MARKET SURVEILLANCE ADMINISTRATOR

Q3/18 Quarterly Report

July - September 2018

December 10, 2018

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

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1 Wholesale Market

1.1 Summary

The third quarter of the calendar year is often characterized by a transition from high demand during the first half of the quarter to lower demand during the second half. This occurrence is primarily due to warm summer temperatures which subside during the latter part of the quarter as fall approaches.

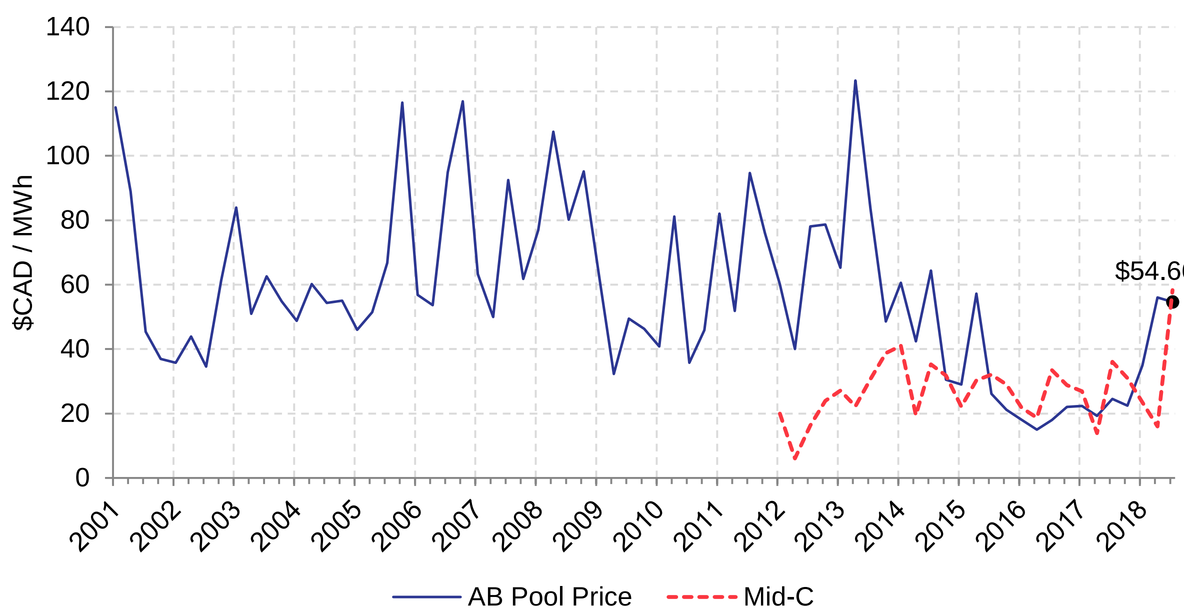
Alberta saw sustained periods of 30°C-plus temperatures in July and August with record highs being set throughout much of the province on several days. On August 10, Alberta saw its highest recorded temperature in Medicine Hat which hit an all-time high of 40.1°C.

As a result of the high temperatures, Alberta saw eight hours which broke the previous record for summer peak demand. Alberta's summer peak load now sits at 11,169 MW set on August 10, 2018 in hour ending (HE) 15. This is up from 10,582 MW last set on July 27, 2017 in HE 17.

Table 1: Market Summary

		2017	2018	*Change*
Pool Price (Avg $/MWh)	Jul	26.96	58.45	*117%*
	Aug	24.57	68.80	*180%*
	Sep	22.11	36.11	*63%*
	Q3	**24.57**	**54.66**	***122%***
Demand (AIL, GWh)	Jul	6,972	7,110	*2%*
	Aug	6,937	7,179	*3%*
	Sep	6,495	6,689	*3%*
	Q3	**20,404**	**20,978**	***3%***
Gas Price (Avg $/GJ)	Jul	1.55	1.22	*-22%*
	Aug	1.65	0.90	*-45%*
	Sep	0.88	1.46	*65%*
	Q3	**1.37**	**1.18**	***-14%***
Wind (GWh)	Jul	256	219	*-15%*
	Aug	225	264	*18%*
	Sep	298	177	*-41%*
	Q3	**779**	**660**	***-15%***
Total Net (Imports) / Exports (GWh)	Jul	69	-215	-411%
	Aug	157	-65	-142%
	Sep	144	-31	-122%
	Q3	**370**	**-312**	**-184%**
Supply Cushion (Avg MW)	Jul	2,081	1,892	*-9%*
	Aug	1,578	1,631	*3%*
	Sep	1,729	1,591	*-8%*
	Q3	**1,797**	**1,706**	***-5%***

Figure 1: Quarterly Pool Prices

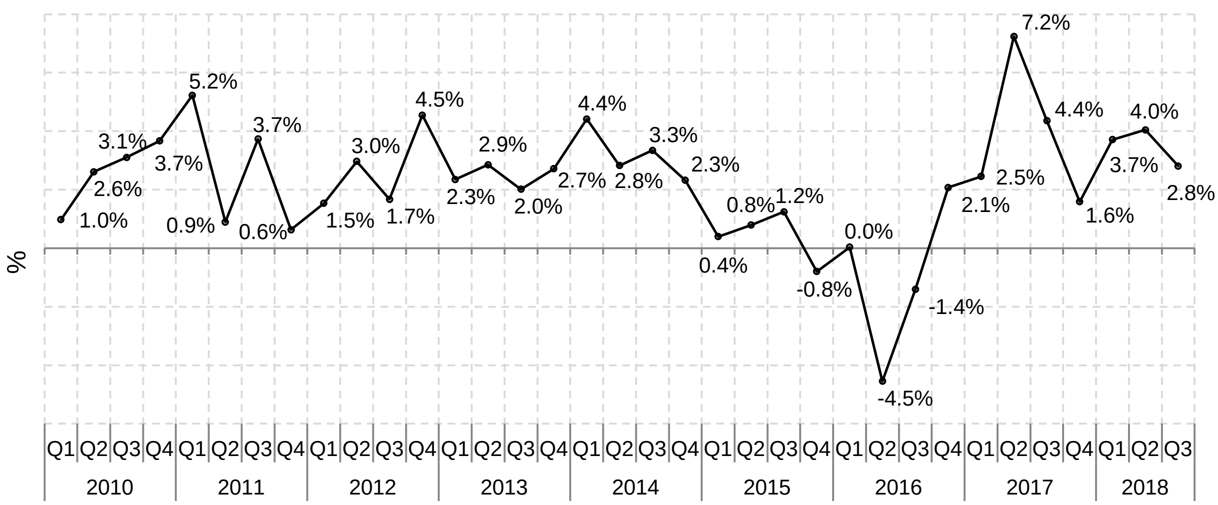


In recent years there has been a narrowing of the gap between the winter (11,697 MW) and summer (11,169 MW) peak demands which now sits at just 528 MW. Due to the higher demand observed during July and August, supply cushion levels were tight on many of these days which led to triple-digit pool prices during these periods.

In Q3/18, pool prices averaged $54.66/MWh ($31.73/MWh ext. off-peak, $66.12/MWh ext. on-peak). This is a 122% increase compared to the same period in 2017, although it is down slightly from the average Q3 pool price of $59.17/MWh observed since 2001. Figure 1 shows the trend in average quarterly pool prices since the inception of Alberta's electricity market.

Alberta's load continues to grow at a fairly healthy pace due to a strengthening economy as it continues to recover from the recession in 2015-16. Total demand, or Alberta Internal Load (AIL), was up approximately 2.8% year-over-year for the quarter. This is largely in step with historical averages observed since 2010. Figure 2 illustrates Alberta's growth in demand.

Figure 2: Growth in Alberta Load (Year-over-year)

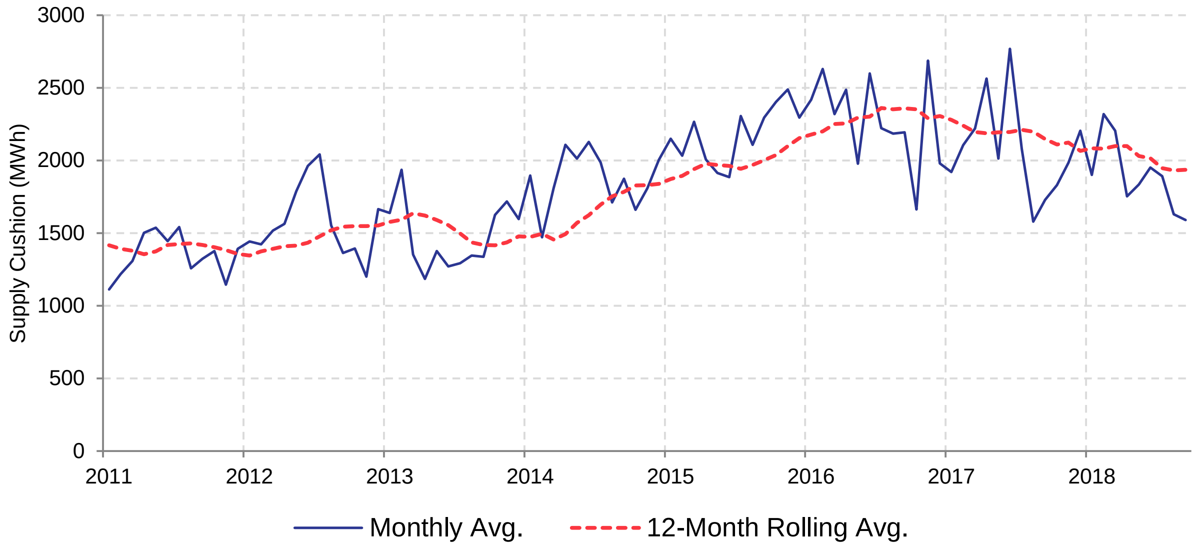


Total wind generation was down by 15% year-over-year. This is likely due to the high number of hot days Alberta saw during the summer. Typically wind generation is poor on extremely hot or cold days due to the low wind conditions which result during these periods.

During the quarter, Alberta had average hourly net imports of 141 MWh from neighbouring power markets. This marks a significant reversal from the same quarter last year when Alberta exported an average of 168 MWh. This may be the result of Mid-C prices being higher than Alberta's pool price in Q3/17 compared to similar prices observed in both markets during Q3/18. The Mid-C power price is included in Figure 1 with Alberta's pool price for comparison purposes.

The average supply cushion for Q3/18 fell by 5% year-over-year. Supply cushion levels have been trending lower during 2018 compared to the previous two years. This is primarily the result of moderate growth in demand coupled with the retirement and mothballing of some coal generation assets since the beginning of 2018. Figure 3 shows the evolution of Alberta's supply cushion since 2011.

