MSA

MARKET SURVEILLANCE
ADMINISTRATOR

Q4/15 Quarterly Report

October – December 2015

January 29, 2016

Contents

Wholesale Market

Summary

Average wholesale electricity prices in Q4/15 set yet another all-time low. The pool price for the quarter averaged $21.19/MWh ($16.59/MWh Ext. Off Peak, $23.49/MWh Ext. On Peak).

The recent price environment remains unprecedented in Alberta's electricity market. Higher supply cushion levels in 2015 have contributed to a reduction in the ability for firms to exercise market power to increase prices.

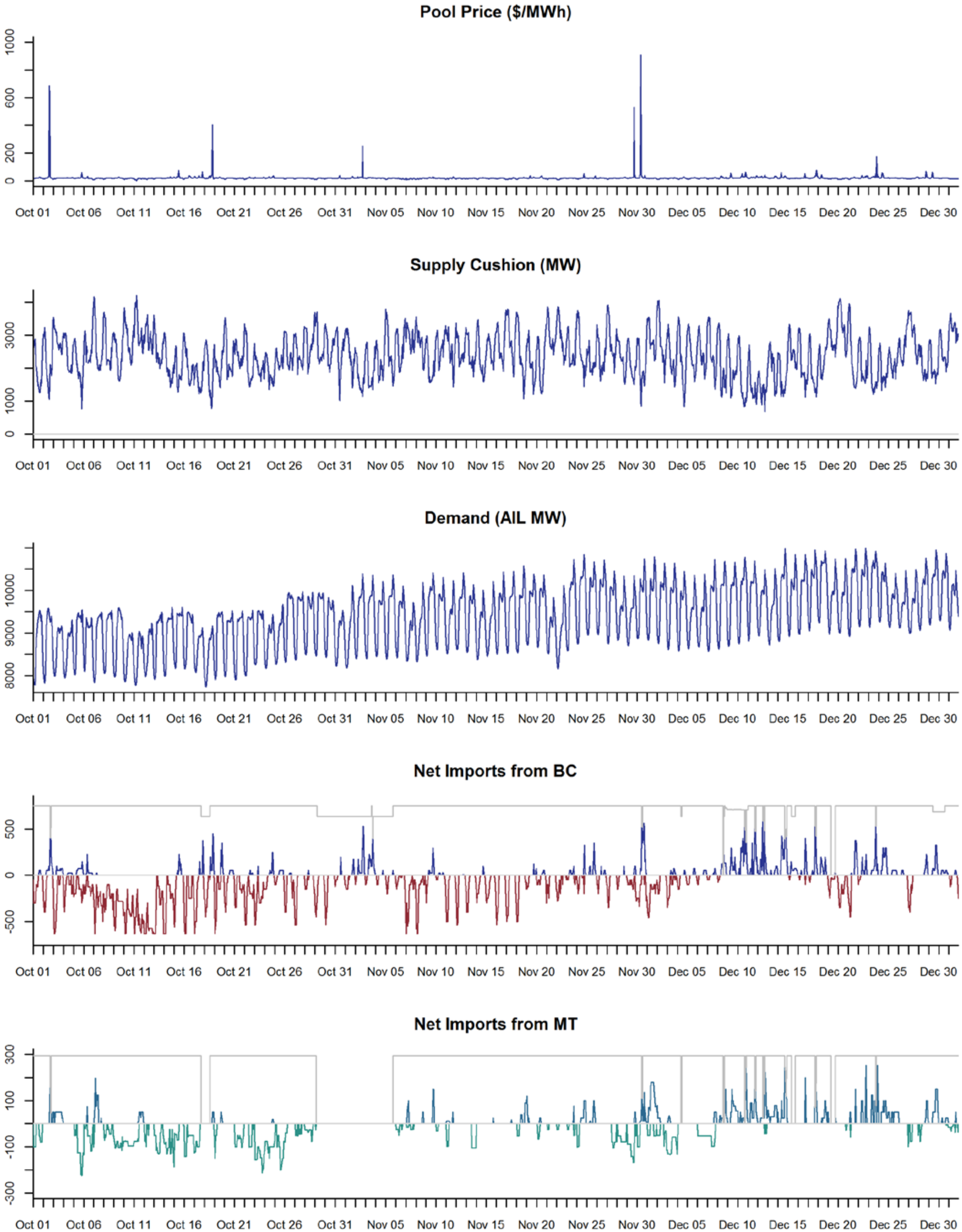
For the calendar year 2015, wholesale prices averaged $33.34/MWh, a 33% decrease from 2014. With the exception of Q2/2015, all quarterly prices during the year were lower than their respective quarters since the market's inception.

Natural gas averaged $2.56/GJ during 2015 as gas continues its long period of 'below normal' pricing.

Table 1: Summary Statistics

		2014	2015	*Change*
Average Pool Price ($/MWh)	October	27.04	21.47	*-20.6%*
	November	37.70	21.17	*-43.9%*
	December	26.90	20.93	*-22.2%*
	Q4	**30.47**	**21.19**	*-30.5%*
Average Gas Price ($/GJ)	October	3.49	2.47	*-29.4%*
	November	3.73	2.40	*-35.6%*
	December	3.04	2.18	*-28.1%*
	Q4	**3.42**	**2.35**	*-31.3%*
Average Supply Cushion (MW)	October	1655	2379	*+43.8%*
	November	1802	2466	*+36.9%*
	December	1993	2293	*+15.1%*
	Q4	**1816**	**2379**	*+30.9%*
Average Outages (MC - AC, MW)	October	4009	3127	*-22.0%*
	November	3396	2837	*-16.5%*
	December	3029	2716	*-10.3%*
	Q4	**3479**	**2894**	*-16.8%*
Average Demand (AIL, MW)	October	9005	8935	*-0.8%*
	November	9646	9459	*-1.9%*
	December	9807	9834	*+0.3%*
	Q4	**9484**	**9409**	*-0.8%*
Average Wind (MW)	October	629	535	*-15.0%*
	November	496	585	*+18.1%*
	December	618	579	*-6.4%*
	Q4	**582**	**566**	*-2.7%*

Figure 1: Summary Data



Net Revenue Analysis

The net revenue for a representative simple cycle, natural gas-fired combustion turbine is illustrated in Figure 2. While low natural gas prices resulted in low marginal costs, this was not enough to offset the effect of low pool prices and so net revenue decreased in 2015 compared to previous years. Nonetheless, based on MSA analysis[1], net revenue over the past six years has cumulatively amounted to approximately $1.4 million per MW of capacity. While the net revenue in 2015 was modest, this analysis suggests there has been sufficient net revenue over the past six years to return the original investment cost to the hypothetical plant's owner.

