Quarterly Report: October – December 2010 (Q4/10)

February 16, 2011

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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.

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General Market Outcomes

The average pool price in Q4/10 was $45.94/MWh an increase of 28% from Q3/10 ($35.77). Following low pool prices in October, those in November and December were higher due to increased demand and some forced outages. Natural Gas prices stayed in the $3 to $4/GJ range and the average market heat rate was 13.4 GJ/MWh. Overall, Alberta was a significant net importer reflecting our higher prices relative to outside markets. However, on the BC intertie there was an unusual amount of counterflow and this is discussed below. Forward market activity continued at a low level and is also discussed below.

Monitoring Indices

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 Q4/10, many more than would be expected based on the historical data used to establish the baseline parameters.

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 residual supply index is developed herein and provides another layer of interpretation on market outcomes as it focuses on individual market participants and their ability to influence pool price in a given hour.

Event Analysis

The report describes in detail anomalous market outcomes of three separate events comprising 36 hours out of a total of 88 hours identified as statistical outliers in the MSA's baseline relationship between the supply cushion and pool price. All three entries are simply factual reports 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.

A fourth event, notable primarily from the perspective of the timing of the outages of two baseload Power Purchase Arrangement (PPA) units, is also summarized. The MSA is about to commence a stakeholder consultation process on discretion around PPA unit forced outages.

Impediments to Intertie Flows

Throughout the period mid November through mid December the market observed an unusually high volume of counterflows on the BC intertie. A concern was raised that profitable import opportunities were impeded by a market participant's timing of its exports. In such cases, increased imports would have mitigated the Alberta pool prices. The MSA's preliminary (and incomplete) analysis revealed that the market participant's submission of e-tags close to gate closure had the apparent effect of limiting some potential imports in 42 hours during the month of November. Inter-jurisdictional 'seams' are a well known challenge to electricity trading so it would be premature to conclude the apparent impediments resulted from anti-competitive behaviour. The MSA is continuing its review of this matter and will report back in due course.

Supply Cushion in the Operating Reserves Market

The utility of the supply cushion – pool price relationship for the energy market as a means to identify anomalous hours for assessment prompted a similar analysis for the operating reserves market. Since early July, 2010 the ISO has procured all the on- and off-peak strips of active regulating, spinning and supplemental reserves using a one-day procurement auction. The analysis examined the relationship between the unfilled orders (volumes offered but not taken, or liquidity) and trade index. The relationships were not very instructive, possibly because there is no 'must offer' obligation in the operating reserves market. A further assessment was made of average price paid and unfilled orders but it too provided no insightful relationship.

Net Revenue Analysis

Net revenue is an important measure of longer term market performance and the assessment of prices in 2010 against the costs and operating parameters of hypothetical unit entrants. The results showed that most generation types fared a little better in 2010 than 2009, due to the moderately higher pool prices. The hypothetical wind farm did not perform as well as in 2009 due primarily to the lower generation capacity factor.

In Texas, ERCOT uses a 'peaker net margin' calculation as a trigger for resetting the market price cap to a lower level. The equivalent peaker net margin value for Alberta in 2010 was quite close to the ERCOT trigger value. However, comparison between Alberta and Texas of the assumed costs for the hypothetical peaker revealed some substantive differences. The MSA will undertake to review our assumed costs and operating parameters prior to the next net revenue update to confirm their reasonableness.

In Australia, the National Energy Market uses a cumulative price threshold as a means to protect the market from 'extreme price risk'. Applying the threshold calculation to Alberta 2010 pool prices revealed the highest 7-day average price to be close to the Australian limit. The fact that the highest value in what is considered by some to be a 'soft price' year is close to the limit adopted in Australia is a testament to the high volatility of Alberta pool prices.

Forward Market Liquidity

Liquidity in the forward market did not recover in Q4/10. A long-term trend of declining market liquidity would be of concern to the MSA, as the levels in Alberta are already quite low compared with other electricity market jurisdictions. A highly liquid forward market provides opportunities for both suppliers and consumers to hedge against the risks associated with the real-time market. It also provides a forward view of market prices that can assist new entrants in making investment decisions. Declining liquidity further out in the curve has continued as participants seem unwilling to take longer term positions in the Alberta market.

Offer Behaviour Enforcement Guidelines

Following a year-long stakeholder engagement process, the MSA issued a draft of the *Offer Behaviour Enforcement Guidelines* in November, 2010, and the final version was issued on January 14, 2011. Concomitant with that, the MSA formally revoked its *Intertie Conduct Guideline*. The MSA thanks those market participants who assisted the MSA in this process.

MSA Advisory Opinions

From time to time, the MSA receives inquires from market participants regarding our views on matters within our mandate, including whether certain conduct would raise issues in respect of the fair, efficient and openly competitive operation of the market from our perspective. The MSA is going to develop an Advisory Opinion program over time that will feature different mechanisms for providing such opinions, the differences depending upon the particular circumstances of the request.

ENMAX ACFA Report

The MSA released its investigation report in November concerning a complaint alleging that certain financial transactions by ENMAX may have contravened sections 5(c), 6 and/or 95(10) of the *Electric Utilities Act (EUA)*. A review of the legislation showed that section 5 of the *EUA* is not capable of contravention, and MSA involvement is not contemplated in issues concerning section 95. The investigation concluded that there was no violation of section 6 of the *EUA*.

1 General Comments on Market Outcomes

Q4/10 proved to be an interesting quarter in terms of market pricing. Readers may recall that pool prices in Q3/10 were very low – the lowest Q3 prices ($35.77/MWh) since 2002. Pool prices for the current quarter started out low with October yielding an average price of $30.92/MWh. Increased system demand and plant outages contributed to tighter conditions in November and December and pool prices were higher. The average pool price for Q4/10 was $45.94/MWh, a 28% increase over Q3/10, but very similar to Q4/09 prices that averaged $46.27/MWh (See Table A.1).

Natural gas prices stayed flat over the quarter, moving in a band from $3 to $4/GJ (See Figure A.2). The average market heat rate for Q4/10 was 13.4 GJ/MWh (On-Peak: 17.2 GJ/MWh, Off-Peak: 8.2 GJ/MWh). Pool price volatility, as measured by coefficient of variation (standard deviation divided by the mean) was much higher in November and December and similar to levels not seen since May and June, 2010.

Plant availability in Q4/10 was higher than Q3/10 with average AC of 9,409 MW vs. 8,910 MW (See Table B.1). With winter approaching, the increased demand on the system in Q4/10 led to a higher capacity factor for the fleet: 66% in Q4/10 compared with 60% in Q3/10 and 63% in Q4/09.

Operating reserves average prices were fairly stable through Q4/10, and the discount to pool price for on-peak reserves was about $30/MWh (See Figure C.1). For the off-peak hours, the relationship was less obvious, although off-peak regulating reserve continues to be a premium product (See Figure C.2). The performance of the market for procuring standby reserves continues to be somewhat erratic and very difficult to make a proper assessment (See Figure C.3). The MSA looks forward to the completion of the redesign of the operating reserves market, particularly regarding the standby market.

Forward market volumes have not recovered from the low levels of summer 2010 and this is a concern for the MSA (See Figure F.1). Although the number of active traders appears to be about the same (Figure F.2) they are, on average, trading less. More detailed analysis and assessment is provided in Section 7.

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*, (OBEGs) on January 14, 2011. The OBEGs 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. In this quarterly report, the MSA builds on the analysis presented in the Q3/10 report. In that report, the focus was on the supply cushion metric and, to a lesser extent, on the price duration curve. In this report we add the residual supply index analysis which is described in more detail in Section 2.2.

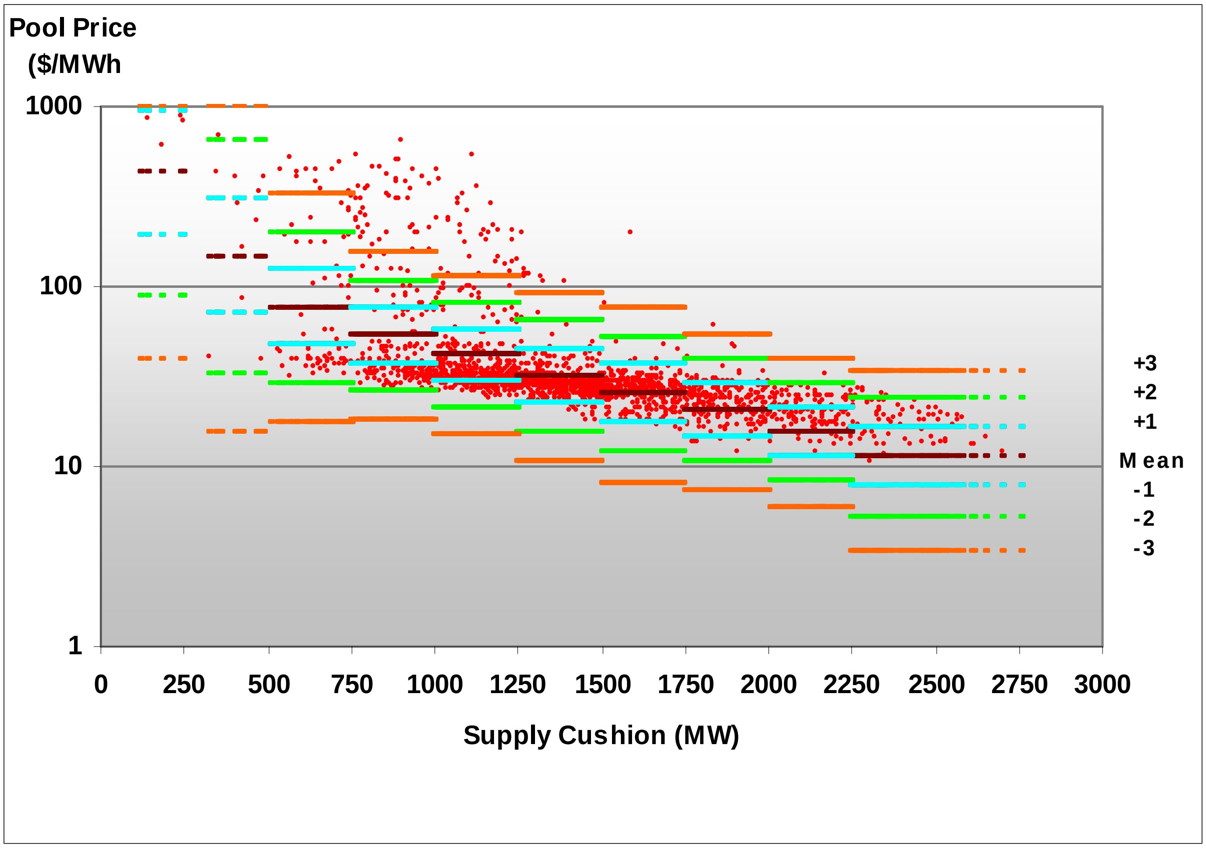
Over time, the MSA hopes to build a suite of metrics that collectively provide a sound assessment of the health of the Alberta market.

2.1 SUPPLY CUSHION ANALYSIS

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 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.

The supply cushion and associated pool price data are plotted on 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 1250 MW. In Q4/10 there were a total of 801 hours in the range 500 MW – 1250 MW of supply cushion and 88 hours (11%) were more than 3 standard deviations above the mean. In contrast, in Q3/10 there were only 6 out of 935 hours (0.6%) 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 lie more than 3 standard deviations above the mean. Whilst the data used to construct the standard deviations has only an approximately normal distribution, the MSA considers that 11% of observations in Q4/10 to be an unusually high amount.

Figure 2.1 : Q4/10 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			11	44	33	9	2	1			100
<+3 & >=2		2	6	7	15	2		3	4	11	50
<+2 & >=1	1	4	8	13	16	6	6	40	53	41	188
<+1 & >=mean	4	3	7	11	36	83	229	143	65	25	606
<mean & >=-1		2	8	37	283	415	138	64	16	2	965
<-1& >=-2		2	39	113	113	16	7	7			297
<-2& >=-3											
<-3											
Total	5	13	79	225	496	531	382	258	138	79	2206

It is apparent in Figure 2.1 that there were no hours in Q4/10 below 2 standard deviations of the mean and only 297 hours below one standard deviation of the mean (In Q3/10, there were both high and low price outliers that were events to be analyzed).

2.2 RESIDUAL SUPPLY INDEX

In its 2006 report, *Market Concentration Metrics,*[1] the MSA first produced tests for pivotal suppliers. As outlined in the MSA's *Analytical Framework,* [2] tests for pivotal suppliers will form one element of the suite of metrics to be employed by the MSA in its regular assessment of the health of competition in the Alberta electricity market. As noted in Appendix C of the MSA's 2006 report, pivotal supply metrics have been used in a number of other electricity markets.

The MSA has produced a pivotal supplier metric for this quarterly report and this section provides a detailed description of the method used to derive the metric, and presents the results of the metric for 2010.

A pivotal supplier is commonly defined as one who could withdraw its supply from the market and result in the market not clearing, or demand exceeding supply. Under the 'must offer' obligation in the Alberta electricity market, the notion of withdrawing supply is more properly thought of as pricing at, or close to, the price cap ($999.99/MWh), with the result of market price being set at, or close to, the cap by some portion of the pivotal supplier's offers. Hence a pivotal supplier could theoretically offer in such a way as to set price regardless of the actions of other participants. The metric does not assess whether a participant has done so, or whether it would be profitable to do so given the supplier's overall portfolio position.

The Residual Supply Index (RSI), represents a refinement over a simple determination of whether a market participant is pivotal, recognizing that market participants have more ability to influence prices as they need to withhold a smaller amount of supply. More formally, when the RSI metric is less than 1 a market participant is pivotal, while a value greater than 1 indicates they are not pivotal. In practical terms, values of RSI close to and less than 1 are of interest to the MSA and thus there is a richness to the RSI metric that is an improvement beyond simply measuring whether a market participant is, or is not, pivotal.

The Residual Supply Index (RSI) for a given hour is calculated as:

$$RSI(MP_{i=j}) = \frac{[Total\_Supply] - \lfloor Supply\_Controlled\_by\_MP_j \rfloor}{Total\_Demand}$$

Where, MP_j is the individual market participant for whom the RSI calculation applies.

Each of the terms, "Total Supply", "Total Demand", and "Supply Controlled by MP_i" is composed of several elements, required to account for unique features of the Alberta market, such as DDS, TMR, wind and interties.

[1] MSA Report, 2006, *Market Concentration Metrics*

[2] MSA Report, 2010,*Analytical Framework for Monitoring of Bids, Offers and Market Health*

The expanded RSI formula for a particular market participant in a given hour is:

$$RSI(MP_{i=j}) = \frac{\left[\sum_{i=1}^{n}(E_i, I_i) + \sum_{i=1}^{n} DDS_i^D + \sum_{i=1}^{n} W_i\right] - \left[\sum_{i=j}(E_i) + \sum_{i=j} DDS_i^D - \sum_{i=j} TMR_i^D\right]}{\sum_{i=1}^{n}(E_i^D, I_i) + \sum_{i=1}^{n} TMR_i^D + \sum_{i=1}^{n} W_i}$$

Where:

E_i – $\mathrm{MP_i}$'s Energy Availabe in EMMO

E_i^D – $\mathrm{MP_i}$'s Energy Dispatched in EMMO

I_i – $\mathrm{MP_i}$'s Imports in EMMO

W – $\mathrm{MP_i}$'s Wind Generation

DDS_i^D – $\mathrm{MP_i}$'s DDS Dispatched in DDSMO

TMR_i^D – $\mathrm{MP_i}$'s TMR Dispatched in the ASMO

For:

i = 1…n   Market Participants

i = j for the j^{th} Market Participant

This RSI specification incorporates several general principles:

1) The metric only measures aspects of the Energy Market Merit Order (EMMO), DDS Merit Order (DDSMO) and Ancillary Services Merit Order (ASMO). The exception is the inclusion of wind generation, which is not present in the EMMO, but does collect pool price and affects the level of dispatch in the market. Behind the fence generation was not included in the metric.
2) The metric is calculated for each settlement interval (hour), and is a measure of 'what was' in that hour, as opposed to 'what might have been' in the sense that it measures the actual availability of assets for a market participant relative to the rest of the market that is available.
3) The metric is a measure of 'ability', based on physical presence in the market. It does measure the 'incentive' to carry out withholding or whether any withholding occurred.

These principles are important to the definition of each of the three major terms of the RSI, explained below.

Total Supply

This is the sum of all energy offers and imports to the EMMO in a given hour, plus all dispatched DDS in the DDSMO, plus the sum of wind generation.

Dispatched DDS was included as available supply because it is energy that is available above reference price and it is not otherwise represented in the EMMO. Wind generation is typically equal to the amount of wind available, the exception being when wind generation is constrained down, which is accounted for in a lower DDS dispatch.

Total Demand

Total demand is equivalent to the sum of all dispatched Energy and Imports in the EMMO, plus the sum of all TMR dispatched in the ASMO, and the sum of wind generation. No additional adjustment is made for exports since export levels are accounted for in the total level of energy dispatched, needed to meet the market demand.

Supply Controlled by MP_i

The "Supply Controlled by MP_i" is the sum of energy offered in the EMMO, plus the sum of dispatched DDS, less the sum of dispatched TMR, all under the control of MP_i. The sum of dispatched TMR is deducted from a market participant's share as the applicable units are required to run for reliability reasons and cannot be withdrawn from the market.

A market participant's wind generation was not included in its share of supply, as wind generation is a price taker and cannot be withdrawn from the market through economic withholding. Similarly, imports attributable to market participants were not included in this term, as imports cannot be priced into the market, and therefore cannot be economically withheld.

The *Market Share Offer Control 2010 Report*[3] was used to define a market participant's share of the market. For this reason RSI metrics were only constructed for the market participants with offer control greater than 5%. For units that are controlled by two participants, such as some units subject to Power Purchase Arrangements (PPAs) and Genesee 3, some assumptions were necessary to allocate the unit availability between the participants, particularly with respect to derates.

For units subject to a PPA, it was assumed that Owners would incur any derate first, and if a derate exceeded the Owner's share of the unit's capacity, the derate was then applied to the Buyer's portion. The ISO rules apply derates in available capability to the highest priced offer block which could belong to either the Owner or the Buyer, and this is a source of error. DDS offers from PPA units are attributed to the PPA Buyers, as is any dispatched TMR. For Genesee 3, all aspects are split evenly between the partners.

RSI Metric Example

A simple example to illustrate the Residual Supply Index calculation is as follows. Starting from the high level definition of RSI:

$$RSI(MP_{i=j}) = \frac{[Total\_Supply] - \lfloor Supply\_Controlled\_by\_MP_j \rfloor}{Total\_Demand}$$

[3] MSA Report, 2010,'Market Share Offer Control'

In a given hour total supply is equal to 10,000 MW, comprised of 9000 MW of EMMO offers, 400 MW of imports, 100 MW of dispatched DDS and 500 MW of wind generation.

In the same hour total demand is equal to 8500 MW, comprised of 7500 MW of dispatched EMMO offers, 400 MW of imports, 100 MW of TMR and 500 MW of wind generation.

Consider a market participant with 1800 MW of EMMO offers, no dispatched DDS and no TMR. The RSI for this participant is calculated as:

$$RSI\,(MP_{i=j}) = \frac{[10{,}000]-[1800]}{8500}$$

$$RSI\,(MP_{i=j}) = 0.965$$

The RSI value of 0.965 is less than 1 and indicates the market participant is pivotal in the market, in that hour. A larger market participant with 3000 MW of EMMO offers, no dispatched DDS or TMR would have a corresponding RSI of 0.82 ([10000-3000] /[8500]). Market participants with less than 1500MW of EMMO offers, no dispatched DDS or TMR would have an RSI greater than 1 i.e. they would not be pivotal.

RSI Metric Results

The MSA calculated the hourly RSI for the 6 largest market participants during 2010. Among the 6 participants, the amount of time a participant was pivotal (RSI =<1) ranged from as little as 2% to as much as 95% of the hours in a quarter.

A useful summary metric is to consider the 'Market RSI' for an hour, as the minimum RSI for that hour. Market RSI values less than or equal to 1 indicate at least one market participant is pivotal. Market RSI values greater than 1 indicate no market participants are pivotal.

Results of the Market RSI show that the Alberta market has at least one participant pivotal between 89 and 95 percent of the hours in any quarter in 2010. Values for Market RSI are defined almost exclusively by the two largest participants, with the single largest participant defining the Market RSI between 71 and 92 percent of the hours in a quarter in 2010. The Market RSI statistics are presented in Table 2.1.

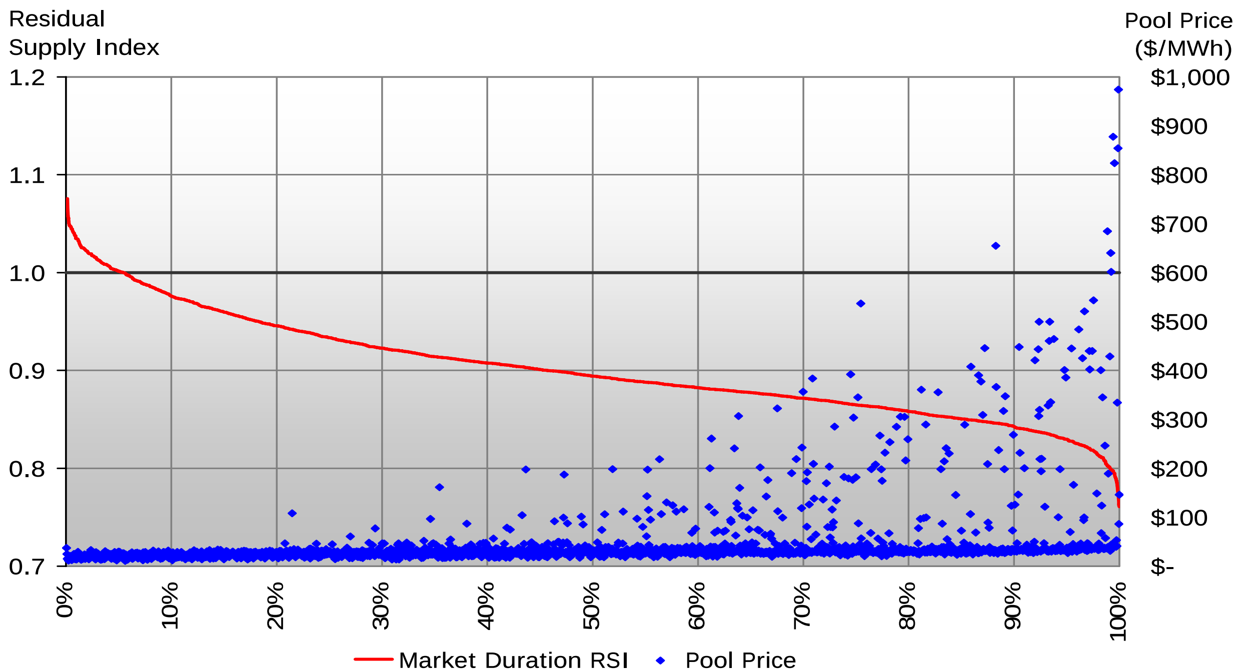
Table 2.1: Market RSI Results – 2010 Quarterly Summary

	Q1/10	Q2/10	Q3/10	Q4/10
% Time Market Pivotal	95%	89%	89%	95%
Average Market RSI	0.91	0.91	0.91	0.90
Max Market RSI	1.10	1.19	1.18	1.08
Min Market RSI	0.77	0.75	0.76	0.76

Figure 2.2 plots the Market RSI duration curve for Q4/10 and a scatter plot of the pool prices observed in the corresponding hour. Where Market RSI was greater than 0.95 (indicating either no market participants were pivotal, RSI >1, or were only just pivotal, 1=>RSI>0.95) market prices did not exceed

$100/MWh (shown in Figure 2.2 as the left-most 20% of the hours in Q4/10). These hours were mostly off-peak hours.

Figure 2.2: Market RSI vs. Pool Price - Q4/10



Where Market RSI was less than 0.95 more variation in prices is seen. In these hours at least one market participant is pivotal. In many cases, high price hours are associated with low values for Market RSI. This in part reflects the relationship between price and supply cushion; high prices tend to be associated with low supply cushions which also tend to be hours with low Market RSIs.

The lack of a clearer relationship between Market RSI and price, suggests that Market RSI does not fully explain price outcomes. This is expected. As noted above, RSI measures only "ability" and not whether there is an "incentive" to exercise that ability. An RSI metric that included the exposure of a market participant to pool price (i.e. net financial position) would likely display a stronger relationship with price.

Table 2.2.summarizes the percentage of time in each quarter in which multiple participants are pivotal in the same hour.

Table 2.2: Percentage of Hours with Multiple Pivotal Participants

No. MPs Pivotal	Percent of Time with Multiple Pivotal MPs			
	Q1/10	Q2/10	Q3/10	Q4/10
1	95%	89%	89%	95%
2	62%	67%	57%	68%
3	29%	41%	31%	17%
4	19%	34%	23%	13%
5	5%	17%	9%	3%
6	1%	6%	3%	1%

For example, in Q4/10 there was at least one participant who was pivotal 95% of the time. Sixty eight percent of the time in Q4/10 there were 2, or more, participants who were simultaneously pivotal in a given hour. When five or six participants are pivotal (3 percent and 1 percent of the time respectively), the market is generally trending towards scarcity in supply.

2.3 SUPPLY CUSHION AND RESIDUAL SUPPLY INDEX ANALYSIS

In the previous section, it was noted that in some hours low values for Market RSI will be driven by small supply cushions. In this section we consider in more detail the intersection of the two metrics in Q4/10. In particular, we examine the Residual Supply Index results during hours that produced outliers in the Supply Cushion analysis.

The analysis in this section focuses on the subset of hours in Q4/10 that experienced a Supply Cushion between 500 and 1250 MW. As can be seen in Figure 2.1, market price outcomes within these supply cushion bands were the most variable, and produced the largest number and proportion of outliers greater than 1, 2, or 3 standard deviations.

This subset of hours was cross referenced against the RSI values to determine if there was a significant difference in the average RSI values between extreme outliers, and expected outcomes. As well, the number of pivotal suppliers in each of the hours that produced extreme or expected outcomes was analyzed. Table 2.3 presents the results of the Supply Cushion – RSI analysis. There were 796 hours in Q4/10 with a supply cushion between 500 MW and 1250 MW. Eleven percent of those hours produced a price outcome greater than three standard deviations from the mean, while 33% of the hours were less than 1 standard deviation below the mean, and 48% of the hours were within +/-1 standard deviation of the mean.

Table 2.3: RSI Analysis of Market Outcomes with Supply Cushion Between 500 MW and 1250 MW

	Price Deviation from Supply Cushion Band Mean				
	3 ≤ X Std	2 ≤ X Std	1 ≤ X Std	1 < X > -1 Std	X ≤ -1 Std
Count of Observations	88	28	37	379	264
% of Total	11.1%	3.5%	4.6%	47.6%	33.2%
Average Market RSI	**0.85**	**0.87**	**0.87**	**0.87**	**0.86**
Max Market RSI	0.91	0.91	0.92	0.94	0.93
Min Market RSI	0.81	0.81	0.80	0.79	0.79
Average No. MP's Pivotal	**3.3**	**3.0**	**3.2**	**2.6**	**3.0**
Average Supply Cushion	932	949	956	1,078	978
Max Supply Cushion	1,248	1,232	1,248	1,249	1,248
Min Supply Cushion	536	573	535	513	534

The average Market RSI (defined above as the RSI of the most pivotal participant in a given hour) varied minimally across the different standard deviation bands with the most extreme prices having an average Market RSI of 0.85, and prices +/-1 standard deviation of the mean having an average Market RSI of 0.87. It is notable that the price outcomes +/-1 standard deviation of the mean had the greatest variation in Market RSI, ranging from 0.79 to 0.94. This indicates that the prices in this range were generated under both the most and least pivotal circumstances.

