MARKET SURVEILLANCE ADMINISTRATOR

Q1/19 Quarterly Report

January – March 2019

May 24, 2019

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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Wholesale Market

Summary

In the first quarter of 2019 more than 5% of hours cleared above $165/MWh. As a result, the average pool price for Q1 2019 was $69.46/MWh ($49.02/MWh ext. off-peak, $79.66/MWh ext. on-peak). This is a 99% increase compared to the quarterly average pool price for Q1 2018. The increase in the quarterly average pool price is due to higher pool prices in February and March.

Average demand in Q1 2019 was not significantly different from demand observed in Q1 2018. Table 1 shows other factors that caused higher pool prices quarter-over-quarter, including: an increase in average gas price, decrease in total wind generation, increase in net exports, and a decrease in the average supply cushion.

Table 1: Market Summary

		2018	2019	*Change*
Pool Price (Avg $/MWh)	Jan	40.83	37.83	*-7%*
	Feb	31.32	109.36	*249%*
	Mar	32.27	65.04	*102%*
	Q1	**34.92**	**69.46**	***99%***
Spark Spread (Avg $/MWh)*	Jan	26.01	24.17	*-7%*
	Feb	16.99	86.33	*408%*
	Mar	17.45	46.84	*168%*
	Q1	**20.26**	**51.32**	***153%***
Demand (AIL, GWh)	Jan	7,656	7,669	*0%*
	Feb	7,036	7,183	*2%*
	Mar	7,432	7,370	*-1%*
	Q1	**22,124**	**22,222**	***0%***
Gas Price (Avg $/GJ)	Jan	1.98	1.82	*-8%*
	Feb	1.91	3.07	*61%*
	Mar	1.98	2.43	*23%*
	Q1	**1.96**	**2.42**	***24%***
Wind (GWh)	Jan	526	476	*-9%*
	Feb	358	175	*-51%*
	Mar	270	249	*-8%*
	Q1	**1,154**	**901**	***-22%***
Net Exports (GWh)	Jan	-191	-10	*95%*
	Feb	-398	66	*117%*
	Mar	-313	92	*129%*
	Q1	**-902**	**148**	***116%***
Supply Cushion (Avg MW)	Jan	1,901	1,598	*-16%*
	Feb	2,317	1,008	*-56%*
	Mar	2,205	1,370	*-38%*
	Q1	**2,135**	**1,336**	***-37%***

* Calculated with a 7.5 GJ/MWh Heat Rate

Pool Price Events

Figure 1 shows that relatively few pool price events fell significantly below the median but a considerable number in February and early March were significantly higher.

In Q1 2019, supply cushion averaged 1,336 MW which equates to a decrease of approximately 37% (799 MW) compared to Q1 2018. This decrease was primarily driven by a reduction in supply cushion by 56% and 38% in February and March, respectively. In February, there were two Energy Emergency Alert (EEA) events described in more detail below.

Figure 1: Hourly Pool Price

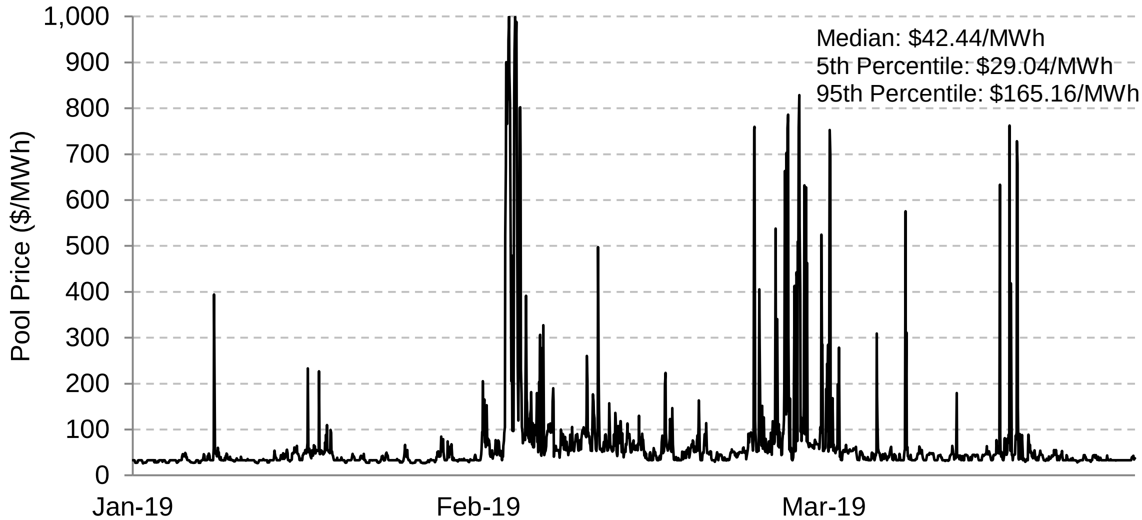
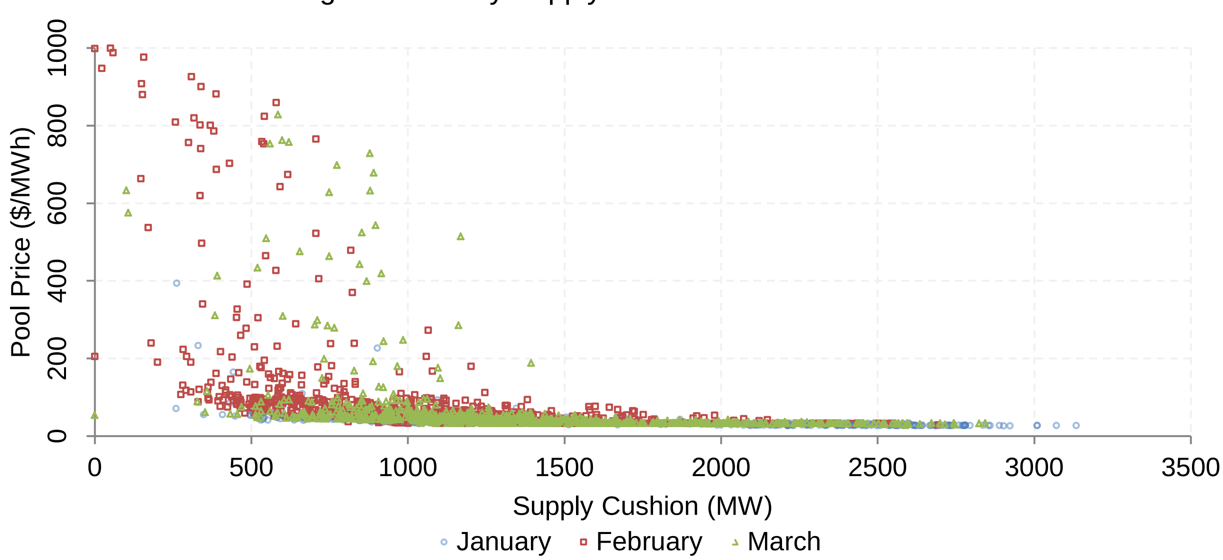


Figure 2 plots the hourly supply cushion and the corresponding pool price in the hour. As expected, in hours where the supply cushion is low pool prices tend to be higher. As stated previously, most of the hours with high pool prices occurred in February and March in situations where the supply cushion was relatively low. There have also been some hours where high pool prices were not due to low supply cushion. However, major prices spikes and pricing events generally represent a small proportion of total hours. Pool prices this quarter that cleared above $100/MWh represented under 8% of total hours. In the following sections, we review in more detail the drivers for pool prices during the quarter.

Figure 2: Hourly Supply Cushion versus Pool Price



Demand

February 2019 was marked by sustained cold temperatures throughout the province. Most areas of the province experienced temperatures below -30°C at some point during the quarter. Average temperatures in February across Alberta ranged between -4.1°C and -25.7°C and approximated an average of -20°C for the duration of the month. Generally, Alberta's winter peak load occurs in the months of December or January as colder temperatures, darker days, and upsurge in Christmas lights subsequently results in higher heating and lighting load. Interestingly, as a result of the record-breaking February temperatures, this year's winter peak of 11,477 MW occurred on February 12 hour ending (HE) 19, with an associated pool price of $156.68/MWh. This year's peak did not surpass the system peak of 11,697 MW set on January 11, 2018.

Figure 3: Daily Average Temperature and Load

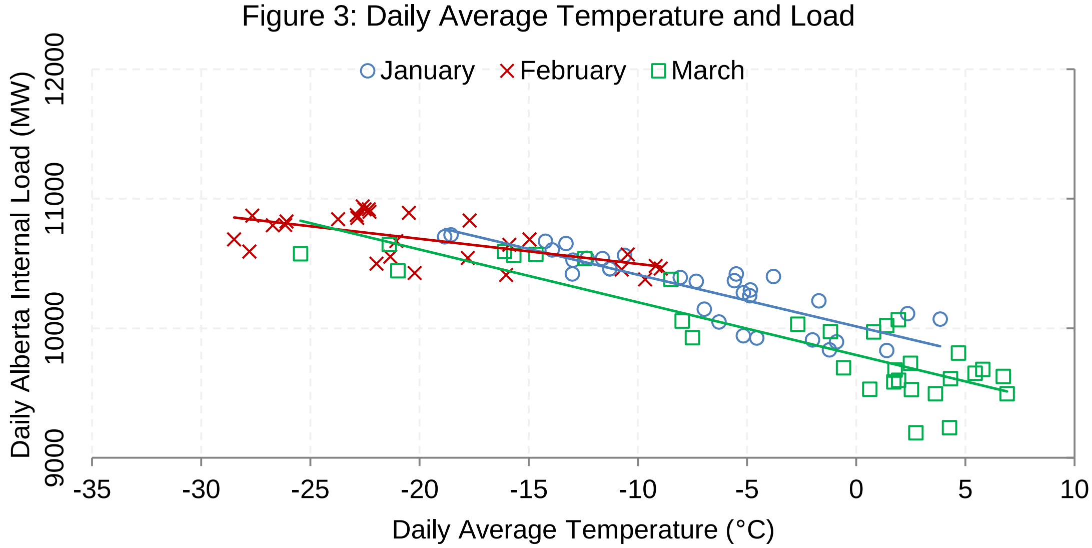
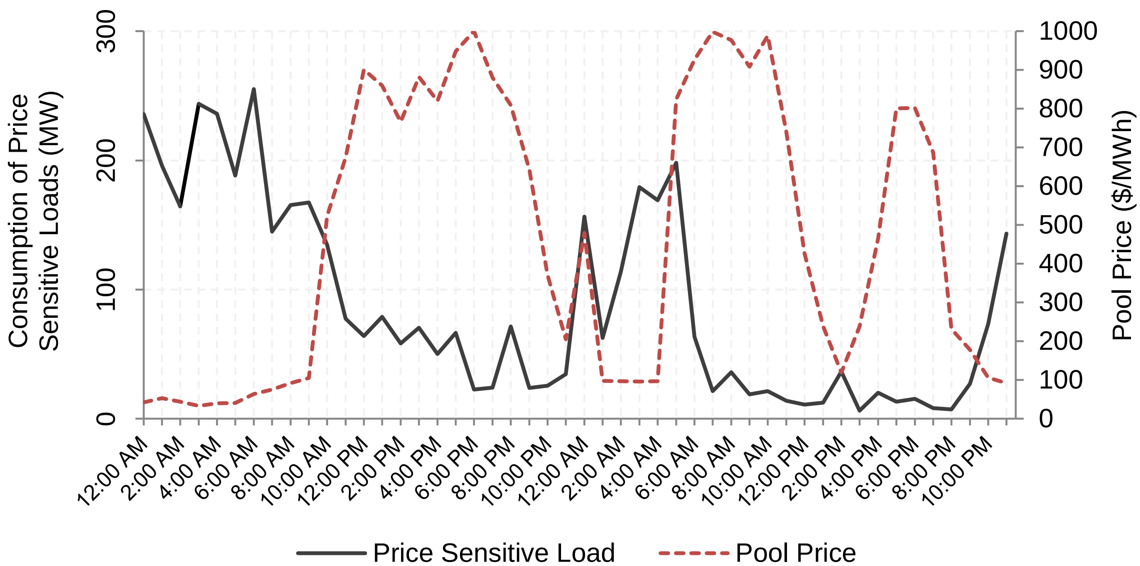


Figure 3 shows the relationship between average temperature and average load across the quarter. As expected during the winter months decreasing temperatures generally results in increased electricity demand. The reason for this is that colder temperatures leads to more individuals staying indoors which translates to higher lighting, heating, and appliance load. In addition, although the majority of Alberta's heating demand is met through natural gas, as temperatures drop there is an increased usage of secondary heating (e.g., space heaters) with electrical components, which also contributes to higher load.

From the visual, the load-temperature trends for January and March are similarly matched, though this trend does not hold for February. Although temperatures were much colder, and average load was higher, the weakening of February's load-temperature relationship can be explained by in part by price responsive loads lowering demand during periods of price spikes. As an example, Figure 4 displays a portion of load that the Alberta Electric System Operator (AESO) tracks which is believed to be price sensitive on February 3 and 4. Consumption at these loads was significantly reduced during periods of higher prices.

Figure 4: February 3 and 4 Pricing Event and Responsive Load



Generator Availability

On February 3, 2019, there was a supply shortfall event which resulted in an EEA1 being declared by the AESO from HE 18 to 20. During the event, there were significant outages and derates, particularly on coal generation, throughout the province. In the hours where the EEA was in effect, total outages and derates ranged between 2,731 MW and 3,594 MW. At the start of the EEA event, wind generation decreased from approximately 110 MW to 50 MW. Demand was high, ranging from 11,068 MW to 11,231 MW during the event. These factors led to supply cushion values of 22 MW in HE 18, 50 MW in HE 19, and 152 MW in HE 20. During the event, Alberta was net importing between 743 MW to 786 MW of energy through the interties. As a result, the pool price in HE 18, 19, and 20 reached $947.76/MWh, $999.99/MWh, and $880.44/MWh, respectively.

On February 4, 2019, an EEA2 was declared in HE 8 which lasted until HE 9. There were continued derates in coal generation capabilities and several other outages and derates throughout the province totaling approximately 3,712 MW in HE 8 and 2,844 MW in HE 9. Demand in HE 8 was 10,818 MW while demand in HE 9 was 10,921 MW. Wind generation and supply cushion in HE 8 were approximately 0 MW. While supply cushion increased to approximately 156 MW in HE 9, wind generation remained the same. Alberta was net importing 855 MW and 889 MW in HE 8 and 9, respectively. The pool price reached $998.75/MWh in HE 8 and decreased to $976.73/MWh in HE9.

While wind generation can be variable at a temperature level, generation is typically low when weather temperatures are very low as observed in Alberta in February and March of 2019. This relationship can be seen in Figure 5 which charts daily average wind generation against the observed average daily temperature observed near Lethbridge. On days where the average daily temperature was under -10°C average wind generation in Lethbridge did not exceed 400 MW. In the quarter, there were 29 days where the average daily temperature was less than -

10°C. When average daily temperatures were above -10°C, average daily wind generation in Lethbridge was highly variable ranging from 0 MW to 977 MW. This variability in generation and low generation levels in cold temperatures contributed to the high pool prices observed in the quarter.