Figure 2: Annual Net Revenue for a Simple Cycle, Natural Gas-fired Generator (Thousands $/MW)

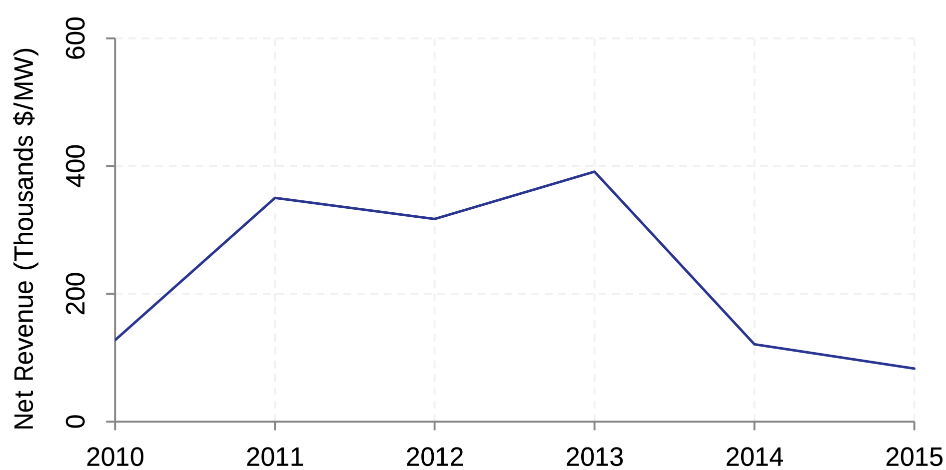
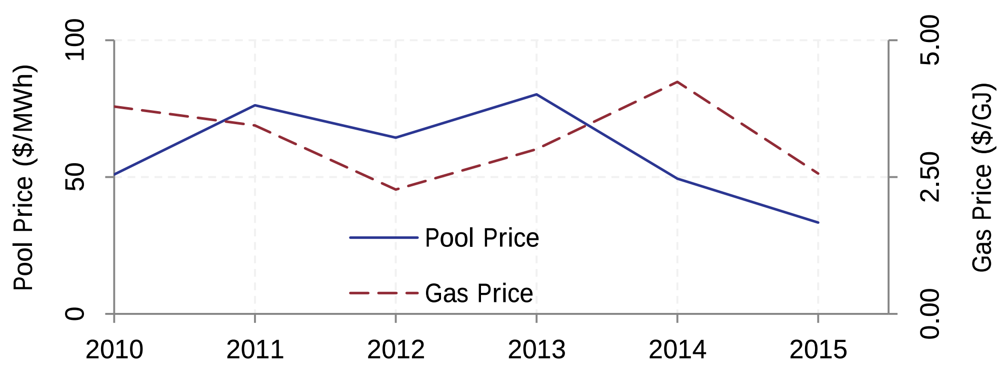


Figure 3: Annual Average Pool Price ($/MWh) and Natural Gas Price ($/GJ)



[1] The MSA analysis used assumptions about costs substantially similar to those in: Brown, David P. and Olmstead, Derek E. H., *Measuring Market Power and the Efficiency of Alberta's Restructured Electricity Market: An Energy-Only Market Design* (January 21, 2016). USAEE Working Paper No. 16-235. Available at SSRN: http://ssrn.com/abstract=2719918

Average Price Received by Wind Generators

Figure 4 illustrates the output-weighted average pool price received by wind generators over the past eight years. Since 2008, the wind output-weighted price has averaged approximately $18/MWh less than the average pool price; in 2015, this difference was $11.01/MWh. In percentage terms the difference is more consistent. As shown in Figure 5, wind output received approximately 30-35% less than the average pool price over the past three years. Note that these are averages and the wind generation in some areas received significantly more.

The difference between the two values in dollar terms is less than in most recent years. This is not unexpected. Absolute differences between average and output-weighted average pool price received by wind generators occur as higher prices are more likely in hours when there is little wind generation available. In years, like 2015, where there is an abundance of thermal generation prices do not rise as much when wind generation is scarce.

Figure 4: Average Pool Price and Wind Output-Weighted Pool Price ($/MWh)

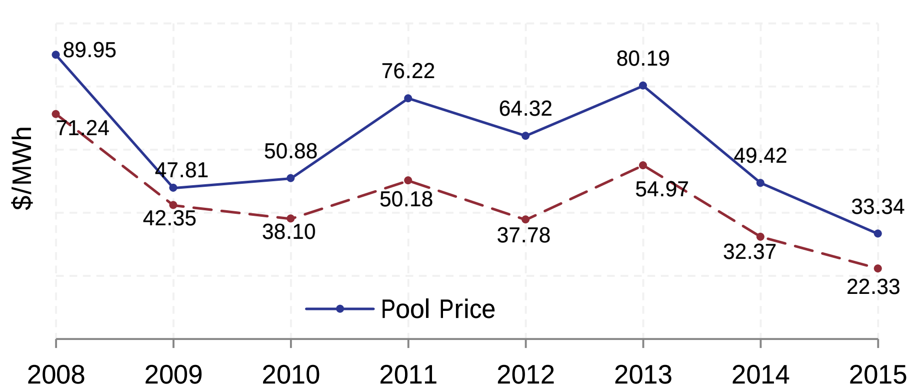
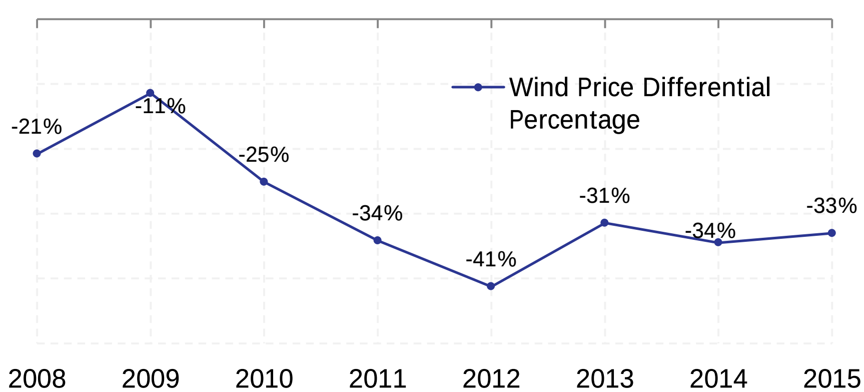


