Quarterly Report for Q4 2024

February 12, 2025

Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

www.albertamsa.ca

TABLE OF CONTENTS

THE QUARTER AT A GLANCE

- **Market fundamentals drive decline in average pool prices:**

  The average pool price in 2024 was $62.78/MWh, a decline of 53% relative to 2023 and the lowest annual average since 2020. While demand was higher in 2024, lower pool prices were driven by significant new thermal generation capacity reaching commercial operation, increased wind and solar generation, and lower natural gas prices.

- **Energy Emergency Alert level 3 (EEA3) on October 22:**

  On October 22 between 07:15 and 08:22, the AESO declared an EEA3 indicating that there was insufficient supply to reliably meet demand. The event was caused by many outages at thermal assets in combination with low wind and solar generation. In 2024, there were eight EEA events spanning 25.4 hours, the most since 2013.

- **Market concentration increases with a major acquisition:**

  Following a review by the Competition Bureau, a large merger was completed on December 4 in which the largest generator in Alberta acquired a further 2,141 MW of offer control by buying one of its main competitors. The market share offer control of the company increased from 14.7% to 23.2% year-over-year despite an increase in overall system capacity.

- **Baseplant begins expanded operations:**

  In Q4 the capacity of the Baseplant asset was increased from 50 MW to 856 MW to reflect the installation of additional generation units at the site. In December, generation from Baseplant averaged 380 MW and output is scheduled to increase early in 2025. These new generation units are expected to increase supply and put downward pressure on pool prices.

- **The AESO issued 10 Unit Commitment Directives (UCDs) in Q4:**

  In total, 10 UCDs were issued in Q4, which the MSA estimates reduced average pool prices over the quarter by $6.63/MWh (11%). These UCDs increased supply cushion during tight market conditions, particularly in October when supply was reduced by thermal generation outages.

- **Transmission constraints decrease in Q4**:

  In Q4, the volume of wind and solar generation that was constrained down was 140 GWh, a 26% decrease from Q4 2023. This does not reflect the year as a whole, however, where the total constrained down volumes in 2024 reached 508 GWh, a 178% increase from 2023. At least 1 MWh of wind and solar generation was constrained down in 45% of hours in 2024, and specifically 47% of hours in Q4. The constrained and unconstrained SMP differed by $1/MWh or more in 26% of hours in Q4, a decrease year-over-year (35% in Q4 2023) but an increase quarter-over-quarter (19% in Q3 2024).

- **Low forward market liquidity continues:**

  Total trade volumes in 2024 were low at 31.2 TWh, a 25% reduction relative to 2023 and the lowest since 2020. Total trade volumes in Q4 were 8.9 TWh which is a slight increase relative to Q3 but is a 25% decline year-over-year. Annual forward prices increased in Q4 in response to a merger announcement and because of potential data centre developments.

- **Low default electricity and natural gas rates, low default switching:**

  The regulated electricity energy price (the Regulated Rate Option or RRO) continued to be low in Q4 while the regulated natural gas energy price (the Default Rate Tariff or DRT) increased, though remained lower than 2023 DRT energy prices. The RRO had the lowest net customers loss in Q3 2024 in the past three years.

- **Competitive electricity energy prices falling, risk-free expected costs increased slightly**:

  Fixed-rate electricity energy prices offered by competitive retailers fell over Q4, despite slight increases in the risk-free expected costs of offering fixed-rate contracts. Declines in fixed-rate electricity energy prices likely reflect falling electricity forward prices earlier in 2024, though energy prices remain above risk-free expected cost.

- **MSA compliance matters stable year to year:**

  From October 1 to December 31, 2024, the MSA closed 160 ISO rules compliance matters; 38 of which were addressed with notices of specified penalty. For the same period, the MSA closed 27 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; none of which were addressed with notices of specified penalty. In addition, the MSA closed no Alberta Reliability Standards Operations and Planning compliance matters.

1 THE POWER POOL

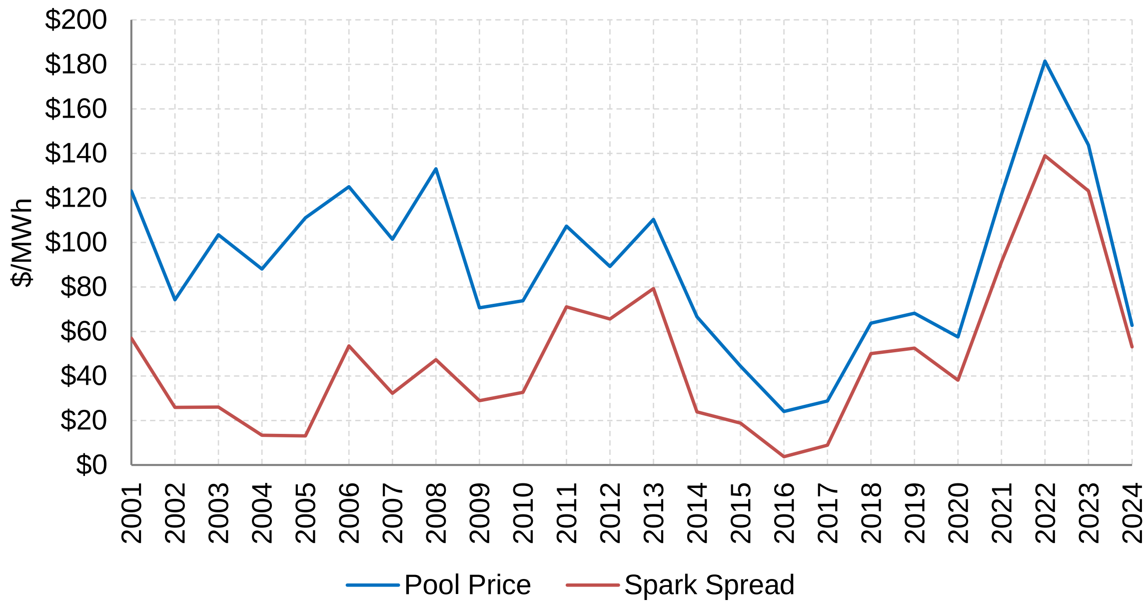
1.1 Annual summary

<u>Year-over-year pool prices lower</u>: Market fundamentals yield lower pool prices in 2024. Despite higher demand, pool prices were lower because of increased supply and decreased input costs.

The average pool price in 2024 was $62.78/MWh, a 53% decline compared to 2023 and the lowest average pool price since 2020. Despite higher demand in 2024, pool prices were lower because of increased competition in the market with new additions of thermal capacity and more wind and solar (intermittent) supply. In addition, natural gas prices were lower in 2024.

Figure 1 illustrates average pool prices and spark spreads by year since 2001. The spark spread illustrates the margin between pool prices and natural gas input costs. The spark spread in 2024 was $53.14/MWh, a 54% decline relative to 2023. In 2024, there was a small gap between the average pool price and spark spread indicating low natural gas prices.

Figure 1: Average pool price and spark spread by year (2001 to 2024)[1]



The price of natural gas hit a historic low in 2024 averaging $1.29/GJ, the lowest annual average going back to 2001 and reflective of a 49% decline year-over-year. Low natural gas prices across North America in 2024 were caused by robust supply and constraints on demand.[2] The lower price of natural gas put downward pressure on pool prices because natural gas is the main input

[1] The spark spread figures assume a heat rate of 7.5 GJ/MWh. The figures are inflation adjusted using the Alberta Consumer Price Index, annual average, not seasonally adjusted.

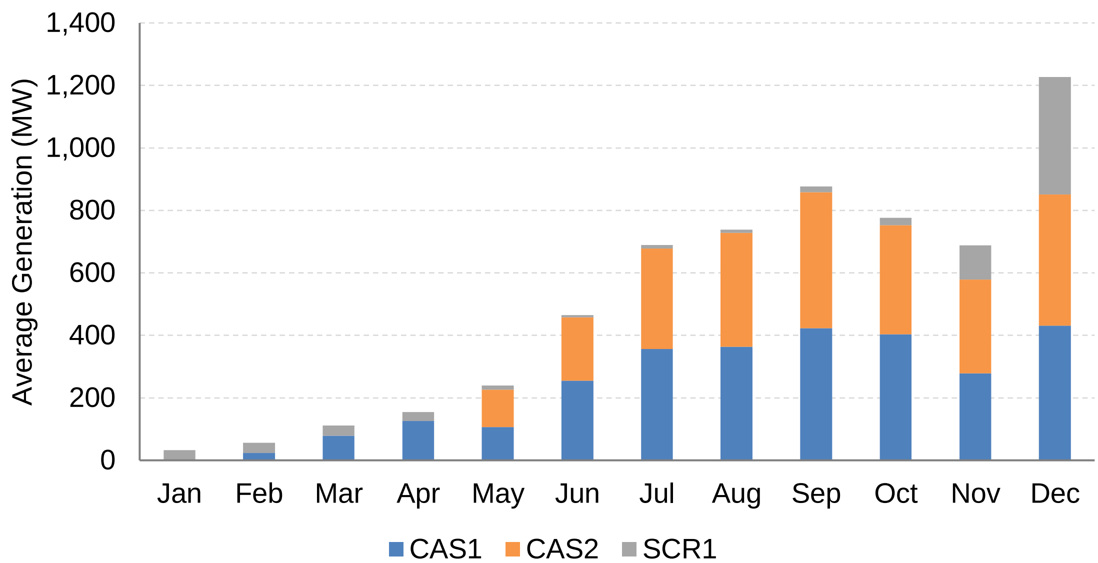
[2] EIA: Spot Henry Hub natural gas prices hit a historic low in 2024 – January 8, 2025

cost for the Alberta power market. In recent years, natural gas assets have set the System Marginal Price (SMP) most of the time. For example, in 2024 natural gas assets set the SMP 93% of the time.

The amount of available thermal capacity was higher in 2024 relative to 2023, largely due to the addition of Cascade 1 and 2, with a combined capacity of 900 MW. Further to this, in Q4 generation from Baseplant increased reflecting the addition of new generation units at the site. These new units are scheduled to take generation at Baseplant up to a capacity of 856 MW in Q1 2025. Figure 2 illustrates the monthly average supply of Cascade 1, Cascade 2, and Baseplant in 2024. The increased supply of these new assets put downward pressure on pool prices, particularly in Q3 and Q4.

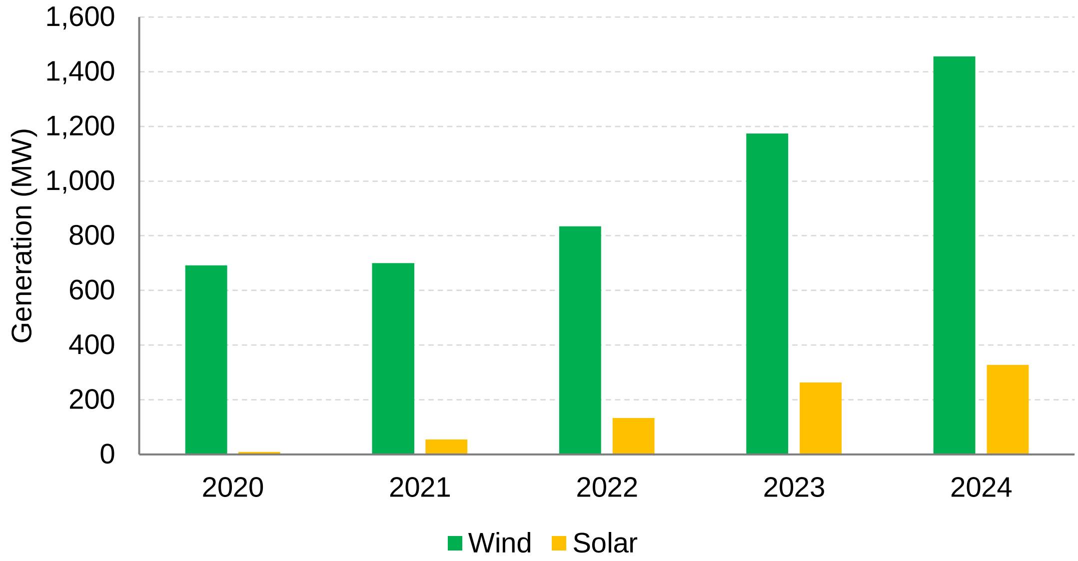
The capacity of wind and solar assets in Alberta continues to increase. In 2024, wind capacity operating in the market increased by 1,063 MW (24%) to 5,544 MW and solar capacity increased by 237 MW (15%) to 1,808 MW.[3] As capacity has increased the supply of intermittent generation has also gone up putting downward pressure on pool prices. In 2024 average wind generation increased by 24% to 1,456 MW, and average solar generation increased by 24% to 328 MW (Figure 3).

Figure 2: Monthly average generation from CAS1, CAS2, and SCR1 (January to December 2024)



[3] New wind and solar capacity is considered added when the asset generates 1 MW or more to the grid.

Figure 3: Average hourly wind and solar generation by year (2020 to 2024)



<u>The supply fleet changes account for significant price variation</u>: Completion of the coal phase out occurred in 2024 as coal has been replaced with new natural gas capacity and intermittent generation. The increase in natural gas capacity in 2024 was greater than the increase in new capacity of wind and solar assets, so overall the fleet became more flexible to address system variability.

2024 saw the end of coal generation in Alberta as the last 820 MW of coal capacity was repowered. On May 17, 2024, Genesee 2, the last remaining coal asset in the province, stopped using coal to produce electricity. The Genesee 1 and 2 coal assets have been repowered to combined cycle natural gas assets by adding a natural gas turbine to the existing steam turbine. This completes Alberta's transition away from coal to gas-fired and intermittent generation, a transition that has significantly lowered carbon emissions as illustrated in section 0.

The increase of wind and solar capacity in 2024 contributed to the increase in the variability on the system. Of significance is the increasing ramps up and down aligning to renewable penetration. The morning ramp up and the evening ramp down create increasing need for flexible assets to respond. This daily and monthly variability can be reflected in the net demand "duck" curve shown in Figure 6. With the increase in thermal assets in 2024 being greater than the increase in new capacity of wind and solar assets, the fleet overall became more flexible to address the system variability.

Natural gas assets continued to set SMP most of the time in 2024 with 93% (Figure 4). Hydro assets set the SMP 4% of the time in 2024 while wind and solar assets set the price 0.4% and 1% of the time, respectively. In 2024 wind and solar assets only set the SMP when prices were at the price floor of $0.00/MWh.

Figure 4: Price setter by fuel type and year (2015 to 2024)

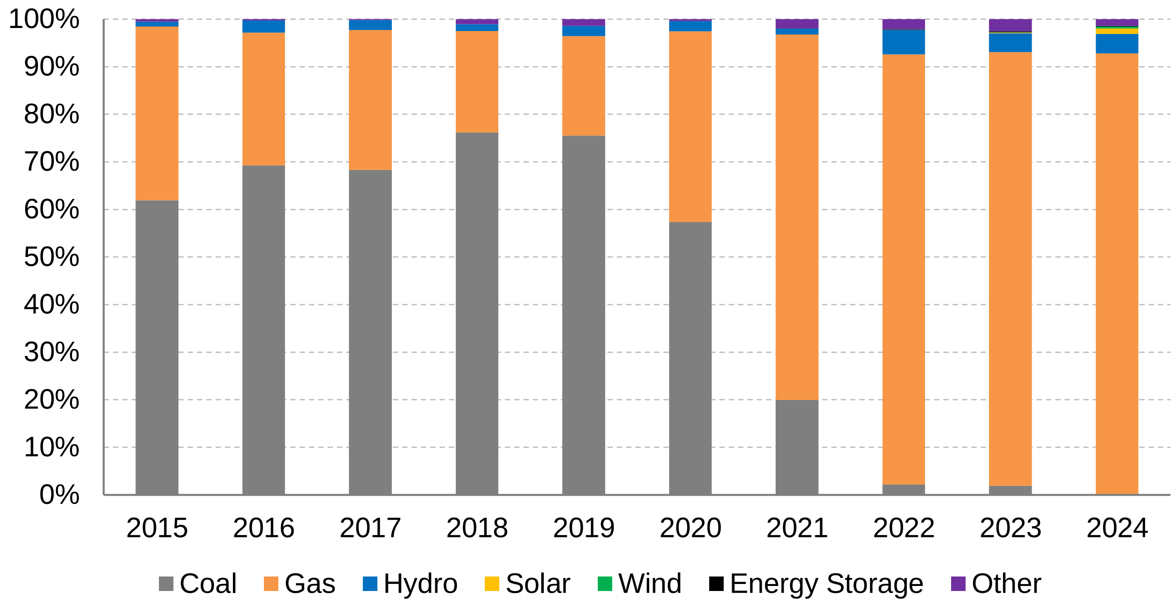
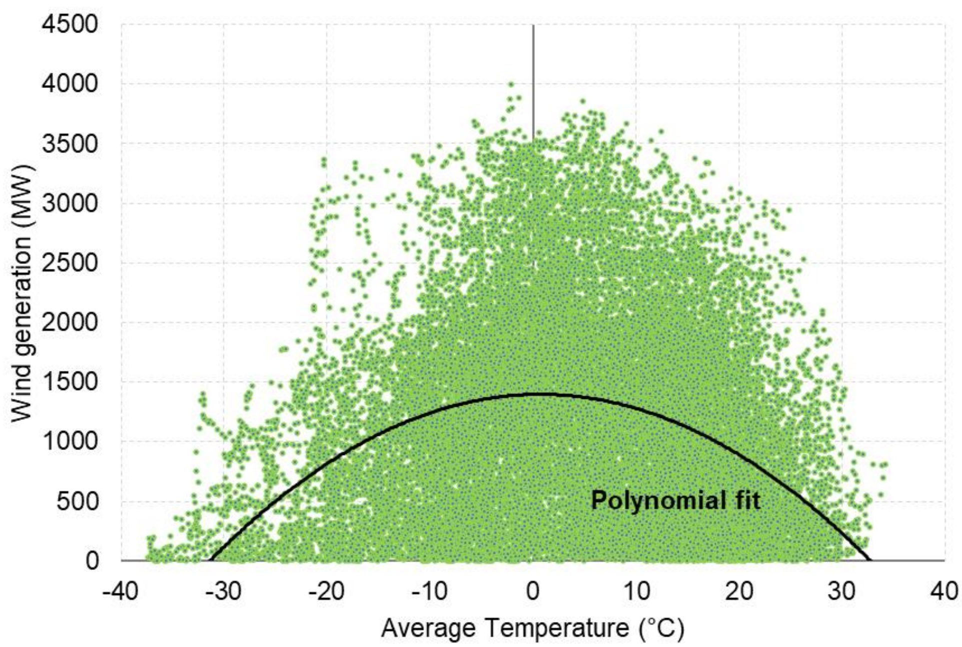


Figure 5 below shows a scatterplot of wind generation and temperature. Wind generation shows up in fairly predictable patterns associated with temperature and is often highest when temperatures are moderate and demand is low, therefore aligning with supply surplus hours particularly in the shoulder seasons. At more extreme temperatures and when demand is higher wind generation is typically low.

Figure 5: Scatterplot of hourly wind generation and average temperature (January 1, 2022 to December 31, 2024)



Along with the increase of intermittent generation has come higher variability in supply, impacting the System Controllers' dispatch. As shown by Table 1, the supply of intermittent generation ranged from 0 MW to 4,506 MW in 2024, and the standard deviation of intermittent supply increased to 977 MW. Since 2020, the standard deviation of intermittent generation has increased by 115% as more intermittent capacity has been added.

Table 1: Hourly minimum, maximum, and standard deviation of intermittent generation by year

Year	Min (MW)	Max (MW)	Standard Deviation (MW)
2020	0	1,704	454
2021	0	2,119	504
2022	0	2,559	568
2023	13	4,122	813
2024	0	4,506	977

The two main measures of market demand, Alberta Internal Load (AIL) and system load, both increased and had a record year in 2024. AIL is a measure of total demand including generation that is produced and consumed on the same industrial site (behind the fence generation) while system load is a measure of demand on the grid and excludes behind the fence generation.

In 2024 average AIL was 10,112 MW which is 229 MW higher than the previous high set in 2022. Similarly, average system load was 7,446 MW which is 169 MW higher than the prior record set in 2022. The higher demand in 2024 was driven by high demand during the extreme temperatures observed in mid-January and mid-July, and by population growth. System load was 74% of AIL on average in 2024, which is consistent with historic values.

The AESO system controllers dispatch the market based on net demand. Net demand is equal to system load less intermittent generation supply. This shows the amount of thermal generation that is required to meet demand net of supply from intermittent generation.

The increase in intermittent generation has more than offset rising demand in recent years to result in a reduction in average net demand. Figure 6 shows average net demand by hour ending and year. Average net demand in hour ending 14 fell from 7,356 MW in 2018 to 5,664 MW in 2024, a decline of 23%. From 2023 to 2024 there was a fall in net demand during daytime hours which reflects more solar generation.

Figure 6: Average net demand by hour ending and year (2018 to 2024)

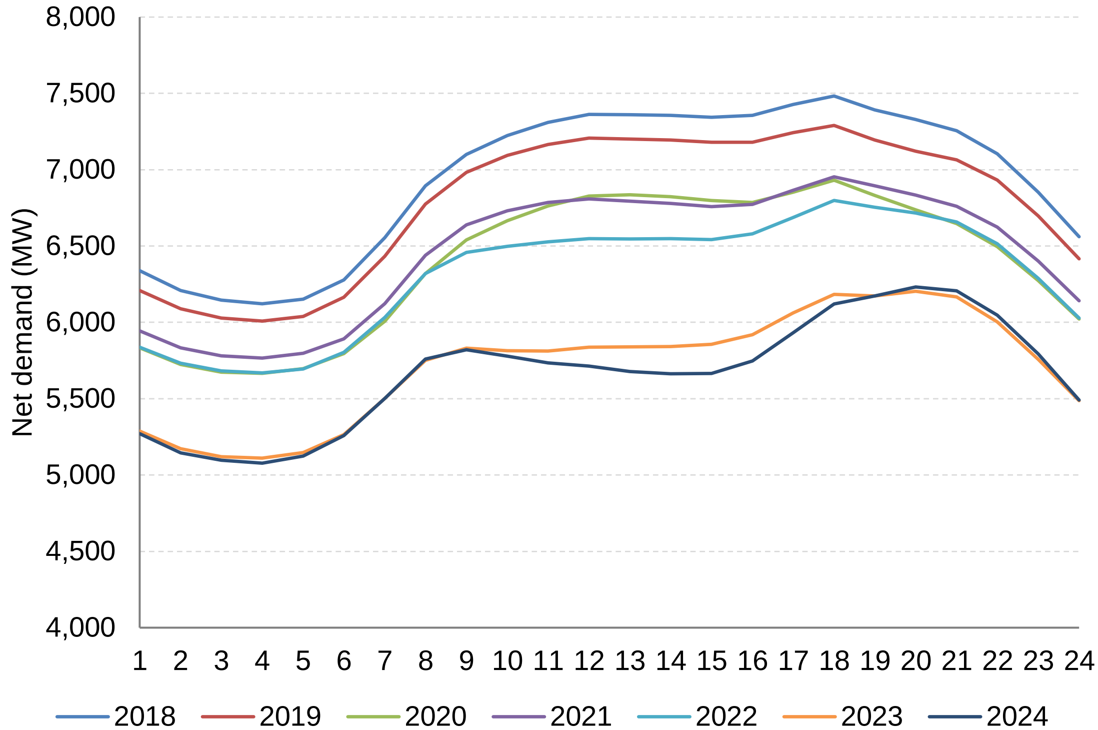


Table 2: Net demand figures by year (2018 to 2024)

	Average of absolute hourly change (MW)	Maximum hourly change (MW)	Standard deviation (MW)
2018	142	748	730
2019	135	718	744
2020	139	814	811
2021	137	790	834
2022	140	741	805
2023	162	1,258	927
2024	184	1,170	1,155

In 2024 the average hourly change in net demand increased from 162 MW to 184 MW in absolute terms (Table 2). This increase was driven by more intermittent capacity which has increased the volatility of intermittent supply. Similarly, the standard deviation of net demand increased by 25% in 2024 from 927 MW to 1,155 MW. This increase in standard deviation illustrates more variation in the demand to be served by thermal generation assets.

The maximum change in net demand from one hour to the next in 2024 was 1,170 MW and occurred on October 2 between 05:00 and 06:00. The material change in net demand in this instance was driven by a reduction in wind generation (-855 MW) and an increase in demand (315 MW).

While the increase in intermittent supply is expected to lower pool prices it can increase price volatility in the energy market. In addition, more system regulation reserves are required to manage increasing net demand variation especially in response to solar volumes.

<u>Price levels in Q3 and Q4 2024 were lowered by the *Market Power Mitigation Regulation* and *Supply Cushion Regulation*</u>: The combination of unit commitment through system supply cushion directives to ensure assets were online with offer price mitigation following revenue thresholds impacted prices.

Concerns related to excessive and persistent market power in 2023 led to the creation of new regulations. These regulations were designed to provide guardrails to excessive economic withholding and associated concerns related to the cycling and physical withholding of long-lead time energy assets while the development of the Restructured Energy Market was finalized. The ISO rules associated with the new regulations were in place effective July 1, 2024.

Prices in Q3 and Q4 were lowered by the implementation of the *Supply Cushion Regulation* (SCR) and *Market Power Mitigation Regulation* (MPMR). The SCR has enabled the AESO to direct online generation assets that are on long-lead time when the forecasted supply cushion is under 932 MW. SCR directives were used 23 times through the final two quarters of 2024. This has increased the supply of thermal generation during certain periods and lowered pool prices. In Q3 the MSA estimates that the SCR directives lowered the quarterly average pool price by $3.63/MWh or 6%[4], and in Q4 the MSA estimates that average pool prices were lowered by $6.63/MWh or 11% (see section 1.4).

The MPMR is used when the net revenues of a hypothetical combined cycle natural gas asset reach 1/6 of its annualized avoidable costs within a calendar month. Under these circumstances, the MPMR restricts the offer prices from the thermal generation assets of large market participants to less than $125/MWh or 25 times the day-ahead natural gas price, whichever is largest. Following implementation on July 1, the MPMR was used after the net revenue threshold was met in HE 21 of July 22. The MSA estimates that the monthly average pool price for July was lowered by $8.13/MWh or 8% as a result.[5] The net revenue threshold was not breached again in 2024.

<u>The change in the generation fleet led to record operations in both supply shortfall and supply surplus conditions in 2024:</u> The system operated in energy emergency alert conditions for 25.4 hours in 2024, the most since 2013, and on April 5, 2024, the AESO shed load for first time since 2013. System operations were also tested by a record amount of supply surplus conditions. The hours in each of these operational conditions for 2024 were substantially higher than in 2023.

Despite the lower average, prices remained volatile in 2024. In total over 2024 there were 39.5 hours in the year when the SMP was set at or above the offer price cap of $999.99/MWh, the

[4] MSA Quarterly Report for Q3 2024 section 1.3.2.

[5] MSA Quarterly Report for Q3 2024 at section 1.3.1.

second highest on record after 2013, which had 45 hours. In addition, 2024 set a record for the amount of time the SMP cleared at the price floor of $0.00/MWh. In 2024, the SMP cleared at the price floor for 532 hours (22 days) with the previous record set at 83 hours (3.5 days) in 2023 (Figure 7).

Figure 7: Time SMP was at the price floor or cap by year (2001 to 2024)

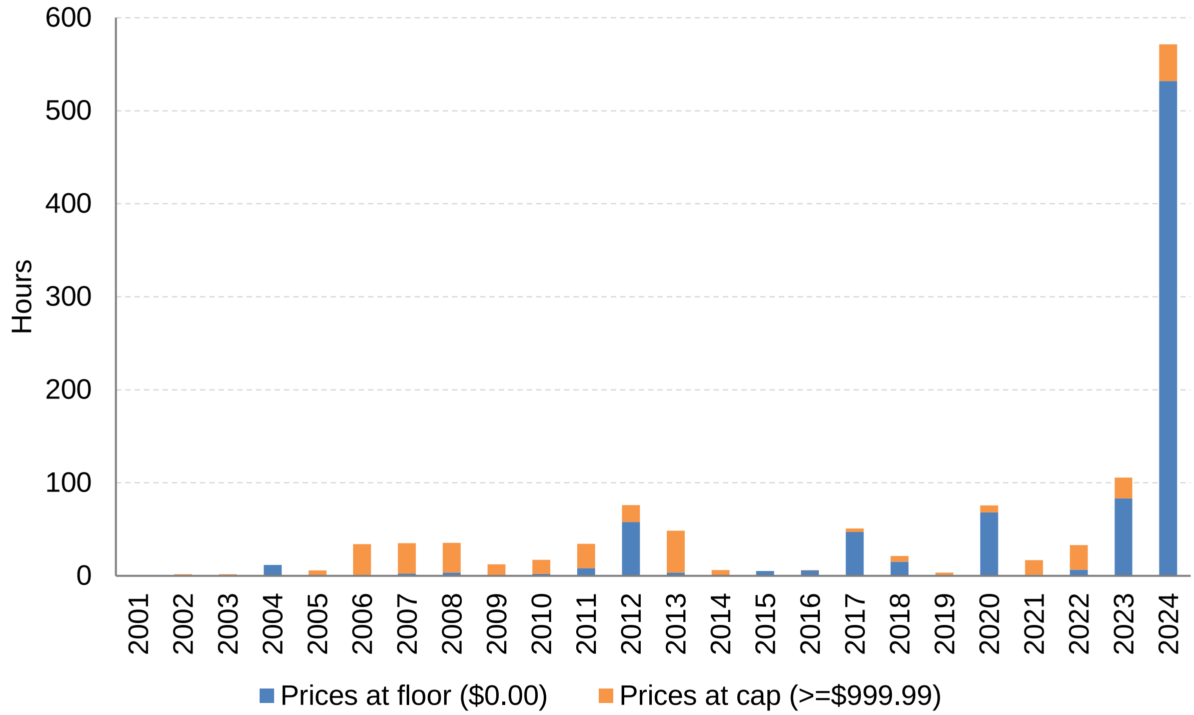
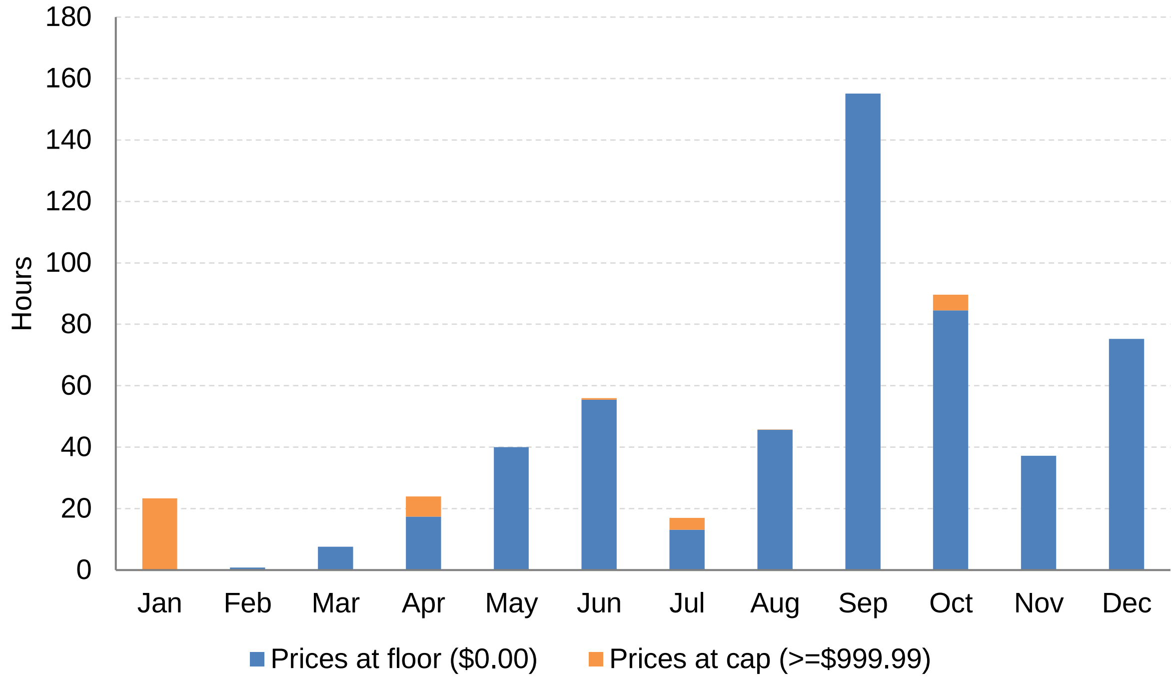


Figure 8 illustrates the amount of time the SMP cleared at the price floor or price cap by month in 2024. September saw the highest amount of time where prices cleared at the floor with 155 hours at $0.00/MWh. The high number of zero-dollar hours in September was driven by mild weather conditions, high wind generation, and the amount of thermal generation offered into the market at $0.00/MWh.

January saw the SMP clear at the offer price cap for 23.5 hours, the highest in the year. The events in January were driven by cold weather in the middle of the month which increased demand and reduced wind generation. In addition, the new generation projects at Cascade were not meaningfully operating at this point.

Figure 8: Time SMP was at the price floor or cap by month in 2024



There were eight separate EEA events spanning 25.4 hours in 2024. This is the highest number of EEA hours since 2013 which had 27.9 hours (Figure 9). Four of the eight EEA events in 2024 occurred during the period of cold weather in mid-January. On the evening of Saturday, January 13 a text alert was disseminated asking Albertans to reduce electricity consumption and advising of possible rolling blackouts.[6] As discussed in the MSA's report on this event, this text alert likely prevented rolling blackouts.

In the EEA event on the morning of Friday, April 5 the AESO shed firm load for the first time since 2013, and for the fourth time since January 2001 (Table 3). The event on April 5 was caused by a high number of thermal generator outages, including planned and forced outages, in combination with low intermittent generation.

Table 3: AESO firm load shed events (since January 1, 2001)

Start Time	**End Time**	**Duration (mins)**	**SMP**
Jul 24, 2006 16:45	Jul 24, 2006 17:05	20	$1,000
Jul 09, 2012 14:10	Jul 09, 2012 17:10	180	$1,000
Jul 02, 2013 16:24	Jul 02, 2013 17:29	65	$1,000
Apr 05, 2024 08:53	Apr 05, 2024 09:19	26	$1,000

[6] This event was discussed in the MSA's report 'Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations' – August 6, 2024

Figure 9: EEA hours by year (2010 to 2024)

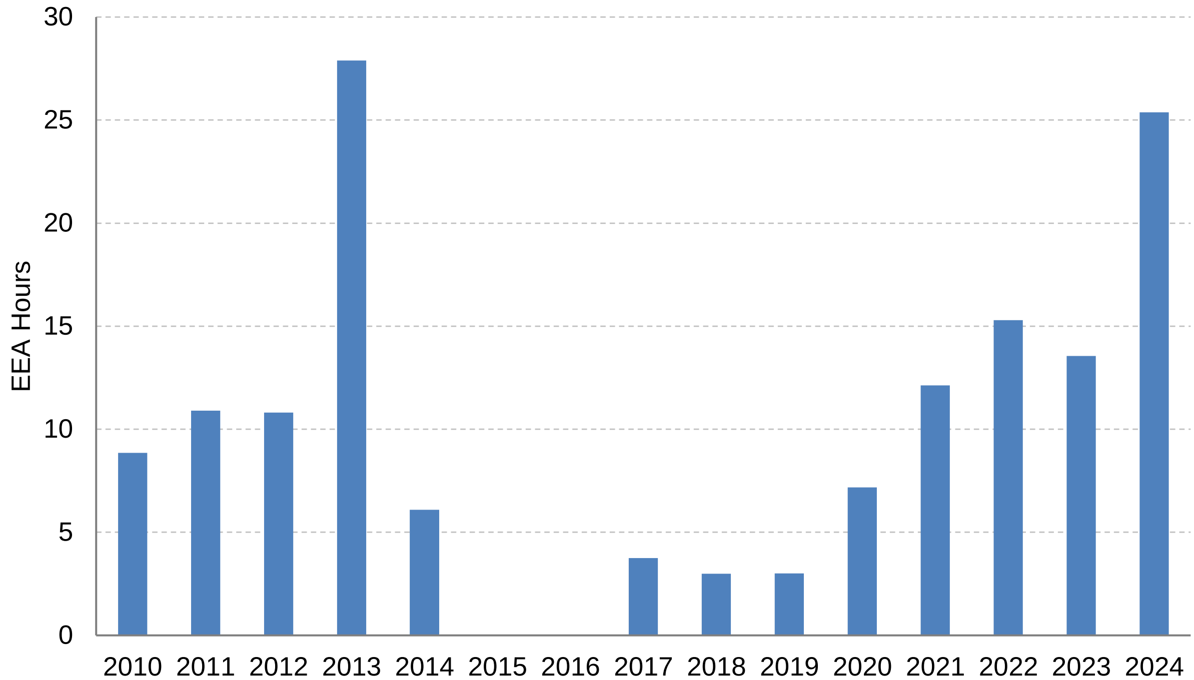


Figure 10 illustrates generation by fuel type on average in 2024 as well as during the EEA events in the year. On average in 2024, natural gas supplied 78% of generation, wind supplied 14%, and solar supplied 3%. However, natural gas generators made up a higher proportion of the supply during the EEA events as intermittent generation was usually low during these events. For example, during the most recent EEA event on October 22, natural gas supplied 89% of generation, wind supplied 2%, and solar supplied 0% with the remainder supplied by hydro (4%), imports (4%), and other (2%).

Figure 11 shows the highest amount of contingency reserves that were directed by the AESO during the EEA events in 2024. The AESO used all their contingency reserves during the EEA events on January 13, 14, and April 5, and on January 12 the AESO had directed almost all their available reserves. During the EEA events on January 15, July 8, and October 22 the AESO used a smaller fraction of the contingency reserves they had available.

Figure 10: Generation by fuel type during the EEA events in 2024

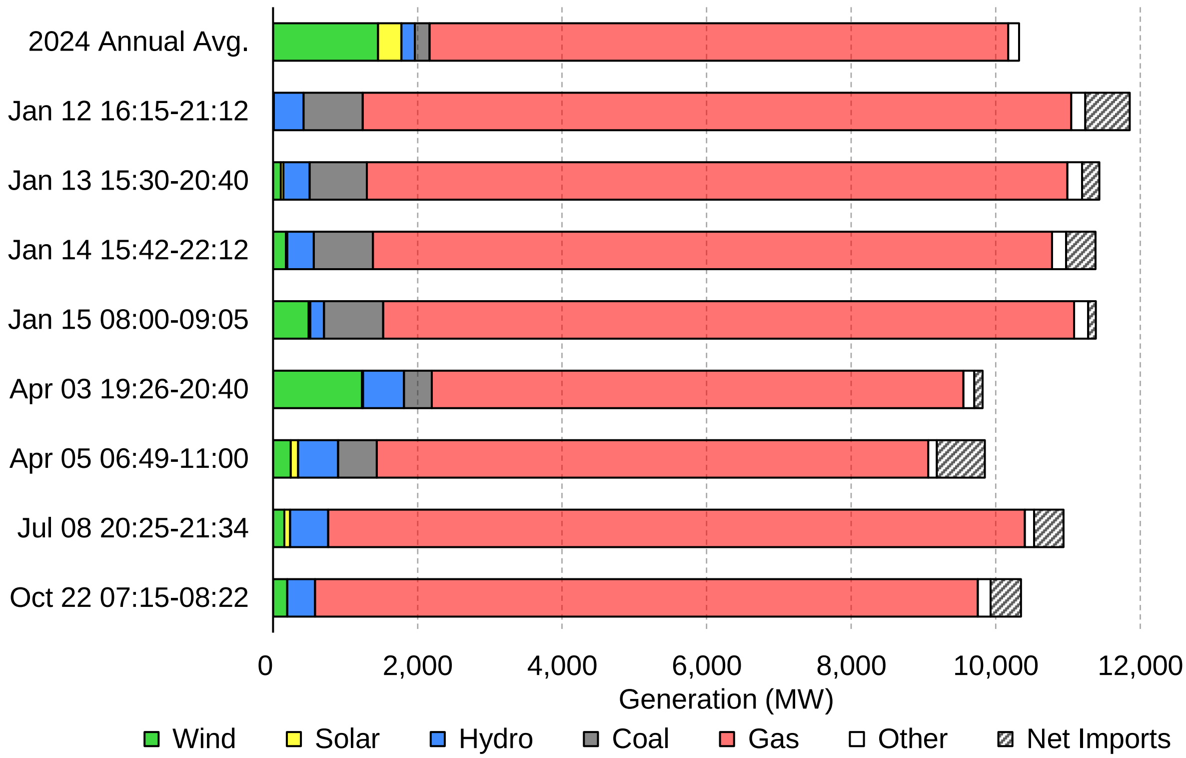
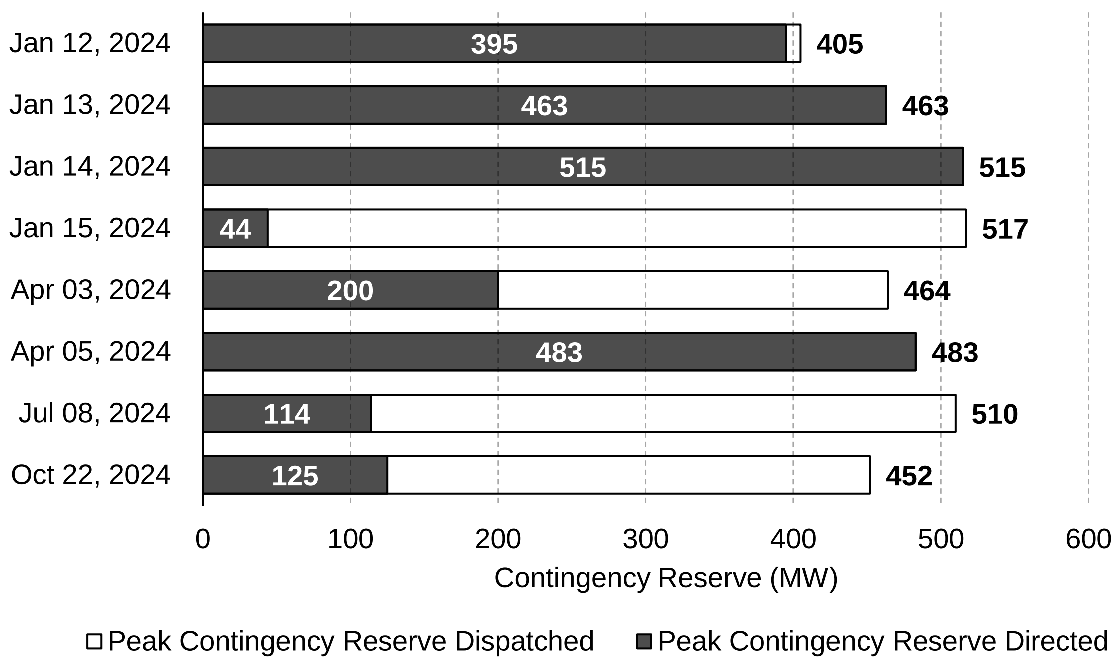


Figure 11: Available and directed contingency reserves during EEA events in 2024



<u>Market concentration increased with a major acquisition</u>: In Q4 a large merger was completed in which the largest generator in Alberta acquired a further 2,141 MW of offer control by buying one of its main competitors. The market share offer control of the company increased from 14.7% to 23.2% year-over-year despite an increase in the overall system capacity in Alberta.

Following a review by the Competition Bureau, the sale was approved on November 14 and was completed on December 4. As part of the Competition Bureau's approval the Poplar Hill (capacity of 48 MW), Rainbow 5 (50 MW), and Rainbow Lake 1 (47 MW) assets are to be sold separately.

The result of this acquisition is an increase in market concentration, especially in the long lead time gas-fired steam fleet. This acquisition has increased the ability of the company to exercise market power and will raise the number of hours the firm is pivotal, all else equal.

<u>Expanded reliance on frequency products to support system variability and islanding risks in 2024</u>: The average amount of dispatched regulating reserves increased by 44 MW or 30% year-over-year and the volume of armed Fast Frequency Response increased year-over-year mainly due to managing islanded operations.

The year-over-year data depicts the reliance of system operations on support services to address frequency related challenges. Frequency products have historically been used to support intertie transmission capacity levels and islanding. With AB-BC intertie import ATC in a range between 400-650 MW, the significant Fast Frequency Response (FFR) volume armed can be ascribed to islanding during the intertie outage in the fall 2024.

However, the system has also added frequency support to address challenges related to the change in the fleet. The physical characteristics of the system change when the supply mix moves from a majority of firm, baseload assets to more renewable energy in that there is a reduction in physical inertia and primary frequency response on the system. To address these immediate challenges, additional frequency products are added – through FFR and also an increase in regulating reserves.

While it is difficult to split the use of regulation products for the intertie compared with overall fleet characteristics, there are some trends to depict the contribution of system risk to the additional use of frequency support services. Figure 12 shows the increase in FFR volumes in 2024, which were largely driven by the need to support the Alberta electrical grid during a prolonged period of islanded operations in late September 2024.

Figure 12: FFR costs vs. armed volumes (January 2023 to December 2024)

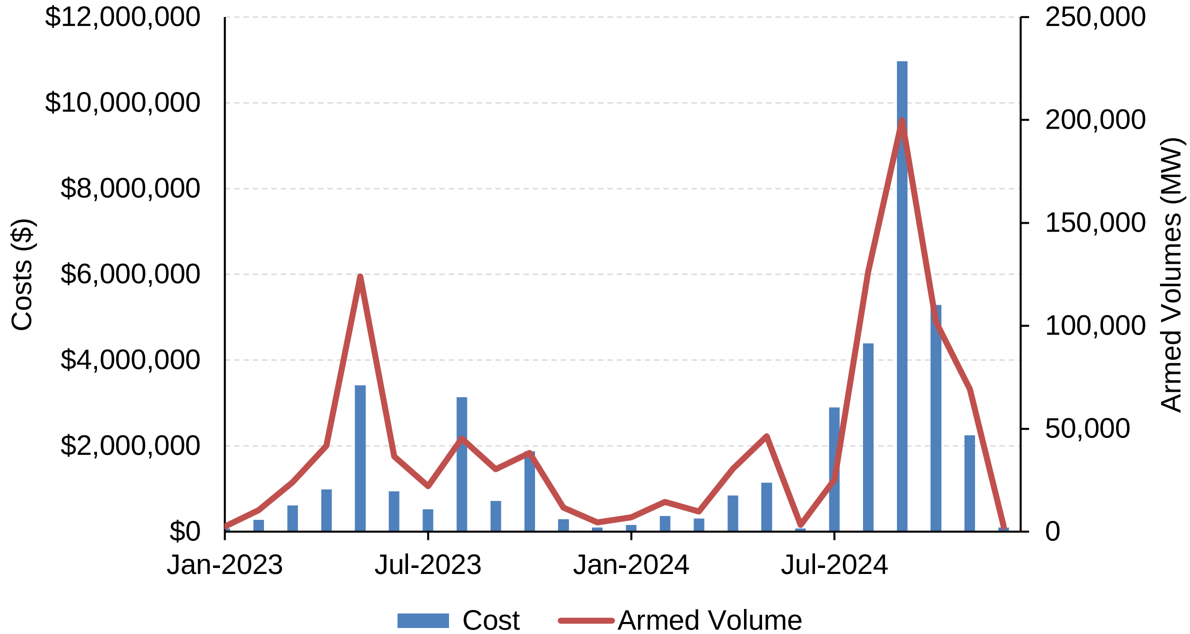
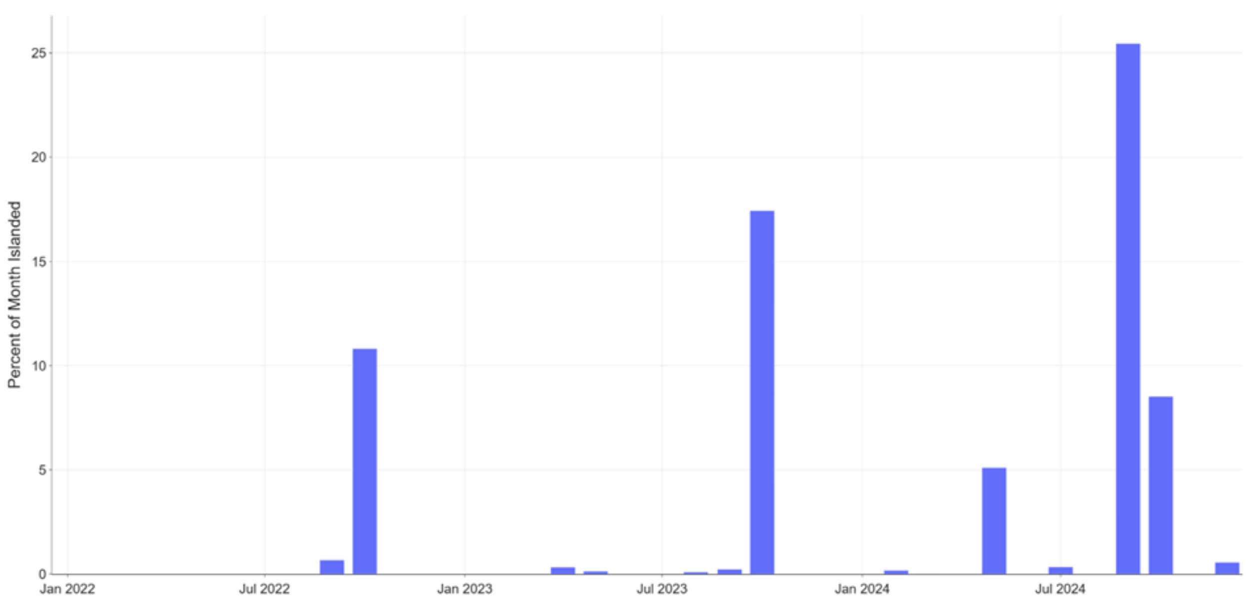


Figure 13 shows the percentage of time in which the Alberta Interconnected Electric System (AIES) was islanded from the rest of the Western Electricity Coordinating Council (WECC) by month. In September 2024 the AIES was islanded from WECC for over 25% of the month, establishing a new 3-year maximum. Extended outages on BC/MATL warrant attention as Alberta leans heavily on these interties for frequency support.

Figure 13: Percentage of time Alberta is islanded from WECC by month (January 2022 to December 2024)



Frequency related deviations are also increasing even when the system is interconnected, partly because of the stability risk with the increasing and often seasonal intermittent generation. Figure 14 below shows the number of minutes by month when system frequency exceeded its frequency threshold boundaries; either above its upper limit or below it's lower limit. Additional regulation is carried to manage system operations during this increasingly demonstrable seasonal pattern.

As shown in the Operating Reserve Markets section, the system required a change in Ancillary Service (AS) capacity from 2023 to provide additional system support especially in light of increasing solar capacity. While the volume armed varied with anticipated system conditions, overall an additional 44 MW or 30% of regulation capacity was added year-over-year to manage the growth and diversity of the solar capacity on the grid. Figure 15 highlights average hourly solar generation and regulating reserve set point by year, illustrating a positively correlated trend.

