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MSA REPORT

2005 Year in Review

28 March, 2006

MARKET SURVEILLANCE ADMINISTRATOR

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EXECUTIVE SUMMARY

In 2005 the headline news was dominated by the booming Alberta economy driven by the run-up in natural gas and oil prices. Over 2005, a generous supply of in-province electricity generation, much of it fuelled by coal and high efficiency cogeneration, provided some insulation against the impact of rising natural gas prices upon electricity prices. Wholesale electricity prices did increase in the second half of the year however, the forward prices for electricity in 2006 are trading near 2005 settlement levels despite continuing bullish prospects for both the Alberta economy and natural gas prices. The new record peak load was set in December at 9,580 MWh and the year-over-year average load increase was 1.8 percent. The annual market heat rate, a measure of the efficiency of generation, continued to decline year-over-year. For 2005, the heat rate was approximately 8.2 gigajoules per MWh, down from approximately 8.8 gigajoules per MWh in 2004.

The fundamentals of demand, market prices and fuel costs are being reflected in the choices made by generators. 2005 saw the official commissioning of new, high-efficiency, coal-fired generation at Genesee 3 and the retirement of older, less efficient natural gas-fired generation at Clover Bar and except for reliability use, at Rossdale.

Two-thousand-five was also a period in which to reflect upon the progress the province has made since restructuring of the electricity industry began ten years ago. In some areas it has been recognized that enhancements can be made, these are reflected in the “Market Policy Framework” paper released by the Department of Energy in June. As market ‘auditor’, the MSA did not participate actively in the policy discussions. We are very encouraged however that policy direction embodies the key themes articulated in our last annual report: keeping the playing field level; ensuring a high fidelity price signal; allowing competition to do the heavy lifting and fostering an information-rich environment.

Given the establishment of policy direction in the first half, the second half of 2005 focused on implementation considerations. The gradual introduction of market refinements – the first set of significant changes since 2001 – will make 2006 a year of transition.

In the coming year, the MSA will support participants’ confidence in the functioning of the market by providing analysis of the fundamentals underlying market signals. As we embark on market refinements, the MSA’s focus will be ensuring the clarity of expectations, fostering a culture of compliance, and in so doing, building the confidence of consumers and investors.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

Fidelity of the market price signal continued to be a key focus for the MSA in 2005. It is the belief of the MSA that the faithfulness of the market price in reflecting market fundamentals facilitates an efficient and competitive market.

The average wholesale market price of electricity in 2005 was $70.36/MWh which was up from $54.59/MWh the year before. **Table 1** shows that monthly average prices held in the $45-$55 range through the first 6 months of the year, then climbed considerably in the second half of the year. Pool prices were particularly elevated in Q4/05, averaging over $115/MWh causing the yearly average Pool price to increase from $54.79/MWh at the end of Q3/05 to $70.36/MWh at the end of the year. Higher market prices during the second half of the year were driven to a large extent by the significant run-up in gas prices with spot prices rising from a monthly average of $6.96/GJ in June to an average of over $11.00/GJ in October. The influence of high gas prices on offer prices in the market was exacerbated in Q4/05 by significant planned and forced coal outages which coincided with the seasonal run-up in system demand setting a new annual peak in December. All of these factors contributed to the highest monthly average prices observed since early 2001.

The price duration curves in **Figure 1** reflect that 2005 saw 793 more hours than 2004 in which Pool price exceeded $100.00/MWh. Looking at these prices relative to fuel costs adds some perspective as implied market heat rates fell once again relative to the prior year.

Figure 2 shows Pool price together with price volatility as represented by the coefficient of variation. The initially high price volatility observed in January, abated through Q1/05 and into Q2/05 but spiked in June. This is attributed to reduced coal availability as a result of maintenance outages typically planned in early summer. While prices were volatile in June, the monthly average price was $55.14/MWh.

Table 1 - Pool Price Statistics

2005	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Jan - 05	50.24	54.73	45.02	66.94	133%
Feb - 05	42.67	48.49	34.90	33.65	79%
Mar - 05	44.78	49.60	38.10	36.69	82%
Apr - 05	50.08	57.68	39.64	42.90	86%
May - 05	49.16	63.68	32.29	50.50	103%
Jun - 05	55.14	71.16	33.21	71.62	130%
Jul - 05	37.75	45.93	28.23	35.04	93%
Aug - 05	88.33	106.26	63.50	74.13	84%
Sep - 05	74.30	104.67	36.34	63.90	86%
Oct - 05	121.95	142.86	95.51	107.82	88%
Nov - 05	124.79	152.99	89.55	148.10	119%
Dec - 05	103.03	141.57	54.16	97.49	95%
2005	**70.36**	**86.86**	**49.28**	**82.39**	**117%**
2004	54.59	64.54	41.88	53.53	98%

Figure 1 – Pool Price Duration Curves

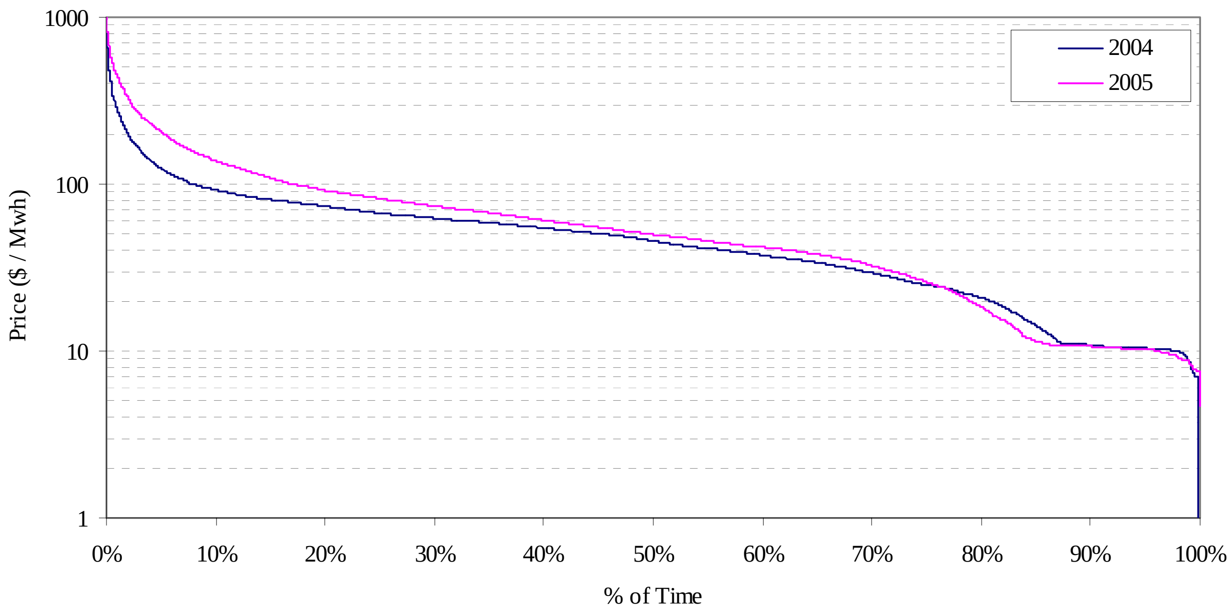
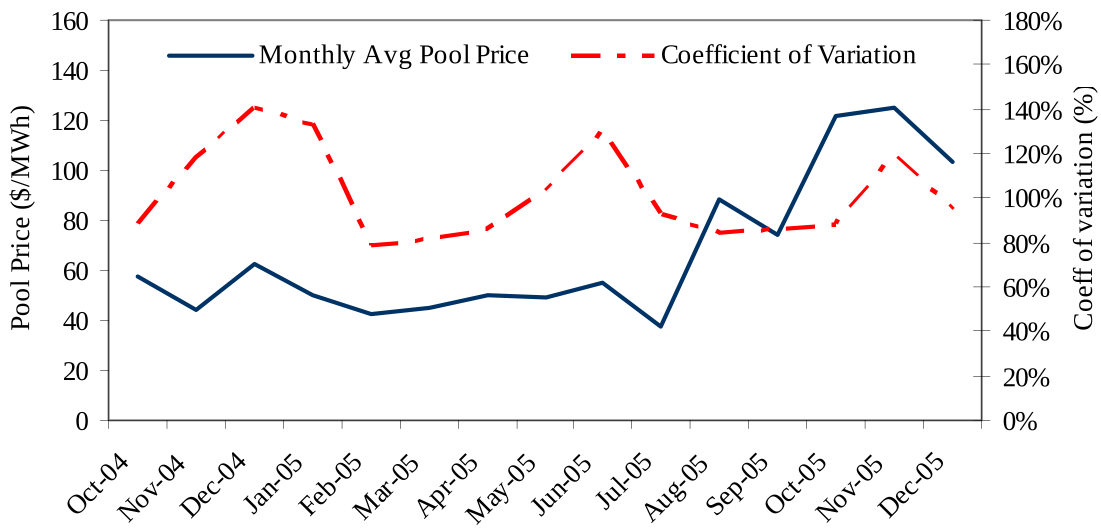


Figure 2 – Pool Price with Pool Price Volatility

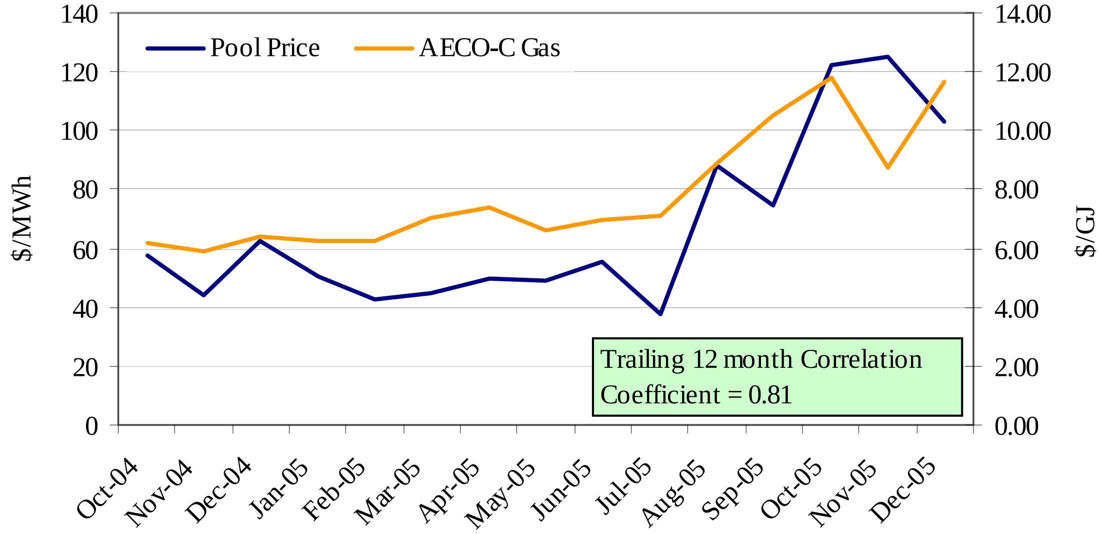


1.2 Natural Gas Prices

Alberta gas prices increased substantially in 2005 averaging $8.27/GJ as compared to $6.19/GJ in 2004. While average gas prices for 2005 increased by about 33%, **Figure 3** shows that within the year, prices monthly average prices rose from the low $6.00/GJ range to nearly $12.00/GJ. This substantial run-up occurred through the second half of the year and was driven largely by supply concerns as a result of catastrophic storms in the Gulf region, and were supported by lofty crude prices.

The trailing 12 month correlation of electricity prices and gas prices was a strong 0.81 at the end of 2005 as compared to 0.66 at the end of 2004. This correlation, while strong in the current 12 month window, fluctuates widely on a short term basis however, over longer periods, this co-movement is more evident.

Figure 3 - Wholesale Electricity Price with AECO Gas Price



1.3 Price Setters

The MSA monitors to ensure that marginal price setting activity is reasonably distributed among participants and not dominated by any one or two parties in the market. **Figure 4** (anonymously) features the participants who most frequently set the system marginal price (SMP) through 2005 relative to the leading price setters in 2004. In 2005, price setting frequency showed greater dispersion as the 5 most frequent price setters were on the margin 66% of the time which was down from 73% of the time last year. In 2005, the most frequent price setter was on the margin 17% of the time at a weighted average SMP of $16.03/MWh while in 2004, the leading price setter was on the margin 23% of the time at a weighted average SMP of $71.58/MWh.

With the redistribution of Sheerness PPA generation completed via the Balancing Pool's MAP III auction, and Genesee pending, the MSA will be looking to see that marginal price setting activity does not greatly concentrate as a result.

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

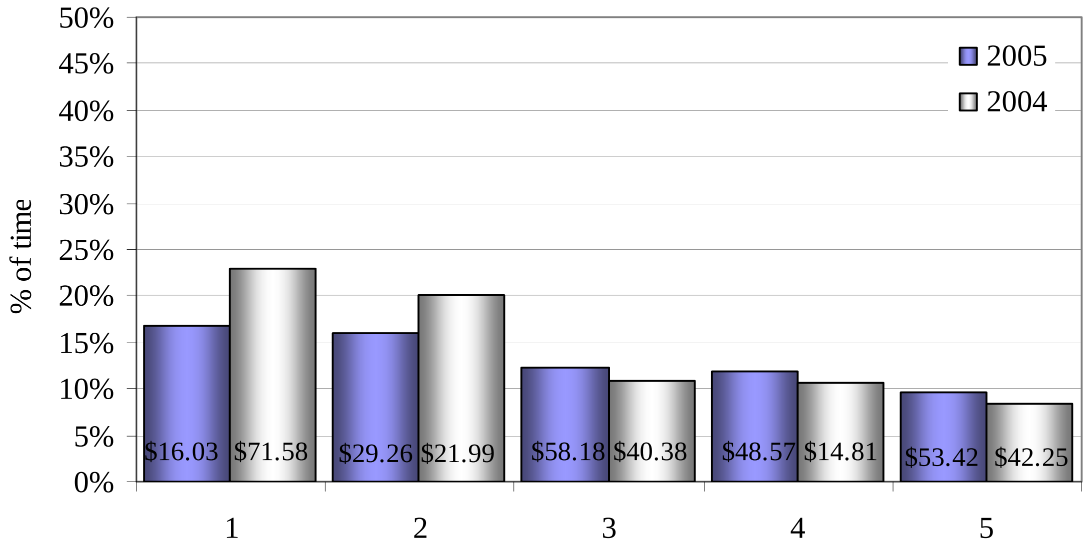
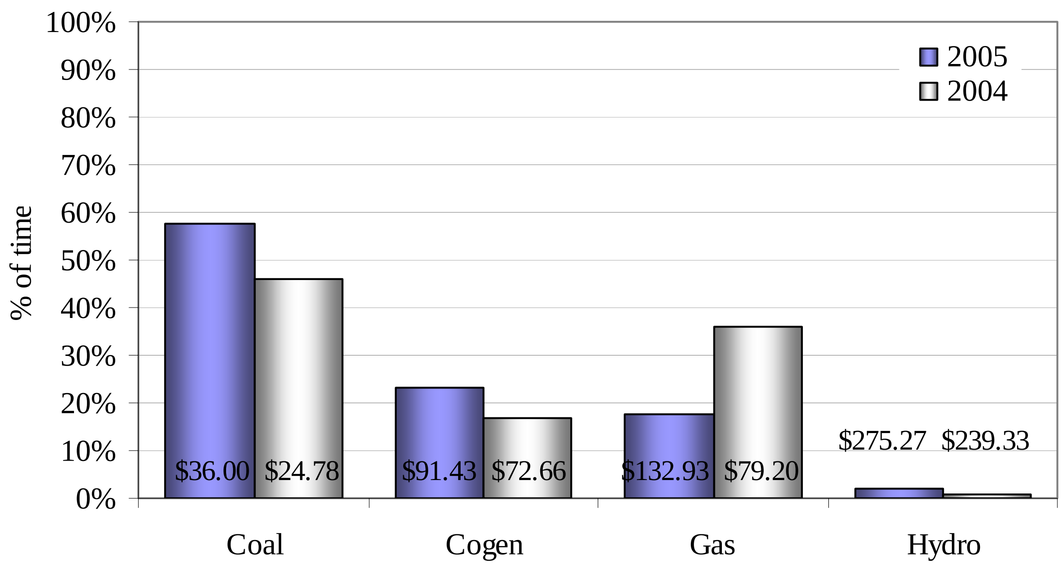


Figure 5 shows a similar price setting format on the basis of generator fuel type. The figure shows that coal units set system marginal price 57% of the time during 2005 but did so at a modest weighted average SMP of $36.00/MWh. All gas units combined (cogen & other gas) were on the margin 41% of the time overall in 2005 as compared to 53% of the time last year however, these units set a significantly higher weighted average SMP of $109.33/MWh vs $77.11/MWh in 2004.

