Quarterly Report: January - March 2011 (Q1/11)

May 10, 2011

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.

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General Market Outcomes

The average pool price in Q1/11 was $82.05/MWh, higher than anticipated and due, in part, to the prolonged outage at Sundance units #1 & #2. Natural gas prices were flat in the $3 - $4/GJ range and accordingly the market heat rates were high. The average market heat rate was 23 GJ/MWh (On-Pk: 33 GJ/MWh, Off-Pk: 10 GJ/MWh). Pool prices in Alberta throughout the quarter were sufficiently higher than those in neighbouring markets to attract significant volumes of imports.

Forward market trading volumes increased somewhat over last quarter although it remains to be seen if this is a new trend of improving market liquidity.

Monitoring Indices

In this report, the MSA presents another metric in detail that will add to the suite of tools at its disposal for assessing competition in the market. The output gap analysis is developed herein and provides another layer of interpretation on market outcomes as it focuses on individual market participants and the shares of the undispatched MW in the merit order.

The supply cushion – pool price relationship was again used to screen hourly market outcomes for the quarter. A significant number of high outliers were identified for Q1/11, many more than would be expected based on the historical data used to establish the baseline parameters. This is a similar situation as occurred in the last quarter.

The report uses the output gap analysis to assess the 55 hours identified as statistical outliers using the MSA's baseline relationship between the supply cushion and pool price. The assessment is simply a factual report of events of interest and part of the MSA's public reporting responsibility. We do not reach any conclusion at this time that they are the result of inappropriate conduct or market design flaws.

Assessment of the Accuracy of ISO's Short-Term Pool Price Forecast

The MSA assessed the ISO's short-term pool price forecast model using data for the second half of 2010. We found that at the 2-hour ahead mark 70% of the forecasts were within a benchmark of +/- 20% and this measure improved moving closer to real time. The ISO's forecasts were markedly better than the results of a persistence model, i.e., using the most recent observed pool price as the forecast for the future price. However, we believe there is room for improvement and we make some recommendations, such as factoring in price responsive load and incorporating a wind forecast.

Retail Markets

Some REA members have expressed concern about their inability to find information about retailers servicing their area. The MSA's review found that such information was not always readily available. Further, individual REAs with their own Distribution Access Tariff and Retailer Service Agreement may have, however unwittingly, created a barrier to entry. These are small markets and it can be difficult for a competitive retailer to make a business case to serve small customers. There did not appear to be any systematic impediments to retailer access.

Residential customers are gradually switching to competitive contracts. In the past 4 years, the switching rate has increased from 18.0% to 27.4%.

An assessment was made of the savings or costs for a residential customer who chose a fixed price contract over some portion of the past 5 years. Generally the gains or losses are relatively small as the average customer in Alberta uses about 600 kWh per month.

Compliance Update

The MSA compliance team has observed that market participants are assisting regulatory efficiency by promptly self-reporting any potential breaches.

On the mandatory reliability standards front, auditing of some market participants is slated for Q2/11 and of the ISO itself in Q4/11. The MSA expects to be increasingly busy in this area for the balance of 2011.

1 General Comments on Market Outcomes

Late in Q4/10, Sundance Units #1 & #2 were offline with the owner, TransAlta, providing notice of a *force majeure* event on January 4, 2011. Subsequently TransAlta issued a notice of termination for destruction under the terms of the PPA. During Q1/11, the PPA buyer for these units provided notice that it intended to dispute both notices. Clearly the future of the Sundance Units #1 & #2 is uncertain. The ISO undertook a sensitivity analysis in February to assess the potential effects of the loss of these units from the system. Whilst the ISO examines and publishes several metrics related to adequacy, the key metric is the Probability of Supply Adequacy Shortfall (PSAS). This metric is a probabilistic estimate of the amount of energy that will not be served in a two-year time period due to lack of generation capacity. The Total Energy Not Served increased from 155 MWh to 1351 MWh with Sundance #1 & #2 removed.[1] The 'threshold' value for Total Energy Not Served is 1600 MWh and values above the threshold would cause the AESO to consider some form of action to protect system adequacy.

The Sundance #1 & #2 units remained offline throughout Q1/11 and the consequent tightening of the market was a factor contributing to the average pool price of $82.05/MWh. This average price is substantially higher than Q4/10 ($45.94/MWh) and Q1/10 ($40.78/MWh) as shown in Table A.1. The pool price duration curve for Q1/11 (See Figure A.1) shows that 20% of pool prices were above $50/MWh and 13% were above $100/MWh, the more extreme prices being the main contributors to the high average quarterly price. The volatility of pool prices, whether measured by standard deviation or coefficient of variation, was higher in Q1/11 than both Q4/10 and Q1/10 (See Table A.1).

AECO-C natural gas prices were very stable throughout the quarter in the range $3 to $4/GJ – a band of prices that have persisted for the past year (See Figure A.2). The low natural gas prices did not translate to low pool prices due to the relative tightness in the market and concomitant portfolio bidding. The quarterly market heat rate was 23 GJ/MWh (On-Peak: 33 GJ/MWh, Off-Peak: 10 GJ/MWh).

Plant availability in Q1/11 was lower than Q4/10 with average available capacity of 9,047 MW vs. 9,409 MW, in large part due to the absence of Sundance #1 and #2 (See Table B.1). Fleet generation was also

[1] The notice was posted on February 17th 2011 at http://www.aeso.ca/downloads/2011_02_LTA_SD1_2_sensitivity(1).pdf

down quarter over quarter by some 553 GWh. Net imports were exceptionally high in Q1/11 at some 1,034 GWh, an increase of 534 GWh from Q4/10. Overall load was very slightly down in Q1/11 vs. Q4/10 which is in line with normal seasonality.

Utilization of the interties for imports was high in Q1/11 as shown in Figure D.1. As noted above, Alberta imported 1,034 GWh on a net basis, equivalent to an average of about 480 MW. The driver for these imports is easy to see in Figures D.2 and D.3 wherein it is evident that Alberta pool prices were markedly higher than those in neighbouring markets, especially in January and February. Imports in Q1/11 were very profitable on an average basis. The outlook for Mid C prices in the near to mid term is that they will be relatively 'soft' and generally lower than Alberta. Hence it seems likely that we will see a continued high level of imports for the next while.

Forward market volumes have recovered somewhat in Q1/11. Figure E.1 shows that with healthier trade volumes in February, driven likely by the news to the market of the uncertainty surrounding Sundance #1 & #2 units, the total volume was the highest since Q2/10. It remains to be seen if this is the start of a new pattern of increased electricity trading in Alberta. Figure E.2 shows that the number of active trading entities has reduced only slightly over the past year.

As mentioned in the MSA's Q4/10 report, we had observed some hours in the quarter where potential importers appeared to be impeded by the 'late' e-tagging of a market participant. In this context, 'late' means close enough to gate closure on the BC Hydro transmission reservation system as to preclude any counterflow. The MSA is continuing its assessment work and will report back in due course.

2 Monitoring Indices

Throughout much of 2010, the MSA consulted with market participants on offer behaviour in the Alberta electricity market. This effort culminated with the release of the MSA's *Offer Behaviour Enforcement Guidelines*, on January 14, 2011. The Guidelines are meant to provide a clear framework for how the MSA will view different types of conduct by market participants, where it might seek enforcement action and where it might seek remedies such as rules changes.

During the consultation process on offer behaviour, a number of stakeholders expressed interest in the monitoring methods used by the MSA. Consequently, the MSA is taking the step of explaining in detail the methodologies it is employing as they are introduced.

The detailed derivation of the supply cushion for each hour was described in the MSA's Q3/10 report. Data for the period February 1, 2008 through June 30, 2010 was used to establish a statistical baseline for the relationship between the supply cushion and pool price. For a given hour, the supply cushion is the volume of energy available to the system controller but not called upon to meet load. Supply cushion measures market tightness and would be expected to be strongly related to pool price. This relationship is a prime metric to enable the MSA to identify anomalous hours. It does not speak to the possible reasons for the anomaly, but it does flag the hour as being unusual.

In this quarterly report, the MSA builds on the analysis presented in the Q3/10 and Q4/10 reports. In the Q3/10 report, the focus was on the supply cushion metric and, to a lesser extent, on the price duration curve. In the Q4/10 report we added the residual supply index analysis. Whilst the residual supply analysis was insightful, it mostly set the stage for the analysis of who is and is not running at different

market prices and what can be deduced from that. This is termed an output gap analysis. In the cases where market prices are higher than the short-run costs of the generators, it is an analysis of economic withholding.

To be clear, as explained in the MSA's *Offer Behaviour Enforcement Guidelines*, economic withholding by individual market participants is not proscribed under Alberta's market construct. However, identification and reporting of its occurrence contributes to stakeholders' understanding of market outcomes and also provides a record for the longer term assessment of the health of the market.[2]

Before explaining and applying the output gap analysis to observed market outcomes, the next section summarizes the Q1/11 supply cushion and price data.

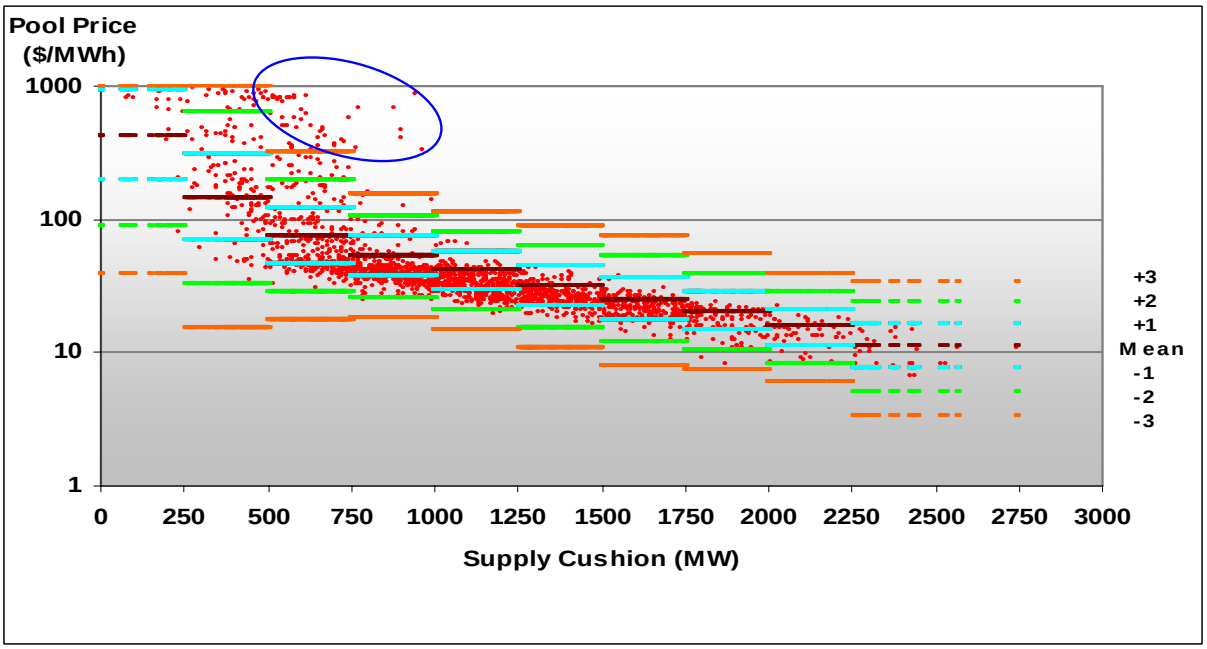
2.1 SUPPLY CUSHION ANALYSIS – Q1/11

The supply cushion and associated pool price data for Q1/11 are plotted in Figure 2.1. It is evident that there are a large number of hours above the line representing 3 standard deviations above the mean in the supply cushion range from approximately 500 MW through about 1000 MW. In Q1/11 there were a total of 777 hours in the range 500 MW – 1000 MW of supply cushion and 54 hours (7%) were more than 3 standard deviations above the mean. In comparison, in Q4/10 there were 88 out of 801 hours (11%) that were more than 3 standard deviations above the mean in this supply cushion range. If the historic data used to establish these bounds are from the normal distribution, less than 0.5% of the observations would be more than 3 standard deviations above the mean.

In terms of pool prices that were unusually low relative to the amount of supply cushion, across the whole spectrum of supply cushion there were no events that were more than 3 standard deviations below the mean and only 8 between 2 and 3 standard deviations below the mean. This lack of low price outliers may be due to a simple upward shift of the curve – basically caused by the same changes that have yielded more high priced hours.

[2] See the Guidelines generally and particularly at pp. 9-12 and 17-18.

Figure 2.1 : Q1/11 Supply Cushion v. Pool Price (Confidence Bands Based on Historic Data)



	=<250	>250 <=500	>500 <=750	>750 <=1000	>1000 <=1250	>1250 <=1500	>1500 <=1750	>1750 <=2000	>2000 <=2250	>2250	Total
>=+3	0	0	46	8	1	0	0	0	0	0	55
<+3 & >=2	0	25	20	4	0	0	0	0	0	0	49
<+2 & >=1	12	22	29	13	6	0	1	0	1	0	84
<+1 & >=mean	19	42	48	20	36	44	37	31	18	9	304
<mean & >=-1	2	35	110	240	263	229	186	65	29	17	1176
<-1& >=-2	0	16	102	133	125	50	16	24	12	2	480
<-2& >=-3	1	0	0	4	0	0	0	2	1	0	8
<-3	0	0	0	0	0	0	0	0	0	0	0
Total	34	140	355	422	431	323	240	122	61	28	2156

2.2 OUTPUT GAP ANALYSIS – THEORY & APPLICATION TO 2010 DATA

The output gap analysis calculates the market supply cushion by market participant, identifying the proportion of the supply cushion that is attributable to each market participant in a given hour.

