MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q1 2021

May 14, 2021

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 for Q1 2021 was $95.45/MWh, the highest since Q2 2013 and a 42% increase compared to Q1 2020. The high pool prices in Q1 2021 were driven by a number of factors including cold temperatures, low wind generation, and thermal outages. The offer behaviour of some larger suppliers was also a factor in the higher prices, as the last of the PPAs expired on December 31, 2020.

- Average demand over the quarter was relatively flat year-over-year as oil prices continued to increase. Average demand was 4% higher in February 2021 compared to February 2020, which was largely driven by colder temperatures this year. A new record for peak demand, 11,729 MW, was set on February 9, 2021. Year-over-year demand fell by around 2% in both January and March as temperatures in these months were mild compared to last year.

- The carbon price for 2021 is $40/tCO2e, an increase from $30/tCO2e in 2020. Coal generation in Alberta continues to decline and has largely been displaced by natural gas generation. In addition to the production decline, coal assets also set market prices less often in Q1 2021 compared to Q1 2020.

- The total cost of operating reserves was 38% higher in Q1 2021 compared to Q1 2020. A principal driver behind this increase was the rise in pool prices, which increased 42% on average. In the active OR markets, index prices for spinning and regulating were generally comparable with last year, while index prices for supplemental reserves continued to decline. In early February the AESO began to procure more active reserves, decreasing the volume of standby activations.

- Trading volumes in the forward market were low compared to historical volumes but trading activity has increased relative to the lows seen in Q2 and Q3 of 2020. Pool prices for Q1 2021 came in above forward market expectations, which in turn has put some upward pressure on forward prices for the balance of 2021. The forward prices for 2022, 2023, and 2024 were $62.25/MWh, $53.25/MWh, and $50.50/MWh, respectively, as of March 31. Forward prices for these annual contracts are decreasing into the future as wind, solar, and combined-cycle developments are expected to increase supply, and natural gas futures are quite low at around $2.30/GJ.

- From January 1 to March 31, 2021, the MSA closed 104 ISO rules compliance matters; 14 matters were addressed with notices of specified penalty. For the same period, the MSA closed 36 Alberta Reliability Standards Operations and Planning compliance matters; four matters were addressed with notices of specified penalty. In addition, the MSA closed 110 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; 40 matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

Table 1 provides summary market statistics for Q1 2021 compared to Q1 2020. The average pool price of $95.45/MWh in Q1 2021 was 42% higher than in Q1 2020, and 107% higher than in Q4 2020. There has been no indication that these prices were the result of anti-competitive conduct.

Monthly pool prices in Q1 2021 were highest in February, with an average price of $152/MWh compared to $73/MWh in January and $67/MWh in March. The higher pool prices in February were partly due to an extended period of cold weather which increased heating demands and lowered wind generation. A similar period of low temperatures was experienced in January 2020 and pool prices averaged $121/MWh.

Table 1: Monthly market summary for Q1

		2021	2020	*Change*
Pool Price (Avg $/MWh)	Jan	72.89	120.67	-40%
	Feb	151.98	36.33	318%
	Mar	66.92	42.16	59%
	Q1	**95.45**	**67.06**	**42%**
Demand (AIL) (Avg MW)	Jan	10,266	10,517	-2.4%
	Feb	10,620	10,208	4.0%
	Mar	9,784	10,008	-2.2%
	Q1	**10,210**	**10,245**	**-0.3%**
Gas Price AB-NIT (2A) (Avg $/GJ)	Jan	2.60	2.17	20%
	Feb	3.57	1.76	103%
	Mar	2.56	1.86	38%
	Q1	**2.89**	**1.93**	**50%**
Wind (Avg MW)	Jan	846	730	16%
	Feb	644	807	-20%
	Mar	820	695	18%
	Q1	**774**	**743**	**4%**
Net Imports (+) Net Exports (–) (Avg MW)	Jan	642	488	31%
	Feb	579	485	19%
	Mar	565	445	27%
	Q1	**596**	**473**	**26%**
Supply Cushion (Avg MW)	Jan	1,981	1,609	23%
	Feb	1,714	1,755	-2%
	Mar	1,868	1,482	26%
	Q1	**1,859**	**1,612**	**15%**

Overall electricity demand in the quarter was relatively flat year-over-year as oil prices continued to rise and Alberta experienced an extended period of low temperatures in early-to-mid February. The year-over-year demand changes by month were a function of prevailing temperatures, with January and March generally milder this year, and February much colder. A new peak demand of 11,729 MW was set on February 9, a 0.3% increase over the previous record.

The average price of natural gas increased by 50% year-over-year which was partly driven by higher pricing in February, as cold temperatures increased heating demand in Alberta and across other parts of Western and Central North America. The same day price for natural gas in Alberta peaked at $6.00/GJ on February 11. Natural gas prices in some US regions were substantially higher in mid-February, with prices reaching CAD$173/GJ and CAD$482/GJ in Southern California and Texas, respectively.[1]

[1] EIA: Natural Gas Weekly Update (February 18, 2021), SoCal Citygate cited at US$144/MMBtu; Houston Ship Channel cited at US$400/MMBtu. Units converted to CAD/GJ using the Bank of Canada's daily exchange rate.

Average wind generation in the quarter was up slightly year-over-year as 105 MW of additional wind capacity was online in Q1 2021; total wind capacity is currently 1,781 MW. In Q1 2021 the average capacity factor of wind was 43% compared to 44% in Q1 in 2020.[2] However, average wind generation was only 644 MW in February 2021, a capacity factor of 36%, as the same weather systems that bring cold temperatures also tend to reduce wind speeds. As a result, wind generation was often low during higher pool price hours across the quarter. The average capacity factor of wind generation was 12% in hours when pool prices were above $200/MWh in Q1 2021, compared to the overall average of 43%.

At the end of 2020, the remaining thermal Power Purchase Arrangements (PPAs) expired, along with the Hydro PPA. As a result, the offer control for 2,284 MW of thermal capacity was transferred from the Balancing Pool back to the legal owners, and the financial obligations pertaining to 790 MW of hydro capacity came to an end. Due to the expiration of the PPAs, Q1 2021 saw an increase in the volume of high-priced offers into the energy market and more thermal capacity was taken offline commercially, both of which put upward pressure on pool prices. These dynamics are discussed further in section 1.3.

Responding to the higher pool prices, imports in Q1 2021 were relatively high; an increase of 26% year-over-year. In mid-February higher prices in other jurisdictions led to some exports being scheduled to US trading hubs such as SP15 in California, North hub in the Southwest Power Pool (SPP), and Mid-Columbia (Mid-C). Later in February Alberta had two frequency events due to the BC/MATL intertie tripping offline while imports were flowing. As a result, the AESO subsequently increased the amount of Load Shed Service for imports (LSSi) that is required for a given combination of imports and demand.

The price of carbon in 2021 is $40/tCO2e, an increase from $30/tCO2e in 2020.[3] The higher carbon price puts upward pressure on pool prices because it increases the marginal cost of dispatchable generation such as converted coal, coal, and simple-cycle natural gas units.[4] The marginal cost of an efficient combined-cycle natural gas unit is largely unaffected under the current *Technology Innovation and Emissions Reduction Regulation* (TIER Regulation) because this technology is used as the benchmark. Coal generation in Alberta continues to convert to natural gas and is expected to no longer be used in the production of electricity in Alberta by the end of 2023. Because natural gas generators, such as combined-cycle and coal-to-gas, are more carbon efficient, the impact of higher carbon prices in the future may be reduced. The federal carbon price is scheduled to increase to $50/tCO2e in 2022, and thereafter by $15/tCO2e each year to $170/tCO2e in 2030. Equivalency arrangements for the TIER Regulation beyond the end of this year are not yet agreed and so the contribution of carbon to marginal cost in the future is uncertain.

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[2] The capacity of a new wind asset is included in the capacity factor analysis once the asset has delivered electricity to the grid.

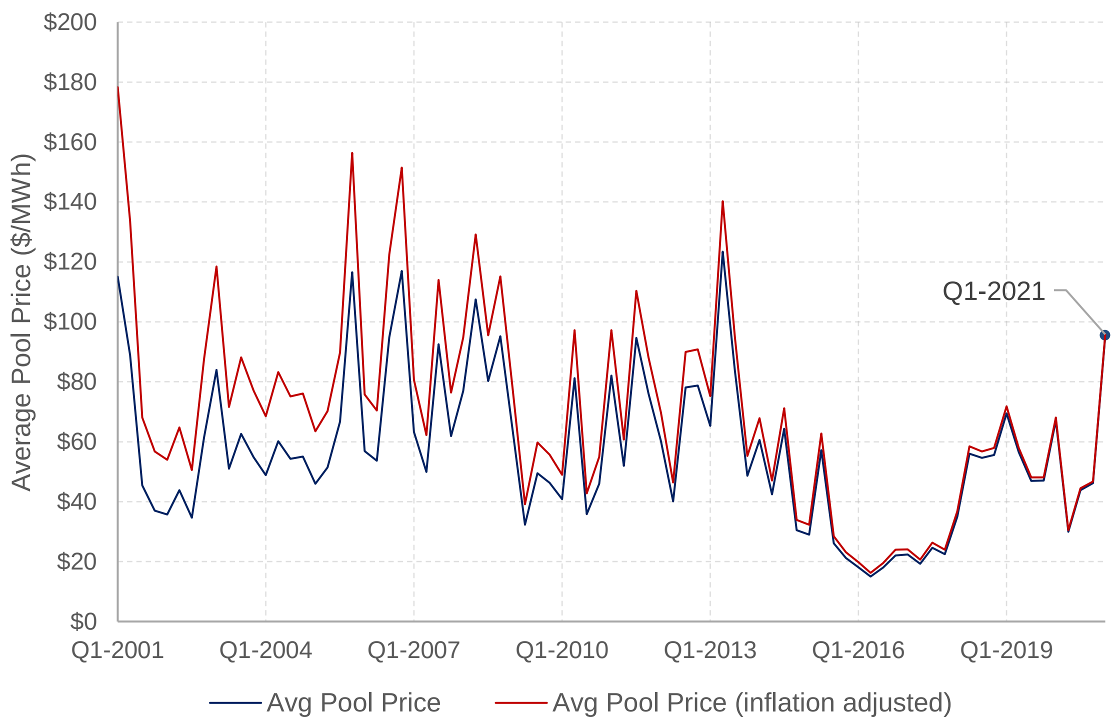
[3] Ministerial Order 36/2020

[4] Converted coal refers to coal assets that have undergone a coal-to-gas or dual fuel conversion, or have otherwise significantly increased their ability to utilize natural gas. It does not include coal assets that have been repowered.

1.2 Market outcomes

Figure 1 shows the average pool price for Q1 2021 in the context of historical pool prices since 2001. As shown, the average price for Q1 2021 was the highest since Q2 2013 as pool prices in the 2014 to 2020 period were lower and less volatile than generally seen historically. The reduced volatility in this period was in part due to the commissioning of the Shepard combined-cycle asset (870 MW) in early 2015, lower oil prices from 2015 through 2017 and in 2020, and the PPA Buyers' termination of the PPAs beginning in early 2016.

Figure 1: Historical average pool price by quarter (Q1 2001 to Q1 2021)[5]



The pool price volatility in Q1 2021 was partly driven by low temperatures, Table 2 provides average monthly temperatures in Q1 2021 and Q1 2020. As shown, average temperatures in February 2021 and January 2020 were quite low. Lower temperatures in winter months increase electricity demand because there is more demand related to heating loads. Average demand was 4.0% higher in February 2021 compared to February 2020, while average demand in January and March was down 2.4% and 2.2%, respectively. Temperatures for January and March were generally warmer this year (Table 2).

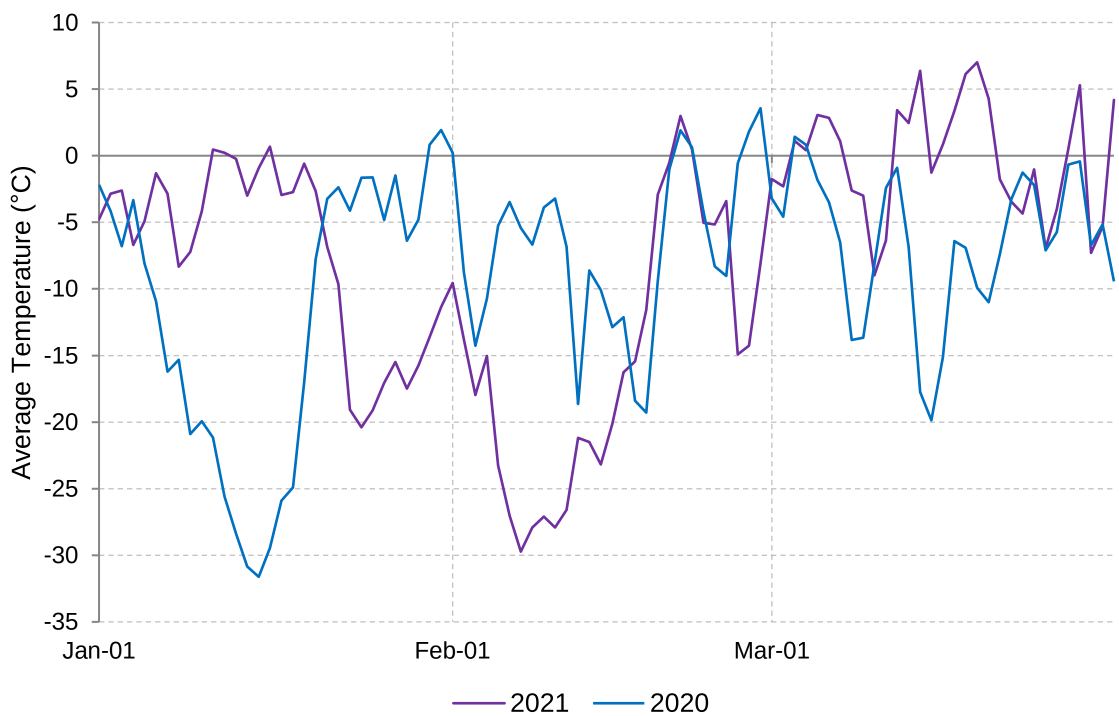
[5] Pool prices are adjusted for inflation using the Consumer Price Index (CPI), all items, monthly, not seasonally adjusted, for Alberta (Table 18-10-0004-01)

Table 2: Average monthly temperatures in Q1 2021 and 2020 [6]

Month	2021	2020	Difference
Jan	-7.2	-12.2	5.0
Feb	-15.2	-6.8	-8.4
Mar	-0.3	-6.7	6.5

Figure 2 shows daily average temperatures in Q1 2021 and Q1 2020. As shown, the low monthly average temperatures for January 2020 and February 2021 were driven by very cold temperatures in mid-January 2020 and early-to-mid February 2021. February 2021 was colder on average than January 2020, with 55% of hours less than -15°C compared to 39% of hours in January 2020. Average demand in February 2021 was 1.0% higher compared to January 2020.

Figure 2: Daily average temperatures in Q1 2021 and 2020

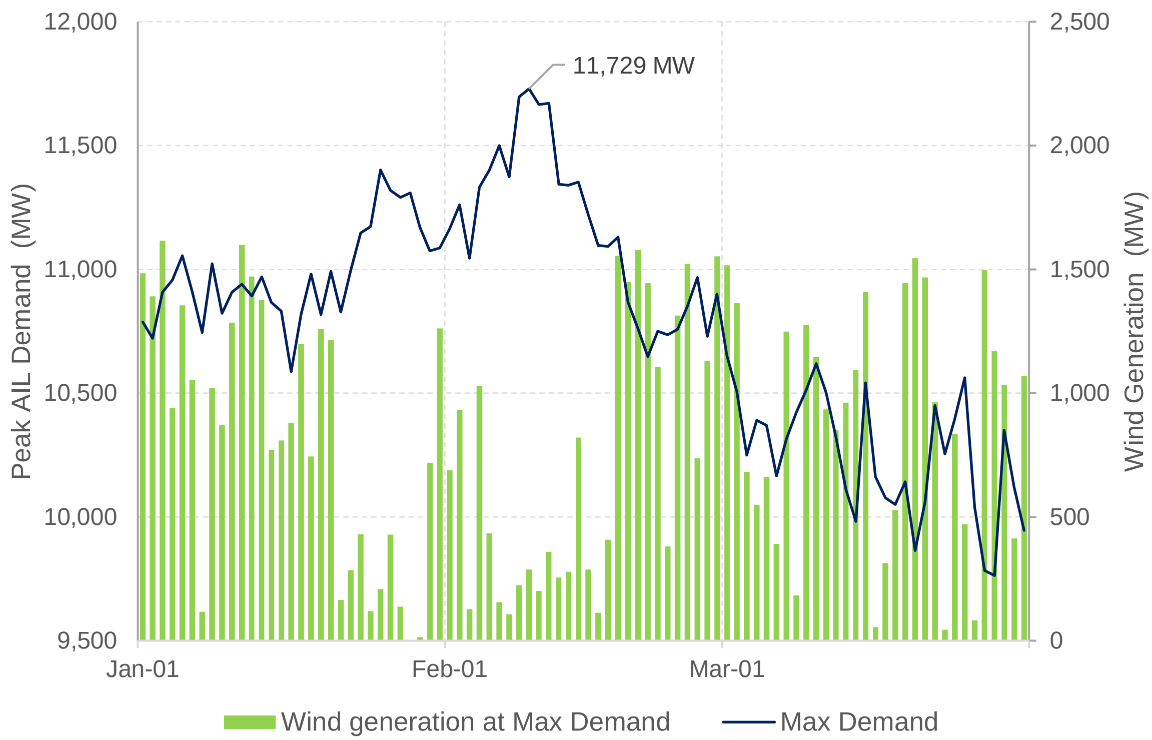


The lower temperatures in late January and early February 2021 increased demand and reduced the supply of wind generation (Figure 3). For example, in late January 2021 demand peaked at 11,401 MW on Monday, January 25 when average temperatures were -18°C. Six days prior, on Tuesday, January 19, demand peaked at 10,817 MW, around 600 MW less, as prevailing temperatures were 5°C. When demand peaked at 11,401 MW on January 25 wind generation was 209 MW, a capacity factor of 12%. When demand peaked at 10,817 MW on January 19 wind generation was 1,259 MW, a capacity factor of 71%. In this example, wind output was 1,050 MW less when peak demand was 600 MW more, with both largely driven by the prevailing weather

[6] Uses hourly temperature data from Calgary, Edmonton, and Fort McMurray.

conditions. During cold temperatures there is normally an increase in demand and a reduction in wind supply, putting upward pressure on pool prices.

Figure 3: Daily peak demand and average wind generation in that hour (Q1 2021)



Temperatures declined again early in February; the daily average for Sunday, February 7 was around -30°C. A few days later, on Tuesday, February 9, demand peaked at 11,729 MW, a new record by 0.3%. As shown in Table 3, prevailing temperatures were slightly warmer during the peak on February 9 compared to temperatures during the previous record. In both cases pool prices were elevated, meaning it is likely that up to 400 MW of price-responsive load was electing not to consume electricity at the time. The supply cushion was materially higher during the peak demand on February 9 as less thermal capacity was on outage or derated.[7]

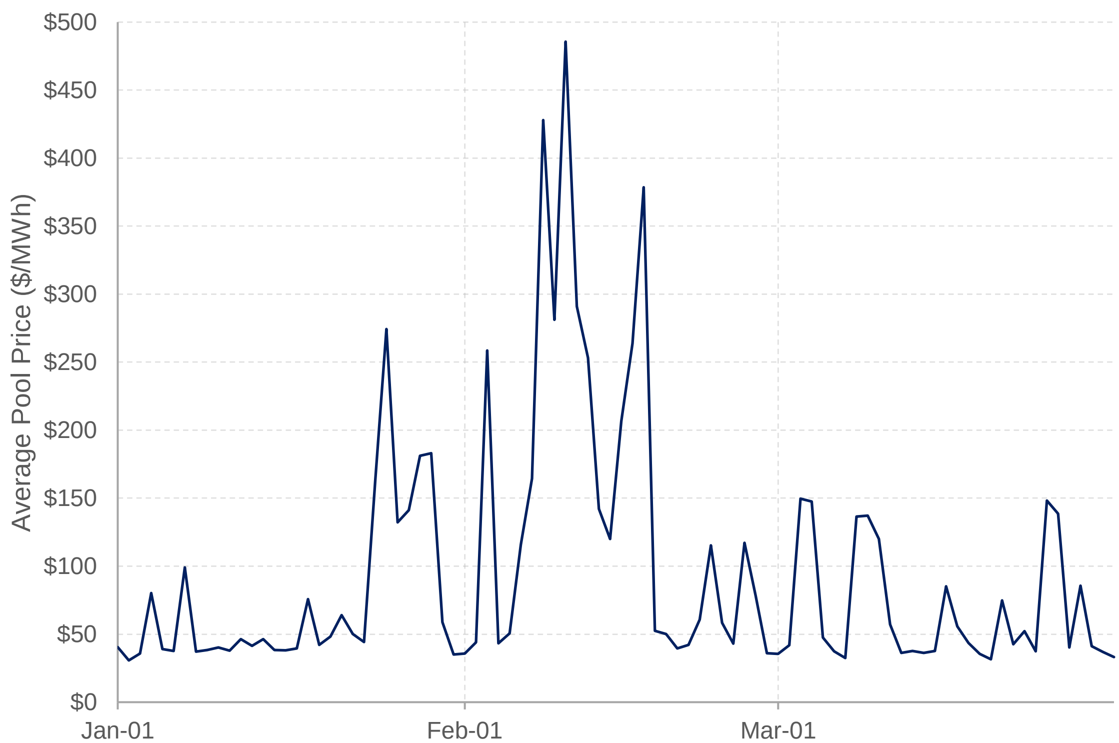
[7] The supply cushion is a summary measure of supply-demand conditions in the energy market at a particular point in time. The supply cushion shows how much available generation capacity the market has above that which is required to meet prevailing demand.

Table 3: The new record peak in AIL demand compared to the previous high

Date	Feb 9, 2021 (Tue)	Jan 14, 2020 (Tue)
Hour Ending	19	18
AIL demand (MW)	11,729	11,698
Pool price ($/MWh)	$567.60	$919.63
Average temp (°C)	-26	-31
Supply cushion (MW)	1,493	285
Wind generation (MW)	287	135

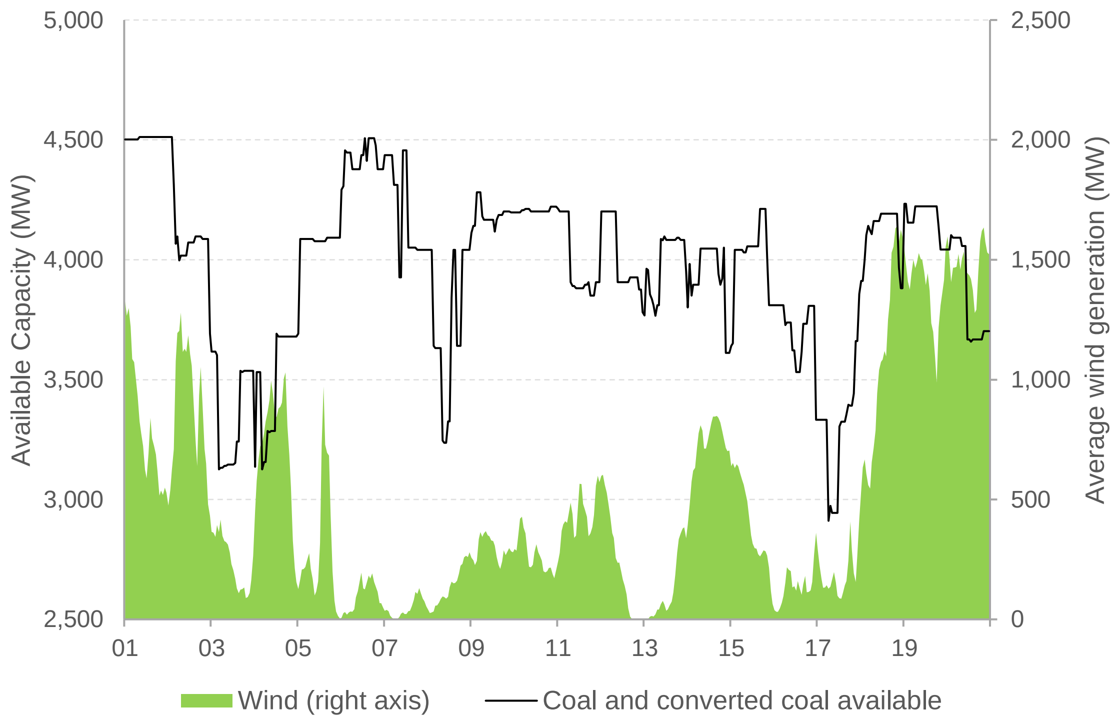
Figure 4 illustrates the daily average pool price in Q1 2021. As shown, pool price volatility was highest in late January and early-to-mid February when colder temperatures increased demand and reduced wind generation. In addition, pool price volatility was elevated by other factors including outages and the offer behaviour of some larger suppliers. The average nominal monthly pool price for February, $152/MWh, is the third highest since January 2001 behind July 2007, $156/MWh, and October 2006, $174/MWh.

Figure 4: Daily average pool price (Q1 2021)



The daily average pool price increased to $259/MWh on February 3, 2021 as a result of low temperatures, low wind generation, and thermal outages (Figure 5). Heading into the overnight off-peak hours of February 2 there was one large thermal unit on outage and two coal or converted coal assets were commercially offline.[8] The daily average price for February 2 was $44/MWh. Between HE24 of February 2 and HE05 of February 3 an additional two large thermal generators tripped offline and another became unavailable, meaning the total amount of thermal capacity offline was around 1,700 MW (including the capacity offline commercially). At approximately 5 a.m. on February 3 the AESO forecast indicated that it would not have sufficient capacity to maintain a 3% reserve margin during the super peak hours later that evening. In HE15 one of the large thermal assets that had tripped offline earlier came back online to provide generation over the super peak, and a supply shortfall event was avoided.

