MARKET SURVEILLANCE ADMINISTRATOR

Quarterly Report for Q3 2021

November 12, 2021

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

www.albertamsa.ca

TABLE OF CONTENTS

THE QUARTER AT A GLANCE

- The average pool price in Q3 2021 was $100.33/MWh, a 4% decline compared to Q2 2021 but a 129% increase relative to Q3 2020. The higher pool prices year-over-year were driven by higher demand, reduced imports, generation outages, increased natural gas prices, a higher carbon price, and variable wind generation. The offer behaviour of some larger suppliers was also a factor in the higher prices year-over-year following the expiration of the PPAs at the end of 2020.

- Average demand in July 2021 was 10.5% higher compared to July last year as temperatures were higher, economic activity increased, and WTI oil prices averaged US$72.43/bbl, the highest since November 2014. On July 7 and 14, thermal outages and low wind generation combined to reduce supply relative to demand. As a result, during the peak demand hours on these two days, the AESO issued Energy Emergency Alerts indicating that the AESO did not have enough supply to reliably meet demand.

- The total cost of operating reserves was significantly higher in Q3 2021 compared to Q3 2020, and higher pool prices were the major driver. The underlying index prices for active spinning and supplemental reserves were lower year-over-year, most notably for supplemental, as a result of increased competition from load, hydro, and battery storage providers.

- Trading volumes in the forward market were much higher year-over-year, largely as a result of increased trading around Calendar 2022 (CAL22). The higher volumes for CAL22 were likely driven by pool price volatility in addition to notable increases in the forward price for natural gas. Over Q3 2021, the power price for CAL22 increased by 29% to $88/MWh, and the natural gas price increased by 32%. Higher natural gas prices also increased the forward power prices for CAL23, CAL24, and CAL25.

- From July 1 to September 30, 2021, the MSA closed 121 ISO rules compliance matters; 21 matters were addressed with notices of specified penalty. For the same period, the MSA closed seven Alberta Reliability Standards Operations and Planning compliance matters; two matters were addressed with notices of specified penalty. In addition, the MSA closed 47 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; eight matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q3[1] was $100.33/MWh, which is 4% lower than in Q2 2021 but an increase of 129% compared to Q3 2020. The higher pool prices in Q3 relative to Q3 2020 were driven by increased demand, particularly in July, reduced imports, higher natural gas prices, more generation outages, a higher carbon price, and higher generator offer prices. There has been no indication that the pool prices in Q3 were the result of anticompetitive conduct.

Table 1 provides summary market statistics for Q3 compared to Q3 2020. The demand for electricity compared to last year increased over the Quarter because oil prices continued to rise and July[2] was warmer than last year.

Hourly demand in Q3 peaked at 11,307 MW on Wednesday, July 14. This peak is 3.5% less than the summer peak set on June 29 as temperatures did not increase to the levels seen at the end of June.

The AESO declared two Energy Emergency Alerts (EEAs) in Q3, one on July 7 and one on July 14. These events are discussed further in section 1.2.

Natural gas is the primary fuel used by a significant proportion of generators in Alberta. As a result, natural gas prices are an important cost driver for the Alberta power market. In Q3, the System Marginal Price (SMP) was set by a natural gas-fired asset 89% of the time, compared to 48% in Q3 2020.[3]

Table 1: Monthly market summary for Q3

		2021	2020	*Change*
Pool Price (Avg $/MWh)	Jul	124.10	54.14	*129%*
	Aug	82.26	41.05	*100%*
	Sep	94.45	36.05	*162%*
	Q3	**100.33**	**43.83**	***129%***
Demand (AIL) (Avg MW)	Jul	9,920	8,974	*10.5%*
	Aug	9,297	8,971	*3.6%*
	Sep	9,015	8,845	*1.9%*
	Q3	**9,415**	**8,931**	***5.4%***
Gas Price AB-NIT (2A) (Avg $/GJ)	Jul	3.73	1.89	*97%*
	Aug	2.82	2.33	*21%*
	Sep	3.33	2.20	*51%*
	Q3	**3.29**	**2.14**	***54%***
Wind (Avg MW)	Jul	340	506	*-33%*
	Aug	488	513	*-5%*
	Sep	766	592	*29%*
	Q3	**529**	**536**	***-1%***
Net Imports (+) Net Exports (–) (Avg MW)	Jul	443	766	*-42%*
	Aug	259	772	*-67%*
	Sep	212	120	*77%*
	Q3	**306**	**558**	***-45%***
Supply Cushion (Avg MW)	Jul	1,664	2,130	*-22%*
	Aug	1,689	2,483	*-32%*
	Sep	1,605	1,951	*-18%*
	Q3	**1,653**	**2,190**	***-25%***

The planned outage at Keephills 3, which started on September 10, was for a coal-to-gas conversion. Conversions to run completely on natural gas have previously been completed at Sheerness 1 and 2, Keephills 2, and Sundance 6. In Q2 2020, HR Milner was repowered from coal to simple-cycle natural gas. In addition, the ability of Battle River 4 and 5 to use natural gas

[1] Reference to Q3 means Q3 2021 unless specified otherwise.

[2] References to a month or a day in a month mean a month or day in 2021 unless specified otherwise.

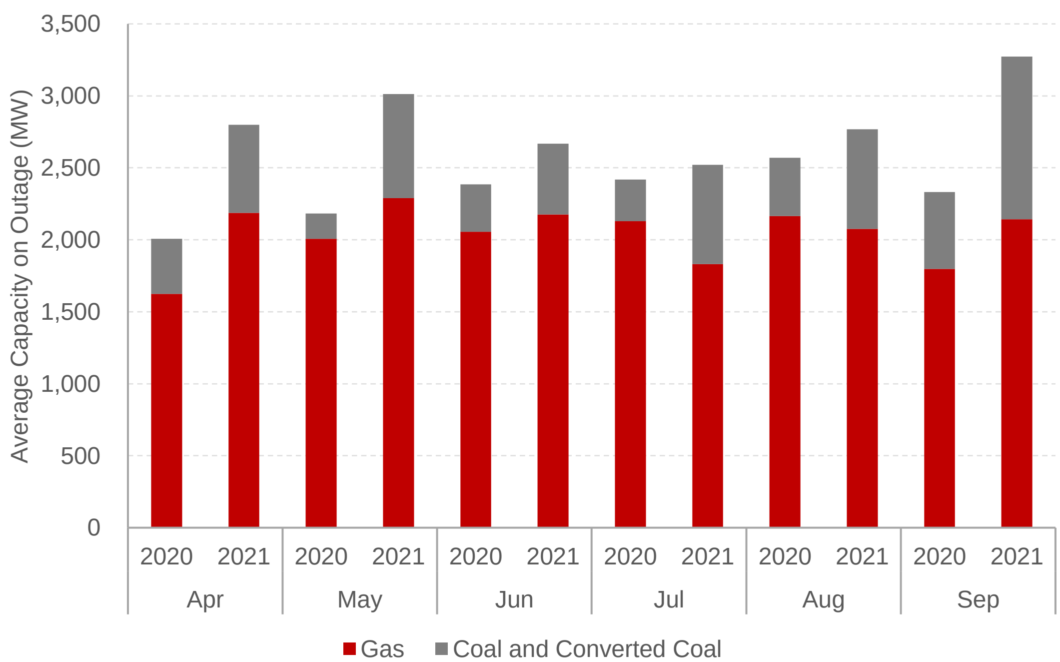
[3] These percentages assume that dual fuel assets exclusively used natural gas to generate electricity.

in addition to coal was previously increased. In total, these assets account for 2,800 MW of thermal capacity.

The increased demand for natural gas to generate electricity has been one factor putting upward pressure on natural gas prices in North America. In addition, the economic recovery and higher demand for Liquefied Natural Gas (LNG) have contributed to higher natural gas prices. Natural gas prices in Europe and Asia have been notably high in recent months as natural gas markets responded to low inventory levels for the coming winter, which has increased demand for LNG from North America. Same-day natural gas prices in Alberta were volatile in August and September as prices fell materially on some days due to pipeline constraints limiting the ability of Alberta to export or store natural gas.

Generator outages were another factor in the higher year-over-year pool prices. In Q3, there was an average of 2,850 MW of thermal capacity on outage or derated; this represents a 17% increase compared to Q3 2020.[4] In September, the average amount of unavailable thermal capacity was 3,270 MW, an increase of 40% relative to September 2020 (Figure 1). The higher outage levels in Q3 were partly caused by an extended forced outage at Genesee 2, which tripped offline on July 18 and is currently scheduled to return in late November.

Figure 1: Average thermal capacity on outage by month year-over-year (April to September)



Overall wind generation across Q3 was similar to Q3 2020 but year-over-year it was 33% lower in July and 29% higher in September (Table 1). Wind generation tends to be lower during extreme temperatures when electricity demand is higher. In Q3, wind generation received an average pool

[4] These outage figures do not include the Sundance 3 and 5 assets, which were mothballed from April 2018. The Sundance 3 asset was retired on July 31, 2020 and the Sundance 5 asset is also scheduled to retire.

price of $74/MWh compared to the average pool price of $100/MWh. The Windrise (207 MW) and Whitla 2 (151 MW) wind assets also began supplying power to the grid in Q3, bringing total wind capacity in Alberta to 2,139 MW.

Solar capacity in Alberta is also growing. On January 1 there was 107 MW of installed solar capacity and as of September 30 this had tripled to 336 MW. That said, solar generation accounted for 0.8% of total generation in Q3. Solar generation tends to produce more generation during on-peak hours when demand is higher. In Q3, solar generation received an average pool price of $140/MWh, which is about 40% greater than the average pool price. In the coming years, Alberta is expected to see a material increase in wind and solar capacity.[5]

Import volumes in July and August were significantly lower compared to 2020 (Table 1). The high import flows in 2020 were partly a reflection of prevailing market conditions in Mid-Columbia (Mid-C) last summer as the economic downturn and high hydro supplies combined to put downward pressure on Mid-C power prices. In August, the average power price in Mid-C was CAD$62.41/MWh, an increase of 122% relative to August 2020, and in July, Mid-C prices averaged CAD$60.32/MWh which is 232% higher than July 2020. Further, the available transfer capability (ATC) for imports was lower this year, partly because the LSSi requirements have been increased.

[5] AESO: Long Term Adequacy Metrics

1.2 Market outcomes

In Q3, the average pool price was $100.33/MWh, which is consistent with the prices observed earlier this year (Figure 2). Based on realized pool prices to the end of Q3 and the monthly forward prices for Q4, the average pool price for 2021 was marked at $98.66/MWh as of September 30. Therefore, 2021 is expected to be the highest average pool price year since the market began in 2001. The previous high was set in 2008 when the nominal average pool price was $89.95/MWh.

Figure 2: Average pool price by quarter (Q1 2001 to Q3 2021)[6]

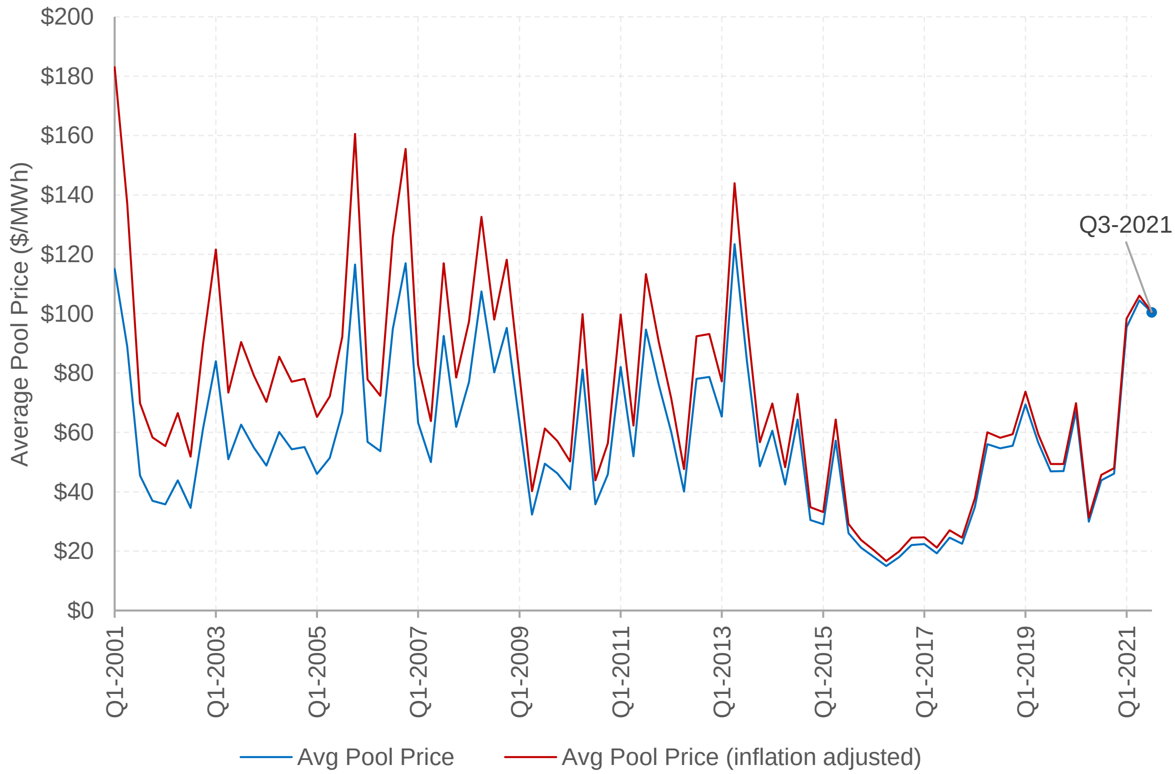
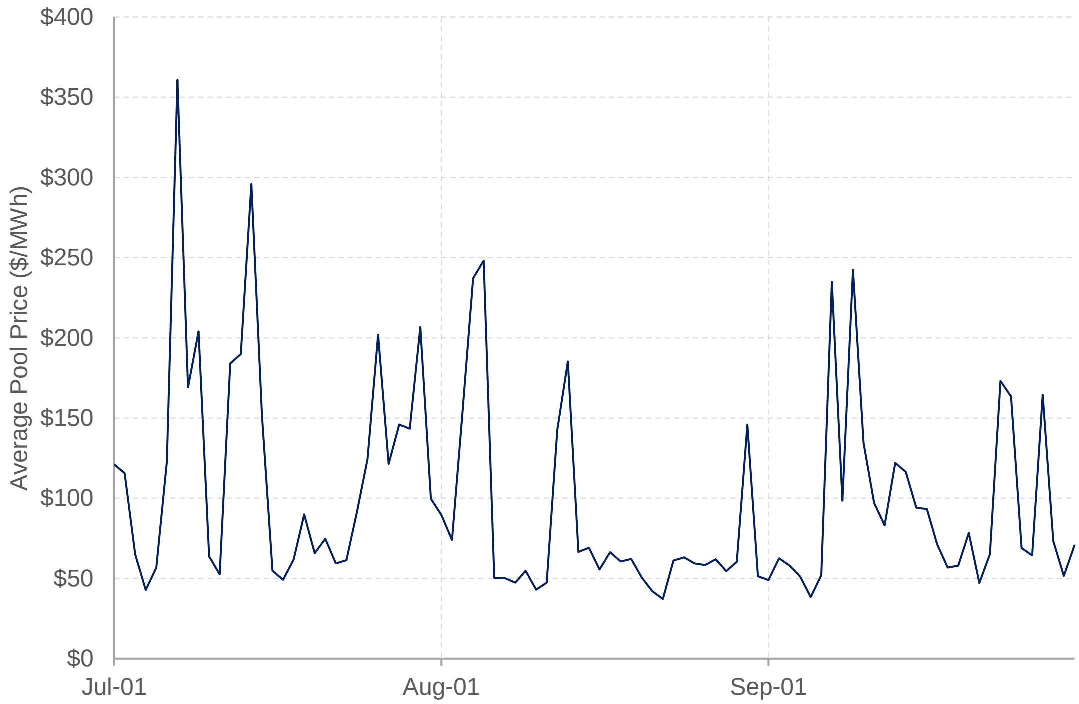


Figure 3 illustrates daily average pool prices over Q3. As shown, pool prices in Q3 were volatile and were highest in early July, specifically on July 7 and July 14. On both of these days the available supply was low relative to prevailing demand causing the SMP and pool price to peak at $999.99/MWh, the offer price cap, and leading the AESO to issue EEAs.

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

Figure 3: Daily average pool prices in Q3 2021



Going into July 7, a gas-fired steam asset was offline for operational reasons, a coal unit was heavily derated, and another coal unit was commercially offline. At around 10:30 another coal asset tripped offline due to operational issues (Figure 4). In addition, the Saskatchewan intertie was unavailable and the BC/MATL intertie was limited to around 450 MW of imports due to a transmission outage. Wind generation was exceptionally low on July 7, with total wind generation under 100 MW between 07:00 and 19:00 (Figure 4). Hourly demand peaked at 10,678 MW in HE17, a relatively modest level, as prevailing temperatures in Edmonton and Fort McMurray were around 29°C, while Calgary was at 24°C.

The SMP was set at $999.99/MWh beginning at 14:27 and the AESO declared an Energy Emergency Alert level 2 (EEA2) at 15:52, indicating that operating reserves were being used to meet energy demand. At 18:06, the AESO ended the EEA, and at 18:10 the SMP fell below $999.99/MWh.

On Wednesday, July 14, hourly demand peaked at 11,307 MW (Figure 5), the highest in Q3, as temperatures reached 30°C in Calgary and 32°C in Edmonton and Fort McMurray. In the morning, a gas-fired steam asset was in the process of returning from an operational outage when it tripped offline. At around 16:00, during the peak demand period, a dual fuel asset tripped offline due to an operational issue (Figure 5).

Figure 4: Demand, wind generation, and the generation of a coal asset (July 7)

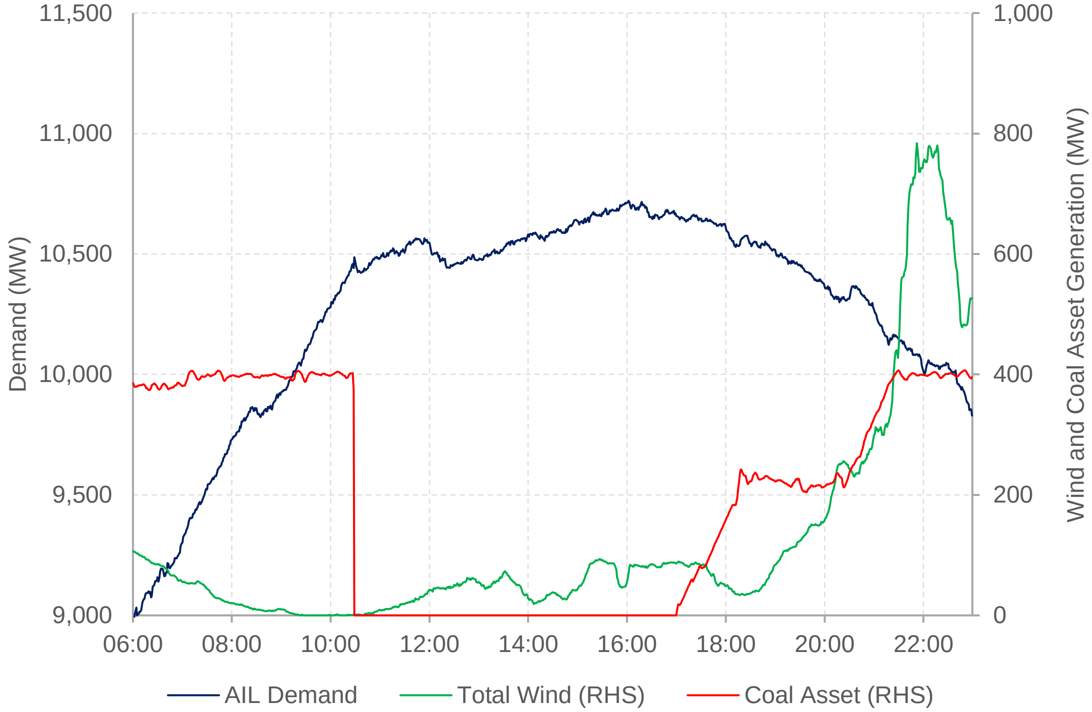
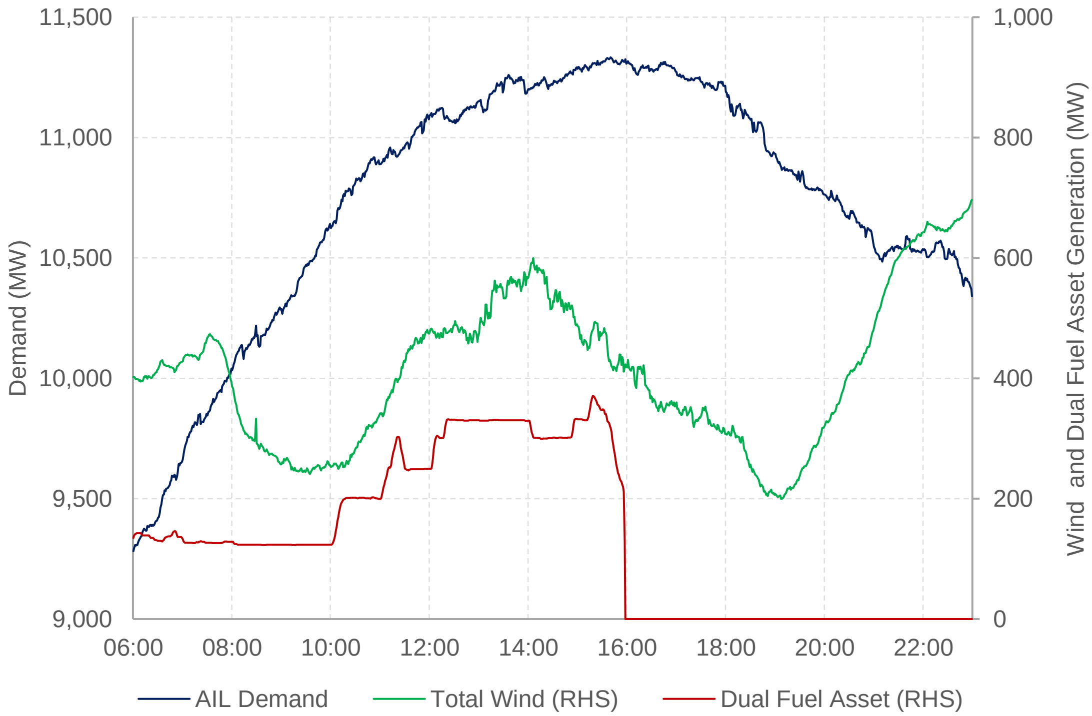


Figure 5: Demand, wind generation, and the generation of a dual fuel asset (July 14)

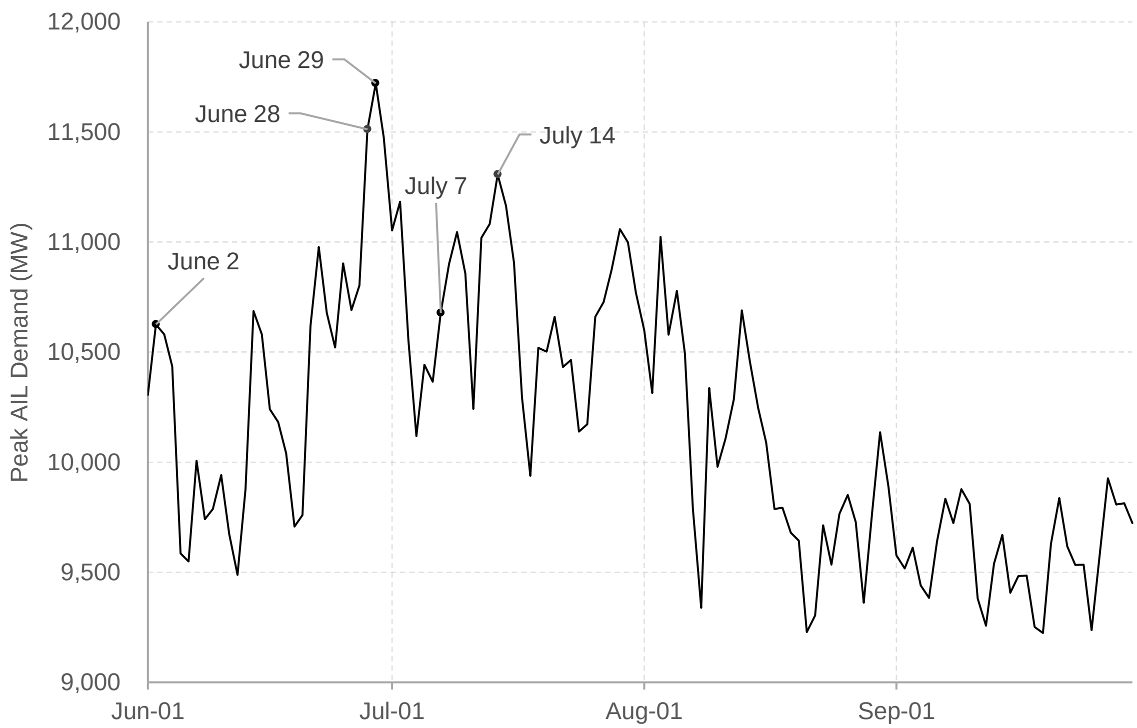


Wind generation was notably variable on July 14, and was declining over the demand peak from around 600 MW at 14:00 to 200 MW at 19:00. (Figure 5). The Saskatchewan intertie remained unavailable and the BC/MATL intertie was only flowing around 470 MW of imports over the peak due to a transmission outage.