Output gap analyses have been explored both in the academic literature and by other market surveillance groups in North American electricity markets. Twomey et al. (2005) summarize the academic work on output gap analysis, referred to there as withholding analysis. The premise of the analysis is the detection of exercises of market power by searching for missed opportunities to profit (in expectation) from the sale of additional units of electricity. When a generator chooses not to sell into a profitable market, market power has been exercised. Analyses conducted in other jurisdictions have taken into account the costs of production when estimating the quantity not being economically produced at prevailing market prices. An output gap analysis was conducted on the California market by Joskow and Kahn (2002), which

focused solely on hours where prices were very high. In these hours, it could be presumed that prevailing market prices fully covered the costs of production of withheld units.

The MSA's output gap analysis follows a model similar to Joskow and Kahn, in that we have not filtered the data on cost, but have instead focused on the high price hours identified in the supply cushion analysis. In this case, this means all hours with pool prices more than 3 standard deviations above the mean for the given supply cushion.[3] This initial analysis required certain assumptions about offer control at different units as explained below.

2.2.1 Methodology

The output gap analysis is fundamentally based on the same methodology as the supply cushion analysis. The difference of Available and Dispatched Energy offers in the Energy Market Merit Order (EMMO), adjusted for Dispatched DDS and Dispatched TMR in the Ancillary Services Merit Order (ASMO) is used to calculate the supply cushion.

As first presented in the Q3/10 Quarterly Report, the formula to calculate the supply cushion is given as:

$$SupplyCushion_h = \sum_{i=1}^{n} (AvailableMW_{ih} - DispMWih\ ) + DDSDisp_h - TMRDisp_h$$

Where:

h = the hour of the year

i = 1 to n is the number of offer blocks in the merit order at 30 minutes past h

The composition of the supply cushion is then calculated by assigning the controlling participant to each un-dispatched block in the supply cushion. The sum of each participant's un-dispatched blocks is then calculated, and presented as a percentage of the supply cushion in that hour. Adjustments are made for units producing TMR, but which are not dispatched in the EMMO.

For example, assume the Energy Market Merit Order for HE12 is as shown below:

HE	Unit	Available (MW)	Dispatched (MW)	Participant Offer Control
12	Gas Unit 1	15	0	Participant A
12	Gas Unit 2	15	0	Participant B
12	Hydro Unit 1	40	0	Participant A
12	Coal Unit 1	50	0	Participant C
12	Gas Unit 3	30	30	Participant B
12	Coal Unit 2	50	50	Participant A

[3] This type of analysis can only be meaningfully applied to high prices. It does not provide insights into hours where pool prices are unusually low for the given level of supply cushion.

This EMMO has 200 MW of offers available and 80 MW are dispatched to meet load. Further assume that Gas Unit 2 has been dispatched on for 10 MW of TMR, and SMP is currently above reference price, so there is no DDS dispatched.

In this situation the Supply Cushion is calculated as:

Supply Cushion = Available MW – Dispatched MW + DDS Dispatched – TMR Dispatched

Supply Cushion = 200 MW – 80 MW + 0 MW – 10 MW = 110 MW

The share of supply cushion attributable to each participant is then calculated by summing the un-dispatched MW of each block under the participant's offer control. This total is adjusted down for any TMR dispatched to any units in the supply cushion.

The share of the supply cushion attributable to each market participant is given below:

Market Participant	Unit with Un-dispatched Blocks	Block (MW)	Dispatched TMR (MW)	Total Undispatched Unit (MW)	Participant Share of Supply Cushion MW (%)
A	Gas Unit 1	15	0	15	
A	Hydro Unit 1	40	0	40	55 MW (50%)
B	Gas Unit 2	15	10	5	5 MW (4.5%)
C	Coal Unit 1	50	0	50	50 MW (45.5%)

2.2.2 Limitations to the Methodology

The assignment of offer control to the individual blocks in the Energy Market Merit Order is based on the data collected through the MSA's Market Share Offer Control Process. This data identified several units that have multiple participants sharing offer control, particularly the PPA coal units, and one non-PPA coal unit. The MSA's analysis is limited by the inability to precisely identify which offer blocks of a shared asset are controlled by which participant in a given hour. For instance, in the case of a PPA unit with up-rated capacity it is not always possible to distinguish in the EMMO between the owner's offers and those of the PPA buyer. The MSA can sometimes infer which blocks of a shared unit belong to which participant, based on each participant's other offers and timing of offer changes. However, it is not possible to determine with certainty the offer control of these shared assets in all hours.

Given these limitations, the MSA made the following simplifying assumptions which potentially limit the accuracy of the analysis. Specifically, we have assumed that the PPA buyer is the sole participant in control of PPA assets, for the purpose of assigning offer control to PPA units. As well, we have assumed that the non-PPA shared coal unit is wholly under the control of the unit operator. These assumptions will only impact the output gap results when the PPA units or other shared units are un-dispatched and hence form part of the supply cushion.

The AESO is currently undertaking a Merit Order Offer Control Reporting project, pursuant to the FEOC Regulation, which will require participants to submit the name(s) of the participant(s) with offer control

for each offer block. This data, when collected, will allow the MSA to identify the offer control associated with specific blocks in the EMMO. However, the MSA understands that the AESO may not complete this project until late in 2012, and in the interim, the MSA may approach participants with interests in shared assets for the offer control data. At this point the MSA has not determined what form, or quantity of data it may request. Additional work needs to be undertaken to establish whether the requested data would significantly enhance the accuracy of the metric.

2.2.3 Application of Output Gap Analysis to 2010 Data

The output gap analysis was conducted for all hours in 2010 focused on the five largest market participants, based on the assumptions outlined above. Blocks in the supply cushion that were not attributable to any of the five largest participants were combined into the 'Other' category.

The analysis focuses on the particularly extreme pool price - supply cushion outcomes, namely, price outcomes more than 3 standard deviations above the mean (denoted '>3 StD'). Most of these hours occurred in three supply cushion bands ranging from 500 MW to 1250 MW.

Table 2.1 presents the average contribution to supply cushion for each participant (not ordered by amount of offer control) in hours with >3 StD and expected pool prices, where 'expected' refers to all the hours where prices were within +/- 1 standard deviation of the mean, for the given supply cushion band. The analysis of this latter group is intended here as a comparator to the >3 StD price outcomes. At these levels of supply cushion, the +/- 1 StD prices are above marginal cost for most generators in Alberta. Hence the differences in composition of the supply cushion between +/- 1 StD prices and >3 StD prices is of interest.

For example, Line 1 of Table 2.1 indicates that for pool price outcomes between +/- 1 standard deviation of the mean when the supply cushion is in the range 501 to 750 MW, Participant C contributed, on average, 18% of the supply cushion in those hours. For the hours where pool price outcomes were greater than 3 standard deviations above the mean, Line 2 shows that Participant C contributed, on average, 22% of the supply cushion in those hours.

Table 2.1: Average Percentage of Supply Cushion Attributable to Market Participants

			Market Participant					
Line No.	Supply Cushion Band	Pool Price Outcomes	A	B	C	D	E	Other
1	501 to 750	+/- 1 StD from Mean	5%	21%	18%	27%	8%	21%
2		>3 StD	2%	21%	22%	37%	10%	9%
3	751 to 1000	+/- 1 StD from Mean	8%	18%	18%	19%	10%	26%
4		>3 StD	3%	16%	41%	24%	9%	7%
5	1001 to 1250	+/- 1 StD from Mean	10%	16%	19%	16%	13%	27%
6		>3 StD	3%	18%	45%	20%	8%	6%
7	All Bands (500 to 1250)	+/- 1 StD from Mean	9%	17%	18%	19%	11%	26%
8		>3 StD	3%	18%	39%	24%	9%	7%

Some participants are more prominent in the supply cushion than others. To a certain extent, this reflects the relative size and different technologies of the market participants. The market share of some participants is much higher in the >3 StD hours than in the +/- 1 StD hours. Participant A, on the other

hand, consistently features less in the >3 StD hours than the +/- 1 StD hours. Comparing >3 StD hours with the +/- 1 StD hours it is apparent that the 'Other' category features much less in the former.

An analysis of market participant behaviour based on averages might provide misleading results. Whether a market participant chooses to exercise an ability to (economically) withhold are expected to vary depending on the portfolio position, competitive dynamics and participant strategy at particular points in time. Currently the most active part of the forward market is the prompt month, in part due to the structure of the RRO for retail customers. Hence, one might expect withholding patterns to vary from month to month for those participants that are actively involved in the forward market. In the next section we consider the use of output gap analysis to scrutinize hours of interest in Q1/11.

2.3 OUTPUT GAP ANALYSIS – Q1/11

In past quarterly reports the MSA identified hours of interest with the supply cushion analysis, and carried out an in-depth analysis of some of those hours of interest believed to be representative of a broader set of outliers. In this quarterly report the MSA has refocused its efforts on an event analysis capturing all hours of interest, using the output gap analysis. We have focused on analysis of the >3 StD hours by monthly groupings.

The application of the output gap analysis has both benefits and drawbacks. The benefit is that the MSA can direct its finite resources to scrutinize all hours of interest, rather than examining a subset of the hours. Examining all hours may reveal trends or patterns which shed light on the state of competition in the Alberta market. The drawback of this analysis is that any given event is not examined in as fine a detail as in previous quarterly reports, and the competitive dynamics of an event may not come through as clearly. For instance, the dynamics of participants re-pricing energy in response to changing market conditions and in response to each other's actions are not clearly demonstrated in this type of event analysis. Further, as already noted, the output gap analysis is not a useful tool to analyze unusually low price events.

For the analysis of Q1/11 data on unusual high-priced hours (>3 StD), the MSA has manually adjusted the supply output gap results. For each of the 55 hours (events), the offer blocks from PPA assets, or shared assets were manually reassigned to the participant believed to have had offer control in that hour. Not all of the 55 hours were affected by this process, and not all participants' monthly average share of supply cushion changed as a result of the manual intervention. We acknowledge that our efforts to assign offer control of specific blocks of shared assets, based on inferences from the EMMO, may contain some errors. However, the quantity and magnitude of those errors is certainly less than in the unadjusted estimates.

The MSA will continue to develop the output gap analysis results and in future quarterly reports, present refinements to the analysis of extreme price events.

2.3.1 Summary of Q1/11 Events

Table 2.2 breaks down the average supply cushion and pool price of >3 StD events by month, and also shows the average percentage contribution by participant to the supply cushion in these hours. Participants A through E are the 5 largest in the market by offer control. These percentages indicate, for instance, that across the 46 >3 StD hours in February 2011, participant B contributed an average of 48% of

the supply cushion. In general, the supply cushion at >3 StD prices tends to be dominated by participants B, C and D, with participant D consistently having a significant share of MW un-dispatched at these prices. Participants B and C have had noticeable changes in their offer behaviour from month to month, which is presumably the result of the changes to their net portfolio position. Participant C was virtually absent from the supply cushion in the >3 StD hours of February, but formed an average of 46% of the supply cushion in the >3 StD hours of March.

It is also notable that for the quarter, three participants, B, C and D on average contribute 91% of the supply cushion. This is largely consistent with observations in previous quarterly reports with several market participants economically withholding output in hours with>3 StD pool price outcomes.

Table 2.2: Output Gap Analysis Summary of >3 StD Events of Q1/11

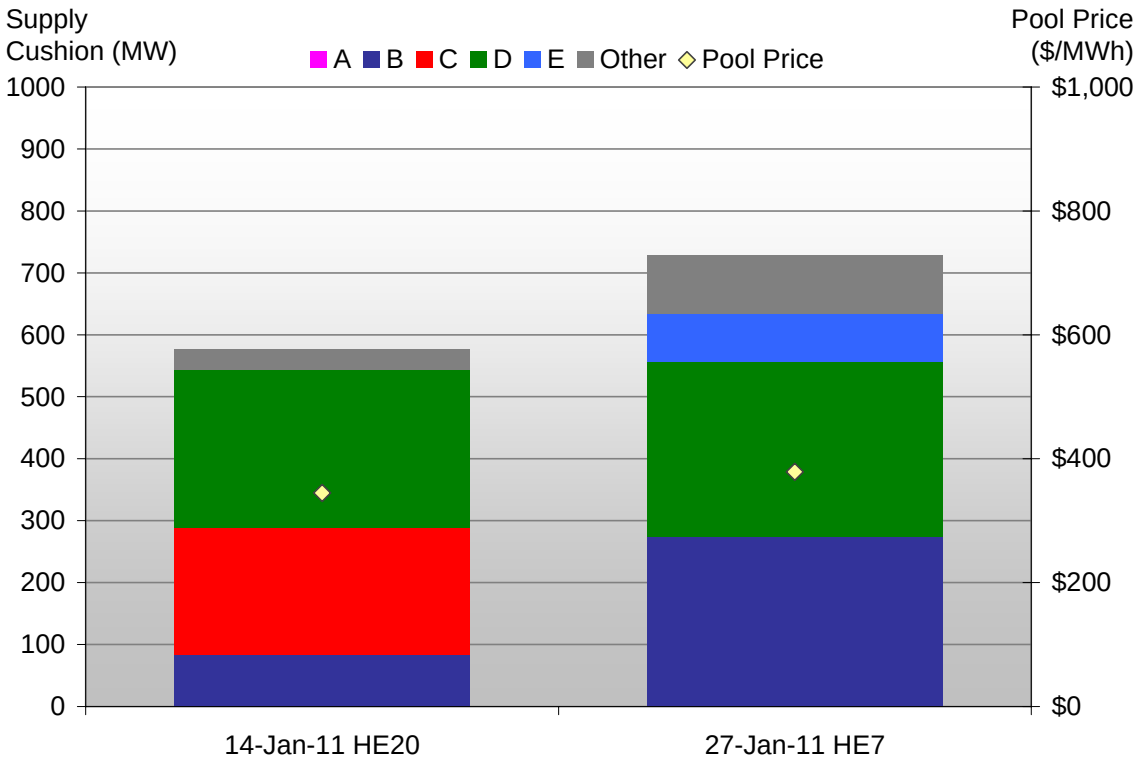
				Average Share of Supply Cushion by Participant					
Month	Count of Events	Average Price	Average SC	A	B	C	D	E	Other
Jan-11	2	$361.84	652	0%	26%	18%	41%	5%	9%
Feb-11	46	$591.80	652	0%	48%	4%	40%	1%	7%
Mar-11	7	$513.60	572	0%	11%	46%	34%	0%	9%
Q1/11	**55**	**$573.48**	**642**	**0%**	**42%**	**10%**	**39%**	**1%**	**7%**

The following sections describe the event analysis on a monthly basis.

