Q1/17 Quarterly Report

January – March 2017

May 5, 2017

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

www.albertamsa.ca

Table of Contents

Wholesale Market

Summary

Pool price in Q1 2017 averaged $22.39/MWh ($18.76/MWh ext. off peak, $24.20/MWh ext. on peak). Although the pool price was 24% higher than last year, the pool price in Q1 remained well below the recent historical average (as shown in Figure 1).

After flat or negative growth in parts of 2015 and 2016 (Figure 2), total electricity demand grew by 2.4% year over year. Demand has grown at an average rate of 1.9% since 2010.

The supply cushion duration curves in Figure 3 show that the first quarter of both 2016 and 2017 had very little scarcity, with supply cushion, once adjusted for import availability or reducing exports, almost never below 1000 MW.

On January 13, 2017, a news release[1] indicated the offer control of the Sheerness and Sundance PPA units was being assumed by the Balancing Pool. The average merit order over Q1/17 is plotted in Figure 4, and shows that offers at PPA units have remained in the region likely to be reflective of a generators' short run marginal cost. Coal offer prices have increased after January 1, 2017 (see Figure 5), likely resulting from changes in the *Specified Gas Emitters Regulation* (SGER) that came into effect. The changes increased the SGER payment rate from $20/tCO2e to $30/tCO2e. Relative to Q1 2016, offer prices from EGC1 Shepherd have increased likely due to the price of natural gas.

Table 1: Summary Data

		2016	2017	*Change*
Average of Pool Price ($/MWh)	Jan	22.25	23.96	*+7.7%*
	Feb	17.22	22.18	*+28.8%*
	Mar	14.79	21.01	*+42.0%*
	Q1	**18.11**	**22.39**	***+23.6%***
Total Demand (AIL, GWh)	Jan	7,342	7,506	*+2.2%*
	Feb	6,642	6,672	*+0.5%*
	Mar	6,837	7,143	*+4.5%*
	Q1	**20,821**	**21,322**	***+2.4%***
Average of Gas Price ($/GJ)	Jan	2.24	2.75	*+22.7%*
	Feb	1.71	2.40	*+40.8%*
	Mar	1.26	2.49	*+97.7%*
	Q1	**1.74**	**2.55**	*+46.8%*
Average of Supply Cushion (MW)	Jan	2,412	1,921	*-20.4%*
	Feb	2,629	2,099	*-20.1%*
	Mar	2,305	2,210	*-4.1%*
	Q1	**2,445**	**2,076**	***-15.1%***
Average of WIND (MWh)	Jan	560	587	*+4.9%*
	Feb	718	461	*-35.8%*
	Mar	607	570	*-6.2%*
	Q1	**626**	**542**	***-13.5%***
Total Net Imports (GWh)	Jan	-2.1	-118.6	*+5644.8%*
	Feb	-20.0	-51.4	*+156.9%*
	Mar	30.1	117.4	*+289.6%*
	Q1	**8.1**	**-52.6**	***-753.1%***

[1] Balancing Pool, "Balancing Pool's Total Energy Offer Control Increases to 3,900 MW", January 13 2017

Figure 1: Average Quarterly Pool Price ($/MWh)

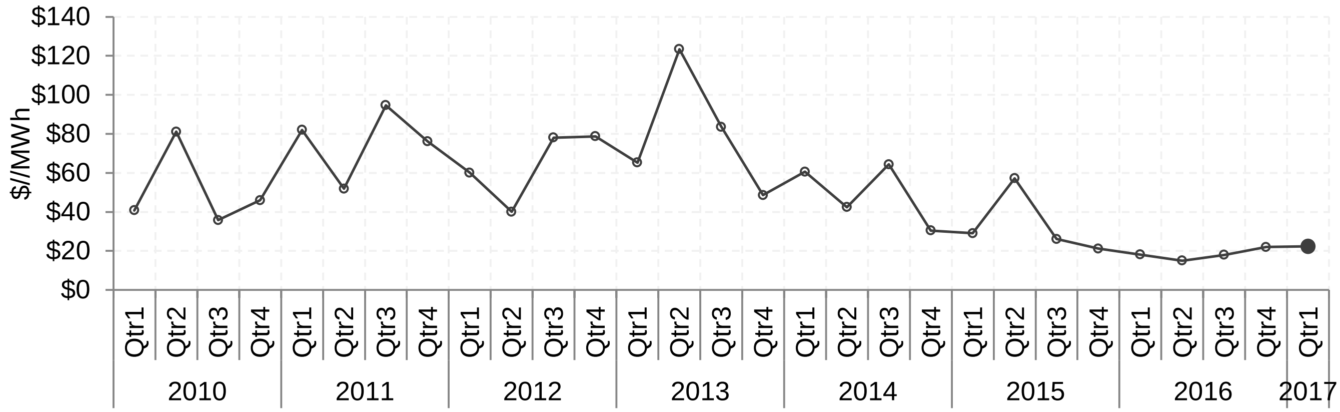


Figure 2: Growth in Total Alberta Internal Load (AIL, % Year over Year)

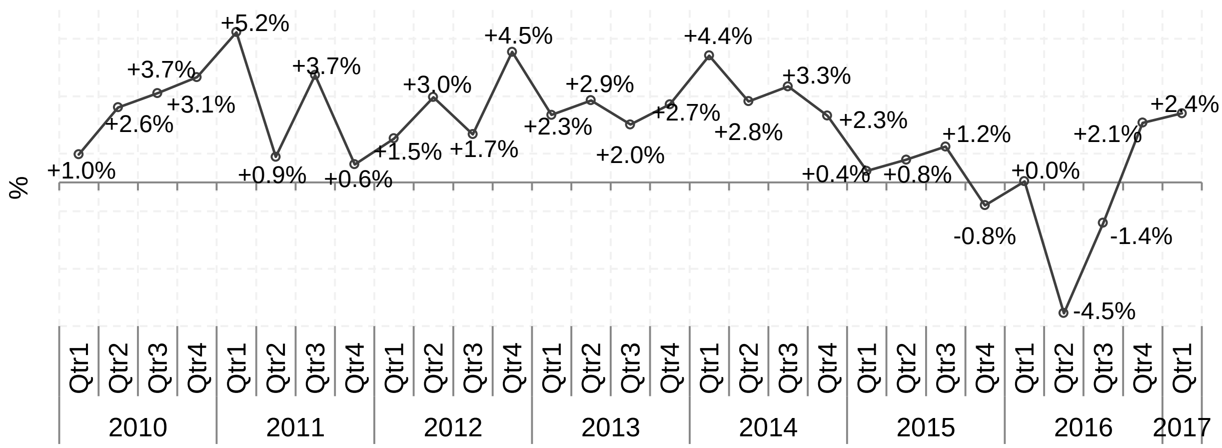
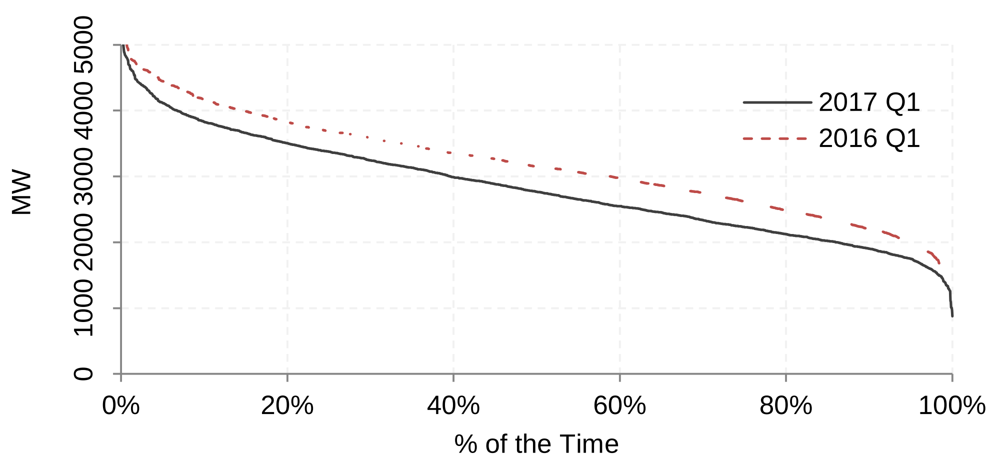


Figure 3: Adjusted[2] Supply Cushion Duration Curves



[2] Includes availability of additional imports or reduced exports in the supply cushion

