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MSA REPORT

2004 Year in Review

14 March, 2005

MARKET SURVEILLANCE ADMINISTRATOR

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Executive Summary

This Year in Review is the MSA's technical report covering 2004 in a similar presentation to the MSA quarterly reports. Under separate cover, the MSA also publishes its annual report.

Two thousand four was a challenging year for generators as average Pool prices were down relative to last year and market heat rates declined for the fourth consecutive year to 8.8 GJ/MWh in 2004. As difficult a year as it was for generators, it doesn't get a lot better for wholesale purchasers of electrical energy out of the Pool. It was entirely expected that prices in 2004 would continue to decline as large amounts of new efficient capacity were brought on-line. While directionally, the market is working as it should, the magnitude and persistence of the price decline raises concerns of sustainability. More than 5,000 MW of supply – over half of the roughly 9,000 MW demand – is regularly offered into the market at $0.00 for part of the day simply to ensure that the units remain in merit and can continue to operate. On December 20th, the Pool price fell to $0.00 for 5 consecutive hours even as Alberta exported power. Quite appropriately, the question of sustainability has been raised and was the subject of a series of consultations hosted by the Department of Energy and the AESO during the second half of the year. In theory, prices will rebound in due course, returning generators to profitability and ultimately signaling the need for additional capacity as demand growth shrinks the current oversupply. We have seen significant new capacity added to Alberta's generation base at no risk to ratepayers over the past three years with attendant price effects; over the next two years we shall have to assure ourselves that the pendulum swings both ways but can do so within reasonable bounds.

For the retail customer, billing accuracy was improved, a number of deferral account charges came to an end, removing some of the "extra" charges related to 2001, and the retail market gained new players. Direct Energy commenced operations, Energy Savings Income Fund announced their arrival for 2005, and various REAs reorganized in anticipation of offering competitive contracts for energy. In spite of the current legislation, there is still uncertainty about whether the regulated retail pricing will go to a Pool price flow-through methodology in mid-2006; a retail market review underway in early 2005 should reduce this uncertainty.

The MSA looks forward to working with industry, policymakers and the other implementing agencies in 2005 to ensure that Alberta's restructured electricity market is fair, efficient, and openly competitive.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

The market price of electricity is the metric that speaks directly and most immediately to market participants – both generators and load. While the absolute level of market prices provides some context as to the current financial health of market participants, it is the fidelity or trueness of this price signal relative to the market and industry fundamentals that is of primary focus to the MSA. In a competitive market, a high fidelity price signal provides incentive for the appropriate market response both in real time as well as long-term which promotes an optimal balance between generation supply and system demand.

Table 1 shows that the average hourly wholesale price for electricity in the Alberta market was down in 2004 to \$54.59/MWh relative to \$62.99/MWh in 2003. Monthly average prices ranged from \$42.46/MWh in March to \$67.13/MWh in May; a significantly narrower range than 2003 in which monthly average prices ranged from \$43.62/MWh to \$87.91/MWh. The relative stability in Pool price through the majority of 2004 is attributed in part to above average coal unit availability through much of the year. As a result, price spikes were more infrequent than in 2003 as indicated by the price duration curves in **Figure 1** which show that prices in 2004 exceeded \$100.00/MWh 7.8% of the time as compared to 12.5% of the time in 2003**.** At the other end of the curve, Pool price was \$20.00 or below 19% of the time in 2004 as compared to 16.7% of the time in 2003.

Figure 2 shows that while price volatility was quite moderate through the middle eight months of the year, January and February as well as November and December saw higher levels of volatility.

Table 1 – Pool Price Statistics 2004

2004	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Jan - 04	56.51	66.61	42.53	61.98	110%
Feb - 04	47.38	50.13	43.99	49.20	104%
Mar - 04	42.46	48.50	34.09	33.80	80%
Apr - 04	51.98	62.24	37.90	39.97	77%
May - 04	67.13	80.44	51.66	53.64	80%
Jun - 04	61.11	70.44	48.34	48.56	79%
Jul - 04	56.55	65.18	45.61	44.94	79%
Aug - 04	50.17	63.00	33.90	45.25	90%
Sep - 04	56.33	68.76	40.79	47.79	85%
Oct - 04	57.84	68.49	44.37	51.07	88%
Nov - 04	44.13	53.54	32.37	52.30	119%
Dec - 04	62.87	75.18	47.26	88.12	140%
2004	54.59	64.54	41.88	53.53	98%
2003	62.99	75.54	46.98	70.40	112%

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

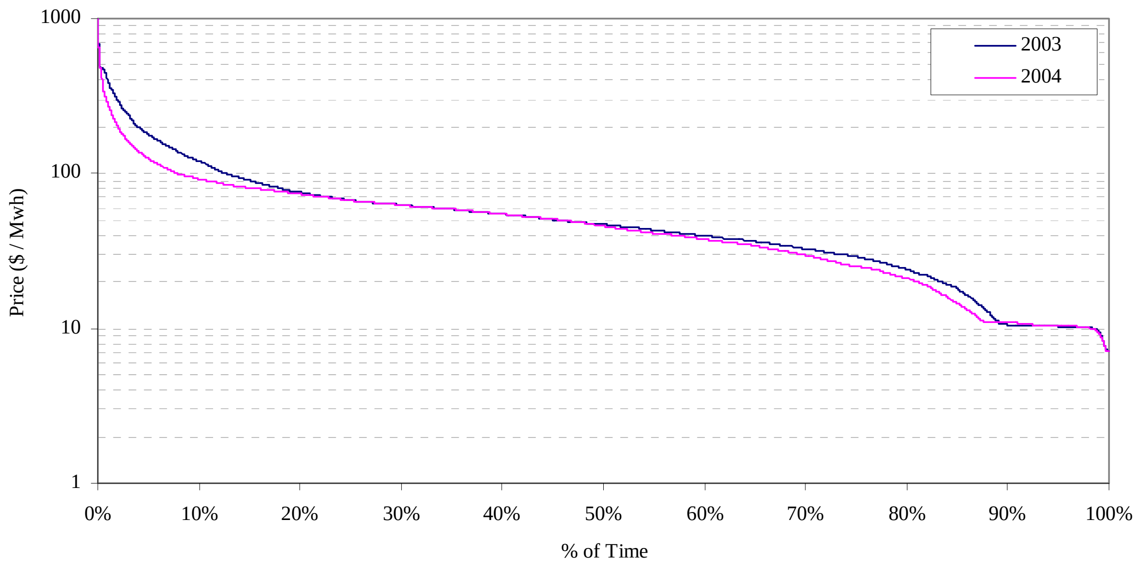
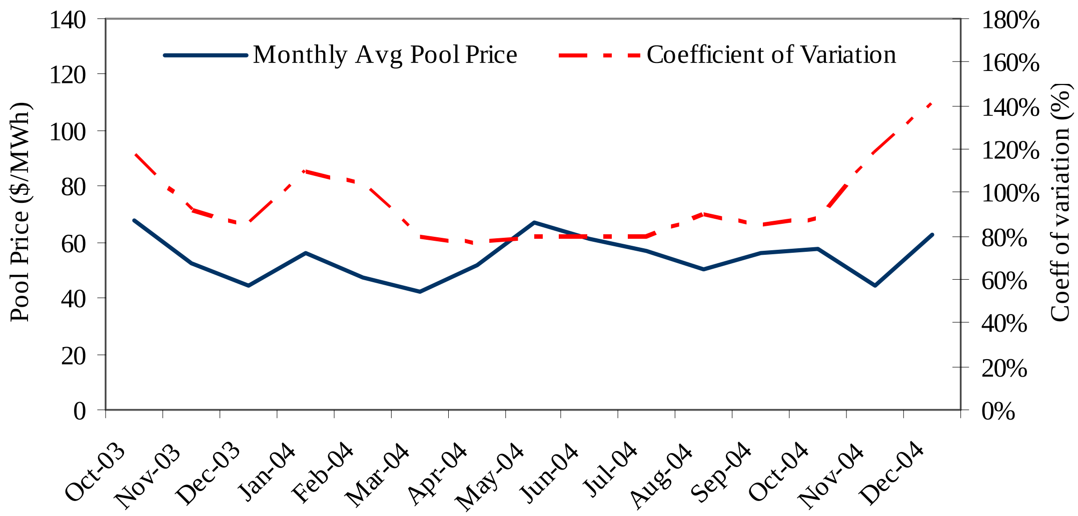


Figure 2 - Pool Price with Pool Price Volatility

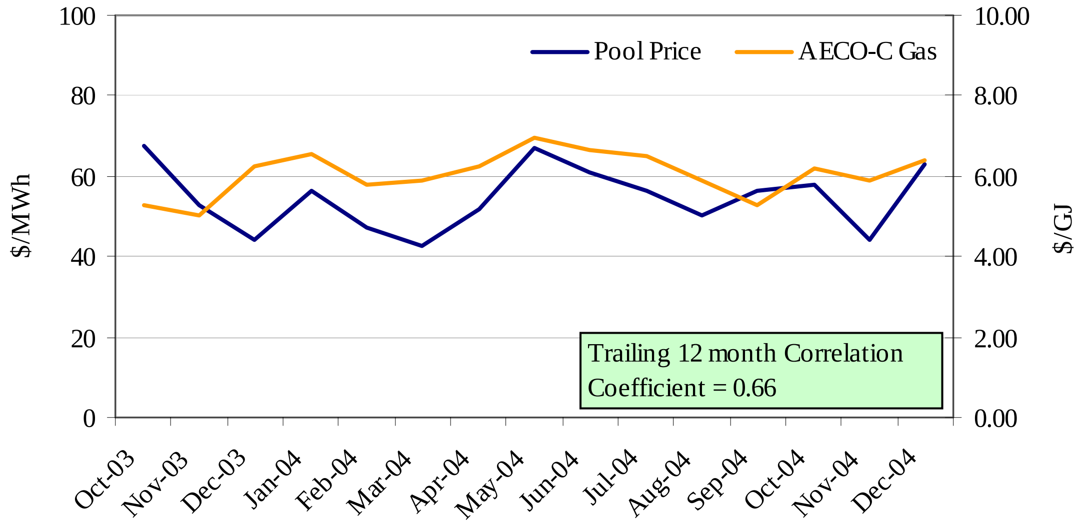


1.2 Natural Gas Prices

Alberta natural gas prices were down marginally in 2004 to $6.19/GJ relative to $6.31/GJ in 2003. While gas prices fluctuated through 2003, they remained closer to the $6.00/GJ level through the majority of 2004. Lack of new production and strong crude prices drove gas prices in 2004 even through robust storage statistics and a mild early heating season.

The trailing 12-month correlation between electricity prices and gas prices improved significantly in the period ending December 31, 2004 to 0.66 from 0.49 in 2003. This is due in large measure to our rolling calculation period moving past the Q3/03 period in which Pool price fluctuated strongly in a flat gas price environment. Clearly, variables other than gas price were driving offer behaviour through this period. With relatively high coal unit availability, the frequency of short-term market tightness was also reduced in 2004 which would also have benefited the correlation.

Figure 3 - Pool Price with AECO - C Gas Price



1.3 Price Setters

Figure 4 shows the 5 most frequent price setting participants in 2004 as compared to 2003 together with the weighted average price at which they set the SMP (the participant at each ranking position is not necessarily the same for both years shown). Price setting activity of each market participant is a function of asset characteristics coupled with offer behaviour. The most frequent price setting participant in 2004 set price 23% of the time at a weighted average SMP of $71.58/MWh. Last year the leading price setter set price 18% of the time at a weighted average SMP of $49.22/MWh. While the lead price setting share increased marginally in 2004, the top 5 price setters share declined to 73% from 76% in 2003. This underscores that while certain participants tend to more commonly be price setters, no one party is on the margin for a disproportionate period of time.

Figure 4 - Price Setters by Participant (All Hours)

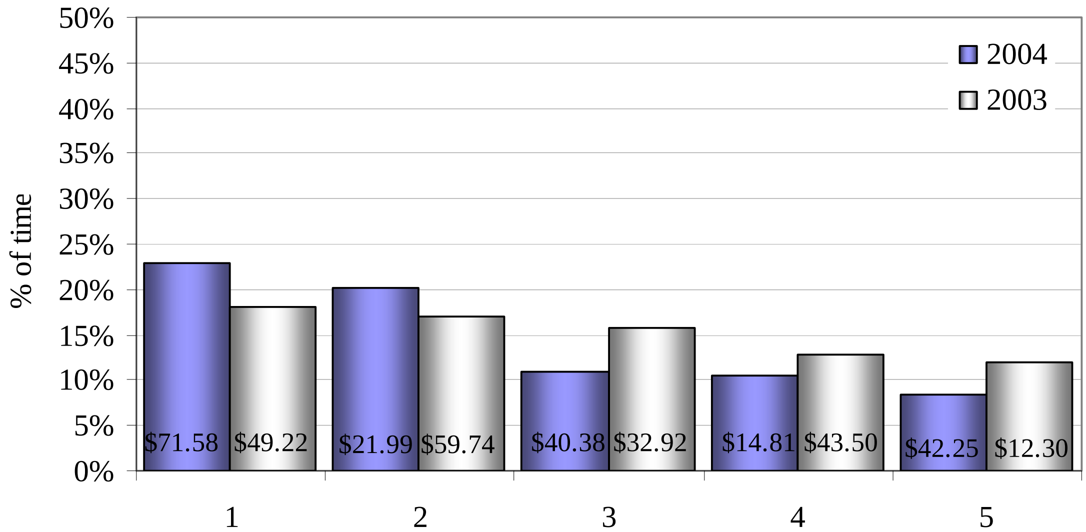
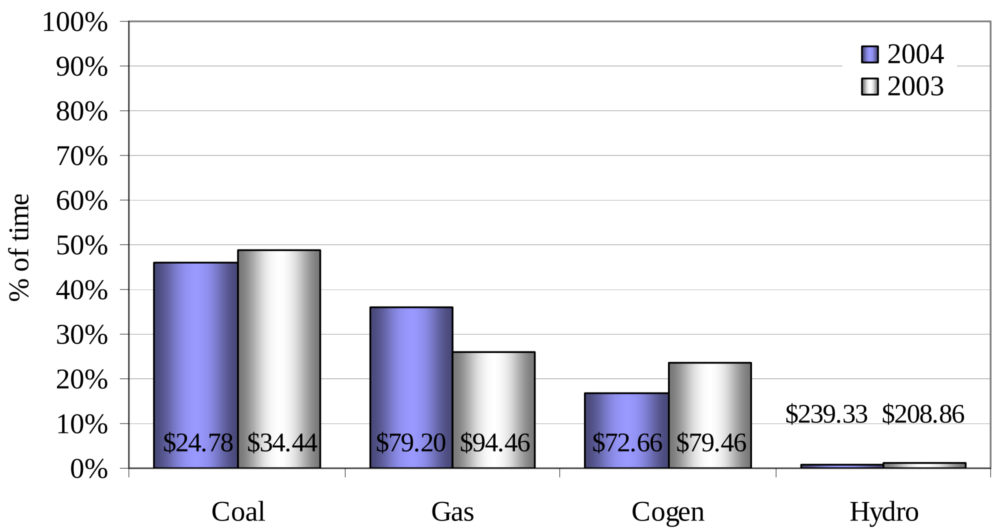


Figure 5 shows similar data broken out by fuel type of the marginal unit for 2004 and 2003. Coal units set price somewhat less frequently in 2004 as compared to 2003 but did so at a lower weighted average marginal price of $24.78/MWh compared with $34.44/MWh last year. Gas units were more frequently marginal units in 2004 while cogen units were less so, and the net effect for all gas units combined was that gas and cogen set price 53% of the time in 2004 vs. 50% of the time in 2003 but at a lower weighted average SMP of $77.11/MWh as compared to $87.33/MWh in 2003.

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



1.4 Implied Market Heat Rate

The implied market heat rate is a metric that places prevailing electricity prices (an absolute measure) into a relative profitability context for gas generators. For generators, electricity prices can only be deemed favorable or unfavorable relative to the cost of feedstock and the thermal efficiency rating of the generating unit. For example, in a $7.00/GJ gas environment, a generator with a relatively efficient heat rate of 8.5 GJ/MWh needs a Pool price of $59.50/MWh just to break even on its fuel costs, excluding other variable operating costs or return of capital. **Figure 6** shows duration curves for heat rates observed through 2004 relative to the three prior years. It was again the case in 2004 that heat rates were lower nearly 100% of the time as compared to the prior year. For context, **Figure 6** shows that a relatively new combined cycle gas generator with a heat rate of about 7.5 GJ/MWh would have been able to recover its variable fuel costs about 60% of the time in 2004, down from 66% of the time in 2003. Implied market heat rates in 2004 exceeded 10.0 GJ/MWh 27% of the time vs. 45% of the time in 2003. As shown in Table 2, monthly average heat rates in 2004 met or exceeded 10.0 GJ/MWh in September and December.