2.3.1.1 January 2011

Two hours in January were identified as hours of interest, producing an average price of $361.84/MWh, on an average supply cushion of 652 MW. Figure 2.2 presents the output gap results by participant for the two hours of interest in January.

Figure 2.2: Output Gap Analysis - January 2011

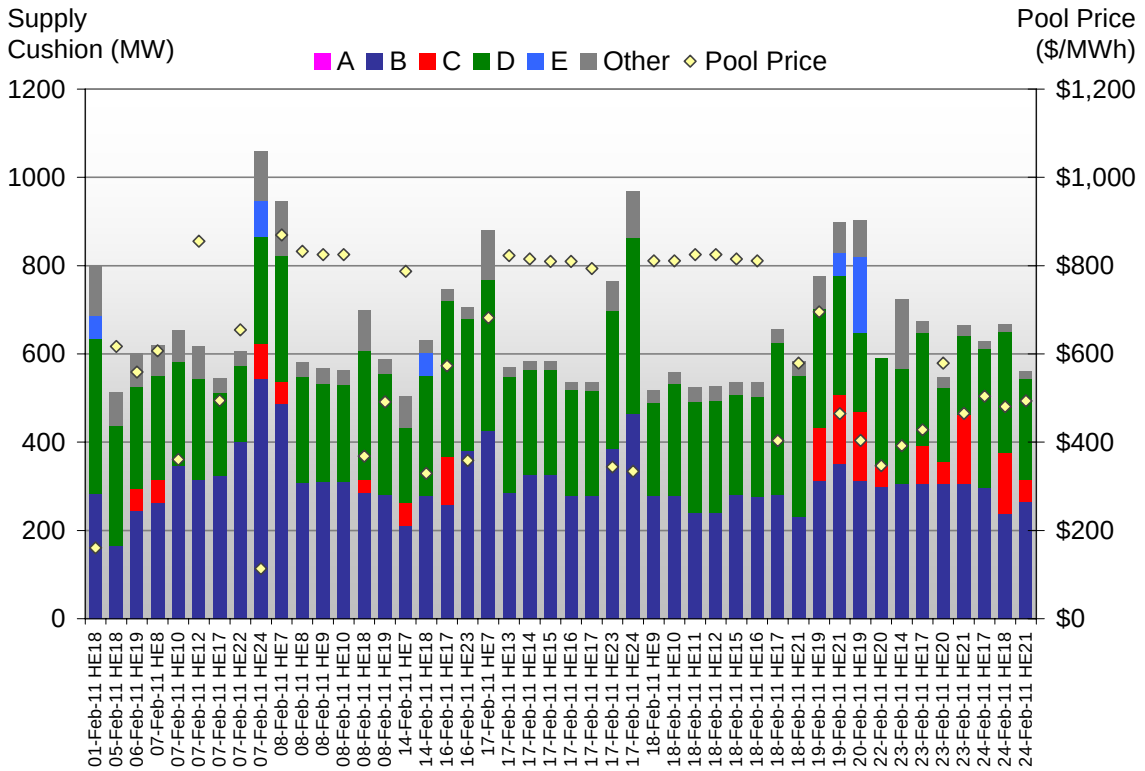


For both hours of interest in January, three participants feature prominently in the supply cushion accounting for more than 500 MW in each case. Participant D is a major contributor to the supply cushion in both hours, while participants B and C each contributed significantly to the supply cushion in one of the hours. A total of 11 other high priced hours in January registered between +2 and +3 standard deviations, but are excluded for the purposes of this analysis.

2.3.1.2 February 2011

February 2011 recorded 46 >3 StD hours, with an average price of $591.80/MWh, on an average supply cushion of 652 MW. Across these events, supply cushion values ranged from a low of ~500 MW to a high of roughly ~1100 MW, while pool prices ranged from a high of $869/MWh to a low of $113/MWh. Figure 2.3 shows the composition of supply cushion in each hour.

Figure 2.3: Output Gap Analysis - February 2011



The output gaps in the hours of interest tend to be dominated by Participant B and D, with participants C and E contributing a small volume in some of the hours. The aggregate group, 'Other' is present in each supply cushion to varying degrees and in some hours exceeds 100 MW. This group tends to be comprised of a number of small units belonging to several different participants.

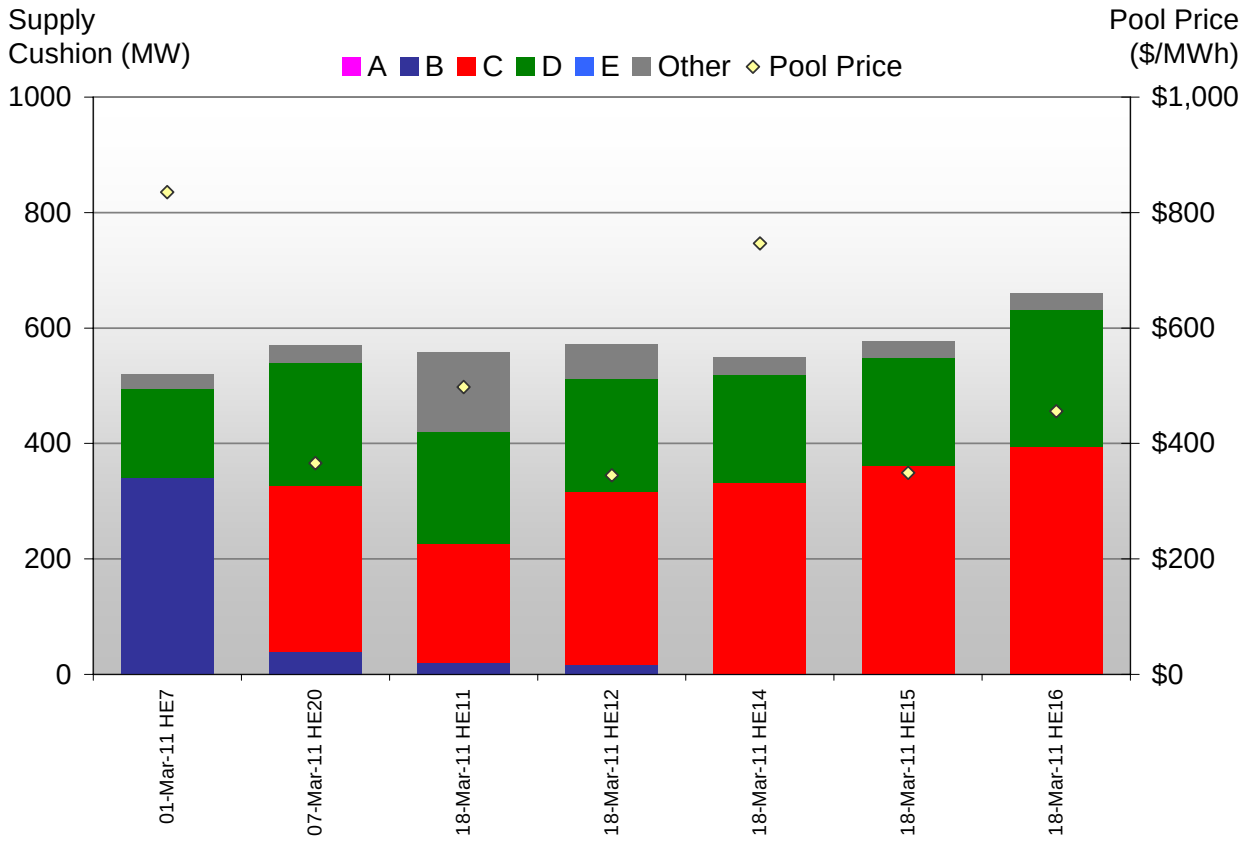
It is also useful to note that the hours of interest are concentrated among several days, namely February 7th, 8th, 17th, 18th, and 23rd. Within each of these days there are often several contiguous hours which produced >3 StD prices given the level of market supply cushion. In particular, February 17th produced >3 StD price outcomes in 5 contiguous hours from HE13 to HE17. Each of these hours had roughly the same level of supply cushion, and very similar prices of about $800/MWh. Also, the share of supply cushion among participants was quite stable through these 5 hours, indicating that un-dispatched MW were not re-priced to undercut the marginal unit, capturing dispatch at those high prices. Any re-pricing that may have occurred in these 5 hours had little net effect on the share of supply cushion among the competitors.

The final observation from the output gap analysis of February 2011 is that two participants, B and D, form the bulk of the output gap in most of the hours of interest.

2.3.1.3 March 2011

March 2011 produced 7 hours of interest, with an average price of $513.60/MWh and an average supply cushion of 572 MW. Prices ranged from ~$350/MWh to greater than $800/MWh, while supply cushions ranged from ~500 MW to ~650 MW.

Figure 2.4: Output Gap Analysis - March 2011



These hours of interest in March were again dominated by two participants, this time C and D.

It is interesting to note that in HE07, on March 1st, participant B is prominent in the supply cushion, and at this time the MSA observed a shift in this participant's offer behaviour. In HE07 Participant B economically withheld ~350 MW of energy from merit at a price of above $800/MWh, and it re-priced nearly all the withheld energy into merit starting in HE08 of that day, which was the first on-peak hour of the March calendar month.

Five of seven hours of interest in March 2011, occurred on March 18th, and were nearly contiguous from HE11 through HE16. Participant C nearly doubled its presence in the supply cushion, from ~200 MW to ~400 MW, from HE11 to HE16, while participant D was fairly stable in its contribution to the supply cushion. Participant B, as well as the 'Other' group receded from the supply cushion after HE12 indicating these participants priced down into merit, or derated from the energy market.

2.4 SUMMARY

The MSA continues to believe the supply cushion analysis provides a useful method for indentifying hours of interest. Based on historical benchmarks, the number of hours >3 StD above the mean in Q1/2011 is larger than expected (55 out of 2159 hours, or approximately 2.5%). In same quarter, no hours were >3 StD below the mean.

As in previous quarterly reports, the MSA seeks to understand the role competition plays in the formation of price in these hours of interest. The MSA continues to apply metrics used in other markets and examine their application in the context of Alberta. In this quarter we have focused on output gap analysis.

Initial results suggest that output gap analysis is a useful tool in summarizing the composition of the supply cushion across a number of hours. We find some evidence to support monthly patterns in economically withholding. During the current quarter the MSA has not assessed whether the cause for these differences is related to forward market trading (a change in the incentive to withhold) or outages (a change in the ability to withhold).

As noted in previous quarterly reports, the findings from a single metric are not likely, when taken in isolation, to form a basis to conclude that market outcomes observed are inconsistent with the *fair, efficient and openly competitive* standard set out in section 6 of the EUA. This information forms part of the record for a longer term consideration of the competitiveness and performance of the Alberta market. In the next quarterly report, the MSA intends to bring together the findings of a number of metrics it has developed to provide a more comprehensive assessment.

3 Accuracy of ISO Short-Term Pool Price Forecast

The MSA's *Offer Behaviour Enforcement Guidelines* apply an analytical framework that relies on effective competition to 'regulate' the behaviour of market participants to help produce good market performance. For competition to be effective, participants need as much notice as possible of changes to market conditions in order to compete. The ISO's short-term forecast is one vehicle to provide such advance notice and, therefore, why the MSA undertook an assessment of its accuracy.

The ISO issues a rolling 2-hour forecast of pool price based on the most current set of locked-down offers.[4] The forecast serves two main purposes:

- It provides some advance notice to price-responsive loads that may wish to prepare to shut down a portion of their consumption to avoid high pool prices; and,
- It potentially alerts market participants to upcoming changes in offer strategies or of the general market tightness that they may elect to factor into their own decisions.

Based on discussions with staff of the association representing most of the known price responsive loads in Alberta, these loads tend to react to current price rather than forecast price. However, the staff

[4] The link is: http://ets.aeso.ca/ets_web/ip/Market/Reports/ActualForecastWMRQHReportServlet

commented that, with the advent of the new load response market to enhance import capacity, its members may wish to use a price forecast to assist them in making the most efficient decisions.[5]

Currently, the ISO is considering different ways that imports and exports could participate in the Alberta market, including consideration of the situation where they are capable of pricing into the market (currently they are forced to be price takers due to their inability to respond to intra-hour dispatch). Some methods, such as those used in the Ontario and New York ISO markets, rely on decisions made at one-hour ahead on which offers / bids on the interties are in merit. The ISO's short-term pool price forecast would assume more importance should the market evolve in this direction in the future. Either way, the better the price forecast is, the better the decisions that can be made by the affected parties.

Our assessment was limited in scope to examine the accuracy of the pool price forecasts at three times:

- (T – 2) hours – the first forecast that is made with the most recent locked-down offers;
- (T – 1) hours – the forecast that might be most relevant to decisions on imports and exports in a future design state here in Alberta; and,
- (T – 0) hours – the last forecast before the settlement hour begins.

The (T – 2) hours forecast is the first one immediately following the lock down of offers by the generators. Hence, it can be a useful leading indicator to market watchers of potential changes in offer strategies that might impact the forecasted pool price. And it may be useful to both loads making decisions on reducing consumption and generators making decisions on their own future participation, the difference being that load can reduce consumption in the particular hour whilst the generators can only make decisions for future hours (2 hours ahead).

The (T – 1) hours forecast may be relevant if the market design in Alberta requires decisions on the part of the ISO regarding the economic viability of priced imports and exports for the upcoming hour. The (T – 0) hours forecast is the final forecast made for the settlement hour and should be the most accurate.

