Q4/17 Quarterly Report

October – December 2017

February 9, 2018

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

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Wholesale Market

Summary

Pool price in Q4/17 averaged $22.46/MWh ($18.60/MWh ext. off-peak, $24.40/MWh ext. on-peak). This is a 2% increase in pool price compared to the same period last year.

For calendar year 2017, pool prices averaged $22.19/MWh, an increase of 21% from 2016 ($18.28/MWh). This marks the first annual increase in pool price since 2013. Some of the increase can be attributed to the carbon levy applied to the large coal plants in Alberta.

In Q4/17, total demand increased 1.6% relative to Q4/16; and increased 4% in calendar 2017 over 2016.

On December 28, 2017 hour ending (HE) 18, Alberta set a new winter peak load of 11,473 MW. This surpassed the previous winter peak load of 11,458 MW set on December 16, 2016 HE 18. The corresponding pool price in the hour on December 28th was $30.85/MWh.

Table 1: Market Summary

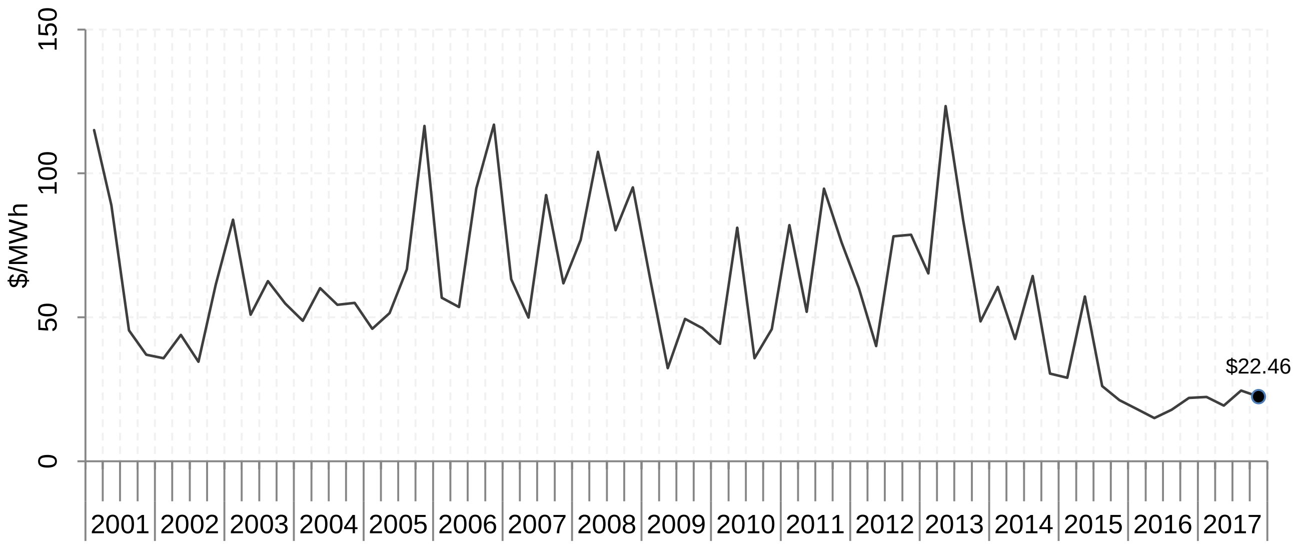
		2016	2017	*Change*
Pool Price (Avg $/MWh)	Oct	25.37	20.45	*-19.4%*
	Nov	16.32	25.03	*53.4%*
	Dec	24.21	21.99	*-9.2%*
	Q4	**22.03**	**22.46**	***2.0%***
Demand (AIL, TWh)	Oct	6.8	6.7	*-0.6%*
	Nov	6.9	7.2	*5.1%*
	Dec	7.6	7.6	*0.4%*
	Q4	**21.2**	**21.6**	***1.6%***
Gas Price (Avg $/GJ)	Oct	2.96	0.78	*-73.7%*
	Nov	2.62	2.18	*-16.7%*
	Dec	3.22	1.78	*-44.8%*
	Q4	**2.94**	**1.58**	***-46.4%***
Wind (TWh)	Oct	0.3	0.5	*78.2%*
	Nov	0.5	0.5	*4.7%*
	Dec	0.5	0.5	*0.2%*
	Q4	**1.2**	**1.5**	***21.2%***
Net Exports (MWh)	Oct	-36,009	77,753	*-315.9%*
	Nov	17,916	-12,975	*-172.4%*
	Dec	16,595	76,419	*360.5%*
	Q4	**-1,498**	**141,197**	***-9523.8%***
Supply Cushion (Avg MW)	Oct	1,662	1,823	*9.7%*
	Nov	2,682	1,979	*-26.2%*
	Dec	1,968	2,202	*11.9%*
	Q4	**2,095**	**2,002**	***-4.4%***

In Q4/17, 141 GWh of net exports flowed out of Alberta, corresponding to an average hourly export flow of approximately 64 MW. Alberta was a net exporter for October and December, while a smaller net import occurred in November. Prior to the low price environment beginning in 2015, Alberta was consistently a net importer. Since then, Q4/15 saw net exports of 166 GWh, while Q4/16 had more balanced flow with a small net import of 1.5 GWh.

Pool Prices

Figure 1 shows that the current Q4/17 average price is an extension of the ongoing low-price environment facing generators in Alberta. Current market prices offer little in the way of contribution to generator fixed costs or return on capital. See the section below on net revenues for more details.

Figure 1: Average Quarterly Pool Price



Load Growth

Figures 2 and 3 illustrate the steady growth in Alberta load despite the economic slowdown due to the low prices for oil and natural gas. The only blip was in Q2/16 due in part to the Fort McMurray wildfire.