Figure 4: Aggregate Merit Order, Q1 2017

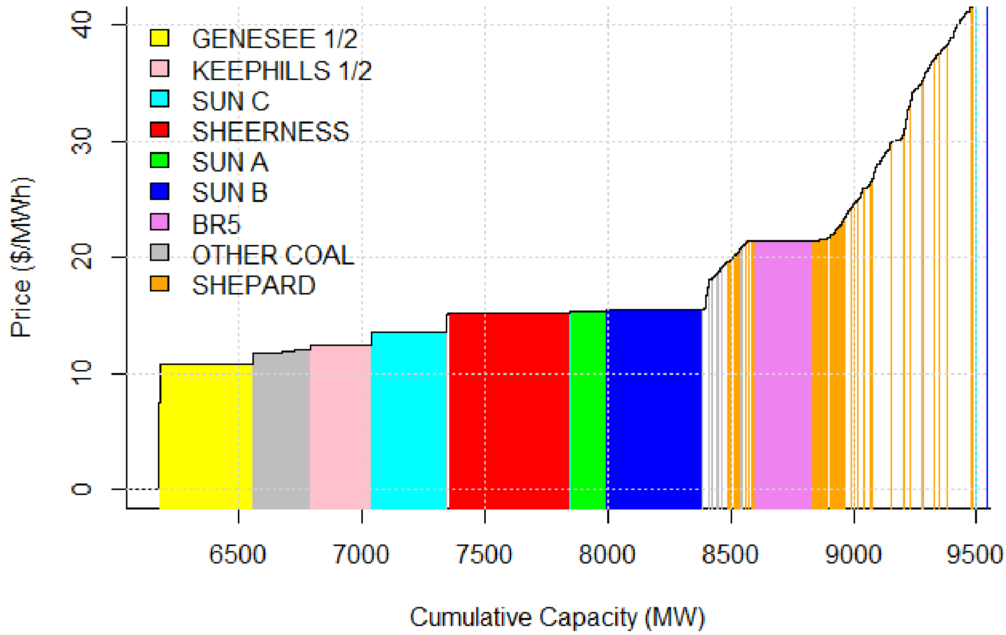
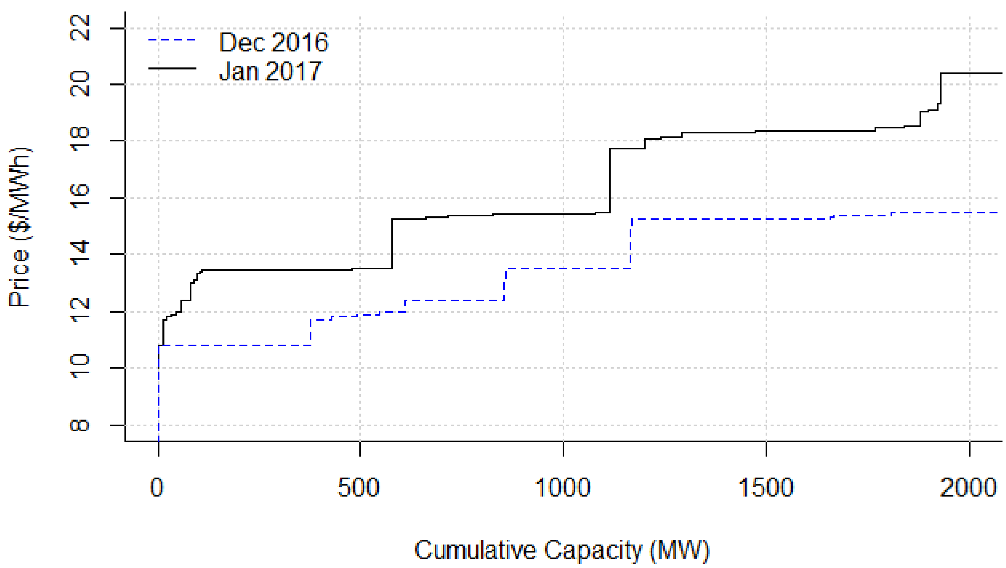
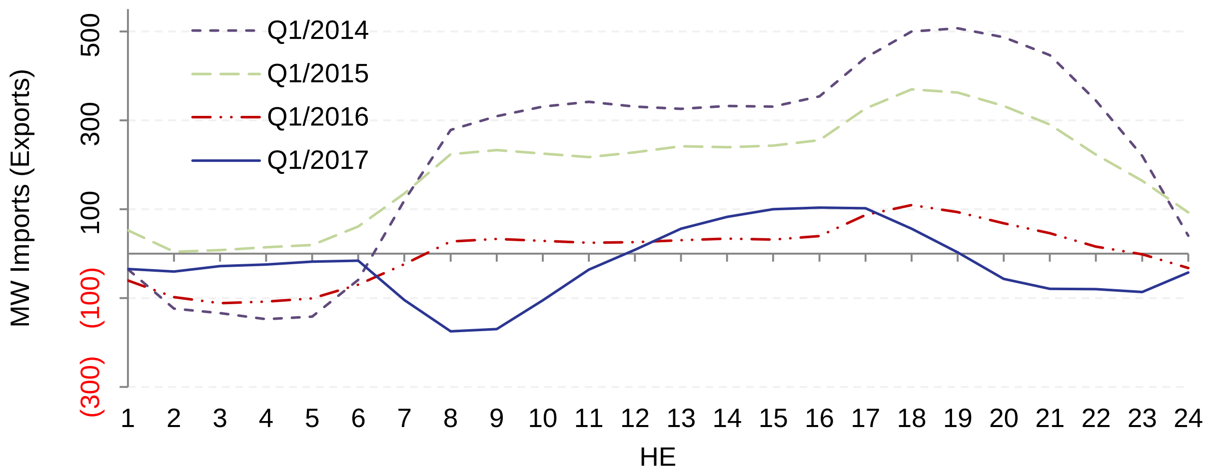


Figure 5: Aggregate Non-Zero Coal Offers, Pre and Post SGER Change



Alberta was a net exporter of electricity in Q1/17. Table 1 shows 52.6 GWh of exports over the quarter, compared to a net importer of 8 GWh in Q1 2016. However, as seen in Figure 6, Alberta routinely both imports and exports electricity. Alberta has historically been a net importer during the day, and would export to a lesser degree overnight. On average Alberta is still a net importer during the afternoon, but there were considerable exports during the mornings this quarter. Unusually high levels of snowpack in regions with significant hydroelectric resources may result in increased import volumes in Q2 2017.

Figure 6: Q1 Average Net Imports by Hour Ending, 2014-2017



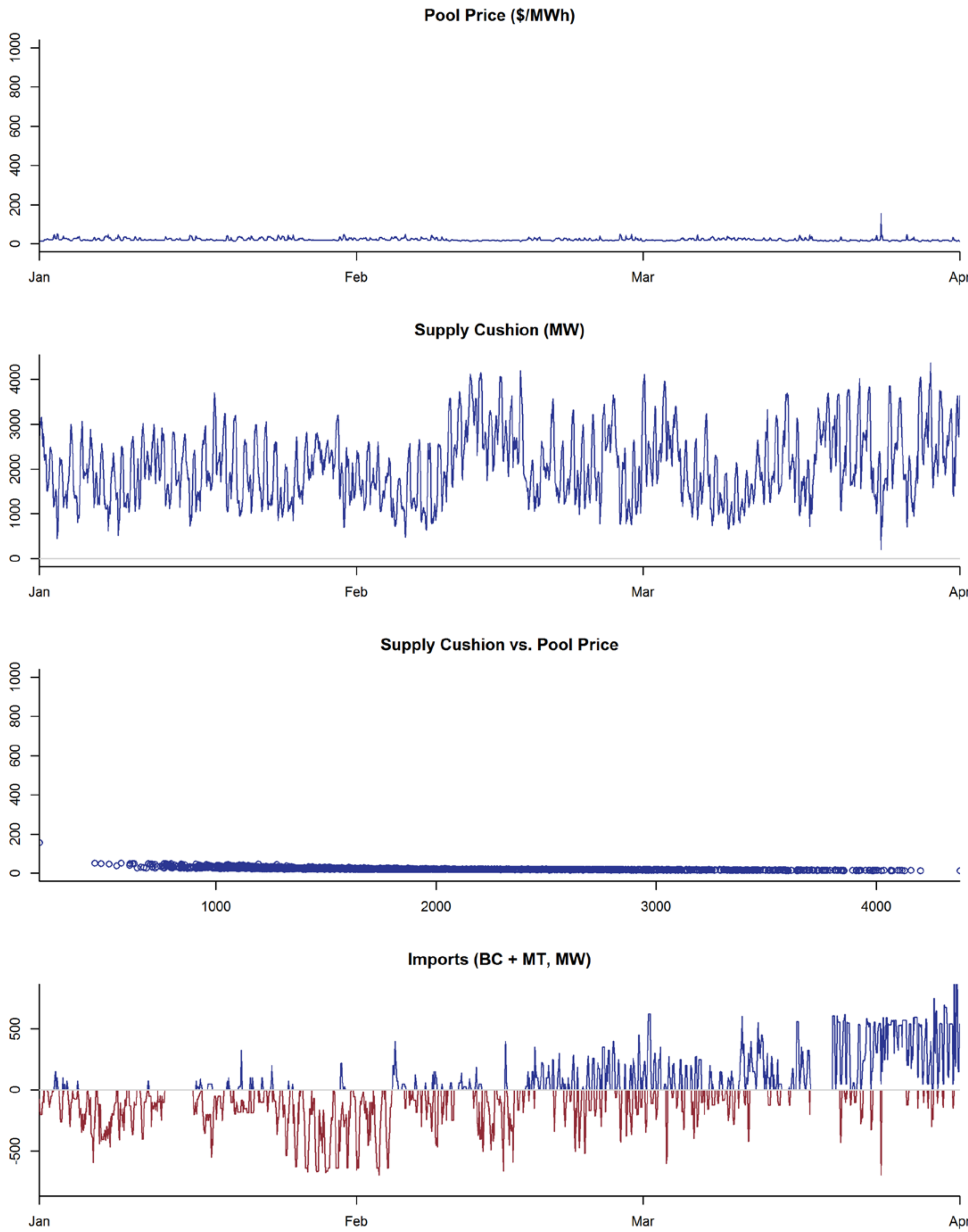
As visible in the summary graphs on Figure 7, the highest pool price in Q1 was $155.78/MWh on March 24, HE 8. The price corresponded with the lowest supply cushion in the quarter: 197 MW. The primary factors were