3.1 POOL PRICE FORECAST METHODOLOGY

A general description of the methodology is provided on the ISO's web site and the following is a brief synopsis.[6] The short-term pool price forecast is calculated for a total of six hours out but the public version covers only the portion where generator offers are locked down by the (T – 2) hour rules. Thus, at any given time the price forecast shows values for the current time and the next two hours. The forecast for the upcoming two hours is updated every 5 minutes in response to changing conditions. For each 10-minute period of the upcoming two hours covered by the forecast, the forecast model calculates a price and the 6 values per hour are averaged to yield the forecasted pool prices.

The price forecast takes account of current and expected load changes, the offers of the generators and any changes in capacity that are known at the time. It assumes that the generation from the wind units in the system will remain at the same level as it is at the time of the forecast. Imports and exports are included as indicated by the offers and bids, capped at available transfer capability if necessary.

[5] The ISO is implementing a market-based service known as Load Shed Service for Imports (LSSi)
[6] The description is available at: http://www.aeso.ca/downloads/Price_Forecast_Calculation_March_8_2011.pdf

3.2 ASSESSMENT OF FORECAST ACCURACY

The data set used to assess the accuracy of the price forecasts spanned the period June 2 through December 31, 2010, a period that provides more than 5000 sample points.[7] For each hour in the period, the three forecasts were identified as follows:

(T – 2) Forecast – the first forecast immediately following the (T – 2) hours lock down on offers

(T – 1) Forecast – the first forecast following (T – 1) hours

(T – 0) Forecast – the last forecast generated just prior to the settlement hour.

The forecast error in percentage was calculated as:

Error (%) = (Actual Pool Price – Forecast Pool Price) / Actual Pool Price

There was one zero dollar pool price over the period which the formula cannot handle (division by zero) but the three forecasts were also zero and so there was no error. Figure 4.1 shows scatter plots for the three forecasts using a logarithmic scale. By inspection it can be seen that there is a reasonable correspondence between the various forecasts and the actual pool prices. There does appear to be a grouping of points with forecasts of several hundred dollars where the actual prices were less than a hundred dollars. This is more obvious in the (T – 2) and (T – 1) forecasts plots.

Table 3.1 presents some statistics on the forecasts. The mean errors are relatively small. Assuming that +/- 20% forecast error is tolerable, the frequency of the forecasts being within such a tolerance is also shown in Table 3.1. There is a clear increase in percentage over the shortening time horizon, as would be expected.

The data is highly skewed – the Root Mean Square Error (RMSE) reduces dramatically for each set of forecasts when the largest 5 errors are removed (less than 0.1% of the data set). The RMSE does not appear to reduce as the forecast lead time shortens which is somewhat surprising.

A simple persistence model as a forecast can sometimes works very well. Under this methodology the most recent observed pool price is used as the forecast for the future price. The statistics of such a forecast are also shown in Table 3.1 and clearly the results are not as good as for the ISO's forecast model. This is noteworthy in that the MSA last assessed the accuracy of the ISO's forecast in 2008 and at that time it was not as accurate as the persistence model.[8]

There are a wide variety of reasons why pool prices can deviate from the short-term forecasts. Some of these are difficult to take into consideration in any model. For example, a unit might have a forced trip which was not known until it actually occurred. The occurrence of such an event would likely cause the pool price to be quite different from the forecast. Other factors that would have a bearing are:

[7] June 1 was eliminated from the data set as there were clearly errors in the data likely due to the cut over to the new dispatch tool which houses the price forecast model.
[8] MSA report, "'Quick Hits' Review: Dispatch Down Service", 2008.

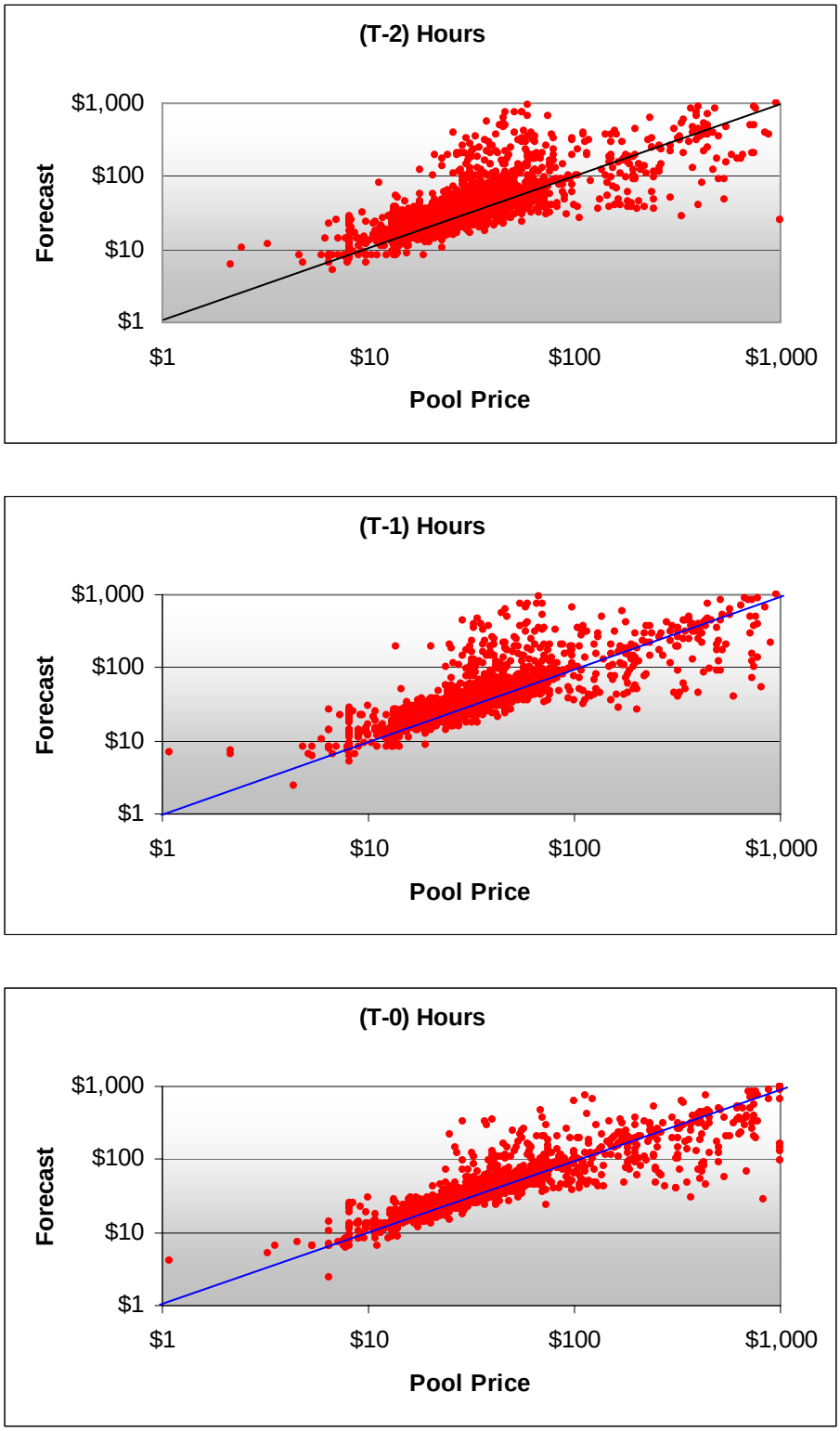
- Changes in the wind regime. The replacement of the current persistence model for wind with a credible forecast would likely improve the pool price forecasts.
- Effect of price responsive load. If the forecast price is a significant increase to levels beyond about $200/MWh it's very likely that some load will come off and mitigate the price spike.
- Load forecast error. Any errors in the load forecast will propagate through to the price forecast. The model self corrects the forecast load to the current level and uses a 'like day' concept to project the future load. If the 'like day' had embedded price responsive load in it the forecast load may be too low.

There may be value to providing some sensitivity around the price forecast so that participants may make their own assessments of the likely pool price outcomes.

Table 3.1: Forecast Accuracy

Forecast	(T - 2)	(T - 1)	(T - 0)
ISO Forecast Model			
Mean Error (%)	3.68	1.70	-5.16
Percentage of Forecast Errors less than 20%	70	77	88
Root Mean Square Error (%)	70	52	63
Root Mean Square Error (%) With Worst 5 Forecasts Removed	37	39	41
Persistence Model Results			
Mean error (%)	-20.0	-13.5	-6.5
Percentage of Forecast Errors less than 20%	48	58	76
Root Mean Square Error (%)	125	93	59
Root Mean Square Error (%) With Worst 5 Forecasts Removed	112	82	49

Figure 3.1: Scatter Plots of the Three Forecasts



3.3 SUMMARY

This assessment of the accuracy of the ISO's short-term pool price forecast reveals that the 70% of forecasts made at (T – 2) hours are within +/- 20% of the actual pool price. This increases to 88% just prior to the settlement hour. The ISO forecast model produces more accurate forecasts than the simple persistence model.

At (T – 2) hours there are still 30% of the forecasts that will be out by more than 20%, some of them by a lot. This level of accuracy is probably not sufficient for market participants to make efficient decisions. It would appear that there is some scope for improvement that would benefit many market participants. We encourage the ISO to consider factoring in price responsive load and incorporating a wind forecast into its model.

4 Retail Market

4.1 RETAIL COMPETITION IN THE REA MARKET SECTOR

4.1.1 Introduction

Over the course of the past year the MSA received queries from consumers who are members of Rural Electrification Associations (REAs). These consumers expressed concern about their apparent inability to contract with a competitive retailer. In addition, the Utilities Consumer Advocate (UCA) received over 20 calls in 2010 from REA members who were inquiring about competitive retail options or complaining about their inability to obtain service from a competitive retailer. Pursuant to section 110 of the *Electric Utilities Act* (EUA), and subject to that Act and related regulations, "a customer has the right to obtain retail electricity services from a retailer". We conducted a preliminary review in order to determine the nature and extent of any potential issues affecting retail competition in the REA market sector. This is described below.

4.1.2 Background

REAs are non-profit organizations set up under the *Rural Utilities Act* (RUA) for the purpose of providing electricity services to members. The Rural Utilities Division, Alberta Agriculture and Rural Development, administers the RUA which provides the framework for the establishment and management of business affairs for the REAs.[9]

The Government of Alberta initiated the Rural Electric Program in 1947 as a cost sharing program to help defray the high cost of electrical service to farmers. In that same year, the first REA was formed and by 1960 there were 381 in Alberta. Since then, approximately one-half of the REAs have been sold to one of the distribution utilities – ATCO Electric or FortisAlberta – for a variety of reasons and a number of the remaining REAs have amalgamated to create larger territories to achieve economies of scale. As of March 2011 there are 46 REAs in Alberta with approximately 44,700 billed services. The Alberta Federation of Rural Electrification Associations (AFREA) currently represents the majority of REAs and provides

[9] http://www1.agric.gov.ab.ca/general/progserv.nsf/all/pgmsrv14

support services, leadership and representation on their behalf, creates strategic alliances to attain goals, and communicates with member REAs on a wide variety of industry issues. [10]

There are two basic types of REAs: 'self-operating' and 'operating'. Eight REAs are self-operating and manage the operation of their distribution systems. The remaining REAs are designated operating and typically have contracted with either ATCO Electric or FortisAlberta for the purpose of operating their electric distribution system.

REAs are "market participants" pursuant to s. 1(1)(ee)(i) of the EUA and accordingly are required to comply with the provisions of the EUA. In addition, REAs are designated as "owners" of electric distribution systems pursuant to s. 1(1)(jj) of the EUA. As owners, REAs are required to prepare distribution tariffs for the purpose of recovering the prudent costs of providing electric distribution service (s. 102(1)) and must apply for approval of its distribution tariff to the REA's board of directors (s. 102(2)(c)). The Alberta Utilities Commission (AUC) typically has regulatory oversight with respect to the approval of wire owner's distribution tariffs; however, this is not the case with REAs. The REAs have a unique status in Alberta's electricity industry where the board of directors for each REA has, at first instance, the responsibility for regulatory oversight for distribution tariffs and the regulated rate tariff.

With respect to the regulated rate tariff, the EUA requires the owner of an electric distribution system, including REAs, to prepare this tariff for the purpose of recovering the prudent costs of providing electricity services to eligible customers (s. 103(1)) which is then submitted to the REA's board of directors for approval [([s. 103(4)). An REA may make arrangements with another person to perform any or all of its duties or functions as the owner under the EUA (s. 104(1)). Section 105(1)(i) of the EUA provides that REAs must act as a regulated rate provider, and must appoint or act as a default supplier in accordance with the EUA (s. 105(1)(j)). The regulated rate tariff is provided by 18 REAs to their members either directly or through another REA. Direct Energy or EPCOR provide the RRO service to 26 REAs and FortisAlberta provides RRO service to one REA.[11]

4.1.3 Access to Competitive Retailers

Section 110 of the EUA affirms the right of a customer to obtain retail electricity services from a competitive retailer. Some REA members have approached the MSA and the UCA with inquiries about where to obtain information about competitive retail options or with complaints about their alleged inability to obtain service from a competitive retailer. The process of trying to obtain information about competitive retail options appears to be a recurring issue.

If a member contacts a REA office in order to obtain information about retail options, the REA refers them to the UCA's website pursuant to s. 2(1)(b) of the Roles, Relationships and Responsibilities Regulation of the EUA. The UCA website only provides contact information for each of the REAs and there is no information concerning which competitive retailers are serving customers on a specific REA's distribution system. The UCA does indicate that three REAs (Battle River Rural Energy Limited, Rocky Rural Power Ltd., and South Alta Rural Energy Division) provide an 'unregulated' energy product but only to members of the respective REAs.[12] Generally, the REA members who have made calls to the MSA or

[10] http://www.afrea.ab.ca/filesaf/afrea/REA%20Contact%20UCA%20March%202011.pdf
[11] http://ucahelps.alberta.ca/documents/REA_Contact_UCA_March_2011.pdf
[12] http://ucahelps.alberta.ca/rural-electrification-associations.aspx

UCA have expressed a high degree of frustration when attempting to obtain information about competitive alternatives.

