Quarterly Report for Q4 2020

February 12, 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 overall price level in the Alberta market indicates the power pool was competitive in Q4 2020.

- The average pool price for 2020 was $46.72/MWh, which is 15% lower than 2019 and 7% lower than 2018. The lower annual pool price was driven in part by lower demand, increased wind generation, and more imports into Alberta on average.

- The average pool price in Q4 2020 was $46.13/MWh, a 1.8% decline compared to Q4 2019, and a 5.2% increase compared to Q3 2020. In 92% of hours in Q4 2020, the pool price was below $50/MWh, with high levels of wind generation on average, particularly in November. The average pool price was increased by a small number of high-priced hours, particularly in October when low wind generation during peak hours occurred while the BC/MATL intertie was on a planned outage.

- Compared to Q2 and Q3 of 2020, year-over-year demand in Q4 increased notably. On an annual basis, average demand for electricity was 2.4% lower in 2020 compared to 2019.

- In hindsight, the price of the Calendar 2020 (CAL20) forward contract generally traded at a premium to the realized pool price of $46.72/MWh with the last trade priced at $56.20/MWh and a volume-weighted average trade price of $49.36/MWh. The lower demand and higher wind generation in 2020 were likely principal factors in this market outcome. The monthly flat contracts for 2020 also traded at a premium to pool price on average, with a premium of $5.07/MWh for the year.

- Trading activity in the forward market increased in Q4 2020, largely as a result of more trading of CAL21 and CAL22, with increased volumes trading at the higher price levels. The trading volumes for monthly contracts remain lower than historical averages; for example, monthly traded volumes for December 2020 were 41% lower than for December 2019.

- The total cost of operating reserves was 33% lower in Q4 2020 compared to Q4 2019. A principal driver behind this decline was the reduction in the average cost of active reserves. The lower costs for active reserves were driven by reduced demand, particularly for regulating reserves, and also by lower-priced offers to supply these markets. The MSA continues to observe some inefficiencies in the markets for standby reserves, where the cost of activating standby reserves is sometimes higher than the prevailing cost of energy.

- From October 1 to December 31, 2020, the MSA closed 168 ISO rules compliance matters; 23 matters were addressed with notices of specified penalty. From October 1 to December 31, 2020, the MSA closed 47 Alberta Reliability Standards Operations and Planning compliance matters; nine matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Annual summary

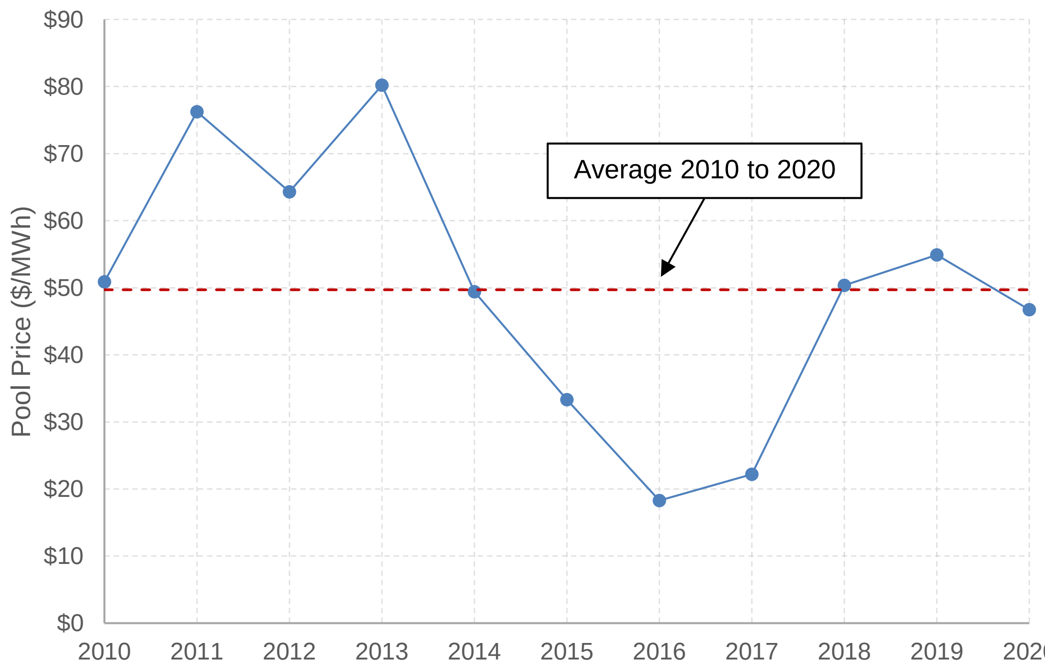
The average pool price in Q4 was \$46.13/MWh, bringing the average pool price for 2020 to \$46.72/MWh. Market summary statistics for the last four years are reported in Table 1.

Figure 1 provides historical context for the average pool price of 2020. As shown, the average pool price in 2020 was lower than some years, such as 2011, 2012 and 2013, and higher than other years, such as 2015, 2016 and 2017.

Table 1: Annual market summary statistics

	2020	2019	2018	2017
Pool Price (Avg \$/MWh)	46.72	54.88	50.35	22.19
Demand (AIL) (Avg MW)	9,462	9,695	9,741	9,426
Gas Price (Avg \$/GJ)	2.11	1.68	1.44	2.05
Wind (Avg MW)	690	470	469	512
Net Exports (+) Net Imports (-) (Avg MW)	-440	-174	-304	-31
Supply Cushion (Avg MW)	1,933	1,604	1,785	2,077

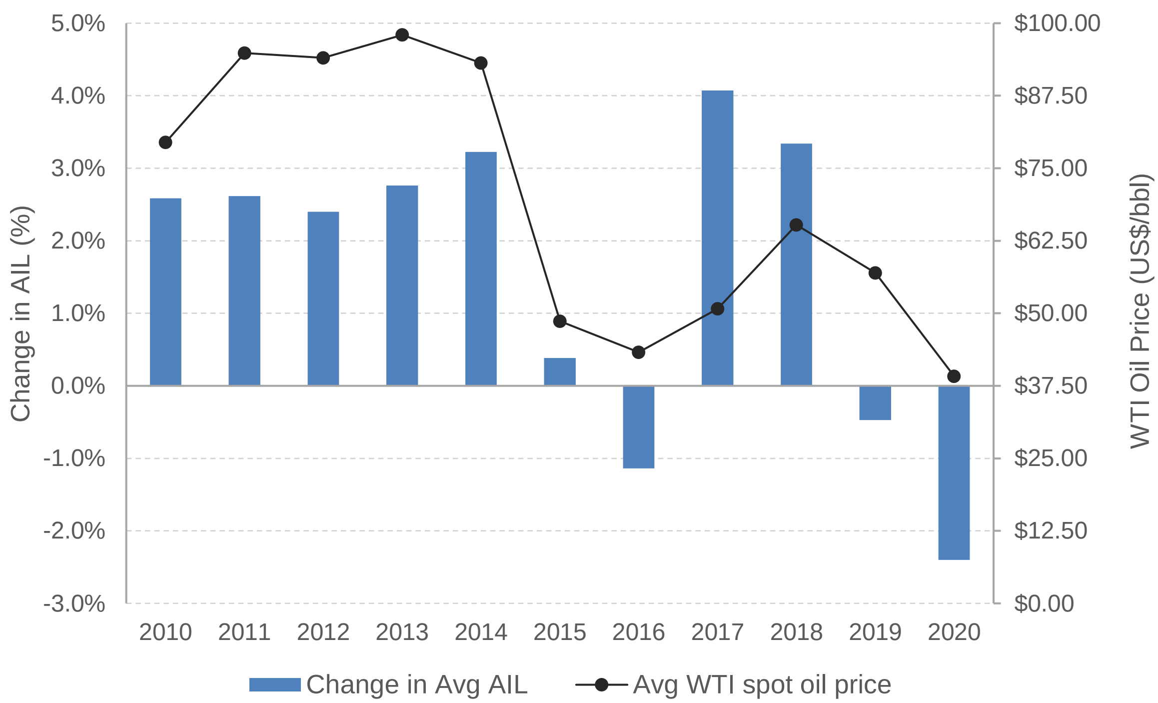
Figure 1: Average pool price by year (2010 to 2020)



Compared to recent years, the average pool price for 2020 was \$8.16/MWh (15%) lower than 2019 and \$3.63/MWh (7%) lower than 2018. The lower average pool price in 2020 was driven in part by lower demand for electricity, higher levels of wind generation, and greater imports (Table 1).

The reduction in economic activity and the decline in oil prices that resulted from the COVID-19 pandemic were major factors in the lower electricity demand observed in 2020. West Texas Intermediate ("WTI") spot oil prices averaged US$39.16/bbl in 2020, compared with US$56.99/bbl in 2019 and US$65.23/bbl in 2018 (see Figure 2).[1] In 2020, average Alberta Internal Load ("AIL") was 233 MW (2.4%) less than 2019, 279 MW (2.9%) less than 2018, and was similar to the average AIL in 2017 (Table 1). The relationship between the change in Alberta's average demand for electricity year-over-year and the average spot price of WTI oil since 2010 is shown in Figure 2.

Figure 2: The annual change in Alberta electricity demand and average WTI oil prices (2010 to 2020)



Wind generation increased notably in 2020 with average hourly wind generation of 690 MW, which was 220 MW (47%) higher than 2019. From late 2019 to early 2020, three new wind assets came online adding 336 MW of capacity and bringing the total installed wind capacity to 1,781 MW. In addition to the new capacity, there was also an increase in the overall capacity factor of wind assets, which increased from 32% in 2018 and 31% in 2019 to 39% in 2020.[2]

[1] EIA Data – Cushing, OK WTI Spot Price FOB

[2] The generation and capacity of new wind assets are included in the capacity factor calculations once the asset has provided electricity to the grid; this avoids including new wind assets that have a stated capacity but are not actually available.

Overall net imports into Alberta were also high in 2020, averaging 440 MW, which was 267 MW (153%) more than in 2019, when average pool prices were higher. Indeed, the annual average net imports of 440 MW is the highest annual average figure on record, with the previous high of 398 MW set in 2012.[3] The increased imports in 2020 were likely driven by a high level of hydro supply and reduced demand for electricity in other jurisdictions.[4]

Higher natural gas prices increase the fuel costs for gas-fired generators, and may increase electrical demands related to natural gas supply. In 2020, the average same day price of natural gas was $2.11/GJ, which was 26% higher than in 2019 and 47% higher than in 2018, although the 2020 price level was still low compared to historical natural gas prices. While there has been an increasing amount of gas-fired generation in Alberta in recent years, coal-fired units often set the System Marginal Price ("SMP"). In 2020, coal-fired units set the SMP 57% of the time, converted coal units 11% of the time, and gas-fired units 29% of the time.[5] The variable cost of coal-fired generation increased considerably in 2018 as a result of changes to Alberta's carbon pricing regime. From 2018 to 2020, the carbon tax on a coal-fired unit with carbon emissions of around 1.0 tCO2e/MWh has been approximately $18.90/MWh (not including the cost of coal itself). This was slightly greater than the average fuel cost of approximately $16.90/MWh for an efficient combined-cycle gas unit in 2020, which under Alberta's good-as-best-gas carbon standard paid negligible carbon costs.

1.2 Quarterly summary

The overall price level in the Alberta market indicates the power pool was competitive in Q4 2020. Table 2 provides summary market statistics for Q4 2020 compared to Q4 2019. The average pool price of $46.13/MWh in Q4 2020 was 1.8% lower than in Q4 2019 and 5.2% greater than in Q3 2020. Pool prices were below $50/MWh for 92% of hours in Q4 2020.

As shown by Table 2, monthly pool prices were highest in October, with an average price of $61.26/MWh compared to $38.44/MWh in November and December. The higher pool prices in October were partly due to a 13-day outage on the BC/MATL intertie and lower average wind generation. October was the only month in Q4 with a higher average pool price compared to last year.

Electricity demand in the quarter increased with greater economic activity and higher oil prices. Alberta's electricity demand in November was 1.6% higher than last year, the first month in which

[3] Uses imports and exports data going back to January 1, 2001.

[4] As of April 1, 2020 the Peace Snow Basin Index was estimated at 121% of normal (BC government – Snow Survey and Water Supply Bulletin – April 1, 2020, see page 9). The Peace River feeds into some large hydro assets (BC Hydro – Peace Region).

For example, average demand in BC was 1.4% lower in 2020 compared to 2019 (BC Hydro – Balancing Authority Load Data).

[5] 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.

there was a year-over-year increase since March. On November 24, increased public health measures were announced in Alberta, which may have affected December demand. The average temperature in December was -5.3°C, which is 3.1°C warmer than December 2019; warmer temperatures in winter decrease electricity demand related to heating loads. Demand in December was on average 1.0% lower in 2020 compared to 2019, although this year-over-year decline is considerably less than was observed for months earlier in 2020, such as May (-6.6%) and July (-5.4%). This may be a reflection of oil prices; by December oil prices had stabilized with Alberta Western Canadian Select ("WCS") oil prices averaging US$33.59/bbl for the month, compared to US$21.95/bbl in May and US$31.78/bbl in July.[6]

On the supply side, wind generation in Q4 2020 was 21% higher than Q4 2019 (Table 2). This is partly attributable to new wind generation capacity but is also due to a higher capacity factor in Q4 2020. In November average wind generation was 1,040 MW, a new monthly record high by a margin of 233 MW (29%) over the previous high set in February 2020. The capacity factor for wind generation in November was 58%, which is substantially higher than historical data, with the previous high being a capacity factor of 50%.[7] On some days in Q4 2020, higher levels of wind generation served to somewhat offset a number of coal assets being offline on forced outage.

Table 2: Monthly market summary for Q4

		2020	2019	*Change*
Pool Price (Avg $/MWh)	Oct	61.26	41.86	46%
	Nov	38.44	56.15	-32%
	Dec	38.44	43.19	-11%
	Q4	**46.13**	**46.97**	**-2%**
Demand (AIL) (Avg MW)	Oct	9,393	9,438	-0.5%
	Nov	10,068	9,913	1.6%
	Dec	10,241	10,346	-1.0%
	Q4	**9,899**	**9,899**	**0.0%**
Gas Price AB-NIT (2A) (Avg $/GJ)	Oct	2.35	2.14	10%
	Nov	2.68	2.61	3%
	Dec	2.44	2.23	10%
	Q4	**2.49**	**2.32**	**7%**
Wind (Avg MW)	Oct	666	715	-7%
	Nov	1,040	658	58%
	Dec	857	736	16%
	Q4	**852**	**703**	**21%**
Net Exports (+) Net Imports (–) (Avg MW)	Oct	-100	-140	-29%
	Nov	-324	-264	23%
	Dec	-307	-168	83%
	Q4	**-243**	**-190**	**28%**
Supply Cushion (Avg MW)	Oct	1,685	1,687	0%
	Nov	2,053	1,558	32%
	Dec	1,730	1,602	8%
	Q4	**1,820**	**1,616**	**13%**

Imports into Alberta were significantly limited for around half of October as the BC/MATL intertie was on outage for planned maintenance; this largely explains the reduction in imports for October year-over-year. In November and December, imports were higher compared to 2019, despite average pool prices being lower this year. As discussed above, Alberta has seen high import flows this year, which are likely the result of a strong hydro year and reduced demand for electricity in other jurisdictions.

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[6] Oil Sands Magazine – Oil and Gas Prices > Monthly Average Oil Prices

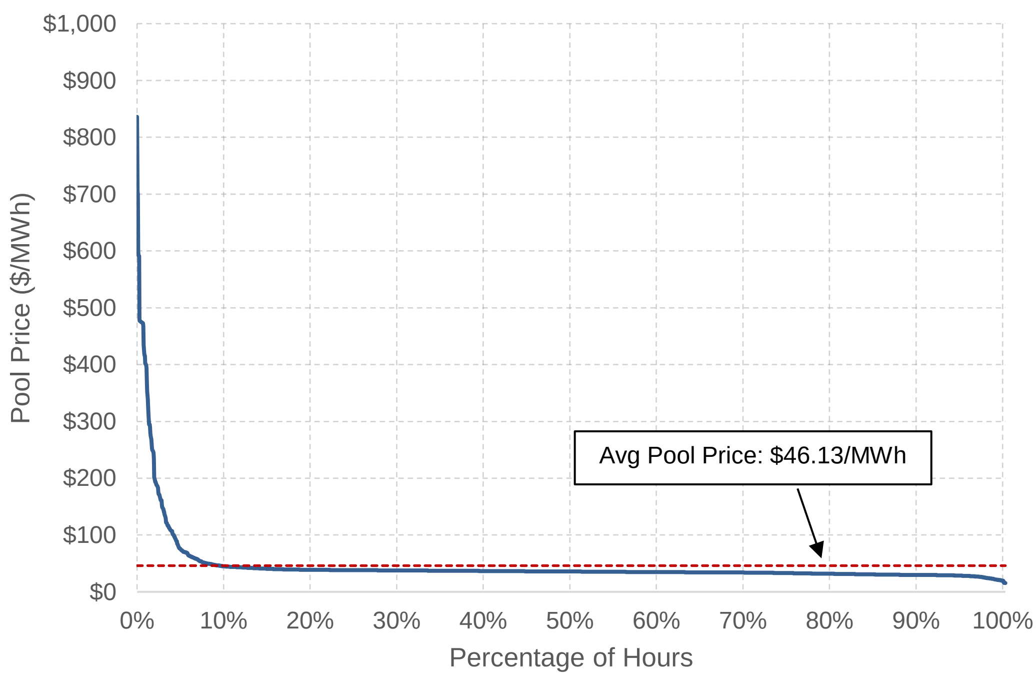
[7] Uses wind generation and capacity data going back to January 1, 2010

Table 2 provides monthly average prices for same day natural gas, although these figures do not fully reflect the dynamic changes observed in Q4 2020. In mid-October, the price of natural gas increased by 189%, from $1.10/GJ to $3.18/GJ, over eleven days. This occurred in part because of the transition to winter, when more gas is used for heating, in addition to less shale production in the US, and increasing LNG exports.[8] The price stayed around $3.00/GJ until early November when it started to trend down. This downward trend continued into early December, with prices reaching $2.10/GJ on December 7. Prices increased slightly thereafter, closing the year at $2.38/GJ.

The supply cushion is a measure of available generation capacity in the energy merit order that is not being used to meet prevailing demand in a given hour. A higher supply cushion value indicates more available capacity competing to serve demand, so higher values of supply cushion are generally associated with lower pool prices, and vice versa. As shown in Table 2, supply cushion was, on average, slightly higher in Q4 2020 compared to Q4 2019. This is partly explained by the higher levels of wind generation and imports, as discussed above.

1.3 Market outcomes

Figure 3: Pool price duration curve (Q4 2020)



The solid line in Figure 3 illustrates the distribution of pool prices in Q4 2020. In particular, the line depicts the percentage of hours with pool prices that were above the corresponding level. In 9.5% of hours in the quarter the pool price was above the average of $46.13/MWh (shown by the

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[8] ICE NGX AB-NIT same day index (2A)

CBC News: Winter is coming — and that could be good news for Alberta's natural gas sector (October 11, 2020) dashed line). The average pool price in these top 9.5% of hours was $154.01/MWh and these hours accounted for $14.57/MWh (32%) of the average pool price for the quarter. The 5% of hours with the highest pool price contributed 26% to the average pool price, and most (63%) of these hours occurred during the BC/MATL intertie outage in October.

This distribution of pool prices is not unusual, as shown by Table 3. In 2020, the 5% of hours with the highest pool price accounted for 34% of the average annual pool price. In 2019 and 2018 the top 5% of hours accounted for 32% and 31% of the average annual pool price, respectively. The concentration of revenue in these high priced hours provided a strong incentive for generation to be available and producing during these hours. Similarly, price-responsive loads had an incentive to reduce consumption during these hours, if possible, in order to lower overall electricity costs. In the long-run higher pool prices in Alberta's energy-only market signal scarcity and incentivize investment in generation capacity.

Table 3: The distribution of pool prices by year (2018 to 2020)[9]

	All Hours	**Top 5% of hours**		**5% to 15% of hours**		**Lowest 85% of hours**	
	Avg Pool Price	**Avg Pool Price**	**Contr. To Avg**	**Avg Pool Price**	**Contr. To Avg**	**Avg Pool Price**	**Contr. To Avg**
2018	$50.35	$316.63	31%	$65.04	13%	$24.71	56%
2019	$54.88	$355.69	32%	$75.31	14%	$26.26	54%
2020	$46.72	$319.42	34%	$45.63	10%	$20.56	56%

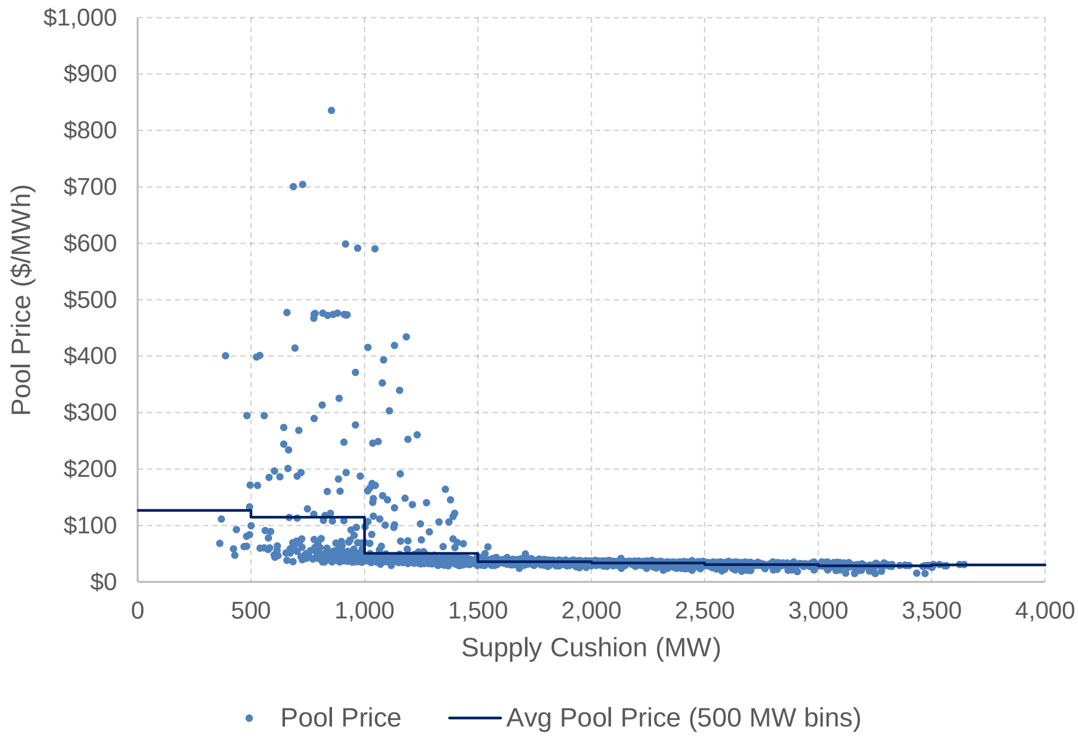
Pool prices during the quarter ranged from $15/MWh to $836/MWh. In contrast to Q2 and Q3 of this year, there were no supply surplus events in Q4. The late fall to early winter normally brings increased demand and reduced imports in comparison to the spring and summer months, so supply surplus is less likely in Q4, even though wind generation is often higher at this time of year.

Figure 4 illustrates the relationship between hourly supply cushion and pool price in Q4 2020.[10] As expected, pool prices tend to be lower when the supply cushion is higher. The figure also shows that the relationship between pool price and supply cushion was more defined when supply cushion was above around 1,500 MW. At lower values of supply cushion there was a much wider range of pool price outcomes. Lower supply cushion values reflect tighter market conditions, such as cold temperatures driving up heating demand in combination with supply restrictions, such as low wind generation or a BC/MATL intertie outage. A low supply cushion hour with a high pool price may be reflective of higher generator offer prices, which may be increased in recognition that there is less supply to serve prevailing demand.

[9] Contribution to the average is calculated by summing the pool prices for all relevant hours (e.g., the top 5%) and then dividing by the total number of hours in the year. This dollar value is expressed here as a percentage of the average annual price.

[10] The supply cushion value is a summary measure of supply-demand conditions in the energy market. In particular, the supply cushion is a calculation showing how much available generation capacity the market has above that which is required to meet prevailing demand.

Figure 4: Scatterplot of supply cushion and pool price (Q4 2020)



However, as shown by Figure 4, there were a number of hours with a low supply cushion that did not result in a high pool price. A low supply cushion hour with a relatively low pool price often reflects less generation capacity offered at a higher price. This may, among other reasons, be caused by the inability of suppliers to forecast the tight market conditions, but may also reflect the portfolio position of one or more large suppliers. For example, a supplier with a large amount of fixed-price sales and a large generating unit on outage may have limited commercial incentive to offer its remaining capacity at prices above its short-run marginal cost.

Table 4 below provides pool price distribution summary statistics for Q4 2020. In October the 5% of hours with the highest pool price averaged $426/MWh and accounted for 36% of the monthly average price. The average pool price in the top 5% of hours in November and December were much lower at $96/MWh and $94/MWh respectively, and accounted for 13% of the monthly average price. However, the overall price level observed during the majority of lower priced hours was very similar across all months in Q4. As shown, the average pool price observed in the lowest 85% of hours was very similar in all three months at around $34/MWh. In summary, the higher pool prices observed in a small percentage of hours in October were the primary cause behind the higher average pool price for that month.

Table 4: The distribution of pool prices by month in Q4 2020

	All Hours	Top 5% of hours		5% to 15% of hours		Lowest 85% of hours	
	Avg Pool Price	**Avg Pool Price**	**Contr. To Avg**	**Avg Pool Price**	**Contr. To Avg**	**Avg Pool Price**	**Contr. To Avg**
Oct	$61.26	$425.83	36%	$105.33	17%	$34.18	47%
Nov	$38.44	$95.63	13%	$42.73	11%	$34.48	76%
Dec	$38.44	$94.38	13%	$42.49	11%	$34.61	76%
Q4 2020	**$46.13**	**$239.87**	**26%**	**$49.09**	**11%**	**$34.32**	**63%**

1.3.1 October 2020

Figure 5 shows how pool price, demand, and supply cushion changed during the month of October. As shown, between October 13 and 25 the pool price was volatile on certain days. A primary driver of pool price volatility during this period was a planned outage on the BC/MATL intertie.

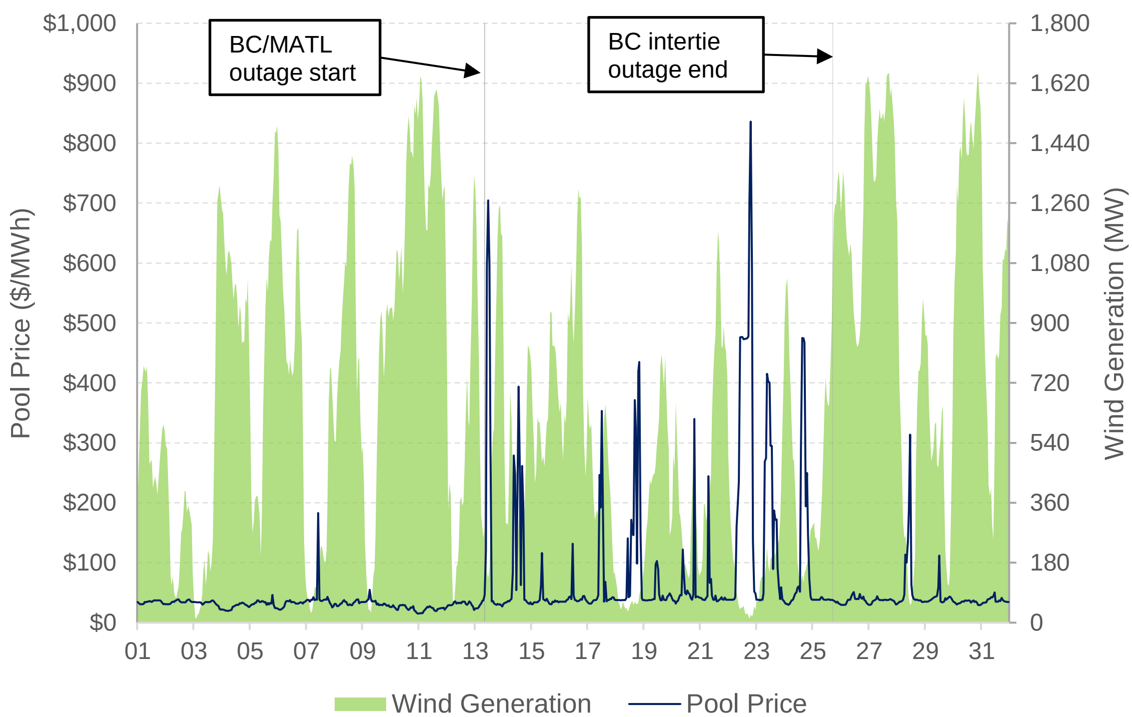
The BC/MATL intertie came offline in hour ending 9 (HE09) of October 13, with the BC intertie returning to service in HE18 of October 25, five days ahead of schedule. The pool price on October 13 increased shortly after the BC/MATL outage started with a pool price of $705/MWh in HE12. This high pool price reflected low wind generation, with an average of 134 MW in the hour, in addition to two coal plants being on outage.[11] As shown by Figure 6 pool prices were more volatile with lower levels of wind generation when the BC/MATL intertie was unavailable in October, as importers from BC and Montana were unable to provide additional supply.

