Quarterly Report for Q2 2021

August 13, 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 for Q2 2021 was $104.51/MWh, the highest since Q2 2013 and a 250% increase compared to Q2 2020. The higher pool prices year-over-year were driven by a number of factors including higher demand, generation outages, increased natural gas prices, low wind generation, and exceptionally hot weather in June. The offer behaviour of some larger suppliers was also a factor in the higher prices year-over-year as the remaining PPAs expired on December 31, 2020.

- Average demand over the quarter was 5.2% higher year-over-year as economic activity increased, oil prices continued to rise, and June saw record-breaking high temperatures. In June average demand was 10.5% higher year-over-year, and on June 29 hourly demand peaked at 11,721 MW, a new record for summer demand. This new summer demand record is 5% higher than the prior summer record, set in August 2018, and is only 0.1% less than the overall demand peak record, set in February 2021.

- The total cost of operating reserves was significantly higher in Q2 2021 compared to Q2 2020, and a principal driver behind this increase was the rise in pool prices. The AESO continues to buy more active spinning and supplemental reserves day-ahead when higher imports are expected, as opposed to activating standby in real-time. The underlying index prices for active spinning and supplemental were lower year-over-year, most notably for supplemental, as a result of increased competition. Battery storage providers have entered the active spinning market and provided 11% of dispatched spinning reserves.

- Trading volumes in the forward market were higher year-over-year but remain low compared to historical levels. Pool prices continued to be higher than forward prices, which has put upward pressure on forward prices for the balance of year. Forward prices for July and August increased significantly as weather forecasts have been predicting a hot summer and drought conditions in the Western US have increased forward prices in California and Mid-Columbia, implying Alberta may see reduced import supply.

- Forward prices for Calendar 2022 (CAL22) and CAL23 were up slightly over the quarter in part due to pool price volatility and higher forward prices for natural gas. CAL22 was priced at $68.25/MWh as of June 30 and CAL23 was priced at $57.00/MWh. The CAL24 and CAL25 contracts last traded on June 10 for $51.00/MWh and $50.75/MWh, respectively. Forward prices are decreasing into the future as natural gas, solar and wind generation developments are expected to increase supply and natural gas futures are quite low; 2023 and 2024 were priced around $2.40/GJ as of June 30.

- From April 1 to June 30, 2021, the MSA closed 112 ISO rules compliance matters; 23 matters were addressed with notices of specified penalty. For the same period, the MSA closed 20 Alberta Reliability Standards Operations and Planning compliance matters; two matters were addressed with notices of specified penalty. In addition, the MSA closed 56 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; nine matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly Summary

The average pool price in Q2 2021 was $104.51/MWh, which is 9.5% higher than in Q1 2021 and an increase of 250% compared to Q2 2020. The higher pool price in Q2 2021 was partly driven by increased demand, particularly in June, higher natural gas prices, more generation outages, and higher generator offer prices compared to Q2 last year. There has been no indication that the pool prices in Q2 2021 were the result of anticompetitive conduct.

Table 1 provides summary market statistics for Q2 2021 compared to Q2 2020. The demand for electricity compared to last year increased over the quarter as oil prices increased, public health measures were reduced, and exceptionally hot weather prevailed on some days in June.

Table 1: Monthly market summary for Q2

		2021	2020	*Change*
Pool Price (Avg $/MWh)	Apr	87.99	28.92	*204%*
	May	85.39	26.39	*224%*
	Jun	140.80	34.51	*308%*
	Q2	**104.51**	**29.90**	***250%***
Demand (AIL) (Avg MW)	Apr	9,088	9,091	*0.0%*
	May	8,961	8,503	*5.4%*
	Jun	9,653	8,739	*10.5%*
	Q2	**9,231**	**8,775**	***5.2%***
Gas Price AB-NIT (2A) (Avg $/GJ)	Apr	2.65	1.89	*40%*
	May	2.93	1.98	*48%*
	Jun	3.23	1.79	*80%*
	Q2	**2.94**	**1.89**	***55%***
Wind (Avg MW)	Apr	621	652	*-5%*
	May	517	598	*-14%*
	Jun	524	637	*-18%*
	Q2	**554**	**629**	***-12%***
Net Imports (+) Net Exports (–) (Avg MW)	Apr	543	280	*94%*
	May	587	592	*-1%*
	Jun	479	592	*-19%*
	Q2	**537**	**489**	***10%***
Supply Cushion (Avg MW)	Apr	1,826	2,242	*-19%*
	May	1,622	2,147	*-24%*
	Jun	1,747	1,932	*-10%*
	Q2	**1,731**	**2,107**	***-18%***

In May average demand was 5.4% higher than May last year even though average temperatures were very comparable. The average price of WTI in May increased to US$65.16/bbl, an increase of 128% relative to May 2020.[1]

Oil prices increased further in June as WTI averaged US$71.35/bbl and average temperatures were 18.5°C, or 3.7°C higher than June 2020, as a number of hot days increased cooling demand. On average, demand was 10.5% higher in June compared to June 2020.

On Tuesday, June 29 in HE14 demand peaked at 11,721 MW, a new summer record. This new peak is 5% higher than the previous summer record, set in August 2018, and is only 8 MW (0.1%) below the winter record set in February 2021.

Natural gas is the primary fuel used by a significant proportion of generators in Alberta and consequently it is an important cost driver for the market. The price of natural gas in Alberta is becoming increasingly relevant as coal generators continue to convert to run on natural gas. The planned outage at Keephills 2, which started in mid-March and concluded in late May, was for a

[1] EIA NYMEX Futures Prices – Contract 1

coal-to-gas conversion. Shepard, a large combined-cycle gas unit, also took a planned maintenance outage in Q2 and was offline from early April to mid-May, reducing supply and putting upward pressure on pool prices during this time.

The average price of natural gas was 55% higher in Q2 2021 compared to Q2 2020, partly as a result of more demand for liquefied natural gas (LNG) exports and lower US shale production. In addition, demand for natural gas has increased in response to greater economic activity compared to last year, coal retirements and conversions, the intermittent generation of renewable capacity, and abnormally high temperatures in June.

Average wind generation in Q2 was 554 MW, a reduction of 12% compared to Q2 2020, and the overall capacity factor of wind generation fell from 35% in Q2 last year to 31% in Q2 2021 (Table 2). Wind generation is an intermittent resource and its total supply can vary meaningfully from one hour to the next. Low wind generation was a factor in higher pool prices on a number of days in Q2 2021. Consequently, total wind generation received an average price of $69.09/MWh, 34% less than the average quarterly pool price of $104.51/MWh.

Table 2: Average wind generation and capacity factor (Q2 2021 and Q2 2020)[2]

	2021		**2020**	
	Avg Wind Gen.	**Capacity Factor**	**Avg Wind Gen.**	**Capacity Factor**
Apr	621	35%	652	37%
May	517	29%	598	34%
Jun	524	29%	637	36%
Q2	**554**	**31%**	**629**	**35%**

Year-over-year, the higher pool prices incentivized more imports into Alberta as average net imports were 10% higher in Q2 2021 compared to Q2 2020. During high pool price hours the supply of imports on BC/MATL is often constrained to around 600 to 700 MW due to the availability of Load Shed Service for imports (LSSi). In June import volumes were slightly lower on average due to a transmission outage on the Saskatchewan intertie from May 31 to June 11, and on June 3 the BC/MATL intertie tripped offline before returning to service on June 5. In addition, there were reduced imports and some exports in mid-June as Alberta pool prices lowered and prices increased in Mid-Columbia and California.

[2] A new wind asset is included in the capacity factor calculation once the asset has delivered electricity to the grid.

1.2 Market outcomes

The average pool price of $104.51 in Q2 2021 was the highest quarterly pool price since Q2 2013, which settled at $123.41/MWh. Figure 1 provides the quarterly average pool price going back to Q1 2001. As shown, pool prices have been materially higher so far this year compared to pool prices in the 2015 to 2020 period when the addition of Shepard, reduced demand, and the termination of the PPAs all served to put downward pressure on pool prices at times.

Figure 1: Average pool price by quarter (Q1 2001 to Q2 2021)[3]

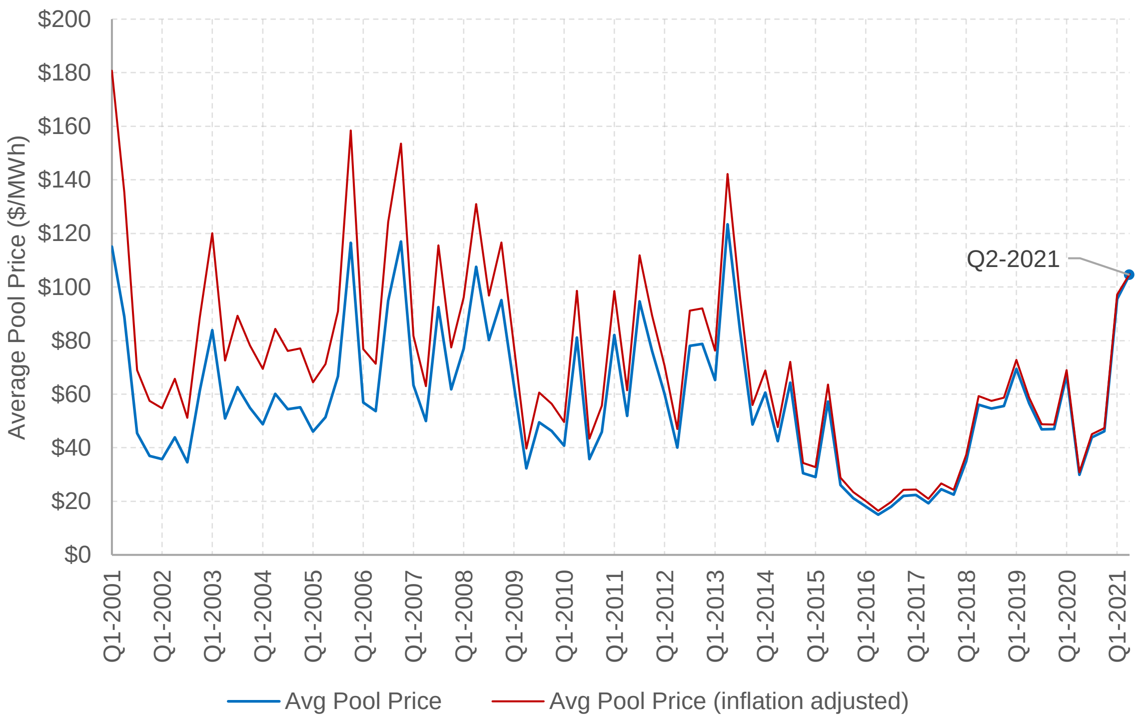


Figure 2 illustrates the daily average pool price over Q2 2021. As shown, pool prices were volatile on a number of days within each month but pool prices were highest in early and late June. This price volatility pushed the average price of June up to $140.80/MWh, compared to $87.99/MWh in April and $85.39/MWh in May. The average price for June 2021 was the highest price for the month of June going back to 2001; the previous high was set at $104.77/MWh in June 2013. As discussed in this section, there were a number of factors that caused higher pool prices in Q2.

Outages at thermal generation units reduced available capacity and put upward pressure on pool prices in Q2 2021. Table 3 provides the average amount of thermal capacity on outage by month in Q2 2021 compared to Q2 2020. In April and May of 2021 the average amount of thermal capacity on outage was approximately 800 MW higher than the same month last year. The increased outages in April and May were partly driven by planned outages at Shepard and Keephills 2.

---

[3] 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 2: Daily average pool prices (April 1 to June 30, 2021)

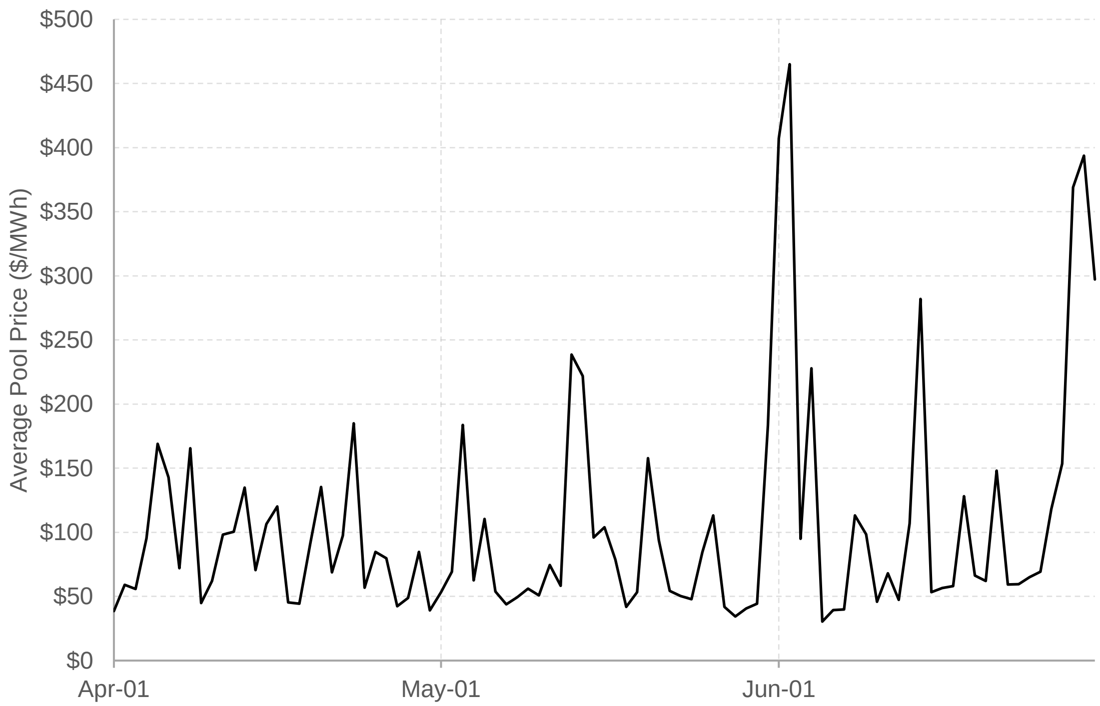


Table 3: Average thermal capacity on outage (MW) by month (Q2 2021 and Q2 2020)[4]

	2021			2020		
	Coal or Conv. Coal	**Gas**	**Total Thermal**	**Coal or Conv. Coal**	**Gas**	**Total Thermal**
April	612	2,187	2,800	383	1,625	2,008
May	723	2,290	3,012	177	2,006	2,183
June	492	2,176	2,668	329	2,055	2,384

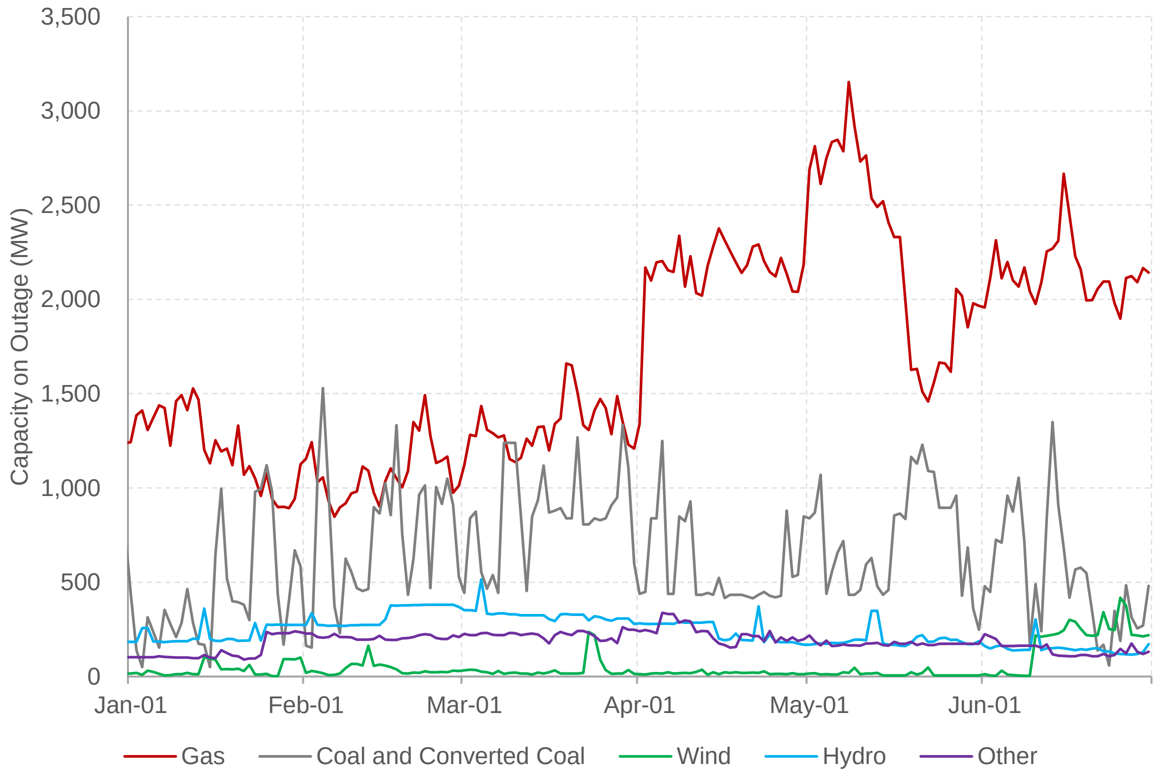
The Shepard asset is an 868 MW combined-cycle asset which was on outage from April 2 to mid-May. It is a large, efficient, and low-cost asset that normally supplies a substantial amount of generation to the grid. Therefore, the long outage at this asset reduced supply significantly during this time. The elevated amount of gas capacity on outage as a result of the Shepard outage is shown in Figure 3.

Keephills 2 is a 395 MW asset that was offline from March 12 to May 28 in order to undergo a coal-to-gas conversion. This conversion process involves modifying certain parts of the existing asset, such as the boilers, fans, and control systems, while adding new equipment, including

[4] Converted coal includes dual fuel and gas-fired steam assets. The capacity on outage includes partial outages or derates. This analysis excludes the capacity of Sundance 3 and Sundance 5. Sundance 3 was mothballed from April 2018 to its retirement on July 31, 2020. Sundance 5 has been mothballed since April 2018.

natural-gas burners, igniters, scanners, piping, and valves, so that the asset can produce the steam used to generate electricity with gas rather than coal.[5] Burning gas rather than coal generally reduces carbon emissions by approximately 50%.

