MSA
MARKET SURVEILLANCE
ADMINISTRATOR

Quarterly Report: July - September 2011 (Q3/11)

November, 2011

Market Surveillance Administrator | 403.705.3181 | #500, 400 – 5th Avenue S.W., Calgary AB T2P 0L6 | www.albertamsa.ca

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.

Table of Contents

Executive Summary 7

1 General Comments on Market Outcomes 10

2 Monitoring Indices 15

2.1 Supply Cushion Analysis – Q3/11 15

2.2 Output Gap Analysis – Q3/11 16

2.3 Summary of >3StD Events 19

2.3.1 July 5 (HE17 and HE18 >3StD) 19

2.3.2 August 4 (HE15 to HE17 >3StD) 23

2.3.3 September 7 (HE21 & HE22 >3StD) 28

2.4 Analysis of Pool Prices for Q1/11 through Q3/11 32

2.5 Scheduled Generation Outage Cancellation 34

3 Impact of Market News on Forward Market Prices 36

3.1 The 1201L Transmission Outage 37

3.2 Coal-Fired Generator Outages 38

3.3 Outage Obligations of the ISO, Generators and Transmission Facility Owners 38

3.3.1 Outage Reporting Obligations for Transmission 38

3.3.2 ISO's Role in Determining Outages with Transmission Facility Owners 39

3.3.3 Outage Reporting Obligations for Generators 40

3.3.4 Transparency of Outages to the Market 41

3.3.4.1 Publishing of Transmission Outage Information 41

3.3.4.2 Publishing of Generator Outage Information 42

3.4 Forward Price Movements for August and October 42

3.5 Discussion ... 45

4 Retail Matters ... 46

5 Compliance Activities ... 48

5.1 ISO Rules Compliance ... 48

5.2 Alberta Reliability Standards ... 49

5.3 Rules Clarifications ... 50

6 MSA Activities ... 52

6.1 Settlement Agreement ... 52

6.2 Data Transparency ... 52

6.3 MSA Feedback Page ... 52

Appendix A: Wholesale Energy Market Metrics ... 54

Appendix B: Supply Availability Metrics ... 56

Appendix C: Operating Reserves Market Metrics ... 57

Appendix D: Intertie Metrics ... 58

Appendix E: Forward Market Metrics ... 61

Appendix F: Hours >3StD in Q3/11 ... 63

Appendix G: Baseline Parameters for Pool Price – Supply Cushion Relationship ... 66

Appendix H: EPCOR EPSP Review ... 67

References ... 75

List of Tables and Figures

Table 1.1: Pool Price Statistics ... 10

Figure 1.1: Pool Price Duration Curves ... 11

Figure 1.2: Value of Pool Prices ... 11

Figure 1.3: Pool Price and AECO Gas Price 12

Figure 1.4: Historical Market Heat Rates in Alberta 13

Figure 1.5: Historical Annual Market Heat Rates 13

Figure 1.6: On-Peak Prices in Neighbouring Markets 14

Figure 2.1: Q3/11 Supply Cushion v. Pool Price (Confidence Bands Based on Historic Data) 16

Table 2.1: Output Gap Analysis - Q3/11 17

Figure 2.2: Output Gap Analysis - July 2011....................17

Figure 2.3: Outpute Gap Analysis - August 2011....................18

Figure 2.4: Output Gap Analysis - September 2011 18

Figure 2.5: Supply Cushion vs. Pool Price, July 5....................19

Figure 2.6: Offer Curve for HE12 to HE16, July 5....................20

Figure 2.7: Price Responsive Load vs. SMP, July 5....................21

Figure 2.8: Offer Curve for HE15 to HE18, July 5....................22

Figure 2.9: Offer Curve for HE18 to HE20, July 5....................23

Figure 2.10: Supply Cushion vs. Pool Price, August 4....................24

Figure 2.11: Offer Curve for HE9 to HE11, August 4....................25

Figure 2.12: Offer Curve for HE9 and HE12, August 4 26

Figure 2.13: Offer Curve for HE14 to HE16, August 4....................27

Figure 2.14: Price Responsive Load vs. SMP, August 4....................27

Figure 2.15: Supply Cushion vs. Pool Price, September 7 28

Figure 2.16: Offer Curve for HE9 to HE12, September 7 29

Figure 2.17: Price Responsive Load vs. SMP, September 7 30

Figure 2.18: Offer Curve for HE12 to HE19, September 7 31

Figure 2.19: Offer Curve for HE19 to HE22, September 7 32

Table 2.2: Supply Cushion - Pool Price 2011 YTD vs Baseline 33

Figure 2.20: Distribution Curves of Supply Cushion....33

Table 2.3: Average Pool Price for Different Supply Cushion Bands....34

Figure 2.21: Supply Adequacy Calculation Results (Source - AESO)....35

Figure 3.1: Monthly Pool Price vs. Forward Price (NGX RRO Index) – Feb. 2008 to Sept. 2011....36

Figure 3.2: August Flat Contract Price (NGX) 37

Table 3.1: Changes to Generator and Transmission Outages and the Impact on Forward Prices 42

Figure 3.3: October Flat Contract Price (NGX) 43

Figure 4.1: Market Share of Top 4 Sellers in EPCOR RRO Auctions 47

Table 5.1: Compliance Files (as of end of Q3/11)....48

Table 5.2: Q3/11 Compliance Files by Month of Contravention....49

Table A.1: Pool Price Statistics 54

Figure A.1: Pool Price Duration Curves 54

Figure A.2: Pool Price and AECO Gas Price 55

Table B.1: Availability and Capacity Factors 56

Figure B.1: Available Capacity (AC) vs Maximum Capacity (MC) 56

Figure C.1: Active Reserves Weighted Average Trade Index and Standby Reserve Prices....57

Figure D.1: Intertie Utilization – Q3/11....58

Figure D.2: On-Peak Prices in Neighbouring Markets 59

Figure D.3: Off-Peak Prices in Neighbouring Markets....59

Figure D.4: Intertie Market Shares – Q3/11 60

Figure E.1: Volume by Trading Month....61

Figure E.2: Market Shares by Participant Type 61

Figure E-3: Number of Active Market Participants 62

Executive Summary

General Market Outcomes

The commissioning of Keephills #3 proceeded throughout Q3/11 and put some downward pressure on pool prices since its energy must be offered at $0/MWh in this phase. However, overall the market was tight in part due to the continued absence of Sundance #1 and #2. Combined with market participant offer behaviour this led to an average pool price of $94.69/MWh. This is substantially higher than Q2/11 ($51.90/MWh) and Q3/10 ($35.77/MWh) as shown in Table 1.1. The pool price duration curve for Q3/11 shows that 13% of pool prices were above $100/MWh and 21% were above $50/MWh. The volatility of pool prices, whether measured by standard deviation or coefficient of variation, continued to be high in Q3/11.

AECO-C natural gas prices were again very stable throughout the quarter in the range $3 to $4/GJ – a band of prices that have persisted for more than a year. The quarterly market heat rate was 28 GJ/MWh (On-Peak: 42 GJ/MWh, Off-Peak: 8 GJ/MWh). Since 2006, there is an upward trend in monthly market rates which are then overlain with occasional extreme values.

The Alberta market heat rates are not in line with regional values. In on-peak hours, Alberta market heat rates are much higher than those of our neighbours in Mid-C and MISO. This arbitrage opportunity naturally encouraged significant volumes of imports in Q3/11 and our limited intertie capacity was well subscribed. This quarter Alberta imported some 860 GWh, equivalent to an average of 390 MW and almost the same amount as in Q2/11.

There was little change to system installed capacity (Maximum Capability) in Q3/11. Keephills #3 continued its commissioning work and the plant is in commercial production as of the end of November. Plant availability in Q3/11 was higher than Q2/11 with an average available capacity of 8,824 MW vs. 8,512 MW, with increased availability in both the coal and gas fuelled fleets. Generation was also up quarter over quarter, but only by a modest amount.

Monitoring Indicia

The supply cushion – pool price relationship was again used to screen hourly market outcomes for the quarter. A total of 126 high outliers were identified for Q3/11, many more than would be expected based on the historical data used to establish the baseline parameters. This is a continuation of a pattern that has persisted for all 2011, with the frequency of outliers increasing over time.

The report uses the output gap analysis to assess the 126 hours identified as statistical outliers using the MSA's baseline relationship between the supply cushion and pool price. A more detailed assessment of three days in the quarter, each with several pool price statistical outliers, reveals a pattern of clustering of offers from different firms. This may be facilitated by the public information that the ISO makes available in, or close to, real time. The MSA is actively assessing the potential for coordinated effects in the wholesale market and what adjustments to market information might mitigate the issue.

Forward Market

Another example of how market information affects the Alberta forward market prices is presented in detail. The 500 kV line to BC was slated for maintenance in August, and the forward prices reflected the expected market impact. Subsequently the transmission outage was shifted first to October and was ultimately deferred. One of the outcomes of the changes was that RRO customers appeared to have 'paid' for the transmission outage twice already and will still have to pay for it again when it is rescheduled in the future. Whilst some rescheduling of outages (both transmission and generation) is inevitable as events unfold, such changes need to be minimized.

Retail Market

Following some concerns that the MSA expressed about the RRO auction procurement process, EPCOR undertook a review that they provided to the MSA and it is appended to this report. The review concluded that the Energy Price Setting Plan was yielding results consistent with a fair, efficient and openly competitive process. Whilst the MSA is in broad agreement with the report's findings, the process has only been in place for a few months and more data is required to properly assess the functionality of any of the three Energy Price Setting Plans.

Compliance Update

The MSA provides guidance to market participants on their obligations with respect to market rules. Where appropriate, we will help the ISO and market participants come to satisfactory outcomes when application of rules in certain circumstances is difficult.

During Q3/11, the MSA received a referral from AESO compliance monitoring in regards to an observed offer practice suspected to be in contravention of ISO rule 3.5.3. Rule 3.5.3 requires participants to offer the maximum capability (MC) of their generation assets into the market unless an acceptable operational reason exists for those offers to be below MC. The issue related to the fact that the plant could not be operated remotely and was not manned 24 hours each day. The plant owner declared it unavailable when the site was not manned. This was not an acceptable operational reason as far as the AESO is concerned. The solution to the problem was to allow the plant to offer as a long lead time asset during the hours when the plant is unmanned.

Also of note in respect of ISO rule 3.5.3, was a matter pertaining to dual fuel capable coal units (i.e. coal/gas) restating offers within T-2 due to poor coal quality. Available Capability (AC) for a generating asset, is defined in the ISO rules as the maximum quantity (MW) that the generating asset is physically capable of providing during each settlement interval of the trading day. Accordingly, ISO rules suggest in this context that the gas capability is captured in the declaration of AC, and that changes to AC must consider the extent of operation in alternative modes i.e. gas. The MSA appreciates that the issue may not be straightforward and that other factors may apply particularly in the context of a PPA. In this regard, the MSA believes there is an opportunity for clarification as rule 3.5.3 is transitioned to the new ISO rules framework through the TOAD process. If PPA owners require further clarity in the interim, they are advised to contact the MSA.

During Q3/11 the MSA received referrals in which coal assets had submitted offer restatements within T-2 to accommodate Relative Accuracy Test Audit testing. These instances had been deemed not to qualify as an acceptable operational reason to restate within T-2 when no test plan had been submitted to the AESO in accordance with OPP 603. OPP 603 contemplates forbearance in respect of dispatch variance contraventions when testing under an approved test plan and the MSA is of the view that a similar approach in respect of other forms of non-compliance while testing is reasonable provided that a test plan has been filed with the AESO. The MSA is aware that contractors who conduct RATA testing on behalf of several participants are often delayed and hence, the testing may not occur on schedule. The MSA recommends that participants intending to conduct RATA testing file a test plan in accordance with OPP 603.

Settlement Agreement Filed with the AUC

On November 4 the MSA and TransAlta filed a settlement agreement with the AUC where it is currently under consideration as Application No. 1607868. The settlement alleges that TransAlta breached section 6 of the Alberta Electric Utilities Act during 31 separate hours during 8 days in November, 2010. The current details may be found at the Commission's web site at www.auc.ab.ca and search for application 1607868.

Market Data Transparency

In late August, the MSA issued a Request for Proposal on market data transparency. The successful bidder was Charles River Associates who are well along with their work as of mid November. In parallel with the work by Charles River Associates, the MSA is conducting a stakeholder process on the same topic. Readers are directed to the MSA's web site for more details. www.albertamsa.ca.

1 General Comments on Market Outcomes

The commissioning of Keephills #3 proceeded throughout Q3/11 and put some downward pressure on pool prices since its energy must be offered at $0/MWh in such situations. However, overall the market was tight in part due to the continued absence of Sundance #1 and #2. Combined with market participant offer behaviour this led to an average pool price of $94.69/MWh. Sections 2.3 and 2.4 also summarize the impact of market participant offer behaviour on pool prices in the quarter. This average price is substantially higher than Q2/11 ($51.90/MWh) and Q3/10 ($35.77/MWh) as shown in Table 1.1.

Table 1.1: Pool Price Statistics

Month	Average Price[1]	On-Pk Price[2]	Off-Pk Price[3]	Std Dev[4]	Coeff. Variation[5]
Jul-11	61.21	91.37	22.96	156.35	255%
Aug-11	126.36	192.39	34.93	223.50	177%
Sep-11	96.57	149.35	24.35	200.08	207%
Q3-11	**94.69**	**144.98**	**27.36**	**196.99**	**208%**
Apr-11	52.23	70.33	27.48	85.53	164%
May-11	32.27	43.92	17.50	51.29	159%
Jun-11	71.85	111.05	18.20	188.90	263%
Q2-11	**51.90**	**75.10**	**20.97**	**123.77**	**238%**
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	*33.10*	22.02	17.94	63%
Q3-10	**35.77**	**44.87**	**23.59**	**37.07**	**104%**

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

The volatility of pool prices, whether measured by standard deviation or coefficient of variation, continued to be high in Q3/11. The pool price duration curve for Q3/11 shows that 13% of pool prices were above $100/MWh and 21% were above $50/MWh (See Figure 1.1). Another way of looking at the volatility of pool prices is to consider the pool price duration curve with a slightly different interpretation. [1] Looking at the total dollar value of pool price in the top X% of hours in a given period as a percentage of the total for the period is a metric which has been coined 'value' and Figure 1.2 shows the relationship for Q3/11 and the same quarter in the previous three years. Regarding Q3/11, fully two thirds of the value of pool price for the quarter is in the top 10% of hours. This is significantly higher than the same quarters in previous years, including 2008 which was the most recent year with high prices.

AECO-C natural gas prices were again very stable throughout the quarter in the range $3 to $4/GJ – a band of prices that have persisted for more than a year (See Figure 1.3). The quarterly market heat rate was 28 GJ/MWh (On-Peak: 42 GJ/MWh, Off-Peak: 8 GJ/MWh). The monthly market heat rates since 2001 are shown on Figure 1.4. It is clear that the volatility in these values has increased over time. Starting in 2006 there are clearly some high values usually associated with a significant event such as major transmission work or clustering of generator outages. Since 2006, there is an upward trend in monthly

[1] Credit needs to go to Mr. Sheldon Fulton who first introduced the MSA to this concept.

market rates which are then overlain with occasional extreme values. The trend is more readily apparent when looking at annual market heat rates as shown in Figure 1.4. The value for 2011 is based on data to the end of September.

Figure 1.1: Pool Price Duration Curves

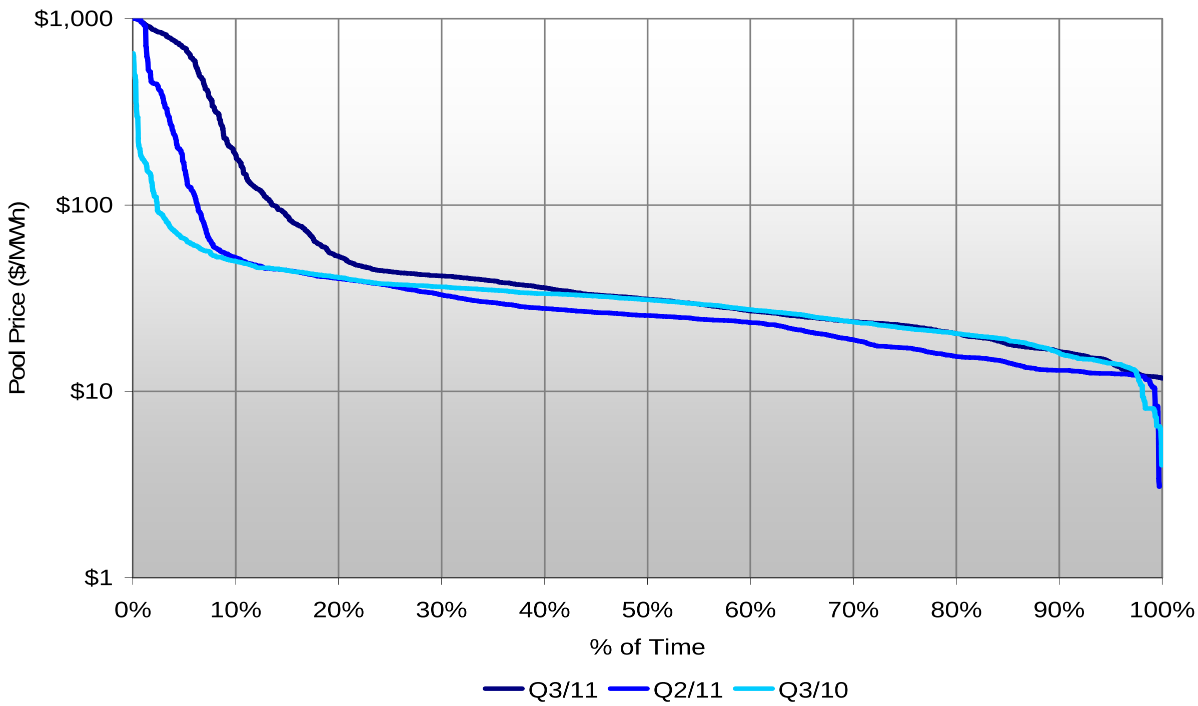
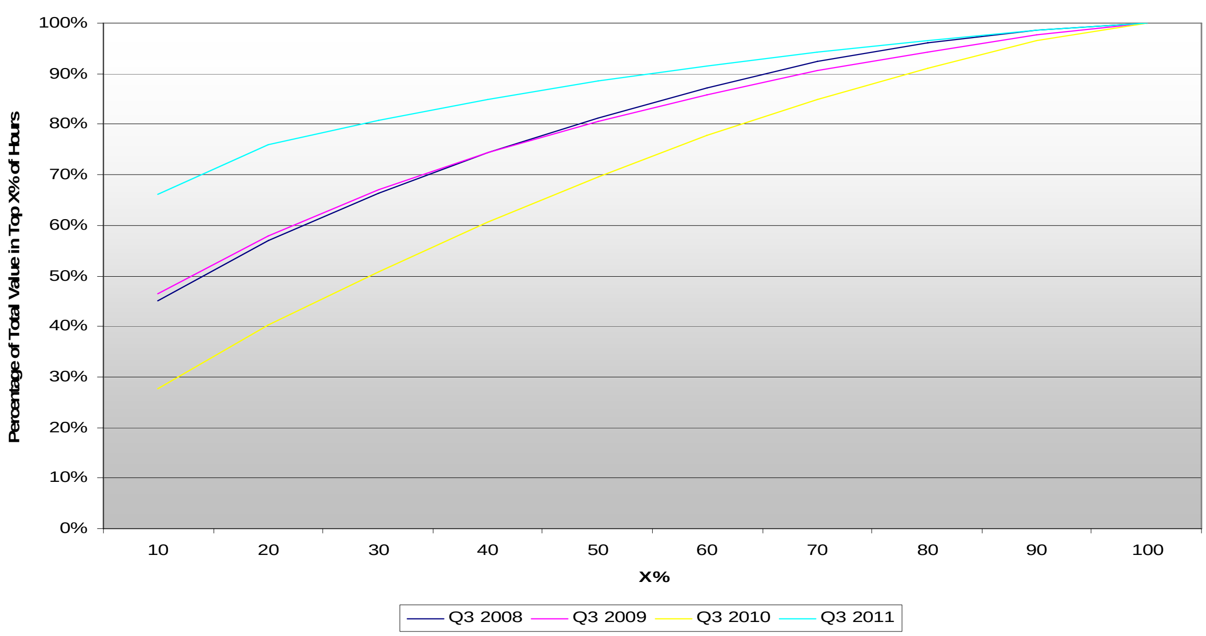


Figure 1.2: Value of Pool Prices



The reason that there is a relationship between pool prices and natural gas prices is that historically in Alberta the marginal unit (price setting unit), particularly in on-peak hours, was fueled by natural gas. The major component of the variable cost of a gas-fired unit is the cost of natural gas. Depending on the technology and other factors, the efficiency of gas-fired units ranges from about 6 to 18 GJ/MWh. Alberta has very few of the older inefficient generators with high heat rates. Most of the current fleet is in the range from 6 to 10 GJ/MWh. Whilst generators cannot be expected to produce at prices that simply cover their variable costs, when the system has plenty of spare capacity on line prices will often settle close to the variable cost of production of the marginal unit. Typically as the market gets tighter, meaning less spare capacity on line, we observe greater mark-ups above variable cost. In recent years and especially in 2011, we have observed greater mark-ups than before and this has contributed to the degradation of the correlation between the cost of natural gas and pool price.

Figure 1.3: Pool Price and AECO Gas Price

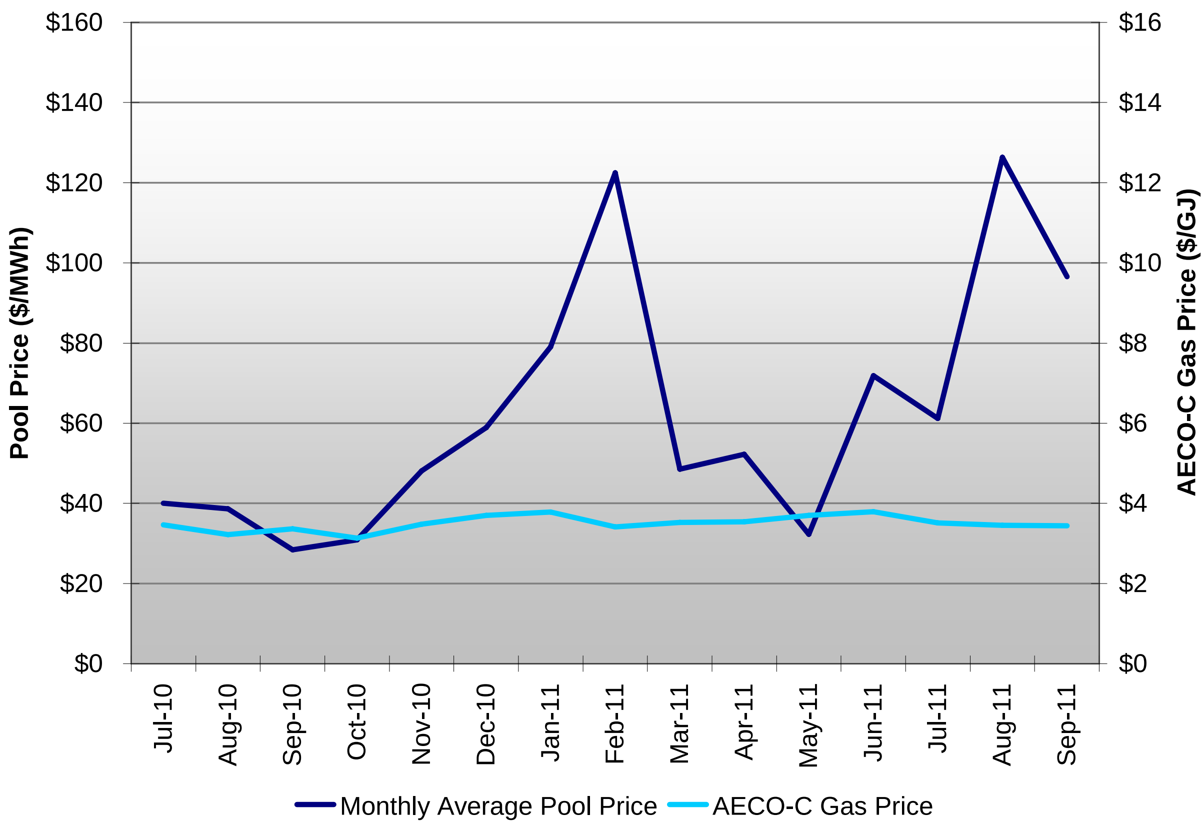


Figure 1.4: Historical Market Heat Rates in Alberta

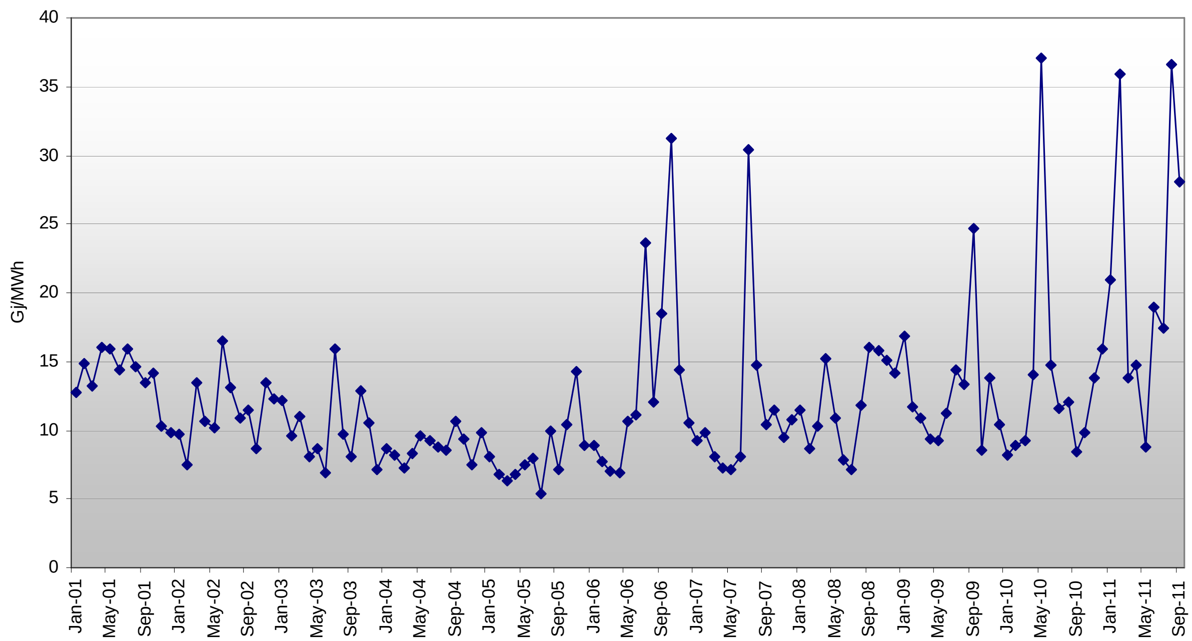
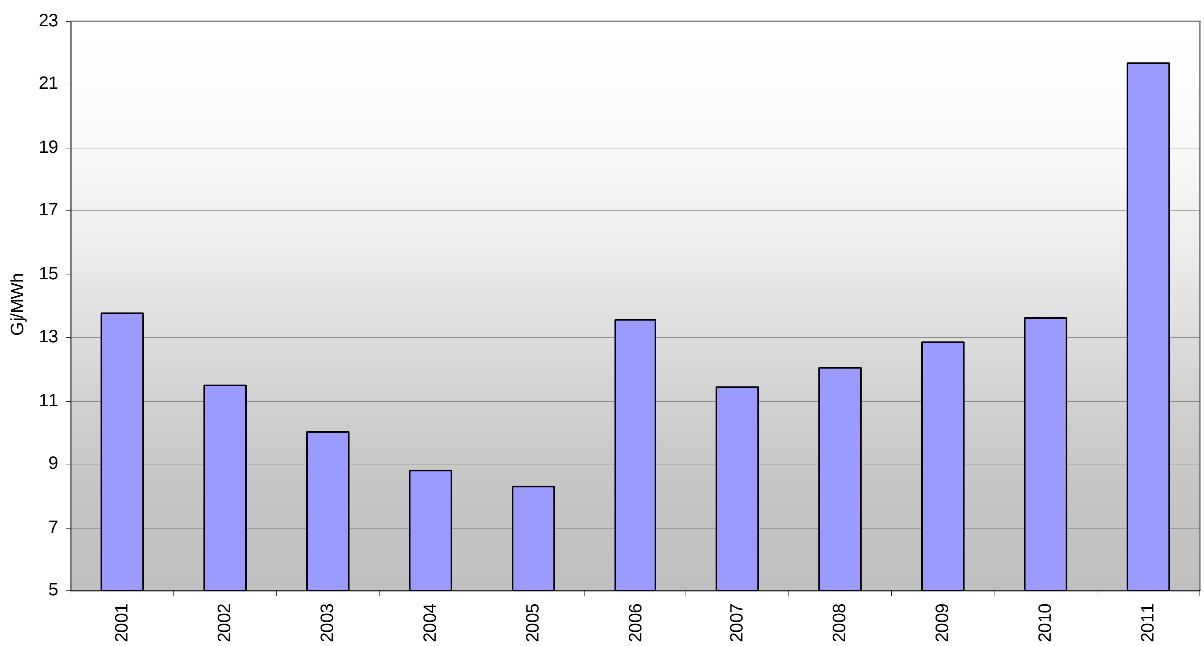
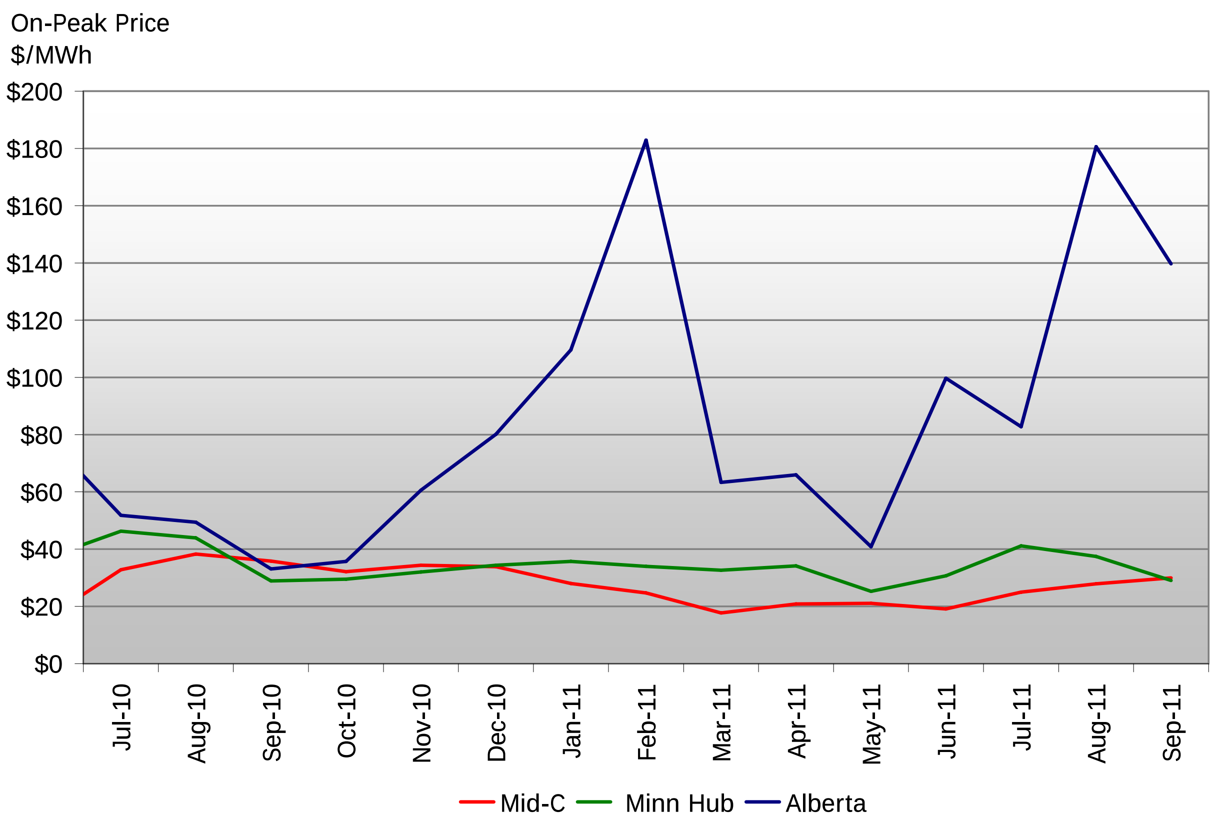


Figure 1.5: Historical Annual Market Heat Rates



The remarkably high Alberta on-peak market heat rate is not in line with regional values. Figure 1.6 shows how high Alberta on-peak prices have been relative to our neighbours in Mid-C and MISO. [2] This arbitrage opportunity naturally encouraged significant volumes of imports in Q3/11 and our limited intertie capacity was well subscribed. This quarter Alberta imported some 860 GWh, equivalent to an average of 390 MW and almost the same amount as in Q2/11.