In HE20 of October 22 the pool price was $836/MWh, which was driven by market fundamentals similar to October 13. In addition to the BC/MATL intertie being unavailable, wind generation was low, averaging 25 MW, one coal plant was on outage, and there were outages at natural gas units with a total capacity of approximately 420 MW.

[11] The number of coal assets on outage quoted here does not include Sundance 5, which has been mothballed since April 2018.

Figure 5: Pool price, demand, and supply cushion (October 2020)

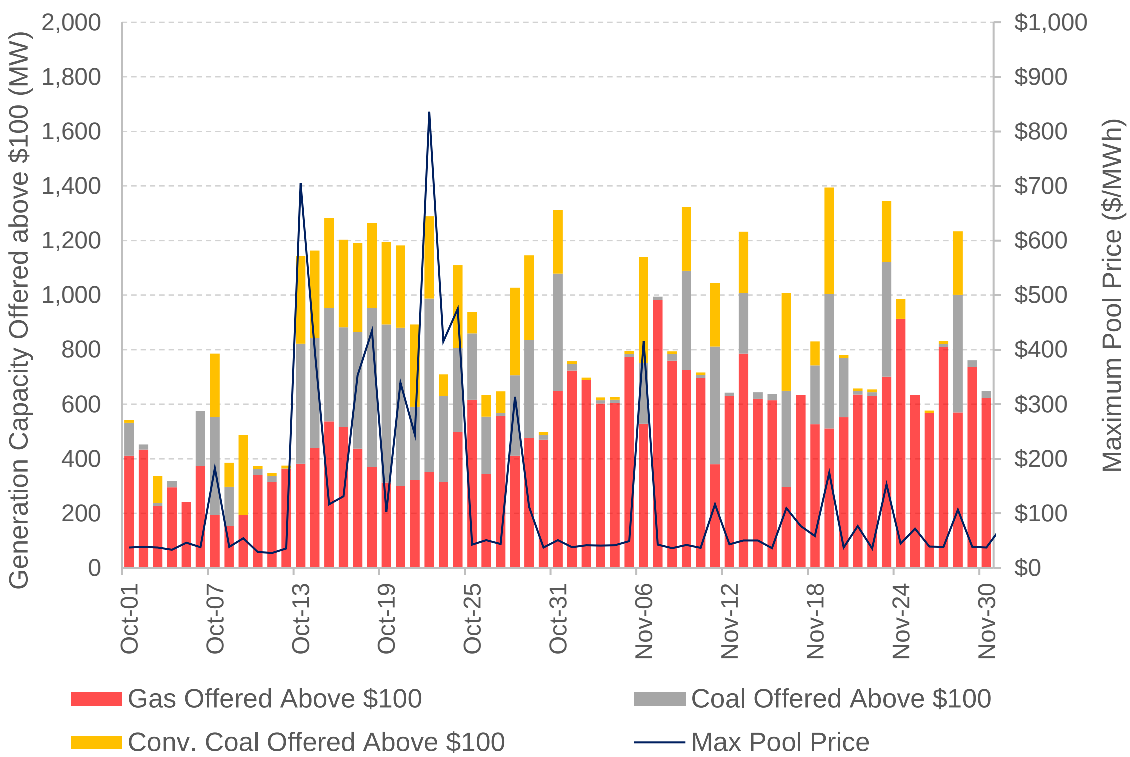
Figure 6: Pool prices, wind generation, and the BC/MATL intertie outage (October 2020)



Generator offer behaviour was also a factor in some of the higher pool prices observed in October as suppliers responded to market fundamentals of variable wind generation, thermal outages, and the BC/MATL intertie outage. Figure 7 illustrates the maximum daily pool price and the amount of thermal capacity offered at higher prices during that particular hour. As shown, participants responded to the reduced supply from BC and Montana in October as more high-priced offers were observed during that period (October 13 through October 25). High priced offers can be seen on other days in October and November, but pool prices were generally not as volatile outside of the intertie outage.

On some low-priced days there is actually a larger amount of gas generation offered at high prices, which may reflect market participants seeking to avoid short dispatches at low prices. An increased amount of starts and stops will increase the wear and tear on generation units, increasing maintenance costs. Therefore, when pool prices are lower, it is less likely for these starts and stops to be economic.

Figure 7: Daily maximum pool price and thermal offers above $100/MWh in that hour (October and November 2020)



The short-run marginal cost for gas generators is heavily influenced by the prevailing price of natural gas. Figure 8 shows the same day price of natural gas in Alberta for Q4 2020. As shown, there was a material increase in natural gas prices in mid-October when the same day price increased by 189%, from $1.10/GJ on October 11 to $3.18/GJ on October 22. The price increase was likely driven by a number of factors, including falling temperatures in Alberta, a reduction in

US shale production, and increasing demand for LNG exports.[12] Coal assets set the SMP 50% of the time in October, with converted coal assets accounting for 27% of the time, and natural gas units 20%. Therefore, the higher gas prices were another factor putting upward pressure on pool prices.

Figure 8: AB-NIT same day natural gas price (Q4 2020)[13]

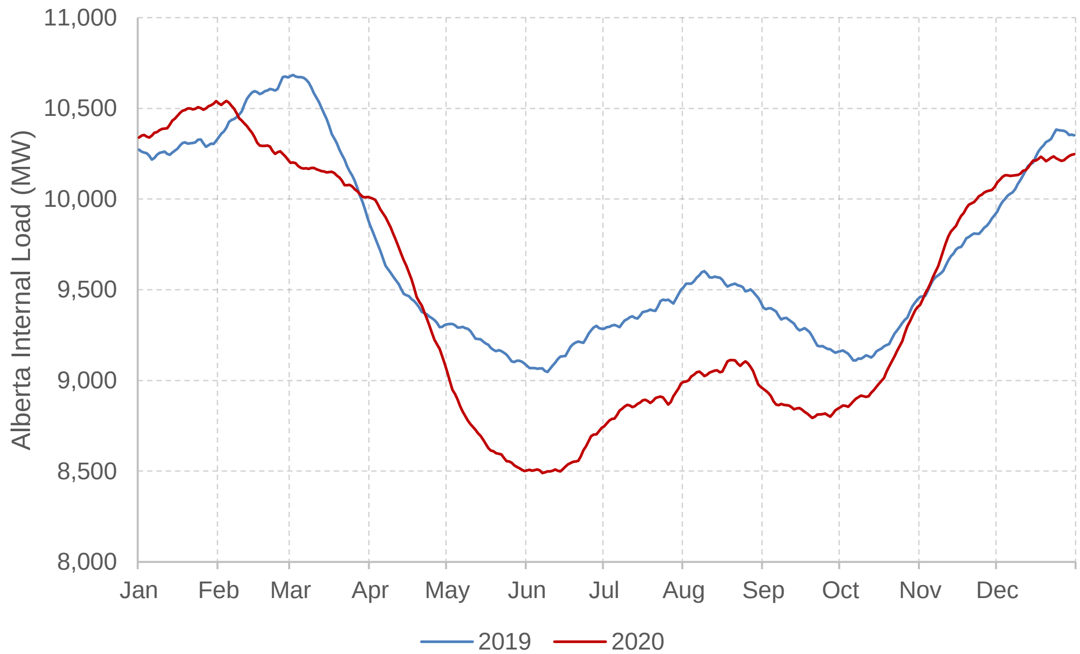
In October, AIL increased gradually from weekday peaks of around 9,500 MW early in the month to a peak of 10,532 MW on October 26 as average temperatures declined and economic activity in Alberta continued to increase (Figure 9).[14] Compared to 2019, average AIL in October 2020 was only 0.5% less and average temperatures were similar (0.6°C lower in 2020). This was a notable increase relative to months in the spring and summer, when average demand was generally 5-6% lower year-over-year (Table 5 on page 16).

[12] CBC News: Winter is coming - and that could be good news for Alberta's natural gas sector (October 11, 2020)

[13] ICE NGX AB-NIT Same Day Index (2A)

[14] AESO: Impact of the COVID-19 pandemic and low oil prices on Alberta load - December 2020 Update

Figure 9: AIL 30-day rolling average (2019 and 2020)



AIL can be broken out into system load and demand met by on-site generation. System load is the power that was consumed from the Alberta grid, and also includes transmission losses. This is generally represented by residential, commercial, and industrial consumers without self-supply generation.[15] Demand met by on-site generation is an estimate of power that was produced and consumed on the same site, and normally reflects large industrial loads, primarily oil and gas facilities, which have developed their own generation (e.g., an oil sands load with cogeneration). The increase in AIL year-over-year during the fall of 2020 was due to an increase in both system load and demand met by on-site generation (Table 5). These fundamentals are likely driven by increased economic activity: public health restrictions were reduced for a period, and oil prices stabilized with WTI generally trading between US$37/bbl and US$43/bbl from June through October, before increasing in November and December to close the year at US$48.52/bbl.[16]

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[15] *Ibid.*

[16] EIA NYMEX WTI Futures Prices – Contract 1

Table 5: Average demand by month in 2020 and year-over-year changes

	Total Demand (AIL) [A]		System Load [B]		Demand met by on-site gen. ([A] – [B])	
	Avg	**YOY**	**Avg**	**YOY**	**Avg**	**YOY**
Jan-20	10,517	2.0%	7,607	1.4%	2,910	3.6%
Feb-20	10,208	-4.5%	7,337	-6.6%	2,871	1.3%
Mar-20	10,008	0.9%	7,206	0.0%	2,802	3.3%
Apr-20	9,091	-2.3%	6,471	-3.2%	2,620	0.0%
May-20	8,503	-6.6%	6,089	-8.0%	2,414	-3.1%
Jun-20	8,739	-5.9%	6,372	-5.0%	2,367	-8.2%
Jul-20	8,974	-5.4%	6,602	-3.5%	2,372	-10.3%
Aug-20	8,971	-5.0%	6,721	-0.8%	2,250	-15.6%
Sep-20	8,845	-3.4%	6,451	-3.5%	2,394	-3.1%
Oct-20	9,393	-0.5%	6,780	-1.9%	2,613	3.5%
Nov-20	10,068	1.6%	7,251	0.7%	2,817	3.9%
Dec-20	10,241	-1.0%	7,255	-2.6%	2,986	3.0%
2020	**9,462**	**-2.4%**	**6,845**	**-2.7%**	**2,617**	**-1.7%**

Figure 10: Total estimated cost of constraints by month (January 2018 to December 2020)

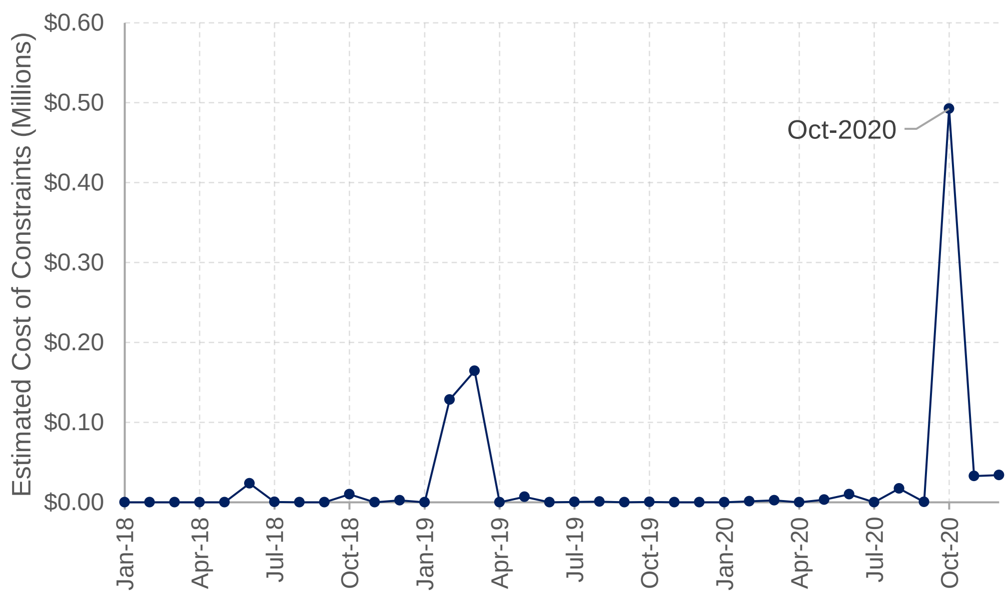


Figure 10 shows the total estimated cost of constraints by month since January 2018. As shown, the total estimated cost of constraints in October 2020 was abnormally high at almost $493,000. In October the AESO constrained the output of some large thermal generators because the AESO was concerned about managing a large contingency event, with the BC/MATL intertie offline and unavailable to provide additional supply in the event of a large generator trip. Almost 90% of the total estimated cost of constraints in October occurred when the BC/MATL intertie was unavailable.

Pool price errors on October 19

On October 19, 2020 in HE16, HE17, and HE18 the AESO initially posted pool prices that were inaccurate (Table 6). The AESO subsequently corrected the pool prices and publically announced the pool price corrections on their website.[17] In this announcement the AESO stated that the issue was "due to a rare data scenario in the dispatch tool," and that "this scenario caused an increase of transmission constraint rebalancing volume, resulting in the inaccurate pool price." Following the event, the MSA had discussions with the AESO to ensure that this rare occurrence was addressed appropriately. The MSA understands the permanent system fix was implemented by the AESO on January 28, 2021.

Table 6: Pool price errors on October 19, 2020

Date	HE	Originally Published Pool Price ($/MWh)	Corrected Pool Price ($/MWh)
October 19, 2020	16	35.79	36.91
October 19, 2020	17	42.38	44.90
October 19, 2020	18	37.98	38.17

1.3.2 November 2020

Demand continued to increase in November when average AIL was 1.6% higher year-over-year, the first time since March that monthly average AIL was higher this year (Table 5). Figure 11 illustrates pool price, AIL, and supply cushion for November 2020. As shown, pool price volatility in November was lower than in October despite higher levels of demand. The principle drivers of lower pool price volatility in November were increased intertie capacity available for imports and higher levels of wind generation (Table 7). In November average wind generation was 1,040 MW which represents a capacity factor of 58%. Using data going back to January 2010, the previous high for a monthly capacity factor was 50%, set in December 2011 and matched in October 2017. This illustrates that wind generation was exceptionally high in November, even accounting for the increase in wind capacity observed earlier in the year.

[17] AESO: Pool Price Errors (October 20, 2020)

Figure 11: Pool price, demand, and supply cushion (November 2020)

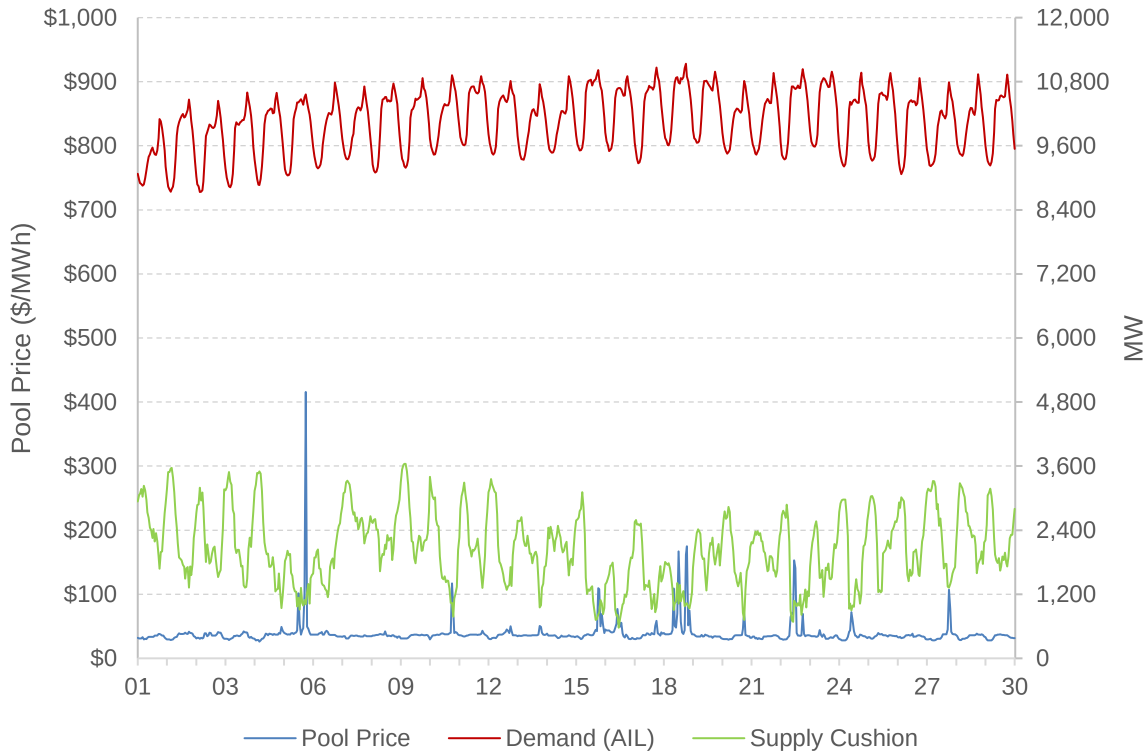


Table 7: Average wind generation and capacity factor by month (Q4 2020 and 2019)[18]

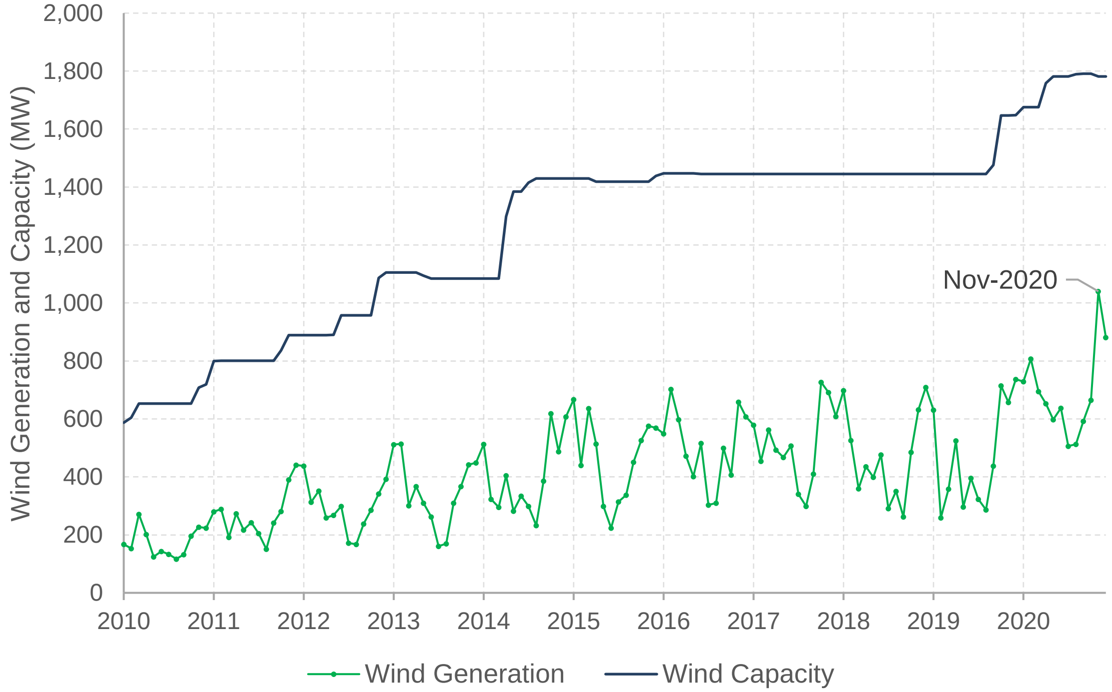
	2020		**2019**	
	Average Wind Gen. (MW)	**Capacity Factor**	**Average Wind Gen. (MW)**	**Capacity Factor**
Oct	666	37%	715	43%
Nov	1,040	58%	658	40%
Dec	881	49%	736	45%
Q4	**860**	**48%**	**703**	**43%**

Figure 12 illustrates the evolution of wind capacity and generation since 2010. On January 1, 2010 there was 587 MW of wind capacity in Alberta, and as of December 31, 2020 there was 1,781 MW, meaning that total wind capacity has tripled in ten years, and more wind capacity is scheduled to come online.[19] The most recent additions came online in late 2019 and early 2020, and these three assets were all part of round one of the Renewable Electricity Program (REP). As shown by Figure 12, average wind generation in November was materially higher than historically, and was driven by increased wind capacity and a material increase in capacity factor.

[18] The capacity of new wind assets is included in the capacity factor analysis when the assets start to provide electricity to the grid.

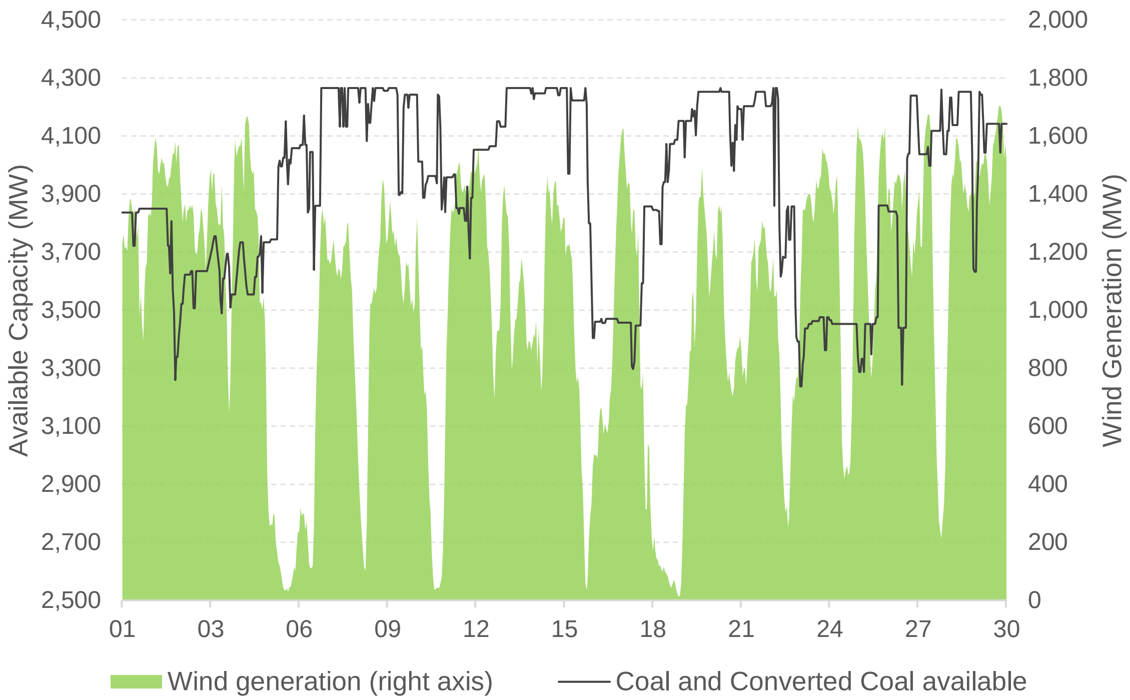
[19] See AESO Long Term Adequacy and REP Results for example.

Figure 12: Wind capacity and average wind generation by month (2010 to 2020)



The availability of coal generation was reduced by around 400 MW for much of Q4 as a large coal asset was unavailable from early September until early January 2021, although it briefly returned to the market for around four days in early November. In addition to this, there were a number of shorter outages at coal assets in November that further reduced the availability of thermal capacity. During the peak hours on many of these days wind generation was high, somewhat offsetting the reduced thermal supply and lowering the potential for pool price increases (Figure 13). For example, three coal units were on outage for the demand peak of 10,905 MW in HE18 of November 17, but average wind generation of 1,276 MW and 650 MW of imports increased supply and the pool price settled at $34.52/MWh.

Figure 13: Available coal and converted coal capacity and wind generation (November 2020)



As discussed previously, November was the first month since March in which average AIL increased year-over-year. This change was not driven by particularly cold temperatures in November 2020. As shown by Table 8 average temperatures in November 2020 were mild and comparable with those observed in November 2019. The increase in AIL was likely driven by increased economic activity, as public health measures were reduced for most of the month, in addition to increased industrial activity; Alberta WCS oil prices increased by 34% from US$25.74/bbl on October 30 to US$34.43/bbl on November 27.[20]

Table 8: Average temperatures by month (September to December 2020)

Month	2020	2019	Difference
Sep	11.96	10.98	0.97
Oct	1.78	2.41	(0.64)
Nov	(3.94)	(3.71)	(0.24)
Dec	(5.30)	(8.42)	3.11

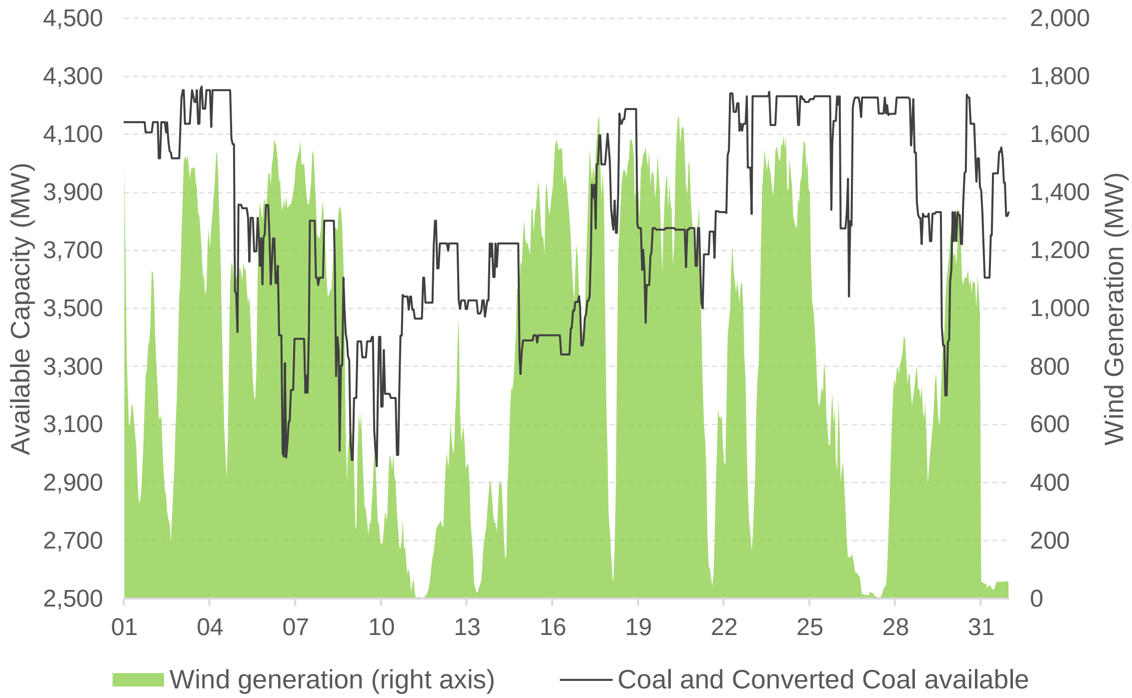
1.3.3 December 2020

Some of the market fundamentals in December were similar to November. In particular, there were a number of coal unit outages in December, which reduced overall thermal availability materially on some days (Figure 14). For example, on December 9 three coal assets were offline for the demand peak of 10,856 MW. In this example, wind generation averaged 397 MW and net

[20] Oil Sands Magazine: Oil and Gas Prices > Oil Prices by Location – Weekly Close

imports were 524 MW. These fundamentals, in addition to some high priced thermal offers, led to a pool price of $399/MWh, the highest in December (Figure 15 on page 22).

Figure 14: Available coal and converted coal capacity and wind generation (December 2020)



Average wind generation in December was 881 MW, a capacity factor of 49%. While these numbers were lower than November they are still high in comparison to historical wind output. That said, wind generation is a variable resource and was still low for some days in December (Figure 14). For example, on December 13 wind generation supplied an average of 298 MW during the evening peak of 11,503 MW in HE18. The weather on Sunday December 13 was cold, with average temperatures of -19°C in HE18. This peak weekend load was only 195 MW less than the highest AIL on record at the time, which was set at 11,698 MW in HE18 of Tuesday January 14, 2020 when average temperatures were -31°C.[21] In addition to the low wind and high demand, there were two coal units on outage on December 13. In response to these market fundamentals, importers supplied 677 MW to the market during HE18 and the pool price settled at $197/MWh.