Figure 5: Available coal and converted coal capacity and wind generation by hour [9] (February 1 to 20, 2021)



The highest daily average pool price in the quarter was $486/MWh on Wednesday, February 10, when the daily average temperature was -28°C. As a result of the low temperatures, demand peaked at 11,665 MW and wind generation averaged 269 MW, a capacity factor of 15%. In addition, two thermal assets totalling around 600 MW were offline for operational reasons during many of the peak hours. That being said, supply cushion during peak hours averaged 1,329 MW, and the hourly supply cushion did not fall below 1,000 MW. This indicates the market was quite well supplied and that generator offer behaviour was a significant factor in the higher pool prices.

[8] The Sundance 5 asset has been mothballed since early 2018 and is not included in the outages numbers or capacity that was commercially offline.

[9] Available coal and converted coal capacity includes generation capacity that is offline commercially.

The pool price on February 10 peaked at $822/MWh in HE19 when 1,500 MW of thermal generation was offered above $100/MWh.

The lowest daily average pool price in the quarter occurred on Saturday, January 2 when the average pool price was $30.73/MWh. Temperatures on January 2 were mild, averaging -3°C, and load peaked at 10,721 MW, 8.6% less than the record demand set on February 9. Wind generation on January 2 was strong, averaging 1,490 MW, a capacity factor of 84%. Similar fundamentals of mild temperatures and strong wind generation meant pool prices were relatively low on a number of days in the quarter, particularly in early and mid-January, late February, and on a number of days in March. The daily average pool price was under $60/MWh for 59% of the days in Q1 2021.

A planned coal conversion outage began on Saturday, February 13 and on Wednesday, February 17 an additional three large thermal assets were offline on forced outages, meaning around 1,700 MW of coal or converted coal capacity was offline during some morning peak hours on February 17 (Figure 5). These outages combined with low temperatures (the daily average was -15°C) and low wind generation to put upward pressure on prices. The average pool price for the day was $379/MWh. In the following days temperatures increased, and generally stayed relatively mild for the remainder of the quarter (Figure 2).

The planned outage that started on February 13 ran through until March 27, after a separate planned coal conversion outage had begun on March 12. In some hours, despite the mild weather conditions, these planned outages did combine with other factors such as forced outages, low wind generation, and generator offer behaviour to put upward pressure on pool prices in late February and on some days in March. Price volatility during this period was lower than had been observed during the cold weather in late January and early-to-mid February (Figure 4).

In HE22 of February 21 the BC/MATL intertie tripped offline due to high wind speeds and the AESO was forced to shed 125 MW of under-frequency load service (UFLS) to prevent frequency from dropping further.[10] On the following day in HE19 the BC/MATL intertie tripped again because of icing at higher elevations and the AESO activated 208 MW of LSSi, but no under-frequency load. In both events the frequency dropped to a low of just under 59.5 Hz.

Following these frequency events, the AESO made use of the "Severe Weather Conditions" table[11] to determine the amount of LSSi required for available import capacity from February 22 until March 4. Subsequent to this, the AESO revised the normal weather table so that more LSSi is now required for a given level of demand and imports, in order to lower the risk of further frequency events. The increased LSSi requirements effectively reduce the amount of imports that can flow, particularly when higher pool prices are expected. This is because some LSSi providers are also price-responsive loads that are typically not consuming when prices are elevated and

[10] AESO Information Session: Learnings and Actions in Response to Recent System Events (March 9, 2021)

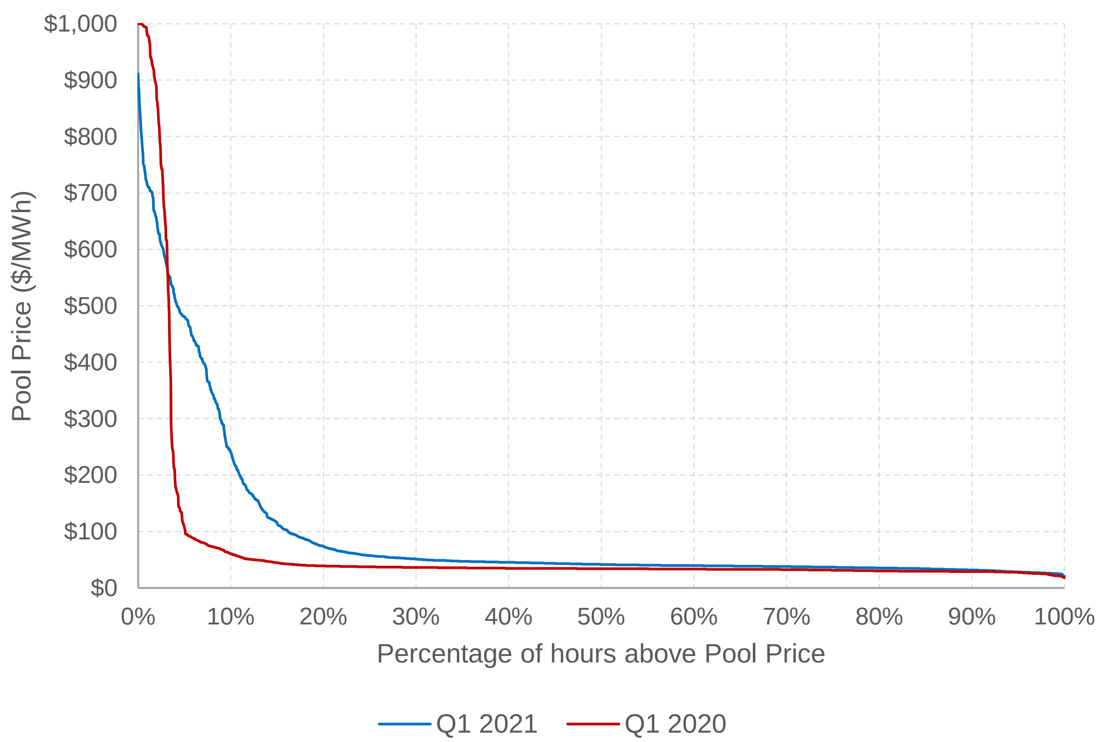
[11] AESO Information Document: ATC and transfer path management (ID #2011-001R) at page 12

then not available to provide LSSi. The reduced import Available Transfer Capability (ATC) was another factor putting upward pressure on pool prices for some hours in late February and March.

1.2.1 Pool price distribution

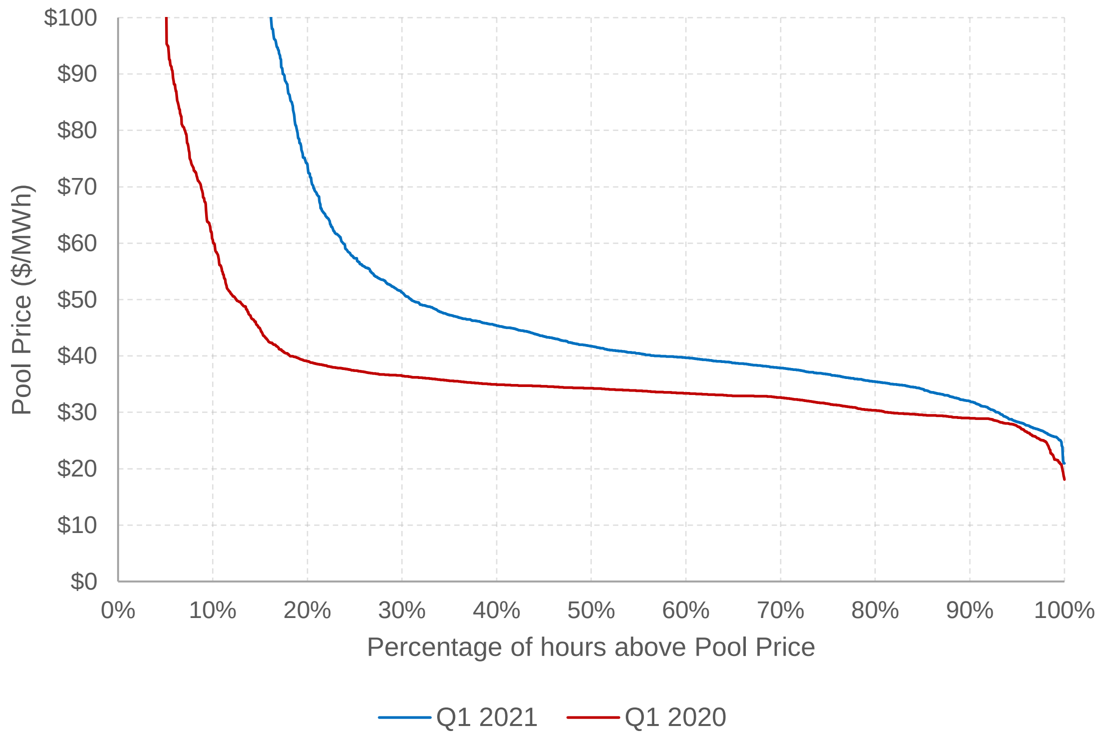
Figure 6 highlights the different distribution of pool prices in Q1 2021 compared to Q1 2020. The average pool price in Q1 2021 was 42% higher than Q1 2020. However, whereas the maximum pool price in Q1 2021 was $911.00/MWh, Q1 2020 had more pool prices that were at, or close to, the offer price cap of $999.99/MWh. These hours last year reflect relative scarcity events that occurred in Q1 2020. For instance, there were 62 hours in which supply cushion was under 500 MW in Q1 2020, compared with 5 hours in Q1 2021. In Q1 2021 there were more hours in which pool prices settled between $100/MWh and $800/MWh and this had an impact on the average pool price for the quarter. Further, in Q1 2021 the top 25% of hours in terms of pool price averaged $263/MWh and contributed 69% to the average pool price, compared to an average of $171/MWh and a contribution of 64% last year. Some of the higher pool prices year-over-year reflected changes in offer behaviour that were observed following the expiration of the PPAs.

Figure 6: The distribution of pool prices for Q1 2021 and Q1 2020



Pool prices that were relatively low in the distribution were also higher in Q1 2021 compared with Q1 2020 (Figure 7). For example, in Q1 2021 pool prices at or below the 50th percentile averaged $35.65/MWh in Q1 2021 compared to $31.09/MWh in Q1 2020, an increase of 15%. The upward pressure on lower-priced hours was partly due to the higher carbon price and also offer control changes, which resulted in more thermal capacity being taken offline commercially.

Figure 7: The distribution of pool prices for Q1 2021 and Q1 2020 (under $100/MWh)



1.2.2 Carbon price and generation fuel types

The carbon price increased from $30/tCO2e in 2020 to $40/tCO2e in 2021. This put upward pressure on pool prices because it increases the carbon costs for thermal generation assets. Table 4 provides some generalized carbon cost figures for select thermal generation types. It is important to note that carbon costs can vary within technology types depending on the efficiency of a given asset at a certain point in time, which will normally depend upon prevailing temperatures. The higher carbon price is shown to impact coal assets more than coal-to-gas and simple-cycle assets because coal assets are generally less efficient in terms of carbon emissions.

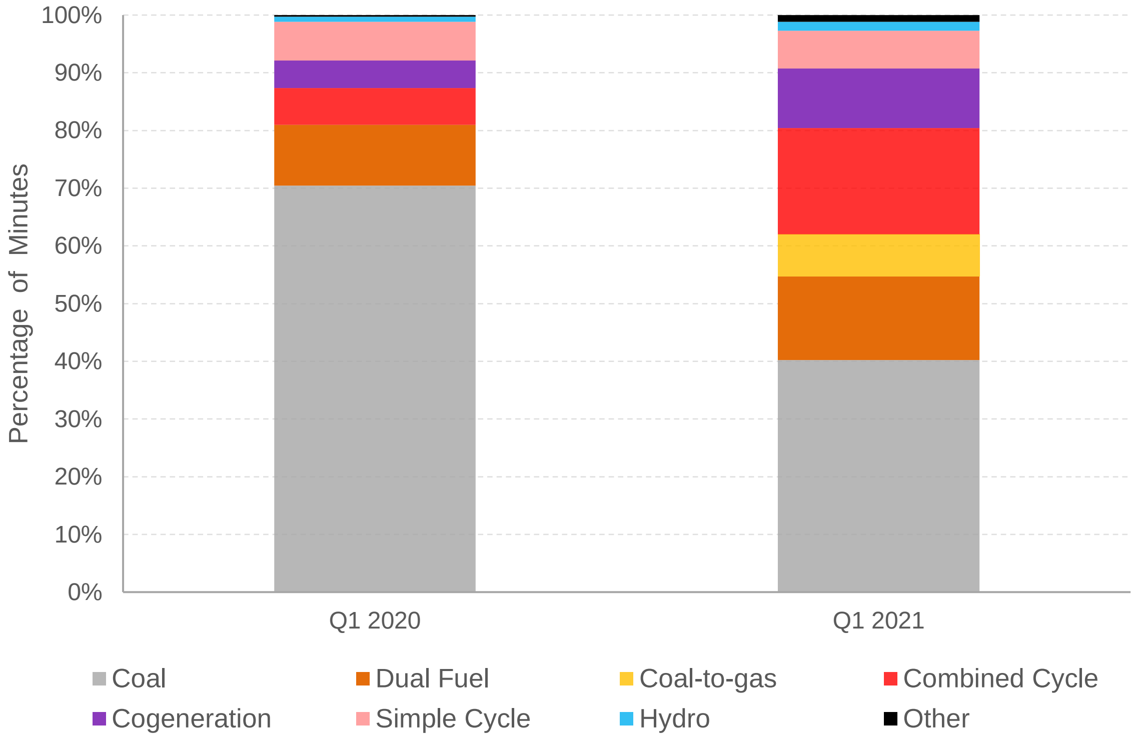
Table 4: Generalized heat rate, carbon emissions, and carbon costs for select thermal types

Generation type	Gas heat rate (GJ/MWh)	Carbon emissions (tCO2e/MWh)	2021 carbon cost ($/MWh)	2020 carbon cost ($/MWh)	Increase in carbon cost ($/MWh)
Combined-cycle	7	0.37	$0.00	$0.00	$0.00
Simple-cycle	10	0.50	$5.25	$3.94	$1.31
Coal-to-gas	11	0.55	$7.25	$5.44	$1.81
Coal	-	1.00	$25.20	$18.90	$6.30

Figure 8 illustrates the percentage of time different generation types set the System Marginal Price (SMP) in Q1 2021 compared to Q1 2020. As shown, there was a significant decline in the amount of time coal offers set the marginal price year-over-year. In Q1 2020, coal assets set the

SMP 70% of the time and in Q1 2021 coal assets set the price 40% of the time. This reduction is the result of more coal capacity being taken offline for commercial reasons, more coal capacity being offered higher in the supply curve, and the three coal conversions that took place in 2020. Dual fuel and coal-to-gas assets combined set the price in 22% of hours in Q1 2021 compared to 10% in Q1 last year, and combined-cycle assets also set the price more often.

Figure 8: Generation type setting system marginal price (SMP) in Q1 2020 and Q1 2021 [12]



Alberta has seen a number of coal assets increase their ability to utilize natural gas or convert completely to natural gas generation in recent years. In early 2018, Battle River 4 (BR4) was partially converted to natural gas firing, enabling up to 50% of generation to be gas-fired.[13] By the end of 2019, Battle River 5 (BR5) had been converted to dual fuel, enabling the unit to operate on coal and/or natural gas.[14] In spring of 2020, H.R. Milner (HRM) was repowered to a simple-cycle unit.[15] In the fall of 2020, Sundance 6 (SD6) was the first unit in Alberta to undergo a full coal-to-gas conversion, meaning existing equipment, such as the boiler, was adapted and new

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[12] The dual fuel category includes coal assets that have been converted to dual fuel and coal assets that have significantly increased their ability to burn natural gas. A coal unit is considered converted after the associated planned outage.

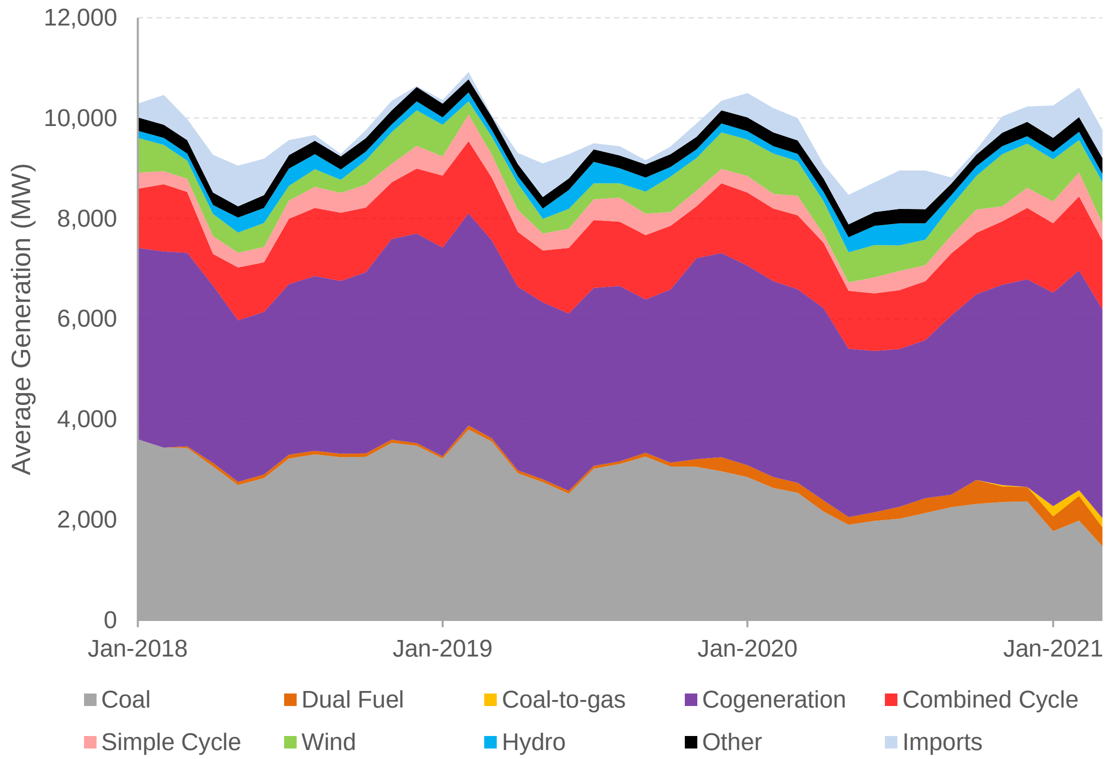
[13] ATCO 2018 Investor Day Presentation (September 14, 2018) at slide 35

[14] ATCO filings in AUC proceeding 23558 (August 16, 2019)

[15] Maxim Power Corp. Website, Power Projects

equipment, such as gas burners, was installed so the unit operates completely on natural gas.[16] The dual fuel conversion of Sheerness 2 (SH2) was completed in early 2020,[17] and the conversion outage for Sheerness 1 (SH1) was completed in late March 2021.[18] As shown by Figure 9 coal generation continues to decline and has largely been replaced by natural gas generation.

Figure 9: Monthly average generation by generation type (January 2018 to March 2021)[19]



1.3 PPA expirations

The PPAs came into effect on January 1, 2001 to help transition Alberta's wholesale electricity market from regulation to competition. The thermal PPAs were legislated contracts that set out the terms by which PPA Buyers compensated asset owners (PPA Owners) for operating and maintenance costs, in exchange for the right and obligation to offer the contracted capacity into Alberta's electricity markets and the associated revenues. These 'virtual divestitures' increased the number of suppliers in the wholesale market and served to increase competition.

[16] TransAlta Q4 and Annual 2020 Results presentation (March 3, 2021) at slide 4

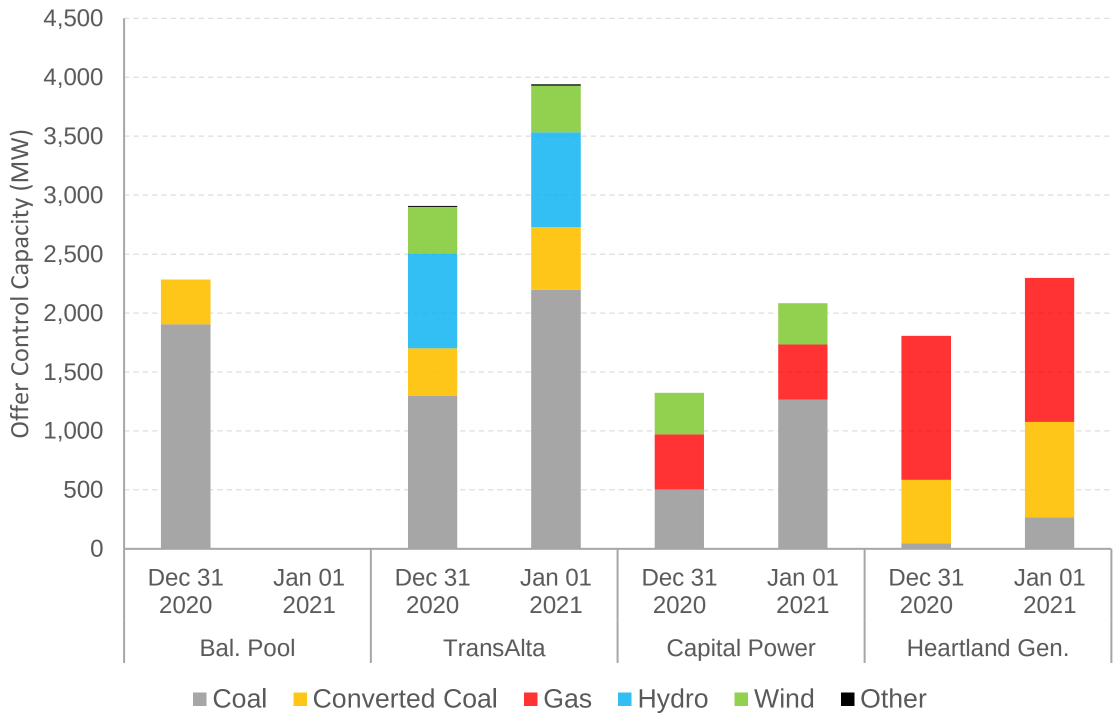
[17] TransAlta news release (May 12, 2020)

[18] TransAlta news release (March 3, 2021)

[19] These figures include generation which was used to serve on-site load

At the end of 2020 the remaining thermal PPAs pertaining to the assets at Genesee, Keephills, and Sheerness expired, along with the Hydro PPA (discussed in section 2.2 of this report). Figure 10 illustrates the offer control changes as a result of the PPA expirations for the former PPA Owners in the context of their other generation assets.

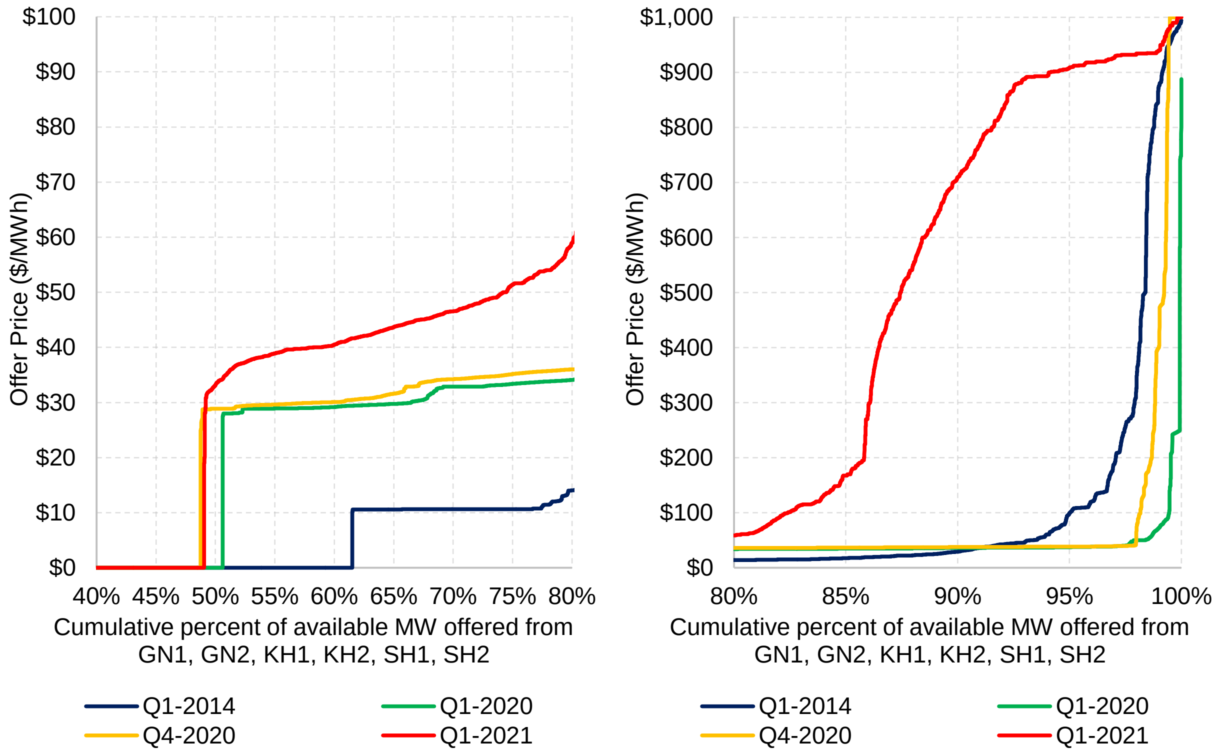
Figure 10: Offer control for select participants by generation type (December 31, 2020 to January 1, 2021)



The thermal assets with PPAs that expired on December 31, 2020 offered more capacity at higher prices in Q1 2021. Figure 11 compares offer duration curves for the combined capacity of these assets in four different quarters, including Q1 2021. Q1 2014 is used for comparison because it is the most recent Q1 that predates the Buyers' PPA terminations, and is prior to the commissioning of the Shepard combined-cycle unit.

