Q2/18 Quarterly Report

April - June 2018

August 3, 2018

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

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1. Wholesale Market

1.1 Summary

The second quarter of the calendar year is historically characterized by increased hydro generation availability leading to increased imports on the interties coupled with lower Alberta demand due to milder temperatures. The resulting impacts on the electricity market are a higher supply cushion and lower pool prices. The result of this is that generators generally schedule more maintenance on their units at this time of year. The increased scheduled maintenance typically levels out the supply cushion and the corresponding pool prices, to some degree.

Table 1: Market Summary

		2017	2018	*Change*
Pool Price (Avg $/MWh)	Apr	19.10	40.55	*112%*
	May	21.90	63.77	*191%*
	Jun	16.78	63.44	*278%*
	Q2	**19.29**	**56.01**	***190%***
Demand (AIL, GWh)	Apr	6,378	6,687	*5%*
	May	6,507	6,743	*4%*
	Jun	6,388	6,622	*4%*
	Q2	**19,273**	**20,052**	***4%***
Gas Price (Avg $/GJ)	Apr	2.69	1.42	*-47%*
	May	2.83	1.11	*-61%*
	Jun	2.38	0.91	*-62%*
	Q2	**2.64**	**1.14**	***-57%***
Wind (GWh)	Apr	360	318	*-12%*
	May	352	300	*-15%*
	Jun	370	347	*-6%*
	Q2	**1,082**	**965**	***-11%***
Exports (GWh)	Apr	-260	-542	*108%*
	May	-305	-602	*97%*
	Jun	-271	-520	*92%*
	Q2	**-836**	**-1,664**	***99%***
Supply Cushion (Avg MW)	Apr	2,563	1,751	*-32%*
	May	2,008	1,833	*-9%*
	Jun	2,759	1,950	*-29%*
	Q2	**2,439**	**1,845**	***-24%***

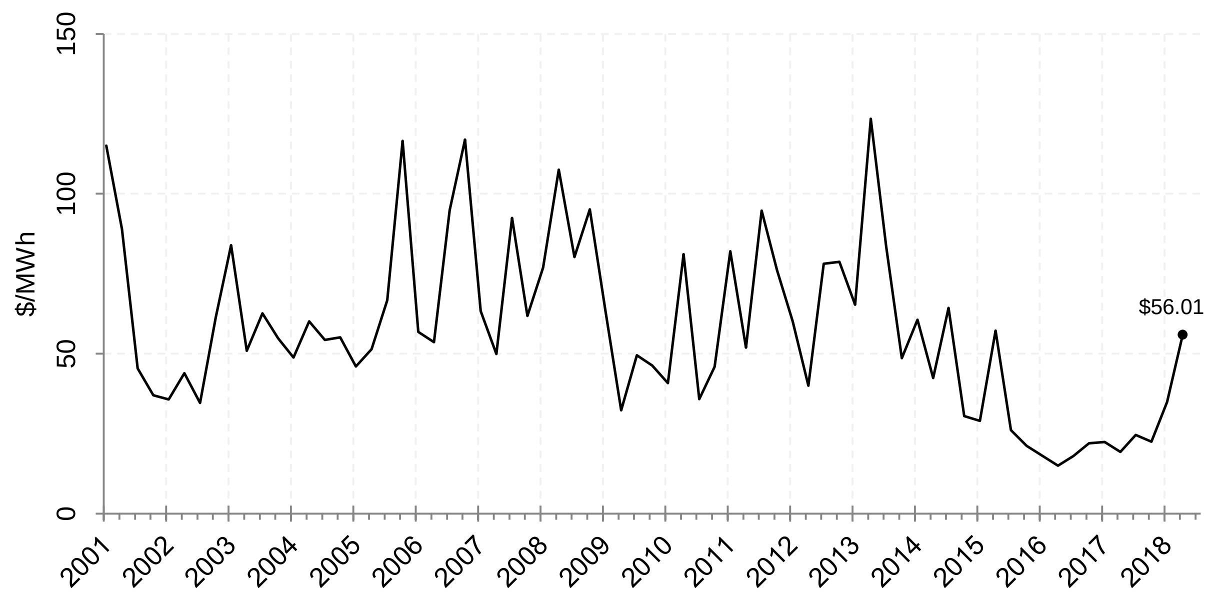
In Q2/18, pool prices were higher than in recent years and averaged $56.01/MWh ($25.75/MWh ext. off-peak, $71.14/MWh ext. on-peak). This is a 190% increase compared to the same period in 2017. Figure 1 shows that the Q2/18 average quarterly price is appreciably higher than those observed since mid-2015.

The increase in pool price is largely explained by a tighter supply cushion coupled with higher offer prices from a few market participants. Together, these factors may represent a return to historical prices prior to mid-2015.

Wind generation continues to play an increasing role in the Alberta electricity market. In spring, wind generation is relatively strong, on average, but, as always, is subject to a high degree of volatility. With a total installed capacity of 1,445 MW, wind generation in Alberta has the ability to fluctuate by hundreds of megawatts in a very short period of time. This materially influences the supply cushion and the serves to limit the ability of generators to successfully price up the market.

Over the past year, Alberta has seen a strengthening economy as it continues to recover from the recession. This is reflected in the 4% year-over-year load growth observed in the quarter.

Figure 1: Quarterly Pool Prices



In Q2/18, the average supply cushion was significantly lower year-over-year. It was also lower than for Q1/18 (1,845 MW vs 2,135 MW) due, in part, to the mothballing of Sundance #3 and #5 at the end of Q1/18.

Figure 2: Average Q2 Supply Cushion vs Pool Price

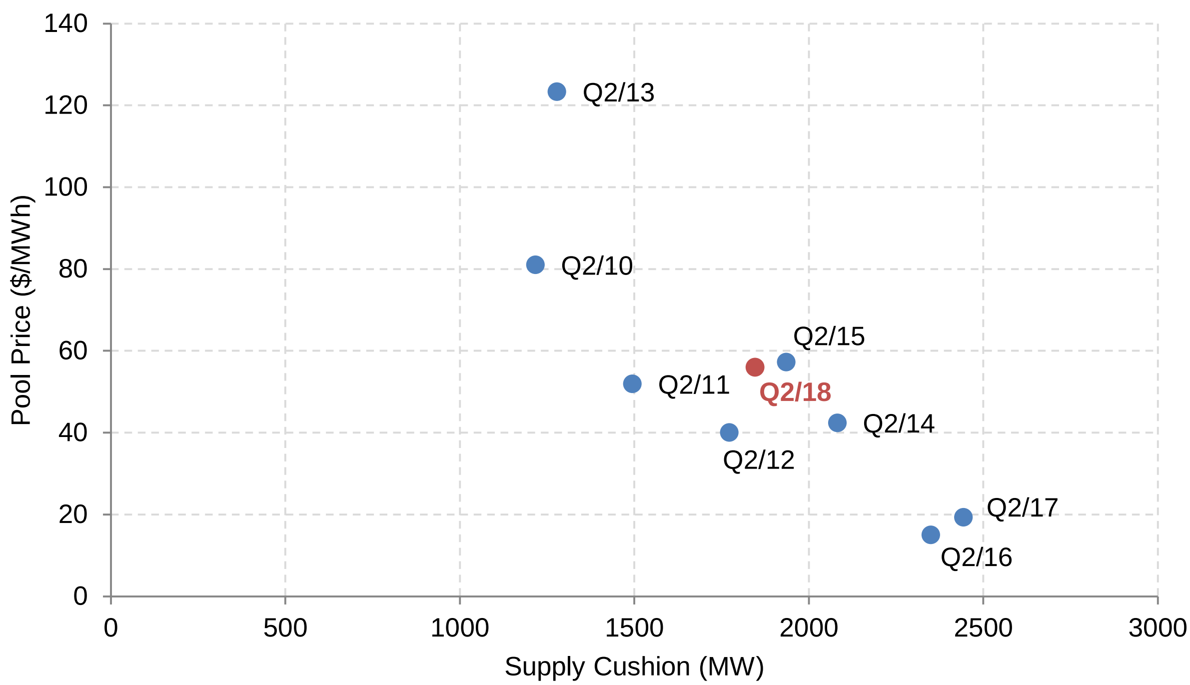


Figure 2 illustrates the relationship between average supply cushion and average pool price. In periods where average supply cushion is low, average pool price tends to be higher, although the distribution of hourly supply cushion has a significant effect.

As observed, the average supply cushion in Q2/18 was higher than the previous second quarters from 2010-2013, but lower than those same quarters from 2014-2017. This correlates reasonably well with the average quarterly pool prices observed in Figure 1.

1.2 Pool Price Events

Figure 3 shows the hourly pool price for Q2/18. Most of the high price events were clustered in groups of several days during the second half of the quarter.

As previously discussed, the high prices observed during the quarter were primarily the result of tighter supply cushion levels accentuated by economic withholding by a few market participants.

Figure 3: High pool price periods during Q2/18

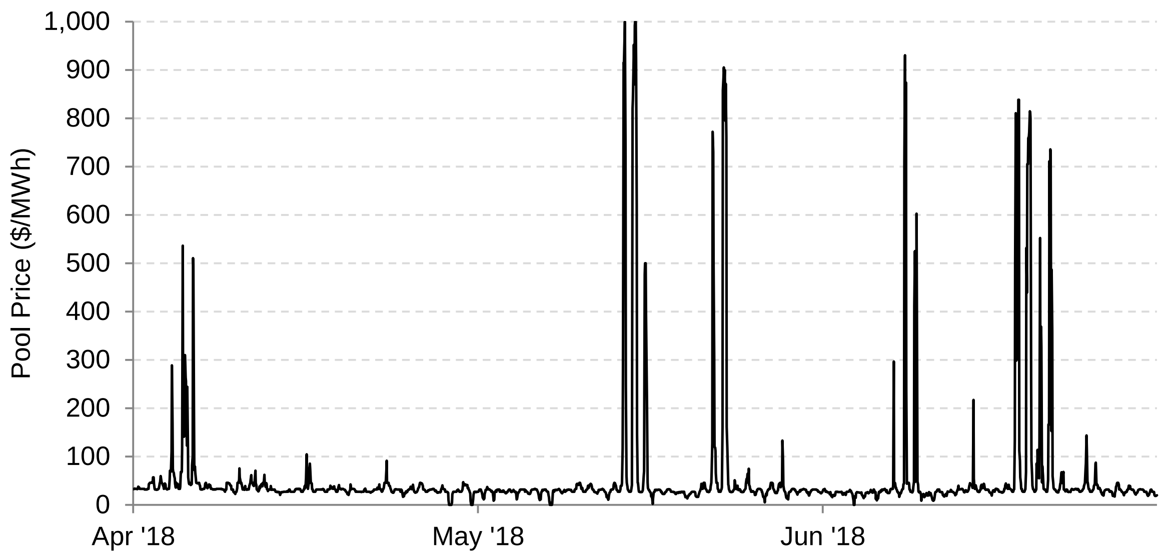
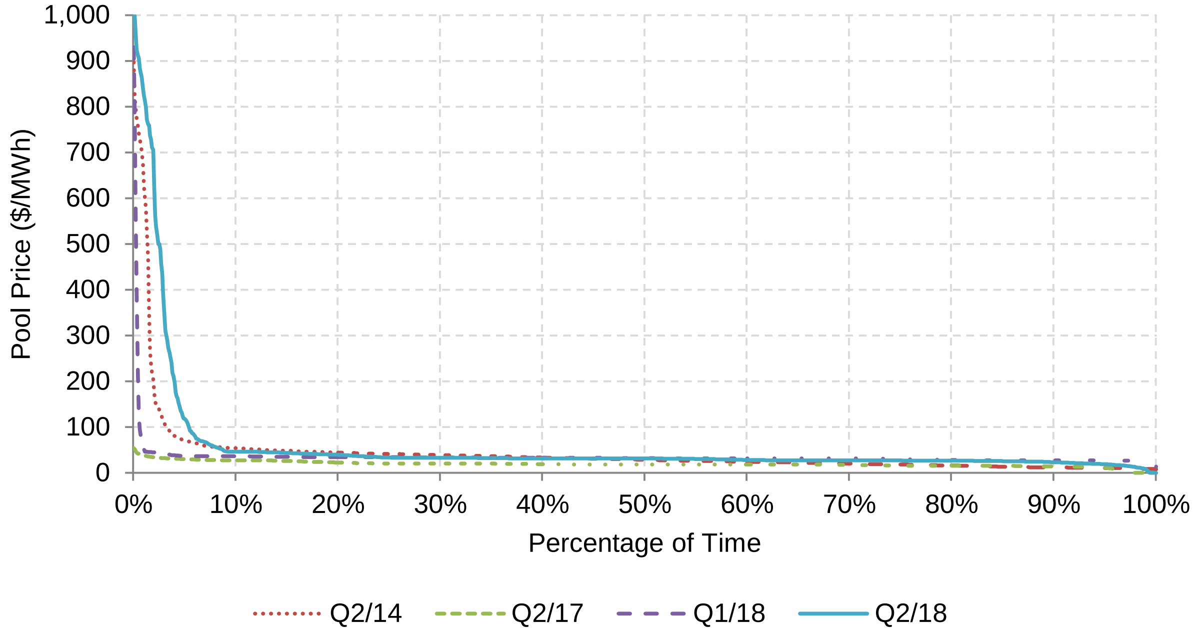


Figure 4 shows the pool price duration curve for Q2/18 compared to previous quarters. As illustrated, there were more high-price events in Q2/18 than in recent quarters over the past two years. Conditions in Q2/14 are more representative of the current quarter.

While the pool price was up compared to recent quarters, the percentage of hours in which these high prices occur remains relatively low. Only 8% of hours during Q2/18 had pool prices above the quarterly average of $56.01/MWh. In the MSA's view, the key take away is that the average quarterly pool price is heavily influenced by a small proportion of high-priced hours.

Figure 4: Pool Price Duration Curve



ISO Rule Section 306.7: *Mothball Outage Reporting* was introduced on June 7, 2016 as an expedited rule, which allows generators to withdraw uneconomic units from the Alberta power market for a period of up to two years.

On April 1, 2018, TransAlta mothballed Sundance #3 and #5 (368 MW and 406 MW, respectively) as it had announced on December 6, 2017. This reduced the total generation supply in Alberta by 774 MW starting at the beginning of Q2/18.This marks the second time ISO Rule Section 306.7 has been used been used by TransAlta in 2018 as Sundance #2 (280 MW) was mothballed on January 1, 2018.[1] Collectively, these three units total 1,054 MW of coal generation mothballed under ISO Rule Section 306.7 in 2018. On July 18, 2018 TransAlta announced that Sundance #2 will be retired effective July 31, 2018.[2]

As a result of Sundance #1 being retired and Sundance #2, #3, and #5 being mothballed in Q2/18, there has been a significant tightening of the supply cushion relative to the previous two years. This is shown in Figure 5.

[1] On April 19, 2017, TransAlta announced that it would mothball Sundance #2 effective January 1, 2018. On December 6, 2018, TransAlta announced that it would mothball Sundance #3 and #5 effective April 1, 2018 and Sundance #4 effective April 1, 2019. Sundance #1 was retired on January 1, 2018.

[2] On July 18, 2018, TransAlta announced that effective July 31, 2018, it would retire the currently mothballed Sundance #2 unit due to its shorter useful life relative to other units, age, size, and the capital requirements needed to return the unit to service.

Figure 5: Supply Cushion Duration Curve

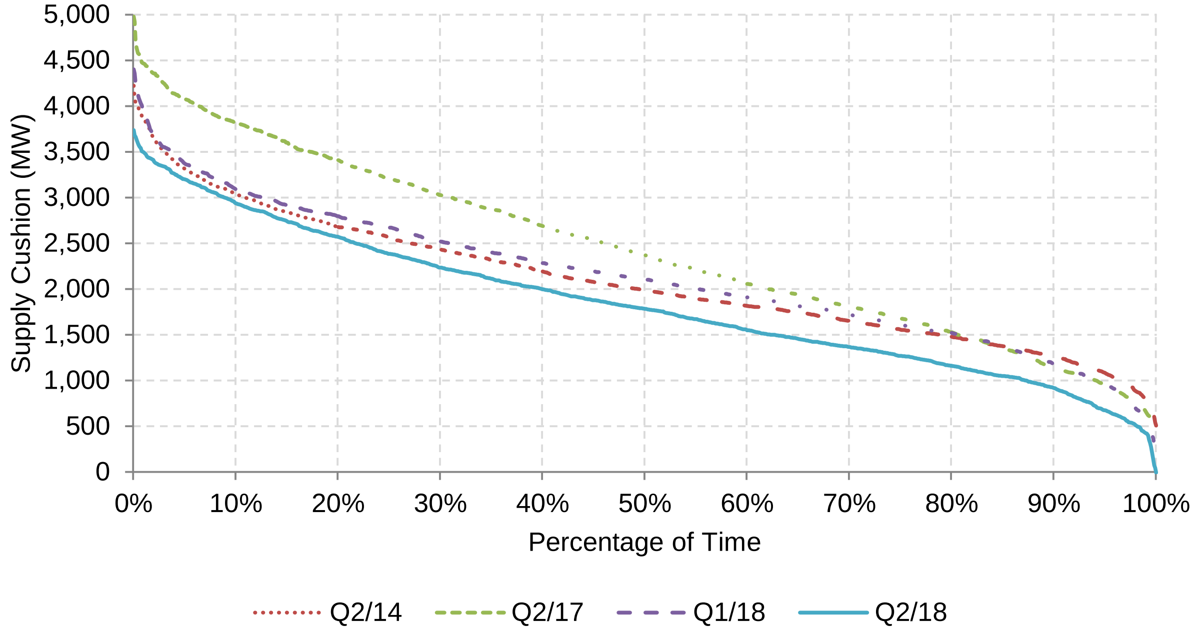


Figure 6: Hourly Supply Cushion vs Pool Price

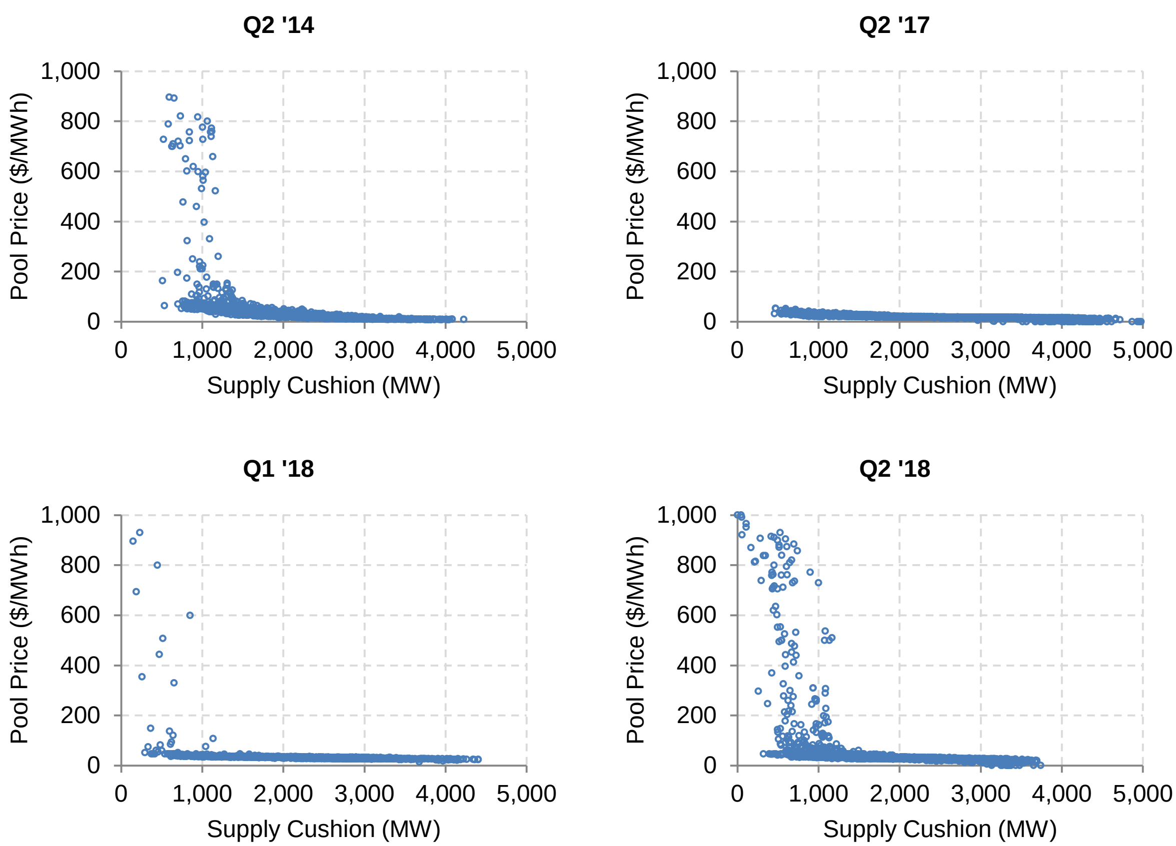


Figure 6 shows the relationship between the supply cushion and the pool price for Q2/18, compared to other recent quarters. It is evident that the Q2/18 chart differs from Q1/18 and Q2/17 while being similar to Q2/14. This is due to the re-emergence of economic withholding in the market, offer behaviour that has been relatively absent for the past two years.

