Q3/2016 Quarterly Report

July – September 2016

October 31, 2016

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 Q3 2016 averaged $17.94/MWh ($14.78/MWh ext. off peak, $19.52/MWh ext. on peak), 31% lower than the same period last year.

Market conditions remain similar to the first half of 2016, with a relatively low natural gas price, the absence of economic withholding, and weakened demand compared to 2015. Supply cushion remains relatively high, despite the increase in exports this quarter.

Given these conditions, the average price in Q3 was the second lowest priced quarter since 2001, just $2.94/MWh higher than last quarter, which was the lowest.

As shown in Figure 1, electricity consumption for Q3 declined from Q3 last year; since 2001, Q3 demand has fallen year over year only in 2007, 2009 and 2016.

The MSA's Q2/2016 Quarterly Report cited a reduction in cogeneration volumes related to the Fort McMurray wildfire. Figure 2 provides an update to that graph showing that starting in mid-June cogeneration volumes have, in most part, recovered.

Table 1: Summary

	Month	2015	2016	*Change*
Avg Pool Price ($/MWh)	Jul	23.15	18.21	*-21%*
	Aug	34.11	17.90	*-48%*
	Sep	20.85	17.70	*-15%*
	Q3	**26.09**	**17.94**	***-31%***
Avg Gas Price (AECO-C, $/GJ)	Jul	2.71	2.27	*-16%*
	Aug	2.80	1.85	*-34%*
	Sep	2.75	2.52	*-8%*
	Q3	**2.75**	**2.21**	***-20%***
Avg Demand (AIL, MW)	Jul	9,163	8,844	*-3%*
	Aug	9,100	8,975	*-1%*
	Sept	8,670	8,741	*+1%*
	Q3	**8,981**	**8,855**	***-1%***
Avg Supply Cushion (MW)	July	2,296	2,220	*-3%*
	August	2,107	2,185	*+4%*
	Sept	2,284	2,193	*-4%*
	Q3	**2,229**	**2,200**	***-1%***
Avg Wind (MW)	Jul	319	307	*-4%*
	Aug	342	312	*-9%*
	Sept	458	505	*+10%*
	Q3	**372**	**373**	***+0%***
Avg BC/MATL combined import ATC (MW)	Jul	825	565	*-31%*
	Aug	824	356	*-57%*
	Sep	810	445	*-45%*
	Q3	**820**	**456**	***-44%***
Total Net Imports (MWh, negative = exports)	July	3,906	-103,576	*-2752%*
	Aug	22,408	-230,260	*-1128%*
	Sep	-124,595	-204,431	*+64%*
	Q3	**-98,281**	**-538,268**	***+448%***

As seen in Table 1, reported BC/MATL combined import available transfer capability (ATC) values were considerably lower in Q3 2016 than 2015; however, much of it may be due to a change in how the AESO updates this information rather than physical capability of the lines. In December 2015 the AESO changed[1] their reporting process to incorporate "insufficient contingency reserve" reductions day ahead. Prior to this, the reduced ATC would only be reported if there were sufficient offers on the intertie to necessitate it. If there were fewer offers to import than the operating reserves limit, the default value (e.g., 820 MW) may have been reported.

[1] Alberta Electric System Operator, "Update to the Forward Looking Intertie Capability Report posting process", May 5, 2016.

Figure 1: Average Q3 Pool Price and Alberta Internal Load (AIL)

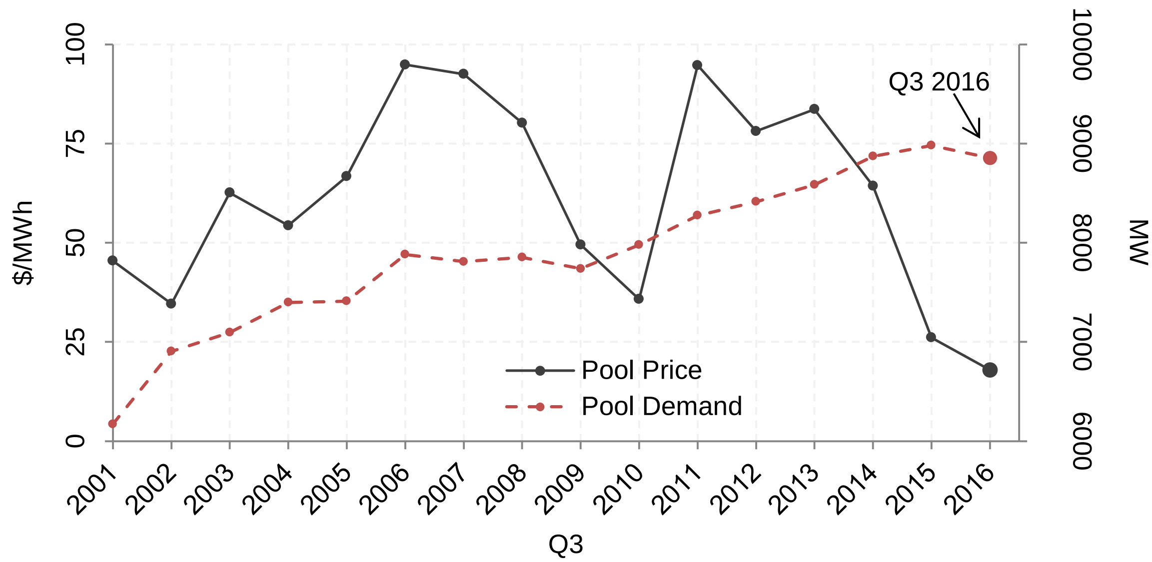
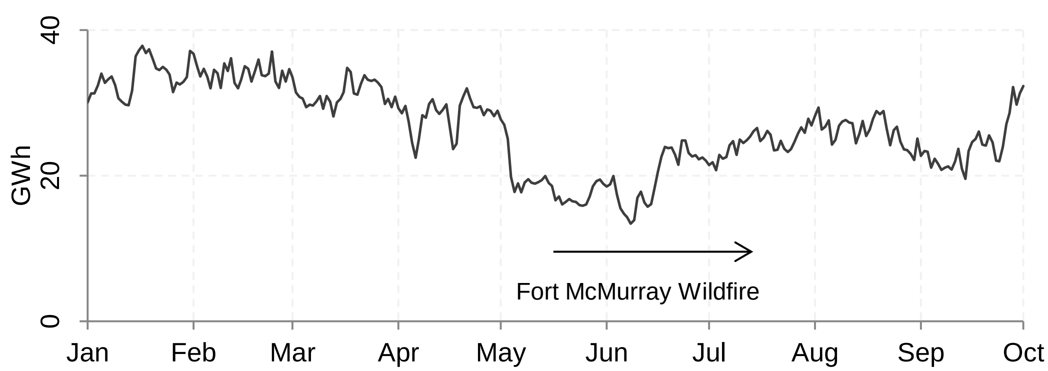


