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MSA Report

2007 Year in Review

9 April, 2008

Market Surveillance Administrator

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EXECUTIVE SUMMARY

The MSA Year in Review is a complementary report to the MSA annual report containing a broader technical review of market outcomes during 2007 and highlights from various studies conducted by the MSA through the year.

2007 in the Alberta electricity market can be characterized as a year of adaptation. Consumers and participants have adapted to the signals of the market and the market has adapted to changes in societal expectations reflected by legislative and regulatory amendments. The surveillance function has also needed to adapt to changes in both the legislative environment and in participant strategies.

During early 2007, the Department of Energy led an extensive process of stakeholder consultation focused on the conduct standard set out in Section 6 of the *Electric Utilities Act*. Changes to legislation and regulation, including the passing of the new *Alberta Utilities Commission Act* were made late in the year and over the same period the AESO proposed and implemented a comprehensive package of new rules known as “quick hits”.

2007 saw the MSA in court on two occasions – in both cases seeking and obtaining clarity about its powers to investigate. In both decisions the court was supportive of the mandate and approach of the MSA.

A robust market design and a level playing field breeds market confidence, a necessary precondition for investment. The number and diversity of generating capacity additions announced in 2007 suggest that investors remain confident in Alberta’s electricity market. The growing participation and trade volumes in the forward markets are also encouraging. In addition, recent regulatory changes have paved the way for micro-generation (small scale distributed power generation projects) to participate in the market.

The notable feature of 2007 was the market’s ability to continue to produce fair, efficient and openly competitive outcomes while adapting to wide ranging change in the marketplace. Pool price averaged $66.95/MWh, down 17% from 2006. The implied market heat rate for 2007 declined to 11.4 GJ/MWh from 13.9 GH/MWh in 2006, however, periods of extreme market tightness and resultant price volatility in Q3/07 saw the market heat rate in Q3/07 average 18.6 GJ/MWh – a quarterly high since Q2/00.

The performance and effect of the interconnections continues to be an area of focus for the MSA. This report summarizes an intertie efficiency study that was undertaken to assess the overall efficiency of the interties in closing the relevant arbitrage from January 2006 to January 2008. The study produced useful efficiency metrics for the period although no obvious trend in the efficiency rates was apparent for either of the two interties.

Another study completed by the MSA during the year was a review of the operating reserves market. The study looked at two measures of efficiency – supply vs. participation as a proxy for liquidity, and market share by fuel type as an indicator of whether resources were being deployed most efficiently. Detailed findings are discussed later in this report.

With approximately 500 MW of wind generation connected to the Alberta grid at year-end, wind development is already having an impact on market outcomes and may also be changing incentives for new investment and existing participant behavior. Growing levels of wind generation on the system prompt more frequent sudden supply level changes. An MSA study summarized later in this report, highlights one of the operational challenges of wind – its general lack of correlation with system demand. So far the market has been able to adapt to increasing supply volatility; with substantial wind generation still in the pipeline, this issue will continue to attract the analytical attention of both investors and the MSA.

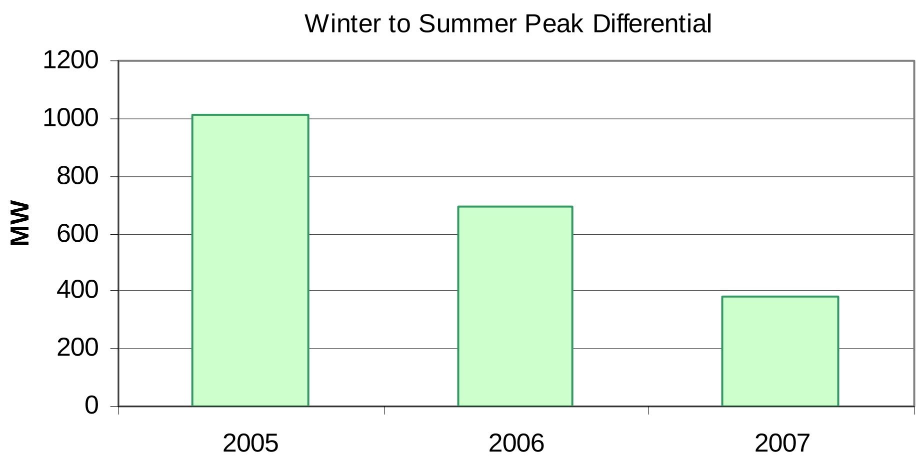
1 FEATURED WHOLESALE MARKET DEVELOPMENTS

1.1 Wholesale Market Prices

In 2007 the Alberta wholesale electricity prices averaged $66.95/MWh. This was down 17% from an average Pool price of $80.79/MWh in 2006 and down 5% from an average of $70.36/MWh in 2005. Average monthly prices followed a similar trend to 2006 for the first 8 months of the year after which 2007 prices from September through November were significantly softer than in 2006. For purposes of comparison, gas prices at AECO-C declined from an average in 2006 of $6.17/GJ to $6.10/GJ in 2007 (a fall of about 1%).

Both July 2006 and 2007 saw instances of extreme market tightness and price volatility. The July 2006 monthly average Pool price was $128.23/MWh which was exceeded in July 2007 when the average monthly Pool price reached $155.73/MWh. Both years saw record setting summer peak demand combined with susceptibility of thermal generators to derates and forced outages under high ambient temperatures. In addition to record summer peaks there is also evidence of a narrowing of the difference between the winter and summer peak. **Figure i** depicts the narrowing differential[1] between the system winter and summer peak demands during the last three years.

Figure i – Winter to Summer Peak Differential

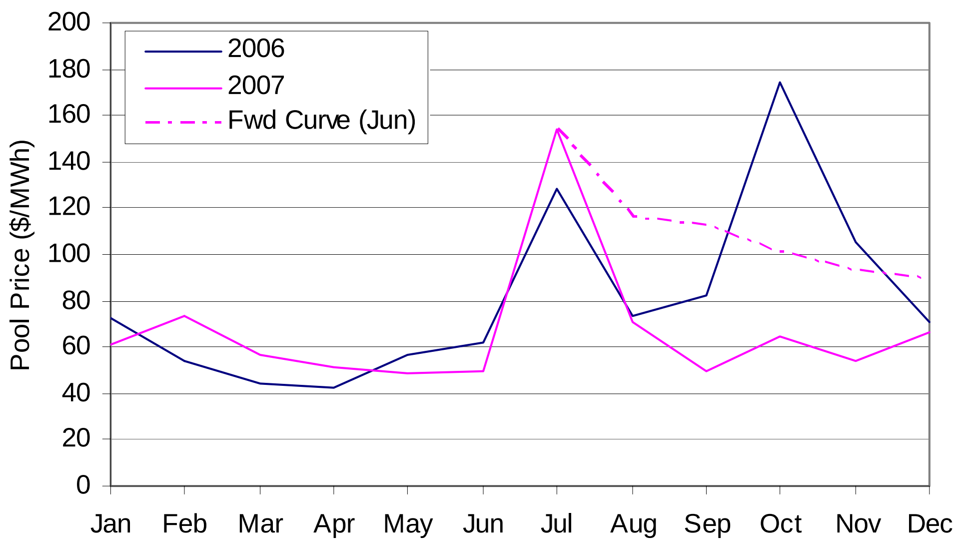


[1] Winter peak demand – summer peak demand for each year indicated.

In general, high summer prices are becoming a notable feature of the Alberta market. Market expectations, as evidenced by the forward price curve, indicate that summer 2008 will also see high prices. These expectations are underpinned by the upward trend in summer system peak demand growth compounded by the advancing age of the existing coal fleet. Although demand is higher still in the cold of winter, at that time most units are fully available having completed their annual maintenance activities in the milder weather.

Prices in late fall and early winter 2007 were softer than expected. The forward curve at the end of June as indicated in **Figure ii** below, was for substantially higher prices than the settled Pool prices for the latter part of the year.

Figure ii – July Forward Curve relative to Settles

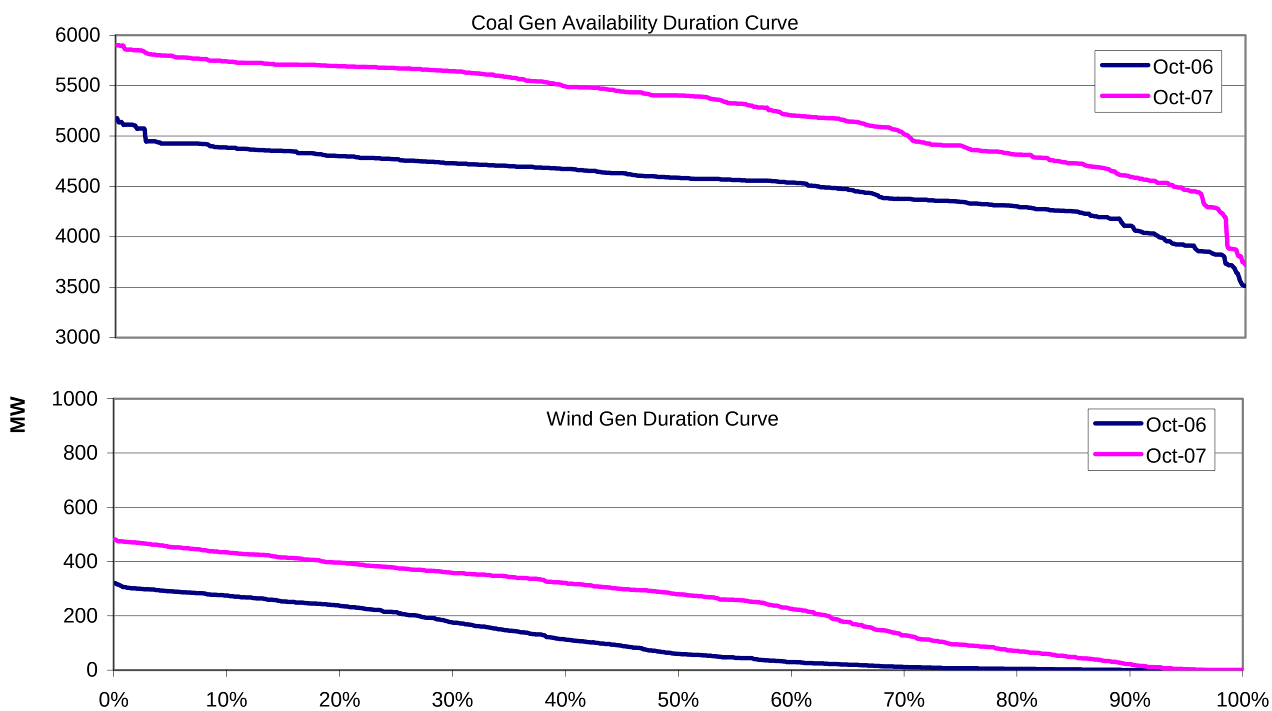


Following the high prices observed in July and despite continued low availability of coal generation, lower temperatures and correspondingly lower system demand in August (on average 287 MW lower than July) saw much more modest prices ($70.92/MWh).

In August the AESO announced a delay of the South Keephills-Ellerslie-Generation (S-KEG) transmission project due to the failure of a major piece of equipment. During the upgrade work planned for September and October some generators would have seen their output restricted. With the delay of the project these restrictions were lifted and high September forward electricity contract prices collapsed from $110/MWh to $80/MWh within a matter of days. The MSA conducted a review of this event and concluded that the price collapse could reasonably be explained by market fundamentals. Further, the MSA found no evidence of contravention of the Trading Practices Guideline. Future transmission upgrades are also likely to be a potential source of price volatility and this may increase as major transmission work gets underway.

October of 2006 had seen an unusually high level of coincident outages across coal generators. It is important to recognize that maintenance at one or two coal generators has a modest impact on price. However, with more than two generators offline, prices are often substantially higher. Availability levels for coal generators during Q4/07 were substantially above Q4/06 levels. The additional availability of wind resources is also likely to have been a factor in moderating prices. **Figure iii** compares supply availability of coal and wind generation year over year for the month of October. From these two sources, system supply was on average, approximately 865 MW better in October 2007 relative to October 2006.

Figure iii - October Year Over Year Supply from Coal and Wind



The changing pattern of prices in the Alberta market is already sending signals to investors and operators. Tight summer conditions prompt generation owners to seek other times of year to conduct maintenance – in 2007 we saw some maintenance delayed until winter when prices were modest. The uncertain generation from wind is also creating opportunities for investment in new fast response generators (typically peaking gas generation).

1.2 Implied Market Heat Rate

Overall, the implied market heat rate in 2007 was 11.4 GJ/MWh, down from 13.9 GJ/MWh in 2006. However, the average implied heat rate of 18.6 GJ/MWh in Q3/07 was the highest quarterly average implied heat rate observed since Q2/00. Sustained weakness in natural gas prices through Q3/07 helped to vault Q3/07 implied heat rates to its historical high. Apart from Q3/07, natural gas prices as shown in appendix A figure 3, generally hovered in the $6.00 - $7.00/GJ range over the balance of 2007 with overall average gas prices down a very marginal 1% from 2006 levels.

As in 2006, observation of Pool price volatility relative to gas (per appendix A, Figures 2 and 3) underscores that supply fundamentals are the primary driver of short-term prices in the Alberta electricity market. However, heat rates together with demand growth are key drivers to investment decisions and thus long-term supply fundamentals.

1.3 Load Growth versus Supply Growth

In 2007 growth in system demand abated from the high rates observed in prior years. Between 2001 and 2006 Alberta's internal load peak demand grew by approximately 4% per year on average. Between 2006 and 2007 a much more modest increase from 9661 MW to 9701 MW or 0.4% was observed. Mild weather through the seasonal peak demand period of late November to mid-December was a moderating factor, as was the case during the same period last year. Average system demand also increased a modest 0.4% year over year however, AESO forecasts indicate that demand growth will rebound closer to the historical average for the next few years.

On the supply side, commissioning of new generation included approximately 180 MW of gas co-generation and approximately 135 MW of new wind generation during 2007. By year-end, the Alberta electric system included just short of 500 MW of wind generation. ATCO's Rainbow 1, 2, and 3 units which were expected to be decommissioned at the end of 2006 remain connected to the system following a contract with the AESO to make the plants available for transmission support services.