Figure 14: Minutes AIES is operating outside frequency bounds while interconnected and islanded (January 2022 to December 2024)

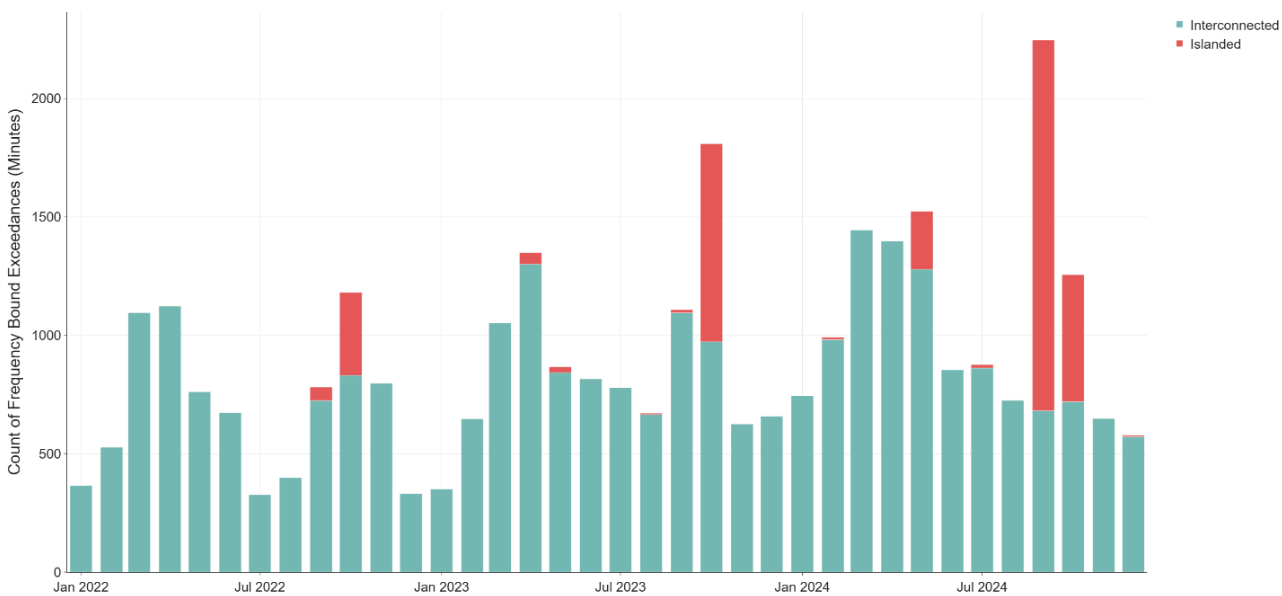
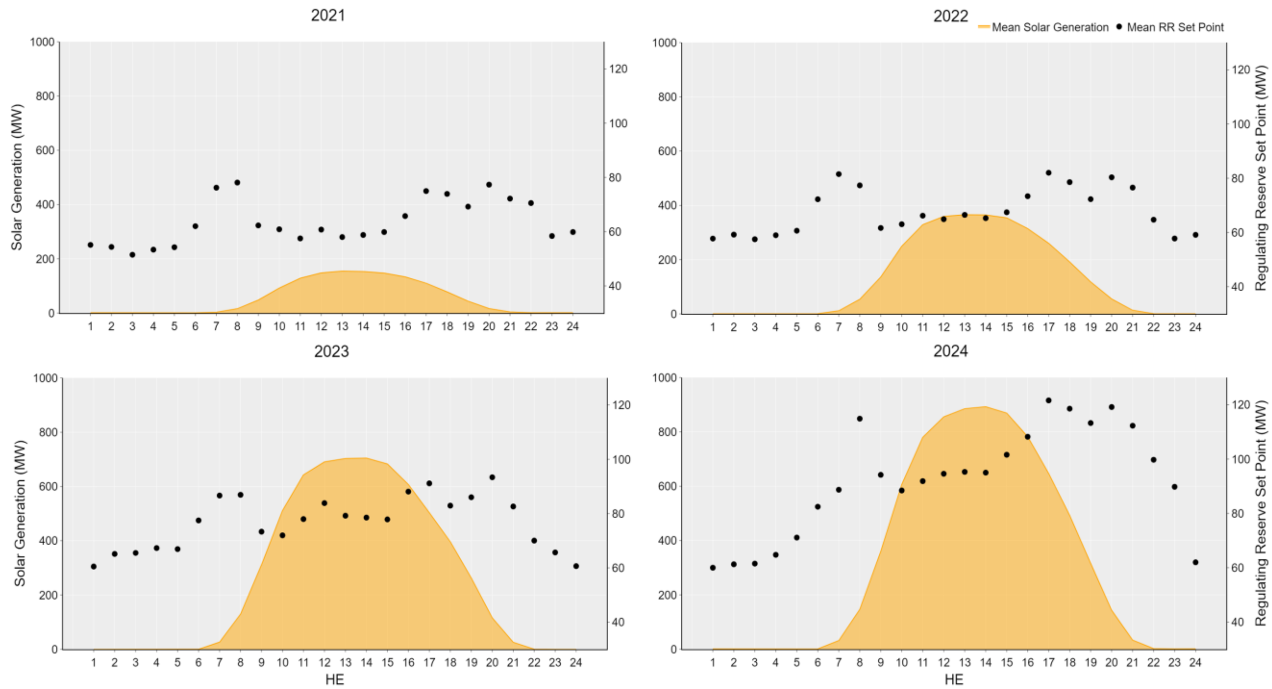
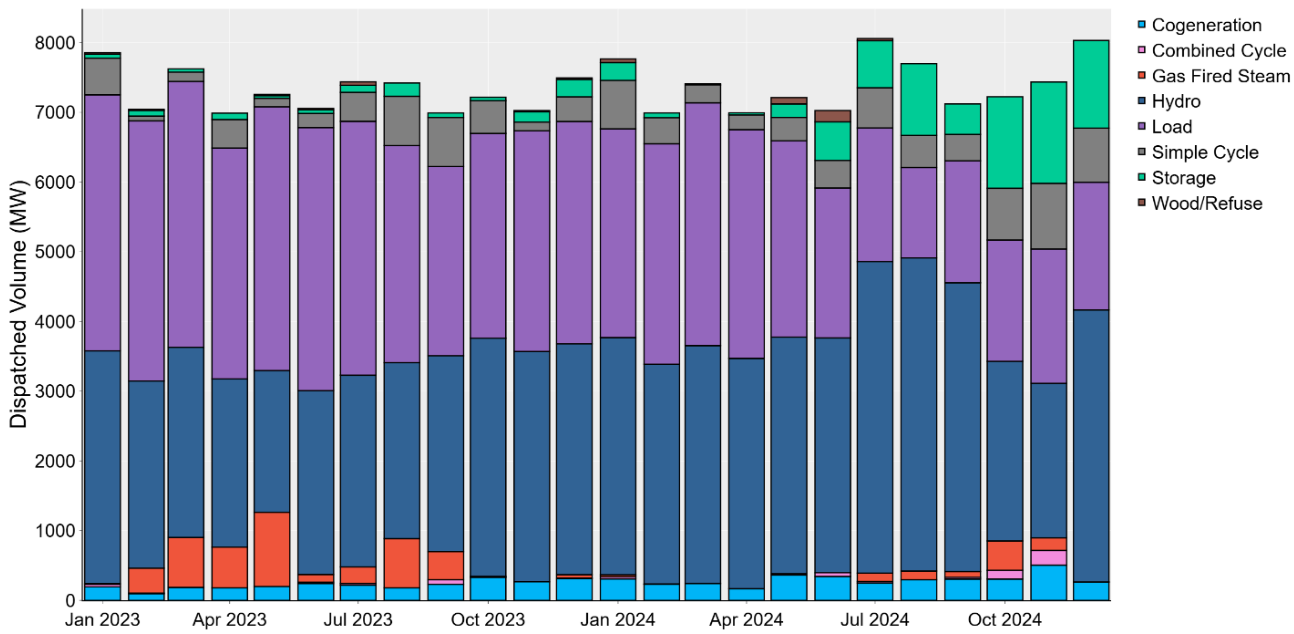


Figure 15: Average hourly solar generation and regulating reserve set point by year



Of further interest is the increasing trend in Energy Storage (ES) capacity in the operating reserves markets. While ES was tested as part of a 2022 pilot for FFR services, specifically targeted for intertie islanding, year-over-year data confirms that the ES assets are increasingly active in the supplemental operating reserves market. In Q4, as shown in Figure 16, energy storage capacity serving the supplemental on-peak market reached almost 20% of the dispatched volume.

Figure 16: Monthly dispatched volume by fuel type for on-peak supplemental reserve (January 2023 to December 2024)

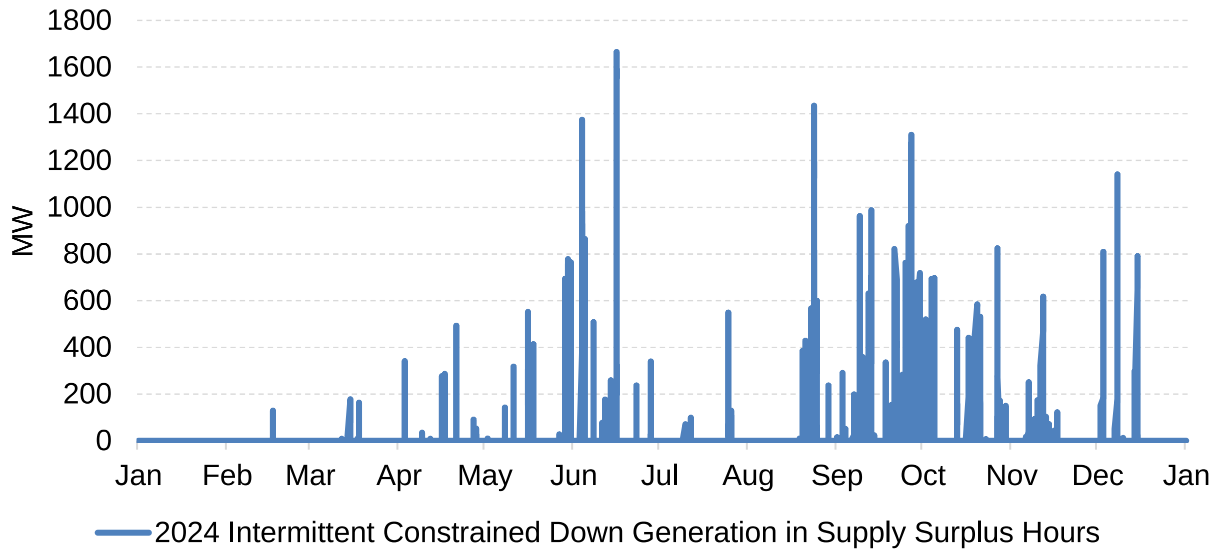


<u>Intermittent generation was increasingly curtailed in 2024, aligning with the trend in increased supply surplus hours</u>: In 2024, 40% of curtailed intermittent generation occurred during supply surplus events compared to 6% in 2023. This trend reflects the increase in supply surplus events as well as the increase in intermittent capacity.

The total constrained intermittent volume for 2024 reached 508 GWh, a 178% increase from 287 GWh in 2023. Of particular note is the growth in constrained volumes associated with supply surplus events. While congestion occurs due to transmission elements being out of service, approximately 40% of congestion from wind resources was associated with high wind leading to excess supply on the system. In times of supply surplus, all energy is prorated and this impacts wind resources as well. As shown in Figure 17, curtailment during supply surplus reached 1,600 MW of intermittent resources.

Transmission capability varies throughout the province, and certain regions experience more congestion than others, often leading to local constraints.

Figure 17: Constrained intermittent generation in supply surplus hours (2024)



<u>Interties support the flow of excess generation and support large economies of scale in AB</u>: Alberta has increasingly become a net exporter of energy in 2024.

Alberta was a net exporter of electricity in 2024, mainly driven by export volumes to BC. In 2024, the net flow of power over the BC intertie averaged 253 MW of exports reflecting a large part of the 211 MW net total export volume (Table 4). The monthly volume of exports to BC varied substantially during the year from 66 MW to 403 MW reflecting pricing opportunities. Alberta prices have been more variable than prices in Mid-Columbia and were often lower.

The trend on the interties is driven by new thermal supply, high intermittent generation, and opportunities in other markets. New generation build in Alberta provides enhanced security to Alberta but needs to rely on access to other markets to improve their economics when opportunities present themselves and especially when Alberta is flush with energy.

Table 4: Average net import (+ve) and export (-ve) volumes for 2023 and 2024

	2023				2024			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
January	-362	-31	137	-256	-372	-10	18	-364
February	-192	63	145	16	-403	84	44	-275
March	-41	115	148	221	-367	103	39	-226
April	-247	103	104	-39	-238	113	74	-51
May	280	122	73	475	-66	55	1	-10
June	82	113	19	215	-192	38	23	-132
July	-34	83	45	95	-167	-39	22	-185
August	7	71	30	108	-362	-64	9	-418
September	-2	97	51	146	-215	-36	19	-233
October	-241	63	32	-145	-177	14	5	-158
November	-340	78	4	-258	-114	55	0	-59
December	-602	27	13	-561	-367	-50	0	-417
Year	**-141**	**75**	**66**	**1**	**-253**	**21**	**21**	**-211**

1.2 Quarterly summary

The average pool price in Q4 2024 was $51.52/MWh, which is a 37% decrease relative to Q4 2023. The lower pool prices in Q4 2024 were the result of more available thermal capacity and lower natural gas prices. These factors offset higher demand, which increased by 3% year-over-year.

Natural gas prices continued to remain low in Q4 averaging $1.42/GJ, a 35% decline compared to Q4 last year.

Available thermal capacity increased by 590 MW on average compared to Q4 2023 as the additions of Cascade 1 and 2 and Baseplant offset more thermal outages in Q4 this year.

In October there were several planned and forced outages at large thermal assets. On the morning of October 22, the AESO declared an EEA3 indicating that there was not enough supply to reliably meet demand. This event was the result of thermal generator outages combined with low intermittent generation.

The average pool price in November was $71.20/MWh, the highest in the quarter. Cold weather for the last eleven days of the month increased demand and lowered wind generation, putting upward pressure on prices. Pool prices for the first nineteen days of November averaged $37/MWh and prices for the last eleven days averaged $131/MWh.

Table 5: Summary market statistics for Q4 2023 and Q4 2024

		2023	2024	Change
Pool price (Avg $/MWh)	October	$99.34	$57.62	-42%
	November	$93.82	$71.20	-24%
	December	$52.05	$26.35	-49%
	Q4	**$81.61**	**$51.52**	**-37%**
Demand (AIL) (Avg MW)	October	9,560	9,861	3%
	November	10,262	10,525	3%
	December	10,518	10,864	3%
	Q4	**10,111**	**10,416**	**3%**
Gas price AB-NIT (2A) (Avg $/GJ)	October	$2.30	$1.13	-51%
	November	$2.48	$1.36	-45%
	December	$1.80	$1.76	-2%
	Q4	**$2.19**	**$1.42**	**-35%**
Wind gen. (Avg MW)	October	1,263	1,783	41%
	November	1,750	1,469	-16%
	December	2,172	1,879	-13%
	Q4	**1,728**	**1,713**	**-1%**
Solar gen. (Avg MW during peak hours)	October	409	254	-38%
	November	153	203	33%
	December	143	155	8%
	Q4	**236**	**204**	**-14%**
Net imports (+) Net exports (-) (Avg MW)	October	-145	-159	10%
	November	-258	-60	-77%
	December	-561	-418	-26%
	Q4	**-322**	**-214**	**-34%**
Available thermal capacity (Avg MW)	October	9,122	9,016	-1%
	November	9,607	10,183	6%
	December	9,964	11,265	13%
	Q4	**9,564**	**10,154**	**6%**

The average pool price in December was the lowest in the quarter at $26.35/MWh, a 49% decrease year-over-year and the lowest price for December since 2017. Prices in December were lowered by mild weather conditions and high thermal availability, including higher availability at Baseplant. Thermal availability in December increased to average 11,265 MW which is 1,300 MW higher than in December 2023 and is the highest value on record (the previous high was 10,748 MW set in January 2016).

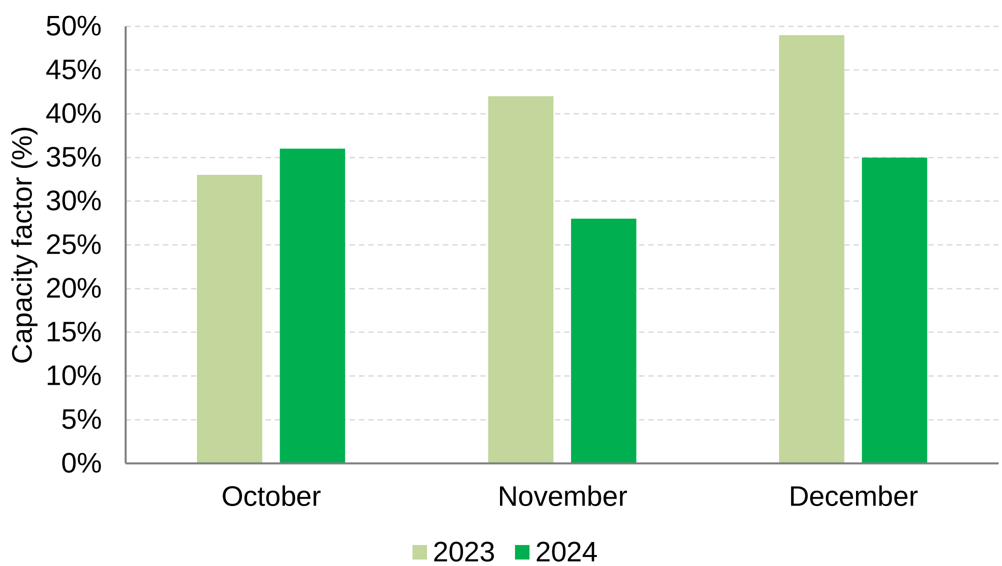
Average demand increased by 3% across all three months in Q4. In October the demand increase occurred despite similar temperatures year-over-year (Table 6). The year-over-year demand growth in October was largely driven by higher oil production and less wildfires relative to October 2023.

Table 6: Monthly average temperatures in Q4 (°C) (2023 and 2024)

	2023	**2024**
October	5.1	5.5
November	-0.5	-5.2
December	-2.4	-7.2

Installed wind capacity in Alberta continues to increase. At the end of 2024 the total capacity of operating wind farms was 5,544 MW, an increase of 1,063 MW compared to the end of 2023.[7] This represents an annual growth rate of 24%. However, despite higher wind capacity, wind generation levels fell year-over-year in November and December due to lower capacity factors (Figure 18).

Figure 18: Wind capacity factors by month in Q4 (2023 and 2024)

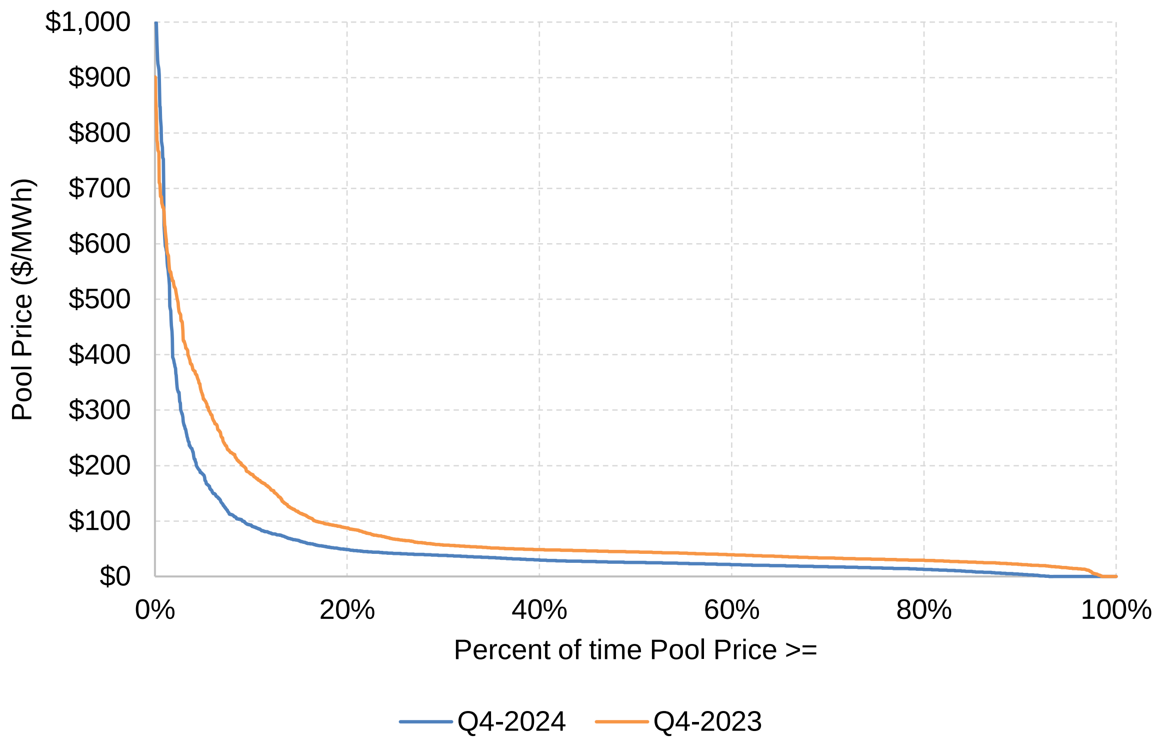


[7] A wind farm is deemed to be operating if it has supplied more than 1 MW to the grid.

1.3 Market outcomes and events

Figure 19 illustrates pool price duration curves for Q4 2024 and Q4 2023. As shown, prices in Q4 2024 were lower for much of the distribution. At lower price levels the reduced prices in Q4 2024 were largely a function of lower natural gas prices. At higher price levels the reduced prices in Q4 2024 were largely caused by less market power being exercised. As discussed in section 1.5, less market power was exercised in Q4 relative to Q4 2023 because more thermal capacity increased competition.

Figure 19: Pool price duration curves (Q4 2023 and Q4 2024)



Q4 saw more prices at the extreme ends of the distribution, i.e. at $0.00/MWh and $999.99/MWh, which partly reflects the increase in intermittent generation capacity. Despite the addition of new thermal generation capacity, the SMP cleared at the price cap of $999.99/MWh on four occasions in October for a total of 312 minutes, including one EEA event. These events are discussed in the following paragraphs.

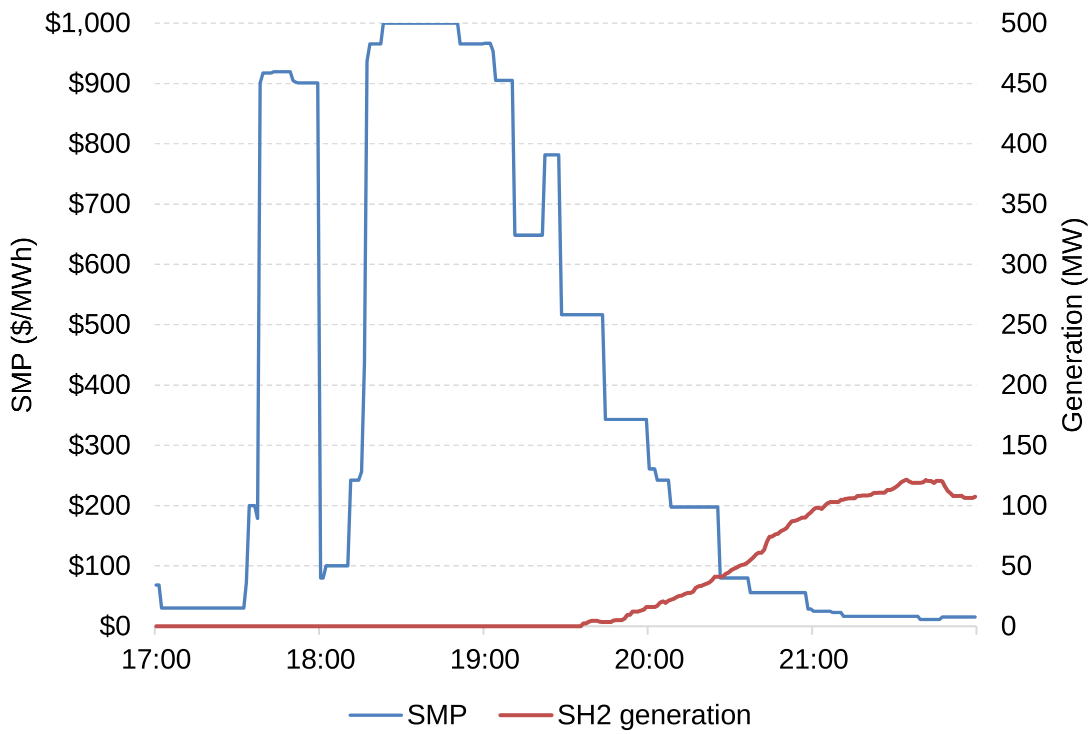
1.3.1 October 2: prices at the offer cap

On the evening of Wednesday, October 2 the SMP increased to the offer price cap of $999.99/MWh between 18:25 and 18:40. System load at the time was around 7,200 MW, which is not abnormally high. Instead, the higher prices in this event were driven by constraints on the supply side.

In particular, the BC/MATL intertie was offline on a planned outage so there was no access to imports from BC or Montana. In addition, there were thermal generation outages at Battle River 4 (outage capacity of 155 MW), Genesee Repower 1 (416 MW), HR Milner (230 MW), Northern Prairie Power Project (105 MW), Nabiye (120 MW), Nexen Inc. 2 (130 MW), and Sheerness 1 (400 MW) was in the process of returning online.

Battle River 5 and Sheerness 2 were commercially offline on long-lead time (LLT) for this event. At 17:53 on October 1 Sheerness 2 had received a unit commitment directive to come online beginning on October 2 at 18:00. However, Sheerness 2 was late coming online, and the asset did not provide any power to the grid until 19:36 (Figure 20).

Figure 20: SMP and SH2 generation on October 2, 2024



Intermittent generation levels were relatively low during this event with wind generation averaging 700 MW, a capacity factor of 13%, and solar generation averaging 100 MW, a capacity factor of 6%. The event ended as wind generation rose and supply from Sheerness 1 increased as the asset returned from outage.

1.3.2 October 15: prices at the offer cap

On October 15 the SMP increased to the offer price cap for a total of 2 hours and 12 minutes, spread over five different increments of time (Table 7). This event was largely caused by thermal outages and low intermittent generation.

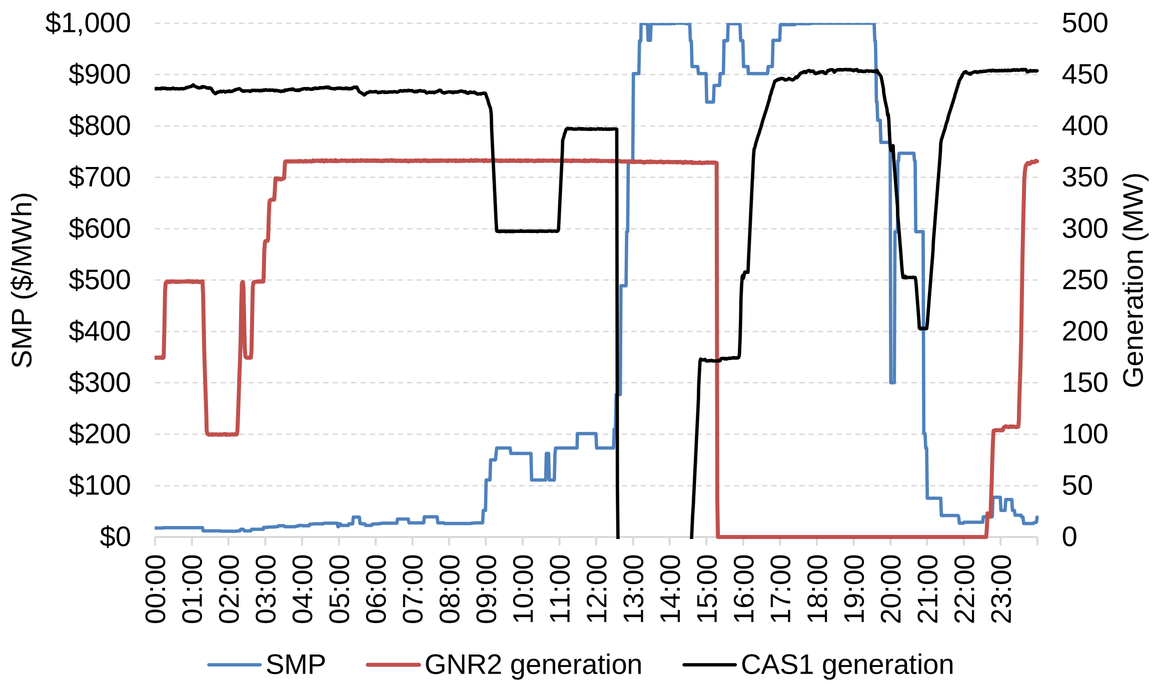
Table 7: Times at which the SMP was $999.99/MWh on October 15, 2024

Start time	End time	Duration
13:13	13:18	0:05
14:03	14:05	0:02
14:08	14:26	0:18
17:25	17:29	0:04
17:50	19:33	1:43

In terms of thermal outages there were planned outages at Calpine (330 MW), Genesee Repower 1 (466 MW), Sheerness 2 (400 MW), HR Milner (250 MW), Northern Prairie Power Project (105 MW), Nabiye (120 MW), and on a Joffre gas turbine (230 MW).

In addition, there were forced outages at Cascade 1 (450 MW) and Genesee Repower 2 (411 MW). As shown in Figure 21, Cascade 1 tripped offline around 12:30 before coming back online at around 14:30. Just after 15:00, as Cascade 1 was increasing supply, Genesee Repower 2 tripped offline and was offline until around 22:30.

Figure 21: SMP and generation at GNR2 and CAS1 October 15, 2024



Battle River 5 was commercially offline on long lead time for this event with a declared start-up time of 24 hours. The AESO did not issue a unit commitment directive for Battle River 5 because many of the factors contributing to the event were unforeseen. In particular, the forced outages at Cascade 1 and Genesee Repower 2 were not expected and the AESO's wind and solar forecasts 24 hours ahead both overpredicted actual generation (Table 8).

Table 8: Wind and solar forecasts compared to actual generation (October 15)

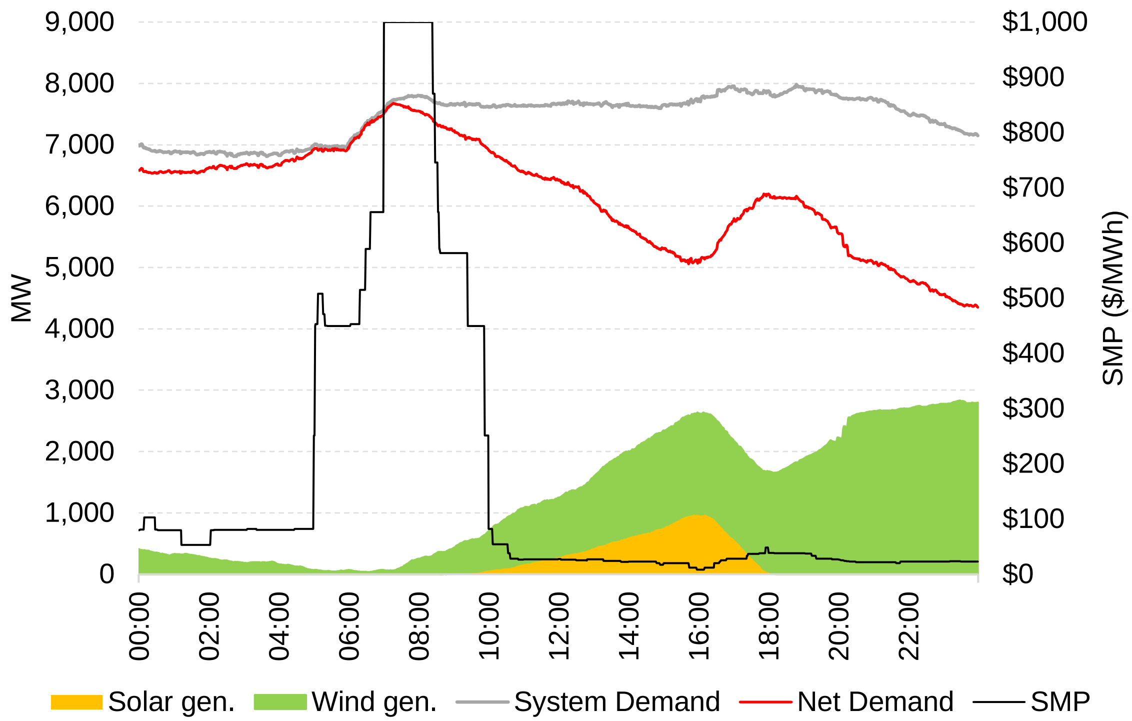
Hour Ending	Wind			Solar		
	24-hour forecast	Actual generation	Difference (Forecast – Actual)	24-hour forecast	Actual generation	Difference (Forecast – Actual)
14	493	128	365	723	386	337
15	514	113	401	607	368	239
16	526	106	420	510	422	88
17	545	129	416	336	387	-51
18	610	104	506	115	171	-56
19	812	173	639	7	13	-6
20	1,043	391	652	0	0	0

1.3.3 October 22: Energy Emergency Alert event

On October 22 the AESO declared an Energy Emergency Alert level 3 (EEA3) from 07:15 until 08:22 because of low intermittent generation and several outages at thermal generators. As shown by Figure 22, solar output during the EEA3 event was 0 MW and wind generation was negligible.

In addition, supply was reduced by thermal outages at Calpine (330 MW), Genesee Repower 1 (266 MW), Genesee Repower 2 (411 MW), Keephills 3 (466 MW), Sheerness 2 (400 MW), Northern Prairie Power Project (105 MW), Nabiye (120 MW), and on a Joffre gas turbine (230 MW). In total these outages accounted for more than 2,300 MW in thermal capacity. There were no assets that were commercially offline on long lead time for this event. This EEA3 event ended because wind generation increased (Figure 22).

Figure 22: Net demand and SMP on October 22, 2024



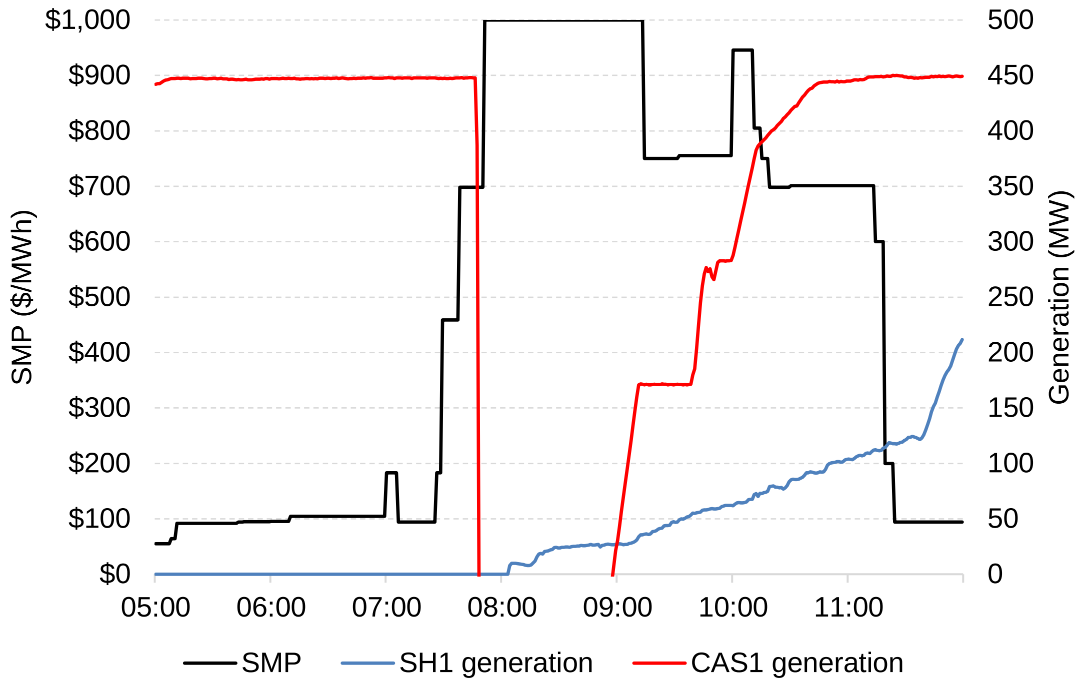
1.3.4 October 29: prices at the offer cap

On the morning of October 29, the price again increased to $999.99/MWh, the fourth day in October where this occurred. The underlying causes were again low intermittent generation combined with several thermal generator outages. When prices were at the cap wind generation was low and solar generation had not yet started to ramp up.

In terms of outages, there were existing outages at Cascade 2 (450 MW), Genesee Repower 2 (466 MW), Sheerness 2 (400 MW), and Northern Prairie Power Project (105 MW). In addition, Cascade 1 tripped offline on a forced outage at 07:48 (Figure 23). As a result, the SMP increased to $999.99/MWh at 07:51 and remained there until 09:15.

Sheerness 1 had received a unit commitment directive to be online beginning at 08:00 on October 29 so the asset was in the process of ramping online when prices increased to $999.99/MWh (Figure 23). This event ended as Cascade 1 came back online and increased generation supply.

Figure 23: SMP, SH1 generation, and CAS1 generation (October 29)



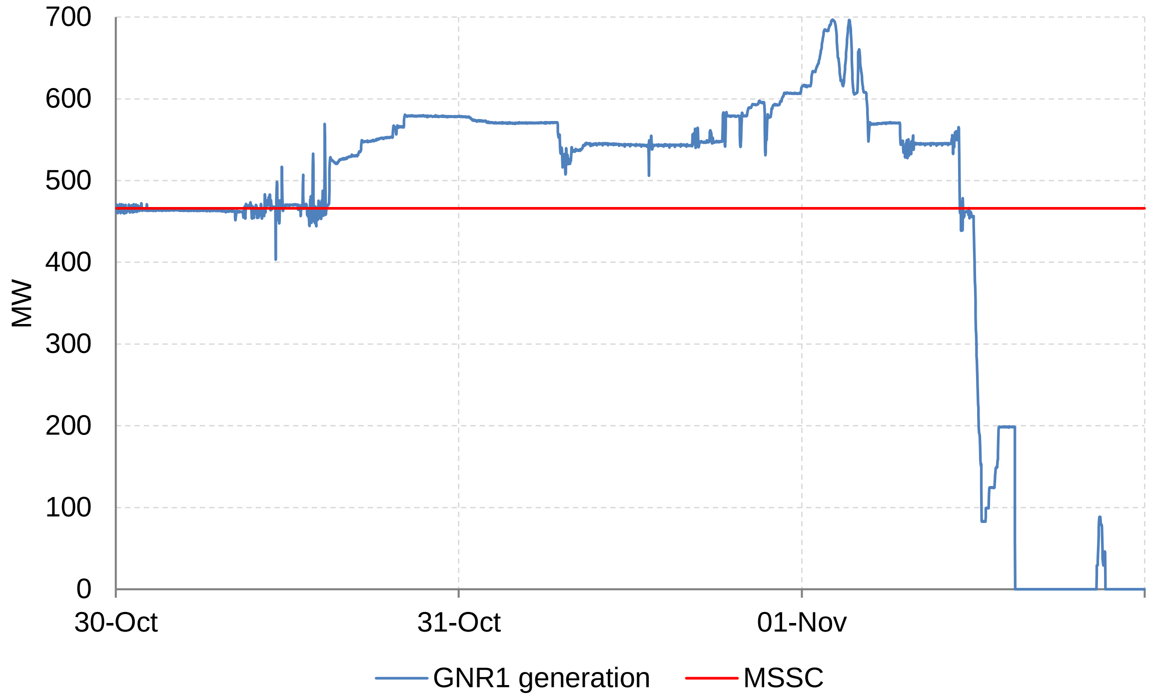
1.3.5 October 30: GNR1 producing above Most Severe Single Contingency limit

The AESO has established a Most Severe Single Contingency (MSSC) limit in Alberta of 466 MW. This is the maximum amount of supply loss the Alberta grid can reliably withstand, although the MSSC limit may be lower during islanded conditions when Alberta is separated from BC and Montana. Therefore, generators are precluded from supplying more than 466 MW from a single unit because it risks the reliability of the Alberta electrical grid.

However, beginning on the evening of Wednesday, October 30 the AESO allowed Genesee Repower 1 (GNR1) to generate above the MSSC limit for testing purposes. GNR1 is a combined cycle asset with one gas turbine and one steam turbine, with the steam turbine coming from the retired Genesee 1 coal asset. The purpose of the test was to see how much electricity the new combined cycle asset could generate. The AESO allowed this testing to occur because in their assessment a trip at GNR1 in this instance did not risk the reliability of the grid given grid conditions. Specifically, the BC/MATL intertie was online and in service.

Figure 24 illustrates the generation of GNR1 over the course of October 30 to November 1. In the early hours of November 1, GNR1 generated up to 697 MW before ramping offline for an outage around midday.

Figure 24: GNR1 generation (October 30 to November 1, 2024)



1.3.6 November 30: GNR1 and GNR2 trips

At 15:26:28 on Saturday, November 30 GNR2 tripped offline from 466 MW. Sixteen seconds later at 15:26:44 GNR1 tripped from 458 MW to 122 MW before going offline completely at 15:26:56 (Figure 25). As a result of these large trips the Area Control Error (ACE) fell to -972 MW, a notably low value which indicates that Alberta was importing well beyond the set schedules (Figure 26).

The schedule on the BC intertie at the time was for 50 MW of exports from Alberta but because of the trips at GNR1 and GNR2 Alberta was importing 570 MW at one point. On the Montana intertie the schedule was for 33 MW of imports, but because of the GNR1 and GNR2 trips Alberta was importing up to 230 MW.

Table 9 puts the trips at GNR1 and GNR2 into context by summarizing some other large contingency events in recent years. Despite the loss of over 920 MW, the GNR1 and GNR2 trips did not cause a large impact on frequency, which only fell to 59.91 Hz. This small impact is because the BC and Montana tielines absorbed much of the shock caused by the trips. In June of 2020, the BC/MATL intertie tripped offline causing a supply loss of 915 MW and frequency fell to 59.17 Hz, a notably low value. The contrast between these events illustrates the importance of the BC/MATL interties in dealing with large contingency events and providing frequency support.

Figure 25: GNR1 generation and GNR2 generation (November 30, 2024)

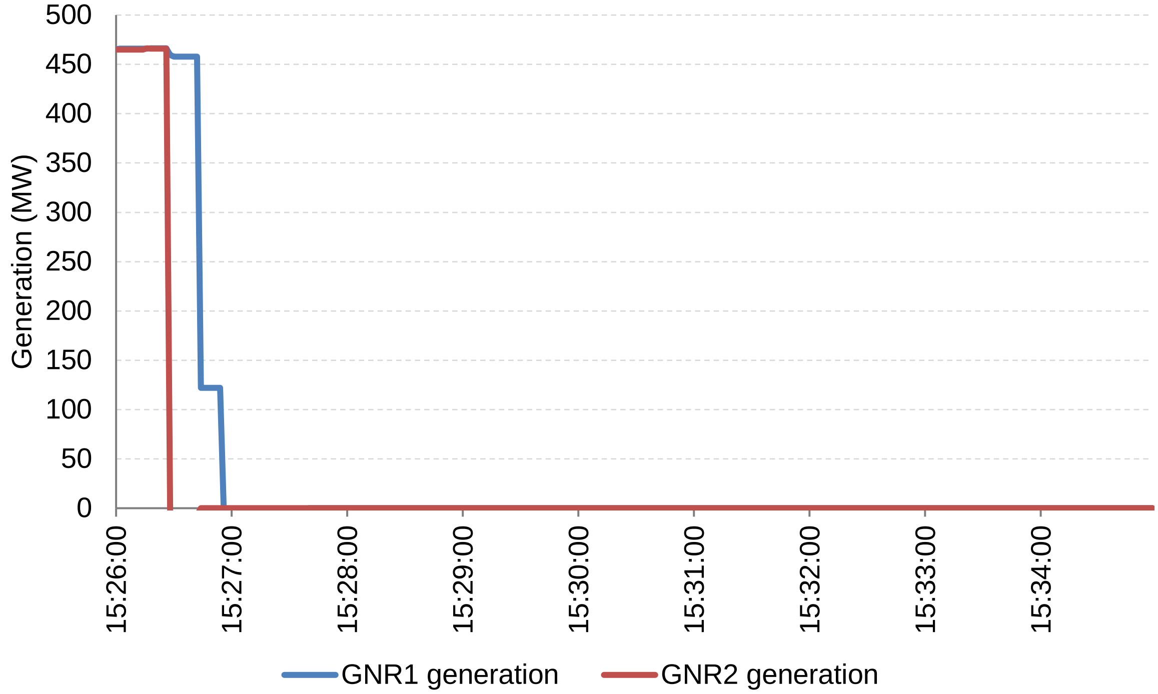


Figure 26: Area Control Error (ACE) (November 30, 2024)

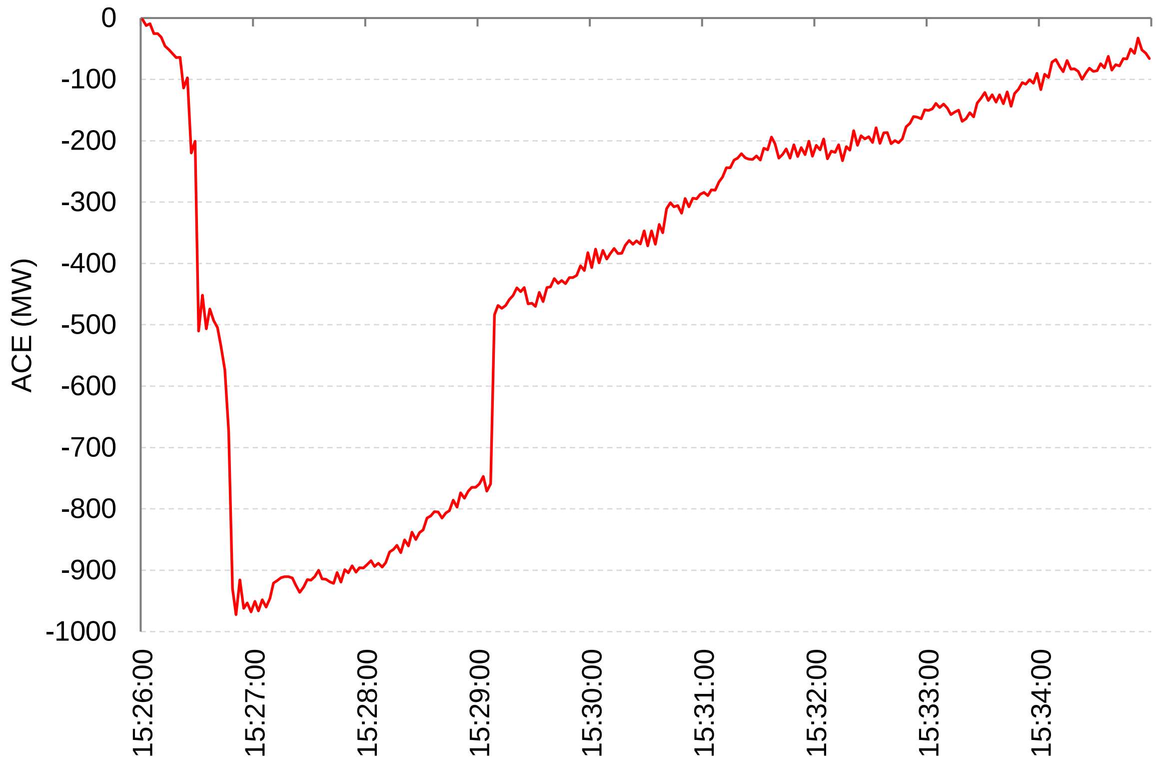


Table 9: Some large contingency events since January 1, 2018 (ordered by generation loss)

Trip event	Date	Gen. Loss (MW)	Min. ACE (MW)	Min. Frequency (Hz)
GNR2 then GNR1	**30-Nov-24**	**924**	**-972**	**59.91**
BC/MATL	7-Jun-20	915	-974	59.17
Wind generation	7-Sep-24	834	-917	59.94
GN1 then GN2	2-Feb-24	800	-880	59.93
EGC1	25-Jul-23	745	-860	59.93
BC/MATL	3-Jun-21	707	-909	59.36
BC/MATL	22-Jun-18	689	-939	59.31
SH1 and SH2	4-Apr-21	668	-711	59.93
SH1 then SH2	2-Jun-21	666	-743	59.95
Wind generation	20-Aug-24	615	-637	59.95
Wind generation	26-Jul-24	580	-731	59.95
KH3 then KH2	14-Dec-21	538	-682	59.93
SH2 then SH1	28-Mar-21	514	-612	59.92
BC/MATL	22-Feb-21	468	-835	59.49
CAS2	18-Sep-24	447	-721	59.9
BC/MATL	21-Feb-21	436	-823	59.44
KH3 then BC (MATL offline)	11-Sep-19	355	-662	59.57
KH1 (BC/MATL offline)	16-Oct-20	258	-624	59.58

1.4 Market power mitigation measures

In March 2024, the *Market Power Mitigation Regulation* (MPMR) and *Supply Cushion Regulation* (SCR) were enacted. Beginning July 1, 2024, these regulations moderate economic withholding and require the AESO to commit generation capacity under some circumstances. These regulations were informed by advice that the Minister requested from the MSA.[8] The MPMR and SCR are implemented through ISO rules 206.1 and 206.2, respectively. While these rules were in force in their expedited form in Q4, they are under consideration on a final basis in Alberta Utilities Commission Proceeding 29093, and a decision is expected near to the publication date of this report.

The MSA first reported on these measures in section 1.3 of its Quarterly Report for Q3 2024, which provides a more comprehensive description of the underlying mechanisms and the MSA's analytical methods.

[8] See the Advice from the MSA

The MSA estimates that the average pool price in Q4 would have been $58.15/MWh absent the measures. Compared to the observed average pool price of $51.52/MWh, this means the measures are estimated to have reduced the average Q4 pool price by $6.63/MWh or 11%. This is comparable to the 10% reduction estimated in Q3 2024, even though the secondary offer price limit was triggered in Q3 2024 but not Q4.

1.4.1 Market Power Mitigation Regulation and ISO rule 206.1

Under ISO rule 206.1, a secondary offer price limit equal to the greater of either $125/MWh or 25 times the day-ahead natural gas price is triggered when the Monthly Cumulative Settlement Interval Net Revenue (MCSINR) exceeds 1/6 of the annualized avoidable costs of a reference combined cycle generating unit.

The secondary offer price limit was not triggered in Q4, as the MCSINR reached only 63%, 78%, and 11% of the threshold in October, November, and December, respectively. As described in section 1.2, lower prices in Q4 were primarily driven by more available thermal capacity and lower natural gas prices.

1.4.2 Supply Cushion Regulation and ISO rule 206.2

Under ISO rule 206.2, the AESO must perform a forecast of supply cushion, called anticipated supply cushion (ASC), and issue unit commitment directives (UCDs) to eligible long lead time (LLT) assets when the ASC falls below 932 MW. The AESO must choose which eligible LLT assets to direct based on economic merit and physical constraints, for which it uses a tool called Power Optimisation (PowerOp).

In Q4, there were 10 UCDs, as listed in Table 10. The October UCDs coincided with very tight supply conditions, which were driven by lower thermal generator availability in October compared to the rest of the quarter.

- On October 2, SH2 was under a UCD starting at 18:00. However, it was late to respond, and supply cushion fell to 0 MW between 18:25 and 18:39. BR5 remained on LLT during this event.
- On October 20, supply cushion fell to 121 MW while SH1 was ramping in response to a UCD. BR5 remained on LLT during this event.
- On October 29, supply cushion was at or near 0 MW from 07:51 to 09:13. During this time, SH1 was ramping in response to a UCD and KH3 was online in advance of a UCD in effect later that day.

Table 10: Unit commitment directives in Q4 2024

Asset ID	Commitment start time	Commitment end time	Minimum anticipated supply cushion	Minimum actual supply cushion
SH2	Oct 2 18:00	Oct 3 20:00	736 MW	0 MW[9]
SH1	Oct 20 07:00	Oct 20 11:00	888 MW	121 MW
KH3	Oct 29 10:00	Oct 29 19:00	266 MW	112 MW
SH1	Oct 29 08:00	Oct 29 19:00	673 MW	0 MW
SH1	Nov 7 10:00	Nov 7 17:00	592 MW	551 MW
SH1	Nov 7 17:00	Nov 7 21:00	908 MW	826 MW
SH1	Nov 20 16:00	Nov 21 21:00	673 MW	516 MW
BR5	Nov 24 18:00	Nov 25 00:00	716 MW	858 MW
BR5	Dec 4 08:00	Dec 4 12:00	896 MW	1,042 MW
SD6	Dec 17 16:00	Dec 17 20:00	796 MW	413 MW[10]

Table 11 shows the estimated price effects of UCDs by month for Q4. Because UCDs are only issued when supply cushion is expected to be low, they tend to reduce high price outlier events. Mild weather and high thermal availability in December resulted in only two UCDs, so the price effect was small.

Table 11: Estimated price impact of unit commitment directives in Q4 2024

Time period	Actual average pool price ($/MWh)	Estimated average pool price without unit commitment directives ($/MWh)	Percentage change (%)
October 2024	$57.62	$67.07	-14%
November 2024	$71.20	$81.59	-13%
December 2024	$26.35	$26.53	-1%
Q4 2024	$51.52	$58.15	-11%

[9] SH2 was late responding to the directive, and the period of 0 MW supply cushion occurred before it was online. Minimum actual supply cushion after it came online was 996 MW.

[10] SD6 declared a forced outage before responding to the UCD. If SD6 had responded with its most recent AC of 401 MW, minimum actual supply cushion would have been 814 MW.