Figure 1.6: On-Peak Prices in Neighbouring Markets



There was little change to system capacity (Maximum Capability) in Q3/11. Keephills #3 continued its commissioning work and the plant appears to be in commercial production as of the end of October. Plant availability in Q3/11 was higher than Q2/11 with average available capacity of 8,824 MW vs. 8,512 MW, with increased availability in both the coal and gas fuelled fleets (See Table B.1). Generation was also up quarter over quarter, but only by a modest amount.

[2] Note that the posted prices in these markets do not include all applicable costs to be directly comparable to Alberta's pool price. IPPSA recently commissioned a study comparing regional electricity prices and the report can be found at www.IPPSA.com.

2 Monitoring Indices

Monitoring indices are data summaries the MSA uses to flag apparent anomalous market outcomes or report on the competitive health of the market for further assessment now, or in the future.

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

In the Q1/11 report, we described a detailed methodology for analysis of the undispatched MW in the merit order. This is termed an output gap analysis. In the cases where market prices are higher than the short-run costs of the generators, it is an analysis of economic withholding. To be clear, as explained in the MSA's *Offer Behaviour Enforcement Guidelines*, economic withholding by individual market participants is not proscribed under Alberta's market construct. However, identification and reporting of its occurrence contributes to stakeholders' understanding of market outcomes and also provides a record for the longer term assessment of the health of the market.

Before explaining and applying the output gap analysis to observed high-price and statistically unusual market outcomes, the next section summarizes the Q3/11 supply cushion and price data.

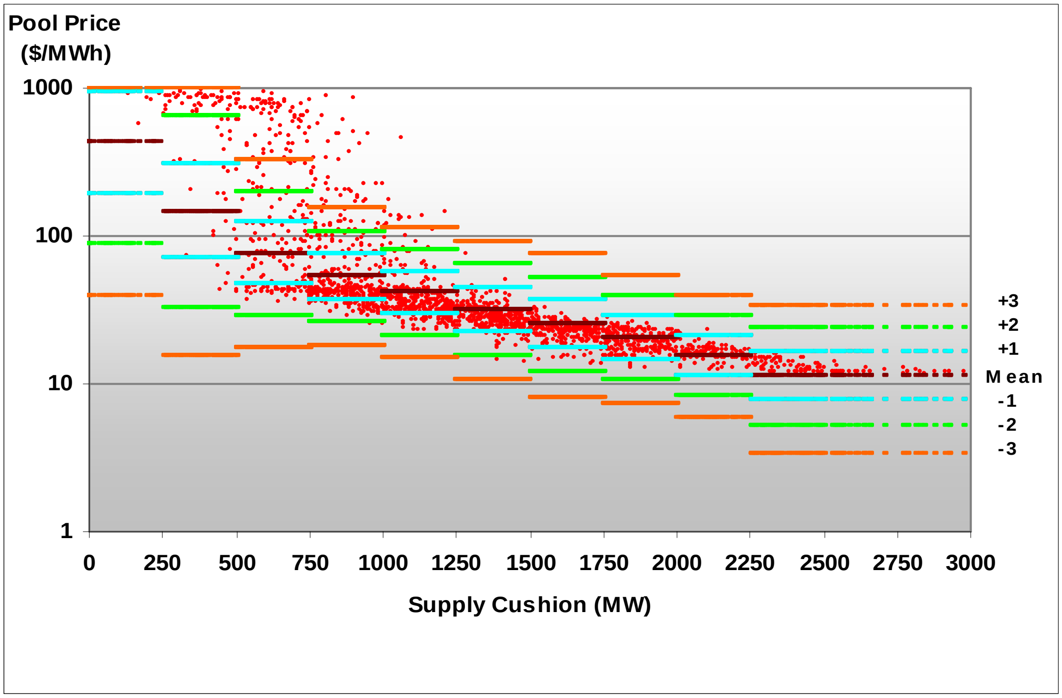
2.1 SUPPLY CUSHION ANALYSIS – Q3/11

In Q3/11, a total of 126 hours were observed when the pool prices were higher than 3 standard deviations above the mean established using the historical data.[3] No hours were observed when the pool prices were lower than -3 standard deviations. Similar to the previous quarters, the prices that were above +3 standard deviations concentrated in the hours when the supply cushion was in the range of 500 MW to 1000 MW. Of the 636 hours when the supply cushion was between 500 MW and 1000 MW, there were 114 hours in which the pool prices were above +3 standard deviations, counting for 18% of the total number of hours in the 500 MW to 1000 MW supply cushion range. If the historic data used to establish these bounds are from the normal distribution, less than 0.5% of the observations would be more than 3 standard deviations above the mean. The data observed in Q3/11 are largely in line with recent quarters.

Appendix F presents more details of the 126 hours identified above. Appendix G shows the parameters used to establish the various price points in Figure 2.1.

[3] For details on how the mean and standard deviations were calculated with the historical data, refer to MSA Quarterly Report for Q3/10.

Figure 2.1: Q3/11 Supply Cushion v. Pool Price (Confidence Bands Based on Historic Data)



	=<250	>250 <=500	>500 <=750	>750 <=1000	>1000 <=1250	>1250 <=1500	>1500 <=1750	>1750 <=2000	>2000 <=2250	>2250	Total
>=+3	0	0	75	39	12	0	0	0	0	0	126
<+3 & >=2	0	49	19	22	9	1	0	0	0	0	100
<+2 & >=1	19	10	19	30	20	2	1	0	3	0	104
<+1 & >=mean	9	6	35	34	51	72	56	90	76	112	541
<mean & >=-1	0	6	35	200	237	239	202	136	39	0	1094
<-1& >=-2	0	5	52	74	58	24	20	5	0	0	238
<-2& >=-3	0	0	0	2	0	2	0	0	0	0	4
<-3	0	0	0	0	0	0	0	0	0	0	0
Total	28	76	235	401	387	340	279	231	118	112	2207

2.2 OUTPUT GAP ANALYSIS – Q3/11

The output gap analysis calculates the market supply cushion by market participant, identifying the proportion of the supply cushion that is attributable to each market participant in a given hour. The theory and its application in our work were fully described in the MSA's Q1/11 report.

For Q3/11, with 126 hours to analyze, we have not done the manual adjustment of the assignment of control by market participants that was done in previous quarterly reports – there were simply too many hours. Table 2.1 shows the results of the unadjusted analysis for the Q3/11 events.

Table 2.1: Output Gap Analysis - Q3/11

Month	Count of Events	Average Price	Average SC	Average Share of Supply Cushion by Participant						
				A	B	C	D	E	Other	Average HHI
Jul-11	6	$529.74	580	30%	19%	29%	19%	0%	3%	3,640
Aug-11	80	$515.10	728	26%	15%	33%	16%	6%	4%	2,707
Sep-11	40	$462.59	791	27%	18%	40%	10%	1%	5%	3,234
Q3/11	126	$499.13	741	26%	16%	35%	15%	4%	4%	2,919

The most significant feature of Table 2.1 is the relative stability of the average market shares of each participant in each month. This suggests that none of the participants took long positions in some months and short positions in others. In previous quarterly reports, it was observed that some participants were behaving in a manner consistent with a position that was short in some months and long in others.

The distribution of the market shares by participant for the events in each month are shown in Figures 2.2, 2.3 & 2.4.

Figure 2.2: Output Gap Analysis - July 2011

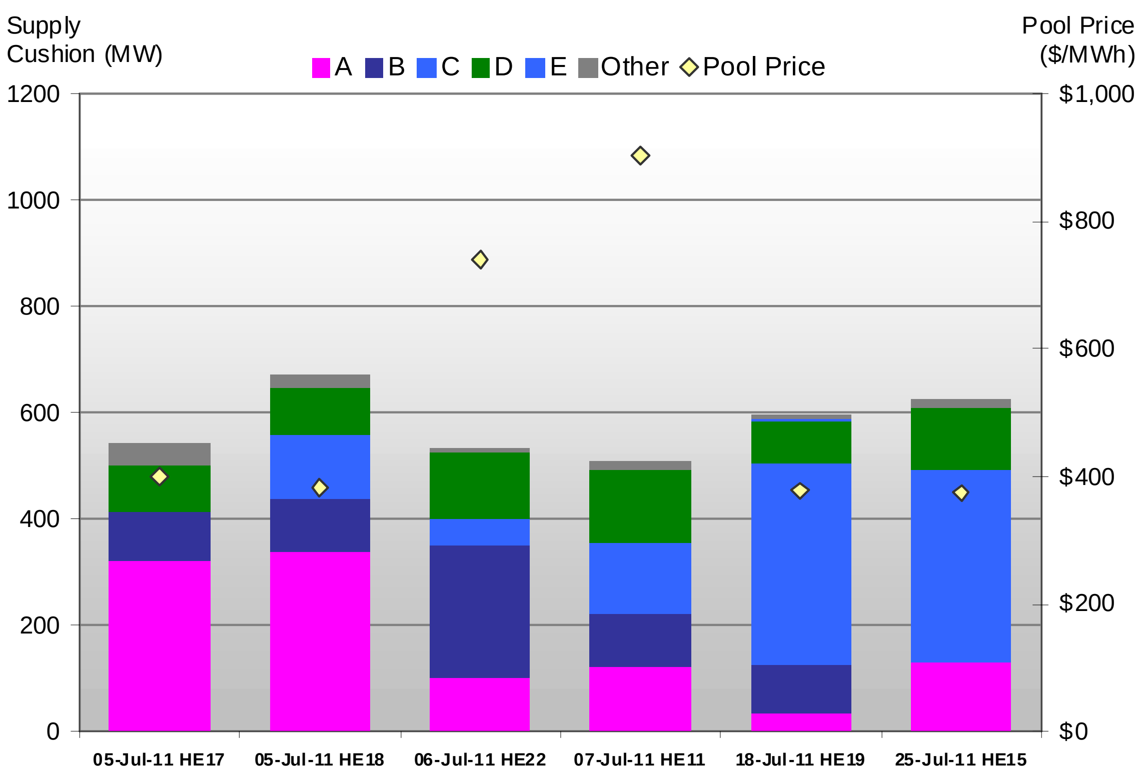


Figure 2.3: Outpute Gap Analysis - August 2011

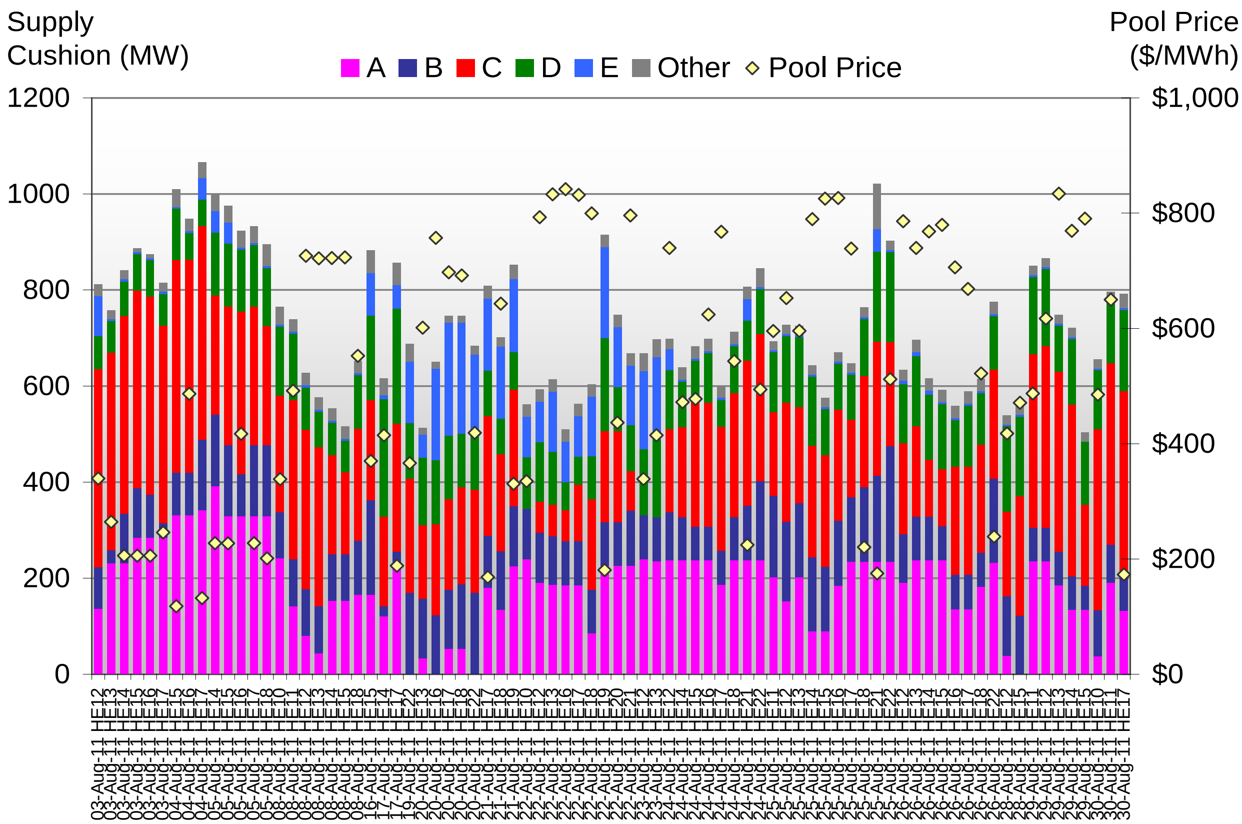
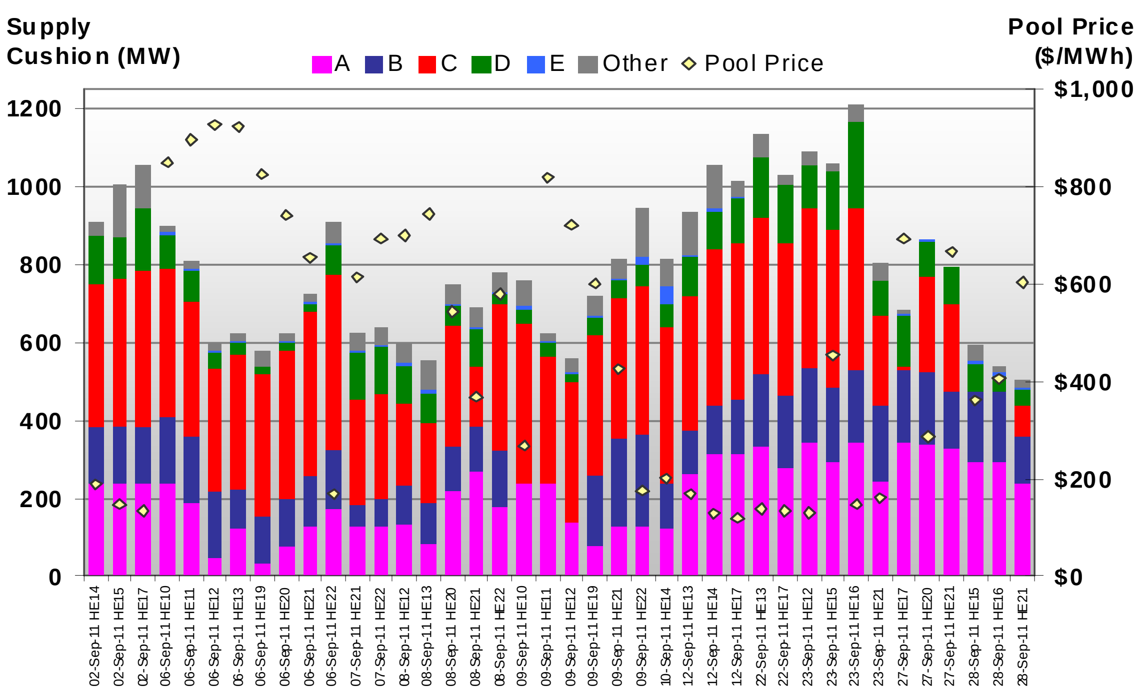


Figure 2.4: Output Gap Analysis - September 2011



2.3 SUMMARY OF >3STD EVENTS

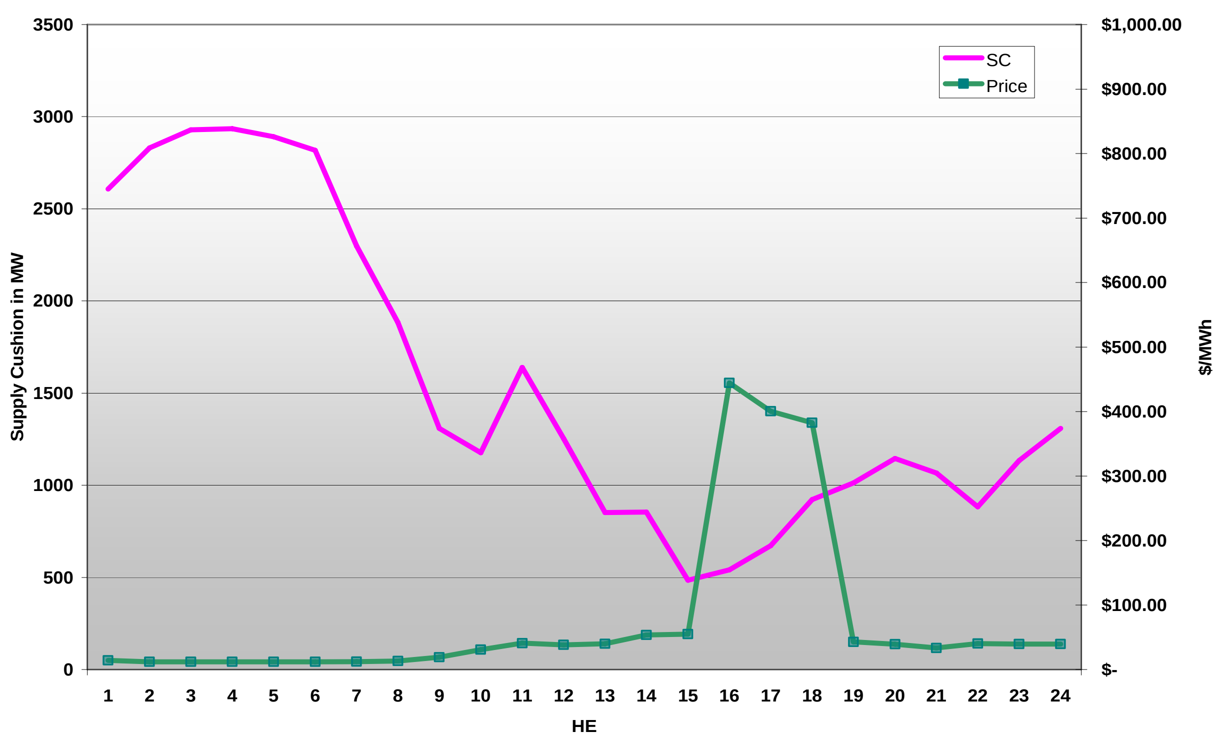
With 126 hours in Q3/11 identified as more than three standard deviations above the mean, it is impractical to provide a detailed assessment of each event. Rather, we have selected three days, one from each month in the quarter, for a detailed analysis. The detailed analysis looks at the dynamics of the events in the days in question and the primary forces driving the market outcomes. The results are considered typical of the dynamics that occurred on the remaining days but not analyzed herein.

2.3.1 July 5 (HE17 and HE18 >3StD)

Tuesday July 5 was expected to be a pleasant summer day; temperatures were forecasted to peak around 25 degrees Celsius and winds were expected to be light. The day-ahead forecasted peak demand was 8971 MW in HE16 while actual peak demand was some 300MW higher at 9,278 MW in HE15. The information day ahead suggested that there would be no issues with supply adequacy and that the supply cushion would not be low. The supply cushion over the peak hours on July 4 was about 1000 MW and similar conditions would have been anticipated for July 5. Figure 2.5 shows the supply cushion and pool price pairs for July 5.

By HE11, the offer curve for the morning of July 5 included ~800 MW priced above $100/MWh. This was down from 1000 MW in HE5 as generators adjusted their prices. In HE17 and HE18, Participant A's share of the supply cushion was nearly 60% (See Figure 2.2 and Appendix F).

Figure 2.5: Supply Cushion vs. Pool Price, July 5



HE13 - HE16

In the afternoon, the supply cushion tightened as a result of a reduction in offers. From HE13 to HE14 imports on the BC intertie reduced by 170 MW to 300 MW. Imports are offered at $0/MWh and in Figure 2.6 the change in these offers would appear as a shift to the left in the offer curve.

The supply cushion tightened further in HE16 when a major unit went on forced outage and had to be withdrawn from service. From HE15 to HE16 there is a further shift in the curve to the left as the generator was removed from service. Thus for the same level of demand one would expect an increase in pool price. In HE15, for a demand of 9278 MW pool price cleared at $54.97/MWh. In HE16, for a demand level of 9260 MW, 27 MW less than HE15, pool price cleared at $444.43/MWh.

Figure 2.6: Offer Curve for HE12 to HE16, July 5

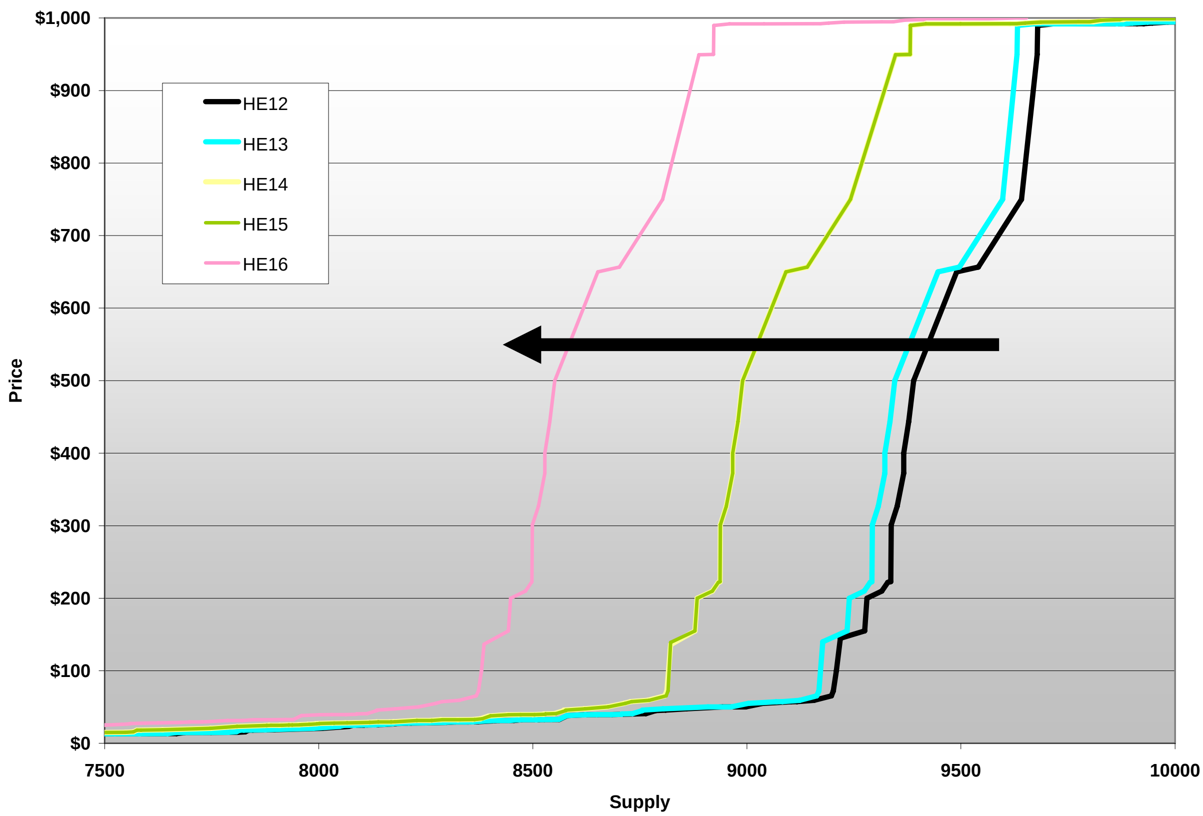
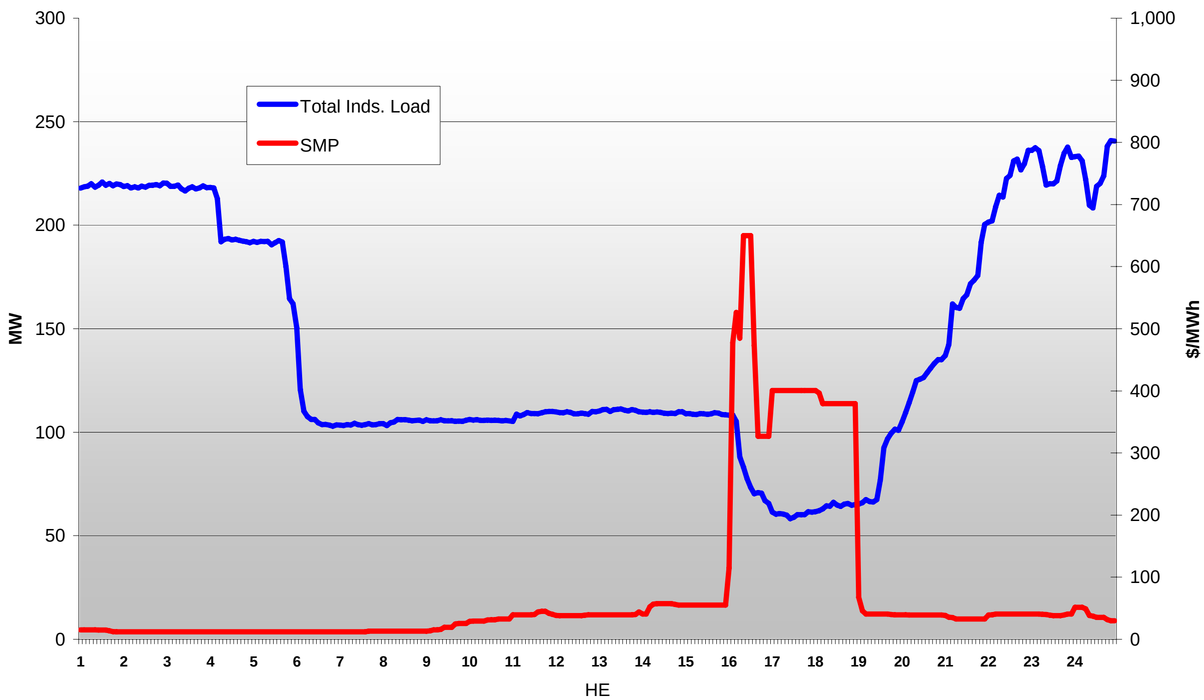


Figure 2.7 shows the total consumption of known price responsive loads in Alberta versus the System Marginal Price (SMP) for July 5. It appears that a major load took an outage for the day as its consumption dropped from ~120 MW to 7 MW for the peak hours. Prices spiked in HE16 due to the loss of the large generator, the remaining price responsive load immediately reacted to the price spike and curtailed ~55 MW. If these loads had not curtailed, all else equal, the peak price of $650/MWh would have been $750/MWh, a reflection of how steep the merit order was at such high price levels.