Figure 5: Daily Average Wind Generation versus Average Daily Temperature (in the Lethbridge Area)

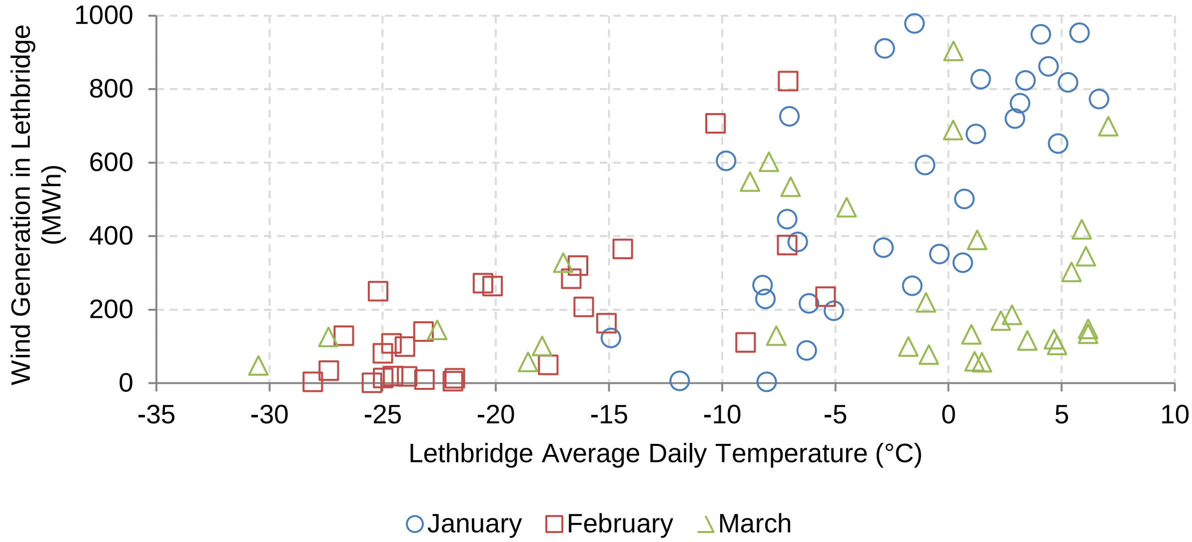
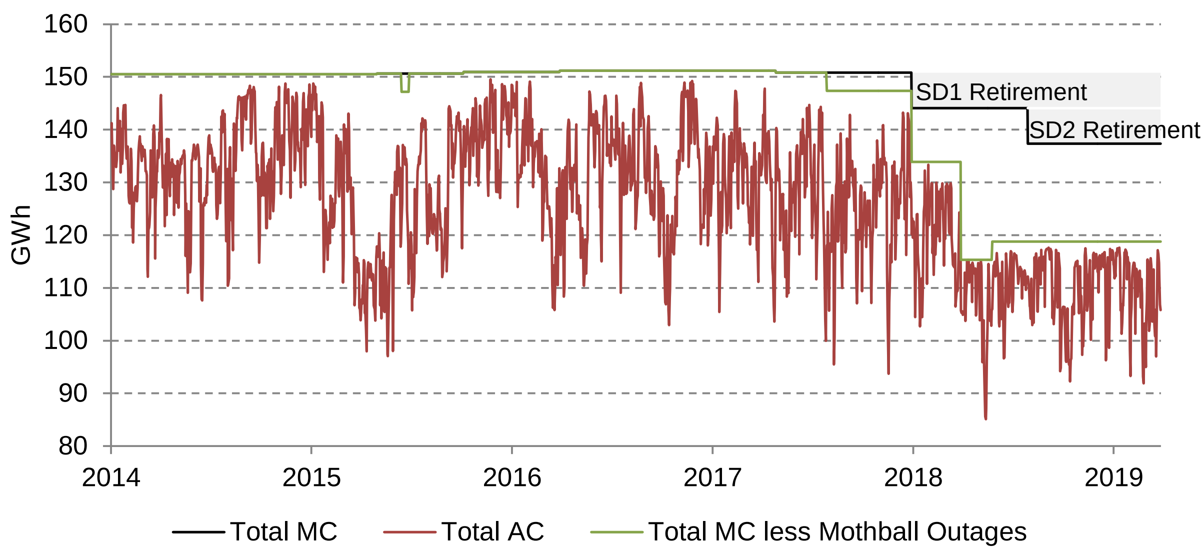


Figure 6 shows the total maximum capability (MC) and total available capability (AC) of the coal assets from January 2014 to March 2019. The total MC of coal has steadily declined since the start of 2018 due to the retirement of the Sundance #1 asset on January 1, 2018 and of the Sundance #2 asset on July 31, 2018. These retirements resulted in a 9% decrease in the total MC of coal generation in Alberta (from 6,283 MW to 5,723 MW).

Figure 6: Total Daily MC and AC Levels of Coal Assets over Time



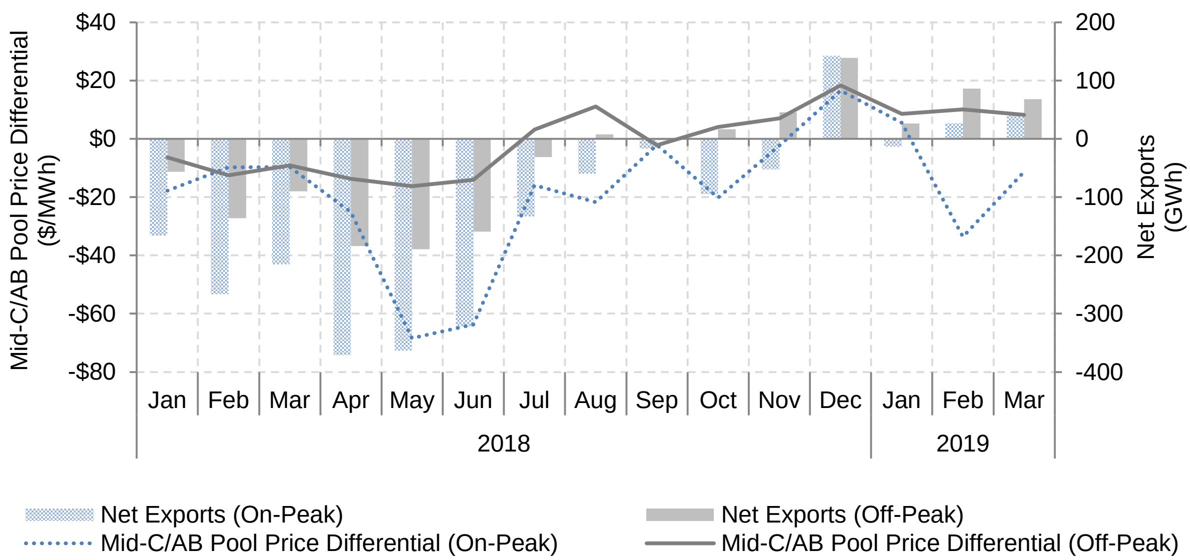
In addition to the decrease in overall MC, the total AC of the coal assets has decreased since January 2018. This is due to mothball outages on Sundance #2 from January 1, 2018 to July 31, 2018, as well as Sundance #3 and #5 since April 1, 2018. The Sundance #3 and #5 mothball outages are a persistent outage of 774 MW representing 14% of the current MC of coal assets. While the retirement and mothballing of several coal assets contributed systematically to lower coal generation availability in the market, the availability of the remaining coal assets in Q1 2019 was similar to the observed availability of coal in 2018.

Interties

In the quarter, Alberta was a net exporter of 148 GWh of energy. In Q1 2018, Alberta imported 902 GWh of energy on a net basis. In February, Alberta exported 66 GWh of energy, which is a significant change from importing 398 GWh of energy in February 2018. The trend observed in March was similar with net exports of 92 GWh in 2019 while in 2018, 313 GWh of net imports was observed.

On the BC/MT intertie, the reversal in the net flow of energy began in mid-2018 when power prices in Mid-C increased and the price differential between the Mid-C price and the Alberta pool price decreased in magnitude, and in some months became positive. This creates an incentive to export power from Alberta to Mid-C when the Mid-C price is greater than the Alberta pool price. Considering the flow of energy solely through the BC/MT intertie, Alberta was a net exporter of 235 GWh of energy through BC/Montana in Q1 2019. In February, Alberta exported 113 GWh of energy through the BC/MT intertie on a net basis. In March, Alberta exported 109 GWh through the same intertie on a net basis.

Figure 7: Total On/Off-Peak BC/MT Intertie Flow and Average Mid-C/Alberta Pool Price Differential



Generally, Alberta was a net exporter on the BC/MT intertie in all periods with the exception of the on-peak[1] period in January. In both February and March, net exports were highest in the off-peak period coinciding with the positive price differential between Mid-C and Alberta. This means that the price in Mid-C was higher than the pool price on average during off-peak which incentivizes generators to export to Mid-C instead of import to Alberta. On average, pool price was higher than the Mid-C price during the on-peak periods in the quarter; however we still observed net exports during the on-peak period. In general, the relationship between the price differential and import/export activity did not hold in the on-peak period during the quarter. However, the total amount of net exports in the on-peak period was quite low. For example, in February the average hourly flow on the BC/MT intertie was 98 MW of net exports.

Offer Behaviour

Figure 8: Average Merit Order Supply Curves (January – March 2019)

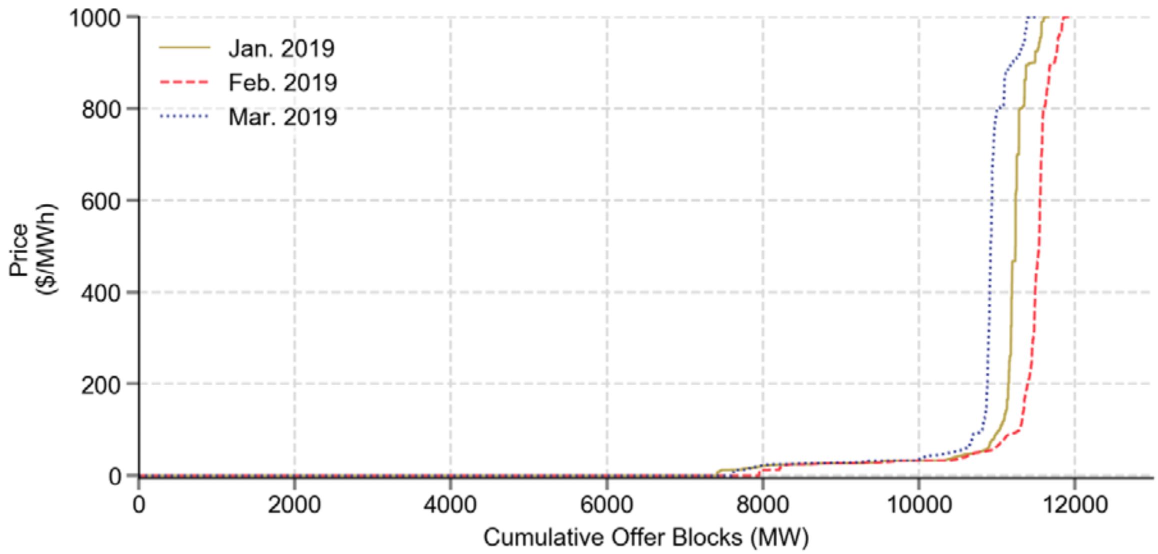


Figure 9 displays the average merit order supply curves for each month in the quarter. The upper segment (greater than $100/MWh) of the merit order curves are quite similar across the months this quarter, although January has more pronounced offer shelfs – indicating a higher concentration of offered volumes at a specific price. On the lower segment of the merit order (less than $100/MWh), there is a notable difference in behaviour. The most significant being the change in offers between January and March. On average, there were approximately 190 MW more zero priced offers in March than in January; although March exhibited significantly higher price-quantity pairs at a lower point in the supply curve. Indicatively, the marginal price-quantity pair for January at 11,000 MW was priced at approximately $93/MWh, whereas in March the same volume corresponded to an offer price of $790/MWh.

In February there was a marginally higher average volume of outages across the month, though conflictingly, there was an outward shift in the merit order curve compared to January -

[1] On-peak is defined as HE 8 through 23. Off-peak is defined as all other hours.

indicating more supply across the system. This difference can be explained by several larger units committing themselves as Long Lead Time Energy (LLTE) assets throughout the quarter, whose volume is not present within the merit order, though the assets are available to be called upon. There was a heavier concentration of assets on long lead time across January, though LLTE assets were also present in periods throughout February and March.

The inward shift of the merit order in March signifies increased amounts of derated and offline capacity. The total outage volume, averaged over March was 3,070 MW - which was approximately 500 MW higher than January and February. Higher levels of outages throughout March can be attributed to repair/replacement derates associated with the Shepard facility, co-gen outages and maintenance/ambient temperature derates, along with outages on several coal units.

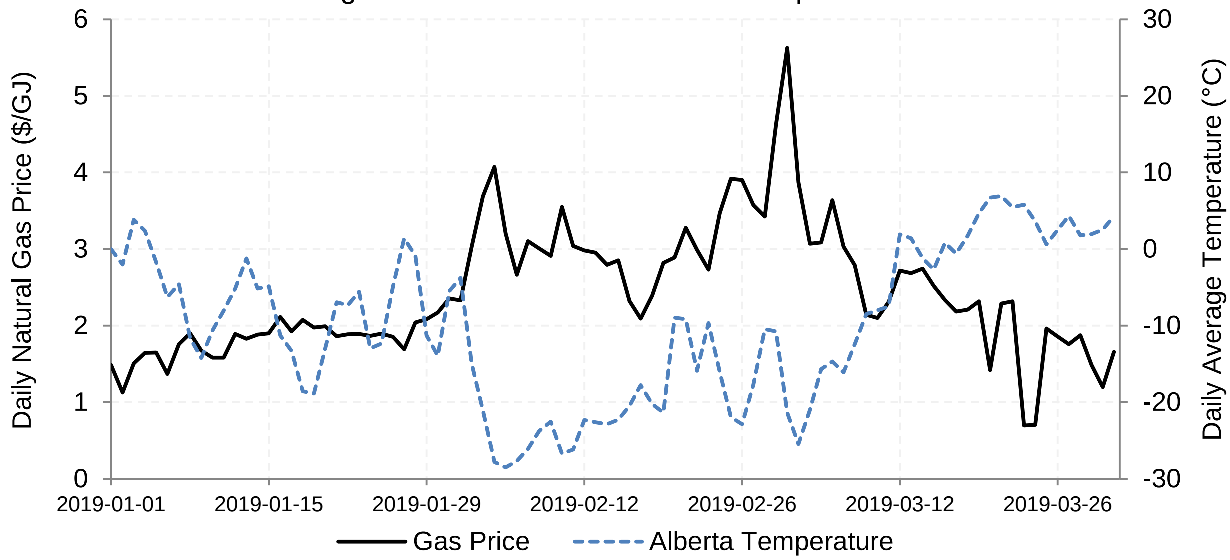
February held the largest volume of supply in the merit order, though correspondingly had the highest pool prices this quarter. Several factors can be attributed to this result. The sustained high prices corresponding to the EEA events on February 3 to 4 as well as market tightness towards the end of the month provided a sizeable increase to the overall monthly average pool price. Referring to the interties section, significant reversals of net energy flows can result in pricing impacts. When exporting, generation is dispatched up in the merit in order to flow electricity out of Alberta to neighbouring jurisdictions, and subsequently provides upward pressure on pool prices. This February, the Alberta system averaged 98 MW of net exports, in comparison; February 2018 averaged 591 MW of net imports. Lastly, February held the highest demand of the quarter, equalling to an average Alberta Internal Load of 10,689 MW.

Natural Gas Prices

Natural gas prices averaged $2.42/GJ over the quarter and reached a peak of $5.63/GJ on March 2.[2] This quarter saw a 24% increase in gas prices compared to Q1 2018, largely driven by a 60% increase this February which held a monthly average price of $3.07/GJ. Natural gas demand in Alberta is attributed to industrial development (e.g., oil sands and petrochemicals), electricity generation, commercial, and residential consumers.[3] Alongside economic growth, seasonality (i.e., heating demand) is a crucial driver of natural gas pricing in winter months. Figure 9 displays Q1 2019 natural gas prices with daily Alberta temperatures. Notably, the cold temperature extremes which were largely experienced throughout February and early March contributed towards periods of elevated gas prices. The increase in average natural gas prices partially explains the increase in pool price quarter-over-quarter; though a 153% increase in the average spark spread would suggest that factors discussed in previous paragraphs carry significant weight in terms of driving overall pool prices this quarter.

[2] Pacific Northwest Sees Highest Daily Natural Gas Spot Prices in the US Since 2014, April 3, 2019.
[3] Alberta Energy Regulator Natural Gas Demand

Figure 9: Natural Gas Price and Temperature



Transmission Congestion

Transmission constraint rebalancing payments occur when there is insufficient transmission capability to allow in-merit generation to deliver their offered volumes to the electric system.[6] As a result, constrained in-merit generation is curtailed, and the energy market merit order is dispatched up until an unconstrained supply-demand balance is achieved. Rebalancing payments are made to compensate higher priced generation which is needed to mitigate transmission constraints. These payments translate to costs which are recovered through the ISO tariff.[7]

Table 2: Transmission Constraint Rebalancing Costs

2016	
Year[4]	**$7,499.00**
2017	
Year	**$15,019.00**
2018*	
Year[5]	**$36,408.02**
2019*	
Q1	**$292,687.17**

*Indicates estimates, final data not yet available

Alberta is comprised of six transmission planning regions: Northwest, Northeast, Edmonton, Central, Calgary, and South. Table 2 shows that there was a significant increase in rebalancing costs this quarter compared to previous years. This was caused by two transmission outages which spanned portions of February and March. The first, which extended from mid-February to early March was the result of a forced outage in the Central planning region. The second lasted from late February to early March and was associated with repairs to the transmission system in the Northwest. As a result of these outages, offers from neighbouring generators that would have otherwise cleared the market were not fully dispatched due to stability concerns. In addition, the Northwest is already

[4] 2018 Annual TCM Report
[5] AESO ETS Historical Reports
[6] ID 2015-006R Calculation of Pool-Price and TCR Costs
[7] ID 2016-017T Transmission Constraint Rebalancing Charge

substantially short generation compared to regional load.[8] The increase of costs this quarter can be attributed to the duration of the outages in the Northwest and Central regions and the subsequent volumes of dispatched up generation that were required to replace constrained down generation throughout system rebalancing periods.

Average Monthly Prices and Long-run Marginal Cost

The MSA has historically compared prices over time with estimates of long-run marginal costs (LRMC). The MSA has previously defined LRMC as "the change in the total cost of satisfying a permanent increment (or decrement) of demand divided by the magnitude of the increment."[9] Estimating the cheapest way an increment of demand can be met can be challenging while comparing average prices with the cost of building new generation resources is less difficult. Based on values from the AESO's recent work on the cost of new entry for a gas peaking plant,[10] a figure of approximately $60/MWh would be required to meet a relatively small increment of demand. The MSA notes that prices in Q1 2019, although volatile, were significantly above this number.