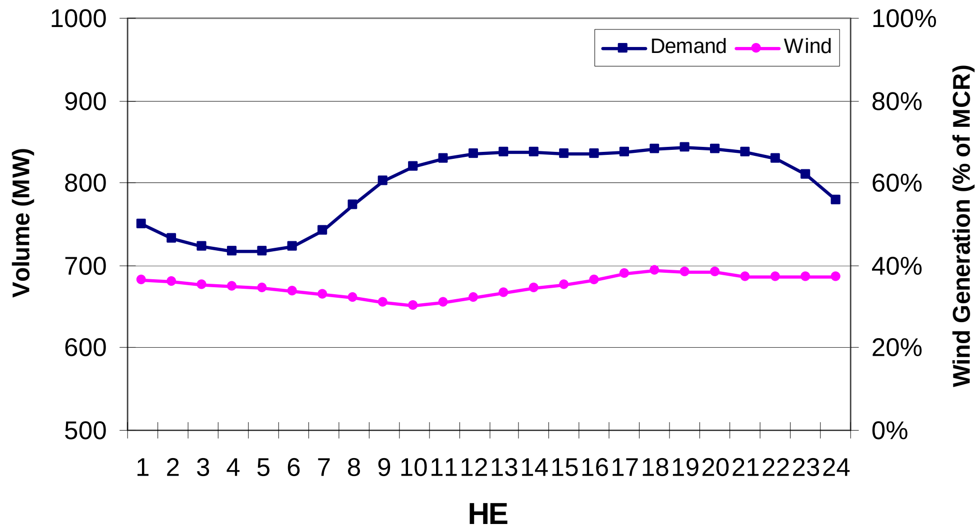
1.4 Wind

2007 has been a year of adaptation for the market particularly in terms of the integration of wind generation. Not only has the physical operation of the market needed to adapt to allow and encourage the participation of wind, participants have had to adapt to the behaviour and impact of wind on the market and on the price signal.

In September 2007, the AESO removed the 900 MW threshold on total wind generation established in April 2006 opening the door to substantial future investment in wind while providing time to address operational challenges associated with wind integration. Foremost among these challenges is the inherent variability of wind output from hour to hour together with its rapid rate of change in output. The ability to forecast wind generation is a key factor in allowing the system operator to accommodate growing levels of wind while ensuring system stability and reliability. During Q2/07 the AESO initiated a wind power forecasting pilot project to assess the effectiveness of various forecasting methodologies – the final results of which are expected in Q2/08.

An element of increasing wind generation that is of particular interest to the MSA is wind's influence on the attractiveness of the various other energy sources going forward. In 2007, the MSA conducted an analysis to explore this question and found a lack of correlation between system demand and wind generation, as indicated in **Figure iv**.

Figure iv - Average Hourly Wind Generation (% of MCR) and System Demand (Jul 1/06 – Jun 30/07)



A steeper residual demand function[2] is likely to be the net result. This is assuming existing geographic diversity in wind generation. Presumably, incremental wind development will bring with it some improvement in geographic diversity which will moderate increased residual demand. A steeper residual demand function suggests enhanced opportunities for peaking generation relative to other generation types as faster ramping intermittent, but dispatchable, units are required to keep pace with steeper load ramps.

1.5 Intertie Efficiency

The MSA analyzed the performance of the Alberta-BC (AB-BC) and Alberta-Saskatchewan (AB-SK) interties for the period January 2006 through January 2008, inclusive. The purpose of the analysis was to assess the overall efficiency of the use of the interties in closing the relevant arbitrage. Lower priced energy should logically flow to the higher priced market and this will tend to close the price difference between them. In a perfect world, sufficient energy will flow to equalize the prices between Alberta and the adjacent markets. A more reasonable expectation would be no residual profit opportunity for an importer or exporter.

[2] residual demand = system demand – wind generation

Definition of intertie efficiency:
For a given hour, an intertie is efficient when no arbitrage opportunity exists. That is, on that intertie no energy can profitably be moved from one market to another in either direction.

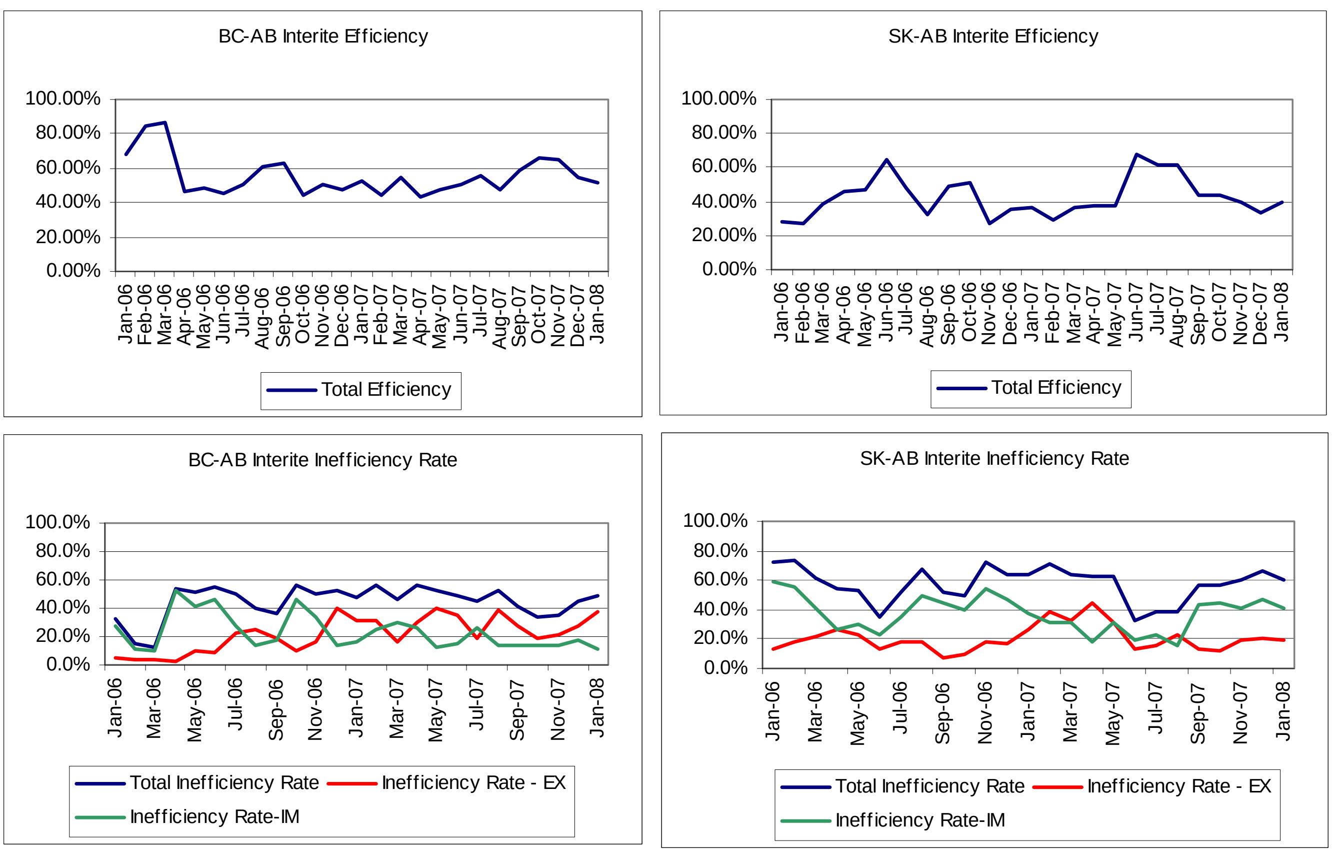
The analysis of the 25 months of data is summarized in **Figure v** and yielded the following findings:

- As shown in the chart, the overall monthly efficiency rate of the AB-BC intertie ranged between 44% and 87%, and averaged 55% in the past 25 months. The overall efficiency rate of the AB-SK intertie ranged between 27% and 67%, and averaged 42% in the same period.

- There is no obvious trend in the efficiency rates of the two interties.

- The lower charts show the inefficiency rates (occurrences of open 'arbs') for the two interties over the 25 months period of analysis. For the AB-BC intertie, the export inefficiency trended up while the import inefficiency trended down leaving the overall inefficiency rate with no obvious trend. A similar situation occurred on the AB-SK intertie.

Figure v - AB - BC and AB - SK Intertie Efficiency



Further analysis of the factors governing these results yielded the following:

- On both interties, the unavailability of the intertie capacity (ATC) was not a common occurrence and thus congestion (through the line being full or on maintenance) did not generally drive the results. However, on the AB-SK intertie we observed that in certain months unavailable ATC prevented half of import arbitrage opportunities from being closed.

- The unclosed arbitrage values in the import direction were higher than in the export direction. The unclosed import price differentials mostly grouped around $40 to $50. The unclosed export price differentials mostly clustered around $20 to $25.

- There were a significant number of hours when high price differentials (> $100) corresponded to high extra import ATC (> 100 MW). This does not indicate a highly efficient outcome.

In considering the sources of inefficiency of the outcomes from the participant's viewpoint, the two main risks are Pool price and transmission access:

- The ex-post nature of Pool price. When market participants export to or import from other markets, they don't have the visibility of the pool price as it is calculated after the fact. As a result, they require greater price differentials in order to cover the risks of unfavorable pool price. Typically imports occur during on-peak hours when price volatility is higher and higher volatility results in higher risk premiums.

- Non-firm transmission. When market participants use non-firm transmission to ship power, dealing with counterparties in other markets can be expensive. For example, when dealing with counterparties at Mid-C, exporters usually have to agree to receive lower prices and the importers usually have to pay higher prices if they don't have firm transmission. This is due to the risk that the deal will fall through at the last minute.

Allowing a $10/MWh drain on efficiency due to these factors, the recalculated average efficiencies for the interties improve from 55% to 73% on AB-BC and from 42% to 60% on AB-SK.

On December 3, 2007 the AESO's Quick Hits package was implemented. There was some concern at the outset that the 2-hour lockdown component of the package would have a detrimental effect on the efficiency of the interties. However, the data did not show any discernible changes in overall intertie efficiency. However, January 2008 had the highest number of uneconomic import hours on the AB-BC intertie over the past 25 months.

It is difficult to draw definitive conclusions on the calculated efficiency rates as calculated herein, but with average rates hovering around 50% it is not likely that this is the best that can be achieved. The MSA will periodically revisit this calculation and look at the trend over time.

1.6 Transmission Development

On September 30, 2007, the Alberta Energy and Utilities Board (EUB) published Decision 2007-075 in which the EUB cancelled proceedings and closed applications to construct and operate a 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.

Decision 2007-075 noted that a reasonable apprehension of bias had compromised the proceedings and therefore there had been a denial of a right to a fair hearing.

The needs identification application for this highly anticipated project was originally approved in April 2005 in EUB Decision 2005-031 and if the 500 kV project were re-launched, it must begin again from the point of needs applications. Although the failure of the project to proceed was an event of great significance, resilience of the market was demonstrated by the lack of movement of the forward price curve which indicated a pricing-in effect of project risk including the protracted regulatory and consultation processes involved in significant transmission projects even before they ever reach the construction phase.

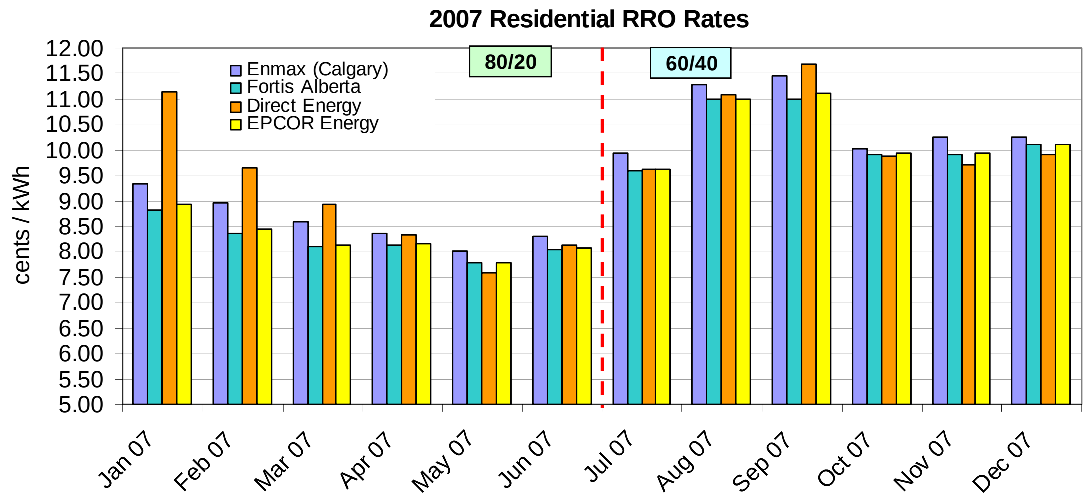
While the MSA is encouraged by the tempered market response to this event, the MSA remains concerned with the potential for growing congestion and the resultant impact this may have on market prices.

2 FEATURED RETAIL MARKET DEVELOPMENTS

2.1 RRO Developments

After trending down through the first half of the year, residential RRO rates increased sharply in Q3/07 as shown in **Figure vi**. A large part of the increase is attributable to the prices of full-load contracts acquired in earlier RFP auctions. The sellers had anticipated, and priced in, high volatility and high average Pool price levels similar to what occurred in 2006. Q4/07 residential RRO rates remained near 10 cents/KWh largely driven by the procurement cost of full-load contracts and the sellers' beliefs that Pool prices would be high. Those full-load contracts were procured when the prevailing forward price curve was reflecting market expectations for higher and more volatile Pool prices through Q3/07 than actually occurred.

Figure vi - 2007 Residential RRO Rates



July 2007 marked the second year of transition rates as contemplated under the new RRO regulation. Beginning in July, the RRO rate basis shifted from an 80/20 split of long term to month ahead pricing basis to a 60/40 split. Enmax and Epcor continued to conduct electronic auctions for the procurement of full load contracts covering the long term proportion of their RRO load obligations. The Direct Energy RRO is somewhat different and does not utilize the same auctions for shaped contracts.

2007 also saw the first of two contemplated DOE reviews of the RRO as well as a review of RRO conducted by the MSA. The scope of the DOE review included defining appropriate metrics to assess the ongoing performance and growth of the retail electricity market. The review and metrics were also a basis to determine whether or not to delay the incremental progression toward a 100% month-forward energy price basis, as contemplated in the RRO Regulation. The review found no reason to suspend this progression. A second DOE review of RRO is contemplated in 2009[3].

[3] http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf

The MSA review of RRO defined a scope of assessing whether ongoing implementation of energy price setting plans of the RRO providers is a balanced process relative to both consumer representative groups and the RRO providers. The review also assessed whether RRO providers are implementing their energy price setting plans as written. The MSA review concluded that the energy price setting plans are indeed balanced processes and are being implemented in an appropriate manner.

2.2 Retail Market Metrics

Overall retail market shares shifted considerably over 2007. While the market share of most large retailers either remained the same or decreased, the largest (Retailer B in Figure 26) increased by 7%. This is equivalent to an impressive annual growth of 26% of their retail business. Conversely Retailer A saw a decrease in business of approximately 5%, or a loss of 1% of their market share. Furthermore the number of large retailers (those that have market shares greater than 5%) decreased from four participants to three.

The percentage of customers electing to switch from the RRO to competitive contracts continued to increase for all customer classes in 2007 (Figures 29 & 30). The most significant increase was among the Small Commercial/Industrial class in the latter half of 2007. This is coincident with the increase in RRO rates experienced during this time. As more customers switched to competitive contracts the largest three retailers in the Small Commercial/Industrial class were all successful in increasing their business. However the total number of retailers holding a market share greater than 5% decreased from four participants to three.

