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MSA REPORT

Quarterly Report

July – September, 2008

31 October, 2008

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1 WHOLESALE MARKET FUNDAMENTALS

1.1 Featured Market Developments During Q3/08

Average pool price for Q3/08 was significantly lower than for Q2/08 and lower than the same quarter in the previous year. The year-to-date average price also declined over the quarter by $4 from $92.23 at the end of Q2/08 to $88.19 by the end of Q3/08.

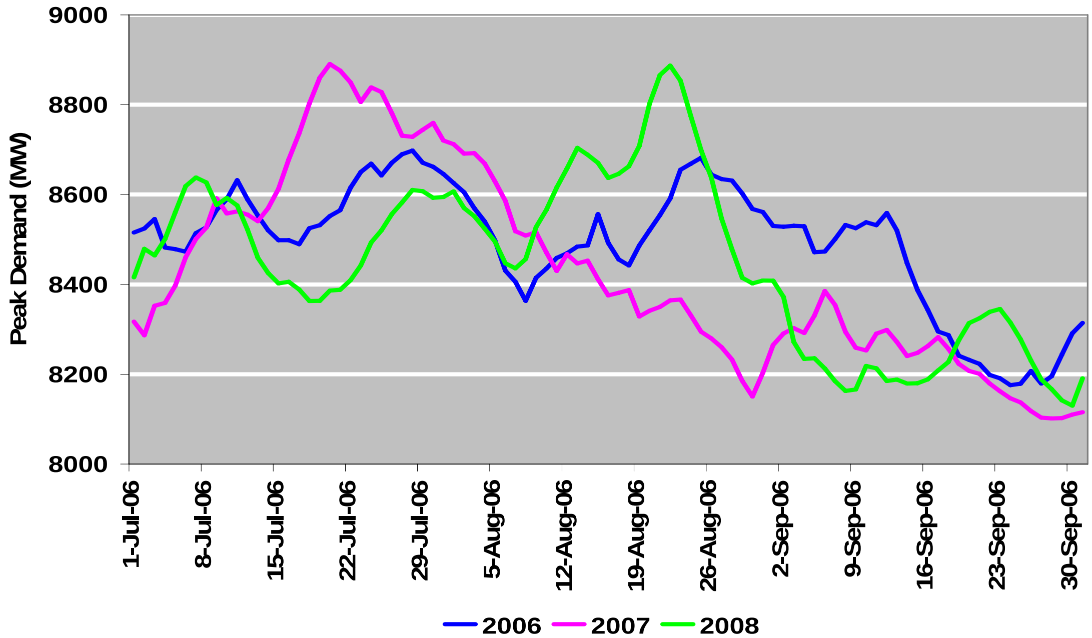
In recent years, average monthly pool prices have been highest during July. However, in 2008, the average monthly pool price for July settled at $64.51 (compared to $128.23 and $154.25 in 2006 and 2007 respectively). Prices in July and much of August were low primarily due to relatively high levels of coal availability, and falling natural gas prices.[1]

July 2008 also saw relatively cool summer temperatures with significantly lower daily peak demands for much of the month in comparison to previous years (as shown in Figure I). Warmer weather arrived in mid August, setting a record summer peak demand on August 18 of 9541 MW, 2.3% higher than previous record set on July 19, 2007. This is slightly lower than the annual average growth rate for the summer peak of 3.7% since 2000. While peak summer demands have continued to increase, overall load during the quarter was only 0.9% higher than in 2007 and below the level of 2006.

Although peak demand occurred mid August, prices were significantly higher during the first week of the month. In fact on August 18 (the day of our new summer record peak demand) the daily average price settled at $85.45 where as the average price from August 4 to August 8 was $194.38. By early August peak demand had started to increase but the primary driver of the high average prices was a period of low coal availability.

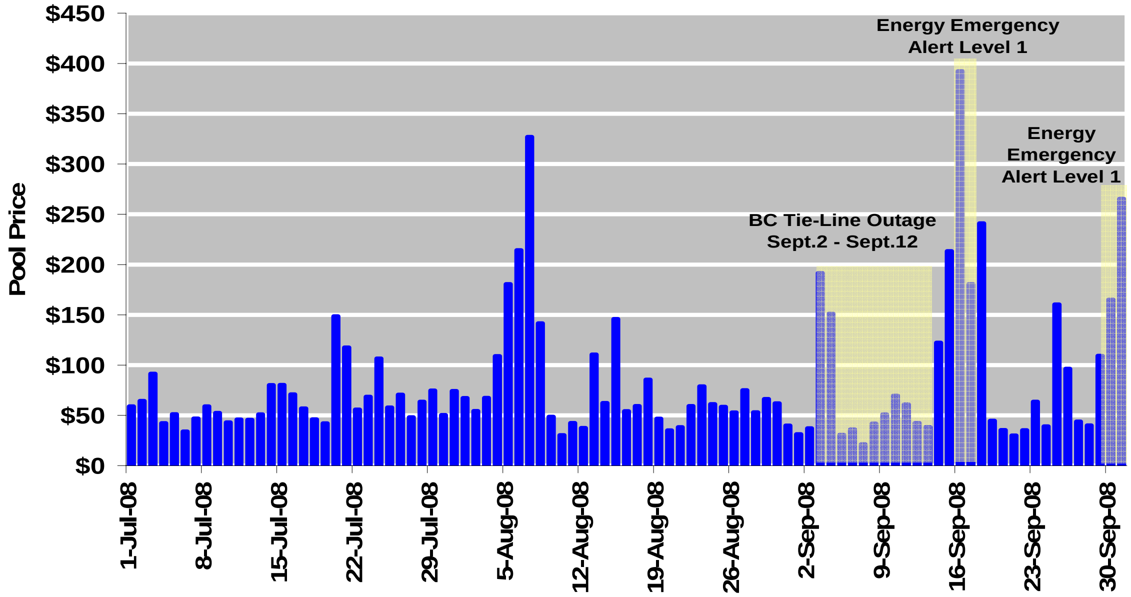
[1] See Figure 3 in Appendix A.

Figure I: Comparison of Peak Demand Q3/08 (7 Day Rolling Average)



Prices were significantly higher and more volatile during the month of September as we experienced a planned outage of the BC tie-line early in the month and significantly lower gas fueled generation availability for the majority of the month. Both factors contributed to price volatility and low gas fueled generation availability was a factor in both the Emergency Alerts experienced in September and one that occurred in early October. We consider both the impact of the BC Intertie outage and the Emergency Alerts in more detail in the following sections.

Figure II: Daily Average Pool Prices and Featured Market Events



1.2 BC Intertie Outage

In Alberta the combination of low off-peak loads and high volumes of baseload thermal generation usually results in low off-peak prices. When the interties are available, exporters take advantage of the low Alberta prices and export power to neighbouring markets – in turn narrowing the price spread between Alberta and the receiving markets. The opposite is typically true in on-peak hours when importers bring power into Alberta, once again narrowing the spread between markets. In many ways the interties act as an equilibrating mechanism that aids in the smoothing of pool price over the course of a day. The interties also play an important role by enhancing competition as importers compete directly with intra-province generators. When intertie outages occur for planned (or forced) maintenance the market loses both of these effects. The MSA monitors these events closely to examine both market participant behavior and outcomes.

Planned maintenance occurred on the BC Intertie between September 2 and 11 (HE 9 September 2 to HE 22 on September 11 (Figure II). This resulted in very low average exports (1,946 MWh, all on the SK Intertie) and contributed to softer off-peak prices ($22.83/MWh during the period of the maintenance compared to $40.54/MWh for the entire quarter) Similarly, imports were lower (6,734 MWh compared to 454,491 MWh for the entire quarter) however the impact on on-peak prices is harder to discern given other factors (for example, a decline in peak demand in late August).

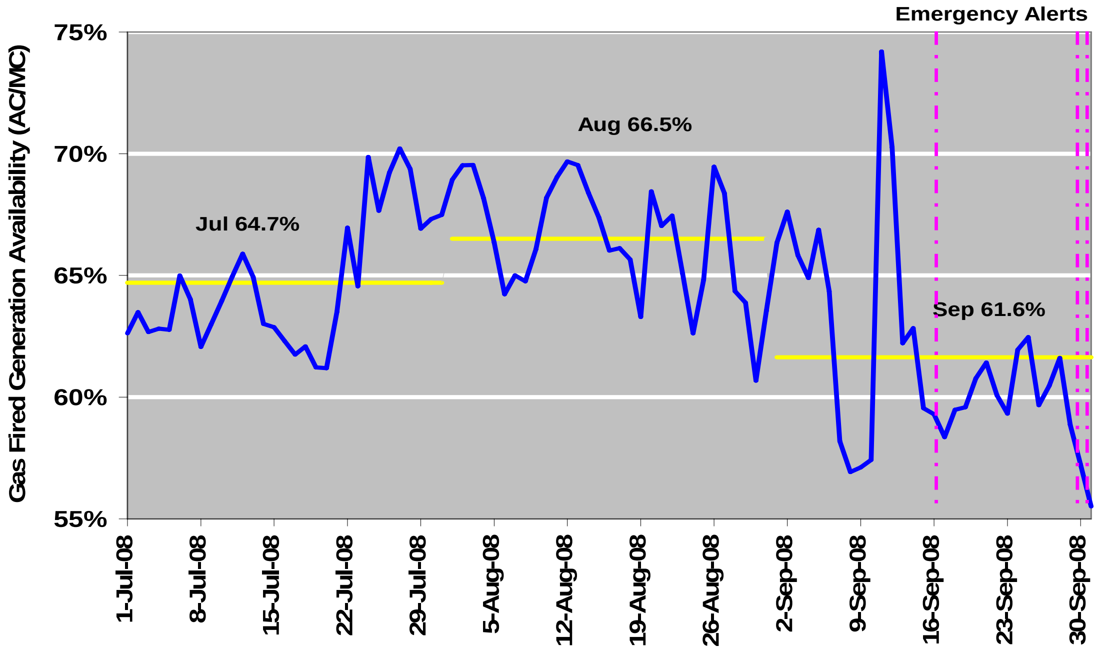
1.3 Emergency Alerts

On two separate occasions during the quarter the system experienced an emergency alert 1, with a third occurrence on October 1. An emergency alert level 1 occurs when all available resources in the energy market have been used to meet demand but operating reserves are still intact (typically about 500MW). An emergency alert level 2 is declared only when operating reserves are being used to supply energy.

In the past, emergency alerts have often coincided with particularly low levels of coal generation availability. During September and early October coal availability was not unusually low rather Figure III shows that the availability of gas-fired generation was low during the times of the emergency alerts. Similarly, wind generation was close to zero. The final trigger in each instance was the sudden loss of a baseload coal unit. The nature of the Alberta market design is such that often times, during on-peak hours, there is only a moderate amount of spare capacity available and online. Effectively this means that a significant drop off in capacity (for example, a large coal unit) will frequently result in a spike in price and on some occasions will result in the issue of an emergency alert, particularly if the loss of capacity coincides with peak demand. We provide a brief summary of the main contributing factors for each of the supply adequacy events below:

- **September 16 (14:38 - 19:32, 16:15 - 16:53):**
    - Little to no wind generation, two coal units offline. KH1 tripped in HE14.
- **September 30 (13:13 - 14:55):**
    - Little to no wind generation, two coal units offline. Approximate loss of 350 MW as three coal units became derated in HE14.
- **October 1 (15:22 – 17:24):**
    - Low levels of wind generation, one coal unit offline in addition to large derates at numerous coal plants. SD6 tripped in HE16.

Figure III: Availability of Gas-Fired Generation Capacity Q3/08

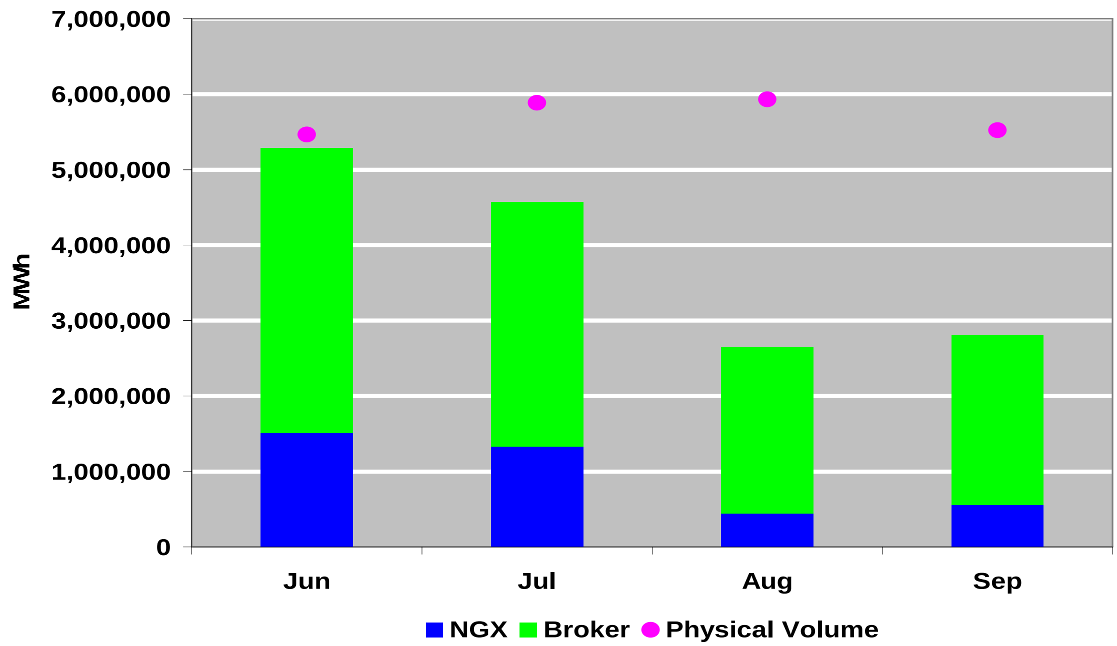


2 FORWARD MARKET ACTIVITY

2.1 Forward Market Trading Volumes

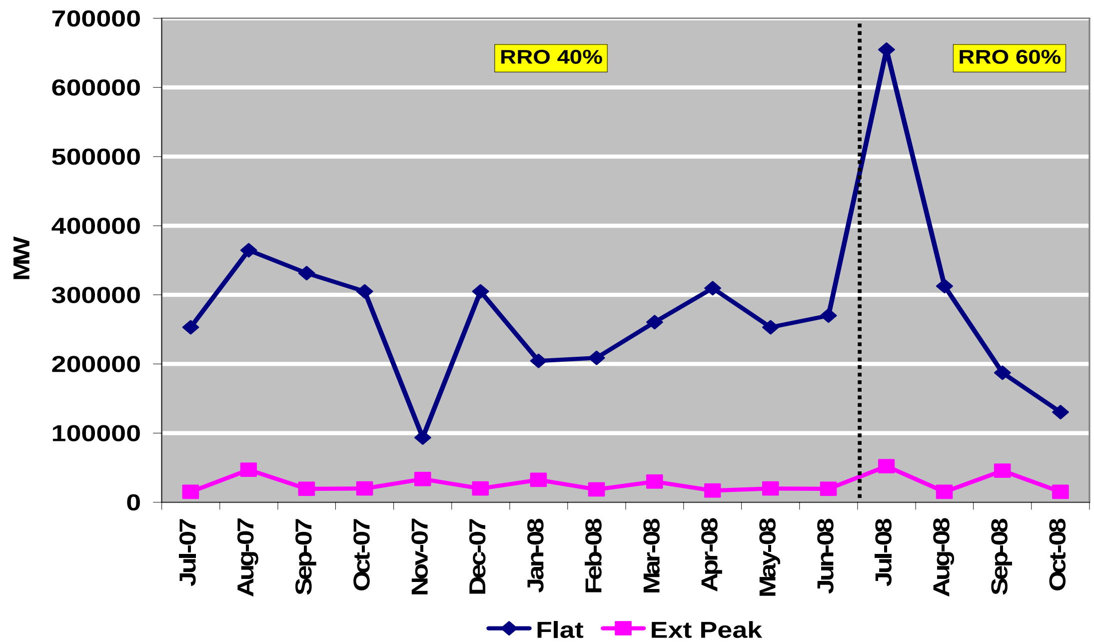
In June 2008, the MSA began to collect transaction data from OTC brokers on a weekly basis. The forward transaction data is depicted below and is divided into two categories: those volumes traded on the NGX electronic platform and those traded through brokers (OTC). The volume transacted on the forward market totaled over 10,000 GWh in Q3/08 which is equivalent to about 58% of the size of the physical market for the same period, however forward market volumes do vary considerably from month to month (Figure IV). For example, relatively small increases in the trading of yearly products can result in big changes in overall volume (for example, 5MW for an entire year equates to 43,800 MWh). Volumes for shorter term products (for example, month ahead) may be greatly influenced by market news. It is unclear at the current time how much of the apparent recent decline in forward market volumes can be attributed to the credit crunch in the financial markets.