We do observe a positive relationship between the number of pivotal participants and the number of extreme outliers (>3 standard deviations from the mean). The average number of pivotal participants when prices were greater than three standard deviations was 3.3, whereas prices +/-1 standard deviation of the mean had, on average, 2.6 pivotal participants.

Figures 2.3 and 2.4 present frequency histograms of multiple pivotal participants when extreme outliers (>3 standard deviations from the mean), and expected outcomes (within +/-1 standard deviation of the mean) occur.

Figure 2.3: Frequency of Multiple Pivotal Participants for Extreme Outliers in Q4/10 (Supply Cushion Between 500 MW and 1250 MW)

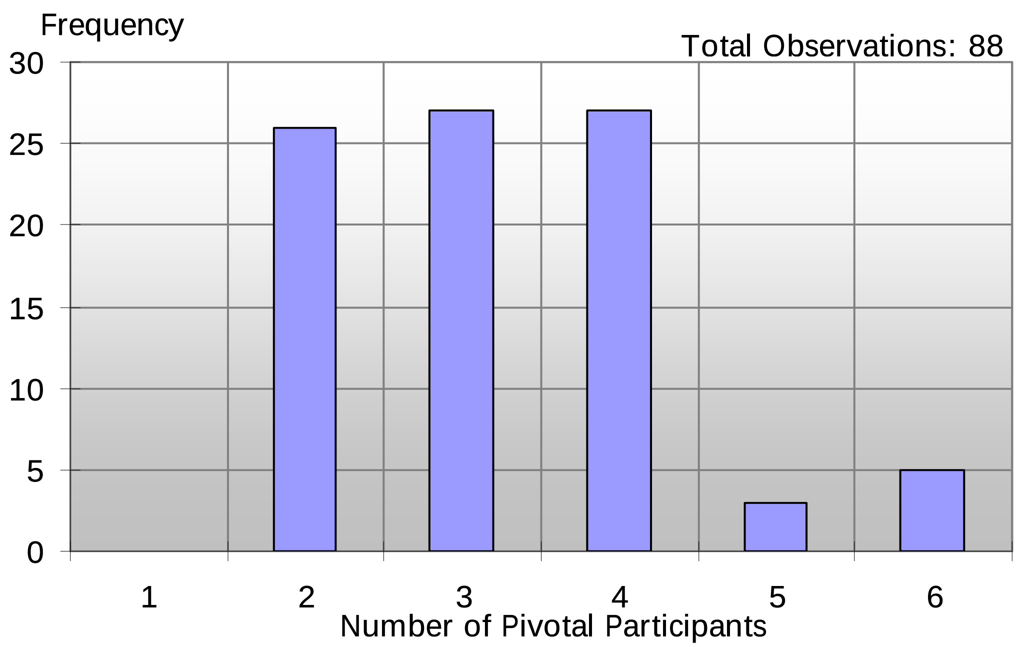
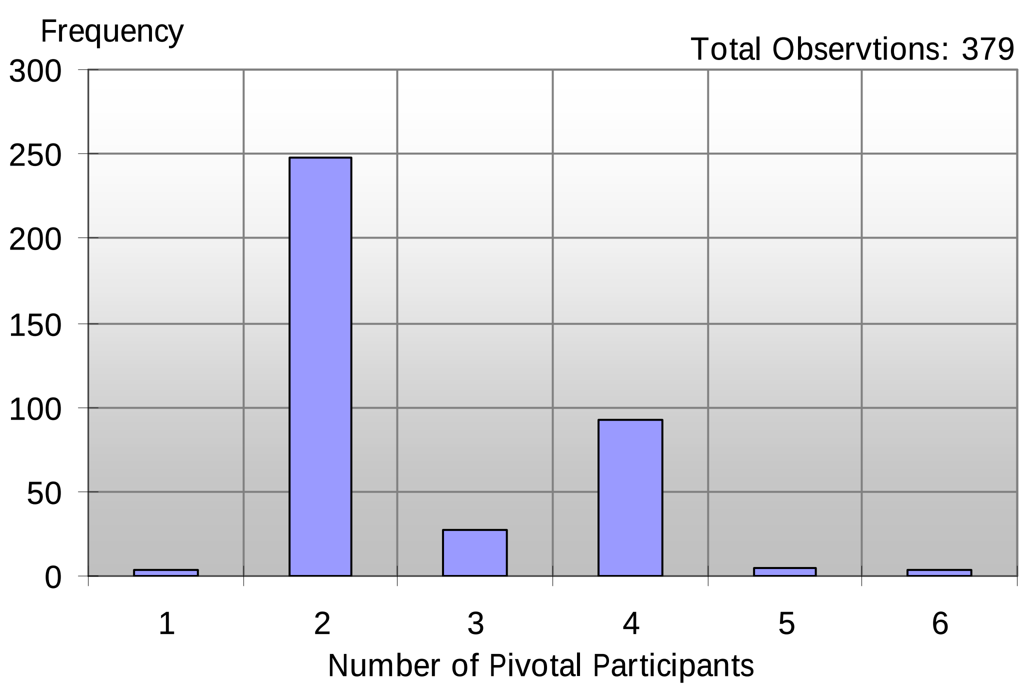


Figure 2.4: Frequency of Multiple Pivotal Participants for Outcomes Within +/- 1 Standard Deviation of the Mean in Q4/10 (Supply Cushion Between 500 MW and 1250 MW)



The first conclusion drawn from this analysis is that average Market RSI values are particularly consistent across the range of price outcomes between 500 MW and 1250 MW of supply cushion. As RSI values are in part a function of supply cushion, one might expect such consistency in results. The second conclusion is that the number of pivotal participants within this range of supply cushions is most frequently between two and four participants. The most extreme price outcomes occur roughly evenly when 2, 3, or 4 participants are pivotal, while the rest of the price outcomes occur predominantly when 2 participants are pivotal.

In general, the consistency of the Market RSI values across the range of price outcomes indicates that the RSI metric does not offer a systematic explanation for the variation in price outcomes. The frequency of multiple pivotal participants is closely related to the size of participant portfolios within the range of supply cushions under examination. Accordingly it does not have significant explanatory power.

The range of price outcomes observed in Q4/10 does not appear to be explained strictly by a measure of ability to affect market prices. Rather, the incentive to affect prices, and ultimately the action of withholding would appear to be the last available (and most likely) explanation for the wide range of price outcomes observed in Q4/10.

2.4 SUMMARY

The supply cushion analysis identified a significant number of hours that were well outside the usual bounds of the pool price – supply cushion relationship and warrant additional scrutiny. Based on historical benchmarks, the number of hours is larger than would be expected considering the number of observations.

The residual supply calculations examine the 'ability' of large market participants to unilaterally influence price. The results indicate in many hours at least one participant is individually pivotal. Examining the RSI in hours that are indicated as outliers in the supply cushion analysis in Q4/10 we have found only a weak relationship. To confirm this conclusion, the MSA believes it is prudent to examine which market participants are engaging in economic withholding and whether the MSA should be concerned about coordinated effects (such as conscious parallelism) or whether outliers are driven by other impediments to competition. The MSA expects to report on metrics in this area in the Q1/11 report. In the interim, the MSA has completed an analysis of some the outlier events identified in Q4/10 and these are presented in the next section.

3 Event Analysis

The supply cushion analysis for Q4/10 yielded 88 hours that were identified as greater than 3 standard deviations above the mean. No hours were identified below 2 standard deviations below the mean. There are a number of possible explanations as to what caused this high number of outliers. These include:

- The supply cushion metric as calculated is not representative of the hour in question;[4]

[4] The supply cushion metric may not always be representative of a particular hour. Limitations of the metric are discussed in the MSA's Q3/10 Report.

- New behaviour by suppliers not seen when the statistical baseline (for the relationship between the supply cushion and pool price) was calculated in the period February 2008 to June 30, 2010; and,
- Impediments to competition resulting from market participant behaviour, unintended consequences of ISO rules or seams with other markets.

Of the 88 hours identified in the supply cushion analysis as greater than 3 standard deviations above the mean, the MSA has selected 3 events to report on in detail. These events account for 36 of the 88 hours identified. Preliminary analysis of the other hours suggests similar circumstances but of shorter duration. The purpose of reporting on these events is simply to document anomalous market outcomes. At this time the MSA has not reached any view that these outcomes are the result of inappropriate behaviour by market participants or reflect flaws in the ISO rules or other aspects of the underlying structure of the market.

A fourth event is described below that was identified through the MSA's routine market monitoring activity.

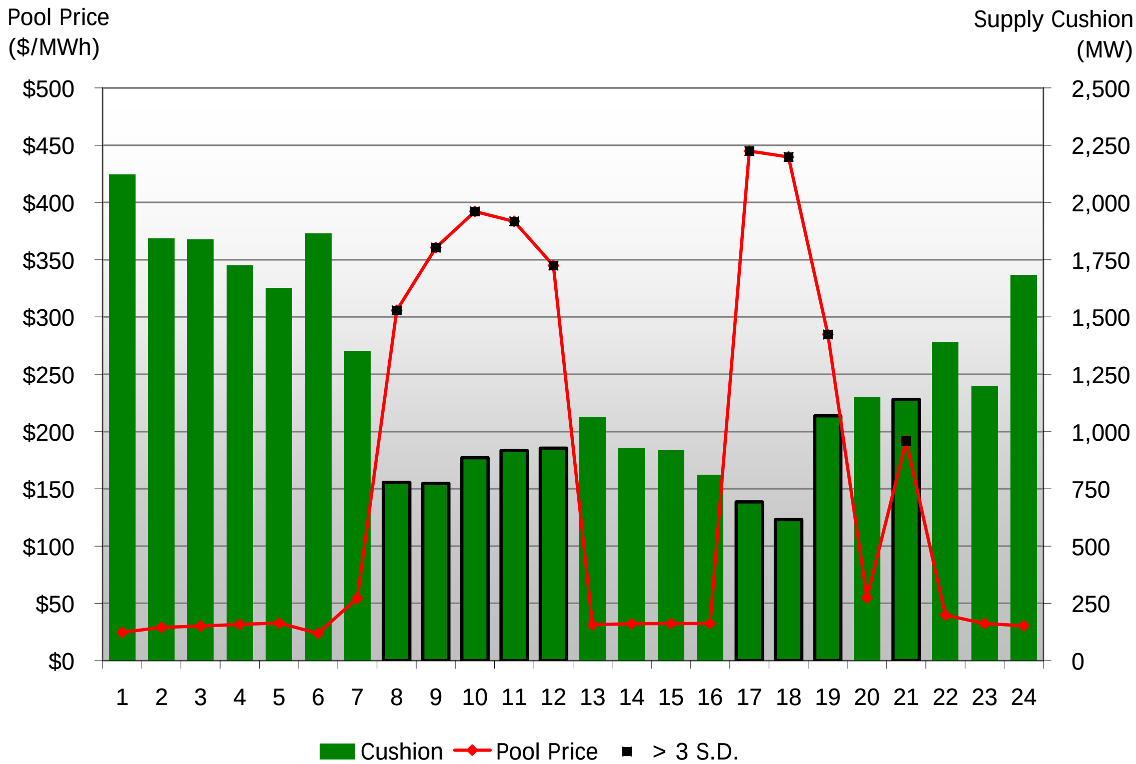
3.1 DECEMBER 16TH, 2010, HE08 TO HE21

Through the on-peak hours of December 16th, several participants priced energy above $350/MWh and contributed to pool price outcomes that exceeded 3 standard deviations in 9 of 14 hours in the on-peak period. There were as many as four participants who priced energy above $350/MWh in this period.[5]

Import levels on the BC and SK intertie were at capacity through most of the hours of interest. Wind generation was near zero, and price responsive load curtailed in response to the high prices. The changes in supply cushion through the day were primarily due to changing demand. Figure 3.1 presents the pool price and supply cushion values for the day, with hours exceeding three standard deviations above the mean highlighted in black.

[5] There are a number of smaller market participants with high-priced offer blocks in the merit order. The total capacity of these offers is small and ignored in this analysis. The offers are included in any supply cushion calculations and in the merit order graphs, but not labeled. This approach is used in all the event descriptions.

Figure 3.1: Pool Price and Supply Cushion - 16 December 2010



Fact Pattern[6]

On-peak pool prices were fairly volatile in the hours of interest, and moved from ~$40 to ~$400/MWh under supply cushion conditions that had a range of about 500 MW. From HE08 through HE12, four participants priced energy between $350 and $998/MWh, creating two 'shelves' in the merit order, at ~$400/MWh, and at ~$990/MWh. Figure 3.2 depicts the relevant portion of the energy merit order in HE12.

In HE12, which is reasonably representative of HE08 through HE12, volumes at high prices were observed as follows: participant A 280 MW, participant B 152 MW, participant C 285 MW, and participant D 220 MW. These four participants accounted for virtually all of the energy offers priced above $350/MWh.

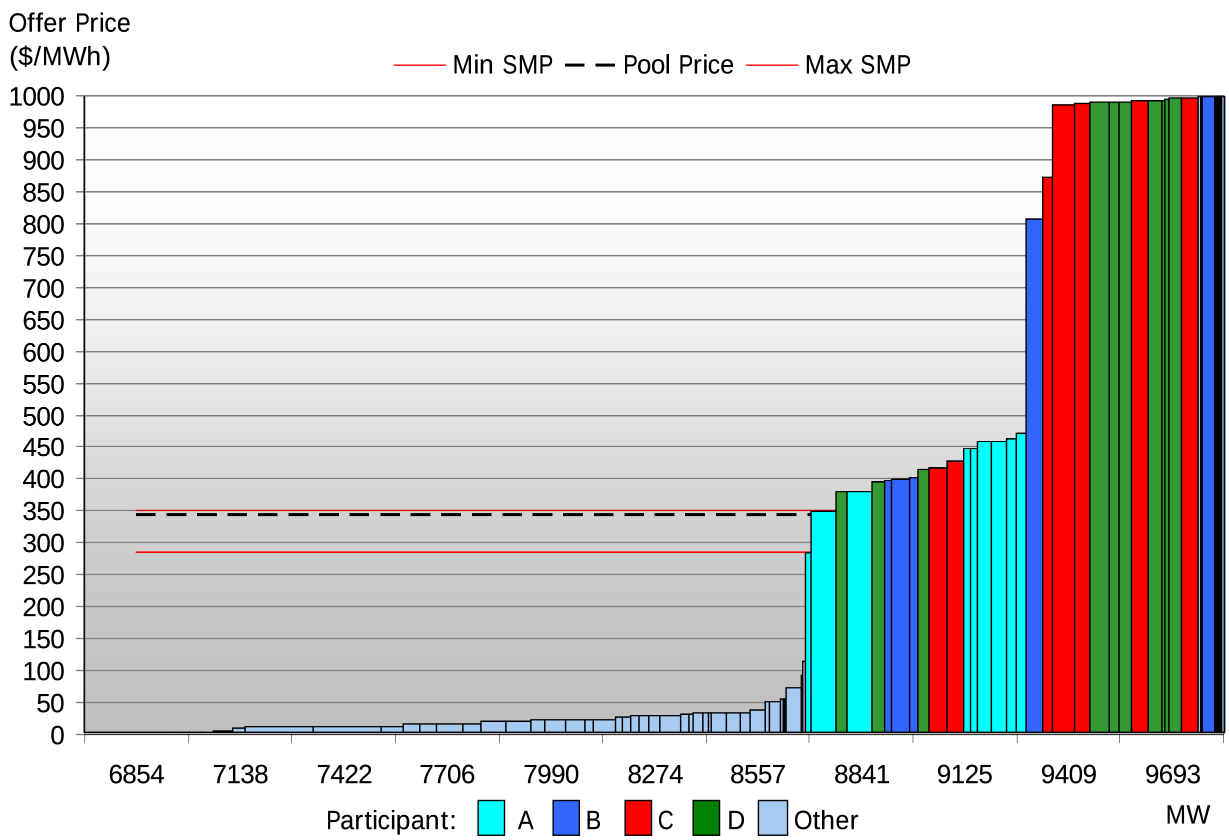
Between HE08 and HE12 some noteworthy offer changes occurred:

- Participant A initially priced 440 MW around $450/MWh in HE08, and by HE12, decreased its high-priced volume to 280 MW, and decreased the offer prices on some of the remaining blocks to about $350/MWh;

[6] In all three event descriptions (Sections 3.1, 3.2 and 3.3), we use the same letter designation for each participant. For example, participant A is the same entity in all three sections.

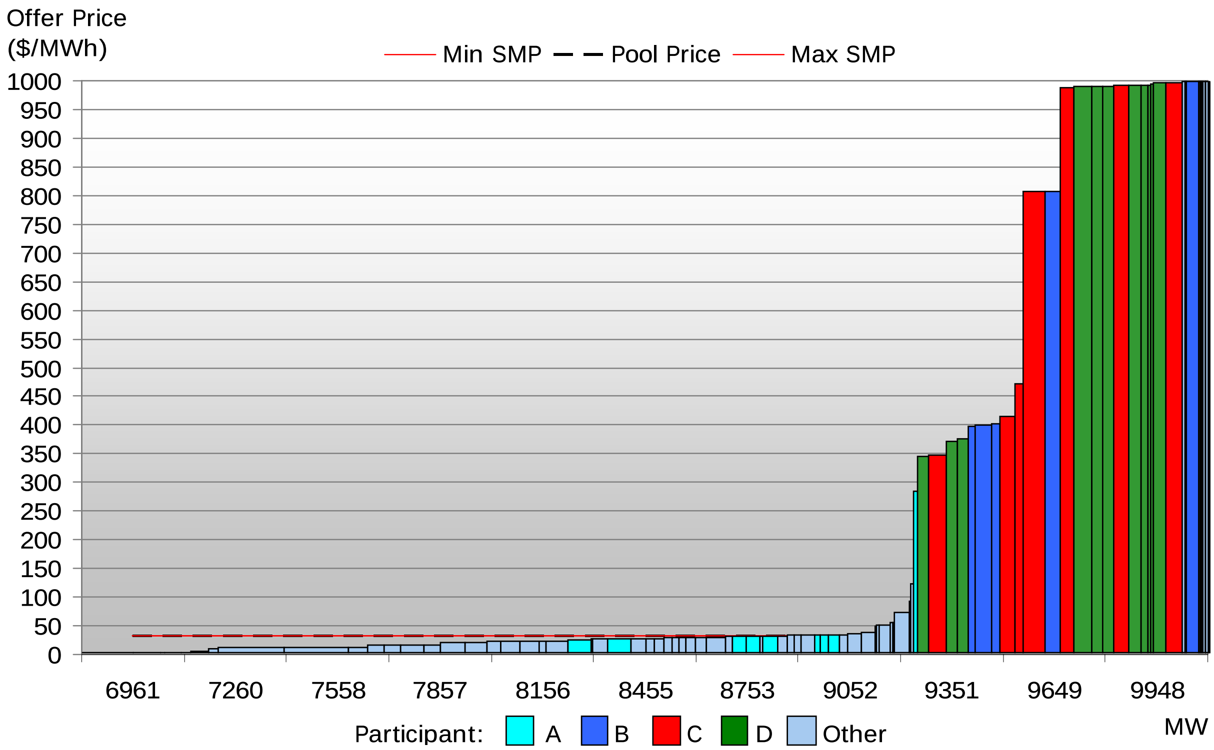
- Participant B increased the volume of high-priced energy from ~70 MW in HE08 to ~150 MW in HE12;
- Participant C further increased the offer price on nearly all its higher-priced offers, moving offers from $200 to $400/MWh, and some energy was added to existing volume offered above $900/MWh; and,
- Participant C reduced the offer price on some higher-priced energy between HE08 and HE12, from ~$990/MWh down to ~$400/MWh. However, this did not materially increase dispatch levels of the affected unit.

Figure 3.2: Energy Market Merit Order – 16 December 2010, HE12



In HE13, participant A offered volumes, priced in earlier hours from ~$350 - $450/MWh, down to below reference price. The change resulted in the market clearing in HE13 through HE17 at approximately $32/MWh. The market outcomes in these hours fell in the -1 to -2 standard deviation range in the supply cushion analysis, meaning lower than expected for hours with similar supply cushions. Figure 3.3 depicts the energy merit order in HE15, with participant A offers below reference price.

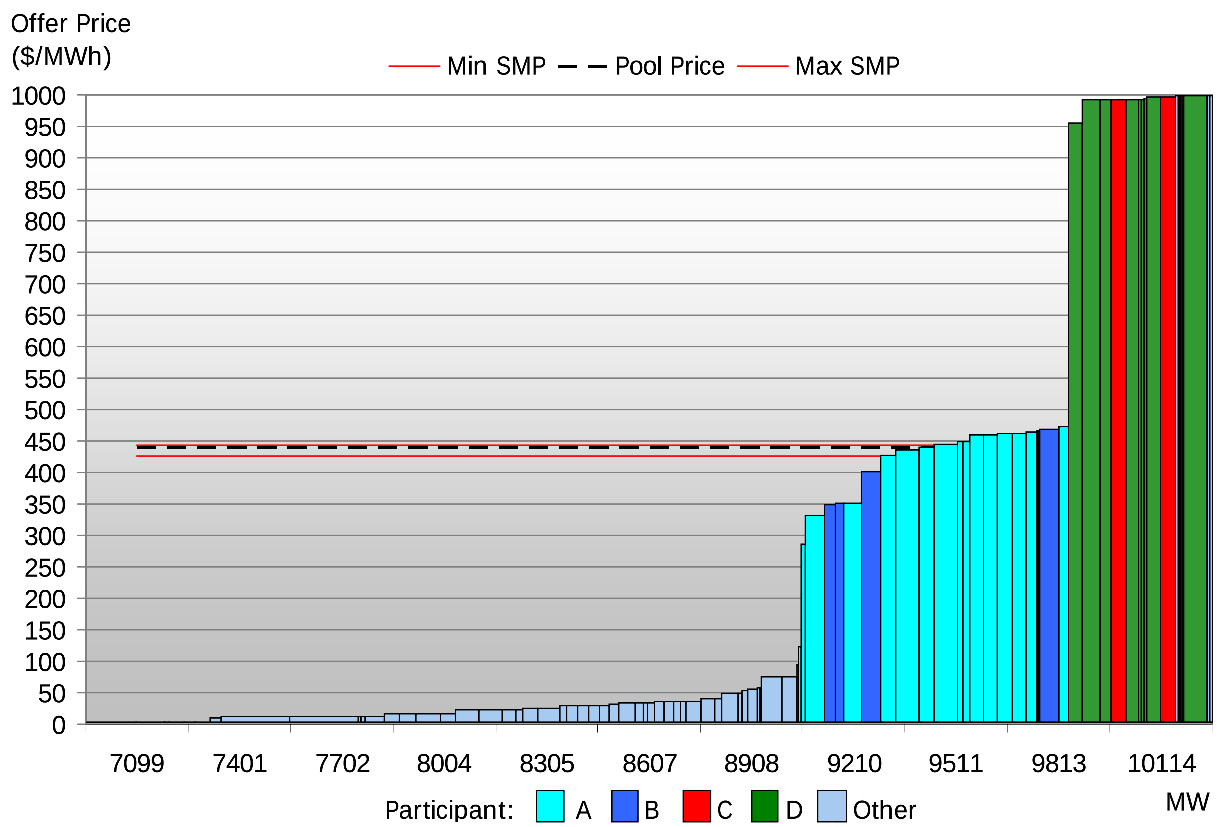
Figure 3.3: Energy Market Merit Order - 16 December 2010 HE15



In HE17, participant A offered approximately 540 MW into the $330 to $475/MWh price range that had previously been offered below reference price. In combination with the offers from participants B, C and D approximately 700 MW was offered around $400/MWh, with another 385 MW offered around $990/MWh, mostly comprised of offers from participants C and D. Participants' offers in this price range were fairly consistent from HE18 through HE22; however participant C did price down some offers to close to reference price through the peak demand in HE18, but returned some offers back to the shelf in HE19. Note that the supply cushion was the smallest in HE17 and HE18 due to the evening peak in demand (See Figure 3.1).

Figure 3.4 presents the relevant portion of the energy merit order for HE18, which is largely representative of the hours from HE17 through HE22.

Figure 3.4: Energy Market Merit Order - 16 December 2010 HE18

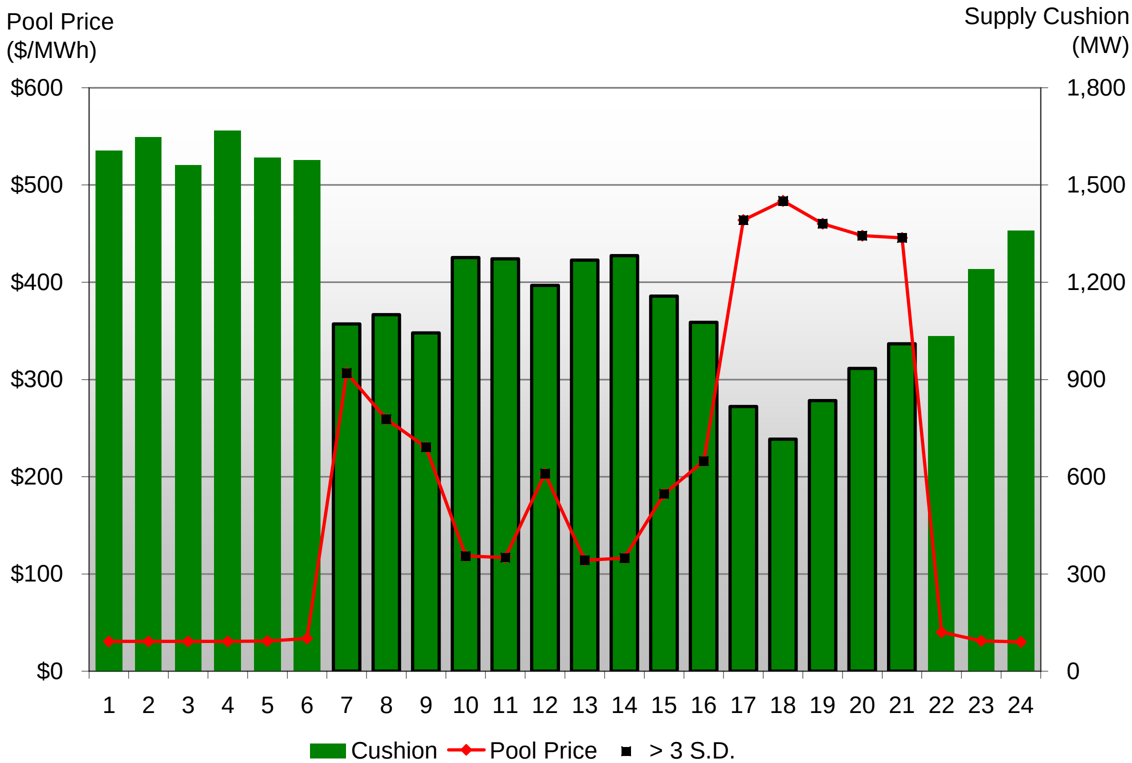


3.2 DECEMBER 2ND, 2010, HE07 TO HE21

From HE07 through HE21 on December 2, there were 15 consecutive hours where the supply cushion analysis indicated outcomes were more than three standard deviations from the mean. Supply cushion variation through these hours was moderate, approximately 600 MW from minimum to maximum.

Import levels on the BC and SK intertie were at capacity through most of the hours of interest. Wind generation was near zero, and price responsive load curtailed once high prices were observed and remained curtailed throughout the remaining hours of interest. Figure 3.5 presents the pool price and supply cushion outcomes for the day, with hours with prices exceeding three standard deviations highlighted in black.