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



1.4 Implied Market Heat Rate

While average Pool prices rose in 2005, the implied market heat rate declined once again year over year to 8.2 GJ/MWh from 8.8 GJ/MWh in 2004. This decline in implied heat rate in the context of rising electricity prices demonstrates the continued efficiency gains in the Alberta market and underscores that those efficiency gains have been masked to an extent by the considerable run-up in gas prices through 2005. **Figure 6** indicates that a gas generator with a thermal efficiency rating of 7.5 GJ/MWh would have met its variable cost of gas just 46% of the time in 2005 as compared to 65% of the time in 2004. **Table 2** provides a monthly look at implied market heat rate values on both an on-peak and off-peak basis. The data shows that the robust heat rates of October and November were driven significantly by off-peak prices as well as on-peak prices.

Figure 6 – Heat Rate Duration Curves (All Hours)

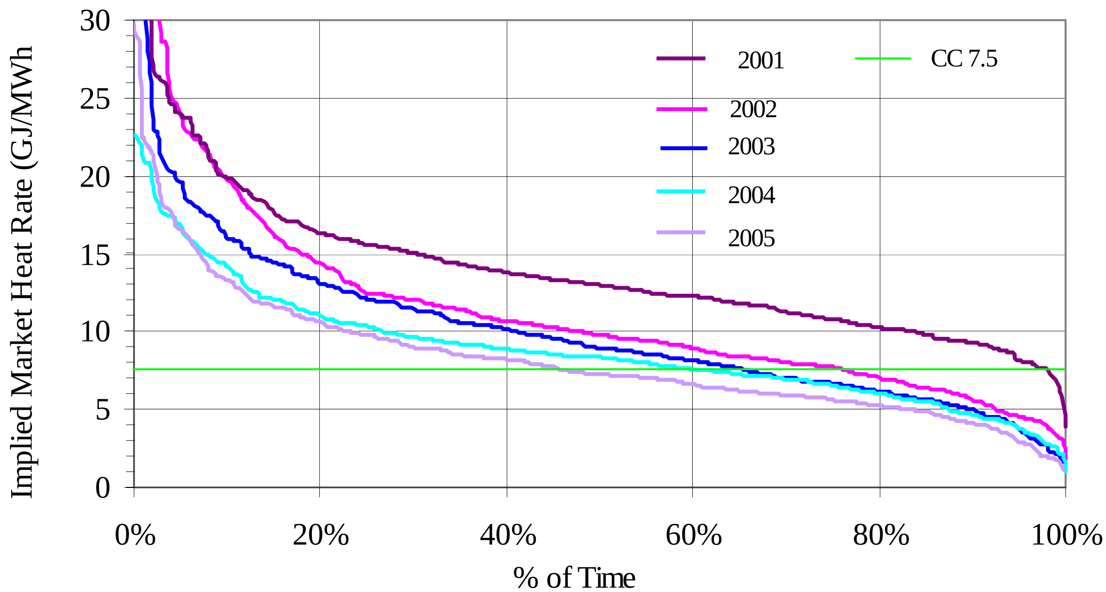


Table 2 – Monthly Average Implied Market Heat Rates (2005)

Month	On-Peak	Off-Peak	All Hours
January	8.8	6.3	8.0
February	7.7	5.5	6.8
March	7.0	5.2	6.3
April	7.8	5.0	6.8
May	9.6	4.6	7.4
June	10.0	4.3	7.8
July	6.4	3.4	5.3
August	11.9	6.7	9.9
September	9.9	3.4	7.1
October	12.2	7.6	10.5
November	17.3	8.1	14.1
December	11.8	4.4	8.6
Average	10.1	5.4	8.2

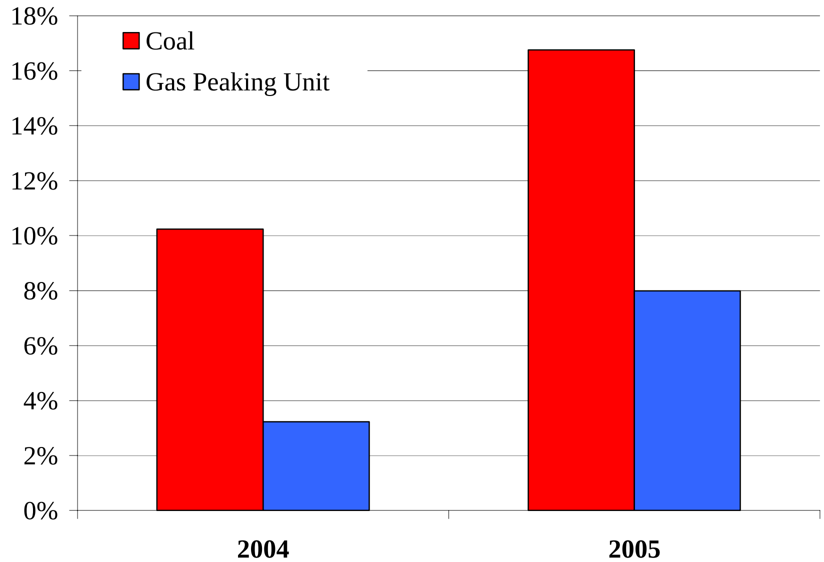
1.5 Net Returns

Expectations of future returns are an important signal for new investment. **Figure 7** shows an estimate of the annual return on capital cost that a typical base-load coal and peaking gas generator could have realized in 2004 and 2005. For both coal and gas generation, returns are estimated to have been higher in 2005 relative to 2004 largely attributed to higher Pool prices during Q4/05. The results shown are highly dependent on the assumptions made and therefore should be considered directional in nature.

For the purpose of this analysis, a base-load coal unit was assumed to be running in all hours at least at minimum stable generation. As well, the unit was assumed to have run at rated capacity in hours when Pool price exceeded variable cost. The case shown for gas assumes that the unit ran at capacity in all hours when Pool price exceeded the unit's variable cost. The basic cost assumptions are as set out in the MSA's April 2004 report entitled Economics of New Entry. For this analysis, we have applied 2006 system average loss factors in the determination of 2004 and 2005 returns for both generators – higher returns could be realized by selecting a location with lower system loss factors. As well, loss assumptions can have a large impact on return calculations so these examples have been selected to minimize the effect.

It may at first appear somewhat contradictory that the estimated returns for gas generation increased while aforementioned implied market heat rates declined once again relative to the prior year (see **Figure 6**). However, this is consistent since in our analysis, the peaking unit only selects to run during profitable hours (when the implied market heat rate is high) and not run when the implied market heat rate is low – thus increased returns are consistent with a more volatile but declining overall implied market heat rate. Higher returns in 2005 may suggest that the "low water" mark on generator returns has been crossed relative to the market effect of recent supply additions. The MSA will continue to assess & report on the build signal implied in net returns.

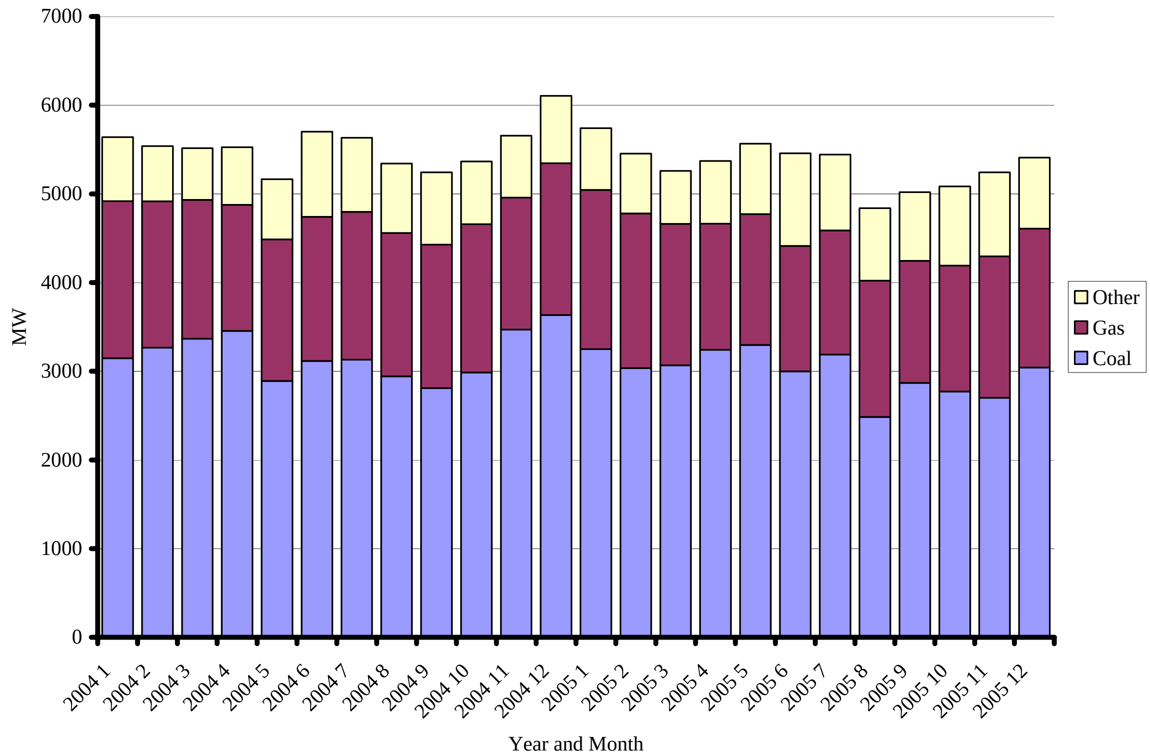
Figure 7 - Estimated Net Returns



1.6 Zero Offers

Overall, the total number of zero dollar offers into the Alberta market was down marginally in 2005 relative to the previous year, as can be seen in **Figure 8**. The Figure shows December 2004 zero offers increasing to 6106 MW, which was attributed to the commissioning of Genesee 3 as the unit was unable to respond to dispatch in this period and thus its capacity was offered at $0.00. Unlike 2004, there were no hours in which Pool price reached $0.00 during 2005. Zero dollar offers and the short-term volatility of zero dollar offers remain a concern to the MSA since where these do not reflect changes in market fundamentals (such as outages), they may harm price fidelity.

Figure 8 – Average Monthly Zero Dollar Offers



1.7 New AESO Rules

In 2005 the AESO worked toward implementation of the new electricity market policy framework. The AESO together with a participant working group formulated a list of "Quick Hits" rule changes to address short-term adequacy concerns. These rule changes have been concluded and will be implemented once impending changes to regulation are finalized.

1.8 New Supply and Load Growth

While Genesee 3 officially entered commercial operation March 1, 2005, this asset was, for most intents and purposes, generating close to its rated capacity by the end of 2004 and thus was counted in our look at generation additions for the year ending Dec 31, 2004. In 2005, no significant generation was brought on-line. However, Epcor announced plans to decommission the Clover Bar generation station.

Average system demand in 2005 was 7565 MW which was up 1.8% from average demand of 7429 MW in 2004. Monthly average system demand in 2005 ranged from 7191 MW in June to 8205 MW in December. 2005 peak demand reached 9580 MW on December 5 in HE 18 which occurred at a price of $239.27/MWh. Peak demand grew approximately 3.7% relative to peak demand last year.

1.9 Imports, Exports, and Prices in Other Electricity Markets

The tie-lines act as a buffer mechanism to Alberta's electricity market, during times of high demand and low supply the tie-lines together can add up to and additional 950MW of supply (under ideal conditions), which not only helps the price of electricity reach equilibrium with our adjacent markets, it also improves the stability of the AIES substantially. During times of oversupply, the tie-lines offer generators alternative markets, which is an important factor given Alberta's large fleet of baseload generation. During off peak hours, significant volumes are generally exported from Alberta to BC.

Flows on the tie-lines are chiefly driven by price differences between regions. The provinces to which Alberta is connected do not have competitive markets, therefore, the comparative could be the marginal cost of generating an additional unit of energy, or the opportunity cost of stored hydro resources. The electricity can also be wheeled through Saskatchewan or BC to markets such as MISO and Mid-Columbia.

Table 3 - 2005 Tie Line Activity

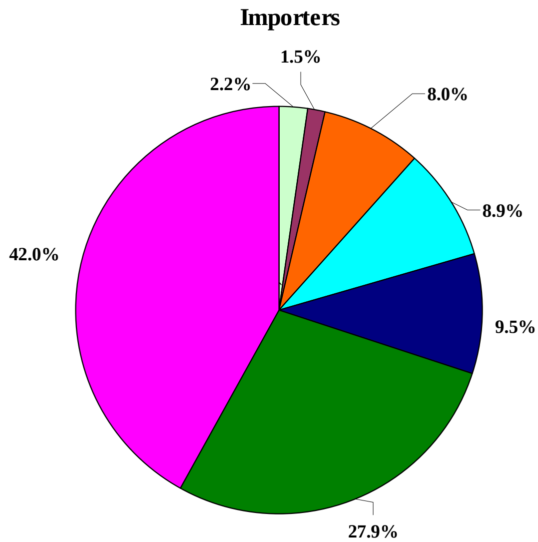
	BC			Saskatchewan			Overall		
	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)
January	83,277	84,845	(1,568)	8,844	10,557	(1,713)	92,121	95,402	(3,281)
February	54,142	93,053	(38,911)	12,786	5,366	7,420	66,928	98,419	(31,491)
March	15,762	156,725	(140,963)	11,336	17,068	(5,732)	27,098	173,793	(146,695)
Q1 Total	153,181	334,623	(181,442)	32,966	32,991	(25)	186,147	367,614	(181,467)
April	75,532	144,202	(68,670)	31,090	1,180	29,910	106,622	145,382	(38,760)
May	107,463	72,928	34,535	36,423	1,003	35,420	143,886	73,931	69,955
June	145,793	63,870	81,923	35,408	234	35,174	181,201	64,104	117,097
Q2 Total	328,788	281,000	47,788	102,921	2,417	100,504	431,709	283,417	148,292
July	60,208	108,747	(48,539)	18,990	10,051	8,939	79,198	118,798	(39,600)
August	71,327	80,682	(9,355)	83,874	639	83,235	155,201	81,321	73,880
September	39,697	61,657	(21,960)	61,078	821	60,257	100,775	62,478	38,297
Q3 Total	171,232	251,086	(79,854)	163,942	11,511	152,431	335,174	262,597	72,577
October	160,786	58,412	102,374	44,710	28	44,682	205,496	58,440	147,056
November	156,292	31,466	124,826	74,878	173	74,705	231,170	31,639	199,531
December	97,934	30,994	66,940	44,309	3,373	40,936	142,243	34,367	107,876
Q4 Total	415,012	120,872	294,140	163,897	3,574	160,323	578,909	124,446	454,463
2005 Total	**1,068,213**	**987,581**	**80,632**	**463,726**	**50,493**	**413,233**	**1,531,939**	**1,038,074**	**493,865**

As shown in **Table 3**, Alberta was a net importer of about 494,000 MWh in 2005, of which 454,500 MWh was transacted during the fourth quarter. There are two reasons for the particularly large difference between volumes imported and exported during the fourth quarter as compared to the earlier quarters. The ability to export to BC declined substantially since November**,** when the AESO reassessed the method of calculating ATC values because of operational issues in the Province. April saw the maximum BC export ATC when the tie-line was capable of exporting 390 MW on average, for the month. In December, the BC export ATC for the month was down to 42 MW on average - a decrease of 89% relative to April levels. This is, in large measure, why volumes exported during November and December are nearly half that of any other month in the year even though the economics of exporting to Mid-Columbia appears to have been the best in December.

Another reason for the large net import position in 2005 was improved import arbitrage opportunities, by comparing the on peak prices (when most imports typically occur) between the various markets, it is evident that November was the best month of the year for imports, and October was the second best month, hence the high import volumes in those periods.