- Wind production less than 100 MW, considerably less than the average of 730 MW in HE 8 of other mornings that week
- Two coal-fired units were offline, which in addition to de-rates resulted in approximately 650 MW less available coal power relative to other mornings that week
- 633 MW of scheduled exports.

The exports, in conjunction with these other factors, had a meaningful impact on price. For example, at 07:30 the 640 MW of exports likely increased the SMP by $145.[3]

[3] At 07:30 the SMP was set at $185.95; reading down the merit order approximately 633 MWs results in a block price of $40/MWh.

Figure 7: Q1/17 Summary Graphs



Import Enablement via Additional Operating Reserves

Electricity interconnections to other jurisdictions provide a valuable service to Albertans. In addition to reliability benefits, imports provide consumers access to cheaper power when the Alberta pool price is high, and generators access to higher prices via exports when the pool price is low. With these benefits comes the risk of sudden intertie interruption (a 'trip'), resulting in a sudden imbalance between generation and load. In order to mitigate reliability concerns, the AESO procures Load Shed Service for Imports (LSSi): loads which can be automatically tripped to rebalance the grid in the event of a sudden loss of imports. Supplemental and spinning standby reserves have also been used to help offset a potential loss of imports.

The MSA has previously reported on challenges of both of these mechanisms for enabling larger volumes of imports on the interconnections. Taking generating units out of merit and paying them an activation payment to provide supplemental/spinning reserves to offset imports may only incur a cost to replace one megawatt with another. In addition, the MSA has previously reported on concerns about the pricing scheme of standby reserves, which may lead to increased costs.

Standby reserves are procured using a two-part pricing scheme: a premium and an activation price. The premium is the standing charge that providers are paid to be on hand in the event that they are required for service. The activation price is what providers are paid in the event they are required in real time. Unlike active reserves that are priced indexed to pool price, activated standby reserves are paid a fixed price for activation. Sellers of standby reserves need to take a forward view on pool price; something that the sellers of active reserves do not.

Ultimately, particularly during periods of price volatility, the cost of standby reserves is high in most part due to the high activation prices commanded by sellers. The MSA is unaware of reasons that support the use of fixed activation prices rather than indexed prices. A simpler and more efficient scheme would be to set the activation price at the price of active reserves. Standby sellers would then compete based on the premium they require to be on standby.

March 31 High Import Volumes

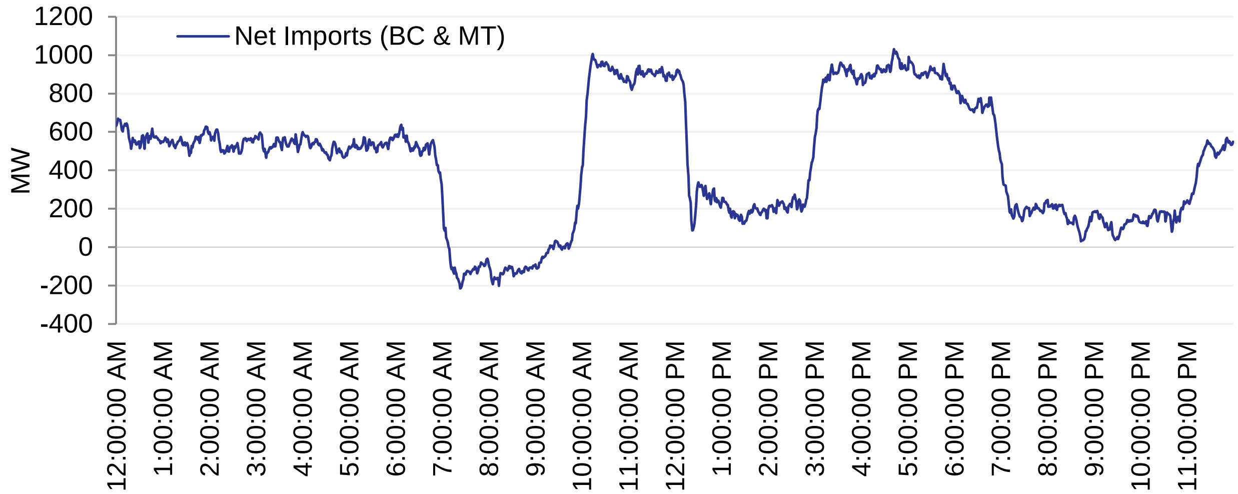
On March 31st, the MSA observed large volumes of imports flowing into Alberta on the BC and Montana interties. Over the course of the day, net imports of 10,986 MWh (see Figure 8) were sold into the Alberta market. To enable this level of imports the AESO armed seven LSSi providers and activated nine standby units providing spinning and supplemental reserves.

The majority of imports during the day came over the BC intertie coinciding with generally low Mid-C prices as shown in Figure 9. The total cost of arming LSSi for the day was $100,704, while the cost of activating standby reserves was $31,091 of which about 99.6% could be attributed to import enablement.[4] Of the 2,622 MWh of activated standby throughout the day, 348 MWh (13%) came out of merit. The weighted average activation price for spinning and

[4] LSSi and activated standby spinning and supplemental reserves are assumed to enable imports if they were armed/activated to offset any hourly imports greater than 400 MW, including any ramp up/down in the hour preceding or following an hour where this occurs.

supplemental standby reserve over their activated hours was \$13.79 and \$8.43/MWh respectively. While these are lower than the average pool price over these same hours (\$18.26/MWh), they were considerably higher than the prices received for active spinning and supplemental reserves, of \$4.11 and \$1.57/MWh. Over the course of the day, approximately 3,869 MWh of imports were enabled by armed LSSi and activated standby spinning and supplemental reserves, at a cost of \$28.18/MWh of enabled imports. On average, the enabled imports earned \$16.46/MWh. The hourly value and costs of enabling these imports are shown in Figure 10.

Figure 8: Net Imports (BC & MT), March 31st 2017



The AESO sets the minimum hourly LSSi requirements based on the hourly load (AIL) and the BC/MT ATC Import Level (MW), as defined in the Information Document on Available Transfer Capability and Transfer Path Management.[5] This minimum LSSi specification generally accounted for the majority of armed LSSi throughout the day.

[5] AESO Information Document – Available Transfer Capability and Transfer Path Management, Table 7, Page 10.