The duration curves show the percentage of available capacity that was offered at or above a given price. For example, in Q1 2021 around 10% of the available capacity of these assets was offered above $710/MWh. The offer duration curve for Q1 2021 rises higher and earlier than it did during the three historical quarters. For these assets, the average price of offers from the 50th percentile and above was $262/MWh in Q1 2021. This is significantly higher than historical values; $55/MWh in Q1 2014, $37/MWh in Q1 2020, and $54/MWh in Q4 2020.

Figure 11: Offer price duration curves for Genesee 1&2, Keephills 1&2, and Sheerness 1&2



As shown by Figure 11, the Q1 2021 offer duration curve for these assets is higher than the previous quarters from the 50th to 99th percentile of offered capacity. Above the 85th percentile, the offer prices begin to differ significantly between Q1 2021 and the three historical quarters. For example 10% of the capacity offered from these assets was priced above $710/MWh in Q1 2021. This is materially higher than the 90th percentile of $29/MWh in Q1 2014, $36/MWh in Q1 2020, and $38/MWh in Q4 2020, even after taking into account increases in carbon costs.

Figure 12 shows the thermal capacity that was offered over $100/MWh in the highest-priced hour of each day from October 1, 2020 to March 31, 2021. The figure shows a distinct increase in high-priced thermal offers beginning in January. On average, 1,168 MW of thermal capacity was offered above $100/MWh during the daily peak price hour in Q1 2021, compared with 921 MW in Q1 2014, 418 MW in Q1 2020, and 742 MW in Q4 2020.

Figure 12: Thermal capacity offered above $100/MWh in the hour of the daily peak pool price (October 2020 to March 2021)

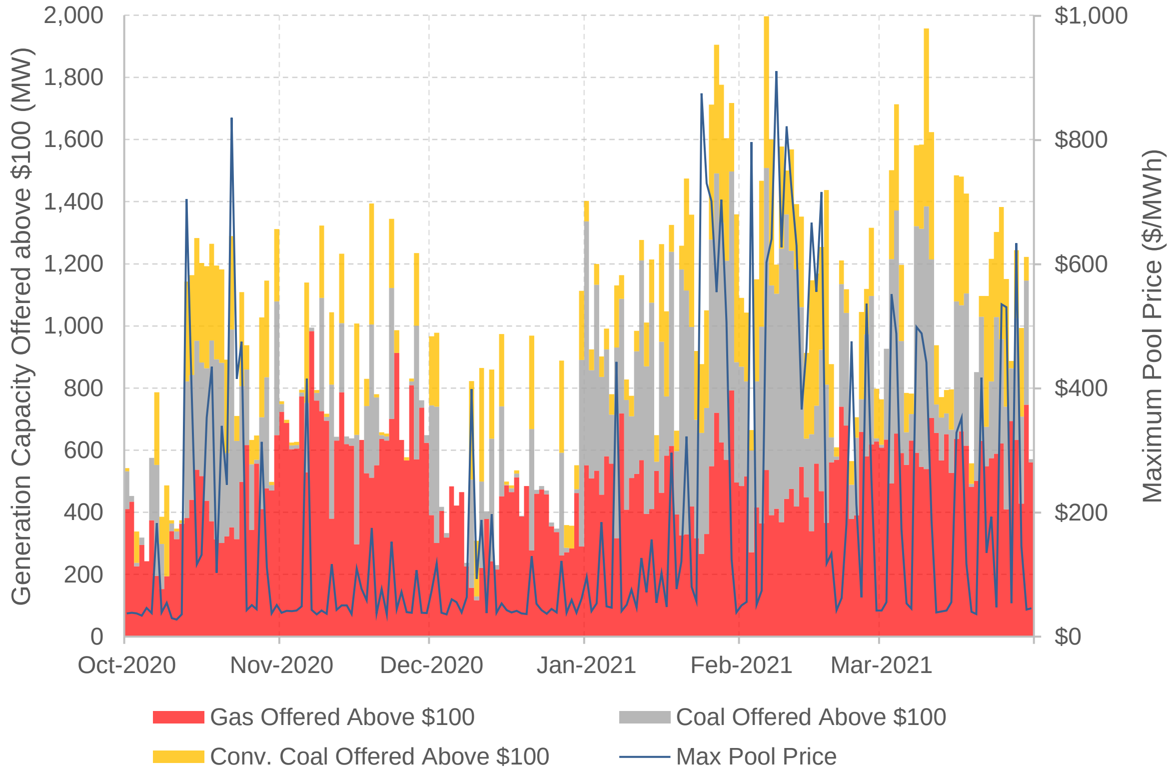
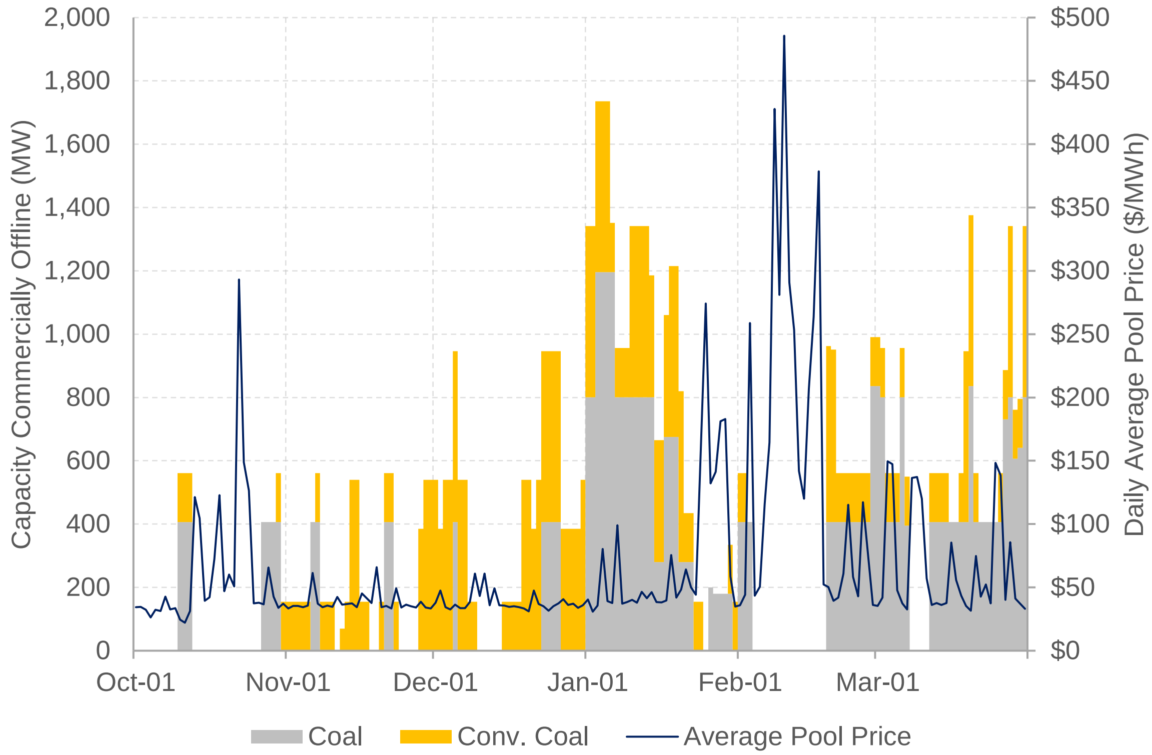


Figure 13 shows that more coal or converted coal capacity was taken commercially offline in Q1 2021 compared to Q4 2020. However, from February 4 through 18, no coal or converted coal assets were offline commercially as temperatures declined and pool prices increased, averaging $218/MWh on these days. The amount of coal or converted coal capacity that was commercially offline during the daily peak in pool price averaged 327 MW in Q1 2020, 252 MW in Q4 2020, and increased to 600 MW in Q1 2021. As shown by Figure 13, the amount of coal and converted coal capacity commercially offline was higher when pool prices were less volatile. On some days in early January around 1,700 MW of capacity was commercially offline.

Figure 13: Coal and converted coal capacity commercially offline coincident with the daily maximum pool price (October 2020 to March 2021)



As a result of higher offer prices, elevated pool prices have been observed for hours with a relatively large supply cushion. Figure 14 and Figure 16 provide scatterplots of pool prices against supply cushion, comparing Q1 2021 to Q1 2020 and Q1 2014, respectively. Figure 15 illustrates the same scatterplot for Q1 of 2021 and Q1 2020, but only for hours in which the pool price was less than or equal to $100/MWh. The figures illustrate that there were a number of high-priced hours in Q1 2021 when supply cushion was relatively high. For example, in some hours the pool price settled at over $500/MWh with slightly less than 2,000 MW of supply cushion. These outcomes were not observed in Q1 2020 or Q1 2014 (Figure 14 and Figure 16).

Pool price variance was higher in Q1 2021 compared to the historical quarters, especially for hours with higher supply cushion. The count of hours that settled above $100/MWh with a supply cushion of over 1,000 MW was 266 in Q1 2021, which is higher than Q1 2014, Q1 2020, and Q4 2020, which had counts of 113 hours, 15 hours, and 37 hours, respectively. Pool price increases were also observed during hours with very high supply cushions (Figure 15). In Q1 2020, the average off-peak pool price when supply cushion was over 2,000 MW was $29.43/MWh. This increased to $37.40/MWh in Q1 2021. This increase is partly due to the higher carbon costs for thermal generation assets that are associated with the rise in carbon price (Table 4). In addition, more units were taken offline commercially in Q1 2021 which may have put upward pressure on pool prices during these hours.

Figure 14: Scatterplot of supply cushion and pool price (Q1 2021 and Q1 2020)

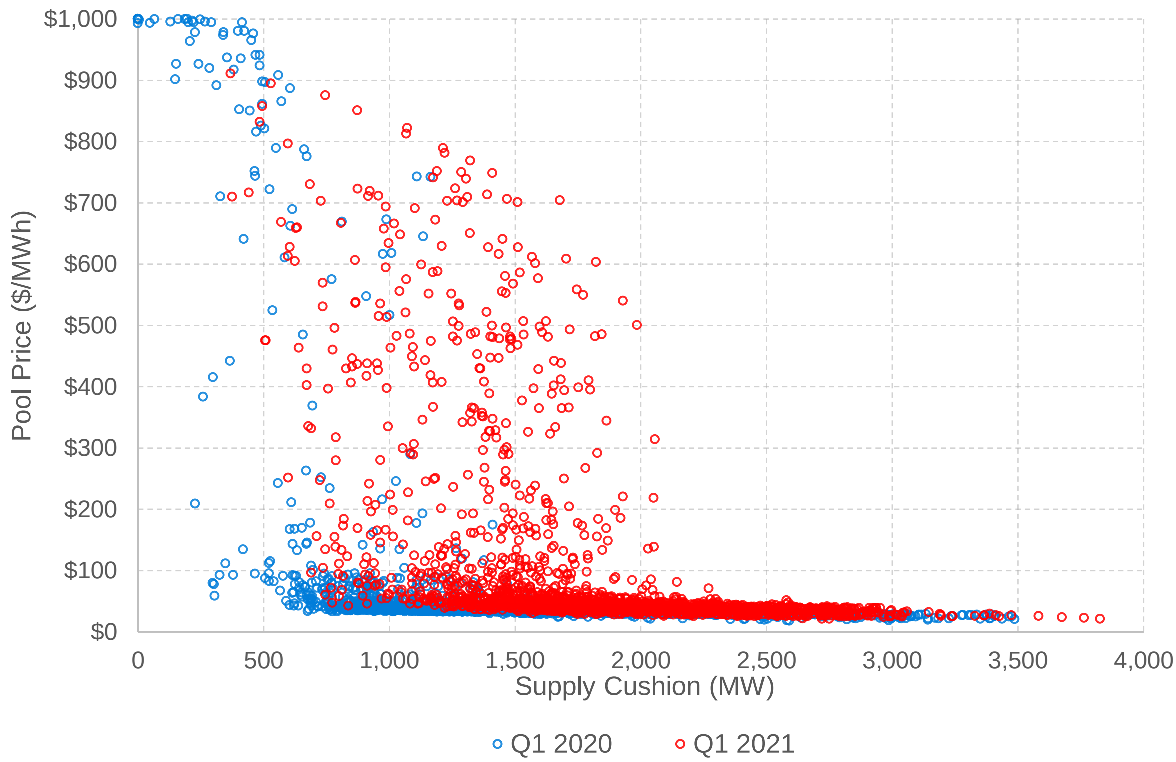


Figure 15: Scatterplot of supply cushion and pool price, up to $100/MWh (Q1 2021 and Q1 2020)

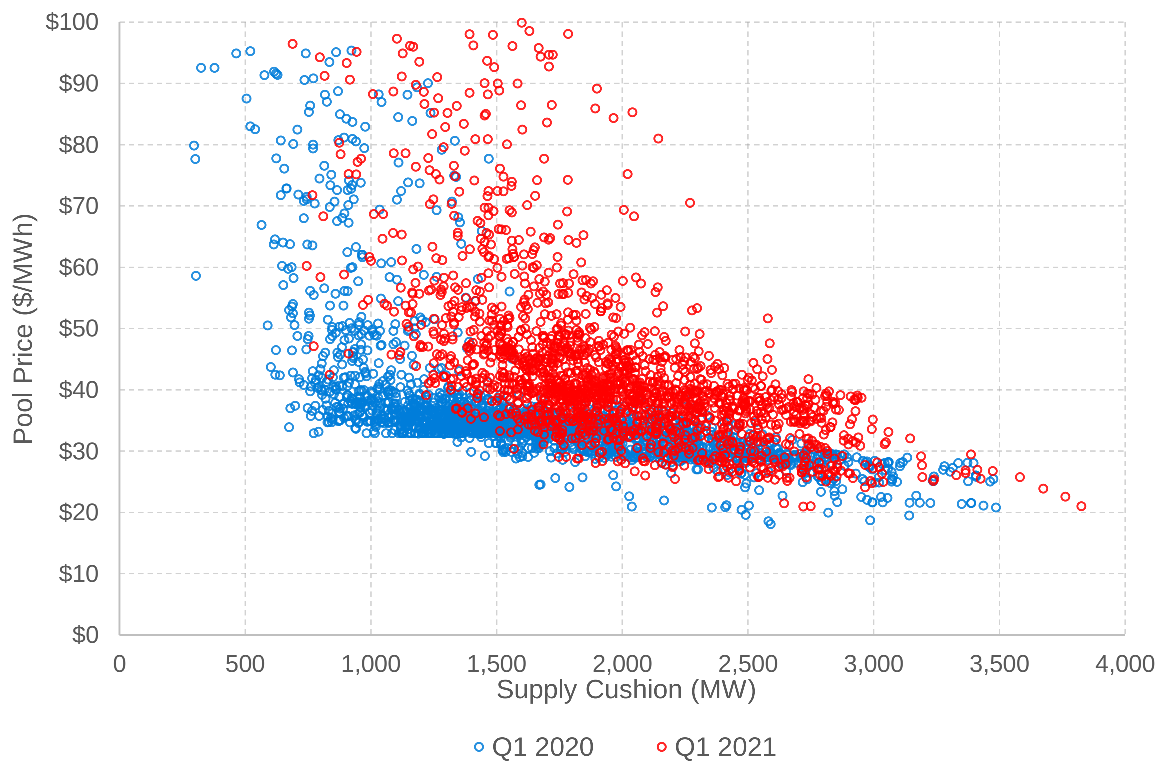
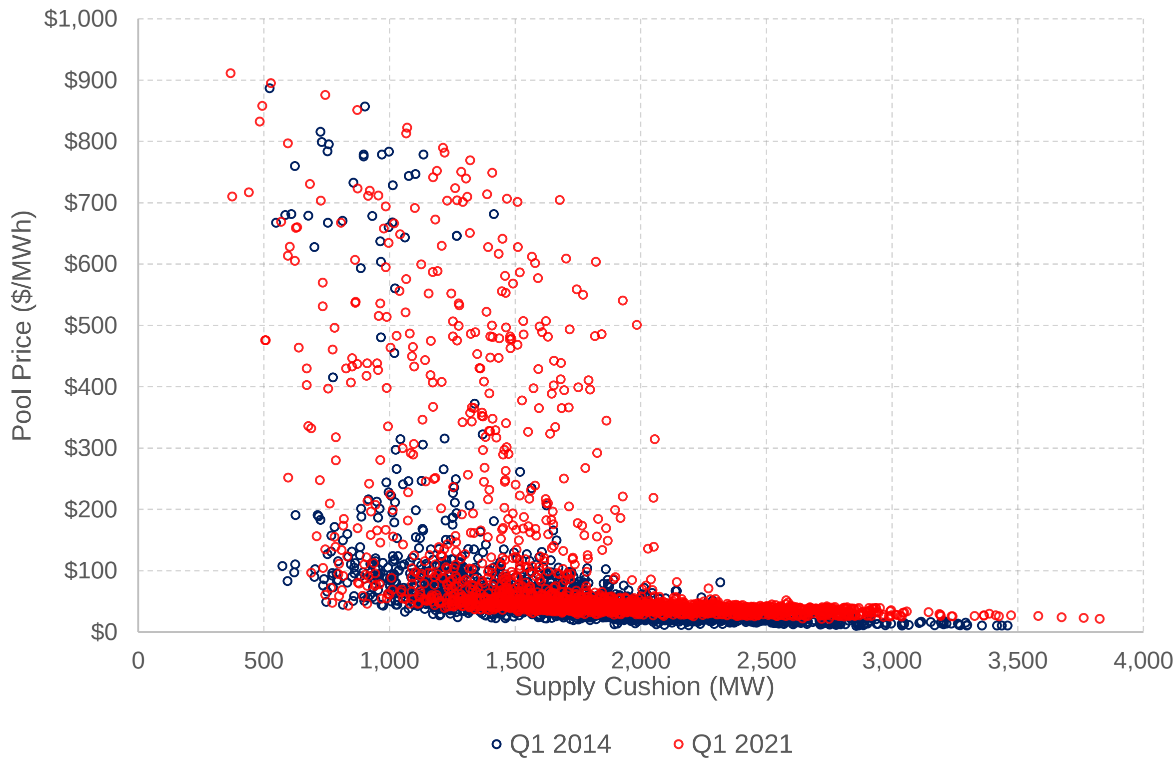


Figure 16: Scatterplot of supply cushion and pool price (Q1 2014 and Q1 2021)



1.4 Interties

Imports into Alberta were significant in 2020 and this trend continued into Q1 2021. Average hourly net imports in Q1 2021 were 596 MW compared to 473 MW in Q1 last year, an increase of 26%. As shown by Figure 17 imports were high for much of the quarter and were generally higher around the pool price volatility in late January and early February, with imports averaging more than 800 MW during the peak hours on a number of days. In mid-February there was some export activity as power prices increased at large trading hubs such as SP15 in California, North hub in the Southwest Power Pool (SPP), and also in Mid-Columbia (Mid-C). The volume of imports declined slightly in March as pool price volatility was lower and also because the AESO increased the LSSi requirements for imports to flow.

Figure 17: Daily Average imports (+ve), exports (-ve) and the AB – Mid-C price differential, peak hours (Q1 2021)

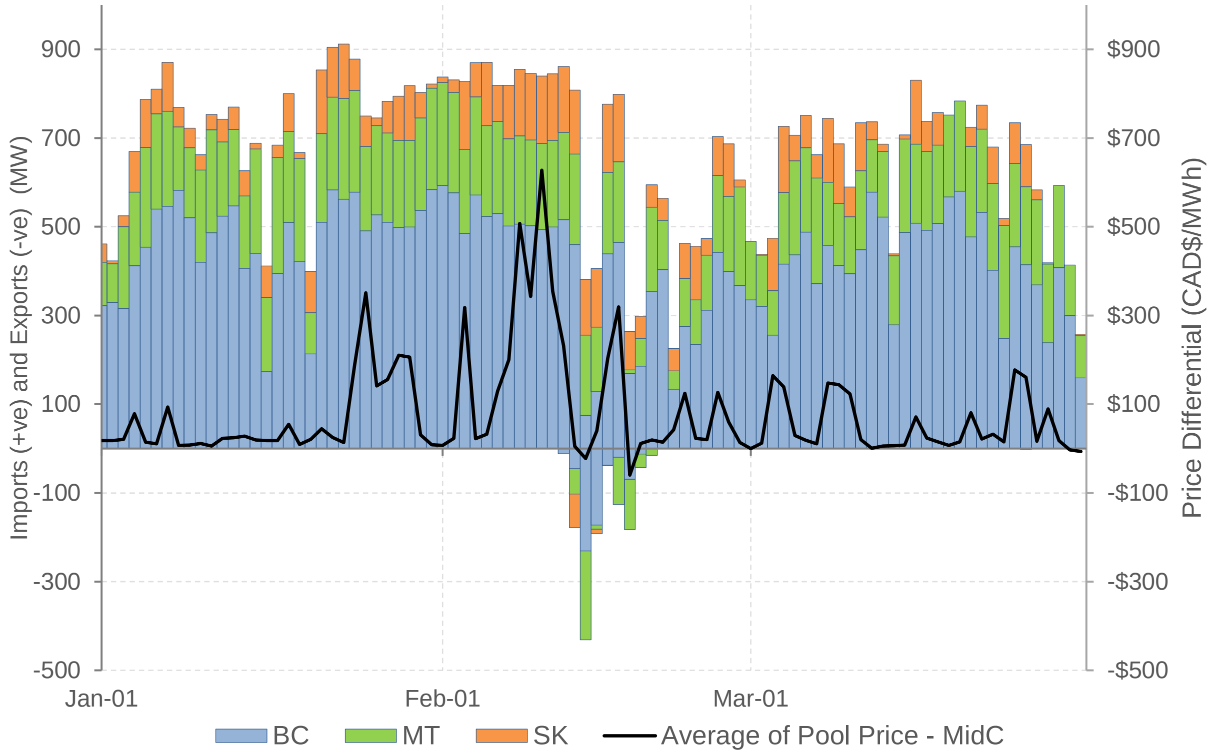
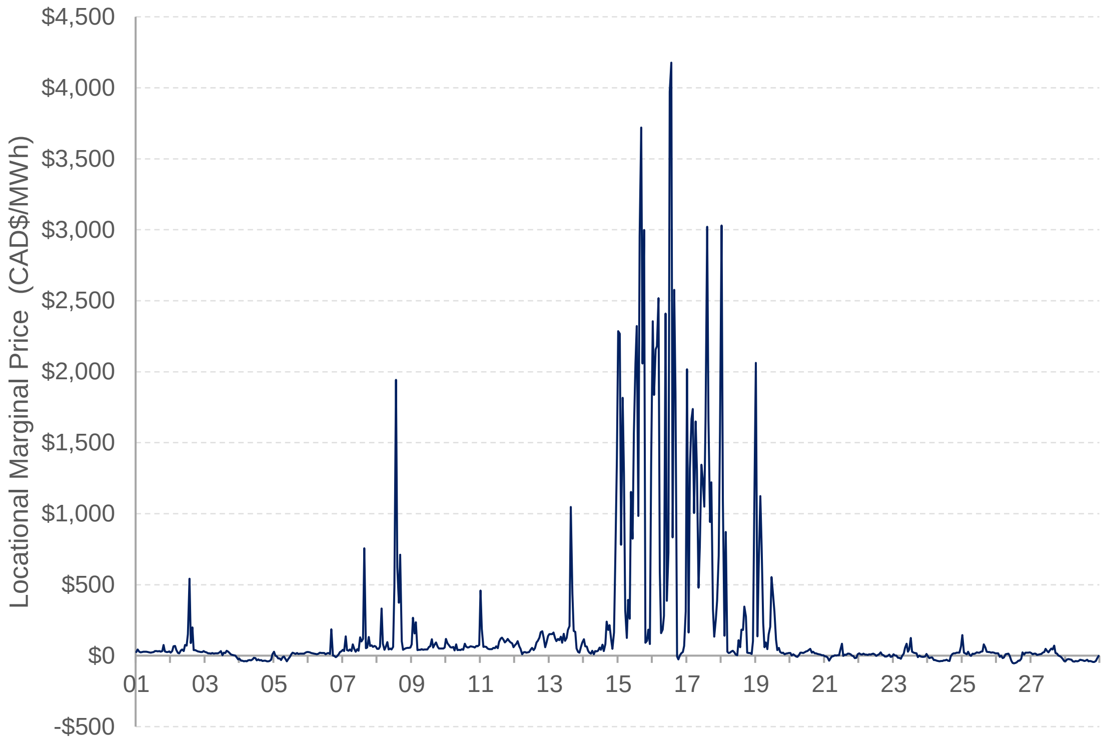


Figure 18 illustrates the hourly locational marginal price (LMP) at North hub in SPP. As shown, prices in SPP were volatile in mid-February as the polar vortex moved south, increasing power and natural gas prices in a number of jurisdictions. Power prices at North hub in SPP were above the AESO price cap of $1,000/MWh on a number of occasions, attracting some exports from Alberta via the Montana and Saskatchewan interties in mid-February despite the Alberta pool price being elevated to around $700/MWh in some instances.

Figure 18: Real-time market prices at North hub in SPP, converted to CAD (February 2021)[20]



1.4.1 BC/Montana intertie

The BC/MATL flow gate consists of interconnections to British Columbia and Montana and is Alberta's largest intertie, allowing participants to flow power to and from power trading hubs such as Mid-C and California. An efficient market is expected to result in electricity flowing from places where price (and cost) is low to where price (and cost) is high. This is expected to occur as a result of traders scheduling exports from low price markets and associated imports into high price markets.