Figure 2: Average Alberta Load

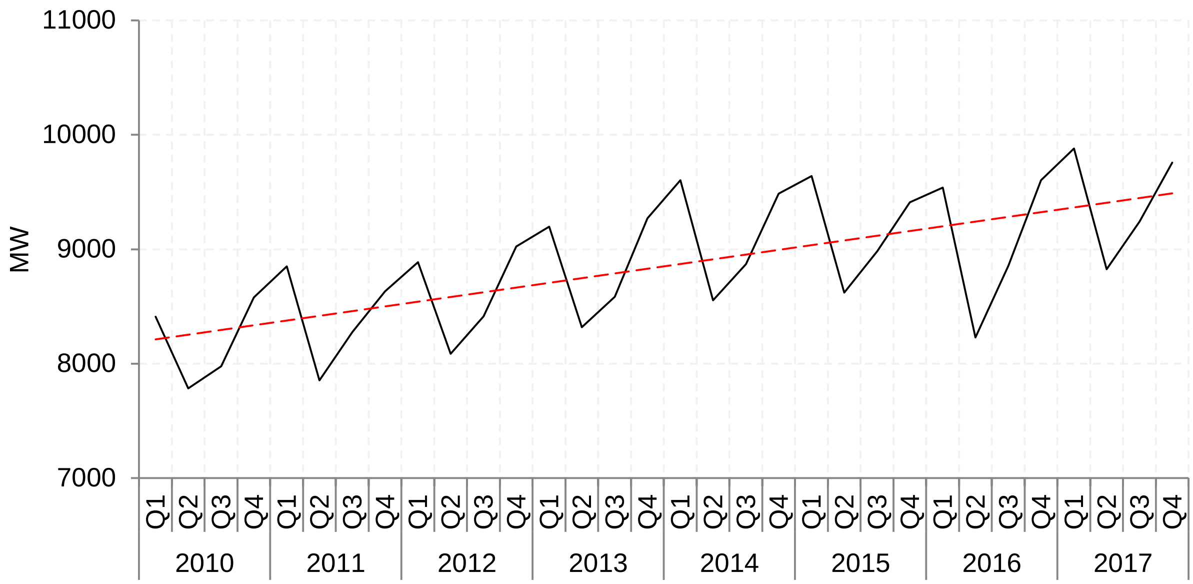
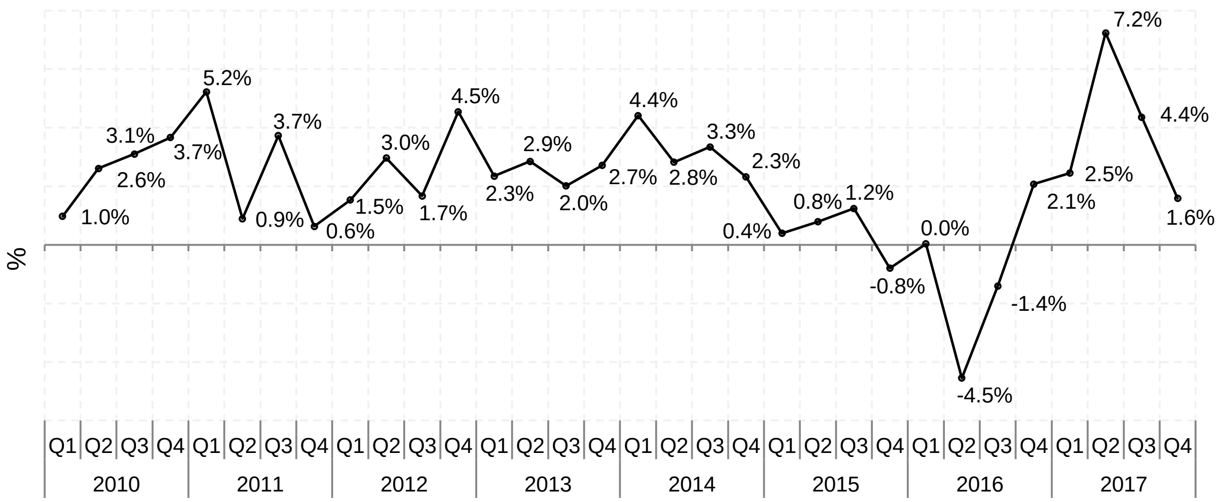


Figure 3: Growth in Total Alberta Load (% Year-over-Year)



High Priced Hours

There were very few high prices in Q4/17 and all corresponded to scarcity of supply.

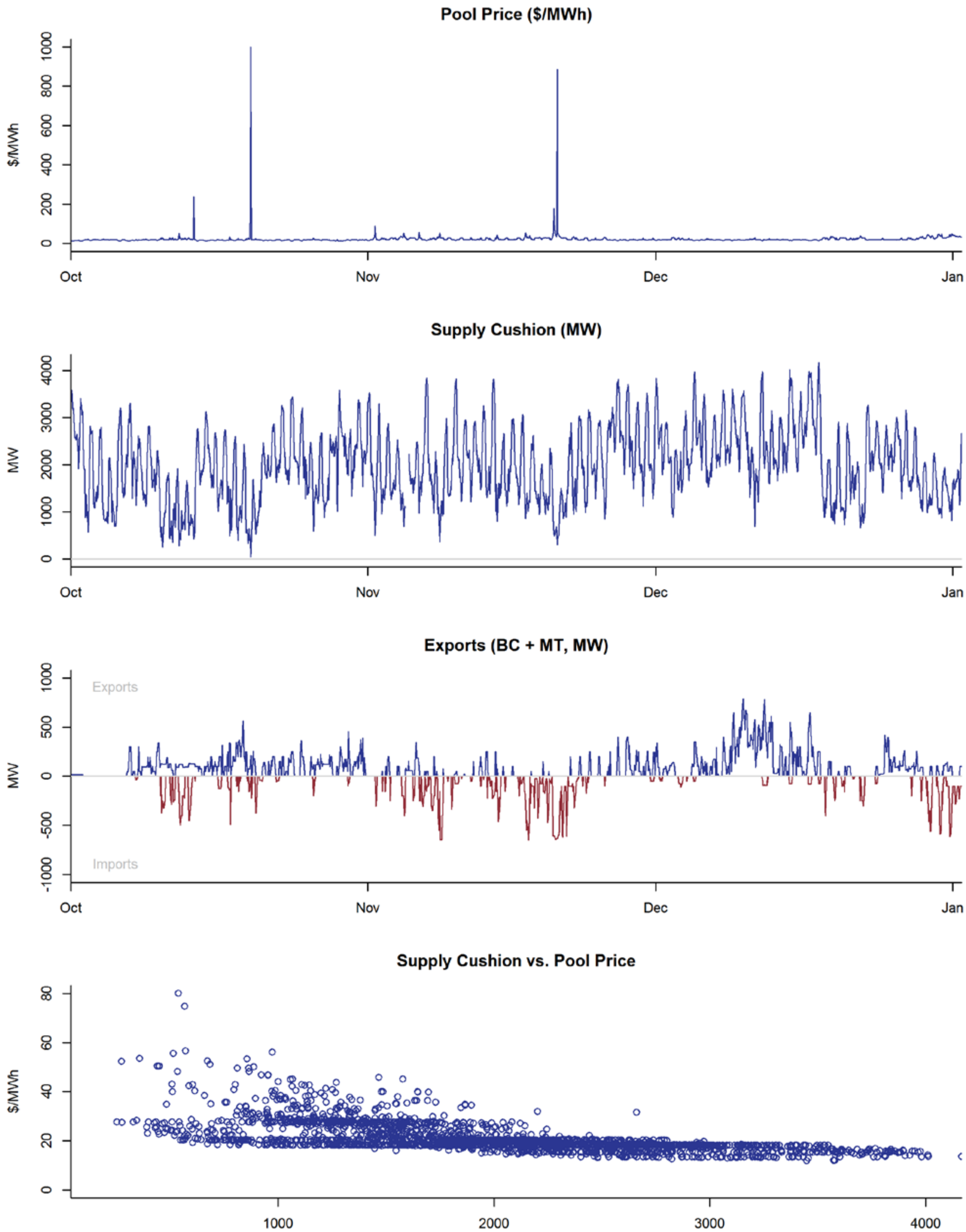
October 19

On October 19 HE 19, pool price settled at $999.00/MWh as a result of the system marginal price (SMP) hitting $999.00/MWh for the whole hour due to low supply cushion. While total system load was moderate (approximately 9,500 MW), new exports out of the province (approximately 210 MW) on the BC/MATL intertie triggered the price spike. These exports were the result of two parties exporting, one to BC and one to Montana. At the time of the event, there were four coal facilities (KH2, KH3, SD3, and SH2) offline and partial derates at several others. Sheerness 2 came back online part way through the hour. Approximately 60 MW of price responsive load turned off shortly after the spike in SMP. Total wind generation averaged 560 MW during the hour.

November 20

On November 20 HE 18, pool price was $886.00/MWh due to a low supply cushion as a result of high loads (approximately 11,000 MW) coupled with six coal facilities (KH2, SD1, SD2, SD5, SD6, and SH1) being offline. During the hour, the province was importing approximately 730 MW on the interties and total wind generation was approximately 480 MW. Approximately 100 MW of price responsive load turned off in reaction to the high SMP.