1.5 Pricing dynamics: Market power and recovery of fixed costs

1.5.1 Overview

- The average mark-up in 2024 was $23/MWh, a decline from $75/MWh in 2023.
- The impacts of a large merger in early December were offset by mild weather conditions and increased thermal supply.
- Firms exercised less market power in Q4 2024 relative to Q4 2023 due to increased competition.
- Net revenue analysis indicates that in recent years gas-fired generators have been economic under observed market prices at all different levels of assumed capital costs.
- Net revenue analysis shows that in recent years wind and solar generators have been economic under observed market prices for some levels of assumed capital costs.
- No generator type was economic under a counterfactual scenario in which prices were set based on short-run marginal cost offers.

1.5.2 Market power

The average pool price in 2024 was $63/MWh which is a mark-up of $23/MWh above the MSA's estimate of what prices would have been had all generators been offered at short-run marginal cost (SRMC). The mark-up of price over SRMC was higher in 2023 at $75/MWh. Indeed, the mark-up in 2024 was the lowest since 2020 when the mark-up was $12/MWh (Figure 27).

Figure 27: Actual and counterfactual average prices by year (2020 to 2024)

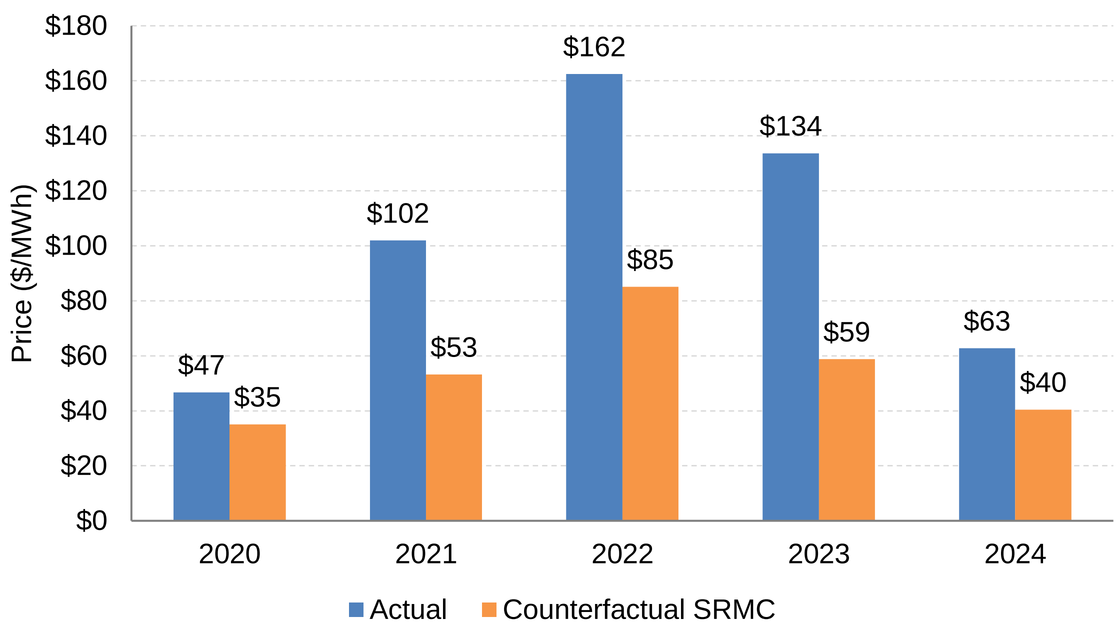
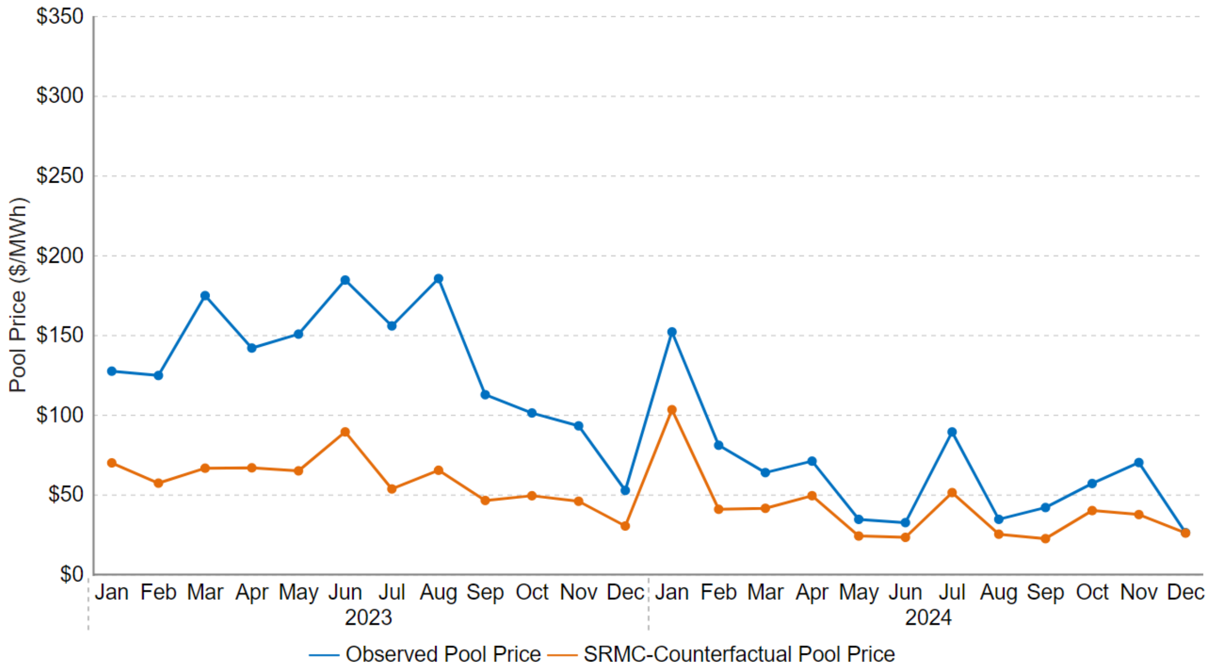


Figure 28 illustrates actual and counterfactual prices by month since January 2023. In Q4 2024 the mark-ups were relatively low with October averaging $18/MWh, November $34/MWh, and December $0.4/MWh. On average in Q4 2024 the mark-up was $17/MWh, which is 57% less than the mark-up of $40/MWh in Q4 2023. Year-over-year the mark-ups in Q4 2024 were lowered by additional thermal supply which increased competition in the market.

Figure 28: Actual and counterfactual average prices by month (January 2023 to December 2024)



A firm is said to be pivotal if some of its withholdable[11] generation capacity is needed for the energy market to clear. Figure 29 illustrates the percent of hours when at least one firm was pivotal by month since 2020. According to this metric, the ability of generators to exercise market power was highest in July 2021 when a firm was pivotal in 39% of hours.

In Q4 the ability of generators to exercise market power was highest in November when at least one firm was pivotal in 14% of hours. In October and December at least one firm was pivotal in 6% of hours. Market power in November was increased by a period of cold weather which increased demand and lowered intermittent generation.

On December 4, a large firm in Alberta completed the acquisition of another firm and took offer control over an additional 2,141 MW of generation capacity. This increased the ability of the firm to exercise market power and will raise the number of hours the firm is pivotal, all else equal. In December, mild weather conditions and more thermal capacity offset the increase in market power that resulted from the acquisition.

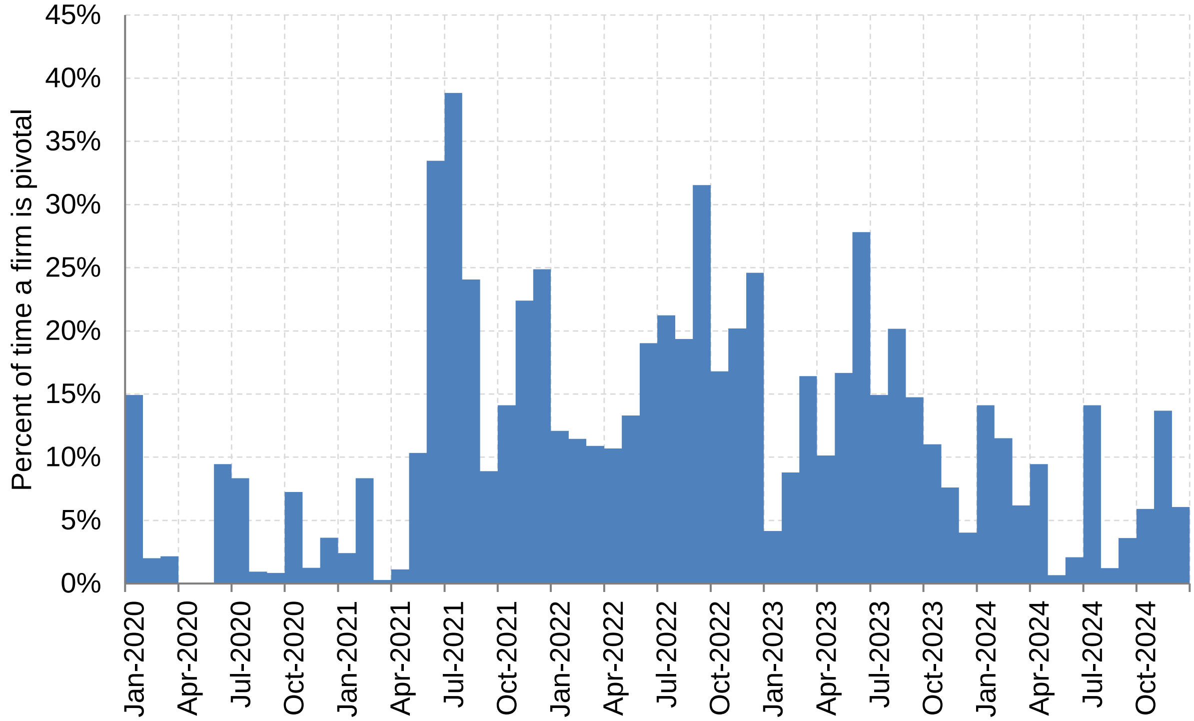
[11] Withholdable generation is everything except for Minimum Stable Generation and wind and solar capacity.

Year-over-year the ability of generators to exercise market power was comparable. In Q4 2024 at least one firm was pivotal in 9% of hours and in Q4 2023 the figure was 8% (Table 12).

Table 12: Percent of time at least one firm was pivotal (Q4 2023 and Q4 2024)

	2023	**2024**
October	11%	6%
November	8%	14%
December	4%	6%
Q4	8%	9%

Figure 29: Percent of time at least one firm was pivotal by month (January 2020 to December 2024)



The extent to which firms are pivotal in the market will vary over time as market fundamentals and the supply controlled by firms changes. The different classifications of pivotality used here are as follows:

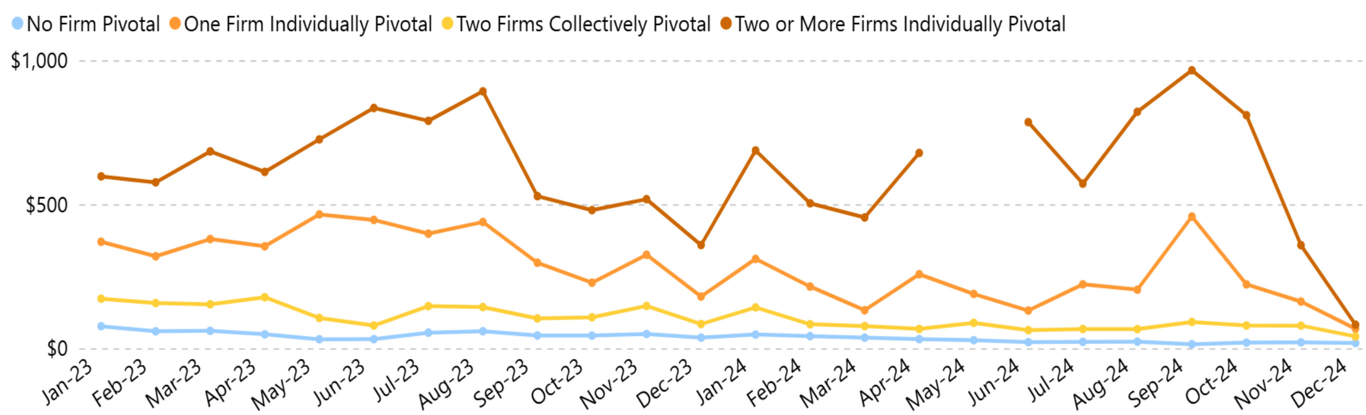
- two or more firms are individually pivotal at the same time (“two or more firms individually pivotal”)
- one firm by itself is pivotal (“one firm individually pivotal”)

- two firms are collectively pivotal with their combined withholdable capacity (“two firms collectively pivotal”), and
- no firm is pivotal or collectively pivotal (“no firm pivotal”).

Figure 30 illustrates the monthly average pool price by pivotality classification. In recent months there has been a wide variation of prices in hours when multiple firms were pivotal. In September the average pool price in hours when multiple firms were pivotal was $965/MWh indicating that market power was being exercised consistently during these hours. However, in December the average pool price was $82/MWh in hours when multiple firms were pivotal, indicating that market power was being exercised less.

Similarly, the average pool in hours when one firm was individually pivotal fell from $458/MWh in September to $68/MWh in December. This decline in prices indicates that less market power was being exercised in December relative to September.

Figure 30: Average pool price by pivotality classification and month (January 2023 to December 2024)

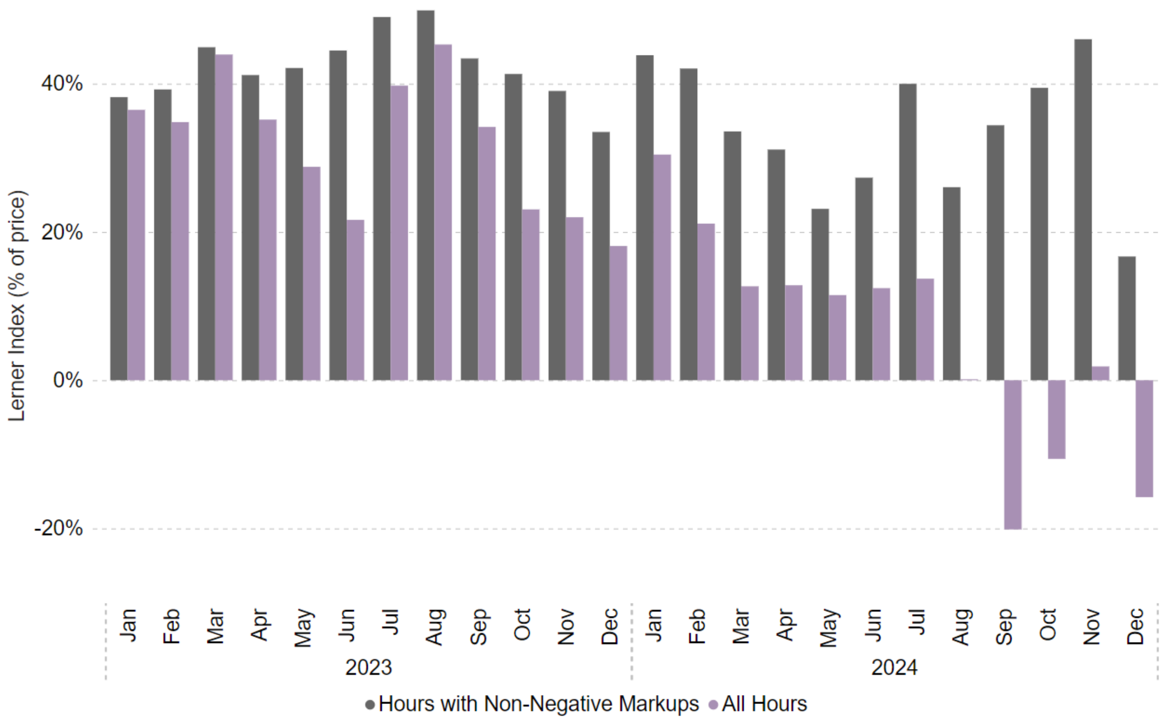


The Lerner index measures market power by calculating the mark-up as a percentage of price:

$$Lerner\ Index = \frac{(Price - SRMC)}{Price}$$

A higher Lerner index indicates greater mark-up and more market power. A negative Lerner index indicates that the observed price was less than the estimated price under SRMC. This occurs when generation capacity is offered into the market below the MSA’s estimate of SRMC for that asset. In Q4 2024 the Lerner index was negative in 49% of hours and the average Lerner index was negative in October at -11% and December at -16%. The average Lerner index for November was 2%, reflecting hours with a negative Lerner index largely offsetting hours with a positive one.

Figure 31: Average Lerner index by month (January 2023 to December 2024)

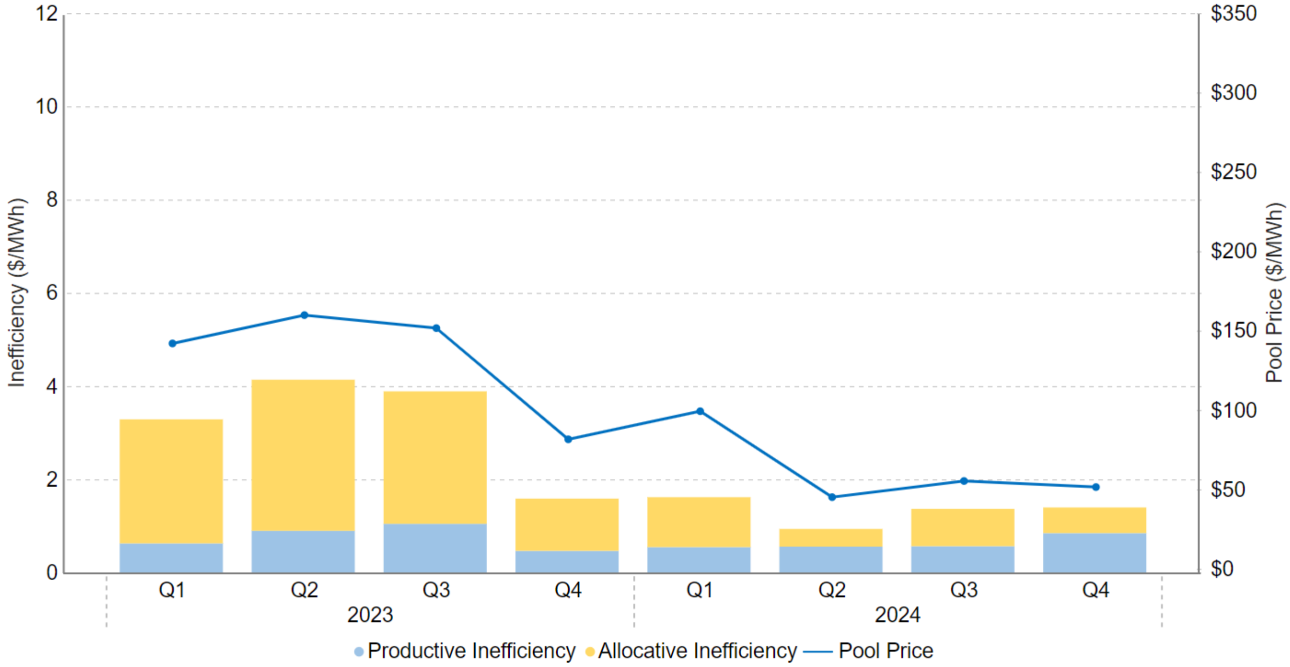


The exercise of market power can lead to short run economic inefficiencies. Productive inefficiencies arise when lower-cost capacity is withheld and replaced by higher-cost generation. Allocative inefficiencies arise when demand is less than it would have been because the exercise of market power increased price.

In total, static inefficiencies declined slightly year-over-year as the decrease in allocative inefficiencies was partly offset by an increase in productive inefficiencies. In Q4 2024 allocative inefficiencies averaged $0.55/MWh, a decrease of $0.57/MWh (51%) from Q3 2024. Allocative inefficiencies in Q4 2024 were highest in November as market power prevailed during a period of cold weather and low intermittent generation later in the month. Allocative inefficiencies averaged $0.58/MWh in October, $1.01/MWh in November, and $0.11/MWh in December. The low allocative inefficiencies in December were the result of mild weather conditions and increased thermal supply.

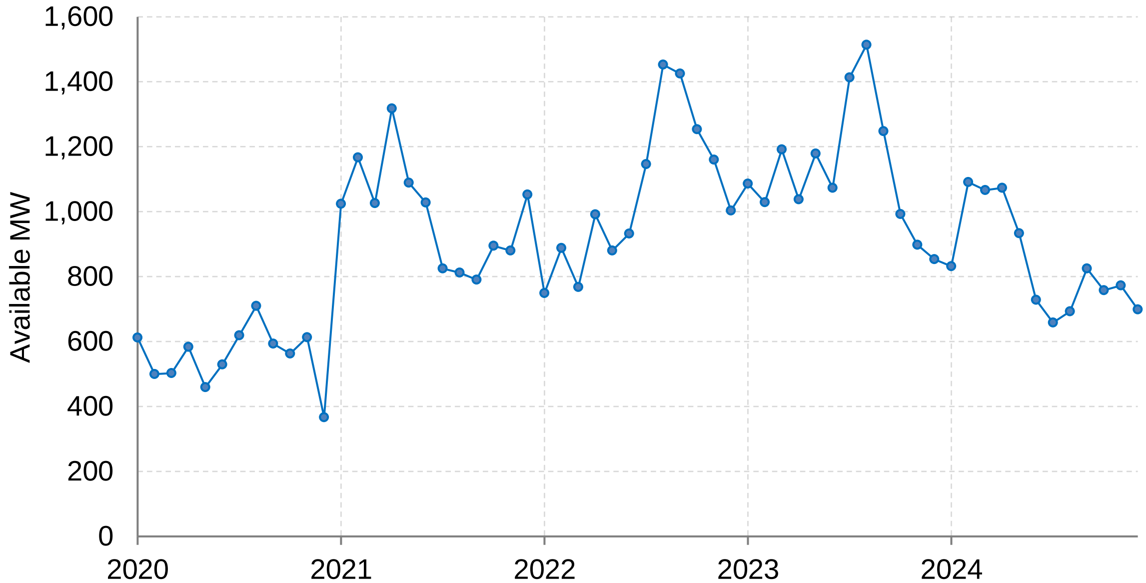
Despite the lower pool prices, productive inefficiencies increased year-over-year. In Q4 2024 productive inefficiencies averaged $0.85/MWh compared to $0.47/MWh in Q4 2023, an 81% increase. Productive inefficiencies have increased in recent months in part because the Cascade assets, which are efficient and low cost, have been economically withheld. When this occurs the AESO must replace the generation with higher-cost thermal assets causing productive inefficiencies.

Figure 32: Static inefficiencies by quarter (Q1 2023 to Q4 2024)



In terms of offer behaviour there was less capacity offered high in the merit order year-over-year. Figure 33 illustrates the average amount of thermal capacity offered above $250/MWh by month since January 2020. In Q4 2024 the average amount of capacity offered above $250/MWh was 743 MW compared to 915 MW in Q4 2023, a reduction of 19%. Less market power was exercised in Q4 2024 as more thermal capacity in the market increased competition.

Figure 33: Average amount of available capacity offered above $250/MWh by month (January 2020 to December 2024)



1.5.3 *Net revenue analysis*

The economics of operating an asset is influenced by factors such as operational flexibility, fixed and variable costs, out-of-market payments, and received energy prices. As a result, the economics of an asset can differ significantly across fuel types. This section highlights the expected net revenues, received prices, and capital cost recoupment for hypothetical combined cycle, gas peaker, wind, and solar generators.

Within this model, wind, solar, and gas peaker units are assumed to have lifespans of 25 years, while combined cycle units are assumed to last 30 years. Both the hypothetical gas peaker and combined cycle units have been modelled after commonly used power plants.[12] Additionally, seasonal impacts on heat rates have been accounted for. Lastly, carbon credits for both wind and solar assets are calculated using the respective carbon price and the Electricity Grid Displacement Factors.[13]

Historical net revenues for each hypothetical generator have been calculated using observed market prices, and counterfactual prices based on short-run marginal costs (Figure 34). Between Q1 2020 and Q4 2024, the hypothetical combined cycle and gas peaker generators received sufficient net revenues in the energy market to recoup their annualized capital costs for all weighted-average cost of capital (WACC) levels.[14] Over the same time horizon, despite out-of-market payments for carbon, hypothetical wind and solar generators received significantly lower net revenues from the energy market and did not recoup their annualized capital costs under the higher WACC levels.

Under the counterfactual scenario in which prices were set based on marginal costs, net revenues were not sufficient to recover the annualized fixed costs for any of the four generation technologies (Figure 34).

---

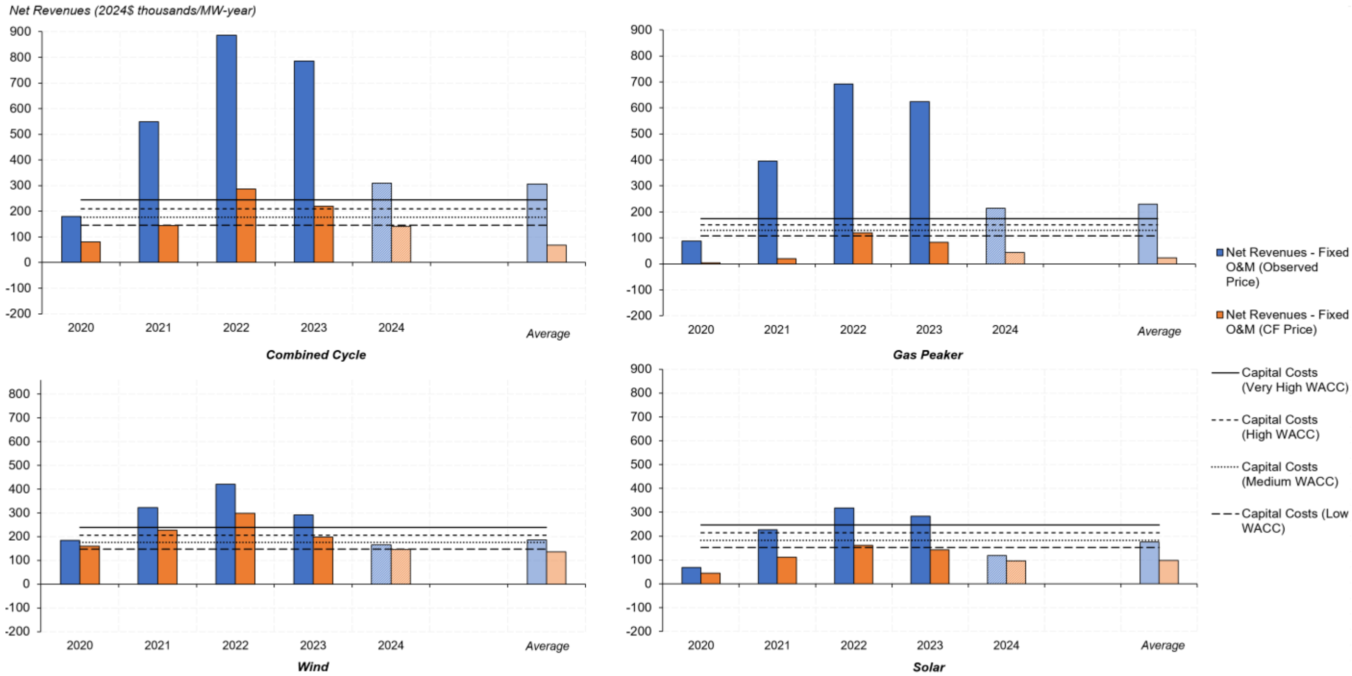
[12] Hypothetical gas peaker unit: GE LM6000 SPRINT 2x0.

Hypothetical combined cycle unit: Siemens SGT6-8000H 1X1.

[13] Government of Alberta, Carbon Offset Emission Factors Handbook, Carbon Offset Emission Factors Handbook.

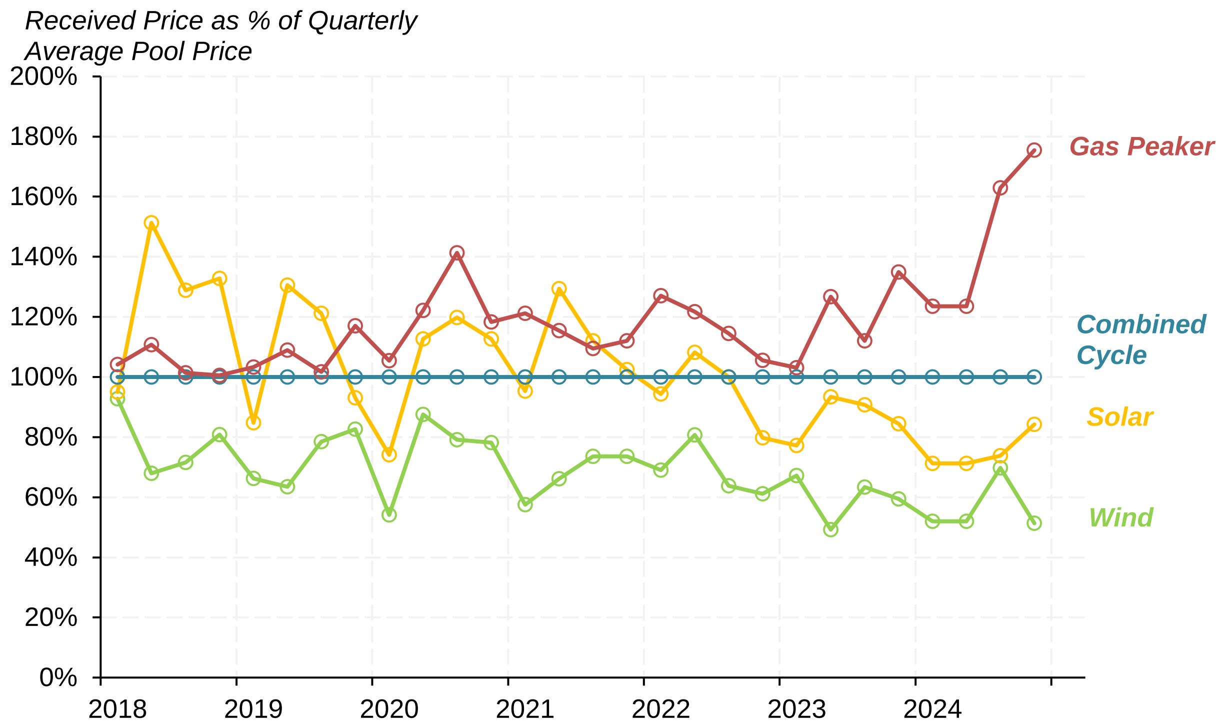
[14] The MSA has modeled annualized capital costs at four WACC levels: 6.5%, 8.5%, 10.5%, and 12.5%, referred to as "Low", "Medium", "High", and "Very High" WACC levels, respectively.

Figure 34: Annual observed, SRMC counterfactual net revenues by hypothetical generator (2024$ thousands/MW-year) (Q1 2020 to Q4 2024)



A hypothetical asset's generation profile and its exposure to pool price plays a significant role in its ability to recover capital costs. Since 2018, the average quarterly pool price received by wind assets was 68% of the hourly average pool price received by combined cycle generation (Figure 35). In 2024, the hypothetical wind generator received 56% of the hourly average pool price received by combined cycle generation, while solar averaged 75%. In 2024, the hypothetical gas peaker received an average pool price 46% higher than that received by a combined cycle generator, an increase of 27% relative to the previous year.

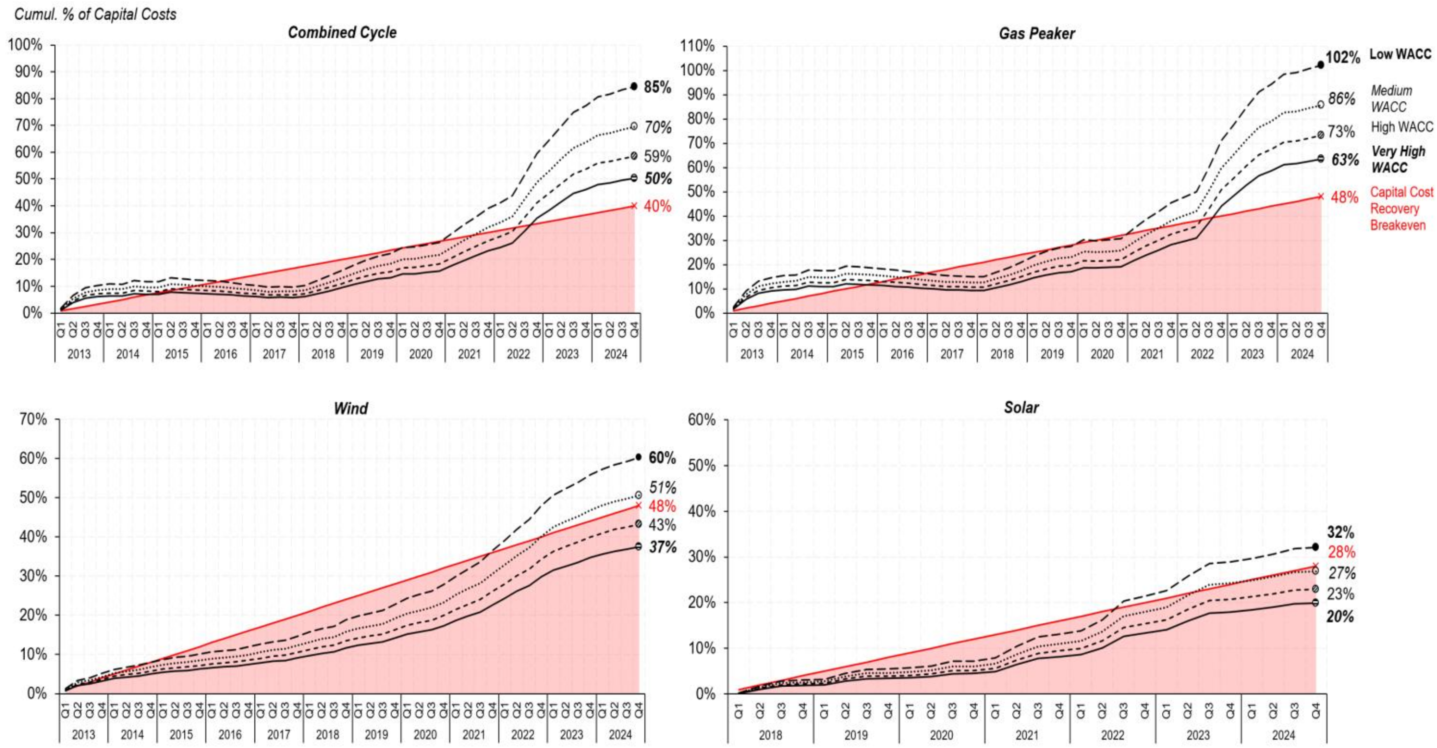
Figure 35: Quarterly received price relative to quarterly average pool price for hypothetical generators (Q1 2018 to Q4 2024)



Capital costs are recouped by receiving net revenues over an asset's lifespan. A hypothetical combined cycle generator connected in 2013 and financed using a Low WACC would have successfully recovered 85% of its total capital costs 12 years into its estimated 30-year lifespan (Figure 36). A hypothetical gas peaker with the same assumptions would have recouped 102% of its capital costs approximately 12 years into its 25-year life. Even with a Very High WACC, both hypothetical gas generators would have received net revenues in excess of their capital cost recovery breakeven over this time horizon. These findings suggest that since 2013, energy market prices have allowed for sufficient cost recovery and have provided strong incentives to invest in natural gas generation.

However, hypothetical wind and solar generators did not receive net revenues sufficient to cover capital costs under all WACC levels. A hypothetical wind generator would have received net revenues in excess of its capacity cost recovery breakeven with a Medium WACC, whereas a solar generator would have exceeded this threshold with a Low WACC.

Figure 36: Quarterly cumulative capital cost recovery by hypothetical generator (Q1 2013 to Q1 2024) (observed net revenues)



1.6 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 on 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.[15]

1.6.1 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 13 shows the minimum, mean, and maximum hourly average emission for Q4 over the past seven years. Notably, the maximum hourly average emission intensity for Q4 2024 was lower than the minimum hourly average emission intensity for Q4 2018. Table 14 shows the same summary statistics for the past four quarters, demonstrating recent declines in the hourly average emission intensity.

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

Table 13: Year-over-year min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2018 Q4	0.56	0.68	0.79
2019 Q4	0.52	0.63	0.75
2020 Q4	0.47	0.59	0.72
2021 Q4	0.41	0.54	0.63
2022 Q4	0.37	0.48	0.57
2023 Q4	0.30	0.43	0.57
2024 Q4	0.25	0.40	0.54

Table 14: Quarter over quarter min, mean, and max hourly average emission intensities (tCO2e/MWh)

Time period	Min	Mean	Max
2024 Q1	0.27	0.45	0.58
2024 Q2	0.26	0.39	0.56
2024 Q3	0.25	0.40	0.53
2024 Q4	0.25	0.40	0.54

Figure 37 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q4 over the past seven years. Figure 38 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The conversion of coal-fired generation to natural gas, in addition to increased intermittent generation, has driven a decline in carbon emission intensity. This decline in carbon intensity over time is demonstrated by the leftward shift of hourly average carbon intensity distributions as shown in Figure 37.

Figure 37: The distribution of average carbon emission intensities in Q4 (2018 to 2024)

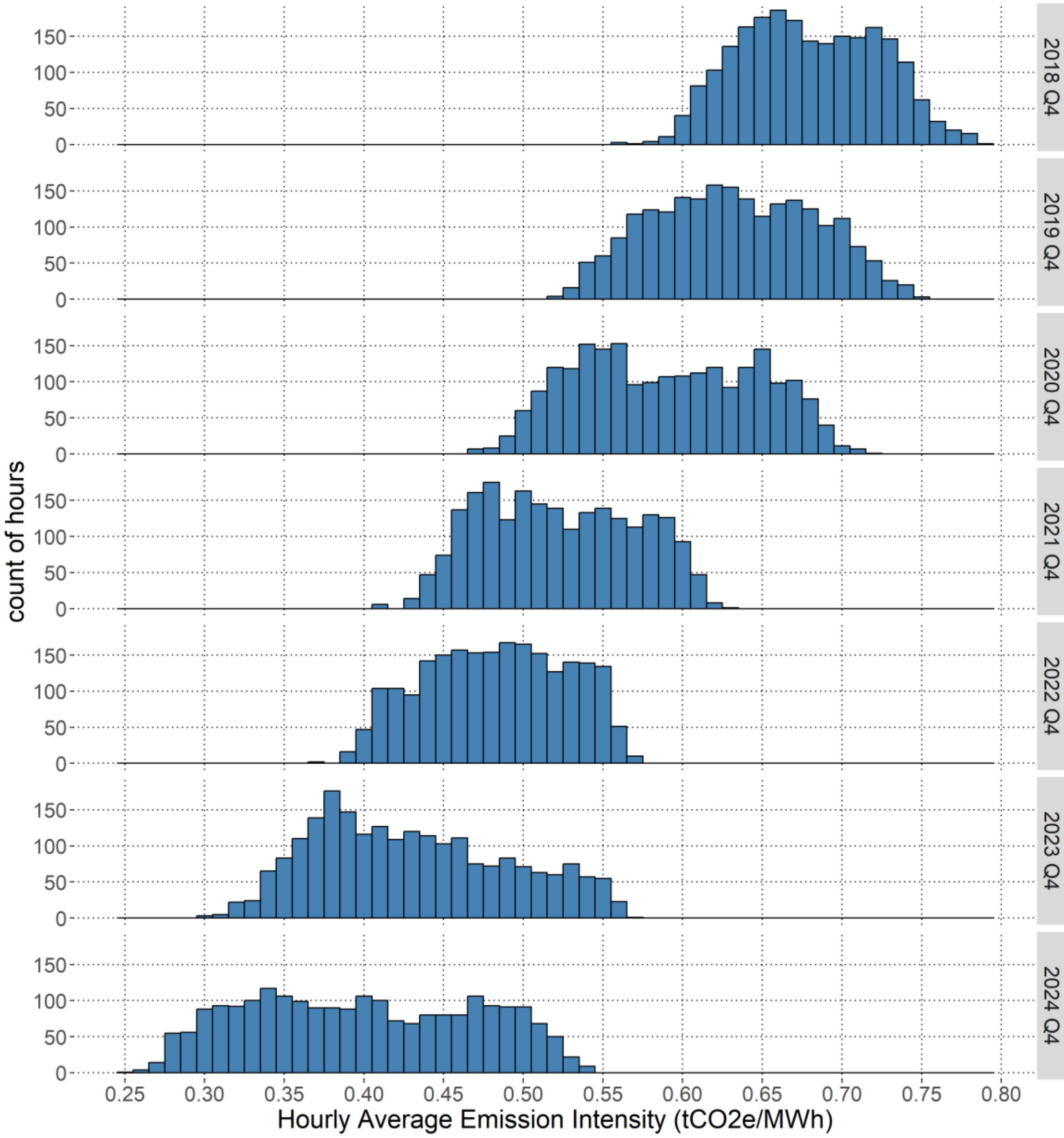
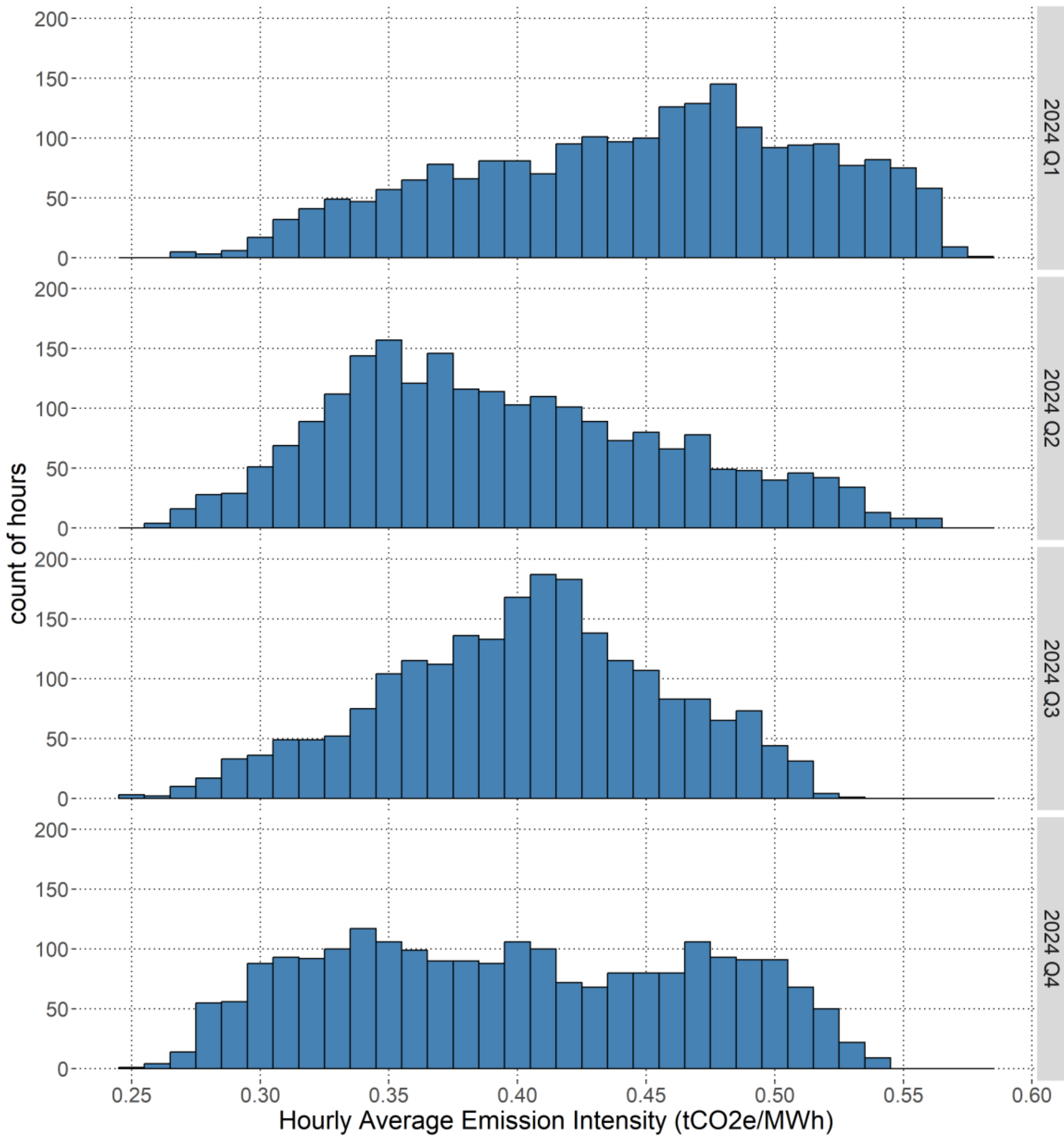
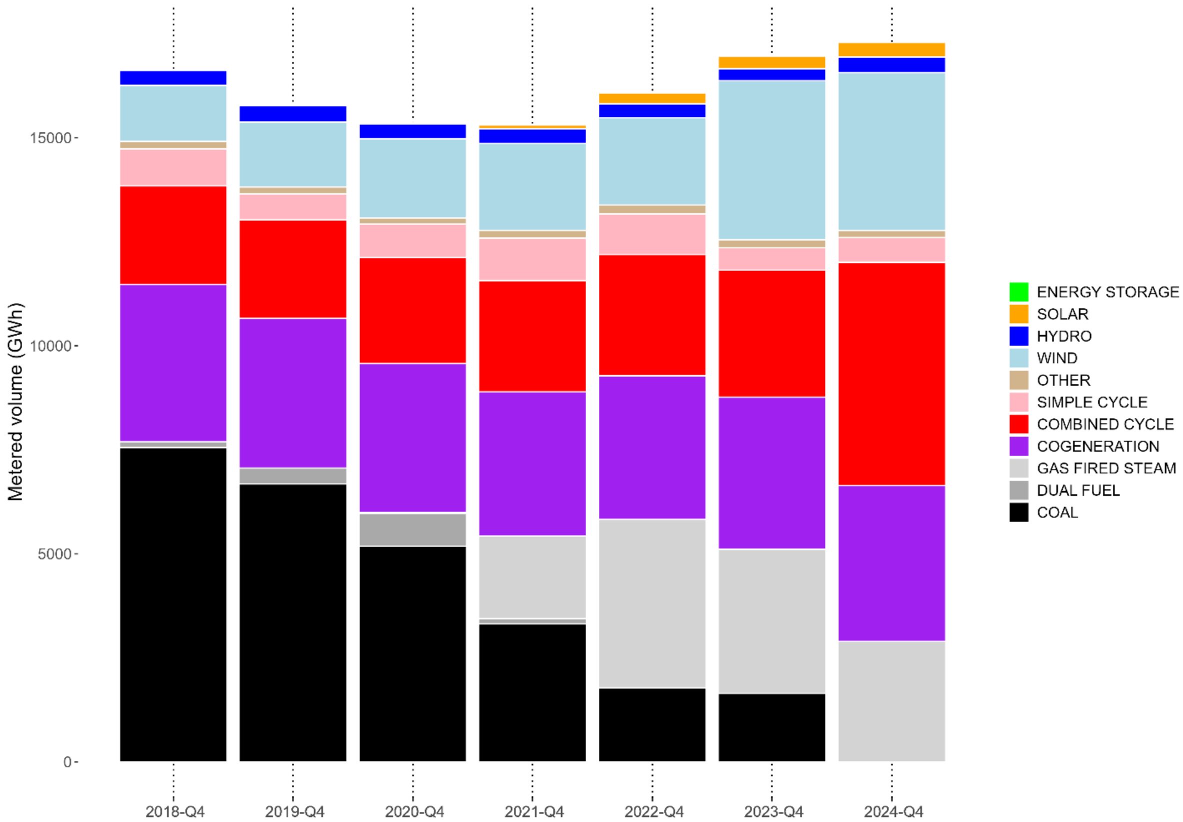


Figure 38: The distribution of average carbon emission intensities in the past four quarters



The leftward shifts of the distributions in Figure 37 can be traced to Figure 39, which shows the net-to-grid generation volumes by fuel type. Since 2019, there has been a material decline in the volume of coal-fired generation due to retirements and coal-to-gas conversions. In addition, the continuous increase in intermittent generation driven by growing capacity has also contributed to the displacement of coal-fired generation. Increased generation from efficient gas assets, Cascade 1 and 2, and Genesee Repower 1 and 2, have put downwards pressure on average carbon intensity more recently.

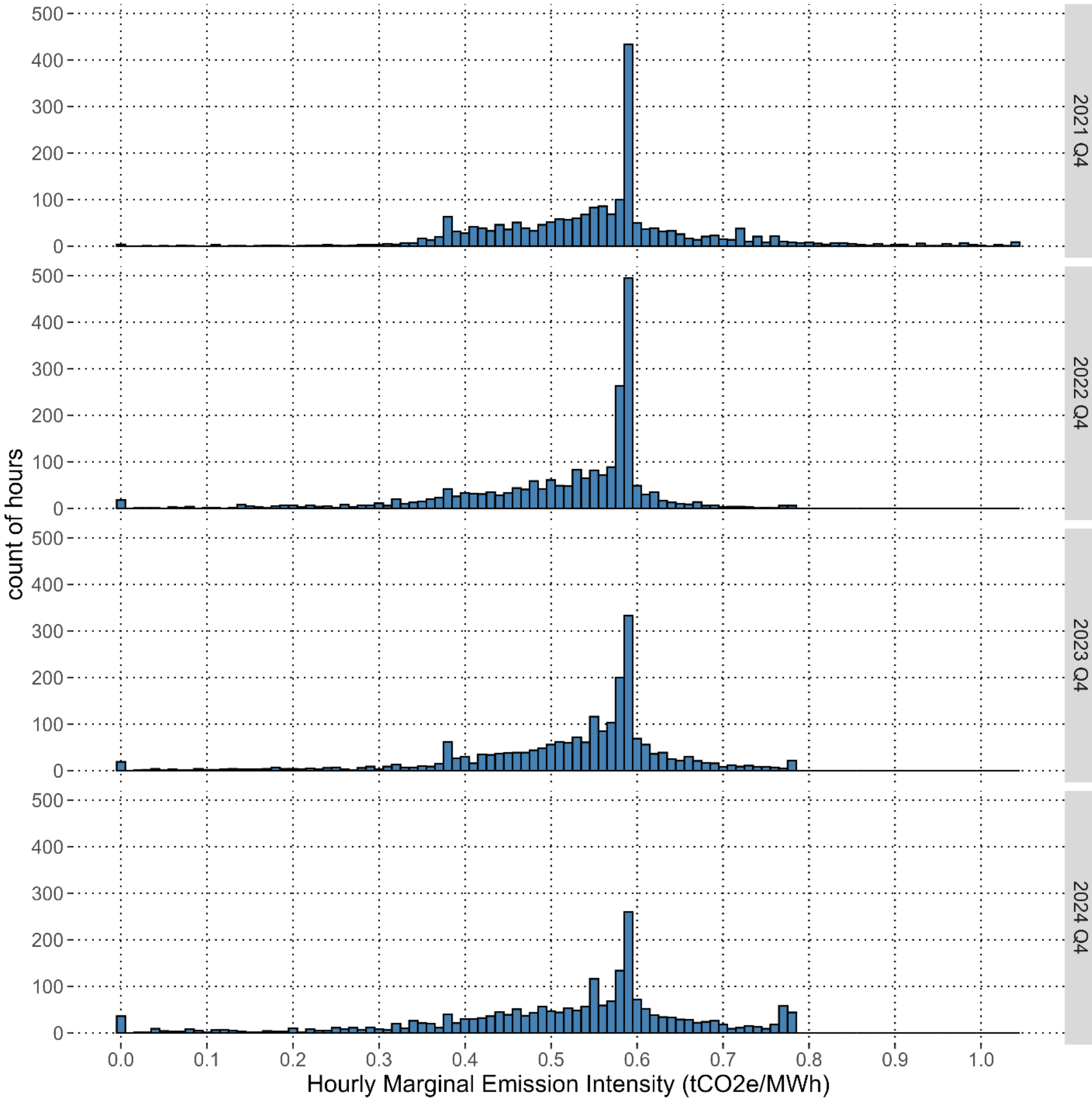
Figure 39: Quarterly total net-to-grid generation volumes by fuel type for Q4 (2018 to 2024)



1.6.2 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 40 shows the distribution of the hourly marginal emission intensity of the grid in Q4 for the past four years. Gas-fired steam assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO2e/MWh from Q4 2021 onwards.