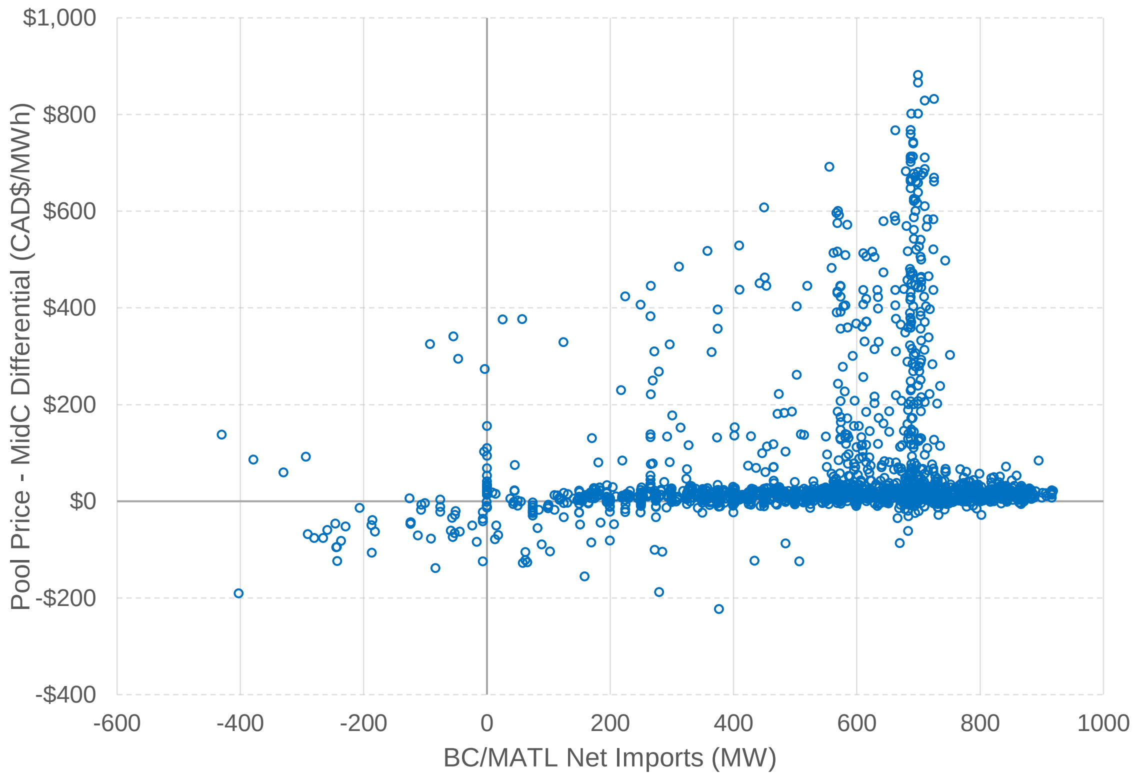
Figure 19 shows a scatterplot of hourly net imports on BC/MATL against the hourly price differential between Alberta and Mid-C. Points in the top-right and bottom-left quadrants indicate the direction of net flow on BC/MATL was economic based on realized prices in Alberta and Mid-C. The top-right quadrant indicates that the Alberta pool price was greater than the prevailing price in Mid-C and the hour observed net imports into Alberta.

As shown, there is a large cluster of points around the horizontal axis and to the right, indicating a large number of hours in which the price differential was relatively small and there was a net flow of power into Alberta. One potential explanation for this is that traders may have assessed a higher upside risk to pool prices in Alberta relative to the price of purchasing power from Mid-C.

[20] For data access see: SPP Marketplace - Menu > Markets > RT Balancing Market > LMP by Location > SPPNORTH_HUB *(link works outside of a VPN).* The USD prices have been converted to CAD using the Bank of Canada's daily exchange rate.

In hours when the Alberta pool price was materially higher than Mid-C, there were generally 600 MW to 700 MW of imports scheduled. Import transmission capacity during high pool price hours is often constrained by the availability of LSSi. The availability of LSSi can decline when pool prices are high because some LSSi providers are price-responsive loads that reduce their consumption when prices rise. This explains why higher levels of imports are often feasible at lower pool prices (Figure 19).

Figure 19: Scatterplot of BC/MATL net exports and Mid-C – Alberta price differential (Q1 2021)[21]

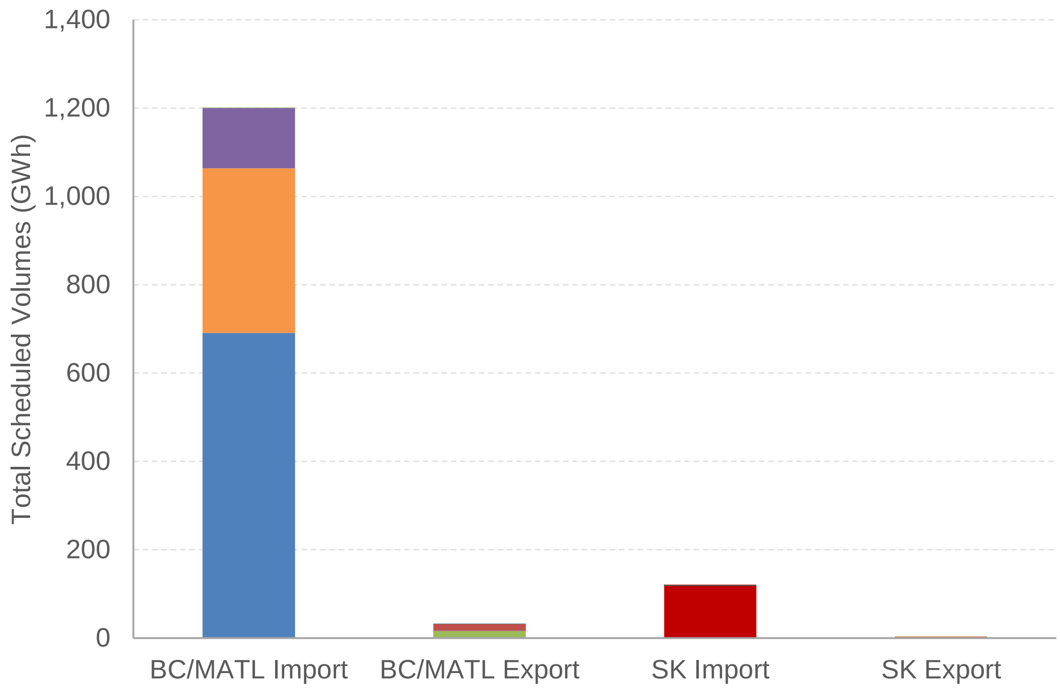


1.4.2 Participation on the interties

The trading and flow of electricity in and out of Alberta in Q1 2021 was largely dominated by a small number of market participants. The volume of electricity traded across Alberta's interties with (i) British Columbia and Montana and (ii) Saskatchewan in Q1 2021 is shown by market participant in Figure 20. The figure shows that imports into Alberta on the BC/MATL intertie had the most volume of flow by far. Imports on the BC/MATL intertie in Q1 2021 were largely carried out by two market participants, with one participant typically importing power on the connection with BC and the other on the Montana line. The limited number of intertie participants means that the MSA closely monitors this aspect of the electricity market to ensure fair, efficient, and open competition.

[21] Mid-C prices were converted from USD to CAD using the Bank of Canada's daily exchange rate.

Figure 20: Intertie scheduled flows by market participant in Q1 2021 [22]



1.4.3 Load Shed Service for Imports (LSSi)

LSSi is an ancillary service procured by the AESO to facilitate higher volumes of imports into Alberta. LSSi allows the AESO to increase the ATC of the BC/MATL intertie by contracting with Alberta loads to trip power consumption in the event that system frequency decreases due to the intertie tripping offline when import volumes are high. LSSi providers are paid for availability, arming, and tripping in the event they are tripped to arrest the drop in frequency.

Following the frequency events on February 21 and 22, which in turn followed frequency events on June 7 and October 16, 2020, the AESO used the severe weather table to determine the amount of LSSi required for imports on BC/MATL between February 22 and March 4. Ultimately this meant more LSSi was required for a given level of imports and demand, meaning import ATC on BC/MATL was generally reduced. Beginning in HE12 of March 4, the AESO enacted a new table for LSSi requirements under normal weather conditions, increasing the amount of LSSi by 50 MW compared to the prior version, and also requiring LSSi volumes at lower levels of imports.[23]

Figure 21 illustrates the total volumes and cost of LSSi by month in the context of total import and export volumes on BC/MATL. In each month of Q1 2021 the total cost of LSSi was around $4 million as the total arming volume was similar. These monthly costs are lower than the highs seen

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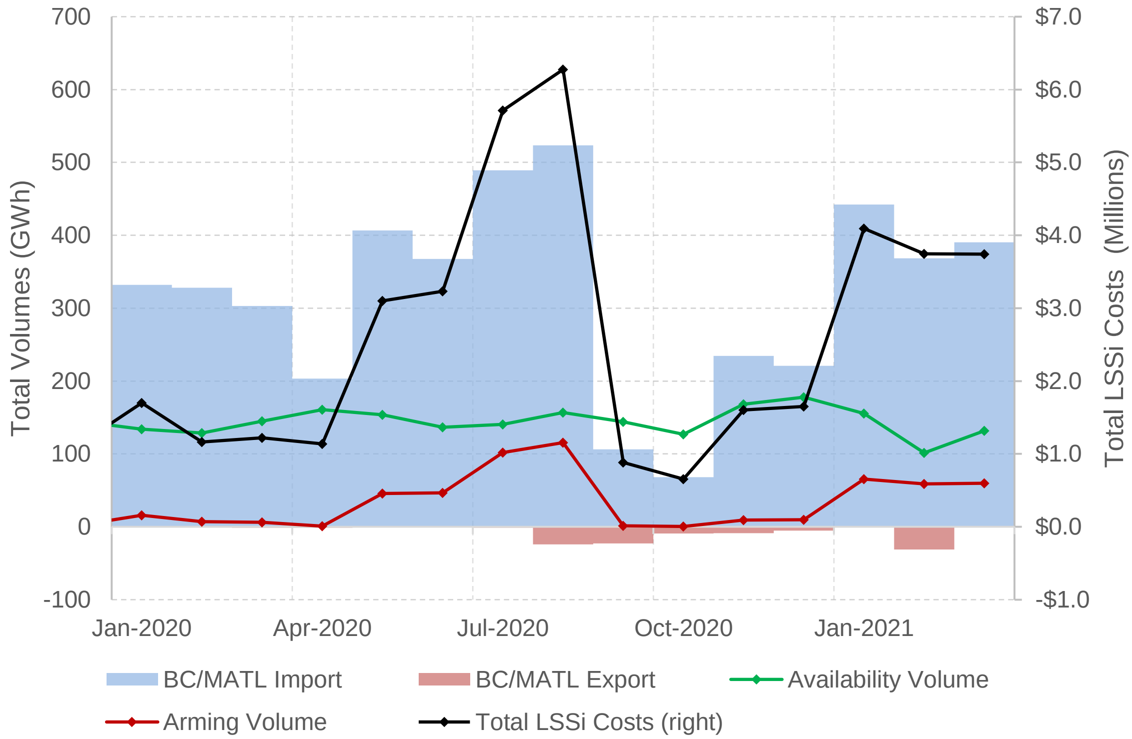
[22] Each colour denotes a different market participant.

[23] AESO Information Session: Learnings and Actions in Response to Recent System Events (March 9, 2021) slide 28

AESO Information Document: ATC and transfer path management (ID #2011-001R) last year in July and August, around $6 million, largely because the total volume of imports was lower in Q1 2021.

Figure 21: BC/MATL import and export volumes, LSSi volumes, and LSSi costs by month (January 2020 to March 2021)



1.5 Carbon price and renewables

On December 11, 2020 the federal government outlined its climate plan. The plan proposed a carbon price rising from \$40/tCO2e in 2021 to \$50/tCO2e in 2022 and thereafter increasing at \$15/tCO2e annually to \$170/tCO2e in 2030. On March 25, the Supreme Court of Canada ruled that the *Greenhouse Gas Pollution Pricing Act* (GGPA), which imposes minimum standards for carbon pricing on the provinces, is constitutional.

As discussed in section 1.2, a higher carbon price increases the carbon costs for thermal generation such as coal, coal-to-gas, and simple-cycle natural gas. Higher carbon prices also have implications for renewable generation, such as wind and solar.

The provincial system for pricing carbon emissions from large emitters as set out in the *Technology Innovation and Emissions Reduction Regulation* (TIER Regulation) is similar to the federal output based pricing system included in the GGPA. So far, TIER has been considered to meet the federal pricing and emissions reduction targets.[24] Carbon prices used for the TIER fund

[24] Government of Canada, news release (December 6, 2019)

credit in 2020 and 2021 have been consistent with the federal scheme and are expected to be kept in tandem in the future to maintain compliance with the federal benchmark.

The TIER Regulation allows for two different and mutually exclusive schemes for renewable generation to receive revenues in relation to carbon policy: emission offsets and emission performance credits.[25] The former is based on electricity grid displacement factor while the latter is based on the high-performance benchmark set out in the TIER Regulation.

Table 5: Carbon emissions offset by year [26]

Year	Carbon price ($/tCO2e)	Displacement factor (tCO2e/MWh)	Carbon emissions offset ($/MWh)
2015	$15.00	0.59	$8.85
2016	$20.00	0.59	$11.80
2017	$30.00	0.59	$17.70
2018	$30.00	0.59	$17.70
2019	$30.00	0.59	$17.70
2020	$30.00	0.53	$15.90
2021	$40.00	0.53	$21.20

Table 5 illustrates how the prevailing carbon price and the grid displacement factor determine the price for emission offsets. This is the highest price a renewable supplier can attain for its emission offsets within the given year, although emission offsets can be carried over and sold in future years. As with a higher capacity factor, a higher offset price will increase offset revenues for renewable generation.

Figure 22 illustrates a breakdown of the estimated revenues for wind generation (per MWh) from 2015 to 2020, using the hourly capacity factor of total wind generation in Alberta. This analysis assumes that all carbon offsets are sold in the year they are produced and for the full offset price.

In 2017 the estimated revenue from carbon offsets increased to roughly 50% of total revenue as the carbon price increased. Pool prices were higher in 2018, increasing energy revenues for wind, and the carbon offsets fell as percentage of total revenues to around a third, with similar percentage levels observed in 2019 and 2020.

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[25] TIER Regulation: Part 2, Opted-In and Aggregate Facilities

[26] Alberta Government: Carbon Offset Emission Factors Handbook (version 1.0), March 2015 at Table 2

Alberta Government: Carbon Offset Emission Factors Handbook (version 2.0), November 2019 at Table 1

Figure 22: Revenue estimates using the capacity factor of total wind (2015 to 2020)[27]

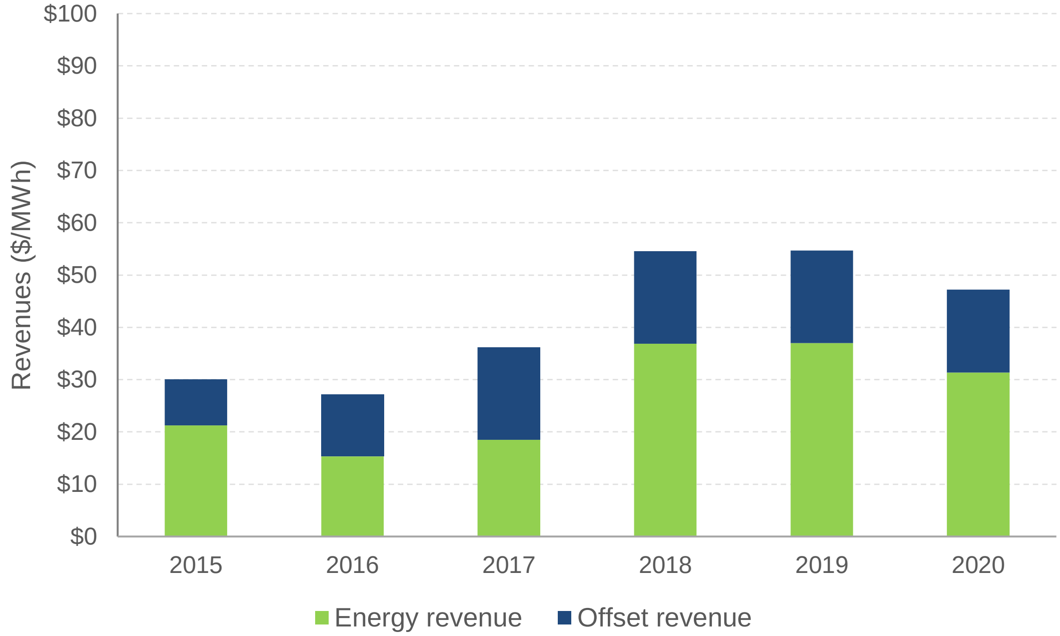
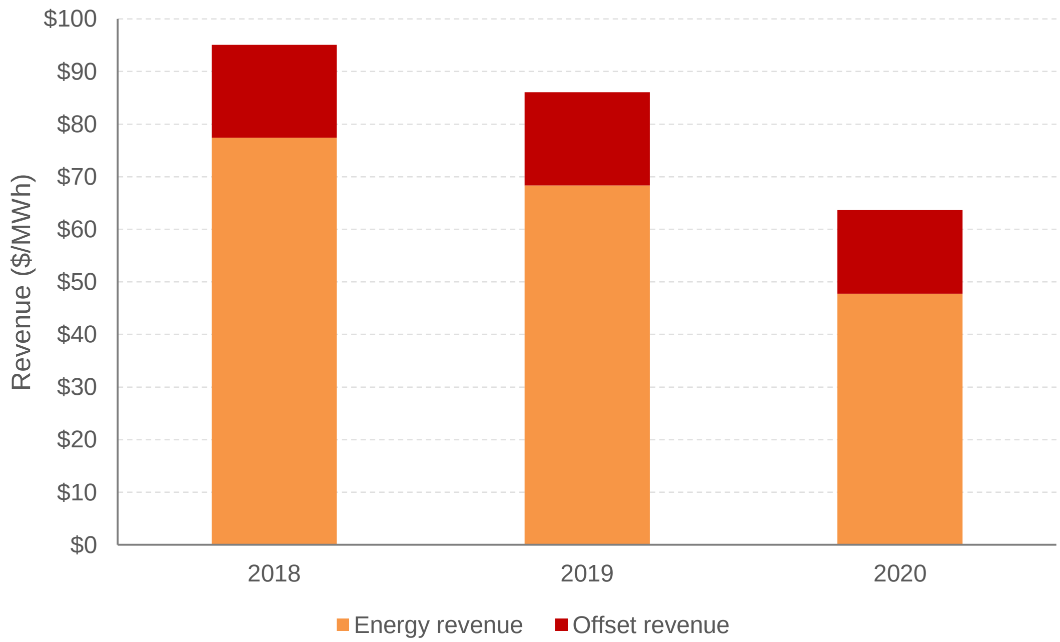


Figure 23: Revenue estimates for solar generation (2018 to 2020)[28]



[27] The capacity factor calculation only includes a new wind asset once it has generated above a capacity factor of 30% in a given hour. Energy revenues are net of estimated transmission losses and the AESO trading charge.

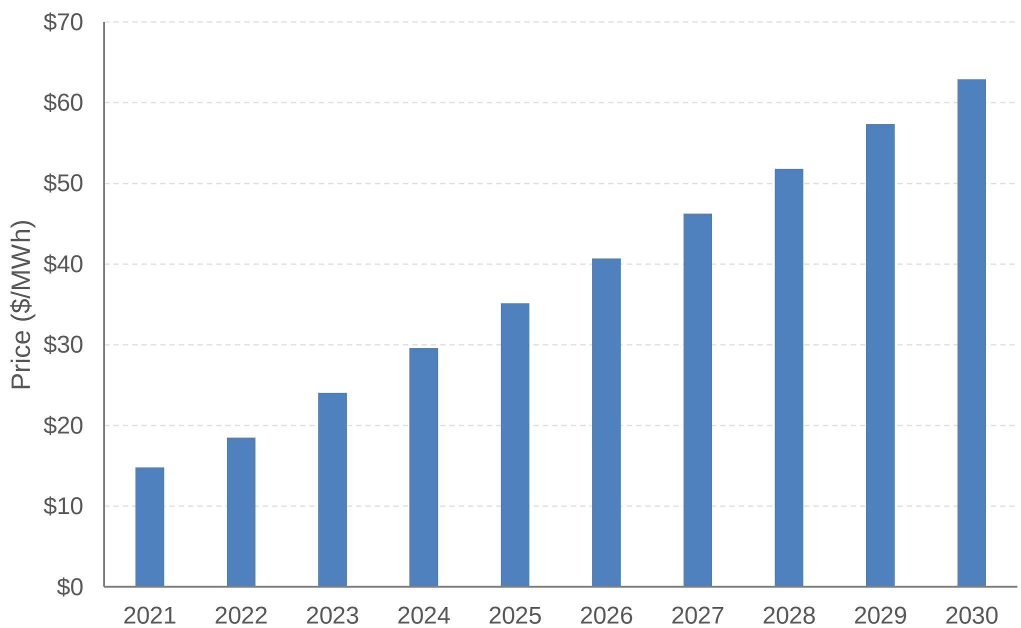
[28] Energy revenues are net of system average transmission losses and the AESO trading charge.

Figure 23 shows the breakdown of estimated revenues for solar, using the methodology outlined in the net revenue analysis discussed in our Q4 2020 report.[29] The offset revenues for solar are a smaller percentage of total revenues than for wind, accounting for 19% to 25% of estimated revenues. This is largely because solar generation has a lower capacity factor than wind (an average of 17% compared to 35% for wind), and because solar is normally providing energy when pool prices are higher.

Looking ahead, the grid displacement factor is expected to decline materially in the coming years as combined-cycle assets replace coal generation, and wind and solar generation increase. By 2030 when combined-cycle, cogeneration, and renewables are expected to be the major generation sources, the displacement factor may be approximately 0.25 tCO2e/MWh, well below the current benchmark of 0.37 tCO2e/MWh.

Under the current framework, renewable generation assets of a capacity 5 MW or greater are able to opt into the TIER Regulation[30] and collect emission performance credits (EPC), which are based on the prevailing price of carbon and the emissions benchmark. The emissions benchmark is set to be at or around 0.37 tCO2e/MWh for the coming years, based on the emissions intensity of an efficient combined-cycle unit. At an anticipated carbon price of $170/tCO2e in 2030, an emissions benchmark of 0.37 tCO2/MWh would imply an EPC price of $62.90/MWh (Figure 24). The EPC price does not include revenues that could be obtained in the energy market.

Figure 24: Potential value of emission performance credits (2021 to 2030)



[29] MSA Q4 2020 report (February 12, 2021) see section 1.6

[30] Alberta Government TIER Opt-In Fact Sheet (July 2020)

To put the potential future value of EPCs into context, the Renewable Electricity Program (REP) was able to purchase wind capacity in Alberta across three auctions for weighted-average prices of between $37/MWh and $40/MWh in 2017 and 2018.[31]

This comparison may underestimate the costs of wind generation if capital and fixed costs increase over time due to inflationary pressures. That being said, the costs of wind generation have fallen significantly in recent years and, if they keep falling, the use of the auction results may overestimate generation costs going forwards, and understate the significance of potential EPC revenues on the economics of wind assets in the coming years.

This analysis shows that for wind generation assets, assuming an increasing carbon price in the presence of the current emissions benchmark, the revenue from the sale of environmental attributes may be sufficient in the future to cover all generation costs without the need for any revenue from the sale of electricity in the power pool. In alternative scenarios where the revenue from the sale of environmental attributes does not cover all generation costs, the significance of this revenue may provide an enduring incentive for ever increasing investment in wind generation capacity.

While investment of this sort would increase supply and result in lower and more volatile pool prices in the short-run, the effects on long-run efficiency, competition, and incentives to invest in other types of generation capacity are unclear.

Given that Alberta's minimum pool price is $0/MWh, negative revenue from the sale of electricity in the power pool is not currently possible. The impact of this limit on the ability of the market to efficiently allocate resources in the short-run is likely to grow through time and the market may be limited in its capability to control investment in this type of generation capacity for which a key source of revenue is outside the market.

1.6 Market share offer control 2021

The MSA will begin publishing market share offer control (MSOC) metrics in its quarterly report. With this change, the MSA will be 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 2021 market share offer control as well as future market share offer control metrics can be found 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:

[31] Alberta Government Renewable Electricity Program

(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 (Process).[32]

1.6.2 Assessment of offer control

In accordance with the Process, the MSA calculated offer control with data obtained from the AESO for January 10, 2021 hour ending 17. On February 26, 2021, 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 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 be typically 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.