Figure 9: Alberta & Mid-C Energy Prices on March 31st, 2017

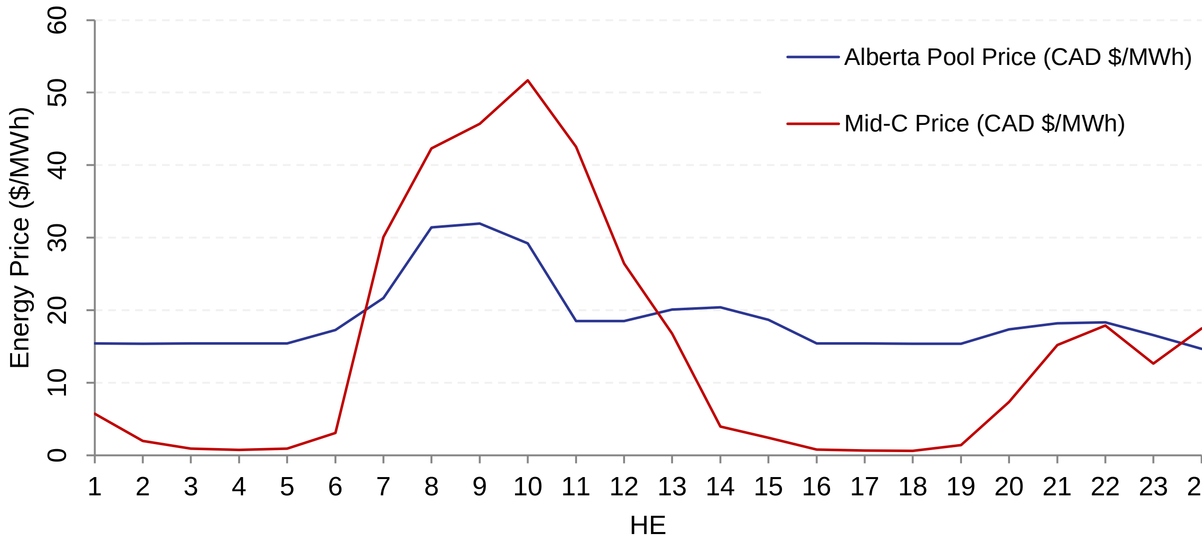
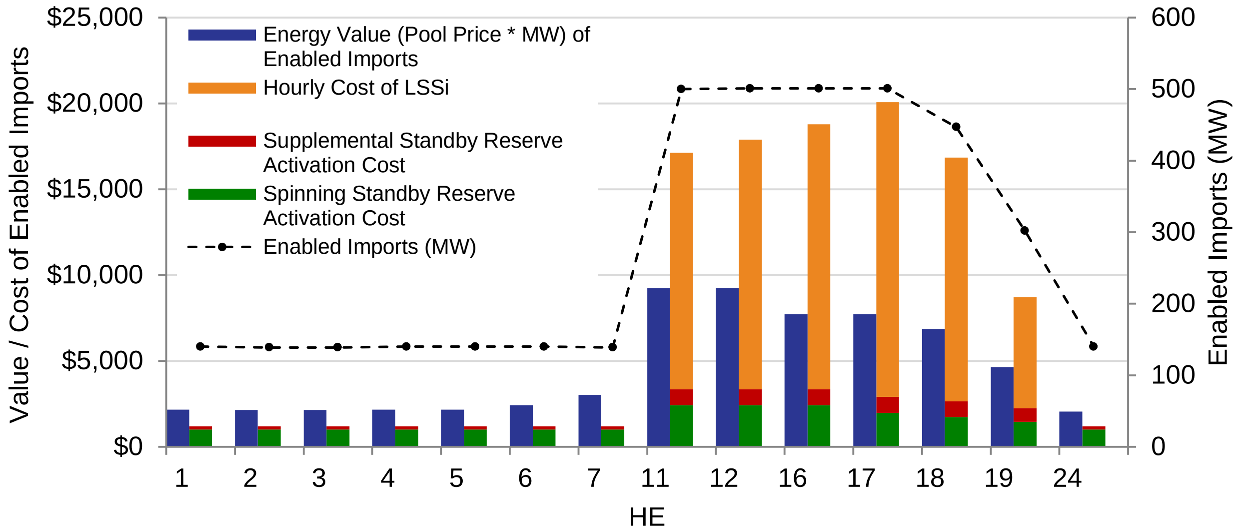


Figure 10: Costs of Enabled Imports, March 31st 2017[6]



From Hours Ending (HE) 1-7, hourly net imports of approximately 540 MW from BC and MT (equal to the BC MATL ATC) prompted 140 MW of standby spinning & supplemental reserves to be activated each hour, at a cost of $8,360. In HE8, the BC MATL ATC was increased to 950 MW, with a subsequent increase to 1000 MW in HE9.

At approximately 9:42, the AESO began arming five LSSi units in preparation for large import volumes in the upcoming hours. An average of 200 MW of LSSi was armed from HE10 to HE13, with net imports reaching highs of 948 and 949 MW in HE11 and HE12. Similarly, approaching

[6] Hours are excluded where no imports were enabled.

the end of HE10, the AESO activated 227 MW of standby spinning and supplemental reserves for HE11 to HE13, at a cost of $10,055. Approximately 1,000 MWh of imports in HE11 and 12 were enabled by these actions.

Net Imports fell off considerably from HE13 to HE15 despite falling Mid-C prices, but similarly high gross import offers for HE16 prompted the AESO to arm seven units for LSSi for the end of HE15 through to HE20. Seven providers of standby spinning and supplemental reserves were also activated for HE16 to HE19, with hourly activations ranging from 168 to 227 MW, at a cost of $11,166. Net imports for HE16 to HE19 ranged from 750 to 949 MW. A large number of offers for HE24 and a BC MATL ATC of 540 MW prompted the AESO to activate 140 MW of standby spinning and supplemental reserves to accommodate the 540 MW of imports in that hour.

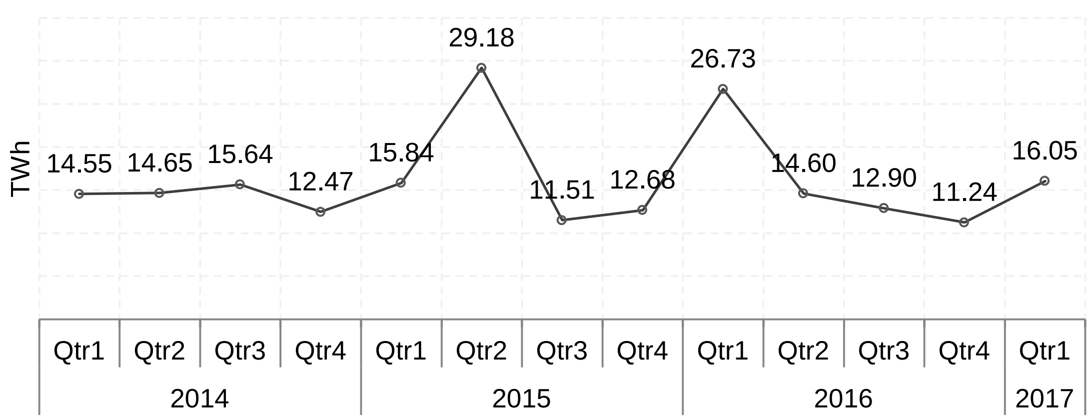
Forward Market

Overall forward market trading volume this quarter was 43% higher than the previous quarter, with contracts of all term lengths increasing in volumes. Although trading was down 40% compared to Q1 16, Figure 11 shows that trading this quarter is in line with historical averages.

Table 2: Trade Volumes by Contract Term (TWh)

		Daily	Monthly	Quarterly	Annual	Other	Total
2015	Qtr1	0.10	9.96	0.84	4.17	0.76	15.84
	Qtr2	0.20	10.46	1.14	16.71	0.66	29.18
	Qtr3	0.06	6.25	0.50	4.40	0.29	11.51
	Qtr4	0.06	5.87	0.98	5.74	0.03	12.68
2016	Qtr1	0.22	9.36	1.78	12.37	3.01	26.73
	Qtr2	0.19	8.25	0.58	4.50	1.08	14.60
	Qtr3	0.07	6.80	1.23	4.56	0.25	12.90
	Qtr4	0.09	5.44	1.46	3.78	0.47	11.24
2017	Qtr1	0.06	6.53	3.03	4.57	1.86	16.05

Figure 11: Total Trade Volumes over Time



Operating Reserves

Market Summary

The total cost of operating reserves almost doubled year-over-year in the first quarter of 2017. Procured volumes are generally similar to those in Q1/2016, although 21% less standby regulating reserve is now being procured. Standby contingency reserve activations have more than tripled year-over-year.

The cost of active reserves doubled year-over-year, despite a much smaller 23.6% increase in pool price and little change in procurement. This increase in costs has been driven by changes in offer behaviour, as well as higher year-over-year pool prices and lower coal participation in auctions. In Q1/2017, coal units offered 75% less volume into active operating reserve auctions than they did in Q1/16.

Standby reserve procurement is generally unchanged since Q1/2016, with the exception of regulating reserves. This is due to a change made by the AESO in September 2016, where they reduced procurement from 100 MW to 80MW. Despite this, standby premiums have increased slightly since last year in part due to the reduction in auction participation from thermal PPA units.