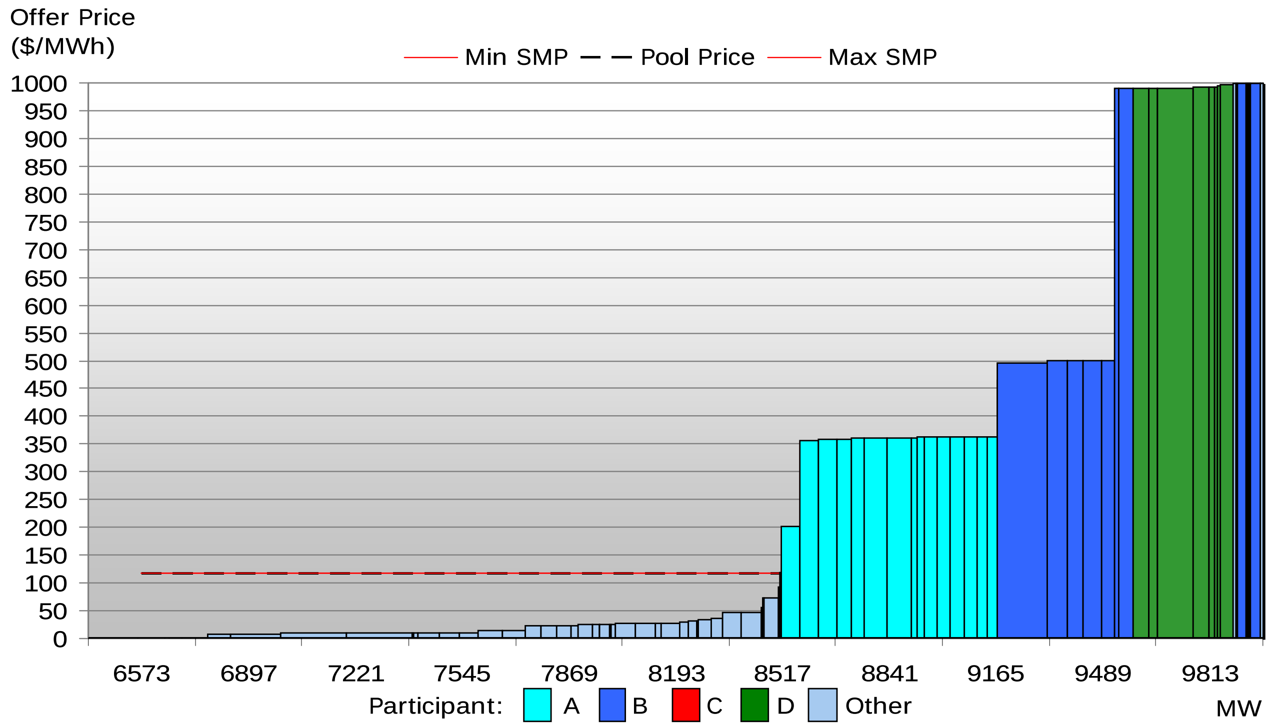
Figure 3.5: Pool Price and Supply Cushion - 2 December 2010



Fact Pattern

From HE07 through HE21, the energy offers from three participants dominated the merit order above $100/MWh, grouped into three blocks primarily of the offers of a single market participant. Early in the day, with lower demand and correspondingly higher supply cushion values, the offered energy rarely set System Marginal Price and was not dispatched. Figure 3.6 presents the relevant portion of the merit order in HE10, the offers of participant A, B and D collectively represented almost all (97.4%) of the 1276 MW supply cushion in that hour.

Figure 3.6: Energy Market Merit Order - 2 December 2010 HE10



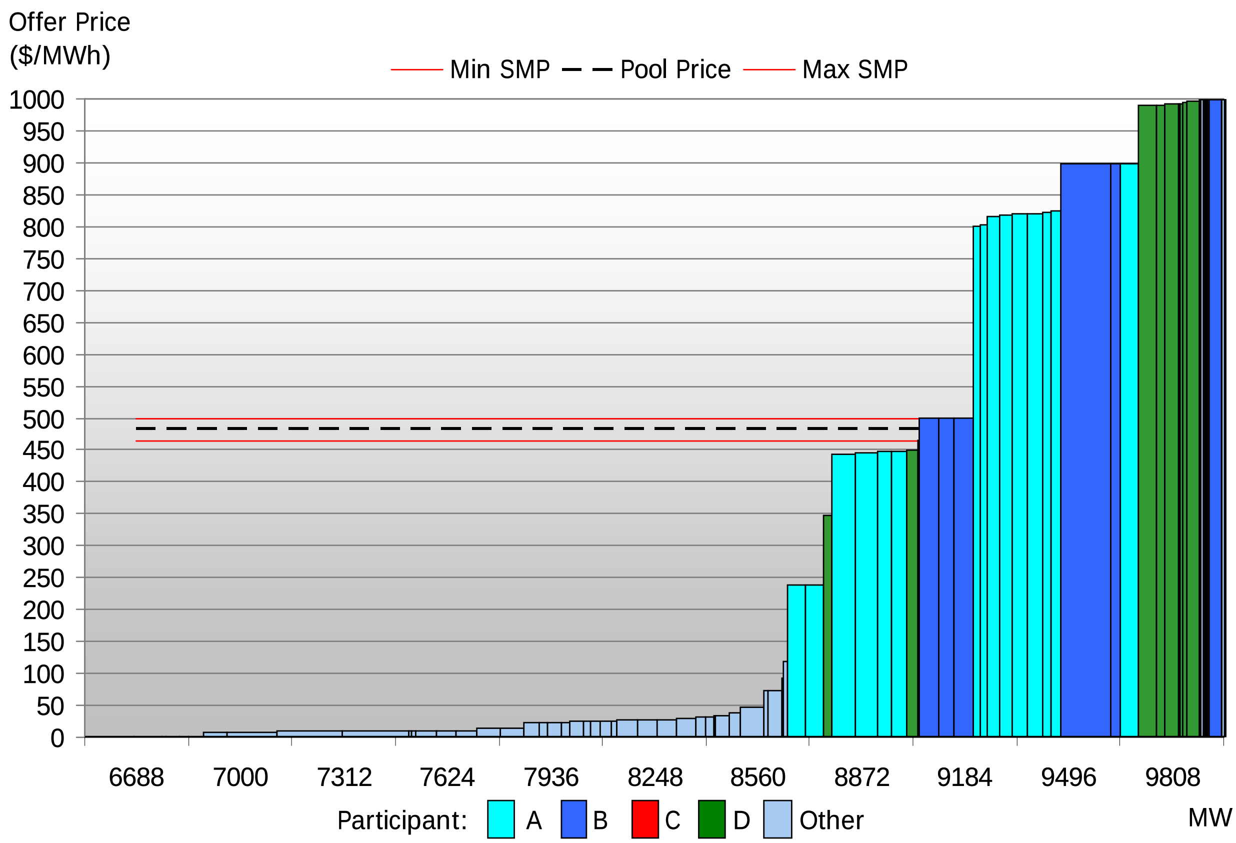
Offer behavior was fairly consistent from HE07 through to HE16. Both participant B and D had engaged in similar offer strategies.

Pool prices rose significantly, starting in HE07 when participant A offered energy at prices higher than it had done in previous hours. Prices did not subside until HE22 when participant A priced its energy offers below reference price.

Participant B changed offer strategy during the day, lowering its offer on 137 MW to undercut participant A in HE13 and HE14, but then raising that same block to $900 in HE17. These re-pricing efforts captured little dispatch through day.

In HE17 there was a shift in participant A's offers, where just less than half of the withheld energy was priced from ~$350 to ~$800/MWh. Also during this time, participant D changed the prices of some of its offers, interspersing them among participant A's offers, and capturing dispatch. Figure 3.7 presents the relevant portion of the energy merit order for HE18. As shown in Figure 3.5, pool price settled between $400 and $500/MWh during HE17 through HE21.

Figure 3.7: Energy Market Merit Order - 2 December 2010 HE18



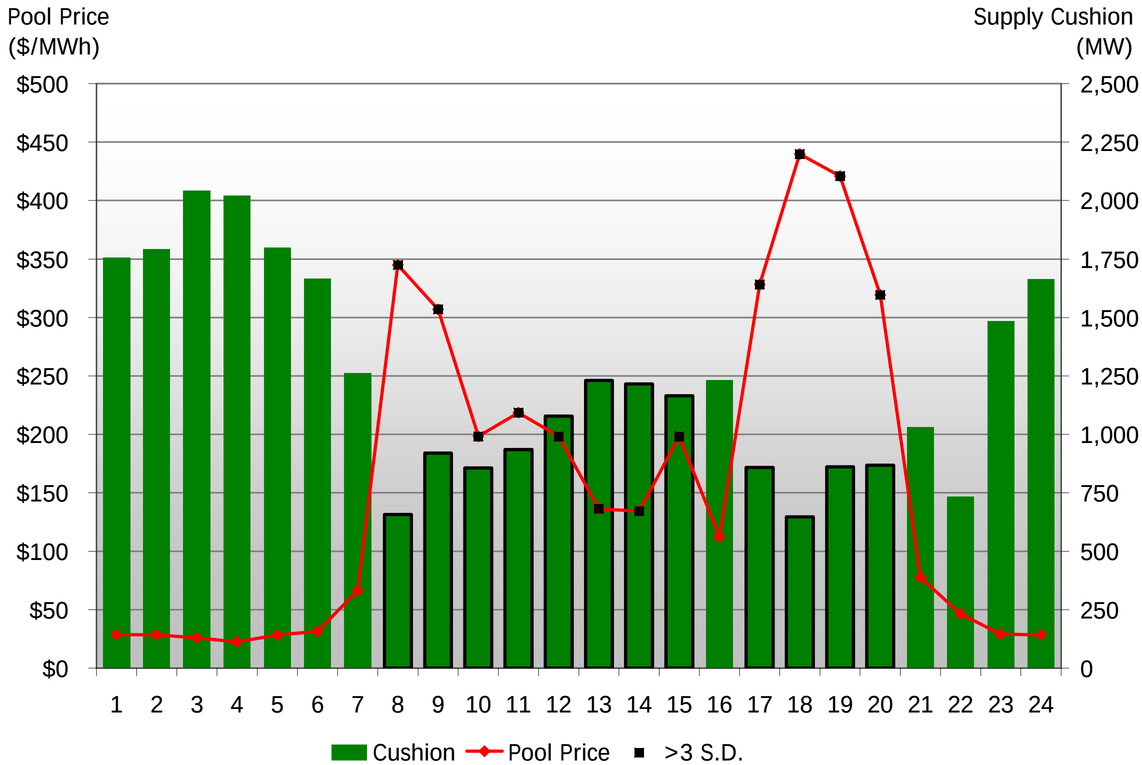
3.3 NOVEMBER 22ND, 2010, HE08 TO HE20

From HE08 through HE20, in 11 of the 12 hours the supply cushion analysis indicated outcomes where prices exceeded three standard deviations from the mean. Market supply cushions were moderately variable through the hours of interest, moving in a range of about 600 MW.

Import levels on the BC intertie were near capacity through most of the hours of interest. In three of these hours, exports were scheduled on the BC intertie. In two of these three hours, HE08 and HE10, the import capacity was not fully used, despite there being sufficient offers at (T - 2) hours. This matter is discussed in more detail in Section 4. The SK intertie was underutilized in almost all hours of interest, though it did flow near capacity from HE17 to HE23.

Wind generation averaged 115 MW, and price responsive load curtailed through the hours of interest. Figure 3.8 presents the pool price and supply cushion outcomes for the day, with hours exceeding three standard deviations highlighted in black.

Figure 3.8: Pool Price and Supply Cushion - 22 November 2010

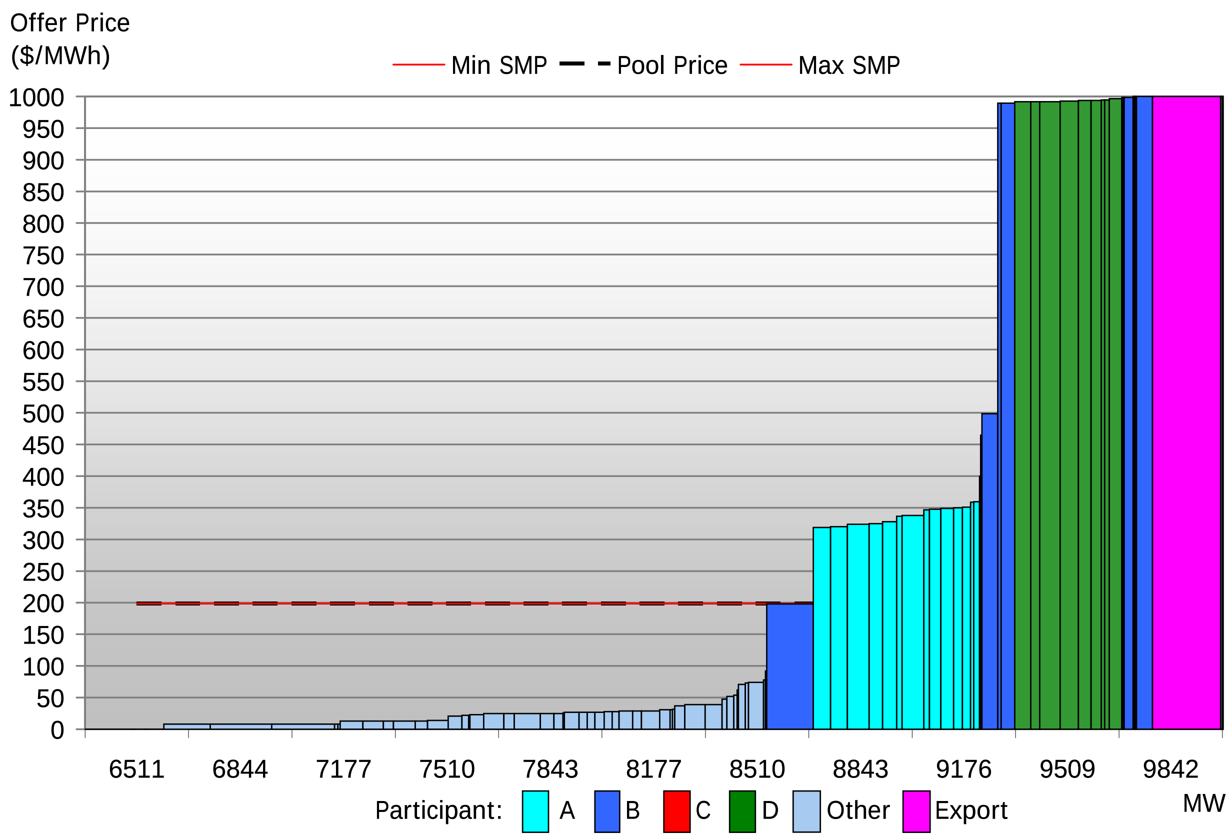


Fact Pattern

From HE08 through HE21, participant A priced between 500 and 600 MW of energy in the $200 to $500/MWh price range. At the same time, participant B priced ~300 MW of energy between $200 and $999/MWh, and, in selected hours, exported up to 200 MW, while participant D withheld ~240 MW above $990/MWh.

This offer behaviour created two shelves in the energy merit order at ~$350 and ~$990/MWh. Throughout much of the day, only the lowest-priced blocks of the lower-priced shelf were dispatched, and the majority of the dispatch accrued to participant B's block priced near $200/MWh. Figure 3.9 presents the relevant section of the energy merit order for HE10.

Figure 3.9: Energy Market Merit Order - 22 November 2010 HE10



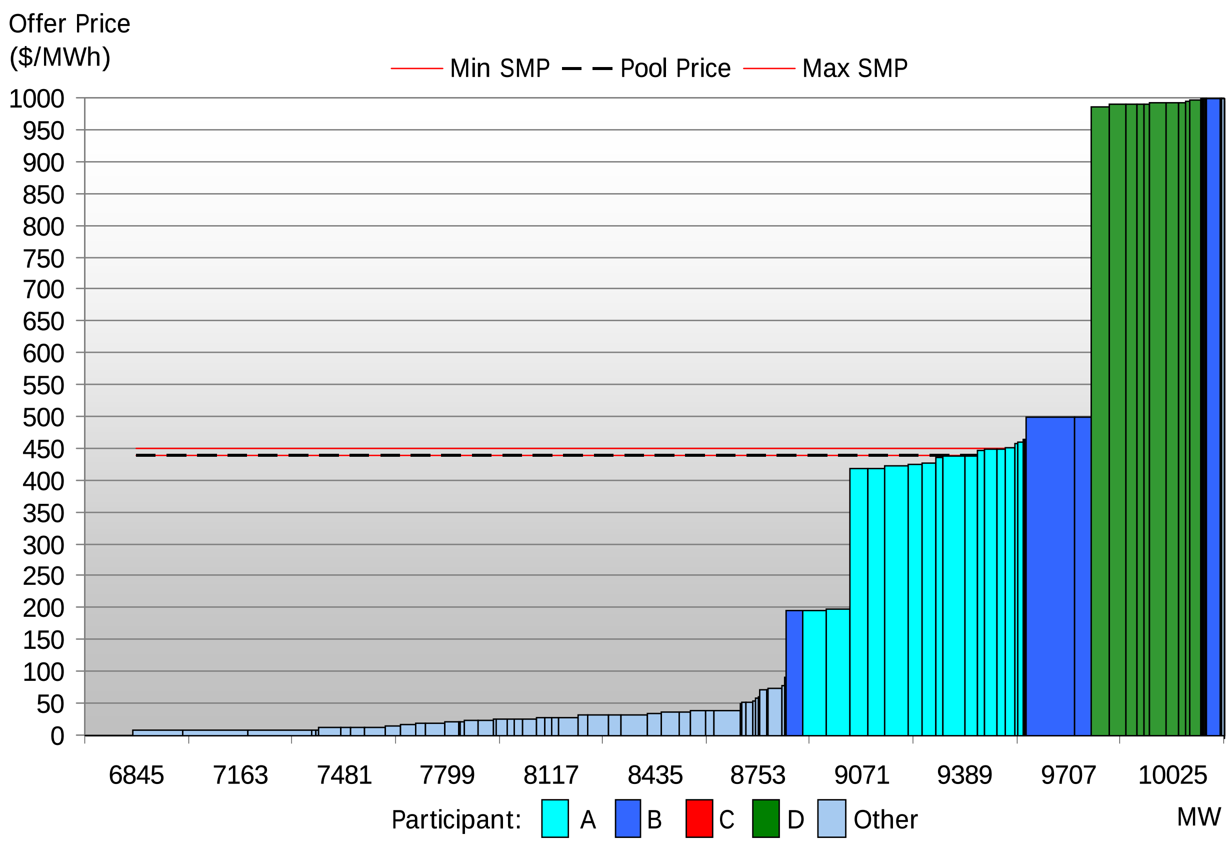
Towards the evening peak demand in HE17, participant B priced energy at $499/MWh, on the high side of participant A's energy tranche at ~$350/MWh, became out of merit and was thus dispatched off.

Also in HE17 participant A priced the lowest two blocks of its previously withheld tranche to under-cut participant B's $200/MWh offer by a few pennies, presumably in an effort to capture the dispatch participant B had been enjoying earlier in the day.

The result was a modified energy merit order shape, which produced similarly anomalous prices through the peak demand hours. However, the make up of participants dispatched during these hours shifted.

Figure 3.10 presents the relevant section of the energy merit order for HE18.

Figure 3.10: Energy Market Merit Order - November 22 HE18



<u>Observations of the three events described above</u>

The events have the following features in common:

- Supply cushions in all events are relatively small but not indicative of a shortage of supply.
- For the most part during the hours under review, the interties were at capacity, price responsive loads had curtailed consumption and wind generation was at zero or not an important factor.
- In none of the events is a single market participant responsible for all of the undispatched MW. In each event, a very small number of market participants represent almost all of the undispatched MW.
- The events suggest that if one of the market participants ceased to economically withhold, prices would be considerably lower. The December 16th event is a good example, as when one participant reduced its offers for HE13 – HE16, pool prices were around $32/MWh, much lower than the pool prices of adjacent hours, and not fully explainable by the modest changes in supply cushion.

- In each case, some offer changes are seen to occur with a market participant with undispatched MW offering them lower in the merit order. In the first event, this resulted in very low prices during the middle of the day. In other cases, this competition for dispatch is ineffective.

Based on the facts presented and taken alone, the MSA has insufficient reason to conclude that the 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. The MSA will continue to monitor the market and to report what we see.

3.4 OTHER MARKET EVENTS

While the above market events were identified through supply cushion analysis, other events in the market come to the MSA's attention through regular daily monitoring of the market. The following section describes any additional events in Q4/10 that are worthy of more detailed consideration.

3.4.1 Simultaneous Forced Outages – 13 December 2010

On the afternoon of Monday December 13th, Unit U1 and Unit U2, both Power Purchase Arrangement (PPA) units under the same ownership, were taken out of service in HE17. The units were taken offline for boiler tube repairs, and were offline until Wednesday and Thursday of that same week.

The AC declaration to ISO indicating that Unit U1 would dispatch offline in HE17 occurred at 2:12 pm on December 13, while the U2 declaration occurred at 1:59 pm that day. Both units began ramping down at the start of HE17.

The combined result of the two outages, together with increasing evening load, created tightness in the market leading to a pool price in HE17 of $601.59/MWh, and in HE18 of $877.75/MWh. Prices throughout the remainder of the evening were generally above $300/MWh. Whilst most of the affected hours did not register as outliers relative to the supply cushion, HE21 produced a pool price that was >3 standard deviations above the mean.

Tube leaks requiring short-term outages are a frequent phenomenon for the Alberta coal fleet. In many cases, such maintenance is timed to occur at lower load hours. This, of course, is subject to the unit operator having any flexibility in the timing of such short-term maintenance.

The MSA is about to commence a stakeholder consultation process on discretion around PPA unit forced outages.

4 Apparent Impediments to Intertie Flows

Starting in mid November and extending through mid December, 2010, an unusual pattern of activity on the BC intertie was observed. This unusual pattern of activity was characterized by:

- Pool price in some hours was much higher than the Mid C hourly price, but the import capability of the BC intertie was not fully utilized.
- The lack of utilization of the BC intertie was not caused by a lack of participants trying to import.
- Despite the observed low price in Mid-C a considerable volume of exports were offered and subsequently flowed.

In addition, the MSA had a concern expressed to them by a market participant who felt that its access to import transmission on the BC intertie was being 'blocked' by an exporting participant.

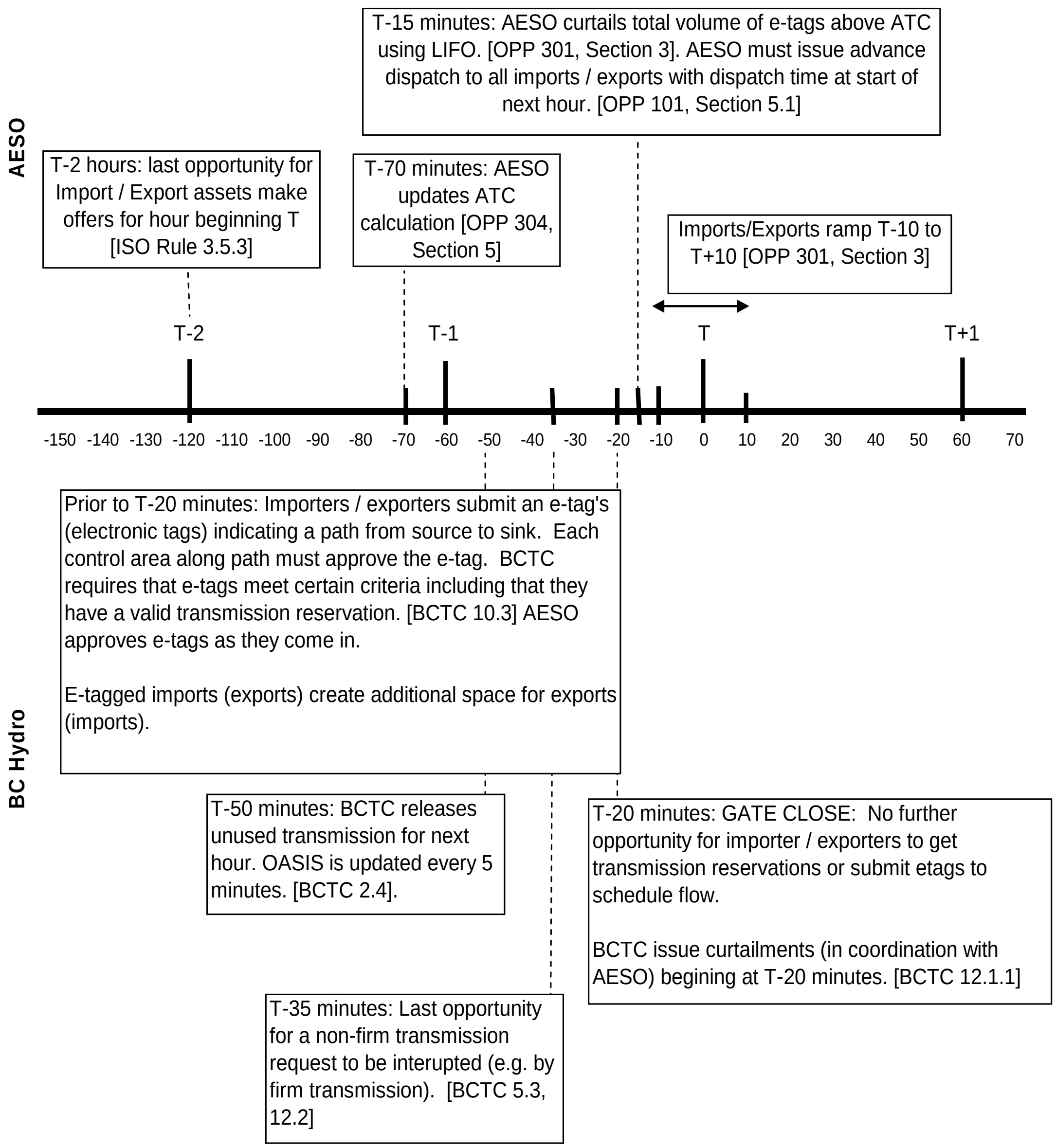
The above factors suggest an impediment to inter-jurisdictional trading potentially caused by anticompetitive behaviour or barriers resulting from 'seams' between jurisdictions. As a consequence, the MSA conducted a preliminary assessment. A summary of our findings are provided in the following sections.

4.1 BACKGROUND

ISO rule 3.5 specifies the timing and requirements of making an offer to the power pool. Importers and exporters have to submit their offers by two hours before the delivery hour (T - 2), the same as intra Alberta participants. The import and export offers reflect the participants' intentions to flow energy on the intertie. In order to flow energy on the intertie, the importers and exporters also have to reserve transmission on the intertie, locate a seller/buyer outside Alberta to provide/accept the energy and schedule the energy flow using electronic tags or 'e-tags'. The 'gate-closure' for e-tags is at 20 minutes before the delivery hour (T – 20) minutes (See Figure 4.1).

Participants who make offers must make reasonable efforts to procure transmission (ISO Rule 6.3.3c). The inability to secure transmission often forms a constraint on whether offers on the intertie can be realized. For example, when Alberta pool prices are expected to be high there are often more offers to import than capacity (Available Transfer Capacity, ATC). In such cases, the ISO expects the intertie to flow full with energy provided by those participants with offers at (T - 2) hours that were successful in obtaining transmission access.

Figure 4.1: Timeline for ISO Offers and BC Hydro Energy Schedules on the BC Intertie[7]



References:

BCTC *Open Access Transmission Business Practices* (http://transmission.bchydro.com/transmission_scheduling/business_practices/)

ISO Rule 3.5.3

OPP101 Dispatching the Energy Market Merit Order (Effective 2010-03-03)

OPP 301 Alberta-BC Interconnection Scheduling (Effective 2009-05-28)

OPP 304 Alberta-BC Interconnection Transfer Limits (Effective 2010-01-22)

[7] This is the correct timeline applicable for the period of this analysis – November, 2010. Since then, BC Hydro has taken over the responsibility for running the OASIS and there have been some modifications to the business practices. http://transmission.bchydro.com/transmission_scheduling/

Where there is scheduled flow in a single direction (only imports or only exports) the amount of physical energy that can be scheduled in either direction is subject to the ATC of the intertie. In those hours where there are both imports and exports occurring simultaneously, the net schedule is the physical flow of energy that is subject to being constrained by the ATC of the direction of flow. In theory, at least, one could have 10,000 MW of imports and 10,000 MW of exports and the net schedule would be 0 MW.