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

Table 6: Market share offer control of electricity market participants with greater than 5% offer control

	2021-01-10	
Company	**Control (MW)**	**%**
TransAlta	3,940	25.1%
Heartland Generation Ltd.	2,298	14.6%
Capital Power	2,085	13.3%
ENMAX	1,452	9.2%
Suncor	1,182	7.5%
Other	4,416	28.1%
Total Dispatchable	15,373	97.9%
Total Non-dispatchable	327	2.1%
Grand Total	**15,700**	**100.0%**

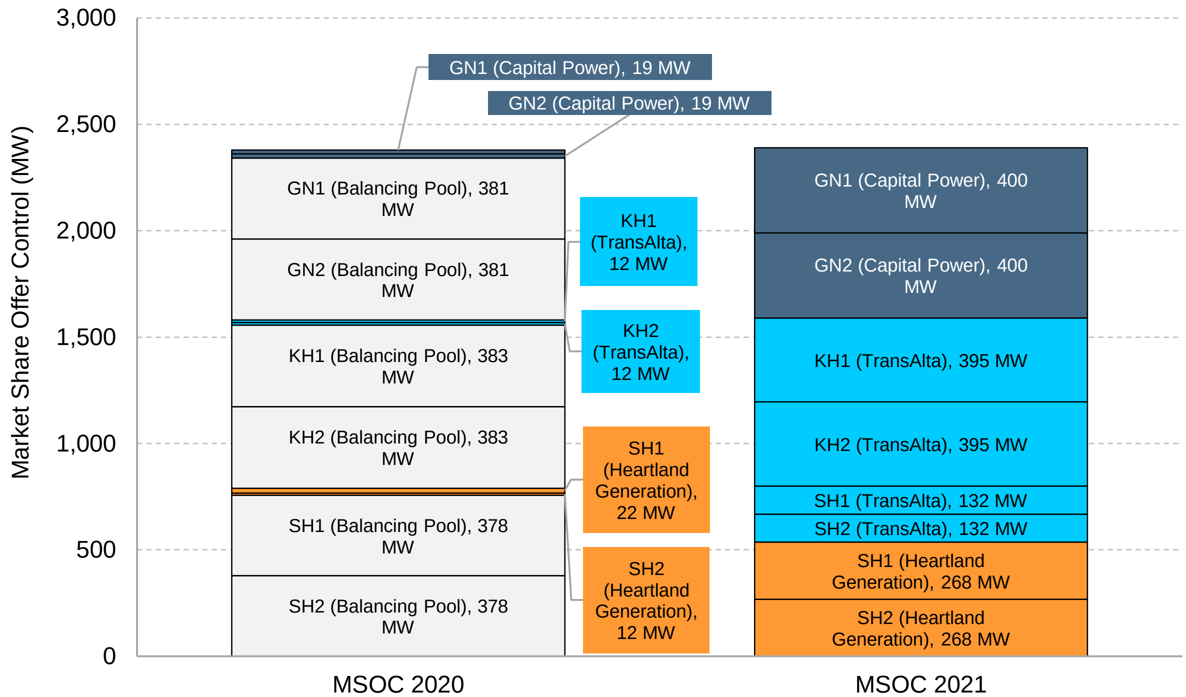
Total offer control for participants with greater than five percent MSOC decreased slightly from 71.3% in 2020 to 69.8% in 2021. However, individual offer control for the largest market participants changed significantly with the expiry of the PPAs.

At end of day on December 31, 2020 the PPAs held by the Balancing Pool expired and offer control was reallocated to the PPA Owners. As a result, the Balancing Pool's 2,284 MW of offer control was divided between TransAlta (+1,030 MW), Capital Power (+762 MW), and Heartland Generation (+491.7 MW) effective January 1, 2021. The transfer of offer control associated with the expiration of the PPAs is shown in Figure 25.

Further details on offer control are provided in the 2021 MSOC 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%.

Figure 25: Market share offer control (MSOC) of thermal PPA assets in 2020 and 2021 [33]



1.6.3 Generation additions and retirements

Alberta's total generating unit capacity saw a net decrease of 151 MW since the last MSOC assessment on January 5, 2020. The decrease in total capacity was primarily due to the retirement of the Sundance 3 (SD3) 368 MW coal asset on July 31, 2020. In addition, the Minnehik-Buck Lake (PW01) 5 MW cogeneration asset was retired at the end of 2020.

The retired capacity was partially offset by a number of new solar and energy storage assets that came online in 2020 (Table 7). In total, 92 MW of solar capacity was added and 30 MW of energy storage.

A few assets were uprated in 2020, most notably 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 144 MW to 208 MW.

[33] The figures in this chart are based on the market share offer control assessments in 2020 and 2021. The capacity of SH2 increased by 10 MW in the fall of 2020, increasing the excess energy on that unit from 12 MW to 22 MW.

Table 7: Capacity additions and retirements between MSOC 2020 and 2021

Asset ID	Gen. Type	2020 (MW)	2021 (MW)	*Diff* [34]	*Date of Change*
VXH1	Solar	--	22	22	Feb 19, 2020 [35]
HUL1	Solar	--	25	25	Apr 24, 2020 [36]
INF1	Solar	--	22	22	Jun 15, 2020 [37]
SUF1	Solar	--	23	23	Aug 30, 2020 [38]
SUM1	Energy storage	--	10	10	Nov 1, 2020 [39]
ERV1	Energy storage	--	20	20	Nov 30, 2020 [40]
Units Added (Units >=5 MW)		**0**	**122**	**122**	
SD3	Coal	368	--	-368	Jul 31, 2020 [41]
PW01	Cogeneration	5	--	-5	Dec 31, 2020 [42]
Units Retired (>=5 MW)		**373**	**0**	**-373**	
EGC1	Combined Cycle	860	868	8	May 1, 2020 [43]
HRM	Coal to S.C.	144	208	64	May 9, 2020 [44]
SH2	Dual fuel	390	400	10	Nov 6, 2020 [45]
MC Changes (Units >=5 MW)		**1394**	**1476**	**82**	
Units <5 MW		138	157	19	
Unchanged Units >=5 MW		13,945	13,945	0	
TOTAL (MW)		**15,851**	**15,700**	**-150**	

[34] The difference between the 2020 (MW) Total and the 2021 (MW) Total differs from the sum of the “Diff” column due to rounding.

[35] New Asset Vauxhall (VXH1) Notice

[36] New Asset Hull (HUL1) Notice

[37] New Asset Innisfail (INF1) Notice

[38] New Asset Suffield (SUF1) Notice

[39] New Asset Summerview (SUM1) Notice

[40] New Asset eReserve1 Rycroft (ERV1) Notice

[41] TransAlta Announces Retirement of Sundance 3 Coal Unit

[42] Keyera Corp. Announces 2020 Year End Results

[43] EGC1 Shepard change in maximum capability (MC) notice

[44] HRM H.R. Milner change in maximum capability (MC) notice

[45] SH2 Sheerness 2 change in maximum capability (MC) notice

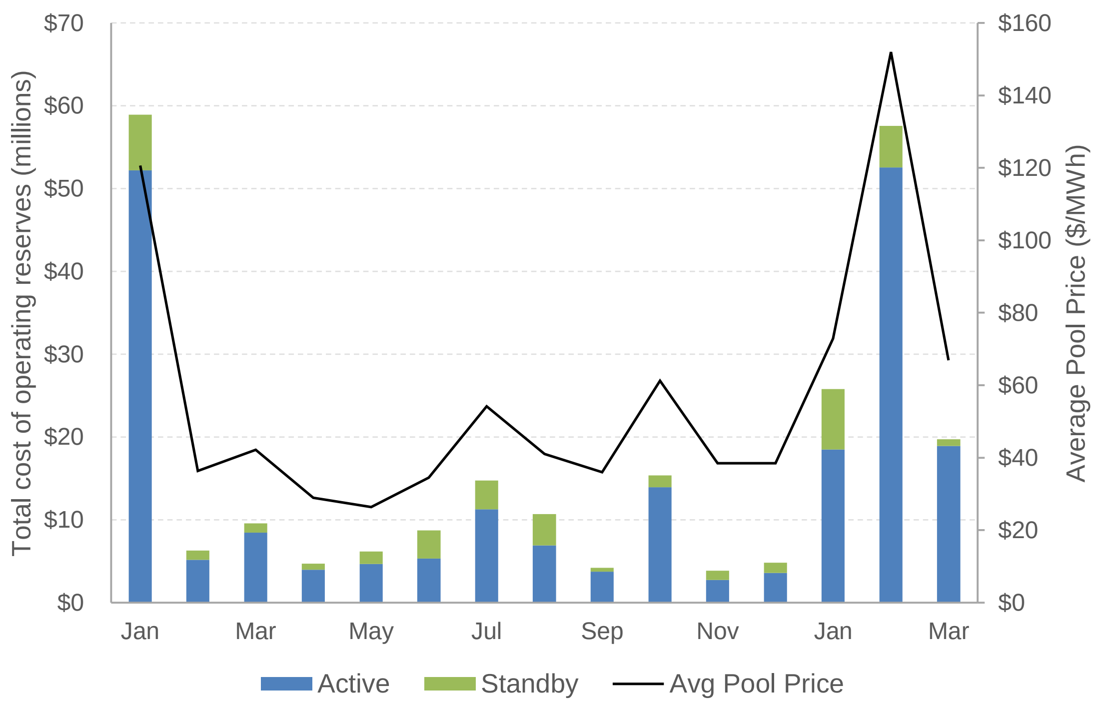
2 THE MARKETS FOR OPERATING RESERVES

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 provide an instantaneous response to an imbalance of supply and demand, whereas spinning reserves are synchronized to the grid and provide capacity that the system controller can call upon in a short amount of time. Supplemental reserves are not required to be synchronized but must be able to synchronize quickly if called upon by the system controller.[46] These products are all bought by the AESO through day-ahead auctions on Watt Ex.

2.1 Costs and procurement volumes

Table 8 provides a detailed breakdown of OR costs by month in Q1 2021 and in total for Q1 2020. Total OR costs for the quarter were $103 million, an increase of 38% from Q1 2020. The increase in average pool price was 42%, indicating this was a major factor in the higher OR costs. Figure 26 shows total OR costs and average pool prices for the past 15 months. The general correlation between the two is clear and expected. The opportunity cost of providing OR is often forgoing the sale of energy, and for active reserves prices are directly indexed to the pool price.

Figure 26: Total cost of active and standby reserves and average pool price by month (January 2020 to March 2021)



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

Table 8: Detailed breakdown of operating reserves costs in Q1 2021 [47]

Total Cost ($ Millions)						
	Jan-21	**Feb-21**	**Mar-21**	**Q1 2021**	**Q1 2020**	***% Change***
Active Procured	**18.5**	**52.6**	**18.9**	**90.0**	**65.8**	***37%***
RR	5.1	10.4	4.4	19.9	18.2	*10%*
SR	8.1	22.7	8.3	39.1	25.6	*53%*
SUP	5.3	19.5	6.2	31.0	22.0	*41%*
Standby Procured	**0.2**	**0.4**	**0.6**	**1.2**	**0.8**	***50%***
RR	0.1	0.1	0.2	0.5	0.4	*9%*
SR	0.1	0.3	0.3	0.7	0.4	*88%*
SUP	0.0	0.0	0.0	0.1	0.0	*125%*
Standby Activated	**7.1**	**4.6**	**0.2**	**11.9**	**8.1**	***46%***
RR	0.4	0.2	0.2	0.8	0.0	*4040%*
SR	5.0	3.3	0.0	8.3	6.0	*39%*
SUP	1.6	1.1	0.0	2.8	2.1	*33%*
Total	**25.8**	**57.6**	**19.7**	**103.1**	**74.8**	***38%***
Total Volume (GWh)						
	Jan-21	**Feb-21**	**Mar-21**	**Q1 2021**	**Q1 2020**	***% Change***
Active Procured	**452.4**	**487.9**	**533.0**	**1,473.3**	**1,546.5**	**-5%**
RR	99.7	88.6	95.2	283.5	355.7	*-20%*
SR	176.3	199.8	219.1	595.2	595.9	*0%*
SUP	176.3	199.6	218.7	594.7	594.9	*0%*
Standby Procured	**163.3**	**132.1**	**118.3**	**413.7**	**489.5**	***-15%***
RR	59.5	38.4	28.6	126.5	174.4	*-27%*
SR	77.9	70.4	67.2	215.5	233.8	*-8%*
SUP	25.9	23.3	22.5	71.7	81.3	*-12%*
Standby Activated	**61.3**	**26.1**	**3.1**	**90.5**	**62.1**	***46%***
RR	3.9	1.2	2.5	7.6	0.3	*2276%*
SR	39.2	17.5	0.6	57.4	43.5	*32%*
SUP	18.2	7.3	0.1	25.5	18.3	*40%*
Total	**677.0**	**646.2**	**654.5**	**1,977.6**	**2,098.1**	***-6%***
Average Cost ($/MWh)						
	Jan-21	**Feb-21**	**Mar-21**	**Q1 2021**	**Q1 2020**	***% Change***
Active Procured	**40.86**	**107.73**	**35.53**	**61.08**	**42.56**	**44%**
RR	51.04	117.75	46.35	70.31	51.12	38%
SR	45.73	113.55	37.97	65.63	42.98	53%
SUP	30.22	97.46	28.38	52.11	37.02	41%
Standby Procured	**1.42**	**3.21**	**4.84**	**2.97**	**1.68**	**77%**
RR	2.49	1.63	8.53	3.60	2.39	50%
SR	0.99	4.47	4.35	3.18	1.55	104%
SUP	0.25	2.00	1.59	1.24	0.49	155%
Standby Activated	**115.57**	**175.69**	**68.40**	**131.26**	**130.78**	**0%**
RR	113.40	131.43	67.38	101.44	58.22	74%
SR	127.74	186.72	79.03	145.24	138.15	5%
SUP	89.73	156.80	10.32	108.72	114.49	-5%
Total	**38.11**	**89.10**	**30.14**	**52.13**	**35.63**	***46%***

[47] Percentage change figures may differ from those implied here due to rounding of the costs and volumes figures.

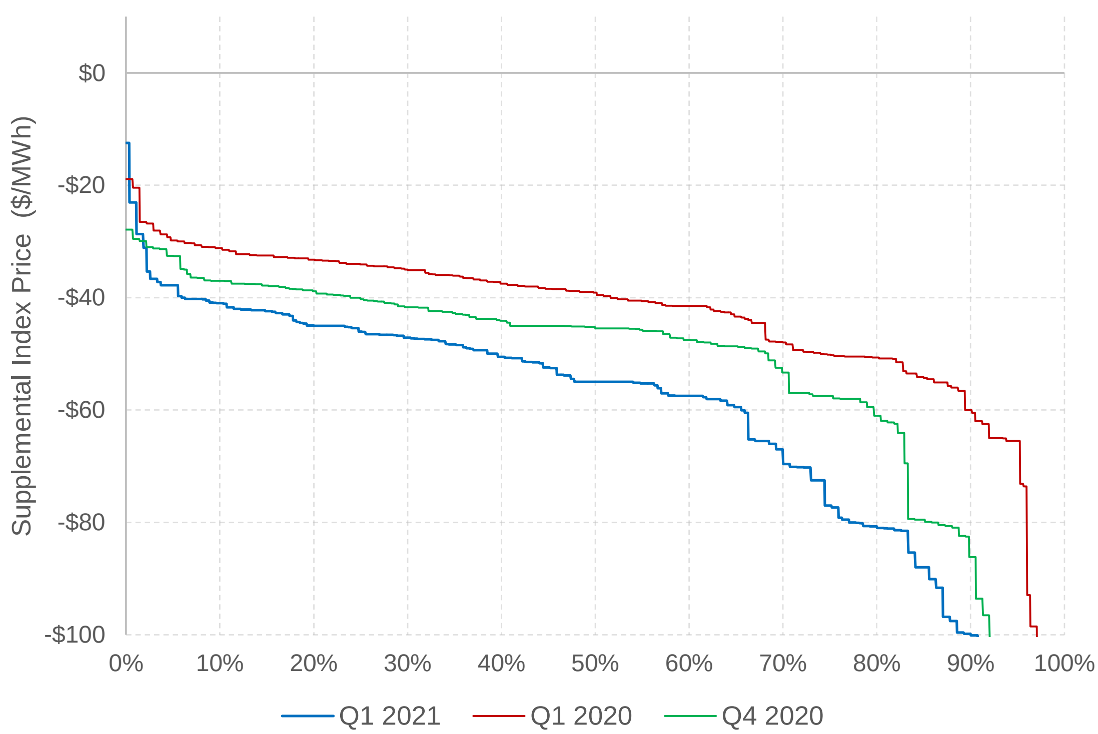
Table 9 shows average costs for active spinning, supplemental, and regulating reserves year-over-year. The increase in average pool price for Q1 2021 is partly reflected in increases to active OR costs. Increased fuel costs in 2021 due to the higher carbon price may have had the effect of widening the discounts to pool price, putting some downward pressure on active OR costs.

Table 9: Average cost ($/MWh) of active OR products

Product	Q1 2021	Q1 2020	Q1 2021 – Q1 2020
Spinning	$65.63	$42.98	$22.66
Supplemental	$52.11	$37.02	$15.09
Regulating	$70.31	$51.12	$19.19
Avg. Pool Price	**$95.45**	**$67.06**	**$28.40**

The increase in the average cost for active supplemental reserves was $15.09/MWh, which is materially lower than the increase in average pool price; $28.40/MWh. Figure 27 shows duration curves of the index prices for active supplemental. The figure illustrates a reduction in the index price over 2020 and into Q1 2021. This is primarily due to an increase in the level of competiton in the supplemental market by new market entrants.

Figure 27: Duration curves of index prices for active supplemental reserves, above -$100 (Q1 2020, Q4 2020, and Q1 2021)



The high pool prices in February attracted significant volumes of imports on the BC/MATL intertie. To support higher imports the AESO uses a combination of LSSi and additional contingency reserves. Figure 28 shows the volume of on-peak active spinning and the volume of standby spinning reserves that were activated in on-peak hours over the quarter. In early February the AESO began to procure more active spinning reserves day-ahead, likely in anticipation of the high import levels continuing. The activation rate of standby reserves correspondingly dropped and remained low for the rest of the quarter. In mid-March, the level of active reserves procured dropped slightly, but no increase in standby activations was observed.

Figure 28: Active spinning and standby spinning activation volumes, on-peak (Q1 2021)

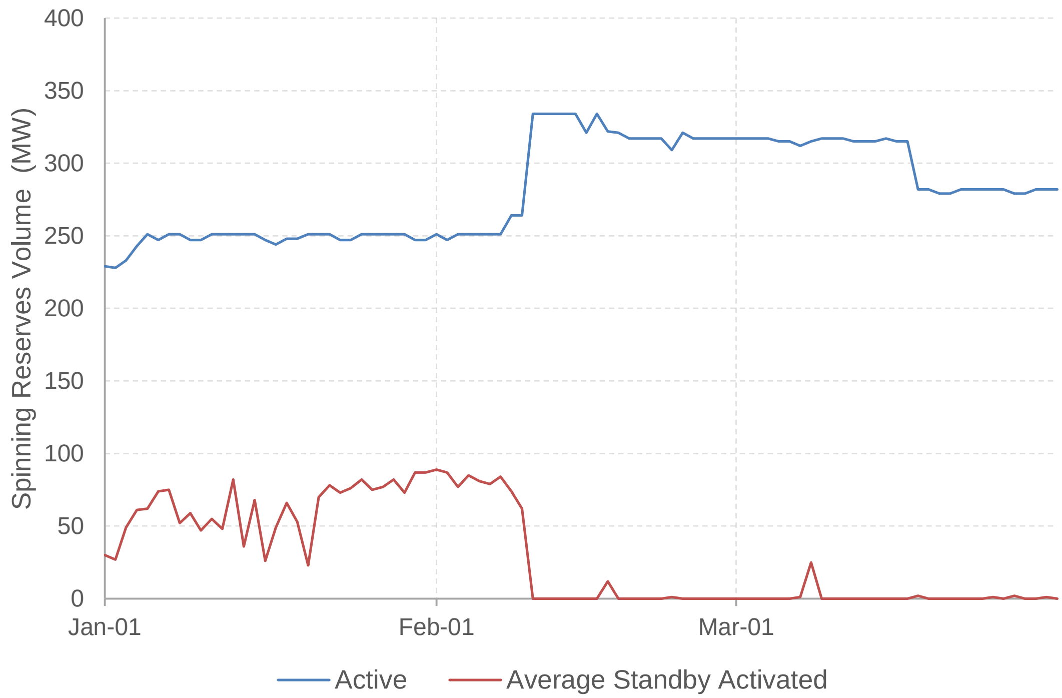
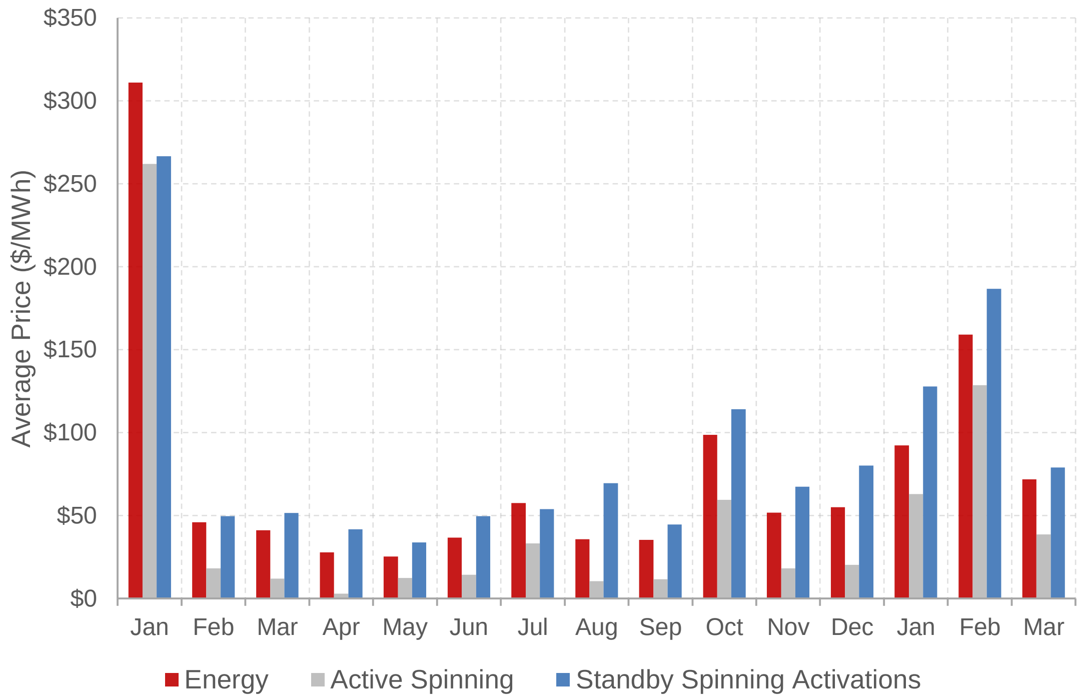


Figure 29 compares the average cost of standby activations with the prevailing cost of active reserves and energy, by month since January 2020. The prices for energy and active spinning are weighted by standby spinning activation volumes. As shown, the cost of activating standby reserves has generally been more expensive than the prevailing cost of energy (Figure 29). This is not an efficient outcome because the cost of providing reserves is lower than the cost of providing energy, given the variable cost savings. In addition, the cost of activating standby spinning reserves has typically been significantly higher that cost of the active spinning reserves. These trends continued into Q1 2021, although the volume of standby reserves activated was low from February 10 (Figure 28).

Figure 29: The volume-weighted average price of standby spinning activations compared to the prevailing price of energy and active spinning reserves (January 2020 to March 2021)[48]



On certain days in Q1 2021 the AESO was unable to procure all of the reserves it was seeking to buy. On Friday, March 19, the Watt Ex auctions were for delivery on March 20, 21, and 22. For both on-peak and off-peak active regulating reserves the AESO was unable to fill its buy volumes for any of the three days. The MSA understands there was a network connectivity issue that caused one of the larger providers not to be able to submit all offers within the timelines of the Watt Ex auction.

The following week, on Friday, March 26, the Watt Ex auctions were for delivery on March 27, 28, and 29. In this instance, the AESO was unable to fill its buy volumes of on-peak and off-peak standby regulating reserves for any of the three days. Again, connectivity issues were suggested as a potential cause. No similar occurrences have been observed since. In the event that the AESO has insufficient regulating reserves after activating all available standby, it has the ability to conscript reserves through established out-of-market contracts if necessary.

2.2 Hydro PPA expiration

At the end of 2020 the Hydro PPA expired, having been in place since January 1, 2001. The Hydro PPA was a series of financial obligations that were enacted as part of the transition process from a regulated to a competitive market for electricity in Alberta. The Hydro PPA covered the

[48] The prevailing prices of energy and active spinning reserves are calculated by weighting these prices by the volume of standby spinning activations in a given hour. The cost of standby activations does not include the standby premium.

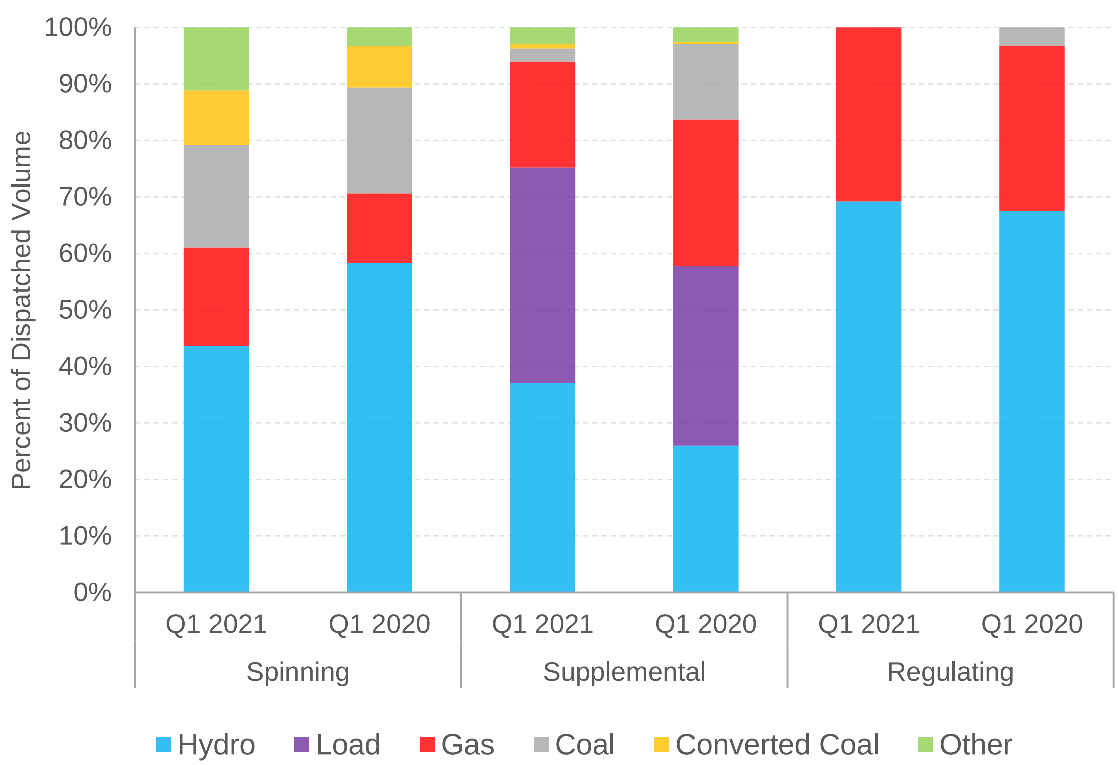
three large hydro assets in the market: Bighorn, Bow River, and Brazeau; together these assets comprise 790 MW of capacity.