Figure IV: Forward Market Trading Volume (MWh) (Jun – Sep 2008)



Volumes traded on NGX are also in part driven by the Regulated Rate Option (RRO) index transactions associated with the Epcor and Enmax Energy Price Setting Plans. Figure V shows the trade volumes for the flat (7X24) and Extended Peak (7X16) products. The volume of trades for the extended peak product is very modest and shows no upward trend. The trade volumes for the flat product do appear to be increasing over time as the RRO index is used to price more of the RRO volume (increasing from 40 to 60% in July 2008). Volumes appear to have fallen off over the past few months (possibly a reaction to the credit crunch being experienced in most financial markets) but current figures indicate strong volumes traded for November.

Figure V: RRO Trading Volume on NGX by Delivery Month (MW)



2.2 Forward Market Participation

In Q3/08 there were 25 different participants that traded in the Alberta forward market and of these participants at least 16 transacted in every month (Figure VI). The four most active participants accounted for 55% of the market share (Figure VII).

Figure VI: Number of Forward Market Participants (Jun – Sep 2008)[2]

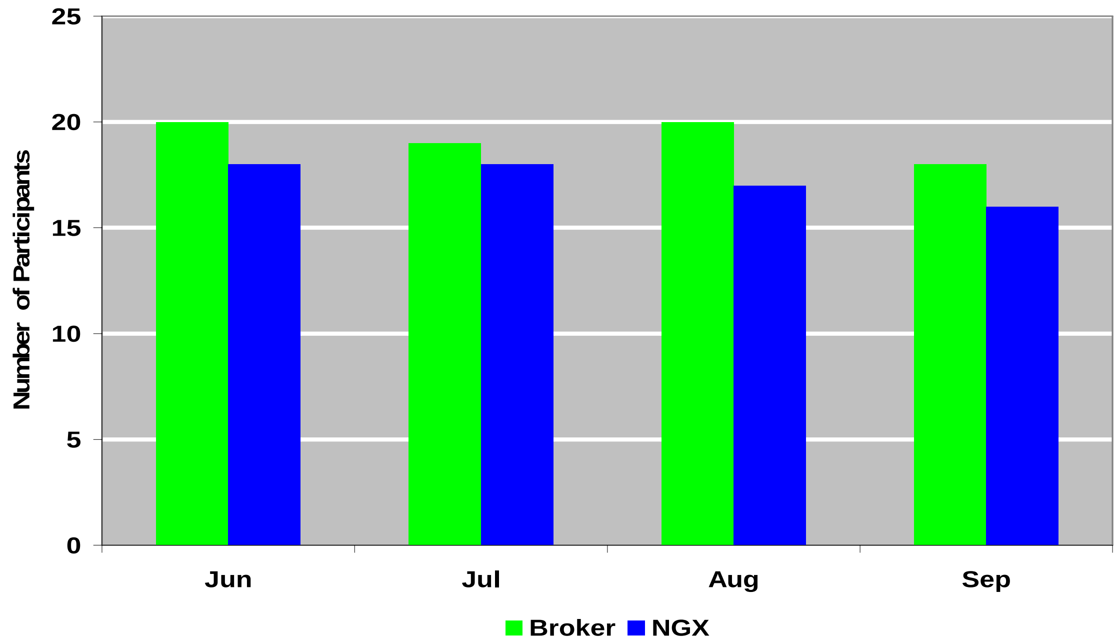
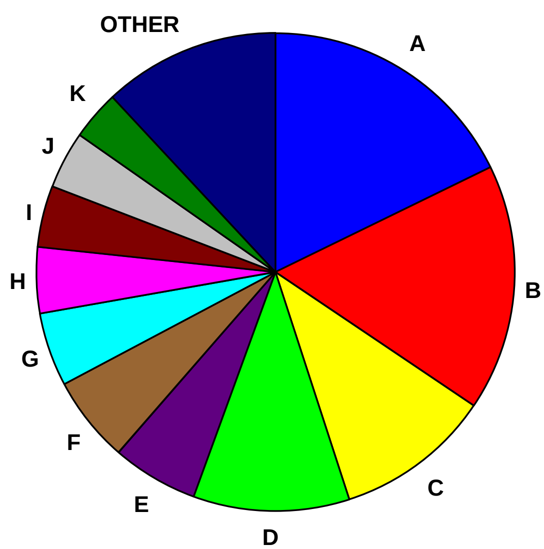


Figure VII: Market Share of Forward Market Participants



[2] Note that the total number of participants actively trading in the forward market is not equal to the sum of the two bars, as some participants are active both on NGX and OTC.

3 RETAIL MARKET DEVELOPMENTS

With the coming into force of the Alberta Utilities Commission Act the MSA's mandate expanded to include surveillance of the retail natural gas market. Given this new responsibility, the MSA has taken the opportunity to conduct a review of both the retail electricity market and the retail natural gas market that will be published in the coming weeks.

In the Quarterly reports we have regularly reported on a variety of metrics describing the performance of the settlement process in the electricity market. The MSA is not responsible for monitoring compliance of the Electric Settlement System Code (SSC) (that responsibility rests with the AESO) but is interested in the settlement process in so far as it influences the development of the competitive retail market. At the time of deregulation, numerous issues related to metering and billing arose as new settlement agents took over leaving consumers with concerns regarding the success of deregulation.

Overall, the MSA is satisfied that system settlement is working reasonably well and not having any detrimental impacts on competition. The MSA intends to cease its regular monitoring of these metrics. In this Quarterly report we provide a final overview. In the past the MSA has reported on two measures of the performance of the settlement system as well as the level of unaccounted for energy. These are:

- PFEC ("pre-final error correction") serves to correct errors prior to a subsequent run of settlement and thus improves settlement results prior to final settlement:
- PFAM ("Post-final adjustment mechanism") is a process that market participants must follow when final settlement data is being disputed and the market participants are requesting financial adjustments as a result of the dispute.
- UFE ("Unaccounted for Energy) exception reports. The number of UFE exception reports reflects the extent of the settlement differences between energy going into the system versus energy consumption and losses. UFE Reasonableness Exception Reports note instances where UFE was outside the tolerances allowed for in the Code. LSA's are required to investigate and report to the market on such variances. The cost of the UFE is recouped via the energy charge on consumer bills.
- Similarly in natural gas there exists unaccounted for gas (UFG) where UFG is the difference between total system receipt and total system consumption by distribution zone. No data is readily available on PFEC and PFAM in natural gas but UFG is calculated

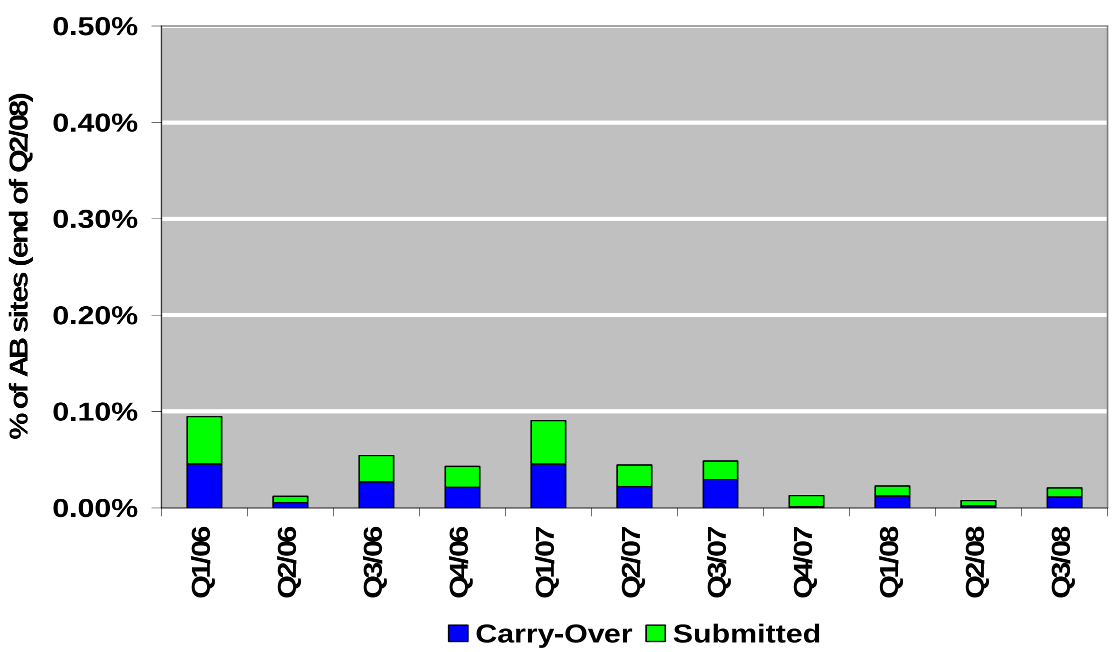
and recouped by the distribution zones on an annual basis via a rate rider "D" charged to all consumers.[3]

3.1 Electricity

3.1.1 PFEC and PFAM

The MSA is primarily monitoring for large increases in errors from quarter to quarter or trends that suggest settlement issues may be of concern to the overall health of the competitive market. The following two figures show the number of PFEC and PFAM that were issued on a quarterly basis since the beginning of 2006 as a percentage of the total sites in the province.[4] The data indicates that on average there are more PFEC submitted than PFAM implying that more errors are detected prior to final settlement. Furthermore, we see that the total PFAM issued in any one quarter has been less than 0.1% of the total sites in the province. (The increase in Q1/07 was a result of consumption having been estimated for approximately 3000 sites that had been metered but had not been entered into the system prior to final settlement. Note that all these were resolved by the end of Q2/07). PFEC or PFAM that are not resolved within the quarter they are issued are almost always resolved within the following quarter indicating a timely resolution process.

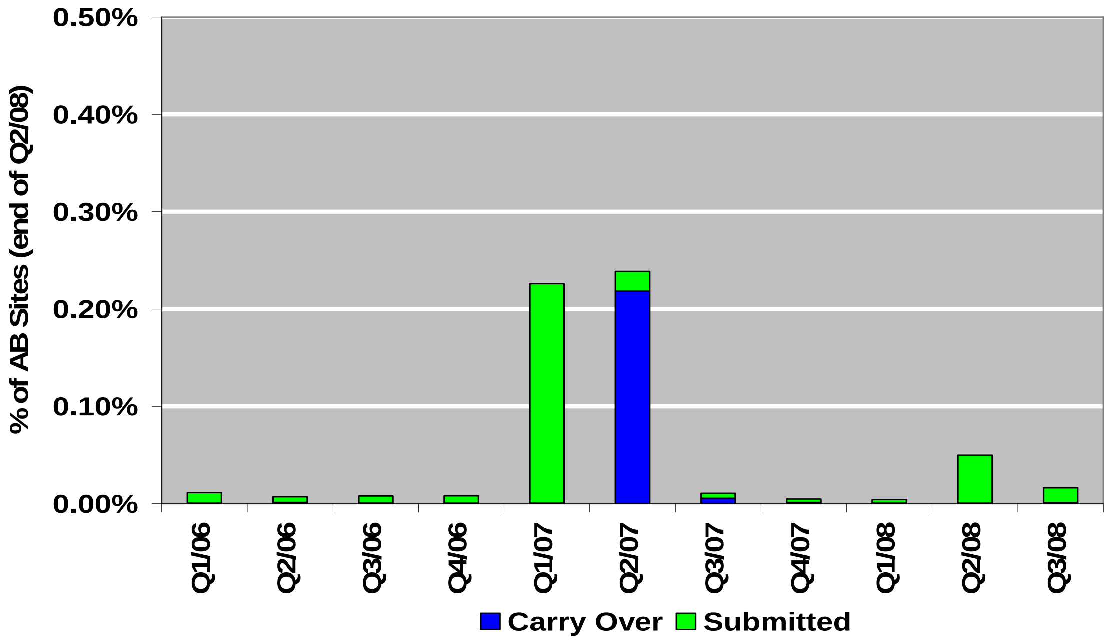
Figure VIII: PFEC issued as a Percentage of Total Sites



[3] In natural gas there is not currently a common system settlement code among the distribution zones and there is no equivalent to the AESO charged with monitoring the settlement process as is the case in the electricity market.

[4] The total number of sites in the province at the end of each quarter was used with the exception of Q3/08 which uses the total number of sites in the province at the end of Q2/08.

Figure IX: PFAM issued as a Percentage of Total Sites



3.1.2 UFE

UFE reasonableness reports indicate those instances when the UFE is out of tolerance. The absence of a MW value associated with the individual report makes it difficult to make comparisons across LSA's or to determine the magnitude of the total UFE in the province. The AESO, in accordance with AUC Rule 021, monitors the Average Zone UFE % for each of the distribution zones and makes the results available to all participants on its website.[5] The data collected by both the AESO and the MSA indicates that the majority of distribution areas have very little problem with UFE on a regular basis and that those that do arise are resolved in a timely manner. Overall the majority of the UFE reports are issued by two distribution zones: Crowsnest and Cardston. In fact the average level of UFE within these zones is out of tolerance. The MSA understands that the AESO has forwarded both these instances of non-compliance to the AUC and adjustments have been made to correct for the high levels of UFE and both zones are working to become compliant with the SSC.

