www.albertaMSA.ca

MSA Report

Quarterly Report

July – September 2007

29 October, 2007

Market Surveillance Administrator

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1 FEATURED MARKET DEVELOPMENTS DURING Q3/07

1.1 Wholesale Market Fundamentals

Average wholesale electricity prices averaged $92.47/MWh in Q3/07, up significantly from $49.95/MWh last quarter but in line with market prices observed in the same quarter last year. As with the third quarter last year, market prices during the month of July drove Q3/07 prices higher overall. With sustained weakness in natural gas prices through the quarter, implied market heat rates reached historical highs. The table below indicates that the average implied market heat rate of 18.6 GJ/MWh ranks Q3/07 fourth highest among all quarters dating back to 1999. It can be seen that five of the ten highest quarters by heat rate shown below occur in the third quarter of the year. This can be attributed to historically diverging gas prices relative to electricity prices through the summer period when gas prices are often trending lower due to elevated gas storage levels while electricity prices tend to move higher due to the confluence of temperature related generation outages and derates and the summer peak system load.

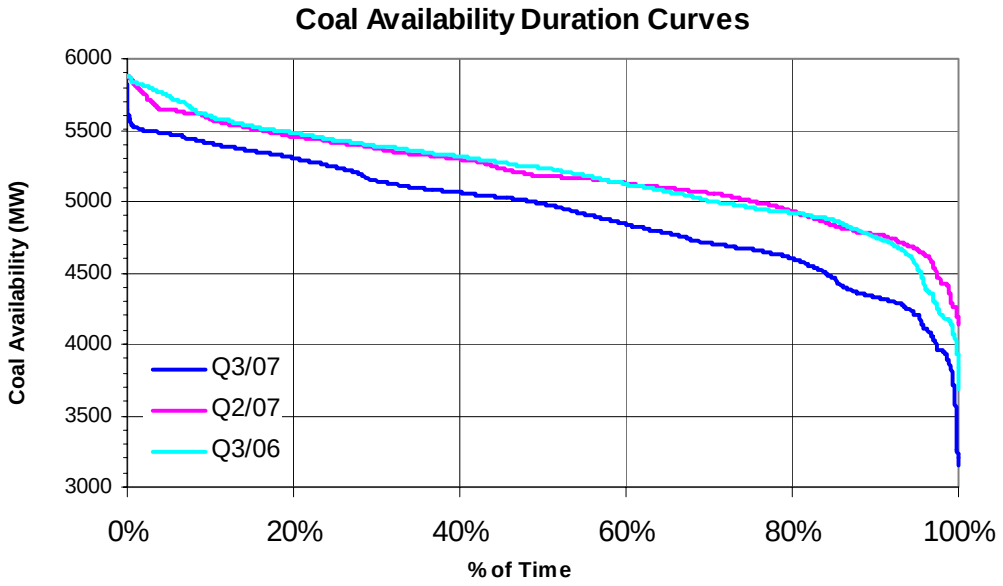
Ten Highest Average Quarterly Heat Rates (1999 – 2007)

Quarter	Average Implied Heat Rate (GJ/MWh)
Q3/00	33.7
Q4/00	29.0
Q2/00	19.1
Q3/07	18.6
Q3/06	17.9
Q1/00	17.8
Q2/99	16.9
Q3/01	16.1
Q3/99	15.6
Q2/01	15.4

System tightness during Q3/07 was a factor with reduced coal generation availability, as shown in the coal generation duration curves below. Seasonally high temperatures often prevailing during the month of July[1], tend to impact the supply side of the market by significant forced outages and derates among coal and

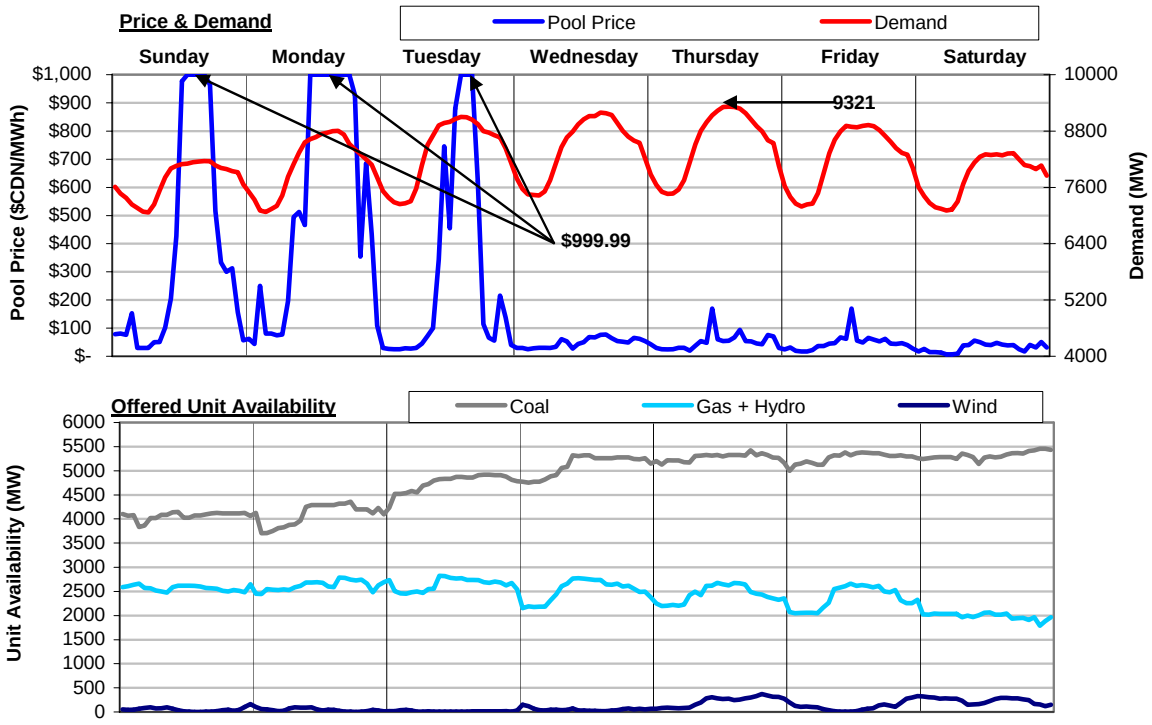
[1] Average max daily temperature (Calgary Int'l) for July 2007 was 26.4 C vs. the (1971-2000) historical average for July of 22.9 C.

gas units. These units are often unable to achieve adequate cooling on hot summer days in order to maintain full output capability.



With tight supply conditions during July as a result of reduced thermal generation availability, wind generation was not observed to provide a meaningful supply buffer, although substantial energy imports responded via the B.C. and Saskatchewan tie lines. The following figure highlights the week ending July 21, 2007 when Pool prices reached the price cap for several hours on consecutive days early in the week while on-peak wind generation was mostly absent. The figure also demonstrates that later in the week, significant wind generation was observed on the Thursday when system demand set a new summer peak of 9321 MW however, the combined effect of approximately 400 MW of on-peak wind generation and significant import volumes resulted in Pool price remaining below $200.00 on the day.

On the demand side, summer peak demand increased 355 MW as compared to July last year for a 3.6% growth rate in peak demand.



1.2 Collapse of September Contract Price

During August 2007, the forward month (September) Alberta electricity contract experienced a steep decline in price. The contract in early August, traded near $120/MWh but by month-end, had plummeted almost $40/MWh. As a result, of this unusually large change, the MSA conducted a detailed analysis of market fundamentals during the month of August to assess whether the collapse in the September contract could reasonably be attributed to fundamental reasons. The analysis indicated that the initial decline in the September contract could be attributed to much lower August settled prices vs. July and continued weakness in gas prices. The major portion of the price collapse was driven by the cancellation of the planned South KEG conversion project (and associated unit derates and outages) that changed the market view of supply adequacy during September. A discussion of the findings on this event can be reviewed on the MSA website at: www.albertamsa.ca.

1.3 Wind Developments

An analysis was conducted by the MSA on how increased wind generation may influence the attractiveness of various energy sources going forward.

Looking at data from July 2006 – July 2007, the analysis examined the residual system demand after subtracting wind generation in all hours and found that because of the lack of correlation between system demand and generation from wind, a steeper residual demand function may result – meaning that wind generation may not provide "portfolio" benefits to the system in terms of a smoother residual demand function. With greater geographic diversity in the installed base of wind generation, greater smoothing benefits would be expected.

The MSA analysis assumed only the existing diversity in wind generation and scaled up actual production for each hour to reflect the generation from new wind stations. The results suggested that a growing wind component in the Alberta's electric system is expected to create an enhanced opportunity for the development of peaking generation in the Alberta market – at the relative expense of base load generation. A presentation on this topic was given at the MSA fall stakeholder meetings. The presentation can be viewed at www.albertamsa.ca.

In late September, the AESO removed the 900 MW cap on wind generation in Alberta. Several thousand megawatts of capacity are currently under consideration. It is expected that some of these projects will not come to fruition but nonetheless, capacity additions over the next several years will be dominated by wind.

1.4 Regulatory Developments

In late September 2007 the EUB announced the hearing schedule for applications relating to the proposed Montana Alberta Tie Ltd. (MATL) merchant transmission line between Alberta and Montana. There are two applications involved, one by MATL for a 240 kV line and related substation between Lethbridge and the Alberta/USA border and one relating to the connection of the MATL facilities to the AESO run system. The hearings commenced October 16, 2007.