Figure 40: The distribution of marginal carbon emission intensities in Q4 (2021 to 2024)



1.7 Market share offer control

The MSA began publishing market share offer control (MSOC) metrics in its quarterly report in 2021. With this change, the MSA is now including a data file on its website with offer control data, along with tables and charts of interest. Certain tables that were included in previous market share offer control reports can be found in the data file. The data file for market share offer control can be found in the MSA Market Share Offer Control Data file located on the MSA's website under Documents & Reporting > Reports > MSOC.

1.7.1 Requirement to publish offer control report and associated process

The MSA's assessment of MSOC information is required by subsection 5(3) of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation). Subsection 5(3) states: (3) The MSA shall at least annually make available to the public an offer control report that (a) shall include the names and the percentage of offer control held by electricity market participants, where the percentage of offer control is greater than 5%, and (b) may include the names and the percentage of offer control held by electricity market participants, where the percentage of offer control is 5% or less. Details of the process to collect and publish information on offer control to meet the requirements of subsection 5(3) are set out in the MSA's Annual Market Share Offer Control Process (MSOC Process).[16]

1.7.2 Assessment of offer control

In accordance with the MSOC Process, the MSA calculated offer control with data obtained from the AESO for January 1, 2025 HE 18. The MSA requested confirmation of offer control from market participants whose total offer control was calculated as greater than five percent, or for joint ventures that required further clarification. As per section 5(2) of FEOC Regulation, an electricity market participant's total offer control is measured as the ratio of generation capacity under its offer control to the sum of maximum capability of all generating units in Alberta.

Generating units are included in the offer control of an electricity market participant (and the denominator) as long as they are registered with the AESO as active assets during the reference hour. Generating units registered as active assets are still required to make offers even if they are not available or are mothballed, and their lack of availability is included in outage data published by the AESO. The total non-dispatchable capacity consists of the total maximum capability of generating units that do not submit offers into the power pool, such as generating units with a maximum capability less than 5 MW.

The maximum capability of assets used to calculate the denominator may not correspond to the name plate maximum capability that is published on the AESO's Current Supply Demand (CSD) Report. Instead, the denominator uses maximum capability as it is registered with the AESO for the purpose of submitting price-quantity offer pairs.

---

[16] MSA Annual Market Share Offer Control Process (April 30, 2013)

Table 15: Market share offer control of electricity market participants with greater than 5% offer control between MSOC 2024 and 2025

	March 31, 2024		January 1, 2025	
Company	**Control (MW)**	**%**	**Control (MW)**	**%**
TransAlta	3,089	14.7%	5,303	23.2%
Capital Power	2,783	13.3%	2,610	11.4%
Heartland Generation Ltd.	2,286	10.9%	--	0.0%
Suncor	1,632	7.8%	2,438	10.7%
ENMAX	1,462	7.0%	1,389	6.1%
Other	9,366	44.7%	10,754	47.1%
Total Dispatchable	20,618	98.4%	22,494	98.4%
Total Non-dispatchable	335	1.6%	362	1.6%
Grand Total	**20,953**	**100%**	**22,856**	**100%**

Total offer control for participants with greater than five percent MSOC increased from 11,252 MW to 11,740 MW, which represented a market share decrease from 53.7% in 2024 to 51.4% in 2025. Generation retirements, additions, and maximum capability changes are discussed further in section 1.7.3.

Table 16 shows the increase in TransAlta's offer control by asset with its acquisition of Heartland Generation, which closed on December 4, 2024.

Table 16: TransAlta acquisition of Heartland assets

Asset	Control (MW)
APS1 Scotford Cogen	195
BR4 Battle River #4	155
BR5 Battle River #5	395
JOF1 Joffre #1	474
MKR1 Muskeg River	202
PR1 Primrose #1	100
SH1 Sheerness #1	260
SH2 Sheerness #2	260
VVW1 Valley View 1	50
VVW2 Valley View 2	50
Grand Total	**2,141**

Figure 41: Dispatchable MW by fuel type (MSOC 2024 and 2025)

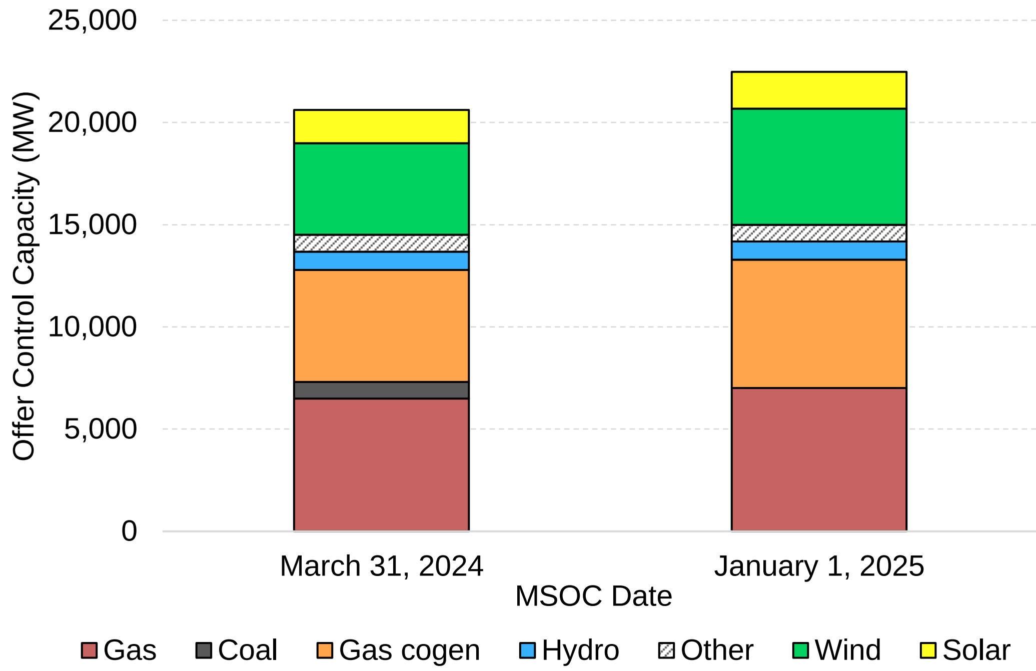
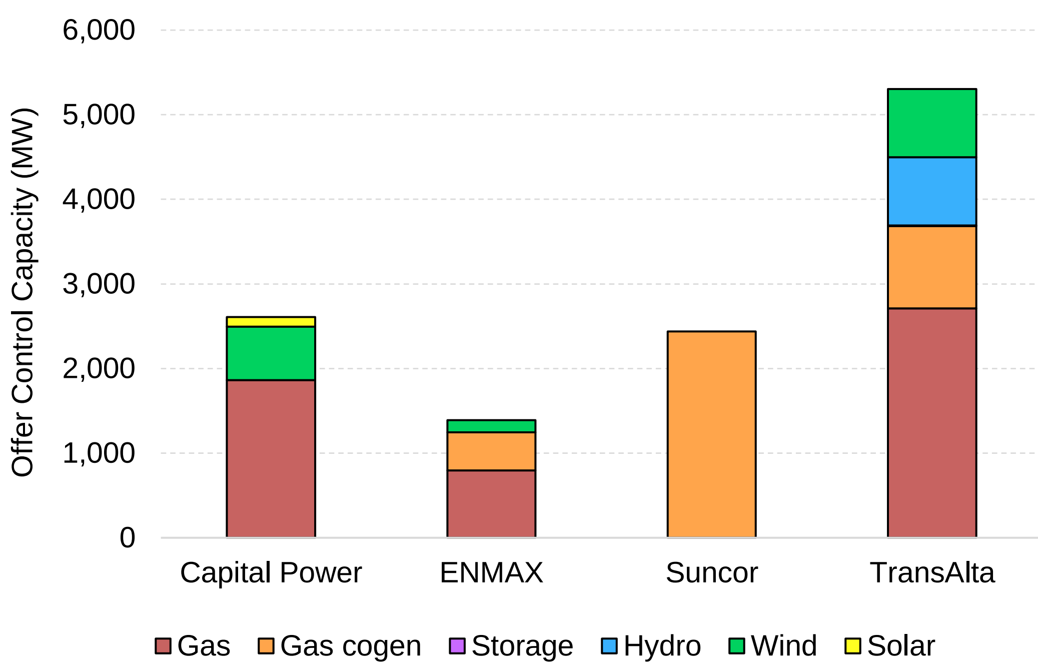


Figure 42: Dispatchable MW by fuel type for market participants with more than 5% offer control



1.7.3 Generation additions, retirements, and maximum capability changes

Since the last MSOC assessment on March 31, 2024:

- 1,801 MW of dispatchable capacity was added;
- existing assets' capacity increased by 894 MW; and
- retirements of GN1 and GN2 (820 MW).

Overall, these changes resulted in Alberta's total capacity increasing by 1,876 MW. Generation additions were comprised of gas, wind, and solar generation assets. A total of 1,801 MW of dispatchable generation capacity was added, of which 1,186 MW (66%) was wind generation, 466 MW (26%) was gas generation, and 149 MW (8%) was solar generation. For the purposes of MSOC, a dispatchable generator is one that submits offers into the power pool. The largest change in existing assets' capacity was from SCR1 Base Plant, which increased its maximum capability from 50 MW to 453 MW on October 10, then to 856 MW on November 9. Specific changes by asset are included in Table 17.

Table 17: Capacity changes between MSOC 2024 and 2025

Asset ID	Fuel Type	2024 (MW)	2025 (MW)	Diff	Date of Change
ACD1	Solar	--	140	140	November 1, 2024
BPW1	Wind	--	466	466	August 20, 2024
CLD1	Solar	--	9	9	October 8, 2024
FRM1	Wind	--	266	266	June 4, 2024
GNR2	Gas	--	466	466	May 7, 2024
HAL2	Wind	--	126	126	September 19, 2024
WIN1	Wind	--	136	136	November 21, 2024
WIR1	Wind	--	192	192	December 18, 2024
Units Added (Units >=5 MW)			**1,801**	**1,801**	
BLS1	Solar	27	31	4	July 24, 2024
DFT1	Solar	37	41	4	July 24, 2024
FCS1	Solar	75	80	5	August 28, 2024
FMG1	Wind	200	220	20	December 6, 2024
GNR1	Gas	411	466	55	August 31, 2024
SCR1	Gas cogen	50	856	806	November 9, 2024
MC Changes (Units >=5 MW)		**800**	**1,694**	**894**	
GN1	Coal	400	--	-400	May 1, 2024
GN2	Coal	420	--	-420	July 1, 2024
Retirements (Units >=5 MW)		**820**		**-820**	
Units <5 MW		198	225	27	
Unchanged Units >=5 MW		19,135	19,135	0	
TOTAL (MW)		**20,954**	**22,856**	**2,722**	

Further details on offer control are provided in the MSA Market Share Offer Control Data file, including:

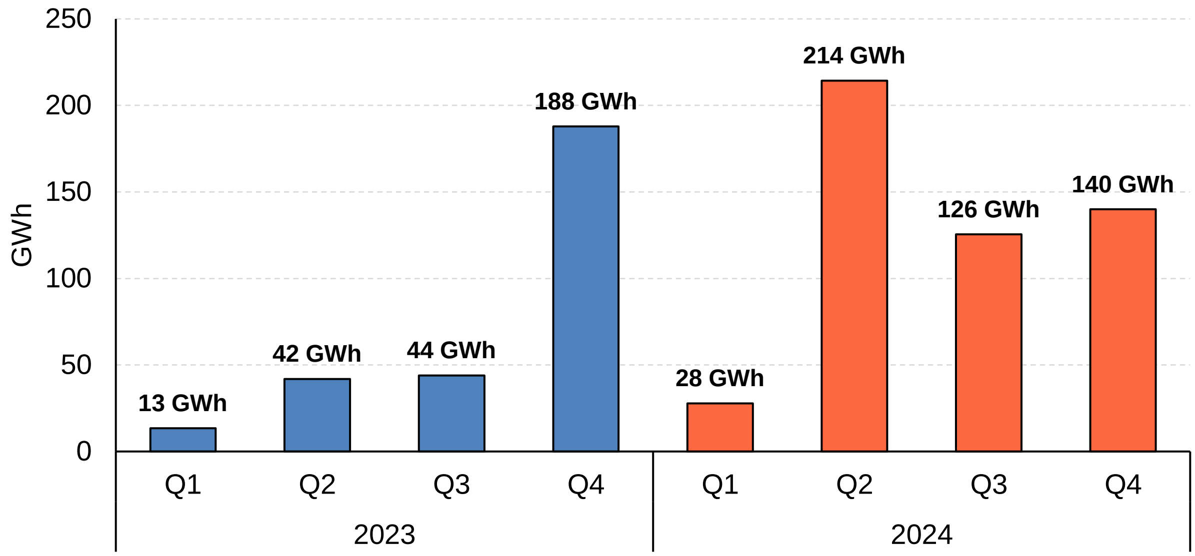
- a table containing offer control data by the affiliates of electricity market participants,
- a summary table of market share offer control in the current year as well as the previous year, and
- tables and charts illustrating the market share offer control of electricity market participants with offer control over 5%

2 THE POWER SYSTEM

2.1 Trends in transmission congestion

2.1.1 Annual Summary

Figure 43: Quarterly total constrained intermittent generation volumes (2023 and 2024)



The total constrained intermittent generation (CIG) volume for 2024 reached 508 GWh, a 178% increase from 286 GWh in 2023 (Figure 43). The 2024 maximum hourly average CIG volume of 1,665 MW was reached on June 16 (Figure 45) and this 2024 peak was 198% higher than 2023 (Figure 44).

In 2024 there were 3,927 hours of CIG greater than 1 MWh which is equivalent to approximately 164 days, or 45% of all hours in 2024. To understand the increasing magnitude of congestion, note that 66 hours in 2024 had more CIG volumes than the single most constrained hour in 2023 (840 MW) (Figure 46).

Figure 44: Maximum hourly constrained intermittent generation (2023)

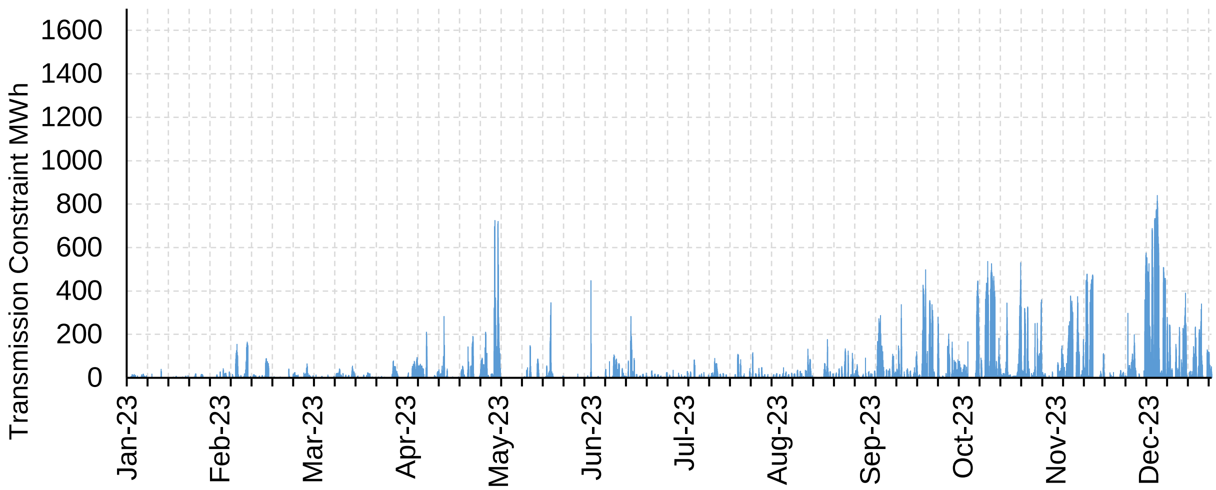


Figure 45: Maximum hourly constrained intermittent generation (2024)

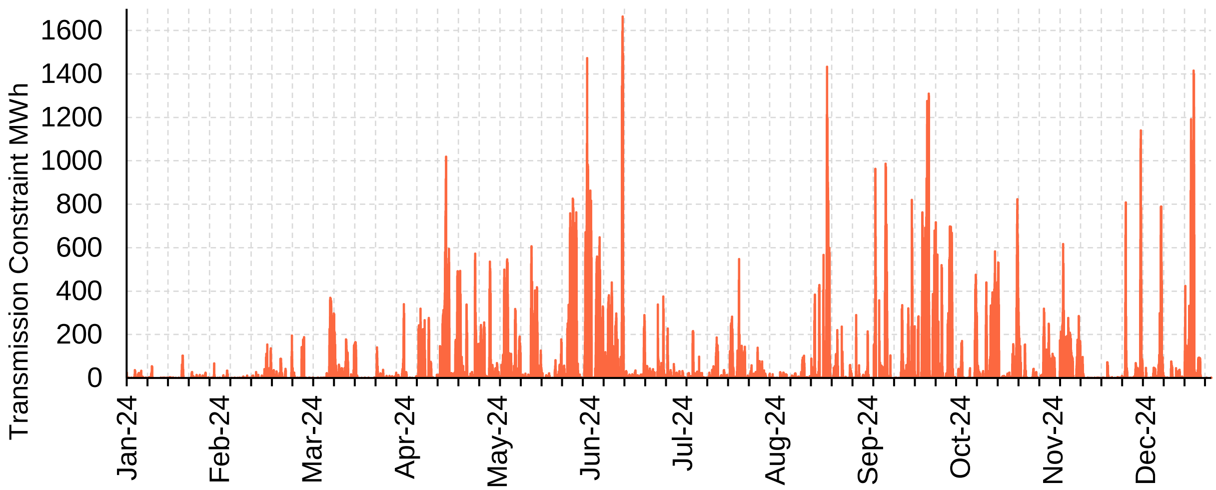
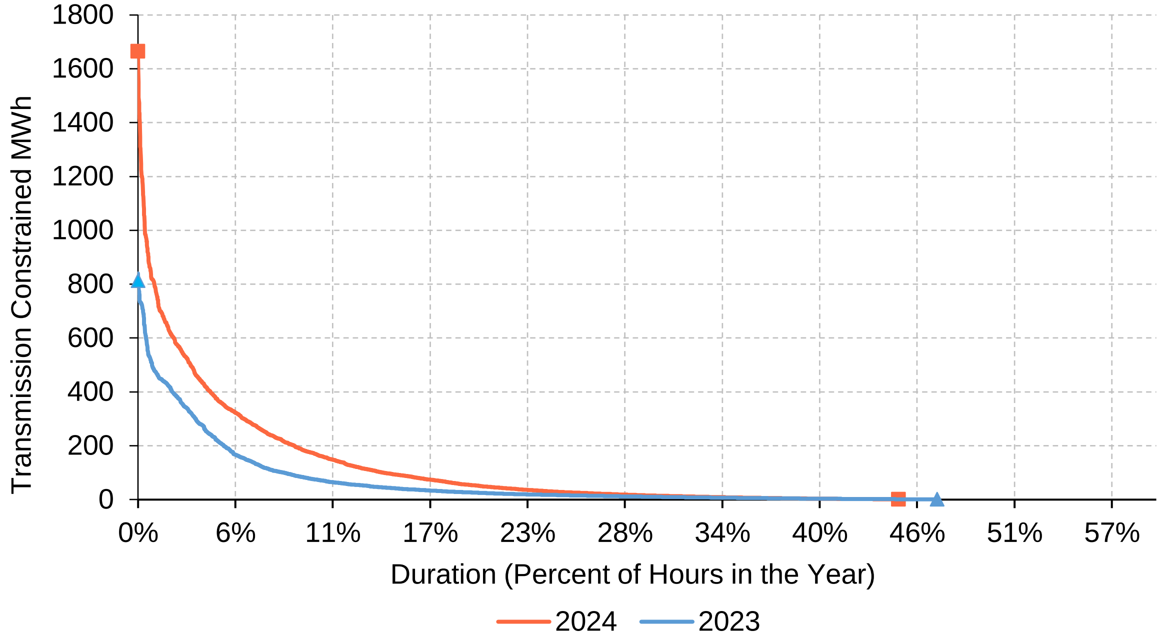


Figure 46: Duration of constrained intermittent generation volume (2023 and 2024)



Throughout 2024, CIG volumes generally occurred in lower priced hours (Figure 47). Of the 508 GWh of CIG volumes, 275 GWh (54%) occurred in hours priced at $10 or less and 216 GWh (43%) occurred in hours priced above $10 but below $50 (Figure 48). The final 17 GWh (3%) occurred in hours priced above $50.

Figure 47: Constrained intermittent generation volumes by pool price in 2024

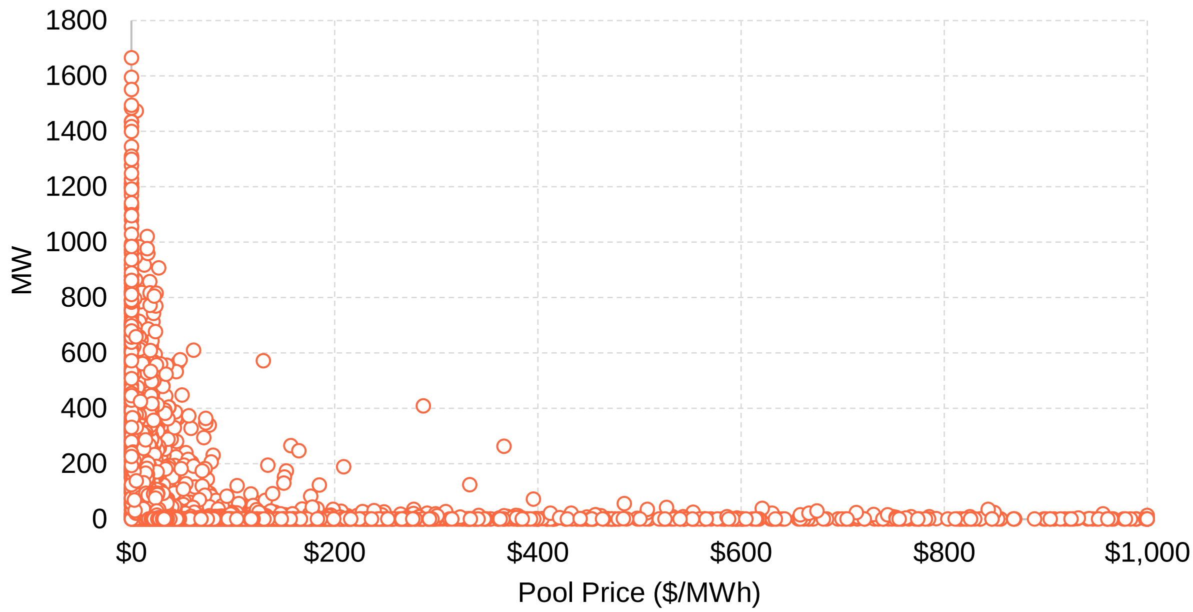
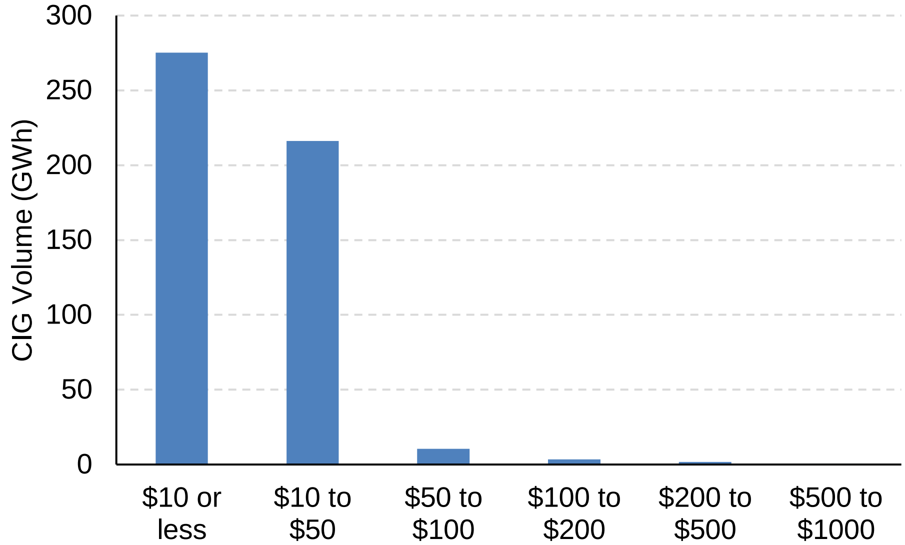


Figure 48: Volume of constrained intermittent generation by pool price in 2024



Transmission capability and contingencies vary through the province and over time, and certain assets may experience more congestion than others. In 2024, the top 10 most constrained intermittent assets (of 95) accounted for 346 GWh of 508 GWh (68%) of all CIG (Table 18). The asset that experienced the highest volume of constraint in 2024 was Paintearth Wind Project (PAW1). PAW1 was constrained for a variety of contingencies, the most prevalent being an overload on 9L16. The constraint for 9L16 often included assets HAL1 and GDP1, the second and fifth most constrained intermittent assets by volume.

Table 18: Top 10 constrained intermittent generation assets by volume in 2024

Asset name	Asset ID	Volume of CIG (MWh)
Paintearth Wind Project	PAW1	49,529
Halkirk Wind Power Facility	HAL1	47,107
Sharp Hill Wind	SHH1	46,360
Rattlesnake Ridge Wind	RTL1	44,512
Garden Plain	GDP1	36,417
Hand Hills	HHW1	31,280
Lanfine Wind	LAN1	26,701
Wheatland Wind	WHE4	24,636
Enmax Taber	TAB1	22,561
Wintering Hills	SCR4	16,429

In 2024, the top constrained assets, measured using CIG as a percentage of potential generation, reached a maximum of 12% (Table 19). Although most assets are similarly on the top constrained intermittent assets by volume, the ordering varies between measurement. JFS1, as the most constrained intermittent asset as a percentage of potential generation, ranks highest but has a low potential generation when compared to other intermittent assets (59th asset in 2024 of 95).

Table 19: Top 10 Constrained intermittent generation assets by percentage of potential generation in 2024

		CIG volume as a share of potential generation (%)	CIG value as a share of total asset revenue (%)
Joffre Solar 1	JFS1	12%	10%
Enmax Taber	TAB1	12%	6%
Paintearth Wind Project	PAW1	11%	5%
Rattlesnake Ridge Wind 1	RTL1	10%	6%
Halkirk Wind Power Facility	HAL1	10%	5%
BRD1 Burdett	BRD1	10%	4%
Garden Plain	GDP1	8%	5%
Wheatland Wind	WHE1	7%	3%
Hand Hills	HHW1	7%	3%
Strathmore 1	STR1	6%	7%

The share of total CIG value by company is calculated using a simplified calculation where the pool price is used to determine the value, which is then multiplied by the associated hours constrained volume. Each company is then given a share based on the total value (Table 20).

Table 20: Top 10 Companies by constrained intermittent generation in 2024[17]

	Value of CIG ($)	**Share of total CIG value (%)**	**Value of CIG as share of total revenue (%)**[18]
Company A *(JNR1, JNR2, JNR3, PAW1, SWP1, WHE1)*	$ 1,159,628	18%	2%
Company B *(CLY1, CLY2, HAL1, STR1, STR2, WHT1, WHT2)*	$ 1,075,708	16%	2%
Company C *(RTL1)*	$ 610,288	9%	6%
Company D *(ARD1, BTR1, CR1, CRE3, GDP1, GWW1, IEW1, IEW2, WRW1)*	$ 601,942	9%	1%
Company E *(SHH1)*	$ 471,343	7%	1%
Company F *(BUL1, BUL2, BUR1, HHW1, HYS1, JER1, SUF1 WCR1, WEF1)*	$ 459,410	7%	1%
Company G *(LAN1)*	$ 327,252	5%	2%
Company H *(AKE1, KHW1, TAB1)*	$ 308,273	5%	2%
Company I *(BFL1, BFL2, BFL3, BFL4, CLR1, CLR2, MIC1, TRH1)*	$ 248,178	4%	1%
Company J *(OWF1, SCR1)*	$ 231,979	4%	2%

2.1.2 Quarterly Summary

Transmission constraints can cause generation to be curtailed. When this occurs, the AESO directs constrained generators to reduce their output to manage the constraint.[19] The MSA

[17] For each Company, all intermittent assets as of March 31, 2024, are listed. However, not all assets listed contributed to the total CIG value.

[18] Total Revenue is total company revenue for all intermittent assets as per the March 31, 2024 MSA Market Share Offer Control Data.

[19] This is known as constrained down generation. See ISO Rule 302.1 Transmission Constraint Management.

estimates the CIG using curtailment limits, available capacity, potential real power capability, and energy dispatch.[20] In this section, the MSA examines trends in CIG.

The frequency and significance of CIG directives decreased from Q4 2023 to Q4. The MSA estimates that CIG volumes were 188 GWh in Q4 2023 and 140 GWh in Q4. Quarter-over-quarter, the CIG volumes increased by 15 GWh. The maximum hourly average volume of CIG in Q4 was 1,417 MW, almost double the maximum of 840 MW in Q4 2023 (Figure 49 to Figure 51). The Q4 maximum hourly average volume of CIG was similar to the previous quarters maximum value of 1,434 MWh (Figure 50).

Figure 49: Maximum hourly constrained intermittent generation (Q4 2023)

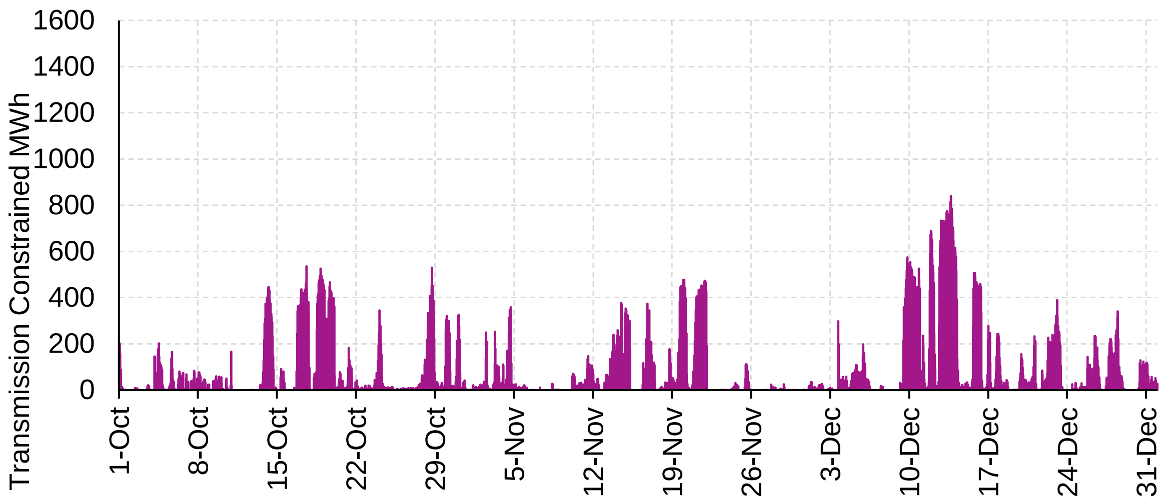
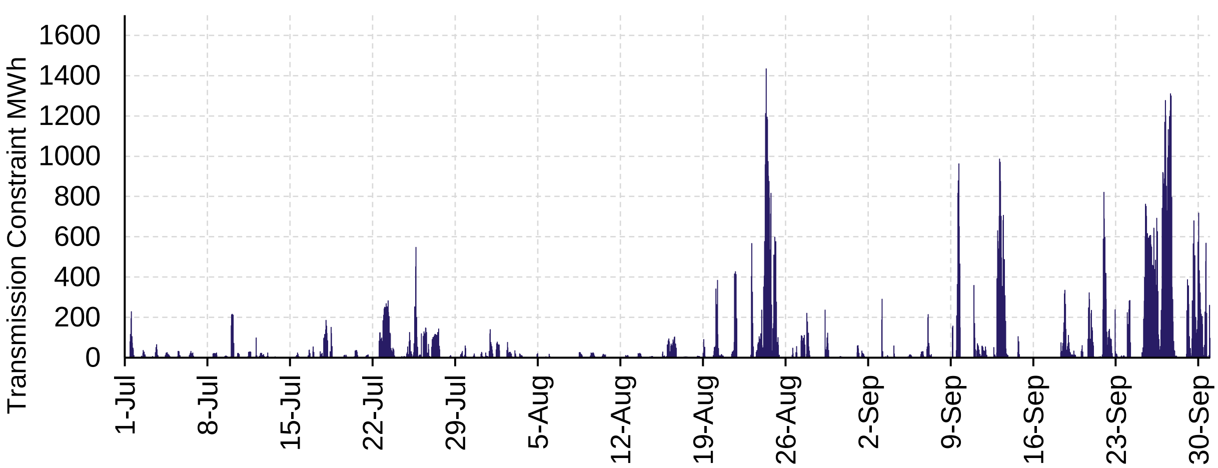
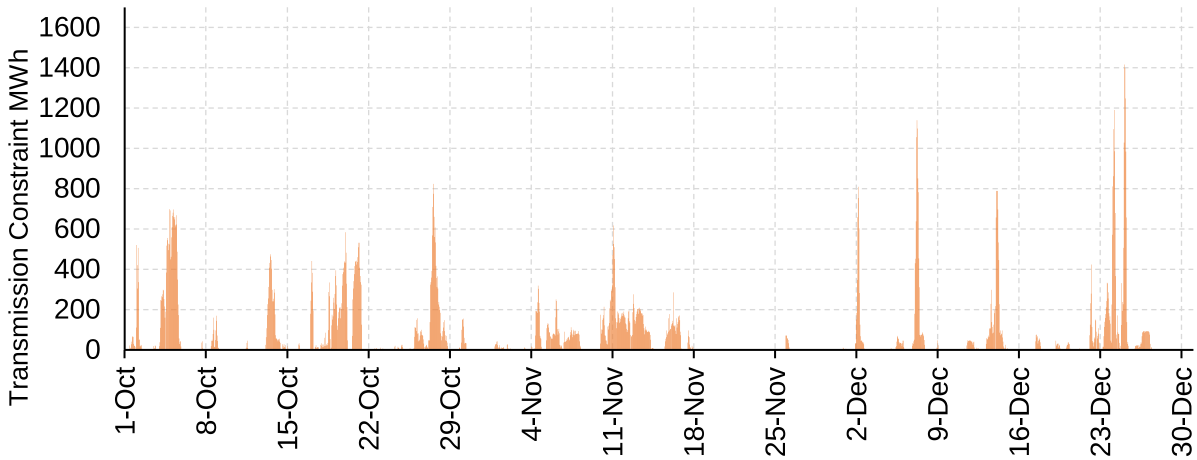


Figure 50: Maximum hourly constrained intermittent generation (Q3 2024)



[20] The AESO's ETS Estimated Cost of Constraint Report calculate TCR volumes using a different methodology than the MSA's estimate of constrained intermittent generation. The MSA's Quarterly Report for Q2 2023 discusses how the MSA calculates the constrained intermittent volumes (formally referenced as constrained down volumes).

Figure 51: Maximum hourly constrained intermittent generation (Q4 2024)



The increased CIG volumes in Q3 are likely due to increased intermittent capacity and high intermittent generation. Generally, higher constrained intermittent volumes align with periods of high intermittent generation or supply surplus events (Figure 52 and Figure 53).

There were over 475 shift log events for constrained down generation in Q4. Increased constrained down generation volumes may also be due to persistent or frequent congestion on certain transmission lines and may affect one or more generation assets. One example of a frequently constrained transmission line is 610L, which is the subject of the Vauxhall Area Transmission Development. However, this quarter saw a wide variety of constraints and zones.

Figure 52: Average hourly potential intermittent generation and constrained intermittent volumes for Q4

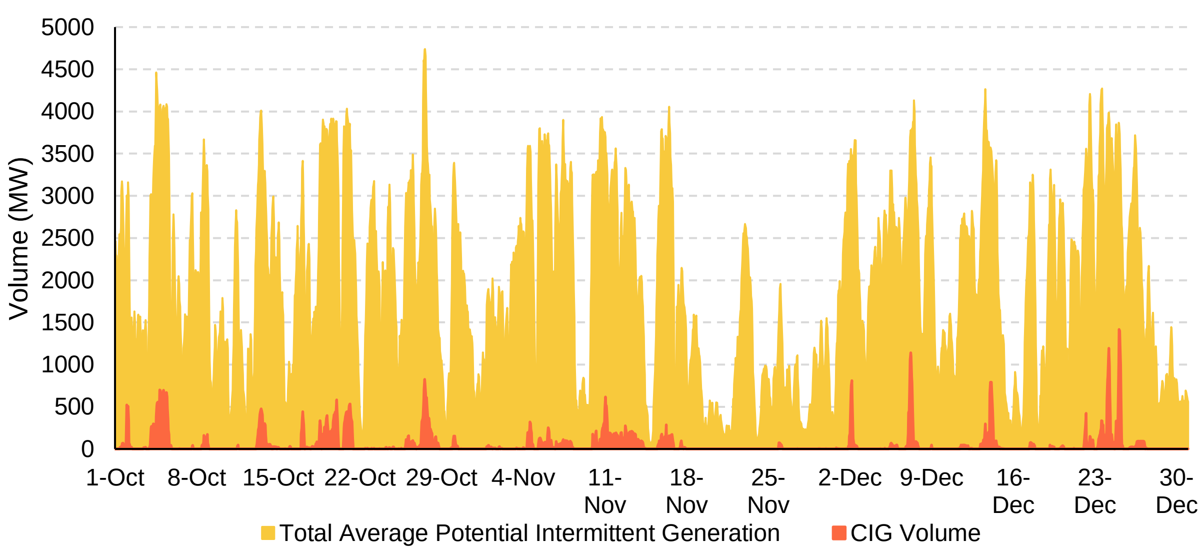
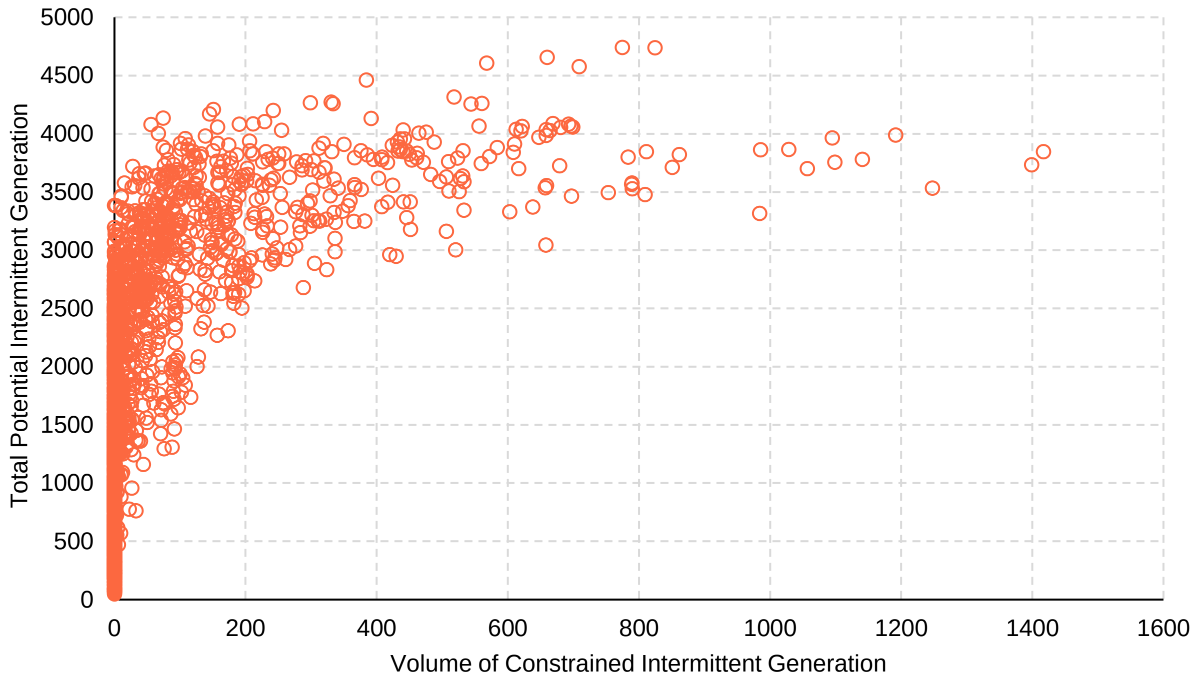


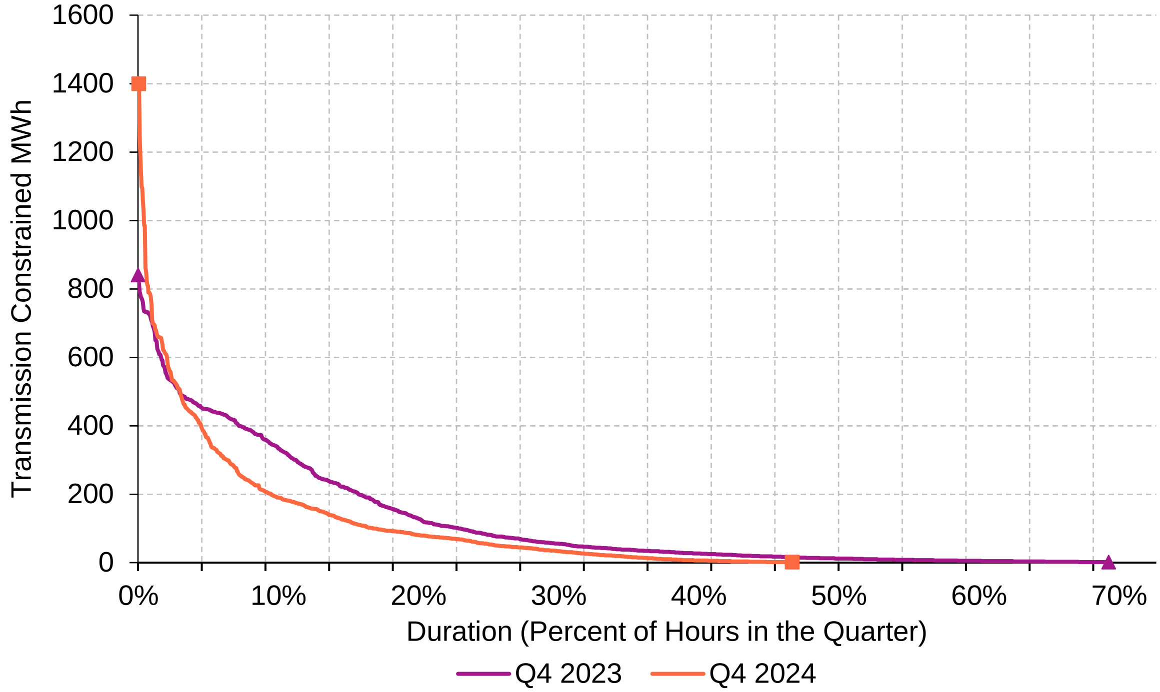
Figure 53: Volume of constrained intermittent generation compared to total potential intermittent generation in Q4



The CIG volume decreased from Q4 2023 to Q4. However, the total installed intermittent capacity continued to increase by 29%. Average hourly CIG volumes, expressed as a percent of installed intermittent capacity, decreased from 1.47% in Q4 2023 to 0.85% in Q4. The average hourly CIG volumes, expressed as a percent of installed intermittent capacity, for Q4 was much closer to the Q3 2024 rate of 0.81%.

Figure 54 illustrates duration curves of CIG year-over-year. The length of the tails to the right of the duration curves show that the frequency of CIG events decreased. There were 1,028 hours of CIG volumes greater than 1 MWh in Q4. This is equivalent to just over 43 days, or 47% of Q4. In contrast, Q4 2023 experienced 1,526 hours of CIG greater than 1 MWh, or over 64 days (69%) of Q4 2023.

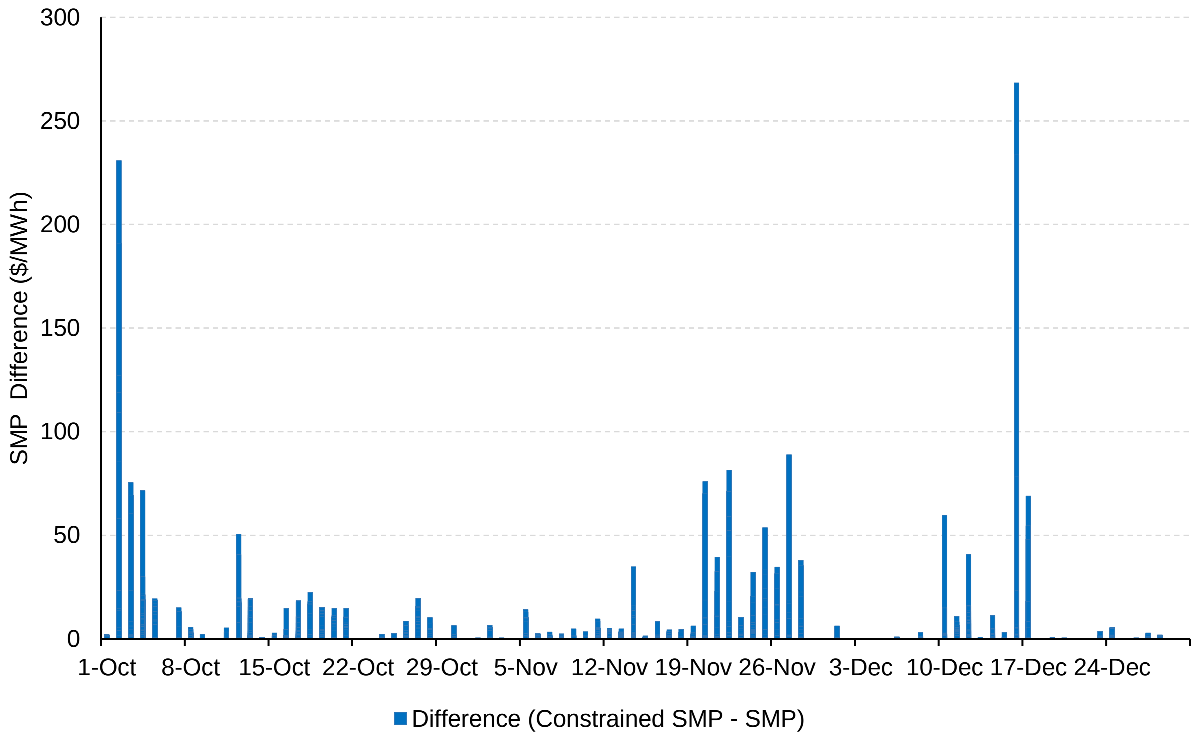
Figure 54: Duration of constrained intermittent generation volume (Q4 2023 and Q4)



Transmission constraints had frequent fluctuations throughout all months of Q4, however October experienced the highest volume of CIG and December experienced the highest peak. The CIG volume in the month of October accounted for 45% of all Q4 volumes. In 52% of October hours there was at least 1 MWh of CIG volume.

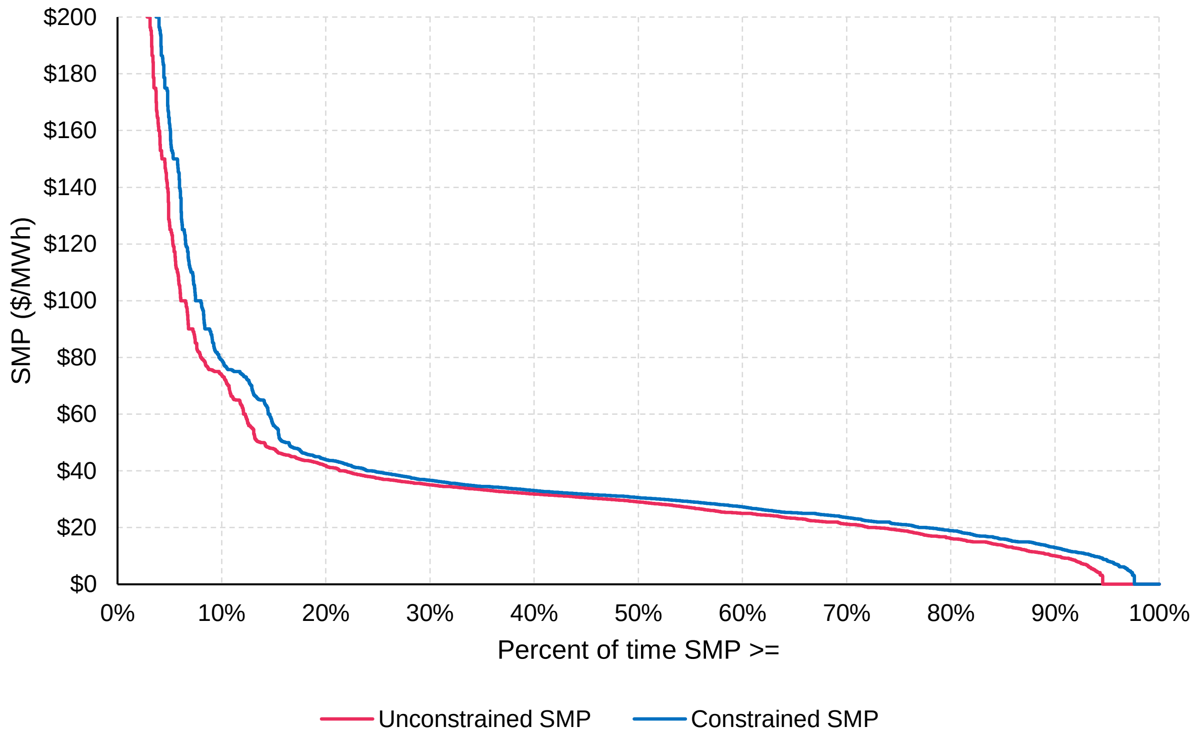
The constrained and unconstrained SMP differed by $1/MWh or more in 26% of hours in Q4 (Figure 55). In comparison, Q4 2023 experienced 35% of hours with a difference of $1/MWh or more between the constrained SMP and unconstrained SMP, and Q3 2024 experienced the difference in 19% of hours. The largest difference between constrained SMP and SMP in Q4 was $268/MWh, which occurred in HE18 of December 16. Despite the frequency and significance of constrained intermittent generation in Q4, the largest difference between unconstrained and constrained price was higher in Q4 2023 at $798/MWh. The largest difference in Q3 2024 occurred on September 23 and reached $152/MWh, $116/MWh less than the Q4 peak. The largest difference in 2024 remains on June 4, 2024, at $637/MWh.

Figure 55: Difference of constrained SMP and SMP in Q4



The periods that experience high volumes of CIG often occur when generation from intermittent resources is high. Given the offer behaviour of these resources, when intermittent generation is higher, SMP is lower as higher priced generation is displaced. Therefore, despite the high amount of CIG volumes in Q4, there was often only a small difference between the unconstrained SMP and the constrained SMP with a few exceptions (Figure 56). This occurs because when prices are low the supply curve is normally relatively flat, meaning that large changes in quantity may have a relatively small impact on prices.

Figure 56: Duration of SMP and constrained SMP for Q4

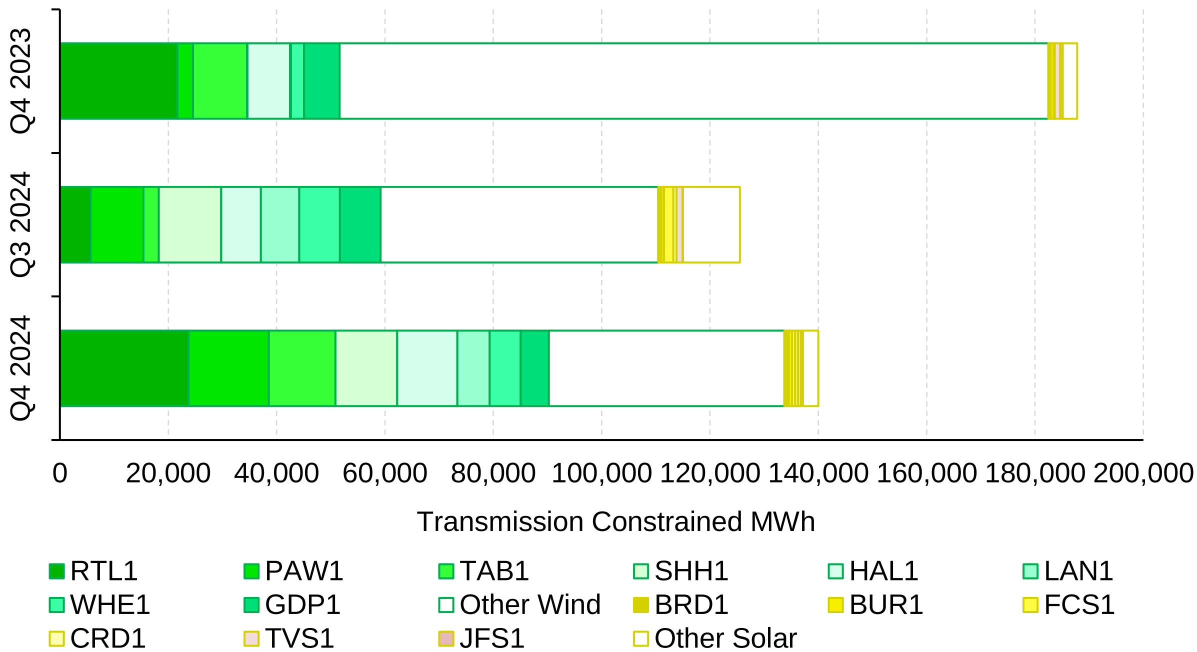


Transmission capability varies throughout the province, and certain regions may experience more congestion than others, often leading to local constraints (Figure 57). Often, wind and solar assets are not constrained uniformly throughout the province. In Q4, the eight most constrained wind assets accounted for 68% of the total CIG volume but only 22% of total installed wind generation.