Overall, imports and exports were quite similar to 2004. Saskatchewan was once again mostly responsible for the positive net imports. Over 2005, Saskatchewan sent about 5 times as much energy (464,000 MWh) to Alberta as they took from Alberta. BC on the other hand is much closer to net zero with only 80,000 MWh of net energy sent to Alberta.

Figure 9 – Market Share of Importers and Exporters (Q4/05)



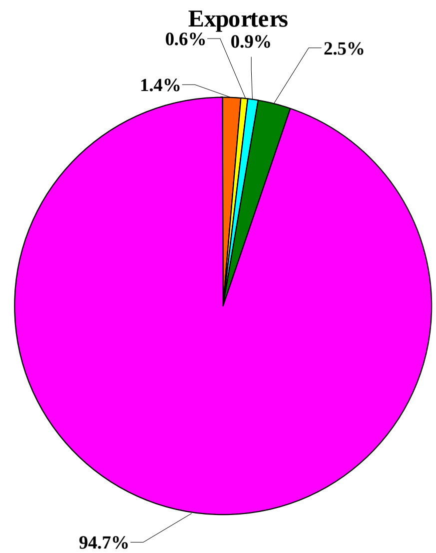


Figure 10 - Market Share of Importers and Exporters (2005)

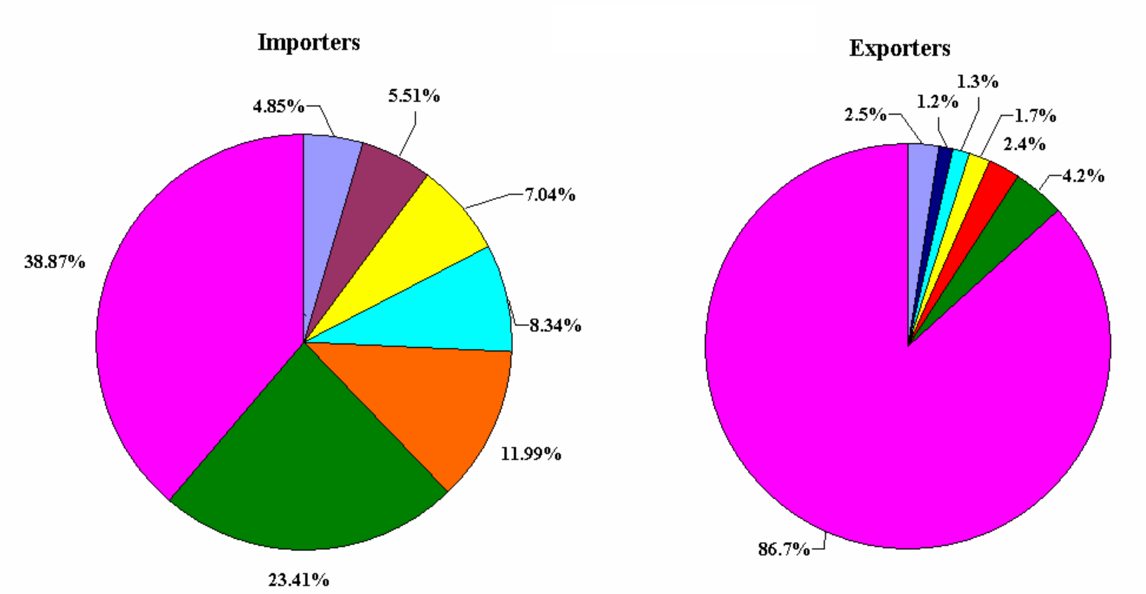


Figure 9 shows the distribution of market shares of importers and exporters on the BC and Saskatchewan tie-lines (combined) in Q4.

Figure 10 shows the same information for the whole of 2005. Market share of importers was reasonably well distributed in Q4/05, and for the entire year. The dominant importer had a 42% market share in Q4 which is up slightly from a full year import share of 39%.

Market shares fluctuated over the course of the year, driven by factors such as ATC limitations and exceptional hydro resources in Saskatchewan and Manitoba. The Q4/05 import and export market shares however, are quite comparable to the overall market share diagram, with two players being responsible for the vast majority of the volumes on the interties. Exporting in particular is dominated by one party who regularly exports from Alberta during off peak hours.

Exporting during the on peak hours was severely limited due to operational constraints that reduce BC Export ATC to zero in periods when provincial demand is over 8100 MW. This export constraint has been identified by the AESO and is planned to be addressed by reinforcing the provincial transmission network.

Figure 11 - Tie Line Utilization (Q4/05)

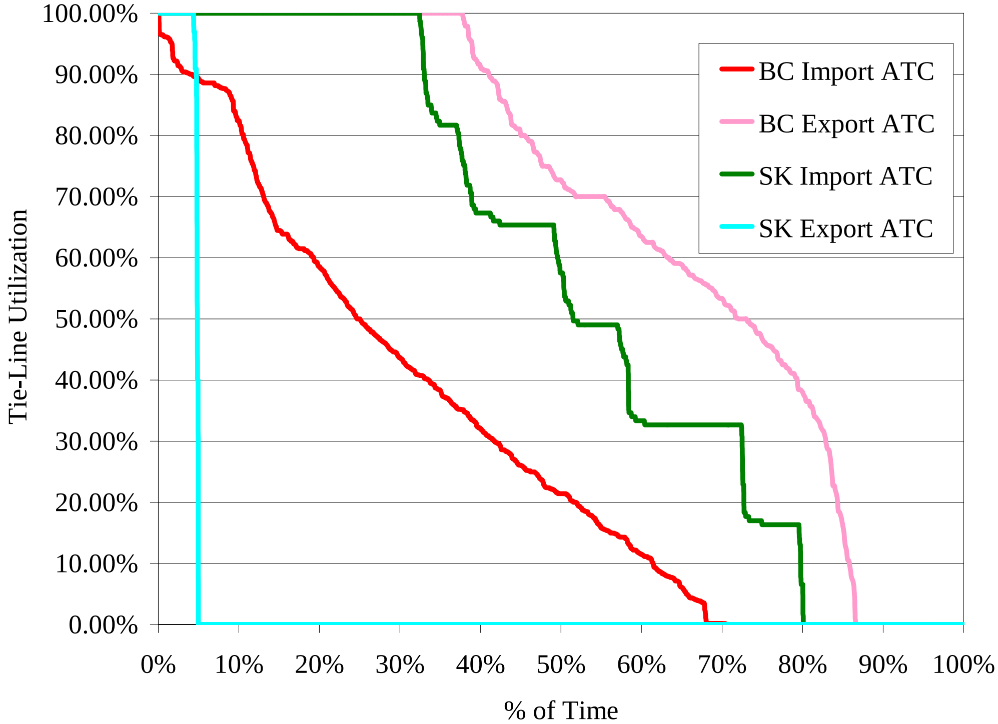
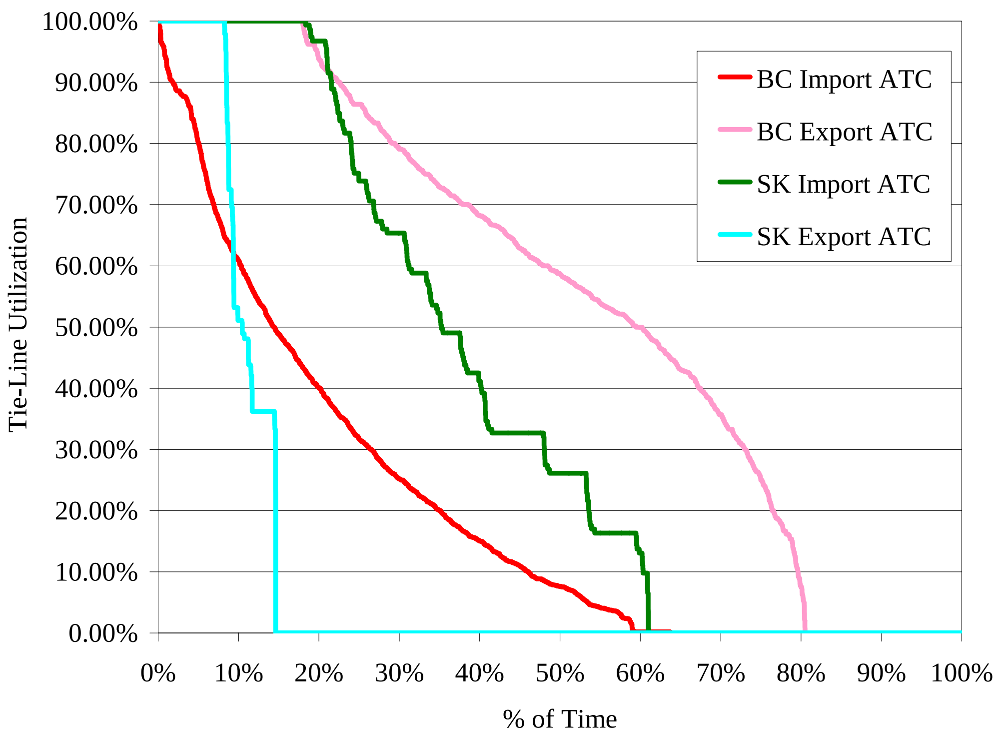


Figure 12 - Tie Line Utilization (2005)



Figures 11 and 12 indicate that the tie-lines were not fully utilized during 2005. This is expected as the difference in price between adjacent markets in some periods does not justify the losses and tariffs incurred in the transaction.

The tie-line utilization in Q4 was notably higher than the overall 2005 tie-line utilization (as presented in **Figure 11** and **Figure 12**). This can be ascribed to the reduced export ATC[1] which would have skewed export utilization upward in November and December. Higher utilization of import ATC in Q4/05 can be attributed to increased Pool prices during this period which enhanced import economics.

[1] Note that utilization of the tie-line cannot be calculated for hours when the ATC is zero. Utilization is measured only when it is possible to move energy across the line.

Figure 13 - Imports with Trade-weighted Prices

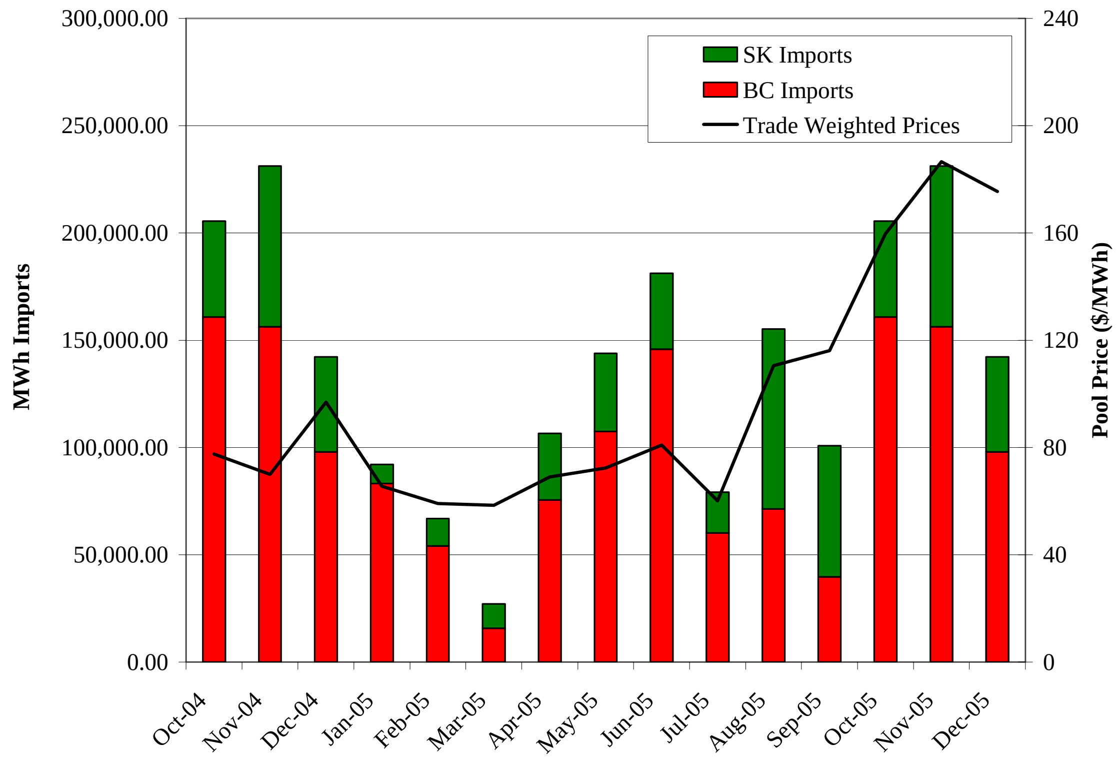
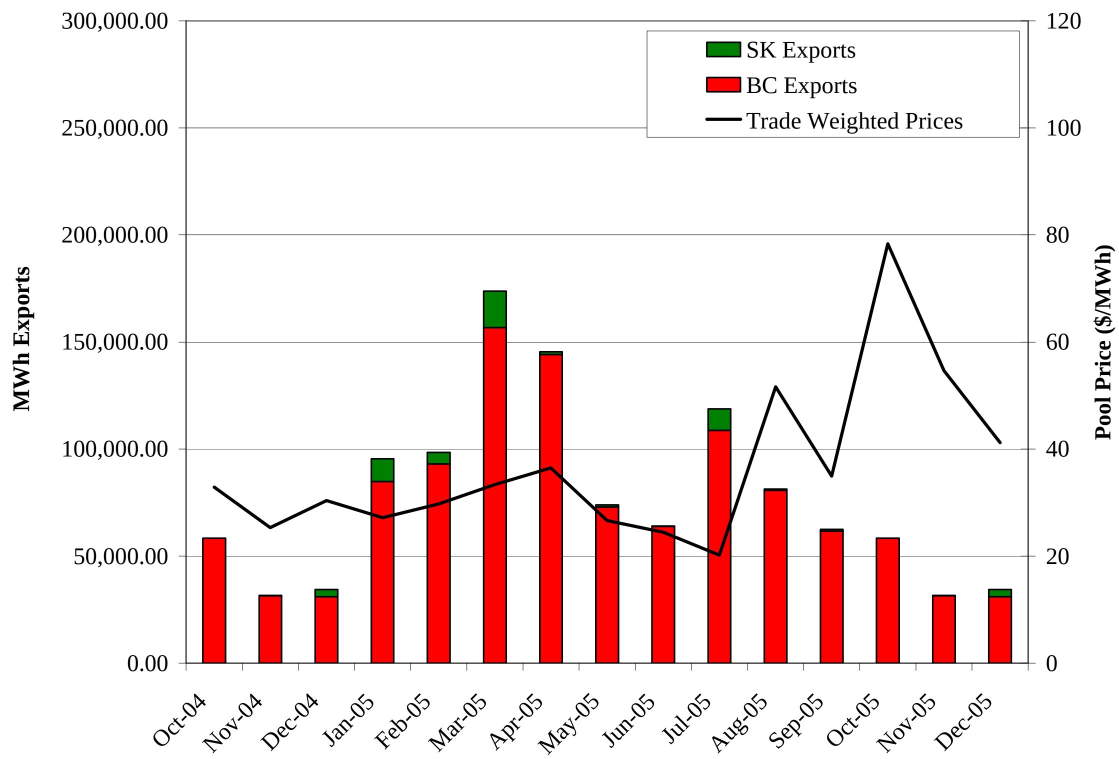


Figure 14 - Exports with Trade-weighted Prices



Figures 13 and 14 show import and export volume by month together with the trade-weighted price of those volumes. Imports and exports should occur to the extent that there is clear economic incentive. As such, one would expect that in general, high import volumes should coincide with high Pool prices and vice versa for exports barring transmission constraints. **Figure 13** shows a reasonable alignment of trend that is less apparent in **Figure 14** since exports were often subject to physical and operational constraints through 2005. Other external factors can have a short term influence as well however, in the interests of price fidelity, the MSA looks for a close correspondence between actual tie line flows and those implied by market fundamentals while considering financial frictions such as transmission and losses.

