MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q1 2022

May 13, 2022

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

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THE QUARTER AT A GLANCE

- The average pool price in Q1 2022 was $89.98/MWh, a 6% decrease relative to the Q1 2021 pool price of $95.45/MWh. On a monthly basis, pool prices were higher in January and March this year compared to 2021 but were not high enough to offset the much lower prices in February this year. The higher January and March prices were a result of higher natural gas prices and increased demand driven by colder temperatures. However, more competitive offer behaviour in addition to higher wind and solar generation in Q1 this year relieved some of this upward pressure.

- Natural gas prices averaged $4.50/GJ over the quarter, up 56% from Q1 2021, whereas the average pool price fell by 6% year-over-year. The higher natural gas prices have raised input costs for gas-fired generation assets, and this has translated to lower a margin between pool prices and natural gas input costs. The current expectation of forward prices is that the margin of pool prices over natural gas input costs is expected to be much lower in 2022 compared to 2021.

- Pool price volatility and variable natural gas prices were the main drivers of forward power prices in the quarter. In January, pool prices came in much lower than forward market expectations, putting downward pressure on forward power prices, particularly February. In mid-February, forward prices increased on the back on pool price volatility and increasing natural gas prices. In early April, natural gas prices increased significantly in response to high demands and reduced gas storage volumes in North America, which put upward pressure on forward power prices in Alberta.

- The MSA has published various retail market analyses in a Supplemental Retail Market Report for Q1 2022.

- From January 1 to March 31, 2022, the MSA closed 84 ISO rules compliance matters; 24 matters were addressed with notices of specified penalty. For the same period, the MSA closed 39 Alberta Reliability Standards Operations and Planning compliance matters; five matters were addressed with notices of specified penalty. In addition, the MSA closed 49 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; eight matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q1 was $89.98/MWh, which is 6% lower than the average Q1 2021 pool price of $95.45/MWh.[1] This decrease is largely attributable to lower prices in February this year. In February 2021, pool prices were raised by a polar vortex that swept over Alberta and had the effect of increasing heating demands as well as depressing wind generation. In contrast, January and March both saw an increase in pool prices year-over-year, largely due to higher natural gas prices and stronger demand.

Table 1 shows summary market statistics for Q1. The average price of natural gas increased by 56% year-over-year, settling at $4.50/GJ, relative to $2.89/GJ in Q1 2021. A growing portion of generation in Alberta is provided by natural gas-fired assets, which means higher natural gas prices will continue to have a substantial impact on generation costs and corresponding pool prices.

Table 1: Monthly market summary for Q1

		2022	2021	*Change*
Pool Price (Avg $/MWh)	Jan	90.81	72.89	25%
	Feb	105.22	151.98	-31%
	Mar	75.38	66.92	13%
	Q1	**89.98**	**95.45**	**-6%**
Demand (AIL) (Avg MW)	Jan	10,512	10,266	2.4%
	Feb	10,417	10,620	-1.9%
	Mar	10,070	9,784	2.9%
	Q1	**10,330**	**10,210**	**1.2%**
Gas Price (Avg $/GJ)	Jan	4.18	2.60	61%
	Feb	4.48	3.57	25%
	Mar	4.83	2.56	88%
	Q1	**4.50**	**2.89**	**56%**
Wind Gen. (Avg MW)	Jan	1,085	846	28%
	Feb	1,011	644	57%
	Mar	919	820	12%
	Q1	**1,005**	**774**	**30%**
Net Imports (+) Net Exports (–) (Avg MW)	Jan	472	642	-27%
	Feb	551	579	-5%
	Mar	615	565	9%
	Q1	**546**	**596**	**-8%**
Thermal Outages[2] (Avg MW)	Jan	1,826	1,666	10%
	Feb	1,540	1,823	-16%
	Mar	1,745	2,246	-22%
	Q1	**1,709**	**1,914**	**-11%**

The average pool price in March was $75.38/MWh, an increase of 13% year-over-year. The average price of natural gas increased to $4.83/GJ in March, an 88% increase year-over-year. As a result, the margin between pool prices and natural gas input costs was much lower in March this year, and the same was true for February.

This indicates that pool prices this year have generally been closer to the cost of generating electricity than was the case in Q1 2021, after considering the higher input cost of natural gas.

Differences in demand between the months in Q1 2022 and Q1 2021 were closely related to temperatures. February 2021 was the coldest month across both quarters with an average temperature of -15.2°C and an average demand of 10,620 MW. Conversely, March 2021 had an

[1] Reference to Q1 means Q1 2022 unless specified otherwise. Reference to a month, or a day in a month, means a month or day in 2022 unless specified otherwise.

[2] The outage figures for Q1 2021 do not include the Sundance 5 mothball outage. The Sundance 5 asset was mothballed beginning in April 2018 and was subsequently retired in the fall of 2021.

average temperature of -0.3°C, which made it the warmest month, and had the lowest demand of 9,784 MW.

Compared to last year, January and March in 2022 were colder on average, which contributed to a year-over-year increase in demand of 2.4% and 2.9%, respectively. A new peak demand of 11,939 MW was set during hour ending 18 (HE 18) on January 3, a 210 MW (1.8%) increase over the previous record set in February 2021. The previous load record was surpassed in ten different hours over the January 3 to 8 period.

Total wind capacity in Alberta was 2,269 MW as of March 31, an increase of 488 MW compared to March 31, 2021. Average wind generation this quarter was up by 30% year-over-year. January had the second highest monthly average wind generation on record at 1,085 MW, which corresponded to a capacity factor of 48%. February and March also saw an increase in average wind generation compared to last year (Table 1). Wind capacity has been growing in recent years which has supported the higher generation, and over 1,200 MW of additional wind capacity is set to be commissioned between April and December of 2022.[3]

The price of carbon under the *Technology Innovation and Emissions Reduction* (TIER) regulation is now $50/tCO2e, up from $40/tCO2e in 2021[4]. This change took effect on January 1, 2022. The emissions intensity benchmark for electricity generators in Alberta is that of an efficient combined-cycle natural gas unit, also known as the “good-as-best-gas” benchmark, which is set at 0.37 tCO2e/MWh. As such, the carbon costs for efficient combined cycle units remains largely unaffected. However, the higher carbon price raises the carbon cost for a number of assets including coal, gas-fired steam, and simple-cycle natural gas assets that have comparatively higher emissions intensities.

The increase in carbon price has the greatest impact on the carbon costs of coal-fired assets. The carbon cost for a generic coal unit has increased from approximately $25.20/MWh to $31.50/MWh. The remaining coal assets in Alberta are scheduled to be converted to natural gas by the end of 2023. The federal carbon price is scheduled to increase by $15/tCO2e each year until it reaches $170/tCO2e in 2030 and it is expected that these will be the applicable carbon prices in Alberta.

[3] AESO: Long Term Adequacy Metrics, projects under construction – February 2022

[4] Ministerial Order 87/2021

1.2 Market outcomes

On January 3 a new record for peak demand of 11,939 MW was set in HE 18. Relative to the previous demand peaks set in 2021, the pool price in HE 18 of January 3 was much lower at $140.51/MWh (Table 2). As shown in the table, average wind generation was 774 MW in HE 18 of January 3, and this played an important role in reducing pool prices over the demand peak.

In comparison to the peak demand hour on December 27, 2021 when the AESO declared an Energy Emergency Alert level 2 (EEA2) event, thermal outages were materially lower on January 3. High levels of unplanned thermal outages, as well as a transmission line outage on BC/MATL, severely restricted supply and resulted in the pool price clearing close to the price cap at $999.96/MWh in HE 18 of December 27. Largely as a result of the higher price, demand on December 27 was around 400 MW lower relative to January 3, despite temperatures being lower on December 27, and January 3 being the observed holiday for New Year’s Day.

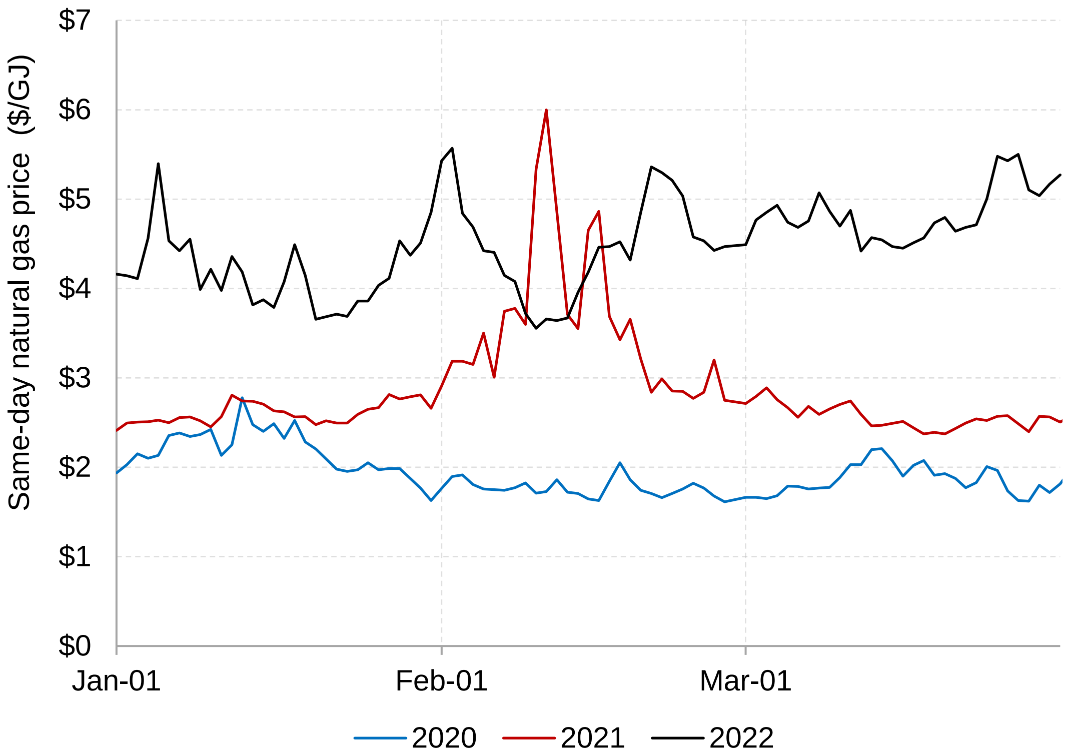
Table 2: Comparison of record peak demand hours and relevant market metrics

	Feb 9, 2021 (prev. peak)	**Jun 29, 2021 (summer peak)**	**Dec 27, 2021 (EEA2 event)**	**Jan 3, 2022 (curr. peak)**
Hour ending	19	14	18	18
Demand (AIL Avg MW)	11,729	11,721	11,508	11,939
Pool price ($/MWh)	$567.60	$639.29	$999.96	$140.51
Wind generation (Avg MW)	287	205	577	774
Temperature (Avg °C)	-26	32	-29	-26
Thermal outages (MW)	1,376	2,403	2,827	1,593
Supply cushion (MW)	1,493	262	194	753

Thermal outages were lower on average this quarter, particularly in February and March (Table 1). On average, thermal outages were 283 MW less in February and 500 MW less in March compared to the same months last year. This somewhat offset the retirement of Keephills 1 (395 MW) on December 31, 2021, and the capacity reduction of Sundance 4 (from 400 MW to 113 MW) on January 1 as the asset switched from running on coal to solely on natural gas. In Q1 last year, Sheerness 1 and Keephills 2 were both offline for coal-to-gas conversion outages beginning in mid-February and mid-March, respectively. The reduction in thermal outages Q1 2022 put downward pressure on pool prices.

Figure 1 compares same-day natural gas prices in Q1 of 2020, 2021, and 2022. Alberta natural gas prices were volatile in mid-February 2021, increasing to $6.00/GJ, largely due to the polar vortex that swept across much of North America. In Q1 2022, natural gas prices were elevated over much of the quarter, with same-day prices typically ranging from $3.70/GJ to $5.50/GJ (Figure 1). The higher natural gas prices in Alberta track closely with Henry Hub prices, which have risen considerably this quarter compared to Q1 2021.[5] The high natural gas prices in North America are reflective of low storage volumes. Storage volumes over the past winter fell by considerably more than most previous years due to higher demand for natural gas. The demand for natural gas in North America has been elevated due to weather conditions, the growing use of natural gas in power generation, and high Liquified Natural Gas (LNG) export volumes.[6]

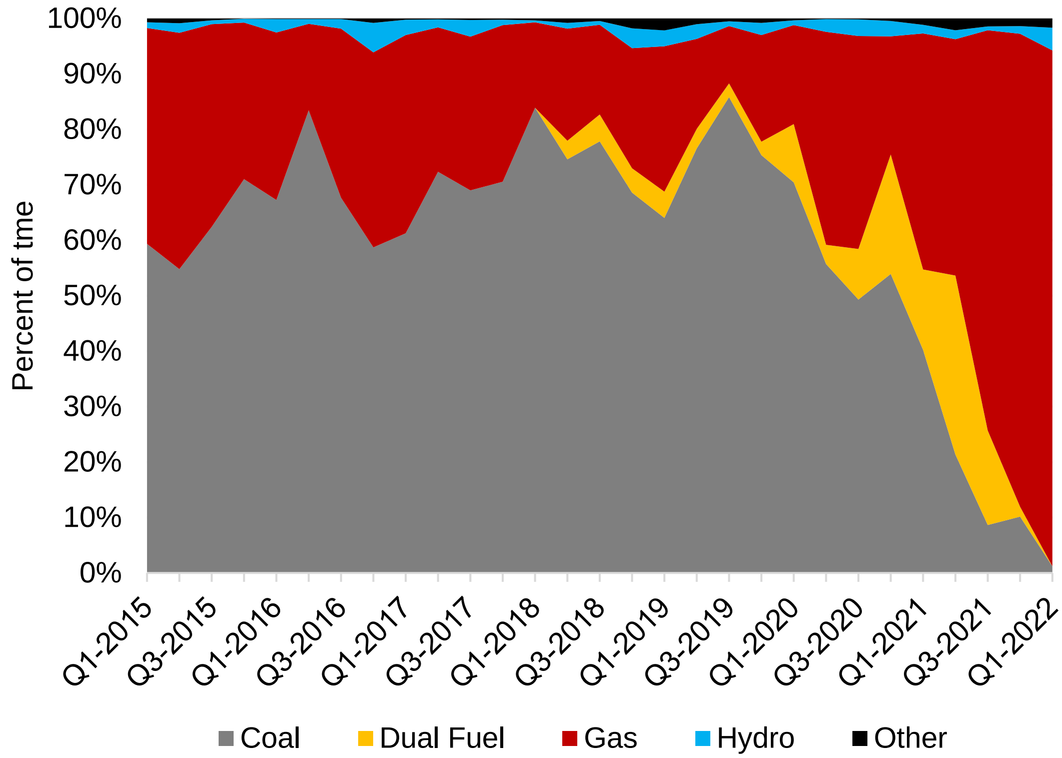
Figure 1: Same-day natural gas prices in Q1 (2020, 2021, and 2022)



[5] Henry Hub Natural Gas Spot Prices

[6] EIA: Natural Gas Weekly Update – April 14, 2022

Figure 2: Percent of time different asset types set system marginal price by quarter (Q1-2015 to Q1-2022)



There has been a shift in the composition of assets that set the system marginal price (SMP). In Q1 2021, gas-fired assets set the SMP 43% of the time, with coal setting it 40% of the time.[7] In Q1 2022, gas-fired assets were on the margin 93% of the time, with coal dropping down to 1% (Figure 2) due to numerous coal-to-gas conversions and coal retirements. As a result, natural gas prices have an increasingly significant impact on pool prices.

Despite more gas-fired assets setting SMP and a substantial rise in natural gas prices, pool prices have not increased to the same extent. In January and March, natural gas prices increased by 61% and 88% year-over-year, while pool prices increased by 25% and 13%, respectively.

This trend is illustrated in Figure 3, which plots the realized spark spread by month in 2021 against the realized and forward spark spread by month in 2022.[8] The average spark spread in Q1 was $44.99/MWh, which is 32% lower than the spark spread of $66.53/MWh in Q1 2021. In March,

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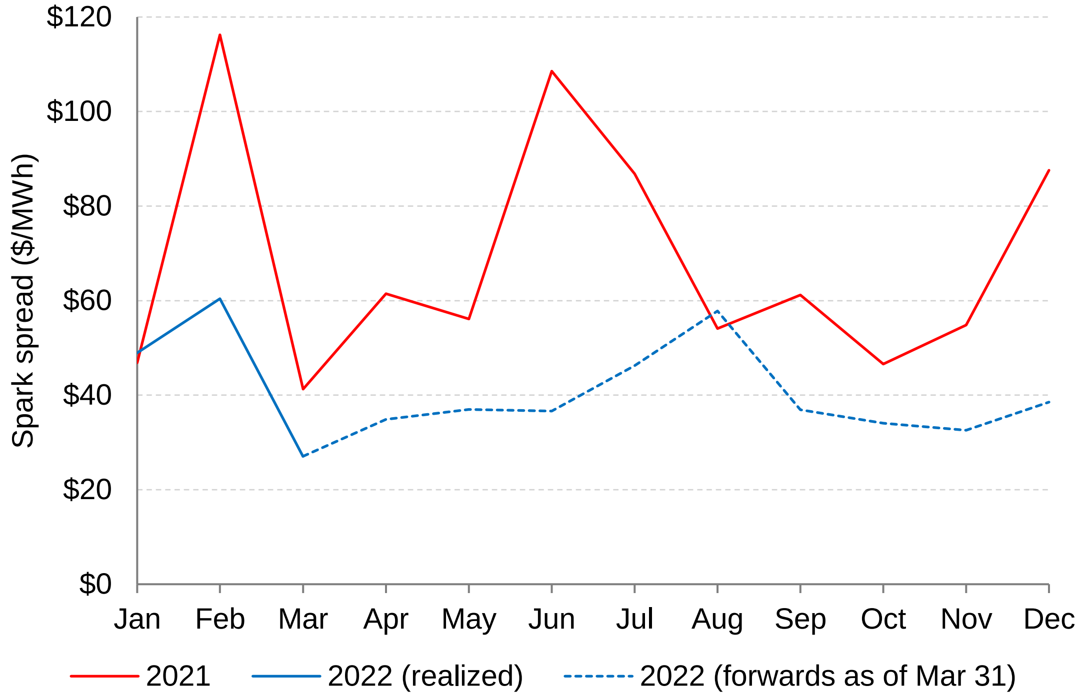
[7] Gas-fired assets include gas-fired steam, cogeneration, combined cycle, and simple cycle generation.

[8] Spark spread is the difference between the price of electricity and the input fuel cost of natural gas. These calculations assume 10 GJ of natural gas are needed to produce a MWh of electricity; a heat rate of 10 GJ/MWh. This heat rate is similar to the efficiency of simple cycle assets and is slightly lower than most gas-fired steam assets. An efficient combined cycle has a lower heat rate of around 7.5 GJ/MWh.

the average spark spread fell by 34%, from $41.27/MWh to $27.06/MWh, marking the lowest monthly spark spread since December 2020.

Figure 3: Realized and forward spark spreads by month (2021 and 2022)[9]



This decrease indicates that pool prices were relatively low in Q1 after accounting for higher natural gas prices. In other words, gas-fired assets generally received prices that were closer to cost. The lower spark spreads this quarter were primarily driven by higher wind generation, lower thermal outages, and more competitive offer behaviour.