Also in late September 2007, the EUB cancelled ongoing proceedings and closed the application for construction and operation of the proposed 500 kV transmission line between Edmonton and Calgary. The EUB also indicated its intention to set aside previous decisions approving the need for the transmission line. Regulatory hearings and public proceedings had been in progress regarding the project for nearly two years. According to the EUB, public confidence in the process was called into question as a result of certain board actions in the course of the hearing process. As a result of the closing of the application, the process for determination of need for the project must be re-initiated. Upon the re-filing of a new application, a new public hearing would be held by a new independent panel which will consider the question of whether a new transmission line is needed and in the public interest.

Delays to transmission development have uncertain impact on market prices. To the extent that the dispatch of resources is constrained, there may be additional need for transmission-must-run services. The mechanism for dealing with real-time congestion management is also likely to result in higher Pool prices. The MSA will examine instances of congestion to ensure the market remains workably competitive at these times.

1.5 Other MSA Activities

Investigations – In furtherance to ongoing investigation proceedings concerning importing activity during 2005, the MSA sought the court's assistance pursuant to sections 55 and 56 of the Act. A decision was issued by the Court of Queen's Bench on July 5, 2007 in respect of these applications. Further detail on the court decision can be found on the MSA website at: www.albertamsa.ca .

Fall Stakeholder Meetings – The MSA held its fall stakeholder meetings in Calgary and Edmonton on September 25 and 26 respectively. The meetings featured analyst presentations on current project work. The meeting presentation can be viewed at: www.albertamsa.ca.

Presentation – Martin Merritt gave a presentation on the Alberta Electricity market to institutional investors at a luncheon hosted by BMO Nesbitt Burns in Toronto. A copy of the presentation is available for review at www.albertamsa.ca .

Staff Changes – Senior Analyst Mark McGillivray departed the MSA during Q3/07. We thank Mark for his valued contributions to the MSA and wish him continued success.

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 - 07	154.25	212.80	87.65	259.73	168%
Aug - 07	70.92	97.05	34.83	116.99	165%
Sep - 07	49.17	58.44	38.59	46.45	94%
Q3 - 07	**92.47**	**122.76**	**53.69**	**173.60**	**143%**
Apr - 07	51.55	69.61	29.31	52.20	101%
May - 07	48.37	67.78	23.75	57.03	118%
Jun - 07	49.87	66.25	27.44	50.71	102%
Q2 - 07	**49.95**	**67.88**	**26.83**	**53.42**	**107%**
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%**

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

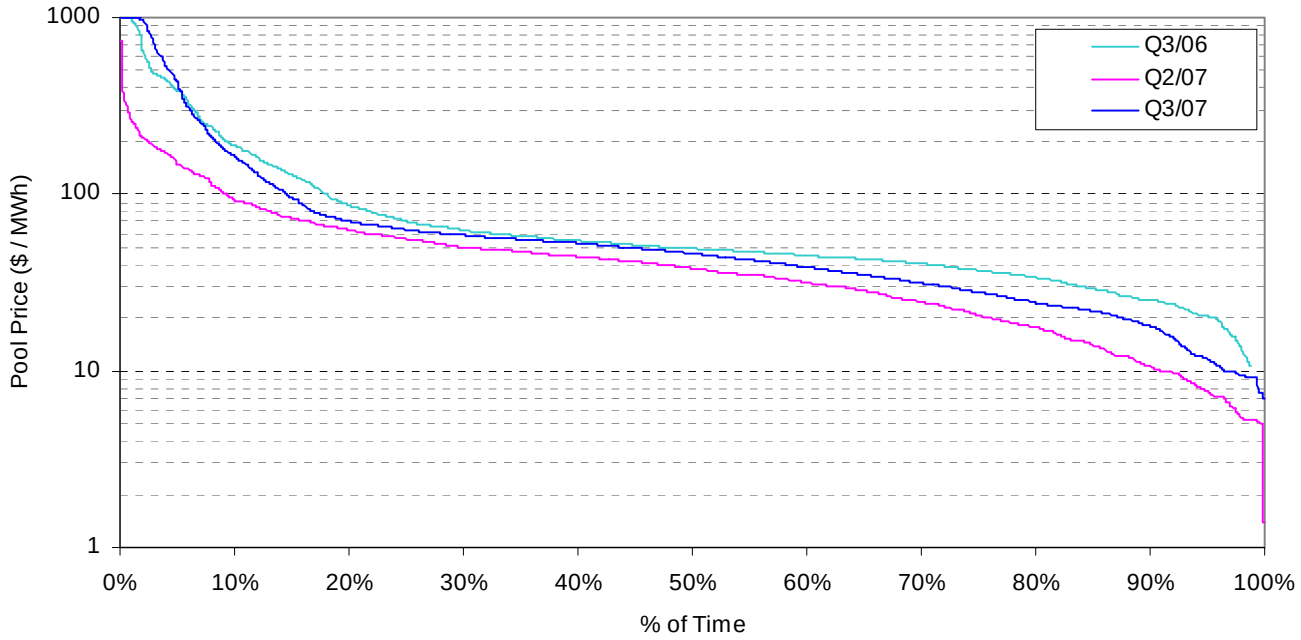


Figure 2 – Pool Price with Pool Price Volatility

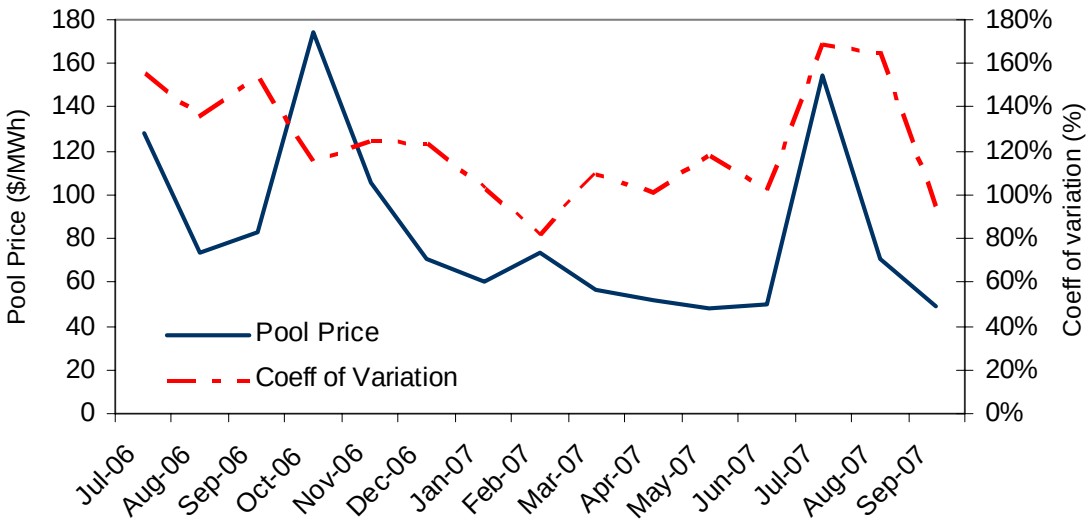


Figure 3 - Wholesale Electricity Price with AECO Gas Price

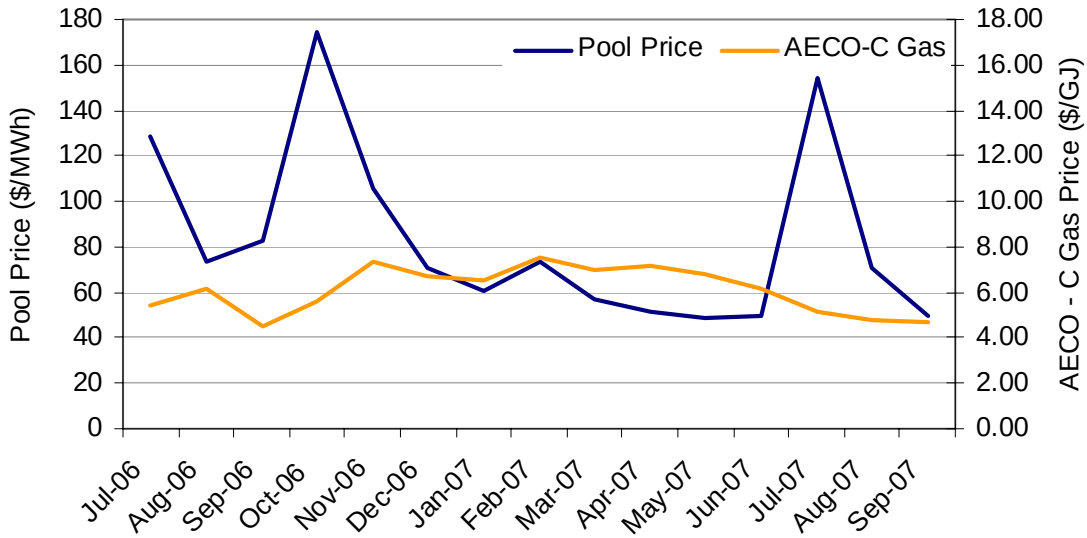


Figure 4 - Price Setters by Submitting Customer (All Hours)