At 16:46, the AESO declared an EEA2 and the SMP increased to $999.99/MWh at 16:47. The SMP fell around 3 hours later, at 19:42, as demand declined and wind generation increased. The AESO ended the EEA at 19:34.

Figure 6 illustrates the daily peak in demand over the course of June through September. Peak demand on dates where the SMP reached the offer price cap are labelled with the date. As shown by the relatively low peak demands on June 2 and July 7, price increases to the offer cap can be driven by supply-side factors and do not necessarily require exceptionally high demand.

Figure 6: Daily peak AIL demand (June 1 to September 30)



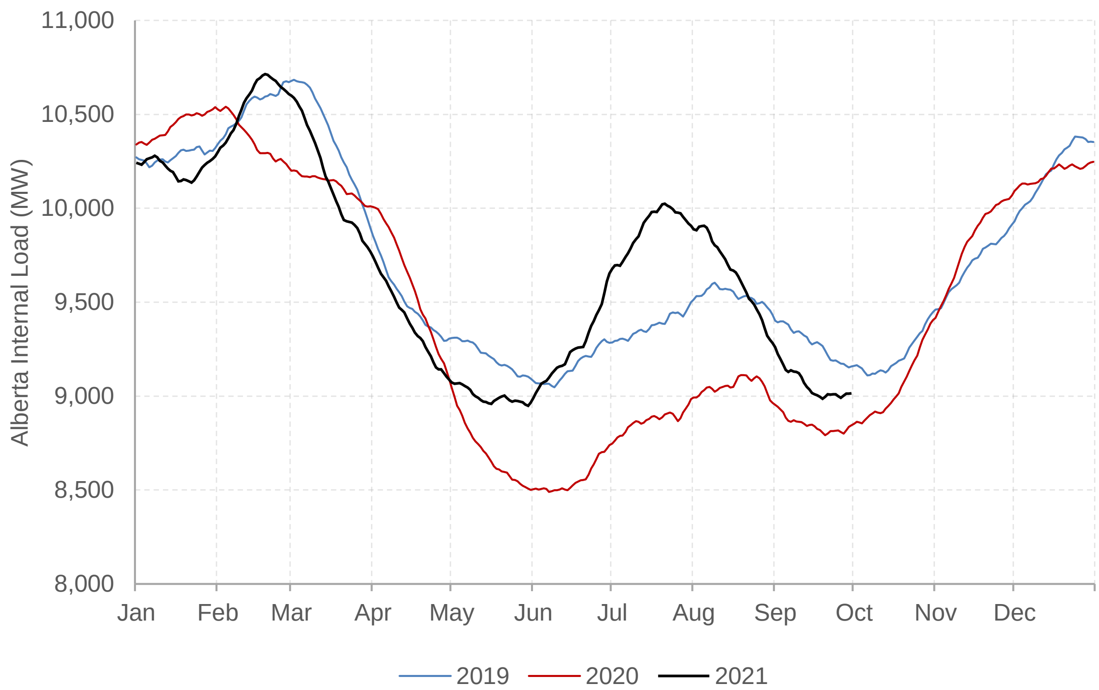
Peak demand in July did not reach the same levels as at the end of June, largely because of lower prevailing temperatures (Table 2). On June 29, temperatures in Calgary peaked at 36°C whereas on July 14 temperatures in Calgary peaked at 30°C. In August, demand peaked at 11,023 MW on the 3rd as temperatures in Calgary were 31°C but Edmonton and Fort McMurray were cooler. Temperatures in August were higher around the weekend of Saturday, August 14, and in July temperatures peaked on Canada Day, but electricity demand is typically lower on weekends and statutory holidays.

Table 2: Daily temperature highs (°C) on the peak demand days in June, July, and August

	Jun-29 (Tue)	**Jul-14 (Wed)**	**Aug-03 (Tue)**
Calgary	36.1	29.6	30.9
Edmonton	36.0	31.7	27.9
Fort McMurray	35.7	32.3	26.0
Peak AIL Demand	**11,721**	**11,307**	**11,023**

Figure 7 illustrates how demand in 2021 has trended compared to 2020 and 2019. As shown, in late June and into July the high temperatures increased demand well above 2019 levels. In addition, oil prices continued to increase with WTI averaging US$72.43/bbl in July, the highest monthly average since November 2014 and a 78% increase year-over-year.

Figure 7: 30-day rolling average of AIL demand (2019 to Q3 2021)



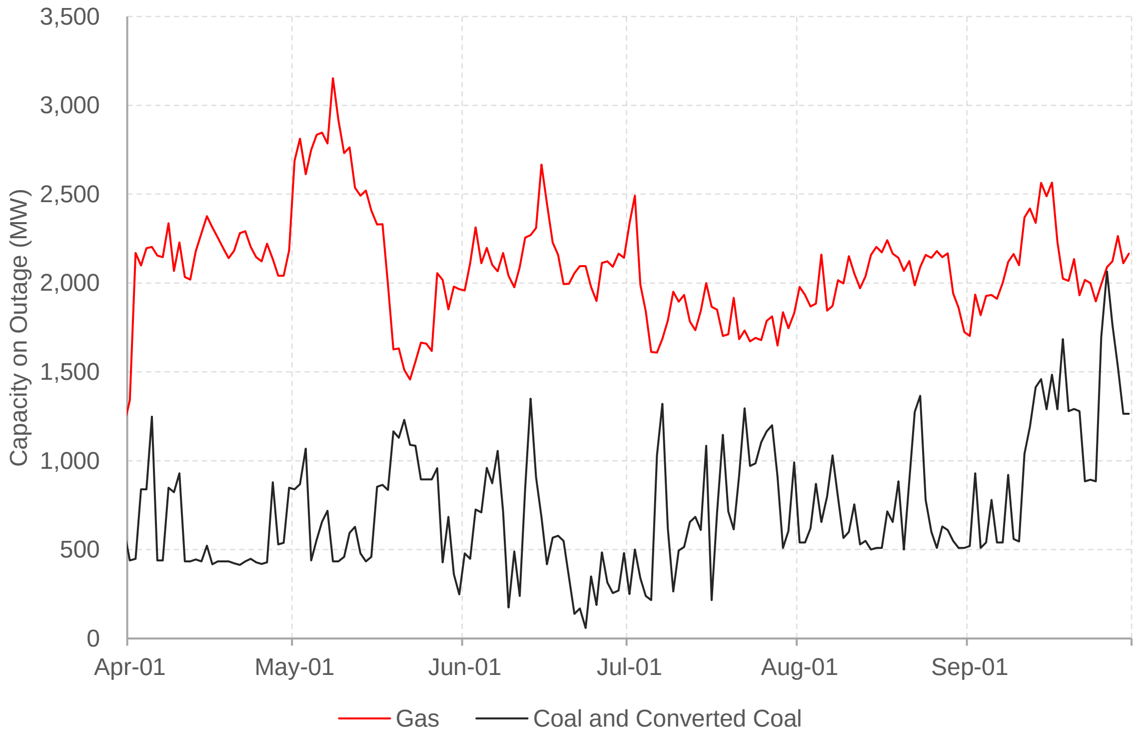
As discussed above, demand in August was moderated because the higher temperatures fell on lower-demand days. In addition, economic activity may have been reduced in August and into September due to the fourth wave of COVID-19. As a result of these factors, the 30-day rolling average of demand in 2021 fell below 2019 levels in late August before flattening out at around 9,000 MW towards the end of September, which is approximately 200 MW more than in 2020 and 200 MW less than in 2019.

Despite lower demand, the average pool price in September was higher than in August. An important factor was the reduced supply in September because of more thermal outages (Figure 8).

On July 18, Genesee 2 tripped offline on a forced outage, and on the 19th the outage was extended into mid-August. On August 9, the outage was further extended into late November. This forced outage reduced supply for much of Q3, putting upward pressure on pool prices.

On September 10, Keephills 3 came offline for its planned outage to undergo a coal-to-gas conversion. In addition, forced outages at other coal or converted coal assets in mid-to-late September put upward pressure on pool prices in this period (Figure 8).

Figure 8: Daily average thermal capacity on outage (April 1 to September 30)



On Monday, September 27, the daily average price increased to $165/MWh as three coal or converted coal assets were offline for operational reasons, one coal asset was heavily derated, a large gas turbine at a cogeneration asset was unavailable, and one dual fuel asset was offline commercially. Wind generation dropped significantly over the demand peak, falling from 1,500 MW in HE15 to 500 MW in HE21. Pool prices peaked at $929/MWh in HE21 when 580 MW of thermal capacity was offered above $100/MWh and net imports into Alberta were only 125 MW.

Natural gas prices in Q3 were 54% higher than last year on average, and were notably volatile in August and September (Figure 9). There has been an increase in power demands for natural gas as coal assets are converted or repowered, power markets are increasingly reliant on intermittent renewable capacity, and because of high temperatures. In addition, the economic recovery and increased demand for LNG have put upward pressure on natural gas prices. Major natural gas hubs in Europe and Asia have seen notably high prices in recent months as markets responded to low inventory levels for the coming winter, and this has increased the demand for LNG in North America.

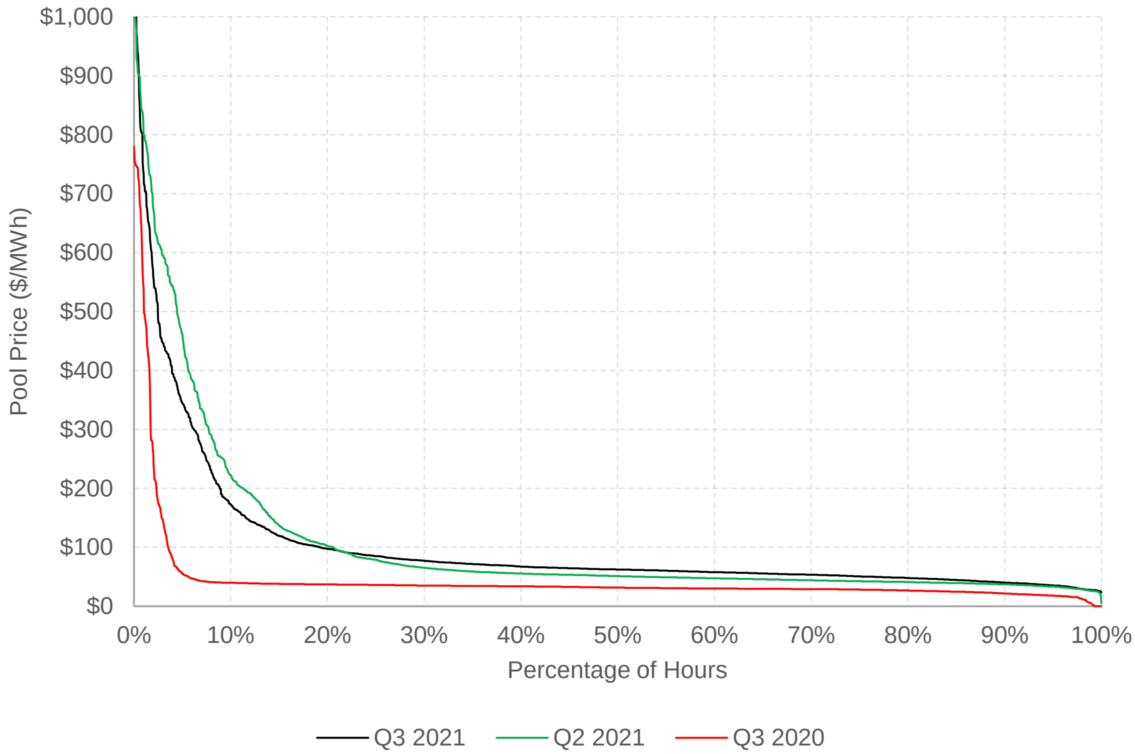
As shown by Figure 9, same-day natural gas prices in Alberta were particularly volatile in August and September as the upward pressure on prices was eroded on some days due to pipeline constraints, which effectively limited demand and pushed the AB-NIT same-day index price down to around $1.00/GJ in some instances. These lower natural gas prices reduced the variable cost of gas-fired assets. The daily average pool price in Q3 was lowest at $37.21/MWh on Sunday, August 22 as the same-day gas index settled at $1.52/GJ, AIL demand peaked at only 9,300 MW, and wind generation averaged 790 MW during peak hours.

Figure 9: Same-day AB-NIT natural gas prices (2A) (January 1 to September 30)

1.2.1 Distribution of pool prices

Figure 10 illustrates the distribution of pool prices in Q3 compared to Q2 2021 and Q3 2020. As shown, the distribution of prices in Q3 was similar to that observed in Q2 2021. In contrast, the year-over-year comparison shows that pool prices were lower last year throughout the distribution. In Q3, higher-priced hours had a slightly larger effect on the average pool price. In Q3, the top 20% of hours contributed 53% to the average price whereas in Q3 2020 they contributed 47% to the average price.

Figure 10: The distribution of pool prices (Q3 2021, Q2 2021, and Q3 2020)



As discussed previously, on July 7 and 14 this year pool prices reached the offer price cap of $999.99/MWh and the AESO declared EEAs. In Q3 2020, pool prices did not reach the offer price cap. At the other end of the distribution, there were no hours where pool price settled at $0.00/MWh in Q3 compared to 16 in Q3 2020 as import volumes fell significantly and average off-peak demand was 480 MW higher in Q3.

1.3 Interties

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

The average volume of net imports into Alberta during Q3 decreased by 45% compared to Q3 2020, even though average pool prices were 129% higher this year.[7] Year-over-year net imports were 42% lower in July and 67% lower in August. In 2020, average net import volumes were 766 MW in July and 772 MW in August, reflecting a consistently high volume of imports throughout these months.

The high import flows in 2020 were partly a reflection of prevailing market conditions in Mid-Columbia (Mid-C) last summer as the economic downturn and strong hydro supplies combined

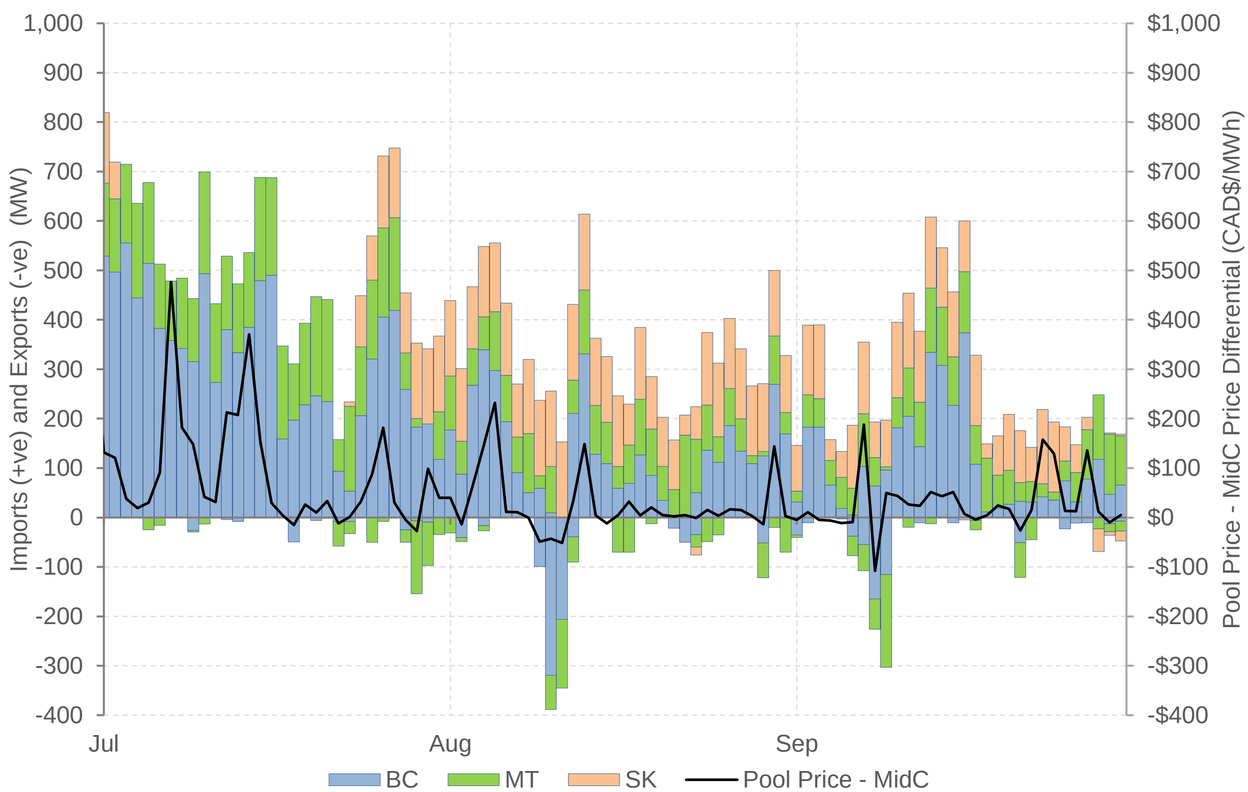
[7] Net imports are total imports less total exports.

to put downward pressure on Mid-C power prices. This year, Mid-C power prices are higher as a result of the economic recovery, high summer temperatures, lower hydro supplies, and increased natural gas prices. In August, the average power price in Mid-C was CAD$62.41/MWh, an increase of 122% relative to August 2020, and in July, Mid-C prices averaged CAD$60.32/MWh, which is 232% higher year-over-year.

In addition, import flows in Q3 were more constrained as ATC fell from Q3 2020 to Q3. This was partly due to the higher LSSi requirements for imports, which were implemented by the AESO for reliability purposes beginning on June 22, 2020, and were increased on March 4.[8]

Figure 11 illustrates daily average imports and exports over Q3 during peak hours (HE08 to HE23). The solid line on the figure illustrates the average price differential between Alberta and Mid-C during peak hours, with a higher positive value indicating Alberta pool prices were well above prevailing prices in Mid-C. As shown, the predominant flow of power during Q3 was imports flowing into Alberta as pool prices were often relatively high.

Figure 11: Daily average imports (+ve) and exports (-ve) and the AB – Mid-C price differential, peak hours (Q3 2021)



[8] AESO: ATC Risk Mitigation Measures Overview Information Session – July 28, 2020; slides 49-50

AESO: Information Session: Learnings and Actions in Response to Recent System Events – March 9, 2021; slide 28

During Q3, imports into Alberta were highest in July when hourly net imports were 443 MW on average. However, imports were meaningfully constrained at certain points in July. In particular, the Saskatchewan intertie was unavailable from July 2 to 23, reducing the average import ATC on this line to 50 MW in July, compared to 146 MW in July 2020. In addition, import flows on BC/MATL were constrained for some of the higher priced hours in July due to transmission outages on the transmission line 2L294, which limited import capacity to under 500 MW from July 6 HE10 to July 9 HE18, and also from July 12 HE10 to July 14 HE22.

Imports were generally lower in August compared to July, although import supply did increase during the higher pool prices on August 4, 5, 13, and 30. On Tuesday, August 10 and Wednesday, August 11, low demand and high wind generation reduced pool prices in Alberta relative to Mid-C, resulting in material export volumes on the BC and MATL interties. For example, in HE21 of August 10, the BC and MATL lines were exporting 550 MW and 136 MW, respectively, while the SK intertie was importing 153 MW. This resulted in overall net exports of 533 MW from Alberta, the highest since March 12, 2019.

Table 3: Pool price, Mid-C price, and net imports for select hours in September

Date	HE	Pool Price ($/MWh)	Mid-C Price (CAD$/MWh)	Total Net Imports (MW)
Sep 7 (Tue)	16	$605	$121	316
	17	$571	$182	516
	18	$704	$191	466
	19	$938	$221	111
Sep 9 (Thu)	17	$590	$280	-101
	18	$679	$382	-220
	19	$821	$456	-224
	20	$868	$531	-359
	21	$811	$481	-300
Sep 27 (Mon)	20	$803	$90	125
	21	$929	$97	125
	22	$581	$88	199

In September, the supply of imports was less responsive to some higher pool price events in Alberta. On September 7, 9, and 27 pool prices were elevated but net import volumes were relatively low in some hours (Table 3). On Thursday, September 9, for example, prices were volatile in both Alberta and Mid-C, as pool prices in Alberta reached $868/MWh in HE20 and prices in Mid-C were CAD$531/MWh.[9]

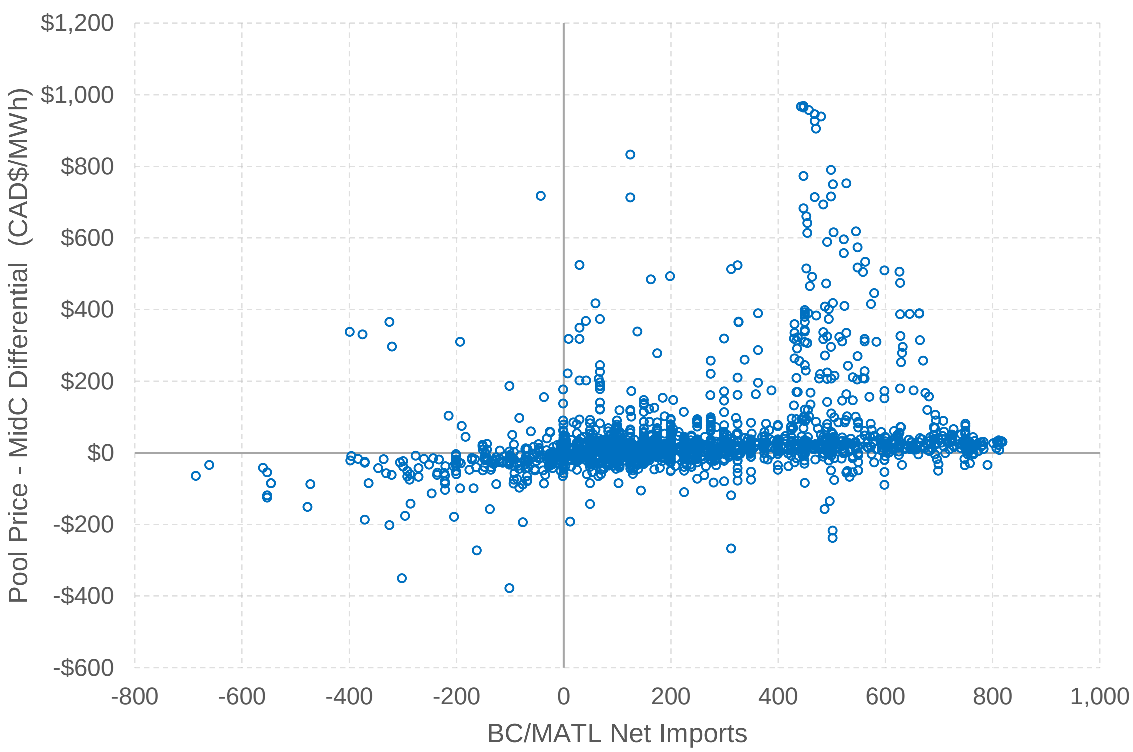
[9] Mid-C is a bilateral trading hub in the Northwestern US, and there are multiple trading locations within Mid-C (see EIA and WECC maps). Prices can differ across different locations in Mid-C. The Mid-C hourly prices used in this section are index prices which incorporate prices from different locations.