At the end of 2007, approximately 97% of all the sites in Alberta are eligible to subscribe to the RRO and approximately 25% are serviced by competitive contracts. These numbers have increased significantly from 2006 in which 18% of RRO eligible sites were on a competitive contract.

2.3 Code of Conduct Regulation

The *Code of Conduct Regulation* (Code) governs the relationships between owners of electric distribution systems and their affiliated retailers, as well as dealings with non-affiliated retailers, customers and customer information to help ensure a level playing field for retailers.

The Code contemplates that the owners and affiliated retailers will undergo a compliance audit on an annual basis, within the oversight of the MSA. The MSA also has the power to obtain information and conduct testing pursuant to its overall surveillance and investigation mandate under the Act.

Parties Tested

A total of 5 parties were subject to the testing, all of them REAs. Other owners with affiliated retailers were not included in the Code testing this period, in part because of a proven track record of Code compliance evidenced by previous audit testing (the REAs began offering retail electricity services more recently than other owners with affiliated retailers, and thus to date have been subject to fewer Code related audits).

In accordance with the *Roles, Relationships and Responsibilities Regulation, 2003* each REA provided their 'owner' and 'retailer' functions through operating divisions within their single REA entity. The specific parties tested were:

- Battle River Rural Electrification Association Limited
- Central Alberta Rural Electrification Association Limited
- North Parkland Power Rural Electrification Association Limited
- Rocky Rural Electrification Association Limited
- South Alta Rural Electrification Association Limited

Nature of Testing

The testing plan this period largely focused on sections 3, 4, 6, 7, 15, 17, 18, 19, 20, 21, 33 and 34 of the Code. In addition, where the MSA wished to follow up on matters arising from previous testing or from its regular monitoring, the scope of the compliance testing was augmented.

The Code sections referenced above can be described as dealing with the following matters: adherence to compliance plans; accuracy of compliance reporting; adherence to Code in relation to customer interactions; unfair competitive advantage through arrangements between owner and affiliated retailer; handling, disclosure and use of customer information; other issues.

The testing was carried out during August and September, 2007. The findings were then shared and discussed with the relevant parties; related reports for the MSA and the parties have been finalized accordingly.

The results of the compliance testing were very positive and encouraging overall. Areas of non-compliance and other comments are set out below:

- In general, the parties followed the systems, policies and mechanisms within their respective compliance plans, and those efforts toward compliance appeared to produce good results. In one case, personnel changes significantly disrupted efforts by the REA to administer their compliance plans; this affected the completeness of training, reporting and other measures.

- In some instances the parties did not provide the required disclosure(s) about retail choice as part of communications regarding their retail electricity services; this constituted a breach of Section 18 of the Code, as well as the applicable compliance plan(s).

- Section 34 of the Code requires that all circumstances of non-compliance be disclosed in the regular compliance reporting. In some instances, deviations from the compliance plan or the Code were not documented as required. However, in all cases the reporting omissions were found to be inadvertent.

- In the view of the MSA, there were no instances of non-compliance which would have materially undermined the *fair, efficient and openly competitive* operation of the market.

- Based upon its findings, Grant Thornton made certain recommendations intended to help the parties assure Code compliance. The MSA will be following up in this regard, as applicable. Other matters arising from the testing have already been addressed, as applicable.

The MSA also notes and appreciates the high degree of cooperation received from the parties being tested, which helped assure the efficiency of the process.

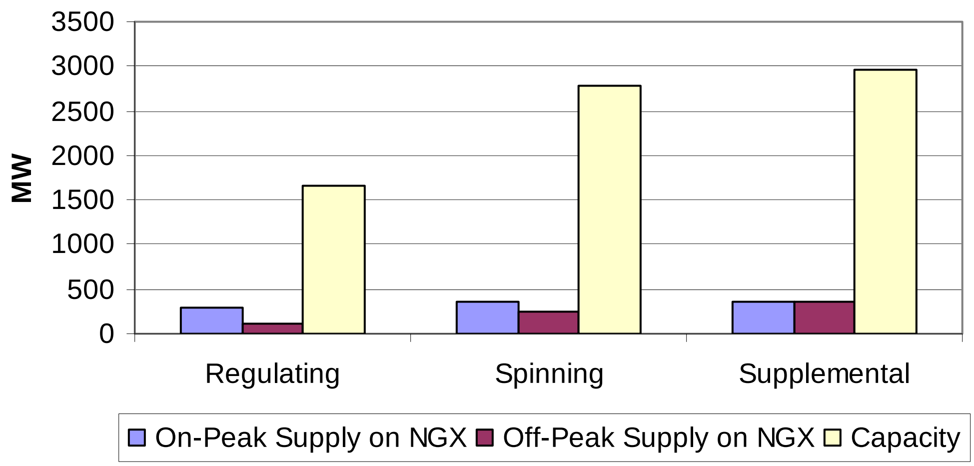
3 FEATURED ANCILLARY SERVICES MARKET DEVELOPMENTS

3.1 Operating Reserves Review

In early 2007 the MSA concluded its analysis of the Operating Reserve (OR) market. The goal of the analysis was to assess the overall performance and efficiency of the OR market as well as to understand the behaviour of market participants. The nature of the work involved confidential data for a market with relatively few players and thus does not lend itself to making a formal public report.

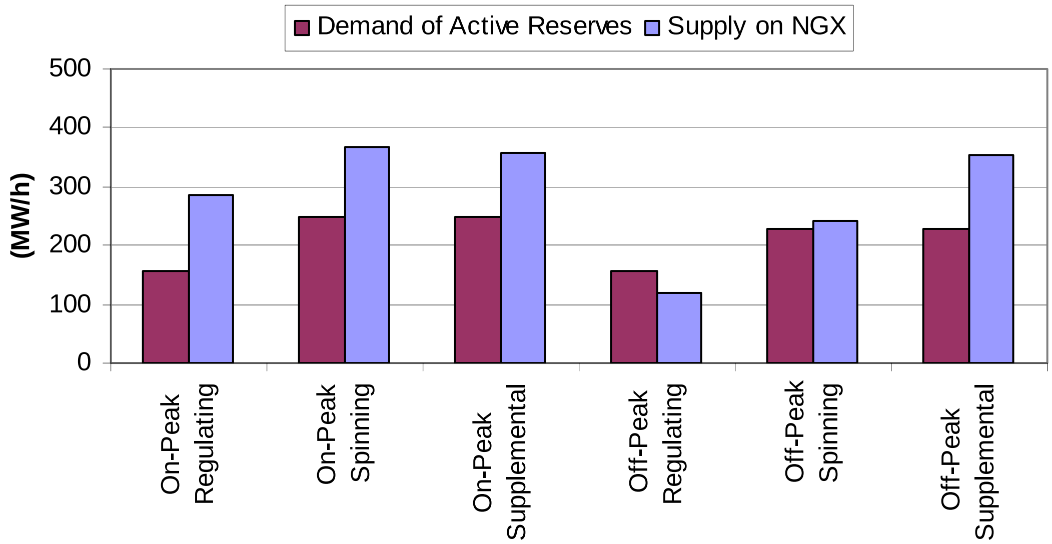
Detailed trade price, supply, and demand data from 2006 were reviewed for both the Active and Standby markets for each of the three products: Regulating, Spinning, and Supplemental Reserves for both on and off-peak products. A high percentage of the volume that is traded in the OR market is traded on NGX (formerly Watt-ex) and the analysis focused only on those volumes. The MSA looked at two measures of efficiency: supply and participation, as well as market share by fuel type. The level of supply and the participation rate is a proxy to the liquidity of the market and the level of competition. The analysis also focused on market share by fuel type in order to determine whether or not resources were being deployed most efficiently to the right markets, without consideration of the product prices. **Figure vii** demonstrates the level of potential supply to demand and shows a healthy supply overhang. One significant outcome of this analysis is that the market will clear even without the largest participant, albeit at higher prices.

Figure vii – Qualified Reserve Capacity vs. Offered



There has been concern that there is a limited supply of OR resources being offered into the market and consequently a lack of competition resulting in inefficient outcomes. Data from 2006 confirms that the qualified capacity in the OR market is far greater than the actual demand for each product as shown in the figure above. However, the actual supply on NGX is only a fraction of that capacity. **Figure viii** indicates that in the case of off-peak regulating reserves the average demand for reserves in 2006 was greater than the average supply on NGX. In such situations the lack of liquidity would not likely lead to an efficient outcome. The AESO was forced to satisfy their demand via the over the counter market on such occasions.

Figure viii – Demand vs. NGX Offered Supply for Active Reserves



Clearly only a portion of the qualified capacity is actively offered to the OR market. Furthermore those market participants who are qualified and who participate in the OR markets essentially must chose between three separate markets: Energy, Active reserves and Energy plus Standby reserves. Those participants that chose to participate in an OR market must choose which of the three types of products they wish to provide. Participants may offer their volume on a total of five different trading days via two different platforms. On any given trading day for any given product the AESO may be faced with a very limited number of offers despite the potential available capacity.

The OR market design is complicated and the effort required to successfully participate in the market is disproportionately higher than the energy market especially when one considers the relative revenue earned in the two markets. Market participants are faced with a number of decisions to make and many variables to consider. These decisions can be expressed mathematically in an optimization problem and can be solved assuming that rational sellers will direct their resources to the market that provides them with the greatest profit. This optimization problem has different implications for participants who are attempting to optimize a portfolio. In order for a participant to choose to participate in the Active reserve market, the participant must believe that the profit received from the OR market will be strictly greater than what he would receive from the Energy market. Conversely a participant choosing to participate in the Standby faces a different set of equations. First it must be determined that the profit received from providing Standby reserves is greater than the profit received from selling Active reserves. Second it must also be considered that participation in the Standby market does not require withdrawal from the Energy market. Rather, the participant is faced with some probability (activation rate) of being forced to leave the Energy market and provide Active reserves in the event of being activated.

3.2 Operating Reserves Participation

In looking at the actual rates of participation in the OR market, the following are some of the key findings.

1. Due to their cost structure, resources with higher generating costs are able to tolerate deeper discounts than low cost resources and are therefore more competitive. In other words those participants whose opportunity cost is lowest in the energy market (i.e. most likely to be out of merit) are capable of offering larger discounts in the OR market. This is consistent with in the data from 2006. Hydro and gas fired peaking resources have disproportionately higher market shares than their capacity shares in the active market in 2006 shown in **Tables i and ii** below.

Table i – Active Operating Reserves Market Share by Fuel Type

	On-Peak			Off-Peak		
Fuel	Regulating	Spinning	Supplemental	Regulating	Spinning	Supplemental
Hydro	89%	77%	68%	69%	63%	68%
Gas	11%	23%	31%	17%	37%	26%
Coal				14%		
Load			4%			5%

Table ii – Standby Operating Reserves Market Share by Fuel Type

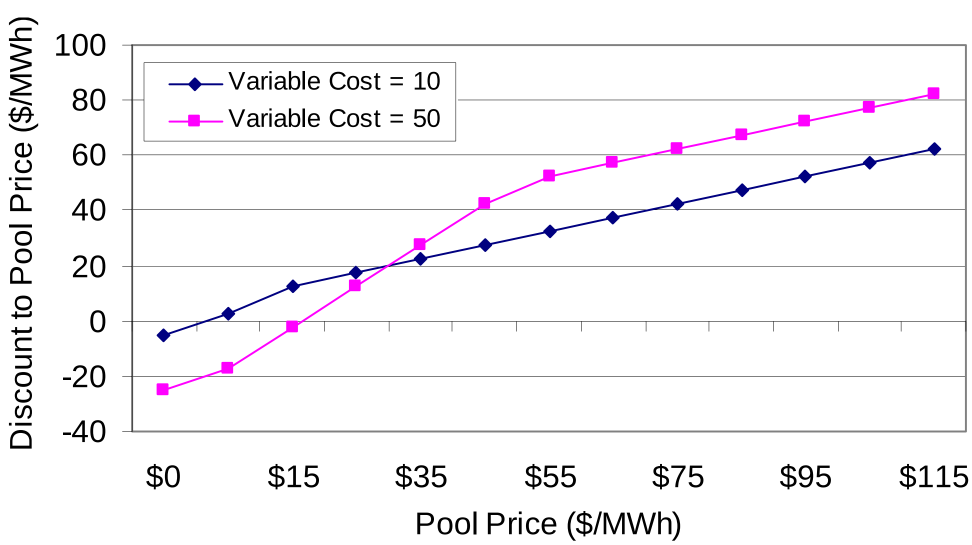
	On-Peak			Off-Peak		
Fuel	Regulating	Spinning	Supplemental	Regulating	Spinning	Supplemental
Hydro						
Gas	29%	52%	55%	34%	43%	72%
Coal	71%	47%	32%	66%	57%	18%
Load			12%			10%

2. Those resources that can ramp up and down without incurring significant extra costs, or those resources that have lower incremental costs, are more competitive. This is also consistent with the observation that hydro and gas resources have disproportionately higher market shares in the active market.

3. Price taking thermal resources with low generating costs offer at the least discount. Although coal units have a large share of the OR capacity; they have negligible market share. In terms of opportunity cost, a low cost thermal unit has a high opportunity cost of not participating in the energy market, since it would likely be generating and therefore cannot tolerate deep discounts in the active reserve market. However low cost thermal units are far more competitive (and hold larger market shares) in the standby market. This is because the unit is not required to give up its opportunity to participate in the energy market (unless activated).

4. Regulating reserves require a higher trade price than spinning or supplemental reserves if it is likely that the asset will incur a loss from following load. This can be shown graphically in the figure below. If one assumes that a resource providing regulating reserves behaves as a price taker in the energy market and then offers in the Active market based on costs, it can be shown that the lower the (forward view of) pool price, the smaller the discount required to be indifferent between the two markets (see **Figure ix**). Note how for low Pool prices the discount to Pool price turns negative meaning that a participant requires a minimum of Pool price plus an amount to be indifferent to the Energy market.

Figure ix – Estimated Indifference between Energy and Active Regulating Reserves



This is confirmed by observations from the OR market. The off-peak regulating reserve price is almost always higher than the trade price received by on-peak regulating products and is often higher than the off-peak spinning and supplemental trade prices. This is due to the fact that during off peak hours the pool price is often very low and load following often results in losses. Conversely load following during on-peak hours is often profitable due to the higher pool prices.

Overall, the analysis seems to suggest that the market has directed the ‘right’ resources to the ’right’ market. It appears that there are still some issues with market performance and it is not clear that the market is operating as efficiently as it could. Much effort on behalf of the sellers is required to optimize between markets and there are a number of inefficiencies that arise due to the fragmentation of the market, existence of participant portfolios and the requirement for an active buyer. The MSA is supportive of the AESO’s efforts to engage industry to find solutions to some of these issues.