In part due to the import enablement already discussed, activations of standby reserves have more than tripled since last year. Of the 35.5 GWh of spinning and supplemental reserves activated in Q1/2017, 7% was activated on March 31st to enable imports. These activations have been used to help enable high imports from neighbouring jurisdictions facing low unusually low prices. However, the impact to standby activation costs has been slightly dampened due to lower activation price offers.

Table 3: Operating Reserves Summary

Total Cost ($ Millions)			
	Q1 2016	**Q1 2017**	***% Change***
Active Procured	**6.5**	**12.9**	***100.3***
RR	2.4	5.9	*143.6*
SR	3.1	5.3	*69.0*
SUP	0.9	1.8	*94.2*
Standby Procured	**1.2**	**1.4**	***12.3***
RR	0.6	0.6	*12.5*
SR	0.6	0.6	*7.3*
SUP	0.1	0.1	*40.4*
Standby Activated	**0.2**	**0.8**	***247.3***
RR	0.0	0.0	*6.2*
SR	0.2	0.6	*294.5*
SUP	0.0	0.2	*284.5*
Total	**7.9**	**15.1**	***90.9***
Total Volume (GWh)			
	Q1 2016	**Q1 2017**	***% Change***
Active Procured	**1,352.8**	**1,355.5**	***0.2***
RR	354.8	351.8	*-0.8*
SR	499.0	501.9	*0.6*
SUP	499.1	501.8	*0.5*
Standby Procured	**522.4**	**480.1**	***-8.1***
RR	217.8	172.1	*-21.0*
SR	228.6	230.2	*0.7*
SUP	76.0	77.9	*2.6*
Standby Activated	**9.0**	**36.6**	***306.3***
RR	1.1	1.1	*-0.6*
SR	5.8	23.9	*310.6*
SUP	2.1	11.6	*462.4*
Total	**1,884.2**	**1,872.2**	***-0.6***
Average Cost ($/MWh)			
	Q1 2016	**Q1 2017**	***% Change***
Active Procured	**4.77**	**9.53**	***99.88***
RR	6.78	16.64	*145.60*
SR	6.30	10.59	*67.98*
SUP	1.81	3.49	*93.11*
Standby Procured	**2.34**	**2.86**	***22.22***
RR	2.61	3.72	*42.36*
SR	2.44	2.60	*6.60*
SUP	1.28	1.75	*36.84*
Standby Activated	**25.10**	**21.46**	***-14.52***
RR	31.60	33.78	*6.91*
SR	26.01	24.98	*-3.92*
SUP	19.00	12.99	*-31.63*
Total	**4.19**	**8.05**	***92.09***

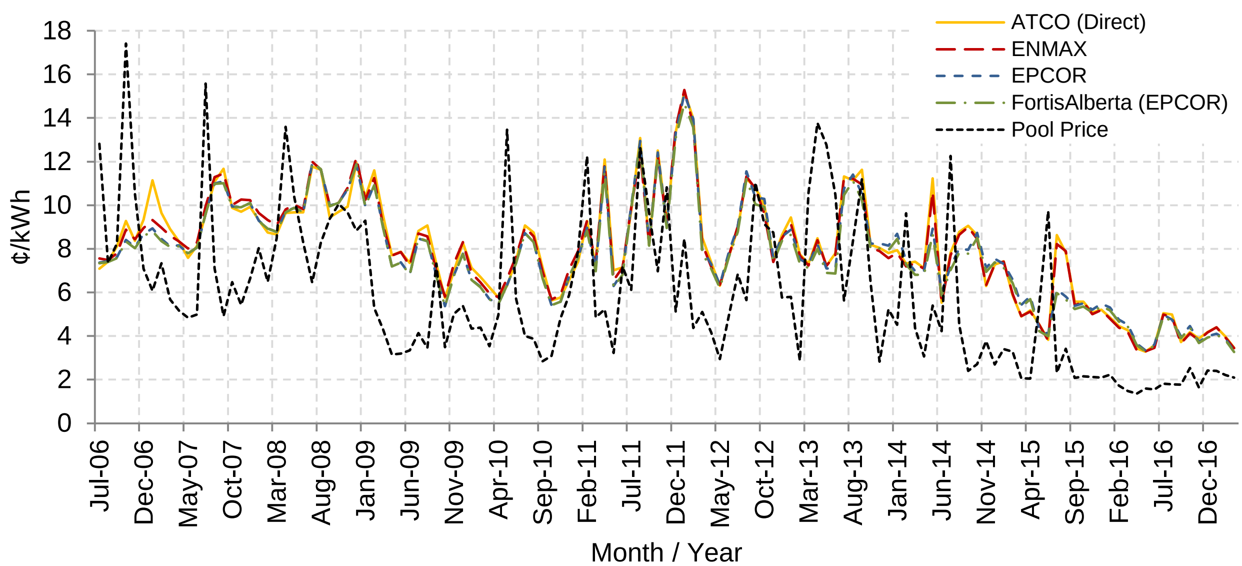
Retail market

Regulated Rate Option Rates

RRO rates fell in the first quarter of 2017, continuing the declining trend observed since 2012. This culminated in a record low rate of 3.275 ¢/kWh for FortisAlberta customers in March 2017, a lower rate than any RRO customer in any distribution zone had paid prior to that month. Figure 12 shows the declining trend in the RRO rate across zones, as well as the decreasing variability in month-to-month rates over the past year. This declining variability in the RRO rate has been coincident with the collapse of monthly pool prices and the monthly forward prices from which the RRO rates are partially derived.

It should be noted that average pool price reflects consuming an equal amount of electricity in each hour, whereas a typical retail consumer does not, which results in a higher price. Therefore, average pool price is not directly comparable to the retail rates provided below. Retailers offer floating rates which are based on the pool price shaped to the residential load profile, plus a retailer's markup.

Figure 12: RRO Rates and Pool Price



Options for Enhancing the Design of the Regulated Rate Option

On April 21, 2017 the MSA published a notice on its website informing stakeholders that the Minister of Energy had requested that the MSA "conduct an analysis and provide a report with options for enhancing the design of the Regulated Rate Option to provide long-term, stable and affordable prices for Alberta's electricity consumers into the future." The MSA requested that stakeholders provide comments related to this request to help inform the MSA's view presented in the report to the Minister. Comments must be received on or before **May 19, 2017**.

Activities

Self-Report regarding the sharing of dispatch information

The MSA received a self-report regarding a contravention occurring in January 2017, where a market participant communicated dispatch instructions to a plant operator of a different asset than the one dispatched by the AESO. The assets are not affiliated with one another. Therefore, the erroneous sharing of the dispatch information is a potential contravention of section 3(1) of the *Fair, Efficient and Open Competition Regulation*. In light of the potential contravention, changes were made to better facilitate monitoring and verification of plant contact information by the market participant. The MSA found no evidence of an impact to the market resulting from the shared information and in this instance declined to investigate.

Section 95 Solar Micro-generation Projects

As part of its mandate the MSA participates as an interested party in applications submitted by municipalities to the Minister of Energy under *section 95* of the *Electric Utility Act* (EUA). In fall 2016 the MSA became aware of a section 95 application related to micro-generation units (MGU). In part this application sought to extend a previously granted approval for units below one MW to units below five MW. At this time the *Micro-Generation Regulation* limited the capacity of MGUs to 1MW. The MSA noted that some existing facilities appeared to have capacities greater than 1MW. The MSA requested information from the market participant concerned in order to examine whether this apparent discrepancy had resulted in a breach of the Section 95 approval, the applicable acts and regulations, including the EUA and the *Micro-Generation Regulation*.

The MSA looked into a number of MGU projects. Some solar projects had capacity denominated in direct current (DC) and some in alternating current (AC), some of those denominated in AC were above 1MW capacity in DC although the differences were not large. While the MSA was assessing this issue the *Micro-Generation Regulation* was revised, notably the maximum allowable MGU size was raised from 1MW to 5MW, the revised *Micro-Generation Regulation* defines maximum allowable capacity as a function of “nameplate capacity” replacing the previous term “total nominal capacity”.