Figure 3: Daily average of generation capacity on outage (January 1 to June 30, 2021)



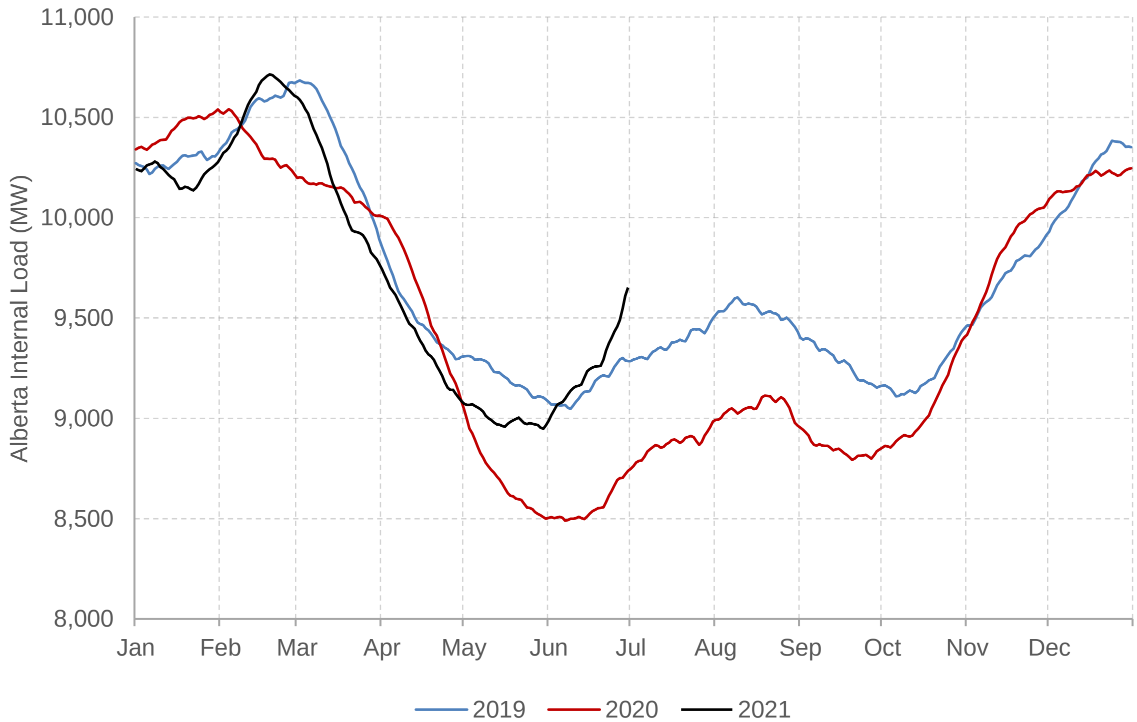
The planned outages at Shepard and Keephills 2 combined with some higher generator offer prices meant that pool prices often increased in response to further reductions in supply, such as low wind generation or more generation outages, during the peak hours of April and early May. For example, the daily average price was $238.66/MWh on Thursday, May 13, partly as a result of low wind generation, an outage at dual fuel asset from HE10 to HE14, and a coal asset and a dual fuel asset being offline commercially. The pool price on May 13 peaked at $787.09/MWh in HE20 when 1,220 MW of thermal generation capacity was priced above $100/MWh.

Figure 4 shows how demand in 2021 has trended compared to 2019 and 2020. As shown, demand in 2021 has been more aligned with 2019, and this is partly a function of prevailing temperatures. February was the main cold month in both 2019 and 2021 whereas in 2020 January was the colder month. In addition, there were cold periods in mid-March and early April of 2020 which increased demand during this period.

---

[5] TransAlta Website: Coal to gas

Figure 4: 30-day rolling average of demand (2019-2021)



The steep demand decline to the lows seen in the spring of 2020 was largely the result of the COVID-19 pandemic and the related public health measures and lower oil prices. In May 2020, the average price of WTI was US$28.53/bbl, after falling to negative US$37.63/bbl on April 20, 2020. In May 2021 WTI oil prices averaged $65.16/bbl, a 128% increase compared to last year, and slightly above the average price of US$60.77/bbl in May 2019. In addition, demand in Q2 2021 has trended above 2020 because economic activity has increased as public health measures were reduced and the economy started to recover.

In early June 2021 demand increased due to higher temperatures. On Sunday, June 1 the temperature in Calgary peaked at 27°C and on June 2 and June 3 the highs were 30°C and 32°C, respectively. As a result, peak demand increased to around 10,300 MW on the Sunday and 10,600 MW on the Monday and Tuesday, well above the demand peaks seen earlier in Q2 (Figure 5).

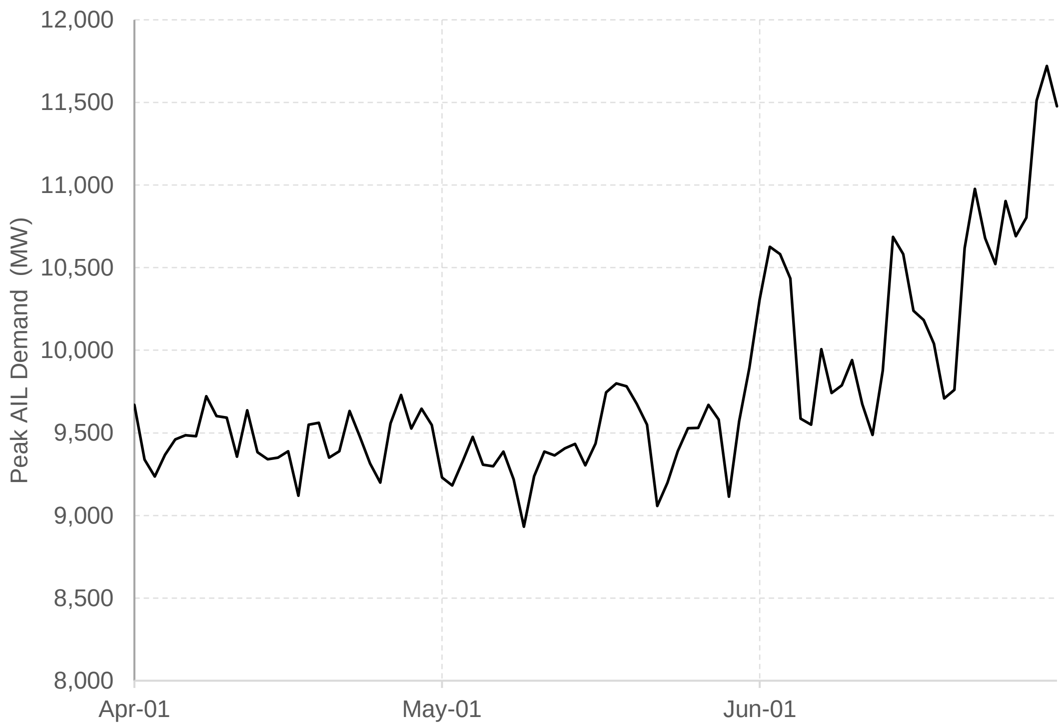
The same weather patterns that cause high temperatures also tend to reduce wind speeds in Alberta and wind generation was low on June 1 and 2 when wind generation averaged 207 MW during peak hours, a capacity factor of 12%. The higher temperatures also reduce the available capacity on a lot of thermal generators, further decreasing supply.

In early June a number of gas assets were completely offline for operational reasons, accounting for 329 MW of maximum capability. In addition, a 400 MW coal asset was operationally offline on June 1 and returned to service in HE10 of June 2. Another coal asset was commercially offline on June 1 and had operational issues starting up on the morning of June 2, so consequently it was offline for operational reasons during most of the peak hours of June 2. At approximately

16:20 on June 2 two converted coal assets at the same site tripped offline simultaneously, reducing the available capacity by 800 MW.

As a result of the higher demand and supply constraints, the daily average pool price was $407.24/MWh on June 1 and $465.03/MWh on June 2. Between 17:25 and 17:33, and from 19:36 to 20:20 on June 2 the System Marginal Price (SMP) rose to the offer price cap of $999.99/MWh.

Figure 5: Daily peak AIL demand (April 1 to June 30, 2021)



The higher prices had the potential to continue into June 3 as demand peaked at 10,581 MW due to high temperatures and a 400 MW coal asset remained offline operationally. In addition, the BC/MATL intertie tripped offline in HE15, meaningfully reducing supply and causing the AESO to utilize 103 MW of LSSi and around 177 MW of under frequency load shedding (UFLS) to maintain reliability. However, wind generation increased in the afternoon of June 3 and was supplying 860 MW during the demand peak. The daily average pool price for June 3 was $95.10/MWh.

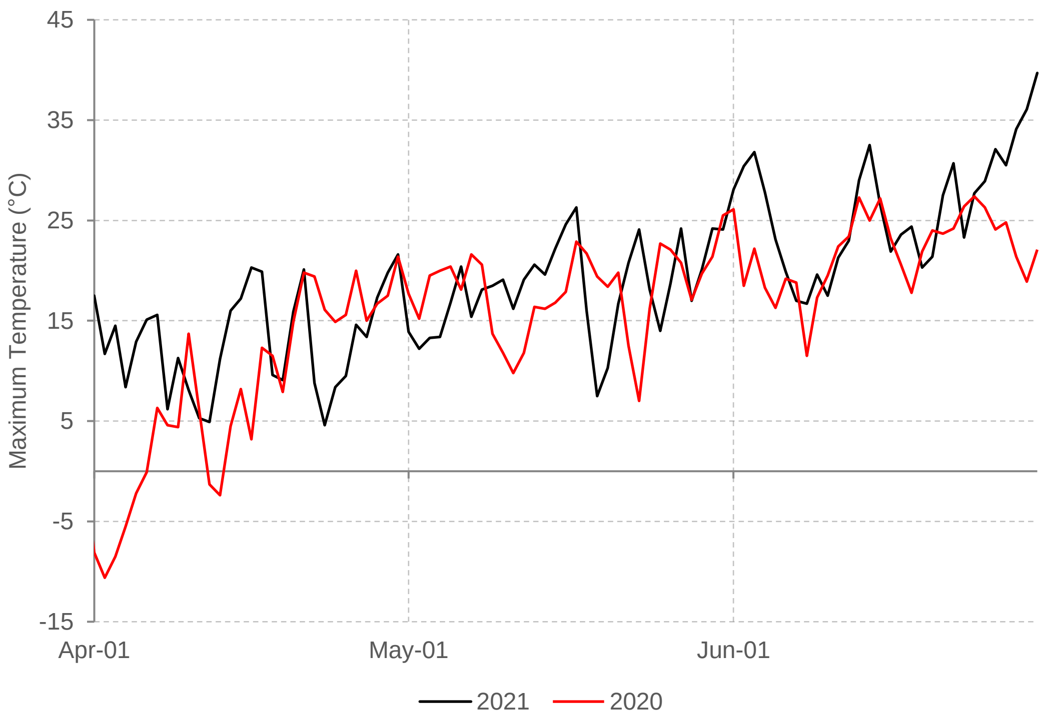
On the last three days of June temperatures in Alberta were exceptionally high (Figure 6). Hourly temperatures during this period peaked at 36.1°C in Calgary, 36.6°C in Edmonton, and 39.7°C in Fort McMurray. A number of temperature records were set across the province during this period.

As a consequence of the weather, demand peaked at 11,721 MW during HE14 of June 29. This new summer demand peak is 5% higher than the previous record which was set on August 10, 2018. In addition, the summer peak was only slightly below the record for winter demand, which was set during the cold weather in February 2021 (Table 4). The substantial increase in the peak summer demand is a result of increased demand for air conditioning and cooling loads in Alberta as more units are installed and also as businesses and offices have reopened but many residents are still working from home and utilizing air conditioners. In addition, the Alberta economy is in the process of recovering as public health measures are reduced and oil prices have increased.

Table 4: AIL peak demand records and market statistics [6]

	Winter Peak	Prior Summer Peak	Summer Peak
Date	Feb 9, 2021 (Tue)	Aug 10, 2018 (Fri)	Jun 29, 2021 (Tue)
HE	19	15	14
AIL Demand (MW)	11,729	11,169	11,721
Pool Price ($/MWh)	$567.60	$919.05	$639.29
Calgary temp (°C)	-26	35	34
Supply Cushion (MW)	1,493	399	262
Wind generation (MW)	287	302	205
Solar generation (MW)	0	10	275

Figure 6: Maximum daily temperature (Q2 2021 and 2020)[7]



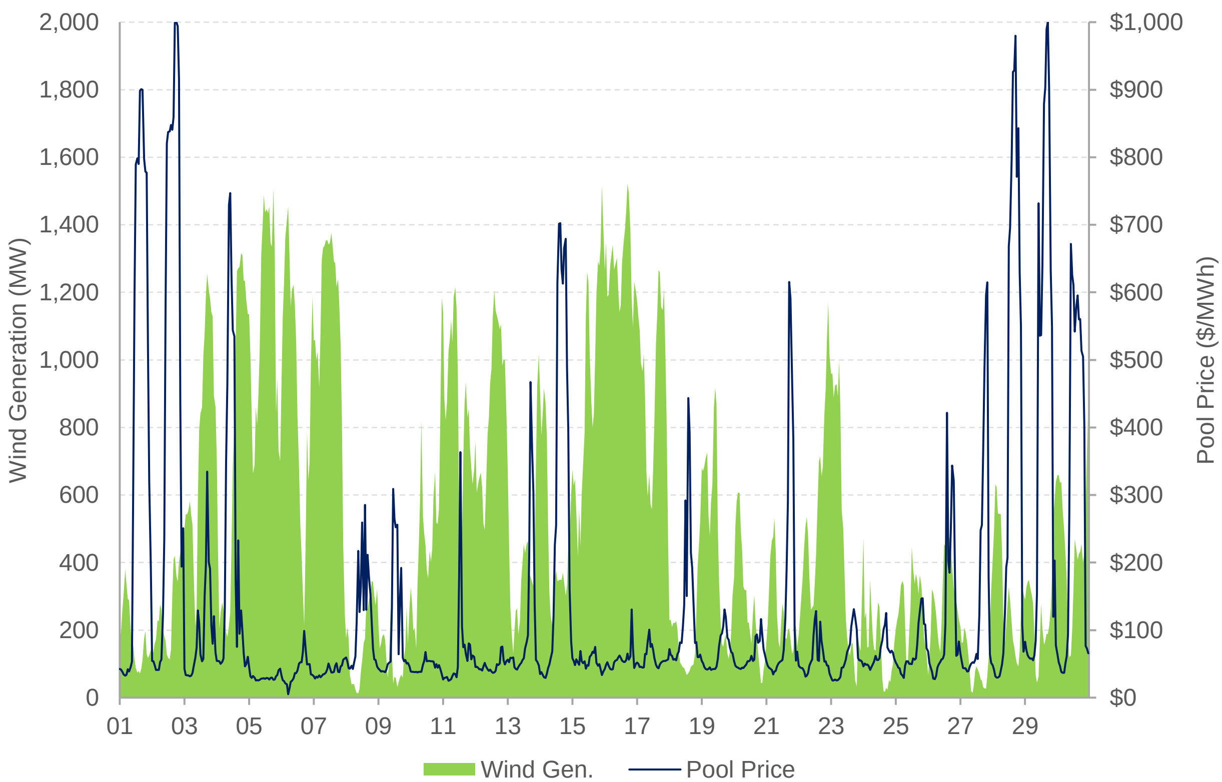
Pool prices peaked at $979.67/MWh on June 28 with the daily average price settling at $369.05/MWh. Demand peaked at 11,512 MW in HE17, a new summer record at the time. On the supply-side, there were no major thermal outages but some capacity was derated as a result

[6] Wind and solar generation figures only include assets greater than or equal to 5 MW (i.e., are or were listed on the AESO's Current Supply and Demand page).

[7] Uses the maximum of hourly temperatures in Calgary, Edmonton, and Fort McMurray.

of the high temperatures. Wind generation was low, averaging 150 MW during the demand peak hour, a capacity factor of 8%. The supply of solar generation was 253 MW during the peak demand hour, a capacity factor of 87%. The SMP increased to the offer price cap of $999.99/MWh from 17:22 to 18:00 but no alert was issued by the AESO, indicating the AESO was using almost all capacity available in the energy supply curve at the time.

Figure 7: Hourly pool price and wind generation (June 2021)



On June 29 demand increased further to peak at 11,721 MW in HE14, 209 MW higher than the day before. Overall, market conditions on June 29 were similar to those seen on June 28. Wind generation supplied 205 MW during the demand peak, a capacity factor of 12% and solar generation supplied 275 MW, a capacity factor of 95%. Aside from temperature-induced derates, the availability of thermal generators was high with no significant outages. Indeed, the high supply of thermal generation was essential to the market meeting the record summer loads on both June 28 and 29.

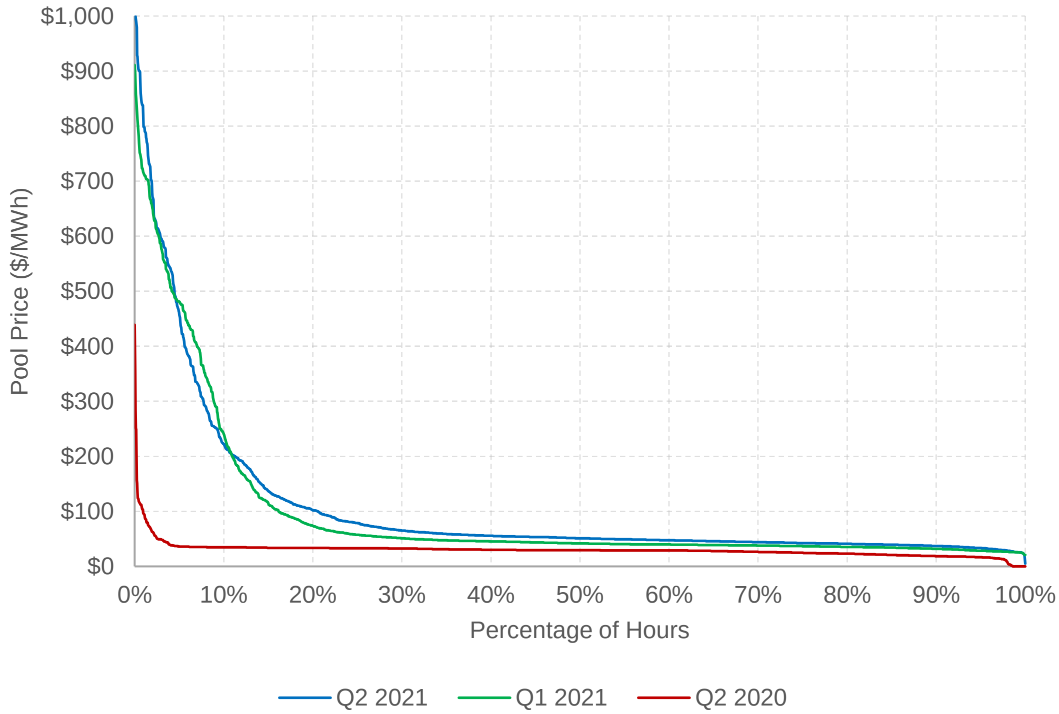
At 16:19 on June 29 the SMP increased to $999.99/MWh and at 16:34 the AESO declared an Energy Emergency Alert 1 (EEA1) indicating that all capacity in the energy market was fully dispatched. At 18:09 the AESO ended the EEA1 and the SMP subsequently fell to $991.91/MWh.

1.2.1 Distribution of pool prices

Figure 8 illustrates the distribution of pool prices in Q2 2021 compared to Q1 2021 and Q2 2020. As shown, the distribution of high-priced hours in Q2 2021 was similar to that seen in Q1 2021. In contrast, the year-over-year comparison reflects the factors discussed above, with significantly more high-priced hours observed in Q2 2021 relative to Q2 2020. For instance, in Q2 2021 the top 10% of hours settled at a pool price of greater than $222/MWh compared to $35/MWh in Q2 2020. There has been no indication that the pool prices in Q2 2021 were the result of anticompetitive conduct.

The average pool price in the top 10% of hours in Q2 2020 was $55/MWh and these hours contributed 19% to the quarterly average price. In Q2 2021, the top 10% of hours averaged $494/MWh and contributed 47% to the quarterly average. This illustrates that relatively few high-priced hours were a principal driver of the average pool price in Q2 2021.