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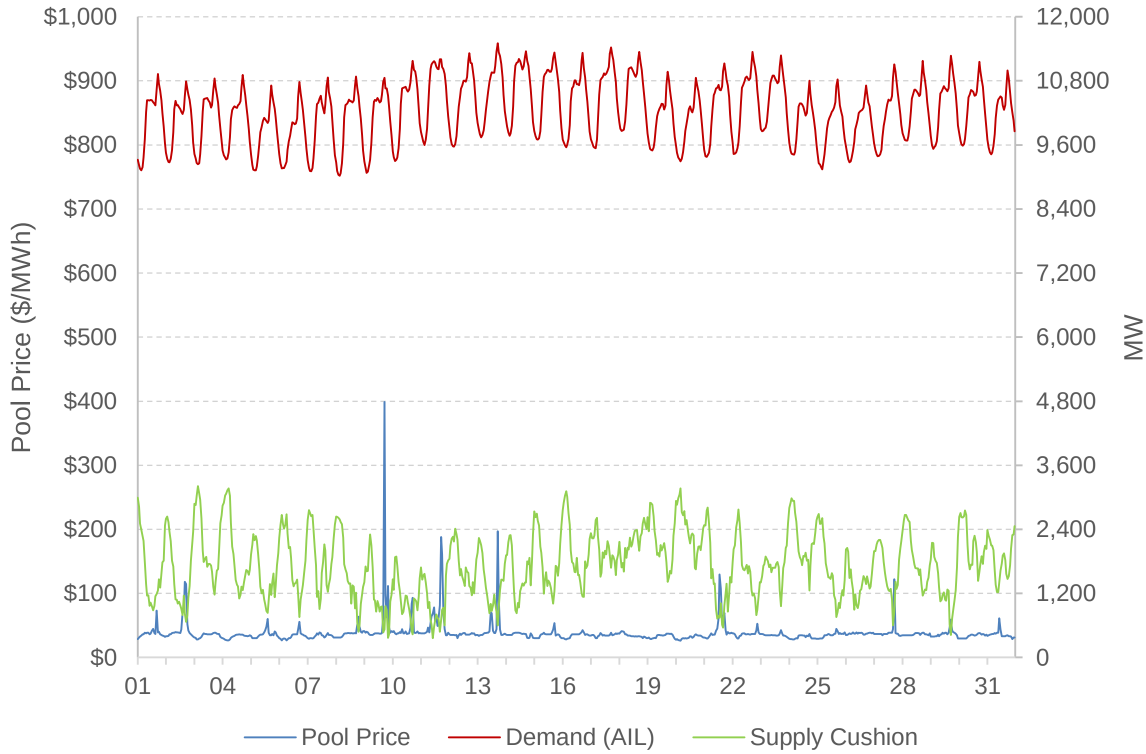
[21] Average of hourly temperatures in Calgary, Edmonton, and Fort McMurray.

Figure 15: Pool price, demand, and supply cushion (December 2020)



Average demand in December was 1.0% lower than average demand in December 2019. This likely reflects the milder temperatures in December 2020 in addition to the public health measures announced on November 24.[22] The average temperature in December 2020 was -5.3°C which is 3.1°C higher than the average temperature in December 2019 (Table 8). The higher temperatures in 2020 would have reduced electricity demands related to heating.

To see this, Figure 16 shows daily average temperatures for December 2020 compared to December 2019. The analysis has been weekday adjusted which means, for example, that the figure compares the average temperature on Tuesday December 1, 2020 and Tuesday December 3, 2019. As shown, in early December daily average temperatures were materially warmer in 2020 compared to 2019. On many days in this period, the average AIL in December 2020 was meaningfully lower than the equivalent weekday in 2019 (Figure 17). For instance, average temperatures on Wednesday December 9, 2020 were 17.1°C higher than those observed on Wednesday December 11, 2019 and average AIL was 600 MW (5.6%) lower.

[22] Global News: Alberta enacts 2nd COVID-19 state of public health emergency (November 24, 2020)

Figure 16: Daily average temperatures in December (2020 and 2019, weekday adjusted)[23]

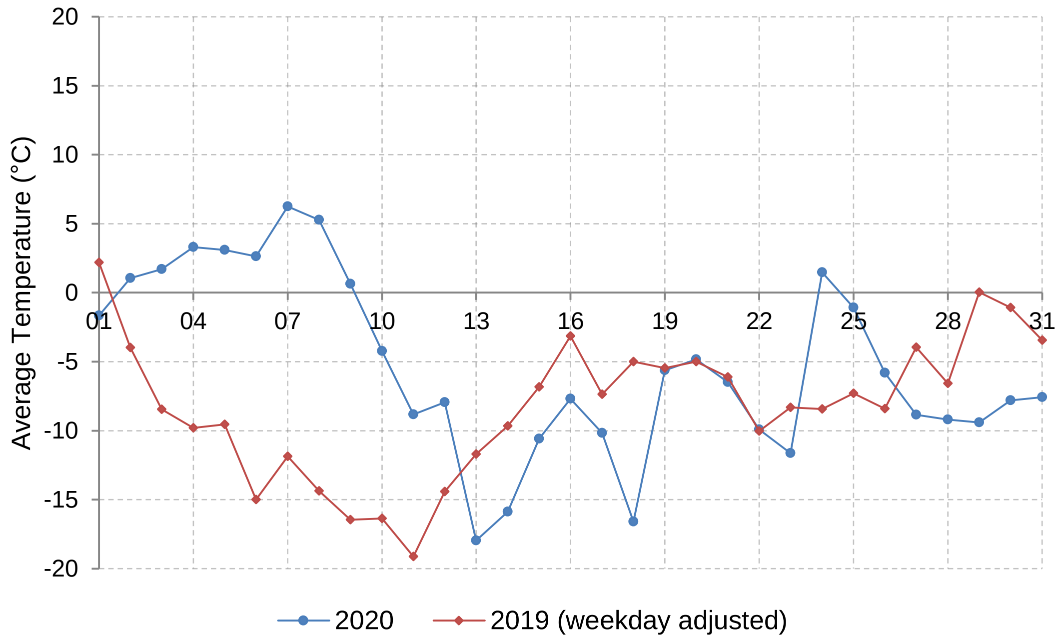
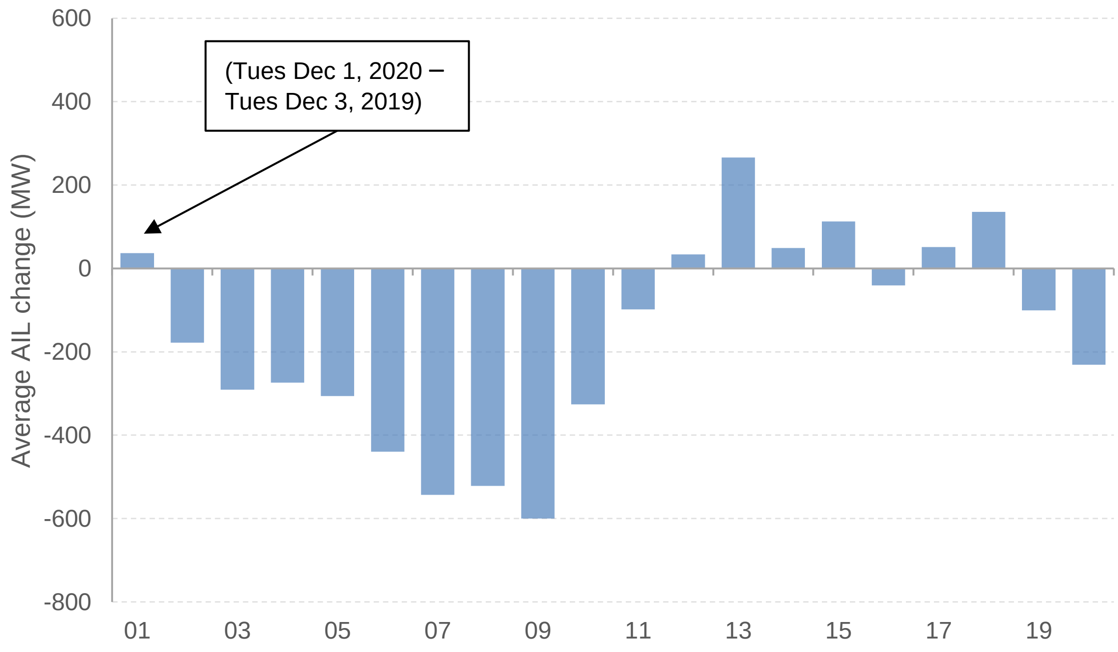


Figure 17: Year-over-year change of daily average AIL (December 1 to 20, weekday adjusted)

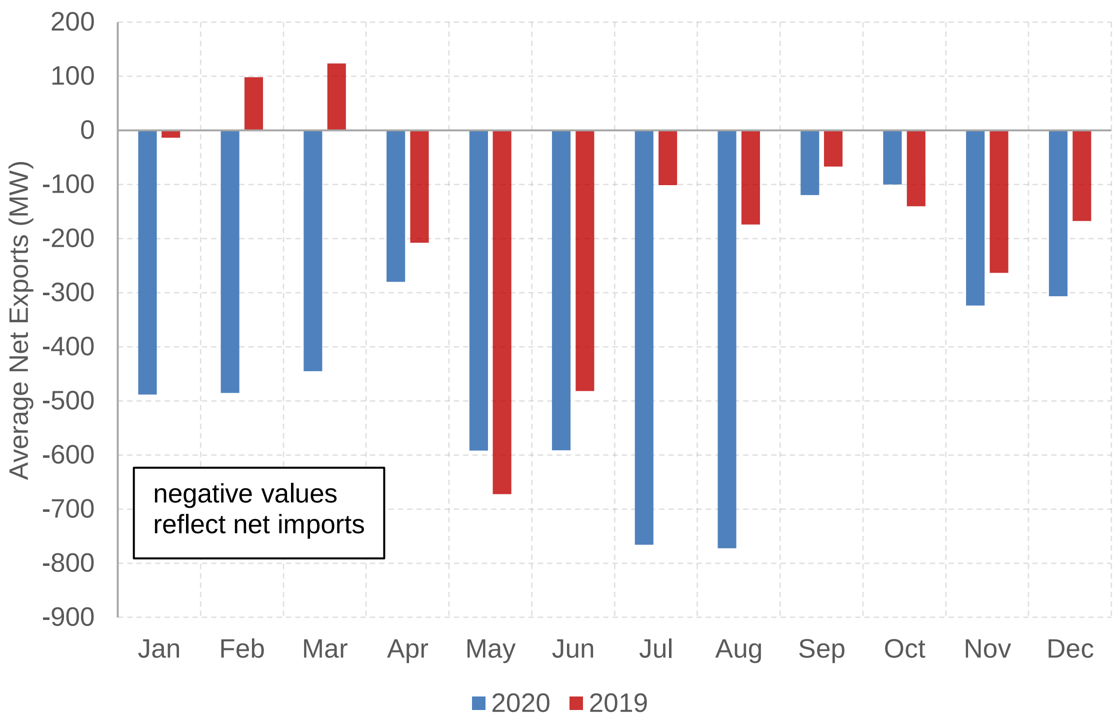


[23] Uses the average of hourly temperatures in Calgary, Edmonton and Fort McMurray

1.4 Interties

Imports into Alberta were significant in 2020. Average hourly net imports were 440 MW, the highest annual value on record, with 2012 setting the previous record at 398 MW.[24] Figure 18 shows average net flows by month for 2020 and 2019. The figure illustrates that net imports were only higher last year in May and October. In 2020 imports were exceptionally high in July and August and were elevated in January, February, March, May, and June. In Q4 2020 average net imports were generally lower. For 13 days in October the BC/MATL intertie was on a planned outage and average pool prices in November and December were relatively low at $38.44/MWh.

Figure 18: Average net exports by month (2020 and 2019)



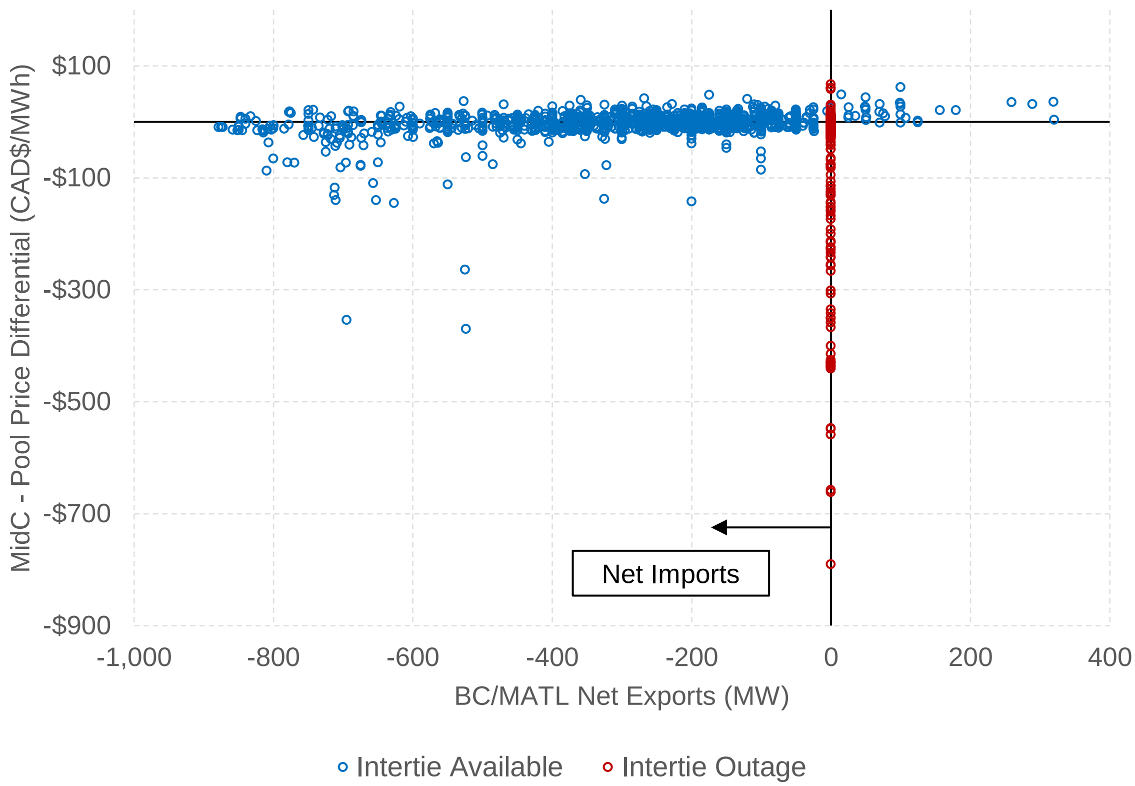
1.4.1 BC/Montana intertie

The BC/MATL intertie 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-Columbia (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.

[24] Uses import and export data going back to January 1, 2001. Hourly net imports are calculated as total imports less total exports.

Figure 19 shows a scatterplot of hourly net exports on BC/MATL against the hourly Mid-C less Alberta pool price differential in Q4 2020. 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 Mid-C and Alberta, with the bottom-left quadrant indicating 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 left, indicating a large number of hours in which the price differential was small and there was a net flow of power into Alberta. Hours in which the BC/MATL intertie was unavailable are distinguished in red because in these hours traders were not able to flow power in response to expected market conditions.

Figure 19: Scatterplot of BC/MATL net exports and Mid-C – Alberta price differential (Q4 2020)[25]



Outside of the intertie outage, 92% of hours in Q4 had a price differential of between -$20/MWh and $20/MWh. Therefore, in the vast majority of hours the absolute price differential was small (Table 9). In 42% of hours outside the BC/MATL intertie outage, realized prices were slightly higher in Mid-C than in Alberta, so the economic direction of flow was to export power from Alberta to Mid-C.[26] However, this is not the overall pattern of trading that was observed. In the vast majority of hours that had a low absolute price differential, traders tended to import power into

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

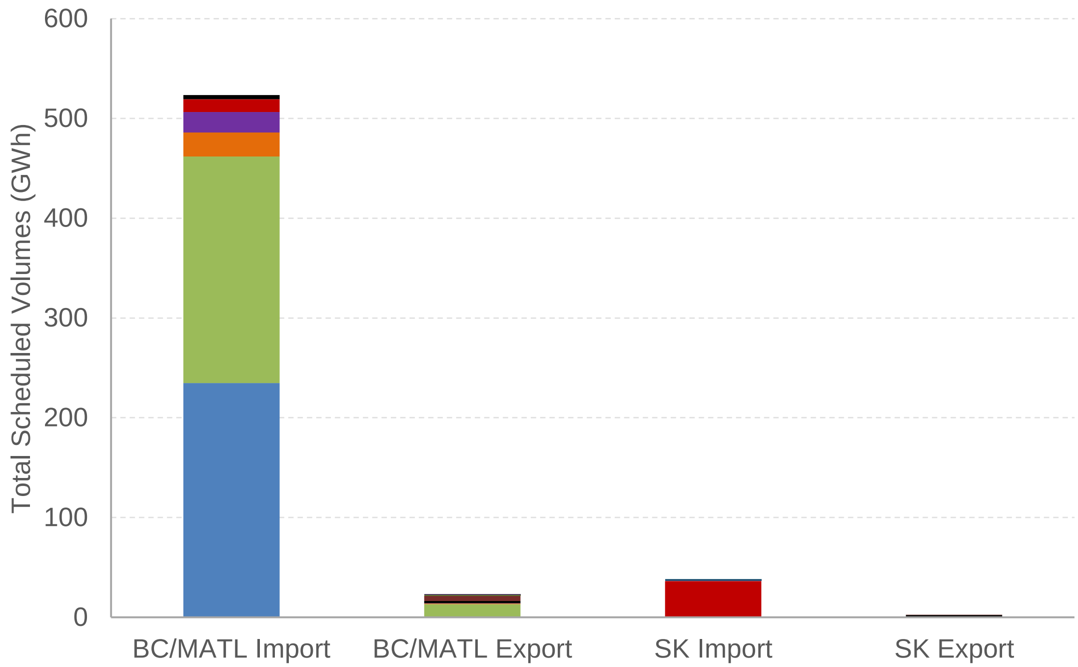
[26] In some hours the economic outcome may have been no flow of power due to transmission costs being too high relative to the price differential. See AESO: Pricing Framework Review Session 3 (May 21, 2020) at slide 39 for estimates of transmission costs.

Alberta. For example, in 82% of hours when realized prices were $10/MWh to $20/MWh higher in Mid-C, 100 MW or more was imported into Alberta. One potential explanation here 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.

Table 9: Percentage of hours in selected price differential ranges (Q4 2020, intertie outage excluded)

Mid-C - Pool Price Differential Range		**All Flows**		**BC/MATL Net Imports >= 100 MW**	
		Count [A]	**Percent of Hours**	**Count [B]**	**Percent [B] / [A]**
($20.00)	($10.01)	293	15%	275	94%
($10.00)	($0.01)	682	36%	590	87%
$0.00	$10.00	566	30%	488	86%
$10.01	$20.00	224	12%	184	82%
TOTALS		**1,765**	**92%**	**1,537**	**87%**

Figure 20: Intertie scheduled flows by market participant in Q4 2020



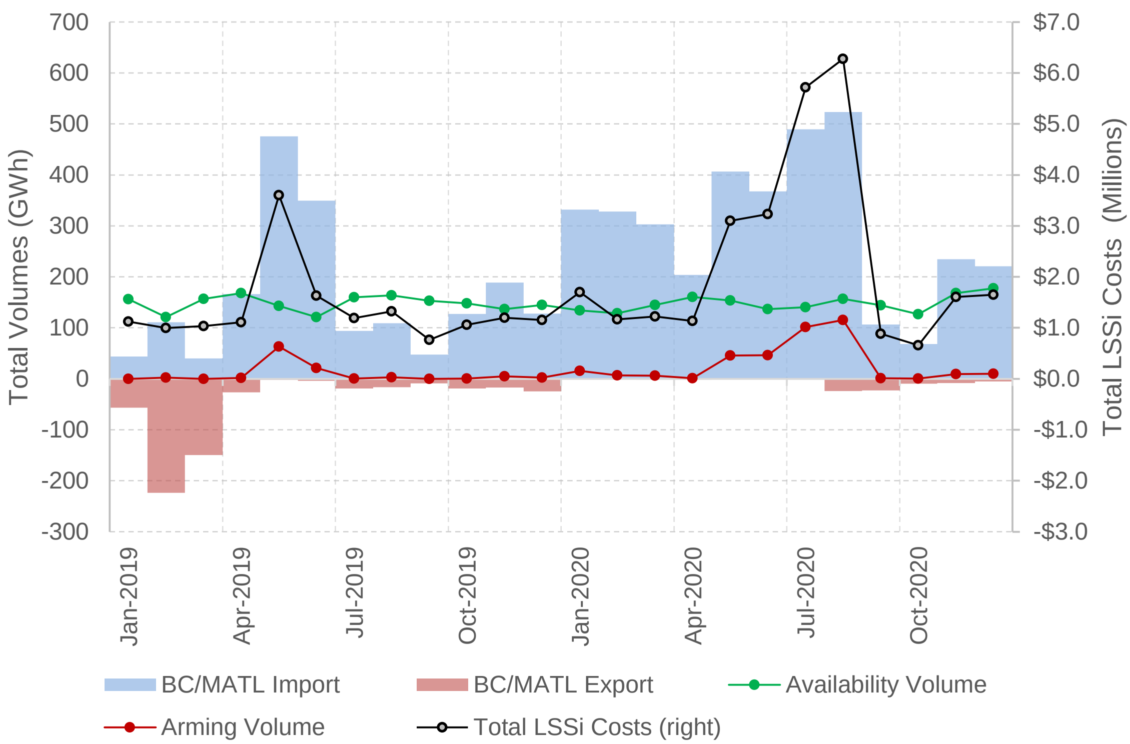
1.4.2 Participation on the interties

The trading and flow of electricity in and out of Alberta in Q4 2020 was largely dominated by a relatively small number of market participants. The volume of electricity traded across Alberta's interties with (i) British Columbia and Montana and (ii) Saskatchewan in Q4 2020 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 Q4 2020 were largely carried out by two market participants, with one participant typically importing power on the connection with BC and the other on the MATL 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.

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.

Figure 21: BC/MATL import and export volumes, LSSi volumes, and LSSi costs by month (January 2019 to December 2020)



In 2020 the total cost of LSSi was approximately $28 million, an 89% increase over 2019. The higher cost in 2020 was largely due to higher import volumes, in addition to changes in the LSSi table. The AESO implemented changes to the LSSi table, effective June 22, 2020 and more recently on August 12, 2020, to include LSSi requirements for severe weather conditions.[27] As discussed in the MSA Q2 and Q3 reports, the LSSi table change on June 22 increased the volume of LSSi the AESO is required to procure. In Q4 2020 total LSSi costs were 70% less than Q3

[27] AESO ID#2011-001R, ATC and Transfer path Management, effective August 12, 2020 (page 12 of 21)

2020, as import volumes fell and the BC/MATL intertie was unavailable for 13 days in October (the AESO does not pay availability payments for LSSi when the BC/MATL intertie is unavailable).

1.5 PPA expirations

On December 31, 2020, the remaining thermal Power Purchase Arrangements (PPAs) pertaining to the assets at Genesee, Keephills, and Sheerness expired, along with the Hydro PPA. Offer control for these assets now rests fully with their owners. The PPAs came into effect on January 1, 2001 and were a significant component of Alberta's electricity market for many years.

The fundamental role of the PPAs was to help transition Alberta's wholesale electricity market from regulation to competition, where multiple suppliers compete with one another to serve demand. The thermal PPAs were legislated contracts that set out the terms by which the PPA Buyer would compensate the owner of the underlying asset for its operating and maintenance costs. In return, the PPA Buyer received the right and obligation to offer the contracted capacity into Alberta's electricity markets and retain the associated revenues. These 'virtual divestitures' increased the number of suppliers in the wholesale market and served to increase competition.

All outstanding PPAs expired at the end of 2020, including the Hydro PPA. Each of the market participants whose offer control increased as a result of this had other assets in the market. In particular, the share of offer control held by these three market participants increased from 18% to 26%, from 11% to 14%, and from 8% to 13%. While the offer control associated with the units in the Hydro PPA has not changed, the expiration of the Hydro PPA eliminated the financial obligations on the owner of the assets. The Hydro PPA is discussed further in section 2.3. The MSA will provide detailed information regarding the current state of offer control in the wholesale market when it publishes its Market Share Offer Control Report for 2021 later this year.

The average pool price in January 2021 was $72.89/MWh, which is 58% higher than the average in Q4 2020, but 40% lower than the average price in January 2020. Pool prices in January 2021 were increased by market conditions and outcomes in the work week of January 25 to 29, when pool prices averaged $182.38/MWh; outside of these days pool prices averaged $51.83/MWh.

In early January temperatures were mild and wind generation was generally quite high, meaning prices were low; prices on January 1 to 3 averaged $35.62/MWh. On January 4, the first business day of the year, three coal and two converted coal assets were offline commercially, totaling around 1,700 MW of capacity (Figure 22). This amount of coal or converted coal capacity commercially offline is significantly higher than the market had observed in Q4 2020. Partly as a result of the reduced thermal supply, pool prices increased to average $80.26/MWh on January 4.

Figure 22: Coal and converted coal capacity commercially offline coincident with the daily maximum pool price (October 2020 to January 2021)

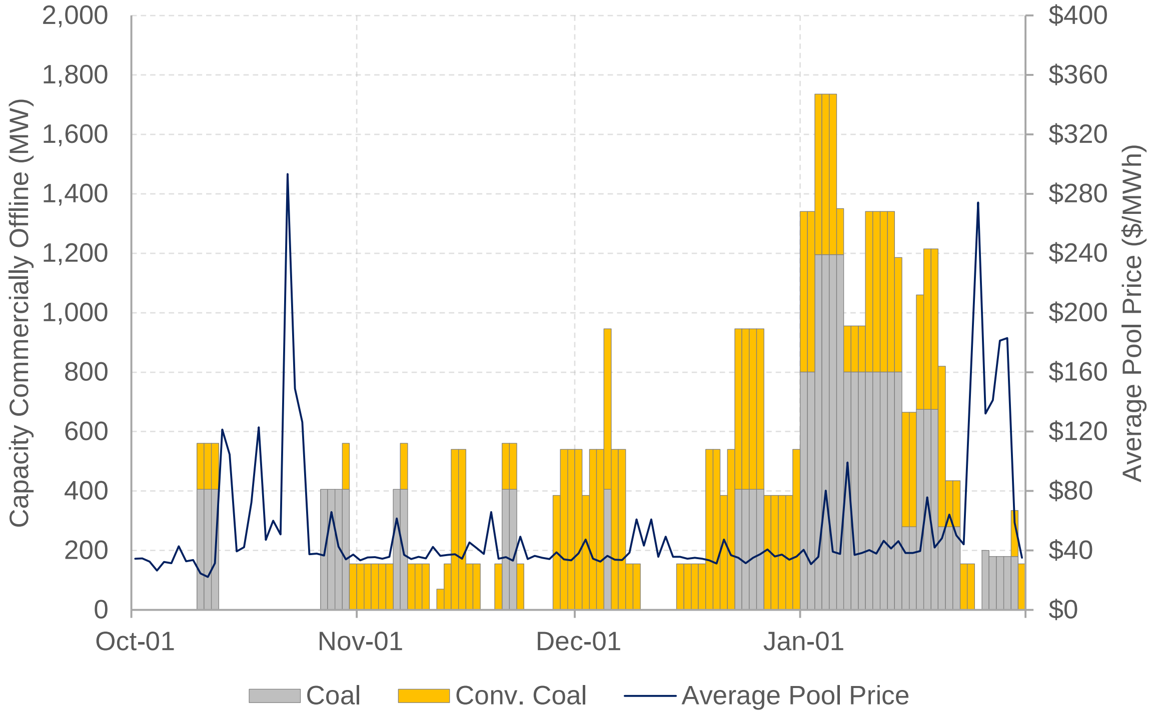
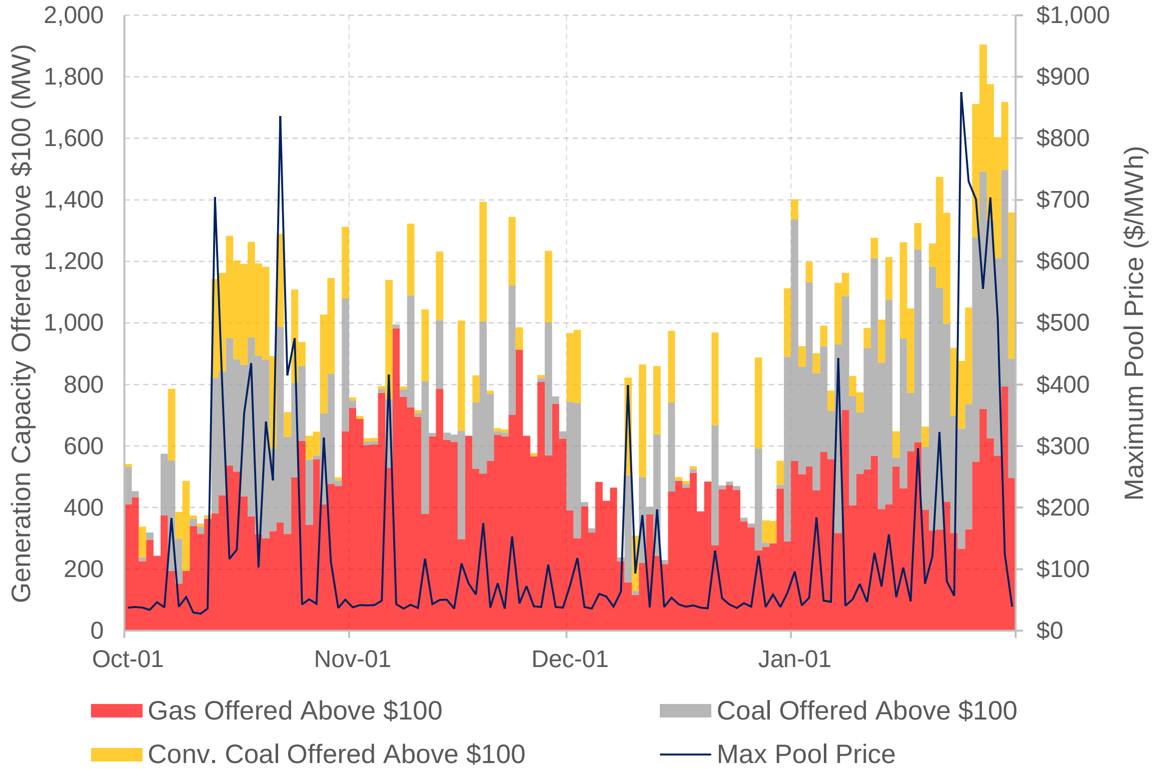


Figure 22 shows that the amount of coal or converted coal capacity commercially offline generally declined over the course of January as the week of January 25 approached. The cold weather, and associated higher demand and lower wind generation, were expected with the period of January 25 to 29 trading for $150/MWh in the forward market on January 11.