[5] http://www.aeso.ca/loadsettlement/14452.html

3.2 Natural Gas

Owners of gas distribution zones must file applications with the AUC in order to determine the rate rider "D" that allows them to recoup UFG. Annual UFG rates are available to the public as a result of this process and are presented below in Table 1. Once approved, the UFG rate is set on an annul basis typically for the period beginning Nov 1 and ending Oct 31 of the following year. The UFG rate riders for the three largest distribution zones are included in the table below since 2004. Overall the riders associated with unaccounted for gas do not show any clear trend over the period and the MSA does not have any particular concerns regarding UFG.

Table I: Historical Rider UFG

Year*	ATCO NORTH	ATCO SOUTH	ALTA GAS
2004	1.01%	0.80%	1.10%
2005	0.84%	0.46%	1.03%
2006	0.80%	0.51%	1.08%
2007	0.76%	0.44%	0.73%
2008	0.81%	0.81%	0.74%

*UFG riders are typically set on Nov 1 and run until Oct 31 of the following year.

The year in the table is associated with the period from Jan 1 to Oct 31 although the rider also applies to the period Nov 1 to Dec 31 of the previous year. On occasion riders can be reassessed with approval from the AUC. In 2005 the ATCO rider was reassessed on Jan 1, 2005 which is the rate shown.

4 QUICK HITS METRICS

4.1 Quick Hits Implementation Issues

In the Q2/08 report, the MSA reported instances of incorrect posting of pool price resulting from IT difficulties experienced by the AESO. The MSA is pleased to report there have been no problems with the posting of pool price since an upgrade was implemented on July 10, 2008. However, in the last quarter the MSA has detected some errors in the dispatching of dispatch down service (DDS). In particular, there have been occasions where DDS is dispatched above the required level (in excess of transmission must run (TMR)) and occasions where units offering DDS have received a dispatch with SMP higher than the reference price. The MSA has alerted the AESO to these problems and understands the problem is being addressed and is IT related.

4.2 DDS Metrics Update

At the end of Q2/08 the MSA published a report discussing the unanticipated consequences resulting from the implementation of the DDS market. In the report the MSA provided a number of metrics which it felt were useful indicators of the overall success of the market as well as measures of the impact of DDS on the energy market. At that time the MSA committed to reporting these metrics quarterly and on a go forward basis the following figures will be included in Appendix D of the quarterly reports entitled DDS Market Metrics.

The cost of payments to DDS providers is recouped entirely from generators and is distributed evenly among those generating in hours where DDS was dispatched. The average estimated monthly costs and revenues for Q3/08 are comparable to those from the first half of the year (Table II). DDS revenues were higher in July which is consistent with the much higher reference price relative to declining gas prices and the limited level of constrained down MW.

In the DDS report, the provision of DDS service was compared with the provision of spinning reserves for the system. A comparison of the estimated monthly revenue paid to DDS providers to those providing Active Spinning reserves is shown in Table II. In some months, it can be more lucrative for participants to participate in the DDS market than in the Active Spinning market. In months with higher average prices, revenue from Spinning Reserves will be higher than revenue strictly from DDS. This occurs as DDS volumes (and hence revenues) cap out at the reference price whereas spinning reserves are unaffected.

Table II: DDS Costs and Revenues

Month	Estimated DDS Charge ($/MWh)	Estimated Revenue to DDS Providers ($/MWh)	Average Price of Active On-Peak Spinning Reserves ($/MWh)	Average Price of Active Off-Peak Spinning Reserves ($/MWh)
July	$0.60	$42.19	$29.70	$21.94
August	$0.35	$28.83	$39.42	$11.02
September	$0.34	$29.53	$90.45	$28.81

Perhaps most obvious is the impact of the Reference Price on the System Marginal Price (SMP) duration curves. Particularly at the beginning of 2008 we were experiencing large ‘shelves’ in the monthly SMP duration curves at the Reference Price level. For example in the month of January SMP was ‘sticky’ for almost 20% of the time in a very narrow band around the Reference Price. Figure X below shows that although there appears to be less “stickiness” about the Reference Price (dotted lines) SMP is still settling at 12.5 heat rate 5% to 10% of the time.

Figure X: SMP Duration Curves (Jul –Sep 2008)

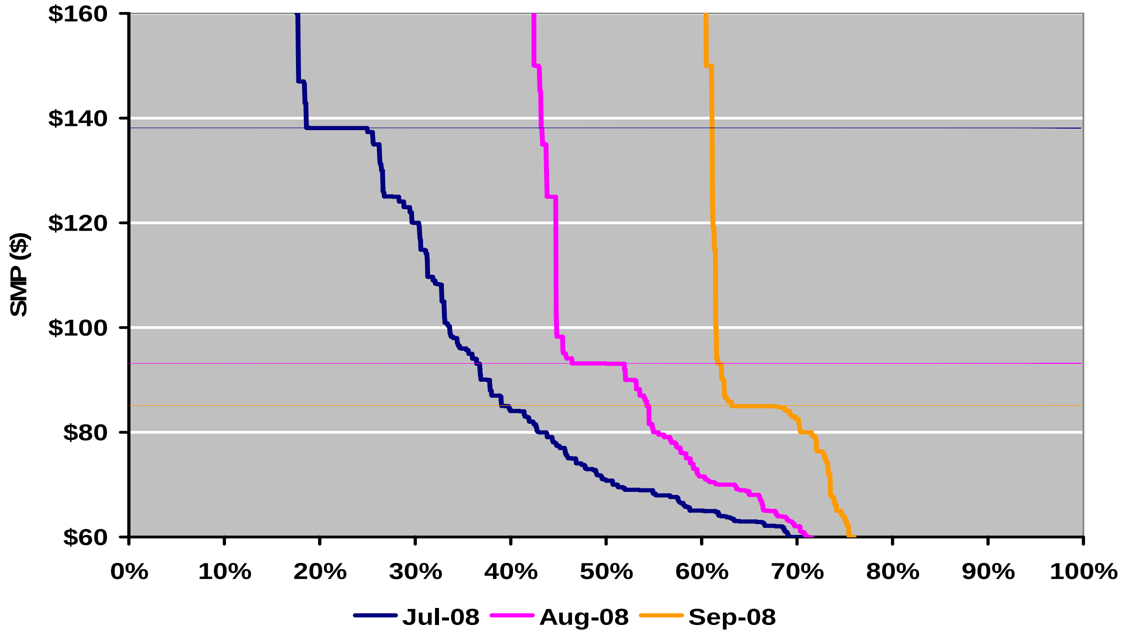
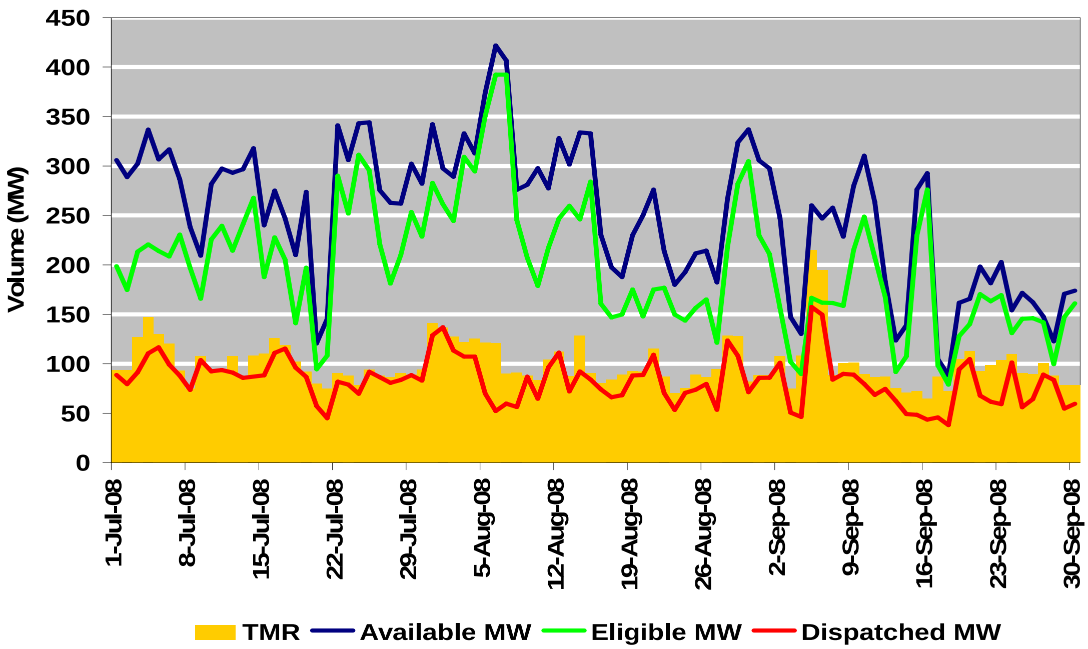


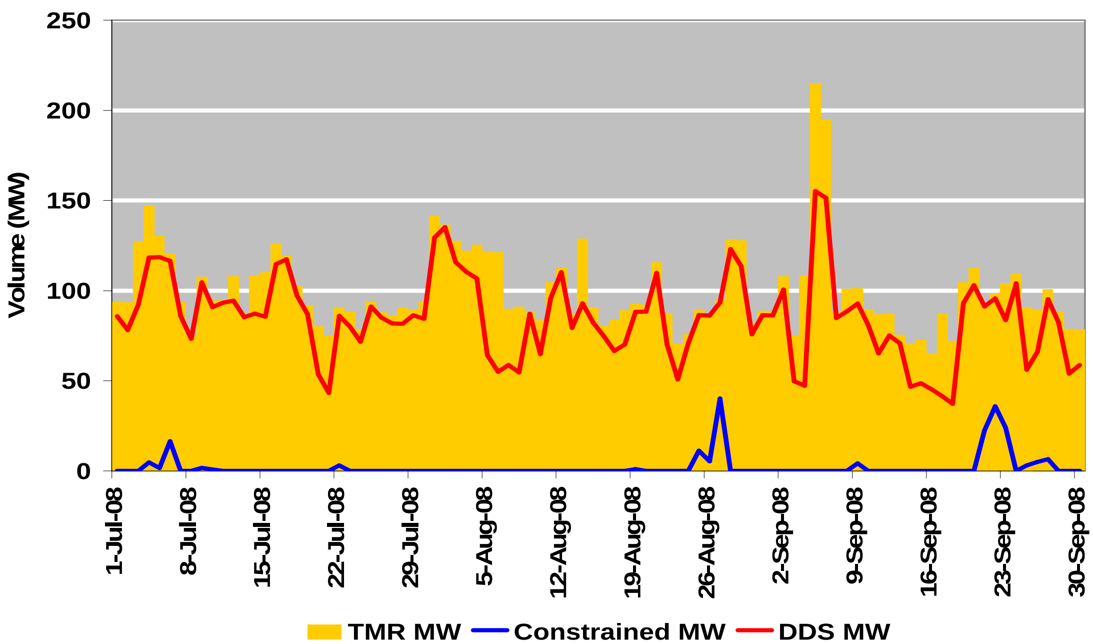
Figure XI shows the average daily TMR and DDS dispatched as well as the level of DDS volume both available (offered) and eligible. The DDS available is equal to the sum of all offers from all participants and in most cases the level of DDS available is significantly higher than the volume that is eligible. There are a number of reasons that offered volume may not be considered eligible and excluded from the DDS merit order. For example, the participant must have an equivalent or greater volume dispatched for energy. Offers from units in constrained areas would not be considered eligible. The majority of the time the volume eligible is greater than the volume dispatched, although, there does appear to be a decreasing trend in offers over the quarter. Typically the level of DDS dispatched is very close to the level of dispatched TMR. Exceptions occur if there are insufficient eligible offers, if price is above the Reference Price or if energy in the system is constrained down.

Figure XI: Average Daily TMR, Available, Eligible & Dispatched DDS Volumes (MW)



When energy in the system is constrained down, level of DDS dispatched is equal to the level of TMR dispatched less the volume of MW constrained down. Aside from the KEG Conversion Project, there have typically been very few instances of constrained down volumes until very recently. Figure XII shows the level of MW constrained down and there are a number of occasions in the past quarter where the volume of dispatched DDS (represented by the area between the red line and the blue line) is below the volume of TMR due to constrained down MW. Some of this reduction is due to transmission maintenance work in the south of the province causing the temporary constraining down of generation. There are potentially significant implications for those participating in the DDS market as the demand for DDS is effectively reduced as a result of the constraint.

Figure XII: Average Daily DDS Dispatched and Constrained Down Volume (MW)

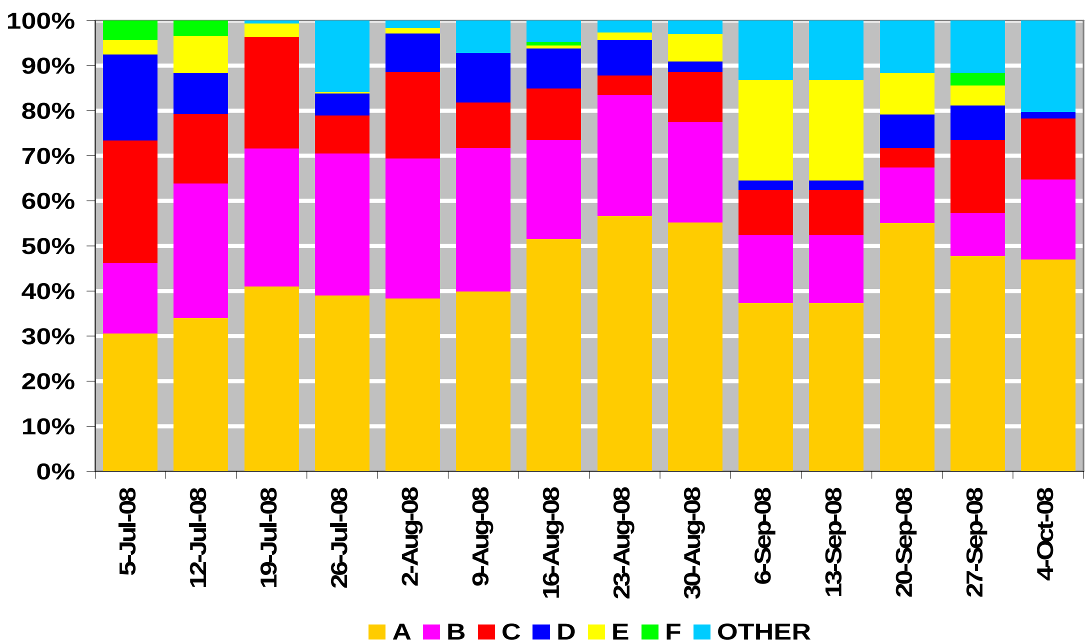


The MSA had also reported on market shares within the DDS market by both participant and fuel type. For the period analyzed in the DDS report there was a total of eight participants that received dispatch for DDS, although the maximum in any one week was seven. For Q3/08 there were seven participants that received a DDS dispatch. In some weeks all seven participants successfully sold. The level of competition within this market is encouraging although there appear to be two or three participants that continue to dominate the supply (Figure XIII).