Figure 8: The distribution of pool prices (Q2 2021, Q1 2021, and Q2 2020)

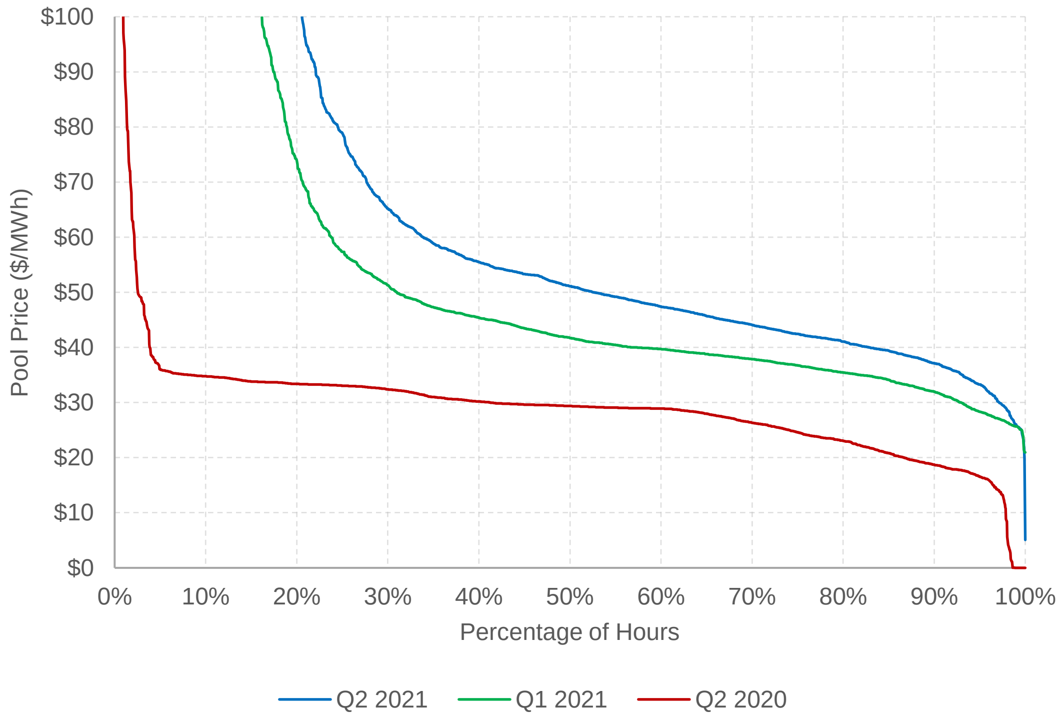


As discussed above, there were three instances in which the SMP increased to the offer price cap of $999.99/MWh in Q2; on June 2, 28, and 29. There was one hour in which SMP was at the offer cap for the entire hour and the pool price settled at $999.99/MWh: June 29 HE18. Prior to Q2 2021, the last time the SMP reached the offer price cap was on January 16, 2020.

The lowest pool price in Q2 2021 was $5.07/MWh and this occurred in HE06 of June 6 when demand was 8,417 MW, wind generation was 1,454 MW, and imports were 531 MW. In contrast to Q2 2020, there were no supply surplus events in Q2 2021 as demand increased, wind generation was less on average, and the minimum stable generation (MSG) of some assets was lower.

Figure 9 shows the same distribution analysis but only for pool prices up to $100/MWh. As shown, the low-priced hours in Q2 2021 were also higher compared to Q2 2020. This is largely due to higher demand, higher gas prices, a higher carbon price, and less wind generation on average. In addition, Q2 2021 saw more thermal outages, less wind generation, and fewer imports compared to Q1 2021 and these were factors driving the increase from Q1 2021 shown in Figure 9.

Figure 9: The distribution of pool prices up to $100 (Q2 2021, Q1 2021, and Q2 2020)



1.3 Offer behaviour

As discussed in the MSA's Q1 2021 Quarterly Report, 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, which has put upward pressure on pool prices. As shown by Figure 10, the year-over-year change in offer behaviour continued into Q2 2021.

The figure illustrates the percentage of available coal and converted coal capacity that was offered at or below a given price. For example, in Q2 2021 90% of available coal and converted coal capacity was offered below $616/MWh and 10% was offered at or above $616/MWh. In Q1 2021 the 90th percentile was at a similar offer price of $634/MWh. In contrast, during Q2 last year the 90th percentile was significantly lower at $35/MWh, and only 0.24% of available coal and converted coal capacity was offered above $616/MWh.

Figure 10: Duration curves of offer prices on available coal and converted coal capacity[8]

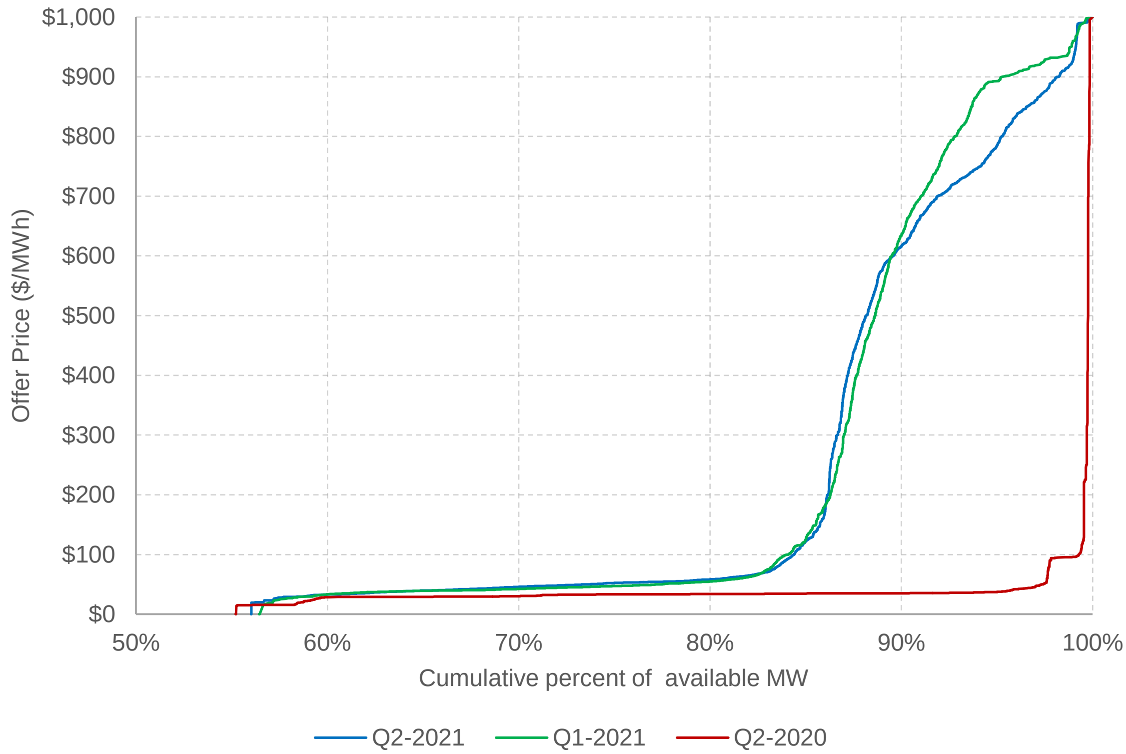


Figure 11 illustrates a scatterplot of pool price and supply cushion for the hours in Q2 2021 and Q2 2020. The supply cushion is a summary measure of supply-demand conditions in the energy market at a particular point in time. The supply cushion shows how much available generation capacity the market has above that which is required to meet prevailing demand.

For a given supply cushion, pool prices were generally higher in Q2 this year, and this is partly driven by cost-drivers such as the higher price of natural gas and the increase in the carbon price. In the supply cushion range from 500 MW to 2,000 MW there were some hours in Q2 2021 that had a much higher pool price compared to last year. For instance, the average price of hours that had a supply cushion of between 1,000 MW and 1,500 MW in Q2 2020 was $35.60/MWh compared to $127.14/MWh in Q2 2021. As a result of higher offer prices, elevated pool prices have been observed for hours with a relatively large supply cushion. This general change in offer behaviour has been observed following the expiration of the remaining PPAs on December 31, 2021.

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

Figure 11: Scatterplot of pool price and supply cushion (Q2 2021 and Q2 2020)

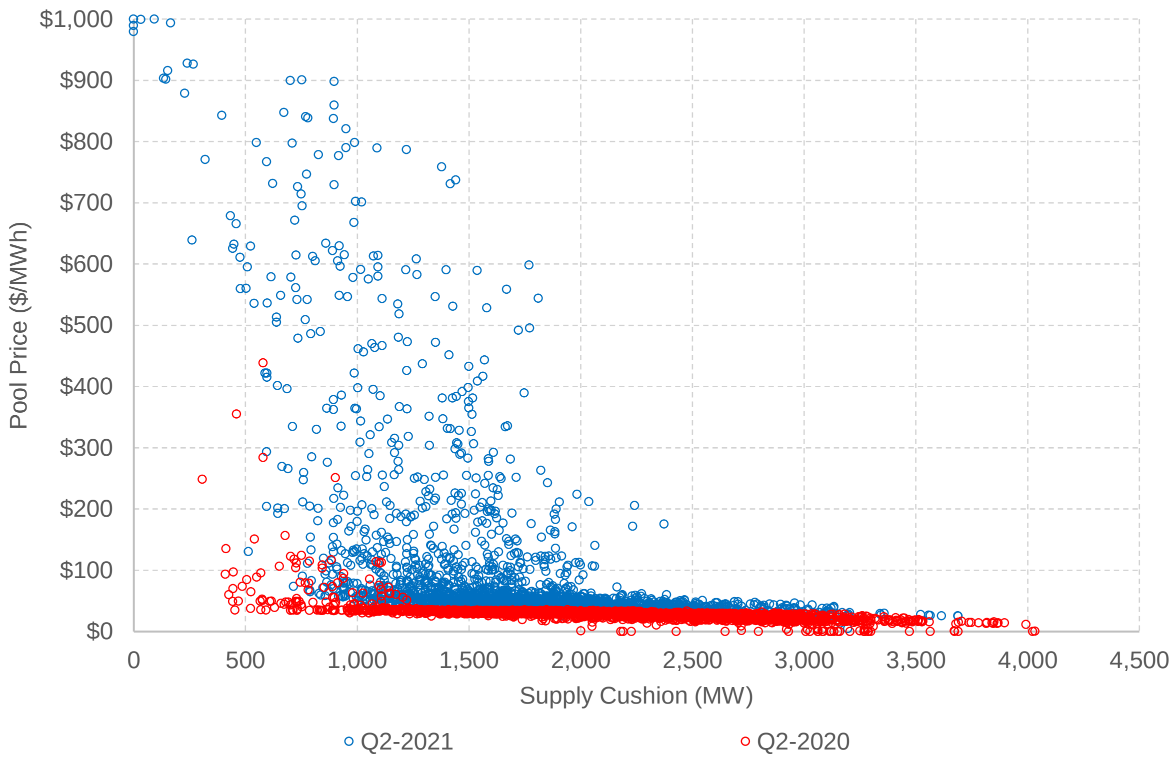


Figure 12: Coal and converted coal capacity commercially offline coincident with the daily maximum pool price (Q2 2021)

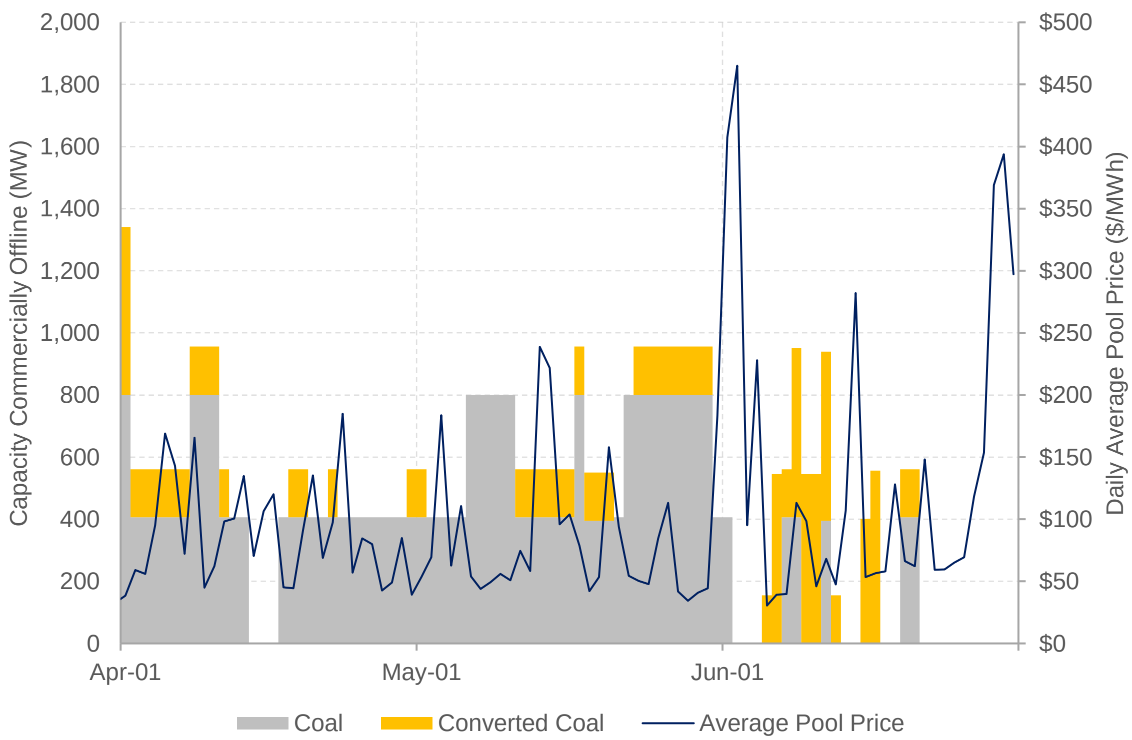


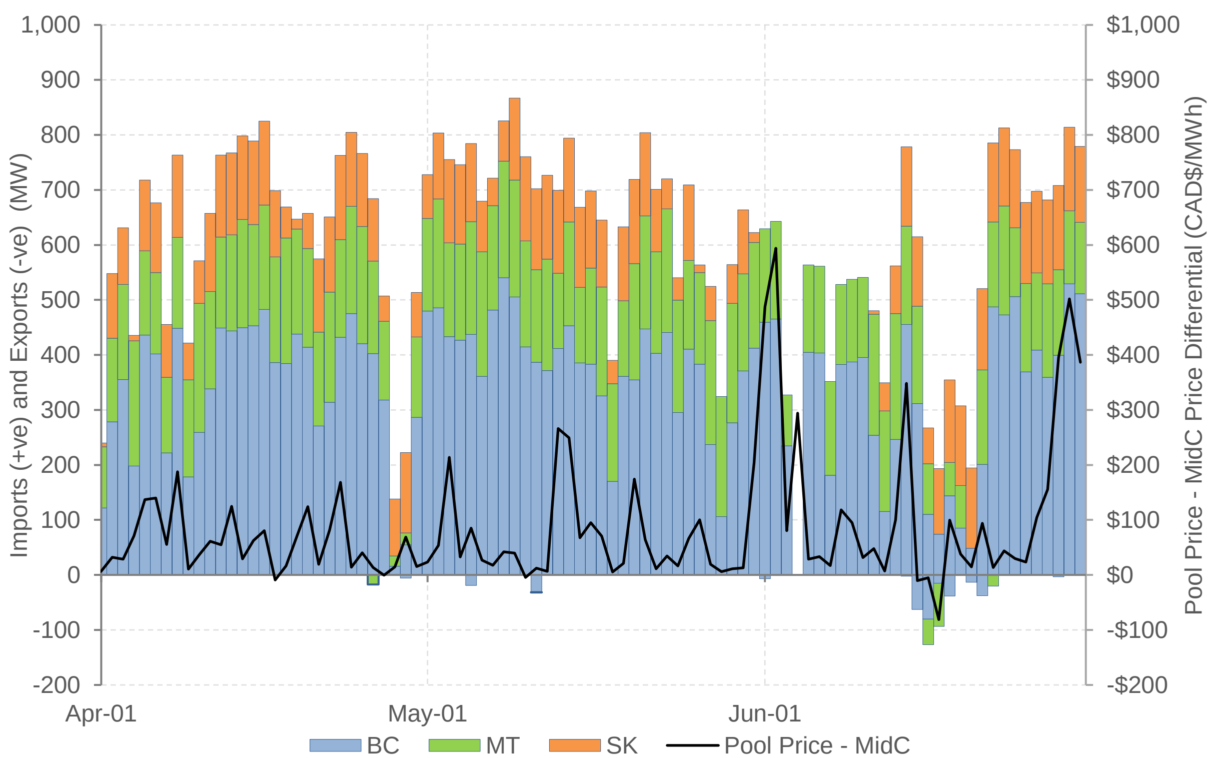
Figure 12 shows the amount of coal and converted coal capacity that was commercially offline over Q2 2021. These large thermal assets were taken commercially offline and were not immediately available for dispatch by the AESO due to start-up time requirements. The analysis does not include mothballed capacity. In April and May one coal asset and one dual fuel asset were often commercially offline as pool prices averaged $87.99/MWh in April and $85.39/MWh in May. On May 13 these two assets were commercially offline as pool prices averaged $238.66/MWh. The coal asset was also offline on June 1 when the pool price spiked to $900.66/MWh and the daily average price was $407.24/MWh. No assets were commercially offline in late June when high temperatures increased cooling demands substantially.

1.4 Interties

The average volume of net imports into Alberta increased by 10% year-over-year as pool prices in Q2 2021 were materially higher than in Q2 2020. The utilization of available import capacity was 89% when pool prices were above $100/MWh, indicating that in most higher-priced hours imports were flowing into Alberta to the extent the transmission capacity was available.

Figure 13 illustrates daily average imports and exports during peak hours (HE08 to HE23). The black line on the figure illustrates the average price differential between Alberta and Mid-Columbia (Mid-C) during peak 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 Q2 2021 was imports flowing into Alberta as pool prices were often relatively high.

Figure 13: Daily average imports (+ve) and exports (-ve) and the AB – Mid-C price differential, peak hours (Q2 2021)



On some days in Q2 there were transmission outages that restricted the flow of power between jurisdictions. On April 28 and 29 the BC/MATL intertie was unavailable for a number of peak hours for scheduled work. On May 31 the Saskatchewan intertie was taken offline in HE15 for planned transmission work and did not return to service until HE20 of June 11.

Furthermore, the BC/MATL intertie tripped offline in HE15 of June 3 sending system frequency down to 59.4 Hz, and AIL demand dropped by approximately 525 MW in 3 minutes as the AESO utilized 103 MW of LSSi and around 177 MW of under frequency load shedding (UFLS). The BC/MATL intertie returned to service in HE02 of June 5.

On some days in mid-June the volume of imports into Alberta was reduced as the price differential lowered (Figure 13), and in some hours exports occurred as prices were elevated in neighbouring markets. On June 15 real-time prices peaked at CAD$543/MWh at the SP15 hub in California and on June 17 Mid-C prices peaked at CAD$288/MWh.

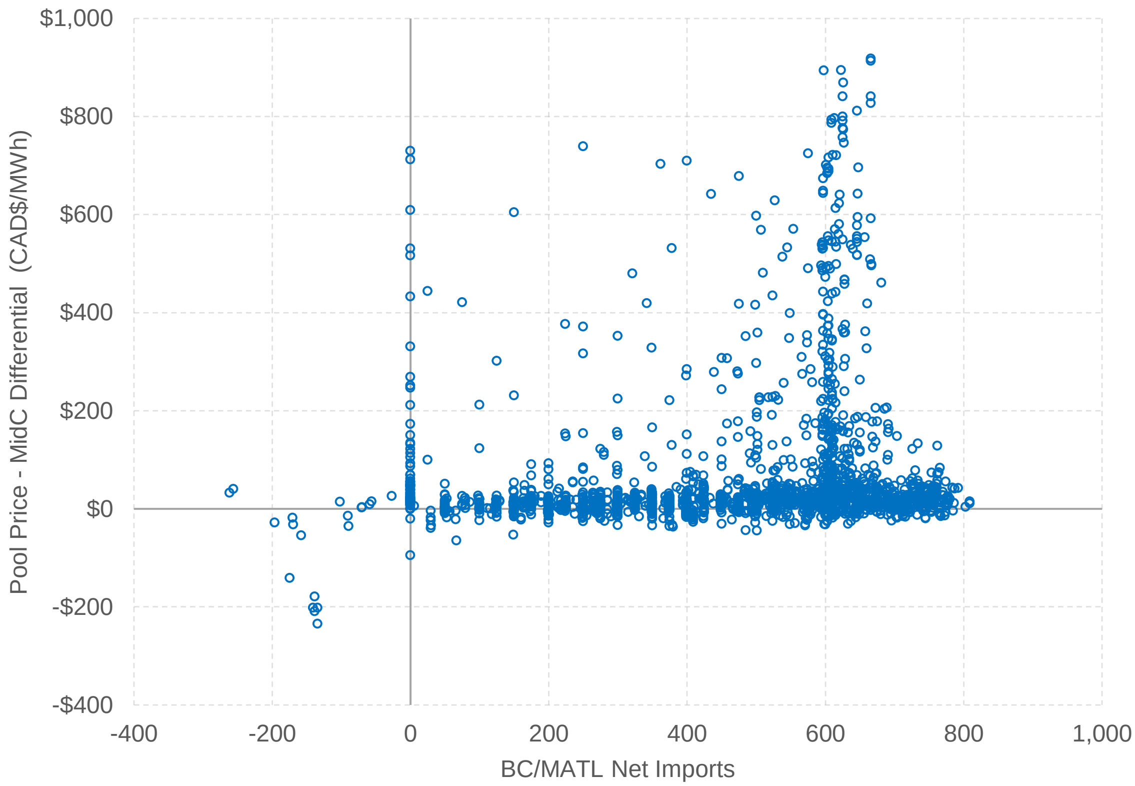
1.4.1 BC/Montana Intertie

Figure 14 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.

