From the events in Table 6, frequency dropped to an average of 59.56 Hz during events in which the BC/MATL intertie tripped or was offline, compared to an average 59.90 Hz when Alberta was interconnected.

Figure 19: The scheduled and actual flow of power over the BC intertie (July 25; exports are positive; data increment is 2 seconds)

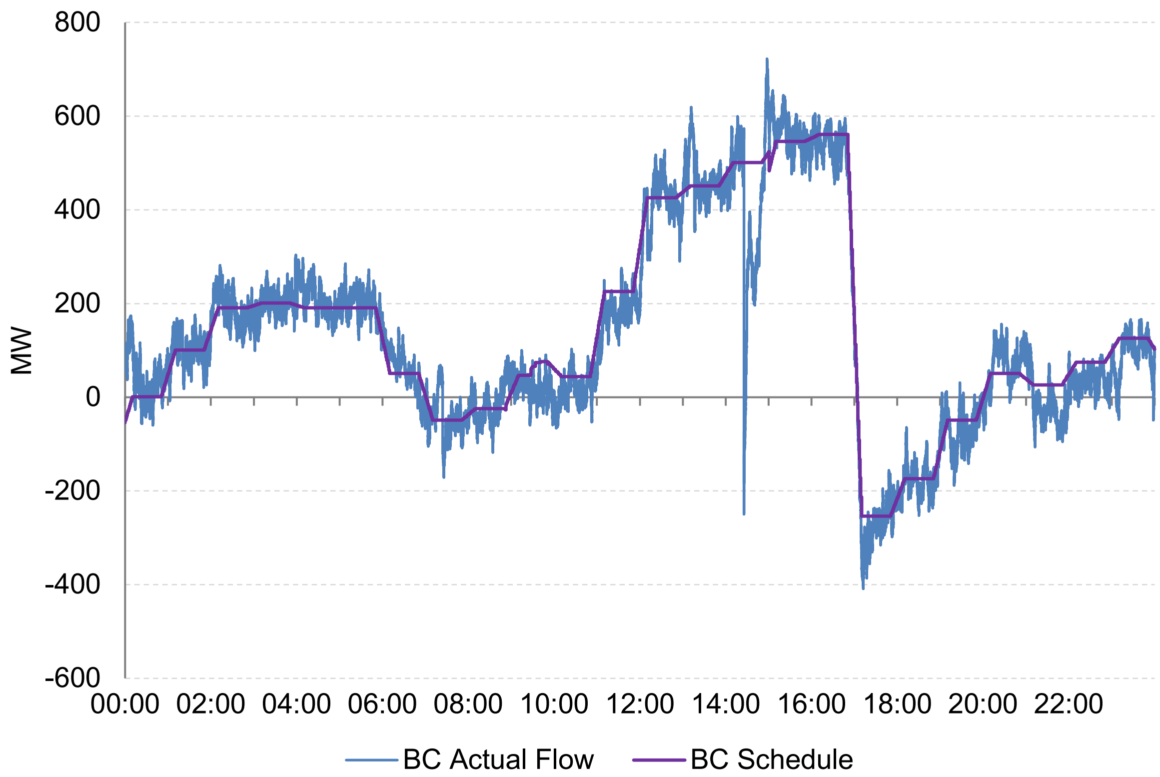


Table 6: ACE and frequency figures for some large contingency events (since January 1, 2018; ordered by generation loss)

Trip event	Date	Gen. Loss (MW)	Min. ACE (MW)	Min. Frequency (Hz)
BC/MATL	Jun 07, 2020	915	-974	59.17
Shepard	**Jul 25, 2023**	**745**	**-860**	**59.93**
BC/MATL	Jun 03, 2021	707	-909	59.36
BC/MATL	Jun 22, 2018	689	-939	59.31
SH1 and SH2	Apr 04, 2021	668	-711	59.93
SH1 then SH2	Jun 02, 2021	666	-743	59.95
KH3 then KH2	Dec 14, 2021	538	-682	59.93
SH2 then SH1	Mar 28, 2021	514	-612	59.92
BC/MATL	Feb 22, 2021	468	-835	59.49
BC/MATL	Feb 21, 2021	436	-823	59.44
KH3 then BC (MATL offline)	Sep 11, 2019	355	-662	59.57
KH1 (BC/MATL offline)	Oct 16, 2020	258	-624	59.58

1.3 Market power and offer behaviour

Market power can be defined as the ability of generators to increase pool prices by offering capacity above short-run marginal cost (SRMC). The average pool price in Q3 was $152/MWh, which is 173% higher than the MSA's counterfactual price based on SRMC (Table 7).

Table 7: Pool prices and SRMC-counterfactual pool prices (Q3, Q3 2022, and Q3 2021)

		2023	2022	2021	Change vs.2022	Change vs.2021
Observed Pool Price (Avg $/MWh)	Jul	$155	$142	$124	9%	25%
	Aug	$187	$258	$82	-28%	127%
	Sep	$112	$266	$94	-58%	18%
	Q3	$152	$221	$100	-32%	51%
SRMC-Counterfactual Pool Price (Avg $/MWh)	Jul	$54	$72	$71	-25%	-24%
	Aug	$66	$89	$46	-26%	44%
	Sep	$47	$94	$50	-50%	-7%
	Q3	$56	$85	$56	-35%	-0.1%

Figure 20 illustrates monthly average pool prices and counterfactual SRMC estimates since January 2022. The margin between pool prices and SRMC averaged $101/MWh in July, $121/MWh in August, and fell to $65/MWh in September. The average margin in September was the lowest since January.

Figure 20: Monthly observed, SRMC-counterfactual pool prices (Jan 2022 to Sep 2023)

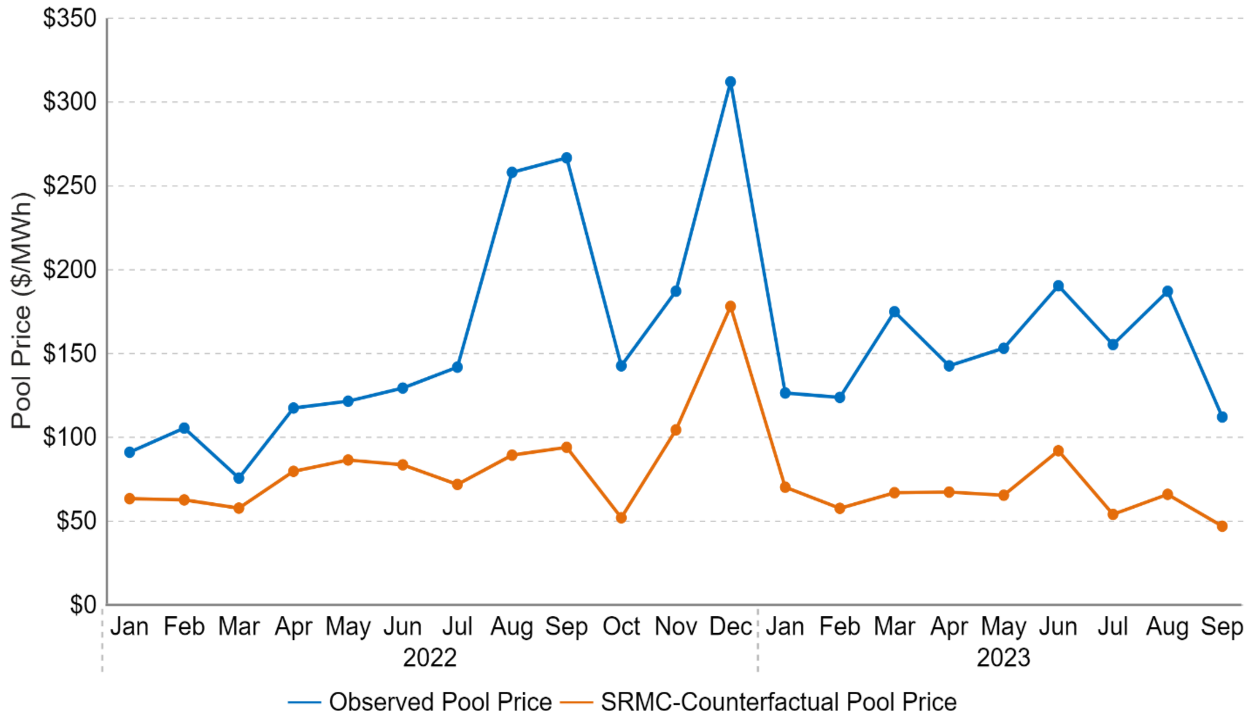


Figure 21 illustrates duration curves of the Lerner index for July, August, and September. The Lerner index is a measure of market power that quantifies the markup of price over the market's marginal cost of generation, expressed as a percentage of the price. As shown, a large percent of hours in each month had a Lerner index between 0 and 40%.

The Lerner indices were highest in August with an average markup of 45% (Figure 22). August was also the highest priced month in the quarter with an average pool price of $187/MWh. September exhibited a lower frequency of hours with high Lerner indices and the average Lerner index was 34%. September was also the lowest priced month in the quarter with an average pool price of $112/MWh.

Figure 21: Lerner index duration curves by month in Q3

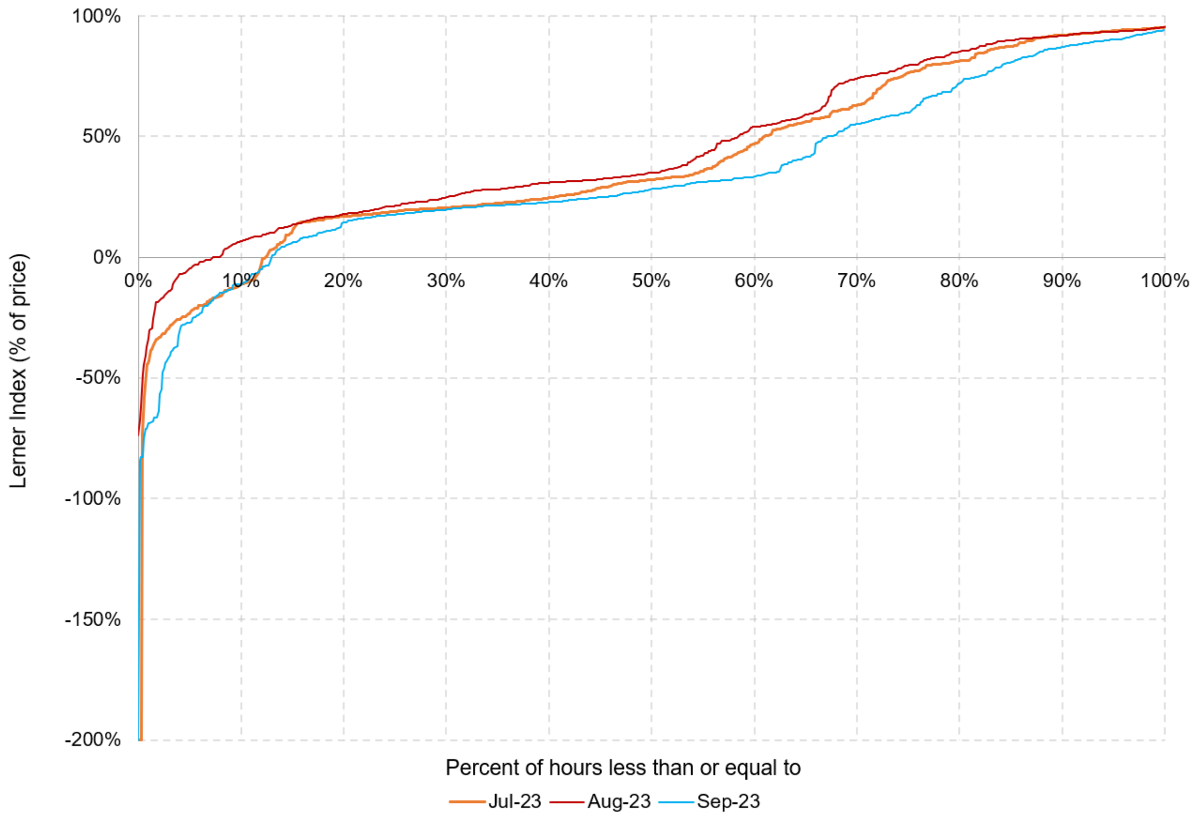


Figure 22: Monthly average market markup (January 2022 to September 2023)

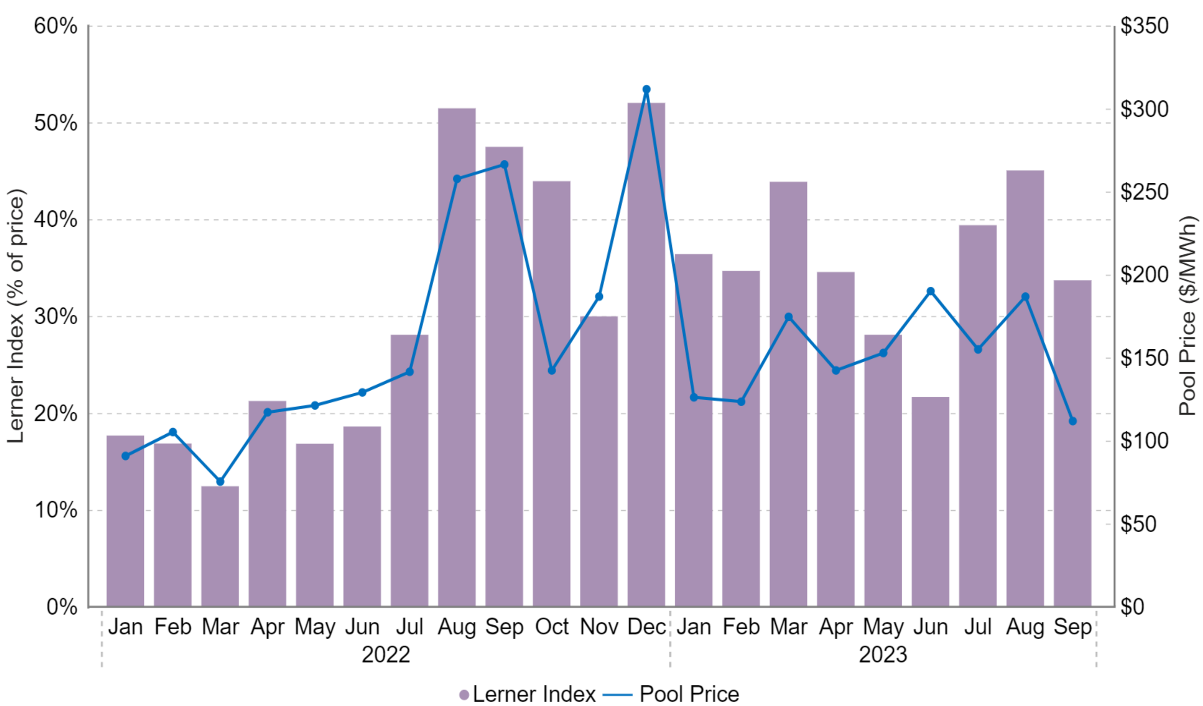


Figure 23 illustrates the average Lerner index by hour ending for Q3, Q3 2022, and Q3 2021. Compared to Q3 2022, the Lerner index in Q3 was lower for most on-peak hours, indicating that market power was less prevalent this year. One factor behind this decline was the increase in intermittent generation, as shown in Figure 24. Analyzing the hourly profile of the Lerner Index in Q3, there was significant drop in the index from HE 07 to HE 08 around sunrise and an increase in the index from HE 19 to HE 20 around sunset. As solar generation continues to increase in Alberta it is having a larger impact on the market, including reducing the ability of larger suppliers to exercise market power. The steady increase in the Lerner index from HE 09 to HE 20 was caused by increasing demand over the day.

Figure 23: Lerner Index by hour ending (Q3 2021, Q3 2022 and Q3)

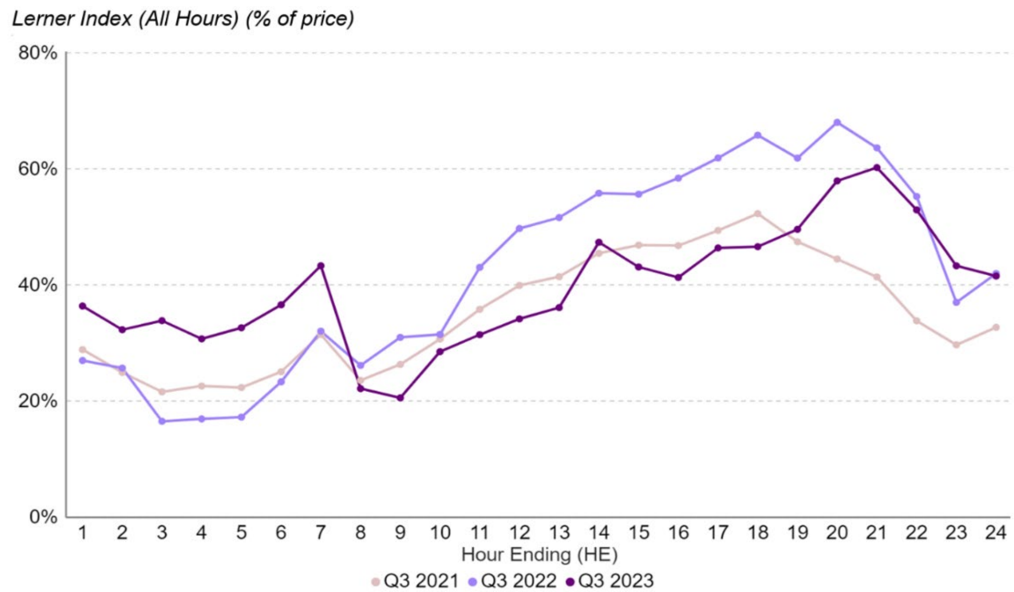
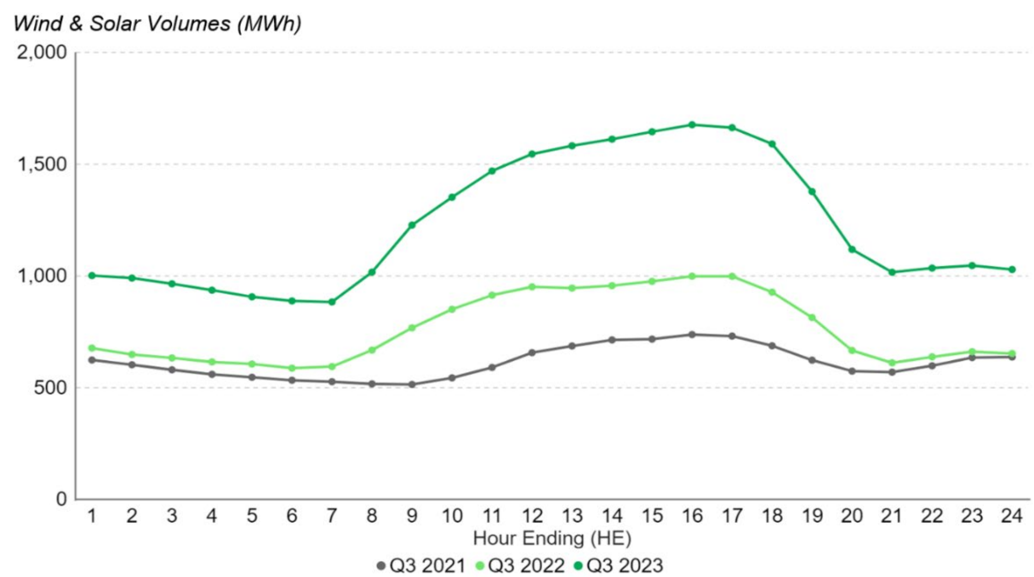


Figure 24: Intermittent generation volumes by hour ending (Q3 2021, Q3 2022 and Q3)



The exercise of market power results in two distinct types of inefficiency: allocative inefficiency and productive inefficiency.

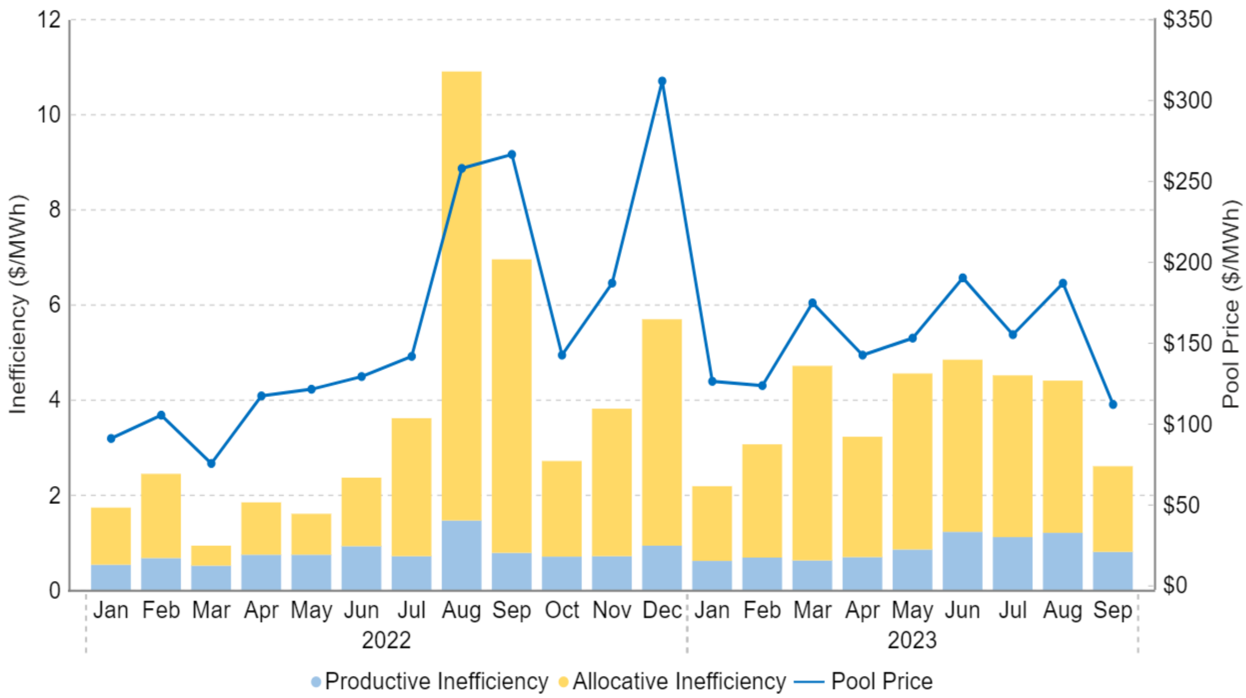
- Allocative inefficiency measures the value of the opportunities for both consumers and producers to benefit from additional trade that are not realized. For there to be no allocative inefficiency, production is increased until the marginal cost to producers is equal to the marginal benefit to consumers.

- Productive inefficiency measures the excess market-level generation cost that occurs when lower cost generation is withheld. For there to be no productive inefficiency, the lowest cost generation in the system must be dispatched to meet system demand.

Combined, these two forms of inefficiency represent total static inefficiencies. In Q3 the average static inefficiency was $3.87/MWh, which is slightly lower than the $4.19/MWh in Q2, a difference of 8%.

On a monthly basis, September had the lowest static inefficiency with an average value of $2.60/MWh, while July and August had values of $4.40/MWh and $4.51/MWh, respectively. (Figure 25). Year-over-year, the static inefficiencies for August and September were 60% and 63% lower, which indicates less exercise of market power in those months this year.

Figure 25: Monthly average static inefficiency (January 2022 to September 2023)



1.3.1 Pivotality

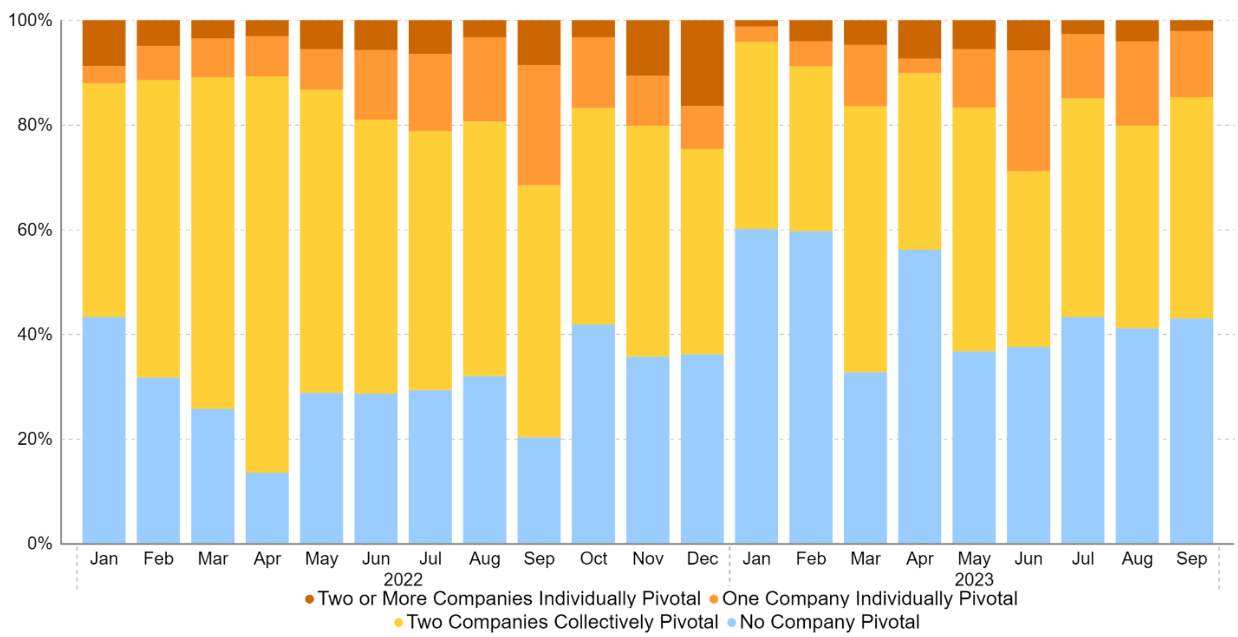
A company is pivotal during hours when its withholdable capacity is essential for the market to clear. Withholdable capacity includes all capacity except for wind, solar, and minimum stable generation (MSG).[6]

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

- there can be multiple companies that are individually pivotal at the same time;
- a company may be individually pivotal on its own;
- two companies may only be pivotal collectively with their combined withholdable capacity; or
- there may be no companies that are individually or collectively pivotal.

Figure 26 illustrates the percent of time in which the market fell into different pivotality classes by month. In Q3, August had the highest percent of hours in which at least one company was pivotal at 20%. Year-over-year, there was a notable decline in September. In September 2022 at least one company was pivotal in 32% of hours compared with 15% of hours in September 2023. Hot weather, low wind generation, and thermal outages tightened market conditions in September 2022.

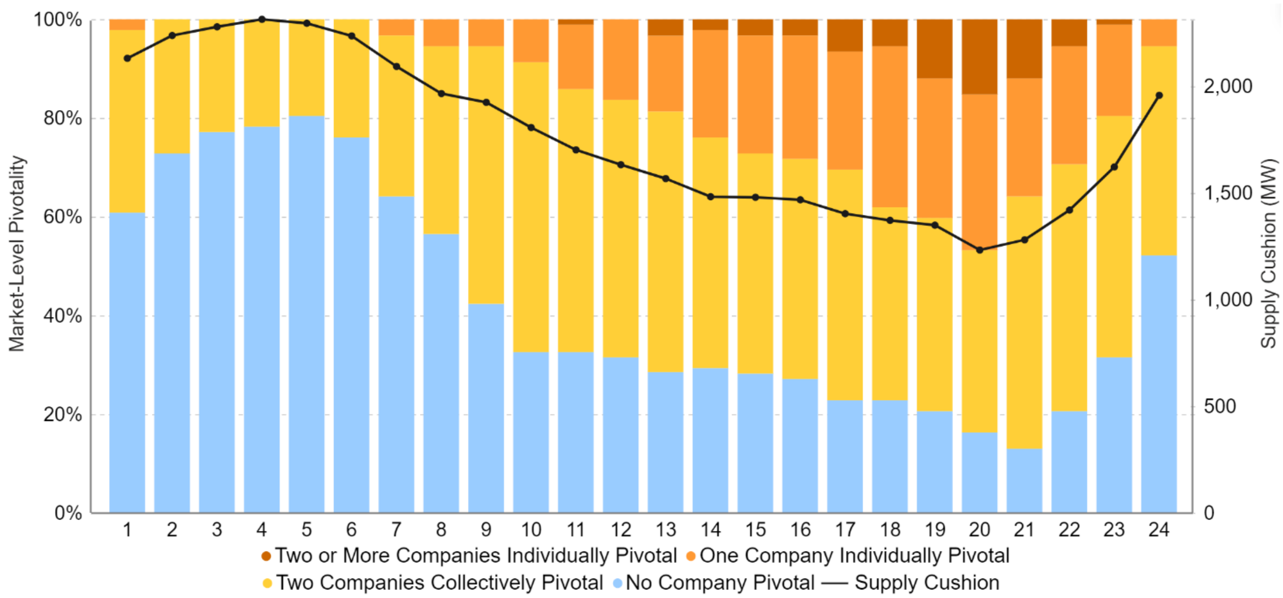
Figure 26: Market-level pivotality by month (January 2022 to September 2023)



[6] Minimum Stable Generation refers to the lowest generation level an asset can run at in a stable manner; at lower levels the generator is unstable.

Figure 27 indicates how pivotality and supply cushion changed by hour ending in Q3. The supply cushion indicates the amount of unused capacity that is available in the merit order, so a lower supply cushion indicates tighter supply-demand conditions. As shown by the figure, the average supply cushion line closely follows the hours when more companies were individually pivotal. Companies were most often pivotal in the evening around sunset when solar generation declines but demand is still elevated. In HE 20 at least one company was pivotal 47% of the time in Q3.

Figure 27: Market-level pivotality by hour ending in Q3



1.3.2 Price outcomes during pivotality conditions

Figure 28 compares average prices in Q3 with average prices in Q3 of 2020, 2021, and 2022 at different categories of pivotality. As shown, pool prices were higher in Q3 of 2022 and 2023 in hours when multiple companies were pivotal or one company was individually pivotal. This indicates a greater exercise of market power in Q3 of 2022 and 2023.

Figure 29 illustrates pool prices by month among different pivotality conditions. In September, there was a decrease in pool prices for hours where at least one firm was pivotal. In August the average pool price was $892/MWh during these hours and this fell to $528/MWh in September, a decline of 40%.

Figure 28: Observed and SRMC pool prices segregated by pivotality condition *(Q3 of 2020 to 2023)*

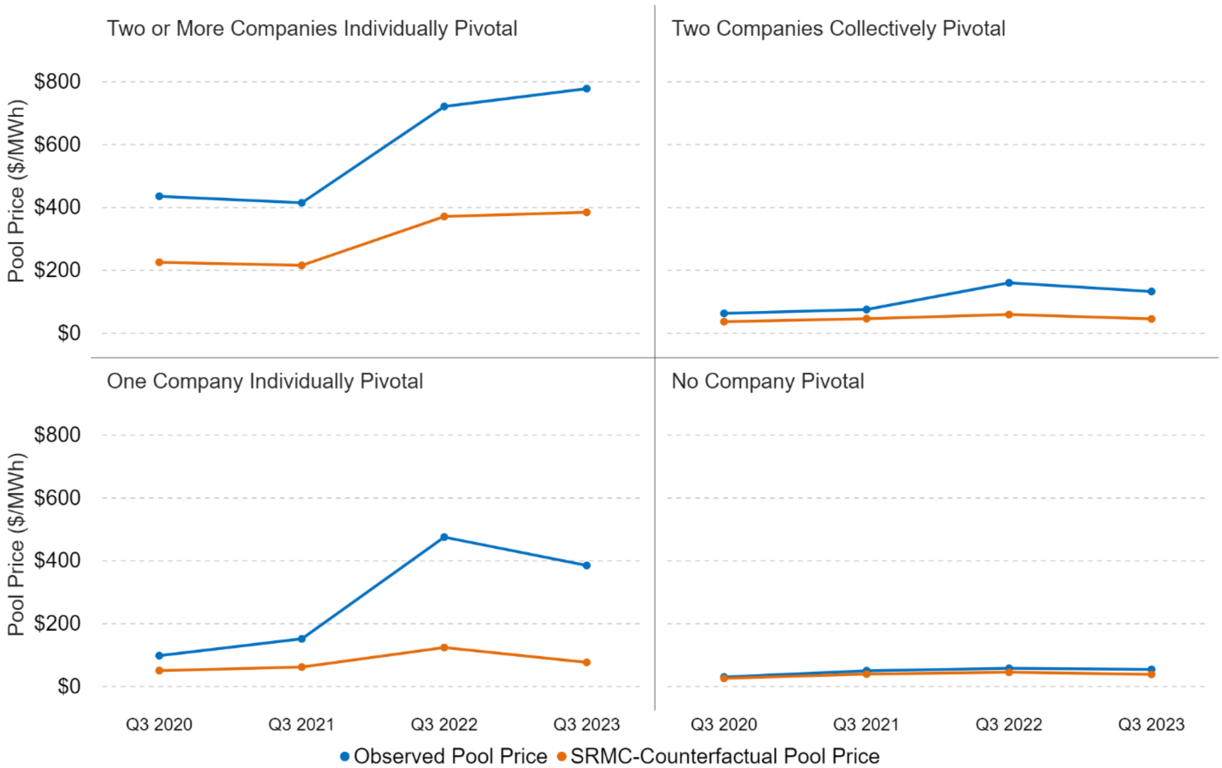
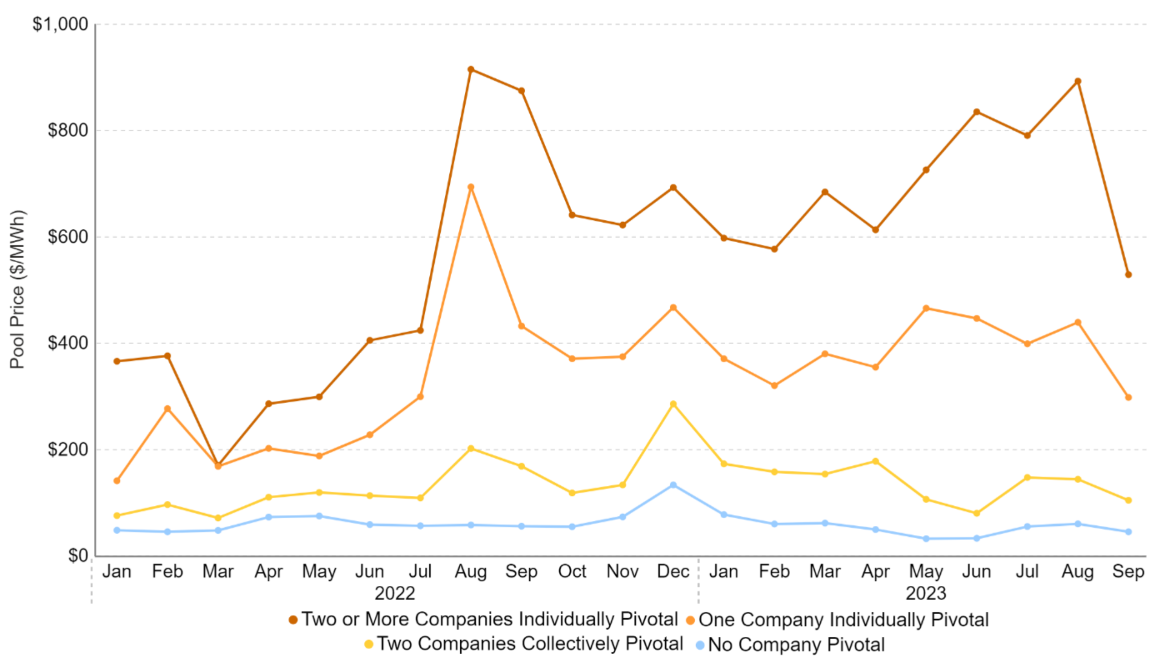


Figure 29: Monthly average pool price by pivotality condition (January 2022 to September 2023)



1.3.3 Offer behaviour

In Q3 there was an average of 1,115 MW of non-hydro capacity offered above $250/MWh which is an increase from 836 MW in Q2, but is a decrease compared to 1,180 MW in Q3 2022 (Figure 30). $250/MWh is well above SRMC for almost all the generation capacity in Alberta given where natural gas prices have been. TransAlta and Heartland continue to be the companies that are offering the most capacity higher in the merit order.

September saw the lowest amount of capacity offered above $250/MWh out of the months in Q3, which supports the earlier observation of lower pool prices during hours where at least one company was pivotal in that month (Figure 30).

TransAlta is the firm with the largest market share in Alberta's electricity market. Figure 31 provides the distribution of its offer prices above $250/MWh. In Q3 TransAlta offered less capacity above $250/MWh compared to Q3 2022. In August TransAlta offered an average of 405 MW above $900/MWh, although this fell to 154 MW in September.

Figure 32 shows the same analysis for Heartland. As shown, when Heartland offers capacity above $250/MWh most of it is concentrated in the range of $250/MWh to $900/MWh, with few offers above $900/MWh.