Figure 23 shows the amount of thermal capacity offered at a high price in the highest-priced hour of each day from October 1, 2020 to January 31, 2021. The figure shows a distinct increase in high priced thermal offers beginning in January, although these offers did not always translate into high pool prices in early January as market fundamentals, including mild weather and high wind generation, also affected the market.

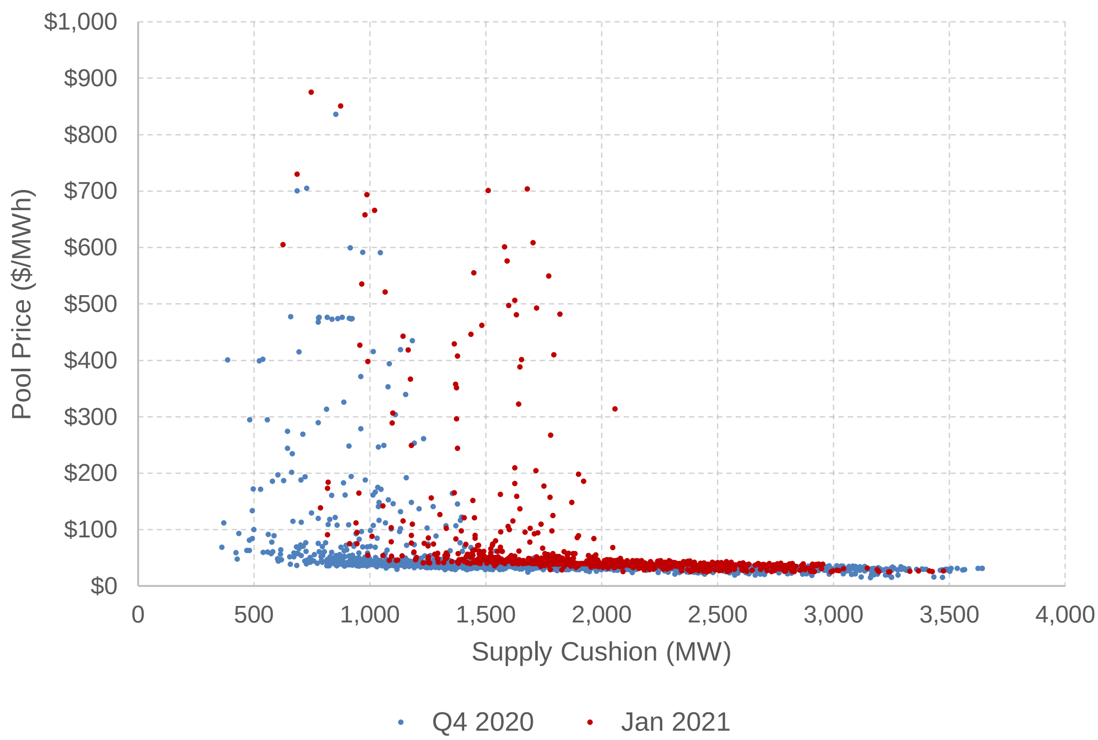
Figure 23: Daily maximum pool price and thermal offers above $100/MWh in that hour (October 2020 to January 2021)



Pool prices did increase beginning on Sunday January 24, as cold weather, low wind, and thermal unit outages combined to yield a supply cushion of 746 MW in HE18. Approximately 900 MW of thermal generation was offered above $100/MWh and the pool price was $875/MWh. Later that week a few thermal units returned from outage but prices remained high. In HE18 of January 26 the supply cushion was 1,510 MW and pool price was $701/MWh. As shown by Figure 23 there were a large number of high-priced offers into the market during the highest-priced hours of January 26 to 30, and one coal unit was commercially offline for much of this period (Figure 22).

Figure 24 provides a scatterplot of pool prices against supply cushion in January 2021 compared to Q4 2020. The figure illustrates that there were a number of high-priced hours in January 2021 when supply cushion was relatively high, more than 1,500 MW in some hours. These outcomes were largely the result of more high-priced offers in January 2021, particularly in the last week of the month.

Figure 24: Scatterplot of supply cushion and pool price (Q4 2020 and January 2021)



1.6 Net revenue analysis

A net revenue analysis can provide some context to historical pool prices as it can be used to compare them to a set of existing costs and estimated performance assumptions to look at the profitability of a hypothetical new entrant into the market. In other applications, developers are assessing the forward-looking net revenue streams for projects that they may wish to build. The analysis here is only backward looking and examines the case of a 2 X LM6000 configuration acting as a pure price-taker in the energy market. We extend the analysis and also look at how historical pool prices and carbon emission offsets compare to recent cost estimates for both wind and solar farms.

1.6.1 Hypothetical gas peaker (2015 to 2020)

The net revenues of a gas peaking plant are estimated using the cost estimates derived from the AESO's work on the net Cost of New Entry. Table 10 provides the specific cost figures used. The purpose of this analysis is to put historical market outcomes in the context of recent cost estimates, so the 2021$ costs are used throughout the analysis.

Table 10: Cost Estimates for GE LM6000-PF SPRINT 2x0 (93 MW)[28]

	Currency	Cost
Overnight Capital Cost ($/kW)	2021$ CAD	1,554
Fixed O&M ($/kW-year)	2021$ CAD	57.3
Variable O&M ($/MWh)	2021$ CAD	4.60

The net revenue analysis considers a number of cost components. To calculate fuel costs the same day AB-NIT 2A index is used, along with a winter heat rate of 9.526 GJ/MWh and a summer heat rate of 9.954 GJ/MWh.[29] The natural gas commodity fuel charge is also included as a component of the asset's fuel cost.[30]

The carbon cost of the asset varies over the analysis as regulations and carbon prices have changed. The carbon emissions from natural gas are set at 0.05012 tCO_2/GJ.[31] This means in the summer of 2015 the hypothetical asset had a carbon cost of $0.90/MWh and in the summer of 2020 its carbon cost was $3.87/MWh.

An hourly variable cost figure is calculated by summing fuel costs, carbon costs, variable O&M, and the AESO trading charge. Transmission losses are estimated using the average loss factor in the Fort Saskatchewan area in combination with applicable calibration factors.[32] The average loss factor over the six years is estimated at 4.04%. The plant is assumed to offer into the energy market at its variable cost, such that it runs whenever pool price less transmission losses is above its variable cost.

In terms of availability, the analysis uses the actual availability of three LM6000 peaking units operating in Alberta over the period to calculate an hourly availability percentage.[33] This yields an overall availability factor of 81.1% across the six years.

Figure 25 shows the resulting net revenues on an annual basis. As shown, the peaking asset earned very little revenue in 2015, and did not make enough to cover its fixed O&M costs in 2016 and 2017 when annual pool prices averaged $18.28/MWh and $22.19/MWh, respectively. Beginning in 2018 the net revenues of the hypothetical peaking asset improved considerably as pool prices increased and became more volatile (Figure 26).

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[28] AESO Cost of New Entry Analysis, prepared by the Brattle Group (September 4, 2018) at Tables 8, 10 and 16. Capital costs are converted from 2018$ to 2021$ using BOC CPI inflation data and assuming 2.00% for 2021.

[29] *Ibid.* at Table 3

[30] TransCanada Energy NGTL Fuel Usage and Measurement Variance

[31] AESO Draft Net CONE and EAS Offset Methodology (August 16, 2018)

[32] *Ibid.*

[33] Availability percentage is calculated as Total Available Capability / Total Maximum Capability for the three assets

Figure 25: Net Revenues by year for the hypothetical gas peaking asset (2015 to 2020)

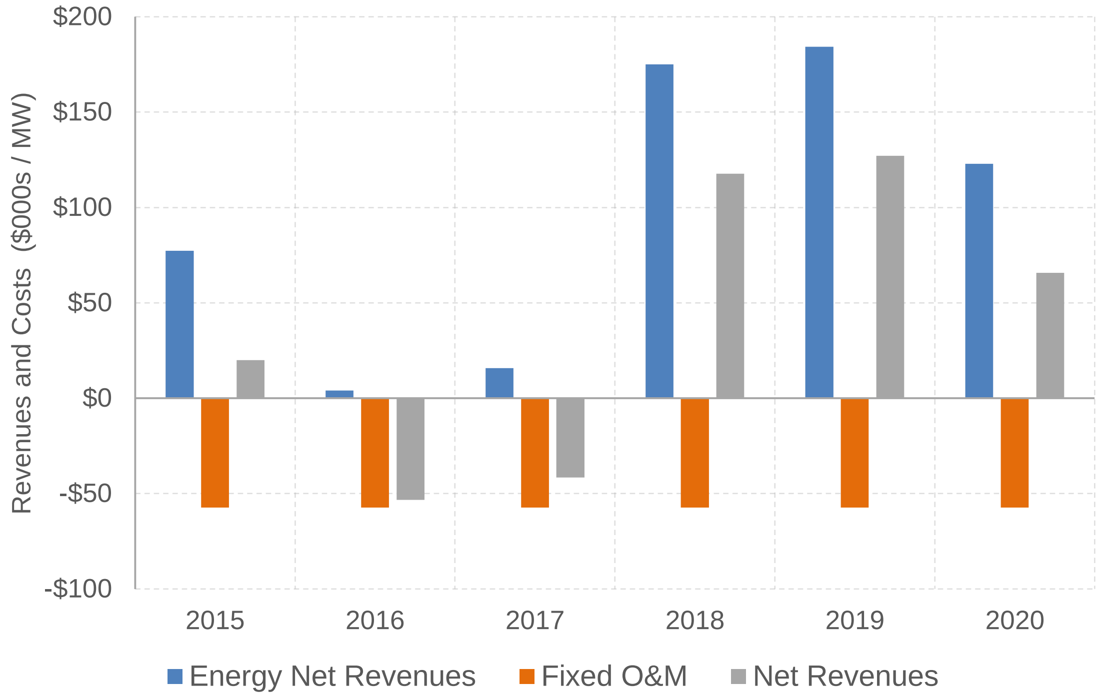


Figure 26: Monthly average pool price and gas price (2015 to 2020)

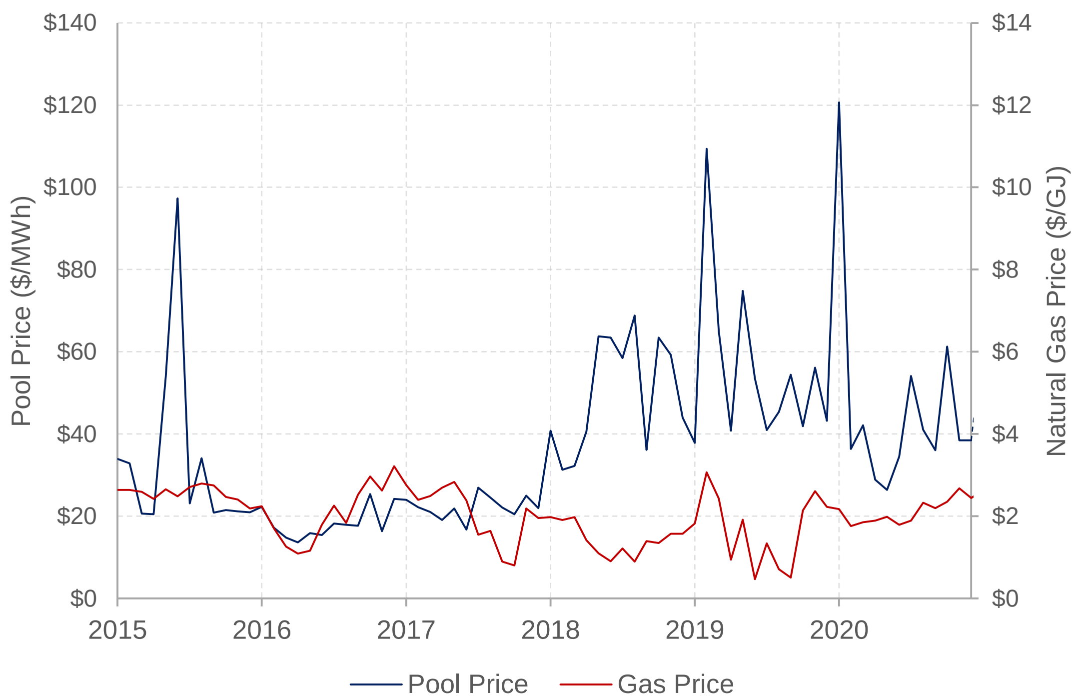
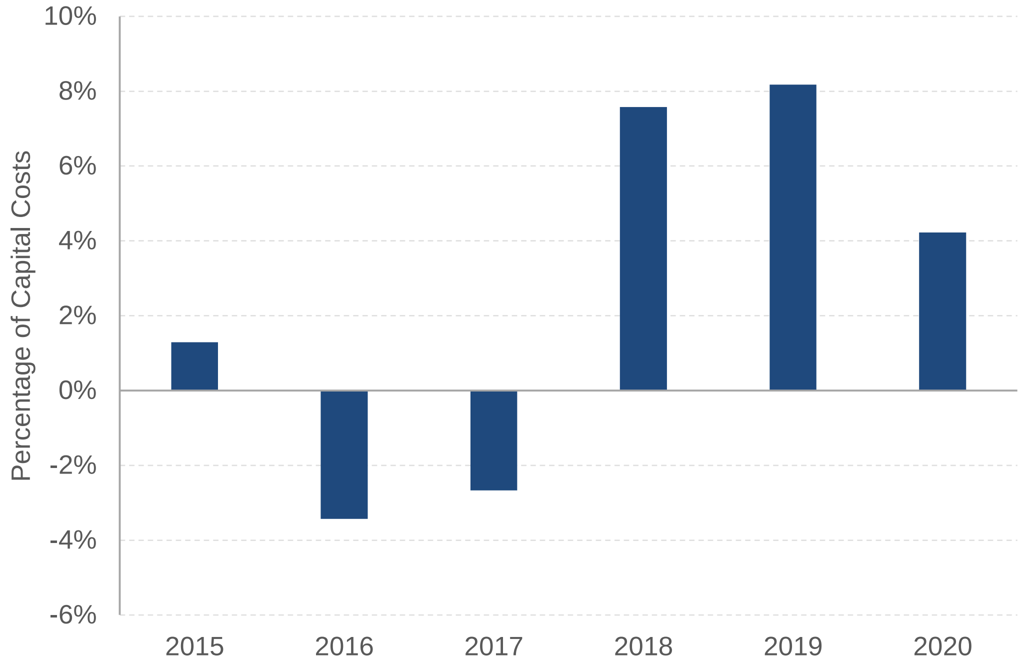


Figure 27 below puts the net revenues in the context of the capital costs for the asset. As shown by Figure 27, the net revenues in 2016 and 2017 resulted in a loss equivalent to around 3% of the overnight capital costs. In 2018 and 2019 the net revenues equate to approximately 8% of the capital costs, and in 2020 the figure was around 4%.

Figure 27: Net revenues for the hypothetical peaking asset (2015 to 2020)



1.6.2 Hypothetical wind assets (2015 to 2020)

To estimate the net revenues for hypothetical wind assets we use cost estimates published recently by the Canada Energy Regulator. The resulting cost figures are given in Table 11.

Table 11: Cost estimates used in the net revenue analysis for wind [34]

	Currency	**Cost**
Overnight Capital Cost ($/kW)	2021$ CAD	1,363
Fixed O&M ($/kW-year)	2021$ CAD	59.21
Variable O&M ($/MWh)	2021$ CAD	0.00

Wind generation in Alberta can be split into assets located in the south of the province, around the Pincher Creek or Lethbridge area, and those further north; east of Red Deer and Calgary. As shown by Table 12, most wind assets are currently located in the south. The net revenue analysis

[34] CER Canada's Energy Future (2020) see table A.3. The high-end estimate of fixed O&M costs is used. Costs are converted from USD to CAD using 1.2806 (the average BOC daily exchange rate in December 2020). To convert the figures from 2019$ to 2021$ BOC CPI inflation data is used and 2.00% is assumed for 2021.

for wind is broken down into a hypothetical asset in the north and one in the south. There is no distinction made between north and south in terms of costs here, only in terms of the hourly capacity factor. For each hour the analysis calculates an adjusted capacity factor based on the actual output of wind assets in that hour compared to the total maximum capability (MC) of the assets.[35]

Table 12: Wind capacity and asset count by north and south

	Asset Count	Total Capacity (MW)	Percent of Wind Capacity
North	5	349	20%
South	18	1,432	80%
Total	**23**	**1,781**	**100%**

The wind assets are assumed to act as price-takers in the energy market. In addition to pool price, the assets are assumed to fully utilize carbon emissions offsets in the year they are created, which are calculated annually using the displacement factor and the price of carbon (Table 13).

The analysis calculates transmission losses using a volume-weighted average of annual loss factors for wind assets in the north and south by year, and also incorporates applicable calibration factors throughout the six years. The estimated losses average 4.20% for the hypothetical wind asset in the south and 4.73% for the north.

Table 13: Carbon emissions offset by year [36]

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

The resulting net revenues, including fixed O&M costs, are shown by year in Figure 28 below. As shown, the net revenues of the hypothetical wind assets have generally increased through time as carbon prices have increased, and because pool prices have generally been higher beginning in 2018. The higher net revenues in 2020 were largely the result of higher capacity factors.

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[35] The adjusted capacity factor used for this analysis excludes new wind assets until they have generated to a capacity factor of 30% or more in one hour. This is designed to prevent new assets that are not fully available from lowering the capacity factor estimates.

[36] 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 28: Estimated net revenues for wind (2015 to 2020)

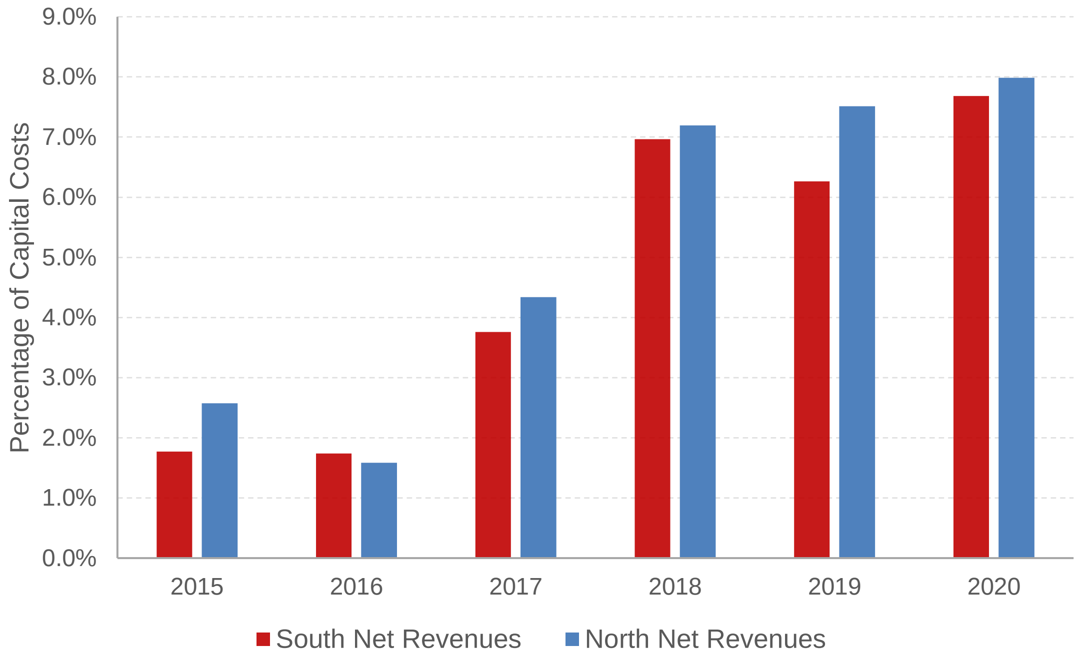


Figure 29 compares monthly average pool prices to the average price received by wind generators. The increase in wind received price beginning in 2018 is apparent. This is likely due to a number of factors that include the increased carbon costs for coal generation assets beginning that year that had the effect of raising pool prices in general.

The average price received by wind generators is typically lower than the average pool price. There are two main reasons. First, wind generation in Alberta tends to be highly correlated, so when wind generation is high at one asset it is likely high at many others, and this increased supply puts downward pressure on the pool price. Second, wind generation tends to be low during periods of extreme cold in the winter and in periods of very hot temperatures in the summer. These weather conditions increase the demand for electricity, which puts upward pressure on pool prices.

Figure 29: Average pool price and price received by wind by month (2015 to 2020)

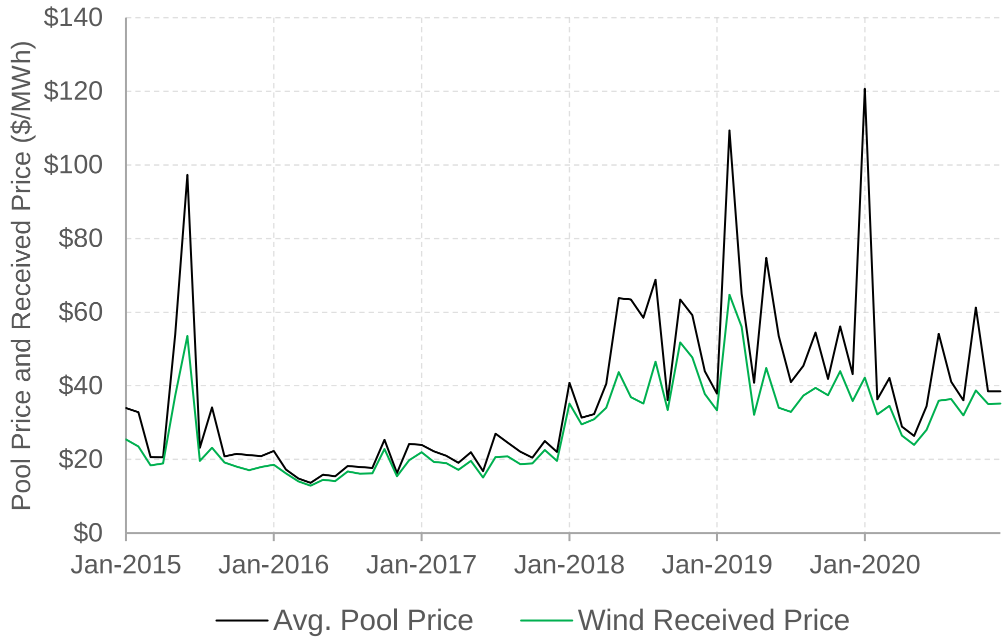


Figure 30: Average price received by wind for north and south by month (2015 to 2020)

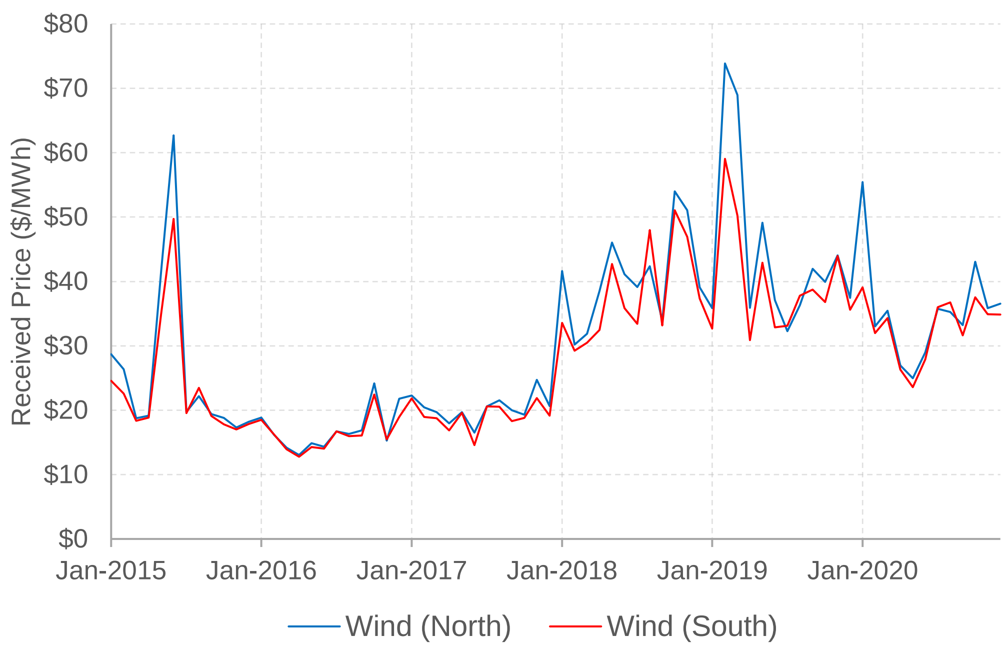


Figure 30 shows the same analysis for wind assets in the south versus those in the north. As shown, wind in the north typically received a higher average price than wind in the south when pool prices were volatile. This likely results from the fact that there are more wind assets in the southern area of Alberta, so the positive supply correlation likely applies more to wind assets located in that area of the province.

In terms of capacity factor, wind assets in the north and south are quite comparable, with the southern assets getting an adjusted capacity factor of 34.6% and the assets in the north getting an adjusted capacity factor of 34.3% over the six years. The table below shows the overall adjusted capacity factor by year. As shown, 2020 was a strong year for wind generation.

Table 14: Adjusted capacity factors for wind by year [37]

Year	South	North
2015	32.4%	33.0%
2016	35.0%	33.5%
2017	35.1%	36.6%
2018	32.5%	32.3%
2019	31.5%	31.5%
2020	39.8%	38.6%

1.6.3 Hypothetical solar asset (2018 to 2020)

To estimate the net revenues for a hypothetical solar asset we again use cost estimates published recently by the Canada Energy Regulator. The resulting cost figures are given in Table 15.

Table 15: Cost estimates used in the net revenue analysis for solar [38]

	Currency	Cost
Overnight Capital Cost ($/kW)	2021$ CAD	1,488
Fixed O&M ($/kW-year)	2021$ CAD	26.32
Variable O&M ($/MWh)	2021$ CAD	0.00

The first large solar farm developed in Alberta came online in December 2017, and is a fixed photovoltaic (PV) asset located in Brooks.[39] The net revenue analysis uses generation output from the Brooks solar farm to estimate a capacity factor for the hypothetical solar asset from January 2018 through to December 2020.

The hypothetical solar farm is assumed to act as a price-taker in the energy market and fully utilize carbon emissions offsets in the year they are created (Table 13). Transmission losses are

[37] These capacity factors have been adjusted to exclude new assets until they have generated above a 30% capacity factor.

[38] CER Canada's Energy Future (2020) see table A.3. The high-end estimate of fixed O&M costs is used. Costs are converted from USD to CAD using 1.2806 (the average BOC daily exchange rate in December 2020). To convert the figures from 2019$ to 2021$ BOC CPI inflation data is used and 2.00% is assumed for 2021.

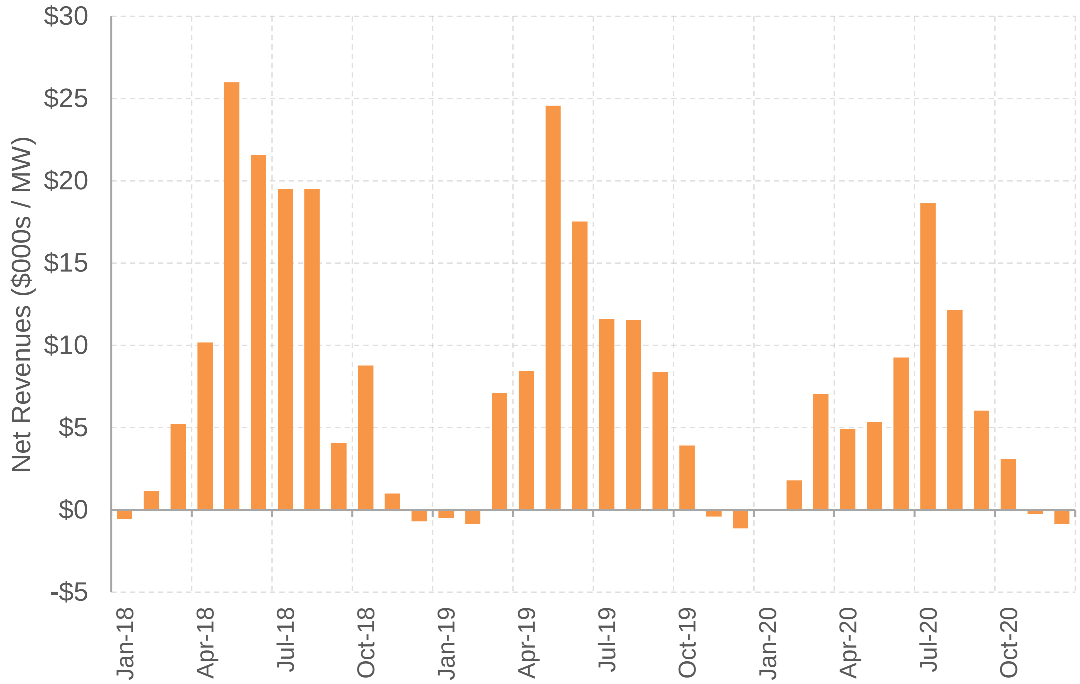
[39] See Brooks solar at Elemental Energy and Borea Construction

estimated using average system losses and the applicable calibration factors. On average this yields estimated losses of 3.64% over the three years.