Figure 6 – Heat Rate Duration Curves (All Hours)

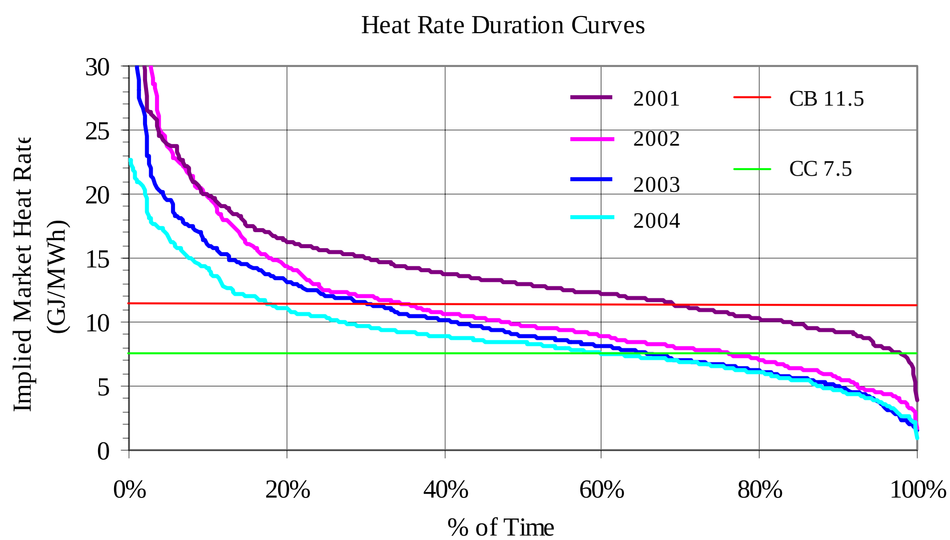


Table 2 – 2004 Implied Market Heat Rates by Month

Month	On-Peak	Off-Peak	All Hours
January	10.1	5.8	8.6
February	8.6	6.3	8.1
March	8.3	5.2	7.2
April	9.9	5.9	8.3
May	11.5	6.8	9.6
June	10.6	7.0	9.2
July	10.1	7.0	8.7
August	10.7	5.4	8.5
September	12.8	7.0	10.6
October	10.9	6.5	9.2
November	9.0	5.0	7.5
December	11.7	6.7	10.0
Average	10.3	6.2	8.8

1.5 New AESO Rules

AESO rule changes of note in 2004 included new short term adequacy rules proposed by industry, which provides some visibility of supply available that is not represented in the merit order. These rules allow system control to direct generating assets to deliver supply shortfall energy if required, based on stated total declared energy of generators.

Also noteworthy was the change in non-compliance threshold for dispatch compliance to ±5 MW from +10 MW relative to a unit's dispatch level. This change also speaks to under-generation whereas the prior rule only applied to over-generation. Details of these rule changes can be reviewed at: http://www.aeso.ca/market/166.html .

1.6 New Supply and Load Growth

Generation additions in 2004 were about equal to additions to the system in the prior year. Some 760 MW of new generation came on-line this year, and with the retirement of TransAlta's Wabamun 1 and 2 units which together comprised 119 MW of coal-fired generation capacity, this yielded a net addition of 641 MW. Overall this represents a year over year increase in installed capacity of about 5.5%. Notable additions included:

- Genesee – Genesee 3 – Coal (450 MW)
- Mackay River – Cogen (165 MW)

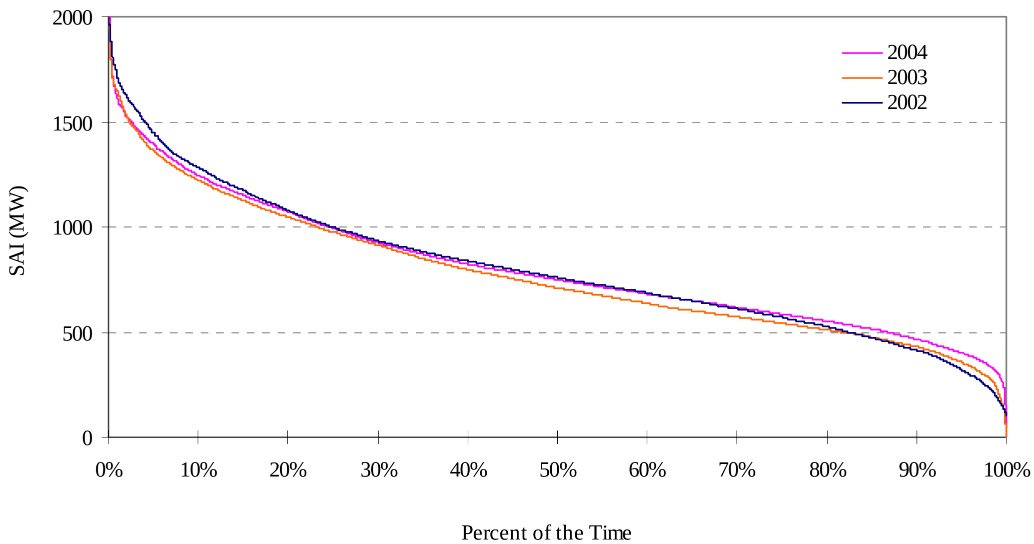
Average system demand in 2004 was 7429 MW (vs. 7159 MW in 2003) and ranged from 7022 MW in the month of May to 7894 MW in December. Peak demand in 2004 reached 9236 MW which occurred on December 22 in HE 18 at a price of $90.00/MWh. Peak demand in 2004 represented an increase of just over 5% relative to peak demand in 2003. Overall, net supply additions in 2004 more than matched the year over year increase in peak system demand.

1.7 Supply Availability Index (SAI)

SAI is defined here as the remaining capacity in the merit order above the level of dispatch. This approximates what additional capacity would have been available to system control in the short term to meet system demand. **Figure 7** shows duration curves for SAI for 2004 together with the two prior years. It can be seen from the figure that the right end of the curve for 2004 reflected fewer hours of short-term market tightness as compared to 2003 and 2002. This is attributed to both the current level of generation supply as well as the relatively high level of coal availability through 2004. The flatter curve for 2004 is also reflected in lower price volatility exhibited in 2004 relative to 2003 and 2002. Supply availability and price are generally negatively correlated since price tends to increase as available supply decreases. In 2004 the correlation coefficient between SAI and hourly Pool price was determined as -0.49. Relative to -0.44 in 2003 and -0.47 2002, the correlation has held stable over the long term.

With the implementation of the AESO's short-term adequacy rules in late 2004, this analysis may be subject to modification.

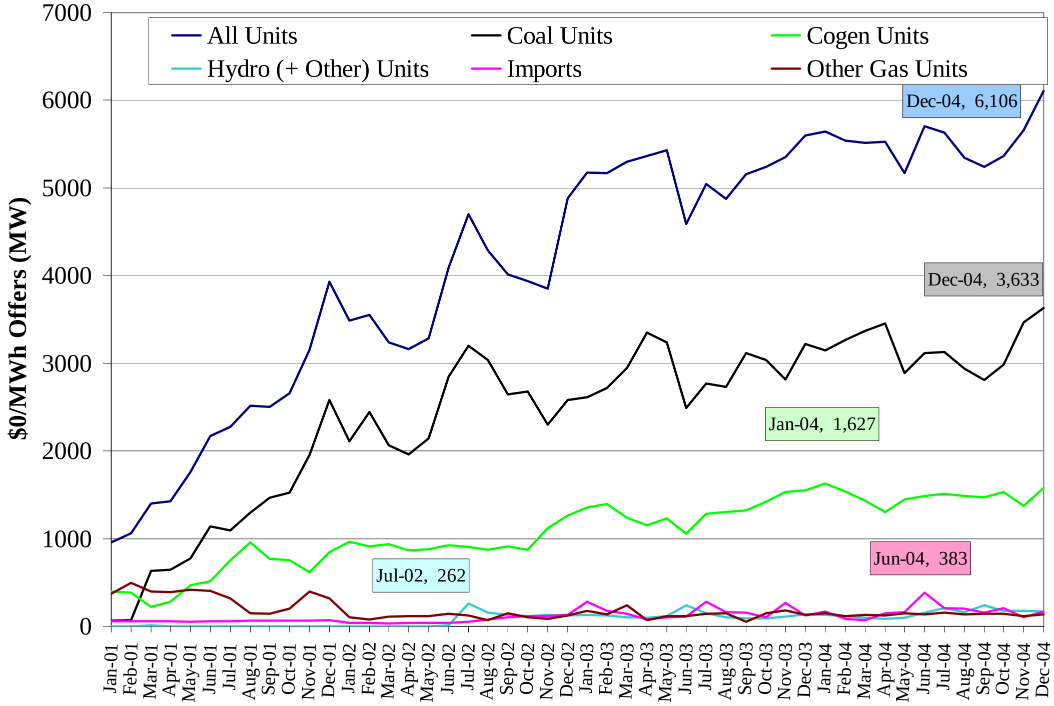
Figure 7 – SAI Duration Curves



1.8 Zero Offers

Over the last four years, zero dollar offers have displayed a steadily increasing trend. **Figure 8** plots monthly average MW offered at $0/MWh by unit type from 2001 to 2004. Monthly high values for each generation type over the four year period are also shown in the figure.

Figure 8 - Zero Dollar Offers

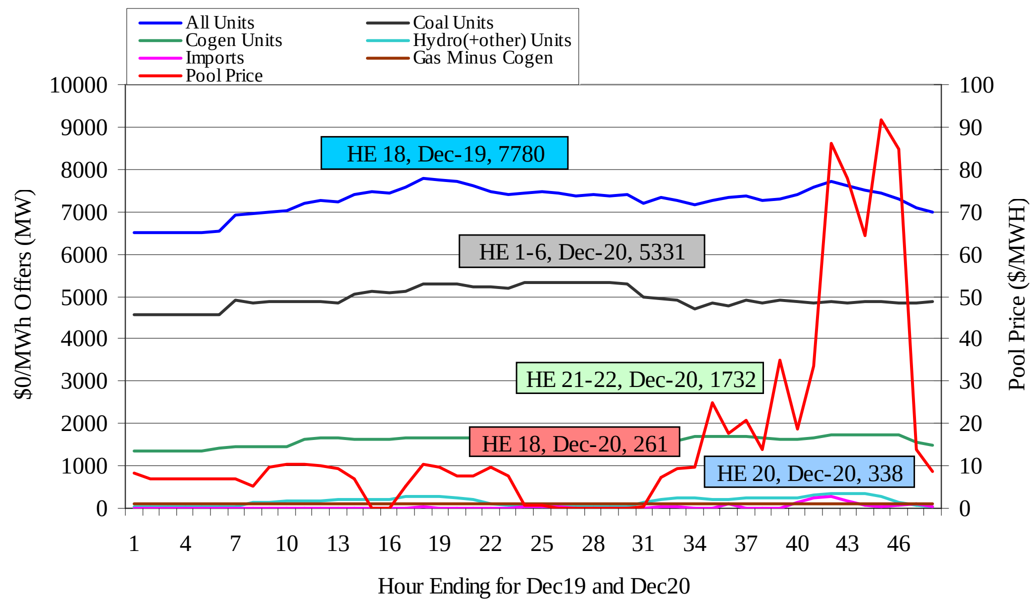


The figure shows that the overall zero offers decreased in Q3/04 from the levels of Q2/04, and then have taken an up-swing over Q4/04. Hourly zero dollar offers averaged 5,709 MW in Q4/04, increasing more than 300 MW from the Q3/04 average of 5,406 MW. The increased volume of zero dollar offers can be partially attributed to relatively high availability of most units, likely in response to anticipated increased winter demand. A similar increase in zero offer volumes was observed from November to December in the past four years, suggesting that the jump is seasonal.

On a monthly basis, total zero dollar offers reached an all-time high in December 2004 at 6106 MW. This was caused primarily by the seasonal effect mentioned above and the commissioning of the Genesee #3 coal unit. This 450 MW unit began commissioning late in 2004 and is expected to go into commercial production by the end of Q1/05. While in the commissioning phase, it is not in a position to respond to system dispatch by SC and thus is offered into the system at zero dollars. When in commercial operation, it is expected that the non base-load portion of the unit will be priced above zero dollars. Zero dollar offers of the other types of generators were relatively stable during 2004.

The presence of Genesee #3 offered at zero dollars exerted some negative pressure on Pool prices in December 2004. Pool price was set at $0 in HE16 on December 19 and from HE2-HE6 on December 20. This was mainly due to high volume of zero offers combined with lower loads than usual due to warm temperatures. The hourly all time high record of zero offers was set at hour 18 in December 19 at 7780 MW. Volume of coal units zero offers set the highest record at HE1 to HE6 in December 20 at 5331 MW which coincides with the zero dollar pool prices. **Figure 9** plots the zero offer volumes and pool price for the 48 hours during the two days period.

Figure 9 - Zero Dollar Offers and Pool Price (Dec 19 and Dec 20)



The continued growth of zero offers in the Alberta market concerns the MSA. In general, provided that the load grows at a rate at least as fast as the growth in zero offers, the occurrence of zero prices will be a relatively rare event. Later this spring load will begin to moderate with the improved weather. However, assuming that some portion of Genesee #3 is offered at a non-zero price and that additional units do not join so-called 'team zero', the change will not be dramatic. Moreover, the high volume of zero offers has already raised concerns for System Control about the best way of dispatching down when system marginal price is set at $0. The MSA will continue to monitor this aspect of the market going forward.

1.9 Imports, Exports, and Prices in Other Electricity Markets

Alberta needs well functioning tie lines since a robust market that wants to continue attracting investment in generation needs the capability to flow excess energy to other markets or to procure shortfalls – our tie-lines provide that service. Tie-line activity can in effect, increase or decrease either supply or demand in the market by up to the physically transfer capacity and therefore, has the potential to significantly impact Pool price. The prices in other markets relative to Alberta prices, affect the activity on the interties which in turn has an impact on price in the Alberta market.

Table 3 summarizes the activity on the tie-lines for 2004 and highlights the tie-line activity in Q4/04 (in yellow).

Table 3 - 2004 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	112,949	53,061	59,888	10,217	21,370	(11,153)	123,166	74,431	48,735
February	49,876	88,322	(38,446)	6,496	18,847	(12,351)	56,372	107,169	(50,797)
March	42,132	103,193	(61,061)	7,713	8,118	(405)	49,845	111,311	(61,466)
Q1 Total	204,957	244,576	(39,619)	24,426	48,335	(23,909)	229,383	292,911	(63,528)
April	68,893	99,625	(30,732)	36,467	4,166	32,301	105,360	103,791	1,569
May	82,726	67,866	14,860	36,976	1,475	35,501	119,702	69,341	50,361
June	199,941	48,907	151,034	74,843	4,046	70,797	274,784	52,953	221,831
Q2 Total	351,560	216,398	135,162	148,286	9,687	138,599	499,846	226,085	273,761
July	132,398	98,363	34,035	54,710	1,415	53,295	187,108	99,778	87,330
August	64,776	118,828	(54,052)	83,866	2,140	81,726	148,642	120,968	27,674
September	64,848	72,274	(7,426)	43,306	700	42,606	108,154	72,974	35,180
Q3 Total	262,022	289,465	(27,443)	181,882	4,255	177,627	443,904	293,720	150,184
October	99,362	49,067	50,295	18,484	8,670	9,814	117,846	57,737	60,109
November	50,417	98,355	(47,938)	18,770	9,580	9,190	69,187	107,935	(38,748)
December	103,884	63,605	40,279	25,901	7,814	18,087	129,785	71,419	58,366
Q4 Total	253,663	211,027	42,636	63,155	26,064	37,091	316,818	237,091	79,727
2004 Total	**1,072,202**	**961,466**	**110,736**	**417,749**	**88,341**	**329,408**	**1,489,951**	**1,049,807**	**440,144**

In Q4/04, Alberta was an overall net importer of almost 80,000 MWh. Heavy importing on the BC tie-line in October and December dominated quarterly BC tie-line activity resulting in net imports for the quarter. The SK tie-line maintained a fairly consistent level of imports and exports in October and November while net imports increased in December. SK tie activity resulted in nearly half the total net imports for Alberta with 37,091 MWhs.

The relatively high level of import activity into Alberta during Q4/04 is due in part to the onset of winter heating season which increases demand. As was identified in the January 2005 MSA report, the tie-line import activity was not always supported by sufficiently high prices in Alberta relative to the neighboring market prices.

Over 2004, Alberta imported nearly 1.5 million MWh of electricity and exported over 1 million MWh resulting in overall net imports of some 440,000 MWh. BC tie-line activity was fairly evenly split between import activity and export activity. The SK tie was used for exporting energy much less often than importing with the Saskatchewan tie-line imports outnumbering exports by a ratio of nearly 5 to 1.