As shown in Table 3, over a number of peak hours on September 9, power flowed out of Alberta despite pool prices being elevated, and often higher than the prevailing prices in Mid-C. In this instance, the net power was largely flowing from Alberta into Mid-C. Prices in California were also high, with day-ahead prices at the SP15 trading hub clearing at CAD$870 in HE20 (MT) of September 9, as hot weather increased load and there were concerns over natural gas supply.[10]

1.3.1 BC/MATL

Figure 12 shows a scatterplot of hourly net imports on BC/MATL against the hourly price differential between Alberta and Mid-C. Points in the top-right and bottom-left quadrants indicate the direction of net flow on BC/MATL was economic based on realized prices in Alberta and Mid-C. The top-right quadrant indicates that the Alberta pool price was greater than the prevailing price in Mid-C and the hour observed net imports into Alberta. As shown, there is a large cluster of points around the horizontal axis and to the right, indicating a large number of hours in which the price differential was relatively small and there was a net flow of power into Alberta.

Figure 12: Scatterplot of BC/MATL net imports and the Alberta – Mid-C price differential (Q3)[11]



Relative to the same analysis in recent Quarters, there is an apparent increase in net exports from Alberta. In most instances, export volumes were economic based on realized prices, but in

[10] S&P Global Platts article – September 9, 2021

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

some hours net exports were around 300 to 400 MW even though pool prices in Alberta were around CAD$300/MWh higher than prices in Mid-C.

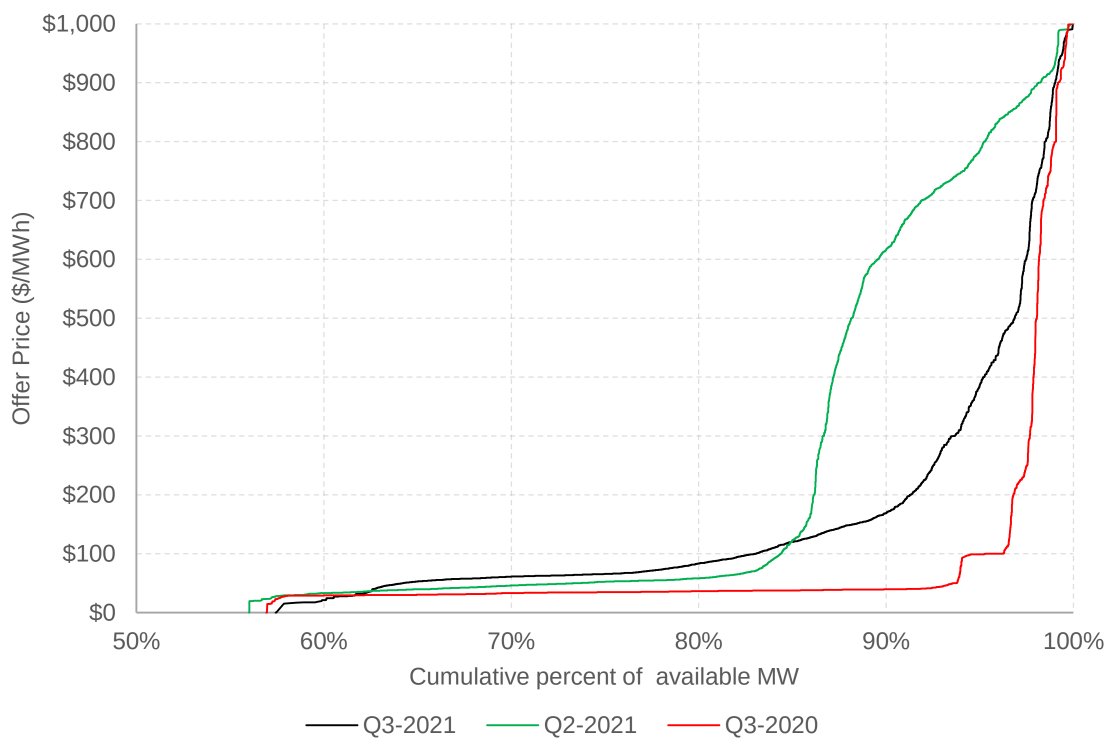
In general, when pool prices were elevated in Q3, import supply was higher. During the two EEA events in July the BC/MATL intertie was constrained to around 450 MW of imports due to a transmission outage. However, imports fully utilized this ATC, and these hours are reflected in the top right of Figure 12.

As discussed in previous MSA quarterly reports, net imports on BC/MATL are often highest when the Alberta pool price is relatively low, with some lower-priced hours in Q3 seeing more then 800 MW of net imports into Alberta on BC/MATL. When pool prices are elevated, the availability of LSSi often falls, so the import ATC is reduced and import volumes are constrained.

1.4 Offer behaviour

As discussed in the MSA's Q1 and Q2 2021 Quarterly Reports, the expiration of the remaining PPAs at the end of 2020 resulted in a material change in offer behaviour in the energy market. Following the end of the PPAs, more generation capacity has been offered into the market at higher prices, putting upward pressure on pool prices.

Figure 13: Duration curves of offer prices on available coal and converted coal capacity[12]



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

Figure 13 illustrates the percentage of available coal and converted coal capacity that was offered at or below a given price in Q3, compared to Q2 2021 and Q3 2020. In Q3, 90% (the 90th percentile) of available coal and converted coal capacity was offered at or below $170/MWh and 10% was offered above $170/MWh. In Q3 2020, the 90th percentile was much lower at $39/MWh as the offer prices on these assets were generally lower in Q3 last year. In Q2 2021, the 90th percentile was at a much higher offer price of $616/MWh, indicating that offer prices on these assets were generally lower in Q3 relative to Q2 2021 (Figure 13).

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

For a given supply cushion, pool prices were generally higher in Q3 relative to Q3 2020. For example, in hours where the supply cushion was between 500 and 1,000 MW the average pool price was $220/MWh in Q3 compared to $141/MWh in Q3 2020.

Compared to Q2 2021, less pool price volatility was generally observed in Q3 for a given supply cushion. During Q2 2021, in hours where the supply cushion was between 500 and 1,000 MW the average pool price was $343/MWh, 56% higher than in Q3. This is consistent with the analysis above which showed that offer prices on coal and converted coal assets were generally lower in Q3 compared to Q2 2021.

Figure 14: Coal and converted coal capacity commercially offline coincident with the daily peak in pool price (Q3 2021)

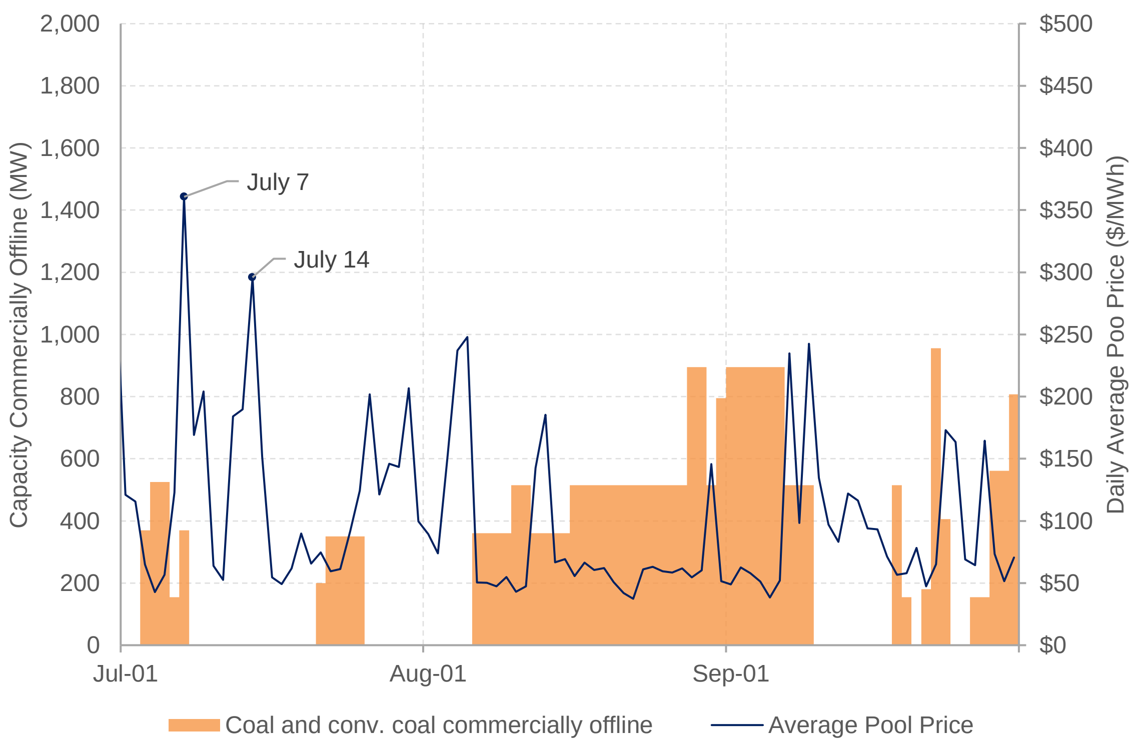


Figure 14 shows the amount of coal and converted coal capacity that was offline for commercial reasons over Q3. When these large thermal assets are commercially offline, they are not immediately available for dispatch by the AESO due to start-up time requirements, which are generally in the range of 8 to 24 hours. The analysis above does not include mothballed capacity.

As noted in MSA Quarterly Reports for Q1 and Q2, in 2021 some coal and converted coal assets have been commercially offline on days when pool prices were elevated. This trend continued in Q3. In HE02 of Wednesday, July 7, a large coal-fired asset returned from an operational outage, but no start-up was initiated as the asset was kept offline for commercial reasons. As discussed above, generation outages and low wind generation meant that the market was short of supply during the peak hours of July 7, and there was an EEA2 event between 16:46 and 19:34. The realized average pool price on July 7 was $361/MWh.

A week later on Wednesday July 14, increased demand, low wind generation, and thermal outages resulted in another EEA2 event. On this occasion, there were no coal and converted coal assets that were commercially offline (Figure 14). The realized average pool price on July 14 was $296/MWh.

1.4.1 Market share estimates

Section 5 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation) requires the MSA to publish a Market Share Offer Control report (MSOC Report) at least once annually. The MSOC Report for 2021 was published as section 1.6 in the MSA's Quarterly Report for Q1 2021.[13] The methodology used in the MSOC Report is set out in the FEOC Regulation and considers market shares in a single hour that is identified in the report.

In this section, the MSA estimates hourly market shares in the energy market for all hours from January 1 to September 30 and follows a different methodology to that used in the MSOC Report. In particular, the calculations here consider the capacity that was available to compete in either the energy market or ancillary services in that hour. Market shares here are estimated using the following methodology:

- The estimates use Block Size (MW) in the energy market merit order, which includes capacity available for energy and also capacity that has been dispatched for operating reserves. Capacity that is on outage, derated, or mothballed is not included.

- For wind and solar assets, average generation over the hour is used instead of the Block Size to reflect the intermittent nature of their supply.

- ATC for imports on the BC/MATL and SK interties are included in the total market size; however, import and export flows are not assigned to market participants because intertie capacity that is not used by one market participant can be used by another and cannot be withheld.

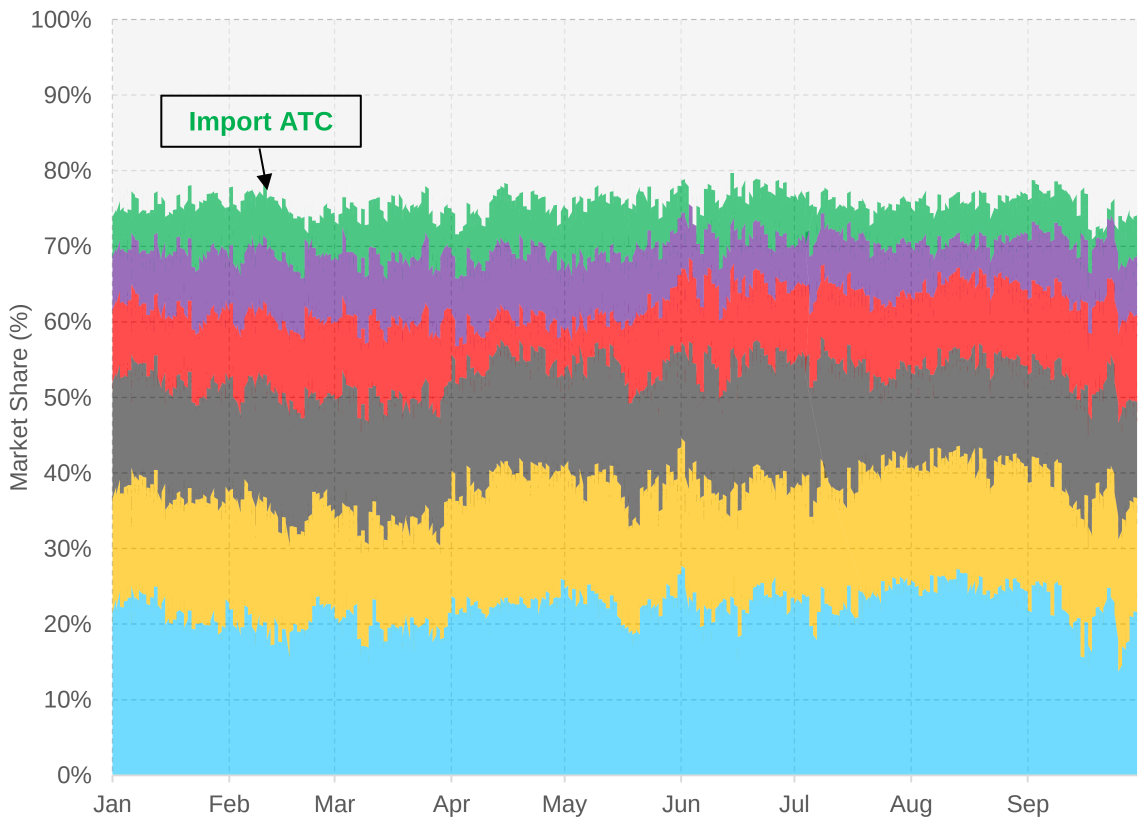
[13] Alberta MSA: Q1 2021 Report, at page 30

- Joint ventures and shared assets are assigned to the respective market participants based on offer control submissions.

- Coal and converted coal assets that were commercially offline (long-lead time type 1)[14] are included in the calculations.

The resulting estimates of market shares for the largest five market participants are shown in Figure 15, alongside import ATC. As shown by the figure, the market shares of these entities vary over time as a result of outages, changes in renewable generation, and changes to the availability of imports. The market share of the largest market participant does vary but it is typically around 22%, which is lower than that calculated in the MSA's 2021 MSOC. This result is largely because mothballed capacity has not been included here, and because actual generation for wind assets is used in these calculations rather than their maximum capability (MC). The combined market share of the top five market participants is normally around 70%.

Figure 15: Hourly market share estimates for the five largest market participants (January 1 to September 30)



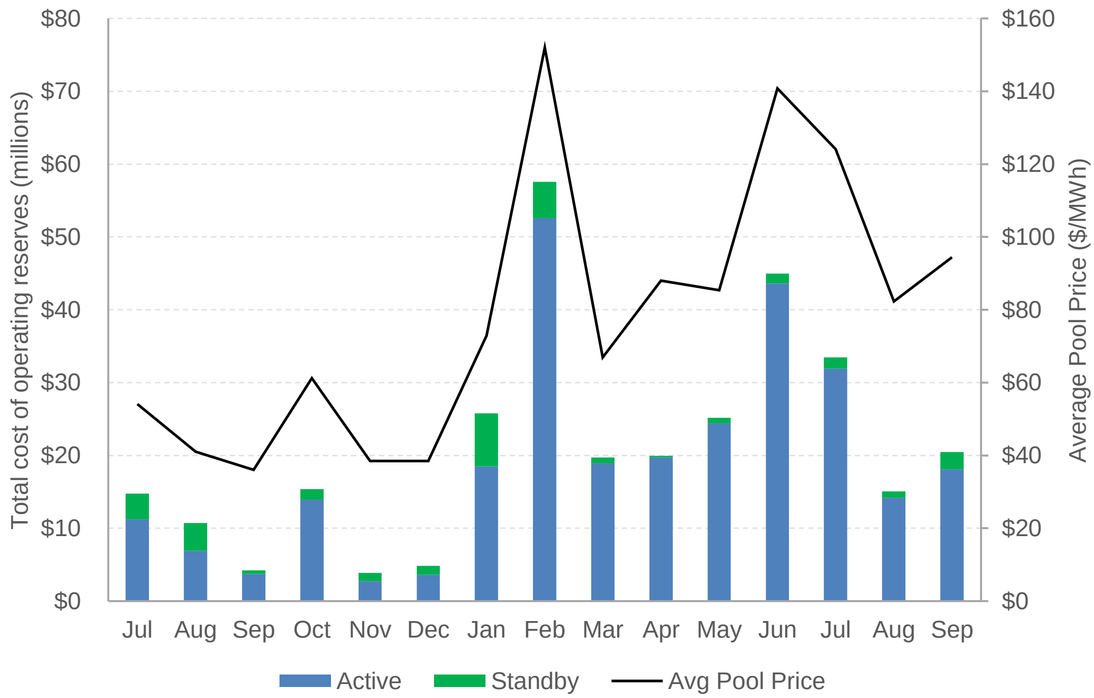
[14] Long lead time type 1 is when a unit is fully offline and not in the energy merit order but is available for dispatch with a lead time.

2 THE MARKETS FOR OPERATING RESERVES

There are three types of operating reserves (OR) that the AESO system controllers use when there is an unexpected imbalance or lagged response between supply and demand: regulating reserves, spinning reserves, and supplemental reserves. Regulating reserves provide an instantaneous response to an imbalance of supply and demand. Spinning reserves are synchronized to the grid and provide capacity that the system controller can call upon in a short amount of time, when there is a sudden drop in supply for example. Supplemental reserves are not required to be synchronized but must be able to synchronize quickly if called upon by the system controller.[15] These products are all bought by the AESO through day-ahead auctions.

Total OR costs for the quarter were $69 million, an increase of 133% from Q3 2020. Higher pool prices in the energy market were a significant factor in this increase. The average pool price was $100.33/MWh in Q3, compared to $43.83/MWh in Q3 2020, an increase of 129%. Figure 16 shows total OR costs and average pool prices by month since July 2020. The general correlation between total OR costs and pool price is expected because the opportunity cost of providing OR is often forgoing the sale of energy, and for active reserves, prices are directly indexed to pool price. Table 4 provides a detailed breakdown of total OR costs by month in Q3.

Figure 16: Total cost of active and standby reserves and average pool price by month (July 2020 to September 2021)



---

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

Table 4: Detailed breakdown of operating reserves costs in Q3 2021

Total Cost ($ Millions)						
	Jul-21	**Aug-21**	**Sep-21**	**Q3 2021**	**Q3 2020**	***% Change***
Active Procured	**31.9**	**14.2**	**18.1**	**64.2**	**21.9**	***193%***
RR	6.9	4.0	5.9	16.7	5.2	*225%*
SR	15.5	7.5	8.2	31.2	9.5	*228%*
SUP	9.6	2.7	4.0	16.3	7.3	*125%*
Standby Procured	**0.4**	**0.2**	**0.9**	**1.5**	**0.5**	***185%***
RR	0.2	0.2	0.8	1.1	0.3	*337%*
SR	0.2	0.0	0.1	0.4	0.3	*41%*
SUP	0.0	0.0	0.0	0.0	0.0	*57%*
Standby Activated	**1.1**	**0.7**	**1.5**	**3.3**	**7.2**	***-54%***
RR	0.2	0.1	0.2	0.5	0.2	*142%*
SR	0.8	0.5	1.0	2.3	5.3	*-57%*
SUP	0.1	0.1	0.3	0.5	1.7	*-70%*
Total	**33.5**	**15.1**	**20.5**	**69.0**	**29.7**	***133%***

Total Volume (GWh)						
	Jul-21	**Aug-21**	**Sep-21**	**Q3 2021**	**Q3 2020**	***% Change***
Active Procured	**481.6**	**441.4**	**419.8**	**1,342.8**	**1,300.2**	**3%**
RR	101.2	101.3	95.1	297.5	298.0	*0%*
SR	190.5	170.1	162.4	523.0	501.5	*4%*
SUP	189.9	170.1	162.3	522.3	500.8	*4%*
Standby Procured	**99.6**	**91.2**	**90.7**	**281.6**	**484.4**	***-42%***
RR	44.4	49.7	50.2	144.4	176.5	*-18%*
SR	44.1	30.5	30.0	104.6	231.5	*-55%*
SUP	11.1	11.0	10.5	32.6	76.4	*-57%*
Standby Activated	**7.8**	**4.6**	**8.0**	**20.4**	**136.3**	***-85%***
RR	0.7	0.7	1.0	2.4	5.0	*-52%*
SR	5.2	2.8	4.9	12.8	87.3	*-85%*
SUP	1.9	1.2	2.1	5.2	44.0	*-88%*
Total	**589.0**	**537.2**	**518.6**	**1,644.8**	**1,921.0**	***-14%***

Average Cost ($/MWh)						
	Jul-21	**Aug-21**	**Sep-21**	**Q3 2021**	**Q3 2020**	***% Change***
Active Procured	**66.30**	**32.13**	**43.10**	**47.81**	**16.85**	**184%**
RR	68.18	39.02	61.82	56.22	17.29	225%
SR	81.11	44.27	50.40	59.59	18.94	215%
SUP	50.44	15.89	24.82	31.23	14.49	116%
Standby Procured	**4.23**	**2.00**	**9.78**	**5.30**	**1.08**	**391%**
RR	4.11	3.21	15.25	7.68	1.44	434%
SR	5.13	0.71	3.74	3.44	1.10	213%
SUP	1.09	0.07	0.91	0.69	0.19	267%
Standby Activated	**143.12**	**153.59**	**184.05**	**161.55**	**53.01**	**205%**
RR	315.67	88.79	237.42	216.70	43.27	401%
SR	147.21	185.31	201.38	175.94	60.33	192%
SUP	66.76	117.18	120.28	100.29	39.62	153%
Total	**56.81**	**28.06**	**39.44**	**41.94**	**15.44**	***172%***

In terms of volumes, the AESO procured 4% more of active spinning and supplemental reserves year-over-year, while the volume of active regulating was almost unchanged (Table 4). In early February 2021, the AESO began to procure more active spinning and supplemental reserves day-ahead in anticipation of higher import volumes, as opposed to activating standby in real-time.

In mid-August 2021, the AESO began to procure less active spinning and supplemental reserves, likely in anticipation of lower import volumes than observed earlier in the summer (Figure 17). The volume of procured standby spinning reserves also fell in early August. Year-over-year the total activation volumes for standby spinning fell by 85% as the AESO procured more active reserves day-ahead (Table 4).