The Hydro PPA was a financial arrangement under which the PPA Buyer covered the expected costs of operating and maintaining the assets in return for payments based on the value of these resources in the market. These payments were based on the market value of estimated volumes, termed notional quantities, for energy and reserves. These notional quantities were calculated based on historical hydro data available at the time. The financial obligations within the Hydro PPA were tied to market prices. For example, the energy payments would increase if pool prices were higher, and the reserves payments would increase if OR prices were higher.

The three large hydro assets that were covered under the Hydro PPA are natural providers of OR because they are resource-constrained generators that are able to quickly deliver a large amount of power to the grid. By selling OR, these assets are able to generate revenue while preserving valuable stored water.

Figure 30 shows the market shares of OR dispatches by fuel type in Q1 2021 and Q1 2020. As shown, hydro assets continue to be a principal supplier of OR. The overall pricing of OR in Q1 2021 has been similar to prior quarters, and the participation of the large hydro assets has continued past the expiry of the Hydro PPA.

Figure 30: Dispatched OR volumes by fuel type (Q1 2021 and 2020)[49]



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

3 THE FORWARD MARKET

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 price 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 our surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2020 are also included. These 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. In 2020 direct bilateral trades accounted for 17% of the total volumes traded, and annual contract trades comprised 42% of direct bilateral volumes in 2020.

Figure 31: Total volumes of standard products by contract terms and trade date

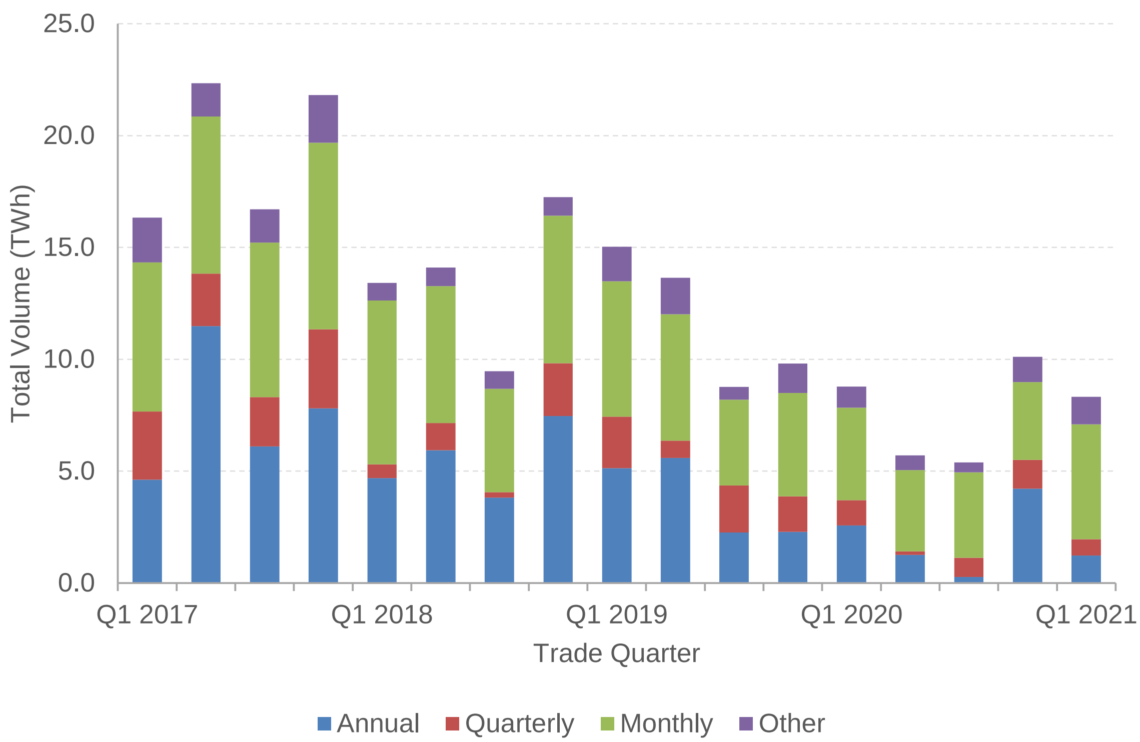
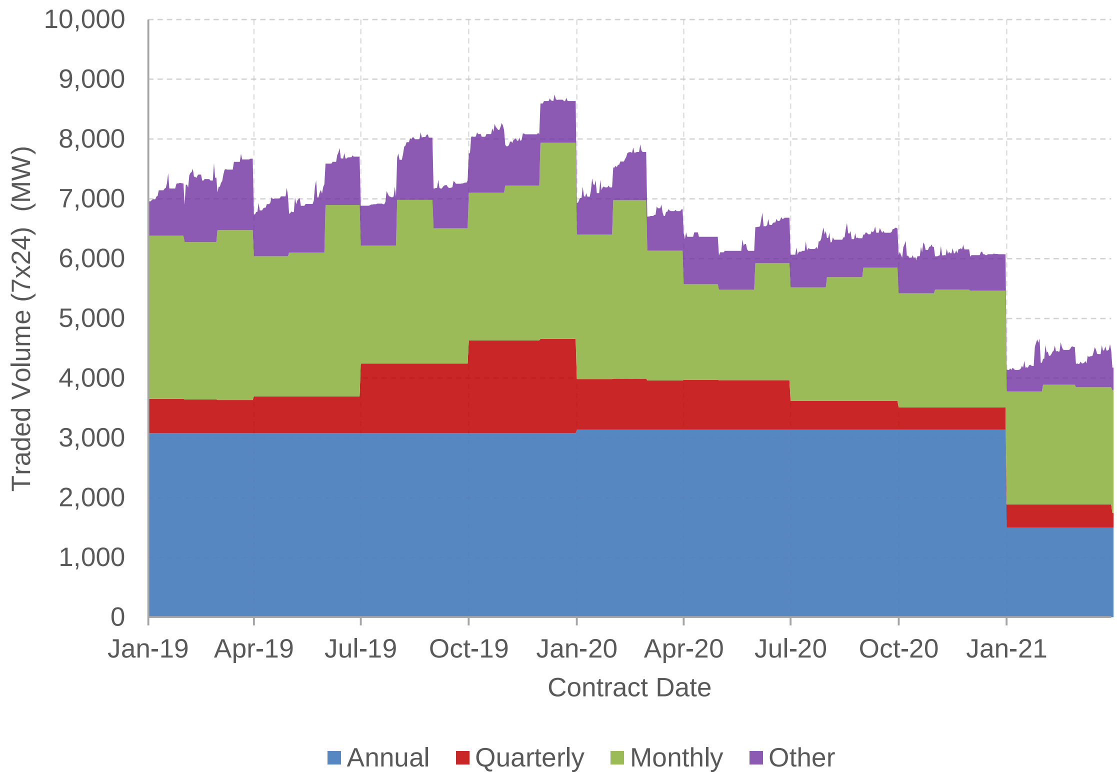


Figure 31 illustrates the total volumes traded for standard products from Q1 2017 to Q1 2021. Total volume is the total amount of power traded financially over the duration of the contract. Standard products include contracts such as flat and extended peak, but do not include custom shapes, such as the full-load RRO trades. Overall trading liquidity increased in Q1 2021 and was materially higher than in Q2 and Q3 of 2020. Compared to Q1 2020 total volumes on ICE NGX and Canax increased by 14%, and compared to Q2 2020 total volumes were up by 76%. Figure

31 shows that the total volumes traded declined slightly from Q4 2020 to Q1 2021 which is largely driven by more annual trades in Q4, some of which were direct bilateral trades. Total volumes on ICE NGX and Canax actually increased slightly, by 4%, from Q4 2020 to Q1 2021, which was largely driven by an increase in monthly volumes that went up by 53%.

Figure 32 illustrates traded volumes by the forward contract delivery date. Traded volume is the hourly volume of power being exchanged financially within a given trade. As shown, the traded volumes that were applicable to Q1 2021 were low in comparison to those applicable to 2019 and 2020. This is largely driven by the fact that traded volumes for Calendar 2021 (CAL21) were approximately 50% of the traded volumes for CAL19 and CAL20. The traded volumes of monthly and quarterly contracts that were applicable to Q1 remained at similar levels compared to previous quarters, but did not increase materially to make up for the reduced volumes of CAL21.

Figure 32: Traded volumes by contract terms and contract date[50]
(January 1, 2019 to March 31, 2021)

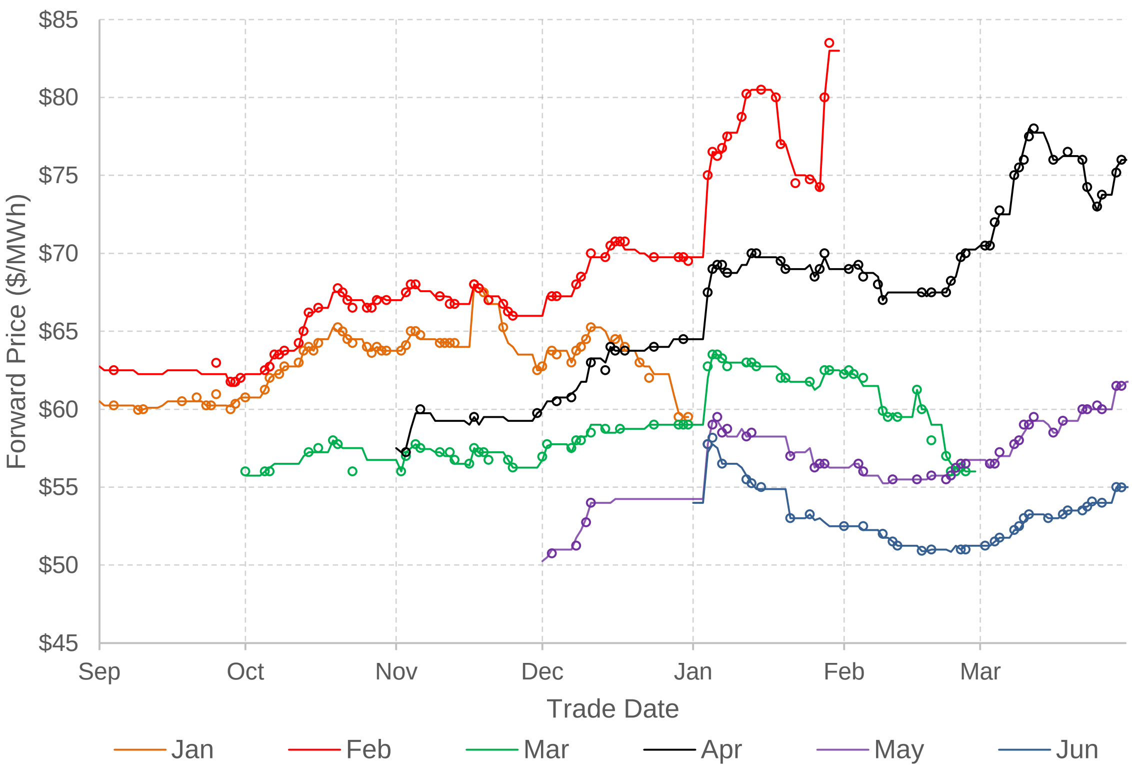


[50] Includes flat, extended peak, extended off peak, and full-load trades; extended peak volumes are weighted by 16/24 and extended off peak by 8/24, full-load traded volumes are estimated using a 4 MW expected value.

3.1 Trading of monthly products

Figure 33 illustrates the evolution of forward prices for the January to June 2021 monthly flat contracts, beginning five months prior to the contract start. Forward prices increased on January 4 as the market observed that around 1,700 MW of thermal capacity was offline commercially for the first business day of 2021. The traded price of the February contract increased by 8% to $75.00/MWh. The price of the February contract continued to increase in subsequent days as cold weather was expected for the end of January, and oil prices increased materially. Later in January, the forward price for February varied based on changing weather forecasts and pool price outcomes in the energy market. The final trade price for February was $83.50/MWh on January 29, which turned out to be $68.48/MWh less than the realized average pool price for the month.

Figure 33: Forward prices for the January to June monthly flat contracts (5 months out) (August 1, 2020 to March 31, 2021)[51]



Despite the pool price volatility in early-to-mid February, forward prices for March declined from $62.50/MWh to $56.00/MWh over the course of February, and forward prices for the April, May, and June contracts changed little in this period as the market appeared to disassociate the pool

[51] The lines show daily settlement prices for the specified monthly contract and the markers indicate the price of the last trade on that day.

price volatility during the cold weather in February from expected price outcomes for the spring months (Figure 33).

The April contract traded at a premium to other spring months largely due to more thermal capacity scheduled to be offline on planned outage. The price for April increased from $67.50/MWh on February 22 to a high of $78.75/MWh on March 11 as pool prices were elevated on some relatively mild weather days in late February and early March. The higher pool prices during this period were due to a number of factors including low wind generation, thermal outages, offer behaviour, and lower import capacity on the BC/MATL intertie. In addition, a BC/MATL intertie outage was scheduled for eleven peak hours of April 29 and 30 on February 25, and on March 11 the outage was extended to include April 28, which also put some upward pressure on the April forward price. The price of the April contract came back down to $73.00/MWh in mid-to-late March as pool price volatility lessened and oil prices pulled back. The forward price for April subsequently increased to close at $76.00/MWh on March 31, partly because of some higher pool prices towards the end of March.

After trading hours on March 24 a planned transmission outage on BC/MATL was altered and moved to start in mid-October rather than late August (Table 10). The flat forward prices for August, September, and October over the course of March are shown in Figure 34. As shown, the BC/MATL outage schedule change had a material impact on forward prices for September and October. The September contract fell by 12% from $70.50/MWh on March 24 to close at $61.75/MWh on March 25. The October contract increased by 8.5% from a trade price of $71.00/MWh on March 24 to close at $77.00/MWh on March 25. The price of the August contract was largely unaffected because the outage was scheduled for one work week at the end of the month, and also because forward prices for markets such as Mid-C and SP15 are elevated for August.

Table 10: BC/MATL intertie planned outage schedule change

Previous Schedule (December 17, 2020)

Start	End	Hours
Aug-23 (Mon) 09:00	Aug-27 (Fri) 19:00	106
Aug-30 (Mon) 09:00	Sep-03 (Fri) 19:00	106
Sep-07 (Tue) 09:00	Sep-17 (Fri) 19:00	250

New Schedule (March 24, 2021)

Start	End	Hours
Oct-18 (Mon) 09:00	Oct-29 (Fri) 19:00	274

Figure 34: Forward prices for the August to October monthly flat contracts (March 2021)[52]

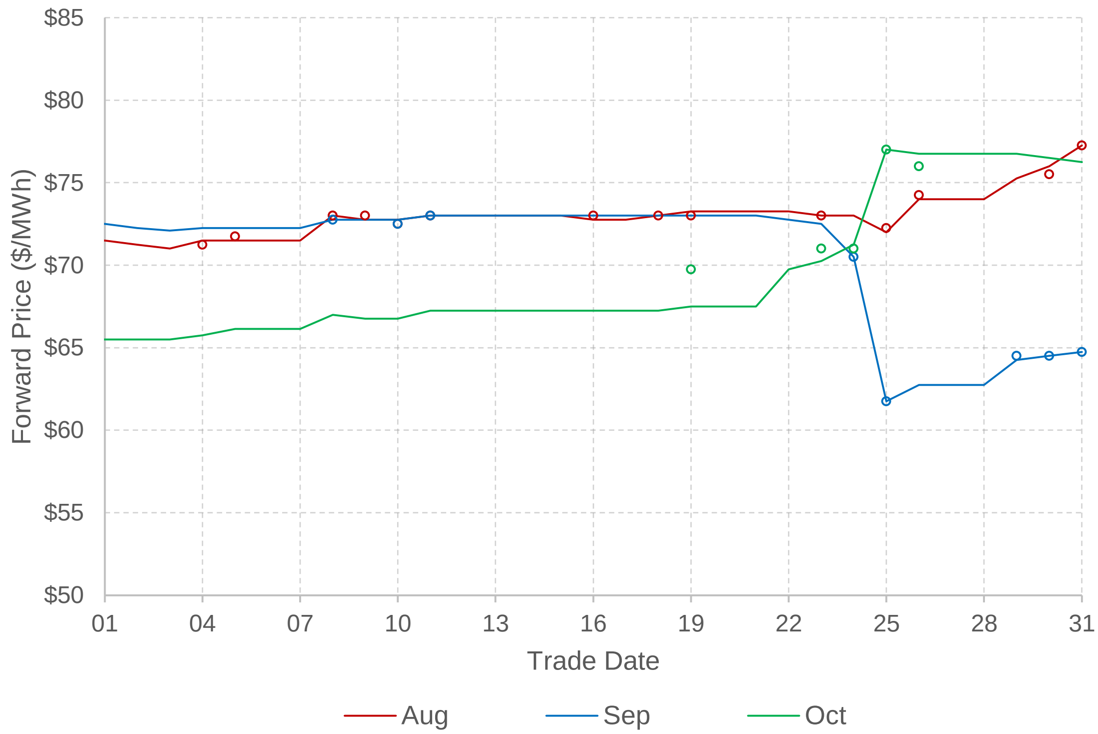
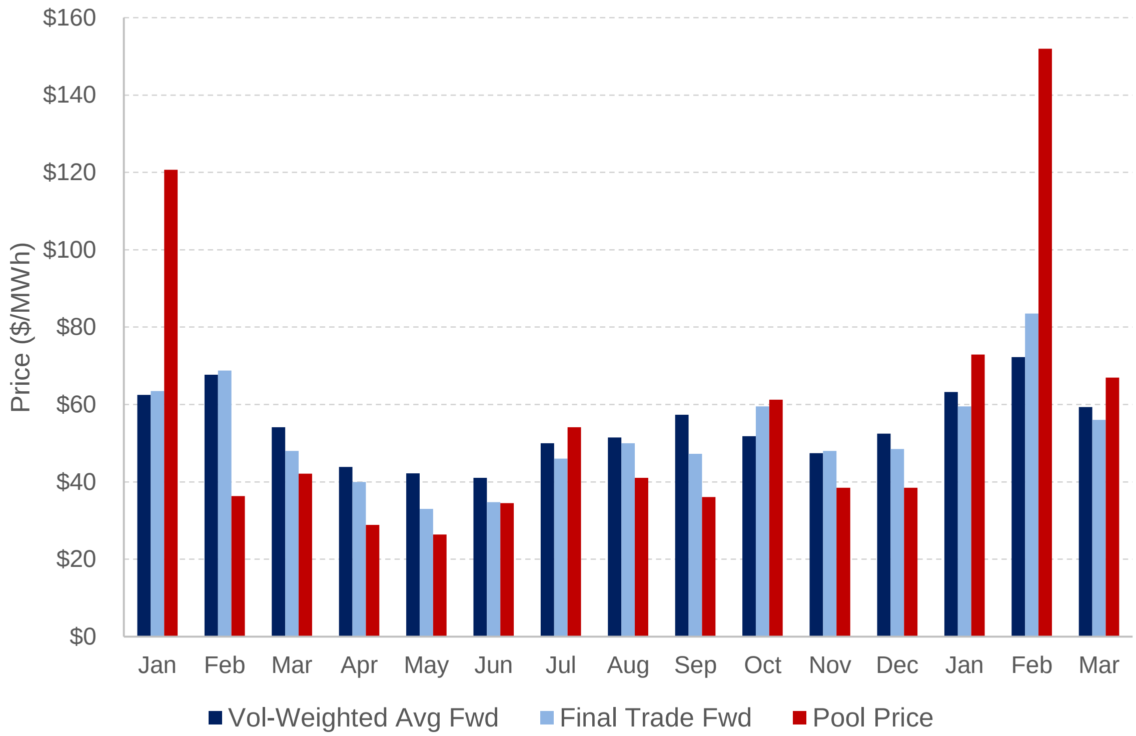


Figure 35 illustrates how the monthly flat forward prices compared to average pool prices from January 2020 through March 2021. The monthly forward prices for Q1 2021 were significantly lower than realized pool prices. This was most notable in February, where the average pool price was $68.48/MWh higher than the final forward trade price, and $79.75/MWh higher than the volume-weighted average forward price. The monthly flat forward prices for Q1 2021 traded at an overall discount of $30.76/MWh relative to the average pool price.[53] In 2020 monthly flat forward prices traded at a premium of $5.07/MWh relative to the average pool price. Forward prices trade based on pool price expectations and can trade at a slight premium to reflect upside risks to pool prices, which are illustrated by January 2020 and February 2021 in Figure 35.

52 The lines show daily settlement prices for the specified monthly contract and the markers indicate the price of the last trade on that day.

53 This figure uses flat monthly trades to calculate a volume-weighted average price for each month in Q1 2021, which are then used to calculate a forward price for the quarter.

Figure 35: Monthly flat forward prices and average pool prices (January 2020 to March 2021)



3.2 Trading of annual products

The marked price of the CAL21 contract increased to $73.67/MWh on March 31, 2021, which is 20% higher than the settlement price of $61.32/MWh on December 31, 2020 and 42% higher than the settlement price on September 30, 2020 (Figure 36). The marked price for CAL21 uses realized pool prices in combination with forward prices for the coming days and months to value the CAL21 contract. The marked price for CAL21 has increased as pool prices have come in above market expectations, and because forward prices for the balance of year have increased.

The forward price for the CAL22 contract increased by 4.4% over the quarter while the prices for the CAL23 and CAL24 contracts fell by 4.5% and 3.8%, respectively (Figure 36). CAL22 traded for $62.25/MWh on March 31 and CAL23 traded for $52.50/MWh on March 11. The CAL24 contract was marked at $50.50/MWh on March 31, having traded for an implied value of $50.75/MWh on February 18 in a multi-year trade. Annual forward prices are decreasing into the future as a material increase in renewable generation supply is expected, and additions to combined-cycle capacity are scheduled to occur as coal capacity declines. Forward prices for natural gas are currently quite low with 2022 priced at $2.37/GJ on March 31, and 2023 and 2024 priced at $2.24/GJ and $2.26/GJ, respectively.[54]

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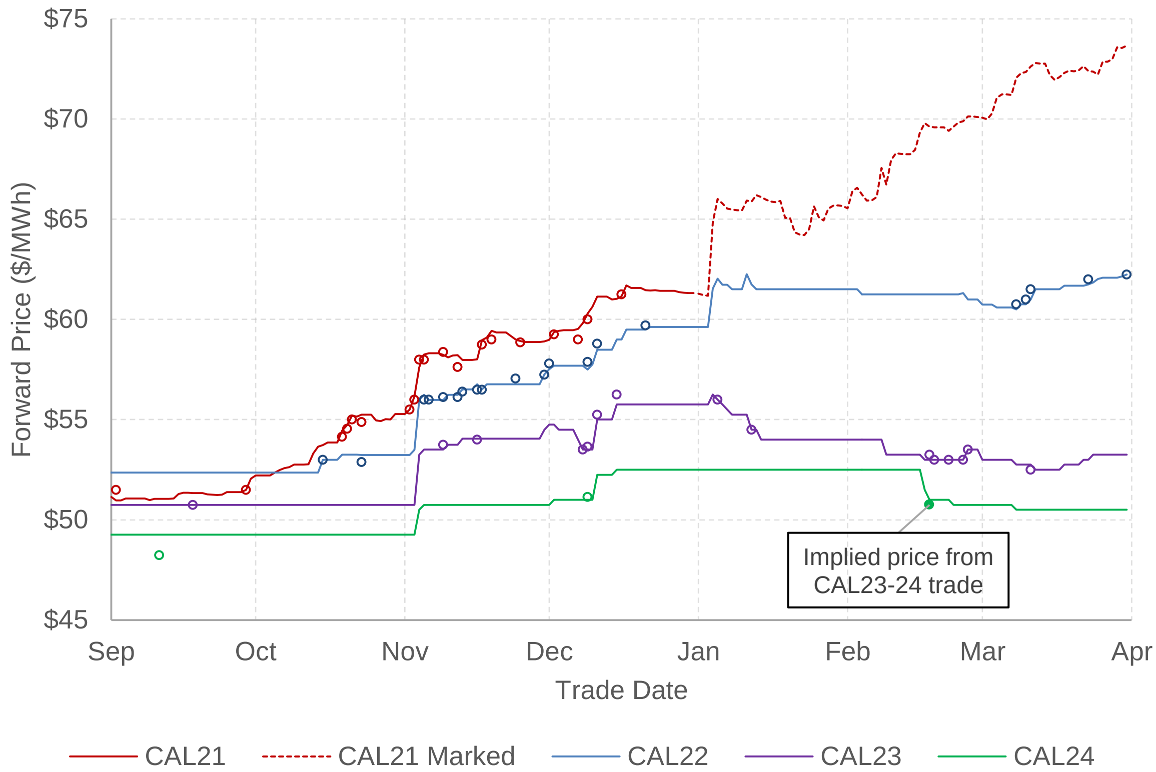
[54] NGX AB-NIT Physical

Figure 36: Forward prices for the calendar 2021 to 2024 flat contracts[55]
(September 1, 2020 to March 31, 2021)



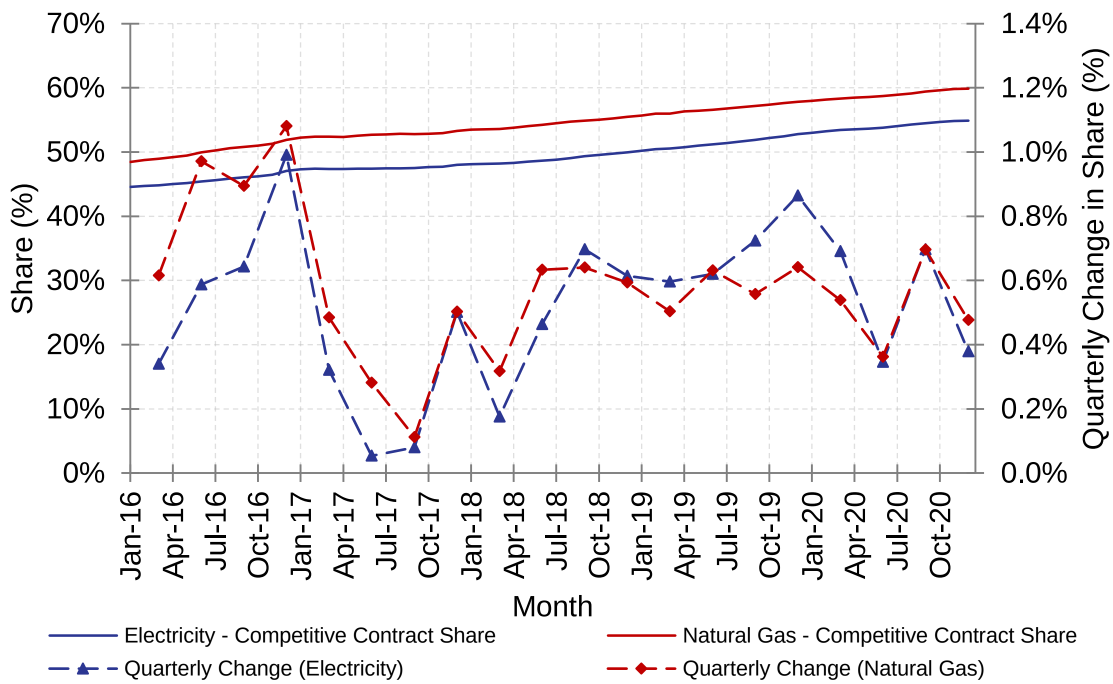
55 The lines show daily settlement prices, the markers indicate the price of the last trade on that day.