4 OTHER MSA ACTIVITIES

4.1 Investigation Proceedings

During 2007, the MSA worked on four major investigation files concerning issues affecting the Alberta electricity markets. The investigations focused on possible breaches of Section 6 of the Alberta Electric Utilities Act (“EUA”) concerning activity related to uneconomic importing, trading in the forward market, inappropriate use of locking restatements, and trading in the ancillary services market.

Investigation into Potential Uneconomic Import Activity

The investigation into certain imports of energy by ENMAX Energy Corporation and ENMAX Energy Marketing Inc (“ENMAX”) was initiated in October 2005 and pertains to the MSA’s concerns about the uneconomic importation of energy into Alberta and the potential undesirable impact this may have on Alberta electric prices. As part of the investigation the MSA interviewed employees of ENMAX wherein they were advised by ENMAX’s legal counsel not to answer specific questions. The MSA responded to ENMAX’s refusal by applying to the Court of Queen’s Bench on February 15, 2007 for an order compelling the ENMAX employees to answer questions.

In response to the MSA’s court application, ENMAX brought a cross application to contest the ability of the MSA to seek the assistance of the court to hear the MSA’s application and to insist the application be held in camera. On July 5, 2007 Mr. Justice A.D. Macleod ruled that the MSA was in fact entitled to seek a court order to compel answers to reasonable questions (“2007 ABQB”). On January 24, 2008 Justice Macleod filed his second decision in this matter and dealt with the questions that had been objected to by ENMAX ("2008 ABQB 54").

The decision is significant for the MSA as the court ruled that all of the objected to questions are appropriate and the MSA is allowed to re-interview the witnesses who will answer the questions previously objected to. Moreover, the MSA is entitled to ask further questions following upon the answers given to the objected questions. The decision also deals with the matter of public interest. In this regard, Justice Macleod noted that the public interest is not served by an order which would shield any further proceedings in this matter from public scrutiny. Justice Macleod determined that the public is entitled to scrutinize the debates between the MSA and ENMAX as to whether or not the extent of the investigation is in the public interest as to whether ENMAX has had the benefit of due process. Further, Justice Macleod indicated that when parties disagree over important issues which relate to the right of those being investigated to due process, the public interest trumps any confidentiality consideration.

The court decisions in this matter will help the MSA to carry out its mandate, and should also help guide the actions of market participants, such that investigations will generally be able to proceed in a more direct and efficient fashion. In this regard, the MSA anticipates completing the investigation this year.

<u>Investigation on forward market trading activity</u>

In October 2006, the MSA commenced an investigation into certain forward market trading activity which occurred during the summer of 2006; the investigation specifically focused on a generating plant outage and the disclosure of related outage information during that period. The MSA was concerned that a market participant may have breached the Trading Practices Guideline (TPG). The TPG was established in 2004 and states:

> *Market participants must not trade on the basis on known but not public information about the status of supply, load, or transmission assets that can reasonably be expected to have a material impact on market price. Trading shall be understood to include any type of financial or physical transaction or operational strategy designed to extract value from known but not public information about the status of supply, load, or transmission assets.*

Investigation on the acceptable use of locking restatements

In October 2006, the MSA commenced an investigation into one market participant's use of a locking restatement. The investigation considered the impact of the activity on:

- whether the price signal was adversely affected;
- whether it was possible for other market participants to respond to the conduct and;
- whether the activity represented an appropriate balance between risk and reward.

The MSA concluded its investigation in the later part of 2007 and decided not to pursue enforcement action. Although the file is closed, the MSA remains interested in the bounds of acceptable offer behaviour, particularly during periods of scarcity. It is reasonable to anticipate that the new ISO rules relating to market offers, and the continuing discussions being led by the Alberta Department of Energy in respect of the recent white paper, may have a significant impact on market participant conduct in this area.

Investigation into OTC trading activity in the ancillary services market

On May 14, 2007, the MSA announced that it had initiated an investigation into certain trading activity in the ancillary services market. The investigation is concerned with the sale and purchase of ancillary service products which were negotiated in the Over-the-Counter market and then posted to the Watt Exchange. The MSA is concerned the trading activity may have a negative impact on the price signal, may not represent a level playing field for market participants and may restrict market participants ability to compete. The MSA expects to complete this investigation in 2008.

Appendix A – Wholesale Energy Market Metrics

Table 1 - Pool Price Statistics

	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
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%
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%
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%
Oct - 07	64.74	83.35	38.97	77.60	120%
Nov - 07	54.24	70.09	34.48	51.72	95%
Dec - 07	66.28	84.67	44.89	79.03	119%
2007	66.95	86.58	41.67	103.73	155%
2006	80.79	104.99	49.67	119.41	148%

1 - Standard Deviation of hourly pool prices for the period

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

Figure 1 – Pool Price Duration Curves

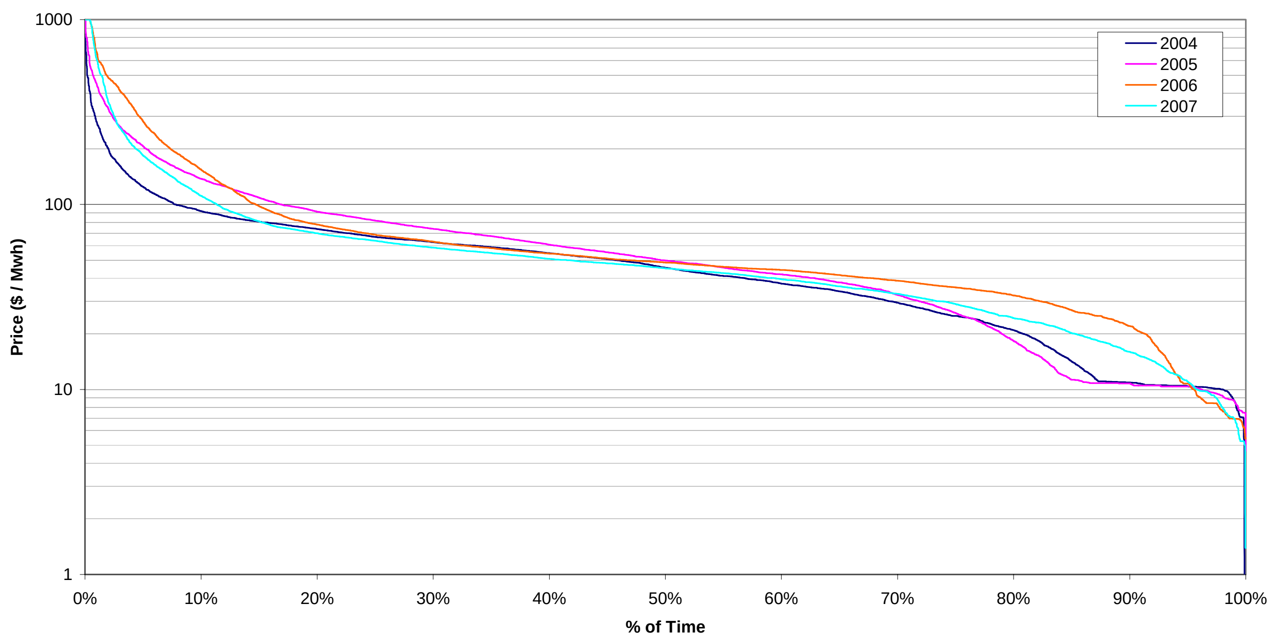


Figure 2 – Pool Price with Pool Price Volatility

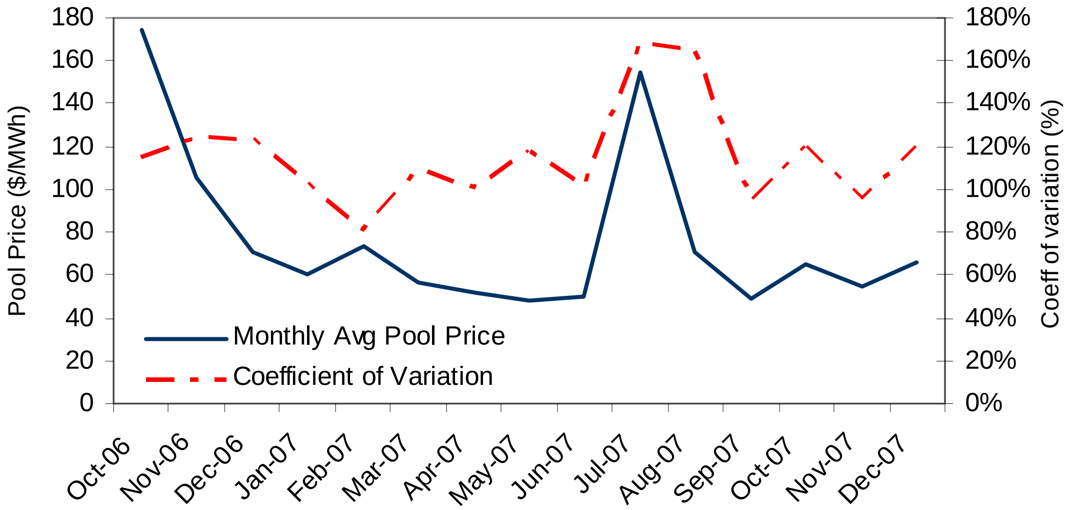


Figure 3 - Wholesale Electricity Price with AECO Gas Price

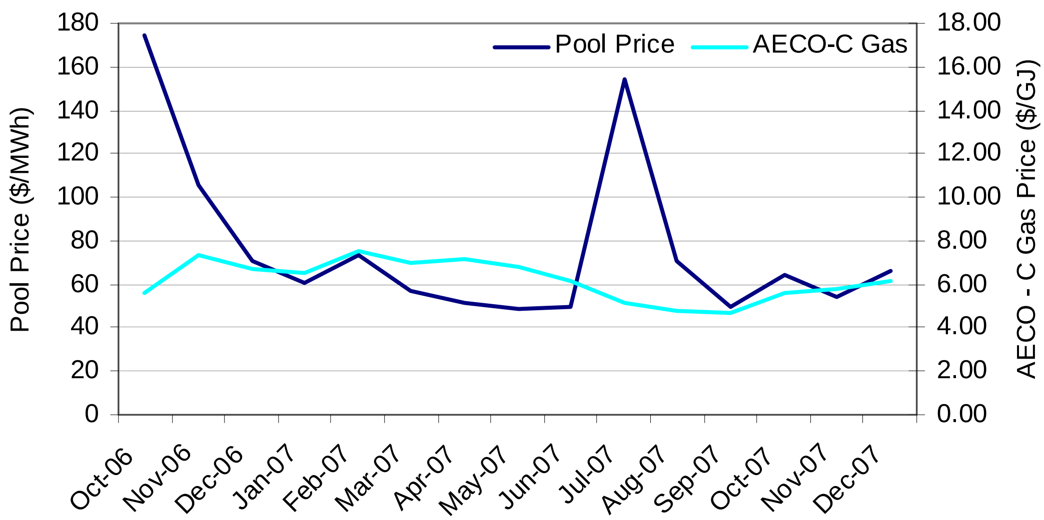


Figure 4 - Price Setters by Participant (All Hours)

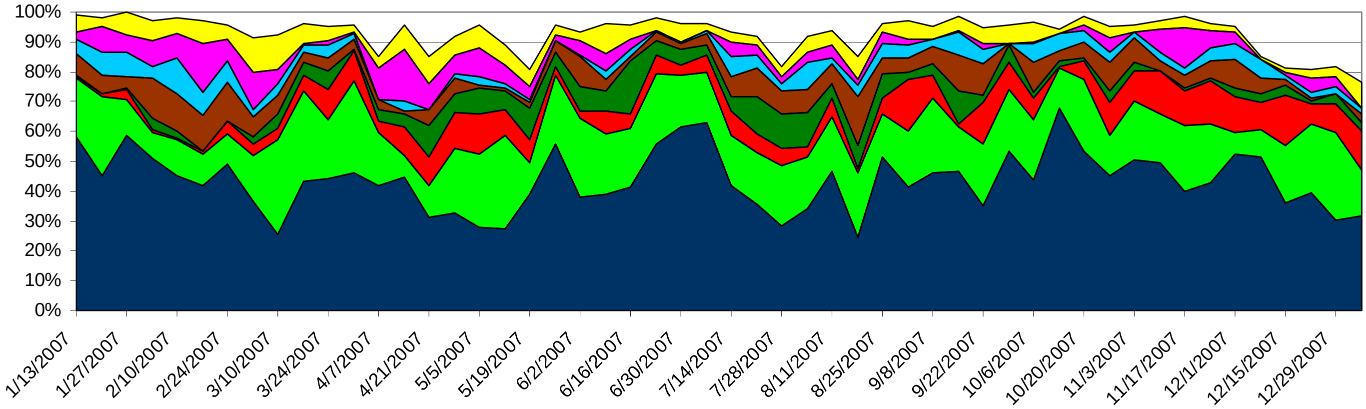


Figure 5 - Price Setters by Fuel Type (All Hours)

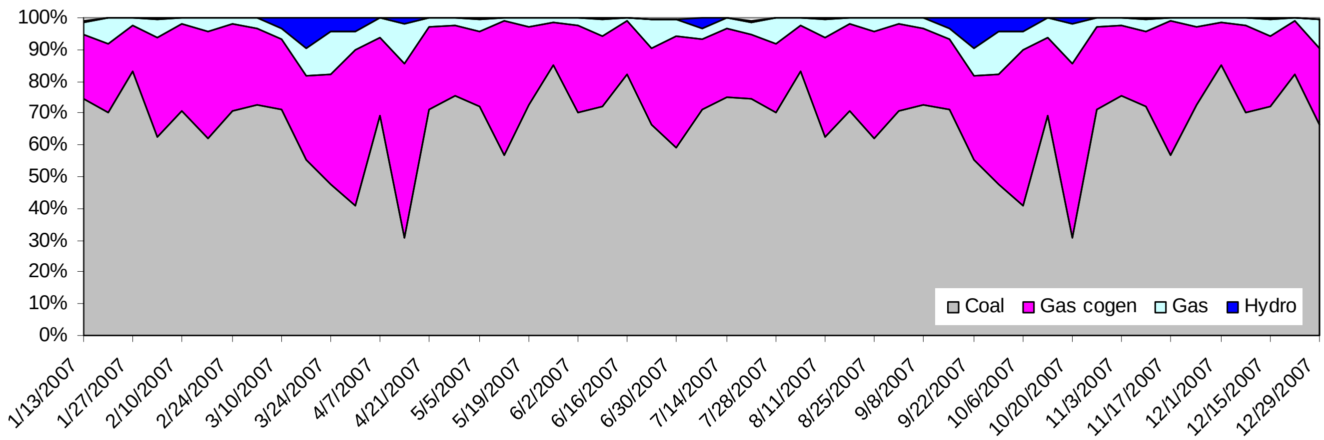


Figure 6 – Heat Rate Duration Curves (All Hours)