[8] 2011-004R Northwest Area

[9] A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta, December 10, 2012, page 4.

[10] Draft Net CONE and EAS Offset Methodology, August 16, 2018.

Operating Reserves

The total cost of operating reserves in Q1 2019 was $60.3 million compared to $31 million in Q1 2018. This represents a 94% increase in total operating reserves cost quarter-over-quarter. The increase in operating reserves cost is largely due to increases in the cost of active operating reserves. The total cost of procuring and activating standby reserves have decreased quarter-over-quarter.

Total active operating reserves cost increased 145% quarter-over-quarter. The total volume of active operating reserves procured did not change quarter-over-quarter. The increase in total active operating reserves cost can be attributed to an increase in pool prices quarter-over-quarter.

The total cost of procuring standby operating reserves saw a 26% decrease quarter-over-quarter. This is due to a decrease in the average premium price for standby operating reserves quarter-over-quarter as the total volume of standby operating reserves procured did not materially change.

Overall, there was a decrease in the total cost of activating standby operating reserves from $6 million in Q1 2018 to $2.3 million in Q1 2019. The total cost of activating standby contingency reserves decreased quarter-over-quarter due to a decrease in the volume of standby contingency reserves activated. However, the average activation price to activate standby spinning reserve increased 51% quarter-over-quarter. The average activation price of standby supplemental reserve did not change significantly.

Table 3: Operating Reserve Summary

Total Cost ($ Millions)			
	Q1 2018	**Q1 2019**	***Change***
Active Procured	**23.1**	**56.6**	***145%***
RR	7.1	16.7	*136%*
SR	10.0	21.8	*119%*
SUP	6.0	18.1	*200%*
Standby Procured	**1.9**	**1.4**	***-26%***
RR	0.7	0.4	*-38%*
SR	0.8	0.7	*-12%*
SUP	0.4	0.3	*-33%*
Standby Activated	**6.0**	**2.3**	***-62%***
RR	0.0	0.0	*20%*
SR	4.0	1.6	*-59%*
SUP	2.1	0.6	*-70%*
Total	**31.0**	**60.3**	***94%***
Total Volume (GWh)			
	Q1 2018	**Q1 2019**	***Change***
Active Procured	**1,439.0**	**1,408.1**	***-2%***
RR	352.0	351.6	*0%*
SR	543.5	528.1	*-3%*
SUP	543.5	528.5	*-3%*
Standby Procured	**491.5**	**509.5**	***4%***
RR	172.2	172.5	*0%*
SR	233.9	243.1	*4%*
SUP	85.4	93.9	*10%*
Standby Activated	**86.2**	**24.8**	***-71%***
RR	0.6	0.5	*-16%*
SR	58.9	16.1	*-73%*
SUP	26.7	8.2	*-69%*
Total	**2,016.8**	**1,942.5**	***-4%***
Average Cost ($/MWh)			
	Q1 2018	**Q1 2019**	***Change***
Active Procured	**16.04**	**40.19**	***151%***
RR	20.09	47.52	*137%*
SR	18.36	41.32	*125%*
SUP	11.08	34.18	*208%*
Standby Procured	**3.89**	**2.77**	***-29%***
RR	4.22	2.60	*-38%*
SR	3.46	2.93	*-16%*
SUP	4.39	2.69	*-39%*
Standby Activated	**70.02**	**91.50**	***31%***
RR	45.79	65.09	*42%*
SR	67.18	101.14	*51%*
SUP	76.87	74.38	*-3%*
Total	**15.38**	**31.03**	***102%***

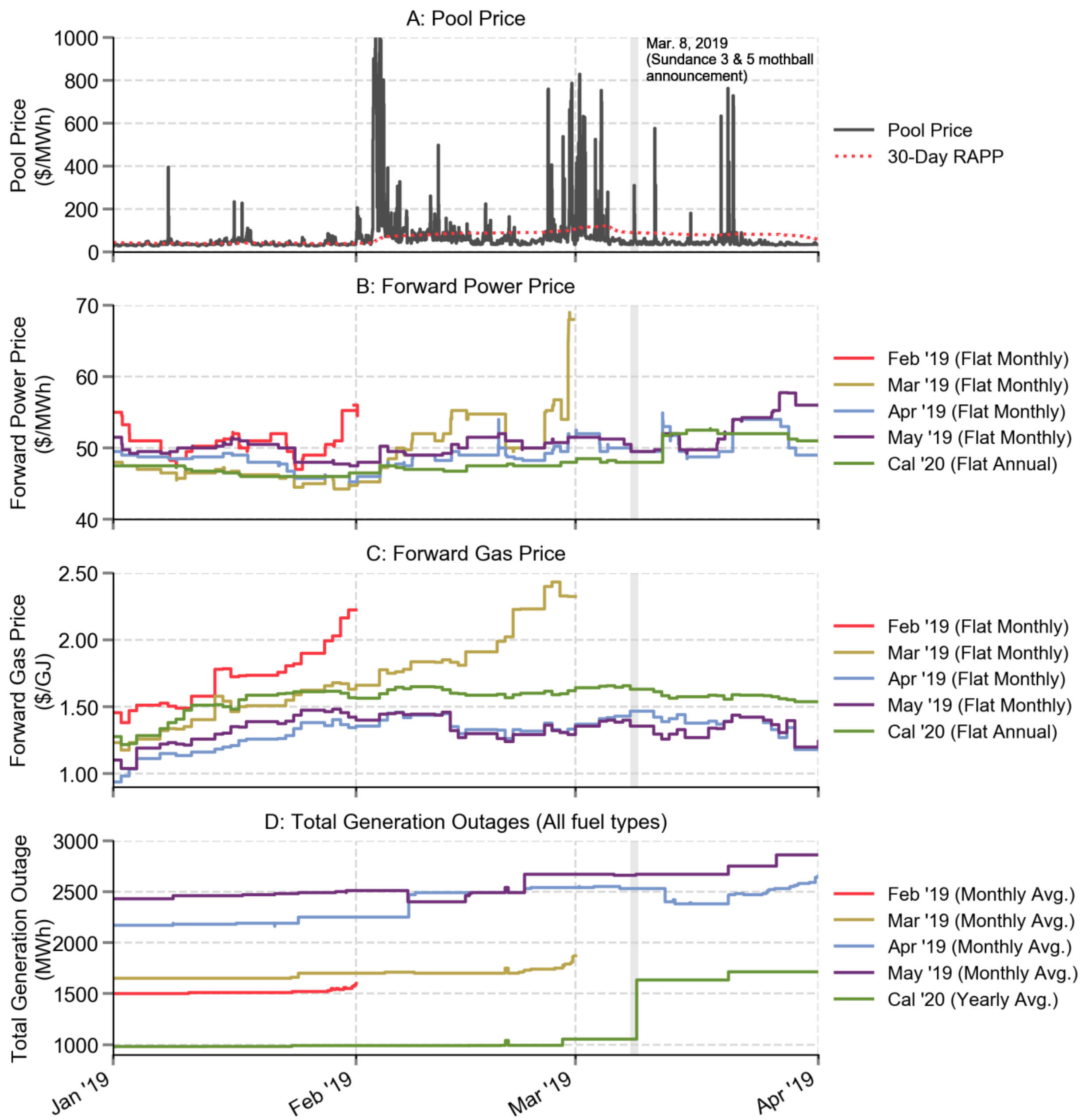
The decrease in standby contingency reserves activated in Q1 2019 is likely due to decreased import activity on the BC and Montana interties compared to Q1 2018. Fewer imports on the BC and Montana interties results in less standby contingency reserves activated in order to support higher electricity flows on the interties.

Forward Market

Forward Prices

Figure 10 shows the change in flat near-term monthly forward prices and Calendar 20 flat prices over Q1 2019, relative to pool price, gas forward price and generation outages. Monthly forward prices generally hovered around $45 to $55/MWh throughout the quarter.

Figure 10: Evolution of Forward Contract Prices

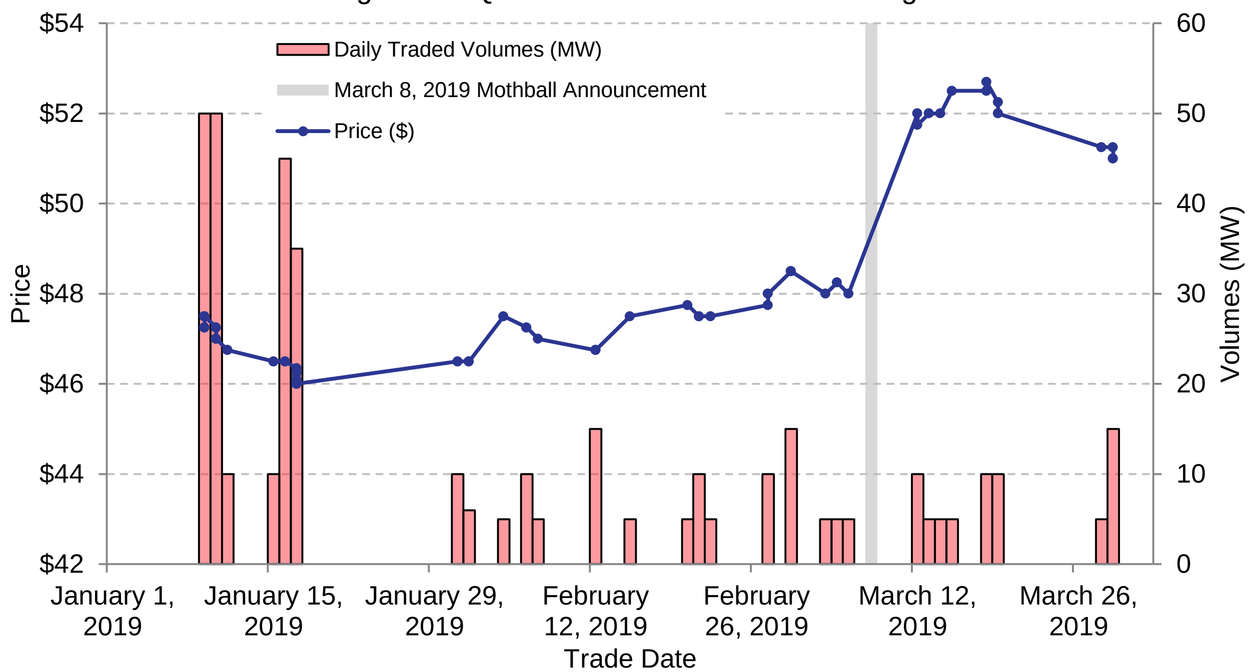


On February 28, 2019, the March 2019 flat contract price increased by $14 to $68/MWh, a significant increase relative to trading earlier in the quarter. This increase may be related to higher March 2019 gas forward prices traded at the end of February. The February 2019 flat contract price also increased in the days before the delivery period, likely motivated by higher gas forward prices for that delivery month.

On March 8, 2019, TransAlta announced the approval of mothball extensions for its Sundance 3 and Sundance 5 units to November 1, 2021.[11] Prior to this announcement, both Sundance 3 and Sundance 5 were scheduled to be mothballed until April 1, 2020. Sundance 3 had planned to mothball from April 1, 2018 to April 1, 2020, as scheduled with the AESO on December 6, 2017. Sundance 5's original mothball plan for the period of April 1, 2018 to April 1, 2019 was scheduled on the same date.[12] On November 21, 2018 the mothball outage for Sundance 5 was extended to April 1, 2020.

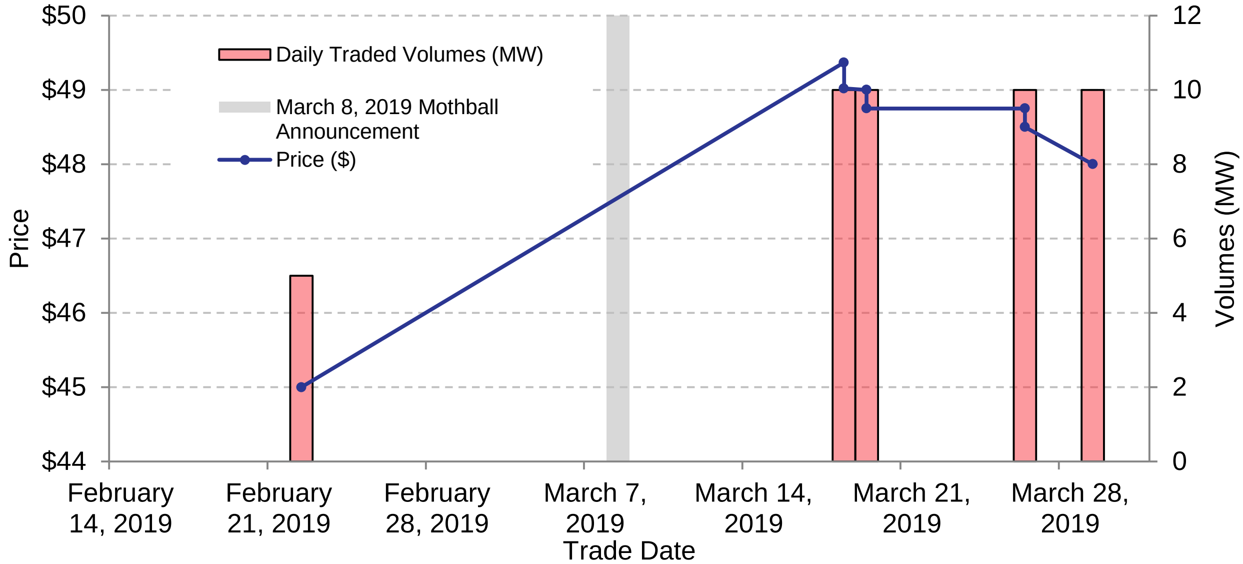
The March 8 approval of the mothball extensions for Sundance 3 and 5 through to 2021 was associated with a $4/MWh increase in the trade prices for both Calendar 2020 and Calendar 2021 flat contracts (Figure 11 and Figure 12), although prices for both contracts declined over the following weeks in the quarter.

Figure 11: Q1/19 Calendar 2020 Flat Trading



11 TransAlta Announces Regulatory Approval to Extend the Mothballing of Certain Sundance Units, March 8, 2019.
12 TransAlta Announces Accelerated Transition to Clean Energy, December 6, 2017.

Figure 12: Q1/19 Calendar 2021 Flat Trading



Trade Volumes

Trade volumes in Q1 2019 were similar to those in Q1 2018, but remain significantly lower than those seen in the first quarter of previous years (Table 4). Overall volumes traded in Q1 2019 fell by 18% compared to the previous quarter, driven mostly by a decrease in annual contract trades.

Monthly contract volumes also fell in Q1 2019 relative to the previous quarter. This may be explained by increased trading of monthly full-load strip products in EPCOR RRO auctions. These contracts pertain to the provision of a fixed percentage of EPCOR's RRO load, and as such the volumes traded for a given delivery month cannot be accurately determined until the settlement period.

Table 4: Trade Volumes by Trade Date (TWh)[13]

		Daily	Monthly	Quarterly	Annual	Other	Total
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	16.05
	Q2	0.13	6.87	2.31	11.13	0.84	21.27
	Q3	0.18	6.77	2.13	5.51	1.17	15.76
	Q4	0.06	8.24	3.51	7.50	1.38	20.69
	Year	0.43	28.40	10.98	28.70	5.26	73.78
2018	**Q1**	0.15	7.28	0.60	4.47	0.41	12.91
	Q2	0.16	6.06	1.20	5.80	0.28	13.49
	Q3	0.10	4.59	0.22	3.60	0.53	9.04
	Q4	0.10	6.55	2.33	6.88	0.43	16.30
	Year	0.52	24.47	4.35	20.75	1.65	51.74
2019	**Q1**	0.16	6.01	2.30	4.16	0.72	13.35

Forward Price Curves

The forward price curve for monthly flat contracts is provided in Figure 13 while the price curve for annual flat contracts is shown in

Figure 14. Monthly flat forward prices for the summer months of July and August are trading around the $70/MWh mark, with lower prices observed for subsequent months in 2019 and early 2020.

[13] Excludes all NGX transactions after 3:00 PM for a given calendar day. Full-load strip trades have not been included as part of trade volumes. Due to changes in methodology, the volumes presented in this table differ slightly from those presented in previous quarterly releases.