Figure 4: Q4/17 Summary Graphs



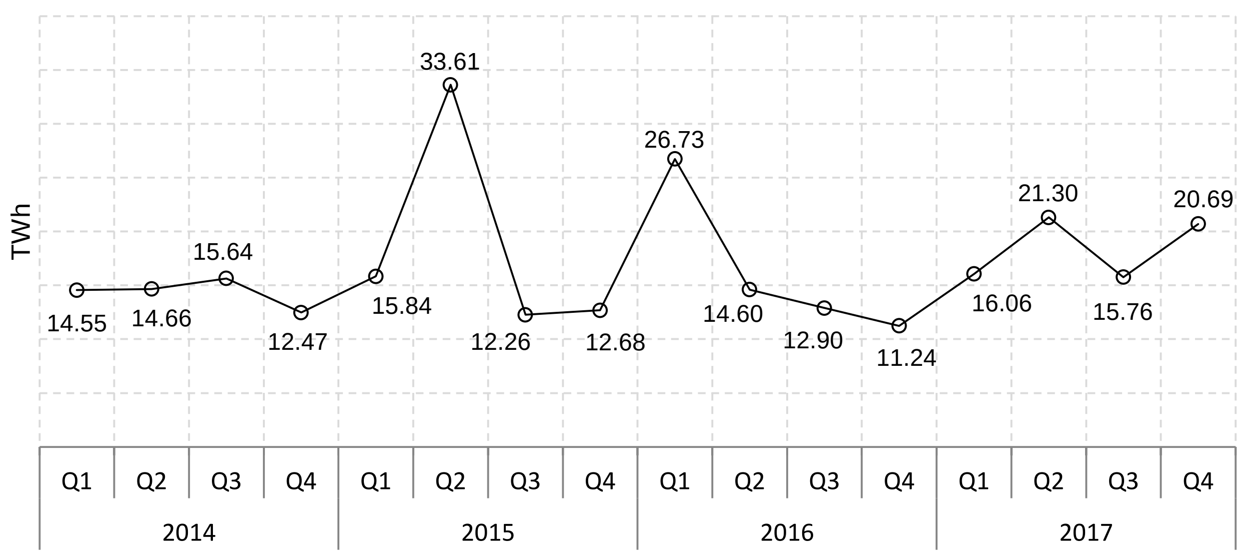
Forward Market

Forward market liquidity in Q4/17 was up 31% compared to Q3 and was 84% higher than liquidity in Q4/16, although liquidity in Q4/16 was lower than average. Monthly, quarterly, and annual trade volumes all increased over the previous quarter, while daily trade volume declined.

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	10.46	1.14	16.71	0.66	29.18
	Q3	0.06	6.25	0.50	4.40	0.29	11.51
	Q4	0.06	5.87	0.98	5.74	0.03	12.68
	Year	0.42	32.54	3.46	31.03	1.74	69.20
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

Figure 5: Total Trade Volumes over Time



Total Traded Volume (MWh)

Contract Term	**Q4 2016**	**Q4 2017**	***Change***
Daily	93,270	59,680	*-36.0%*
Monthly	5,435,899	8,243,376	*51.6%*
Quarterly	1,460,845	3,509,110	*140.2%*
Annual	3,776,760	7,495,440	*98.5%*
Other	474,992	1,382,900	*191.1%*
Total	**11,241,766**	**20,690,506**	*84.1%*

Forward Market Event

On December 6, 2017 a market participant announced its plans to mothball three Sundance units following the schedule below:

- Sundance Unit 3 will be mothballed on April 1, 2018 for a period of up to two years;
- Sundance Unit 5 will be mothballed on April 1, 2018 for a period of up to one year; and
- Sundance Unit 4 will be mothballed on April 1, 2019 for a period of up to two years.

With Sundance Unit 1 retired and Unit 2 already mothballed as of the start of 2018, this represents 1,334 MW exiting the market as of April, 2018 relative to December 31, 2017.

The Dec. 6, 2017 mothball announcement had a noticeable impact on forward prices, with April 2018 flat contracts trading up to $7.25/MWh higher the next trading day, while March 2018 contracts remained relatively unchanged. Figure 6 and 7 illustrate the price effect of the announcement.

This use of ISO rule 306.7 by a market participant with market power is concerning to the MSA. The MSA is continuing its assessment work on the market impacts of ISO rule 306.7 and has asked the AESO to explain to the MSA whether or not it analyzed the market impacts of the rule. If the MSA concludes that the rule may have an adverse effect on the structure and performance of the market, does not support FEOC operation of the market, or is not in the public interest by, inter alia, enabling a market participant to restrict or prevent competition, or enabling the manipulation of market prices away from a competitive market outcome, the MSA may then make a written complaint about the rule to the AUC under s. 25(1.1) of the *Electric Utilities Act*

Figure 6: Annual Contract Forward Prices

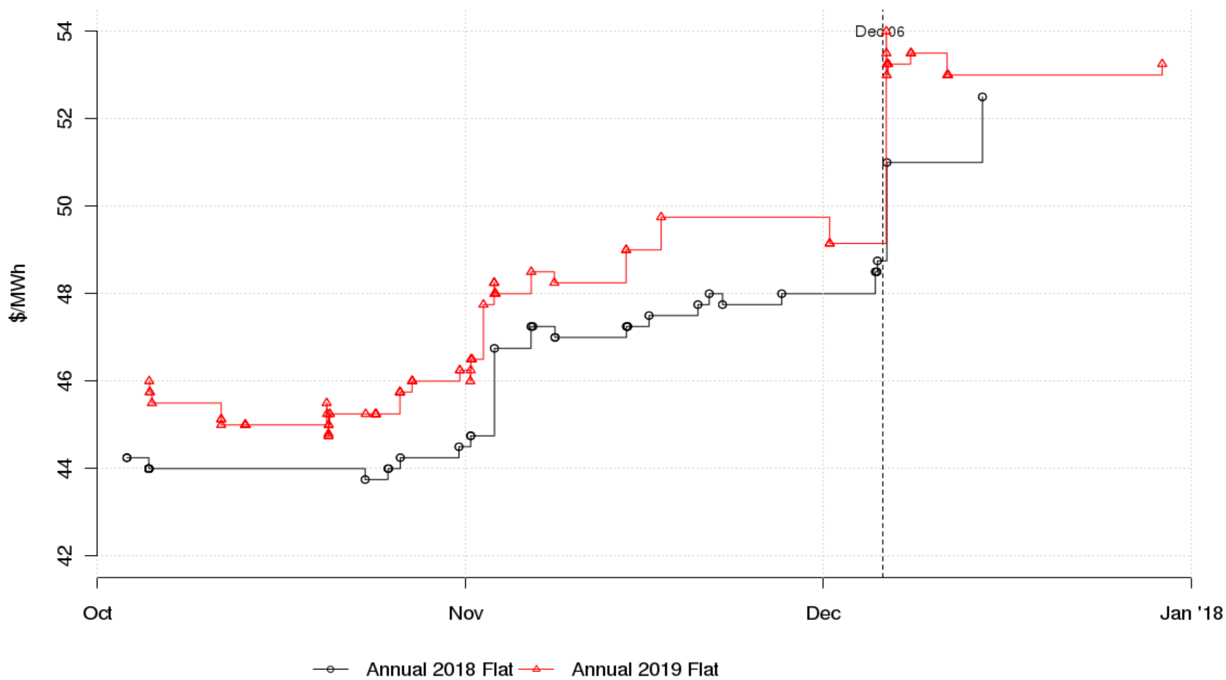
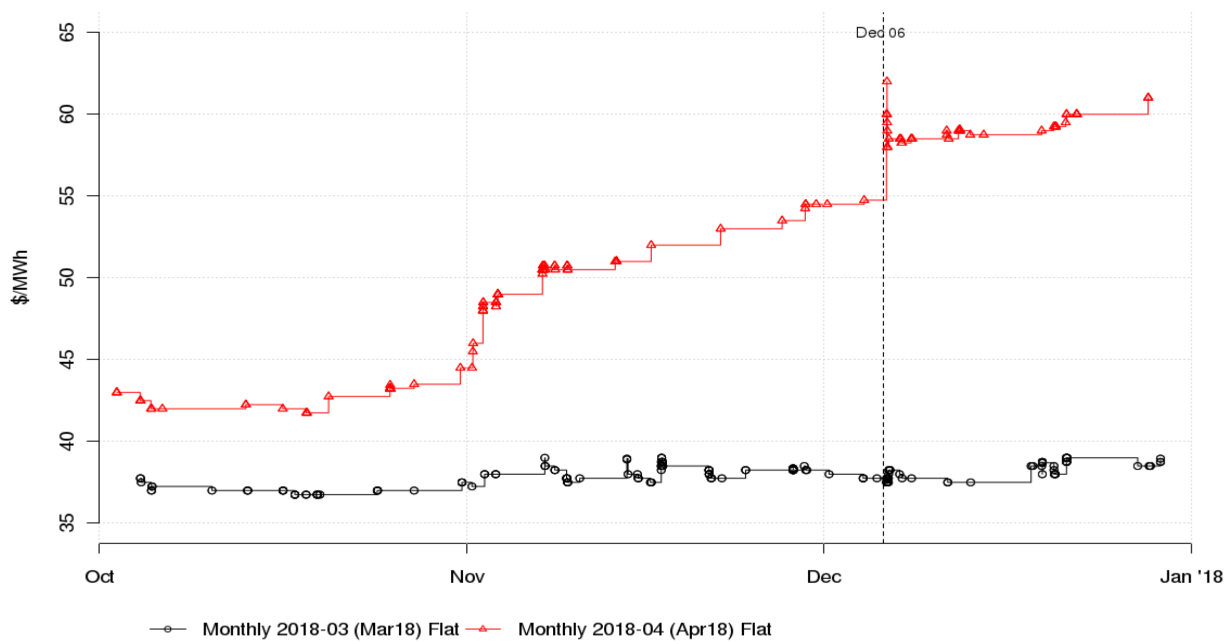


