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MSA REPORT

Quarterly Report

July – September 2006

27 October, 2006

MARKET SURVEILLANCE ADMINISTRATOR

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1 FEATURED MARKET DEVELOPMENTS DURING Q3/06

1.1 Market Heat Rate

Implied market heat rates moved substantially higher in Q3/06, averaging 17.9 GJ/MWh relative to 9.5 GJ/MWh last quarter and 7.4 GJ/MWh in the same quarter last year. System events of late July leading to record Pool prices were a significant driver with an average on-peak heat rate for July of 30.0 GJ/MWh. While elevated July heat rates were driven in large measure by scarcity of supply, the decline, then increase of heat rates through August and September reflected the fluctuating trend in natural gas prices with Alberta gas prices ending Q3/06 at $3.49/GJ, down 50% from August highs.

On a historical basis, 17.9 GJ/MWh is the highest quarterly average market heat rate value observed since 2000. The table below shows Q3/06 ranking fourth highest in terms of average implied heat rate among all quarters back to 1999. Note that the efficiency of gas units in the system is currently much higher than it was in 1999 – 2000 thus the market heat rate observed in Q3/06 is even more exceptional than an equal value in 1999/00. A combined cycle gas generator with an efficiency rating of 7.5 GJ/MWh would have at least met its variable cost of gas 85% of the time through Q3/06 up from approximately 50% of the time during Q2/06 (see Appendix A, Figure 6).

Ten Highest Average Quarterly Heat Rates (1999 – 2006)

Quarter	Average Implied Heat Rate (GJ/MWh)
Q3/00	33.7
Q4/00	29.0
Q2/00	19.1
Q3/06	**17.9**
Q1/00	17.8
Q2/99	16.9
Q3/01	16.1
Q3/99	15.6
Q2/01	15.4
Q4/99	14.7

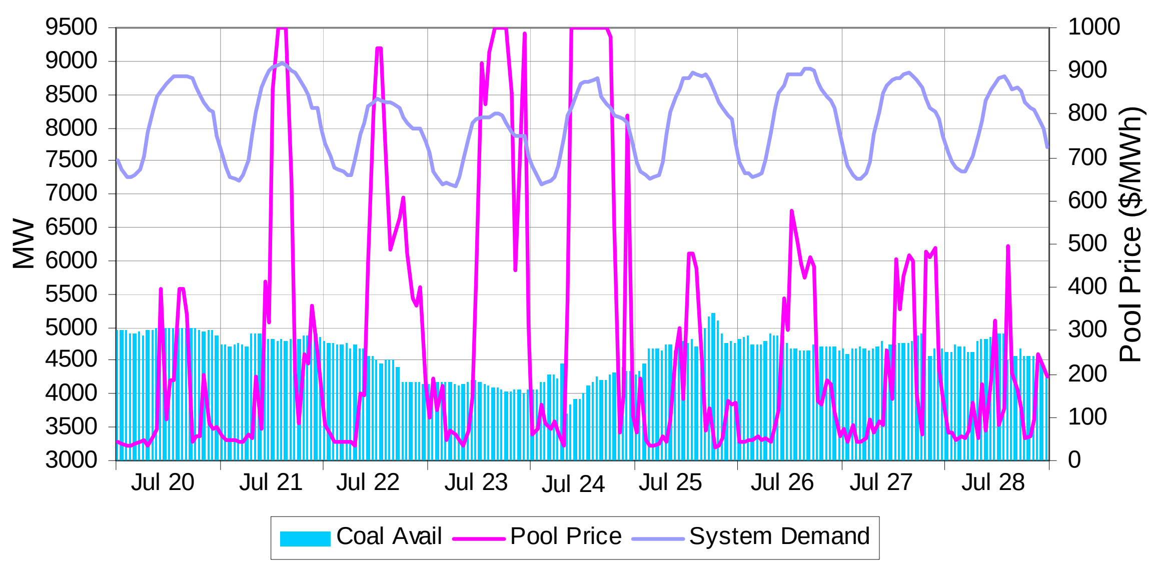
1.2 Events of late July

Due to exceptional operational circumstances, July 24, 2006 saw the brief shedding of firm load under OPP 801 and the setting of a record high daily average Pool price of $526/MWh[1]. The MSA published a report on August 9th containing a detailed analysis of market conditions giving rise to the high prices on July 24. This report is available for review on the MSA website at www.albertamsa.ca .

In follow up to that report, the MSA reviewed market conditions in the days prior to and following July 24th. The graph below shows that coal generation availability was significantly reduced in the days prior to July 24 as higher than average July temperatures resulted in several forced outages and cooling related derates further reducing availability of the coal fleet with 900 MW already offline for maintenance.

With the extent of planned and forced coal outage, market prices reflected tightness of the system. The system continued to meet firm load on July 24th even with the transmission related trip of both Sheerness units in HE 9 which reduced coal availability to 3689 MW. Only when the BC tie line tripped in HE 17 due to a lightning strike while importing over 400 MW, was shedding of firm load necessary for a duration of about 15 minutes.

Availability of Coal Generation with Pool price and System Load

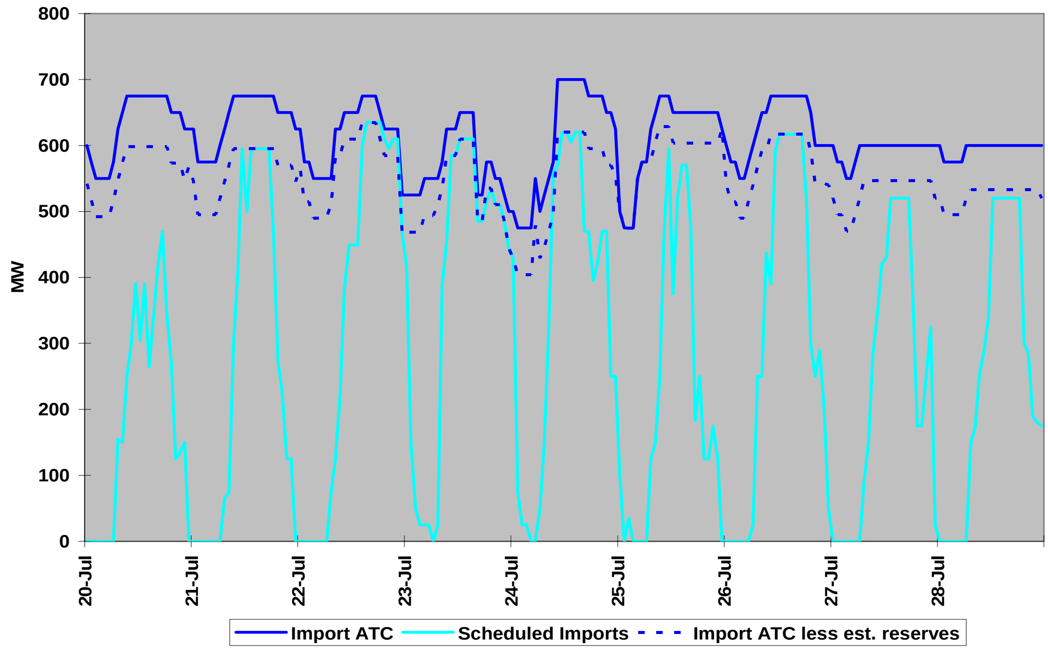


[1] This record daily average Pool price has since been surpassed in early October.

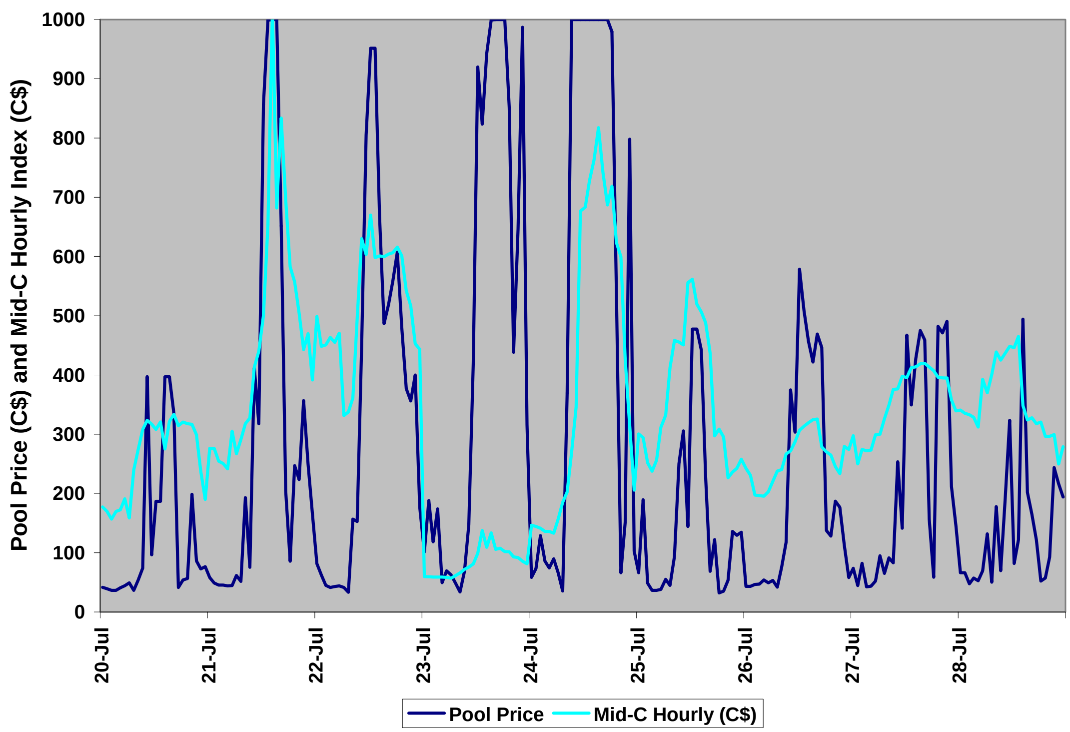
While a significant portion of July 24th market outcomes were governed by OPP 801, analysis of days prior and following July 24th indicated that the market and interconnection responded appropriately to scarcity of supply.

The graph below shows BC Intertie available transfer capacity and scheduled import flows. Note that when the tie-line is supplying reserves (typically spinning reserve) transfer capability is reduced by the amount of reserves being provided. Over the period July 20-28 the intertie appeared to have been close to full utilization during hours of high prices. The second graph below shows Pool prices and hourly index prices at Mid-C. On July 24th, in particular, Mid-C prices were particularly robust in response to the demand from both Alberta and to the high demands (temperatures) experienced in other control areas. Given these ‘tight’ conditions at Mid-C it was encouraging that energy continued to flow to Alberta. The higher price cap in Alberta than elsewhere may have been a contributory factor in attracting imports from neighboring jurisdictions.