1.3 Review of High Priced Events

Thursday, April 5 – Friday, April 6

Pool prices on Thursday, April 5 and Friday, April 6 were relatively high with the daily averages settling at $148/MWh and $96/MWh, respectively. Hourly pool prices on both days spiked to over $500/MWh. The market was tight at this time due to low wind generation and unit outages. Sundance #2, #3 and #5 had recently been mothballed and Shepard and Genesee #2 were offline for maintenance. This left a total of over 2,300 MW of thermal generation offline. Load peaked at 10,200 MW during the morning of April 5 and supply cushion during the peak hours was approximately 1,000 MW. In addition to these market fundamentals, approximately 800 MW of thermal generation was priced above $500/MWh during the price spikes on April 5, with approximately 500 MW being controlled by a single market participant. In HE 09 of April 6, 900 MW of thermal generation was priced above $500/MWh. This offer behaviour was partly responsible for the pool price clearing at $510/MWh in this hour.

Monday, May 14 – Wednesday, May 16

Pool prices were elevated on May 14, 15, and 16. The daily average pool prices for the three days were $239/MWh, $396/MWh, and $124/MWh, respectively. A number of units were offline during this time including Sundance #2, #3, and #5 which continued to be mothballed. In addition, Sundance #4, Sundance #6, and Keephills #1 were all on an outage, and Joffre was heavily derated. Battle River #3 was commercially offline (available but not online) until the morning of May 15 and there was over 2,200 MW of coal generation offline when Battle River #3 came back on. In addition, the MT intertie was out of service on May 14, and the BC-MT intertie had a maximum net import capability of approximately 600 MW during this event. Market demand for electricity peaked at 9,998 MW and wind generation was moderate, averaging 400 MW.

Market conditions were so tight that pool prices cleared at the offer cap of $999.99 on both May 14 (for one hour) and 15 (for two hours). In addition, at 16:41 on May 14 the AESO declared an Energy Emergency Alert (EEA1), which ended at 18:08 on May 14.

In addition to the tight market fundamentals, the MSA finds that market participant offer behaviour contributed to the high pool prices observed during this event. For example, in HE 14 on May 14 over 600 MW of thermal generation was priced above $100/MWh.

Tuesday, May 22 – Wednesday, May 23

High load, low wind generation, unit outages, and supplier offer behaviour caused prices to spike on May 22 and May 23, with daily average pool prices of $142/MWh and $324/MWh, respectively. Sundance #2, #3 and #5 continued to be mothballed and the Joffre plant was heavily derated during this event. In addition, there was an issue with the Keephills #2 plant which forced the unit to come offline at around 21:00 on May 22. Temperatures in the Calgary area reached a high of 26°C helping load to peak at 10,294 MW on May 22. Wind generation was low throughout this event, with total wind averaging only 110 MW during the peak hours.

As a consequence of these fundamentals the market was relatively tight. The market supply cushion during peak hours averaged 1,170 MW on May 22 and 880 MW on May 23. In addition to these market fundamentals, the MSA observed that market participant offer behaviour contributed to the pool price spikes. For example, 900 MW of thermal generation was priced above $100/MWh in HE16 of May 22.

Friday, June 8 – Saturday, June 9

Pool prices spiked to over $900/MWh on June 8, sending the daily average pool price to $161/MWh. The daily average pool price for June 9 was $116/MWh with the pool price peaking at $602/MWh in HE 16. These prices were the result of unit outages combined with market participant offer behaviour. Sundance #2, #3, and #5 remained mothballed. Further, Sundance #4 and Battle River #3 were commercially offline for this event. In addition, Keephills #1 went offline for operational reasons at around 21:00 on June 8. Therefore, there was up to 2,000 MW of coal offline during the event. In addition to this, the combined cycle plant, Calgary Energy Centre (320 MW) was on an outage.

Load on the Friday peaked at 10,200 MW and was 9,700 MW on the Saturday. In addition, the BC-MT intertie was only available for approximately 600 MW on Saturday whereas it was available for 750-900 MW on Friday. Total wind generation was relatively small, averaging approximately 450 MW during the peak hours on both days.

Along with the tight market fundamentals the MSA finds that market participant offer behaviour was a factor in the high pool prices seen during this event. For example, 400 MW of thermal generation was priced above $900/MWh in HE15 of June 8.

Monday, June 18 – Thursday, June 21

Pool prices spiked again in late June with the daily average pool prices for June 18 – 21 of $278/MWh, $328/MWh, $107/MWh, and $186/MWh, respectively. Unit outages, low wind generation and market participant offer behaviour were all factors driving these high prices. In addition to the mothballed units, Keephills #2 and Sundance #6 were operationally unavailable for this event. Also, the Calgary Energy Centre (320 MW) was on outage and there were a number of cogeneration outages as well. Wind generation during this period was low, with the average total wind being only 170 MW. In addition to the restricted supply, system load peaked at over 10,300 MW on three of the four days.

As a result of these fundamentals, the market was relatively tight, and the hourly supply cushion fell below 500 MW on June 18, 19, and 20. In addition to the market fundamentals, the MSA notes that market participant offer behaviour was again a factor in the high pool prices that were observed. For example, during HE 11 on June 19 480 MW of thermal generation was priced above $600/MWh.

1.4 Alberta Load

Alberta load continues to grow at a fairly healthy pace, largely in step with historical averages which indicates that the market is recovering from the recession in 2015-16.

Figure 7: Growth in Alberta Load (Year-over-year)

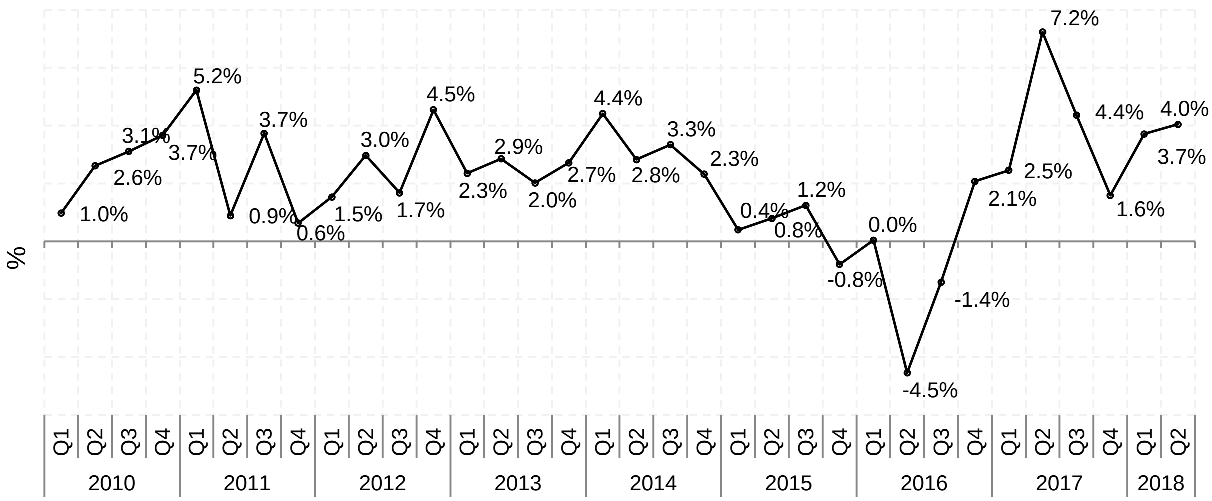
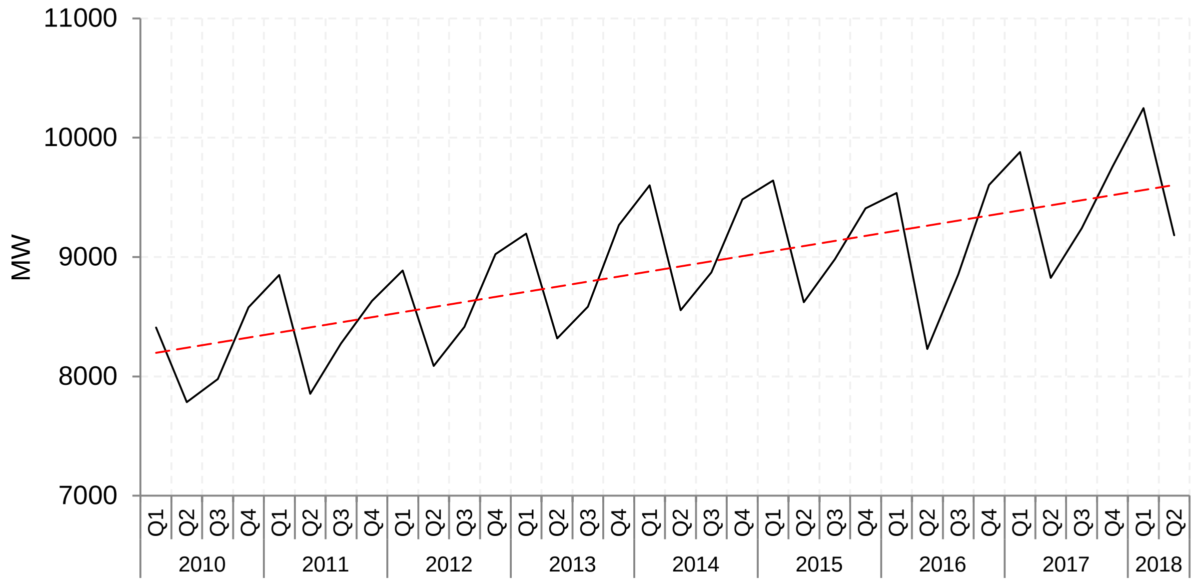


Figure 8: Average Alberta Load (MW)



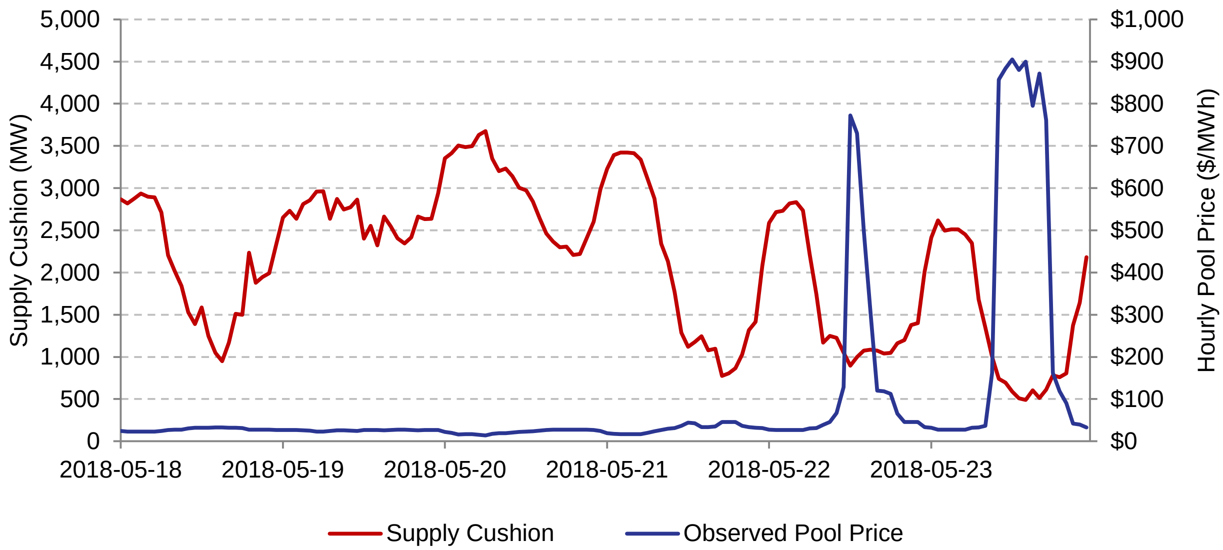
1.5 Efficiency Analysis

Pool prices in Q2/18 were higher than the prices observed in the Alberta market in almost three years. Pricing up by some generators in a moderate number of hours was the main cause of the high quarterly average price.

This section of the report describes an analysis of the price outcomes from an economic efficiency perspective. The MSA has undertaken a preliminary assessment of some of the specific high price events as part of ongoing efforts to understand whether market participants' conduct has supported fair, efficient and open competition.

Figure 9 shows the supply cushion and the pool price between May 18 and May 23, 2018. The figure shows that, over this six-day period, while there were four periods where the supply cushion was less than 1,000 MW there were only two corresponding high priced periods. This indicates the possibility that other factors, such as changes in offer behaviour, precipitated the high price events.

Figure 9: Low Supply Cushion Need Not Lead to High Price Events



As shown in Table 2, over the evening of May 21 the supply cushion fell below 1,000 MW for three hours and approximately 500 MW of thermal generation was priced above $100/MWh, resulting in relatively low prices. Despite a higher supply cushion on the afternoon of May 22, pool prices peaked above $700/MWh due to a greater pricing up by thermal generators. Of the thermal generation offered above $100/MWh on May 22 in HE 13 and 14, the majority of this withheld capacity was coal generation whose offer control was held by a single market participant.

Table 2: More Thermal MW are Withheld in Periods of High Demand, Low Supply Cushion

Date	Supply Cushion (MW)	Demand (MW)	Thermal MW Price Above $100/MWh	Pool Price ($/MWh)
May 21, HE 18	774	9,822	521	46.06
May 21, HE 19	807	9,794	521	46.06
May 21, HE 20	867	9,665	527	45.80
May 22, HE 13	897	10,165	986	772.33
May 22, HE 14	997	10,142	1,050	730.08

The MSA believes that further insight can be gained by estimating the efficiency loss that occurs in different hours. Hours with high efficiency losses are of concern to the MSA.

In the following analysis, the MSA considered both productive and allocative efficiency losses. Productive efficiency losses occur when a high cost resource is dispatched over a low cost resource. An allocative efficiency loss occurs when consumption of electricity is reduced relative to what would have occurred had prices been at a competitive level.

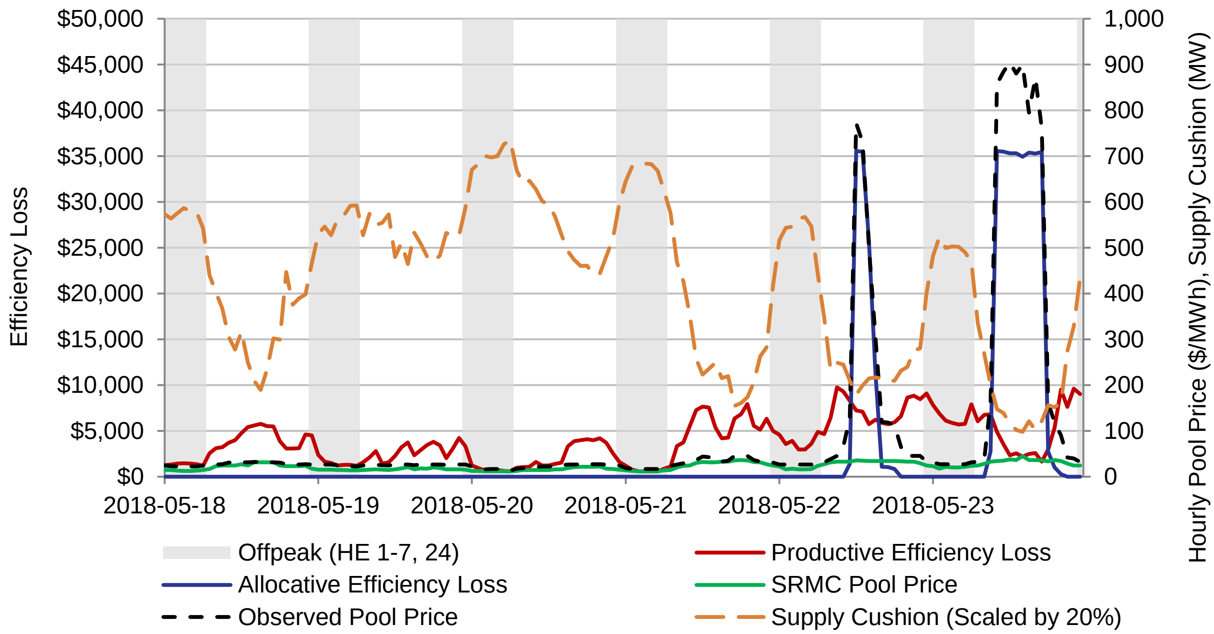
To estimate the extent of the static efficiency losses, the MSA relied on a similar method to that which was presented in the MSA's *Assessment of Static Efficiency in Alberta's Energy-Only Electricity Market* report as part of its 2012 State of the Market Report.[3] In this respect, the MSA notes that the method used to estimate allocative efficiency is relatively simplistic and the results may not be indicative of the actual allocative efficiency loss. However, for the purposes of this report, the MSA considers that the results of the allocative efficiency loss analysis indicate where market power may have been exercised.

As shown in Table 2, the MSA examined the period between May 18 to May 23 to illustrate the magnitude of static efficiency losses that can occur in only one of the high price events listed in Section 1.3 and to provide additional context to the event. Figure 10 shows the efficiency losses throughout the event.

During the period from May 18 to May 23, estimates of productive efficiency losses are generally low during hours where the supply cushion is high. During the high priced hours of May 23, the productive efficiency losses were low which indicates that the high prices did not have a significant impact on which units were dispatched. In other hours where there was a tight supply cushion, even those hours where prices did not increase, the MSA found substantial productive efficiency losses. Over the six-day period, the MSA estimates that $568,307 of productive efficiency losses occurred, of which approximately half occurred on May 22 and May 23, with 44% occurring in hours when the supply cushion was between 1,000 and 2,000 MW.

[3] See Assessment of Static Efficiency in Alberta's Energy-Only Electricity Market, December 21, 2012.

Figure 10: Static Efficiency Losses Occurred During High Price Events



Between May 18 and May 23, the MSA estimates that $402,122 of allocative efficiency losses occurred due to a combination of changes in offer behaviour, low supply cushion, and high demand. All of the allocative efficiency losses are estimated to have occurred on May 22 and May 23.

In conclusion, the MSA finds recent trends in offer behaviour concerning. During periods when market conditions begin to tighten, but prior to conditions of true scarcity, the exercise of market power results in measureable static efficiency losses. The MSA is concerned that future occurrences of static efficiency losses may result in pool prices that are not competitive. The MSA reminds market participants that their conduct must support fair, efficient and open competition. In order to assist market participants in meeting this obligation, the MSA is considering commencing a guideline making process for a guideline on offer behaviour to be in effect during the transition period to a capacity market.

