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MSA REPORT

Quarterly Report

April – June 2007

31 July, 2007

MARKET SURVEILLANCE
ADMINISTRATOR

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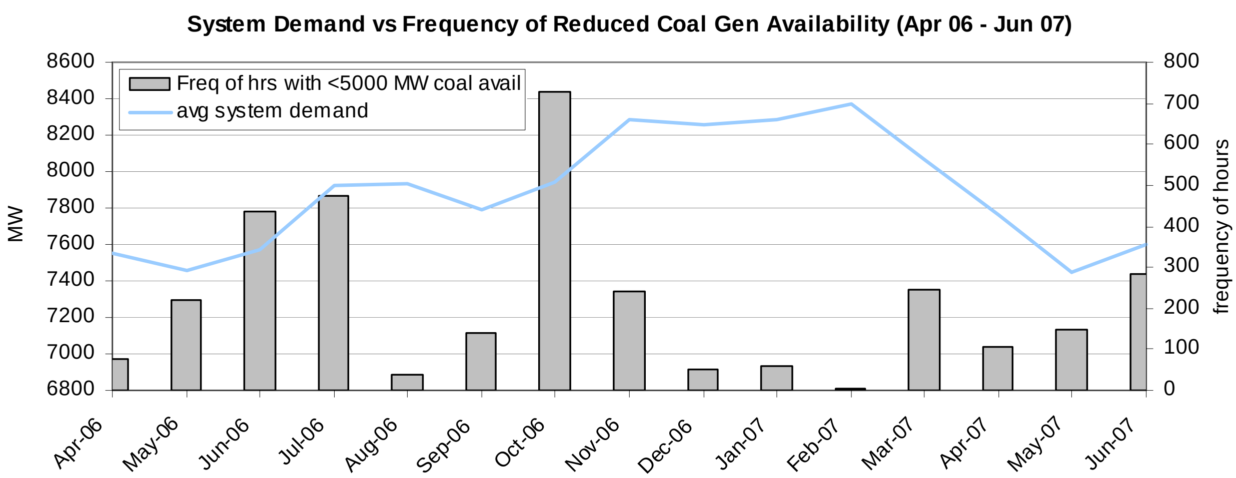
1 FEATURED MARKET DEVELOPMENTS DURING Q2/07

1.1 Wholesale Market Fundamentals

Wholesale prices in the Alberta electricity market during Q2/07 averaged $49.95/MWh which was down from last quarter ($63.29/MWh). Normally, the level of coal generation availability tends to be a strong directional predictor of market prices. However, the falling market prices quarter over quarter coincided with a decline in coal generation availability. Softer Q2/07 prices in this context are attributed to seasonally low system load combined with robust spring water levels due to greater than average snow pack both in Alberta and adjacent jurisdictions. The additional generation from hydro and hydro-based import volumes provided a buffer to the effect of reduced coal generation.

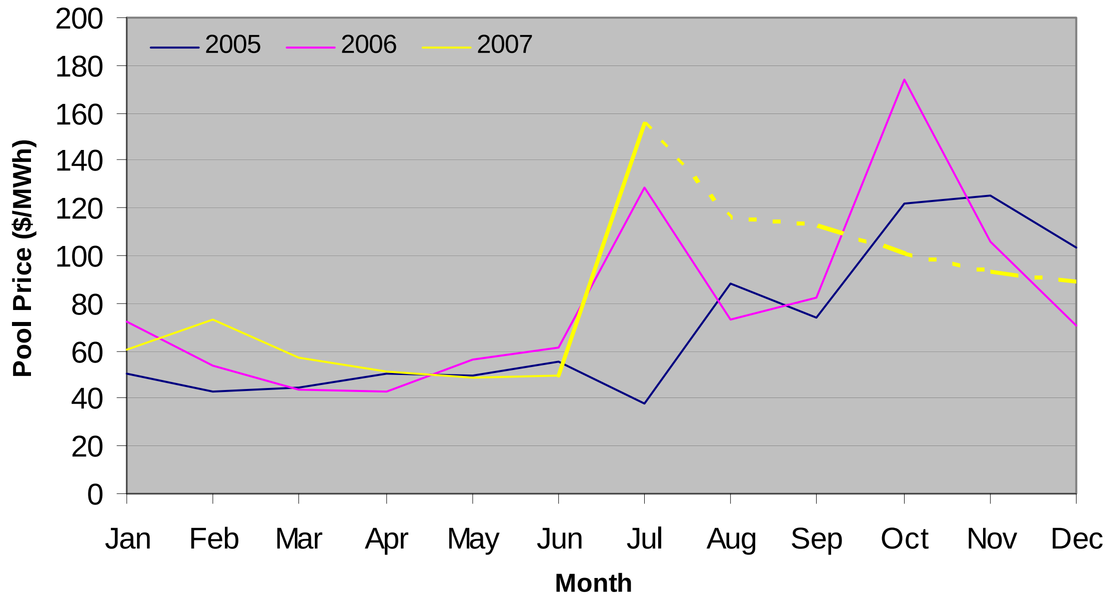


Q2/07 prices were also lower than the same quarter the previous year ($53.59/MWh). Unlike Q2/06 which saw periods of significant price volatility, market conditions during Q2/07 remained relatively calm as indicated by the flattening of the heat rate duration curve[1] and the infrequent price excursions indicated by the price duration curve for the quarter[2].

2007 is looking to unfold in a similar manner to the previous two years - a relatively flat modest price first half followed by greater volatility and higher prices through the second half. The graph below shows monthly average Pool prices for 2005 – 2007 with the second half of 2007 represented by the forward curve as at mid-July. The current forward curve reflects expectations of greater

[1] See Appendix A, Figure 6
[2] See Appendix A, Figure 1

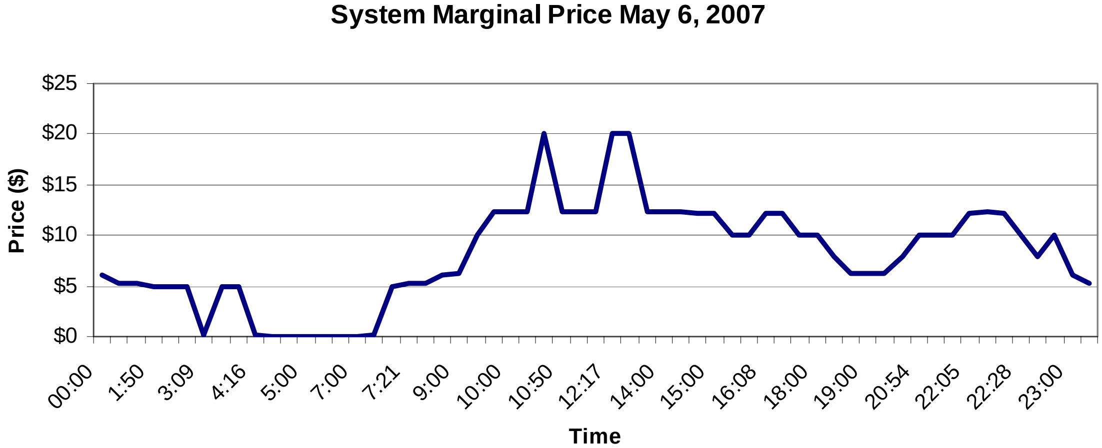
price volatility for the balance of the year due to temperature related forced outages and derates, growing summer peak load, and outages prompted by the KEG transmission conversion project[3].



1.2 Zero Price Event

Sunday May 6, 2007 saw System Marginal Price (SMP) reach $0.00 from 4:48 A.M. until 7:10 A.M. resulting in pool price settling at $0.00 for HE 6 and 7. During this time the system controller followed OPP 103: Dispatching Multiple $0.00 Offers, resulting in the curtailment of scheduled imports in these hours. The system controller did not direct any in-province generation to dispatch down. System marginal price in other hours that morning were also low as can be seen in the following figure.

[3] Discussed in further detail in section 1.4 of this report



Zero dollar price events are of interest to the MSA since in such instances, the market may clear only through the intervention from the system controller. Occurrence of extremely low pool prices, particularly $0.00 prices are uncommon events. As shown in the table below, there have been only ten occurrences of hourly pool price settling at or below one cent since 2001. The events on May 6, 2007 coincide with a year to date low for demand, although other occurrences of zero dollar prices did not[4].

Low Price Events 2001-2007				
Date	HE	Price	Demand	Percent Rank Of Demand[5]
2002-06-30	5	$0.01	6011	7%
2002-06-30	7	$0.01	5907	11%
2004-12-19	16	$0.00	7687	61%
2004-12-20	2	$0.00	7008	27%
2004-12-20	3	$0.00	7001	27%
2004-12-20	4	$0.00	6996	26%
2004-12-20	5	$0.00	7037	29%
2004-12-20	6	$0.00	7359	44%
2007-05-06	6	$0.00	6532	0%
2007-05-06	7	$0.00	6458	0%

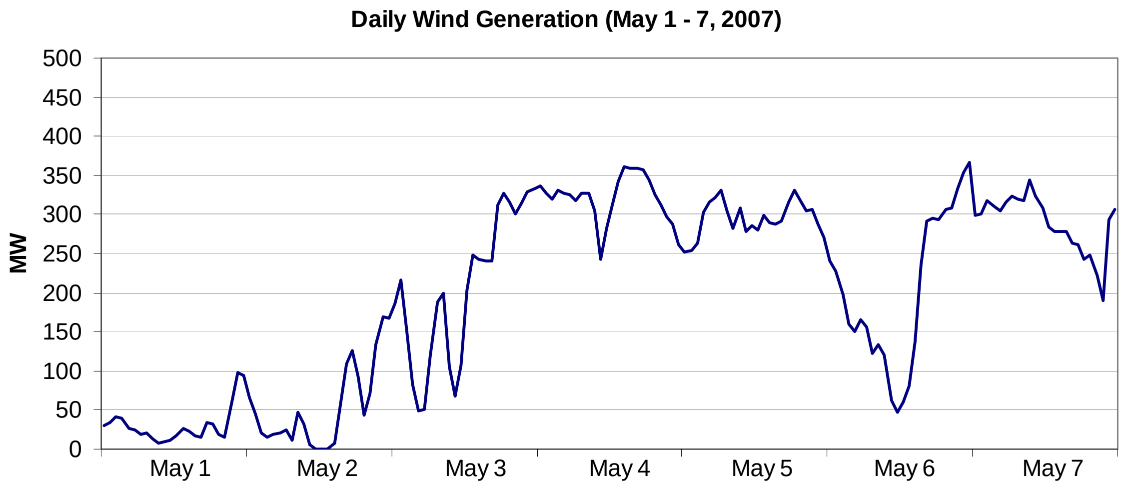
Wind Generation as a Factor

As shown in the following graph, wind generation had been averaging over 300 MW on the two days prior to May 6 however, on the morning of May 6, it was much lower at approximately 115 MW. Had wind generation remained near 300 MW, it appears

[4] HE6 and HE7 correspond to the lowest and third lowest hourly system loads observed in 2007 year to date.