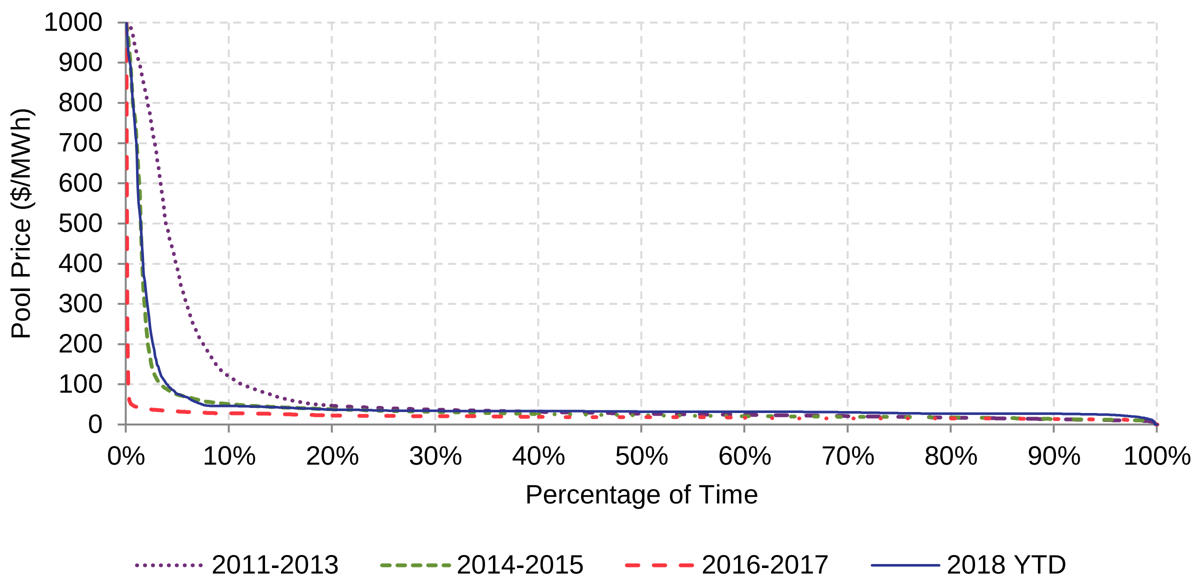
Figure 3: Evolution of Supply Cushion



As discussed, Alberta has recently seen an increase in average pool price compared to the previous two years. This may be attributed to the lower supply cushion levels coupled with economic withholding by a few large market participants in periods of tight supply.

Figure 4 shows the year-to-date (YTD) pool price duration curve for 2018 compared to previous years. As illustrated, there have been significantly more high-price events in 2018 than over the past two years. Conditions this year have been more representative of those observed in 2014-15, with fewer high-priced hours than those seen in the years 2011-13.

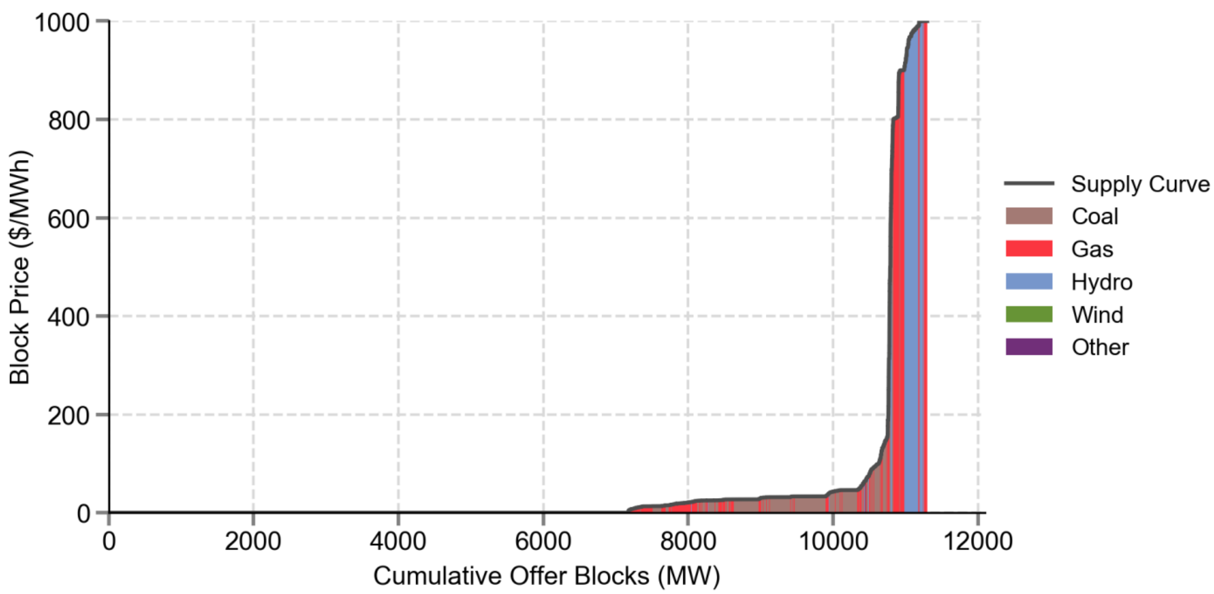
Figure 4: Pool Price Duration Curve



Despite higher pool prices this year, particularly over the previous two quarters, the percentage of hours in which these high prices occur remain relatively low. Only 13% of hours during Q3/18 had pool prices above the quarterly average of $54.66/MWh.

Figure 5 shows the weighted-average supply curve by fuel type for Q3/18. The supply curve is calculated by taking the cumulative sum of all time-weighted average price-quantity pair blocks within each merit order over the quarter.

Figure 5: Weighted Average Supply Curve by Fuel Type for Q3/18



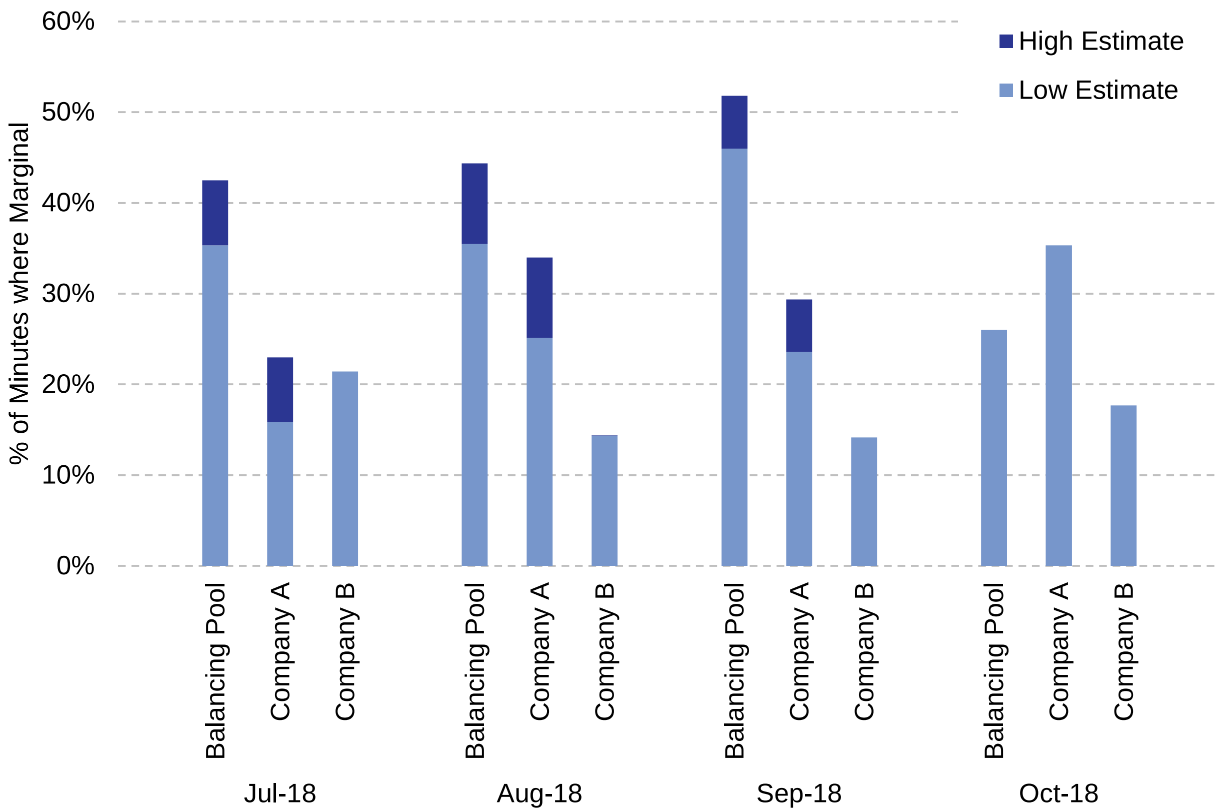
For the current quarter, approximately 7,000 MW of generation was priced at or close to $0/MWh on average. These offer blocks were mostly comprised of wind, cogeneration and minimum-stable thermal generation. For these zero-dollar offer blocks, generators are price takers who are satisfied to receive the pool price during a given hour in exchange for having their asset dispatched and not having to incur the high-cost of restarts for large thermal generators.

The next block of generation, from 7,000-11,000 MW, primarily consists of coal and gas generation. Approximately 1,000 MW of coal generation has persistently been offered at prices in the high-20s to low-30s dollar per megawatt hour range since the beginning of 2018 when Alberta’s carbon price last increased.

Starting just below 11,000 MW, there is a significant increase in the offer price. As a result, a small shift in demand can have a significant impact on the pool price within this upper portion of the supply curve. This region of the supply curve is typically comprised of hydro and small gas peakers, with total hydro volumes dependent upon the time of year.

During the quarter, there were three market participants which set the system marginal price (SMP) most of the time. Overall, the Balancing Pool set SMP the most from July through September. However, this percentage fell off noticeably in October following the return of BR5 to ATCO. Figure 6 illustrates these results. Note that the high and low estimates within the figure are due to uncertainty as to which market participant had offer control on certain shared offer blocks. This uncertainty results from how the merit order data is collected.