2. Forward Market

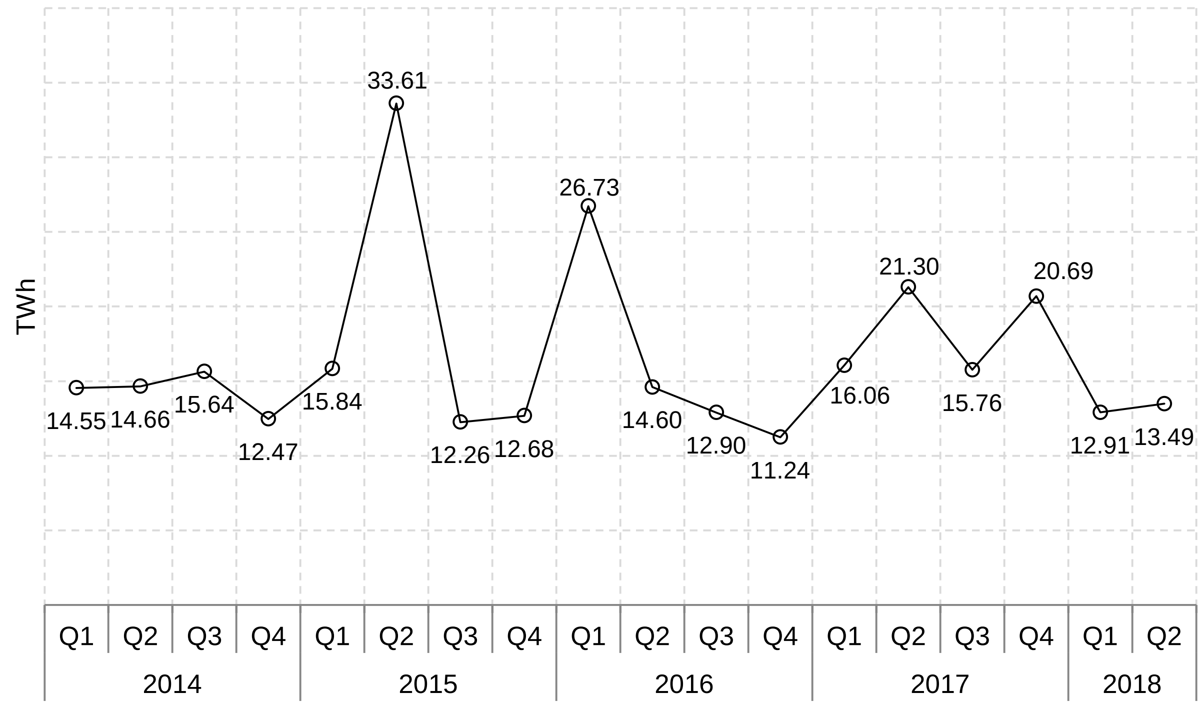
2.1 Trade Volumes

Trade volumes in Q2/18 were moderate, being at the lower end of the range seen in recent years. Trade volumes of monthly contracts remained robust, driven in part by RRO associated trading. The trading of quarterly products has been very thin in the past few years.

Table 3: Trade Volumes by Contract Term (TWh)

		Daily	Monthly	Quarterly	Annual	Other	Total
2015	Q1	0.10	9.96	0.00	4.17	1.60	15.84
	Q2	0.20	10.46	0.00	16.71	1.80	29.18
	Q3	0.06	6.25	0.00	4.40	0.79	11.51
	Q4	0.06	5.87	0.00	5.74	1.01	12.68
	Year	0.42	32.54	0.00	31.03	5.21	69.20
2016	Q1	0.22	9.36	1.58	12.37	3.21	26.73
	Q2	0.19	8.25	0.00	4.50	1.66	14.60
	Q3	0.07	6.80	0.00	4.56	1.47	12.90
	Q4	0.09	5.44	0.00	3.78	1.94	11.24
	Year	0.57	29.85	1.58	25.20	8.28	65.47
2017	Q1	0.06	6.53	0.86	4.57	4.04	16.05
	Q2	0.13	6.87	0.25	11.13	2.90	21.27
	Q3	0.18	6.77	0.00	5.51	3.30	15.76
	Q4	0.06	8.24	0.66	7.50	4.23	20.69
	Year	0.43	28.40	1.76	28.70	14.48	73.78
2018	Q1	0.15	7.28	0.00	4.47	1.02	12.91
	Q2	0.16	6.06	0.04	5.75	1.47	13.49
	Year	0.31	13.33	0.04	10.23	2.49	26.41

Figure 11: Total Trade Volumes over Time



2.2 Forward Price Curves

The forward curve for the next year, as of late July, is shown in Figure 12. The prices shown here are for flat contracts (7X24).

For regulated residential customers, the RRO procurement is a mixture of flat and extended-peak contracts. If these forward prices persist, the data suggests that the buying necessary for the RRO will result in rates above the Retail Price Cap of 6.8 ¢/kWh (equivalent to $68/MWh), which will therefore bind for regulated customers for some months in the near future.

Figure 12: Forward Price Curve for Monthly Contracts (7 X 24, July 25, 2018)

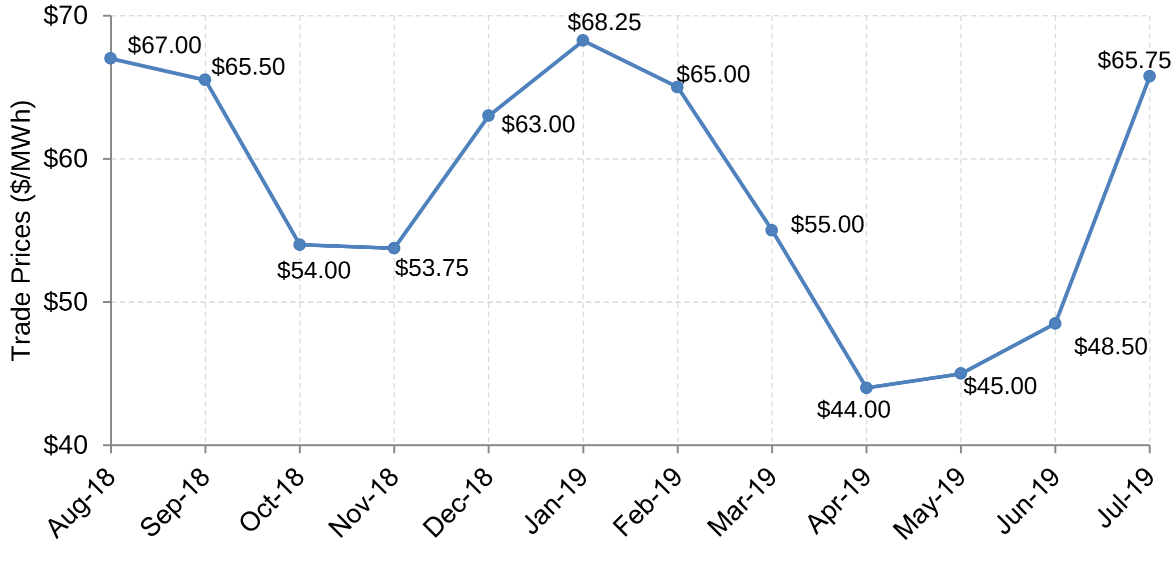


Figure 13: Forward Price Curve for Annual Contracts (7 X 24, July 25, 2018)

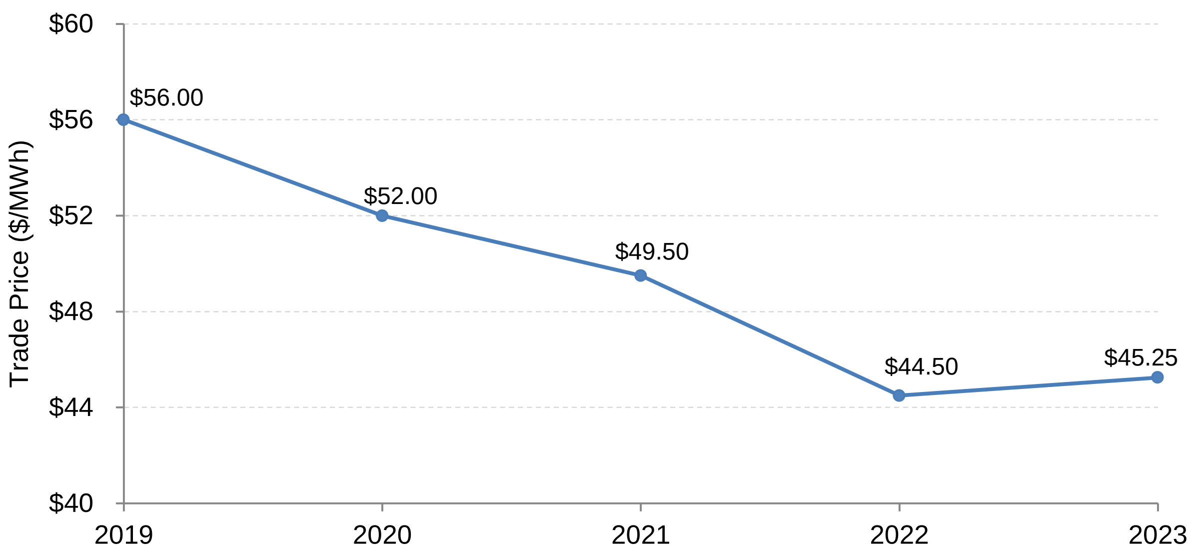
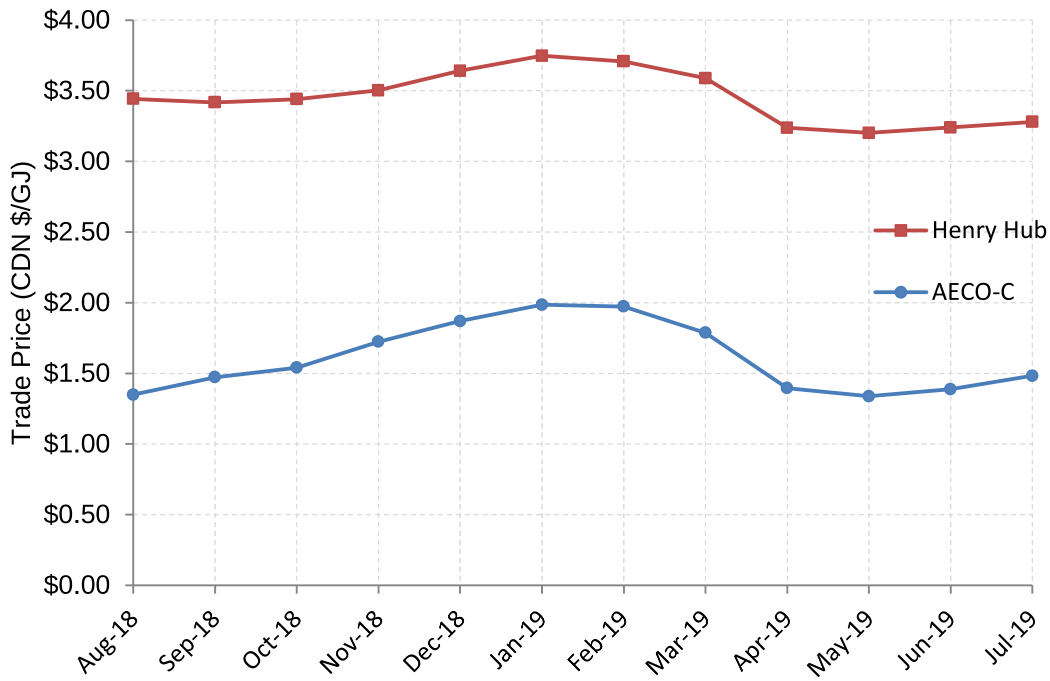


Figure 14 shows the forward curve for natural gas at the AECO-C Hub in Alberta, as well as at the Henry Hub in Louisiana. As shown, the price of natural gas in Alberta is relatively low with August currently trading at $1.35/GJ and December trading at $1.87/GJ. Winter months are typically more expensive as gas is used for heating load. Comparatively, AECO-C is trading at an average discount of $1.90/GJ to Henry Hub for the balance of year. This is partly due to pipeline constraints which limit the amount of natural gas that can be exported from Alberta. This results in inexpensive natural gas for Alberta consumers but reduced income for Alberta natural gas producers.

Figure 14: Forward Curve for Natural Gas, AECO-C Hub and Henry Hub (July 25, 2018)



2.3 Link Between Forward Market Prices and Real-Time Prices

Real time market outcomes can affect traders' views on future market prices. As a consequence there are often spikes in the real-time price for electricity which can move forward market prices upwards, and not necessarily just the near-term future prices. Conversely, depressed real-time prices may lead traders to adjust their expectations of future market prices and forward prices can decrease as a result. The relationship between real-time prices and forward prices has been evident this quarter (Figure 15).

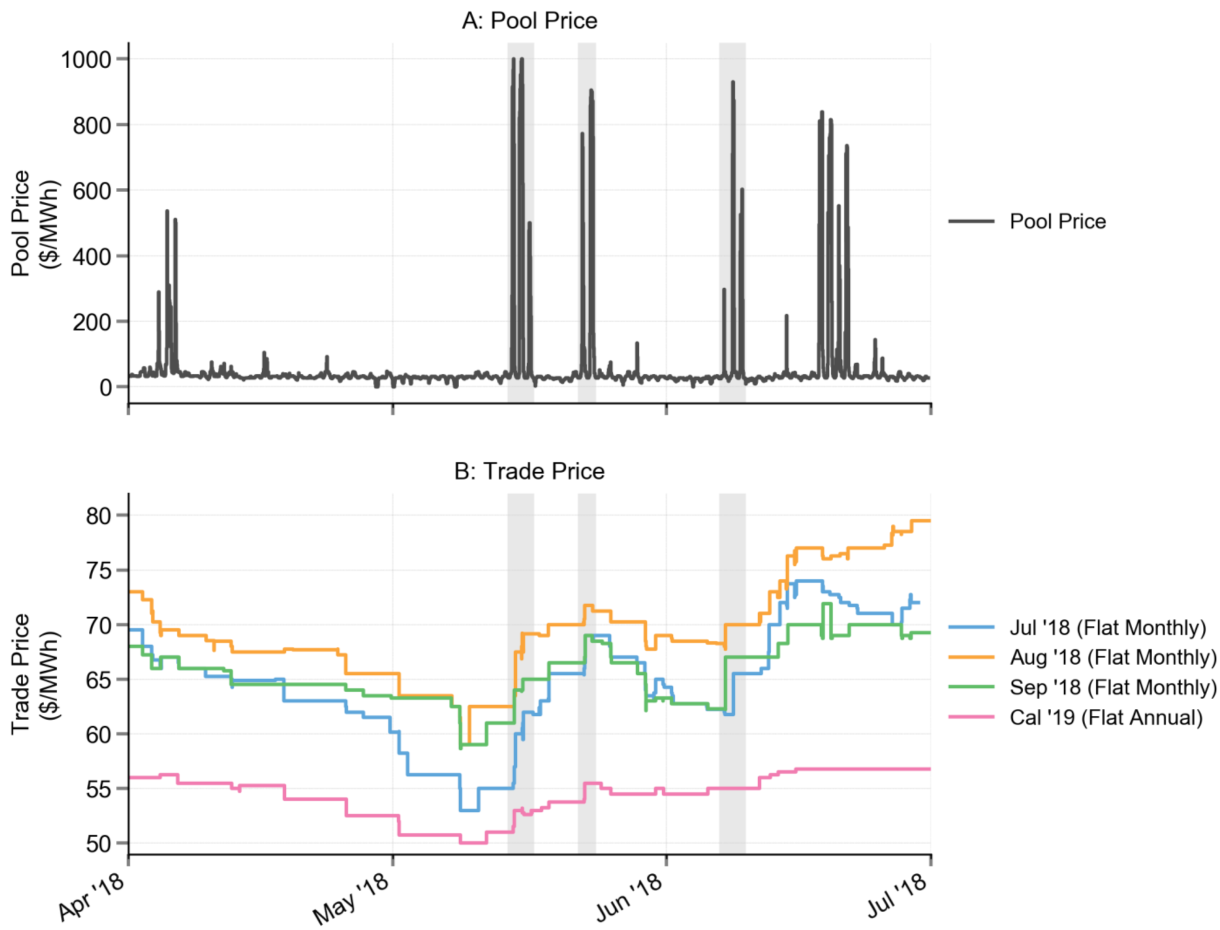
Between May 14 and 16 the market yielded high pool prices due to tight market conditions and supplier offer behaviour. At this time, the forward prices for June, July and August moved up by approximately $6.40/MWh, $7.40/MWh, and $6.40/MWh, respectively. In addition, the MSA observed increases in the forward prices for Calendar 19 and Calendar 20. Calendar 19 increased by $2/MWh over the week of May 14, while Calendar 20 was up by $1.75/MWh compared to where it had been trading previously.

On May 22 and May 23 forward prices again increased in response to real-time market conditions. May 22 and May 23 had pool price averages of $142/MWh and $324/MWh, respectively. As discussed above, these prices were a result of tight market conditions as well as market participant offer behaviour. Around this time there was a run-up of forward prices for June, July and August of $4/MWh, $6/MWh, and $2.75/MWh, respectively. The MSA also observed that the forward price for Calendar 19 moved upwards by approximately $2/MWh.

Spot prices were elevated once again from June 7 to 9. As discussed above, these elevated prices were the result of tight supply conditions in addition to market participant offer behaviour.

Around the time of these events, forward prices for July increased by $3.57/MWh, while flat monthly contracts for August and September increased by $2.25/MWh and $4/MWh, respectively.

Figure 15: Evolution of Forward Prices in response to High Pool Prices during Q2/18



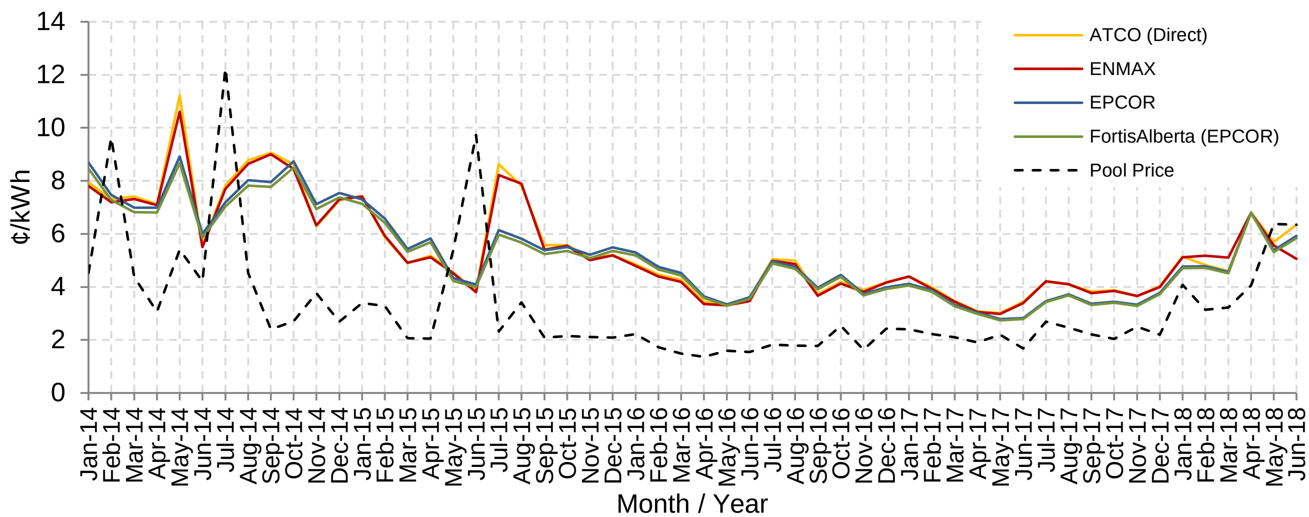
2 Retail Market

3.1 Regulated Retail Market

3.1.1 Regulated Rate Option (RRO)

Q2/18 saw RRO rates continue to rise in response to elevated forward market prices for monthly flat and extended peak products. The Government of Alberta's cap on regulated retail electricity rates bound for the first time in April 2018 and a second time in July 2018 for all of the four largest service areas.