4 THE RETAIL MARKETS

4.1 Competitive market shares

Residential customers continued to switch away from regulated retail electricity and natural gas products in Q4 2020,[56] albeit at a lower rate compared to the previous quarter (Figure 37). Competitive market shares for both contracts typically trend together owing to the popularity of dual-fuel contracts among residential customers.

Figure 37: Share of residential customers on competitive retail contracts, 2016 to 2020



In 2020 the share of commercial customers on competitive electricity contacts increased by 1%, reaching a new high of 55%, while the share of commercial customers on competitive natural gas contract increased by 2%, reaching a new high of 60%. Recent years have seen competitive natural gas contract uptake outpace electricity contract uptake among commercial customers (Figure 38), indicative that dual-fuel contracts may not be as popular among commercial customers.

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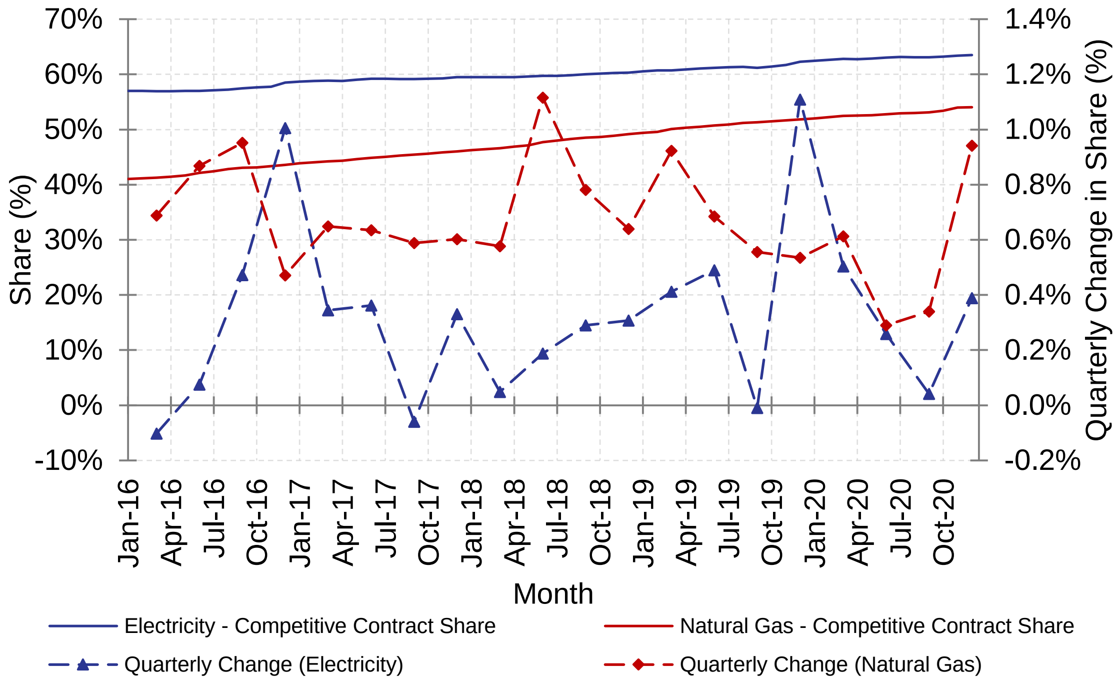
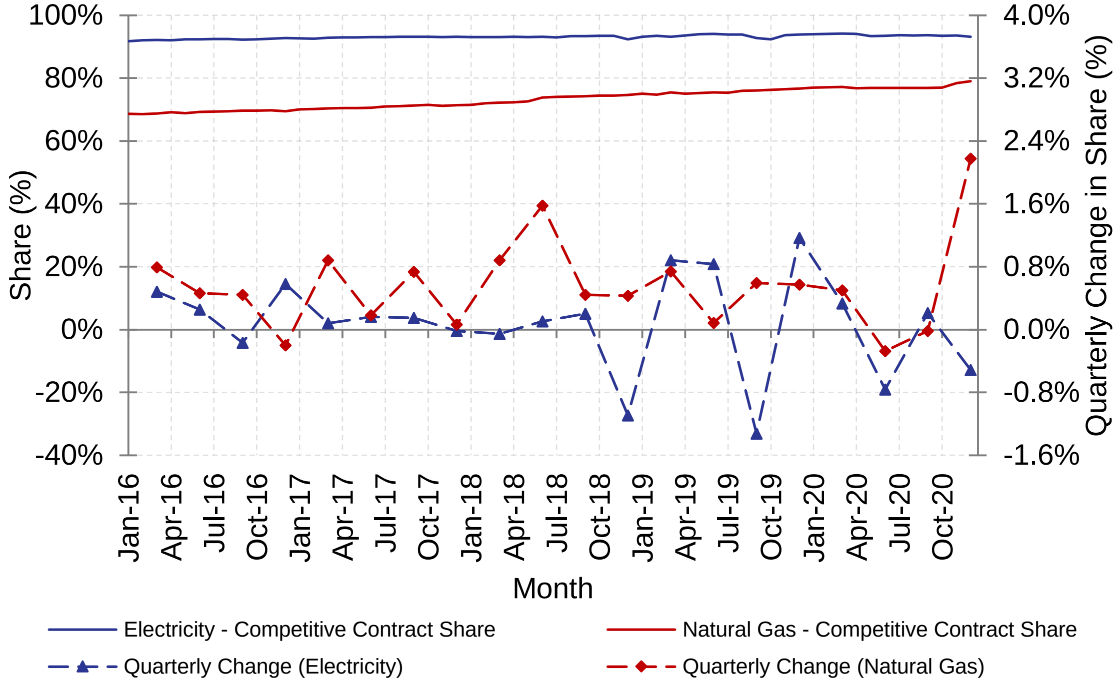
[56] MSA Retail Statistics (2021-04-06). Data up to Q4 2020 is presented here as the MSA Retail Statistics reports data using a one-quarter delay.

Figure 38: Share of commercial customers on competitive retail contracts, 2016 to 2020



The share of industrial customers on competitive retail electricity contracts has remained stable at around 93% to 94% since Q4 2016 (Figure 39). Over the same period, the share of industrial customers on competitive natural gas contracts has grown, with a significant increase observed in Q4 2020.

Figure 39: Share of industrial customers on competitive retail contracts, 2016 to 2020



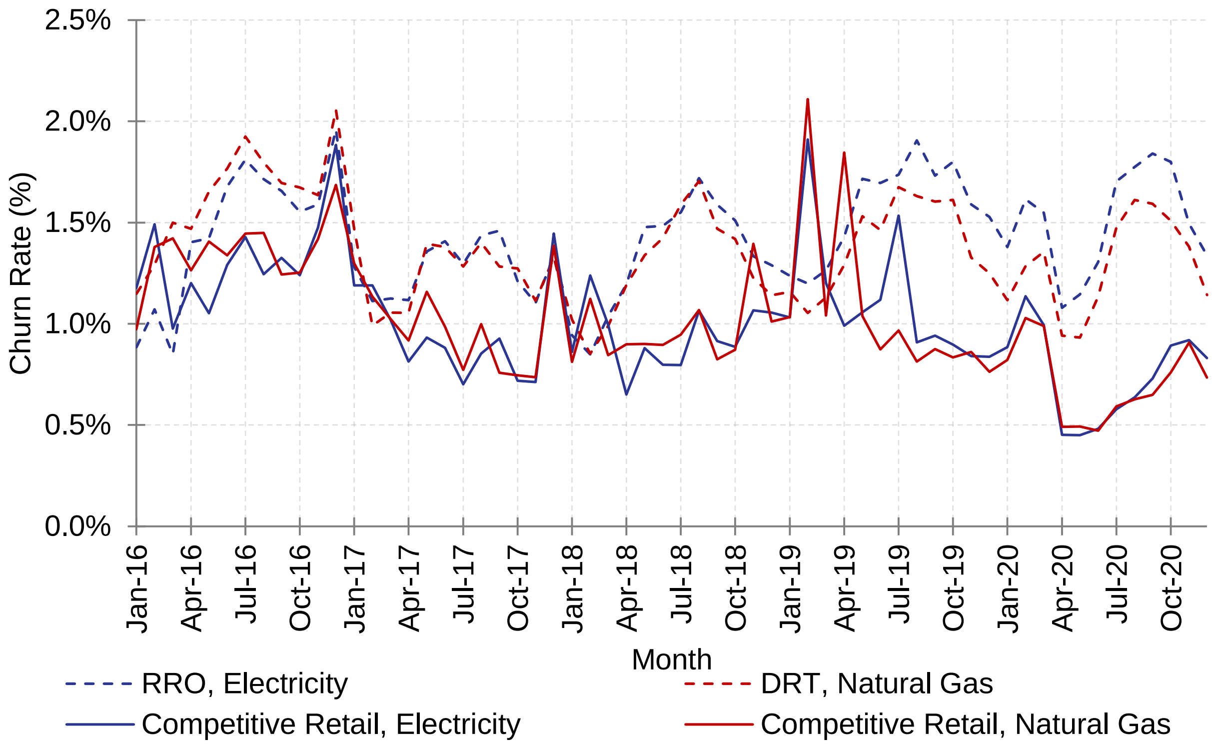
4.2 Churn

Churn rates show how frequently customers switch retailers, expressed as a percentage of retailers' existing customers. High churn rates can indicate a healthy retail market where retailers can more effectively compete for customers.

Churn rates typically range between 1 to 2% per month, and are usually greater among regulated retailers that provide Regulated Rate Option (RRO) electricity services or natural gas services under the Default Rate Tariff (DRT), indicating the share of regulated customers that leave their regulated providers for competitive retailers is greater than the share of competitive customers that leave their retailer.

Churn rates for both regulated and competitive retailers fell over Q4 2020 (Figure 40) despite increases in RRO rates over that quarter. Churn rates typically trend together as a result of the popularity of dual-fuel contracts.

Figure 40: Retail churn rates, residential customers, January 2016 to December 2020



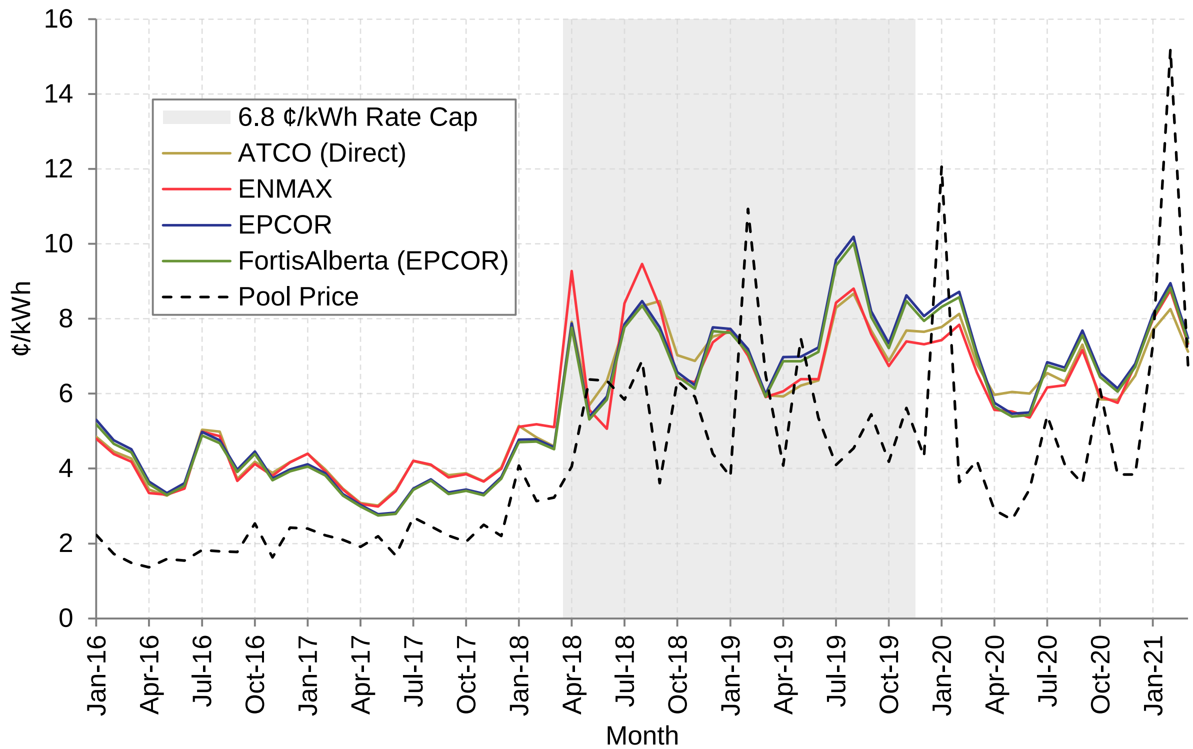
4.3 Regulated retail market

Albertans who do not choose a competitive retailer are served by a regulated electricity or natural gas retailer. The RRO is the regulated electric energy rate provided by the regulated retailer in the customer's electricity distribution service area. The DRT is the regulated natural gas rate, which varies by gas service area. Regulated rates are set by regulated retailers and approved by the Alberta Utilities Commission (AUC).

4.3.1 Regulated Rate Option (RRO)

Residential RRO rates averaged 8 cents/kWh in the four largest distribution service areas in Q1/2021, a 1.7 cent/kWh increase compared to the previous quarter (Figure 41).

Figure 41: (Uncapped) residential RRO rates, January 2016 to March 2021[57]



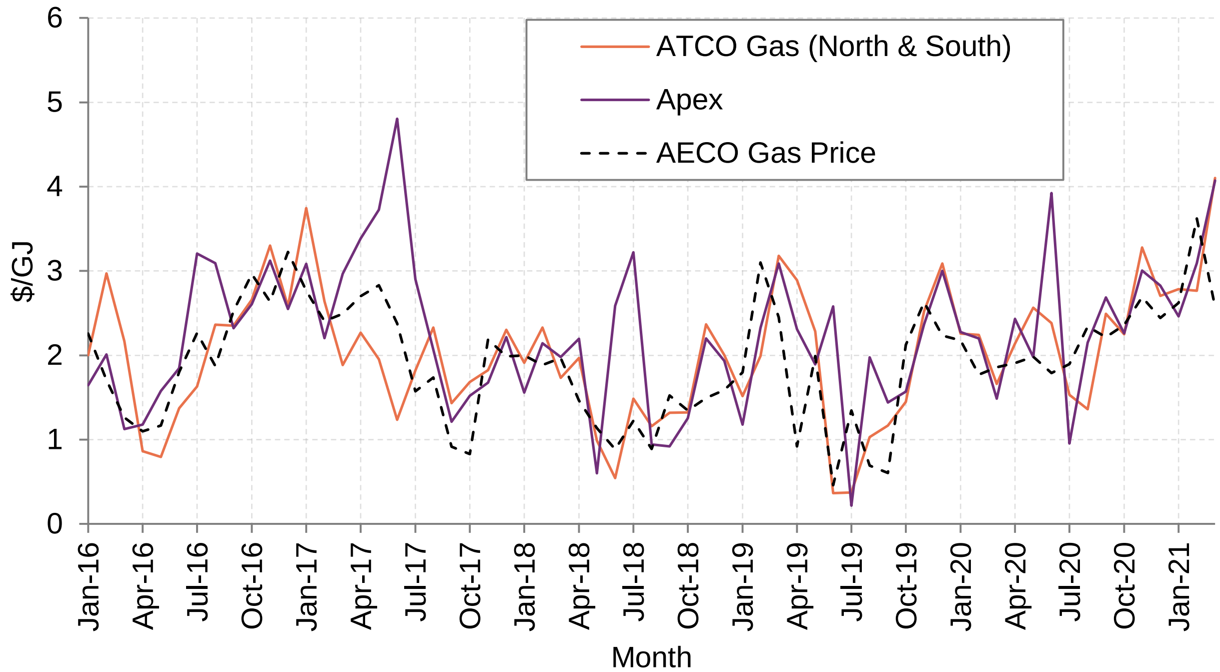
In February 2021 residential RRO customers faced the highest RRO billing rates since 2013, with rates exceeding 8 ¢/kWh across all service areas. As RRO rates are primarily set based on the prices of monthly forward electricity contracts, the increase in RRO rates seen in early 2021 is largely a result of the increase in forward electricity prices for 2021 products (Figure 33).

4.3.2 Default Rate Tariff (DRT)

Average DRT rates increased to $3.22/GJ in Q1/2021, up from $2.73/GJ the previous quarter (Figure 42). Year-over-year, DRT rates in Q1/2021 were over $1/GJ higher than Q1/2020. Higher DRT rates were a result of higher wholesale gas prices in Q1/2021 resulting from the February 2021 polar vortex that impacted much of North America.

[57] Between June 2017 and November 2019, RRO rates were capped at 6.8 ¢/kWh, with the rate cap first binding in April 2018.

Figure 42: DRT rates, January 2016 to March 2021



4.4 Retailer insolvency

On March 9, 2021 Just Energy, an electricity and natural gas retailer, announced it had received creditor protection under the *Companies' Creditors Arrangement Act* following significant losses incurred by the retailer from its operations in Texas during the mid-February polar vortex, enabling it to continue its retail operations.[58] Just Energy provides retail energy services for over 56,000 Alberta customers[59] operating as 'Just Energy Alberta L.P.' and 'Hudson Energy' (as of December 2020).[60]

The MSA continues to monitor this issue to assess potential impacts of the insolvency on retail energy customers.

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58 Just Energy Press Release, March 9, 2021.

59 MSA Retail Statistics, April 6, 2021.

60 Just Energy – About Us.

5 ENFORCEMENT MATTERS

5.1 Retail rates for small micro-generation

The MSA has conducted an assessment of the rates paid to small micro-generation generating units for electricity under the *Micro-generation Regulation* (MGR). Small micro-generation generating units are defined as having a total nameplate capacity of less than 150 kW and are powered exclusively by renewable or alternative energy sources. For the most part, they are small scale residential and commercial solar photovoltaic panel installations.[61]

There are two purposes to this assessment. First, to develop initial insights into "whether or not the conduct of an electricity market participant supports the fair, efficient and openly competitive operation of the electricity market and whether or not the electricity market participant has complied with or is complying with the [EUA] [and] regulations under that Act…"[62] The MGR is a regulation enacted under the EUA. Second, to develop initial insights into effect of "the conduct of electricity market participants" in respect of the MGR on the "structure and performance of the electricity market."[63]

In summary, the MSA found that:

- At the end of 2015, there were 1,344 small micro-generation generating units. By the end of 2020, this increased to 6,111. Over this period, the number of new small micro-generation sites grew at an average annual compounded rate of 35%.

- The rates paid to small micro-generation generating units vary widely across retailers and have been increasing systematically through time. The rates with at least 1 MWh of export volume for every month in the year have increased from a high of 9 cents per kWh in 2015 to 23 cents per kWh in 2020.

- The total cost of the associated payments to small micro-generation generating units has increased in absolute terms and relative to a proxy for the market value of the electricity production as (i) rates have increased and (ii) additional units became eligible and began participating. The total annual cost of small micro-generation exports to Alberta consumers that is recovered through the AESO's tariff has increased from less than $250,000 in 2015 to greater than $2.6 million in 2020.

- The 2020 program cost of $2.6 million was $1.1 million in excess of the $1.5 million market value of the electricity that was generated. As a result, the average price paid to small micro-generation generating units was about 70 per cent higher than its market value.

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[61] "Micro-generation generating unit" is defined in section 1(1)(h) of the MGR. Issues beyond the rates paid to small micro-generating units, such as the sizing of these units, were not considered in this assessment.

[62] AUCA, section 39(3)(a)(i)

[63] AUCA, sections 39(2)(a)(i) and (ii)

- Retailers are permitted to charge and pay arbitrarily high rates for electricity under the MGR. While retailers do not receive a mark-up on the rate that is paid to small micro-generation units for exports, they earn additional administration fees when they serve a larger number of customer accounts. The retailer also receives excess margin for any energy consumed by the micro-generator while on a high rate. Further, retailers do not bear any of the costs of exports since they are entirely recovered through the AESO's tariff.

- At least one retailer has a practice of cycling sites from high rates when they tend to be net producers of electricity (e.g., in the summer) to low rates when they tend to be net consumers of power (e.g., in the winter). This gives retailers an incentive to costlessly offer high rates in periods where small micro-generation generating units are net producers in order to attract customers.

- Given that the rates can be set arbitrarily and independently of market prices under the MGR, with cost recovery through the AESO's tariff, there are no competitive or explicit regulatory restraints on this behaviour and consequently there are no restraints on the total cost borne by Alberta consumers. Consumers with small micro-generation generating units benefit from high rates in the form of a subsidy paid by other Alberta consumers.

- It is the MSA's view that retailers that set rates above market value have strictly complied with the explicit language of the MGR.

- It is an open question for the MSA whether retailers that set rates above market value are supporting the fair, efficient and openly competitive operation of the electricity market.

- While not all retailers have set high rates, those that have not done so have an incentive to do so over time to prevent small micro-generation customers they serve from defecting to retailers that do set high rates.

5.1.1 Background

The AUC's *Distribution System Inquiry Final Report* summarized the interaction of micro-generation with the market as follows:[64]

> 164. […] The MGR specifies that a micro-generator's retailer must act as the electricity market participant and deal with the AESO in respect of the electric energy generated by the micro-generator. The retailer also provides a credit to the micro-generator for the electricity it supplies to the grid.
>
> 165. In the case of small micro-generation, this credit is calculated using the rate the retailer charges the micro-generator's site for electricity consumed from the grid. For example, if a customer is paying an RRO rate for the electricity it draws

[64] Alberta Utilities Commission. *Distribution System Inquiry Final Report*. Proceeding 24116. February 19, 2021.

from the grid, that customer will also receive the same RRO rate for the electricity it supplies to the grid. Or, if a customer is paying a contract price (for example, a fixed three-year rate of $0.06/kWh), that customer will receive the same retail price for the energy supplied to the grid.

166. As per the *Micro-generation Regulation*, the AESO must compensate small micro-generation customers, through their retailers, based on the aggregate amount of electricity supplied by the customer to the grid for the billing period, multiplied by the retail rate agreed upon between the retailer and the small micro-generation customer for that same period. The AESO has no influence on the retail rate agreed to by the retailer and the small micro-generation customer, even though it must compensate the small micro-generation customers at this rate through its tariff. These payments to small micro-generation customers from the AESO, via their retailers, are not settled within or recovered from the power pool (i.e., wholesale electricity market).

167. In the case of large micro-generation, all electricity supplied to the grid from large micro-generation sites is settled at the power pool price. This means that the AESO must compensate the large micro-generator's retailer at the pool price for each settlement interval in the billing period (i.e., the wholesale price). The retailer then provides this amount as a bill credit to the large micro-generator, unless a different rate is agreed upon between the retailer and the large micro-generator (i.e., a contract price). As such, any difference between the pool price and the rate that large micro-generation customers receive for their energy exports is borne by their retailer.