In Alberta, during heavy load hours (usually the on-peak hours) export ATC is frequently 0 MW and import ATC is 600 MW. Import ATC may be reduced due to operational issues. Import and export offers at (T - 2) imply a net schedule for the delivery hour. In principle, if the implied net schedule is less than the ATC in that direction of flow, all offers should result in scheduled energy. If they do not, it may indicate either there was an impediment to obtaining an e-tag, in one or both directions, or that transmission was available and flow did not occur for other reasons (for example, a market participant failed to submit an e-tag prior to gate closure).

For purpose of illustration consider the following example:

- Export ATC is 0 MW

- Import ATC is 600 MW

- Offers at (T - 2) are 200 MW export and 800 MW import.

The implied net schedule is 600 MW (= 800 – 200) in the import direction. The schedule at 600 MW is equal to the import ATC (600 MW) and is feasible and should flow in real time. Timing issues can occur. Because export ATC is 0 MW, the would-be exporters cannot access transmission until some of the imports have submitted e-tags that free up export capacity and hence export ATC. Similarly, the last 200 MW of imports cannot gain access to transmission until the exporters have submitted e-tags and freed up further import capacity. In such situations, the actual schedule will only match the offers made at (T - 2) if participants submit their e-tags in such a way as those importers / exporters that are dependent on the submissions of others have time to do so prior to gate closure at (T – 20) minutes.

During the MSA's consultation on offer behaviour, market participants raised the concern that timing of the submission of e-tags close to the gate closure, while allowed under the scheduling protocol, could limit competition, simply because a competing participant does not have sufficient time to undertake all necessary steps to submit its e-tag. The MSA concurred with this assessment and included its views in the *MSA Illustrative Examples* (September 10, 2010) and subsequently in the draft and final *Offer Behaviour Enforcement Guidelines* [8] noting that the conduct raises potential concern under Section 2(h) of the FEOC Regulation.

4.2 EVENT ANALYSIS

The MSA analysis focused on the month of November, 2010, with a total of 721 hours. Although the focus was on the hours with significant counterflows and these didn't start until mid November, it was felt that a more thorough review of all hours in the month was warranted. (Ideally, the preliminary assessment would have extended into December but because of the time consuming nature of the analysis it was not

[8] reference

possible to do so for this Quarterly Report.) The analysis comprised two parts: firstly identifying the hours when schedules on the BC intertie were possibly impeded, and secondly, for the hours identified, examination of the time stamps of the e-tags in the hour to see if tagging close to gate closure of importers or exporters resulted in an impediment. The MSA also assessed whether the observed tagging close to gate closure was the result of one or more market participants.

4.3 IDENTIFICATION OF HOURS WHERE SCHEDULES WERE APPARENTLY IMPEDED

The hours where schedules were possibly impeded were identified by eliminating hours in which no impediments could occur because:

- There were no import or export offers at (T - 2) hours.
- Intertie flows were equal to the (T – 2) offers.
- Net intertie flows were greater than the (T – 2) offers. This type of situation does not suggest any impediment to flow but does raise a potential compliance issue with ISO rule 6.3.3 or 6.3.4.
- Offers at (T – 2) were less than ATC.

Eliminating hours for the above reasons left 50 hours where import flow was apparently impeded and 17 hours where export flow was apparently impeded.

4.4 EXAMINATION OF TIME STAMPS OF E-TAGS FOR THOSE HOURS WHERE SCHEDULES WERE APPARENTLY IMPEDED

For the hours when imports or exports were possibly impeded by late tagging, the MSA conducted a detailed analysis of the timing of each e-tag.

If there were sufficient e-tags submitted to facilitate all offers made at (T - 2) hours prior to (T-45) minutes, the MSA rejected the hypothesis that late tagging caused an impediment in the hour. Flows that did not occur in these hours could be caused by a lack of transmission elsewhere or might indicate compliance issues (i.e. a market participant not fulfilling the offers made at (T – 2) hours without an acceptable operational reason). On this basis, a further 6 hours where import impediments were suspected were eliminated and a further 9 hours where export impediments were suspected.

The MSA also considered hours where import and export e-tags were submitted after (T - 45) minutes such that both importers and exporters had limited time to submit e-tags for the quantities offered at (T - 2) hours. In these cases, it is difficult to assess whether either or both importers and exporters were impeded. Such instances were uncommon in the hours examined, accounting for 2 hours where import impediments were suspected and 2 hours where export impediments were suspected. These hours were not considered further by the MSA.

The above screens resulted in 42 hours where there were apparent import impediments and 6 hours where there were apparent export impediments, in both cases due to tagging after (T - 45) minutes.

The MSA then examined when e-tags were submitted in these hours. If e-tags were submitted close to (T - 45) minutes there would still be sufficient (if limited) time for flow to be tagged in the opposite direction. The closer e-tags were submitted to the gate closure, (T - 20) minutes, the more likely the tagging contributes to an impediment.

The time distribution of the submission of the e-tags is shown in Table 4.1. In the 42 hours when imports were possibly impeded, there were a total of 104 export e-tags. The distribution of the times appears to be concentrated closer to the (T – 20) minutes gate closure. Of these 104 e-tags, 97% corresponded to the exports of one market participant. In the 6 hours when exports were possibly impeded there were a total of 47 import e-tags. Seven e-tags were submitted prior to (T – 45) minutes and were not a factor in the possible impediment. The distribution of the remaining e-tags was also concentrated closer to the (T – 20) minutes gate closure. Of the 47 e-tags, 70% corresponded to the exports of one market participant.

Table 4.1: Distribution of Times of E-Tags for the Identified Hours – November 2010

	Before or at T - 45 Mins.	After T - 45 Mins. Before T - 35 Mins.	After T - 35 Mins. Before T - 30 Mins.	After T - 30 Mins. Before T - 25 Mins.	After T - 25 Mins	Total
No. of E-tags When Imports Impeded	0	0	14	38	52	104
No. of E-tags When Exports Impeded	7	1	1	9	29	47

From a market perspective one would like to see all participants' imports/exports offers made at (T – 2) hours flow in the delivery hour, subject to actual ATC in the relevant direction of flow. The primary reason why this may not be possible is access to transmission. The detailed analysis revealed there were 42 hours where imports appear to have been impeded and 6 hours where exports may have been impeded, in both cases apparently because of e-tags close to gate closure at (T – 20) minutes.

The number and distribution of hours in which exports were impeded is small. However, the larger number of hours where imports were possibly impeded is more concerning. In some of the hours, pool price was above $150/MWh (substantially higher than the price in Mid-C) and import ATC was more than 200 MW underused (See Table 4.2). In these circumstances, additional import flow would have been highly profitable to the importer and the differential between the pool price and Mid-C price would have been reduced.

Table 4.2: Hours in November 2010 when Imports were Apparently Impeded by E-Tags Close to Gate Closure

Date	HE	Under-Used Import ATC (MW)[9]	Pool Price ($/MWh)	MidC Price in CDN ($/MWh)	Price Differential (AB Minus MidC)	Exchange Rate	MidC (US)
11/19/2010	13	40	$40.11	$35.69	$4.42	$1.02	$35.00
	16	17	$32.84	$35.28	-$2.44	$1.02	$34.59
	18	202	$407.63	$41.81	$365.82	$1.02	$41.00
	19	113	$218.91	$36.33	$182.58	$1.02	$35.62
11/21/2010	13	69	$29.49	$39.31	-$9.82	$1.02	$38.67
	22	215	$34.51	$39.64	-$5.13	$1.02	$39.00
11/22/2010	7	30	$66.31	$32.20	$34.11	$1.02	$31.68
	8	280	$344.89	$33.73	$311.16	$1.02	$33.18
	10	211	$198.36	$35.47	$162.89	$1.02	$34.89
	16	61	$112.25	$40.82	$71.43	$1.02	$40.16
11/23/2010	22	160	$38.95	$45.80	-$6.85	$1.02	$45.09
	23	168	$35.10	$35.93	-$0.83	$1.02	$35.38
11/24/2010	7	350	$26.01	$48.98	-$22.97	$1.02	$48.00
	9	178	$28.95	$66.24	-$37.29	$1.02	$64.92
	10	228	$35.69	$68.14	-$32.45	$1.02	$66.78
	11	375	$73.10	$64.56	$8.54	$1.02	$63.27
	12	300	$26.46	$67.60	-$41.14	$1.02	$66.25
	13	278	$25.35	$60.99	-$35.64	$1.02	$59.77
	14	318	$25.68	$61.22	-$35.54	$1.02	$60.00
	15	318	$26.04	$61.22	-$35.18	$1.02	$60.00
	16	393	$25.77	$64.29	-$38.52	$1.02	$63.00
	17	328	$27.04	$61.22	-$34.18	$1.02	$60.00
	18	328	$31.35	$66.33	-$34.98	$1.02	$65.00
	19	186	$40.96	$66.33	-$25.37	$1.02	$65.00
11/25/2010	8	28	$38.89	$41.20	-$2.31	$1.02	$40.50
	9	268	$38.86	$38.66	$0.20	$1.02	$38.00
	11	85	$31.13	$44.27	-$13.14	$1.02	$43.52
	12	8	$28.52	$47.37	-$18.85	$1.02	$46.57
	13	8	$27.89	$40.44	-$12.55	$1.02	$39.75
	17	58	$27.00	$38.69	-$11.69	$1.02	$38.03
	18	68	$29.15	$37.64	-$8.49	$1.02	$37.00
	19	68	$27.66	$37.64	-$9.98	$1.02	$37.00
	20	123	$29.04	$36.50	-$7.46	$1.02	$35.88
	21	83	$30.66	$34.59	-$3.93	$1.02	$34.00
	23	58	$26.64	$38.66	-$12.02	$1.02	$38.00
11/26/2010	18	400	$42.81	$37.54	$5.27	$1.01	$37.18
11/27/2010	15	190	$34.96	$41.63	-$6.67	$1.02	$41.00
	16	15	$32.10	$36.46	-$4.36	$1.02	$35.90
	17	240	$47.01	$37.57	$9.44	$1.02	$37.00
	19	20	$169.28	$40.62	$128.66	$1.02	$40.00
	20	300	$266.80	$42.65	$224.15	$1.02	$42.00
	21	213	$35.49	$43.67	-$8.18	$1.02	$43.00

[9] Calculated as Min [(Import ATC – Net Import), (Import Offer – Import)].

4.5 NEXT STEPS

The MSA will continue its assessment of this matter, including extending the period of analysis, working with the participant in question to understand its conduct and probing the dynamics of inter-jurisdictional trading. Further fact finding should help us to distinguish whether the situation is driven by participant behaviour, the underlying structure of inter-jurisdictional trading or a combination of both. Overall we will be working to form a view as to whether market outcomes of the kind highlighted represent a serious impediment to assuring a *fair, efficient and openly competitive* market and, if so, the appropriate remedies to address it.

5 Supply Cushion in the Operating Reserves Market

In the MSA's Q3/10 report, the supply cushion metric for the wholesale energy market was described in detail and historic data used to establish a benchmark for a relationship between supply cushion and pool price. In the section, we explore the development of a similar metric for each of the active operating reserves that the ISO procures on a daily basis. In principle, there should be a similar relationship between supply, demand and price.

A significant difference between the energy market and that for the active reserves is that there is no 'must offer' obligation for active reserves. Whilst in the energy market all available supply is in the merit order (with the exception of any long-lead units that are not running), in the active reserves the offers are voluntary and are usually only a modest subset of the total that could make offers to the market.

The six products examined are:

- On- and off-peak regulating reserve;
- On- and off-peak spinning reserve; and,
- On- and off-peak supplemental reserve.

Starting in early July, 2010, the ISO began procuring the majority of its needs for active reserves on Watt-Ex with a one day procurement auction. Previously, the ISO procured over a 5-day window such that the sum of purchases over the 5 days matched the demand. As part of the staged process of evolution of this market, the ISO had for a period of time gradually procured more of its requirements on (D-1), meaning the last trading day before delivery, and this became 100% in early July. This applies to all the reserves except for the hourly shaping products that continue, for the time being, to be transacted OTC.

In each of these markets, the ISO posts a bid volume and price, the price acting as a price cap. The market is cleared from lowest offers to more expensive offers until the bid volume is satisfied. Price (trade index) is set at the mid-point of the cap and most expensive offer that was required.

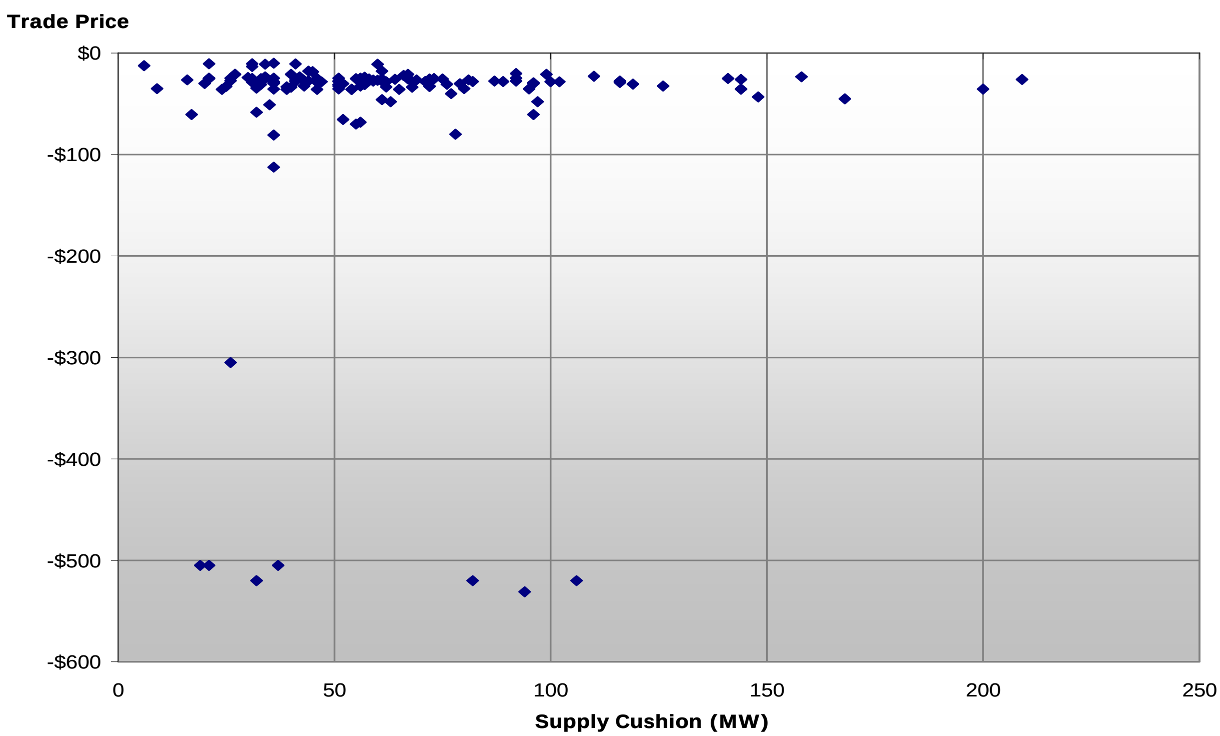
The basic data set comprised one price value per day per product and this was paired with the applicable supply surplus (offered MW not required by AESO). The number of observations for each product was 171. There was no evidence of a strong relationship between trade index and supply cushion for any of the products. The data for on-peak regulating reserves are plotted in Figures 5.1. Note that the prices are discount to pool price.

When sellers contract to provide active reserves, they do so for a 'strip' of hours and each hour is settled at (pool price less trade index). If pool price is less than the trade index in an hour, sellers received nothing for that hour. The on-peak strips run from HE07 through HE23, inclusive, and off-peak is defined as HE1 through HE7, plus HE24 of the same calendar day. A second analysis was undertaken to see if a relationship was more evident between average paid price and supply cushion. Figure 5.2 shows the data for on-peak regulating reserve and does not appear to exhibit a strong relationship. The other products were similar in outcome and are not reproduced here.

The supply cushion values used in this analysis afforded the opportunity to assess whether market liquidity was improving. Readers may recall in the MSA's Q3/10 report, whilst assessing the performance of the OR market in response to the change to (D-1) procurement, it was observed that liquidity has decreased in some market segments.[10] The average supply cushion is shown in Figure 5.3 and the following observations can be made:

- There has been an improvement in market liquidity between Q3/10 and Q4/10 for all products except off-peak regulating reserve. Off-peak regulating reserve liquidity had not reduced at the time that (D-1) procurement was introduced to the market.
- On-peak regulating reserve liquidity has improved but has not yet recovered to the level observed prior to the switch to (D-1) procurement.

Figure 5.1: On-Peak Regulating Reserve - Trade Index vs Supply Cushion (Jul – Dec, 2010)



[10] MSA Report, 2010,'Quarterly Report, July – September, 2010'.

Figure 5.2: On-Peak Regulating Reserve - Average Paid price vs Supply Cushion (Jul – Dec, 2010)

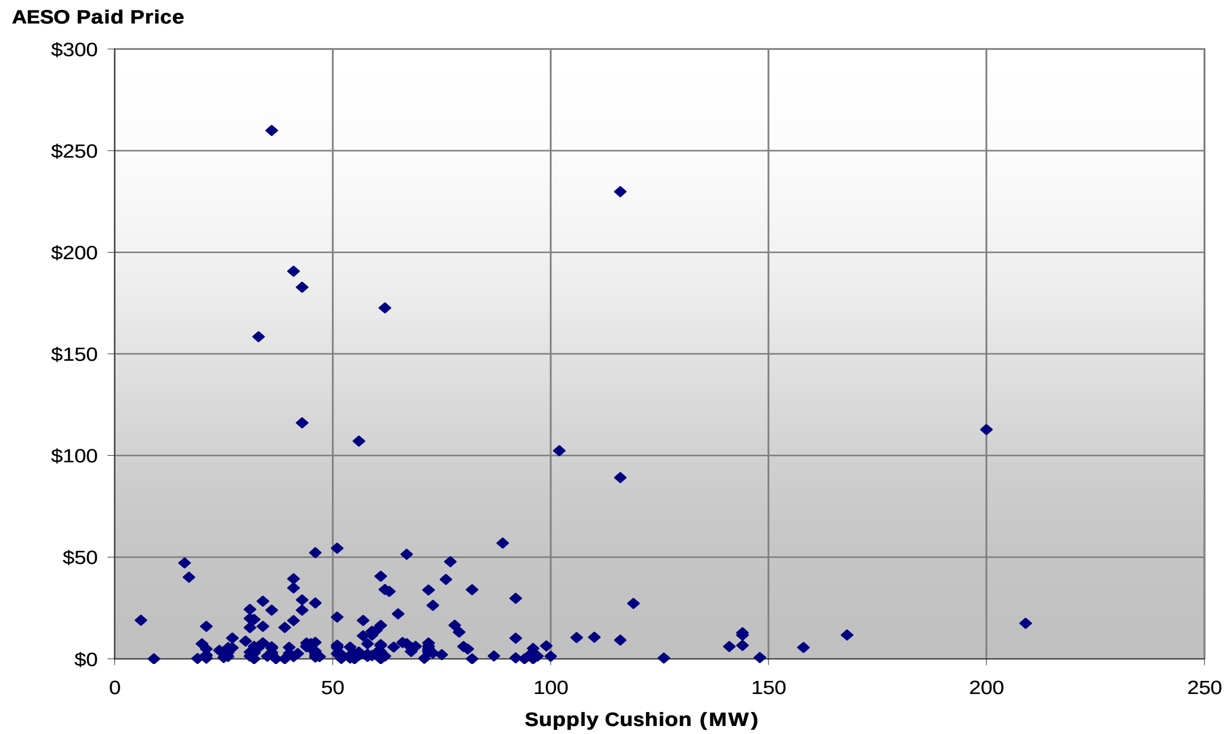
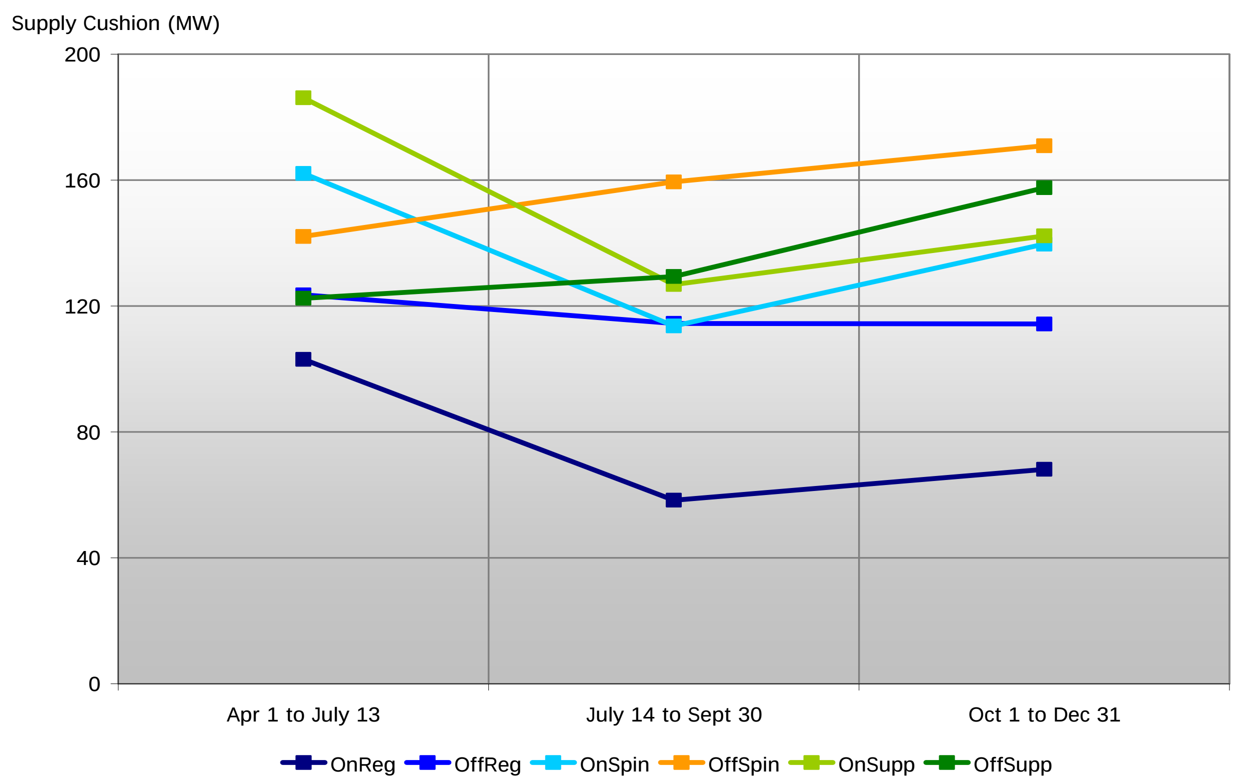


Figure 5.3: Operating Reserves Market Liquidity



6 Net Revenue Analysis

For several years, the MSA has undertaken simple net revenue calculations as a means to check the health of the market. A market that seldom returns profits to generators is unlikely to attract sufficient new build to be sustainable. Similarly, a market that continually provides large profits to existing generators with no build response from new entrants would be equally worrisome from the perspective of sustainability.

As in previous assessments the analysis looks at the potential profitability of different types of new entrants to the markets. They are hypothetical in that costs are estimated, overnight build is assumed with an availability as of January 1, 2010 and, what can be a critical assumption at times, we take the pool prices as they occurred – ignoring the effects that one would expect to occur.

The four types of generation that are examined are:

- Coal-fired steam unit (450 MW);
- Natural gas-fired combustion turbine (47 MW);
- Natural gas-fired combined cycle (250 MW); and,
- Wind farm (66 MW).

The development costs and relevant technical parameters adopted for use in this analysis are presented in Table 5.1. For each type of unit, assumptions are made about typical operation in the market and then simulated on an hourly basis to calculate hourly revenues and variable costs. The hourly revenues and variable costs are summed up for each month to generate monthly revenues and monthly variable costs. The monthly profit is calculated by subtracting monthly variable and fixed costs from the monthly revenue.

Table 6.1: Key Costs and Technical Parameters of Hypothetical New Entrants

		UNIT			
		Coal	Combustion Turbine	Combined Cycle	Wind
Maximum Output	(MW)	450	47	250	66
Availability Factor	(%)	92%	94%	92%	100%
Capital Cost	($)	$1,575,000,000	$47,000,000	$375,000,000	$112,200,000
Annual Fixed Cost		$33,794,778	$3,041,530	$16,897,389	$1,650,000
Minimum Output	(MW)			85	
Variable Cost					
O&M	($/MWh)	$1.15	$0.55	$1.15	
Fuel Cost	($/MWh)	$10.00	variable	variable	
Heat Rate - Full Load	(GJ/MWh)		10	8	
Heat Rate - Min Stable	(GJ/MWh)		10	10	
Supply Transmission Service					
Avg. System Loss 2010	(%)	4.42%	4.42%	4.42%	4.42%
Start up Cost	($/start)		$340		

In addition, the analysis examines how Alberta's market prices in 2010 can be assessed with some of the market protection measures that are in place in two other energy-only electricity markets: Texas and Australia.

6.1 COAL-FIRED STEAM UNIT

Since the majority of new coal generation in the province has been built at existing facilities, the analysis herein assumes that the hypothetical new coal unit was also built at an existing site (as opposed to a green field site). The rated capacity of the unit is assumed to be 450 MW.

Coal plants are base-loaded units and therefore for this analysis it is assumed that the hypothetical unit runs full load for the entire period, with no interruption. Even when the pool price is lower than its variable cost the unit is assumed to continue to generate, as if it were offered at $0/MWh. The effect of the outages is mimicked by simply scaling annual generation and revenue parameters by the availability factor.

Results of the monthly cash flow analysis for the coal unit are presented in Table 5.2. The simulated average generation output for the hypothetical coal unit was 414 MW. With an average Pool price of $50.88/MWh in 2010, the revenue generated by the unit was about $185 million. Once variable and fixed costs have been accounted for, the net revenue as a percentage of capital cost was 6.5%. Significant uncertainties exist regarding the impacts of climate change on the future operational costs of newly built coal units. For this analysis, no emission costs are included in the calculations. In 2009, the hypothetical coal unit had a net revenue of $91 million corresponding to 5.8% of capital cost.

Table 6.2: Coal-Fired Steam Unit - Monthly Cash Flow

		Monthly Revenue	Monthly Costs (In $1000)			Monthly Net	%
Year	Month	(In $1000)	Variable	Fixed	Total	(In $1000)	Capital Cost
2010	1	$13,376	$4,026	$2,816	$6,842	$6,535	0.4%
	2	$12,212	$3,642	$2,816	$6,458	$5,754	0.4%
	3	$10,863	$3,910	$2,816	$6,726	$4,137	0.3%
	4	$14,818	$3,979	$2,816	$6,795	$8,023	0.5%
	5	$41,486	$5,268	$2,816	$8,084	$33,402	2.1%
	6	$17,070	$4,078	$2,816	$6,894	$10,175	0.6%
	7	$12,324	$3,974	$2,816	$6,791	$5,533	0.4%
	8	$11,903	$3,960	$2,816	$6,777	$5,126	0.3%
	9	$8,473	$3,698	$2,816	$6,514	$1,958	0.1%
	10	$9,525	$3,855	$2,816	$6,672	$2,853	0.2%
	11	$14,354	$3,963	$2,816	$6,779	$7,575	0.5%
	12	$18,138	$4,236	$2,816	$7,052	$11,085	0.7%
Annual		**$184,541**	**$48,589**	**$33,795**	**$82,384**	**$102,157**	**6.5%**

6.2 NATURAL GAS-FIRED COMBUSTION TURBINE

A 47 MW single GE LM6000 gas turbine generator set is chosen to represent a typical new gas-fired peaking unit in the Alberta market. Peaking units do not typically run all of the time and are generally more opportunistic in their operation, frequently offering energy at prices above variable costs. However, in this analysis, the unit is assumed to run at full output whenever pool price is greater than the variable operating costs; that is, the units operates as a 'price taker'. The effect of outages is again simulated by scaling the annual generation and revenue parameters by the availability factor.