BC Intertie: Import ATC and Scheduled Imports (Jul 20 – 28/06)



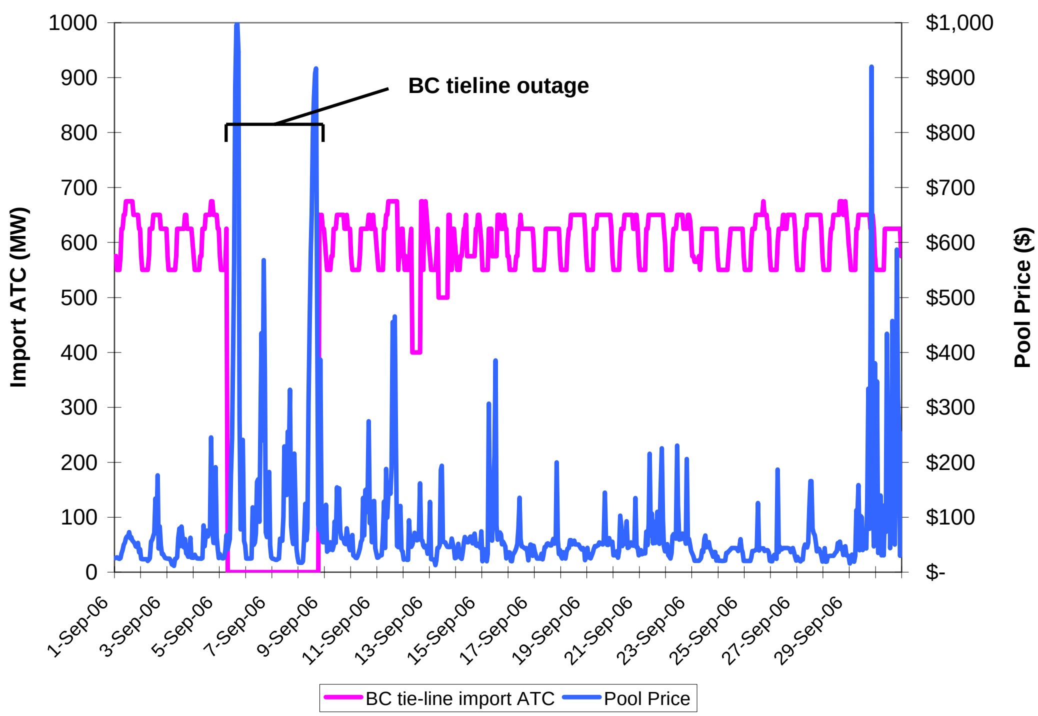
Pool Price and Mid-C Price (C$)



Tight system conditions in late July were a function of substantially reduced availability of coal generators during the same period that system demand was setting new summer highs. In fact, peak summer demand set this year on July 21, was up 4.7 % relative to last year's peak which translates to a 400 MW increase in peak demand year over year. An examination of price setting shares and market offers during this period revealed no evidence of untoward behaviour by participants.

1.3 September BC Tie line Outage

Between September 5 and September 8, the BC tie line was unavailable due to an outage. During this time, the Sundance 3 unit was also on maintenance. As shown in the graph below, this period corresponded to high on-peak prices. In particular, September 5 saw Pool prices reach $998.98 with all resources in the merit order dispatched. At this time, some other coal units were experiencing derates and warm temperatures added to system demand[2]. The period from September 5-8 demonstrates the significant role that imports have on moderating prices during on-peak hours. Availability on the BC tie line was good for the remainder of the month with high pricing from late on Friday September 29 coincident with reduced coal availability that continued into October.



[2] Temperature at Calgary International Airport reached 29.4 degrees C at 15:00

1.4 Net Revenues

The table below shows estimates of net revenue expressed as a percentage return for a theoretical gas peaking plant through 2005 and 2006 year to date. We have previously considered an annual return of about 15% to indicate a peaker would be generating a sufficient annual return. While these calculations are indicative only, they suggest that 2006 is on pace to provide a substantially better return than 2005 with July 2006 alone providing a 6.6% return. From monthly estimates for 2005, the importance can be seen of what is typically higher price volatility in the fourth quarter of the year, in making up for modest returns for peakers in earlier months of the year as was the case of 2005.

Estimated Monthly Net Returns on Capital Cost

(Hypothetical Gas Peaker)

Month	2005	2006
Jan	0.5%	0.6%
Feb	-0.2%	-0.3%
Mar	-0.2%	-0.4%
Apr	-0.1%	-0.1%
May	0.2%	1.2%
Jun	0.5%	1.4%
Jul	-0.3%	6.6%
Aug	1.1%	1.5%
Sep	0.4%	3.0%
Oct	2.5%	n/a
Nov	4.0%	n/a
Dec	1.6%	n/a
Total	9.8%	13.5%

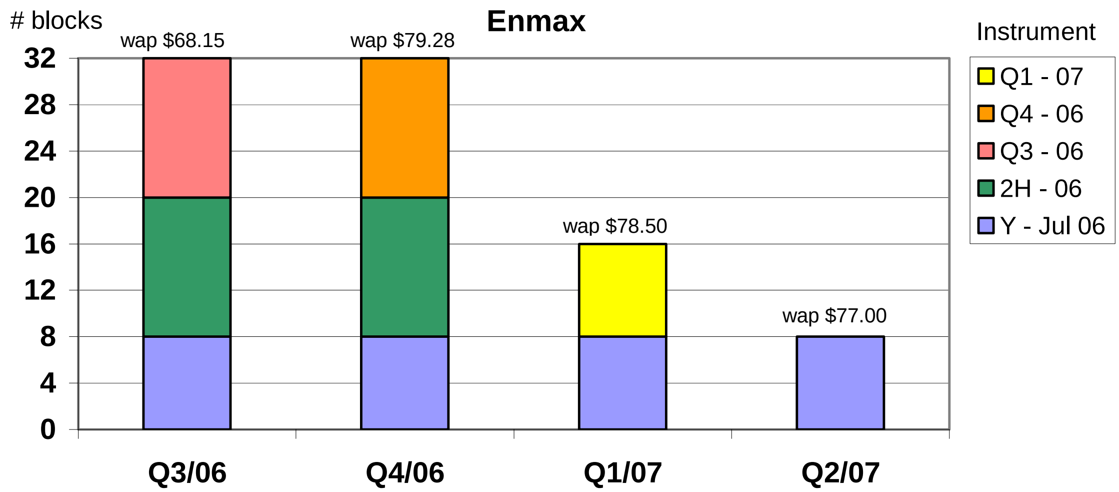
1.5 Regulated Rate Developments

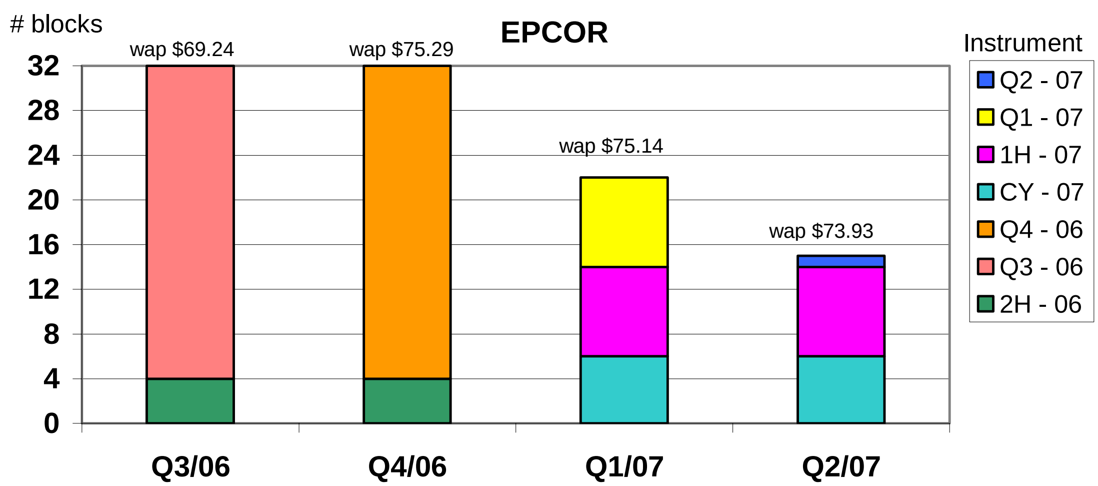
Q3/06 marks the first full quarter for retail rates established under the new regulated rate option regulation and associated energy price setting plans of the wire owners. RRO rates are set monthly with at least 20% procured one month ahead. For the two largest RRO providers – Epcor and Enmax, 80%[3] is procured through an auction process for 'full load' product on a quarterly, half-year, and yearly basis. As such, the changes in cost of these volumes may create more significant rate changes when going into a new quarter. While residential RRO rates trended upward through Q3/06, initial Q4/06 rates for October (determined in late Q3/06) stepped up with higher cost full load procurements for Q4/06

[3] 32 blocks of full load requirement transacted in 2.5% increments

flowing through as indicated by the weighted average procurement prices (WAP) noted below:

Full Load RFP procurement for RRO (2006 ytd)

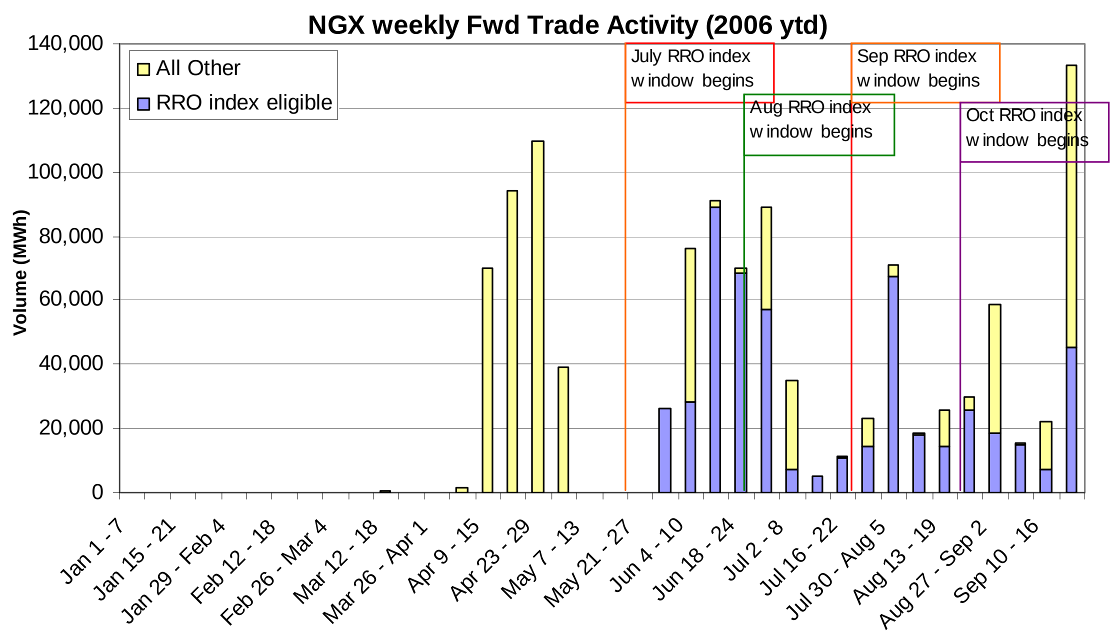




The graph also shows that full load procurements have been completed for the balance of 2006 under both the Enmax and EPCOR energy price setting plans with more recent auctions taking place for 2007 procurements[4]. The RFP auctions have shown strong participation and competitive bidding thus far, which is particularly evident in the closing phase of the auctions prior to the random close. Auctions have reflected a premium for shaped to flat product averaging approximately $7.00 – 8.00 which is a competitive level.