Figure 10 - Market Share of Importers and Exporters (Q4/04)

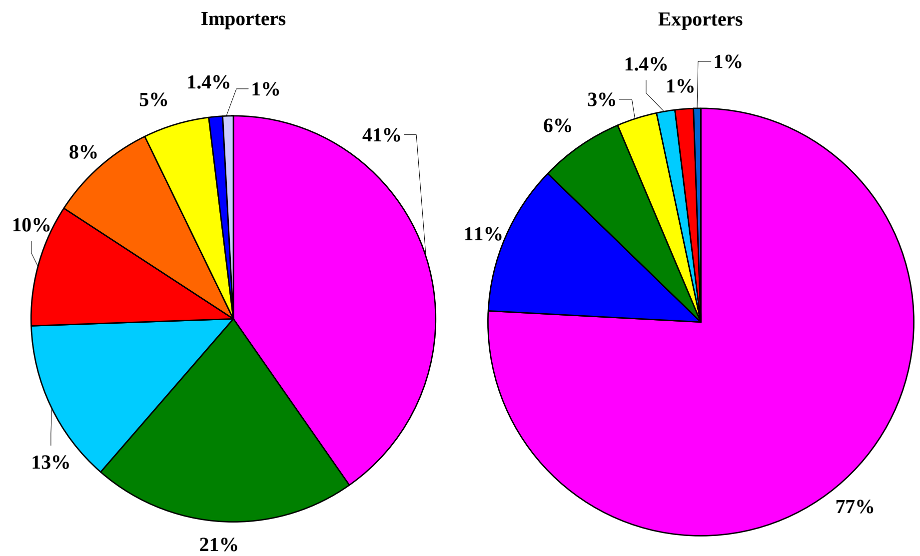


Figure 11 - Market Share of Importers and Exporters (2004)

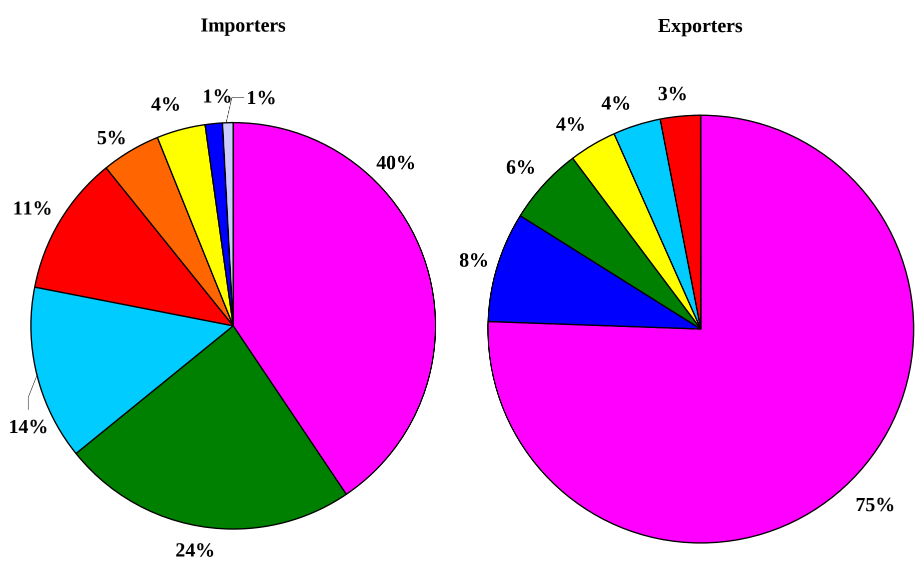


Figure 10 shows the distribution of market shares of importers and exporters on the BC and Saskatchewan tie-lines (combined) in Q4. **Figure 11** shows the same information for the whole of 2004. Market share of importers was reasonably well distributed in Q4/04, and for the entire year. The dominant importer (Powerex) had a 41% market share in Q4 which is consistent with the entire 2004 market share they had of 40%.

The other participants hold a relatively constant market share position for the entire year and from quarter to quarter. Some significant import activity by individual participants have been observed over the course of 2004 but the majority of this activity is in response to a physical short position experienced locally in Alberta and the imported energy being used as replacement energy for a unit on outage.

Market share of exporters is more clearly dominated by a single participant on both a quarterly and an annual basis. This is not surprising as this participant (Powerex) has access to firm transmission rights on the BC tie-line and has the only natural storage option due to its hydro system. Powerex primarily makes use of the export transmission capacity during off-peak hours.

Exporting during the on peak hours has been impossible for many of the hours due to physical constraints that bring the Export ATC levels down 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. The AESO 10 year Transmission System Plan 2005 – 2014, outlines a series of planned upgrades to the grid.

Figure 12 shows a duration curve of tie-line utilization for Q4/04 as a function of available transfer capability (ATC) – the maximum amount of energy which can be moved across the tie-line in any given hour[1]. **Figure 13** looks at the whole of 2004. Note that we would not expect all of the tie-lines to be full, or even in use, 100% of the time. A number of factors including (but not limited to) transmission access, Pool price and market position contribute to determining whether or not it is profitable to make use of the available tie-line capacity.

[1] For example, if the ATC of an intertie for an hour was 500 MW and only 200 MW flowed across that line in that hour, the utilization would be 40%. ATC is posted on the AESO website and varies on an hourly basis.

Figure 12 - Tie-Line Utilization (Q4/04)

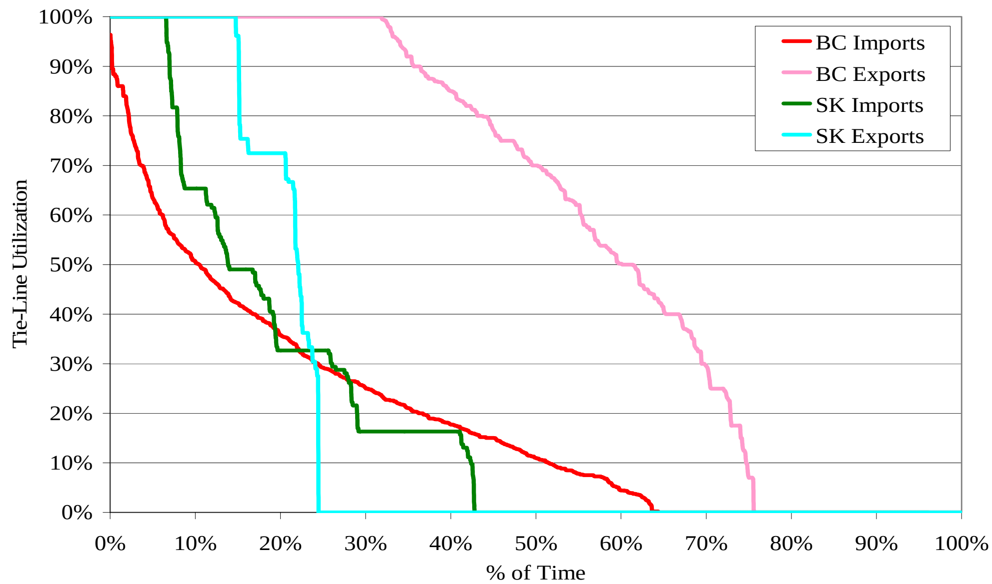
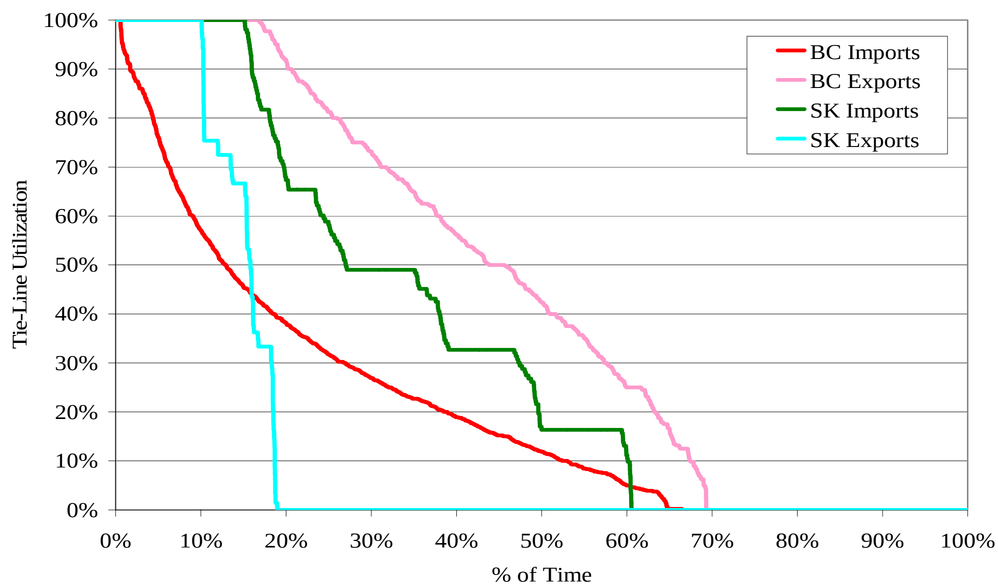


Figure 13 - Tie-Line Utilization (2004)



The figures show that there is unutilized tie-line capacity available on all of the tie lines for significant periods of time. This fact does not necessarily indicate a problem with use of the interties as it is feasible for the conditions to exist which make the use of the intertie economically unappealing.

In both the Q4 graph and the 2004 figure, the BC export line is the most utilized while the Saskatchewan export line is the least utilized. The pictures also show that the SK import tie was less used in Q4 when compared to the year as a whole. This is consistent when looking at the volumes in the table which indicate that SK imports were higher in both Q2 and Q3 relative to Q4.

The ATC of the tie-lines is somewhat dependent on generation and transmission constraints within the province for the highest demand hours of the day. In 2004, the BC export line ATC was often reduced to zero[2] in on peak periods due to physical constraints on the system.

Activity on the tie lines can and should be highly dependent on Pool price. **Figures 14 and 15** plot total monthly imports with average monthly on-peak Pool prices and total monthly exports with average monthly off-peak Pool prices respectively for the October 2003 through December 2004 period. During Q4/04, 89% of imports occurred during on-peak hours and 84% of exports occurred during off-peak hours, therefore comparisons with on and off-peak prices are appropriate.

[2] 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 14 - Imports and On-Peak Pool Price

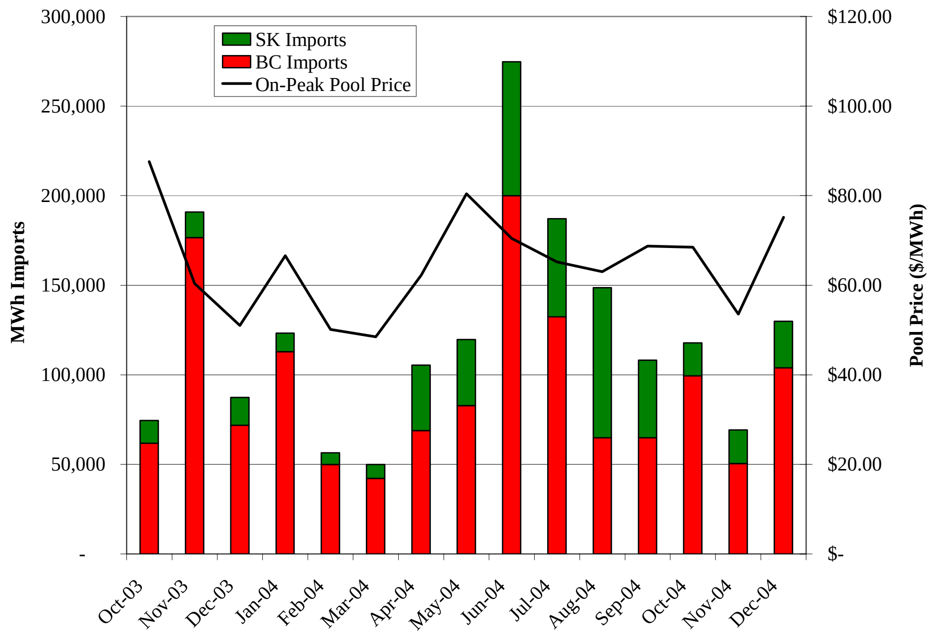
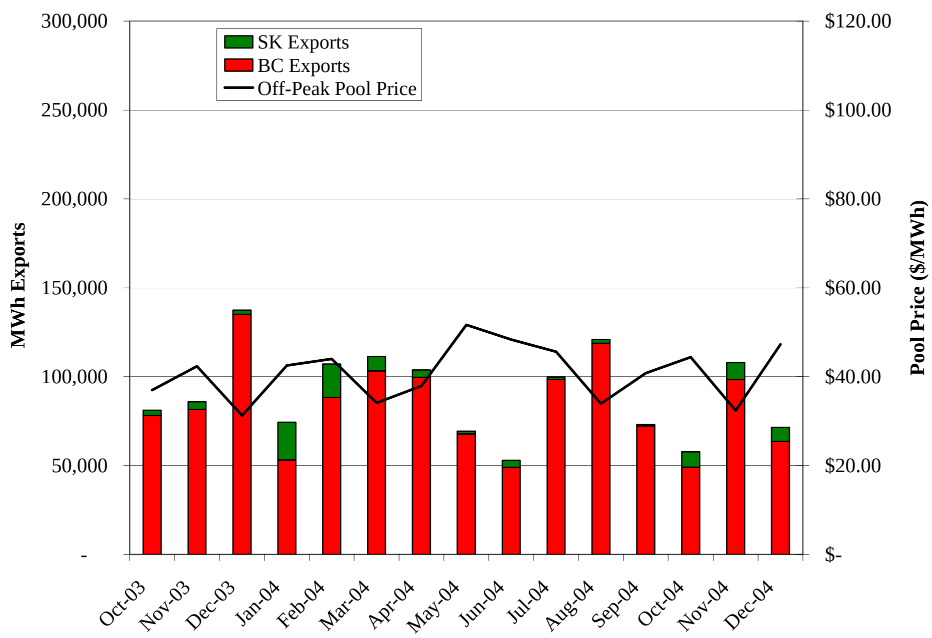


Figure 15 - Exports and Off-Peak Pool Price



Import volumes do not correspond very well with on-peak Pool prices for every month. Irregular patterns as observed in May and June 2004 demonstrate an often reoccurring counter-intuitive relationship between on-peak price and import volumes. The expected pattern should be one where imports from outside Alberta increase as Pool prices rise. This indicates that factors other than Pool price were likely driving import behavior.

In Q4/04, the average on peak price was $65.74/MWh with a total of over 316,000 MWh of electricity being imported over both BC and SK tielines.

During Q4/04, exports were fairly moderate in October and December but were especially strong in November when the average off-peak price fell to just over $32.00/MWh. Total export volumes for Q4/04 were over 237,000 MWh which is down about 70,000 MWh when compared to the same period in 2003. This can be at least partially attributed to a higher average off-peak Pool price in Q4/04 than in Q4/03.

Prices in other markets also have an impact on the economics of importing and exporting electricity into and out of the province. Although neither of Alberta's neighbors operates a competitive electricity market, electricity is often moved through these areas and into adjoining markets. **Figures 16 and 17** show monthly average on-peak and off-peak price indices for MAPP-North (US Mid-West) and Mid-C (US Pacific Northwest) compared to Pool price. All prices are in Canadian dollars converted using daily exchange rates.