Figure 2: 2016 Daily Total Metered Volumes at Cogeneration Assets



High Price Hours during Q3 2016

July 26

On July 26 in HE 18, the pool price settled at $323.51/MWh, which was the first time wholesale prices had exceeded $100/MWh since January 2016. This high price event was brought on by a unit trip from Sundance 4 (SD4). The unit remained on outage until HE 22. Just prior to the start of the trip, SD4's generation was approximately 395 MW, with high exports of approximately 600 MW, low wind generation of approximately 20 MW, and a system load just over 10,100 MW. No major coal or gas units were offline at this time. System Marginal Price (SMP) was $999.99/MWh for approximately fifteen minutes during HE 18 while supply cushion dropped to -7 MW (excluding unused intertie capacity) for the hour.

August 16

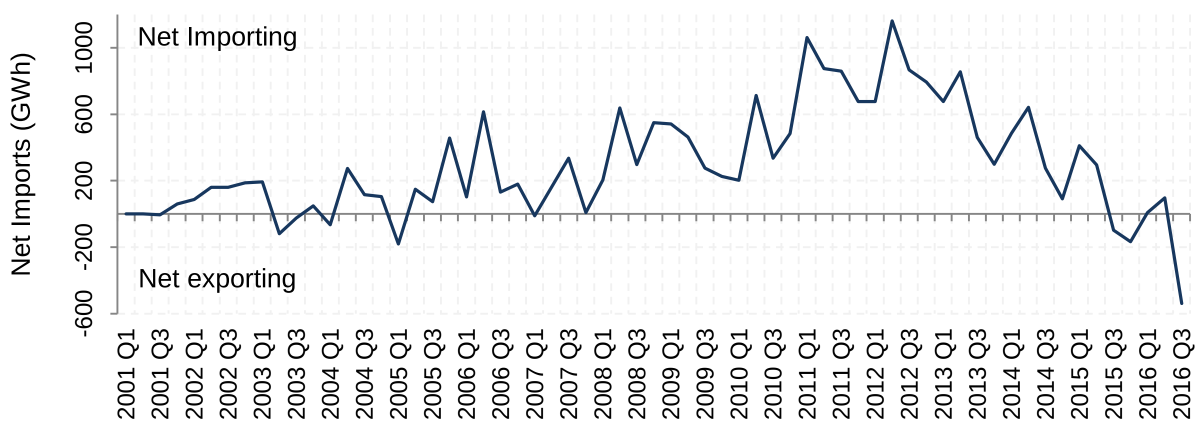
On August 16 in HE 15, the pool price settled at $631.30/MWh as a result of low supply cushion levels. The SMP was $999.00/MWh for approximately 35 minutes while supply cushion fell to

109 MW for the hour. At the time of the SMP increase, Keephills 2 (KH2) and SD4 were offline and Joffre 1 (JOF1) was in the process of ramping down from 260 MW to 40 MW. Wind generation was approximately 150 MW while exports totaled approximately 400 MW.

Trends in Export Volumes

As shown in Figure 3, there has been a trend of rising electricity exports from Alberta together with declining imports since 2012. Over this time period, Alberta has moved from being a net importer of electricity to a net exporter. Q3 2016 net exports were the highest they have been in any quarter since 2001.

Figure 3: Net Electricity imports to Alberta



In addition, the total volume of electricity moving across Alberta's interties has fallen dramatically. Lower pool prices since the beginning of 2015 are one possible explanation for these changes. Another explanation for the trend is the parity of inter-jurisdictional prices which reduces arbitrage opportunity. Alberta's electricity price has been at historical lows, creating more opportunities for arbitrage from Alberta to other markets, as shown in Figure 4.