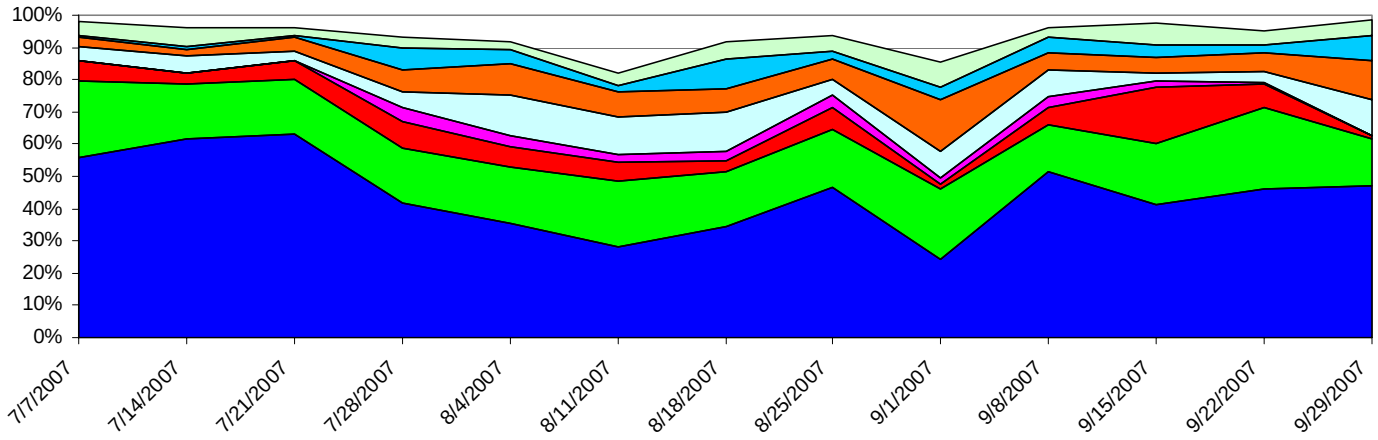


Figure 5 - Price Setters by Fuel Type (All Hours)

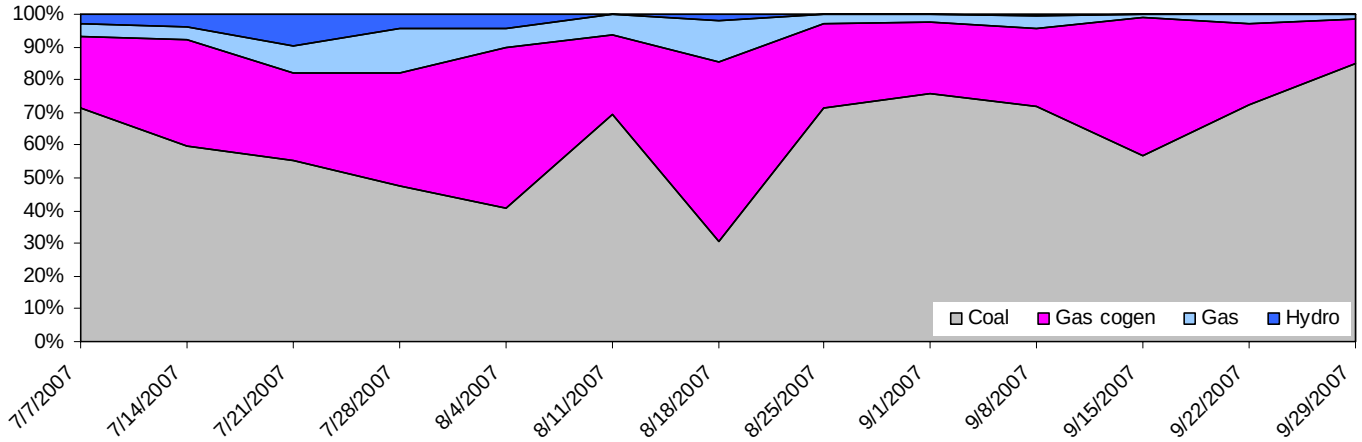
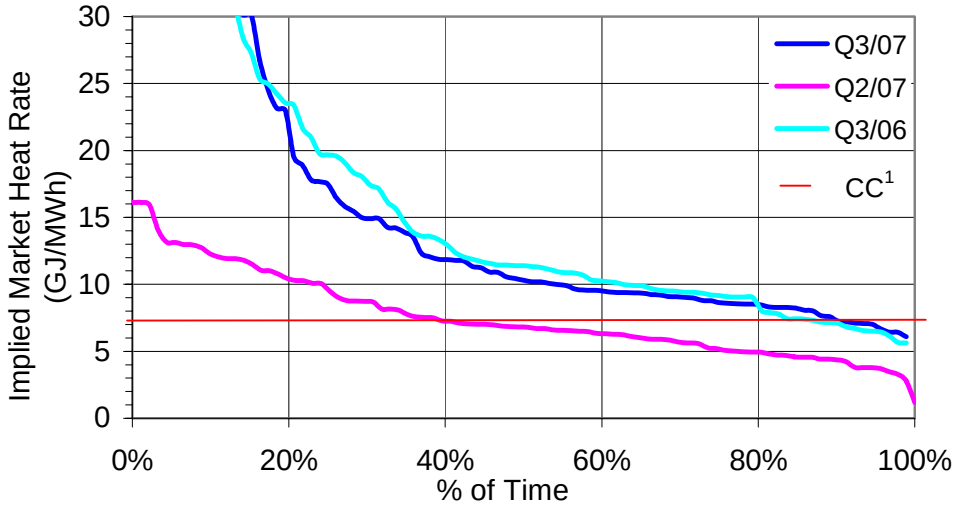


Figure 6 – Heat Rate Duration Curves (All Hours)



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

Figure 7 - Implied Market Heat Rates (Q3/07)