Gas generators continue to provide the bulk of the product although their market share did drop off at the beginning of September (Figure XIV). This corresponds to the lower levels of gas availability mentioned earlier and gas market share has been increasing fairly steadily since the drop. Hydro resources were also dispatched in most weeks of Q3/08. The relative dominance of gas and hydro resources in this market decreases the level of reconstitution that actually occurs as participants who, absent the DDS market, would not have been running.

The MSA recognizes that the DDS method of price reconstitution is complicated and is uncertain as to how much real reconstitution is actually occurring. The MSA continues to support the AESO's efforts to build more transmission lines as the elimination of TMR is the best way to preserve price fidelity.

Figure XIII: Average Weekly DDS Market Share by Submitting Participant



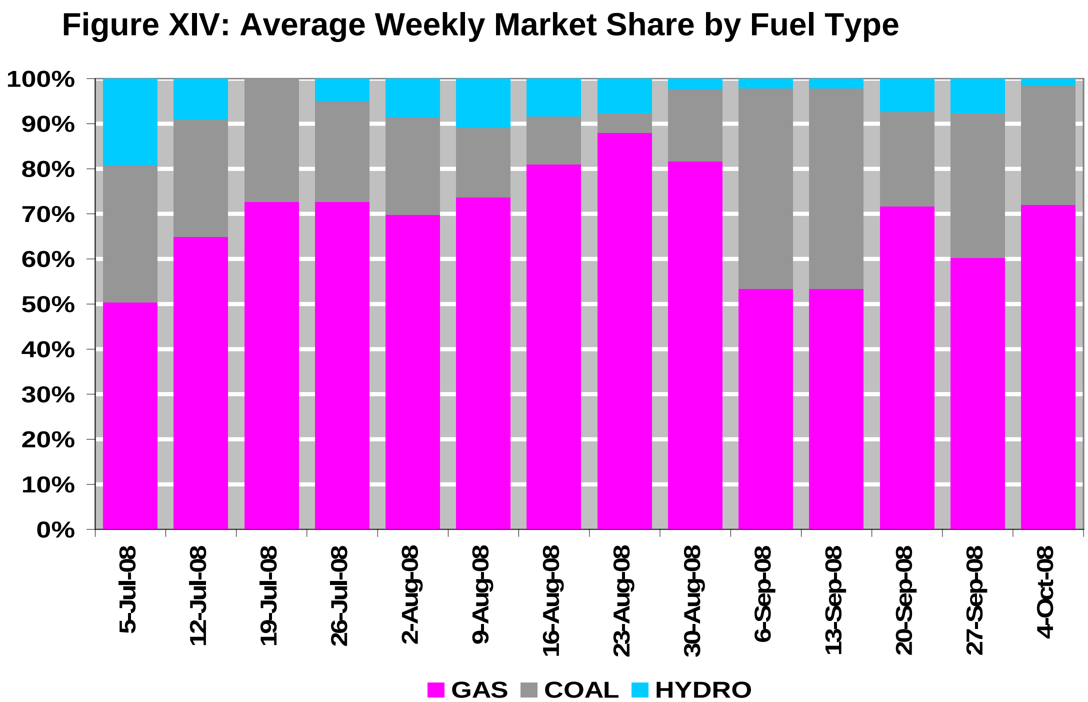


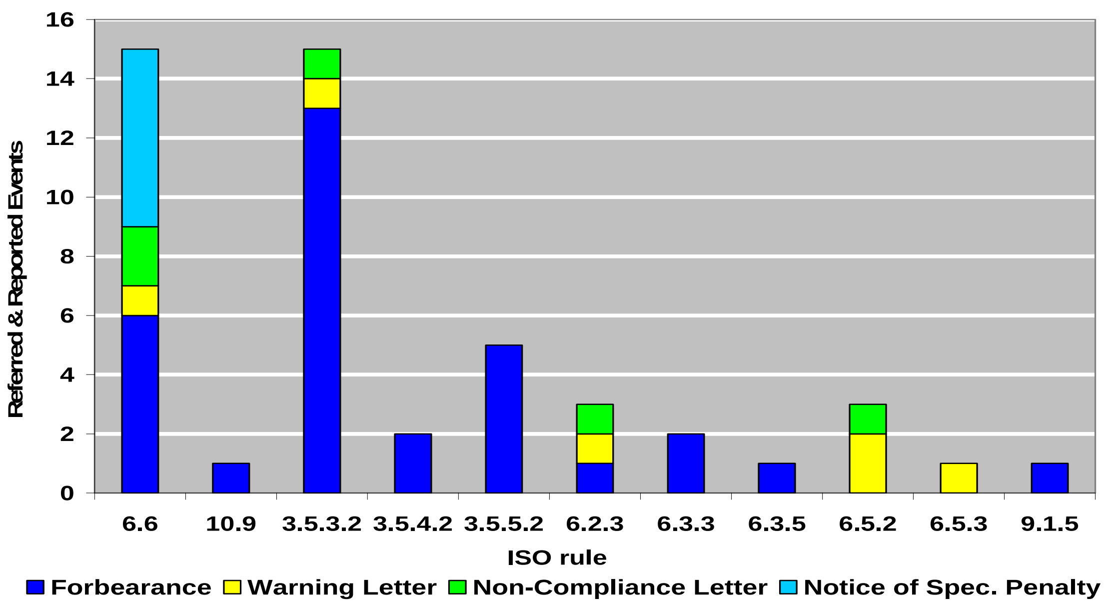
Figure XIV: Average Weekly Market Share by Fuel Type
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
5-Jul-08
12-Jul-08
19-Jul-08
26-Jul-08
2-Aug-08
9-Aug-08
16-Aug-08
23-Aug-08
30-Aug-08
6-Sep-08
13-Sep-08
20-Sep-08
27-Sep-08
4-Oct-08
GAS
COAL
HYDRO

5 ISO RULES COMPLIANCE

In September, the MSA provided a status report on the ISO rules compliance process to participants as part of the MSA fall stakeholder meeting presentation.[6] Further to the material presented there, and further to feedback provided by participants, metrics indicating the outcome of compliance matters dealt with are shown below. Ongoing reporting of this type is expected to be included in the data appendices of subsequent MSA quarterly and annual reporting.

In reference to Figure XV, forbearance denotes events in which AESO suspected a rule breach but where there were sufficient operational or mitigating circumstances such that the MSA chose not to pursue the event further. In addition, broader based forbearance was extended with respect to new rules coming into force with the implementation of quick hits. Information requests were directed to a collection of events relating to these rules but not pursued further in an effort to raise awareness of the new rules in the weeks following their implementation.

Figure XV: Year to Date Referred and Reported Compliance Events



6 This presentation can be found on the MSA website at: http://www.albertamsa.ca/files/MSA_Fall_Stakeholder_Meeting_2008.pdf

6 OTHER MSA ACTIVITIES

6.1 AUC Proceedings

During Q3/08 the MSA has been actively involved in three proceedings before the Alberta Utilities Commission:

- **Proceeding 66: ENMAX Energy Corporation 2006-2011 RRT EPSP Amendment Application** – The MSA registered a Statement of Intent to Participate (SIP) in this proceeding on June 19, 2008 as it was unable to determine whether the amendment met the requirements of the Regulated Rate Option Regulation. Subsequently, the MSA met with Enmax Energy Corporation (EEC) and the Consultation Parties to clarify certain aspects of the amendment with notes of that meeting being filed with the Commission. The Commission also sought information from EEC through an Information Request and on September 4, 2008 requested the views of the involved parties as to whether the proposed amendment met the requirements set out. The MSA was of the view that with the clarifications provided and certain commitments from EEC the MSA concerns with the amendment had been met. On September 30, 2008 the AUC issued Decision 2008-091 approving the amendment and further directed EEC to consult with the MSA before filing future amendments and in making future applications EEC should indicate which sections of regulation underpin an amendment. Overall the MSA was pleased with the outcome of the proceeding and the co-operation of EEC and the Consultation parties throughout.
- **Proceeding 75: Notice of Specified Penalty issued to EPCOR** - On August 25th there was an oral hearing for this proceeding. The AUC decided in Order M2008-08 that parts of the hearing would not be open to the public due to representations from TransAlta that certain information should be subject of a confidentiality order. The oral hearing for this proceeding occurred on August 25, 2008. Having heard the evidence that was subject to the confidentiality order the Commission noted on September 8 that it was reconsidering the need for this information to be kept confidential and sought the views of the parties involved. Having considered these views the AUC issued order M2008-09 rescinding the previous confidentiality order. In doing so the Commission reaffirmed its strong presumption in favor of the open court principle in AUC proceedings. All previously confidential materials, including sections of the transcript that were kept confidential are now publicly available. A decision from the AUC on the Notice of Specified penalty is expected within 90 days of the hearing date.
- **Proceeding 71: Notice of Specified Penalty issued to TransCanada Energy** – An oral hearing was held for Proceeding

71 on September 19, 2008. A decision from the AUC on the Notice of Specified penalty is expected within 90 days of the hearing date.

6.2 Evaluation of the Stakeholder Consultation Process

The MSA established its stakeholder consultation process in July, 2006. At that time the MSA committed to evaluate the process after having used it on two occasions. The second project using the process led to an MSA Guideline on Intertie Conduct and was completed in mid July 2008.

Consequently the MSA commenced its evaluation of the overall process on July 28 by presenting a summary of its views as to whether the process had met its intended goals. The MSA also sought the views of stakeholders. On September 5, 2008 the MSA, having considered the comments from the one submission, concluded that the process was meeting its objectives and saw no reason to amend the process at this time

6.3 EISG

The MSA was represented at the fall conference of the Energy Inter-Market Surveillance Group (EISG) – an association of electricity market monitoring groups in other jurisdictions in North America and abroad. This group meets on a semi-annual basis to review and discuss matters of mutual interest regarding monitoring of competitive electricity markets.

6.4 Fall Stakeholder Meetings

The MSA held its annual fall Stakeholder meetings in Edmonton and Calgary on September 23rd and 24th respectively. At these meetings the MSA presented a summary of work during the last six months and provided further information about our compliance work, forward market monitoring and assessment of retail competition.

6.5 Retail Coordinating Committee

The MSA continues to participate in the activities of the Retail Coordinating Committee. At the September meeting of the committee the MSA presented some of its findings from its ongoing review of retail competition.

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table 1 - Pool Price Statistics

	Average Price[1]	On-Pk Price[2]	Off-Pk Price[3]	Std Dev[4]	Coeff. Variation[5]
Jul-08	64.51	81.00	41.67	64.84	101%
Aug-08	82.72	114.86	41.95	123.83	150%
Sep-08	93.86	135.29	37.15	162.35	173%
Q3-2008	**80.36**	**110.38**	**40.26**	**124.09**	**141%**
Apr-08	135.95	173.08	85.15	158.75	117%
May-08	103.73	137.54	56.90	108.73	105%
Jun-08	82.98	125.96	29.26	156.94	189%
Q2-2008	**107.55**	**145.53**	**57.10**	**145.33**	**137%**
Jul-07	155.73	210.02	86.89	259.73	167%
Aug-07	71.10	97.29	34.83	118.47	167%
Sep-07	49.17	60.12	35.49	48.70	99%
Q3-2007	**92.00**	**122.48**	**52.40**	**174.32**	**144%**

1 - $/MWh

2 - On-peak hours in Alberta include HE08 through HE23, Monday through Saturday

3 - Off-peak hours in Alberta include HE01 through HE07 and HE24 Monday through Saturday, and HE01 through HE24 on Sundays

4 - Standard Deviation of hourly pool prices for the period

5 - Coefficient of Variation for the period (standard deviation/mean)