Figure 5: Average Wind Price Difference from Average Pool Price (%)



Residual Supplier Index Update

At the 2015 MSA Stakeholder Meeting, a plan was announced to update the Residual Supplier Index (RSI) measures featured in the MSA's State of the Market Report 2012,[2] and described in detail in the companion document, Measuring Generator Market Power.[3] The RSI is a structural measure of market power that considers the concentration of offer control relative to the level of market demand. It is a structural measure because it does not indicate if a participant has the incentive to exercise market power (e.g., it does not take into account a firm's financial position), but rather simply whether or not it may have the ability to exercise market power.

In particular, the RSI indicates the extent to which a participant is 'pivotal'. A participant is pivotal if some portion of its available capacity is required to meet market demand, assuming all other available capacity is dispatched. The extent to which a particular firm's available capacity is required to meet market demand for a given hour is what is captured by the RSI. When the RSI value for a given firm is less than or equal to one, that firm is pivotal, whereas an RSI value greater than one indicates that the firm is not, by itself, required to meet prevailing market demand. Intuitively, the larger market demand or the larger a given firm's share of supply, the smaller the RSI value for that firm and the more likely it is that the firm will be pivotal.

The largest-firm RSI value is the value for the most pivotal firm in a given hour. Figure 6 plots duration curves of largest-firm RSI by year, showing a trend of more hours with higher RSI values (indicating less structural market power) through time, especially in terms of the number of pivotal hours (RSI less than or equal to 1). As may be expected, periods in which the largest firm was pivotal were associated with higher average realized pool prices than periods in which the largest firm was not pivotal.

[2] http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Final%20Report%2020130104.pdf

[3] http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Market%20Power%20103112.pdf

Figure 6: Duration Curves for Largest-Firm RSI by Year

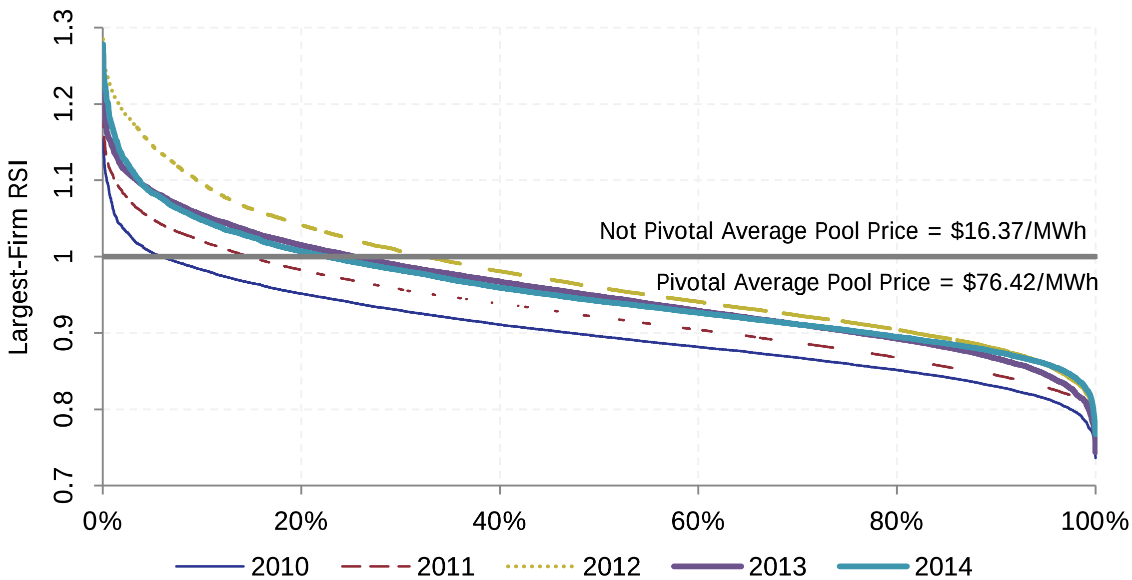


Table 2 shows the percentage of hours in which each of the five largest generators was individually pivotal in each year. Here we observe a generally downward trend of pivotality over time, with the exception of 2011, suggesting that most firms are pivotal less often. It is notable that one firm was pivotal for a majority of hours during each year.