Figure 30: Monthly average non-hydro capacity offered at/above $250/MWh by company

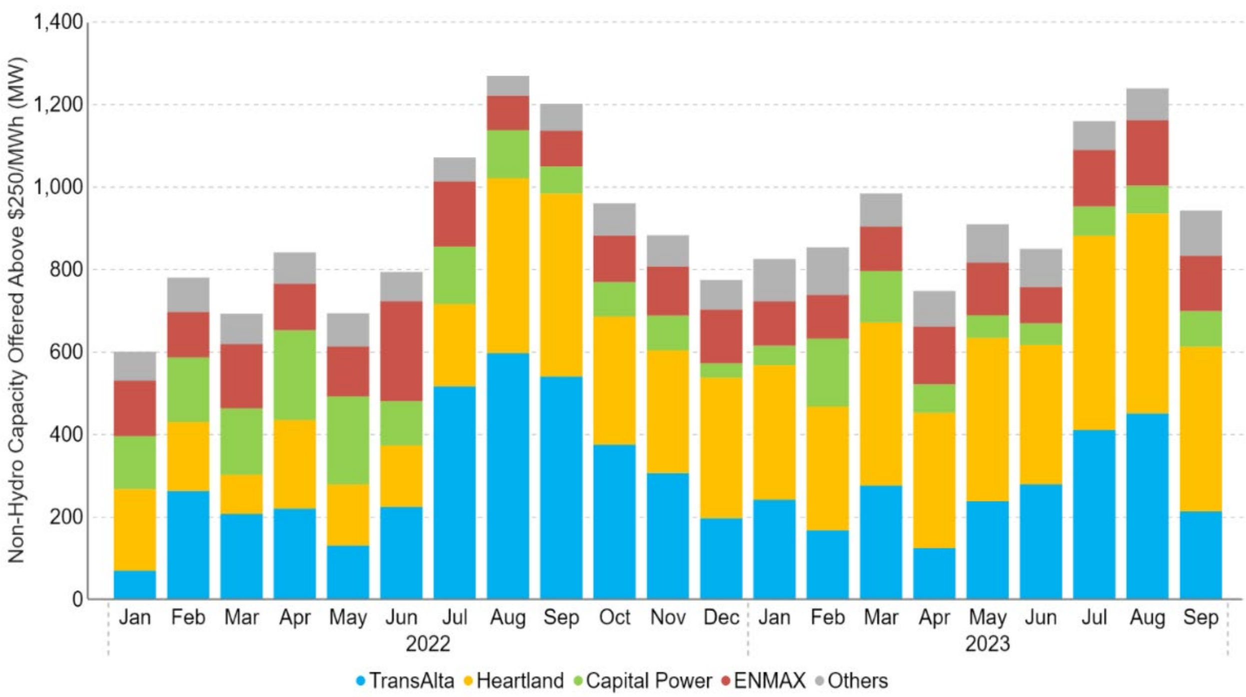


Figure 31: Monthly average non-hydro capacity offered at/above $250/MWh by TransAlta

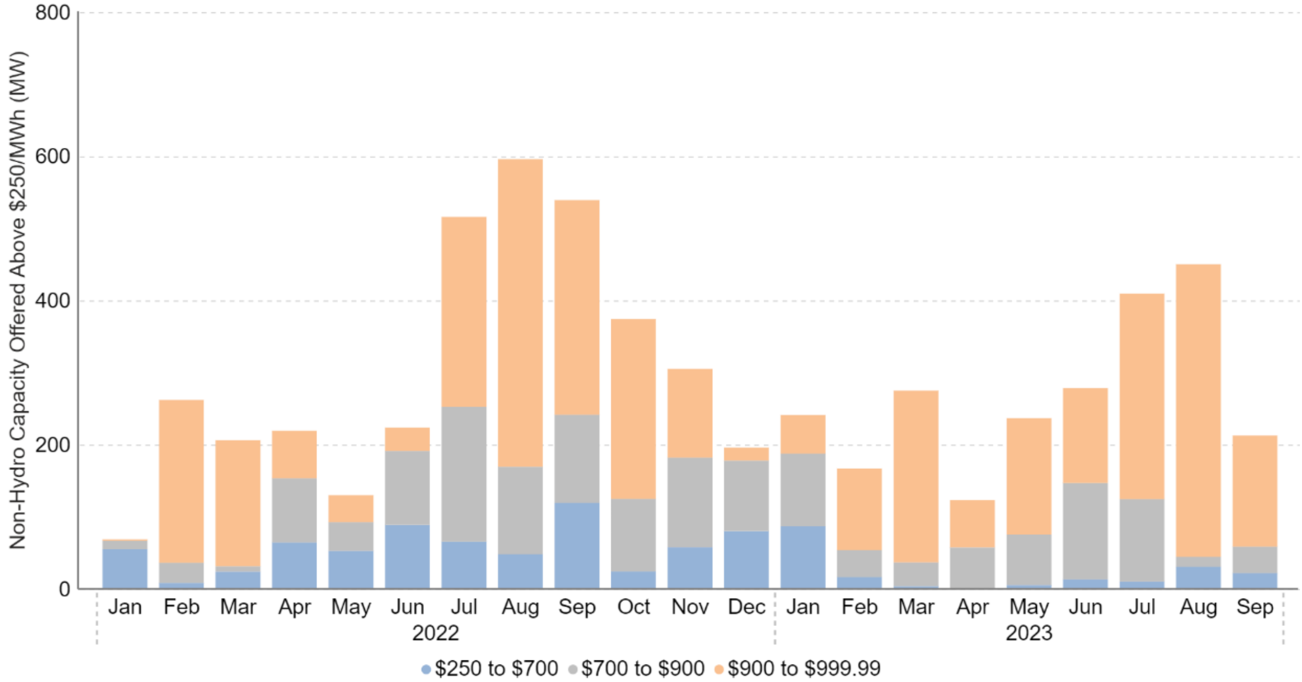
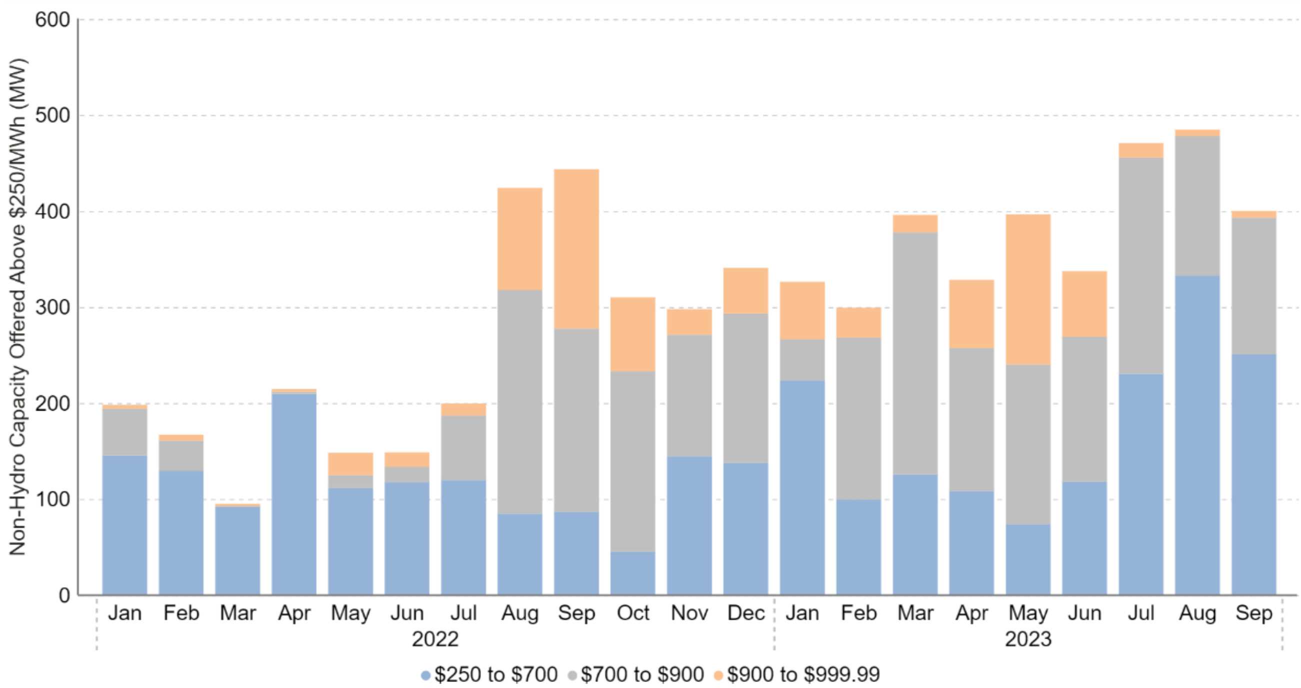


Figure 32: Monthly average non-hydro capacity offered at/above $250/MWh by Heartland



1.4 Carbon emission intensity

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

1.4.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in each hour. Table 8 shows the minimum, mean, and maximum hourly average emission for Q3 over the past seven years, and Table 9 shows the same information for the past four quarters. The mean carbon intensity has remained relatively stable since Q4 2022. Notably, the maximum hourly average carbon emission intensity in Q3 was lower than the minimum hourly average carbon emission intensity in Q3 2017.

Table 8: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2017 Q3	0.62	0.77	0.88
2018 Q3	0.55	0.68	0.77
2019 Q3	0.53	0.65	0.74
2020 Q3	0.44	0.59	0.70
2021 Q3	0.43	0.55	0.64
2022 Q3	0.38	0.50	0.59
2023 Q3	0.31	0.45	0.56

Table 9: Quarter over quarter min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2022 Q4	0.37	0.48	0.57
2023 Q1	0.36	0.47	0.57
2023 Q2	0.28	0.44	0.57
2023 Q3	0.31	0.45	0.56

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

Figure 33 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q3 for the past seven years. Figure 34 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The conversion of coal-fired generation to natural gas in addition to increased intermittent generation has driven this decline in carbon emission intensity. This decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions as shown below in Figure 33 and Figure 34.

Figure 33: The distribution of average carbon emission intensities in Q3 (2017 to 2023)

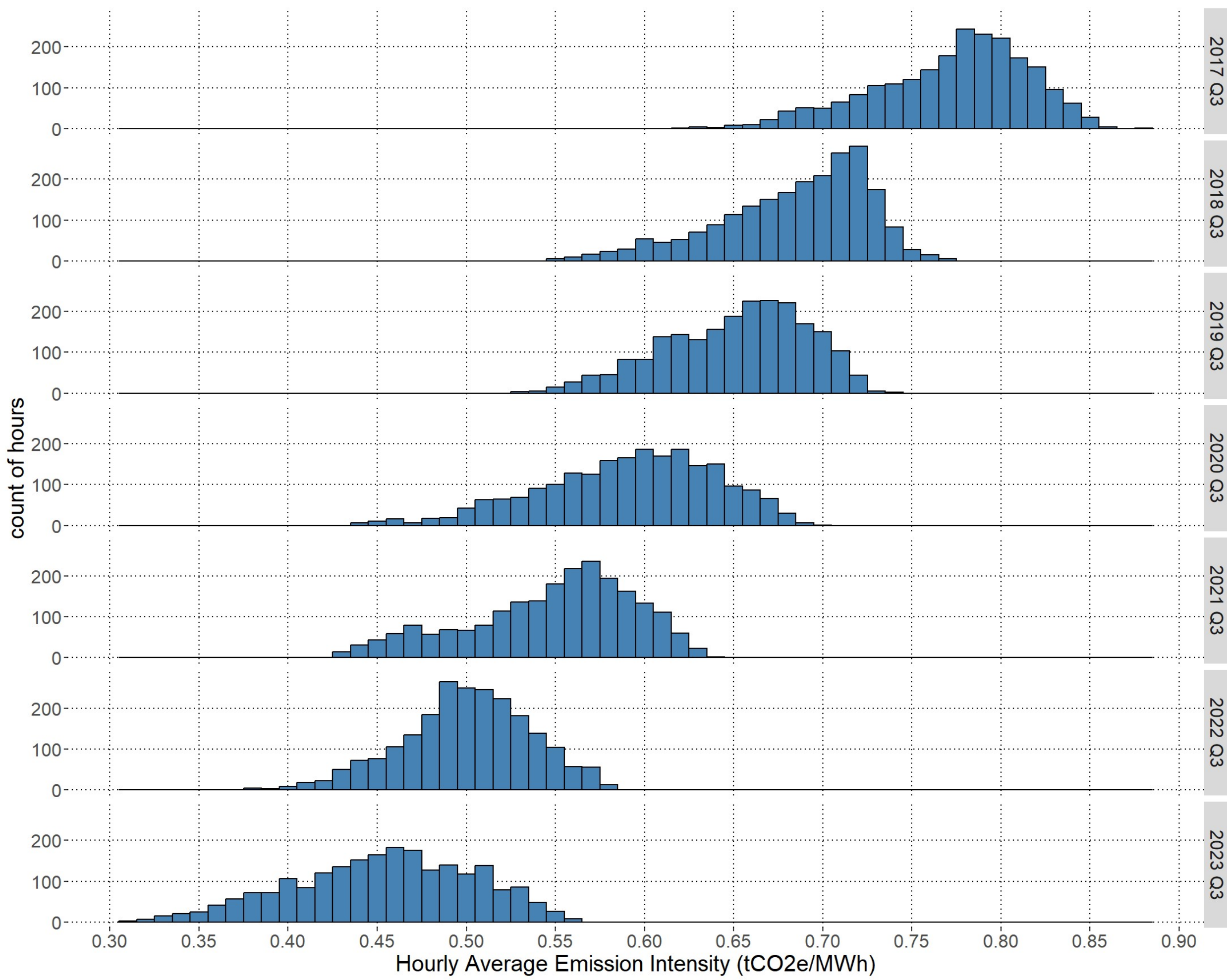
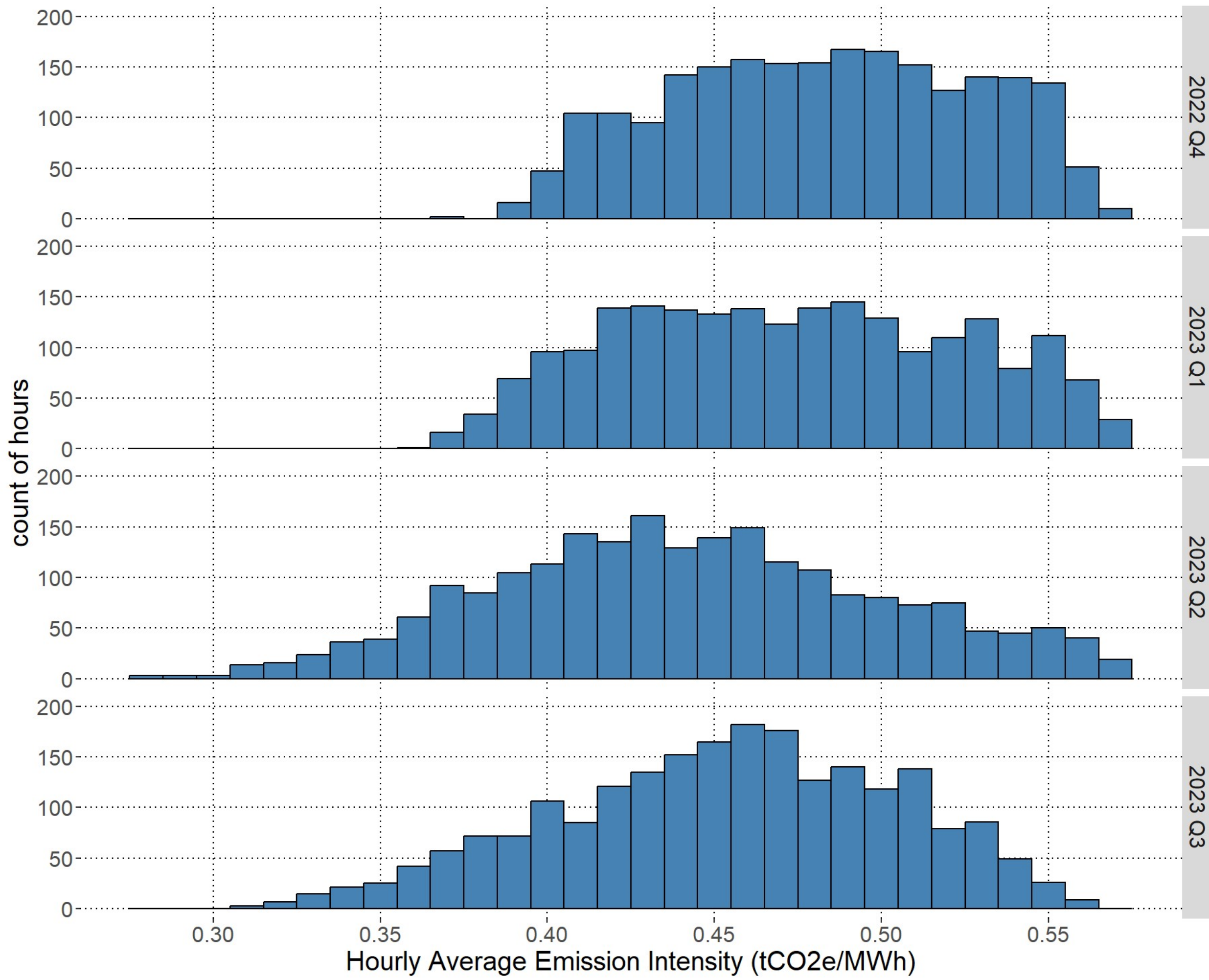
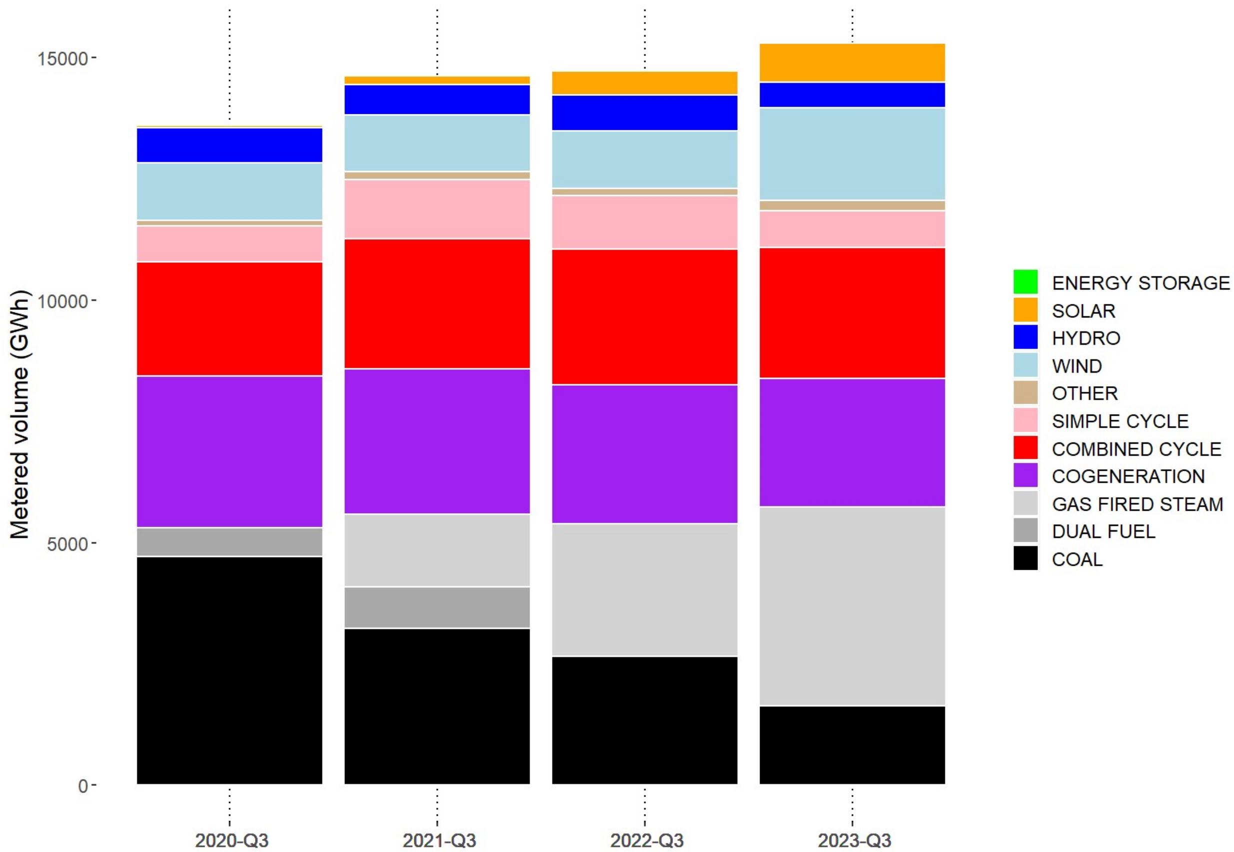


Figure 34: The distribution of average carbon emission intensities in the past four quarters



The general trends observed in the above distribution figures can be traced in Figure 35, which shows net-to-grid generation volumes by fuel type. Since 2020, there has been a decline in the volume of coal-fired generation, with generation from gas-fired steam assets replacing it. The increase in intermittent generation driven by growing capacity has also contributed to the displacement of coal-fired generation since 2020. In the coming months, increased production from HR Milner and Cascade 1 and 2 will put downwards pressure on emission intensity, while reduced solar capacity factors over the late fall and winter months will apply some upward pressure.

Figure 35: Quarterly total net-to-grid generation volumes by fuel type for Q3 (2020 to 2023)

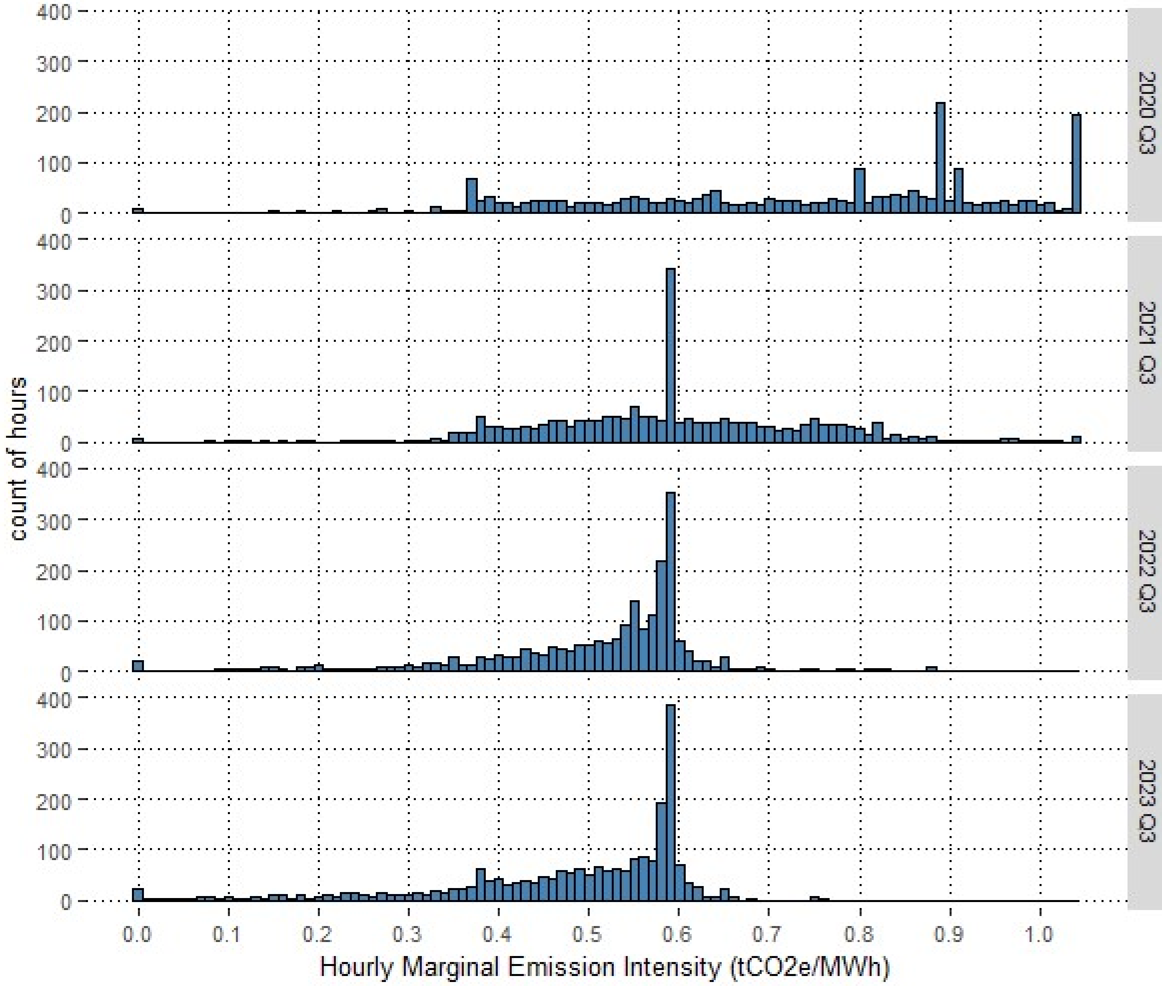


1.4.2 Hourly marginal emission intensity

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 36 shows the distribution of the hourly marginal emission intensity of the grid in Q3 for the past four years. Converted coal assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO2e/MWh from 2021 Q3 onwards.

Figure 36: The distribution of marginal carbon emission intensities in Q3 (2020 to 2023)

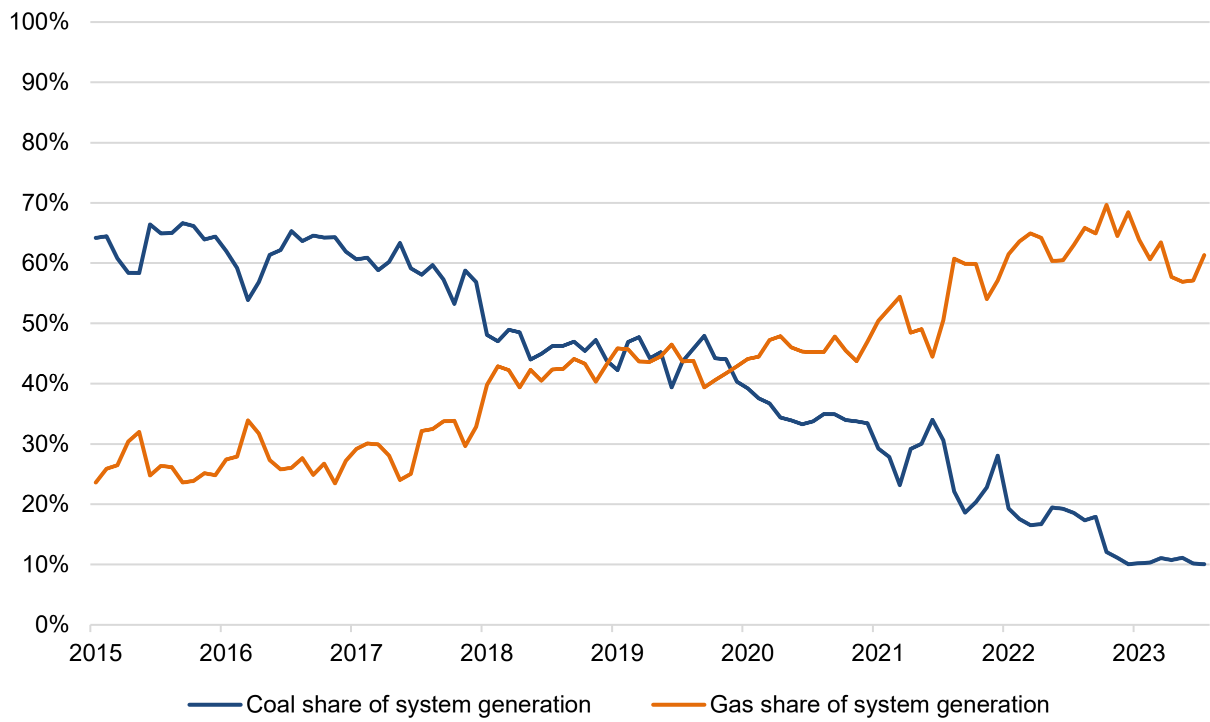


1.5 Fuel supply

This section examines the framework for how generators must manage their fuel supply and how fuel supply constraints impact participation in the energy market. The focus is on natural gas-fired generators; however, similar considerations apply to other fuel types with energy limitations such as hydro and energy storage. The following events discussed this section, and other analyses in the MSA's Quarterly reports, focus on reliability events and their implications. With the rapid technological changes taking place in the market, reliability has become increasingly relevant to the MSA's market assessment work.

The MSA is of the view that fuel supply management has become more relevant to grid reliability as the proportion of natural gas-fired generation has increased. As shown in Figure 37, the share of system generation from gas-fired generators increased from approximately 30% in 2017 to over 60% in 2023 as coal-fired generators have converted to gas or retired.

Figure 37: Share of coal and gas-fired generation (2015 to 2023)



Whereas coal-fired generators typically have onsite, independent fuel supplies, natural gas-fired generators depend on a shared network of gas transmission infrastructure, resulting in correlated supply interruptions. This makes reliability of the electric system vulnerable to outages on the natural gas system. Beyond this, the MSA previously documented the critical role that gas-fired generation plays when intermittent generation is limited.[8]

In July 2023, the North American Energy Standards Board (NAESB) released a report on harmonization between the gas and electric systems.[9] This report was prepared in response to a 2021 recommendation from the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), and regional reliability entities[10] to "identify concrete actions to improve the reliability of the natural gas infrastructure system necessary to support the [bulk electric system]."[11] These reports and recommendations were made in response to the 2021 extreme weather event that compromised electric systems in Texas and the South Central United States. The NAESB report made 20 recommendations in key areas, including implementing measures to improve:

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[8] See, for example, Quarterly Report for Q4 2022, section 1.2.1 and Quarterly Report for Q2 2023, section 1.2.

[9] NAESB Gas Electric Harmonization Forum Report

[10] Regional entities include the Western Electricity Coordinating Council (WECC), of which the AESO is a member.

[11] FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States

- gas-electric information-sharing for improved system performance during extreme cold weather emergencies;

- reliability of natural gas facilities during cold weather (freeze protection, electric supply); and,

- the ability of generators to obtain fuel during extreme cold weather events when natural gas heating load and natural gas-fired generators are both in high demand for natural gas, at the same time that natural gas production may have decreased.

FERC, NERC, and the regional reliability entities also conducted a joint inquiry into the 2022 extreme weather event that compromised electric systems in the Eastern United States.[12] This inquiry resulted in 11 recommendations, including the following for gas-electric coordination:

- FERC should consider obtaining a one-time report from FERC-jurisdictional natural gas entities, describing their vulnerability to extreme cold weather events, and how they are trying to minimize these vulnerabilities.

- NAESB should convene natural gas and electric grid operators, and local distribution companies to identify improvements in communication during extreme cold weather events to enhance situational awareness across the natural gas supply chain.

- Initiate study(s) by an independent research group to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of local distribution companies. The study would include information about the cost of the infrastructure buildout.

The MSA recognizes that weatherization efforts in Alberta are more advanced than in other jurisdictions, given the frequency of extreme cold events in the province. This MSA is also aware that the AESO has taken actions to improve gas-electric coordination, with their Q4 2022 Stakeholder Report stating "the AESO and NGTL are operationally coordinated and have a risk matrix and protocols in place to deal with events."[13] However, the MSA is of the view that the Alberta gas and electric systems would benefit from a proactive review of the recommendations from these initiatives to leverage their analysis and determine where there may be opportunities to improve gas-electric operational coordination, information sharing, and weatherization.

The current framework for fuel supply management in Alberta

The current authoritative framework for electricity market participation does not include specific provisions related to fuel supply management. Instead, the rules and legislation create general requirements that govern participation broadly. The application of the requirements to

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[12] FERC-NERC-Regional Entity Joint Inquiry into Winter Storm Elliott, Presentation

FERC-NERC-Regional Entity Joint Inquiry into Winter Storm Elliott, Full Report

[13] AESO Q4 2022 Stakeholder Report. Page 5.

circumstances with fuel constraints is clarified in Information Document #2009-003R, *Acceptable Operational Reasons* (AOR ID).

The *Fair, Efficient and Open Competition Regulation* prohibits market participants from misrepresenting their availability, capability, or operational status, or failing to offer all electric energy from a generating unit to the power pool.[14] The ISO rules require that pool participants offer available capability (AC) equal to the maximum capability (MC) of each source asset to the power pool unless the asset has an acceptable operational reason (AOR).[15] The AESO *Consolidated Authoritative Document Glossary* (CADG) includes several definitions for AOR, including "re-positioning a generating source asset within the energy market to manage physical or operational constraints."[16]

Section 2(b) of the AOR ID interprets the definition of AOR above, and states that "a restatement for the rationing of fuel or the prioritization of fuel for use in one settlement interval over another does not meet the definition of acceptable operational reason." Market participants are required to submit AC equal to MC for as long as they are physically able to operate at MC. Once the fuel supply becomes limited such that the asset is no longer physically capable of operating at MC, an AOR is triggered.

If a market participant wishes to conserve fuel, they may do so using high offer prices to lower their dispatched volume. However, once SMP reaches $999.99/MWh, fuel rationing through offer price is no longer possible because all offers will receive a dispatch and be needed to meet demand at that time.[17]

Section 1.5.1 outlines an example event in which gas network supply constraints impacted reliability. The MSA makes the following recommendations with respect to this issue:

- the AESO should develop and publicly communicate revisions to the fuel management framework that allow it to coordinate fuel supply management (section 1.5.2), and
- the AESO should reconsider and clarify the application of the fuel supply management framework to cogeneration (section 1.5.3).

1.5.1 Example event (December 2021)

Natural gas in Alberta is transported primarily via the NOVA Gas Transmission Ltd. (NGTL) system. This section describes a period of gas supply constraints on the NGTL system on December 27 and 28, 2021. During this period, gas supply in the North East Delivery Area (NEDA)

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[14] *Fair, Efficient and Open Competition Regulation* AR 159/2009 (FEOC Reg). Sections 2(d), (e), and (g).

[15] ISO rule 203.1, *Offers and Bids for Energy*. Section 5.

[16] AESO Consolidated Authoritative Document Glossary (CADG). Page 1.

[17] As per ISO rule 202.3, *Issuing Dispatches for Equal Prices*, offers at $999.99/MWh will be dispatched on a pro rata basis.

of the NGTL system was curtailed to 75% of firm (FT-D) and 0% of interruptible (IT-D) capacity due to a compressor outage.[18]

This curtailment, combined with high electricity demand, low intermittent generation, and reduced interchange capacity, resulted in scarce supply, with the AESO declaring Energy Emergency Alert (EEA) 2 as of 19:29 on December 27, ending at 01:00 on December 28.[19] During this period, fuel supply management using offer price was not possible, with system marginal price (SMP) set at the cap for approximately six hours.

Table 10 shows the development of short-term supply adequacy (STA) codes leading up to real time during this event, for the period with lowest supply cushion. The MSA commented in more detail on the short-term Supply Adequacy Report in section 1.5.1 of the Q2 2023 Quarterly Report.[20] The STA report assigned the highest adequacy code of 4 to all hours in the period up to two hours ahead of real time. In three instances, a code of 4 was assigned just one hour ahead, despite the forecast being calculated and realized during an EEA event.

Table 10: Supply cushion and Supply Adequacy Codes up to 2 hours ahead of real time

Hour Begin	T-2 STA Code	T-1 STA Code	Realized Supply Cushion (MW)
12/27/2021 16:00	4	3	580
12/27/2021 17:00	4	3	194
12/27/2021 18:00	4	2	154
12/27/2021 19:00	4	2	0
12/27/2021 20:00	4	1	0
12/27/2021 21:00	4	3	0
12/27/2021 22:00	4	4	0
12/27/2021 23:00	4	1	0
12/28/2021 0:00	4	4	0
12/28/2021 1:00	4	4	424

Figure 38 shows the timeline of AC restatements for 13 assets that were made for fuel supply-related reasons during this event. The colours denote the AC restatement reasons that were reported by market participants. The first shaded entry shows the period when SMP was at the offer cap, preventing fuel supply management through offer price. SMP was also very high in the surrounding hours. Therefore, given that offers must be finalized two hours ahead, it would have been difficult to predict whether offers priced at the offer cap would receive a dispatch.