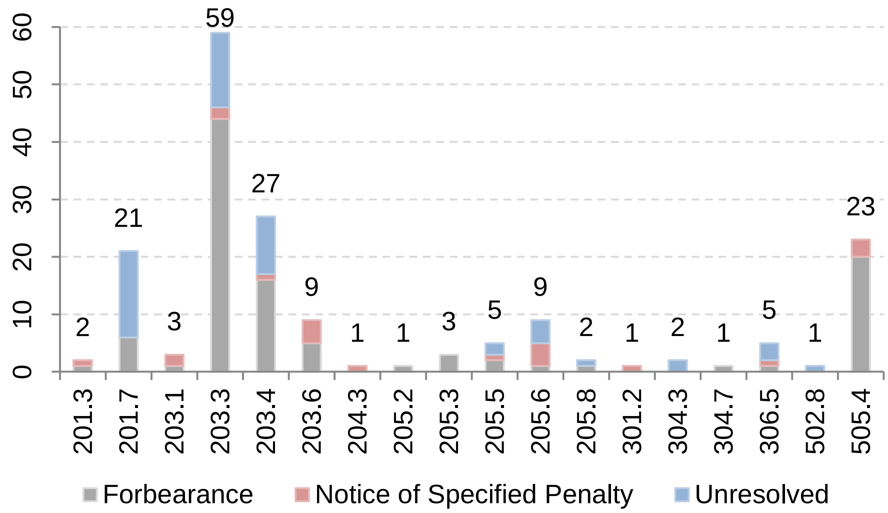
As a result of these changes and the size of the projects concerned the MSA did not pursue the above matter to investigation.

To avoid uncertainty of how the *Micro-Generation Regulation* is interpreted, the MSA believes that there exists an opportunity to clarify what “name plate” capacity means in relation to AC/DC ratings of solar generators. The MSA has provided comments to the Alberta Utilities Commission that clarity could be improved by incorporating the appropriate AC/DC language into either Rule 24 or the Micro-Generator Application Process & Guidelines.

Compliance

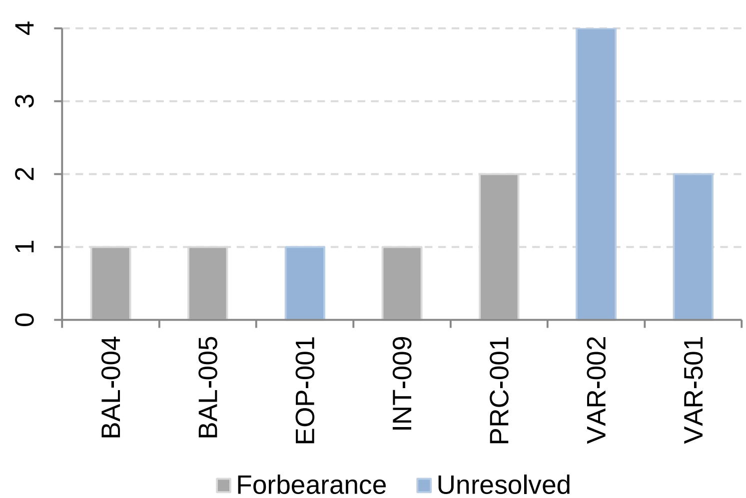
From January 1 to March 31, 2017, the MSA addressed 124 ISO rules compliance matters, while 51 remained unresolved. 21 matters resulted in notices of specified penalty, totalling $17,500 in financial penalties.

Figure 13: ISO Rule Matters Addressed and Received in Q1 2017



For Alberta Reliability Standards, the MSA has closed five matters since the start of 2017, while seven remained unresolved. None of the matters closed during this quarter were addressed with a notice of specified penalty.

Figure 14: Reliability Standard Matters Addressed and Received in Q1 2017



Outage Reporting

As required by section 4 of the *Fair, Efficient and Open Competition* (FEOC) *Regulation*, the AESO is required to make public the aggregate amount of generation outage by generation fuel type. Currently the AESO posts several reports that in total are designed to meet this requirement:

- 7-day generation availability by fuel type (hourly time scale)
- Daily outage by fuel type (approximately 3 months out on a daily time scale)
- Monthly outage by fuel type (2 years out on a monthly time scale)

The issue that has been identified primarily affects the 7-day outage chart.

In its Q2/13 and Q4/15 reports, the MSA reported on the inaccuracy of the AESO's daily outage report for natural gas fired generation ahead in the days approaching real time, an issue that also affects the 7-day outage report. The outage information is used by market participants to help take a price view in the very near term and is also used by some generators to make unit commitment decisions.

The primary causes of the inaccuracy were:

- The timeliness of restatements for on-site load at cogeneration facilities and ambient condition de-rates
- The use of derates to represent the lead time on a portion of an asset's capability

The MSA committed to exploring possible improvements for this report.

Restatements for Ambient Conditions or On-Site Load Effect on Outage Reporting

Perhaps the simplest way of improving the quality of the report would be for facilities to enter expected ambient condition, on site load and de-rates at an earlier date. Outages and outage records are addressed by both legislation and ISO Rules.

The FEOC regulation prohibits trading on non-public outage records. In general, the desire to hedge an outage or otherwise participate in the forward market may provide sufficient incentive to input outages promptly to make the outages public. However, for market participants that are not active on the forward markets, there may be little incentive to input outages until closer to real time. In particular, the ISO Rules distinguish between a pool participant's responsibilities prior to and after an offer is made to the pool.

ISO Rule 203.3 2(2) states that:

> A pool participant **that submits an offer** must, if there is a change to the available capability of the source asset as a result of any of the circumstances outlined in subsections 2(1)(a), (b) or (c) [such as an acceptable operational reason], submit an available capability

> restatement revising the available capability for the applicable hours, **as soon as reasonably practicable**. [emphasis added]

However, ISO Rule 203.1 2(2) states that:

> A pool participant submitting an offer or bid must submit such offer or bid:
>
> > (a) before 12:00 hours on the day before the day that the offer or bid is effective, subject to any extension of time granted pursuant to subsection 3 of section 201.4 of the ISO rules, Submission Methods and Coordination of Submissions; and
> >
> > (b) no earlier than 00:00, seven (7) days prior to the day that the offer or bid is effective.

In accordance with ISO Rule 306.5, planned outages must be submitted to the ISO out 24 months, and newly added or revised planned outages must be submitted as soon as reasonably practicable. However, a planned outage is defined in the AESO's Consolidated Authoritative Document Glossary as:

> the full or partial unavailability of a facility which is anticipated as part of a legal owner's regular maintenance, including for the purposes of construction, commissioning or testing, and occurs as a result of a deliberate manual action.

Therefore, based on the MSA's understanding of the ISO Rules and the definition of planned outages, ambient condition de-rates are not planned outages and as such from the perspective of complying with ISO rules may not need to be input until (no later than) noon day ahead.

Long Lead Time Units Effect on Outage Reporting

A long lead time unit that is economically offline with a start-up time longer than one hour inputs its full availability, and is not included in the AESO's outage reporting. However, a unit that has some part of its energy available with a lead time, the AC is restated to the amount dispatchable within the delivery hour.

Based on discussions with the AESO, due to the structure of the Energy Trading System (ETS), a more effective handling of long lead time energy would require significant changes of how participants enter availability information. At this time, the MSA understands the AESO has no immediate plans to make modifications to ETS in this regard.

Next Steps on Outage Reporting

Given the challenge of addressing the inaccuracy of outage reports without changes to the market systems or ISO rules, the MSA sought to examine whether there was sufficient impact of the discrepancies to warrant any further action. Natural gas generation plays an increasingly large role in Alberta's electricity market, and participants rely on publicly available outage information when planning generator outages, or making forward market transactions. However, while the report may change significantly approaching real time, if the changes were sufficiently predictable there may be no harm.

Therefore, the MSA sought to examine relatively short term outages being planned within the three day window before delivery. Outages longer than a few days may be discernible in the public report as they may appear as a level shift across several days (particularly ones that do not have long lead time or ambient condition de-rates entered yet). But natural gas outages lasting two days or less may be obscured by the “noise” of entered derates. The MSA believes this is likely to be relatively rare, but still possible, as shown in the example below.