Table 2: Percentage of Hours in which Firms were Pivotal by Year using RSI

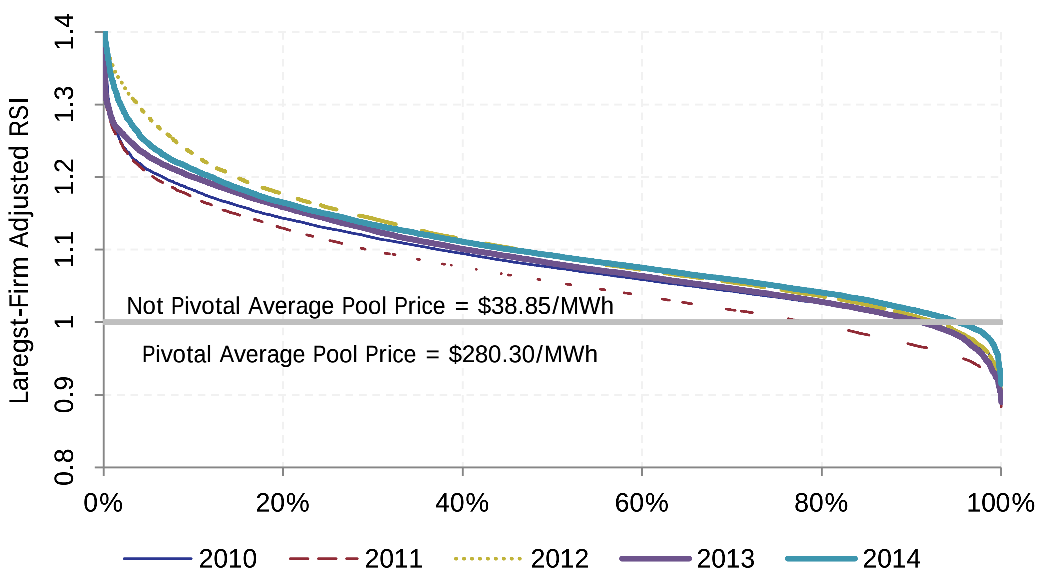
	2010	2011	2012	2013	2014
Participant A	7.4	13.9	7.2	10.9	8.8
Participant B	27.7	35.2	33.4	31.7	8.8
Participant C	31.2	45.0	37.1	38.0	14.4
Participant D	65.4	74.6	48.2	43.6	14.7
Participant E	93.8	82.6	63.3	73.4	77.4

One fundamental assumption underpinning a standard RSI analysis is that firms are able to control all of their available supply. However, due to operational or environmental constraints, this may not be true. These constraints may include minimum stable generation levels (e.g., to avoid shut-down and start-up costs), requirements of related industrial processes (e.g., steam levels for oilsands projects), or flow requirements for hydroelectric facilities. In terms of offer behaviour, firms with these constraints would typically offer the constrained capacity at $0/MWh.[4]

[4] See MSA Report on Zero Dollar Offers http://albertamsa.ca/files/Zero_Offers_042903.pdf

To account for these constraints, RSI may be adjusted to only consider a firm's available capacity of offers made at prices above $0/MWh. The general effect of this adjustment is to reduce the effective size of a firm's available capacity, resulting in larger adjusted-RSI values, implying that a firm is less pivotal than an unadjusted measure would suggest. As with the unadjusted RSI analysis, periods when the largest firm was pivotal are associated with higher pool prices than periods when the largest firm was not pivotal. By removing the offers $0/MWh, a firm is less likely to be pivotal, resulting in an average pool price for adjusted pivotal hours that is materially greater than the average pool price for unadjusted pivotal hours. Figure 7 illustrates the duration curves for largest-firm adjusted-RSI by year, which generally follows the pattern in Figure 6, but with a much lower number of pivotal hours. 2010 and 2011 show a different trend in the adjusted RSI duration curves, which is a result of coal outages in 2011 and the relatively low number of zero-dollar offers.

Figure 7: Duration Curves for the Largest-Firm Adjusted RSI by Year



Finally, Table 3 displays firm-level adjusted-RSI data. Here we observe that removing the zero-dollar hours greatly reduces the number of hours a given firm is pivotal relative to the unadjusted measure, but that the generally decreasing trend of pivotal hours over time still holds.

Table 3: Percentage of Hours in which Various Firms were Pivotal by Year using Adjusted-RSI

	2010	2011	2012	2013	2014
Participant A	0.7	1.5	0.7	1.4	0.2
Participant B	0.8	2.0	1.1	2.3	0.2
Participant C	1.4	4.0	2.5	5.6	0.4
Participant D	6.3	18.2	3.6	2.9	0.2
Participant E	6.5	13.9	5.8	5.0	4.8

Natural Gas-fired Generation Outages

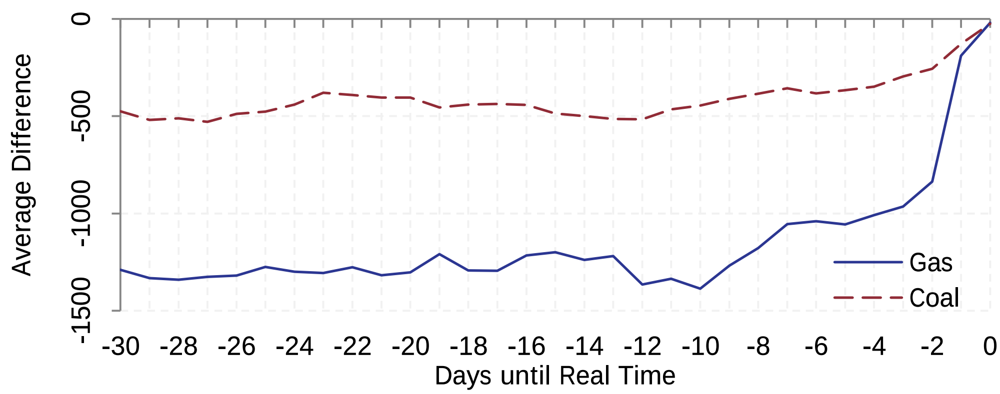
The Alberta Electric System Operator's (AESO) public reports are an important source of information to the market and as such need to be timely and accurate. Many of these reports are generated directly from data provided by market participants. Quality then depends on the inputs provided by participants as well as the AESO.

The MSA previously wrote about outage reporting for natural gas-fired generators in its Q2/2013 report.[5] In that report we identified that the total available capability (AC) of natural gas-fired generators was consistently underreported relative to real time. Only close to real time did the amount of natural gas outages begin to align with the actual. Similar analysis for Q4 2015 concludes that the outage graph still changes substantially approaching real time in the same manner.