Figure 1 – Pool Price Duration Curves

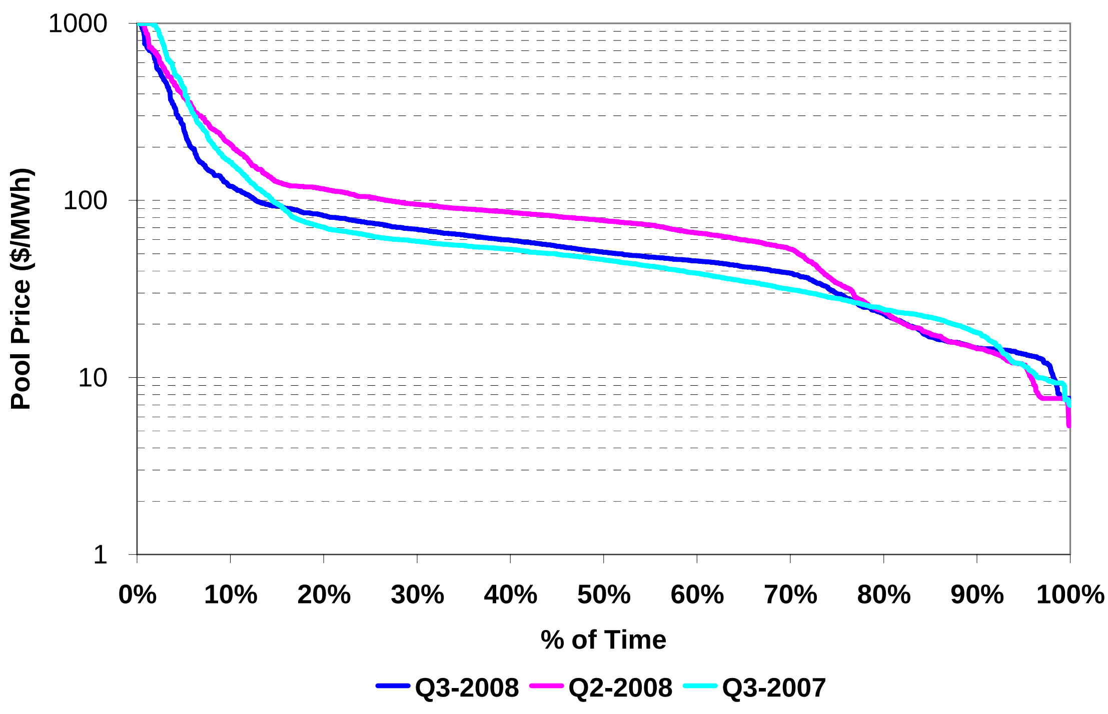


Figure 2 – Pool Price with Pool Price Volatility

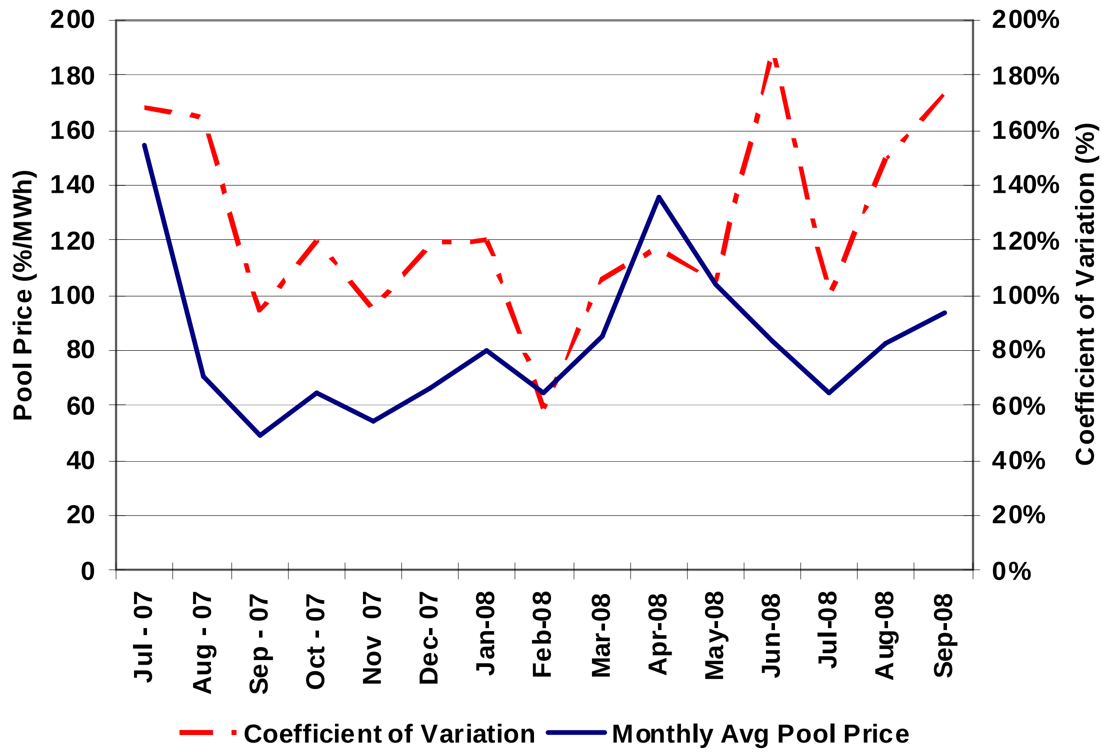


Figure 3 - Pool Price with AECO Gas Price

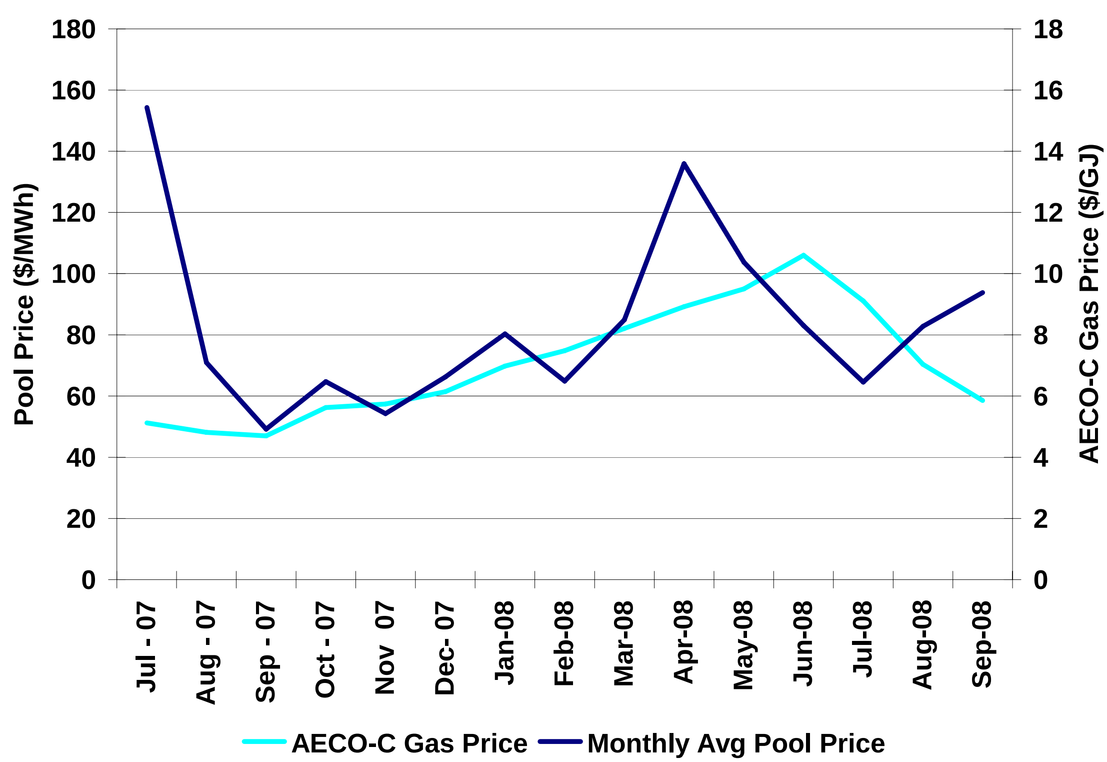


Figure 4 - Price Setters by Pool Participant (All Hours)

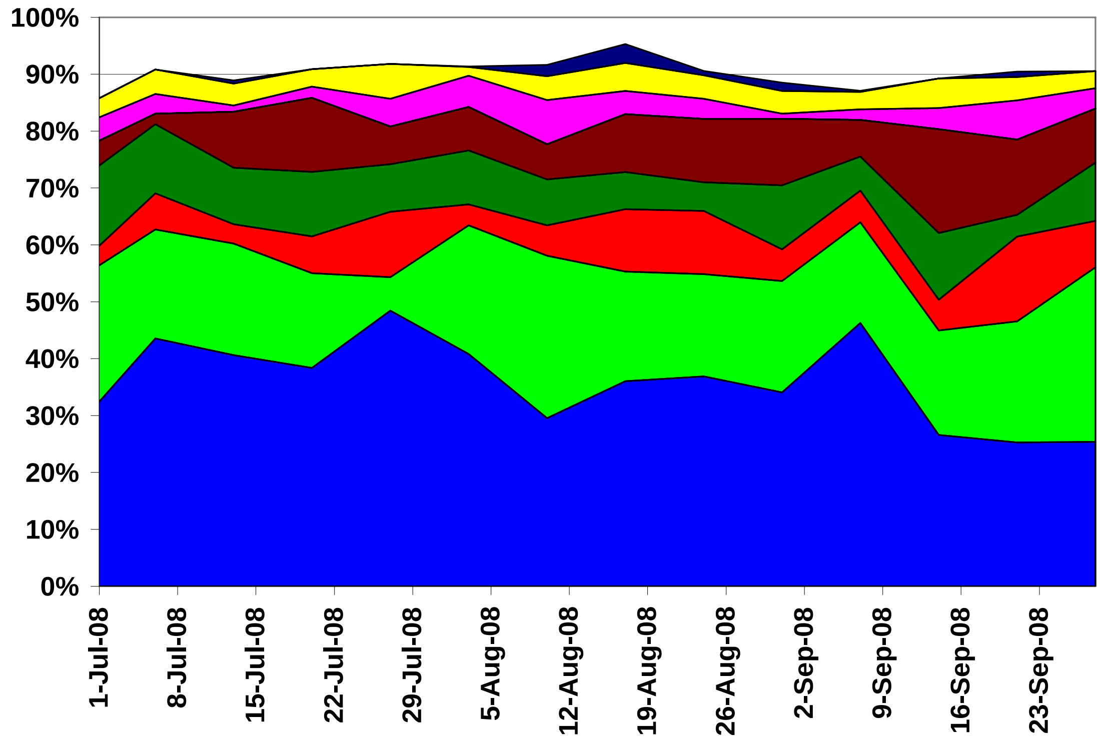


Figure 5 - Price Setters by Fuel Type (All Hours)

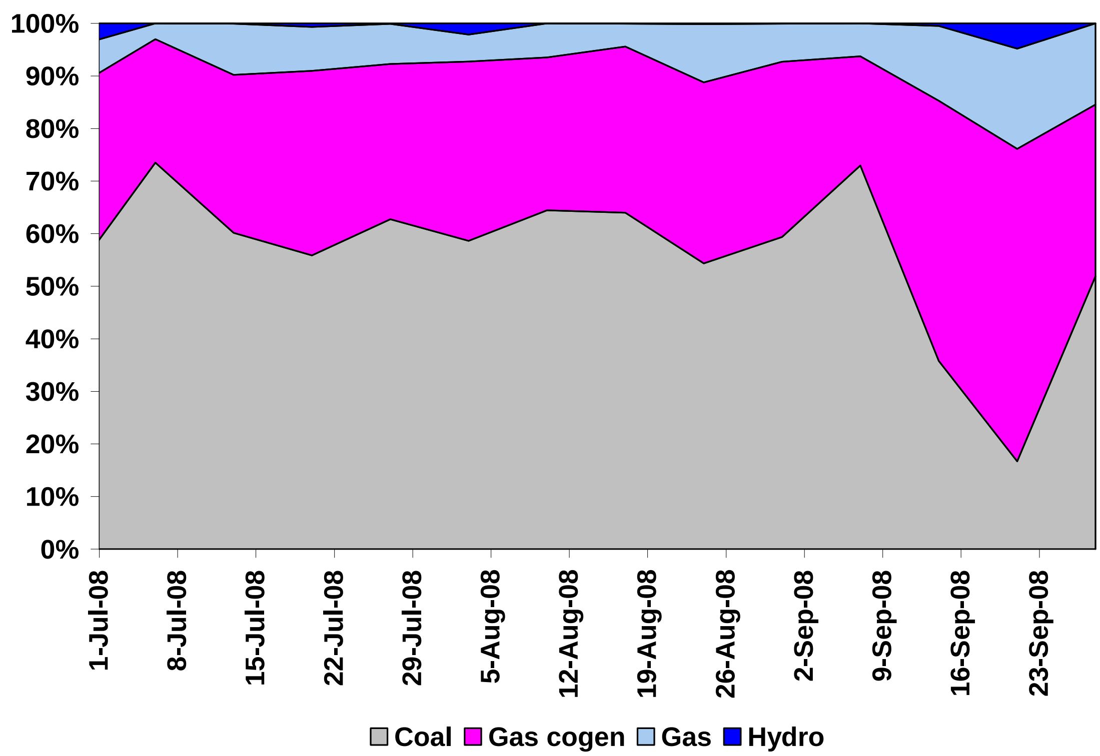
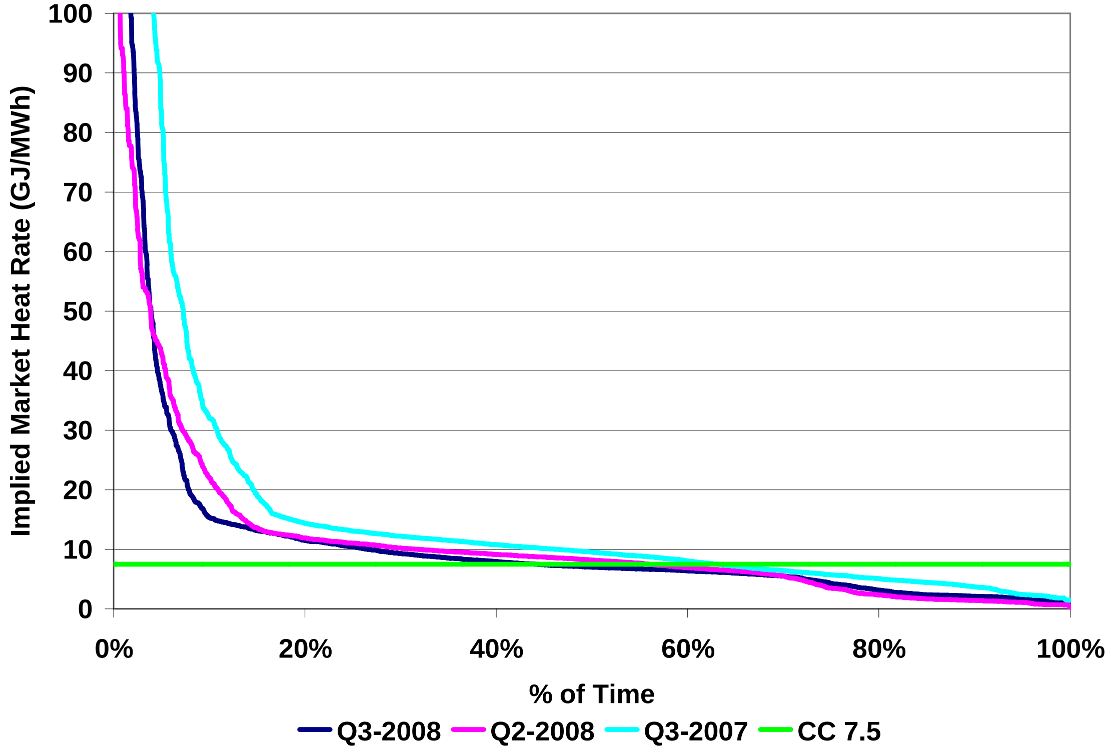


Figure 6 – Heat Rate Duration Curves (All Hours)



1 – CC denotes a representative combined-cycle generator with a heat rate of 7.5 GJ/MWh