In hours when the Alberta pool price was materially higher than Mid-C, there were generally 600-700 MW of imports. Import transmission capacity during high pool price hours is often constrained by the availability of LSSi. The availability of LSSi can decline when pool prices are high because some LSSi providers are price-responsive loads that reduce their consumption when prices rise. This explains why higher levels of imports are often feasible at lower pool prices (Figure 14).

In some hours with a high price differential net imports are well below the typical 600-700 MW level. This was sometimes caused by the transmission constraints discussed above, and on other occasions traders may not have anticipated the higher pool prices. For example, on April 4 at around 9:37 p.m. two large converted coal assets at the same site tripped offline simultaneously. Prior to these trips the SMP was $65.00/MWh but prices soon increased materially, and the pool prices for HE23 and HE24 settled at $767/MWh and $630/MWh, respectively. Since offers for a delivery hour cannot be changed within two hours of the beginning of the hour, imports were not able to respond immediately and net imports on BC/MATL were only 250 MW in HE23 and 150 MW in HE24.

Figure 14: Scatterplot of BC/MATL net imports and the Alberta – Mid-C price differential (Q2 2021) [9]



1.4.2 Load Shed Service for imports (LSSi)

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

Figure 15 illustrates LSSi volumes and total cost by month, alongside import and export volumes. The total cost of LSSi in Q2 2021 was $9.3 million, a 20% reduction compared to Q1 2021 as import volumes fell. Compared to Q2 2020 the total cost of LSSi increased by 24% as import volumes increased. This was most notable in April when costs rose by 158% year-over-year as imports rose materially and the AESO armed much more LSSi. In May 2021 the AESO armed more LSSi compared to May 2020 despite a lower volume of imports and this was partly driven by the increased LSSi requirements.

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

Figure 15: BC/MATL import and export volumes, LSSi volumes, and LSSi costs by month (April 2020 to June 2021)

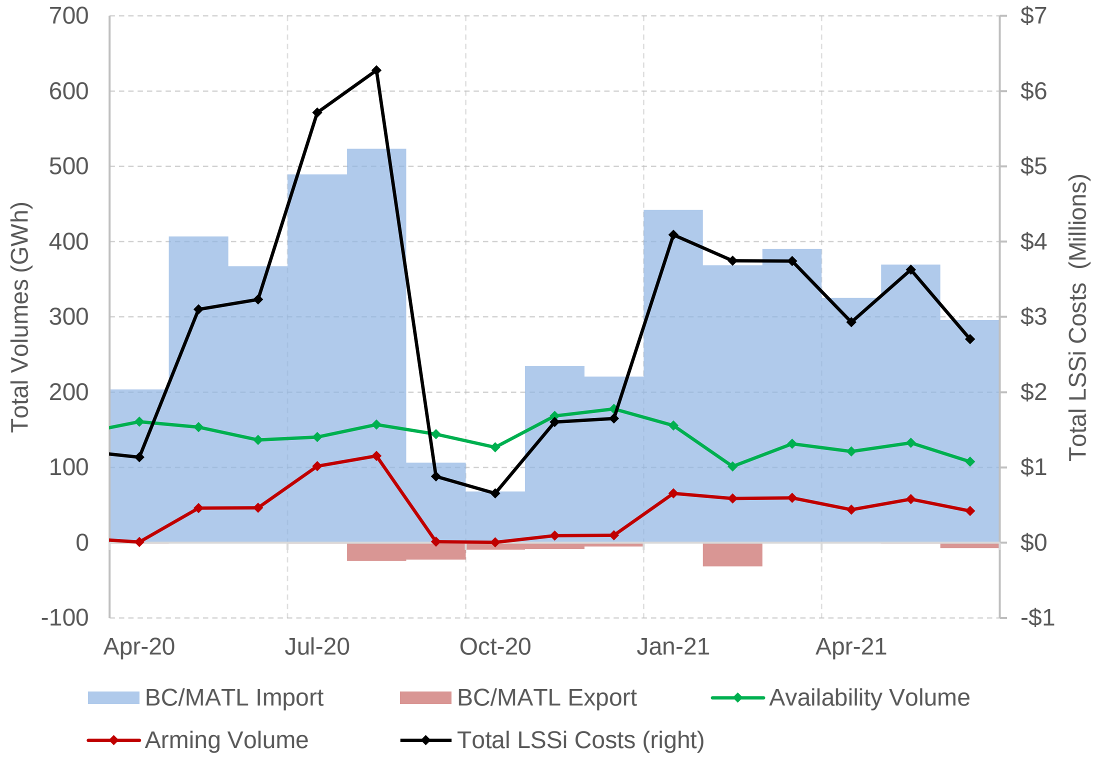


Table 5 shows the average availability of LSSi in Q1 and Q2 2021. In hours when the pool price was under $100/MWh in Q1 2021, the average amount of LSSi available to the AESO was 198 MW. In higher priced hours the available volume of LSSi was lower, 85 MW on average or 57% lower. In Q2 2021 the same trend was evident; in hours when the pool price was greater than or equal to $100/MWh the availability of LSSi fell by 46% compared to lower priced hours.

This pattern occurs because some LSSi providers are price-responsive loads that reduce their consumption when pool prices are relatively high and therefore they are not in a position to offer LSSi at these times.

Table 5: Average LSSi available and armed volumes, by pool price (Q2 and Q1 2021)

	Q1 2021		**Q2 2021**	
	PP < $100	**PP >= $100**	**PP < $100**	**PP >= $100**
Armed (MW)	102	66	75	79
Available (MW)	198	85	183	99
Utilization (%)	51%	78%	41%	80%

The AESO recently procured LSSi for the period of January 2022 through December 2024. As announced, they bought 366 MW from seven providers, an increase of 36 MW from the current period.

For this procurement cycle, the AESO fixed availability payments at $6/MWh and will continue to pay $1,000/MW if an asset providing LSSi is tripped. Bidding LSSi suppliers competed for contracts based on their arming cost offers in $/MWh. The LSSi contracts in effect between January 2019 and December 2021 are based on a procurement process that allowed bidding for both availability and arming payments. The total volume under contract until December 2021 is 330 MW.

1.5 Information sharing among market participants

Offer and operational information is generally not shared between market participants. Section 3(1) of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation) prohibits sharing between market participants of information related to past, current, or future price and quantity offers made to the power pool or for the provision of ancillary services. However, there are cases where such information needs to be shared. Some of these cases are listed as exemptions under section 3(2) of the FEOC Regulation. Other situations are not exempted and require an order from the Alberta Utilities Commission (AUC) to share such information. These situations include:

- Appointment of an agent: Market participants may contract with an agent to conduct the real-time operations for one or more assets. This arrangement would require the agent and the market participant to share past, current, and future price and quantity pair information, which would be submitted by the agent to the AESO.

- Joint ventures: Some market participants have joint venture agreements for certain generation assets. Information related to the operation of the asset, including the scheduling of outages, needs to be shared between the parties in a joint venture.

To accommodate the need to preferentially share information in the circumstances outlined above, the AUC may issue an order permitting the preferential sharing of information under section 3(3) of the FEOC Regulation. In applying for an order under section 3(3) the market participants must demonstrate that the preferential sharing of information is reasonably necessary to carry out their business and that the information will not be used for any purpose that does not support the fair, efficient, and openly competitive operation of the electricity market. Market participants that apply for an information sharing order must also demonstrate that the sharing of information is limited to what is necessary and that there is a compliance plan in place with controls to maintain the confidentiality of information.

An AUC order permitting the preferential sharing of information may apply to information related to:

- energy market offers (including available capability information),

- operating reserves market offers,

- dispatch down service (DDS) offers, and

- operational/outage information.

On January 30, 2020, the AUC ruled that an AUC order for the preferential sharing of information is not required in cases where only operational information is shared as the use of non-public outage information to trade is already restricted under section 4 of the FEOC Regulation.[10]

There are currently 41 active AUC orders for information sharing. Of those, 29 (71%) permit the sharing of energy and operating reserves market offer information, 5 (12%) permit the sharing of only energy market offer information, 4 (10%) permit the sharing of only operating reserves market offer information, and 3 (7%) relate only to the sharing of outage/operational information.

1.5.1 Appointment of an agent

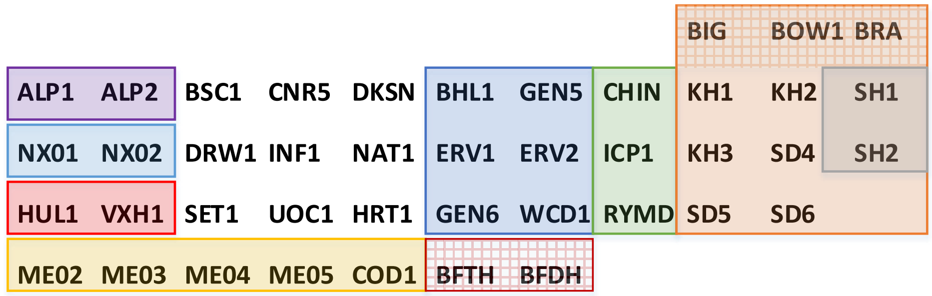
Real-time operations of assets involve the submission and updating of available capability, offer, and operational information to the AESO. Real-time operations also involves responding to dispatch instructions from the AESO. This requires a market participant to have personnel on hand at all times to manage an asset. Thus, some market participants may find it more economical to contract with an agent to carry out the real-time operational responsibilities for their asset. In order for an agent to manage the real-time operations of a market participant's asset, information related to price quantity pairs must be shared between the two parties. It should be noted that agents do not have ultimate offer control for the assets that they manage. Offers made into the wholesale electricity market are typically determined by the asset owners.

Currently, there are two commercial agents that provide real-time operations support for market participants that are not providing the service as a counterparty to a joint venture, URICA Energy Real Time Ltd. and Apex Wind Asset Management, LLC.

URICA Energy Real Time Ltd. is the largest real-time operations agent operating in Alberta, conducting real-time operations for 27.2% of the capacity in the wholesale electricity market. The figure below shows the assets that have contracted with URICA Energy Real Time Ltd. for real-time operations services. Assets belonging to the same market participant are grouped together in coloured boxes. A cross hatched box indicates that the information being shared with URICA Energy Real Time Ltd. is for real-time operations services for the management of operating reserves only. For SH1 and SH2, URICA Energy Real Time Ltd. conducts the real-time operations for the assets on behalf of the joint venture between TransAlta Corporation and Heartland Generation Ltd.

[10] AUC Disposition 25054-D01-2020

Figure 16: URICA Energy Real Time Ltd. agency agreements[11,12]



In 2017, Oldman 2 Wind Farm Limited contracted with Apex Wind Asset Management, LLC to provide real-time operations services for its 46 MW Oldman 2 Wind Farm (OWF1) and 88 MW Wintering Hills Wind Farm (SCR4). As a result, Apex Wind Asset Management, LLC conducts real-time operations for 0.9% of the capacity in the wholesale electricity market.

1.5.2 Joint ventures

One important aspect of joint ventures is determining how offers for the asset will be submitted to the AESO while maintaining the confidentiality of offer information from the other party or parties in the joint venture. In some cases, one joint venture partner has offer control for the entire asset and the other party is solely a financial partner. In other cases, an agent is assigned to aggregate and submit the offers on behalf of the joint venture partners.

The figure below shows the joint venture relationships between market participants with greater than 5% offer control in terms of percentage of capacity in the market. For each market participant all assets are listed and those that are joint ventures have boxes that overlap with the joint venture partner. A dashed box around the joint venture asset indicates only one party of the joint venture has offer control of the asset. If there is no dashed box, offer control is divided between the joint venture parties. It does not include joint ventures the market participants have with other smaller market participants.

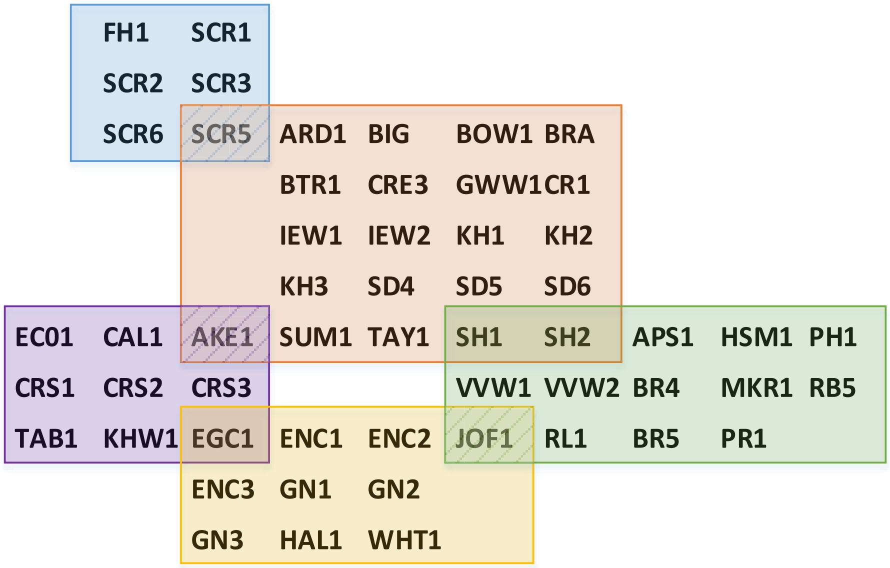
The figure shows that the market participants with greater than 5% offer control generally have a couple of joint ventures with the other large market participants. With the exception of TransAlta Corporation and Heartland Generation Ltd.'s joint venture at Sheerness (SH1 and SH2) and Capital Power Corporation and ENMAX Corporation's joint venture at Shepard (EGC1), the offer control of the joint venture assets is allocated to one party. However, as noted above, this does

[11] AUC Order 26507-D02-2021 permits the preferential sharing of information between WCSB Power Holdings GP Ltd., WCSB Power Holdings Limited Partnership, URICA Energy Real Time Ltd., and URICA Asset Optimization Ltd. related to the 20 MW eReserve2 Battery Energy Storage Power Plant (denoted as ERV2 in the figure). While the AUC Order has been active since May 26, 2021, the asset is not connected to the electric system at time of writing.

[12] AUC Order 26543-D02-2021 permits the preferential sharing of information between Fengate Central Utilities Block GP Inc., Fengate Central Utilities Block LP, Heartland Petrochemical Complex Limited Partnership, Inter Pipeline Propylene Ltd., URICA Energy Real Time Ltd., and URICA Asset Optimization Ltd. related to the 102 MW Heartland Petrochemical Complex Central Utility Block Power Plant (denoted as HRT1 in the figure). While the AUC Order has been active since June 10, 2021, the asset is not connected to the electric system at time of writing.

not mean that non-public information is freely shared by the joint venture parties as information shared is restricted to what is necessary and such information is further controlled within each organization.

Figure 17: Joint venture relationships between Market Participants with greater than 5% Market Share Offer Control

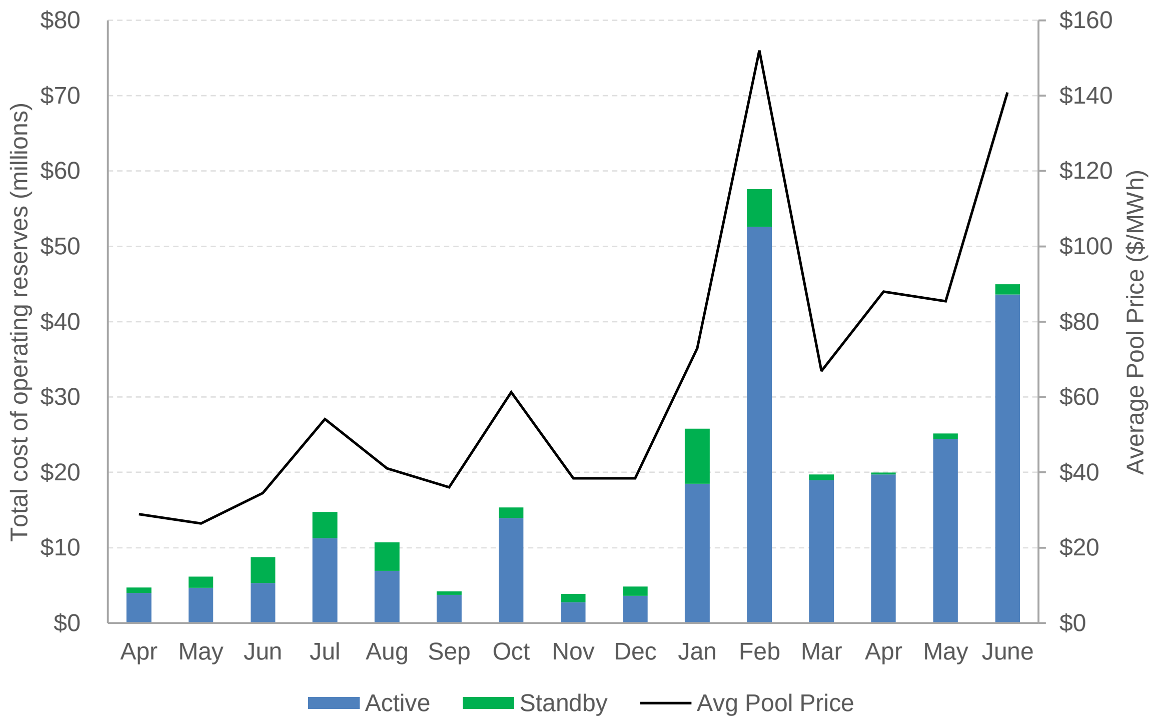


2 THE MARKETS FOR OPERATING RESERVES

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.[13] These products are all bought by the AESO through day-ahead auctions.

Total OR costs for the quarter were $90 million, an increase of 359% from Q2 2020. Higher pool prices in the energy market were a significant factor in this increase, with an average pool price of $104.51/MWh in Q2 2021 compared to $29.90/MWh in Q2 2020. Figure 18 shows total OR costs and average pool prices by month since April 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 6 provides a detailed breakdown of total OR costs by month in Q2 2021.