Figure 8 below compares the last same-day, or 'real time' version of the daily outage table to the corresponding value published on prior days. The figure averages the differences for each day in Q4 2015. For comparison the same data for coal is presented. The difference is considerably higher for natural gas-fired generators than coal units. Some change is expected to occur as outages not forecast can and do occur for both gas and coal units. The amount calculated for the natural gas-fired generators seems to be high.

[5] MSA Q2/13 Quarterly Report

Figure 8: Average Difference Compared to Real Time, Daily Outage Table (Q4 2015)



The MSA has identified a number of factors influencing this discrepancy for natural gas-fired generators:

- AC submissions for long-lead time units
- On-site load at cogeneration facilities
- Inputting of derates due to ambient conditions

As noted in the Q2/2013 report, derates due to ambient temperatures should be possible to foresee into the near future, if only approximately. To the extent on-site load is planned, this too would be a potential area for improvement in AC submissions.

The handling of long lead time units remains an area the MSA will explore further. These units could be made available to the grid for a given day, but over a few hours are not fully available. Natural gas-fired generators that are routinely long-lead time on the day-at-hand restate their available capability to reflect this, and may contribute to the discrepancy in the outage reporting. In other words, the way the data management systems handle long lead time units may contribute significantly to the discrepancy in natural gas outage reporting.

The MSA will continue to monitor this matter with a view to finding any possible improvements that could be made. As noted elsewhere in this report, the quality of such information made available to the market is important.

Forward Market

Summary

As part of its regular monitoring, the MSA routinely collects broker data related to forward market transactions. Beginning this quarter and on an ongoing basis, additional trades from brokers have been added to our trade volume metrics. Previously, the MSA statistics included ICE/NGX trading and some brokered trades. As a result of updating the historical data, previous trade volume figures may not match those in the current report.

Table 4: Trade Volumes by Contract Term (TWh)

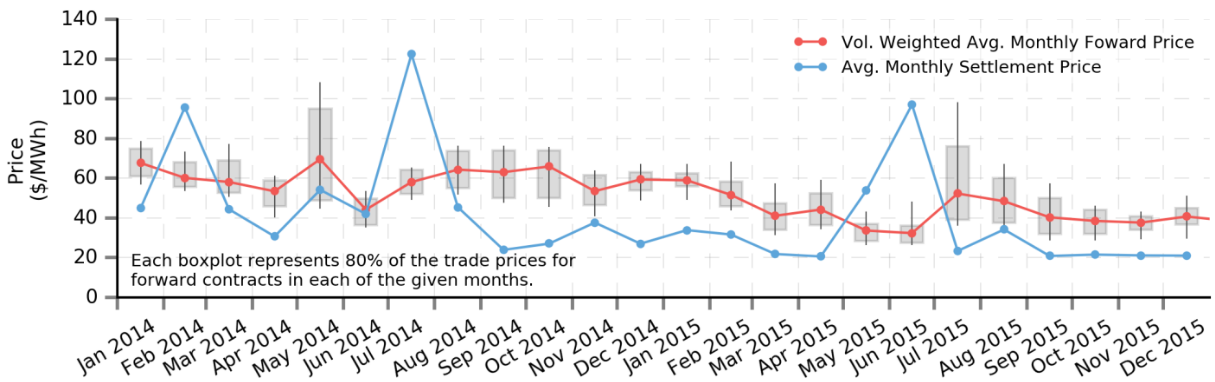
		Daily	Monthly	Quarterly	Yearly	Other	Total
2014	**Q1**	0.05	9.41	1.21	2.64	1.24	14.55
	Q2	0.05	7.62	0.90	5.51	0.58	14.66
	Q3	0.03	7.31	2.76	5.23	0.32	15.64
	Q4	0.02	7.36	2.32	2.43	0.34	12.47
	Year	**0.14**	**31.70**	**7.19**	**15.81**	**2.48**	**57.32**
2015	**Q1**	0.10	9.97	0.84	4.17	0.76	15.84
	Q2	0.20	10.47	1.14	16.71	0.66	29.19
	Q3	0.06	6.25	0.50	5.02	0.43	12.26
	Q4	0.06	5.87	0.98	5.74	0.03	12.68
	Year	**0.42**	**32.56**	**3.46**	**31.64**	**1.88**	**69.97**

As shown in Table 4 above, volume for Q4/15 is up slightly from last quarter as well as from the same quarter last year. On a yearly basis, trade volumes were up significantly compared to 2014, however most of the increase in liquidity was due to higher trading of yearly contracts in Q2/15. Overall, liquidity levels appear to be back to historical norms for the time being.

Monthly flat forward contract prices for Q4/15 were relatively stable and traded between \$29/MWh and \$51/MWh, averaging \$39.30/MWh on a volume-weighted basis. Meanwhile, pool prices for the quarter averaged \$21.19/MWh.

As shown in Figure 9, we continue to see forward contracts trading well above pool price the majority of the time. Over the past 24 months there have been four months where the average pool price settled at a higher level than the average monthly forward price. This may reflect a risk premium built into the price of forward contracts to compensate for those months when the average pool price settles at relatively high levels.

Figure 9: Forward Prices vs Average Settled Prices ($/MWh)



Bilateral Data Request

During 2015 the MSA issued an information request for forward market transactions directly between market participants. This request covered transactions that occurred during the years 2013 and 2014. These data are not routinely collected, and do not form part of the MSA's regular reporting on the forward market. To this end, the MSA has prepared the following public summary of the data collected last year.

As shown in Table 5, the MSA collected a total of 20 TWh of contracts, in approximately 340 transactions.[6] The reported bilateral volumes were roughly even between 2013 and 2014.

Table 5: Total Volume of Trading by Contract Term (TWh, 2013 and 2014)

	Routine Collection	Bilateral Request	**Total**
Multi-Year	0.4	8.9	**9.3**
Annual	26.8	8.1	**35.0**
Custom Annual	0.0	0.4	**0.4**
Bal Year	0.9	0.4	**1.4**
Quarterly	13.1	1.1	**14.2**
Multi-Month	0.5	0.4	**0.9**
Monthly	66.7	0.6	**67.4**
Bal Month	2.0	0.0	**2.0**
Daily	0.3	0.0	**0.4**
Grand Total	110.8	20.1	**130.9**

[6] Due to differences in how trades are recorded between participants, the term 'transaction' here is an MSA construct based on a single price for a flow of energy over a set period of time and hourly schedule.