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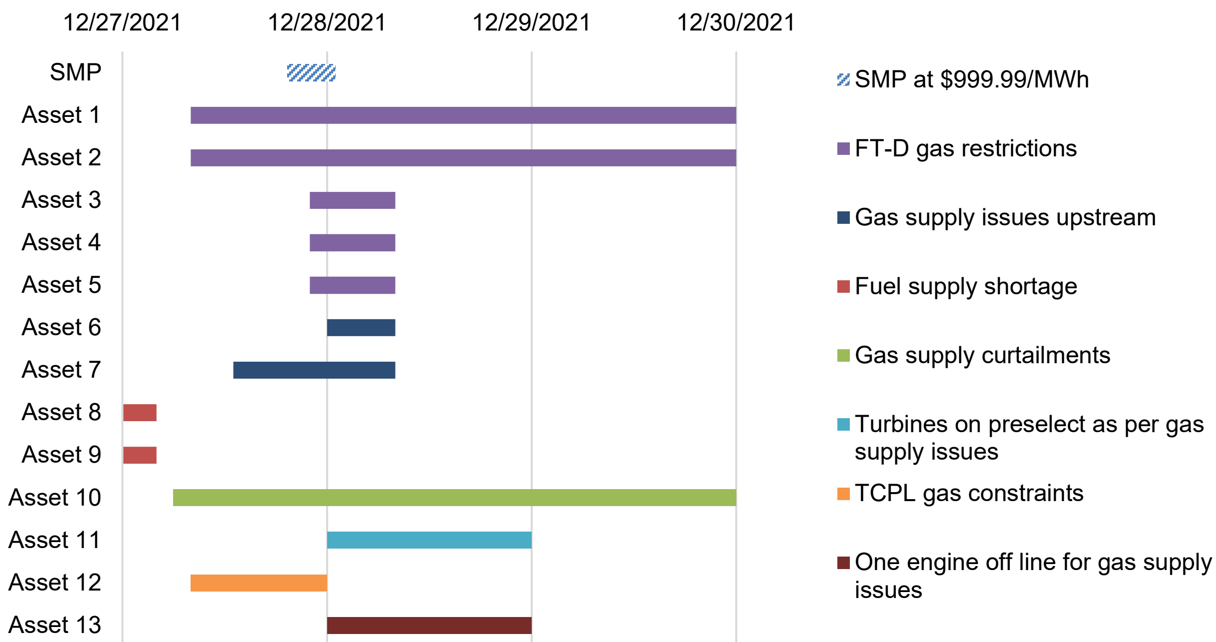
[18] NEDA IT-D and NEDA FT-D: TC Energy, Bulletins

[19] At the time of this event, EEA 2 was declared when "operating reserve are committed to maintain balance of supply and demand ensuring that the regulating reserve margin is maintained."

[20] MSA Quarterly Report for Q2 2023, section 1.5.1

Figure 38: SMP and fuel supply-related AC restatement reasons declared by market participants (December 27-29, 2021)



The December 2021 event is a good example of when system-level visibility and coordination of fuel supply constraints may be beneficial. While some market participants gave advance notice of impending constraints to AESO system operators, others did not, and market participants seemingly held different interpretations of their entitlements and obligations under the ISO rules.

The range of AC restatement reasons demonstrates the lack of standardization in how market participants describe gas supply constraints. For example, generic reasons such as “gas supply issues” could involve fuel rationing or onsite equipment failures. Since 2018, there have been approximately 3,500 distinct restatements that reference fuel supply issues without clearly indicating a more specific reason. No restatement reasons since 2018 have referenced FT-D or firm gas transmission constraints outside the above period. The lack of clear AC restatement reasons leaves system operators with less information and impedes effective compliance monitoring.

In this example, market participants’ restatements were somewhat staggered, in part due to varying interpretations of the current rule framework. Restatements from all participants at the same time may have created operational challenges, including assets cycling off during tight supply conditions overnight. This highlights the deficiency of the current framework, even with consistent interpretations of the current rule framework, and the need for the AESO to coordinate the management of binding fuel supply constraints.

1.5.2 The AESO should develop and publicly communicate revisions to the fuel management framework that allow it to coordinate fuel supply management

As the current framework emphasizes, it is unacceptable for a supply shortfall to result from a market participant refusing to deliver energy for the purpose of rationing fuel. However, it is also unacceptable for a forecasted supply shortfall to materialize that could have been avoided through forward-looking, system-level coordination of fuel constraints. Therefore, the current framework for fuel supply management cannot be reasonably expected to provide reliability in all circumstances.

The MSA is of the view that the current framework for fuel supply management does not enable the AESO to effectively coordinate the provision of reliability in the presence of fuel supply constraints. A significant barrier in this respect is the lack of relevant data that the AESO would use for this function. Market participants are not currently obligated and have no systematic ability to provide the AESO with details of their fuel supply arrangements or any constraints they may face. This leads to an information asymmetry, in which a market participant may have advance notice of a forced derate, while the AESO would only learn of the constraint when the AOR is declared. While the MSA is aware that some market participants have voluntarily shared this information with the AESO, it is not currently required by the ISO rules or facilitated by the AESO's market tools.

The lack of energy limit data is representative of a broader issue with the current AC data. AC, which is meant to represent the maximum MW an asset is physically capable of providing, is not able to reflect the intertemporal constraints, such as fuel supply, that are becoming increasingly relevant to system operations. In general, it is problematic when market participants have information that is consequential to the power system but have no obligation or systematic ability to share that information with the AESO.

In addition to asset-level data, there may be an opportunity to better communicate network-level constraints to the AESO. In line with the recommendations in the NAESB report, the AESO should work with gas system operators to seek opportunities to improve visibility and coordination of fuel supply networks with electric system operations. There will be no time to do this when a crisis arises.

In some other markets, energy limitations are submitted to the system operator.[21] These may include daily gas supply constraints and could also include other similar constraints such as hydro reservoir levels and state-of-charge[22] for battery assets. As the AESO consults on the current market design, the MSA recommends considering fuel supply management in the review of dispatch and unit commitment mechanisms.

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[21] See, for example, the daily energy limit (DEL) in Ontario (Market Rules Chapter 7 Section 3.5.7).

[22] Energy Storage Resources are required to provide state-of-charge data under Appendix 6 of future ISO rule 503.16, *SCADA*, effective April 1, 2024.

1.5.3 The AESO should reconsider and clarify the application of the fuel supply management framework to cogeneration

A unique feature of Alberta's generation fleet is the proportion of natural gas-fired cogeneration. The integration of these generators with industrial processes creates strong incentives outside the electricity market that result in distinct operational characteristics.

The electricity framework in Alberta has several features that enable the efficient integration of cogeneration. For example, in the CADG definition of minimum stable generation (MSG), cogeneration facilities are permitted to set MSG "to avoid… a forced shut down of the onsite industrial processes."

The interpretation in the AOR ID requires cogenerators facing fuel constraints to make their full MC available to the AESO until there is no longer sufficient fuel to operate at MSG, resulting in the forced shut down of the generator and the onsite industrial processes. While fuel conservation using offer price may be possible in some instances, when the SMP reaches the offer cap, as was the case in the December 2021 example, this is no longer possible. In the MSA's view, this treatment is inefficient and inconsistent with other elements of the framework for cogeneration participation.

The MSA recommends that the AESO reconsider how the current framework for fuel supply management applies to cogeneration. Specifically, the CADG definition of AOR should be reviewed, which currently includes a "physical or operational constraint." This could be interpreted similarly to MSG to include the forced shut down of onsite industrial processes.

2 THE POWER SYSTEM

2.1 Trends in transmission congestion

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

The frequency and significance of intermittent constrained down generation directives increased from Q3 2022 to Q3. The MSA estimates that intermittent constrained down generation volumes were 8.4 GWh in Q3 2022 and 43.9 GWh in Q3.[23] This represents an increase by a factor of five year-over-year. The quarter-over-quarter increase, from 41.8 GWh in Q2 to 43.9 GWh in Q3, was substantially smaller at a 4.5%.

The maximum hourly average volume of intermittent generation constrained down in Q3 was 498 MWh, close to five times the maximum of 102 MWh in Q3 2022 (Figure 39 to Figure 41). However, this value is smaller than the Q2 2023 maximum hourly average volume of intermittent constrained, which was 725 MWh (Figure 30). Although there was a greater total volume of intermittent constrained down volume in Q3, the magnitude of peak congestion was smaller than in Q2 2023.

Transmission constraints occurred consistently throughout July and August, then increased in September. The intermittent constrained down volume in the month of September accounted for 71% of all Q3 volumes. In 62% percent of September hours there was at least 1 MWh of intermittent constrained down volume.

Although the total installed capacity of wind and solar generators increased year-over-year, the increase in constrained down volume from Q3 2022 to Q3 grew at a faster rate. While total installed intermittent capacity increased by 26%, average hourly constrained down volumes, expressed as a percent of installed capacity, increased from 0.16% in Q3 2022 to 0.53% in Q3, an increase of more than three times. The growth of constrained down volume outpaced the growth in installed capacity.

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

Figure 39: Hourly transmission constrained wind and solar generation (Q3 2022)

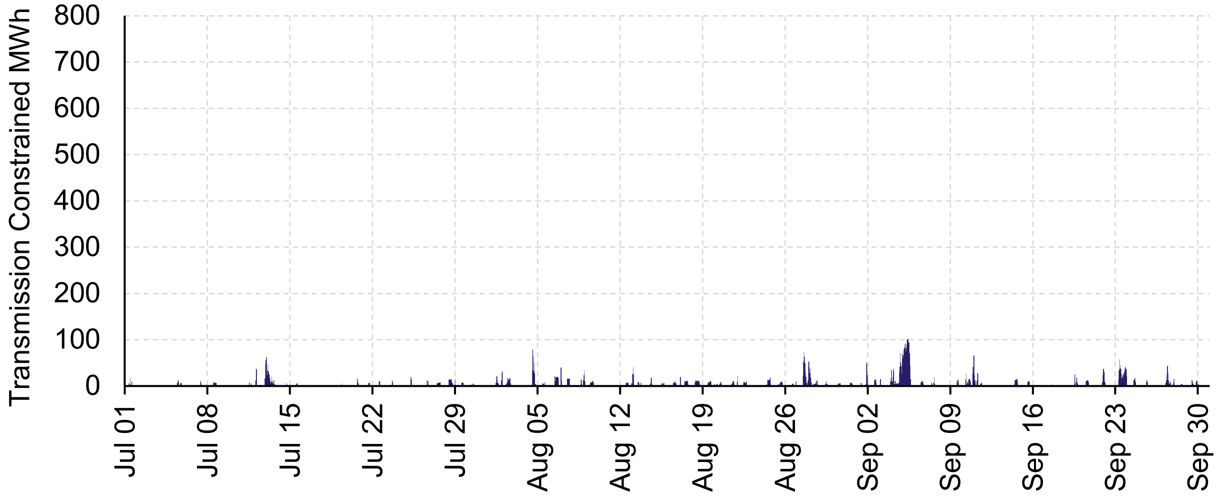


Figure 40: Hourly transmission constrained wind and solar generation (Q2 2023)

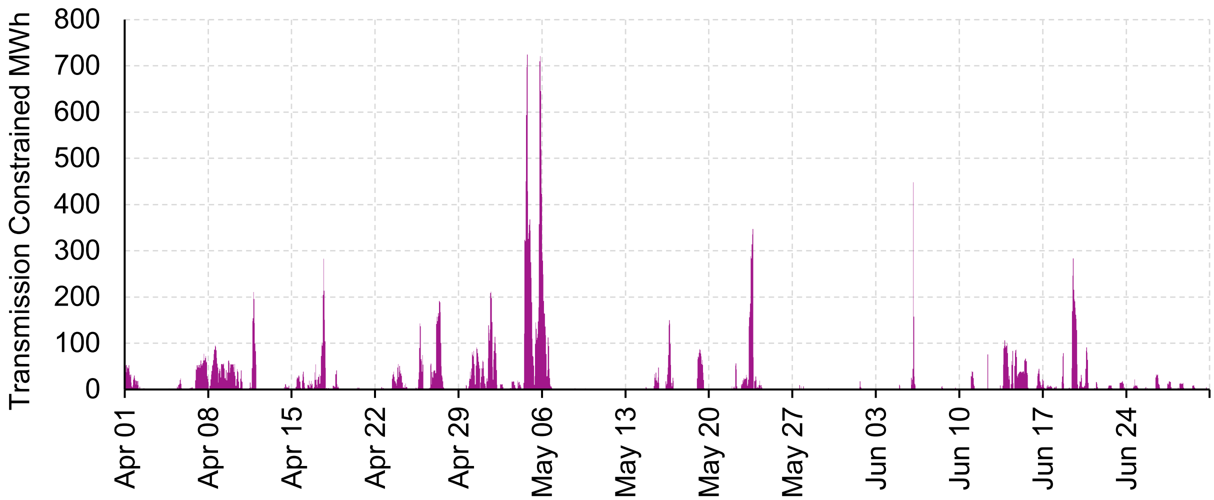
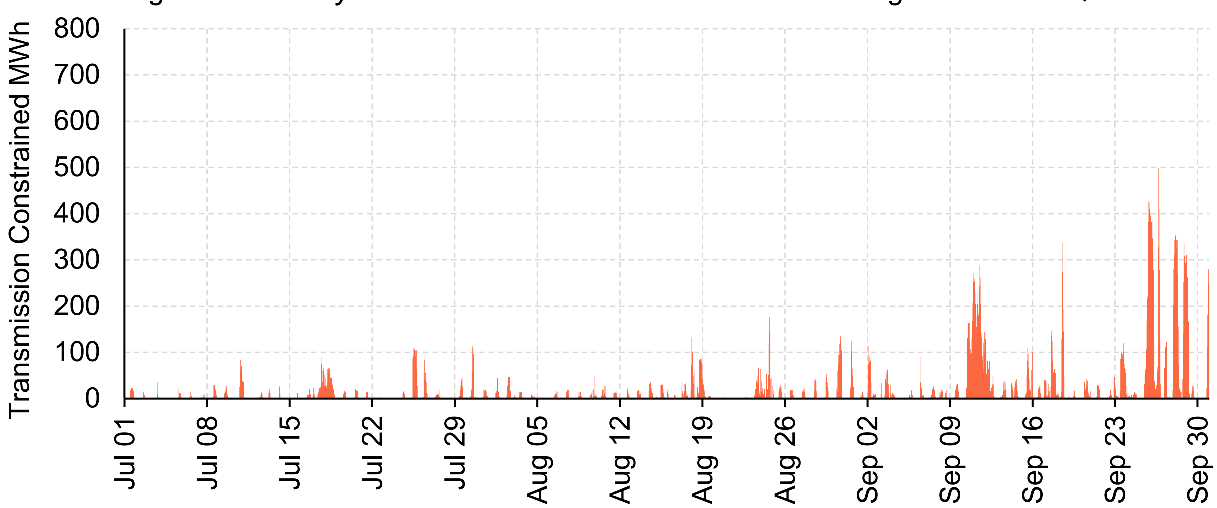
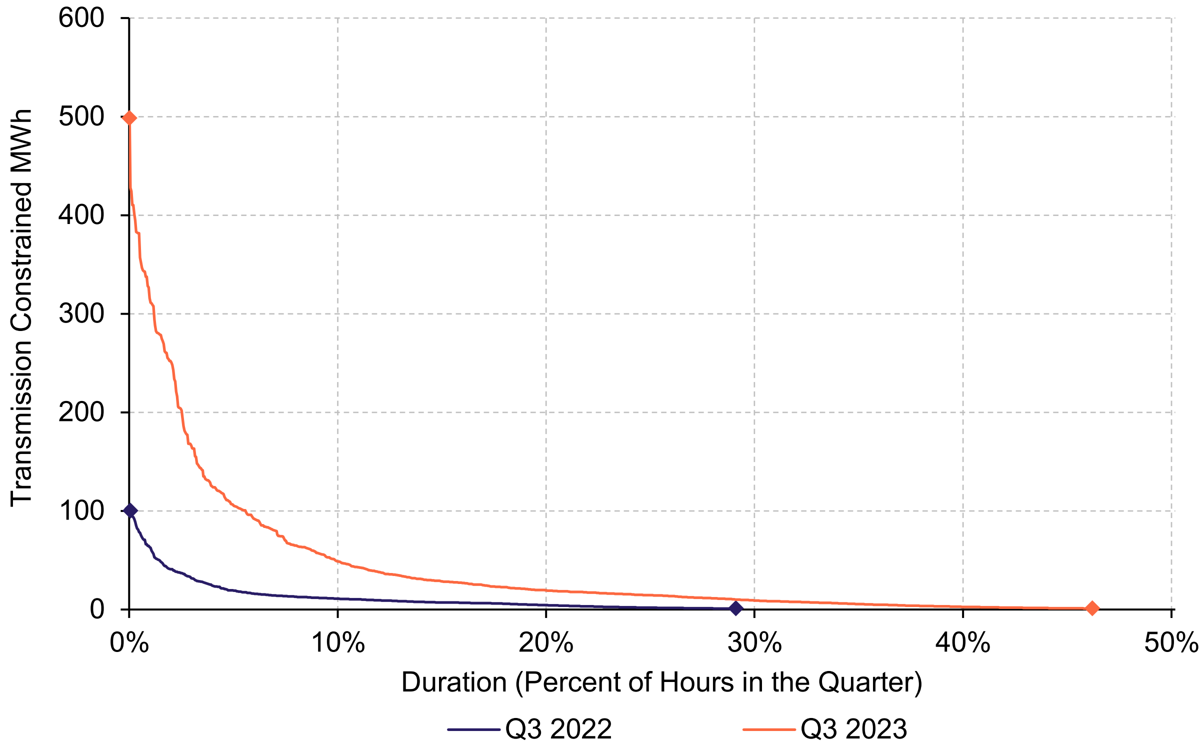


Figure 41: Hourly transmission constrained wind and solar generation in Q3



Increased intermittent constraints resulted in over four times the constrained volume year-over-year (Figure 42).[24] To illustrate the increasing magnitude of congestion, note that in Q3 greater than 5.3% of hours had more congestion than the single most congested hour in Q3 2022. The length of the tails of the duration curves to the right show that the frequency of intermittent constrained down events increased. The percent of hours where at least 1 MWh of intermittent generation was constrained down was 46% in Q3.

Figure 42: Duration of wind and solar constraint volume (Q3 2022 and Q3)



Examining the congestion in September more closely, most constrained down generation occurred during two events. The first occurred from September 10 to 12 and most significantly impacted the generation assets Hand Hills (145 MW) and Wheatland Wind (120 MW). Over this period transmission limits were implemented to mitigate the risks associated with N-1 contingencies. The total constrained down volume for all assets over the period was 7.5 GWh, or 17% of the Q3 total constrained down volumes. Hand Hills was the most constrained over this period, being curtailed by 2.9 GWh. On September 11, at 18:18, the constrained SMP reached $999.96/MWh and remained over $999.00/MWh for nine minutes. In contrast, the unconstrained SMP during the same period averaged just under $840/MWh as the AESO reconstituted price.

[24] In hours where the estimated volume of wind and solar constrained down generation that was less than 1 MWh, the estimate was rounded down to 0 MWh.

Figure 43: Wind and solar transmission constrained MW (September 10 to 12, 2023)

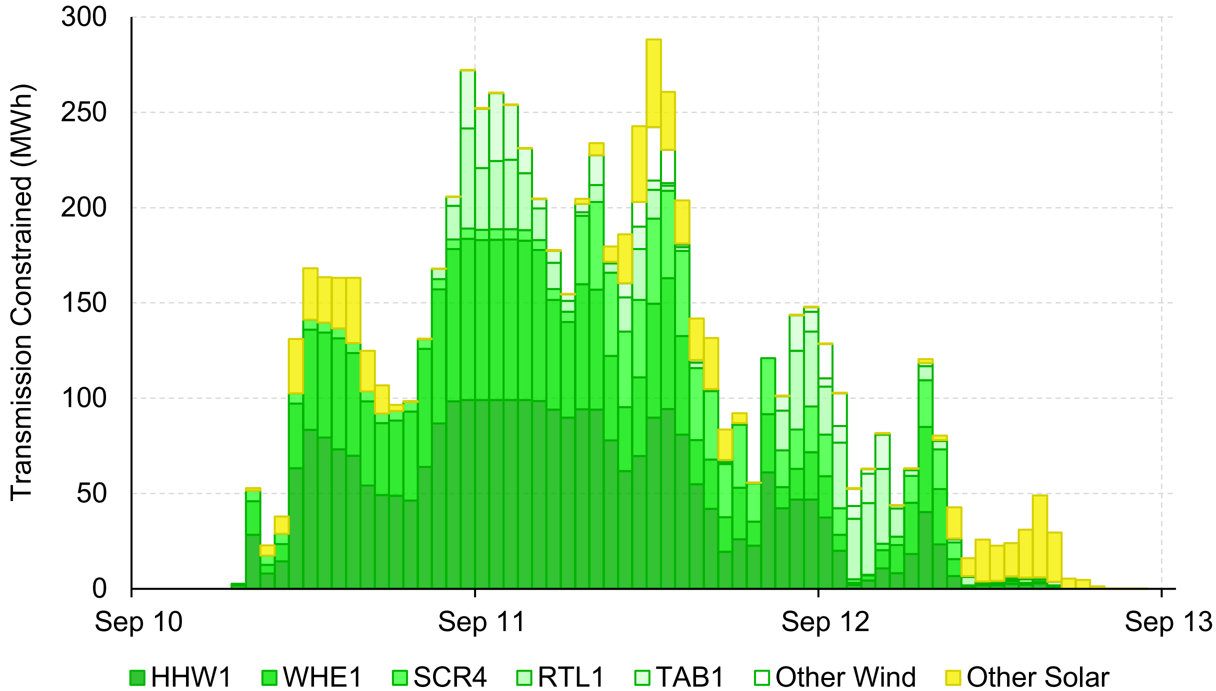
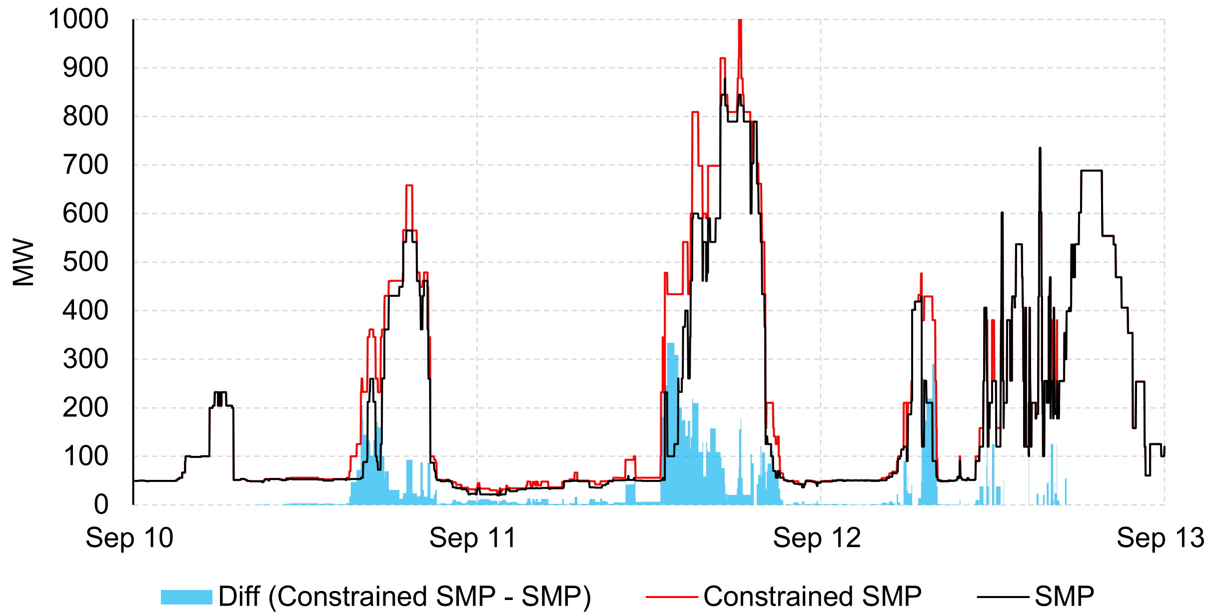


Figure 44: Constrained SMP vs. SMP (September 10 to 12, 2023)



In the second event, the AESO initiated a series of zonal constraints to manage the risk of flows on 1035L exceeding the 466 MW MSSC limit while interconnected. This constraint was related to a scheduled outage on 1034L. 1034L and 1035L are the elements of a 240kV double circuit line located in the South region near Brooks and Medicine Hat. Wind and solar constrained down volume peaked at 498 MWh on September 26 in HE 17. From 16:04 to 16:24 SMP was $0/MWh and the constrained SMP was $27.50/MWh. Similarly, on September 28 from HE 01 to HE 04, there were 171 minutes when SMP was $0/MWh and the constrained SMP was positive.

Figure 45: Wind and solar transmission constrained MW (September 25 to 29, 2023)

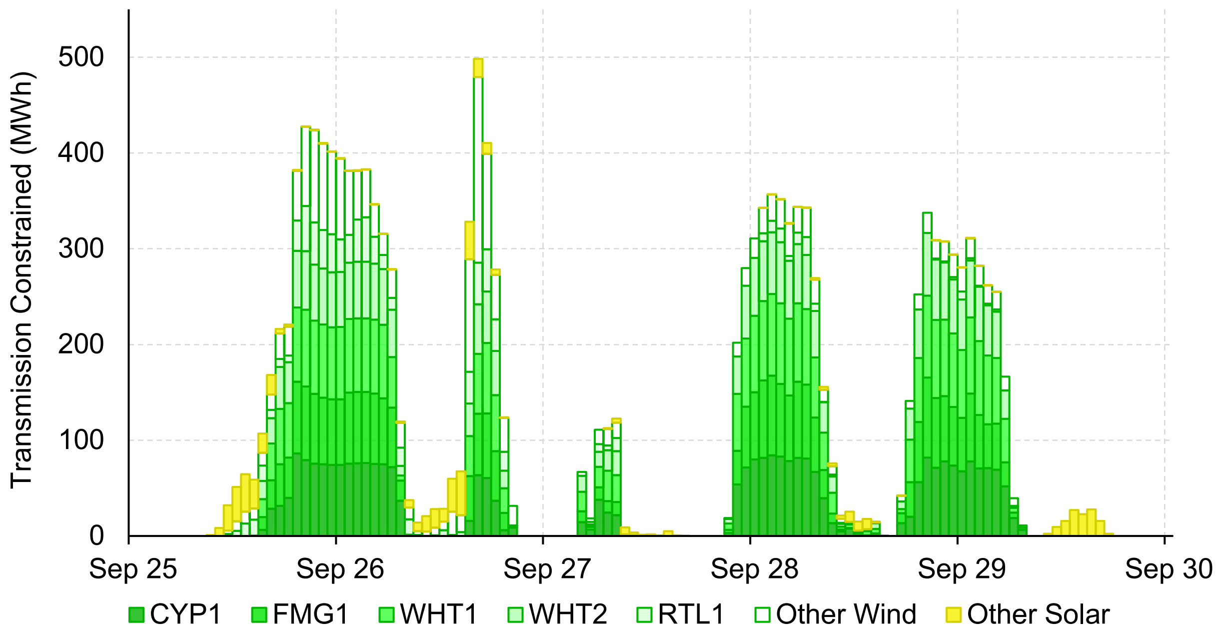
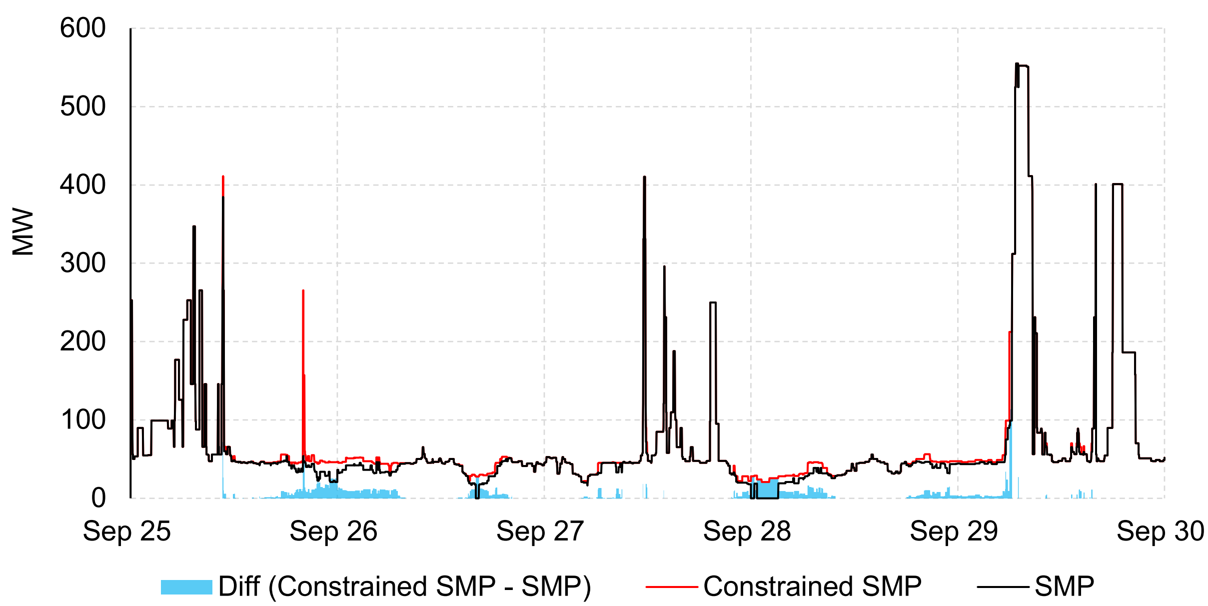


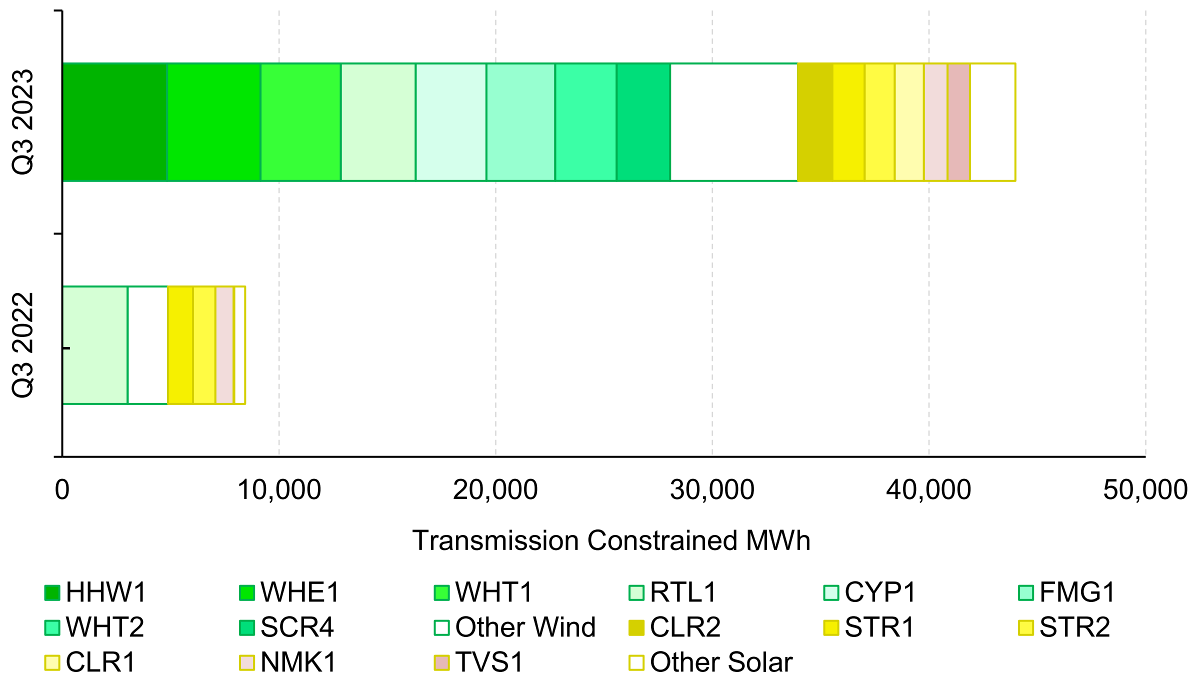
Figure 46: Constrained SMP vs. SMP (September 25 to 29, 2023)



Wind and solar assets are not constrained uniformly throughout the province. In Q3, the eight most constrained wind assets accounted for about two thirds of the total constrained down volume (Figure 47). Unlike previous quarters, Hand Hills and Wheatland Wind, were the most constrained wind assets. These assets represent 7% of Alberta's installed wind capacity, however they accounted for approximately 27% of the wind constrained volume in Q3.

Claresholm 2 (75 MW) was the most-constrained solar asset in Q3, with a total of 1,573 MWh constrained. The five most constrained solar assets have an aggregate maximum capability of 194 MW and were constrained by 6,891 MWh in Q3. These 5 assets are all located near Claresholm or Strathmore. The sixth most constrained, Travers (465 MW), is the largest solar facility in Alberta and was constrained by 1,034 MWh in Q3. This illustrates the uneven concentration of constraints within Alberta.

Figure 47: Wind and solar transmission constrained MWh by asset (Q3 2022 and Q3)



2.2 Pool price inaccuracies caused by inaccurate price reconstitution

The AESO uses constrained down generation to manage outflow transmission constraints.[25] When this occurs, the electricity price is set as if, notionally, the system is not transmission constrained. This report refers to this price adjustment process as price reconstitution. Specifically, the highest pool asset marginal price is set ignoring MW dispatched for transmission constraint rebalancing. Pool asset marginal price is used to calculate SMP and pool price.[26] The

[25] AESO ID 2015-006R, *Calculation of Pool Price and TCR Costs*

[26] ISO rule 201.6, *Pricing*

MSA further discussed how the AESO sets pool price during periods with transmission constraint rebalancing in section 2.1 of the Q2 2023 report.[27]

In order for the AESO to accurately reconstitute pool price during periods of congestion, it must accurately know the volume of system-wide outflow transmission constraints. If the AESO inaccurately calculates the transmission constraint rebalancing volume, it may inaccurately set the SMP and pool price. The MSA has identified four cases where the pool price is at risk of being set inaccurately.

1. When a wind or solar asset over-reports its potential real power capability, and is transmission constrained, the pool price may be set too low.

2. When a wind or solar asset under-reports its potential real power capability, and is transmission constrained, the pool price may be set too high.

3. When there are data issues resulting in no price reconstitution, when there ought to be, the pool price may be set too high.

4. When the AESO uses constrained down generation to manage wind and solar power ramp up constraints, the pool price may be set too low.

Each case is explained with examples in the following sections.

The MSA conducted a preliminary analysis to quantify the frequency of price inaccuracies. From April 9 to August 8, 2023, the MSA identified approximately 100 hours where issues related to potential real power capability data (categorized as case 1 and 2 above) resulted in price inaccuracies. This represents about 3% of hours over the analysis period. These events can result in price being set too high or too low.

2.2.1 MSA recommendations to prevent price inaccuracies

The pool prices inaccuracies identified in this analysis share a similar root mechanism—inaccurately calculating the transmission constraint rebalancing volume can result in inaccurate price reconstitution. The MSA makes the following recommendations with respect to this issue:

- the AESO should improve its compliance monitoring process to quickly detect when the legal owner of an asset reports inaccurate potential real power capability data,

- the AESO should develop an alternative methodology to calculate the volume of constrained down generation from assets with potential real power capability data that the AESO suspects is inaccurate, and the AESO should use this alternative methodology to reconstitute price when it suspects transmission constrained asset are reporting inaccurate data,

[27] Quarterly Report for Q2 2023

- for instances where the current version of section 502.8 of the ISO rules (Section 502.8) is not applicable to a legal owner, the AESO should determine (as per the existing requirements of Section 502.8) if compliance with the most current version is necessary for the safe and reliable operation of the interconnected electric system and whether the legal owner must comply with any specific provision or all provisions of the current version of Section 502.8. Specifically, the AESO should consider the possible reliability risks associated with incorrect potential real power capability data being reported by assets that were energized and commissioned prior to April 7, 2017.

- the AESO should examine its IT system tools and verify that price is being reconstituted in all minutes when price ought to be reconstituted, and

- the AESO should develop a procedure to not use constrained down generation for a purpose other than real-time transmission constraint mitigation.

2.2.2 Potential real power data quality issues resulting in price being set too low

Most wind and solar assets are required to have meteorological equipment on site to calculate their potential real power capability, an estimate of how much power the site could provide absent any constraints.[28] When a wind or solar asset is constrained down, the counterfactual generation the asset would have provided is not directly observable. Instead, potential real power capability is used to calculate the volume of energy that was constrained down. If an asset reports incorrect potential real power data and is transmission constrained, the AESO may incorrectly calculate the volume of constrained down generation. If the magnitude of this miscalculation is greater than the quantity of MW dispatched from the marginal operating block, then the AESO may incorrectly reconstitute price.

Sections 2.2.2 and 2.2.3 consider the implications of data issues associated with an 88 MW wind asset. It appears that the asset sometimes reports erroneous potential real power data; specifically, it reports a level of potential that appears frozen for days at a time. For example, on May 1, 2023, the asset continuously reported 79 MW of potential real power capability—these data appear to be incorrect. The asset was transmission constrained from HE 09 to HE 20, as shown in Figure 48. In that figure, the asset's reported potential real power is shown as a red shaded area. Overlaid in blue is the asset's generation. When the asset is dispatched to a level below AC, and the dispatch is equal to the curtailment limit, the asset is under a transmission constraint directive. When the asset is dispatched at AC, but the curtailment limit is below AC, the asset is subject to a power ramp management limit.