[4] Procurements for Q1/07 and Q2/07 are currently in progress and weighted average prices (WAP) shown for those quarters are therefore preliminary.

20% of current RRO rates are based on the NGX forward month RRO index[5]. The forward month component of RRO procurement has shown encouraging signs of improved forward market liquidity. As shown in the graph below, no forward energy volume transacted on NGX during Q1/06. While Q2/06 showed a few weeks of significant trade volume, the first RRO procurement window for July demonstrated that RRO eligible volumes comprised a substantial proportion of trade volume on NGX. Since early June, improved forward market liquidity is evident.



1.6 MSA Activities

Fall Stakeholder Meetings – The MSA held its fall stakeholder meetings in Edmonton and Calgary on Oct. 2 and 3 respectively. The meetings contained a status report on several current issues as well as short presentations on project work underway. The presentation from the meetings is available to view on the MSA website at : www.albertamsa.ca .

Stakeholder Engagement – In late July, the MSA released its final report outlining the consultation protocol which it will use when matters arise requiring broad stakeholder consultation, including any future development of market Guidelines. The development of this protocol included two phases of written stakeholder comment which were valued inputs to the process.

[5] Beginning October 23, the MSA has included a new graph in its weekly Market Monitor which describes the monthly RRO index for the forward month.

TPG Investigation – The MSA published its investigation report into certain trading activity observed in November 2005 which was questionable under provisions of the Trading Practices Guideline. The report identified the party involved as Enmax and concluded that Enmax was found to be in breach of the TPG. A negotiated settlement was concluded between Enmax and the MSA in which the party acknowledged its transgression, pledged to implement policies and procedures to ensure TPG compliance, and host a speaking / educational event for the benefit of industry. The complete investigation report is available for review on the MSA website at: www.albertamsa.ca/3396.html .

Section 73 Complaint – A decision was delivered by the EUB Chair in late Q4/06 in relation to a complaint filed against the MSA by TransAlta Corp. in November 2005 under Section 73 of the Electric Utilities Act. Section 73 allows any person to file a complaint with the Chair of the EUB with regard to conduct of the MSA. In its complaint, TransAlta took exception to the MSA's publication of a preliminary assessment (PA) on the PPA buyer – owner relationship within the context of the TPG. While this PA did not find a basis to proceed with a formal investigation, the MSA was of the opinion that industry would benefit from disclosure of the PA. The Chair's decision concluded that he did not have authority to speak to the mandate of the MSA but went on to conclude that while the MSA acted in good faith, the MSA acted inconsistent with its established publication process. The MSA has corrected this by revising its investigation procedures and indicating clearly that preliminary assessments will not be published in the future. In the event that positions on broader issues are developed through conducting a PA that the MSA believes industry would benefit from, a separate process will be undertaken for which a publication may result.

MSA Staff Changes – The MSA welcomed two new analysts to the group during Q3/06 - Kerry Snelson and Janene Taylor. Kerry is an MBA graduate and will be working with the investigations team while Janene is a recent Masters Economics graduate and will be working with the market monitoring & analysis group. Etienne Snyman recently departed the MSA. The MSA thanks Etienne for his valued contributions during his tenure in the group.

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table 1 - Pool Price Statistics

	Average Price[1]	On-Pk Price	Off-Pk Price	Std Dev[2]	Coeff. Variation[3]
Jul - 06	128.23	167.78	82.24	199.59	156%
Aug - 06	73.46	92.83	46.65	99.46	135%
Sep - 06	82.53	112.07	45.61	126.44	153%
Q3 - 06	**94.74**	**124.23**	**58.17**	**150.10**	**148%**
Apr - 06	42.87	56.02	26.37	46.59	109%
May - 06	56.26	76.55	30.52	77.70	138%
Jun - 06	61.64	86.28	27.92	96.09	156%
Q2 - 06	**53.59**	**72.95**	**28.27**	**76.64**	**143%**
Jul - 05	37.75	45.93	28.23	35.04	93%
Aug - 05	88.33	106.26	63.50	74.13	84%
Sep - 05	74.30	104.67	36.34	63.90	86%
Q3 - 05	**66.79**	**85.62**	**42.69**	**63.66**	**95%**

1 - $/MWh

2 - Standard Deviation of hourly pool prices for the period

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

Figure 1 – Pool Price Duration Curves

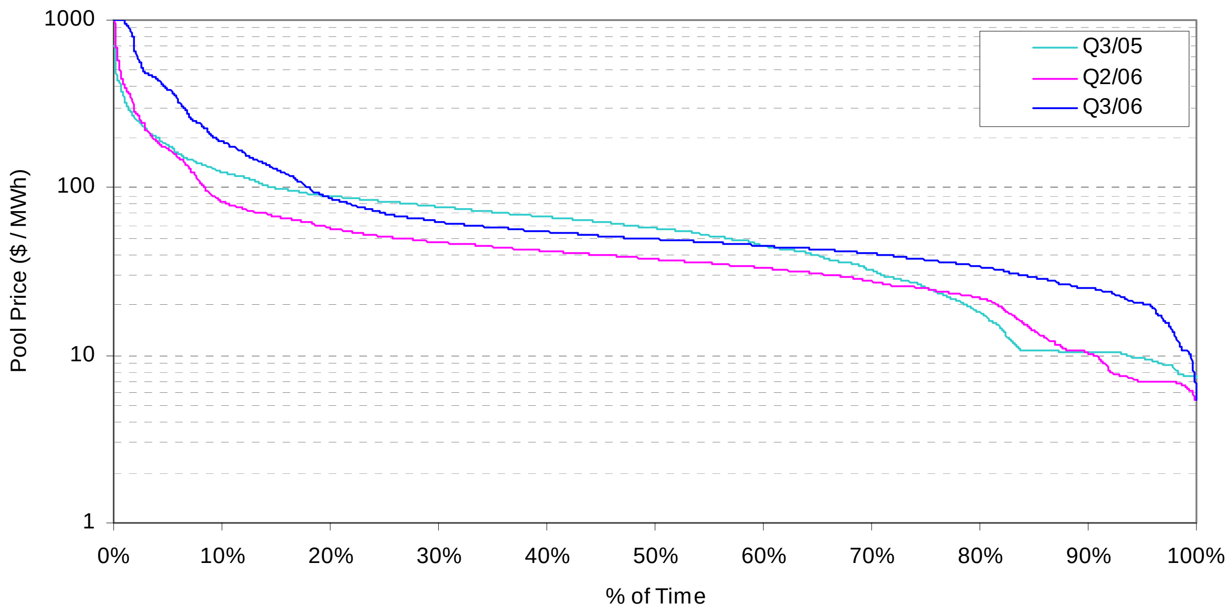


Figure 2 – Pool Price with Pool Price Volatility

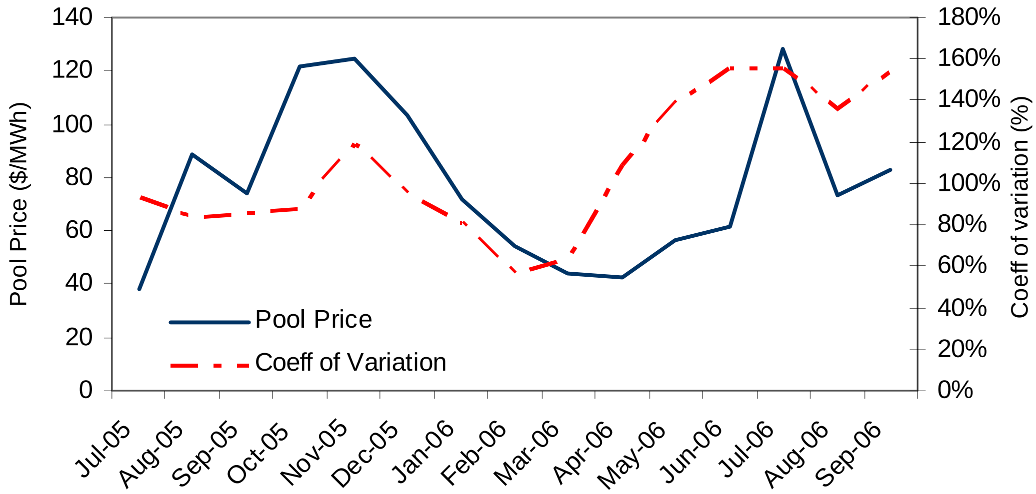


Figure 3 - Wholesale Electricity Price with AECO Gas Price

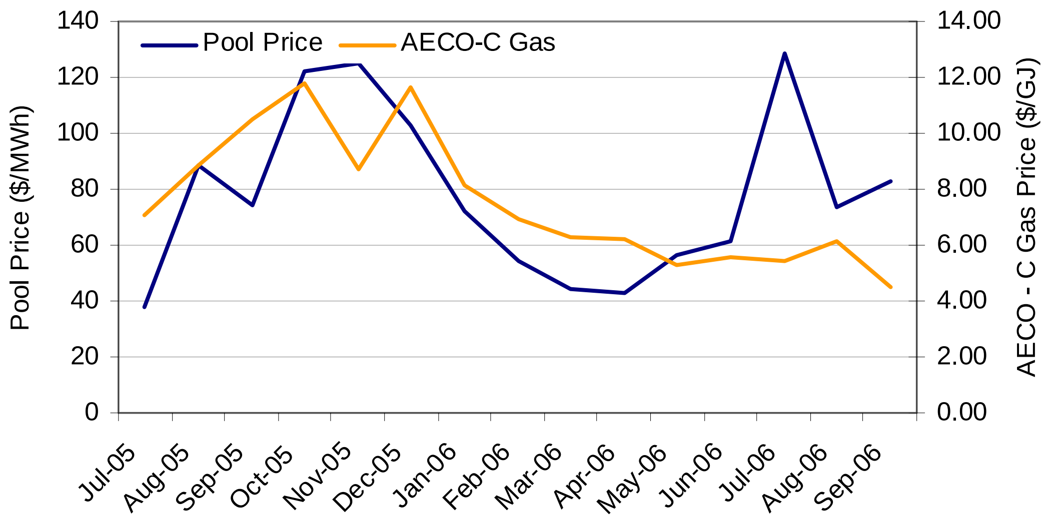


Figure 4 - Price Setters by Submitting Customer (All Hours)