Figure 7: Monthly Contract Forward Prices



Operating Reserves

Quarterly Summary

The total cost of active reserves this quarter increased slightly year-over-year. The cost of contingency reserves increased $2.5 million whilst the cost of regulating reserves decreased $1.9 million. The total volume of active contingency reserves procured increased slightly.

The total cost of standby procured decreased slightly year-over-year.

Table 3: Operating Reserves

Total Cost ($ Millions)			
	Q4 2016	**Q4 2017**	***% Change***
Active Procured	**16.5**	**17.0**	***3.3***
RR	9.5	7.6	*-20.6*
SR	4.4	6.5	*47.1*
SUP	2.6	3.0	*16.3*
Standby Premiums	**2.0**	**1.8**	***-8.5***
RR	1.2	0.9	*-28.3*
SR	0.6	0.8	*29.9*
SUP	0.2	0.2	*-4.8*
Standby Activations	**0.5**	**0.5**	***1.7***
RR	0.1	0.0	*-50.1*
SR	0.3	0.4	*11.3*
SUP	0.1	0.1	*13.0*
Total	**19.0**	**19.4**	***2.0***
Total Volume (GWh)			
	Q4 2016	**Q4 2017**	***% Change***
Active Procured	**1,372**	**1,394**	***1.6***
RR	363	363	*0.0*
SR	504	515	*2.1*
SUP	505	515	*2.1*
Standby Premiums	**486**	**485**	***-0.2***
RR	176	176	*-0.1*
SR	231	231	*0.0*
SUP	79	78	*-0.9*
Standby Activations	**20**	**20**	***-0.3***
RR	1.0	1.4	*39.5*
SR	12.9	12.5	*-3.5*
SUP	5.8	5.7	*-0.3*
Total	**1,878**	**1,899**	***1.1***
Average Cost ($/MWh)			
	Q4 2016	**Q4 2017**	***% Change***
Active Procured	**12.02**	**12.23**	***1.7***
RR	26.17	20.78	*-20.6*
SR	8.79	12.66	*44.0*
SUP	5.06	5.77	*13.9*
Standby Premiums	**4.13**	**3.79**	***-8.3***
RR	6.96	5.00	*-28.2*
SR	2.67	3.47	*29.9*
SUP	2.10	2.02	*-4.0*
Standby Activations	**26.48**	**27.02**	***2.1***
RR	81.99	29.30	*-64.3*
SR	24.93	28.78	*15.4*
SUP	19.99	22.64	*13.3*
Total	**10.13**	**10.23**	***0.9***

Annual Summary

The total cost of operating reserves in 2017 increased 21.4% year-over-year from $66.7 million to $81.0 million. This is primarily due to an increase in the yearly average pool price and the fact that most reserves are indexed to pool price.

The total cost of active reserves increased 27.6% year-over-year primarily due to increases in the cost of contingency reserves which are indexed to pool price. This was also partly due to slight increases in the volume of contingency reserves procured in 2017.

The cost of procuring standby reserves decreased 37.1% year-over-year driven by the reduced cost of standby regulating reserve. The cost of standby contingency reserves increase due to increases in the volume of standby contingency reserves procured. The costs associated with activating standby reserves increased 210.7% year-over-year due to an increase in the activation of standby contingency reserves. In quarterly reports over the course of 2017, it has been noted that in some cases of the standby contingency reserves activated has been to enable higher import flows over the BC and Montana interties.

Table 4: Annual operating reserves summary

	Total Cost ($ Millions)			Total Volume (GWh)		
	2016	**2017**	***% Change***	**2016**	**2017**	***% Change***
Active Procured	**52.6**	**67.2**	***27.6***	**5,262.0**	**5,449.2**	***3.6***
RR	29.4	26.9	*-8.5*	1,405.6	1,405.3	*0.0*
SR	16.1	28.6	*77.8*	1,927.8	2,022.0	*4.9*
SUP	7.2	11.7	*62.6*	1,928.6	2,022.0	*4.8*
Standby Procured	**12.1**	**7.6**	***-37.1***	**2,048.6**	**2,058.2**	***0.5***
RR	7.8	3.1	*-60.4*	823.1	697.8	*-15.2*
SR	3.5	3.6	*2.6*	918.3	985.2	*7.3*
SUP	0.8	0.9	*19.3*	307.2	375.1	*22.1*
Standby Activated	**2.0**	**6.3**	***210.7***	**85.1**	**236.0**	***177.2***
RR	0.3	0.2	*-31.1*	7.9	5.9	*-24.7*
SR	1.3	4.2	*224.1*	54.1	141.4	*161.4*
SUP	0.4	1.8	*335.5*	23.2	88.7	*282.8*
Total	**66.7**	**81.0**	***21.4***	**7,395.8**	**7,743.4**	***4.7***

Participation Rates in the Operating Reserves Markets

As reported in the MSA's Q4/16 report, the quantity of offers in the active reserves market declined from 2013 to 2016.

In 2017, the ratio between the quantity of offers and the quantity of reserves required for all active operating reserves products did not materially change compared to the ratio calculated for 2016.

In the standby markets, the ratio of offer quantities over AESO procurement volumes has been decreasing from 2013 to 2016. With the exception of the on-peak supplemental reserves market, there was a slight increase in the offer-to-bid ratio for standby operating reserves in 2017.