Figure 16 – On-Peak Prices in Other Markets

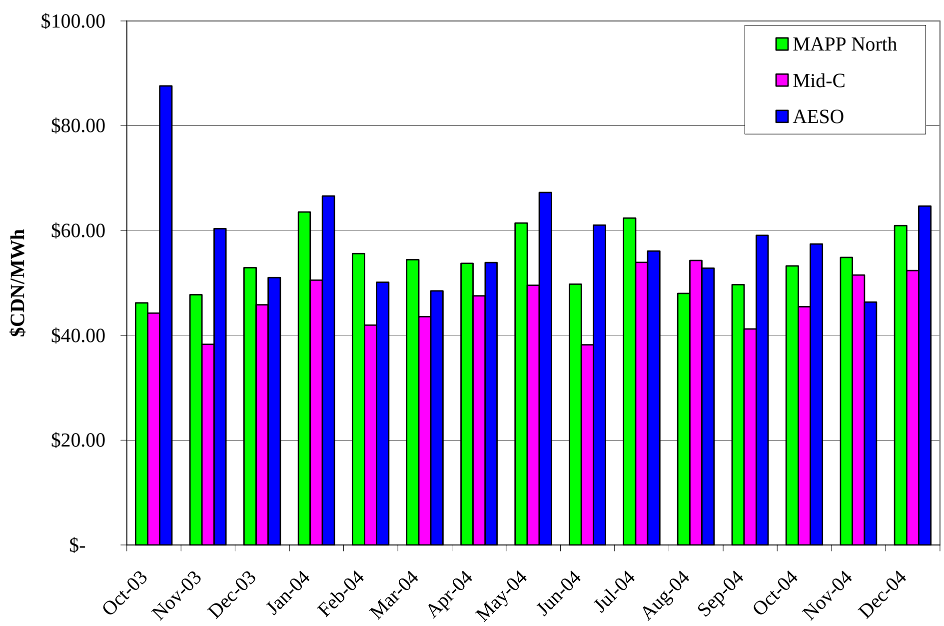
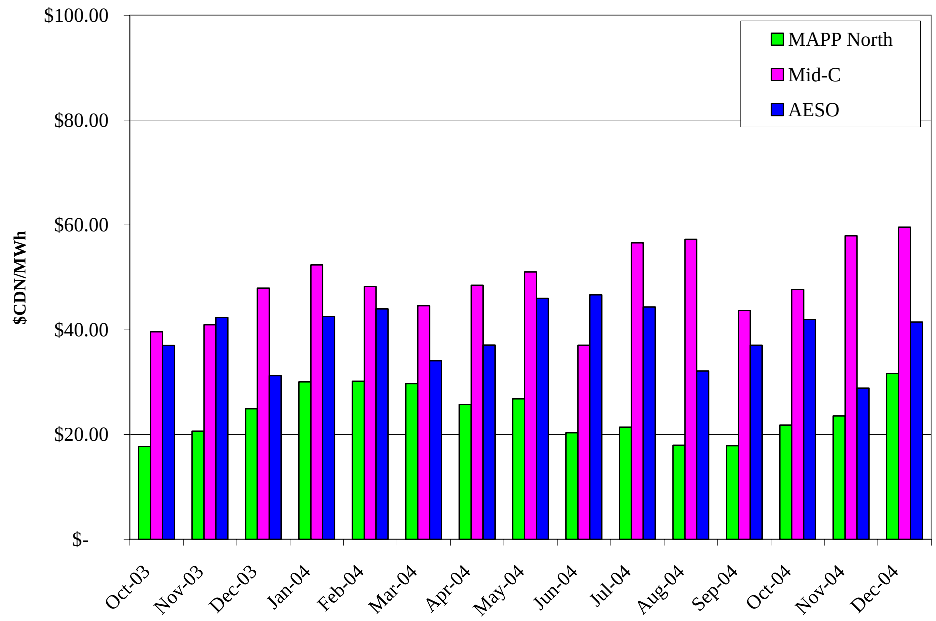


Figure 17 - Off-Peak Prices in Other Markets



On-peak prices in Alberta were within close range of the neighboring markets for Q4. Throughout October and December prices were higher in Alberta relative to other markets, potentially encouraging importing activity. During November the price differential reversed with Alberta having lower prices than its neighbors. These price differentials are in line with observed import/export volumes and provide a partial explanation for the some of the volumes of imports over the BC tie-line.

Alberta off-peak prices remained strong compared to MAPP-North prices throughout 2004. This relative pricing has been prevalent over the past five quarters. Off-peak prices in Mid-C continue to be stronger than off-peak Alberta prices, particularly in November and December when PNW prices averaged near $60.00/MWh compared to the $30.00 - $40.00 /MWh in Alberta. These price differentials support the off peak export activity over the BC tie observed over the quarter and the majority of the year.

2004 saw market concerns that uneconomic activity on the tie lines was negatively impacting the Alberta market. The matter is discussed in further detail in the Market Issues section of this report.

1.10 Outages and Derates

The MSA monitors the outages and derates of generating units in Alberta. When the amount of outage exceeds a unit's historical average, the MSA will probe to understand the cause of the variation. Of particular interest, is the coal fired units that are operated under the terms and conditions of the Power Purchase Arrangements (PPAs). Outages at these PPA plants have a tendency to impact Pool price significantly as they represent a major contingent of total installed generating capacity in Alberta and also make up the largest portion of what could be considered “base load” power.

Figure 18 shows the comparison of outages from the most recent quarter and compares it to the same quarter a year ago. This year over year look 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

In the graph, it appears that Owner C is consistent in its behaviour and takes outages more frequently in Q4 while the other owners have experienced less outages in this time period versus the same period last year. The MSA will continue to monitor outage levels of specific owners to ensure they are reasonable and within tolerances given the age and past performance of the generation units.

Figure 18 - Total Outages – Q4/04 vs Q4/03

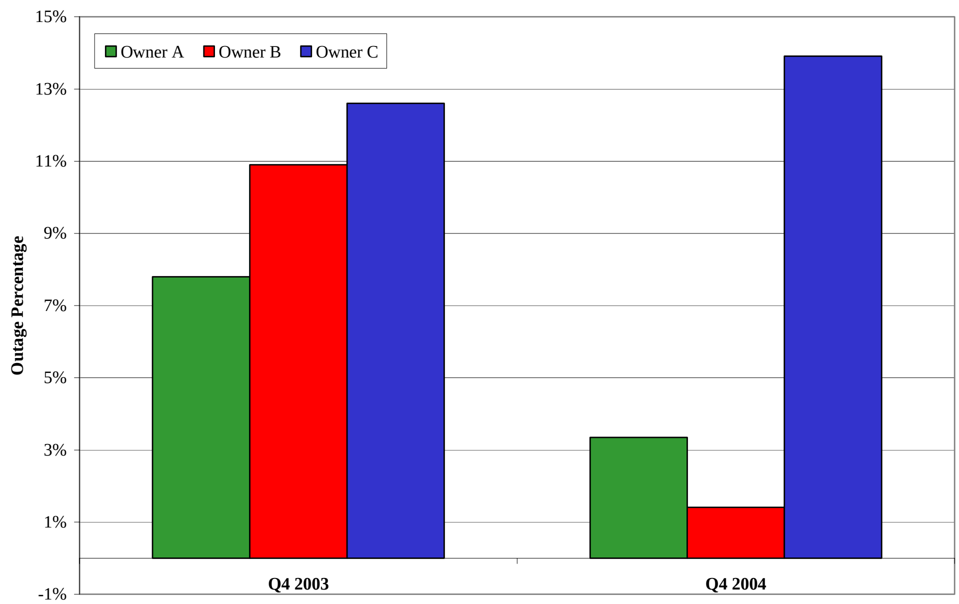


Figure 19 illustrates the total outage levels at the coal fired generation facilities and is separated by PPA owner. This graph provides an overview of the outage levels for each quarter of 2004. It indicates that Owner A experienced a large amount of outage in Q2 while Owner C outages occurred mostly in Q3 and Q4.

Figure 19 - Total 2004 Outages by Quarter

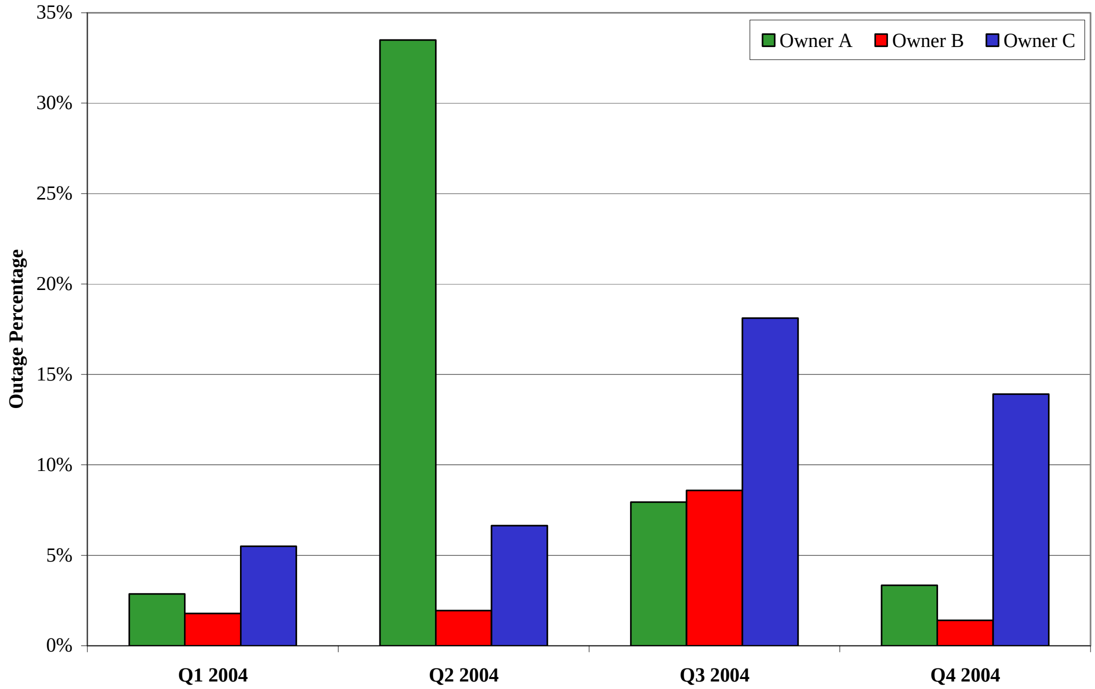


Table 4 reports the unplanned outages for the fourth quarter of 2004 with the next column being the entire 2004 period. It also provides a look at the annual unplanned outages in 2001-2003 for reference. The numbers show that Owner C had a high level of unplanned outages for Q4/04 while the others were in line with their historical norms.

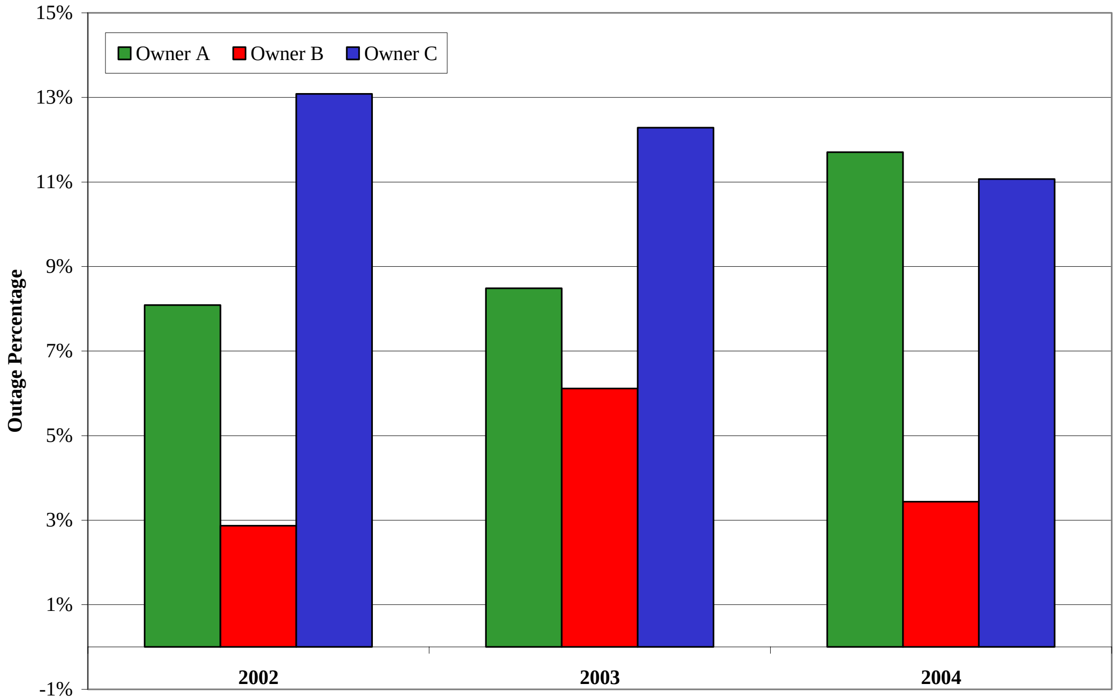
Table 4 - Unplanned Outage Rates for PPA Coal Units (%)

	Q4/04	2004	2003	2002	2001
Owner-A	**3.3%**	6.1%	4.9%	4.2%	3.2%
Owner-B	**1.3%**	1.5%	1.5%	0.5%	1.2%
Owner-C	**7.0%**	6.3%	5.7%	10.8%	8.8%
PPA weighted average	**5.1%**	5.5%	4.9%	7.7%	6.3%

Note:
1) PPA Coal 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 20 provides a summary of the total outages, on a percentage of total PPA capacity, for the past 3 years. It shows minimal variation in the levels of outages over the time period. All outage levels are within the tolerances of historical outage rates.

Figure 20 - Historical Outage Rates by Owner



Each PPA document specifies the target availabilities for the 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 2002 -2004. The owners continue to exceed target availability each year, indicating that the incentives within the PPA structure to maintain high availability seem to be working well.

Table 5 - MW Weighted Portfolio Target vs Actual Availability (%)

	Target Availability 2002	Actual Availability 2002	Target Availability 2003	Actual Availability 2003	Target Availability 2004	Actual Availability 2004
Owner-A	88%	92%	87%	92%	87%	88%
Owner-B	90%	97%	90%	94%	90%	97%
Owner-C	85%	87%	85%	88%	87%	89%
PPA weighted Average	87%	90%	87%	90%	87%	90%

1.11 Ancillary Services Market

Active Reserves Markets

Figure 21 shows trade indices or differential to Pool price for the three active reserve products over the last 15 months. While spinning reserve indices broke from a declining trend at the end of Q3/04, the regulating reserve market grew more competitive with increasingly negative trade differentials as longer term contracts pulled volume out of the daily procurement market leaving market participants chasing smaller volumes. The figure also reflects the change in trade indices of supplemental reserves to relatively more reasonable differentials in early August following a revisiting of the existing Hydro PPA notional reserve quantities agreement between the Balancing Pool and TransAlta. As the MSA has previously noted, particularly in its spinning reserve market report dated January 23, 2004, the prior structure of the PPA notional reserve quantities agreement provided an incentive for TransAlta to have a strong negative influence on the trade index for supplemental reserves in order to mitigate being unable to meet full notional volumes prescribed in the agreement. The terms of the new agreement have not been made public but the effect on the supplemental trade index is readily apparent.

Figure 21 - Active Trade Indices - (Watt-Ex & OTC)

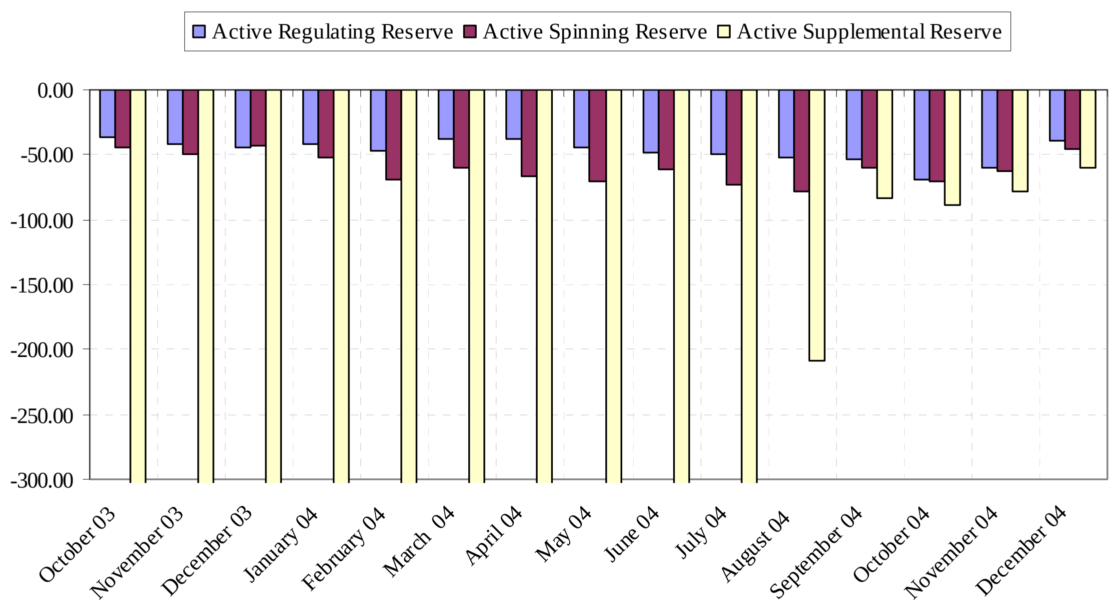
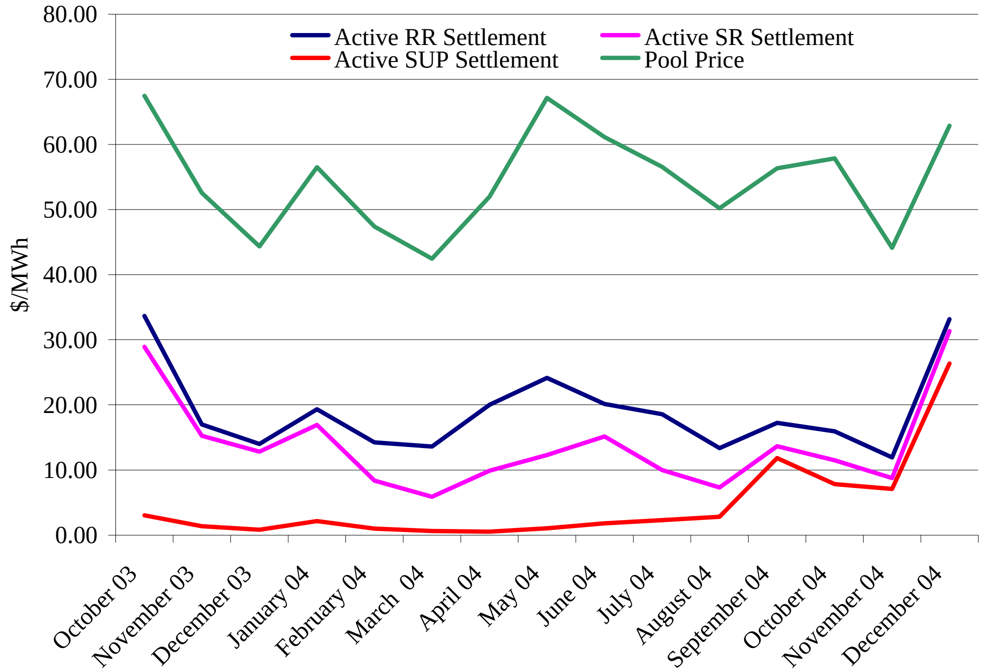


Figure 22 shows monthly average settlement prices for the three active reserve products with monthly average Pool price. Since the prices of active reserve products are indexed to Pool price, the overall pattern of settlement prices over the period mirrors the trend in Pool prices. The figure also shows that the differential in settlement prices between the reserve types narrowed significantly in Q4/04. This is attributed to a more competitive regulating market in Q4/04 together with less discounting of

supplemental reserves relative to regulating and spinning. The pronounced change in supplemental settlements reflects the new trading environment for supplemental reserve following a renegotiation of the terms and conditions of the hydro PPA notional reserves agreement between the Balancing Pool (holder of the PPA) and TransAlta (owner and operator of the hydro assets).