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

Figure 48: Constrained down generation for the asset (May 1, 2023)

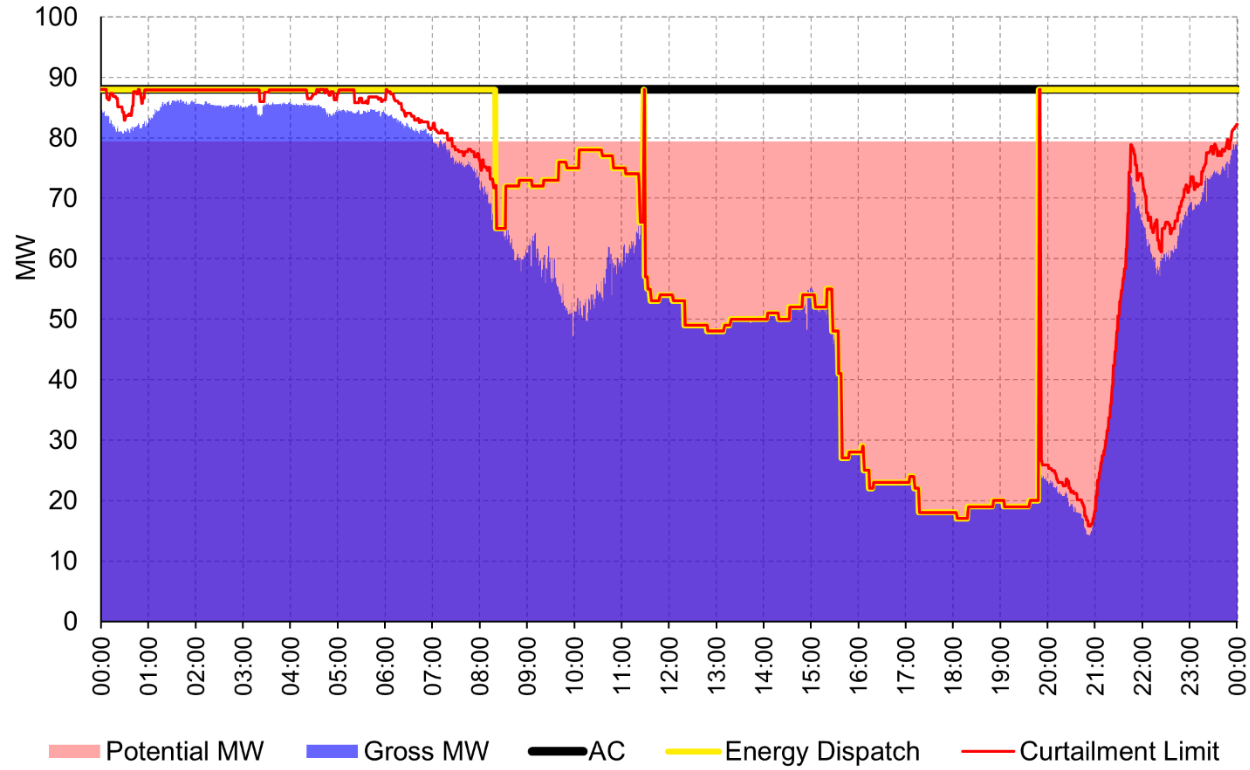
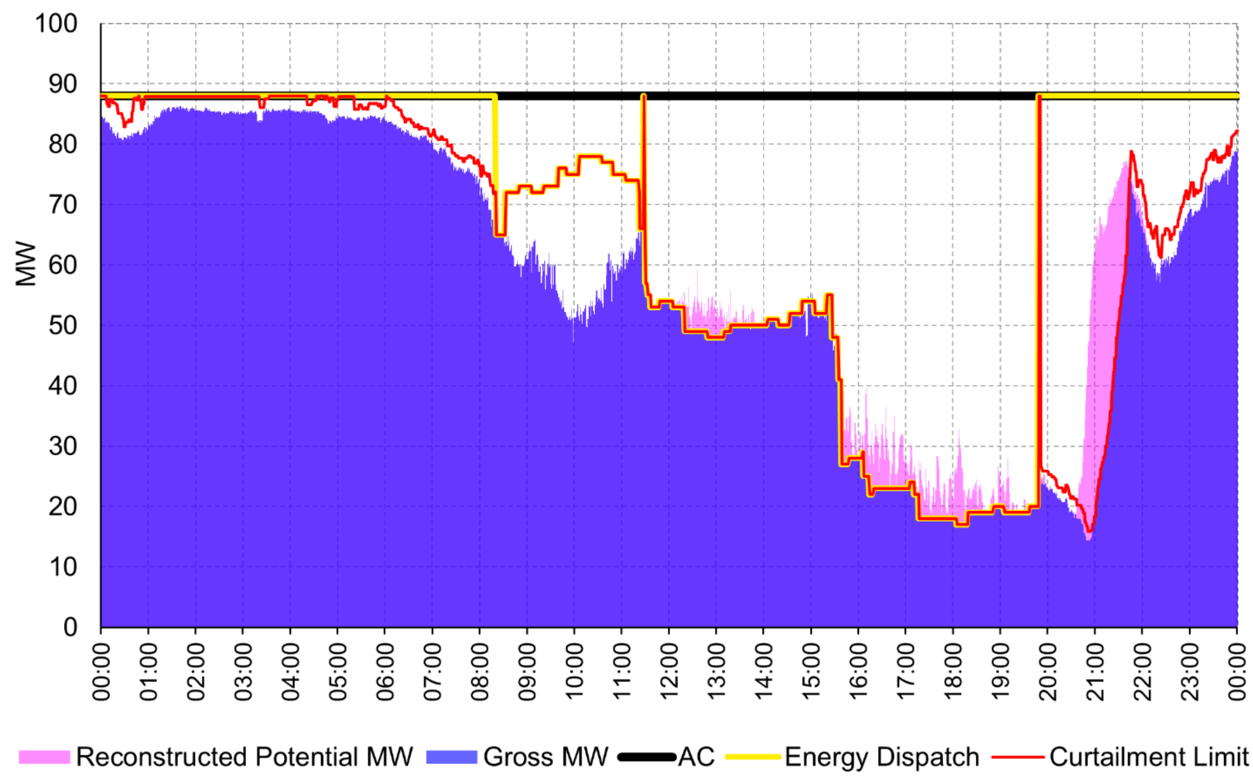


Figure 49: Reconstructed constrained down generation for the asset (May 1, 2023)

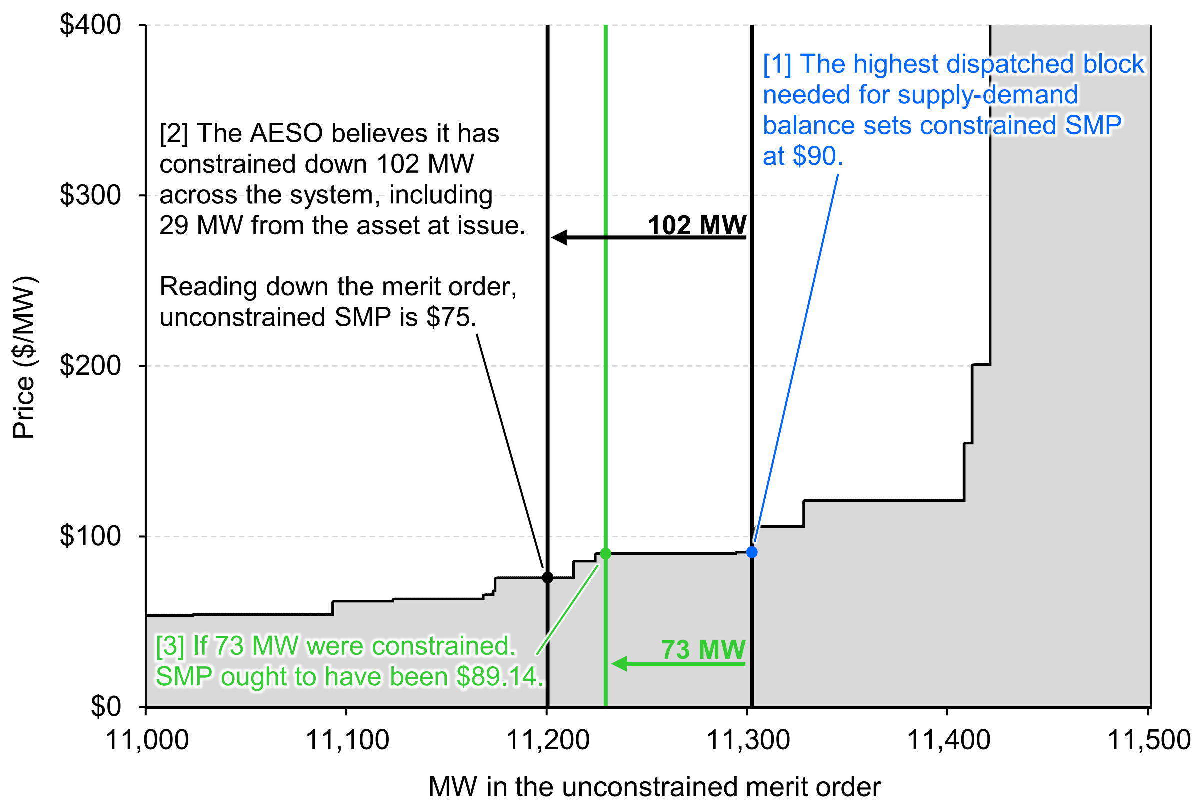


It appears that the AESO calculated the volume of constrained down generation based on the asset's reported, and likely incorrect, potential real power data. As an example, at 14:30:30 the AESO directed the asset to 50 MW. Based on 79 MW of reported potential, the AESO's tools assume the asset was constrained down by 29 MW.

The MSA estimated what the potential real power capability of the asset ought to have been based on the potential of a nearby wind asset. This reconstructed potential real power suggests that that the asset had less than 79 MW of potential during the period that it was transmission constrained. At 14:30:30, the asset's reconstructed potential suggests that it had the potential to generate 50 MW. This suggests that the asset's 50 MW constraint level did not bind in that minute, and there were 0 MW of constrained down generation from this asset at 14:30:30 (Figure 49).

The unconstrained energy market merit order at 14:30:30 shows the highest dispatched block set SMP at $90/MWh. The AESO, believing it constrained down 102 MW across the system, including 29 MW from the asset at issue, reconstituted price to $75/MWh. However, if the asset's constraint level was not binding, and the asset was not constrained down, then there were 73 MW constrained down across the system, and zero MW from the asset. At that moment, the AESO ought to have reconstituted price by 73 MW, to $89.14/MWh. As a result, the AESO set price too low due to this data quality issue.

Figure 50: Unconstrained energy market merit order snapshot on May 1, 2023, at 14:30:30



2.2.3 Potential real power data quality issues resulting in price being set too high

On July 26 to 27, 2023, the same wind asset continuously reported 0 MW of potential real power capability—these data appear to be incorrect, as the asset delivered positive volumes of energy to the grid when it was not constrained.

From July 26 HE 21 to July 27 HE 05, the AESO implemented a zonal transmission constraint limit impacting two wind assets near Drumheller to manage N-1 constraints on 7L171 and 801s T1 overload. It appears this zonal limit was barely binding, resulting in, on average, 2 MW of constrained down generation during the event. In some minutes, the constraint did not bind. A snapshot of this event on July 27 at 01:30:30 shows this constraint was allocated to the impacted assets as follows:

- The asset reported 0 MW of potential real power capability. The AESO IT system determined the asset could not be further curtailed, so the asset was directed to 0 MW.
- The nearby asset reported 97 MW of potential real power capability. The constraint was not binding in this minute, as the asset was directed to 98 MW.

Although the asset reported 0 MW of potential real power capability, the MSA estimates it would have been able to generate 81 MW absent the constraint at 01:30:30 (Figure 51 and Figure 52). From the AESO's perspective, the asset was constrained down by 0 MW because the asset reported 0 MW potential real power capability. In this minute, the AESO calculated 0 MW of constrained down generation and so did not reconstitute price.

At 01:30:30, the asset was directed to 0 MW and the nearby asset was directed 98 MW. If the asset had instead correctly reported its potential real power capability, of about 81 MW, it is possible that either:

- 81 MW of additional in-merit supply would have been generated by the asset. This scenario suggests that the asset's incorrect data resulted in 81 MW of forgone energy that ought not to have been curtailed, or
- the zonal limit would have bound, and the asset, and the nearby asset, would have been constrained down by, in aggregate, 81 MW. In this case the aggregate generation from the two assets would remain the same. The AESO would then reconstitute price for the use of 81 MW of constrained down generation. This scenario suggests that the AESO ought to have reconstituted price by 81 MW but did not.

In either of the above scenarios, the incorrect data reported by the asset resulted in the AESO setting price too high, according to an offer price that was 81 MW higher up in the merit order than it should have.

Figure 51: Constrained down generation for the asset (July 26 to 27, 2023)

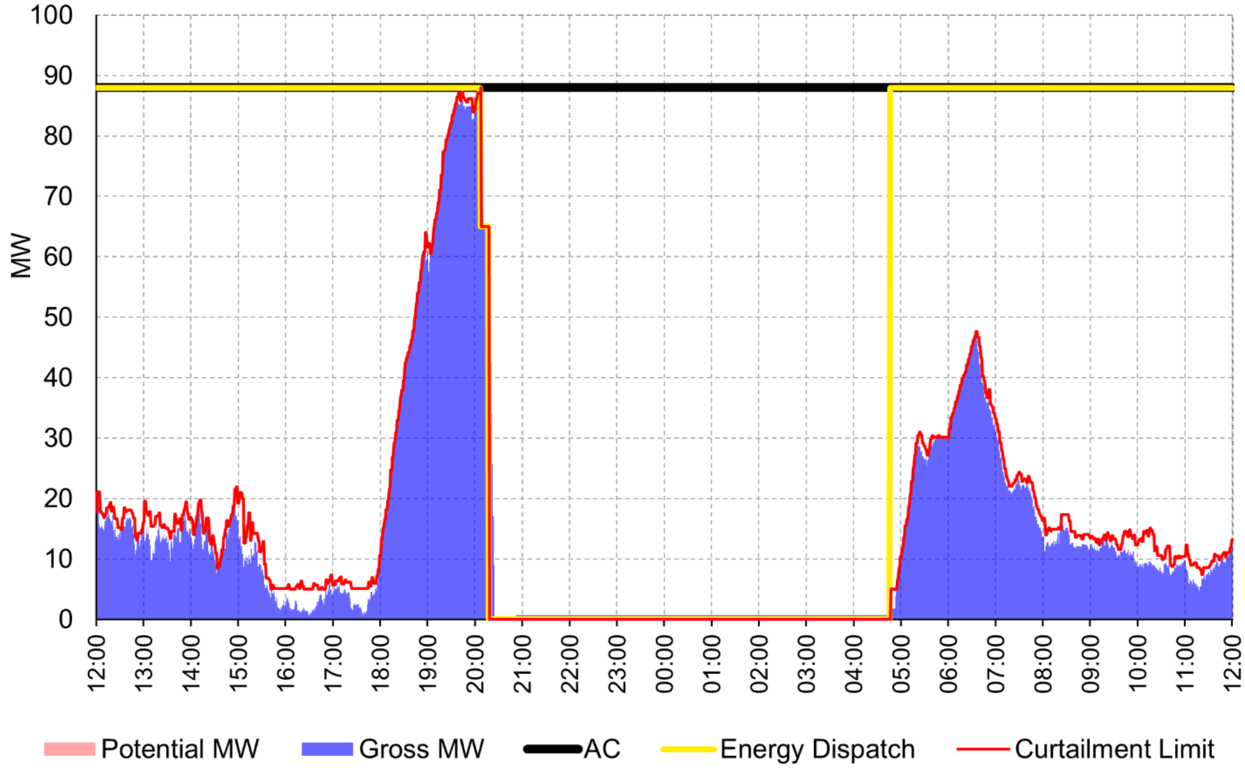
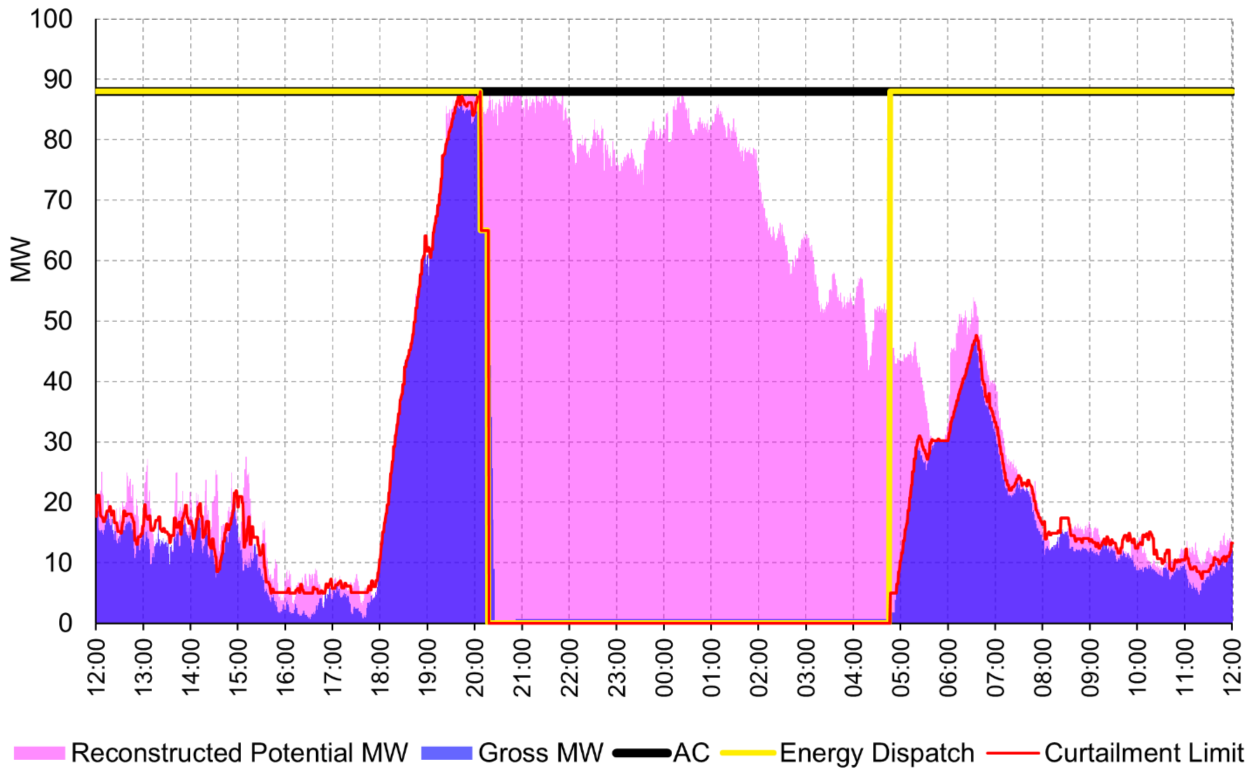


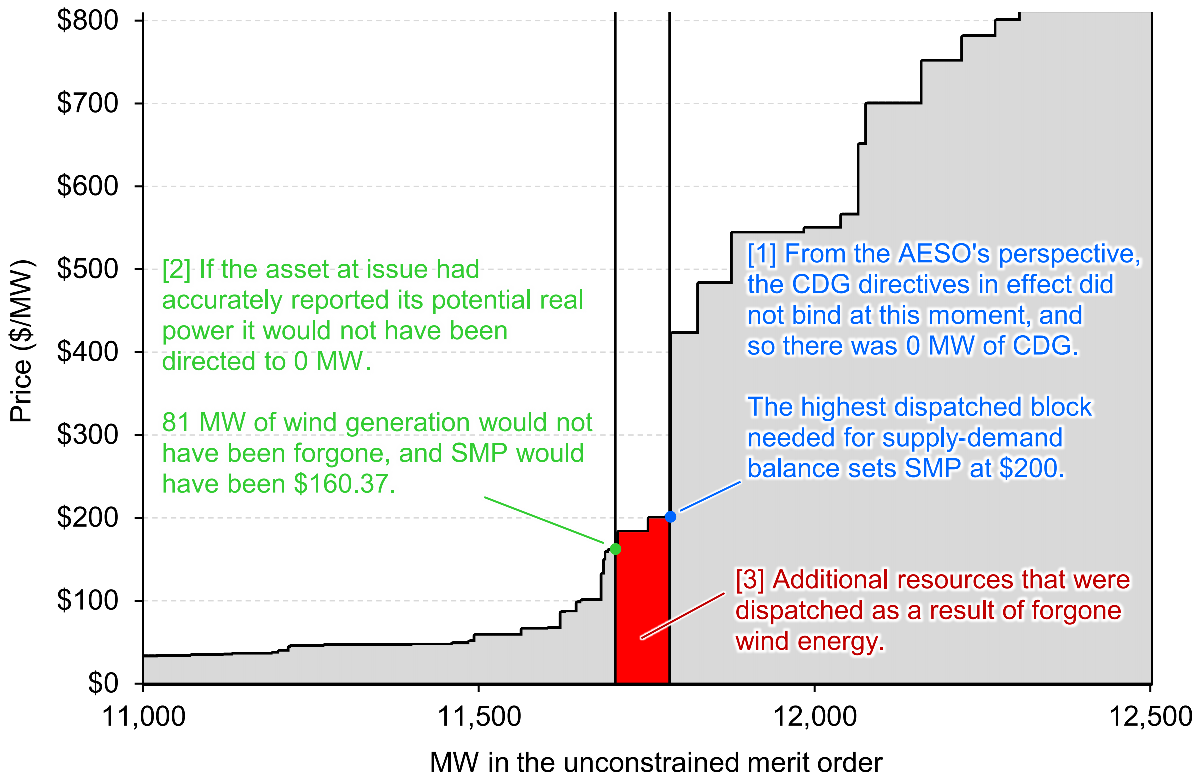
Figure 52: Reconstructed constrained down generation for the asset (July 26 to 27, 2023)



The unconstrained energy market merit order at 01:30:30 shows that the highest dispatched block set the SMP at $200/MWh (Figure 53). Had there been 81 MW of additional in-merit supply at that minute, or 81 MW of reconstitution, price would have been lower. Reading down the merit-order by 81 MW suggests SMP would have been $160.37/MWh. This suggests the AESO set SMP too high as a result of this data quality issue.

The price inaccuracies discussed in this section and section 2.2.2 both result from the owner of a generating unit submitting incorrect potential real power capability data, resulting in the AESO's tools inaccurately reconstituting price. The MSA recommends that the AESO use its monitoring process to detect erroneous potential real power data, and adjust its price reconstitution methodology when it suspects erroneous data is being submitted for a transmission constrained asset.

Figure 53: Unconstrained energy market merit order snapshot on July 27, 2023, at 01:30:30



2.2.4 *Data issues resulting in no price reconstitution, when there ought to be, resulting in price being set too high*

On rare occasions, it appears the AESO does not reconstitute pool price during periods of congestion even though it ought to. On April 17, 2023, at 20:23, the AESO issued transmission constraint directives that constrained down four wind assets to 0 MW. The assets HAL1, WHE1, SCR4, and GDP1 reduced their generation to 0 MW. They were later dispatched at 20:32 to levels above 0 MW as system conditions changed and the constraints were relaxed.

Table 11 shows data extracted from a merit order snapshot on April 17, 2023, at 20:30:30. The four rows of data pertain to four constrained wind assets that offer their entire available capability at $0/MW in a single operating block. The data in the columns are described as follows:

- *Asset* is the asset ID of the pool asset.

- *Available MW* is the amount of MW that are available to be dispatched for energy from this operating block. When a wind or solar asset is not transmission constrained, and if the asset has offered its capacity in a single operating block, *Available MW* will reflect the available capability of the entire asset. In most cases, when a wind or solar asset is transmission constrained, *Available MW* reflects the asset's potential real power capability. In cases when a wind or solar asset is transmission constrained to 0 MW, *Available MW* may reflect the entire size of the operating block (which is often the asset's available capability) or it may reflect the asset's potential real power capability. It is unclear why *Available MW* sometimes reflects the operating block size or potential under these conditions.

- *Dispatched? (Y/N)* is a binary variable that is equal to *Y* if the asset is dispatched to a non-zero level, else it is *N*.

- *Dispatched MW* is the volume of MW dispatched for energy from this operating block. For wind and solar assets that offer their capacity in a single operating block, this reflects the energy dispatch for the entire asset.

- *Estimated reconstructed CDG MW* is the MSA's estimate of the volume of constrained down generation. This estimate factors in adjustments the MSA has made for data it believes are erroneous. In the particular table below:

    - HAL1's *Available MW* and its potential real power were 38 MW; at that moment, 38 MW were constrained down from HAL1.

    - WHE1 shows 115 MW of *Available MW*, this was the asset's available capability at the time. The asset had 6 MW of potential real power, and so there were 6 MW of estimated CDG from WHE1.

    - SCR4 shows 88 MW of *Available MW,* the asset's maximum capability. The asset reported 79 MW of potential real power at the time, but this value appears to be incorrect. Based on SCR4's actual output, and the potential of a nearby wind asset, SCR4's reconstructed potential real power is estimated to be 4 MW, and so the asset was constrained down by 4 MW.

    - GDP1 shows 35 MW of *Available MW,* which was the asset's available capability. The asset reported 122 MW of potential real power, which appears to be incorrect.

Based on the asset's output during the moments before and after the constraint, GDP1's reconstructed potential real power is estimated to be 0 MW.

Table 11: Dispatch and CDG data snapshot on April 17, 2023 at 20:30:30

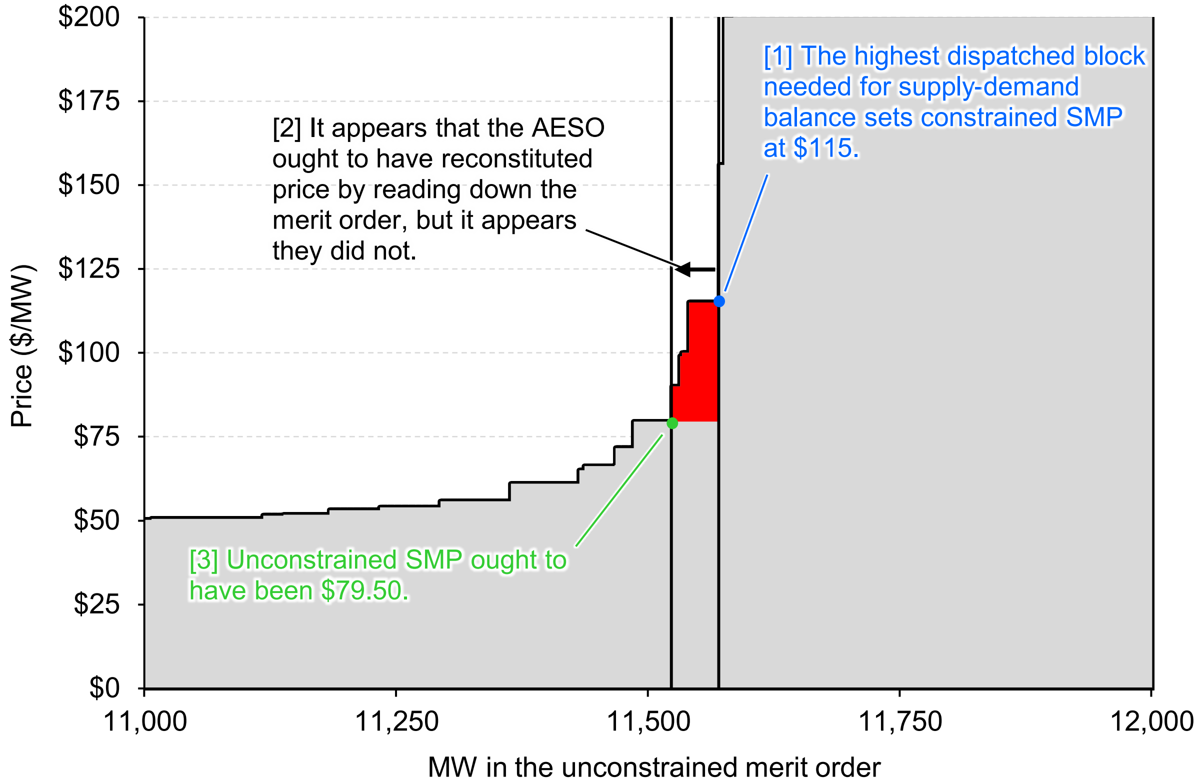
Asset ID	Available MW	Dispatched? (Y/N)	Dispatched MW	Estimated reconstructed CDG MW
HAL1	38	N	0	38
WHE1	115	N	0	6
SCR4	88	N	0	4
GDP1	35	N	0	0
			Total estimated CDG MW	48

At 20:30:30, there were approximately 48 MW of CDG across the system. As a result, the transmission constraint rebalancing volume was 48 MW, and the AESO ought to have reconstituted price by reading down the unconstrained merit order by 48 MW. However, it appears the AESO did not reconstitute price.

From 20:23 to 20:32, when four wind assets were constrained to 0 MW, the pool asset marginal price of the highest dispatched block (CMH1, block 5, 30 MW) was $115/MWh. The posted SMP over this period was also $115/MWh, set by CMH1, block 5. This indicates that price was not reconstituted. As an example, reading down the 20:30:30 merit order by 48 MW would have resulted in a reconstituted, unconstrained SMP of $79.50/MWh. As a result, it appears the AESO set price too high (Figure 54).

The MSA recommends that the AESO examine its IT system tools and verify that price is being reconstituted in all moments when price ought to be reconstituted.

Figure 54: Unconstrained energy market merit order snapshot on April 17, 2023, at 20:30:30



2.2.5 *Use of constrained down generation for power ramp up management, resulting in price being set too low*

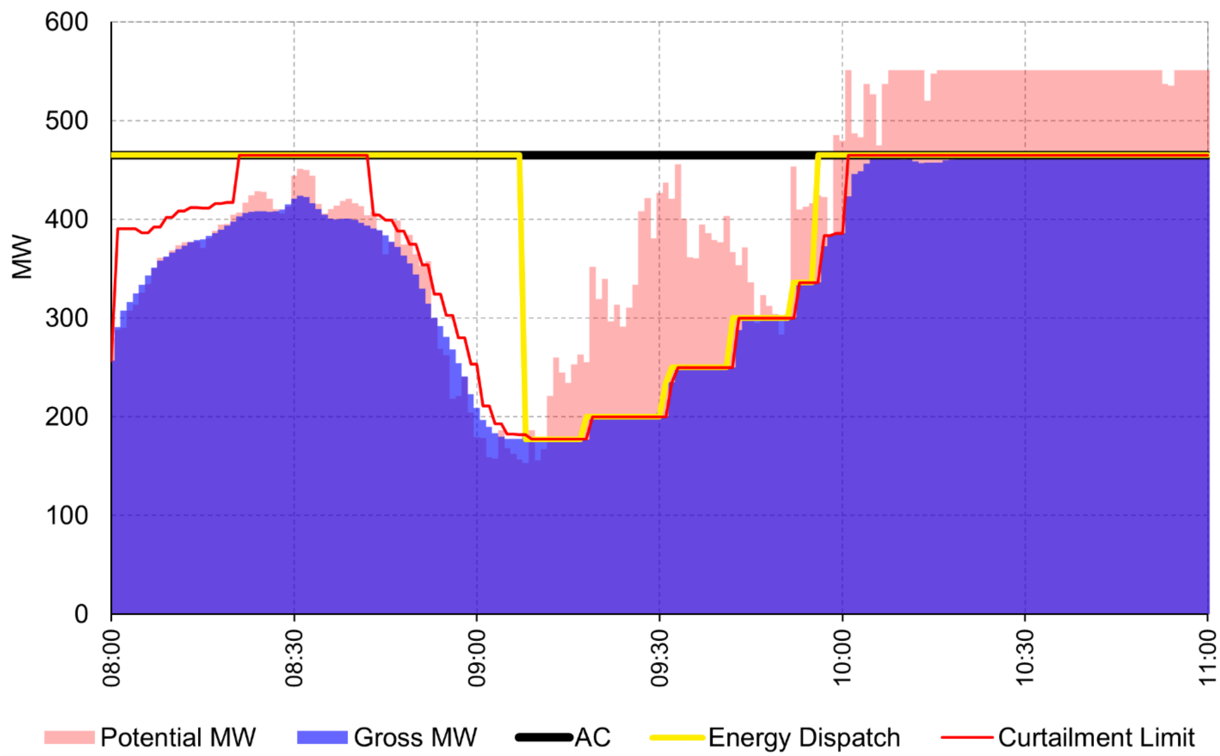
Wind and solar assets in Alberta are subject to ramping constraints, set out in section 304.3 of the ISO rules.[29] When ramping constraints bind, the generation from constrained assets is effectively curtailed. The AESO does not reconstitute pool price for the volume of energy curtailed for the purpose of power ramp up management.

On June 12, 2023, from 08:30 to 09:00, changing conditions at the Travers solar asset (465 MW) caused generation to fall by 200 MW. Travers's potential real power data indicates that the asset would have increased its generation by 200 MW from 09:10 to 09:30 absent any ramping limitations. From 09:08 to 09:56 the AESO sent a series of transmission constraint directives through ADaMS to Travers. These directives had the effect of limiting the asset's ramp rate. Information available to the MSA indicates that the AESO system controller implemented these constraints for the purpose of power ramp up management. However, these constraints were implemented through constrained down generation. Constrained down generation ought to be used for real-time transmission constraint mitigation, in a manner consistent with the procedures

[29] ISO rule 304.3, *Wind and Solar Power Ramp Up Management*

set out in section 302.1 of the ISO rules.[30] As a result of these constraints, the volume of energy curtailed from Travers to manage ramping limitations was included in the transmission constraint rebalancing volume used for price reconstitution. Had these constraints been classified as ramping constraints, price would not have been reconstituted.

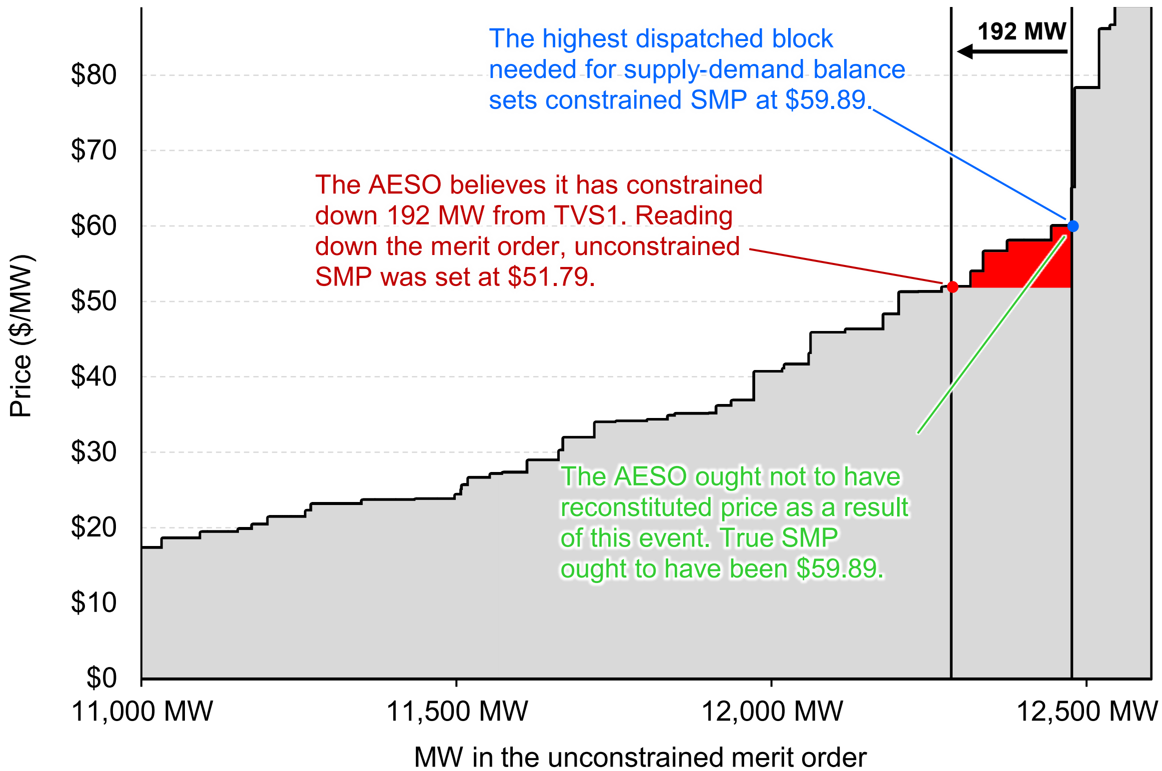
Figure 55: Constrained down generation for TVS1 (June 12, 2023)



On June 12, at 09:31:30, it appears that constrained down generation was applied to one asset—192 MW were curtailed from Travers. The highest dispatched block set constrained SMP at $59.89/MWh, and price was reconstituted down to $51.79/MWh. However, it appears that this curtailment would have more appropriately been categorized as a ramping constraint, and the volume of curtailed energy from Travers should not have been counted in the calculation of the transmission constraint rebalancing volume. As a result, the AESO ought not to have reconstituted price at this moment, and SMP ought to have been set at $59.89/MWh. The use of constrained down generation for a purpose other than real-time transmission constraint mitigation has the potential to distort pool price.