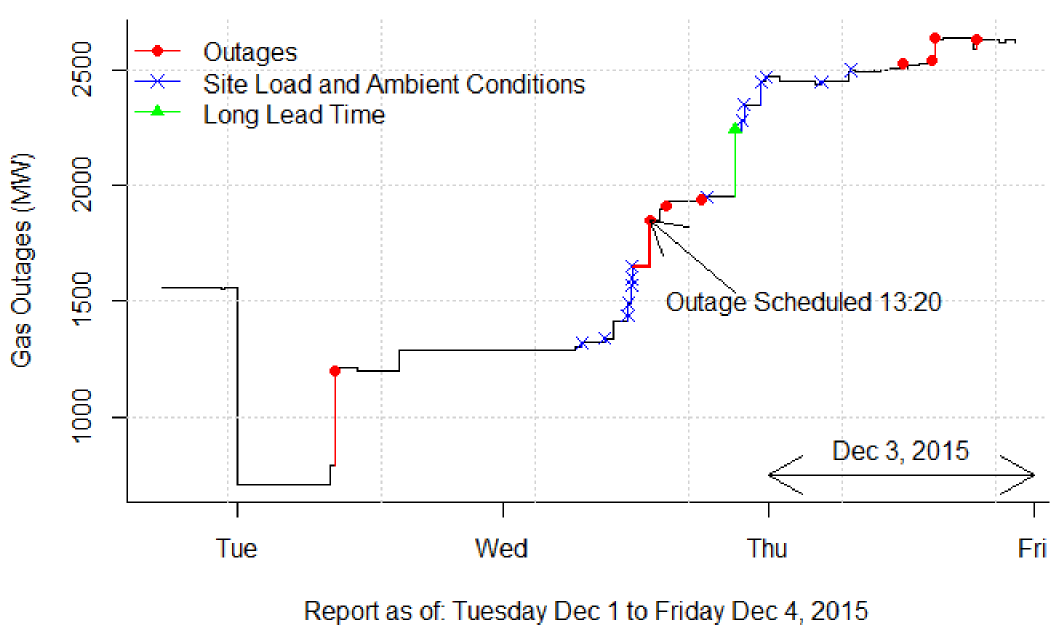
December 3, 2015

The following describes the AESO’s daily outage report for December 3, 2015, and in particular how it changed over the preceding days.

On December 2, 2015 at 13:18 an outage for EGC1 Shepard was entered to begin that evening (at 22:00) and continue until 11:00 the following day, December 3. As Shepard was already de-rated, this new 13 hour outage would add approximately 200 MWs to the daily outage report for December 3. At 13:20 the amount of publicly reported gas outage increased from 1650MW to 1850MW.

Figure 15 shows the evolution of the December 3 gas outage value from December 1 to December 4. The MSA categorized changes based on the underlying operating reasons submitted to the AESO. The figure shows significant changes leading up to and after the outage entry, which would have made it difficult to determine whether there was a new outage or a more “routine” increase.

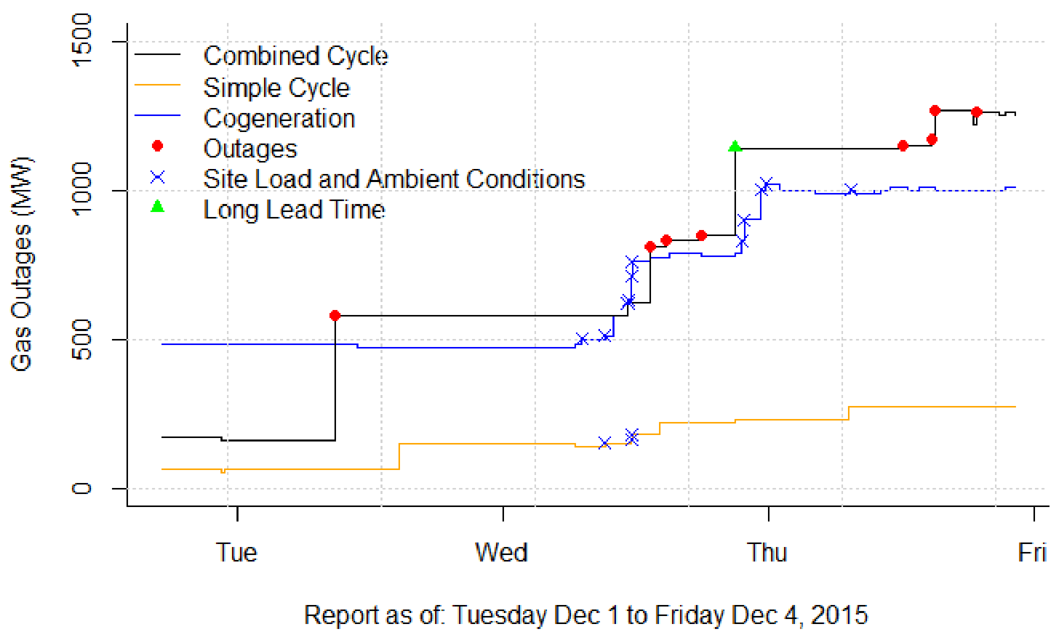
Figure 15: AESO Daily Outage Report for December 3, 2015



As one possible remedy, the MSA explored breaking out the gas outages based on the AESO's Current Supply/Demand page categories. The MSA was able to closely replicate the versioned AESO outage graph as published, and then modified it to include new natural gas categories.

Figure 16 shows how the December 3, 2015 gas outage values would have evolved had they been separated into cogeneration, simple cycle, and combined cycle. As is clear, most of the site load or ambient condition de-rates occur in the cogeneration category, making it easier for participants to notice the change in the combined cycle category, which was the result of an outage.

Figure 16: Potential Daily Outage Report for December 3, 2015



One benefit to this change is that it would not require significant changes to underlying systems or ISO rules. While partial long lead time outages will still be a source of inaccuracy, it may be a considerable improvement to the current method of reporting. Therefore, the MSA recommends the AESO disaggregate natural gas outages by simple cycle, combined cycle, and cogeneration in the public outage reports.

Standby Regulating Reserve Volumes

In Q2/2016 Quarterly Report, MSA analysis indicated that that the AESO could make a small decrease in its daily standby regulating reserve procurement and realize savings on the total costs while maintaining low rates of conscription.[7]

The AESO procures standby regulating reserve each day for the day ahead to cover any active regulating reserves that can no longer provide the product in real time or where system controller requires additional regulating reserves due to prevailing circumstances. The amount of standby regulating reserve procured each day was 100 MW for both on- and off-peak periods. However, the AESO only activated 1% of the standby regulating reserve procured each year, on average.

Based on the daily procurement amount and the historical activation percentage for standby regulating reserve, the MSA hypothesized that decreasing the amount of standby regulating reserve procured daily can decrease the cost of OR without decreasing system reliability. To test the hypothesis, the MSA undertook an analysis to determine the cost of standby regulating reserves for each year for the years 2013 to 2015 while decreasing the daily procurement amount. A key assumption in this analysis was that the AESO will conscript any shortfall of reserves that was needed to be activated. For example, if the AESO historically activated 50 MW of regulating reserves in an hour but the hypothetical amount of standby regulating reserves procured by the AESO was 40 MW, then the AESO would have conscripted 10 MW of regulating reserve to meet the 50 MW of activated standby regulating reserve.

The MSA found that the total cost of standby regulating reserve steadily decreases as the daily volume procured decreases. On the other hand, the number of hours where the AESO would have to conscript regulating reserve increases. Based on these results, the MSA recommended that a small decrease in procurement volumes can result in savings on the total cost of procuring standby regulating reserve while maintaining low rates of conscription.

The MSA met with AESO commercial staff to discuss the results of the analysis. On September 14th, 2016 the daily standby regulating reserve procurement was reduced from 100 MW to 80 MW.

Post-Change Assessment

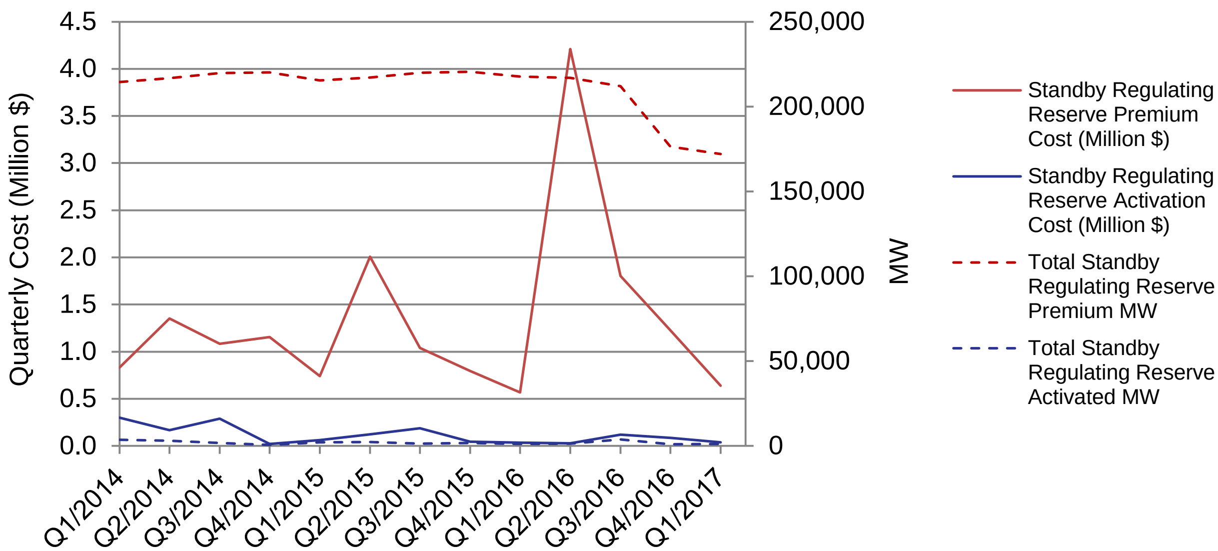
The MSA sought to look at the effects of this change (if any) on regulating reserve standby cost, as well as offer behaviour. As illustrated in Figure 17, standby regulating reserve procurement fell by approximately 40,000 MWh in both Q4/2016 and Q1/2017. While both the activation costs and activated volumes of regulated reserve fell after this policy change, these were reasonably small changes. A counterfactual analysis was performed on offers over the September 14th 2016 to March 31st, 2017 period, to determine the actual savings of reducing standby regulating reserve procurement by 20MW. All else constant, if the AESO had procured 100 MW rather than 80 MW, there would have been approximately $1 million more in standby