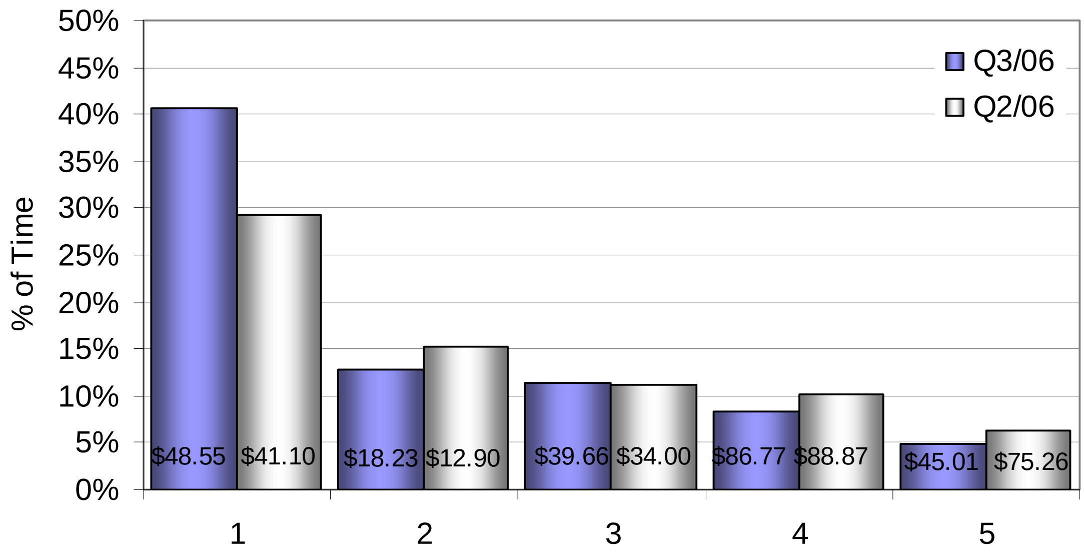


Figure 5 - Price Setters by Fuel Type (All Hours)

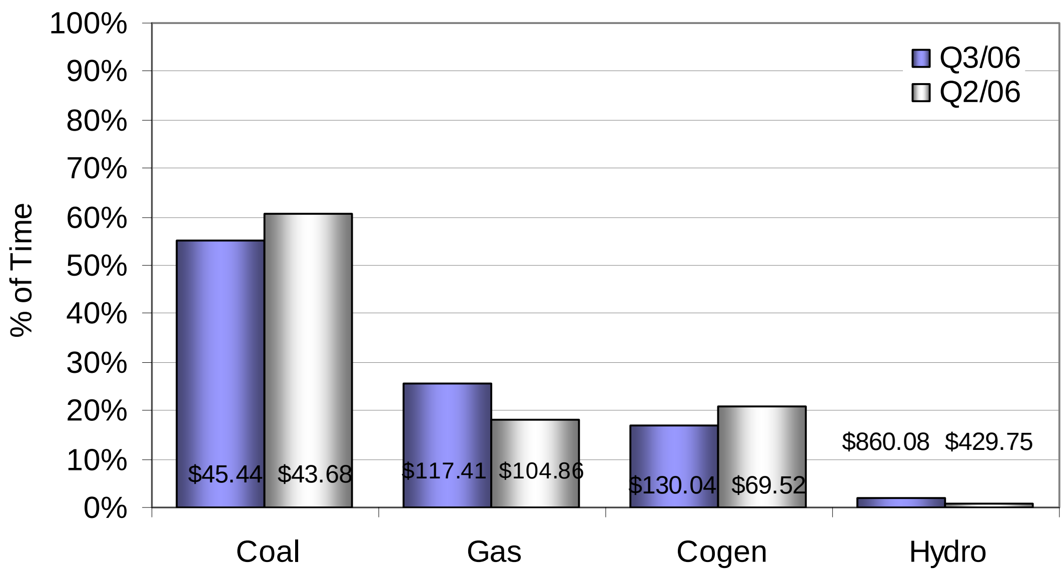
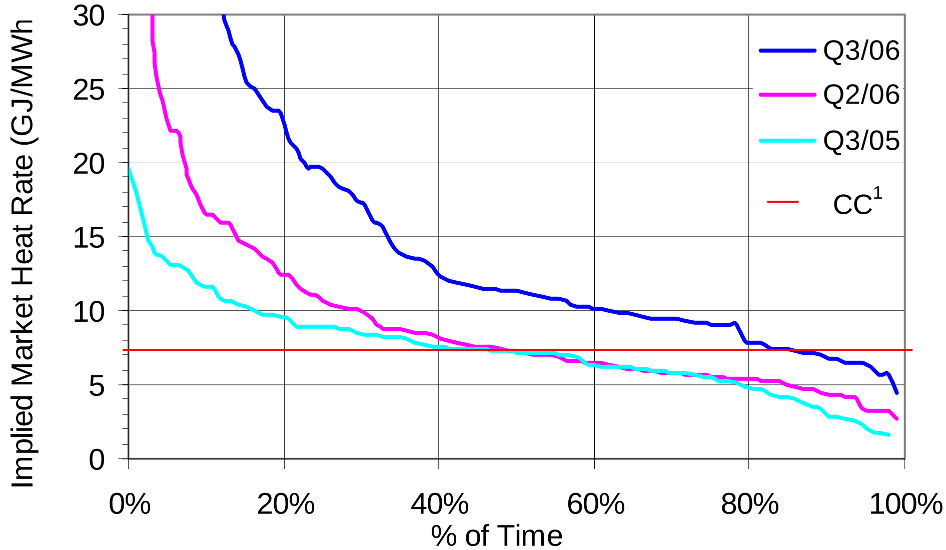
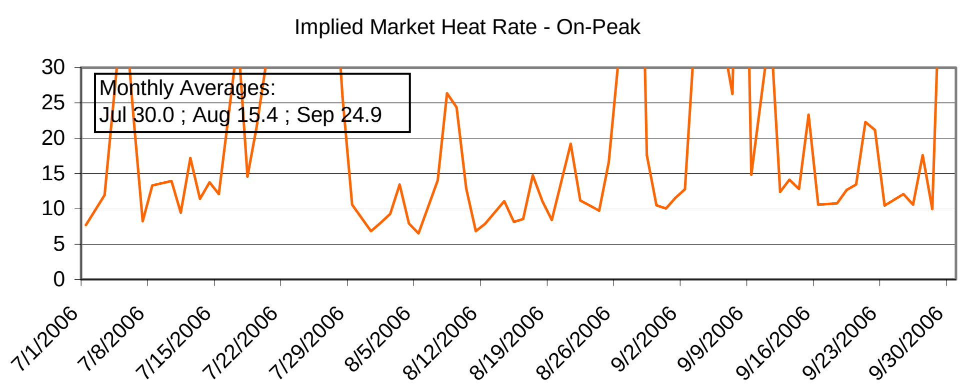


Figure 6 – Heat Rate Duration Curves (All Hours)



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

Figure 7 - Implied Market Heat Rates (Q3/06)



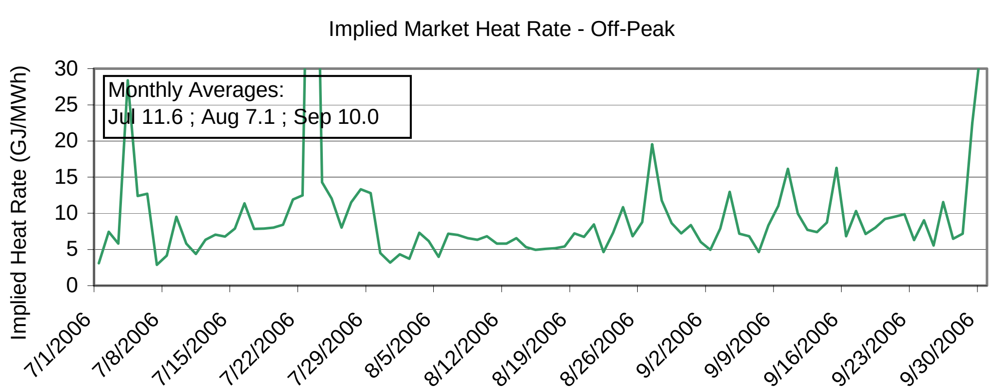


Figure 8 – PPA Outages by Quarter

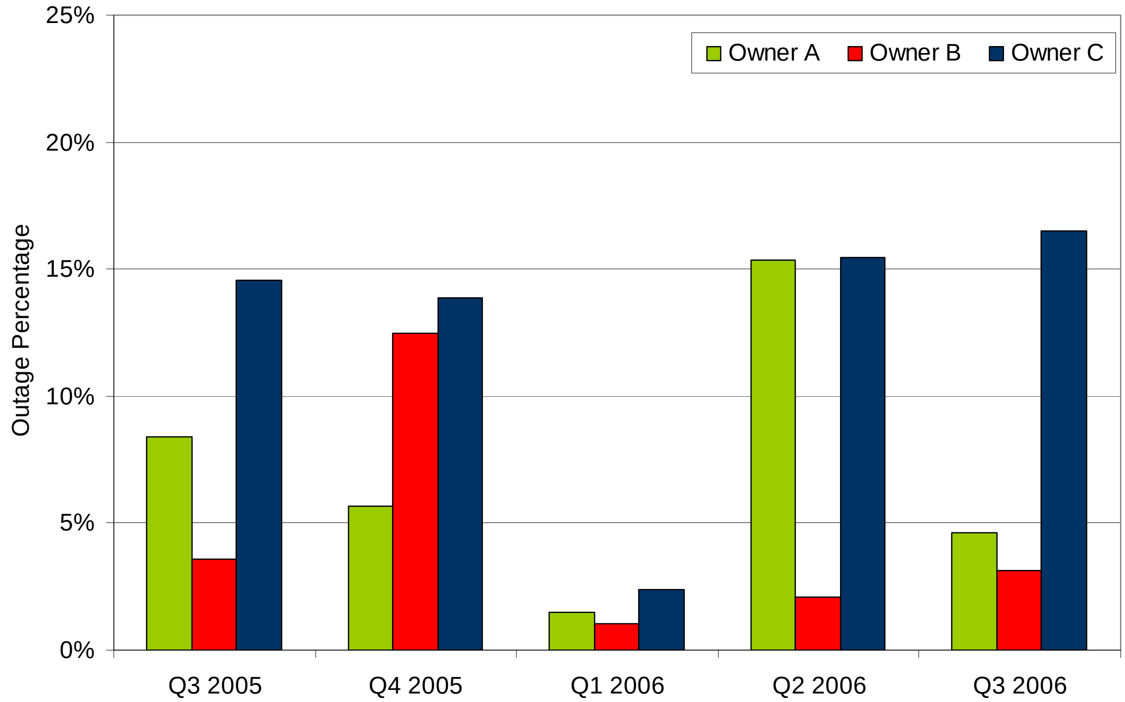


Table 2 - Percentage of Unplanned Outages for PPA Units

	Q3/06	Q2/06	Q1/06	2005	2004	2003	2002	2001
Owner-A	**3.1%**	9.3%	1.4%	5.0%	6.1%	4.9%	4.2%	3.2%
Owner-B	**2.4%**	1.8%	1.0%	5.4%	1.5%	1.5%	0.5%	1.2%
Owner-C	**7.9%**	4.9%	1.9%	6.5%	6.3%	5.7%	10.8%	8.8%
PPA weighted average	**5.7%**	5.7%	1.6%	5.9%	5.5%	4.9%	7.7%	6.3%

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

	Target 2004	Actual 2004	Target 2005	Actual 2005	Target 2006	Actual Q3 2006
Owner-A	87%	88%	87%	90%	87%	95%
Owner-B	90%	97%	89%	90%	89%	97%
Owner-C	87%	89%	87%	88%	87%	84%
PPA weighted Average	87%	90%	87%	89%	87%	89%