Figure 4: Electricity Price Alberta Relative to Neighbouring Markets (Average monthly prices ($CAD /MWh))

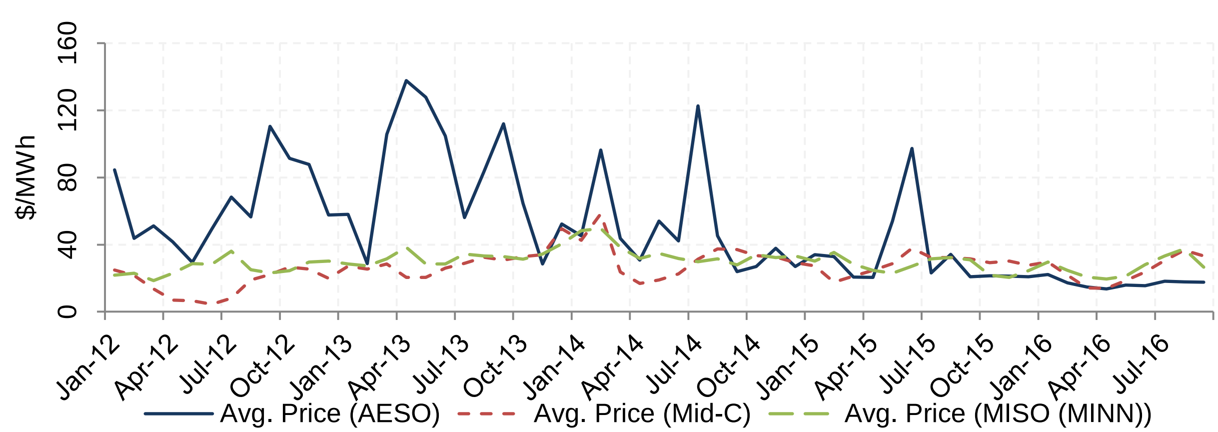
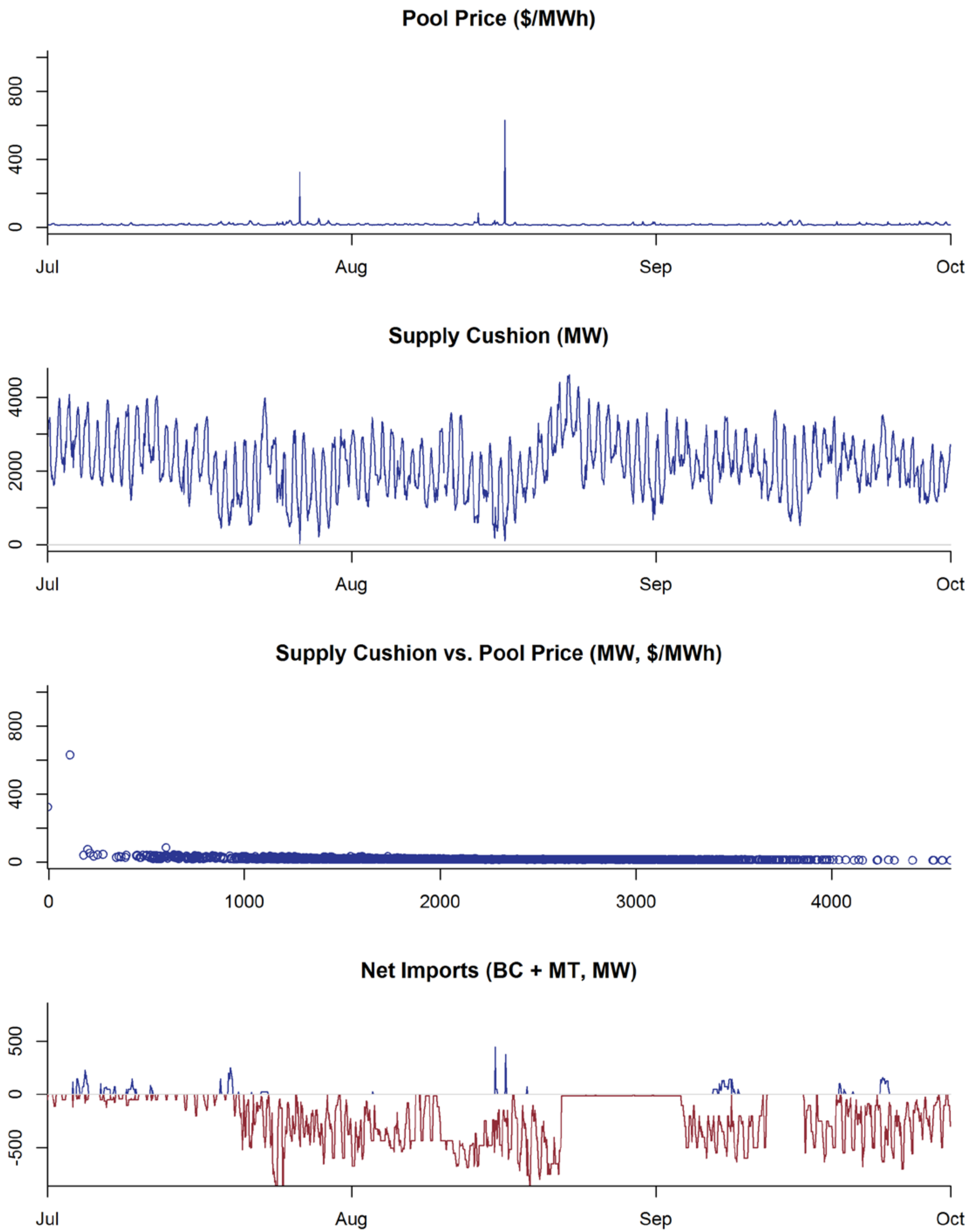