Combining these trades with existing data, the MSA re-calculated a "'trading multiple" (the proportion of forward market trading volume to market demand) for 2013 and 2014. The results are shown in Table 6.

Table 6: Total Volume of Trading Relative to Demand

Year	Trading (TWh)	Demand (TWh)	Multiple (Trading/Demand)
2013	64.4	77.5	**0.83**
2014	66.4	79.9	**0.83**
Total	**130.9**	**157.4**	**0.83**

In summary, the information received supports the following conclusions about Alberta's electricity forward market:

- **Bilateral transactions represent a relatively small share of overall activity:** Comparing bilateral trading with previously collected data added an additional 20 TWh to the existing 110 TWh of observed trading activity.
- **Bilateral transactions are a meaningful portion of longer term contracts**. The information requests yielded 8.1 TWh, or roughly a quarter of all annual contracts and significant volumes of multi-year contracts.
- **Most of the short term, 'liquid' products are captured by the existing data collection.**

Based on the relatively low liquidity of most contracts traded bilaterally and the time-intensive nature of the information request the MSA has decided not to routinely collect the bilateral data but may on occasion make similar requests in the future.

July 2015 Forward Market Event

At the end of June 2015, the forward price for July was $94/MWh. July ultimately settled at $23.15/MWh, resulting in the largest difference between the monthly flat forward price and settled price since 2011. In its Q2/2015 quarterly report, the MSA identified offer behaviour, in addition to outages and uncertainty about the return of Shepard Energy Centre, as contributing to July's elevated forward price. The MSA noted we were assessing the relationship between observed offer behaviour in the spot market and outcomes, competition, and liquidity in the forward market.

The MSA assessed theories of harm involving hypothetical conduct whereby a market participant might influence spot market prices to affect forward market prices. Such a strategy was judged to be difficult to execute profitably. More generally, the MSA had discussions regarding the health of the forward market with several forward market participants with no, or very few, generation assets in Alberta. The participants generally understood and accepted

Alberta's market structure, including the existence of generator market power, and expressed few concerns with the forward market.

The MSA has concluded its review of the July event and no future action is contemplated at this time, but will continue to monitor the market for any similar occurrences.

Forward Market Incident: SCR1 Split

On November 30, 2015, confusion about changes in the AESO's outage report resulted in a modest and temporary uptick in forward market trade prices.

The operator of the SCR1 gas asset (MC = 901 MW) into three asset IDs more reflective of the physical situation at the site (SCR1 = 50 MW, SCR5 = 376 MW and SCR6 = 473 MW). The changeover was planned for midnight December 1, 2015. On November 30 at about 9:30 a.m., the operator entered the new data reflecting the change effective midnight. Since technically SCR5 and SCR6 did not come into existence until midnight, the outage chart for natural gas at the time of the data entry by Suncor reflected only the reduction in available capacity of SCR1. To market watchers, it looked very much like a new gas outage starting at midnight.

Compounding the situation, at about 8:30 a.m. on November 30, the ECG1 (Shepard) asset operated by another market participant went on forced outage. This asset ultimately came back online in the evening. However, the combination of the two events may have appeared to some in the forward market as if ECG1 would likely be on outage for some time and prices in the forward market rose accordingly. The flat December contract price rose from $30/MWh to $33/MWh, although only a small number of trades were involved. At midnight, SCR5 and SCR6 came 'live' and the outage chart reflected actual circumstances again. Prices in the forward market returned to their previous levels on the morning of December 1 as it became a balance of month contract.

The AESO has systems in place to deal with the addition or retirement of generation assets to the system. At any given time the outage reflects the existing assets at the time in question. So, if a new asset is added to the system as soon as it exists on the CSD page its outages and derates are reflected in the relevant outage charts. It is not a common situation to have an existing asset split itself into two or more assets as occurred in this case. In retrospect, a notice to market participants by the AESO alerting them to the forthcoming change would have been helpful.

While only modest trade volumes were directly affected it is another example of how the forward market trades on news and much of that news emanates from AESO reports. These reports often designed by the AESO and populated directly from data provided by market participants. It behooves all involved to make their best efforts so that the published information is as reliable and informative as possible.

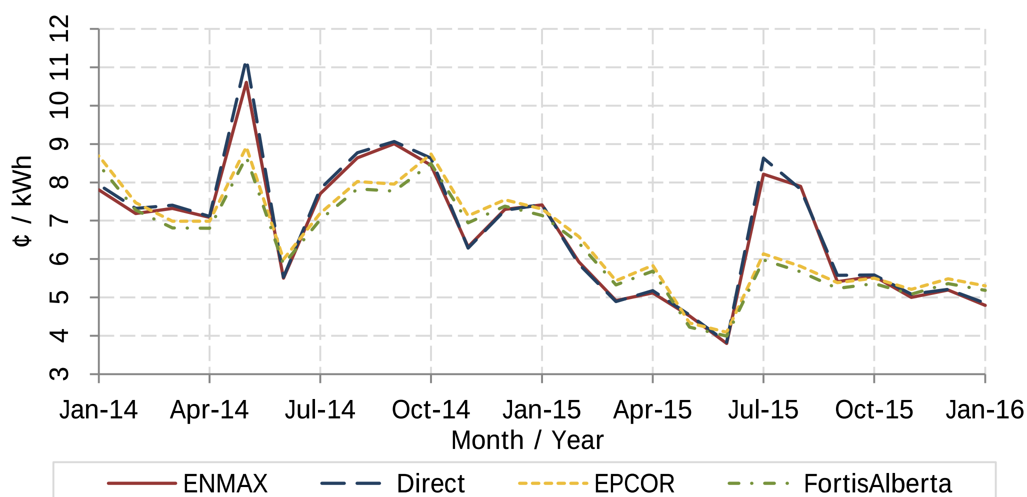
Retail

Regulated Retail Option prices for electricity

Regulated Rate Option (RRO) electricity prices averaged about five cents per kWh in Q4 2015 in each of the four major electricity service territories. There was little variation in the rates offered in the Direct and ENMAX territories (which are set based on forward prices in the 45 days leading into each delivery month) compared to those offered in the EPCOR and FortisAlberta territories (which are set based on forward prices observed in the 120 days leading into each delivery month). This is because forward prices over the whole 120-day period leading into each delivery month were relatively stable; see the forward market section for more information about forward market outcomes observed in the quarter.