Solar generation output is significantly higher during the summer months compared to the winter. For example, in 2020 the highest monthly capacity factor was 29% in July, whereas in December the capacity factor was 3%. This trend is evident in Figure 31 which shows monthly net revenue for the hypothetical asset. For the purposes of this analysis, the annual fixed O&M costs have been spread equally across each month. The highest month in terms of net revenue occurred in May 2018 when the capacity factor was 27% and the asset received an average price of $126.34/MWh compared to a monthly average pool price of $63.77/MWh.

At present in Alberta, production from solar generators is concentrated in relatively high price hours and as a result the average price received by solar generators is generally higher than the average pool price.

Figure 31: Net revenues by month for the hypothetical solar asset (2018 to 2020)



The net revenues in 2020 for the hypothetical solar asset were estimated at 4.5% of capital costs, which is a decline from 6.1% in 2019 and 7.8% in 2018. This was driven in part by lower pool prices this past summer. For example, in May of 2018 and 2019 the asset received average prices of $126.34/MWh and $131.06/MWh, respectively. In 2020, the highest monthly average received price was $84.24/MWh in July.

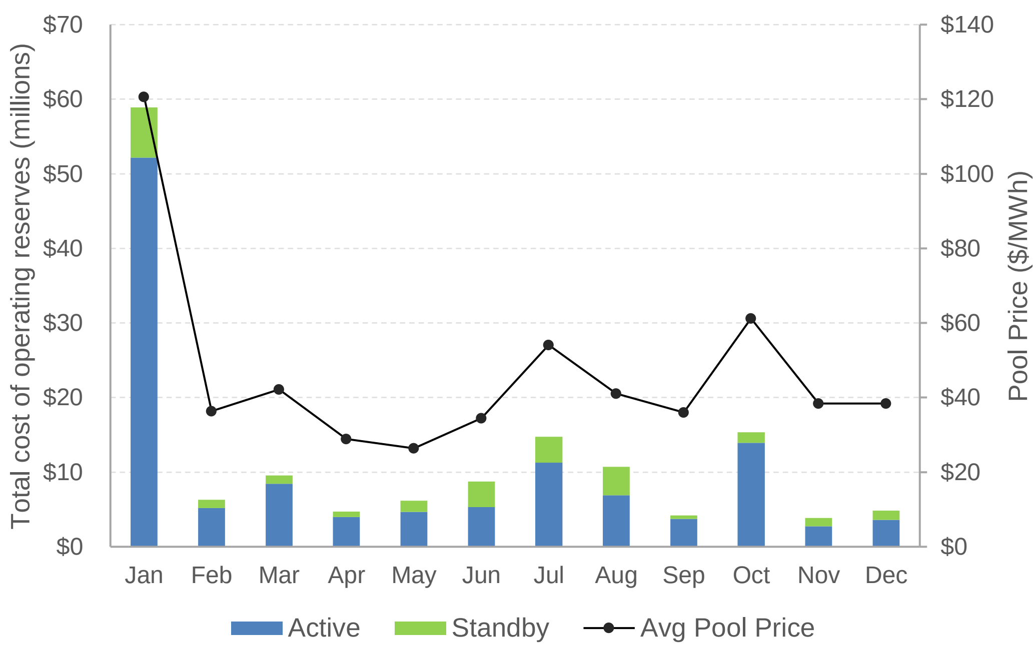
2 THE MARKETS FOR OPERATING RESERVES

There are three types of operating reserves (OR) that system controllers in Alberta 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.[40]

2.1 Annual summary

Figure 32 shows the total cost of active and standby OR and the average pool price for each month in 2020. The positive relationship between energy prices and OR costs is to be expected, given that the opportunity cost of providing reserves is often supplying energy and also because active reserves are indexed to pool price. In active reserves suppliers compete to provide a product by bidding in a discount or premium to the pool price, and the market-clearing price is set as an index to pool price. In standby OR participants bid in a standby premium price and an activation price, neither of which are directly indexed to pool price. As shown by Figure 32, the majority of OR costs in 2020 were associated with active reserves. In 2020 active reserves accounted for 82% of total OR costs, with standby activations accounting for 15% and standby premium costs accounting for 2%.

Figure 32: Total cost of operating reserves and average pool price by month (2020)



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

The total cost of OR in 2020 was $148 million, which was 23% lower than the $193 million total in 2019, and 36% lower than the $240 million total in 2018. Decreasing costs associated with the procurement of active reserves was the major source of cost reductions. In 2020 the average cost of active reserves was $21.94/MWh, a decline of $8.16/MWh compared to the average cost of $30.55/MWh in 2019. As shown in Table 16, the decline in average costs has been observed in all three active OR product markets. In spinning and supplemental markets, the decline in average costs was similar to the decline in average pool prices, indicating that overall costs in these markets have fallen largely due to the decline in pool prices.

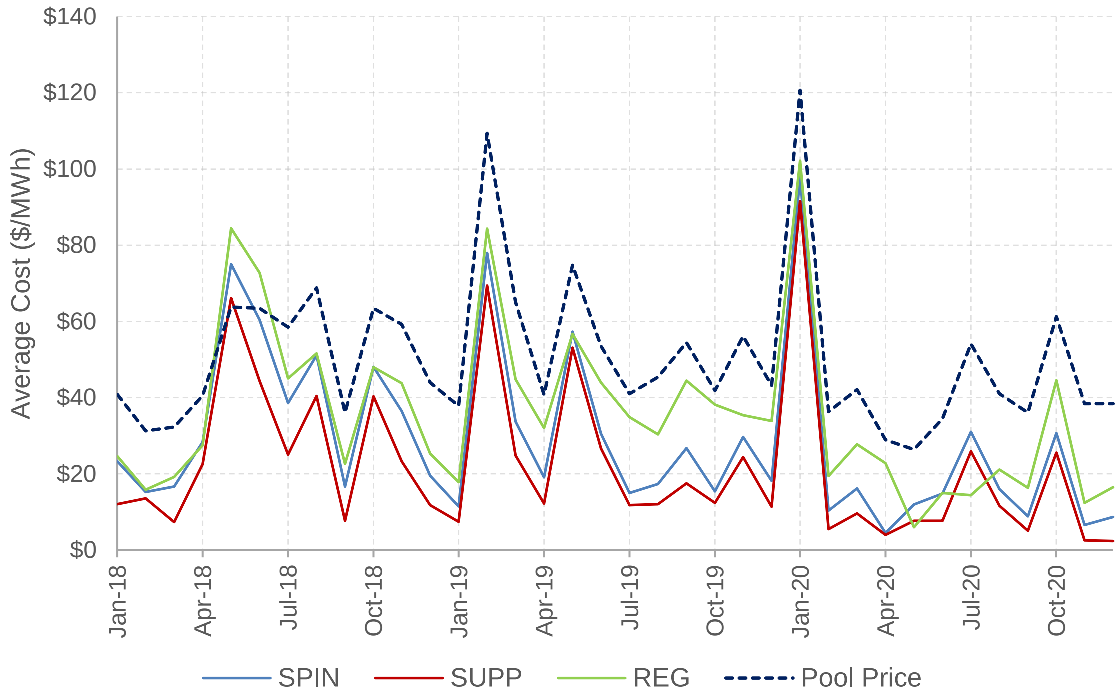
Table 16: Average cost ($/MWh) of active OR products by year (2018 to 2020)

Product	2018	2019	2020	2020 - 2019
Spinning	$36.44	$29.95	$22.62	($7.33)
Supplemental	$26.89	$24.25	$17.67	($6.57)
Regulating	$39.95	$40.98	$28.00	($12.98)
Active OR	**$33.67**	**$30.55**	**$21.94**	**($8.62)**
Avg Pool Price	**$50.35**	**$54.88**	**$46.72**	**($8.16)**

In the regulating reserves market the decline in average costs has been $12.98/MWh year-over-year, which is a larger decline relative to average pool prices. In 2020 the AESO procured 1,940 TWh of active regulating reserves, which is 10% lower than the total procured in 2019. Starting on June 1, 2020 the AESO began purchasing 20 MW per hour less regulating volume because they are now able to manage the reliability of the system using less than had previously been the case. All else equal, using less regulating reserves provides for greater price fidelity, meaning a closer response between changes in the supply/demand balance and dispatches in the energy merit order. On the supply-side of the regulating reserve market, the MSA has observed a greater volume of highly-discounted offers, particularly in the offers for on-peak reserves from the start of May to the end of October.

Figure 33 shows the average costs of active OR by month since 2018. As shown, the average cost of OR is normally a discount to pool prices because supplying energy has higher fuel and operating costs. For most of 2020 the average cost of regulating reserves was at a larger discount to pool price as compared to 2019.

Figure 33: Average costs of active OR and pool price by month (2018 – 2020)



The majority of the costs associated with standby reserves arise from activations rather than premiums. In 2020, 87% of total standby costs were from activations, an increase from 69% in 2019 but similar to the 82% seen in 2018. Standby activations are often implemented in response to a higher level of import volumes (Figure 34). When imports volumes are elevated the AESO typically needs a higher amount of contingency reserves to manage the possibility of the BC/MATL intertie tripping offline.

In 2020 total standby activation volumes were 348 GWh, a 93% increase over the 180 GWh activated last year, but in line with the 343 GWh activated in 2018. As shown in Figure 34, import volumes were notably higher in some months in 2018 and 2020 and in these months a significant amount of standby reserves were activated.

Despite the higher demand for standby activations year-over-year, the average activation price actually fell by $11.23/MWh for spinning and $16.42/MWh for supplemental (Table 17). That said, it is important to note that the market conditions at the time of activations will have a material influence on their average costs. To account for this Table 17 provides the average cost of energy during the standby activations, with the pool prices being weighted by the volume of standby activations for the relevant product. As shown, the average pool price during standby activations was materially lower in 2020 compared to 2019, implying a lower opportunity cost. In 2019 a high proportion of activations occurred in May when pool prices averaged $74.78/MWh. In 2020, the months with a higher volume of activations (June, July and August) had lower average pool prices. As a result, in 2019 the average pool price during spinning activations was $97.16/MWh, and this fell to an average of $64.61/MWh in 2020. In 2020 the average cost of spinning activations was actually higher than the average pool price in those hours. This indicates a market inefficiency because the design should not cause the AESO to pay more to activate standby reserves than it does for energy. The MSA believes allowing participants to offer standby reserves at an index to pool price, as is done in the active OR markets, would improve the efficiency of the standby markets.

Figure 34: Total imports and standby activation volumes by month (2018 to 2020)[41]

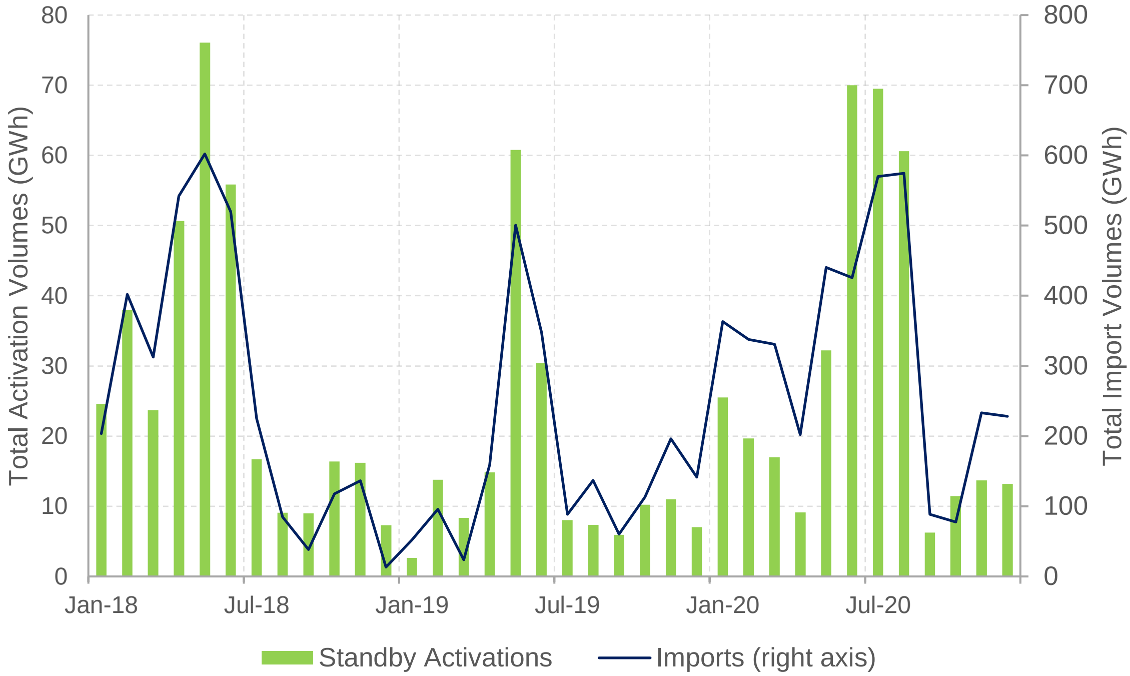


Table 17: Average cost ($/MWh) of standby activations by year (2018 to 2020)

Product	2018	2019	2020	2020 - 2019
Spinning	$114.66	$83.55	$72.32	($11.23)
Energy (spinning)	$66.11	$97.18	$64.27	($32.91)
Supplemental	$89.70	$68.33	$51.90	($16.42)
Energy (supplemental)	$61.10	$86.23	$62.69	($23.54)
Regulating	$60.43	$52.82	$51.46	($1.36)
Energy (regulating)	$38.51	$42.85	$45.86	$3.01
Avg Pool Price	**$50.35**	**$54.88**	**$46.72**	($8.16)

[41] Imports represents the total of hourly net imports; hours with net exports are set to 0 MW.

2.2 Costs and procurement volumes in Q4 2020

In Q4 2020, the total cost of operating reserves was 33% lower than in Q4 2019 (Table 19). A primary driver of OR costs is pool price, but the average pool price in Q4 2020 was only 2% less than Q4 2019. The lower costs in Q4 2020 were largely a function of lower active OR costs.

The average cost for active regulating reserves was $10.92/MWh lower in Q4 2020 compared to Q4 2019 (Table 18). In June 2020, the AESO reduced the active regulating reserves procurement volumes by 20 MW per hour. This is a fairly significant reduction and the typical demand is now 130 during on-peak and 115 MW in off-peak. The lower demand was a factor in Q4 2020 having more days when the clearing index price for regulating reserves settled at a deep discount to pool price, compared to Q3 2019. On those occasions sellers generally receive no revenue from providing the regulating service and only earn revenue from the associated provision of energy.

Table 18: Average cost ($/MWh) of active OR products (Q4 2020 and Q4 2019)

Product	Q4 2020	Q4 2019	Q4 2020 – Q4 2019
Spinning	$15.15	$21.10	($5.95)
Supplemental	$9.98	$16.05	($6.07)
Regulating	$24.88	$35.80	($10.92)
Active OR	**$15.36**	**$23.01**	**($7.65)**
Avg Pool Price	**$46.13**	**$46.97**	**($0.85)**

Figure 35: Duration curves of trade index prices for active spinning reserves (Q4 2020 and Q4 2019)

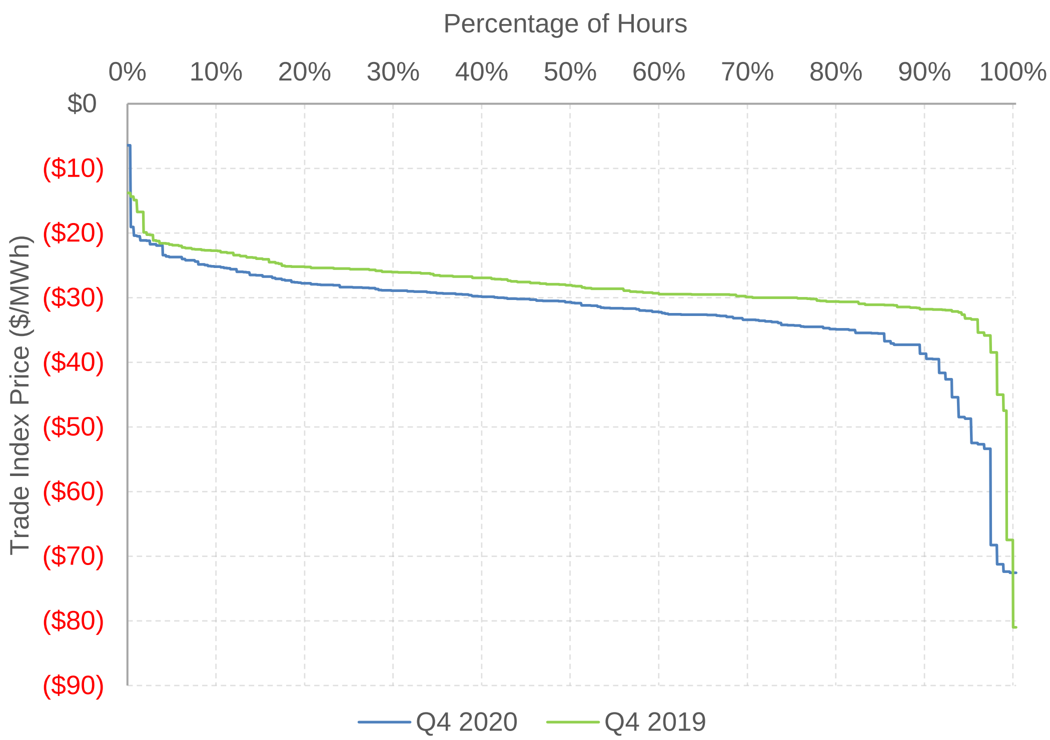


Table 19: Detailed breakdown of operating reserves costs in Q4 2020

Total Cost ($ Millions)						
	Oct-20	**Nov-20**	**Dec-20**	**Q4 2020**	**Q4 2019**	***% Change***
Active Procured	**13.9**	**2.7**	**3.6**	**20.3**	**32.5**	***-38%***
RR	4.6	1.2	1.6	7.4	13.0	*-43%*
SR	5.1	1.1	1.5	7.7	11.1	*-30%*
SUP	4.2	0.4	0.4	5.1	8.4	*-39%*
Standby Procured	**0.4**	**0.3**	**0.2**	**0.9**	**1.3**	***-28%***
RR	0.1	0.1	0.1	0.3	0.5	*-47%*
SR	0.3	0.2	0.1	0.6	0.6	*-6%*
SUP	0.1	0.0	0.0	0.1	0.2	*-45%*
Standby Activated	**1.0**	**0.8**	**1.0**	**2.8**	**2.1**	***38%***
RR	0.4	0.0	0.1	0.5	0.0	*3318%*
SR	0.4	0.6	0.7	1.7	1.4	*21%*
SUP	0.2	0.2	0.3	0.6	0.6	*0%*
Total	**15.4**	**3.9**	**4.8**	**24.1**	**35.8**	***-33%***
Total Volume (GWh)						
	Oct-20	**Nov-20**	**Dec-20**	**Q4 2020**	**Q4 2019**	***% Change***
Active Procured	**434.7**	**432.5**	**452.8**	**1,319.9**	**1,411.1**	**-6%**
RR	103.4	96.3	99.7	299.4	363.4	*-18%*
SR	165.8	168.3	176.6	510.7	523.9	*-3%*
SUP	165.6	167.9	176.4	509.8	523.9	*-3%*
Standby Procured	**163.4**	**158.1**	**162.9**	**484.4**	**511.4**	***-5%***
RR	59.5	57.7	59.4	176.6	176.5	*0%*
SR	78.0	75.4	77.7	231.1	244.7	*-6%*
SUP	25.9	25.0	25.7	76.7	90.2	*-15%*
Standby Activated	**11.5**	**13.7**	**13.2**	**38.3**	**28.2**	***36%***
RR	5.8	0.8	1.4	8.0	0.4	*1929%*
SR	3.8	9.0	8.2	21.0	18.5	*14%*
SUP	1.8	3.9	3.6	9.3	9.4	*-1%*
Total	**609.6**	**604.2**	**628.8**	**1,842.6**	**1,950.7**	***-6%***
Average Cost ($/MWh)						
	Oct-20	**Nov-20**	**Dec-20**	**Q4 2020**	**Q4 2019**	***% Change***
Active Procured	**32.04**	**6.34**	**7.97**	**15.36**	**23.01**	**-33%**
RR	44.54	12.44	16.51	24.88	35.80	-31%
SR	30.70	6.59	8.72	15.15	21.10	-28%
SUP	25.57	2.59	2.38	9.98	16.05	-38%
Standby Procured	**2.61**	**1.82**	**1.42**	**1.95**	**2.56**	**-24%**
RR	1.86	1.37	1.58	1.60	3.03	-47%
SR	3.40	2.49	1.61	2.50	2.52	-1%
SUP	1.98	0.86	0.48	1.11	1.73	-36%
Standby Activated	**87.45**	**61.44**	**75.96**	**74.21**	**73.03**	**2%**
RR	69.50	38.28	52.35	63.44	37.66	68%
SR	114.20	67.30	80.23	80.83	76.40	6%
SUP	88.79	52.55	75.15	68.48	67.89	1%
Total	**25.19**	**6.41**	**7.70**	**13.06**	**18.37**	***-29%***

Figure 35 shows that index prices for active spinning reserves in Q4 2020 were consistently lower compared to Q4 2019. This general trend was observed with supplemental as well as regulating reserves. In 2020 there was more competition in supply and the AESO procured less volume in Q4 2020, with active spinning and supplemental volumes down 3% and regulating volumes down 18% year-over-year (Table 19). These factors combined to result in lower overall costs for all three active products.

In Q4 battery technology was introduced into Alberta's power markets. In November, a 10 MW battery associated with an existing wind farm was connected, and is capable of providing 10 MW of energy for up to two hours. A second battery asset was connected in December, and this standalone unit has a capacity of 20 MW which it is capable of providing for one hour. Battery technology is well-suited to providing OR, and the MSA observed that these assets have been suppliers of active reserves. In January 2021 the two assets were dispatched for a combined total of around 14,000 MWh of active OR.

Standby activation costs were higher in Q4 2020 compared to Q4 2019 as the market observed higher activation volumes year-over-year (Table 19). That being said, the pool price was generally lower when activations for spinning and supplemental occurred in Q4 2020 compared with activations in Q4 2019, implying a lower opportunity cost (Table 20). The average activation cost for standby spinning in Q4 2020 was $80.83/MWh compared to an average pool price of $61.49/MWh during the activations. A similar observation is made for supplemental activations in Q4 2020. Again, this highlights an inefficiency in the standby market design as the AESO was paying more to activate standby reserves than it was for actual energy.

Table 20: Average cost of standby activations in Q4 2020 and 2019

	Q4 2020	**Q4 2019**	**Q4 2020 – Q4 2019**
Spinning	$80.83	$76.40	$4.43
Energy (spinning)	$61.49	$85.21	($23.72)
Supplemental	$68.48	$67.89	$0.59
Energy (supplemental)	$56.03	$80.88	($24.86)
Regulating	$63.44	$37.66	$25.78
Energy (regulating)	$73.45	$38.61	$34.84

Standby contingency reserves are often used to support import volumes on the BC/MATL intertie, in addition to covering for load forecast errors, and forced outages of active reserve providers. Standby regulating reserves are also used to provide the system controllers increased ramping capability in certain situations. The volume of regulating reserves activated in Q4 2020 was materially higher than last year. During the period of the BC/MATL intertie outage the system controllers procured more active regulating reserves and also activated more standby regulating reserves.

2.3 Hydro PPA expiration

On December 31, 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 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, and the energy payments would increase if pool prices were higher, and the reserves payments would increase if OR prices were higher.

The initial Hydro PPA outlined notional energy quantities of around 1,650 GWh per year (an hourly average of 188 MW) and approximately 3,350 GWh annually in notional reserve quantities (an hourly average of 382 MW).[42] At the time that the PPAs were formulated there was no market for operating reserves in place. Subsequently the market for OR was implemented and a supplemental agreement was established that set out specific details. In 2004 this agreement was adjusted after the MSA raised concerns around abnormal outcomes in the OR markets.

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. As shown in Table 21, the assets under the Hydro PPA have supplied just under half of the dispatched OR volumes in each of the past three years, and have supplied a higher share of spinning and regulating volumes. The volumes have been fairly consistent from year to year in this period.

Table 21: BOW1, BIG, and BRA as a percentage of dispatched OR volumes[43]

Product	2018	2019	2020
Spinning	52%	55%	52%
Supplemental	26%	23%	20%
Regulating	65%	65%	68%
Disp. OR	**45%**	**46%**	**43%**

Table 22 provides summary statistics for the distribution of active OR index prices in January 2021 as compared with Q4 2020 and January 2020. As shown, index prices for spinning and regulating were generally comparable with previous market outcomes, for example the median

[42] MSA estimates based on schedule C from the original Hydro PPA

[43] Dispatched OR volumes include active reserves and activated standby volumes

index price for supplemental in January 2021 was -$28.08/MWh which is slightly higher than the median index price observed in Q4 2020 and January 2020. In the supplemental market, index prices were lower in January 2021, potentially indicating more competition in this market. In terms of volumes, the MSA observed that the three large hydro assets continued to provide a meaningful amount of active reserves in January 2021.

Table 22: Distribution statistics for active OR index prices in January 2021[44]

	Percentile		
	10%	**50%**	**90%**
Spinning			
Jan-2021	($51.52)	($28.08)	($24.09)
Q4 2020	($39.48)	($30.80)	($25.20)
Jan-2020	($39.45)	($30.00)	($25.45)
Supplemental			
Jan-2021	($91.62)	($55.00)	($42.98)
Q4 2020	($86.15)	($45.50)	($37.00)
Jan-2020	($65.50)	($40.62)	($32.47)
Regulating			
Jan-2021	($47.10)	($22.59)	($12.32)
Q4 2020	($92.00)	($24.67)	($6.74)
Jan-2020	($44.73)	($20.11)	($3.16)

[44] Regulating index prices are calculated as a volume weighted average of the applicable active index prices.

3 THE FORWARD MARKET

Table 24 shows total volumes traded for standard products from Q1 2016 to Q4 2020. Standard products include contracts such as flat and extended peak, but do not include custom shapes, such as the full-load RRO trades. The MSA's analysis in this section incorporates data on direct bilateral trades up to and including Q4 2020. 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 17.4% of the total volumes traded; annual contract trading comprises a significant share of direct bilateral trades (42% in 2020).

In the year 2020 liquidity in the forward market for Alberta power was relatively low. In total 30 TWh of standard products traded in 2020, compared to 47 TWh in 2019 and 54 TWh in 2018. In 2016 and 2017 the total volumes were higher, around 77 TWh. There are a number of potential reasons that drove the reduced liquidity in 2020; these reasons were discussed by the MSA in its Q3 2020 report.[45]

In Q4 2020 forward market volumes increased materially compared to Q2 and Q3 of 2020. In Q4 the total volume of trades increased to 10.11 TWh from 5.39 TWh in Q3, an increase of 88%. This increase in trading activity was largely driven by a surge in annual trades, which increased from 0.26 TWh in Q3 to 4.21 TWh in Q4. The increase in annual trades may have been driven by an increase in the forward prices for annual contracts such as CAL21 and CAL22. As shown by Table 23 below, annual trading in 2020 was largely driven by trades for CAL21 and CAL22. The trading of 'Other' contracts was also a factor in the Q4 liquidity growth. Multi-year and multi-month contracts drove most of the increase in 'Other' contract trading, accounting for 60% and 26%, respectively, of 'Other' volumes in Q4.

Table 23: Total volume of annual trades by contract in 2020 [46]

Contract	Total Volume (TWh)	Percent of Total Annuals Volume
CAL21	4.66	56%
CAL22	2.40	29%
CAL23	0.76	9%
CAL24	0.36	4%
CAL25	0.11	1%
TOTAL	**8.30**	**100%**

[45] Alberta MSA – Q3 2020 report (page 37)

[46] These figures do not include multi-year or custom annual contracts.