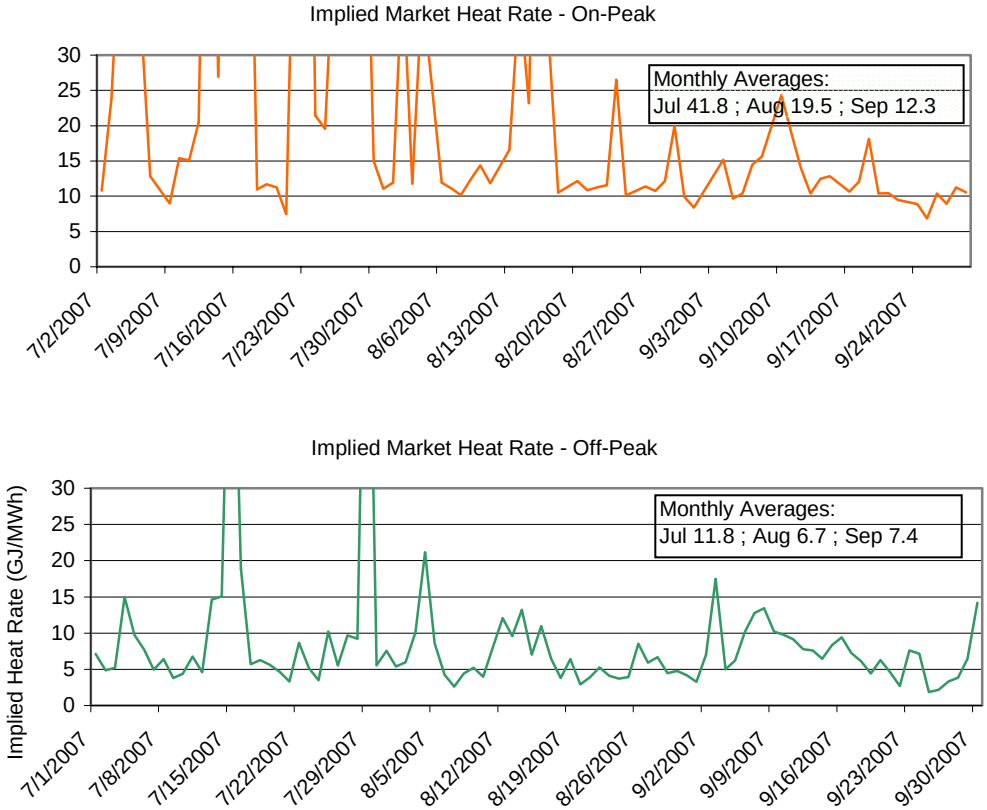


Figure 8 – PPA Outages by Quarter

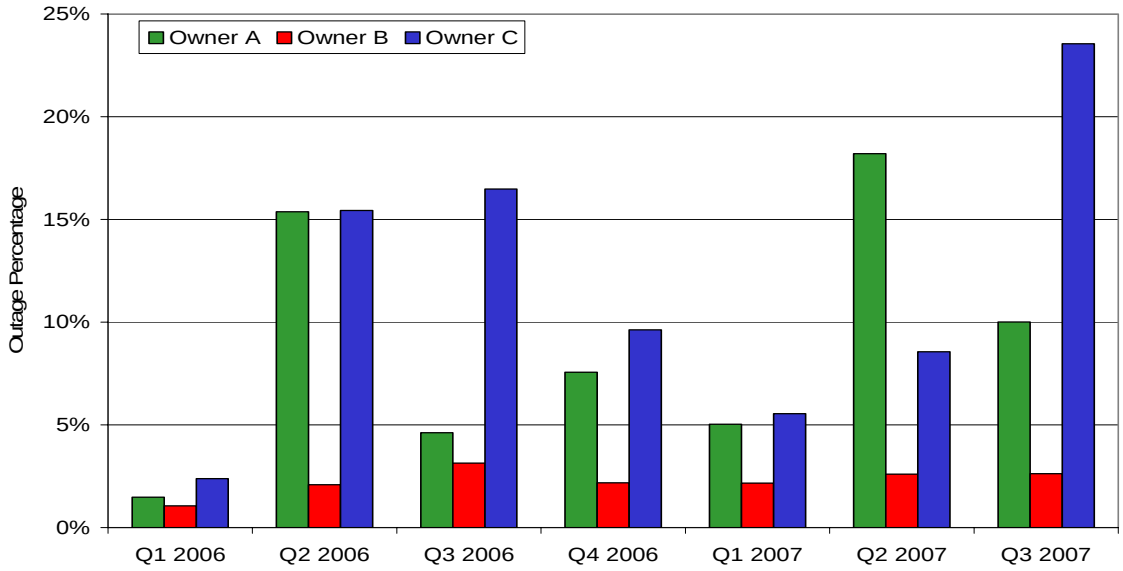


Table 2 - Percentage of Unplanned Outages for PPA Units

	2004	2005	2006	Q1/07	Q2/07	Q3/07
Owner-A	6.1%	5.0%	5.2%	4.9%	**6.0%**	**8.7%**
Owner-B	1.5%	5.4%	1.8%	1.6%	**2.6%**	**2.1%**
Owner-C	6.3%	6.5%	5.3%	5.2%	**4.4%**	**11.9%**
PPA weighted average	5.5%	5.9%	4.8%	4.6%	**4.6%**	**9.4%**

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 gross unit capacity.

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

	Target Availability 2004	Actual Availability 2004	Target Availability 2005	Actual Availability 2005	Target Availability 2006	Actual Availability 2006	Target Availability 2007	Actual Availability Q3 2007
Owner-A	87%	88%	87%	90%	87%	93%	87%	90%
Owner-B	90%	97%	89%	90%	89%	98%	89%	97%
Owner-C	87%	89%	87%	88%	87%	89%	86%	76%
PPA weighted Average	87%	90%	87%	89%	87%	91%	87%	84%

PFEC and PFAM, are mechanisms by which corrections and adjustments can be made to settlement calculations pursuant to the retail Settlement System Code ("Code"), which is part of the ISO rules. 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 be made as a result of the dispute.

UFE ("Unaccounted-for energy") reflects the extent of the settlement differences between energy going into the system vs. energy taken out by consumption and losses. UFE reasonable exception reports note instances where UFE was outside the tolerances allowed for in the Code. Load settlement agents (LSAs) are required to investigate and report to the market on such variances.

Table 4 – PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q3/07	19	466	254	60	171	NA
Q2/07	19	355	270	86	19	NA
PFAM						
Q3/07	85	76	94	36	31	(5,008,848)
Q2/07	3,179	296	3,370	20	85	3,346,451

Table 5 – Summary of UFE Reasonable Exception Reports

Quarter	Outstanding	New	Resolved	Unresolved
Q3/07	447	107	0	554
Q2/07	353	98	4	447

APPENDIX B – TIE LINE METRICS

Table 6 – Q3/07 Tie Line 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)
July	159,354	22,505	136,849	89,145	2,178	86,967	248,499	24,683	223,816
August	74,094	48,512	25,582	83,191	1,487	81,704	157,285	49,999	107,286
September	55,946	83,203	-27,257	41,095	11,668	29,427	97,041	94,871	2,170
Q3 Total	289,394	154,220	135,174	213,431	15,333	198,098	502,825	169,553	333,272

Figure 9 – Market Share of Importers and Exporters (Q3/07)

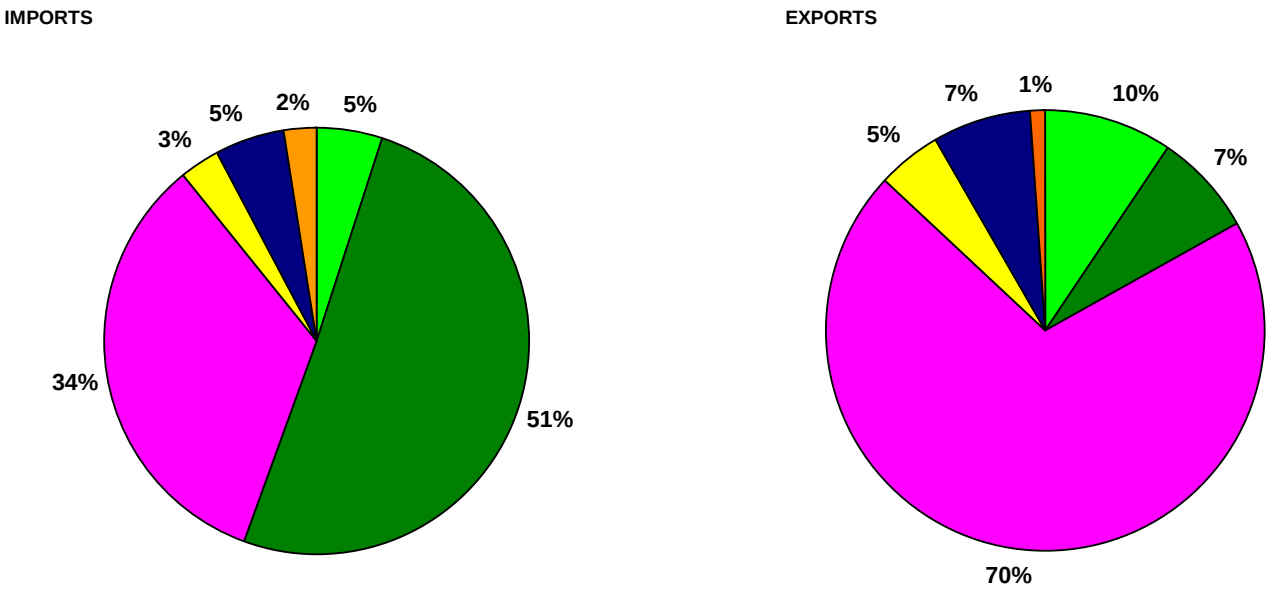


Figure 10 - Tie Line Utilization (Q3/07)