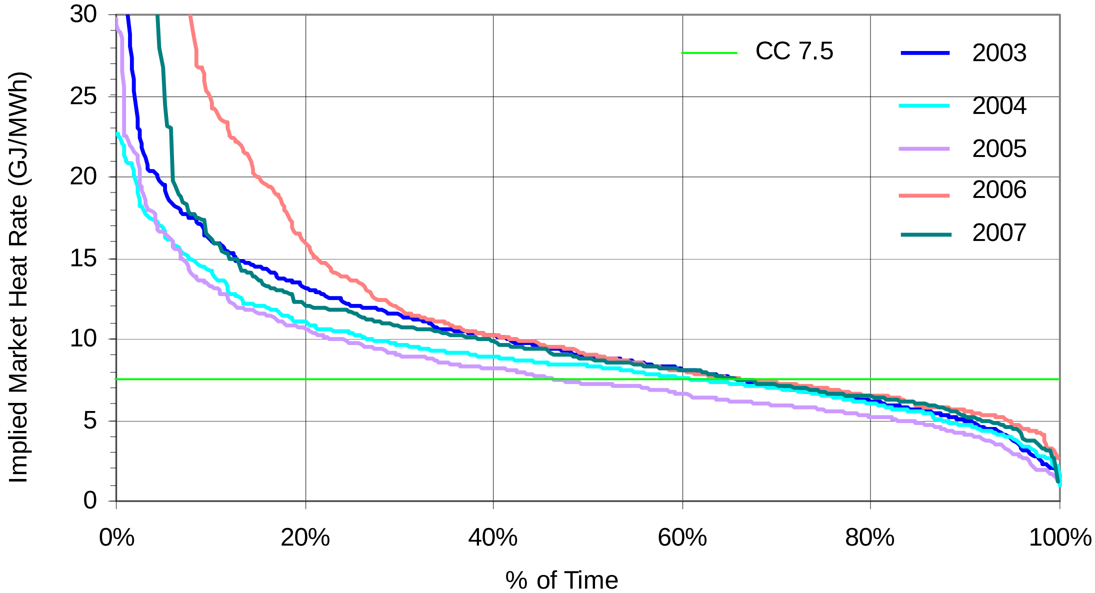


Figure 7 - Implied Market Heat Rates (2007)

Month	On-Peak	Off-Peak	All Hours
January	11.3	6.3	9.3
February	11.2	7.8	9.8
March	10.1	5.1	8.1
April	9.7	3.7	7.2
May	10.0	3.1	7.2
June	10.9	3.8	8.2
July	41.8	11.8	30.7
August	19.5	6.7	14.4
September	12.3	7.4	10.5
October	14.8	6.6	11.5
November	11.7	5.7	9.4
December	13.8	6.8	10.8
Average	14.8	6.2	11.4

Figure 8 – PPA Total Outages by Quarter

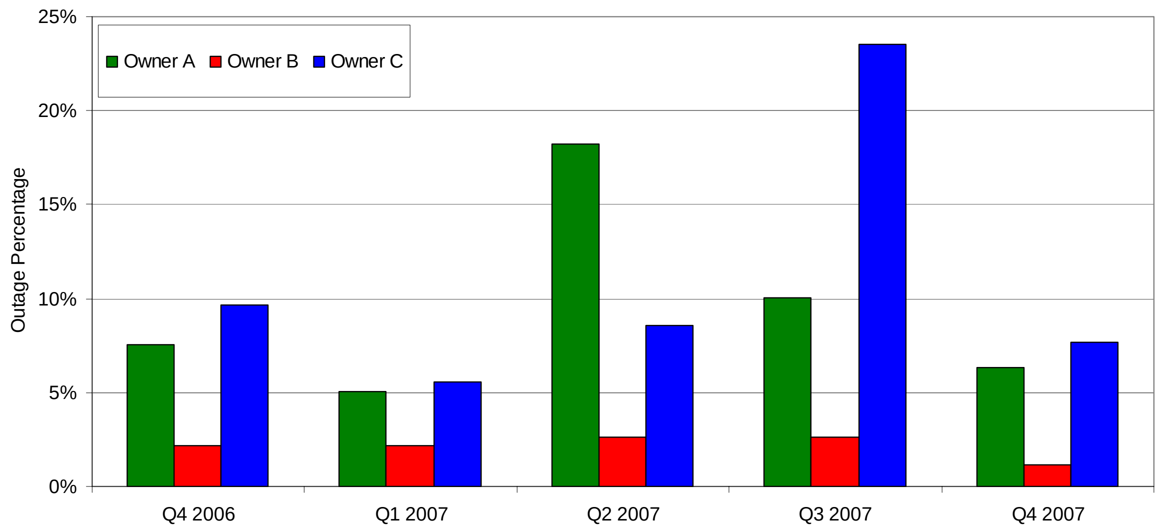


Table 2 – Percentage of Unplanned Outages for PPA Units

	Q4/2007	Q3/07	Q2/07	Q1/07	2007	2006	2005	2004	2003	2002
Owner-A	**4.4%**	8.7%	6.0%	4.9%	**6.0%**	5.2%	5.0%	6.1%	4.9%	4.2%
Owner-B	**0.8%**	2.1%	2.6%	1.6%	**1.8%**	1.8%	5.4%	1.5%	1.5%	0.5%
Owner-C	**7.3%**	11.9%	4.4%	5.2%	**7.2%**	5.3%	6.5%	6.3%	5.7%	10.8%
PPA weighted average	**5.5%**	9.4%	4.6%	4.6%	**6.0%**	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 2005	Actual Availability 2005	Target Availability 2006	Actual Availability 2006	Target Availability 2007	Actual Availability 2007	Actual Availability Q4 2007
Owner-A	87%	90%	87%	93%	87%	90%	94%
Owner-B	89%	90%	89%	98%	89%	98%	99%
Owner-C	87%	88%	87%	89%	86%	89%	93%
PPA weighted Average	87%	89%	87%	91%	87%	94%	94%

APPENDIX B – TIE LINE METRICS

Table 4 – 2007 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)
January	47,144	133,086	-85,942	28,664	7,649	21,015	75,808	140,735	-64,927
February	41,148	133,141	-91,993	9,488	10,623	-1,135	50,636	143,764	-93,128
March	152,322	22,726	129,596	26,282	10,920	15,362	178,604	33,646	144,958
Q1 Total	240,614	288,953	-48,339	64,434	29,192	35,242	305,048	318,145	-13,097
April	65,911	38,055	27,856	40,827	13,361	27,466	106,738	51,416	55,322
May	62,700	55,752	6,948	43,556	7,143	36,413	106,256	62,895	43,361
June	77,101	59,831	17,270	43,857	402	43,455	120,958	60,233	60,725
Q2 Total	205,712	153,638	52,074	128,240	20,906	107,334	333,952	174,544	159,408
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
October	63,785	66,851	-3,066	57,818	2,474	55,344	121,603	69,325	52,278
November	43,714	127,069	-83,355	50,262	8,662	41,600	93,976	135,731	-41,755
December	74,011	93,998	-19,987	25,928	11,024	14,904	99,939	105,022	-5,083
Q4 Total	181,510	287,918	-106,408	134,008	22,160	111,848	315,518	310,078	5,440
2007 Total	**917,230**	**884,729**	**32,501**	**540,113**	**87,591**	**452,522**	**1,457,343**	**972,320**	**485,023**

Note: Import and Export figures shown above are relative to Alberta ie: BC imports means import volumes flowing to Alberta from BC