Figure 15 - On-Peak Prices in Other Markets

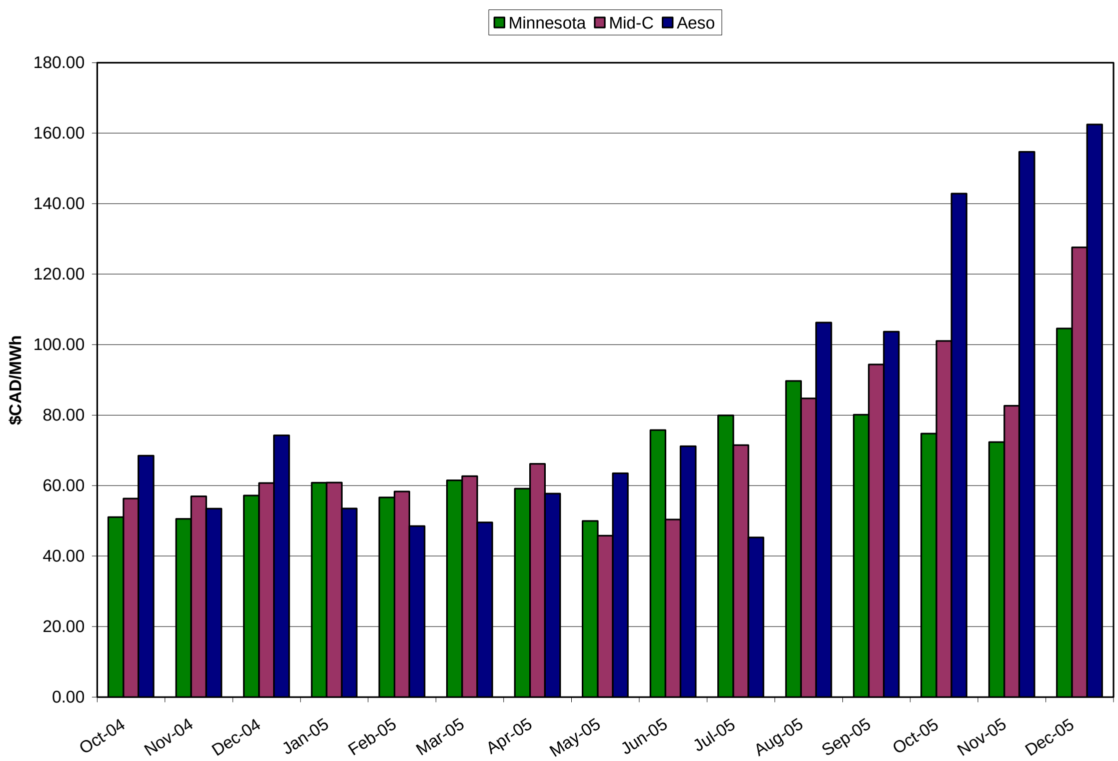
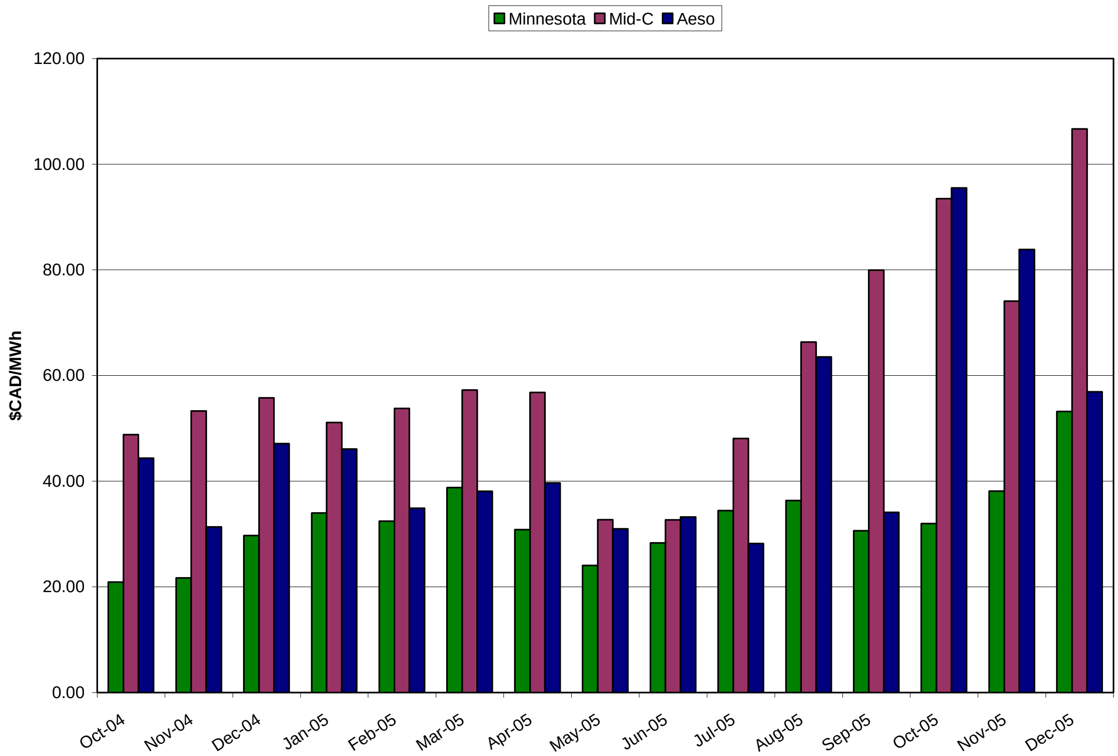


Figure 16 - Off-Peak Prices in Other Markets



Alberta on-peak and off-peak prices (see **Figures 15 and 16**) were reasonably competitive with Mid-C and MISO prices for the majority of the year, deviations did however occur particularly in the last quarter of 2005. Typically, base load generators schedule major maintenance for summer to assure adequate supply availability during the winter when peak system load is reached. Q4/05 featured some scheduled maintenance although this was compounded by numerous forced outages that reduced availability of base load generation causing more expensive generators to run and set price. This set the stage for high October and November pool prices (see the following section for more information on outages).

The high Alberta prices seen in August can be attributed to high natural gas prices, reduced base load availability and also reduced import ATC on the BC tie-line[2]. The 134% jump from the July price to the August price is discussed in more detail in a memo released by the MSA in September 2005.

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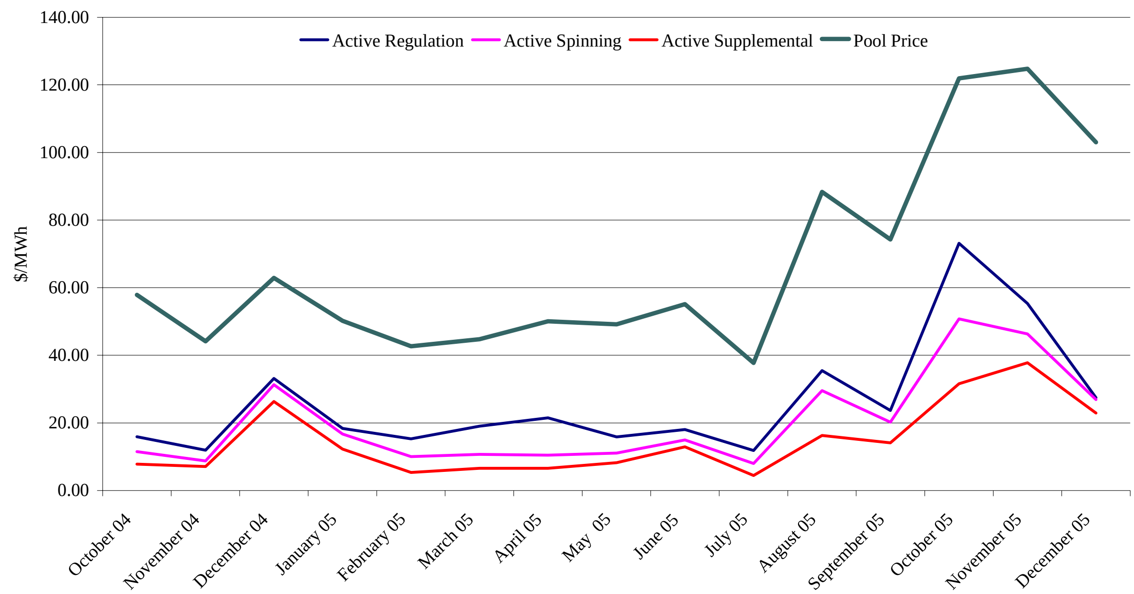
[2] Imported energy from outside the Alberta border is often a substitute for higher priced peaking energy in Alberta.

1.10 Ancillary Services Market

Active Reserves Market

Active regulating, spinning, and supplemental reserves are priced at a negative differential to Pool price. For example, a reserves contract might transact at -$60.00 meaning that for each hour of the contract, it will settle at the Pool price for that hour - $60.00 x the volume per hour of the contract. Due to this price mechanism, the trend in settlement prices mirrors the trend in Pool prices quite closely assuming trade differentials remain relatively stable. As such, it is not surprising that settlement prices for active reserve products trended up significantly in 2005, primarily in the second half of the year in response to increasing Pool prices during the same period. Trade indices tightened in late Q2/05 and into Q3/05 as shown by the thin line separation in **Figure 17**. Settlements for active regulating and spinning reserve moved up proportionally more than supplemental reserves in Q4/05 as supplemental discounts were more pronounced.

Figure 17 - Active Settlement Prices - All Markets (Watt-ex and OTC)



Standby reserve premiums are shown in **Figure 18** for the last 15 month period. After moving down sharply in July, standby premiums again moved up strongly for the balance of the year. Only standby regulating premiums moderated in Q4/05. This increase in standby premiums is attributed largely to the significantly higher Pool prices in the second half of the year and the fact that activation rates remained fairly low during this period. In a low activation rate environment, sellers would tend to bid up standby premiums (and activation prices) which are fixed, to compensate for the variable upside forgone in either the energy market or the active reserves market.

Figure 18 - Standby Premiums - All Markets (Watt-ex and OTC)

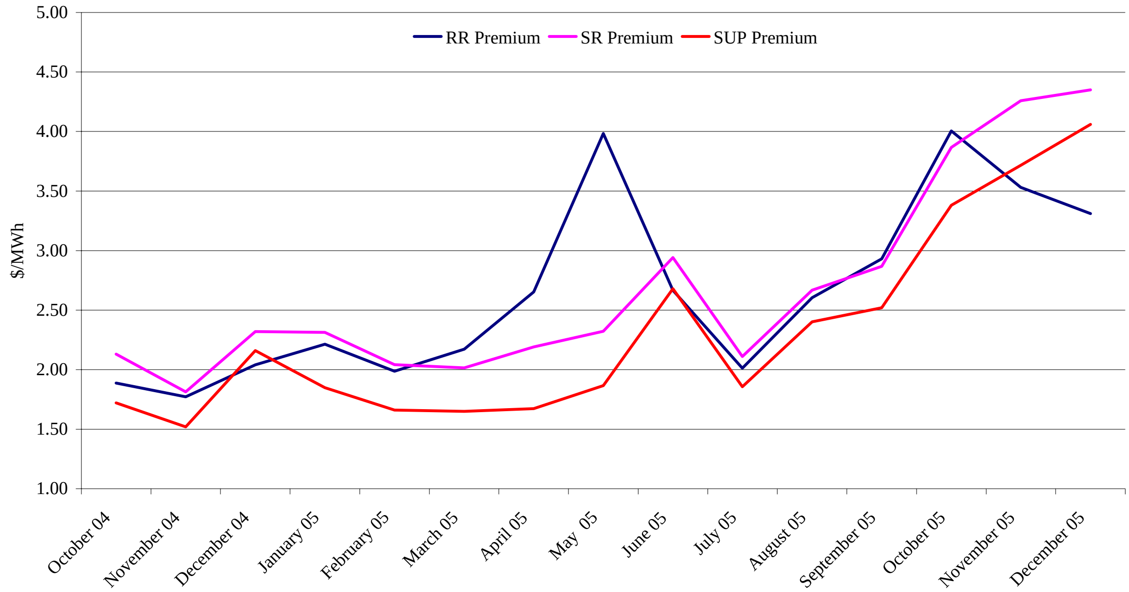


Figure 19 shows activation prices for standby reserve services that were actually activated. Activation prices moved up in the second half of 2005 in response to increasing Pool prices since a reserve provider must withdraw volumes from the energy market in order to position the unit to provide active reserve service. In the higher Pool price environment prevailing in late 2005, sellers would have required higher activation prices in order to compensate for being out of the energy market.

Figure 20 shows monthly activation rates for standby reserve service. As noted previously, activation rates remained relatively low in 2005 with the exception of Q1/05 in which standby spinning and standby supplemental reserve activations were somewhat elevated. This was attributed largely to the commissioning process for Genesee 3 during this period.

Figure 19 – Activation Prices – All Markets (Watt-ex and OTC)

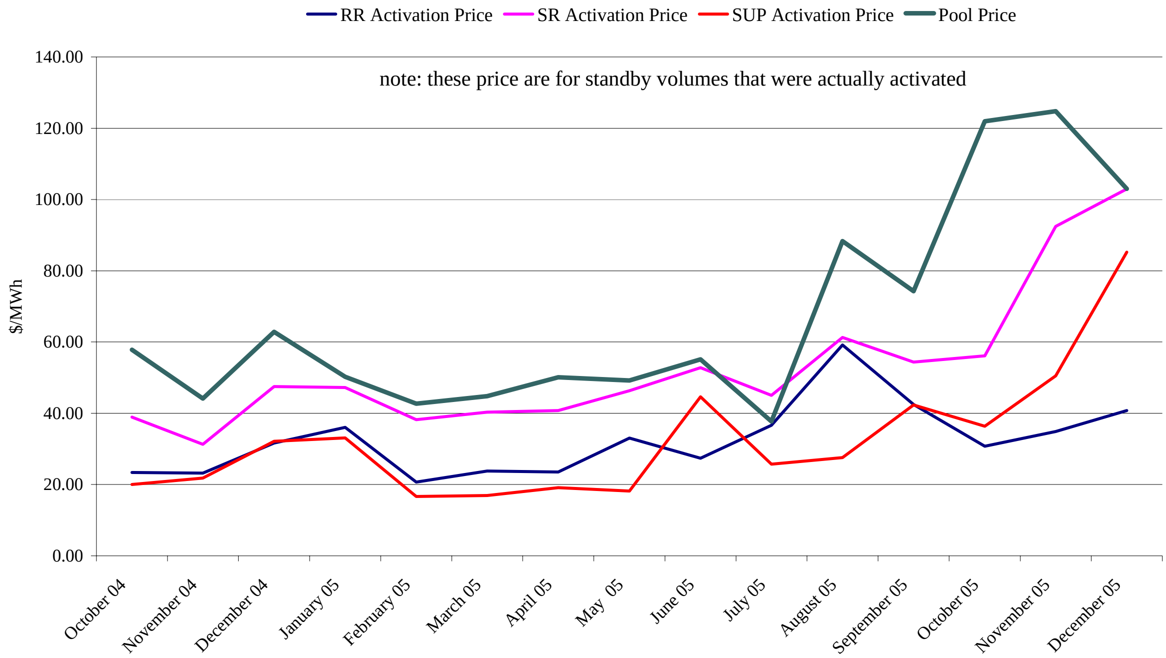
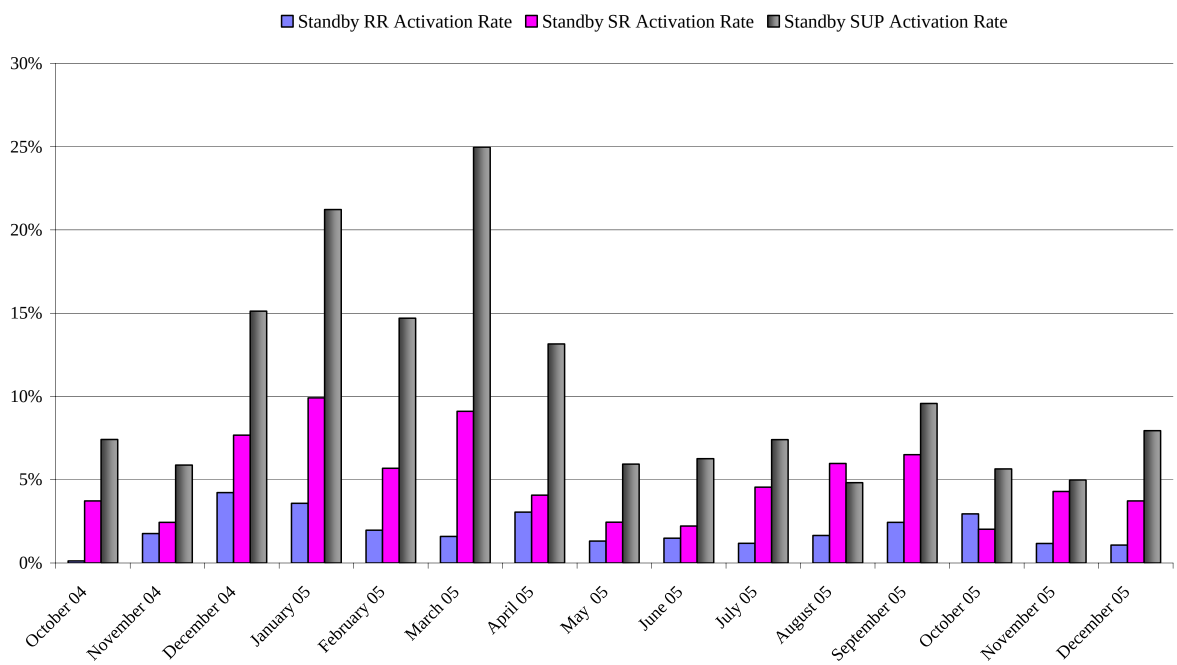


Figure 20 - Standby Activation Rates



OTC Procurement

Figure 21 shows the proportion of active reserves procured OTC in 2005. The balance of reserve procurements were transacted on the Alberta Watt Exchange (Watt-Ex). OTC procurements of active regulating reserve were down significantly relative to levels observed late last year. In 2005, regulating reserve was most prominent among OTC procurements and averaged approximately 30% of total active regulating volumes. OTC procurement of spinning reserves generally ranged from 10 – 20 % of total procurement while OTC procurement of supplemental reserves was somewhat higher ranging from 20 – 30 % of total active supplemental volumes. Concerns in the market relating to the AESO's reliance on the OTC market declined in 2005 with improved data transparency by the AESO along with a reduction in overall OTC volumes relative to 2004.