Rattlesnake Ridge Wind, Paintearth Wind Project, Enmax Taber, Sharp Hill Wind, and Halkirk Wind Power Facility were the most constrained wind assets in Q4. These 5 assets represent 15% of Alberta's installed wind capacity, however they accounted for approximately 55% of the wind constrained volume in Q4.

BRD1 Burdett (11 MW) was the most-constrained solar asset in Q4, with a total of 827 MWh constrained. The asset was constrained due to a persistent issue related to 610L (Vauxhall Area Transmission Development) and real time overloads of 879L. The following five most constrained solar assets have an aggregate maximum capability of 624 MW (159 MW excluding Travers) and were constrained by 2,649 MWh (2,137 MWh excluding Travers) in Q4. The top 6 constrained solar assets account for 34% of the maximum capability of the market and accounted for 55% of solar constrained volumes in Q4. The uneven distribution of CIG volumes to intermittent assets continues within Alberta.

Figure 57: Wind and solar transmission constrained MWh by asset

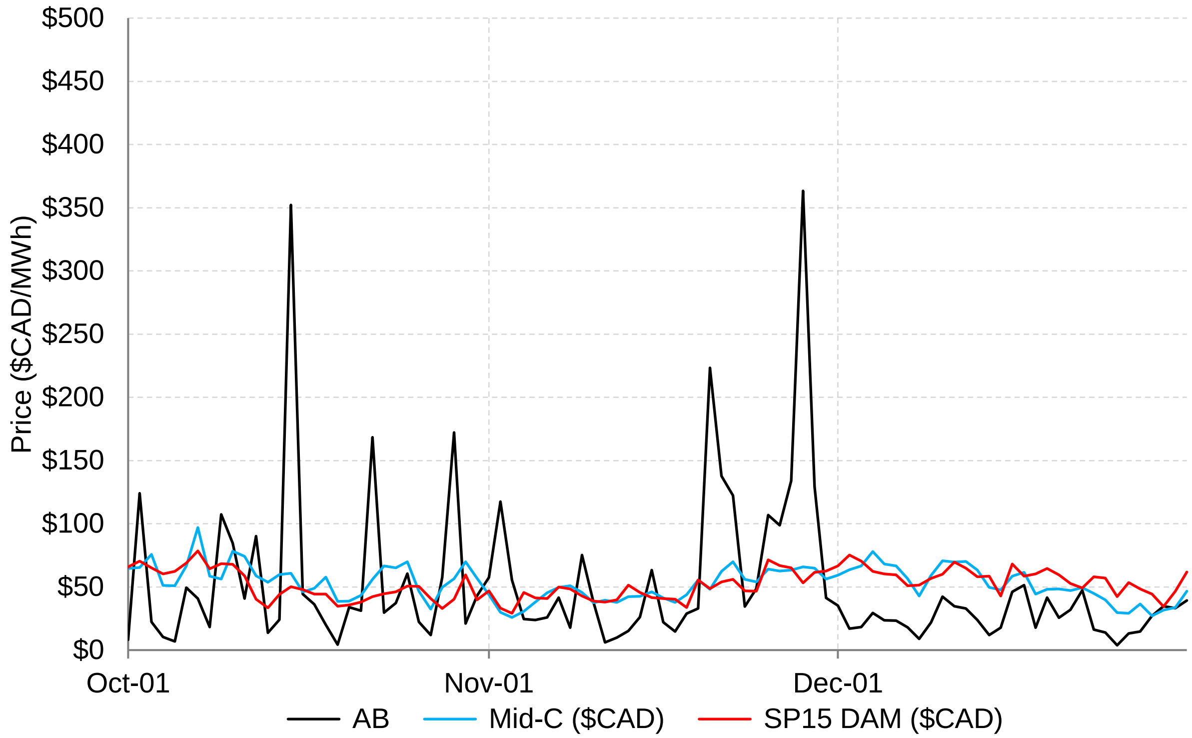


2.2 Imports and exports

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

Figure 58 shows daily average power prices in Alberta, Mid-C, and California (SP-15) over Q4 (shown in Canadian currency). Over the quarter, Alberta prices averaged $51.52/MWh, while Mid-C and California averaged $52.97/MWh and $52.11/MWh, respectively. As shown, Alberta prices were more volatile than Mid-C and SP-15 prices over October and November and were consistently lower during December. Although the quarterly average prices in Alberta and Mid-C were comparable, in 80% of hours prices in Mid-C were higher than in Alberta. As a result of lower pool prices over December, exports from Alberta were higher in December compared to October and November.

Figure 58: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q4)



Alberta was a net exporter of electricity over the quarter, largely driven by export volumes to BC. In Q4, the scheduled flow of power over the BC intertie averaged 221 MW of exports, with the highest monthly volume of exports occurring in December at an average of 367 MW (Table 21). In December, exports were higher during the off peak averaging 517 MW compared to 292 MW during on peak hours.

In Q4 last year, the scheduled flow of power on the BC intertie averaged 395 MW of exports, with December averaging 601 MW of net exports. The higher level of exports to BC last year can be attributed to higher Mid-C prices and a low water resource year. As of January 2025, the accumulated BC snowpack is below normal but is higher than last year.

The scheduled flow of power on MATL averaged 6 MW of imports, compared to 56 MW of imports in Q4 2023. The decrease in imports can be partly explained by lower pool prices in Alberta, especially over December, with net exports during 84% of hours in the month, corresponding to a weighted average pool price of $23/MWh for the exports.

The scheduled flow of power on the SK intertie averaged 2 MW of imports, compared to 17 MW of imports in Q4 2023. The SK intertie went offline beginning on October 4 through the end of the year. Currently, the intertie is set to return for commercial operation beginning June 30, 2025, and has resumed operation on an emergency basis as of January 15, 2025.

Table 21: Average net import (+ve) and export (-ve) volumes for Q4 2023 and 2024

	2023				2024			
	BC	**MATL**	**SK**	**Total**	**BC**	**MATL**	**SK**	**Total**
October	-241	63	32	-145	-177	14	5	-158
November	-340	78	4	-258	-114	55	0	-59
December	-601	27	13	-561	-367	-50	0	-417
Q4	**-395**	**56**	**17**	**-322**	**-221**	**6**	**2**	**-213**

Figure 59: Daily average import (+ve) and export (-ve) volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q4)

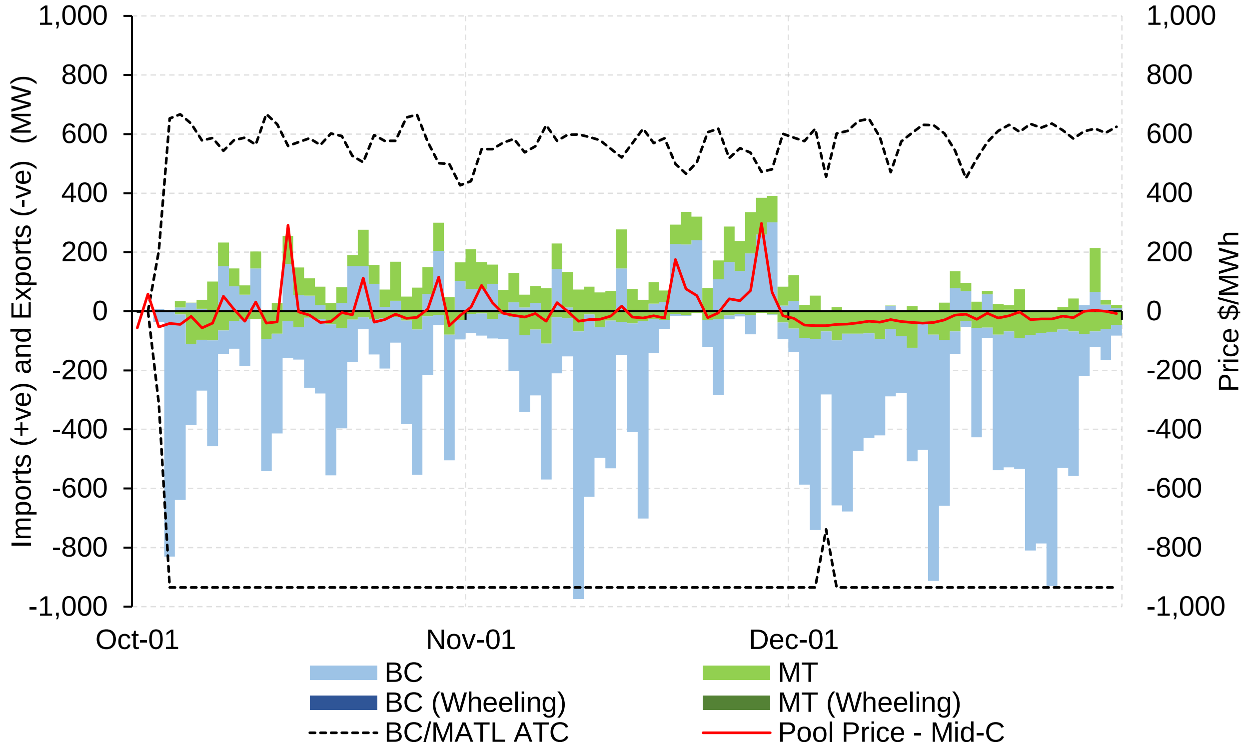


Figure 59 shows the daily average schedule of intertie volumes for BC/MATL, with intertie capability and the price differential between Alberta and Mid-C also illustrated. Over the quarter BC/MATL import capability averaged 577 MW, excluding hours of zero capability, while over Q4 2023, import capability averaged 512 MW. As shown, import capability was zero in early October, which was the continuation of planned intertie outages for BC and Montana beginning September 23, 2024. Additionally, there was a decrease in BC/MATL capability on December 4, which was due to a forced outage that caused unexpected islanding for approximately five hours.

Figure 60 shows a scatterplot of the price differential between Alberta and Mid-C against the net scheduled flows on BC/MATL for each hour over the quarter. Economic flows are generally in the top right and bottom left segments based on the realized price differential (without consideration of transmission costs or other factors). Observations of high price differential with no net scheduled flow are associated with intertie outages in early October.

In certain hours the net import offers on BC/MATL were at or above import capability, meaning that BC/MATL was import constrained (shown in red). Over Q4, BC/MATL imports were constrained for 188 hours or 9% of the time. While import constrained, the price differential between Alberta and Mid-C averaged $168/MWh and import capability averaged 474 MW.

There were also hours where net export bids were at or above BC/MATL export capability, meaning that BC/MATL was export constrained (shown in green). Constrained values at 0 MW are associated with the islanding event on December 4, and constrained values ranging from -400 MW to -700 MW are associated with insufficient transmission availability. Over Q4, BC/MATL exports were constrained for 217 hours or 10% of the time. While BC/MATL was export constrained, the price differential between Alberta and Mid-C averaged -$34/MWh and export capability averaged 926 MW. Additionally, there were hours where net export bids were at or above BC export capability, with net import offers on MATL, meaning that only the BC intertie was export constrained (shown in yellow). Over the quarter, BC exports were constrained for 41 hours or 2% of the time. While BC was export constrained, the differential between Alberta and Mid-C averaged -$35/MWh and export ATC averaged 935 MW.

Figure 60: Alberta and Mid-C price differential and net BC/MATL flows (Q4)

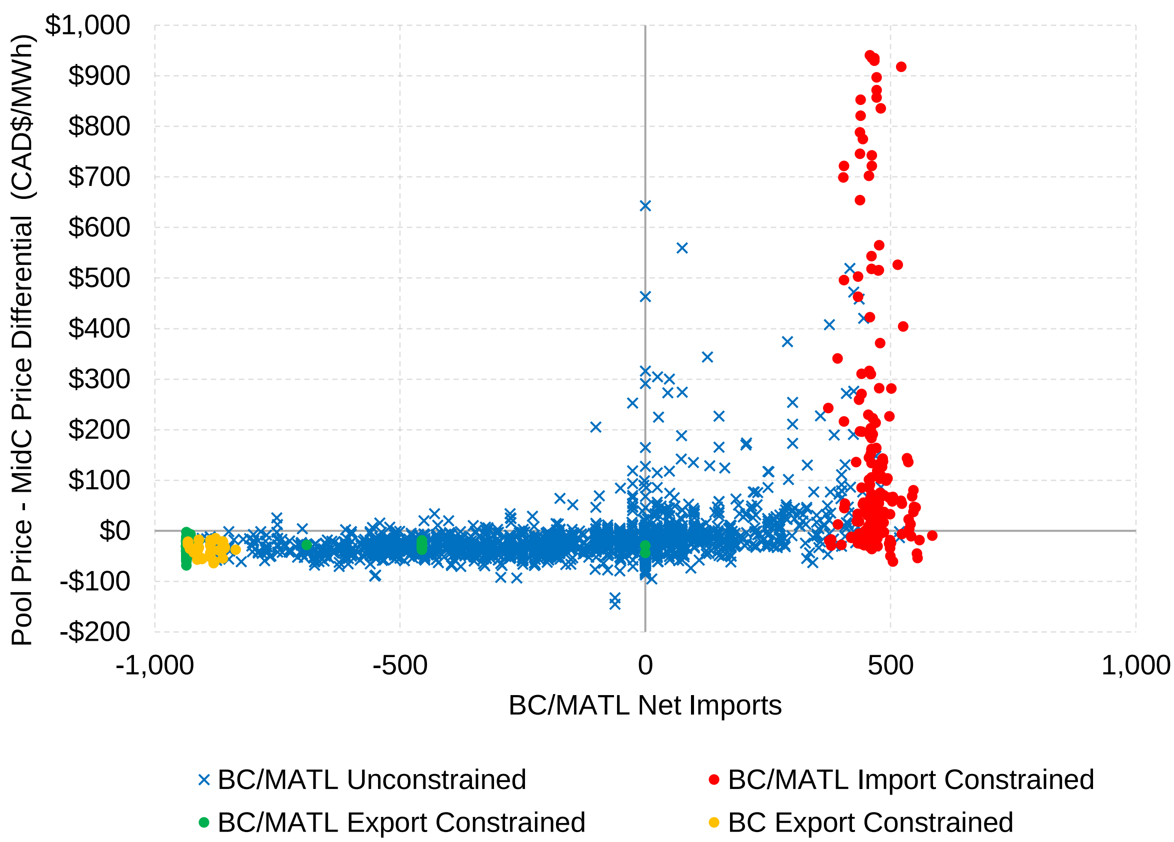
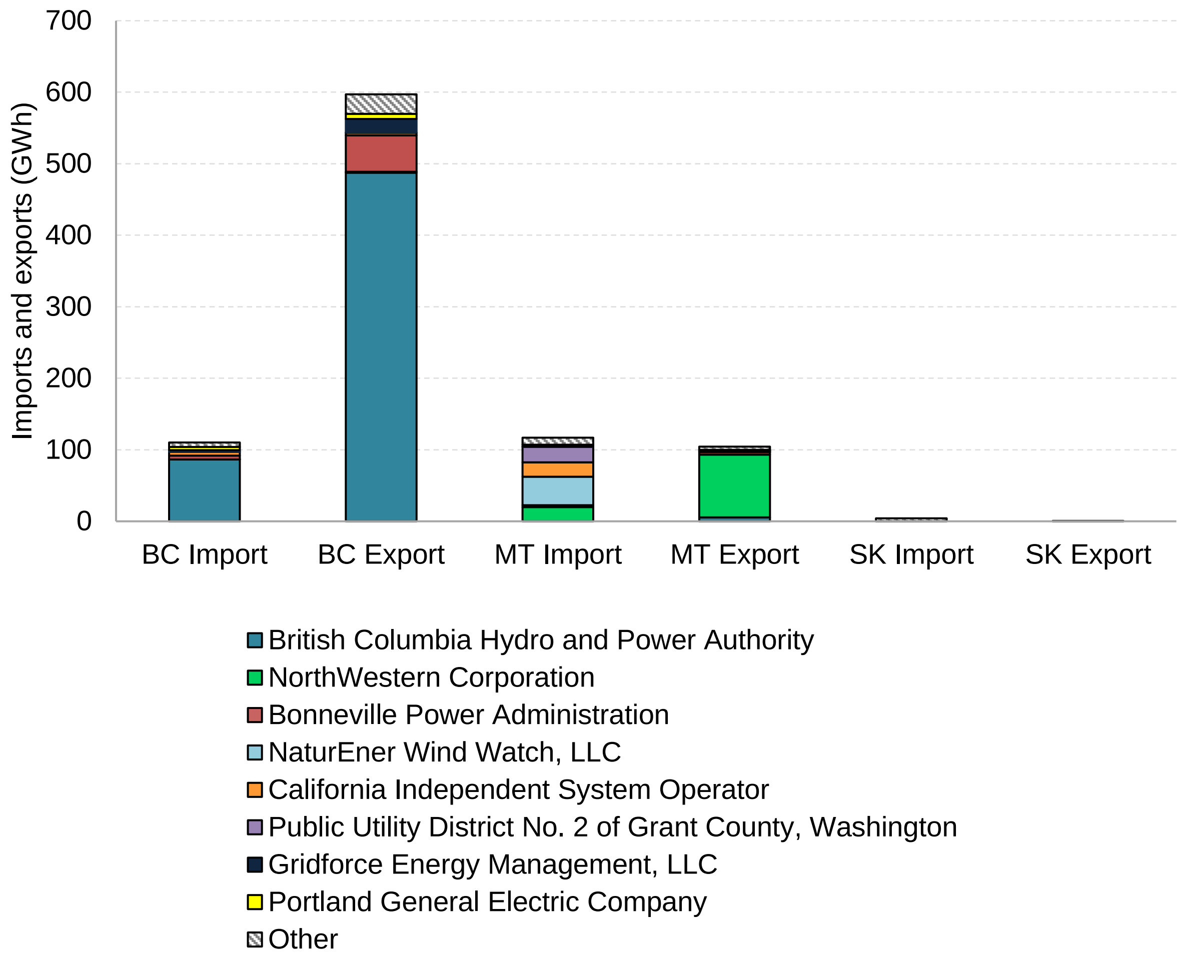


Figure 61 shows import volumes in the quarter by the point of receipt (POR) and export volumes by the point of delivery (POD).[21] The Balancing Authority regions directly connected with Alberta have a high share of import and export flows.

For imports on the BC intertie, approximately 78% originated from BC, 17% from the US Northwest, and 5% from California. For exports on the BC intertie, 82% was delivered to BC, 18% to the US Northwest, and 1% to California.

For imports through MATL, 82% originated from the US Northwest, 17% from California, and 1% from US Central. For exports on MATL 93% was delivered to the US Northwest, 5% to BC, 1% to California, and 1% to US Central.

Figure 61: Interchange point of receipt (imports) and point of delivery (exports) for interchange volumes by Balancing Authority (Q4)[22]



[21] 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.

[22] This includes the highest eight Balancing Authorities by volume.

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

Compliance with the Alberta Reliability Standards (ARS) is necessary to ensure the reliable operation of the Alberta interconnected electric system. BAL-001-AB-2, Real Power Balancing Control Performance (BAL-001), is a reliability standard that is applicable only to the ISO which has the purpose to control interconnection frequency within defined limits. This section reports an MSA analysis of the ISO's performance in respect of the requirements and measures set out in BAL-001 for the period of January 1, 2017, to December 31, 2024 (the assessment period).

BAL-001 applies to the ISO except when:

(i) the ISO is receiving overlap regulation service;

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

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

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

BAL-001 contains two requirements and two corresponding measures:

> R1: The ISO must operate such that the control performance standard 1 (CPS1) is greater than or equal to 100% for each preceding 12 consecutive month period, evaluated monthly.
>
> MR1: Evidence of operating such that the control performance standard 1 is greater than or equal to 100% as required in requirement R1 exists. Evidence may include dated calculation output from spreadsheets, system logs, or other equivalent evidence.
>
> R2: The ISO must operate such that its clock-minute average of reporting area control error does not exceed the clock-minute area control error limit of the balancing authority for more than 30 consecutive clock-minutes.
>
> MR2: Evidence of operating such that the clock-minute average of reporting area control error does not exceed the clock-minute area control error limit of the balancing authority for more than 30 consecutive clock-minutes as required in requirement R2 exists. Evidence may include dated calculation output from spreadsheets, system logs, or other equivalent evidence.

2.3.1 Assessing R1: Control Performance Standard 1 (CPS1)

CPS1 measures the relationship between Area Control Error (ACE) and system frequency deviations relative to the targeted frequency bound for the western interconnection as determined by the North American Electric Reliability Corporation (NERC). Details surrounding the specifics of the CPS1 calculation can be found in the MSA's Q2 2024 report.[23] CPS1 averaged 181% in Q4 2024, a reduction of two percentage points compared to Q4 2023. The average CPS1 for 2024 was 180%, signifying a year-over-year decline in its average by 1%.

Figure 62: Monthly average CPS1 (January 2017 to December 2024)

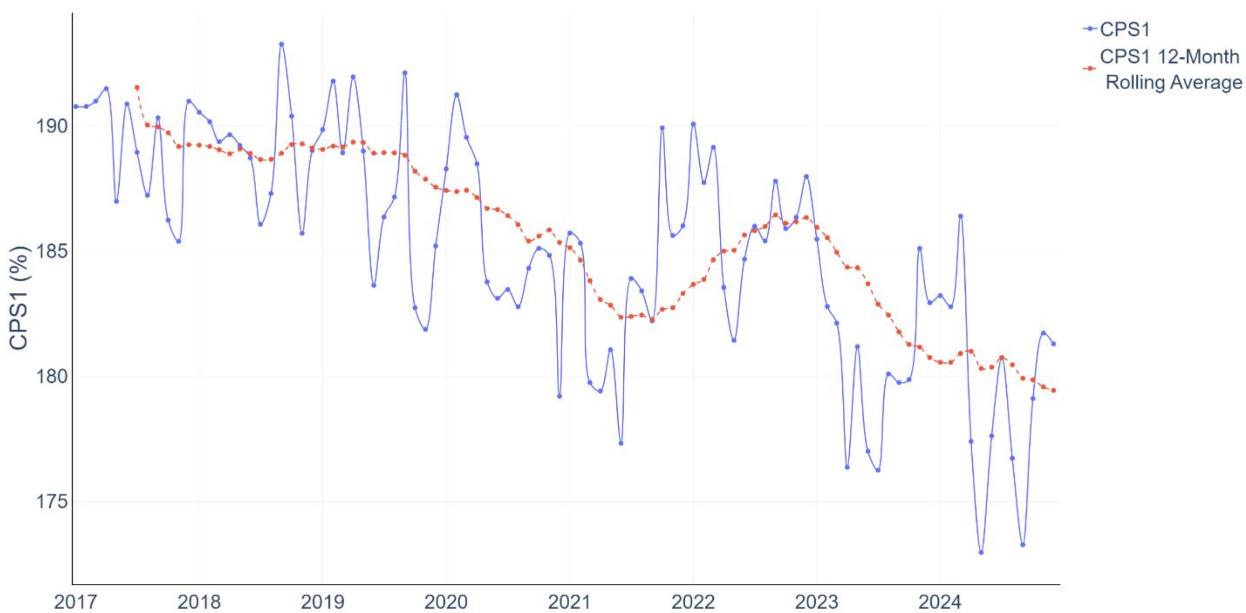
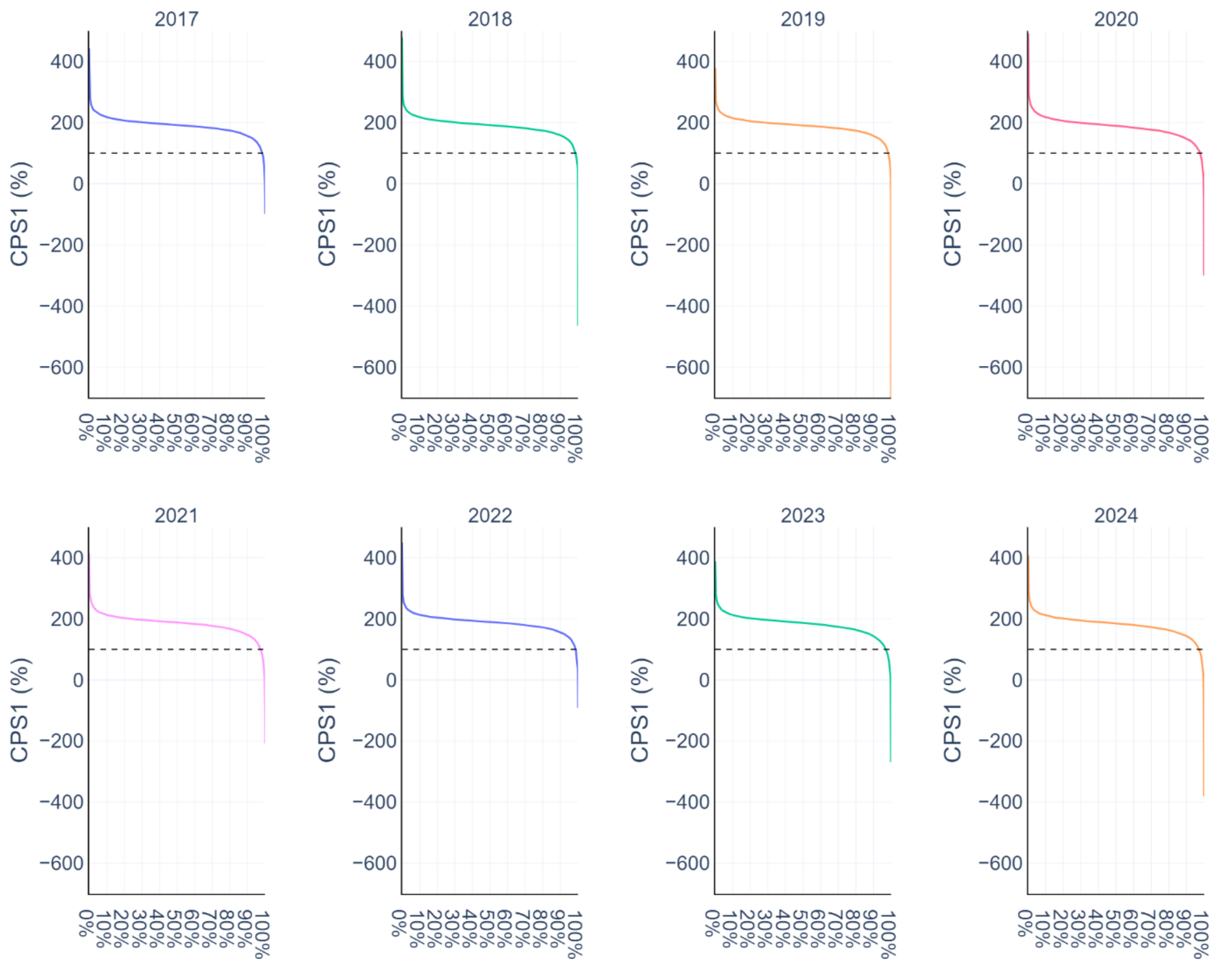


Figure 63 highlights average hourly CPS1 duration curves over the assessment period. On average, CPS1 exceeded the 100% threshold in 97% of hours in 2024.

[23] MSA, Q2 2024 Report.

Figure 63: Hourly CPS1 duration curves by year (2017 to 2024)

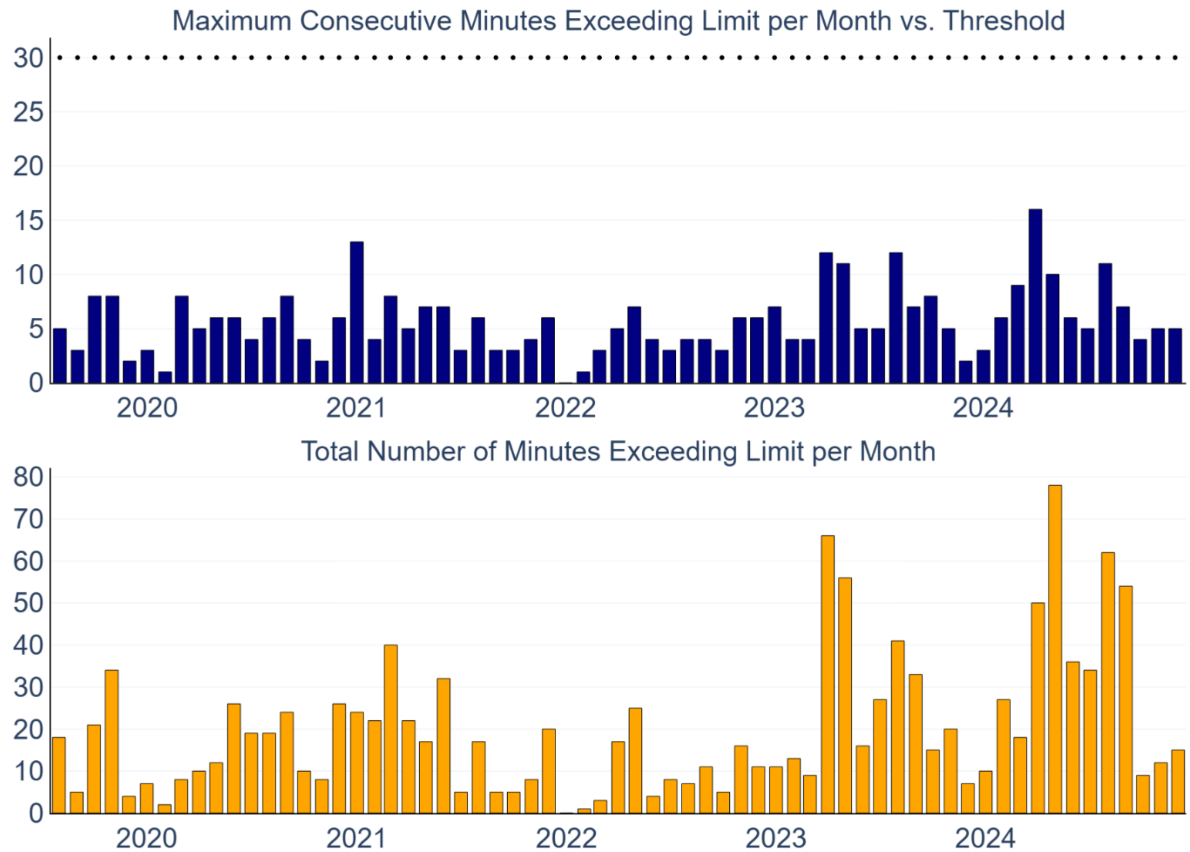


2.3.2 Assessing R2: Balancing Area ACE Limit (BAAL)

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

Figure 64 is divided into two panels, with the upper most subplot referring to the maximum amount of consecutive minutes in which the boundaries were exceeded, and the lower subplot illustrating the total amount of minutes in exceedance of the bounds. The largest number of consecutive ACE limit exceedances for 2024 occurred on April 10 due to low output from wind and solar assets in combination with rapid loss of generation due to outages. This was discussed at a greater length within the MSA's Q2 2024 report.[24] May 2024 had the greatest number of minutes exceeding BAAL over the assessment period with a total of 78 minutes. Notably, this was the same month CPS1 reached its minimum.

Figure 64: Monthly ACE limit exceedances (July 2019 to December 2024)



[24] Quarterly Report for Q2 2024 at page 45

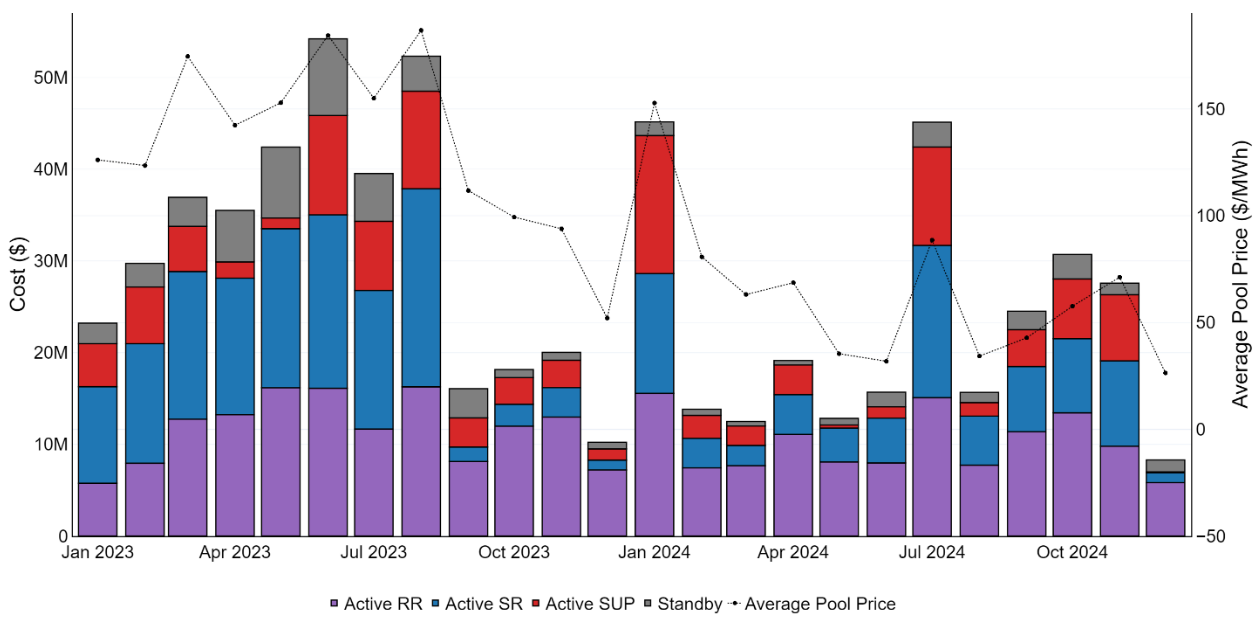
3 OPERATING RESERVE MARKETS

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

3.1 Annual summary

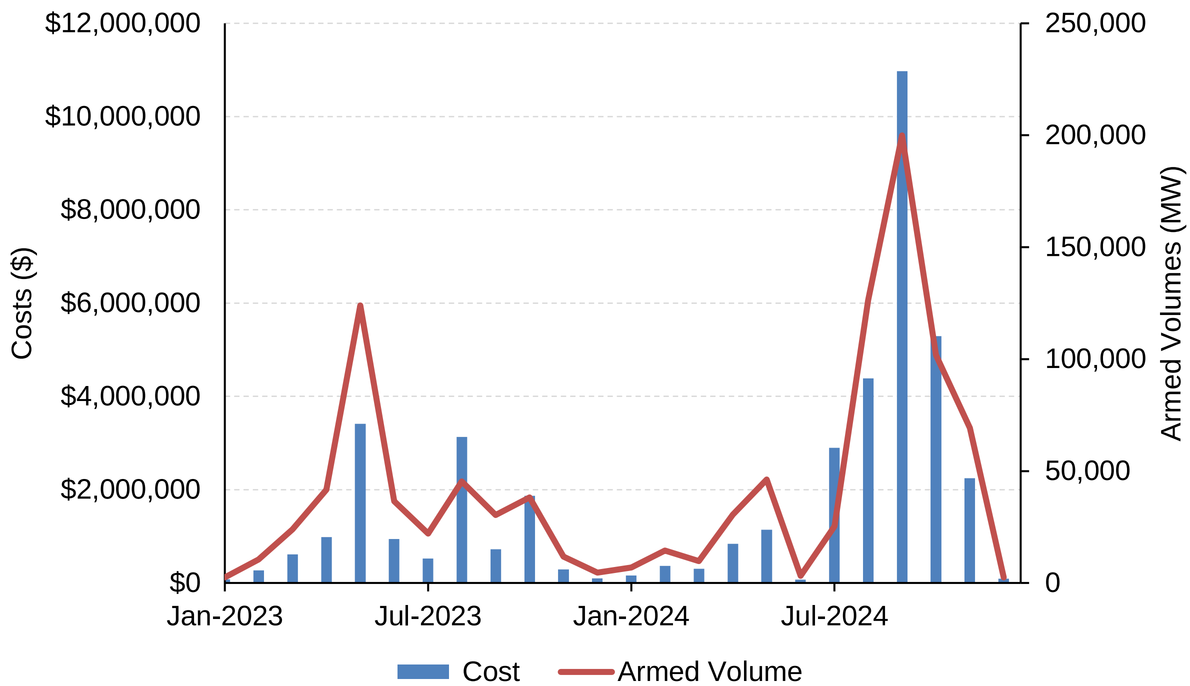
Operating reserve costs include active and standby costs for regulating, spinning and supplemental reserves. Total operating reserve costs in 2024 were $271 million, a 28% decrease from $378 million in 2023. Year-over-year we saw an increase in the proportional cost contributions of regulating (+8 percentage points) and supplemental reserve (+5 percentage points), while spinning and standby reserve costs declined by 7 and 6 percentage points, respectively. In 2024 regulating reserves made up 45% of total operating reserve costs, while spinning reserves comprised of 29%, supplemental reserves made up 20%, and standby reserves contributed 6%.

Figure 65: Monthly operating reserve costs ($ millions) and pool price ($/MWh) (January 2023 to December 2024)



Annual costs for Fast Frequency Response (FFR) increased year-over-year, jumping from $13 million to $29 million in 2024. 63% of the AESOs FFR costs were incurred during Q3. The large spike in FFR costs in Q3 was largely driven by a surge in demand for the product during the islanding of the Alberta electrical grid in late September when BC/MATL was on a planned outage. Costs in September 2024 were $11 million, accounting for 38% of annual FFR costs (Figure 66). As demand for FFR fell, FFR costs declined falling from $18 million in Q3 to $8 million in Q4. In addition to demand-side cost drivers, FFR costs are also impacted by the contractually agreed upon price which varies from company to company.

Figure 66: FFR costs vs. armed volumes (January 2023 to December 2024)

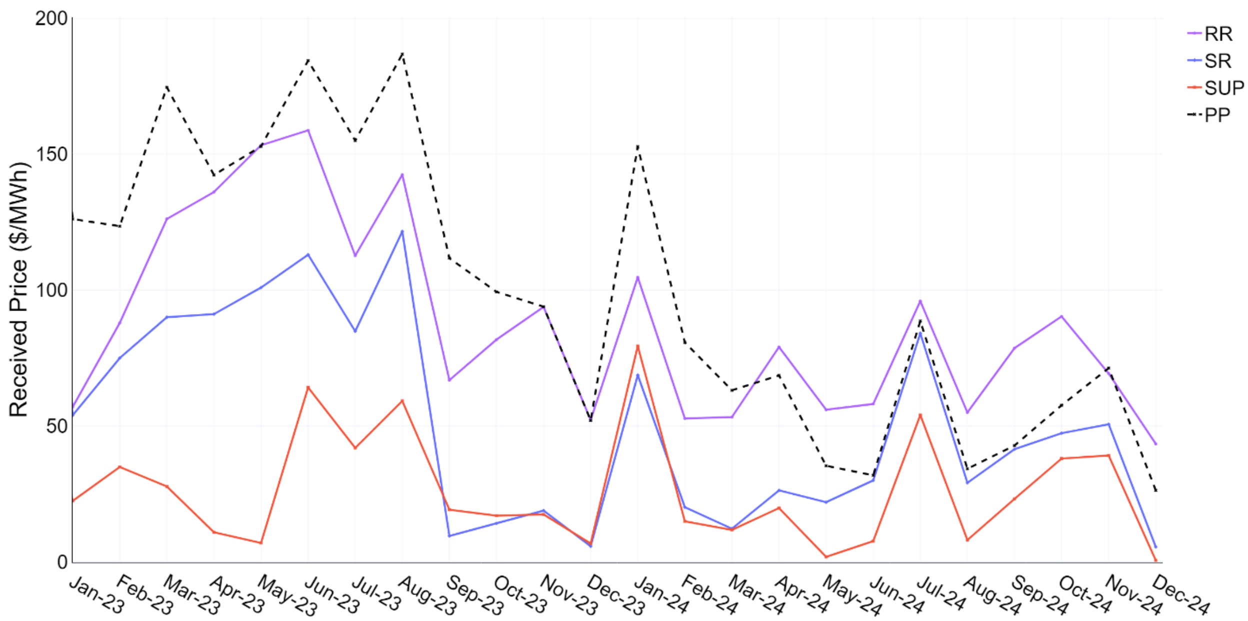


3.2 Received prices

Received prices for operating reserves are calculated by indexing pool prices with the equilibrium prices set in the day-ahead auctions. Figure 67 highlights the monthly average received prices for OR products over time. Mean received prices for all products declined in 2024, following the decline in pool prices (Figure 67). Year-over-year average the AESO's procurement volume for each product increased.

In December the received price of supplemental reserves was close to $0/MWh. This reflects the fact that pool prices were sufficiently low so as not to cover the equilibrium discount set in the day-ahead auctions for supplemental reserves.

Figure 67: Monthly active received price for spinning, supplemental and regulating reserves (January 2023 to December 2024)

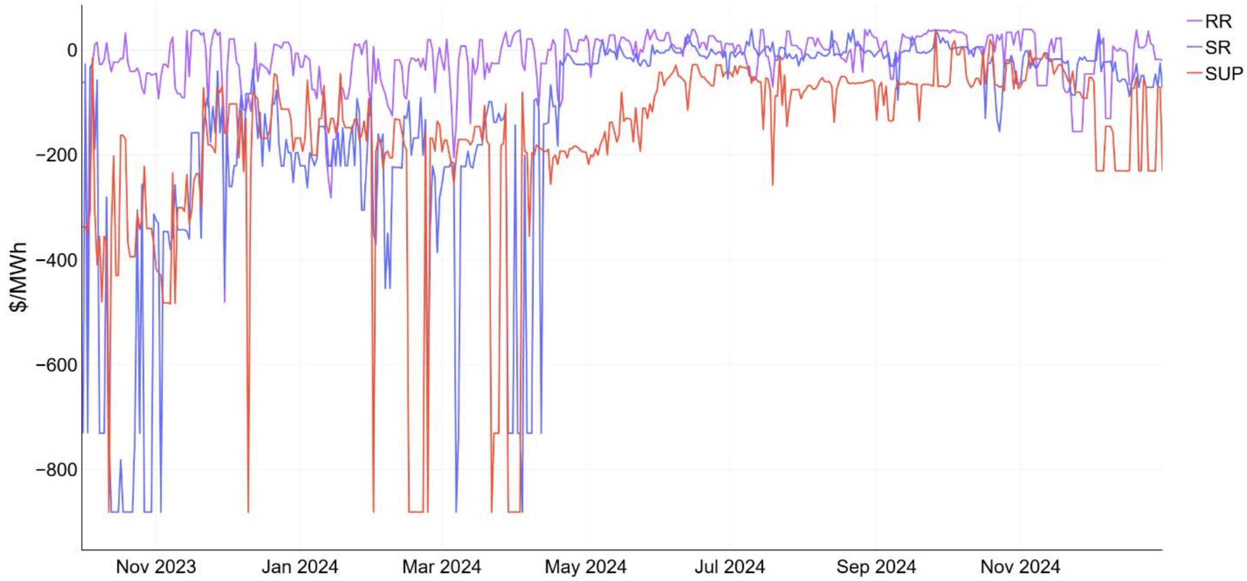


The average annual pool price fell by $71/MWh from 2023 to 2024. However, received prices for regulating, spinning, and supplemental reserves only declined by $36/MWh, $28/MWh and $2/MWh respectively (Table 22). This dampened decline in received prices is due to higher equilibrium prices for all products year-over-year. Received prices for supplemental reserves declined by the smallest margin in comparison to the other OR products. This was largely driven by a decline in load participation and an increase in occurrences where energy storage assets set the marginal price.

Table 22: Average received price and AESO bid volume for active regulating, spinning and supplemental reserves (2023 and 2024)

	Received Price ($/MWh)			**Volume (MW)**		
Products	**2023**	**2024**	***Difference***	**2023**	**2024**	***Difference***
RR	106	70	*(36)*	152	196	*44*
SR	65	37	*(28)*	230	234	*4*
SUP	27	25	*(2)*	230	234	*4*
Pool Price	134	63	*(71)*	-	-	-

Figure 68: Daily active on-peak equilibrium prices (Q4 2023 to Q4 2024)



In Q4 the average pool price declined by $31/MWh year-over-year. However, the average received price for spinning and supplemental reserves increased by $22/MWh and $12/MWh, respectively, and the price for regulating reserves declined by only $8/MWh (Table 23). The change in received prices for OR products in the face of lower average pool prices shows that equilibrium prices set in the OR auctions increased.

The increase in spinning reserve equilibrium prices occurred as the market rebounded from a historically low period in Q4 2023, which resulted from competition for dispatch between hydro and energy storage (Figure 68). In the supplemental market, prices have risen due to less participation from load assets and more offers from energy storage. In general, contributing to the price hikes for OR products was a decline in offered volumes and an increase in AESO procured volumes. The total offered volumes for each on-peak OR product, and corresponding AESO bid volumes can be seen in Figure 69, Figure 70 and Figure 71 below. As shown, in recent months there has been less supply cushion between total offers and the AESO procurement (bid) volume.

Table 23: Q4 active received prices (2023 and 2024)

	Q4 2023 ($/MWh)	Q4 2024 ($/MWh)	Change ($/MWh)
RR	$76	$68	($8)
SR	$13	$35	$22
SUP	$14	$26	$12
Pool Price	$82	$51	($31)

Figure 69: On-peak regulating reserve offered volumes vs. AESO bid volumes (January 2023 to December 2024)

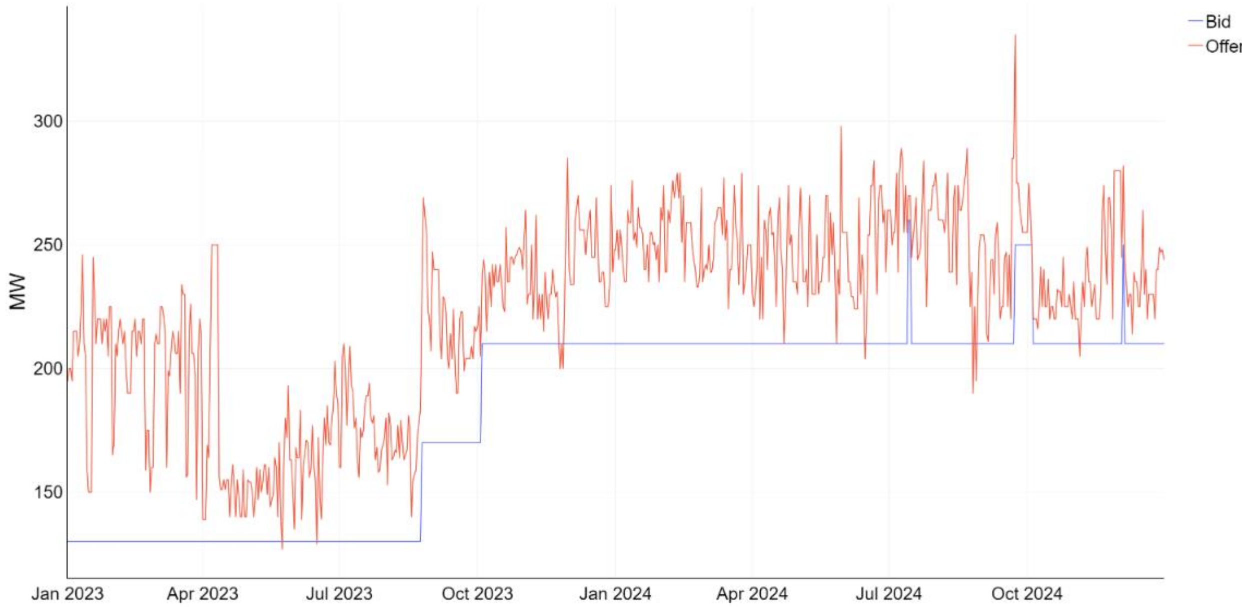


Figure 70: On-peak spinning reserve offered volumes vs. AESO bid volumes (January 2023 to December 2024)

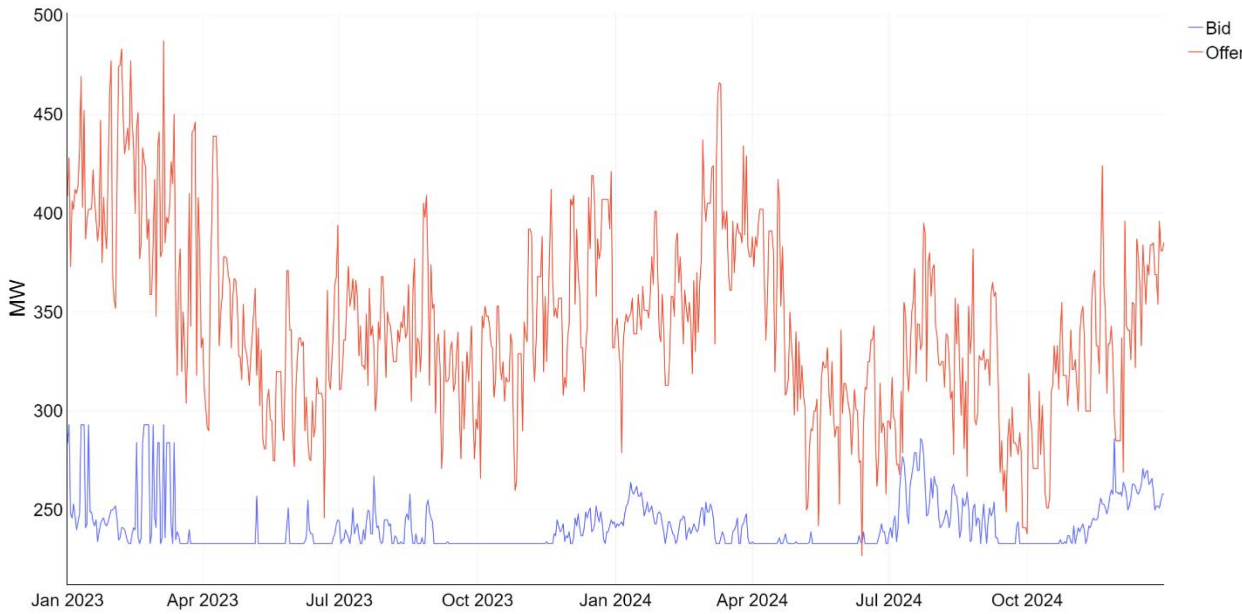
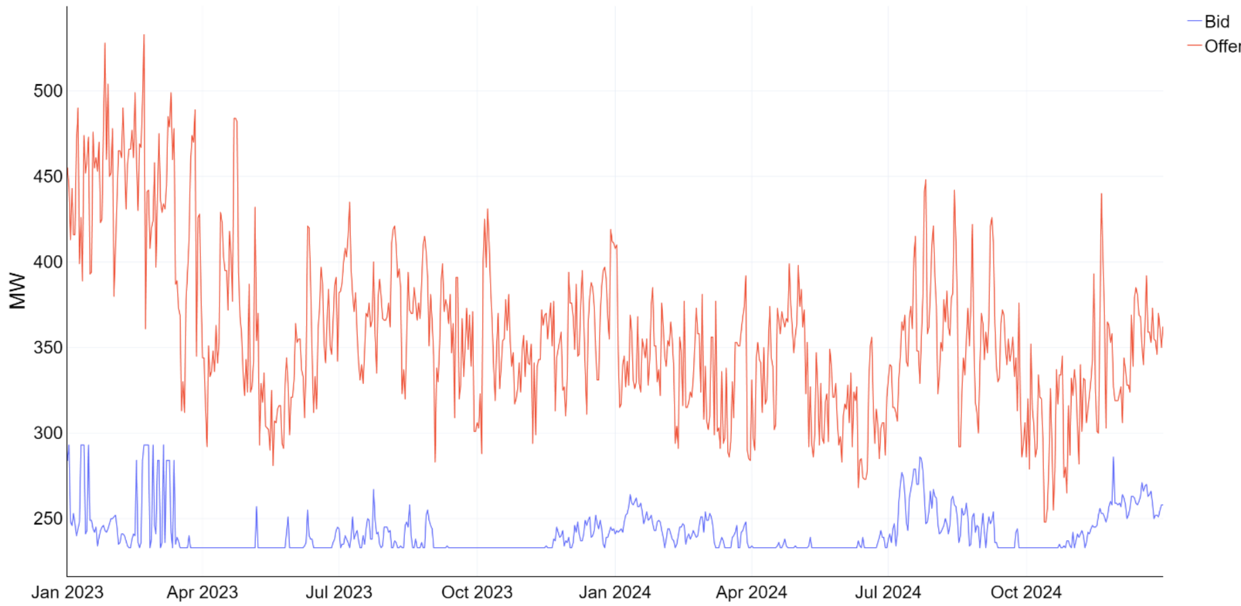


Figure 71: On-peak supplemental reserve offered volumes vs. AESO bid volumes (January 2023 to December 2024)



Loads, which typically offer at a steep discount to pool price, began to lower their participation in the on-peak supplemental reserve market, contributing to an increase in equilibrium price. As this transition occurred, energy storage became the dominant marginal fuel type in the on-peak supplemental reserve market leading to an increase in prices (Figure 68). During this time, energy storage assets more frequently acted as the marginal unit in the on-peak spinning reserve market as well (Figure 72 and Figure 73).