Figure 6: Top Market Participants setting SMP during Q3/18



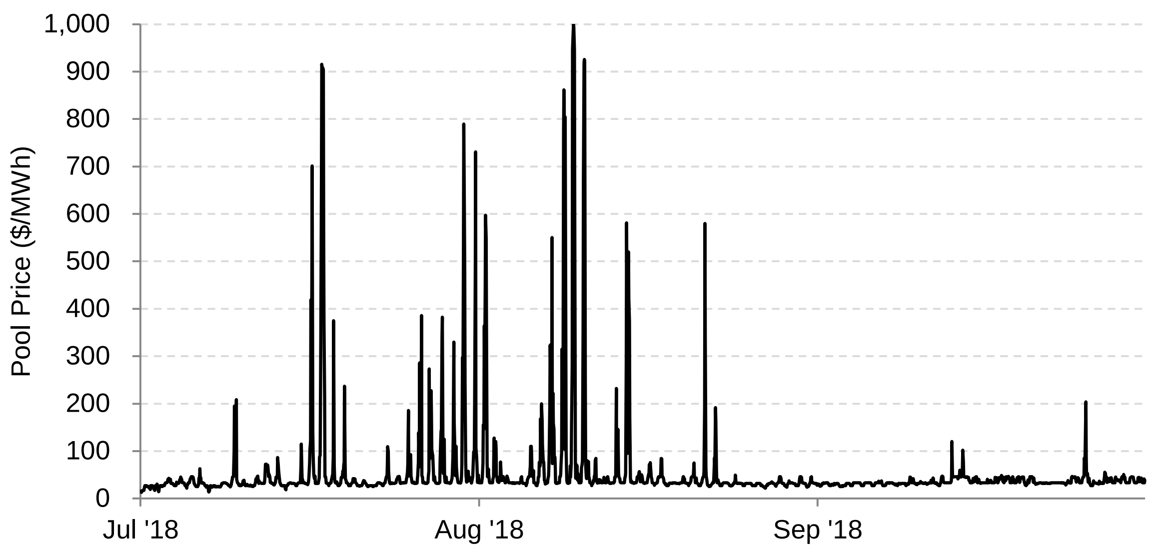
1.2 Pool Price Events

As part of its oversight, the MSA monitors market conditions present during periods of low and high pool price. These periods illustrate the market forces of supply and demand at work and, over prolonged time frames help to inform the state of competition within Alberta's market.

Figure 7 shows the hourly pool price for Q3/18. During the quarter, Alberta had no zero-priced hours, although there were numerous high-priced hours as are typical during periods of high summer peak load. Most of the high-priced hours were clustered in groups of several days during the first half of the quarter.

As previously discussed, the high prices observed during the quarter were the result of tighter supply cushion levels coupled with economic withholding by a few market participants. The tighter supply cushion levels primarily stemmed from higher than normal demand as well as the retirement and mothballing of a number of coal generators since the beginning of 2018.[1]

Figure 7: High pool price periods during Q3/18



July 17, 2018

Pool prices spiked up above $900 between HE 15 to HE 18 on July 17, with pool prices peaking at $915/MWh during HE 15. Prices were elevated for much of the day, and the daily average settled at $275/MWh. The supply cushion remained below 810 MW for the duration of the high-priced hours and fell to 188 MW in HE 17. The primary factors driving these high prices were outages, low wind generation and market participant offer behavior. Sundance #2, #3, and #5 (1,054 MW) were offline, H.R Milner (144 MW) was on a forced outage, and several larger units were derated due to warm ambient temperatures. Wind output was low for the majority of the

[1] TransAlta retired Sundance #1 on January 1, 2018 and Sundance #2 (previously mothballed since January 1, 2018) on July 31, 2018. TransAlta mothballed Sundance #3 and #5 effective April 1, 2018. On December 6, 2017, TransAlta announced that it would mothball Sundance #4 effective April 1, 2019.

day (below 330 MW), and was only generating 35 MW during the highest priced hour. In addition to restricted supply, demand reached 11,099 MW in HE 17, which at the time broke the previous summer peak record. In addition to the tight market fundamentals, approximately 450 MW of thermal generation was offered above $890/MWh during this event.

<u>July 26, 2018</u>

Pool prices were volatile on July 26 and fluctuated from a high of $385/MWh to a low of $66/MWh between HE 12 to HE 18. These prices were a result of unit outages, market participant offer behavior, prices in neighbouring markets, and low wind generation. Sundance #2, #3, and #5 remained offline and wind generation was low throughout the day, averaging only 48 MW from HE 12 to HE 18. During these high price hours the BC/MATL tielines were not fully utilized for imports, in HE 18 for example the market was exporting 112 MW on the BC/MATL tielines. Although the BC/MT Available Transfer Capability (ATC) was above 580 MW, imports from BC remained relatively low due to average Mid-C prices of $126/MWh from HE 12 through HE 18. HE 18 had the largest supply cushion (1,021 MW) of the pricing event; however this corresponded to the highest priced hour. This suggests that in addition to market fundamentals, market participant offer behavior was a major driver for high prices in HE 18. More than 600 MW of thermal generation was priced above $500/MWh in this hour.

<u>July 30, 2018</u>

On July 30 pool prices reached $789.64/MWh for HE 15 and averaged $458/MWh from HE 12 through HE 18. Supply cushion was low throughout the event reaching a minimum of 477 MW for HE 15 which coincided with the peak clearing price. High demand, summer derates, mothballed units, and low wind generation all factored into supply issues seen throughout the day. Market demand for electricity peaked at 10,968 MW and approximately 3,100 MW of thermal generation was unavailable over the course of these hours.

Beginning in HE 12 imports from Montana were unavailable due to a transmission outage. A drop of imports from 142 MW to 0MW was observed along the Saskatchewan tie line, which was sustained for much of the pricing event until participants began exporting 75 MW in HE 17 and HE 18. In HE 12, 530 MW of thermal generation was priced above $770/MWh and in combination with the supply issues, economic withholding was responsible for the high clearing prices over the next several hours.

<u>July 31, 2018</u>

Pool Prices were elevated on July 31 and spiked between HE 15 to HE 18 with a peak clearing price of $730/MWh for HE 17; the daily average settled at $108/MWh. The market experienced some tightness due to limited wind generation, mothballed units, prices in neighbouring markets, and summer derates. During this period Sundance #2, #3, and #5 were offline and several larger units were heavily derated due to ambient temperatures. In HE 16 the Saskatchewan Available Transfer Capability (ATC) fell to zero in order to address stability issues, though the loss of imports was partially offset by increasing wind generation. There was at least 200 MW of room for BC imports throughout the pricing event, however due to prevailing Mid-C prices exceeding $100/MWh, full utilization of the intertie didn't materialize.

Load peaked at 10,846 MW in HE 15 and in HE 17 the supply cushion fell to 736 MW, corresponding to the highest price of the event. Approximately 650 MW of thermal generation was priced at over $600/MWh in HE 15.

August 9, 2018

On August 9 prices averaged $970/MWh from HE 14 to HE 18 and hit the price cap of $999/MWh in HE 16. Load peaked at 11,163 MW and the market was extremely tight from HE 12 through HE 19; the supply cushion was effectively zero for HE 16 and HE 17. The AESO declared an Energy Emergency Alert (EEA1) at 15:07, followed by an EEA2 at 15:39, before terminating the alert (EEA0) at 16:39. Temperatures reached 34°C in Edmonton and Calgary, and as a result of the warm weather a large number of units were derated. In addition, Sheerness 2 (390 MW) was offline until HE 18. Imports from Montana were unavailable until HE 16 and wind generation averaged only 82 MW over HE 12 to HE 19.

Along with market fundamentals, market participant offer behavior was a factor in the observed high pool prices; 400 MW of thermal generation was offered above $900/MWh throughout much of the pricing event.

August 10, 2018

On August 10 prices peaked at $925/MWh in HE 16 and averaged $672/MWh from HE 13 through HE 18. These prices were the result of high demand, unit outages, and market participant offer behavior. A new record for summer demand was set on August 10, with load peaking at 11,169 MW in HE 15. Supply cushion reached a minimum of 399 MW and remained low (below 560 MW) for the duration of the event. Sundance #2, #3, and #5 remained offline and large volumes of capacity were derated due to ambient temperatures or other operational issues. Approximately 3,040 MW of thermal generation was offline during the beginning of the pricing event. Wind was fairly low for the majority of the high-priced hours and averaged 206 MW from HE 13 through HE 18. In addition to supply issues, economic withholding of capacity was observed to be a contributor to the high-priced hours.

September 17, 2018 – October 5, 2018

On September 17 HE 10, the BC and Montana intertie went offline for scheduled maintenance lasting from September 17 to October 5, with some intermittent energization of the BC line in late September. The combined BC/MATL intertie has a normal System Operating Limit (SOL) of 1,110 MW of imports, though actual capability varies based upon system conditions.

Tieline maintenance is often scheduled for the fall due to lower demand during this time of year. Despite the lower demand, Alberta's interconnections still provide a significant source of generation and increased competition to the province during periods of tight supply.

Notwithstanding the loss in generation, pool prices remained unexpectedly low throughout the intertie outage this quarter. This was primarily due to low demand and ample supply within the province.

From September 17 through September 27 the pool price averaged $38.34/MWh and had reached over $100/MWh for only two consecutive hours on September 25 in HE 13 through 14. Throughout the duration of the maintenance period, load remained below 10,000 MW. Although the supply cushion had periods below 1,000 MW, we did not observe sustained high prices as in the prior months in the quarter.

On September 27 in HE 8 the supply cushion fell to 359 MW, though the resulting price in that hour was a modest $55.81/MWh. Comparatively, on August 10 a supply cushion of 399 MW resulted in a clearing price of 919.05/MWh. An underlying factor for modest prices under tight market conditions is that there are fewer high price-quantity pair offers. In HE 8, approximately 110 MW of thermal generation was offered at above $980/MWh. In addition, a relative absence of offers between marginal cost and the price cap was observed. During some hours with tight supply, the units belonging to participants that could otherwise influence prices were unavailable.