Figure 8: Active Reserves Offer/Bid Ratio

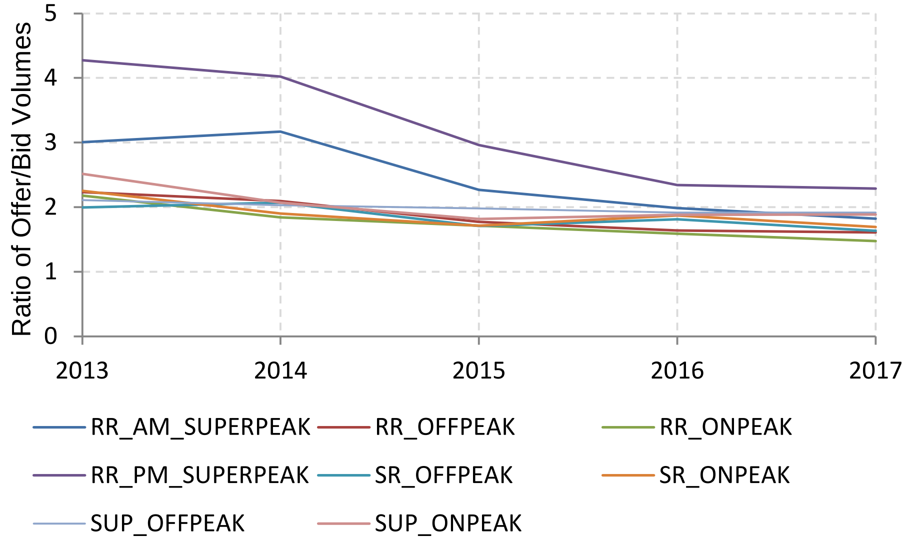
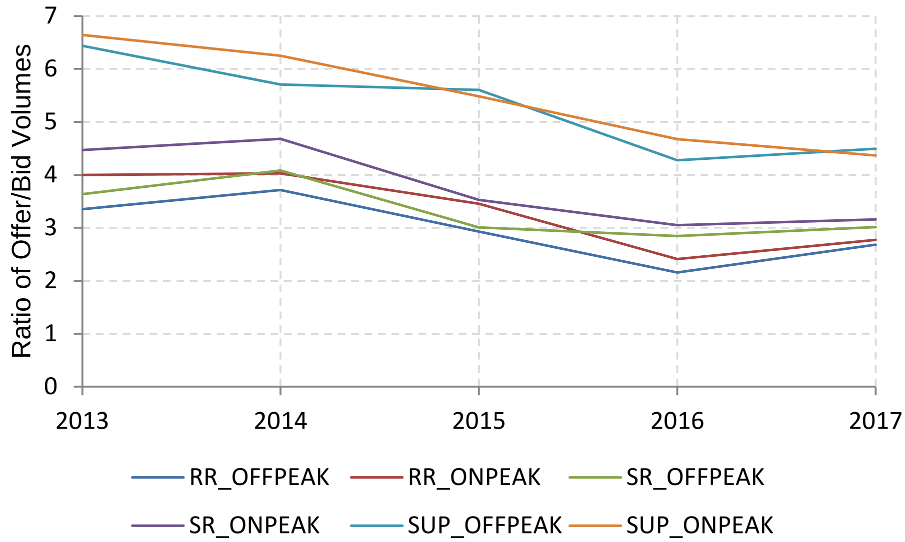


Figure 9: Standby Reserves Offer/Bid Ratio



In the MSA's Q4/16 report, the decline in operating reserves offer quantities was attributed in part to a decrease in the participation of the PPA units in the operating reserves markets. This decline in participation is illustrated below. Between 2015 and 2016, there was a sharp decrease in quantity of operating reserve offers from the PPA units. The ratio of operating reserve offers-to-bids from the PPA units continued to decrease in 2017 in both the active and standby operating reserve markets. It appears other participants increased their offer quantities in the operating reserves markets in 2017 given there was an increase in the offer-to-bid ratio in the operating reserves markets overall in 2017 and a decrease in the offer-to-bid ratio for PPA units.

Figure 10: PPA Units Active Reserves Offer/Bid Ratio

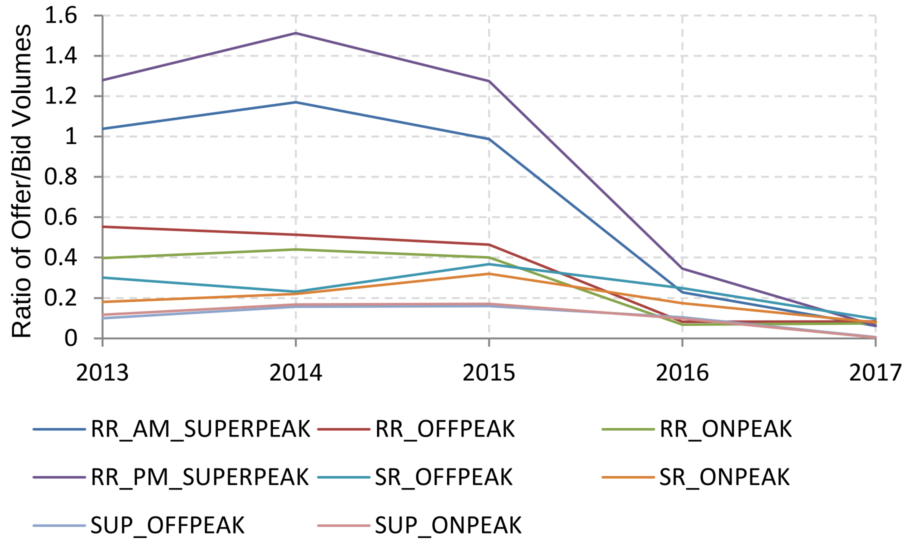
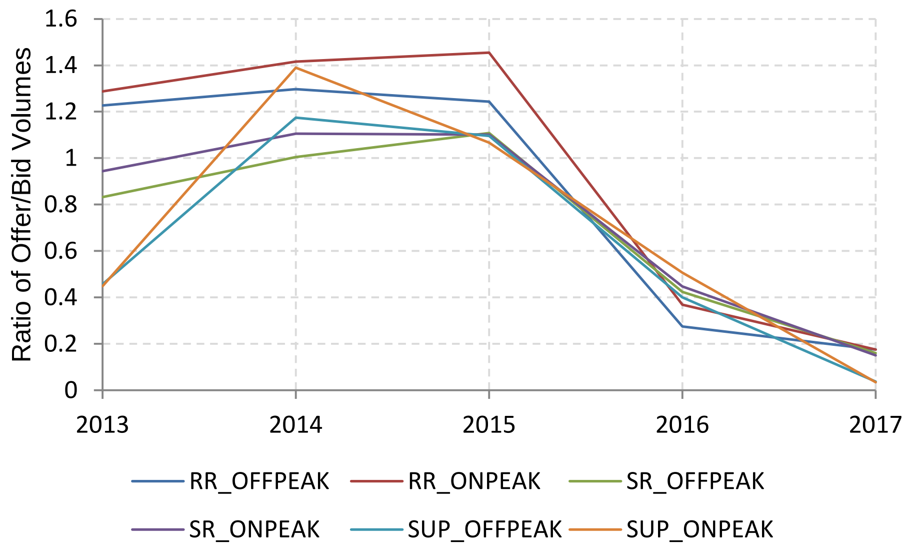


Figure 11: PPA Units Standby Reserves Offer/Bid Ratio



Net Revenue Analysis

Net revenue analysis of a hypothetical new entrant to the market provides useful context to assess pool prices. To the extent that net revenues to a new entrant are high should be a signal for new entry to the market. When net revenues are low one would not expect new entry to occur.

The MSA has previously conducted net revenue analyses to compare the estimated returns to a hypothetical generator from participating in the energy and operating reserves markets. Comparing net revenues is a rough test of market efficiency. If the markets are efficient then the returns from participating in the energy market or the operating reserves market should be equal.

For this analysis, the MSA is estimating the net revenue of a simple-cycle natural gas generator. The assumed characteristics of the simple-cycle gas turbine used in this analysis are listed below:

Assumptions		
Heat rate	9.8	GJ/MWh
Availability factor	94	%
Proportion of time active RR are directed	50	%
Variable O&M	6.00	$/MWh
Fixed O&M	18.00	$/kW-yr

The MSA also assumed that the generator will behave in the following manner:

1. The generator acts as a price-taker in the energy market and only produces when the pool price is higher than its variable costs.
2. The generator is also a price-taker in the various operating reserves markets.
3. While dispatched for regulating reserve, the unit will generate 50% of the regulating range and receive pool price minus variable cost for the associated energy.
4. When providing super-peak regulating reserve, the generator provides energy in the hours that are not super-peak hours when pool price is above the unit's variable cost.