Figure 21 - OTC Procurement as a % of Total Procurement

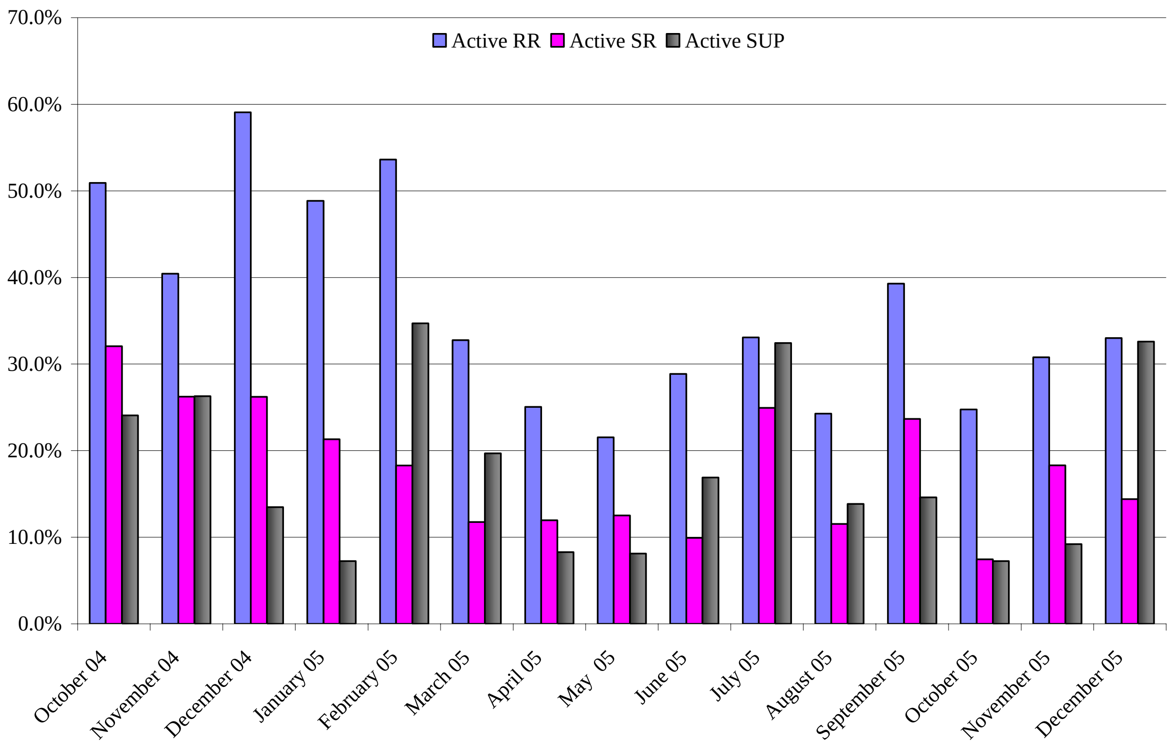
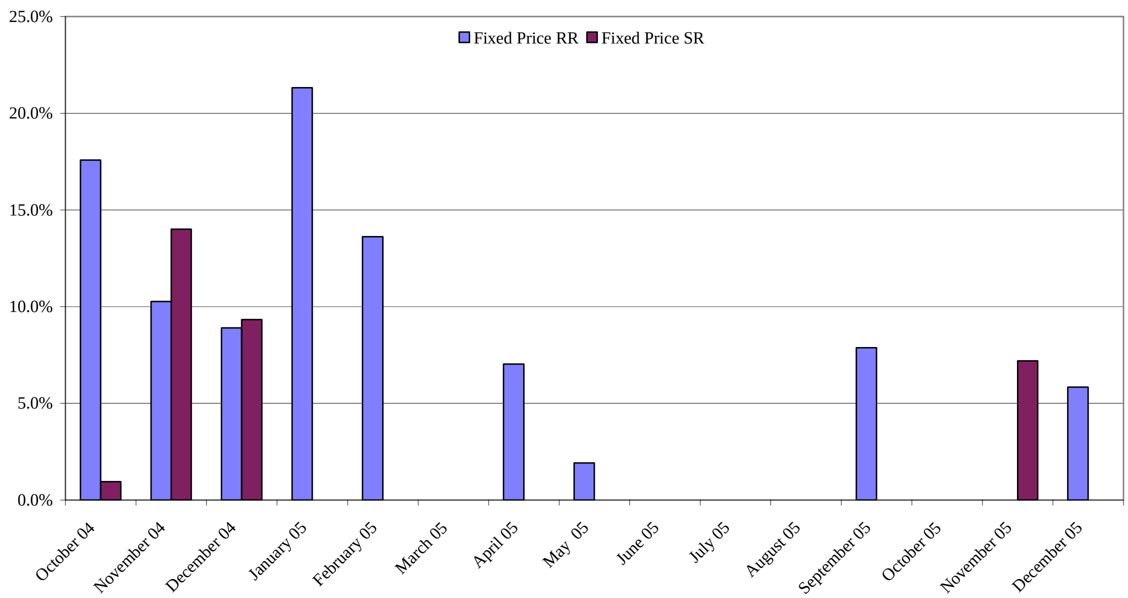


Figure 22 indicates the percentage of fixed price volumes procured relative to overall procurement volumes. For regulating reserves, it can be seen that other than January and February procurements, fixed price contracts represented a modest component of procured volumes. For spinning reserves, fixed price procurements, with the exception of November, were negligible during 2005.

Figure 22 - % of Active Regulating and Spinning Purchased at Fixed Price



Figures 23, 24, and 25 show settlement prices for active regulating, spinning and supplemental reserves, and these are segregated between exchange traded volumes and OTC procured volumes. This separation reflects differences in prices paid via one procurement method vs the other. **Figure 23** indicates that OTC procured regulating volumes were about as often purchased below exchange traded values as above. The narrow deviation between the "all volumes" line and the "watt-ex" line reflect that OTC was a minority component of volume and that price differentials did not significantly skew the overall cost of regulating reserves. **Figure 24** indicates periods in which there was a substantial premium paid to OTC spin volumes, in Q2/05 and Q4/05, however, this did not have a significant bearing on the weighted average cost of spinning reserves due to OTC being a small component of the overall volumes. Likewise with supplemental reserves, **Figure 25** reflects some periods of substantially higher cost OTC volume, however it did not have a strong influence on overall supplemental reserve costs being a small component of total volumes.

Figure 23 - Active Regulating Reserve Settlement by Market

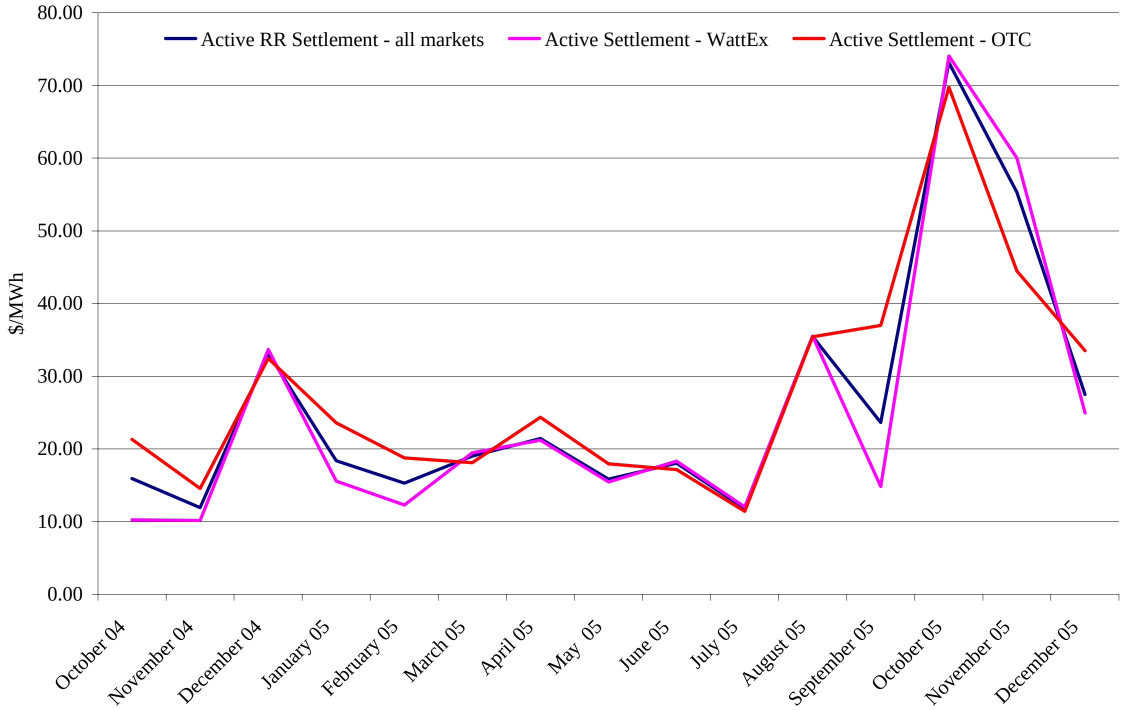


Figure 24 - Active Spinning Reserve Settlement Price by Market

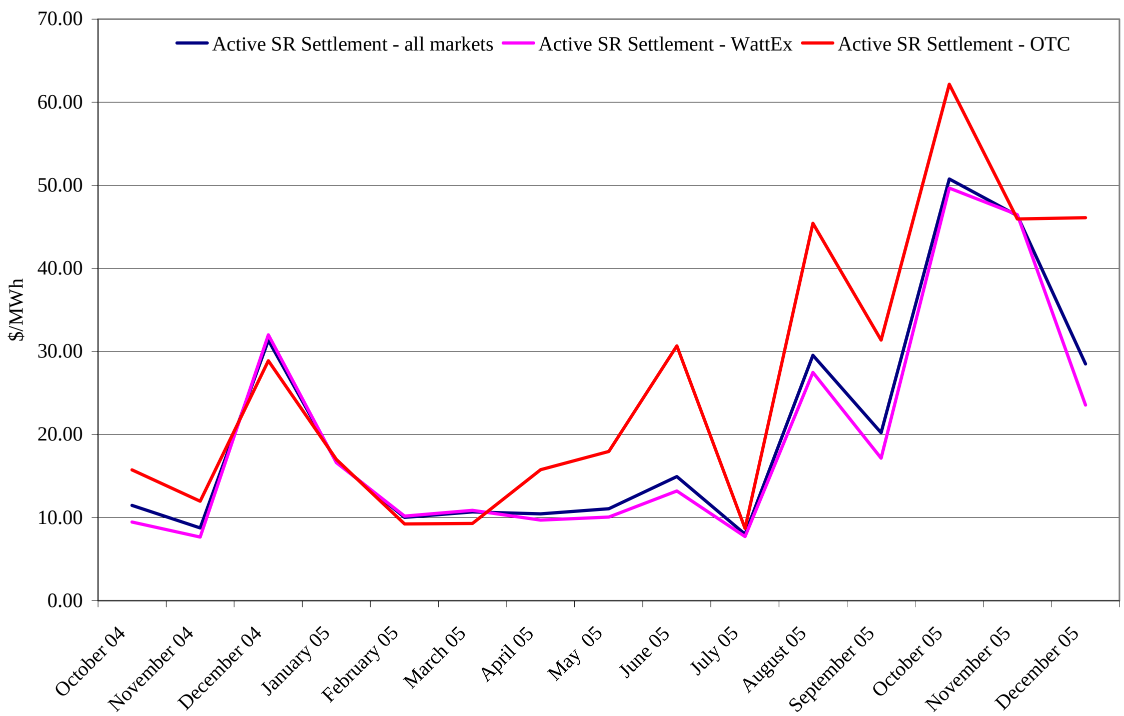
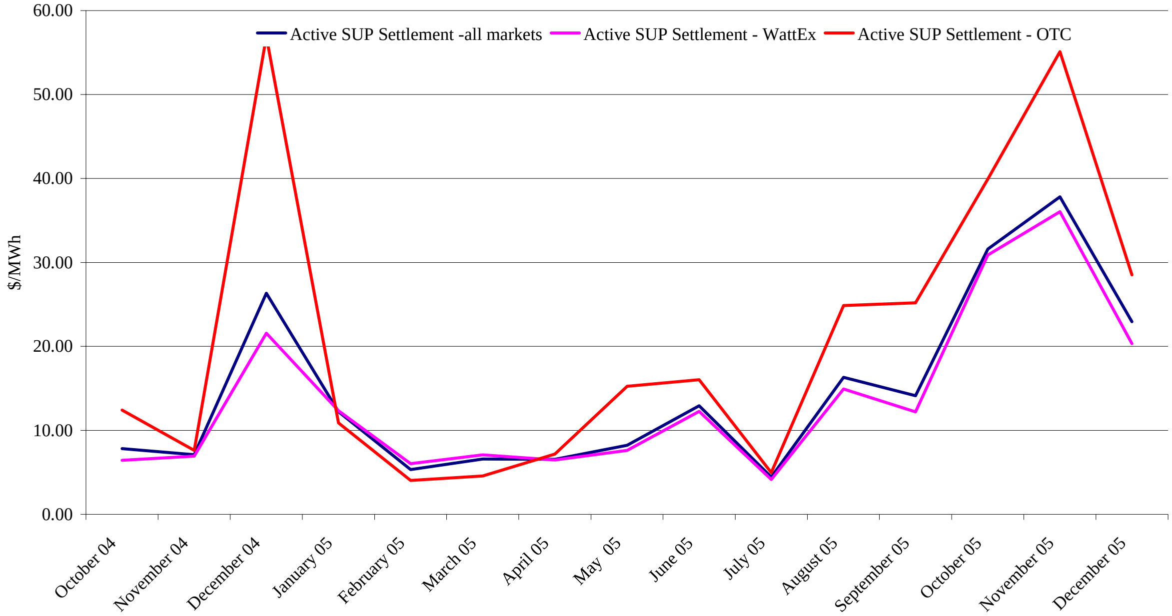


Figure 25 - Active Supplemental Reserve Settlement Price by Market



Figures 26, 27, and 28 show the market share breakdown for each active reserve service by generator fuel type. In the regulating reserves market shown in **Figure 26**, hydro share moved substantially higher in 2005 relative to the 50 – 60% range in 2004, reaching 76% for the month of July but generally falling between 60 – 70 %. Hydro assets clearly shifted greater focus to the higher value regulating market in 2005 from the other reserve markets. Coal share of regulating was relatively stable in the 20 – 25 % range with the majority of the variability derived from the back and forth between hydro and gas generators. For spinning reserves, **Figure 27** shows that market share was dominated by gas, hydro and the BC-AB interconnection. Gas units gained ground in 2005, averaging approximately 42% as compared to 37% in 2004. Gas units and hydro gained market share through 2005 at the expense of the tie line which had historically been in the mid - 30% range but declined to the low to mid 20% range in 2005. **Figure 28** shows the supplemental market dominated by gas, hydro and load. The advent of the new notional reserves addendum to the hydro PPA during 2004 created greater room for participation of reserve providers other than hydro in 2005 although hydro continues to be a prominent supplemental provider being well suited for this type of reserve service. Load share of supplemental grew more prominent in 2005 reaching 23% in the month of March then declined through the second half of the year.