Based on forward power and natural gas prices as of March 31, 2022, there is an expectation that spark spreads in the energy market will be much lower this year compared to 2021 (Figure 3). As of March 31, the average spark spread for 2022 was marked at $40.82/MWh, which is 40% lower than the realized spark spread of $68.04/MWh for 2021.

Oil prices continued to rise throughout 2021 and into Q1 this year (Figure 4). On March 8, WTI prices closed at US$123.70/barrel, the highest on record since August 2008. Oil production in Alberta during January fell by 4.8% relative to January 2021, while February and March saw production increase by 4.7% and 3.2%, respectively.[10] A portion of Alberta's electricity demand is driven by oil production, so higher oil prices can put upward pressure on electricity demand to some extent.

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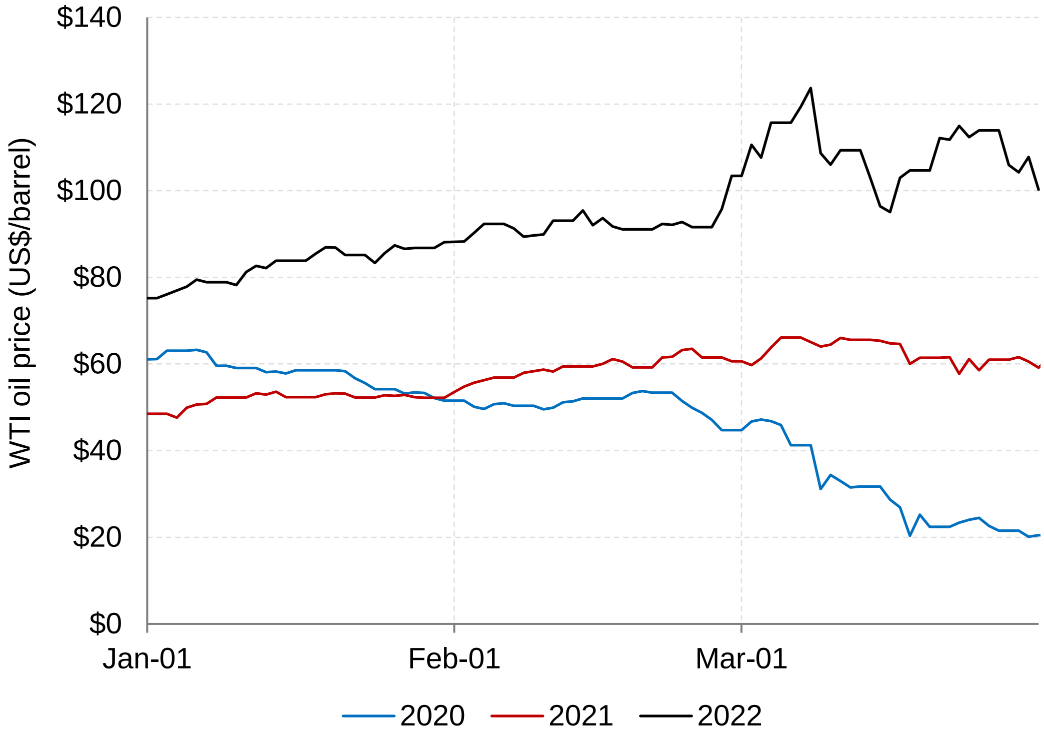
[9] The spark spread calculations are based on a heat rate of 10 GJ/MWh.

[10] AER ST3 Report

Figure 4: Daily next month WTI oil prices in Q1 (2020, 2021, and 2022)



Wind generation is an important determinant of pool price outcomes, especially during certain hours when other supplies are limited, or demand is high. These effects were particularly obvious in the month of February, where there was a 57% year-over-year increase in wind generation.

Figure 5 and Figure 6 show hourly pool prices and average wind generation in February 2022 and February 2021, respectively. The two months differed significantly not only in their level of wind generation, but also in the timing of when wind assets were producing. High wind generation tends to correspond to lower pool prices, and low wind generation tends to correspond to higher pool prices.

Extreme weather conditions can reduce wind generation, and the effects of the prolonged cold spell in the first half of February 2021 are reflected in Figure 6 when high demand and low wind generation drove high and volatile pool prices. It was common for prices to settle in the hundreds of dollars during this period, sometimes for many consecutive hours, and this increased the average pool price in February last year. In contrast, wind generation was often higher in February 2022 as weather conditions were milder, which translated into pool prices being lower for extended periods and fewer higher priced hours.

Figure 5: Average hourly wind generation and pool price in February 2022

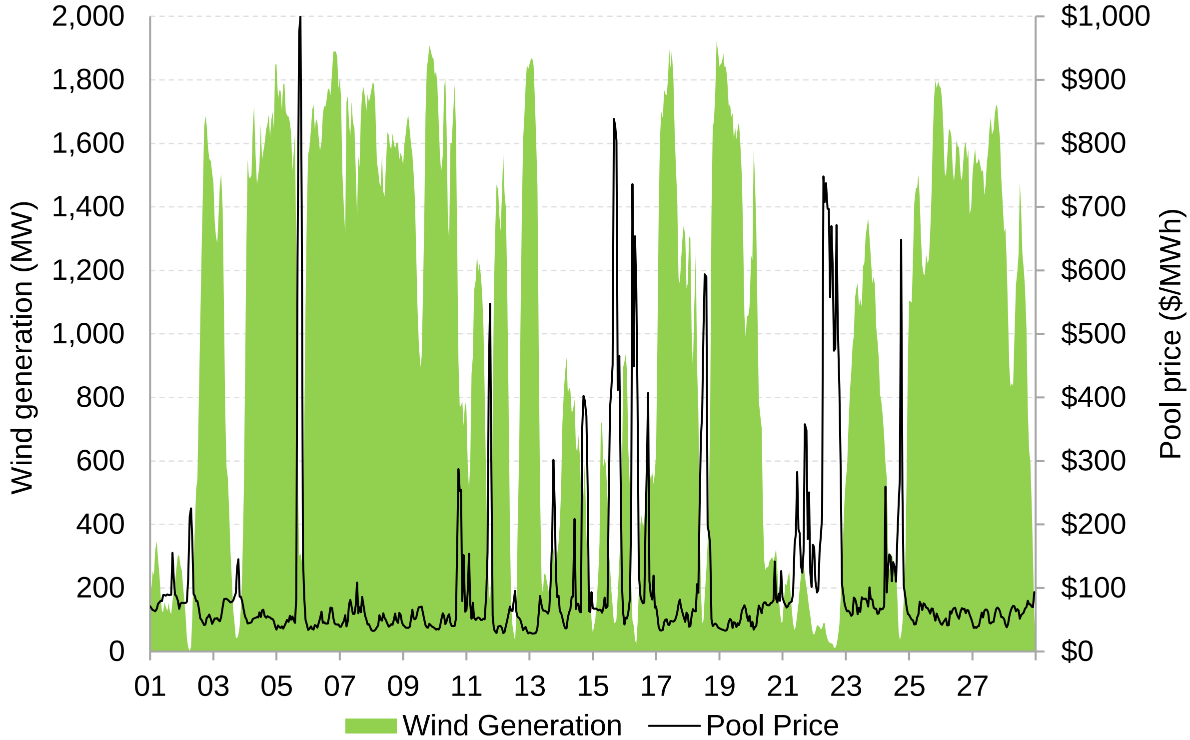
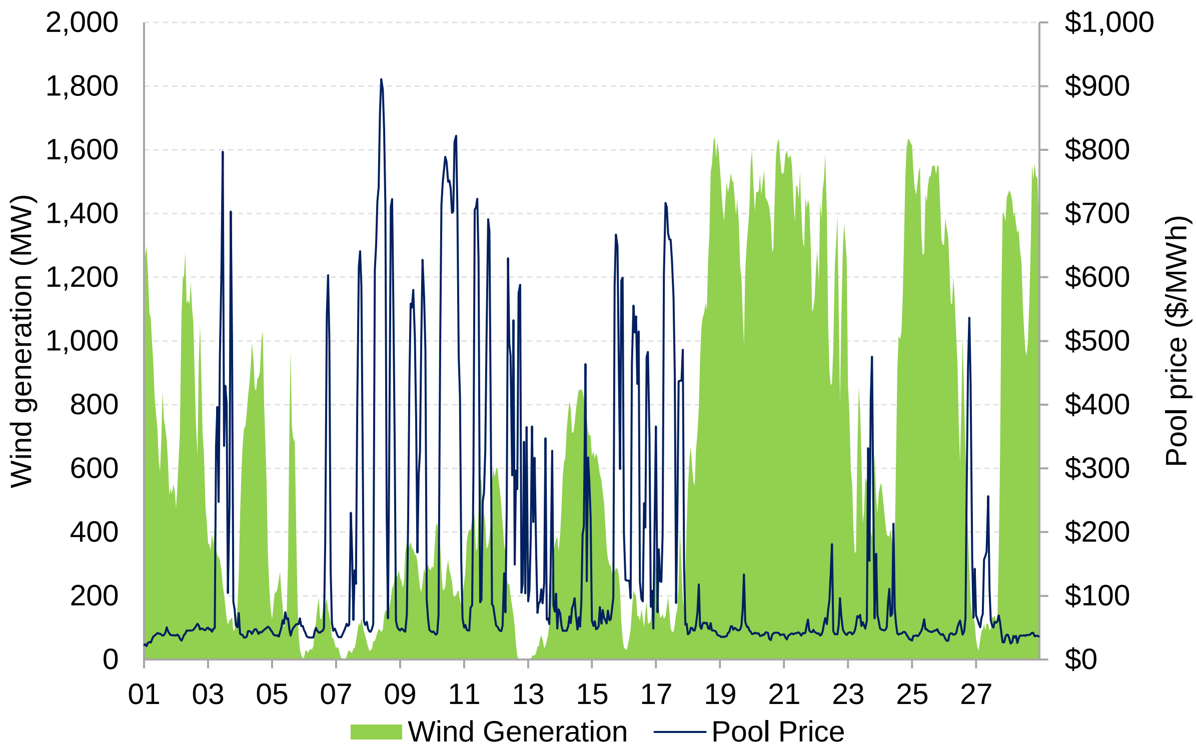


Figure 6: Average hourly wind generation and pool price in February 2021



The importance of wind generation in determining pool prices was also illustrated by events on Saturday, February 5. Going into February 5, pool prices were expected to be low as wind generation was forecast to be quite high and demand was forecast to be relatively low. Likely due to the expected market conditions, five gas-fired steam assets totaling 1,800 MW of capacity were taken commercially offline on the preceding days. Once offline, these generation assets have a long lead time and are not able to immediately return to the market.

During the evening demand peak on February 5, wind generation dropped sharply, well below what the AESO's 12-hour ahead forecast had predicted (Figure 7). As a result, supply cushion hit 0 MW for a short period and pool prices increased from $84.20/MWh to $999.64/MWh within three hours. Although the demand peak was not particularly high on this day, the potential for inadequate supply clearly exists when wind generation suddenly declines in an already-tight market. The MSA is of the view that events like this will occur more frequently in the future.

Figure 7: Wind generation, AESO wind forecast, and Alberta Internal Load (AIL) on February 5, 2022

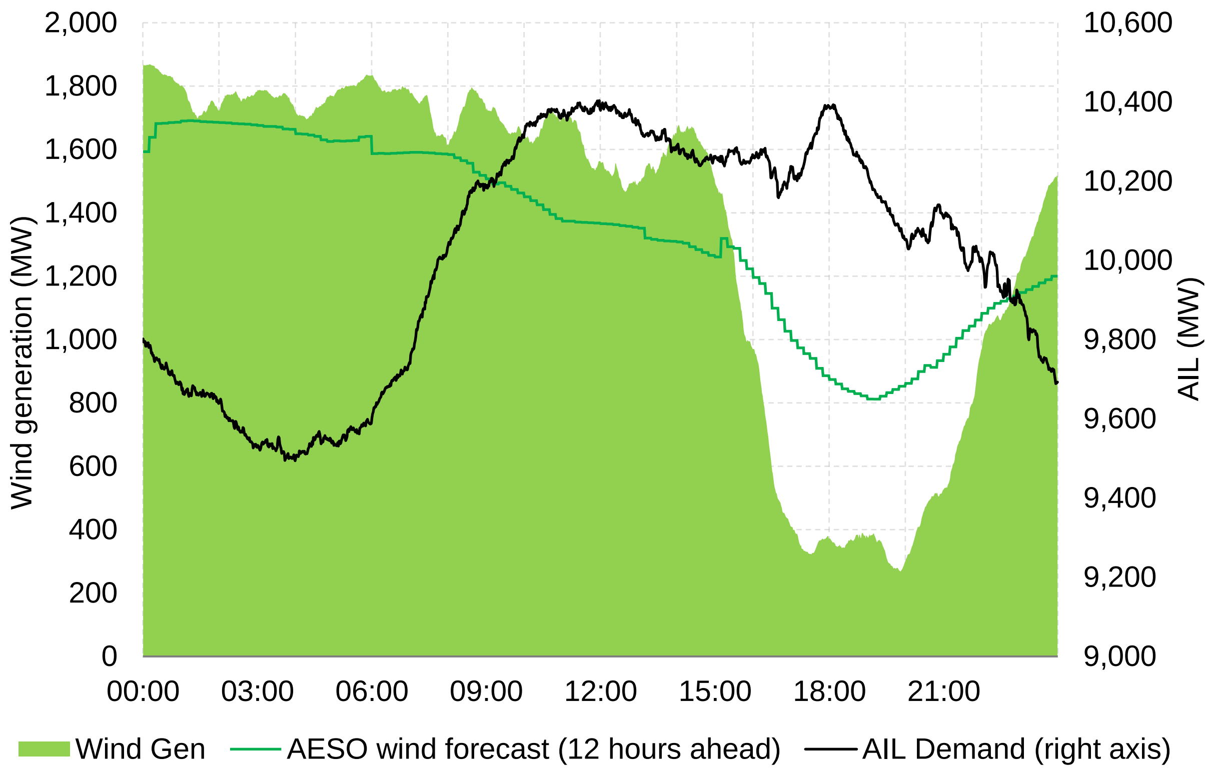


Figure 8 shows the average hourly generation for solar assets in Q1 2022 and 2021. In March 2022, HE 14 had an average solar generation level of 249 MW, up 117% from 115 MW in the same hour in March 2021.

Solar capacity in Alberta has significantly increased year-over-year (Figure 9). Solar capacity for most of Q1 was 336 MW, which is nearly double the average solar capacity in Q1 2021. Solar generation is set to increase further this year as the Travers solar farm (465 MW) began commissioning in Q1 and started generating to the grid on March 30. The Travers asset is scheduled to increase its generation in the coming months and is planned to be fully operational by Q4 2022.[11]

Figure 8: Average hourly solar generation (Q1 2021 (left) and Q1 2022 (right))

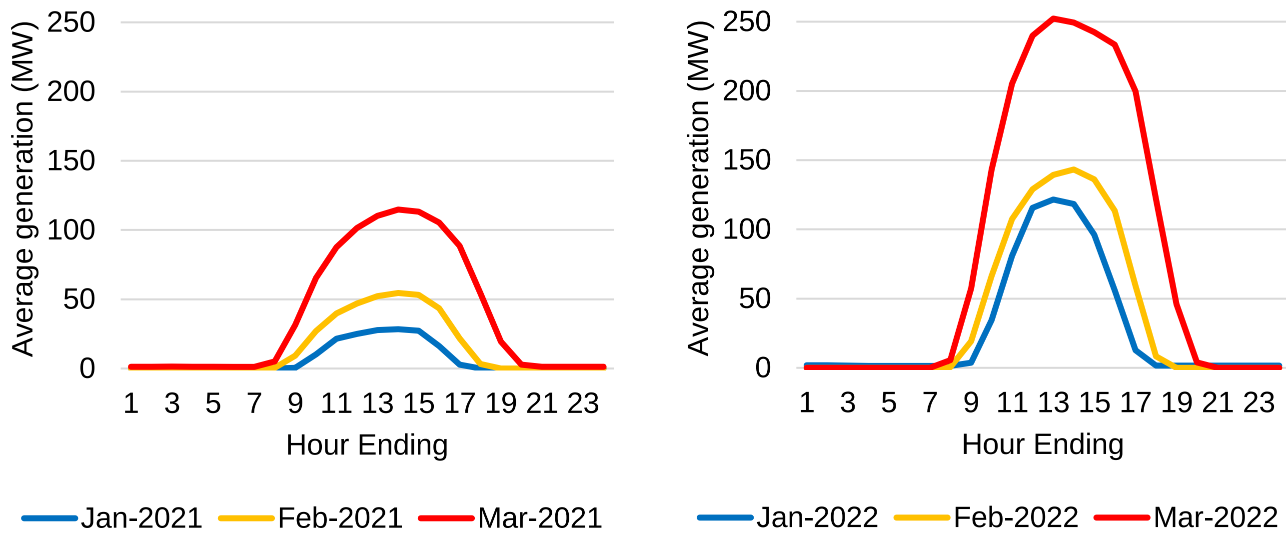
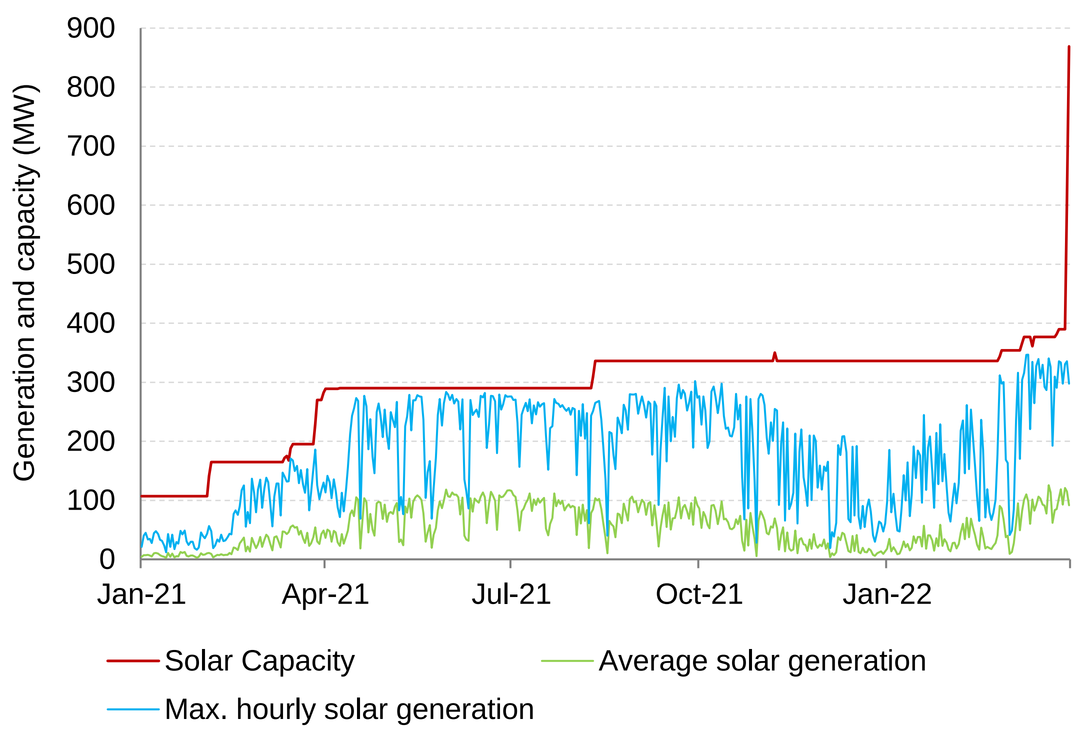


Figure 9: Solar generation and capacity by day (January 1, 2021 to March 31, 2022)[12]



[11] [Travers Solar Project website]

[12] In this chart, the capacity of a new solar asset is added in full once the asset starts to generate to the grid.