Figure 17: Active and standby spinning volumes, on-peak (January 1 to September 30)

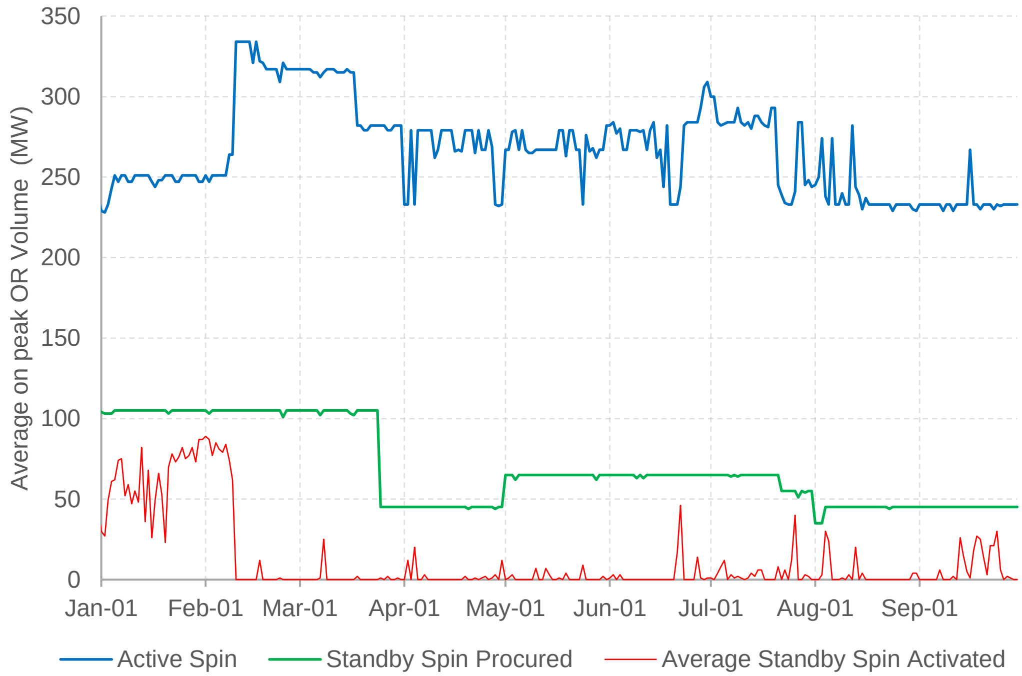


Table 5: Average cost ($/MWh) of active OR products

Product	Q3 2021	Q3 2020	Q3 2021 - Q3 2020
Spinning	$59.59	$18.94	$40.65
Supplemental	$31.23	$14.49	$16.74
Regulating	$56.22	$17.29	$38.93
Avg. Pool Price	**$100.33**	**$43.83**	**$56.50**

Table 5 shows the average cost of active reserves in Q3 and Q3 2020. While there was a $56.50/MWh increase in the average pool price year-over-year, this was not fully reflected in increases to active reserve costs. This indicates that the increase in costs for active reserves was driven by higher pool prices in the energy market. The underlying index prices for active reserves generally fell year-over-year.

Figure 18: Duration curves of index prices for active supplemental reserves, between $50 and -$300 (Q3 2021, Q2 2021 and Q3 2020)

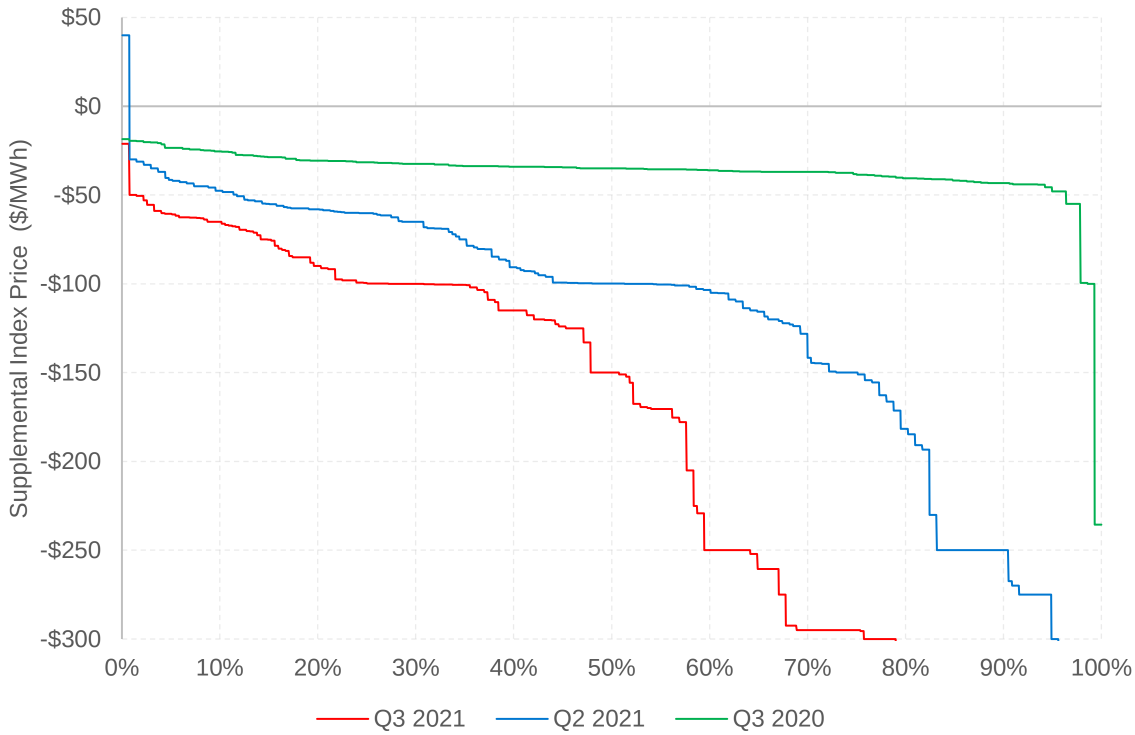


Figure 18 shows duration curves of the index prices for active supplemental reserves. The Figure illustrates the percentage of hours the index price for active supplemental was at or above a certain price. For example, in Q3, 50% of hours had a supplemental index price of greater than negative $150/MWh; in Q3 2020, the median index price was significantly higher at negative $35/MWh.

Figure 18 shows a meaningful reduction in index prices year-over-year. The lower index prices this year are a function of higher pool prices and increasing competition in the supplemental reserves market. As pool prices increase, a lower index price yields the same settlement price for active reserves. In addition, competition in the supplemental reserves market has increased as a result of more load and hydro participation. New battery providers in the spinning reserve market have also displaced some spinning providers into the supplemental reserves market.

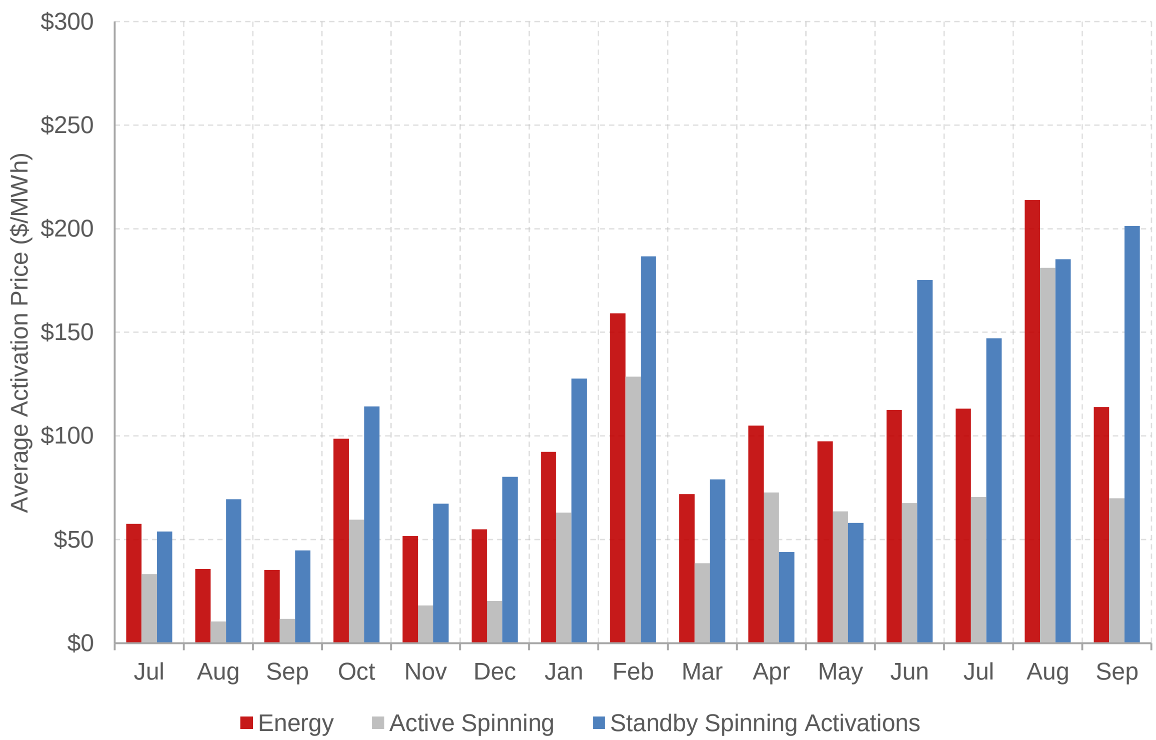
Load providers of supplemental reserves may have different opportunity cost profiles compared to generators. The main opportunity cost for load providers is a low-probability interruption to their commercial process. The main opportunity cost for generation is to provide energy at pool price. As a result, the load providers may be in a position to provide supplemental reserves at a lower cost if pool prices are expected to be high.

In addition, the variable cost for most thermal generators has increased year-over-year as natural gas prices increased and the carbon price rose by $10/tCO2e. Higher variable costs will reduce the opportunity cost of providing energy for these generators, putting some downward pressure on the index prices for active reserves.

As explained in section 1.3, import volumes in July and August were significantly lower than in July and August last year. To support imports the AESO uses a combination of LSSi and contingency reserves, so lower import volumes would lower demand and put downward pressure on index prices for spinning and supplemental reserves.

Figure 19 compares the average cost of standby spinning activations with the prevailing cost of active spinning reserves and energy by month since July 2020. The prices for energy and active spinning are weighted by standby spinning activation volumes. As shown, the cost of activating standby reserves has generally been greater than the cost of energy, with the exception of April, May, and August 2021.

Figure 19: Standby spinning activation prices compared to the prevailing price of energy and active spinning reserves (July 2020 to September 2021)[16]



This is not an efficient outcome because the cost of providing reserves is lower than the cost of providing energy, given the variable cost savings. In addition, the cost of activating standby spinning reserves has often been significantly higher than the cost of active spinning reserves. While these trends have been observed for most months of 2021, in April, May, and August the

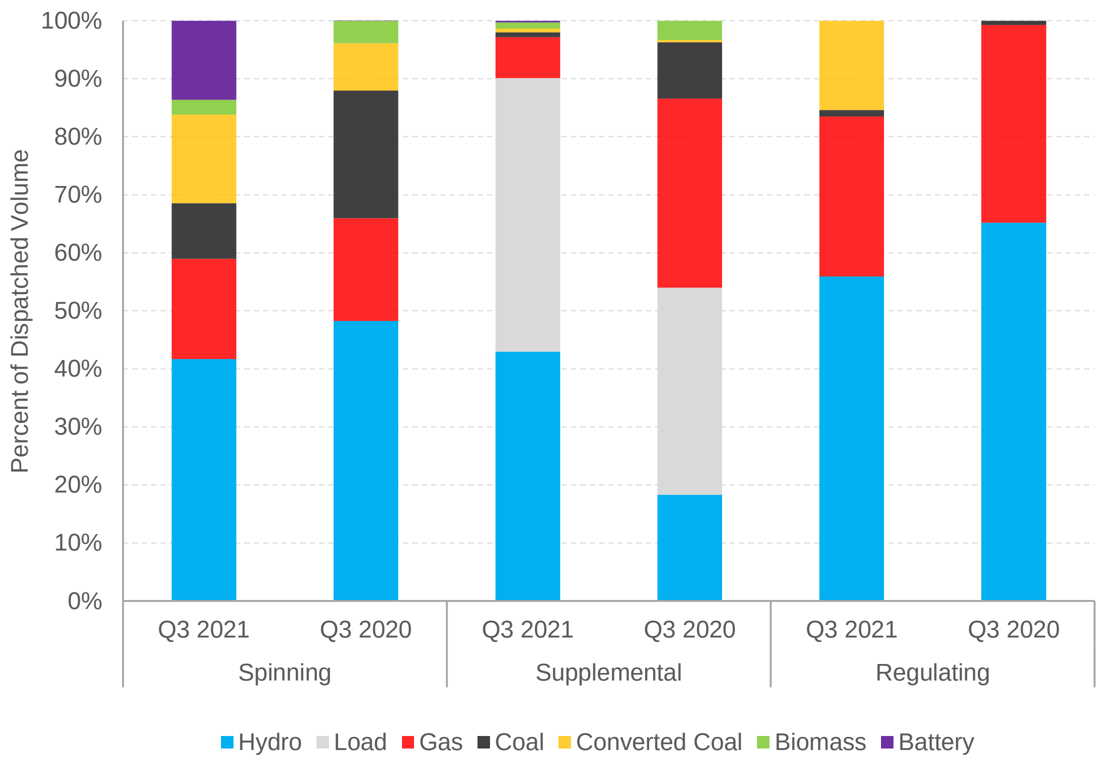
[16] The prevailing prices of energy and active spinning reserves are calculated by weighting these prices by the volume of standby spinning activations in a given hour. The cost of standby activations does not include the standby premium.

cost of activating standby reserves was lower than the prevailing cost of energy. The volume of standby contingency reserves activated in Q3 was much lower than Q3 2020 (Table 4).

Figure 20 shows the market shares of OR dispatches by fuel type in Q3 and Q3 2020. As shown, hydro assets continue to be a major supplier of OR, though these assets shifted some of their volumes from spinning to supplemental reserves compared to Q3 2020. Three battery storage providers, including a hybrid asset, were regular participants in the active spinning market during Q3, as battery storage provided 14% of dispatched spinning reserves. In supplemental reserves, hydro and load providers have increased market share while the shares of coal and gas fell.

In 2020, coal and converted coal assets provided very little regulating reserve volumes (Figure 20). In Q3, converted coal assets provided 15% of regulating volumes. This change was largely driven by the fact that the Bighorn hydro facility was providing more energy beginning in late July, presumably to manage elevated water levels.[17] As a result, the Bighorn asset supplied less regulating reserves.

Figure 20: Dispatched OR volumes by fuel type (Q3 2021 and Q3 2020)[18]



[17] [TransAlta Website](): Bighorn Dam to Release Water from Spillway to Manage Water Elevation – July 20, 2021

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

3 THE FORWARD MARKET

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

The MSA's analysis in this section incorporates trade data from ICE NGX and Canax, an over-the-counter (OTC) broker, which are routinely collected by the MSA as part of our surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2020 are also included. These bilateral trades occur directly between two trading parties, not via ICE NGX or through a broker, and the MSA generally collects information on these transactions once a year.

Figure 21: Total volumes of standard products by contract term and trade date (Q1 2017 to Q3 2021)[19]

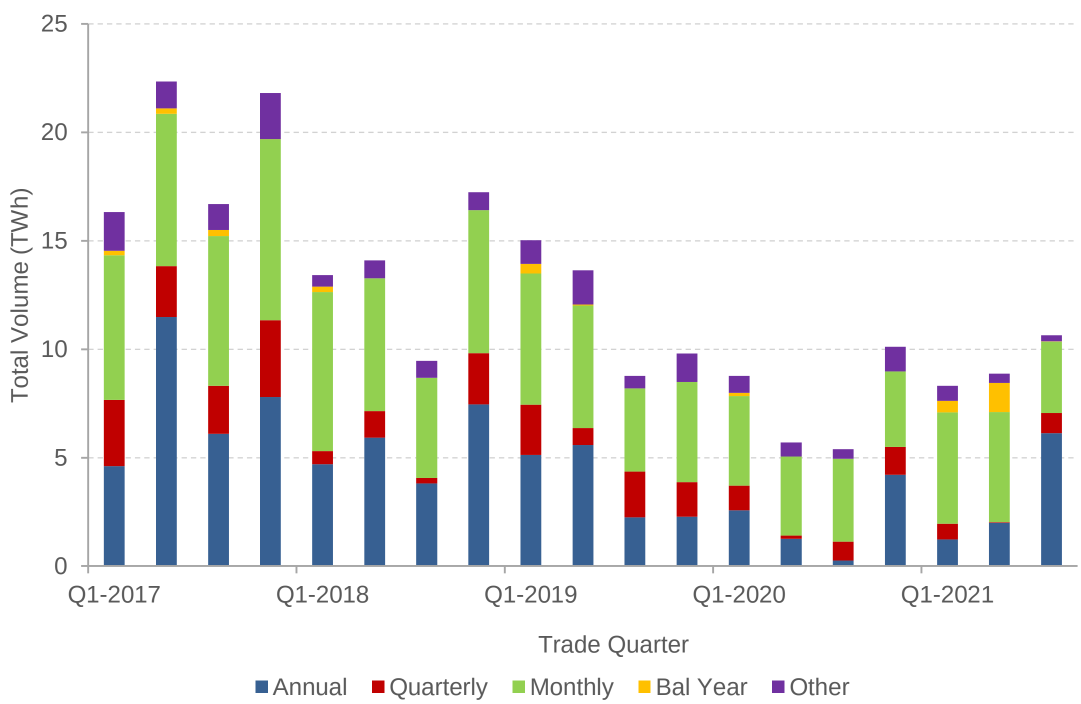


Figure 21 illustrates the total volume of standard products traded from Q1 2017 to Q3 2021. Total volume is the total amount of power traded financially over the duration of a contract. Standard products include contract shapes such as flat and extended peak, but do not include custom shapes, such as the full-load RRO trades.

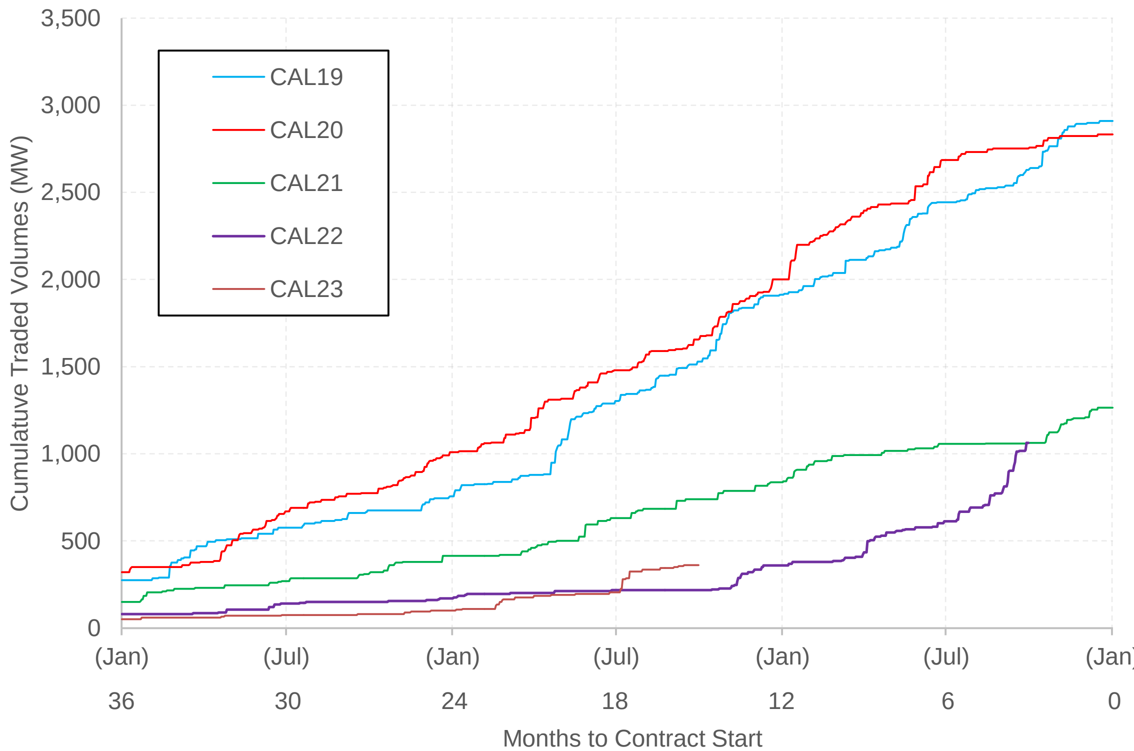
[19] The data here includes direct bilateral trades up to the end of 2020.

The total volume of power traded in Q3 was 20% higher than in Q2 2021, which was largely driven by an increase in annual trading. In Q3, the total volume of trades undertaken on ICE NGX and Canax was 123% higher compared to Q3 2020, and this increase was also driven by higher annual volumes. The volume of annual trades in Q3 was the highest, for annual forward product, since Q4 2018.

Calendar 2022 (CAL22) accounted for 64% of the annual volumes in Q3, so this contract was the principal driver behind the higher trade volumes. As discussed later in this section, the price of CAL22 increased by 29% in Q3, largely on the back of pool price volatility in the energy market and significant increases to forward natural gas prices for 2022. These factors were likely also key drivers in explaining the increased trading activity for CAL22.

Figure 22 illustrates traded volumes for CAL22 relative to other annual contracts as the beginning of 2022 approaches. Traded volume is the hourly volume of power being exchanged financially within a given trade. For the sake of comparison, only volumes that were traded through ICE NGX or Canax are included in this analysis because the MSA does not yet have data on direct bilateral trades past December 31, 2020.

Figure 22: Cumulative traded volumes for CAL19 to CAL23 (up to September 30, 2021)[20]



The figure shows a marked increase in trading for CAL22 over Q3 as volumes for the CAL22 contract caught up to the volumes for CAL21 at this point in time, with three months left until the

[20] This figure excludes direct bilateral trade data for the sake of comparison.

CAL22 contract begins. However, as shown in Figure 22, the traded volumes for CAL22 are significantly lower than the volumes for CAL19 and CAL20.

3.1 Trading of monthly products

Figure 23 compares monthly flat forward prices to realized pool prices for July 2020 to September 2021. As shown, monthly forward prices in 2021 have generally traded at a discount to realized pool prices. For February, June, and July forward prices traded significantly below the realized average pool price. For July, the volume-weighted average forward price was $79.43/MWh compared to the average pool price of $124.10/MWh, a discount of 36%.

The average pool price for January through September was $100.12/MWh but monthly forward prices have traded well below this level with the volume-weighted average forward prices yielding a price of $69.87/MWh for the same period, a discount of 30%.

Over the first nine months of 2021, August was the only monthly flat contract for which forward prices traded at a premium to the average pool price. For August, the volume-weighted average forward price was $91.56/MWh compared to the average pool price of $82.26/MWh, a premium of 11%. As discussed in section 1.2, the weather in August was relatively mild, and the higher temperatures fell on lower-demand days such as Fridays and weekends.