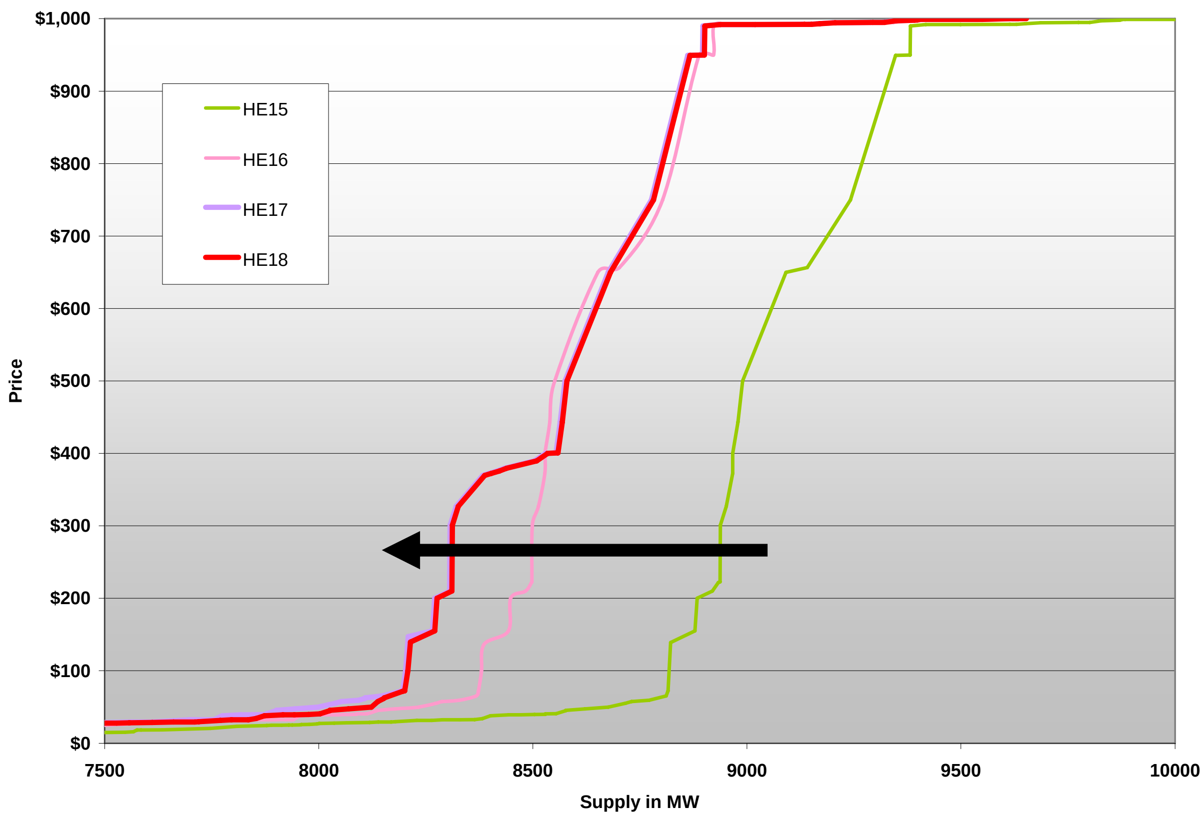
Figure 2.7: Price Responsive Load vs. SMP, July 5



HE16 - HE18

Participant C priced up about 150 MW in HE17 and HE18 as the lower end of the offer curve further shifted to the left (see Figure 2.8). Although Participant C could not have anticipated the forced outage in HE 16, they could foresee the high demand in HE17 and HE18. The offers spanned a price range of ~$25/MWh, so effectively a ledge was built at ~$400/MWh that, as load dropped, prices would remain elevated until the load reduction was greater than 150 MW. The combination of ~600 MW of generation already priced up and the addition of a further 150 MW was sufficient to create pool prices in HE17 and HE18 that were exceptional for the amount of supply cushion available.

Figure 2.8: Offer Curve for HE15 to HE18, July 5



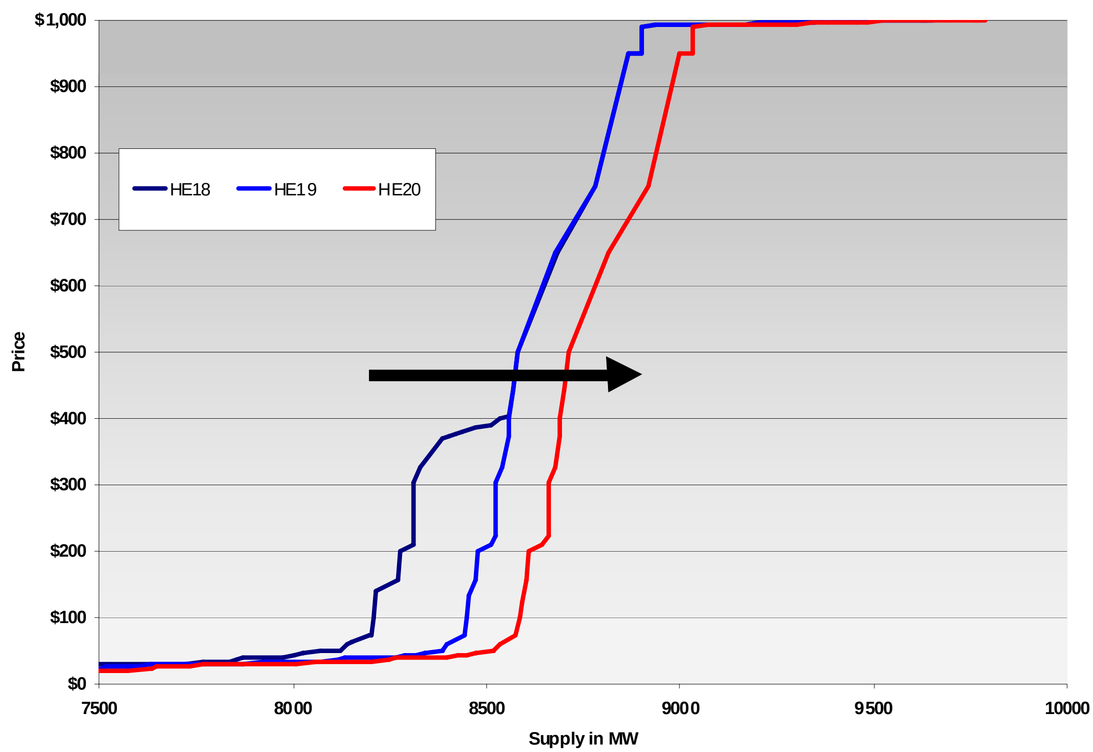
On the BC intertie, 275 MW (plus 80 MW of reserves) were imported in HE17 and HE18, while there were no imports from Saskatchewan. The fact that both interties were not full testifies to the fact that the high prices were not readily identifiable by importers.

Absent the forced outage of a significant size unit, the pricing up would not have been rewarded and prices would have settled at about $50/MWh.

HE19 - HE20

Participant C that had created the ledge in HE17 and HE18 at ~$400/MWh, reduced the offers closer to variable cost in HE19 (see Figure 2.9). The offer curve shifted to the right and prices fell to ~$40/MWh. Participant C would have anticipated that demand would fall in HE19 (it had been forecasted to fall 200 MW, the actual reduction was 170 MW). The energy blocks would have fallen out of merit if the price had not been reduced.

Figure 2.9: Offer Curve for HE18 to HE20, July 5



2.3.2 August 4 (HE15 to HE17 >3StD)

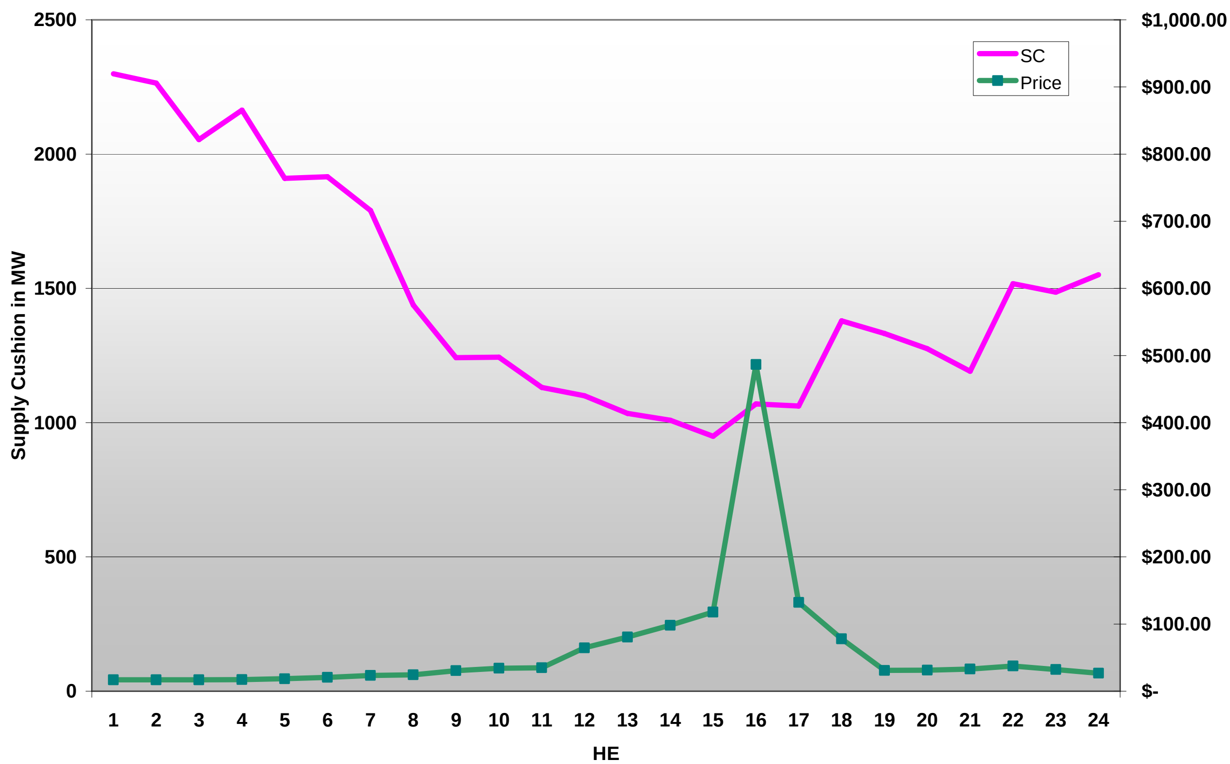
August 4 was expected to be a warm day with a high temperature of 23 degrees Celsius. The day-ahead forecast peak demand was 9080 MW and anticipated to occur in HE16. Actual peak demand was 9275 MW occurring in HE15, and was close to the Alberta record summer peak demand of 9552 MW.

No major generator outages were expected, although the Saskatchewan intertie was limited to 30 MW due to an ongoing transmission outage within Saskatchewan. Common to many summer days, winds were forecasted to be light and wind generation was less than 30 MW during the on-peak hours.

Based on available information, the lowest level of supply cushion was expected to be ~1000 MW. In other words, the total amount of available energy to the Alberta market was expected to exceed demand by at least 1000 MW in all hours. The significance of this is that attempts to increase pool price by economic withholding are generally less successful if the supply cushion is greater than about 1000 MW.

Figure 2.10 shows the actual supply cushion values and corresponding pool prices for August 4, 2011. Note that the lowest levels of supply cushion are slightly below 1000 MW. The high price of the day was $486.82/MWh and occurred in HE16 where the supply cushion was 949 MW.

Figure 2.10: Supply Cushion vs. Pool Price, August 4

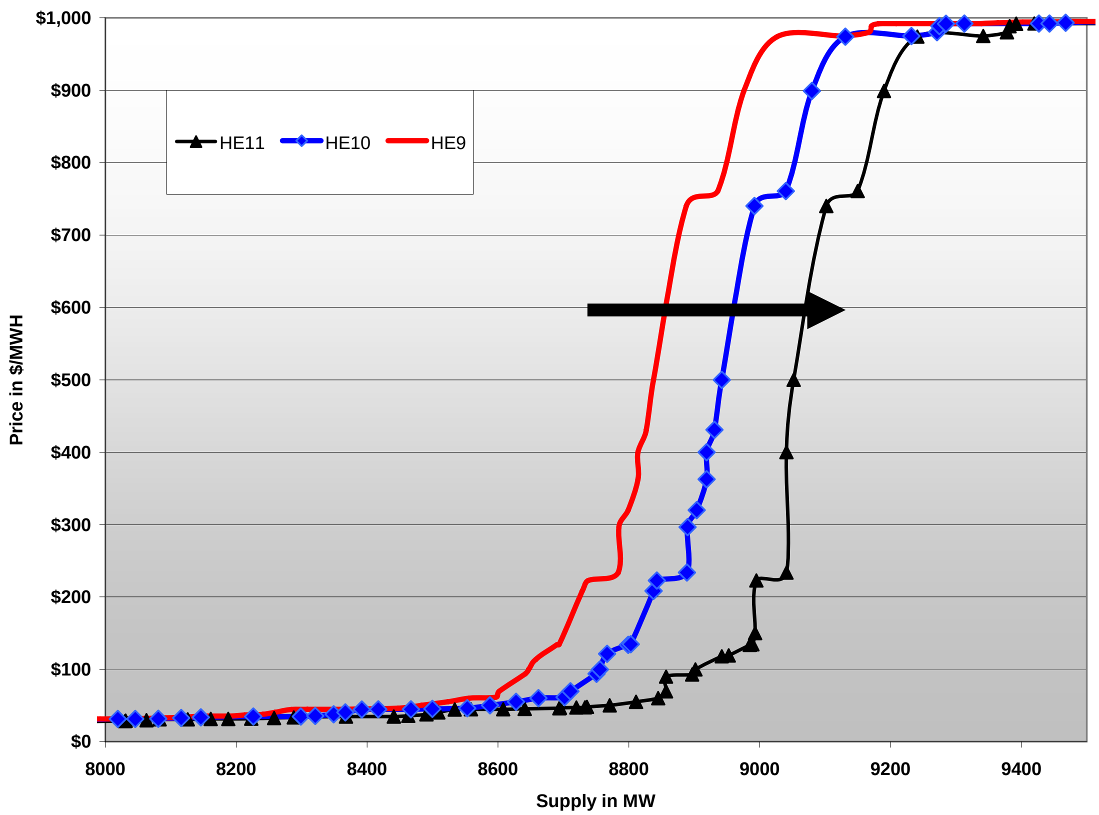


At first glance, a price spike seemed unlikely given the high supply cushion. From a review of the day, prices spiked primarily due to pricing up by four internal generators.

HE9 - HE11

In the morning hours demand rose and at the same time BC imports increased from 250 MW to 415 MW by HE11 (imports are all priced at $0/MWh) and a large commissioning unit increased its output from 221 MW to 345 MW (all offers at $0/MWh in the commissioning phase). There was an increase in availability of approximately 240 MW. As can be seen in Figure 2.11, the offer curve shifted to the right so that, for a similar level of demand, price would be lower.

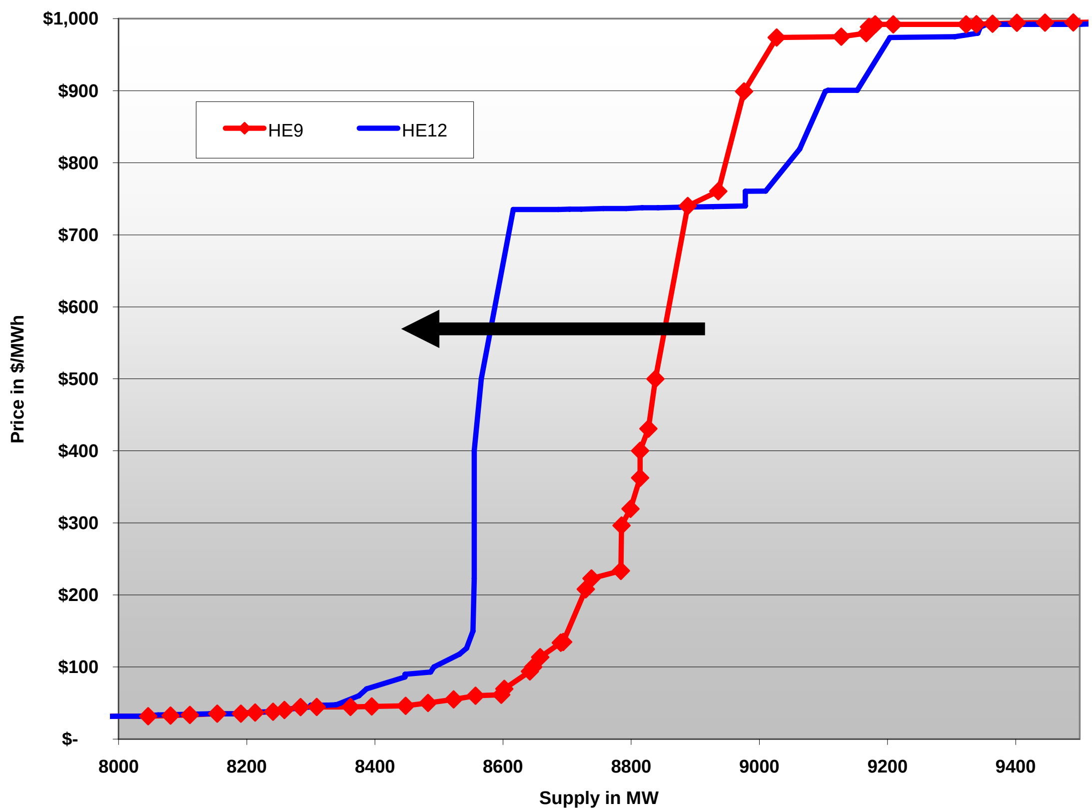
Figure 2.11: Offer Curve for HE9 to HE11, August 4



HE12

In HE 12, as can be seen in Figure 2.12 there was a major change in the offer curve as Participant C raised the offer prices of 373 MW from below $46.27/MWh to prices close to $735/MWh. Upon reviewing the offer curve for HE9, it can be seen that there was a 'ledge' at $740/MWh of approximately 50 MW (see Figure 2.11). Below the ledge, the offer curve was very steep. It would appear that the participant used that ledge as guidance as to where it could shadow price in the most profitable manner. It priced just below its competitor by as little as $0.73/MWh. The changes were such that for a similar level of demand one would expect price to be higher. Price rose in HE12 to $64.68/MWh while demand increased 93 MW from the previous hour.

Figure 2.12: Offer Curve for HE9 and HE12, August 4



HE16

In HE16, the offer price of 60 MW was raised from $80.02/MWh to $689.16/MWh. The highest pool price was $486.82/MWh and occurred in HE16 whilst the highest demand of 9275 MW was in HE15. As can be seen in Figure 2.13, the offer curve continued to shift slightly to the right, meaning that for a similar demand one would expect higher prices. From HE14 to HE16 system demand reduced by 22 MW but prices increased. Price responsive load began to react to increasing prices in HE14 with a reduction of 27 MW in response to the pool price of $118/MWh (see Figure 2.14). Subsequently, as the SMP reached $689.16 the responsive load reduced a further 118 MW. As on July 5, the effect of the curtailment of the load was to mitigate pool price increases by a significant amount due to the steepness of the merit order.

Figure 2.13: Offer Curve for HE14 to HE16, August 4

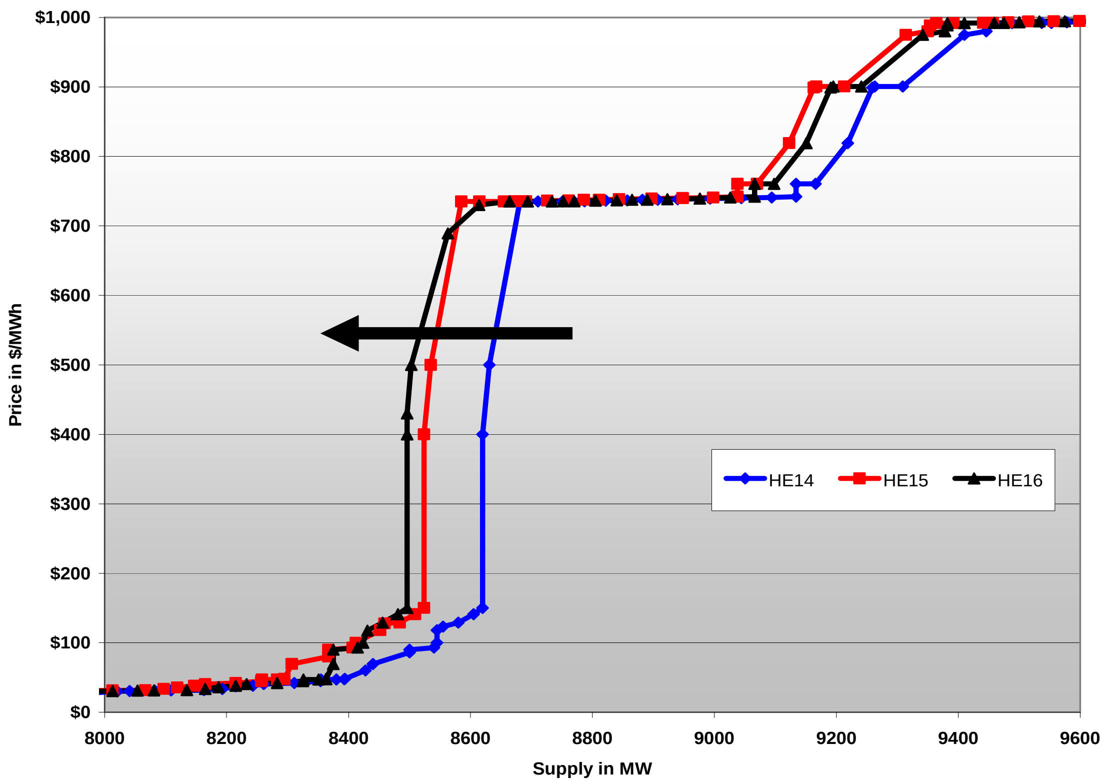
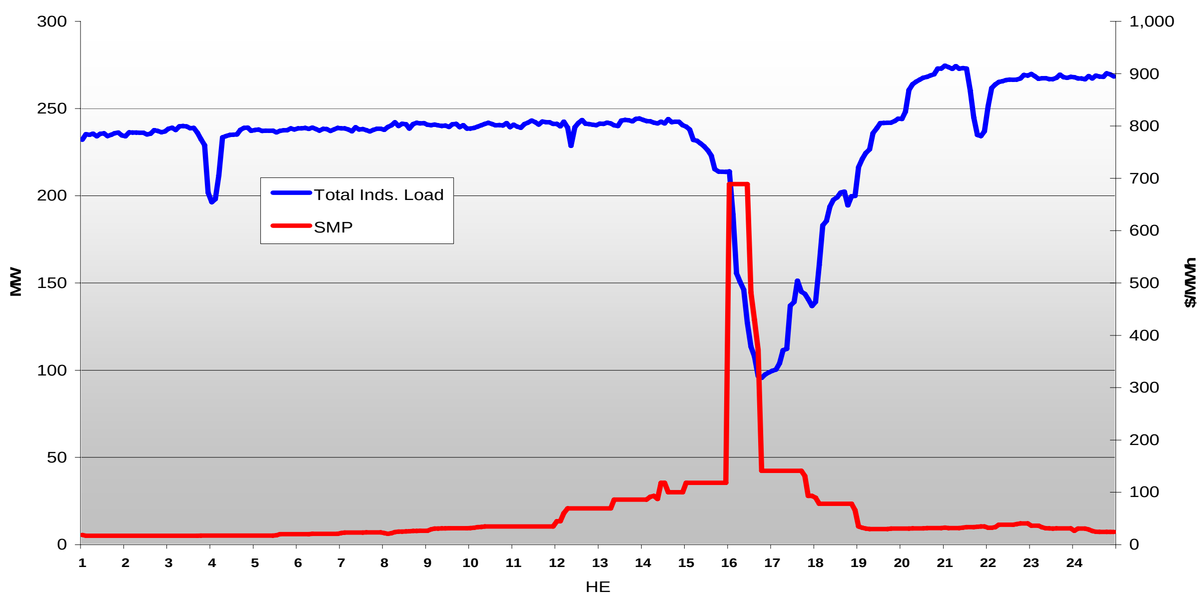


Figure 2.14: Price Responsive Load vs. SMP, August 4



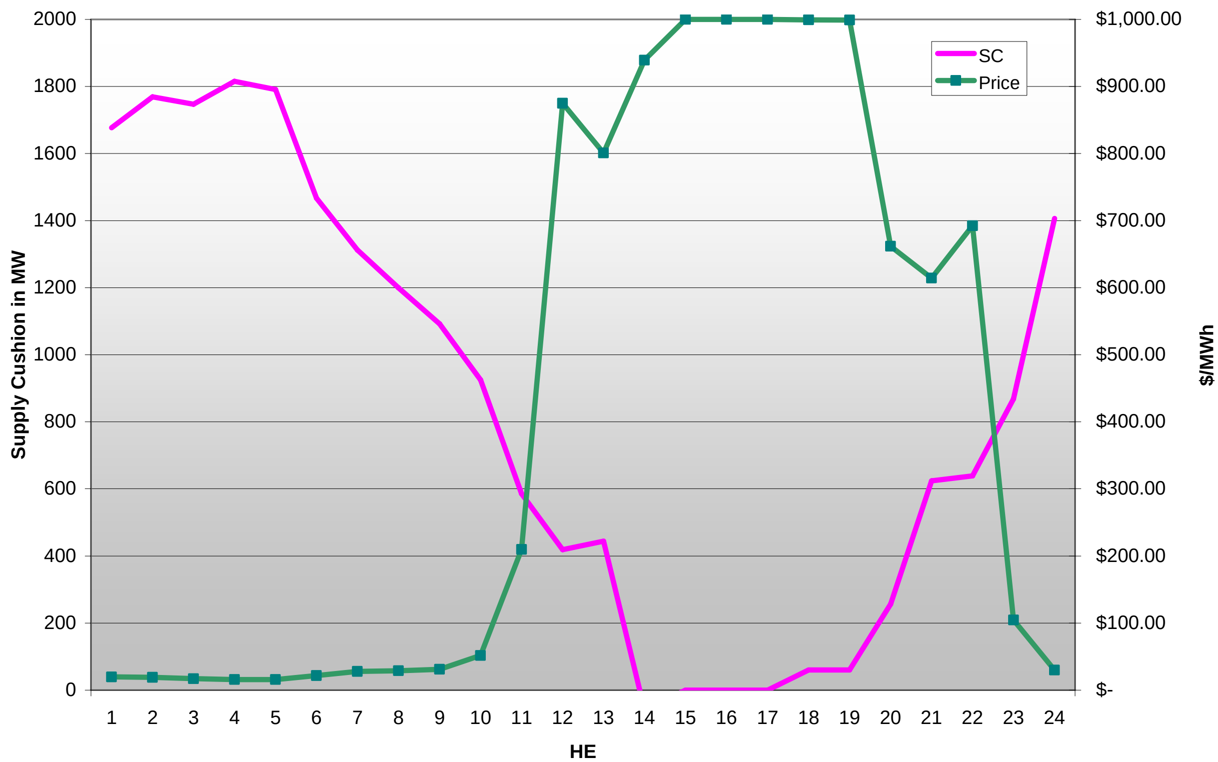
2.3.3 September 7 (HE21 & HE22 >3StD)

September 7 was expected to be a high priced day. The average pool price on September 6 was $439.14/MWh and September 7 was forecast to be a hotter day; temperatures in Calgary reached a high of over 27 degrees Celsius.

Demand had peaked at 9,249 MW in HE17 on September 6 and was forecasted to be slightly higher at 9300 MW in HE17 on September 7. Overall, September 6 seemed to be an analog for September 7 with an expectation of high pool prices.

As shown in Figure 2.15, the supply cushion tightened through the morning and early afternoon to a point where the cushion for HE14 through HE17 was effectively 0 MW. The average pool price for the day was $423.92/MWh, similar to that for the previous day. Peak pool price was $999.99/MWh in HE15, HE16 and HE17 consistent with the 0 MW supply cushion.