2 Forward Market

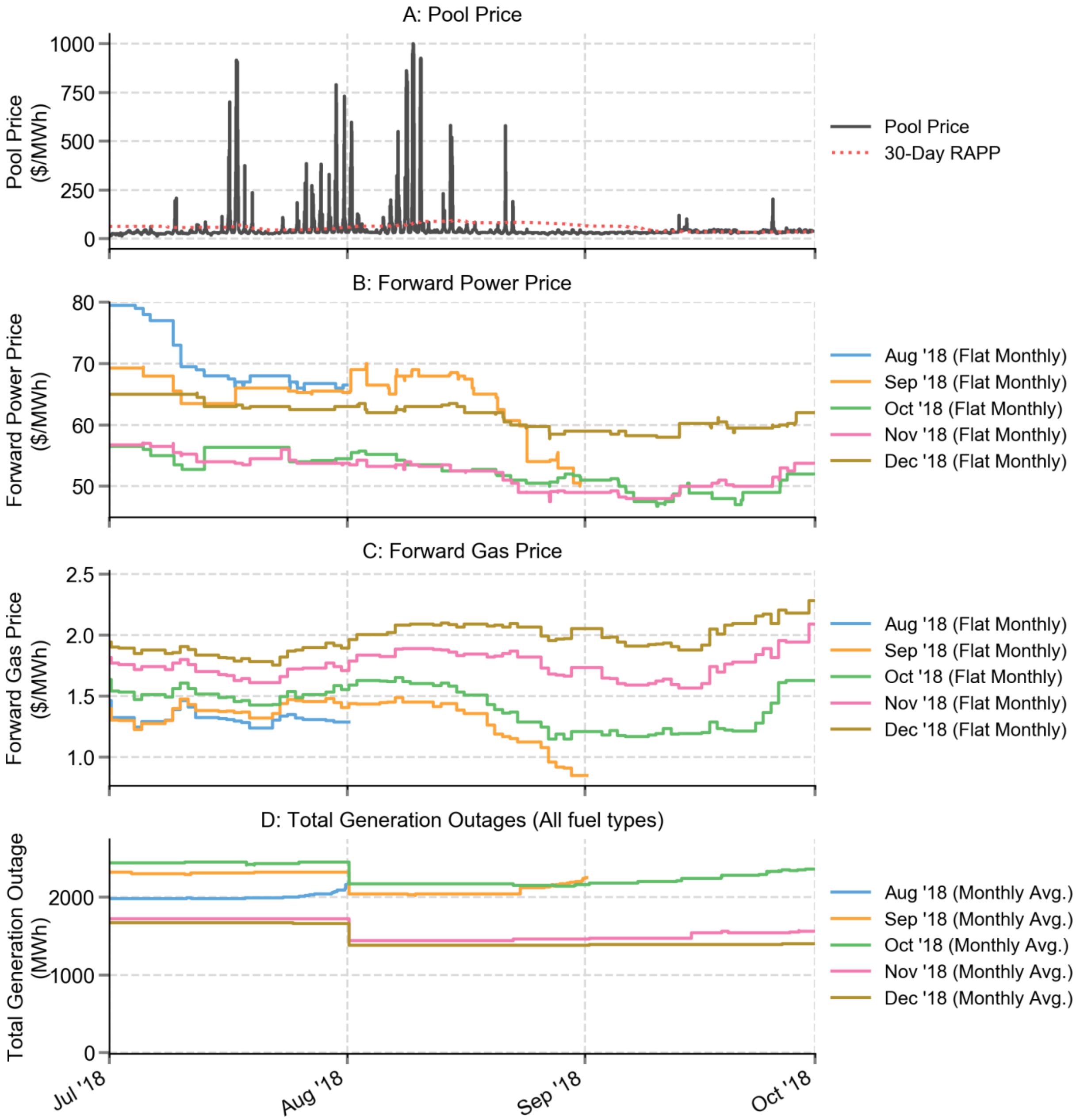
2.1 Forward Prices

Figure 8 shows the evolution of flat-monthly forward power prices in relation to several factors which often influence market prices. Overall, monthly prices moved down throughout the quarter.

During the month of August, the drop in price of the September 2018 flat-monthly contract was particularity noticeable, although October and November prices remained relatively unchanged. September prices fell from approximately $70/MWh to $50/MWh. This may be partially attributed to a similar drop in forward natural gas price for the monthly September 2018 contract. Throughout the month of August, the monthly gas contract price for September fell by nearly half, from approximately $1.50/GJ to $0.80/GJ. At the beginning of August, total outages fell by 280 MW due to the retirement of Sundance #2. While major changes to the AESO's published outage table typically impact forward prices, Sundance #2 had previously been mothballed since January 1, 2018 and, as a result, would have already been built into traders' expectations of future supply conditions beforehand.

During the quarter the BC/MATL tieline was offline from September 17 to October 5 due to scheduled maintenance. While tieline outages may have a material impact on forward prices, there were no changes to scheduling during the month of August and as a result should not have had an impact on the September 2018 forward price.

Figure 8: Evolution of Forward Contract Prices



2.2 Trade Volumes

Trade volumes in Q3/18 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 longer term products, such as annuals and quarterlies, has seen the largest decline in trade volumes in 2018.

Table 2: Trade Volumes by Contract Term (TWh)

		Daily	Monthly	Quarterly	Annual	Other	Total
2015	Q1	0.10	9.96	0.84	4.17	0.76	15.84
	Q2	0.20	11.53	1.51	18.73	1.64	33.61
	Q3	0.06	6.25	0.50	5.02	0.43	12.26
	Q4	0.06	5.87	0.98	5.74	0.03	12.68
	Year	0.42	33.61	3.84	33.66	2.86	74.39
2016	Q1	0.22	9.36	1.78	12.37	3.01	26.73
	Q2	0.19	8.25	0.58	4.50	1.08	14.60
	Q3	0.07	6.80	1.23	4.56	0.25	12.90
	Q4	0.09	5.44	1.46	3.78	0.47	11.24
	Year	0.57	29.85	5.05	25.20	4.81	65.47
2017	Q1	0.06	6.53	3.03	4.57	1.86	16.06
	Q2	0.13	6.87	2.33	11.13	0.85	21.30
	Q3	0.18	6.77	2.13	5.51	1.17	15.76
	Q4	0.06	8.24	3.51	11.61	1.38	24.81
	Year	0.43	28.41	11.01	32.82	5.27	77.93
2018	Q1	0.15	7.28	0.60	4.47	0.41	12.91
	Q2	0.16	6.06	1.20	5.75	0.32	13.49
	Q3	0.10	4.59	0.22	3.60	0.53	9.04
	Year	0.41	17.92	2.02	13.82	1.27	35.44

2.3 Forward Price Curves

The forward curve for the next year, as of late October, is shown in Figure 9. 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 9: Forward Price Curve for Monthly Contracts (7X24, October 23, 2018)

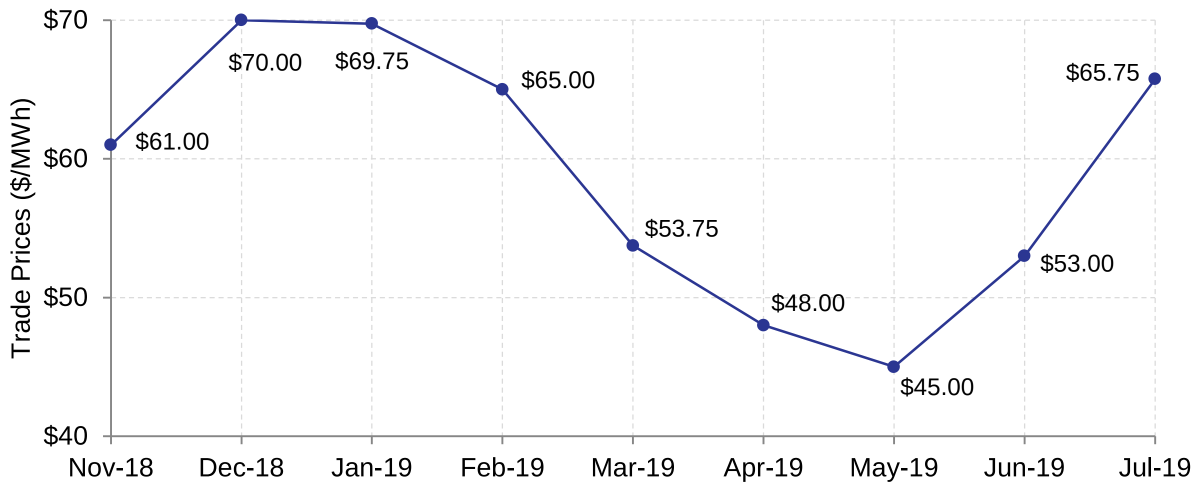


Figure 10: Forward Price Curve for Annual Contracts (7X24, October 23, 2018)

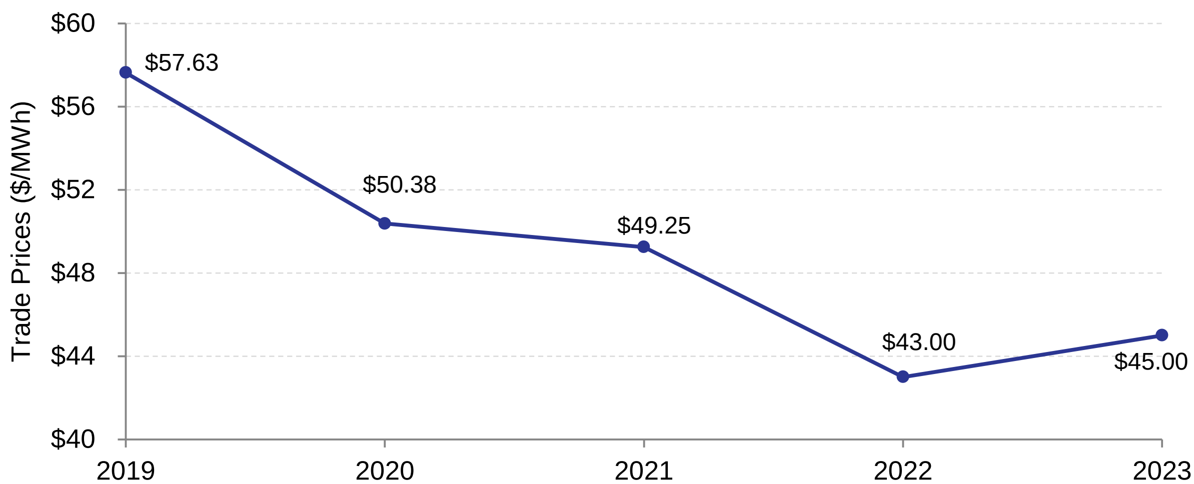
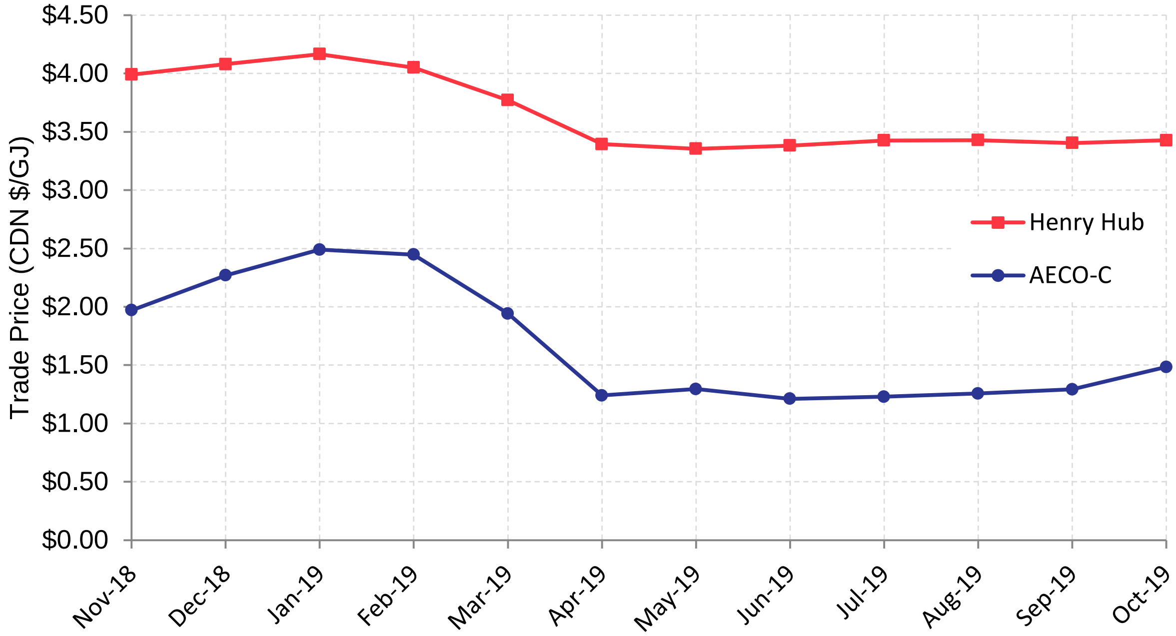