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

Figure 56: Unconstrained energy market merit order snapshot on June 12, 2023 at 09:31:30



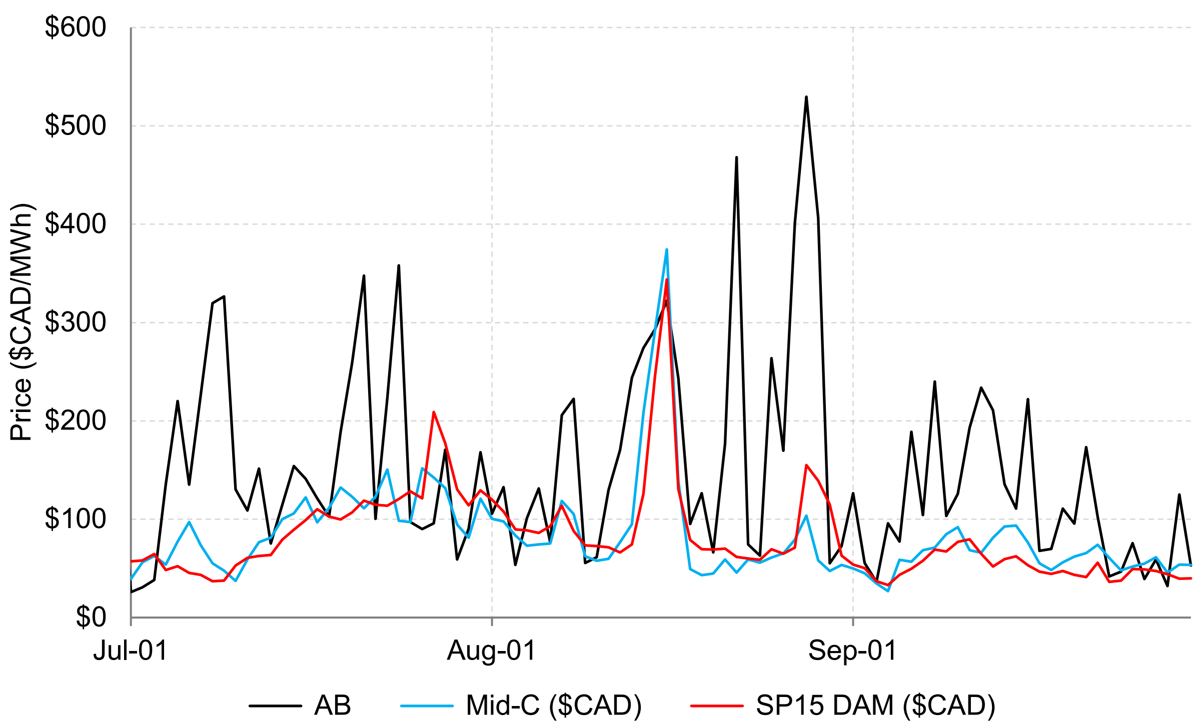
The price inaccuracy outlined here resulted from the use of constrained down generation to manage operational constraints that were not outflow transmission constraints – the constraints were ramping constraints. The MSA recommends that the AESO develop a procedure to not use constrained down generation for a purpose other than real-time transmission constraint mitigation.

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. 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 57 illustrates daily average power prices in Alberta, Mid-C, and SP-15 over Q3.[31] As shown, prices in Alberta were generally higher and more volatile relative to these other markets. The price differential between Alberta and these other markets was highest in the last week of August in part due to a transmission outage that materially reduced import capacity from BC/MATL. Prices in Mid-C and SP-15 did increase in mid-August due to high summer temperatures across the Western US and low water supply in the Pacific Northwest.

Figure 57: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q3)



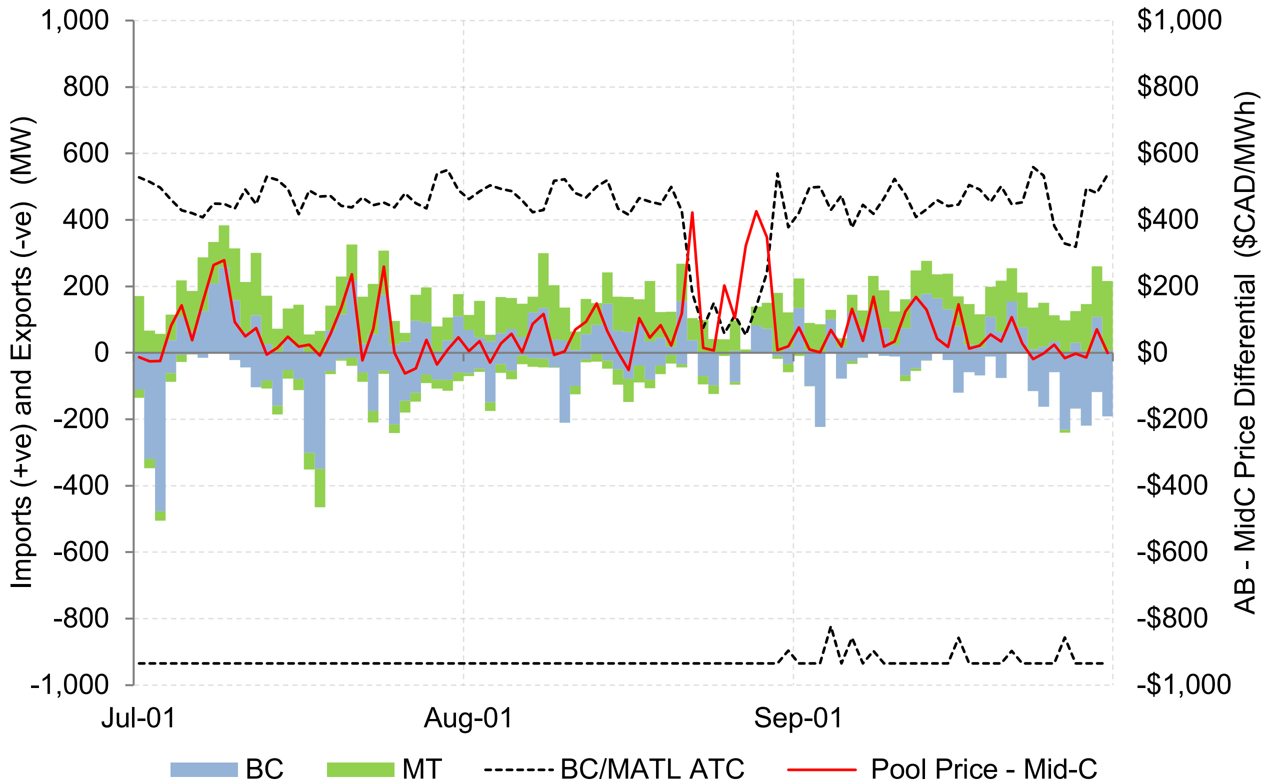
Price differentials between Alberta and other markets drive intertie flows. Figure 58 illustrates the daily average price differential between Alberta and Mid-C, the daily average import and export volumes on the BC and MATL interties, and the intertie capacity on BC/MATL. As shown, reduced import capacity led to pool prices being well above Mid-C prices in late August.

Over the quarter, flows on the BC interties averaged 10 MW of exports, and flows on MATL averaged 83 MW of imports. The higher level of exports to BC can be partly attributed to a lower

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

water resource year. In total, net imports on BC/MATL averaged 74 MW, an 82% reduction relative to average imports of 419 MW in Q3 2022. Imports were higher last year because of a larger price differential and because of higher import capability.

Figure 58: Daily average import (+ve) and export (-ve) volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q3)



Hourly BC/MATL volumes during the Western US heat wave in mid-August are shown in Figure 59. During this event, prices in Mid-C peaked at over CAD$1,700/MWh which led to some exports over the MATL line while pool prices were over $900/MWh.

Figure 59: Hourly import (+ve) and export (-ve) volumes on BC/MATL and Alberta/Mid-C pricing (August 15 and 16, 2023)

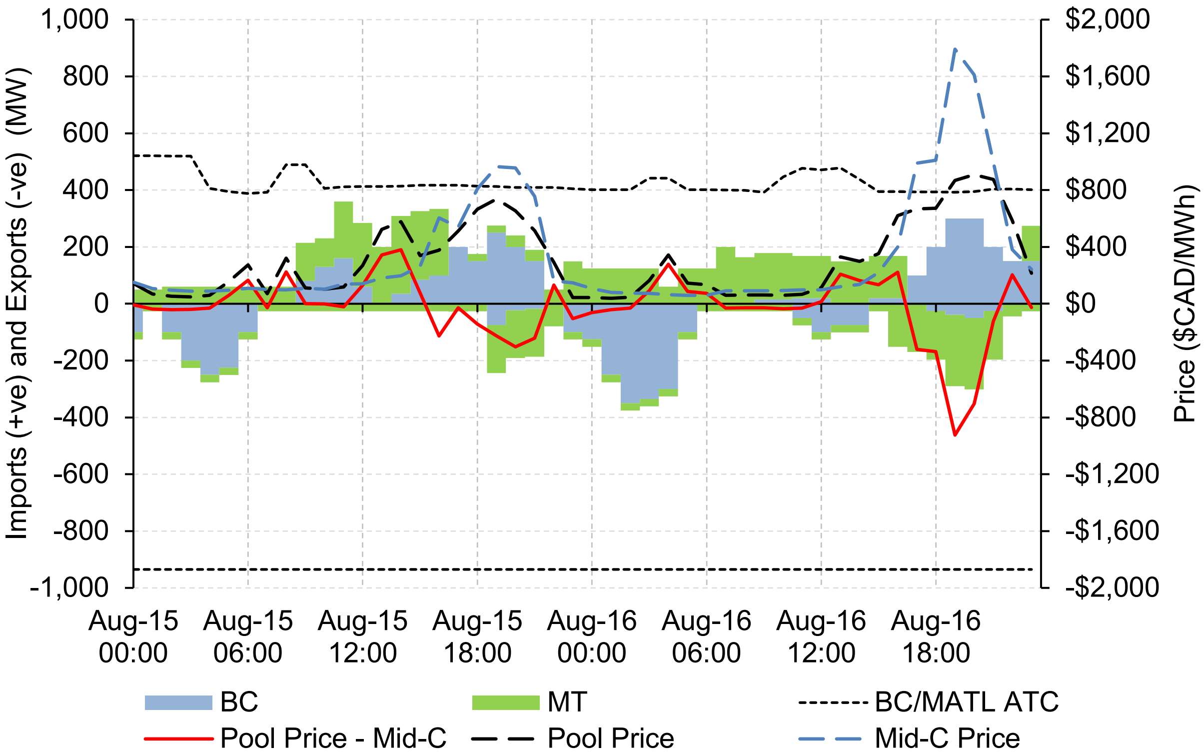


Figure 60 shows a scatterplot of the price differential between Alberta and Mid-C against the net flow on BC/MATL for each hour in Q3. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors).

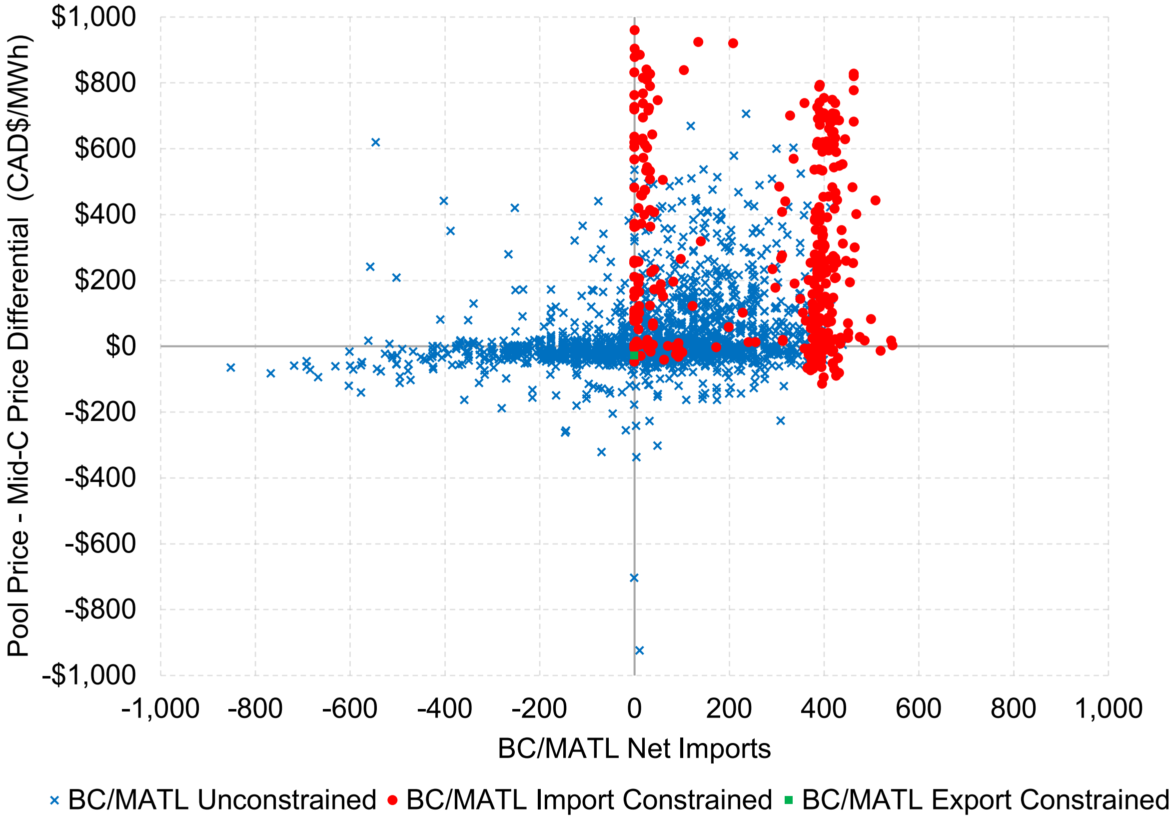
In certain hours the net import offers on BC/MATL were at or above available import capacity, meaning the interties were import constrained (shown in red). There were generally two clusters of import constraints over the quarter; near 0 MW and around 400 MW. The 0 MW segment reflects derates and outages on BC/MATL during late August, while the segment in the range of 400 MW represents the normal operation of the interties. The import capacity on BC/MATL was lowered in March when the AESO increased the amount of Load Shed Service for imports (LSSi) required.[32]

BC/MATL was import constrained in 16% of hours of Q3, and the average price differential between Alberta and Mid-C during these hours was $279/MWh. The average import capability on BC/MATL during these constrained hours was 296 MW. BC/MATL was export constrained

[32] LSSi is a reliability product developed to increase import intertie capability and is contracted between the AESO and load providers who agree to instantaneously shed consumption in the case of a sudden loss of imports to manage under frequency

approximately 0% of the time in Q3, which is the result of relatively modest price differentials for exports in addition to the export capability normally being much higher at 935 MW.

Figure 60: Alberta and Mid-C price differential and net BC/MATL flows (Q3)



As mentioned, 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 periods of derates and outages on BC/MATL spanning late August. When the BC/MATL intertie was offline, the AESO did not lower the MSSC by limiting generation supply of large thermal assets in Alberta. MSSC remained at 466 MW while BC/MATL was offline for up to nine consecutive hours.

For some hours in Q3, heavy export flows occurred despite pool price settling well above prices in Mid-C. For example, on July 25 in HE 15 and HE 16 net exports through BC/MATL were 502 MW and 546 MW, although Alberta pool prices increased to $291/MWh and $710/MWh, much higher prices in Mid-C. In the preceding 18 hours, Mid-C prices were $32/MWh higher on average. The higher pool prices for HE 15 and 16 were largely caused by the Shepard asset tripping offline (as discussed in section 1.2).

Figure 61: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q3)[33]

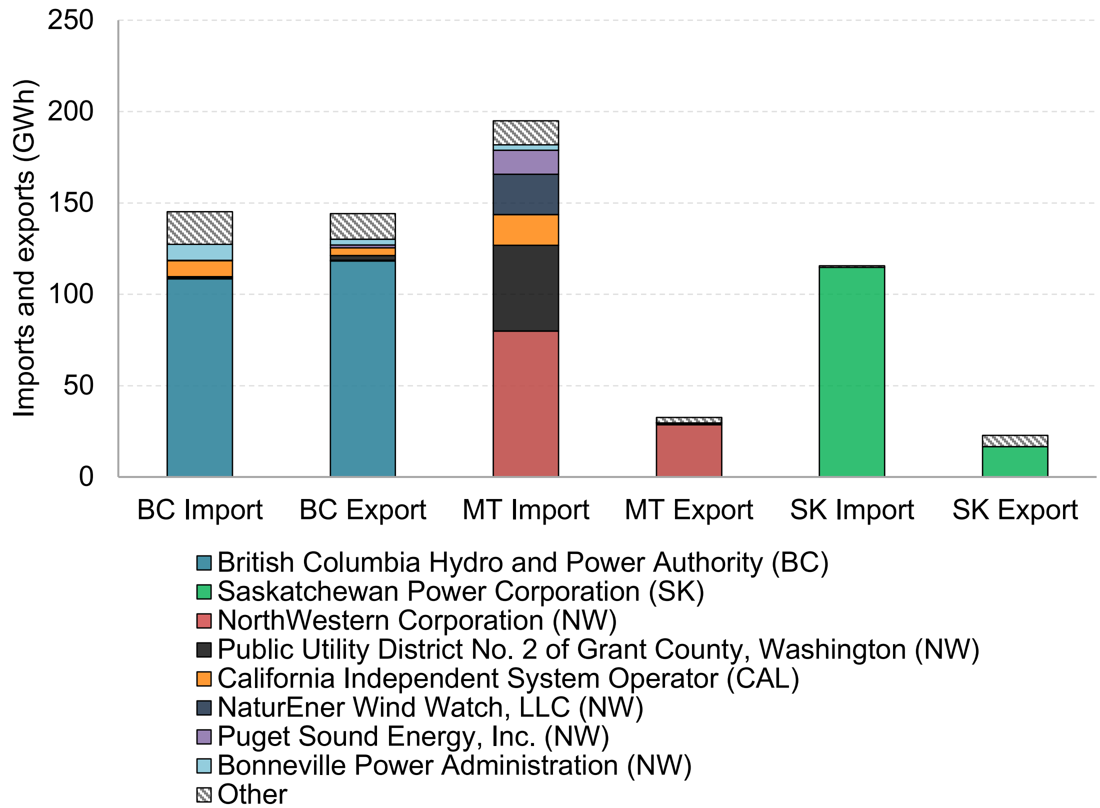


Figure 61 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD). The POR for imports is the point on the electric system where electricity was received from. The POD for exports is the point on the electric system where electricity was delivered to.

The Balancing Authority regions directly connected with Alberta have a high share of import and export flows. For imports on the BC intertie, approximately 75% originated from BC, 18% from the US Northwest, and 6% from California. For exports on the BC intertie, 82% was delivered to BC, and 14% to the US Northwest, and 3% to California.

For imports through MATL, 91% originated from the US Northwest and 8% from California. For exports on MATL 99% was delivered to the US Northwest. For imports through the SK intertie, 99% originated from Saskatchewan. For exports through the SK intertie, 73% was delivered to Saskatchewan and 27% was delivered to the Southwest Power Pool.

[33] This includes the highest eight Balancing Authorities by volume. Wheel-through volumes are not included in Figure 61, though represent 525 MWh from BC to Montana, and 23,808 MWh from Montana to BC.

3 OPERATING RESERVE MARKETS

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

3.1 Operating reserve received prices

Figure 62 shows the average received price for active regulating, spinning, and supplemental reserves by month since July 2022. The average received price for each month depends on hourly pool prices and the equilibrium prices set in OR auctions; these calculations cover all hours in the month. The received prices for regulating, spinning, and supplemental reserves all decreased in Q3 relative to their averages in Q2 2023 and Q3 2022 (Table 12).

Figure 62: Average received price for active spinning, supplemental, and regulating reserves (July 2022 to September 2023)

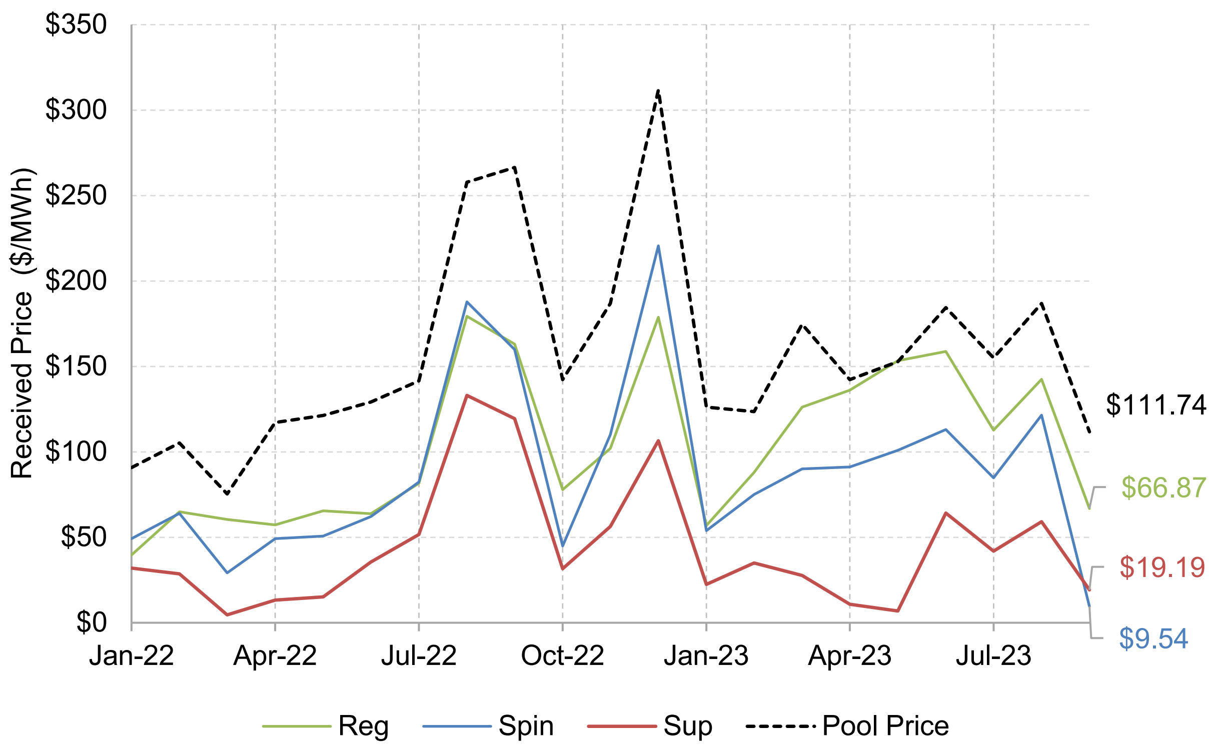


Table 12: Average received price for active regulating, spinning and supplemental reserves ($/MWh)

	Regulating Reserve	Spinning Reserve	Supplemental Reserve
Q3 2022	$141	$143	$101
Q2 2023	$149	$102	$27
Q3 2023	$108	$74	$40

In September, the average received price for supplemental reserves ($19.19/MWh) exceeded the received price for spinning reserves ($9.54/MWh). This price inversion does not align with the technical requirements for these products, which are more stringent for spinning reserves. To provide spinning reserves requires that an asset can provide a frequency response in addition to the requirements for supplemental reserves. Therefore, the price inversion of spinning and supplemental reserves in September was not intuitive, particularly given the urgency placed around the procurement of fast ramping products.

Figure 63 highlights the proportion of hours with $0/MWh received prices by month for regulating, spinning, and supplemental reserves. The received price for spinning reserves was $0/MWh for 94% of hours in September, an increase of 48 percentage points relative to August.

Figure 63: Percentage of hours with $0/MWh received price (July 2022 to September 2023)

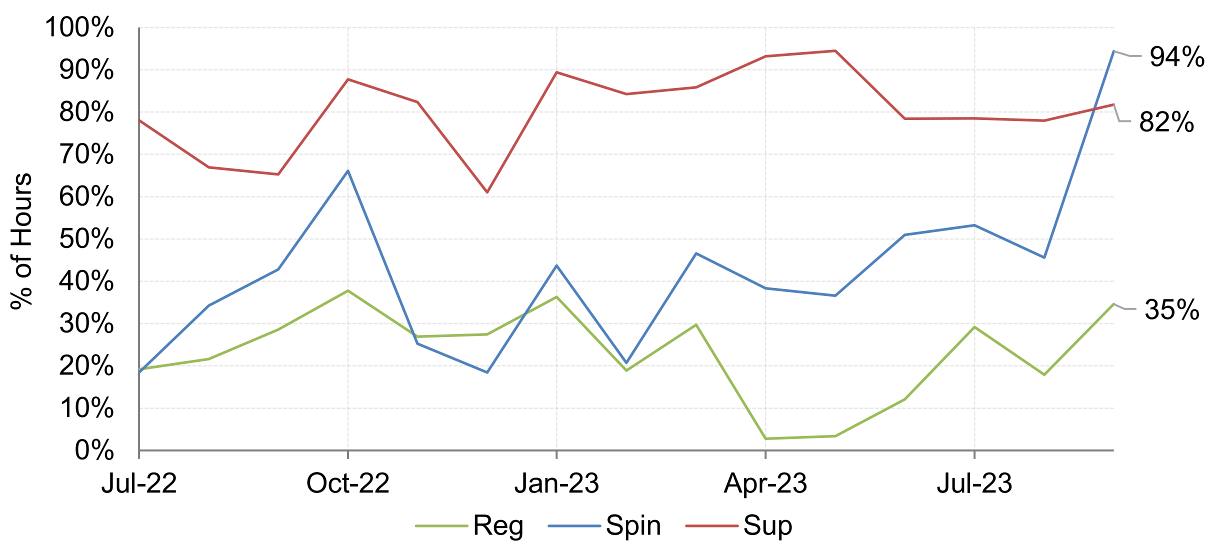


Figure 64 shows on-peak equilibrium prices for active regulating, spinning, and supplemental reserves over Q3. The on-peak price of active supplemental reserves exceeded the price of spinning reserves on 27% of days in Q3. This was most commonly observed in September.

Figure 64: Daily active on-peak equilibrium prices (Q3 2023)

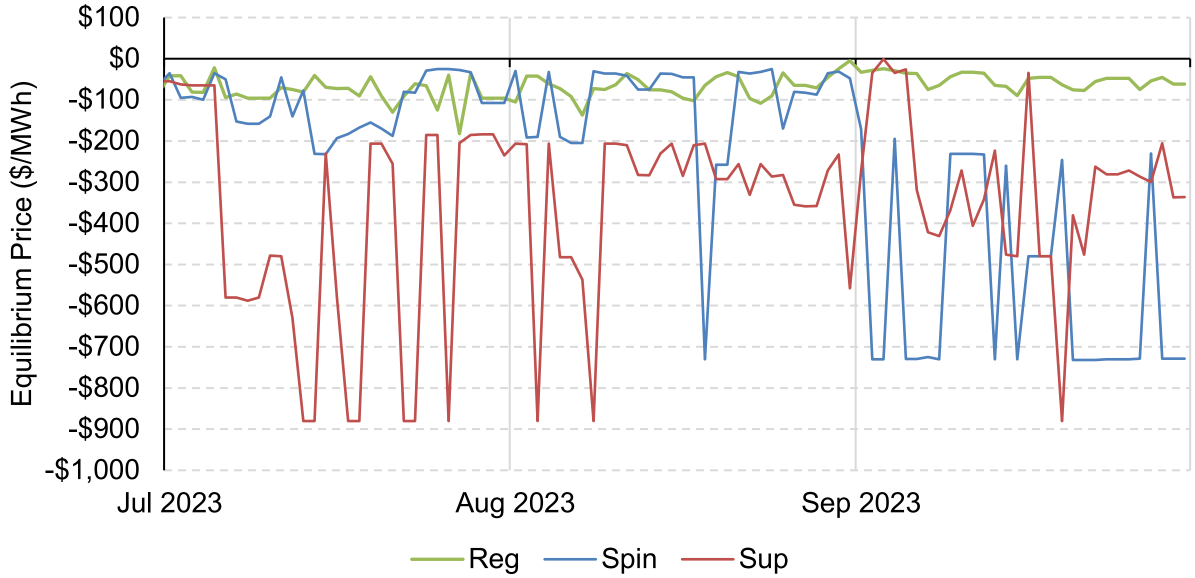
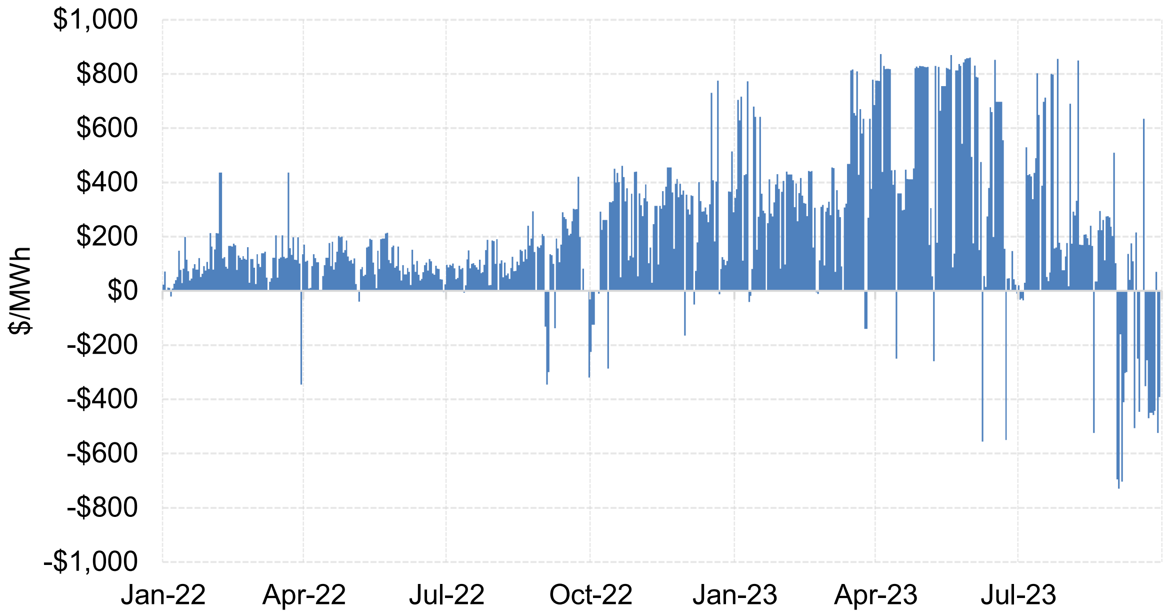


Figure 65 illustrates the differential between the equilibrium price for on-peak active spinning and the equilibrium price for on-peak active supplemental. As discussed above, suppliers of spinning reserves can provide supplemental reserves, but not visa versa. Nevertheless, on-peak equilibrium prices for supplemental exceeded spinning prices 25 times in Q3 compared to 7 times in Q2, and 20 times during 2022. Supplemental reserve equilibrium prices have exceeded spinning reserve prices 37 times so far in 2023.

Figure 65: Daily equilibrium price difference between active spinning and supplemental reserve (on-peak, January *1,* 2021 to September *30,* 2023)



On September 20, 21, and 22, on-peak active spinning reserves cleared at an equilibrium price of negative $732/MWh, with active on-peak supplemental reserves averaging negative $373/MWh over these days. Figure 66 and Figure 67 depict the offer curves for active on-peak spinning and supplemental reserves on September 21, when spinning reserves reached their lowest equilibrium price in the quarter. Low spinning reserve prices were largely driven by competition between hydro and battery providers.

Figure 66: Offers for active on-peak spinning reserve (September 21, 2023)

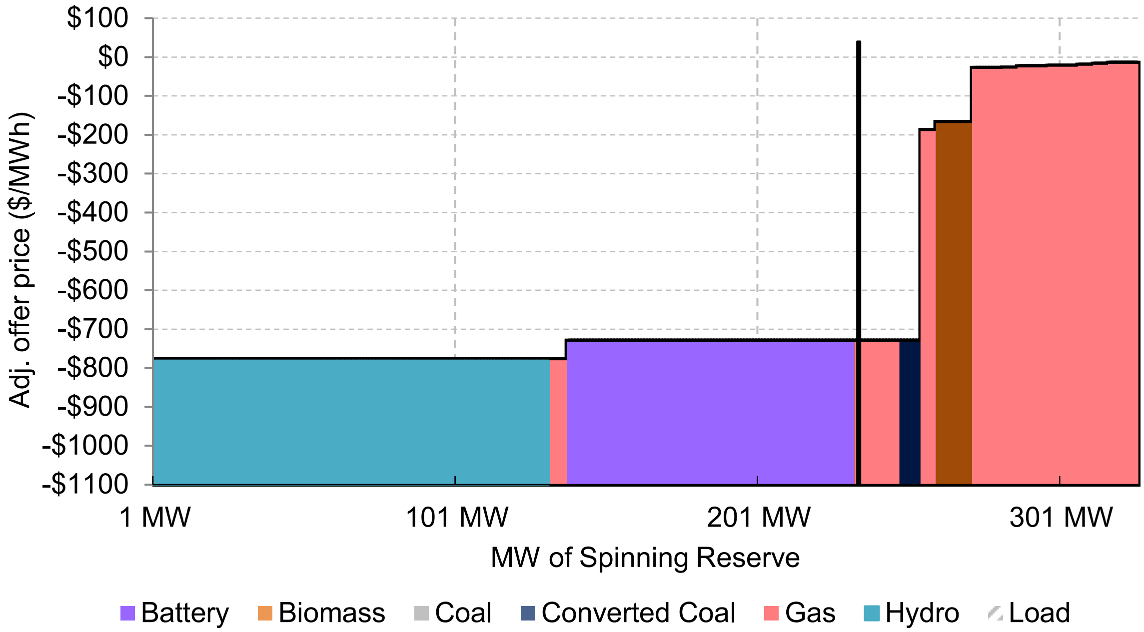
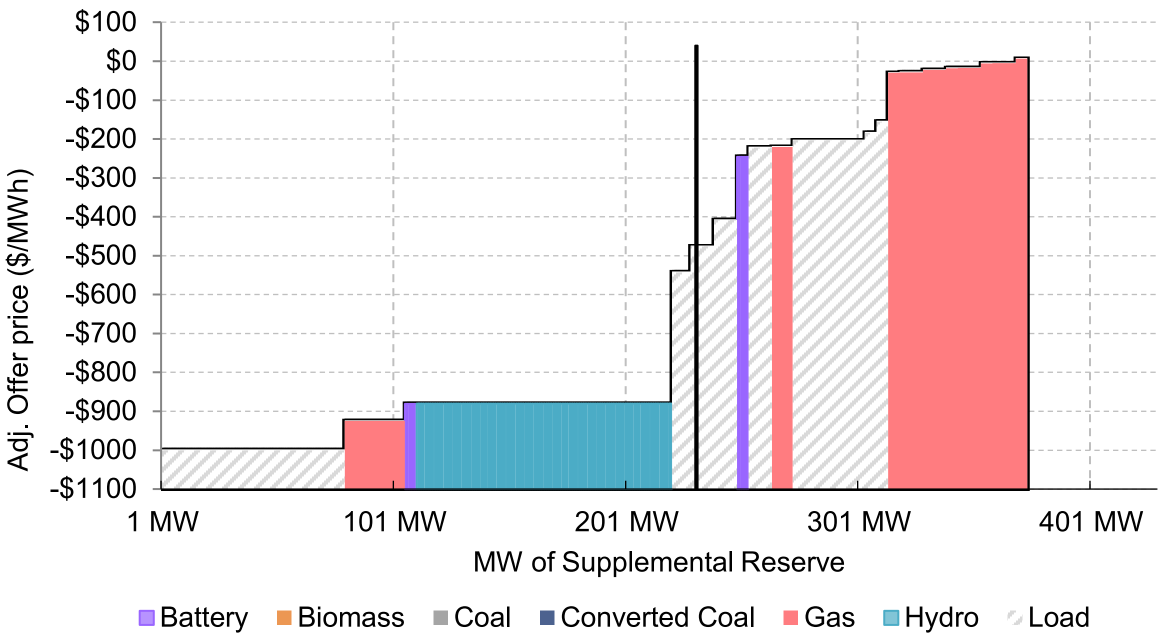


Figure 67: Offers for active on-peak supplemental reserve (September 21, 2023)



3.2 Operating reserve directives

Figure 68 shows the percent of dispatched contingency reserves that were directed to provide energy by fuel type.[34] Historically, hydro and coal assets have been most heavily directed due to their size, reliability, and responsiveness during contingencies.

In response to market participant concerns over the fairness of directives the AESO updated its directive issuance practice on March 29 to rank providers based on the time elapsed since their last directive. MSA calculations are on a per capita basis, meaning that they measure the ratio of instructed MWs relative to total dispatched MWhs. Given the MSA's calculations, we would expect the trends for directives by fuel type (Figure 68) and asset size (Figure 69) to converge in the long run. The directive rates appear to be converging and the MSA will continue to monitor this matter.

Figure 69 illustrates the proportion of dispatched contingency reserve that were directed based on the size of the block dispatched.[35] Historically, larger blocks were directed more frequently than smaller ones, though rates have begun to converge in recent months. In Q3, the average rate of directives decreased for all asset sizes relative to rates calculated in Q2 2023 and Q3 2022.

[34] 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.