Figure 23: Monthly flat forward prices and average pool prices (July 2020 to Sep. 2021)

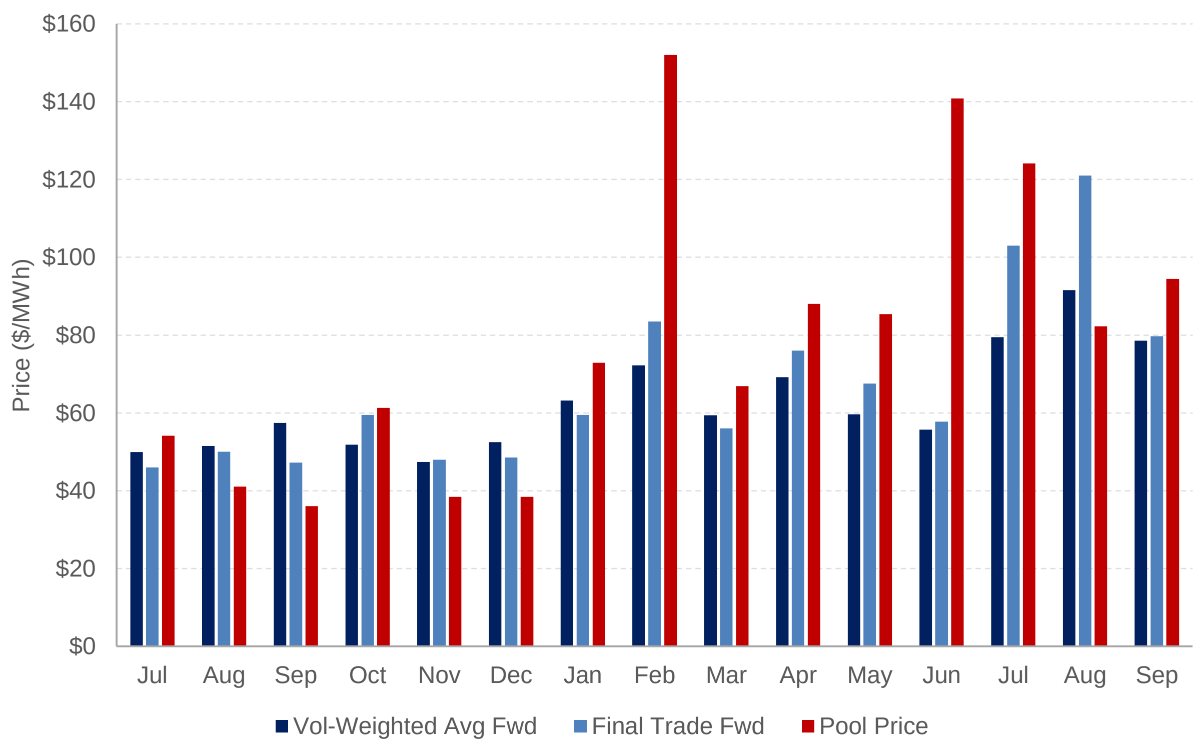
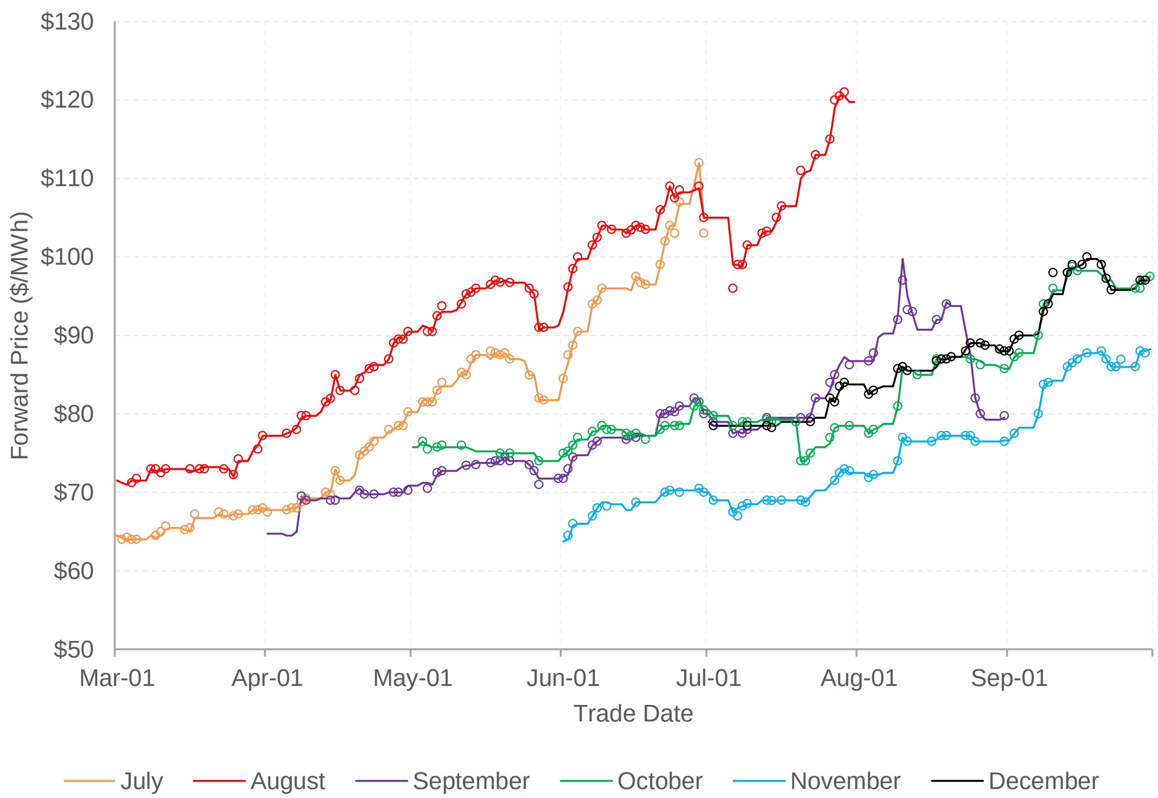


Figure 24 shows the development of forward prices for the monthly contracts of July to December. As shown, the forward prices for July and August increased significantly in the spring and into summer due to forecasts of high summer temperatures, increasing natural gas prices, and pool price volatility in the energy market. In addition, forward prices in major markets such as Mid-C and California increased, in part due to drought conditions and reduced hydro supplies. On July 29, the Mid-C peak forward price for August was US$180/MWh, 80% higher than on April 15.

The flat price of the Alberta August contract increased from $99.00/MWh on July 8 to trade for $121.00/MWh on July 29. In addition to the factors outlined above, an extended forced outage at a Genesee 2 also put upward pressure on the forward price for August. On Sunday, July 18, Genesee 2 tripped offline due to an operational issue. Subsequently, after trading hours on Monday, July 19, the outage was extended into mid-August. As a result, the forward price of the August contract increased from $106.50/MWh on July 19 to $111.00/MWh on July 20.

In addition, Genesee 2 had some planned outage work that was scheduled to occur in October but this was moved into August to take place during the extended forced outage. This increased expected supply and put downward pressure on the October price, which fell from $79.00/MWh on July 19 to $74.00 on July 20. As shown in Figure 24, the October contract traded at a premium to November, which was largely because more planned thermal outages were scheduled for October, in addition to the planned BC/MATL intertie outage scheduled for October 18 to 29.

Figure 24: Forward prices for the July to December monthly flat contracts (5 months out; March 1 to September 30)[21]



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

After trading hours on Monday, August 9, the end of the Genesee 2 outage was extended from late August to late November. As a result of the reduced expected supply, forward prices for September, October, and November increased meaningfully on August 10. The September flat contract traded for $92.00/MWh on the afternoon of Monday, August 9 and increased to $98.00/MWh during morning trading on Tuesday, August 10. In the EPCOR RRO auction, the September flat cleared at $101.84/MWh on August 10.

In subsequent days the price of the September contract fell to $92.00/MWh, in part due to declining forward prices in Mid-C. The price of the September contract later dropped further to $80.00/MWh on August 26 as pool prices in August were coming in well below market expectations.

Natural gas prices have increased considerably this year due to the economic recovery, rising LNG demand, higher power demands, and cold weather forecasts for the coming winter. On the supply-side, gas production has been relatively slow to respond as US shale production remains flat. The forward price of natural gas for December 2021 was $3.00/GJ on April 30 but this increased by 37% to $4.09/GJ as of July 31. As of September 30, the price of the December natural gas contract had risen to 5.09/GJ. Higher natural gas prices have been an important factor in the rising forward prices for power, particularly for the winter months.

3.2 Trading of annual products

The marked price of the CAL21 contract increased from $93.30/MWh on June 30, 2021 to $98.66/MWh on September 30, an increase of 5.7%.[22] The CAL21 contract last traded for $61.25/MWh on December 16, 2020, and its value as of September 30 was 61% higher (Figure 25). The marked value of CAL21 has increased over time as pool prices have come in above forward market expectations, and because forward prices for the balance of year have increased. The higher price of CAL21 tends to put upward price pressure on other annual contracts, particularly CAL22.

The CAL22 contract was actively traded in Q3. In addition to volatile pool prices, the CAL22 contract was reacting to forward prices in the natural gas market. The increase in natural gas prices has not been limited to the coming months.

Figure 26 shows how forward gas prices for CAL22 to CAL25 have evolved from October 1, 2020 to September 30, 2021. As shown, natural gas prices increased consistently from late June into early September, at which point there was a significant rise. The price of gas for CAL22 was $2.51/GJ on May 31 but rose to $3.84/GJ as of September 30, an increase of 53%. Similarly, the prices of natural gas for CAL23, CAL24, and CAL25 all rose meaningfully increasing forward power prices.

[22] The marked price for CAL21 uses realized pool prices in combination with forward prices for the coming days and months to value the CAL21 contract.

Figure 25: Forward power prices for the calendar 2021 to 2025 flat contracts

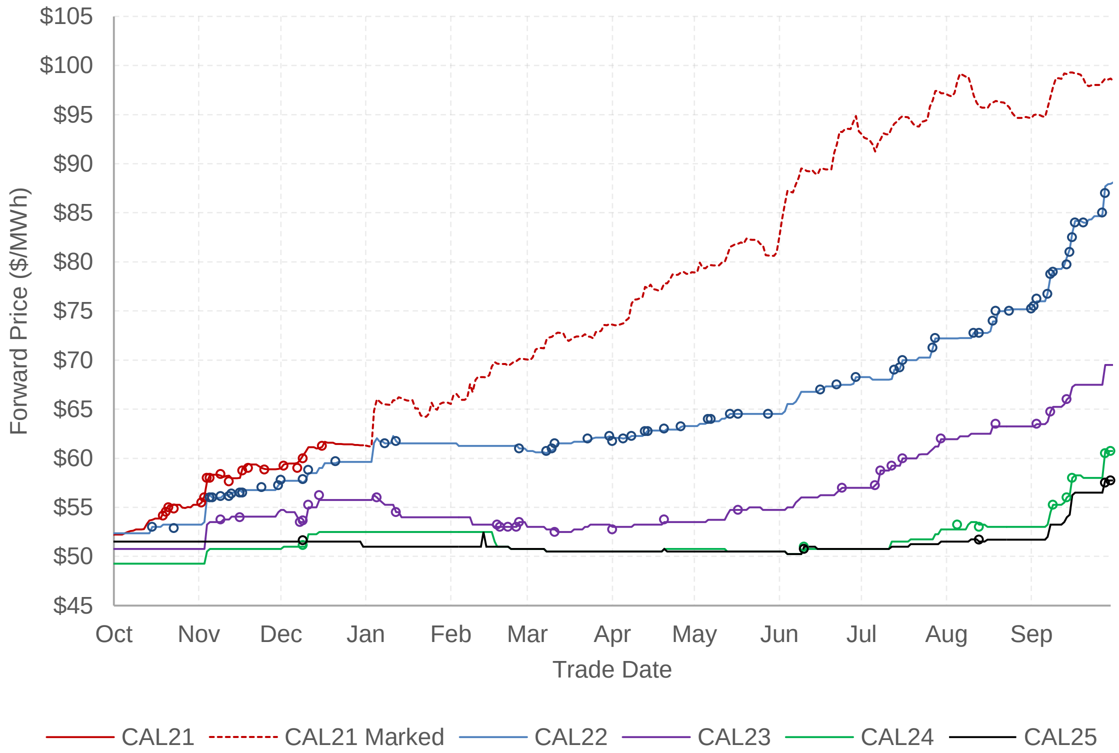
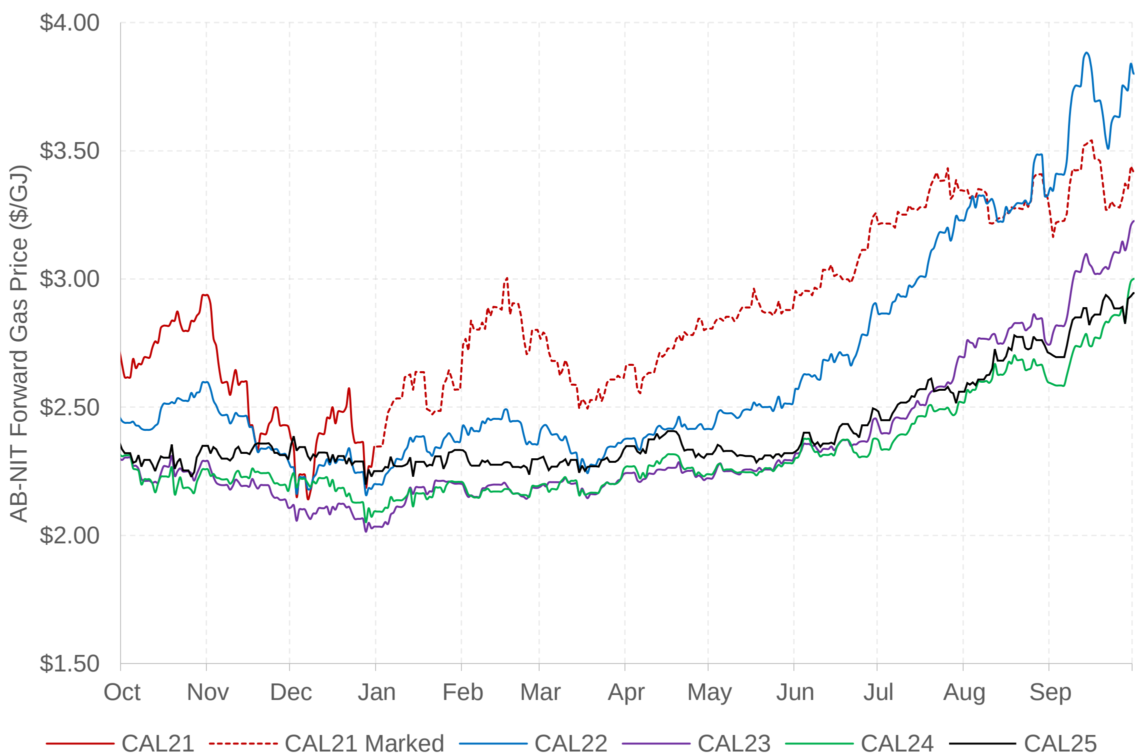


Figure 26: Forward natural gas prices for the calendar 2021 to 2025 contracts



On Tuesday, September 28, the retirement of Keephills 1 on December 31, 2021 and Sundance 4 on April 1, 2022 was announced.[23] These assets had previously been scheduled to run solely on natural gas effective January 1, 2022, at a reduced capacity of around 70 MW and 113 MW, respectively.[24] The announcement on September 28 also indicated that the conversion of Sundance 5 to a combined-cycle asset was suspended as the owner outlined its intent to focus on renewable energy and storage developments.

Forward prices increased following the announcement, with CAL22 increasing by 3.4% to $87.69/MWh on September 28. Longer-term forward prices also rose, as CAL24 increased by 4.7% to $60.75/MWh on September 28.

Table 6 summarizes the changes to annual power and natural gas prices over Q3. As shown, power and natural gas prices increased materially over the quarter, with the largest observed change being in the CAL22 contracts. Annual forward power prices are decreasing into the future as a material increase in renewable generation supply is expected, and significant additions to gas-fired capacity are scheduled to occur in the coming years.

Table 6: Forward price changes for annual electricity and natural gas (Q3 2021)

	Electricity ($/MWh)			**Natural Gas ($/GJ)**			**Spark Spread at 7.5 HR ($/MWh)**		
	30-Jun	**30-Sep**	**% Chg**	**30-Jun**	**30-Sep**	**% Chg**	**30-Jun**	**30-Sep**	**% Chg**
CAL22	$68.25	$87.94	29%	$2.90	$3.84	32%	$46.47	$59.16	27%
CAL23	$57.00	$69.50	22%	$2.46	$3.21	31%	$38.58	$45.45	18%
CAL24	$50.75	$60.75	20%	$2.38	$2.99	26%	$32.92	$38.34	16%
CAL25	$50.75	$57.75	14%	$2.49	$2.93	18%	$32.07	$35.76	11%

[23] TransAlta Website – September 28, 2021

[24] TransAlta Website – November 4, 2020

4 THE RETAIL MARKETS

Retail energy customers have choices. Electricity customers can choose between the Regulated Rate Option (RRO) or can sign a contract for electricity services with a competitive retailer. Customers can receive retail natural gas services from competitive retailers or through the regulated Default Rate Tariff (DRT).

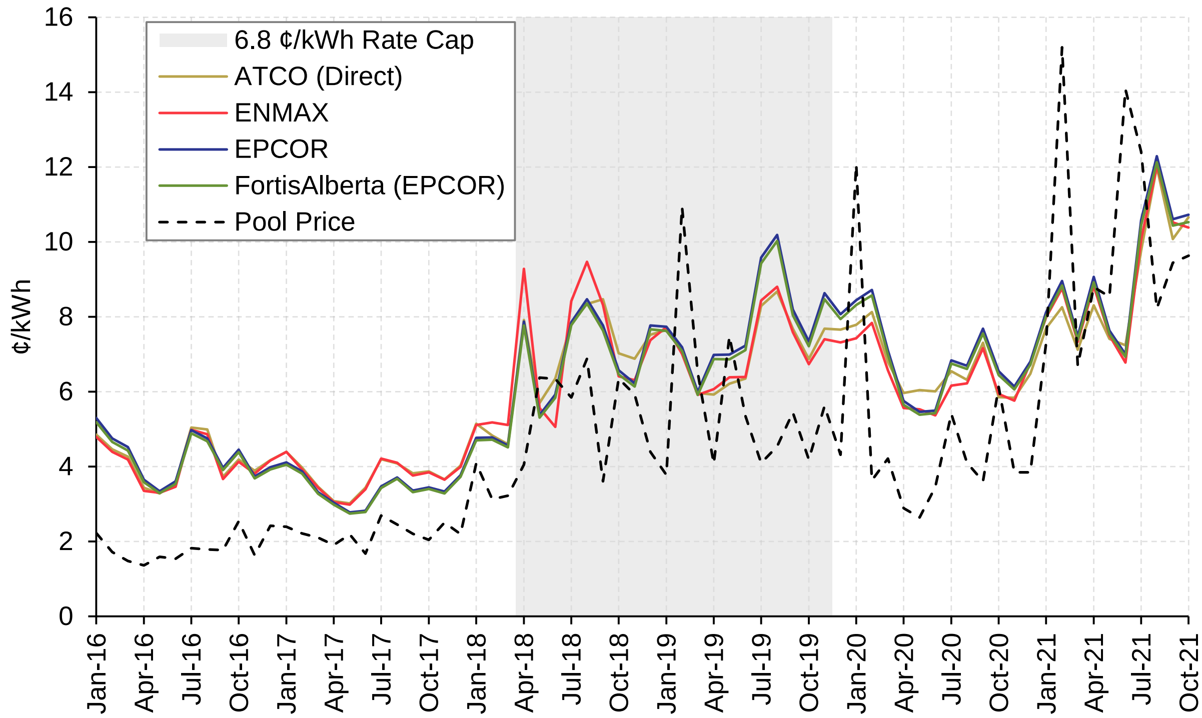
4.1 Regulated retail market

4.1.1 Regulated Rate Option

Residential RRO rates increased significantly in Q3 compared to the previous two quarters (Figure 27), averaging 10.9 ¢/kWh across the four largest service areas over the quarter, compared to 8 ¢/kWh and 7.8 ¢/kWh in Q1 and Q2, respectively. August 2021 saw RRO rates increase to 9-year highs, averaging 12.1 ¢/kWh across the service areas.

RRO rates in Q4 2021 have so far remained in line with Q3 rates, with RRO rates averaging 10.6 ¢/kWh in the first two months of the quarter.

Figure 27: Residential Regulated Rate Option by service area, January 2016 to October 2021

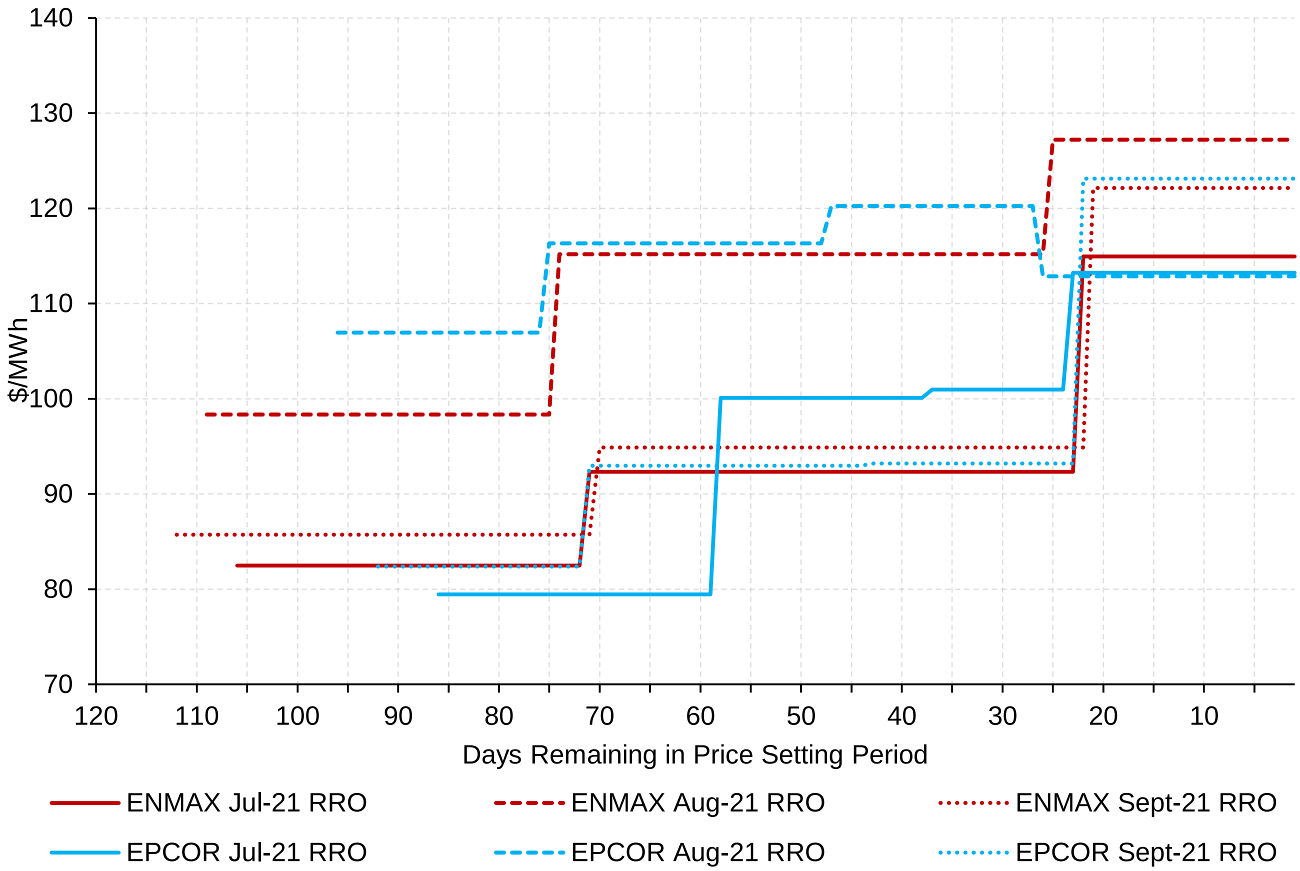


RRO rates for a given delivery month are set based on forward market prices established within the 120-day buying period preceding the start of the delivery month. The price of EPCOR and ENMAX RRO full-load strips – a forward market product where a seller arranges to supply a fixed percentage of the RRO load over the delivery month – are the primary basis for RRO rates set across the four largest service areas. These hedges are procured at various times throughout the

120-day buying period, limiting the exposure of RRO rates to forward prices directly preceding the beginning of the delivery period and reducing RRO rate variability between months.