Figure 13: Forward Price Curve for Monthly Contracts (7x24, April 9, 2019)

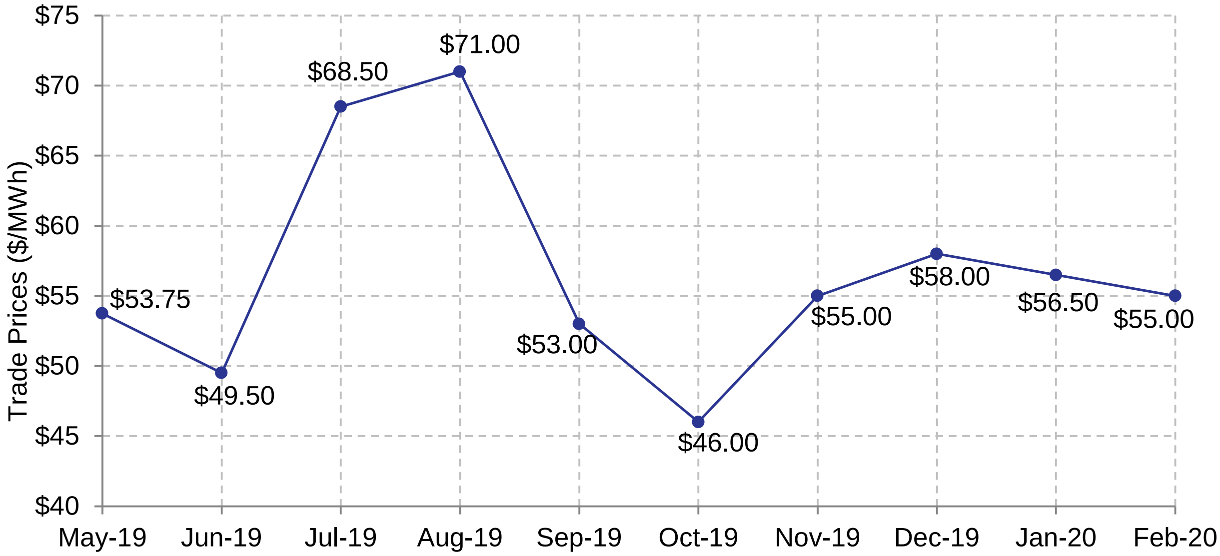
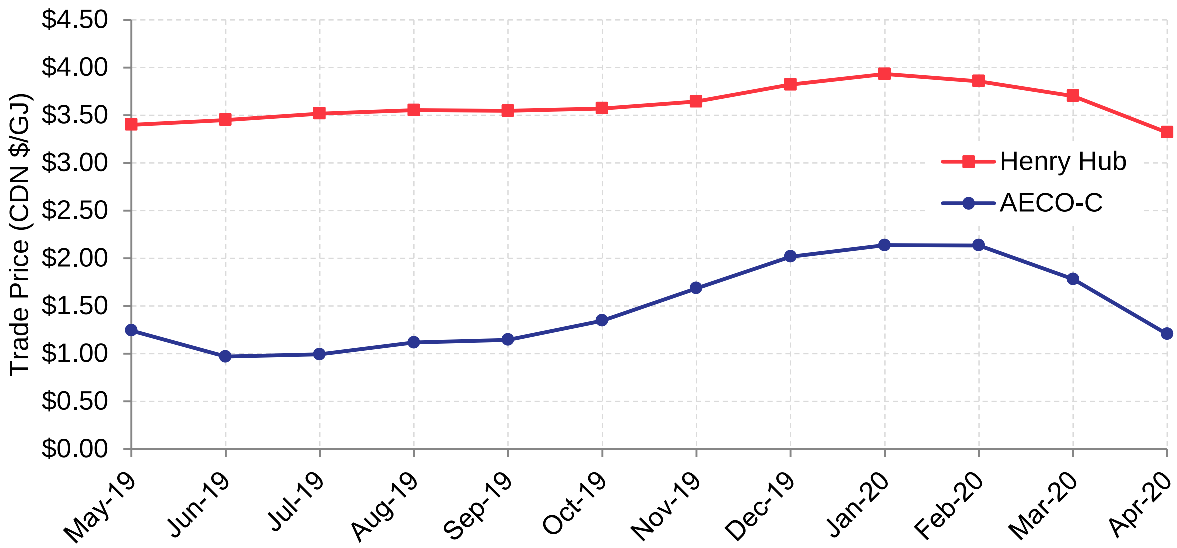


Figure 14: Forward Price Curve for Annual Contracts (7x24, April 9, 2019)

The Alberta natural gas price for May 2019 was trading below $1.25/GJ on April 2, 2019, with prices remaining relatively stable until fall 2019 (Figure 15). For most of the winter months of 2019/2020 natural gas traded just above $2/GJ.

On April 2, 2019, Alberta natural gas traded at a discount of approximately $2 to Henry Hub for May 2019, primarily due to excess gas supply relative to demand in Alberta, transportation costs and pipeline constraints. This discount decreases somewhat towards the winter months of late 2019 and early 2020 as demand for natural gas increases with colder temperatures.

Figure 15: Forward Curve for Natural Gas, AECO-C Hub and Henry Hub (April 2, 2019)



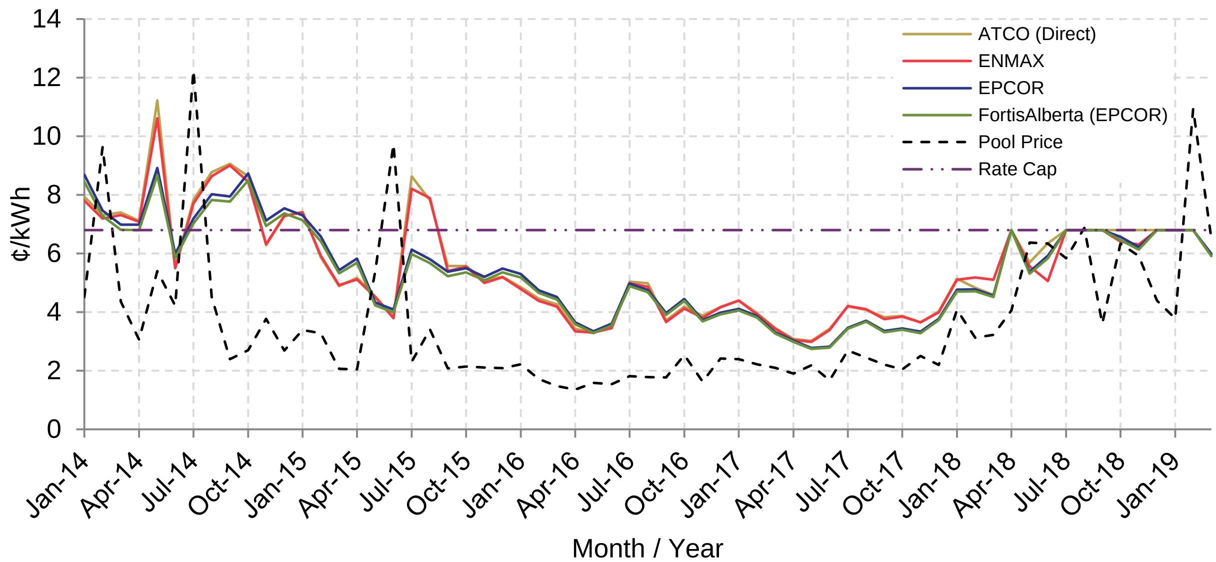
Retail Market

Regulated Retail Market

Regulated Rate Option (RRO)

RRO billing rates averaged 6.52 ¢/kWh across the four largest distribution service areas in Q1 2019. Billing rates in these areas reached the Government of Alberta's 6.8 ¢/kWh cap in all four service areas for the first two months of the quarter (Figure 16).[14] Billing rates fell to below 6 ¢/kWh in all four service areas in March 2019.

Figure 16: Residential RRO Billing Rates, January 2014 - March 2019

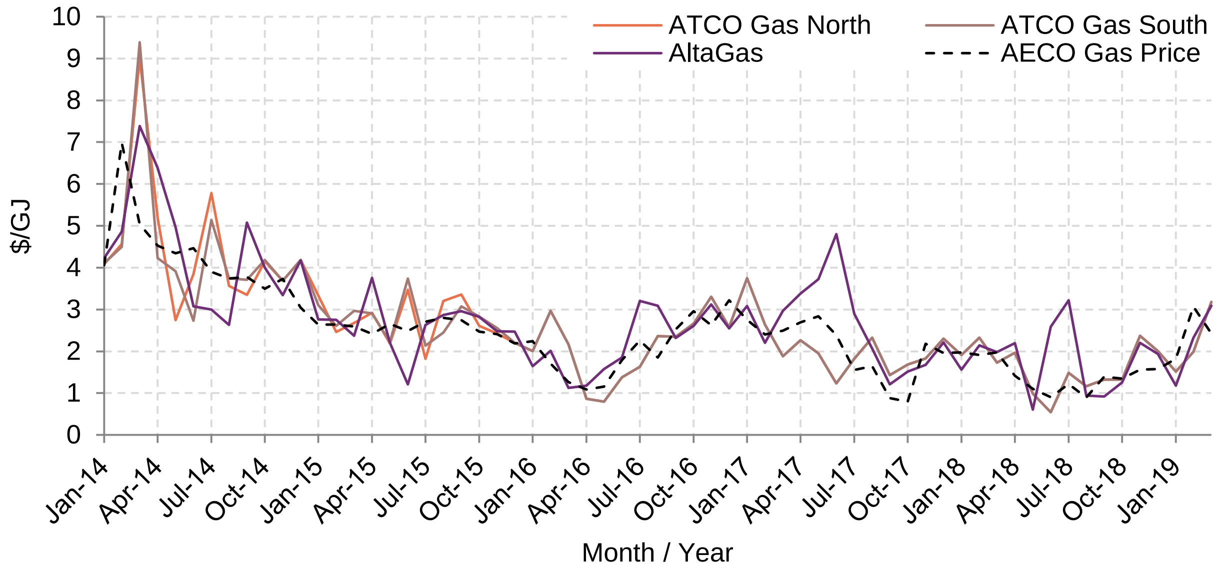


Default Rate Tariff (DRT)

DRT rates increased across Q1 2019, reaching over \$3/GJ in March 2019 (Figure 17). This increase could be explained by increased withdrawals of natural gas in response to the cold temperatures seen in the quarter.

[14] RRO billing rates here refers to the RRO energy rate charged to retail electricity customers after accounting for the effect of the rate cap.

Figure 17: DRT Rates, January 2014 – March 2019



Energy Price Setting Plans – Recent Developments

On January 31, 2019, Direct Energy Regulated Services (DERS) submitted its 2018-2020 energy price setting plan (EPSP) compliance filing with the Alberta Utilities Commission (AUC).[15] In its application, DERS addressed a number of directions issued in the decision for Direct Energy's initial 2018-2020 EPSP proceeding.[16] These adjustments included changes in the EPSP load forecasting methodology and changes to the commodity risk compensation methodology (CRC) to reflect the Beblow methodology.[17]

On March 14, 2019, Direct Energy submitted an application to the AUC regarding errors it had discovered in its RRO calculations for months spanning February 2018 to February 2019.[18] Over that period, these errors resulted in an overcharge of approximately $450,000, the majority of which is owed to the Alberta Government for funds reimbursed as part of the electricity rate cap process.[19] These errors occurred in AUC-approved RRO rates and rates for ten Rural Electrification Associations (REAs) for which Direct Energy provide RRO services. In its application, DERS stated that the amount owed to customers (approximately $69,000) will be reimbursed in a single month by adjusting rates approved in an upcoming rate filing.[20] Amounts owed to the Alberta Government will be re-payed using established deferral account statement processes.[21] The MSA encourages any RRO provider which submits deferral account statements to the MSA to approach the MSA upon discovery of such an error.

[15] Exhibit 24296-X0004 - Direct Energy 2018-2020 EPSP Compliance Filing, January 31, 2019.
[16] Decision 22635-D01-2018 – Direct Energy Regulated Services 2018-2020 Energy Price Setting Plan, December 21, 2018.
[17] Exhibit 24296-X0004 - Direct Energy 2018-2020 EPSP Compliance Filing, January 31, 2019, PDF Pages 3-5.
[18] Exhibit 24412-X0001 – DERS' 2019 UFE Correction Application, March 14, 2019, PDF Pages 2, 3.
[19] *Ibid*, PDF Page 3, Paragraph 5.
[20] *Ibid*, PDF Page 3, Paragraph 6.
[21] *Ibid*, PDF Page 3, Paragraph 7.

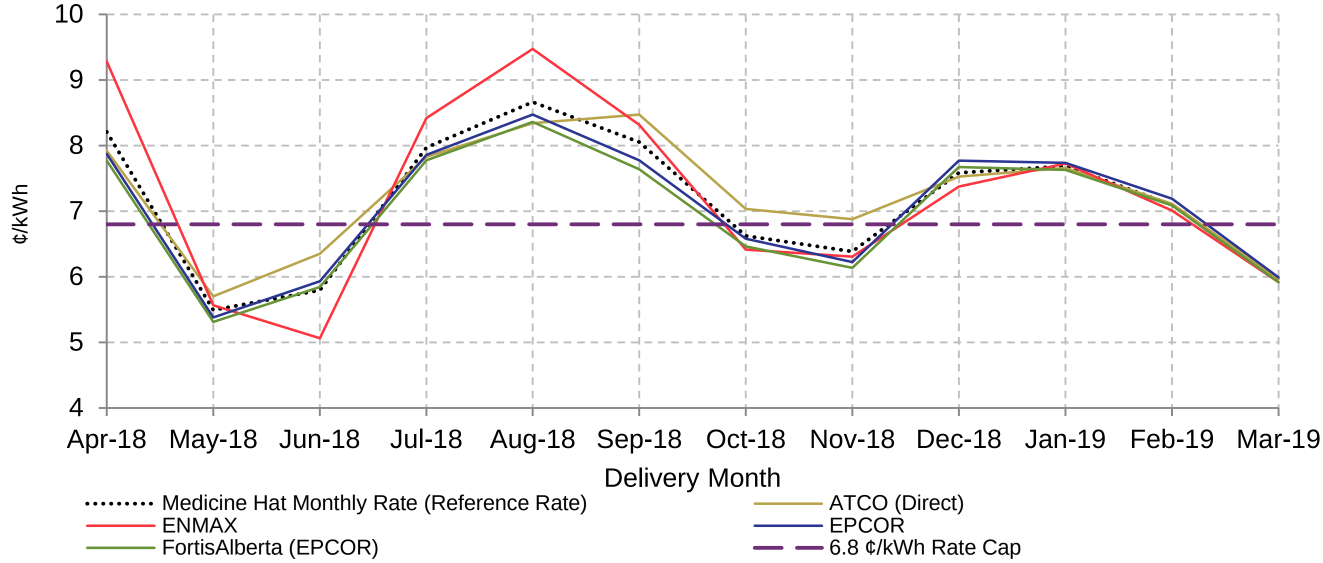
On January 11, 2019, the AUC issued an errata to the ENMAX Energy Corporation 2016-2018 EPSP Second Compliance Filing decision originally issued June 15, 2018.[22] In this errata, the AUC directed ENMAX to adjust its calculation of the risk cycle adder.[23] Accordingly, on February 21, 2019, ENMAX submitted an application requesting the approval of its changes to the risk cycle adder calculation.[24] The AUC approved these changes on April 9, 2019.[25]

On January 28, 2019, EPCOR Energy Alberta GP Inc. (EEA) applied to the AUC for an amendment to its 2018-2021 EPSP.[26] EPCOR wished to shorten the auction length range from 10-25 minutes to 2-15 minutes, in response to feedback it had received from suppliers.[27] The AUC reached a decision in this proceeding on February 21, 2019, approving the requested amendment.[28]

Rate Cap Regulation

The regulated retail electricity rate cap bound in January and February 2019 for the three largest RRO providers that cover the four largest service areas.[29] Residential monthly rates for these providers averaged 7.685 ¢/kWh and 7.098 ¢/kWh in these two months (respectively). The City of Medicine Hat sets its residential energy rate as the average of the four AUC-approved monthly rates or 6.8 ¢/kWh, whichever is lowest (Figure 18).