As illustrated in Figure 10, RRO prices in Q4 2015 (and January 2016) represent a continuation of relatively low RRO prices, in particular in the EPCOR and FortisAlberta territories, observed from early 2015 onward.

Figure 10: RRO Electricity Price by Provider (¢/kWh)

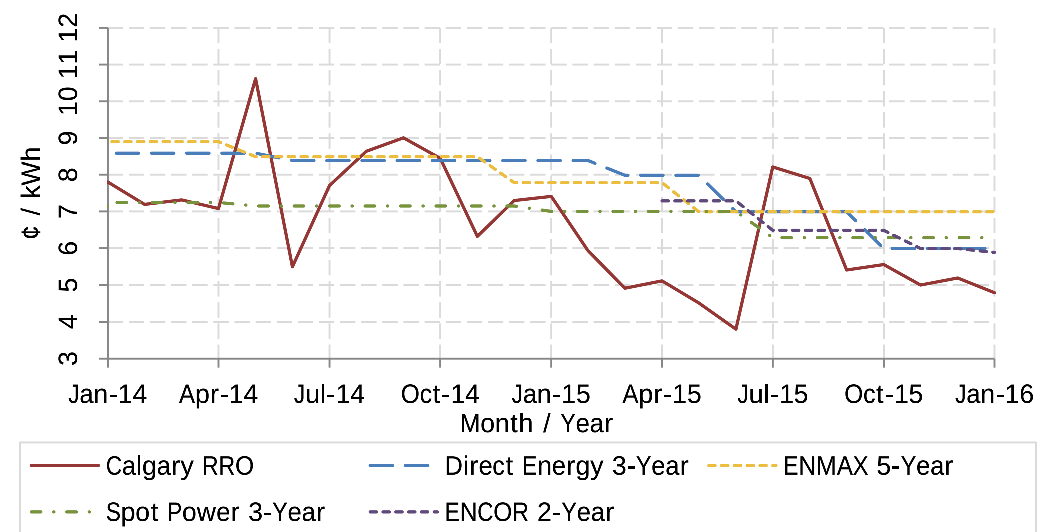


Competitive, fixed-price contract prices for electricity

Competitive, fixed-price contract prices for electricity reached all-time lows in Q4 2015, with the lowest 5-year contract prices falling to slightly below 7 cents per kWh and some shorter duration (2- and 3-year) contract prices falling further, including to slightly below 6 cents per kWh. These price changes have followed, with a delay, a downward trend of spot prices over the past few years and continued low forward prices (which are relatively low in the near term future, as reflected in 2- and 3-year contract prices being lower than 5-year contract prices).

A selection of contract prices is illustrated in Figure 11. Information on other retail offerings is contained on the Utilities Consumer Advocates website (ucahelps.alberta.ca). For comparison purposes, the RRO rate in Calgary is included (this is the ENMAX RRO rate in the figure in the previous section).

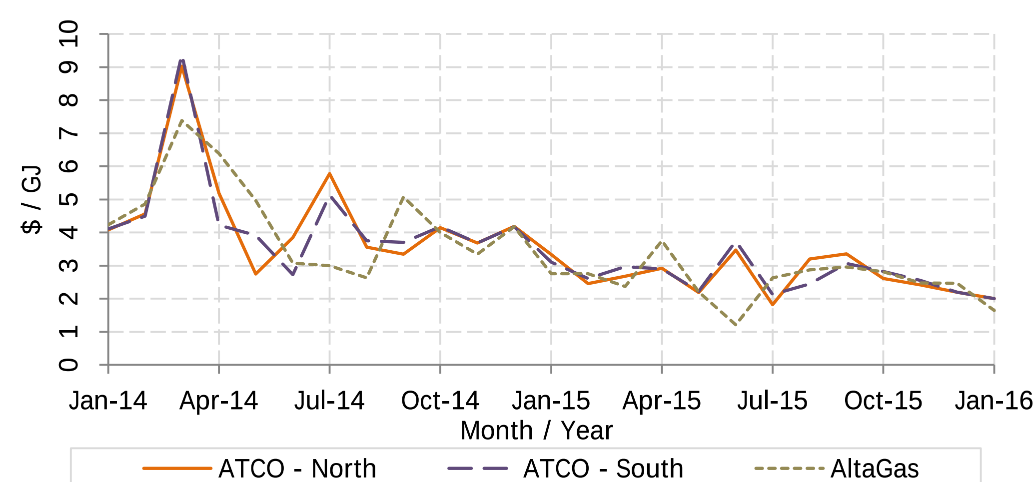
Figure 11: Electricity Contract Rates (¢/kWh)



Default Rate Tariff prices for natural gas

Default Rate Tariff (DRT) natural gas prices declined to approximately $2 per GJ in each natural gas service territory in January 2016. As illustrated in Figure 12, recent DRT prices represent a continuation of the generally downward trend of DRT prices observed over the past few years. These prices are the result of a similar trend in wholesale market natural gas prices, which has flowed through to the retail market.

Figure 12: Natural Gas Price (Default Rate Tariff, $/GJ)



Operating Reserves

As shown in Table 7, overall costs for operating reserves were down a quarter in 2015 compared to 2014. This is largely a result of decreases in average pool price. There were few high pool prices in Q4 2015 and the costs of all reserves, both active and standby, remained moderate. The high standby activation costs of recent quarters did not occur this quarter.