[35] 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 68: Percent of dispatched contingency reserves directed by fuel type (July 2022 to September 2023)

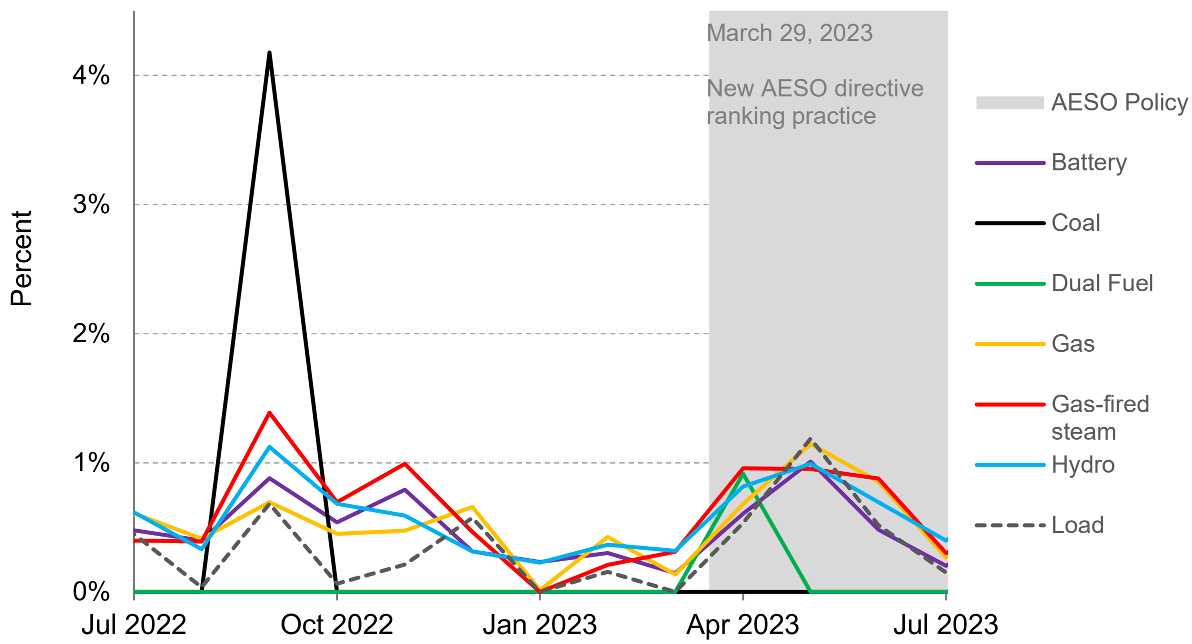
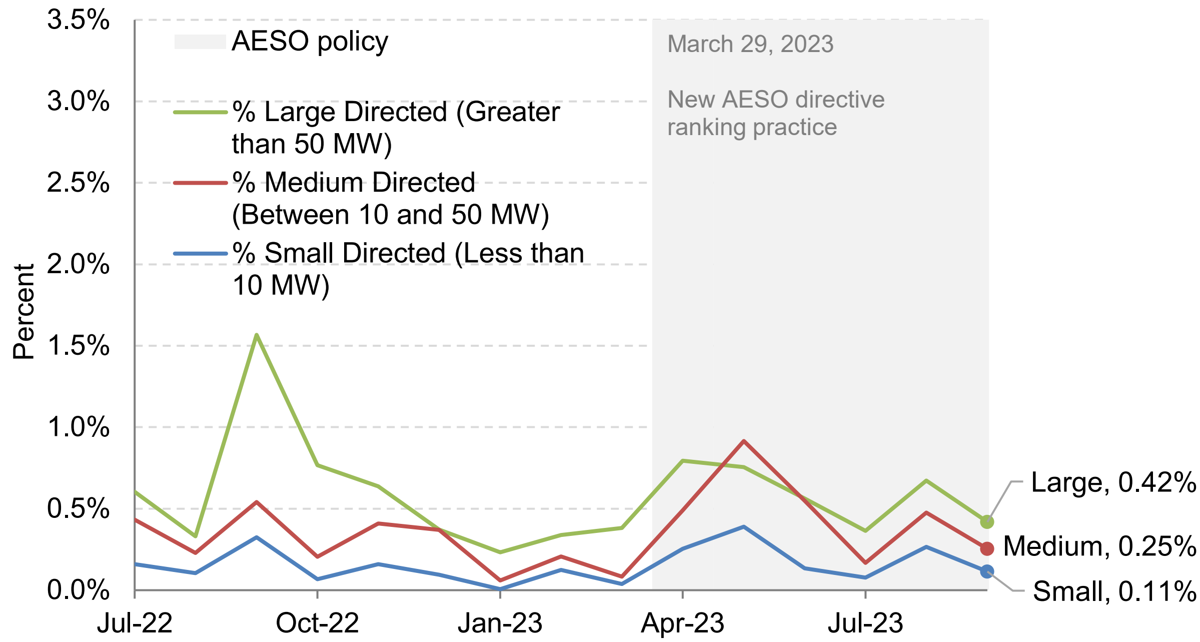


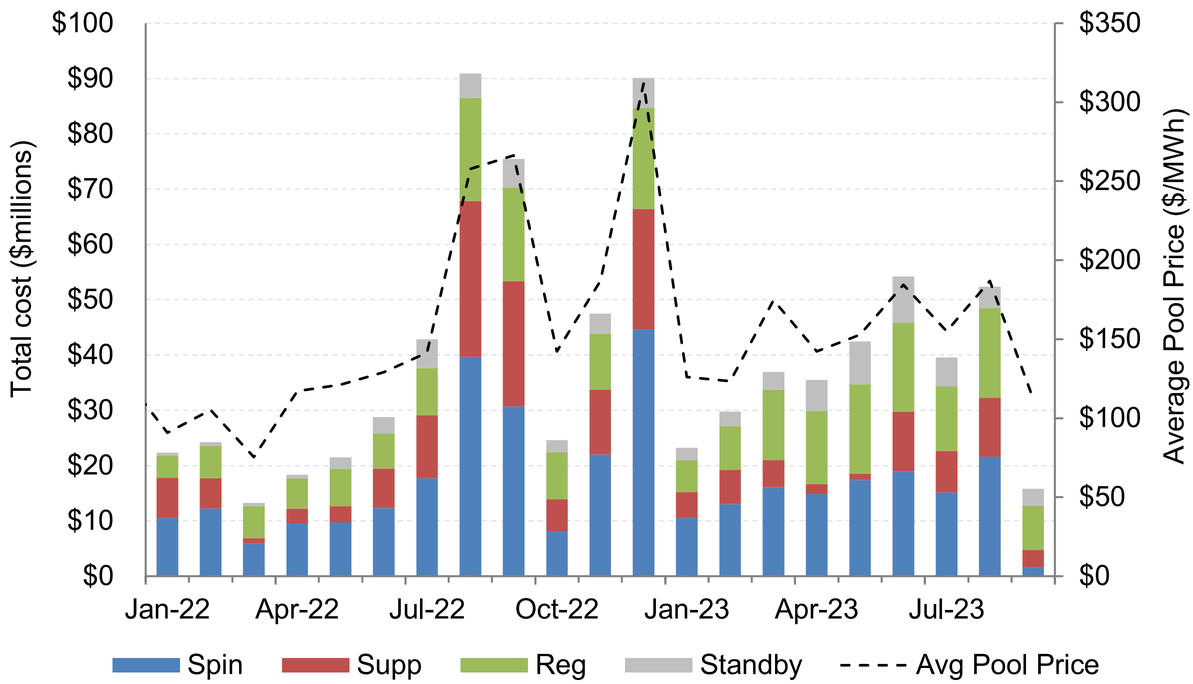
Figure 69: Percent of dispatched contingency reserves directed by asset size (September 2021 to September 2023)



3.3 Total operating reserve costs

In Q3 the total cost of operating reserves was $108 million, a decline of 19% relative to Q2 and a decline of 49% relative to Q3 2022. Year-over-year, the total cost of OR was lower because of lower pool prices and lower average costs for active regulating, spinning, and supplemental reserves. In addition, the volume of spinning and supplemental reserves procured was lower in Q3 relative to Q3 2022. In March, the AESO increased the LSSi requirements for imports on BC/MATL which lowered the flow of imports into Alberta. With lower import supply on BC/MATL there has been lower demand for spinning and supplemental reserves. The total cost of operating reserves in September was $16 million, the lowest since March 2022 (Figure 70).

Figure 70: Total cost of operating reserves by month (January 2022 to September 2023)



3.4 Operating reserve dispatch by fuel type

Figure 71 highlights the proportion of regulating, spinning, and supplemental reserves dispatched by fuel type. Beginning in late June, a large hydro asset was removed from the OR markets for two weeks. This decrease in volume dispatched was offset by an increase in gas and gas-fired-steam offers into the regulating reserve market.

Historically, hydro assets have been the major providers of spinning reserves but battery penetration continues to increase. June marked the first month in which battery dispatch volumes in spinning reserve surpassed the dispatch volumes provided by hydro assets. This occurred again in September with 55,883 MWh being provided by batteries, and 49,844 MWh from hydro. Q3 experienced a 46% increase in the volume of batteries dispatched for spinning reserve relative to Q3 2022.

Figure 71: Monthly percentage of regulating, spinning, and supplemental dispatch by fuel type (July 2021 to September 2023)

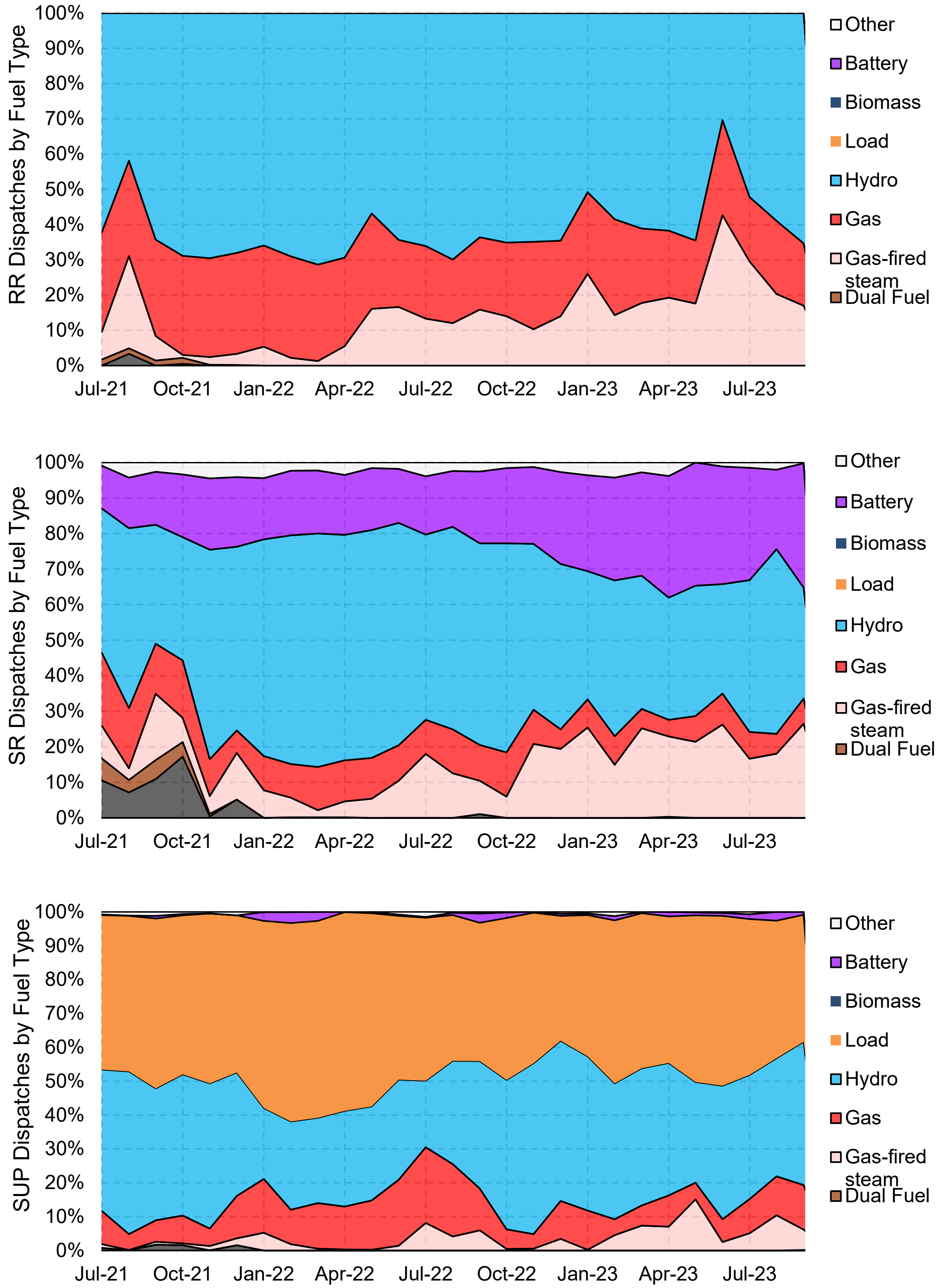
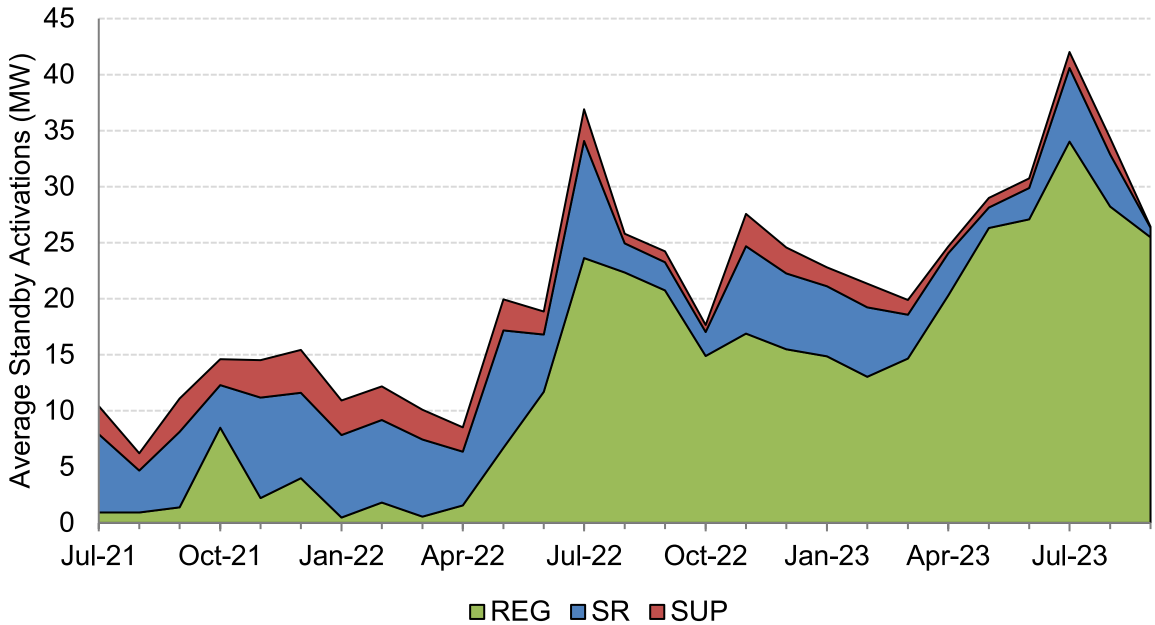


Figure 72 illustrates average hourly activations of standby reserves from July 2021 to September 2023. In Q3 average hourly activations of standby regulating reserves increased by a magnitude of approximately 26 times relative to Q3 2021, and increased by 31% relative to Q2 averages. Despite a decline in average hourly activations for spinning and supplemental reserves in September, both products saw an increase in hourly activations relative to Q2 2023 values. In Q3, average hourly activations for spinning reserves increased by 44% and supplemental reserves by 27%.

Figure 72: Hourly average of standby activations by operating reserve product and month



The AESO increased the procurement of on-peak active regulating reserve volumes from 130 MW to 170 MW on August 25. This increase was due to the volatility of intermittent generation, particularly solar, and because of systematic transmission constraints which restrict the output of a natural gas asset that often provides active regulating reserves. Figure 73 illustrates on-peak active, standby, and average standby activated volumes by day from January to September.

Figure 73: Active, standby, and activated standby volumes for on-peak OR (MW)

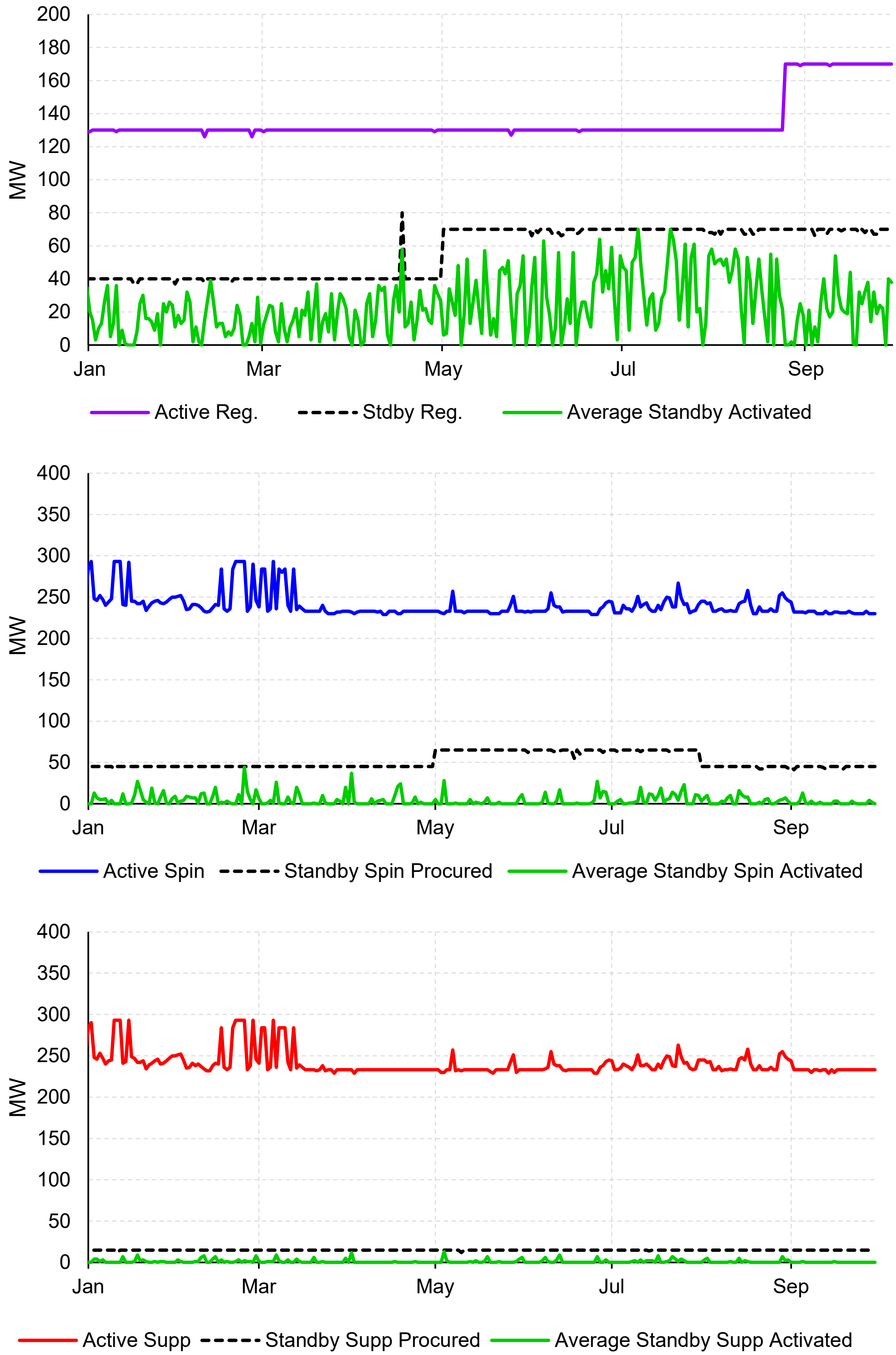
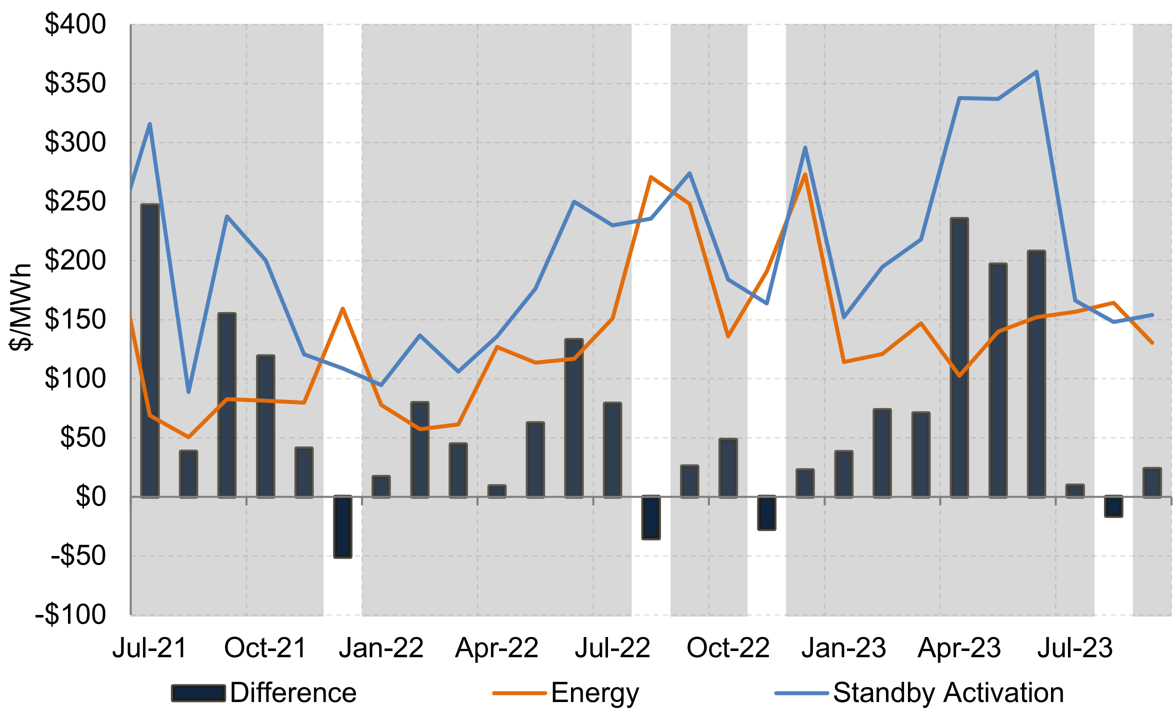


Figure 74 highlights the difference between activation prices for regulating[36] and prevailing energy prices[37] from July 2021 to September 2023. Under the current structure of the operating reserve market, standby pricing consists of two components: a premium price, and an activation price. Providers are paid the activation price when standby volumes are activated to supply active reserves.

Historically, activation prices for regulating reserves have often been above prevailing energy prices. This is not intuitive because providing energy consumes more fuel, for example water or natural gas, relative to providing active regulating reserves. In 2023 the positive correlation between activation prices for regulating reserves and prevailing energy prices weakened, with standby activation prices for regulating reserves largely surpassing prevailing energy prices in Q2.

The bars in the figure below signify the difference between activation prices for regulating reserves and prevailing energy prices. In Q2 activation prices for regulating reserves were $213/MWh higher than prevailing energy prices on average, although this price differential declined to $6/MWh in Q3.

Figure 74: The price of standby activations for regulating reserves vs. prevailing energy prices (July 2021 to September 2023)



[36] The regulating reserve activation prices are volume-weighted activation prices using standby activation volumes.

[37] The regulating reserve energy prices are the volume-weighted average pool price, which are weighted by activation volumes of standby regulating reserves.

4 THE FORWARD MARKET

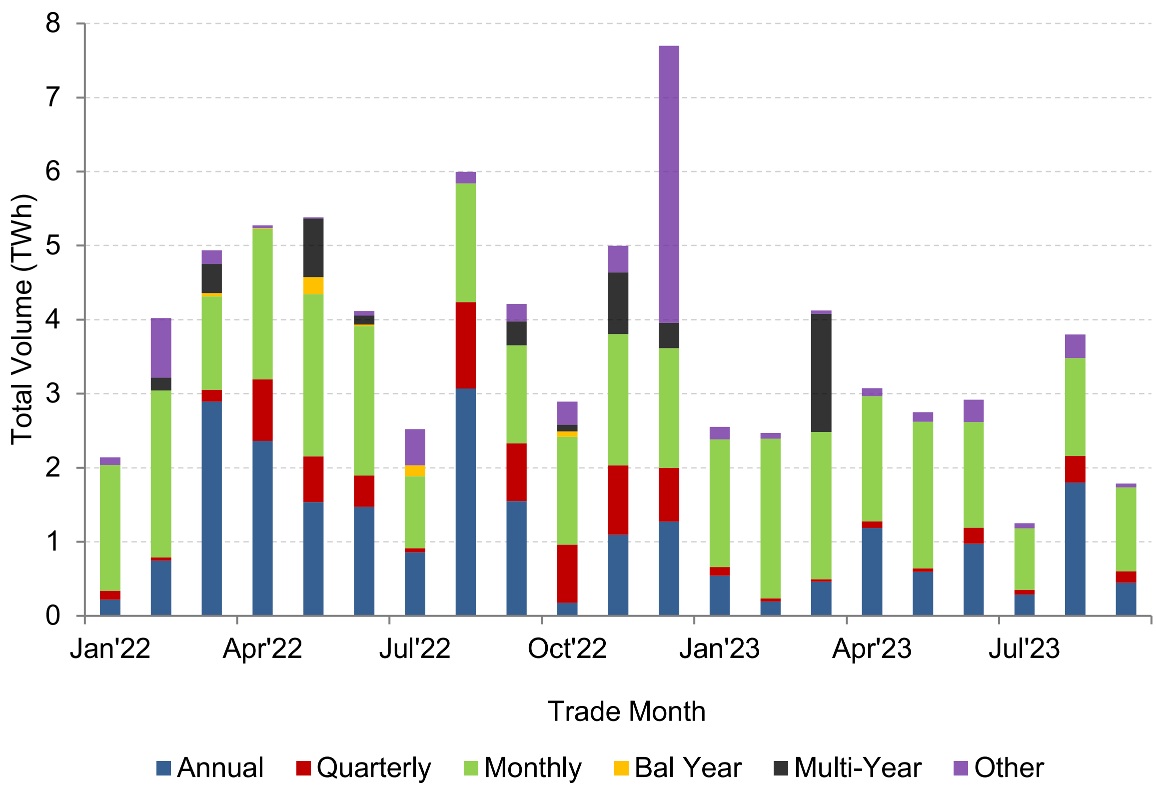
Alberta's financial forward market for electricity is an important component of the market because it allows for generators and larger loads to hedge against pool price volatility, and it enables retailers to reduce price risk by hedging sales to retail customers.[38]

4.1 Forward market volumes

In Q3 the total volume of trades on NGX and via brokers was 6.84 TWh, which is a 38% decrease compared to Q3 2022, and a 22% decline compared to Q2 2023. Figure 75 illustrates total volumes by trade month and term since January 2022.

Year-over-year, trade volumes were lower across a range of contract terms, with annual volumes down 49%, quarterly volumes down 71%, and monthly volumes 14% lower.

Figure 75: Total volumes by trade month and term (January 2022 to September 2023)[39]



[38] 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.

[39] This figure includes bilateral volumes prior up to January 2023.

Figure 76 illustrates total volumes by trade date over Q3. There was an increase in trading of annual products on Tuesday, August 29 when 0.94 TWh of annual volumes cleared. These annual trades pertained to the years 2024, 2025, and 2026 (Table 13) and accounted for 37% of annual volumes over the quarter.

Figure 76: Total volumes by trade date and term in Q3

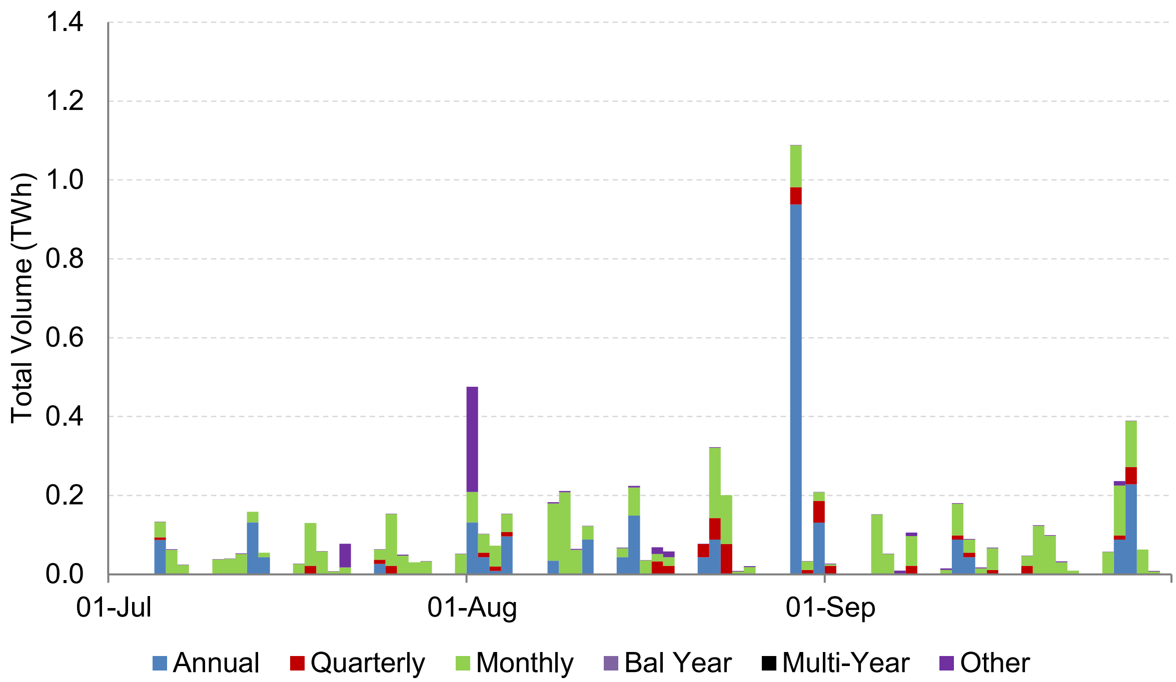


Table 13: Total and traded volumes for annual products on August 29[40]

	Total Volume (MWh)	Traded Volume (MW)
CAL24	193,248	22
CAL25	394,200	45
CAL26	350,400	40

4.2 Trading of monthly products

Forward prices for July, August, and September were higher than realized pool prices. For September, the volume-weighted average forward price was $174/MWh, which was 55% higher than the average pool price of $112/MWh. In July the forward premium was 21% and in August it was 9% (Figure 77).

[40] Total volume is the amount of power traded financially over the duration of the contract. Traded volume is the amount traded per hour.

Figure 77: Monthly forward prices relative to realized pool prices (January to September)

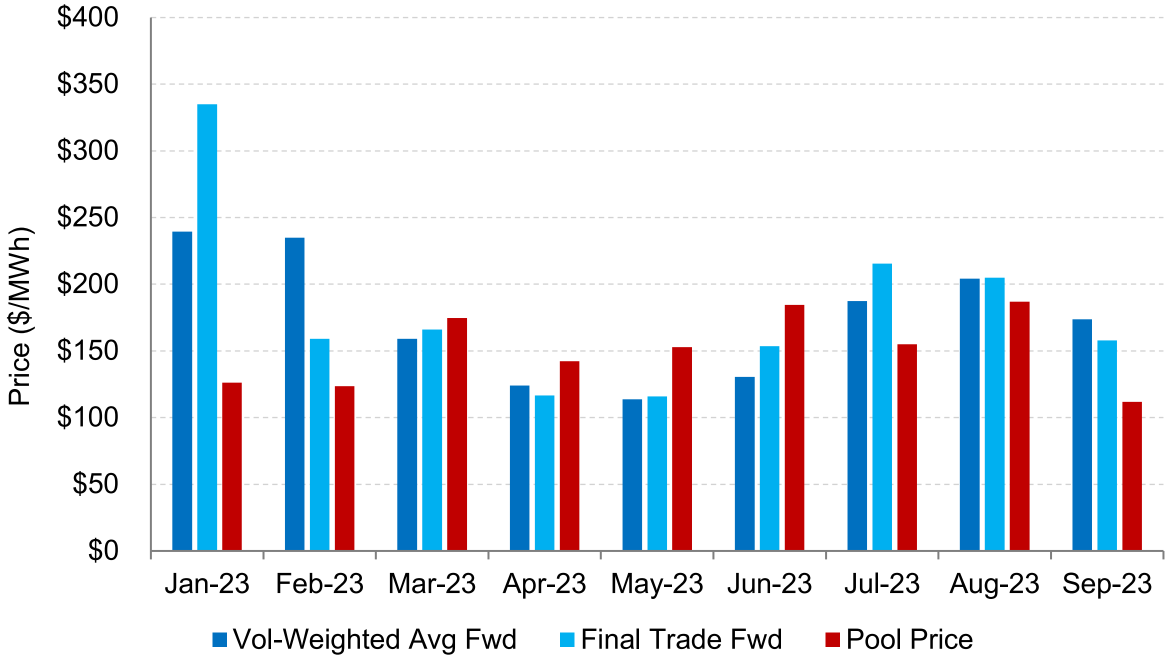


Figure 78 illustrates the decline in prices with monthly forward curves as of June 30 and September 30. The forward price for Q4 fell by 16% over the quarter and the forward price for Q1 2024 fell by 25%.

Figure 78: Monthly forward curve for July 2023 to December 2024 (as of Jun. 30 and Sep. 30)

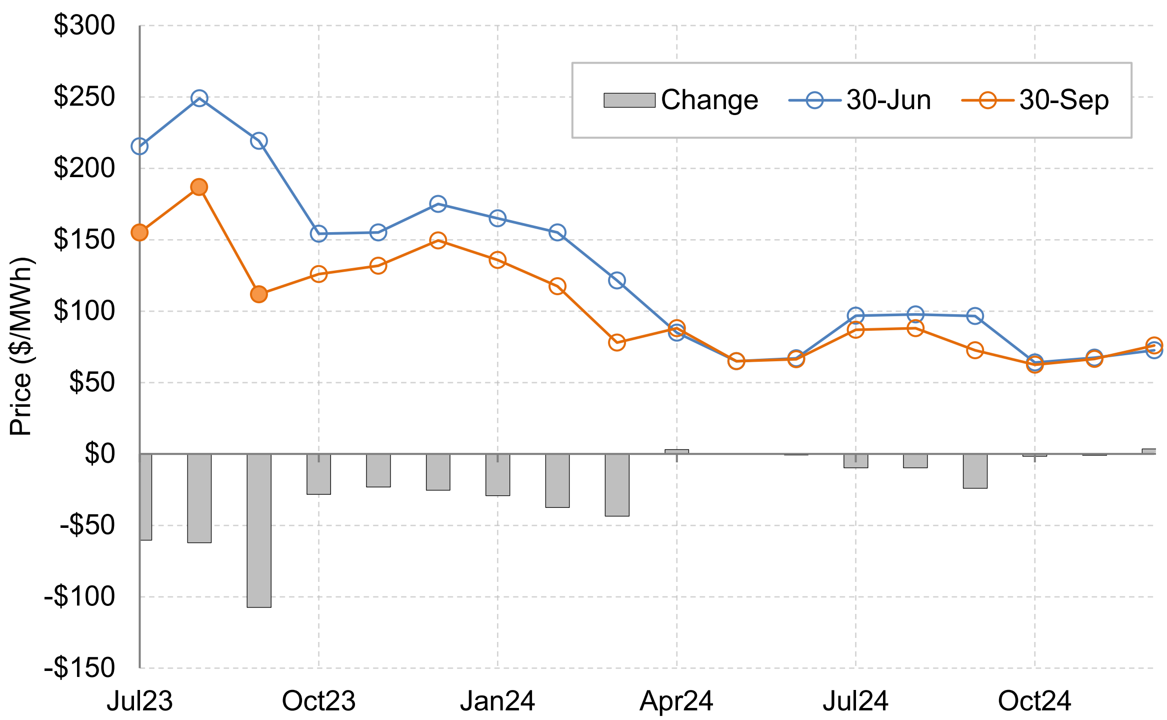


Table 14 provides monthly forward prices for Q4 and Q1 2024 for Alberta and Mid-Columbia (Mid-C). Winter prices in Mid-C were trading at a premium to Alberta at the end of Q3, in part because of low hydro levels this year, both across the Pacific Northwest and in BC.[41]

Table 14: Monthly forward prices for Alberta and Mid-C ($CAD; as of September 29)

	AB	Mid-C	Difference (AB - MidC)
Oct 2023	$126	$86	$40
Nov 2023	$132	$111	$21
Dec 2023	$150	$157	($8)
Jan 2024	$136	$157	($21)
Feb 2024	$118	$142	($24)
Mar 2024	$78	$91	($13)

4.3 Trading of annual products

The expected average pool price for 2023 fell from $173/MWh on June 30 to $147/MWh on September 30, a decline of 15%. This decline occurred as pool prices in Q3 came in below forward market expectations, and this in turn put downward pressure on forward prices for Q4.