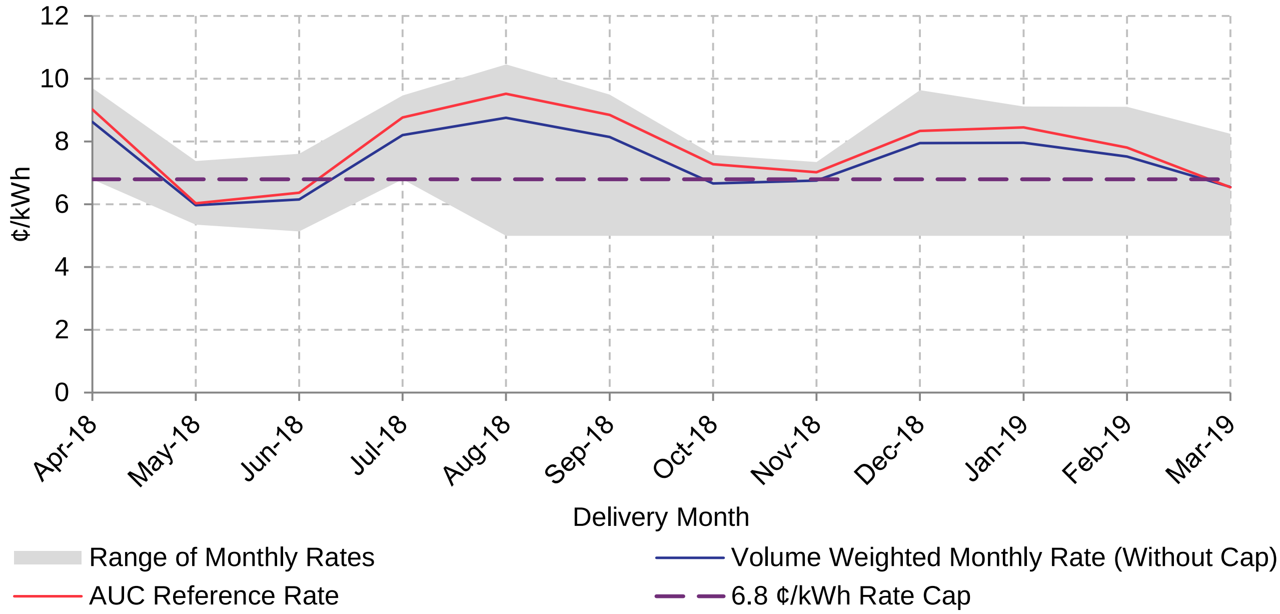
Figure 18: Monthly Rates for Medicine Hat and AUC-Regulated RRO Providers



[22] Decision 23223-D01-2018 (Errata) – ENMAX Energy Corporation Errata to Decision 23223-D01-2018 2016-2018 Energy Price Setting Plan Second Compliance Filing, January 11, 2019.
[23] *Ibid*, PDF Page 4, Paragraph 5.
[24] Exhibit 24341-X0001 – Application to Amend EPSP pursuant to Decision 23223-D01-2018 (Errata), February 21, 2019.
[25] Decision 24341-D01-2019 – ENMAX Energy Corporation 2016-2018 Energy Price Setting Plan Amendment, April 9, 2019.
[26] Exhibit 24284-X0002 – EPCOR Energy Alberta GP Inc. 2018-2021 Energy Price Setting Plan Amendment Application, January 28, 2019.
[27] *Ibid*, PDF Page 3.
[28] Decision 24284-D01-2019 – EPCOR Energy Alberta GP Inc. Application for Amendment to the 2018-2021 Energy Price Setting Plan, February 21, 2019.
[29] ENMAX provides the RRO for the ENMAX service area, EPCOR provides the RRO for the EPCOR and FortisAlberta service area, and Direct Energy Regulated Services provides the RRO for the ATCO service area.

The reference rate was above 6.8 ¢/kWh in January and February 2019, enabling RRO providers for REAs and wire owning municipalities to be reimbursed for a portion of their RRO costs if their monthly rates are greater than 6.8 ¢/kWh.[30] The reference rate ranged from 6.541 ¢/kWh to 8.454 ¢/kWh across Q1 2019.[31] Figure 19 shows the range of monthly rates submitted to the MSA since April 2018 by 37 RRO providers for REAs and municipalities as part of the Deferral Account Statement (DAS) process.

Figure 19: Monthly Rates for REAs and Municipalities[32]



As of April 2019, the Government of Alberta has paid $55.3 million in compensation to RRO providers (Table 5) for their RRO energy costs incurred between April 2018 and March 2019. RRO providers for the four largest service areas receive approval for reimbursement from the AUC, while REAs, wire-owning municipalities and the City of Medicine Hat receive reimbursement approval from the MSA.

[30] Not including the City of Medicine Hat.

[31] 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.

[32] Does not include data from the City of Medicine Hat.

Table 5: Rate Cap Compensation[33]

Delivery Month	Reimbursement (AUC Approved DASs)	Reimbursement (MSA Approved DASs - REA and Municipalities)	Reimbursement (MSA Approved DASs - Medicine Hat)	**Total Reimbursement**
Apr-18	$ 7,909,578.53	$ 941,035.38	$ 314,610.78	**$ 9,165,224.69**
May-18	$ -	$ -	$ -	**$ -**
Jun-18	$ -	$ -	$ -	**$ -**
Jul-18	$ 7,087,019.48	$ 751,899.43	$ 378,125.51	**$ 8,217,044.42**
Aug-18	$ 10,898,911.89	$ 1,003,188.95	$ 547,761.17	**$ 12,449,862.01**
Sep-18	$ 6,367,832.62	$ 703,569.55	$ 271,050.87	**$ 7,342,453.04**
Oct-18	$ 194,148.96	$ 80,101.57	$ -	**$ 274,250.53**
Nov-18	$ 70,788.58 *	$ 53,033.20 *	$ -	**$ 123,821.78**
Dec-18	$ 6,370,359.36 *	$ 778,489.79 *	$ 202,260.10	**$ 7,351,109.25**
Jan-19	$ 6,785,544.02 *	$ 827,781.95 *	$ 217,752.01	**$ 7,831,077.97**
Feb-19	$ 2,013,934.42 *	$ 431,219.69 *	$ 80,518.30	**$ 2,525,672.41**
Mar-19	$ -	$ -	$ -	**$ -**
Total	**$ 47,698,117.85**	**$ 5,570,319.50**	**$ 2,012,078.74**	**$ 55,280,516.10**

Competitive Retail Market

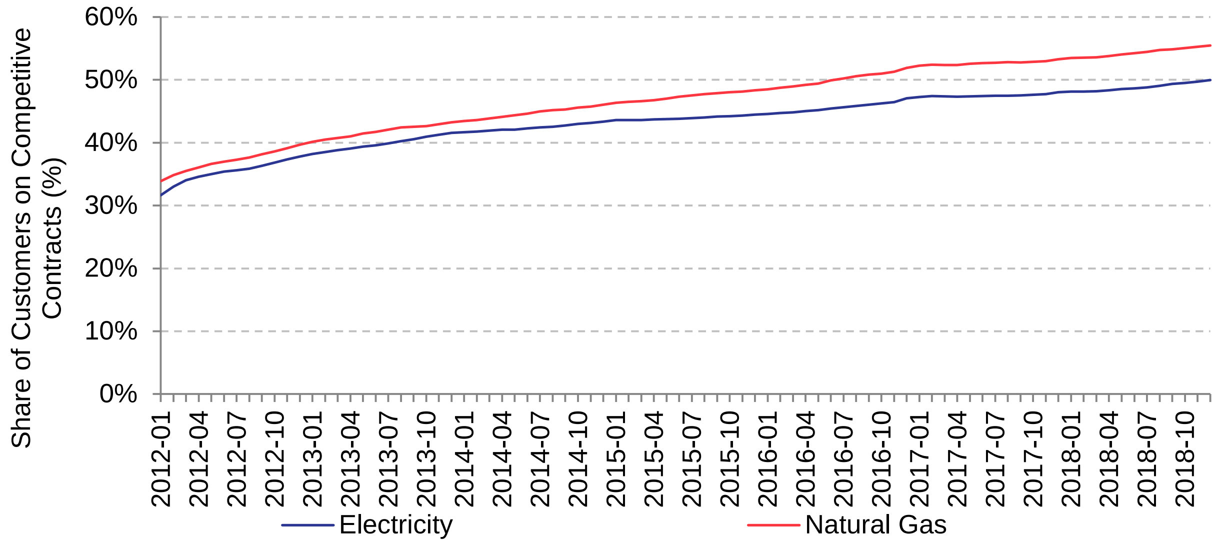
Competitive Contract Market Share

Competitive contract market shares for residential electricity customers grew by 0.6% over Q4 2018, reaching a total competitive share of 49.97% (Figure 20). The MSA anticipates that the competitive market share for residential electricity customers will surpass 50% in 2019.

Competitive natural gas contract shares for residential customers grew by 0.6% over Q4 2018, reaching a competitive share of 55.5%.

[33] For deferral account true-ups, reimbursement values are reported by delivery month rather than the month in which the reimbursement was paid. For example, the true-up for September 2018 MSA approved deferral accounts was paid in March 2019 but has been included as part of the September 2018 reimbursement. An asterisk (*) indicates that compensation values are non-final as true-ups have not been accounted for.

Figure 20: Share of Residential Customers on Competitive Retail Contracts, January 2012 - December 2018

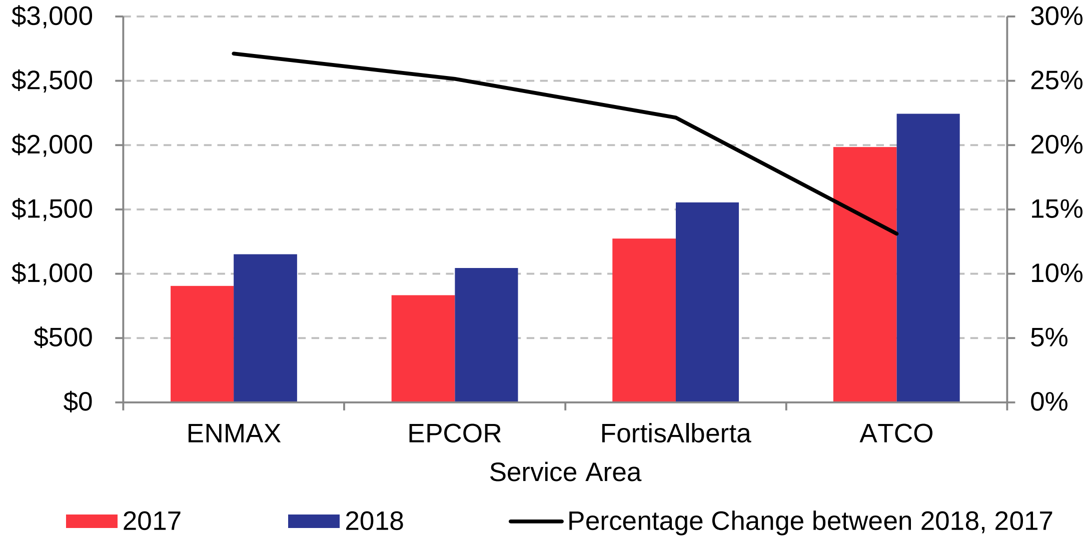


Regulated Retail Electricity Bills

Annual Review of 2018 Electricity Bills

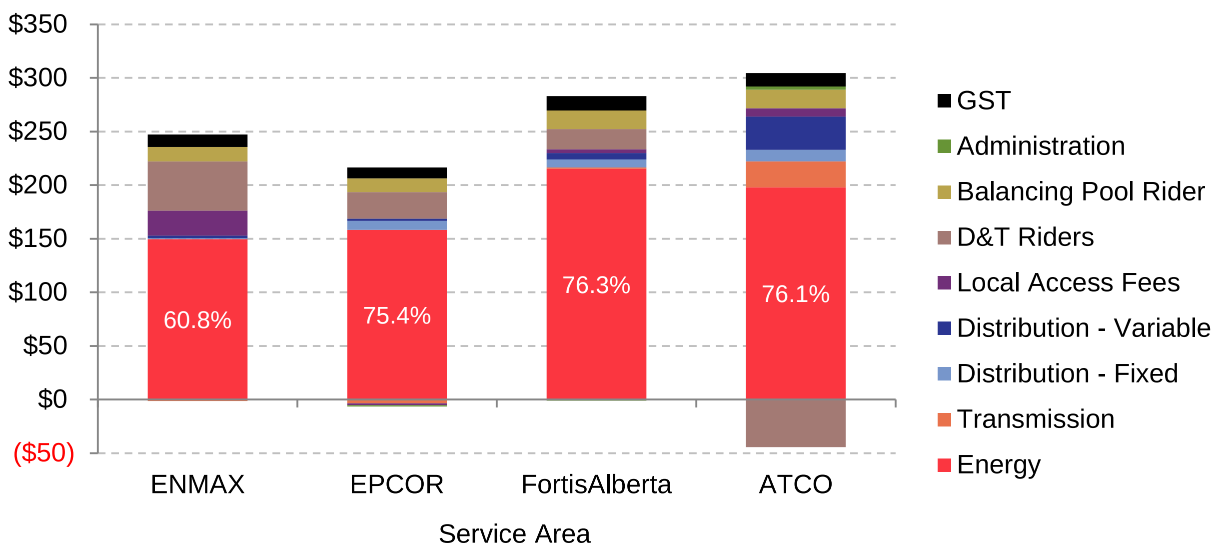
In 2018, regulated residential electricity bills increased to 2014 levels in all four of the large distribution service areas. A typical residential RRO customer living in a detached home saw their annual electricity bills increase by $200-$300 in 2018 when compared to the previous year (Figure 21).

Figure 21: Change in Annual Regulated Electricity Bills for Detached Home Residential Customers by Service Area, 2017 and 2018[34]



The majority of this increase can be attributed to increases in the energy charge, with smaller increases attributable to increases in riders across service areas (Figure 22). RRO billing rates averaged 6.06 ¢/kWh across all service areas in 2018, as compared to an average rate of 3.57 ¢/kWh in 2017.

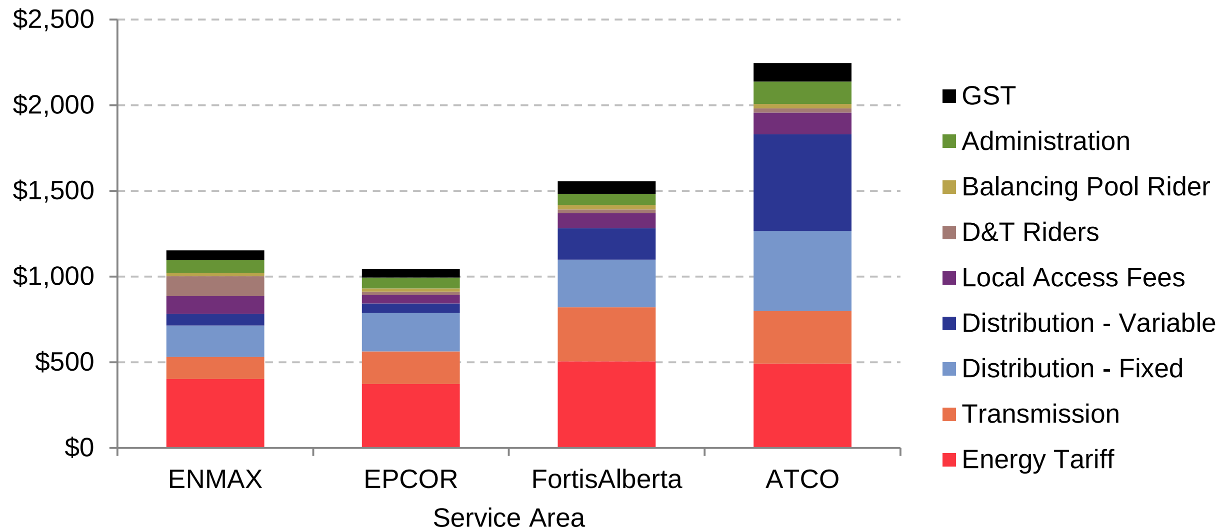
Figure 22: Bill Component Increases in 2018 Regulated Detached Home Electricity Bills as Compared to 2017 Bills[35]



[34] In this section, access fees for Calgary, Edmonton, Hinton and Grande Prairie have been used to model bills in the ENMAX, EPCOR, FortisAlberta and ATCO service areas (respectively).
[35] Percentage labels here indicate the percent of the bill increase attributable to energy charges.

Despite higher energy charges that year, the majority of residential customers' electricity bills in 2018 were comprised of non-energy charges, including transmission, distribution, rider and administration charges (Figure 23).

Figure 23: Annual Residential Detached Home 2018 Electricity Bills by Service Area



Impact of the Rate Cap on Regulated Electricity Bills

The RRO rate cap bound for the first time in April 2018 across the four large service areas and bound in four or six subsequent months, depending on service area (see Figure 18). In months where the rate cap bound, residential RRO customers paid an energy billing rate of 6.8 ¢/kWh rather than the higher monthly rate determined by their RRO provider's EPSP.

Absent the rate cap, a residential electricity customer living in a detached home would have spent between $30 and $55 more on their electricity bills across 2018, depending on their service area (Table 6).[36] A breakdown of the monthly bill savings from the rate cap program for a residential RRO customer living in a typical detached home can be found in Figure 24 below.