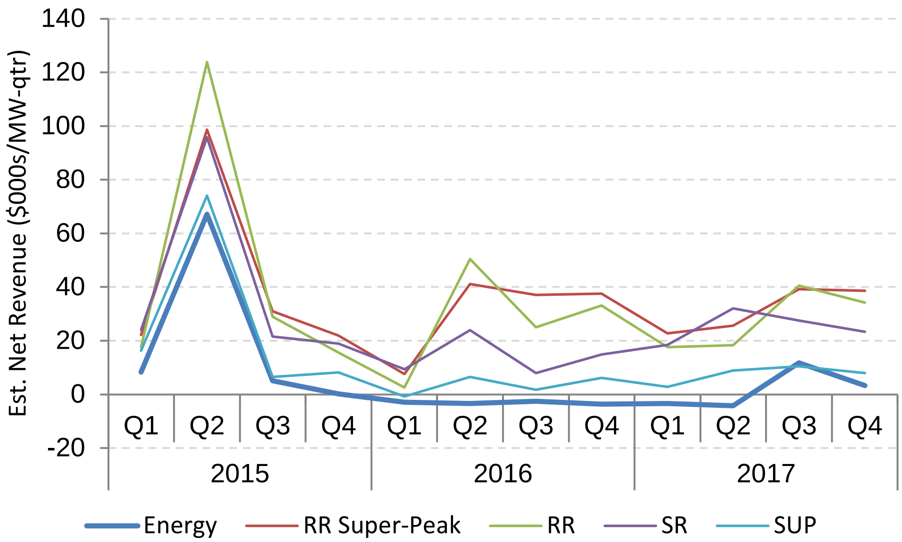
The net revenue calculation is calculated as the sum of the hourly net revenues less the fixed operations and maintenance costs. Thus, the estimated net revenue can be negative if the revenue accrued from a particular market is less than the fixed operations and maintenance cost of the generator.

The figure below shows the net revenues for the past 3 years. It is clear that energy market revenues have been very low since Q2/15. Note that this is despite the fact that natural gas prices in Alberta have been low for this period providing a cost advantage to gas generators over coal generators. The cost advantage should translate to enhanced net revenues for gas-fuelled generators.

The results of the net revenue analysis suggests that a hypothetical simple-cycle generator can realize higher revenues from participating in the regulating and spinning reserves markets compared to the energy or supplemental reserve markets in both 2016 and 2017. There was a sharp increase in net revenue for all markets in Q2/15 but net revenues in all markets were less than $60,000/MW in all other quarters from 2015 to 2017. On a persistent basis, returns appear higher in the operating reserves markets than what can be obtained from participating in the energy market (power pool).

The net revenue analysis assumes the costs of carbon emissions are part of the variable operations and maintenance cost. The introduction of the *Carbon Competitiveness Incentive Regulation* (CCIR) on January 1, 2018 changes the operational assumptions and expected net revenue of a hypothetical simple-cycle generator going forward.

Figure 12: Net Revenue Analysis



Carbon Competitiveness Incentive Regulation

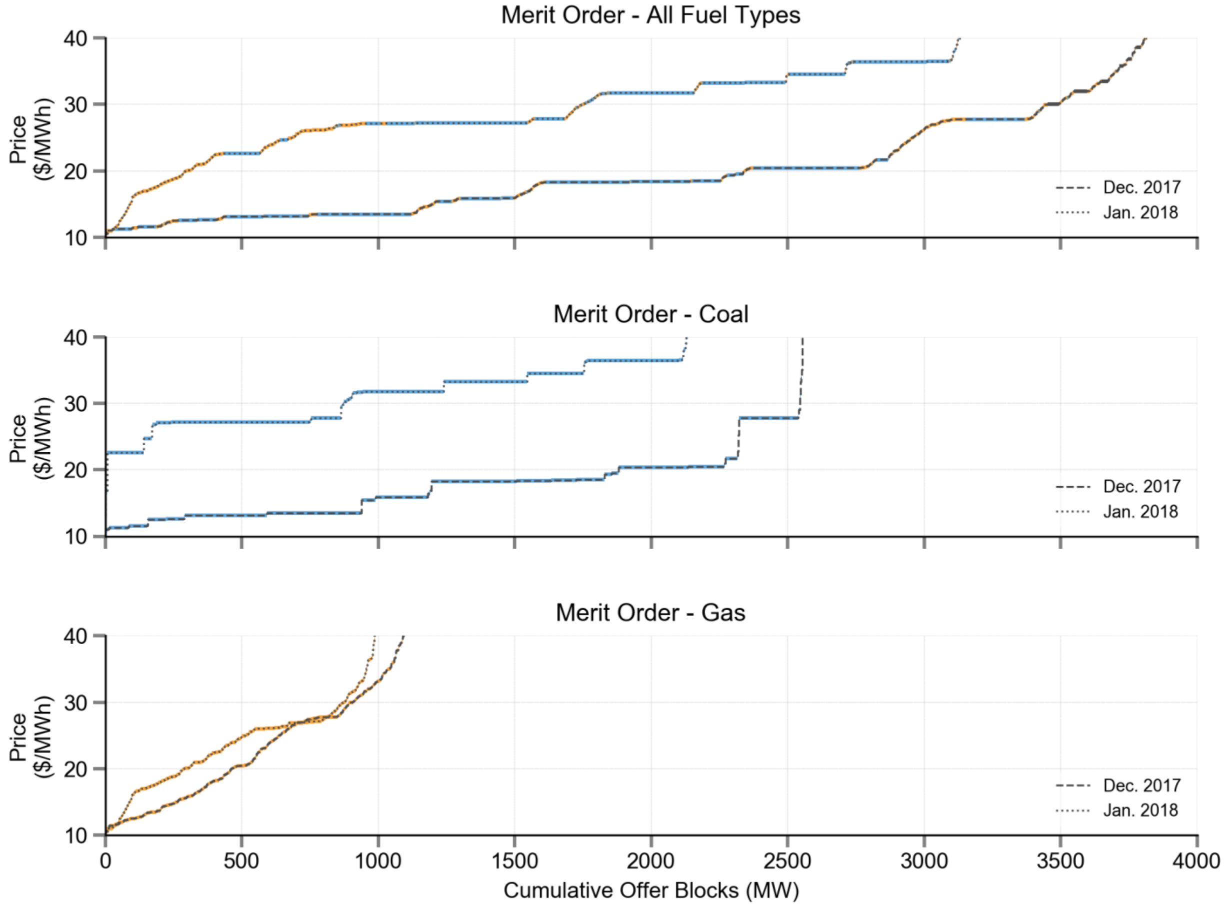
On January 1, 2018, Alberta transitioned from the *Specified Gas Emitters Regulation* (SGER) to the *Carbon Competitiveness Incentive Regulation* (CCIR). The change affected the marginal cost of electricity generation facilities that are subject to regulation, which in turn affects offers made to Alberta's electricity market. The MSA has sought to understand the power pool price impact of the CCIR.

Prior to January 1, 2018, the SGER required large emitters to make payments of $30/tCO2e for any emissions above a facility-specific emissions intensity target, which was set at up to 20% below the established baseline for the respective facility. The SGER, which first came into effect in 2007, applied to all facilities with annual emissions of 100,000 tCO2e or more.

Like the SGER, the CCIR applies to the same large emitters although it imposes a more stringent emissions target for many of Alberta's largest facilities. Under the CCIR, all facilities are now assessed by the "good as best gas" standard. For 2018, the emission intensity target has been set at 0.37 tCO2e/MWh. In addition to a lower emission intensity target, Alberta's technology fund price increased to $30/tCO2e.