Table 2: Net exports on Alberta's interties

Scheduled volumes (GWh)	**2012**	**2013**	**2014**	**2015**	**2016 YTD**
Imports (BC/MATL)	3,063	1,985	1,910	977	236
Exports (BC/MATL)	58	183	318	497	566
Net Exports (BC/MATL)	**-3,005**	**-1,802**	**-1,592**	**-480**	**330**
Imports (SK)	505	516	55	60	13
Exports (SK)	13	30	154	100	116
Net Exports (SK)	**-492**	**-486**	**99**	**40**	**103**
Total Net Exports	**-3,497**	**-2,289**	**-1,493**	**-440**	**434**

Figure 5: Summary Graphs



Forward Market

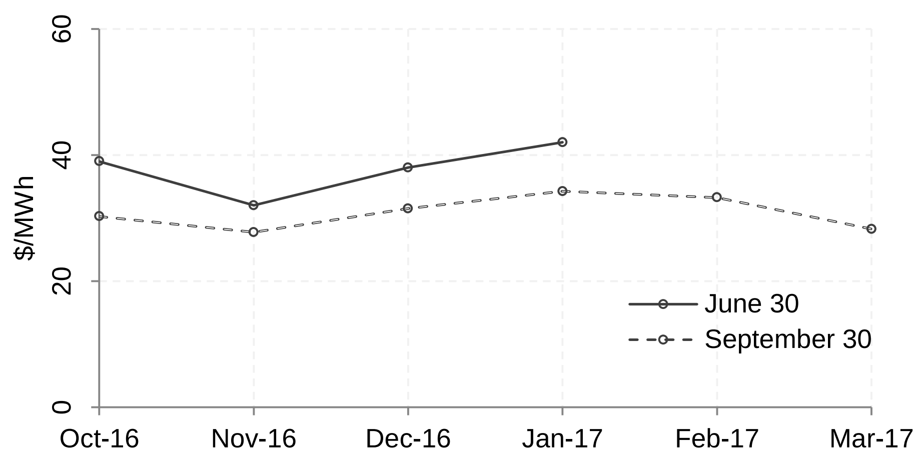
Overall forward market trading volume this quarter was lower than in the previous quarter; however it remains higher than the volume observed in the third quarter of 2015.

Table 3: Trade Volumes by Contract Term (TWh)

		Daily	Monthly	Quarterly	Yearly	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

The forward price curves for both monthly and annual flat products have decreased materially over the course of the quarter. As of September 30, all monthly flat contracts were trading below $35.00/MWh through March 2017.

Figure 6: Monthly Flat Forward Curve as of June 30 and September 30, 2016



The annual forward curve also decreased during the third quarter, with prices at or below $50.00/MWh through 2020.

Figure 7: Annual Flat Forward Curve as of June 30 and September 30, 2016

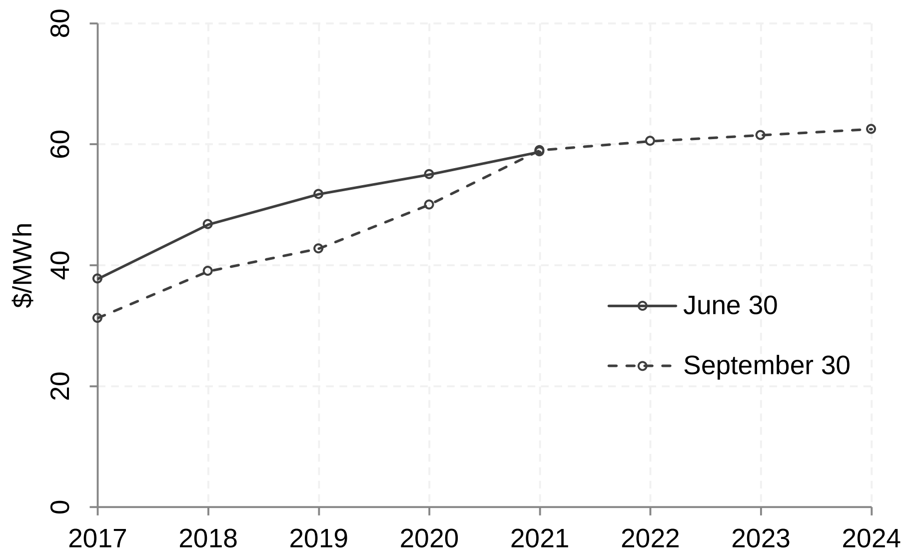
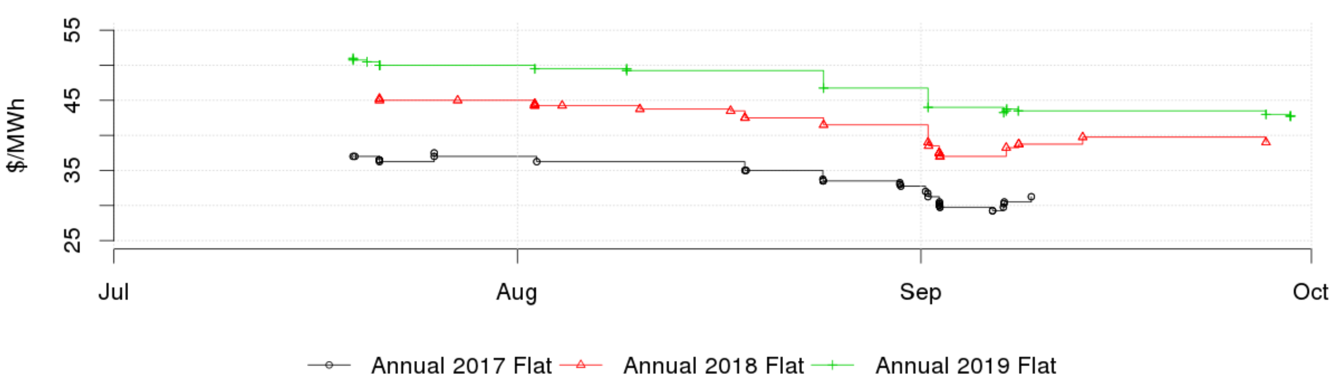