Figure 22 - Active Settlement Prices - All Markets (Watt-ex and OTC)



Standby Reserve Markets

Unlike active reserve service where normally all purchased reserves are dispatched, standby reserves are only dispatched when an active reserve provider is unable to perform, or more is required due to forecast error. Standby reserves are compensated two-fold – a premium and an activation price if the service is called to provide active service. Premiums for all three standby reserve products are shown in **Figure 23** which indicates that regulating and spinning premiums held stable through the first three quarters of the year, then in Q4/04 premiums fluctuated. Supplemental premiums varied to a greater degree through 2004. Premiums tend to respond to the frequency of activation and also reflect the AESO's procurement practices in terms of the relative amounts of high premium/low activation and low premium/high activation procurements.

Figure 23 - Standby Premiums - All Markets (Watt-ex and OTC)

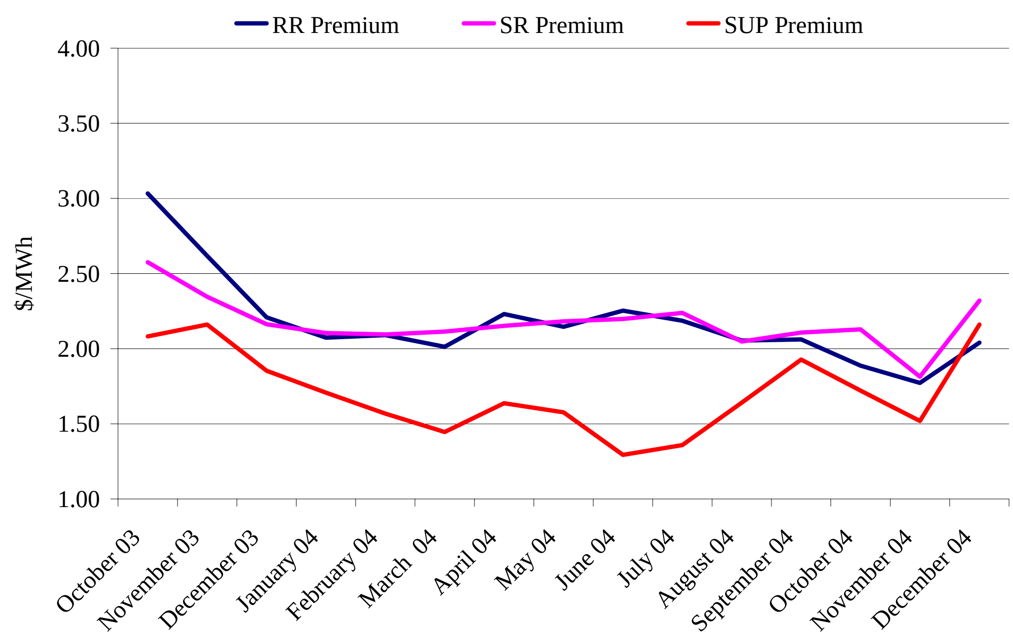


Figure 24 shows Standby activation prices with Pool price over the last 15 months. The figure shows a generally declining trend over the period with an upward shift in late Q3/04 and into Q4/04. This does not appear to be a function of the activation rates shown in **Figure 25** which also trend downward in Q4/04 but more likely, it reflects the more volatile Pool price environment in Q4/04 and the fact that the optionality imbedded in standby reserves are worth more when the Pool price is more volatile. It is important to note that the activation prices shown in the figure are averages for all standby reserves procured and are only paid for those standby reserves which were activated (roughly 5-10%). With more players in the active supplemental reserve market, activation prices in the standby supplemental market have recovered and are more in line with the other two standby products.

Figure 24 - Activation Prices - All Markets (Watt-ex and OTC)

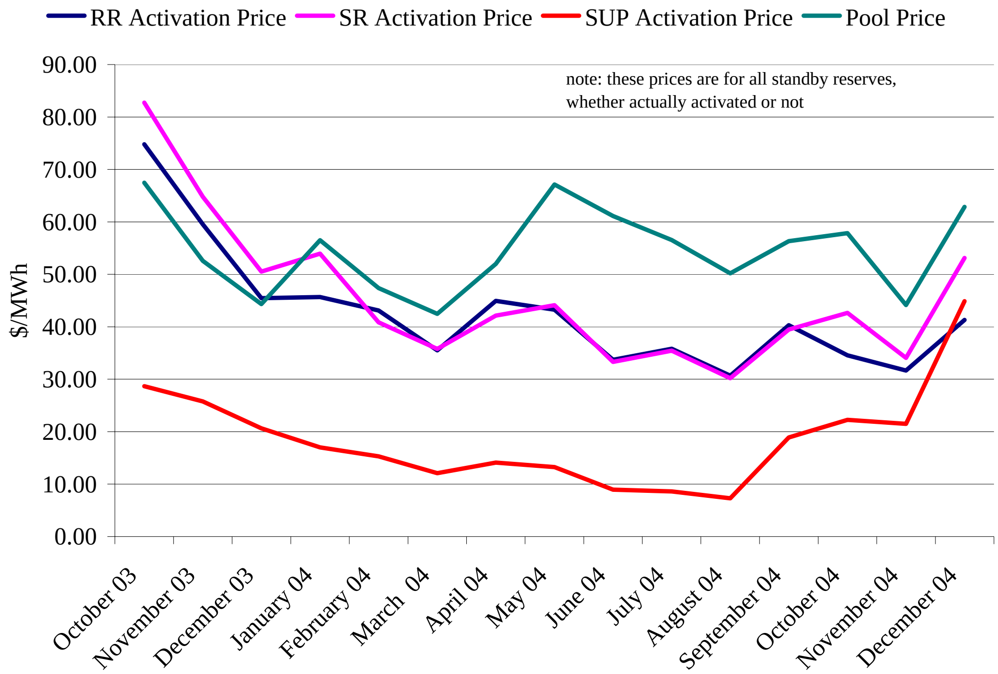
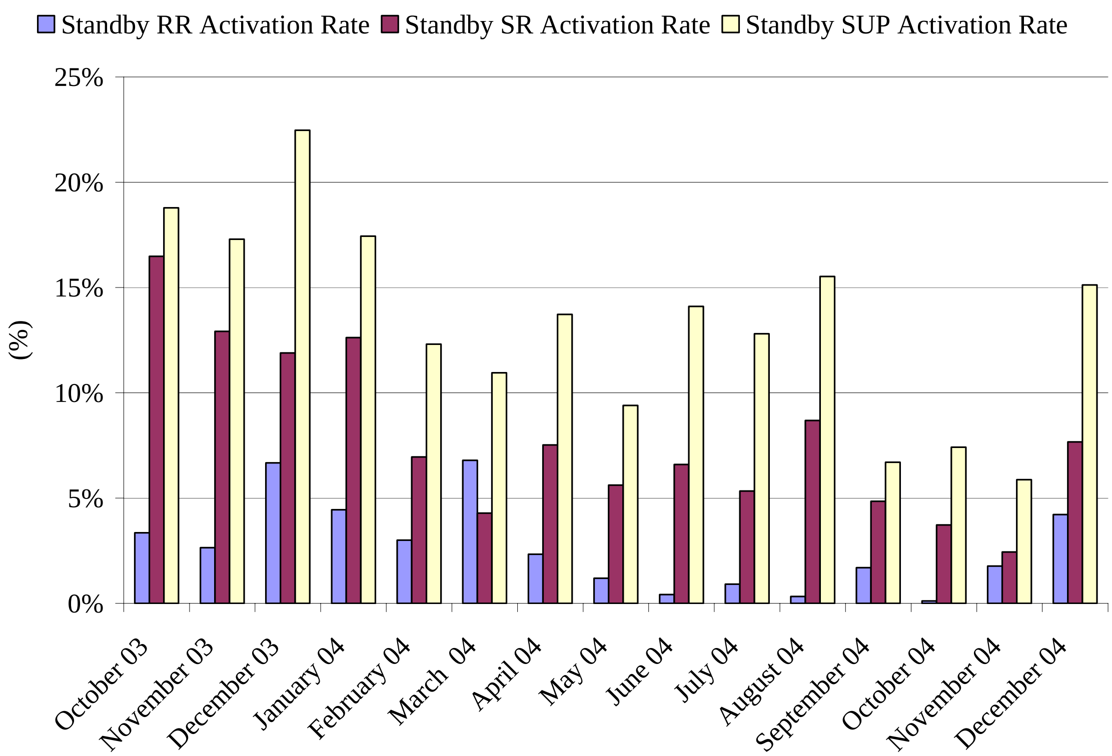


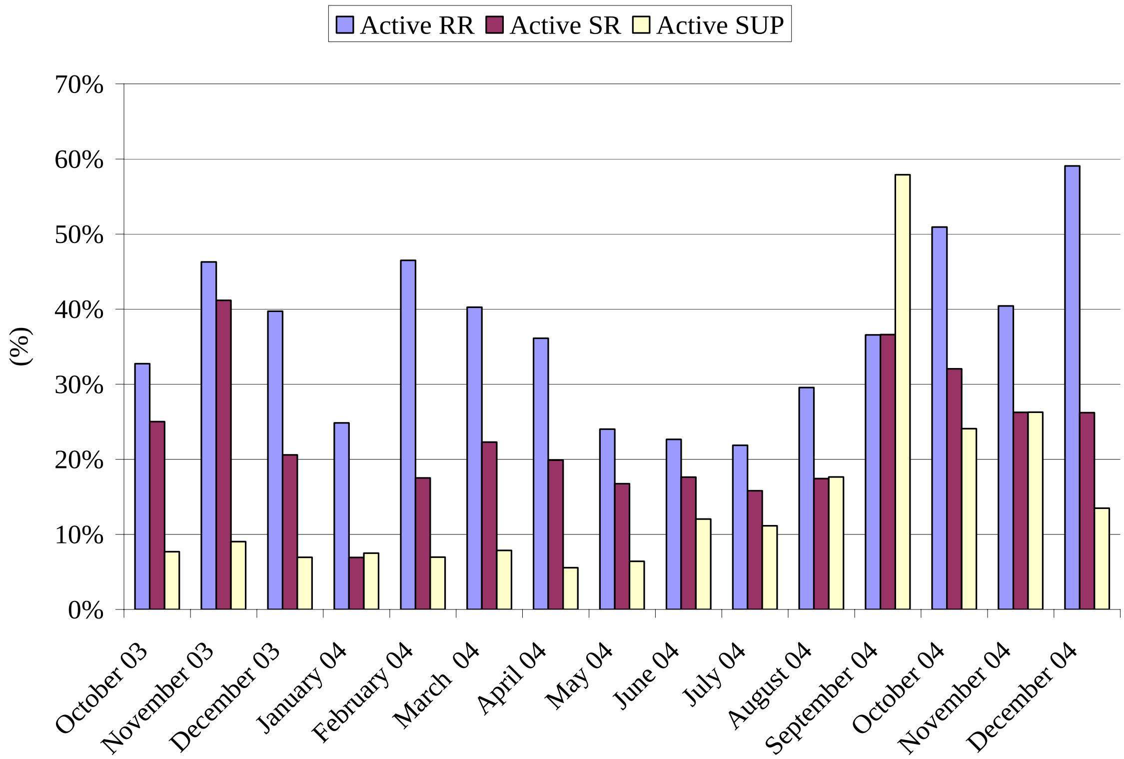
Figure 25 - Standby Activation Rates



OTC Procurement

The AESO procures system reserve requirements via both Watt-ex and directly from counter-parties (OTC). **Figure 26** shows the proportion of volumes that were procured OTC for each active reserve type. While the OTC proportion generally decreased from February to July 2004, it moved up noticeably for the balance of 2004, particularly with respect to regulating reserve, where over 50% of volumes were procured OTC in the months of October and December. With the OTC market being a more prominent part of the AESO's procurement strategy, the AESO has increased transparency of this market during 2004 in terms of price and volume data. The MSA continues to evaluate the level of OTC transparency to assess whether OTC practices are fair and reasonable to participants.

Figure 26 - OTC Procurement as a % of Total Procurement



Fixed Price OTC Products

All Watt-ex traded active reserve contracts are indexed to the Pool price, therefore a differential is locked in rather than a fixed settlement price. Fixed price contracts which are offered OTC by the AESO have provided another basis for participants to sell ancillary service products. While these products do provide added choice to participants, fixed price contracts tend to be longer term arrangements which then divert volume away from the daily market and in the case of regulating reserves, this caused a period of unusual price competition in October as competitors fought for the AESO's remaining volume requirements.

Figure 27 shows that fixed price volumes for active regulating and spinning reserve were modest through most of 2004 but grew more significant in Q4/04 as the AESO more frequently sought out longer term reserve contracts which happened to also be fixed price.

Figure 28 indicates that fixed price contracts for active regulating reserve were relatively stable while similar contracts for active spinning reserve fluctuated somewhat more.

Figure 27 - % of Active Regulating and Spinning Purchased at Fixed Price

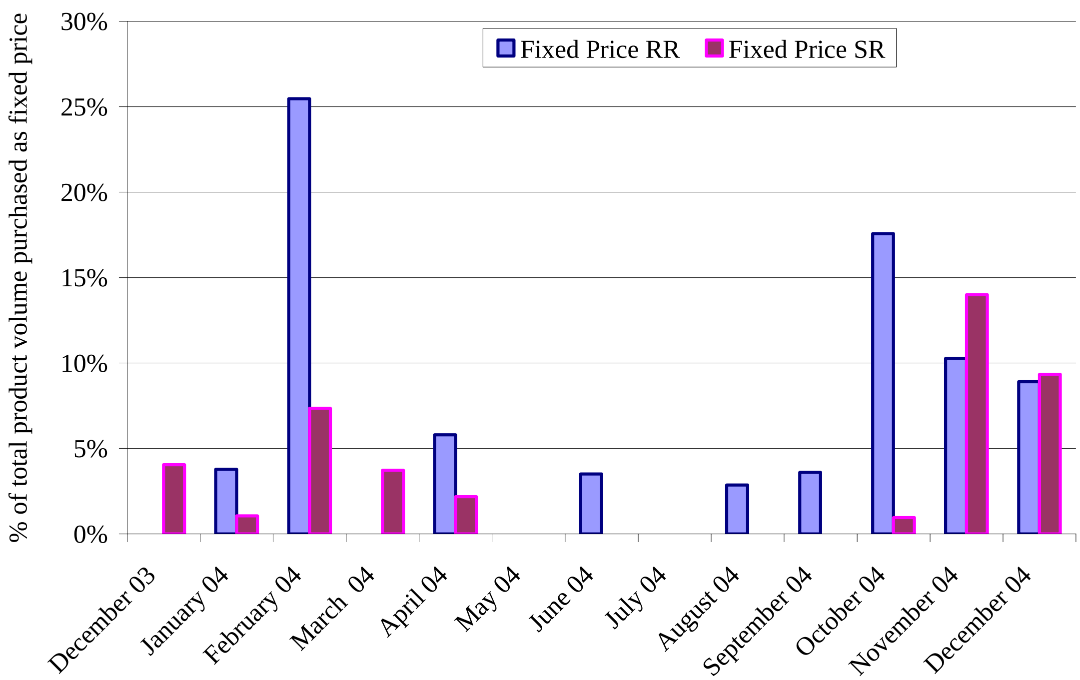
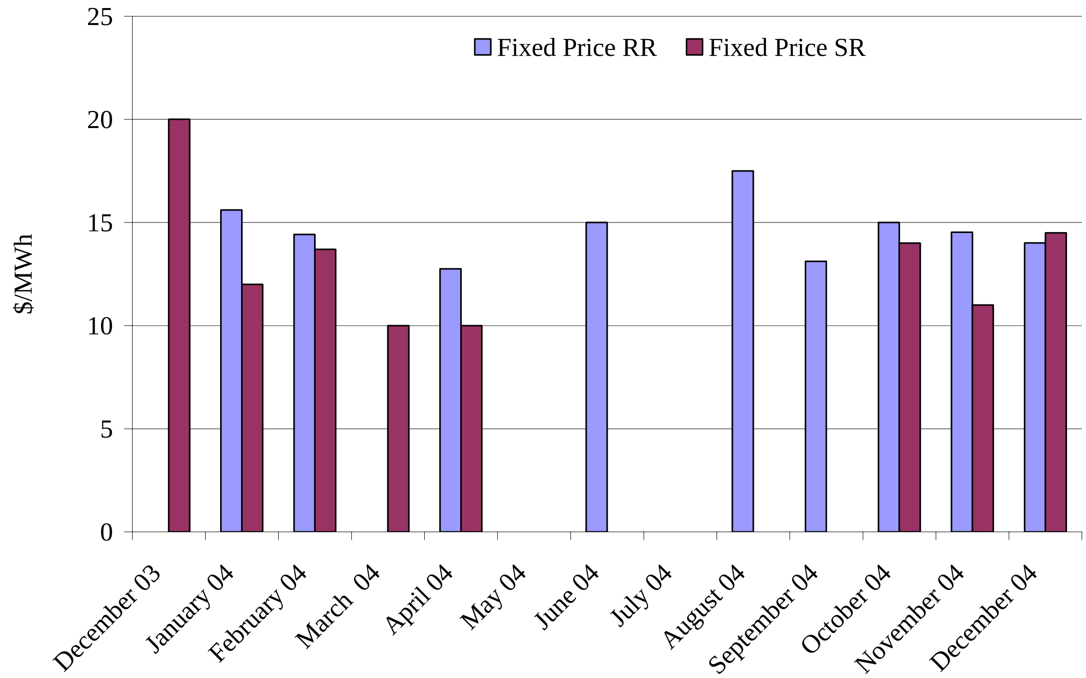