Inquiries for information tend to originate with members of REAs that are self-operated. In an effort to overcome the information gap about competitive options, we contacted AltaGas Ltd, Direct Energy, and ENMAX Energy to determine the extent of their marketing activities to customers who are on REA distribution systems. The responses indicate that the penetration into the REA market by competitive retailers is quite extensive. Customers in 9 REAs are served by at least 1 competitive retailer, customers in 18 REAs are served by 2 or more retailers and 16 REAs are served by 3 retailers. Only 3 REAs do not have a competitive retailer serving customers on those systems. While this information is in the public domain, it does not seem to be readily available to REA members who are interested in obtaining service from a competitive retailer.

There does appear to be an absence of an active marketing effort which is directed towards residential customers in rural areas. Competitive retailers generally regard REAs as specialty markets. Two retailers indicated they need a sufficient number of customers and/or volume to offset customer acquisition and maintenance costs in order to make the 'business case' to support serving customers on an REA system. Accordingly, competitive retailers typically focus their marketing efforts on higher consumption customers and/or higher density customers.

In one case, a competitive retailer was unwilling to sign a Retailer Service Agreement as prepared by the REA. Such Retailer Service Agreements, with clauses unique to an REA, can be a barrier to competition. As stated previously, REAs are required under the EUA to prepare Distribution Access Tariffs (DAT) which typically includes a Retailer Service Agreement (RSA). These documents specify the terms and conditions under which a competitive retailer has access to the REA's system. At least one competitive retailer raised an issue concerning a REA's distribution tariff documents to the effect that they were not compliant with the Settlement System Code (SSC) and the Tariff Billing Code (TBC) and required some physical communications and manual transactions. In regard to this issue, we undertook, with the assistance of the AUC, to suggest revisions to AFREA's template for the DAT and RSA. A number of years ago, AFREA had prepared a template for use by REAs when developing their DATs and RSAs. REAs, in some cases, modified the templates in relation to their own particular situation. With the passage of time, there have been a number of amendments to the EUA, SSC and TBC which were not reflected in the DAT or RSA documents. AFREA is currently considering the MSA's suggested revisions to the DAT and RSA documents and we expect a revised template to be circulated to member REAs in the near future.

4.1.4 Summary

In this review, there did not appear to be any systemic issue which is impeding access to competitive retailers in the REA market segment. However, we will continue to monitor competitive activity in the REA market. The MSA is currently developing market share and switching statistics which will provide additional insights into the robustness of retail competition in this market segment. In addition, we will continue to revise background information concerning competitive options and provide that information to AFREA and the UCA so that those organizations can better inform consumers who are interested in obtaining service from a competitive retailer. The MSA will continue to identify and review areas where

there may be potential barriers to competition, including any requirements for manual transactions and the extent to which prudential requirements may be an issue.

4.2 ELECTRICITY SWITCHING ACTIVITY

Customer switching is a standard measure of competitive activity in retail markets and high switching rates are often interpreted as an indicator of a competitive market. As of December 2010, over 468,000 sites, or 29.6% of billed sites, in Alberta have switched from regulated or default service to competitive energy supply. Since 2006, the total number of switched sites has increased by approximately 169,000 which represent a change of about 56% over the 2006 to 2010 time period.

Table 4.1 summarizes the number of sites and the corresponding percentage for each market sector that have switched to competitive energy supply since 2006. The residential and farm market sectors, while having relatively low percentages of switching activity, about 27% and 19%, respectively, have experienced significant growth over the past 5 years. The number of switched sites in the residential sector increased by roughly 148,000 (72%) and the number of switched sites in the farm sector increased by about 8,700 (75%) over the same time period. The growth in switching activity suggests that residential and farm consumers are becoming increasingly aware of their options in terms of energy supply and then choosing among the competitive retail suppliers.

Table 4.1: Alberta Switching Summary - Sites

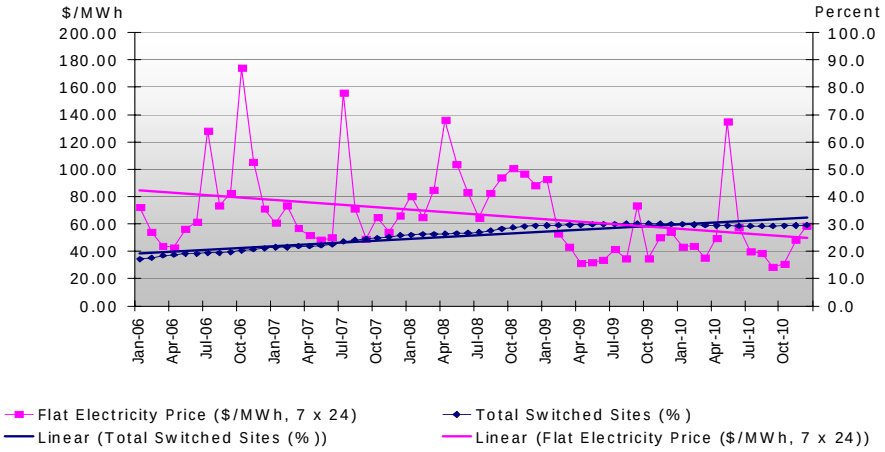
	December 2006		December 2010		Change	
Market Segment	# of Sites	%	# of Sites	%	# of Sites	%
Residential	204,350	18.0	352,389	27.4	148,039	72.4
Farm (Incl. Irrigation)	11,536	11.3	20,233	19.1	8,697	75.4
Small Commercial/Industrial (<250 MWh/Yr)	72,328	44.3	82,031	46.8	9,703	13.4
Large Commercial/Industrial (>250 MWh/Yr)	11,845	78.6	14,247	82.5	2,402	20.3
Total Alberta	300,059	21.2	468,900	29.6	168,841	56.3

Source: Alberta Department of Energy

Consumers in the small and large commercial/industrial (C&I) market sectors have shown a higher propensity to switch than consumers in the residential and farm sectors. These sectors have had a much lower level of growth than the Residential and Farm markets reflecting a more static market environment. A key characteristic in the C&I markets is that these customers have higher electricity usage rates and thus have a greater incentive to manage their energy costs.

Figure 4.1 shows the total site switching for the Alberta market, the Flat Electricity Price (i.e., the monthly average of the wholesale spot price) for the period January 2006 to December 2010 time period. The trend line for each series is also shown. As evident from Figure 5.1, switching activity increased over the past 5 years opposite to a declining trend in the Flat Electricity Price. This was a somewhat surprising result as one might expect less interest in switching in an environment where market prices are falling.

Figure 4.1: Total Switched Electricity Sites & Average Pool Price



Given that the main factor underpinning the upward trend in switching is residential switching, we consider this to be a positive indicator of competitive activity.

Table 4.2 illustrates the switching activity on an energy consumption basis. Similar to the results shown in Table 4.1, the residential and farm market sectors have relatively low percentages of switched energy but have experienced significant growth over the past 5 years. The small and large C&I market sectors have high levels of switched energy but it has reduced in the past 5 years. For the small C&I switched energy reduced from 62.2% to 57.3%, whilst for large C&I the reduction was from 95.5% to 82.5%.

Table 4.2: Alberta Switching Summary by Market Segment – Energy

	December 2006		December 2010		Change	
Market Segment	(MWh)	%	(MWh)	%	(MWh)	%
Residential	143,778	19.3	286,740	29.7	142,962	99.4
Farm (Incl. Irrigation)	30,467	18.4	47,526	25.1	17,059	56.0
Small Commercial/Industrial (<250 MWh/Yr)	448,930	62.2	342,548	57.3	-106,382	-23.7
Large Commercial/Industrial (>250 MWh/Yr)	2,579,283	95.5	2,856,816	82.5	277,533	10.8
Total Alberta	3,202,458	73.4	3,533,630	29.6	331,172	10.3

Source: Alberta Department of Energy

It may be concluded that the growth in residential and farm site switching, particularly in an environment of falling market prices, is a positive indicator of competitive activity in the retail market. In future quarterly reports the MSA will explore switching activity in individual market segments in relation to individual retailer market activities.

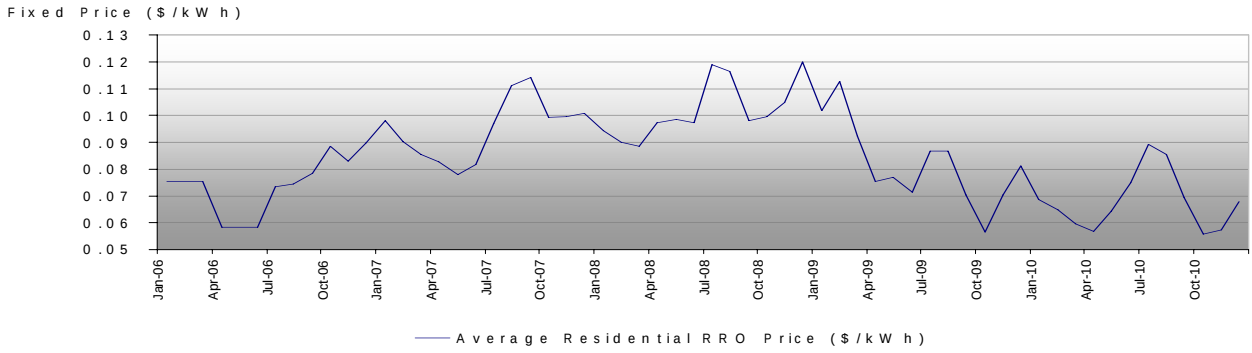
4.3 HISTORICAL COMPARISON OF FIXED VS. REGULATED PRICES FOR REGULATED CUSTOMERS

During the last 5 years, competitive electricity retailers have offered fixed price contracts to residential consumers ranging from $0.07/kWh to $0.12/kWh with terms ranging from 1 year to 5 years. We conducted an analysis, using generic assumptions, to test whether switching from the Regulated Rate Option (RRO) to a fixed price contract would have resulted in cost savings for residential consumers. For residential consumers who do not switch, the RRO is the monthly energy price set in accordance with the Regulated Rate Option Regulation, AR 262/2005. This is not an analysis to test the performance of fixed price contracts offered by competitive retailers but rather a simplified comparison of energy costs under the RRO versus fixed prices.

4.3.1 General Assumptions

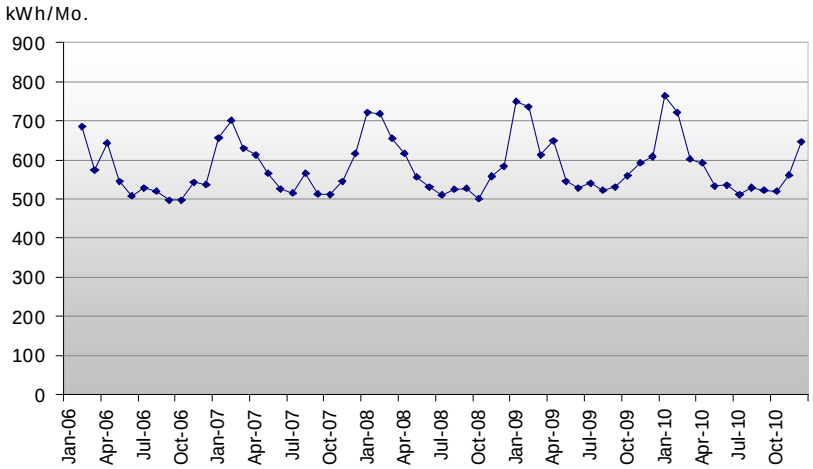
For the analysis, we first developed a composite RRO monthly price based on a simple average of the RRO prices, as reported by the Utilities Consumer Advocate (UCA), for Direct Energy Regulated Services (serving customers in ATCO's service area), ENMAX Energy Corporation (serving Calgary customers), and EPCOR Energy Alberta Inc. (serving Edmonton customers). The resulting average monthly RRO price reflects the unit cost of energy ($/kWh) for those residential consumers in the province who have not switched. Note that the monthly spread among the different RRO providers was very minor. Figure 4.2 compares the average monthly RRO price to various fixed prices used in the analysis.

Figure 4.2: Average RRO Residential Price (Jan. 2006 – Dec. 2010)



The estimated average monthly consumption for residential customers is based on data compiled and published by the Alberta Department of Energy. Figure 4.3 illustrates the monthly residential consumption profile for the period January 2006 to December 2010.

Figure 4.3: Average Monthly Residential Consumption



Contract terms of 1, 3 and 5 years over the 2006 to 2010 time period were considered. As a simplifying assumption, all contract terms are considered on a calendar year basis. In practice, however, contract terms could begin at any time. The calculated estimate of the monthly savings or cost was made by taking the difference between the average monthly RRO price and the fixed price multiplied by the monthly average residential energy consumption.

The analysis is strictly focused on the energy cost that a residential consumer may have saved or incurred over a specific contract term. The analysis does not consider discounts, rebates or other incentives that may have been offered by a competitive retailer nor does it include administration costs, exit fees, or other costs; any of which would have an impact on the actual savings or cost that a consumer may have incurred. In addition, as the actual RRO price fluctuates monthly, the results obtained from the historical analysis may not be indicative of future savings or costs.

4.3.2 Results of the Analysis

The results of the analysis are presented in Table 4.3. The table shows that a customer selecting a 3-year fixed price contract from 2007-9 at $0.08/kWh would have saved $277 ($7.69/month) relative to staying the 'average' RRO we calculated herein. A contract taken at the same time and same length but at $0.10/kWh would have 'lost' $148 ($4.11/month) relative to the 'average' RRO. Note that these contracts are hypothetical and not all were necessarily available in each year of the analysis. The level of savings or costs varied considerably depending on the fixed price, the contract term and the time when the contract commenced. In most cases, the savings/costs are relatively modest when considered on a monthly basis reflecting Alberta's modest electricity consumption at the residential level. It should be noted that customers buy fixed price contracts for a number of reasons and may not be focused on simply 'beating' the RRO price.