[7] MSA Q2/2016 Quarterly Report, Pages 13, 14.

premium costs.[8] Over the six and a half months since the change, the savings have averaged $147,600/month, and there have been no additional conscriptions as a result.

The total costs of standby regulating reserve procurement before and after September 14th was also impacted by changes in offer behaviour. Standby regulating reserve services are awarded to units through a pay-as-bid auction, ranked by blended price.[9] When looking at auctions for both August and October 2016 (before and after the volume change, respectively), blended price offers appear to fall for both on-peak and off-peak standby regulating reserve products after the decrease in daily procurement from 100 MW to 80 MW (see Figure 18 and Figure 19). This shift in the merit order is primarily due to decreasing standby premiums offered. Notably, while the portion of the on-peak merit order that would be procured decreased due to the lowered buy volume (100 to 80 MW), cumulative offers greater than 120 MW offered at higher blended prices after the September change in procurement volume. The MSA has not ruled out other potential causes but it is possible that the lower procurement volumes result in lower offers further explaining some of the cost reduction.

Figure 17: Quarterly Costs and Volumes of Standby, Activated Standby Regulating Reserves



[8] This analysis uses Wattex offers and procures 20 more MWs based on the blended price ordering
[9] Blended Price = Standby Price + (Activation Price * Activation Factor). The Activation Factor is 1% for Onpeak Standby Regulating Reserves, and 3% for Offpeak Standby Regulating Reserves.

Figure 18: August, October 2016 Average Daily Onpeak Standby Regulating Reserves Merit Order[10]

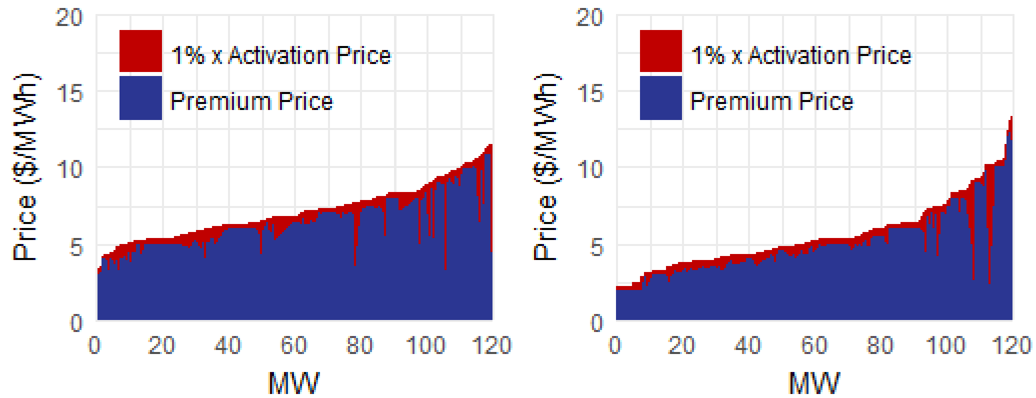
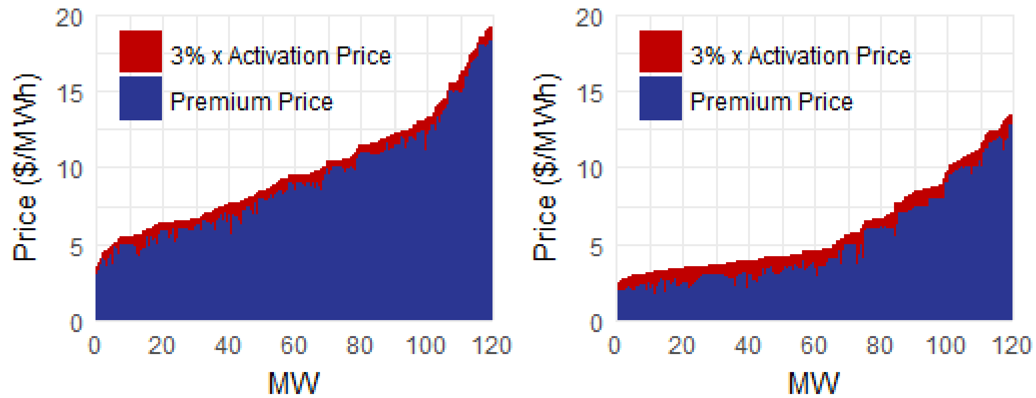


Figure 19: August, October 2016 Average Daily Offpeak Standby Regulating Reserves Merit Order[10]



[10] Note that activation prices have been scaled by their respective activation factors.

Recommendations

Over the years the MSA has made many recommendations, mostly focused on the wholesale electricity market. We have not made any attempt to track how the recommendations were received and dealt with. Starting with this quarterly report, the MSA will track the recommendations that have been made and review the list on a periodic basis. The table below is a summary of recommendations made or referenced in 2015 and 2016 quarterly reports, and will be maintained going forward.

Table 4: Current Status of MSA Recommendations

First Report	Subject	Recommendation	Comments/Outcome
2013 Q2	Natural Gas Generation Outage Reporting by the AESO	Public outage information used for generator outage coordination or forming future price views is inaccurate until close to real time. The MSA recommends disaggregating natural gas outages by simple cycle, combined cycle, and cogeneration in the outage reports. [Q1 2017]	The initial analysis was revisited in Q4/15, and subsequent discussions with the AESO informed the analysis and recommendation presented in the 2017 Q1 report.
2015 Q2	Import Enablement via Additional Operating Reserves	In real time AESO will activate standby contingency reserves if required and if available. However, on many occasions the standby reserves are generators that are already running and providing energy to the system. As they are activated from standby they withdraw from the energy market. Paying to withdraw from the energy market to enable imports also requiring payment does not seem like an efficient outcome. Therefore, given the current structure of Alberta's operating reserves market, the MSA does not recommend the use of active operating reserve (or standby activations) as a mechanism of enabling imports.	A further example outlining the MSA's concern over this practice was described in the 2017 Q1 report.
2015 Q2	Activation Prices of Standby Reserves	A pay as bid activation price for standby reserve appears to be inefficient, particularly in periods of price volatility. The MSA recommends setting the activation price for standby at that of the active reserves and standby sellers then compete based on the premium they require.	

First Report	Subject	Recommendation	Comments/Outcome
2016 Q2	Standby Regulating Reserve Volumes	The AESO rarely used all of the standby regulating reserves procured. The MSA recommended reducing the buy volume of standby regulating reserve as it appeared reductions in procurement would not increase conscription rates. [2016 Q2]	The AESO reduced the buy volume by 20 MWs in September 14, 2016. The MSA estimates the reduction in procurement costs is approximately $1m from the time the change to the end of Q1 2017. This in turn reduces the amount that needs to be charged to consumers through Rate DTS of the ISO tariff.
2016 Q4	LSSi contract structure	In 2016 $10 million was spent on availability payments for LSSi, but there were no armings. With the aim to change the payments structure such that LSSi payments were for actual services provided, the MSA recommends the AESO re-examine the three part pricing structure of LSSi contracts prior to the expiry in 2018.	
2017 Q1	Micro Gen Regulation	To avoid uncertainty of how the Micro-Generation Regulation is interpreted, the MSA believes that there exists an opportunity to clarify what “name plate” capacity means in relation to AC/DC ratings of solar generators. The MSA recommends the Alberta Utilities Commission create such clarity by incorporating the appropriate AC/DC language into either Rule 24 or the Micro-Generator Application Process & Guidelines.	