Figure 18: Total cost of active and standby reserves and average pool price by month (January 2020 to June 2021)



[13] For more detailed information, see [AESO: Operating Reserve](#)

Table 6: Detailed breakdown of operating reserves costs in Q2 2021

Total Cost ($ Millions)						
	Apr-21	**May-21**	**Jun-21**	**Q2 2021**	**Q2 2020**	***% Change***
Active Procured	**19.7**	**24.4**	**43.6**	**87.8**	**14.0**	***527%***
RR	5.5	7.1	9.3	21.9	4.7	*367%*
SR	8.8	10.3	19.6	38.6	5.8	*571%*
SUP	5.5	7.0	14.8	27.3	3.5	*668%*
Standby Procured	**0.1**	**0.4**	**0.4**	**1.0**	**1.2**	***-21%***
RR	0.0	0.2	0.2	0.5	0.6	*-23%*
SR	0.1	0.2	0.2	0.5	0.5	*-8%*
SUP	0.0	0.0	0.0	0.0	0.1	*-76%*
Standby Activated	**0.1**	**0.3**	**0.9**	**1.3**	**4.4**	***-70%***
RR	0.0	0.2	0.2	0.5	0.3	*34%*
SR	0.1	0.1	0.6	0.7	3.2	*-77%*
SUP	0.0	0.0	0.1	0.1	0.9	*-84%*
Total	**20.0**	**25.2**	**45.0**	**90.1**	**19.6**	***359%***
Total Volume (GWh)						
	Apr-21	**May-21**	**Jun-21**	**Q2 2021**	**Q2 2020**	***% Change***
Active Procured	**465.8**	**480.7**	**472.7**	**1,419.2**	**1,394.2**	**2%**
RR	95.0	101.2	98.1	294.3	313.8	*-6%*
SR	185.5	189.8	187.4	562.7	540.5	*4%*
SUP	185.4	189.7	187.1	562.2	539.9	*4%*
Standby Procured	**69.5**	**109.0**	**104.9**	**283.4**	**482.1**	***-41%***
RR	28.8	52.0	50.0	130.8	174.1	*-25%*
SR	30.0	45.8	44.2	120.0	230.5	*-48%*
SUP	10.8	11.2	10.7	32.6	77.4	*-58%*
Standby Activated	**3.4**	**3.8**	**5.4**	**12.6**	**111.4**	***-89%***
RR	0.9	1.5	1.1	3.5	7.8	*-55%*
SR	1.6	1.8	3.2	6.6	72.0	*-91%*
SUP	0.8	0.5	1.1	2.4	31.6	*-92%*
Total	**538.7**	**593.5**	**583.0**	**1,715.2**	**1,987.7**	***-14%***
Average Cost ($/MWh)						
	Apr-21	**May-21**	**Jun-21**	**Q2 2021**	**Q2 2020**	***% Change***
Active Procured	**42.34**	**50.82**	**92.27**	**61.84**	**10.04**	**516%**
RR	57.70	70.27	94.72	74.36	14.94	398%
SR	47.16	54.31	104.40	68.64	10.65	545%
SUP	29.65	36.95	78.84	48.49	6.57	638%
Standby Procured	**1.28**	**3.86**	**4.21**	**3.36**	**2.49**	**35%**
RR	1.07	4.79	3.77	3.58	3.49	3%
SR	1.74	3.60	5.50	3.84	2.16	77%
SUP	0.56	0.55	0.97	0.69	1.23	-44%
Standby Activated	**42.09**	**79.95**	**165.33**	**106.61**	**39.83**	**168%**
RR	52.74	121.19	208.69	131.45	44.16	198%
SR	43.92	58.09	175.21	111.33	44.59	150%
SUP	27.09	38.96	91.28	58.15	27.91	108%
Total	**37.04**	**42.38**	**77.11**	**52.51**	**9.88**	***432%***

In terms of volumes, the AESO procured 4% more active spinning and supplemental reserves year-over-year, while the volume of active regulating fell by 6% (Table 6). As discussed in the MSA's Q1 2021 report, beginning in February 2021 the AESO began to procure more active spinning and supplemental reserves, likely in anticipation of high import volumes. Increased purchases of active spinning and supplemental reserves led to a reduction in the volume of standby reserves procured and standby activations.

Table 7 shows the average cost of active reserves in Q2 2021 and Q2 2020. While there was a $74.62/MWh increase in the average pool price year-over-year, this was not fully reflected in increases to active OR costs. This indicates that the increase in costs for active reserves was driven by higher pool prices in the energy market, and the underlying index prices for active reserves generally fell year-over-year.

Table 7: Average cost ($/MWh) of active OR products

Product	Q2 2021	Q2 2020	Q2 2021 - Q2 2020
Spinning	$68.64	$10.65	$57.99
Supplemental	$48.49	$6.57	$41.91
Regulating	$74.36	$14.94	$59.42
Avg. Pool Price	**$104.51**	**$29.90**	**$74.62**

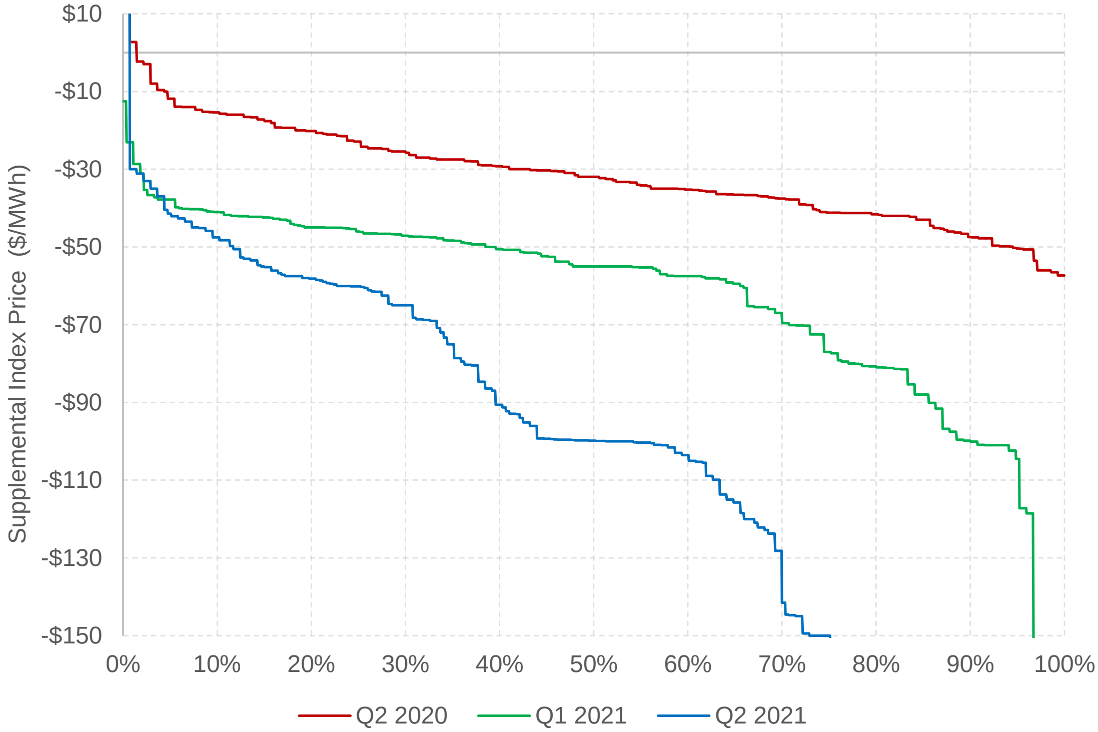
Figure 19 shows duration curves of the index prices for active supplemental. The figure illustrates the percentage of hours the index price for active supplemental was at or above a certain price. For example, in Q2 2021 50% of hours had a supplemental index price of greater than negative $100/MWh; in Q2 2020 the median index price was higher at negative $32/MWh.

The figure shows a meaningful reduction in index prices from Q2 2020 to Q1 2021, and also a reduction from Q1 to Q2 2021. The lower index prices this year are a function of increasing competition in the supplemental market. Competition in this market has increased as a result of new load providers in supplemental, new battery participation in spinning, and also a shift by suppliers to active from standby markets given the shift in demand.

Load providers of supplemental reserves have different opportunity cost profiles compared to generators. The main opportunity cost for load providers is a low-probability interruption to their commercial process, which is unlikely to be directly connected to prevailing pool prices. In contrast, the opportunity cost for generation is generally 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, particularly 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 were 55% higher on average and the carbon price has increased by $10.00/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.

Figure 19: Duration curves of index prices for active supplemental reserves, between $10 and -$150 (Q2 2020, Q1 2021 and Q2 2021)



The high pool prices in Q2 2021 attracted high import volumes on the BC/MATL intertie. To support these imports the AESO uses a combination of LSSi and additional contingency reserves. Figure 20 shows the volume of on-peak active supplemental purchased and the volume of standby supplemental reserves that were activated in on-peak hours.

In early February, the AESO began to procure more active supplemental reserves day-ahead, likely in anticipation of high import levels. The activation rate of standby supplemental reserves correspondingly dropped in February, and remained low for the rest of Q1 and throughout Q2. Starting in March, lower levels of standby supplemental reserves were procured by the AESO. In late-June, the level of active reserves procured increased due to the expected hot weather and associated high demand and import forecasts.

Figure 20: Active and standby supplemental volumes, on-peak (January 1 to June 30, 2021)

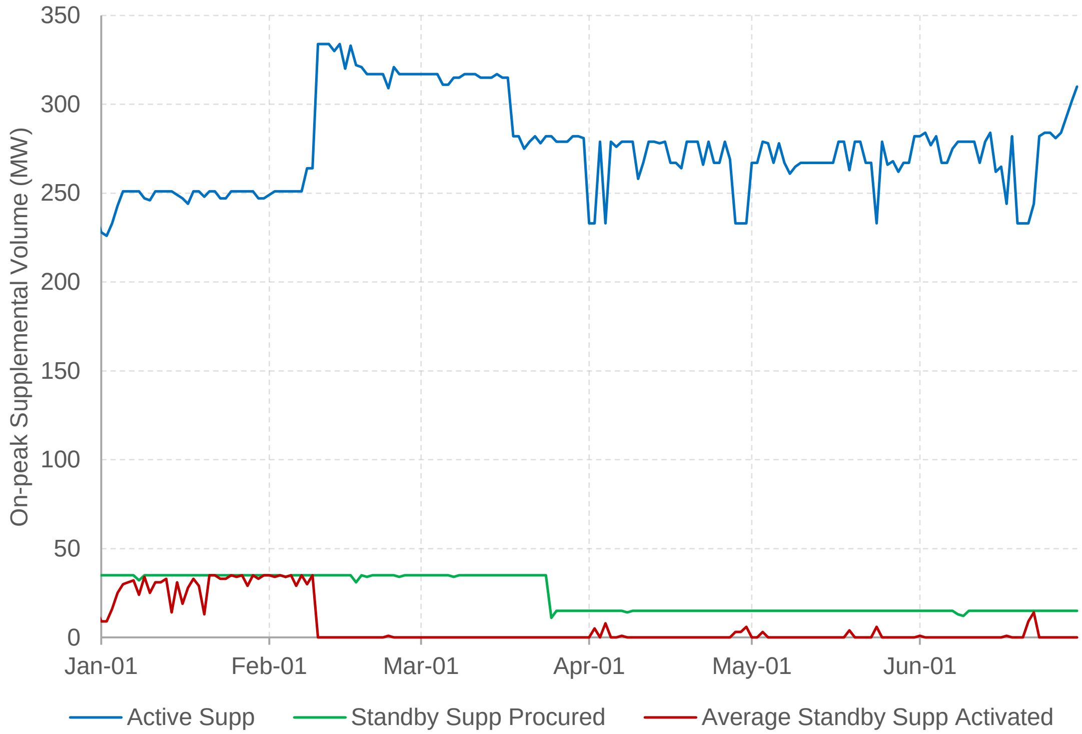


Figure 21 compares the average cost of standby spinning activations with the prevailing cost of active spinning reserves and energy by month since January 2020. The prices for energy and active spinning are weighted by standby spinning activation volumes. As shown, the cost of activating standby reserves has generally been greater than the cost of energy, with the exception of April and May 2021.

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 were observed throughout Q1 2021 and in June 2021, in April and May the cost of activating standby reserves was lower than the prevailing cost of energy. The volume of standby contingency reserves activated remained low from February 10 through Q2.

Figure 22 shows the market shares of OR dispatches by fuel type in Q2 2021 and Q2 2020. As shown, hydro assets continue to be a principal supplier of OR, though these assets shifted some of their volumes from spinning to supplemental reserves compared to Q2 2020. Battery storage providers have entered the active spinning market and provided 11% of dispatched spinning reserves in Q2. In supplemental reserves, hydro and load providers have increased market share while the shares of coal and gas fell. The fuel-type composition of regulating reserves volumes remained relatively unchanged.

Figure 21: The volume-weighted average price of standby spinning activations compared to the prevailing price of energy and active spinning reserves (January 2020 to June 2021)[14]

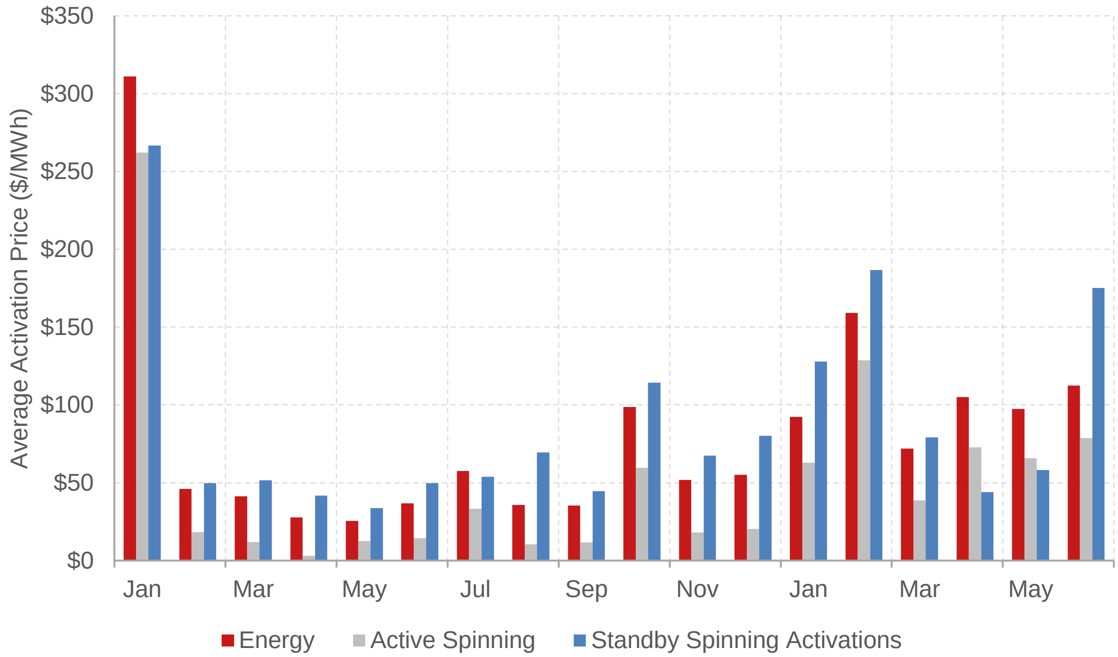
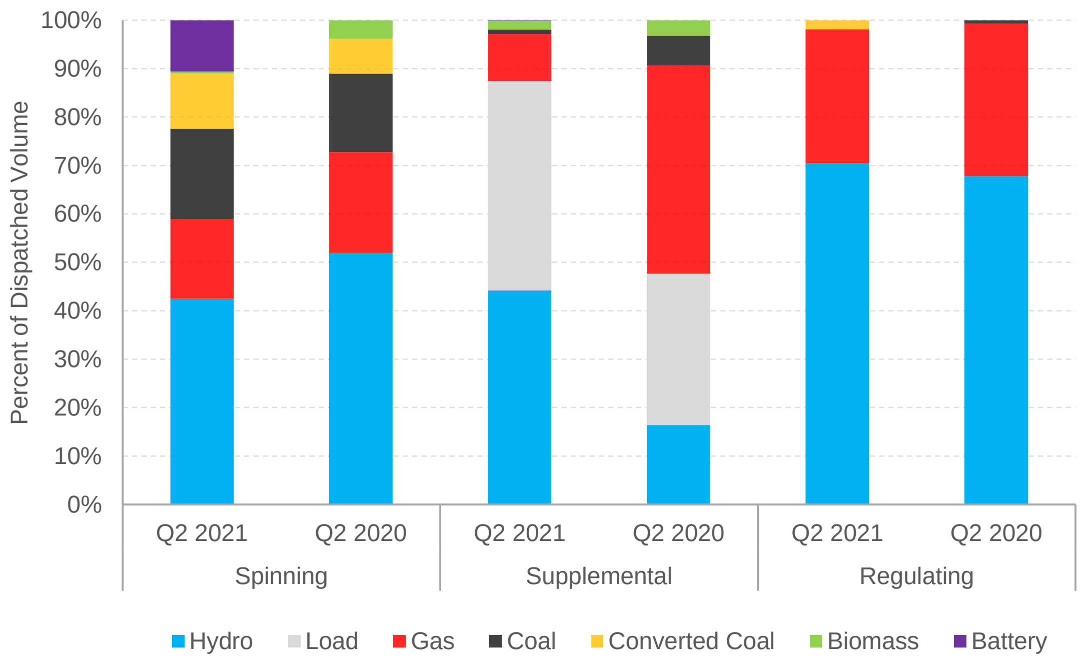


Figure 22: Dispatched OR volumes by fuel type (Q2 2021 and Q2 2020)[15]



[14] 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.

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 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 23: Total volumes of standard products by contract term and trade date (Q1 2017 to Q2 2021)

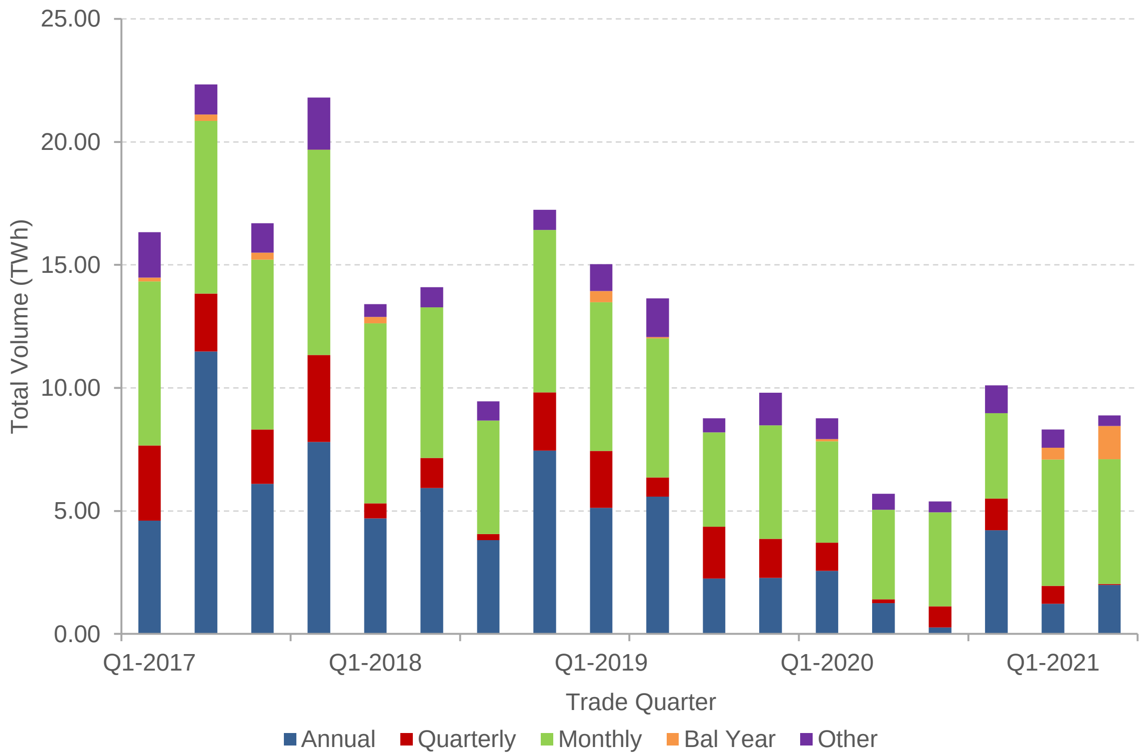


Figure 23 illustrates the total volumes traded for standard products from Q1 2017 to Q2 2021.[16] Total volume is the total amount of power traded financially over the duration of the contract.