Figure 26 - Regulating Reserve Market Share by Fuel Type

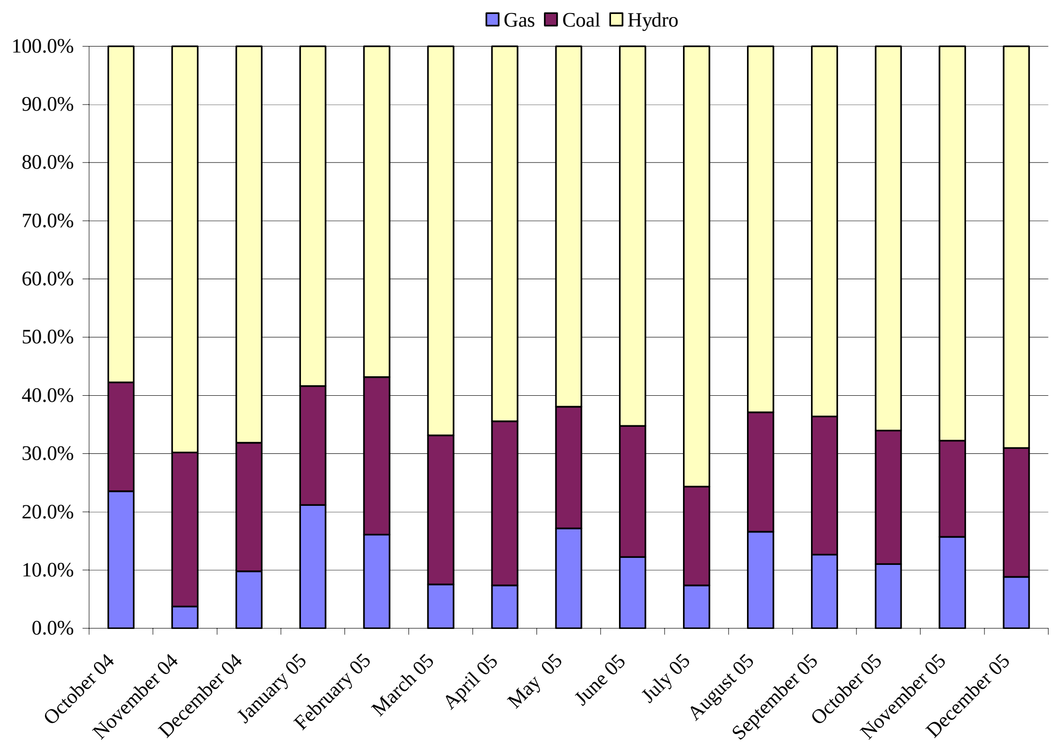


Figure 27 - Spinning Reserve Market Share by Fuel Type

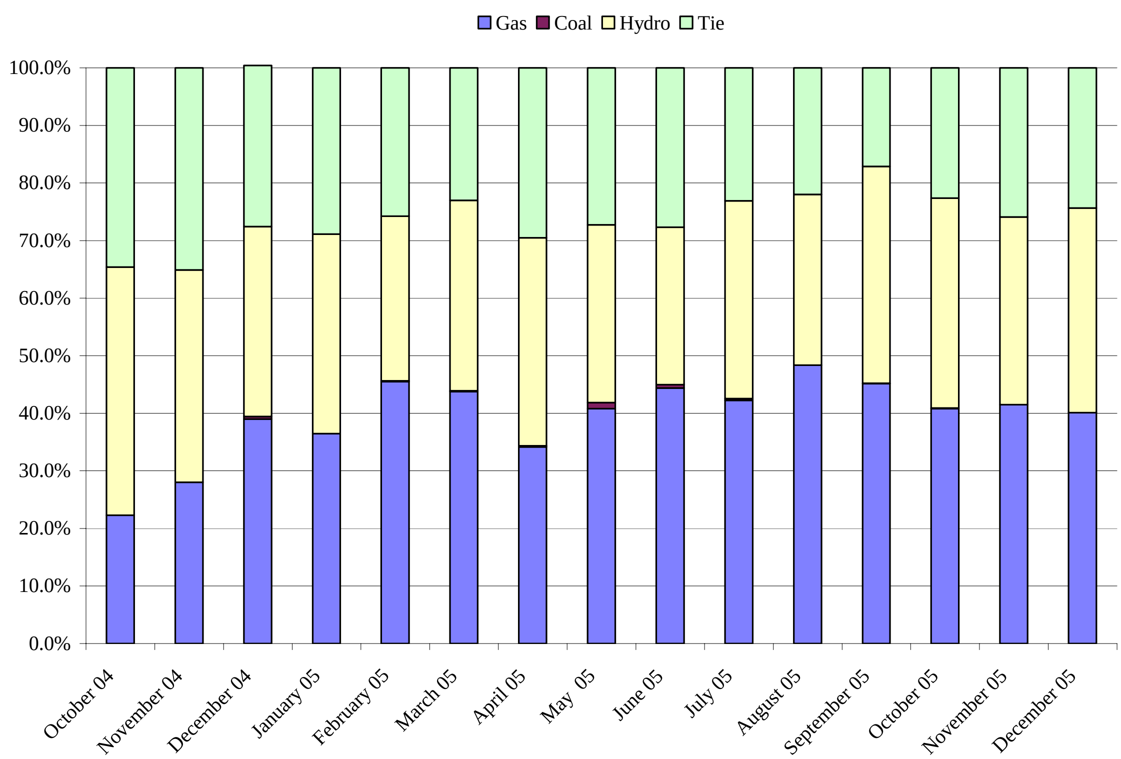
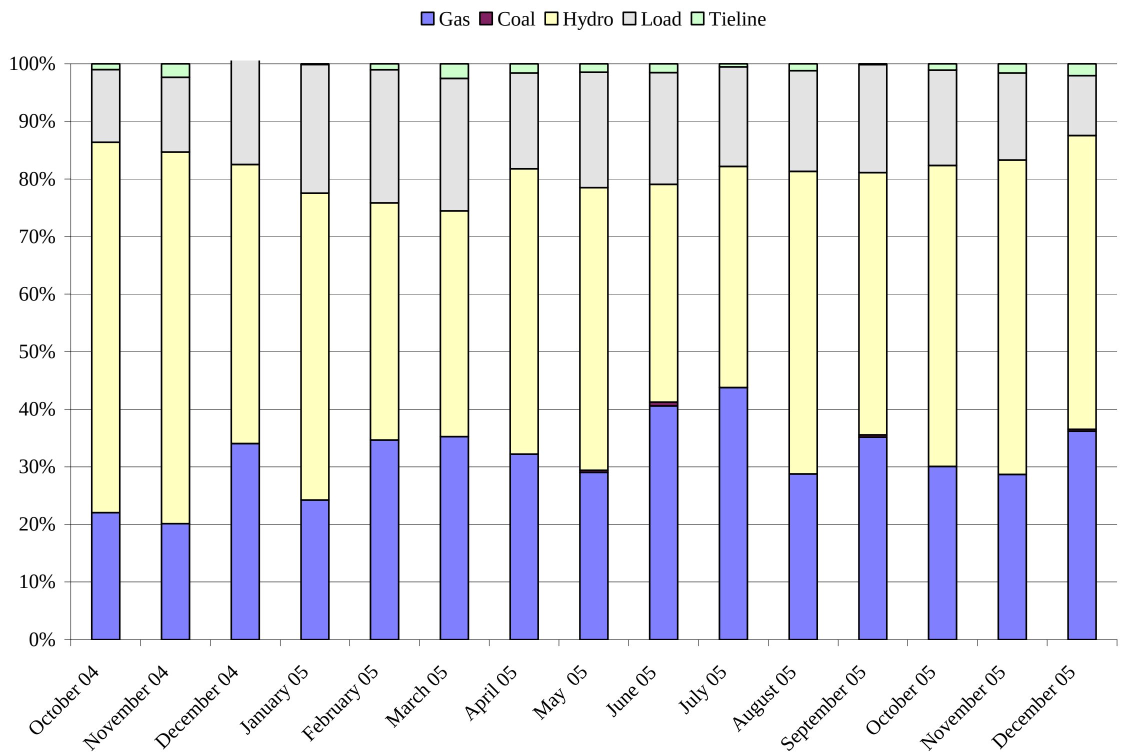


Figure 28 - Supplemental Reserve by Fuel Type



1.11 Forward Markets

As noted in the MSA's Q3/05 report, an assessment of TPG/IDP in mid-2005 indicated that over an 18-month study period, less than 5% of Participant's forward energy volumes flowed through electronic exchanges and the vast majority of the trade volumes were transacted via brokers and bi-lateral deals. As such, the MSA has discontinued regular reporting on exchange traded volumes in contemplation that it may be more useful to conduct voluntary surveys from time to time to assess forward market liquidity.

1.12 Outages and Derates

The MSA monitors the frequency and duration of the outages and derates of generating units in Alberta. Of particular interest are the coal fired thermal generation units that are operated under the terms and conditions of the Power Purchase Arrangements (PPAs). Outages at these PPA plants tend to have a large impact on Pool price as they represent a major contingent of Alberta's total installed base load generating capacity.

When these base load PPA units are derated or trip off due mechanical reasons, a higher cost peaking unit is often dispatched to replace the base load energy that is no longer available for the provincial electricity needs. When the amount of outage exceeds a PPA unit's historical average, the

MSA seeks to understand the cause of the variation and may request additional data from the generation owner.

Figure 29 illustrates the total outage levels at the coal fired generation facilities separated by PPA owner. The graph shows the total outage levels through the past five quarters and provides a context for the outage behavior in the most recent quarter.

This presentation helps to filter out aspects of seasonality that occurs with generation outages. It should be noted that some variation is expected on a year over year basis due to the nature of the multi-year planned outage schedules.

The Figure shows that outages for Owners A and B were quite elevated in Q2/05 which is the normal period in which planned outages are scheduled as system demand is relatively low. The graph also indicates that contrary to Owners A and B, Owner C's outages were lowest in Q2/05 and relatively higher in the other three quarters. The majority of Owner C's planned maintenance occurred in Q3/05 rather than Q2/05. Q4/05 outages were predominantly forced outage and were a significant factor in the higher Pool prices seen in Q4/05. The MSA continues to monitor outage levels of each owner to ensure they are reasonable and explainable to the extent that they are not within ranges implied by the age and past performance of the generation units.

Figure 29 - Outages by Quarter

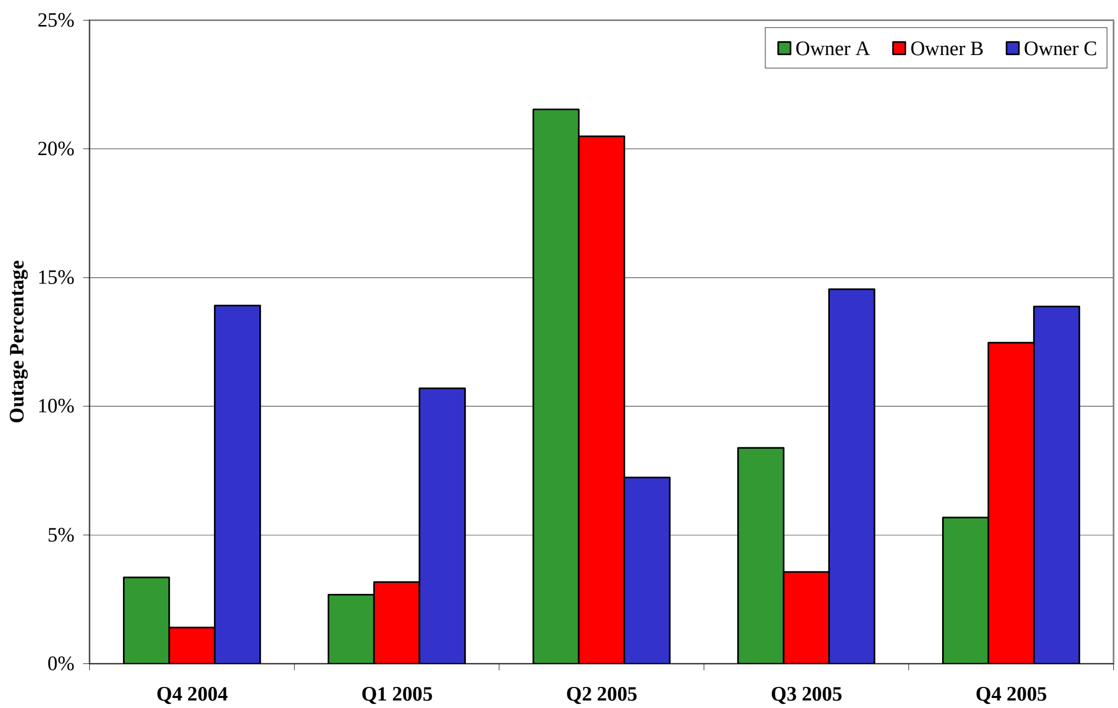


Table 4 reports the unplanned outages by quarter in 2005 together with historical annual unplanned outages for reference. The numbers show that Owner B had a high level of unplanned outages for Q4/05 while the others were in line with their historical norms.

Table 4 - Percentage of Unplanned Outages for PPA Coal Units

	Q4/05	Q3/05	Q2/05	Q1/05	2005	2004	2003	2002	2001
Owner-A	5.7%	4.0%	7.9%	2.6%	**5.0%**	6.1%	4.9%	4.2%	3.2%
Owner-B	12.5%	2.3%	3.6%	3.1%	**5.4%**	1.5%	1.5%	0.5%	1.2%
Owner-C	7.2%	3.3%	6.5%	8.9%	**6.5%**	6.3%	5.7%	10.8%	8.8%
PPA weighted average	7.6%	3.3%	6.4%	6.2%	**5.9%**	5.5%	4.9%	7.7%	6.3%

Note:
1) PPA units include: Genesee 1 & 2, Battle River 3,4,5, Sheerness 1 & 2, Sundance units 1 through 6, Keephills 1&2.
2) Outages rates are based on maximum continuous rating (MCR), not gross unit capacity.

Figure 30 provides a summary of the total outages, on a percentage of total PPA capacity, for the past 4 years. The overall trend suggests that Owner C has the highest levels of outages, followed by Owner A, then Owner B. All outage levels are within contract limits of the PPAs. Each PPA document specifies the target availabilities for each of the PPA units and these targets are determined with information based on historical performance and factors such as the unit age and design. By Owner, **Table 5** reports the MW weighted average target availability for each coal fired portfolio and the actual availability achieved during 2003 -2005. All units operated at levels above their target availability.