Table 4.3: Estimated Savings/Costs to Residential Consumers Based on Various Fixed Price Contracts

	5-year Contract	3-year Contracts			1-year Contracts				
Fixed Price ($/kWh)	2006 to 2010	2006 to 2008	2007 to 2009	2008 to 2010	2006	2007	2008	2009	2010
0.06	$851	$637	$702	$509	$97	$245	$295	$162	$52
0.07	$501	$429	$489	$297	$30	$175	$225	$90	($18)
0.08	$152	$222	$277	$84	($37)	$105	$154	$18	($88)
0.09	($198)	$14	$65	($128)	($105)	$34	$84	($54)	($158)
0.10	($548)	($194)	($148)	($341)	($172)	($36)	$14	($126)	($229)
0.11	($898)	($402)	($360)	($553)	($239)	($106)	($57)	($198)	($299)
0.12	($1,248)	($610)	($573)	($765)	($307)	($176)	($127)	($270)	($369)

5 Compliance Activities

5.1 ISO RULES COMPLIANCE

Table 6.1 provides an update of the MSA's ISO rules compliance activities as of the end of Q1/11. From the beginning of 2011, 16 notices of specified penalty have been issued. In 59 other cases, the MSA chose to forbear, while 12 other matters remained under review. Additionally, 2 referrals remain under review, each of which contains multiple suspected contraventions of ISO rule 3.5.3 during 2010. However, these two matters have been excluded from Table 6.1 and Table 6.2. For comparison, for the first 3 months of 2010, the MSA had issued 9 notices of specified penalty, 4 forbearances and had 6 files under review. Seventy-six new files were opened in Q1/11 which is a significant increase compared to the 19 files opened in Q1/10

Table 5.1: Compliance Files (as of end of Q1/11)

	Under Review	Notice of Specified Penalty	AUC Administrative Proceedings	Forbearance
6.6	1	3		25
3.5.3	1			5
3.6.2	2			
6.2.2		1		
6.3.3	8	11		24
6.5.3		1		3
OPP 102				2
Total	12	16		59

The contravention dates of the 16 notices of specified penalty issued in Q1/10 ranged from July 2010 through December 2010. Fifteen of these notices of specified penalty were referrals from the AESO. One notice of specified penalty is attributed to a self report that did not meet the MSA's criteria to forbear. Table 6.2 segments the second, third and fourth columns of Table 6.1 by month of contravention date.

Table 5.2: Q1/11 Compliance Files by Month of Contravention

		2010						2011			Total
	Rule	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	
Under Review	6.6				1						1
	3.5.3				1						1
	3.6.2				1	1					2
	6.2.2										
	6.3.3							2	1	5	8
	6.5.3										
	OPP 102										
	Total										12
NSP	6.6		1				2				3
	3.5.3										
	3.6.2										
	6.2.2					1					1
	6.3.3		2	3	5	1					11
	6.5.3	1									1
	OPP 102										
	Total	1	3	3	5	2	2				16
Forbearance	6.6					3	4	10	7	1	25
	3.5.3				1	1	3				5
	3.6.2										
	6.2.2										
	6.3.3			2	1	2	7	7	4	1	24
	6.5.3							1		2	3
	OPP 102							1	1		2
	Total			2	2	6	14	19	12	4	59

5.1.1 Emerging Trends

The most prominent trend is the significant increase in self reported events compared to Q1/10. During Q1/11 the MSA received 53 self reports - a substantial increase from the 5 received in Q1/10 when current self reporting procedures were not yet in place. The number of self reports also increased compared to Q4/10 which witnessed 40 self reports. The MSA does not believe that this trend is indicative of growing compliance problems, but rather, it reflects growing diligence on behalf of participants to detect and report even marginal issues of non-compliance.

In addition to self reporting to a greater extent, participants have been timely in submitting their self reports. Thirty percent of the Q1/11 self reported events were reported to the MSA in less than one week from the event date. Fifty-five percent of self reported events were reported within two weeks of the

event date. Participants are reminded that a self report must occur prior to the participant being alerted to a compliance matter by the AESO or the MSA. Based upon compliance monitoring procedures, this could occur within 30 days of the event in cases where the event has occurred near the end of the previous month. Accordingly, participants are advised to report issues promptly and not wait until the end of the 30 day period approaches. If necessary, a participant can follow up a self report with additional information it considers relevant to the self report.

5.2 ALBERTA RELIABILITY STANDARDS

As of the end of Q1/11, the MSA has received 3 self reported compliance matters relating to Alberta Reliability Standards (ARS). All three of these matters were related to reporting obligations within PRC-001-AB-1. At present, no referrals have been received by the MSA and no specified penalties have been issued to date.

On April 6, 2011, the AESO published a schedule for ARS compliance monitoring audits indicating the commencement of audits for certain registered entities as early as Q2/11.

In respect of forthcoming audits, registered entities should note that in cases where forbearance was extended by the MSA regarding an ARS compliance matter, the MSA will not pursue the event further subject to there being no misrepresentation of any material fact and that the entity meets the agreed terms and conditions. MSA written communications were recently revised to include this messaging in contemplation that a compliance audit may reveal errors or omissions pertaining to a matter previously self reported. Based upon audit findings, if the basis of the forbearance is found to be in question, any forbearance granted may subsequently be withdrawn.

6 MSA Activities

6.1 ANNUAL REPORT TO THE MINISTER

In March, the MSA delivered its Annual report for 2010 to the Minister of Energy as required under subsection 38(1) of the *Alberta Utilities Commission Act*.

The report provides a general synopsis of the MSA's activities for the year as well as the audited financial statements.

6.2 MSA INVESTIGATION INTO THE TIMING OF DISCRETIONARY OUTAGES AT PPA UNITS

On March 11, the MSA announced that it was undertaking an investigation into the above-noted matter following the receipt of a formal complaint. The notice also announced that, since the complaint was on substantially the same matter, the MSA's proposed stakeholder consultation was deferred.

6.3 STAFF CHANGES AT THE MSA

Nandan Randhawa and Jeff Crozier have both recently left the MSA to pursue careers outside the electricity industry. The MSA thanks them for their contributions and wishes them well in their future endeavors. On the other side of the ledger, Richard Penn has joined the MSA team as senior advisor and brings to us significant experience in market operations and trading.

Appendix A: Wholesale Energy Market Metrics

Table A.1: Pool Price Statistics

Month	Average Price[1]	On-Pk Price[2]	Off-Pk Price[3]	Std Dev[4]	Coeff. Variation[5]
Jan-11	79.05	109.66	40.23	149.02	189%
Feb-11	122.45	182.94	41.79	232.14	190%
Mar-11	48.52	63.32	27.96	78.61	162%
Q1-11	**82.05**	**116.25**	**36.60**	**164.29**	**200%**
Oct-10	30.92	35.68	24.89	15.73	51%
Nov-10	48.09	60.63	30.97	80.78	168%
Dec-10	58.89	80.14	29.45	99.3	169%
Q4-10	**45.94**	**59.09**	**28.36**	**75.25**	**164%**
Jan-10	43.43	50.84	34.03	15.56	36%
Feb-10	43.90	49.30	36.69	14.33	33%
Mar-10	35.31	43.33	24.19	31.64	90%
Q1-10	**40.78**	**47.72**	**31.56**	**22.52**	**55%**

1 - $/MWh
2 - On-peak hours in Alberta include HE08 through HE23, Monday through Saturday
3 - Off-peak hours in Alberta include HE01 through HE07 and HE24 Monday through Saturday, and HE01 through HE24 on Sundays
4 - Standard Deviation of hourly pool prices for the period
5 - Coefficient of Variation for the period (standard deviation/mean)

Figure A.1: Pool Price Duration Curves

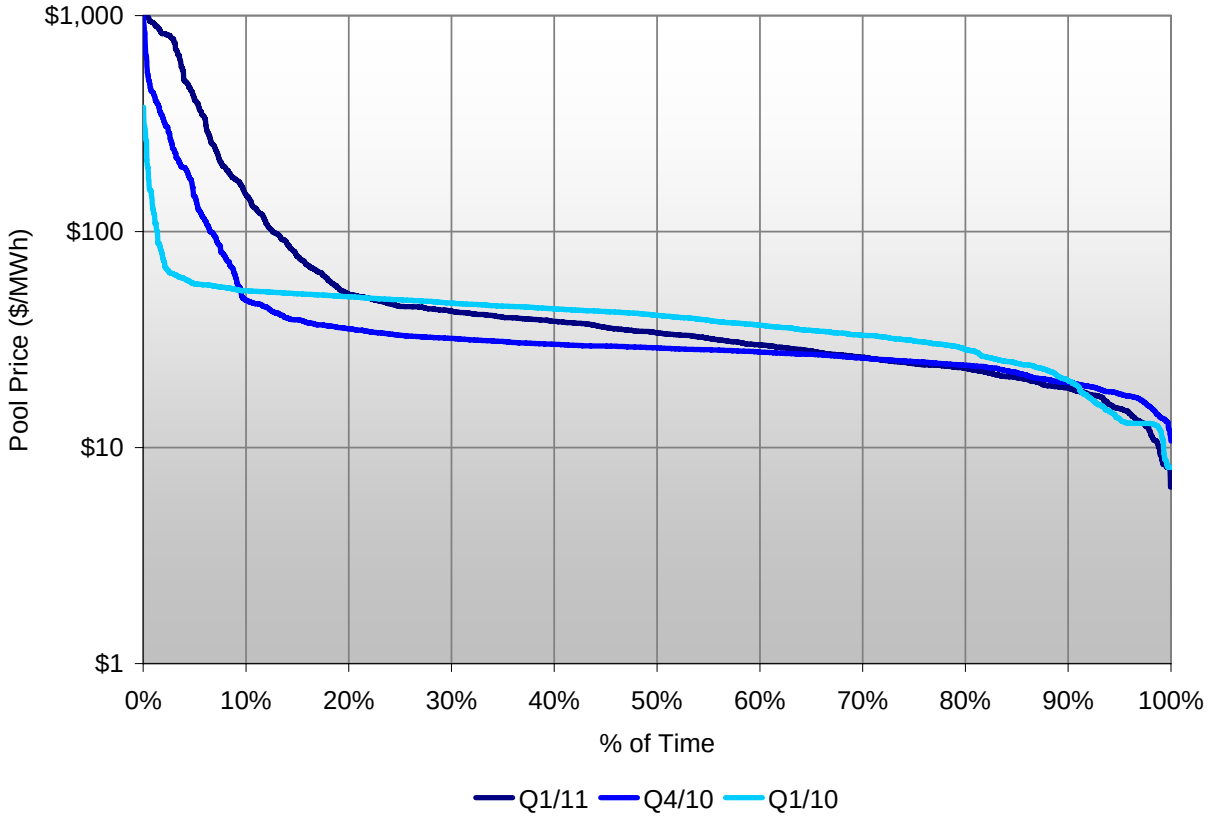
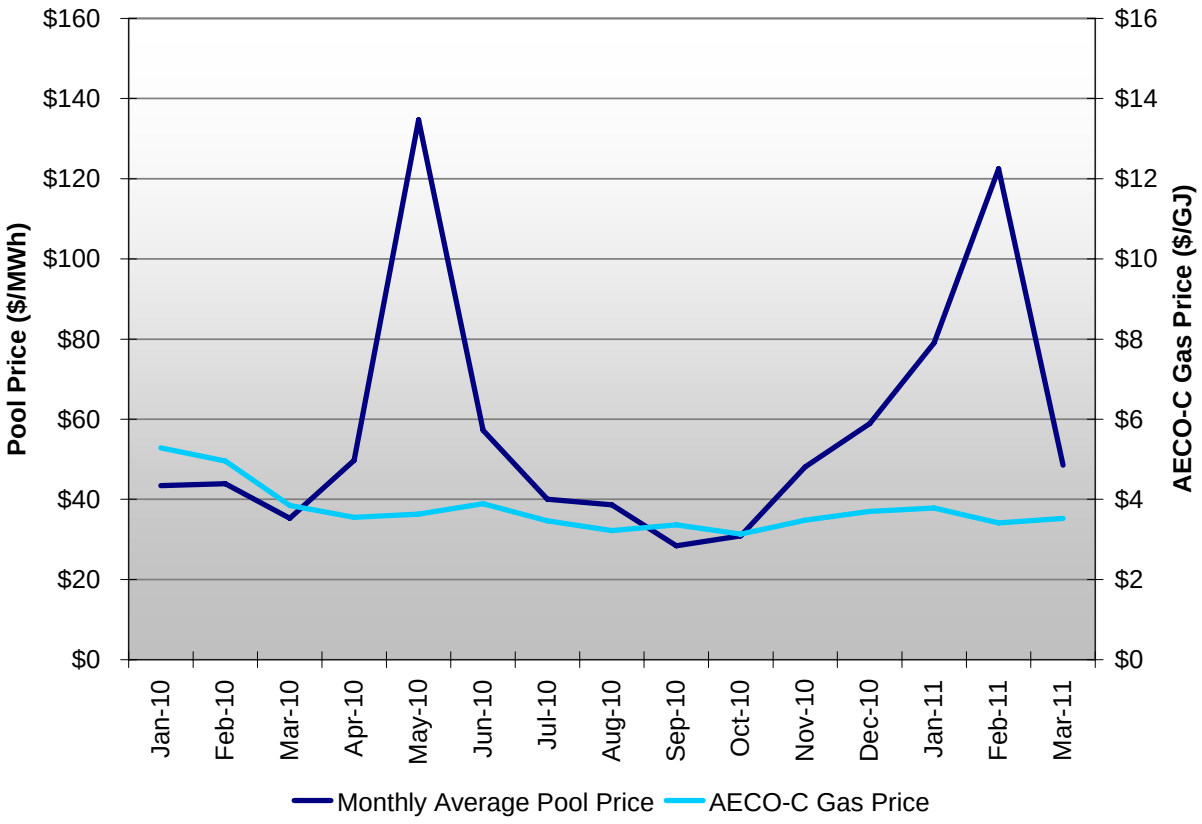