The net revenue generated by the hypothetical peaking unit is about in 2010 was $3.8 million, corresponding to 8.0% of capital cost. Under the assumed generating conditions, the unit would be running 28% of the time. In 2009, the corresponding net revenue was $2.8 million, some 5.9% of capital cost, and the unit ran at a 16% capacity factor.

Table 6.3: Natural Gas-Fired Combustion Turbine - Monthly Cash Flow

		Monthly Revenue	Monthly Costs (In $1000)			Monthly Net	%
Year	Month	(In $1000)	Variable	Fixed	Total	(In $1000)	Capital Cost
2010	1	$189	$160	$253	$413	-$224	-0.5%
	2	$251	$229	$253	$482	-$231	-0.5%
	3	$391	$251	$253	$504	-$113	-0.2%
	4	$1,008	$539	$253	$793	$216	0.5%
	5	$3,967	$813	$253	$1,066	$2,900	6.2%
	6	$1,345	$567	$253	$820	$525	1.1%
	7	$860	$516	$253	$770	$90	0.2%
	8	$787	$507	$253	$760	$26	0.1%
	9	$222	$177	$253	$430	-$209	-0.4%
	10	$354	$269	$253	$523	-$169	-0.4%
	11	$810	$228	$253	$481	$328	0.7%
	12	$1,231	$333	$253	$586	$644	1.4%
Annual		**$11,414**	**$4,589**	**$3,042**	**$7,630**	**$3,783**	**8.0%**

6.3 NATURAL GAS-FIRED COMBINED CYCLE PLANT

The hypothetical combined cycle new entrant is rated at 250 MW and its operation is highly dependent on the price of natural gas and pool price. The plant is assumed to be running at full capacity when the pool price exceeds the variable cost and at minimum stable generation for all other hours. Outages are treated in the same fashion as the coal unit, i.e. the generation and revenue parameters are scaled down to reflect the availability factor of the unit.

The revenue generated by the hypothetical combined cycle gas-fired unit is about $20.1 million in 2010, corresponding to net revenue as a percentage to capital cost of 5.4% (see Table 5.4). The simulated operation of the unit indicates that its capacity factor in 2010 would be 73%. A number of operational strategies are available for combined cycle generators that may differ from the strategy assumed in this analysis. For example, the plant operators may turn off the unit during the off-peak hours and recommence operating with a 'warm start'. Hence, the net revenue in this analysis is likely understated.

Table 6.4: Natural Gas-Fired Combined Cycle Plant - Monthly Cash Flow

Year	Month	Monthly Revenue (In $1000)	Monthly Costs (In $1000)			Monthly Net (In $1000)	% Capital Cost
			Variable	Fixed	Total		
2010	1	$6,361	$6,279	$1,408	$7,687	-$1,326	-0.4%
	2	$6,047	$5,708	$1,408	$7,116	-$1,069	-0.3%
	3	$5,138	$4,457	$1,408	$5,865	-$727	-0.2%
	4	$7,957	$4,928	$1,408	$6,336	$1,620	0.4%
	5	$22,529	$5,564	$1,408	$6,972	$15,557	4.1%
	6	$8,697	$4,628	$1,408	$6,036	$2,661	0.7%
	7	$6,073	$4,178	$1,408	$5,586	$487	0.1%
	8	$5,971	$4,186	$1,408	$5,595	$377	0.1%
	9	$3,862	$3,761	$1,408	$5,169	-$1,307	-0.3%
	10	$4,732	$4,091	$1,408	$5,499	-$767	-0.2%
	11	$7,186	$4,268	$1,408	$5,677	$1,509	0.4%
	12	$8,747	$4,282	$1,408	$5,690	$3,058	0.8%
Annual		**$93,300**	**$56,329**	**$16,897**	**$73,226**	**$20,074**	**5.4%**

6.4 WIND FARM

The new entrant wind farm is assumed to be rated at 66 MW, comprised of 22 units at 3 MW each. Since many of the wind farms in Alberta are in the southwest of the province, the hypothetical new entrant is assumed to be located in the general area of existing wind farms. For this analysis, the generation output for the new entrant is based on the capacity factor for all existing wind farms in the province. As such, it is assumed to have the production characteristics of the average of the total fleet of wind farms.

Results of the monthly cash flow analysis for the hypothetical wind farm are presented in Table 5.5. Estimated net revenues include the Federal Government's production incentive of $10/MWh. We did not include any revenues that would accrue from the sale of renewable energy credits and thus the returns may be somewhat understated. The hypothetical wind farm generated net revenues of about $6.1 million in 2010 corresponding to 5.4% of the capital cost. Average production was 18 MW, representing a capacity factor of 28%.[11] The new entrant received an average pool price of $38.04/MWh, some 75% of annual pool price ($50.88/MWh).

For comparison, in 2009 the net revenue was $7.5 million, or about 6.7% of capital cost. In that year, production averaged 22 MW, significantly more than the 18 MW for 2010. This accounts for much of the difference since average pool price in 2009 was 47.81/MWh, similar to that for 2010.

[11] Some actual wind farm production in 2010 was curtailed due to transmission issues. As such, the average of this is embedded in the overall production from which the new entrant is derived. The capacity factor of 28% is likely on the low side and hence net revenues are somewhat understated.

Table 6.5: Wind Farm - Monthly Cash Flow

Year	Month	Monthly Pool Revenue	Monthly Incentive	Fixed O&M	Monthly Net	% Capital Cost
2010	1	$591	$150	$138	$604	0.5%
	2	$449	$111	$138	$423	0.4%
	3	$647	$219	$138	$729	0.6%
	4	$696	$155	$138	$713	0.6%
	5	$667	$101	$138	$630	0.6%
	6	$412	$110	$138	$385	0.3%
	7	$370	$107	$138	$339	0.3%
	8	$307	$87	$138	$256	0.2%
	9	$254	$102	$138	$218	0.2%
	10	$429	$153	$138	$445	0.4%
	11	$511	$162	$138	$535	0.5%
	12	$809	$160	$138	$831	0.7%
Annual		**$6,143**	**$1,615**	**$1,650**	**$6,108**	**5.4%**

6.5 COMPARISON WITH OTHER MARKETS

6.5.1 Texas

The Texas electricity market is operated by ERCOT following rules set by the Texas Public Utilities Commission. That market has a scarcity pricing mechanism whereby a peaker net margin (PNM) calculation is done on an annual resource adequacy cycle.[12] Should the PNM value in a year sum to $175K per MW, the system wide price cap is set to a lower value for the balance of the year. This action reflects the notion that sufficient revenues have accrued to generators at that time. The PNM is calculated quite simply as the sum of market price less fuel cost (estimated as natural gas price in $/MMBTU times 10 MMBTU/MWh) when the hypothetical unit is profitable to run.

Applying this approach to the Alberta situation, converting the heat rate to metric units (10.55 GJ/MWh), and ignoring all other costs leads to a PNM for 2010 of $166K. Ignoring the (small) differences in exchange rates, it may appear surprising to some that in 2010 the PNM was relatively close to a value whereby the price cap would be lowered (if Alberta had a price cap design like Texas). The corresponding values of PNM for 2008 and 2009 are $291K and $142K, respectively. The PNM for 2008 at $281K clearly exceeds the ERCOT 'trigger' of $175K.

The seeming discrepancy between the 2010 PNM value of $166K and a net revenue of $80.5K (8.0% of capital cost) warranted further scrutiny. The assumed costs and operating parameters for a new peaker in ERCOT are different in two main areas from those assumed for Alberta.

[12] Potomac Economics, 2010, '2009 State of the Market Report for the ERCOT Wholesale Electricity Markets'

In ERCOT the assumed capital cost for a conventional combustion turbine is ~$700,000/MW compared with Alberta's $1,000,000/MW. This partially explains how in ERCOT the PNM value is considered an adequate return for any given year since $175K is 25% of their assumed capital cost.

In ERCOT, the assumed fixed and variable O&M costs are $12,380/MW/yr and $3.65/MWh vs. $64,710/MW/yr and $0.55/MWh in Alberta. The effect is that overall O&M costs for a hypothetical new combustion turbine plant in Alberta are significantly higher than in ERCOT.

There may be *bone fide* reasons for these costs differences. For example, labour costs here in Alberta may well be higher than in Texas. Alberta is a smaller more remote market and construction materials may be more expensive. The MSA will discuss these costs with Alberta market participants with actual build and operate experience of such plant with a view to ensure that the assumed costs are reasonable for net revenue analysis.

6.5.2 Australia

In Australia, the National Electricity Market uses a concept called the cumulative price threshold as a means to protect load from 'extreme price risk'. It is defined in clause 3.14.1 of the Code (market rules). If the cumulative price over one week (336 half-hour settlement intervals) reaches $150K, administrative pricing is applied until the rolling calculation drops below $150K. Unlike Texas, where once the PNM reaches the annual limit the price cap is adjusted down for the balance of the year, in Australia it is possible for the market to go into and out of administrative pricing multiple times in severe situations.

Applying this approach to Alberta and ignoring the (small) difference in exchange rates, the equivalent is that administrative pricing would apply if the seven-day rolling average price reached ~ $445/MWh ($150,000/336). In 2010, the highest seven-day rolling average pool price was $360.33/MWh and occurred on May 18. The fact that the highest value in what is considered by some to be a 'soft price' year is close to the limit adopted in Australia is a testament to the high volatility of Alberta pool prices.

The equivalent maximum values of 7-day average pool price for 2008 and 2009 were $240.70/MWh and $217.49/MWh, respectively. The average pool price in 2008 was $89.95/MWh and in 2009 it was $47.81/MWh.

6.6 SUMMARY

The net revenue calculation results for 2010 are similar to those for 2009, not too surprising given that the average prices are similar. The hypothetical combustion turbine yielded a net revenue of 8.0% in 2010, compared with 5.9% for 2009. The new coal unit earned 6.5% in 2010 vs. 5.8% in 2009. Both the hypothetical combined cycle plant and wind farm earned net revenues of 5.4% in 2010, compared with 3.9% and 6.7%, respectively. The reduced net revenue for the wind farm is attributable to the lower output in 2010 – only an average of 18 MW compared with 22 MW for 2009. Overall, the results are not suggestive of a strong 'build' signal, which is consistent with the observed supply surplus.

Examination of the 2010 pool prices through the lenses of the ERCOT and Australian electricity markets yields some interesting results. The ERCOT PNM calculation for Alberta prices in 2010 suggests healthy returns – somewhat at odds with our net revenue calculation of 8% of capital cost. The MSA will endeavor to shore up the cost estimates used in the net revenue calculations prior to the next update. The maximum 7-day rolling average price in Alberta for 2010 was $360.33/MWh compared with the trigger value of $445/MWh that exists in the Australian market. This is confirmation of the high volatility in Alberta pool prices, particularly last May which generated the yearly maximum value.

7 Forward Market Liquidity

In the MSA's Q3/10 report, we commented on the apparent decline in forward market trading volumes through the summer and early fall of 2010. Figure F.1 shows that the volumes have not recovered to previous levels. Figure F.2 shows that the number of active market participants has not declined and therefore the amount of trading activity of some of the traders has reduced. A long-term trend of declining market liquidity would be of concern to the MSA because the levels in Alberta are already quite low compared with other electricity market jurisdictions.[13] A highly liquid forward market provides opportunities for both suppliers and consumers to hedge against the risks associated with the real-time market. It also provides a forward view of market prices that can assist new entrants in making investment decisions.

Several analyses were undertaken to ascertain which segments of the market have been most affected by this reduction.

Figure 7.1 shows the market share by three different types of participants: those who own generating assets in the province (Generators), those who do not own generating assets but may or may not have loads (Marketers/Loads), and financial institutions or hedge funds (Banks/Funds). The market share of banks/funds has fluctuated over the period of the data presented, but clearly has been sliding throughout 2010.

Figure 7.2 shows the proportion of different length of contract terms in the total trading volumes. It is evident that the proportion of the longer term contracts, Quarterly and Calendar Year, started to decline since the beginning of the year and remained at low levels through to the end of 2010.

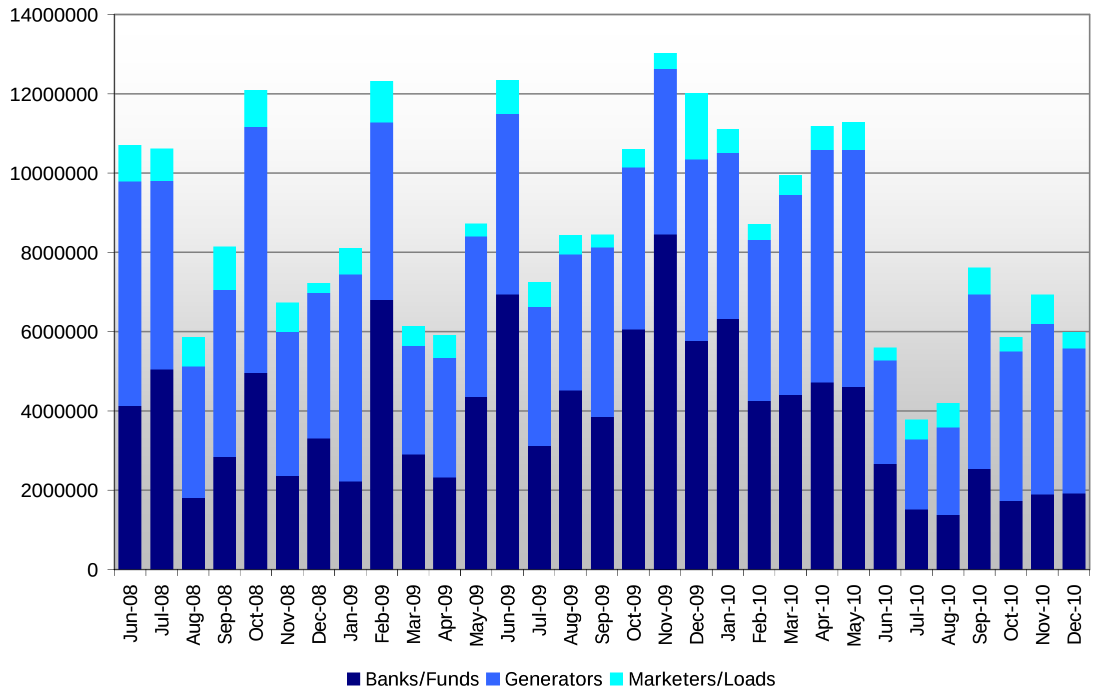
Figure 7.3 shows the continuing decline of the volume of trading further out in the curve. Monthly trades dominate activity, with the focus being primarily the front month, in part driven by the RRO on NGX. The decline in trading of the calendar year contracts contributes to the fluctuating market shares by type of market participant as evident in Figure 7.4. The general growth of market share on NGX (vs. the OTC brokers) is evident in Figure 7.5, but it must be remembered that this result is driven in part by declining forward volumes with the brokers rather than increased participation at NGX.

Informal discussions were held with some of the entities whose trade volumes have declined the most in the second half of 2010. The objective of these discussions was to develop a better understanding of the principal reasons – to the extent that participants were willing to share them with the MSA. Based on these discussions, whilst there are a number of factors, it was clear that one factor of importance is the actual or perceived increased volatility in the real-time market. Whilst some uncertainty may have existed during the stakeholder process leading to the MSA's *Offer Behaviour Enforcement Guidelines*, the ambiguity exists no longer. Some felt that there will be an uptick in activity once participants re-

[13] MSA Q3/10 Report.

calibrated to the new paradigm. Others remain concerned. Whilst the MSA takes some comfort from these discussions, only time will tell if the forward market liquidity improves through 2011.

Figure 7.1: Market Share by Participant Type (Volume)[14]



[14] Both sides of each trade are considered in developing the volumes in this graph.

Figure 7.2: Market Share by Contract term (Volume)

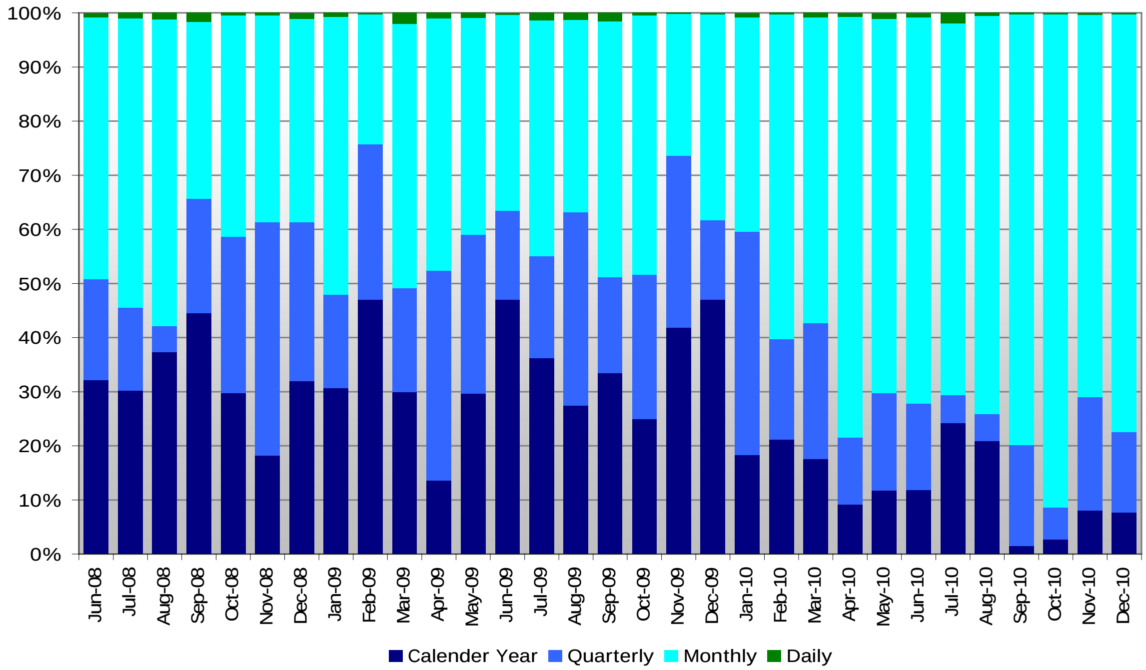


Figure 7.3: Percentage of Contracts by 'Months Out'

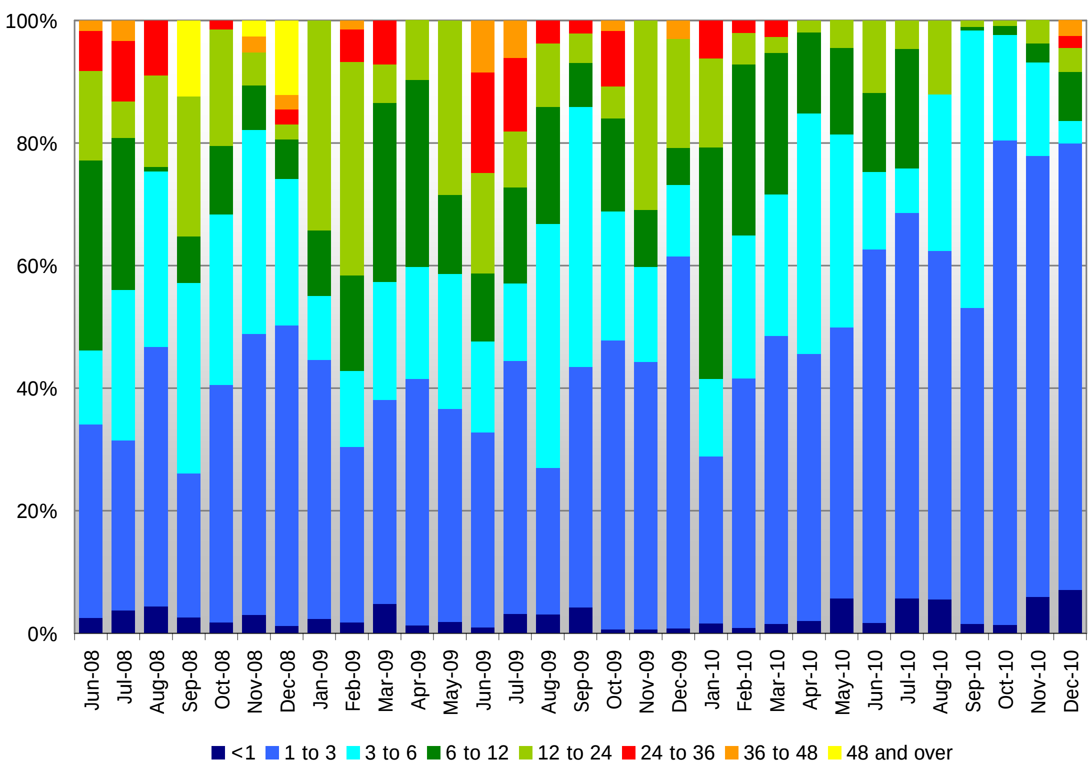


Figure 7.4: Calendar Year Contract Monthly Market Share by Participant Type

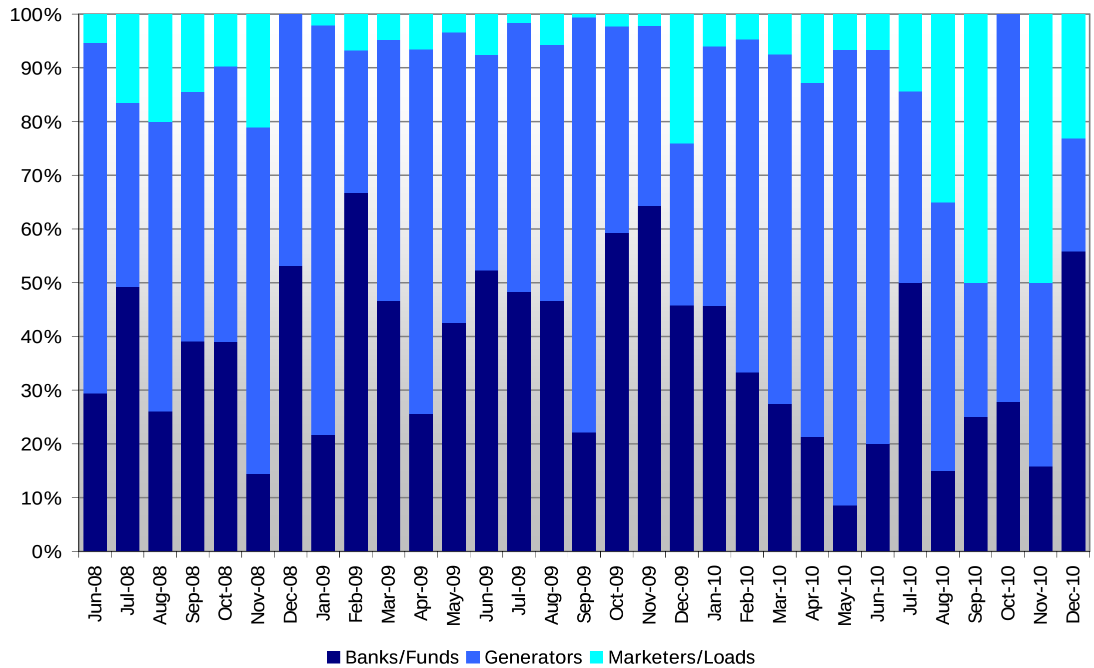
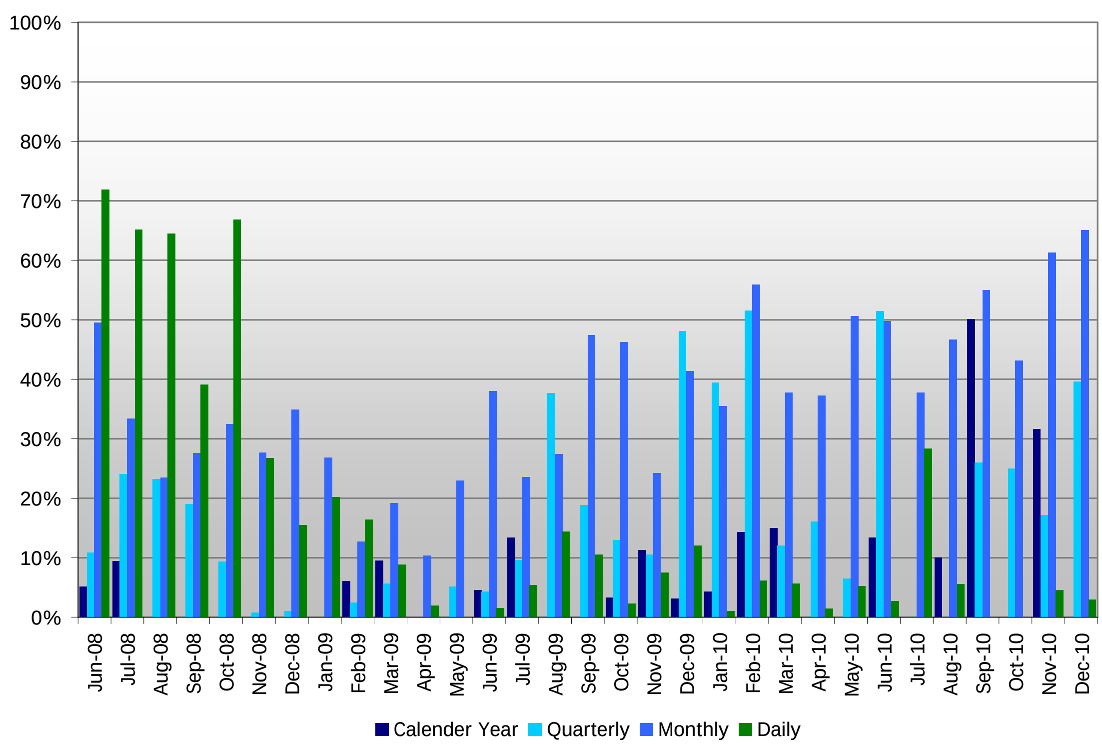


Figure 7.5: Percentage of Volume Traded on NGX by Contract Term



8 Retail Market

8.1 RETAIL SERVICE PROVIDERS[15]

There were two basic types of retail electricity and natural gas retail service available to Alberta consumers during 2010 – regulated and competitive. Retailers providing the bulk of regulated service in Alberta included Direct Energy Regulated Services, ENMAX Power Corp, EPCOR Energy Inc and the City of Lethbridge. Natural gas regulated service providers consisted of AltaGas Utilities and Direct Energy Regulated Services. Regulated services are provided pursuant to the Regulated Rate Option (RRO) Regulation for electricity and the Default Gas Supply (DGS) Regulation for natural gas.

Companies offering competitive electricity and natural gas contracts to residential, farm and small business consumers included Direct Energy, ENMAX Energy Corporation, Just Energy and Spot Power. These retailers offered a broad range of products and services to Alberta consumers. In particular, competitive retailers offered a variety of contract terms and pricing mechanisms, in some cases, in combination with price adders, price discounts and rebates.

8.2 RETAIL PRODUCTS AND PRICING

8.2.1 Regulated Products

Regulated service companies are required by the RRO Regulation and the DGS Regulation to provide service to customers who do not choose a competitive retailer. Electricity and natural gas regulated services are basic products that use pricing mechanisms based on forward market prices for electricity and flow through of procurement costs plus and a deferral account adjustment for natural gas. The Alberta Government is currently considering how pricing for electricity and natural gas might be harmonized. In this regard, the Alberta Utilities Commission is expected to release its decision concerning the Harmonization Proceeding in Q1/11.

In considering how regulated electricity and natural prices compare to competitive prices, we compare the NGX Alberta Flat Electricity RRO Price and the NGX Alberta Extended Peak Electricity RRO Price to the wholesale settled prices in Figures 8.1 and 8.2, and the NGX AB-NIT Month Ahead Index (7A) to the regulated cost of gas for AltaGas Utilities and Direct Energy in Figure 8.3.