Table 4 – PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q3/06	18	396	344	52	18	NA
Q2/06	76	385	396	47	18	NA
PFAM						
Q3/06	12	103	92	13	10	241,329
Q2/06	21	79	62	28	12	(252,833)

Table 5 – Summary of UFE Reasonable Exception Reports

Quarter	Outstanding	New	Resolved	Unresolved
Q3/06	208	71	12	267
Q2/06	170	39	1	208

APPENDIX B – TIE LINE METRICS

Table 6 – Q3/06 Tie Line Statistics

	BC			Saskatchewan			Overall		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
July	130,444	22,770	107,674	48,666	2,495	46,171	179,110	25,265	153,845
August	51,012	78,267	(27,255)	21,350	2,677	18,673	72,362	80,944	(8,582)
September	38,551	83,451	(44,900)	31,105	571	30,534	69,656	84,022	(14,366)
Total	220,007	184,488	35,519	101,121	5,743	95,378	321,128	190,231	130,897
On-Peak	91%	11%		60%	49%		81%	12%	
Off-Peak	9%	89%		40%	51%		19%	88%	

Figure 9 – Market Share of Importers and Exporters (Q3/06)

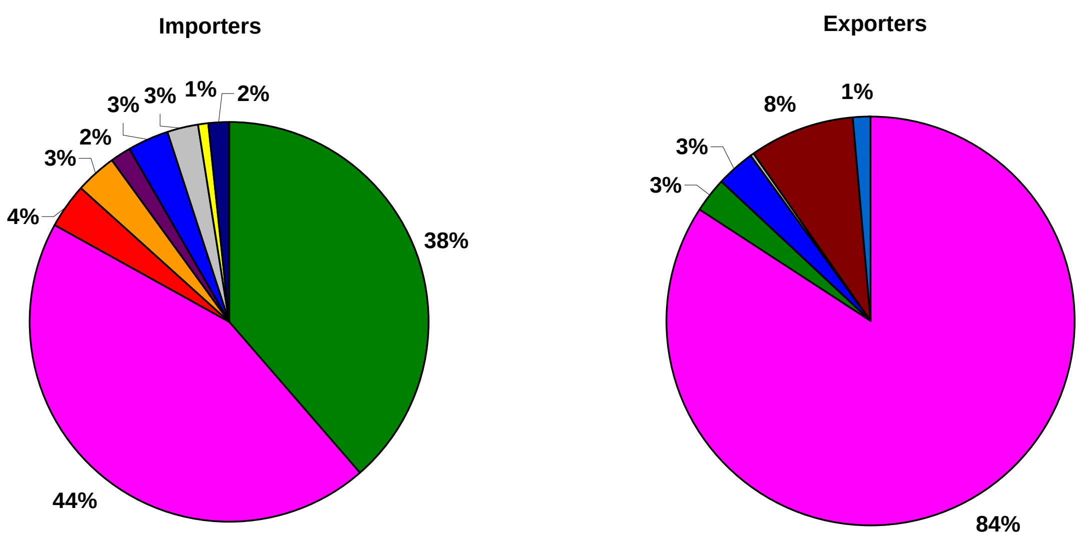


Figure 10 - Tie Line Utilization (Q3/06)