Figure 9 – 2007 Market Shares of Importers and Exporters

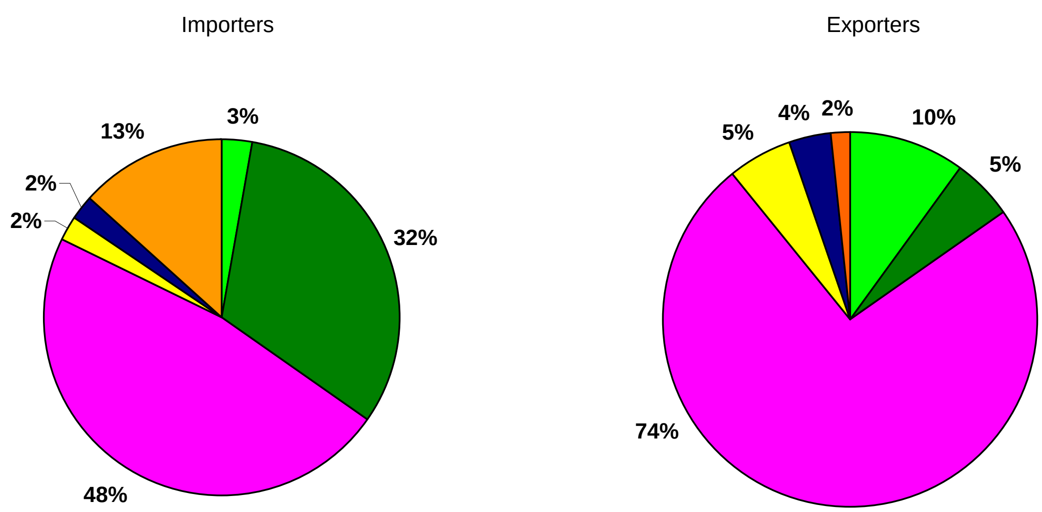


Figure 10 – 2007 Tie Line Utilization

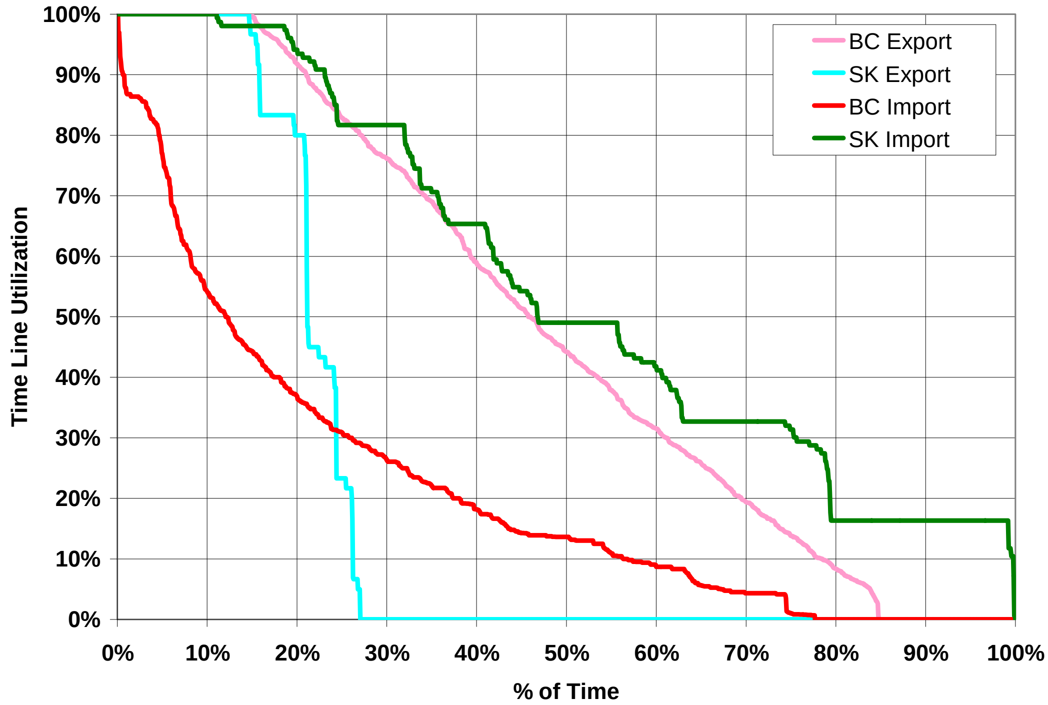


Figure 11 - Imports with Trade-weighted Prices

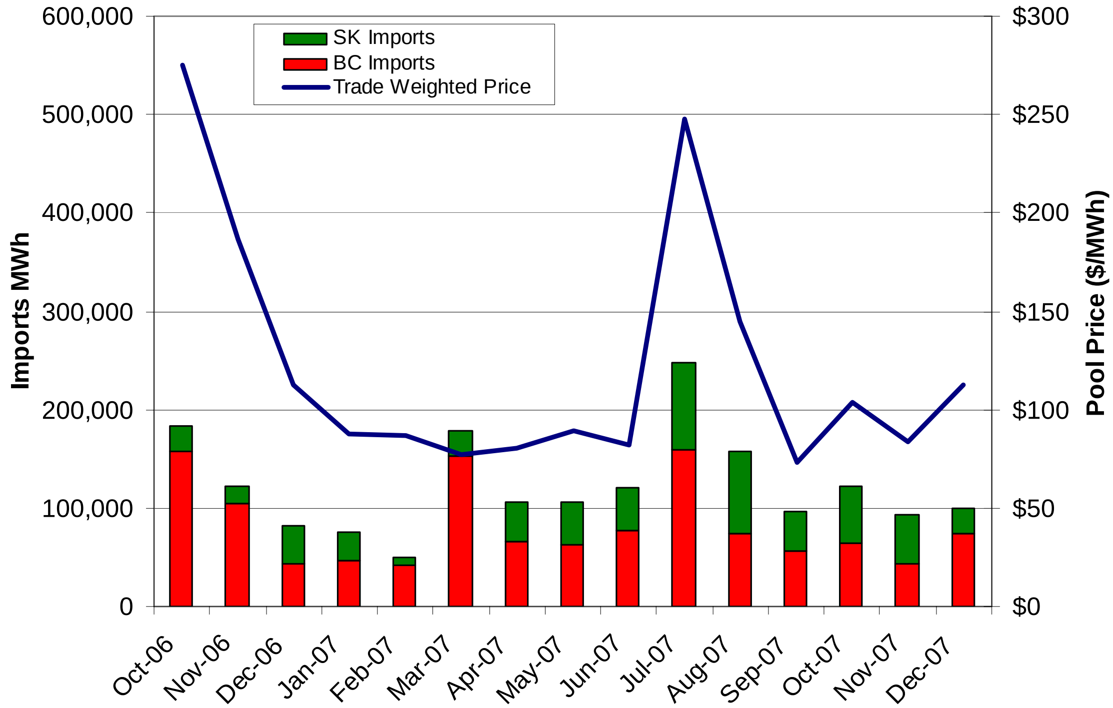


Figure 12 - Exports with Trade-weighted Prices

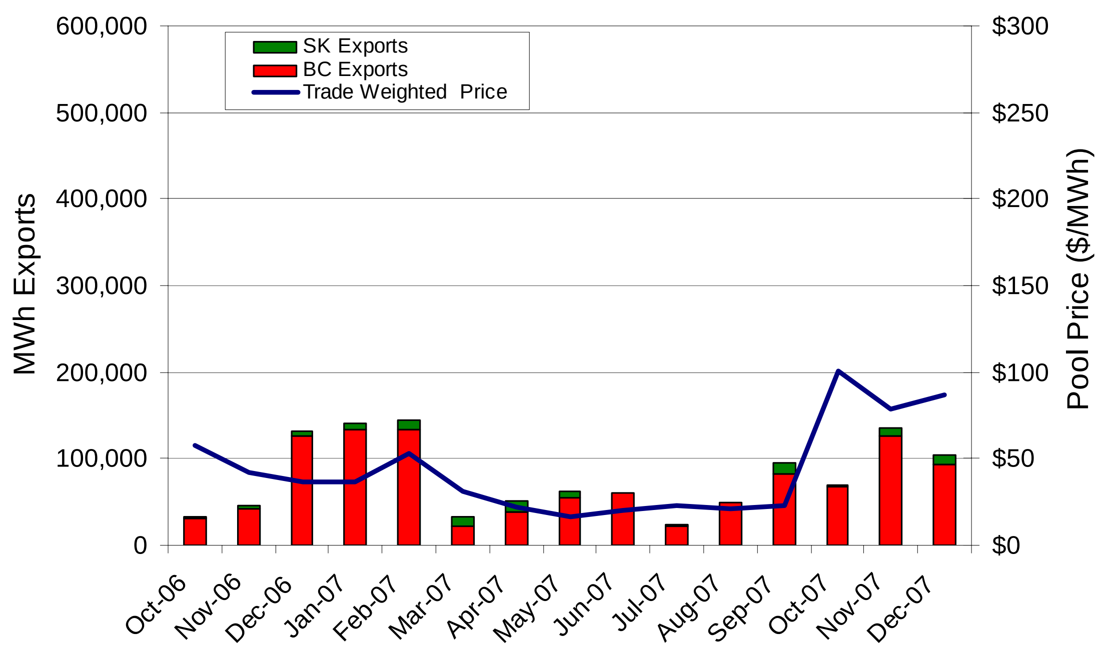


Figure 13 - On-Peak Prices in Other Markets

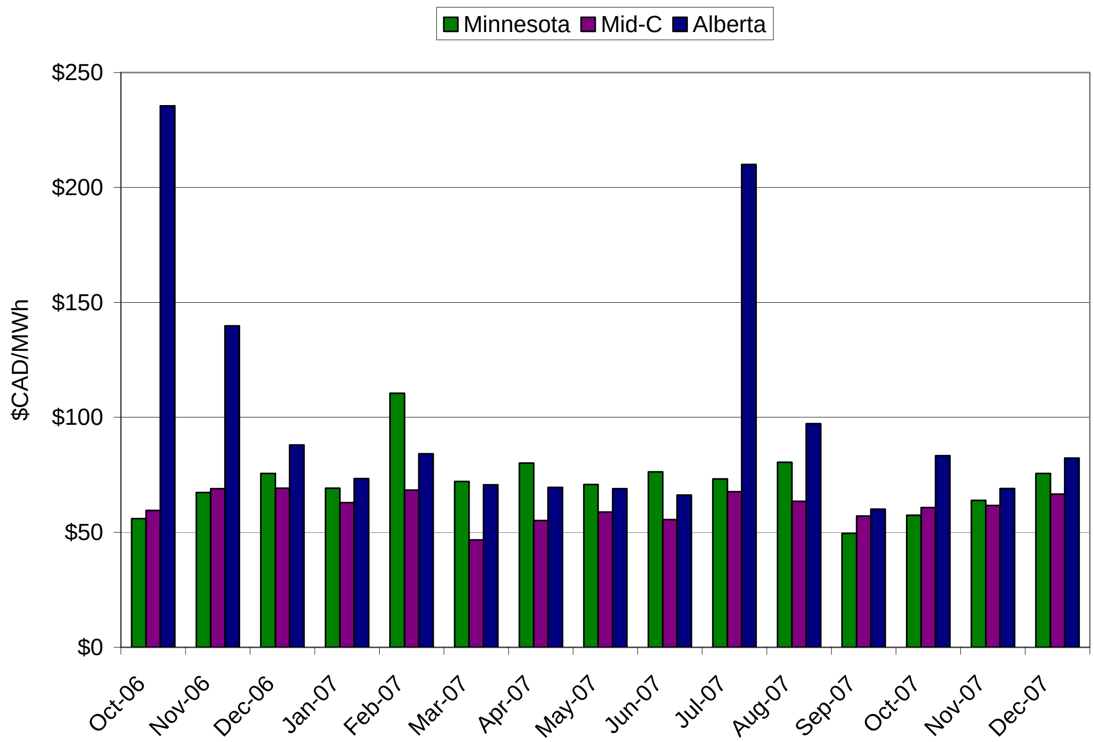
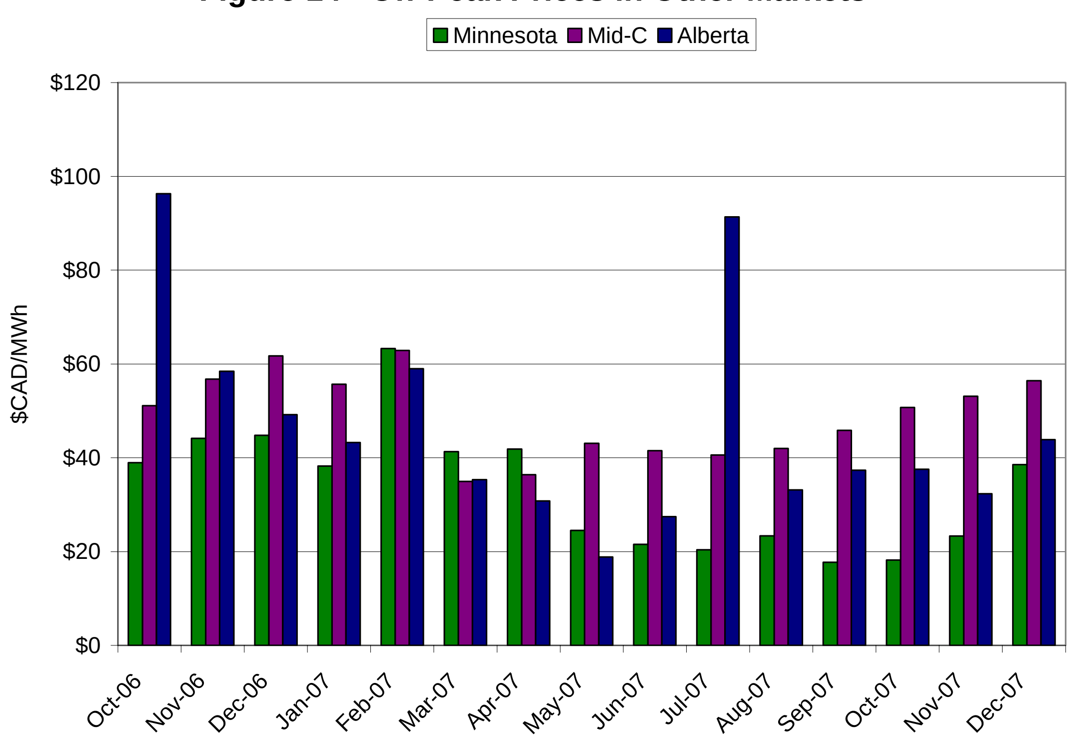


Figure 14 - Off-Peak Prices in Other Markets



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)

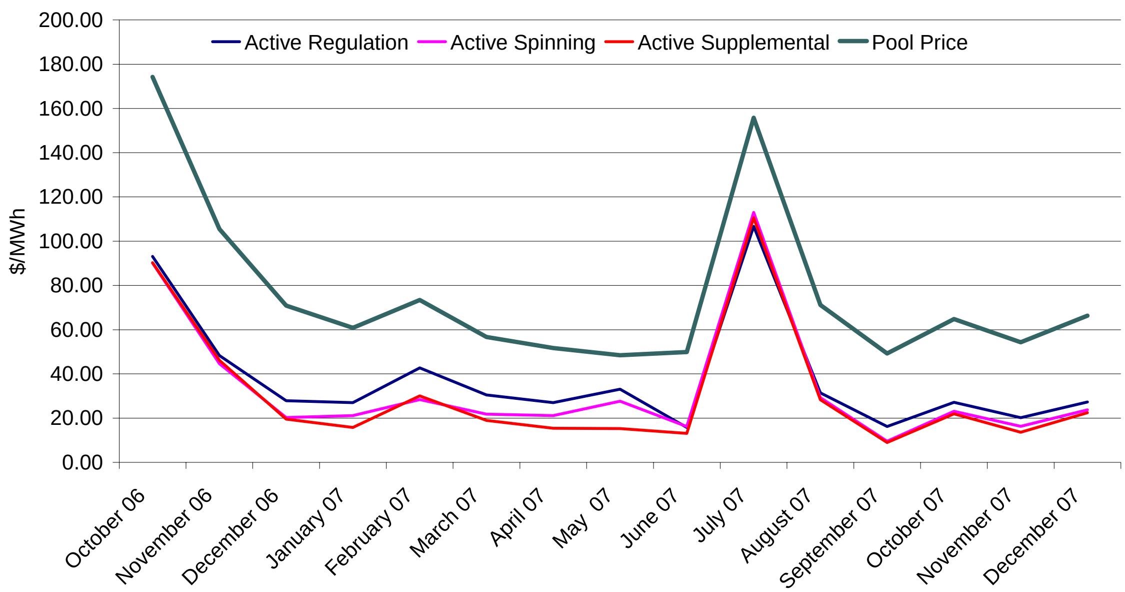


Figure 16 - Standby Premiums - All Markets (Watt-ex and OTC)

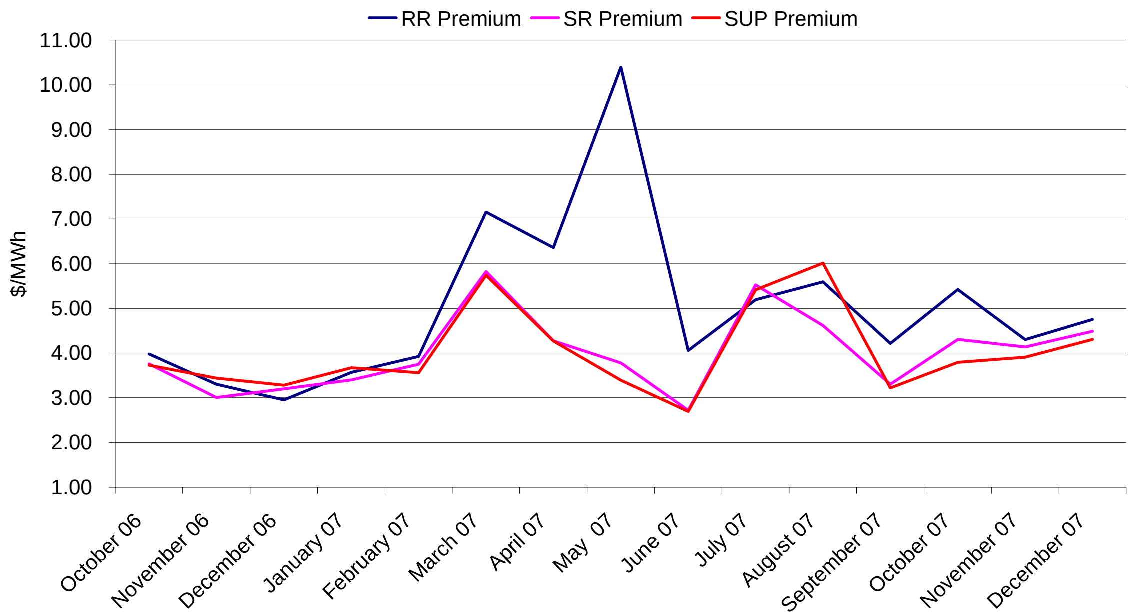


Figure 17 – Activation Prices – All Markets (Watt-ex and OTC)