Figure 28 - Active Regulating and Spinning Fixed Prices



Figures 29, 30, and 31 show weighted average settlement prices by market for active regulating, spinning, and supplemental reserves respectively. Generally, OTC procured volumes for regulating and spinning reserve are priced on average, slightly above exchange procured volumes. This is in part, due to requirements by the AESO to procure custom contracts with hourly shaping and which tend to command a premium. The OTC settlements shown in the three figures also include fixed price contracts which may be priced to include a risk mitigation premium.

Figure 29 - Active Regulating Reserve Settlement by Market

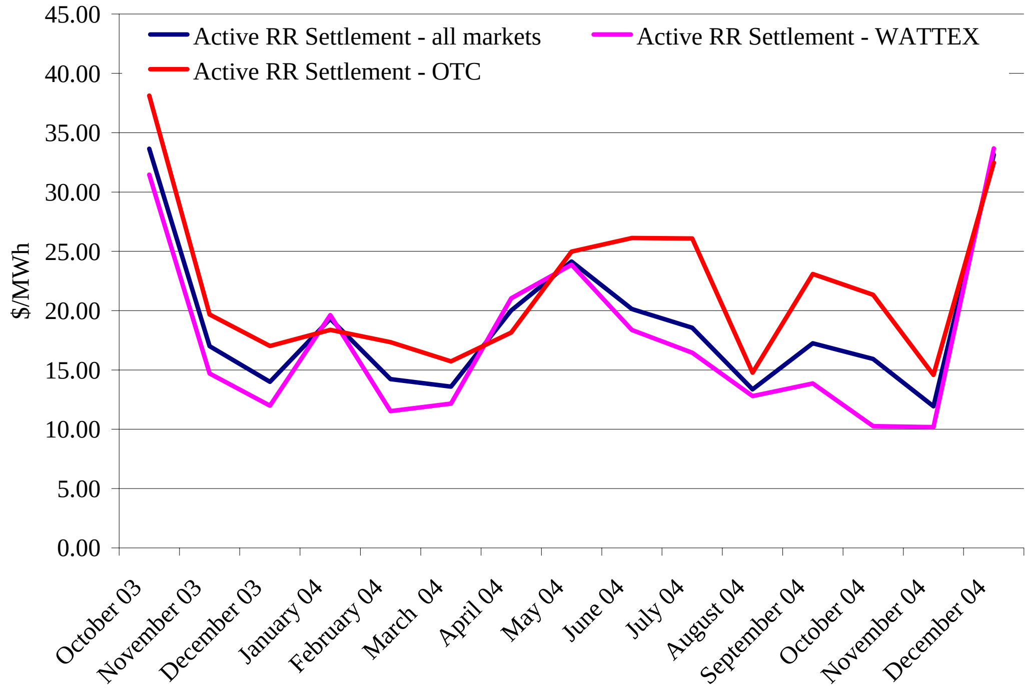


Figure 30 - Active Spinning Reserve Settlement Price by Market

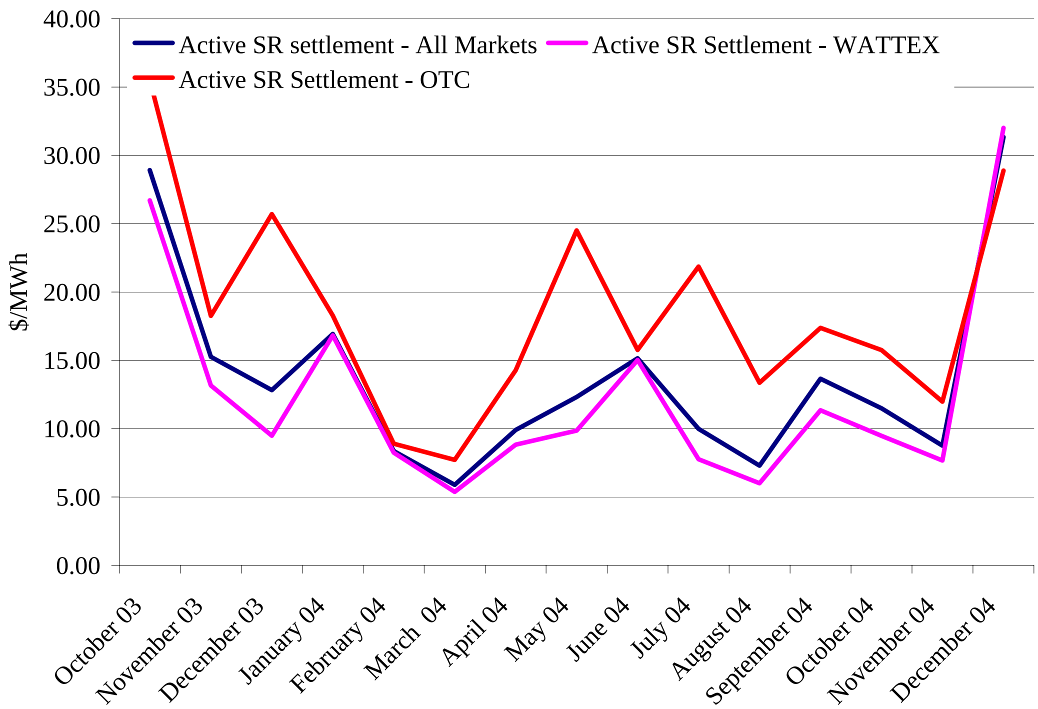
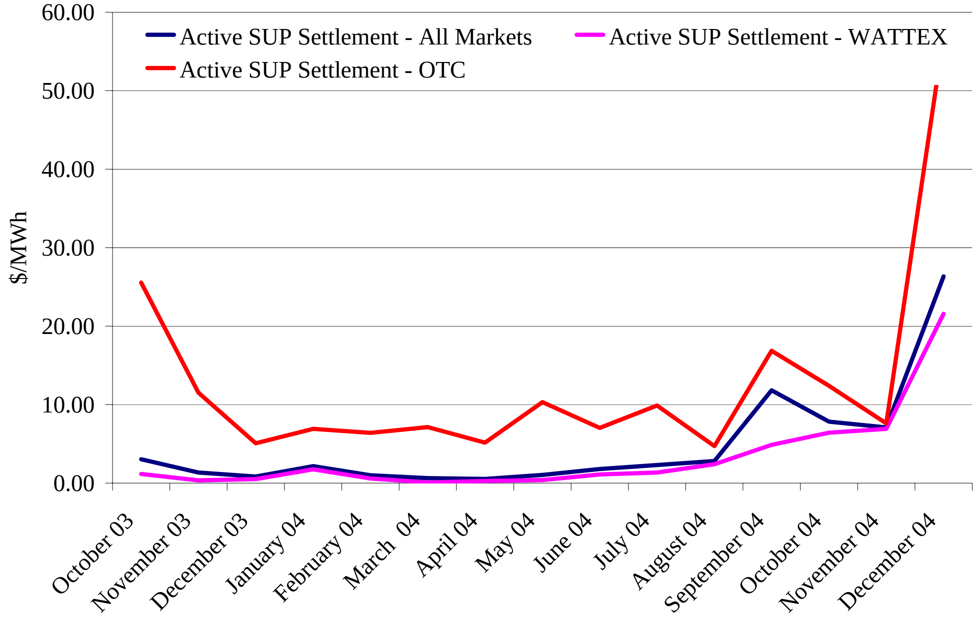
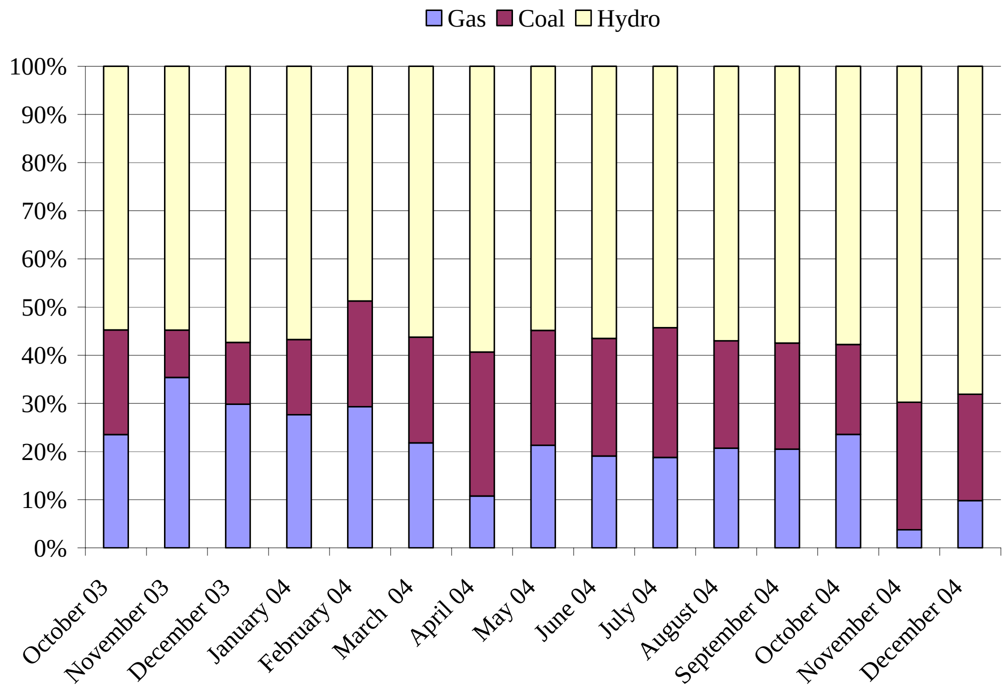


Figure 31 - Active Supplemental Reserve Settlement Price by Market



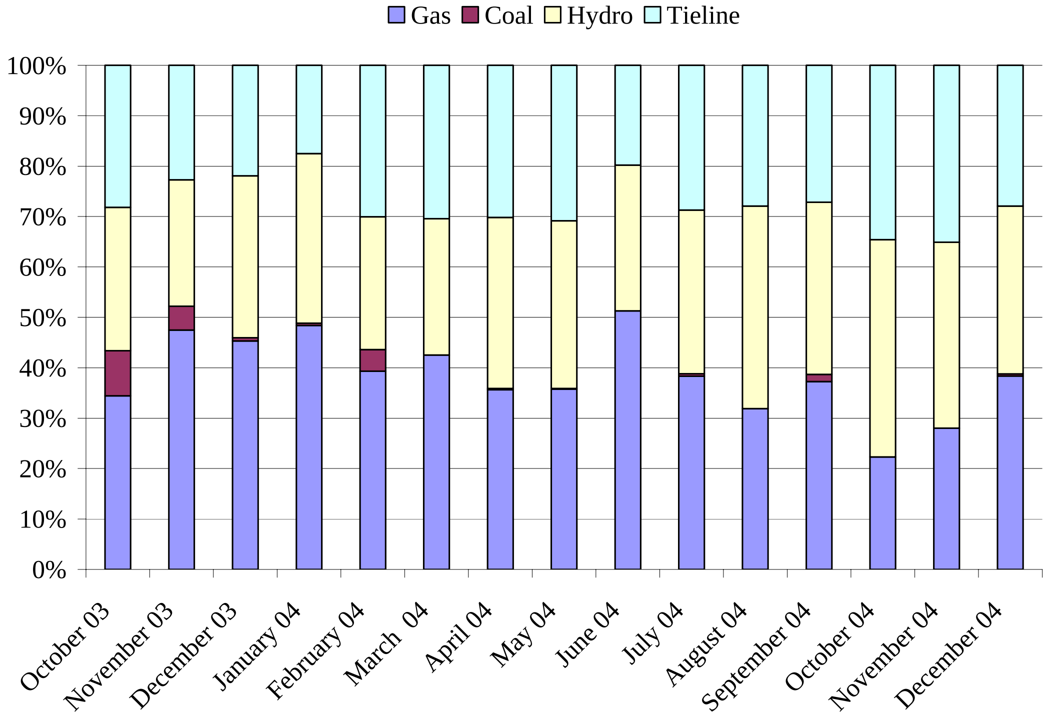
Figures 32, 33, and 34 show the market share distribution for active regulating, spinning, and supplemental reserves by fuel type. In the active regulating market, gas providers market share was stable through most of the year but dropped lower in the last two months of the year which is attributed to a relatively more attractive energy market in these months for gas generators. Coal providers' market share was squeezed marginally from Q2/04 to Q3/04 as hydro market share incrementally increased through Q3/04. In the same quarter a year ago, gas providers had significantly higher share of the regulating market at the expense of the coal units.

Figure 32 - Regulating Reserve Market Share by Fuel Type



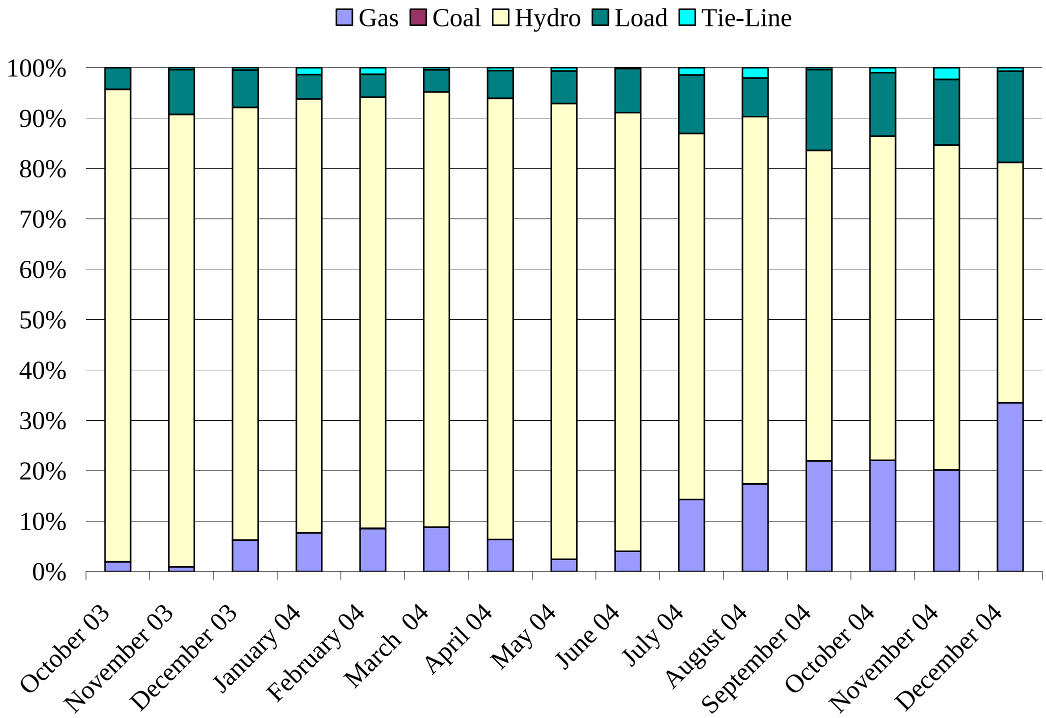
Market shares in the active spinning reserve market fluctuated but within stable ranges through 2004. Coal tends not to supply any significant level of active spin due to the baseload nature of coal plants and the small volumes that are provided are typically off-peak. Hydro market share tends to be stable in active spinning reserves and as can be seen in **Figure 33**, the relative fluctuations that occur tend to be back and forth between tie line market share and gas share (largely co-gen).