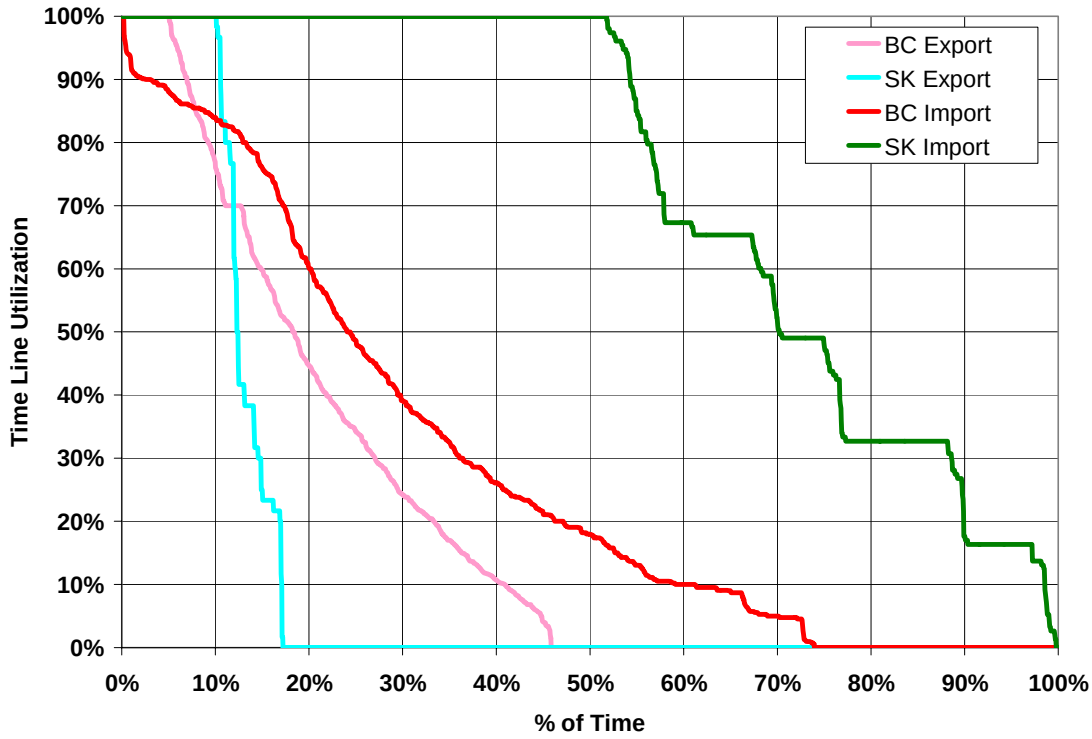


Figure 11 - Imports with Trade-weighted Prices

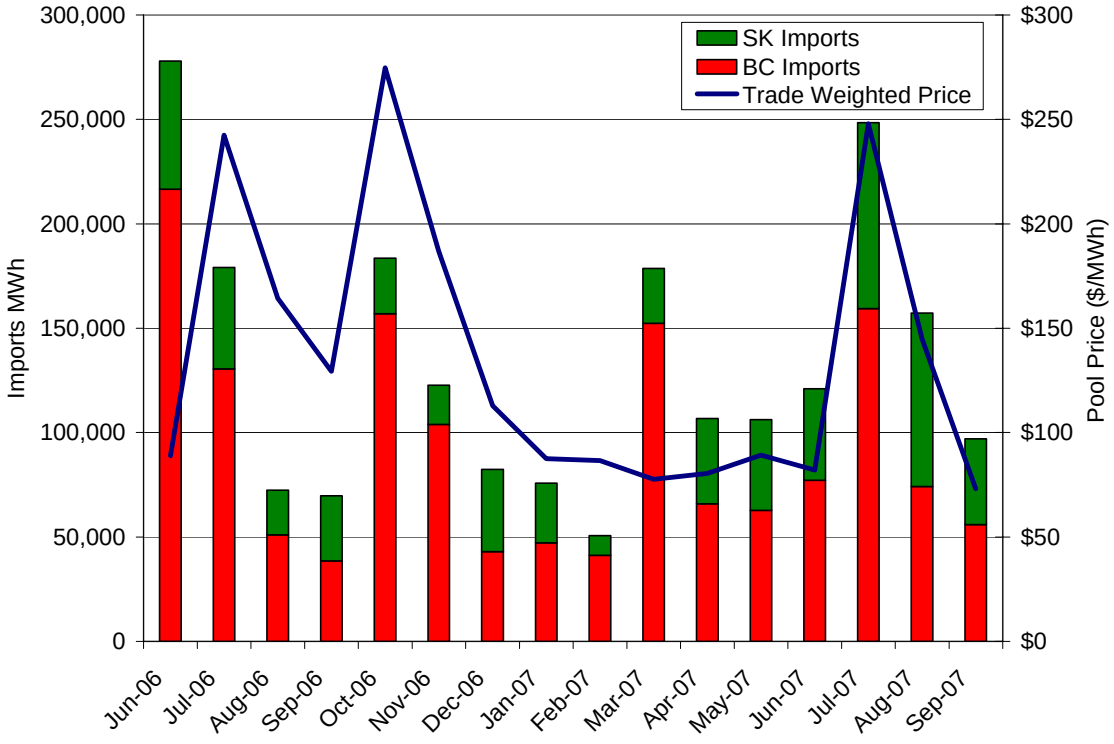


Figure 12 - Exports with Trade-weighted Prices

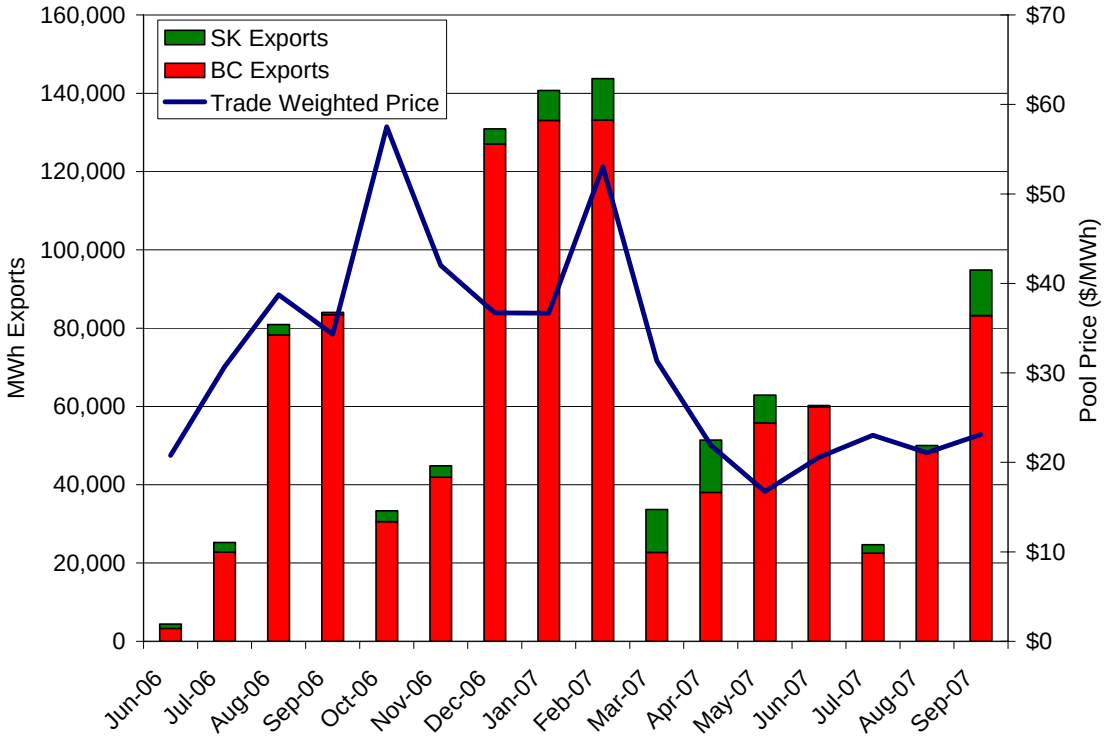


Figure 13 - On-Peak Prices in Other Markets

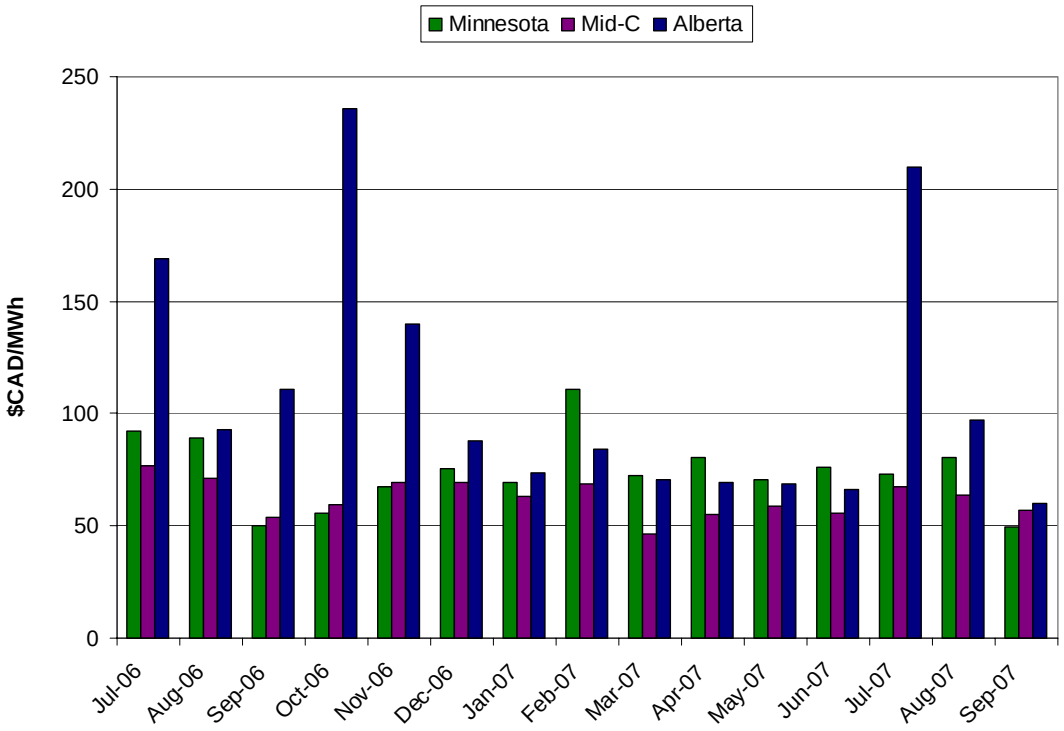
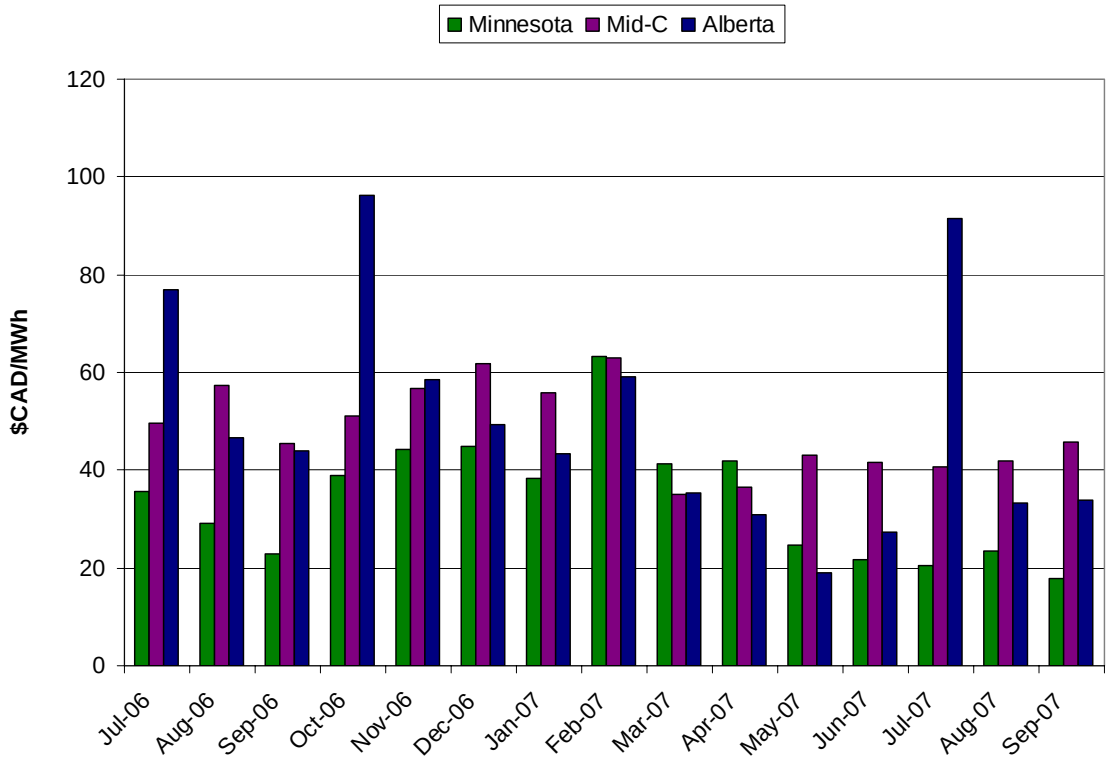