Figure 8: 2017, 2018, and 2019 Annual Flat Forward Prices



Retail Market

Retail Trends Reports

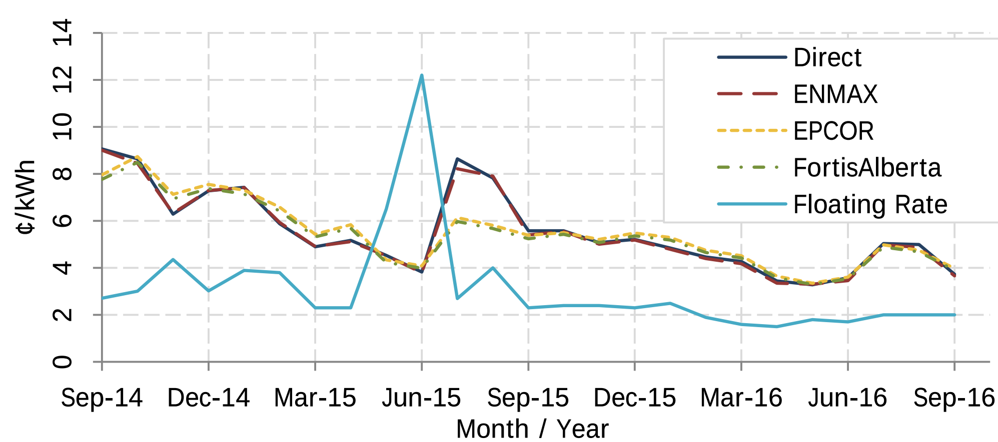
On September 6, 2016 the MSA published two reports related to the retail electricity and natural gas markets. The first report, Assessment of Inter-jurisdictional Retail Rate Comparisons, outlines and comments on the results of recent studies comparing monthly electricity bills in municipalities and provinces between 2013 and 2016. The second report, Trends in Regulated Retail Electricity and Natural Gas Bills, examines trends in various components of regulated bills between 2012 and early 2016.

RRO Rates

Regulated Rate Option (RRO) rates have remained below their historical average the last quarter, including a 1.5¢ lift in rates for the summer months of July and August. This increase was due to higher forward prices going into the months, likely a result of expected summer cooling load and summer derates for coal and gas units. A similar, but higher jump in RRO rates was seen in July and August 2015.

There remains a gap between the RRO and the pool price flow through rate (floating rate). Figure 9 below compares the RRO rates to the floating rate, which is the pool price shaped to the consumer load profile. It does not include the retailer's markup, which ranges from 0.5¢ to 1.8¢ per kWh. The remaining gap is likely accounted for by forward market risk premiums and regulated risk compensation and return margins.

Figure 9: RRO Rates and Floating Rate



Energy Price Setting Plans – Status Update

The Regulated Rate Option (RRO) is provided by the regulated divisions of ENMAX, EPCOR and Direct Energy, in addition to Rural Electrification Associations and small municipalities. Energy Price Setting Plans (EPSPs), as approved by the Alberta Utilities Commission, govern the procurement of energy and RRO provider compensation for ENMAX, EPCOR and Direct

Energy. EPCOR is operating under its 2016 – 2018 EPSP;[2] Direct Energy is in a Negotiated Settlement Process,[3] while the ENMAX application[4] is currently in front of the Commission. The important elements of the 2016-2018 EPSPs are summarized below. Of these EPSPs only the EPCOR plan is in force.

Procurement

Energy is procured in the 120-day window in advance of the delivery month in all three 2016-2018 plans.[5] EPCOR procures 7x24 and 7x16 (days x hours) blocks of energy to fill its forecast requirements using six random close auctions, spread evenly over its procurement window. ENMAX and Direct Energy have instead applied to use daily target pricing to acquire flat and peak blocks in the forward market. It is proposed that daily target prices and volumes be set by the regulated business through a mechanistic approach, rather than an independent advisor. All three EPSPs have established confidential backstop procedures; where any blocks not procured before the delivery month are provided by a backstop supplier.