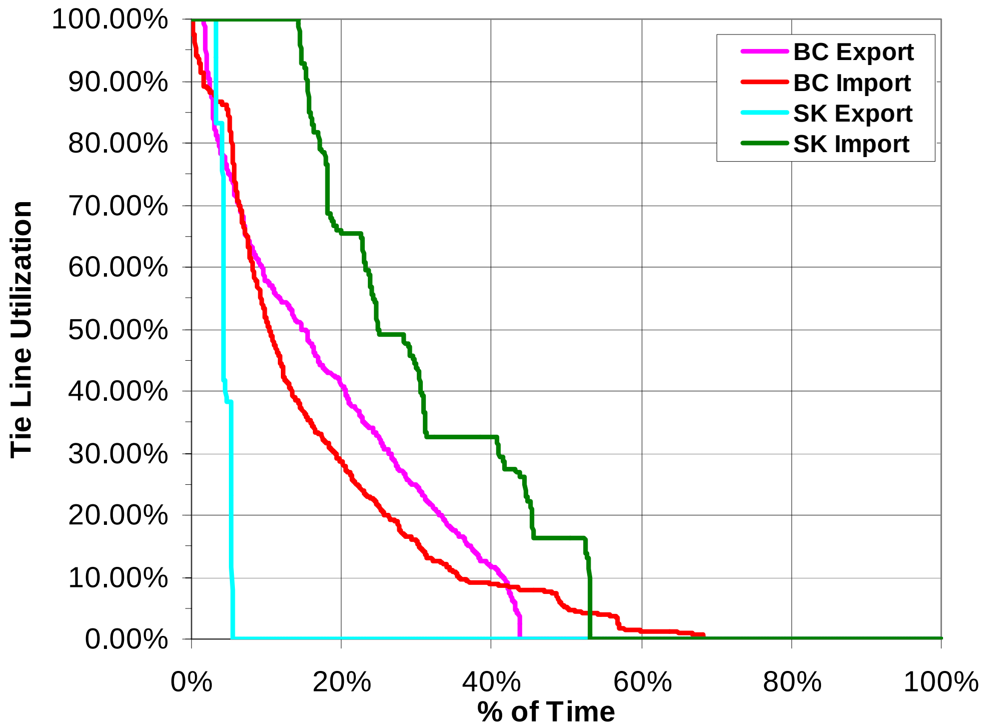


Figure 11 - Imports with Trade-weighted Prices

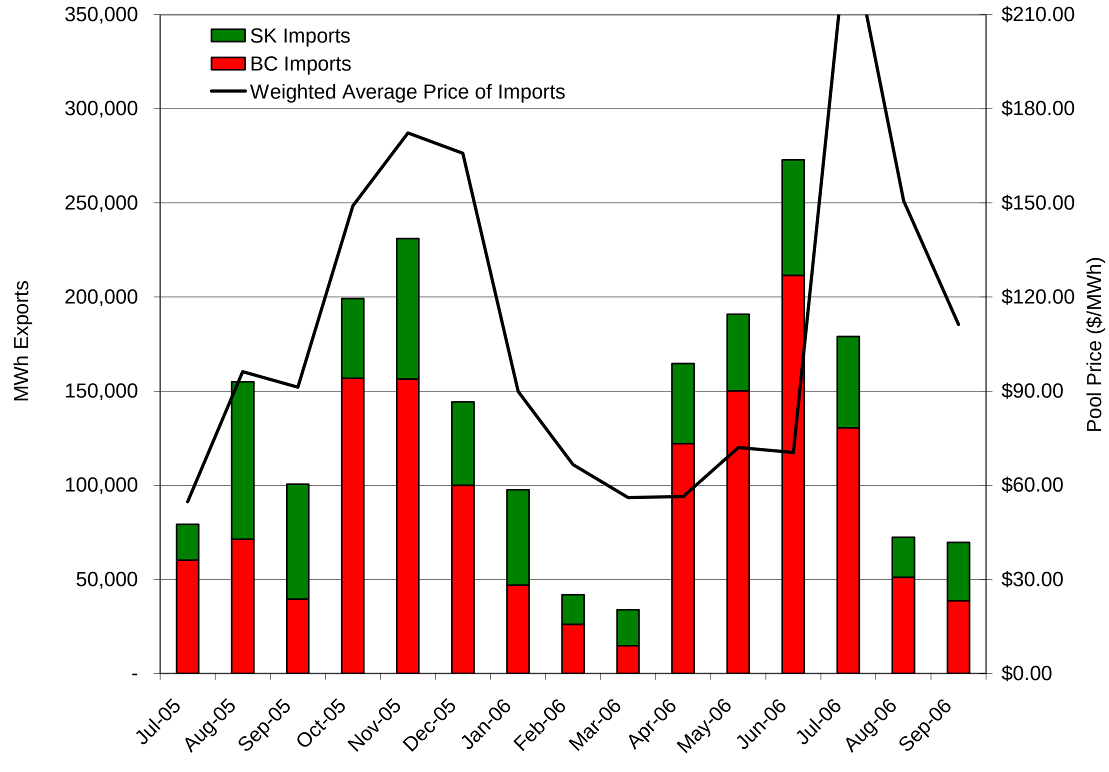


Figure 12 - Exports with Trade-weighted Prices

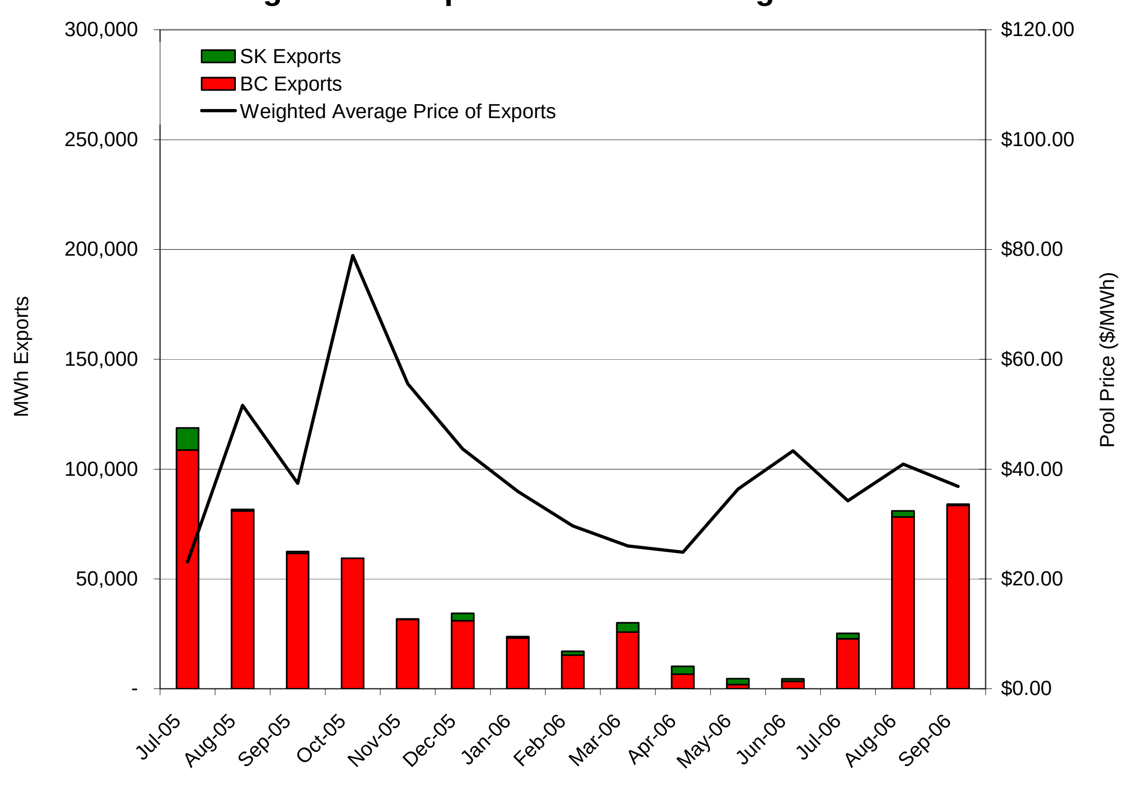


Figure 13 - On-Peak Prices in Other Markets

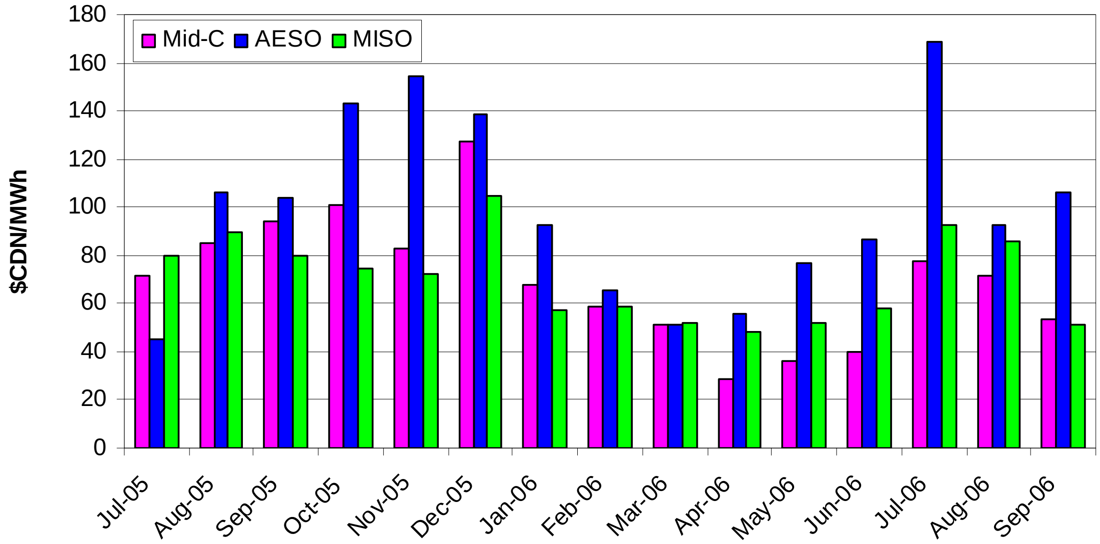
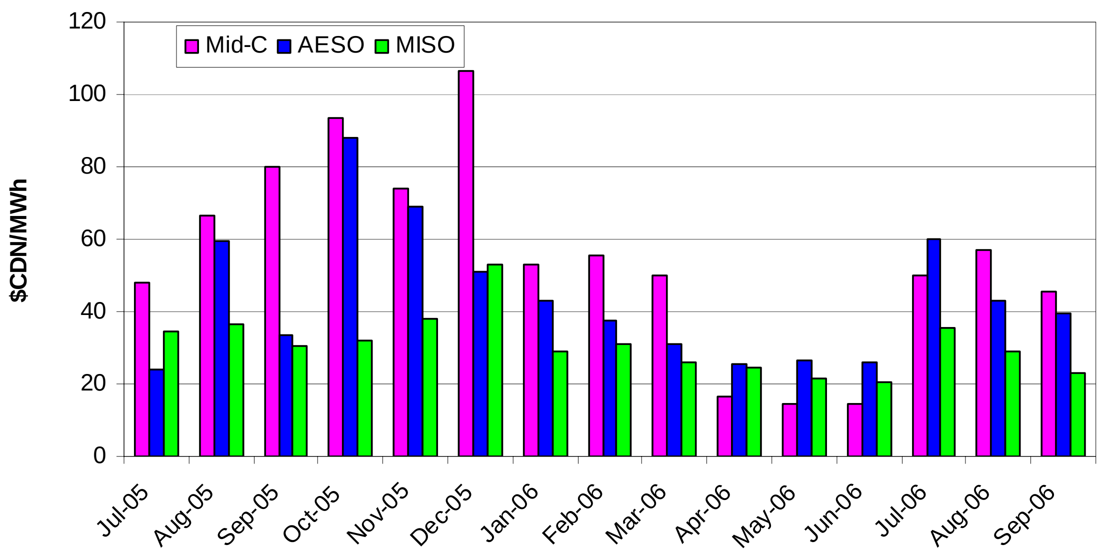


Figure 14 - Off-Peak Prices in Other Markets



APPENDIX C – ANCILLARY SERVICES 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 reserves in order to assist in the recovery of any unexpected loss of generation or an interconnection. Reserves are competitively procured by the AESO through the Alberta Watt-Exchange (Watt-Ex) and over the counter (OTC). Standard ancillary services products (contracts) include active and standby products for each of Regulating, Spinning, and Supplemental reserves. The majority of active reserve products are indexed and settled against Pool price prevailing during the contract period. Standby 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 15 - Active Settlement Prices - All Markets (Watt-ex and OTC)

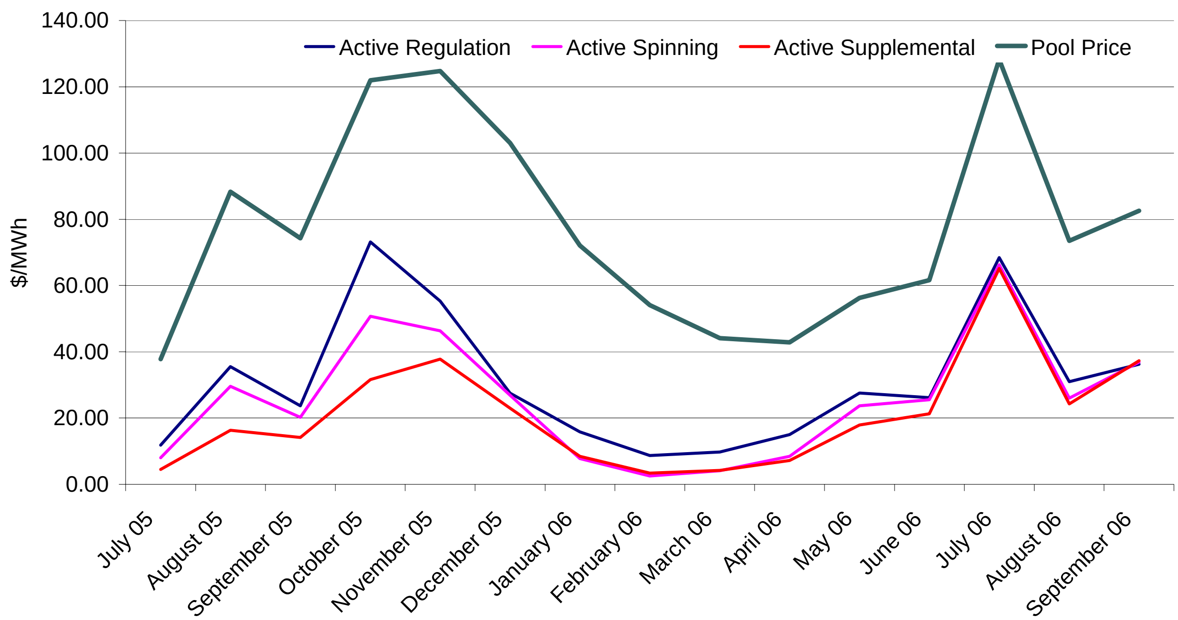


Figure 16 - Standby Premiums - All Markets (Watt-ex and OTC)

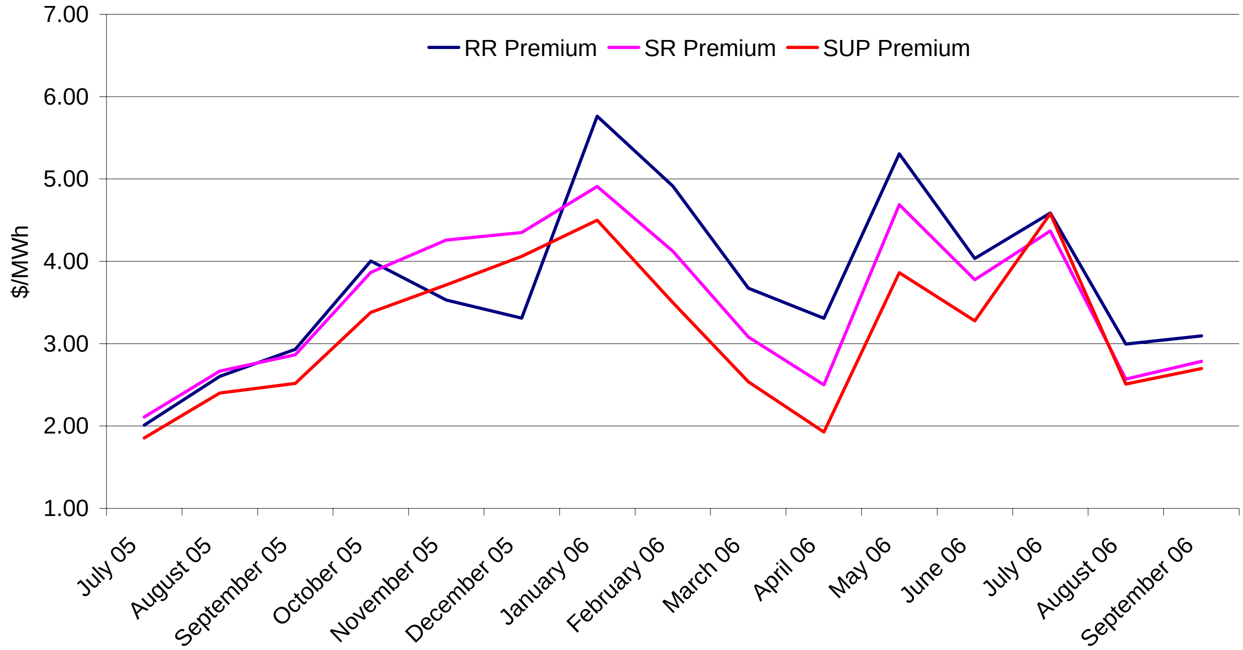
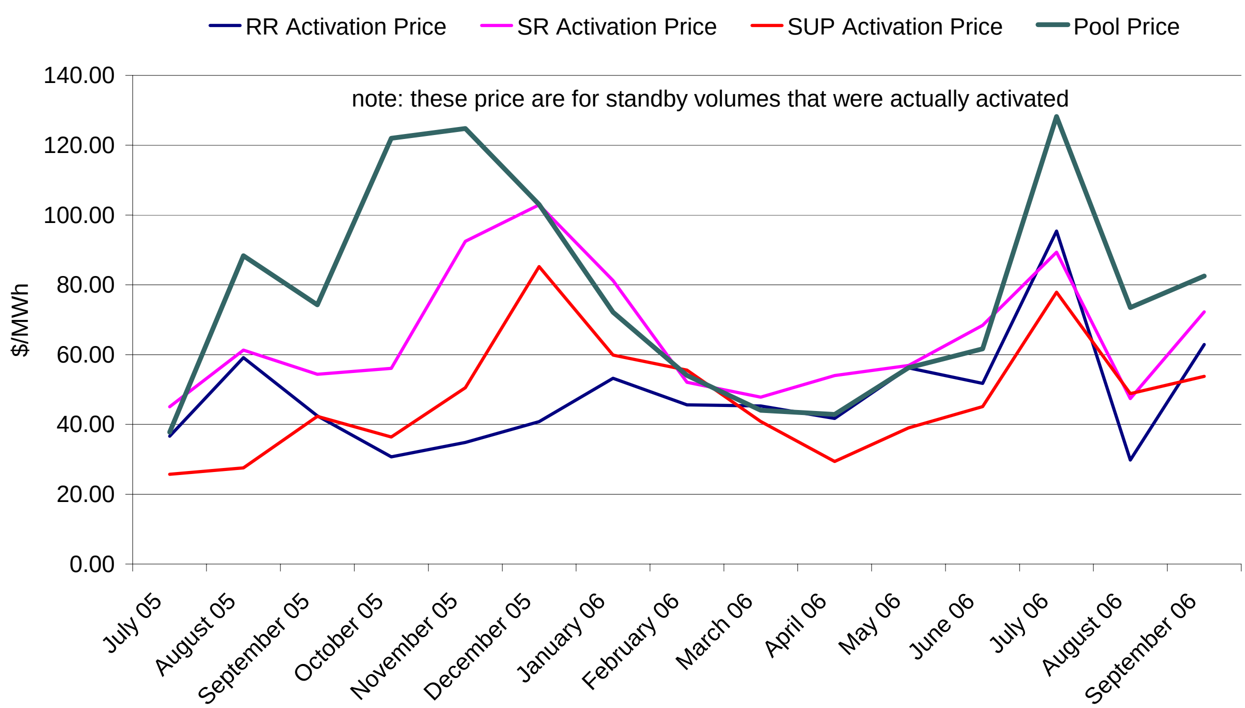