1.3 Interties

Interties connect Alberta's electricity grid directly to those in British Columbia (BC), Saskatchewan (SK), and Montana (MATL), with the intertie to BC being the largest. For reliability purposes, the AESO treats BC and MATL as one intertie (BC/MATL) because a trip on the BC intertie would also cause MATL to trip offline. Indirectly, these interties link Alberta's electricity market to markets in Mid-Columbia (Mid-C) and California.

In Q1 the direction of flow on these interties was largely imports into Alberta. As shown by Figure 10, pool prices in Alberta were more volatile and often higher than prices in Mid-C and California.[13]

Figure 10: Daily average prices in Alberta, Mid-C, and California (SP15) (Q1 2022)

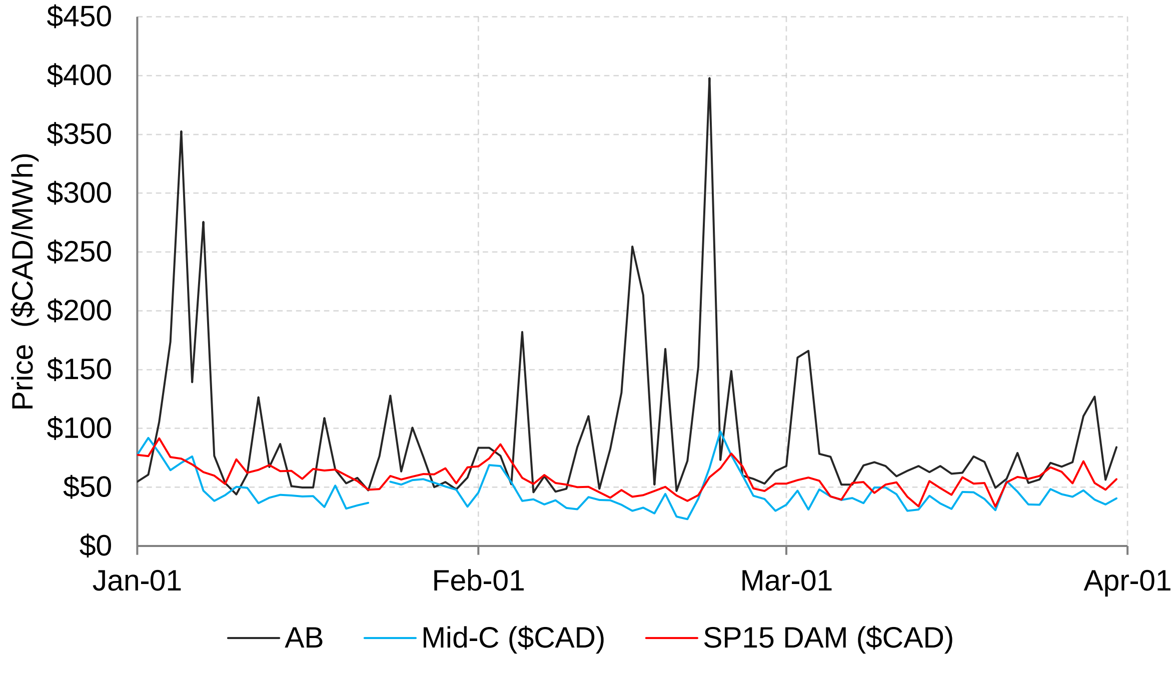
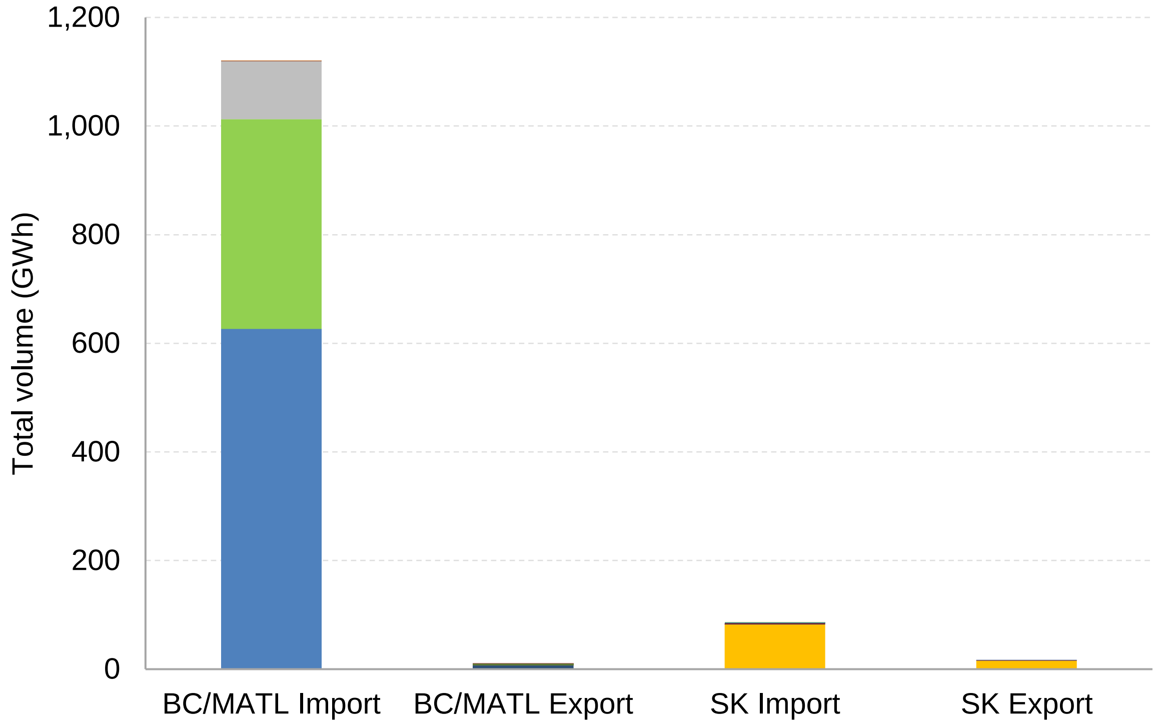


Figure 11 illustrates the total volume of imports and exports in Q1, broken down by intertie and by market participant (anonymized). Imports on BC/MATL were the main source of flow in Q1, and import flows were largely undertaken by market participants with firm transmission rights. Imports from BC were generally undertaken by two market participants, represented by the blue and grey shaded areas in Figure 11, and import flows on MATL were largely undertaken by a single market participant, represented by the green area. Import and export flows on SK were mostly undertaken by a single market participant.

[13] South of Path 15 (SP15) is a major electricity hub in Southern California, the average prices shown here are from the Day-Ahead Market (DAM). Mid-C prices for January 23 are not available and have not been included.

Figure 11: Total import and export volumes by intertie and market participant (Q1 2022)



As shown by Figure 12, import and export volumes varied over the quarter as market conditions varied, including the availability of import transmission capacity. In hours when pool prices were sufficiently above Mid-C prices, the available transmission capacity for imports (import ATC) was highly utilized. Over the course of Q1, BC/MATL import ATC was 90% utilized when the Alberta pool price was more than CAD$12.00/MWh above prices in Mid-C.

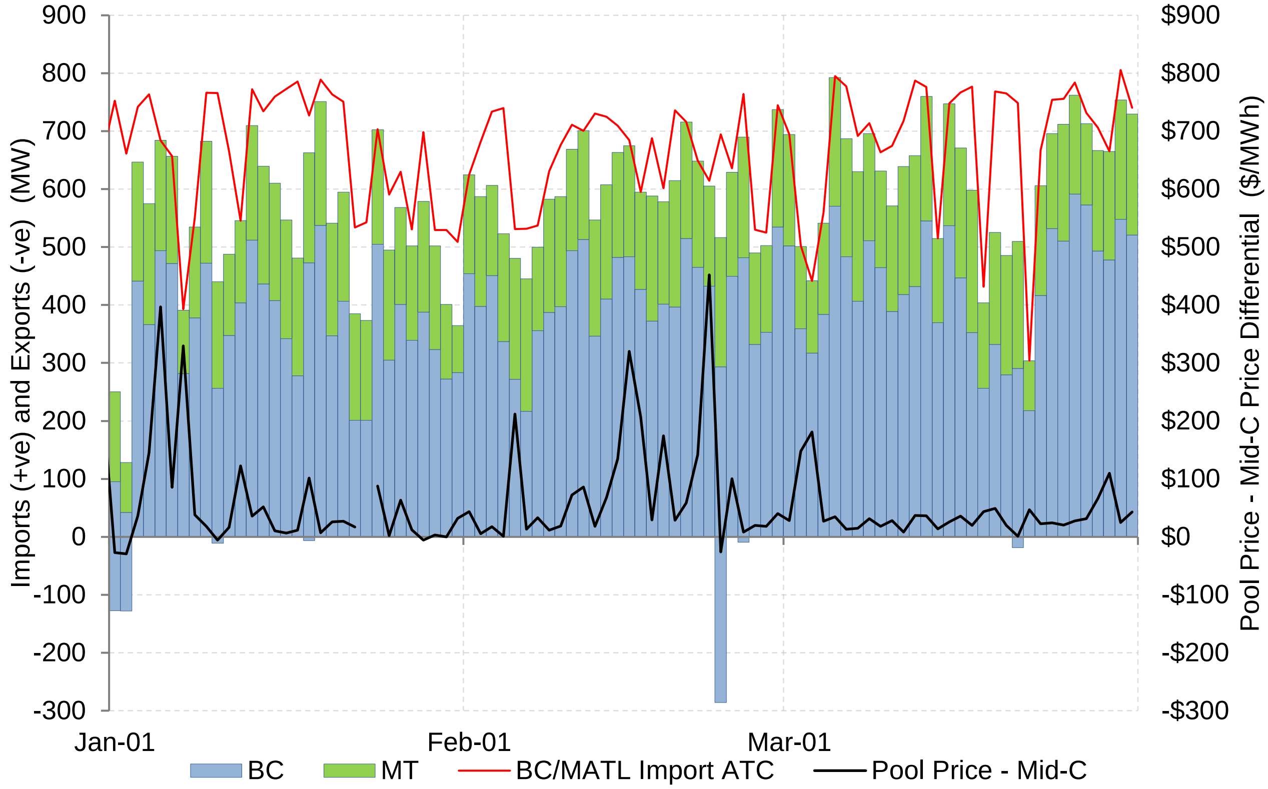
On several days in the quarter, import volumes were constrained by reduced import ATC (Figure 12). For example, on Friday, January 7 the 2L294 transmission line tripped out of service and reduced BC/MATL ATC to around 380 MW for much of the peak.[14]

On Monday, January 31 the BC/MATL intertie was unavailable from HE 13 to HE 16 due to a scheduled transmission outage on line 1201L. Despite the reduction in imports, pool prices were relatively low on this day, in part due to high levels of wind generation.

There were a small number of exports from Alberta in Q1. In early January and on February 23 pool prices fell below prices in Mid-C, resulting in some exports on the BC intertie (Figure 12). In addition, there were some exports on the SK intertie in late February (not shown in the figure). During the peak hours on Tuesday, February 22 there were 50 to 147 MW of exports on the SK intertie in some instances when pool prices were around $700/MWh.

[14] Peak hours run every day from 07:00 to 23:00.

Figure 12: Daily average import (+ve) and export (-ve) volumes, import ATC, and the AB – Mid-C price differential (peak hours, Q1 2022)[15]



Line outages on 2L294 reduced import ATC on BC/MATL on several days in March including March 3, March 18, and March 22. In addition, the SK tieline was largely unavailable from March 18 to 22.

Despite these constraints, total net imports in March averaged 615 MW, the highest in the quarter. The average of net imports on BC/MATL was 571 MW in March, 53 MW higher than in February (Table 3). While the average pool price in March was lower than in January and February, a higher percentage of hours in March saw pool prices that were more than CAD$12.00/MWh higher than prices in Mid-C. The transmission costs associated with importing power from Mid-C are in the region of CAD$12.00/MWh, so these hours would tend to encourage imports into Alberta.

[15] Mid-C prices for January 23 are not available and have not been included.

Table 3: Monthly averages of pool price, BC/MATL net imports, and BC/MATL import ATC

Month	Avg. pool price ($/MWh)	Avg. BC/MATL net imports (MW)	Avg. BC/MATL import ATC (MW)	Hours where pool price was $12 higher than Mid-C (%)
Jan/2022	$90.81	453	602	54%
Feb/2022	$105.22	518	610	64%
Mar/2022	$75.38	571	667	79%

1.4 Offer behaviour

Overall, there was less thermal capacity offered into the energy market at higher prices in Q1 compared to Q1 2021. Figure 13 illustrates offer price duration curves for coal and converted coal capacity.[16] These duration curves show the percent of available capacity that was offered at or below a particular price year-over-year.

In Q1, 90% of coal and converted coal capacity was offered below $165/MWh and 10% was offered above $165/MWh. In Q1 2021 the 90th percentile was much higher as 10% of coal and converted coal capacity was offered above $634/MWh. The lower offer prices in Q1 this year would tend to reduce pool prices in hours when the supply-demand balance is tighter. The reduction in higher priced offers may have been motivated in part by increased generator hedging. In their financial reporting, some larger market participants indicated that more capacity had been sold forward at a fixed price for Q1 2022 compared to Q1 2021.[17]

At lower offer price levels, the duration curve for Q1 is slightly above the duration curve for Q1 2021. This result is largely because of higher natural gas prices year-over-year, in addition to the increase in the carbon price from $40/tCO2e to $50/tCO2e. The higher natural gas and carbon prices would both put upward pressure on the variable costs for thermal assets.

Towards the lower end of the duration curves, some offer prices were lower in Q1 this year and more capacity was offered into the market at $0.00/MWh this quarter, both of which would put some downward pressure on pool prices during lower priced hours.

[16] Converted coal capacity largely represents gas-fired steam assets although in Q1 2021 some assets were dual fuel.

[17] TransAlta Q4 and Annual 2021 Results presentation (slide 12) – February 24, 2022

TransAlta Q3 2020 Results presentation (slide 17) – November 4, 2020

Capital Power 2021 Q4 presentation (slide 12) – February 24, 2022

Capital Power 2020 Q4 presentation (slide 7) – February 19, 2021

Figure 13: Duration curves for offer prices on coal and converted coal assets (year-over-year) [18]

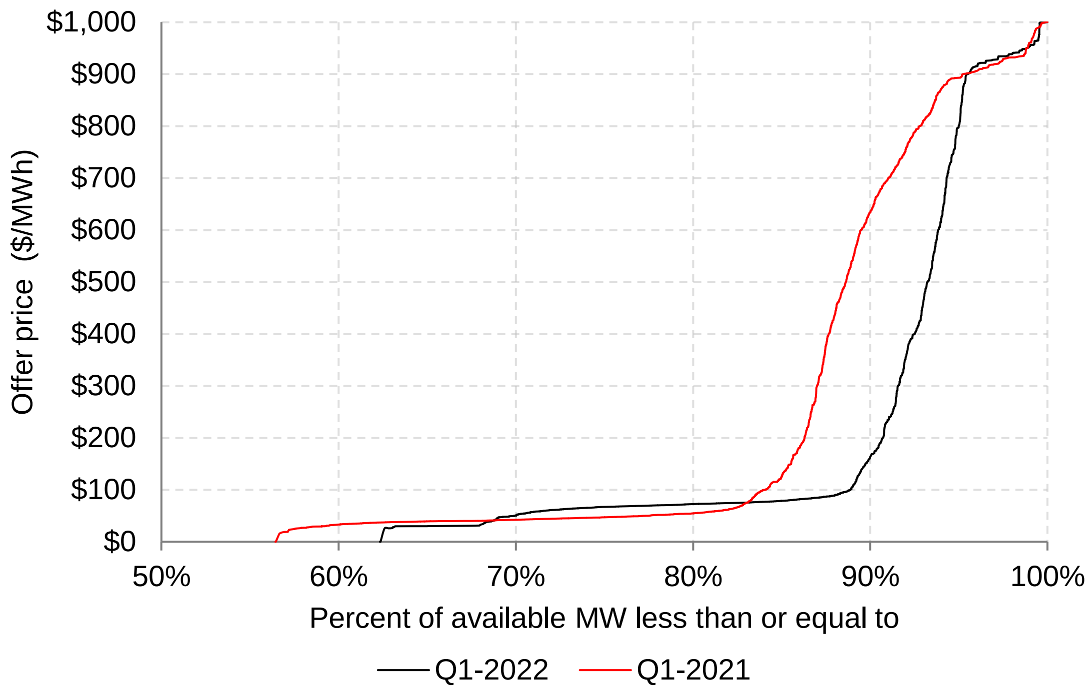
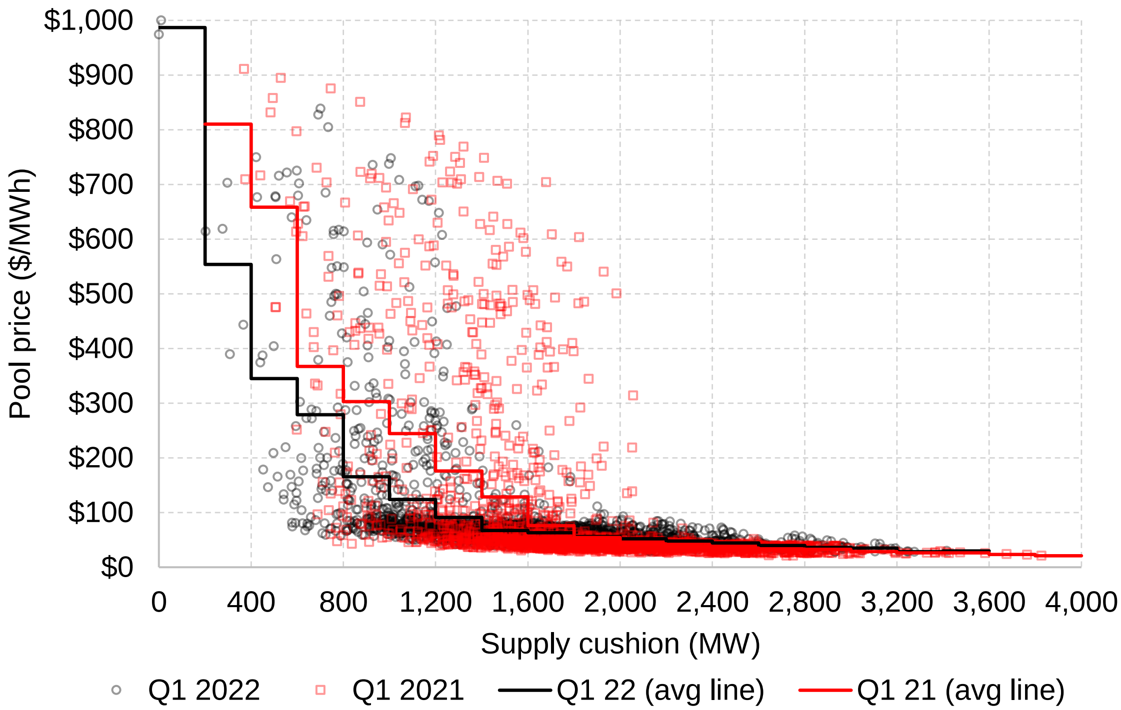


Figure 14: Scatterplot of pool price and supply cushion (year-over-year)



[18] The analysis includes the thermal assets at Battle River, Genesee, Keephills, Sheerness, and Sundance.