Figure 11 shows the forward curve for natural gas at the AECO-C Hub in Alberta, as well as at the Henry Hub in Louisiana. The price of natural gas in Alberta for November 2018 is currently trading at $1.97/GJ while January 2019 is trading at $2.49/GJ. Winter months are typically more expensive as gas is used for heating load. As shown, prices for April 2019 onward are significantly lower than the forward prices over the next few months. Comparatively, AECO-C is trading at an average discount of $1.23/GJ to Henry Hub for calendar year 2019. This is primarily due to high supply relative to demand within Alberta, pipeline constraints which limit the amount of natural gas that can be exported from the province, and the cost of pipeline transport to other markets. This results in inexpensive natural gas for Alberta consumers, but reduced income for Alberta's natural gas producers.

Figure 11: Forward Curve for Natural Gas, AECO-C Hub and Henry Hub (October 23, 2018)



3 Ancillary Services

3.1 Operating Reserves

The total cost of operating reserves in Q3/18 was $50.4 million compared to $20.7 million in Q3/17. This represents a 144% increase over the same period last year.

Most of the cost increase was for active reserves which had an increase in total cost from $17.9 million in Q3/17 to $45.0 million in Q3/18. This is due to an increase in procurement volumes (41.5 GWh increase year-over-year) along with higher pool prices in the quarter ($54.66/MWh in Q3/18 compared to $24.57/MWh in Q3/17) as active reserve payments are a function of pool price.

An increase in the volume of standby contingency reserve activations also contributed to the increase in total operating reserve costs during the quarter. The total amount of standby contingency reserves activated in Q3/18 were 30.2 GWh compared to 24.4 GWh in Q3/17. This increase is reflected in the total cost of standby contingency reserves activations which increased from $0.8 million in Q3/17 to $4.2 million in Q3/18.

Table 3: Operating Reserve Summary

Total Cost ($ Millions)			
	Q3 2017	**Q3 2018**	***% Change***
Active Procured	**17.9**	**45.0**	***152***
RR	7.0	13.9	*99*
SR	7.3	18.4	*152*
SUP	3.6	12.7	*258*
Standby Procured	**1.9**	**0.8**	***-59***
RR	0.7	0.5	*-35*
SR	1.0	0.3	*-74*
SUP	0.2	0.1	*-67*
Standby Activated	**0.9**	**4.5**	***417***
RR	0.0	0.3	*6,522*
SR	0.6	2.9	*366*
SUP	0.2	1.3	*434*
Total	**20.7**	**50.4**	***144***
Total Volume (GWh)			
	Q3 2017	**Q3 2018**	***% Change***
Active Procured	**1,329.6**	**1,371.1**	***3***
RR	347.9	347.4	*0*
SR	490.8	512.2	*4*
SUP	490.8	511.5	*4*
Standby Procured	**482.8**	**500.5**	***4***
RR	175.5	176.4	*1*
SR	230.7	239.2	*4*
SUP	76.6	84.8	*11*
Standby Activated	**24.6**	**34.8**	***41***
RR	0.2	4.6	*2,977*
SR	15.2	19.7	*30*
SUP	9.3	10.5	*13*
Total	**1,836.9**	**1,906.3**	***4***
Average Cost ($/MWh)			
	Q3 2017	**Q3 2018**	***% Change***
Active Procured	**13.43**	**32.84**	***145***
RR	20.05	39.92	*99*
SR	14.92	36.01	*141*
SUP	7.24	24.87	*243*
Standby Procured	**4.02**	**1.60**	***-60***
RR	4.17	2.71	*-35*
SR	4.50	1.12	*-75*
SUP	2.24	0.66	*-71*
Standby Activated	**35.74**	**130.66**	***266***
RR	30.42	65.46	*115*
SR	41.71	149.69	*259*
SUP	26.07	123.58	*374*
Total	**11.26**	**26.42**	***135***

4 Retail Market

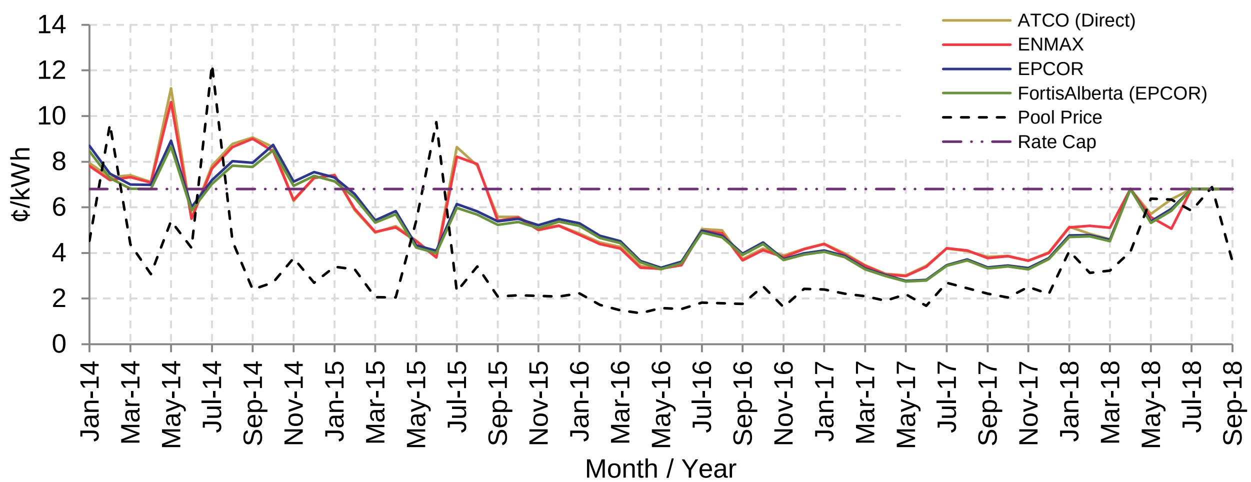
The retail market is comprised of regulated and competitive components. All customers who do not select a competitive retailer for electricity or natural gas services are on some form of default rate. The electricity regulated rate for smaller customers is called the Regulated Rate Option (RRO) and the mechanism for pricing this option is regulated, not the actual prices. For larger electricity customers, the default tariff is at the discretion of the wires service provider. Smaller natural gas customers who have not chosen a competitive retailer are on the Default Rate Tariff (DRT).

4.1 Regulated Retail Market

4.1.1 Regulated Rate Option (RRO)

RRO rates continued to rise in Q3/18 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 over all three months of the quarter. Absent this cap, RRO rates would have reached levels not seen since summer 2015 (see Figure 15).

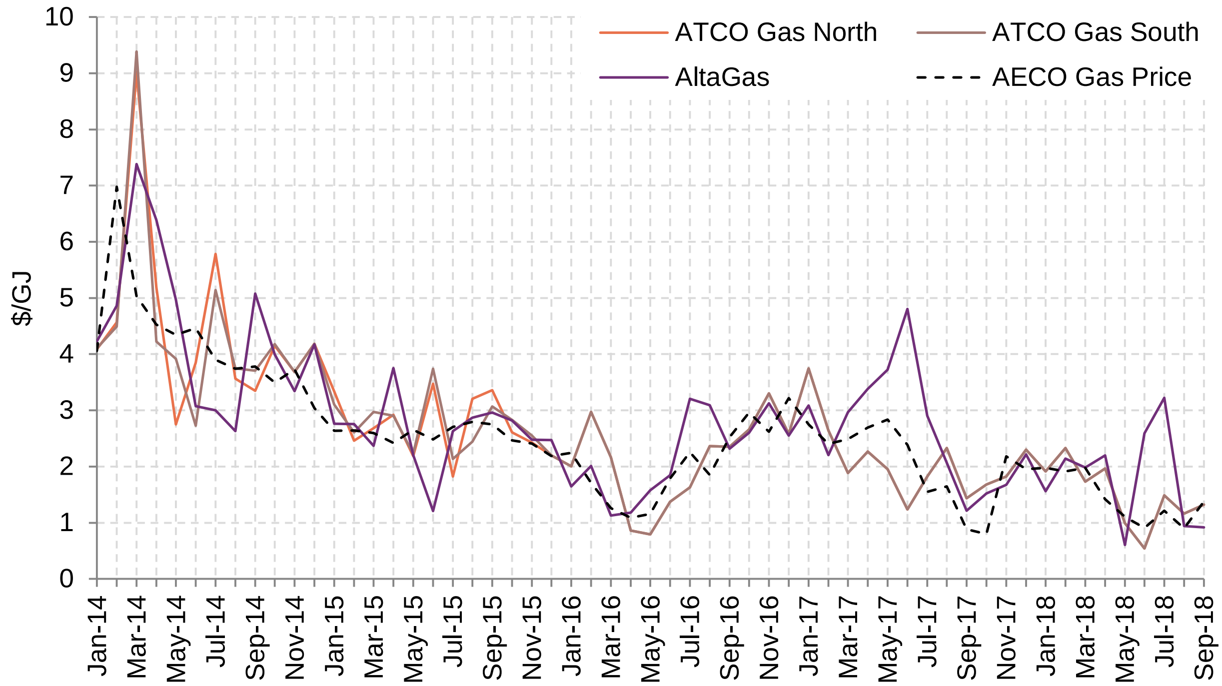
Figure 12: Residential RRO Rates, January 2014 – June 2018



4.1.2 Default Rate Tariff (DRT)

Default Rate Tariff rates increased modestly in Q3/18, although rates have remained relatively low when compared to recent historical norms. This quarter over quarter increase has been driven primarily by natural gas fundamentals.