[5] The percent rank is calculated for the year of the occurrence and refers to the relative rank of demand within the year of interest.

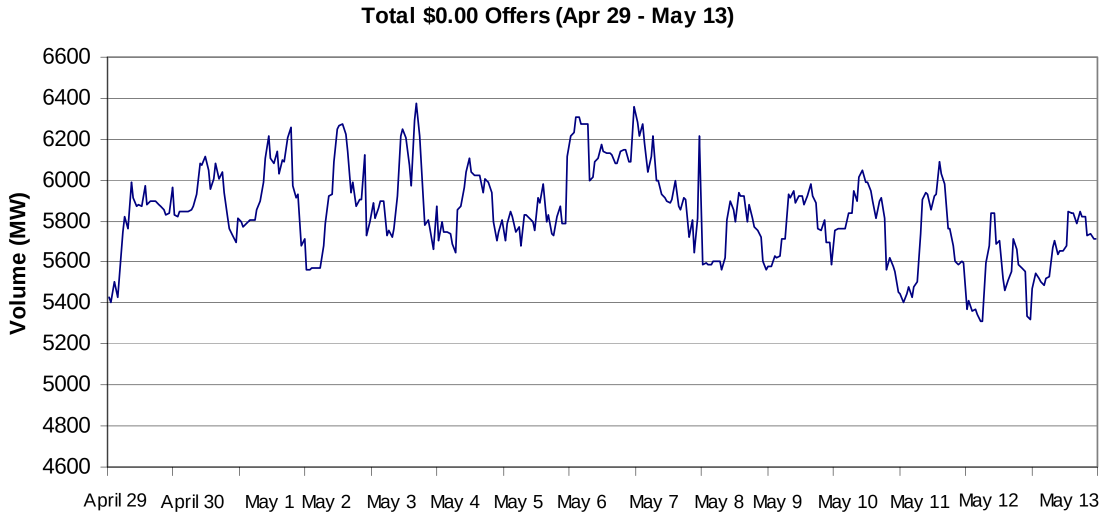
absent any additional response, that pool price would have been zero dollars for much of the off-peak period.



Net Imports
On May 6, prices in both Mid-C and Minnesota Hub were very low, indicating it was difficult to profitably export power from Alberta, although some exports on the BC tie were observed early that morning. 153 MW of imports had been scheduled to flow from Saskatchewan to Alberta during each hour of the off-peak period. In accordance with OPP 103, the system controller curtailed 103 MW in HE6 and 153 MW in HE7. No further curtailment was necessary in the following hours.

Total Zero Dollar Offers
The total volumes of zero dollar offers from April 29 to May 13 are presented below. As can be seen in the figure, the volumes of zero dollar offers were significantly higher on May 6 relative to the Sunday in adjacent weeks (April 29 and May 13). One reason for the elevated volume of zero dollar offers on May 6 appears to be the low level of unit outages and derates of coal fired units that usually offer significant energy volumes at $0.00 representing a desire to be generating regardless of the prevailing market price.

While a number of units were generating at levels above their minimum stable generation and could potentially have been directed down, the curtailment of scheduled imports reduced aggregate generation sufficiently to maintain balance with system load. Coal units have a natural incentive to offer their output at $0.00 to ensure that they are dispatched and on low price days the incentive becomes even greater as the probability of being dispatched off increases.



Conclusions

The $0.00 Pool prices observed in HE 6 and 7 are attributed to the low demand on a Sunday morning together with the high volume of zero dollar offers from generators. Wind generation was relatively moderate.

OPP 103 appears to have worked well in enabling the system controller ensure that the system remain in balance through the curtailment of resources (in this case imports). The MSA is of the view that, assuming zero dollar events remain infrequent, the OPP provides a suitable method for dispatching resources. Nevertheless, the MSA remains keenly interested where the market clears only with intervention from the system controller (whether at $0 or $999.99). With respect to zero dollar offers, the MSA continues to monitor the impact of increased wind generation and changes in market rules which may affect the probability of increased zero dollar offer events.

In examining the sustained low prices during the morning of May 6 it might have been expected that any generators with discretionary volumes offered at zero dollars may have issued restatements. The MSA has found little evidence of any such response. This may indicate either there were no discretionary volumes offered at zero or that participants had little capability to respond early on a Sunday morning. Approved, but not yet implemented AESO rules will result in the reporting of minimum stable generation, allowing discretionary offers at zero dollars to be determined. This information should provide additional clarity on participants' responses during future low price events.

1.3 Ancillary Services Market

Operating reserves are a key component of the ancillary services that the AESO must procure in order for the system to operate in a reliable manner. The AESO is required to purchase these reserves in a prudent manner and meets this requirement by using a market-based mechanism. The total requirement in terms of MWs is quite modest, and much less than that for the energy market. Similarly, the dollar value of the operating reserves is generally much lower than in the energy market.

Operating reserves are composed of active and standby types. The required active reserves and the energy demand must be serviced from the available generating fleet and, as such, pricing in the active reserves market is based on opportunity cost relative to the energy market alternative. Standby reserves are free to participate in the energy market unless called into service and thus have a different pricing structure.

The MSA announced in October 2006 that is was conducting an assessment of the performance of the ancillary services market. This assessment has recently concluded. Much of the material involved is of a financially sensitive nature and thus does not lend itself to a report publishable on our web site. The following table shows some of the (generalized) highlights from the work together with comparisons with the energy market:

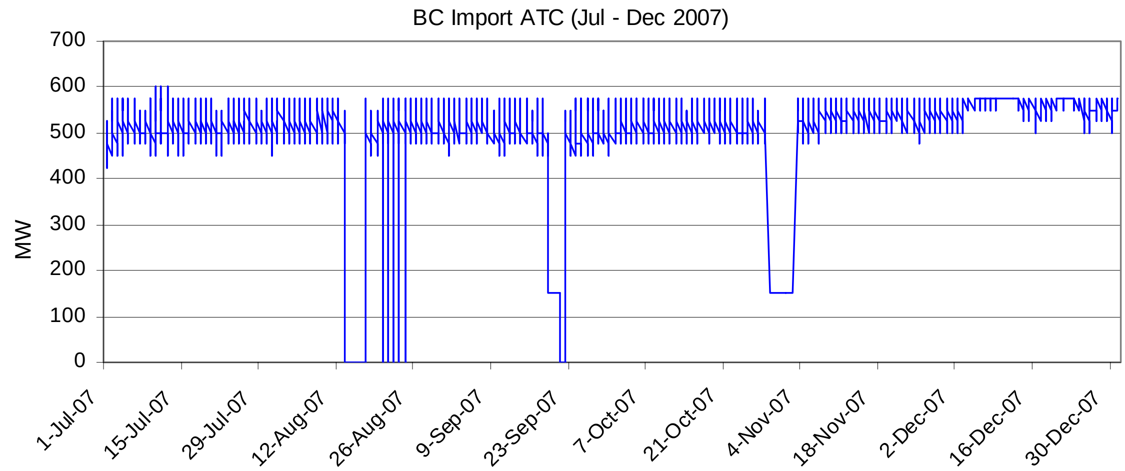
Operating Reserves Market	Energy Market
The operating reserves market is a complex two-sided market where the market clearing price is determined by both the marginal offer and the marginal bid. The sellers' offer strategy not only reflects their views on market conditions but also on the (sole) buyer's bids. Transactions for each delivery day can typically occur on the five trading days prior to delivery. The efficient operation of the market requires participants on both sides to be knowledgeable about market conditions and the information revealed on each trading day.	The energy market is essentially a one-sided market where the market clearing price is only determined by the marginal offer from the sellers. The sellers' offer strategy reflects their views on market conditions, not on buyers' bid strategies.
The operating reserves market is a financially binding physical forward market without a secondary market. The sellers and the buyer are required to reflect their views on the physical market ahead of the delivery in their offers and bids. As it approaches to delivery, market views may change, the sellers and the buyer are expected to have the ability to manage that change by factoring it in their offers and bids.	The energy market is a physical real time market. Since the offers are submitted close to real time, it's more straightforward for the sellers to incorporate their market views in the offers. Participants also have more flexibility to restate their offers in response to changing market conditions.
The value of the operating reserves market is relatively small and the complexity of its market structure tends to work against participation by 'small' participants. The level of market analysis makes the cost of participation higher relative to the potential gain and hence may discourage some participants from identifying values.	The value of the energy market is high and the cost of non-strategic participation is quite low relative to the potential gain from active participation.
The active operating reserves market is dominated by a few large players even though the potential supply of reserves is large. The analysis shows that the cost structure of the assets, not the amount of capacity under their control leads naturally to this dominance.	The energy market is similarly dominated by a few large players. However, because lower cost resources tend to be controlled by participants with large size, dominance here is closely aligned with size of holdings as well as the type of assets under control.
The capacity that can potentially provide the service is much greater than the demand; however, much of this capacity does not routinely participate. The amount that is traded on NGX on a trading day is often much less than the amount the AESO wishes to buy. If volumes remain to be bought after close on Day (D-1), the AESO must then use the over-the-counter process with its attendant lack of transparency.	There is no bid-offer price matching mechanism in the energy market. All demand is satisfied by supply, except in those rare circumstances when load is shed. All generation is required to participate unless unable to do so.

The analysis revealed that, despite the complexities of the market design for active and standby operating reserves, the 'right' types of units appear to be providing the 'right' type of service accordant with market theory. Similarly, profitability levels appear reasonable or at least not excessive over a significant time frame. It is not possible to measure, or indeed to estimate, the toll on efficiency due to the complexity of the market structure. The AESO's participation as a sole buyer, albeit with a volume that must be bought, has been a concern to some participants citing the high potential for the exercise of market power. A revised structure that resulted in: reduced complexity (increased potential participation); elimination of the need for the AESO to be an active buyer; greater transparency; and closer alignment with the new two-hour lock down world of the energy market might work better.