Figure 7 - Implied Market Heat Rates On-Peak

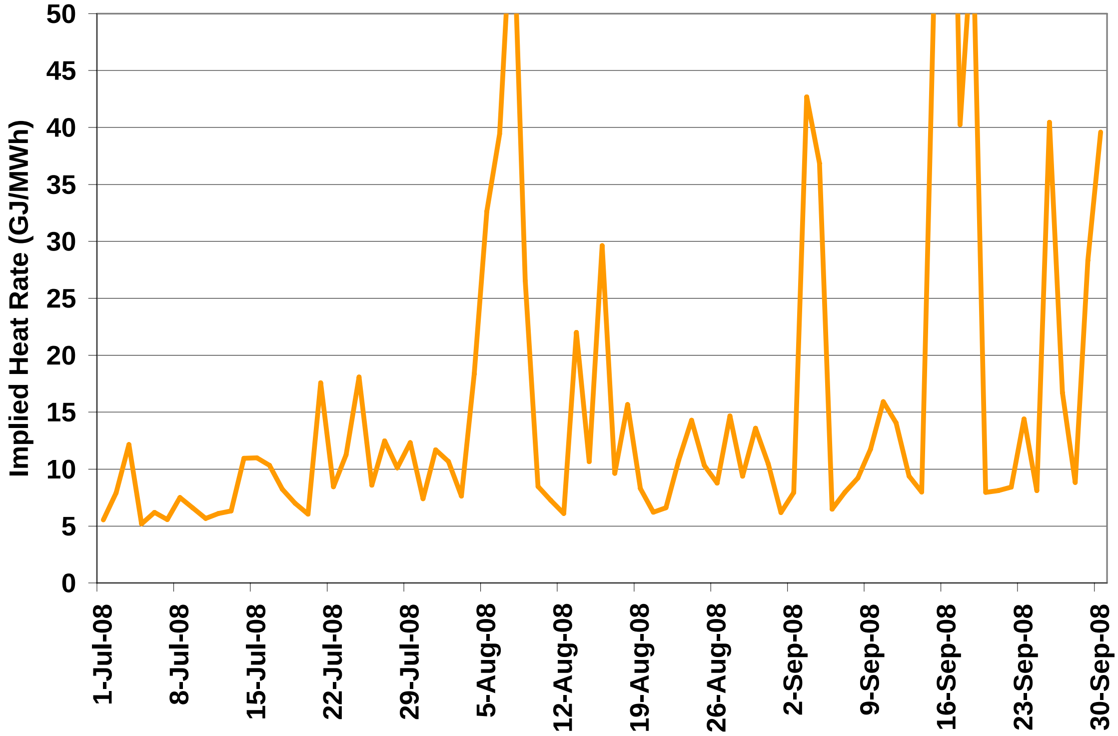


Figure 8 – Implied Market Heat Rates Off-Peak

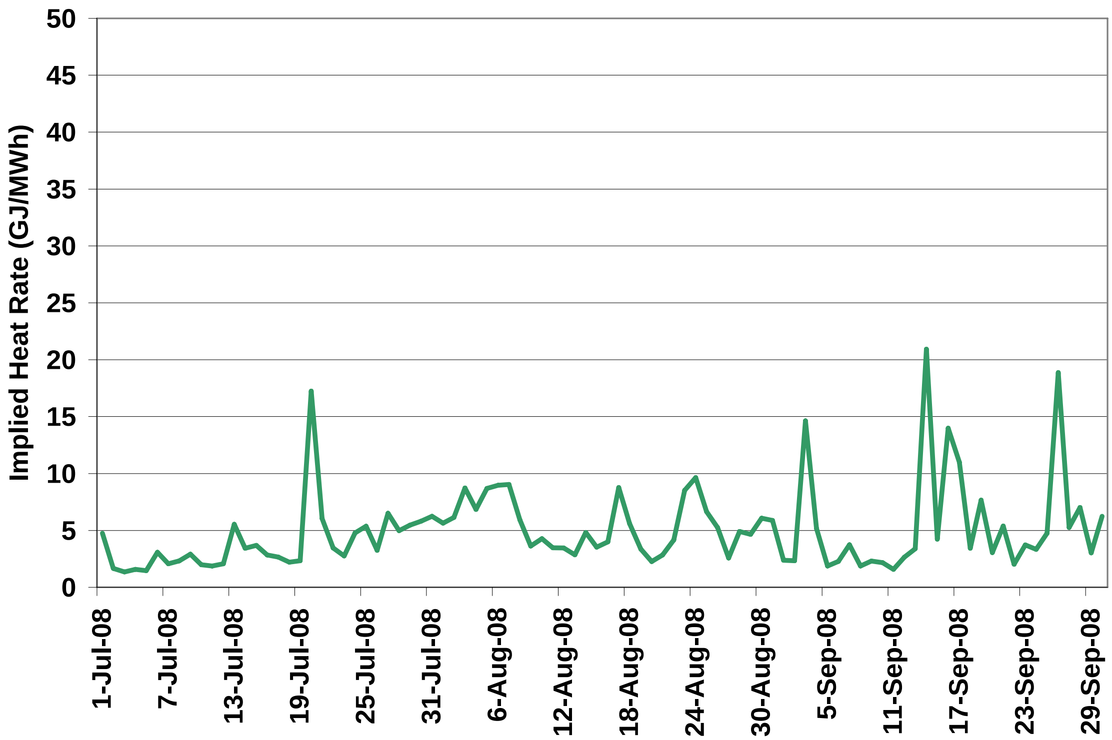


Figure 9 – PPA Outages by Quarter

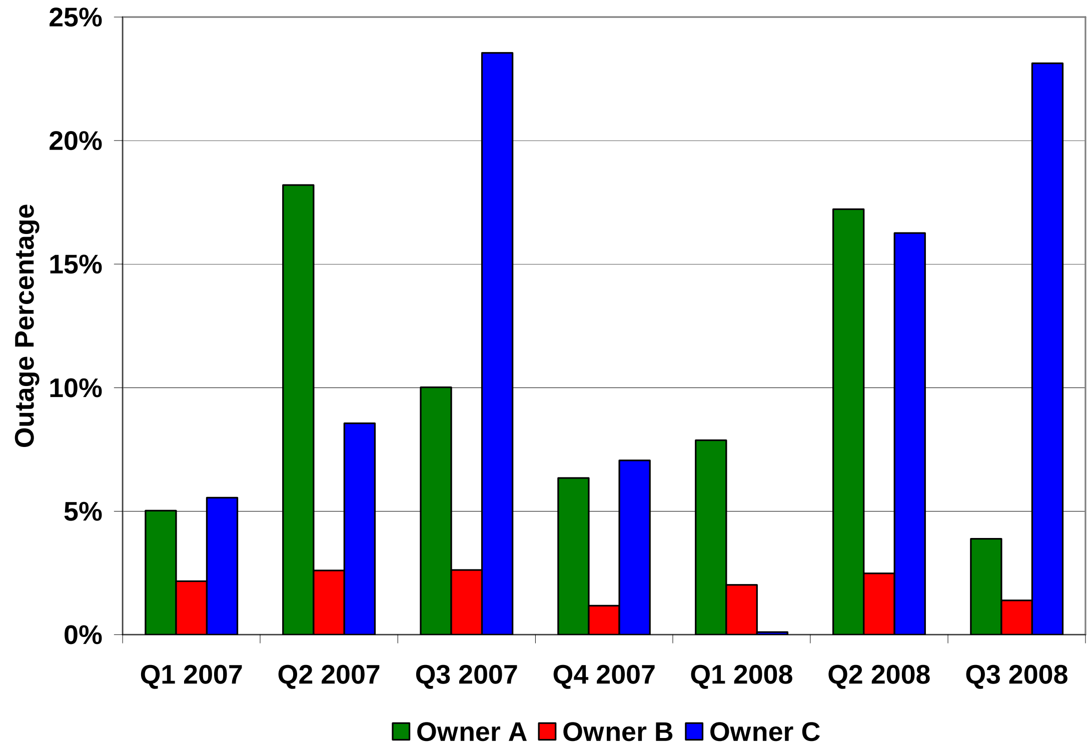


Table 2 - Percentage of Unplanned Outages for PPA Units

	Q3 2008	Q2 2008	Q1 2008	2007	2006	2005	2004
Owner-A	3.78%	3.6%	7.9%	6.0%	5.2%	5.0%	6.1%
Owner-B	1.39%	1.9%	1.9%	1.8%	1.8%	5.4%	1.5%
Owner-C	14.10%	11.4%	7.9%	7.1%	5.3%	6.5%	6.3%
PPA weighted average	9.20%	7.7%	6.9%	6.0%	4.8%	5.9%	5.5%

Note:
1) PPA units include: Genesee 1 & 2, Battle River 3, 4, 5, Sheerness 1 & 2, Sundance 1 - 6, Keephills 1 & 2
2) Outages rates are based on maximum continous rating (MCR), not Maximum Capability.

Table 3 - MW Weighted Portfolio Target Availability (%) vs. Actual Availability (%) - Coal Fired PPA Units

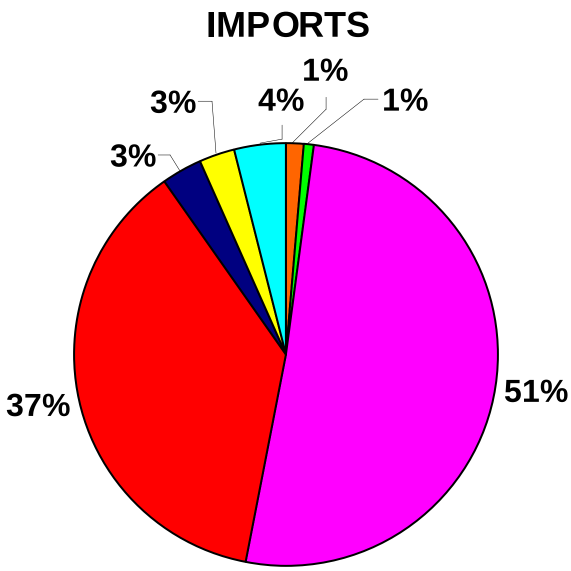
	Target Availability 2006	Actual Availability 2006	Target Availability 2007	Actual Availability 2007	Target Availability 2008	Actual Availability Q3 2008
Owner-A	87%	93%	87%	90%	87%	96%
Owner-B	89%	98%	89%	98%	89%	99%
Owner-C	87%	89%	86%	89%	86%	77%
PPA weighted Average	87%	91%	87%	94%	87%	86%

APPENDIX B – INTERTIE STATISTICS

Table 4 – Intertie Statistics

	British Columbia			Saskatchewan			Overall		
	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)
Sep-08	68,809	35,994	32,815	23,425	6,776	16,649	92,234	42,770	49,464
Aug-08	67,196	57,126	10,070	78,877	0	78,877	146,073	57,126	88,947
Jul-08	136,177	48,308	87,869	67,994	1,563	66,431	204,171	49,871	154,300
Q3-2008	272,182	141,428	130,754	170,296	8,339	161,957	442,478	149,767	292,711