Figure 33 - Spinning Reserve Market Share by Fuel Type



Hydro assets are well suited to provide supplemental reserves and thus they continue to dominate this segment of the AS market. Supplemental reserves were the largest proportion of reserves under the previous PPA notional quantities agreement which has since been renegotiated and this is possibly why hydro share declined in the second half of 2004. Note that the hydro share of regulating reserve increased in the latter part of 2004 indicating that TransAlta chose to participate to a greater extent in that market rather than the lower value supplemental reserve market. It is encouraging that Supplemental reserves provided by load have gradually but steadily increased over the last 15 month period and accounted for 18% of active supplemental reserves in December.

Figure 34 - Supplemental Reserve by Fuel Type



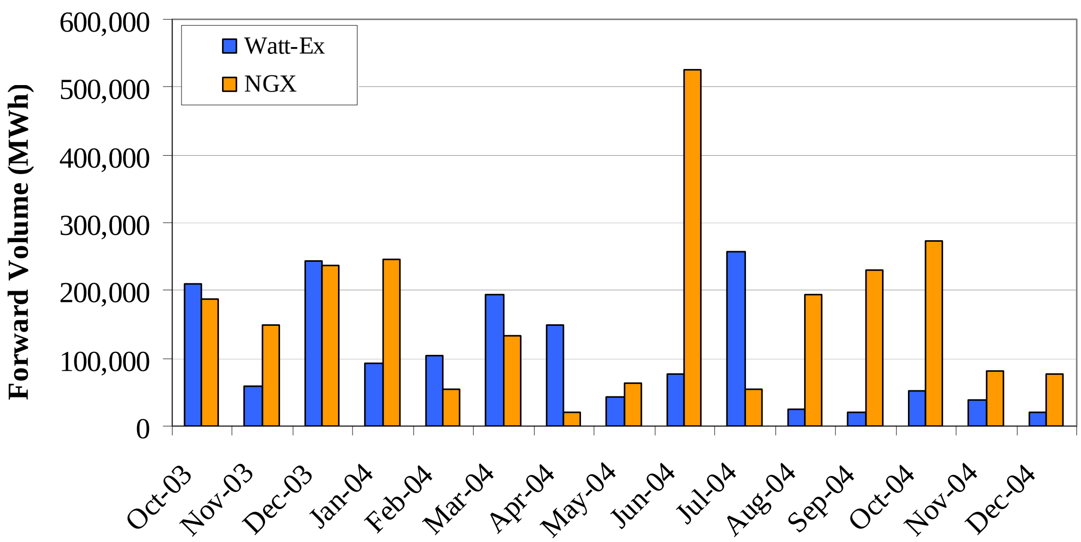
Summary

A key highlight for the AS market in 2004 was the renegotiation of the notional reserve quantities agreement between the Balancing Pool and TransAlta, the operator of the PPA hydro assets. The outcome of the new agreement has been a return of the trading index for active supplemental reserve to "rational" levels since the incentive for TAU's prior offer behaviour in the supplemental market has been effectively removed. Another impediment to market efficiency has been addressed with respect to disclosure by the AESO of price and volume information for OTC procured volumes. The daily OTC transactions report is located on the AESO website at http://ets.powerpool.ab.ca/Market/reportsIndex.html and selecting Historical/Reports/Daily OTC Transactions. The MSA will continue to evaluate whether sufficient transparency has been provided by this additional disclosure or if further disclosure may be required to provide participants reasonable comparability between the two procurement mechanisms.

1.12 Forward Energy Markets

The exchange-traded forward energy market in Alberta is comprised of the Alberta Watt Exchange and NGX although the majority of deal volume in forward energy contracts is still believed to flow through the OTC market via intermediaries such as Natsource and Canax. **Figure 35** compares monthly deal volume between the two on-screen exchanges over the last 15 month period. In 2004, total deal volume for Watt-Ex was flat relative to 2003 at 1,070,000 MWh. NGX launched trading in its forward electricity products in April 2003 although taken on an annualized basis, deal volume was also flat as compared to last year at 1,950,000 MWh or nearly twice the deal volume of Watt-Ex.

Figure 35 – Exchange Traded Forward Energy Volumes



2 REVIEW OF THE RETAIL MARKET

2.1 Regulatory Proceedings

The MSA pays close attention to regulatory proceedings considered relevant to its mandate. Key among those would be various EUB proceedings in 2004, some of which are briefly described below.

Sale of Aquila Networks Canada (Alberta) Ltd.

On April 29, 2004, the EUB issued Decision 2004 – 035, approving the sale of the shares of Aquila Networks Canada (Alberta) Ltd. to Fortis Alberta Holdings Inc.

As a result of the sale, Aquila Networks Canada (Alberta) Ltd. was renamed FortisAlberta Inc.

Transmission

The new transmission policy approved by Alberta Energy late in 2003, was brought into force via regulation 174/2004 in August, 2004. Highlights included a change to the process of system losses recovery and criteria for their adjustment. Also, in the interests of addressing congestion issues, a location-based generator system contribution payment is prescribed for generators locating in areas where current generation already exceeds load. These directions are required to be implemented for the start of 2006.

As per part 1, 4(1) of the new Regulation, the AESO published its 10-year transmission system plan in December 2004. Publication of a 20 year plan is prescribed by the Regulation by July 1, 2005. For further information, the DOE's transmission policy paper is available for review at: http://www.energy.gov.ab.ca/docs/electricity/pdfs/transmissionPolicy.pdf and the associated transmission regulation can be found at: http://www.qp.gov.ab.ca/documents/Regs/2004_174.cfm?frm_isbn=0779731603.

Southwest Alberta development

On October 14, 2004, the EUB issued Decision 2004 – 087, which was an addendum to Decision 2004 – 075 and set out the reasons for that decision. Both of those decisions related to Application 1340849, pertaining to a Needs Identification Document submitted by the Alberta Electric System Operator (AESO) in respect of a proposed Southwest Alberta 240 KV Transmission System Development.

Decision 2004 – 075 referred Application 1340849 back to the AESO, with requests for additional information and analysis.

North/South development

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

The Application is particularly significant in that the Alberta Department of Energy requested, and received, permission to intervene.

A decision in respect of this application is expected in early Q2 2005.

Further details on the two preceding needs identifications can be found at: http://www.aeso.ca/files/fastfacts_transmission_development.pdf .

Article 24 Application

In August, 2004, the AESO submitted an application for amendments to the existing Article 24 of the ISO Tariff (Application 1357161). Specifically, the application sought to change certain payment provisions in respect of Transmission Must Run (TMR) services conscripted pursuant to Article 24. In response, ATCO Electric Ltd. filed a motion seeking relief against the Application.

Given the coincident jurisdictions of the EUB and the MSA in respect of related matters, and given that MSA was planning its own investigation into TMR, the EUB invited comment from interveners as to whether some or all of the matters within the Application or motion should be referred to the MSA.

Ultimately, the EUB determined to proceed to hear the Application. A hearing has been set down for April, 2005.

2.2 Code of Conduct

Annual Compliance Reports

The Code requires that all owners and affiliated retailers provide an annual compliance report to the MSA. The annual compliance reports speak to the following matters: (i) any non-compliance with the regulation or compliance plan; (ii) the action taken to remedy the non-compliance; and (iii) any complaints about non-compliance and how such complaints have been dealt with. The reports must be approved by the board of directors of the filing entity.

As previously indicated, the MSA recognized that 2003/2004 was a transition period, during which parties subject to the Code were getting up to speed on new reporting requirements. As such, during 2004 the MSA worked with parties to assist them in understanding how the Code impacts them.

The MSA issued a notice in December indicating that on a go forward basis, the deadline for filing of the annual compliance report would be March 31st of each year.

Quarterly Compliance Reports

The annual compliance reports described above are effectively a summary of quarterly compliance reporting which must be undertaken by owners and affiliated retailers. However, the quarterly reports are not required to be approved by the board of directors, nor are they generally required to be filed with the MSA.

Given that the reporting is created in any event, the MSA came to the view that there would be no real incremental burden on parties caused by also sending a copy of the existing reporting to the MSA. Accordingly, in 2004 the MSA began requesting this reporting from all owners and all affiliated retailers.

Audits for 2003 Year

Pursuant to the Code, owners and their affiliated retailers are required to undergo compliance audits. The Code stipulates that the audits are to be done in either Q1 or Q2, depending upon the circumstances of the party involved. The MSA is given the power to approve both the proposed auditor, as well as the audit work plan.

Preliminary discussions around audit plans commenced in 2003, and remained ongoing into March, 2004, in relation to the Code audits to be performed. The audits were to be completed by March 31, 2004, and the audit reports were delivered thereafter. The parties subject to audit were ENMAX Energy Corporation, ENMAX Power Corporation, EPCOR Distribution Inc., EPCOR Energy Services Inc., EPCOR Energy Services (Alberta) Inc. and EPCOR Merchant and Capital L.P.

In respect of the scope of the 2003 audits, the MSA advised the parties involved that the audits would test for compliance with the Code by owners and affiliated retailers for the period June 1 to December 31, 2003 inclusive. Further, the audits would not be required to test for adherence to compliance plans during the year.

The reason for this approach for 2003 is that the Code came into effect June 1; the previous regulation was substantially different, therefore making it very difficult to design useful testing. In addition, the previous regulation did not require compliance plans from affiliated retailers, and the compliance plans previously filed by the owners were based upon the old regulation. The MSA also based its decision upon other assurances as to compliance.

Applications for Exemption or Other Relief

Pursuant to s. 43 of the Code, an owner or affiliated retailer can apply to the MSA for various forms of exemption or alternative compliance arrangements in relation to the Code. Before granting the relief, the MSA must be satisfied that it is in the public interest, as well as meeting other criteria.

In 2004, the MSA dealt with four formal applications under s. 43. All of these are documented on the MSA website under Notices and Decisions.

Application for Exemption – 2004 – 00101- Aquila Networks Canada (Alberta) Ltd.

The MSA received an application from Aquila Networks Canada (Alberta) Ltd. seeking an exemption from section 2(2)(c) of the Code, in respect of the definition of affiliated retailer.

After due consideration, the MSA came to the view that the application should be handled through a concurrent Notice of Application and Decision. The basis for this approach was that the MSA concluded that it did not have the jurisdiction or power under the Code to grant the exemption sought by Aquila; thus, there was no reason for a broader process around the application.

Application for Exemption – 2004 - 00102 - ATCO Electric Ltd.

On November 25, 2003, the MSA issued its Decision in relation to Application 2003 – 00101. The Decision was issued pursuant to section 43 of the Code.

Decision 2003 – 00101 granted approval for the disclosure and use of customer information upon certain conditions, including conditions which effectively established an end date to the approval. A copy of Decision 2003 – 00101 is also available on the MSA website.

By letter dated February 27, 2004, ATCO requested an extension to the date contained in condition 6 of the Decision. The extended date would be April 15, 2004.

Given the proximity between the date of the request for the extension and the February 29, 2004 end date, the MSA issued its approval for the extension via email on February 27, 2004. The approval granted the extension to April 15, 2004, as requested.

Application for Exemption – 2004 – 00103 - Direct Energy Marketing Limited

By letter dated April 12, 2004, Direct Energy Marketing Limited (DEML) requested relief pursuant to section 43 of the Code.

The Application sought to address certain Code related implications which could arise depending upon how the regulated rate tariff functions of various third parties were handled by DEML. The Application was denied by the MSA on various grounds.

Application for Exemption – 2004 - 00104 - ATCO Electric Ltd.

In a letter dated April 14, 2004, ATCO Electric Ltd. (ATCO) requested relief pursuant to section 43 of the Code. Specifically, ATCO sought an extension to the date by which Direct Energy Marketing Limited (DEML) was required to return certain customer information to ATCO.

The customer information was initially provided to DEML pursuant to MSA Decision 2003 – 00101; an extension to certain conditions in that Decision was then granted in MSA Decision 2004 - 00102.

Based upon communications between the MSA, ATCO and DEML in relation to the Application, it was determined that an alternate request for exemption would be better suited to the circumstances facing ATCO and DEML. In particular, timeliness was an issue.

By letter dated April 22, 2004, ATCO commenced an alternate course of action, with a revised request for relief. This request was designated by the MSA as Revised Application 2004 – 00104.

On April 23, 2004, the MSA granted the exemption sought in the Revised Application, and published its Decision within the Notice of Application and Decision 2004 – 00104.

MSA Guideline

On March 4, 2004, the MSA issued a Guideline pursuant to s. 49(4) of the *Electric Utilities Act*. Section 49(4) of the Act allows the MSA, as part of its mandate, to establish guidelines to further the fair, efficient and openly competitive operation of the market. The MSA must make such guidelines public.

The Guideline discusses the manner in which the MSA will treat reporting required of owners and their affiliated retailers pursuant to the Code. The MSA has been following the approach described in the Guideline and will continue to do so until further notice. A copy of the Guideline can be found on the MSA website.

Negative Option Issue

In late summer, 2003, the MSA became aware that at least one market participant was utilizing a negative option approach to obtain consent for use of customer information. The approach involved use of mass mailing and website communications to notify customers that their consent to disclosure and use of their information would be considered given unless the customer indicated that they were in fact not consenting.

The MSA issued a letter to several wires owners and retailers in September, 2003 setting out its views around the manner of customer consent required for disclosure and use of customer information. In essence, the MSA considers that written or electronic consent is the standard required under the Code. The letter was intended to clarify any uncertainty amongst market participants in this regard.

Based upon its inquiries, it appeared to the MSA that ENMAX Energy Corporation was the only party utilizing this approach. ENMAX agreed to stop the negative option practice, and gave undertakings to the MSA in this regard. ENMAX also agreed to inform its customers that the practice would not be followed, in order to correct any impression to the contrary.

Partly in order to inform the market and other stakeholders on these matters, the MSA took the unusual step of issuing a news release to broadly publicize matters. The news release was issued March 3, 2004.

A copy of the news release and backgrounder document can be found at: http://www.albertamsa.ca/files/GuidelineReCodeofCoductReporting030404.pdf

Default Supply Issue

At the end of 2003, the MSA was informed by ENMAX Energy Corporation (ENMAX) that it had been using default supply customer information for sales and marketing purposes, believing this to be acceptable under the Code. The MSA immediately advised ENMAX of its view that this was, in fact, not acceptable.

ENMAX offered to mitigate any harm caused by the misuse of the customer information, and proposed to offer the affected customers the right to cancel their contracts. In order to assess the proposed remedy, and the extent of the underlying harm, the MSA requested detailed information from ENMAX surrounding the matters. Under the circumstances, the information requests were not treated as an investigation, although the MSA reserved its prerogative to take that step if required.

In April, 2004 the MSA completed its assessment of the matters. The MSA concluded that the measures suggested by ENMAX, along with some added conditions, would be sufficient to address the circumstances at issue.

In May, 2004, the MSA issued a notice in respect of these matters, including as to the remedial measures agreed to. A copy of the notice can be found on the MSA website under Notices and Decisions.

Compliance Plan Approvals

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

Depending upon the complexity of the business operations involved, the drafting, review and approval process can require a significant amount of time and effort from the parties before final approval is granted.

Interim Approvals

In December, 2003 the MSA issued interim compliance plan approvals for Aquila Networks Canada (Alberta) Ltd., ENMAX Energy Corporation, ENMAX Power Corporation, EPCOR Distribution Inc., EPCOR Energy Services Inc., EPCOR Energy Services (Alberta) Inc. and EPCOR Merchant and Capital L.P., based upon compliance plan filings received to that point.

The interim approvals allowed those parties to meet the requirements of the Code and undertake retail activities while work continued toward full compliance plan approval. The interim approvals carried terms and conditions, including a February 29, 2004 expiry date and the requirement for additional reporting.

By request, the interim approvals granted to those parties were further extended to June 1, 2004, to facilitate continued work on the compliance plans and other matters.

None of the parties operating under interim approval was able to obtain final approval of their compliance plan by June 1. All parties requested a further extension to the expiry date; however, under the circumstances, the MSA did not consider it appropriate to extend the interim approvals past that date. Thus, after June 1 all of the parties operating on interim approval became non-compliant with the Code requirement to have an approved compliance plan in place.

Ultimately, all of those parties were subsequently able to obtain final approval for their respective compliance plans during the month of June. Of note, Aquila Networks Canada (Alberta) Ltd. became FortisAlberta Inc., pursuant to a transaction effective May 31, 2004.