The price of Calendar 2024 (CAL24) also fell over Q3; from $96/MWh to $84/MWh a decline of 13% (Table 15). The price of CAL24 declined over August and September (Figure 79) and is trading well below the expected price of 2023. This difference is largely due to the expected addition of the Cascade power project, which is expected to add 900 MW of combined cycle natural gas capacity later this year.[42] In addition, Genesee 1 and 2 are being repowered from coal to combined cycle, and more intermittent generation is expected to increase supply and put downward pressure on pool prices next year.

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[41] Northwest River Forecast Centre, Water Supply Forecasts, the Dalles Dam

BC Government: Drought information - resources and response for BC

[42] Kineticor, Cascade Power Project

Figure 79: Annual forward prices (from January 1 to September 30)

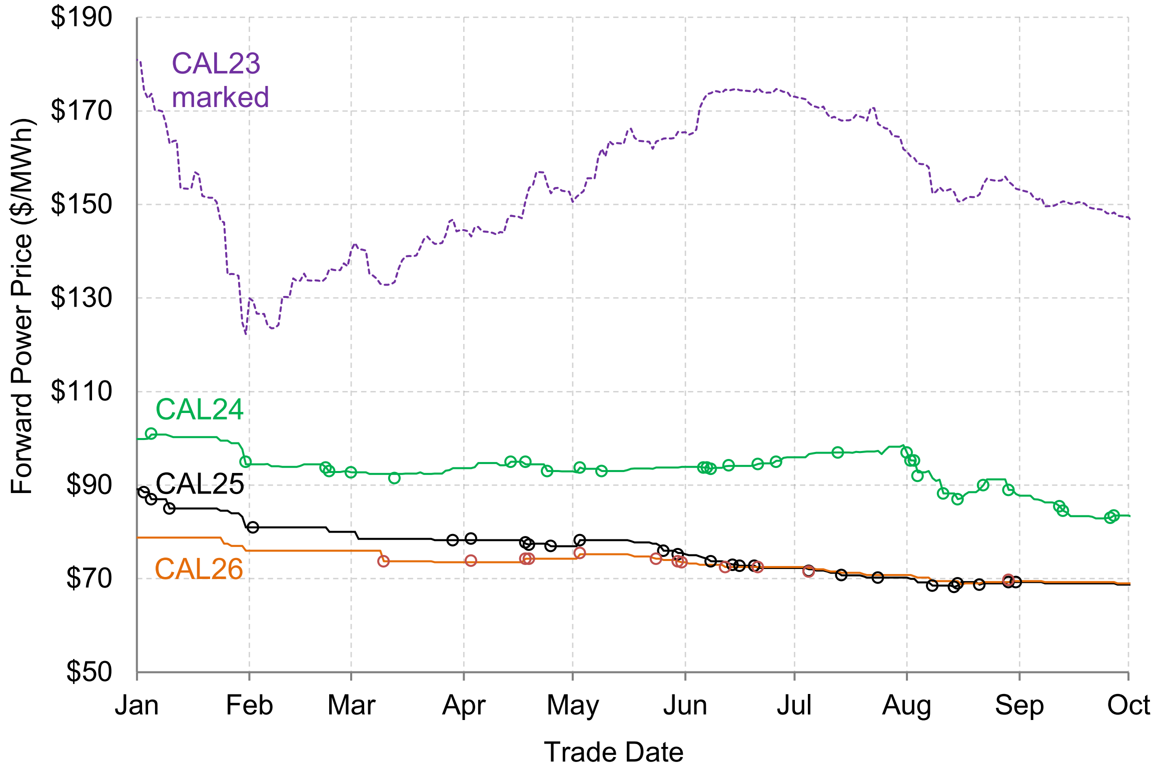


Table 15: Forward power and natural gas price changes over Q3

Contract	Power price ($/MWh)			Gas price ($/GJ)			Spark spread ($/MWh)		
	Jun 30	**Sep 30**	**% chg**	**Jun 30**	**Sep 30**	**% chg**	**Jun 30**	**Sep 30**	**% chg**
CAL23 (marked)	$173	$147	-15%	$2.63	$2.64	0%	$147	$121	-18%
CAL24	$96	$84	-13%	$2.95	$2.79	-5%	$67	$56	-16%
CAL25	$72	$69	-5%	$3.47	$3.50	1%	$38	$34	-10%
CAL26	$73	$69	-5%	$3.57	$3.74	5%	$37	$32	-14%

5 THE RETAIL MARKET

5.1 Quarterly summary

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

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

The average RRO rate in Q3 was 83% higher than Q3 2022 (Table 16) because of high forward power prices for July, August, and September. The collection rates incurred by the RRO customers further increased the RRO rates in Q3.[43] The collection rates increased the RRO prices in Q3 by around 2.6 ¢/kWh.

The average residential Default Rate Tariff (DRT) rates in Q3 was 63% lower than last year. The DRT rate in July was $6.64/GJ less than last year, a decline of 73%. The decline in DRT rates was observed in August and September as well.

Table 16: Monthly retail market summary for Q3 (Residential customers)

		2023	2022	Change
RRO (Avg ¢/kWh)	Jul	27.50	14.79	*86%*
	Aug	32.27	17.17	*88%*
	Sep	27.63	15.79	*75%*
	Q3	**29.15**	**15.92**	***83%***
DRT (Avg $/GJ)	Jul	2.45	9.09	*-73%*
	Aug	3.21	6.68	*-52%*
	Sep	2.85	7.21	*-61%*
	Q3	**2.84**	**7.67**	***-63%***
Competitive variable electricity rate (Avg. ¢/kWh)	Jul	18.09	16.83	*7%*
	Aug	21.49	30.35	*-29%*
	Sep	12.70	29.64	*-57%*
	Q3	**17.48**	**25.56**	***-32%***
Competitive variable natural gas rate (Avg. $/GJ)	Jul	3.42	6.13	*-44%*
	Aug	3.61	3.68	*-2%*
	Sep	3.44	5.32	*-35%*
	Q3	**3.49**	**5.04**	***-31%***
Expected cost, 3-year electricity contract (Avg.¢/kW)	Jul	10.27	9.16	*12%*
	Aug	9.16	9.62	*-5%*
	Sep	8.51	10.25	*-17%*
	Q3	**9.32**	**9.67**	***-4%***
Expected cost, 3-year natural gas contract (Avg. $/GJ)	Jul	3.45	4.86	*-29%*
	Aug	3.64	5.25	*-31%*
	Sep	3.47	5.14	*-33%*
	Q3	**3.52**	**5.08**	***-31%***

In contrast to the RRO, the average competitive variable electricity rate faced by residential customers was lower than last year, by 8 ¢/kWh on average. Even though the variable rates were higher in July, rates declined in August and September to reduce the quarterly average by 32% year-over-year. Competitive variable natural gas rates also showed a year-over-year decline, by $1.55/GJ.

[43] Collection rates result from the deferred revenues associated with the rate ceiling set on RRO rates for January, February, and March 2023.

Retailers' expected cost of providing 3-year fixed rate electricity contracts was 4% lower year-over-year and 12% lower than Q2. The expected cost of providing 3-year fixed rate natural gas contracts dropped by 31% year-over-year but was largely unchanged relative to Q2 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 Q2 2023.

5.2.1 Regulated retailer customer losses

The total number of residential RRO customers fell by around 25,000 in Q2 2023 (Figure 80), which is the highest net reduction in any quarter since 2012. The decline in RRO customers in April contributed to the high net loss in Q2. The number of residential customers that left RRO in April was over 27,000, the highest since January 2012. The RRO customers lost normalized in May and June to losses that were comparable with the numbers in Q2 2022 (Figure 81). The termination of the RRO rate ceiling beginning on April 1 may have resulted in the increased RRO customers losses observed in April.

Figure 80: RRO customer net losses, residential customers (Q1 2020 to Q2 2023)

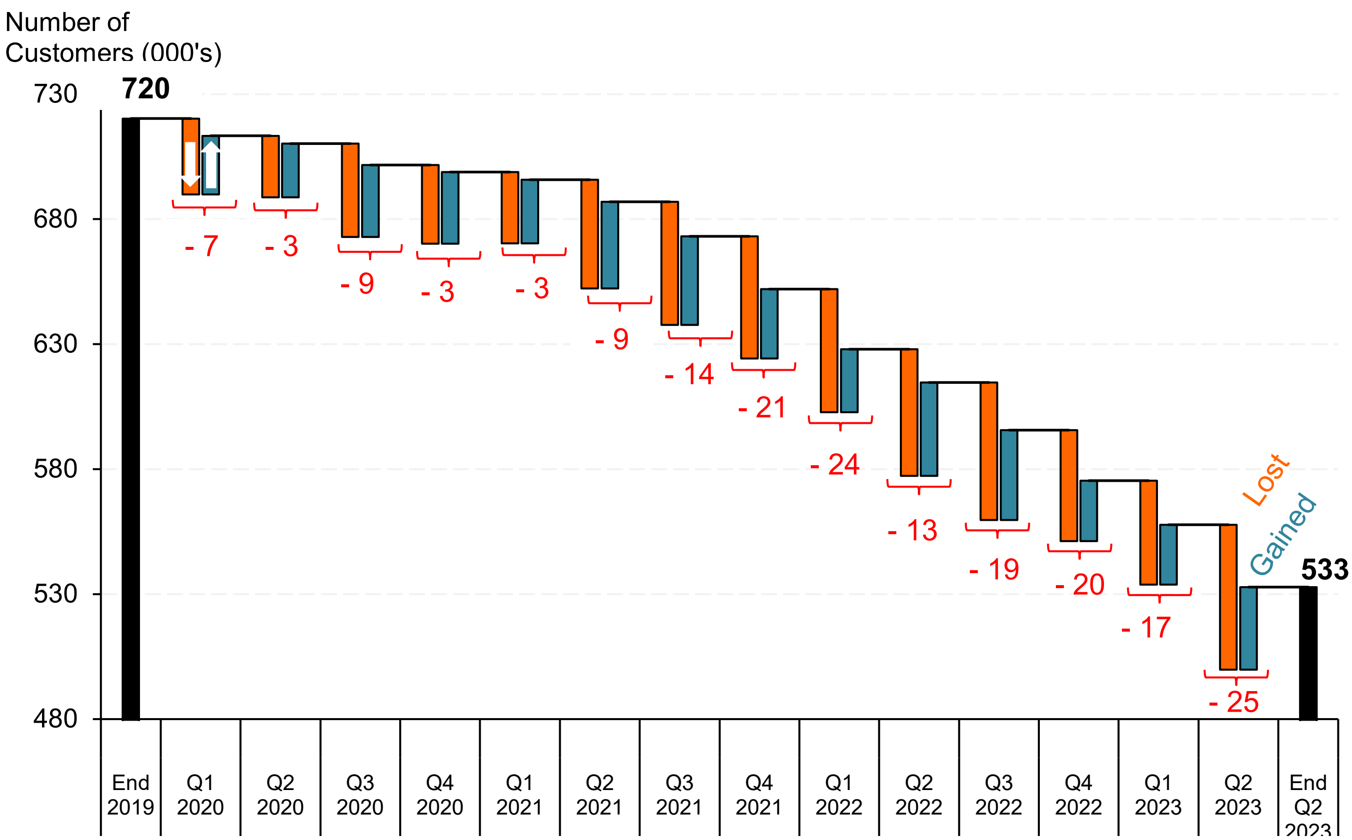
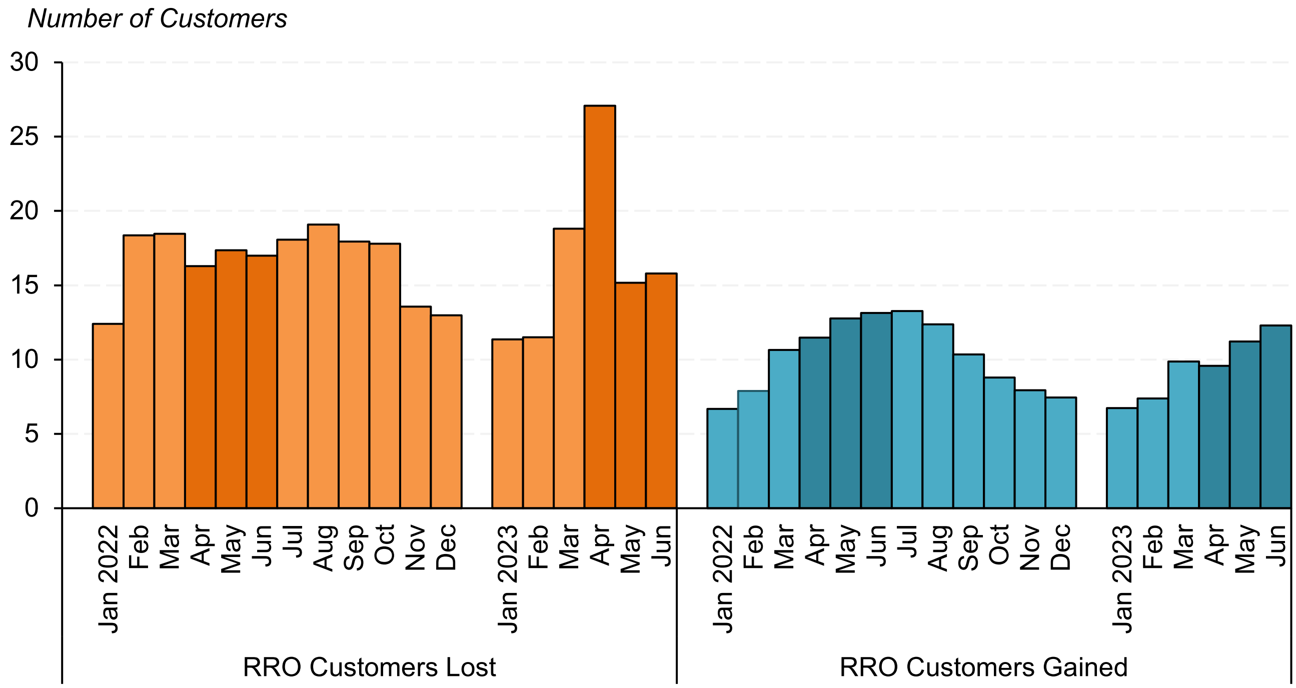
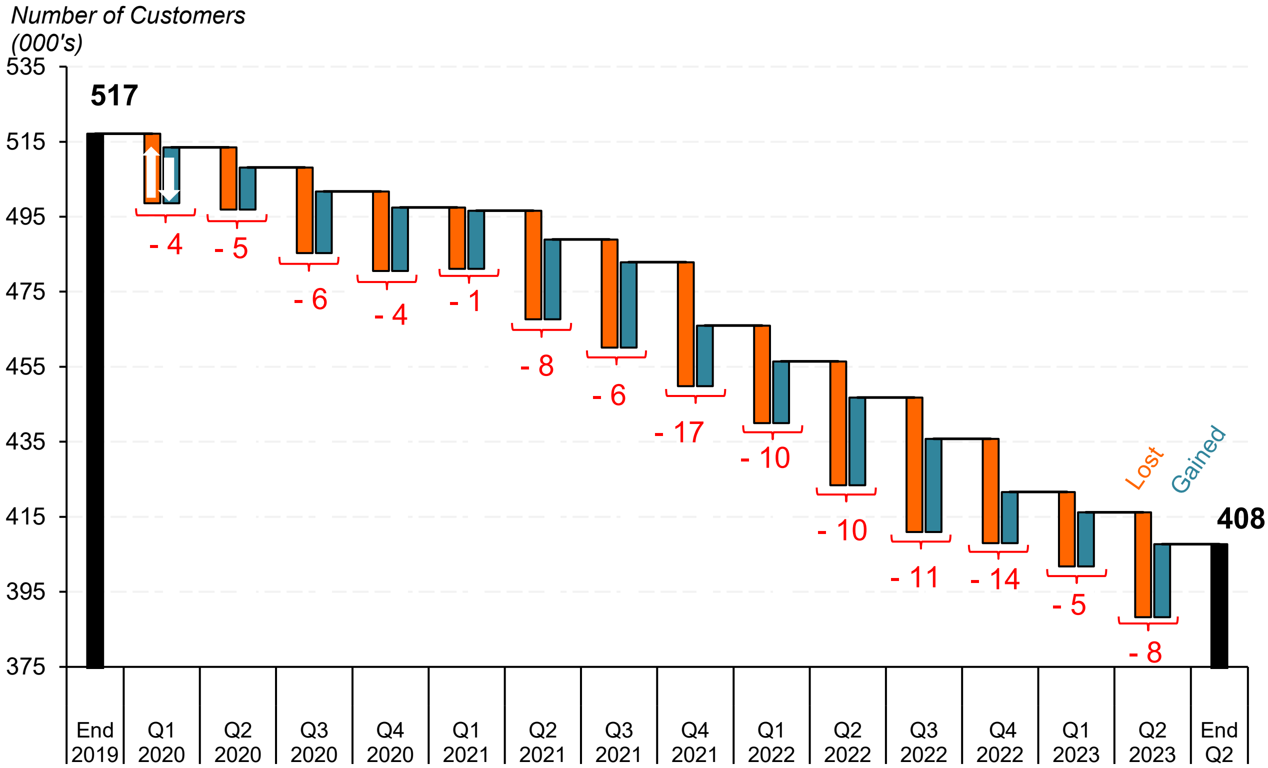


Figure 81: RRO customer losses and gains, residential customers (January 2022 to June 2023)



The total number of residential DRT customers fell by around 8,300 in Q2 2023 (Figure 82). While around 27,800 residential customers left the DRT, around 19,500 residential customers joined DRT in Q2. The net loss in DRT customers was not that high, as DRT rates have often been less than the prevailing competitive natural gas rates.

Figure 82: DRT customer net losses, residential customers (Q1 2020 to Q2 2023)



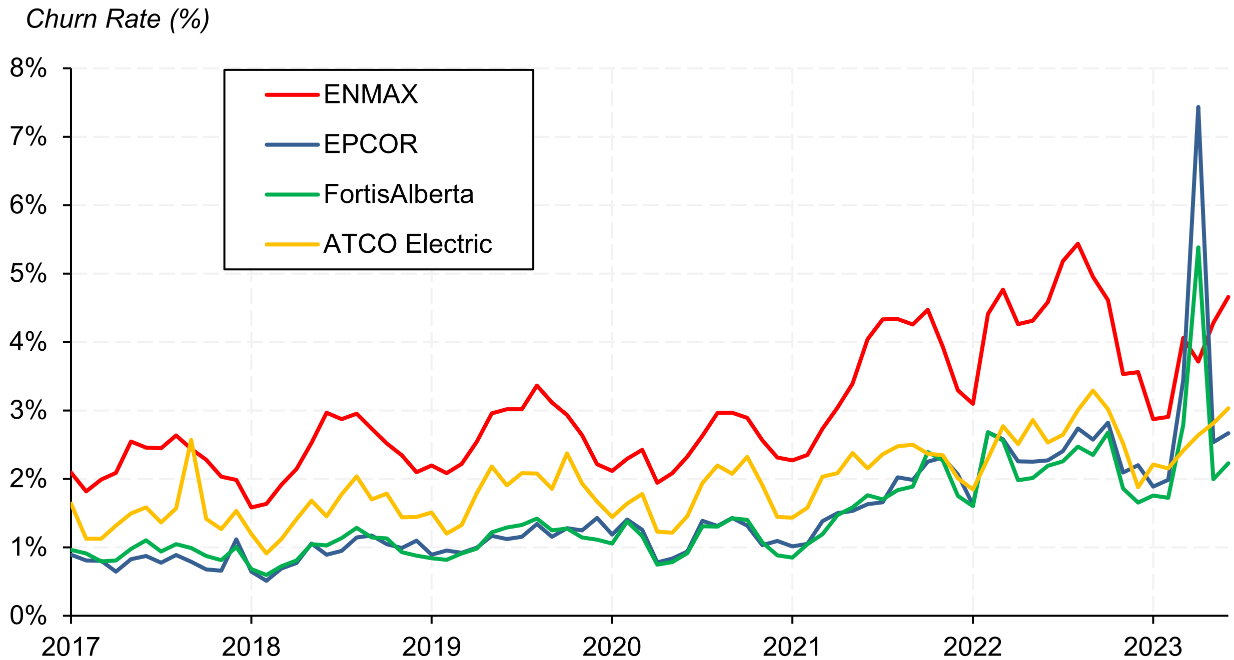
5.2.2 Dynamics of retail switching

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

The large net loss of RRO customers in April was due to high churn rates in the EPCOR and FortisAlberta service areas.

Since 2018, residential RRO churn rates in the ENMAX service area have exceeded that of other service areas, while churn rates in the EPCOR and FortisAlberta service areas were generally the lowest among the four (Figure 83). In April however, the churn rates in the EPCOR and FortisAlberta service areas exceeded ENMAX service area. The churn rate in the EPCOR service area increased from 3.4% in March to 7.4% in April, and in FortisAlberta churn rates increased from 2.8% to 5.4%. However, these high churn rates were not sustained into May and June.

Figure 83: 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 electricity contract increased by 1.78% in Q2 to 67% (Figure 84). The market share increase was highest in the EPCOR service area at 3.3%, followed by FortisAlberta at 2.3% (Table 17). The competitive retail market share increased marginally by 0.6% and 0.8% in the ENMAX and ATCO service areas, respectively.

Figure 84: Competitive retail customer share (electricity) by service area, residential customers (January 2012 to June 2023)

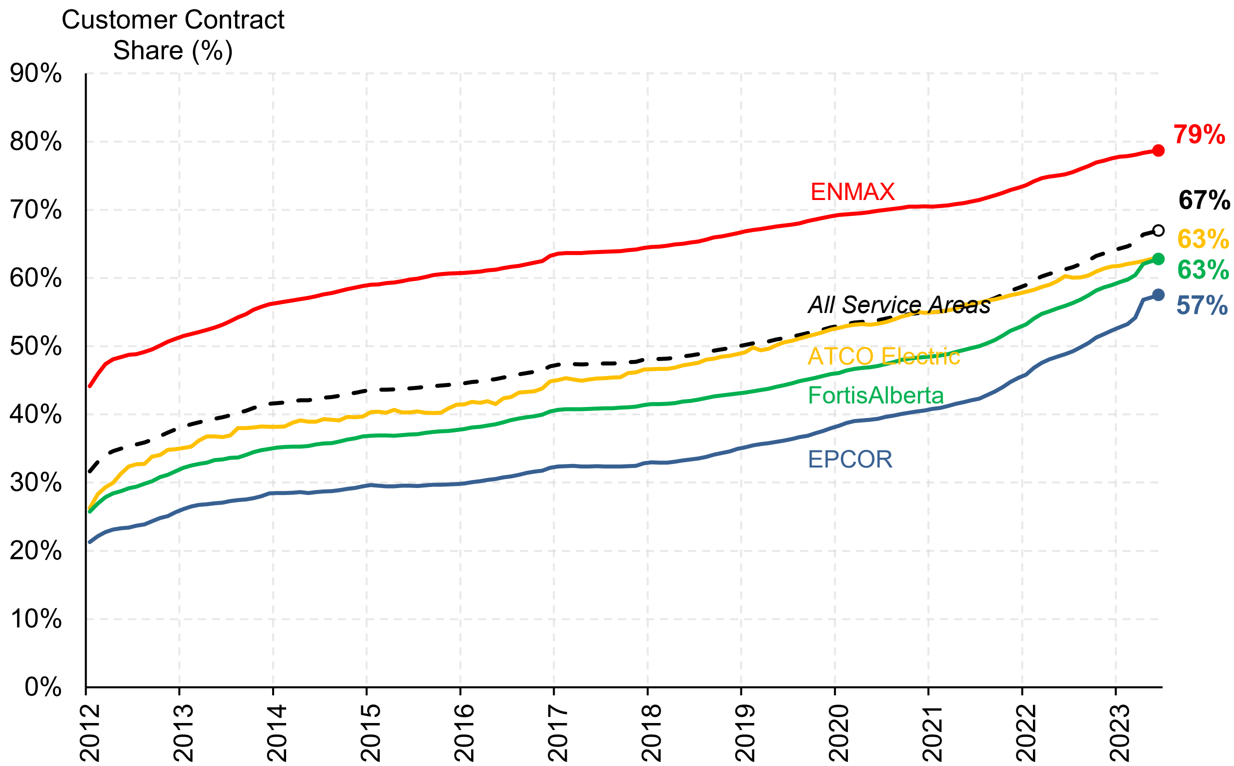


Table 17: Change in retail competitive shares (electricity) by service area, residential customers

	ENMAX	EPCOR	FortisAlberta	ATCO
Change (Q1 2023)	+0.6%	+1.9%	+1.4%	+0.5%
Change (Q2 2023)	+0.6%	+3.3%	+2.3%	+0.8%
Competitive share (as of June 30)	78.7%	57.5%	62.7%	63.0%

The percent of residential customers on a competitive retail contract for natural gas did not change notably over Q2 2023 (Figure 85). Market shares across all service areas had a small increase from 67.5% in Q1 to 68.2% in Q2 2023. The changes in competitive retail market shares for natural gas across all service areas was similar to the changes observed in the previous quarter (Table 18).

Figure 85: Competitive retail customer share (natural gas) by service area, residential customers (January 2012 to June 2023)

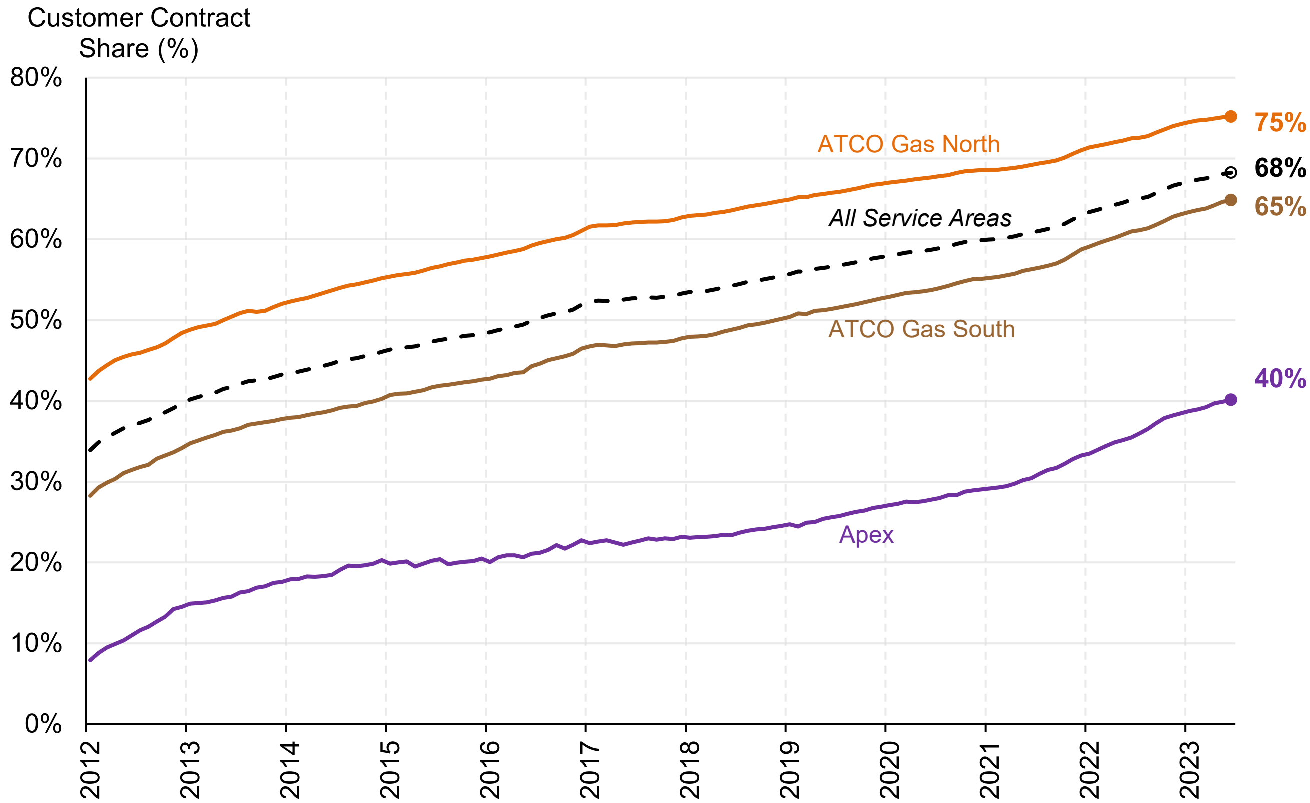


Table 18: Change in retail competitive shares (natural gas) by service area, residential customers

	ATCO Gas North	ATCO Gas South	Apex
Change (Q1 2023)	+0.7%	+0.5%	+0.7%
Change (Q2 2023)	+1.0%	+0.4%	+0.9%
Competitive share (as of June 30)	64.8%	75.2%	40.1%

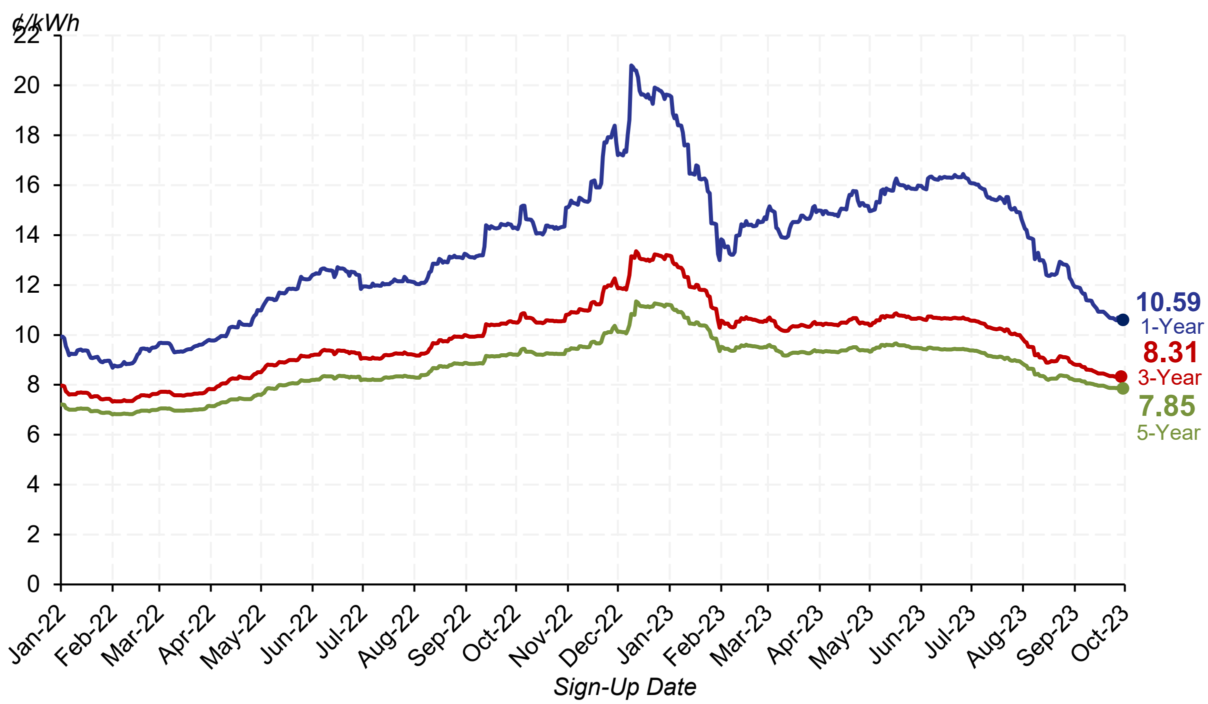
5.3 Competitive fixed retail rates

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

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

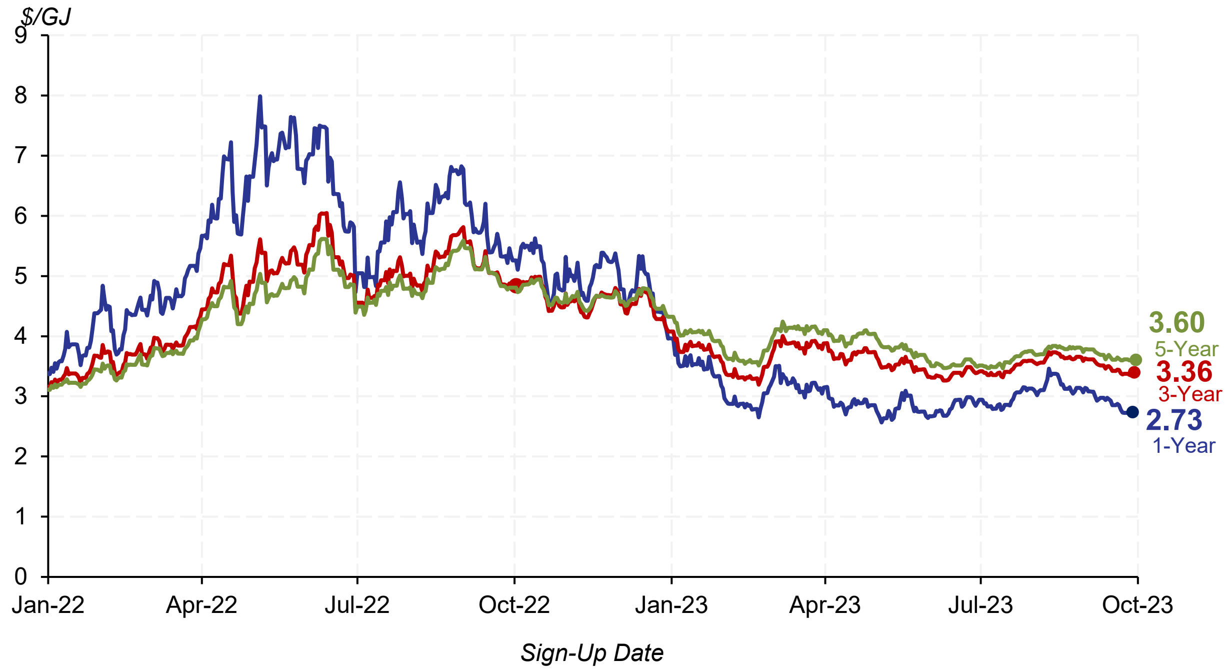
The expected cost for 1-, 3-, and 5-year fixed rate electricity contracts decreased over Q3 as the near term and longer term forward prices for power dropped. The expected cost for 1-, 3-, and 5-year fixed rate contracts decreased by 34%, 21%, and 16% respectively in Q3 (Figure 86). The expected cost for longer term contracts is lower than the 1-year contract as prices for annual forward contracts such as CAL24 and CAL25 are lower than prices for near term forward monthly prices.

Figure 86: Expected cost, fixed rate electricity contract, residential customer (January 1, 2022 to September 30, 2023)



The expected cost for fixed rate natural gas contracts increased in the first half of Q3, but then decreased over the later part of the quarter (Figure 87). Unlike expected costs for electricity contracts, expected costs for natural gas contracts are higher for longer term contracts. The expected cost of 1-, 3-, and 5-year natural gas fixed rate contracts changed by -7%, -1%, and +3% respectively in Q3. The prevailing prices for natural gas contracts in 2023 are much lower than they were in 2022.

Figure 87: Expected cost, fixed rate natural gas contract, residential customer (January 1, 2022, to September 30, 2023)



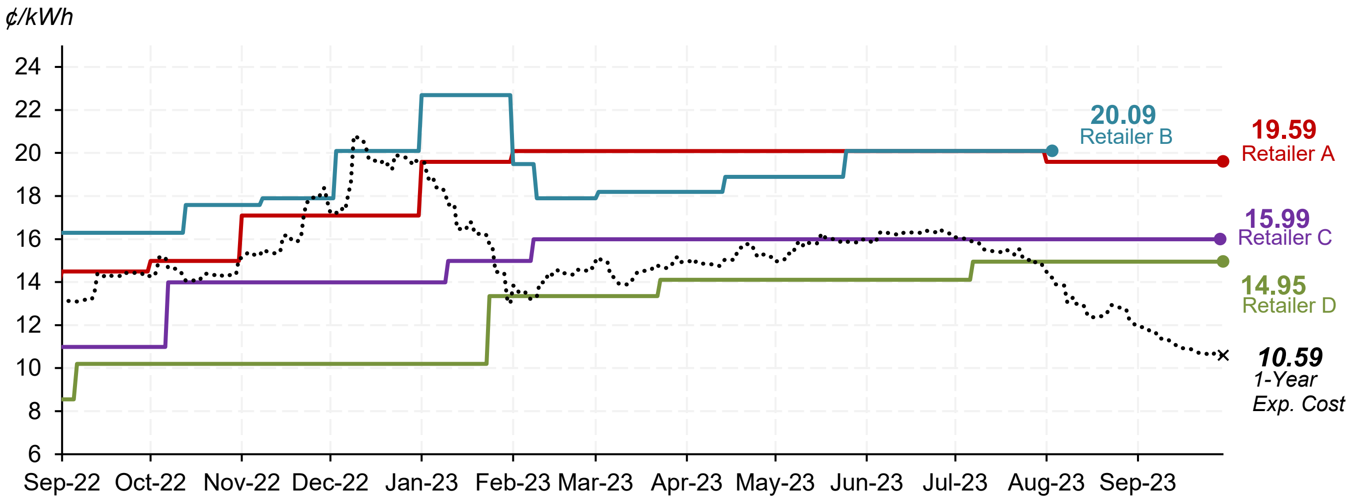
Most of the competitive retailers in Alberta did not change their fixed rate offerings in Q3, aside for some of the higher-cost retailers reducing their pricing to reflect the reduction in expected costs (Figure 88). All the fixed rate electricity contracts were offered well above the respective expected costs over Q3.