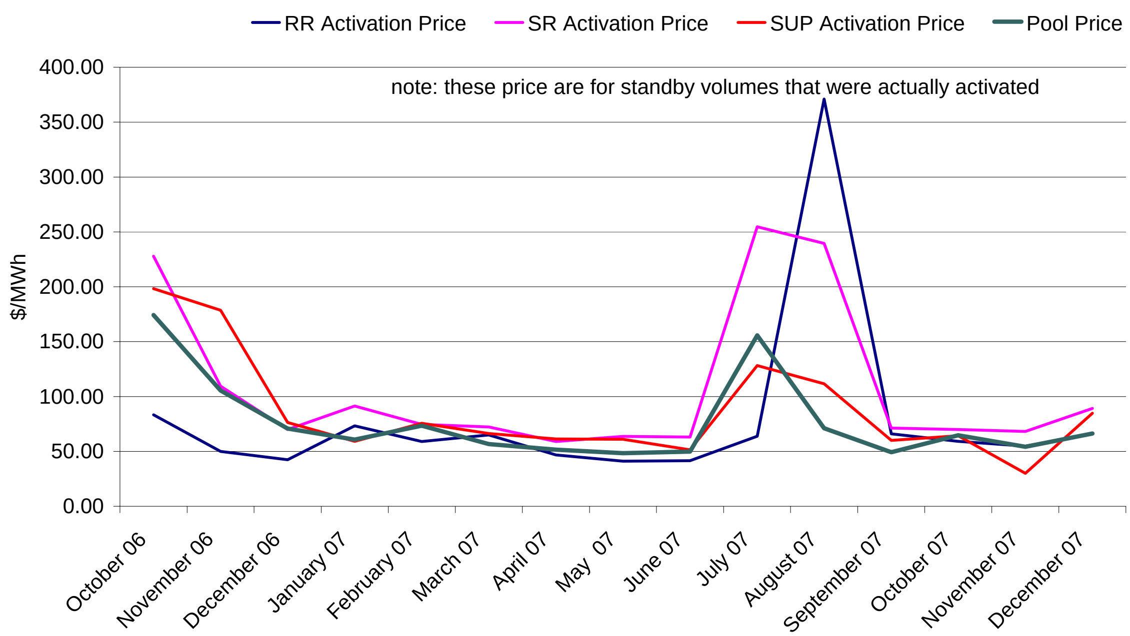


Figure 18 - Standby Activation Rates

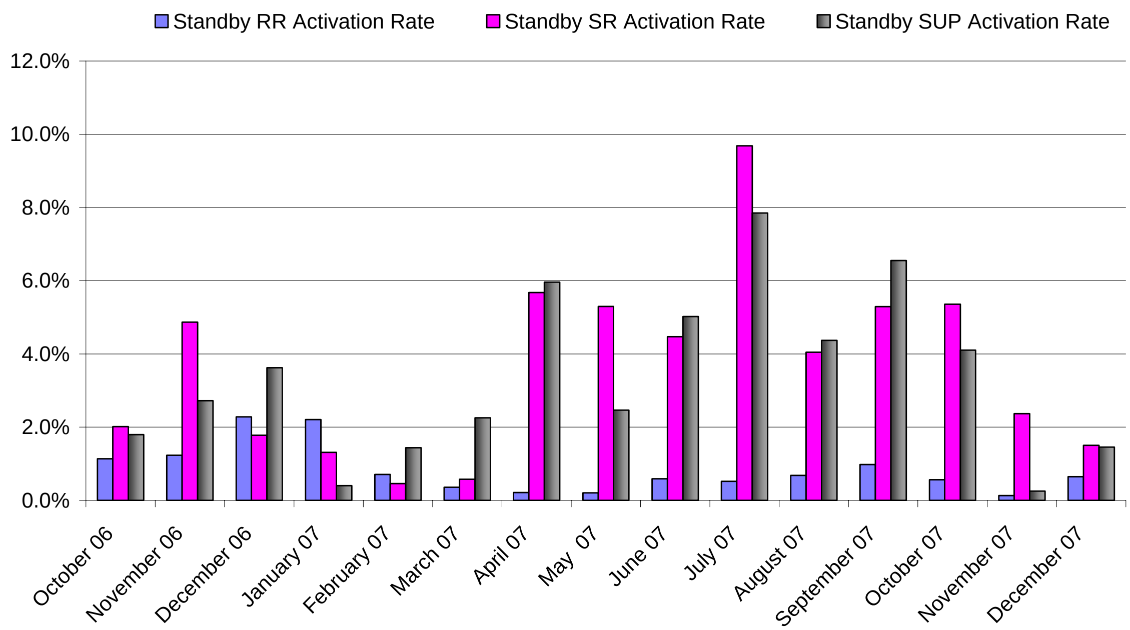


Figure 19 - OTC Procurement as a % of Total Procurement

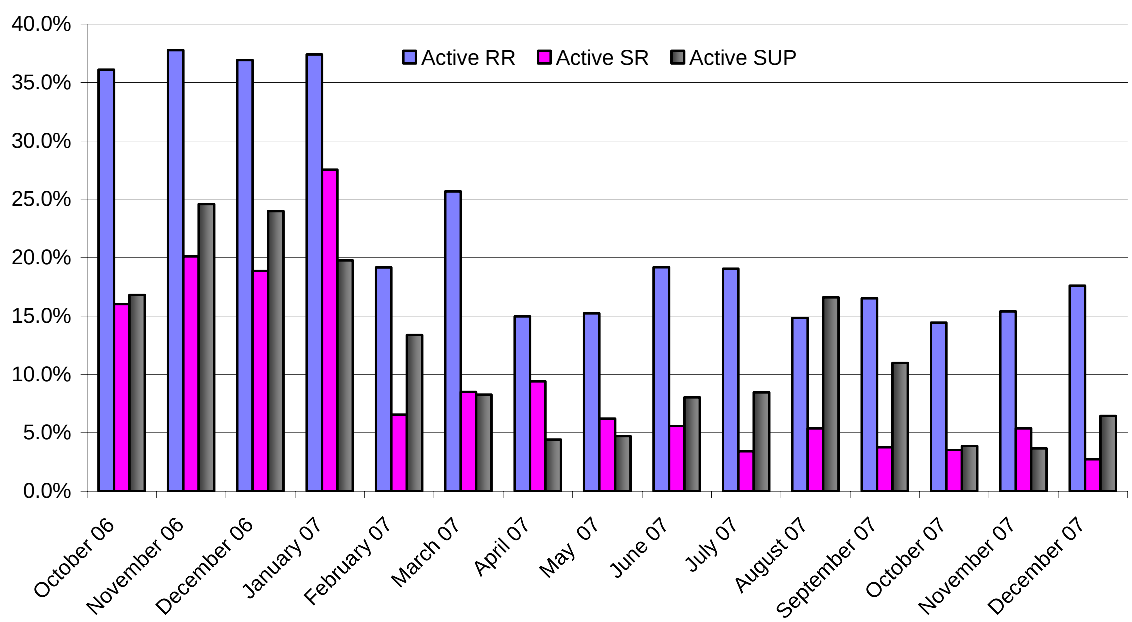


Figure 20 - Active Regulating Reserve Settlement by Market

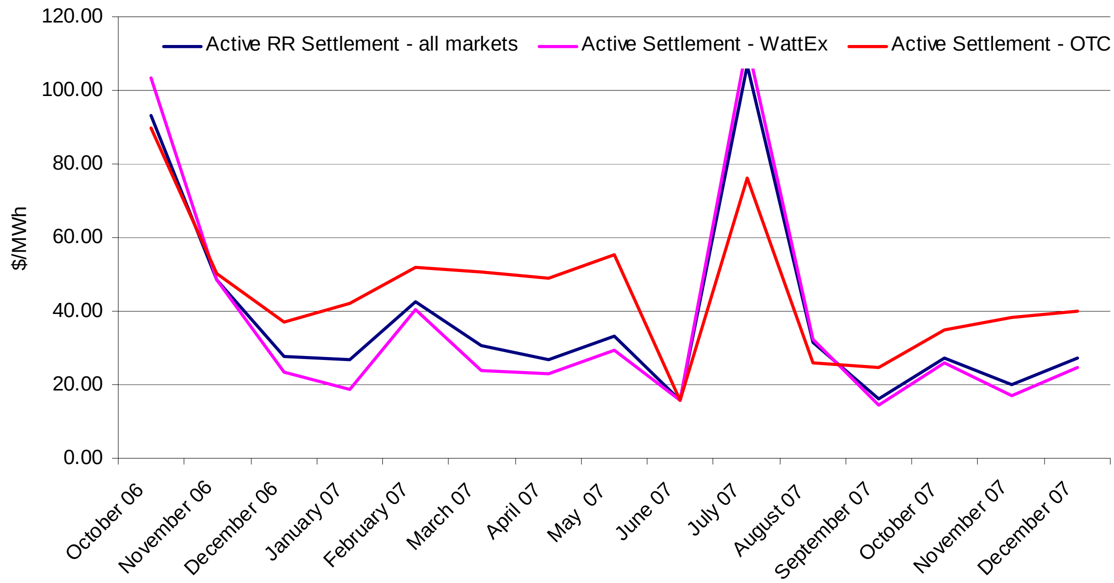


Figure 21 - Active Spinning Reserve Settlement Price by Market

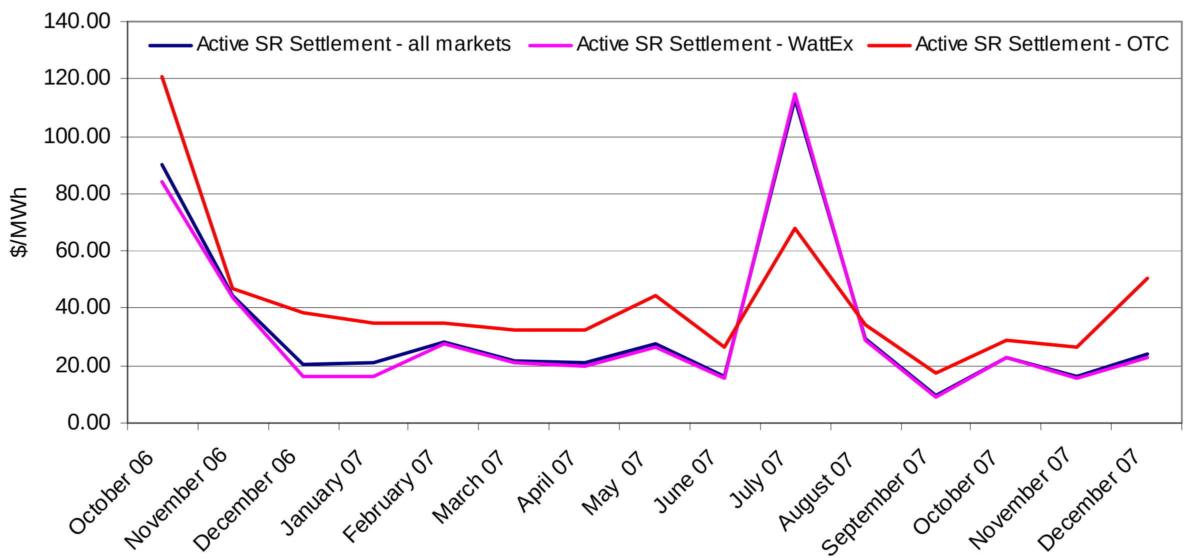


Figure 22 - Active Supplemental Reserve Settlement Price by Market

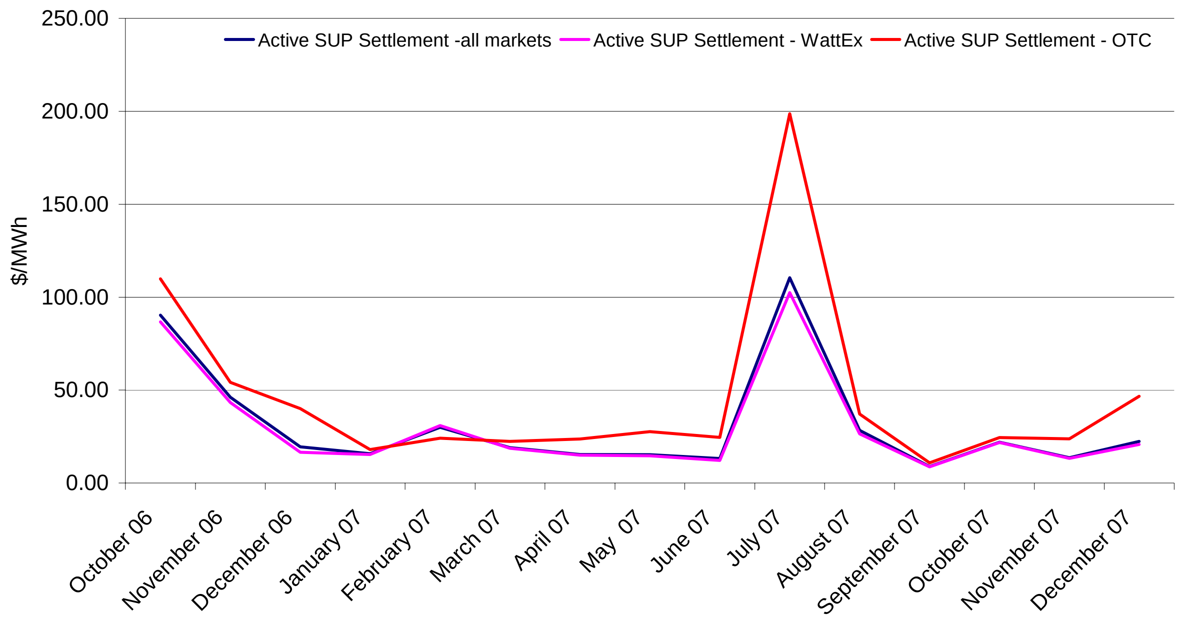


Figure 23 – Active Regulating Reserve Market Share by Fuel Type

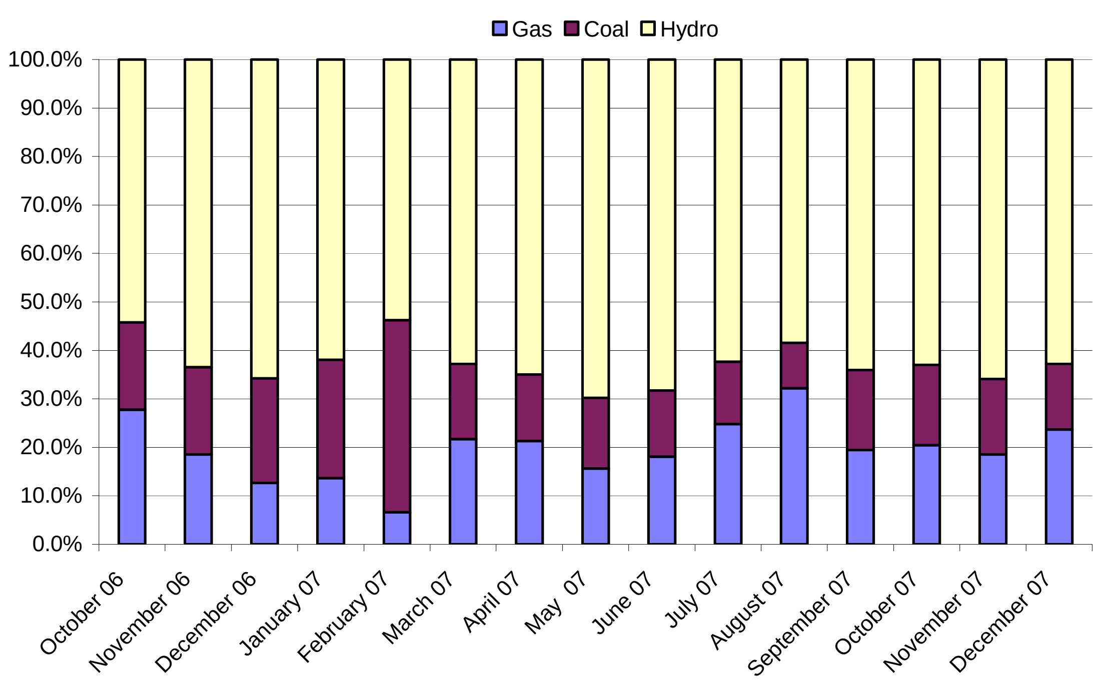


Figure 24 – Active Spinning Reserve Market Share by Fuel Type

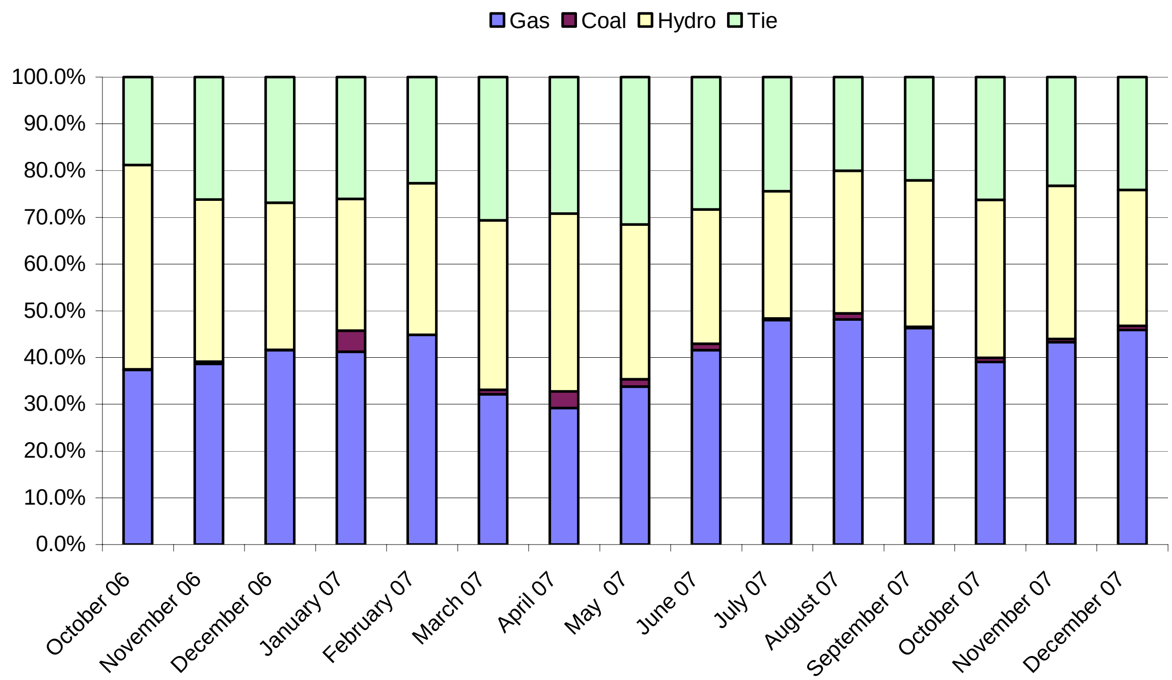
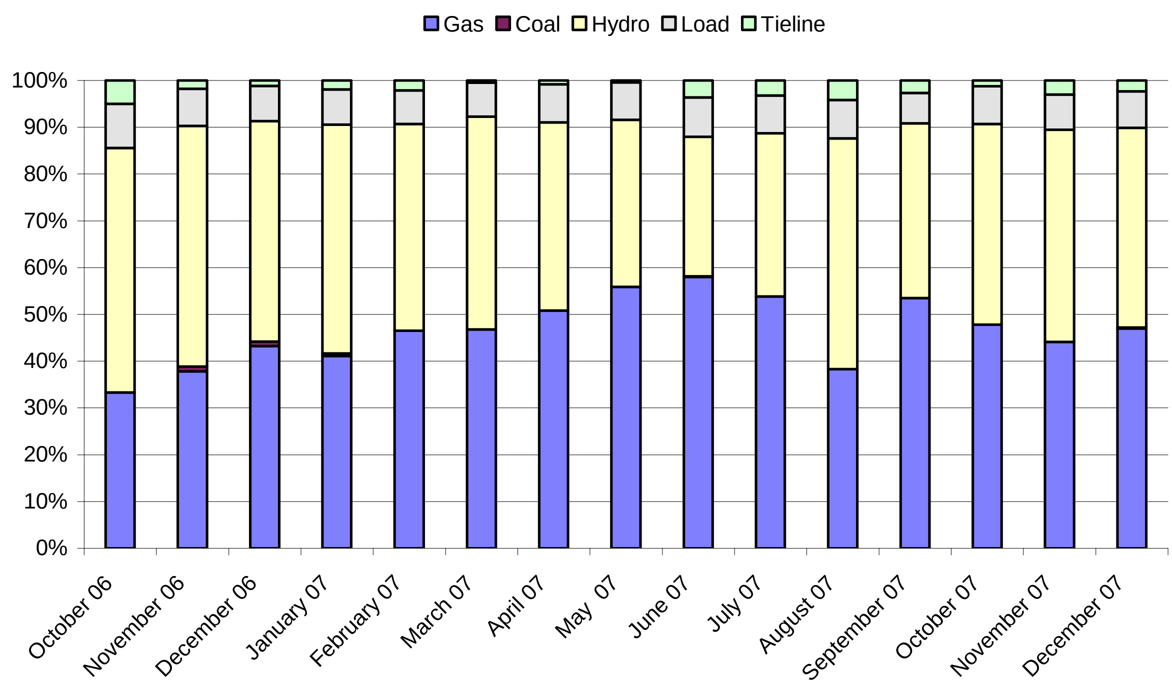


Figure 25 – Active Supplemental Reserve by Fuel Type



APPENDIX D – RETAIL MARKET METRICS