Figure 30 - Four Year Look

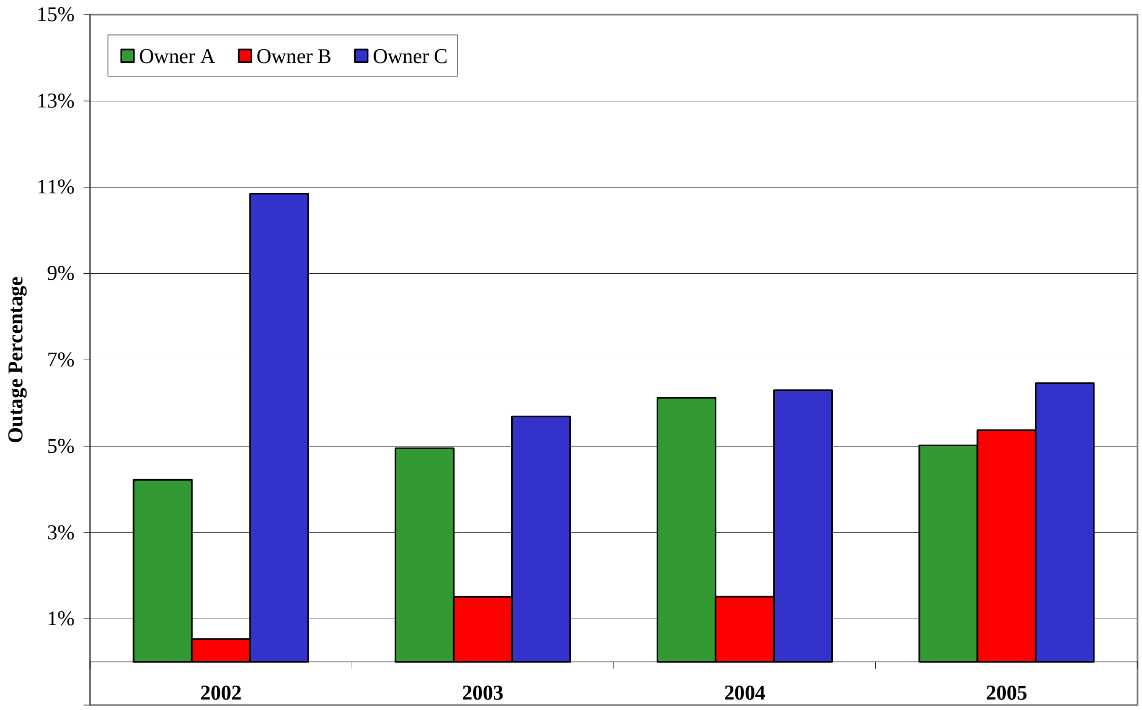


Table 5 - MW Weighted Portfolio Target Availability (%) vs Actual Availability (%) - Coal Fired PPA Units

	Target Availability 2003	Actual Availability 2003	Target Availability 2004	Actual Availability 2004	Target Availability 2005	Actual Availability 2005
Owner-A	87%	92%	87%	88%	**87%**	**90%**
Owner-B	90%	94%	90%	97%	**89%**	**90%**
Owner-C	85%	88%	87%	89%	**87%**	**88%**
PPA weighted Average	87%	90%	87%	90%	**87%**	**89%**

2 REVIEW OF THE RETAIL MARKET

2.1 Code of Conduct

Compliance Plans

Compliance plans are required from owners of electric distribution systems and their affiliated retailers; the plans set out the systems, policies and mechanisms to be used to ensure compliance with the electricity *Code of Conduct Regulation* (Code). Compliance plans must be approved by the MSA before they are effective, and before the affiliated retailer begins to provide retail electricity services.

The general practice has been for each owner and each affiliated retailer to establish and adopt a distinct compliance plan. However, based upon discussions with various stakeholders, the MSA agreed in May, 2005 that a unified plan approach would also be acceptable – in other words, that a common plan could be developed, and adopted by all relevant parties (owner and affiliated retailer(s)) within an organization.

Various parties adopted the unified plan approach, upon the view that it will add efficiency to their compliance structures and make it simpler to train their personnel.

Another significant change to compliance plan requirements was brought about specifically to facilitate efforts by Rural Electrification Associations (REAs) seeking to carry out retailer functions for their members.

Under the *Electric Utilities Act* (EUA), it is generally stipulated that the functions of owners of electric distribution systems and the functions of retailers must be done separately. This functional separation has meant that the owner functions are handled by a different legal entity than the retailer functions. Based upon feedback given by the REAs, the MSA and stakeholders, in June 2005 Alberta Energy enacted certain regulatory amendments to allow an REA an additional structural option.

Consistent with other enactments governing retailers, an REA is now able to carry out retailer functions for its members without setting up a distinct legal entity separate from the owner entity. Certain REAs have been availing themselves of this new option, allowed under the *Roles, Relationships and Responsibilities Regulation, 2003 Amendment Regulation*.

All of the foregoing developments serve to increase regulatory efficiency and to reduce the regulatory burden faced by market participants. Those gains should lead to reduced costs for all parties, including relevant customers.

As at December 31, 2005, a total of 14 approved compliance plans were operational. That total is expected to shrink in 2006, given efforts by some parties toward unified (single) compliance plans.

In addition, 2 REAs had received approval for their respective compliance plans but had not yet commenced retail operations; those compliance plans were therefore not yet operational.

Code of Conduct Audits 2005

The Code contemplates that the owners of electric distribution systems and their 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 EUA.

As in 2004, the MSA elected to test Code compliance through one independent audit firm retained by the MSA (Grant Thornton LLP), utilizing one common testing plan. The period tested was July 1, 2004 through June 30, 2005, inclusive, with an additional stub period for certain parties due to their operational status in May and June, 2004.

A total of 13 parties were subject to the testing, including the Direct Energy, ENMAX, EPCOR and Fortis organizations.

Grant Thornton carried out random call centre testing in June, 2005, and the balance of the testing plan was carried out between August and September. The MSA posted the results of the testing on its website in early November.

Municipal Generation Deficiency Correction Regulation

This regulation expands upon s. 95 of the EUA, addressing the circumstances under which a municipality or a subsidiary of a municipality may hold an interest in a generating unit.

Under the regulation, a municipality or a subsidiary of a municipality may hold an interest in a generating unit located within the boundaries of the municipality if certain pre-conditions are met, including that the municipality has received approval from the MSA for a compliance plan setting out how the requirements of the regulation will be met.

In the fall of 2005, the MSA received a request for such approval(s) in relation to two small generating units located at landfill sites. In October, 2005 the MSA issued the necessary approval(s).

Access to Customer Information

The MSA continued its work with representatives of the Alberta Energy, the Alberta Energy & Utilities Board (EUB) and industry stakeholders around ways to make access to customer information as practical and fair as possible. The main initiative to date pertains to simplifying information access between the owners of electric distribution systems and retailers.

Based upon the work of all parties, the EUB has designed a representation and warrant protocol to be implemented as part of the Tariff Billing Code. The MSA has been asked to support the protocol through its ongoing compliance monitoring, and has agreed to do so. Final details regarding implementation and monitoring remain to be determined.

Regulatory Proceedings

In accordance with its mandate, the MSA continued to monitor regulatory proceedings before the EUB, the British Columbia Utilities Commission (BCUC), and before other bodies. Certain key proceedings are described below.

EUB - Transmission – North/South

In December, 2004, the EUB commenced its hearing in relation to Application 1346298, pertaining to a Needs Identification Document submitted by the AESO in respect of a proposed 500 KV Transmission System Development between the Edmonton and Calgary areas.

This proceeding was of particular interest to the MSA by virtue of the importance of the transmission system to the fair, efficient and openly competitive operation of the market. Apart from the magnitude of the proposed transmission upgrade(s), the application was also significant in that Alberta Energy requested, and received, permission to intervene. Further, the proceeding took into account the new Transmission Regulation.

Final argument was heard in January 2005, and the EUB decision was issued April 14, 2005 (2005-031). The decision can be found on the EUB website – www.eub.gov.ab.ca.

EUB - Article 24 Application

In August, 2004, the AESO submitted an application to the EUB for amendments to the existing Article 24 of the ISO Tariff (Application 1357161). The application sought to change certain payment provisions in respect of Transmission Must Run (TMR) services conscripted pursuant to Article 24. In response, ATCO Power filed a motion seeking relief against the Application. There was considerable stakeholder intervention in the proceeding.

The subject matter of this EUB proceeding was of significant interest to the MSA; in fact, the MSA had undertaken its own investigation into the market for TMR in Alberta. A report was issued by the MSA in this regard in early 2005.

In the spring of 2005, the EUB proceeding was put on hold to take into account relevant policy initiatives which had been commenced by Alberta Energy. In addition, the parties involved in the application and some other stakeholders undertook discussions in an effort to settle at least some of the outstanding issues.

The settlement discussions did not resolve the matters at issue, and the AESO filed an amended application in August, 2005. The EUB set a hearing date for late 2005, and then moved that date into early 2006 for procedural reasons. However, the hearing was adjourned in November, 2005, after the EUB received an indication that Alberta Energy would be implementing measures in new regulation(s) directly addressing the issues.

BCUC – Open Access Transmission Tariff

The BCUC conducted a hearing in relation to an application by the British Columbia Transmission Corporation (BCTC) for an Open Access Tariff. Given the interconnectedness between the Alberta and B.C. transmission systems, the matters were of keen interest to the Alberta market and to the MSA.

The AESO intervened in the proceeding and presented evidence and argument on various matters, including on so-called "network economy" and assurance of non-discriminatory transmission access.

On June 20, 2005 the BCUC issued its written decision in relation to the proceeding. The decision can be found on the BCUC website at: www.bcuc.com.

Of particular and ongoing interest to Alberta, the BCUC directed BCTC to file regular reporting in relation to network economy. The BCUC also appointed a separate panel to review the conduct of B.C. Hydro in relation to network economy. That review concluded that violations of the existing network economy rules had occurred. Accordingly, it was recommended that a formal process leading to a new, enforceable tariff provision should be initiated.

In November, 2005 the BCUC issued an order (G-127-05) directing BCTC to undertake a consultation process and then to apply to the BCUC for approval of a clear, enforceable network economy tariff provision. A consultation process was conducted during January and February 2006 which included public presentations as well as submission of written comments by interested. Based on feedback received, BCTC redrafted the network economy provision and filed its tariff with the BC Utilities Commission as directed on March 1, 2006.

2.2 Retail Market Metrics

The MSA continues to track performance in the retail market based on various metrics across four general customer groups

The four primary customer categories that are reviewed include: the Residential RRT eligible, the Farm RRT eligible, the small commercial RRT eligible and finally the non RRT eligible category which are those that historically consume greater than 250 MWh annually.

Figure 31 - Current Market Share of Retailers by Load (Q4/05)

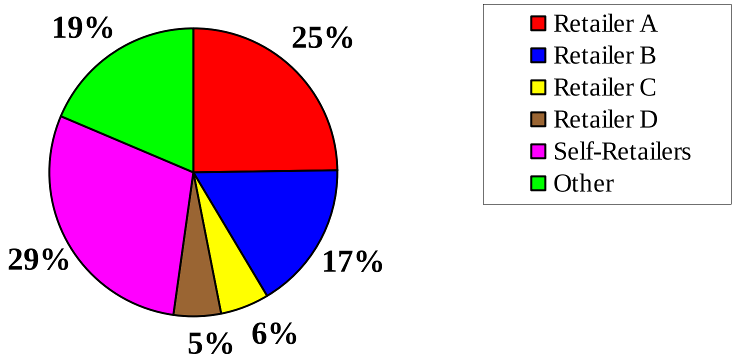
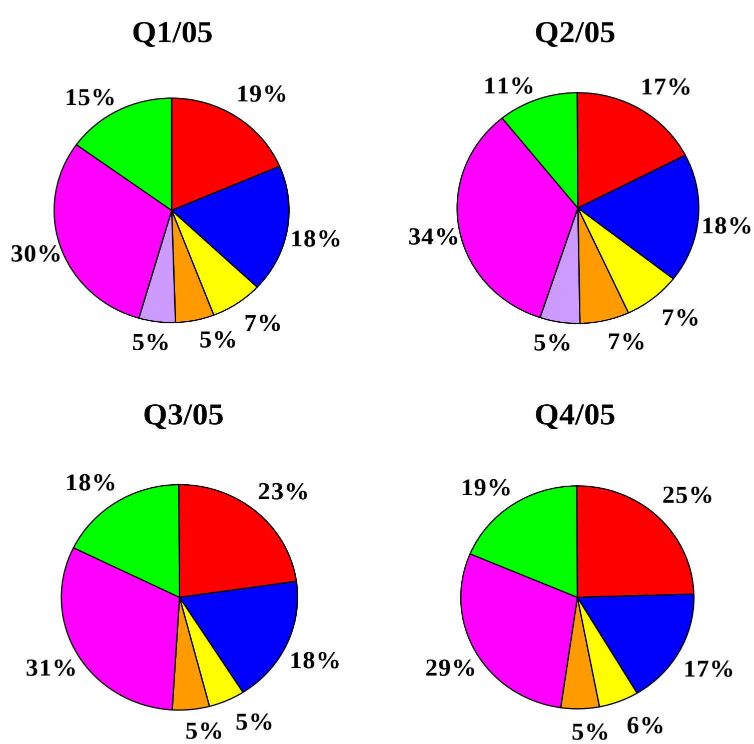


Figure 31 shows the overall provincial market share of retailers for Q4/05. The largest four retailers are servicing over 53% of the total provincial load. Self-retailers, usually large industrial organizations, make up another 29%, while assorted smaller retailers are competing for the remaining 19% of the market. The large amount of load in the self-retail category reflects the ability of larger industrial firms to manage their energy options in-house as opposed to relying on default supply options provided by the incumbent retailers.

Figure 32 - Historical Market Share of Retailers by Load



**Note: Colours indicate individual Retailers and do not necessarily represent the same retailer for each quarter.

Figure 32 provides a look at the changes in retailer market share by load in the four quarters of 2005. Demand patterns are of course influenced by factors such as weather so it would not be uncommon to see variation from quarter to quarter. The above figure shows a fairly stable trend in the market shares of retailers.

Figure 33 below, shows retailer market share by customer class for Q4/05.

Market shares of the three dominant retailers in the Residential – RRT Eligible class have not substantially changed over the last two years. One of these retailers has recently launched a retail campaign for residential customers aimed at acquiring more market share in this category. This has had some impact on market shares in Q4 and is expected to have a continued effect on this market.

In the Farm – RRT Eligible category, market shares have changed little in the past quarter and have remained quite constant through 2005. For Q4/05, market shares of the two main retailers in the Commercial/Industrial – RRT Eligible category have remained steady. The cumulative market share of the three largest retailers comprises 70% of the total load. For some customers in this category, self-retailing may be appealing in order to have greater control over their energy costs.

Figure 33 - Q4/05 Market Share of Retailers by Customer Class

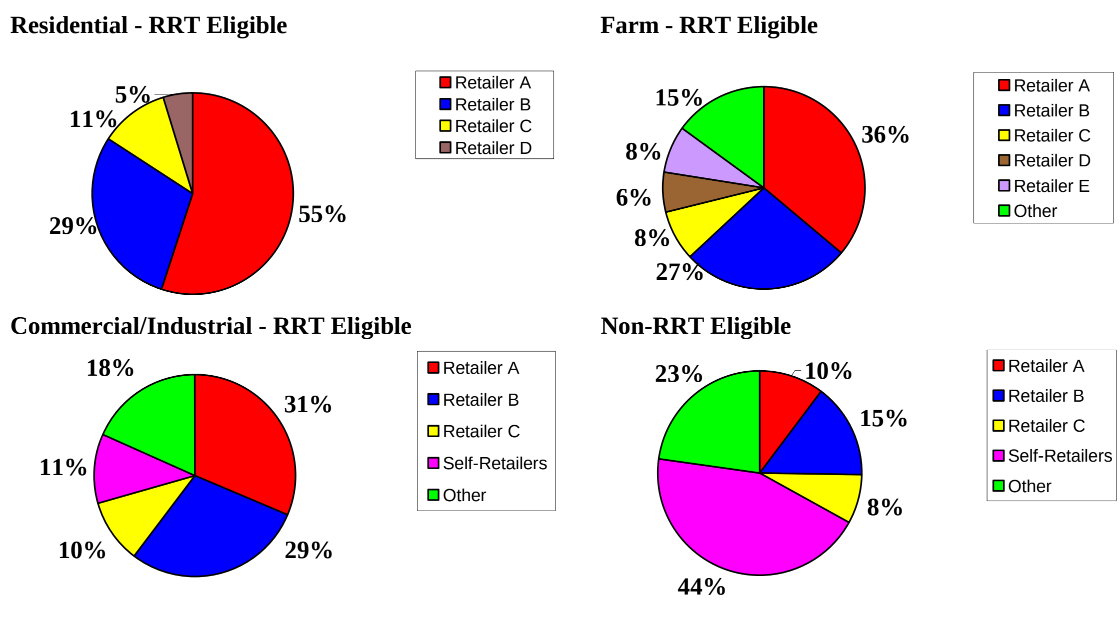


Figure 34 is another way to look at the shift in market share in the four categories. The picture is useful in providing an overall view of the change in market share over the past 12 quarters and demonstrates the changes experienced in the retail market. It is worthwhile to note the entry

and exit of new retailers in the graphs which clearly shows the ongoing battle for market share in certain parts of our retail market.