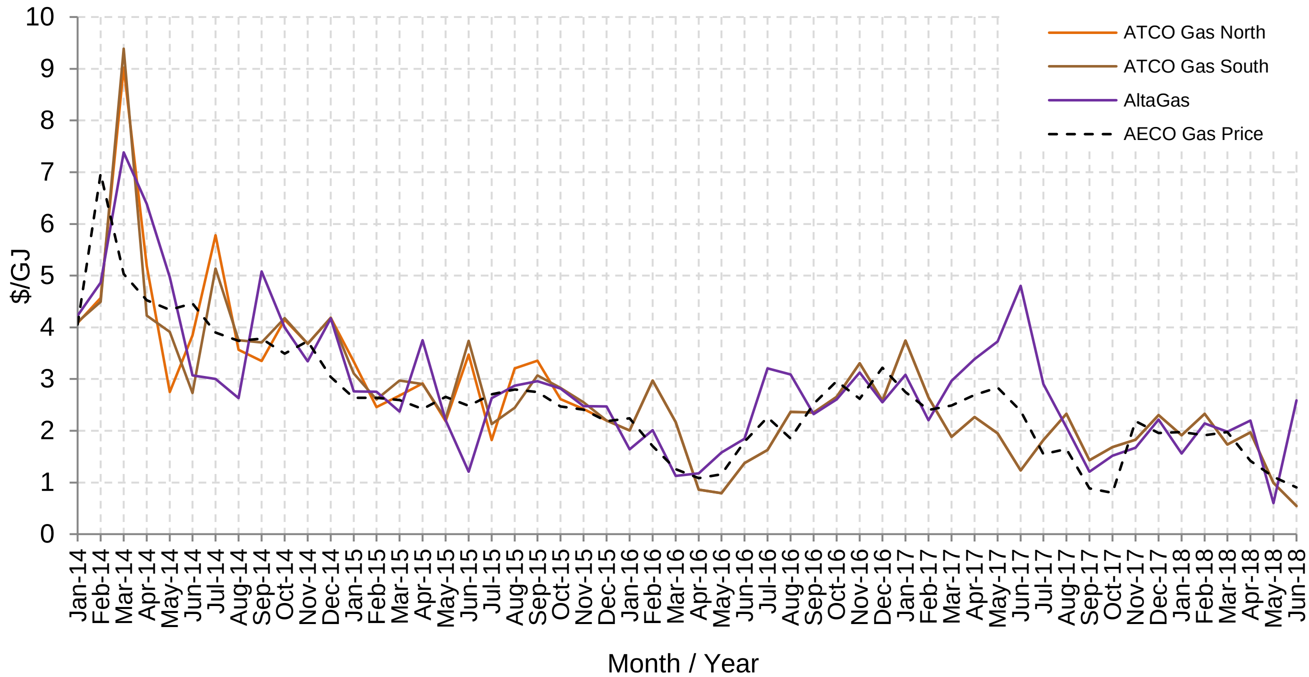
Figure 16: RRO Rates, January 2014 – June 2018



3.1.2 Default Rate Tariff (DRT)

Default Rate Tariff rates generally fell in Q2/18, driven primarily by natural gas fundamentals. DRT rates in the ATCO North and South service areas fell to record lows of $0.544/GJ in June 2018, while rates in the AltaGas service area fell to $0.603/GJ in May 2018.

Figure 17: DRT Rates, January 2014 - June 2018



3.1.3 Energy Price Setting Plans – Recent Developments

On June 15, the Alberta Utilities Commission (AUC or Commission) approved ENMAX's application for its 2016-2018 Energy Price Setting Plan (EPSP).[4] A key issue in the proceeding was ENMAX's commodity risk compensation. Under the approved EPSP, ENMAX's risk compensation is calculated using the Commodity Risk Compensation methodology, also utilized by EPCOR and Direct Energy under their respective 2016-2018 EPSPs.[5] As directed by the Commission, ENMAX's commodity risk compensation formulas are adjusted annually and procurement is expected to begin in July 2018, with the first energy rates coming into effect in November of 2018.[6] The 2016-2018 EPSP will expire on October 31, 2019, at which time it will either be extended on an interim basis or a new EPSP will come into effect.[7]

Direct Energy filed its 2018-2020 EPSP application with the Commission on May 5, 2017.[8] The AUC placed Direct Energy's application in abeyance until September 6, 2017 so that the AUC could finish processing the application for Direct Energy's 2016-2018 EPSP.[9] In its 2018-2020 EPSP application, Direct Energy applied for a fixed level of level of risk compensation of

[4] See AUC Decision 23223-D01-2018 – ENMAX Energy Corporation 2016-2018 Energy Price Setting Plan Second Compliance Filing.
[5] under their 2016-2018 EPSPs
[6] Ibid, PDF Page 27.
[7] Ibid, PDF Pages 20, 21.
[8] See Direct Energy Regulated Services May 2018 – April 2020 Energy Price Setting Plan Application, May 5, 2017, Proceeding No. 22635.
[9] See AUC Recommencement of proceeding, September 6, 2017, Proceeding No. 22635.

$7.97/MWh which is a departure from the Commodity Risk Compensation methodology used in the 2016-2018 EPSPs whereby risk compensation was set based on historical commodity losses.[10] The application proposes an end date of April 30, 2020 for this EPSP, and anticipates a one month period would be required to transition from the 2016-2018 EPSP to the 2018-2020 EPSP.[11] The AUC is currently processing Direct Energy's application and a hearing is scheduled for September of 2018.[12]

The Commission approved EPCOR's 2018-2021 EPSP on May 31, 2018.[13] The Commission's original approval of EPCOR's 2018-2021 EPSP was subject to a number of directives.[14] The directives included adjusting the duration of auction rounds from 15-25 minutes to between 10 and 25 minutes, modifying the return margin calculation to reflect an approved Commission methodology and reporting the historical risk compensation received.[15]

3.1.4 Rate Cap Regulation

The Government of Alberta's regulated retail rate cap bound for the first time in April of 2018 and a second time in July of 2018. Reference rates for rural electrification associations (REAs) and other RRO providers not regulated by the AUC reached 9.03 ¢/kWh in April 2018 and 8.766 ¢/kWh in July 2018.[16] The AUC determines these reference rates as ten percent greater than the average of approved residential RRO rates submitted by the three RRO providers it regulates.[17] Reference rates for REAs and other RRO providers were below the 6.8 ¢/kWh rate cap for May and June 2018. For both April and July, REAs and other RRO providers were reimbursed at a rate equal to the lesser of the difference between their approved RRO rate and 6.8 ¢/kWh or the difference between the AUC reference rate and 6.8 ¢/kWh.

The reference rate for the City of Medicine Hat was 8.21 ¢/kWh and 7.969 ¢/kWh for April and July 2018, respectively. The AUC determines these reference rates as the average of approved residential RRO rates submitted by the three RRO providers it regulates. Reference rates for the City of Medicine Hat for May and June 2018 were below the 6.8 ¢/kWh rate cap. On June 12, the MSA approved Medicine Hat's deferral account statement for April 2018.[18] The City of Medicine Hat does not follow the same submission process used for REAs and other RRO providers, but instead follows a process with a delayed timeline and uses final consumption data rather than forecasts. The MSA has updated its April 2018 rate cap summary table to include the reimbursement amount paid to the City of Medicine Hat (Table 4).

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[10] See Direct Energy Regulated Services May 2018 – April 2020 Energy Price Setting Plan Application, May 5, 2017, Proceeding No. 22635, PDF Pages 12, 24, 25.
[11] Ibid, PDF Pages 5, 35.
[12] See AUC Extension to the process schedule, July 3 2018, Proceeding No. 22635.
[13] See EPCOR Energy Alberta GP Inc. 2018-2021 Energy Price Setting Plan Compliance Filing, April 10, 2018, Proceeding No. 23492.
[14] See AUC Decision 22357-D01-2018 – EPCOR Energy Alberta GP Inc. 2018-2021 Energy Price Setting Plan.
[15] See AUC Decision 23492-D01-2018 – EPCOR Energy Alberta GP Inc. 2018-2021 Energy Price Setting Plan Compliance Filing, PDF Pages 6, 7.
[16] See AUC Rural electrification associations and other regulated rate option providers not regulated by the AUC table.
[17] The AUC regulates RRO rates set by ENMAX, EPCOR and Direct Energy. ENMAX is the RRO provider for the ENMAX service area, EPCOR is the RRO provider for both the EPCOR and FortisAlberta service areas, and Direct Energy is the RRO provider for the ATCO service area.
[18] See MSA April 2018 Approved DASs, PDF Page 37.

Table 4: April 2018 Rate Cap Summary - Updated

Service Area	Consumption Weighted Average RRO Rate/AUC Reference Rate (¢/kWh)[19]	Reimbursement Rate (¢/kWh)[20]	Reimbursement Amount (Thousands)
Direct[21]	7.89	1.09	$979.9
ENMAX[22]	9.28	2.48	$2,615.2
EPCOR[23]	7.87	1.07	$1,635.7
Fortis[24]	7.79	0.99	$2,234.1
Board or Council Approved[25] (MSA Approved)	9.03	2.23	$865.3
City of Medicine Hat[26] (MSA Approved)	8.21	1.41	$314.6
Total			$8,644.7

On July 16, the MSA approved acceptable deferral account statements that it received for July of 2018. Table 5 summarizes the approved and maximum reimbursement rates for July 2018, along with the reimbursement amounts to date, which total $7.633 million dollars (not including the City of Medicine Hat).

[19] Direct, EPCOR, and Fortis have rate classes with varying rates, which were weighted by forecast consumption to produce an average. The AUC Reference Rate is calculated by the AUC for the board or council approved regulated rate tariff entities and the City of Medicine Hat. See AUC Regulated rate option price cap: Electricity price cap information and reference rates.
[20] For Direct, ENMAX, EPCOR, and Fortis, the reimbursement rate is the difference between the calculated weighted RRO Rate and 6.8 ¢/kWh, while for the board or council approved regulated rate tariff entities and the City of Medicine Hat, the values reported are the maximum possible reimbursement rate (the reimbursement rate may be lower if these entities approve a monthly rate that is below the AUC Reference Rate).
[21] See Direct Energy Regulated Services Electric Energy Charges - April 2018 Proceeding 23445, PDF Page 4.
[22] See ENMAX Energy Corporation Electric Energy Charges - April 2018 Proceeding 23442, PDF Page 6.
[23] See EPCOR Energy Alberta GP Inc. Electric Energy Charges and Non-Energy Charges - April 2018 Proceeding 23449, PDF Page 6.
[24] Ibid. EPCOR is the recipient of any deferral account reimbursement for the FortisAlberta service area, as EPCOR is the RRO provider therein.
[25] See MSA April 2018 Approved DASs.
[26] Ibid.

Table 5: July 2018 Rate Cap Summary

Service Area	Consumption Weighted Average RRO Rate/AUC Reference Rate (¢/kWh)[27]	Reimbursement Rate (¢/kWh)[28]	Reimbursement Amount (Thousands)
Direct[29]	7.81	1.01	$882.4
ENMAX[30]	8.42	1.62	$1,868.0
EPCOR[31]	7.85	1.05	$1,713.7
Fortis[32]	7.78	0.98	$2,475.4
Board or Council Approved[33] (MSA Approved)	8.766	1.966	$693.8
City of Medicine Hat (MSA Approved)	7.969	1.169	Not Yet Available
Total			$7,633.3

3.2 Competitive Retail Market

3.2.1 Update to the MSA Retail Statistics

In early August 2018, the MSA published the latest iteration of its retail statistics, which includes retail consumption and site count data up to the end of Q1/18, consistent with the policy of a one quarter delay in publishing the data. This publication includes four new sheets containing graphs and statistics regarding market shares and switching rates. An additional sheet containing data and graphical representations of churn rates since January 2012 has also been included.

The spreadsheet may be found on the MSA's web site under the 'Market Reporting' tab.

3.2.2 Competitive Contract Market Share

Despite steady increases in RRO rates in Q1/18, the share of residential customers on competitive electricity contracts stagnated in that quarter, increasing by only 0.2% relative to December 2017 (Figure 18). This could be explained by consumers feeling secure on the RRO

[27] Direct, EPCOR, and Fortis have rate classes with varying rates, which were weighted by forecast consumption to produce an average. The AUC Reference Rate is calculated by the AUC for the board or council approved regulated rate tariff entities and the City of Medicine Hat. See AUC Regulated rate option price cap: Electricity price cap information and reference rates.

[28] For Direct, ENMAX, EPCOR, and Fortis, the reimbursement rate is the difference between the calculated weighted RRO Rate and 6.8 ¢/kWh, while for the board or council approved regulated rate tariff entities and the City of Medicine Hat, the values reported are the maximum possible reimbursement rate (the reimbursement rate may be lower if these entities approve a monthly rate that is below the AUC Reference Rate).

[29] See Direct Energy Regulated Services Electric Energy Charges - July 2018, June 28, 2018, Proceeding 23686, PDF Page 4.

[30] See ENMAX Energy Corporation Electric Energy Charges - July 2018, June 28, 2018, Proceeding 23689, PDF Page 6.

[31] See EPCOR Energy Alberta GP Inc. Electric Energy Charges and Non-Energy Charges - July 2018, June 28, 2018, Proceeding 23692, PDF Page 6.

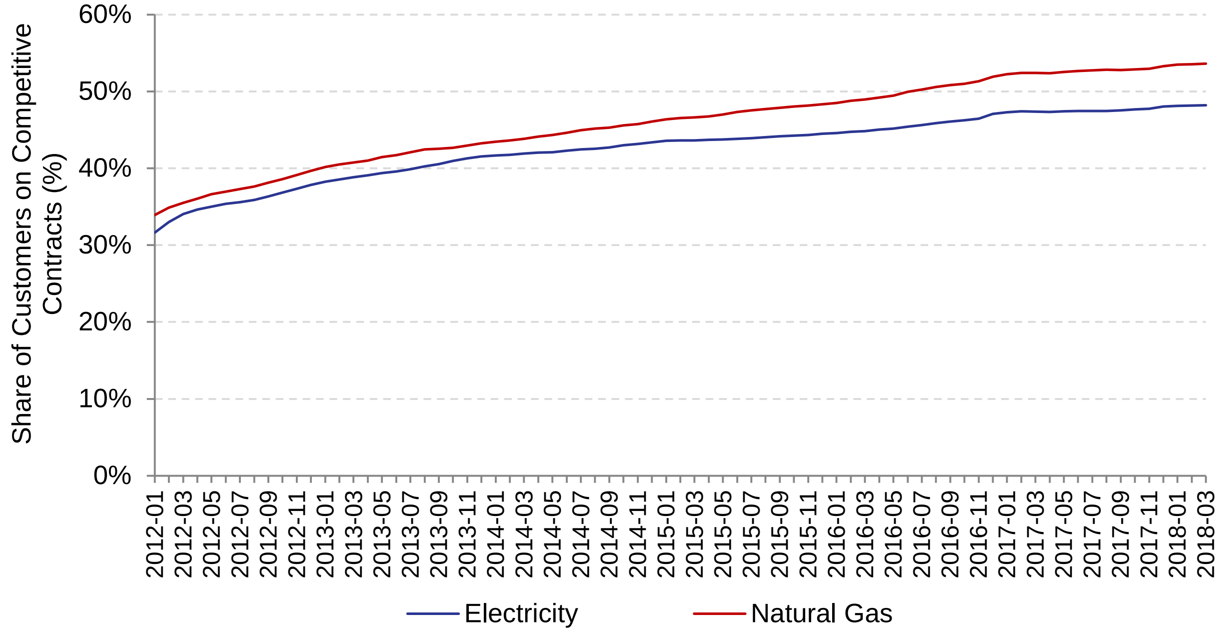
[32] Ibid. Note that EPCOR is the recipient of any deferral account reimbursement for the FortisAlberta service area, as EPCOR is the RRO provider therein.

[33] See MSA July 2018 Approved DASs.

considering the 6.8 ¢/kWh rate cap is in place, although it did not bind in Q1/18. Alternatively, consumers may have found that competitive contracts could not adequately compete with the RRO over price in that quarter. Generally, RRO rates have been quite moderate over the past few years and the impetus to switch to competitive contracts has abated.

Similarly, low DRT rates in Q1/18 may have contributed to the low growth rate of the residential competitive natural gas contract share in that quarter.

Figure 18: Share of Residential Customers on Competitive Retail Contracts, January 2012 – March 2018



3.2.3 Market Shares

Market shares of the largest retailers in the residential customer market segment are presented in Figure 19 and Figure 20. Alberta-wide retailer market shares are generally similar for electricity and natural gas products, which is likely driven by the consumer preference for dual-fuel contracts.

Figure 19: Electricity Retailer Market Shares, Residential Customers, All Service Areas, January 2012 – March 2018

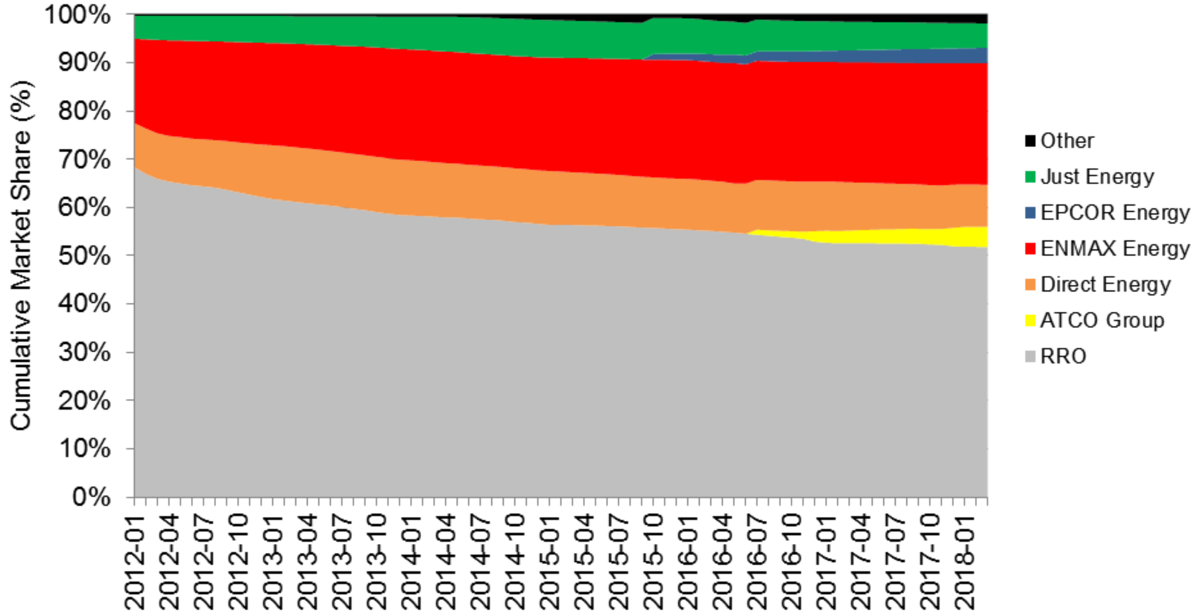
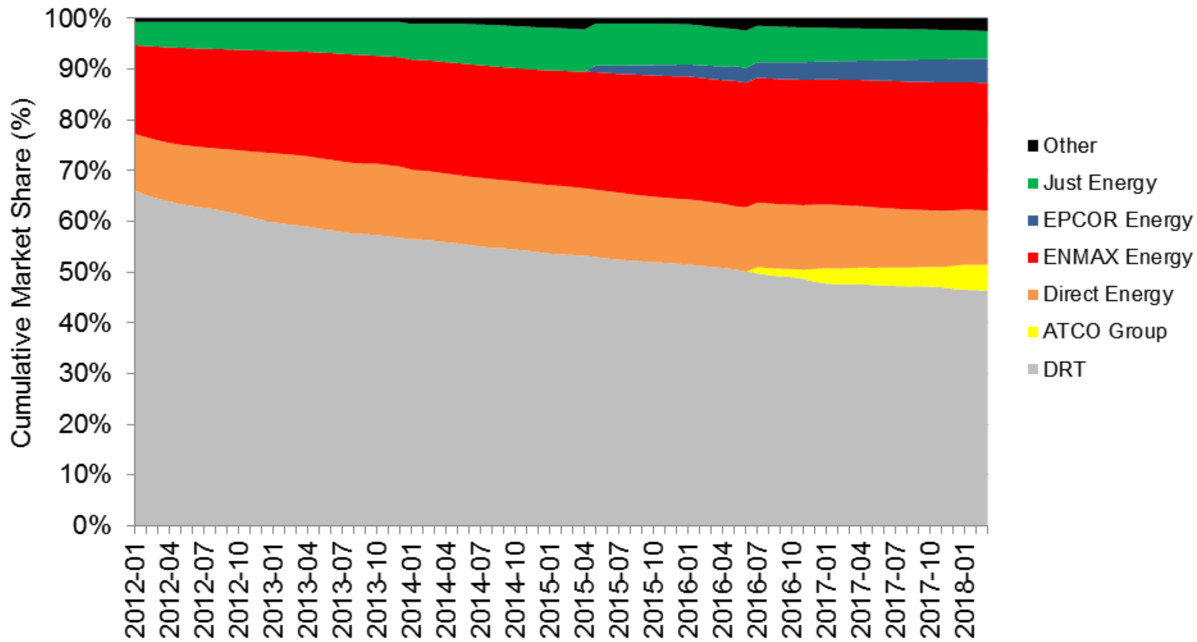