On an annual basis, total costs in 2015 were down 25% from 2014, a reflection of the reduced volumes purchased and lower average pool price. Reliability standard BAL-002-WECC-AB-2 defines the volume of contingency reserves that the AESO must purchase. In October 2014 the formula was changed with the effect of reducing the volume purchased. As reported in recent quarterly reports, standby activation costs were considerably higher in 2015. Although this is only a small portion of total operating reserves costs, the average activation cost in 2015 was almost $150/MWh.

Table 7: Operating Reserve Summary Statistics

	ANNUAL			QUARTERLY		
Cost of Operating Reserves ($ Millions)						
	2014	**2015**	*Change*	**Q4 2014**	**Q4 2015**	*Change*
Active Reserves	167.8	105.2	*-37.3%*	16.6	13.7	*-17.2%*
Standby Activation	3.0	20.1	*+566.7%*	0.5	0.4	*-19.6%*
Standby Premiums	13.8	13.0	*-5.6%*	3.1	1.9	*-38.0%*
Total	**184.5**	**138.3**	*-25.0%*	**20.2**	**16.0**	*-20.5%*
Volume of Operating Reserves (GWh)						
	2014	**2015**	*Change*	**Q4 2014**	**Q4 2015**	*Change*
Active Reserves	6005.9	5333.3	*-11.2%*	1412.3	1366.1	*-3.3%*
Standby Activation	64.8	135.7	*+109.4%*	13.8	15.2	*+10.6%*
Standby Premiums	2142.4	2140.3	*-0.1%*	528.4	528.8	*+0.1%*
Total	**8213.2**	**7609.3**	*-7.4%*	**1954.5**	**1910.2**	*-2.3%*
Average Operating Reserves Costs ($/MWh)						
	2014	**2015**	*Change*	**Q4 2014**	**Q4 2015**	*Change*
Active Reserves	27.93	19.73	*-29.4%*	11.72	10.03	*-14.4%*
Standby Activation	46.49	148.03	*+218.4%*	33.47	24.32	*-27.3%*
Standby Premiums	6.42	6.07	*-5.5%*	5.94	3.68	*-38.1%*
Total	**22.47**	**18.18**	*-19.1%*	**10.31**	**8.38**	*-18.7%*

Regulatory

AUC Proceeding 21115: Historical Trading Report

On December 2, 2015, the MSA filed an application with the Alberta Utilities Commission (AUC) in relation to the MSA's concerns about the AESO's publication of the Historical Trading Report. Subsequently, the AUC established Proceeding 21115 to consider all aspects of this issue.

AUC Proceeding 3110

On October 29, 2015 the AUC approved the consent order proposed by the MSA and TransAlta. The AUC's decision (Decision 3110-D03-2015) and an executed copy of the order can be found on the AUC's website. This decision and order brought Proceeding 3110 to a final and binding conclusion.

Possible contravention of Section 3 of the *FEOC Regulation*

In October and December 2015 the MSA received two separate self-reports regarding sharing, between competitors, of non-public information relating to price and quantity offers. The MSA assessed these self-reports as possible contraventions of Section 3 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation). There was no evidence that either incident had resulted in trading on non-public outage information (prohibited by section 4 of FEOC Regulation). In each case the MSA declined to investigate. The timely self-reporting of the issues was a factor in the MSA's decision not to investigate.

The MSA would like to stress, however, that the sharing of information not available to the public related to price and quantity offers is prohibited, unless excused or allowed as set out in s. 3 of the FEOC Regulation. The MSA encourages market participants to assess their FEOC compliance procedures to ensure that their policies and practices take all reasonable care to ensure they avoid committing an offence. While the MSA, in these cases, determined that the inadvertently shared information did not warrant further action, in other cases it may be more likely that the MSA would take enforcement action.

October 2015 Self-Report

This incident occurred when the real time operator at one joint venture partner sent updated outage information to marketers at both joint venture partners, but failed to update ETS before doing so. The information shared related to only a small number of MWs and ETS was updated a few hours later, after which the information was included in publicly available outage graphs on the AESO website. The MSA declined to investigate this matter.

December 2015 Self-Report

This incident occurred when a market participant was preparing to bring a unit back from an unexpected outage. In preparation for bringing the unit online, the participant's operations group sent generation testing information to the AESO and inadvertently copied another market participant. This testing information related to price and quantity offers. The operations testing information was sent after the 15 day advance notice period required in normal circumstances by ISO Rule 505.4, but before it would be reasonable to call the system operator as described in subsection 3(4) of the same rule. The MSA declined to investigate this matter and requested that the market participant provide the MSA with a copy of an internal operations compliance bulletin it had undertaken to prepare after an internal review.

Compliance Plans

In addition to sector-specific regulation, the majority of business conduct in Canada is subject to the *Competition Act*. The Competition Bureau, which enforces the *Competition Act*, publishes a Corporate Compliance Programs Bulletin, which may be a useful reference for companies establishing or reviewing a compliance program. The bulletin outlines the basic requirements for a credible and effective compliance program and provides a framework for establishing and evaluating the program. Being able to demonstrate a credible and effective compliance program may assist market participants in advancing a due diligence defense in an enforcement proceeding.

MSA activities and releases

Notices

Notice re Appointment of Market Surveillance Administrator (2015-12-18)

Notice re OBEG Refresh- Request for Written Comments (2015-12-10)

Notice re MSA 2016 Budget (2015-12-09)

OBEG Stakeholder Meeting Agenda (2015-12-08)

Notice re Retail Market Update 2015 (2015-11-23)

Notice re OBEG Stakeholder Meeting (2015-11-19)

Notice MSA Staff Changes (2015-11-17)

Forbearance Letter re AESO Compliance per ISO Rule Section 501.10 (2015-11-06)

Notice re Consent Order 3110 (2015-11-03)

MSA 2015 Third Quarter Report (2015-10-28)

2015 Stakeholder Meeting Summary (2015-10-20)

Notice re Stakeholder Meeting Agenda Details (2015-10-07)

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.