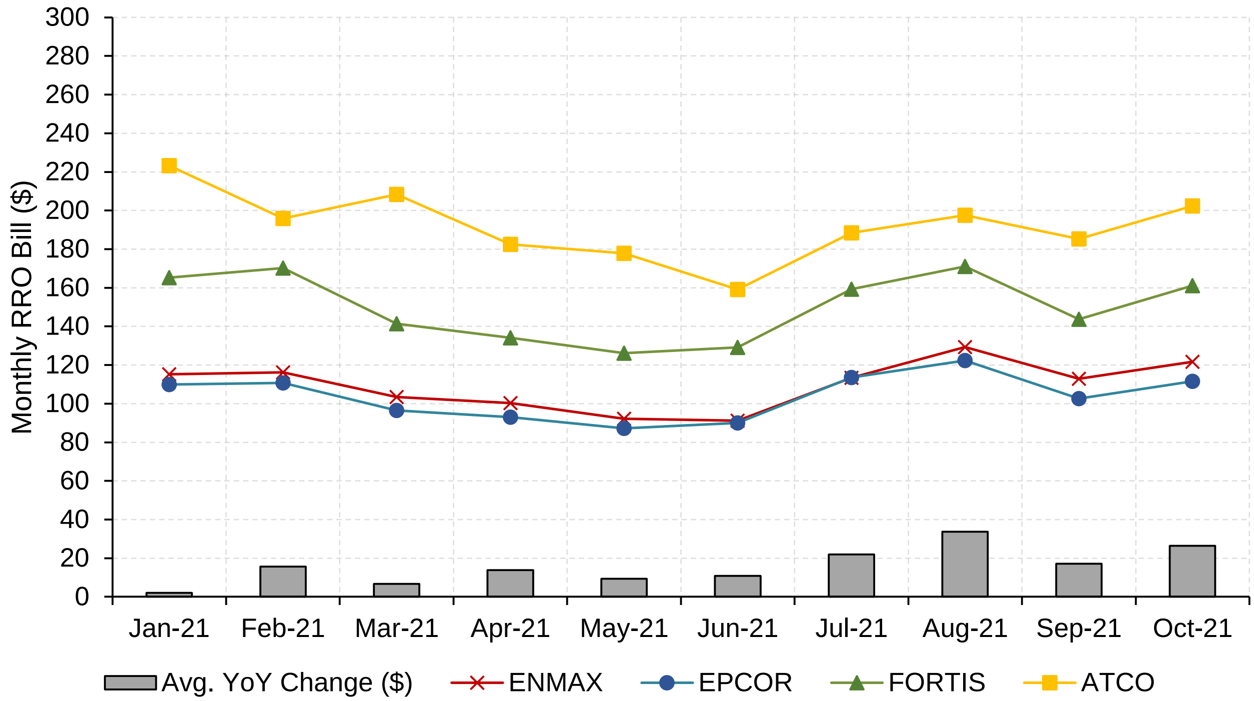
Relatively high forward prices for summer months led to increases in higher RRO rates over the quarter (Figure 28), with prices for the underlying full-load strip products increasing by an average of 35 % over the 120-day buying period preceding each delivery month. This increase in full-load strip prices over the period was consistent with increases in the corresponding flat monthly forward prices over the same period, which increased by 43% over the 120-day buying period.

Figure 28: ENMAX and EPCOR RRO Full-Load Strip Prices, Q3 2021 Delivery Dates



Over the first ten months of 2021, residential RRO customers' electricity bills increased by approximately $16/month compared to RRO bills in the previous year (Figure 29). These bill increases varied by service area: customers living in the comparatively rural ATCO and FortisAlberta service areas saw their RRO bills rise by slightly greater amounts compared to customers in the ENMAX and EPCOR service areas. Year-over-year differences in RRO bills increased throughout the year as RRO rates steadily increased.

Figure 29: Residential RRO electricity bill estimates by service area, January to October 2021[25]



The MSA monitors RRO auction prices and has observed a significant increase in RRO auction prices for the December 2021 to March 2022 delivery months. This increase in auction prices has coincided with an increase in natural gas futures prices over the same delivery period.

While the RRO rates for these months have not yet been established, the MSA has constructed a simple model using publicly available gas futures prices, monthly flat settlement prices, and historical RRO auction prices to generate residential RRO rate estimates under different gas futures price scenarios.

In the base case, the MSA has generated RRO rate estimates under the assumption that natural gas futures prices and monthly flat prices for the relevant months would not deviate from prices established on October 21, 2021. A range was constructed on the basis that natural gas futures prices could increase or decrease at a rate up to approximately $0.014/GJ/day – the average daily change in gas futures prices between April 1 and October 6, 2021 – over the period leading up to each delivery month, affecting the expected monthly flat and RRO full-load strip prices in accordance with historical data.

A range of RRO estimates for one service area has been provided in Figure 30. These estimates are broadly indicative of the range of RRO estimates for other service areas. Under the base case, residential RRO rate estimates increase into 2022, reaching highs of 17.50 ¢/kWh in

[25] July through October bill estimates have been constructed using forecasted RRO consumption.

February before falling below 12 ¢/kWh in the following month. These estimates are significantly higher than RRO rates observed in any service area in recent years (Figure 31).

Figure 30: Residential RRO rate estimates & underlying gas futures prices prior to delivery month, EPCOR service area, December 2021 to March 2022

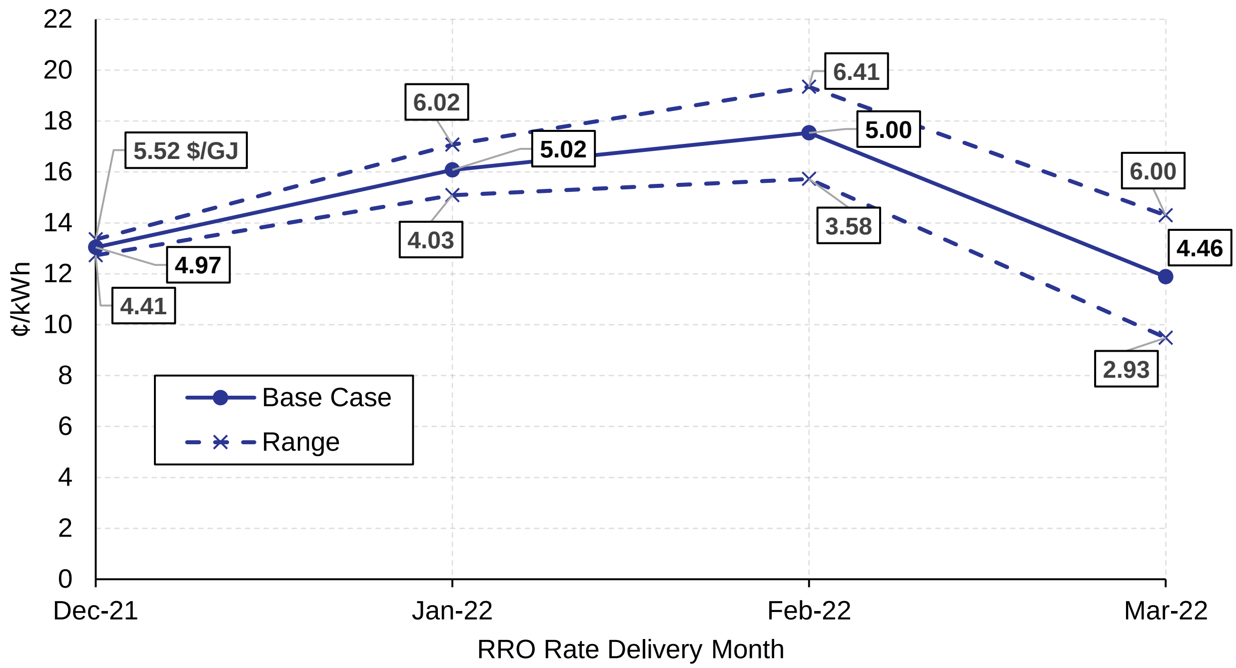
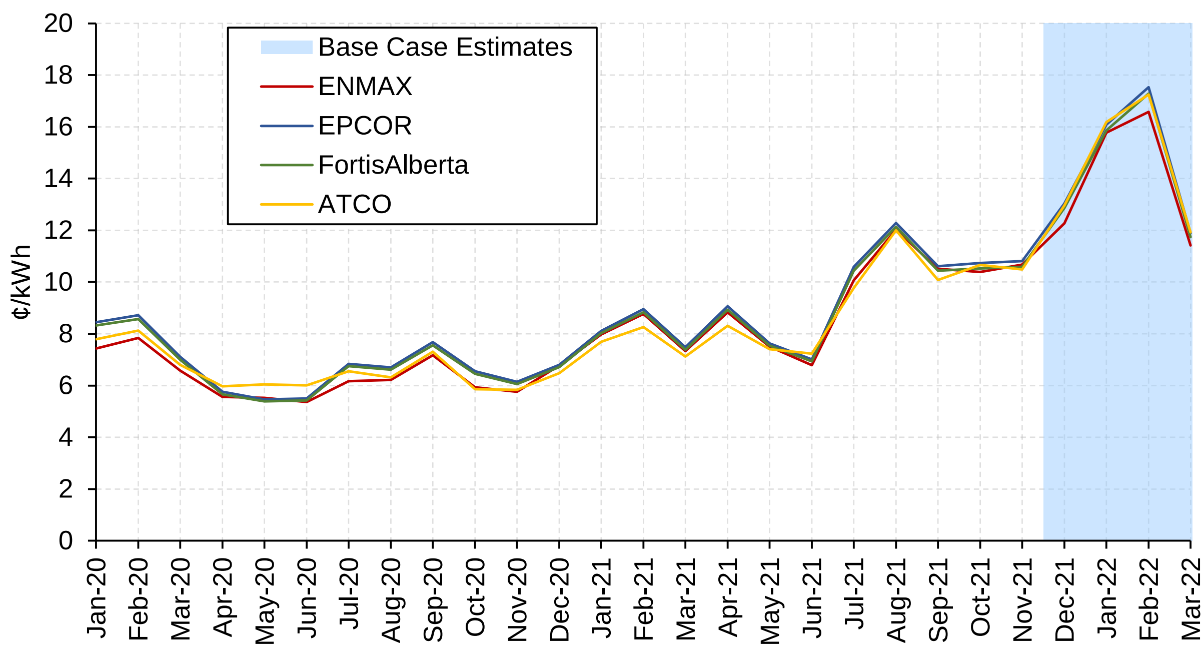


Figure 31: Residential RRO rate base case estimates & historical RRO rates by service area, January 2020 to March 2022



The MSA estimates RRO customers may see their electricity bills increase by an average of $25 to $70 per month over the December 2021 to March 2022 period compared to similar bills in the previous year.

4.1.2 Default Rate Tariff

Residential DRT rates averaged $3.59/GJ in Q3, a 95% increase year-over-year and an increase over DRT rates in the previous two quarters, which averaged $3.21/GJ and $3.10/GJ in Q1 and Q2, respectively (Figure 32).

Rising natural gas prices have driven this increase in DRT rates over 2021. Prevailing futures prices indicate DRT rates could increase to around $5/GJ in winter 2021/22.

Figure 32: Residential Default Rate Tariff by service area, January 2016 to October 2021

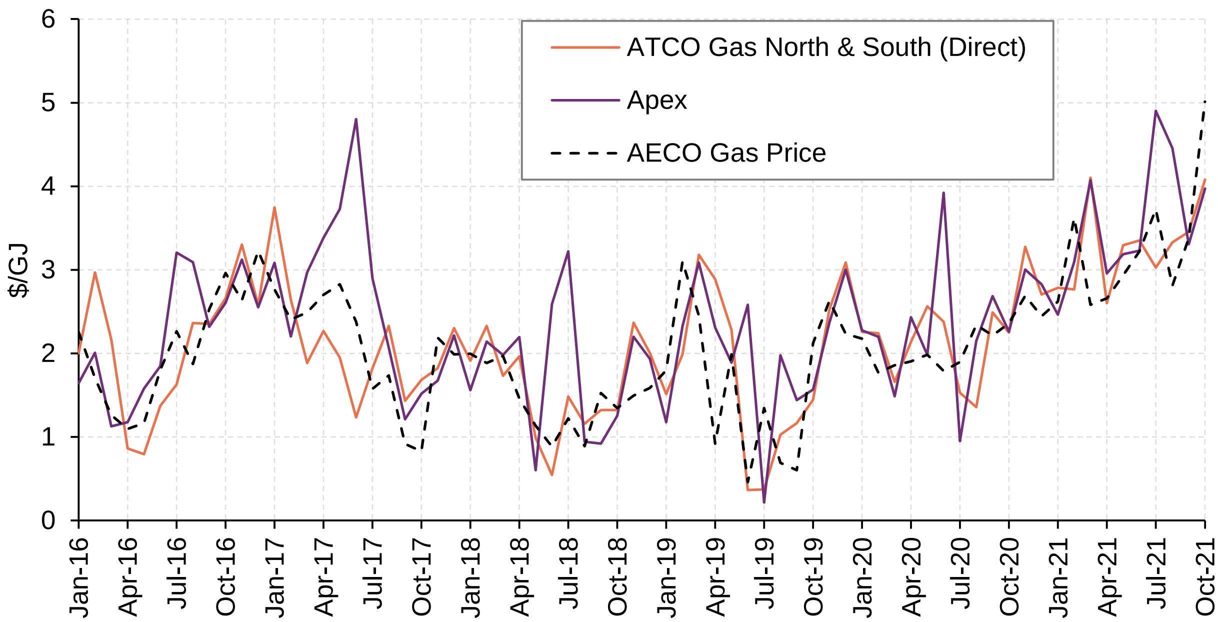
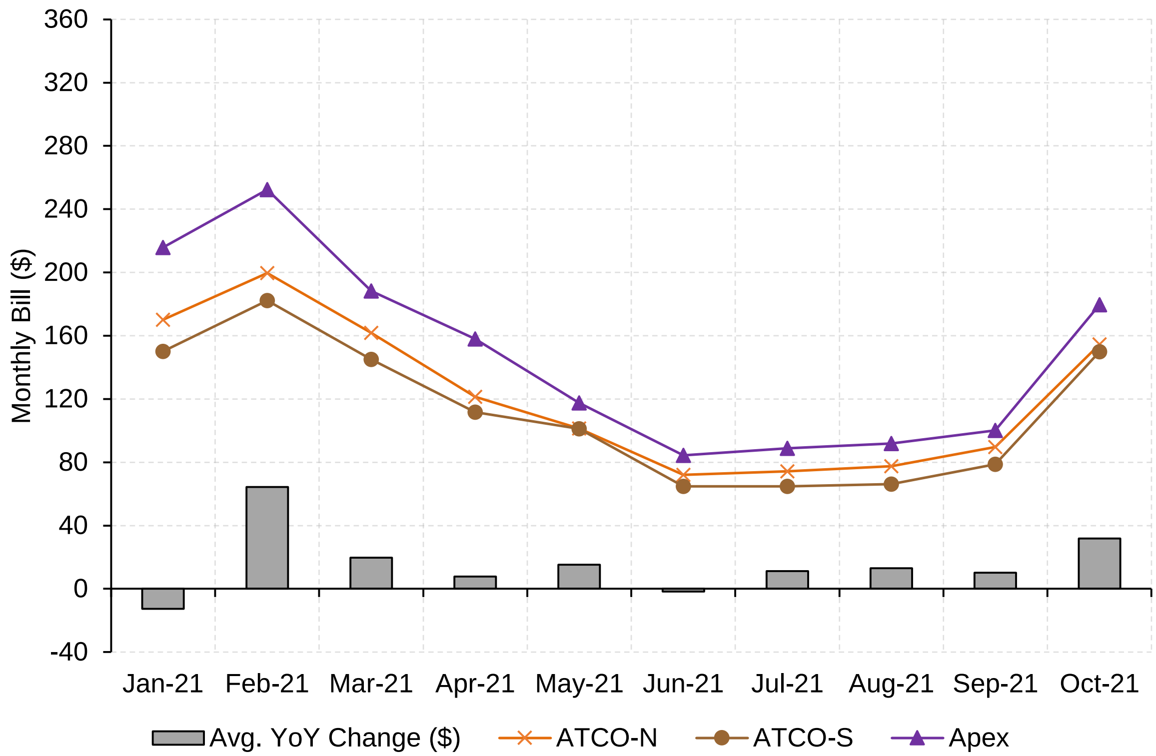


Figure 33: Residential DRT electricity bill estimates by service area, January to October 2021[26]



Residential DRT bills increased by approximately $16/month over the first ten months of 2021, compared with DRT bills in the previous year (Figure 33). Year-over-year changes in DRT bills were particularly large in February and October, where DRT rate increases and seasonally higher gas consumption led to average bill increases of $64 and $32, respectively. Based on prevailing futures prices, the MSA estimates DRT bills could increase by an average of $15 to $75 per month over the November 2021 to March 2022 period compared to similar bills in the previous year.

4.2 Competitive retail market

Competitive retailers typically offer two types of energy rates to retail customers: a fixed rate set over a prescribed term, and variable rates tied to wholesale market prices or other variable rate products. Fixed rates are typically offered with terms between one and five years, while variable rates typically change monthly.

Fixed energy rates offer customers greater bill stability, but will not necessarily be lower than variable or regulated rates over the entire term of the fixed rate.

4.2.1 Competitive electricity rates

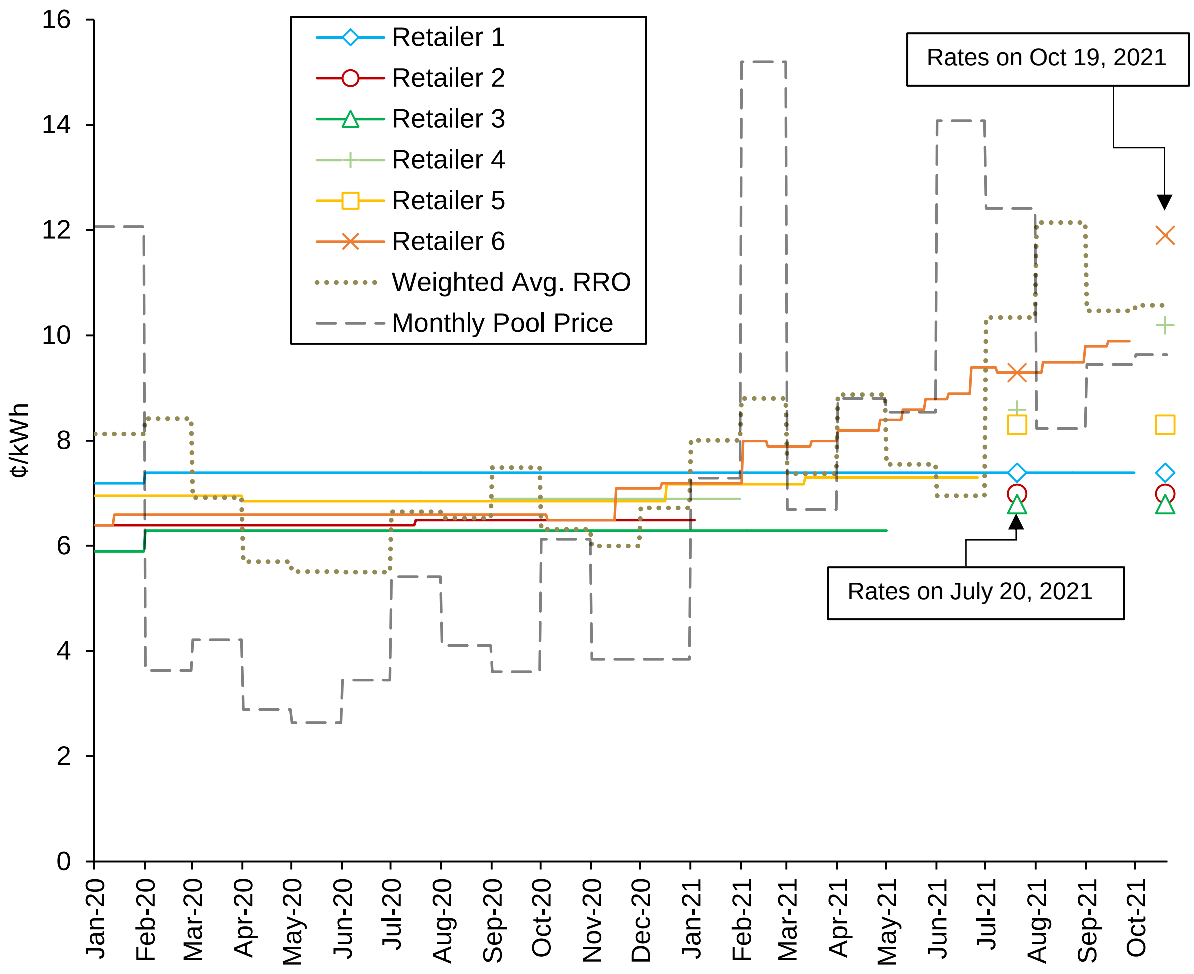
Competitive fixed electricity rates offered by most retailers increased in the first half of 2021, likely driven by increases in pool prices, forward market prices, and RRO rates. 1-year fixed rates

[26] July through October bill estimates have been constructed using forecasted DRT consumption.

offered by the largest retailers averaged 8.6 ¢/kWh on October 19, 2021, up from 7.9 ¢/kWh as of July 20, 2021 (Figure 34).

Much of this increase in average 1-year fixed rates resulted from a small number of retailers increasing their competitive fixed rates significantly over the quarter. However, many retailers' 1-year rates did not significantly change over the quarter. Retailers with significant forward market length may have lower expected costs if such length was acquired in periods of lower forward market prices, and could therefore compete at lower fixed rate prices. Alternatively, retail rate structure may play a role by enabling retailers to offset lower energy revenues with greater revenues acquired through retail administration fees.

Figure 34: 1-Year competitive fixed residential electricity rates, January 2020 to October 2021[27]



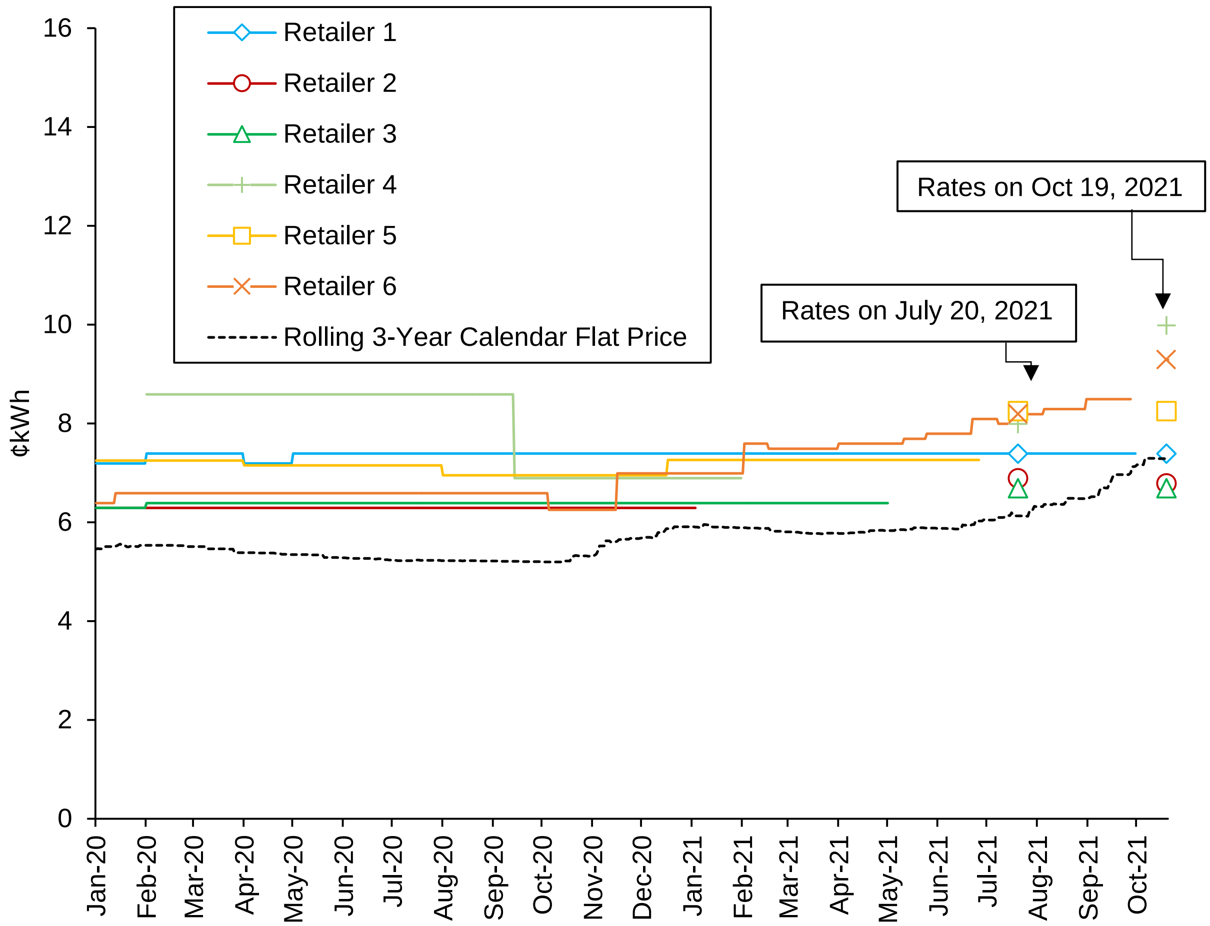
Longer-term fixed rates are less susceptible to changes in near-term market fundamentals when compared with 1-year fixed rates, but are more susceptible to long-term fundamentals. Between

[27] Competitive rate data sourced from the Utilities Consumer Advocate Historic Rates Dataset.