Figure A.2: Pool Price and AECO Gas Price

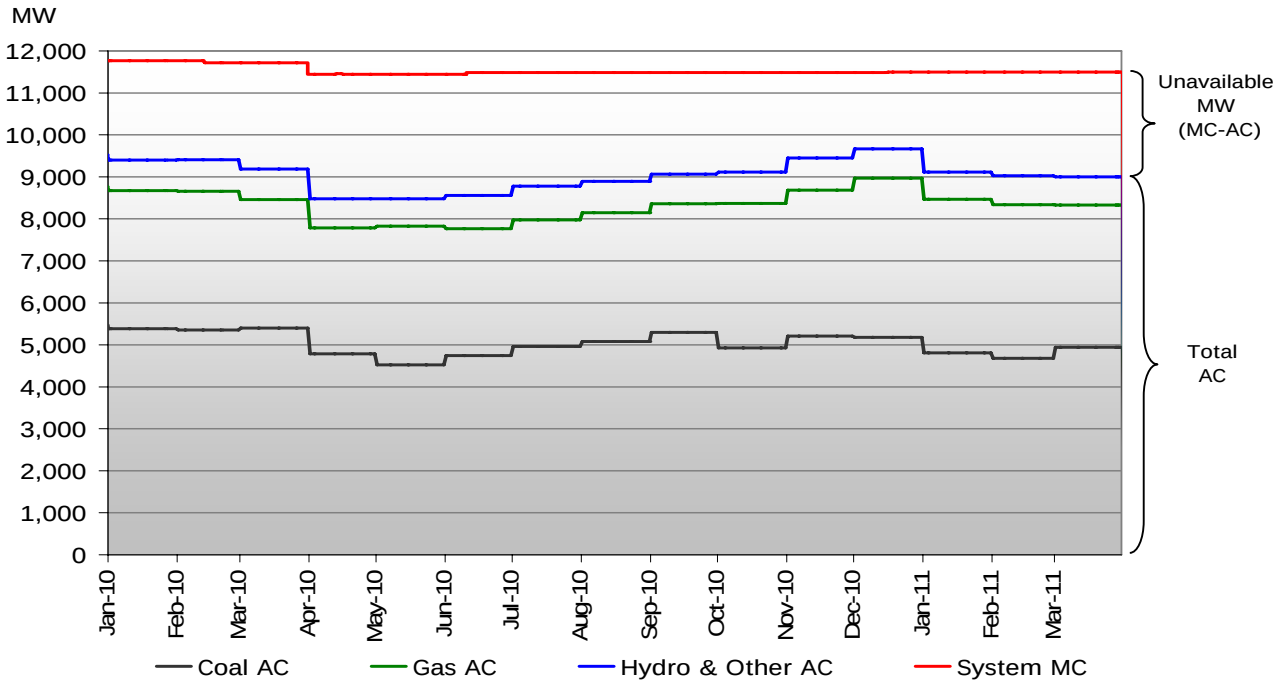


Appendix B: Supply Availability Metrics

Table B.1: Availability and Capacity Factors

Fuel Type	Quarter	Average MC [A] (MW)	Average AC [B] MW (MW)	Availability Factor [C]=[B]/[A] (%)	Generation [D] (GWh)	Capacity Factor [E] = ([D]x1000)/([A]xhrs) (%)
All Fuels *(excl. Wind)*	Q1/11	11,499	9,047	79%	16,186	65%
	Q4/10	11,487	9,409	82%	16,739	66%
	Q1/10	11,739	9,331	79%	16,304	64%
Coal	Q1/11	5,782	4,816	83%	9,938	80%
	Q4/10	5,782	5,102	88%	10,531	82%
	Q1/10	6,054	5,379	89%	10,970	84%
Natural Gas	Q1/11	4,800	3,562	74%	5,743	55%
	Q4/10	4,788	3,572	75%	5,718	54%
	Q1/10	4,768	3,216	67%	4,934	48%
Hydro & Other	Q1/11	917	668	73%	505	25%
	Q4/10	917	734	80%	490	24%
	Q1/10	917	735	80%	400	20%
Wind	Q1/11	762	n/a	n/a	424	26%
	Q4/10	671	n/a	n/a	411	28%
	Q1/10	600	n/a	n/a	448	35%

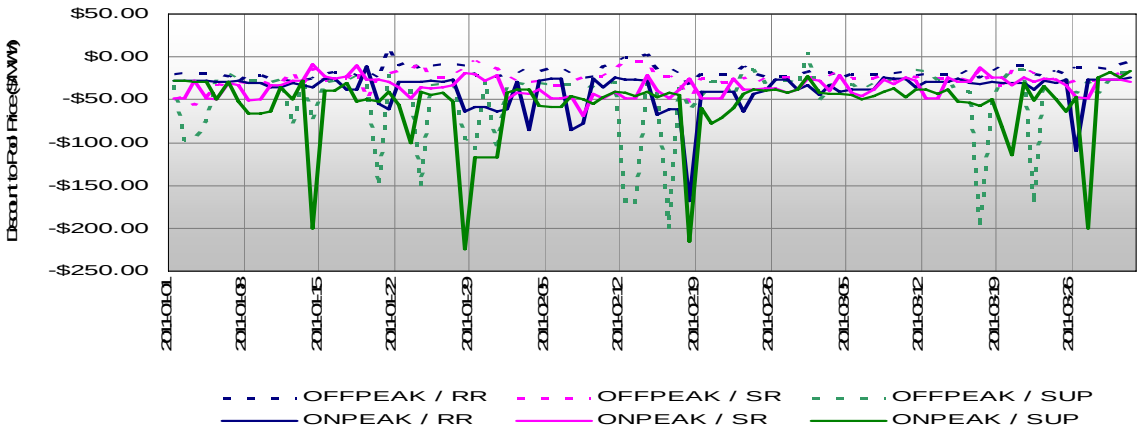
Figure B.1: Available Capacity (AC) vs Maximum Capacity (MC)



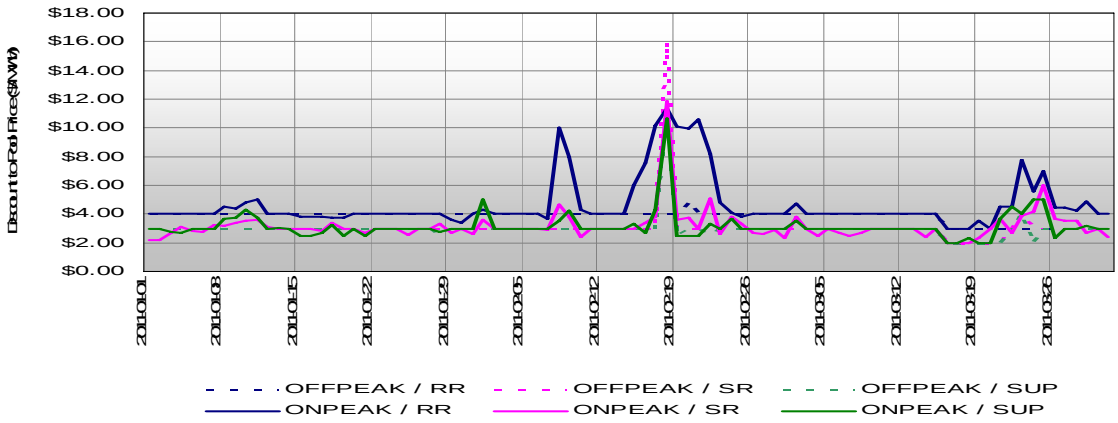
Appendix C: Operating Reserves Market Metrics

Figure C.1: Active Reserves Weighted Average Trade Index and Standby Reserve Prices

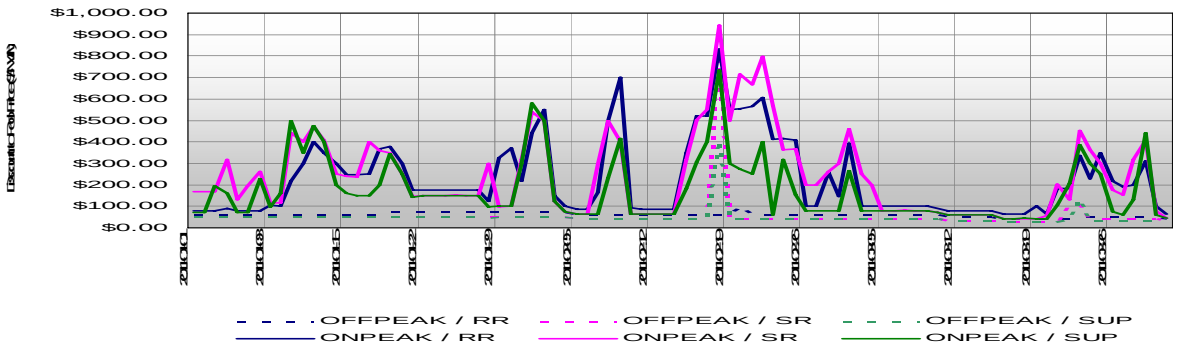
NGX Active Reserves Weighted Trade Index