Generally, the trend in the NGX Flat RRO Price continues to follow the trend in the monthly average pool price over the July 2006 to December 2010 time period. We observe that a pricing pattern occurs around months where there is a spike in the pool price relative to the RRO Index. In the months immediately following, there is a tendency for the index price to rise relative to the average pool price. It is worth noting that, on average, the difference between the two prices is very small over the time period.

[15] A complete list of retail service providers for electricity and natural gas is available on the Utility Consumers Advocate's web site at www.ucahelps.alberta.ca

In Figure 8.2, we observe a similar pricing pattern to the one that occurs in Figure 8.1. The differences between Extended and Flat prices are higher volatility and a larger difference in the average of the NGX Extended Monthly Price and the average of the monthly Extended Peak pool price.

Figure 8.3 shows that the general trend in the monthly cost of gas tends to coincide with the trend in the NGX price index. As in monthly electricity prices, the average difference between the cost of natural gas for each retailer and the NGX index over the course of the year was quite small, suggesting a strong relationship.

Figure 8.1: Monthly Flat RRO Index vs. Monthly Average Pool Price

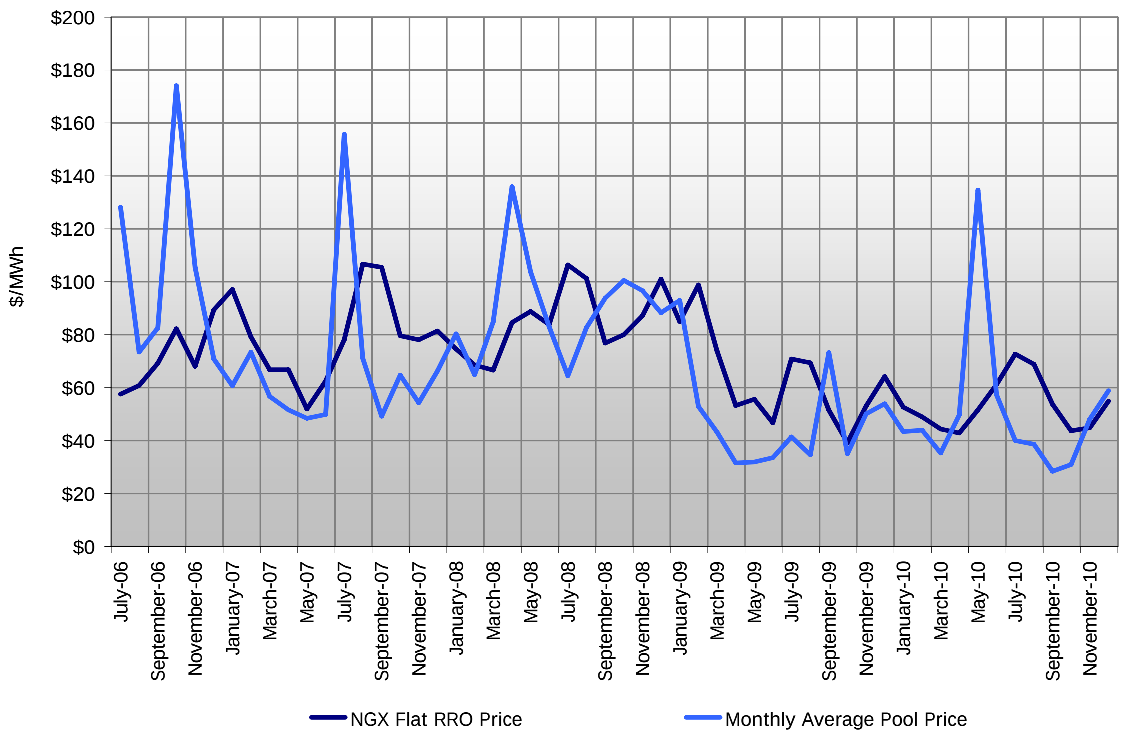


Figure 8.2: Monthly Extended Peak RRO Index vs. Monthly Extended Peak Pool Price

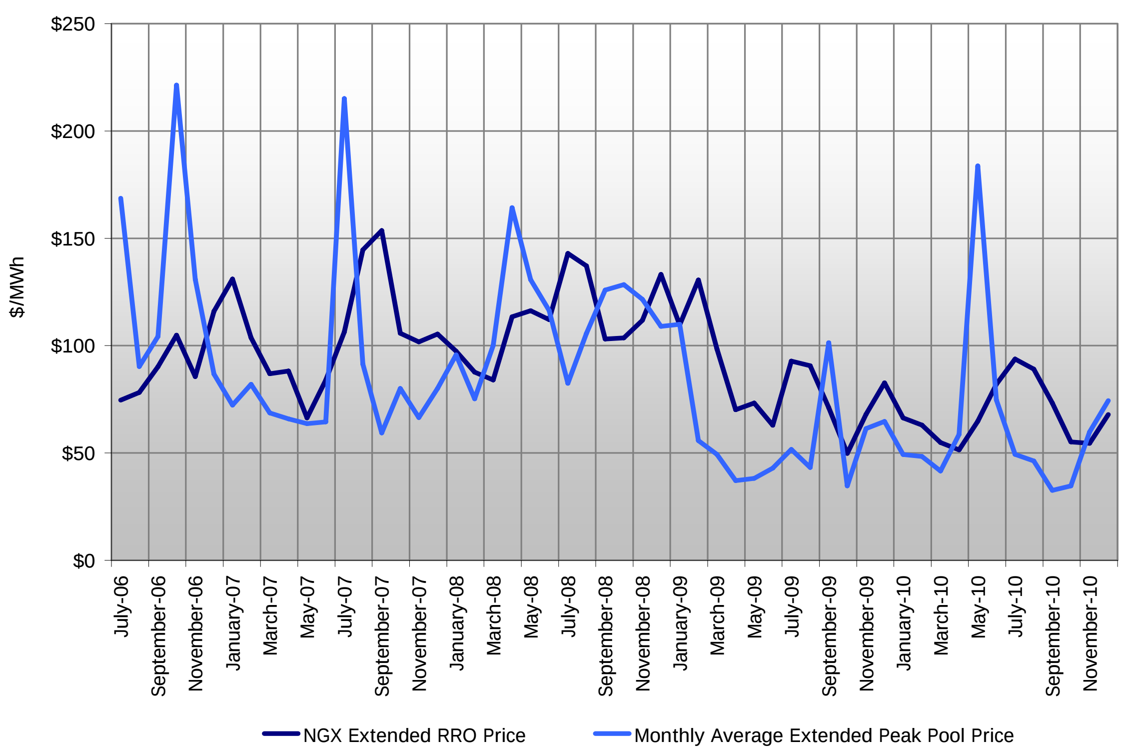
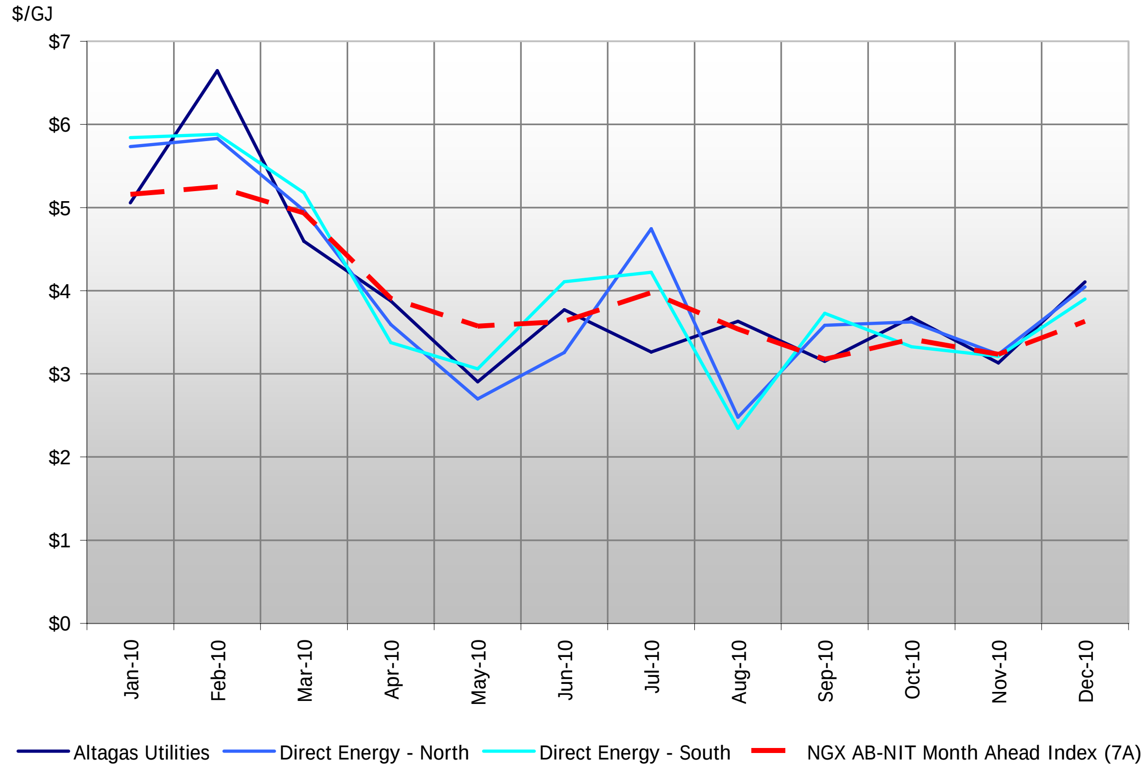


Figure 8.3: Month-Ahead Price vs. Monthly Cost of natural Gas



8.2.2 Competitive Products

According to product information published by the Utilities Consumer Advocate (UCA), competitive retailers offered 18 single energy products and 10 duel fuel products during 2010. The product categorization is somewhat arbitrary; however, our goal is to refine this type of analysis for future quarterly reports. Table 8.1 illustrates the extent of product diversification in the competitive electricity and natural gas markets.

Table 8.1: Diversity of Competitive Product Offerings

Product Diversification						
	Pricing Mechanism					
	Electricity		Natural Gas			
Product	Fixed/Flat	Floating/Flow - Through	Fixed/Flat	Floating/Flow - Through	Seasonal	Total
Single Product Contract						
Open	-	3	-	1	-	**4**
Monthly	2	-	-	-	-	**2**
1-year	2	-	-	-	-	**2**
2-year	1	-	-	-	-	**1**
3-year	1	-	1	-	-	**2**
5-year	2	-	2	-	-	**4**
Green Energy Option	3	-	-	-	-	**3**
Sub-total	11	3	3	1	0	**18**
Duel Fuel Contract						
Open	-	1		1	-	**2**
1-year	1	-	1	-	-	**2**
2-year	1	-	-	1	-	**2**
3-year	3	1	3	-	1	**8**
5-year	2	1	2	-	1	**6**
Sub-total	7	3	6	2	2	**20**
Total	**18**	**6**	**9**	**3**	**2**	**38**

Competitive products used three general types of pricing including fixed/flat, floating/flow-through and seasonal prices and products were offered with various terms ranging from one month to five years. In total there were 38 product variations assuming that duel fuel contracts are counted twice. Three retailers offered green energy options to consumers who were interested in "greening-up" their electricity consumption. One retailer actively mixed and matched term and pricing mechanisms throughout the year in response to changing market conditions and competitive pressures. The growing diversity of product offerings is considered to be a healthy sign for the market, as noted by Distributed Energy Financial Group.[16]

Significantly, 2010 saw the entry of a new competitor in the electricity market, Spot Power, which offered floating and fixed price products. Our observation is that market entry by a new competitor is a positive indicator of a workably competitive retail market.

Most competitive contracts may be cancelled with 15 to 30 days notice and only one retailer to the residential and small business market specified exit fees for early termination. The short notice periods and general lack of exit fees help facilitate switching between retailers.

The comparison of competitive product prices is challenging given the extent of product diversification. However, to provide a rough indication of the difference in energy prices, we compared the absolute value of prices for different products as published by the UCA during 2010.

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[16] Distributed Energy Financial Group, 2010,'ABABBUUS: An Assessment of Restructured Electricity Markets'. http://defgllc.com/news/news.asp?show=VIEW&a=90

Table 8.2 shows the minimum, maximum and median electricity and natural gas prices by contract term as reported by the UCA. The table was generated by considering all available offers each month, and then summarizing the monthly values. The most significant observation that can be made from the data is that the contract prices for electricity and natural gas trend upwards with the contract length. We will continue to develop and refine mechanisms to compare product prices in subsequent quarterly reports.

Table 8.2: Range of Competitive Prices in 2010

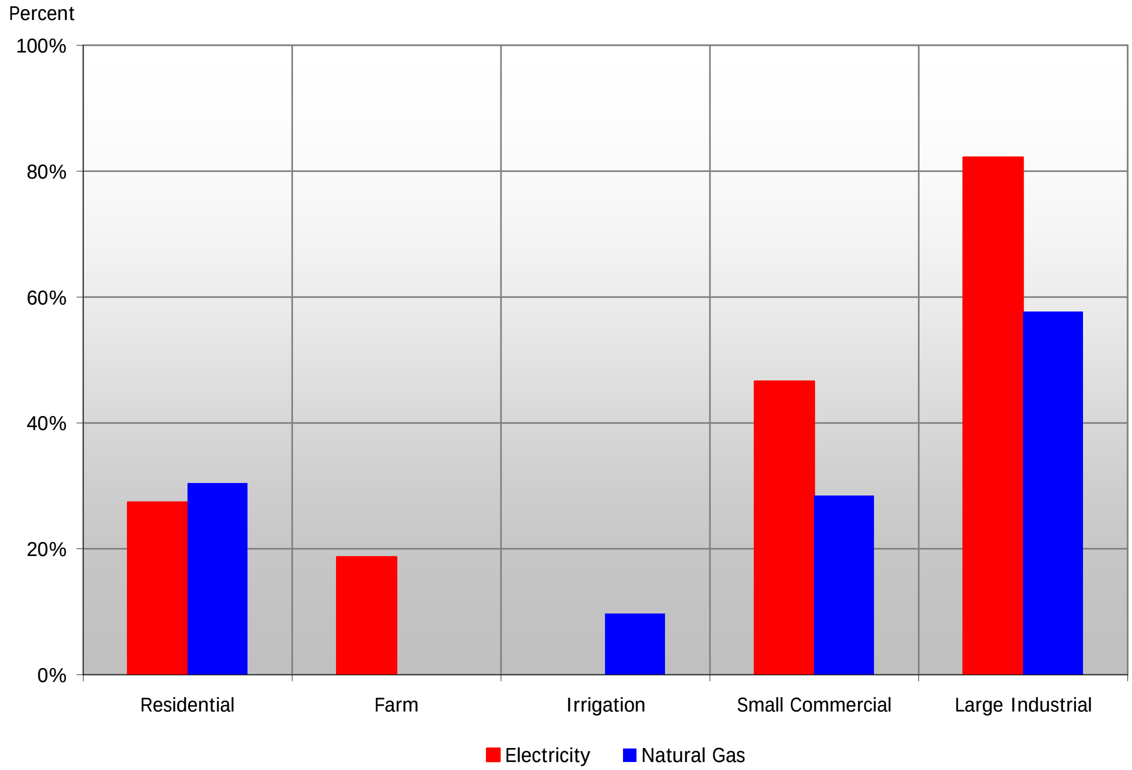
Products by Term	Minimum	Maximum	Median
Electricity (Cents/kWh)			
1-year	6.50	7.79	6.89
2-year	6.33	7.69	6.80
3-year	7.39	7.99	7.79
5-year	7.99	10.99	8.00
Natural Gas ($/GJ)			
1-year	6.49	7.79	6.99
2-year	5.79	7.99	7.50
3-year	5.99	8.49	7.99

8.2.3 Switching Activity

We base our analysis of site switching from regulated to competitive service on data published by the Alberta Government.[17] Figure 8.4 indicates the average percentage of sites that have switched from regulated supply to competitive supply in the four major electricity and natural gas market segments over the November 2009 to November 2010 time period. Over this time frame there was no discernable trend in switching. In electricity market segments, switching rates averaged 27.4% for residential, 18.7% for farm, 46.6% for small commercial 46.6% and 82.2% for large industrial. With respect to natural gas market segments, residential switching rates are 30.4%, irrigation at 9.7%, small commercial at 28.4% and large industrial switching rates are at 57.7%.

[17] Alberta Department of Energy.
http://www.energy.gov.ab.ca/Electricity/1570.asp

Figure 8.4: Average Percentage of Sites on Competitive Contracts in 2010



The level of switching activity among electricity customers compares favourably with other deregulated energy markets in North America. Distributed Energy Financial Group[18] ranked Alberta markets relative to other restructured electricity markets in North America. According to the study, the switching rate for the residential market ranked 3rd, switching in the medium commercial and industrial market segment ranked 10th, and the switching rate in the large commercial and industrial market segment ranked 7th.

9 MSA Activities

9.1 STAKEHOLDER CONSULTATION PROCESS ON PARTICIPANTS' OFFER BEHAVIOUR

In Q1/10, the MSA initiated a stakeholder consultation process on participants' offer behaviour. Following the publication of two discussion papers, the MSA developed some hypothetical examples to illustrate some of the finer points of the MSA's intended approach to enforcement. This was published in early September and a roundtable was held later in the month to discuss the examples. Subsequently, the MSA received several additional hypothetical examples from a market participant and published both the examples and its assessment of them. The MSA issued draft guidelines in late November and solicited stakeholder comments that were due by December 17, 2010. The final guidelines were issued on January 14, 2011.

[18] Ibid

9.2 MSA ADVISORY OPINIONS

From time to time the MSA receives inquires from market participants regarding our views on matters within our mandate, including whether certain conduct would raise issues in respect of the fair, efficient and openly competitive operation of the market from our perspective. The MSA is always open to such discussions. We believe it is part of our mandate to provide such views where we reasonably can and, where appropriate, to make the views publicly available for the benefit of all stakeholders.

Where a matter seems to have broad implications the MSA will consider invoking a stakeholder consultation toward a possible MSA guideline. Where a matter appears to be more limited in its implications, for example where it would only directly affect very few market participants, the MSA will provide its formal views in a different manner. To that end we are contemplating an 'Advisory Opinion' program which will provide in writing the MSA views on a particular scenario, itself presented as a hypothetical. The Advisory Opinion will speak to whether the MSA would take issue with the conduct, including whether we would take enforcement action. Our intention is to make such Advisory Opinions public on our website.

Not all matters will be eligible for Advisory Opinions. For example, the MSA will not give an Advisory Opinion on actual conduct which is occurring or has occurred. Further, the person seeking our views may be content with informal feedback, given verbally. In addition, some matters will more squarely be within the mandate of another body, such as the AESO or the Alberta Utilities Commission, and the MSA will leave it to that body to provide whatever formal feedback is appropriate. This is a form of coordination between regulatory bodies and is consistent with regulatory efficiency.

We will be providing further updates as the Advisory Opinion program is developed.

9.3 ENMAX ACFA REPORT

The MSA released its investigation report in November concerning a complaint alleging that certain financial transactions by ENMAX may have contravened sections 5(c), 6 and/or 95(10) of the *Electric Utilities Act (EUA)*. The transactions involved concessionary funds (i.e., at lower interest rates than would otherwise likely be available to a local authority) which are sourced from the Alberta Capital Finance Authority by ENMAX Corporation through The City of Calgary. A review of the legislation showed that section 5 of the *EUA* is not capable of contravention, and MSA involvement is not contemplated in issues concerning section 95. The investigation concluded that there was no violation of section 6 of the *EUA*.

9.4 COMPLIANCE YEAR-IN-REVIEW REPORT

The MSA compliance team completed their annual report, 'Compliance Review 2010', and it was posted on the MSA's web site on February 4, 2011.

9.5 RETIREMENT OF WAYNE SILK

Wayne Silk officially retired at the end of 2010 following ten years of service at the MSA. The MSA staff thank him for his tremendous contribution over the years and wish him well in his retirement in the balmy climes of Kelowna with his wife Michele.

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]
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	99.30	169%
Q4-10	**45.94**	**59.09**	**28.36**	**75.25**	**164%**
Jul-10	40.01	51.83	23.64	52.54	131%
Aug-10	38.64	49.41	24.98	30.50	79%
Sep-10	28.42	79.43	22.02	17.94	63%
Q3-10	**35.77**	**44.87**	**23.59**	**37.07**	**104%**
Oct-09	34.93	41.57	25.73	12.76	37%
Nov-09	50.16	65.07	31.57	63.57	127%
Dec-09	53.86	64.93	38.52	65.13	121%
Q4-09	**46.27**	**56.99**	**31.94**	**53.55**	**116%**

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

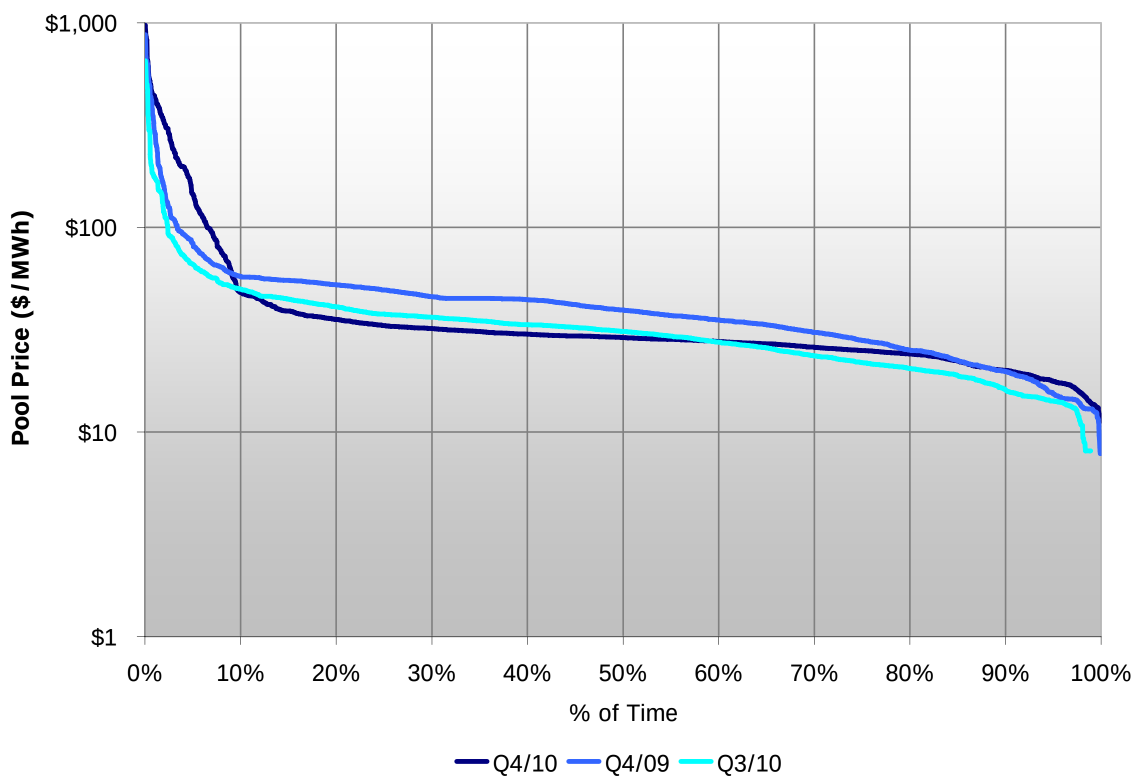
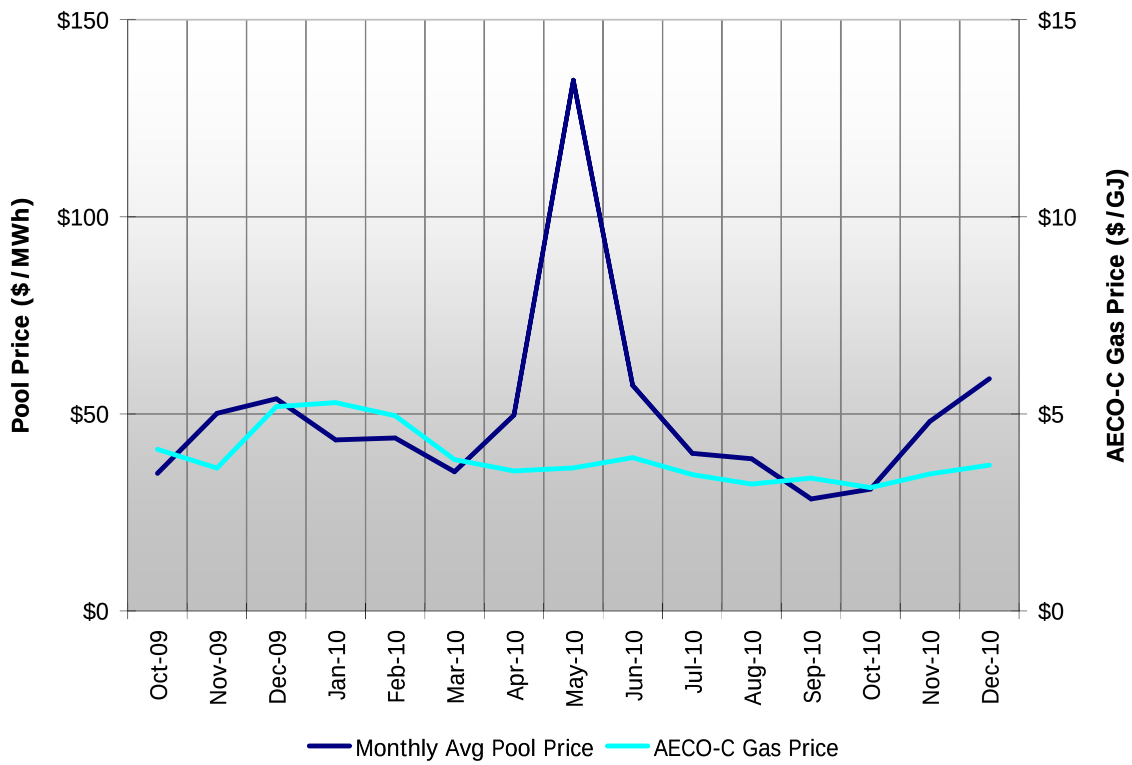