Table 24: Total volumes by trade date, standard products only (TWh)[47]

		Daily	Monthly	Quarterly	Annual	Other	Total
2016	**Q1**	0.22	9.40	2.00	12.92	8.38	32.92
	Q2	0.23	8.33	0.65	5.05	4.87	19.13
	Q3	0.08	6.84	1.23	4.69	0.40	13.24
	Q4	0.10	5.54	1.71	3.92	0.70	11.97
	Year	**0.63**	**30.12**	**5.58**	**26.58**	**14.35**	**77.26**
2017	**Q1**	0.06	6.66	3.06	4.61	1.94	16.33
	Q2	0.14	7.02	2.35	11.48	1.34	22.34
	Q3	0.19	6.90	2.21	6.10	1.29	16.70
	Q4	0.06	8.34	3.54	7.80	2.06	21.81
	Year	**0.45**	**28.93**	**11.16**	**30.00**	**6.64**	**77.17**
2018	**Q1**	0.15	7.33	0.61	4.69	0.63	13.41
	Q2	0.17	6.13	1.22	5.93	0.65	14.10
	Q3	0.10	4.62	0.25	3.82	0.68	9.46
	Q4	0.10	6.59	2.37	7.46	0.72	17.24
	Year	**0.52**	**24.66**	**4.45**	**21.89**	**2.68**	**54.21**
2019	**Q1**	0.16	6.05	2.31	5.13	1.39	15.03
	Q2	0.10	5.65	0.78	5.58	1.52	13.64
	Q3	0.05	3.84	2.10	2.25	0.53	8.77
	Q4	0.03	4.62	1.59	2.28	1.29	9.81
	Year	**0.34**	**20.15**	**6.78**	**15.25**	**4.73**	**47.25**
2020	**Q1**	0.09	4.13	1.14	2.57	0.85	8.77
	Q2	0.04	3.65	0.15	1.26	0.61	5.70
	Q3	0.10	3.82	0.87	0.26	0.34	5.39
	Q4	0.08	3.47	1.29	4.21	1.06	10.11
	Year	**0.30**	**15.07**	**3.44**	**8.30**	**2.86**	**29.97**

3.1 Trading of monthly products

Unlike the annuals, the total traded volumes of monthly contracts did not see an increase from Q3 to Q4, as trading volumes for monthly contracts declined slightly. Figure 36 illustrates traded volumes by contract month from January 2019 to January 2021. Monthly traded volumes remain well below those observed in 2019, with the totals for November and December 24% and 41% lower, respectively. There was not a notable increase in trading activity around the January contract despite the expiration of the PPAs and the higher carbon price in 2021.

[47] Other includes multi-year, multi-month, balance-of-year, custom annual and balance-of-month trades.

Beginning with the contract month of December 2020, the ENMAX RRO began to procure a portion of its volume through full-load contracts. This accounts for some of the higher volume of full load trades in December and January given RRO providers will procure more for these months due to higher expected consumption (Figure 36).

Figure 36: Traded volumes for monthly contracts (January 2019 to January 2021)

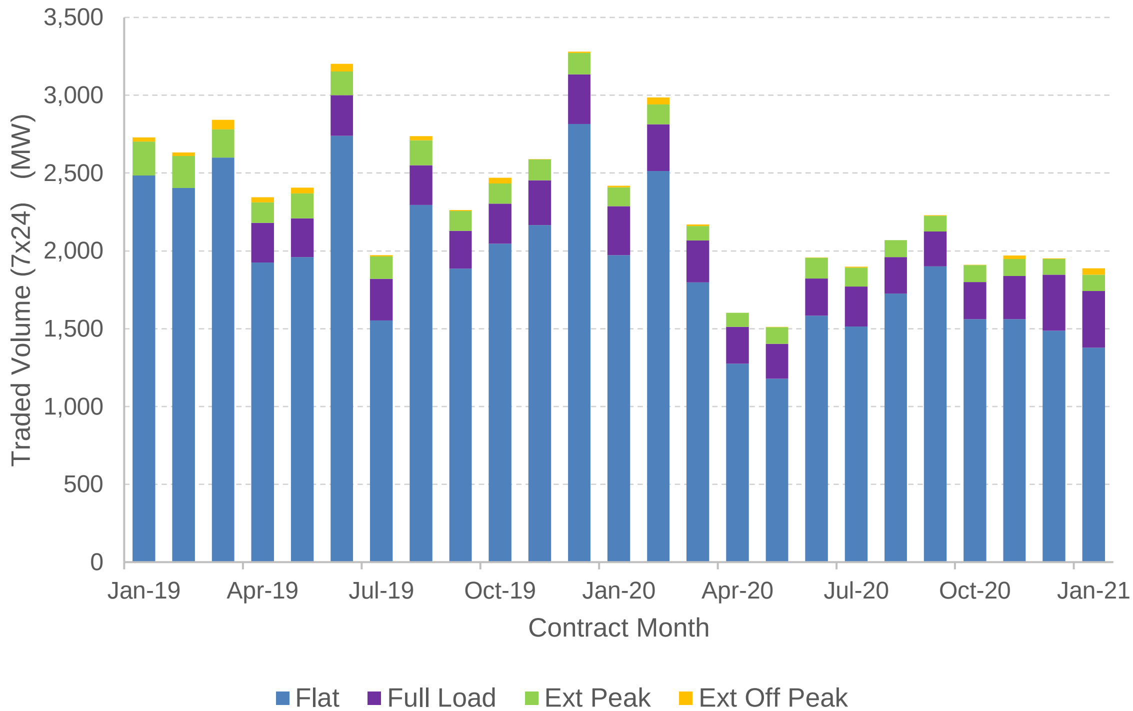
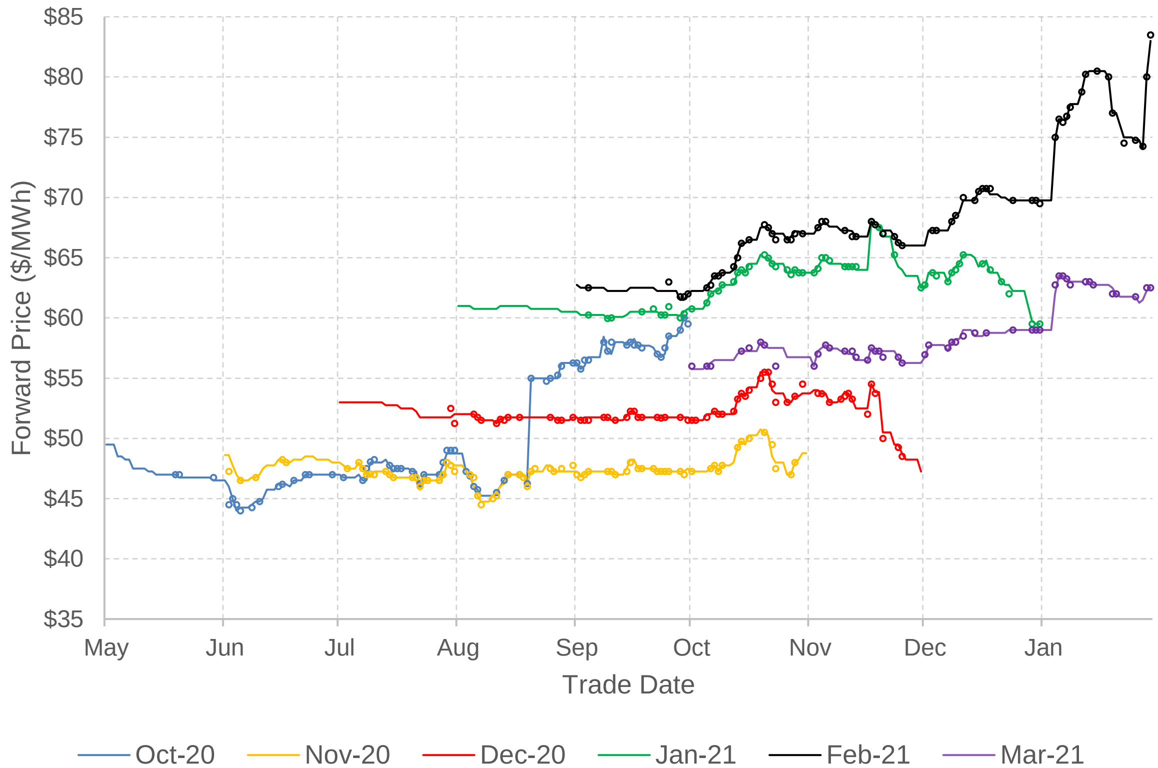


Figure 37 illustrates the evolution of forward prices for the October 2020 to March 2021 monthly flat contracts in the five months prior to the contract start. The value of the October contract increased significantly on August 20 when the planned outage on the BC/MATL intertie was moved from September into October. The last trade for the October contract on August 20 was priced at $55.00/MWh, 19% higher than the day before.[48] October contract prices continued to increase prior to the contract start with a final trade price of $59.50/MWh on September 30. The realized average pool price for October was $61.26/MWh, reflecting the absence of the BC/MATL intertie for around 13 days, in addition to reduced wind generation and/or thermal outages in some periods.

[48] As discussed in the MSA Q3 2020 report, the forward price for September declined materially on August 20.

Figure 37: Forward prices for monthly flat contracts (October 2020 to March 2021)[49]



The price of the November flat contract was relatively stable at around $47.50/MWh for most of the five month period illustrated in Figure 37. The price of the contract did increase to $50.50/MWh during the BC/MATL intertie outage in mid-October before coming back down, with a final trade price of $48.00/MWh on October 28. The realized pool price for November was $38.44/MWh, close to $10/MWh lower than the final forward price. As discussed above, wind generation was exceptionally high in November, increasing market supply and putting downward pressure on pool prices.

The price of the December flat contract was also well above its pool price average of $38.44/MWh. Figure 37 shows the December contract was valued at around $52.00/MWh for much of August and September. As with the November contract, the December contract increased in value slightly during the BC/MATL intertie outage before lowering again. On November 17 the price of the December and January contracts increased, in part due to the extension of a coal unit outage. After market hours on November 16 a coal unit outage was extended from late November to mid-January. However, the higher forward price for December soon began to decline as the market started to price in the possibility of further public health measures, in addition to the low pool

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

prices being seen in November.[50] The final trade price for December was $48.50/MWh on November 25, which was $10.06/MWh higher than the average pool price in December.

The January contract generally traded at a premium to December, in part due to the higher carbon price scheduled for 2021 and the expiration of the PPAs.[51] The price of the January contract peaked at $69.00/MWh on November 17 before declining through late November and into December, partly due to the relatively low pool prices for much of this period and the public health measures announced on November 24. After market hours on Friday November 27 the outage end date for a coal asset was moved from mid-January to late December, increasing available capacity in January. In addition, on December 8 the Alberta government announced further public health measures.[52] The final trade of the January contract was priced at $59.50/MWh, which was $13.39/MWh below the realized average pool price of $72.89/MWh.

Figure 37 shows the price of the February contract has typically been higher than January. This is partly a reflection of more coal unit outages being scheduled for February. The price of the February contract trended upwards from $62.00/MWh in early October to $69.50/MWh on December 31, and did not seem to be materially affected by the announcements of increased public health measures in November and December.

On January 4, 2021, the first business day of the year, the traded price of the February contract increased by 7.9% to $75.00/MWh as the market observed that five coal assets, comprising around 1,700 MW in capacity, were offline commercially. 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 considerably in response to Saudi Arabia production cuts.[53] 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.

Figure 38 illustrates how the monthly flat forward prices compared to average pool prices in 2020. Forward prices for most of the months in 2020 were above the average pool price, with January, July, and October being the exceptions. Forward prices for January were significantly lower than realized pool prices, which were high as a result of exceptionally cold temperatures, low wind generation, and thermal unit outages. The comparative outcomes in September and October were largely driven by the movement of the intertie outage from September into October in late August, as the intertie outage was a significant factor in the higher forward prices for September prior to the outage move, as well as the higher pool prices observed in October. As discussed above, the final trade price for October was close to the realized pool price, but for November and December

[50] Additional public health measures were announced on November 24, 2020 (see Global News)

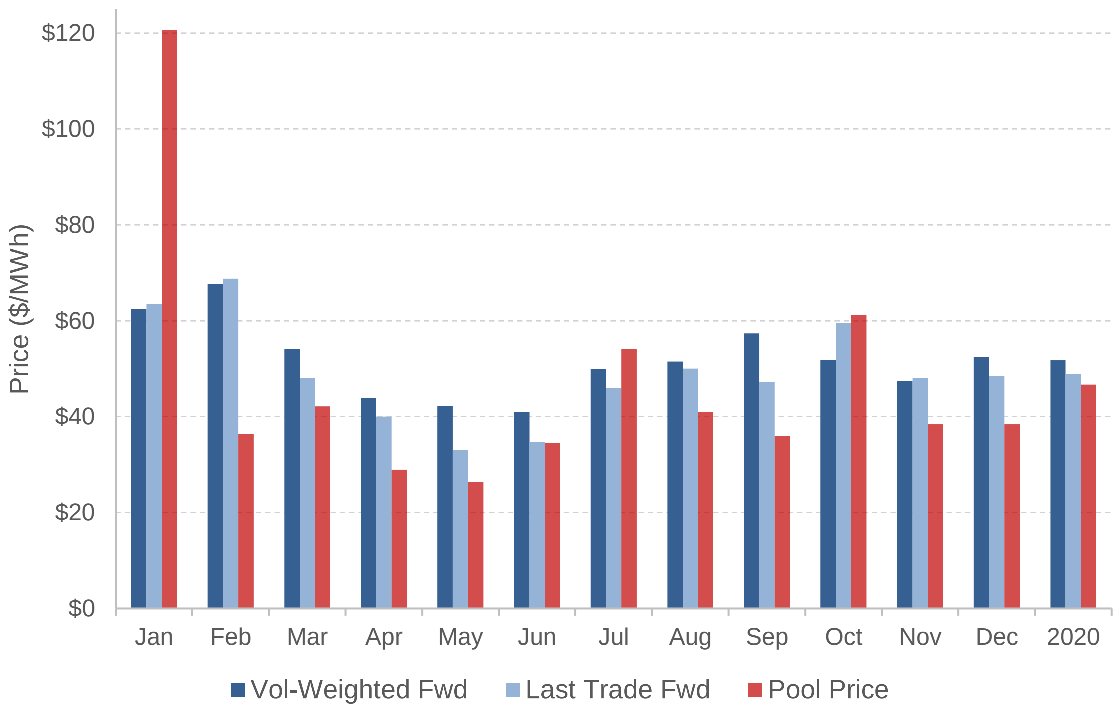
[51] The carbon price of $40.00/tCO2e for 2021 was confirmed on November 3, 2020 (see Ministerial Order 36/2020)

[52] Additional public health measures were announced on December 8, 2020 (see BNN)

[53] WTI oil prices increased almost 5% on January 5, 2021 (see Reuters)

forward prices were well above the average pool price. For 2020 as a whole monthly flat contracts were priced at a $5.07/MWh (10.9%) premium to the average annual pool price.[54]

Figure 38: Monthly flat forward prices and average pool prices in 2020



3.2 Trading of annual products

Traded volumes of annual contracts were higher in Q4 2020 compared to Q3 and Q2. Figure 39 illustrates the cumulative traded volumes for annual contracts from Calendar 2019 (CAL19) to CAL23. The increase in trading activity for CAL21 and CAL22 in Q4 is clearly visible although it is not abnormally high compared to historical trading data for CAL19 and CAL20. Overall, trading for the CAL21 contract was low compared to the level of trading observed for CAL19 and CAL20, and the contracts for CAL22 and CAL23 are currently on an even lower trajectory. The total of traded volumes for CAL21 was almost 1,500 MW, approximately half of the traded volumes for CAL19 and CAL20.

[54] This calculation uses the volume-weighted average forward price for each month to calculate an average price for 2020

Figure 39: Traded volumes for flat calendar contracts (3 years prior to contract start)[55]

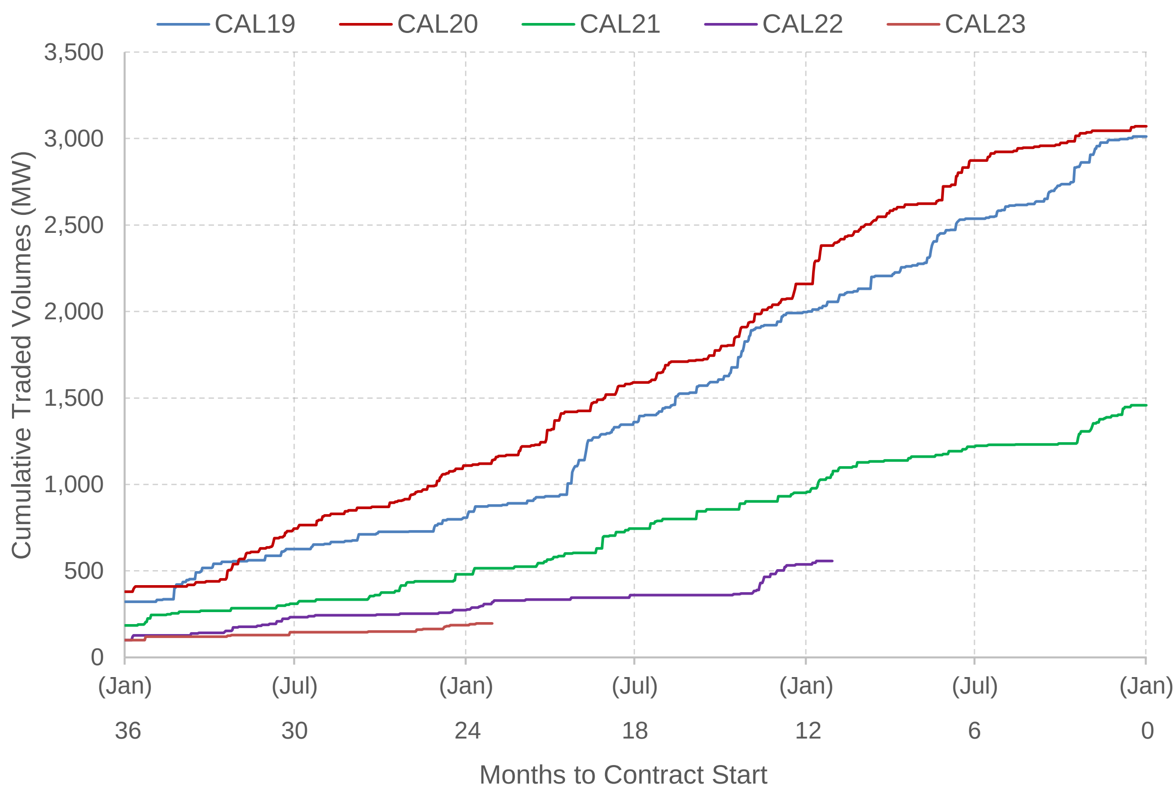
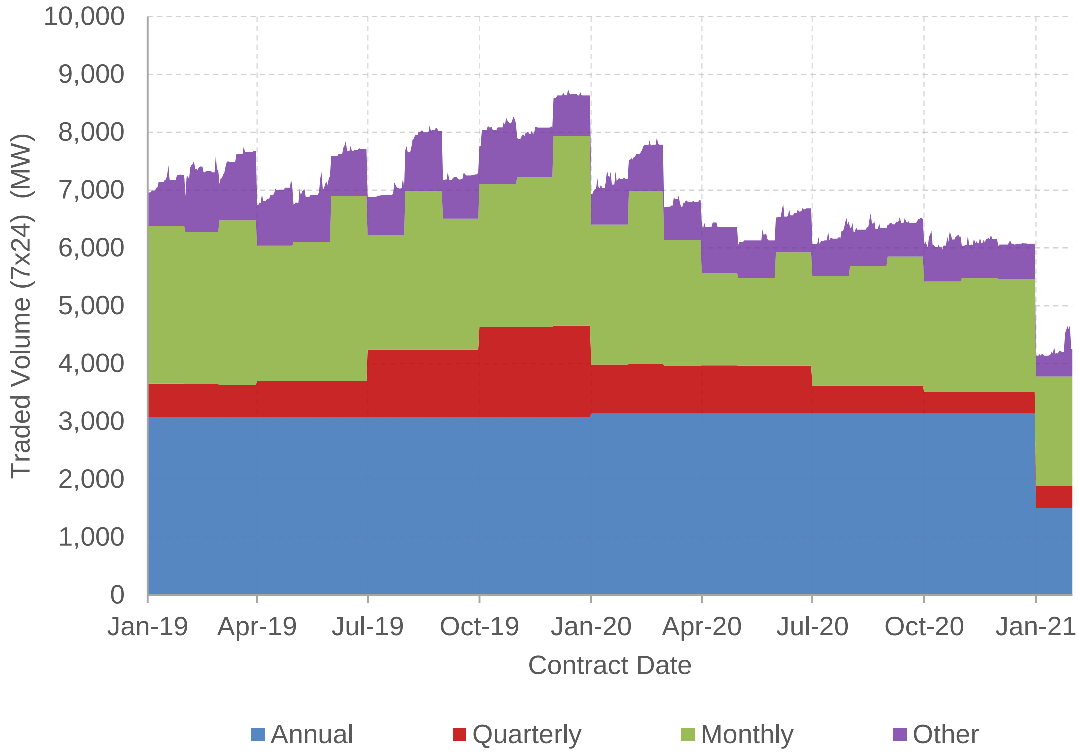


Figure 40 sets this decline in annual trading activity in the context of overall traded volumes by contract date. The figure illustrates the decline in monthly and quarterly trading that occurred as trading activity declined in 2020. The significant decline in traded volumes for annual contracts in 2020 is shown to materially affect overall traded volumes beginning with the contract date of January 1, 2021. As shown, the decline in annual traded volumes was not offset by increased volumes for monthly or quarterly contracts, despite the higher carbon price for 2021 and the expiration of the PPAs.

55 Uses trade data from January 1, 2014 to January 29, 2021.

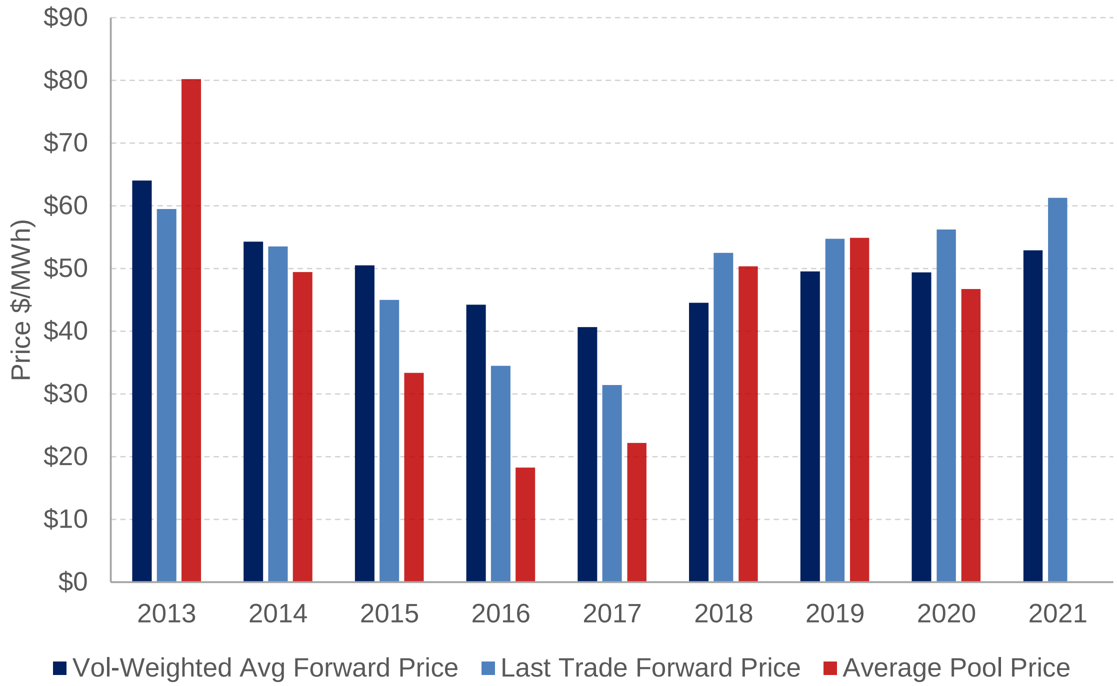
Figure 40: Daily traded volumes by contract date (January 2019 to January 2021)[56]



The average price of $46.72/MWh in 2020 was below forward market expectations for CAL20, with a final forward trade price of $56.20/MWh on December 20, 2019 and a volume-weighted average forward price of $49.36/MWh. The fact that CAL20 forward prices were generally above the average pool price in 2020 was likely driven largely by the economic implications of the COVID-19 pandemic, in addition to high wind generation and imports. Figure 41 shows how average pool prices have compared to forward market pricing levels since CAL13. It is important to note that the volume-weighted average forward price is a general reflection of the overall pricing level in the forward market, and will likely incorporate a wide range of forward prices traded over a number of years. The last trade forward price is reflective of forward market expectations when the market had the most information.

[56] 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 the 4 MW expected value. Daily volumes are included in 'Other'.

Figure 41: Annual flat forward prices and average pool prices in 2020[57]

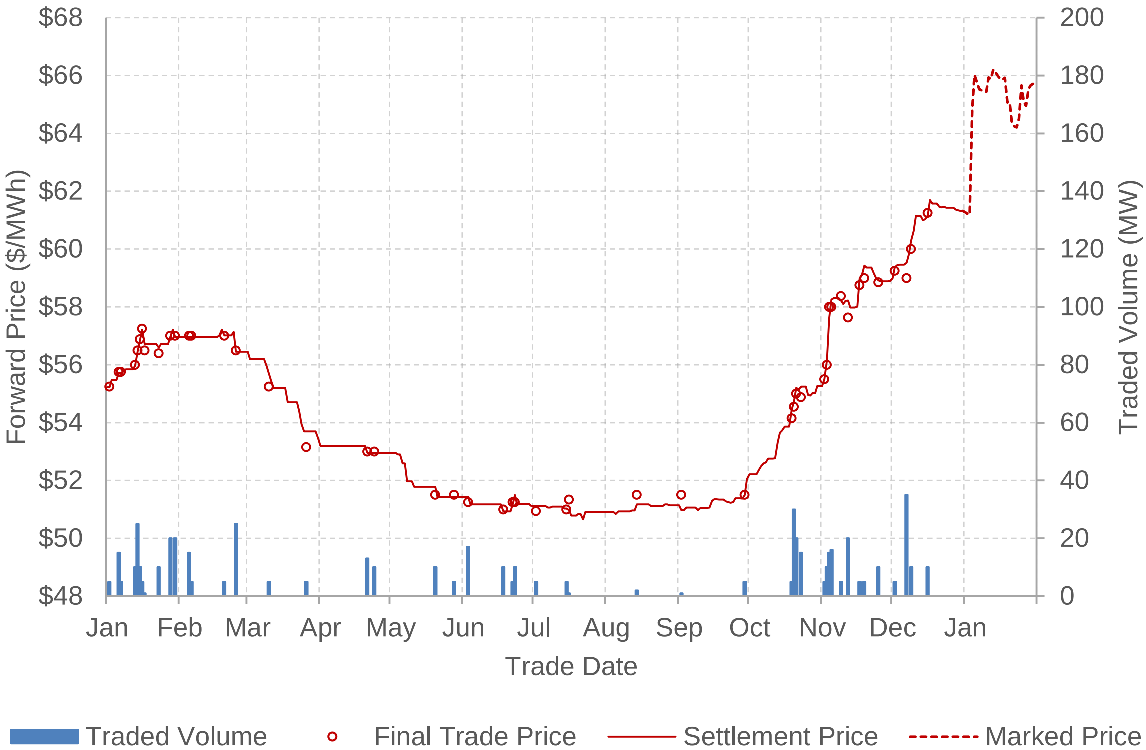


As shown in Figure 41, historical forward prices for annual contracts were often quite different from realized pool prices, with the CAL13 forward contract considerably undervalued compared to realized pool prices, and the CAL15, CAL16, and CAL17 contracts significantly overvalued compared to realized pool prices. The overall forward pricing levels for the CAL18, CAL19, and CAL20 contracts have generally been a more accurate predictor of realized pool prices. The final trade price for CAL21 was $61.25/MWh on December 16, 2020.

Figure 42 illustrates how the forward price for CAL21 has varied over the course of 2020. In mid-January of 2020 the price of CAL21 increased to $57.25/MWh as cold weather, low wind, and thermal outages increased pool price volatility in the energy market. Later in February the price of CAL21 began to decline as global markets started to respond to the developments surrounding the COVID-19 pandemic. The price of CAL21 fell from $57.00/MWh at the end of January to $51.00/MWh in June. Thereafter, there was very little change in the price for much of the summer when few volumes traded. As shown by Figure 42, the price of CAL21 increased materially in Q4. On December 16, 2020 CAL21 traded for $61.25/MWh, 19% higher than the traded price of $51.50/MWh on September 29, 2020.

[57] The figure uses trade data from ICE NGX and brokers going back to a trade date of January 1, 2009; direct bilateral trade data is included beginning on January 1, 2013.