Figure 10 – Market Share of Importers and Exporters



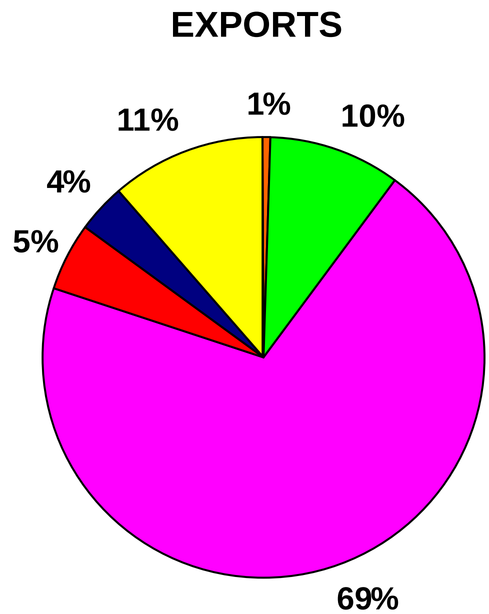


Figure 11 – Intertie Utilization Q3/08

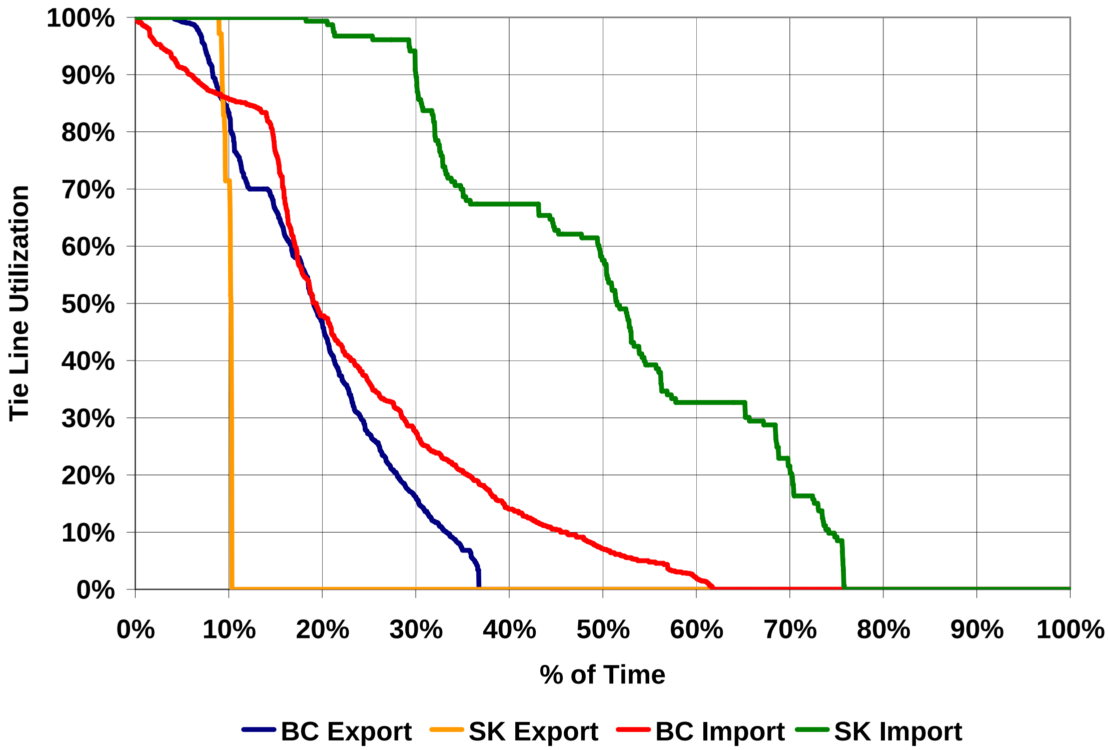


Figure 12 - Imports with Trade-weighted Prices

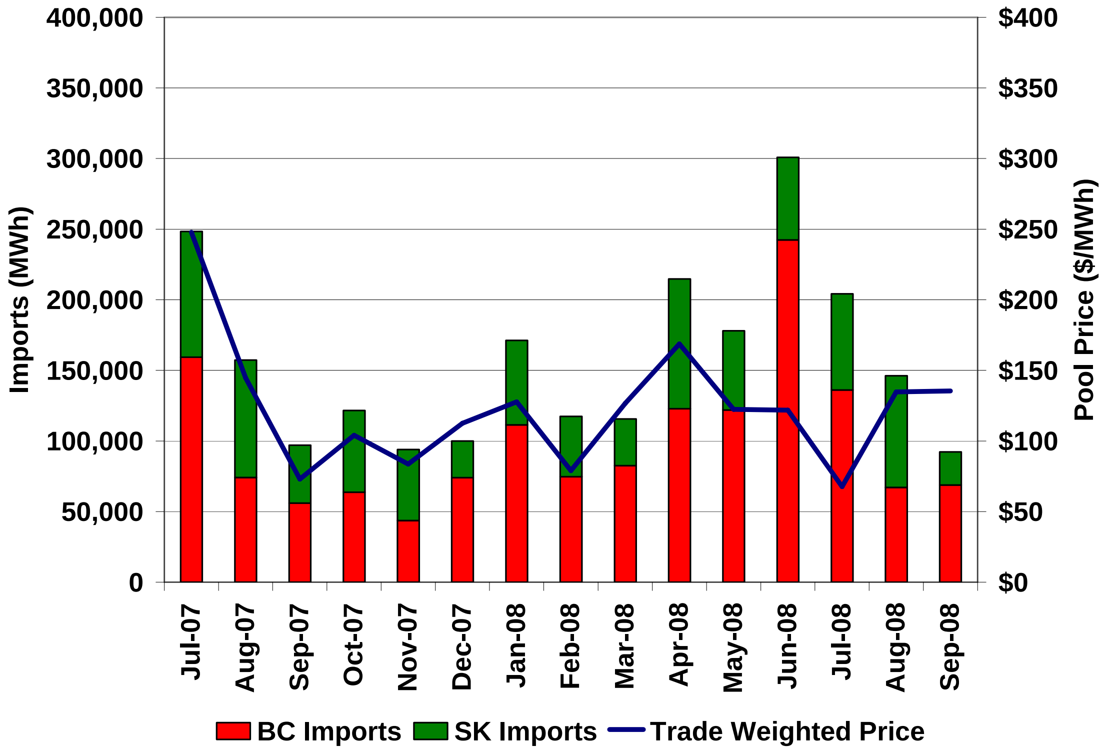


Figure 13 - Exports with Trade-weighted Prices

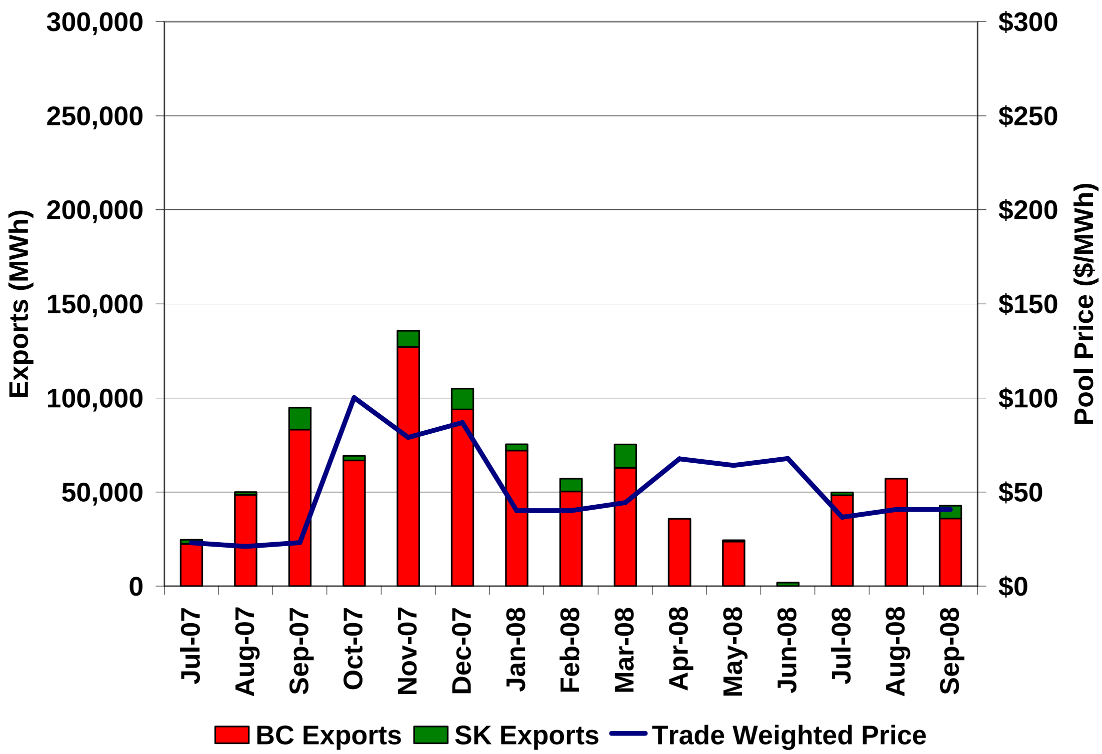


Figure 14 - On-Peak Prices in Other Markets

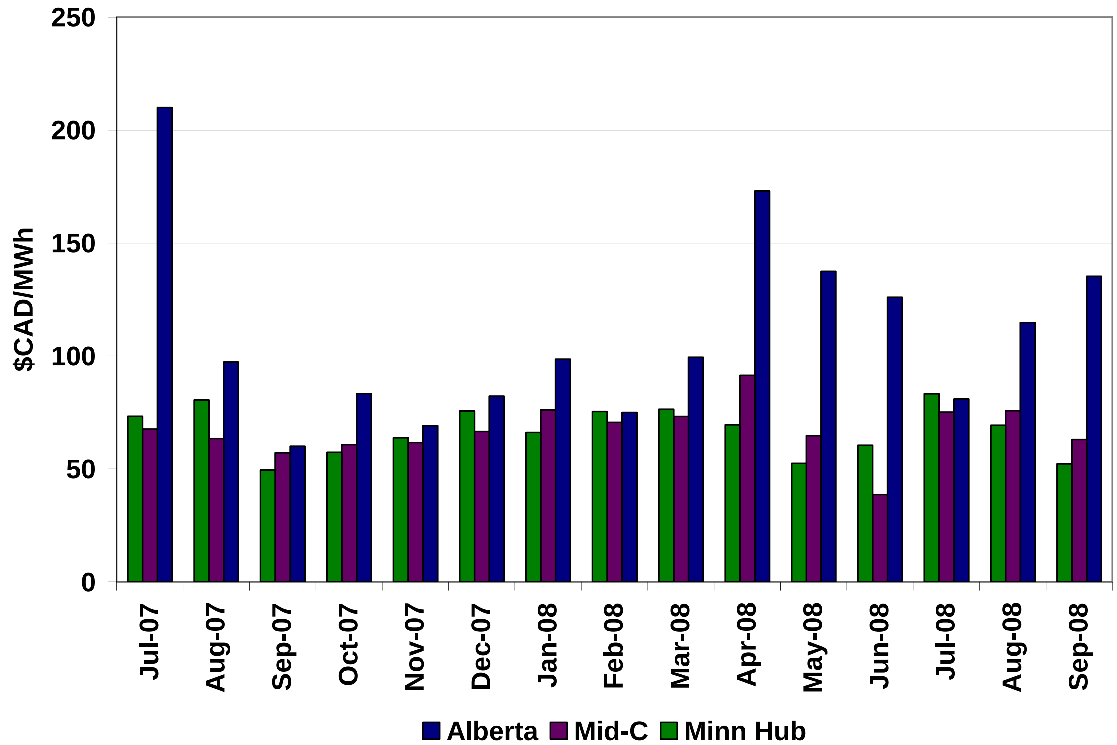
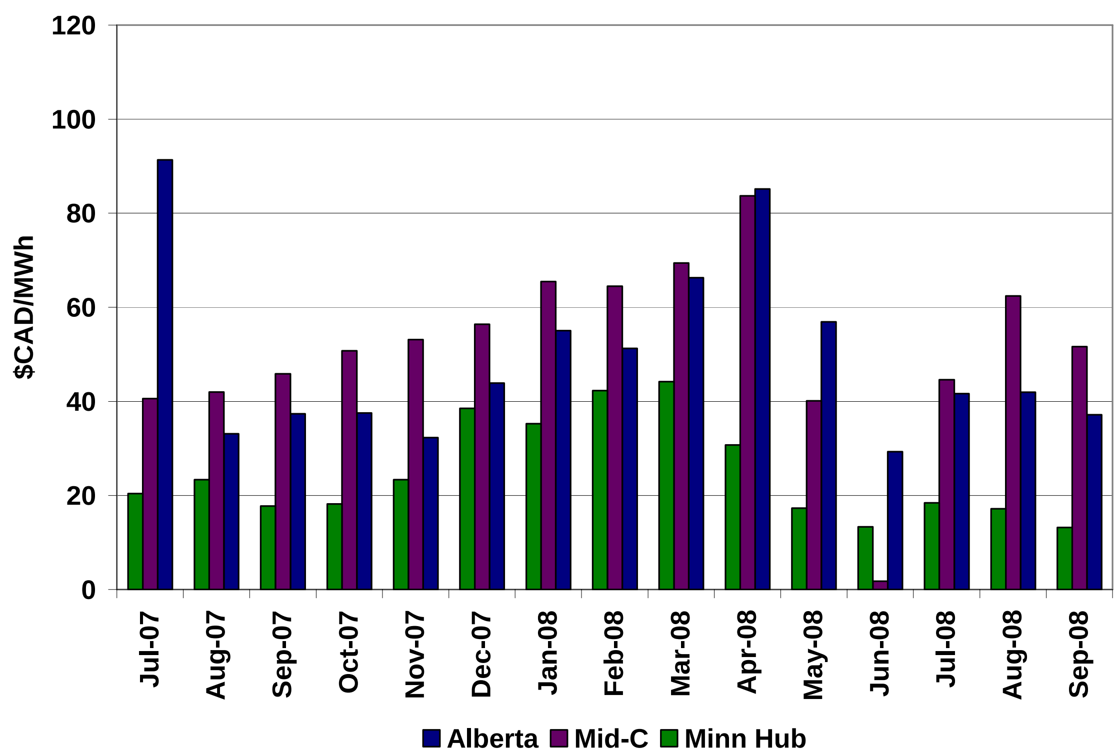


Figure 15 - Off-Peak Prices in Other Markets



APPENDIX C – OPERATING RESERVE MARKET METRICS

Ancillary services are the system support services that ensure system stability and reliability. The Alberta Interconnected Electric System (AIES) is required to carry sufficient operating reserves in order to assist in the recovery of any unexpected loss of generation or an interconnection. Operating reserves are competitively procured by the AESO through the Alberta NGX Exchange (NGX) and over the counter (OTC). Standard operating services products (contracts) include active and standby products for each of Regulating, Spinning, and Supplemental operating reserves. The majority of active operating reserve products are indexed and settled against the Pool price prevailing during the contract period. Standby operating reserve products are priced in a similar manner to options with a fixed premium and an exercise price (activation price). The activation price is only paid in the event that the contract is activated.

Figure 16 - Active Settlement Prices - All Markets (NGX and OTC)

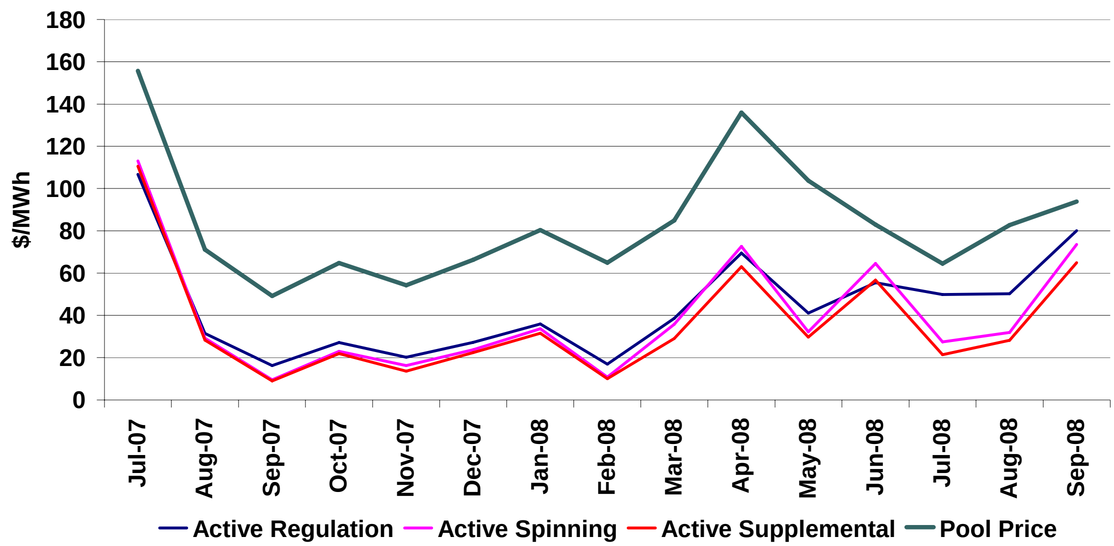


Figure 17 – Standby Premiums – All Markets (NGX and OTC)

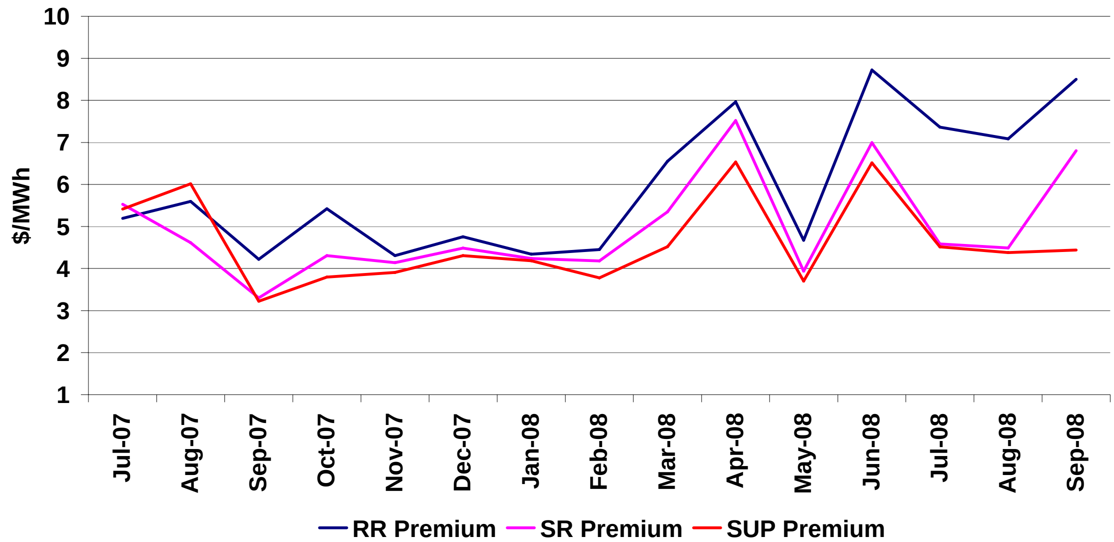
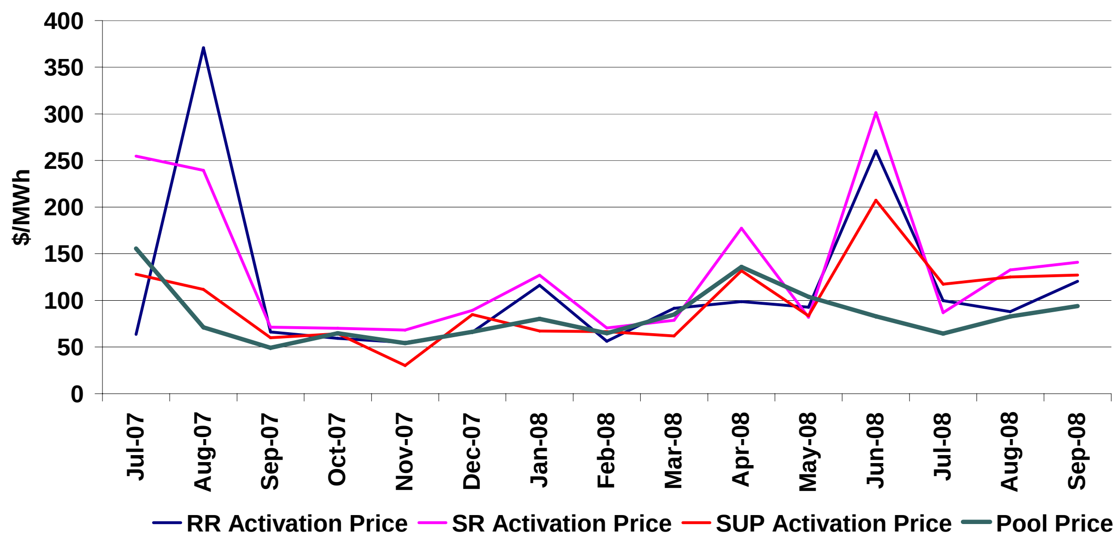