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

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

Standard products include contracts such as flat and extended peak, but do not include custom shapes, such as the full-load RRO trades. Overall trading liquidity increased slightly in Q2 as total volumes increased by 7% from Q1 2021. Year-over-year the increase was more significant; the total volumes traded on NGX and Canax were 88% higher year-over-year. However, forward trading volumes in Q2 2021 were still low compared to historical figures.

In April, 230 MW of the balance-of-year contract traded, covering the period from May 1 to December 31. This is a relatively high volume for this type of contract and this trading may have reduced the volumes of quarterly contracts (Figure 23). The trading of annual contracts continued at a low level, although slightly higher than in Q1 2021.

Figure 24: Total volumes by contract term and delivery date (January 1, 2019 to June 30, 2021) [17]

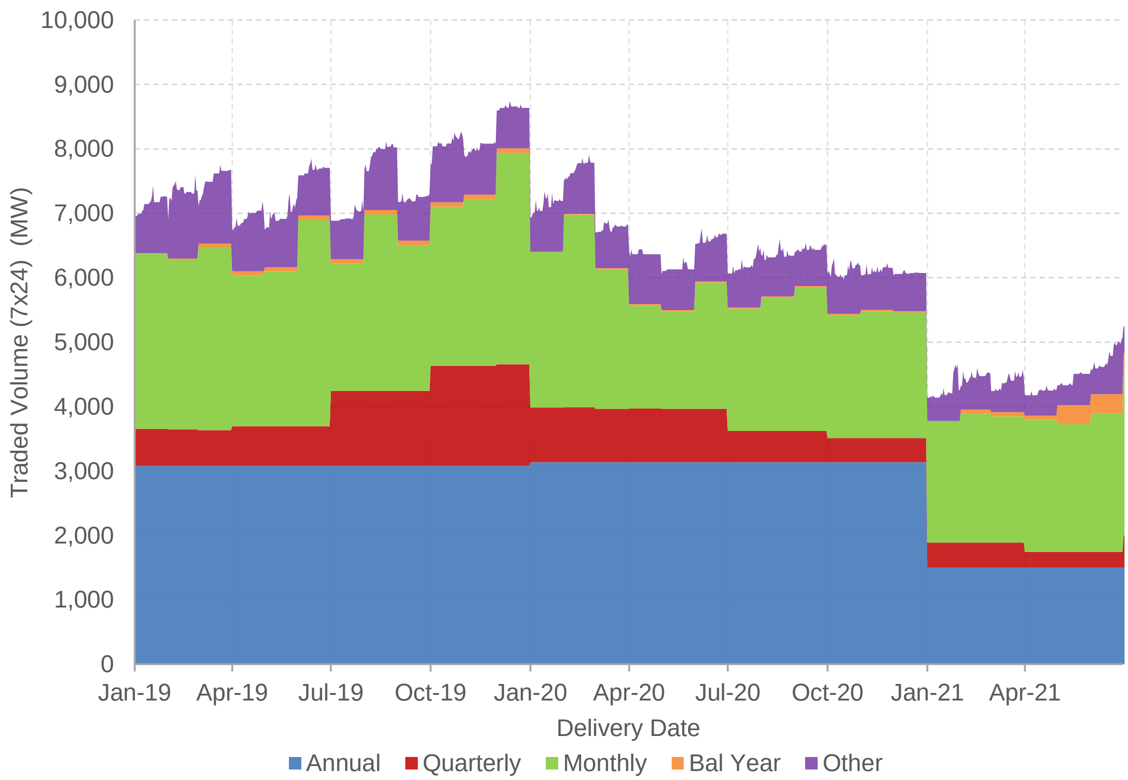


Figure 24 illustrates traded volumes by the contract delivery date. Traded volume is the hourly volume of power being exchanged financially within a given trade. The figure shows the traded volumes that were applicable to Q2 2021 were largely a continuation of what occurred in Q1 2021. This is driven by the fact that traded volumes for Calendar 2021 (CAL21) were approximately 50% of the traded volumes for CAL19 and CAL20. The traded volumes of other products has not increased sufficiently to fill the decline in annual volumes.

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

3.1 Trading of monthly products

The MSA's Q1 2021 report illustrated that for all three months in Q1 monthly forward prices were below the realized pool prices. This trend continued into Q2 as forward prices for April, May and June were below the realized pool prices (Figure 25). Forward prices for February and June were materially below pool prices. For February the volume-weighted average forward price was $72.23/MWh, or $79.75/MWh lower than the average pool price; for June the difference was $85.13/MWh. Over the first six months of 2021, the premium of pool prices over the monthly forwards has been $36.94/MWh for the volume-weighted forward prices and $33.58/MWh for the final trade prices.

The typical relationship between forward prices and pool prices is a slight risk premium in the forward prices, although, on occasion, pool prices in a month will be much higher than anticipated.

Figure 25: Monthly flat forward prices and average pool prices (April 2020 to June 2021)

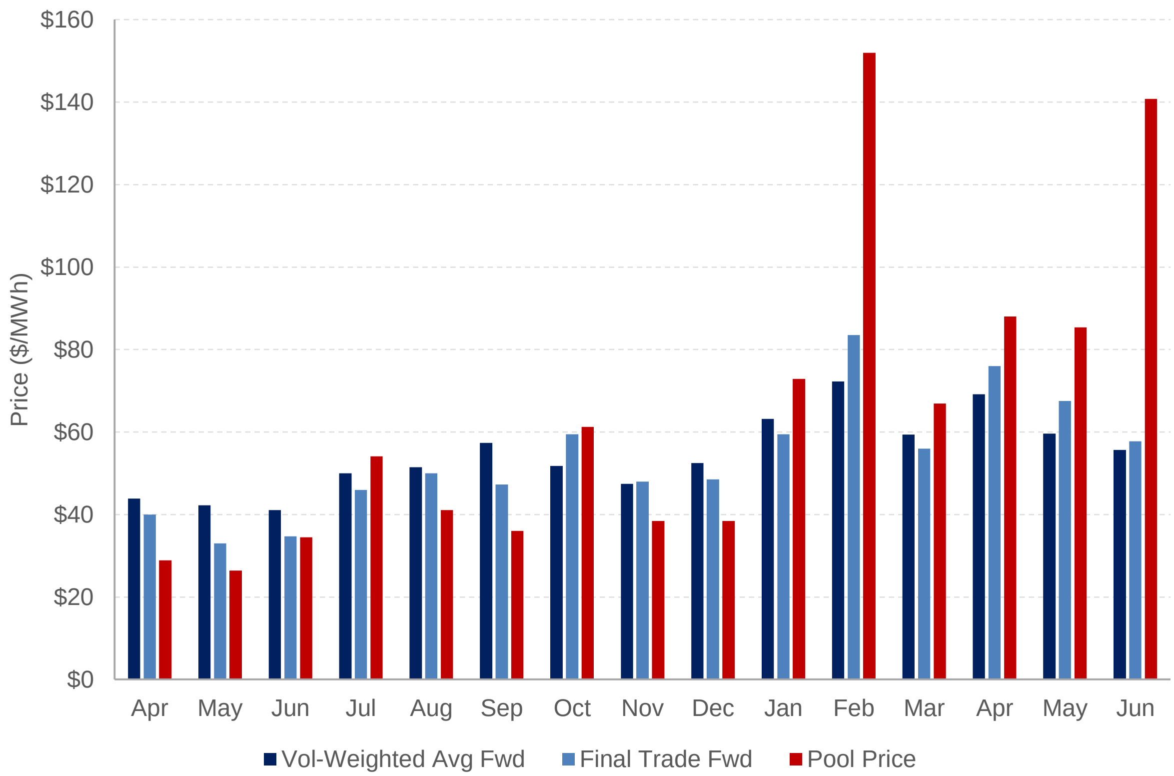


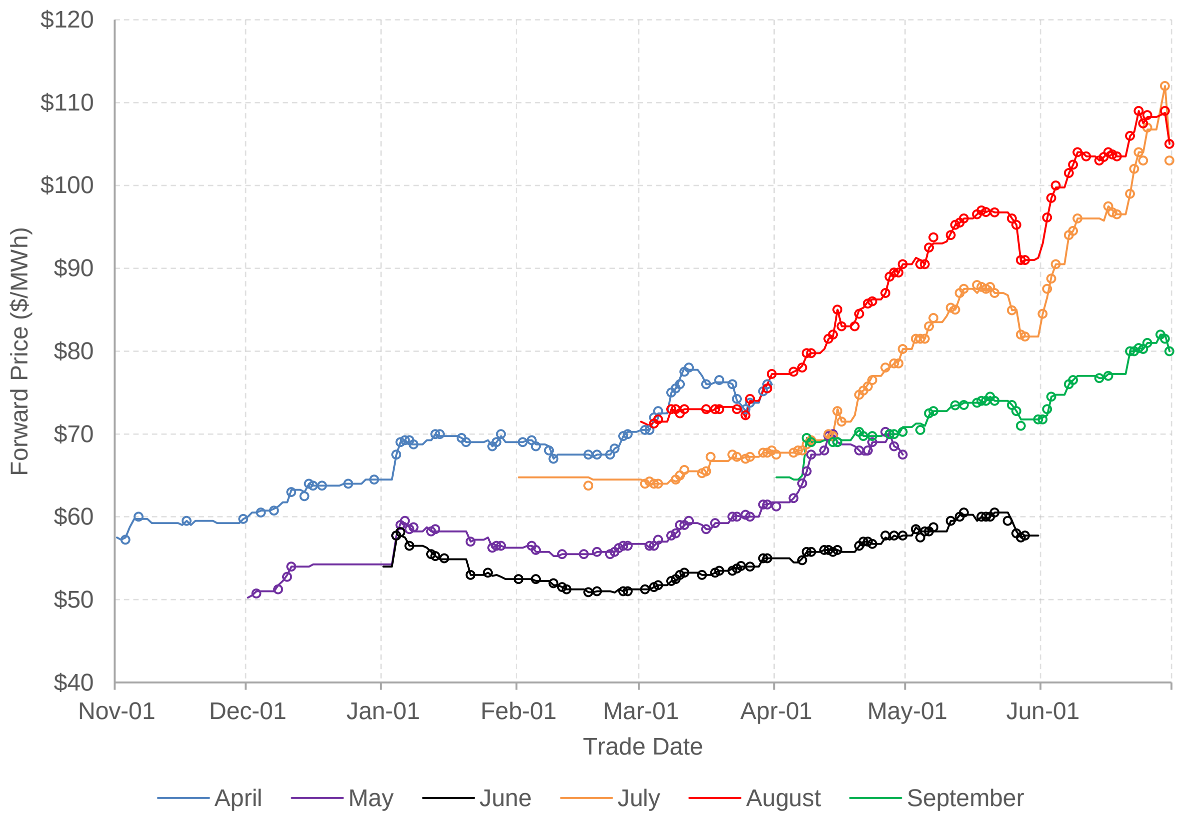
Figure 26 shows the development of forward prices for the monthly contracts of Q2 and Q3 2021. During the Q2 trading period monthly forward prices increased in value, in part because pool prices in the energy market were consistently settling above prior forward market expectations. The forward prices for July and August increased significantly due to forecasts of hot summer temperatures, and also because forward prices in major markets such as Mid-Columbia (Mid-C) and California have increased on the back of drought conditions. The higher forward prices in other markets implies that Alberta could see reduced imports supply and increased export demand.

In late May, the prices for the June through September contracts came off for a few days in response to softer real-time pool prices and declining forward prices in other markets.

The June contract stopped trading at the end of May, but the Q3 contracts continued to trade and their prices began to increase again in early June when Alberta experienced hot weather and supply constraints resulting in higher pool prices. In addition, forward prices in Mid-C and California increased. In early June the price of the August contract went above $100/MWh, and the July contract followed on June 22, rising to a high of $112/MWh on June 29.

As shown by Figure 26, June was anticipated to be a month with a healthy amount of generation supply relative to demand and was priced in the $50/MWh to $60/MWh range by the forward market. The June contract last traded on Friday, May 28 at $57.75/MWh. In real-time pool prices came in much higher than anticipated and as of June 4, the June contract was valued at $104/MWh, an 80% increase compared to May 28.

Figure 26: Forward prices for the April through September monthly flat contracts (5 months out) (November 1, 2020 to June 30, 2021) [18]

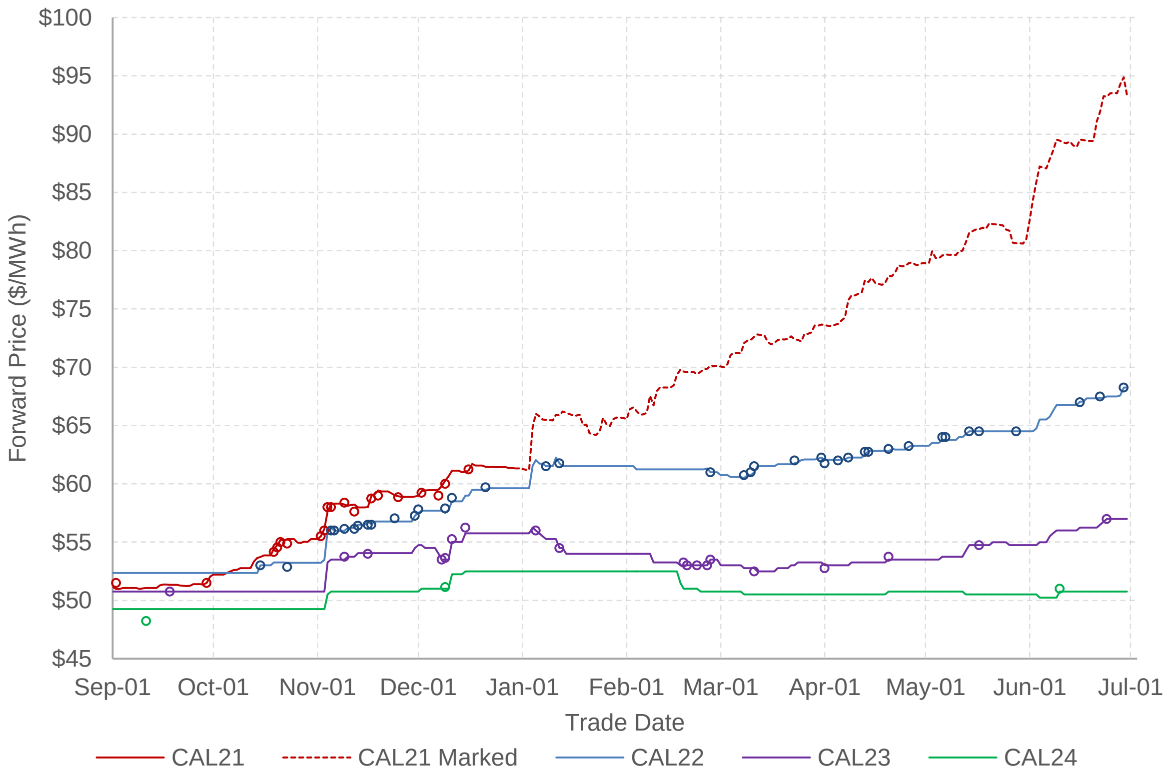


[18] The lines show daily settlement prices, the markers indicate the price of the last trade on that day.

3.2 Trading of annual products

The marked price of the CAL21 contract increased from $73.67/MWh on March 31, 2021 to $93.30/MWh on June 30, 2021, an increase of 27%.[19] The CAL21 contract last traded for $61.25/MWh on December 16, 2020 and its value as of June 30 was 52% higher (Figure 27). The 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.

Figure 27: Forward prices for the calendar 2021 to 2024 flat contracts (September 1, 2020 to June 30, 2021) [20]



The forward prices for CAL22 and CAL23 also increased in Q2 2021 but not to the same extent as CAL21 (Figure 27). The CAL22 contract was actively traded for much of Q2 and ended the quarter at $68.25/MWh, 10% higher than on March 31 (Table 8). The increase in the marked price of CAL21 would tend to put upward price pressure on future annual contracts, particularly the prompt year. Another factor increasing the price of CAL22 was higher forward prices for natural gas, which increased by 22% over Q2 2021. As shown in Table 8, the spark spread for CAL22 at a 7.5 GJ/MWh heat rate increased by 5% in Q2 2021.

---

[19] 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.

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

The price of CAL23 increased by 7% to $57.00/MWh as gas prices for 2023 also increased. The price of CAL24 was largely unchanged despite higher gas prices over the quarter. The CAL24 contract last traded for $51.00/MWh on June 10. The CAL25 contract also traded on June 10, at a price of $50.75/MWh.

Annual forward 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 8: Forward price changes for annual electricity and natural gas (Q2 2021)

	Electricity ($/MWh)			**Natural Gas ($/GJ)**			**Spark Spread at 7.5 HR ($/MWh)**		
	31-Mar	**30-Jun**	**% Chg**	**31-Mar**	**30-Jun**	**% Chg**	**31-Mar**	**30-Jun**	**% Chg**
CAL22	$62.25	$68.25	10%	$2.37	$2.90	22%	$44.45	$46.46	5%
CAL23	$53.25	$57.00	7%	$2.24	$2.46	10%	$36.46	$38.58	6%
CAL24	$50.50	$50.75	0.5%	$2.26	$2.38	5%	$33.57	$32.92	-2%

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).

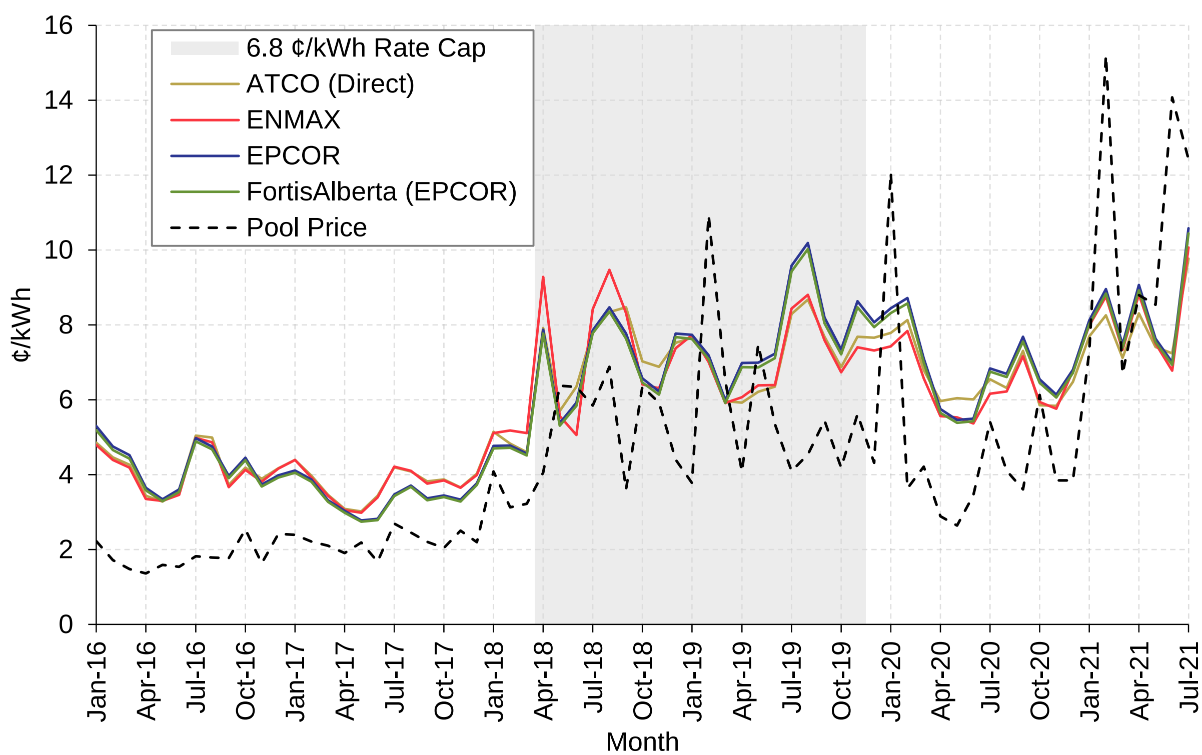
4.1 Regulated retail market

Residential RRO rates averaged 7.8 ¢/kWh across the four largest service areas in Q2 2021 compared to 8 ¢/kWh in the previous quarter (Figure 28).