Figure 42: Forward prices and traded volumes for CAL21 flat (January 1, 2020 to January 31, 2021)



The increase in price for CAL21 in Q4 2020 was likely driven by multiple factors, potentially including the following:

- Beginning around mid-September there was a notable increase in electricity demand as economic activity increased and oil prices stabilized. In October 2020 average AIL was only 0.5% lower than October last year, and in November AIL was 1.6% higher year-over-year (Figure 9 and Table 5). Average temperatures year-over-year were very comparable in both October and November (Table 8).
- The market observed some pool price volatility in mid-October when the BC/MATL intertie was unavailable for around 13 days (Figure 6).
- On November 3 the Government of Alberta confirmed that the carbon price would be $40/tCO2e for 2021.[58]
- In early November, as part of their Q3 reporting, two large generating companies separately stated their view that the price of CAL21 had upside potential.[59]

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[58] The carbon price of $40.00/tCO2e for 2021 was confirmed in Ministerial Order 36/2020

[59] Capital Power Q3 2020 Results Conference Call Transcripts (November 2, 2020) at pages 3-4, 7, and 11-12

TransAlta Q3 2020 Results Conference Call Transcripts (November 4, 2020) at pages 14-15 and 21-22

- On November 4 it was confirmed that the Sundance 5 coal unit, which is currently mothballed, would be repowered into a larger combined-cycle gas unit, with the repowered asset scheduled to be online in late 2023.

- Global oil prices increased materially in November, and into December, in part due to optimism on demand recovery.[60]

- On December 17, the AESO scheduled a planned transmission outage meaning the BC/MATL intertie is expected to be unavailable for a series of dates between August 23, 2021 and September 17, 2021 (Table 25).

Table 25: BC/MATL intertie planned outage schedule (August to September 2021)

Scheduled Outage Start	Scheduled Outage End	Hours
Mon, Aug-23-2021 09:00	Fri, Aug-27-2021 18:00	105
Mon, Aug-30-2021 09:00	Fri, Sep-03-2021 18:00	105
Tue, Sep-07-2021 09:00	Fri, Sep-17-2021 18:00	249

The marked price for CAL21 uses observed pool prices and forward settlement prices to mark the current value of the CAL21 contract over time. As shown by Figure 42 the marked price of CAL21 increased materially in early January. On January 4, 2021 the marked price of CAL21 increased by $3.66/MWh (6.3%) as forward prices for the remainder of 2021 increased. As discussed above, on January 4 the market observed that around 1,700 MW of coal capacity was offline for commercial reasons. On January 5 WTI oil prices increased by close to 5% and the marked price for CAL21 increased a further $1.18/MWh.[61]

Figure 43 illustrates how the forward price for CAL22 evolved from January 1, 2020 to January 29, 2021. As shown, the price of CAL22 was relatively stable for much of 2020. In particular, the settlement price did not decline materially in response to developments regarding the COVID-19 pandemic beginning in late February. The chart also demonstrates that, outside of January, there was very little trading for CAL22 over the first three quarters of 2020. On November 4 the settlement price of CAL22 increased by 4.7% to $55.98/MWh. This price increase may have been, in part, a response to the confirmation that the Sundance 5 coal asset would be repowered to a combined cycle unit and that coal mine operations at Highvale would cease at the end of 2021, meaning that Keephills 1 (395 MW) and Sundance 4 (406 MW) are scheduled to be derated to 70 MW and 113 MW, respectively, effective January 1, 2022.

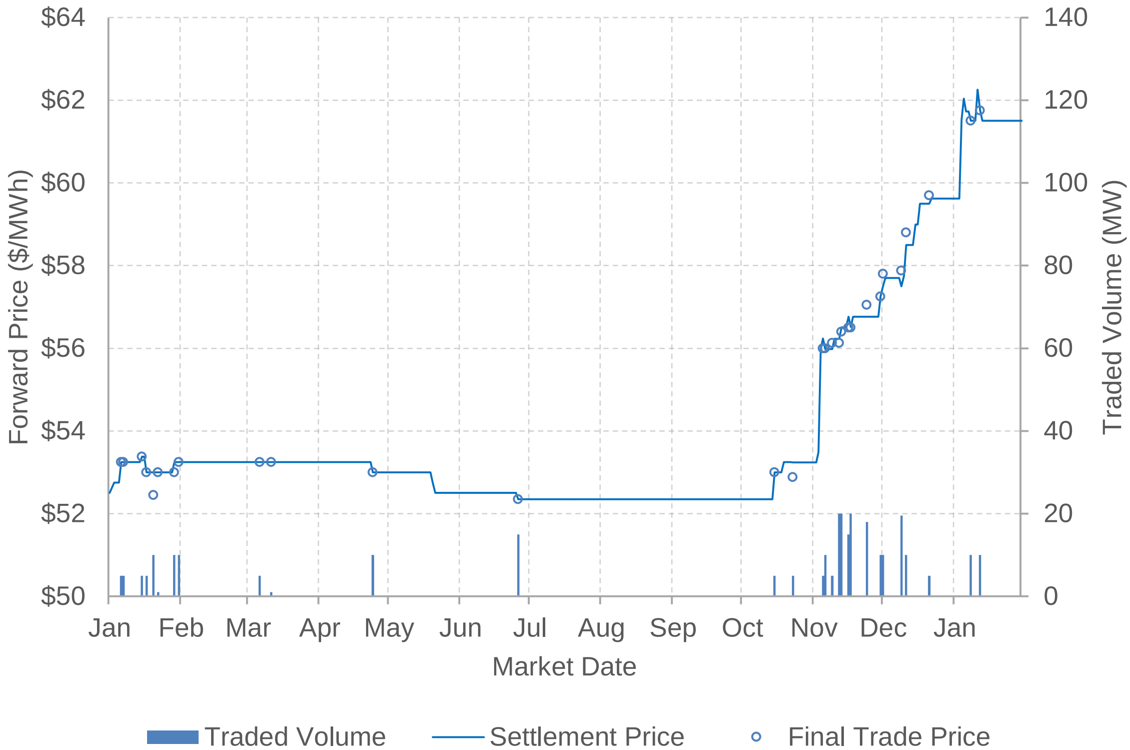
The higher price level saw an increase in traded volumes, as shown by Figure 43. The price of CAL22 continued to increase through November and December with the final trade of 2020 priced at $59.70/MWh on December 21. The price of CAL22 increased further on January 4, 2021 with

[60] The price of WTI increased by 31% between November 6 and December 31, 2020 (EIA NYMEX WTI Futures Prices – Contract 1). See Reuters (November 9, 2020) for example.

[61] Reuters: Oil prices jump 5% on OPEC+ output talks, Iran tension (January 5, 2021)

the settlement price rising 3.2% to $61.54/MWh, and the contract traded for $61.75/MWh on January 12.

Figure 43: Forward prices and traded volumes for CAL22 flat (January 1, 2020 to January 29, 2021)



On December 3, 2020 it was announced that the Genesee 1 and 2 coal assets (800 MW total) are scheduled to be repowered to larger combined cycle assets, with a total generation capacity of 1,360 MW, by Q2 of 2024. The forward settlement price for CAL22 did not change on December 3, 2020. The owner of Genesee 1 and 2 has publically outlined a staged construction schedule for the conversion process in which the coal assets will continue to operate as the gas turbines are assembled, and then the gas turbines will run in simple cycle mode as adjustments are made to the steam turbines. The repowering of Genesee 1 and 2, the development of Cascade, the repowering of Sundance 5, and other coal unit conversions means that Alberta should continue to see a significant reduction in carbon emissions related to electricity generation.

On December 11, 2020 the federal government outlined its climate plan.[62] 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.

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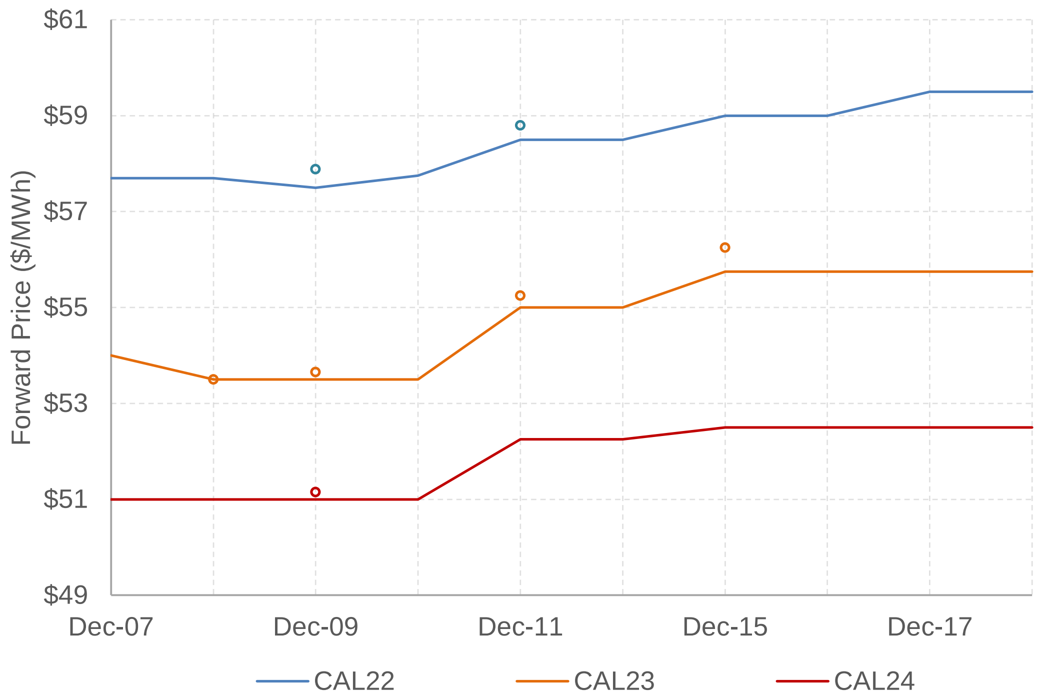
[62] Government of Canada: A Healthy Environment and a Healthy Economy - backgrounder and full plan (December 11, 2020)

Figure 44 shows forward prices for CAL22, CAL23, and CAL24 on the days before and after the federal carbon plan announcement. The lines illustrate the daily settlement price and the markers show the traded price of the day's final trade. As shown, forward prices did increase on December 11. For example the traded price of CAL23 increased by 3.0% to $55.25/MWh, and the contract subsequently traded for $56.25/MWh on December 15. The impact of higher carbon prices on Alberta electricity prices would depend upon a number of factors including the carbon intensity of generation technologies in Alberta and how carbon emissions are benchmarked. For example, combined cycle technology is currently used to benchmark carbon emissions in Alberta so an efficient combined cycle unit has negligible carbon costs at present.

Figure 44: Forward prices for CAL22, CAL23 and CAL24 (December 7 to 18, 2020)

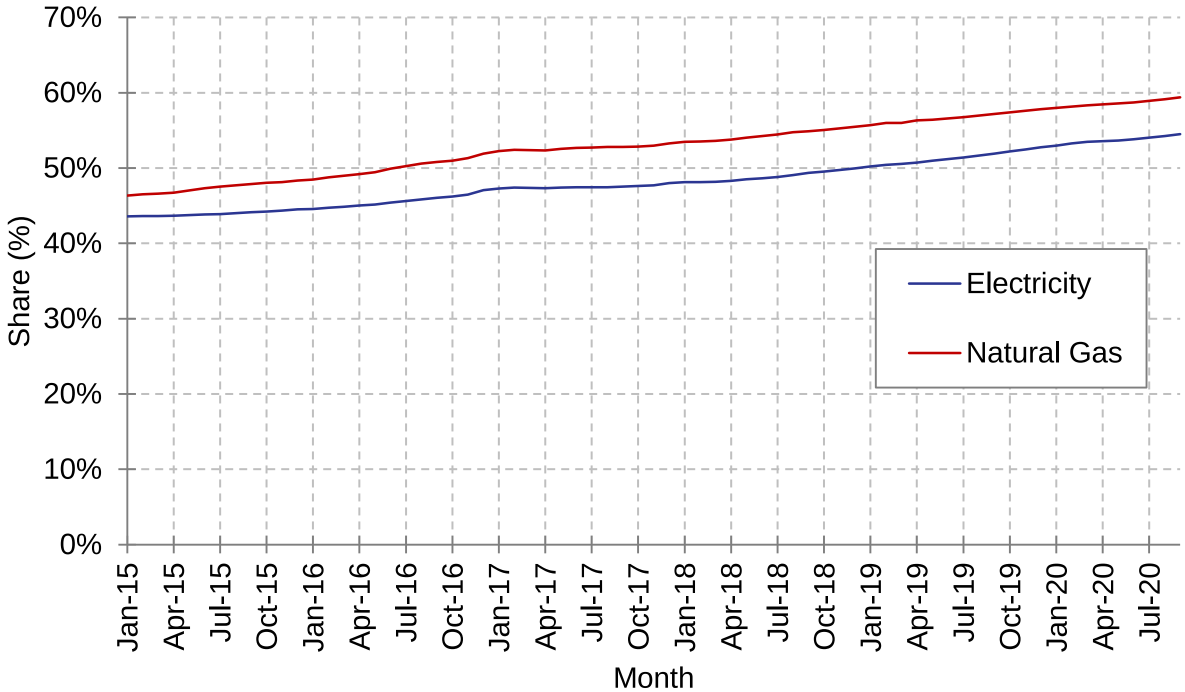


4 THE RETAIL MARKETS

4.1 Competitive market shares

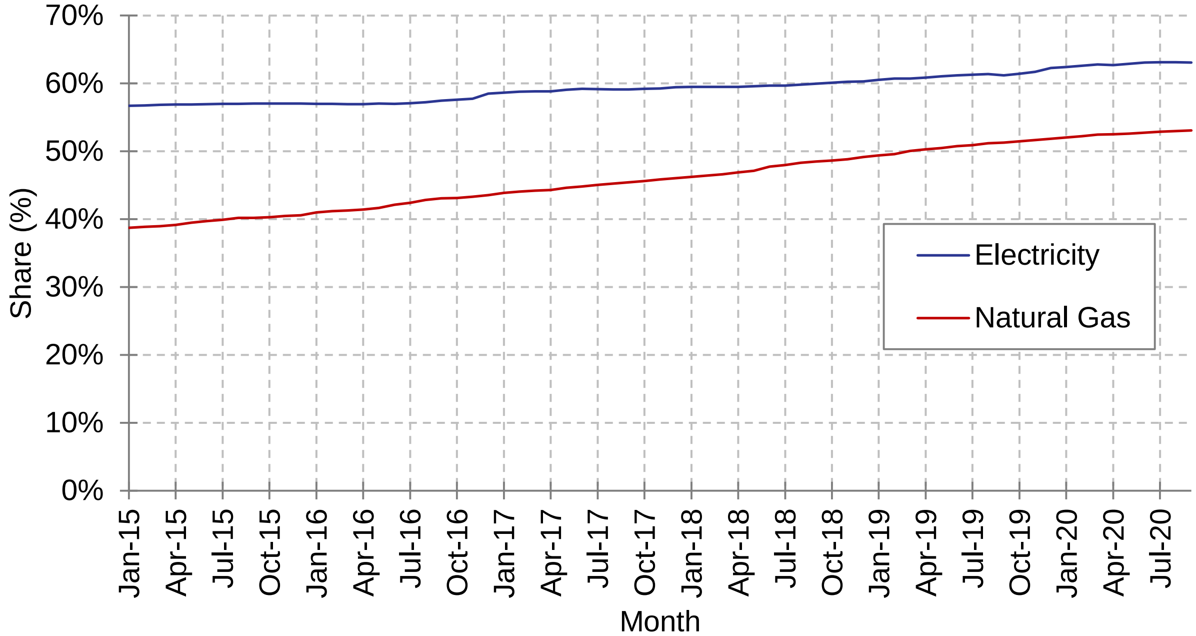
Residential customers continued to switch away from regulated retail electricity and natural gas products in Q3 2020 (Figure 45). Since the beginning of 2020 the share of residential customers on competitive retail contracts has increased by 2% in both retail electricity and retail natural gas markets. Competitive market shares for both contracts typically trend together owing to the popularity of dual-fuel contracts among residential customers.

Figure 45: Share of residential customers on competitive retail contracts, January 2015 to September 2020



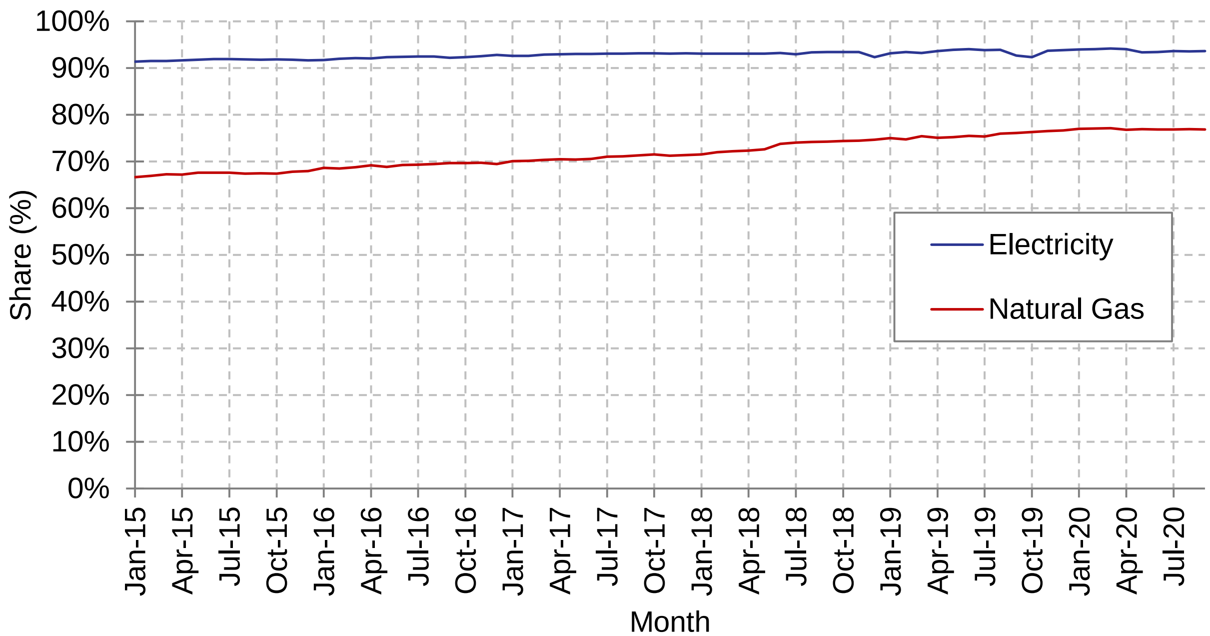
Since the beginning of 2020, the share of commercial customers on competitive electricity contacts has increased by 1% for both the retail electricity and retail natural gas markets. Greater shares of commercial customers are on competitive electricity contracts compared with residential customers, but fewer have switched to competitive natural gas providers (Figure 46).

Figure 46: Share of commercial customers on competitive retail contracts, January 2015 to September 2020



The share of industrial customers on competitive retail electricity contracts has remained stable at around 94% since Q2 2019 (Figure 47). Over the same period, the share of customers on competitive natural gas contracts has grown by 2%.

Figure 47: Share of industrial customers on competitive retail contracts, January 2015 to September 2020



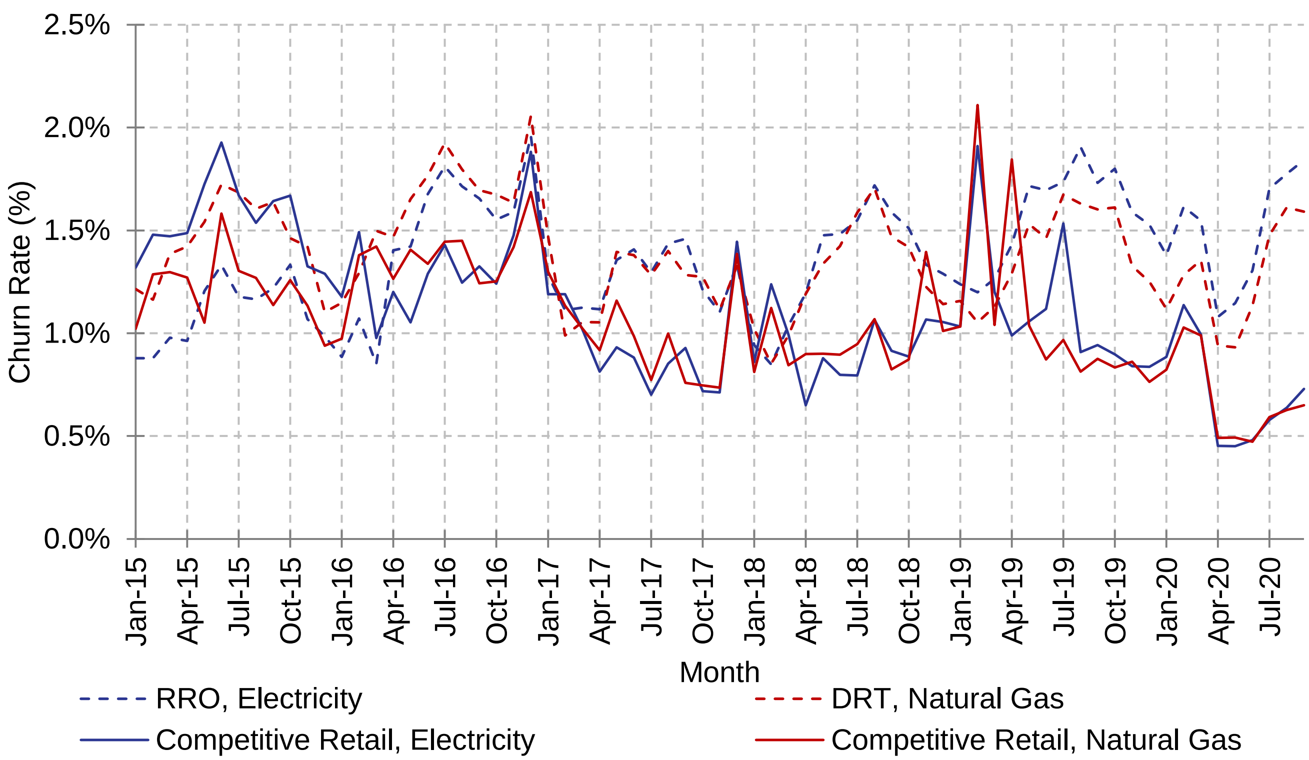
4.2 Churn

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 competitive retailers continued to recover in Q3 2020 from the lows experienced in the previous quarter (Figure 48). Regulated retail churn increased quarter over quarter in line with seasonal trends and possibly as a result of increasing RRO rates over Q3 2020 (Figure 49). Churn rates typically trend together as a result of the popularity of dual-fuel contracts.

Figure 48: Retail churn rates, residential customers, January 2015 to September 2020



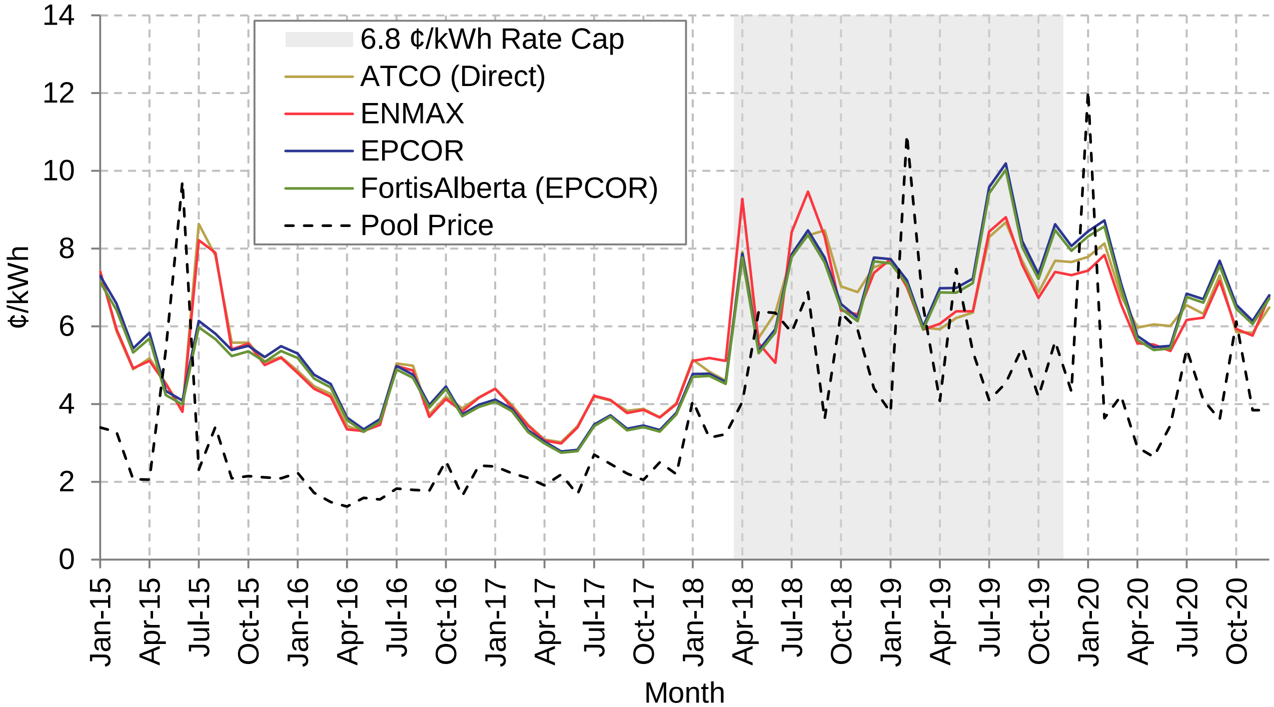
4.3 Regulated retail market

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 6.28 cents/kWh in the four largest distribution service areas in Q4/2020, a 0.5 cent/kWh decrease compared to the previous quarter (Figure 49).

Figure 49: (Uncapped) residential RRO rates, January 2015 to December 2020[63]

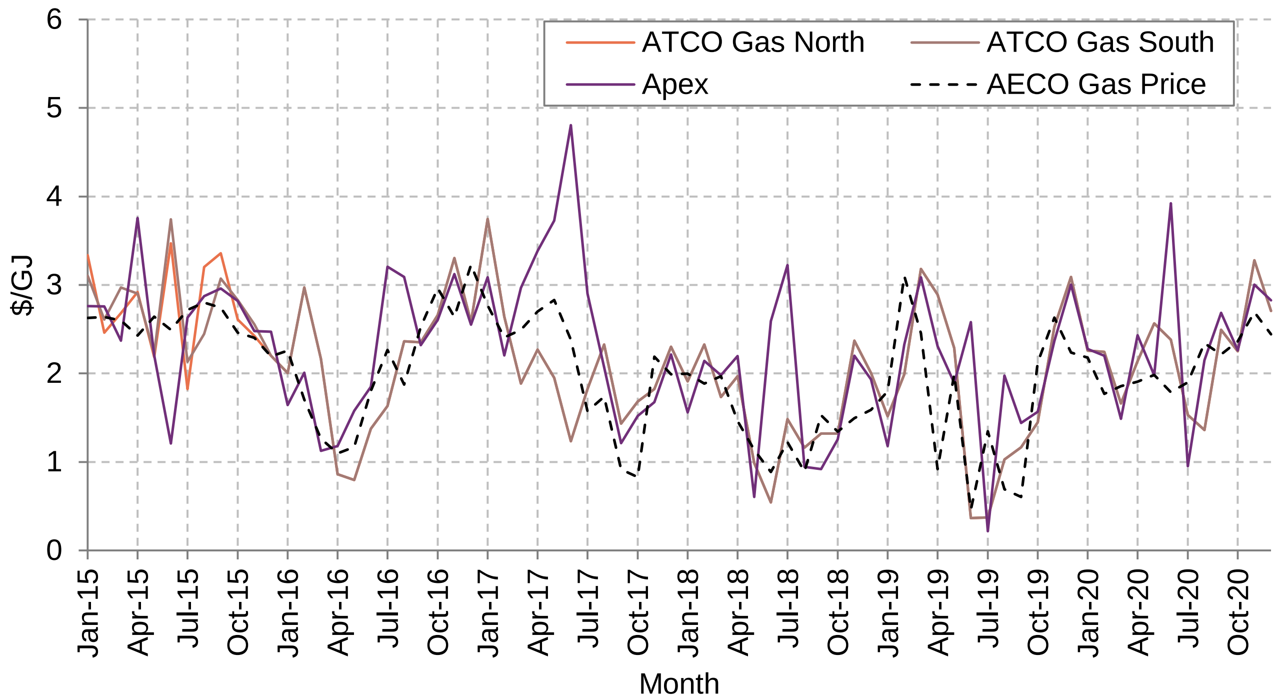


4.3.2 Default Rate Tariff (DRT)

Average DRT rates increased to $2.73/GJ in Q4/2020, up from $1.84/GJ the previous quarter (Figure 50). Wholesale natural gas prices increased over 2020 and were comparable to wholesale prices seen between 2015 and 2017.

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

Figure 50: DRT rates, January 2015 to December 2020[64]



4.4 Energy Price Setting Plans

In August 2020, the Alberta Utilities Commission (AUC) approved the 2019-2022 energy price setting plan (EPSP) for ENMAX Energy Corporation.[65] In accordance with its EPSP, ENMAX will hold descending clock auctions to procure flat, extended peak and full-load strip products which will be used to set RRO rates. ENMAX's EPSP is similar in many respects to the EPCOR EPSP but differs in the proportion of its forecast RRO load hedged by procured full-load strips.[66] In September 2020 ENMAX held its first auctions under its new EPSP to set RRO rates for December 2020 and subsequent months. Thus far, the observed ENMAX RRO rates since December 2020 have been similar to EPCOR RRO rates.