Figure 14 - Off-Peak Prices in Other Markets



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)

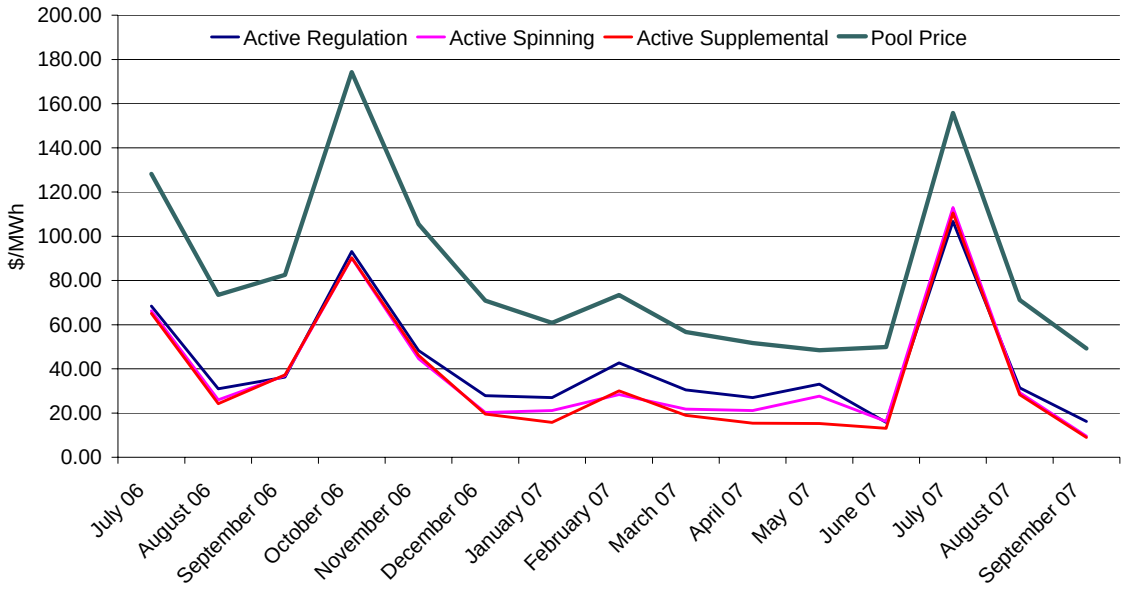


Figure 16 - Standby Premiums - All Markets (Watt-ex and OTC)

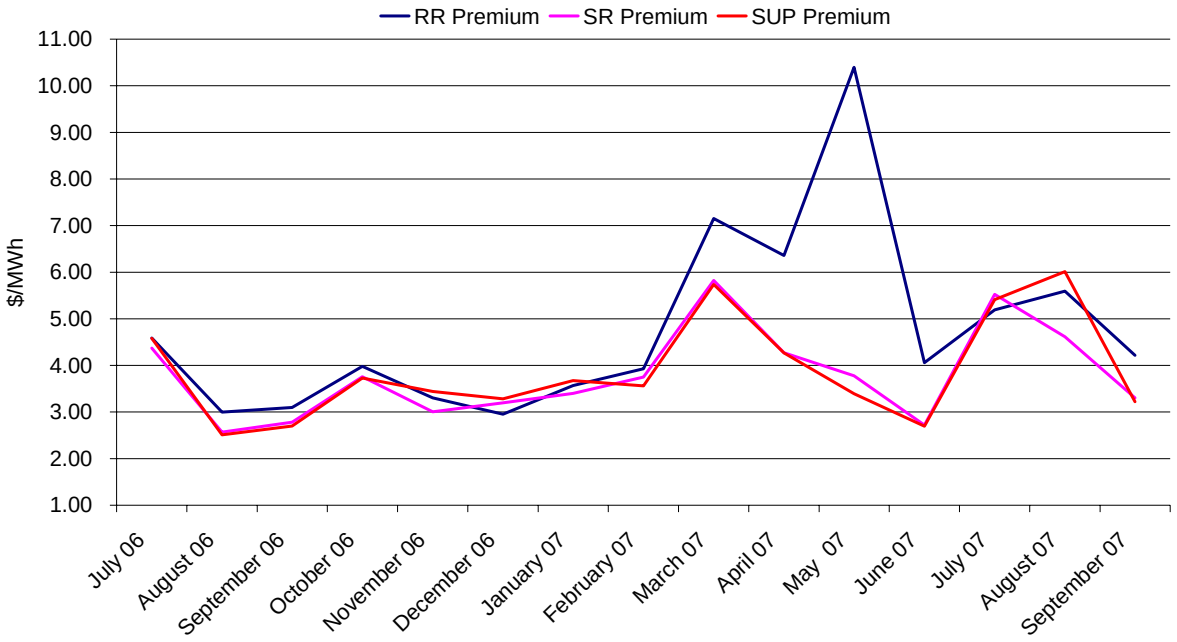


Figure 17 – Activation Prices – All Markets (Watt-ex and OTC)