Figure 20: Natural Gas Retailer Market Shares, Residential Customers, All Service Areas, January 2012 – March 2018



The market shares of the largest retailers by service area as of March 2018 are presented in Figure 21 and Figure 22. These figures indicate the likely presence of co-branding effects in the residential retail market, most notably in the ENMAX and EPCOR service areas, where the RRO provider therein has significant market share not observed in other service areas.[34]

Figure 21: Electricity Retailer Market Shares by Service Area, Residential Customers, March 2018

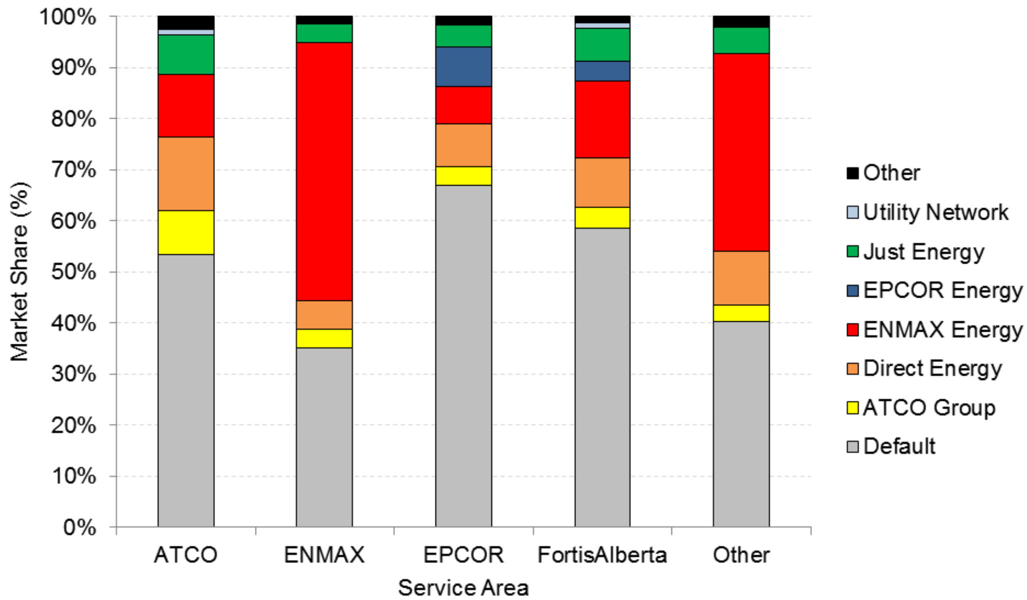
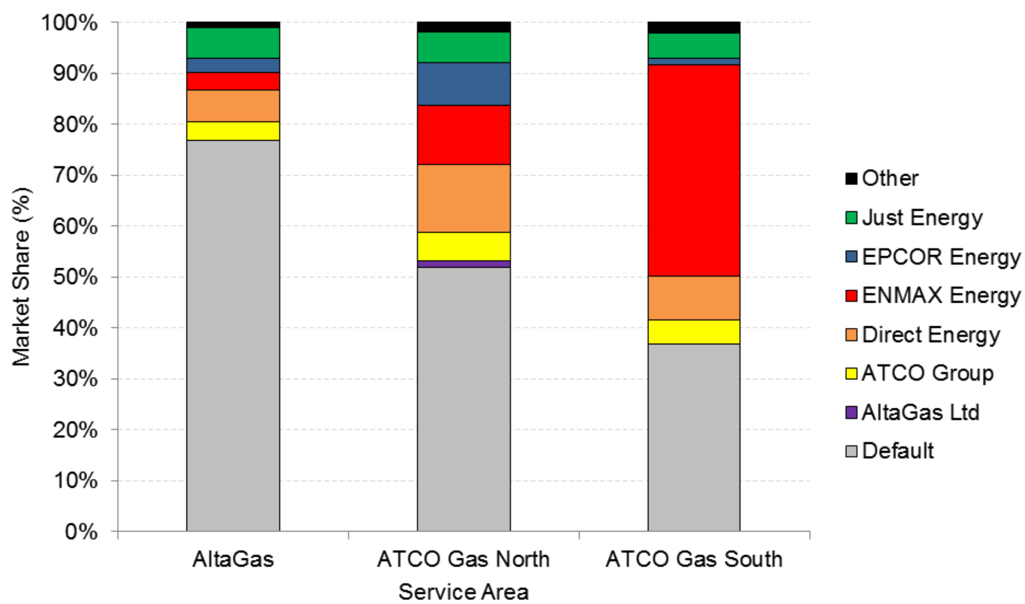


Figure 22: Natural Gas Retailer Market Shares by Service Area, Residential Customers, March 2018



[34] Note that the 'Other' Service Area category includes a number of municipalities, many of whom receive RRO services from ENMAX.

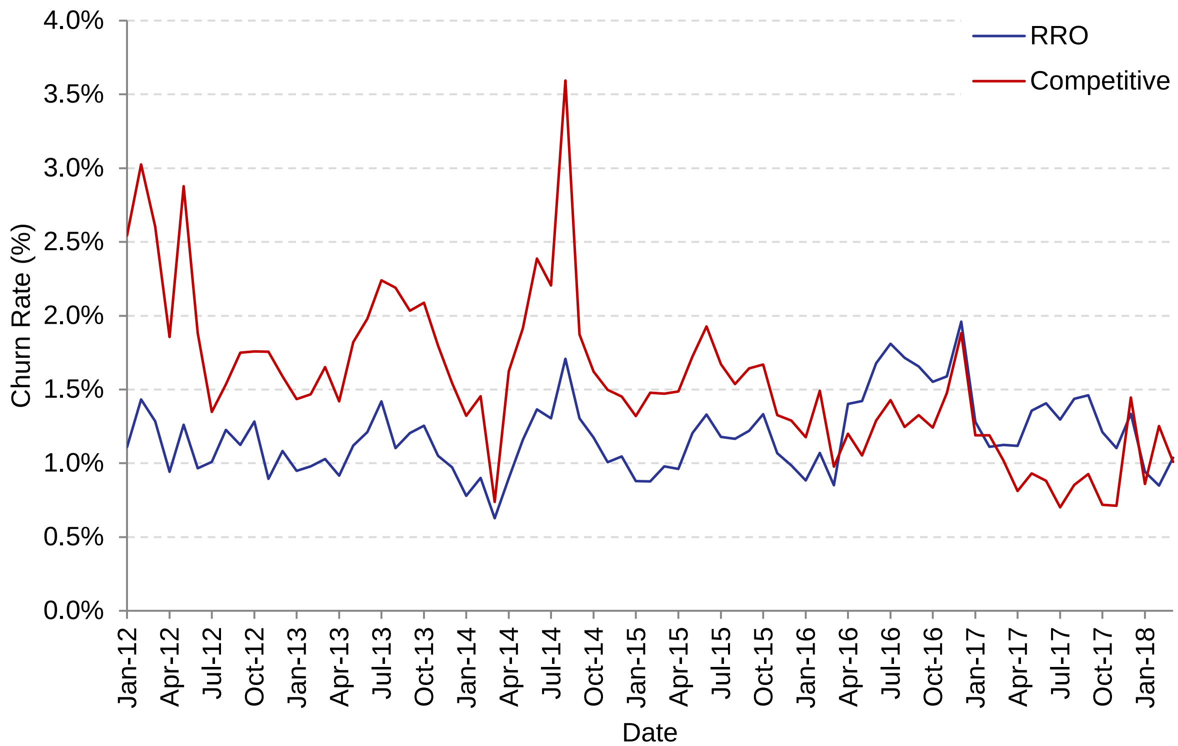
3.2.4 Churn

Churn rates represent the loss of customers over a given period, expressed as a percentage of the existing customer base. The monthly churn rates for competitive and regulated electricity retailers are shown in Figure 23. There appears to be a fair degree of correlation between the two.

Churn rates for competitive electricity retailers have fallen since 2012. This may indicate that more customers on competitive contracts are satisfied with their retailer. Alternatively, customers may find a lack of suitable alternatives to their existing retailer.

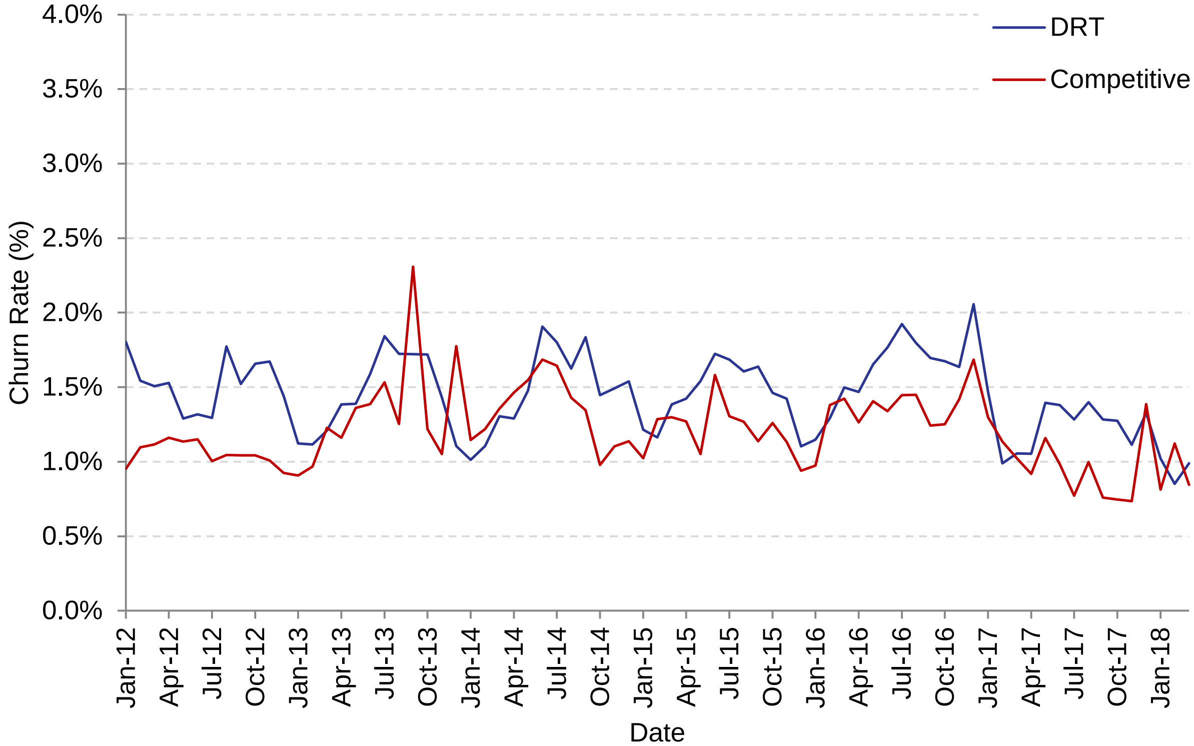
Churn rates for regulated electricity retailers have generally remained steady around 0.75% – 1.5% per month.

Figure 23: Monthly Churn Rates for Residential Electricity Retailers, January 2012 - March 2018



Churn rates for competitive and regulated natural gas retailers have been largely stable settling between 1% to 2% per month since 2012 (Figure 24).

Figure 24: Monthly Churn Rates for Residential Natural Gas Retailers, January 2012 - March 2018



3.3 Residential Retail Bills

3.3.1 Historical Retail Billing Tool

In early August 2018, the MSA published the Historical Retail Billing Tool, which models retail electricity and natural gas bills in the major Alberta service areas. The Historical Retail Billing Tool was first released as part of the MSA's *2016 Retail Market Reports*, where it contained billing data from January 2012 to April 2016.[35]

The Historical Retail Billing Tool has now been updated with billing data up to the end of Q1/18, including household consumption data derived from the MSA's Retail Statistics. A one quarter lag has been implemented to align with the delay in place for the Retail Statistics. The ability for users to model competitive retail bills has also been included as part of this release, although the MSA has not included historical data on competitive retail rates.

The MSA has also included the ability to model regulated retail bills using both the capped RRO rates and RRO rates as they would have been absent the rate cap. As this iteration of the tool only includes data up to Q1/18 (before the rate cap first bound in April 2018) this functionality is expected to become useful in the next release of the tool.

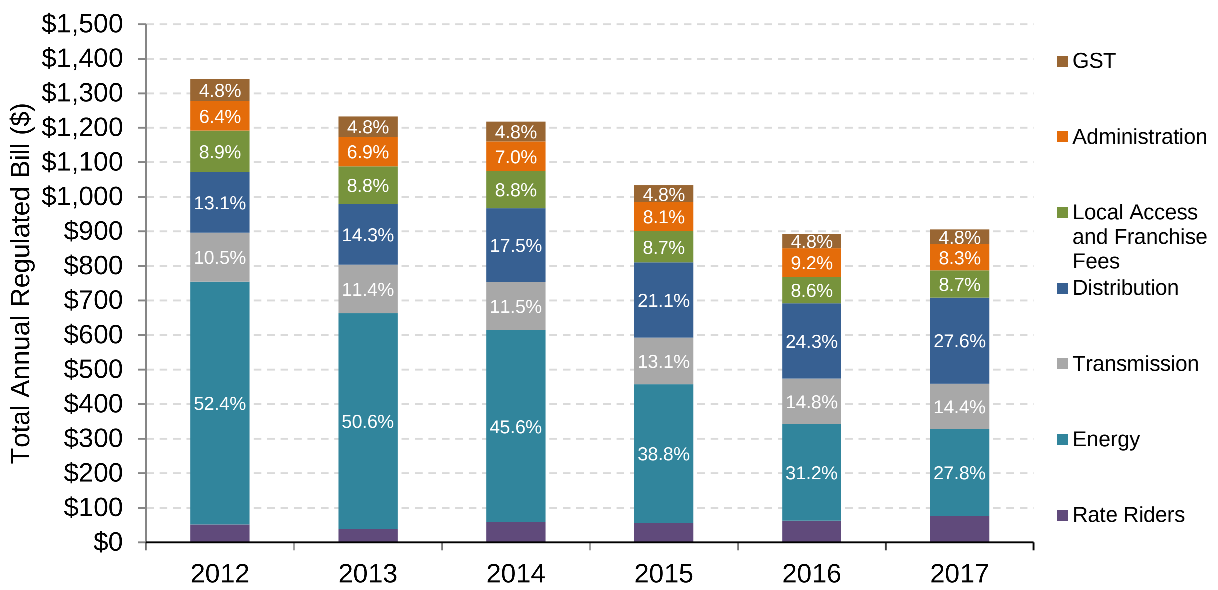
The tool may be found on the MSA's web site under the 'Market Reporting' tab.

[35] See MSA 2016 Retail Market Reports.

3.3.2 Billing Trends

Regulated electricity bills in 2017 were of a similar magnitude to those observed in 2016 in most service areas (Figure 25), primarily due to low RRO rates in those years. In January 2017, the Balancing Pool rider became a charge on customers' bills where it had previously been a credit.[36] This change had a net impact of approximately $2 to $3 per month on customers' bills in most service areas.

Figure 25: Regulated Electricity Bills for an Average Detached-Home Customer in the ENMAX Service Area, 2012 - 2017

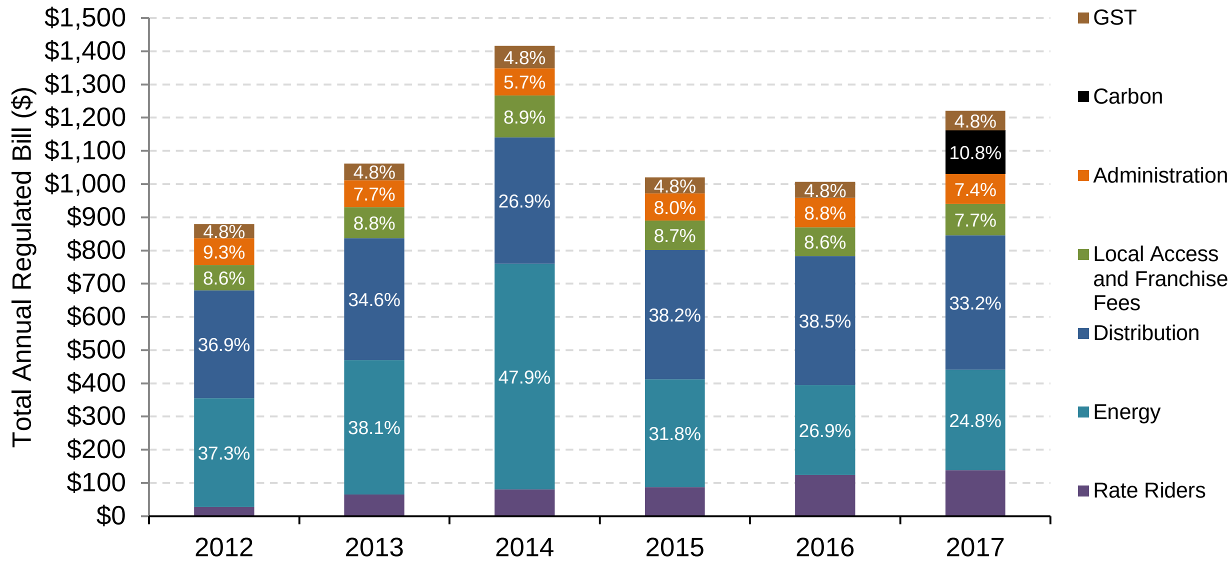


Q1/18 saw an increase in quarterly regulated electricity bill expenditures of approximately $33 - $60 when compared with Q1/17, depending on the service area examined. On average, approximately 43% of this increase was due to higher RRO rates in that quarter, with the remainder explained by increases in consumption and other rates charged to customers.

Regulated natural gas bills increased in 2017 relative to 2016 primarily due to the imposition of the carbon levy on natural gas and higher consumption in that year (Figure 26). Moderate increases in DRT and distribution rates also contributed to higher regulated natural gas bills in that year.

[36] See Balancing Pool Consumer Allocation for 2017.

Figure 26: Regulated Natural Gas Bills for an Average Detached-Home Customer in the ATCO Gas South Service Area, 2012-2017



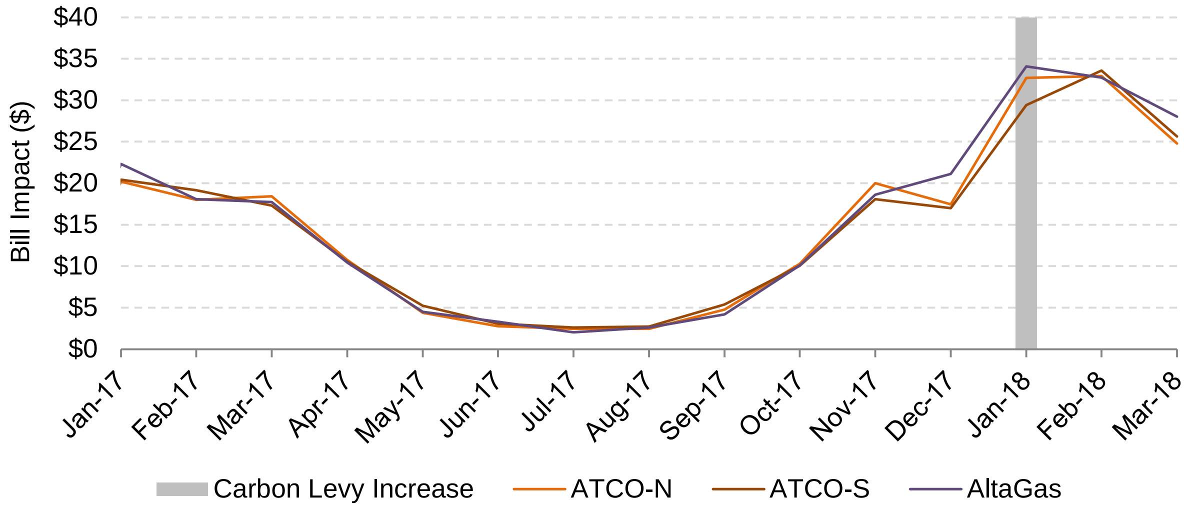
Lower DRT rates in Q1/18 were the primary cause for the decrease in quarterly regulated natural gas bill expenditures of approximately $5 to $31 in that quarter when compared to Q1/17. This decrease in energy costs managed to more than offset the increase in the carbon levy beginning in January 2018.