Figure 17 – Activation Prices – All Markets (Watt-ex and OTC)



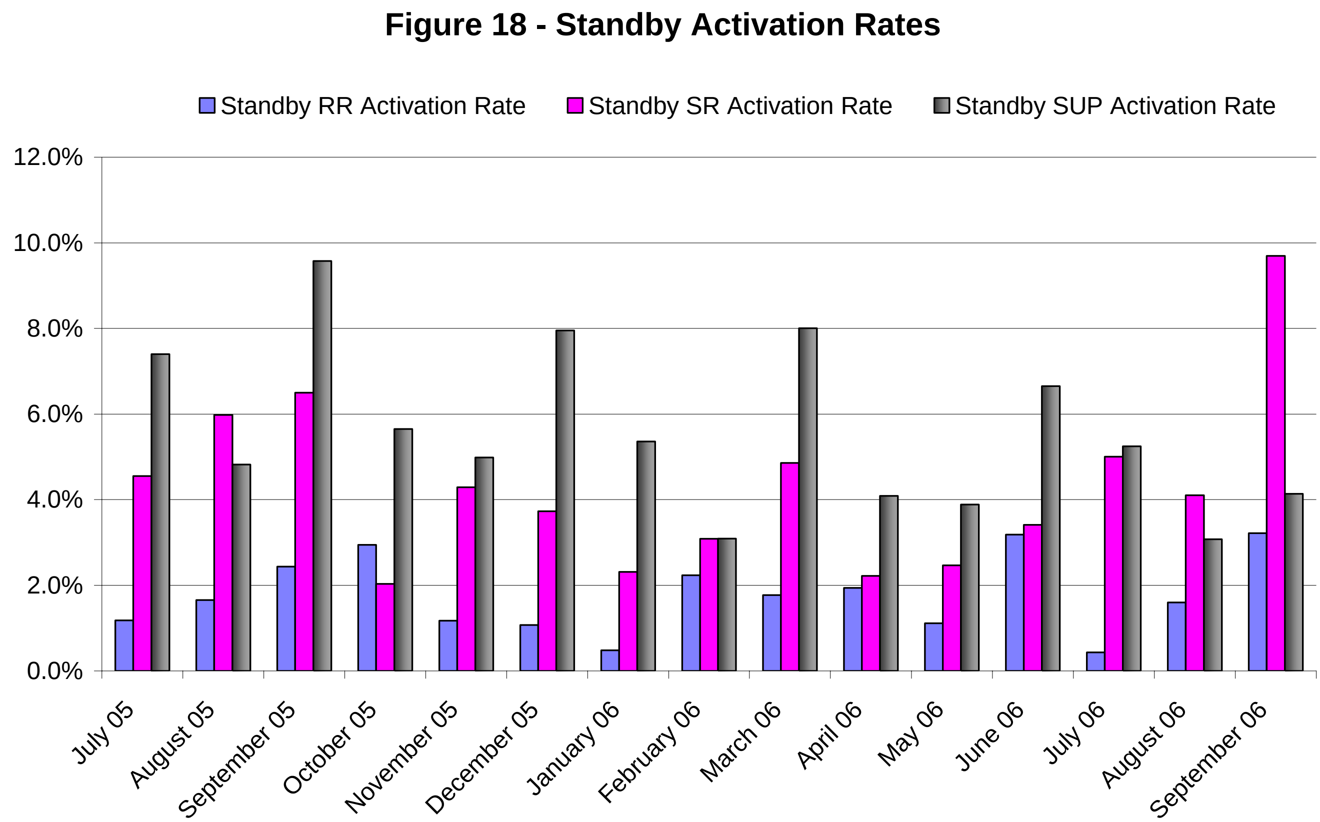


Figure 18 - Standby Activation Rates
Standby RR Activation Rate
Standby SR Activation Rate
Standby SUP Activation Rate
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
July 05
August 05
September 05
October 05
November 05
December 05
January 06
February 06
March 06
April 06
May 06
June 06
July 06
August 06
September 06

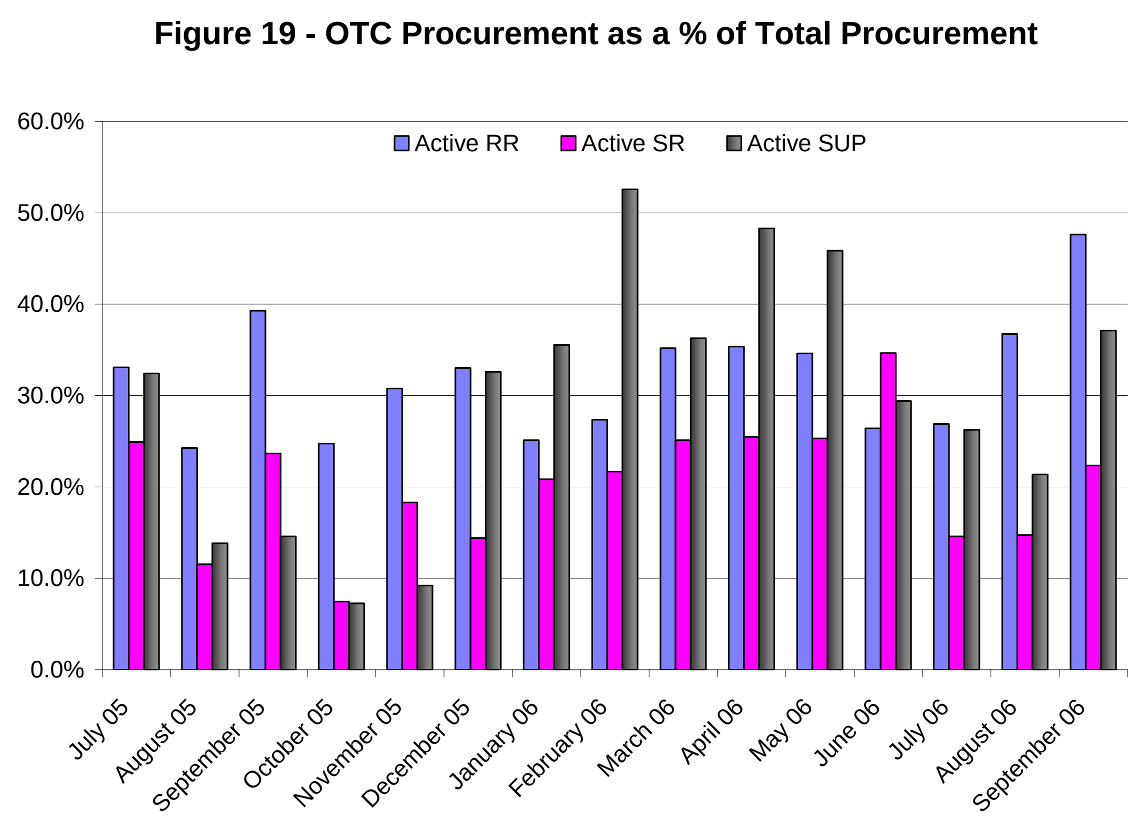


Figure 19 - OTC Procurement as a % of Total Procurement
Active RR
Active SR
Active SUP
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
July 05
August 05
September 05
October 05
November 05
December 05
January 06
February 06
March 06
April 06
May 06
June 06
July 06
August 06
September 06