1.4 Transmission Upgrades in KEG Area

The Edmonton-Calgary 500 kV transmission development involves two phases – first, the conversion of the existing south 240 kV transmission leg (1203L and 1209L) linking Keephills, Ellerslie, and Genesee (KEG), followed by the construction of a new 500 kV line between Genesee and Langdon. The KEG conversion project is currently underway. Consequently, various parts of the transmission system will be temporarily taken out of service during the second half of 2007 to allow required work to proceed. As a result of these transmission outages, KEG area generators will be subject to temporary curtailment and transfer capability of the Alberta – BC interconnection will be reduced[6] due to reliability criteria. Certain generation outages have been timed to coincide with anticipated transmission outages and these are reflected in published outage graphs available on the AESO website. Unforseen derates and extension of some outages are also likely and these are not captured in published outage information. Based on the latest available BC import ATC data presented below, three periods of BC tie line outage are expected in late August, late September, and early November respectively.

[6] OPP 517 specifies the various remedial action schemes applicable to transmission outage situations in the KEG area.



1.5 Alberta Utilities Commission Act

On June 14, 2007, Bill 46, the Alberta Utilities Commission Act, was given first reading in the Alberta legislature. The legislation sets out changes which would impact the Alberta Energy and Utilities Board (EUB) as well as various implementing agencies, including the Alberta Electric System Operator (AESO), the Utilities Consumer Advocate (UCA) and the MSA.

The new Act contemplates splitting the EUB into two bodies, the Energy Resources Conservation Board (ERCB) and the Alberta Utilities Commission (AUC). The ERCB will generally focus on oil and gas matters; the AUC will generally focus on utilities, including electricity, natural gas and water, as well as the transmission and distribution of those commodities.

Bill 46 contemplates that the UCA will become a part of the AUC, although the UCA will to the greatest extent possible seek to operate independently, in furtherance of the interests of consumers.

Bill 46 contemplates the reduction of operational overlap amongst the implementing agencies (particularly as amongst the MSA, the AESO, and EUB) and creates a standing hearing body to which the MSA can bring matters for adjudication (the existing tribunal, as created by the Electric Utilities Act, will be replaced by the AUC). The MSA will have new roles in relation to the natural gas market as well as water utilities.

The AUC Act is contemplated to come into force on January 1, 2008, along with changes to various regulations impacted by the new legislative scheme. Bill 46 will go to second reading in the fall of 2007; changes to other relevant enactments will move in parallel.

Before that time there is much work to be done by the Department of Energy, by the implementing agencies, and by other stakeholders, insofar as legislative drafting efforts and operational implementation of the new legislative scheme.
A copy of Bill 46 can be reviewed at:
http://www.assembly.ab.ca/net/index.aspx?p=bills_status&selectbill=046

1.6 MSA Activities

Section 6 Committee - During the quarter, the MSA continued to be an active participant in Section 6 committee discussions. This committee of electric industry stakeholders was established to provide recommendations on principles that further clarify fair, efficient and openly competitive conduct (as specified in Section 6 of the Electric Utilities Act) and which regulatory mechanisms and agencies are best suited to ensure market participants adhere to the principles. Phase II of the committees work concluded at the end of June with recommendations on some principles and methods of dealing with market power. In the view of the MSA, the committee did not fully address all areas where additional clarity would be beneficial. However, the discussions did provide a good basis upon which to build future work, whether in the form of MSA guidelines or regulations.

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]
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%**
Jan - 07	60.75	74.10	43.81	62.44	103%
Feb - 07	73.38	84.15	59.01	59.48	81%
Mar - 07	56.72	70.72	37.29	62.24	110%
Q1 - 07	**63.29**	**76.32**	**46.70**	**61.83**	**98%**
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%**

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

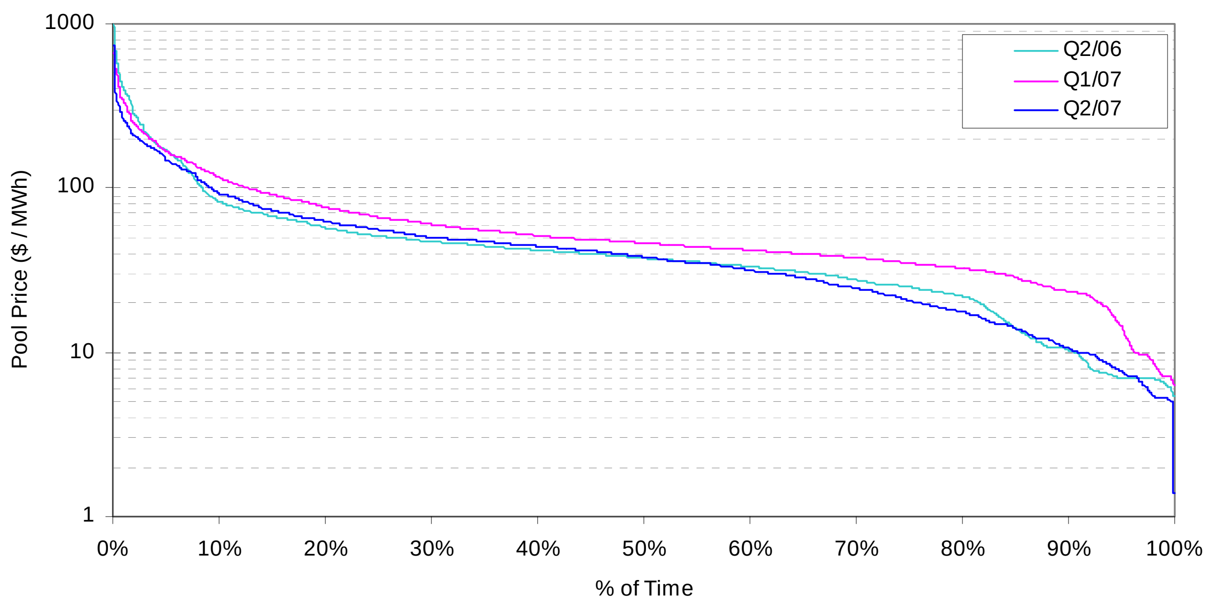


Figure 2 – Pool Price with Pool Price Volatility

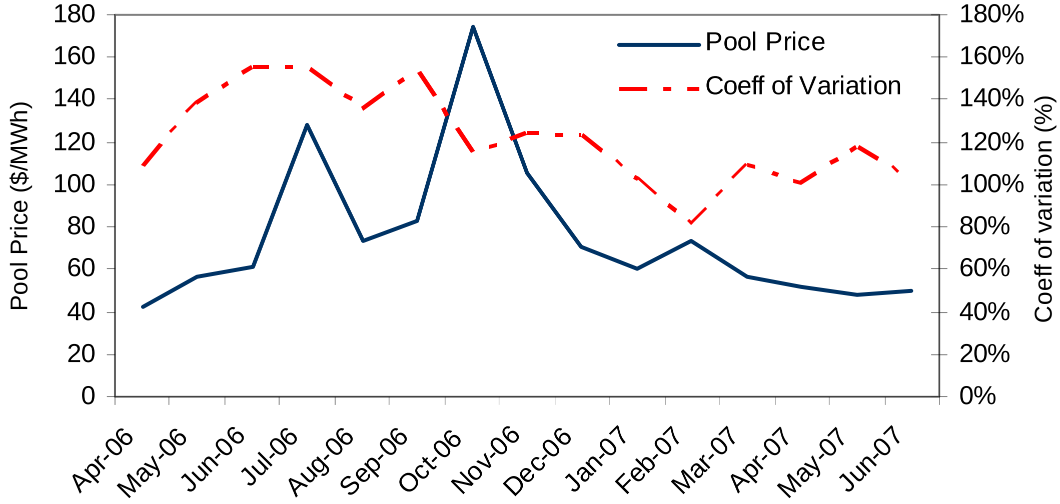


Figure 3 - Wholesale Electricity Price with AECO Gas Price

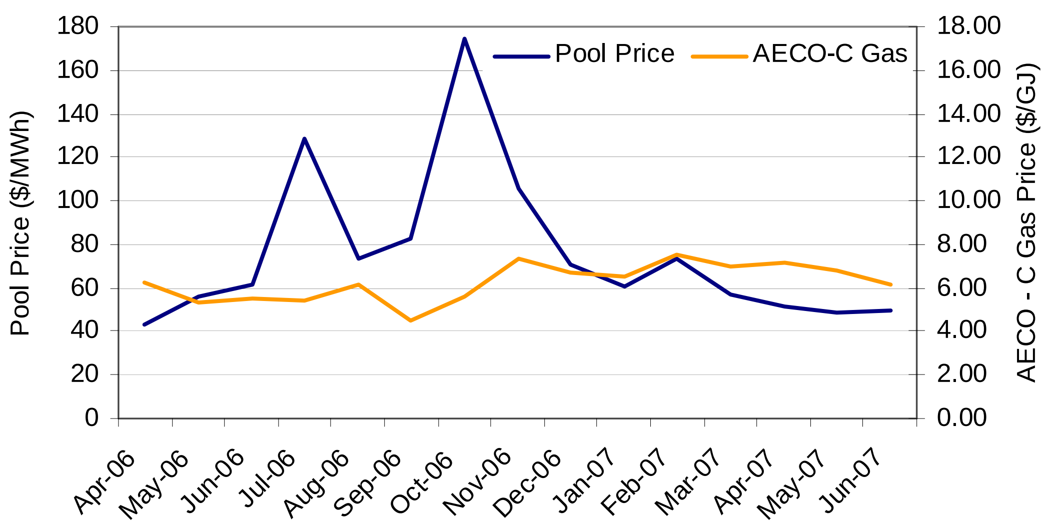


Figure 4 - Price Setters by Submitting Customer (All Hours)