July 20 and October 19, 2021, 3-year fixed rates offered by the largest retailers increased from 7.6 ¢/kWh to 8.1 ¢/kWh (Figure 35).

While natural gas futures price increases over Q3 were particularly significant for winter 2021/22, longer-term gas futures prices also increased over the quarter (Figure 26). The impact of these higher gas futures prices on wholesale electricity costs has likely increased retailers' expected costs associated with 3-year fixed rates, although the impact of such higher expected costs has not translated to higher rates across all retailers. Notably, some retailers were still offering 3-year fixed rates below the 3-year average flat price as of October 19, 2021, with one such retailer decreasing their 3-year rate between July and October 2021.

Figure 35: 3-Year competitive fixed residential electricity rates, January 2020 to July 2021[28]



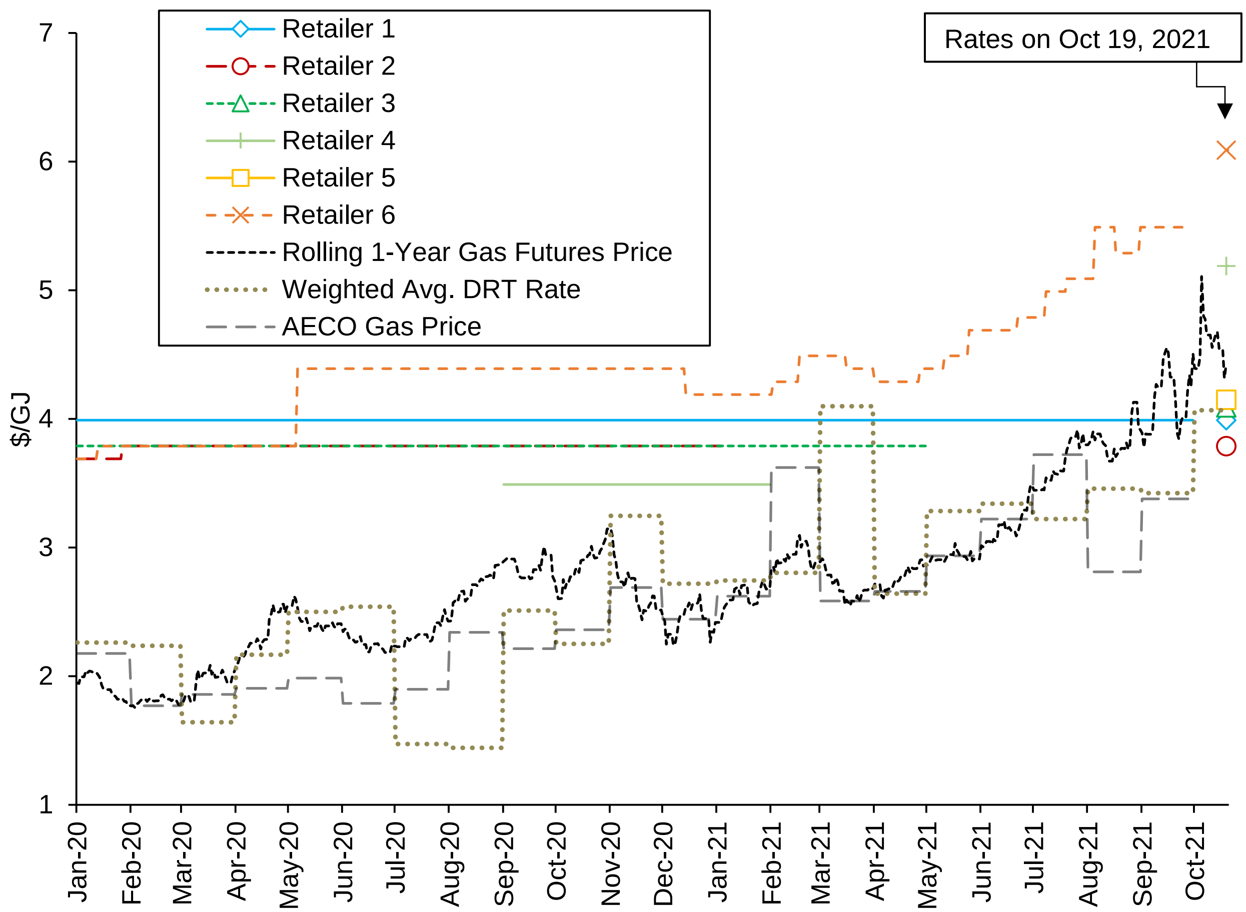
[28] Competitive rate data sourced from the Utilities Consumer Advocate Historic Rates Dataset.

4.2.2 *Competitive natural gas rates*

As with competitive electricity offerings, some retailers have increased their fixed rate natural gas prices significantly over 2021, while other retailers' rates remain similar to those offered in 2020 (Figure 36).

Among the largest retailers, 1-year fixed rates averaged $4.55/GJ as of October 19, 2021, although many retailers continued to offer rates around $4/GJ, despite significant increases in gas futures prices since Q2 2021. With recent increases in DRT rates, some 1-year competitive natural gas offerings have become increasingly competitive.

Figure 36: 1-Year competitive fixed residential natural gas rates, Jan. 2020 to Oct. 2021[29]



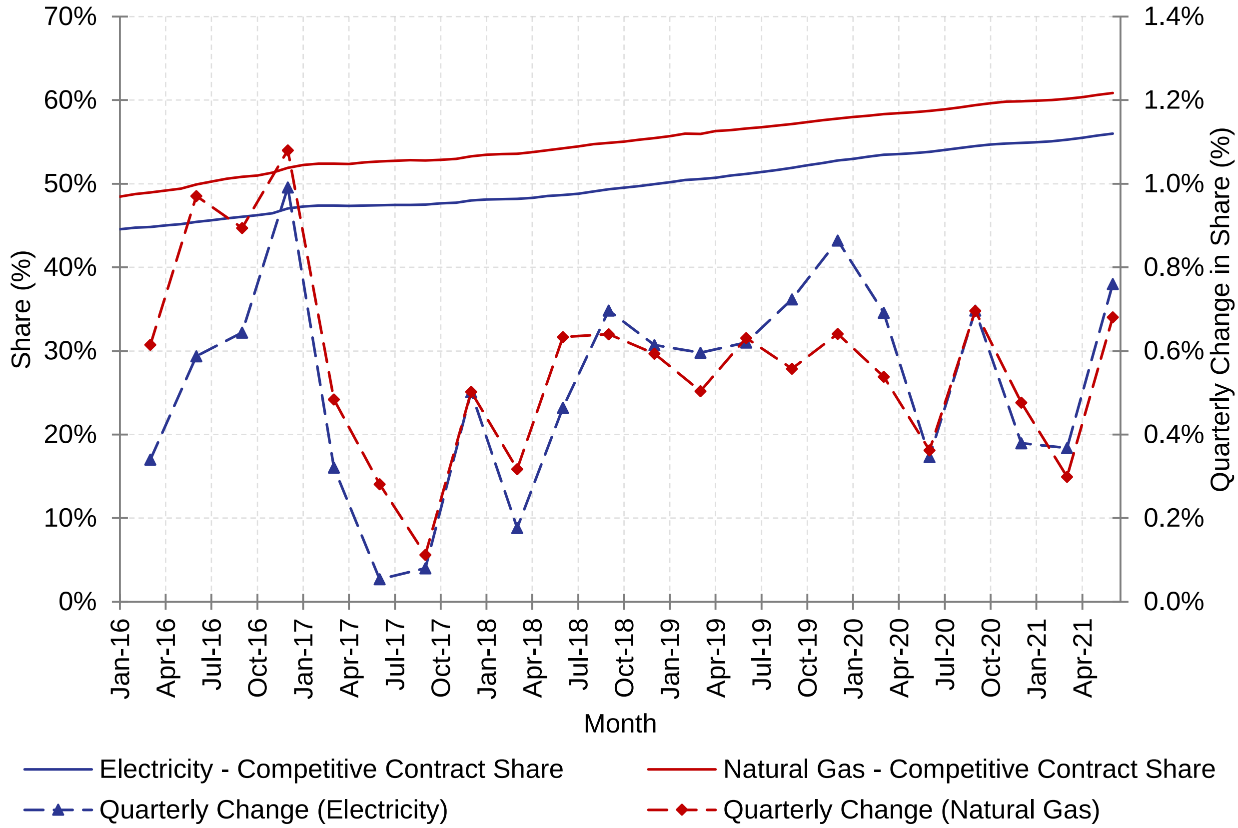
---

[29] Competitive rate data sourced from the Utilities Consumer Advocate Historic Rates Dataset.

4.2.3 *Competitive market shares*

Competitive market shares among residential customers increased by around 0.7% in both the retail electricity and natural gas markets over Q2 2021, in line with levels observed since 2019 (Figure 37).[30] Although competitive market shares have increased steadily over the previous years, the MSA anticipates competitive market shares may increase at greater rates in the second half of 2021 prompted by customers receiving higher-than-expected regulated energy bills.

Figure 37: Competitive retailer market shares, residential customers, Jan. 2016 to Jun. 2021



4.3 Churn

Churn represents the share of a retailers' customers that leave the retailer in any given month. Since 2019, residential customer churn among regulated retailers has exceeded that of competitive retailers (Figure 38). Churn among regulated retailers increased significantly in Q2 2021.[31]

[30] MSA Retail Statistics (2021-10-04). Data up to Q2 2021 is presented here as the MSA Retail Statistics reports data using a one-quarter delay.

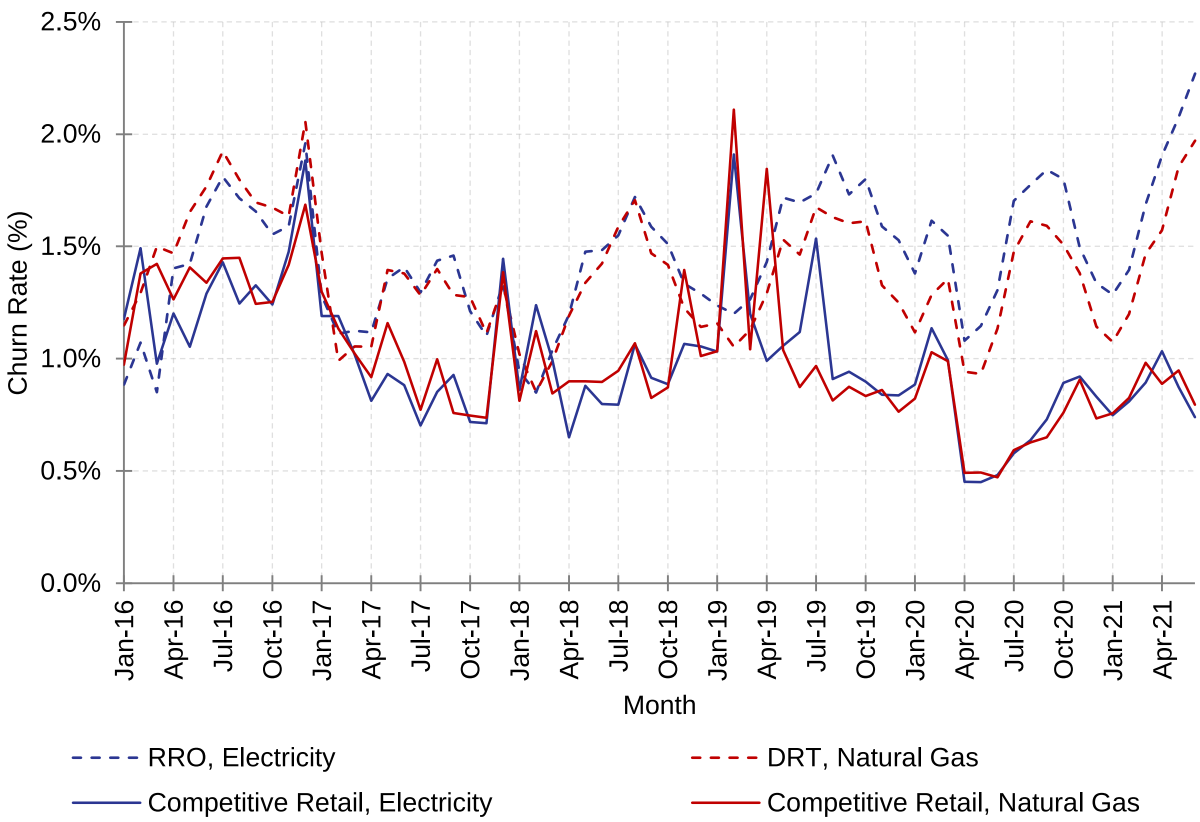
[31] MSA Retail Statistics (2021-10-04). Data up to Q2 2021 is presented here as the MSA Retail Statistics reports data using a one-quarter delay.

The MSA considers retail churn to play an important role in the development of competitive retail energy markets, as high churn can enable vigorous competition to exist between retail competitors. Conversely, low churn may limit the incentive for competitive retailers to compete on price if customers are less willing to switch from their existing retailers.

Churn among RRO and DRT customers increased significantly in Q2 2021 to around 2%, while competitive retail churn remained steady near 0.75%, possibly in response to higher regulated rates compared to the previous year or the anticipation that regulated rates could increase further throughout the summer months.

Notably, this increase in regulated churn rates was not accompanied by a significant increase in competitive retail market shares (Figure 37). Together, this may indicate competitive customer switching rates towards regulated rates may have increased in Q2 alongside an increase in regulated customers switching away from regulated products as a proportion of their customer base.

Figure 38: Regulated & competitive retailer churn, residential customers, Jan. 2016 to Jun. 2021



4.4 Retail regulatory updates

4.4.1 Energy Price Setting Plan developments

On February 11, 2021, EPCOR Energy Alberta GP Inc. (EPCOR) applied to the Alberta Utilities Commission (the Commission) for approval of its 2021-2024 energy price setting plan (EPSP).[32] Although substantially similar to its previously approved 2018-2021 EPSP, EPCOR's proposed EPSP includes improvements to the clarity of EPSP language and calculations, and adjustments to the backstop mechanism, among others. On September 29, 2021, the Commission released its first decision on EPCOR's application, requiring EPCOR to make specific amendments to the EPSP and to file an executed backstop agreement for this iteration of its EPSP.[33]

4.4.2 Utility payment deferrals

In response to the onset of the COVID-19 pandemic, the Government of Alberta introduced a 90-day utility payment deferral program to assist eligible Albertans with their utility bills between March 18 and June 18, 2020. Customers enrolled on the program were required to repay any utility payments deferred via this program by June 18, 2021. More than 350,000 retail customers deferred utility payments using the program.

In the spring 2020 deferral period, electricity retailers could apply to the Commission to recover deferred bill payments with funding from the Balancing Pool,[34] while natural gas retailers recovered deferral funding from the Government of Alberta.[35] As customers repaid deferred amounts to retailers throughout 2020 and 2021, retailers were required to remit these repayments to the appropriate creditor in accordance with the *Utility Payment Deferral Program Act* (Chapter U-4, 2020) (UPDPA).[36] Alternatively, retailers could self-fund these deferrals and apply to recover deficiencies at the end of the repayment period in accordance with the *Utility Payment Deferral Program Regulation* (AR 287/2020) (UPDPR).[37]

Unpaid bill deferral amounts that were not collected from customers will be recovered using rate riders on energy bills. On August 18, 2021, the Commission released its decisions in proceedings 26684 and 26699, approving approximately $9 million and $6 million in uncollected bill amounts

---

[32] EPCOR Energy Alberta GP Inc. 2021-2024 Energy Price Setting Plan Application, Exhibit 26316-X0006, February 11, 2021.

[33] EPCOR Energy Alberta GP Inc. 2021-2024 Energy Price Setting Plan, September 2021.

[34] Deferred electricity transmission costs were not recovered via Balancing Pool funding. Instead, deferred transmission costs were to be repaid to distributors and subsequently the AESO during the repayment period.

[35] Gas transmission costs were not recovered from the Government of Alberta, and were instead to be repaid to distributors during the repayment period.

[36] *Utility Payment Deferral Program Act* (Chapter U-4, 2020).

[37] *Utility Payment Deferral Program Regulation* (AR 287/2020).

to be recovered from electricity and natural gas customers (respectively) using a rate rider beginning in November 2021.[38] [39]

On August 31, 2021, the AESO established a $0.43/MWh ISO Tariff rider to recover uncollected electricity bill amounts.[40] This rider will be recovered from electricity customers between November 1, 2021 and February 28, 2022. The MSA estimates this rider will increase residential electricity bills by $0.25 to $0.34/month over the four month period.

Uncollected natural gas bill amounts will be recovered from natural gas customers over the same period at a rate of $0.037/GJ.[41] The MSA estimates this rider will increase residential natural gas bills by $0.70 to $0.89/month over the four month period.

4.4.3 September 2021 RRO over-procurement

In their September 2021 RRO filing to the Commission, ENMAX Energy Corporation (EEC) advised the Commission of an inadvertent over-procurement of one full-load strip in RRO auctions for September 2021 forward market products.[42] While the cost of this additional block was excluded from the September RRO calculation, EEC estimated this over-procurement increased the average price of its full-load strip purchases which in turn increased its September RRO rate by 0.018 ¢/kWh.[43] The Commission has approved a $15,738.91 refund to RRO customers via the November RRO energy charge to mitigate the impact of this over-procurement.

The MSA estimates the impact of this refund on an ENMAX RRO customer consuming 600 kWh in November to be a reduction in their November RRO electricity bill by approximately $0.13.

---

[38] Decision 26684-D01-2021 Utility Payment Deferral Program: Rate Rider – Electricity, August 18, 2021, PDF Pages 4, 13.

[39] Decision 26699-D01-2021 Utility Payment Deferral Program: Rate Rider – Natural Gas, August 18, 2021, PDF Page 1.

[40] UPDP Rate Rider – Electricity Post Disposition Report #1 of the Alberta Electric System Operator, Proceeding 26684, August 31, 2021.

[41] Decision 26699-D01-2021 Utility Payment Deferral Program: Rate Rider – Natural Gas, August 18, 2021, PDF Pages 1, 13.

[42] Disposition 26790-D01-2021 – ENMAX September 2021 RRT Electric Energy Charges, August 27, 2021, Page 1.

[43] Disposition 26878-D01-2021 – ENMAX October 2021 RRT Electric Energy Charges, September 27, 2021, Page 2.

5 ENFORCEMENT MATTERS

5.1 Micro-generation sizing

The MSA has conducted an assessment of micro-generation units that were net exporters on an annual basis to the interconnected electric system between 2016 and 2020. The *Micro-generation Regulation* (MGR) states that micro-generation (MG) units are intended to meet all or a portion of the customer's total annual energy consumption at the customer's site or aggregated sites.[44] A site with generation capacity that is capable of producing more electricity than it consumed, on an annual basis, is said in this assessment to be "over-sized." Over-sized small micro-generation sites with the capacity to provide significant annual net exports to the grid could exacerbate the issue of retail rates for small micro-generation, which was discussed in the MSA's Quarterly Report for Q1 2021.[45]

Small micro-generation sites typically are residential, small commercial, and farm solar photovoltaic panel installations, and have a nameplate capacity less than 150 kW. Large micro-generation sites are those with a nameplate capacity between 150 kW and 5 MW. Although large micro-generation sites are also intended to meet all or a portion of the customer's total annual energy consumption, large micro generation is compensated at the pool price for each settlement interval.[46] As such, over-sized large micro-generation does not impact the aforementioned issue of retail rates.

The purpose of this assessment is to determine the fraction of small micro-generation sites that are over-sized and any trends in this respect. In summary, the MSA found that of small micro-generation units that had not changed generation capacity during the year, the percent of over-sized sites increased from 10.5% in 2016 to 18.5% in 2020. The average volume of annual excess net exports from over-sized sites increased from 2.5 MWh/year in 2016 to 3.9 MWh/year in 2020. Despite these increases, in general it does not appear that small MG sites are systematically increasing their levels of excess net exports over time, rather, new sites are being commissioned at increasingly over-sized levels. The top 2% highest exporting sites were responsible for the majority of total excess net exports in 2020.

A customer with a small micro-generation site that is over-sized is not necessarily in breach of the MGR. When a customer intends to supply energy from a micro-generation generating unit to the grid, the customer must notify the owner of the applicable electric distribution system, or DFO. If the DFO believes the customer's generating unit will not qualify as a micro-generation generating unit, the DFO may, but is not obligated to, dispute the generating unit and take the matter to the Alberta Utilities Commission. One reason a DFO may be of the opinion that a generating unit will not qualify as a micro-generation generating unit, is that the unit is sized to

[44] *Micro-generation Regulation,* section 1(1)(h)(ii)

[45] MSA Quarterly Report for Q1 2021, section 5.1

[46] *Micro-generation Regulation,* section 7(5)(b)

produce more energy than the customer would intend to consume, on an annual basis; in other words, the unit is over-sized.

In addition to the magnitude of possible over-sizing being small as discussed in this assessment, other reasons that are not considered in the assessment are that the results may vary across years (due to either consumption or generation variation) and that the intent behind the generation installation decision may have changed after installation occurred.

5.1.1 Methodology

Each small micro-generation site is equipped with a bi-directional cumulative meter which separately measures cumulative flows of (i) net imports from the distribution system and (ii) net exports to the distribution system from the site. These flows are measured at all points in time between readings of the meter.[47] Within this time range, a site may sometimes be a net importer and sometimes a net exporter, meaning that both values may be positive. As a result, for small micro-generation sites, only the cumulative totals of net imports and net exports between meter readings are observed and used for load and micro-generation credit settlement purposes.[48]

To conduct this assessment, the MSA has calculated the "annual excess net exports" for each small micro-generation site. The site-level calculation is as follows:

$$Annual\ excess\ net\ exports = Annual\ net\ exports - annual\ net\ imports$$

A site's "annual net exports" and "annual net imports" are the sums of the flows measured at a site's respective net export and net import registers of the bi-directional cumulative meter, for each calendar year considered. As a result, "annual excess net exports" will be positive if "annual net exports" exceed "annual net imports" and negative otherwise.

As mentioned, the MGR states that micro-generation units are intended to meet all or a portion of the customer's total annual energy consumption. The MSA only considered sites that did not change micro-generation capacity during the year, because the balance of net exports and net imports relating to a specific level of installed generation capacity must be considered on a full-year basis. Sites that installed new capacity or expanded existing capacity mid-year were not considered in this analysis until the next full year in which the site had unchanging capacity. Sites with negative annual excess net exports are not over-sized. This is clear because their on-site generation is less than their on-site consumption. Conversely, those sites with positive annual excess net exports, and unchanging generation capacity during the year, are said here to be over-

[47] A small micro-generation site may request the installation of a bi-directional interval meter. If this request is granted then the micro-generation site is treated as a large micro-generation site for the purposes of the MGR. *Micro-generation Regulation,* section 3(4)

[48] As a result of the meter configuration vis-à-vis on-site consumption and generation, neither gross on-site consumption nor generation are observable. This is not different even with an interval meter. Separate meters for consumption and generation would be necessary for any gross values to be observable.

sized. This is because their on-site generation is greater than their on-site consumption on an annual basis.

5.1.2 Observations regarding small micro-generation

Table 7 below summarizes the number of small micro-generation sites that are considered over-sized, relative to the total number of sites, considering only sites with unchanging capacity throughout the year. Additionally, the table includes the total and average amounts of annual excess net exported energy from over-sized sites.