168. The difference in treatment between small and large micro-generation is likely driven by metering limitations. For small micro-generation, only a bi-directional cumulative meter is required. These meters are only capable of measuring the electricity drawn from and supplied to the grid for the cumulative period between reads. This means that the electricity supplied to the grid during hourly intervals by small micro-generation is not known and thus cannot be settled at the hourly power pool price. Without an ability to settle electricity supplied to the grid by small micro-generation at the power pool price, the AESO uses the retail rate (on which the retailer and the customer agreed) to compensate small micro-generators through its tariff. For large micro-generation customers, a bi-directional interval meter is required by the regulation, and thus electricity supplied to the grid from these sites can be settled at the hourly power pool price.

169. Because the retailers bear no risk in compensating small micro-generation customers at retail rates different from the pool price (since they are not the party ultimately responsible for paying these amounts), this arrangement is prone to gaming. Some retailers offer retail rates to small micro-generation customers that are approximately triple that of the average retail contract during months when solar output is greatest, and then allow these customers to switch to a lower rate

during months with much lower solar output. In 2020, these retail rates were approximately $0.22/kWh. Micro-generation customers that are net energy exporters during the higher output solar months benefit from these higher retail contracts, even though they are paying a higher amount for electricity consumed from the grid during non-daylight hours. Retailers benefit because they are able to sell electricity to these customers at these high retail rates when the customer is consuming electricity from the grid. Overall, this creates a wealth transfer from other AESO tariff customers to the small micro-generators participating in these high retail rates.

[Footnotes in the original omitted.]

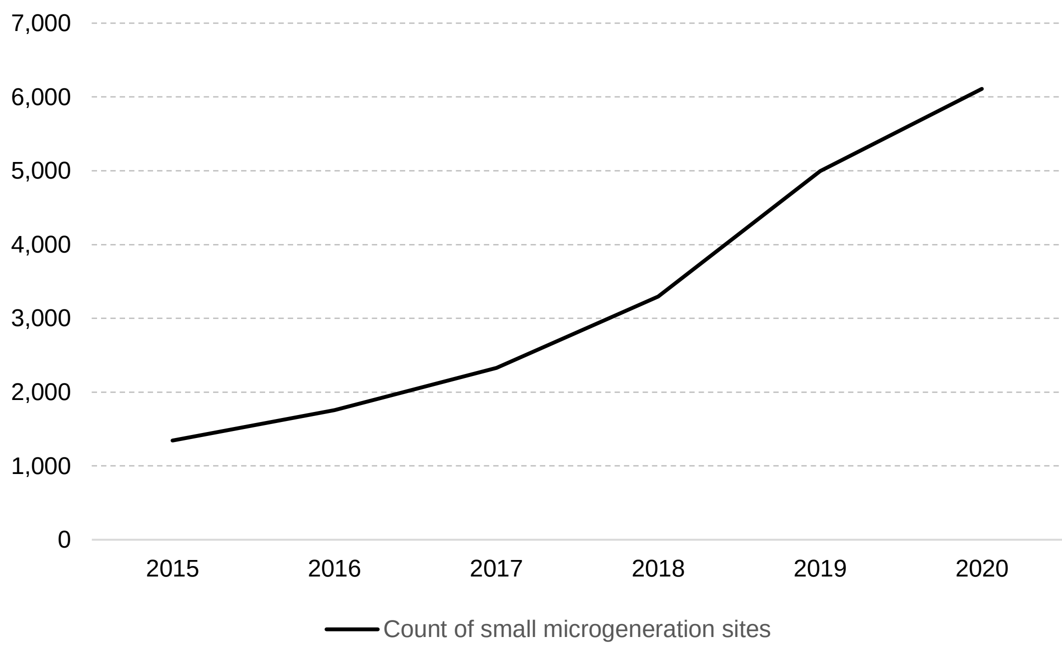
5.1.2 MSA assessment

In its assessment the MSA has analyzed site-level small micro-generation price and export volume data between 2015 and 2021. The assessment is summarized below by providing summary answers to questions that arose during the assessment.

What is the extent of participation under the MGR?

From 2015 to 2020, the number of small micro-generation units increased from 1,344 to 6,111. In 2020, 68 retail entities provided service to small micro-generators.

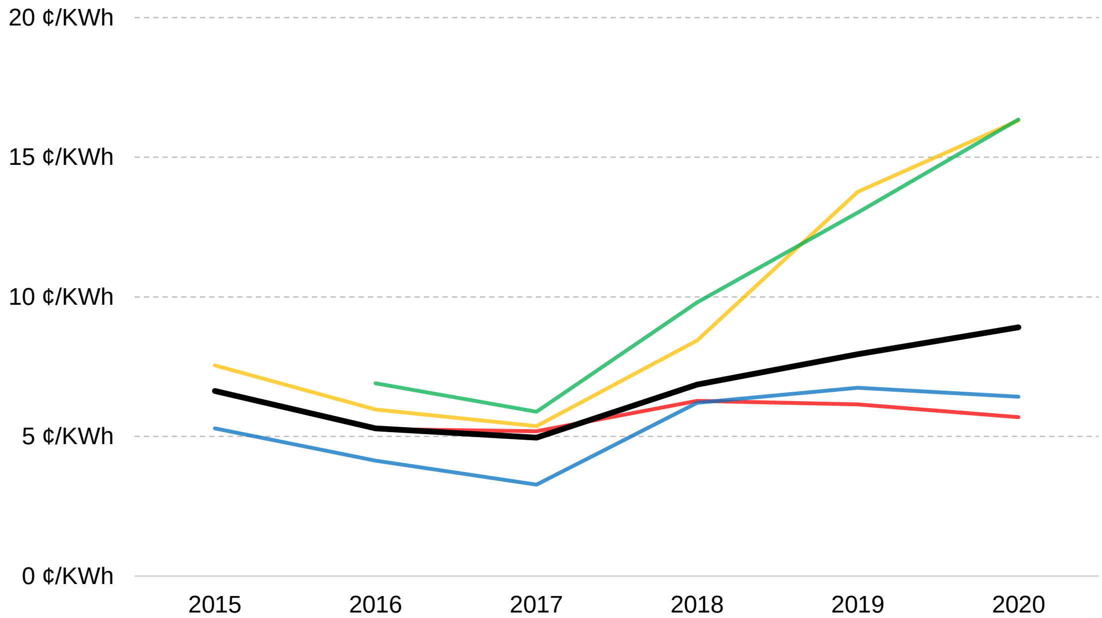
Figure 43: Count of small micro-generation sites



What is the distribution of rates paid to small micro-generation generating units under the MGR and how have they changed through time?

As illustrated in Figure 44, the volume-weighted average rate paid to small micro-generating units has been relatively stable over the period from 2015 to 2020, whereas the maximum rates have increased considerably as illustrated in Figure 45. These two figures chart the rates from four select retailers shown in colour. In Figure 44, the black line shows the volume weighted average of all retailers. In Figure 45, the black dashed line shows the maximum rate charged by any retailer where there was at least 1 MWh of energy exported per month, for the summer months, from small micro-generators at the rate.[65] The growing difference between the average and maximum rates suggests that a small number of retailers are setting rates increasingly above average.

Figure 44: Volume-weighted average rates by year



[65] In Figure 45, instances where the dashed green and red line are above the dashed black line illustrate maximum rates that correspond to small volumes of exported micro-generation energy. There was less than 1 MWh of exports per month, for the summer months, associated with these rates.

Figure 45: Maximum rates by year

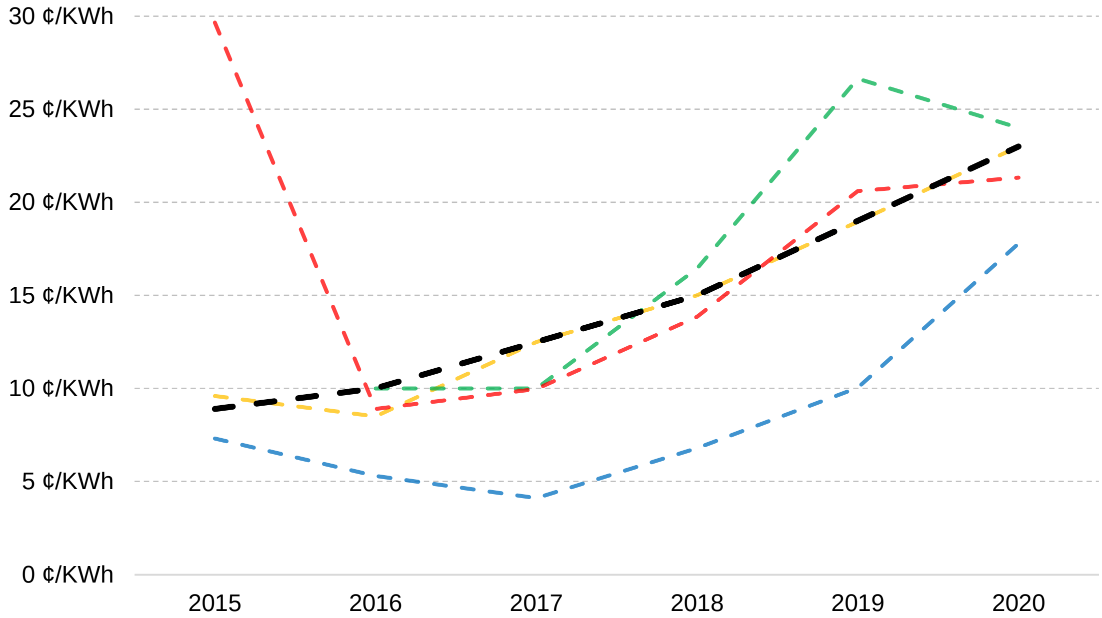


Table 11 summarizes the volume of energy exported from small micro-generators, by different rate ranges. In 2019 and 2020, there were significant increases in energy associated with retail rates ranging from 18¢/kWh to 22¢/kWh.

Table 11: Micro-generation energy by ranges of retail rate (MWh by $/KWh)

Year	(0, 0.02]	(0.02, 0.04]	(0.04, 0.06]	(0.06, 0.08]	(0.08, 0.1]	(0.1, 0.12]	(0.12, 0.14]	(0.14, 0.16]	(0.16, 0.18]	(0.18, 0.2]	(0.2, 0.22]	(0.22, 0.24]	(0.24, 99]	Total (MWh)
2015	11	266	936	1,538	471	6	2	0	0	0	0	0	2	**3,233**
2016	323	1,080	1,424	1,453	195	2	0	0	0	0	0	0	0	**4,477**
2017	96	3,133	1,397	2,299	170	0	9	0	0	0	0	0	0	**7,103**
2018	4	177	4,316	6,129	479	73	55	710	4	0	0	0	0	**11,947**
2019	15	229	5,956	11,360	325	124	21	266	5	2,490	2	0	0	**20,794**
2020	1	2,093	9,616	11,270	441	8	40	25	5	344	4,629	456	0	**28,930**

What is the total cost of the associated payments in absolute terms and relative to a proxy for the market value of the electricity production?

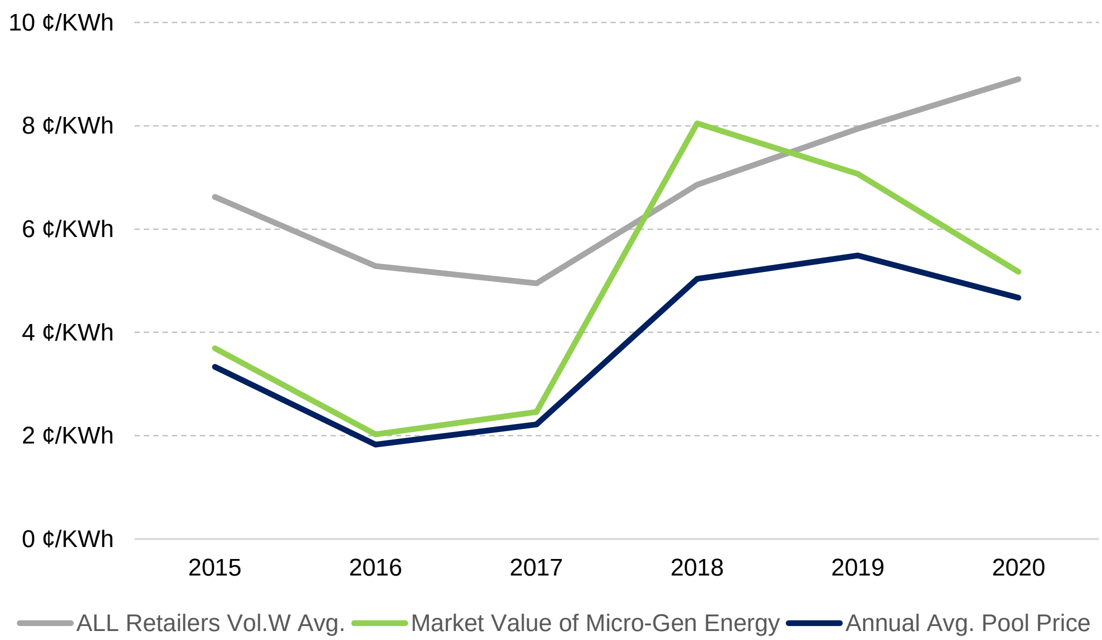
The MSA has observed increasing volumes of energy receiving small micro-generator compensation at increasing retail rates, the highest of which do not appear to be based on costs or the market value of electricity. Table 12 summarizes the volume of exported energy from small micro-generators and payments.

Table 12: Volume of exported energy from small micro-generators and payments

Year	MWh	Payments issued
2015	3,233	$214,137
2016	4,477	$236,711
2017	7,103	$351,651
2018	11,947	$819,390
2019	20,794	$1,651,227
2020	28,930	$2,575,297

The MSA estimated the counterfactual rate that a utility-scale solar generation facility would receive when selling at hourly pool price given a typical generation profile. The counterfactual is the market value of the generation from small micro-generator units. The hourly power pool price and therefore the counterfactual market value accounts for the cost of carbon emissions and, as with other renewable generators, compensation for additional environmental attributes may be available outside of the electricity market. Figure 46 illustrates the estimated[66] average annual market value of energy from small micro-generation units, compared to annual average pool price and the volume-weighted average rate charged by all small micro-generation retailers.

Figure 46: Volume-weighted average rates by year



[66] This market value estimate is calculated based on the received price of utility scale solar assets, which weighs pool prices by the hourly capacity factor of generation from the following solar assets: BSC1, VXH1, HUL1, INF1, and SUF1. A new asset is included in the capacity factor calculation once it has delivered energy to the grid. For the years 2015 through 2017, the percent price premium that an average solar asset would receive is based on the percent premium the aforementioned assets received compared to pool price in the year 2020.

A comparison of the actual rates illustrated in Figure 44 to the market value in Figure 46 makes clear that the actual rates are increasingly high compared to market value. To consider the total cost of this difference, Table 13 compares actual small micro-generation program costs, in column 1, to the market value of the generation, holding the volume of small micro-generation constant, in column 2. The difference is recorded in column 3. This analysis suggests that in 2020, small micro-generators in aggregate received approximately $1.1 million in excess of the market value of the electricity that they produced.

Table 13: Actual and counterfactual small micro-generation program costs (millions of dollars)

	Actual [1]	**Counterfactual [2]**	**Difference [3]**
	Program cost	**Market value**	**Program cost less market value**
2019	1.65	1.50	0.15
2020	2.58	1.48	1.10
Jan 2019 to Feb 2021	4.50	3.25	1.25
Effective average rate from Jan 2019 to Feb 2021	8.58¢/kWh	6.20¢/kWh	2.38¢/kWh

What would the cost be had all units been paid the maximum rate?

The MGR does not limit the maximum retail rate for small micro-generators. Table 14 compares actual program costs with counterfactual program costs had all retailers charged maximum rates. Column 2 shows program costs if all retailers charged the highest rate observed in each month, with at least 1 MWh of export volume. Column 3 shows program costs if all retailers charged 100.00¢/kWh, the highest rate observed.[67] Had all retailers decided to set rates equal to the highest observed rate in each month for which there was at least 1 MWh of export volume, the program cost in 2020 would have been $6.6 million, compared to the actual cost of $2.6 million. If all retailers instead set rates of 100.00¢/kWh the 2020 program costs would have been $28.9 million.

[67] In April 2018, a payment for 143.01 KWh was observed at a rate of 100¢/kWh, resulting in a payment of $143.01. Although higher rates have been observed, these rates do not relate to net payments. The highest rate observed since the start of the MSA's analysis occurred in 2016. Records indicate a payment for 4.67 KWh at a rate of 4,152.5¢/kWh resulted in a payment for $193.88; however, there are also records for a chargeback for 4.67 KWh at the same rate, for the same site, resulting in no net payment.

Table 14: Actual and counterfactual small micro-generation program costs (millions of dollars)

	Actual [1]	**Counterfactual [2]**	**Counterfactual [3]**
	Program cost	**Rate = highest significant rate observed in each month**	**Rate = highest rate ever observed**
2019	1.65	3.92	20.79
2020	2.58	6.58	28.93
Jan 2019 to Feb 2021	4.50	11.18	52.41
Effective average rate from Jan 2019 to Feb 2021	8.58¢/kWh	21.33¢/kWh	100.00¢/kWh

What are the incentives faced by retailers (market participants) in the setting of these rates?

The MGR provides retailers with a strong incentive to compete for micro-generation customers by offering high rates and flexibility to switch between rates. Without appropriate limits in place, the MSA believes that the incentives encourage further increases in retail rates for micro-generators, with no obvious limit. Offering high rates to micro-generators acts as an additional incentive for customers to switch retailers, at no additional cost to the retailer, since the costs of micro-generation exports are paid by other consumers. While retailers do not receive a mark-up on the rate that is paid to small micro-generation generating units, they earn additional administration fees when they serve a larger number of customer accounts. The retailer also receives excess margin for any energy consumed by the micro-generator while on a high rate.

What constraints, either competitive or regulatory, restrain retailers from offering at rates above market value and consequently the total cost borne by Alberta consumers?

The MSA has not identified significant competitive or regulatory restraints on this behaviour. While concerns regarding adherence to the spirit of fair, efficient, and open competition could be a possible restraint on this conduct, this has not prevented a small number of retailers from expanding their offerings at rates above market value. The MGR does not provide for any limit on the rate charged by retailers or the costs payable by other consumers in respect to this program.

Are there any efficiency-enhancing aspects associated with retailers offering at rates above market value?

The MSA has not identified efficiency-enhancing aspects to retailers offering at rates above market value. The higher ranges of rates offered by retailers are often in excess of the MSA’s estimated fair market value. The most efficient outcome would be for each micro-generator to receive the real time value of their exports in the Alberta electricity market and the market value for their displacement of carbon emissions. This is the value captured in the MSA's counterfactual market rate.

In some cases micro-generators are paid a rate significantly above market value of their energy and other micro-generators receive a rate below market value. The MSA believes this outcome is neither fair nor efficient.

Are retailers who set rates above market value complying with the EUA and the regulations under the EUA?

It is the MSA's view that retailers who set rates above market value have strictly complied with the explicit language of the MGR. The MGR requires that:

> 7(5) […] a micro-generator's service provider shall credit the micro-generator for electric energy supplied out of the micro-generator's micro-generation site at the following rates:
>
> > (a) in the case of small micro-generation, at the rate the service provider charged the micro-generator for electric energy supplied to the micro-generation site; […]

The AESO is then required by section 7(6) of the MGR to compensate the retailer an amount equal to the energy supplied out of the site during the month, multiplied by the rate the service provider charged the micro-generator for electric energy supplied to the site during the month. The MSA believes that section 7 of the MGR allows the retailer to specify any rate for micro-generators to pay and be compensated at, and requires the AESO to reimburse the retailer for the cost of the exported energy. As such, offering at retail rates above market value does not appear to be in contravention of the MGR. This does not imply compliance with any other applicable legislation or regulation.

Are retailers who set rates above market value supporting the fair, efficient, and openly competitive operation of the electricity market? Does this conduct have an adverse effect on the structure and performance of the electricity market?

It is an open question for the MSA whether retailers that set rates above market value are supporting the fair, efficient, and openly competitive operation of the electricity market. As discussed above, retailers paying rates above market value results in wealth transfers from Alberta rate payers in general to those with small micro-generators. The MSA is of the view that market participant conduct that results in an inefficient allocation of resources may also have an adverse effect on the structure and performance of the electricity market.

5.2 Retailer security

The MSA received a complaint from a competitive retailer against a distributor regarding the terms and conditions of service for retailers operating in the wires service area. The allegation was that the security requirements were higher than allowed by the *Distribution Tariff Regulation*[68] (DT Regulation), which provides the framework for the relationship between retailers and distributors. The complaint asserted that this could be used as a means of increasing the costs for retailers competing in the wires service area to the benefit of the distributor's affiliated retailer.

The requirement for the posting of security is a way to protect wires owners in the event of retailer bankruptcy. The DT Regulation specifies the maximum security as the sum of 45 days of estimated daily charges owing to the distribution service provider. At the time of the complaint the maximum requirement was 75 days, which was changed to 45 days on March 1, 2021. Additionally, section 8(6) of the DT Regulation states:

> 8(6) **If a retailer's actual outstanding charges under the owner's distribution tariff are materially greater** than the value projected by the retailer under subsection (2), the owner must update the projection under subsection (2) and, if additional security is required based on the updated projection, **require the retailer to provide the additional security.** [Emphasis added]

Clearly, the regulation contemplates that a wires owner can demand additional security in cases where the actual amount owed is more than the posted amount.

The wires owner at issue in the complaint had an upfront requirement that automatically required an increased amount of prudential from all retailers without consideration of actual amounts owed. The maximum prudential requirement was effectively increased from 75 days to 90 days. This increased security requirement could act as a means of discouraging retailer competition in the wires owner's service area.

Following discussions with the wires owner, changes were made to align the terms and conditions with the DT Regulation and the MSA matter has been closed.

[68] *Distribution Tariff Regulation*

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, 2021 the MSA closed 104 ISO rules compliance matters, as reported in Table 15.[69] An additional 118 matters were carried forward to the next quarter. During this period 14 matters were addressed with NSPs, totalling $24,250 in financial penalties, with details provided in Table 16.

Table 15: ISO rules compliance outcomes from January 1 to March 31, 2021

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.12	1	1	-
201.1	1	-	-
201.3	-	2	-
201.4	2	-	-
201.7	2	-	1
203.3	21	2	-
203.4	21	1	1
203.6	3	1	-
205.3	6	1	-
205.4	4	-	-
205.5	5	2	1
205.6	7	3	-
304.4	-	1	-
306.4	2	-	-
306.5	2	-	-
502.5	2	-	-
502.6	2	-	-
505.3	1	-	-
505.4	5	-	-
Total	**87**	**14**	**3**

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

Table 16: Specified penalties issued between January 1 and March 31, 2021 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)									Total ($)	Matters
	103.12	201.3	203.3	203.4	203.6	205.3	205.5	205.6	304.4		
Balancing Pool							250			250	1
Capital Power (Whitla) L.P.				750						750	1
CNOOC Marketing Canada / ENMAX Balzac LP			750							750	1
Hut 8 Holdings Inc.						750				750	1
Northstone Power Corp.								750		750	1
TA Alberta Hydro LP			5,000							5,000	1
TransAlta Generation Partnership	500	500					10,000		500	11,500	4
TransCanada Energy Sales Ltd.					750					750	1
Voltus Energy Canada Ltd.								3,250		3,250	2
Whitecourt Power Ltd.		500								500	1
Total	500	1,000	5,750	750	750	750	10,250	4,000	500	24,250	14

The sections of ISO rules listed in Table 15 and Table 16 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
505	Legal Owners of Generating Facilities

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 (generators, transmission operators/owners, independent system operators, and distribution system operators/owners) 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 creates a security risk in itself. As such, the MSA will only report aggregated statistics regarding CIP ARS.

From January 1 to March 31, 2021, the MSA closed 36 O&P ARS compliance matters, as reported in Table 17.[70] An additional five matters were carried forward to the next quarter. During this period, four matters were addressed with NSPs, totalling $6,750 in financial penalties, with details provided in Table 18. For the same period, the MSA closed 110 CIP ARS compliance matters, as reported in Table 19,[71] and 40 matters were addressed with NSPs, totalling $104,500 in financial penalties. An additional 62 matters were carried forward to the next quarter.

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

[71] Of the 110 closed matters, one was rejected.

Table 17: O&P ARS compliance outcomes from January 1 to March 31, 2021

Reliability standard	Forbearance	Notice of specified penalty
EOP-001	1	-
EOP-005	1	-
EOP-008	1	-
FAC-008	4	3
FAC-501-WECC	1	-
PER-005	3	-
PRC-002	1	-
PRC-005	6	1
PRC-018	1	-
PRC-023	2	-
VAR-002	9	-
VAR-002-WECC	2	-
Total	32	4

Table 18: Specified penalties issued between January 1 and March 31, 2021 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)		Total ($)	Matters
	FAC-008	**PRC-005**		
AltaLink L.P., by its general partner, AltaLink Management Ltd.	2,250		2,250	1
TransAlta Generation Partnership		2,250	2,250	1
Western Sustainable Power Inc.	2,250		2,250	2
Total	4,500	2,250	6,750	4

O&P ARS listed in Table 17 and Table 18 are contained within the following categories:

EOP	Emergency Preparedness and Operations
FAC	Facilities Design, Connections, and Maintenance
PER	Personnel Performance, Training, and Qualifications
PRC	Protection and Control
VAR	Voltage and Reactive

Table 19: CIP ARS compliance outcomes from January 1 to March 31, 2021

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	3	1	3
CIP-003	1	3	-
CIP-004	9	7	2
CIP-005	4	5	-
CIP-006	4	3	1
CIP-007	30	10	-
CIP-010	11	9	-
CIP-011	1	2	-
Total	63	40	6

The ARS listed in Table 19 are contained within the following categories:

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