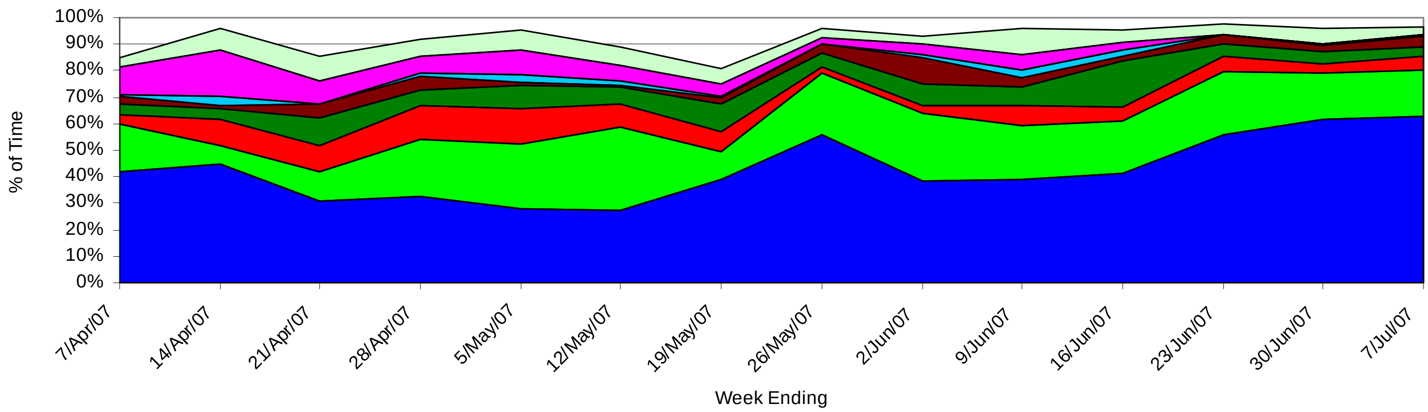


Figure 5 - Price Setters by Fuel Type (All Hours)

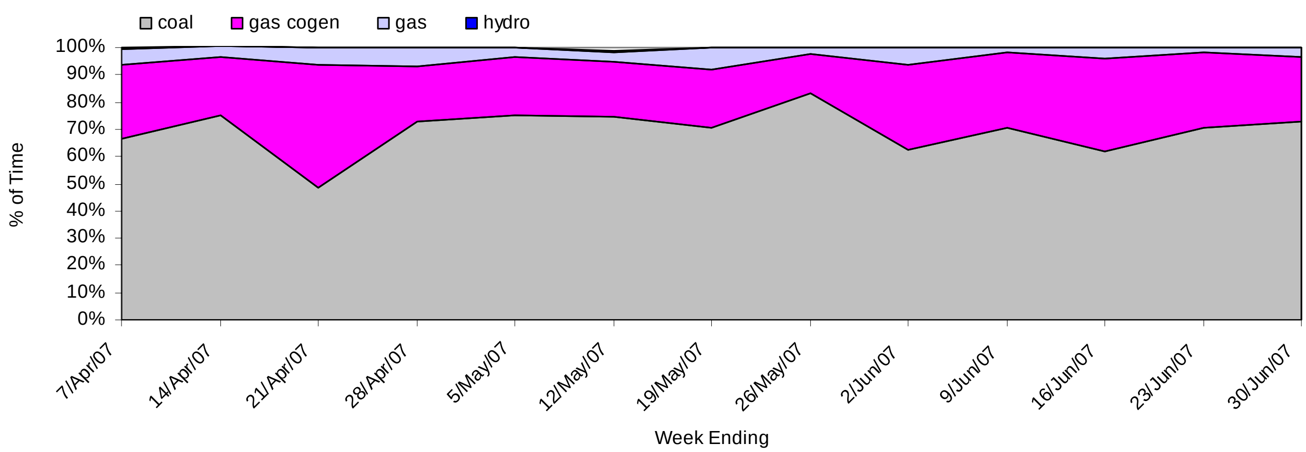
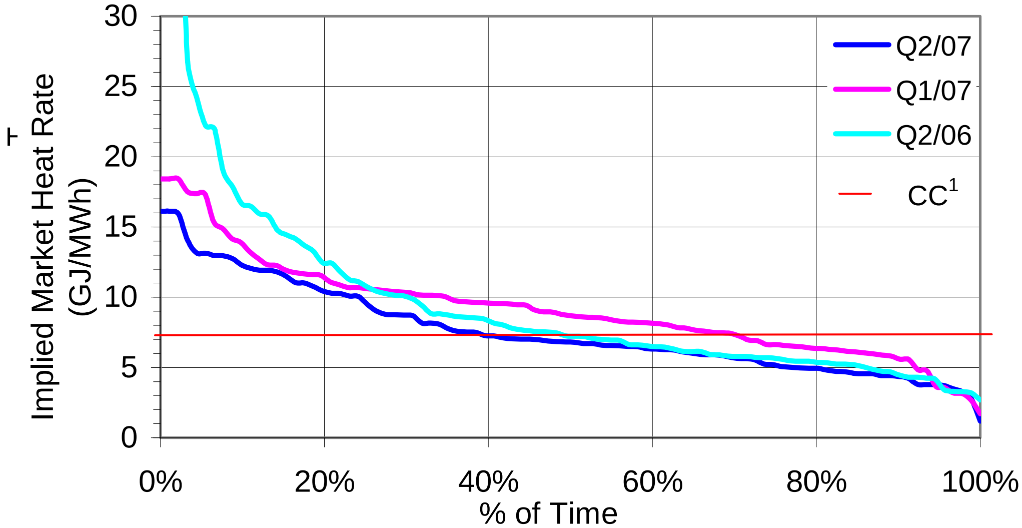
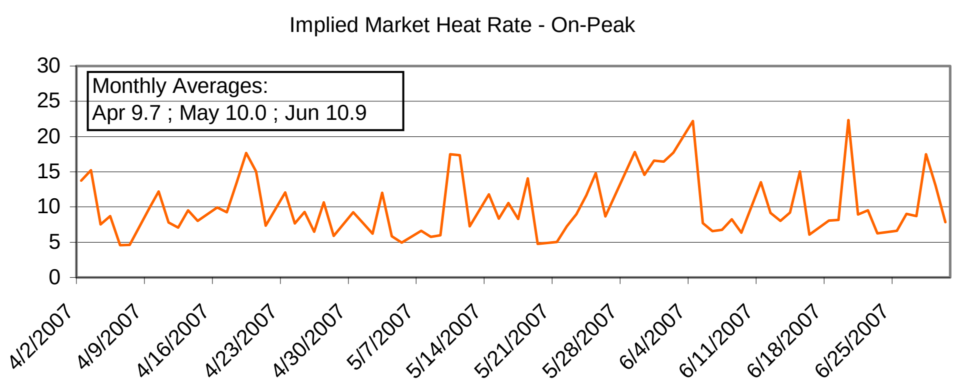


Figure 6 – Heat Rate Duration Curves (All Hours)



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

Figure 7 - Implied Market Heat Rates (Q2/07)



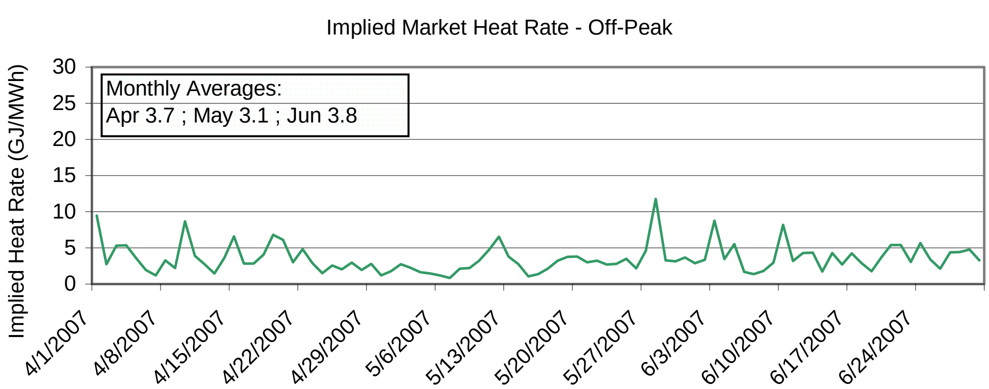


Figure 8 – PPA Outages by Quarter

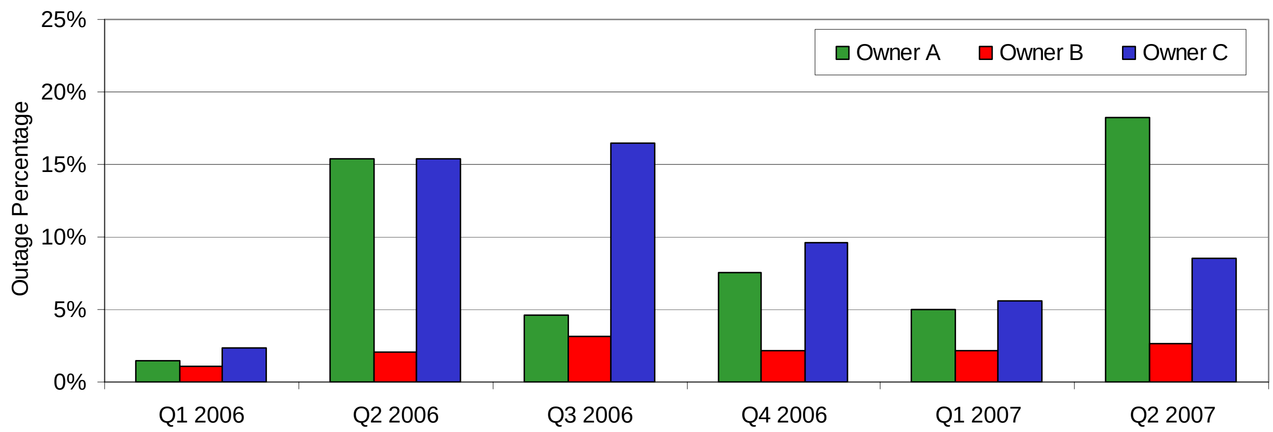


Table 2 - Percentage of Unplanned Outages for PPA Units

	Q2/07	Q1/07	2006	2005	2004	2003	2002
Owner-A	**6.0%**	4.9%	5.2%	5.0%	6.1%	4.9%	4.2%
Owner-B	**2.6%**	1.6%	1.8%	5.4%	1.5%	1.5%	0.5%
Owner-C	**4.4%**	5.2%	5.3%	6.5%	6.3%	5.7%	10.8%
PPA weighted average	**4.6%**	4.6%	4.8%	5.9%	5.5%	4.9%	7.7%

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 Q2 2007
Owner-A	87%	88%	87%	90%	87%	93%	87%	82%
Owner-B	90%	97%	89%	90%	89%	98%	89%	97%
Owner-C	87%	89%	87%	88%	87%	89%	86%	91%
PPA weighted Average	87%	90%	87%	89%	87%	91%	87%	90%