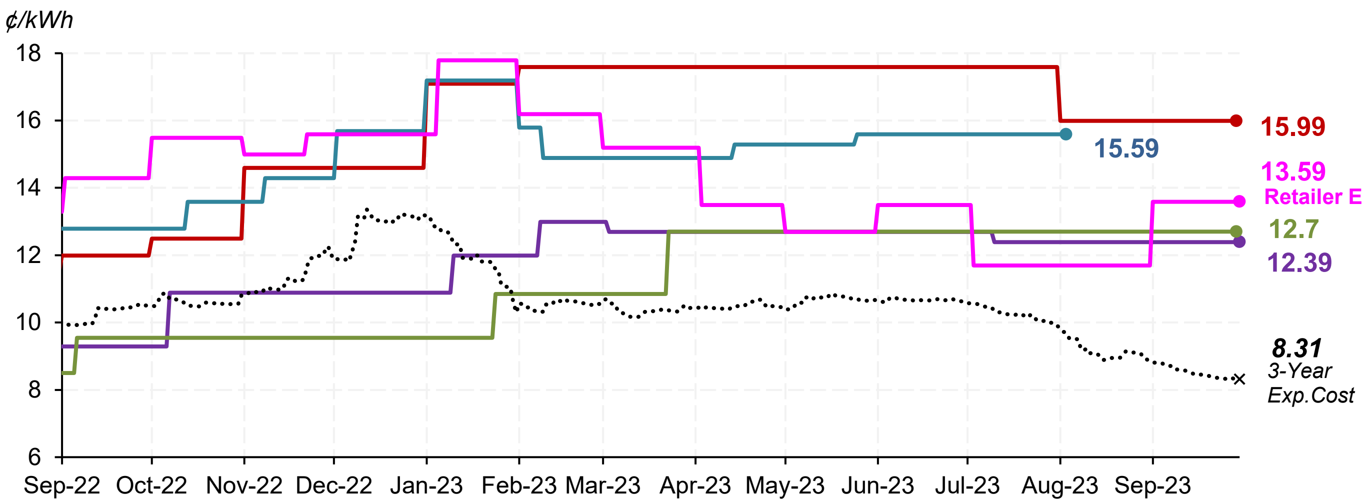
Retailer B, that provided 1-, 2-, 3-, and 5-year fixed rate electricity and natural gas services, stopped offering in Alberta's retail electricity market after the first week of August. With the departure of Retailer B, Retailer A has become the highest cost provider of electricity in 1-, 3-, and 5-year contracts (Figure 88).

At the beginning of Q3, Retailer E was the lowest priced provider of the 3-year fixed rate for electricity. However, by the end of Q3, they became the second-highest priced provider of the 3-year by increasing their rates by around 2 ¢/kWh. Retailer C, that previously offered the same 5-year fixed rates as Retailer F and Retailer G, reduced their rates in Q3 by 0.30 ¢/kWh to become the lowest rate provider of 5-year contracts.

Fixed rate natural gas rates in Q3 were also largely unchanged by the competitive retailers, except Retailer A (Figure 89). Retailer A dropped their 1-, 3-, and 5-year fixed rate offerings by $3.20/GJ, $2.70/GJ and $1.30/GJ respectively in Q3. All the fixed rate natural gas contracts were offered above their respective expected costs over Q3.

Figure 88: 1-, 3-, and 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (September 1, 2022 to September 30, 2023)





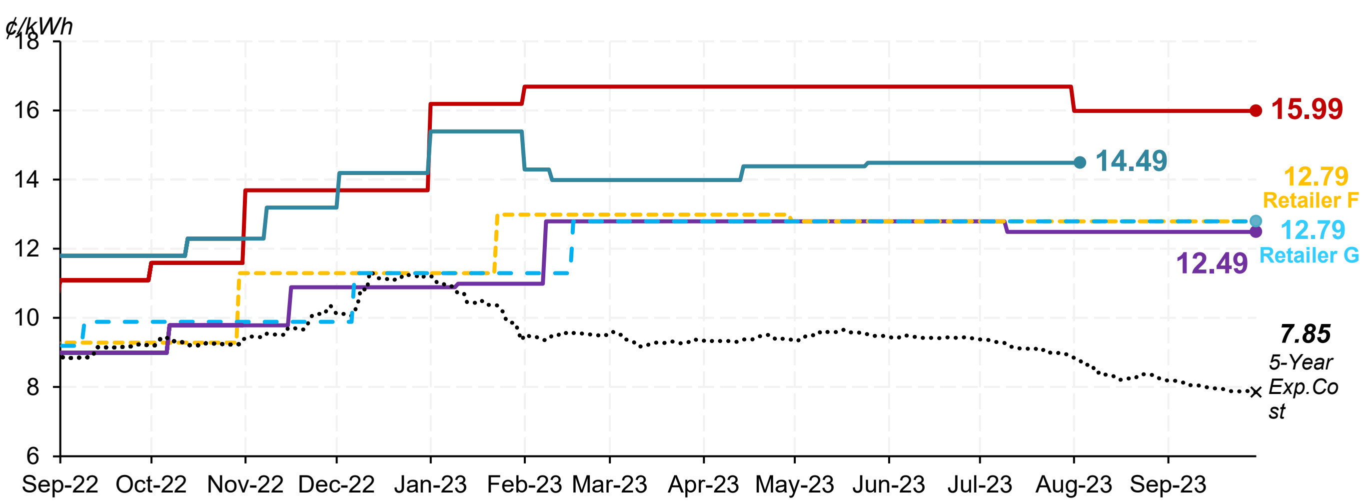
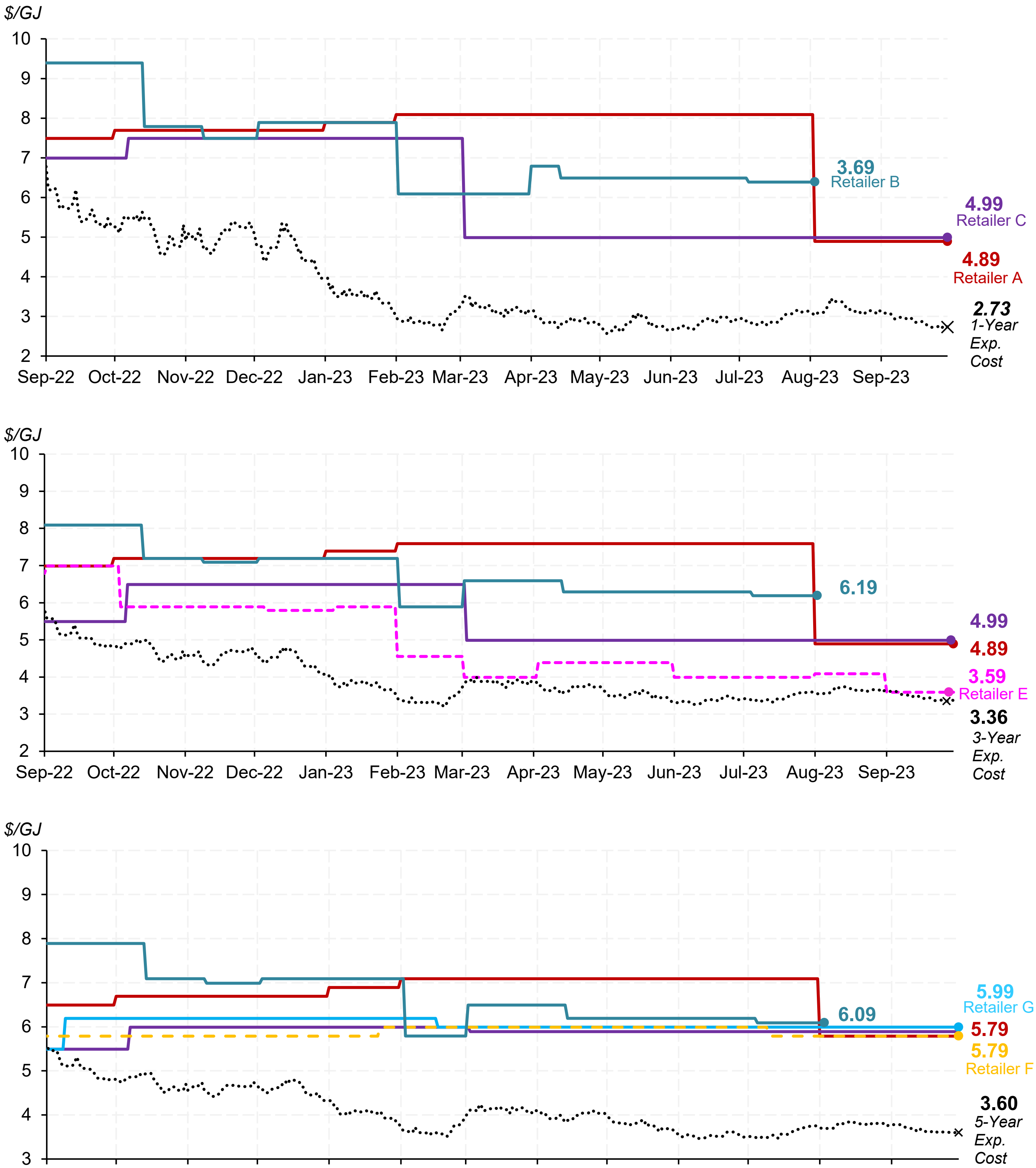


Figure 89: 1-, 3-, and 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (September 1, 2022 to September 30, 2023)



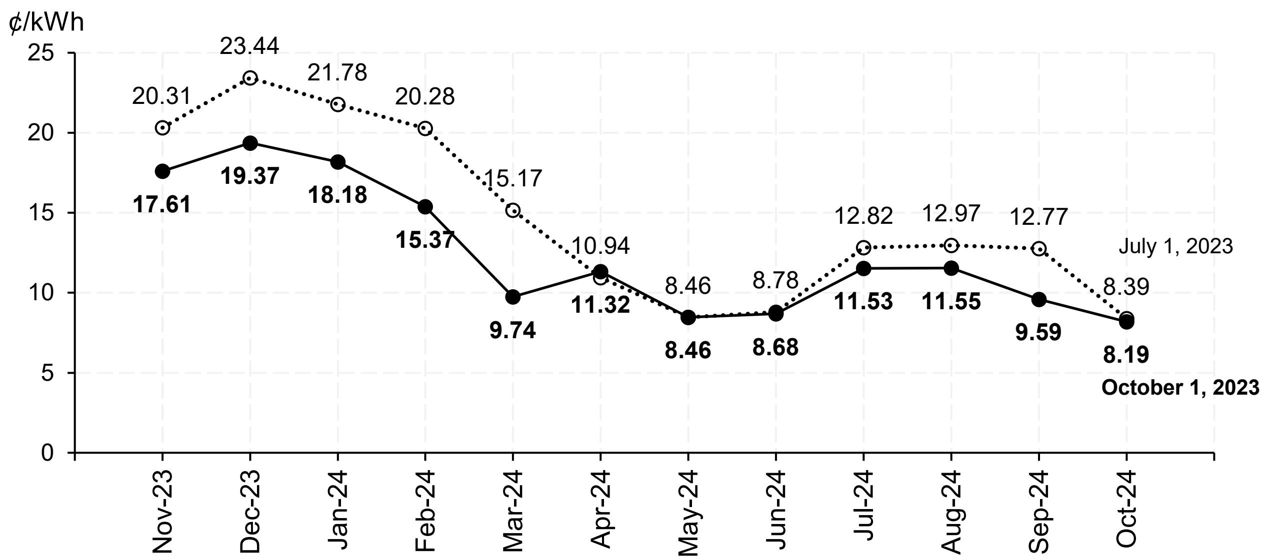
5.4 Regulated retail rate estimates

5.4.1 Electricity regulated rate estimates

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

Expected residential RRO monthly rates over the November 2023 to October 2024 period have decreased since July 1 (Figure 90). The RRO estimates dropped significantly for the upcoming winter and slightly for next summer. However, the estimates did not change notably for April, May, and June of 2024 (Figure 90). On average, RRO rates for the period November 2023 to March 2024 reduced by around 4 ¢/kWh in the EPCOR service area. This decrease can be attributed to the decline in monthly forward prices over Q3.

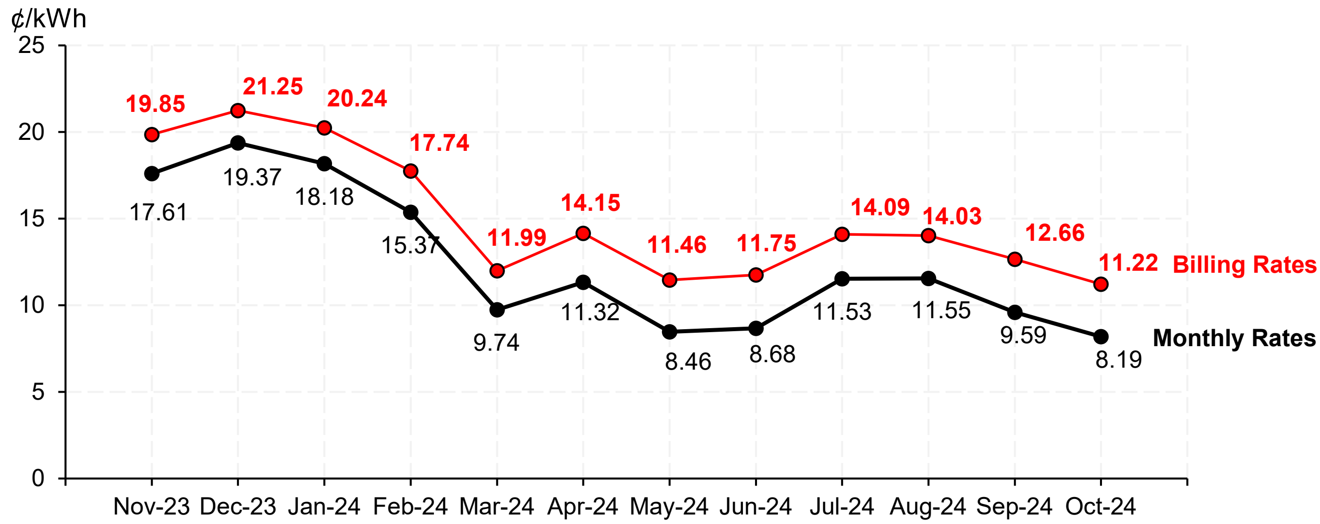
Figure 90: November 2023 to October 2024 residential RRO monthly rate estimates, EPCOR service area (as of July 1, 2023 vs. October 1, 2023)



In Q3, RRO providers continued collecting the deferred revenue that resulted from the Q1 regulated rate celling through collection rates. These collection rates are added on top of the monthly base RRO rates to give the billing rates paid by RRO customers (Figure 91). 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 has forecasted residential collection rates using RRO site counts as of Q2 2023, monthly recovery amounts, and historical seasonal changes in residential RRO customer site. The expected collection rate in the EPCOR service area averaged 2.57 ¢/kWh over the period of November 2023 to October 2024, as of October 1, 2023 (Figure 91). In other service areas, the collection rate averaged 2.00 ¢/kWh, 2.41¢/kWh, and 2.33 ¢/kWh in the ENMAX, FortisAlberta, and ATCO service areas, respectively for the same period.

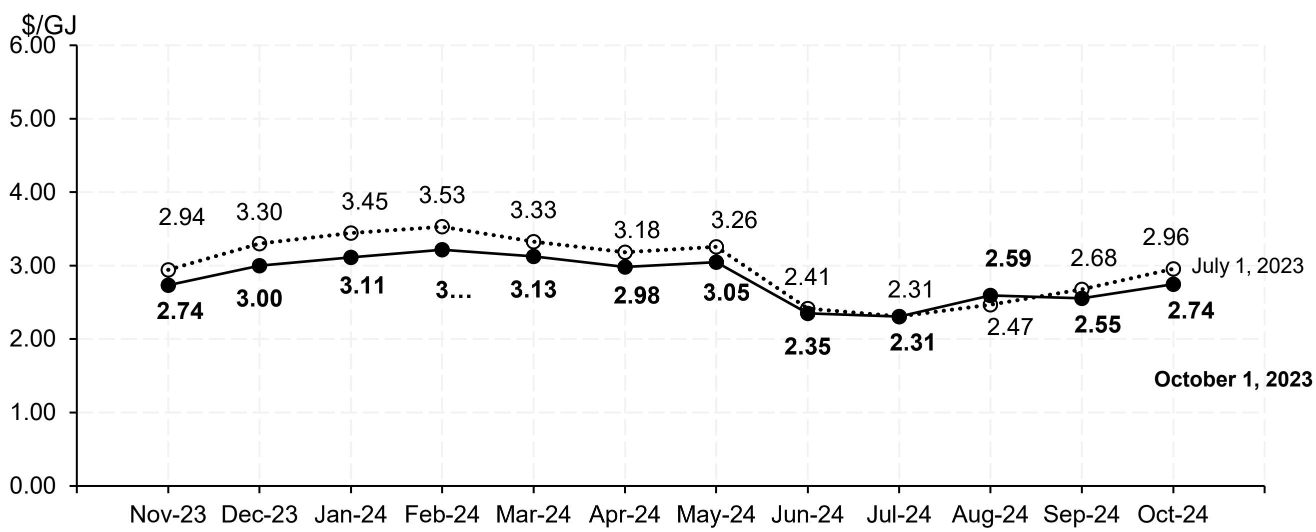
Figure 91: November 2023 to October 2024 estimated residential RRO monthly rates and billing rates, EPCOR service area (as of October 1, 2023)



5.4.2 Natural gas regulated rate estimates

Expected DRT rates for the November 2023 to October 2024 period have decreased slightly by an average of $0.17/GJ since the MSA's estimates on July 1 (Figure 92). The decline in forecasted DRT rates was mainly for the period of November 2023 to May 2024. Expected DRT rates largely remain unchanged for the summer of 2024.The forecasted rates remain well below the $6.50/GJ threshold for natural gas rebates by the Government of Alberta.

Figure 92: November 2023 to October 2024 residential DRT estimates, ATCO Gas service areas (as of July 1, 2023 vs. October 1, 2023)



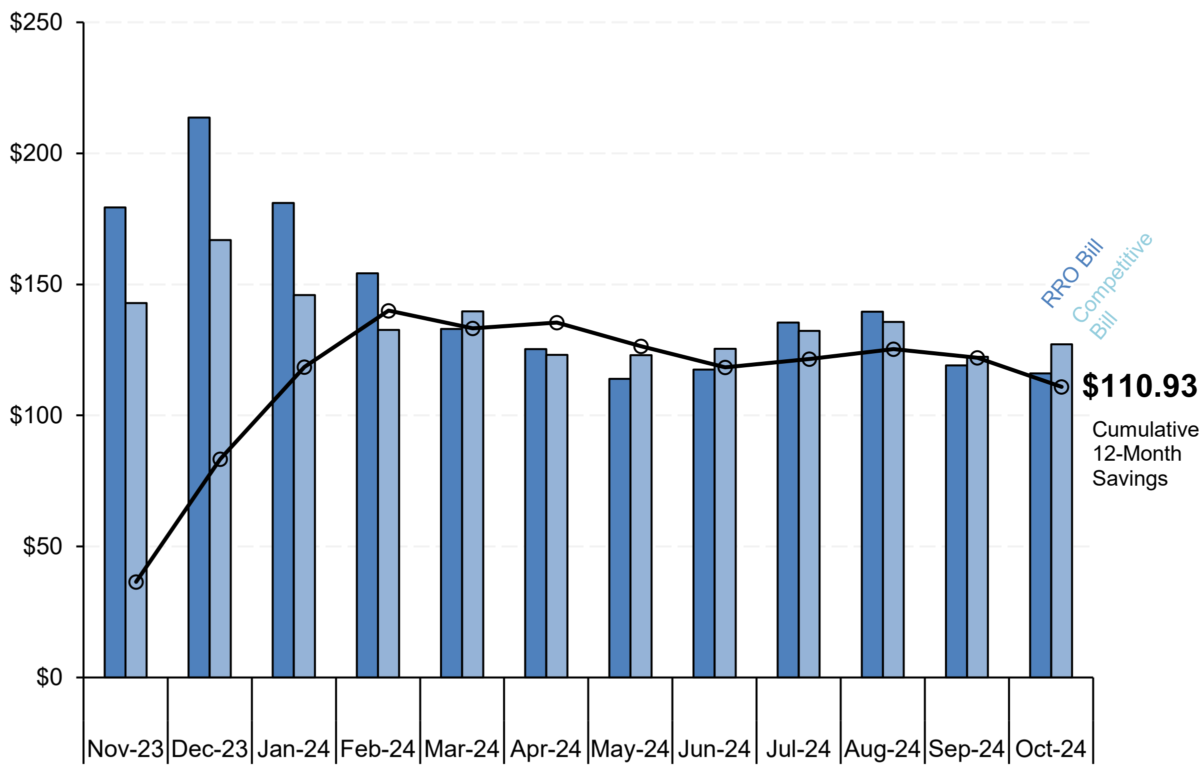
5.4.3 Fixed rate switching incentives

The financial incentive to switch to a competitive fixed electricity rates for Residential RRO customers have come down based on the RRO rate expectations for the November 2023 to October 2024 period (Figure 93).

An average residential RRO customer in the ENMAX service area could expect to save around $111 over 12 months if they switched to the lowest priced 3-year fixed rate electricity contract on October 1, 2023 (displayed in Figure 88). This incentive to switch from the RRO to a competitive electricity fixed rate was higher at $512 on July 1, 2023.

The RRO rate is much higher than the 3-year fixed rate only for the November 2023 to February 2024 period. After February 2024, the RRO and the 3-year fixed rate are comparable. In certain months, such as May and June of 2024, the 3-year fixed rate of $12.39 is expected to be higher than the RRO rates for that month.

Figure 93: Expected RRO bill vs. competitive electricity bill
(3-year fixed rate at 12.39 ¢/kWh, $8.99/month)[44]

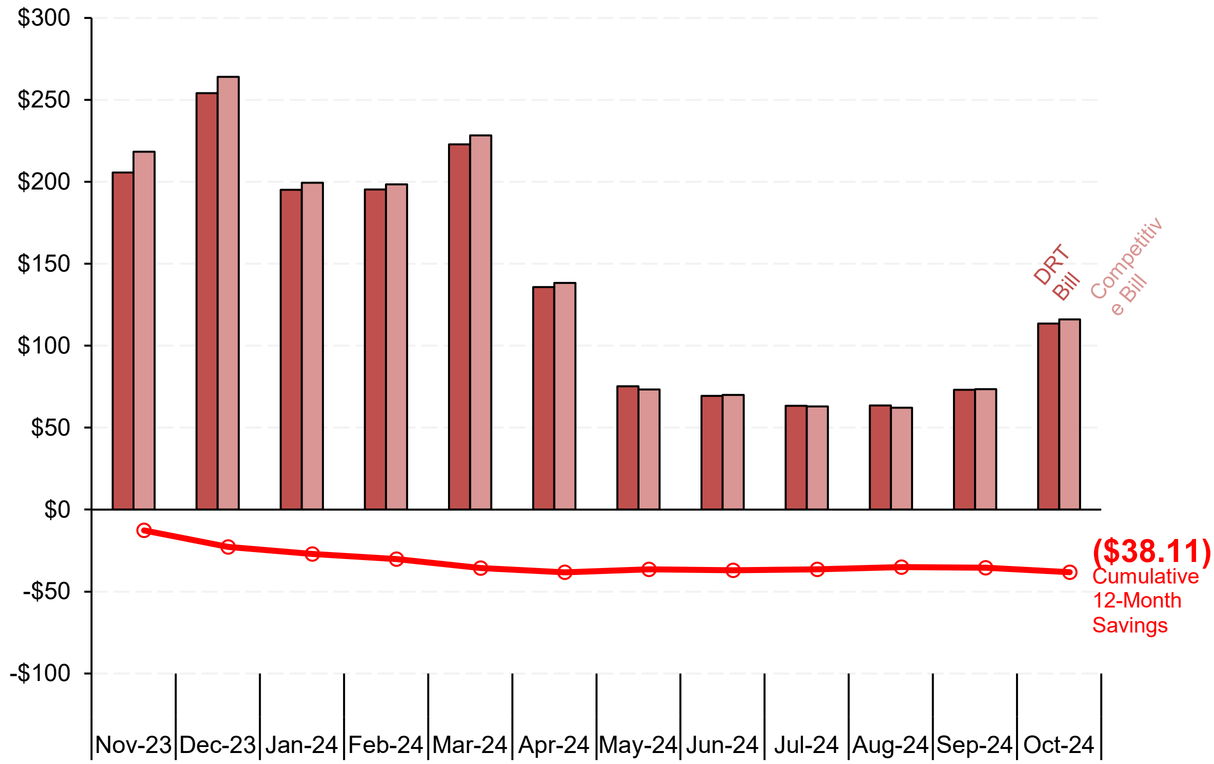


Residential DRT customers are not financially incentivized to switch onto competitive rates at present. If an average residential DRT customer had switched to the lowest priced 3-year fixed

[44] Estimated bills for a residential customer in the ENMAX service area over November 2023 to October 2024 period.

natural gas contract on October 1, 2023, they could expect to pay around $38 more in the 12 months that followed (Figure 94).

Figure 94: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at $3.59/GJ, $6.85/month)[45]



[45] Estimated bills for a residential customer in the ATCO Gas South service area over the November 2023 to October 2024 period.

6 REGULATORY AND ENFORCEMENT MATTERS

6.1 SUM1 frequency response

In August 2021, the AESO referred two suspected contraventions of ISO Rule 205.5 *Spinning Reserve Technical Requirements and Performance Standards* (ISO Rule 205.5) by Canadian Hydro Developers Ltd. (Canadian Hydro) in relation to the Summerview1 battery storage asset (SUM1). The AESO suspected Canadian Hydro contravened ISO Rule 205.5 based on two instances where the Alberta Interconnected Electric System (AIES) frequency dropped below the prescribed deadband, but SUM1 did not increase its real power output in proportion to the drop in system frequency.

Following an investigation, the MSA was satisfied that, contrary to ISO Rule 205.5, TransAlta Corporation (TransAlta), as the operator of SUM1, and Canadian Hydro failed to ensure SUM1 was equipped with a governor that had control settings providing an immediate, automatic and sustained response to frequency deviations on the AIES. The MSA also found that, contrary to ISO Rule 205.5, when SUM1 was dispatched to provide spinning reserve, SUM1 failed to provide the immediate, automatic, and sustained response to drops in system frequency below the deadband required by ISO Rule 205.5.

The contraventions of ISO Rule 205.5 arose because two settings necessary to allow SUM1 to meet the requirements of ISO Rule 205.5 were not enabled in the software which controls SUM1. Because the necessary settings were not enabled, SUM1 was incapable of providing the required frequency response from October 27, 2020 to June 1, 2021. During this period, Canadian Hydro offered spinning reserve from SUM1 on the WattEx Exchange and derived revenue of $1,931,204.68 from the sale of spinning reserve, net of recoveries for directive/dispatch non-compliance and costs to charge SUM1 following responses to directives. The MSA found that, by offering spinning reserve while SUM1 was incapable of meeting the requirements of ISO Rule 205.5, TransAlta misrepresented the availability of ancillary services from SUM1, contrary to subsection 2(d) of the *Fair, Efficient and Open Competition Regulation* AR 20

TransAlta and Canadian Hydro fully and completely co-operated with the MSA in the course of the investigation. After it received the MSA's summary of facts and findings, TransAlta implemented a program of corrective actions to prevent similar contraventions from occurring.

The MSA, TransAlta, and Canadian Hydro reached a comprehensive settlement agreement which provided for:

a) payment of an Administrative Monetary Penalty (AMP) of $2,470,204.68, composed of:

   i) $1,931,204.68 as disgorgement of the estimated economic benefit to Canadian Hydro of;

   ii) $39,000 in interest on the benefit wrongly taken in the amount; and

    iii) $500,000 as an additional administrative monetary penalty;

b) payment of the MSA's costs, in the amount of $65,000; and

c) an order directing TransAlta and Canadian Hydro to meet with the MSA to share and discuss their progress in meeting the program of corrective actions and permitting the MSA to seek a further order from the Alberta Utilities Commission (Commission) if it determined TransAlta had not made adequate progress toward implementing its program of corrective actions.

The Commission approved the Settlement Agreement in *Decision 28217-D01-2023 Market Surveillance Administrator - Application for Approval of a Settlement Agreement Between the Market Surveillance Administrator, Canadian Hydro Developers Inc. and TransAlta Corporation*, a copy of which is available here.

6.2 EPCOR customer information sharing

Following an investigation, the MSA was satisfied that EPCOR Energy Alberta GP Inc, as general partner of EPCOR Energy Alberta LP (collectively, "EEA") and 1772387 Alberta Ltd, as general partner of 1772387 Alberta Limited Partnership (collectively, "Encor") each contravened subsection 17(2) of the *Code of Conduct Regulation* AR 58/2015 (Code of Conduct) and section 6 of the EUA (collectively, the "Contraventions").

Encor is a "retailer" within the meaning of the EUA and the Code of Conduct, and EEA is a regulated rate supplier within the meaning of the Code of Conduct. The Contraventions arose out of an arrangement between EEA and Encor, under which EEA provides services to Encor for a fee, including the assessment of prospective Encor customers' creditworthiness. In assessing some prospective Encor customers creditworthiness, EEA relied on customers' billing history (RRO Billing History), including overdue balances, collections steps taken, and pending service disconnections.

Section 17(2) of the Code of Conduct prohibits the sharing of customer information between a regulated rate option (RRO) provider and its affiliates that creates an unfair competitive advantage for the regulated rate supplier or its affiliate. Section 18 of the Code of Conduct suggests that sharing of customer information for a sales purpose would be prohibited under Section 17(2). When EEA shared the creditworthiness assessment derived from its RRO Billing History with Encor, it shared customer information with Encor for a sales purpose. By using the RRO Billing History to assess creditworthiness, EEA avoided the cost of an external credit check, which resulted in a lower fee charged to Encor from July 1, 2016 to June 20, 2021 and gave Encor an unfair competitive advantage.

EEA and Encor fully co-operated with the MSA's investigation. After they received the MSA's summary of facts and findings in its investigation, EEA and Encor took remedial steps, and agreed to the imposition of conditions to maintain the remedial steps in order to prevent a recurrence of the contraventions. The MSA, Encor, and EEA reached a comprehensive settlement agreement which provided for:

a) EEA and Encor to maintain the remedial actions taken after receiving the MSA's facts and findings;

b) Encor's payment of an AMP of $105,000, including:

    i) $84,000 as the approximate benefit taken by Encor; and

    ii) $21,000 as an additional AMP;

b) EEA's payment of an AMP of $21,000; and

c) payment by Encor and EEA, jointly and severally, of the MSA's costs in the amount of $20,000.

The Commission approved the settlement agreement in *Decision 2023-D01-28207 Market Surveillance Administrator - Application For Approval of a Settlement Agreement Between the Market Surveillance Administrator, EPCOR Energy Alberta GP Inc. and 1772387 Alberta Ltd. (Encor by EPCOR)*, a copy of which is available here.

6.3 MSA comments on AESO initiatives

On September 5, the MSA provided comments to the AESO regarding its Market Pathways Initiative.[46] In these comments, the MSA agreed that the AESO had identified a variety of issues requiring urgent consideration and action. The MSA also highlighted additional issues identified through its ongoing surveillance program, including unit commitment and the long lead time rule; management of real-time congestion; increasing number of Energy Emergency Alert events; restrictions on the use of Alberta's interconnection capacity; and market software / tools issues and limitations. The MSA expressed its view that these issues required prompt attention and could only be dealt with by the AESO through technical changes to the market design and / or requirements applicable to market participants.

On October 30, the MSA provided comments to the AESO related to its Fast Frequency Response Services Procurement.[47] This procurement is focused on the restoration of the available transfer capacity of the intertie and contemplates contracting for up to 180 MW of Proportional Fast Frequency Response (PFFR) over a four-year period. In these comments, the MSA highlighted the benefits of following the well-established framework for developing ISO rules for ancillary services and questioned why this framework was not being used for PFFR. Beyond this, the MSA highlighted concerns about a multi-year procurement constraining or foreclosing market and technical design options and recommended that a bridging mechanism, if necessary, be as brief as possible. Finally, the MSA indicated support for allowing the participation of emerging technologies and maximizing competition wherever feasible.

[46] Alberta MSA Notice – MSA comments regarding AESO's Market Pathways Initiative and Primer, September 5, 2023

[47] Alberta MSA Notice – MSA comments regarding AESO's Fast Frequency Response Services Procurement, October 30, 2023

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 September 30, 2023, the MSA closed 194 ISO rules compliance matters, as reported in Table 19.[48] An additional 280 matters were carried forward to next quarter. During this period 72 matters were addressed with NSPs, totalling $145,000 in financial penalties, with details provided in Table 20.

Table 19: ISO rules compliance outcomes from January 1 to September 30, 2023

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.12	1	-	-
201.4	-	10	-
201.7	6	7	-
203.3	53	10	-
203.4	16	4	3
203.6	17	20	-
205.3	1	-	-
205.6	4	5	4
301.2	2	4	-
304.3	2	-	-
304.9	2	-	-
306.4	1	-	-
306.5	1	3	-
502.5	2	-	-
502.6	3	1	-
502.8	-	8	-
502.9	1	-	-
502.16	2	-	-
505.4	1	-	-
Total	**115**	**72**	**7**

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

Table 20: Specified penalties issued between January 1 and September 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	301.2	306.5	502.6	502.8		
Air Liquide Canada Inc.		500									500	1
Alberta Pacific Forest Industries Inc.				250							250	1
Alberta Solar One, Inc.										500	500	1
British Columbia Hydro and Power Authority										500	500	1
Canadian Hydro Developers, Inc.	57,000										57,000	10
Claresholm Solar LP										1,000	1,000	2
Conrad Solar Inc.							4,000				4,000	4
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
Evolugen Trading and Marketing LP					17,000						17,000	4
Grande Prairie Generation Inc.			2,000								2,000	2
Heartland Generation Ltd.					250						250	1
MAG Energy Solutions Inc.					3,750						3,750	4
MEG Energy Corp.								500			500	1
Mercer Peace River Pulp Ltd.		250									250	1
Morgan Stanley Capital Group Inc.					500						500	1
NRGreen Power Limited Partnership								500			500	1
Powerex Corp.					9,250						9,250	5
Syncrude Canada Ltd.				250					250		500	2
TransAlta Corporation			500							5,000	5,500	6
TransAlta Energy Marketing Corp.					250						250	1
TransAlta Generation Partnership				500							500	2
TransCanada Energy Ltd.			500								500	1
TransCanada Energy Sales Ltd.					10,000						10,000	2

Table 20: Specified penalties issued between January 1 and September 30, 2023 for contraventions of the ISO rules (continued)

Market participant	**Total specified penalty amounts by ISO rule ($)**										**Total ($)**	**Matters**
	201.4	**201.7**	**203.3**	**203.4**	**203.6**	**205.6**	**301.2**	**306.5**	**502.6**	**502.8**		
Vitol Inc.					750						750	2
Voltus Energy Canada Ltd.						12,500					12,500	3
West Fraser Mills Ltd.		2,000	2,000								4,000	4
Windrise Wind LP								500			500	1
Total	57,000	3,750	6,250	1,000	41,750	22,500	4,000	1,500	250	7,000	145,000	72

The ISO rules listed in Table 19 and Table 20 fall into the following categories:

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

8 ARS COMPLIANCE

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

The ARS ensure the various entities involved in grid operation have practices in place, including procedures, communications, coordination, training, and maintenance to support the reliability of the AIES.[49] ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach to compliance with ARS focuses on promoting awareness of obligations and a proactive compliance stance. The MSA's process, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

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

From January 1 to September 30, 2023, the MSA addressed 41 O&P ARS compliance matters (Table 21).[50] 43 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 22). For the same period, the MSA addressed 154 CIP ARS compliance matters, as reported in Table 23, and 53 matters were addressed with NSPs, totalling $149,875 in financial penalties. 84 CIP ARS matters were carried forward to next quarter.

Table 21: O&P ARS compliance outcomes from January 1 to September 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

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

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

Table 22: Specified penalties issued between January 1 and September 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 21 and Table 22 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 23: CIP ARS compliance outcomes from January 1 to September 30, 2023

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	3	3	1
CIP-003	13	2	-
CIP-004	18	6	-
CIP-005	7	4	-
CIP-006	8	5	-
CIP-007	24	18	1
CIP-008	1	-	-
CIP-009	2	3	-
CIP-010	17	11	-
CIP-011	6	1	-
Total	99	53	2

The ARS outcomes listed in Table 23 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