Figure A.2: Pool Price and AECO Gas Price

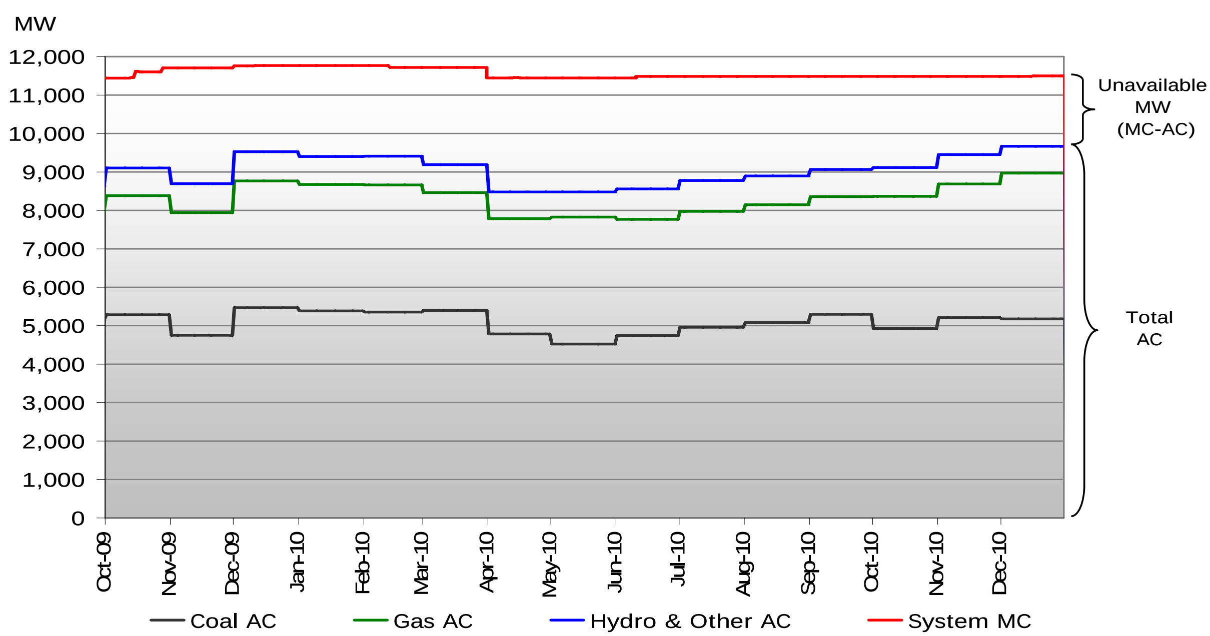


Appendix B: Supply Availability Metrics

Table B.1: Availability and Capacity Factors

Fuel Type	Quarter	Average MC	Average AC	Availability Factor	Generation	Capacity Factor
		[A]	[B] MW	[C]=[B]/[A]	[D]	[E] = ([D]x1000)/([A]xhrs)
		(MW)	(MW)	(%)	(GWh)	(%)
All Fuels *(excl. Wind)*	Q4/10	11,487	9,409	82%	16,739	66%
	Q3/10	11,484	8,910	78%	15,254	60%
	Q4/09	11,671	9,111	78%	16,228	63%
Coal	Q4/10	5,782	5,102	88%	10,531	82%
	Q3/10	5,782	5,110	88%	10,183	80%
	Q4/09	6,048	5,173	86%	10,677	80%
Natural Gas	Q4/10	4,788	3,572	75%	5,718	54%
	Q3/10	4,785	3,047	64%	4,663	44%
	Q4/09	4,706	3,194	68%	5,129	49%
Hydro & Other	Q4/10	917	734	80%	490	24%
	Q3/10	917	753	82%	407	20%
	Q4/09	917	745	81%	423	21%
Wind	Q4/10	671	n/a	n/a	411	28%
	Q3/10	629	n/a	n/a	282	20%
	Q4/09	563	n/a	n/a	517	42%

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



Appendix C: Operating Reserves Market Metrics

Figure C.1: On-Peak Active Settlement Prices - All Markets (NGX and OTC)

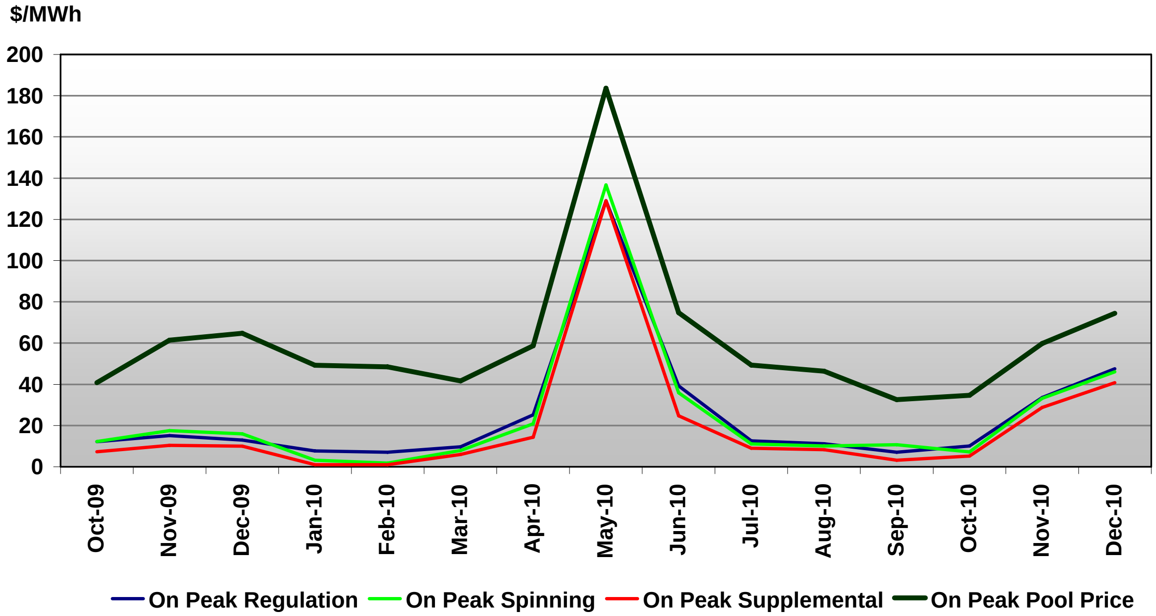


Figure C.2: Off-Peak Active Settlement Prices - All Markets (NGX and OTC)

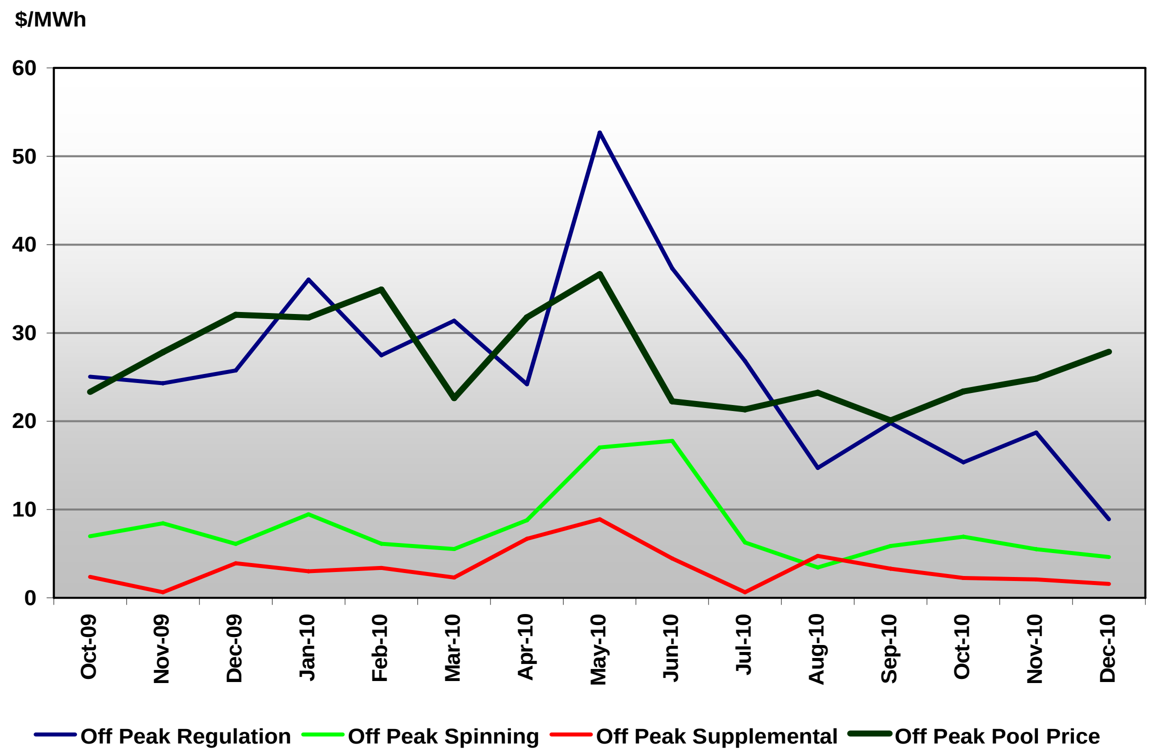
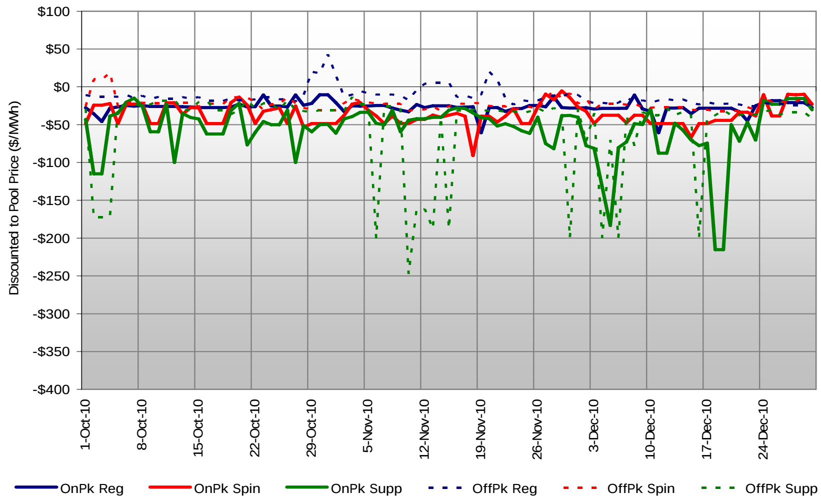
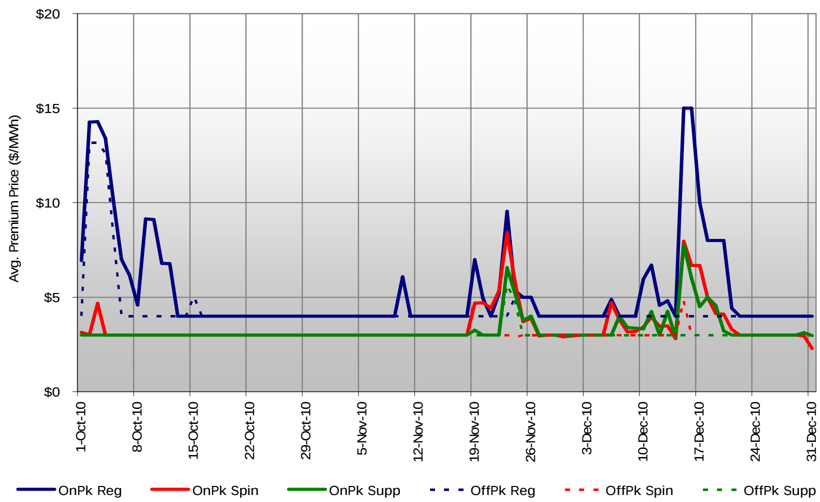


Figure C.3: Active Reserves Weighted Average Trade Index and Standby Reserve Prices

NGX Active Reserves Weighted Average Trade Index



Standby Reserves Average Premium Price



Standby Reserves Average Activation Price

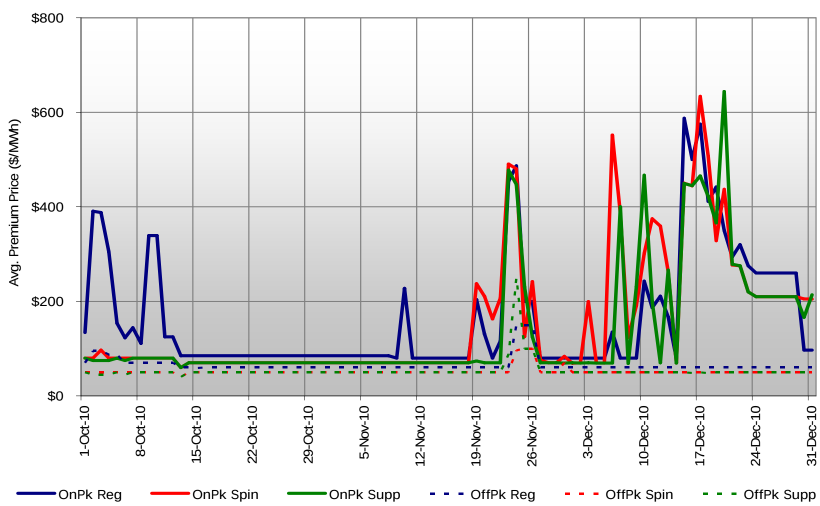


Figure C.4: Active Regulating Reserve Market Share by Fuel Type

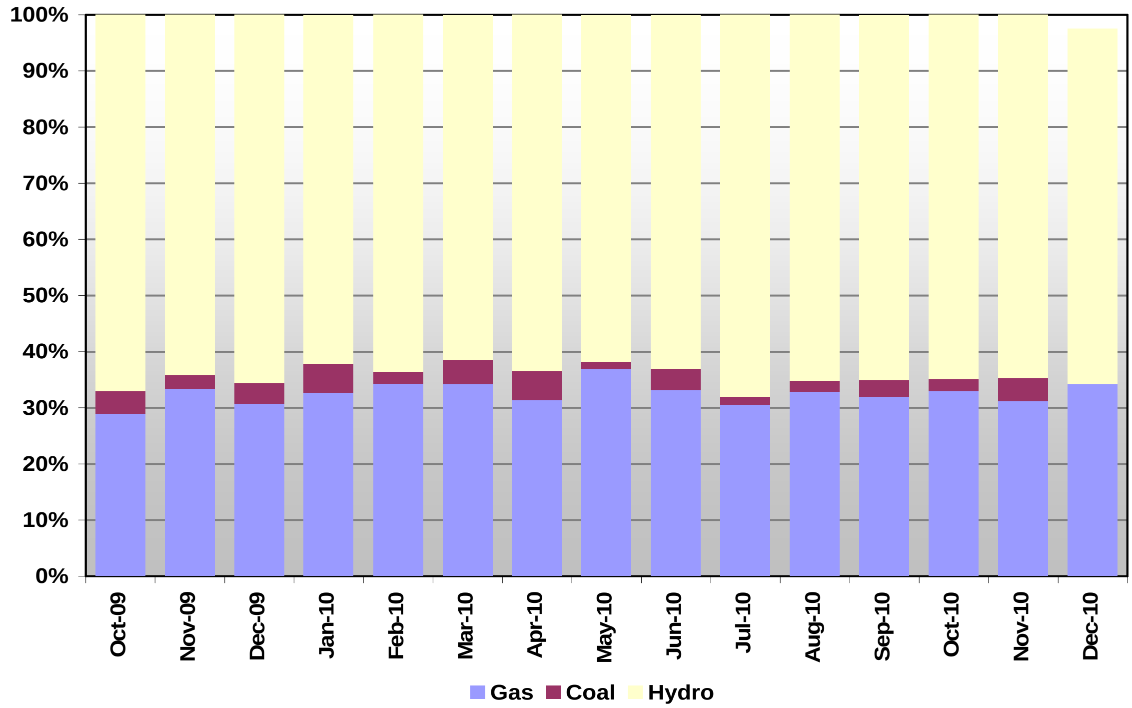


Figure C.5: Active Spinning Reserve Market Share by Fuel Type

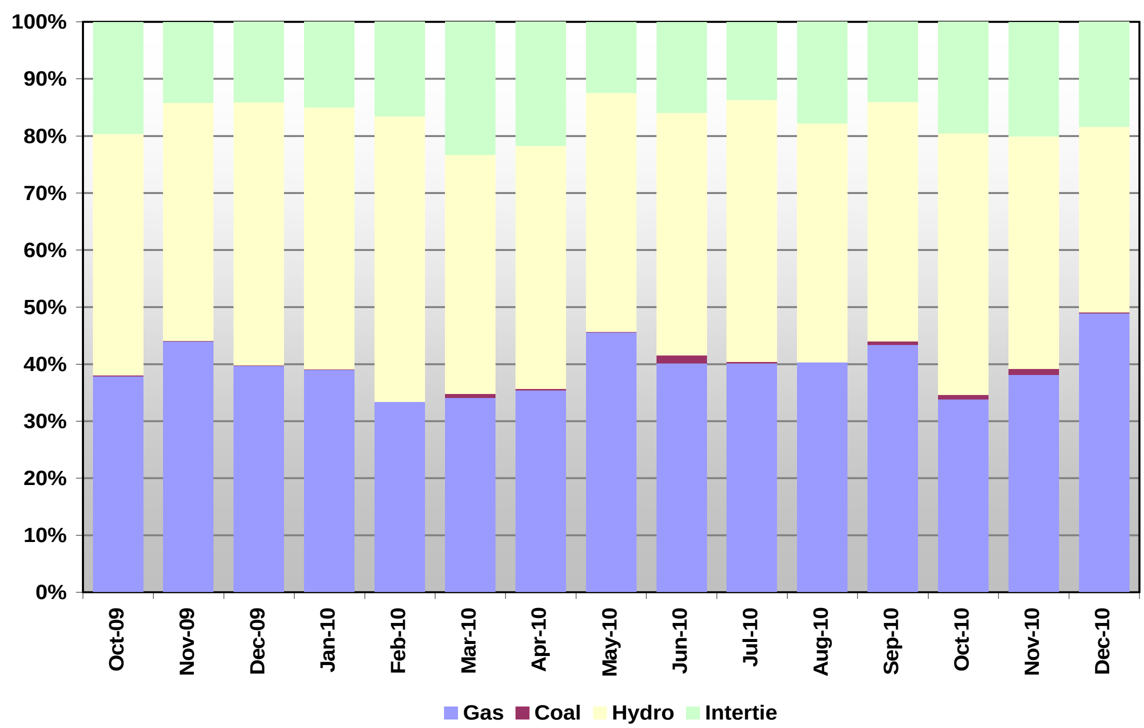
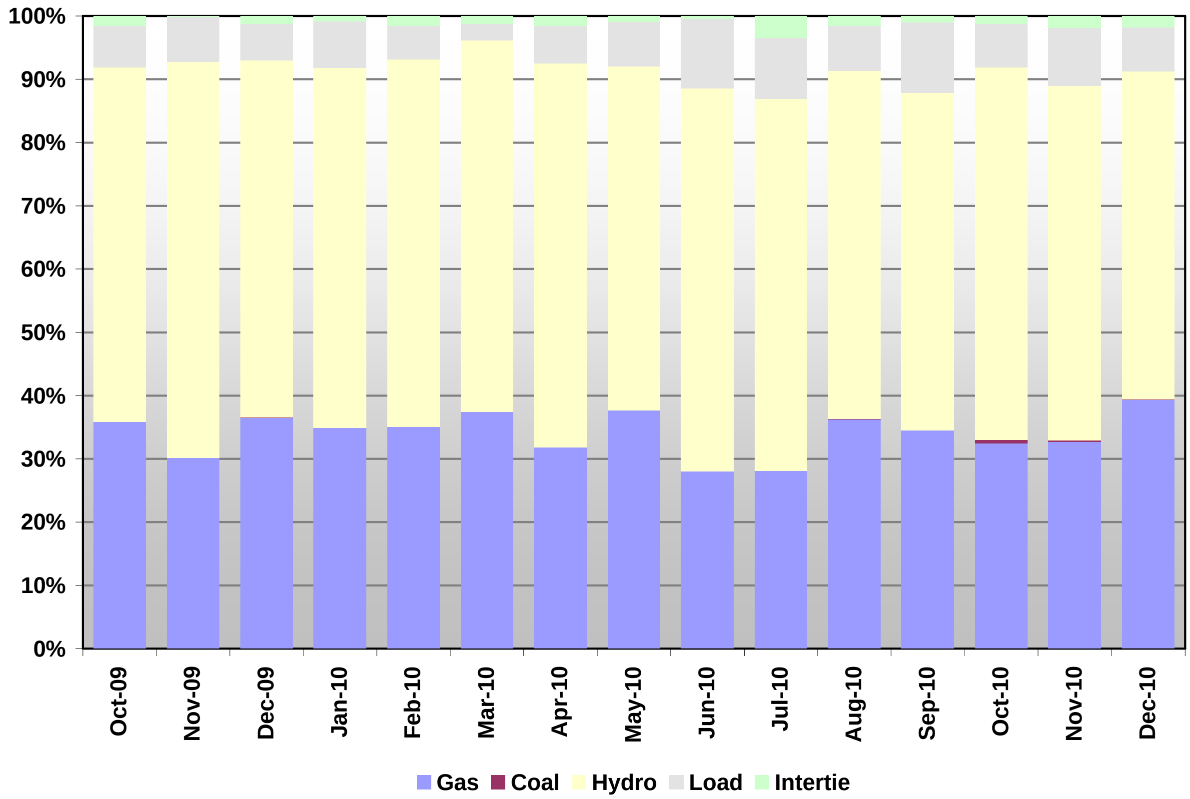


Figure C.6: Active Supplemental Reserve Market Share by Fuel Type



Appendix D: Dispatch Down Service (DDS) Metrics

Figure D.1: Average Daily TMR, Eligible, Constrained and Dispatched DDS Volumes (MW)

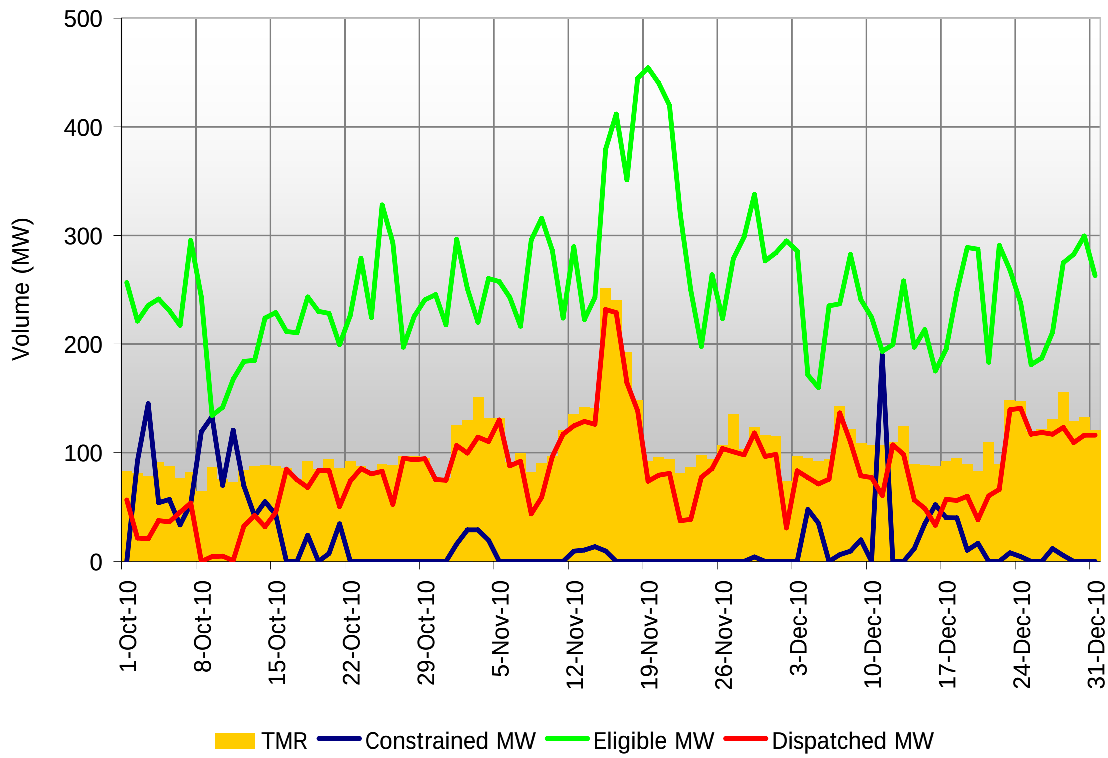
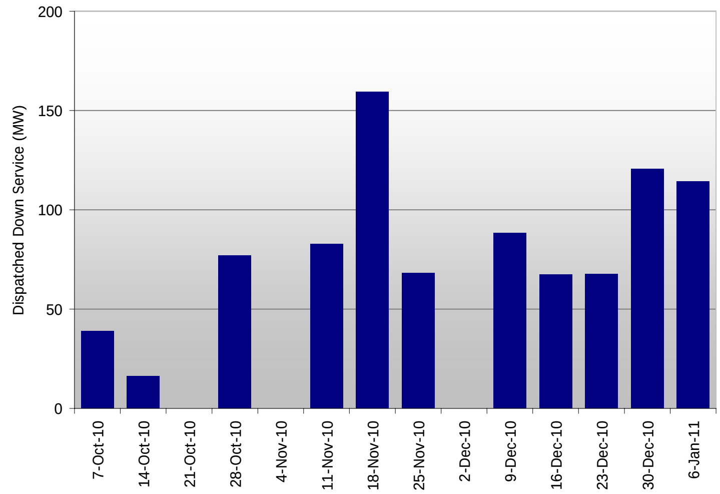
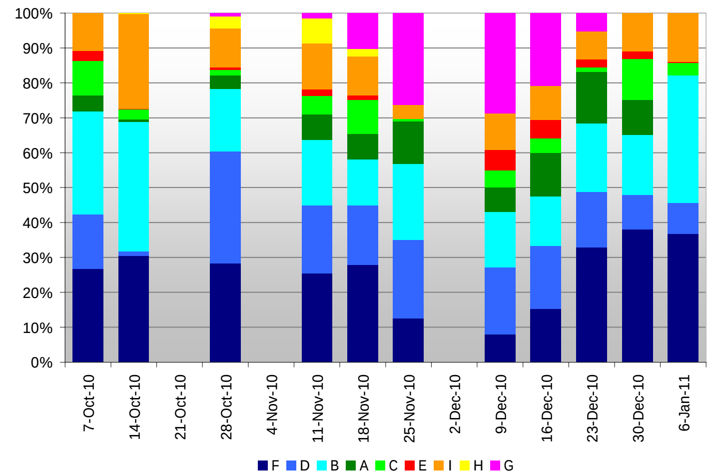


Figure D.2: Average Weekly DDS Volume, Market Share by Participant and by Fuel Type