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 reasonableness 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						
Q2/07	19	355	270	86	19	NA
Q1/07	15	659	324	331	19	NA
PFAM						
Q2/07	3,179	296	3,370	20	85	3,346,451
Q1/07	10	3,275	84	22	3,179	122,942

Table 5 – Summary of UFE Reasonableness Exception Reports

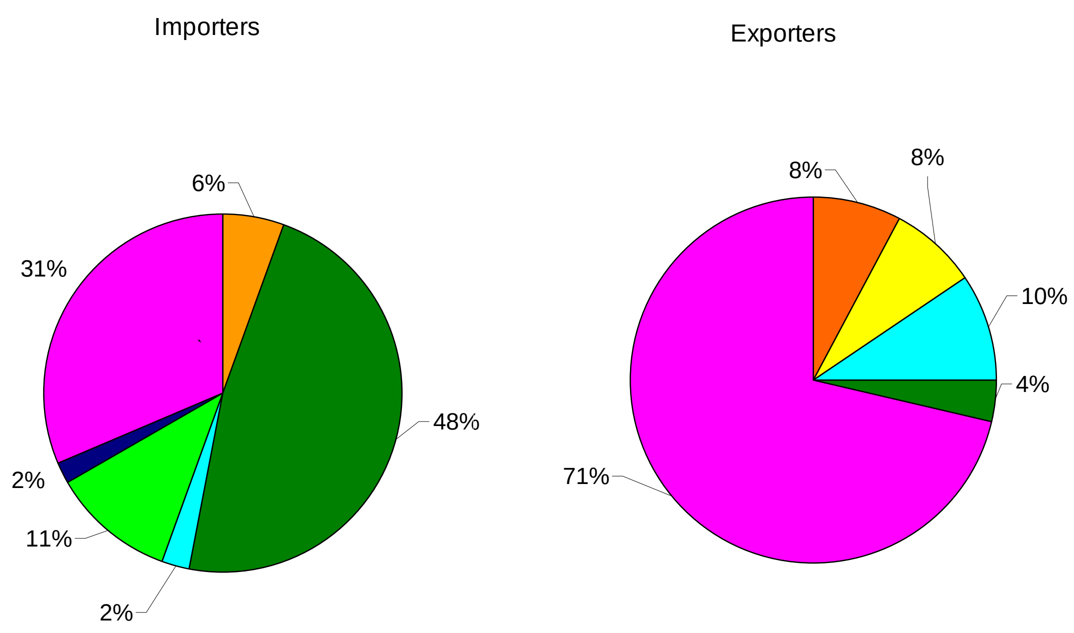
Quarter	Outstanding	New	Resolved	Unresolved
Q2/07	353	98	4	447
Q1/07	353	1	1	353

APPENDIX B – TIE LINE METRICS

Table 6 – Q2/07 Tie Line Statistics

	BC			Saskatchewan			Overall		
	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)
April	67,067	37,150	29,917	40,827	13,358	27,469	107,894	50,508	57,386
May	63,429	55,753	7,676	43,556	7,117	36,439	106,985	62,870	44,115
June	77,391	59,831	17,560	43,857	402	43,455	121,248	60,233	61,015
Q2 Total	207,887	152,734	55,153	128,240	20,877	107,363	336,127	173,611	162,516

Figure 9 – Market Share of Importers and Exporters (Q2/07)



Note: The same color does not necessarily denote the same participant in each of the import and export graphs

Figure 10 - Tie Line Utilization (Q2/07)