Figure 13: DRT Rates, January 2014 – June 2018



4.1.3 Energy Price Setting Plans – Recent Developments

Direct Energy's 2018-2020 Energy Price Setting Plan (EPSP) application has completed the reply argument phase and the Commission is expected to render a decision in early 2019.

On October 18, 2018, the Commission approved amendments to EPCOR's 2018-2021 EPSP as applied for on September 20, 2018.[2] These amendments included the rendering of certain portions of the EPSP confidential, as well as an adjustment to the auction price decrement algorithm.[3]

4.1.4 Rate Cap Regulation

The Government of Alberta's regulated retail rate cap bound for the months of July, August, September and October 2018. Reference rates for rural electrification associations (REAs) and other RRO providers not regulated by the AUC ranged from 8.766 ¢/kWh to 9.525 ¢/kWh over these three months.[4]

As part of the Deferral Account Statement (DAS) process, RRO providers for REAs and municipalities submit a monthly rate to the MSA. This rate is the provider's RRO rate as determined from its Energy Price Setting Plan, before consideration of the rate cap. Figure 14 illustrates the wide range of monthly rates submitted to the MSA by 37 RRO providers for REAs

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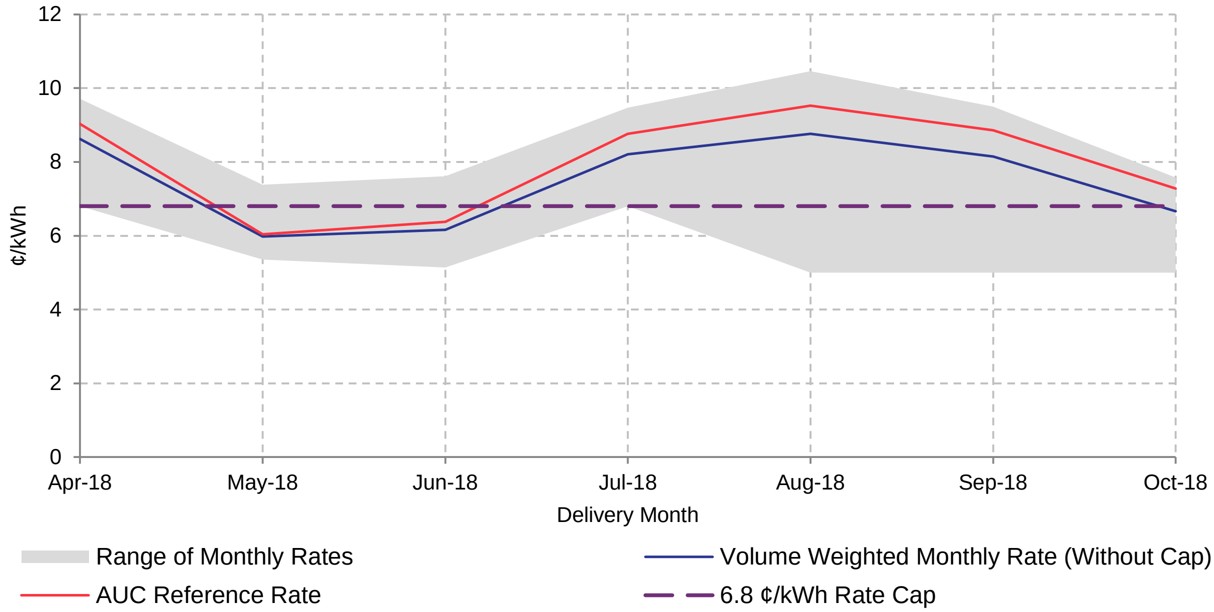
[2] See AUC Decision 23916-D01-2018 – EPCOR Energy Alberta GP Inc. Application for Amendments to the 2018-2021 Energy Price Setting Plan.
[3] Ibid, PDF Page 5.
[4] The AUC determines these reference rates as ten percent greater than the average of approved residential RRO rates submitted by the three RRO providers it regulates. See MSA Q2/2018 Quarterly Report for more information.

and municipalities. Notably, some monthly rates are greater than the reference rate in a given month; in this situation, customers are billed at 6.8 ¢/kWh plus the difference between the monthly rate and the reference rate.

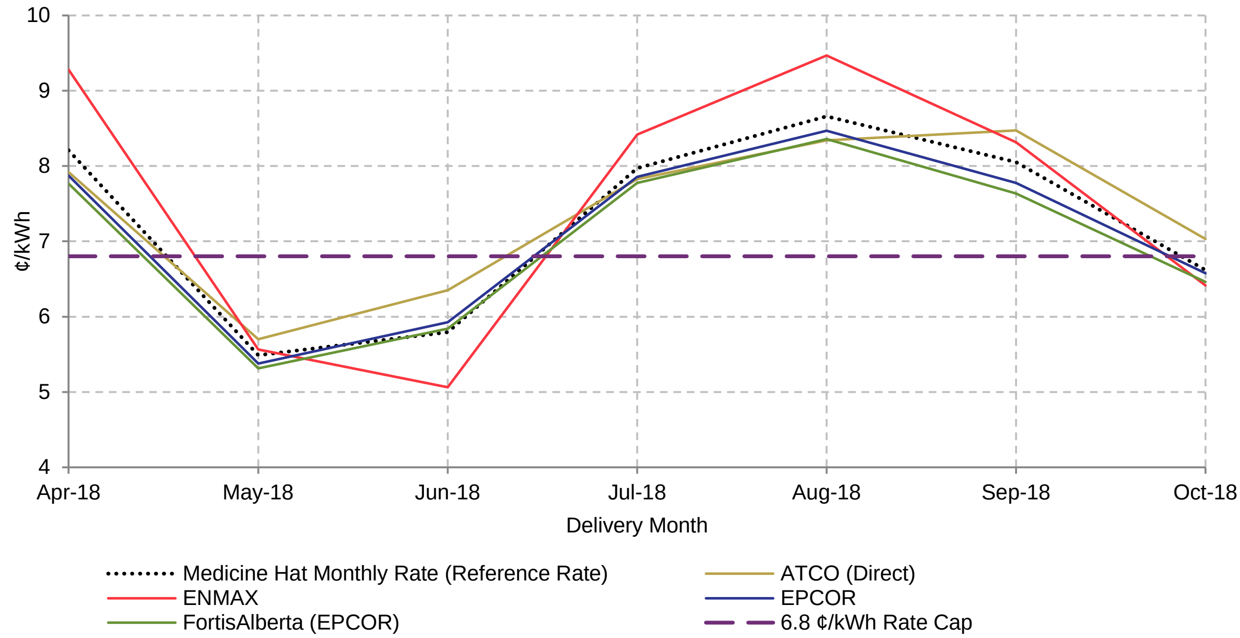
Figure 14: Monthly Rates for REAs and Municipalities[5]



The MSA also approves DAS submissions from the City of Medicine Hat. Medicine Hat sets its monthly rate as the average of uncapped residential RRO rates (monthly rates) in the four largest service areas. The reference rate applicable to the City of Medicine Hat is determined by the same calculation. Figure 15 below shows the evolution of the monthly rate/reference rate for Medicine Hat over time, compared with the monthly rates for the four largest service areas.[6]

[5] Does not include data from the City of Medicine Hat.
[6] DAS submissions for the four largest service areas are approved by the AUC.

Figure 15: Monthly Rates for Medicine Hat and AUC-Regulated RRO Providers



Between April and October 2018, the Government of Alberta paid $33.7 million in compensation to RRO providers (Table 4). In October 2018, the MSA received Deferral Account Statements containing Part B submissions for the delivery month of April 2018. Part B submissions are used to 'true-up' deferral accounts for a delivery month using final settlement consumption values. The MSA has incorporated this 'true-up' into the compensation reported for October 2018, rather than retroactively incorporating it into the reimbursement reported for April 2018.

Table 4: Rate Cap Compensation

Month	Reimbursement (Commission Approved DASs)	Reimbursement (MSA Approved DASs - REA and Municipalities)	Reimbursement (MSA Approved DASs - Medicine Hat)	**Total Monthly Reimbursement**
Apr-18	$ 7,464,812.05	$ 865,316.49	$ 314,610.78	**$ 8,644,739.32**
May-18	$ 0.00	$ 0.00	$ 0.00	**$ 0.00**
Jun-18	$ 0.00	$ 0.00	$ 0.00	**$ 0.00**
Jul-18	$ 6,939,467.95	$ 693,831.03	$ 378,125.51	**$ 8,011,424.49**
Aug-18	$ 7,739,014.48	$ 954,938.81	$ 547,761.17	**$ 9,241,714.46**
Sep-18	$ 6,362,440.33	$ 636,039.17	*TBD*	**$ 6,998,479.50**
Oct-18	$ 648,272.34	$ 145,959.29	*TBD*	**$ 794,231.63**
Total	**$ 29,154,007.14**	**$ 3,296,084.79**	**$ 1,240,497.46**	**$ 33,690,589.39**

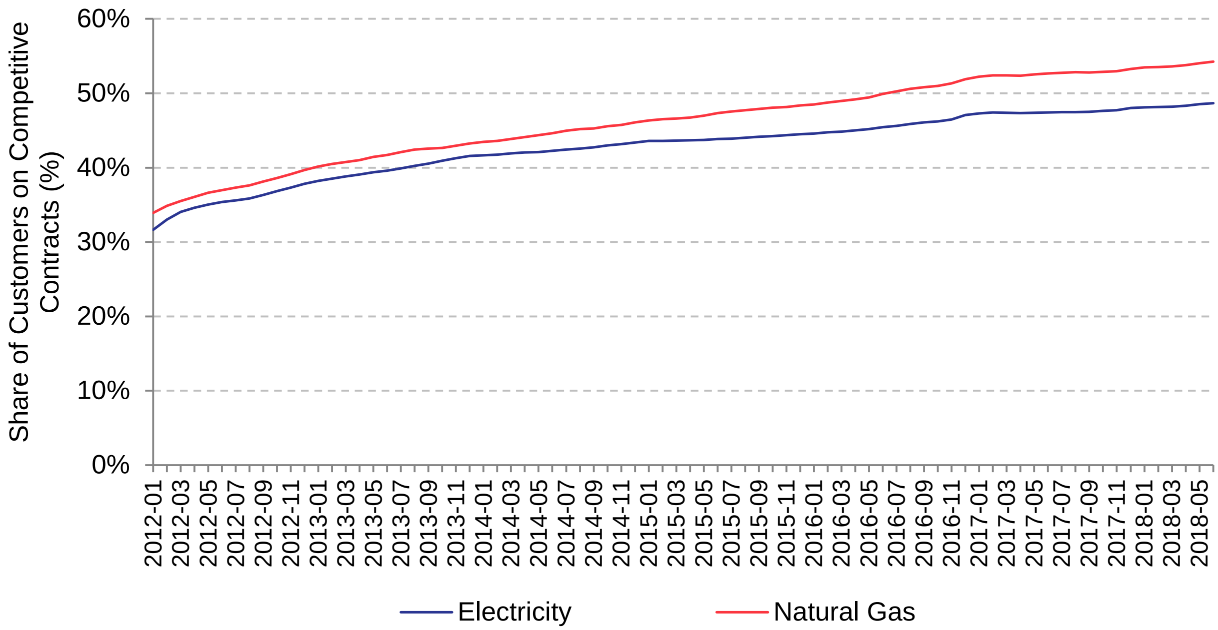
4.2 Competitive Retail Market

4.2.1 Competitive Contract Market Share

Competitive contract market shares for residential electricity customers grew modestly over Q2/18, increasing by 0.5% relative to the end of Q1/18 (Figure 16) consistent with historic norms. The rate cap first bound in April 2018 but this does not seem to have caused a significant change in switching rates. The MSA is continuing to examine whether the rate cap influences competitive market shares. For example, a binding rate cap may incentivize some customers to switch to a more stable competitive contract or it may encourage other customers to seek protection from higher rates by switching to the capped RRO.