3.3.3 Carbon Levy Impact on Natural Gas Bills

As part of the Government of Alberta's Climate Leadership Plan,[37] a carbon levy of $1.011/GJ was applied to natural gas bills in 2017.[38] This rate was later increased to $1.517/GJ beginning in January 2018. The MSA sought to understand the impact of the carbon levy and its subsequent increase on retail natural gas bills. Figure 27 shows that the direct impact of the carbon levy on natural gas bills is highly dependent on seasonal consumption trends, with increases ranging from $2 to $22 per month for an average regulated customer living in a detached-home in 2017.

[37] See Government of Alberta Climate Leadership Plan.
[38] See Government of Alberta Carbon levy and rebates.

Figure 27: Impact of the Carbon Levy on Retail Natural Gas Bills for Detached-Home Residential Regulated Customers, by Service Area



This analysis indicates that such a customer living in the ATCO Gas South service area paid approximately $132 in carbon payments on their natural gas consumption in 2017. In Q1/18, these customers paid approximately $89 in carbon payments, 56% more than the charge in Q1/17.

4. Interconnections

Alberta has electrical connections (interties) to three jurisdictions: British Columbia (BC), Saskatchewan (SK), and Montana (MT). The lines from Alberta to British Columbia and Montana are synchronous and all three entities are part of Western Electricity Coordinating Council (WECC). The connection to Saskatchewan is an AC-DC-AC connection since Saskatchewan is at the western edge of the Eastern Interconnection and Alberta is not connected synchronously with the Eastern Interconnection. The interties provide reliability benefits to all parties and also provide opportunities for commercial transactions. The MSA's interest is focused on the economic performance of the interties, including how imports and exports interact with Alberta's energy and ancillary service markets.

Figure 28 compares Alberta's pool price to those of the Minnesota Hub and Mid-C markets. Over the past few years, the wholesale market price of Alberta's electricity has generally been lower than prices in neighbouring markets. However, due to tighter supply cushion levels, economic withholding, and increases to Alberta's carbon price starting January 1, 2018 Alberta's pool price was significantly higher than its neighbouring markets during Q2/18.

Figure 28: Monthly Prices in Neighbouring Markets (7 X 24)

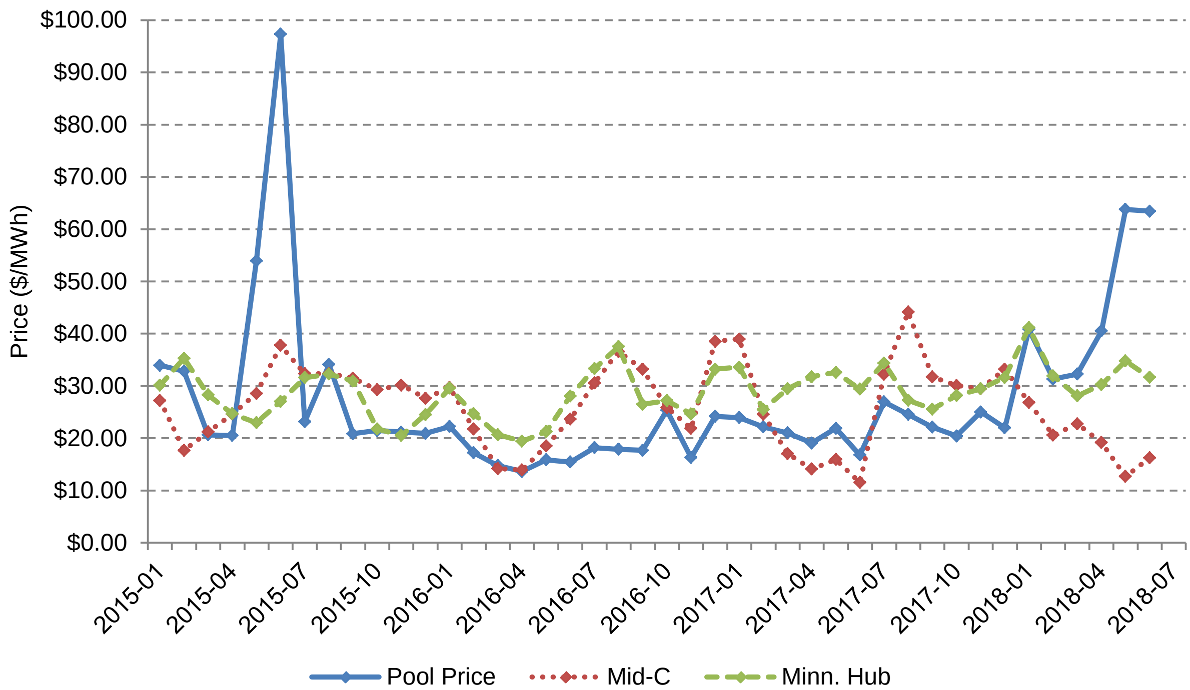


Figure 29 shows a scatterplot of the price differential and scheduled net flow between Alberta and Mid-C using the combined import/export capability on the BC and MT lines. In efficient markets, energy should flow from regions of low prices to those of high prices. As a result of higher prices relative to Mid-C in Q2/18, Alberta observed high imports from Mid-C during the quarter. It can be seen in the expanded part of Figure 24 that the majority of the data points are in the upper-left and lower-right quadrants, consistent with the economics of flow.

Figure 29: Intertie Price Differential and Net Flow (BC/MT Intertie)

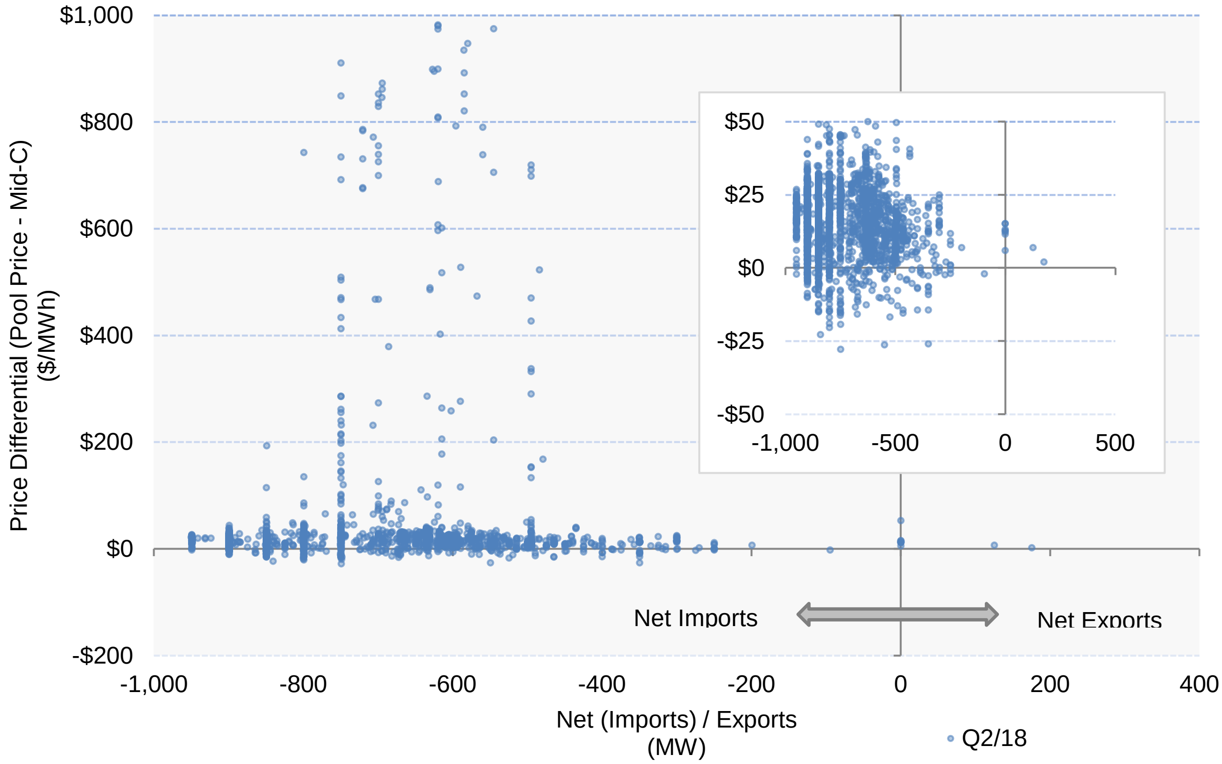
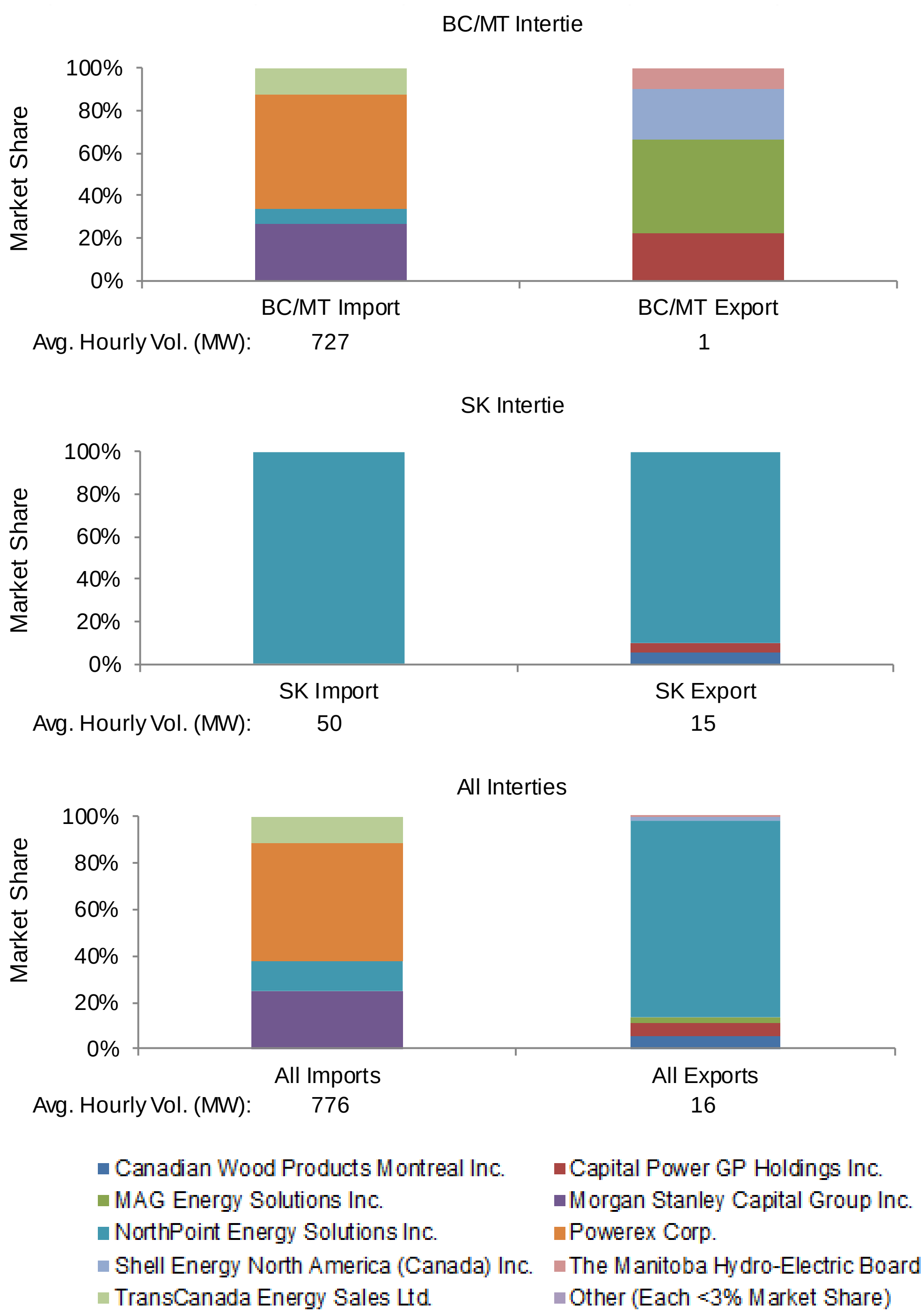


Figure 30 shows the quarterly volumes of imports and exports on Alberta's interties as well as the market share by company. Imports averaged 776 MW per hour compared to exports of 16 MW per hour during Q2/18. Approximately 94% of imports to the province came from the BC and MT interties while 94% of all exports went over the SK intertie.

For the western interconnect, the dominant firms were Powerex Corp. and Morgan Stanley Capital Group Inc., both of whom own substantial firm transmission rights on the British Columbia and Montana interties, respectively. For Alberta's eastern interconnect NorthPoint Energy Solutions Inc. was the dominant player for both imports and exports on the Saskatchewan intertie.

Figure 30: Intertie Market Shares (Q2/18)



5. Import Capacity Restoration

The *Transmission Regulation* (AR86/2007) requires the AESO in Section 15(g) to:

> make rules respecting the preparation of needs identification documents for, and the planning and processing of, enhancements or upgrades to transmission facilities that existed on August 12, 2004 for the purpose of providing transmission capacity to import or export electricity to or from Alberta in excess of the path ratings that existed on August 12, 2004 for those transmission facilities.

The AESO has managed this requirement primarily through a combination of Load Shed Service for imports (LSSi) and additional contingency reserves. Over the past several years, the amount of LSSi required for a particular combination of import volume and load level has decreased, based on reliability studies conducted by the AESO. As the amount of LSSi reduced, there was often a shortfall of active contingency reserves in Alberta to cover for the net loss of the intertie. This required the AESO to procure increased volumes of standby contingency reserves which were then activated to meet this need.

There are aspects of the designs of both the LSSi contracts and the standby operating reserve market that are troubling to the MSA and the MSA has commented on both in the past. The AESO is currently in the middle of a competitive procurement process for LSSi, with contracts resulting from the procurement to be in place starting January 2019. It seems appropriate at this time to re-examine the use of LSSi and standby reserves and what changes have been made in the LSSi contract design.

5.1 LSSi

To increase the available capacity of the BC and MT interties, the AESO buys LSSi from load participants who are willing and able to have their consumption interrupted (i.e. deliberately tripped offline) in the event of a contingency event on the BC or MT intertie. If the BC or MT intertie trips offline, loads that are armed for LSSi are automatically tripped offline as well, and this reduces the impact of the event on the Alberta electric system. Note that when heavily loaded, the trip of either line (BC or MT) would lead to a trip of the other line.

The amount of LSSi the AESO arms in an hour is based on the amount of LSSi offered, the load level within the province, and the combined import level on the BC and MT interties. As the load level increases the AESO requires less LSSi for a given import level. As the level of imports increases the AESO requires more LSSi. More specifically, the AESO uses a table published within Information Document #2011-001R: *Available Transfer Capability and Transfer Path Management*.[39] The table specifies the minimum amount of LSSi that is required for a given level of imports and a given level of load. For example, if Alberta's load is between 9,000 MW

[39] https://www.aeso.ca/assets/downloads/2011-001R-ATC-and-Transfer-Path-Management.pdf

and 9,499 MW and there is an import schedule between 751 MW and 800 MW on the BC and MT interties then the table reports a minimum LSSi level of 67 MW.[40]

5.2 LSSi Payments

LSSi participants are paid for their services through a number of avenues. Firstly, there is an hourly availability payment which is paid when a load makes its consumption available to be armed for LSSi. At present the availability price for LSSi is set at $5/MWh so the availability payment is: $(Available\ MWh \text{ x } \$5)$.

Secondly, LSSi participants can receive an arming payment, which the AESO pays to the provider in the event that their available consumption is actively armed for LSSi. The arming payments are based on the hourly volume armed and the arming price that varies according to the supplier's individual contract. Arming payment is: $(Armed\ MWh \text{ x } Arming\ Price)$.

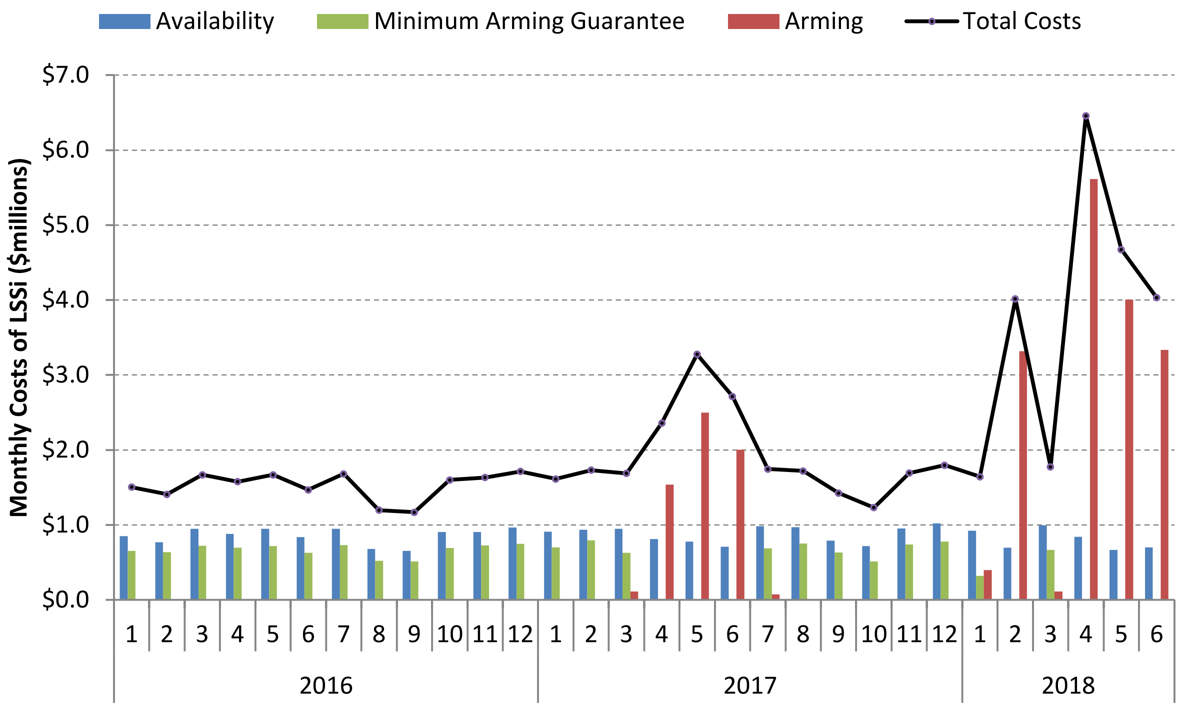
The third source of revenue for LSSi providers is the trip payment. The trip payment is paid out in the event that there is a contingency event on the BC or MT intertie, frequency drops and the LSSi provider is tripped offline. The price for trip payments is set at $1,000/MWh so the trip payment is: $(MWh\ Tripped\ Offline \text{ x } \$1{,}000)$.

The final source of revenue for LSSi providers is the minimum arming guarantee payment. This payment is made in months where the AESO does not arm LSSi providers with sufficient frequency. In these months, the LSSi providers can be entitled to a monthly minimum arming guarantee payment. The minimum arming guarantee payment will increase as a supplier's availability increases but will fall as the level of armed payments increase.