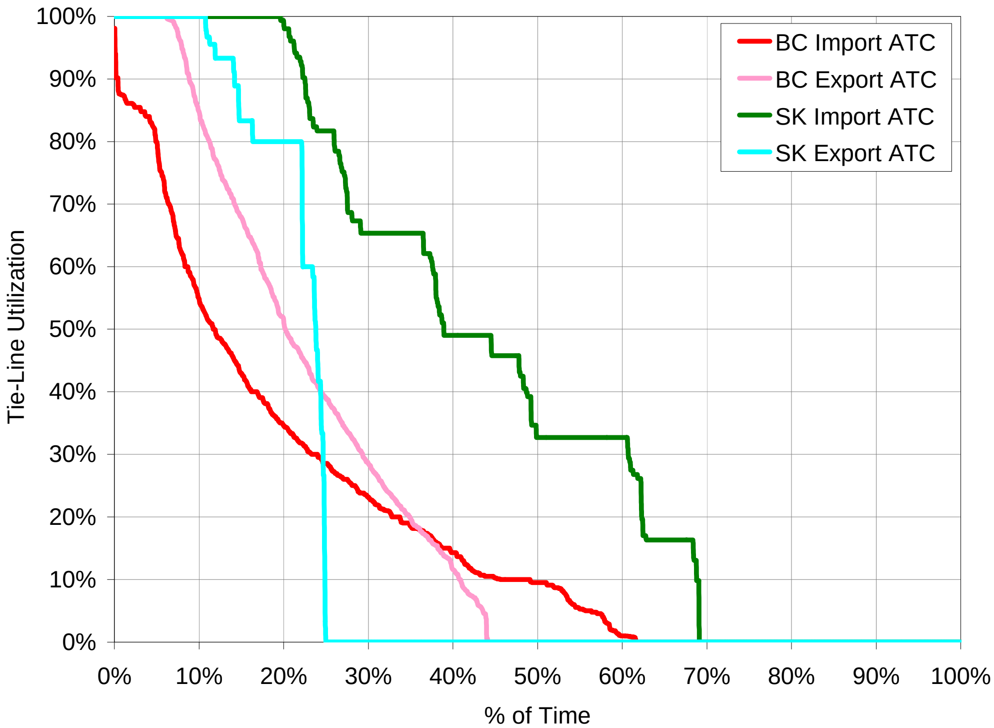


Figure 11 - Imports with Trade-weighted Prices

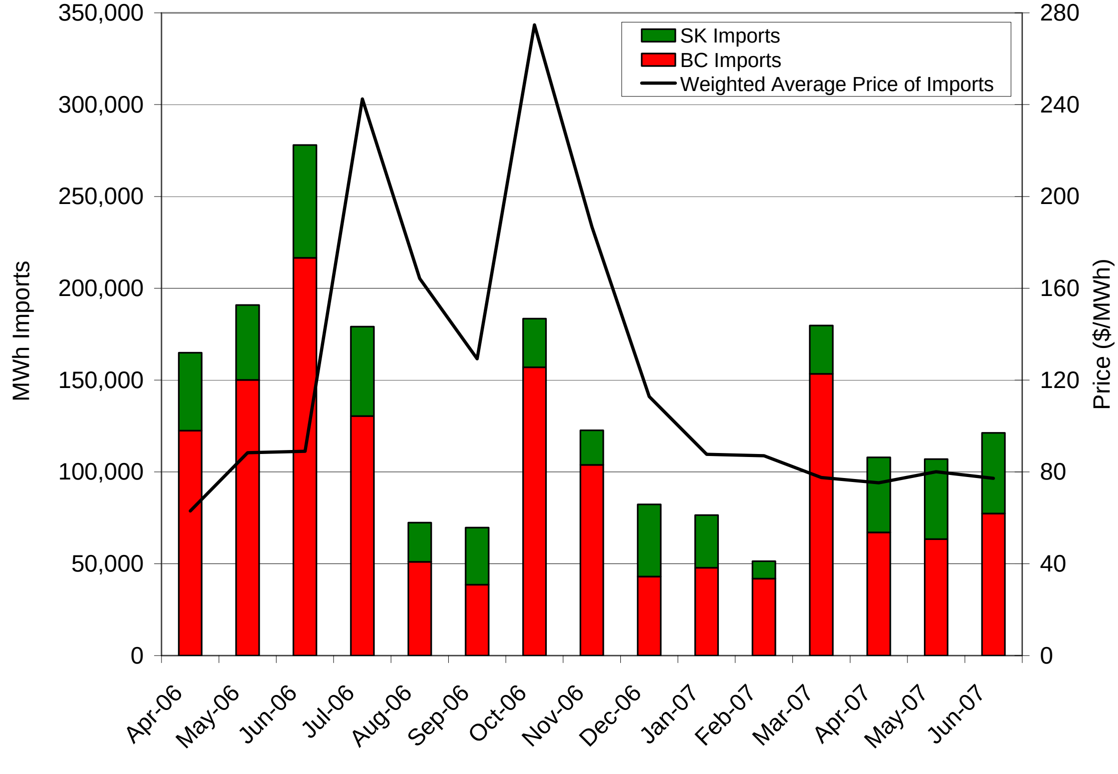


Figure 12 - Exports with Trade-weighted Prices

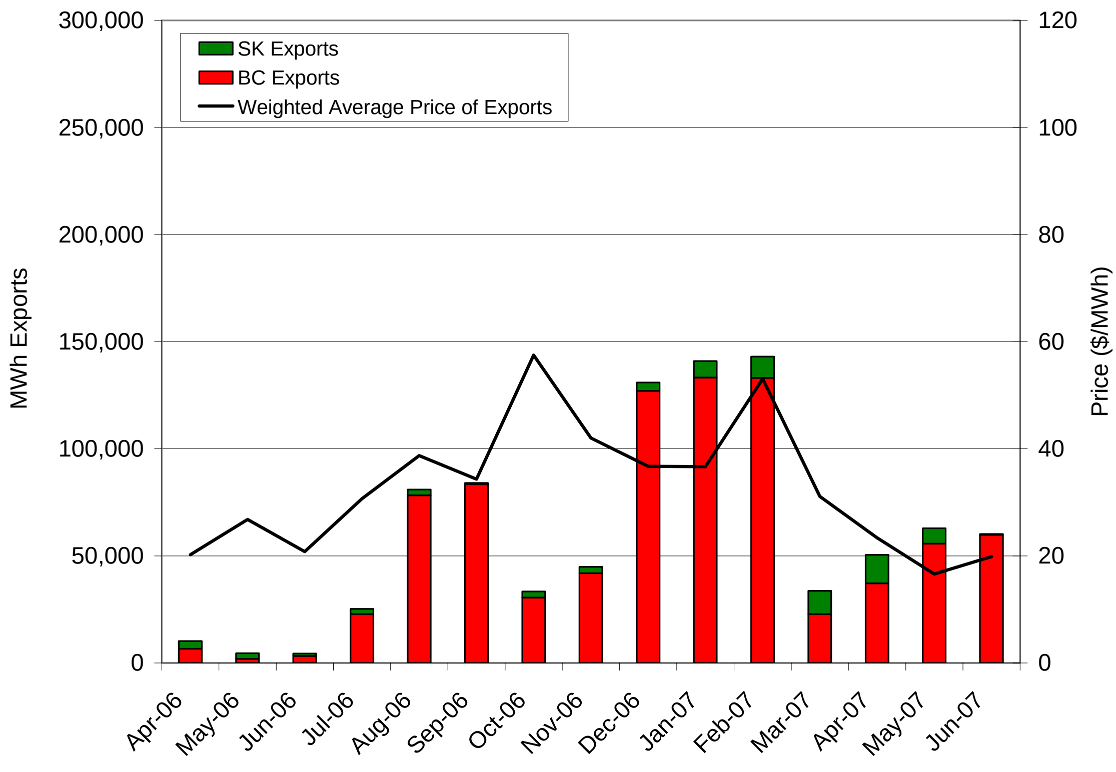


Figure 13 - On-Peak Prices in Other Markets

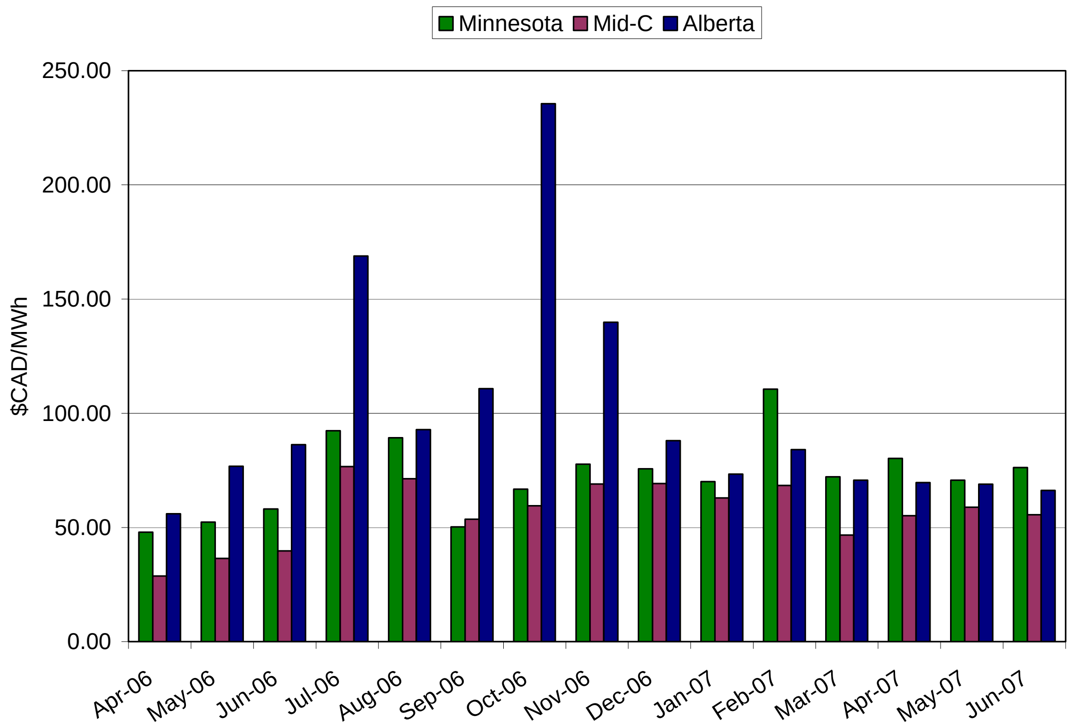
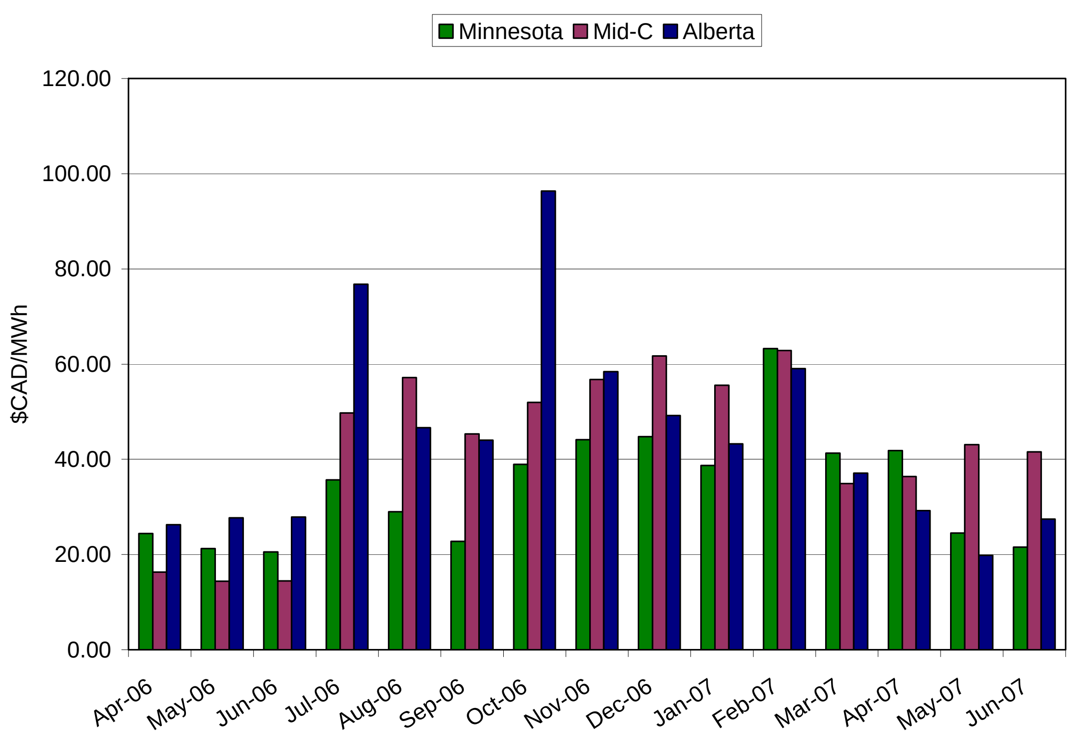


Figure 14 - Off-Peak Prices in Other Markets



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)

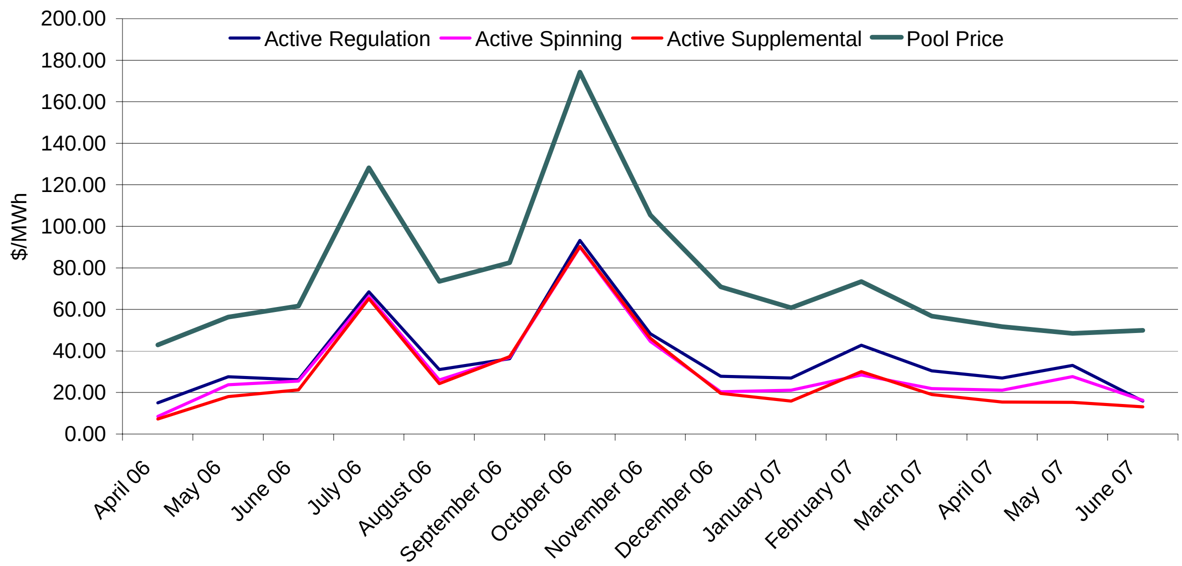


Figure 16 - Standby Premiums - All Markets (Watt-Ex and OTC)

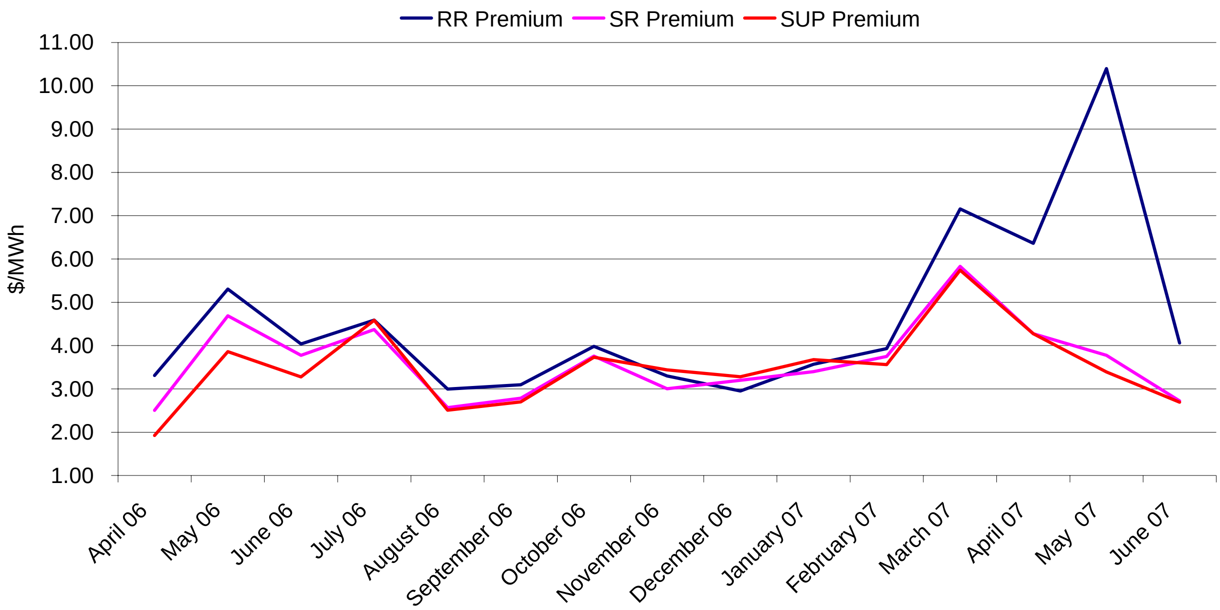


Figure 17 – Activation Prices – All Markets (Watt-Ex and OTC)