ENMAX's EPSP is unique, as it proposes the option to self-supply blocks in certain market conditions. When self-supplying, ENMAX will first make the volume it proposes to self-supply available on the Natural Gas Exchange (NGX) for offers from suppliers. The price at which ENMAX self-supplies is subject to various constraints as detailed in the proposed EPSP.[6] ENMAX has also proposed a procurement incentive mechanism similar to its current EPSP. Through this mechanism it would receive compensation for any volumes acquired ten cents or more below the Daily Target Price; this mechanism has been critiqued by the Utilities Consumer Advocate.[7]

Risk compensation

The RRO Rate includes various other costs, namely system charges, commodity risk compensation (CRC) and an energy return margin. The 2016 – 2018 EPSPs use a form of CRC which is intended not as a true-up or a risk margin, but a means of accounting for market risk that targets profit neutrality over the term of the EPSP.[8] The method uses: i) adaptive CRC – risk compensation based on a 12-month rolling average of commodity gains and losses (without CRC) as a percentage of revenues; and ii) risk cycle CRC – a similar mechanism that includes the CRC in the calculation and will be updated annually to account for any systematic increases in market risk.[9]

The current EPSP for EPCOR and the proposed EPSP for Direct Energy use these two CRC calculations, although they are termed "Variable Risk Compensation" and "Risk Cycle Adder," respectively. ENMAX has proposed a variation of the adaptive CRC, whereby risk compensation is calculated using commodity gains and losses per unit of consumption.

[2] See Decision 20342-D02-2016 for the initial approval of the EPSP, and 20342-D03-2016 for subsequent amendments.
[3] See Exhibits 21295-X0032 and 21295-X0054, AUC Proceeding 21295 (available through the AUC eFiling System).
[4] See Exhibit 20448-X0199, AUC Proceeding 20448 (available through the AUC eFiling System).
[5] Direct Energy and ENMAX currently procure in the 45-day window under their 2011-2016 EPSPs.
[6] See Exhibit 20448-X0219, AUC Proceeding 20448, Page 2, Section 2.4 (available through the AUC eFiling System).
[7] See Exhibit 20448-X0246, AUC Proceeding 20448, Pages 6 – 9 (available through the AUC eFiling System).
[8] See Exhibit 0139.02.UCA-2941, AUC Proceeding 2941, Pages 40, 41 (available through the AUC eFiling System).
[9] See Exhibit 0139.02.UCA-2941, AUC Proceeding 2941, Pages 39 – 44 (available through the AUC eFiling System).

ENMAX has also proposed a five year volume-weighted average return be used to calculate its annually updated Risk Cycle CRC (which it calls “Other Risk Compensation”).

Energy return margin

The three principal RRO providers have proposed different energy return margins in their EPSPs. In its application, ENMAX has applied for a $2.49/MWh after-tax energy return margin (with taxes administered under the Payment in Lieu of Taxes Program).[10] EPCOR collects a $2.51/MWh after-tax return margin under its operational 2016 – 2018 EPSP.[11] Direct Energy currently collects a $2.65/MWh after-tax energy return margin, which was approved in Decision 20349-D01-2015. Direct Energy has proposed to increase its after-tax energy return margin to $2.83/MWh, as of January 1, 2017. The proposed increase in the energy return margin reflects the removal of the non-energy return margin; the overall return margin would remain the same.[12]

[10] See Exhibit 20448-X0199, AUC Proceeding 20448, Pages 9, 41 (available through the AUC eFiling System).
[11] See Decision 20342-D02-2016, Page 8, Section 20.
[12] See Exhibit 21295-X0032, AUC Proceeding 21295, Page17, Schedule “F”, Section A, “ERM” (available through the AUC eFiling System). Direct Energy had been directed to use this return margin structure in Decision 20349-D01-2015; see Exhibit 21295-X0002, AUC Proceeding 21295, Page 6, Commission Direction No. 1.

Operating Reserves

Market Summary

The total cost of operating reserves decreased 40% quarter-over-quarter. Overall, the total volume of standby activated decreased by 30%. The total cost of standby activations decreased by 94%. The volume of active and standby reserves procured remained steady.

Active regulating reserve trends

Beginning in April, the MSA observed that the super-peak equilibrium prices had frequently cleared close to the AESO's bid prices of $100/MWh for the super-peak AM period and $30/MWh for the super-peak PM period. This trend has been progressing downwards since August for the super-peak AM period. There was a sharp decrease in the super-peak PM equilibrium prices in July, but the equilibrium prices increased again in August.

Standby regulating reserve trends

The volume of standby regulating reserve activated in Q3 increased by 159% compared to Q3 2015. However, the average cost of activating standby regulating reserve decreased by 75% quarter-over-quarter. This is because, on average, the standby activation prices of the assets activated have decreased.