To examine the potential effect of the change in carbon costs, Figure 13 shows the cumulative generation offered between $10/MWh and $40/MWh for December 2017 (SGER in place) to January 2018 (CCIR in place). Offers within this price region are likely to be more reflective of a generator's marginal cost.

Figure 13: Weighted Average Merit Order by Fuel Type



The figure illustrates the upward shift in the merit order curve between December 2017 and January 2018. The segments of each line highlighted in blue represent coal facility offers while those highlighted in orange represent gas facility offers. Notice how the low price of natural gas in Alberta combined with the greater impact of the carbon levy on coal plants relative to gas plants has affected the merit order. On a variable cost basis, in part due to CCIR many gas-fired plants are now cheaper to run than the coal plants. This is the first time in Alberta that this has occurred.

Depending on the age of a facility and its technology type, the emission intensity of a coal facility often ranges between 0.90 to 1.10 tCO2e/MWh while for gas it ranges from 0.35 to 0.55 tCO2e/MWh. As a result of higher emission intensity, coal facilities bear a higher cost per megawatt hour of output. This is observed in the higher merit order spread for coal facilities compared to gas facilities for the period between December 2017 and January 2018.

CCIR would not necessarily increase the price of electricity in every hour of the year. The extent to which the price consumers pay is impacted depends on the frequency with which the market is clearing at a cost-based offer that was increased by the change in regulation.

Impact of Wind Generation on Alberta's Energy Market

Over the past decade the Alberta power system has seen a substantial growth in the installed capacity of wind generators. In early 2018 total wind capacity is 1,445 MW and the AESO's recent REP auction will ensure that more will be built in the near future.

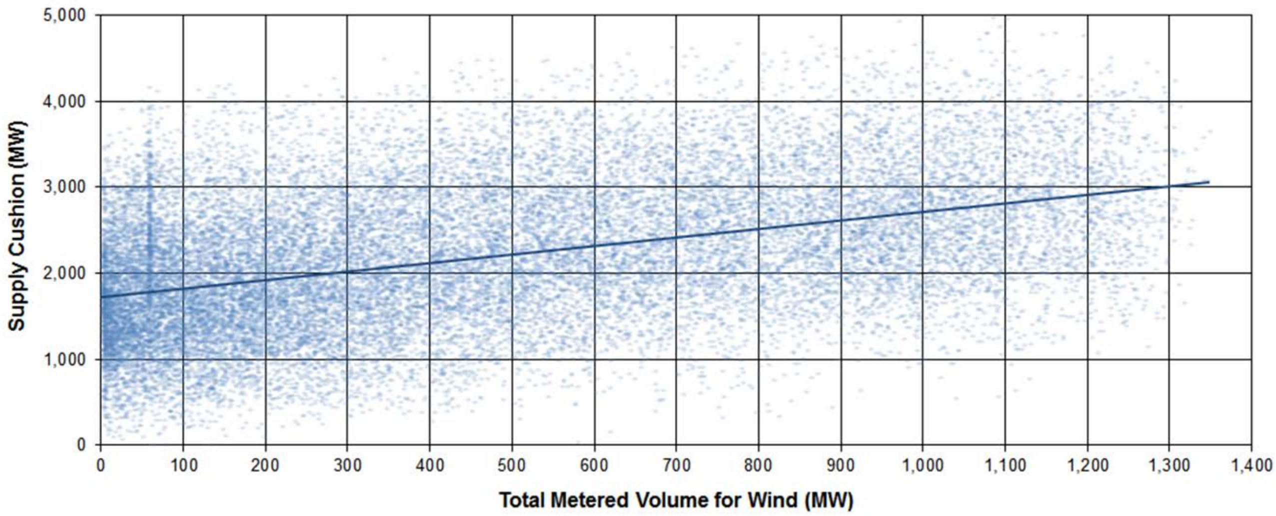
Wind Generation and Pool Price

On April 1, 2015, the AESO's dispatchable wind rule changes came into effect. These rule changes required that wind assets offer energy into the Energy Merit Order (EMO) like other generation assets in the province. Previously wind assets did not offer into the EMO, but rather received the prevailing pool price for energy produced. Wind assets are now dispatchable and may offer energy at various price and quantity pairs.

While wind assets now have the ability to choose their offer strategy, almost all wind assets offer their maximum capability at $0/MWh which is consistent with price-taking behavior. Thus, wind generation has the effect of lowering pool price within the energy market, all else equal.

As a result of being offered at or near $0/MWh, wind generation displaces the generation of other fuel types in the merit order with higher offer prices. Since wind generation is intermittent, it is not included in the supply cushion calculation. Therefore, an increase in wind generation directly translates into a higher supply cushion as dispatchable units at the margin in the merit order are dispatched down in response. This is illustrated in Figure 14 which shows the relationship between the metered volumes for all wind generation compared to the supply cushion for each hour between April 1, 2015 and December 31, 2017. The average relationship is nearly one-to-one, which implies that for every additional megawatt of wind generation, there is a corresponding increase in supply cushion.

Figure 14: Supply Cushion vs Metered Volume for Wind (2015 - 2017)



Metered Volume (MW)	0-99	100-199	200-299	300-399	400-499	500-599	600-699	700-799	800-899	900-999	1000-1099	1100-1199	1200-1299	1300-1399
Pool Price ($/MWh)	$35.71	$28.61	$27.46	$21.74	$19.81	$19.47	$18.12	$17.44	$16.87	$16.76	$16.42	$15.75	$16.27	$16.62

Furthermore, since wind assets offer energy at or near $0/MWh, pool price will generally be low when wind assets are generating. Overall, it has been observed that a small increase in wind generation can have a substantial downward impact on the hourly pool price.

Over a three year period (2015-2017)[1], pool price averaged $35.71/MWh when total hourly wind generation in Alberta was less than 100 MW. For all hourly wind generation exceeding 400 MW, pool price averaged less than $20/MWh. Therefore, on average, the addition of 400 MW of wind generation had the effect of depressing hourly pool price by approximately $16/MWh over the past three years. This is partially due to the shape of the merit order in which price escalates quickly in the latter portion of the offer blocks.