Competitive natural gas contract shares for residential customers also grew modestly over Q2/18 despite record low DRT rates in that quarter. This may be due to better offerings having been made available to competitive customers, or customers may have switched to take advantage of dual-fuel competitive contracts.

Figure 16: Share of Residential Customers on Competitive Retail Contracts, January 2012 – June 2018

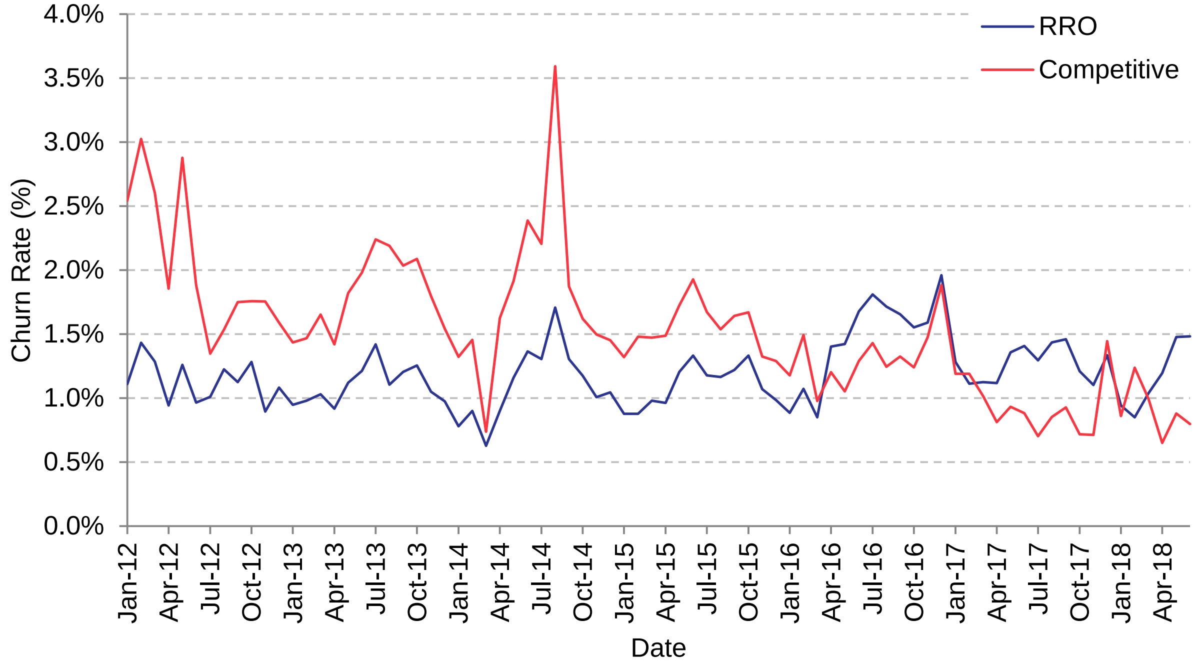


4.2.2 Churn

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 17.

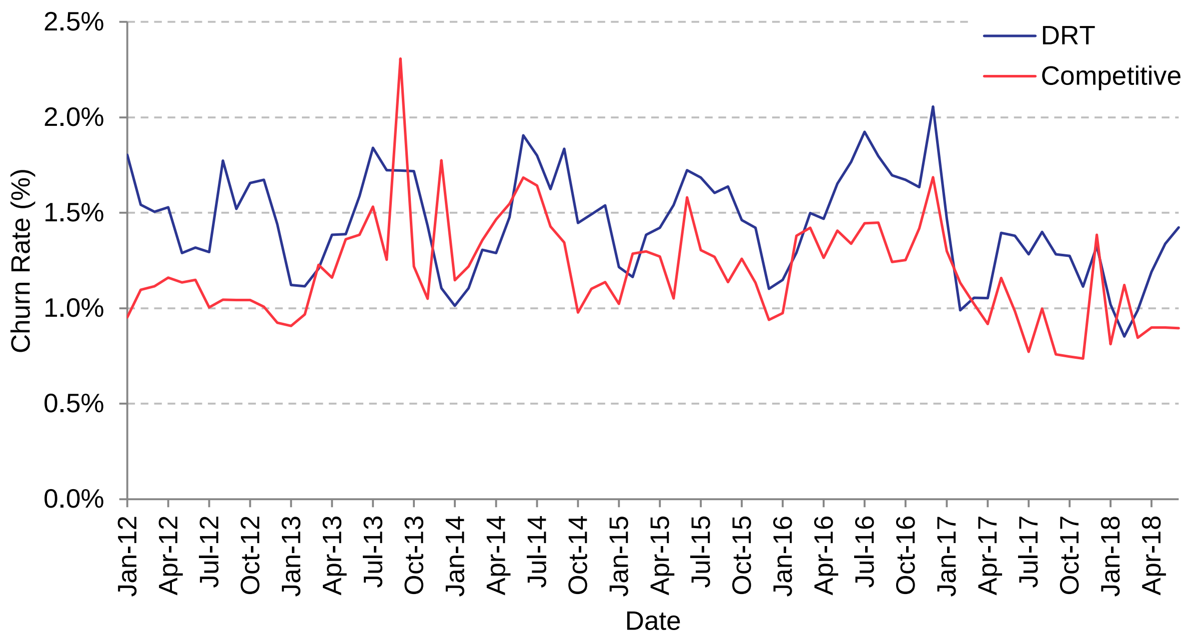
Churn rates for regulated electricity retailers increased in Q2/18, although rates remain within historical norms. In contrast, competitive churn rates reached historic lows in Q2/18.

Figure 17: Monthly Churn Rates for Residential Electricity Retailers, January 2012 – June 2018



Churn rates for regulated natural gas retailers increased during Q2/18 despite record low DRT rates in that quarter (Figure 18). This may have been due to customers switching to dual-fuel contracts, or there may have been better rates provided by competitive gas retailers.

Figure 18: Monthly Churn Rates for Residential Natural Gas Retailers, January 2012 – June 2018



4.2.3 ATCO Energy Code of Conduct Compliance Plan Decision

On September 17, 2018, the Alberta Utilities Commission released its decision with respect to ATCO Energy's application for approval of its amended Code of Conduct Regulation Compliance Plan.[7] ATCO Energy applied to the Commission for three modifications to its Compliance Plan:

1. The addition of definitions for *Advertising*, *Branding* and *Generic Messaging*, in effect limiting the applicability of the Fair Competition Statement (FCS) only to *Advertising*.
2. The removal of Mechanism 5 of Section 4.0 of the Compliance Plan, which states that the FCS is to be applied to all points of enrolment.
3. The addition of Mechanism 6 to Section 7.0 of the Compliance Plan, which would state that a radio spot in conjunction with an associated website constitute a single advertisement, to which the FCS need only be applied to the latter.

In its Decision, the Commission rejected the proposed changes to ATCO Energy's Compliance Plan. The Commission ruled that any formal definition of *Advertising* would restrict the wording within the *Code of Conduct Regulation* which states that the FCS be applied to "any advertising that markets energy services". The Commission rejected the proposed removal of Mechanism 5 of Section 4.0 on the basis that customers may not have had the opportunity to view the FCS prior to enrolment, and that this mechanism helps to support the prohibition of tying contained in Section 4 of the *Code of Conduct Regulation*. The Commission did not approve the addition of Mechanism 6 to Section 7.0 on the basis that it does not believe a radio spot in conjunction with an associated website to be a single advertisement, and that the Commission cannot vary the FCS requirements based on advertising medium.

[7] https://www2.auc.ab.ca/Proceeding23407/ProceedingDocuments/23407_X[]_Decision_23407-D01-2018_0031.pdf

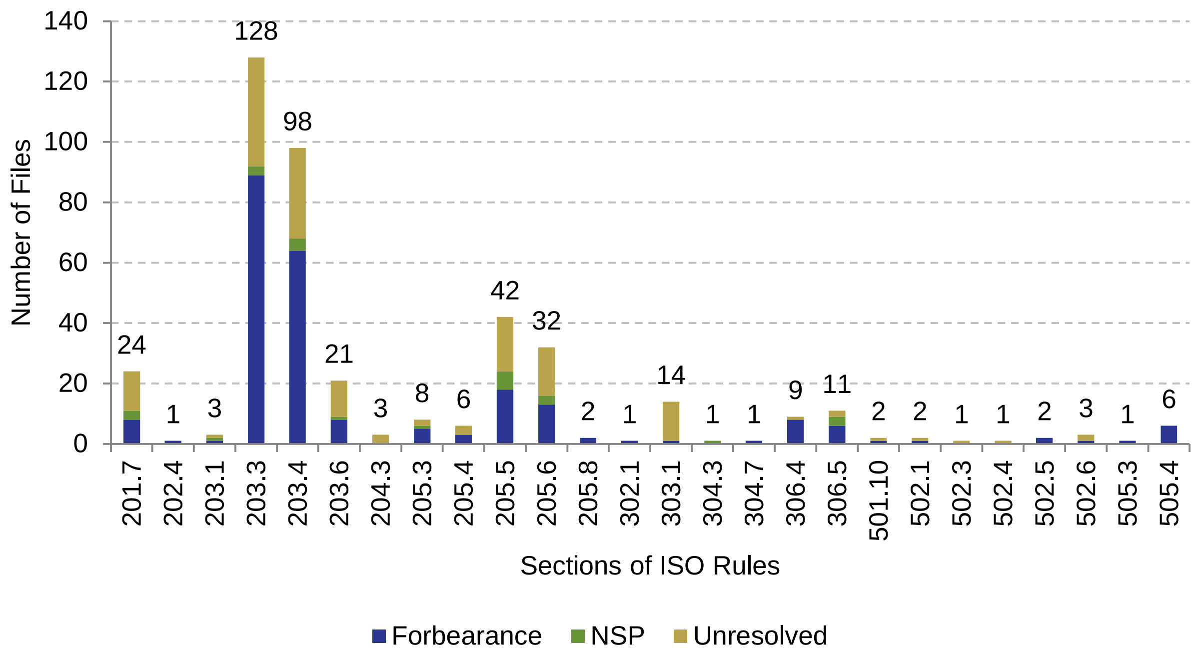
5 Compliance

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.