Figure 14 illustrates a scatterplot of pool prices and supply cushion year-over-year. The supply cushion is the amount of capacity that is available but not dispatched. When the available supply is low relative to demand, the supply cushion is smaller and pool prices tend to be higher. The lines in Figure 14 show the average pool price in 200 MW supply cushion bins.

At lower supply cushion levels, pool prices in Q1 were generally lower than in Q1 2021 (Figure 14). As discussed above, there has been less coal and converted coal capacity offered at higher prices in Q1 compared to Q1 2021, which was a factor in these lower pool price outcomes.

At higher supply cushion levels, when more supply is available relative to demand, pool prices have generally been higher year-over-year. Figure 15 shows the same analysis depicted in Figure 14 but focuses on pool prices under $100/MWh for illustration purposes. At supply cushion levels above 1,800 MW, market pool prices have generally been higher this year, and this increase has largely been driven by higher input costs. As discussed in section 1.2 an increase in natural gas prices, in addition to the higher carbon tax, has put upward pressure on the variable costs of gas-fired generation, which is the asset type that most frequently sets price.

Figure 15: Scatterplot of pool price and supply cushion, under $100 (year-over-year)

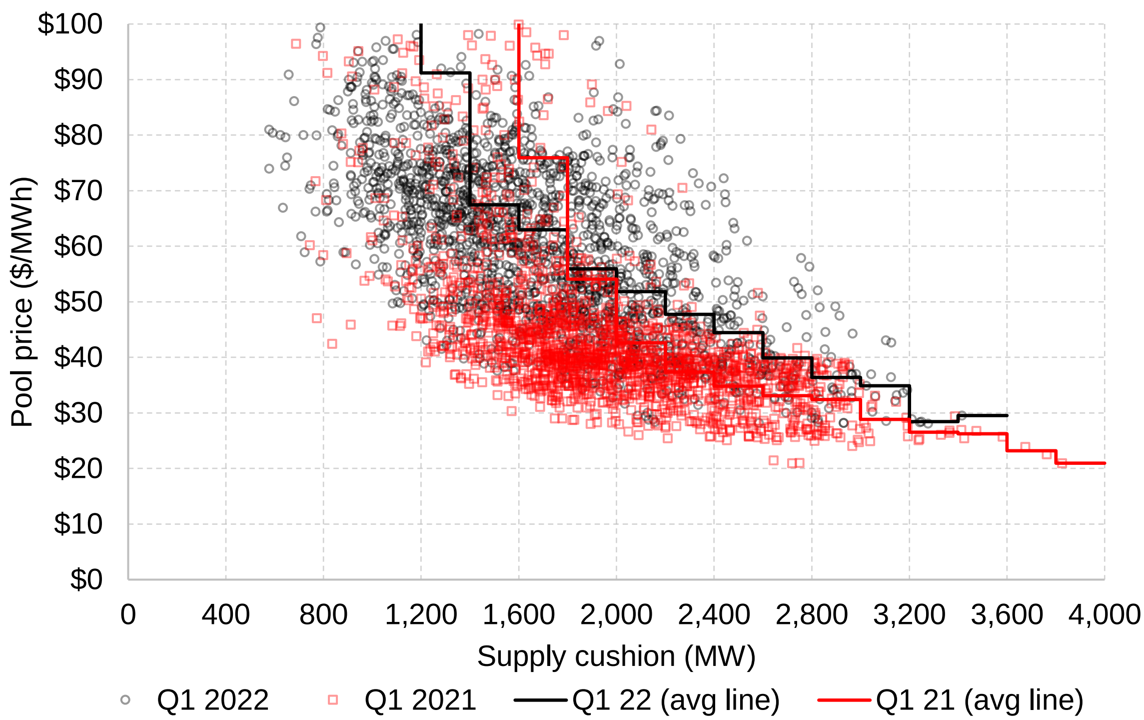


Figure 16 is a stacked bar chart showing the amount of coal and converted coal that was either offered above $100/MWh or was commercially offline during the daily peak in pool price. The figure spans from December 1, 2021 to March 31, 2022. Capacity that is commercially offline and capacity that is offered above $100/MWh are treated independently of one another in this analysis. A coal or converted coal asset that is commercially offline is not included in the hourly supply curve due to the required start up time. Consequently, the offers on these assets are not included in the calculation of capacity that was offered above $100/MWh.

Figure 16: Capacity offered above \$100/MWh and capacity taken commercially offline (coal and converted coal, December 1, 2021 to March 31, 2022)[19]

During the peak pool prices of the December 27 EEA2 event, no coal or converted coal capacity was offline commercially and very little was offered above \$100/MWh. Indeed, there was next to no capacity taken offline commercially during the cold spell from mid-December into early January when pool prices were volatile. As temperatures increased and pool prices became less volatile later in January, more capacity was taken offline commercially.

On Saturday, February 5, around 1,800 MW of converted coal capacity was offline commercially, a level not seen since early January 2021 when around 1,700 MW was offline commercially. The weather on February 5 was mild and wind generation was expected to be high. However, as discussed in section 1.2, wind generation fell more than anticipated late in the afternoon, and the AESO forecasted an energy emergency alert (EEA) event in the AIES event log due to the reduction in supply.

In mid-February there was a material amount of generation capacity that was either commercially offline or offered higher in the supply curve (Figure 16). This put upward pressure on pool prices in the energy market in addition to prices in the forward market.

[19] The analysis includes the thermal assets at Battle River, Genesee, Keephills, Sheerness, and Sundance.

In March, mild temperatures and lower demand put downward pressure on pool prices and the market heat rate for the month was 15.6 GJ/MWh. As shown in Figure 16, a number of gas-fired steam assets were taken offline commercially, particularly in late March.

1.5 Carbon emissions intensity

In the context of power generation, carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. Starting with the Q4 2021 report, the MSA has been publishing analysis of the carbon emission intensity of the Alberta electricity grid in its quarterly reports. The results are indicative only, in the sense that the MSA has not sought to collect the precise carbon emission intensities of assets from market participants, but rather relied on information that is publicly available. The results reported here do not include imported generation.[20] Some minor updates to data have been made since the last report.

1.5.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of the assets supplying the grid in a given hour. Figure 17 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q1 for the past four years.

Figure 17 illustrates a significant shift of the distribution to the left, indicating a decline in carbon emission intensity over time. The displacement of coal-fired generation with natural gas-fired generation has been the major factor driving this outcome. In addition, increased wind and solar generation have reduced the carbon emission intensity. Mean hourly average emission intensities are reported in Table 4 showing year-over-year and quarter-over-quarter comparisons.

Table 4: The mean of hourly average emission intensities (tCO2e/MWh)

	Mean
2019 Q1	0.670
2020 Q1	0.609
2021 Q1	0.555
2022 Q1	0.493

	Mean
2021 Q2	0.578
2021 Q3	0.543
2021 Q4	0.519
2022 Q1	0.493

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

Figure 17: The distribution of average carbon emission intensities in Q1 (2019 to 2022)

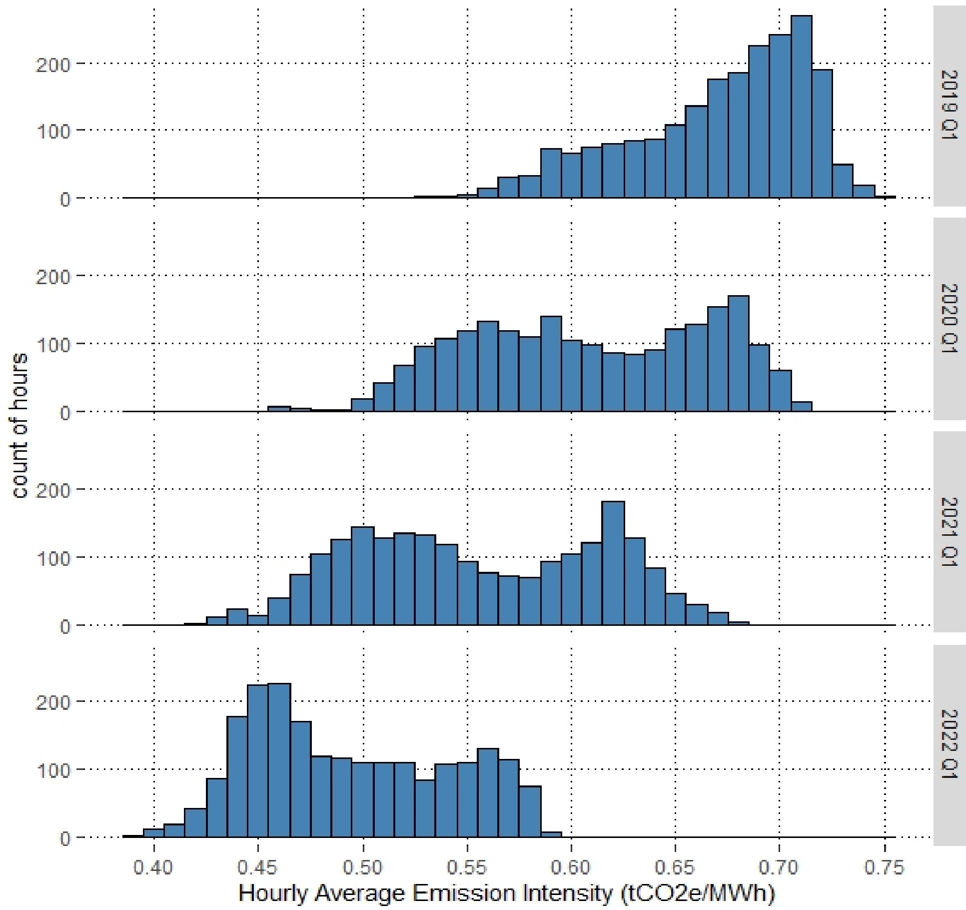
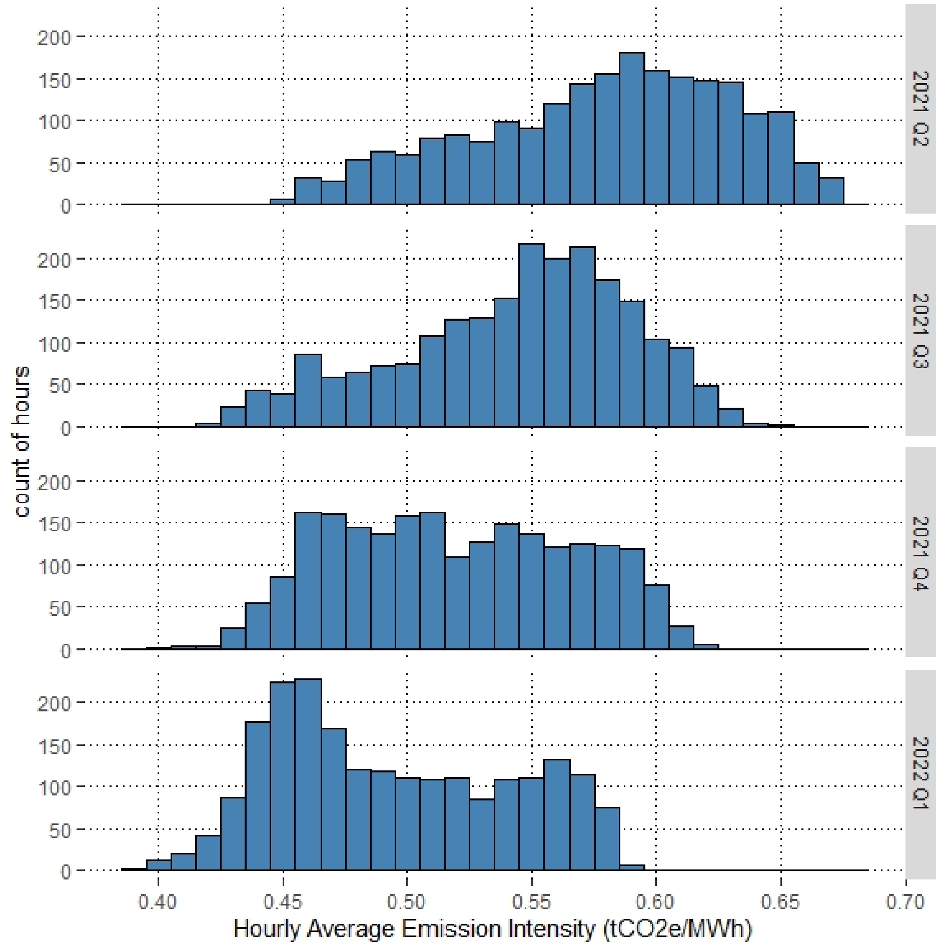


Figure 18 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. As shown, a shift of the distribution to the left can be observed, illustrating a decline in carbon emissions intensity since Q2 2021. The mean of the distribution has declined from 0.578 t/CO2e/MWh in Q2 2021 to 0.493 tCO2e/MWh in Q1 2022, a 15% decrease (see right of Table 4). The change in these distributions reflect the coal-to-gas conversions that took place over the course of 2021.

In the spring of 2021, Sheerness 1 (400 MW) and Keephills 2 (395 MW) underwent conversions, and in the fall of 2021 Keephills 3 (463 MW) and Battle River 4 (155 MW) were converted. In addition to this, at the end of July 2021, Sheerness 1 and 2 were reclassified as gas-fired steam assets rather than dual fuel, as the asset owners committed to using only natural gas. In November 2021, the Battle River 4 and 5 assets were also reclassified as gas-fired steam rather than dual fuel, which decreased the carbon emission intensity of these assets in our estimations.

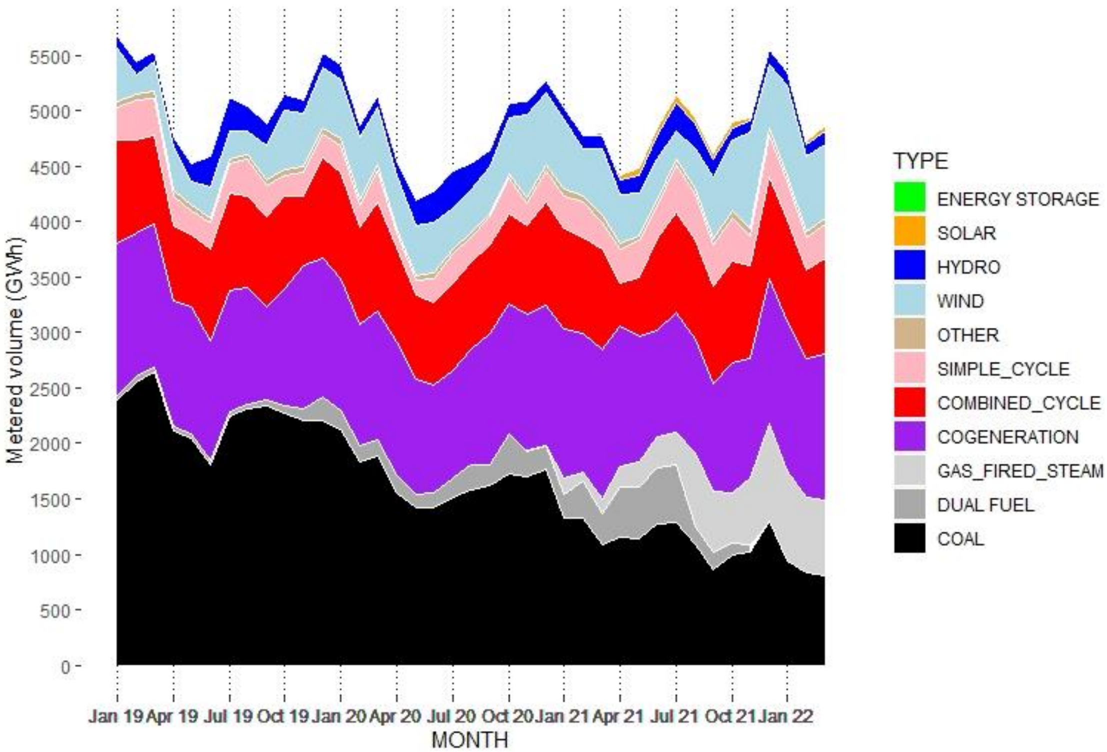
Further to this, at the end of 2021, the Keephills 1 coal asset was retired, and the capacity on the Sundance 4 asset was lowered to reflect that it would no longer generate using coal but instead would run solely on existing gas-firing capabilities. The Sundance 4 asset was retired at the end of Q1.

Figure 18: The distribution of average carbon emission intensities in the past four quarters



The trends observed in the previous figures can be traced in Figure 19, which shows net-to-grid generation volumes by generation type. Specifically, since January 2019, there has been a decline in the volume of coal-fired generation, with generation from dual fuel and gas-fired steam assets replacing it. The increase in wind and solar generation driven by growing capacity has also contributed to the displacement of coal-fired generation.