Figure 31 shows the break-down of LSSi costs since 2016 by month. As shown, the total availability payment is a relatively constant amount generally ranging from $0.8 to $0.9 million per month. The minimum arming guarantee is also a relatively constant amount in months were the AESO does not arm a sufficient level of LSSi; generally in the region of $0.6 to $0.7 million per month. When LSSi is armed the monthly cost is highly variable because it depends upon the amount of LSSi armed and also which providers have been armed. The highest monthly arming cost was $5.7 million and this occurred in April 2018.

[40] The figure in this example is taken from Table 7b which the AESO used beginning at 10am on July 3, 2018. Prior to that, the AESO made use of Table 7a.

Figure 31: LSSi Costs January, 2016 through June, 2018



Note that LSSi was not armed at all in 2016, and infrequently in 2017. This is mainly due to the fact that electricity prices in Mid-C were higher than pool prices in Alberta for large parts of this period. Therefore, the economics of the intertie favoured exports from Alberta as opposed to imports into Alberta. Despite it not being used, LSSi providers continued to offer and collect availability payments and also their minimum arming guarantee payments. In 2016 the AESO paid out $10.3 million in availability payments and $8.0 million in minimum arming guarantee payments.

In the spring/early summer of 2017 the economics of transactions on the BC-MT line changed. Prices in Alberta were on average higher than prices in Mid-C, and consequently increased imports into Alberta began to occur. When import volumes were large, the AESO armed LSSi to increase the capacity available. As a result, LSSi arming costs increased and minimum arming guarantee payments in April, May or June of 2017 were not required.

In total, the AESO paid $63.89 million for LSSi between Jan 2016 and June 2018. Of this total, availability payments represent $25.6 million (or 40%), minimum armed guarantee payments represent $15.2 million (24%), and armed payments represent $23.0 million (36%). There were no trip payments within this period.

5.3 LSSi Effectiveness

The objective of LSSi is to enable the AESO to increase the available capacity of the BC and MT interties and ultimately to allow more imports to flow. To estimate the level of additional imports that were enabled due to the use of LSSi the MSA has used the following equation:

$$LSSi\ Imports\ Enabled = BC\_MT\ Imports - \min(LSSi\ Table, Total\ CR)$$

Where *BC_MT Imports* are observed import flows from the BC and MT interties,

Total CR is total active contingency reserves plus total standby contingency reserves, and,

LSSi Table is the maximum level of imports the AESO can allow when LSSi is 0. This is 650 MW when AESO load is <7,500; 700MW when AESO load is >=7,500 and <10,500; and 750 MW when AESO load is >=10,500

To illustrate the equation, consider the following hypothetical example:

- AESO Load = 9,200 MW
- Imports = 800 MW
- LSSi Armed = 200 MW
- Active Contingency Reserves = 560 MW
- Standby Contingency Reserves = 160 MW

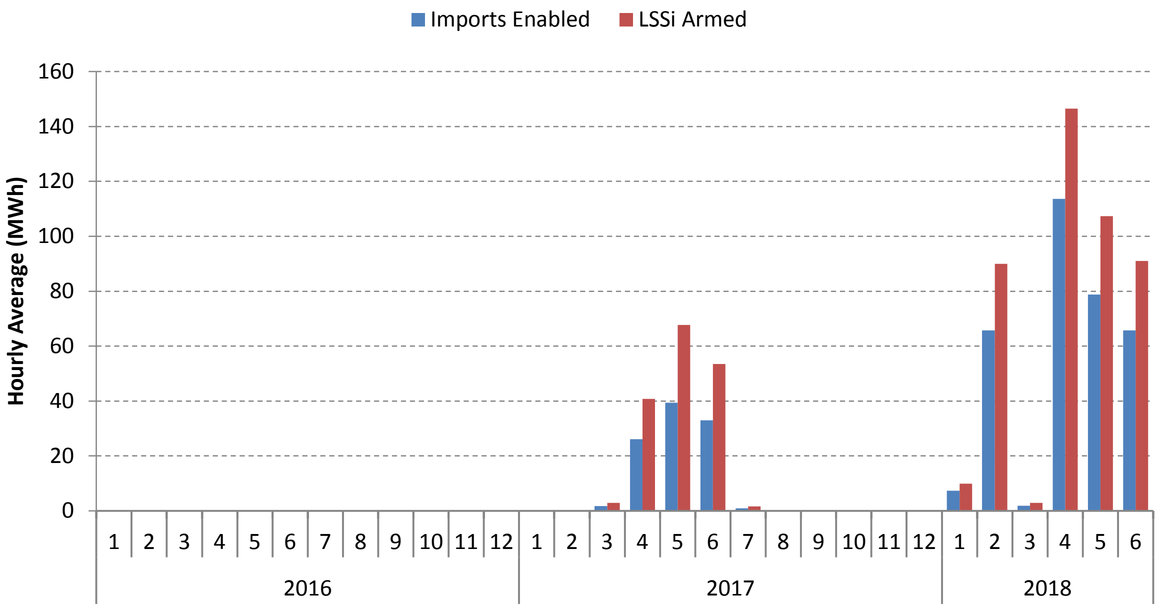
In this example, without the use of LSSi, the AESO would be able to import 700 MW at a load of 9,200 MW based on the AESO's table for LSSi.[41] In addition the AESO had sufficient contingency reserves to cover for 700 MW of imports (total contingency reserves = 560+160 = 720 MW). Therefore the imports enabled by the use of LSSi in this example is (800-min(700,720)) = (800-700) = 100 MW.

However, suppose the AESO had only 100 MW of standby contingency reserves. In this case, the AESO would only have been able to import 660 MW without the use of LSSi. This is because total available contingency reserves in this example would be 660 MW, which would not have allowed more than 660 MW to flow. In this case imports enabled by the use of LSSi would have been (800-min(700,660) = (800-660) = 140 MW.

Figure 32 illustrates the estimated additional imports that were enabled due to the arming of LSSi since 2016. The figure shows the average levels of imports that were enabled over the course of a month. For example, the highest level of imports that were enabled by LSSi occurred in April 2018 when the AESO enabled an additional 114 MWh of imports by arming 149 MWh of LSSi, on average.

[41] See page 11 of https://www.aeso.ca/assets/downloads/2011-001R-ATC-and-Transfer-Path-Management.pdf

Figure 32: Imports Enabled Through the Use of LSSi Jan, 2016 through June, 2018



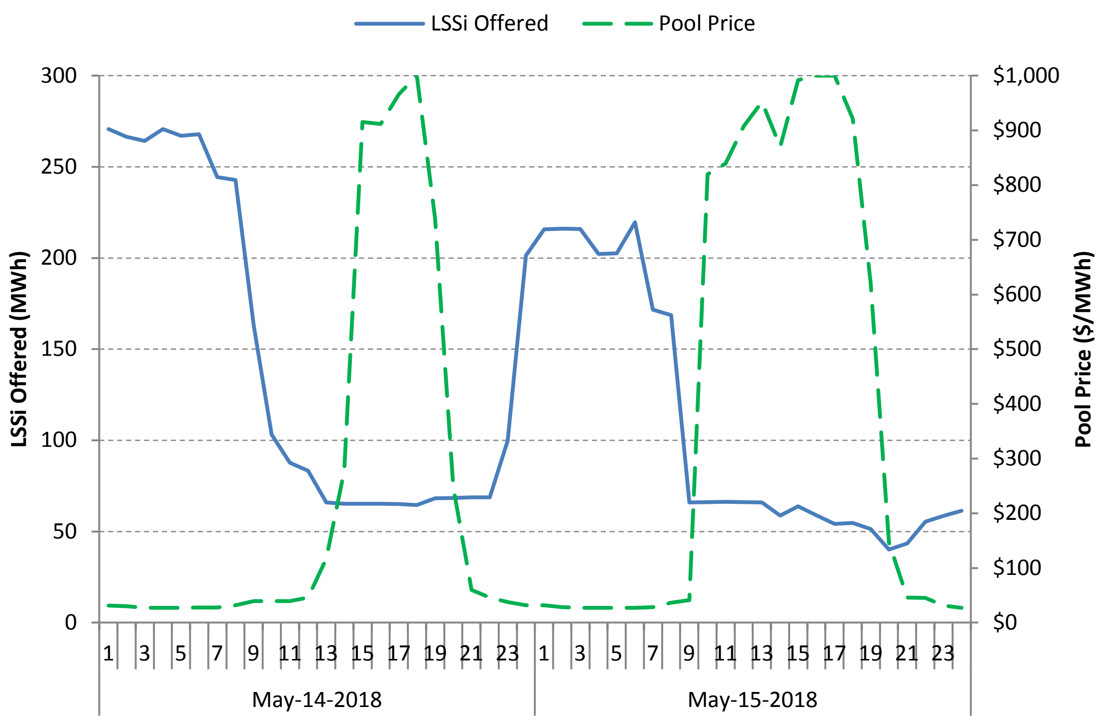
In total the AESO enabled an additional 313 GWh of imports by using LSSi between Jan 2016 and June 2018. Comparing this to the total cost of $63.89 million yields an average cost of $204/MWh for the additional imports. The average pool price received by the imports enabled by LSSi was $29.86/MWh over the sample period (Jan 2016 – June 2018).

One of the main reasons that LSSi does not provide more value to the market is that most of the LSSi providers are price-responsive loads that actively monitor pool price levels in real-time. Before pool prices increase beyond a certain level, most of these LSSi providers have removed their offers to supply LSSi and instead curtailed their consumption in order to avoid the high prices. This means that the AESO cannot arm LSSi to increase the flow of imports when they are most valuable (i.e. when pool prices are high and the supply cushion is low). Instead, LSSi typically allows for more imports to flow when there is a relatively modest differential between pool prices and power prices in Mid-C; for example when pool prices are in the $30-$40/MWh range and Mid-C prices are $10-$20/MWh. At these times there is typically plenty of supply available in Alberta. This serves to limit the value that LSSi can provide from a market perspective.

The fact that many LSSi providers respond to pool price also means that LSSi has a limited contribution to reliability. When the market in Alberta is tight and additional supply in the province is more valuable, pool prices are high. As a result LSSi providers have reduced their consumption and are not in a position to provide the service. Consequently the AESO has a limited ability to arm LSSi when the additional imports would be most valuable from a reliability perspective.

Figure 33 provides an illustrative example. As shown by the chart, pool prices on May 14 and 15, 2018 were high and indeed the market hit the offer cap of $999.99/MWh on both days. As can be seen by the total LSSi offered on these days, there is a negative correlation with the pool price. Before market conditions become tight and pool prices increase, most of the LSSi providers have reduced their consumption and no longer offer LSSi.

Figure 33: Relationship between Offered LSSi and Pool Price



5.4 LSSi Table Changes

Based on electrical engineering studies, the AESO has concluded that generally less LSSi is required for a given level of imports and system load. Therefore, on July 3, 2018 at 10 AM the AESO transferred from using Table 7a to using Table 7b in ID #2011-001R to calculate the minimum level of LSSi that is required.[42] The levels of LSSi reported to be required are generally lower in Table 7b, so the AESO will typically be required to arm less LSSi for a given level of load and imports. For example, for a load between 9,000 MW and 9,499 MW, and an import level between 751 MW and 800 MW Table 7b requires only 67 MW of LSSi to be armed compared to the 118 MW required in Table 7a. While this could mean more imports being enabled for a given armed volume of LSSi, the market could see less LSSi being used and more standby contingency reserves being procured and activated. This may occur because the total volume of imports on the BC-MT intertie cannot exceed the sum of armed LSSi and active contingency reserves:

$$Import\ Schedule\ \leq LSSi\ Armed + Contingency\ Reserves$$

[42] See https://www.aeso.ca/assets/downloads/2011-001R-ATC-and-Transfer-Path-Management.pdf

Now that the level of armed LSSi is being reduced the AESO may be required to carry more standby reserves in order to allow for additional imports to be scheduled. With lower levels of LSSi it is more likely that the combination of LSSi and contingency reserves is not sufficient to allow for the scheduling of more imports without additional activation of contingency reserves.

5.5 Previous MSA Reports on LSSi

The MSA has previously noted that there are some fundamental issues with LSSi. When LSSi was first introduced, our Q2/12 report noted that LSSi providers were also price responsive loads and therefore the provision of the service was lower at higher pool prices: "it is apparent that much more LSSi is offered at lower pool prices than higher pool prices… LSSi does not seem to provide any incremental benefits to competition in high price hours."

As well, the MSA's Q4/16 report noted that the availability payments and the minimum arming guarantee payments were costing millions of dollars but providing no actual use: "there was no direct benefit to procuring LSSi in 2016, at least not in terms of enhanced imports, as this service was not called on." The report also stated that "there is a strong argument in favour of removing both the availability payment and the minimum arming guarantee...Changing the payment structure could be advantageous because LSSi payments would only go towards actual services provided. The MSA recommends that the AESO examine the three-part pricing structure and the volume of LSSi to be contracted prior to the expiry dates of the existing contracts in 2018."

In its Q3/17 report the MSA reiterated that the AESO should review the payment structure of the LSSi contracts: "Based on the total cost of LSSi over the last five years, the MSA remains of the view that changing the current payment structure to one where LSSi payments would only go towards actual services provided would be beneficial."

5.6 Current Request for Proposal (RFP) for LSSi

On June 1, 2018 the AESO put out an RFP to procure 315 MW of LSSi for a 3-year term beginning in January 1, 2019. The RFP submission deadline was on July 16, 2018 and the AESO plans to award the LSSi contracts in Q4 of 2018.[43]

The new contracts within the RFP have a few changes compared to the existing LSSi contracts.[44] Firstly, there is no minimum arming guarantee payment in the new LSSi contracts. The MSA feels this is a positive step because the providers of LSSi did not have to provide a service to receive the minimum arming guarantee.

Secondly, the hourly availability payment remains in the LSSi contract although it has been modified. Historically the availability payments for LSSi have been set based on a fixed availability price of $5/MWh:

$$Availability\ Payment = (Available\ MWh\ \times \$5)$$

[43] See https://www.aeso.ca/assets/Uploads/05-07-18-LSSi-REOI-Stakeholder-Session-FINAL.pdf
[44] See https://www.aeso.ca/assets/Uploads/LSSi-FAQ-updated-May-24-2018.pdf

In the new contracts, the availability price is bid into the RFP by participants when competing for the LSSi contracts and the availability price will be set at the price submitted by the winning bidders. All successful bidders will now have individual availability and arming payment values. In addition the hourly availability payment will now be determined by the equation below. As shown, the availability price will be weighted by the amount the load is offering to provide relative to its total contract volume. This will generally incent the LSSi provider to make more LSSi available to the extent that they are able.

$$Availability\ Payment = Available\ MW\ \times\ Availability\ Price\ \times \left(\frac{Available\ MW}{Contract\ MW}\right)$$

Overall, the MSA remains concerned that the availability payments will continue to provide compensation when LSSi is not armed and no imports are being enabled. In addition, the MSA does not believe that any of the changes will alter the fact that most LSSi is not typically available when pool prices are high. The key is to incent suppliers who are cost effective and not price-responsive loads.

5.7 Standby Operating Reserves

How much LSSi is armed by the AESO is dependent upon the AESO having sufficient contingency reserves available to support the resulting import schedule. At all times the total of active contingency reserves plus LSSi must be greater than or equal to the total flow of imports on the BC and MT interties. Therefore, in order to support imports enabled by LSSi the AESO often has to activate standby contingency reserves.

The AESO procures standby operating reserves on a day-ahead basis, as is the case with active contingency reserves. These reserves are procured on Watt-Ex with the results being sent on to the AESO.

Active reserves are priced as an index to pool price. For the provision of the service, active reserve sellers receive pool price less the equilibrium price; the equilibrium price being the same for all providers. In the event that an active reserve provider is directed to provide energy in a contingency, it receives pool price for that energy.

Standby contingency reserves are not priced as an index to pool price. Standby contingency reserves are compensated via three avenues. Firstly, sellers are paid a standby premium which they receive regardless of whether or not they are activated. Secondly they are paid an activation price in the event that their standby reserves are required. Finally, they are paid pool price for the energy they produce in the event that their activated reserves are directed on in the event of a market contingency.

The AESO (via Watt-Ex) selects standby contingency reserves based on the blended prices of the sellers. For contingency reserves, this is calculated using a participant’s submitted premium and activation prices as follows:

$$Blended\ Price = Premium\ Price + (0.1 \times Activation\ Price)$$

The offers are ranked based on their blended prices and the AESO then takes the required quantity of standby. The factor (0.1) in the equation represents the long-term activation rate for standby contingency reserves. The necessity to select activation prices forces participants to take a view on next day's pool prices. Successful standby participants are paid based on their submitted offer prices.

Market participants are aware that on days when the AESO is expected to be importing large volumes there is a much higher probability of being activated. On these days, it is rational for participants to submit a very low premium price so they can submit a higher activation price and still remain competitive. Participants may also submit higher offer prices for standby operating reserves when they believe that pool prices will be high because if the unit is activated on standby it means the unit can no longer participate in the energy market and collect pool price. This mismatch between pool price and standby activations can lead to some peculiar market outcomes, a few examples of which are discussed below.

<u>May 4, 2018</u>

Pool prices on May 4, 2018 were relatively low; the average pool price was $28/MWh and hourly prices did not exceed $32/MWh. However, it was economic to import power into Alberta, because prices in the Mid-C region averaged $16/MWh over the day.[45]

The import capacity available on the BC-MT intertie ranged between 800 MW and 900 MW. However, frequently more than 1,000 MW was offered into the Alberta market. The AESO relied on LSSi and standby activations to increase the availability of the BC-MT intertie. In terms of LSSi, the AESO armed an average of 198 MW at an average arming cost of $51/MWh. The total cost of arming LSSi for the day came to $242,400.

In terms of contingency reserves, the AESO purchased 560 MW of active contingency reserves for the on-peak hours in the day-ahead Operating Reserves market. The active contingency reserves were purchased at index prices of +$34/MWh for spinning reserves and +$23/MWh for supplemental reserves. The AESO also needed to activate standby reserves in order to support the import capacity levels on the BC-MT intertie. The AESO activated an average of 106 MW of standby contingency reserves during the on-peak hours of May 4. On average, the activation cost for these standby reserves was $396/MWh. Similarly, in off-peak hours, the AESO activated an average of 119 MW of standby contingency reserves at an average activation price of $274/MWh. The total cost of standby activations for the day was $929,900.

Overall, during the peak hours of May 4 the AESO was paying $396/MWh to remove supply from the Alberta energy market (and placed it into active contingency reserves) in order to increase the flow of imports from British Columbia and Montana, which were being paid a pool price of $29/MWh.

[45] Mid-C prices are all quoted in Canadian dollars

May 17, 2018

May 17 was a day coming in on the back of high pool prices, with May 14 averaging $239/MWh, May 15 $396/MWh and May 16 $124/MWh. However, May 17 was a relatively quiet day with the average pool price clearing at $26/MWh.

Despite the relatively soft pool prices in Alberta, there was a high influx of imports on the BC-MT intertie. Prices in the Mid-C region were relatively low, clearing in the $0-$15/MWh range during peak hours. The result was a high level of imports. As a consequence of the import levels the AESO armed LSSi in order to support the available import capacity on the BC-MT intertie. In particular, the AESO armed an average of 215 MW of LSSi at an average cost of $52/MWh. The total cost for arming LSSi on May 17 was $268,900.

The AESO had purchased 560 MW of active contingency reserves for the peak hours, at index prices of +$18/MWh for spinning reserves and +$20/MWh for supplemental reserves in the day-ahead Operating Rserves market. In addition, the AESO activated significant volumes of standby contingency reserves in order to support the import capacity of the BC-MT intertie. For most of the day, the import capacity of the BC-MT intertie was in the 850-900 MW range and, typically, there were 1,100 MW of imports offered into the Alberta market.

Therefore, during the on-peak hours of May 17 the AESO activated an average of 105 MW of standby contingency reserves per hour at an average activation cost of $379/MWh. That's a total average cost of $39,900 per hour or $638,500 for all peak hours. On May 17 the average on-peak pool price settled at $30/MWh.