5.1 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 September 30, 2018, the MSA addressed 267 ISO rules compliance matters, and an additional 156 matters were carried forward to the next quarter. During this time frame, the MSA issued 26 notices of specified penalty, totalling $21,250 in financial penalties.

Figure 19: Overview of ISO Rules Matters Addressed or Unresolved at the End of Q3/18[8]



The sections of ISO rules listed in Figure 19 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

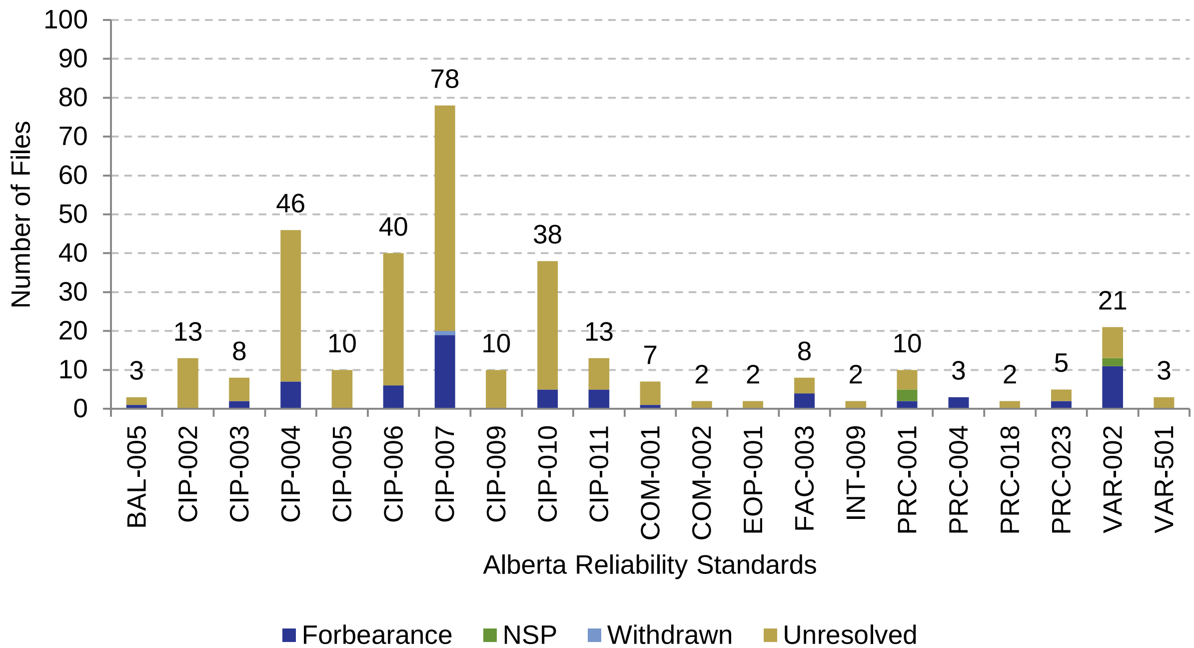
[8] As unresolved matters are analyzed/reviewed, minor changes to these data could occur.

306 Outages and Disturbances
501 General (Facilities)
502 Technical Requirements
505 Legal Owners of Generating Facilities

5.2 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 74 matters since the start of 2018, while 250 remain unresolved. Financial penalties remained unchanged (year-to-date penalties total $19,750).[9]

Figure 20: Overview of Alberta Reliability Standards Matters Addressed or Unresolved at the End of Q3/18[10]



The Alberta Reliability Standards listed in Figure 20 fall into the following categories:

BAL Resource and Demand Balancing
CIP Critical Infrastructure Protection
COM Communications
EOP Emergency Preparedness and Operations
FAC Facilities Design, Connections and Maintenance
INT Interchange Scheduling and Coordination

[9] The Q2/18 Quarterly Report contained an error. It stated "Five of the matters closed during this quarter were addressed with a notice of specified penalty, totalling $19,750 in financial penalties." This should have said "Four of the matters closed during this quarter were addressed with a notice of specified penalty, totalling $16,000 in financial penalties."
[10] As unresolved matters are analyzed/reviewed, minor changes to these data could occur.

PRC	Protection and Control
VAR	Voltage and Reactive (includes VAR-###-WECC standards)

6 MSA Consultations

The *Market Surveillance Regulation* requires the MSA to consult with market participants on new or materially changed guidelines and to make public the general process used to develop such guidelines. The MSA also may initiate a stakeholder consultation at its discretion where it believes a matter under its consideration would benefit from broad stakeholder feedback. This quarter, the MSA announced it is commencing consultations on two matters.

For both consultations the MSA has engaged a consultant to provide guidance on the matter. The MSA intends to publish the consultants' reports and then implement a consultation under its established stakeholder consultation process with market participants and the AESO.

6.1 Offer Behavior Guidelines

The MSA expects provisional Independent System Operator ("ISO") rules regarding offer behaviour into the energy market to come into force in time for the commencement of the capacity market's first obligation period on November 1, 2021. The MSA has previously indicated that prior to this time there may be a need for MSA guidelines to address acceptable offer behaviour.

On September 27, 2018, the MSA provided notice that it will hold a consultation to determine if guidelines during the transition period are warranted. To this end the MSA has retained an independent consultant to prepare a Report that will start that process. The consultant's Report will address three questions.

- Could there be a problem with offer behaviour that would need to be addressed during the transition period?
- If so, could the problem identified be addressed in whole, or in part, through MSA guidelines and what form could those guidelines take?
- If guidelines were made and market participants did not follow those guidelines what remedies should the MSA seek from the Alberta Utilities Commission ("Commission") in an enforcement proceeding?

Once the MSA has received the consultant's Report the MSA will make that Report public and stakeholders will be invited to provide written comments. Following the written comments the MSA will hold a consultation and receive oral submissions. Participants will have an opportunity to address questions to the consultants. Once that process has been completed, the MSA will decide if guidelines are warranted and, if so, what guidelines will be put in place. The MSA expects to make this decision in February 2019.

For this work the MSA has selected Charles River Associates as its consultant. The MSA expects that the consultant Report will be publicly available before the end of December.

The MSA has decided not to consider guideline making for the post-transition period at this time. Instead, the MSA intends to participate, and call independent expert evidence in Commission Proceeding 23757 to consider the proposed ISO Rules to regarding the capacity market.

Following the Commission Decision in proceeding 23757 the MSA will determine whether Offer Behavior Guidelines are required. If the MSA finds that guidelines are required it will implement a consultation process similar to the process the MSA is proposing for the guidelines during the transition period.

6.2 Advisory Opinion Programme

The MSA has received requests from market participants to establish a voluntary Advisory Opinion Programme to provide guidance on specific planned conduct.

On October 22, 2018, the MSA gave notice that it has decided to hold a consultation to determine if the establishment of an Advisory Opinion Programme is warranted. To this end the MSA has retained an independent consultant to prepare a Report that will start that process. The consultant's Report will address three questions.

- Could an Advisory Opinion Programme assist market participants?
- If so, what form should that programme take?
- What has been the experience of other regulators with these types of programmes?

Once the MSA has received the consultant's Report the MSA will make that Report public and stakeholders will be invited to provide written comments. Following the written comments the MSA will hold a consultation and receive oral submissions. Participants will have an opportunity to address questions to the consultant. Once that process has been completed, the MSA will decide if an Advisory Opinion Programme is warranted and, if so, what programme should be implemented. The MSA expects to make this determination in the first quarter of 2019.

The MSA has selected Ian Nielsen-Jones as its consultant. Mr. Nielsen-Jones is a former Deputy Commissioner of Competition who was actively involved in the administration of the Advisory Programme carried out by the Bureau of Competition Policy in Ottawa for over 20 years. The MSA expects that the consultant Report will be publicly available by December 15, 2018.

7 Commission Proceedings

7.1 Commission Proceeding 23757

On September 14, 2018, the MSA filed a statement of intent to participate on the record of Proceeding 23757 indicating its intention to fully participate in the hearing to consider the ISO rules to implement the capacity market. The MSA retained Charles River Associates as its independent expert and has filed a submission on scoping and a response to the report prepared by the AUC independent expert on November 2, 2018.[11]

7.2 Commission Proceeding 23828

The MSA investigated the Balancing Pool's termination and management of the Power Purchase Agreements and reached a settlement agreement with the Balancing Pool. The MSA filed the settlement agreement with the Commission for approval on August 15, 2018. The Commission has initiated a written proceeding to consider the settlement and the MSA has responded to information requests on November 7, 2018, as a part of that process. The MSA anticipates that the proceeding will conclude in the first half of 2019.

8 Highlights

The following points summarize key takeaways from the quarter:

- Pool price averaged $54.66/MWh in Q3/18, very similar to Q2/18 ($56.01/MWh).
- Periods of high prices which occurred during the first part of the quarter were driven primarily by supply scarcity and economic withholding by a few market participants.
- High prices were largely absent during the outage of the BC/MATL intertie.
- During the quarter, three market participants set System Marginal Price most of the time with the Balancing Pool setting price most often. Following the return of BR5 to ATCO, the Balancing Pool's share of price setting has reduced.
- Overall, flat forward monthly contract prices through the end of 2018 fell throughout the quarter. Trade volumes were moderate, being at the lower end of the range seen in recent years.
- The total cost of operating reserves in Q3/18 increased 144% over the same period last year. Most of this cost increase was due to active reserves and was driven by an increase in procurement volumes along with higher pool prices.

The MSA continues to monitor market activities with regards to competition and efficiency as per its mandate.

[11] See Exhibits 23757-X0123,23757-X0124 and 23757-X0141.