Figure 72: Monthly percentage of marginal fuel type for on-peak supplemental reserve (January 2023 to December 2024)

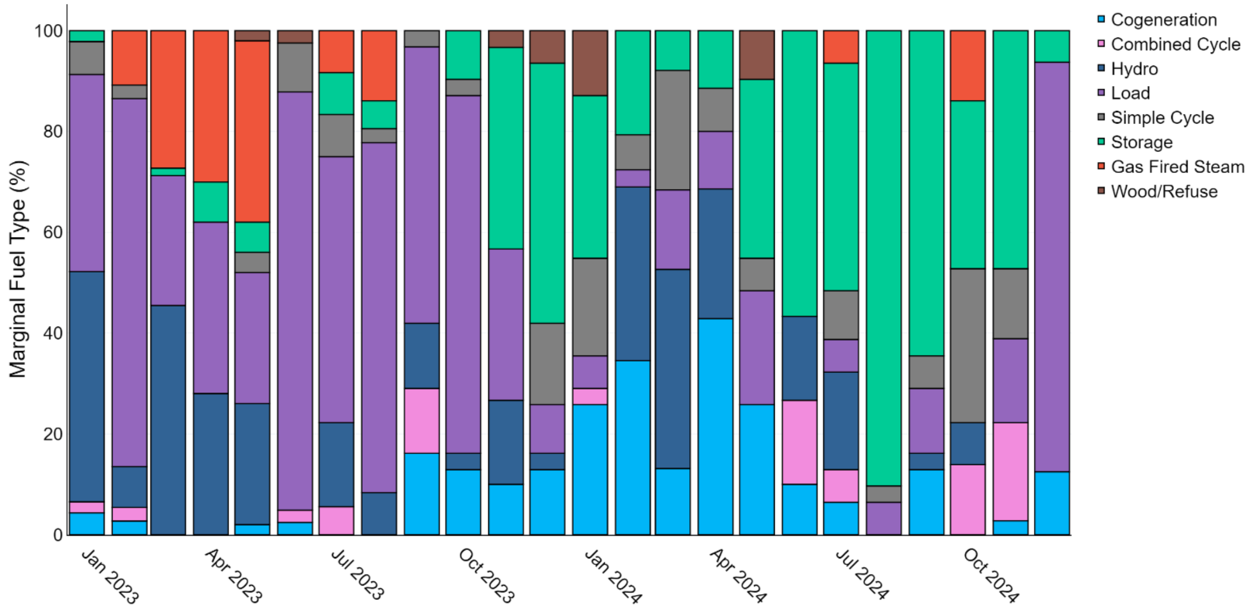
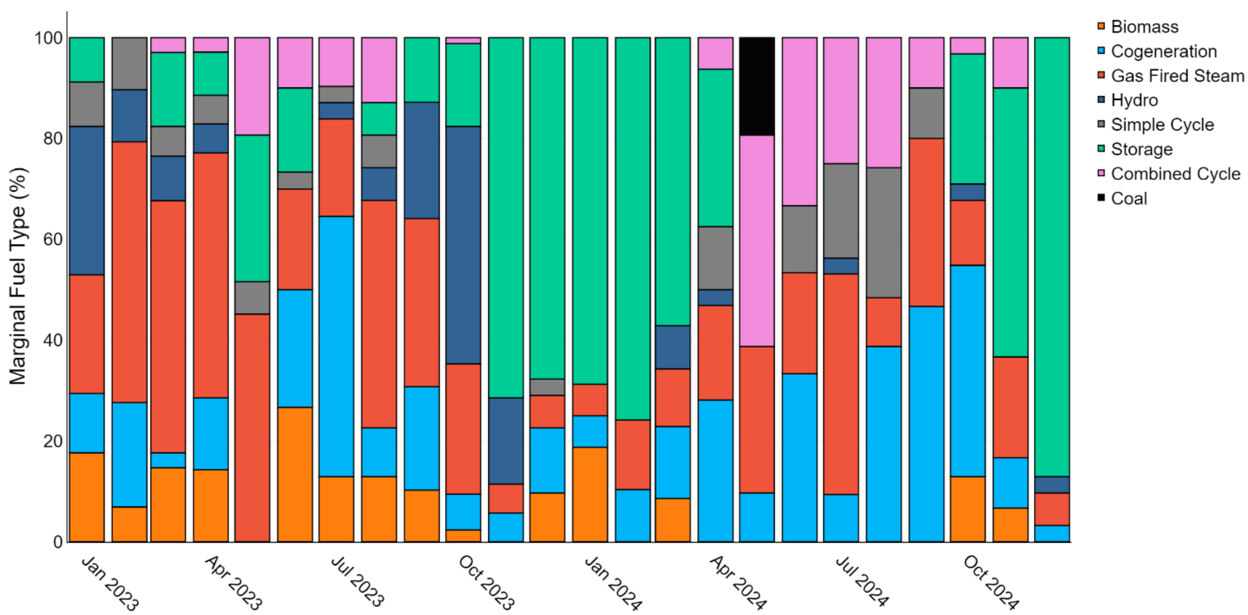


Figure 73: Monthly percentage of marginal fuel type for on-peak spinning reserve (January 2023 to December 2024)



3.3 Standby

Standby ORs are used to provide volumes to the market when all active reserves have been dispatched, and additional reserves are required. The standby market follows a pay-as-bid structure and uses a blended price formula to rank standby offers for market clearing.[25] Market participants receive the premium price for contracted standby volumes, the activation price for dispatched active volumes, and pool price for directed volumes. The activation percentages in the blended price formula are determined by the AESO and are intended to reflect historical activation rates for on- and off-peak hours.

In Q4 2023 the MSA calculated the annual on- and off-peak standby activation rates for the years 2022 and 2023. In response to these findings, the AESO updated the activation percentage used in the blended price formula to reflect current activation rates more accurately at the time (Table 24). However, as noted within the MSA's Q4 2023 report, it was expected that standby activation rates for regulating reserve would decline as the AESOs increased procurement of active volumes for the product. Activation rates for on-peak standby regulating reserve averaged 3% throughout 2024, marking a 34 percentage point decline relative it's 2023 average. Activation rates for on- and off-peak spinning and supplemental reserve aligned relatively well with the AESOs benchmark.

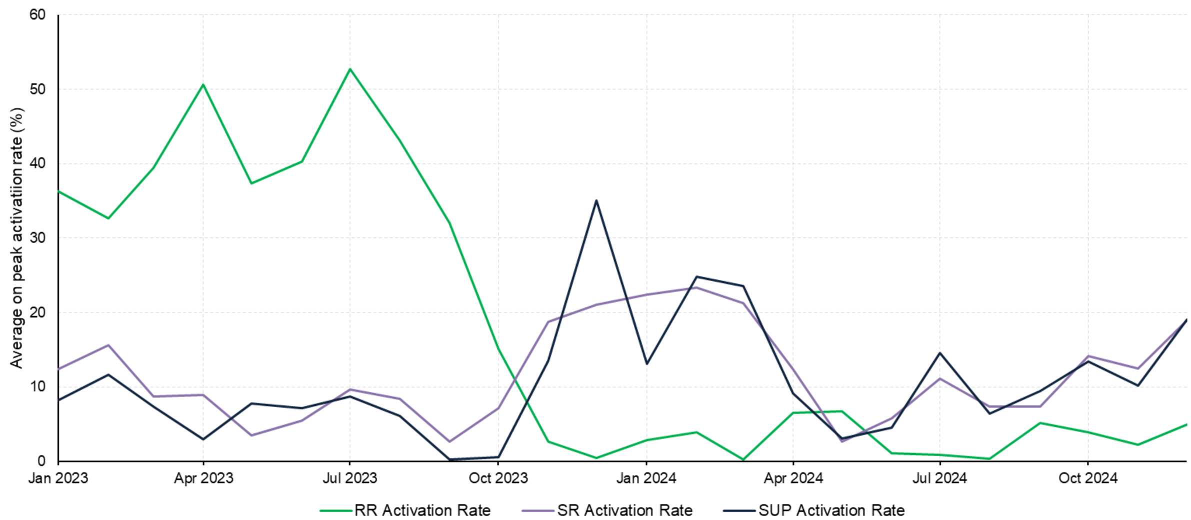
Table 24: Annual standby activation rates by block and product (2023-2024)

Block	Product	AESO Activation % (Updated April 2024)	Annualized Activation % (2023)	Annualized Activation % (2024)
On Peak	**RR**	37%	37%	3%
	SR	10%	10%	13%
	SUP	9%	9%	13%
Off Peak	**RR**	38%	38%	13%
	SR	14%	14%	18%
	SUP	15%	15%	17%

Quarter-over-quarter, we observed an increase in activation rates for all on-peak standby reserve products. The fourth quarter on-peak activation rates for regulating, spinning and supplemental reserves were: 4%, 15% and 14%, respectively (Figure 74).

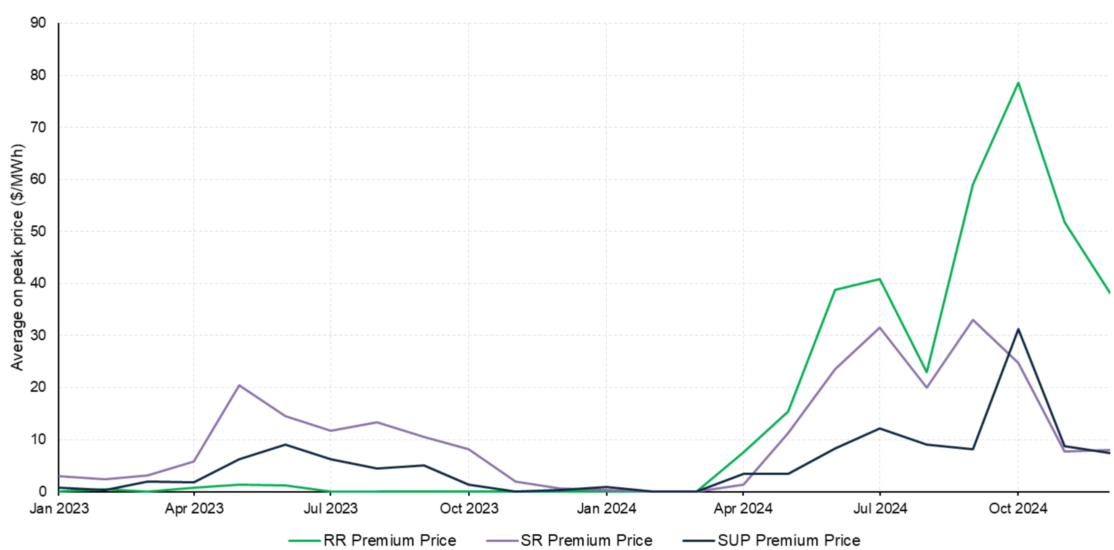
[25] Blended Price = Premium Price + (Activation Price * Activation Percentage)

Figure 74: On-peak standby activation rates for regulating, spinning and supplemental reserve (January 2023 to December 2024)



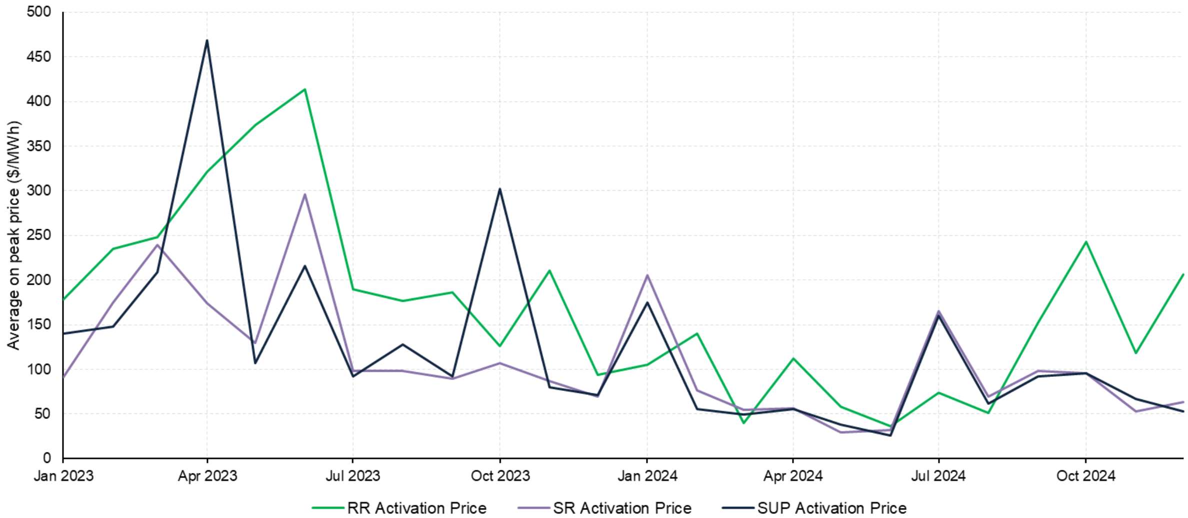
The change in the AESO's activation rates for standby reserve products has resulted in a large shift in how market participants structure their standby reserve offers. While this change was felt in activation prices, it has had the largest impact on premium prices. Premium prices for standby reserves increased drastically in 2024 for all products year-over-year (Figure 75). Most notably, premium prices for regulating reserves increased from an annual average of $0.37/MWh in 2023 to an average of $26.69/MWh in 2024. Additionally, premium prices for spinning reserve increased by $4.63/MWh to $11.58/MWh, while premium prices for supplemental reserve grew from $2.56/MWh to $6.83/MWh. Compared to Q3, premium prices for on-peak regulating and supplemental reserve increased in Q4 by 38% and 62% respectively, while prices for spinning reserve declined relative to the previous quarter.

Figure 75: On-peak standby premium prices for regulating, spinning and supplemental reserve (January 2023 to December 2024)



Year-over-year, on-peak activation prices declined for all standby reserve products due to lower pool prices and the increase in the activation rates used in the blended price formula. On-peak supplemental reserve activation prices fell by the largest margin, declining by 78%, while regulating and spinning reserves declined by 69% and 54%, respectively. While quarter-over-quarter activation prices for regulating reserve increased 48%, activation prices for spinning and supplemental reserves declined by 44% and 41%, respectively (Figure 76).

Figure 76: On-peak standby activation prices for regulating, spinning and supplemental reserve (January 2023 to December 2024)



4 THE FORWARD MARKET

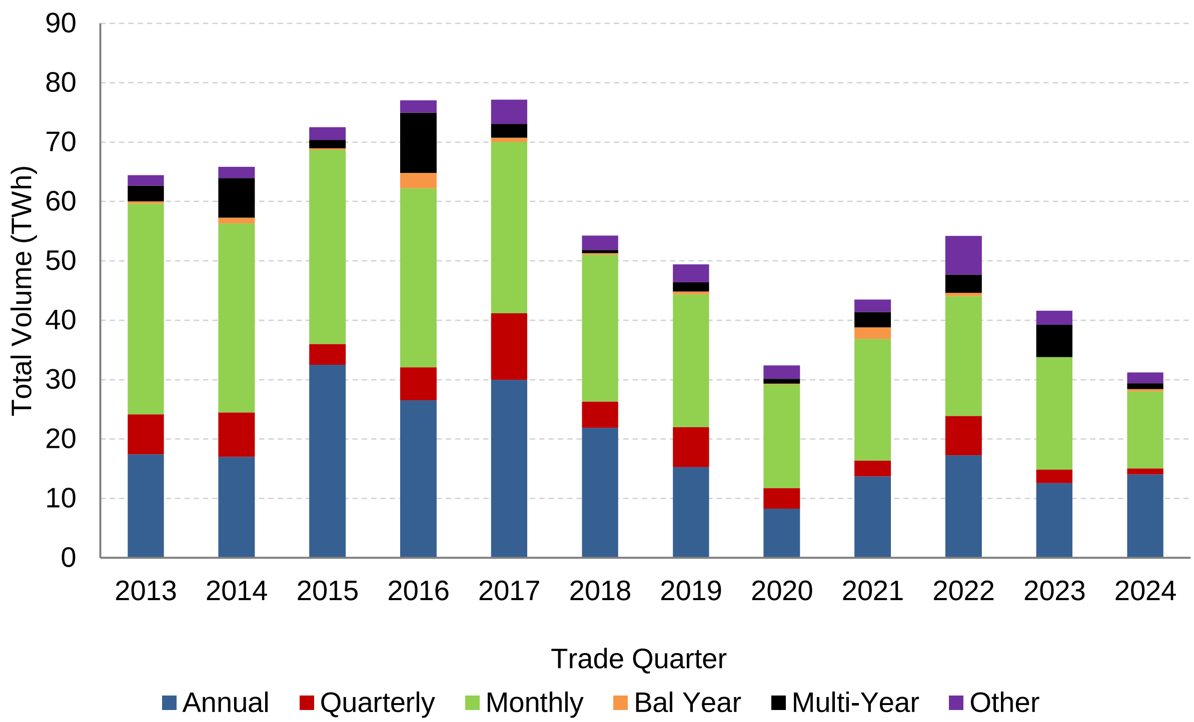
Alberta's financial forward market for electricity is an important component of the market because it allows for generators and larger loads to hedge against pool price volatility, and it enables retailers to reduce price risk by hedging sales to retail customers.[26]

4.1 Forward market volumes

Total trade volumes in 2024 were 31.2 TWh, a 25% decline from 41.6 TWh in 2023. Total volumes in 2024 were comparable with 2020 (Figure 77) when uncertainty around the COVID-19 pandemic lowered trading activity.

Direct bilateral trades accounted for 5.4 TWh or 17% of the total volumes in 2024. In 2023 direct bilateral trades totalled 6.5 TWh and accounted for 16% of total volumes. The majority of trading activity continues to occur on ICE NGX which accounted for 57% of total volumes in 2024 with over-the-counter brokers accounting for 26%.

Figure 77: Total trade volumes by term and year (2013 to 2024)



---

[26] 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, 2024 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.

Figure 78 provides total trade volumes by quarter since Q1 2019. Total volumes were 8.85 TWh in Q4 2024 which is an 8% increase relative to Q3 2024 but represents a 25% decrease compared to Q4 2023. In Q4 2024 there were more annual volumes and less monthly volumes compared to earlier in the year, a trend that was partially driven by the transition from the Regulated Rate Option to the Rate of Last Resort as the default retail product for electricity.

Figure 78: Total trade volumes by term and quarter (Q1 2019 to Q4 2024)

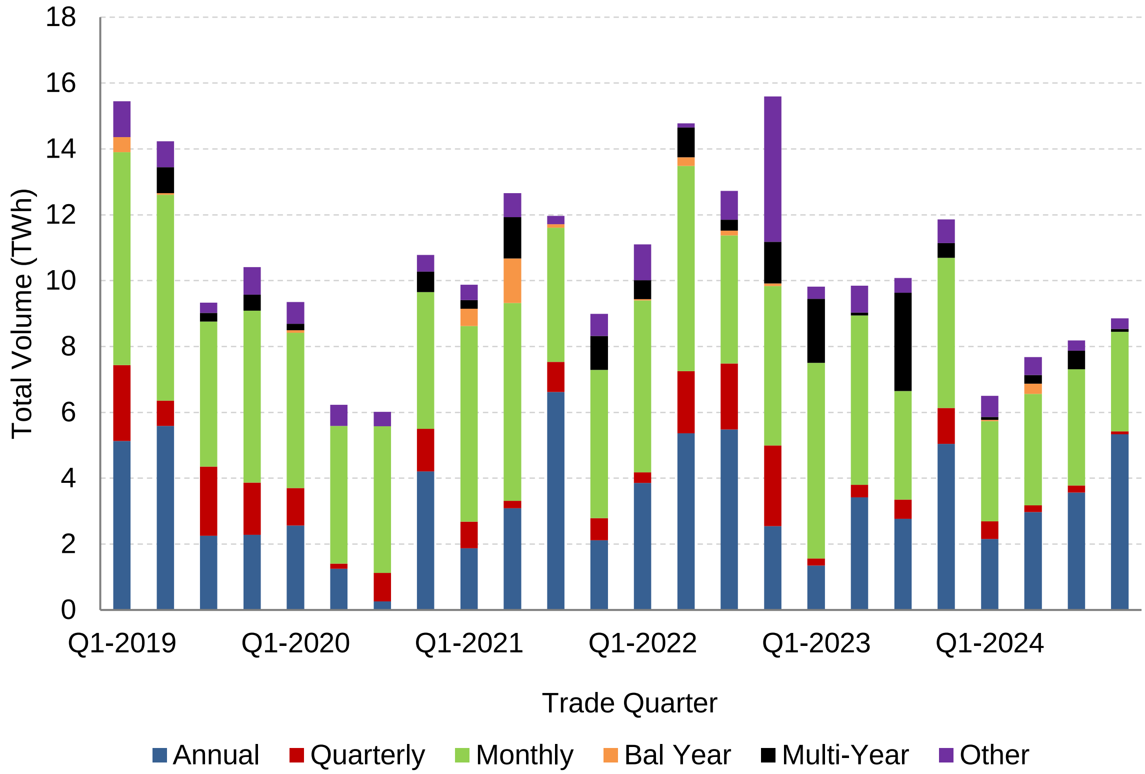
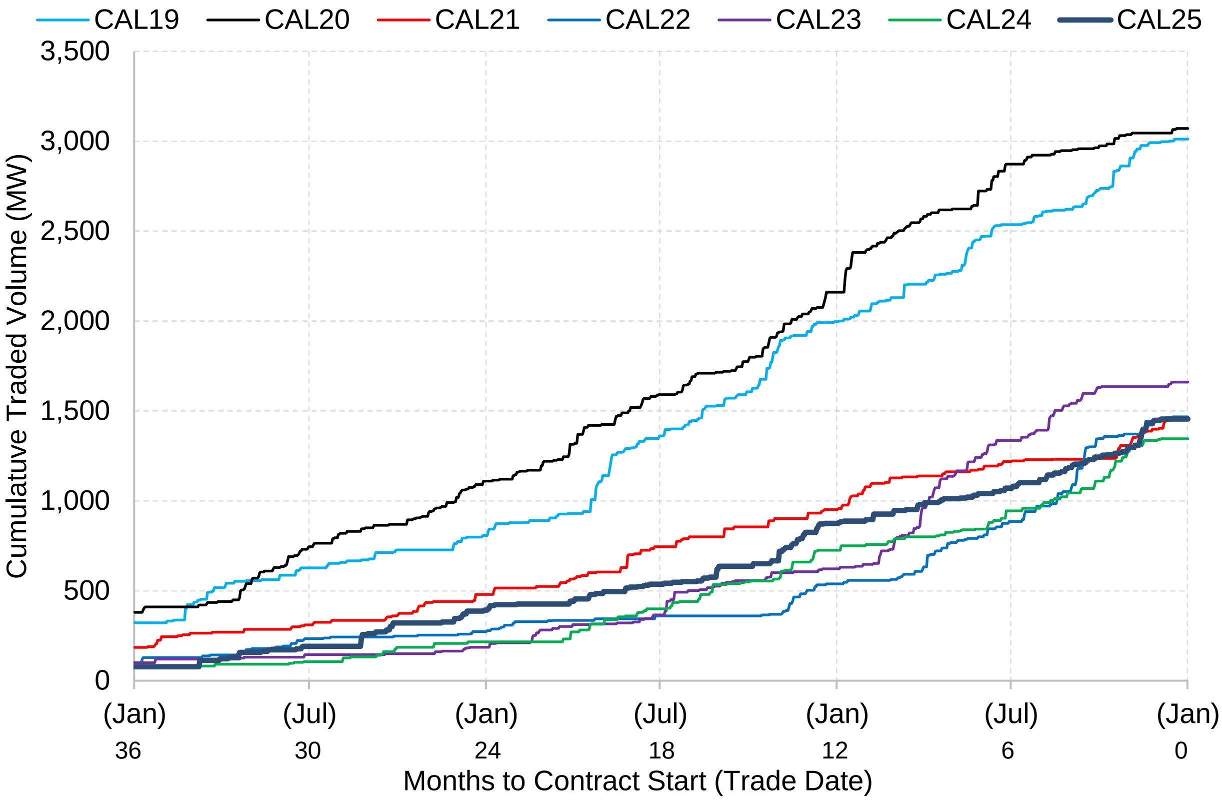


Figure 79 illustrates the cumulative traded volume of power for different annual contracts leading up to the contract start date. As shown, traded volumes for Calendar 2019 (CAL19) and CAL20 far exceed the volumes observed in recent years. For CAL25 1,455 MW traded which is very comparable with the volumes traded for CAL21 and CAL22, and is slightly above the volumes for CAL24.

Figure 79: Cumulative trade volumes for annual contracts (CAL19 to CAL25)



4.2 Trading of monthly products

Pool prices came in above forward market expectations in October and November but below forward market expectations in December (Figure 80). In October the average pool price settled 8% above the volume-weighted average forward price and in November the average pool price exceeded the volume weighted average forward price by 34%. Pool prices in November were increased by a period of cold weather late in the month, which raised demand and reduced wind generation.

In December the average pool price was $26.35/MWh which is 61% below the volume weighted average forward price of $67.70/MWh. Pool prices in December were lowered by mild weather conditions and high levels of thermal availability.

Overall in 2024, monthly forward prices traded at a premium relative to settled pool prices. The average pool price in 2024 was $62.78/MWh whereas the average volume-weighted monthly forward price was $77.21/MWh, a 23% forward premium.

Figure 80: Monthly forward prices compared to pool prices (January to December 2024)

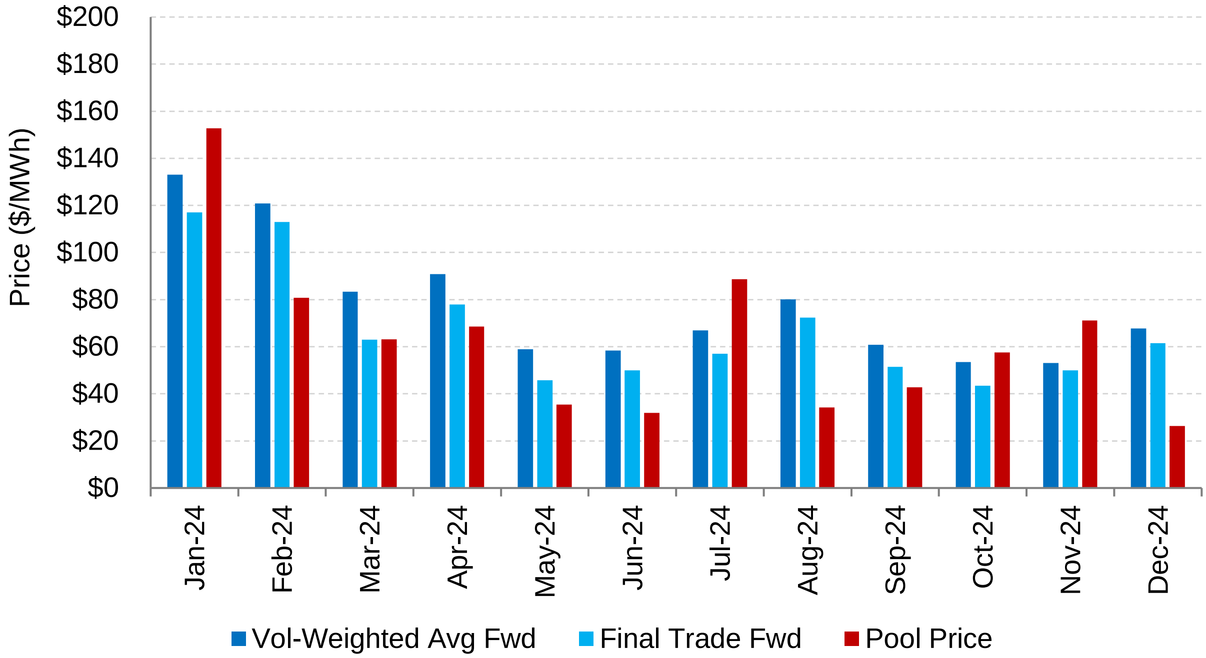


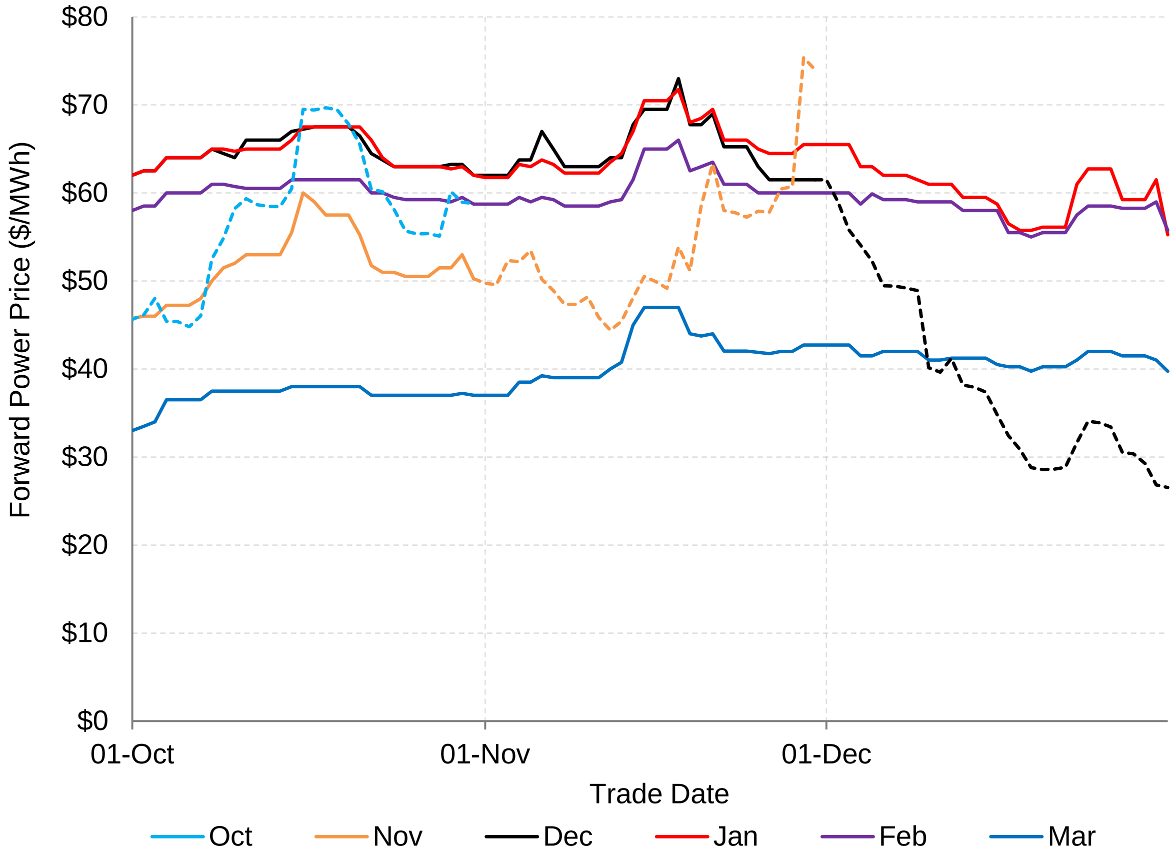
Figure 81 illustrates the evolution of select monthly forward prices over Q4 2024. The dashed lines in the figure illustrate the marked price of a contract, which provides the expected average price for the month as it unfolds.

Pool price volatility increased the marked price of October in the middle of the month, and this put upward pressure on other forward contracts particularly November. However, the pool price volatility abated and the marked price of October came back down and alleviated the upward pressure on monthly forward contracts.

In mid-November monthly forward prices increased due to the announced approval of a merger between two large suppliers. On November 14 the Competition Bureau announced it had approved the acquisition subject to the sale of certain assets. Subsequently, the price of January increased from $64.50/MWh on November 13 to $70.50/MWh on November 15, an increase of 9%. Likewise, the price of December increased by 9% while February increased by 10%. However, forward prices moderated later in the month, for example the price of January fell to $64.50/MWh on November 26 (Figure 81).

In December pool prices came in well below forward market expectations as the marked price fell from $61.50/MWh to $26.35/MWh over the month. This put downward pressure on forward prices for January and February; the price of January fell from $65.50/MWh to $55.25/MWh over the course of December and the price of February fell from $60.00/MWh to $55.75/MWh.

Figure 81: The evolution of select monthly forward prices over Q4 2024



4.3 Trading of annual products

Figure 82 illustrates the evolution of annual forward prices over the course of Q4. On the morning on November 5 the mothballing of Sundance 6 was announced beginning on April 1, 2025 for a period of up to two years. The mothball outage was inputted into the AESO's Energy Trading System (ETS) after trading on November 4. Despite the reduction in supply, the announcement had little impact on forward prices with CAL25 increasing by 0.3% and CAL26 rising by 0.8% while CAL27 was flat.

The main event of the quarter was the increase in annual forward prices that occurred following the acquisition announcement. On the morning of Thursday, November 14, the Competition Bureau announced they had approved the deal subject to the sale of certain generation assets. Reflecting the increase in market concentration that resulted from the acquisition, forward prices went up on November 14 and 15 (Table 25). For example, the price of CAL25 increased by 10% from $48.35/MWh at close on November 13 to $53.01/MWh at close on November 15.

Table 25: The change in annual forward prices from November 13 to 15

	13-Nov	15-Nov	% change
CAL25	$48.35	$53.01	10%
CAL26	$48.62	$51.99	7%
CAL27	$56.25	$61.00	8%
CAL28	$63.75	$68.50	7%

There was also an increase in the forward prices for CAL26, CAL27, and CAL28 on December 6. For example, CAL26 increased from $53.25/MWh to $55.00/MWh. This increase in prices reflected news articles about the ability of Alberta to attract data centres. To the extent these data centres are grid connected, they will increase the demand for electricity and put upward pressure on pool prices. However, in the latter half of December, forward prices came back down as pool prices came in under forward market expectations.

Figure 82: The evolution of annual forward prices over Q4 2024

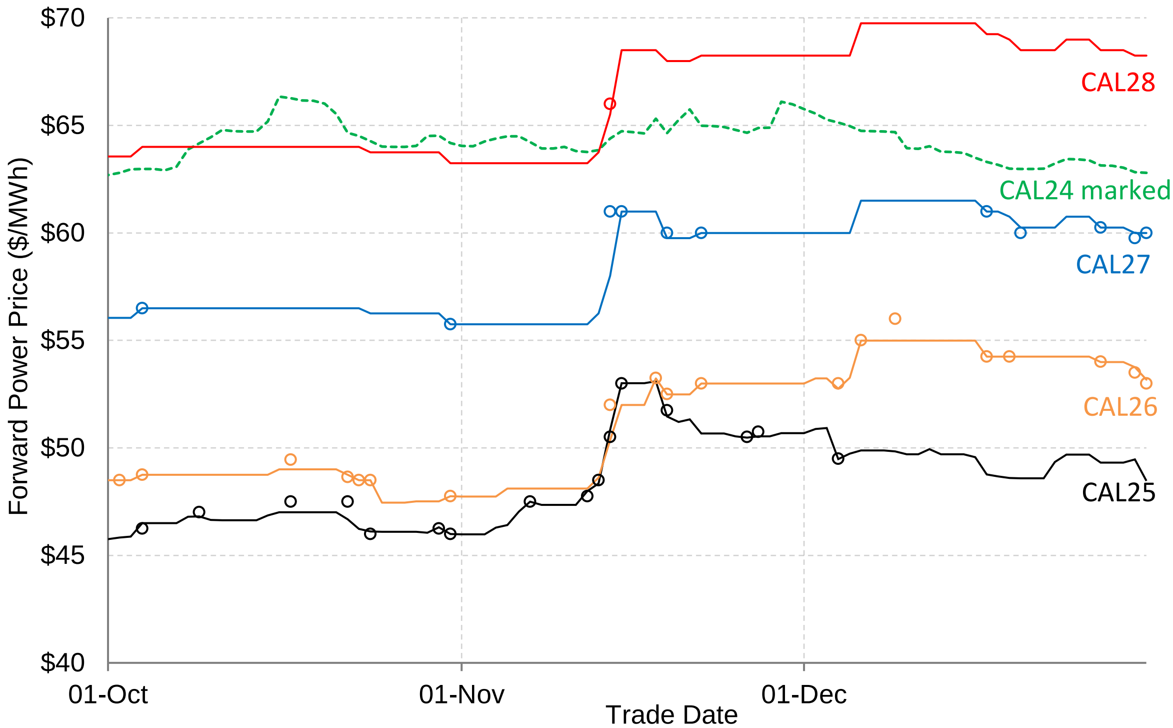


Table 26 provides the changes to annual power and natural gas prices over Q4. As discussed above, power prices increased over the quarter to reflect higher market concentration and potentially increased demand from data centres. The price of CAL26 increased by the most, rising by 10% from $48.50/MWh to $53.17/MWh.

The price of natural gas for CAL25 fell by 13% over the quarter while for other years the price of natural gas was largely unchanged. The lower price of natural gas for 2025 resulted from a decline of prices in October; while prices for 2025 fell prices for future years remained relatively constant.

The increase in power prices and the decline or small increase in natural gas prices meant that annual spark spreads increased over the quarter. Spark spread provides the margin between power prices and natural gas input costs, the figures below assume a heat rate of 7.5 GJ/MWh. The spark spread for CAL25 increased by 17% from $28/MWh to $33/MWh although the spark spread for CAL28 remains higher at $45/MWh.

Table 26: Annual power and natural gas price changes over Q4 2024

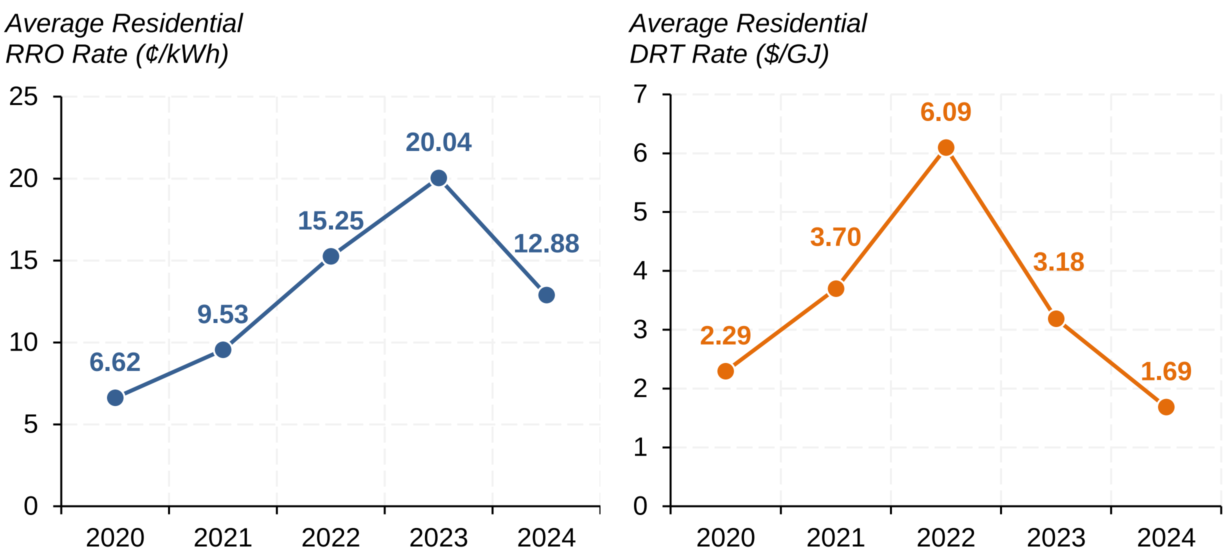
Contract	Power Price ($/MWh)			Gas Price ($/GJ)			Spark Spread ($/MWh)		
	Sep 30	**Dec 31**	**% Chng**	**Sep 30**	**Dec 31**	**% Chng**	**Sep 30**	**Dec 31**	**% Chng**
CAL24 Marked	$62.59	$62.78	0%	$1.30	$1.29	-1%	$53	$53	1%
CAL25	$45.91	$48.47	6%	$2.33	$2.01	-13%	$28	$33	17%
CAL26	$48.50	$53.17	10%	$2.85	$2.87	1%	$27	$32	16%
CAL27	$56.05	$60.00	7%	$2.93	$2.99	2%	$34	$38	10%
CAL28	$63.55	$68.25	7%	$2.96	$3.07	4%	$41	$45	9%

5 THE RETAIL MARKET

5.1 Annual summary

Declines in forward electricity and natural gas prices caused regulated electricity and natural gas energy prices to fall significantly in 2024 compared the previous year (Figure 83). Regulated Rate Option (RRO) energy prices fell by 36% year-over-year, while Default Rate Tariff (DRT) energy prices fell by 47%.

Figure 83: Annual average residential RRO and DRT energy prices, 2020 to 2024



In response to significant volatility in RRO energy prices over 2023 and 2024 (Figure 84), the Alberta Government replaced the RRO with the Rate of Last Resort (RoLR), a two-year fixed rate for customers that have not chosen a competitive retailer. While the DRT continues to be relatively volatile (Figure 85), an effective DRT price ceiling of $6.50/GJ remains in effect.[27] If DRT rates exceed $6.50/GJ, rebates will be provided to ensure a net natural gas energy price of $6.50/GJ.

[27] Government of Alberta, Natural Gas Rebate Program.

Figure 84: Monthly average residential RRO energy price, 2020 to 2024

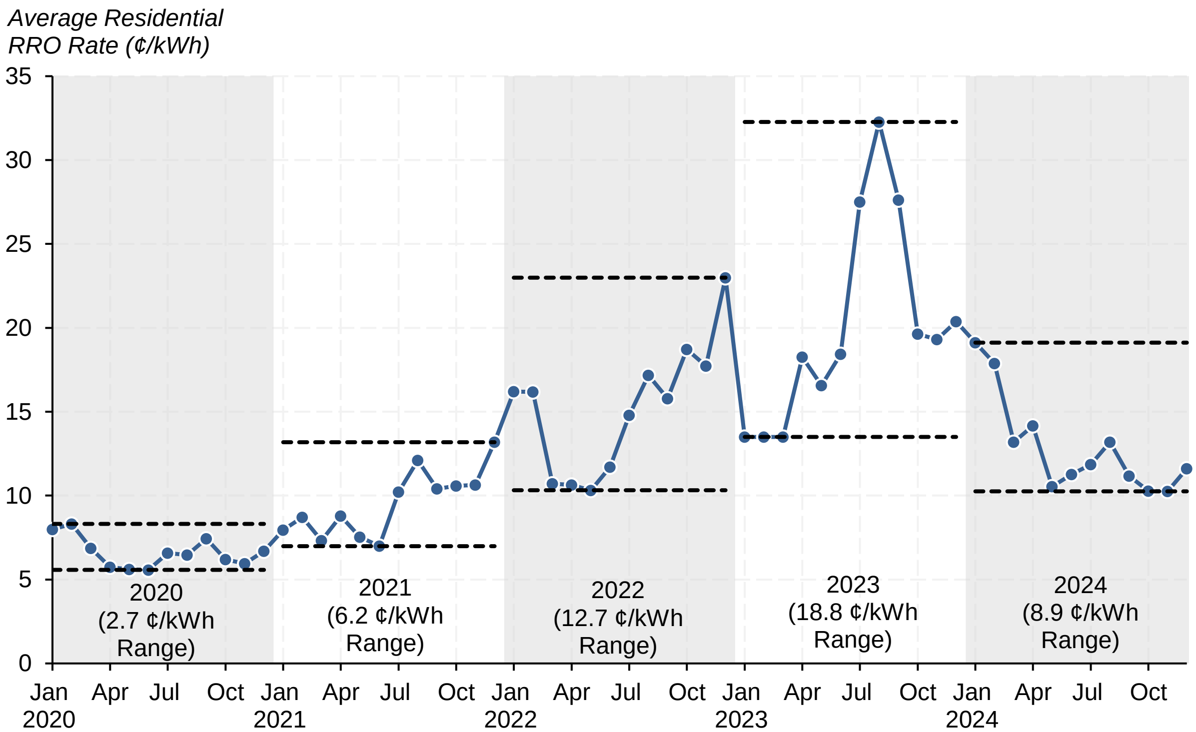
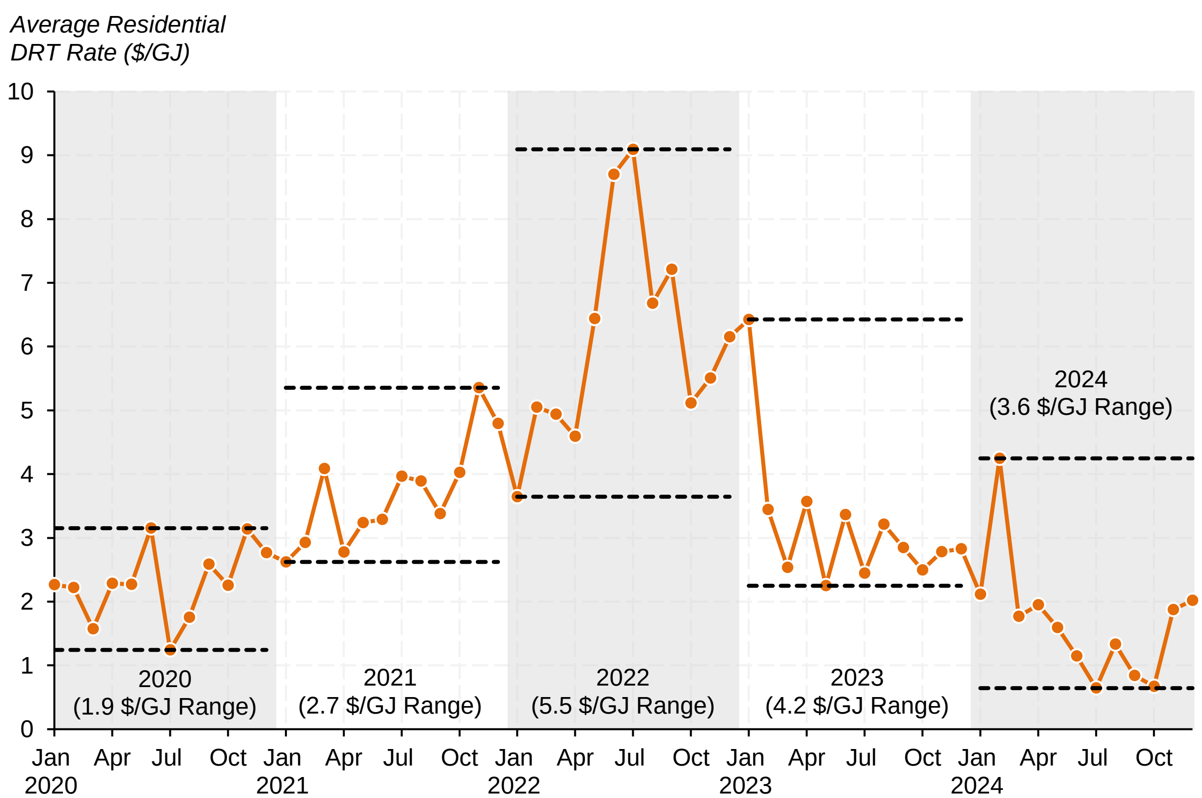


Figure 85: Monthly average residential DRT energy price, 2020 to 2024



Competitive retailer fixed rate energy prices also declined in 2024 as a result of declines in forward prices (Figure 86 and Figure 87). Despite these declines, fixed rate offerings have remained generally higher than the risk-free expected cost a retailer could expect to face by offering these contracts. This is particularly true of electricity contract offerings and may suggest an increase in the perceived risk of offering fixed rates in the last two years.