During the peak hours of May 17, the AESO was paying $379/MWh to remove supply from the Alberta energy market and place it into active contingency reserves in order to increase the flow of imports from BC and Montana, which were being paid a pool price of $30/MWh.

The above examples are a few from Q2/18 but many more have occurred in the past. In the MSA's view, they are a consequence of weak competition in a market that is poorly designed. The MSA is not aware of any reason why the standby reserve market needs to have fixed activation prices. A better structure would have the activation price of all standby reserves set at the same level as the applicable active reserve market, and thus indexed to pool price. The standby auction would then be based on the premium price required by the providers.

6. Net Revenues

The MSA undertook a net revenue analysis to illustrate the potential profitability for a hypothetical gas peaking unit in the Alberta energy market. The analysis reported here serves as a check on what levels of return on capital the pool prices could have provided to a potential new entrant. The period analyzed is January 2016 through June 2018. The hypothetical new entrant analyzed is a peaking plant consisting of one GE LM6000PF Sprint turbine. The assumed plant characteristics and development costs are provided below:[46]

Table 6: Net Revenue Plant Parameters

Plant Characteristics: 1 x GE LM6000PF Sprint

	Winter	Summer
Plant Capacity (MW)	46.5	39
Heat Rate (GJ / MWh)	9.526	9.954
CO_2 Emissions (t / MWh)	0.533	0.557
Availability Factor (%)	94	94

Development Cost Assumptions ($2018)

Overnight Capital Costs	$ 1,452 / kW	$67.52 m
Fixed O & M	$ 48.4 / kW-year	$2.25 m / year
Variable O & M	$ 4.36 / MWh	

For the analysis the plant is assumed to be a price-taker and is run at full-capacity whenever the pool price is above the plant's variable cost. The plant is assumed to have no impact on observed pool prices. The effect of outages is mimicked by scaling the hourly generation capacity by the availability factor.

Beginning in 2018, carbon costs were determined under the *Carbon Competitiveness Incentive Regulation* (CCIR). Under this regulation, generation units pay carbon taxes based on their performance relative to the most efficient gas unit. This leaves the hypothetical unit with a carbon cost of $4.90/MWh in the winter and $5.62/MWh in the summer when the plant is less efficient. Prior to CCIR there was no equivalent carbon cost regime for a new unit.

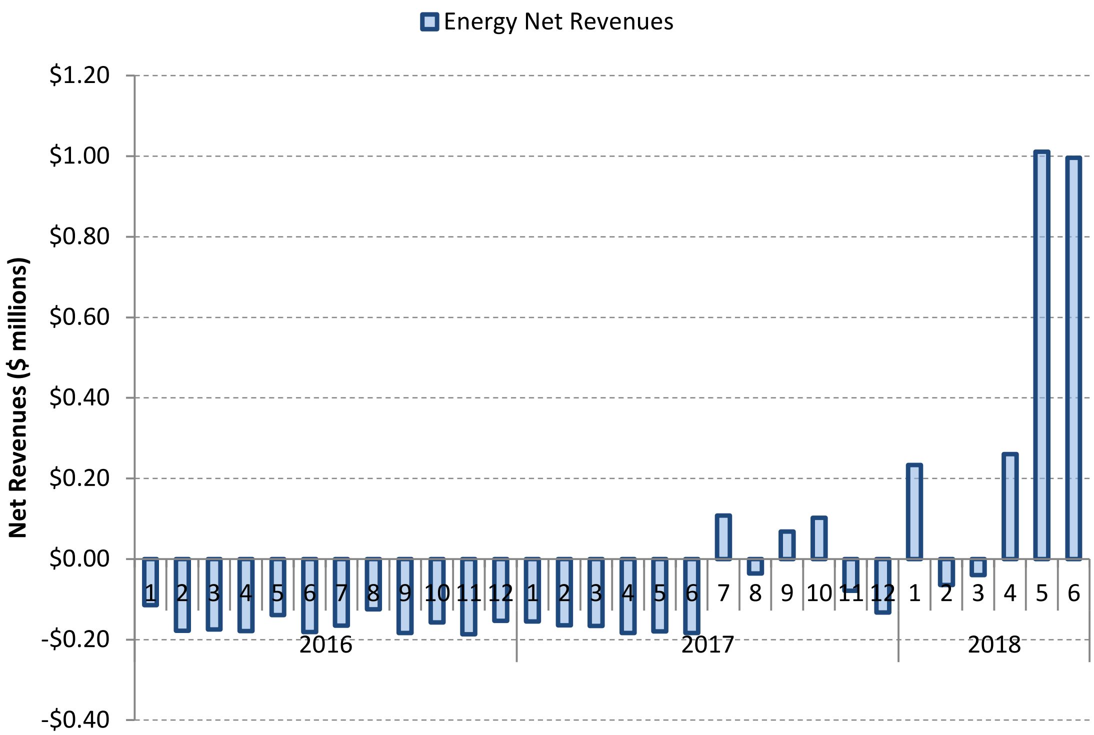
The monthly net revenue figures are calculated as the sum of the hourly net revenues less the fixed operating and maintenance costs. Therefore, the estimated net revenue figures will be negative in months where the revenues accrued from the energy market are less than the fixed operating and maintenance costs of the generator.

Figure 34 shows the monthly net revenues for the hypothetical peaking unit since 2016. The net revenue figures are consistently negative for 2016 and for most of 2017. Despite the low gas prices during this period, pool prices were not high enough for the unit to earn sufficient revenues to cover its fixed costs. In Q2/18 the net revenues were significantly higher,

[46] The cost estimates are taken from the AESO's preliminary estimates for Cost of New Entry: https://www.aeso.ca/assets/Uploads/CONE-WG-Presentation-June-14-v4.pdf

particularly in May and June, as pool prices increased, gas prices fell and the plant would have been able to earn an increased margin on its generation. The estimated net revenues were approximately $1 million for both May and June. In Q2/18 the hypothetical peaking plant earned a 3.36% return on its capital costs from the net energy revenues. This return is equivalent to about 13% on an annual basis and likely would incent a commercial entity to make an investment.

Figure 34: Net Revenues



7. Operating Reserves

The total cost of operating reserves in Q2/18 was $108.6 million compared to $25.9 million in Q2/17. Most of the cost increase was for active reserves which had an increase in total cost from $19.3 million in Q2/17 to $81.5 million in Q2/18. This is primarily due to an increase in the amount of active contingency reserves procured and higher pool prices in the quarter ($56.01/MWh in Q2/18 compared to $19.29/MWh in Q2/17) as active reserve payments are a function of pool price.

Table 7: Operating Reserve Summary

Total Cost ($ Millions)			
	Q2 2017	**Q2 2018**	***% Change***
Active Procured	**19.3**	**81.5**	***321***
RR	6.5	21.1	*224*
SR	9.4	33.4	*254*
SUP	3.4	27.1	*695*
Standby Procured	**2.4**	**4.5**	***87***
RR	0.8	4.1	*384*
SR	1.2	0.4	*-63*
SUP	0.4	0.1	*-88*
Standby Activated	**4.1**	**22.5**	***452***
RR	0.1	0.1	*-51*
SR	2.6	17.3	*552*
SUP	1.3	5.2	*295*
Total	**25.9**	**108.6**	***320***
Total Volume (GWh)			
	Q2 2017	**Q2 2018**	***% Change***
Active Procured	**1,370.0**	**1,565.9**	***14***
RR	342.0	341.9	*0*
SR	514.0	612.8	*19*
SUP	513.9	611.2	*19*
Standby Procured	**610.1**	**485.8**	***-20***
RR	174.0	173.6	*0*
SR	293.4	232.7	*-21*
SUP	142.7	79.6	*-44*
Standby Activated	**155.2**	**182.6**	***18***
RR	3.2	1.0	*-68*
SR	89.9	126.4	*41*
SUP	62.1	55.2	*-11*
Total	**2,135.3**	**2,234.4**	***5***
Average Cost ($/MWh)			
	Q2 2017	**Q2 2018**	***% Change***
Active Procured	**14.12**	**52.04**	***269***
RR	19.02	61.62	*224*
SR	18.34	54.43	*197*
SUP	6.63	44.27	*568*
Standby Procured	**3.99**	**9.36**	***134***
RR	4.82	23.38	*385*
SR	3.98	1.87	*-53*
SUP	3.01	0.66	*-78*
Standby Activated	**26.28**	**123.34**	***369***
RR	35.87	55.30	*54*
SR	29.46	136.69	*364*
SUP	21.17	94.04	*344*
Total	**12.11**	**48.58**	***301***

Another contributor to total operating reserve costs was an increase in the amount of standby contingency reserve activations in the quarter. The total amount of standby contingency reserves activated in Q2/18 were 181.6 GWh compared to 152 GWh in Q2/17. Most of the standby contingency reserves were activated to enable imports into Alberta. As a result, the total cost of standby contingency reserves activations increased from $3.9 million in Q2/17 to $22.5 million in Q2/18.

The increase in total cost for standby contingency reserves activations was due to increases in activation price and quantity. Contingency reserve providers expect that the chance of activation is higher when the AESO elects to procure more contingency reserves than normal. In Q2/18, the activation rates of standby contingency reserves when import levels were greater than 750 MW was 59% for standby spinning reserves and 83% for standby supplemental reserves. The average activation rates for the quarter were 54% and 71% for spinning and supplemental reserves, respectively. These are much higher than the AESO's benchmark activation rate of 10% for standby contingency reserves used in the blended price formula to clear the market.

When the AESO activates standby reserves, it must pay the provider an activation price per MWh. The activation price is determined by each individual provider in the day-ahead Operating Reserves market. As previously mentioned in the analysis of import capacity restoration, contingency reserve providers submit offers into the standby contingency reserve markets with high activation prices guided by the expectation that the unit will be activated to provide contingency reserves. As a result, when the AESO activates standby contingency reserves in real-time to enable imports, the cost is much higher compared to activating standby reserves under normal market conditions. Thus, standby contingency reserve activation prices in the quarter were, on average, higher than the payment price for active contingency reserves. On average for spinning reserves, the activation prices were $69.18/MWh higher than the active payments. For standby supplemental reserves, the activation prices were $51.71/MWh higher than active payments, on average.

By submitting high activation prices the providers must offer lower premium prices as the market clears using a blended price of the two parameters. An example of this phenomenon is the average cost of standby contingency reserves procured between Q2/17 and Q2/18. In Q2/17, the average cost of procuring standby spinning reserve was $3.98/MWh and the average cost of procuring standby supplemental reserve was $3.01/MWh. In Q2/18, the average cost of procuring standby spinning reserve was $1.87/MWh and the average cost of procuring standby supplemental reserve was $0.66/MWh.

The activation and premium price trade-off described above can lead to inefficient outcomes. As articulated in its Q2/15 report, the MSA is of the view that the activation price for standby reserves should be set at that of the active reserves (which is the value of active reserves for the day) and standby providers should then compete, based on the premium that they require to provide the service.

8. Regulatory

8.1 MSA Complaint re Section 306.7 of the ISO Rules

On March 16, 2018, the MSA filed a complaint with the AUC concerning Section 306.7 of the ISO Rules entitled *Mothball Outage Reporting* (Section 306.7 or the mothball rule).[47] The MSA reached a settlement with market participants and the AESO on the complaint. As a result of this settlement, the AESO amended Section 306.7 on an expedited basis pursuant to Section 20.6(2) of the *Electric Utilities Act* and AUC Rule 017: *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission*[48] and the MSA withdrew its complaint.

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[47] Market Surveillance Administrator, Complaint Regarding Section 306.7 of the Independent System Operator Rules, AUC Proceeding 23427, Application 23427-A001.

[48] Alberta Electric System Operator, Notice of filing of expedited ISO rules, Proceeding 23594 Application 23594-A001. May 20, 2018.

The amendments to Section 306.7 include a new subsection on attestation. Specifically, a pool participant who has provided notification to the AESO of a mothball outage or an extension to the duration or increase in the megawatts of a mothball outage must provide an attestation to the AESO from a corporate officer that forecast market prices and market conditions, based on the market participant's reasonable assessment, are insufficient to recover avoidable costs for the source asset for the duration of the mothball outage, and that the mothball outage will be cancelled if, based on the market participant's reasonable assessment, forecast market prices and market conditions become sufficient to recover avoidable costs for the source asset for the remainder of the mothball outage.

The amended Section 306.7 became effective on May 28, 2018.

8.2 ATCO Energy Code of Conduct

On March 12, 2018, ATCO Energy applied to the AUC to revise its Code of Conduct Compliance Plan.[49] Key components of the application are changes pertaining to Section 7 of the *Code of Conduct Regulation* which governs advertising and Section 1 which pertains to definitions. More specifically, the revised compliance plan seeks to clarify the situations where the Fair Competition Statement, pursuant to Section 7, is required. The AUC held a written process to consider ATCO Energy's application and a decision from the AUC is expected before the end of 2018.

8.3 Complaint against the *Price Cap Regulation*

The MSA received a complaint against the Government of Alberta concerning the *Price Cap Regulation*. The complaint alleged that the government:

- Was subsidizing RRO customers using funds from the carbon levy; and
- Was promoting the RRO by contacting all Albertans, including the complainant's customers.

The complainant also alleged that these actions were inconsistent with the spirit of the *Fair, Efficient and Open Competition Regulation*.

The MSA declined to investigate the matter because the Government of Alberta is not a market participant and because it is within the purview of government to make and implement policy decisions.

9. Compliance

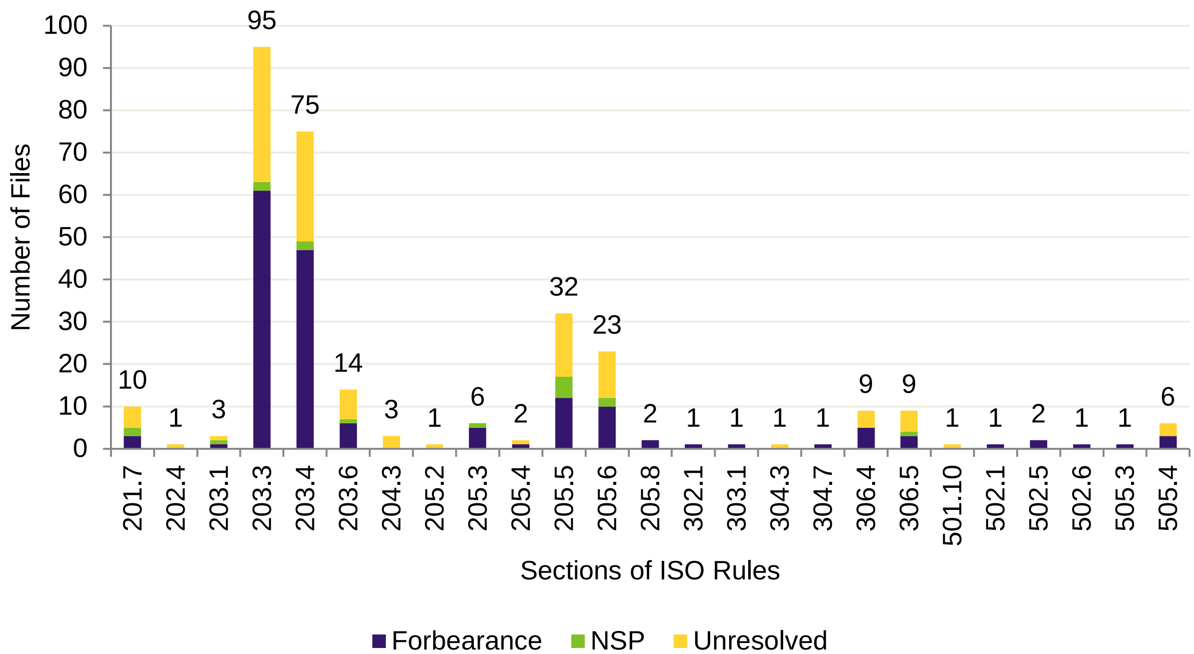
Through enforcement of ISO rules and Alberta Reliability Standards the MSA contributes to the reliability and competitiveness of the Alberta electric system and promotes a culture of compliance and accountability among market participants.

[49] Alberta Utilities Commission, Proceeding 23407

9.1 ISO Rules

ISO Rules promote orderly and predictable actions on the part of market participants and support the role of the AESO in coordinating those actions. From January 1 to June 30, 2018, the MSA addressed 184 ISO rules compliance matters, and an additional 117 matters were carried forward to the next quarter. The MSA issued 17 notices of specified penalty, totalling $13,750 in financial penalties.

Figure 35: Overview of ISO Rules Matters Addressed During or Unresolved at the End of Q2/18



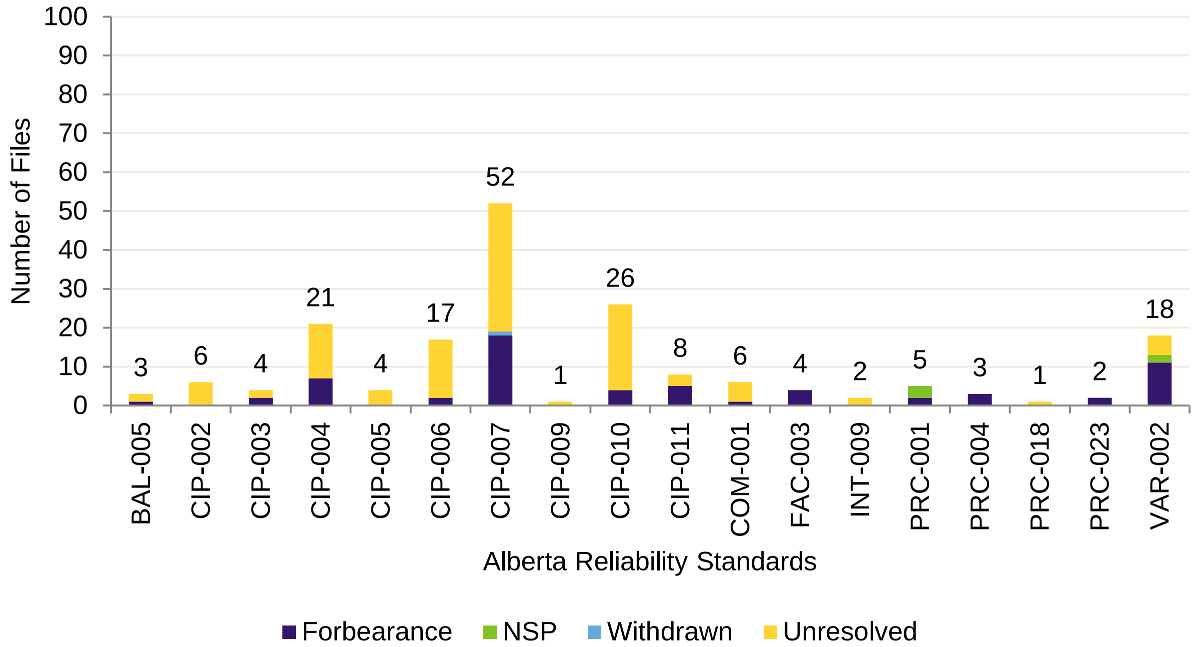
The sections of ISO rules listed in Figure 35 fall into the following categories:

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

9.2 Alberta Reliability Standards

Alberta Reliability Standards ensure that various entities involved in grid operations (e.g., generators, transmission operators and the AESO) are doing their part by way of procedures, communication, coordination, training, and maintenance, among other practices, to support the reliability of the interconnected electric system. For Alberta Reliability Standards, the MSA closed 68 matters since the start of 2018, while 115 remain unresolved. Five of the matters closed during this quarter were addressed with a notice of specified penalty, totalling $19,750 in financial penalties.

Figure 36: Overview of Alberta Reliability Standards Matters Addressed During or Unresolved at the End of Q2/18



The Alberta Reliability Standards listed in Figure 36 fall into the following categories:

BAL	Resource and Demand Balancing
CIP	Critical Infrastructure Protection
COM	Communications
FAC	Facilities Design, Connections and Maintenance
INT	Interchange Scheduling and Coordination
PRC	Protection and Control
VAR	Voltage and Reactive