Figure 34 - Change in Market Share by Category (Q4/05)

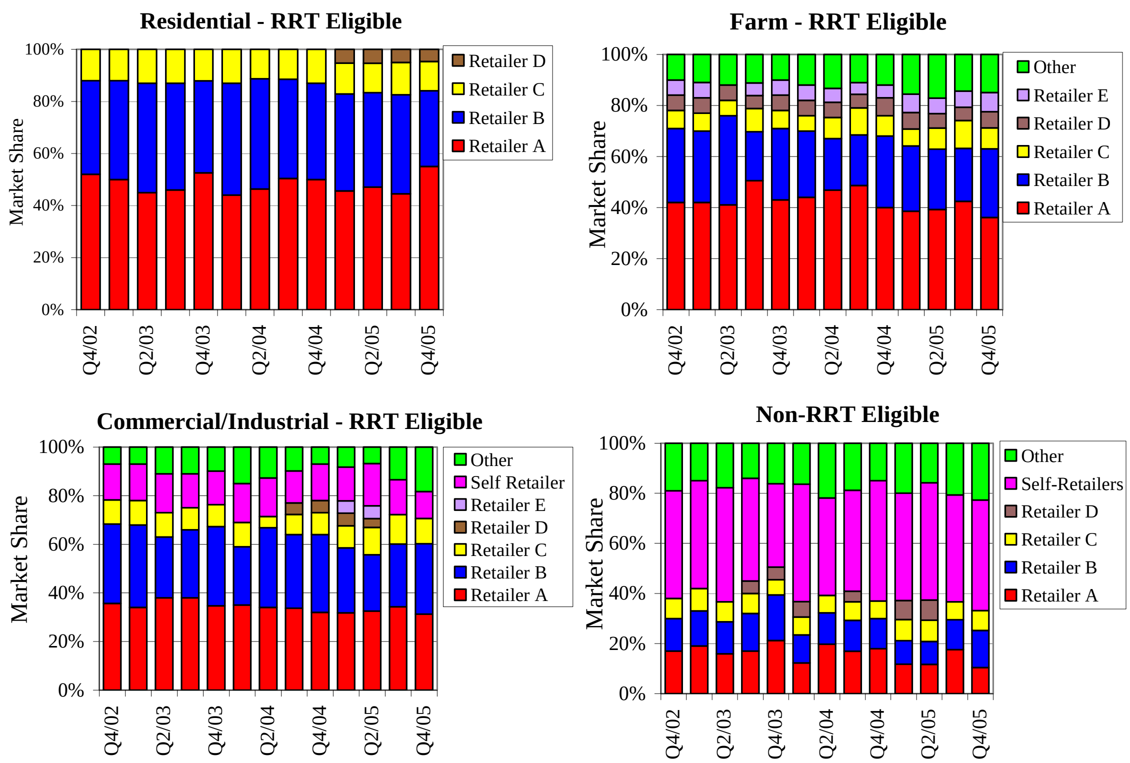


Figure 35 shows that the overall progression of customer sites off of the RRT to competitive electricity contracts has previously been relatively steady but has risen in the most recent quarter.

Figure 35 – Progression of Eligible sites switching off RRT

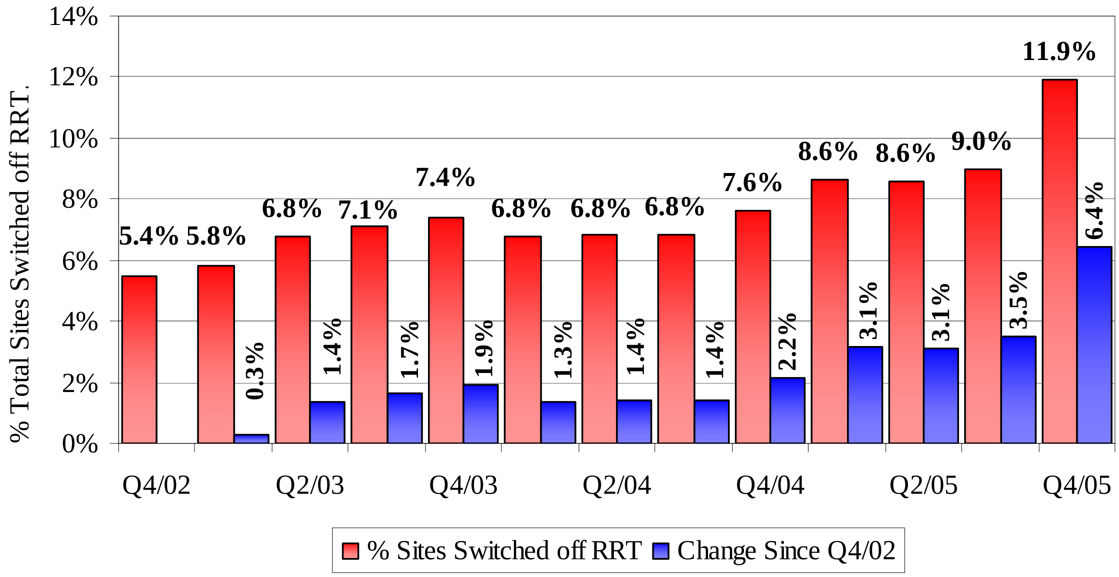


Figure 36 - Progression of Eligible sites switching off RRT by Customer Type

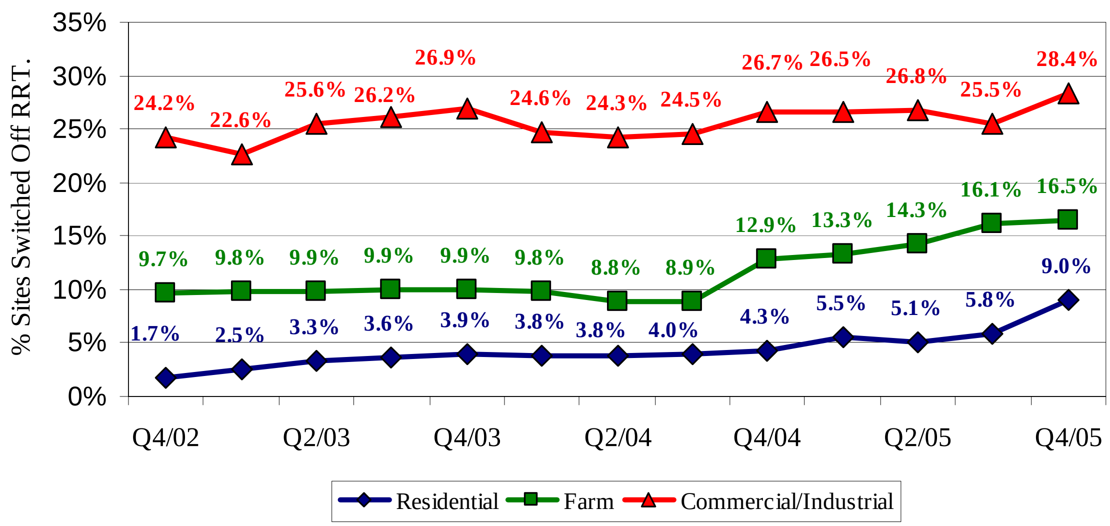


Figure 36 shows the progression of RRT eligible sites switching off RRT by customer type. Switching results are encouraging in all categories as each made gains in 2005.

Switching rates in the Commercial/Industrial – RRT eligible category experienced an increase of about 3% and reached the level of 28.4%.

Farm category switching has remained steady in the past quarter. This category is the smallest in terms of total load but with REAs becoming more involved in retailing, there has been noticeable change in market shares in the past year.

The Residential – RRT eligible customer category has experienced the most dramatic increase both in terms of total numbers and as a percentage. The increase in switching indicates retailers are able to find customers in this category who find competitive contracts an attractive option to the regulated rate. The data collected by the MSA seems to provide a slightly lower switching rate in the residential category when compared to other sources which report switching levels of around 11%. This discrepancy may be attributed to source data inconsistencies and will be reviewed in the coming months. Nevertheless, the switching rates are on the rise in this category and are certainly in the range of 9%-11%.

2.3 Settlement System Code Monitoring

The MSA maintains an interest in a wide variety of issues relating to Settlement System Code (SSC) and monitors how settlement is working in Alberta. As detailed monitoring of settlement and compliance to the SSC is the role of the AESO, the MSA observations will tend to be more directional in nature, identifying trends in the settlement process.

Complaints

The SSC uses PFECs, PFAM[3]s and Notices of Dispute as tools to resolve disputes resulting from the settlement process and calculations. PFECs occur prior to final settlement while PFAMs occur after or post-final settlement. Statistics regarding the number of PFEC/PFAMs submitted, accepted and rejected were collected from the four load settlement agents (LSAs) in the province. **Table 6 and 7** summarizes the PFEC and PFAM tracking for 2005.

Table 6 - PFEC Tracking (by Quarter)

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved
PFEC					
Q4/05	195	594	611	51	127
Q3/05	191	531	506	21	195
Q2/05	67	317	187	6	191
Q1/05.	224	56	202	11	67

A large number of PFEC's were submitted in the last 3 quarters of the year with the majority being accepted within the same quarter or the following quarter. For the most part the PFEC process is operating well and is dealing with the majority of settlement errors prior to final settlement. This in turn has a positive impact on the flow of PFAMs.

[3] PFEC – Post-final Adjustment Mechanism; PFAM – Pre-final Error Correction

In Q4, the bulk of the PFEC's were submitted shortly before the year end and were not able to be addressed immediately due to the holiday break but were dealt with early in Q1 2006.

The PFEC process will be continued to be closely monitored by the MSA to ensure the PFECs are dealt with in a timely manner and the number of unresolved do not grow.

Table 7 - PFAM Tracking (by Quarter)

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFAM						
Q4/05	48	79	100	19	8	36,081,731
Q3/05	93	185	171	59	48	3,999,846
Q2/05	56	318	260	21	93	(12,246,637)
Q1/05.	20	141	26	79	56	(2,648,937)

There has been a noticeable positive trend in the timeliness of addressing PFAM issues in 2005. There have been fewer issues carried over from one quarter to the next with most being dealt with soon after they are submitted. As we start 2006, there are only 8 unresolved issues.

Unaccounted For Energy (UFE)

The MSA also collected data regarding UFE in the form of UFE Reasonable Exception Reports for each of the 10 settlement zones in the province. These reports are posted on the LSAs websites and updated each time UFE in any given zone exceeds either general tolerances or tolerances set by the LSA. **Table 8** summarizes the UFE Reasonable Exception Reports (UFE reports) filed over the last year.

Table 8 - Summary of UFE Reasonable Exception Reporting

Quarter	Carry-Over	New	Resolved	Unresolved
Q4/05	93	50	11	132
Q3/05	32	85	24	93
Q2/05	19	18	5	32
Q1/05	12	21	14	19

At the end of Q4/05 there were 132 unresolved UFE reports with the majority residing in only 3 of the settlement zones. This means that some

LSAs are exceeding UFE tolerances more than others. The existence of any outstanding UFE reports is not an encouraging sign that UFE issues are handled in an efficient manner. We would expect to see significant improvement in the resolution of these UFE issues in 2006.

3 MARKET ISSUES

3.1 TPG / IDP Review

As promised at the outset of TPG/IDP implementation in 2004, a review was conducted after one year to assess whether the desired outcome was achieved. The principle objective of TPG was to level the playing field with respect to advance knowledge of planned or discretionary generation outages. The large incumbent generators historically held an information advantage in the marketplace since knowledge of their own outages was not disseminated to the market at large. As a result, trading counterparties found themselves on the wrong side of a distinct information asymmetry. The intent of TPG was to oblige parties to disclose their outage information in advance of transacting on it. The IDP is the set of procedures by which parties are required to provide outage notification. The information is then disseminated to the market at large in an aggregate format.

The MSA's 2005 review of TPG/IDP revealed an upward trend in overall forward market volumes contrary to the concerns voiced by some participants that this initiative would damage forward market liquidity. As well, concerns that a party in a short position would be disadvantaged by outage disclosure were mitigated by disguise mechanisms imbedded in the IDP protocol. Finally, a stakeholder survey revealed strong support for the notion that TPG/IDP is a fundamental part of ensuring a level playing field – analogous to controls on insider trading in equity markets. As a result, the TPG/IDP mechanism was retained. The MSA implemented further improvements to the IDP process during 2005 by leading the progression from a three reports per day format to a real time reporting format linked to the ETS system of the AESO. The MSA also facilitated the implementation of an automated messaging system to resolve further notification issues between PPA owners and buyers.

3.2 Tie Line Economics

Import conduct on the transmission interconnections was a continued source of controversy into 2005. In the view of the MSA, imports or exports undertaken for the primary purpose of driving Pool price up or down to benefit a portfolio position is seen as harmful to Pool price fidelity. In brief, managing a portfolio to suit the market is acceptable whereas attempting to manage the market to suit a portfolio is not.

In January, the MSA published a report entitled "A Review of Imports, Exports, and Economic use of the BC Interconnection". This review contained findings that were presented to the market in the MSA's fall 2004 stakeholder meeting and outlined the MSA's position on uneconomic tie line behaviour. In early Q3/05, the MSA published a notice to market participants in which a standard of conduct for tie line activity was more clearly articulated. In September, the MSA followed with an update paper on economic use of the BC interconnection.

Findings of the September update showed that uneconomic imports on the BC tie line were prevalent in three distinct periods of 2005. These were primarily attributed to the activities and conduct of one of three parties in each case. The analysis underscored this and also showed in each case that after the MSA clarified its guidance with the party in question, the participant's behaviour substantially improved. The MSA continues to closely monitor activity on both the BC and Saskatchewan tie lines to ensure conduct is consistent with guidance that has been provided to market participants.

3.3 Transmission Must-Run (TMR)

In Q1/05, the MSA published a report on its investigation into Transmission-Must-Run (TMR) procurement which was initiated in late 2004. The process around TMR procurement had grown contentious as participants questioned the competitiveness of the process and the practice of non-RFP procurement mechanisms for TMR used by the AESO. The MSA's investigation and report attempted to answer the question of if a competitive market for TMR exists and if not, to identify alternatives. Charles River Associates (CRA) assisted the MSA in reviewing this issue and a report by CRA is appended to the MSA paper.

3.4 Investigations

At the end of 2005, the MSA had two formal investigations underway.

Further details of these proceedings can be found on the MSA website at: http://www.albertamsa.ca/3080.html and at: http://www.albertamsa.ca/470.html . Investigation reports on these investigations will be published upon resolution of these proceedings during 2006.

4 OTHER MSA ACTIVITIES

4.1 Stakeholder Meetings

The MSA held its spring and fall stakeholder meetings which continue to be well attended events. The spring meeting has historically served to highlight MSA work plan and priorities for the coming year. The fall meeting has tended to be a forum to apprise Participants of important initiatives or project work the MSA may be undertaking and to highlight some of the conclusions of this work. The stakeholder meetings are also intended to elicit discussion and feedback on important market issues of the day.

4.2 Other Papers Published in 2005

In addition to MSA publications noted elsewhere in this report, the MSA published papers on undesirable conduct and market power and on a common understanding of FEOC. The paper on undesirable conduct and market power sought to clarify for participants, the MSA's view on what constitutes a fair, efficient, and openly competitive market. This paper proposed the use of individual conduct compliance plans as a flexible option to address issues of market concentration in a post-holding restrictions marketplace. The paper entitled *A common understanding of FEOC* was intended to build on the undesirable conduct paper in further clarifying the MSA's approach to discharging its surveillance and enforcement obligations under the EUA particularly in respect of assessing conduct against participant's obligations under section 6 of the Act.

4.3 EISG

In 2005, the MSA continued to participate in and support the efforts of the Energy Inter-Market Surveillance Group (EISG) - an affiliation of agencies with a similar mandate in other competitive electricity markets in North America and abroad. This group meets twice annually to discuss issues of mutual concern from the perspective of facilitating fair and competitive electricity markets.