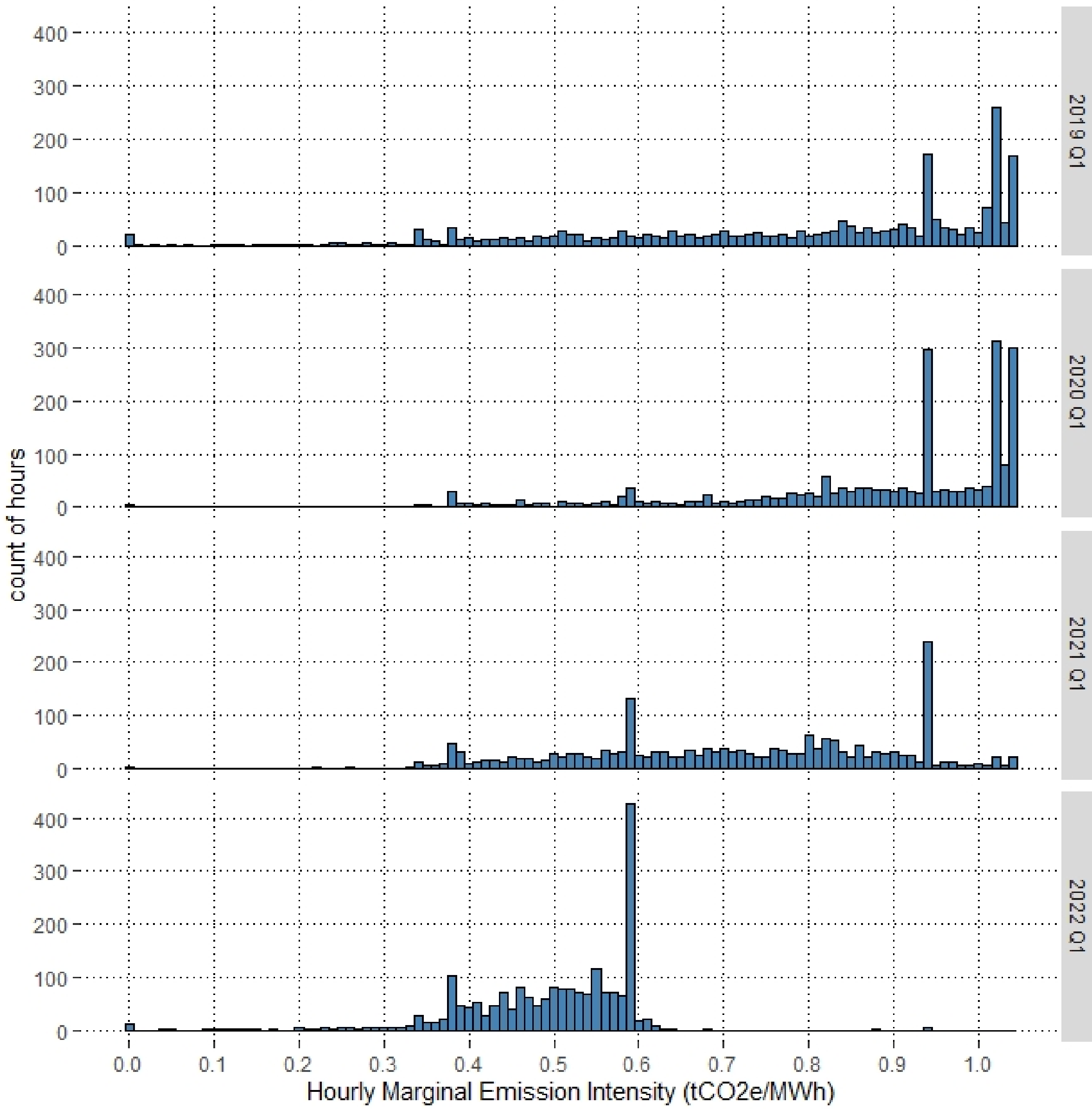
Figure 19: Monthly total net-to-grid generation volumes by generation type



1.5.2 Hourly marginal emission intensity

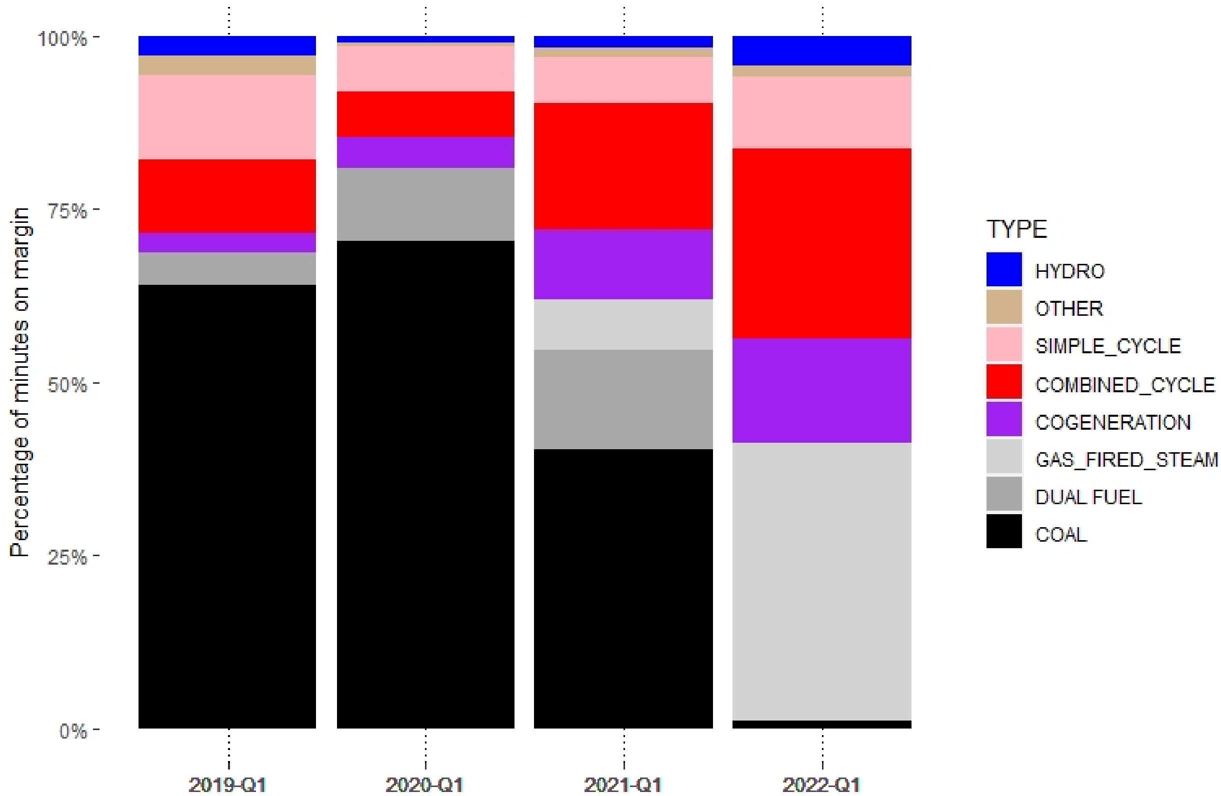
The hourly marginal emission intensity of the grid reflects the carbon emission intensity of the asset setting the System Marginal Price (SMP) in a given hour. In hours where there were multiple SMPs and multiple marginal assets, a time-weighted average of the carbon emission intensities of those assets is used. Figure 20 shows the distribution of the hourly marginal emission intensity of the grid in Q1 for the past four years. In Q1 2022, the increase in converted coal capacity, which was setting the price quite often was a material factor in the spike observed around 0.59 tCO2/MWh.

Figure 20: The distribution of marginal carbon emission intensities in Q1 (2019 to 2022)



To connect the trend observed in Figure 21 to marginal assets by generation type, the figure shows the percentage of time assets of a certain generation type were on the margin. From Q1 2021 to Q1 2022, coal and dual fuel assets on the margin were primarily replaced by gas-fired steam, with other types of generation also increasing their share.

Figure 21: Marginal assets by generation type



1.6 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.

1.6.1 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).[21]

1.6.2 Assessment of offer control

In accordance with the MSOC Process, the MSA calculated offer control with data obtained from the AESO for April 3, 2022 hour ending 17. On April 8, 2022, 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 megawatts under its control to the sum of maximum capability of 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 time. 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 capabilities of assets used to calculate the denominator may not correspond to the name plate maximum capabilities as they would typically be viewed on the AESO's Current Supply Demand Report. Instead, the denominator uses maximum capability as it is registered with the AESO for the purpose of submitting price-quantity offer pairs.

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

Table 5: Market share offer control of electricity market participants with greater than 5% offer control

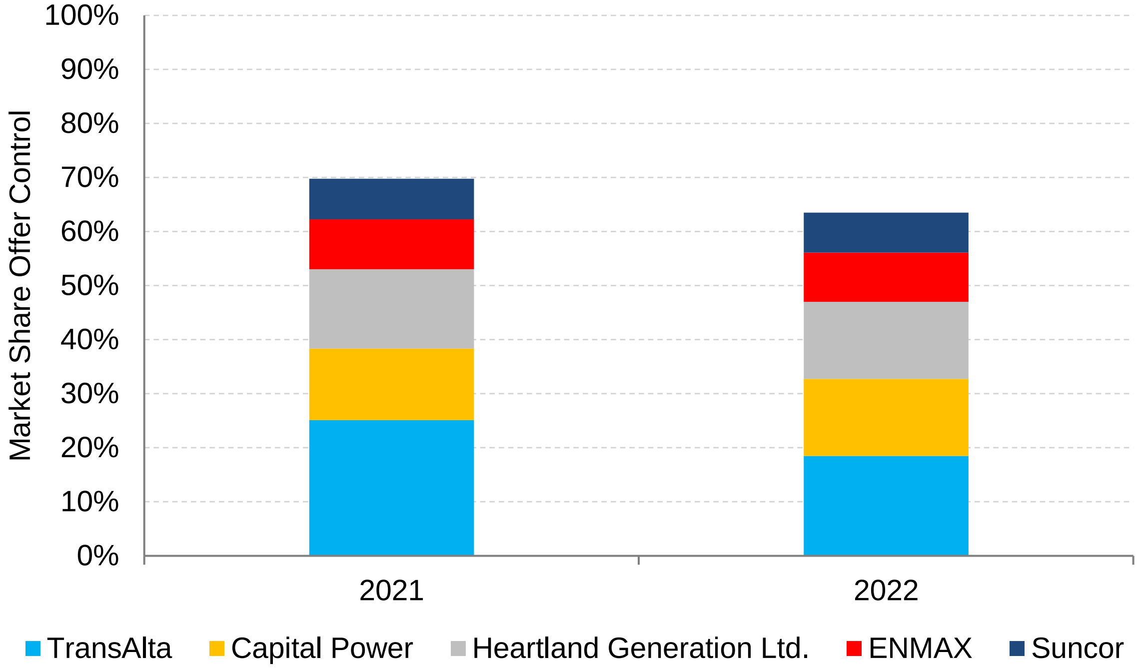
	2022-04-03	
Company	**Control (MW)**	**%**
TransAlta	2,956	18.5%
Capital Power	2,277	14.3%
Heartland Generation Ltd.	2,276	14.3%
ENMAX	1,452	9.1%
Suncor	1,182	7.4%
Other	5,509	34.5%
Total dispatchable	15,652	98.0%
Total non-dispatchable	319	2.0%
Grand total	**15,971**	**100.0%**

Table 6: Market share offer control of by technology type

	2022-04-03	
Technology type	**Control (MW)**	**%**
Gas cogen	5,170	32.4%
Natural gas	4,788	30.0%
Wind	2,292	14.4%
Coal	1,273	8.0%
Hydro	903	5.7%
Solar	893	5.6%
Oil/Gas	387	2.4%
Biomass	121	0.8%
Wood/Refuse	85	0.5%
Storage	50	0.3%
Diesel Oil	8	0.1%
Grand total	**15,971**	**100.0%**

Total offer control for participants with greater than five percent MSOC decreased from 69.8% in 2021 to 63.5% in 2022 (Figure 22). Since the last MSOC assessment on January 10, 2021, TransAlta retired 1,207 MW of generation and added 207 MW, resulting in a decrease in its overall offer control from 25.1% in 2021 to 18.5% in 2022. Generation retirements and additions are discussed further in section 1.6.3.

Figure 22: 2021 and 2022 market share offer control for participants with greater than 5%



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%.

1.6.3 Generation additions and retirements

Since the last MSOC assessment on January 10, 2021, a total of 1,207 MW of generation capacity retired, while 1,415 MW of new capacity was added, and other MC changes occurred (Table 7).[22] These retirements, additions, and other MC changes resulted in Alberta's total generating unit capacity increasing by 271 MW.

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[22] In Table 7, the difference between the 2020 (MW) Total and the 2021 (MW) Total differs from the sum of the "Diff" column due to rounding.

In addition to the unit retirements shown in Table 7, the STG1 asset (Gas Cogen, 34 MW) was also updated to retired status in the AESO Energy Trading System (ETS) on July 16, 2021. This occurred to reflect that the STG1 measurement point was end dated in 2011 in the AESO Compliance and Data Management System (CDMS). This change is reflected in the determination of "Total (MW)" for 2022 that is in the final row of this Table.

The generation retirements that took place were predominantly coal-fired generation assets. A total of 1,207 MW of the 1,241 MW of capacity that retired was coal-fired generation, comprised of the Sundance 4 (406 MW), Sundance 5 (406 MW), and Keephills 1 (395 MW) coal assets.

New generation additions were largely comprised of solar and wind generation assets. A total of 1,415 MW of new generation capacity was added, of which 488 MW was wind generation and 762 MW was solar generation. The new Travers (465 MW) solar generation asset that was added is the largest solar generation asset in Canada.[23]

Several assets were downrated or uprated in 2021, with the most notable uprate being H.R. Milner (HRM). The HRM asset was repowered from coal to simple-cycle natural gas in the spring of 2020; the asset's MC increased from 208 MW to 300 MW in December of 2021.

[23] Journal of Commerce - $700-million Travers Solar Project largest farm ever built in Canada – September 20, 2021

Table 7: Capacity additions and retirements between MSOC 2021 and 2022

Asset ID	Gen. type	2021 (MW) *as at January 20, HE 17*	2022 (MW) *as at April 3, HE 17*	*Diff*	*Date of change*
BRD1	Solar	--	11	11	Feb 18, 2021
BRK1	Solar	--	13	13	Mar 18, 2022
BRK2	Solar	--	14	14	Mar 16, 2022
BUR1	Solar	--	20	20	Feb 22, 2021
CLR1	Solar	--	58	58	Jan 25, 2021
CLR2	Solar	--	75	75	Jan 25, 2021
ERV2	Energy Storage	--	20	20	Oct 1, 2021
HRT1	Gas Cogen	--	116	116	Nov 30, 2021
HYS1	Solar	--	23	23	Aug 4, 2021
JER1	Solar	--	23	23	Aug 9, 2021
NPC3	Gas	--	9	9	Jan 14, 2022
RTL1	Wind	--	130	130	Dec 2, 2021
SET1	Gas	--	20	20	Mar 1, 2021
STR1	Solar	--	18	18	Feb 15, 2022
STR2	Solar	--	23	23	Feb 15, 2022
TVS1	Solar	--	465	465	Dec 20, 2021
WEF1	Solar	--	19	19	Feb 22, 2021
WHT2	Wind	--	151	151	Sep 15, 2021
WRW1	Wind	--	207	207	Jun 10, 2021
Units Added (Units >=5 MW)		**0**	**1,415**	**1,415**	
KH1	Coal	395	--	-395	Dec 31, 2021
SD4	Coal	406	--	-406	Apr 1, 2022
SD5	Coal	406	--	-406	Nov 1, 2021
Units Retired (>=5 MW)		**1,207**	**0**	**-1,207**	
GPEC	Wood/Refuse	27	18	-9	Dec 1, 2021
HRM	Gas	208	300	92	Dec 9, 2021
HSM1	Gas	6	4.8	-1.2	Mar 5, 2021
MUL1	Gas	4.8	5	0.2	Jan 15, 2021
NPC1	Gas	11	3	-8	Jan 14, 2022
MC Changes (Units >=5 MW)		**257**	**331**	**74**	
Units <5 MW		157	182	25	
Unchanged Units >=5 MW		14,046	14,043	-3	
TOTAL (MW)		**15,700**	**15,971**	**270**	

2 THE MARKETS FOR OPERATING RESERVES

There are three types of operating reserves (OR) that the AESO system controllers use when there is an unexpected imbalance or lagged response between supply and demand: regulating reserves, spinning reserves, and supplemental reserves. Regulating reserves (RR) provide an instantaneous response to an imbalance of supply and demand. Spinning reserves (SR) are synchronized to the grid and provide capacity that the system controller can call upon in a short amount of time, when there is a sudden drop in supply for example. Supplemental reserves (SUP) are not required to be synchronized but must be able to synchronize quickly if called upon by the system controller.[24] These products are all bought by the AESO through day-ahead auctions.

2.1 Costs and volumes

In Q1 2022, total and average OR costs were lower than in Q1 the previous year, reflecting lower pool prices, import volumes, and greater competition. Total OR costs in Q1 2022 were $59.9 million, compared to $103.1 million in Q1 2021. Table 8 shows the year-over-year average cost changes for active OR products in the first quarter of 2022. Across the three main products, average costs fell by more than the decrease in pool price. Average costs for supplemental reserves fell the most, reflecting more significant changes in that market, as discussed later (Figure 24).

Table 8: Average cost ($/MWh) of active OR products

Product	Q1 2022	Q1 2021	Q1 2022 - Q1 2021
Spinning	$50.12	$65.63	($15.52)
Supplemental	$23.84	$52.11	($28.27)
Regulating	$54.91	$70.31	($15.41)
Avg. pool price	**$89.98**	**$95.45**	**($5.47)**

Figure 23 shows the total cost of OR by month, with the columns shaded to indicate costs attributable to active and standby reserves. The share of total OR costs attributable to standby reserves fell from 12.7% in Q1 2021 to 3.1% in Q1 2022. This change was driven by both lower procured standby volumes, as well as lower standby activation rates (Figure 28).

[24] For more detailed information, see AESO: Operating Reserve

Figure 23: Total cost of active and standby reserves and average pool price by month

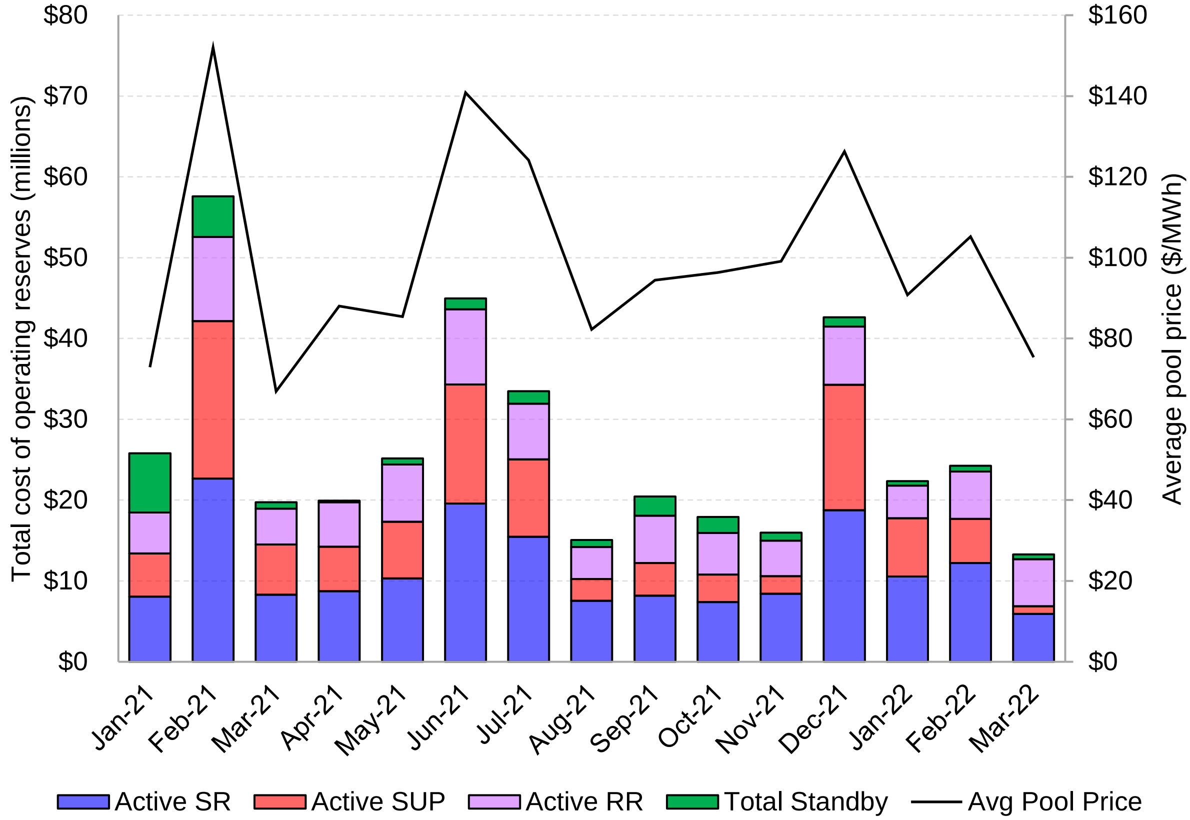


Figure 24 shows duration curves of the index prices (indexed to the hourly pool price) for active spinning and supplemental reserves. The figure illustrates the percentage of hours in which the index prices for spinning and supplemental were at or above a certain price. In Q1 2022, 50% of hours had a spinning index price greater than negative $43/MWh, compared to the Q1 2021 median of negative $30/MWh.

While the Q1 decline relative to Q1 2021 was $12/MWh in the median index price for spinning reserves, it fell by $75/MWh in the supplemental reserve market. This significant drop, from negative $55/MWh to negative $130/MWh was driven by a greater volume of offers from legacy hydro assets and newer load assets in the supplemental reserve market (Figure 25), indicating greater competition. Typically, hydro and load assets have lower opportunity costs to providing OR, and so are able to offer at lower prices.