Figure 86: Annual average residential fixed rate electricity energy prices, select retailers, 2020 to 2024

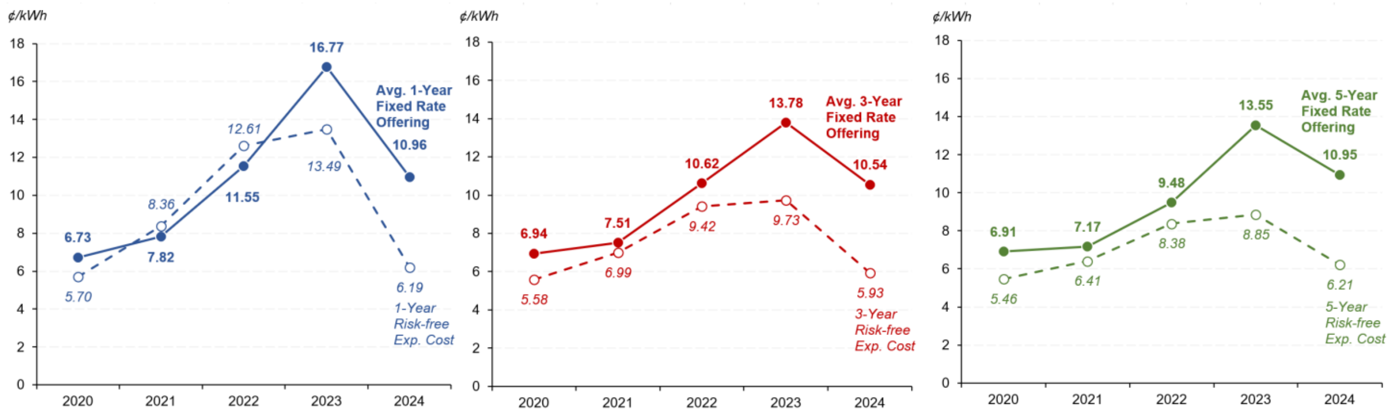
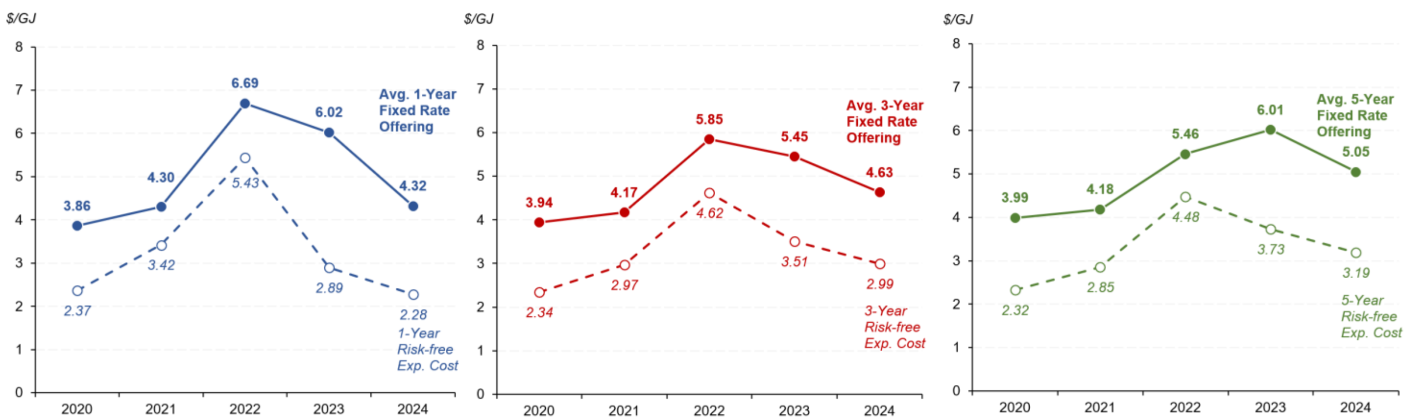
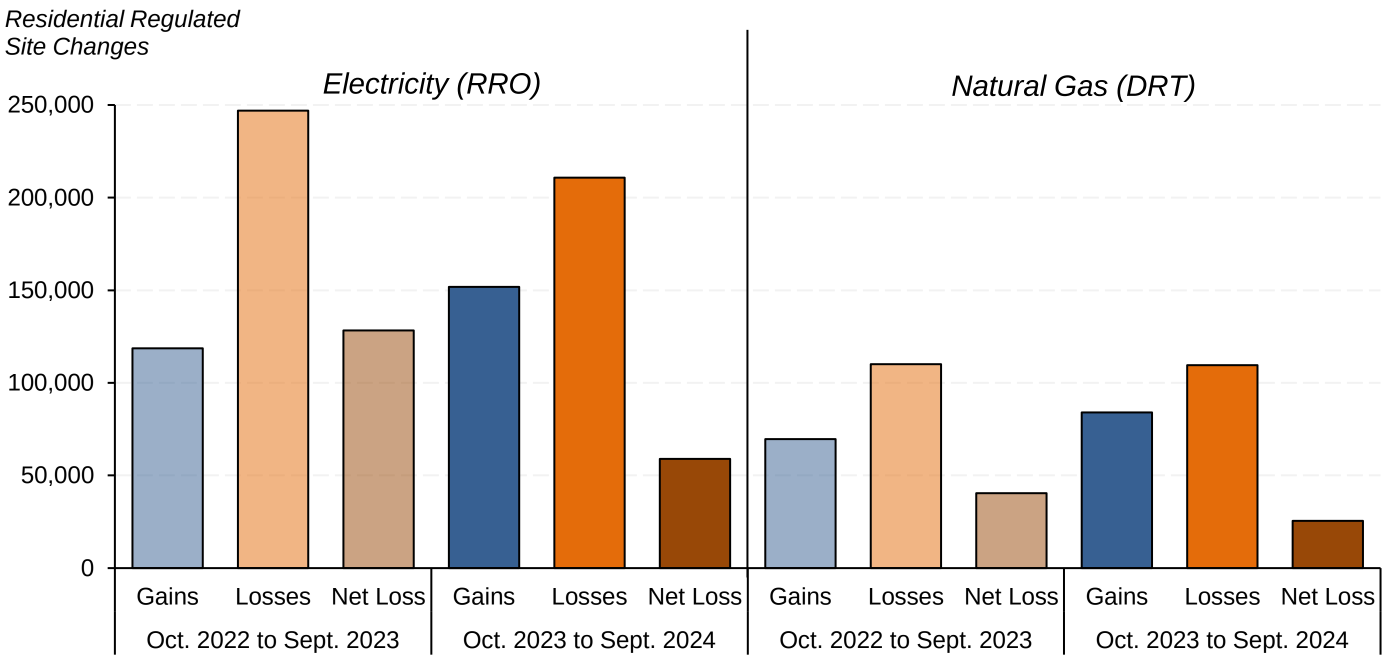


Figure 87: Annual average residential fixed rate natural gas energy prices, select retailers, 2020 to 2024



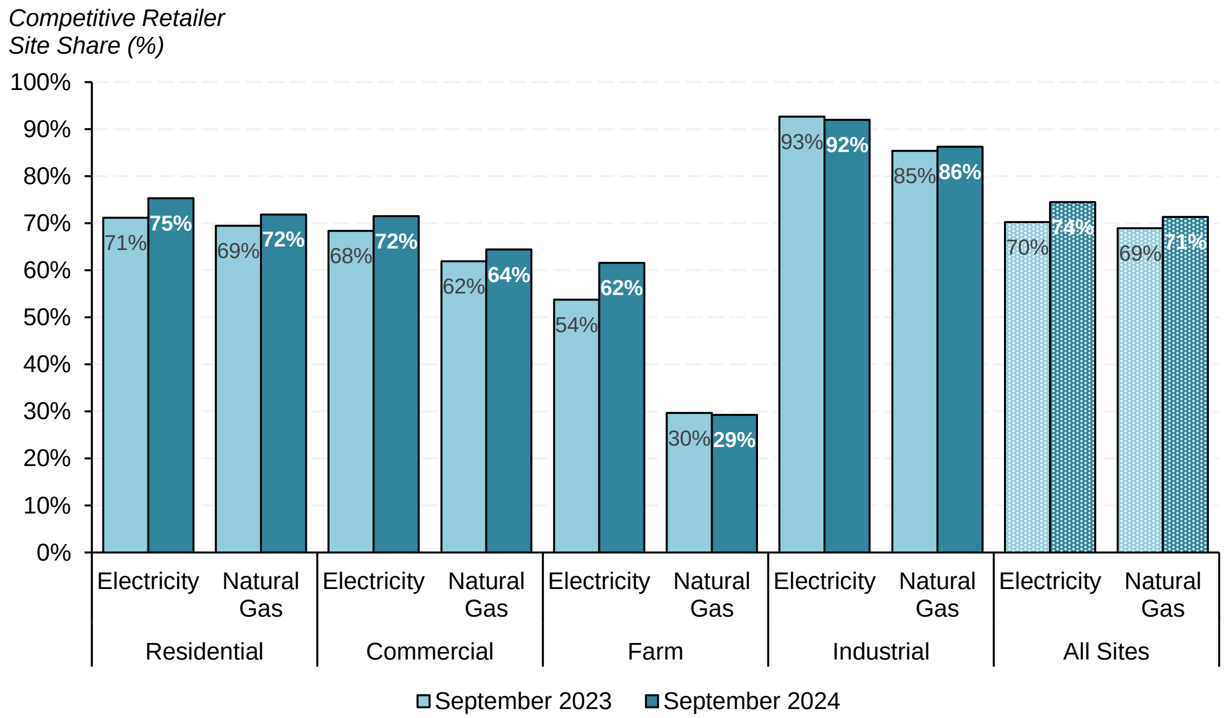
While market shares of residential customers on the RRO and DRT continued to fall in 2024, the rate of decline slowed between October 2023 and September 2024 compared to the previous twelve-month period (Figure 88). The RRO gained more new residential customers and lost fewer residential customers over this period compared to the previous twelve-month period, while the lower DRT net residential customer loss was caused by increases in new sites.

Figure 88: RRO, DRT customer gains, losses, net losses



The share of electricity and natural gas retail sites served by a competitive retailer increased year-over-year among most customer types, reaching 74% of electricity sites and 71% of natural gas sites (Figure 89). Competitive retailers served 91% of electricity volumes and 77% of natural gas volumes in September 2024, up from 89% and 75% respectively year-over-year.

Figure 89: Competitive retailer site share, by commodity type and customer type, September 2023 vs. September 2024



5.2 Quarterly summary

Residential retail customers can choose from several retail energy rates. Effective January 1, 2025, customers that have not chosen a competitive electricity retailer are on the Rate of Last Resort (RoLR). RoLR energy prices are fixed for two years and vary by distribution service area. The RoLR replaces the Regulated Rate Option (RRO) as the regulated electricity rate. RRO rates varied monthly and by distribution service area. Natural gas customers that have not chosen a competitive natural gas retailer are on a Default Rate Tariff (DRT) rate, which varies monthly.

Table 27: Monthly retail market summary for Q4 (Residential customers)

		2023	2024	Change
RRO (Avg ¢/kWh)	Oct	19.63	10.27	-48%
	Nov	19.32	10.26	-47%
	Dec	20.37	11.60	-43%
	Q4	**19.78**	**10.71**	**-46%**
DRT (Avg $/GJ)	Oct	2.50	0.67	-73%
	Nov	2.78	1.88	-33%
	Dec	2.83	2.02	-28%
	Q4	**2.70**	**1.52**	**-44%**
Competitive Variable Electricity Rate (Avg. ¢/kWh)	Oct	11.46	7.13	-38%
	Nov	10.83	8.68	-20%
	Dec	6.42	3.76	-41%
	Q4	**9.56**	**6.50**	**-32%**
Competitive Variable Natural Gas Rate (Avg. $/GJ)	Oct	3.30	2.13	-36%
	Nov	3.48	2.36	-32%
	Dec	2.80	2.76	-1%
	Q4	**3.19**	**2.42**	**-24%**
Expected Cost, 3-Year Electricity Contract (Avg. ¢/kWh)	Oct	8.21	5.26	-36%
	Nov	8.32	5.52	-34%
	Dec	7.65	5.70	-25%
	Q4	**8.06**	**5.49**	**-32%**
Expected Cost, 3-Year Natural Gas Contract (Avg. $/GJ)	Oct	3.50	2.77	-21%
	Nov	3.50	2.65	-24%
	Dec	2.95	2.75	-6%
	Q4	**3.31**	**2.73**	**-16%**

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

Average Q4 residential RRO rates were 46% lower year-over-year (Table 27) and were 11% lower compared to Q3 2024. RRO rates shown in Table 27 include the collection rates.[28] The collection rates included in RRO rates in October, November and December 2024 averaged 3.2 ¢/kWh, 2.9 ¢/kWh and 2.6 ¢/kWh, respectively.

Average residential DRT rates in Q4 were 44% lower year-over-year (Table 27). The average DRT rate in October 2024 was particularly low at $0.67/GJ, the second lowest rate ever recorded after July 2024. However, average DRT rates in Q4 were 67% higher than in Q3 2024 due to relatively high rates in November and December.

---

[28] Collection rates result from the deferred revenue associated with the January to March 2023 13.5 ¢/kWh RRO rate ceiling. Deferred revenue was recovered from RRO customers from April 2023 until December 2024 using collection rates incorporated into RRO rates.

In Q4, the average competitive variable electricity and natural gas rates offered to residential customers were 32% and 24% lower year-over-year, respectively (Table 27). The risk-free expected cost[29] of providing fixed-rate electricity and natural gas contracts in Q4 declined by 32% and 16% respectively as forward price expectations for electricity and natural gas fell year-over-year.

5.3 Retail customer movements

5.3.1 Regulated retailer customer losses

The RRO experienced a net loss of approximately 5,000 residential customers in Q3 2024 (Figure 90), the lowest net loss in the last three years. This was a significant decline in RRO net customer losses compared to net losses in 2023, and was a result of declines in customers leaving the RRO and increases in customers switching or reverting to the RRO. For example, 103,000 residential customers left the RRO in Q3 2023 while less than 50,000 customers left the RRO in Q3 2024. In Q3 2023, the RRO gained 37,000 new residential customers, while the RRO gained 45,000 new customers in Q3 2024. As of September 2024, there were around 408,000 residential customers on the RRO.

The lower net loss numbers observed in 2024, relative to previous years, may be attributed to lower RRO rates and a diminishing pool of customers eligible for competitive retail rates. Average residential RRO rates in 2024 were 35% lower than average RRO rates in 2023, which may have reduced customers' willingness to switch to competitive retail plans. Additionally, not all customers are eligible for competitive retail plans. Customers with insufficient credit who are unable to pay a security deposit have generally been unable to switch to competitive retail plans. Reduced RRO switching rates suggests the pool of regulated rate customers able to switch to a competitive plan may be diminishing.

The DRT experienced a net loss of 2,000 residential customers in Q3 2024 (Figure 91). While around 27,000 customers left the DRT in Q3, around 25,000 new customers joined. As of September 2024, there are around 370,000 residential customers on DRT.

Unlike RRO rates, DRT rates were lower than competitive fixed and variable rates in 2024. The departure of customers from the relatively low-priced DRT may be attributed to customers switching to dual-fuel contracts offered by the competitive retailers. These contracts enable customers to bundle their electricity and natural gas services with a single retailer.

[29] The MSA has projected retailers' risk-free expected cost of providing energy under fixed-rate retail contracts by examining prevailing forward energy prices.

Figure 90: RRO customer net losses, residential customers (Q1 2022 to Q3 2024)

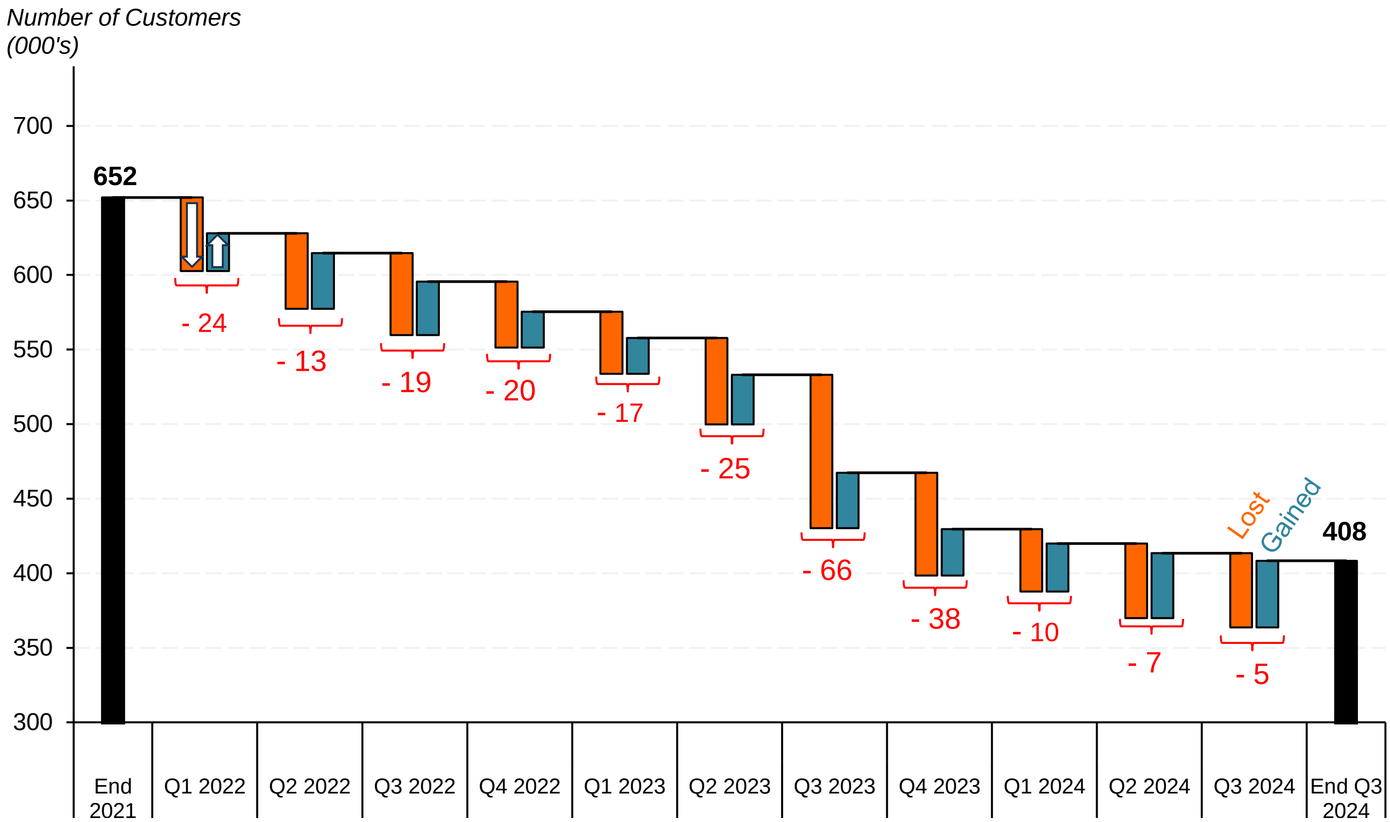
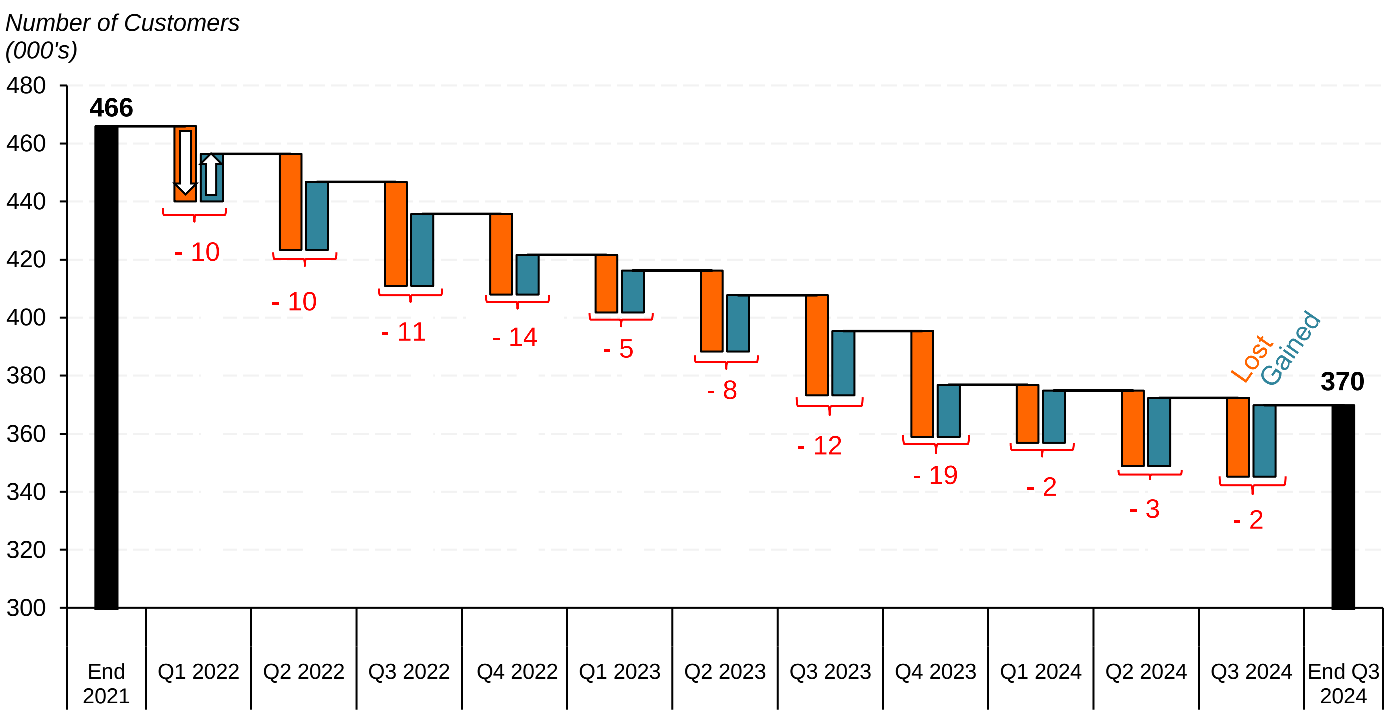


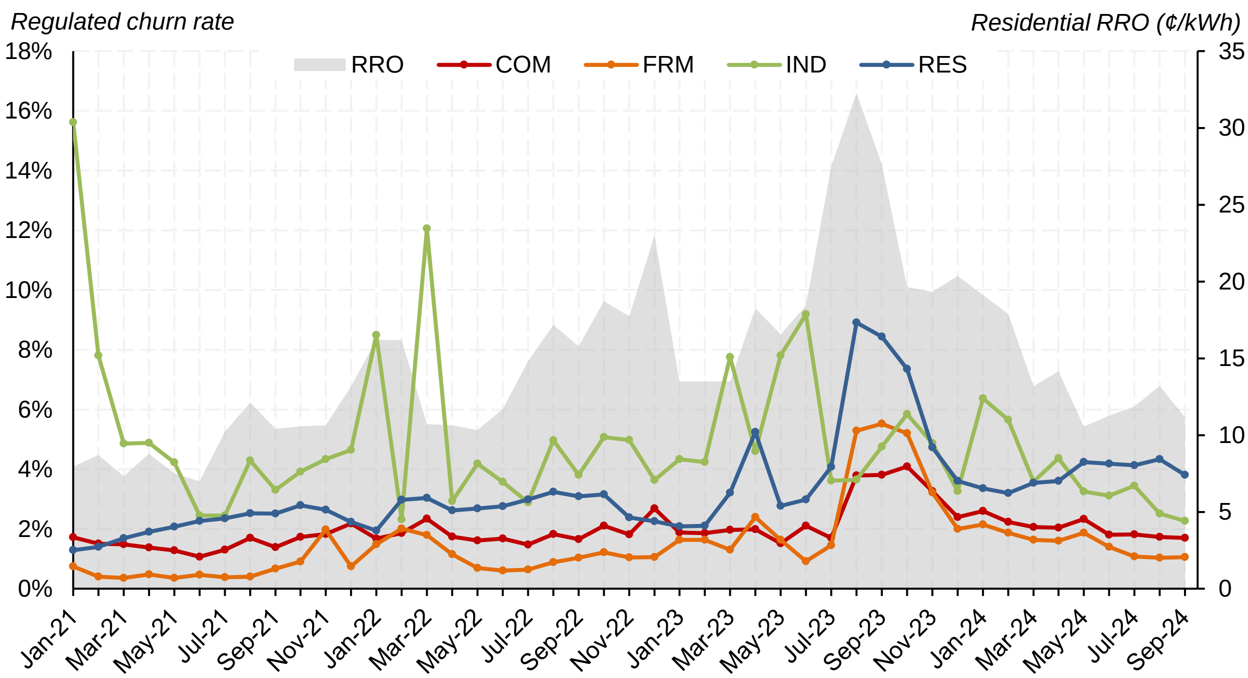
Figure 91: DRT customer net losses, residential customers (Q1 2022 to Q3 2024)



5.3.2 *Churn rates*

Churn rates represent the share of a retailer's customer base that leave the retailer in a given month. Figure 92 compares average residential RRO rates and regulated churn rates for electricity across four sectors: Commercial (COM), Farm (FRM), Industrial (IND) and Residential (RES). Customers that consume less than 250,000 kWh annually are eligible for the RRO, while customers that consume more than 250,000 kWh are eligible for default supply rates.[30] Most suppliers set default supply rates at the end of the month, based on pool prices.

Figure 92: Regulated (RRO and default supply) electricity churn rates, January 2021 to September 2024



RRO rates have been highly volatile since 2021 and peaked in August 2023. Residential customers are somewhat sensitive to RRO rates, as residential churn increases significantly during periods of higher RRO rates. Notably, there appears to be a slight lag, which may suggest consumers take time to learn RRO rates have increased and evaluate their options before switching providers. Regulated farm and commercial customers are generally less responsive to RRO rates than residential customers.

Industrial regulated churn is not well correlated with RRO rates as most industrial customers consume over 250,000 kWh and are therefore not eligible for the RRO. The highest churn in this

[30] The majority of residential, farm, and commercial customers are eligible for the RRO, while most industrial customers are eligible for default supply.

sector occurred in January 2021, possibly because of price uncertainty related to the expiry of Power Purchase Arrangements (PPA) at the end of 2020.

Figure 93 shows the regulated natural gas option churn rates and the average DRT rate faced by residential customers. Residential and commercial churn is correlated with DRT rates prior to 2023, with significant spikes during the same periods, suggesting these regulated natural gas customers were sensitive to changes in the regulated natural gas price. Since 2023, residential and commercial regulated natural gas churn rates appear disconnected from DRT rates and are better correlated to residential and commercial regulated electricity churn rates (Figure 92). This may suggest customers leaving their regulated electricity provider have also been leaving their regulated natural gas provider for competitive dual fuel contracts.

Figure 93: Regulated natural gas churn rates, January 2021 to September 2024

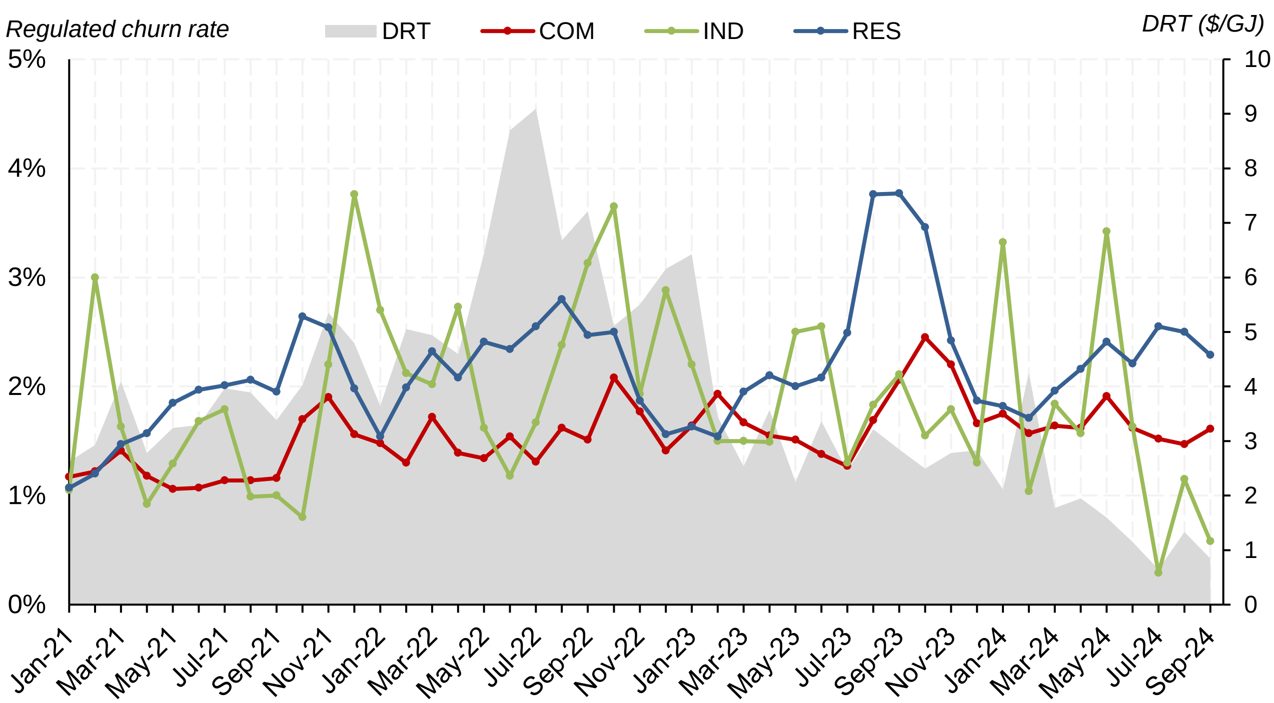
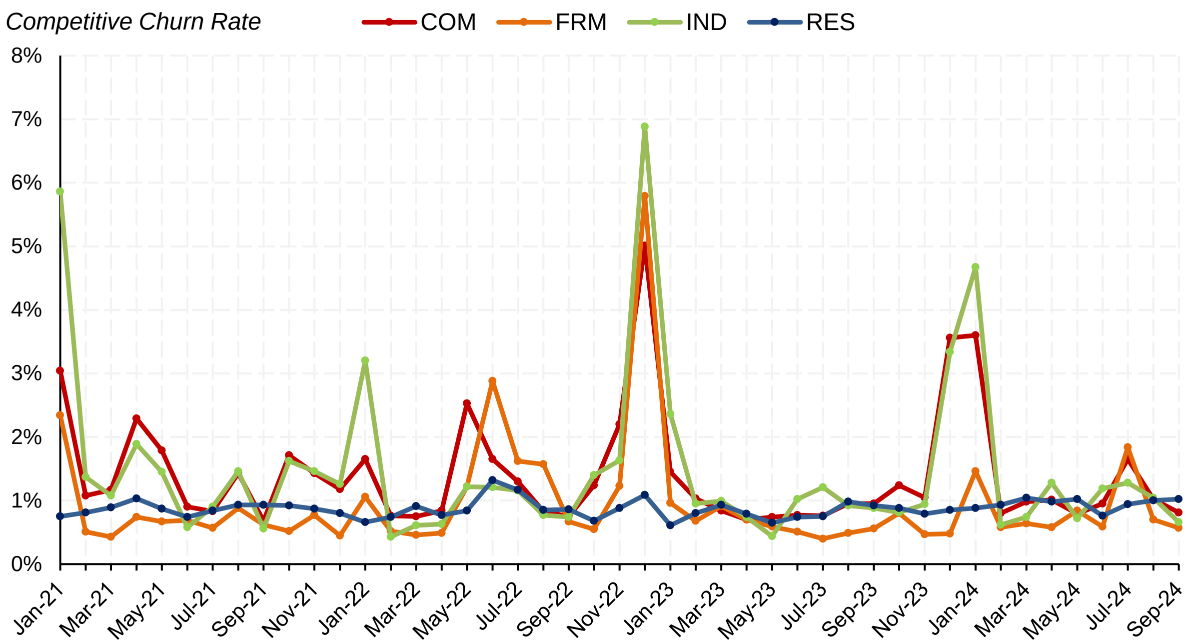


Figure 94 shows churn rates among competitive electricity customers across the four consumer sectors. Significant peaks, such as observed in January 2021, December 2022, and January 2024, may suggest potential contract terminations. Commercial and industrial customers may have greater financial incentive to learn about competitive product offerings than residential or farm customers and may therefore be more likely to switch competitive retailers if competing offers are priced lower.

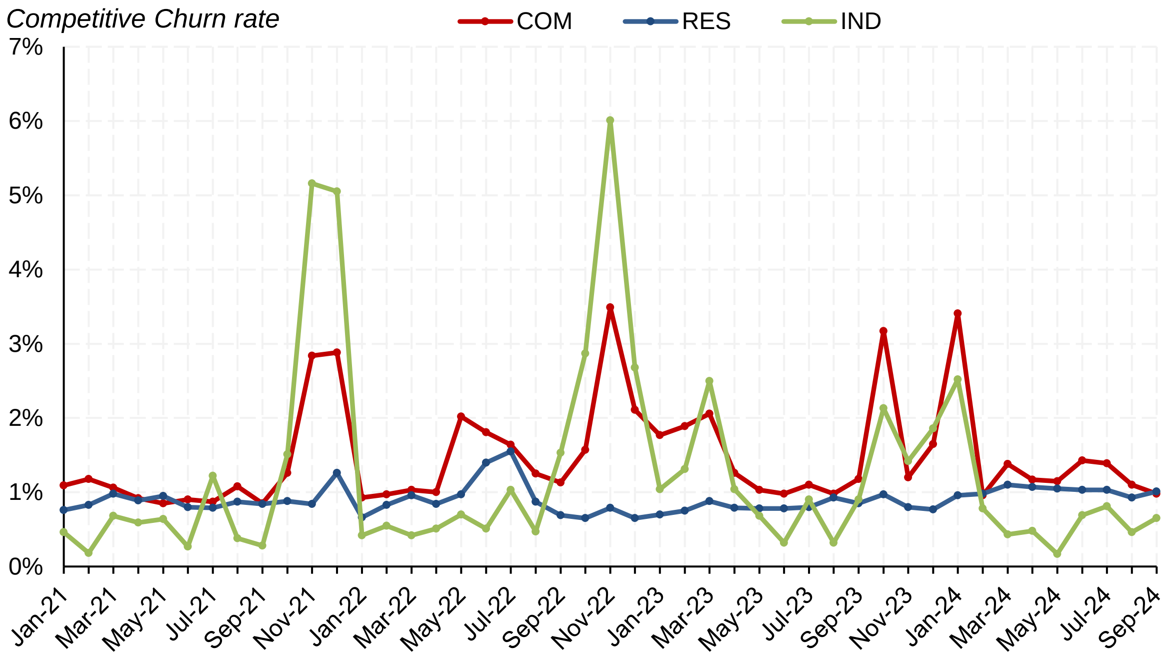
The residential sector maintains a relatively stable competitive churn rate throughout the observed period, with no significant spikes. This stability could indicate that residential customers are less responsive to market changes, or that residential customers are more likely to choose long-term contracts relative to other customer types.

Figure 94: Competitive electricity churn rates, January 2021 to September 2024



Natural gas churn rates for residential customers are more stable than industrial or commercial natural gas churn rates, and are consistently low, generally remaining below 1% (Figure 95). This pattern suggests that residential customers are less likely to switch to alternative options, such as the DRT or other competitive natural gas retailers. Peaks in natural gas churn rates in commercial and industrial sectors are common in winter months, which may reflect switching induced by higher natural gas costs, seasonal offers by competitive natural gas retailers, or greater consumer awareness of natural gas bills in these months.

Figure 95: Competitive natural gas churn rates, January 2021 to September 2024



Competitive churn rates do not distinguish between customers that switch to other competitive retailers or to a regulated provider. Figure 96 and Figure 97 illustrate competitive churn rates and new regulated sites across consumer sectors for electricity and natural gas retailers, respectively.

Regulated residential customer growth among new electricity and natural gas customers is highly seasonal, peaking in the summer and falling in winter months, while competitive churn rates among residential customers is relatively stable. The seasonality in regulated residential customer growth may be related to immigration trends, or seasonality in housing sales or leasing dates.

In both electricity and natural gas, the residential sector has the strongest correlation between competitive churn rates and new regulated sites, with the correlation for natural gas being the strongest among all charts (Figure 96 and Figure 97). This may suggest that some residential customers leaving their competitive retailer switch to regulated providers. Overall, competitive churn and new regulated sites are better correlated in retail natural gas markets than in retail electricity markets.

Figure 96: Competitive electricity churn rates and new regulated sites, January 2021 to September 2024

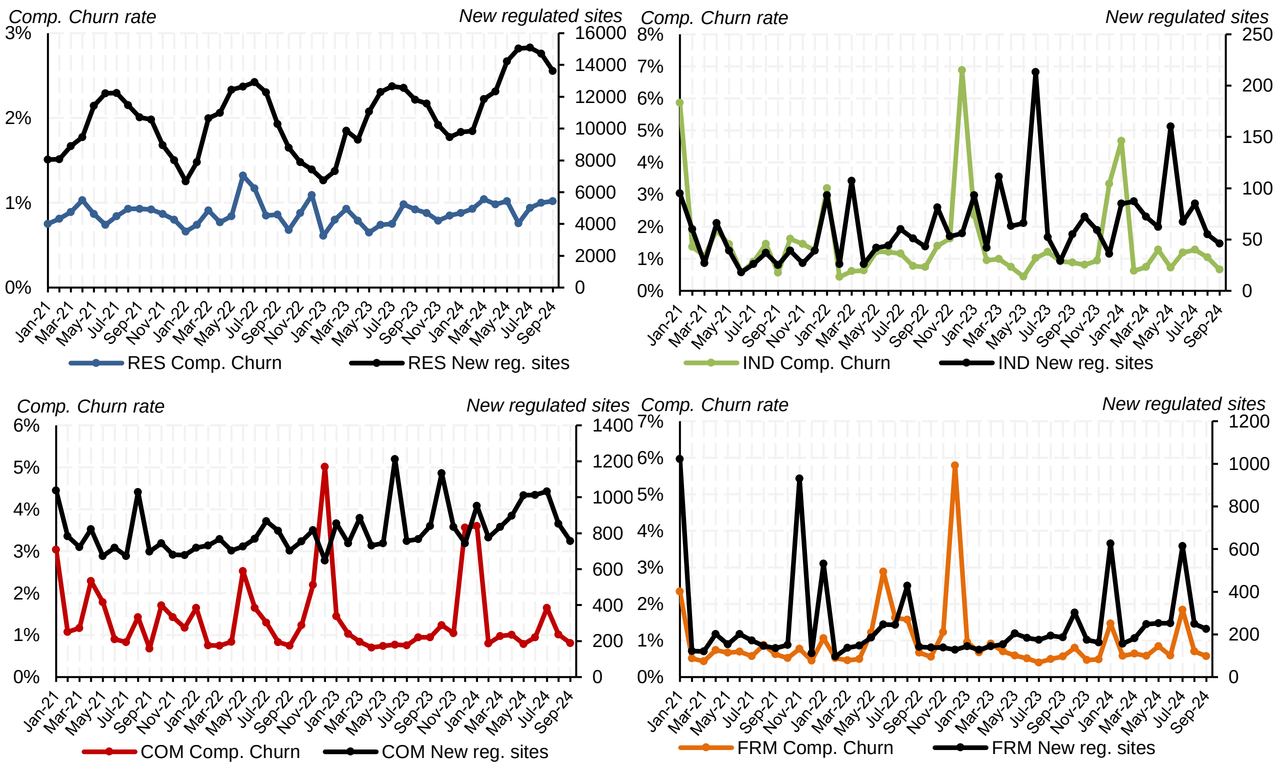
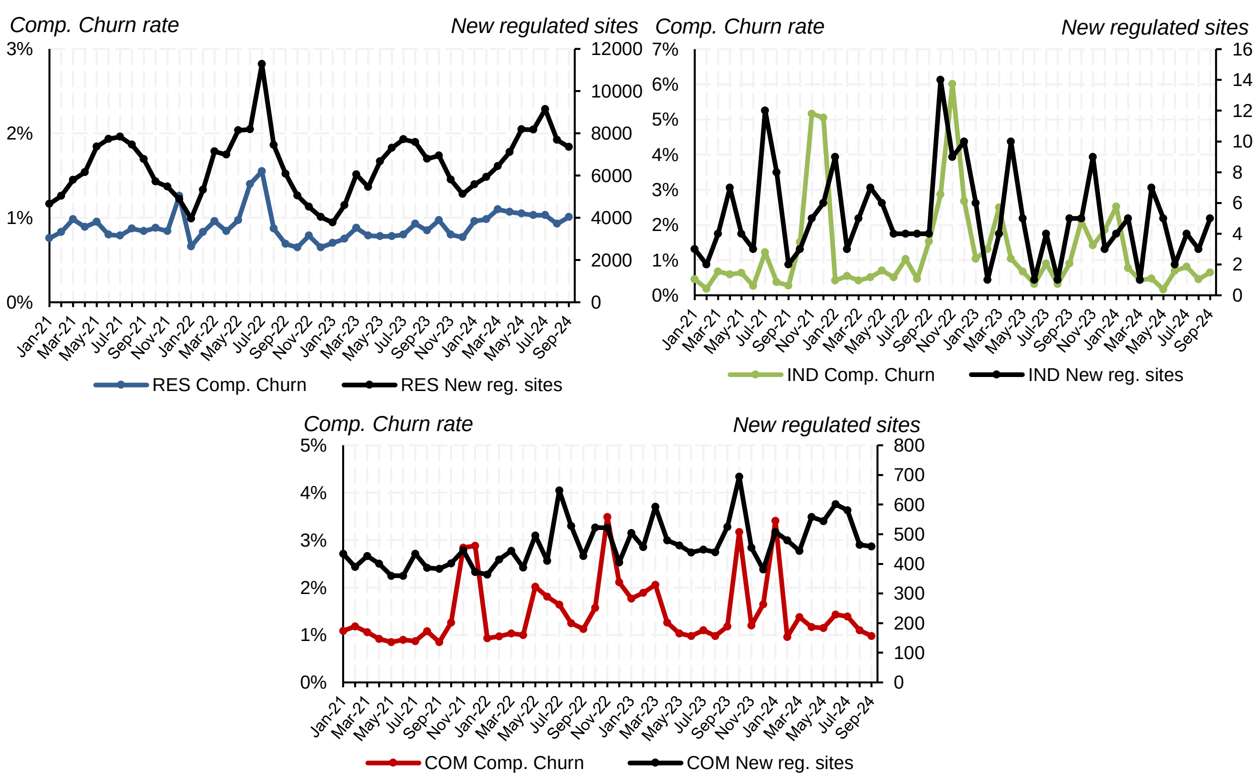


Figure 97: Competitive gas churn rates and new regulated sites, January 2021 to September 2024



5.3.3 Retail market shares

Figure 98 and Figure 99 show the electricity and natural gas retail market shares in September 2024. A significant majority of customers are enrolled with retailers affiliated with and branded similarly to a regulated provider or distributor in their service area. These retailers, known as co-branded retailers, vary across different service areas.

Retail customers may sign with a co-branded retailer for several reasons including local brand recognition using similar name and logo as their regulated affiliate. Customers on a regulated product wanting to switch to a competitive product may be more inclined to try a co-branded product, or may be unaware that other competitive retailers operate in their area.

Customers that are not informed about the market may also perceive energy provided by a co-branded retailer as more reliable if that retailer is affiliated with a distributor. Co-branded retailers have greater market shares among residential customers than among industrial and commercial customers.[31] Industrial and commercial customers may have greater knowledge about competitive retailers, and may favour specialized retailers that offer retail contracts tailored to the customer's risk tolerance and load shape.

There is a notable difference in the performance of regulated providers. Regulated providers have been most successful in the residential and commercial sectors, while their market share is lower among industrial customers. This may be because these industrial customers consume more energy and therefore have greater incentive to explore different retailers and their rates to minimize their operational costs.

As of September 2024, the competitive retail electricity and natural gas market shares in the residential sector were 75% and 72% respectively. In the industrial sector the competitive market shares are considerably higher, at 92% for electricity and 86% for natural gas.

Regulated providers have the highest market share among farm customers (Figure 98). The electricity consumption of farm sites is typically much lower than that of industrial and commercial sites and tends to be more seasonal. As a result, fluctuations in electricity rates may have a lower impact on farm customers' overall operational costs. As of September 2024, the competitive electricity retail market share in the farm sector was 62%.

[31] MSA Retail Statistics, "Market Shares Snapshot Sep 2024" sheet.

Figure 98: Retail market share by customer type, electricity, September 2024[32]

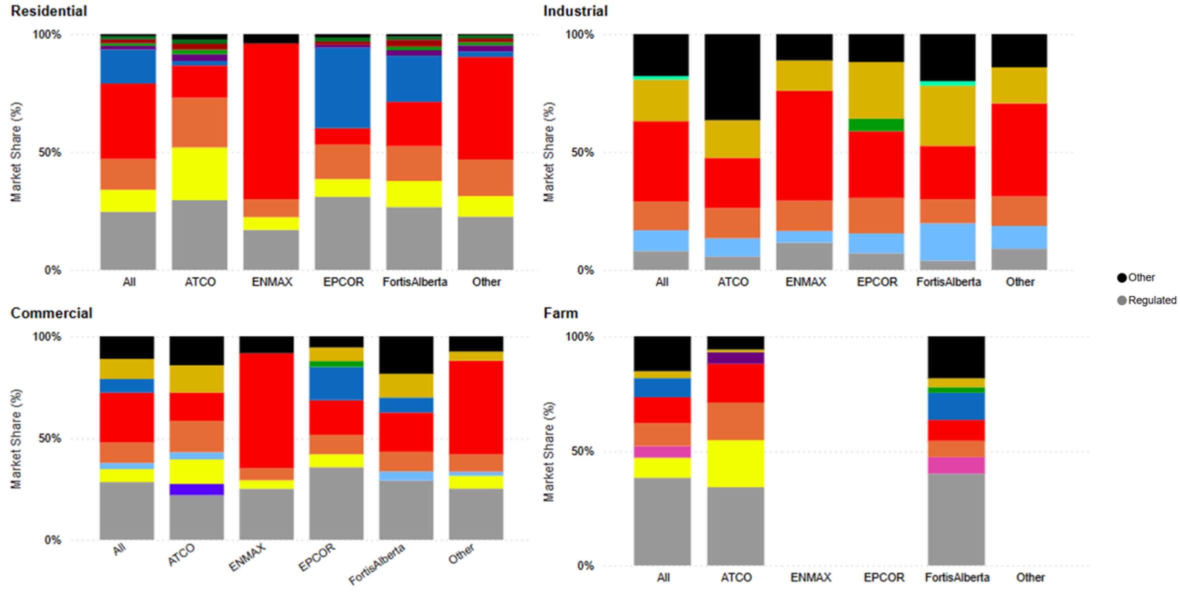
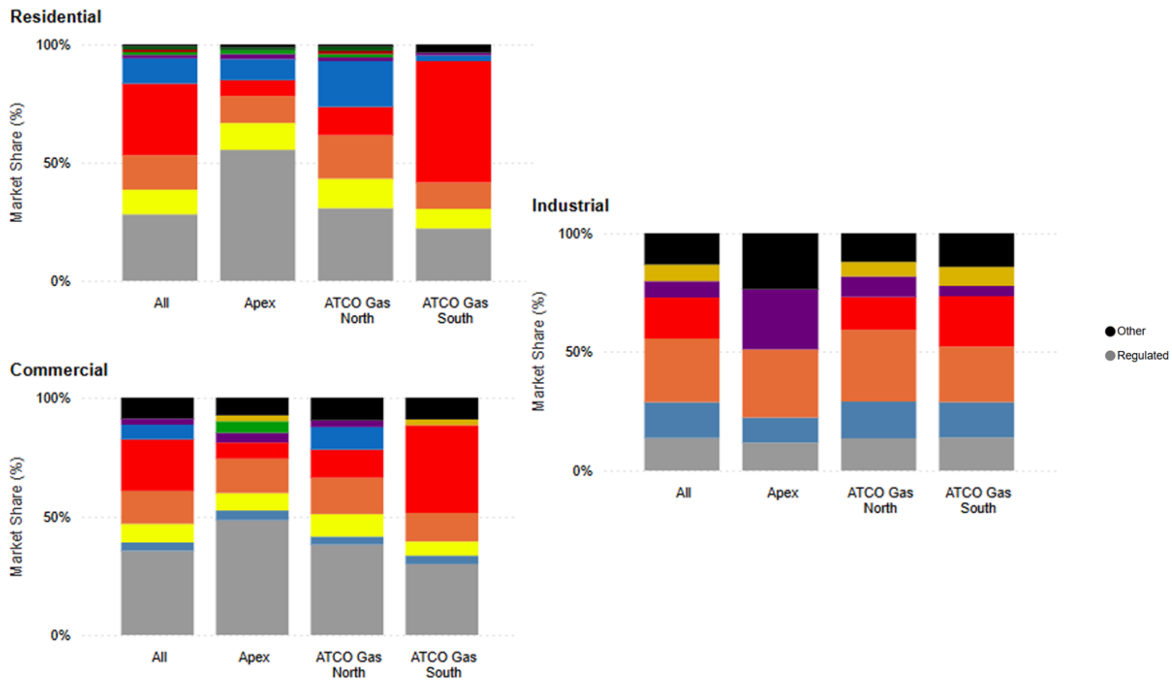


Figure 99: Retail market share by customer type, natural gas, September 2024



[32] Competitive retailers have been represented by differently coloured components of each market share bar.

5.4 Competitive retail rates

5.4.1 Competitive fixed retail rates

Competitive retailers typically offer fixed and variable energy rates. Fixed rates are fixed over a defined contract term; usually between 1 and 5 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 customers' consumption over the length of the contract term. The MSA refers to these energy costs as risk-free expected costs, which represent residential customer load-shaped forward prices that exclude any volumetric risk. In a well-functioning retail market competitive retailers would adjust fixed rates offered to new customers in response to changes in the risk-free expected cost.

The MSA calculates risk-free expected cost of serving residential customers using forward settlement prices. In 2023 the risk-free expected cost of serving residential customers was higher for 1-year contracts than 3- and 5-year contracts. However, the 1-year risk-free expected cost fell below the risk-free expected costs of both 3- and 5-year contracts in 2024 (Figure 100). This shift is due to greater declines in forward prices for 2024 to 2026 contracts, compared to 2027 and 2028 contracts.

The risk-free expected cost for 1-, 3-, and 5-year fixed rate electricity contracts increased quarter-over-quarter by 5%, 9% and 9% respectively, with notably increases occurring in the middle of November with increases in forward market prices. On December 31, the risk-free expected cost for 1-, 3-, and 5-year fixed rate electricity contracts were 5.10 ¢/kWh, 5.61 ¢/kWh and 6.25 ¢/kWh respectively (Figure 100).

Figure 100: Risk-free expected cost, fixed rate electricity contract, residential customer (January 1, 2023 to December 31,2024)

In Q4, the risk-free expected costs for 1-, 3-, and 5 -year natural gas contracts increased slightly with increases in forward natural gas prices (Figure 101). Risk-free expected costs increased by 6%, 3% and 4%, respectively, for 1-, 3-, and 5-year natural gas contracts. On December 31, the risk-free expected cost for 1-, 3-, and 5-year fixed rate natural gas contracts were \$2.14/GJ, \$2.79/GJ and \$3.01/GJ respectively (Figure 101).

Figure 101: Expected cost, fixed rate natural gas contract, residential customer (January 1, 2023, to December 31, 2024)

Retailer A was the only retailer to increase its electricity fixed rate among select retailers in Q4. More generally, electricity fixed rates either remained constant or decreased compared to the previous quarter (Figure 102).

Retailer B reduced its rate by 2.61 ¢/kWh for its 3-year contract, marking the largest fixed electricity rate reduction of the quarter. Retailer D made no changes to its rates in Q4. Retailer F offers 2-year contracts and reintroduced its 3-year contract starting December 1. On November 4, Retailer G discontinued its 5-year contracts offerings and now only offers 2-year contracts to residential customers.

Retailer B and C offered the lowest 1-year fixed rate electricity rate (8.99 ¢/kWh) at the end of Q4. Retailer B provides the lowest 3-year fixed rate electricity rate at 8.69 ¢/kWh, while Retailer A offers the lowest 5-year fixed rates at 9.69 ¢/kWh.