ENMAX RRO rates were significantly higher than other RRO rates in many months of 2018. As a result, monthly bill savings from the rate cap program for residential RRO customers living in the ENMAX service area were greater than the savings for RRO customers in other service areas. This may have been influenced by the 45-day ENMAX RRO procurement period that was in place up until November 2018, when ENMAX shifted to a 120-day procurement period specified in their 2016-2018 EPSP.[37]

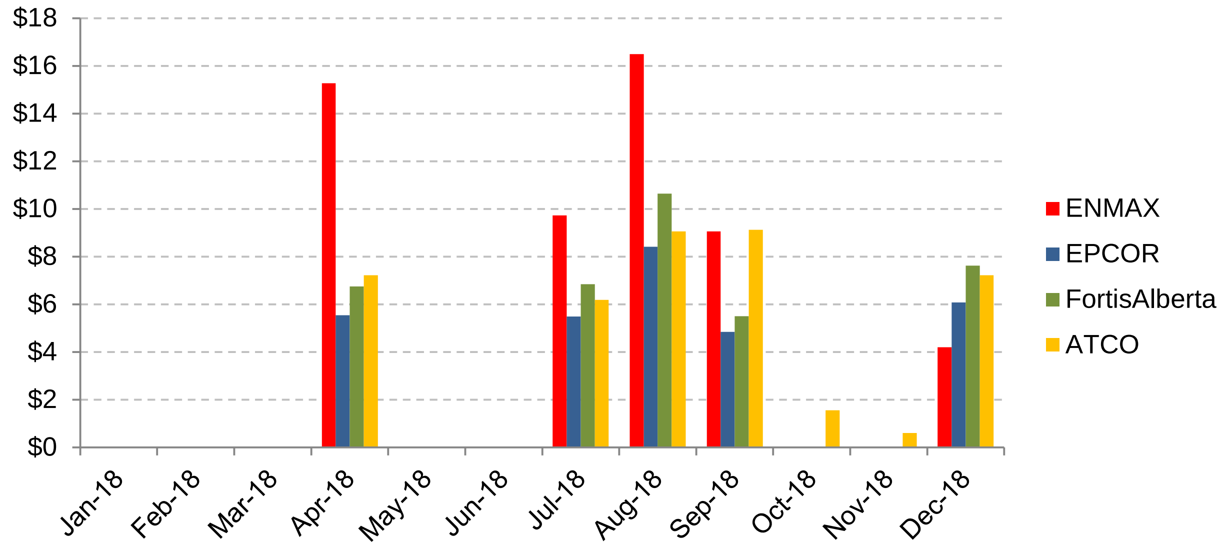
[36] This estimate accounts for the direct impact of the rate cap (lower energy charges) and the indirect impact stemming from lower access fees and riders that may incorporate the energy charge in their calculation. Any (potential) changes in consumption behavior stemming from the rate cap have not been accounted for.

[37] Decision 23223-D01-2018 (Errata) – ENMAX Energy Corporation Errata to Decision 23223-D01-2018 2016-2018 Energy Price Setting Plan Second Compliance Filing, January 11, 2019, PDF Pages 3, 4, Paragraph 4.

Table 6: Annual Rate Cap Bill Savings for Residential Detached Home Customers

Service Area	Energy Charge Savings ($)	Other Charge Savings ($)	Total Rate Cap Bill Savings ($)
ENMAX	$ 46.93	$ 7.82	**$ 54.76**
EPCOR	$ 28.94	$ 1.45	**$ 30.39**
FortisAlberta	$ 35.58	$ 1.78	**$ 37.36**
ATCO	$ 39.01	$ 1.95	**$ 40.97**

Figure 24: Monthly Rate Cap Bill Savings for Residential Detached Home Customers in 2018

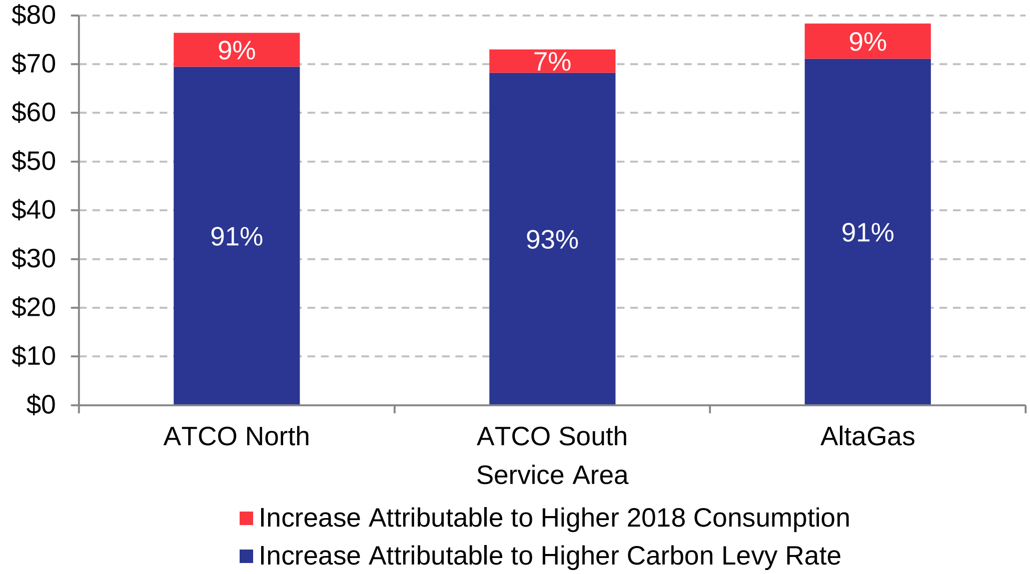


Regulated Retail Natural Gas Bills

The carbon levy rate on natural gas increased from $1.011/GJ to $1.517/GJ beginning January 1, 2018.[38] The MSA estimates a regulated residential customer living in a detached home paid between $73 and $78 more in carbon charges on their natural gas bills in 2018, relative to 2017 (Figure 25). The majority of this increase is attributable to the increased carbon levy rate, although some of the increase is due to higher natural gas consumption levels in 2018 relative to the previous year.

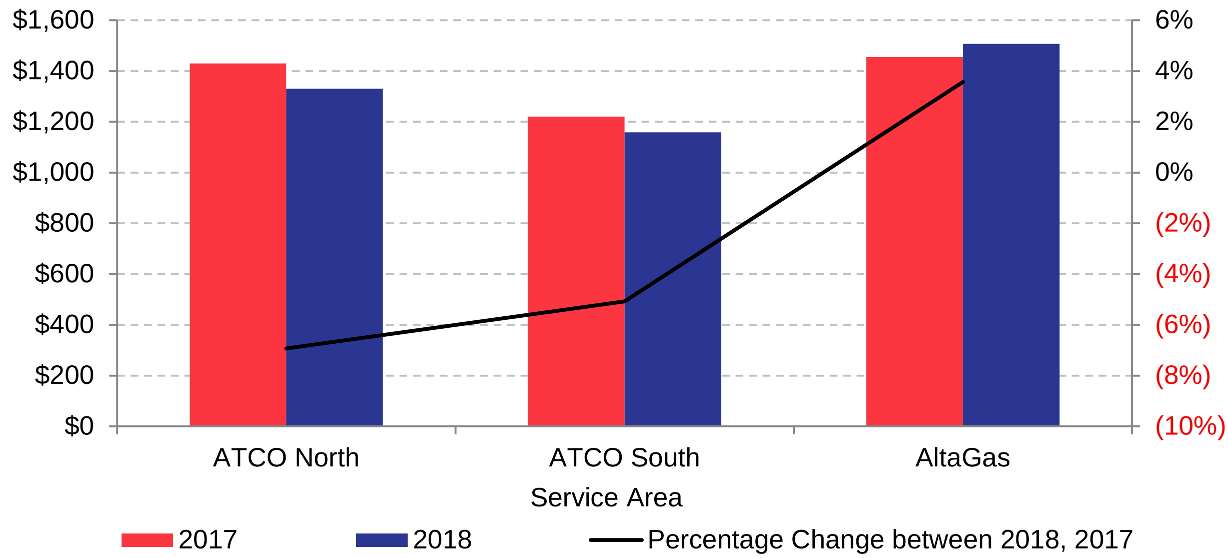
[38] Alberta Carbon levy and rebates.

Figure 25: 2018 Increase in Natural Gas Carbon Charge for Regulated Residential Detached-Home Customers by Service Area



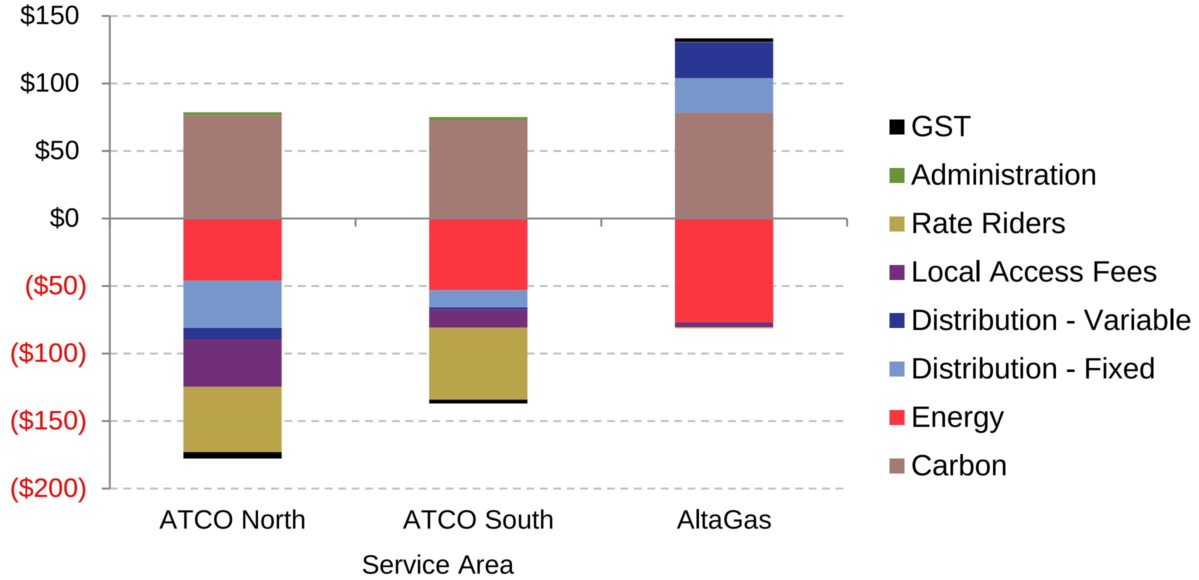
Despite this increased carbon rate, regulated natural gas bills fell in the ATCO North and ATCO South gas distribution service areas in 2018, while gas bills in the AltaGas service area increased (Figure 26).

Figure 26: Change in Regulated Natural Gas Bills for Detached Home Residential Customers by Service Area, 2017 and 2018



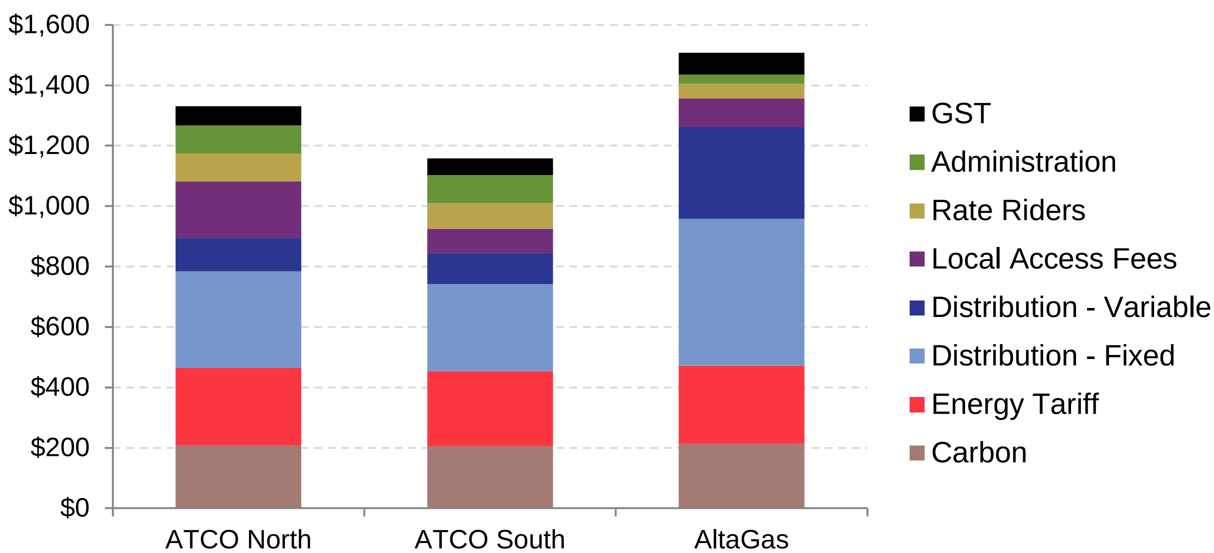
In all three service areas, the increase in carbon charges was largely offset by lower energy charges in 2018 (Figure 27). DRT rates averaged $1.59/GJ and $1.80/GJ in the ATCO and AltaGas service areas (respectively) in 2018, as compared to average rates of $2.09/GJ and $2.65/GJ in 2017. While distribution rates fell in both ATCO service areas in 2018, these rates increased in the AltaGas service area in that year.

Figure 27: Bill Component Increases in 2018 Regulated Detached Home Natural Gas Bills as Compared to 2017 Bills



The majority of residential customers' natural gas bills in 2018 were comprised of charges unrelated to energy or the carbon levy, such as distribution charges, access fees, riders and administration charges (Figure 28).

Figure 28: Annual Residential Detached Home 2018 Natural Gas Bills by Service Area

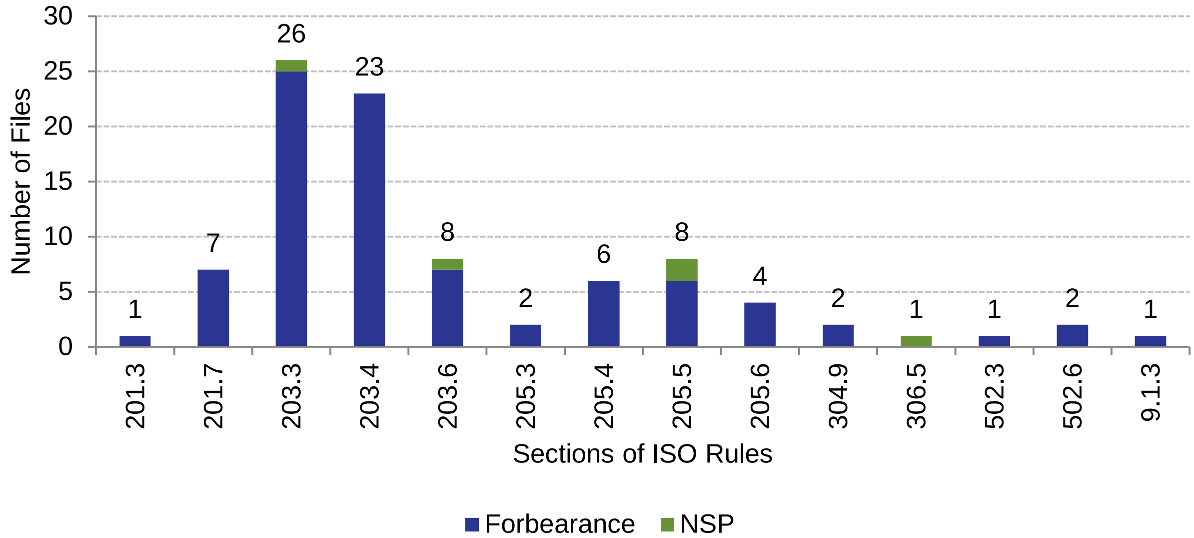


Compliance

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 March 31, 2019, the MSA addressed 92 ISO rules compliance matters, and an additional 146 matters were carried forward to the next quarter. During this time frame, the MSA issued 5 notices of specified penalty, totalling $4,250 in financial penalties.

Figure 29: Overview of ISO Rules Matters Addressed at the end of Q1/19



The sections of ISO rules listed in Figure 29 fall into the following categories:

201	General (Markets)
203	Energy Market
205	Ancillary Services Market
304	Routine Operations
306	Outages and Disturbances
502	Technical Requirements
9	Transmission

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 5 non-CIP[39] matters since the start of 2019, while 53 remain unresolved. These closed

[39] CIP means Critical Infrastructure Protection

matters related to COM and VAR standards.[40] One notice of specified penalty was issued in 2018, but the matter was closed in 2019 after certification of completion of a mitigation plan was received.

[40] COM means Communications and VAR means Voltage and Reactive (includes VAR-###-WECC standards)

Market Share Offer Control

The MSA will begin publishing market share offer control metrics as well as estimates of capacity market shares in conjunction with its market reports. The increased frequency of publishing these metrics will also require an information requests to be issued more frequently to electricity market participants with over 5% offer control.

Assessment of Offer Control

Section 5 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation) requires that the MSA publish the percentage of offer control held by electricity market participants at least annually. Details of the process to collect and publish information on offer control are set out in the MSA's Market Share Offer Control (MSOC) Process.

In accordance with the process, the MSA calculated offer control information from the AESO for the period January 31, 2019 hour ending 16. On February 21, 2019, the MSA requested confirmation of offer control from participants whose total offer control was calculated as greater than five percent, or for joint ventures that required further clarification.

As per Section 5(2) of FEOC Regulation, an electricity market participant's total offer control is measured as the ratio of megawatts under its control to the sum of maximum capability of generating units in Alberta.

	2019-01-31	
Company	**Control (MW)**	**%**
TransAlta	3,270	21.0%
Balancing Pool	2,284	14.7%
ATCO	1,977	12.7%
ENMAX	1,446	9.3%
Suncor	1,158	7.4%
Capital Power	1,118	7.2%
Other	4,002	25.7%
Total Dispatchable	15,254	98.0%
Total Non-dispatchable	316	2.0%
Grand Total	**15,570**	**100.0%**

Further details on offer control are provided in Appendix A of this report, including: a table listing the market share offer control of all electricity market participants, a list of affiliates of electricity market participants with offer control over five percent, the individual assets under the control of electricity market participants with offer control over five percent, and a breakdown of offer control by unit. The definition of "electricity market participant" in Section 5 of the FEOC Regulation means an electricity market participant as defined in the *Electric Utilities Act* (EUA) and also includes any affiliates of an electricity market participant.