Most of the standby regulating reserve activations in Q3 2016 occurred in August due to congestion limiting energy output from the Brazeau area, including regulating reserve. In response, the AESO activated standby regulating reserve in an uncongested area to

Table 4: Operating Reserves Summary

Total Cost ($ Millions)			
	Q3 2015	**Q3 2016**	***% Change***
Active Procured	**15.4**	**11.5**	***-25.3***
RR	7.0	7.3	*4.2*
SR	5.8	2.8	*-52.3*
SUP	2.6	1.4	*-45.7*
Standby Procured	**2.8**	**2.5**	***-9.3***
RR	1.0	1.8	*73.2*
SR	1.4	0.6	*-60.7*
SUP	0.3	0.2	*-49.3*
Standby Activated	**5.7**	**0.4**	***-93.5***
RR	0.2	0.1	*-34.9*
SR	3.6	0.2	*-94.8*
SUP	2.0	0.1	*-96.8*
Total	**23.9**	**14.4**	***-39.8***
Total Volume (GWh)			
	Q3 2015	**Q3 2016**	***% Change***
Active Procured	**1304.6**	**1306.3**	***0.1***
RR	346.1	347.6	*0.5*
SR	479.5	479.4	*0.0*
SUP	479.1	479.3	*0.0*
Standby Procured	**540.1**	**519.3**	***-3.8***
RR	219.9	212.0	*-3.6*
SR	237.2	230.7	*-2.7*
SUP	83.0	76.6	*-7.7*
Standby Activated	**26.2**	**18.3**	***-30.2***
RR	1.5	3.8	*159.0*
SR	15.5	10.0	*-35.2*
SUP	9.3	4.5	*-51.4*
Total	**1870.9**	**1843.9**	***-1.4***
Average Cost ($/MWh)			
	Q3 2015	**Q3 2016**	***% Change***
Active Procured	**11.8**	**8.8**	***-25.4***
RR	20.4	21.1	*3.8*
SR	12.0	5.7	*-52.2*
SUP	5.5	3.0	*-45.7*
Standby Procured	**5.1**	**4.9**	***-5.7***
RR	4.7	8.5	*79.7*
SR	6.0	2.4	*-59.6*
SUP	3.7	2.1	*-45.0*
Standby Activated	**218.1**	**20.2**	***-90.7***
RR	128.4	32.3	*-74.9*
SR	231.0	18.5	*-92.0*
SUP	210.6	13.7	*-93.5*
Total	**12.8**	**7.8**	***-38.9***

compensate.

The activation of standby regulating reserve did not impact the cost of constraint in the energy market. This is because the cost of activating standby reserve is determined by the activation price that was offered in the operating reserve market the day before. When a unit is activated to provide operating reserve they are paid their activation price. The total cost of activating standby reserves is the sum of these payments and is paid as an ancillary service cost through the ISO Tariff. The activation payments are independent on pool price under normal system conditions and in congestion events. Thus, there was no change in the pool price as a result of the congestion on regulating reserve.

In the Q2/2016 Quarterly Report, the MSA noted that standby regulating reserve costs increased 110% quarter-over-quarter. This trend was not as pronounced in Q3 2016 where the cost of procuring standby regulating reserve increased 73% compared to Q3 2015. The monthly cost of procuring standby regulating reserve began to gradually decrease in July down to near historical low levels in September. This is due to a decrease in the average premium payment for standby regulating reserve from Q2 to Q3 this year. The decrease was also aided by a decrease in the volume of standby regulating reserve procured each day from 100 MW to 80 MW starting on September 14th.

Regulatory

Self-Report Regarding the Sharing of Offer Information

In August, the MSA received a self-report from a market participant stating that they had inadvertently shared offer information with a competitor. A real-time trader for the market participant opened the wrong email template and sent an email containing the previous day's offer information for four assets to several email addresses belonging to a competitor that has no responsibility for the assets. The competitor confirmed that the emails were deleted and were not distributed within the company.

In response to this error, the market participant changed its procedures such that offer information will no longer be shared via email and will be communicated through information channels with limited internal access. The MSA declined to investigate.

The market participant submitted the self-report promptly. However, the self-report did not include all relevant information for the MSA to fully assess the incident. Thus, the MSA sent an information request to the market participant for more information. Market participants are strongly encouraged to send all information related to a contravention at the time of the self-report.

Over the course of the year, the MSA has seen a number of events where market participants inadvertently distributed non-public information to other participants. The MSA stresses that market participants should remain vigilant when sending emails containing non-public information and should put controls in place to minimize the need to email sensitive information wherever possible. If it is necessary to email sensitive information, market participants should consider other controls, such as protecting attachments with passwords with the associated password provided in another communication.