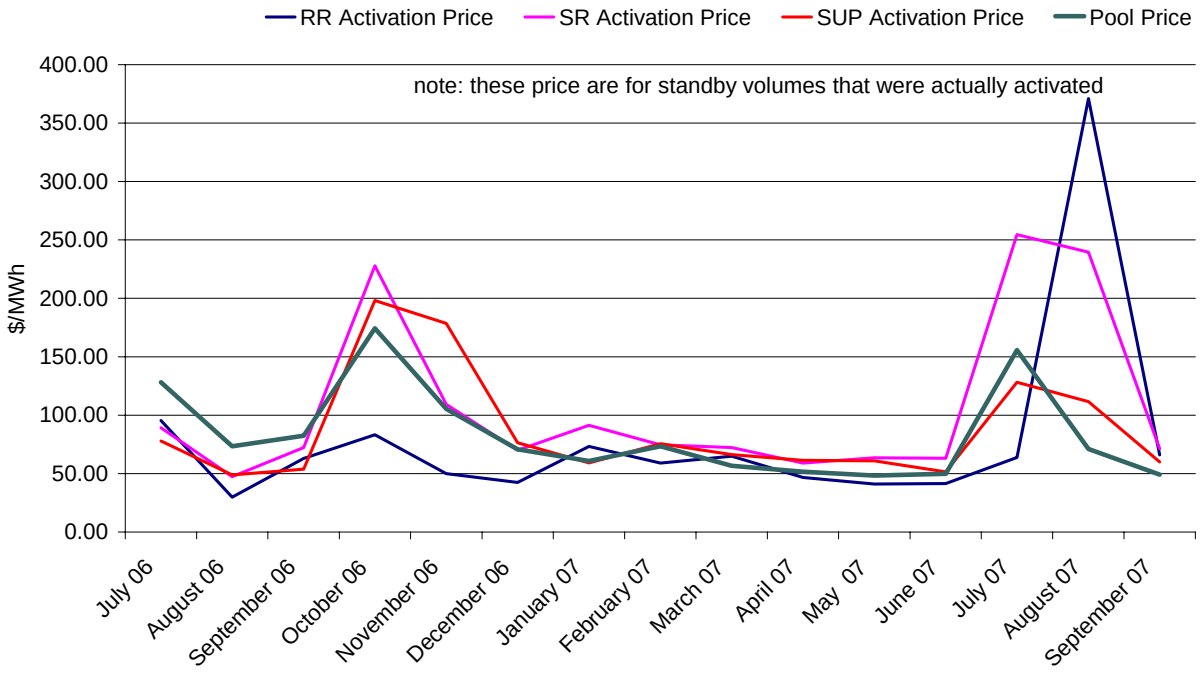


Figure 18 - Standby Activation Rates

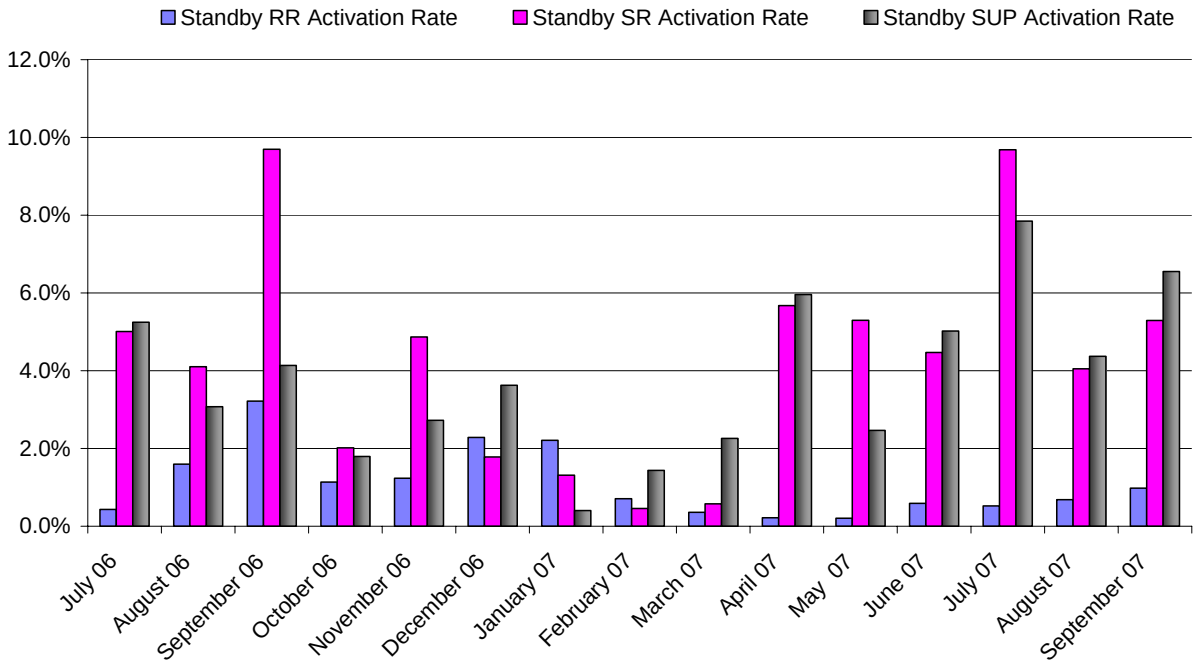


Figure 19 - OTC Procurement as a % of Total Procurement

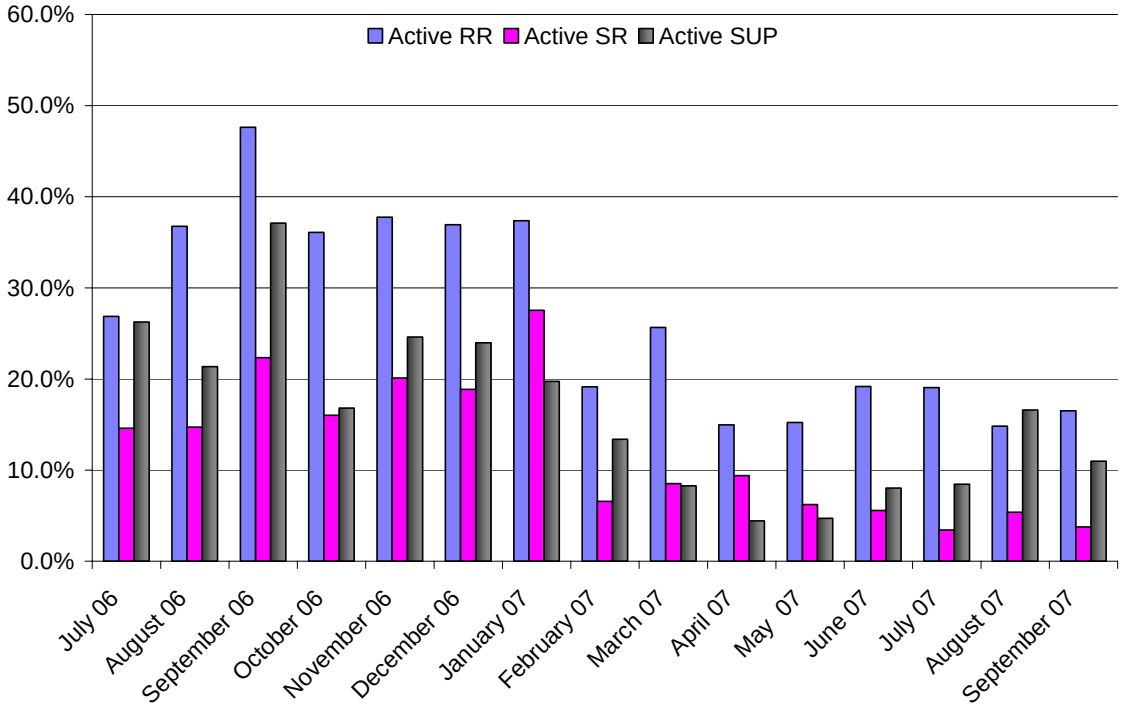


Figure 20 - Active Regulating Reserve Settlement by Market

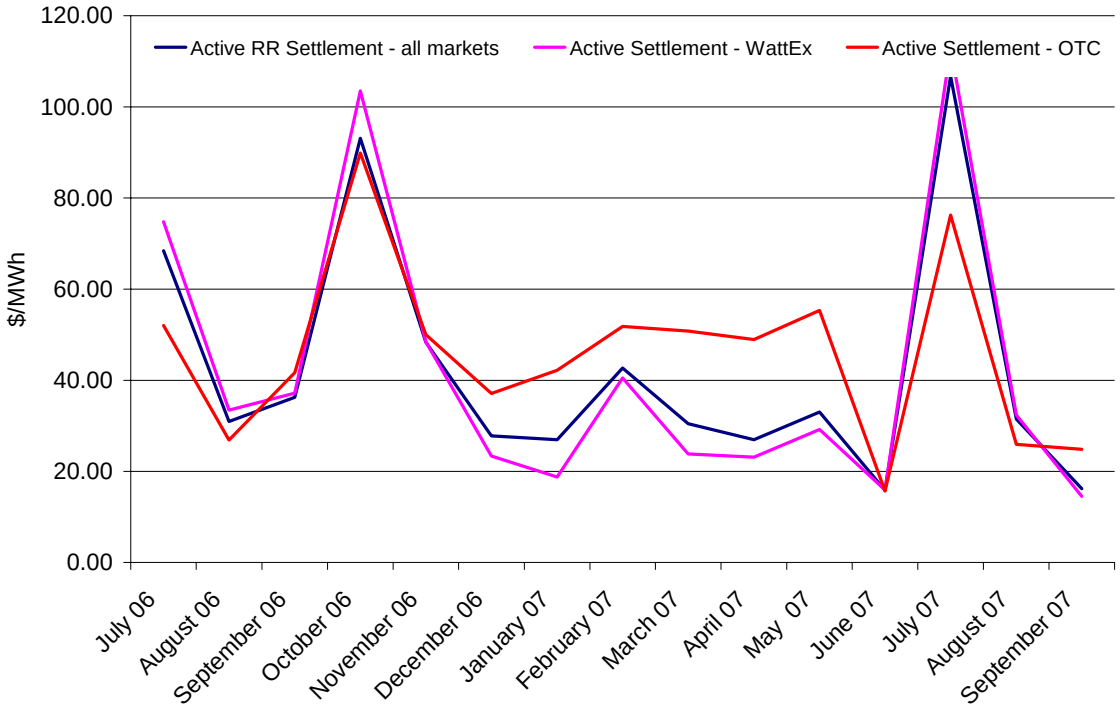


Figure 21 - Active Spinning Reserve Settlement Price by Market