RRO rates are set ahead of a delivery month based on monthly forward prices. This means that consumers on the RRO rate do not pay pool prices observed in a given delivery month. However, higher than expected pool prices may influence forward market prices for subsequent delivery months, which would impact future RRO prices. While June 2021 saw a significant month-to-month increase in pool prices, RRO rates declined over this period, a result of the June 2021 RRO being established based on June 2021 monthly forward prices established over the preceding four months.

RRO rates in Q3 2021 have so far significantly exceeded those observed in the first two quarters, with July 2021 residential RRO rates averaging 10.2 ¢/kWh and the August 2021 RRO averaging 12.1 ¢/kWh. The MSA expects RRO rates to decline in the fall given prevailing forward prices for fall contracts.

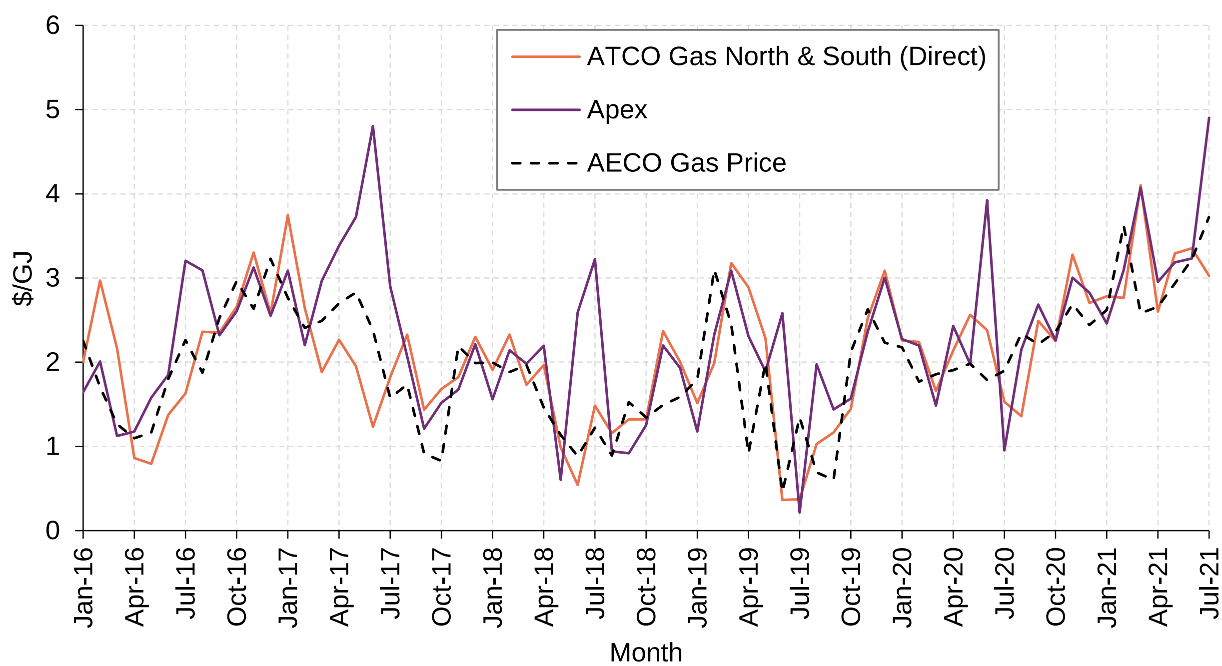
Figure 28: Residential Regulated Rate Option by service area, January 2016 to July 2021



Residential DRT rates averaged $3.10/GJ in Q2 2021, compared to $3.21/GJ in the previous quarter (Figure 29). DRT rates have increased 39% year-over-year in the first two quarters of 2021.

While July 2021 DRT rates in the two ATCO service areas have remained in line with rates observed in the first two quarters, DRT rates in the Apex Utilities (formerly AltaGas Utilities) service area increased significantly in order to recover previous months' gas costs that went under-collected.[21]

Figure 29: Residential Default Rate Tariff by service area, January 2016 to July 2021



4.2 Competitive retail market

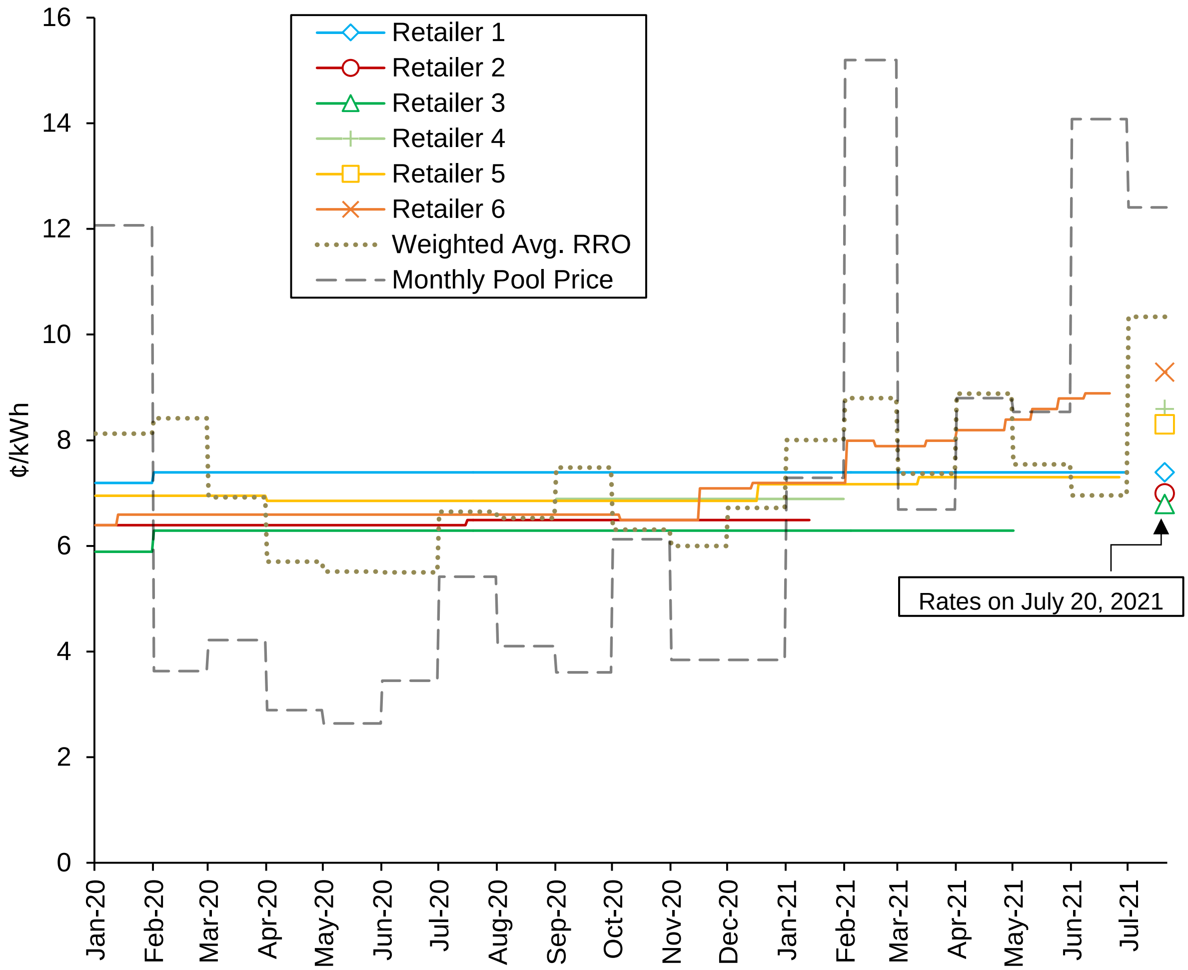
4.2.1 Competitive energy rates

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 monthly wholesale market prices. While fixed rates are more stable than variable rates or regulated energy rates, they do not necessarily result in lower energy rates over the entire term of the rate.

Competitive fixed electricity rates offered by most retailers increased in 2021, likely driven by increases in pool prices, forward market prices and RRO rates. 1-year fixed rate electricity rates offered by the largest retailers averaged 7.9 ¢/kWh on July 20, 2021, up from 6.9 ¢/kWh at the beginning of the year (Figure 30).

[21] Apex Utilities Inc. Gas Cost Recovery Rate (GCRR) Rider D July 2021 Filing for Acknowledgement, June 24, 2021.

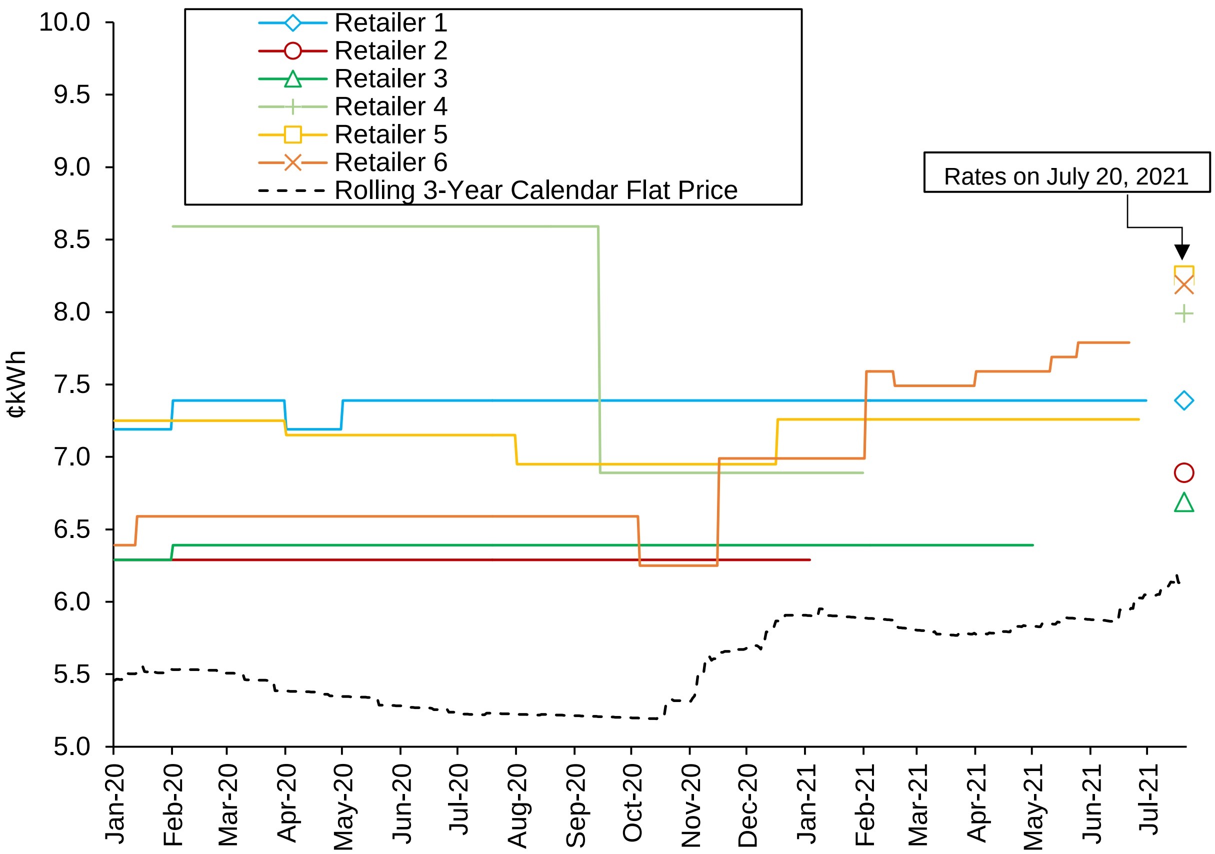
Figure 30: 1-Year competitive fixed residential electricity rates, January 2020 to July 2021[22]



As 1-year fixed rates cover shorter delivery periods than other fixed rates, they are more responsive to changes in short or near-term market fundamentals. Similarly, longer term fixed rates are more responsive to expected future or long-term market changes. While 3-year fixed electricity rates have also increased since the start of the year, the increase has been lower compared to 1-year fixed rates, with 3-year rates increasing from 6.9 ¢/kWh to 7.6 ¢/kWh between January 1 and July 20 (Figure 31). While pool prices and RRO rates in 2021 have impacted 3-year fixed electricity rates, these rates are also affected by forward market prices for future years. The increases in forward prices for 2022 and 2023 products that occurred in 2021 may have contributed to the increase in 3-year rates observed in recent months.

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

Figure 31: 3-Year competitive fixed residential electricity rates, January 2020 to July 2021[23]



4.2.2 Competitive market shares

Competitive retailers typically have greater market share in service areas where they have a regulated affiliate. This is particularly true for residential and commercial customers, who may recognize a competitive retailer as being related to their former regulated rate provider or current distributor. The MSA refers to such affiliate relationships that benefit competitive retailers as "co-branding".

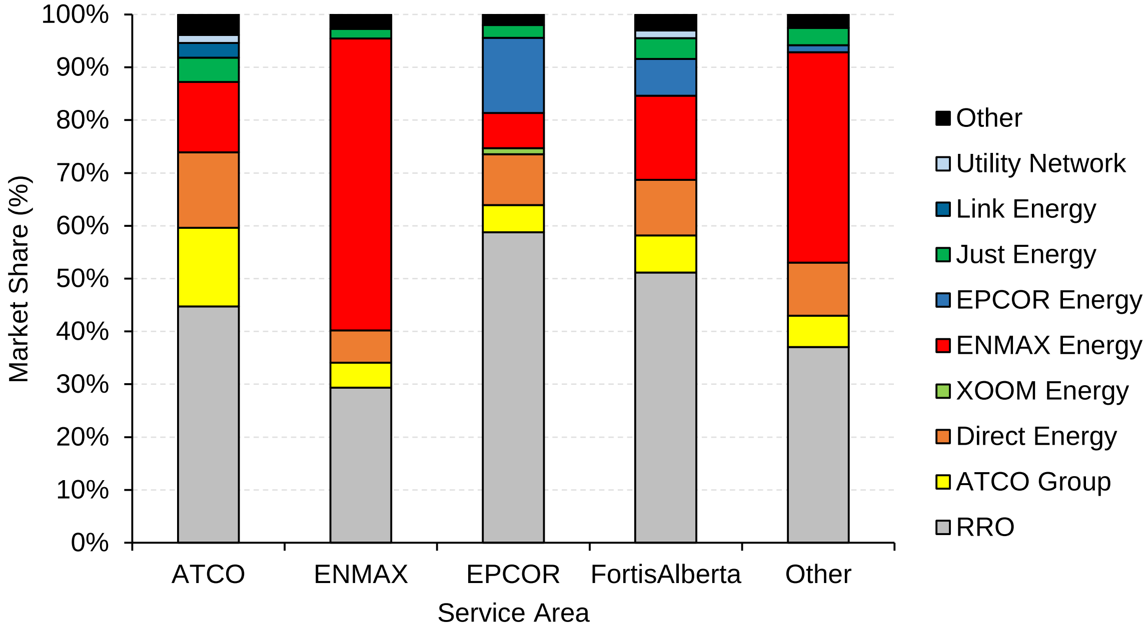
Among residential customers, ENMAX has the largest competitive retail market share, particularly in the ENMAX service area where its affiliates act as the distributor, RRO provider and municipal utility services provider, and in some other service areas where it provides RRO services (Figure 32).[24]

---

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

[24] MSA Retail Statistics (2021-07-09). Data up to Q1 2021 is presented here as the MSA Retail Statistics reports data using a one-quarter delay.

Figure 32: Electricity retailer market shares by service area, Residential customers, March 2021[25]



ENMAX also has the largest competitive market share among residential natural gas customers, despite not having a regulated gas affiliate (Figure 33). As residential customers often purchase dual-fuel contracts offering both electricity and natural gas, a co-branding advantage in retail electricity can be leveraged into a larger retail natural gas market share, and vice-versa.

Retailers with regulated natural gas affiliates such as ATCO (affiliated with the distributor ATCO Gas) and Direct Energy (affiliated with the DRT provider Direct Energy Regulated Services) enjoy co-branding advantages in most parts of the province, given the size of the ATCO natural gas service areas.

On aggregate, competitive retailer market shares continued to increase slightly in Q1 2021, with 55.2% of residential electricity customers having a competitive retailer in March 2021, compared to 54.9% in December 2020 (Figure 34). Competitive natural gas retailer market shares among residential customers increased similarly in Q1 2021, from 59.9% to 60.2%.

[25] MSA Retail Statistics (2021-07-09). Direct Energy and XOOM Energy are jointly owned by NRG Energy.

Figure 33: Natural gas retailer market shares by service area, Residential customers, March 2021

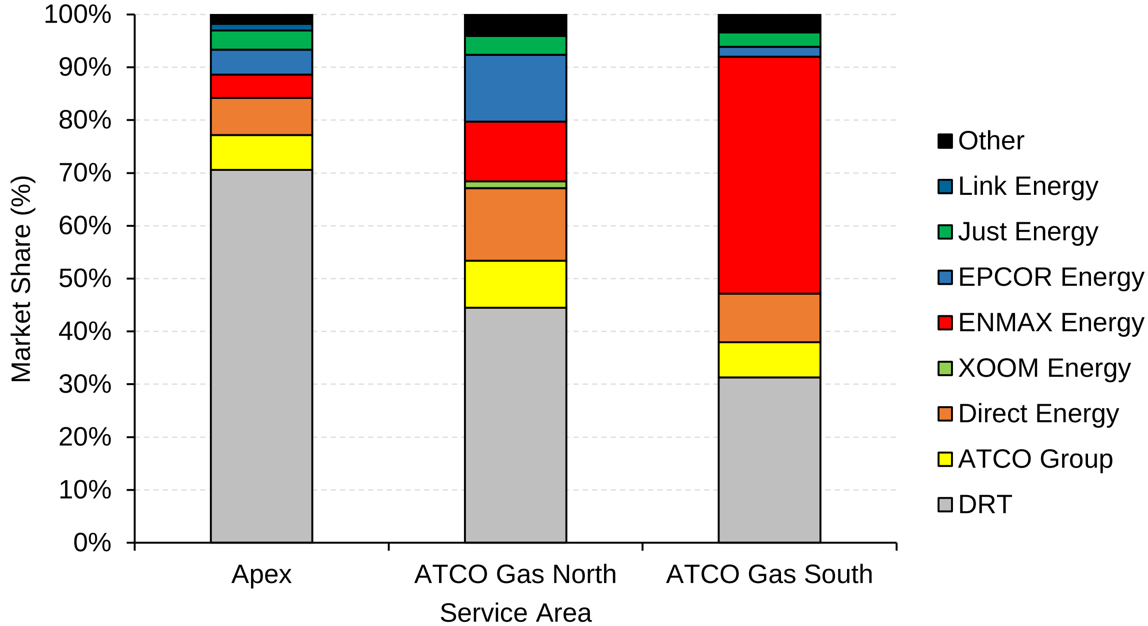
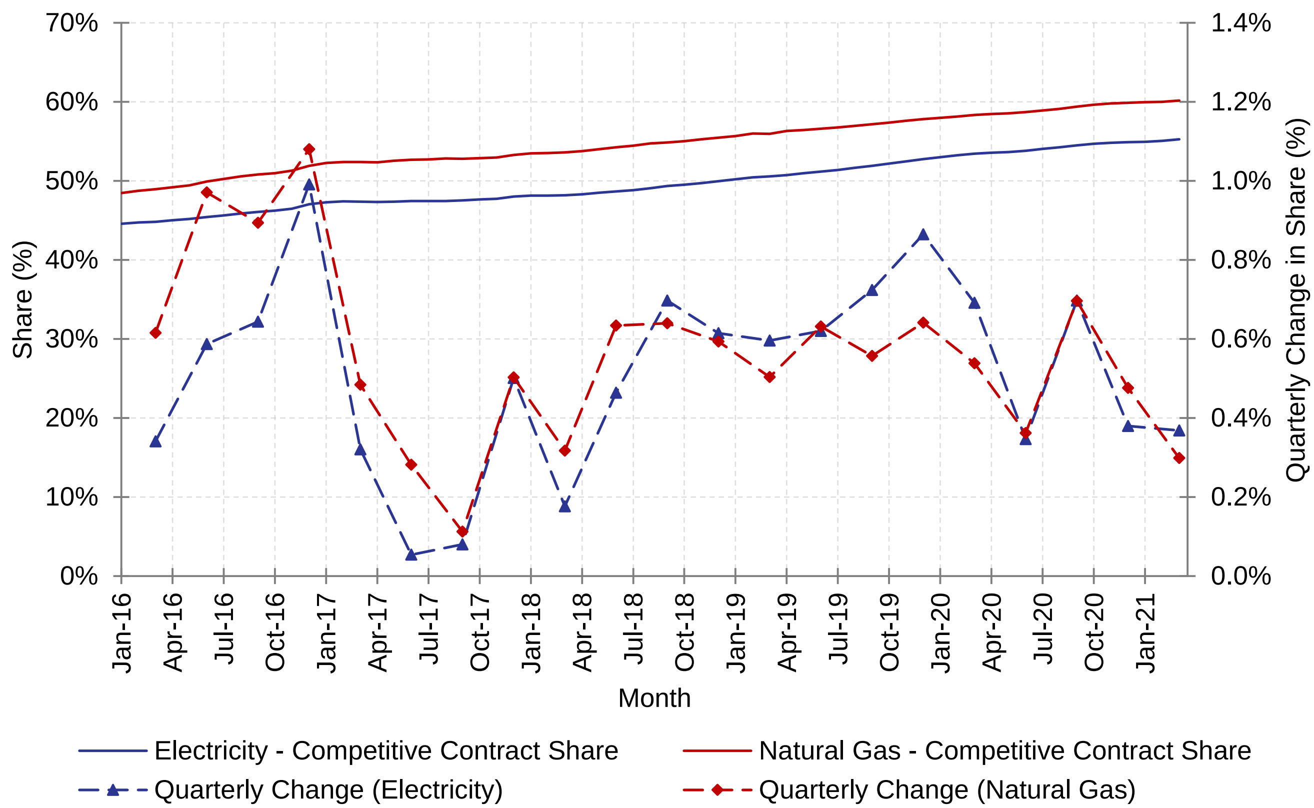