Figure 2.15: Supply Cushion vs. Pool Price, September 7



HE9 - HE12

By HE9 there were roughly 850 MW priced above $100/MWh in the offer curve based on the expectation of higher prices through the day. In HE12 the offer curve shifted to the left as ~200 MW priced lower to be in merit (see Figure 2.16). At the same time, as can be seen in Figure 2.17, price responsive load began to reduce its demand by close to 200 MW by HE12. Without the price responsive demand, pool price could have been ~$450/MWh whereas the actual price was $213.29/MWh – again a demonstration of the steepness of the merit order.

Figure 2.16: Offer Curve for HE9 to HE12, September 7

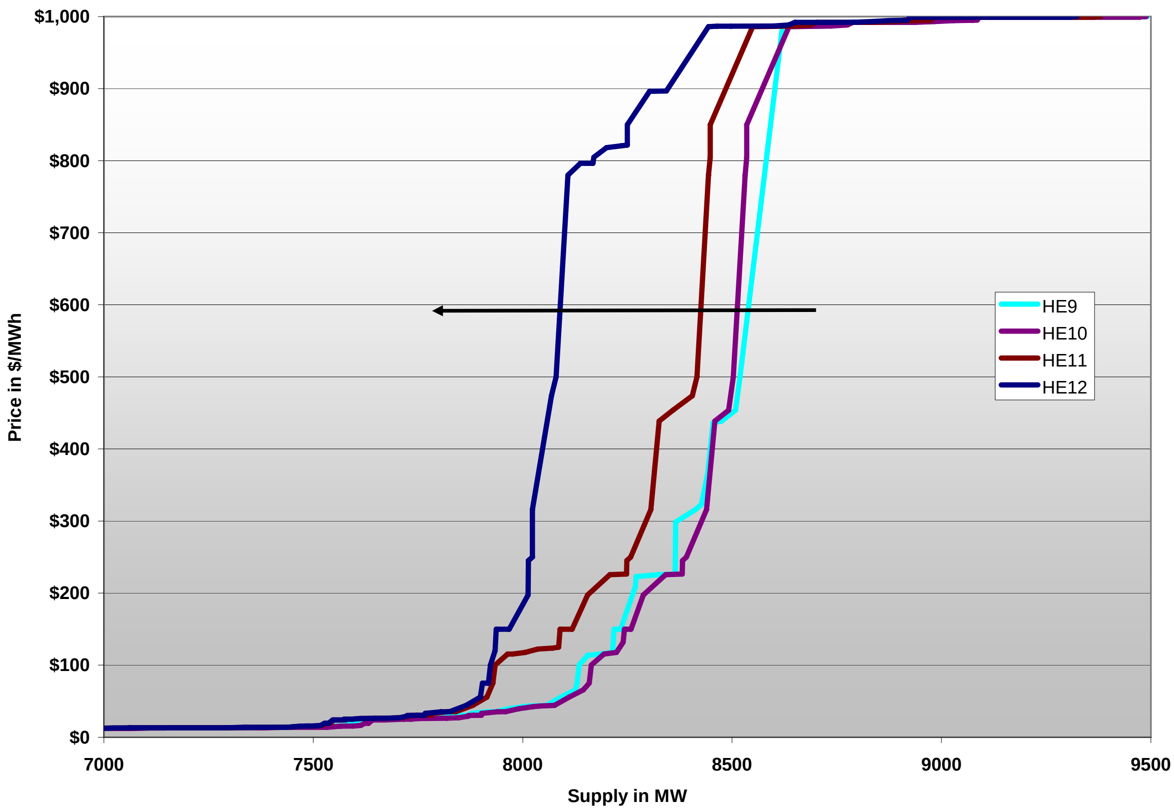
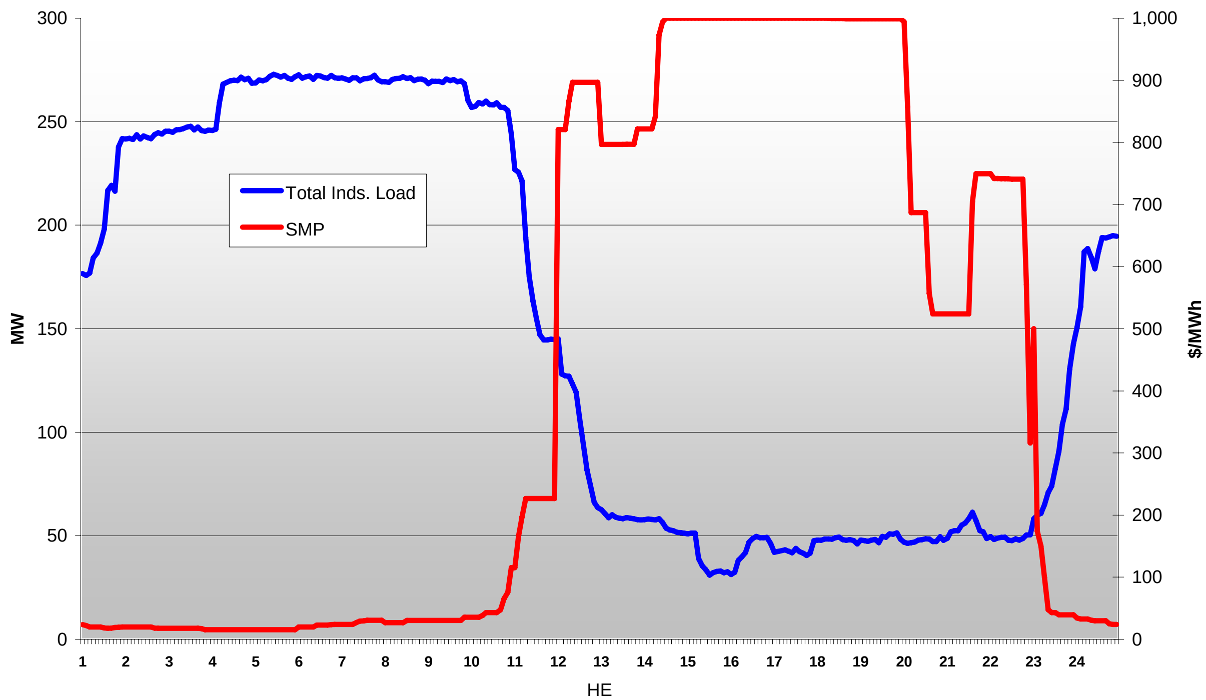


Figure 2.17: Price Responsive Load vs. SMP, September 7



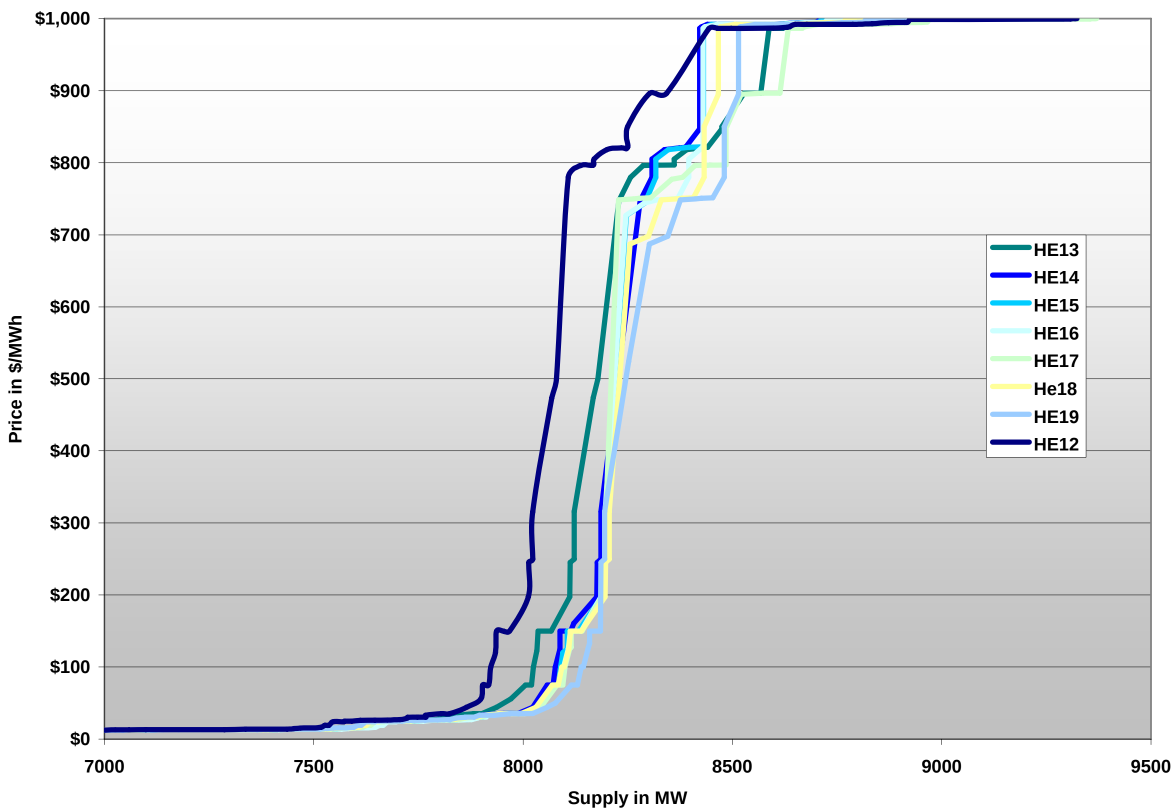
HE13 - HE19

In HE13 close to 200 MW were added to the lower priced part of the merit order – a combination of volume that had been priced very high plus some new offers. When a participant lowers the offer prices on some of its portfolio, the hope is to increase profits by maximizing generation, even though the pool price might be somewhat lower. In this case, while demand increased 29 MW between HE12 and HE13, pool price actually fell from $875.08/MWh to $800.80/MWh. Without the lowering of the offer prices the pool price would have been ~$900/MWh.

In HE14 two generators were derated by a total of 260 MW; this capacity had been offered at ~$800/MWh and the loss caused the upper portion of the HE13 curve to shift to the left. At the same time, a 58 MW gas fired generator went on outage. By 13:26, the AESO had declared an Energy Emergency Alert 1, with all resources dispatched but sufficient operating reserve remaining. Prices reached $999.99 (the price cap) for the next 5 hours.

In HE17 the two units derated in HE14 returned to full service with 260 MW priced between $796/MWh and $999/MWh. The upper end of the offer curve for HE17 shifted to the right. For HE17 while demand increased by 24 MW pool price remained at $999.99/MWh, all generation was being dispatched.

Figure 2.18: Offer Curve for HE12 to HE19, September 7

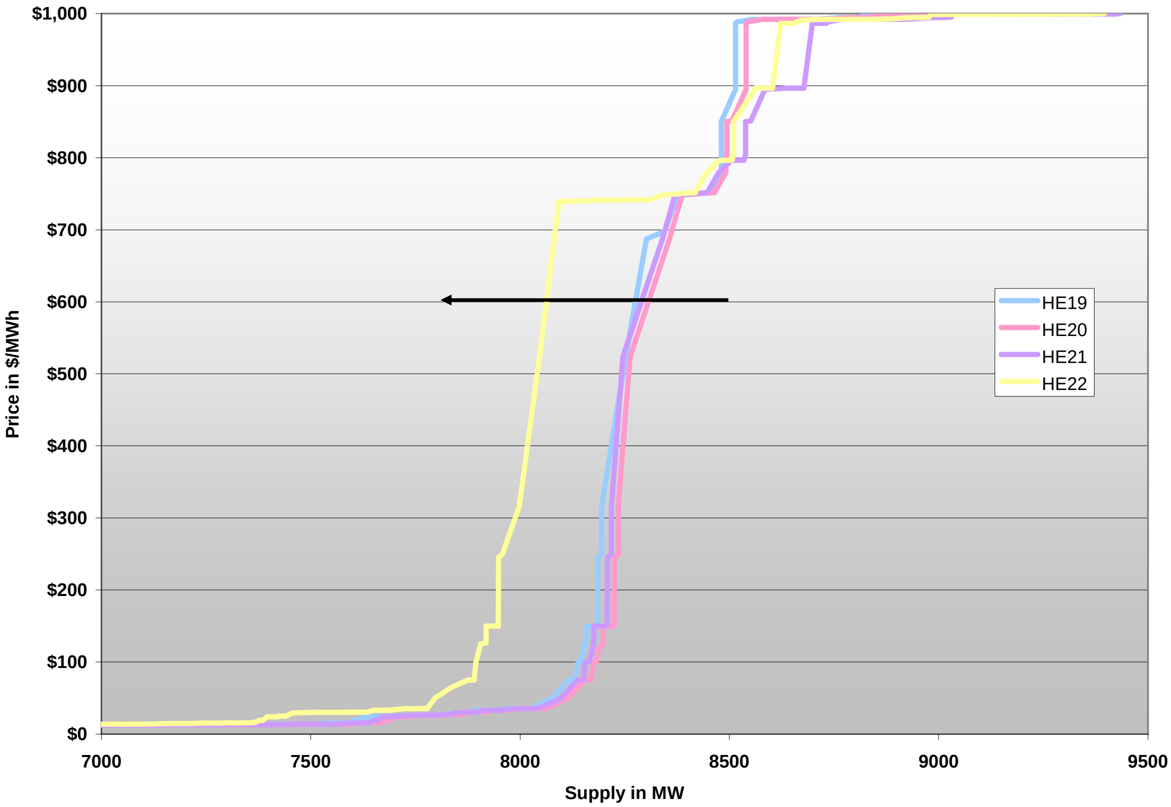


HE19 - HE22

In HE19 the supply cushion was 0 MW and price was $999.99/MWh. The two previously derated units were again derated by 256 MW in HE19 and HE20 (see Figure 2.19). By HE21 the supply cushion had increased to 624 MW primarily due to the recovery of supply. While supply cushion had increased, pool price remained high at $614.33/MWh representing a value >3StD. In HE22, while demand fell 154 MW, supply also fell by 58 MW and pool price settled at $692.41/MWh. This was in part driven by offering strategies.

By HE23 demand had fallen a further 460 MW and pool price fell to $104.52/MWh.

Figure 2.19: Offer Curve for HE19 to HE22, September 7



2.4 ANALYSIS OF POOL PRICES FOR Q1/11 THROUGH Q3/11

The quarterly reports in 2011 have commented on the persistent high number of outliers of pool price that are more than 3 standard deviations above the mean of the baseline period. With three quarters of data now available for 2011 it is possible to make a very preliminary assessment of the effects of the apparent change in market participant offer behaviour. A significant complication is that Sundance #1 & #2 went off line in late December 2010 and have not yet returned to service. Thus we have two effects occurring possibly simultaneously. The loss of Sundance #1 & #2 means that the supply cushion this year has been significantly smaller than it would have been otherwise. The observed change in offer behaviour means that for certain bands of supply cushion the level of pool price is higher than it was in the baseline period.

Table 2.2 shows the percentage distribution of pool prices in the different supply cushion bands for the first three quarters of 2011 as well as the values from the data used to construct the baseline statistics (February 2008 through June 2010). The first observation is that the frequency of smaller supply cushions (less than 1000 MW) is less in 2011 than over the baseline period despite the loss of Sundance #1 & #2. The average pool prices in the supply cushions at the lower (tighter) end of the range are much higher in 2011 leading to an average pool price of $76.29/MWh for 2011 to the end of Q3/11 compared with $66.56/MWh over the baseline period. In fact, in 2011 if pool prices had averaged similar to the baseline period for the given level of supply cushion the average would be $55.20/MWh, all else equal.

Table 2.2: Supply Cushion - Pool Price 2011 YTD vs Baseline

Supply Cushion Band (MW):	< 250	251 - 500	501 - 749	750 - 999	1000 - 1249	1250 - 1499	1500 - 1749	1750 - 1999	2000 - 2249	> 2250	Total
2011 YTD:											
No. Observations	87	256	732	1119	1247	1058	810	560	357	320	6546
Observations (%)	1.3	3.9	11.2	17.1	19.0	16.2	12.4	8.6	5.5	4.9	100
Mean Pool Price ($/MWh)	877.89	396.03	188.09	64.75	36.55	27.35	21.89	17.98	14.84	12.21	76.29
Baseline (2008 - 2010):											
No. Observations	355	1482	2928	4167	4078	3042	2109	1387	815	630	20993
Observations (%)	1.7	7.1	13.9	19.8	19.4	14.5	10.0	6.6	3.9	3.0	100
Mean Pool Price ($/MWh)	548.67	199.45	88.63	57.00	43.85	33.70	26.90	21.62	16.32	11.90	65.56

Some additional analysis was undertaken to see if the observed change in offer behaviour had been occurring gradually over the past several years. Figure 2.20 shows the duration curves for the supply cushions of recent years. It can be seen that 2008 was the year with greatest amount of tightness whilst the other three years are in a group. This is somewhat surprising given the loss of Sundance #1 & #2 - it was thought that the market would be tight in 2011. Whilst it is tighter than it would have been, it is similar to 2009 and 2010 in overall tightness.

Figure 2.20: Distribution Curves of Supply Cushion

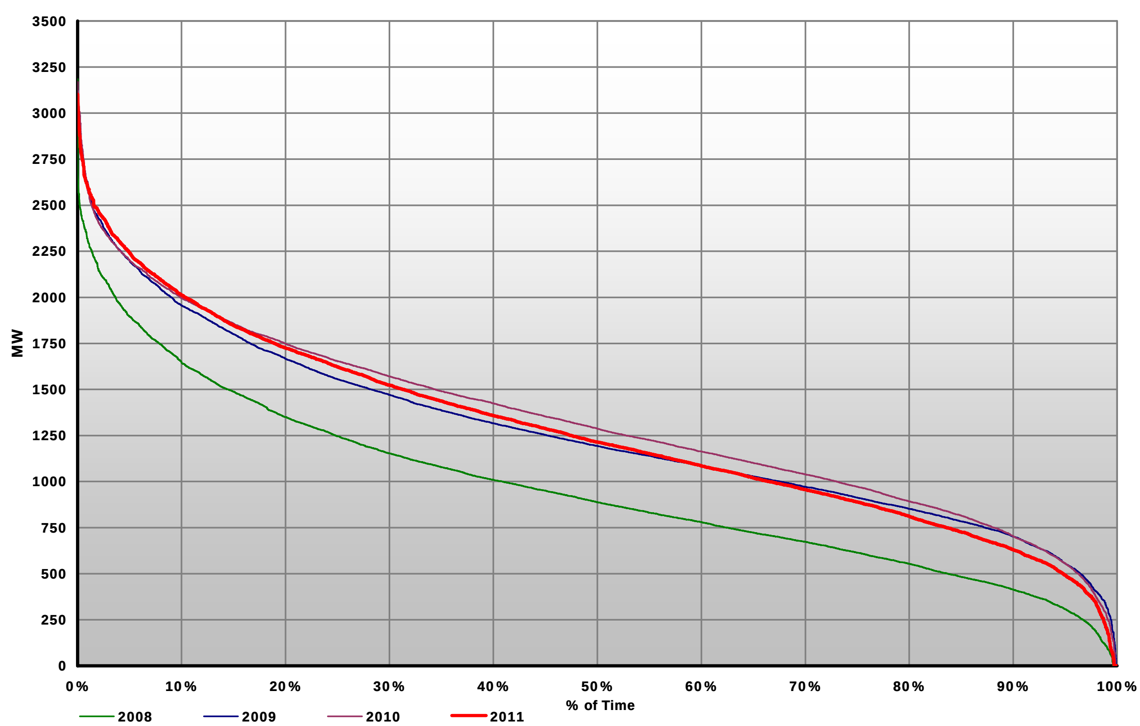


Table 2.3 shows the average prices of all the hours in each supply cushion band for each year. At higher supply cushion levels, the differences are small across the years and exhibit no systematic pattern. At the lower values of supply cushion, the bands covering supply cushion from 0 MW through 750 MW, the average prices in 2011 are much higher than in the other years. Further, whilst there may have been a

gradual increase of average price in each of the bands across years, the change from 2010 to 2011 is the most marked.

Table 2.3: Average Pool Price for Different Supply Cushion Bands

	=<250	>250 <=500	>500 <=750	>750 <=1000	>1000 <=1250	>1250 <=1500	>1500 <=1750	>1750 <=2000	>2000 <=2250	>2250
2008	488.54	185.08	95.29	65.46	49.87	36.64	28.22	23.41	14.76	10.38
2009	681.94	212.32	78.70	50.84	40.47	30.72	24.14	19.39	16.06	12.45
2010	622.81	235.80	81.13	57.65	42.77	33.51	28.01	22.94	18.67	13.44
2011	877.89	396.03	188.09	64.75	36.55	27.35	21.89	17.98	14.84	12.21

A tentative finding then is that the change in behaviour commented upon in the past several quarterly reports is mostly a shift in market participant behaviour from 2010 to 2011. Also, it appears that the change is a significant contributor to the overall level of pool price.

We draw no adverse conclusion from this finding and other observations about Q3/11 market outcomes with respect to our responsibilities to ensure a fair, efficient and openly competitive market. As stated in the MSA's *Offer Behaviour Enforcement Guidelines*, market participants are free to offer energy at whatever price level they choose, as long as they don't impede competition or collude with others.

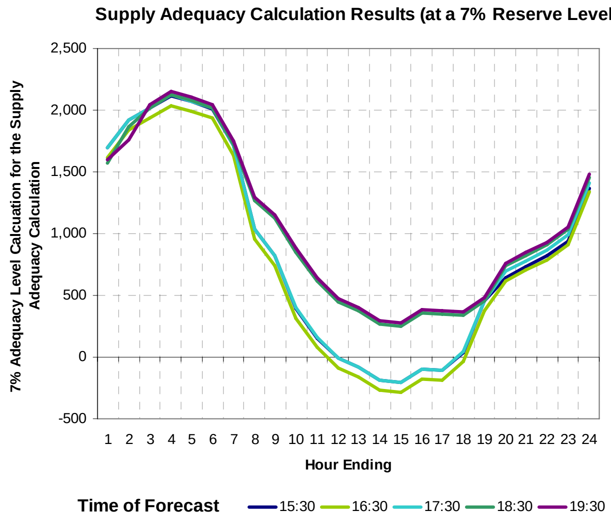
2.5 SCHEDULED GENERATION OUTAGE CANCELLATION

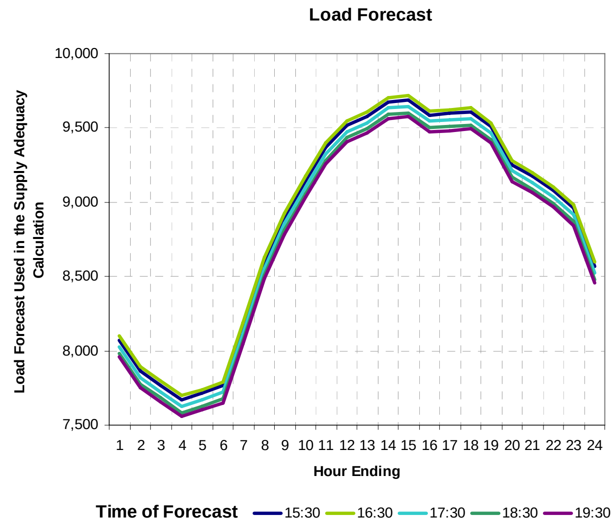
On August 21, 2011 the ISO cancelled a scheduled outage for August 22 for Keephills Unit #3 that was in its commissioning phase at the time. The process followed was as described in ISO rule 5.3.3. This is the first time that the ISO has issued such a directive and is thus newsworthy in its own right. The following description relies heavily on the Cancellation Report published shortly after the event.[4]

On August 21, the Supply Adequacy Report for the following day indicated there could be seven hours during which the market would be short of meeting 7% reserves by upwards of 250-300 MW due to high forecast demand and outages to three coal units. This assessment for August 22 is depicted in Figure 2.21 where it can be seen that the hours of potential shortfall are HE12 through HE18. Absent any mitigating action on the ISO's part, this could have resulted in operating reserves being used to balance supply and demand. A review of the August 22 merit orders showed that all Long Lead Time Energy as outlined in OPP 705 was fully offered into the market. In order to mitigate the shortfall to supply adequacy for August 22, the ISO proceeded under rule 5.3.3 and issued a directive to Keephills #3 to cancel its planned outage under its commissioning plan for August 22.

[4] Scheduled Generator Outage Cancellation Report.
http://www.aeso.ca/downloads/Scheduled_Generator_Outage_Cancellation_Report.pdf

Figure 2.21: Supply Adequacy Calculation Results (Source - AESO)





The outage at Keephills #3 was scheduled for August 22, HE10 through HE17, inclusive. With an MC value of 450 MW, this was sufficient to ameliorate the forecasted supply shortage. In the event, whilst August 22 was a high-priced day, higher than forecasted wind generation amounts mitigated some of the tightness although available capacity for dispatch reached a low of 427 MW. Absent the directive cancelling the outage an OPP 801 event would likely have ensued. When an owner has had a scheduled outage cancelled by the ISO in such circumstances they are entitled to compensation; essentially to cover any incremental costs caused by the directive. The ISO has informed the MSA that they did not receive an invoice from the owners of Keephills #3 unit, indicating that the owners had no incremental costs that were not recovered from the market.

The ability to cancel or modify a scheduled generator outage is a tool that the ISO is understandably reluctant to use except when reliability may be clearly compromised without such an action. It appears that this case was one where the action was warranted. The size of Keephills #3 (450 MW) and the close overlap of the timing of the scheduled outage to the forecast shortage made it a logical choice. The decision was taken the day before the outage was to occur. That makes sense in that the need for the action is most clear when the lead time is short. Since the use of forecasts is necessary, using shorter lead times tends to improve accuracy. The current short-term adequacy assessment has some components that are not forecast, per se, but rather a single average or notional amount is assumed. For example no wind forecast is available for use in the assessment at the present time. There are a number of areas in the Alberta market where forecasting will play an increasingly important role. Examples include price forecasts that enable load shed service (LSSi) providers to make efficient commitment decisions.

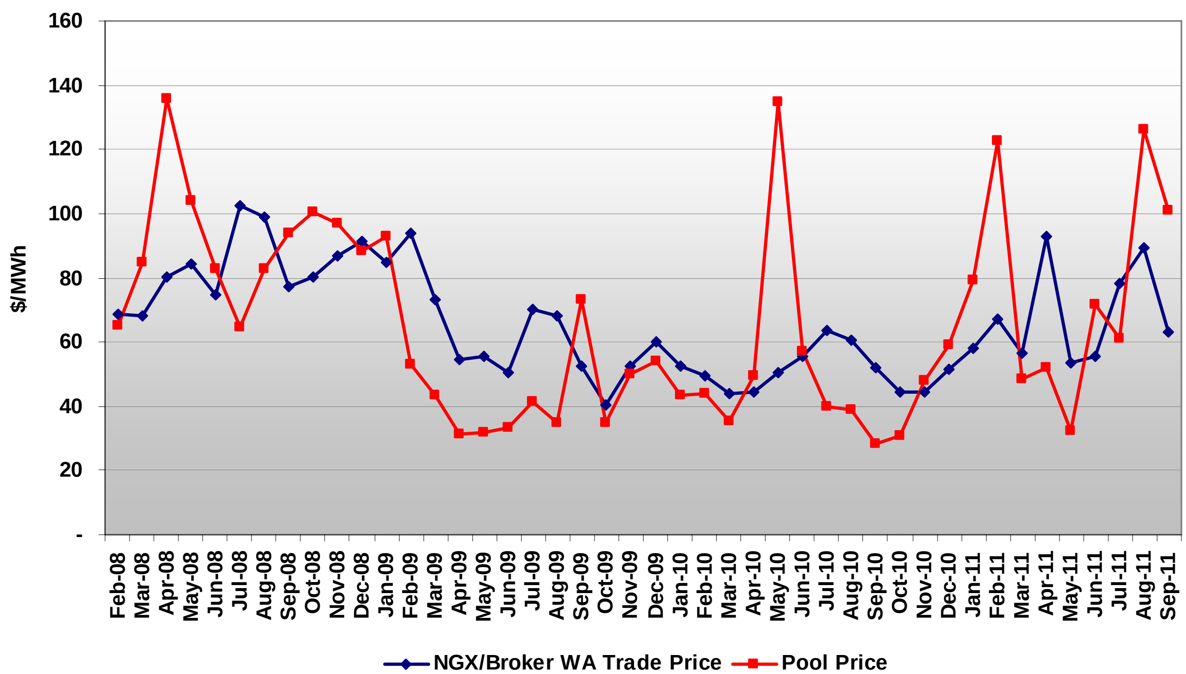
Generally, the Alberta market model relies on market forces to yield efficient outcomes in terms of the overall scheduling of generator outages. We are doing further work to satisfy ourselves that the pool price continues to promote efficient scheduling of planned outages and is not being muted by considerations of portfolio economics.

3 Impact of Market News on Forward Market Prices

Loads and generators that want price certainty can trade energy in the forward market. The forward market trades on expected (real time) pool prices which in turn are influenced by any news that affects the views of the buyers and sellers in the forward market – basically anything that impacts the tightness of supply and demand. The expectation is that with sufficient transparency of reliable information the forward market prices should be a reflection of the future pool prices. The MSA has commented on this many times in its quarterly reports and has provided examples of how the development of the forward price was influenced by market 'news'.

Figure 3.1 shows the monthly average pool prices and the NGX weighted average forward price for the month. The volatility of the forward prices is higher than that of the monthly average pool price. Since the start of 2008, the prompt month contract has averaged $65.82/MWh while the average monthly pool price was $65.40/MWh, a difference of $0.42/MWh (<1%). On average, at least, forward prices have been reflective of the real-time prices.