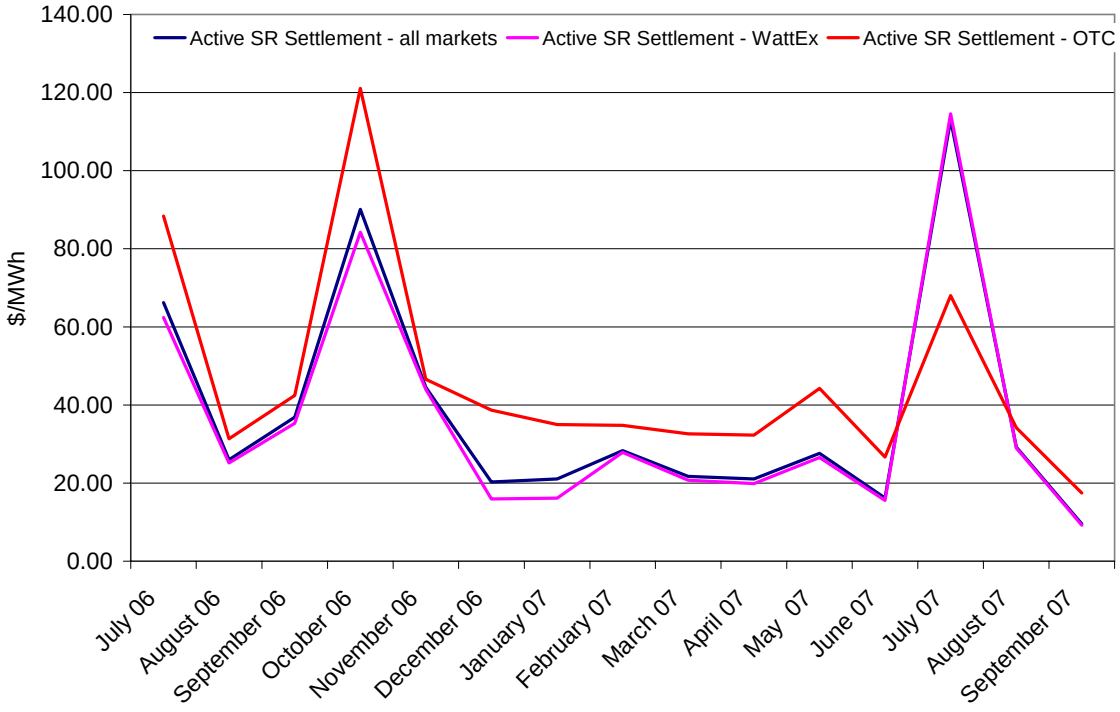


Figure 22 - Active Supplemental Reserve Settlement Price by Market

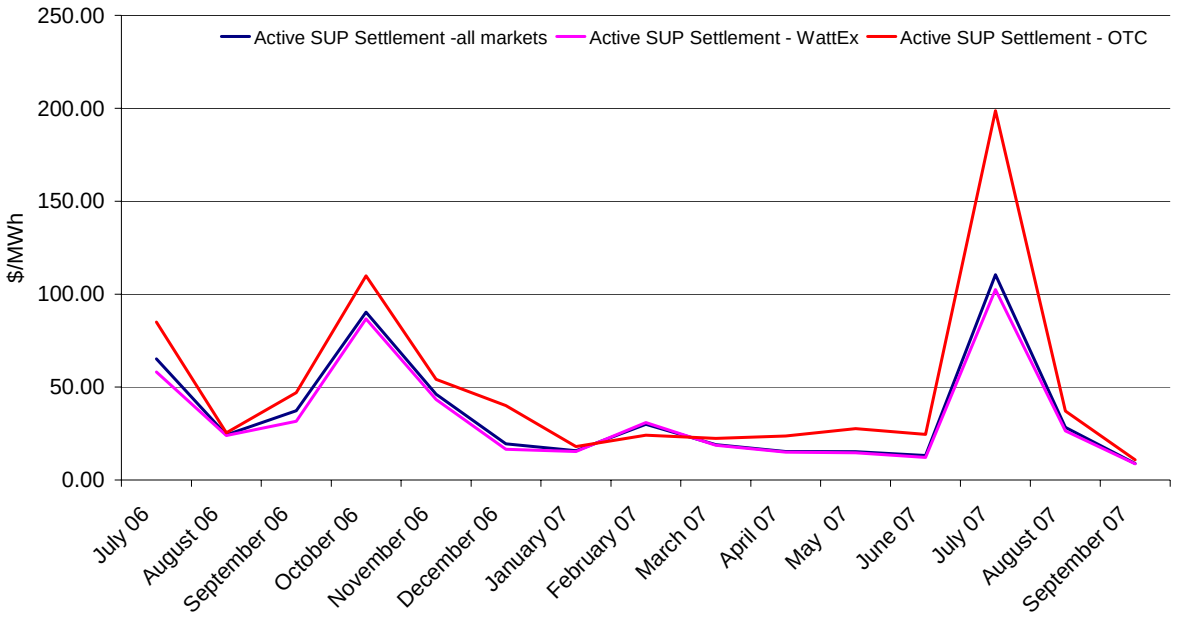


Figure 23 – Active Regulating Reserve Market Share by Fuel Type

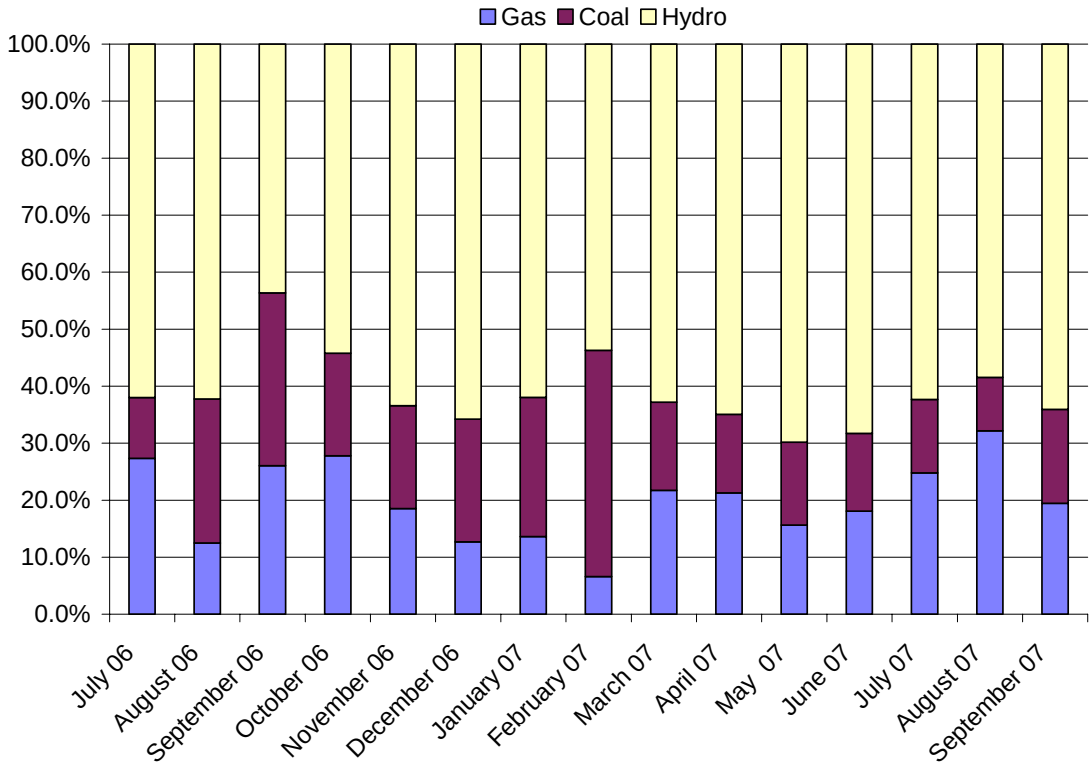


Figure 24 – Active Spinning Reserve Market Share by Fuel Type

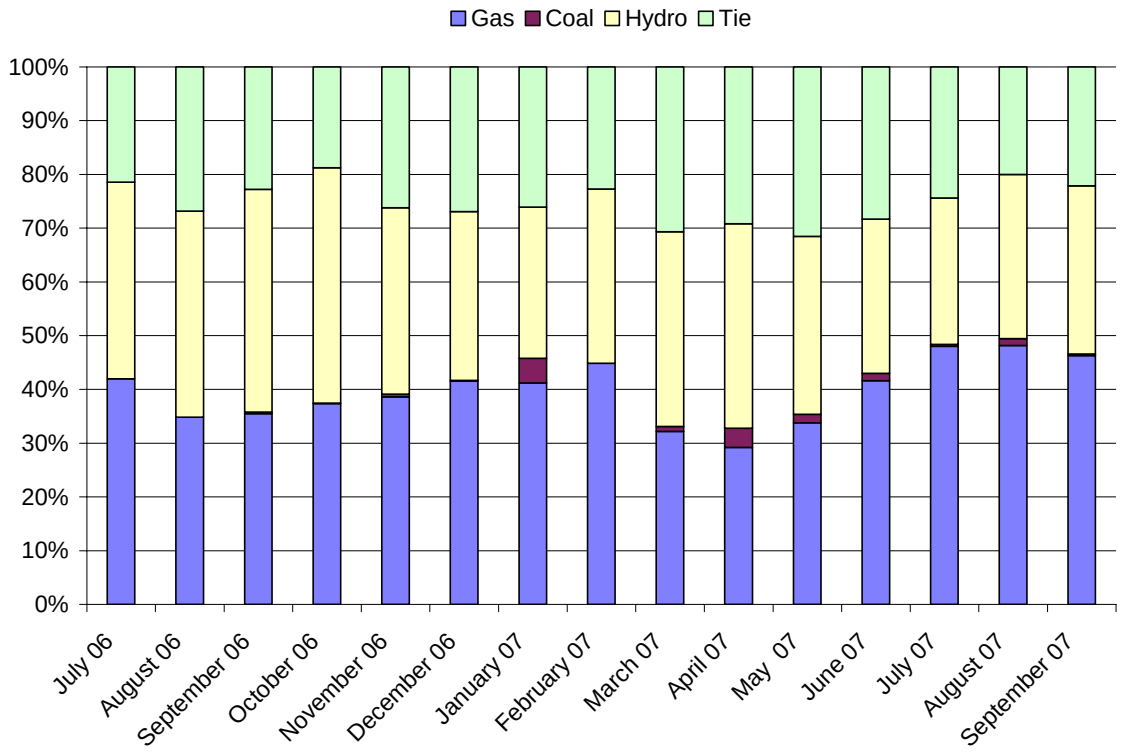


Figure 25 – Active Supplemental Reserve by Fuel Type