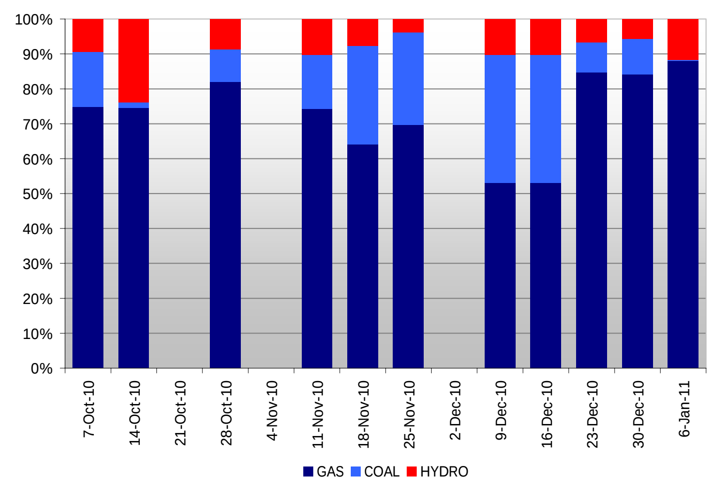
Average Weekly DDS Volume



Average Weekly DDS Market Share by Participant



Average Weekly DDS Market Share by Fuel Type



Appendix E: Intertie Metrics

Figure E.1: Intertie Utilization

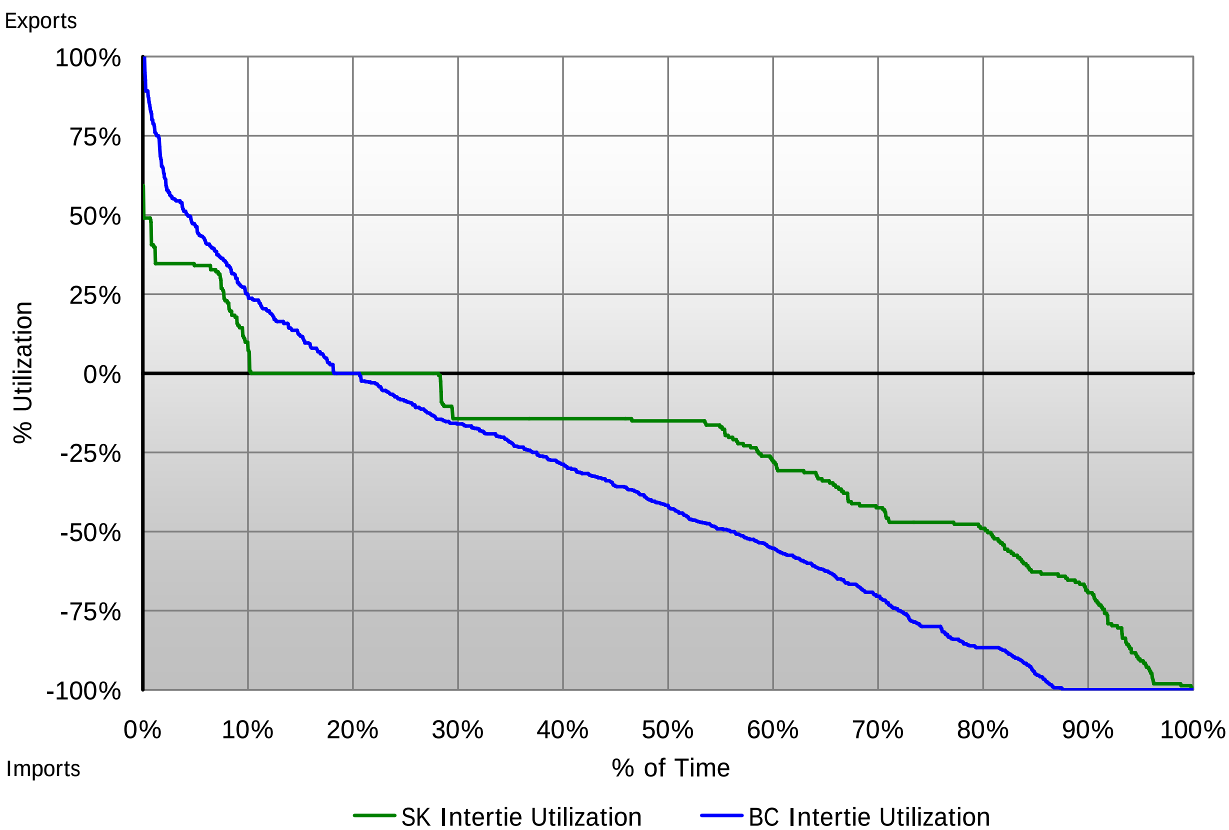


Figure E.2: On-Peak Prices in Neighbouring Markets

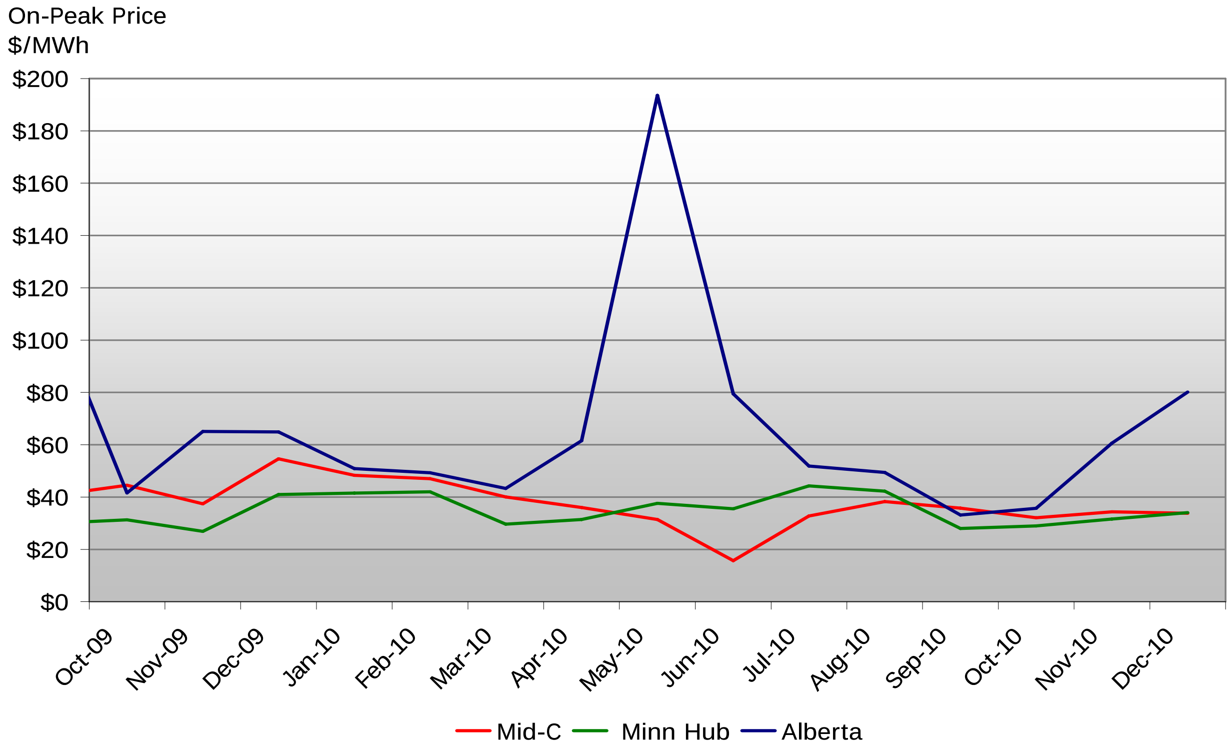


Figure E.3: Off-Peak Prices in Neighbouring Markets

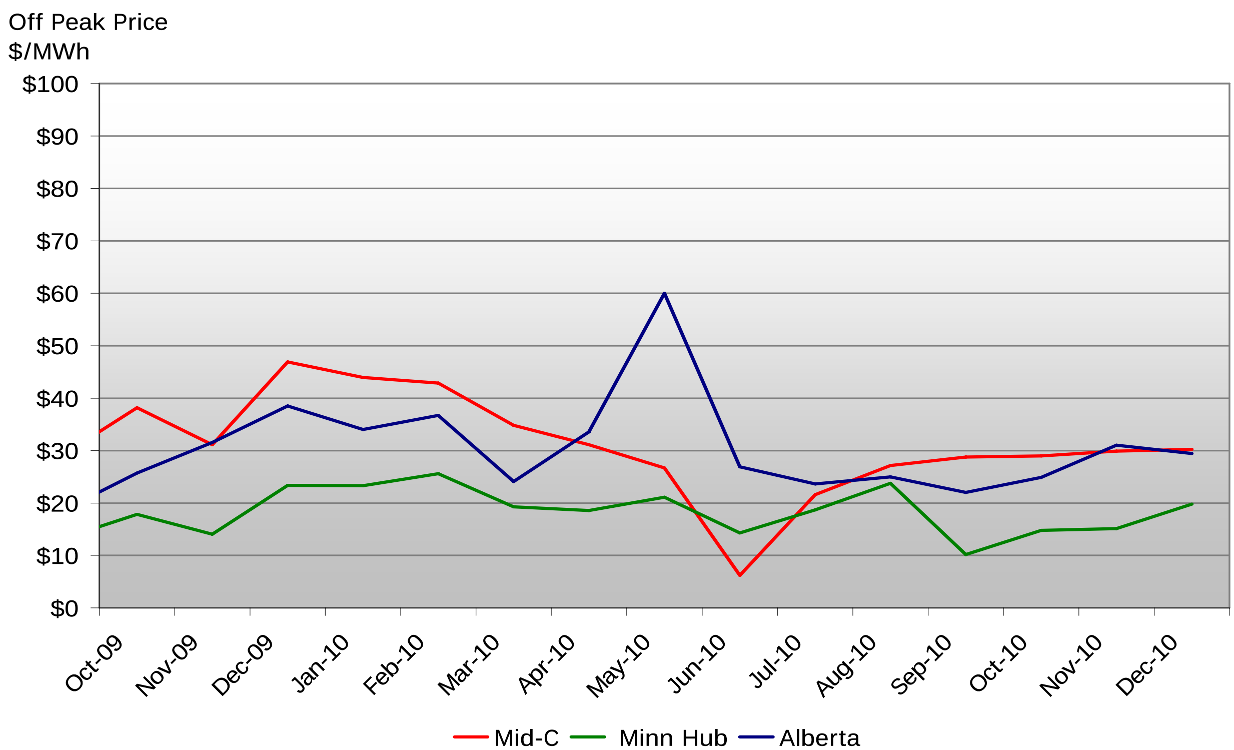


Figure E.4: Intertie Price Differentials and Net Flow - British Columbia

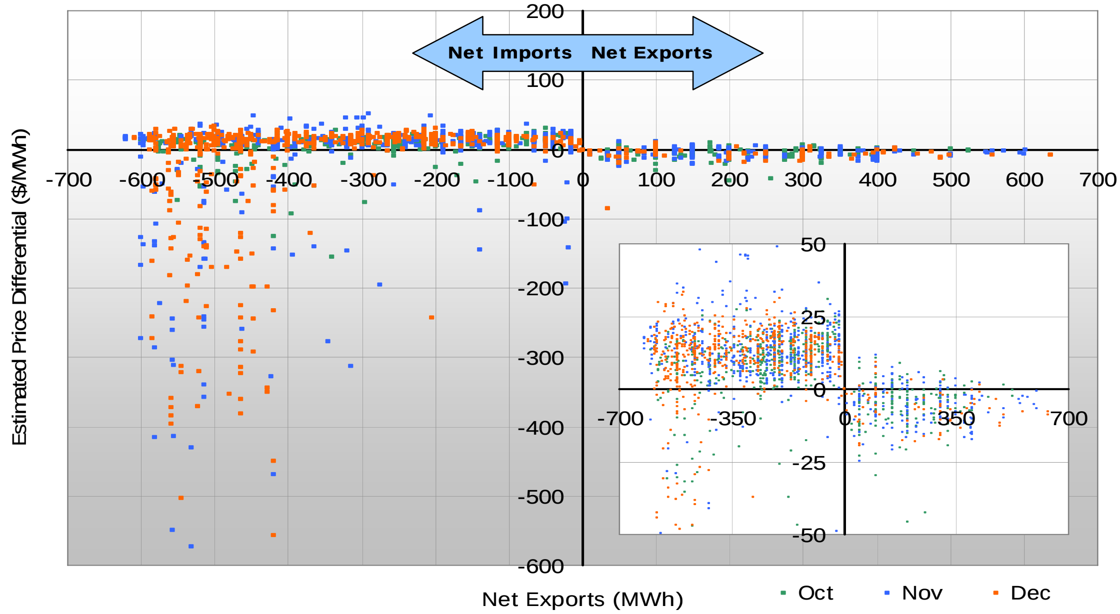


Figure E.5: Intertie Price Differentials and Net Flow – Saskatchewan

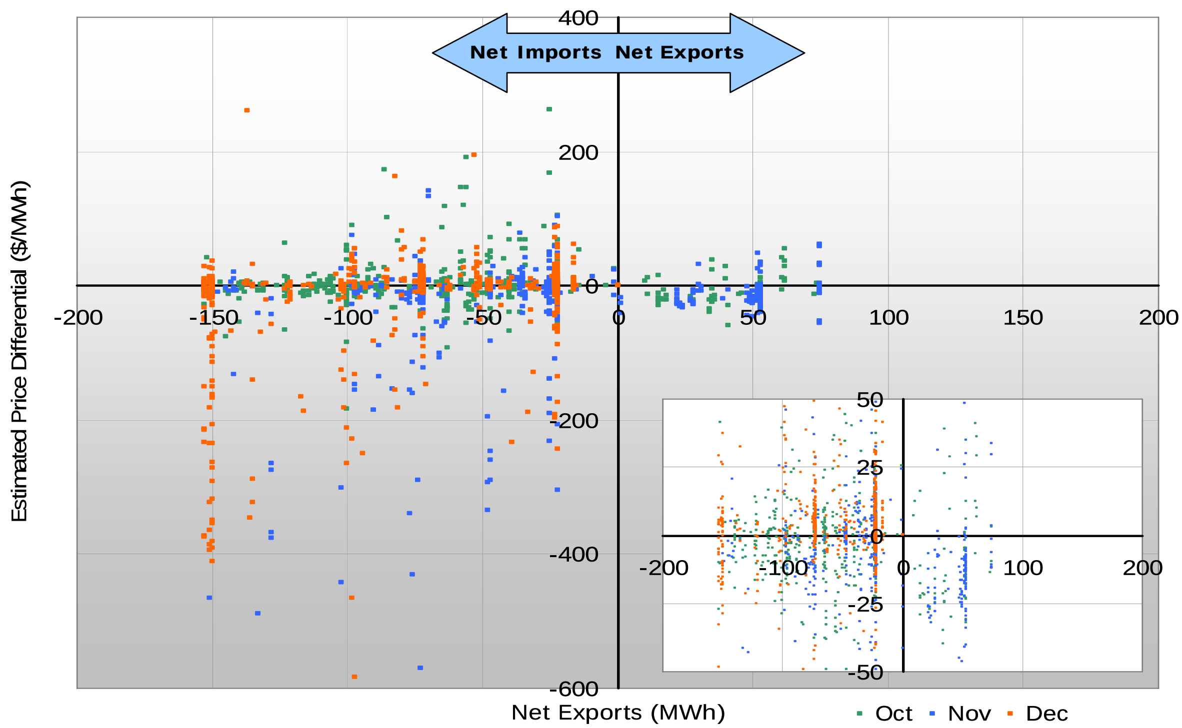


Figure E.6: Imputed Profitability and Unused Capacity - British Columbia

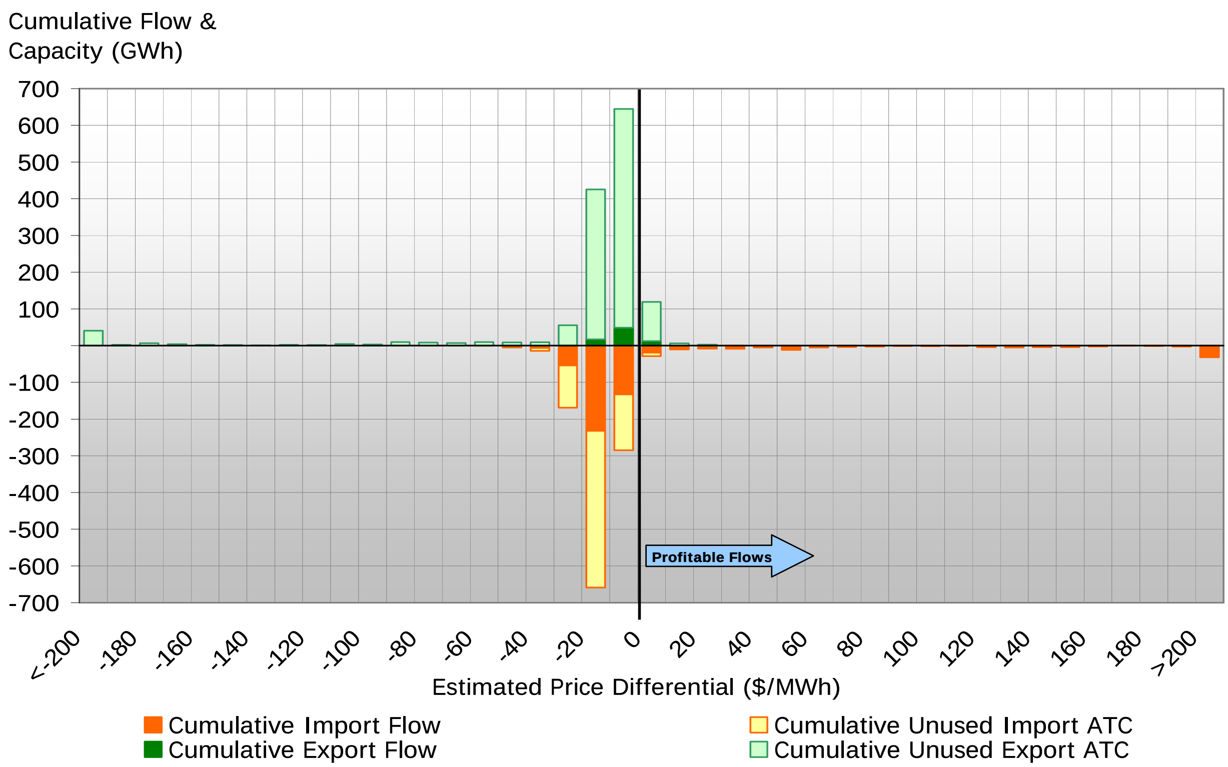


Figure E.7: Imputed Profitability and Unused Capacity – Saskatchewan

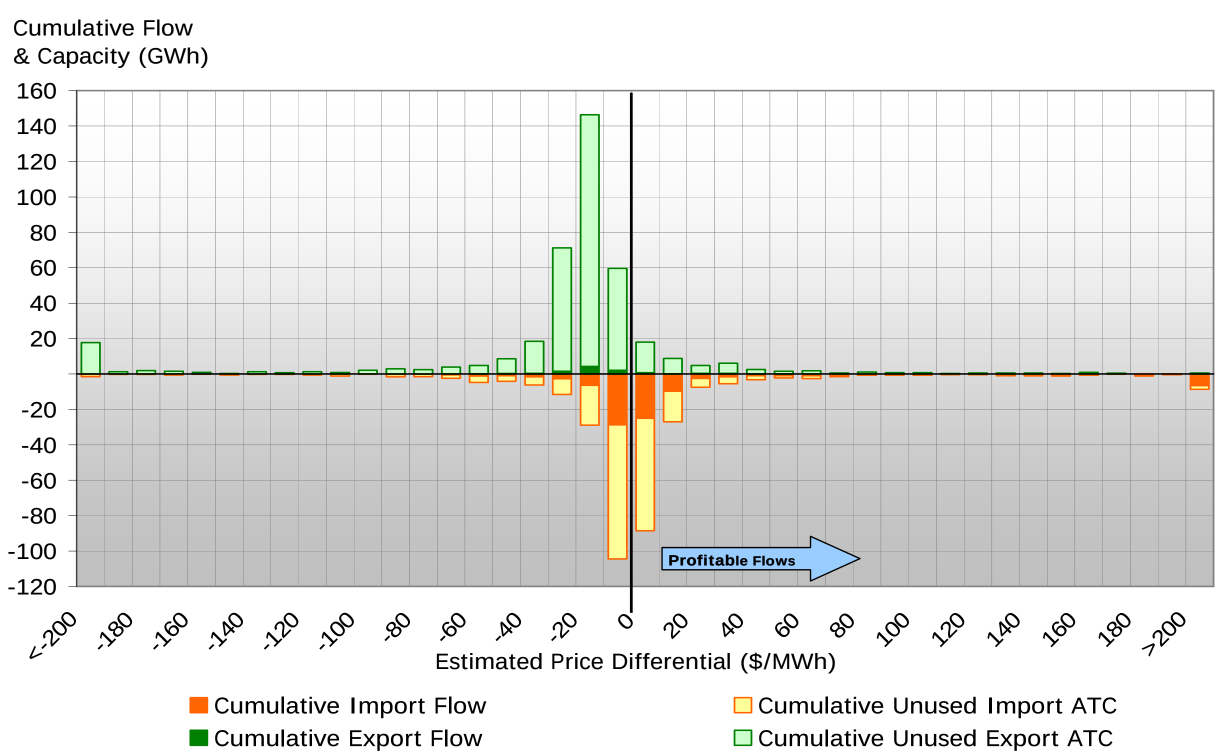
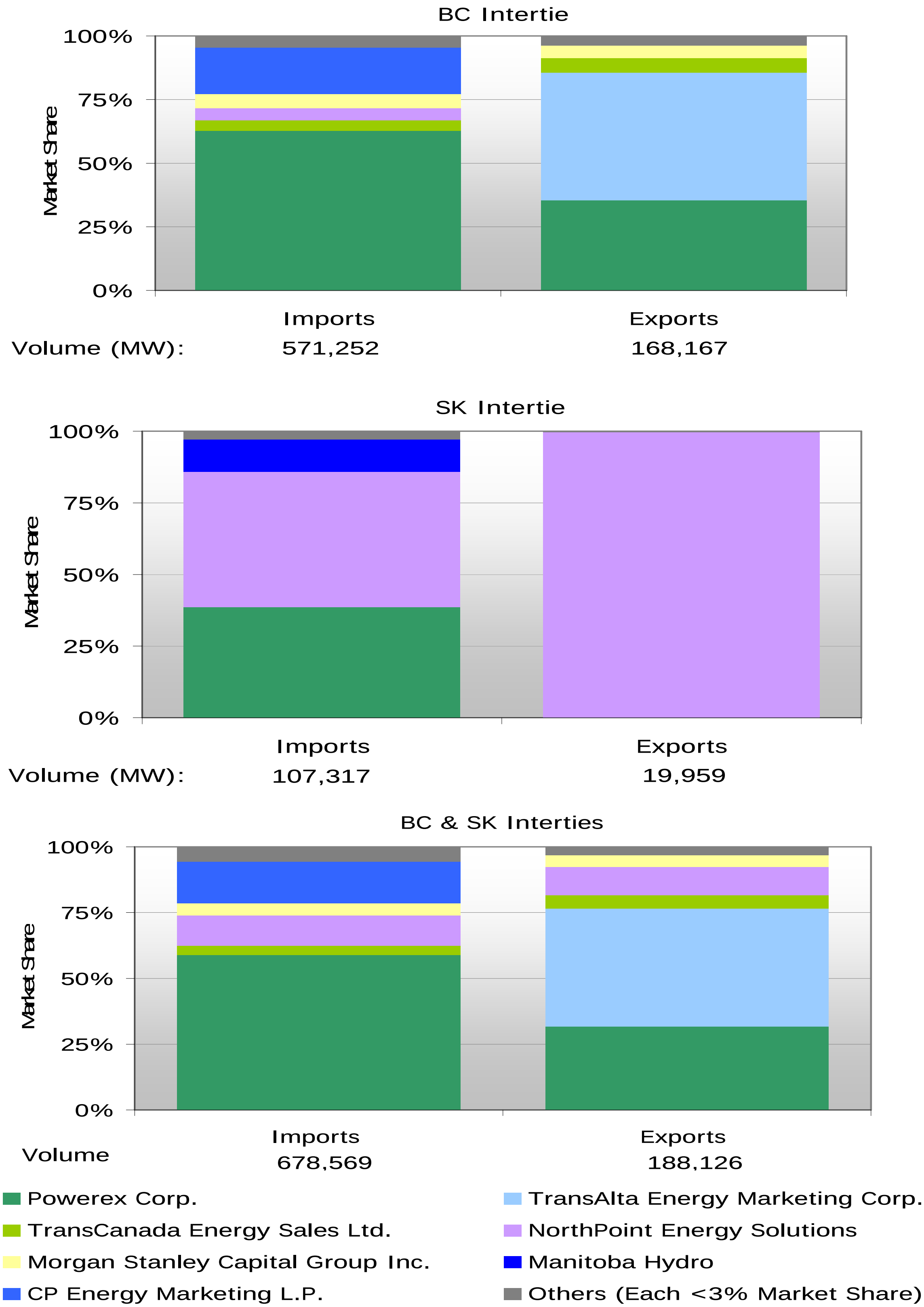


Figure E.8: Intertie Market Shares



Appendix F: Forward Market Metrics

Figure F.1: Volume by Trading Month

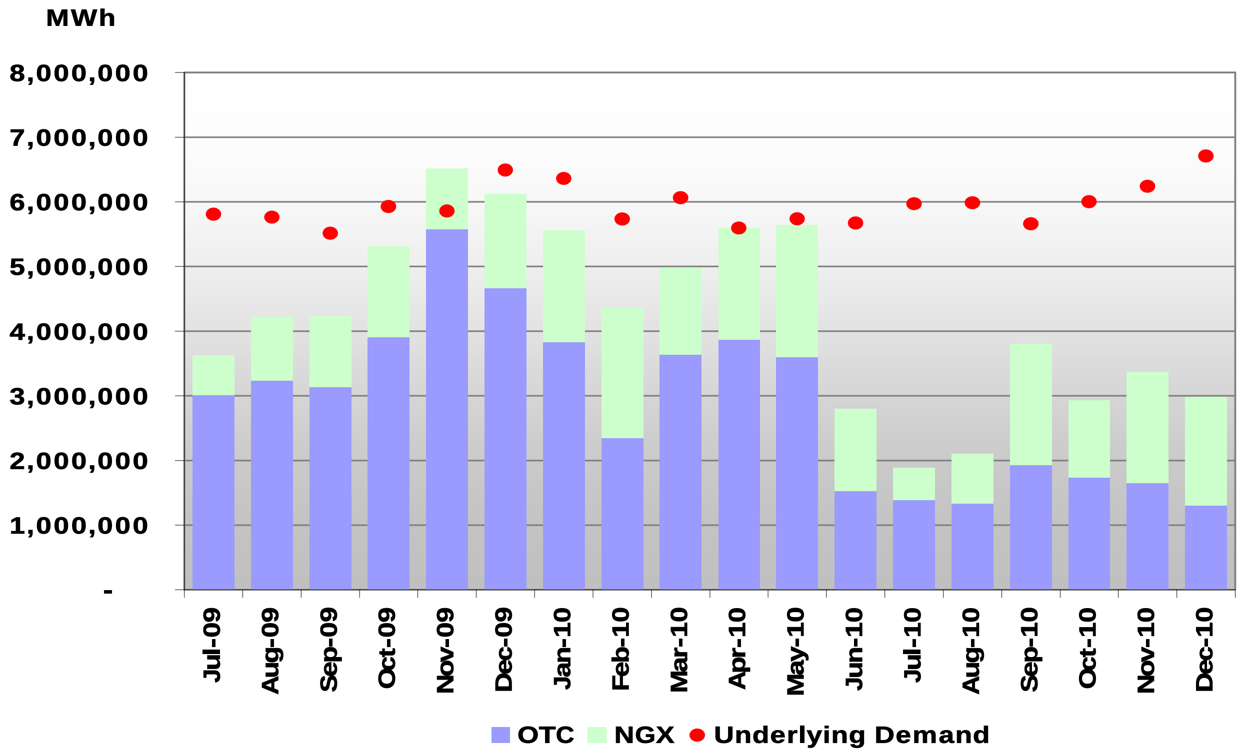
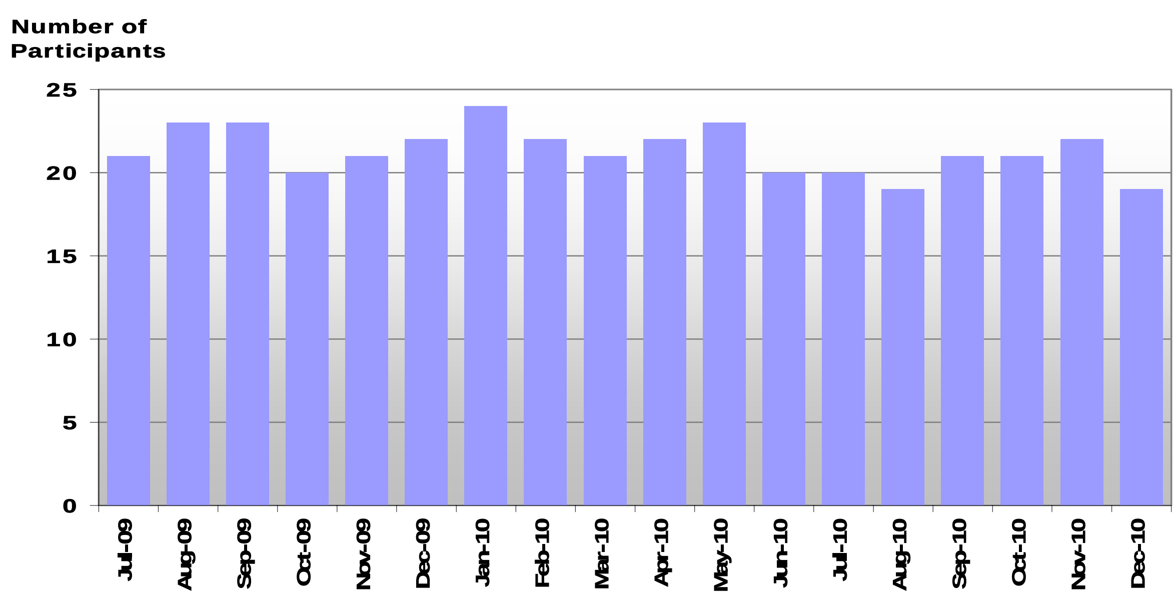


Figure F.2: Number of Active Market Participants by Trading Month



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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.