Table 7: Summary of small MG sites with constant capacity, from 2016 to 2020

Year	Number of sites	Over-sized	Percent over-sized	Total excess net exports from over-sized sites	Average excess net exports per over-sized site
2016	1,308	137	10.5%	347 MWh	2.5 MWh
2017	1,701	196	11.5%	507 MWh	2.6 MWh
2018	2,270	338	14.9%	933 MWh	2.8 MWh
2019	3,274	575	17.6%	1,597 MWh	2.8 MWh
2020	4,949	917	18.5%	3,588 MWh	3.9 MWh

Notably, the share of sites considered oversized and the volumes of excess net exported energy increased every year from 2016 through 2020. Despite these increases, a majority of sites are not over-sized (89.5% of sites in 2016 were not over-sized and 81.5% of sites in 2020). Although the frequency and magnitude of over-sized sites has increased since 2016, most sites have not systematically increased export levels over time, rather a small number of recently commissioned and significantly over-sized sites are responsible for a majority of the total excess net exports (see the discussion of Figure 42).

Figure 39 shows the excess net exports duration curve for small micro-generation units considered in this analysis, with Figure 40 highlighting the top 1% of these sites. These duration curves illustrate the distribution and magnitude of annual excess net export levels. Segments of the curves equal to or below zero represent sites that are not over-sized. Of the sites that are over-sized, most are small net-exporters. Approximately 98% of sites net-exported less than 7 MWh to the grid in 2020. A site’s generation and consumption vary from year-to-year, so sites that have annual excess net export levels close to zero may be oversized in some years but not others (by the measure of excess net exports being above or below zero).

Looking to Figure 40, the rapidly increasing slope at the top 1% of the duration curve illustrates that a very small share of sites is responsible for a disproportionate amount of excess net exports. The curves for 2016 through 2019 are relatively similar, while 2020 varies more significantly from the rest, illustrating a greater increase in oversized sites than in previous years. In 2020, the top 2% of sites accounted for 58% of the total excess net exports from over-sized sites.

Figure 39: Annual excess net exports duration curve for small MG units, 2016 to 2020

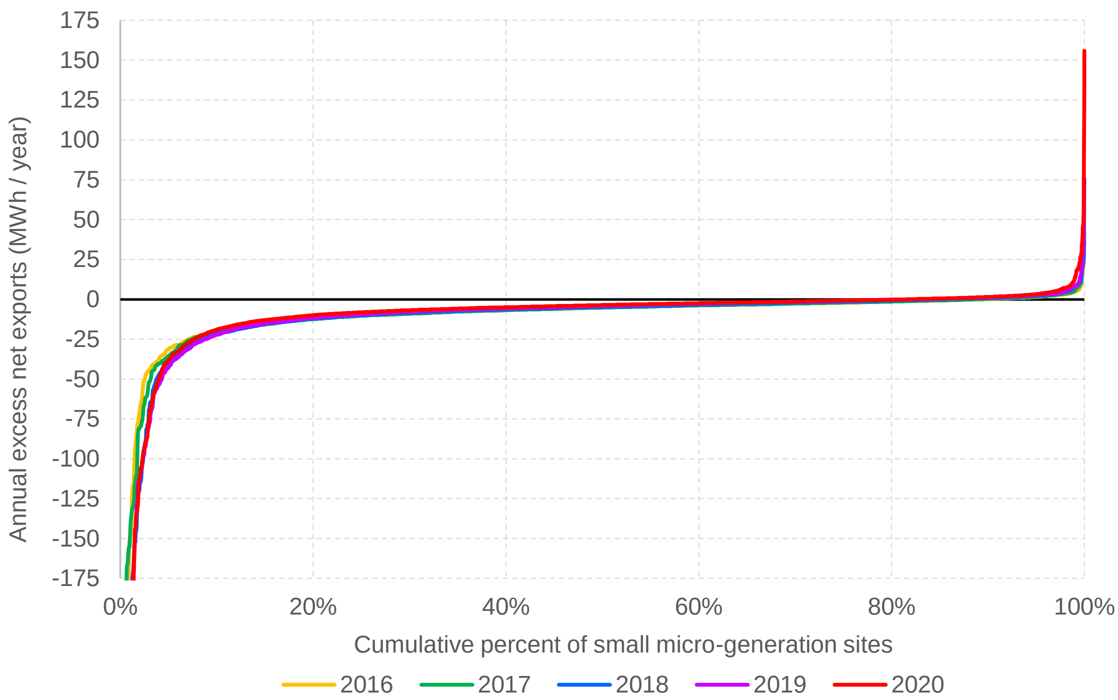
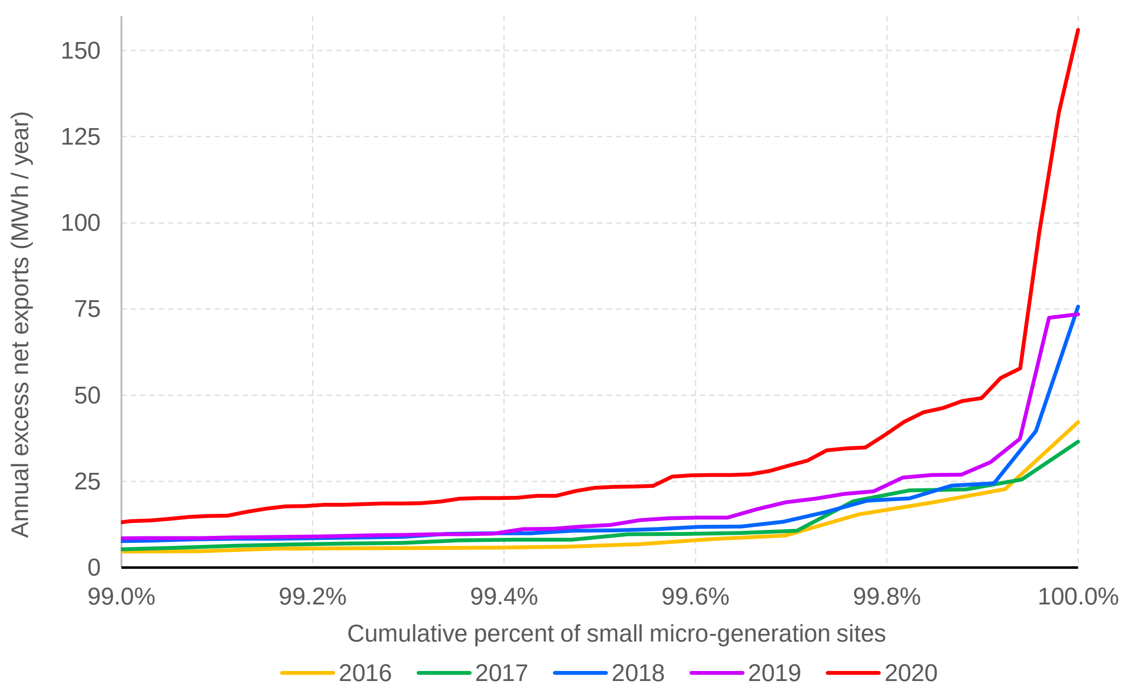


Figure 40: Annual excess net exports duration curve for small MG units (top 1% charted), 2016 to 2020



The increase in over-sized sites through time appears to mostly relate to the commissioning of new micro-generation sites that are over-sized, and less so to pre-existing sites later increasing their levels of excess net exports. Figure 41 shows the change over time of the level of annual excess net exports from the 20 sites that had the highest exports in 2020. The first and second largest sites, which appear as single-dot observations, were commissioned as MG sites in 2019. Of the top 20 sites, 14 were commissioned in 2018 or 2019. This means many of the largest sites are sites that more recently commissioned.

Figure 41: Levels of annual excess net exports from the 20 largest exporting small MG sites in 2020 (from 2016 to 2020)

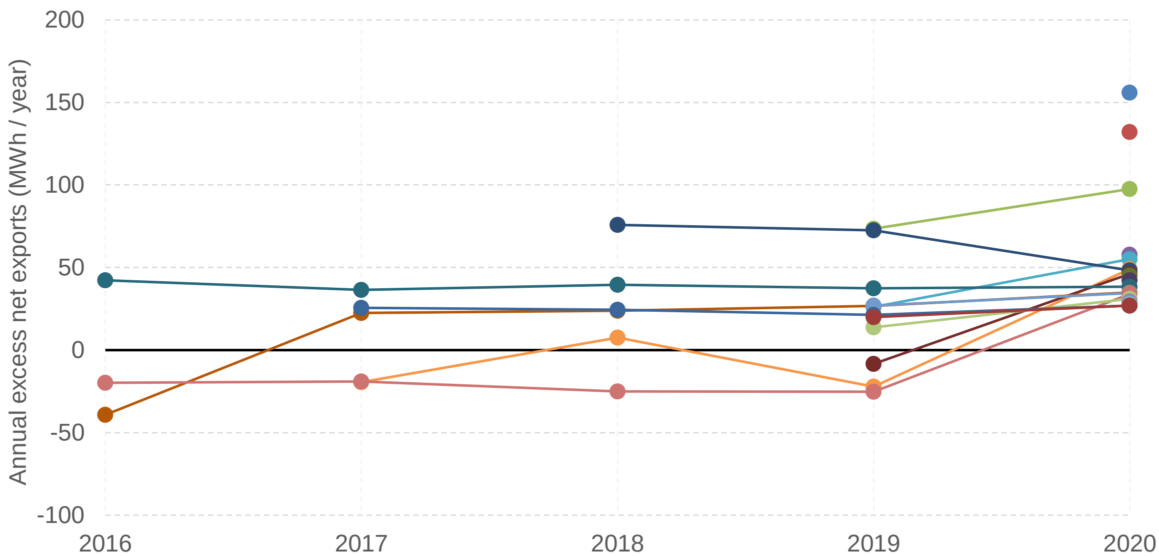
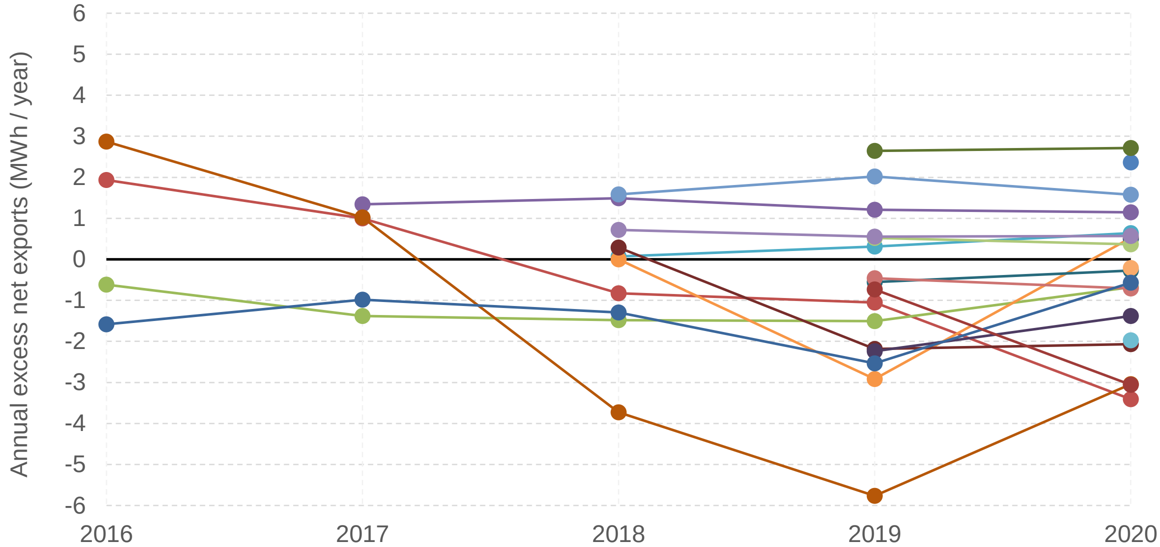


Figure 42 shows the level of annual excess net exports from 20 sites that had export levels around the median in the most recent observation period spanning from January 1 through September 5, 2021. In both Figure 41 and Figure 42, while some sites had varied levels of excess net exports year-to-year, overall the flatness through time indicates that there has not been a systemic increase in the level of excess net exports from pre-existing sites. Rather, it appears that new sites were commissioned at increasingly over-sized levels. Of these 20 sites around the median in Figure 42, some were annual net exporters, net importers, or changed from one to the other over the charted period. That there is no observed trend of increasing excess net export levels indicates that the median site is not increasing its export levels over time, other than for year-to-year variations.

Overall, a majority of small micro-generation sites have annual excess net export levels below or close to zero and a very small number of sites have been recently commissioned at increasingly over-sized levels.

Figure 42: Levels of annual excess net exports from 20 sites around the median level over-sized site[49] (from 2016 to 2020)



5.1.3 Observations regarding large micro-generation

The MSA also analyzed the sizing of large micro-generation units. Although large micro-generation sites are compensated at the pool price in each settlement interval for their energy exports, and so are not affected by micro-generation retail rates, the MSA has noted that excess net exports are increasing. Site specific annual excess net exports were calculated in an analogous way as to what is described in the methodology for small micro-generation sites, though large micro-generation sites typically have different metering data.

Table 8 below summarizes the number of over-sized large micro-generation sites. Notably, the number of observations is much lower than in the small micro-generation site analysis. The number of oversized sites and volume of excess net exports increased significantly in 2020, partly reflecting the general increase in the number of observed large micro-generation sites that year. The MSA will continue to monitor any increasing trends in large over-sized micro-generation units.

[49] For this chart, 20 representative sites were chosen to illustrate net export levels from sites that are close to the median over-sized site. From the latest available data on September 5, 2021, the median level of excess net-exports from January 1, 2021 through September 5, 2021 from over-sized small micro-generation sites was calculated. Sites that were commissioned in 2020 or later were dropped, because these site do not have a full year of data for 2020. Ten sites closest to and above and ten sites below the median level were selected and their excess net-export levels through time were charted.

Table 8: Summary of large MG sites with constant capacity, from 2016 to 2020

Year	Number of sites	Over-sized	Percent over-sized	Total excess net exports from over-sized sites	Average excess net exports per over-sized site
2016	6	2	33.3%	286 MWh	143.1 MWh
2017	12	2	16.7%	321 MWh	160.4 MWh
2018	18	3	16.7%	545 MWh	181.7 MWh
2019	30	3	10.0%	475 MWh	158.3 MWh
2020	50	13	26.0%	2,781 MWh	213.9 MWh

5.2 Complaint dismissed as frivolous, vexatious, and trivial

Section 43(1) of the *Alberta Utilities Commission Act* (SA 2007, Chapter A-37.2) (AUCA)[50] provides that "[t]he Market Surveillance Administrator may decline to investigate a complaint or referral or discontinue an investigation if the Market Surveillance Administrator is satisfied the complaint or referral is frivolous, vexatious or trivial..." The existence of this provision supports the efficient processing of matters under consideration by the MSA. During the quarter, the MSA received a complaint that alleged contraventions by multiple market participants which was closed on the application of this standard.

[50] *Alberta Utilities Commission Act* (SA 2007, Chapter A-37.2), Section 43(1), PDF Page 31.

5.3 Advisory Opinion Notice to Market Participants and Stakeholders

The MSA issued an Advisory Opinion on October 12. Its substance is reproduced below.

Re: MSA Advisory Opinion Program – Response to a Request for an Advisory Opinion

Purpose

This Advisory Opinion ("AO") is being issued by the MSA pursuant to its Advisory Opinion Program ("AOP") and subject to the Advisory Opinion Program Process ("AOP Process").[51]

The AOP Process provides, inter alia, as follows:

- the identity of the market participant who submitted a request pursuant to the AOP ("Applicant") and any commercially sensitive information will not be disclosed; and
- the AO is "non-binding" on the MSA. The Applicant and other market participants are advised to seek independent legal advice or contact the MSA as to whether any legislative or ISO rule changes may have impacted this AO.

Request

On July 28, 2021 the MSA received a written request ("Request") from an Applicant for an AO under the AOP. The Request contained the information required under the AOP for consideration by the MSA and for the MSA to make a decision on the Request. The MSA did not request any additional information from the Applicant.

The fact pattern relied on by the MSA for this AO is as follows:

> A market participant ("Retailer") was a "retailer" as defined in the *Electric Utilities Act* ("EUA") and as such provided power to a commercial customer ("Customer"). For some reason, the Customer had been, but was no longer, able to obtain "retail electricity services" from its retailer or any other supplier (see s. 3(2) of the *Roles, Relationship and Responsibilities Regulation ("*RRR")). As such, pursuant to s. 3(3) of the RRR, the customer would have been given the name of the "default supplier" that would provide it with "retail electricity services" ("Default Supplier"). The Default Supplier would have been appointed pursuant to s. 3(1) of the RRR by the "owner" as defined in the RRR ("Owner").
>
> The Retailer had obtained "business contact information" for the Customer from the Customer in the course of providing the foregoing retail services. That information was apparently not available to the Default Supplier after the Owner had notified the Customer of the name of the Default Supplier.

[51] A copy of the AOP Process is available on the MSA's website.

The Applicant would like the Retailer to provide the Customer's "business contact information" to the Default Supplier for "collection purposes only".

MSA Assessment

There is no specific authority to provide such "customer information" without the Customer's consent in the RRR. However, the *Code of Conduct Regulation* ("CCR"), a regulation made pursuant to the EUA and *Gas Utilities Act*, contains "Division 2, Customer Information". Section 9 of the CCR provides that a "retailer" shall not disclose "customer information" except as permitted by section 10 of the CCR.

Section 10(3) of the CCR contains in subsection (m) the following provision:

> "10(3) Customer information about a customer may be disclosed without the customer's consent
>
> (m) for the purpose of collecting the customer's unpaid bill."

The CCR does not define "collecting". However, subsection 10(3)(l) provides the following:

> "10(3) Customer information about a customer may be disclosed without the customer's consent
>
> (l) for the purpose of billing the customer;"

Given the foregoing subsection 10(l) "collecting" and "billing" appear to be considered separate functions.

Advisory Opinion

Subject to the foregoing, the MSA is of the opinion that the Retailer may provide the Customer's "customer information" to the Default Supplier pursuant to subsection 10(3)(m) for the "purpose of collecting the customer's unpaid bill" within the meaning of the CCR. The MSA does not offer in this AO a definition of "collection" with the meaning of s. 10(3)(m) of the CCR.

6 ISO RULES COMPLIANCE

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

From January 1 to September 30, 2021 the MSA closed 337 ISO rules compliance matters, as reported in Table 9.[52] An additional 87 matters were carried forward to the next quarter. During this period 58 matters were addressed with NSPs, totalling $99,000 in financial penalties, with details provided in Table 10.

[52] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 337 closed matters, one matter was rejected and one matter was withdrawn.

Table 9: ISO rules compliance outcomes from January 1 to September 30, 2021

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.12	2	1	-
201.1	1	-	-
201.3	-	3	-
201.4	2	-	-
201.7	30	2	13
203.1	3	3	-
203.3	70	7	-
203.4	49	2	11
203.6	11	4	1
205.3	9	5	-
205.4	4	-	-
205.5	8	9	3
205.6	9	18	6
205.8	1	-	-
301.2	1	-	-
303.1	-	-	2
304.3	1	-	-
304.4	2	1	-
306.4	12	1	-
306.5	2	1	-
502.1	1	-	-
502.4	-	-	1
502.5	5	-	-
502.6	3	-	-
502.8	-	1	-
502.9	1	-	-
502.10	1	-	-
505.3	2	-	-
505.4	10	-	-
Total	240	58	37

Table 10: Specified penalties issued between January 1 and September 30, 2021 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)														Total ($)	Matters
	103.12	201.3	201.7	203.1	203.3	203.4	203.6	205.3	205.5	205.6	304.4	306.4	306.5	502.8		
ATCO Electric Ltd.												500			500	1
Balancing Pool									500						500	2
Campus Energy Partners LP								500							500	1
Canadian Hydro Developers, Inc.		250						500	500						1,250	3
Capital Power (Genesee) L.P.									250						250	1
Capital Power (Whitla) L.P.						750									750	1
CNOOC Marketing Canada / ENMAX Balzac LP					750										750	1
DAPP Power L.P.						1,500									1,500	1
Enel X Canada Ltd.										26,000					26,000	7
ENMAX Cavalier LP					750										750	1
ENMAX Generation Portfolio Inc.				1,000											1,000	2
Hut 8 Holdings Inc.								750							750	1
Millar Western Forest Products Ltd.										250					250	1
Milner Power Limited Partnership by its General Partner Milner Power Inc.				500									1,500		2,000	2
Morgan Stanley Capital Group Inc.							1,500								1,500	1
Northstone Power Corp.			1,000		2,250					750					4,000	5
Powerex Corp.							750								750	1
TA Alberta Hydro LP					5,000			2,000	500						7,500	4
TransAlta Corporation														500	500	1
TransAlta Generation Partnership	500	500			1,250				15,000		500				17750	6
TransCanada Energy Sales Ltd.							1,500								1500	2
Voltus Energy Canada Ltd.										26,500					26500	9
WCSB Power Holdings GP Ltd.									1,000						1000	2
West Fraser Mills Ltd.					750										750	1
Whitecourt Power Ltd.		500													500	1
Total	500	1,250	1,000	1,500	10,750	2,250	3,750	3,750	17,750	53,500	500	500	1,500	500	99,000	58

The sections of ISO rules listed in Table 9 and Table 10 are contained within the following categories:

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

7 ALBERTA RELIABILITY STANDARDS COMPLIANCE

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

The purpose of ARS is to ensure the various entities involved in grid operation (generators, transmission operators/owners, independent system operators, and distribution system operators/owners) are doing their part by way of procedures, communications, coordination, training and maintenance, among other practices, to support the reliability of the AIES. ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach with respect to compliance with ARS is focused on promoting awareness of obligations and a proactive compliance stance. The MSA has established a process that, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

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

From January 1 to September 30, 2021, the MSA addressed 63 O&P ARS compliance matters, as reported in Table 11.[53] An additional 27 matters were carried forward to the next quarter. During this period, eight matters were addressed with NSPs, totalling $11,250 in financial penalties, with details provided in Table 12. For the same period, the MSA addressed 213 CIP ARS compliance matters, as reported in Table 13,[54] and 57 matters were addressed with NSPs, totalling $144,250 in financial penalties. An additional 91 matters were carried forward to the next quarter.

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

[54] Of the 213 closed matters, one matter was rejected.

Table 11: O&P ARS compliance outcomes from January 1 to September 30, 2021

Reliability standard	Forbearance	Notice of specified penalty
COM-001	2	-
EOP-001	1	-
EOP-005	2	-
EOP-008	2	-
FAC-003	1	-
FAC-008	8	7
FAC-501-WECC	1	-
IRO-008	2	-
PER-003	1	-
PER-005	3	-
PRC-001	1	-
PRC-002	4	-
PRC-005	10	1
PRC-018	1	-
PRC-023	2	-
VAR-002	11	-
VAR-002-WECC	3	-
Total	55	8

Table 12: Specified penalties issued between January 1 and September 30, 2021 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)		Total ($)	Matters
	FAC-008	PRC-005		
AltaLink L.P., by its general partner, AltaLink Management Ltd.	2,250		2,250	1
Enmax Energy Corporation	2,250		2,250	2
MATL Canada L.P.	2,250		2,250	2
TransAlta Generation Partnership		2,250	2,250	1
Western Sustainable Power Inc.	2,250		2,250	2
Total	9,000	2,250	11,250	8

The ARS listed in Table 11 and Table 12 are contained within the following categories:

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

Table 13: CIP ARS compliance outcomes from January 1 to September 30, 2021

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	8	2	4
CIP-003	4	6	-
CIP-004	35	9	2
CIP-005	7	6	-
CIP-006	11	4	2
CIP-007	48	11	-
CIP-009	3	1	-
CIP-010	23	12	-
CIP-011	6	6	-
CIP-014	2	-	-
Total	147	57	8

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

CIP-002 BES Cyber System Categorization
CIP-003 Security Measurement Controls
CIP-004 Personnel & Training
CIP-005 Electronic Security Perimeter(s)
CIP-006 Physical Security of BES Cyber Systems
CIP-007 System Security Management
CIP-009 Recovery Plans for BES Cyber Systems
CIP-010 Configuration Change Management and Vulnerability Assessments
CIP-011 Information Protection
CIP-014 Physical Security