On August 21, 2020, Direct Energy Regulated Services (DERS) submitted an application to the AUC for approval of its 2020-2022 EPSP incorporating a procurement methodology similar to that

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[64] On November 6, 2020 AltaGas Utilities Inc. changed its name to Apex Utilities Inc ("Apex"). See Apex Utilities Inc. Corporate Name Change.

[65] For the first decision regarding the application see Decision 24721-D01-2020 ENMAX Energy Corporation 2019-2022 Energy Price Setting Plan, March 19, 2020. This decision was subsequently amended by Decision 22537-D01-2020 and Disposition 25537-D02-2020 in July and August 2020.

[66] ENMAX will procure full-load strips equal to 40% of its forecast RRO load volume, while EPCOR procures half of its forecast load using full-load strips. See Disposition 25537-D02-2020, PDF Page 21.

approved for the ENMAX.[67] On November 5, DERS requested approval to initiate a negotiated settlement process, which was approved by the Commission.[68] On November 30, DERS and interveners in the EPSP proceeding reached a negotiated settlement agreement (NSA) with respect to the EPSP,[69] agreeing to an EPSP wherein DERS would procure flat and extended peak hedges on the ICE NGX screens and would utilize the full load price from the EPCOR RRO filings and the procured flat and extended peak hedge prices to set its RRO rates.[70] The AUC has not yet approved NSA.

4.5 Non-residential retail market shares

Many competitive retailers' regulated affiliates operate under similar names and branding, a strategy known as "co-branding". The impacts of co-branding are seen in the electricity market shares for commercial customers (Figure 51) and to a lesser extent, industrial customers (Figure 52). Customers may more often choose competitive retailers who are familiar to them as their distributor or regulated rate provider, resulting in more favourable market shares in service areas served by their regulated affiliate(s), although the magnitude of such co-branding impacts can differ between retailers.

Some retailers tailor their electricity product offerings to larger industrial customers with more complex energy pricing needs; as a result these retailers have had greater success in acquiring industrial customers (Figure 52) than they have had with commercial customers (Figure 51).

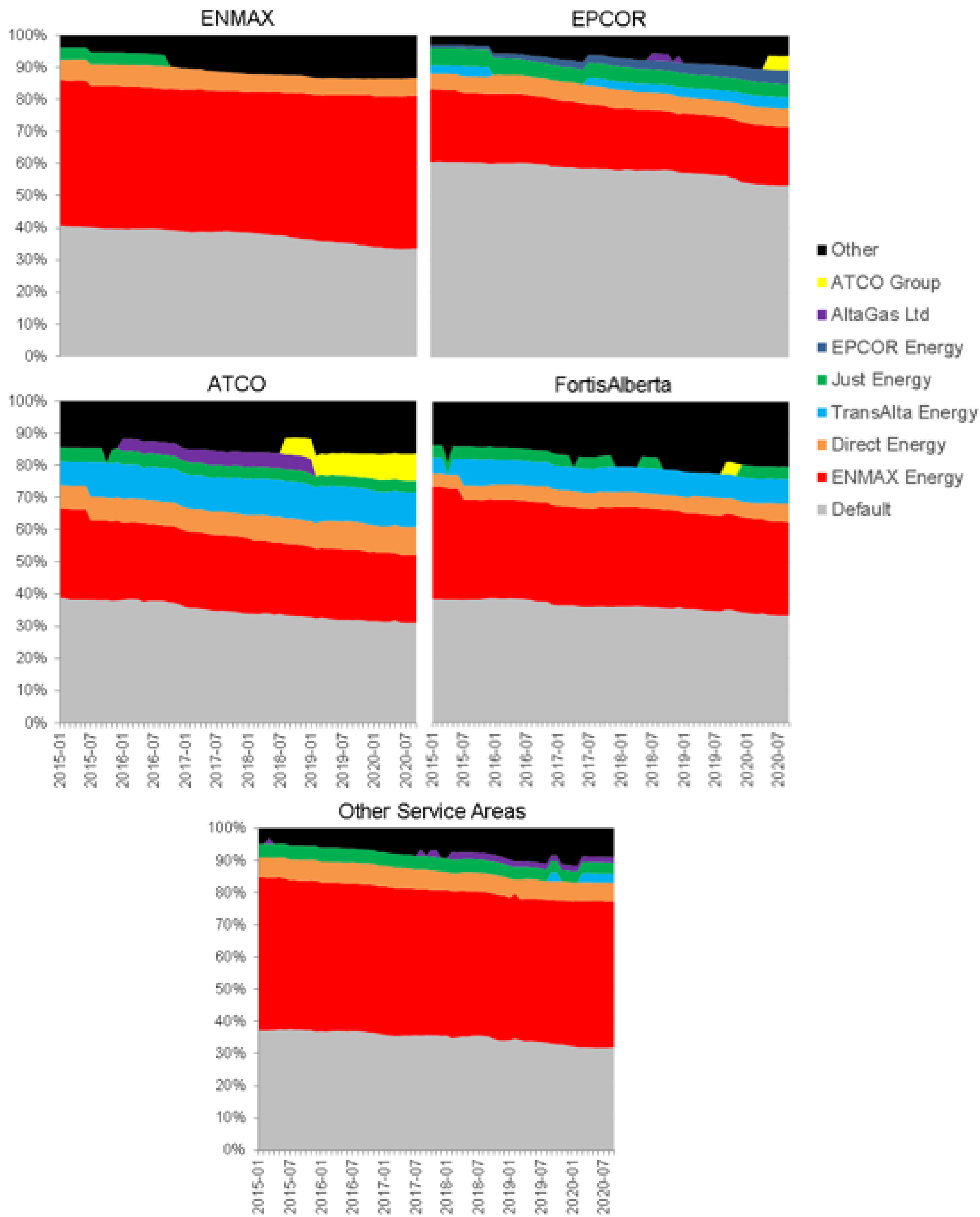
[67] For the application letter see DERS 2020-2022 EPSP Cover Letter, Proceeding 25818, Exhibit 25818-X0001, August 21, 2020. For the applied-for EPSP see Direct Energy Regulated Services 2020-2022 Energy Price Setting Plan, Proceeding 25818, Exhibit 25818-X0014, September 3, 2020.

[68] Response to DERS' request for approval to initiate a negotiated settlement process, and updated process schedule, Proceeding 25818, Exhibit 25818-X0093, November 6, 2020.

[69] Negotiated Settlement Agreement Direct Energy Regulated Services 2020-2022 Energy Price Setting Plan Application, Proceeding 25818, Exhibit 25818-X0112.01, December 2, 2020.

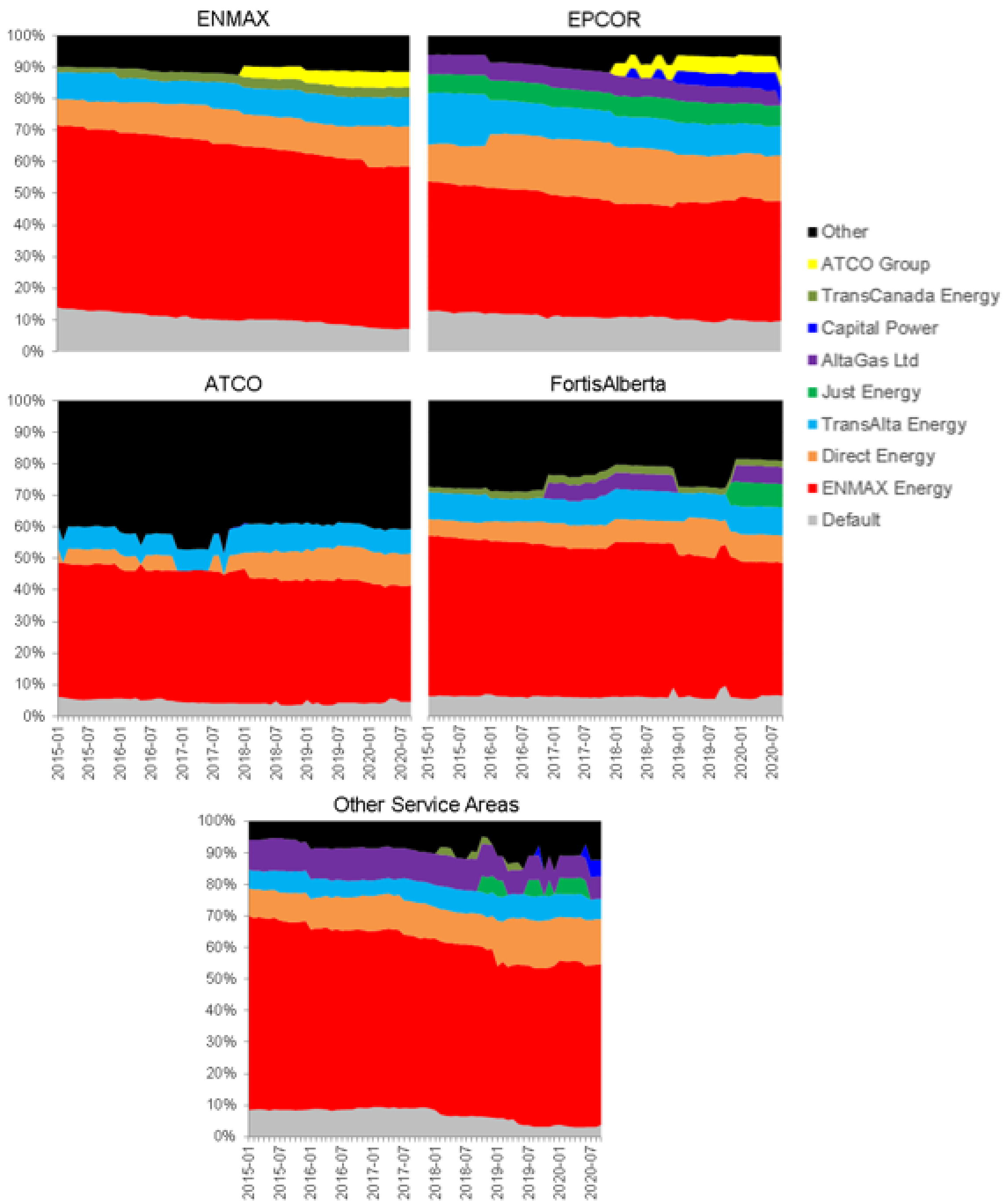
[70] NSA Appendix B – 2020-2022 EPSP (Index) Clean Public (with Redactions), Proceeding 25818, Exhibit 25818-X0113.01, December 8, 2020. See DERS Application Settlement Brief, Proceeding 25818, Exhibit 25818-X0122, December 2, 2020.

Figure 51: Retail electricity share of commercial sites by service area, January 2015 to September 2020[71]



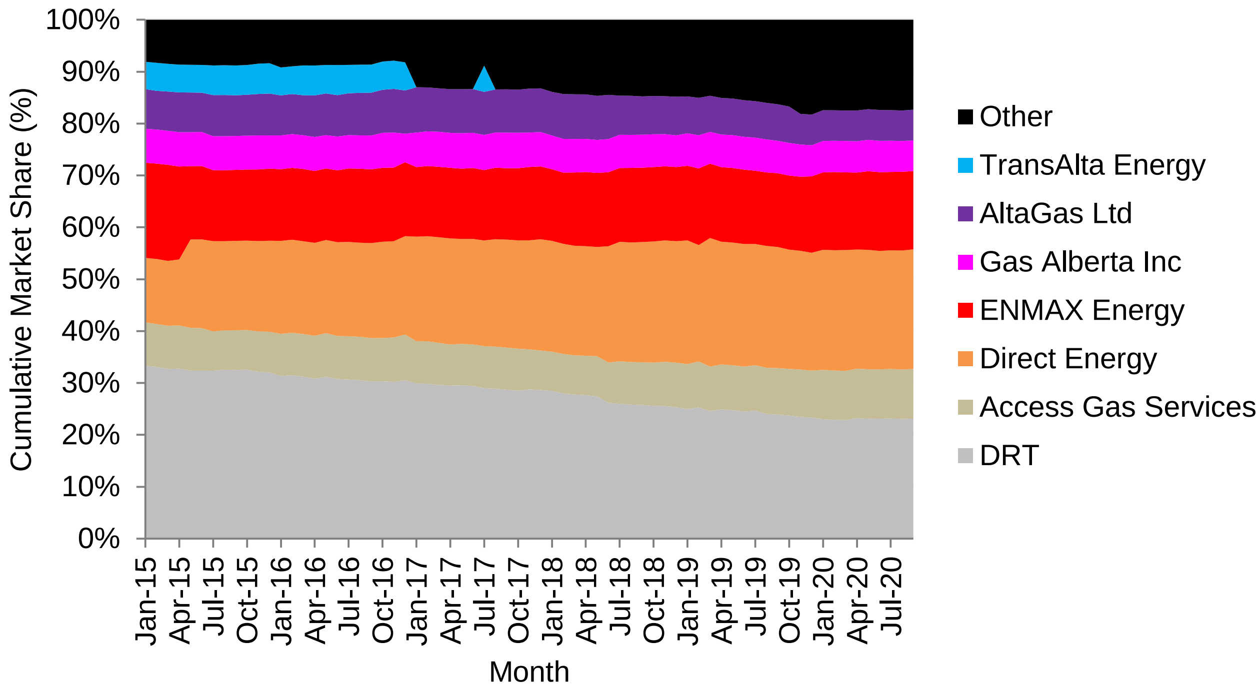
[71] 'Default' refers to customers on Regulated Rate Option (RRO) or Regulated Default Supply (RDS) rates.

Figure 52: Retail electricity share of industrial sites by service area, January 2015 to September 2020



Unlike the competitive electricity market for industrial customers, the competitive market for natural gas does not have a dominant competitive retailer in terms of market share (Figure 53).

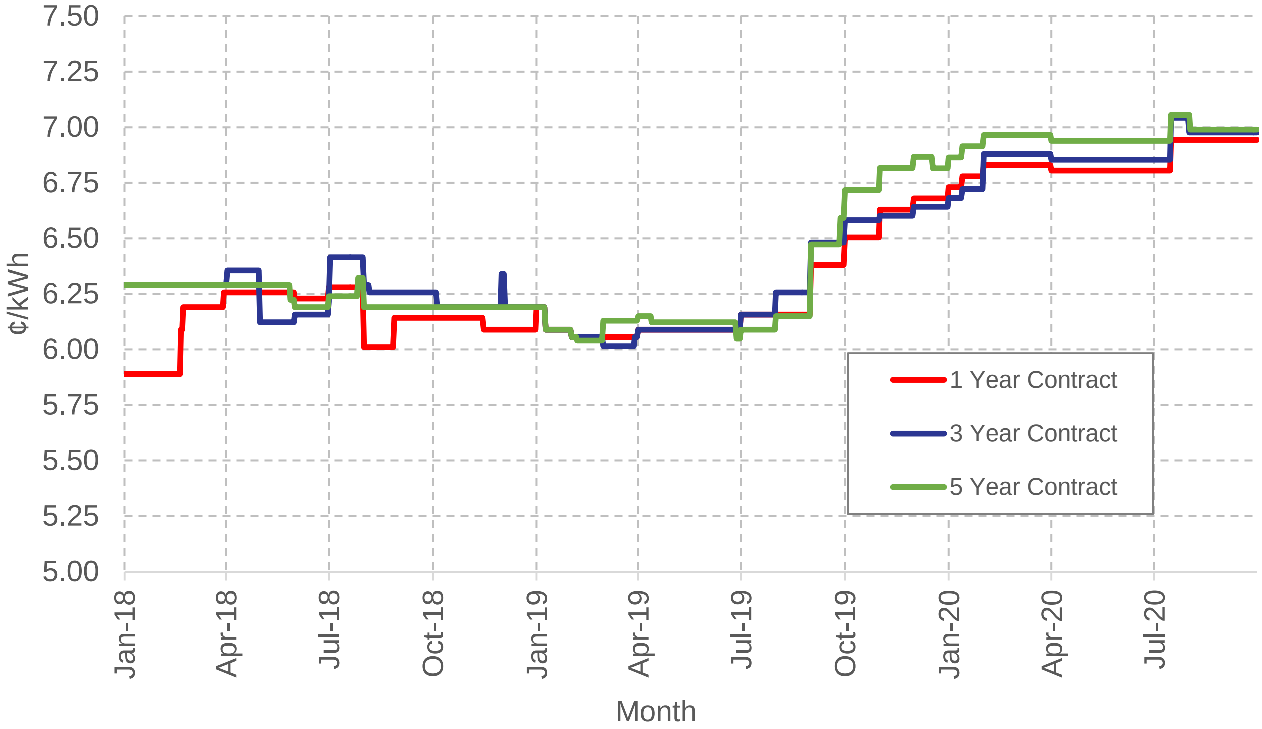
Figure 53: Retail natural gas share of industrial sites, all service areas, January 2015 to September 2020



4.6 Competitive energy rates

Much like forward market prices, fixed price competitive energy rates are set in a forward-looking manner. Fixed price competitive rates began increasing in 2019 (Figure 54), in parallel to increases forward market prices for annual contracts following the cancellation of the capacity market. Competitive energy rates were relatively stable over the course of 2020, and are approximately one cent/kWh higher than rates in early 2019.

Figure 54: Average competitive fixed price contract, residential customers, select retailers, January 2018 to September 2020[72]



[72] Competitive rate data sourced from the Utilities Consumer Advocate.

5 ENFORCEMENT MATTERS

5.1 Long lead time declarations

The MSA has observed an increase in the use of long lead time declarations as more combined cycle units are added to the Alberta electric system, coal units convert to natural gas, or as coal units find themselves operating on the margins. As a result, the MSA has received some requests for clarity around ISO rule 202.4, *Managing Long Lead Time Assets*. There are two types of long lead time declarations. The first occurs when the unit is offline and declares a start-up time, in hours, indicating when it could return to service; the unit may also submit a time when it intends to actually start. This is sometimes referred to as a type 1 long lead time declaration. The second, known as a type 2 long lead time declaration, occurs when an asset is providing electricity to the grid through in-merit offers, but cannot increase its generation to full availability within the timeline required by the rules. This typically occurs in assets with operational constraints; for example, a combined cycle unit where one or more turbines are not currently running. The MSA offers the following observations regarding the two types of long lead time declarations.

Type 1 – Unit offline

Long lead time declarations are not treated as outages. While a unit on long lead time will not appear in the merit order, it is still considered available. During the time a long lead time declaration is in force it does not appear in the outage graphs. In the MSA's view, if an asset decides to conduct maintenance activity while having a long lead time declared, and this maintenance activity reduces the available capability of the unit, it should declare an outage for the period that the maintenance activity will occur, in accordance with ISO rule 306.5, *Generation Outage Reporting and Coordination*, and/or ISO rule 203.3, *Energy Restatements*. Having completed the maintenance activity, the unit may continue to declare a long lead time. Following this process ensures outages are reported appropriately and market participants do not find themselves in potential violation of Section 2(e) or Section 4 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation).

Section 2 of ISO rule 202.4 states that start-up times must be no greater than 36 hours. Information Document 2012-007 associated with this rule indicates that start-up times should be adjusted for operational reasons. The MSA is of the view that section 2(e) of the FEOC Regulation requires that the start-up time stated be accurate, i.e., reflective of actual operational conditions. For example, a coal unit that has recently gone offline may be capable of a "hot" start in a small number of hours, then sometime later a "warm" start with a longer lead time, and as the unit remains offline it would transition to a "cold" start with an even longer lead time. The MSA is aware that the AESO's Energy Trading System does not facilitate the easy entry of these constraints and recommends that the AESO consult with stakeholders around improvements in this area.

Type 2 - Unit online with partial long lead time

The second type of long lead time declaration is when a unit is running and in-merit but cannot supply all of its available capability to the market within the prescribed time frame. While the unit may be fully available (with a lead time), a long lead time declaration of this nature is currently entered into the Energy Trading System as an Available Capability restatement and is therefore included as an outage in the AESO's published outage data. However, a generator in such a situation is not on outage and therefore the published outage data are incorrect. The MSA believes the market would be better served if information regarding partial long lead time units could be entered into the AESO's systems as long lead time instead of a partial outage. The MSA recommends that the AESO explore whether a system and rule change could be implemented to enable accurate information regarding these long lead time units to be submitted to the AESO and included in its reports.

5.2 Retail advertising

In Q3 2020 the MSA was made aware of a market participant with both competitive and regulated retail affiliates that had advertised competitive retail products to customers of an affiliated non-energy business. The MSA determined that the market participant had not contravened the *Code of Conduct Regulation* ("the Code") by advertising to these customers, as the Code does not prohibit the marketing of competitive retail products to customers of affiliated non-energy businesses, provided such advertising contains the Fair Competition Statement when required in accordance with section 7 of the Code. The MSA takes the view that these practices are a form of retail co-branding and as such promote the development of the competitive retail energy market by incentivizing retail switching.

The same market participant also provided links to regulated rate customers on their online account pages where customers could elect to switch to the retailer's competitive affiliate products. The MSA takes the view that provided this information is not included with a regulated rate customer's billing information and customers have to first 'opt-in' to starting new energy services, presenting regulated rate customers with options to switch to competitive affiliates does not contravene the Code.

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. 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 is appropriate, then AUC Rule 019 guides the MSA on how to issue a notice of specified penalty.

From January 1 to December 31, 2020 the MSA closed 437 ISO rules compliance matters, as reported in Table 26.[73] An additional 77 matters were carried forward to the next quarter. During this period 98 matters were addressed with notices of specified penalty, totaling $157,750 in financial penalties, with details provided in Table 27.

[73] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 437 closed matters, two were withdrawn.

Table 26: ISO rules compliance outcomes for matters closed from January 1 to December 31, 2020[74]

ISO rules	Forbearance	Notice of specified penalty	No contravention
103.1	2	-	-
103.3	1	-	-
201.1	1	-	-
201.3	1	-	-
201.4	-	1	-
201.7	54	12	1
202.4	1	1	-
203.1	1	1	-
203.3	72	23	2
203.4	76	13	11
203.6	14	3	-
204.3	2	-	-
205.1	-	1	-
205.3	8	7	-
205.4	34	-	-
205.5	6	8	1
205.6	9	16	-
301.2	1	-	-
303.1	2	-	-
304.4	1	-	-
304.7	1	-	-
304.9	10	-	-
306.4	3	2	-
306.5	4	6	-
306.7	-	-	1
501.10	1	-	-
502.1	1	-	-
502.2	1	-	-
502.4	1	1	-
502.6	5	-	-
505.4	8	2	-
9.1.5	-	1	-
Total	**321**	**98**	**16**

[74] Two closed matters were withdrawn (not shown).

The ISO rules listed in Table 26 and Table 27 fall into the following categories:

103	Administration
201	General (Markets)
202	Dispatching the Markets
203	Energy Market
204	Dispatch Down Service Market
205	Ancillary Services Market
301	General (System Reliability and Operations)
303	Interties
304	Routine Operations
306	Outages and Disturbances
501	General (Facilities)
502	Technical Requirements
505	Legal Owners of Generating Facilities
9	Transmission

Table 27: Specified penalties issued between January 1 and December 31, 2020 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)																Total ($)	Matters[75]
	201.4	201.7	202.4	203.1	203.3	203.4	203.6	205.1	205.3	205.5	205.6	306.4	306.5	502.4	505.4	9.1.5		
Air Liquide Canada Inc.	500								500								1,000	2
Alberta Electric System Operator														250			250	1
Alberta Newsprint Company					1,250	5,000											6,250	2
Alberta Pacific Forest Industries Inc.						1,250											1,250	1
Alberta Power (2000) Ltd.		500															500	1
AltaGas Ltd.		500			1,500												2,000	2
AltaLink L.P., by its general partner, AltaLink Management Ltd.												250					250	1
ATCO Power (2010) Ltd.					750												750	1
Balancing Pool						5,000			500								5,500	5
Bitfury Technology Inc.									500		2,500						3,000	2
Calgary Energy Centre No. 2 Inc.					3,750												3,750	2
Canadian Natural Resources Ltd.					1,500	1,500											3,000	2
Capital Power (G3) Limited Partnership								250			250						500	2
City of Medicine Hat					2,500						500						3,000	2
Dow Chemical Canada ULC						750											750	1
Enel X Canada Ltd.											23,250						23,250	6
ENMAX Power Corporation												250					250	1
EPCOR Distribution & Transmission Inc.																500	500	1
Halkirk I Wind Project LP		500															500	1
Heartland Generation Ltd.										250							250	1
Horseshoe Power GP Ltd.		2,000															2,000	3

[75] Addressed with a penalty

Table 27: Specified penalties issued between January 1 and December 31, 2020 for contraventions of the ISO rules (Continued)

Market participant	Total specified penalty amounts by ISO rule ($)																Total ($)	Matters[76]
	201.4	201.7	202.4	203.1	203.3	203.4	203.6	205.1	205.3	205.5	205.6	306.4	306.5	502.4	505.4	9.1.5		
International Paper Canada Pulp Holdings ULC						2,500											2,500	1
MEG Energy Corp.		500															500	1
Mercer Peace River Pulp Ltd.					2,500												2,500	1
Milner Power Limited Partnership by its General Partner Milner Power Inc.		500			12,500	5,750							500				19,250	6
NorthPoint Energy Solutions Inc.							750										750	1
Northstone Power Corp.					1,500						750						2,250	2
Oldman 2 Wind Farm Limited													2,000				2,000	2
Pincher Creek Limited Partnership													500				500	1
Powerex Corp.		3,250			750		750										4,750	4
Repsol Canada Energy Partnership					1,500								500				2,000	2
Riverview Limited Partnership													500				500	1
The Manitoba Hydro-Electric Board							1,500										1,500	1
Tourmaline Oil Corp.		500															500	2
TransAlta Corporation					4,000												4,000	5
TransAlta Generation Partnership			250		9,000	750			3,000	25,000	2,500				1,000		41,500	22
Voltus Energy Canada Ltd.											10,750						10,750	3
WCSB GP III Ltd.				500	1,500	1,500											3,500	3
Total	500	8,250	250	500	44,500	24,000	3,000	250	4,500	25,250	40,500	500	4,000	250	1,000	500	157,750	98

[76] Addressed with a penalty

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 Alberta Interconnected Electric System. 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.

Effective October 21, 2020, AUC Rule 027 was amended to specify that only O&P ARS specified penalties are to be made public. CIP ARS specified penalties and information related to the nonpayment or a dispute of a CIP ARS specified penalty will not be made public. CIP matters often deal with cyber security issues and there is concern that broad public reporting creates a security risk in itself. Accordingly, at present, the MSA will continue to refrain from publishing CIP statistics.

From January 1 to December 31, 2020 the MSA closed 112 ARS O&P compliance matters, as reported in Table 28.[77] An additional 43 matters were carried forward to the next quarter. During this period, 19 matters were addressed with notices of specified penalty, totaling $45,250 in financial penalties, with details provided in Table 29.

[77] An ARS matter is considered closed once a disposition has been issued and mitigation (where applicable) is complete. Of the 112 closed matters, one matter was rejected.

Table 28: Outcomes for O&P ARS matters closed between January 1 and December 31, 2020[78]

Reliability standard	Forbearance	Notice of specified penalty	No contravention
BAL-005	3	-	-
COM-001	1	2	3
COM-002	-	-	2
EOP-001	2	-	-
EOP-005	3	-	-
EOP-008	5	2	-
FAC-003	1	1	-
FAC-008	4	-	-
INT-009	3	-	-
PER-005	2	1	-
PRC-001	14	4	-
PRC-002	4	-	-
PRC-004	1	-	-
PRC-005	6	1	-
PRC-018	-	1	-
PRC-023	3	-	-
VAR-002	28	6	1
VAR-002-WECC	2	-	-
VAR-501-WECC	4	1	-
Total	86	19	6

[78] One matter was rejected (not shown).

Table 29: Specified penalties for matters closed between January 1 and December 31, 2020 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)									Total ($)	Matters[79]
	COM-001	EOP-008	FAC-003	PER-005	PRC-001	PRC-005	PRC-018	VAR-002	VAR-501-WECC		
Alberta Newsprint Company								2,250		2,250	1
Canadian Natural Resources Limited			1,500							1,500	1
Cancarb Limited								7,500		7,500	2
Cenovus Energy Inc.					3,750					3,750	1
City of Lethbridge		2,250								2,250	1
City of Medicine Hat		2,250		1,500		1,500				5,250	3
EPCOR Distribution & Transmission Inc.							250			250	1
Fort Hills Energy Corporation					3,750					3,750	1
Heartland Generation Ltd.									1,500	1,500	1
Oldman 2 Wind Farm Limited					3,750			7,500		11,250	4
Pembina NGL Corporation	2,250				3,750					6,000	3
Total	2,250	4,500	1,500	1,500	15,000	1,500	250	17,250	1,500	45,250	19

O&P ARS listed in Table 28 and Table 29 fall into the following categories:

BAL Resource and Demand Balancing
COM Communications
EOP Emergency Preparedness and Operations
FAC Facilities Design, Connections, and Maintenance
INT Interchange Scheduling and Coordination
PER Personnel Performance, Training, and Qualifications
PRC Protection and Control
VAR Voltage and Reactive

[79] Addressed with a penalty