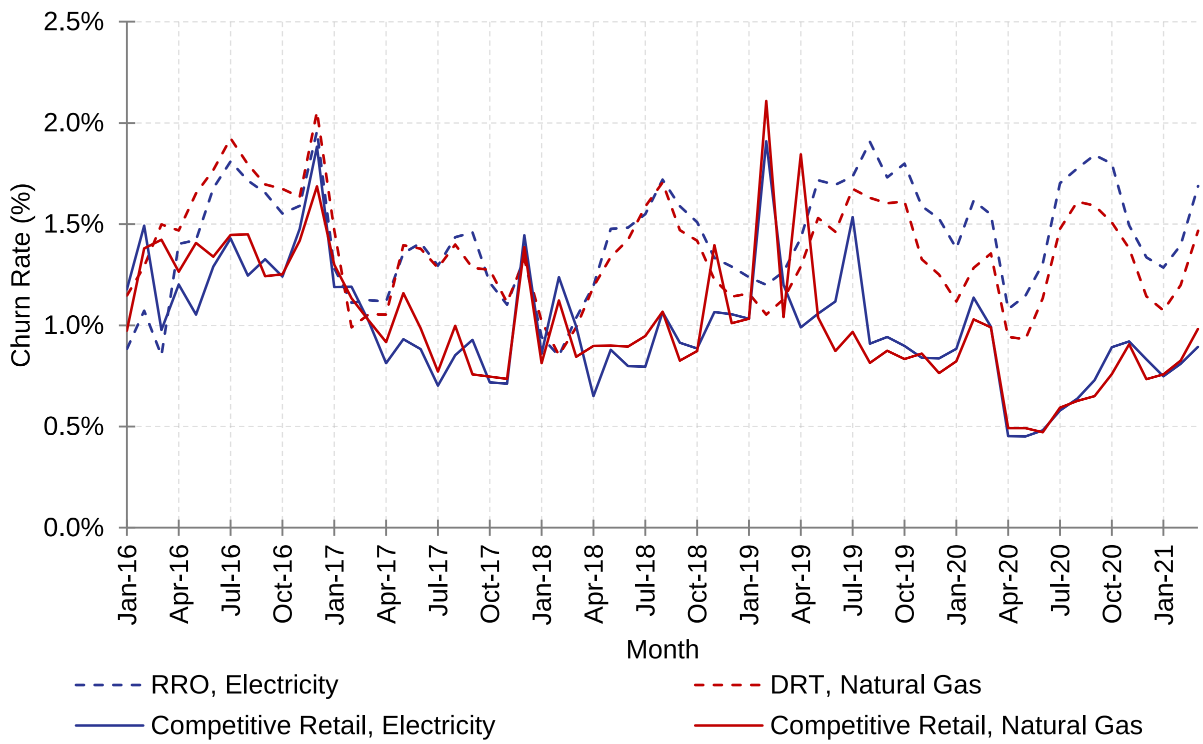
Figure 34: Competitive retailer market shares, Residential customers, January 2016 to March 2021



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 for competitive retailers (Figure 35).[26] The MSA considers retail churn to play an important role in the development of competitive retail energy markets, as it can enable vigorous competition to exist between retail competitors.

Figure 35: Regulated & competitive retailer churn, Residential customers, January 2016 to March 2021



4.4 Retail regulatory updates

4.4.1 Energy Price Setting Plan developments

On February 11, 2021 EPCOR Energy Alberta GP Inc. (EEA) applied to the AUC for approval of its 2021-2024 energy price setting plan (EPSP).[27] Although substantially similar to its previously approved 2018-2021 EPSP, EEA's proposed EPSP includes improvements to the clarity of EPSP language and calculations, and adjustments to the backstop mechanism, among others.

---

[26] MSA Retail Statistics (2021-07-09). Data up to Q1 2021 is presented here as the MSA Retail Statistics reports data using a one-quarter delay.

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

On February 25, 2021 the AUC approved the Direct Energy Regulated Services (DERS) 2020-2022 EPSP negotiated settlement agreement (NSA).[28] Prior to its 2020-2022 EPSP, DERS set RRO rates primarily based on the price of procured monthly flat and extended peak forward products, including a risk margin based on rolling commodity losses. The DERS 2020-2022 EPSP utilizes an index methodology whereby calculation of DERS RRO rates would be based on the price of full-load strips procured by EPCOR in its RRO auctions and the price of flat and extended peak forward products separately procured by DERS. The first RRO rates based on the 2020-2022 DERS EPSP came into effect in July 2021.

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 AUC to recover deferred bill payments with funding from the Balancing Pool,[29] while natural gas retailers recovered deferral funding from the Government of Alberta.[30] 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").[31] 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").[32]

While retailers were required to make efforts to recover deferred amounts from customers, some deferred amounts have not been recoverable from customers. In accordance with the UPDPA and UPDPR, such deficiencies must be recovered from all Alberta customers using rate riders. The AUC has initiated proceedings 26684 and 26699 to establish appropriate electricity and natural gas rate riders charged to electricity and natural gas customers, respectively. The AESO has indicated it and the Balancing Pool require approximately $5 million to be made whole for uncollected amounts relating to electricity utility payments,[33] while the Government of Alberta

---

[28] Decision 25818-D01-2021 Direct Energy Regulated Services 2020-2022 Energy Price Setting Plan – Negotiated Settlement Agreement, Proceeding 25818, February 25, 2021.

[29] 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.

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

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

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

[33] Alberta Electric System Operator and the Balancing Pool Utility Payment Deferral Program Rider L Application, Proceeding 26684, Exhibit 26684-X0002, July 16, 2021, PDF Pages 4, 5.

requires approximately $5 million in outstanding natural gas utility deferrals.[34] Additional amounts payable to natural gas distributors and self-funding retailers will also be recoverable from Alberta customers via rate riders. The MSA estimates the resulting riders will increase residential energy bills by less than $1.50 per month if the riders are in place over a four month period.

[34] Letter from Government of Alberta – Outstanding Loan Balance, Proceeding 26699, Exhibit 26699-X0020, July 22, 2021.

5 ENFORCEMENT MATTERS

5.1 Out-of-merit energy from generating units with dispatch levels above SMP

Through its routine market monitoring, the MSA discovered a notable Payment to Supplier on the Margin (PSM) in late 2020. This related to an event involving a generating unit delivering energy to the interconnected electric system, with dispatched operating blocks that have offer prices above system marginal price (SMP). The MSA refers to these as out-of-merit-energy events. To understand the frequency of these events, the MSA conducted an analysis from January 1, 2018 through May 31, 2021.

In its assessment the MSA defines an out-of-merit-energy event as occurring when an operating block was dispatched for energy and at some point during the dispatch system marginal price was less than the offer price of the operating block. If the dispatch was related to real time transmission constraint management it is not considered an out-of-merit-energy event.

Out-of-merit-energy events generally occur at the beginning of the hour when there are significant changes in the merit order that require operating blocks to be re-dispatched. As the start of an hour approaches, if currently in-merit generation is likely to become out-of-merit or currently out-of-merit generation is likely to become in-merit, the associated generating units will receive advanced dispatches that are effective at the beginning of the hour. An out-of-merit-energy event occurs when, following the beginning of the hour, the dispatch to an out-of-merit operating block is delayed and it continues to generate according to its previous dispatch instruction.

Table 9 below summarizes the count and duration of out-of-merit-energy events over a period from January 1, 2018 to May 31, 2021. The number of events in 2018 and 2020 was notably higher. In 2018, most of the significant out-of-merit-energy events occurred in one continuous period. On August 6, 2018 at 23:16:48, the AESO declared limited market operations that impacted HE24. During this time, the AESO had to dispatch units based on the previous hour's merit order. In 2020, on September 23 HE15, four out-of-merit operating blocks continued to deliver energy according to their dispatch level, which was above SMP, for the first five minutes of the hour, until they received a corrective dispatch. Notably, two of these blocks had offers greater than $999.00/MWh, while the SMP at the time was $29.72/MWh.

Table 9: Summary of out-of-merit-energy events

	Count of Events	**Avg. Capacity**	**Avg. Duration**	**Avg. Vol.**	**Vol. * Price Difference**
2018	56	19 MW	12.3 min	6.4 MWh	$ 100,548
2019	27	6 MW	7.1 min	0.5 MWh	$ 8,072
2020	40	16 MW	3.7 min	1.2 MWh	$ 40,524
To May 31, 2021	8	4 MW	4.4 min	0.2 MWh	$ 273

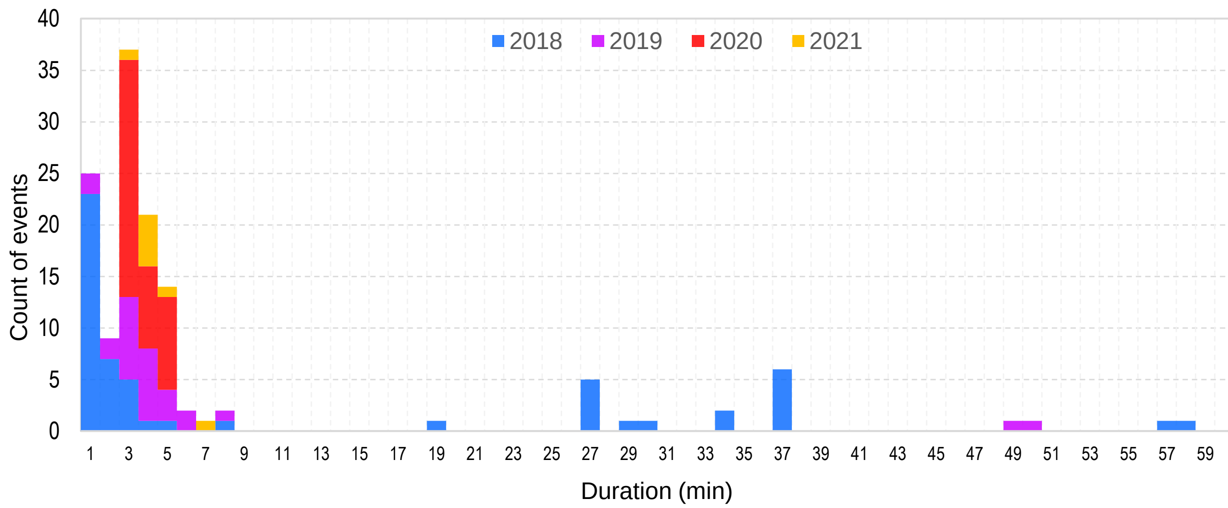
The last column of Table 9 is the offer volume of energy that remained dispatched above SMP, multiplied by the difference between the operating block's offer price and SMP at the time. This estimated amount represents the costs of out-of-merit-energy events, which from 2018 through

May 31, 2021 was approximately $150,000. This corresponds to about 3% of the total value of all PSM charges, which totaled $4.9 million from 2018 to May 31, 2021.

Generators involved in out-of-merit-energy events receive payment for the energy they deliver and additional payments to suppliers on the margin. The out-of-merit volume multiplied by price difference in Table 9 does not necessarily correspond to actual PSM payments. PSM is based on the difference between offers and hourly pool price, whereas the *Vol. * Price Difference* metric used here is a comparison of offers to minute-by-minute SMP.

Figure 36 below illustrates the duration distribution of out-of-merit-energy events. A majority of events begin at the top-of-the-hour and persist for a few minutes before the asset receives a corrective dispatch to a lower level.

Figure 36: Duration distribution of out-of-merit-energy events



From 2018 to July 2, 2019, most events lasted one or two minutes. From July 3, 2019 to May 31, 2021, most events lasted three to four minutes, and none lasted less than three minutes. This change appears to relate to the delay between the AESO initiating a current hour dispatch instruction and the instruction's effective time. Prior to July 3, 2019, current hour energy dispatches were effective at the time the instruction was initiated. A change to ADaMS, effective July 3, 2019 resulted in all current hour energy dispatches becoming effective at the top-of-the-minute, plus two minutes.[35] As a result, a dispatch instruction that is initiated less than a minute after the top-of-the-hour would not be effective until three minutes into the hour, potentially explaining why out-of-merit-energy events had longer durations after July 3, 2019. The MSA expects the duration of these events to decrease following a change to ADaMS effective June 30, 2021, that makes current hour dispatches effective at the top-of-the-minute plus one minute.[36]

---

[35] AESO, ADaMS Notice – June 18, 2019

[36] AESO, ADaMS Notice – June 15, 2021

Additionally, the frequency of these events has declined in 2021 as a result of several internal system improvements the AESO has implemented.

From January 1, 2018 to May 31, 2021, over 85,000 instances of system marginal price changes were analyzed,[37] and only 103 SMP changes, or 0.1%, had associated out-of-merit-energy events. These events appear to be uncommon, and only a few settlement intervals account for a majority of the observed events.

5.2 Small Scale Generation Regulation

In Q2 2021 the MSA received a complaint regarding the *Small Scale Generation Regulation* (SSGR). The SSGR provides various benefits to eligible, primarily renewable, distribution-connected small scale, or community generators. The complainant took issue with the SSGR's mandated provision of dispatch services by the Balancing Pool to eligible generators at no cost. The complainant suggested that it is the responsibility of larger eligible generators to opt out of section 7 of the SSGR and the associated dispatch services to maintain a level playing field.

The MSA found that the issue did not warrant investigation. The MSA reached the decision not to investigate because the conduct is in compliance with the specific provisions of SSGR and is not in breach of section 6 of the *Electric Utilities Act* or the *Fair, Efficient and Open Competition Regulation*. The MSA is of the view it is at the discretion of eligible generators whether to opt out of section 7 of the SSGR.

[37] The SMP changes analyzed do not include periods with incomplete data, or hours during which there were transmission constraint rebalancing charges.

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 June 30, 2021 the MSA closed 216 ISO rules compliance matters, as reported in Table 10.[38] An additional 124 matters were carried forward to the next quarter. During this period 37 matters were addressed with NSPs, totalling $54,750 in financial penalties, with details provided in Table 11.

[38] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 216 closed matters, one matter was rejected and one matter was withdrawn.

Table 10: ISO rules compliance outcomes from January 1 to June 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	9	2	2
203.1	3	1	-
203.3	49	6	-
203.4	37	2	5
203.6	5	1	-
205.3	8	3	-
205.4	4	-	-
205.5	8	4	2
205.6	8	11	3
205.8	1	-	-
301.2	1	-	-
304.3	1	-	-
304.4	1	1	-
306.4	9	-	-
306.5	2	1	-
502.5	2	-	-
502.6	3	-	-
502.8	-	1	-
505.3	1	-	-
505.4	8	-	-
Total	**165**	**37**	**12**

Table 11: Specified penalties issued between January 1 and June 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**	**306.5**	**502.8**		
Balancing Pool									500					500	2
Campus Energy Partners LP								500						500	1
Canadian Hydro Developers, Inc.		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.										8,500				8,500	4
ENMAX Cavalier LP					750									750	1
Hut 8 Holdings Inc.								750						750	1
Milner Power Limited Partnership by its General Partner Milner Power Inc.				500								1,500		2,000	2
Northstone Power Corp.			1,000		1,500					750				3,250	4
TA Alberta Hydro LP					5,000			500	500					6,000	3
TransAlta Corporation													500	500	1
TransAlta Generation Partnership	500	500			1,250				10,000		500			12,750	5
TransCanada Energy Sales Ltd.							750							750	1
Voltus Energy Canada Ltd.										14,000				14,000	6
West Fraser Mills Ltd.					750									750	1
Whitecourt Power Ltd.		500												500	1
Total	500	1,250	1,000	500	10,000	2,250	750	1,750	11,000	23,250	500	1,500	500	54,750	37

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

103	Administration
201	General (Markets)
203	Energy Market
205	Ancillary Services Market
301	General (System Reliability and Operations)
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 June 30, 2021, the MSA addressed 56 O&P ARS compliance matters, as reported in Table 12.[39] One additional matter was carried forward to the next quarter. During this period, six matters were addressed with NSPs, totalling $9,000 in financial penalties, with details provided in Table 13. For the same period, the MSA addressed 166 CIP ARS compliance matters, as reported in Table 14,[40] and 49 matters were addressed with NSPs, totalling $120,875 in financial penalties. An additional 46 matters were carried forward to the next quarter.

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

[40] Of the 166 closed matters, one matter was rejected.

Table 12: O&P ARS compliance outcomes from January 1 to June 30, 2021

Reliability standard	Forbearance	Notice of specified penalty
COM-001	1	-
EOP-001	1	-
EOP-005	2	-
EOP-008	2	-
FAC-003	1	-
FAC-008	6	5
FAC-501-WECC	1	-
IRO-008	2	-
PER-003	1	-
PER-005	3	-
PRC-001	1	-
PRC-002	2	-
PRC-005	10	1
PRC-018	1	-
PRC-023	2	-
VAR-002	11	-
VAR-002-WECC	3	-
Total	50	6

Table 13: Specified penalties issued between January 1 and June 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
TransAlta Generation Partnership		2,250	2,250	1
Western Sustainable Power Inc.	2,250		2,250	2
Total	6,750	2,250	9,000	6

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

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

Table 14: CIP ARS compliance outcomes from January 1 to June 30, 2021

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	5	2	4
CIP-003	3	5	-
CIP-004	23	8	2
CIP-005	4	6	-
CIP-006	9	3	2
CIP-007	40	11	-
CIP-009	2	1	-
CIP-010	17	10	-
CIP-011	3	3	-
CIP-014	2	-	-
Total	108	49	8

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

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