Figure 24: Duration curves of index prices for active spinning and supplemental reserves, between $40 and -$200 (Q1 2022 and Q1 2021)

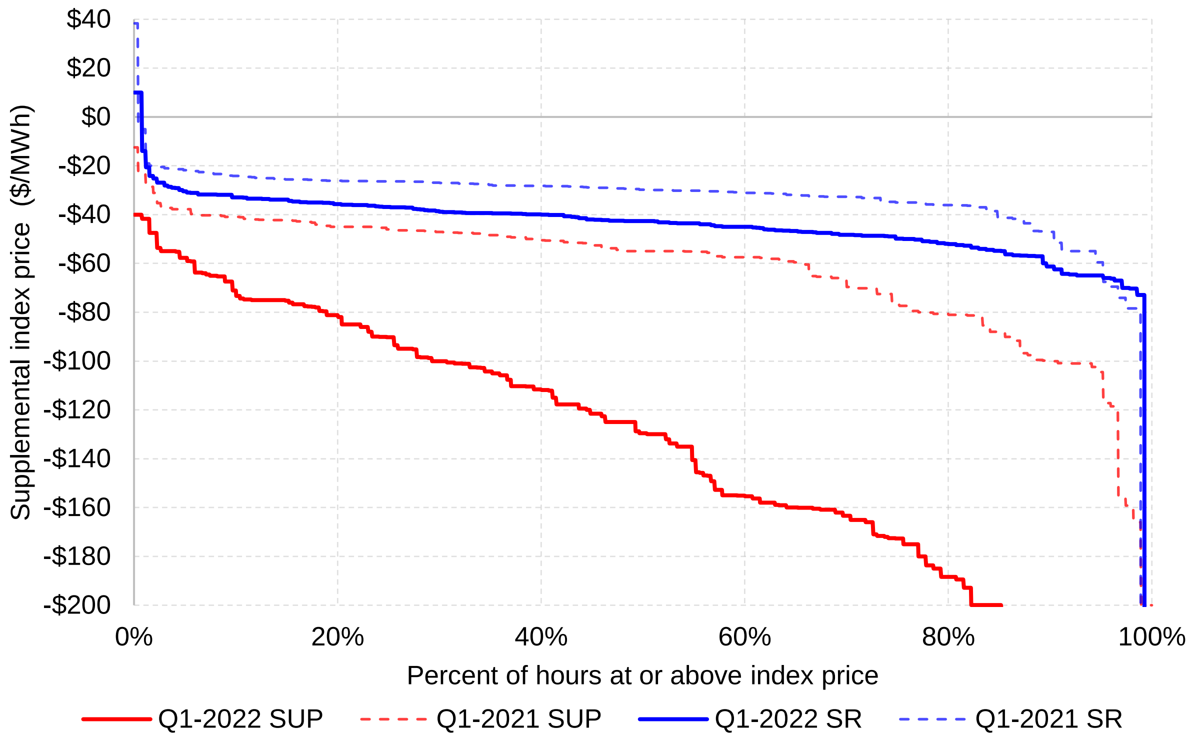


Figure 25: Average on-peak SUP offer volume by hydro and load assets

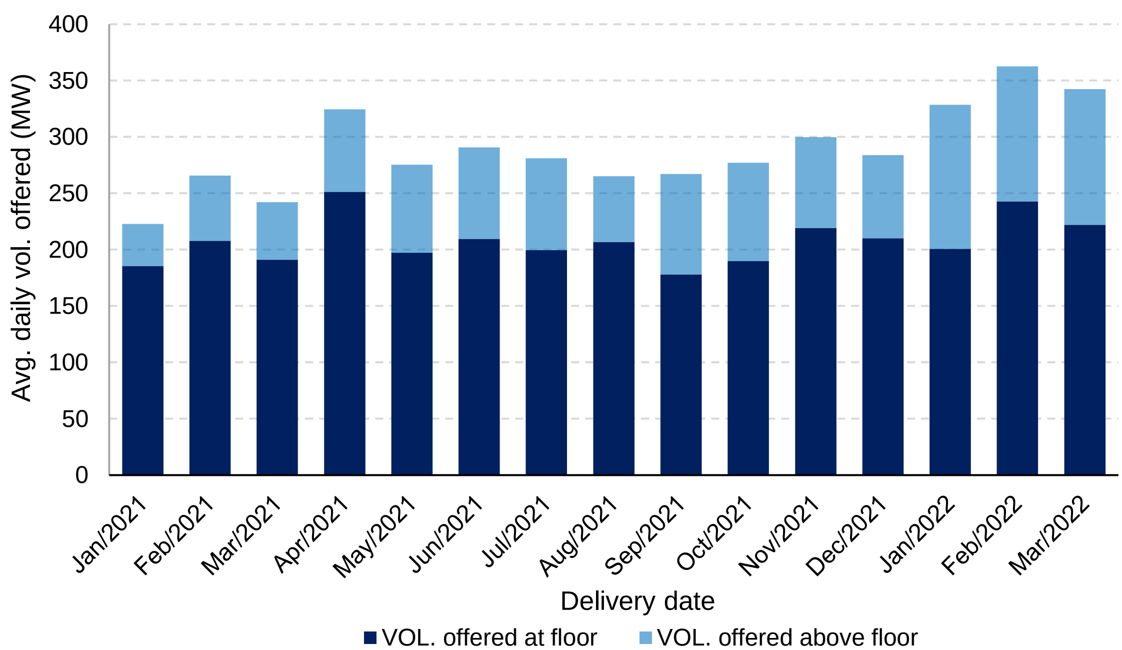
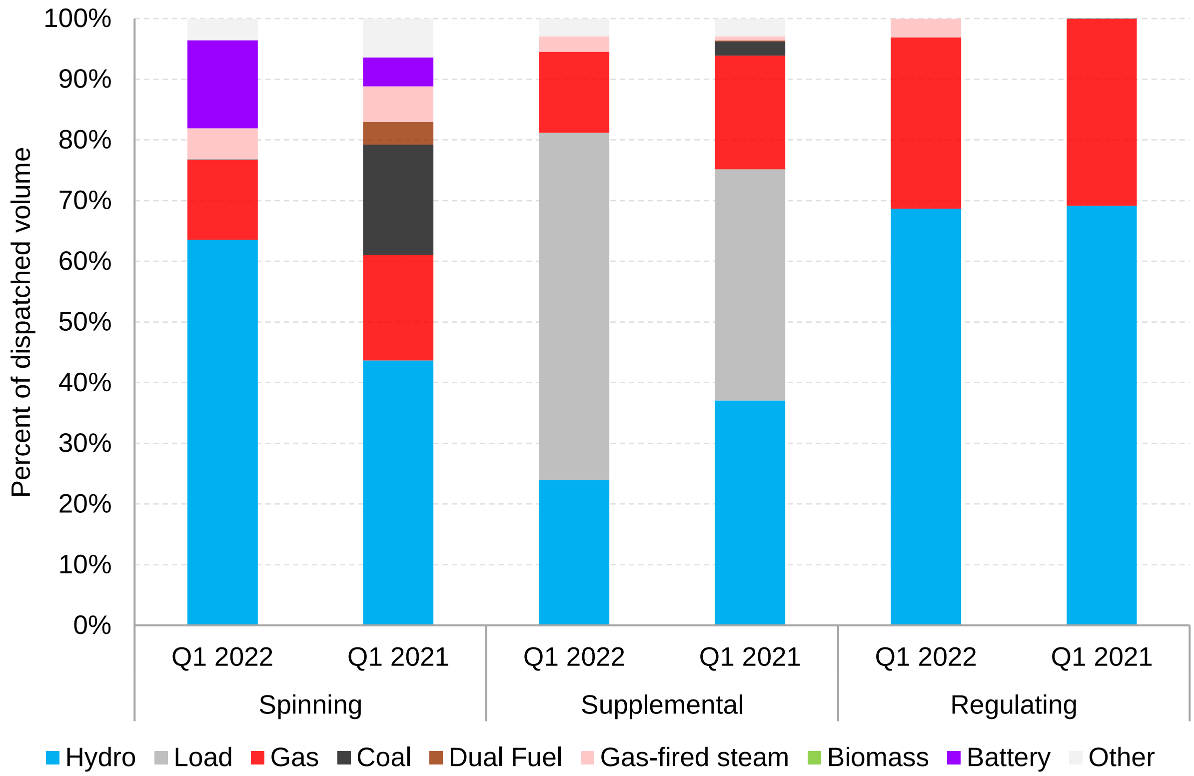


Figure 25 shows the average volume offered into on-peak supplemental reserves by hydro and load assets. Offer volumes are shaded based on offer prices, at either the offer price floor, or above the floor. In Q1 2021, hydro and load assets typically offered less than 250 MW into the on-peak supplemental market. Offer volumes increased in Q1 2022 to around 350 MW, which was a driver in lowering supplemental prices. As shown, most of the capacity offered into supplemental by hydro and load assets is offered at the price floor. These offers translate to an index price of negative $480/MWh.

Figure 26 shows the market shares of OR dispatches by fuel type in Q1 2022 and 2021. Since the conversion of Sundance 4 from coal to gas-fired steam, effective January 1, 2022, only one coal asset has been dispatched for OR products. This asset's spinning reserve dispatches account for 0.1% of spinning reserve dispatches in Q1 2022, whereas coal assets provided 18% of spinning reserve dispatchs in Q1 2021. There were no coal assets dispatched to provide supplemental or regulating reserve in Q1 2022. Battery and load assets continue to gain dispatch share in the spinning and supplemental reserve markets respectively. Battery assets provided 15% of spinning dispatch volumes in Q1, and load provided provided 57% of supplemental dispatch volumes.

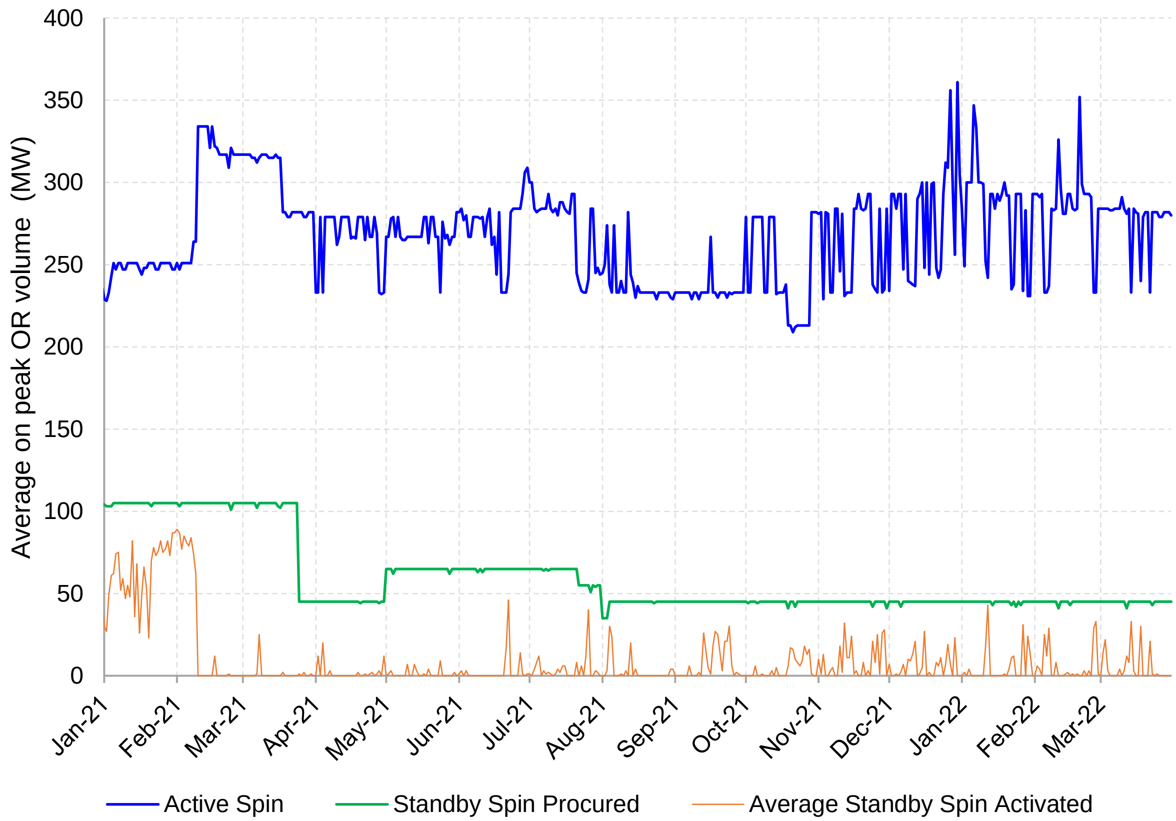
Figure 26: Dispatched OR volumes by fuel type (Q1 2022 and Q1 2021)[25]



[25] Dispatched OR volumes include active reserves and activated standby volumes.

Figure 27 shows daily on-peak spinning reserve volumes from January 1, 2021, to March 31, 2022. Procured active and standby volumes in Q1 2022 have not changed substantially from Q4 2021. Compared to Q1 2021, the day-to-day variance in the procured level of active reserve was much higher in 2022. This reflects a shift in focus from relying more heavily on standby activations versus procuring active reserves based on anticipated intertie flows.

Figure 27: Active and standby spinning volumes, on-peak (Jan. 1, 2021 to Mar. 31, 2022)



2.2 Standby activations

When the real-time operating and reliability requirements of the interconnected electric system require additional operating reserves, the system controller can dispatch assets that are providing standby reserve into the current active reserve portfolio. These standby activations may occur when an asset in the active reserve portfolio suffers a forced outage, requiring additional reserve resources to make up the shortfall.

Figure 28 shows the percent of standby reserves that were activated, plotted with average net imports. From June 2020 to February 2021, the activation rate for spinning and supplemental reserve varied significantly, and was strongly correlated with intertie flows. During this period, the AESO generally procured lower levels of active reserves (Figure 29) and relied more heavily on standby activations to meet real-time reserve shortfalls. From February 2021 through March 2022 the level of procured active reserve varied widely, often based on anticipated intertie flows, and correspondingly, standby activations stabilized at lower levels.

Figure 28: Standby reserve activation rate and net imports

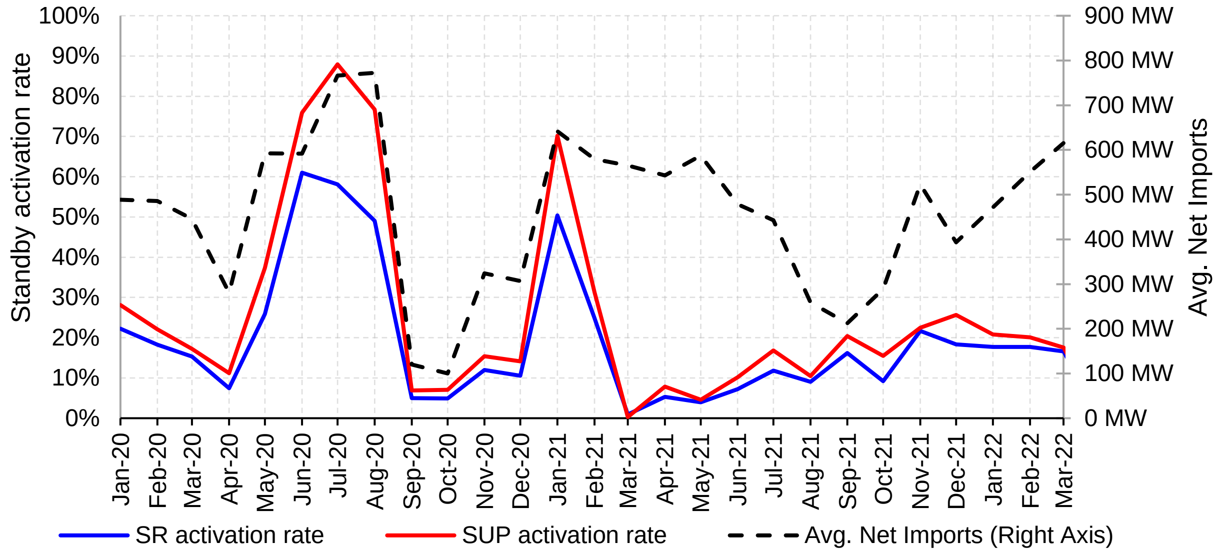
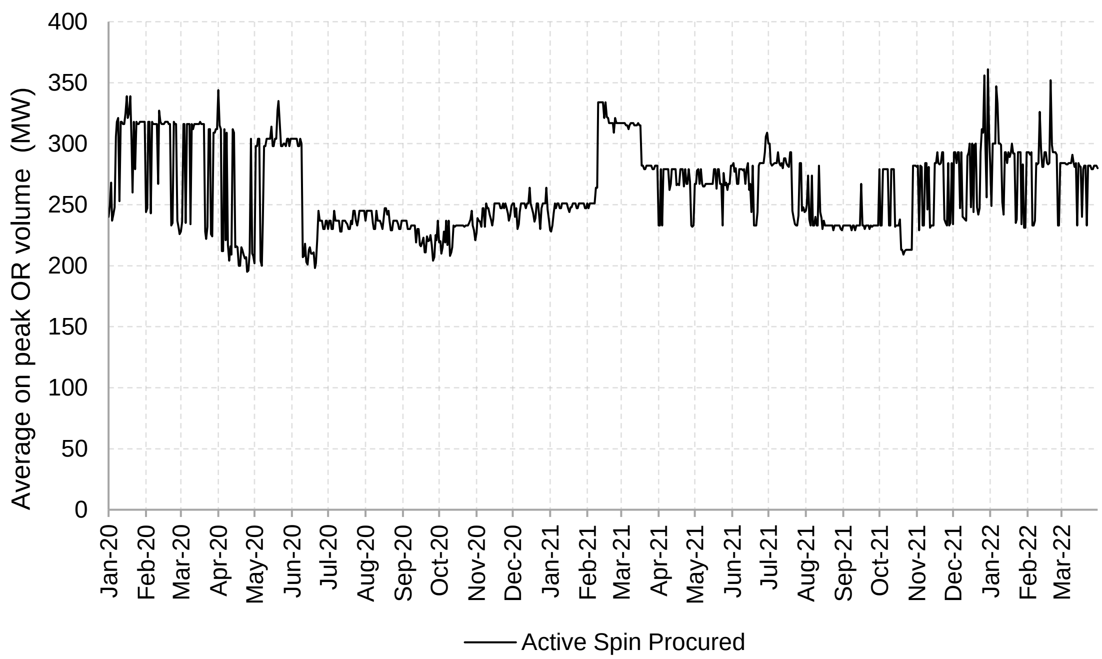


Figure 29: Active spinning volumes, on-peak (Jan. 1, 2020, to Mar. 31, 2022)



As mentioned, Q1 total OR costs have generally declined year-over-year (Figure 23). Standby reserve's share of costs have notably declined from Q1 2021 to Q1 2022. Activating standby reserves is costly and the decline in total standby costs is largely driven by lower activation rates.

3 THE FORWARD MARKET

3.1 Forward market volumes

The financial forward market is an important component of Alberta's energy-only market design. In particular, it allows generators and larger loads to hedge themselves from pool price volatility. Hedging involves reducing exposure to pool prices by buying or selling in the forward market for a fixed price, to diversify the buy/sell price and reduce risk. Similarly, the forward market enables retailers to reduce the risks associated with selling electricity to retail customers at a fixed price, which will tend to lower the fixed prices available to retail customers.

The MSA's analysis in this section incorporates trade data from ICE NGX and Canax, an over-the-counter (OTC) broker, which 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, 2021 is also included. These bilateral trades occur directly between two trading parties, not via ICE NGX or through a broker. The MSA generally collects information on these transactions once a year.