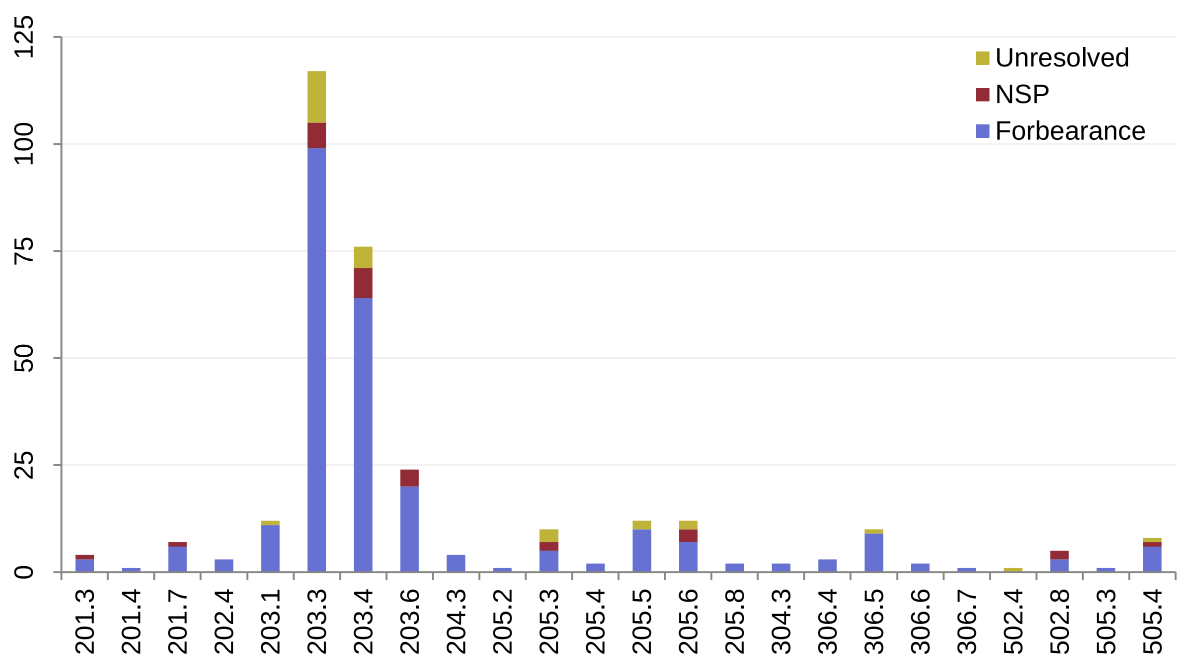
Compliance

On October 19th, the MSA released a revised version of the Compliance Process, following the conclusion of a stakeholder consultation process.[13] This new process document is now in effect and participants are encouraged to familiarize themselves with it accordingly.

From January 1, 2016 to September 30, 2016, the MSA addressed 292 ISO rules compliance matters, of which 27 resulted in a notice of specified penalty. The total financial amount of the notices of specified penalties was $50,000. The MSA notes an increase in the number of ISO rules contraventions relating to spinning and supplementary reserve directives and encourages participants to review their practices. Participants are reminded that discrete instances of rules non-compliance should be self-reported separately, rather than compiling multiple events into a single self-report.

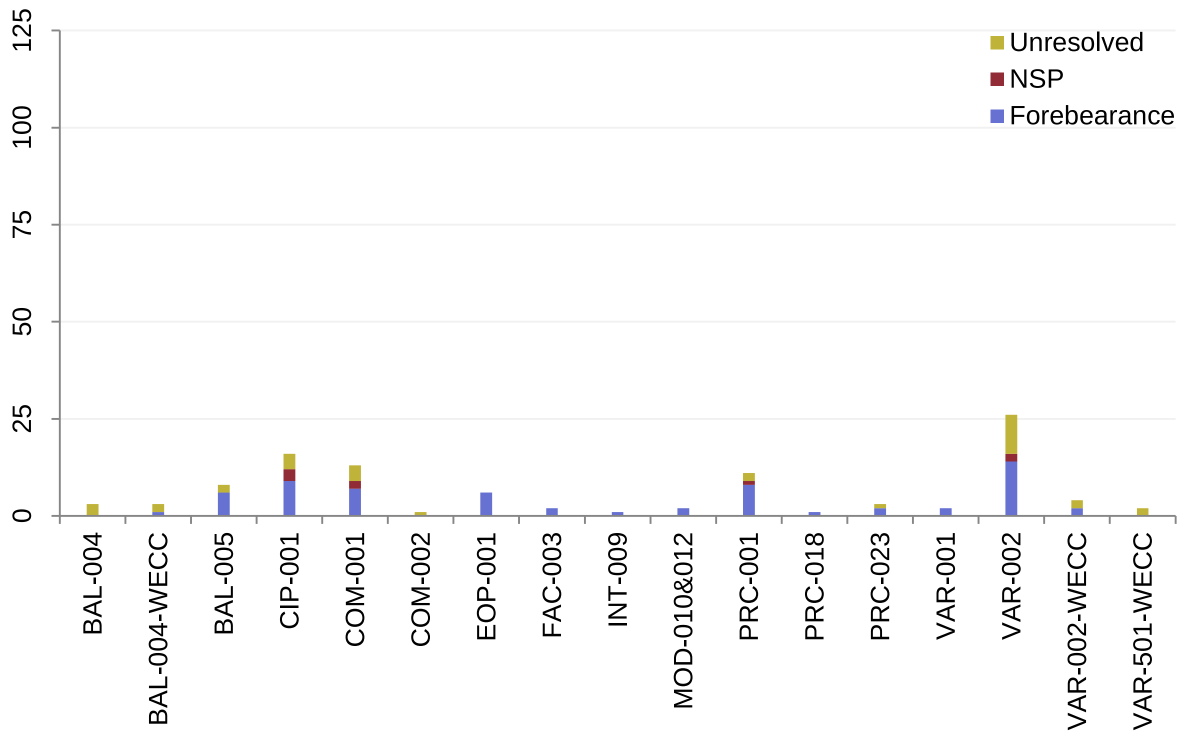
In the same period, the MSA addressed 71 Alberta Reliability Standards compliance files, of which eight resulted in a notice of specified penalty. The total financial amount of the notices of specified penalties was $33,750.

Figure 10: ISO Rules Compliance



[13] Notice re Final Version of Compliance Process

Figure 11: Reliability Standards Compliance[14]



[14] The statistics for VAR contraventions were inadvertently omitted in the 2016 Q2 report, but are accurately reported in this report.