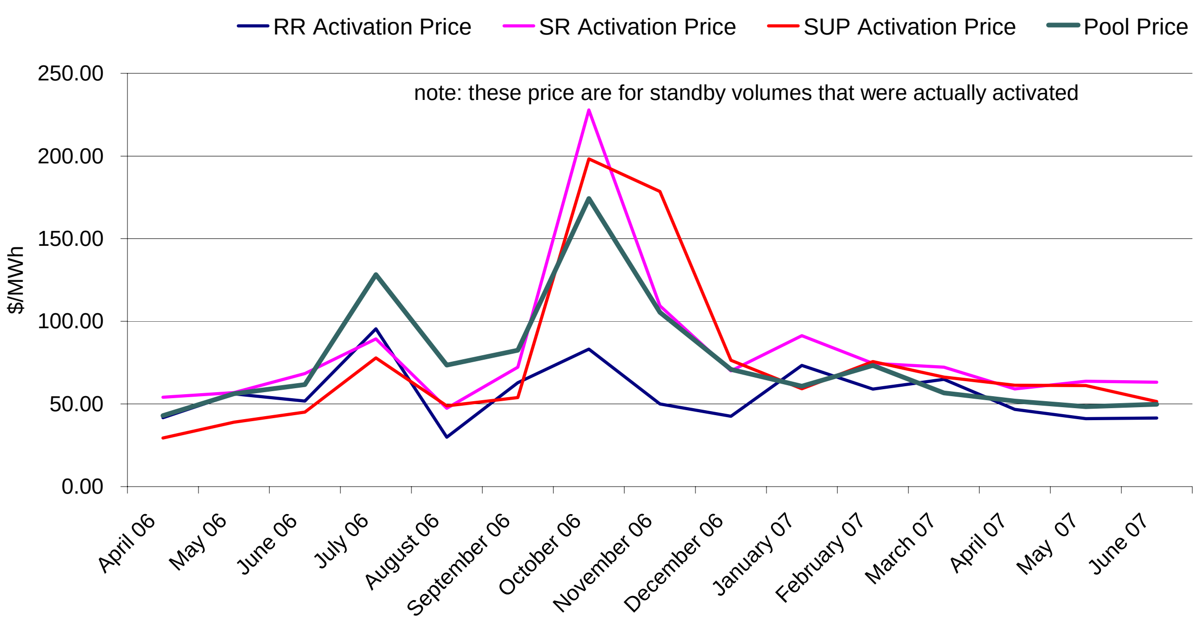


Figure 18 - Standby Activation Rates

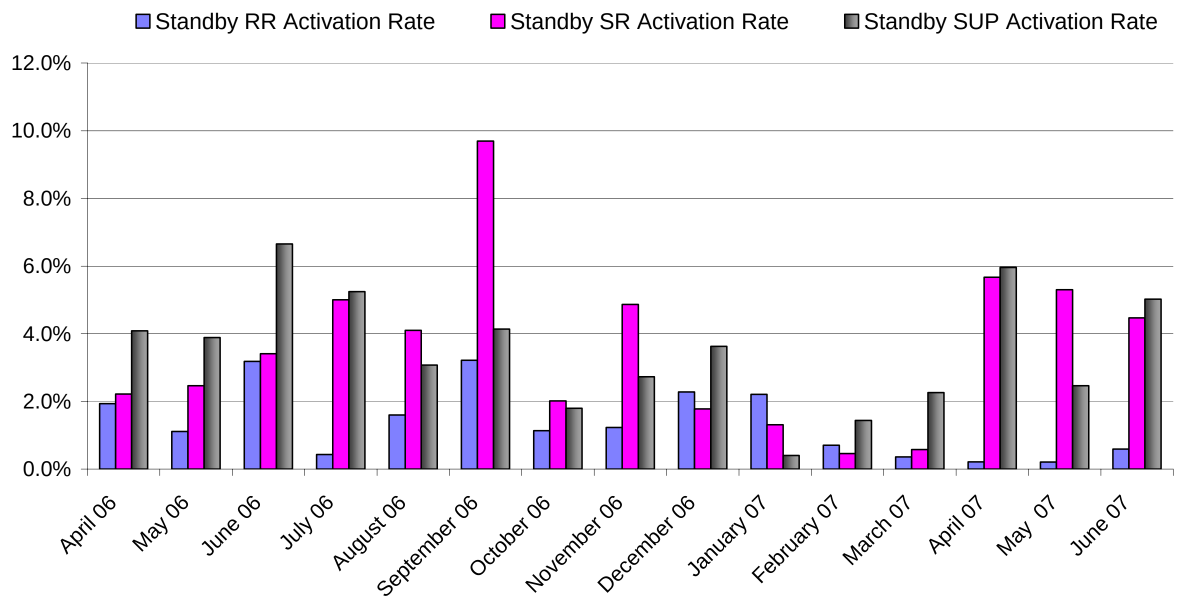


Figure 19 - OTC Procurement as a % of Total Procurement

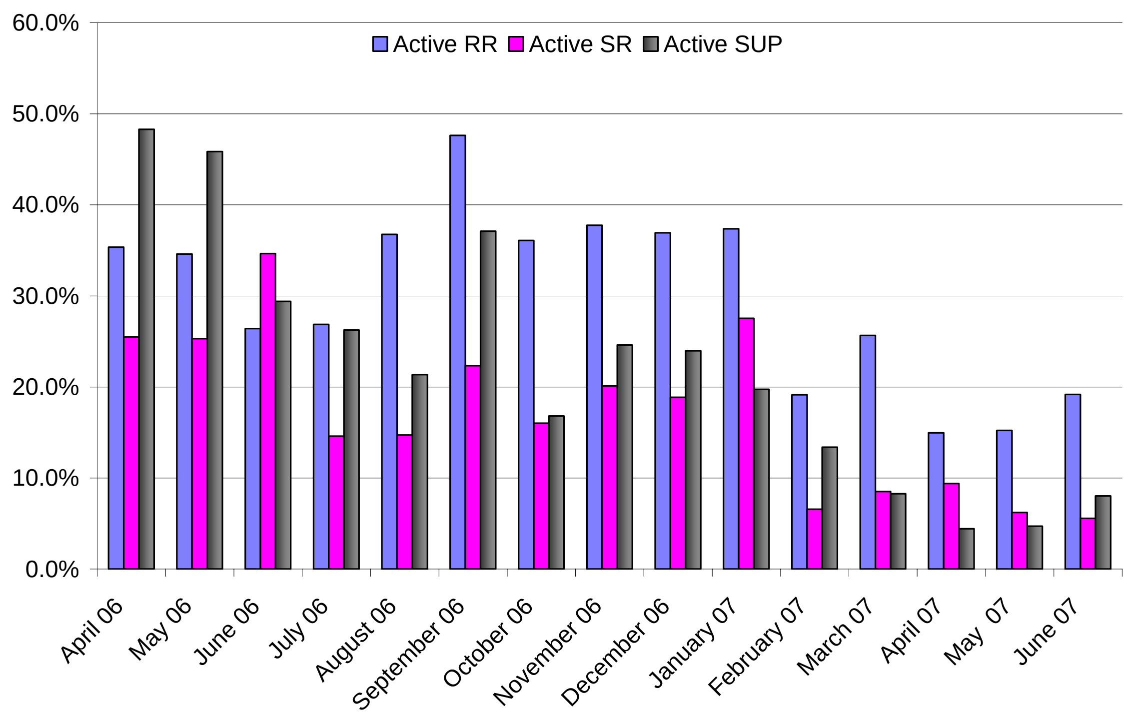


Figure 20 - Active Regulating Reserve Settlement by Market

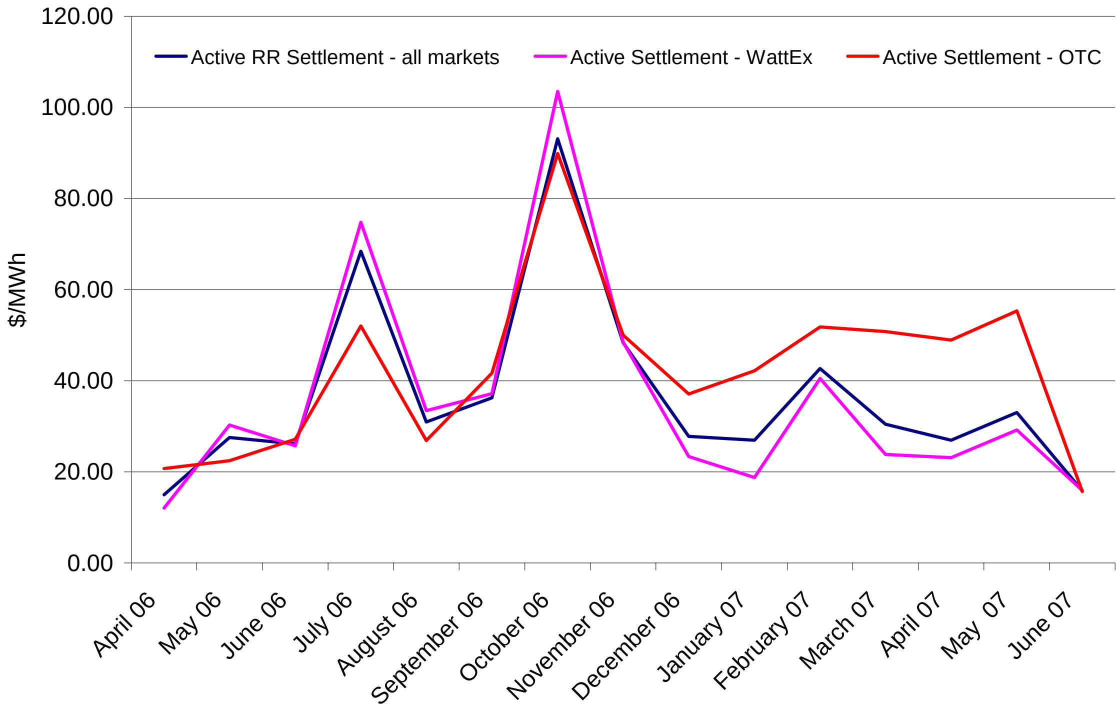


Figure 21 - Active Spinning Reserve Settlement Price by Market