Standby Reserves Average Premium Price



Standby Reserves Average Activation Price



Appendix D: Intertie Metrics

Figure D.1: Intertie Utilization

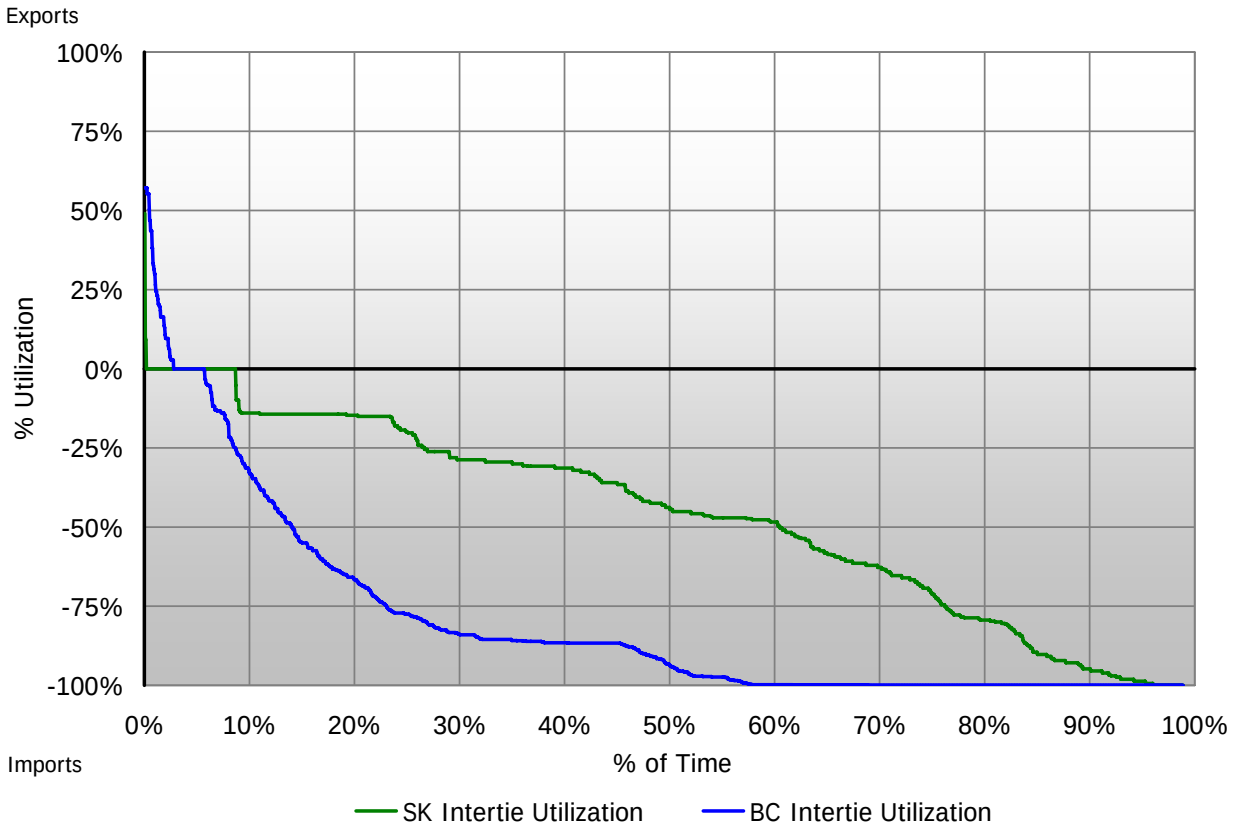


Figure D.2: On-Peak Prices in Neighbouring Markets

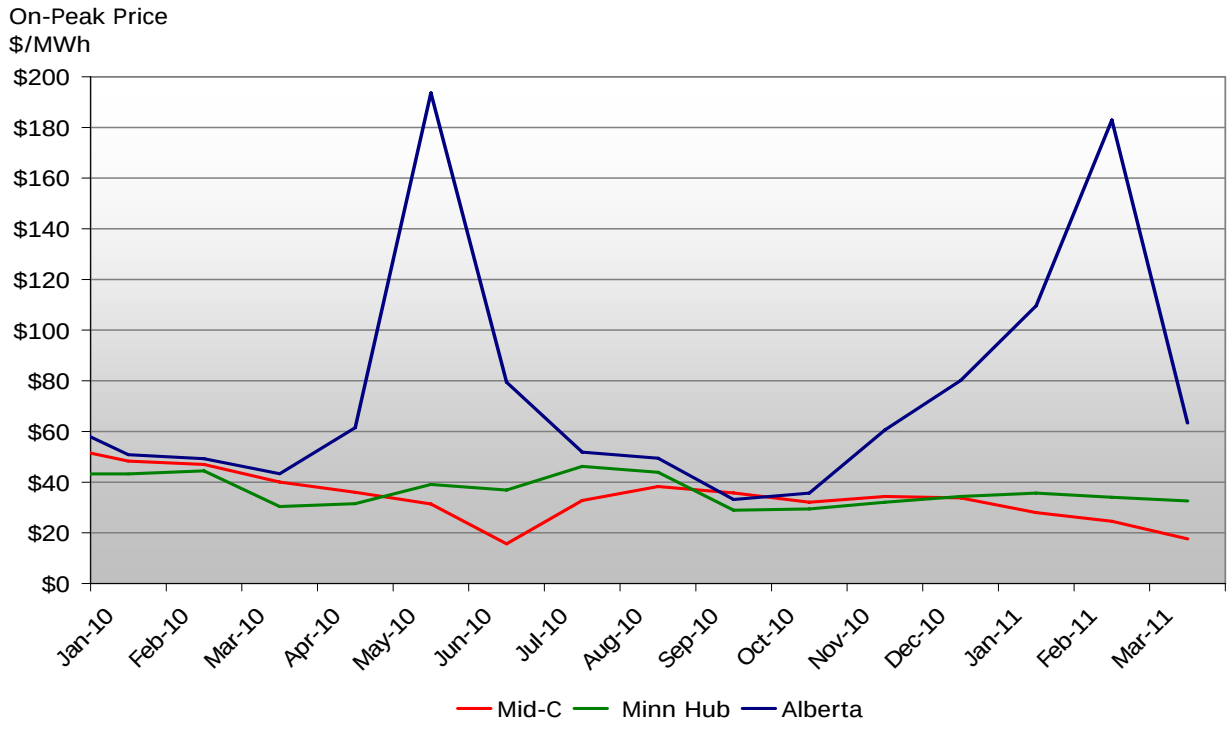


Figure D.3: Off-Peak Prices in Neighbouring Markets

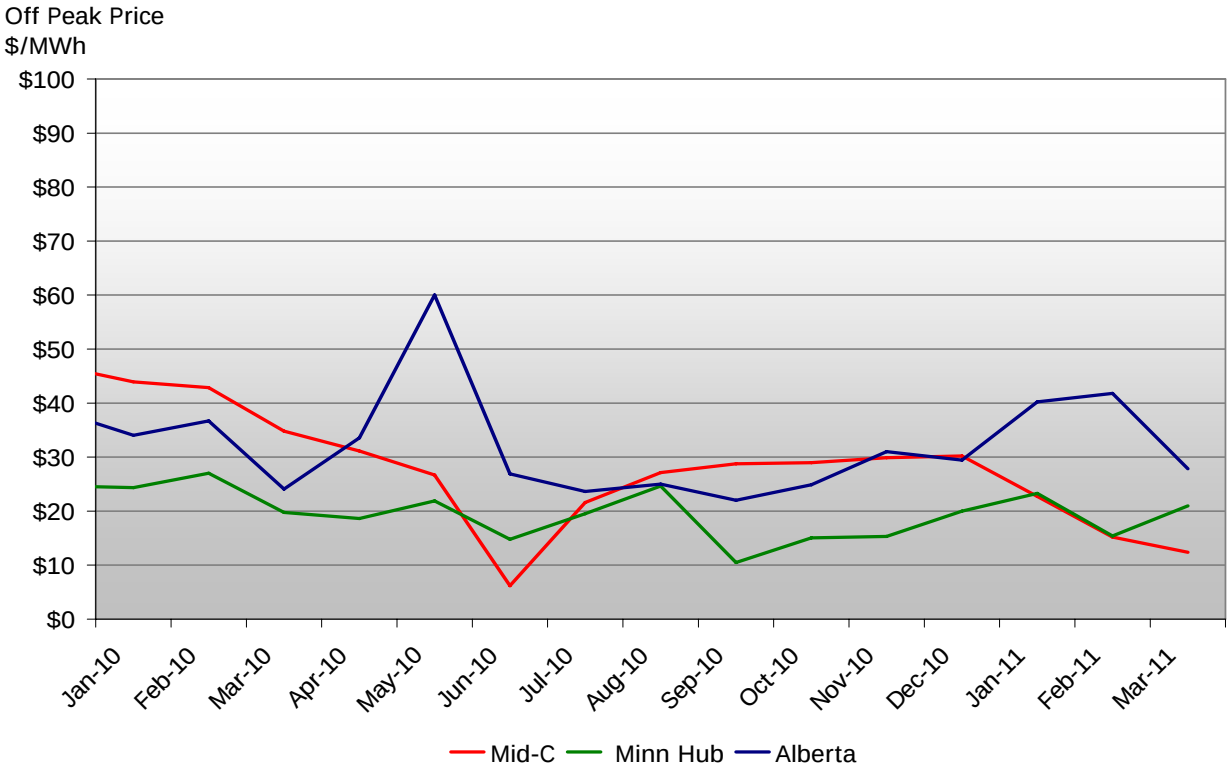
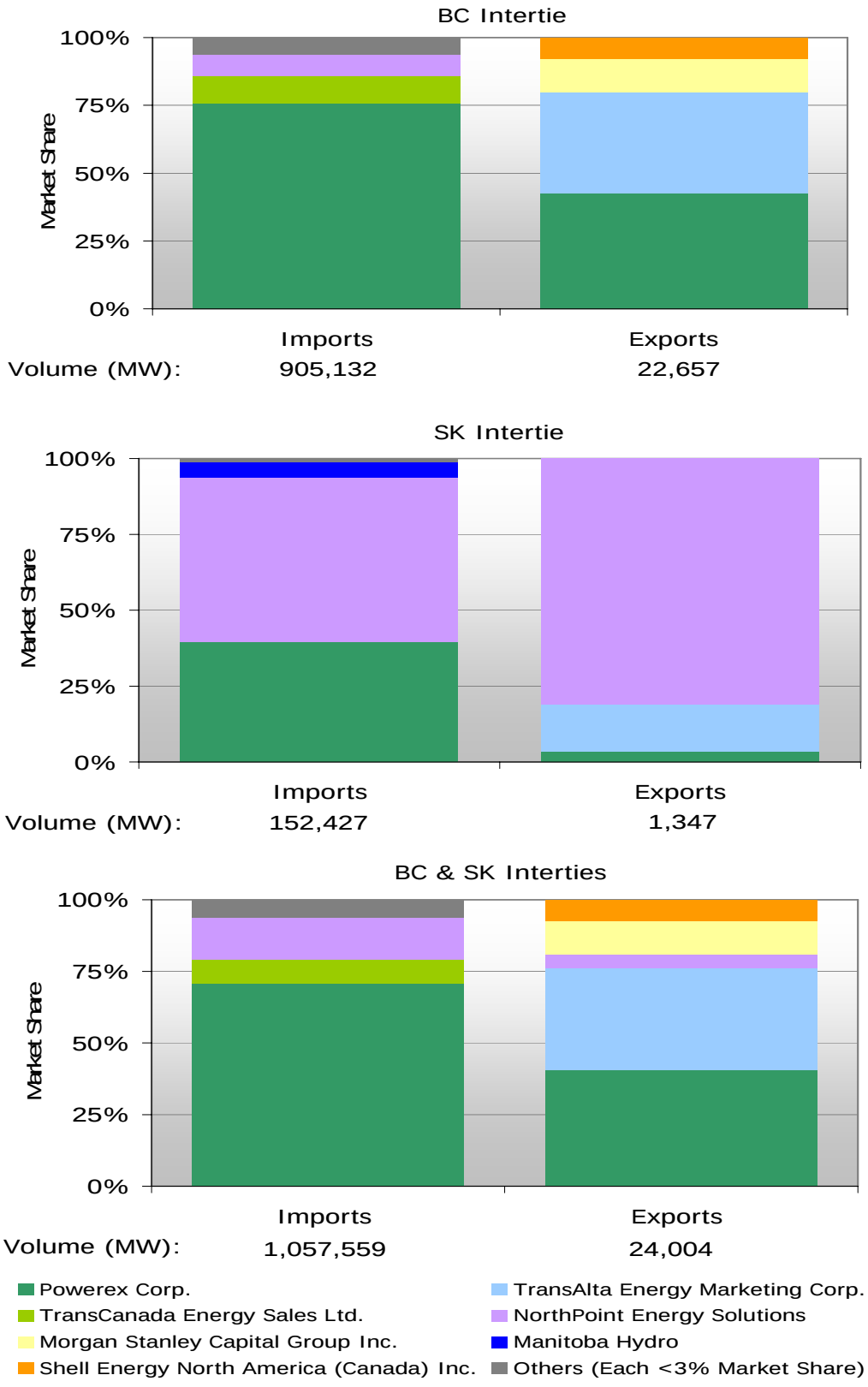


Figure D.4: Intertie Market Shares



Appendix E: Forward Market Metrics

Figure E.1: Volume by Trading Month

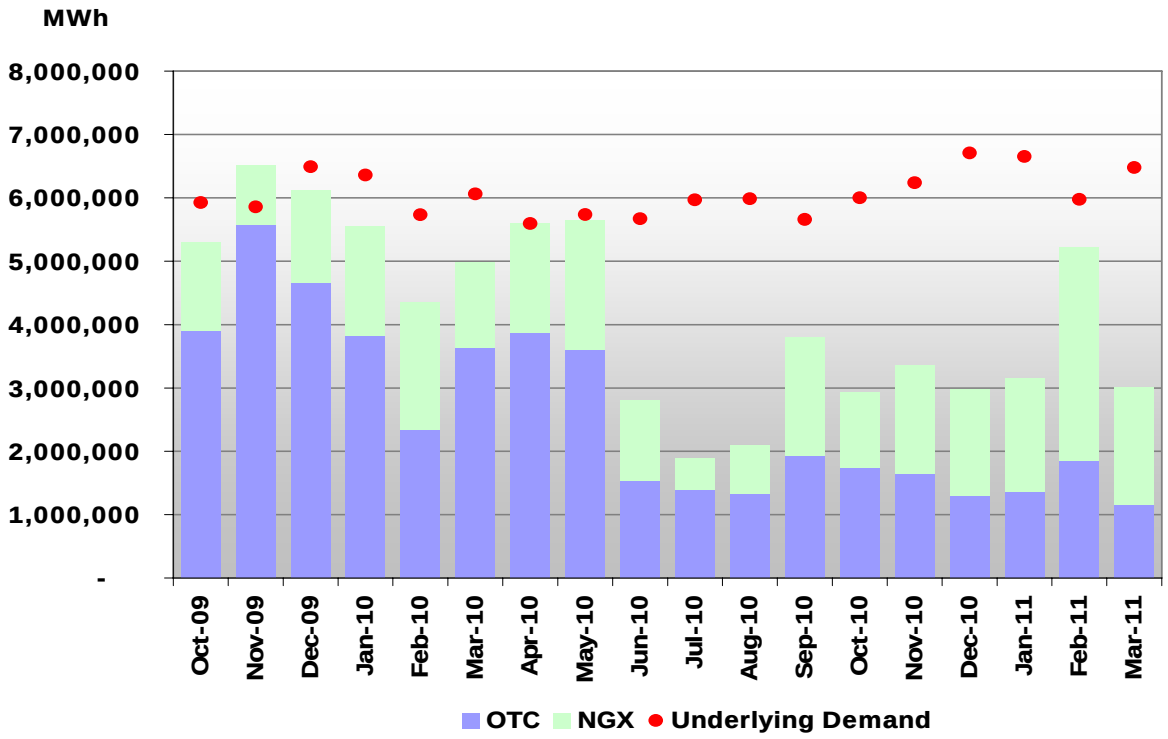
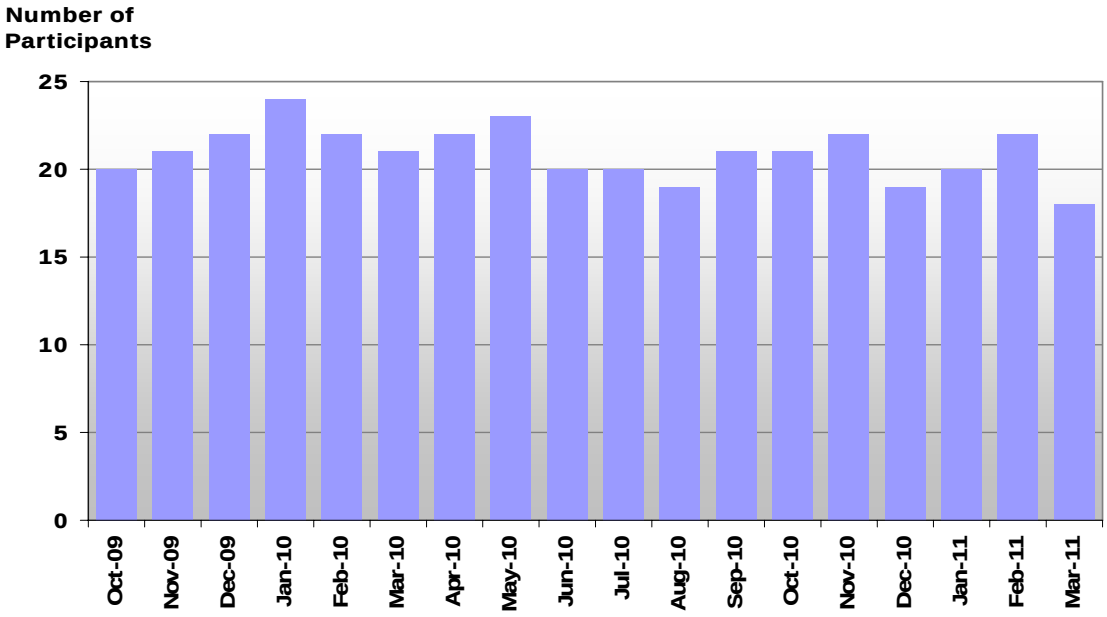


Figure E.2: Number of Active Market Participants by Trading Month



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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.