Figure 26 – Market Share of Retailers by Load

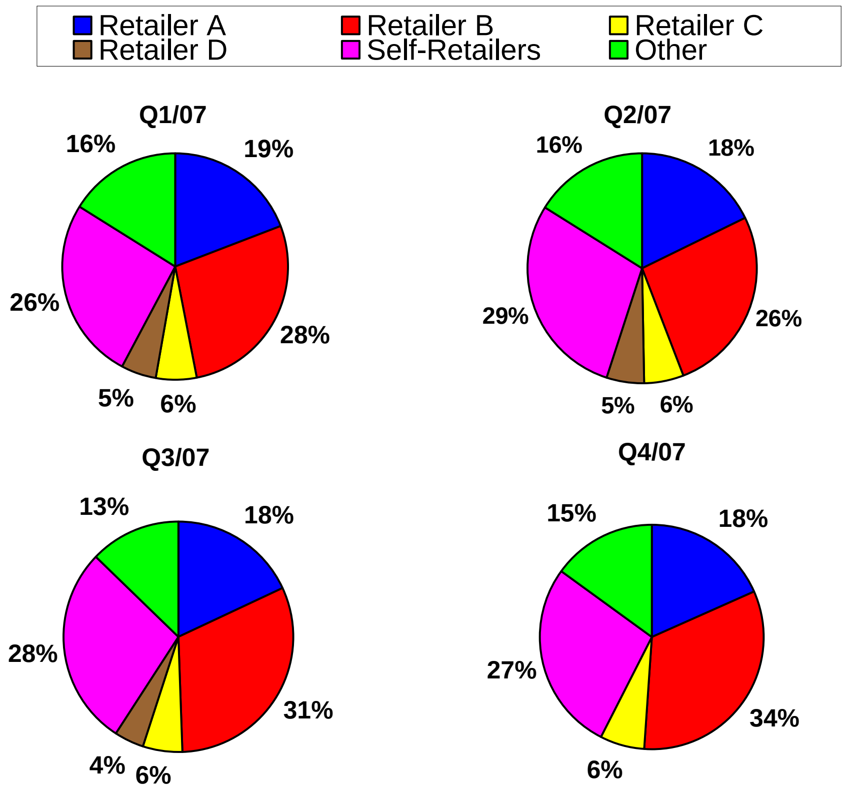


Figure 27 – Market Share of Retailers by Customer Class

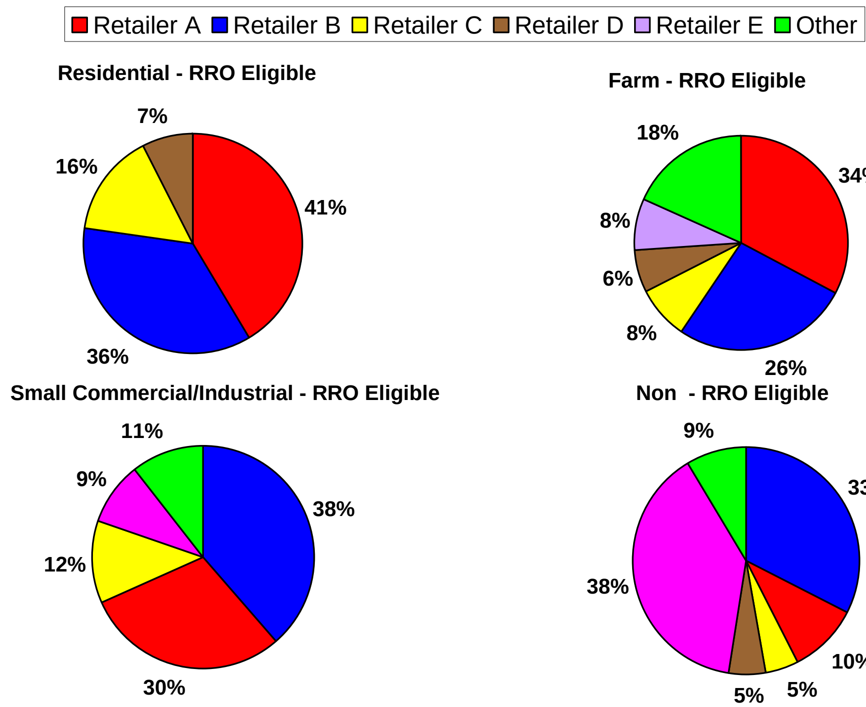


Figure 28 – Change in Market Share by Category

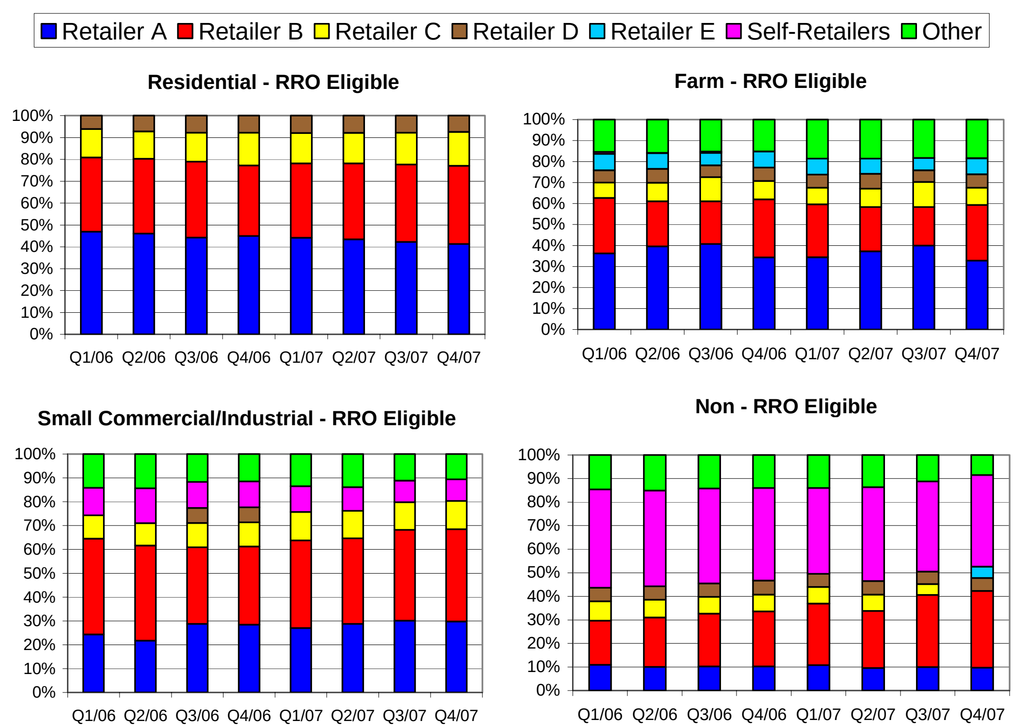


Figure 29 – Progression of Eligible Sites Switching off RRO

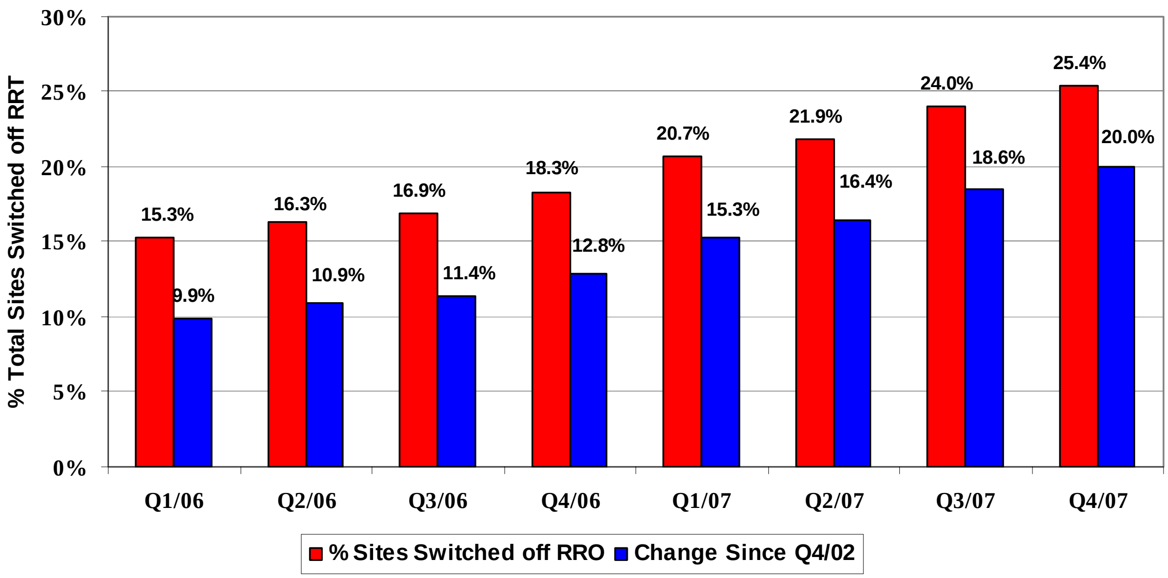
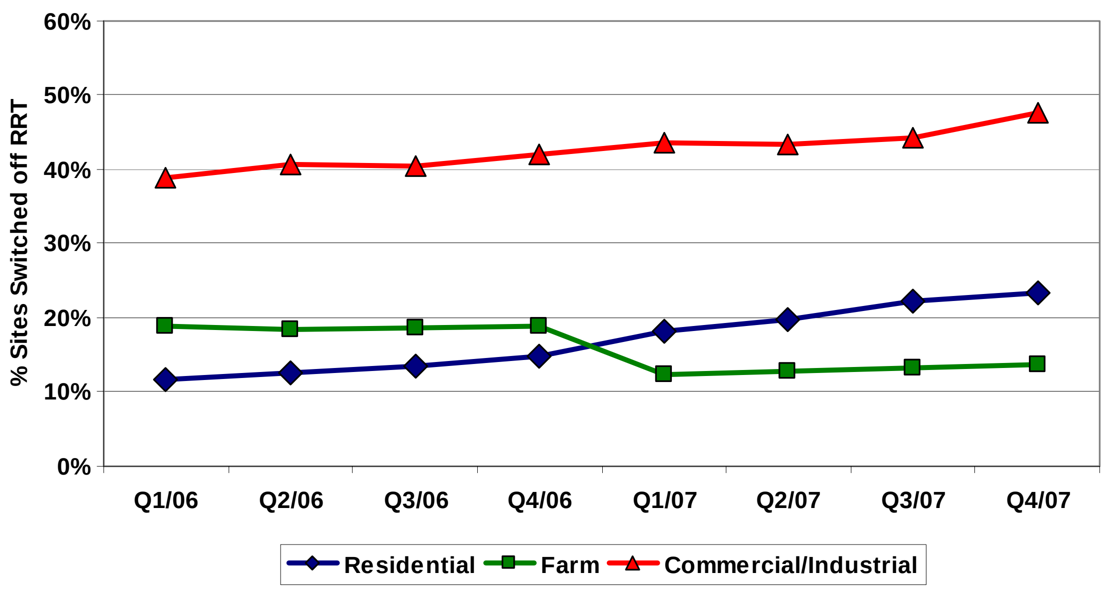


Figure 30 – Progression of Eligible Sites Switching off RRO by Customer Type



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 5 – PFEC and PFAM Tracking (by Quarter)

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q4/07	171	47	168	35	15	NA
Q3/07	19	466	254	60	171	NA
PFAM						
Q4/07	31	51	40	21	21	(86,692)
Q3/07	85	76	94	36	31	(5,008,848)

Table 6 – Summary of UFE Reasonable Exception Reports

Quarter	Outstanding	New	Resolved	Unresolved
Q4/07	554	22	0	576
Q3/07	447	107	0	554