Figure 18 – Activation Prices – All Markets (NGX and OTC)



1 - These prices are for Standby volumes that were activated

Figure 19 – Standby Activation Rates

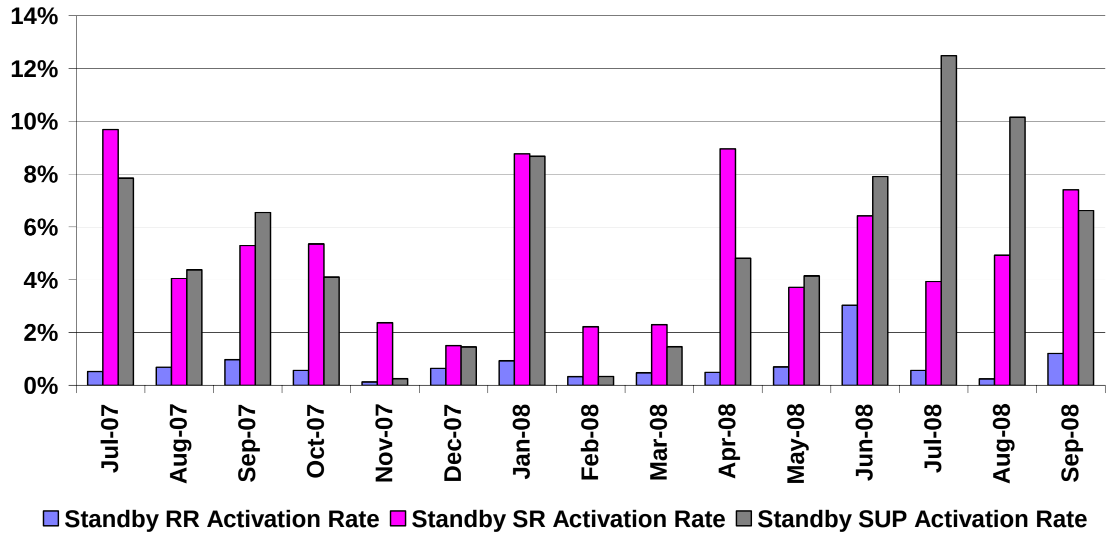


Figure 20 – OTC Procurement as a % of Total Procurement

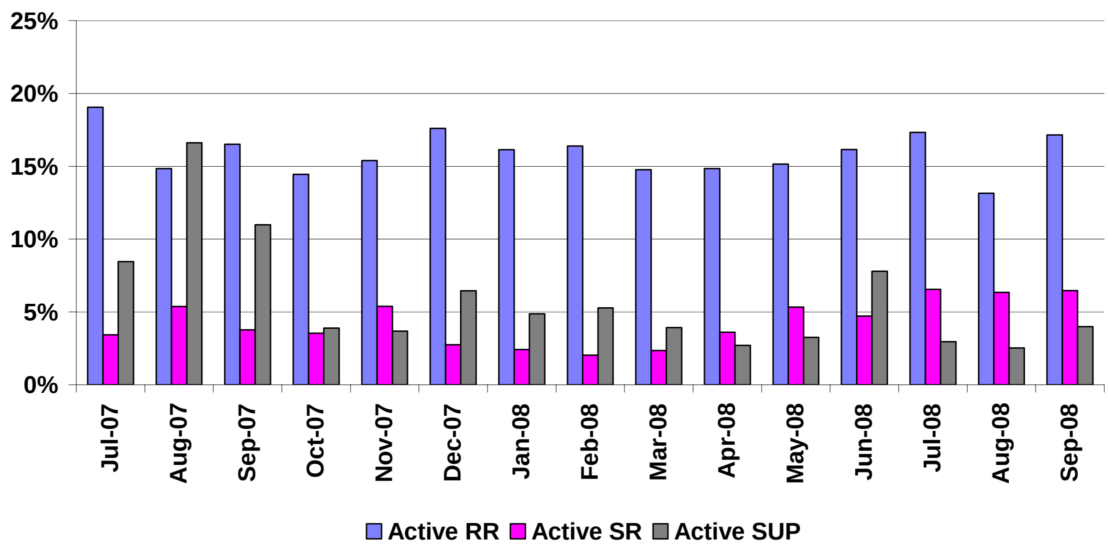


Figure 21 – Active Regulating Reserve Settlement by Market

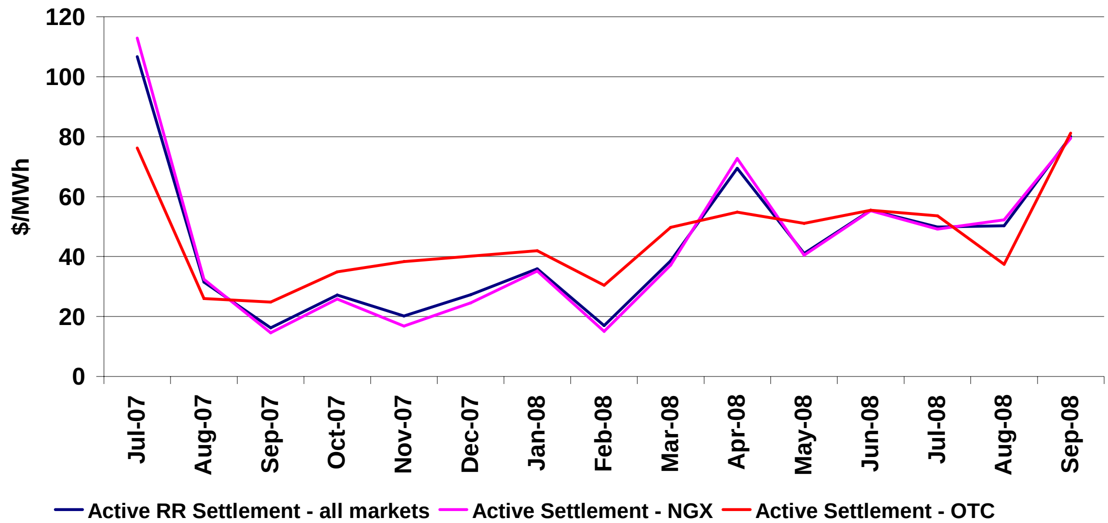


Figure 22 – Active Spinning Reserve Settlement Price by Market

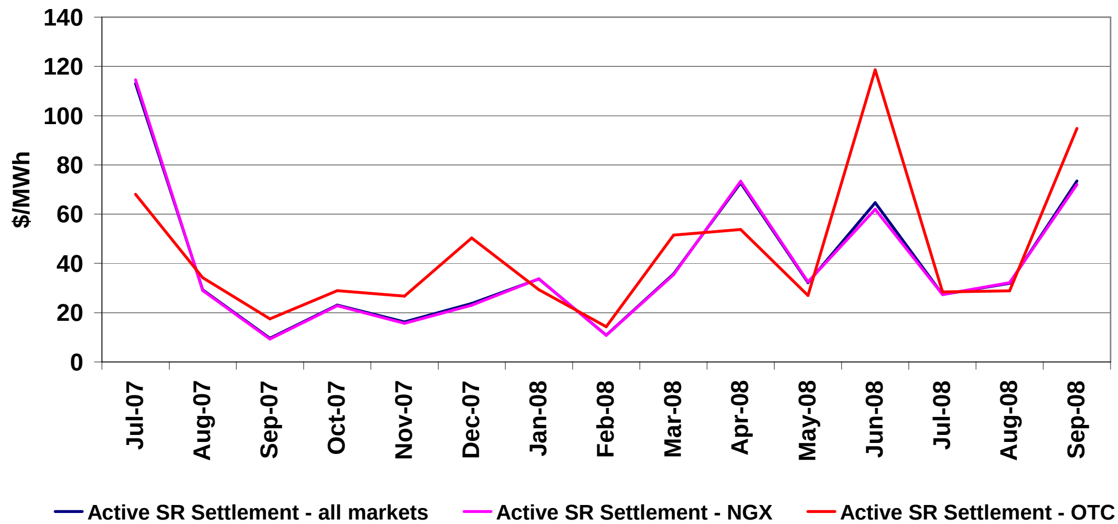


Figure 23 – Active Supplemental Reserve Settlement Price by Market

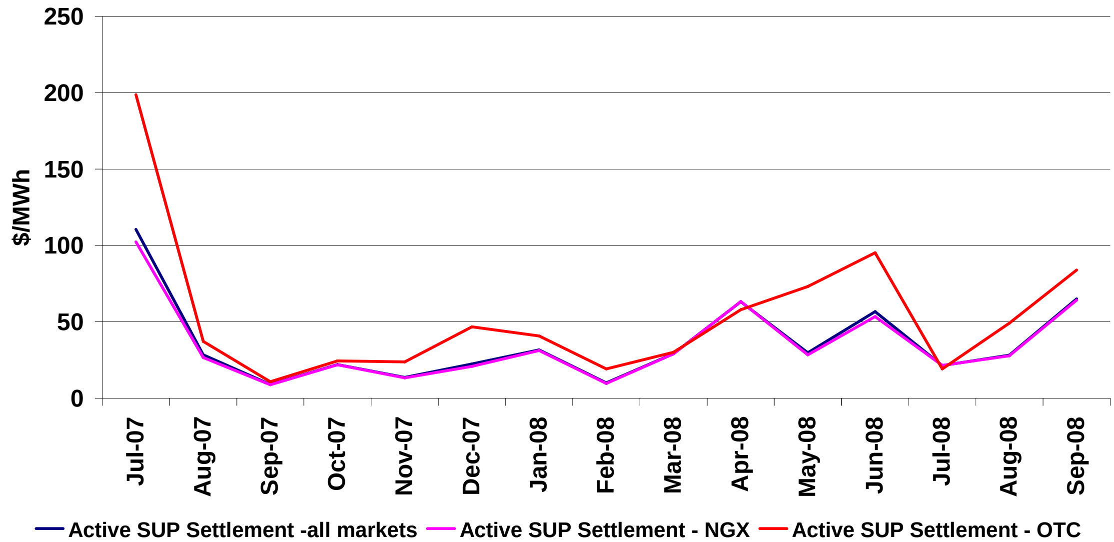


Figure 24 – Active Regulating Reserve Market Share by Fuel Type

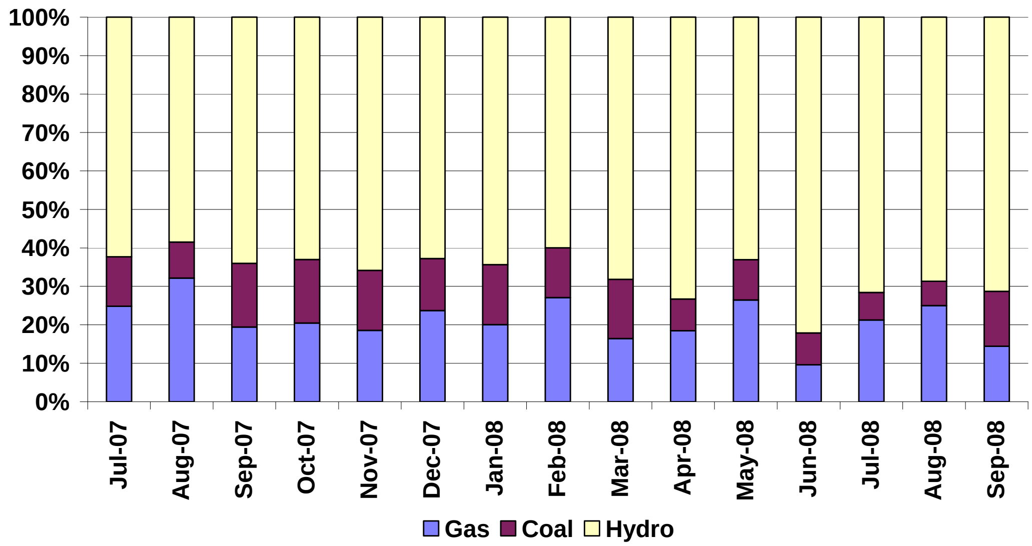


Figure 25 – Active Spinning Reserve Market Share by Fuel Type

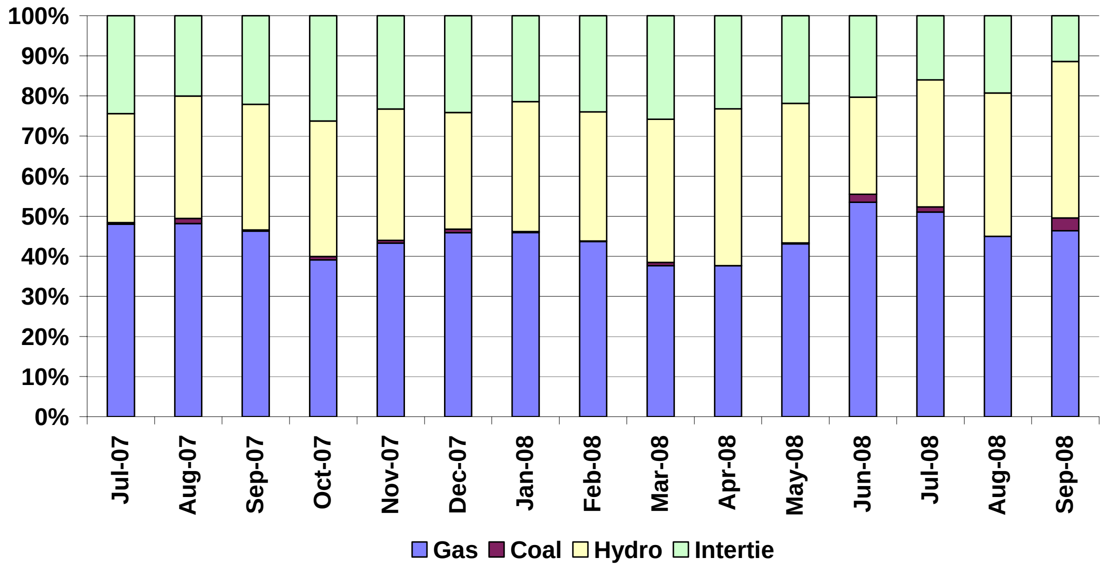


Figure 26 – Active Supplemental Reserve by Fuel Type