Figure 30: Total trade volumes by contract term and trade quarter (Q1 2018 to Q4 2022)[26]

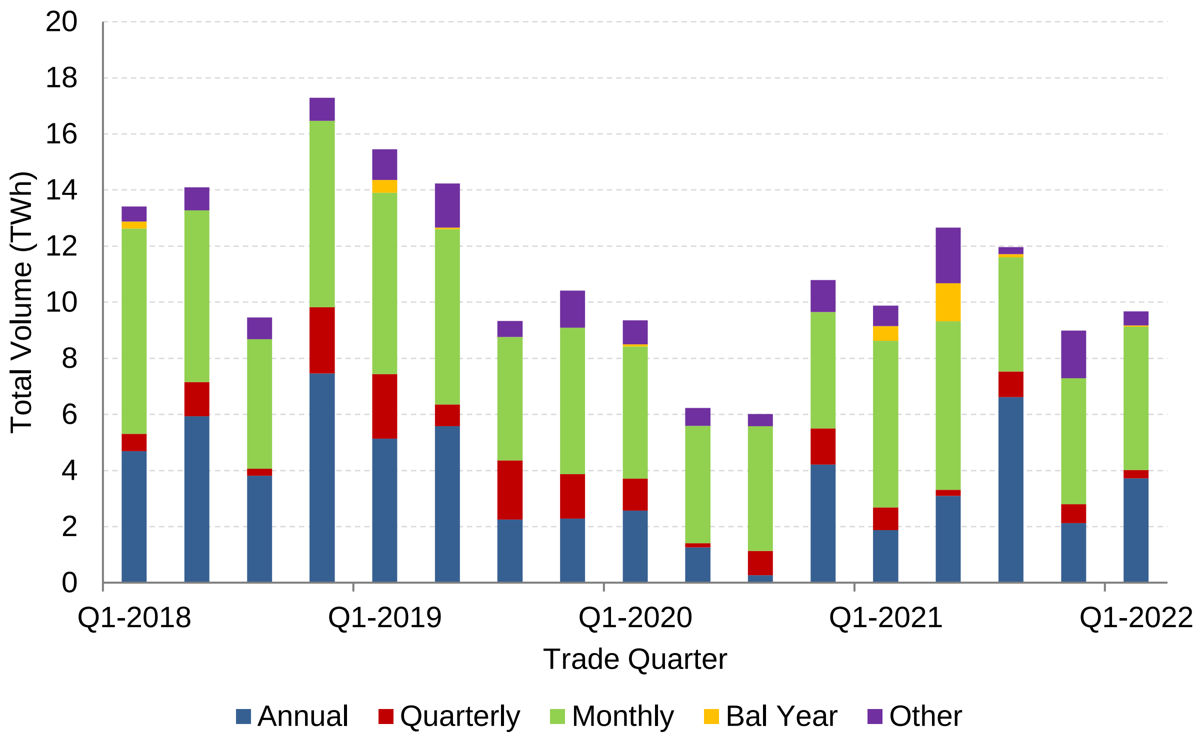


Figure 30 illustrates the total volume of trades, by the quarter in which the trades took place, from Q1 2018 to Q1 2022. Total volume is the total amount of power traded financially over the duration of a contract. The volumes are categorized based on the duration of the contract, such as annual and monthly, and these volumes include standard contract shapes such as flat, extended peak,

[26] The monthly volumes include full-load RRO trades based on the expected 4 MW traded volume.

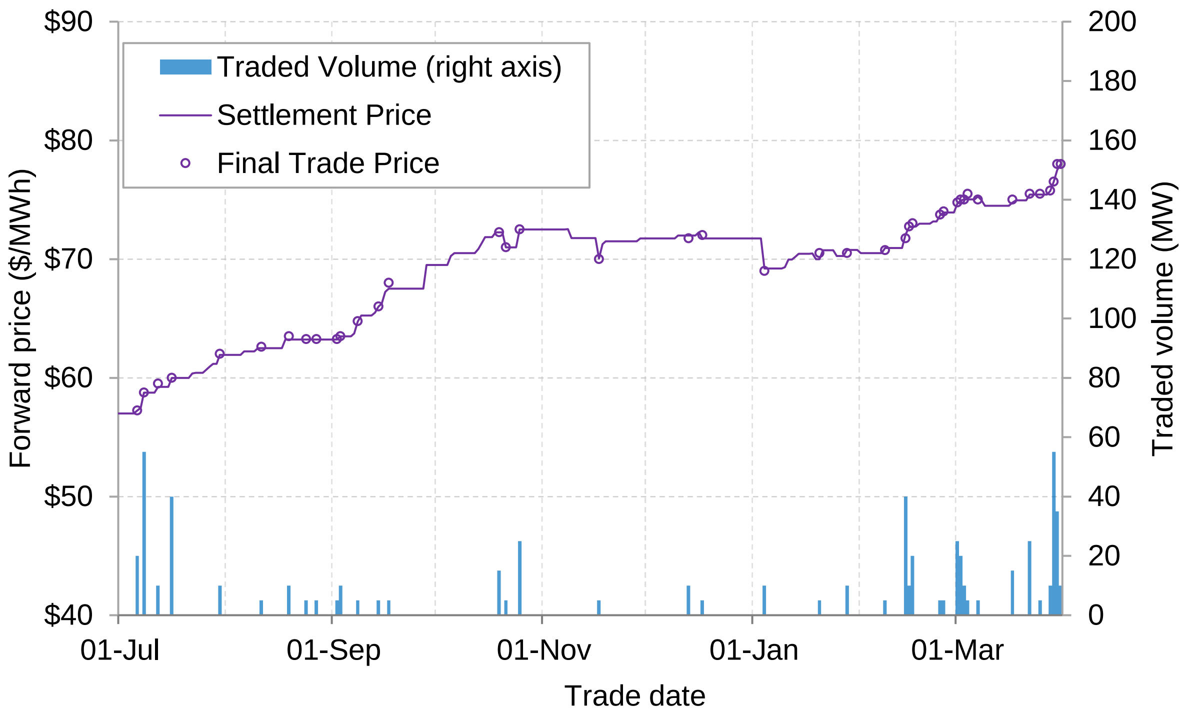
and off-peak, in addition to the monthly full-load RRO volumes.

In Q1 the total volume that traded on ICE NGX or Canax was 16% higher compared to Q4 2021. This was mainly due to an increase in trading of annual contracts during Q1, which largely occurred from mid-February to the end of the quarter.

Annual trades accounted for 3.72 TWh, or 38% of total volumes in the quarter. In March, 1.93 TWh of CAL23 volumes traded, representing 67% of the CAL23 volumes in Q1. The price of CAL23 increased by 9% over Q1, largely on the back of pool price volatility in the energy market and material increases in forward natural gas prices. These factors were also important drivers behind the increased trading activity for CAL23 since annual contracts provide longer-term price stability and can mitigate risk.

Figure 31 illustrates the daily forward price and traded volume for the CAL23 flat contract, from July 1, 2021 to March 31, 2022.[27] As shown in the figure, from mid-February onwards there were days with elevated trading activity for the CAL23 flat contract, reaching a daily volume of 55 MW (or 0.48 TWh in total volume[28]) on March 29.

Figure 31: CAL23 price and traded volume by day (flat; July 1, 2021 to March 31, 2022)[29]



[27] Flat contracts cover HE01-24 for all days in the contract period and settle against the average pool price. The term 'traded volume' refers to the volume of power being exchanged financially in each applicable hour of a contract

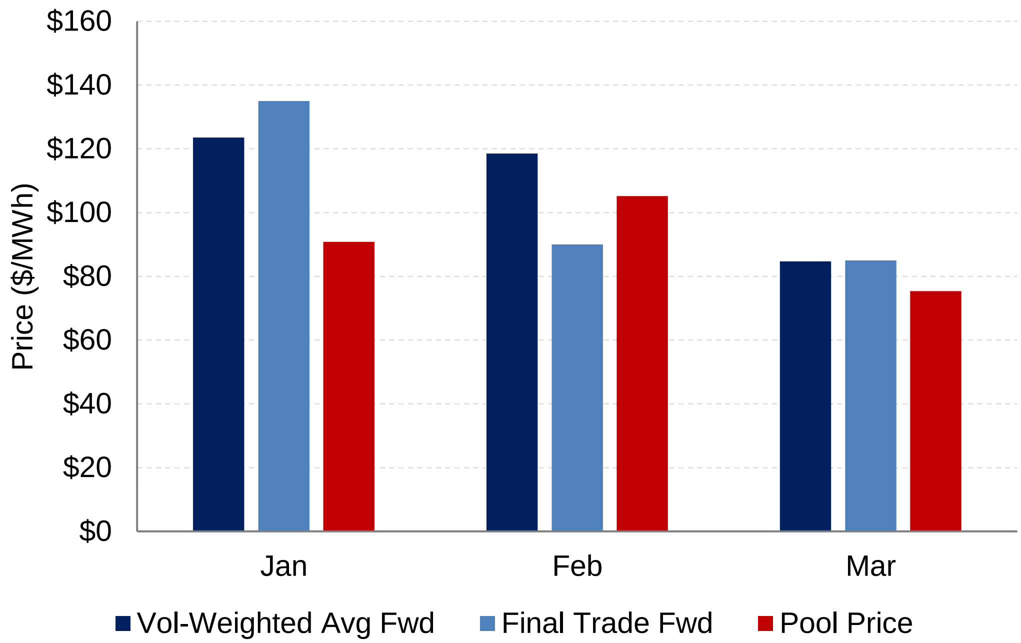
[28] The 55 MW of traded volumes applies to all 8,760 hours of 2023, giving a total volume of 481.8 GWh.

[29] The solid lines in the chart illustrate daily settlement prices and the markers illustrate the latest trade price on a given day.

3.2 Trading of monthly products

Figure 32 compares monthly flat forward prices to the realized average pool price for January to March 2022. Monthly forward prices in Q1 traded at a premium to realized pool prices, which is a reversal of the general trend that prevailed last year. As shown in Figure 32, the difference between the monthly volume-weighted average forward price and the realized pool prices declined over the quarter.

Figure 32: Monthly flat forward prices and average pool prices (January to March 2022)



The final forward trade for January was on December 31 at a price of $135.00/MWh, a premium of $11.48/MWh to the volume-weighted average forward price. The forward price for January increased in late December in part because of pool price volatility and weather forecasts. The last trade for January was also higher than the realized monthly pool price, by $44.19/MWh.

Pool prices during the first week of January settled well below forward market expectations. This put downward pressure on forward prices, particularly for the February contract, which fell from $127.75/MWh on December 31 to $112.00/MWh on January 6 (Figure 33). The forward price for February continued to fall through January, and the final forward trade price for February was $90.00/MWh on January 31. This was a discount of $28.53/MWh compared to the volume-weighted average forward price, and a discount of $15.22/MWh relative to realized pool prices (Figure 32).

Figure 33: Forward power prices for the January to July flat contracts (5-months out)

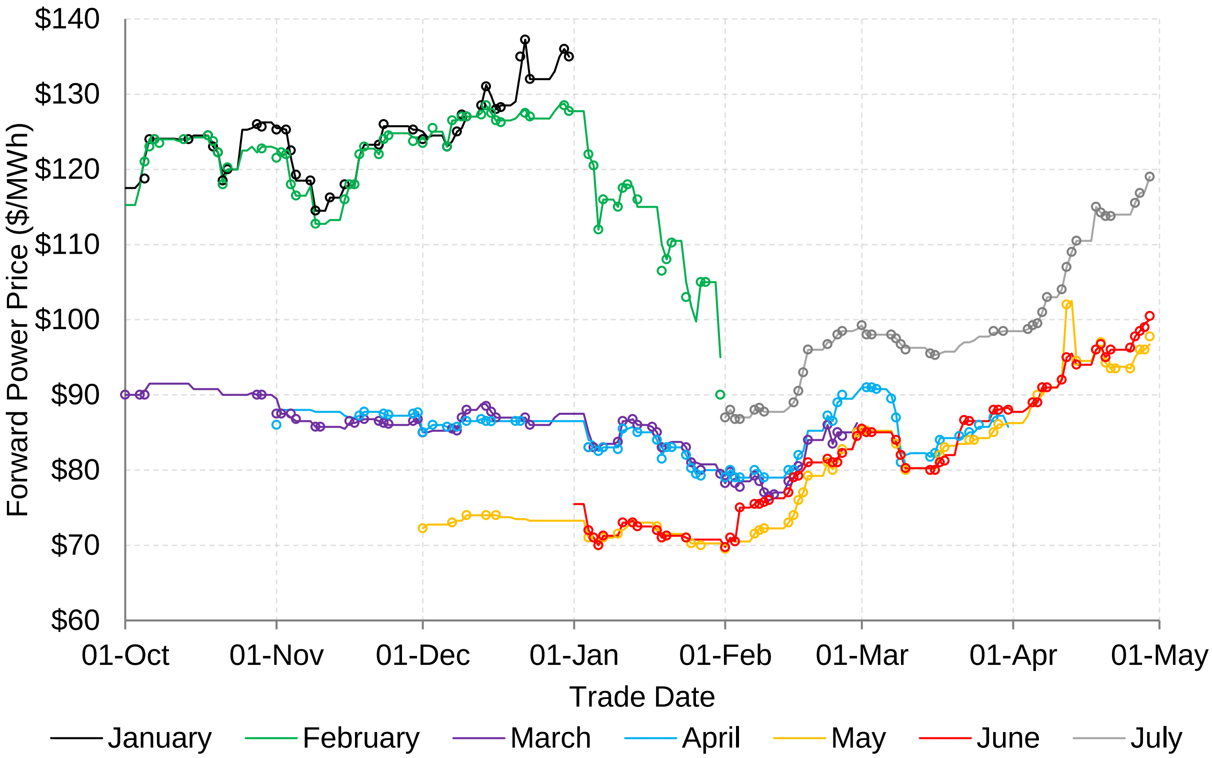
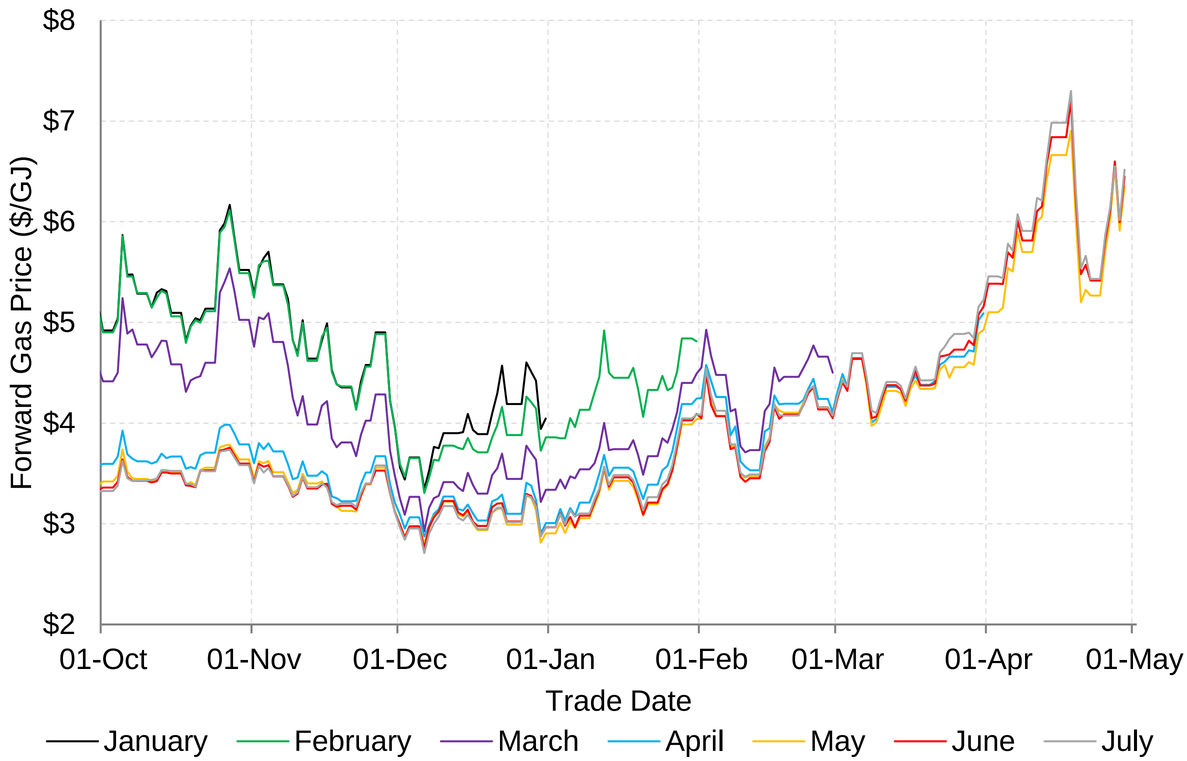


Figure 34: Forward AB-NIT natural gas prices for the January to July flat contracts



In early February, the marked price of the February contract dropped to around $80.00/MWh because of relatively low pool prices and a decline in natural gas prices (Figure 34). This trend reversed around mid-February as pool price volitility increased and natural gas prices rose, putting upward pressure on forward power prices. The March contract increased from $79.00/MWh on February 15 to $86.25/MWh at closing on February 28.

Forward prices for the March contract were much lower and less volatile compared to January and February, largely because March does not have the same potential for extremely cold weather. The volume-weighted average forward price and the final forward trade price for March were very comparable at around $85.00/MWh (Figure 32).

The marked price of the March contract dropped by 12% to around $75.00/MWh early in the month, as pool prices were relatively low during a few days with little wind generation and relatively low temperatures. This, along with falling natural gas prices, put downward pressure on forward power prices. The price for April fell from $90.00/MWh on March 7 to $82.00/MWh on March 10.

On February 4, the price of the June contract increased by 6% from $70.50/MWh to $75.00/MWh and the price of August increased by $3.00/MWh to $103.00/MWh due to proposed maintenance work on the BC intertie. The proposed work would limit imports on the BC intertie to 110 MW from June 6 to 12 and from August 5 to 12. The price of the June contract also increased by $3.00/MWh on March 21 on the back of increased generation outage figures.

Beginning in early April, Alberta natural gas futures increased materially (Figure 34) along with futures prices at Henry Hub, the main natural gas hub in North America. Natural gas storage levels in North America are well below the five-year average, largely due to increased demand for natual gas. Demand for natural gas has increased because of increased power generation demands, higher levels of LNG exports to Europe, and high heating demands over the 2021/22 winter. The increase in natural gas prices has put upward pressure on forward prices for Alberta power (Figure 33). For example, the July contract increased from $98.50/MWh on April 1 to $110.50/MWh on April 14. Volatility in natural gas markets continued to be a major driver of forward power prices over the remainder of April.