Figure 20 - Active Regulating Reserve Settlement by Market

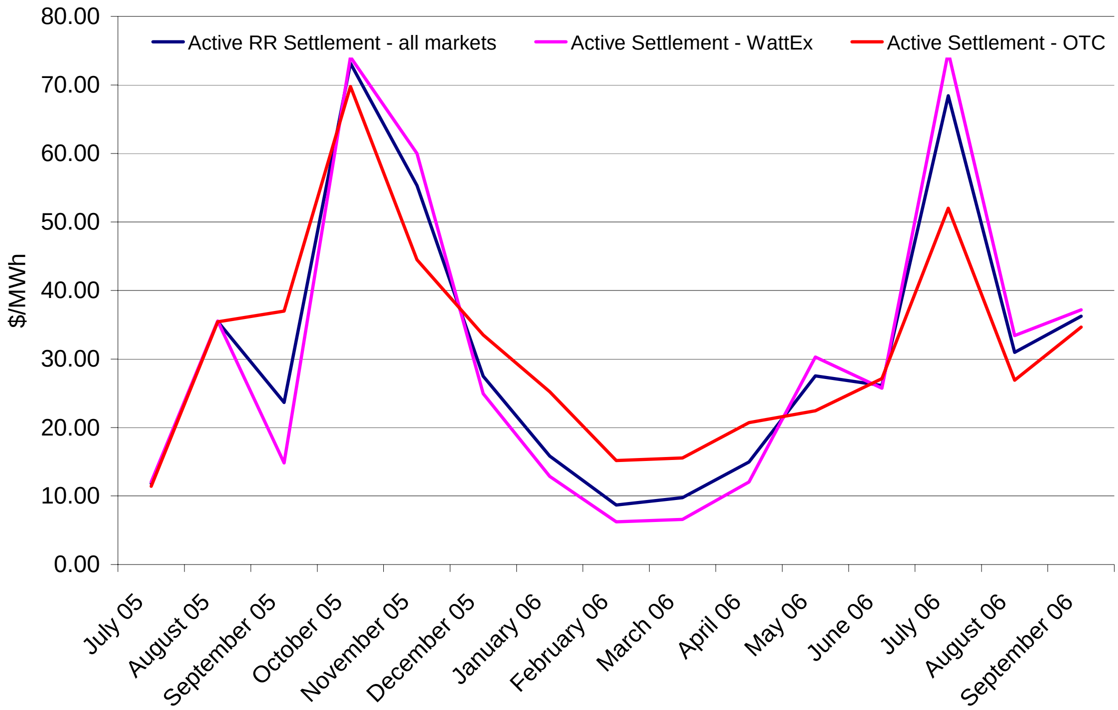


Figure 21 - Active Spinning Reserve Settlement Price by Market

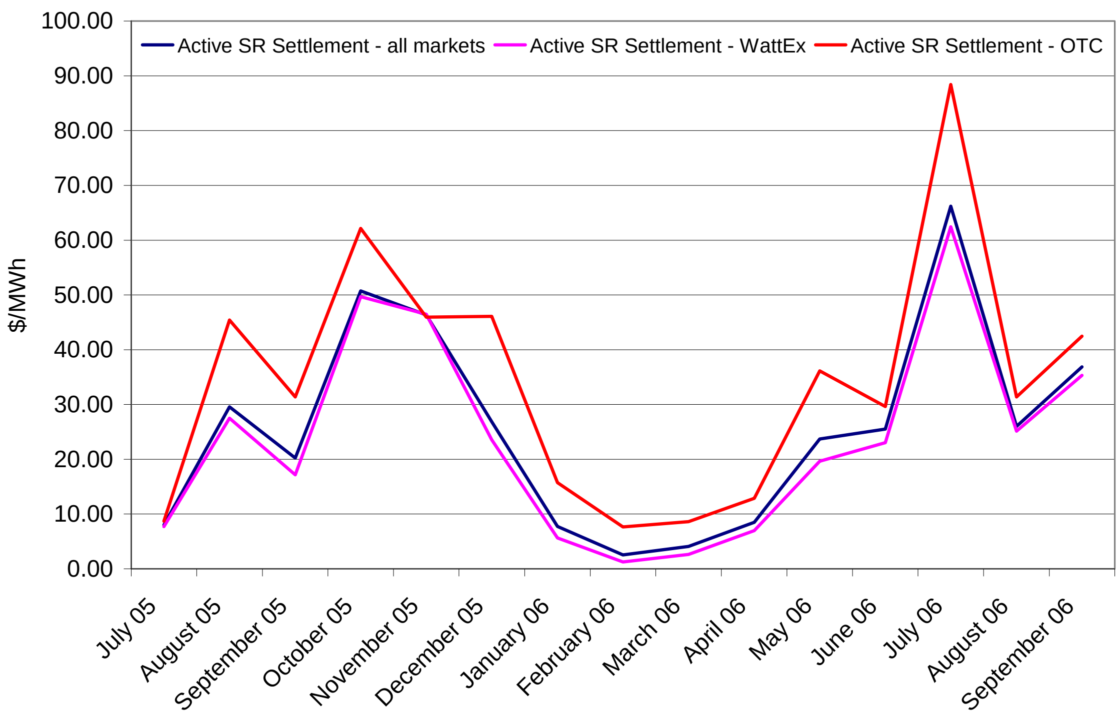


Figure 22 - Active Supplemental Reserve Settlement Price by Market

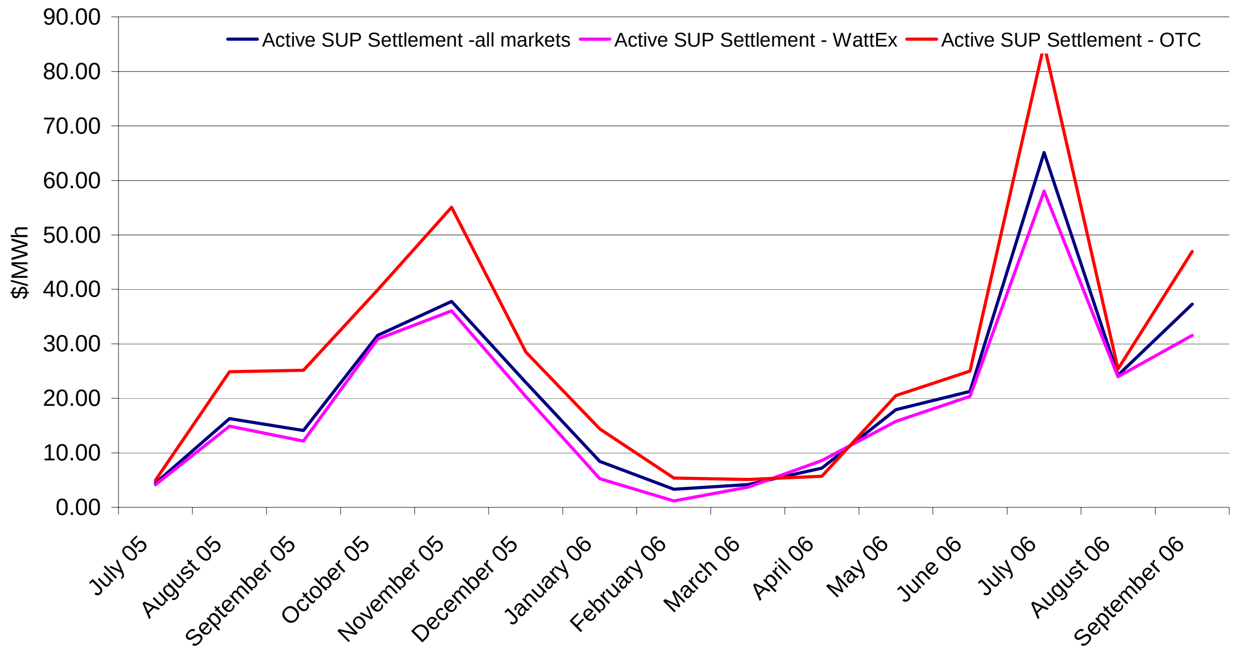


Figure 23 – Active Regulating Reserve Market Share by Fuel Type

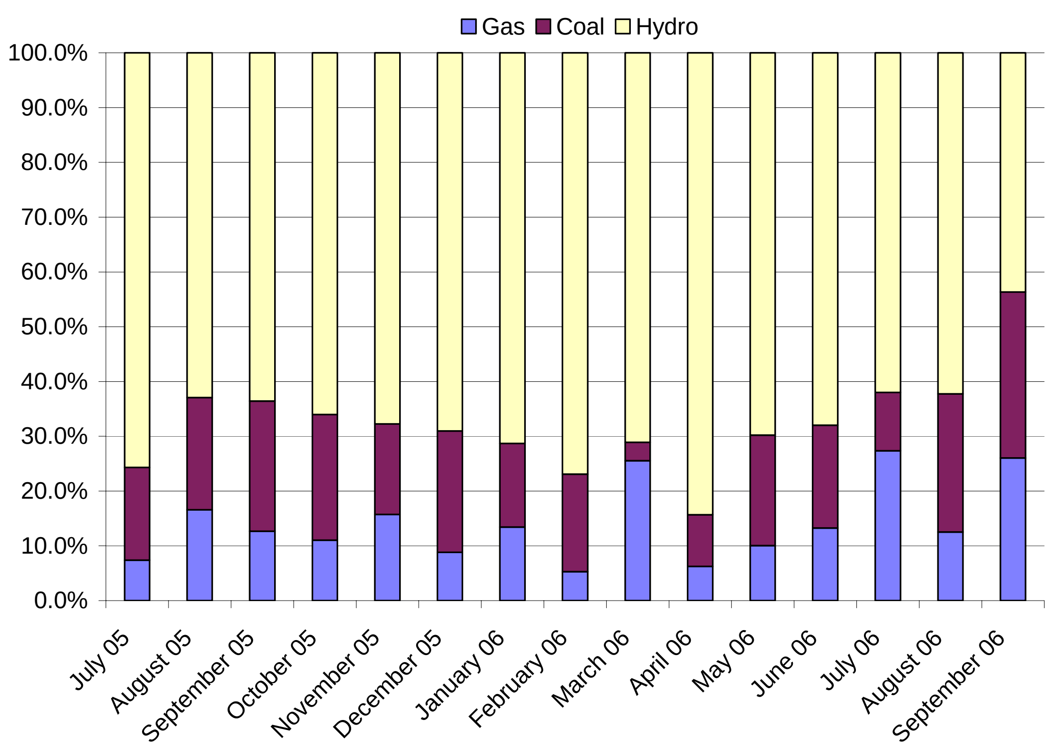


Figure 24 – Active Spinning Reserve Market Share by Fuel Type

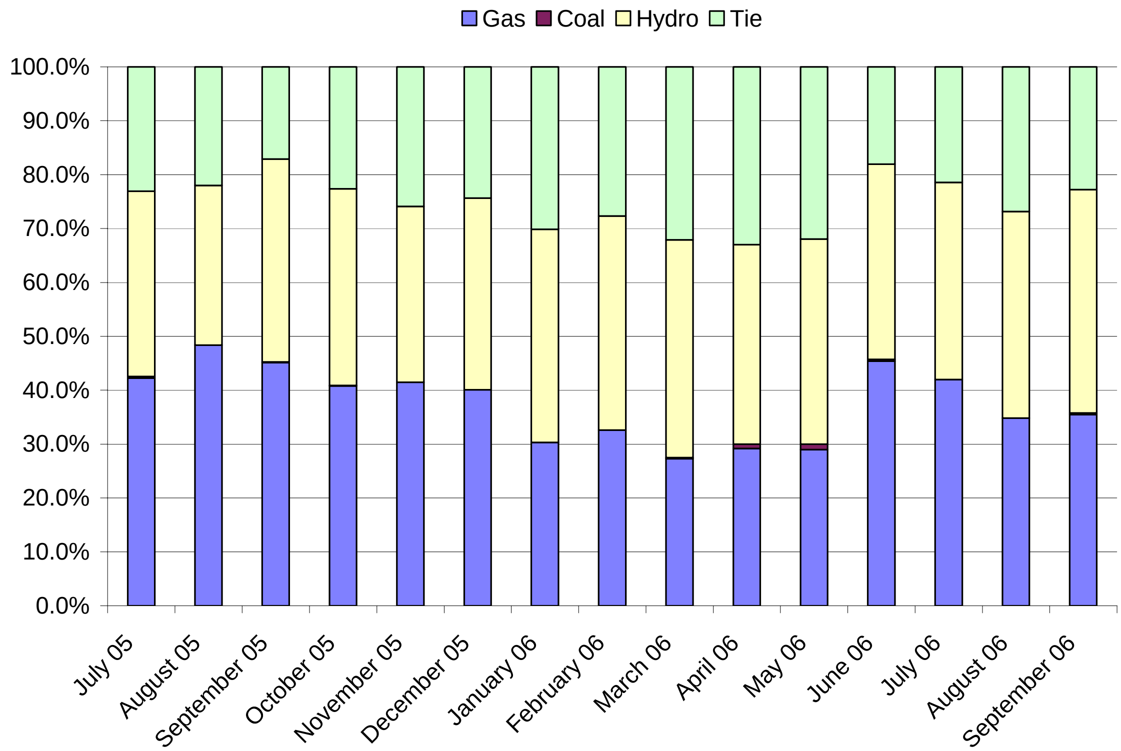


Figure 25 – Active Supplemental Reserve by Fuel Type