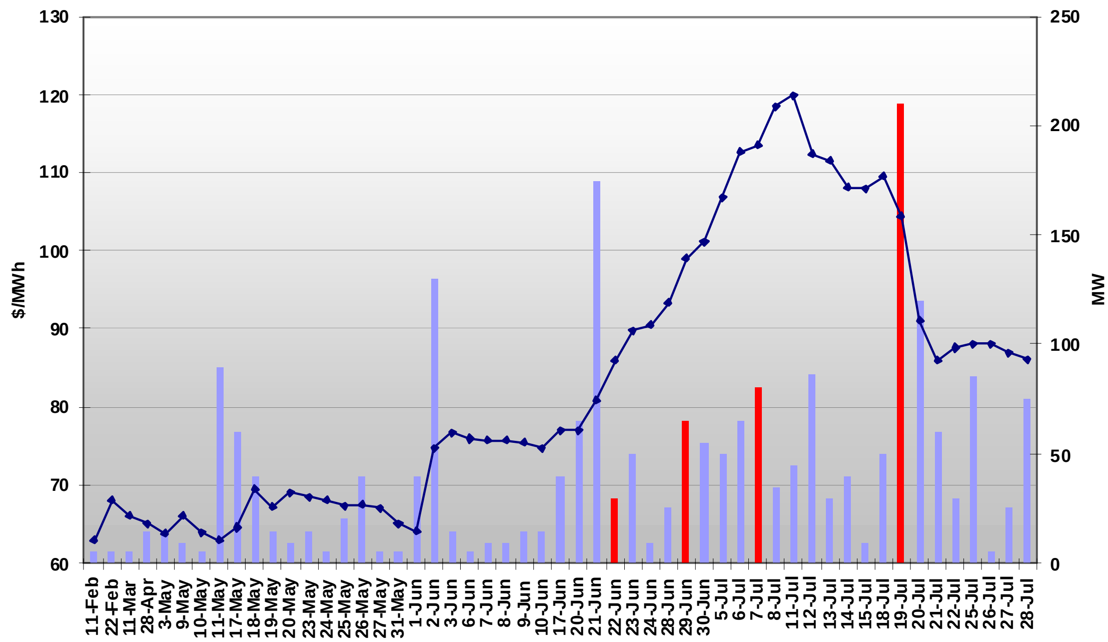
Figure 3.1: Monthly Pool Price vs. Forward Price (NGX RRO Index) – Feb. 2008 to Sept. 2011



In the last few months, the MSA observed several large price movements in the forward price related to 'news'. The news involved transmission and generation outages both of which impact the tightness of the supply demand balance and hence the forward views on market prices. Several price movements appeared to be due to a major transmission outage being scheduled into a month, later moved to another month and finally cancelled (deferred). The addition of scheduled generator outages, previously not in the outage plan, also caused significant price movements in this period.

Figure 3.2 shows the run-up in the price of the August flat contract. In February, the August contract was transacting at ~$65/MWh and as news of both transmission and generator outages was revealed to the market the price rose as high as $120/MWh by early July. Later news caused the August price to decline such that by the end of July the August contract was trading below $100/MWh. A portion of the later news was the movement of the 1201L transmission outage out of August.

Figure 3.2: August Flat Contract Price (NGX)[5]



Buyers of the prompt month contract, such as the RRO consumers, have expressed some concern that with the movements of the 1201L transmission outage they will have 'paid' three times in the RRO for the outage.

3.1 THE 1201L TRANSMISSION OUTAGE

1201L is the major 500 kV transmission line connecting British Columbia and Alberta. AltaLink, as the owner/operator, had planned that the line be taken out of service for maintenance from August 22 to September 2, 2011. With the line out of service the intertie capability is zero for commerce. Its removal from service is equivalent to more than the outage of the largest coal generator within Alberta and hence has a market price impact.

The interties with BC provide reliability benefits beyond the ability to flow energy for commerce. When a generator in the province has a sudden trip and its output goes to zero the first response is the intertie – effectively all of our neighbours in WECC increase their generation levels a small amount to compensate for the loss of generation here in Alberta. Alberta's own operating reserves then gradually take over and

[5] The red bars in the chart are associated with the EPCOR RRO Auctions

supply the 'missing' energy. With the 1201L line on maintenance the response from WECC is much more limited and ISO has to pay special attention to managing the system at such times.

The1201L outage overlapped with another long planned outage to an Altalink 138 kV transmission line, 170L, two outages that should not be scheduled to overlap. The ISO's Operating Policies would not allow both outages to proceed at the same time.[6]

3.2 COAL-FIRED GENERATOR OUTAGES

On June 21, 2011 two outages at coal-fired generators were scheduled into August.

While transmission outages are completely transparent to the market, generator outages have always been masked to protect the owners of the units being scheduled for maintenance. The degree of masking is a compromise between the needs of the market to formulate views on future market prices and the commercial concerns of the generators taking the outages. On June 21 the market became aware of significant generator outages impacting the market price in August. However the market was not privy to the precise details.

The scheduled outages feed into the ISO's monthly outage graph and become known to the market, albeit not in specific detail - two coal-fired units of about 400 MW were planned to be out for one week each and the outage graph indicated an average change for the month of 145 MW.

3.3 OUTAGE OBLIGATIONS OF THE ISO, GENERATORS AND TRANSMISSION FACILITY OWNERS

To better understand the issue of outages and their movement it is necessary to understand the responsibilities and authorities of the AESO, Generators and Transmitters in terms of communicating, scheduling and authorizing outages

3.3.1 Outage Reporting Obligations for Transmission

The ISO's OPP 601 Section 4.2 sets out the Transmission Facility Owners (TFO's) responsibilities to report on outages:

> TFOs must:
>
> • Provide outage schedules prior to February 15 of each year a schedule of all planned outages and live line work known at the time for its facilities operating at 69 kV

[6] According to discussions with the AESO and the public AESO communication of September 20, 2011 explaining why the 1201L outage had to be delayed:

Under the AESO's operating policies, if one of the 138kV intertie circuits (e.g. 170L) and 1201L are out of service at the same time, the Alberta Interconnected Electric System (AIES) must entirely separate from the WECC Interconnection. While coordinating the 1201L outage, the AESO has determined that, from a transmission reliability perspective, operating isolated from the WECC Interconnection for the periods October 3 - 6 and October 11 - 14 should be avoided as this could cause operational concerns on the B.C. electric system.

and above, identifying the quarter in which the work is expected to be carried out, paying particular attention to 240 kV facilities, and those facilities that provide interconnections with other balancing areas or interconnections to generation facilities.

- Provide to the ISO 30 days prior to the commencement of each operating week a preliminary schedule of planned outages and work notifications for transmission facility outages and live line work for such operating week, for facilities operating at 69 kV and above, which have been scheduled by the TFO. The TFOs will make reasonable effort to coordinate their outage schedules with interconnected facility owners and system access customers prior to submitting their outage schedules to the ISO.
- In recognition of the particular importance of facilities 240 kV and above, and balancing area interconnections, to the reliability of the AIES and the impacts on transfer capabilities of these facilities, the ISO and TFO will make reasonable efforts to finalize each outage schedule in respect of such facilities at least 30 days prior to the commencement of the relevant operating week.

3.3.2 ISO's Role in Determining Outages with Transmission Facility Owners

While the ISO must accept any generator outage as long as it meets its reporting requirements, the ISO has the ability to move or alter transmission outages. For generator outages, the underlying belief is that the market price (pool price) will provide a 'reliability' signal for generators to schedule outages in periods where it is expected that pool prices will be low. In turn that tends to levelize the supply cushion across the seasons and is an efficient outcome. TFOs have no 'reliability' price signal to schedule outages and their main driver is to minimize costs. Thus the rules provide the ISO with the ability to move a transmission outage in the event that the reliability of the system may be at risk. OPP 601 sets out the obligations for both the ISO and the TFOs including both reporting and accountability. Fundamentally, no transmission outage can occur without the ISO's approval.

Under OPP 601 Section 3 on policy it is clear that the ISO has the ultimate responsibility to assess transmission outages:

> 3.1 Outage Coordination and Reliability
>
> The ISO has overall accountability for assessment of the risk to the transmission system from maintenance and commissioning activities. The ISO will carry out assessments of the risk to the transmission system posed by maintenance and commissioning operations, and work in cooperation with the other parties to resolve any issues that are identified
>
> TFOs will not interrupt or curtail transmission services to carry out scheduled maintenance or work until the ISO confirms that to do so would not adversely affect system reliability or, if during real-time, the SC approves the timing of the outage, on the basis of the impact of the requested outage on AIES system reliability.

OPP 602 (Risk Assessment for Transmission Maintenance Outages and Commissioning Activities) further reinforces the obligations of both the TFO and the ISO. Under OPP 602 Section 4 on responsibilities:

The ISO will:

- Have the overall responsibility and accountability to review and to coordinate all the transmission outage plans, and commissioning and testing activities, in Alberta, which may have an impact on system security.
- Based on its assessment and in consultation with the TFO's, will coordinate any necessary outage schedule changes.

The Transmission Facility Owners (TFO) will

- TFO's are accountable for performing risk analysis of their outage plans prior to submitting them to the ISO.

Generation Facilities Owners (GFO) will:

- GFOs will submit requests for commissioning and testing activities to the ISO ….in accordance with the requirements of OPP 604.

Thus if there are conflicting generator and transmission outages that could impact reliability, the ISO has the ability to move the transmission outage. In the case of the 1201L outage, it appears the ISO in discussion with AltaLink moved the outage twice, in August and again in October.

3.3.3 Outage Reporting Obligations for Generators

ISO Rule 5.2.1 requires that the owner of a generating unit must provide timely and complete information so as to enable the pool participant responsible for submitting outage information to the AESO compliant with obligations set out under section 5.2. The reporting requirements for the pool participant are different depending on whether the outage is a "scheduled generator outage" or a "forced outage". ISO Rule 5.2.2(2) states:

> (2) The designated pool participant must comply with the following specific requirements when submitting either forced outage or scheduled generator outage information to the ISO:
>
> (a) by the first (1st) day of every month subsequent to the date of commissioning, submit scheduled generator outages that are planned to occur at any time within the next twenty four (24) months after that day, with any subsequent revisions to the plans submitted to the ISO as soon as reasonably practical after the decision is made by the Owner of the generating unit to change the plans, but in any event no later than three (3) months prior to the first day the scheduled generator outage is planned to commence;
>
> (b) for scheduled generator outages that are planned to be required within the next three (3) months after the first (1st) day of a month, submit the plan as soon as reasonably practical after that planning decision is made by the Owner of the generating unit if the plan is different from the one referred to in Subsection (2) (a) above, which submission must include a statement setting out the reasons that any new plan for the scheduled

generator outage was not included in, or must vary from, the original Subsection (2) (a) submission;

Both the coal-fired generator planned outages for August, were submitted within the 3 month window. From a review of the market rules and discussions with the ISO, it appears that the only obligation on a generator to add, remove or change an outage at any time is to provide a reason. If a generator meets the obligation of submitting a reason it can alter its outage plans at any time up to real time.

As stated earlier, it has been assumed that within a market structure the economics of the market should drive generator behaviour and that the generator owner would manage its outages based on anticipated pool prices. The price signal pointing to a shift in these outages to a lower priced period apparently did not outweigh all other costs and benefits that may be associated with such a move.

3.3.4 Transparency of Outages to the Market

Information, on both transmission and generation outages, is an important source for traders to take a view on forward prices. Outage information (transmission or generation) is released by the ISO via a series of reports described below. Many of the price movements in the forward market took place after the release of outage information.

3.3.4.1 Publishing of Transmission Outage Information

The ISO publishes transmission outage information to the market through four separate mechanisms that are founded on the information provided by the TFOs:

The first mechanism being via the AESO Critical outages page at: www.aeso.ca/outage_reports/Longterm_Critical_Outages.html. The report provides a list of transmission line outages and the proposed dates. Intertie outages obviously impact supply and hence views on market prices. Some of the outages constrain internal generators and hence expectations of pool prices. The report notes that the transmission outages have not yet been approved.

The approved outages for the next operating week are provided at: www.aeso.ca/outage_reports/qryOpPlanTransmissionTable_1.html

Available Transfer Capability (ATC) for the interties is published for the next 6 months by the ISO at http://itc.aeso.ca/itc/public/atcQuery.do The report provides hourly information on the available capacity on the interties with British Columbia and Saskatchewan and hence is a primary source of information to traders in the forward market. This report uses the AESO Critical outages page as a source of input data.

The 24-Month Supply and Demand forecast indicates the total supply and demand and the expected maximum ATC of both the BC and SK intertie. This report uses the AESO Critical outages page as a source of input data.
http://ets.aeso.ca/Market/Reports/Manual/AiesGraphs/24_month_supply_and_demand.html

3.3.4.2 Publishing of Generator Outage Information

The information on generator outages is less specific than that for transmission outages. There are two reports available.

The Short Term Generator Outage Report shows aggregated outages and derates by fuel type and averaged over various time horizons designed to match contracts that are traded. This includes current day (on- and off-peak), next day, weekend, balance of month etc. The aggregation includes elements of disguise. The chart is updated as conditions change and is located at: http://ets.aeso.ca/ets_web/ip/Market/Reports/ShortTermOutageForecastReportServlet?contentType=graph. Traders monitor this chart constantly to see if outages are changing in the near future as changes in supply always impacts the forward view of pool price.

The Monthly Generator Outage Chart shows similar information for the next 24 Months. The outages are averaged across each month. Hence, an outage of 300 MW for three weeks will appear the same as 450 MW for two weeks, whilst the effect on pool prices would not normally be the same. The report is located at: http://ets.aeso.ca/ets_web/ip/Market/Reports/MonthlyOutageForecastReportServlet?contentType=image&imageTableIndex=1. Traders monitor this chart constantly to discern any changes.

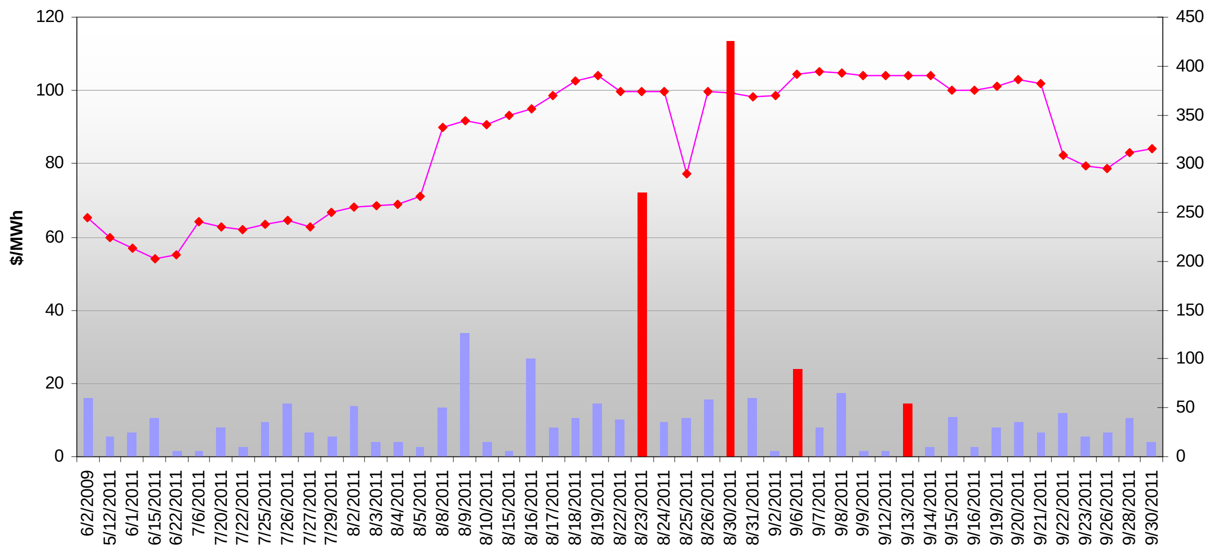
3.4 FORWARD PRICE MOVEMENTS FOR AUGUST AND OCTOBER

Table 3.1 provides a list of some of the major price swings and the 'news' that precipitated the changes. The following paragraphs provide more details. Figure 3.3 shows forward prices and volumes purchased for the October contract and is illustrative of the impact news can have on forward prices. The sharp price drop on August 24 and its rise on August 25 shows how quickly and decisively the market will react to news.

Table 3.1: Changes to Generator and Transmission Outages and the Impact on Forward Prices

Outage	Date	Date of Outage	Date of Release to Public	Est'd Price Change August Forward	Est'd Price Change October Forward
1201L	1-Jun-11	Aug 22 - Sep 2, 2011	1-Jun	$10	
Coal Units	21-Jun-11	Aug 5 - 12, 2011	21-Jun	$13	
1201L	5-Aug-11	Oct 3 - 14, 2011			$19
1210L	24-Aug-11	Removed from Outage sheet	24-Aug		($22)
1210L	25-Aug-11	Oct 3 - 14, 2011	25-Aug		$22
1210L	26-Aug-11	Oct 3 - 6 and Oct 11 - 14, 2011	26-Aug		$0
1210L	29-Aug-11	Oct 3 - 6 and Oct 11 - 14, 2011	29-Aug		$0
1210L	30-Aug-11	Oct 3 - 6 and Oct 11 - 14, 2011	30-Aug		$0
1210L	20-Sep-11	Cancelled for October	20-Sep		($20)

Figure 3.3: October Flat Contract Price (NGX)[7]



June 1, 2011

The ISO Critical Transmission Outage Report of June 1 showed the proposed 1201L outage as occurring from August 22 to September 2. The August price moved up $10/MWh in response to the news. This was in reaction to the market being roughly 500 MW tighter. All traders would understand the supply implications due to the outage although their forward views on prices might not all be the same.

June 21, 2011

With the news of the coal unit outages in the AESO's Monthly Generator Outage Report on June 21, over the next two days forward prices for August moved up approximately $13/MWh.

The owners of the units under outage (and Buyers in the case of PPA units) would have specific knowledge of the reasons and the timing of the outages. All other participants in the forward market would know that the Monthly Generator Outage report changed by 145 MW and would attempt to infer the impact of the outage(s) on the August supply.

June 22, June 29 and July 6 and July 19, 2011

EPCOR was buying energy for the month of August for its RRO customers through several auctions. The 1201L outage and newly scheduled generator outages, together with all previously known information on supply and demand conditions, were now influencing the August forward price curve, and hence the prices that EPCOR was paying for its RRO energy.

[7] The red bars in the chart are associated with EPCOR RRO Auctions

August 5, 2011

The 1201L outage was rescheduled to the first half of October resulting in October forward prices increasing by $19/MWh. The RRO prices for August were already set and had factored in the 1201L outage as scheduled in August. Now the October RRO began to price in the incremental effect of the rescheduled 1201L outage.

It appears that the 1201L outage was in conflict with the 170L outage which was scheduled to occur at the same time. If this conflict had been identified earlier in the process it may have eliminated the need for one of the reschedules of the 1201L outage. The MSA understands that normal ISO practice is to scrutinize the outages that impact the market early in the process, but that in this specific case, the link between the two was not straightforward and was not identified early on.

With the 1201L outage moved to October 3-14, October forward prices moved up by approximately $22/MWh.

August 23, 2011

EPCOR bought energy for its RRO customers for the month of October with the impact of the 1201L outage as part of the mix of market information now influencing the October price.

August 24 & 25, 2011

The events of these two days serve to illustrate quite clearly the importance of market news to those involved in forward market trading activity. In late August it became apparent to the AESO that there was some uncertainty in the specific schedule of the 1201L outage. On August 24, ISO removed the 1201L outage from the list of Critical Transmission Outages (put it on hold) and the October price fell by $22/MWh on that day. The ISO reposted the outage on the next day and prices recovered. In the interim, 40 MW of October contract traded resulting in a wealth transfer of some $650,000 – gains for some and losses for others.

In retrospect, where the uncertainty is only regarding the specific timing within a short window of time, it might be better for ISO to keep the outage in the schedule and to make the relatively minor adjustment once the details are more firm.

August 30, September 6 and 13, 2011

EPCOR was buying energy for its RRO customers for October from the forward market with the impact of the 1201L outage as part of the mix of market information continuing to influence the price.

September 22, 2011

Due to an unfortunate delay in the completion of the 170L outage, ISO was forced to cancel the 1201L outage again. October forward prices dropped $20/MWh as a result. However, the RRO had effectively priced that outage into the October RRO by that time – the second time that the RRO 'paid' for the 1201L outage.

In this particular case delay was caused by circumstances beyond anyone's control.

The maintenance on 1201L is still required and will likely again have an impact on both forward and real-time prices.

3.5 DISCUSSION

News in the market does have an impact upon forward prices. Having that news as far in advance and as transparent as possible allows the forward market to absorb and integrate this information. In terms of the planned generator outages taken in August, earlier planning may have allowed the market to better integrate this news into its price forecasts. It is not clear why the planned outage information came so late in the planning cycle. While the language of Rule 5 places a lot of onus on generators to plan outages well ahead of time with no changes inside a three month window, the actual practice seems to be less strict.

The shifting of the 1201L outage from August to October and then cancelling it had a significant impact on forward prices. All information was available to the ISO to make its judgment back in early June before RRO had bought energy for August. It is clear from the September 22, 2011 ISO press release that this condition would not allow both outages together and something had to move, first in August and again in October, although the second change was unavoidable. Adding 170L to the list of critical transmission elements would help to avoid a similar situation in the future. The ISO might consider reviewing all reasonable outage possibilities to assess if other similar situations exist.

More broadly, we encourage the ISO to undertake a review to identify changes that would avoid similar problems in the future.

4 Retail Matters

On June 22, June 29 and July 7, EPCOR Energy Alberta Inc. (EEAI) experienced difficulties in the procurement of the August extended peak product for the Regulated Rate Option (RRO) customers. All three August extended peak RRO auctions were deemed as 'not competitive'. On July 7, 2011, with the assistance of the Independent Advisor (IA) of EEAI's 2011-2014 Energy Price Setting Plan (EPCOR EPSP), the MSA provided a letter addressed to Alberta Utilities Commission (AUC) in support for an amendment to the EPCOR EPSP. The amendment was limited to the adjustment of the calculation of the seed price, which is the 'price cap' of the auction session, in order to better reflect the variations in price and encourage adequate participation.

In the letter, the MSA also recommended that EEAI, the consultation parties and the IA undertake a review of the mechanism as to its continuing appropriateness as the sole procurement mechanism for the EPCOR EPSP. The review was completed and share by EEAI with the MSA. The conclusion of the review is that "the EPCOR EPSP is producing results consistent with a fair, efficient and openly competitive process". The review is in Appendix H.

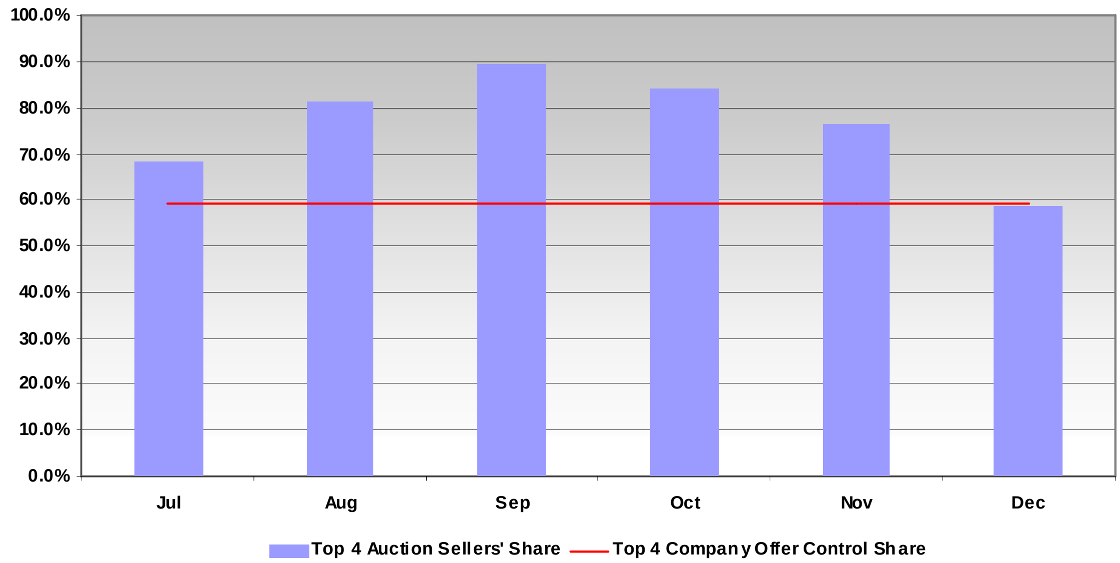
EEAI observed in its review:

- The RRO rates across the three major providers, EPCOR, ENMAX and Direct Energy are comparable.
- The procurement prices were consistent with the trends on the broader NGX forward market.
- There was evidence of broad participation in the auctions from both generators and financial players.

The MSA acknowledges the first two observations but is not as convinced about the third observation regarding broad participation in the auctions. With the December RRO auctions now complete, the MSA was able to draw on 6 months of data in terms of participation in the auctions. Figure 4.1 shows the market shares in each month of the top four sellers. It can be seen that in terms of sales that the market is generally more concentrated that the offer control of the physical market. This observation does not mean that the process is not competitive.

At the present time, the MSA is reserving judgment on the overall performance of the EPCOR EPSP and will continue to monitor the procurement process.

Figure 4.1: Market Share of Top 4 Sellers in EPCOR RRO Auctions



The MSA monitors and evaluates the RRO market for all three providers in conjunction with the financial futures market and the wholesale spot market. This is because the RRO procurement is influenced by its pricing mechanism, which uses the prices of the prompt month financial futures contract as the foundation to calculate the RRO index. The prices of the prompt month financial futures are in turn determined by the market expectation of the pool price. Therefore, the outcome of the RRO procurement, including the price and volumes, can not be formed free of the impact of the activities in the forward market or the spot market. As long as the RRO remains to be priced off the prompt month financial contract, the MSA will use a broad range of metrics in its on-going monitoring and assessment activities of the retail market, including the areas associated with RRO procurement mechanism.

The MSA has two preliminary observations:

- An increased premium (small but increasing) in the average prices paid by the RRO providers relative to the prices in the non-RRO market; and,
- In the case of EPCOR, a fairly consistent run-up in price on the trading days leading up to the first RRO auction each month.

While the MSA recognizes that it's premature to draw any conclusions until more procurement months are observed, we believe that closely monitoring metrics such as these is helpful in the effort of assessing whether the outcomes of all the RRO EPSPs remain consistent with the expectations of a fair, efficient and openly competitive market.

5 Compliance Activities

5.1 ISO RULES COMPLIANCE

Table 5.1 provides an update of the MSA's ISO rules compliance activities as of the end of Q3/11. The MSA issued 34 notices of specified penalty during the first nine months of 2011. This figure is comparable to the previous year with 33 notices of specified penalty issued as of the end of Q3/10. In 153 other cases, the MSA chose to forbear, 13 other matters remained under review, while two matters are proceeding through the administrative penalty process. For comparison, the MSA issued 45 forbearances and had 6 matters under review at the end of Q3/10. Additionally, 2 referrals received forbearance each of which contained multiple suspected contraventions of ISO rule 3.5.3 during 2011. Due to the unique nature of these two matters, they have been excluded from Tables 5.1 and 5.2 - refer to Section 5.1.1 for more details. One hundred and ninety new files were opened during the first three quarters of 2011 which is more than double files opened during the same time period in 2010.

Table 5.1: Compliance Files (as of end of Q3/11)

	Under Review	Notice of Specified Penalty	AUC Administrative Proceedings	Forbearance
3.5.3	3	2		17
3.5.5	1	1		1
3.6.2			2	
5.2.2				2
6.2.2		1		
6.3.3	6	17		63
6.4.3		2		1
6.5.3		2		9
6.6	2	7		51
OPP 003.2				1
OPP 102				3
OPP 402				3
OPP 515				1
OPP 603	1	1		
OPP 806		1		
Total	13	34	2	152

The contravention dates of the 34 notices of specified penalty issued to the end of Q3/11 ranged from July 2010 through May 2011. Twenty-nine of these notices of specified penalty were issued in cases where a suspected contravention was referred by the AESO. All penalties issued during Q3/11 were matters that were referred to the MSA by the AESO. Table 5.2 segments the second, third and fourth columns of Table 5.1 by month of contravention date.

Table 5.2: Q3/11 Compliance Files by Month of Contravention

		2010						2011									
	Rule	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Under Review	3.5.3									1			1		1		3
	3.5.5															1	1
	3.6.2																
	5.2.2																
	6.2.2																
	6.3.3														1	5	6
	6.4.3																
	6.5.3																
	6.6														2		2
	OPP 003.2																
	OPP 102																
	OPP 402																
	OPP 515																
	OPP 603										1						1
	OPP 806																
	Total										1				4	6	13
NSP	3.5.3									1		1					2
	3.5.5									1							1
	3.6.2																
	5.2.2																
	6.2.2					1											1
	6.3.3		2	3	5	1	2	3		1							17
	6.4.3							2									2
	6.5.3	1									1						2
	6.6		1		1		2	2		1							7
	OPP 003.2																
	OPP 102																
	OPP 402																
	OPP 515																
	OPP 603										1						1
	OPP 806									1							1
	Total	1	3	3	6	2	4	7		5	2	1					34
Forbearance	3.5.3				1	1	3				2	4	2	1	3		17
	3.5.5									1							1
	3.6.2																
	5.2.2											2					2
	6.2.2																
	6.3.3			2	1	2	7	8	5	6	5	4	3	9	11		63
	6.4.3													1			1
	6.5.3							1		2	1		3	1	1		9
	6.6				1	3	4	10	7	6	9	2	5	3	1		51
	OPP 003.2												1				1
	OPP 102							1	1				1				3
	OPP 402										1		2				3
	OPP 515											1					1
	OPP 603																
	OPP 806																
	Total			2	3	6	14	20	13	15	18	13	17	15	16		152

5.2 ALBERTA RELIABILITY STANDARDS

During Q3/11, the MSA received 7 self reported compliance matters relating to Alberta Reliability Standards (ARS). Three of these self reports were related to CIP-001-AB-1, the remaining four were each for a different ARS including, PRC-001-AB01 and PRC-004-AB-1. The MSA has not received any referrals from either the AESO or from WECC. No specified penalties have been issued thus far in relation to ARS compliance.