Total offer control among participants with greater than five percent MSOC remained largely the same year-over-year with percentages of 74.3% in 2019 and 74.8% in 2018.

Changes from 2018

Alberta's total capacity decreased 318 MW since the last MSOC assessment on April 22, 2018. This decrease was primarily due to the retirement of Sundance #2 on July 31, 2018.[41] Other retirements that occurred since the previous MSOC assessment include: the Drayton Valley (DV1) 11 MW biomass unit on September 30, 2018.

On November 28, 2018, Genalta III GP Ltd. connected Bellshill (BHL1) a 5.4 MW gas unit.[42] While the unit is owned and operated by Genalta III GP Ltd. the offer control for the unit has been assigned to URICA Asset Optimization Ltd.

On September 30, 2018, the Battle River #5 PPA was terminated. Upon termination, 368 MW of offer control was transferred to ATCO from the Balancing Pool.[43]

Units are included in offer control (and the denominator) as long as they are registered as active assets during the reference time. Units registered as active are still required to make offers (even if they are not available or mothballed) and their lack of availability is included in outage data published by the AESO.

The maximum capability of an asset used to calculate the denominator may not correspond to the name plate maximum capabilities as they would be typically viewed on the AESO's Current Supply Demand Report. Instead, the denominator uses maximum capability as it is registered with the AESO for the purpose of submitting price-quantity offer pairs.

[41] TransAlta Announces Retirement of Sundance Unit 2, July 18, 2018.
[42] New Asset Bellshill (BHL1) Notice.
[43] Balancing Pool to Terminate Battle River 5 PPA, March 21, 2018.

Unit	2018 (MW)	2019 (MW)	*Diff*
BHL1 Bellshill	--	5.4	5.4
Units Added (Units >=5 MW)	**0**	**5.4**	**5.4**
DV1 Drayton Valley	11	--	-11
SD2 Sundance #2	280	--	-280
Units Retired (>=5 MW)	**291**	**0**	**-291**
MKRC MacKay River Cogeneration Plant	205	207	2
MC Changes (Units >=5 MW)	**205**	**207**	**2**
Units <5 MW	124.1	127.9	3.8
Unchanged Units >=5 MW	15,229	15,229	0.0
TOTAL (MW)	**15,849**	**15,570**	**-280**

Capacity Market Shares based on Estimated UCAP

The MSA has also calculated an initial estimate of capacity market shares based on the uniform capacity (UCAP) values of the generating assets in Alberta.[44] The UCAP calculations are based on the methodologies set out in proposed ISO Rule 206.3 ("Proposed UCAP rule"). The Proposed UCAP rule outlines in detail the methodologies the AESO has put forward to calculate the UCAP values for different types of assets. The MSA calculated UCAP values for all the dispatchable assets in Alberta and the corresponding capacity market shares by owner.

The UCAP value determinations are based on two primary methodologies: availability factor and capacity factor. The availability factor methodology was used for assets that can change generation levels in response to a dispatch signal from the AESO and have metered volumes that align with dispatch levels. Additionally, self-supply assets that are dispatchable on a gross-production basis undergo a further adjustment based on their net-to-grid output relative to their energy market dispatches. The capacity factor methodology was used for wind, solar and run-of-river hydroelectric assets.

A capacity market participant's market share has been quantified as the ratio of total UCAP MW under the participant's offer control to the sum of UCAP MW of all generating assets in Alberta. For the purposes of this analysis, capacity resources other than dispatchable Alberta generators are not included in the determination of market shares.

The capacity market shares have been calculated assuming that, if the asset is individually owned, its full capacity is controlled by its owner; if the asset is jointly owned, each owner controls only its offer control portion of the asset as per the MSA's Market Share Offer Control reporting. The reported market shares have been obtained by using the 2019 Market Share

[44] It is important to note that these UCAP estimates are initial not final and will be subject to change. For example, the MSA did not use a time-weighted average supply cushion for this analysis and the MSA has not fully accounted for all asset exclusion hours.

Offer Control figures assuming that the PPA assets are returned to their owners, as they will be prior to the beginning of the capacity market. In particular, the offer control for the Keephills 1 and 2 assets is assumed to be 100% TransAlta, the offer control for the Genesee 1 and 2 assets is assumed to be 100% Capital Power, and the offer control for the Sheerness 1 and 2 assets is assumed to be 50% ATCO and 50% TransAlta. It should be noted that no new additions or asset retirements are accounted for in this market shares analysis. In addition, to be consistent with the Market Share Offer Control methodology, import assets are not included in the analysis.

All participants with a capacity market share of greater than five percent are listed in Table 7. As shown, the MSA's initial estimates of UCAP in the capacity market imply that the market will be relatively concentrated with TransAlta controlling over 35% of Alberta's generation UCAP and the top-four firms controlling approximately 80%.

Table 7: 2019 Non-PPA Capacity Market Shares based on UCAP Values

Company	MW	%
TransAlta	3,157	35.7%
Capital Power	1,504	17.0%
ATCO	1,364	15.4%
ENMAX	972	11.0%
Other	1,853	21.0%
Grand Total	**8,850**	**100.0%**

Regulatory

Current AUC Proceedings

AUC Proceeding 23757: ISO Rules to Implement and Operate the Capacity Market

On January 31, 2019, the AESO filed an application with the AUC for approval of rules to implement a capacity market. The application will be heard in Proceeding 23757.[45] Further to the mandate letter from the Deputy Minister, Energy dated March 27, 2017, which requested "the MSA provide market-related advice to support the transition to a capacity market framework" the MSA filed intervenor evidence in Proceeding 23757 on February 28. The MSA's evidence was comprised of two reports, each from a panel of independent experts.

The first report, titled "Regulatory Oversight in the Alberta Capacity Market," provided independent expert evidence related to the issue of regulatory oversight issues in existing U.S. capacity markets. This report was prepared by Joseph T. Kelliher, former Chair, U.S. Federal Energy Regulatory Commission, David B. Patton, President, Potomac Economics, which is the independent electricity market monitor in New England, New York, the Midcontinent ISO, and the Electric Reliability Council of Texas, and Adonis Yatchew, Professor of Economics, University of Toronto and Senior Consultant, Charles River Associates (CRA).[46] The second report, titled "Market Design Issues in the Alberta Energy and Capacity Markets," provided independent expert evidence related to certain market design issues before the AUC for decision in Proceeding 23757. This report was prepared by Potomac Economics and CRA.[47]

Following consideration of other parties' intervenor evidence, the MSA filed two expert rebuttal reports on the same topics on April 4.[48] The oral hearing in the matter began on Monday, April 22.

AUC Proceeding 24116: Electric Distribution System Inquiry

On December 6, 2018 the AUC launched a distribution inquiry and stated that "the purpose of the inquiry is to map out the key issues related to the future of the electric distribution grid, to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system".[49] The MSA submitted its preliminary submission into the inquiry on January 18, 2019, in this submission we outlined our views on the scope and process of the inquiry and stated our intention to file expert evidence.[50] On March 29, 2019 the AUC outlined the scope and process of the inquiry, expanding the scope of the inquiry to include natural gas distribution, and splitting the inquiry process into three principal modules.[51]

45 Exhibit 23757-X0284 – Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, January 31, 2019.
46 Exhibit 23757-X0389.01 – Regulatory Oversight in the Alberta Capacity Market, March 19, 2019.
47 Exhibit 23757-X0390 – Market Design Issues in the Alberta Energy and Capacity Markets, February 28, 2019.
48 Exhibit 23757-X0510 – Intervenor Rebuttal Evidence, April 4, 2019.
49 AUC Bulletin 2018-17 at page 1.
50 MSA Preliminary Submission for the Distribution System Inquiry.
51 AUC Letter on Scope and Process for the Distribution System Inquiry.

AUC Proceeding 24297: Pembina request for an order to share preferential information with TransCanada

On January 31, 2019, Pembina NGL Corporation (Pembina) filed an application with the AUC pursuant to section 3 of the FEOC Regulation for an interim AUC order permitting the sharing of non-public information between Pembina, and TransCanada Energy Ltd. (TransCanada) for an uprate on the Redwater ISD (TC02). On February 1, 2019, the MSA filed a statement of intent to participate supporting the application for an interim order. The AUC granted an interim order on February 14, 2019 for Pembina to share non-public information regarding TC02 with TransCanada. [52] The interim order was set to expire on May 15, 2019. On May 2, 2019, the AUC extended the termination date of the interim order to June 14, 2019.[53]

The proceeding is still ongoing. The MSA expects a final order in Q2 2019.

AUC Proceeding 23828: Market Surveillance Administrator application for approval of a settlement agreement with the Balancing Pool pursuant to Sections 44 and 51(1)(b) of the *Alberta Utilities Commission Act*

The MSA filed an application for the approval of a settlement with the Balancing Pool in August 2018.[54] Argument and reply argument were filed in January of 2019. In February 2019, an application was made to review and vary the decision by the AUC to strike in its entirety the evidence filed by Independent Power Producers Society of Alberta (IPPSA).[55] The AUC dismissed the request for a review in a ruling issued on February 25, 2019.[56] On April 26, 2019 the AUC requested that parties provide submissions on a report prepared by the Independent Assessment Team (IAT). The MSA and other parties responded to this request on May 6, 2019. The MSA anticipates a decision regarding the approval of the settlement agreement in Q3 2019.

Concluded AUC Proceedings

AUC Proceeding 24239: Application for an Order Permitting the Sharing of Records Not Available to the Public Between Campus Energy Partners LP and URICA Energy Real Time Ltd.

Campus Energy Partners LP (Campus) filed an application with the AUC on January 14, 2019 pursuant to sections 3 and 3.1 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation) for an order to share non-public records between Campus and URICA Energy Real Time Ltd. (URICA) regarding the Bantry and Parkland power plants.

On January 24, 2019, the MSA filed a statement of intent to participate expressing concerns with the request for an order under section 3.1 of the FEOC Regulation which concerns the sharing of non-public capacity auction information. The MSA argued that the application did not

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[52] Decision 24297-D01-2019 – Application for an Order Permitting the Sharing of Records Not Available to the Public Between Pembina NGL Corporation and TransCanada Energy Ltd., February 14, 2019.
[53] Exhibit 24297-X0014 – Extension of Interim Order 24297-D02-2019, May 2, 2019.
[54] Exhibit 23828-X0001 – Application for Approval of a Settlement with the Balancing Pool, August 15, 2018.
[55] Exhibit 23828-X0055 – Application of the Independent Power Producers Society of Alberta for Review and Variance, February 8, 2019.
[56] Exhibit 23828-X0056 – Ruling on IPPSA Application for Review and variance of AUC December 12, 2018 Ruling, February 25, 2019.

provide sufficient detail that: the sharing of records relating to past, current and future offer or bids in a capacity auction; how Campus and URICA intended to share capacity auction information; and why the sharing of capacity auction offer or bid information was reasonably necessary for Campus to carry out its business. The MSA had no concerns regarding Campus' request for an order under section 3 of the FEOC Regulation regarding non-public information related to the power pool and ancillary services market. On January 25, 2019, Campus submitted a letter requesting a withdrawal of its request to share non-public records with URICA under section 3.1 of the FEOC Regulation.

On January 31, 2019, the AUC approved the application and issued an order permitting the requested preferential information sharing under section 3 of the FEOC Regulation given: the support of the MSA, that the sharing of records is reasonably necessary for Campus to carry out its business, and that the records will not be used by the parties for any purpose that will not support the FEOC operation of the electricity market.[57]

AUC Proceeding 24268: Application for an Order Permitting the Sharing of Records Not Available to the Public Between Canadian Natural Resources Limited, URICA Energy Real Time Ltd. and URICA Asset Optimization Ltd.

On January 24, 2019, Canadian Natural Resources Ltd. (CNRL) filed an application with the AUC pursuant to section 3 of the FEOC Regulation for an AUC order permitting the sharing of non-public information between CNRL, URICA, and URICA Asset Optimization Ltd. for the Horizon Oil Sands Cogeneration Facility (CNR5). On February 12, 2019, the MSA filed a statement of intent to participate in the proceeding stating that the MSA supported the application and did not require further evidentiary process. On February 27, 2019, the AUC approved the application and issued an order permitting the requested preferential information sharing given: the support of the MSA, that the sharing of records is reasonably necessary for CNRL to carry out its business, and that the records will not be used by the parties for any purpose that will not support the FEOC operation of the electricity market.[58]

MSA Activities

Advertisements under the Code of Conduct Regulation

In the summer of 2018, the MSA examined a number of advertisements released by one affiliated energy retailer, with the purpose of assessing compliance with section 7 of the *Code of Conduct Regulation* (AR 58/2015). After examining these advertisements the MSA subsequently closed the file on this matter.

Energy Emergency Alerts on February 3 & 4

Cold weather and some critical coal unit outages caused the AESO to declare energy emergency alerts on February 3 and 4. Notably, some coal assets declared that coal supply

[57] Decision 24239-D01-2019 – Application for an Order Permitting the Sharing of Records Not Available to the Public Between Campus Energy Partners LP and URICA Energy Real Time Ltd., January 31, 2019.
[58] Decision 24268-D01-2019 – Application for an Order Permitting the Sharing of Records Not Available to the Public Between Canadian Natural Resources Limited, URICA Energy Real Time Ltd. and URICA Asset Optimization Ltd., February 27, 2019.

problems were the primary cause of the reported outages. Given the extreme power shortages that resulted from the outages, the MSA conducted an issue assessment as per section 3 of the MSA's Investigation Procedures. During the course of the issue assessment, the MSA contacted the two affected companies requesting more details on the nature of the outages and whether this would be a recurring problem. The market participants provided detailed explanations and assurances that there was no expectation that there would be a recurring problem in the future. The MSA was satisfied by the explanations and has closed its file on this matter.

Municipal Own Use Regulation (AR 80/2009)

This regulation applies to municipalities wishing to develop generating facilities within their municipal boundaries and is in addition to any requirements under section 95 of the EUA. The key requirement under the regulation is that all energy produced by such a facility must be consumed by the municipality, but not necessarily at the site. In other words, if the sum of the retail load of the municipality exceeds the energy produced it meets the requirements of the regulation. The general idea of the regulation is to prevent interference of the competitive market by actions of municipalities that may not have the same project development considerations as commercial entities.

The proponent must first develop a compliance plan that is approved by the MSA and will include annual reporting requirements. Currently, Grand Prairie and Calgary are the two municipalities with compliance plans. The town of Wainwright is currently developing a compliance plan and more applications are expected.

Consultation on the need for Offer Behaviour Enforcement Guidelines

In September 2018, the MSA initiated a stakeholder consultation to consider whether a guideline on participant offer behaviour should be implemented during the transitional period before the capacity market commences. The MSA commissioned a report by CRA to address this issue. The CRA report was published in December[59] and a meeting was held with stakeholders in January 2019 where CRA was present to address questions.

The MSA has decided to postpone further consultation regarding offer behaviour guidelines until the following two issues have been determined:

- Proceeding 23757 has concluded and a decision has been rendered, which is expected by July 31, 2019, and
- the newly-elected provincial government's 90 day consultation on whether Alberta should retain an energy-only market or continue to create a capacity market has been concluded.

[59] Notice to Participants and Stakeholders re: Offer Behaviour Guidelines prior to the Implementation of a Capacity Market, December 10, 2018.

Consultation on an MSA Advisory Opinion Programme

In October 2018, the MSA initiated a stakeholder consultation to consider whether a voluntary advisory opinion programme would be helpful to market participants. The MSA has considered the input it received and has decided to proceed with the implementation of a non-binding AOP.

The decision to issue non-binding opinions was made after considering the feedback received from stakeholders and, in particular, from one stakeholder who commented on the possible lack of legislative authority that would specifically enable the MSA to issue binding opinions. The MSA notes that participation in the non-binding AOP programme will be entirely voluntary and that opinions will not be issued with respect to matters for which the AESO provides guidance pursuant to its Information Document 2017-001.

The MSA will issue a set of proposed AOP procedures, which will help guide market participants so that they can take best advantage of the programme.

Future Market Reporting

Going forward the MSA will no longer publish market reports on a quarterly basis. The MSA believes that a longer timeframe will make the reports more useful to market participants. Instead, the MSA will publish two market reports each year. The new reports will deal with both the energy and capacity markets. The MSA expects as a result of the AUC's decision in capacity market proceeding (AUC Proceeding 23757) that additional and more detailed reporting will be required with respect to these new market constructs.

There will be an annual report published on January 31 and a semi-annual report published on July 31. The first of these new reports will be published in July 2019.