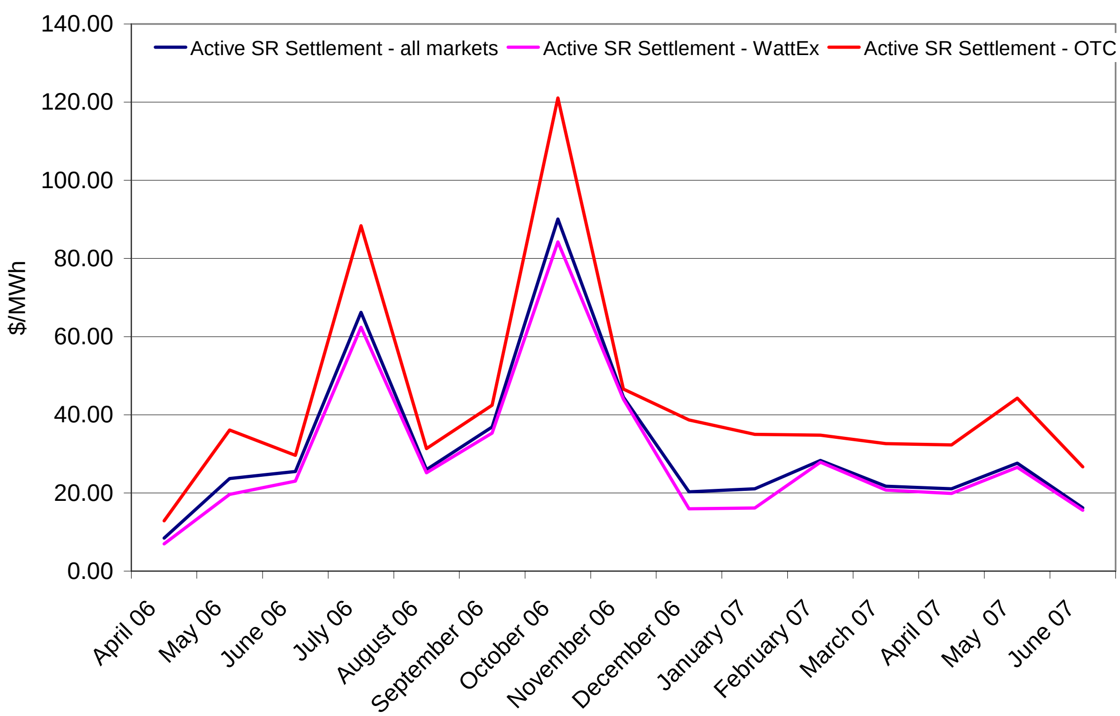


Figure 22 - Active Supplemental Reserve Settlement Price by Market

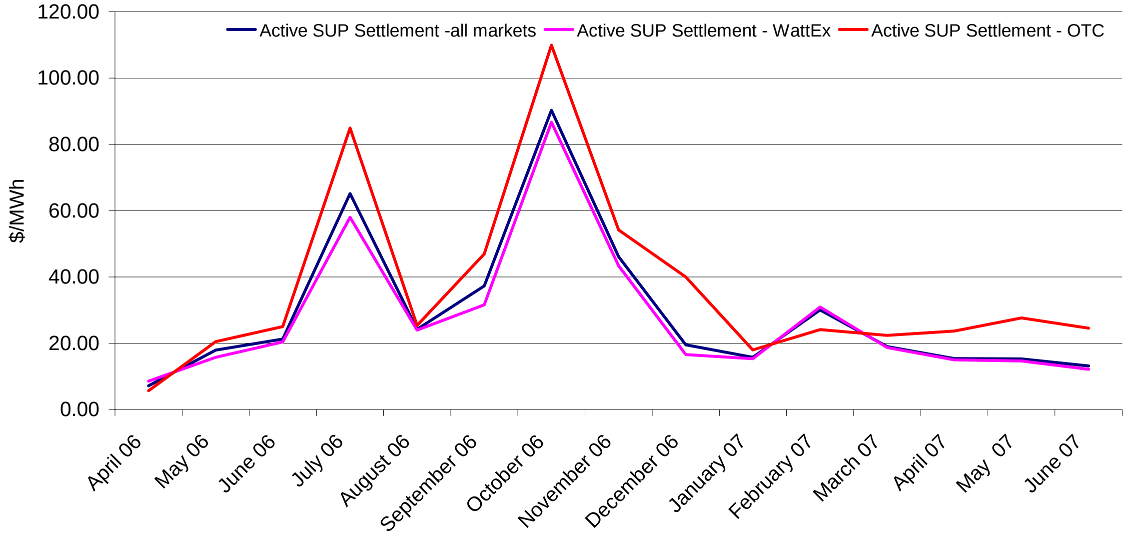


Figure 23 – Active Regulating Reserve Market Share by Fuel Type

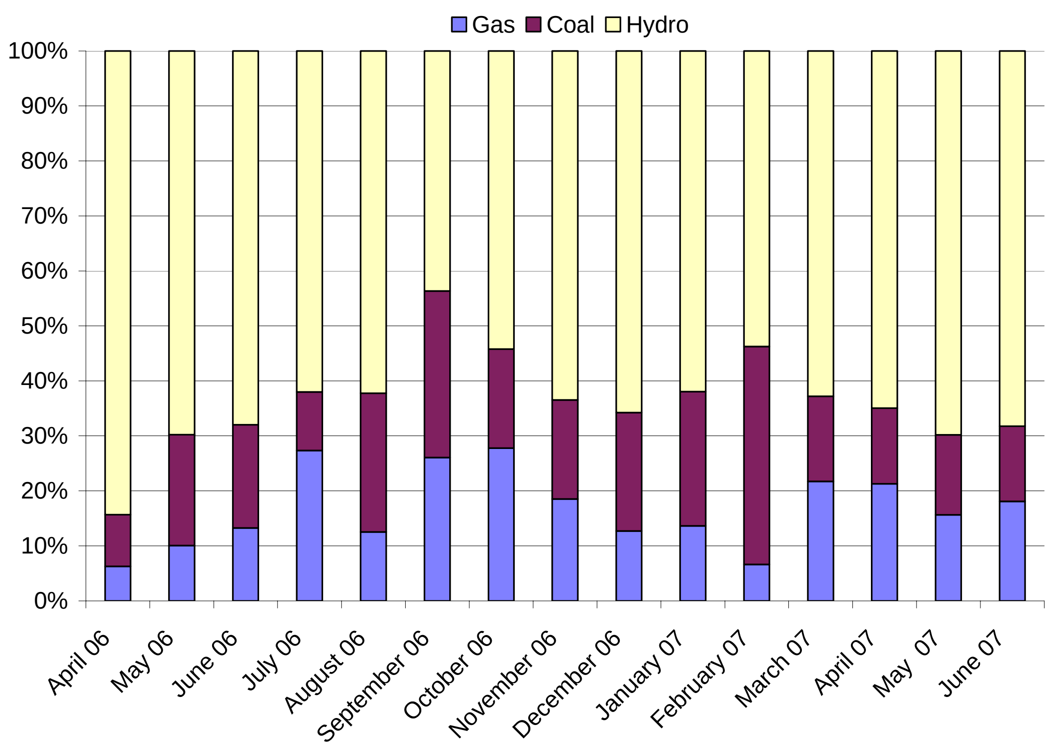


Figure 24 – Active Spinning Reserve Market Share by Fuel Type

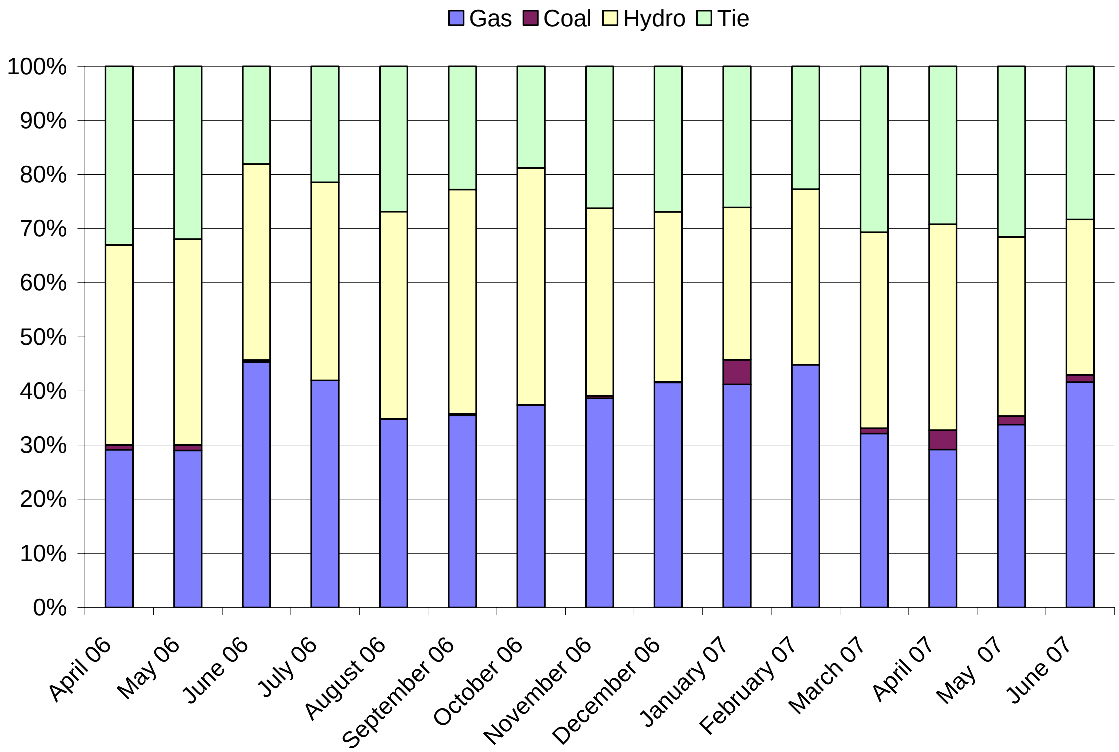


Figure 25 – Active Supplemental Reserve by Fuel Type