5.3 RULES CLARIFICATIONS

The MSA's role in compliance with respect to ISO rules is not one simply about looking for and measuring transgressions - occasionally handing out 'parking tickets' or seek administrative penalties in more serious matters. We see the role as one where the desire is to foster a climate of compliance in the industry. It is already evident that many participants consider compliance to be a normal part of operations, to be taken with an appropriate degree of seriousness and resourced accordingly. The MSA is most interested in seeing reasonable outcomes, whether that requires forcing discussions with rule owners or helping market participants to better understand their obligations. The following are examples where participants should take guidance for future conduct.

ISO rule 3.5.3

During Q3/11, the MSA received a referral from AESO compliance monitoring in regards to an observed offer practice suspected to be in contravention of ISO rule 3.5.3. Rule 3.5.3 requires a participant to offer the maximum capability (MC) of its generation assets into the market unless an acceptable operational reason exists for those offers to be below MC. In this case, the asset could not be operated safely during overnight hours since the facility is unmanned during this period and does not have remote operating capability. The participant believed these circumstances constituted an acceptable operational reason to declare the asset unavailable during those hours. The view of the AESO was that the asset itself was mechanically capable of operating and therefore an acceptable operational reason did not exist to declare the asset unavailable. On review of the matter, the MSA believed the offer practice to be contrary to the must-offer principle of rule 3.5.3 but also recognized that prevailing operational constraints warranted consideration. The MSA put forward the view that the asset could be described as a long lead time generating asset (within defined limits) and facilitated the implementation of an offer protocol whereby the participant undertook to the AESO to offer the asset as a long lead time asset during overnight hours and otherwise offer the asset according to standard offer rules. The MSA believes this outcome reasonably achieved compliance obligations in respect of ISO rule 3.5.3 while recognizing existing constraints of the generation facility.

Also of note in respect of ISO rule 3.5.3, was a matter pertaining to dual fuel capable coal units (i.e. coal/gas) restating offers within T-2 due to poor coal quality. Available Capability (AC) for a generating asset, is defined in the ISO rules as the maximum quantity (MW) that the generating asset is physically capable of providing during each settlement interval of the trading day. Accordingly, ISO rules suggest in this context that the gas capability is captured in the declaration of AC, and that changes to AC must consider the extent of operation in alternative modes i.e. gas. The MSA appreciates that the issue may not be straightforward and that other factors may apply particularly in the context of a PPA. In this regard, the MSA believes there is an opportunity for clarification as rule 3.5.3 is transitioned to the new ISO rules framework through the TOAD process. If PPA owners require further clarity in the interim, they are advised to contact the MSA.

OPP 603

During Q3/11 the MSA received referrals in which coal assets had submitted offer restatements within T-2 to accommodate Relative Accuracy Test Audit (RATA) testing. These instances had been deemed not to qualify as an acceptable operational reason to restate within T-2 when no test plan had been submitted to the AESO in accordance with OPP 603. OPP 603 contemplates forbearance in respect of dispatch variance contraventions when testing under an approved test plan and the MSA is of the view that a similar approach in respect of other forms of non-compliance while testing is reasonable provided that a test plan has been filed with the AESO. The MSA is aware that contractors who conduct RATA testing on behalf of several participants are often delayed and hence, the testing may not occur on schedule. The MSA recommends that participants intending to conduct RATA testing file a test plan in accordance with OPP 603.

6 MSA Activities

6.1 SETTLEMENT AGREEMENT

On November 4, 2011 the MSA and TransAlta filed a settlement agreement with the AUC where it is currently under consideration as Application No. 1607868. The settlement alleges that TransAlta breached section 6 of the Alberta Electric Utilities Act during 31 separate hours during 8 days in November, 2010. The current details may be found at the Commission's web site at www.auc.ab.ca and search for application 1607868.

6.2 DATA TRANSPARENCY

In late August, the MSA issued a Request for Proposal on market data transparency. The successful bidder was Charles River Associates and their report was posted on the MSA's web site in late November. In parallel with the work by Charles River Associates, the MSA is conducting a stakeholder process on the same topic. Readers are directed to the MSA's web site for more details. www.albertamsa.ca

6.3 MSA FEEDBACK PAGE

Given its mandate, from time to time the MSA receives an inquiry from a market participant or other person seeking a clarification on a matter. The topics are varied. Most often the inquiry involves a discrete issue, such as a question regarding a proposed commercial arrangement. Another topic might involve an operational question or the practical effect of an enactment, for example the electricity *Code of Conduct Regulation*. [8] Our experience has been that market participants generally work hard to stay within the rules and make their inquiries in furtherance of that aim.

For our part, we consider it both fair and responsible to provide timely feedback to such inquiries where possible, although in some cases, such as where a matter is before the Alberta Utilities Commission, the MSA may be unable to respond. In furtherance of transparency, we will also look to publish it for the benefit of other stakeholders where appropriate. In the Q4/10 Quarterly Report the MSA mentioned that an 'Advisory Opinions' program was under development for that purpose. During 2011 the idea has been stress tested and revised, evolving into the 'MSA Feedback Page' approach described below. The basic concept is the same, but now better reflects the fact that most of the time in response to such inquiries the MSA is giving informal feedback rather than a formal opinion.

The Feedback Page will be a spot where such MSA views are distilled and gathered over time. That said, not all such inquiries and responses will be published. In fact, many queries tend to be too fact specific or too minor to have relevance for a larger stakeholder audience. Another constraint is commercial

[8] See, for example, http://albertamsa.ca/uploads/pdf/Archive/2011/Notice%20re%20Code%20of%20Conduct%20Regulation%20111611.pdf.

sensitivity. Although the MSA will try to make a fact pattern generic so as to not identify the person who made the inquiry, some such matters will not be readily susceptible to efforts to respect anonymity.

As contemplated above, the Feedback Page will take up a space not covered by the formal guideline making process utilized by the MSA for other types of matters, those which deal with standards of broad application (so called, 'public projects'). [9] Our belief is that by filling this gap the MSA will improve the playing field for market participants.

The MSA Feedback Page will soon be found on the MSA website, through a link shown on the home page banner.

[9] See MSA Stakeholder Consultation Process http://www.albertamsa.ca/files/Principles_and_Framework_for_MSA_Public_Projects_July_28_2006%281%29.pdf.

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]
Jul-11	61.21	91.37	22.96	156.35	255%
Aug-11	126.36	192.39	34.93	223.50	177%
Sep-11	96.57	149.35	24.35	200.08	207%
Q3-11	**94.69**	**144.98**	**27.36**	**196.99**	**208%**
Apr-11	52.23	70.33	27.48	85.53	164%
May-11	32.27	43.92	17.50	51.29	159%
Jun-11	71.85	111.05	18.20	188.90	263%
Q2-11	**51.90**	**75.10**	**20.97**	**123.77**	**238%**
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	*33.10*	22.02	17.94	63%
Q3-10	**35.77**	**44.87**	**23.59**	**37.07**	**104%**

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

Figure A.1: Pool Price Duration Curves

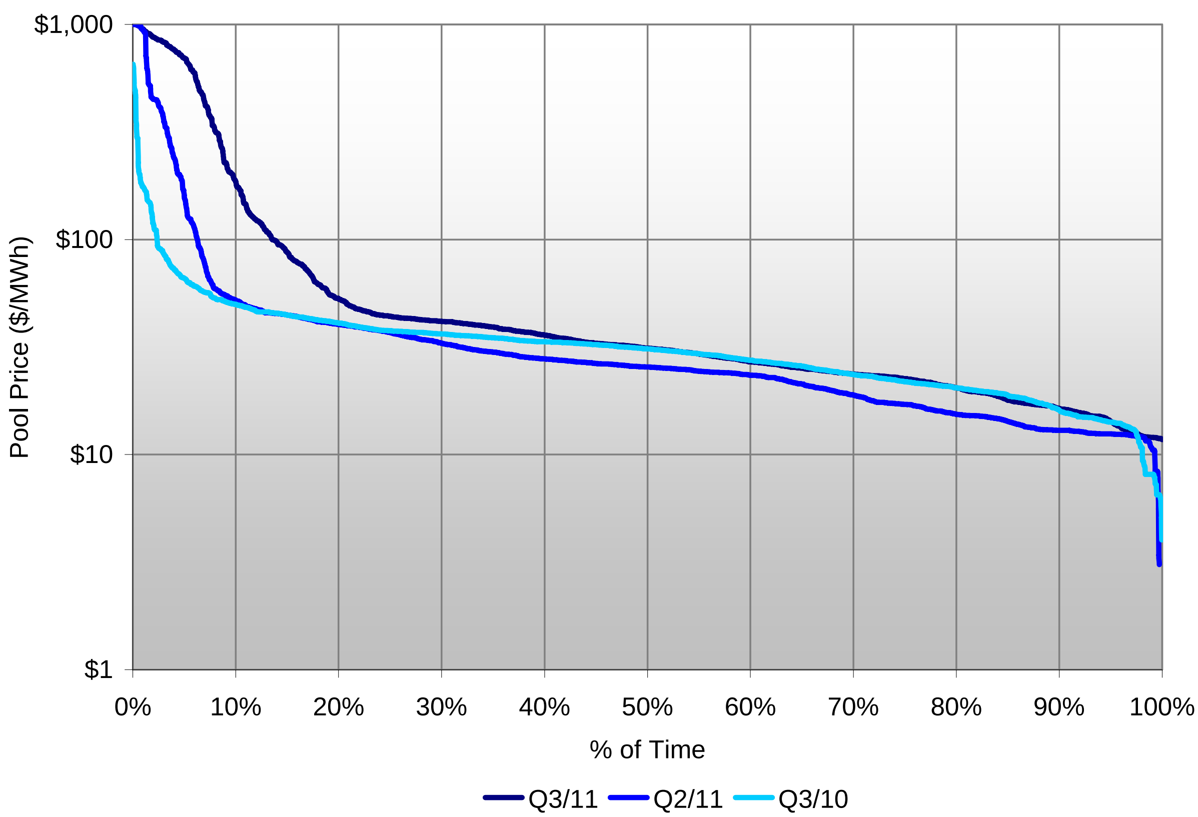
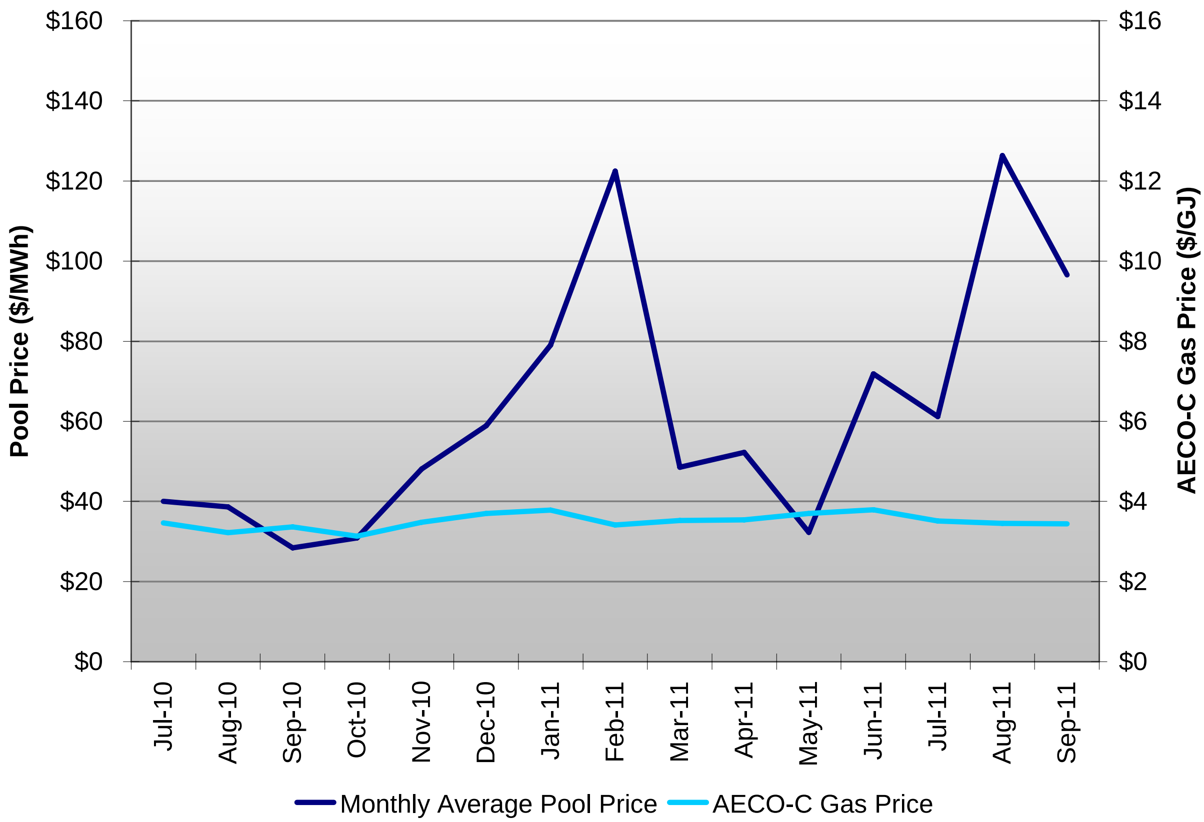


Figure A.2: Pool Price and AECO Gas Price

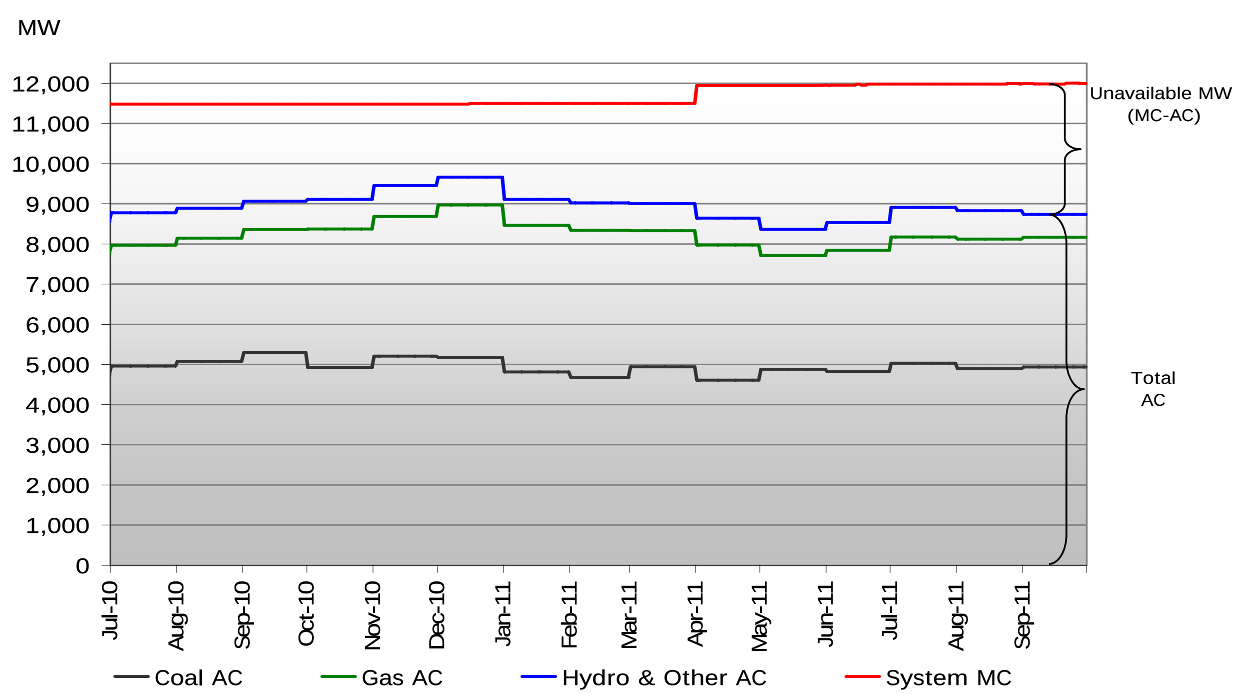


Appendix B: Supply Availability Metrics

Table B.1: Availability and Capacity Factors

Fuel Type	Quarter	Average MC [A] (MW)	Average AC [B] MW (MW)	Availability Factor [C]=[B]/[A] (%)	Generation [D] (GWh)	Capacity Factor [E] = ([D]x1000)/([A]xhrs) (%)
All Fuels *(excl. Wind)*	Q3/11	11,984	8,824	74%	15,704	59%
	Q2/11	11,952	8,512	71%	14,403	55%
	Q3/10	11,484	8,910	78%	15,254	60%
Coal	Q3/11	6,244	4,956	79%	10,082	73%
	Q2/11	6,235	4,775	77%	9,129	67%
	Q3/10	5,782	5,110	88%	10,183	80%
Natural Gas	Q3/11	4,798	3,200	67%	4,942	47%
	Q2/11	4,796	3,066	64%	4,615	44%
	Q3/10	4,785	3,047	64%	4,663	44%
Hydro & Other	Q3/11	942	669	71%	679	33%
	Q2/11	921	671	73%	659	33%
	Q3/10	917	753	82%	407	20%
Wind	Q3/11	777	n/a	n/a	427	25%
	Q2/11	777	n/a	n/a	534	31%
	Q3/10	629	n/a	n/a	282	20%

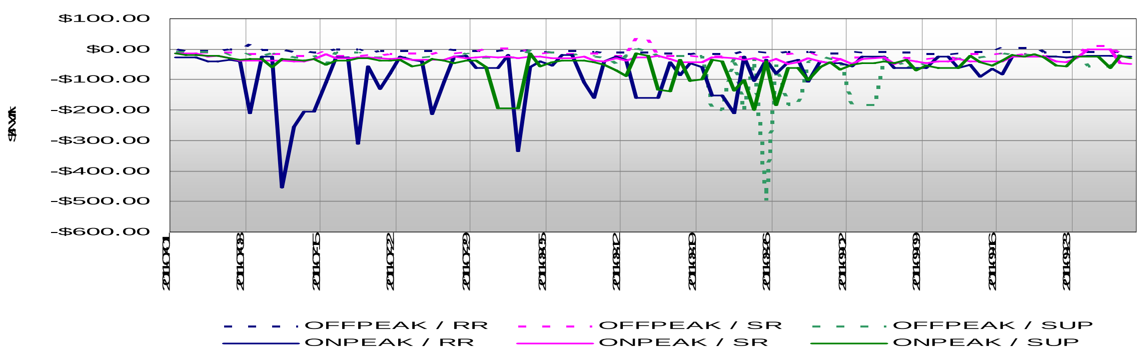
Figure B.1: Available Capacity (AC) vs Maximum Capacity (MC)



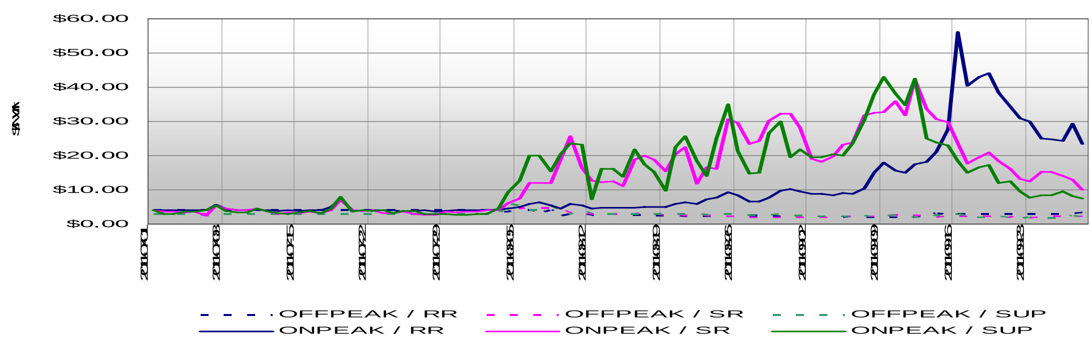
Appendix C: Operating Reserves Market Metrics

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

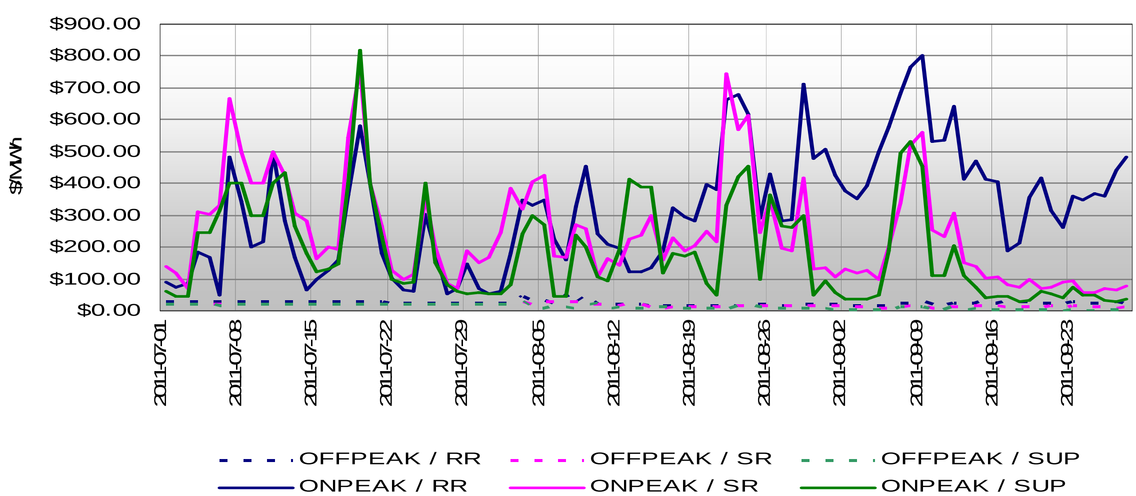
NGX Active Reserves Weighted Trade Index