Highlights

The following points summarize key takeaways from the quarter:

- The first quarter of 2019 was marked by the fact that more than 5% of hours had a pool price above $165/MWh. As a result, the average pool price for Q1 2019 was $69.46/MWh ($49.02/MWh ext. off-peak, $79.66/MWh ext. on-peak). This is a 99% increase compared to the quarterly average pool price for Q1 2018. The increase in the quarterly average pool price is due to higher pool prices in February and March.
- Contributing to the increase in pool price observed during February and March were higher demand driven by extremely low temperatures throughout the province and increases in export activity on the interties due to higher Mid-C prices.
- During Q1 2019, Alberta was a net exporter of 148 GWh through the interties. In comparison, in Q1 2018, Alberta was a net importer of 902 GWh of energy. The price in Mid-C was higher than the Alberta pool price, on average. This incentivizes exports from Alberta into Mid-C.
- With higher pool prices, total operating reserves costs also increased by 94%. While active reserve costs increased, there were some smaller reductions in the cost of activating standby operating reserves from $6 million in Q1 2018 to $2.3 million in Q1 2019. The decrease in standby contingency reserves activated is likely due to decreased import activity on the BC and Montana interties. Fewer imports on the BC and Montana interties results in less standby contingency reserves activated in order to support higher import flows.
- As noted in the last quarterly report, the Balancing Pool has seen its Market Share Offer Control (MSOC) decline between the 2018 and 2019 assessment. Overall market concentration among the six largest participants remains stable at around 75%. Estimates of uniform capacity (UCAP) indicate the capacity market will be highly concentrated with the top four market participants accounting for over 80% of total UCAP.
- Calendar year forward prices for 2020 and 2021 increased during the quarter. Prices were higher following the announced extension to mothball outages at Sundance 3 and 5.
- In Q1 2019, residential RRO billing rates averaged 6.52 ¢/kWh across the four largest distribution service areas. Billing rates in these areas reached the Government of Alberta's 6.8 ¢/kWh cap in all four service areas for the first two months of the quarter, but fell below 6 ¢/kWh in all four in March.

Appendix – Market Share Offer Control

Market Share Offer Control for all market participants

Company	2018-04-22 Control (MW)	2018-04-22 %	2019-01-31 Control (MW)	2019-01-31 %
TransAlta	3,550	22.3%	3,270	21.0%
Balancing Pool	2,652	16.7%	2,284	14.7%
ATCO	1,609	10.1%	1,977	12.7%
ENMAX	1,446	9.1%	1,446	9.3%
Suncor	1,158	7.3%	1,158	7.4%
Capital Power	1,118	7.0%	1,118	7.2%
Other	**4,006**	**25.3%**	**4,002**	**25.7%**
TransCanada	446	2.8%	448	2.9%
Imperial Oil	365	2.3%	365	2.3%
Nexen Inc.	340	2.1%	340	2.2%
Dow Chemical Canada ULC	326	2.1%	326	2.1%
EDF Renewables Development Inc.	300	1.9%	300	1.9%
City of Medicine Hat	255	1.6%	255	1.6%
MEG Energy Corp.	202	1.3%	202	1.3%
Cenovus Energy Inc.	198	1.2%	198	1.3%
URICA Asset Optimization Ltd.	156	1.0%	161	1.0%
Maxim Power	149	0.9%	149	1.0%
Oldman 2 Wind Farm Ltd.	134	0.8%	134	0.9%
Exelon	105	0.7%	105	0.7%
Syncrude Canada Ltd.	100	0.6%	100	0.6%
Air Liquide Canada Inc.	96	0.6%	96	0.6%
NextEra	82	0.5%	82	0.5%
Castle Rock Ridge LP	77	0.5%	77	0.5%
Powerex Corp.	73	0.5%	73	0.5%
Alberta Pacific Forest Industries	67	0.4%	67	0.4%
Canadian Natural Resources Ltd.	65	0.4%	65	0.4%
Alberta Newsprint Company / ANC Power	63	0.4%	63	0.4%
AltaGas Ltd.	62	0.4%	62	0.4%
Daishowa-Marubeni Int. Ltd.	52	0.3%	52	0.3%
International Paper Canada Pulp Holdings ULC	48	0.3%	48	0.3%
Cancarb Ltd.	42	0.3%	42	0.3%
Bull Creek Wind Power Limited Partnership	29	0.2%	29	0.2%
Canadian Forest Products Ltd.	27	0.2%	27	0.2%
Whitecourt Power Ltd.	25	0.2%	25	0.2%
Northstone Power Corp.	20	0.1%	20	0.1%
NRGreen Power Limited Partnership	16	0.1%	16	0.1%
Algonquin Power Operating Trust	15	0.1%	15	0.1%

Brooks Solar Corporation	15	0.1%	15	0.1%
Repsol Canada Energy Partnership	13	0.1%	13	0.1%
University of Calgary	12	0.1%	12	0.1%
West Fraser Mills Ltd.	10	0.1%	10	0.1%
Keyera Partnership	5	0.0%	5	0.0%
University of Alberta	5	0.0%	5	0.0%
Valley Power L.P.	11	0.1%	--	--
Total Dispatchable	**15,538**	**98.0%**	**15,254**	**98.0%**
Total Non-dispatchable	**349**	**2.2%**	**316**	**2.0%**
Grand Total	**15,849**	**100.2%**	**15,570**	**100.0%**

Market Share Offer Control by Company

The tables below detail the units for each electricity market participant with offer control greater than five percent, as well as the affiliates of the electricity market participant (as defined in Section 5(1)(a) of the FEOC Regulation) insofar as they were making offers into the power pool. Offers for import energy are not applicable to offer control as contemplated in the FEOC Regulation, and affiliates offering imports may not be included.

ATCO
ATCO Power Canada Ltd.

ATCO

Asset	**Offer Control (MW)**
APS1 Scotford Cogen	195
BR3 Battle River #3	149
BR4 Battle River #4	155
BR5 Battle River #5	385
HSM1 House Mountain	6
JOF1 Joffre #1	474
MKR1 Muskeg River	202
OMRH CUPC Oldman River	32
PH1 Poplar Hill #1	48
PR1 Primrose #1	100
RB5 Rainbow #5	50
RL1 Rainbow Lake #1	47
SH1 Sheerness #1	22
SH2 Sheerness #2	12
VVW1 Valley View 1	50
VVW2 Valley View 2	50
Grand Total	**1,977**

Balancing Pool

Balancing Pool

Balancing Pool	
Asset	**Offer Control (MW)**
GN1 Genesee #1	381
GN2 Genesee #2	381
KH1 Keephills #1	383
KH2 Keephills #2	383
SH1 Sheerness #1	378
SH2 Sheerness #2	378
Grand Total	**2,284**

Capital Power
Capital Power GP Holdings Inc.
Halkirk I Wind Project LP

Capital Power

Asset	Offer Control (MW)
EGC1 Shepard	215
ENC1 Cloverbar #1	48
ENC2 Cloverbar #2	101
ENC3 Cloverbar #3	101
GN1 Genesee #1	19
GN2 Genesee #2	19
GN3 Genesee #3	233
HAL1 Halkirk Wind Power Facility	150
KH3 Keephills #3	232
Grand Total	**1,118**

ENMAX

Calgary Energy Centre No. 2 Inc.
ENMAX Cavalier LP
ENMAX Energy Corporation
ENMAX Generation Portfolio Inc.
ENMAX Kettles Hill Inc.

ENMAX

Asset	**Offer Control (MW)**
AKE1 McBride Lake Windfarm	73
CAL1 CALP Gen #1	320
CRS1 Summit- Crossfield	48
CRS2 Summit- Crossfield	48
CRS3 Summit- Crossfield	48
EC01 Cavalier	120
EGC1 Shepard	645
KHW1 Kettles Hill Wind	63
TAB1 Enmax Taber	81
Grand Total	**1,446**

Suncor

Suncor Energy Inc.

Suncor	
Asset	**Offer Control (MW)**
FH1 Fort Hills	199
SCR1 Base Plant	50
SCR2 Magrath	30
SCR3 Suncor Chin Chute	30
SCR5 Poplar Creek	376
SCR6 Firebag	473
Grand Total	**1,158**

TransAlta

TransAlta Corporation

TransAlta Energy Marketing Corp.

TransAlta Generation Partnership

TransAlta

Asset	Offer Control (MW)
ARD1 Ardenville	68
BIG Bighorn Hydro	120
BOW1 Bow River Hydro	320
BRA Brazeau Hydro	350
BTR1 Blue Trail Wind	66
CR1 ARM2262 Castle River	39
CRE3 Cowley Ridge Expansion #3	20
GN3 Genesee #3	233
GWW1 GW Wind #1	71
IEW1 Summerview Phase 1	66
IEW2 Summerview Phase 2	66
KH1 Keephills #1	12
KH2 Keephills #2	12
KH3 Keephills #3	232
SD3 Sundance #3	368
SD4 Sundance #4	406
SD5 Sundance #5	406
SD6 Sundance #6	401
TAY1 Taylor Hydro 1	14
Grand Total	**3,270**

Market Share Offer Control by Unit

The following table provides a breakdown of offer control by unit. The total for each unit is its maximum capability.

Unit - Control	MW
AFG1 APF Athabasca	**67**
Alberta Pacific Forest Industries	67
AKE1 McBride Lake Windfarm	**73**
ENMAX	73
ALP1 ALP	**7**
AltaGas Ltd.	7
ALP2 ALP	**10**
AltaGas Ltd.	10
ALS1 Air Liquide Scotford #1	**96**
Air Liquide Canada Inc.	96
ANC1 AB Newsprint	**63**
Alberta Newsprint Company / ANC Power	63
APS1 Scotford Cogen	**195**
ATCO	195
ARD1 Ardenville	**68**
TransAlta	68
BCR2 Bear Creek Cogen Plant	**36**
TransCanada	36
BCRK Bear Creek Cogen	**64**
TransCanada	64
BHL1 Bellshill	**5**
URICA Asset Optimization Ltd.	5
BIG Bighorn Hydro	**120**
TransAlta	120
BOW1 Bow River Hydro	**320**
TransAlta	320
BR3 Battle River #3	**149**
ATCO	149
BR4 Battle River #4	**155**
ATCO	155
BR5 Battle River #5	**385**
ATCO	385
BRA Brazeau Hydro	**350**
TransAlta	350
BSC1 Brooks Solar	**15**
Brooks Solar Corporation	15
BSR1 Blackspring Ridge	**300**
EDF Renewables Development Inc.	300

BTR1 Blue Trail Wind	**66**
TransAlta	66
BUL1 Bull Creek	**13**
Bull Creek Wind Power Limited Partnership	13
BUL2 Bull Creek	**16**
Bull Creek Wind Power Limited Partnership	16
CAL1 CALP Gen #1	**320**
ENMAX	320
CCMH Cancarb Medicine Hat	**42**
Cancarb Ltd.	42
CHIN Chin Chute	**15**
URICA Asset Optimization Ltd.	15
CL01 Christina Lake	**100**
Cenovus Energy Inc.	100
CMH1 Medicine Hat #1	**255**
City of Medicine Hat	255
CNR5 CNRL Horizon	**65**
Canadian Natural Resources Ltd.	65
CR1 ARM2262 Castle River	**39**
TransAlta	39
CRE3 Cowley Ridge Expansion #3	**20**
TransAlta	20
CRR1 Enel Alberta Castle Rock Wind Farm	**77**
Castle Rock Ridge LP	77
CRS1 Summit- Crossfield	**48**
ENMAX	48
CRS2 Summit- Crossfield	**48**
ENMAX	48
CRS3 Summit- Crossfield	**48**
ENMAX	48
DAI1 52MW Turbo Generator	**52**
Daishowa-Marubeni Int. Ltd.	52
DKSN Dickson Dam	**15**
Algonquin Power Operating Trust	15
DOWG Total Gen. & SR	**326**
Dow Chemical Canada ULC	326
DRW1 Drywood	**6**
URICA Asset Optimization Ltd.	6
EAGL Whitecourt Power	**25**
Whitecourt Power Ltd.	25
EC01 Cavalier	**120**
ENMAX	120
EC04 EnCana Foster Creek	**98**

Cenovus Energy Inc.	98
EGC1 Shepard	**860**
Capital Power	215
ENMAX	645
ENC1 Cloverbar #1	**48**
Capital Power	48
ENC2 Cloverbar #2	**101**
Capital Power	101
ENC3 Cloverbar #3	**101**
Capital Power	101
FH1 Fort Hills	**199**
Suncor	199
FNG1 Fort Nelson	**73**
Powerex Corp.	73
GEN5 Carson Creek	**15**
URICA Asset Optimization Ltd.	15
GEN6 Judy Creek	**15**
URICA Asset Optimization Ltd.	15
GN1 Genesee #1	**400**
Balancing Pool	381
Capital Power	19
GN2 Genesee #2	**400**
Balancing Pool	381
Capital Power	19
GN3 Genesee #3	**466**
Capital Power	233
TransAlta	233
GOC1 Gold Creek Facility	**5**
Maxim Power	5
GPEC Grande Prairie	**27**
Canadian Forest Products Ltd.	27
GWW1 GW Wind #1	**71**
TransAlta	71
HAL1 Halkirk Wind Power Facility	**150**
Capital Power	150
HMT1 ALP	**45**
AltaGas Ltd.	45
HRM H.R. Milner	**144**
Maxim Power	144
HSM1 House Mountain	**6**
ATCO	6
ICP1 Drops 4, 5, 6	**7**
URICA Asset Optimization Ltd.	7

IEW1 Summerview Phase 1	**66**
TransAlta	66
IEW2 Summerview Phase 2	**66**
TransAlta	66
IOR1 Mahkeses Central Plant	**180**
Imperial Oil	180
IOR2 Nabiye	**185**
Imperial Oil	185
JOF1 Joffre #1	**474**
ATCO	474
KH1 Keephills #1	**395**
Balancing Pool	383
TransAlta	12
KH2 Keephills #2	**395**
Balancing Pool	383
TransAlta	12
KH3 Keephills #3	**463**
Capital Power	231.5
TransAlta	231.5
KHW1 Kettles Hill Wind	**63**
ENMAX	63
ME02 Lethbridge Taber	**8**
URICA Asset Optimization Ltd.	8
ME03 Lethbridge Burdett	**7**
URICA Asset Optimization Ltd.	7
ME04 Lethbridge Coaldale	**6**
URICA Asset Optimization Ltd.	6
MEG1 Christina Lake	**202**
MEG Energy Corp.	202
MFG1 MFC Mazeppa	**16**
URICA Asset Optimization Ltd.	16
MKR1 Muskeg River	**202**
ATCO	202
MKRC MacKay River Cogeneration Plant	**207**
TransCanada	207
NAT1 Ralston	**20**
URICA Asset Optimization Ltd.	20
NEP1 Ghost Pine	**82**
NextEra	82
NPC1 Denis St. Pierre	**11**
Northstone Power Corp.	11
NPC2 JL Landry	**9**
Northstone Power Corp.	9

NPP1 Constellation	**105**
Exelon	105
NRG3 NRGreen Cogen	**16**
NRGreen Power Limited Partnership	16
NX01 Nexen Inc #1	**120**
Nexen Inc.	120
NX02 Nexen Inc. #2	**220**
Nexen Inc.	220
OMRH CUPC Oldman River	**32**
ATCO	32
OWF1 Oldman 2 Wind Farm 1	**46**
Oldman 2 Wind Farm Ltd.	46
PH1 Poplar Hill #1	**48**
ATCO	48
PR1 Primrose #1	**100**
ATCO	100
PW01 Minnehik-Buck Lake	**5**
Keyera Partnership	5
RB5 Rainbow #5	**50**
ATCO	50
RL1 Rainbow Lake #1	**47**
ATCO	47
RYMD Raymond Reservoir	**21**
URICA Asset Optimization Ltd.	21
SCL1 Syncrude #1	**100**
Syncrude Canada Ltd.	100
SCR1 Base Plant	**50**
Suncor	50
SCR2 Magrath	**30**
Suncor	30
SCR3 Suncor Chin Chute	**30**
Suncor	30
SCR4 Wintering Hills	**88**
Oldman 2 Wind Farm Ltd.	88
SCR5 Poplar Creek	**376**
Suncor	376
SCR6 Firebag	**473**
Suncor	473
SD3 Sundance #3	**368**
TransAlta	368
SD4 Sundance #4	**406**
TransAlta	406
SD5 Sundance #5	**406**

TransAlta	406
SD6 Sundance #6	**401**
TransAlta	401
SH1 Sheerness #1	**400**
ATCO	22.4
Balancing Pool	377.6
SH2 Sheerness #2	**390**
ATCO	11.9
Balancing Pool	378.1
TAB1 Enmax Taber	**81**
ENMAX	81
TAY1 Taylor Hydro 1	**14**
TransAlta	14
TC01 Carseland Cogen	**95**
TransCanada	95
TC02 Redwater Cogen	**46**
TransCanada	46
TLM2 Edson	**13**
Repsol Canada Energy Partnership	13
UOA1 UofA Generator	**5**
University of Alberta	5
UOC1 U of C Generator	**12**
University of Calgary	12
VVW1 Valley View 1	**50**
ATCO	50
VVW2 Valley View 2	**50**
ATCO	50
WCD1 West Cadotte	**20**
URICA Asset Optimization Ltd.	20
WEY1 Steam Turbine 48MW	**48**
International Paper Canada Pulp Holdings ULC	48
WWD1 Weldwood	**10**
West Fraser Mills Ltd.	10
Grand Total	**15,254**