Figure 102: 1-, 3-, and 5-year fixed rate electricity contract prices, residential customers, ENMAX service area, January 1, 2023 to December 31, 2024

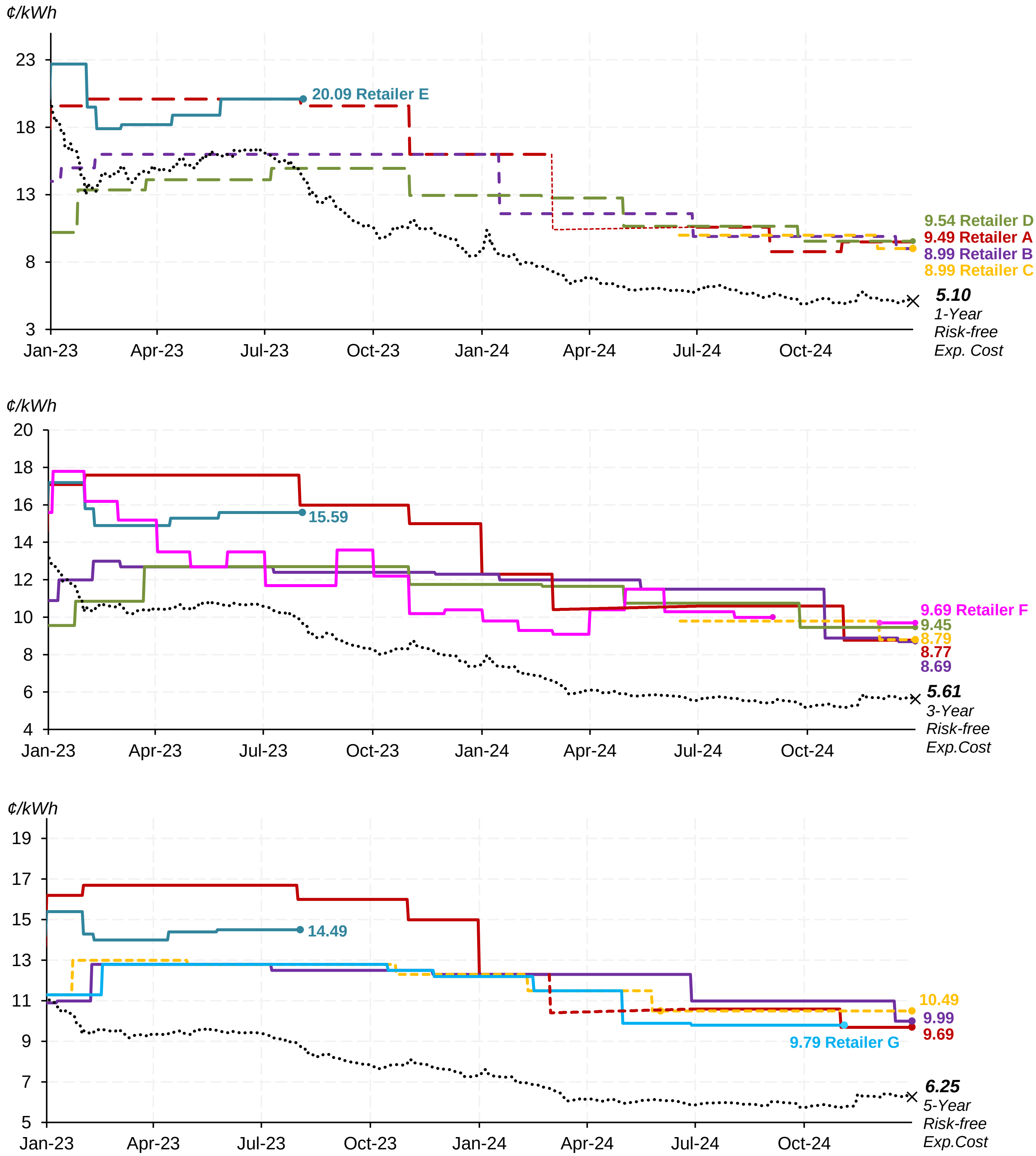
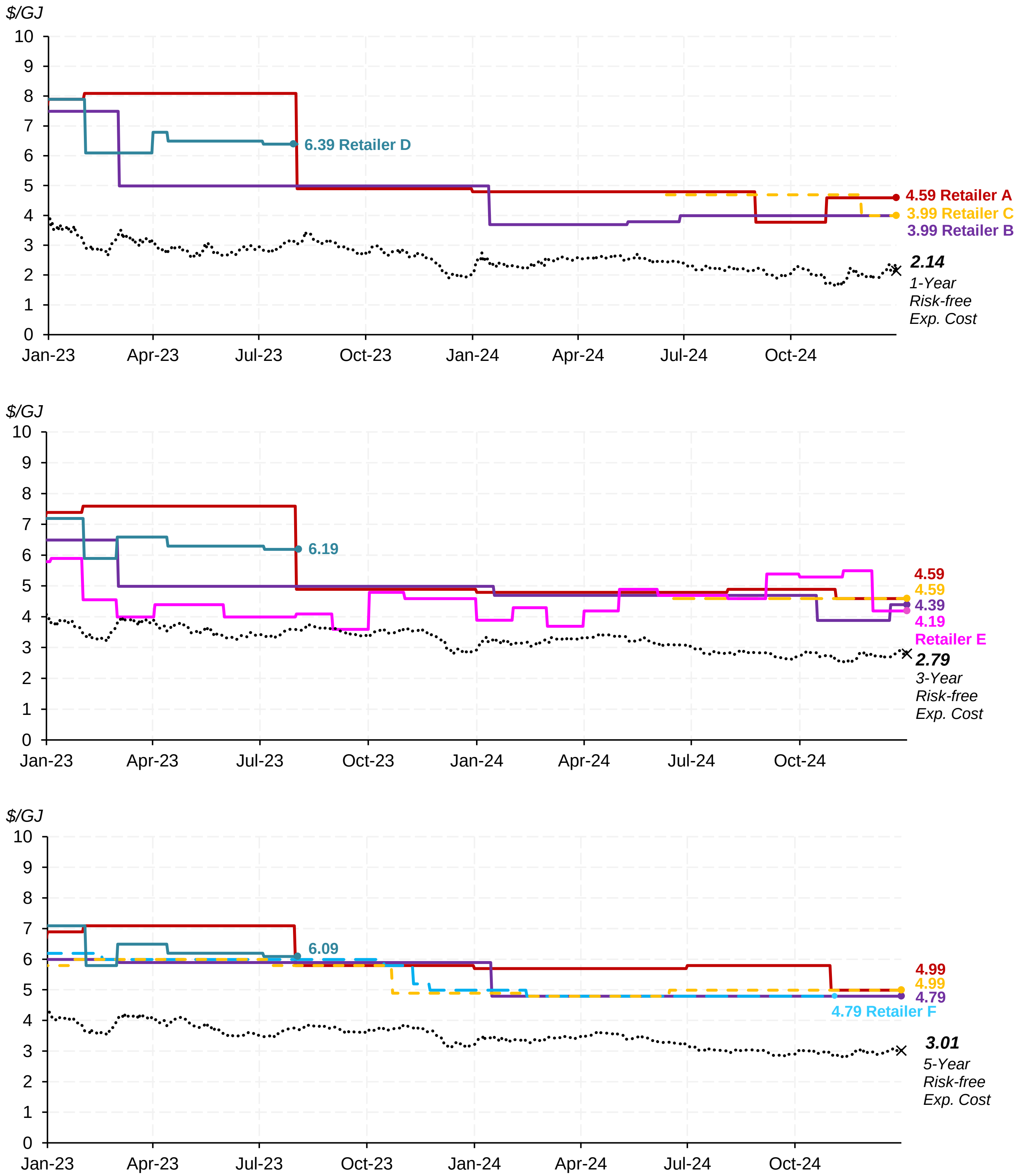


Figure 103: 1-, 3-, and 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area, January 1, 2023 to December 31, 2024



Retailer A increased its 1-year fixed-rate for natural gas on November 1 to a level slightly below the fixed-rate it offered until the end of August. Retailer C reduced its 1-year rate to $3.99/GJ, the same rate offered by Retailer B (Figure 103). Retailer E reduced its 3-year rates from $5.49/GJ to $4.19/GJ on December 2, the largest natural gas fixed-rate change observed over the quarter. Retailer A reduced its 5-year rate to $4.99/GJ, the same rate offered by Retailer C at the end of the quarter. Similar to the electricity contracts, Retailer F stopped offering 5-year contracts on November 4 and only offered 2-year natural gas rates by the end of the quarter.

As of December 31, Retailer B and C offer the lowest 1-year fixed rate natural gas contracts at $3.99/GJ. Retailer E provides the lowest 3-year fixed rate natural gas contracts at $4.19/GJ, while Retailer B offers the lowest 5-year fixed rates at $4.79/GJ.

Low credit impedes some customers from switching to a competitive retailer from their regulated providers. The MSA observed one retailer in Q4 offering a fixed rate product catered to customers with low credit or no credit. The retailer stopped offering the low credit product in December 2024, though they have offered a similar product in previous years. The low credit product did not require customers to provide a deposit but was offered at a premium with an energy rate and administration fee above those offered by other retailers. The MSA is encouraged that retailers are experimenting with new types of retail products and expects the RoLR may provide incentives for additional retailers to offer products to customers that would otherwise not be eligible for competitive contracts.

5.4.2 Competitive variable energy rates

In addition to the regulated rates and competitive fixed rates, residential customers can choose a competitive variable rate plan that fluctuates based on the current market conditions. These rates are referred to as variable energy rates that vary monthly and are tied to pool prices and daily gas index prices.

Estimated variable electricity rates averaged 6.50 ¢/kWh in Q4, with the highest estimated rates occurring in November (8.68 ¢/kWh) and the lowest in December (3.69 ¢/kWh). Estimated variable electricity rates in Q4 were 11% lower than in Q3 and 32% lower than Q4 2023. The RRO also varies monthly and was higher than the variable rates in almost all 2024 months (Figure 104). Customers on competitive variable electricity rates may have therefore faced electricity bills significantly lower than the RRO in 2024.

Estimated variable natural gas rates in Q4 averaged $2.42/GJ with rates ranging from $2.13/GJ to $2.76/GJ throughout the quarter. Estimated variable natural gas rates were 47% higher than in Q3 but were 24% lower year-over-year. Contrary to electricity, estimated variable natural gas rates were higher than regulated natural gas rates (DRT) in most 2024 months (Figure 105). Therefore, customers on variable natural gas rates may have faced significantly higher natural gas bills compared to DRT customers in 2024.

Figure 104: Estimated competitive variable electricity rates vs. RRO, residential customers, ENMAX service area, Q1 2023 to Q4 2024[33]

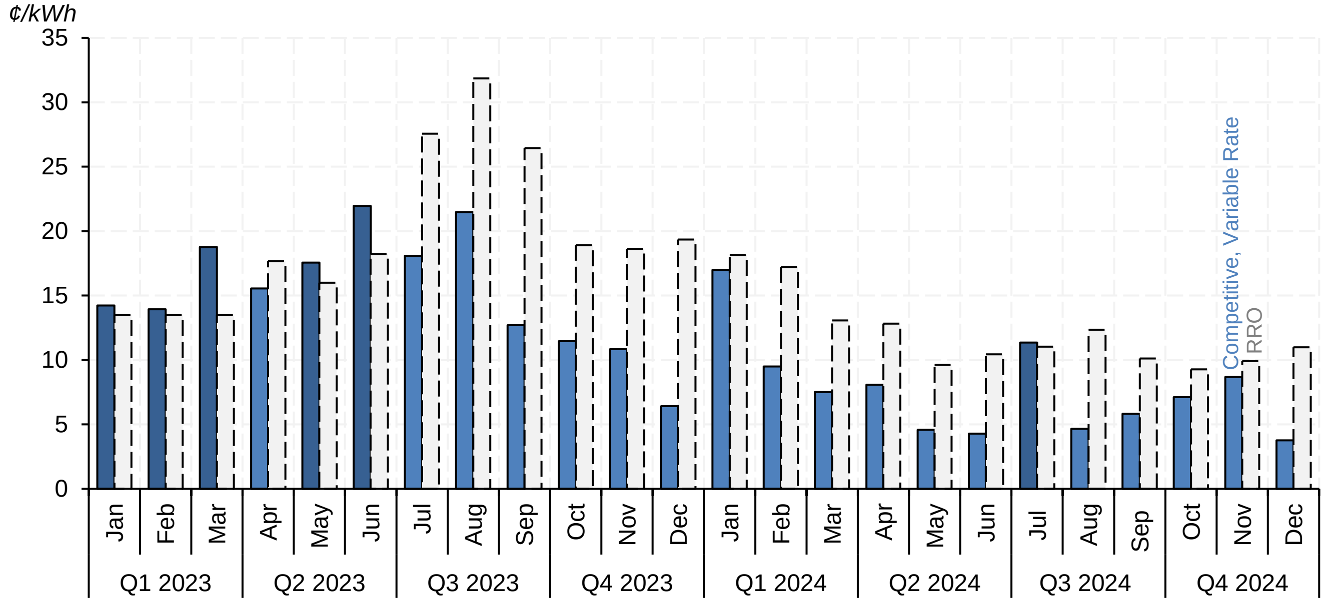
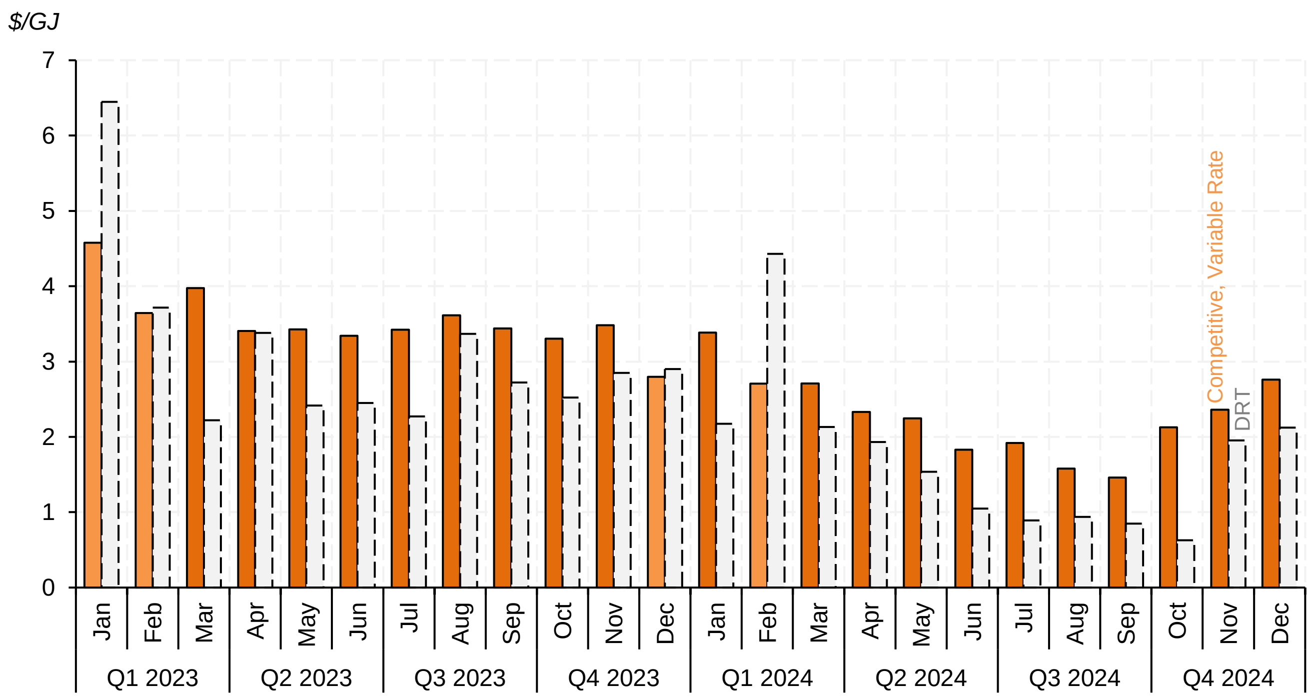


Figure 105: Estimated competitive variable natural gas rates vs. DRT, residential customers, ATCO Gas South service area, Q1 2023 to Q4 2024[34]



[33] Variable electricity rates calculated as residential load-shaped pool price; includes a 1 ¢/kWh adder.

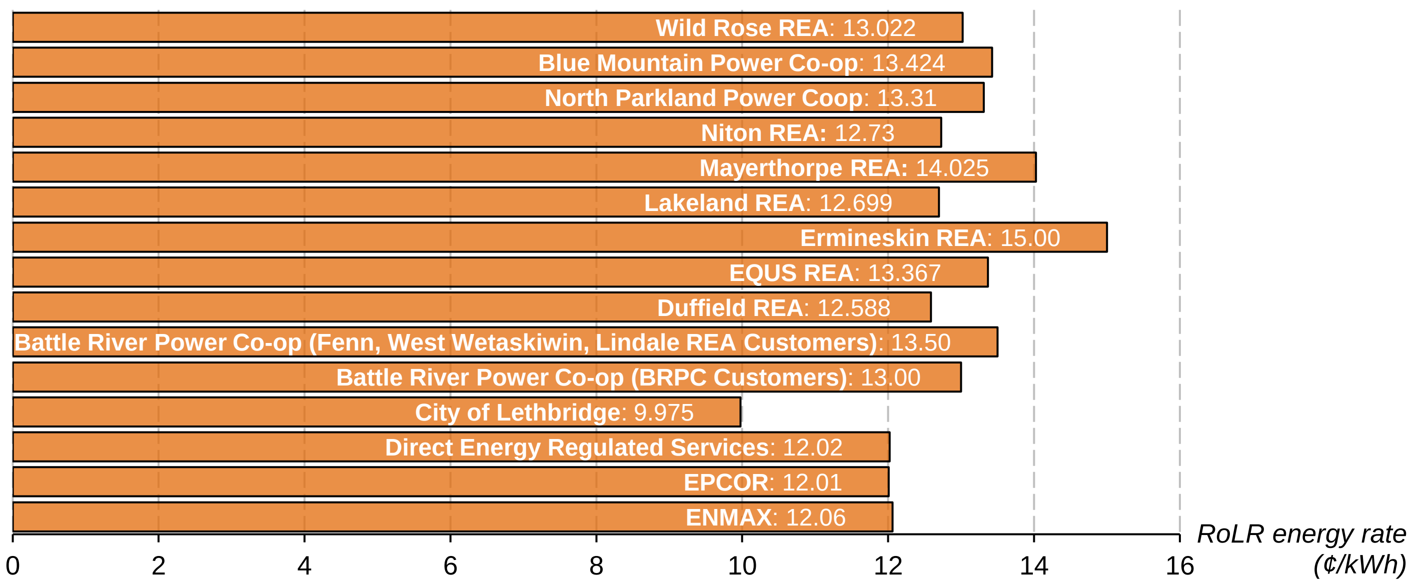
[34] Variable natural gas rates calculated using daily gas index price and residential load shape; includes a $1/GJ adder.

5.5 Regulated retail rates

5.5.1 Implementation of the Rate of Last Resort

The Rate of Last Resort (RoLR) came into effect on January 1, 2025. Customers that consume under 250,000 kWh per year are eligible for the RoLR.[35] Eligible customers who have not signed a contract with a competitive retailer will be automatically enrolled on the RoLR. RoLR energy rates are fixed for two-year terms, with the first term ending at the end of 2026. There are fifteen RoLR providers each serving customers in different distribution service areas (Figure 106). RoLR rates are approved by distributors' regulatory authority.

Figure 106: Rate of Last Resort (RoLR) energy rates, 2025 to 2026



The RoLR replaces the RRO, a regulated rate that varied monthly. RRO customers who did not sign a contract with a competitive retailer were automatically transitioned to the RoLR. Structural differences between the RoLR and the RRO are presented in Table 28.

[35] Customers that consume more than 250,000 kWh per year that have not signed a contract with a competitive retailer are instead enrolled on the Default Supply rate offered by the distributor service provider.

Table 28: Structural differences between the RRO and RoLR

	RRO	**RoLR**
Term	Monthly term	Two-year term
Rate calculation requirements	RRO energy rates must be based on: • Monthly forward electricity prices • Load forecasts	RoLR energy rates must be based on: • Electricity market prices prevailing during the price-setting period set by the RoLR provider • Load forecasts
Limitations	No limit on changes in RRO energy rates between months	RoLR rate cannot change by more than 10% between two-year terms
Regulatory approval	RRO energy rates are approved by regulatory authority monthly	Rates are approved by regulatory authority every two years
Other factors		• UCA will contact RoLR customers to advise on competitive retail options • 0.1 cents/kWh included in the RoLR energy rate to fund UCA activities • RoLR energy rate can be reopened during the two-year term by the regulatory authority based on MSA financial performance report

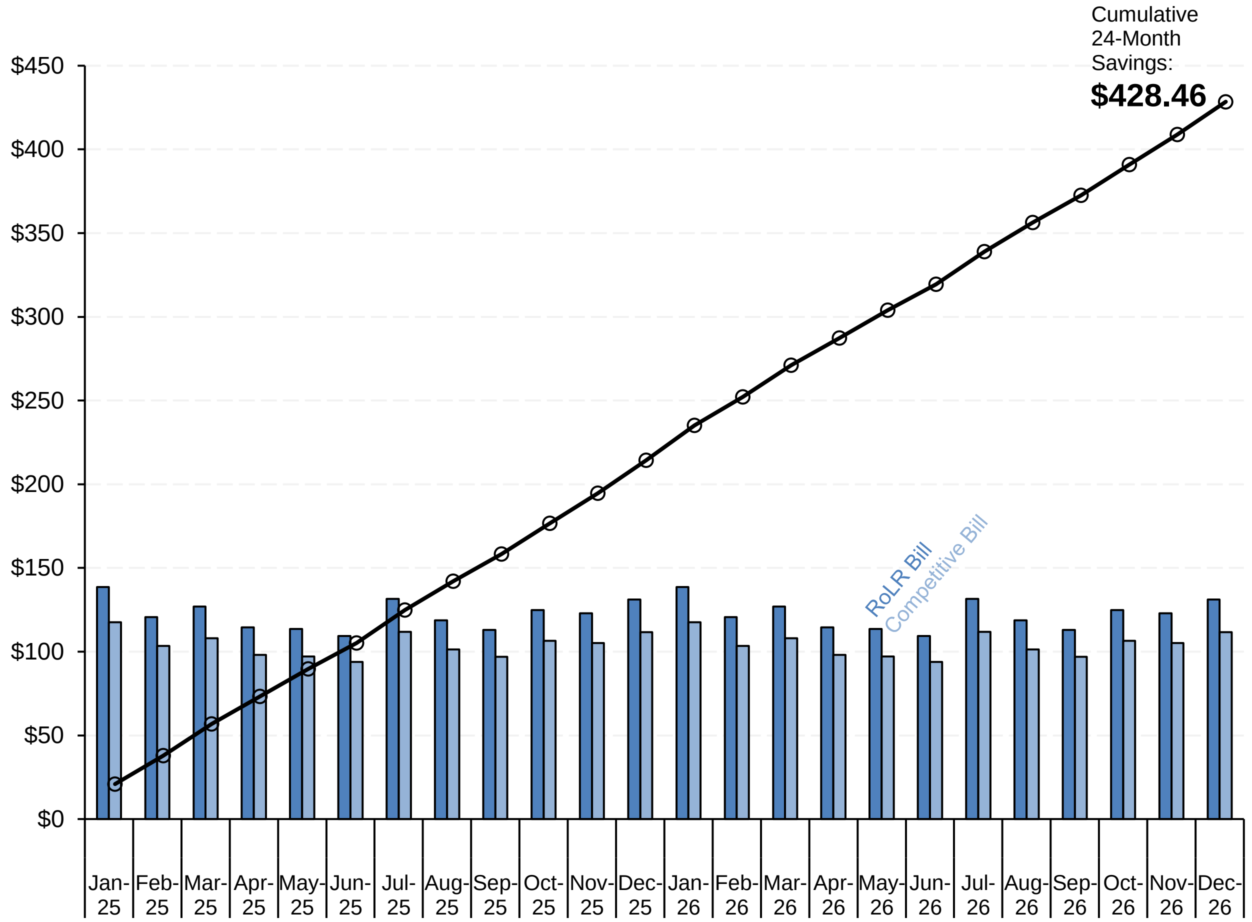
5.5.2 Switching incentives

Residential customers continue to have a strong incentive to switch from regulated rates to competitive fixed rates with the transition of regulated rates from the RRO to the RoLR.

An average residential RoLR customer in the ENMAX service area could expect to save around $428 over the first two-year fixed term RoLR[36] period, starting in January 2025 and ending in December 2026, if they had switched to the lowest priced 3-year contract available as of December 31, 2024 (Figure 107). Since both energy rates are fixed over this period, the monthly savings is relatively consistent; as a result the cumulative monthly savings line is highly linear. The slight fluctuations in the line are due to seasonal consumption levels and differences in administration charge calculation methodologies between the two products.

[36] The approved RoLR rate in ENMAX service area for 2025-2026 term is 12.06 ¢/kWh

Figure 107: Expected RoLR bill vs. competitive electricity bill (3-year fixed rate at 8.69 ¢/kWh, $9.90/month Admin fee)[37]



While RoLR customers have an incentive to switch to competitive rates, residential DRT customers do not. If an average residential DRT customer had switched to the lowest 3-year fixed natural gas rate on January 1, 2025, they could expect to pay around $209 more in the 24 months that followed (Figure 108). DRT rate forecasts used to estimate DRT bills reflect forward prices for natural gas as of December 31, 2024 (Figure 109).

[37] Estimated bills for a residential customer in the ENMAX service area over January 2025 to December 2026 period.

Figure 108: Expected DRT bill vs. competitive natural gas bill (3-year fixed rate at $4.19/GJ, $6.85/month Admin fee)[38]

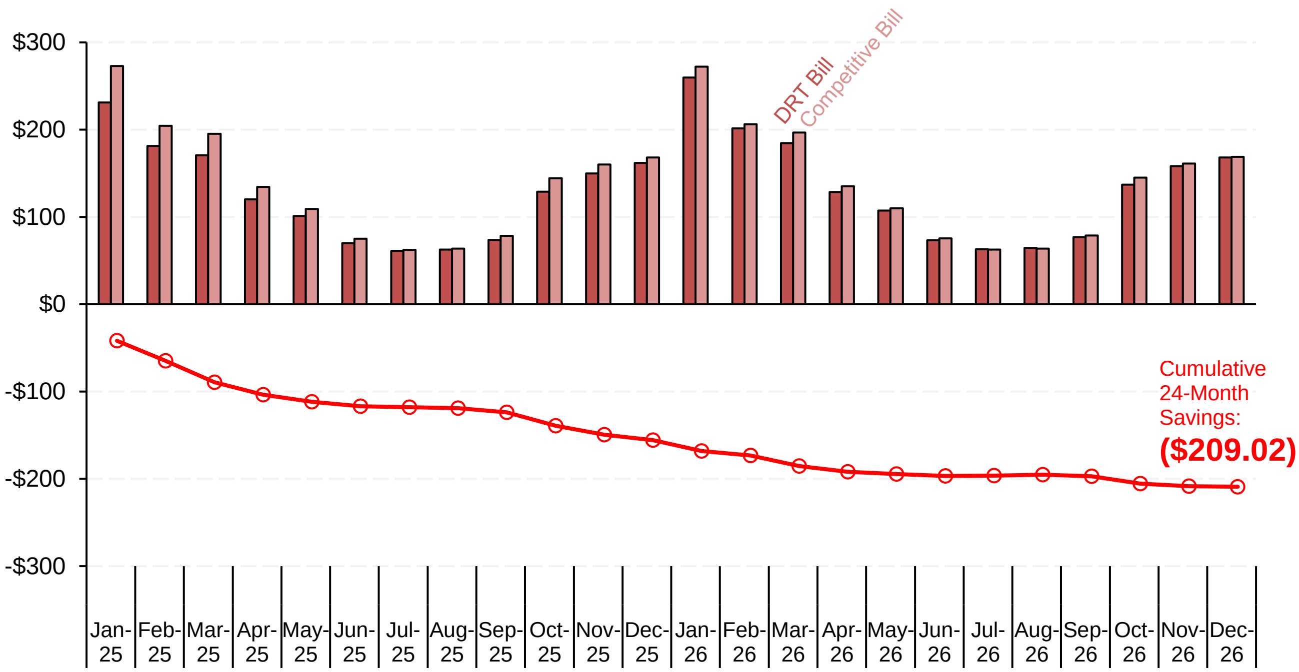
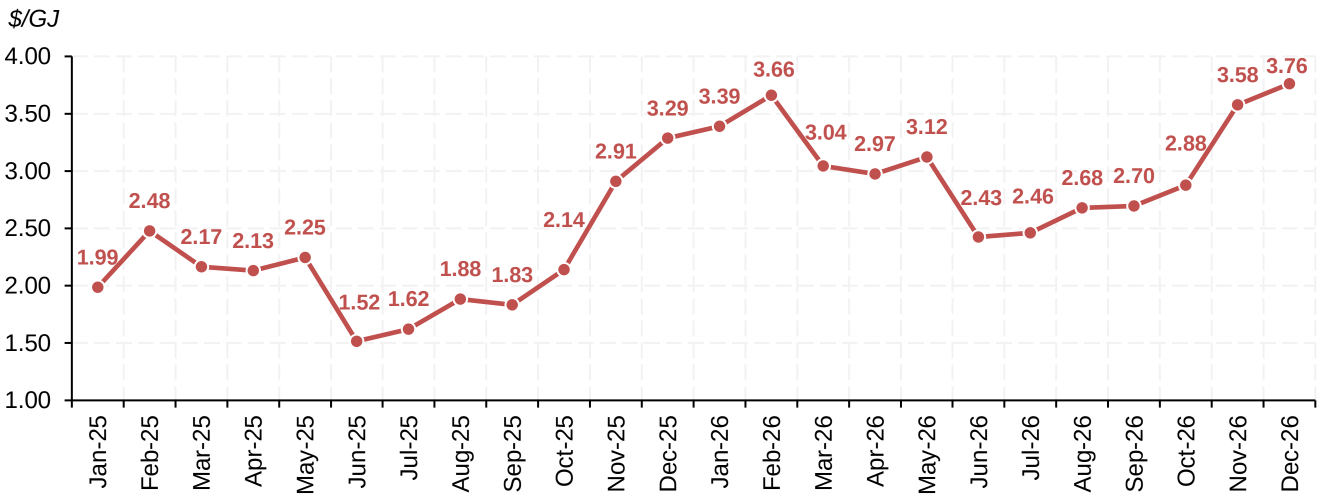


Figure 109: January 2025 to December 2026 residential DRT estimates, ATCO Gas service areas (as of December 31, 2024)

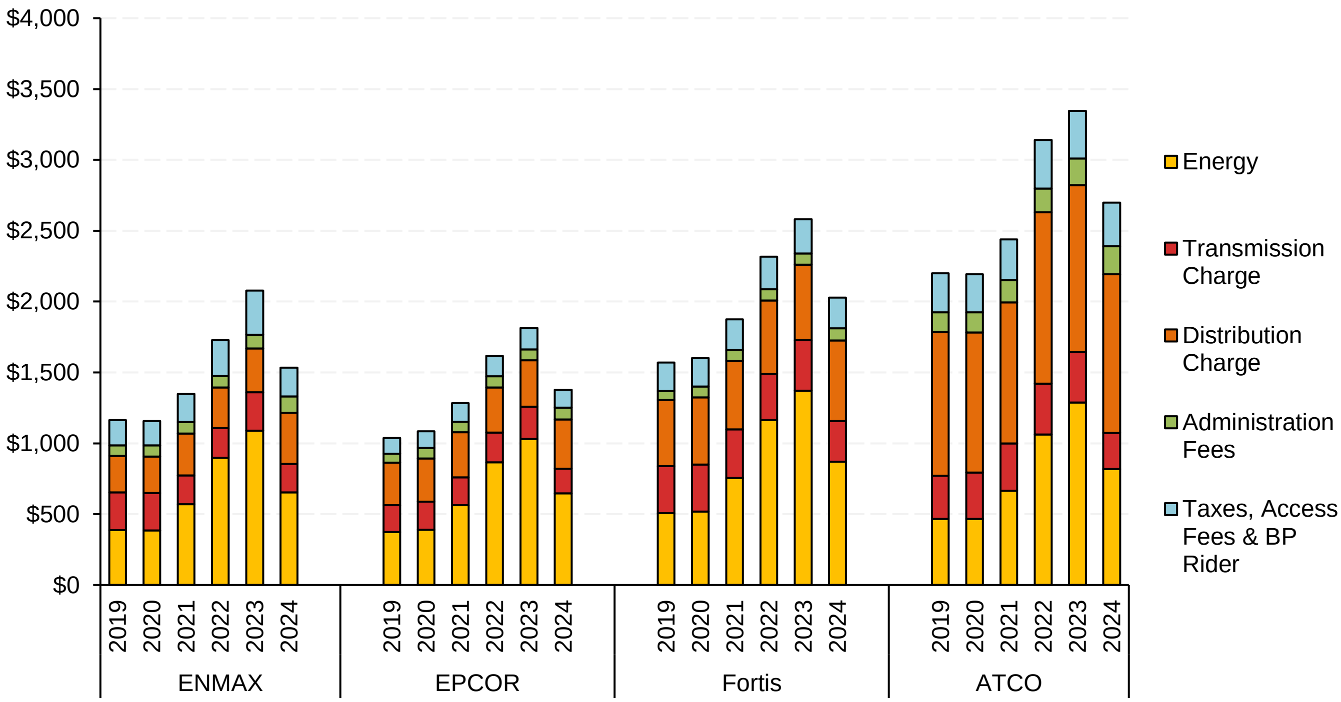


[38] Estimated bills for a residential customer in the ATCO Gas South service area over the January 2025 to December 2026 period.

5.6 Regulated bills

Residential RRO electricity bills fell in 2024 compared to 2023 (Figure 110), with declines ranging from 19% to 26%, depending on the service area. RRO electricity bill declines were primarily driven by decreases in RRO rates throughout the year (Figure 83 and Figure 84).

Figure 110: Residential RRO bill composition (2019 to 2024) without rebate[39]



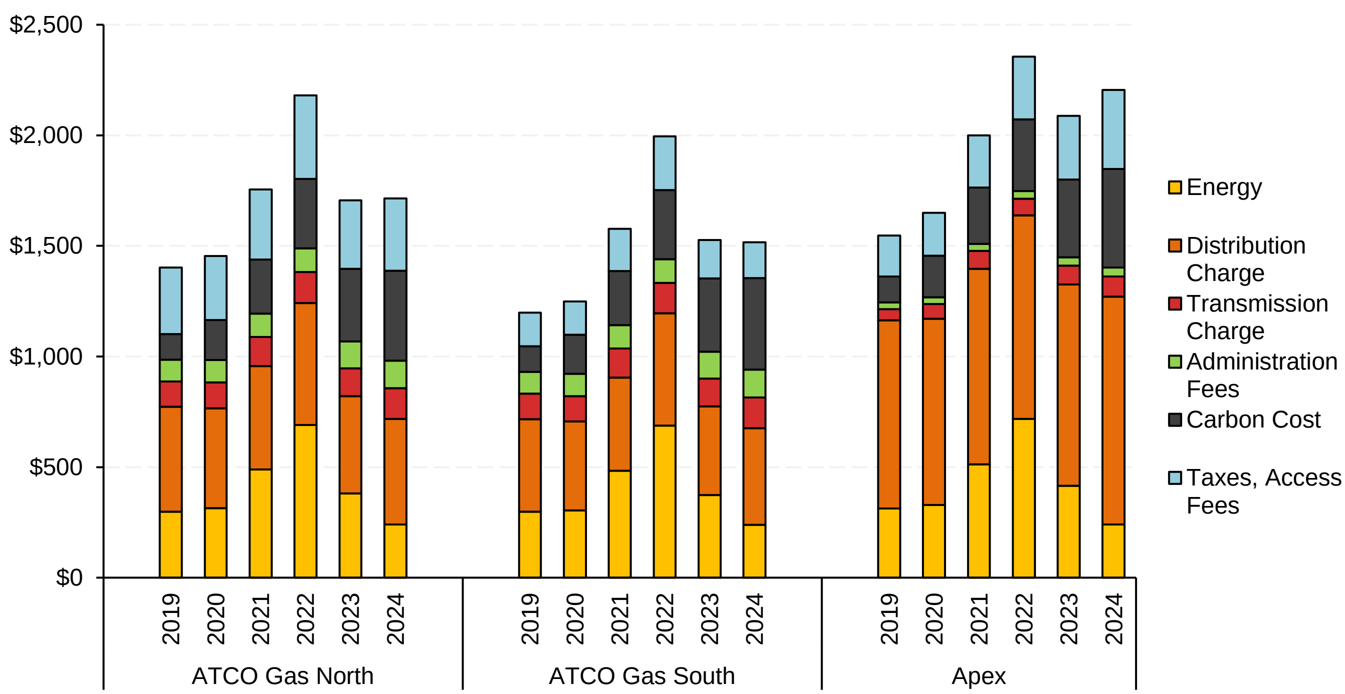
Energy has consistently been the largest component of an average residential RRO customer's electricity bill since 2019 except for customers in the ATCO Electric service area, where distribution charges are greater than energy charges for an average residential customer. In 2024, energy charges accounted for an average of 44% of the bill in the ENMAX, EPCOR, and FortisAlberta service areas, compared to just 30% in the ATCO Electric service area. Although RRO energy charges fell in 2024, they averaged 72% higher than RRO energy charges in 2019, adding approximately between $270 and $360 to annual bills across all service areas. Administration fees for RRO customers also increased since 2019, with a growth rate of at least 33% across all service areas.

[39] Electricity bill rebates of $500 were applied from July 2022 to April 2023, but are not accounted for in Figure 110.

Transmission charges were slightly lower in 2024 compared to 2019, with ENMAX distribution customers experiencing the largest bill decrease of $65 over the period. Distribution costs have risen across all service areas over the period, increasing an average residential customer's electricity bills by $50 to $110 annually. Distribution charges in the ENMAX service area increased by 41% over the period, while other service areas saw an increase of around 16% on average.

Residential DRT natural gas bills increased between 22% and 43% from 2019 to 2024 (Figure 111). The overall increase in DRT bills was primarily driven by the carbon levy, which in 2024 represents 24% of the average gas bill and has more than tripled in cost, rising from an average of $116 in 2019 to $422 in 2024 across all service areas.

Figure 111: Residential DRT bill composition (2019 to 2024)



Transmission charges are a relatively small component of natural gas bills, though they increased significantly between 2019 and 2024, averaging 21% higher in the ATCO Gas service areas and 86% higher in the Apex service area. Distribution charges also increased more in the Apex area (21%, equating to a $178 increase in annual bills), while the other areas saw an average increase of 3%.

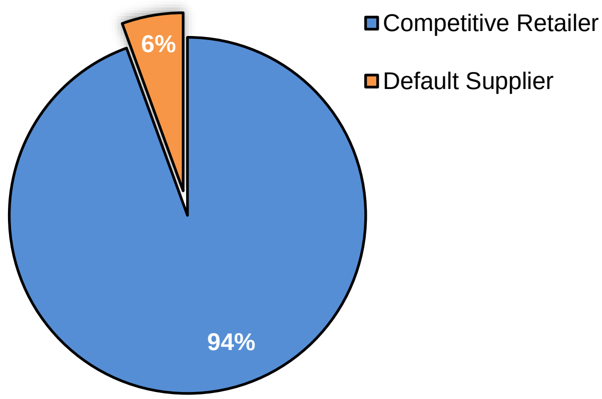
DRT energy charges were particularly high in 2022 but have since decreased, following declines in natural gas prices. In 2024, DRT energy charges averaged 14% of the total DRT bill (around $239). Additionally, administration fees have increased by approximately 28% on average for all service areas over the past five years.

5.7 Cessation of retailer offerings

In September 2024, a retailer (Retailer A) stopped offering new competitive retail products to large commercial and industrial electricity customers that consume more than 250,000 kWh annually (large C&I). Retailer A has a market share of approximately 23% among large C&I customers. Retailer A has continued to offer competitive products to small commercial or industrial customers who consume less than 250,000 kWh annually. Retailer A's existing large C&I customers will need to choose a new retailer following the end of their competitive contracts with Retailer A. While these large C&I customers are generally ineligible for the RoLR due to their consumption levels, some of these customers may switch to the Default Supply Rate if they do not choose to switch to a competitive retailer. Customers on the Default Supply Rate are generally exposed to pool prices.

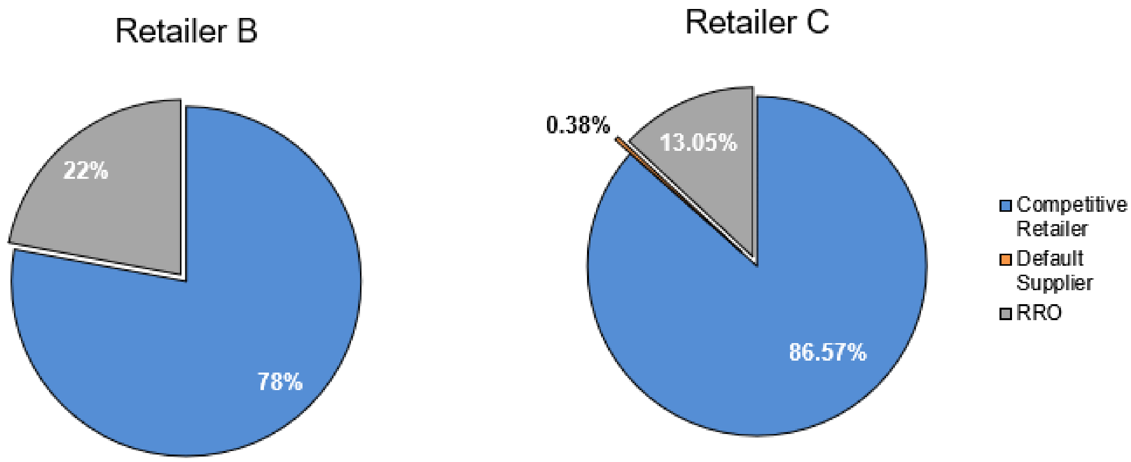
Around 1.6% of Retailer A's large C&I customers left Retailer A in Q4 2024. Of these departing customers, 94% of them switched to a different competitive retailer and only 6% switched or reverted to the default supplier (Figure 112).

Figure 112: Retailer A's large C&I site losses, by destination, October 2024 to December 2024



Retailer A is not the first significant retailer to leave the Alberta retail market. In August 2023, two competitive retail providers in Alberta, Retailer B and Retailer C, stopped offering new retail products, and will only serve existing customers until their contract expiration dates. Approximately 60% and 35% of Retailer B and Retailer C's customers, respectively, have switched to a different retailer since the retailers stopped offering new contracts. Most of these customers switched to a competitive plan after leaving Retailer B and C (Figure 113).

Figure 113: Retailer B & C site losses, by destination, August 2023 to December 2024



While Retailer B and C served various customer types and not only large C&I customers, the MSA is encouraged that customers that have switched to competitive retailers retain awareness of competing retailers and would not simply revert to a regulated retailer if their existing competitive contracts were not renewed. On this basis, the MSA expects most of Retailer A's remaining large C&I customers will transition to a competitive retailer, with some opting to revert to the default supplier. Given Retailer A's significant market share among large C&I customers, the MSA will continue to monitor the competitiveness of the large C&I retail market and the behaviour of customers departing Retailer A.

6 REGULATORY AND ENFORCEMENT MATTERS

6.1 TA Alberta Hydro LP Brazeau Spinning Reserves

On November 30, 2022, the MSA received a self-report from TA Alberta Hydro LP (TransAlta) regarding a contravention of ISO rule 205.5 (Spinning Reserve Technical Requirements and Performance Standards) at its Brazeau hydro-electric asset, for the period of August 13, 2021, to November 1, 2022. This self-report was submitted to the MSA during the course of a previous investigation of conduct under the same ISO rule related to a different asset (SUM1) that was also owned by TransAlta.[40]

The MSA investigated whether TransAlta was physically able to provide the frequency response that the AESO paid it to provide from the Brazeau hydro-electric asset. The AESO procures frequency response as part of spinning reserves because it is essential to the reliable operation of Alberta's power system.

As a result of the investigation, the MSA found that TransAlta was not able to provide the required frequency response from the Brazeau hydro-electric asset for 7,412 hours between August 13, 2021, to November 1, 2022.

A penalty was assessed for every hour of contravention in this period, with a maximum of $100,000 of penalty a day – a limitation that is set out in section 52(7)(b) of the Alberta Utilities Commission Act. Notices of Specified Penalties summing to $32,683,500 were issued by the MSA to TransAlta on November 29, 2024, for payment on or before January 10, 2025. Payment was received on January 10, 2025. The Notices of Specified Penalties are available on the MSA website.

6.2 Rate of Last Resort energy price setting plan determination reports

RoLR Energy Prices are set in accordance with a methodology contained in a RoLR provider's energy price setting plan (EPSP). Section 5.2 of the *Rate of Last Resort Regulation* (AR 262/2005) requires the MSA to produce determination reports on EPSPs and indicate whether they comply with the requirements for a fair, efficient, and openly competitive (FEOC) electricity market.

The MSA produced determination reports for seventeen EPSPs received by the MSA from RoLR providers. Of the EPSPs received by the MSA, eleven were determined to be consistent with "fairness", three were consistent with "efficiency", and all EPSPs were consistent with an "openly competitive" electricity market.

An EPSP was determined to be inconsistent with "fairness" if it would produce RoLR Energy Prices that generate cross-subsidies between identifiable customer types or across time, among

---

[40] See section 6.1 of the MSA's Quarterly Report for Q3 2023. Also see section 6.1 of the MSA's Quarterly Report for Q1 2024.

other factors. EPSPs determined to be inconsistent with “fairness” generally included cross-subsidies between types of customers or customers in different distribution service areas.[41]

An EPSP was determined to be inconsistent with “efficiency” if it would not produce RoLR Energy Prices reflective of the expected cost associated with providing electric energy to customers, accounting for prevailing forward market prices and the expected value of risks the RoLR provider expected to face, among other factors. EPSPs determined to be inconsistent with “efficiency” generally did not use appropriate estimators of the expected value of risks.

An EPSP was determined to be inconsistent with an “openly competitive” electricity market if it would not produce RoLR Energy Prices calculated using prices established in an openly competitive market or competitive procurement, among other factors.

6.3 Rate of Last Resort stakeholder consultation

In addition to the MSA’s role in producing determination reports on EPSPs, the *Rate of Last Resort Regulation* (AR 262/2005) also requires the MSA to monitor RoLR provider financial performance and produce financial performance reports every six months.[42] The first financial performance report will be completed by July 1, 2025. As part of this monitoring and reporting obligation, the MSA is required to establish parameters for what constitutes acceptable RoLR provider financial performance and must consult with persons likely to be affected by these parameters.[43]

On December 20, 2024 the MSA initiated a stakeholder consultation on its Rate of Last Resort activities.[44] The objectives of this stakeholder consultation are to collect feedback from RoLR providers and other affected persons on:[45]

1. the most appropriate measure(s) of financial performance under the RRT;
2. the most appropriate acceptable financial performance parameters; and
3. the MSA report on RoLR provider financial performance.

The MSA requested written responses from participants by January 17, 2025. Responses were subsequently published on the MSA’s website. The MSA is currently developing its draft process for monitoring and reporting on RoLR provider financial performance, and the establishment of parameters pursuant to section 11.2 of the RoLR Regulation.

---

[41] More information on the MSA’s FEOC standards for evaluating EPSPs is available in its Rate of Last Resort Implementation by Rural Electrification Associations and municipalities presentation, Slides 19-21.

[42] *Rate of Last Resort Regulation* (AR 262/2005), ss. 11.2(1)(a), 11.2(1)(b).

[43] *Ibid*., ss. 11.2(3), 11.2(4).

[44] Notice Re: MSA stakeholder consultation on *Rate of Last Resort Regulation* MSA activities, December 20, 2024.

[45] *Ibid*., p. 3.

7 ISO RULES COMPLIANCE

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

From January 1 to December 31, 2024, the MSA closed 517 ISO rules compliance matters, as reported in Table 29.[46] An additional 301 matters were carried forward to the next quarter. During this period 117 matters were addressed with NSPs, totalling $33,614,000 in financial penalties, with details provided in Table 30.

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

Table 29: ISO rules compliance outcomes from January 1 to December 31, 2024

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.1	2	-	-
103.12	-	1	-
201.1	1	-	-
201.3	1	2	-
201.4	-	1	-
201.7	49	17	-
203.1	11	4	1
203.3	99	10	8
203.4	86	14	3
203.6	29	3	-
205.3	2	6	-
205.4	4	-	-
205.5	5	3	1
205.6	6	27	2
301.2	12	8	1
303.1	1	-	-
304.3	3	-	-
304.4	1	-	-
304.6	1	-	-
304.9	3	-	-
306.4	4	5	-
306.5	6	5	-
502.1	3	1	-
502.4	6	6	-
502.5	1	-	-
502.6	8	1	-
502.8	6	2	-
502.9	1	-	-
502.10	1	-	-
502.14	-	1	-
502.15	3	-	-
502.16	10	-	1
503.17	1	-	-
504.4	4	-	-
505.3	5	-	-
505.4	7	1	-
Total	382	118	17

Table 30: Specified penalties issued between January 1 and December 31, 2024 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)																				Total ($)	Matters
	103.12	201.3	201.4	201.7	203.1	203.3	203.4	203.6	205.3	205.5	205.6	301.2	306.4	306.5	502.1	502.4	502.6	502.8	502.14	505.4		
Achernar GP Ltd.							1,000														1,000	2
Air Liquide Canada Inc.	7,000			7,000					2,000												16,000	6
AltaGas Ltd.				500			6,500														7,000	3
ATCO DB Solar GP Services Ltd.				250	500																750	3
ATCO Electric Ltd.													500								500	2
BFL3 Buffalo Atlee 3							250														250	1
BHE Canada Rattlesnake L.P.																		500			500	1
Bull Creek Wind Power Limited Partnership						250															250	1
Calgary Energy Centre No. 2 Inc.						250															250	1
Canadian Hydro Developers, Inc.			250		250				500	678,500									250		679,750	5
Capital Power (CBEC) L.P.									500												500	1
Castle Rock Ridge LP						500															500	1
Concord Monarch Partnership						500															500	1
Concord Stavely Partnership												500									500	1
Concord Vulcan Partnership												500						500			1,000	2
Conrad Solar Inc.												5,000									5,000	1
CP Energy Marketing L.P.								500													500	2
Cypress 2 Renewable Energy Centre Limited Partnership				13,750												1,250					15,000	4
Cypress Renewable Energy Centre Limited Partnership		250		13,750										500		1,250					15,750	6
Dow Chemical Canada ULC				250																	250	1
Enel X Canada Ltd.											97,500										97,500	20
Enfinite Corporation									250												250	1
Enfinite Generation Corporation							250														250	1
ENMAX Generation Portfolio Inc.						250															250	1
Forty Mile Granlea Wind GP Inc.				28,750			1,000						250								30,000	6
Ghost Pine Windfarm, LP							500														500	1
Grande Prairie Generation Inc.														500							500	1

Table 30: Specified penalties issued between January 1 and December 31, 2024 for contraventions of the ISO rules (continued)

Market participant	Total specified penalty amounts by ISO rule ($)																				Total ($)	Matters
	103.12	201.3	201.4	201.7	203.1	203.3	203.4	203.6	205.3	205.5	205.6	301.2	306.4	306.5	502.1	502.4	502.6	502.8	502.14	505.4		
Halkirk I Wind Project LP							250					3,500					250				4,000	5
Hays Solar LP						500															500	1
Heartland Generation Ltd.											250										250	1
Jenner 3 Limited Partnership						500															500	1
Kneehill Solar LP														500		500					1,000	2
Lanfine Wind 1 LP														500							500	1
MEG Energy Corp.							250														250	1
Mercer Peace River Pulp Ltd.					250																250	1
Michichi Solar LP														500		500					1,000	2
Morgan Stanley Capital Group Inc.								10,000													10,000	1
NAT-1 Limited Partnership							250														250	1
Northstone Power Corp.				500																	500	2
Oldman 2 Wind Farm Limited												500									500	1
Paintearth Wind Project Limited Partnership												250									250	1
Pincher Creek Limited Partnership						500															500	1
Signalta Resources Limited		250																			250	1
Suncor Energy Inc.													1,000								1,000	2
Syncrude Canada Ltd.																			250		250	1
TA Alberta Hydro LP									250	32,683,500											32,683,750	2
Taber Solar 1 Inc.						500															500	1
Taber Solar 2 Inc.						250															250	1
Tourmaline Oil Corp.				500																	500	1
TransAlta Generation Partnership							750			250											1,000	2
Voltus Energy Canada Ltd.											30,000										30,000	6
Wheatland Wind Project LP							500														500	1
Whitecourt Power Ltd.				500																	500	1
Windrise Wind LP															250						250	1
Total	**7,000**	**500**	**250**	**65,750**	**1,000**	**4000**	**11,500**	**10,500**	**3500**	**33,362,250**	**127,750**	**10250**	**1,750**	**2,500**	**250**	**3,500**	**250**	**1,000**	**250**	**250**	**33,614,000**	**118**

The ISO rules listed in Table 29 and Table 30 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
504	Legal Owners of Transmission Facilities and Load Facilities
505	Legal Owners of Generating Facilities

8 ARS COMPLIANCE

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

The ARS ensure the various entities involved in grid operation have practices in place, including procedures, communications, coordination, training, and maintenance to support the reliability of the AIES.[47] ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach to compliance with ARS focuses on promoting awareness of obligations and a proactive compliance stance. The MSA's process, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

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

From January 1 to December 31, 2024, the MSA addressed 112 O&P ARS compliance matters (Table 31).[48] 56 O&P ARS matters were carried forward to the next quarter. During this period, 35 matters were addressed with NSPs, totalling $148,500 in financial penalties (Table 32). For the same period, the MSA addressed 98 CIP ARS compliance matters, as reported in Table 33, two matters were addressed with NSPs, totalling $7,500. 161 CIP ARS matters were carried forward to next quarter.

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

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

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

Reliability standard	Forbearance	Notice of specified penalty	No Contravention
COM-001	17	4	1
COM-002	2	-	-
EOP-005	-	1	-
EOP-008	6	8	-
EOP-011	1	2	-
FAC-008	12	1	-
IRO-008	1	-	-
PER-003	-	1	-
PER-005	-	3	-
PER-006	3	-	-
PRC-001	2	-	-
PRC-002	3	-	1
PRC-005	11	7	2
PRC-018	1	-	-
PRC-019	5	2	-
VAR-002	7	5	2
VAR-501	-	1	-
Total	71	35	6

Table 32: Specified penalties issued between January 1 and December 31, 2024 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)											Total ($)	Matters
	COM-001	EOP-005	EOP-008	EOP-011	FAC-008	PER-003	PER-005	PRC-005	PRC-019	VAR-002	VAR-501		
City of Lethbridge					2,250			3,750				6,000	22
City of Medicine Hat	15,000		5,000									20,000	2
City of Red Deer								3,750				3,750	1
Forty Mile Granlea Wind GP Inc.										10,000		10,000	14
MEG Energy Corp.								2,500				2,500	3
Suncor Energy Inc.			32,500	12,500		12,500	14,500					72,000	13
Syncrude Canada Ltd.								5,500				5,500	1
TA Alberta Hydro LP		3,750						5,000	2,500	5,000	5,000	21,250	1
Windrise Wind LP										7,500		7,500	3
Total	**15,000**	**3,750**	**37,500**	**12,500**	**2,250**	**12,500**	**14,500**	**20,500**	**2,500**	**22,500**	**5,000**	**148,500**	**112**

The ARS outcomes listed in Table 31 and Table 32 are contained within the following categories:

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

Table 33: CIP ARS compliance outcomes from January 1 to December 31, 2024

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	8	1	-
CIP-003	15	-	-
CIP-004	31	-	-
CIP-005	4	-	-
CIP-006	9	-	-
CIP-007	10	-	-
CIP-008	2	-	-
CIP-009	2	-	-
CIP-010	15	-	-
CIP-011	8	1	-
CIP-012	2	-	
Total	106	2	-

The ARS outcomes listed in Table 33 are contained within the following categories:

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