Standby Reserves Average Premium Price



Standby Reserves Average Activation Price



Appendix D: Intertie Metrics

Figure D.1: Intertie Utilization – Q3/11

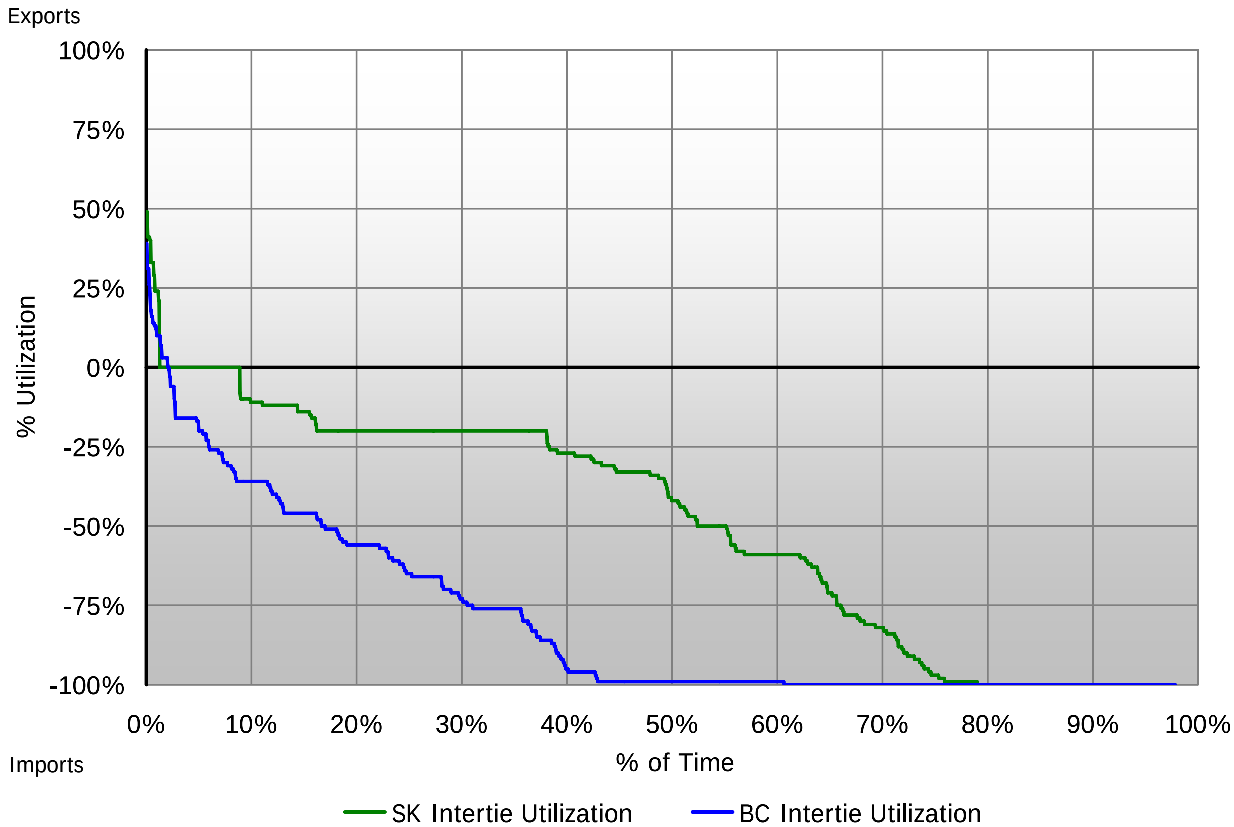


Figure D.2: On-Peak Prices in Neighbouring Markets

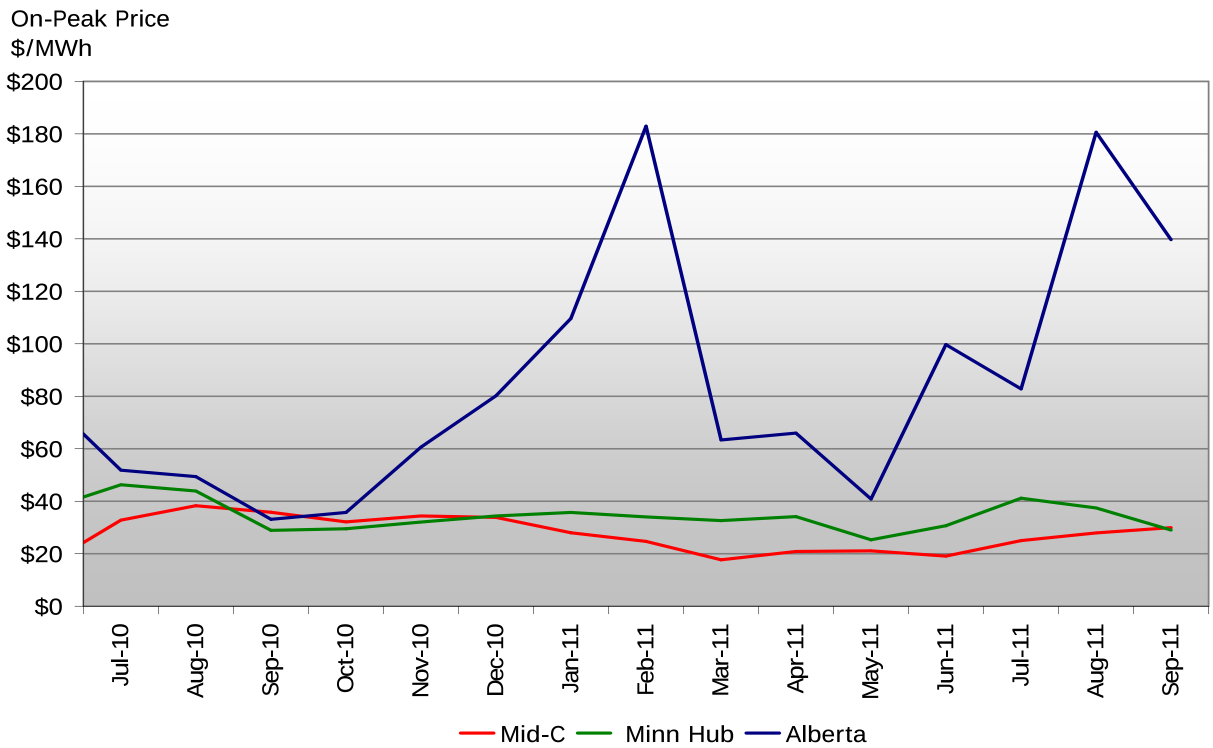


Figure D.3: Off-Peak Prices in Neighbouring Markets

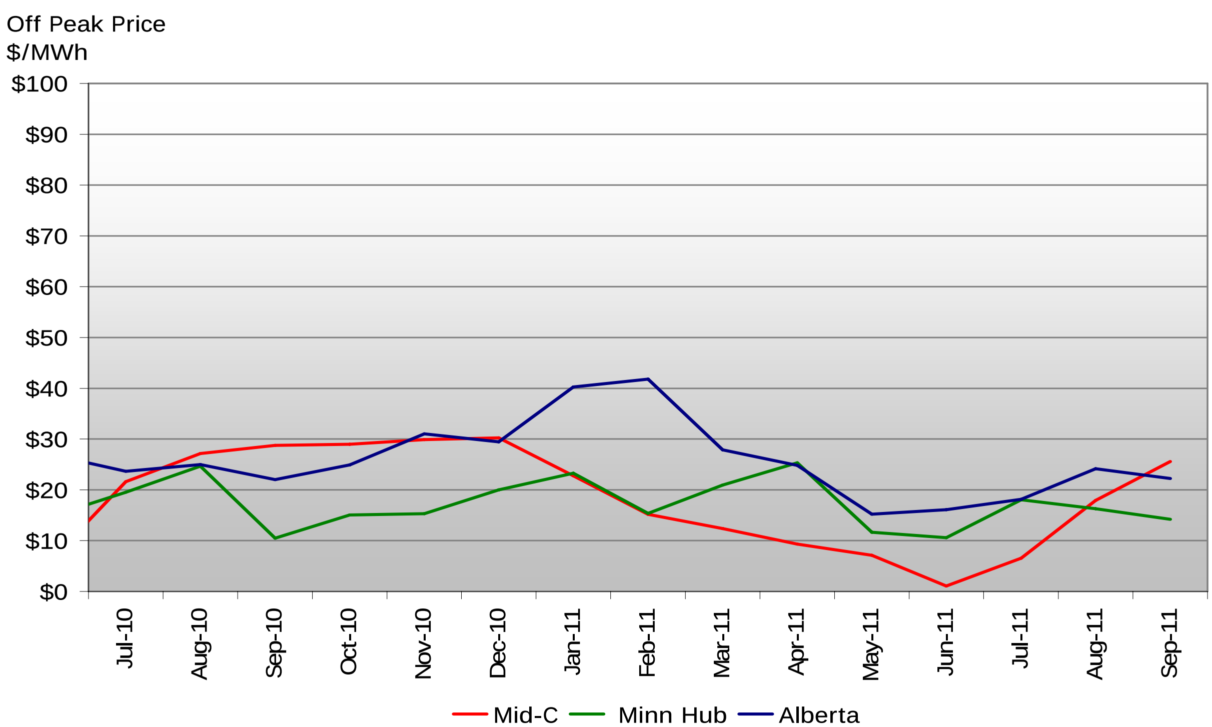
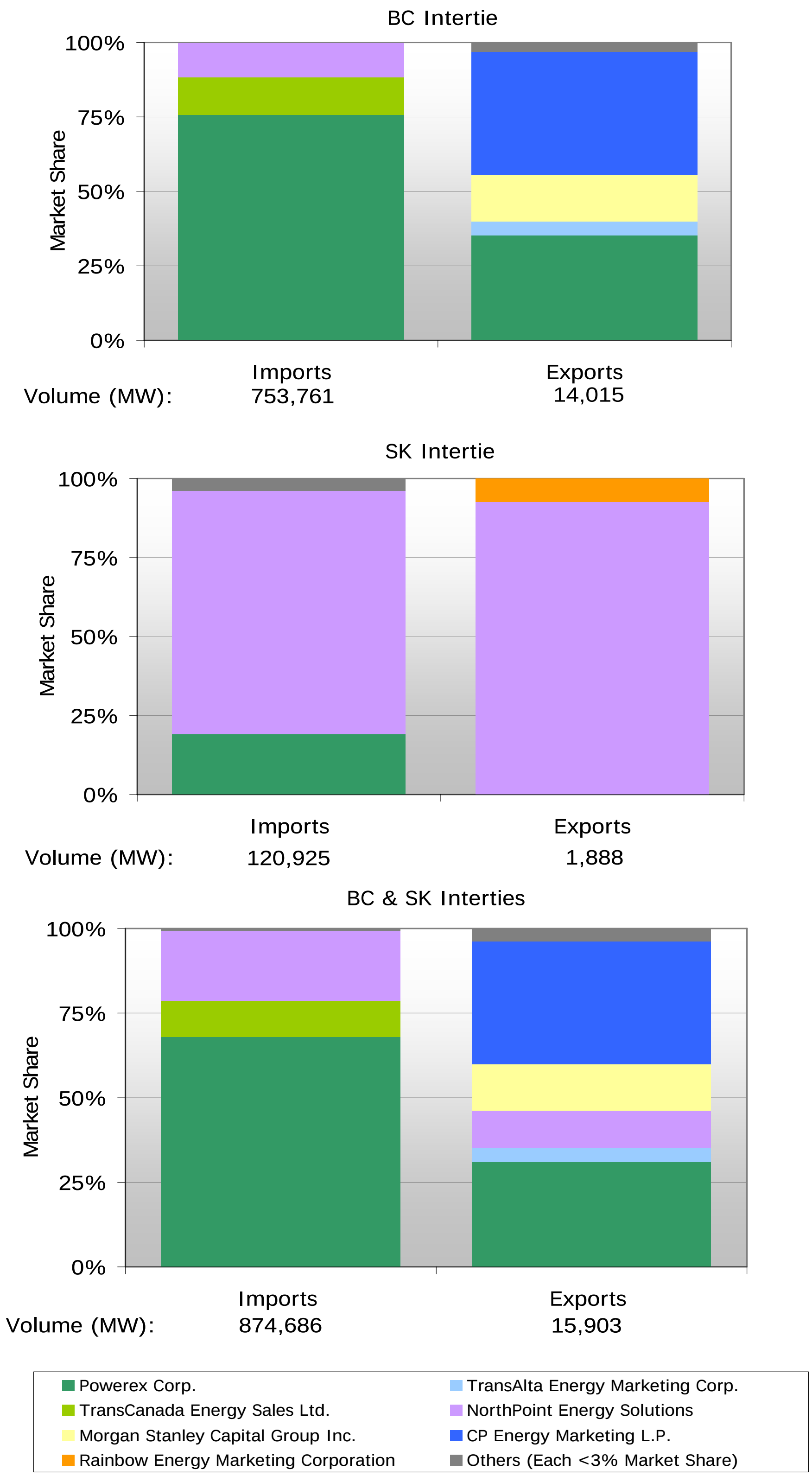


Figure D.4: Intertie Market Shares – Q3/11



Appendix E: Forward Market Metrics

Figure E.1: Volume by Trading Month

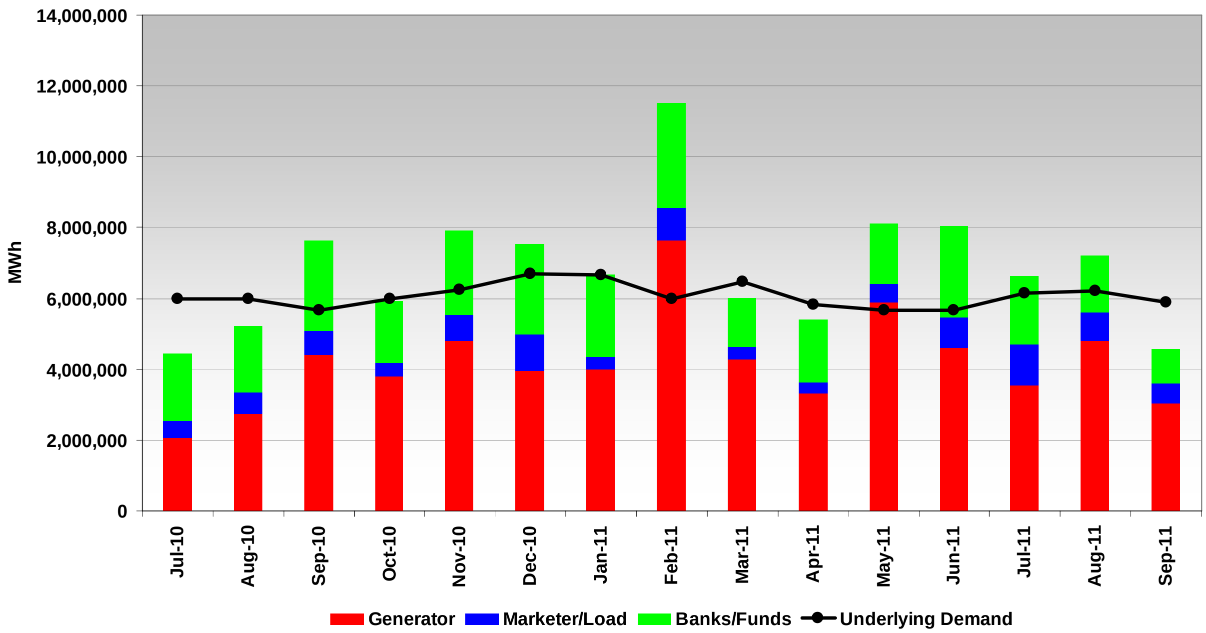


Figure E.2: Market Shares by Participant Type

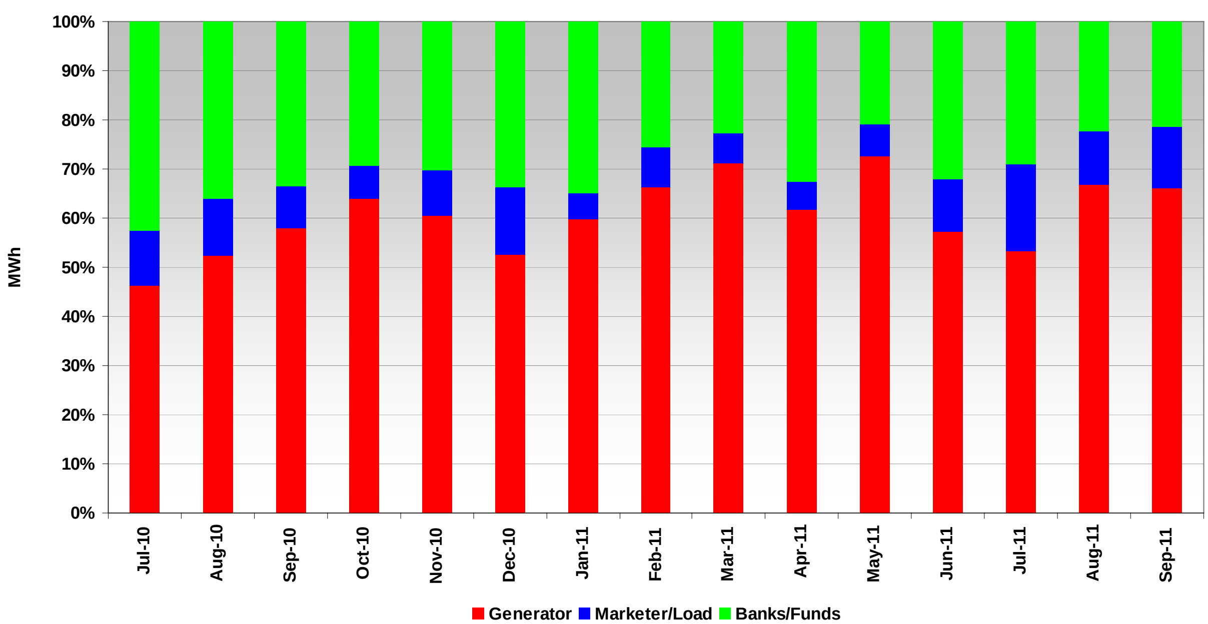
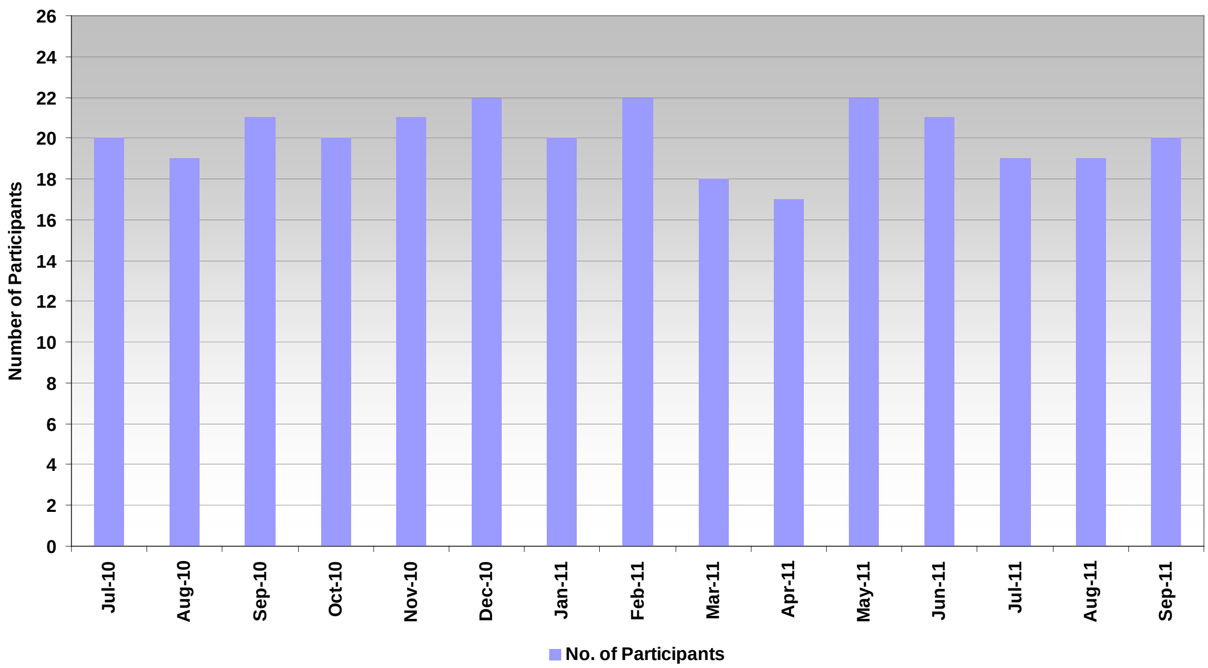


Figure E-3: Number of Active Market Participants



Appendix F: Hours >3StD in Q3/11

											% of Supply Cushion					
Date	HE	Pool Price	Demand	MC	AC	Dispatched MW	Supply Cushion	BC Net Import	SK Net Import	Wind	A	B	C	D	E	Other
7/5/2011	17	$400.64	9,230	11,980	9,132	8,514	542	275	0	46	60%	17%	0%	16%	0%	7%
7/5/2011	18	$382.71	9,183	11,980	9,165	8,417	672	275	0	74	51%	15%	18%	13%	0%	4%
7/6/2011	22	$740.18	8,820	11,980	8,819	8,207	535	420	22	61	19%	47%	9%	24%	0%	1%
7/7/2011	11	$903.47	9,095	11,980	8,994	8,409	508	420	23	46	24%	20%	26%	27%	0%	3%
7/18/2011	19	$377.42	9,187	11,980	9,291	8,618	597	420	57	13	6%	15%	64%	14%	1%	1%
7/25/2011	15	$374.03	9,355	11,980	9,494	8,792	626	420	149	23	21%	0%	58%	18%	0%	3%
8/3/2011	12	$339.61	9,091	11,979	9,196	8,298	792	415	15	18	17%	11%	51%	8%	10%	3%
8/3/2011	13	$264.64	9,031	11,979	9,185	8,351	758	415	30	46	30%	4%	54%	9%	1%	3%
8/3/2011	14	$206.00	9,058	11,979	9,212	8,295	841	415	30	98	27%	12%	49%	9%	0%	2%
8/3/2011	15	$206.00	9,084	11,979	9,213	8,250	887	415	30	146	32%	12%	46%	9%	0%	1%
8/3/2011	16	$206.00	9,088	11,979	9,210	8,260	874	415	30	183	32%	10%	47%	9%	0%	1%
8/3/2011	17	$246.09	9,004	11,979	9,258	8,367	815	415	118	200	35%	4%	51%	8%	0%	2%
8/4/2011	15	$118.00	9,275	11,979	9,658	8,572	1,010	415	30	13	33%	9%	44%	10%	0%	4%
8/4/2011	16	$486.82	9,222	11,979	9,627	8,602	949	415	30	29	35%	9%	47%	6%	0%	3%
8/4/2011	17	$132.17	9,256	11,979	9,757	8,615	1,066	415	30	33	32%	14%	42%	5%	4%	3%
8/5/2011	14	$227.37	9,294	11,979	9,701	8,634	999	415	30	7	39%	15%	25%	13%	4%	4%
8/5/2011	15	$227.24	9,245	11,979	9,549	8,505	976	415	30	7	34%	15%	30%	14%	5%	4%
8/5/2011	16	$417.31	9,206	11,979	9,545	8,554	923	415	30	33	36%	10%	37%	14%	0%	4%
8/5/2011	17	$227.31	9,163	11,979	9,382	8,381	933	415	30	49	35%	16%	31%	14%	0%	4%
8/5/2011	18	$200.92	9,086	11,979	9,396	8,435	893	415	30	31	37%	17%	28%	14%	0%	5%
8/8/2011	10	$338.45	8,753	11,979	9,017	8,176	750	474	30	0	32%	13%	32%	19%	1%	5%
8/8/2011	11	$491.83	8,893	11,979	9,017	8,202	739	474	30	0	19%	13%	45%	19%	1%	4%
8/8/2011	12	$726.15	8,977	11,979	8,973	8,270	627	474	30	0	13%	15%	53%	14%	1%	4%
8/8/2011	13	$721.86	9,011	11,979	8,959	8,306	577	474	30	0	8%	17%	58%	13%	1%	5%
8/8/2011	14	$721.95	9,070	11,979	8,969	8,340	553	474	30	0	28%	18%	37%	12%	1%	5%
8/8/2011	15	$723.15	9,106	11,979	9,083	8,492	516	474	30	1	30%	19%	33%	13%	1%	5%
8/8/2011	18	$552.46	9,067	11,979	9,042	8,313	653	474	30	47	25%	17%	36%	17%	1%	4%
8/16/2011	15	$369.82	8,833	11,979	8,762	7,803	883	415	30	343	19%	22%	24%	20%	10%	5%
8/17/2011	14	$414.50	8,852	11,979	8,575	7,883	616	415	15	259	20%	3%	30%	40%	1%	6%
8/17/2011	17	$188.22	8,861	11,979	8,801	7,869	856	415	17	377	22%	4%	33%	35%	1%	5%
8/19/2011	22	$366.39	8,310	11,979	8,400	7,636	687	420	30	9	0%	25%	34%	17%	19%	5%
8/20/2011	13	$601.45	8,256	11,979	8,187	7,598	513	472	30	2	7%	24%	30%	27%	9%	3%
8/20/2011	16	$757.21	8,246	11,979	8,380	7,655	649	472	30	5	0%	19%	29%	21%	29%	2%
8/20/2011	17	$697.24	8,292	11,979	8,483	7,661	746	472	30	2	7%	16%	25%	18%	32%	2%
8/20/2011	18	$692.00	8,316	11,979	8,384	7,562	746	472	30	1	7%	18%	27%	15%	31%	2%
8/20/2011	22	$418.80	8,290	11,979	8,378	7,618	684	472	30	17	0%	25%	31%	17%	25%	3%
8/21/2011	17	$168.63	8,768	11,979	8,586	7,701	809	459	30	457	22%	13%	31%	12%	19%	3%
8/21/2011	18	$642.95	8,738	11,979	8,422	7,645	701	459	30	476	19%	17%	29%	11%	21%	3%
8/21/2011	19	$330.76	8,603	11,979	8,440	7,511	853	459	30	409	26%	15%	28%	9%	18%	4%
8/22/2011	10	$335.07	8,920	11,979	8,764	8,127	561	436	30	307	43%	19%	0%	19%	15%	5%

											% of Supply Cushion					
Date	HE	Pool Price	Demand	MC	AC	Dispatched MW	Supply Cushion	BC Net Import	SK Net Import	Wind	A	B	C	D	E	Other
8/22/2011	12	$792.92	9,170	11,979	8,801	8,171	593	436	30	449	32%	18%	11%	21%	14%	4%
8/22/2011	13	$832.74	9,215	11,979	8,778	8,127	614	436	30	477	30%	17%	11%	18%	20%	4%
8/22/2011	16	$841.69	9,342	11,979	8,798	8,249	510	431	30	484	36%	18%	13%	11%	16%	5%
8/22/2011	17	$831.65	9,339	11,979	8,799	8,197	563	431	30	472	33%	16%	21%	10%	15%	5%
8/22/2011	18	$799.83	9,278	11,979	8,896	8,219	602	431	30	465	14%	15%	31%	15%	21%	4%
8/22/2011	19	$180.69	9,097	11,979	8,900	7,910	915	431	30	519	25%	10%	21%	21%	21%	3%
8/22/2011	20	$436.72	9,005	11,979	8,499	7,675	748	431	30	448	30%	12%	25%	12%	17%	3%
8/22/2011	21	$795.86	8,892	11,979	8,504	7,760	668	431	30	428	34%	17%	12%	14%	19%	4%
8/23/2011	12	$338.75	9,103	11,979	9,027	8,317	668	447	30	212	36%	14%	0%	21%	24%	6%
8/23/2011	13	$414.62	9,058	11,979	9,017	8,240	697	447	30	219	34%	13%	0%	23%	25%	5%
8/24/2011	12	$739.47	9,174	11,995	9,152	8,406	698	486	30	111	34%	14%	25%	17%	6%	3%
8/24/2011	14	$472.08	9,244	11,995	9,164	8,477	639	486	30	215	37%	14%	29%	15%	1%	4%
8/24/2011	15	$477.95	9,293	11,995	9,179	8,448	683	486	30	245	35%	10%	38%	13%	1%	4%
8/24/2011	16	$624.22	9,397	11,995	9,269	8,494	699	486	30	258	34%	10%	37%	15%	1%	4%
8/24/2011	17	$767.68	9,455	11,995	9,271	8,594	601	486	30	312	31%	12%	43%	9%	1%	4%
8/24/2011	18	$543.08	9,395	11,995	9,212	8,423	713	486	30	360	33%	13%	36%	14%	1%	4%
8/24/2011	21	$224.65	9,069	11,995	9,155	8,247	803	486	30	242	29%	14%	37%	10%	5%	3%
8/24/2011	22	$494.16	8,989	11,995	9,086	8,140	845	486	30	223	28%	20%	36%	11%	0%	5%
8/25/2011	11	$595.50	8,961	11,995	9,175	8,386	693	440	30	34	29%	25%	25%	18%	1%	3%
8/25/2011	12	$652.71	8,942	11,995	9,091	8,288	727	440	30	14	21%	23%	34%	19%	1%	3%
8/25/2011	13	$596.00	8,987	11,995	9,117	8,316	725	440	30	11	28%	21%	27%	20%	1%	3%
8/25/2011	14	$789.58	9,074	11,995	9,187	8,469	642	440	30	2	14%	24%	36%	22%	1%	3%
8/25/2011	15	$825.00	9,108	11,995	9,141	8,492	575	406	30	1	15%	23%	40%	17%	1%	3%
8/25/2011	16	$826.28	9,123	11,995	9,189	8,445	670	440	30	11	27%	20%	35%	14%	1%	3%
8/25/2011	17	$738.59	9,151	11,995	9,164	8,443	647	424	30	58	36%	21%	25%	15%	1%	3%
8/25/2011	18	$220.44	9,122	11,995	9,121	8,283	764	402	30	134	31%	20%	30%	15%	1%	3%
8/25/2011	21	$174.71	8,892	11,995	9,168	8,071	1,021	440	30	76	23%	18%	27%	18%	5%	9%
8/25/2011	22	$511.75	8,783	11,995	9,048	8,070	902	440	30	38	26%	27%	24%	21%	0%	2%
8/26/2011	12	$785.91	8,919	11,995	9,014	8,305	634	495	30	11	30%	16%	30%	19%	1%	3%
8/26/2011	13	$739.55	8,908	11,995	9,027	8,256	694	495	30	13	34%	13%	27%	21%	1%	4%
8/26/2011	14	$768.28	8,985	11,995	9,018	8,327	616	495	30	19	38%	15%	19%	22%	1%	4%
8/26/2011	15	$779.64	9,036	11,995	9,018	8,351	590	495	30	18	40%	12%	20%	23%	1%	4%
8/26/2011	16	$706.18	9,046	11,995	9,018	8,384	559	495	30	24	24%	13%	40%	17%	1%	5%
8/26/2011	17	$668.55	9,008	11,995	8,995	8,331	589	495	30	65	23%	12%	38%	22%	1%	4%
8/26/2011	18	$521.73	8,923	11,995	8,975	8,285	615	495	30	28	30%	12%	37%	17%	1%	4%
8/26/2011	22	$238.71	8,702	11,995	8,905	8,053	776	500	30	34	30%	23%	29%	14%	1%	3%
8/28/2011	12	$417.72	8,318	11,995	8,455	7,840	539	487	30	7	7%	23%	33%	33%	1%	4%
8/28/2011	15	$471.11	8,523	11,995	8,572	7,927	569	487	30	5	0%	21%	44%	29%	1%	5%
8/29/2011	11	$487.21	9,042	11,995	9,105	8,180	850	495	30	240	28%	8%	43%	19%	0%	2%
8/29/2011	12	$617.20	9,155	11,995	9,118	8,177	866	495	30	297	27%	8%	44%	18%	0%	2%

Date	HE	Pool Price	Demand	MC	AC	Dispatched MW	Supply Cushion	BC Net Import	SK Net Import	Wind	% of Supply Cushion A	B	C	D	E	Other
8/29/2011	13	$833.86	9,219	11,995	9,094	8,270	749	495	30	344	25%	9%	50%	13%	1%	3%
8/29/2011	14	$769.47	9,314	11,995	9,076	8,280	721	495	30	373	19%	10%	50%	19%	1%	3%
8/29/2011	15	$790.60	9,335	11,995	8,963	8,384	504	495	30	321	27%	10%	34%	26%	0%	4%
8/30/2011	10	$485.37	8,718	11,985	8,891	8,139	656	432	30	19	6%	14%	58%	19%	1%	3%
8/30/2011	11	$650.08	8,789	11,985	8,995	8,102	797	432	30	17	24%	10%	47%	15%	1%	2%
8/30/2011	17	$172.97	8,976	11,985	9,220	8,353	792	432	30	64	17%	10%	48%	21%	1%	4%
9/2/2011	14	$189.16	8,589	11,995	8,870	7,882	902	466	30	127	26%	16%	40%	14%	0%	4%
9/2/2011	15	$147.05	8,527	11,995	8,914	7,806	1,007	466	30	160	24%	14%	38%	10%	0%	14%
9/2/2011	17	$134.64	8,506	11,995	8,879	7,733	1,045	466	30	172	23%	14%	38%	15%	0%	10%
9/6/2011	10	$848.80	8,624	11,985	8,986	8,008	902	441	30	79	26%	19%	43%	9%	1%	2%
9/6/2011	11	$895.38	8,756	11,985	8,930	8,043	811	441	30	29	23%	21%	43%	10%	1%	2%
9/6/2011	12	$926.57	8,898	11,985	8,931	8,258	588	441	30	13	8%	28%	53%	7%	1%	3%
9/6/2011	13	$923.24	8,982	11,985	9,063	8,356	623	441	30	14	19%	16%	56%	5%	1%	3%
9/6/2011	19	$825.44	8,997	11,985	8,952	8,315	581	441	30	47	6%	20%	63%	3%	1%	7%
9/6/2011	20	$741.38	8,823	11,985	9,056	8,376	624	441	75	72	13%	19%	62%	3%	1%	3%
9/6/2011	21	$654.33	8,853	11,985	9,113	8,333	724	441	75	119	18%	18%	59%	3%	1%	3%
9/6/2011	22	$169.75	8,778	11,985	8,925	7,960	909	441	30	152	19%	16%	49%	8%	0%	6%
9/7/2011	21	$614.33	9,032	11,985	8,901	8,231	624	429	30	2	21%	9%	43%	20%	1%	7%
9/7/2011	22	$692.41	8,879	11,985	8,843	8,158	639	429	30	3	20%	11%	42%	19%	1%	7%
9/8/2011	12	$699.40	9,018	11,985	9,124	8,443	598	474	65	0	15%	18%	37%	14%	1%	14%
9/8/2011	13	$743.88	9,084	11,985	9,147	8,516	554	474	64	0	29%	21%	43%	1%	2%	4%
9/8/2011	20	$542.87	8,931	11,985	9,143	8,348	747	474	64	9	29%	15%	42%	7%	1%	7%
9/8/2011	21	$367.75	9,067	11,985	9,163	8,427	690	474	65	10	39%	17%	23%	14%	1%	8%
9/8/2011	22	$578.82	8,922	11,985	9,168	8,342	779	474	89	8	23%	19%	48%	3%	1%	7%
9/9/2011	10	$268.09	8,832	11,985	9,060	8,246	744	433	30	11	31%	0%	54%	5%	1%	9%
9/9/2011	11	$818.03	8,922	11,985	9,019	8,340	624	387	30	3	38%	0%	52%	5%	1%	3%
9/9/2011	12	$720.57	9,013	11,985	8,978	8,363	560	387	30	1	25%	0%	65%	3%	1%	7%
9/9/2011	19	$600.08	8,991	11,985	9,184	8,410	717	433	107	3	11%	25%	50%	6%	1%	7%
9/9/2011	21	$426.11	8,945	11,985	9,141	8,279	779	433	119	30	16%	27%	44%	6%	0%	6%
9/9/2011	22	$175.12	8,765	11,985	9,134	8,105	946	433	114	41	14%	25%	40%	6%	2%	13%
9/10/2011	14	$201.49	8,724	11,985	8,959	8,107	815	440	152	49	15%	14%	49%	7%	5%	9%
9/12/2011	13	$169.21	8,701	11,985	9,010	8,010	925	448	153	5	28%	11%	37%	10%	1%	12%
9/12/2011	14	$129.09	8,680	11,985	9,182	8,057	1,050	448	153	2	30%	12%	38%	9%	1%	10%
9/12/2011	17	$119.80	8,798	11,985	9,087	8,026	1,015	448	123	136	31%	14%	40%	11%	1%	4%
9/22/2011	13	$138.46	8,687	12,003	8,877	7,691	1,171	399	0	431	29%	16%	35%	14%	0%	6%
9/22/2011	17	$134.50	8,841	12,003	8,937	7,861	1,141	424	0	519	27%	18%	38%	15%	0%	2%
9/23/2011	12	$130.42	8,893	12,003	9,127	7,988	1,074	355	152	448	32%	17%	38%	10%	0%	3%
9/23/2011	15	$454.47	9,013	12,003	9,078	7,955	1,062	330	153	632	27%	18%	39%	14%	0%	2%
9/23/2011	16	$146.96	8,929	12,003	9,072	7,801	1,210	330	153	630	28%	15%	34%	18%	0%	4%
9/23/2011	21	$161.31	8,802	12,003	8,685	7,836	763	355	86	435	30%	25%	28%	11%	0%	6%
9/27/2011	17	$692.83	8,972	11,995	8,625	7,894	685	433	153	567	50%	27%	2%	19%	1%	2%
9/27/2011	20	$286.61	8,885	11,995	8,917	7,731	764	433	153	535	44%	25%	32%	12%	1%	-13%
9/27/2011	21	$665.45	8,804	11,995	8,837	7,834	617	433	153	441	53%	23%	37%	15%	0%	-29%
9/28/2011	15	$361.74	8,876	11,995	8,787	7,994	595	426	153	141	50%	30%	0%	12%	1%	7%
9/28/2011	16	$405.42	8,868	11,995	8,837	8,101	538	426	153	155	55%	33%	0%	8%	1%	3%
9/28/2011	21	$602.74	8,826	11,995	8,735	8,023	501	426	153	104	47%	24%	17%	8%	1%	3%

Appendix G: Baseline Parameters for Pool Price – Supply Cushion Relationship

Supply Cushion	=<250	>250 <=500	>500 <=750	>750 <=1000	>1000 <=1250	>1250 <=1500	>1500 <=1750	>1750 <=2000	>2000 <=2250	>2250
-3 Standard Deviations	1,000.00	1,000.00	323.41	152.90	112.62	90.10	75.41	54.29	38.76	33.88
-2 Standard Deviations	1,000.00	639.55	199.99	107.64	80.75	63.79	52.51	39.38	28.71	23.64
-1 Standard Deviation	946.11	306.68	123.53	75.68	57.81	45.08	36.48	28.49	21.21	16.41
Mean	429.00	146.79	76.15	53.13	41.32	31.77	25.25	20.53	15.60	11.30
+1 Standard Deviation	194.22	69.99	46.80	37.21	29.45	22.31	17.38	14.72	11.41	7.69
+2 Standard Deviations	87.63	33.10	28.61	25.97	20.90	15.58	11.88	10.48	8.27	5.14
+3 Standard Deviations	39.24	15.38	17.35	18.04	14.76	10.79	8.02	7.39	5.93	3.34

1. The mean and standard deviation are calcualted using the natural logarithem of pool price plus one and then converted back to the actual values by taking the anti-logarithm.
2. The maximum price is capped at $1000.