Correlations among Wind Generators

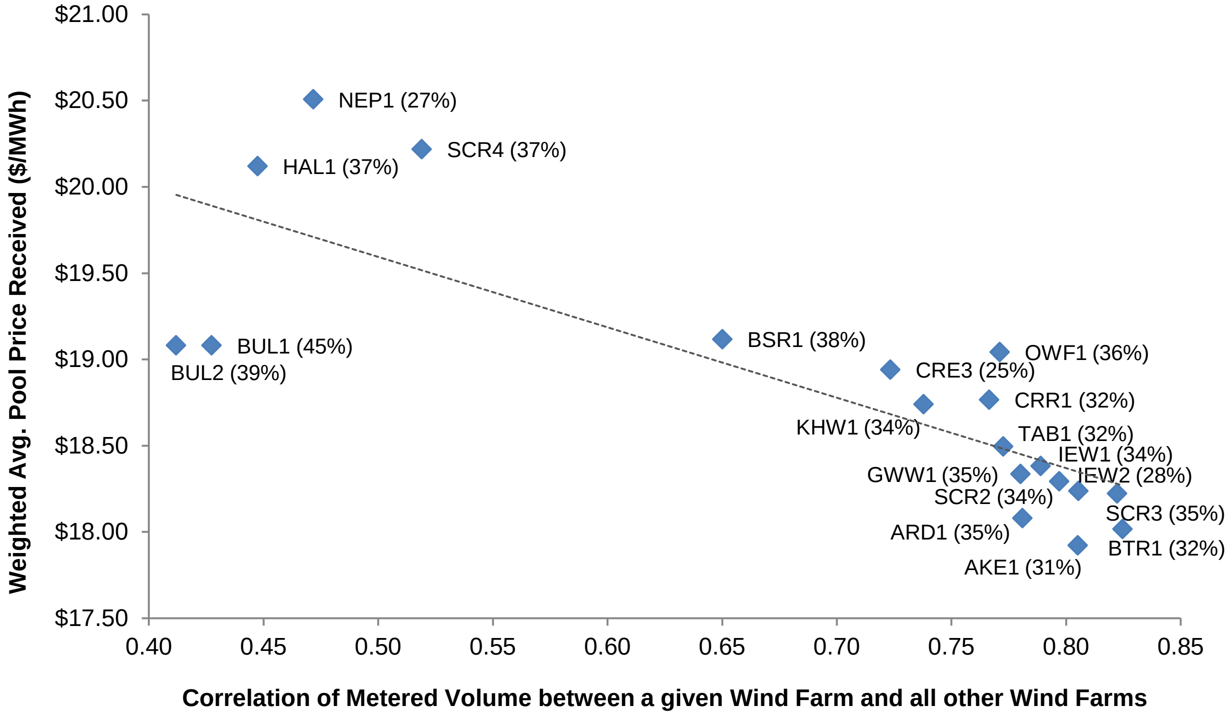
In Alberta, the majority of wind farms are concentrated in the southern region of the province where sustained winds are most prevalent. Due to this high concentration, the hourly wind generation of wind farms located in close proximity to one another tend to be highly correlated. When wind blows in the southern portion of the province, Alberta's total wind generation tends to be high and vice-versa.

As previously discussed, since wind offers at or near $0/MWh wind generation tends to reduce pool price. Overall, the higher the total wind generation, the lower the pool price. Therefore, the pool price received by a wind farm is dependent upon the correlation of its wind generation with all other wind generation in the province.

[1] April 1, 2015 to December 31, 2017

Figure 15 illustrates that less correlated wind farms generally receive a higher pool price. The capacity factor of each wind farm is provided in brackets within the figure. There does not appear to be a relationship between the capacity factor of a wind farm and its correlation of production with the total of all other wind farms.

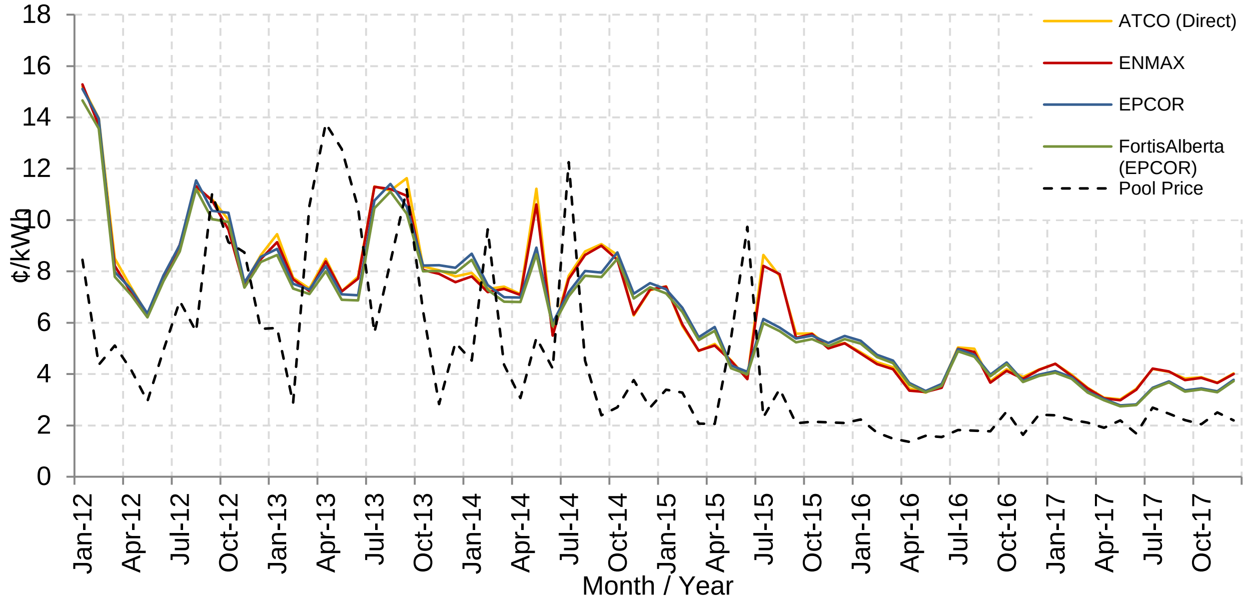
Figure 15: Average Pool Price Received by Wind Facility (2015 – 2017)



Retail Market

Regulated Rate Option (RRO) Rates were relatively stable over Q4 with a slight uptick in December. Rates in the ATCO (Direct) and ENMAX areas remained slightly higher than those in the EPCOR and FortisAlberta areas. Over the past two years, pool prices in the wholesale market have been low. Over this period, RRO prices have gradually decreased and are now more consistent with the prices in the underlying wholesale electricity market.

Figure 16: Residential RRO Rates and Monthly Average Pool Price



Price Cap Regulation

Forward market prices suggest that the RRO reference rate for April will exceed 6.8 cents/kWh, resulting in payments to RRO providers that also have an RRO rate over 6.8 cents/kWh. The forward curve also suggests that the reference rate may exceed 6.8 cents/kWh in Summer 2018.

Forward prices for the flat 7 X 24 monthly contract as of early February are:

Mar. ’18 - $38.50

Apr. ’18 - $70.75

May ’18 - $48.25

Jun ’18 - $55.25

Jul. ’18 - $69.00

Aug. ’18 - $72.25

Sep. ’18 - $66.00

The price cap regulation does not apply to customers on competitive retail contracts. In the event that RRO prices exceed the reference rate by a significant amount customers may switch from competitive retailers to the RRO, especially those customers on pool price flow through type contracts. This would negatively impact the development of the competitive retail market as well as increase the total amount of subsidy the government would be required to spend on RRO customers.

In December 2017 the MSA conducted a test of the deferral account statement approval process for the Regulated Rate Option rate cap. The MSA asked all distribution system owners subject to the *Rate Cap (Board or Council Approved Regulated Rate Tariffs) Regulation* to submit a test deferral account statement to the MSA. The MSA thanks all parties for participating and believes this test was valuable in helping all parties become familiar with the submission process and to identify any improvements that could be made.

There were a number of errors and issues identified with submitted deferral account statements (DAS) that we identify here so they can hopefully be avoided moving forward:

1) DAS must be received by the MSA by the fifth business day of the month. If they are not received on time they will not be processed for that month.
2) DAS must be submitted by email to deferralsubmission@albertamsa.ca.
3) DAS must be submitted in the Excel file format provided in the template. The MSA will not accept PDF or any other format.
4) The submitted Excel file should have the filename in the following format: "Name of Owner – Date submitted – Deferral Account Statement"
5) Consumption values are in kWh and monetary values are in dollars. Consumption of 250 MWh must be entered as 250,000 kWh and a rate of 7.56 cents / kWh must be entered as $0.0756.
6) Do not sign the DAS; the signature field is for the MSA.
7) Please submit the historical consumption values, as required by 1(a) of the process.

Compliance

A compliance review is not included in this Quarterly Report as an annual compliance report will be published shortly.

Capacity Market Design

The MSA is of the view that the capacity market design must be developed in light of the entire electricity market in Alberta. Any framework or proposed market design should model the costs and address the fair, efficient and openly competitive impacts to the entire market including transmission, generation, distribution, the wholesale market and retail electricity services. The MSA provided detailed comments and concerns about the AESO's CMD Version 1.0 to the AESO in early February 2018.