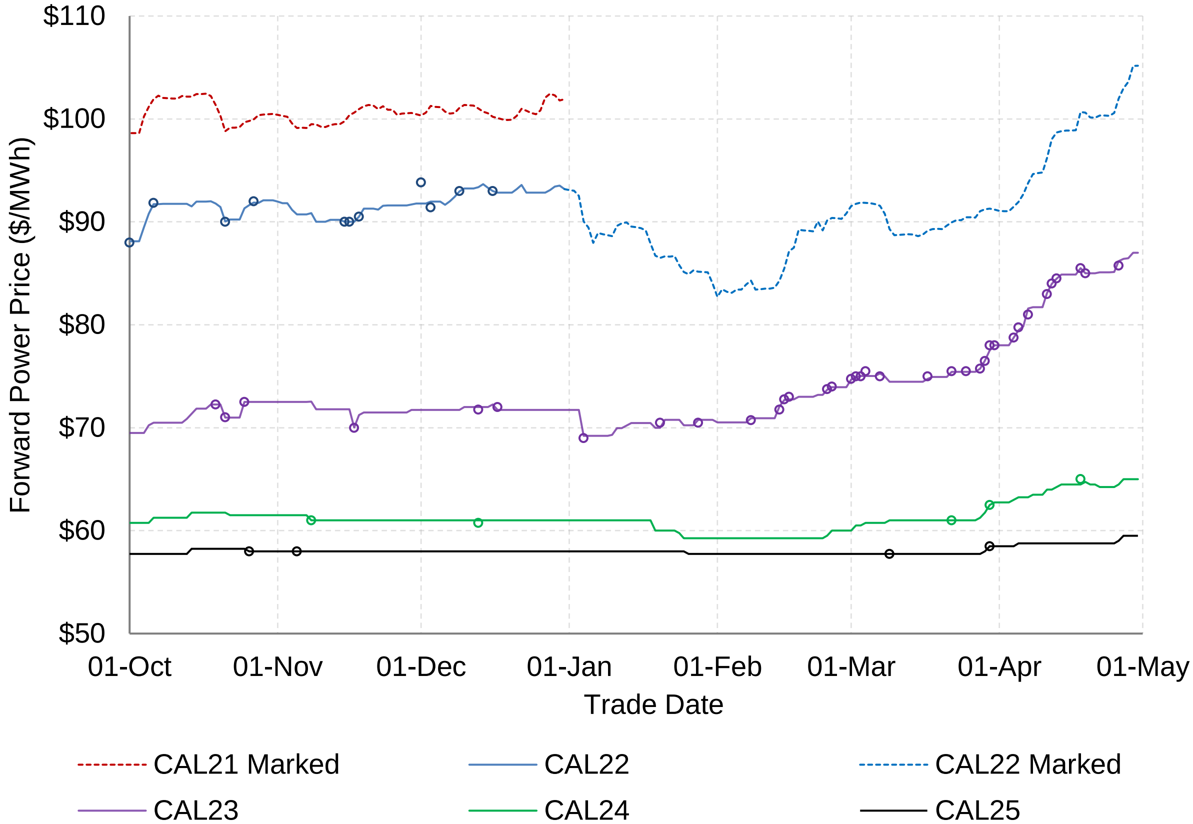
Increasing natural gas prices and RRO buying pressure put upward pressure on the May contract, which traded for $102.00/MWh on April 12. A few days later, the forward price for May fell significantly as the planned conversion outage at Genesee 3 was moved into the fall. The price of May fell by 8% to $94.50/MWh on April 14, while the price of October increased by 9% from $91.50/MWh to $100.00/MWh.

3.3 Trading of annual products

The marked price of the CAL22 contract declined to $91.19/MWh on March 31, 2022, which is 2% less than the forward price of $93.19/MWh on December 31, 2021.[30] The marked price of CAL22 declined in January as pool prices settled much lower than market expectations. This decline continued into early February because of warmer-than-usual temperatures, which resulted in lower demand, high wind generation, and declining natural gas prices.

Midway through February, pool prices started to increase due to rising natural gas prices, supplier offer behaviour, generator outages, and periods of low wind generation. This pool price volatility combined with increasing natural gas prices to put upward pressure on the marked price for CAL22 (Figure 35).

Figure 35: Forward power prices for the calendar 2021 to 2025 flat contracts (over trade dates October 1, 2021 to April 14, 2022)



[30] The marked price for CAL22 uses realized pool prices in combination with forward prices for the coming days and months to value the CAL22 contract.

As discussed above, the CAL23 contract was actively traded in the latter half of Q1. In addition to pool prices in the energy market, the price of CAL23 was reacting to forward prices in the natural gas market. The power price for CAL23 increased by 21% from December 31 to April 30, with the prices for the CAL24 and CAL25 contracts increasing by 7% and 3%, respectively (Figure 35 and Table 9).

Alberta natural gas prices increased materially in Q1 and continued to rise significantly in early April. From March 31 to April 14, the price of natural gas for the balance of 2022 (May through December) increased by 32% to $6.91/GJ. The CAL23 gas price increased by 23% to $5.07/GJ over the same period. As of April 30, natural gas for delivery in January 2023 was priced at $7.32/GJ, with December 2022 and February 2023 priced at similar levels.

Table 9: Power and natural gas forward prices (as of December 31, 2021 and April 30, 2022)

	Power			Natural Gas (AB-NIT)			Spark Spread (at 10 HR)		
	31-Dec	30-Apr	Change	31-Dec	30-Apr	Change	31-Dec	30-Apr	Change
CAL22	$93.19	$105.17	13%	$3.20	$6.05	89%	$61.21	$44.70	-27%
CAL23	$71.75	$87.00	21%	$2.95	$4.84	64%	$42.27	$38.63	-9%
CAL24	$61.00	$65.00	7%	$2.81	$3.73	33%	$32.92	$27.68	-16%
CAL25	$58.00	$59.50	3%	$2.88	$3.62	26%	$29.20	$23.33	-20%

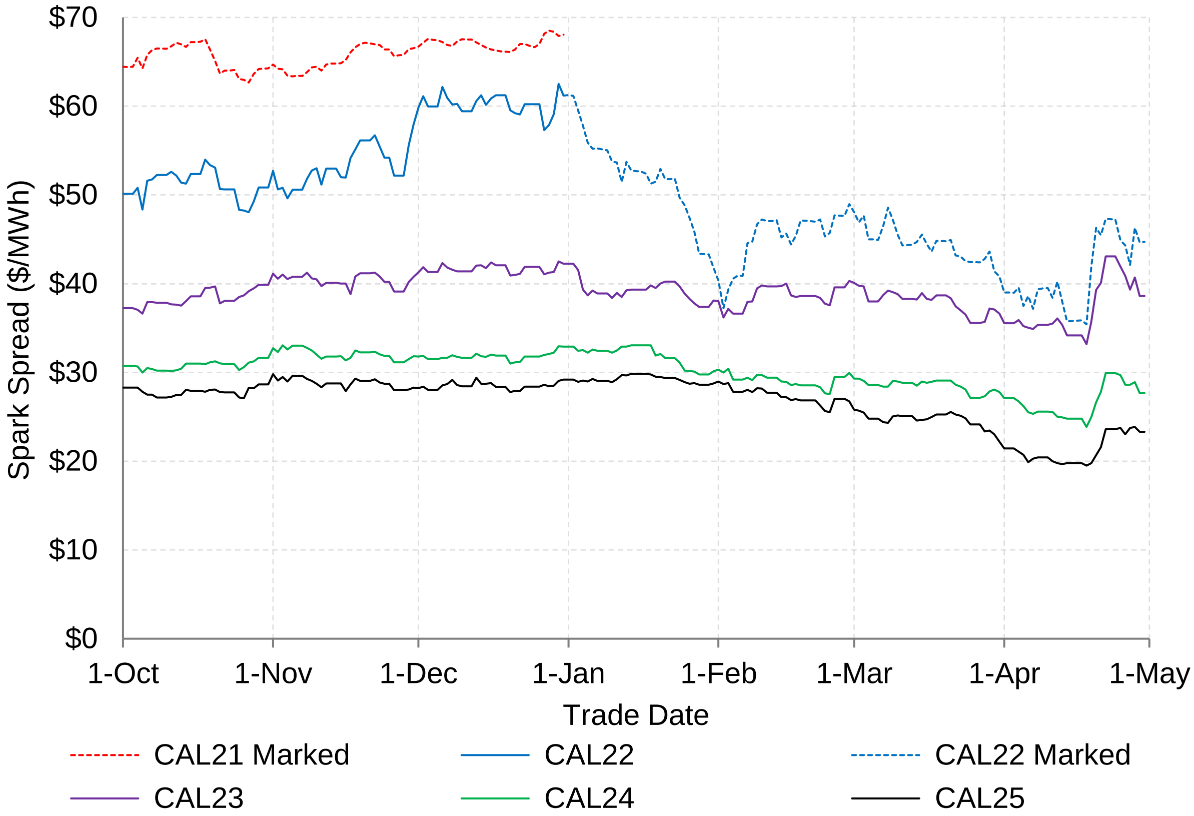
As shown by Table 9, forward power prices have increased since the start of the year, but not to the same extent as prices for natural gas, and this has put downward pressure on forward spark spreads. Figure 36 illustrates spark spreads for CAL22 to CAL25 since October 1, 2021. Spark spread is the difference between the price of electricity and the input fuel cost of natural gas. The calculations here assume a heat rate of 10 GJ/MWh.[31]

The spark spread for CAL22 has fallen materially compared to where it was trading in December. At the end of April, the spark spread for CAL22 was $44.70/MWh, which is 27% lower than on December 31. This is also well below the realized spark spread for CAL21, which was $68.04/MWh. Figure 36 shows that CAL24 and CAL25 are trading at lower spark spreads relative to CAL22 and CAL23, and this is largely due to the increased supply that is scheduled to come online. For example, Cascade combined-cycle (900 MW) is scheduled to enter the market in the fall of 2023, Genesee 1 and 2 (a net increase of 560 MW) are expected to be repowered to combined-cycle assets in late 2023 and early 2024, and the Base Plant cogeneration project (806 MW) is expected to come online in late 2024.[32]

[31] A 10 GJ/MWh heat rate is similar to the efficiency of simple cycle assets and is slightly lower than most gas-fired steam assets. An efficient combined cycle asset has a heat rate of around 7.5 GJ/MWh.

[32] AESO Long Term Adequacy Metrics – February 2022

Figure 36: Forward spark spreads for CAL22 to CAL25



4 THE RETAIL MARKET

The MSA has published a standalone retail market update for Q1 2022.[33] This update includes various analyses, including a quarterly update, regulated rate outlook, historical retail billing analyses and regulated switching analyses.

[33] Supplemental Retail Market Report for Q1 2022

5 ENFORCEMENT AND REGULATORY MATTERS

5.1 Forbearance regarding certain small municipally owned solar generators

The MSA undertook an assessment of whether municipalities (Generating Municipalities) that own generating units funded through the Alberta Municipal Solar Program (AMSP) are exempt from the prohibition on municipal ownership of generating units under section 95 of the *Electric Utilities Act* SA 2003 c E-5.1 (EUA). The MSA concluded that several Generating Municipalities likely do not meet the requirements for an exemption to the prohibition on municipal ownership under either section 95 of the EUA or the *Municipal Own Use Generation Regulation* AR 80/2009.

Due to the unique circumstances surrounding this issue, the MSA decided to conditionally forbear from taking enforcement steps with respect to municipally owned generating units constructed with funds from the AMSP. This forbearance is available on the MSA website.

5.2 Fast Frequency Response pilot forbearance update

On February 25, 2022, the MSA published a letter to the AESO providing an update to the MSA's forbearance regarding the AESO's Fast Frequency Response (FFR) pilot.[34] This letter expanded the scope of the MSA's forbearance to include additional rules and sections of rules that had been identified by the AESO as possibly affected by the FFR pilot.

5.3 Available capability information while commissioning

In March 2022, the MSA received a complaint regarding the accuracy of outage information submitted to the AESO during the commissioning stage for a new generating asset. The complainant was concerned that an outage for the full maximum capability of the asset had been submitted to the AESO on energization of the site and that the end date of the outage had been pushed forward repeatedly. At the end of the outage the available capability went immediately to the maximum capability, even though it was unlikely this asset would perform at this level at the outset of commissioning.

After discussions with the AESO, the outages for this asset were modified by the asset owner to reflect the latest commissioning schedule, which had the asset's availability slowly increasing throughout the commissioning stage. The MSA declined to investigate the complaint and granted forbearance from enforcement action to the market participant, in part, because the issue was resolved immediately by the asset owner after being notified of the issue and the contravention did not result in financial gain or jeopardize the safe, reliable, and economic operation of the interconnected electric system.

The MSA believes that the accuracy of public outage information is important for the fair, efficient, and openly competitive operation of the forward electricity market. The MSA is of the view that all commissioning assets must reflect their most recent commissioning schedule in their outage

[34] AESO Fast Frequency Response Pilot Project (″FFR Pilot¸) Update to The List of FFR Pilot Impact Rules.pdf (albertamsa.ca)

submissions to the AESO through the Energy Trading System (ETS). If the capability of the asset changes throughout commissioning, this should be reflected in the outage submissions. If the schedule changes, the asset owner or agent should provide timely updates to the AESO through the ETS.

5.4 Merit order release

On July 5, 2021, the MSA received a self-report from the AESO regarding the release of merit order data pertaining to the period between June 22 and July 6, 2021 prior to 60 days after the relevant settlement intervals. Following the AESO's self-report, the MSA requested further information from the AESO, which the AESO provided.

The MSA has completed its assessment of the AESO's self-report and the other information provided by the AESO. Based on the information provided, the MSA is satisfied that contraventions of ISO rule 103.1 *Confidentiality* and section 6(3) of the FEOC Regulation occurred.

The MSA has determined that no further enforcement steps are warranted in this matter. The MSA is satisfied that the contravention was inadvertent and took place over a relatively short period of time. In addition, the AESO has taken steps which will ensure a similar event does not occur in the future. In making this determination, MSA has relied on the information and submissions provided by the AESO; should any further or other information come to light, the MSA may initiate an investigation and pursue further enforcement steps.

5.5 Information sharing

In August 2021, the MSA received a self-report regarding a contravention of section 3 of the FEOC Regulation where an agent provided asset dispatch information to the wrong asset operator not affiliated with the owner of the dispatched asset. This was a contravention of the FEOC Regulation as the agent does not have an Alberta Utilities Commission Order under section 3(3) of the FEOC Regulation to share dispatch information related to an asset with a market participant that is not related to the owner of the asset. The MSA spoke with the agent regarding the technical controls it has in place to prevent similar contraventions and further steps it was taking to minimize human error. The MSA decided to not proceed to an investigation as there was no impact on the wholesale electricity market from the sharing of the information and the issue was self-reported.

5.6 Submission on Electricity Grid Displacement Factor

On March 4, 2022, Alberta Environment and Parks (AEP) released a Draft Methodology for Electricity Grid Displacement Factor (EGDF) Update that outlined the proposed EGDF in effect for January 1, 2023 to December 31, 2023. AEP initiated a 30-day public comment period regarding the proposed update, seeking comments on the methodology document and EGDF. The MSA submitted comments to AEP on April 1, 2022.

6 ISO RULES COMPLIANCE

The purpose of the ISO rules is to promote orderly and predictable actions by market participants and to facilitate the operation of the Alberta Interconnected Electric System (AIES). The MSA is responsible for the enforcement of 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 that a contravention has occurred and has determined that a notice of specified penalty (NSP) is appropriate, then AUC Rule 019 guides the MSA on how to issue an NSP.

From January 1 to March 31, 2022, the MSA closed 84 ISO rules compliance matters, as reported in Table 10.[35] An additional 70 matters were carried forward to next quarter. During this period 24 matters were addressed with NSPs, totalling $46,500 in financial penalties, with details provided in Table 11.

Table 10: ISO rules compliance outcomes from January 1, 2022 to March 31, 2022

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.1	1	-	-
201.7	5	2	-
203.3	27	1	-
203.4	3	1	1
203.6	4	1	-
205.3	2	-	-
205.5	-	5	-
205.6	-	9	-
304.3	5	-	-
306.4	4	-	-
306.5	6	3	-
502.8	-	2	-
502.10	1	-	-
Total	**58**	**24**	**1**

[35] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 84 closed matters, one matter was referred by the MSA to another body.

Table 11: Specified penalties issued between January 1 and March 31, 2022 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)								Total ($)	Matters
	201.7	203.3	203.4	203.6	205.5	205.6	306.5	502.8		
Air Liquide Canada Inc.					2,000	500			2,500	3
Alberta Pacific Forest Industries Inc.						2,000			2,000	2
Capital Power (G3) Limited Partnership							500		500	1
Capital Power (Genesee) L.P.							1,000		1,000	2
Claresholm Solar LP								1,000	1,000	2
Enel X Canada Ltd.						15,000			15,000	3
Mercer Peace River Pulp Ltd.					750				750	1
Milner Power II Limited Partnership by its General Partner, Milner Power II Inc	500								500	1
Powerex Corp.	250								250	1
Suncor Energy Inc.		250							250	1
TA Alberta Hydro LP			1,500						1,500	1
TransAlta Generation Partnership					5,500				5,500	2
TransCanada Energy Sales Ltd.				750					750	1
Voltus Energy Canada Ltd.						15,000			15,000	3
Total	750	250	1,500	750	8,250	32,500	1,500	1,000	46,500	24

The sections of ISO rules listed in Table 10 and Table 11 are contained within the following categories:

103 Administration
201 General (Markets)
203 Energy Market
205 Ancillary Services Market
304 Routine Operations
306 Outages and Disturbances
502 Technical Requirements

7 ALBERTA RELIABILITY STANDARDS COMPLIANCE

The MSA has the jurisdiction to assess whether or not a market participant has complied with Alberta Reliability Standards (ARS) and apply a specified penalty where appropriate.

The purpose of ARS is to ensure the various entities involved in grid operation (legal owners and operators of generators, transmission facilities, distribution systems, as well as the independent system operator) are doing their part by way of procedures, communications, coordination, training and maintenance, among other practices, to support the reliability of the AIES. 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 with respect to compliance with ARS is focused on promoting awareness of obligations and a proactive compliance stance. The MSA has established a process that, 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 will only report aggregated statistics regarding CIP ARS outcomes.

From January 1 to March 31, 2022, the MSA addressed 39 O&P ARS compliance matters, as reported in Table 12.[36] An additional four matters were carried forward to next quarter. During this period, five matters were addressed with NSPs, totalling $27,375 in financial penalties, with details provided in Table 13. For the same period, the MSA addressed 49 CIP ARS compliance matters, as reported in Table 14, and eight matters were addressed with NSPs, totalling $15,375 in financial penalties. An additional 62 matters were carried forward to next quarter.

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

Table 12: O&P ARS compliance outcomes from January 1 to March 31, 2022

Reliability standard	**Forbearance**	**Notice of specified penalty**
COM-001	1	-
EOP-001	1	-
EOP-005	1	-
FAC-008	11	1
PRC-001	2	-
PRC-002	-	1
PRC-005	12	2
PRC-006	1	-
PRC-019	3	-
PRC-023	-	1
VAR-002	1	-
VAR-501-WECC	1	-
Total	34	5

Table 13: Specified penalties issued between January 1 and March 31, 2022 for contraventions of O&P ARS

Market participant	**Total specified penalty amounts by ARS ($)**				**Total ($)**	**Matters**
	FAC-008	**PRC-002**	**PRC-005**	**PRC-023**		
Imperial Oil Resources Limited	2,250	375	2,250		4,875	3
Suncor Energy Inc.			3,750	18,750	22,500	2
Total	2,250	375	6,000	18,750	27,375	5

The ARS outcomes listed in Table 12 and Table 13 are contained within the following categories:

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

Table 14: CIP ARS compliance outcomes from January 1 to March 31, 2022

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	2	-	-
CIP-003	-	1	-
CIP-004	10	4	1
CIP-005	2	-	-
CIP-006	5	-	-
CIP-007	10	1	-
CIP-008	1	-	-
CIP-009	-	-	1
CIP-010	7	1	-
CIP-011	2	1	-
Total	39	8	2

The ARS outcomes listed in Table 14 are contained within the following categories:

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