Appendix H: EPCOR EPSP Review

EPCOR EPSP Review

On July 7, 2011, the MSA provided a letter of support for an amendment to EPCOR Energy Alberta Inc.'s (EEAI) 2011-2014 Energy Price Setting Plan (the "EPCOR EPSP") – the purpose of the amendment was to adjust the calculation of the seed price (the 'price to beat') that is used to start each auction session. In that letter, the MSA also encouraged EEAI, the consultation parties and the Independent Advisor "to undertake a review of the auction mechanism as to its continuing appropriateness as the sole procurement mechanism for the EPCOR EPSP".

Background on the Seed Price Issue

Under EPCOR's EPSP, as discussed in section 3.1.3.1 of the MSA 2011 Second Quarter Report, energy supply procurement is conducted in three auctions run on NGX. In circumstances where EPCOR is unable to procure its target base and peak load requirement in the three auctions, a contingency auction –an additional auction session- is held to acquire any remaining amount of target volume. EPCOR was unable to procure any of its target volume of peak product for August through the regular three auctions. Despite this challenge, EPCOR was successful in acquiring its full target volume of peak product in the contingency auction session held on July 19, 2011.

The difficulties experienced in procuring August product were attributed to the calculation of the seed price. Pool price volatility was trending higher going into July and August than in previous months due to outages and Keephills 3 commissioning. Consequently, the seed price calculation was unable to reflect the significant day-to-day swings in price, which resulted in a lower percentage of offers on target volumes. The reason for this was that seed price calculation was based on historic forward prices; as a result, it did not effectively capture changes in current market conditions which can happen rapidly and without forewarning in the Alberta market. As shown in Table 1 below, no peak product was procured in the three auctions for August product due to this shortcoming in the seed price calculation.

Table 1: EPCOR EPSP Auction Statistics (July – October)

Date of Auction	Auction Round	Number of Active Participants	Total Number of Attendees	Received Offers (as a percentage of Monthly Target Base (7x24) product)	Received Offers (as a percentage of Monthly Target Peak (7x16) product)
May 18, 2011	Round 1 (July)	11	13	145%	152%
May 25, 2011	Round 2 (July)	13	14	185%	195%
June 8, 2011	Round 3 (July)	12	15	155%	138%
June 15, 2011	Contingency (July)	11	15	N/A	176%
June 22, 2011	Round 1 (August)	5	16	40%	Not Competitive
June 29, 2011	Round 2 (August)	4	16	20%	Not Competitive
July 7, 2011	Round 3 (August)	5	16	45%	Not Competitive
July 19, 2011	Contingency (August)	14	16	165%	209%
July 19, 2011	Round 1 (September)	11	16	147%	132%
July 26, 2011	Round 2 (September)	11	16	137%	159%
August 2, 2011	Round 3 (September)	10	16	111%	141%
August 23, 2011	Round 1 (October)	13	16	138%	109%
August 30, 2011	Round 2 (October)	13	16	95%	150%
September 6, 2011	Round 3 (October)	13	16	57%	105%
September 13, 2011	Contingency (October)	9	16	N/A	132%

EPCOR, the consultation parties and the Independent Advisor determined that it was appropriate to amend the seed price calculation. EPCOR filed an application to amend the formula on July 8, 2011 which was subsequently approved by the Alberta Utilities Commission on July 22, 2011 in Decision 2011-314.

Since making the amendment to the seed price, EPCOR has experience no difficulties in procuring its target volumes using the auction mechanism.

Performance of the EPCOR EPSP

The auction mechanism in the EPCOR EPSP is consistent with the price setting protocol used in the 2006-2011 Energy Price Setting Plan. In contrast to the old plan under which target volume was self-supplied at an Index price, 100% of the target volume of the EPCOR EPSP is purchased from suppliers participating in the auction process. This difference increases the openness and competitiveness of the EPCOR EPSP.

The auction mechanism continues to be an appropriate procurement mechanism for the EPCOR EPSP because:

- It is transparent – the procurement methodology is well understood by participants and most of the elements of the EPCOR EPSP, except for confidential, commercially sensitive aspects, are publicly available.
- It is simple – the EPCOR EPSP is mechanical and requires limited judgment on procurement decisions.
- It is an open process – the auctions are conducted on the NGX platform and all participants that meet the credit requirements can participate.
- It is low in administrative burden – the Independent Advisor is not involved on a daily basis to set a price to beat as is the case with Direct Energy's Energy Price Setting Plan.

Although there is limited data and history with the 2011-2014 Energy Price Setting Plans, an analysis of RRO monthly energy prices, procurement prices for base and peak product under the EPCOR EPSP, the NGX index and actual trades on NGX, and the supply mix of the EPCOR EPSP indicate that EPCOR EPSP is performing comparably to the Energy Price Setting Plans of other RRO providers.

RRO Monthly Energy Prices

Figure 1 below compares the month energy prices of EPCOR to those of other RRO providers. As previously noted by the MSA in the Quarterly Report for April – June 2011, there was little difference in RRO prices in the 2006 to 2011 period despite the differences in the RRO procurement methodologies. Since July 2011, the EPCOR EPSP continues to produce results that are similar to other RRO providers - an indication of the competitive nature of the EPCOR EPSP.

Figure 1: RRO Monthly Energy Prices from July 2010 to October 2011

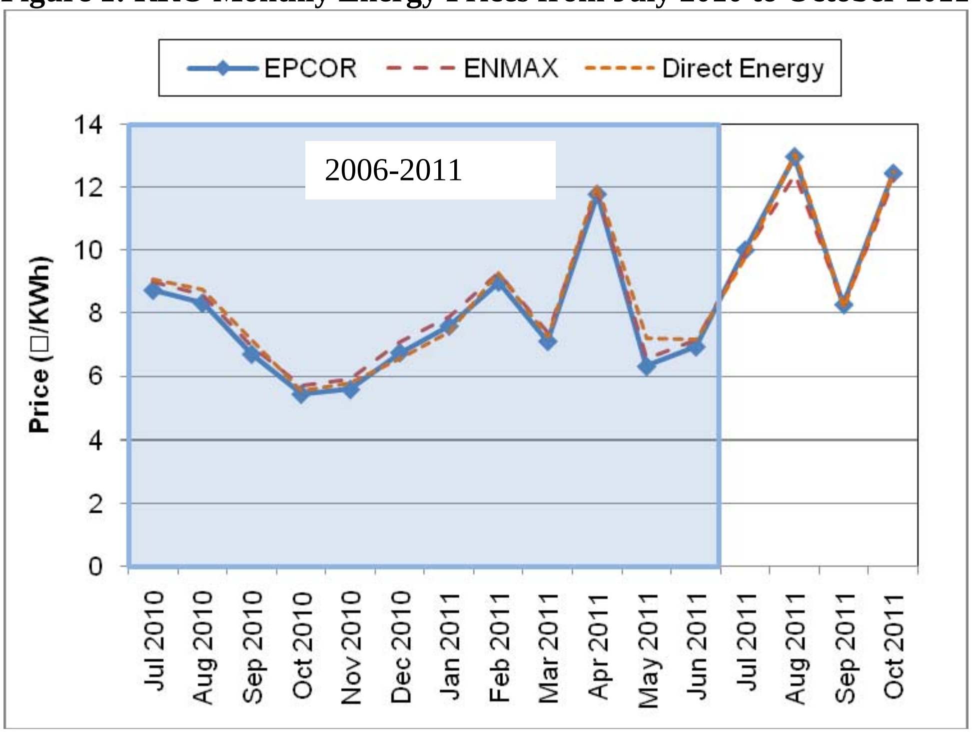


Table 2: RRO Monthly Energy Prices from July 2010 to October 2011

RRO Monthly Energy Charges			¢/kWh
Month	**EPCOR**	**ENMAX**	**Direct Energy**
Jul 2010	8.718	8.977	9.069
Aug 2010	8.303	8.576	8.744
Sep 2010	6.687	6.950	7.146
Oct 2010	5.418	5.677	5.527
Nov 2010	5.565	5.879	5.764
Dec 2010	6.732	7.059	6.559
Jan 2011	7.581	7.894	7.418
Feb 2011	8.976	9.293	9.284
Mar 2011	7.093	7.356	7.227
Apr 2011	11.763	11.885	12.095
May 2011	6.299	6.555	7.210
Jun 2011	6.920	7.149	7.146
Jul 2011	9.989	9.888	9.754
Aug 2011	12.953	12.432	13.079
Sep 2011	8.256	8.213	8.161
Oct 2011	12.426	12.255	12.513

In addition, the EPCOR EPSP auctions are consistent with the trends on the broader NGX forward market. The Figures 3 and 10 below show comparisons between procurement under the EPCOR EPSP, the NGX index and actual trades on the NGX for Base and Peak products.

Figure 3: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Base Product from July

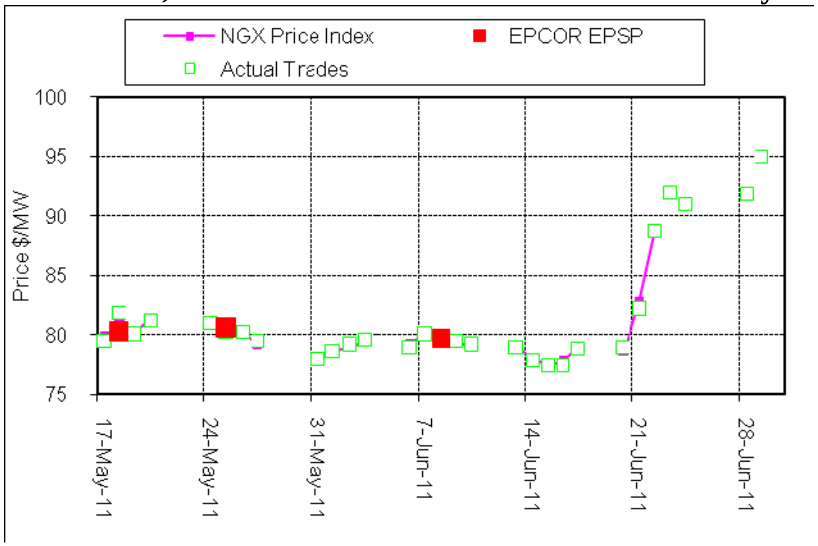


Figure 4: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Peak Product from July

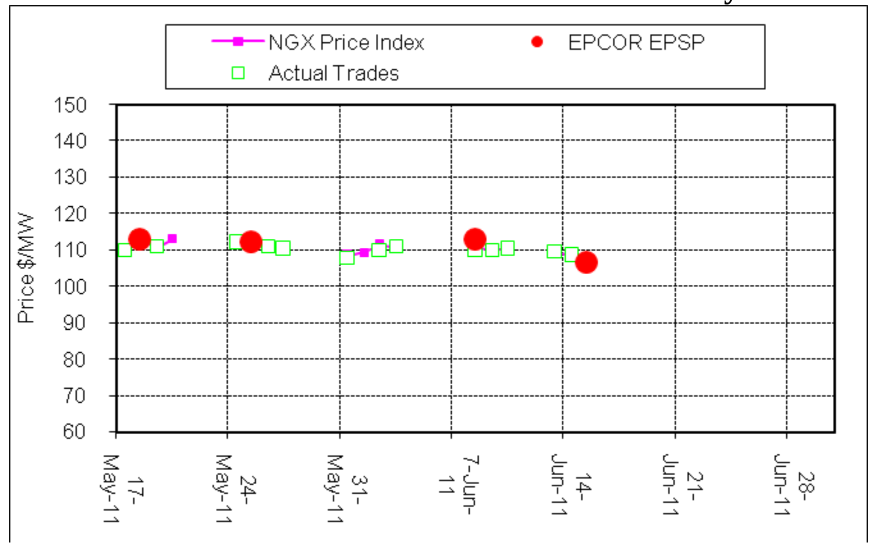


Figure 5: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Base Product from August

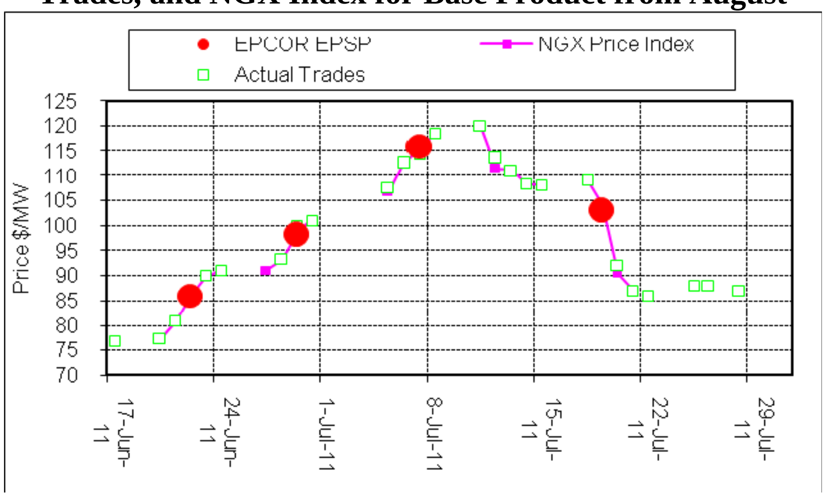


Figure 6: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Peak Product from August

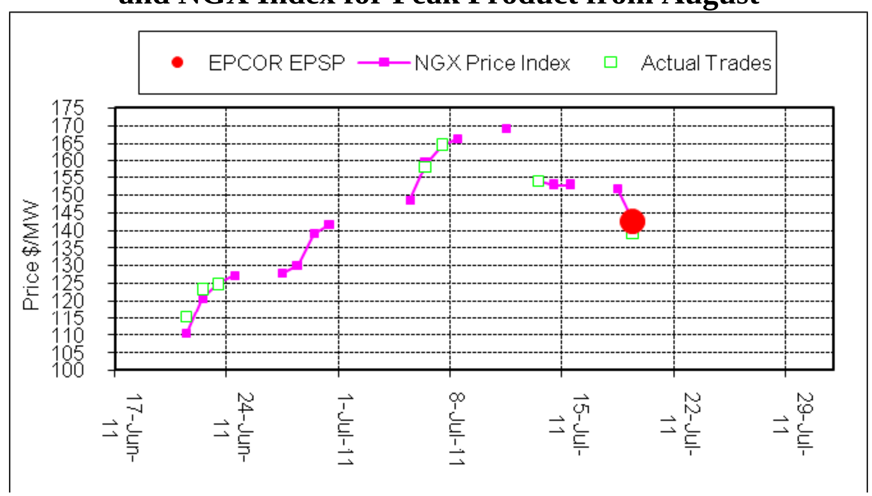


Figure 7: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Base Product from September

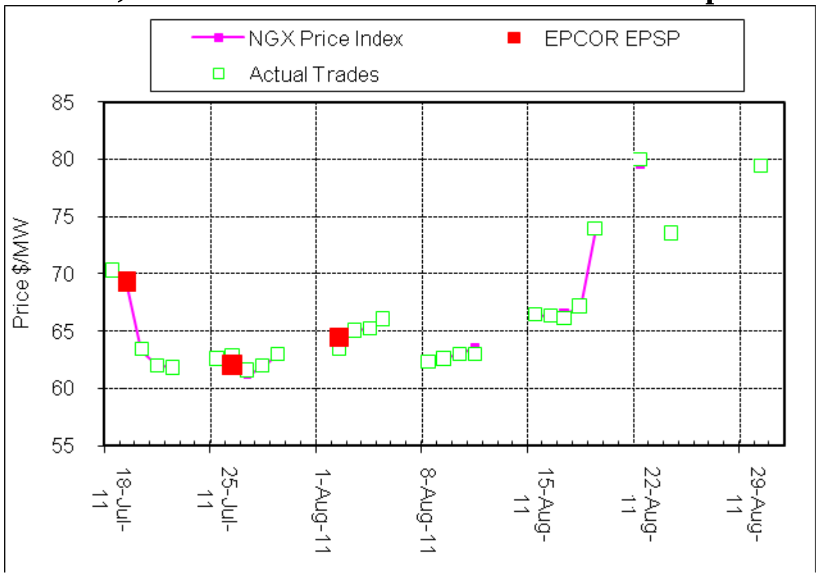


Figure 8: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Peak Product from September

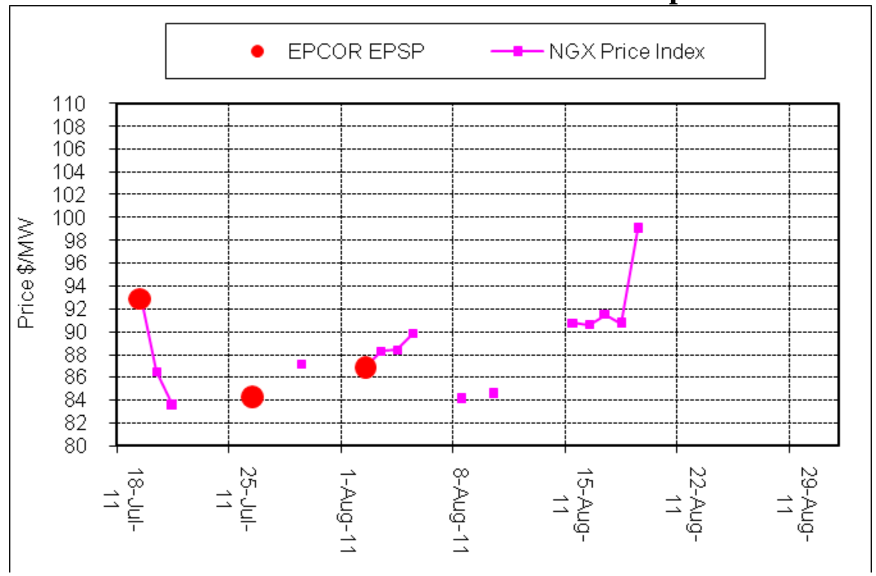


Figure 9: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Base Product from October

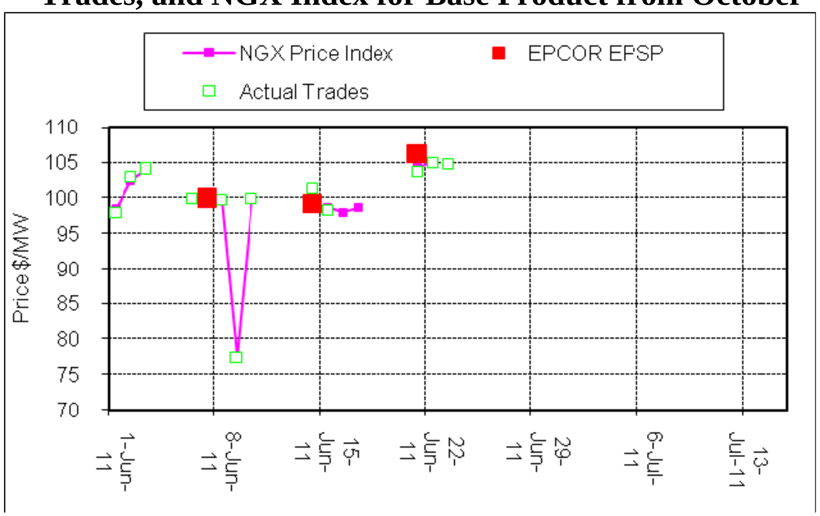
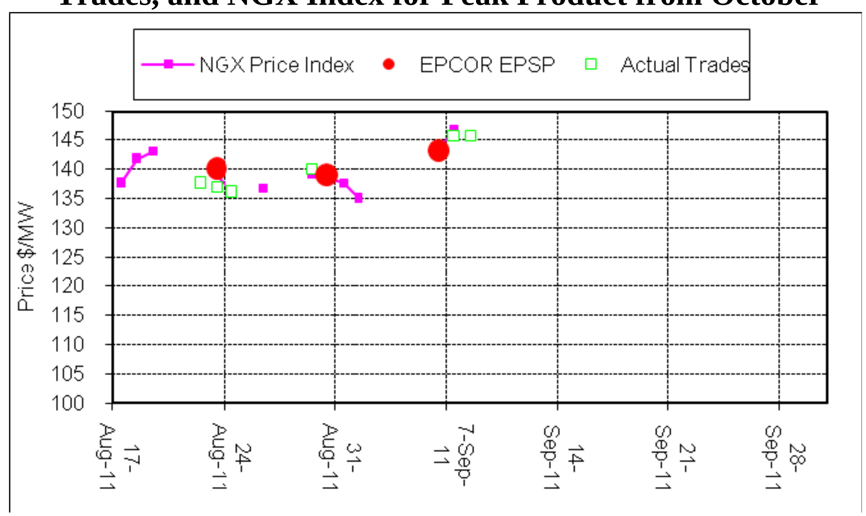


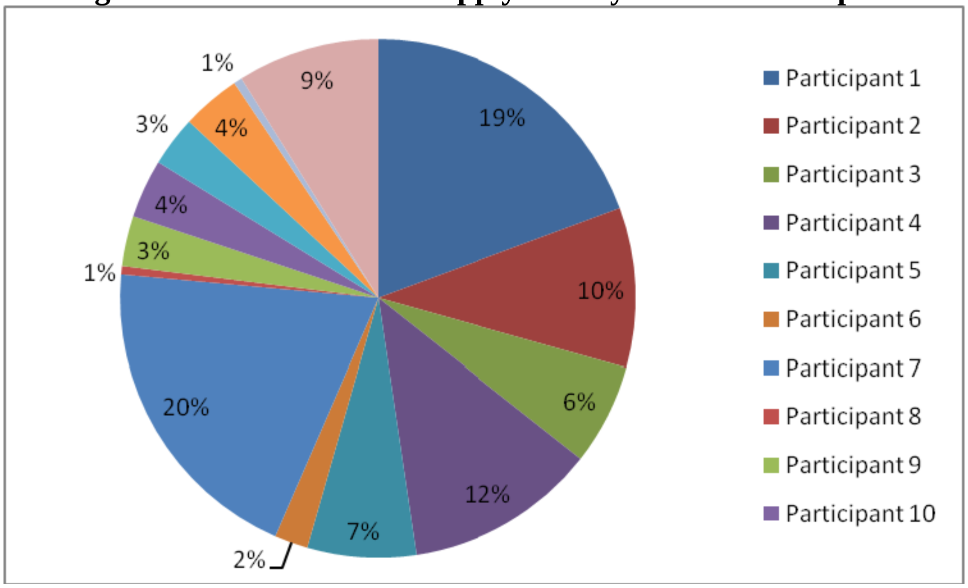
Figure 10: Procurement Prices for EPCOR EPSP, NGX Trades, and NGX Index for Peak Product from October



EPCOR EPSP Supply Share Percentages

75% of the EPCOR EPSP supply has been provided by market participants with generation and the remaining 25% is provided by financial market participants. The share percentages for the EPCOR EPSP are shown in Figure 11 below. The EPCOR EPSP encourages broad participation and as shown in the figure, EPCOR's target volumes are provided by a diverse group of suppliers with no disproportionate share from any single participant. This is indicative of the competitiveness of the auction procurement mechanism of the EPCOR EPSP.

Figure 11: EPCOR EPSP Supply Mix By Market Participant



Conclusion

The EPCOR EPSP is producing monthly energy prices that are comparable with the prices of other RRO providers. It is generally oversupplied with offers as a percentage of target volumes which is consistent with a high degree of supplier competition. Participation in the auctions is representative of the broader wholesale market and the supply mix demonstrates a diverse and fair distribution between suppliers. Overall, the EPCOR EPSP is producing results consistent with a fair, efficient and openly competitive process.

References

Market Surveillance Administrator

Offer Behaviour Enforcement Guidelines, 2011
http://albertamsa.ca/uploads/pdf/Consultations/Market%20Participant%20Offer%20Behaviour/Decide%20-%20Step%205/Offer%20Behaviour%20Enforcement%20Guidelines%20011411.pdf

Stakeholder Consultation on Market Data Transparency, 2011 (ongoing)
http://albertamsa.ca/uploads/pdf/Archive/2011/Notice%20re%20Stakeholder%20Consulation%20Market%20Data%20Transparency%20100611.pdf

MSA Quarterly Reports
http://albertamsa.ca/index.php?page=quarterly-reports

MSA Letter to AUC Re: EPCOR Energy Alberta Inc – Amendment to 2011-14 Energy Price Setting Plan, July 2011
http://albertamsa.ca/uploads/pdf/Archive/2011/Letter%20AUC%20EPCOR%20EPSP%20070711.pdf

Statutes and Regulations

Electric Utilities Act, Statutes of Alberta, 2003, Chapter E-5.1

Regulated Rate Option Regulation (AR 262/2005)

Independent System Operator

Scheduled Generator Outage Cancellation Report.
http://www.aeso.ca/downloads/Scheduled_Generator_Outage_Cancellation_Report.pdf

ISO Operating Policies and Procedures
http://www.aeso.ca/rulesprocedures/9073.html

ISO Rules
http://www.aeso.ca/rulesprocedures/18592.html

AESO Long term Critical Transmission Outges > 10 days
www.aeso.ca/outage_reports/Longterm_Critical_Outages.html

AESO System Co-ordination Plan. Approved Outages
www.aeso.ca/outage_reports/qryOpPlanTransmissionTable_1.html

AESO Available Transfer Capacity Report Query
http://itc.aeso.ca/itc/public/atcQuery.do

AESO 24 Month Supply and Demand Forecast
http://ets.aeso.ca/Market/Reports/Manual/AiesGraphs/24_month_supply_and_demand.html

AESO Short Term Outage
http://ets.aeso.ca/ets_web/ip/Market/Reports/ShortTermOutageForecastReportServlet?contentType=graph

AESO Monthly Outages
http://ets.aeso.ca/ets_web/ip/Market/Reports/MonthlyOutageForecastReportServlet?contentType=image&imageTableIndex=1

Commission Decisions and Rules

Application No. 1607868 Settlement Agreement MSA TransAlta
https://www.auc.ab.ca/eub/dds/iar_query/ApplicationAttachments.aspx?AppNumber=1607868

Other

IPPSA Commissioned Study: Power Prices in Context: comparing Alberta delivered electricity prices to other Canadian province's on a level playing field, 2011. www.IPPSA.com

Charles River Associates. Electricity Market Data Transparency. 2011. Report Prepared for MSA.
http://albertamsa.ca/uploads/pdf/Archive/2011/Market%20Data%20Transparency/CRA%20Report%20for%20MSA%2011-22%202011.pdf

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.