In addition to the reporting provided as a condition of each interim approval, the parties were required to address their non-compliance in their quarterly and annual compliance reporting.

Review – Compliance During Interim Approvals

In September, the MSA began planning an audit-style review of the operations and conduct of each of those parties, both in respect of the period between expiry of the interim approval and the granting of final approval, and the period during which their interim approval was operative. The MSA retained Grant Thornton LLP to carry out the review on behalf of the MSA.

This review was designed to test whether the parties adequately met the other requirements of the Code despite their failure to obtain final compliance plan approval on a timely basis. Coincidentally, the review will complement the regular audit requirements of the parties for a part of the 2004 calendar year.

The MSA expects to formally report on the review during Q1 2005.

Final Compliance Plan Approvals

Final compliance plan approvals were granted to the following parties in February, 2004: Battle River REA Ltd., Battle River Rural *Energy* Limited, Direct Energy Marketing Limited (in respect of Direct Energy Regulated Services), and Direct Energy Partnership.

In September, 2004, the MSA approved compliance plans for Rocky REA Ltd. and Rocky Rural Power Limited.

Pursuant to a re-organization within the EPCOR group of companies, the MSA approved compliance plans for the following new EPCOR companies: EPCOR Energy Inc., EPCOR Energy (Alberta) Inc. and EMCC Limited. The MSA also approved amended compliance plans for EPCOR Distribution Inc. and EPCOR Merchant and Capital L.P.

As a result of the re-organization, two other EPCOR companies, being EPCOR Energy Services Inc. and EPCOR Energy Services (Alberta) Inc., have been amalgamated with EMCC Limited. As such, their related compliance plans ceased to have force and effect as at September 1, 2004.

Thus, in addition to approvals which were granted in June, 2004 to the parties which had been subject to interim approvals, as at the end of September, 2004 a total of 14 compliance plan approvals were in force.

Code of Conduct Audits 2005

During Q3 2004, the MSA undertook planning discussions with parties who will be subject to the audit requirements under the Code for the 2004 calendar period. In response to a common desire to make the audits as cost and resource efficient as possible, the MSA has proposed that the next regular Code audits should occur at the end of Q2 2005, rather than during Q1 2005. This initiative is intended to address concerns raised by various parties about the difficulties caused by having the Code audits occurring during the first quarter of each year, when financial audits and tax matters were also at the forefront.

Further, and in concert with the review and other matters described above, the MSA intends that the Code audit period will move from a calendar year approach to a period being July 1 through June 30. Among other things, this will place the annual audit close in time to the period under review.

Finally, the MSA is also examining the benefits of having all of the regular Code audits conducted by one independent audit firm retained by the MSA, and utilizing one common audit plan, rather than having each of the parties seek approval for its own auditor and audit plan. Again, the intent is to make the audits as efficient and effective as possible.

The MSA is continuing its discussions with the various parties who would be directly affected by these initiatives.

Access to Customer Information

During Q3 and Q4, the MSA participated in discussions with representatives the Department of 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 goals of the MSA are to further the fair, efficient and openly competitive operation of the retail market.

The discussions to date have been at a high level, and will continue during 2005 under the lead of the EUB. These discussions may ultimately impact the manner in which customer information is handled under the Code. The MSA continues to stress, however, that protection of the interests of the customer has been and will remain a paramount consideration in the discussions and in any changes which may result from this initiative.

2.3 Load Settlement Monitoring & Enforcement

The MSA looks at a number of metrics related to settlement and enforcement of the settlement system code (SSC). These metrics are intended to be indicators of potential problems and substantial delays in the settlement process. 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 significant trends in the settlement process.

The MSA will continue to monitor the SSC for the purpose of the assessing how well the settlement function is operating in Alberta.

Disputes

The SSC uses PFECs, PFAMs and Notices of Dispute as tools to resolve financial disputes resulting from settlement calculations. PFECs (pre-final error corrections) occur before final settlement has been completed. PFAMs (post final adjustment mechanisms) are submitted after the final settlement has been calculated. Notices of Dispute are used when two parties disagree over the results of a PFAM. Statistics regarding the number of PFEC/PFAMs submitted, accepted and rejected were collected from the four load settlement agents in the province. **Tables 6 and 7** summarize the PFEC and PFAM tracking for 2004.

Table 6 - PFEC Tracking, 2004

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved
PFEC					
Q4/04	957	251	7	979	222
Q3/04	102	1,204	337	12	957
Q2/04	32	396	307	19	102
Q1/04	803	166	935	2	32

A large number of PFEC's were submitted in Q3 and later rejected in Q4. The root cause of the PFECs was an IT issue at one of the LSA's which was quickly sorted out. 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.

The PFEC process will be continued to be closely monitored by the MSA to ensure the PFECs are dealt with in a timely manner.

Table 7 - PFAM Tracking, 2004

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFAM						
Q4/04	137	53	13	157	20	(1,710,555)
Q3/04	323	134	229	91	137	94,633,426
Q2/04	1,409	290	708	674	317	(9,535,801)
Q1/04	6,958	2,089	7,500	138	1409	(57,357,137)

There has been a noticeable positive trend in the timeliness of addressing PFAM issues. There have been substantially fewer issues carried over from one quarter to the next. As we start 2005, there are only 20 unresolved issues when at the beginning of 2004, there were close to 7000 outstanding PFAMs.

Not only has there been an improvement in the handling of the issues but it is also observed that there has been an overall decrease in the number of PFAMs submitted as the year progressed. Over 2000 were submitted in Q1 while in Q4 there was only 53.

The decreasing number of PFAMs is an indicator that the LSAs are improving their processes for dealing with complaints and are being proactive in resolving issues before final settlement occurs.

Over the last quarter of 2004, one Notice of Dispute was forwarded to the MSA. Soon after the dispute process began, the issue was resolved. Notices of Dispute are used to initiate the dispute process as outlined in the SSC. This process requires parties involved in the dispute to notify the MSA of the negotiation efforts that have been made to resolve the dispute. If a dispute can not be resolved by negotiation, mediation or binding arbitration can be pursued and the MSA will be made aware of the outcome.

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 9** summarizes the UFE Reasonable Exception Reports (UFE reports) filed over the last year.

Table 8 - Summary of UFE Reasonable Exception Reporting

Quarter	Outstanding (from all previous quarters)	New	Resolved	Unresolved
Q4/04	19	10	17	12
Q3/04	18	3	2	19
Q2/04	13	8	3	18
Q1/04	8	11	6	13

At the end of Q3/04 there were 19 unresolved UFE reports. By the conclusion of 2004 this number dropped to 12. This shows that the LSAs are managing the exceeded UFE tolerances in a manner better than they had in the previous quarter. Overall, the existence of any outstanding UFE reports is not an encouraging sign that UFE issues are handled in an efficient manner[3]. It indicates UFE reports not being resolved and the results posted within the quarter in which they were submitted. We would expect to see significant improvement in the resolution of these UFE issues in 2005 with very few outstanding issues being carried over to the next quarter.

Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices

In late 2003 the AESO initiated an enforcement ladder for the SSC[4]. The ladder identifies four levels of enforcement (increasing in order of severity from level 1 through level 4) depending on the seriousness of the non-compliance. If a party is assessed to be non-compliant at a certain level and the actions taken to correct the non-compliance are found to be unsatisfactory, the AESO may issue the party an Enforcement Escalation notice informing the party that their non-compliance has been elevated to the next level. Enforcement Withdrawal Notices are issued when the AESO finds that the party in question has satisfactorily dealt with the non-compliance issue or if the AESO finds that its initial assessment of the non-compliance issue was more severe than warranted.

The MSA began collecting this data in 2004. **Table 10** summarizes the Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices filed by the AESO in 2004.

[3] Some unresolved UFE reports are attributable to the implementation of new systems at one LSA while others are attributable to system level errors.

[4] See Section 4 of Appendix C of the SSC.

Table 9 – 2004 Non-Compliance Notices

2004	Non-Compliance Notices Issued			
	Level 1	**Level 2**	**Level 3**	**Level 4**
January	-	-	-	-
February	4	-	-	-
March	1	1	-	-
April	-	-	-	-
May	-	-	-	-
June	-	-	-	-
July	-	-	-	-
August	-	-	-	-
September	1	-	-	-
October	-	-	-	-
November	-	-	-	-
December	-	-	-	-
Total	**6**	**1**	**0**	**0**

The table shows that to date six Level 1 Non-Compliance notices and one Level 2 Non-Compliance notice have been issued by the AESO. This appears to indicate that overall compliance with the SSC is going well and a co-operative nature exists between all settlement parties.

2.4 Retail Market Metrics

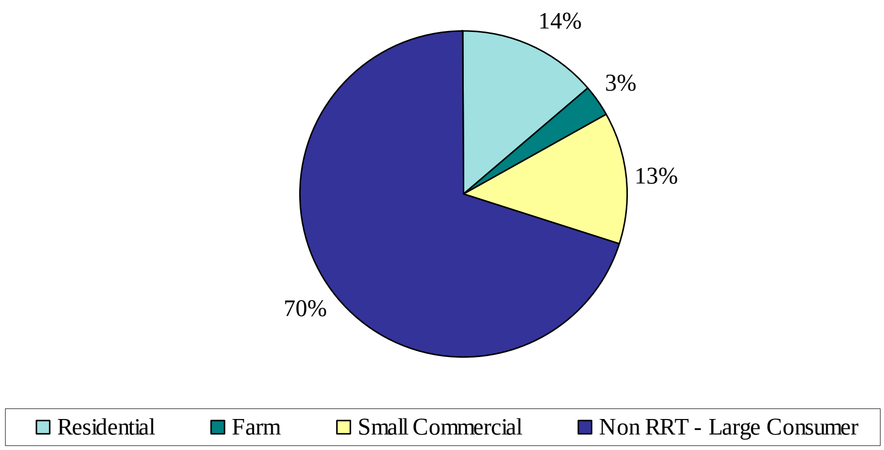
The MSA continues to track performance in the retail market based on the following metrics:

- Number of active retailers
- Market share of retailers (with respect to load)
- Trends in customer switching off the Regulated Rate Tariff (RRT) to sign competitive contracts.

The four primary customer categories that are tracked 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 consumer greater than 250 MWh annually.

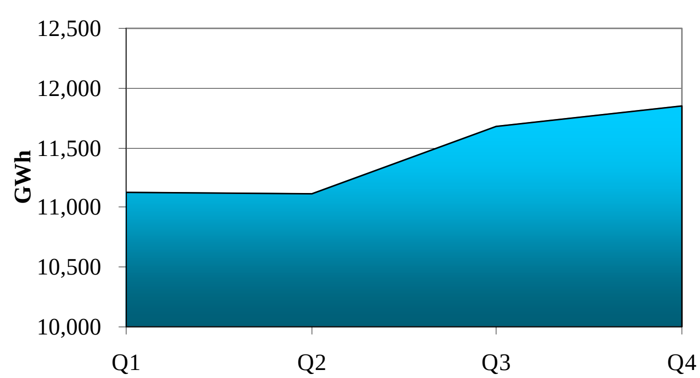
An overview of Alberta's consumption by category is provided below in **Figure 36**. For Q4, 2004, the Residential market with over one million customer sites used about 14% of the total internal load. The Farm category represents approximately 3% and the Small commercial sites encompass about 13% of the load. These 3 categories that are all RRT eligible constitute less than one third of the total provincial consumption while the Non RRT eligible or large consumers make up the remaining 70% of the provincial internal load.

Figure 36 - Consumption by Category, Q4/04



It is not always simple to identify trends in the retail market share when consumption of electricity varies from month to month, thereby impacting the market share denominator of total provincial electricity consumption. Changes in weather patterns as well as provincial economic growth cause large changes in overall demand for electricity. The following figure provides a context for the market share by load representations as it looks at the fluctuation in load by quarter for 2004.

Figure 37 - Alberta Site Consumption, 2004



As of December 31, 2004 there were 115 active retailers in the Alberta electricity market, 80 of which are self-retailers. Some of the larger retailers have individual companies that are classified as separate entities for financial reporting reasons but are essentially the same organization under a single brand.

Self retailers are a unique type of retailer that only procure electricity for their own consumption and do not resell to other customers. For the most part, entities that act as self retailers are larger industrial organizations that consume large quantities of electricity.

Figure 38 - Current Market Share of Retailers by Load, Q4/04

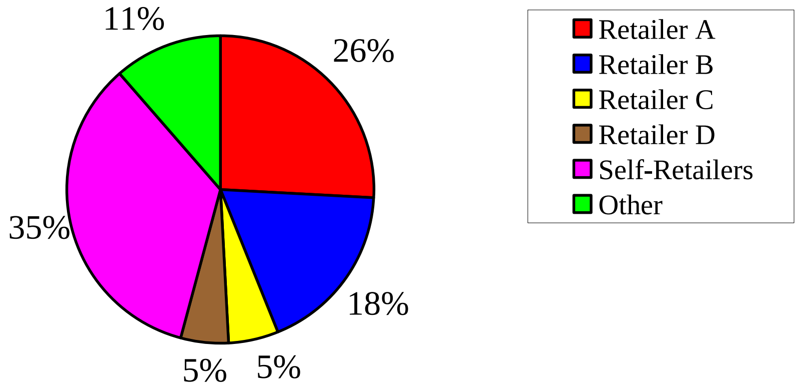
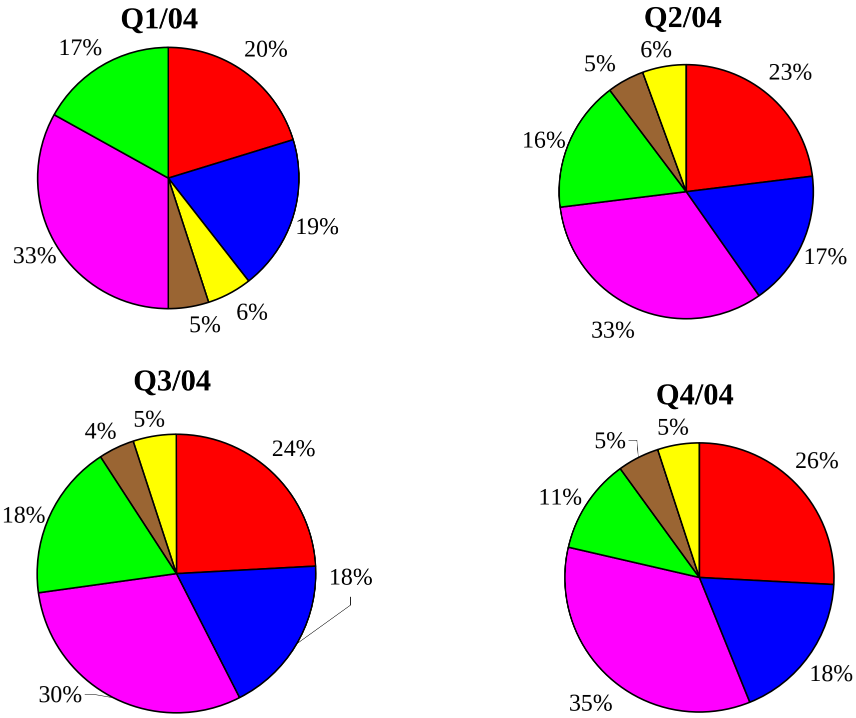


Figure 38 shows the overall provincial market share of retailers for Q4/04. The largest four retailers are servicing over 54% of the total provincial load. Self-retailers, usually large industrial organizations, make up another 35%, while assorted smaller retailers are competing for the remaining 11% of the market.

Over the past quarter, we have seen a change in distribution of the market shares as the cumulative market share of retailers with at least 5% market share has increased (retailers A, B, C and D). This is largely due to Retailer D gaining sufficient market share to break out of the "Other" category. "Other" refers to all other retailers that have a market share of less than 5 %. Since the last assessment in Q3, the "Other" category has decreased its share by 7 % while the "Self Retailer" portion has increased by 5%.

Figure 39 - Historical Market Share of Retailers by Load



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

Figure 39 provides an annual look at the changes in retailer market share since the beginning of 2004. The above figure shows a fairly stable trend in the market shares of retailers with a slight growth in the self retailer category. 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 40 below, shows retailer market share by customer class for Q4/04.

Market shares of the three dominant retailers in the Residential – RRT Eligible class have not substantially changed over the last two years. There has been some competition for market share between the two largest retailers over the years with the combined shares of these two retailers ranging between 87 and 90 percent.

The Farm – RRT Eligible category had 5 retailers with 5% or greater market share. This is the smallest category in terms of total load but with REAs becoming more involved in retailing, there is a noticeable effect on market shares in the Farm - RRT eligible category.

For Q4/04, market shares of the main retailers in the Commercial/Industrial – RRT Eligible category have remained steady with smaller retailers breaking out of the "Other" category. The cumulative market share of the four retailers with at least 5% market share adds up to 78% of the total load. Again, a trend towards self-retailing seems appealing to those wishing to have more control over the energy portion of their business.

Figure 40 - Q4/04 Market Share of Retailers by Customer Class

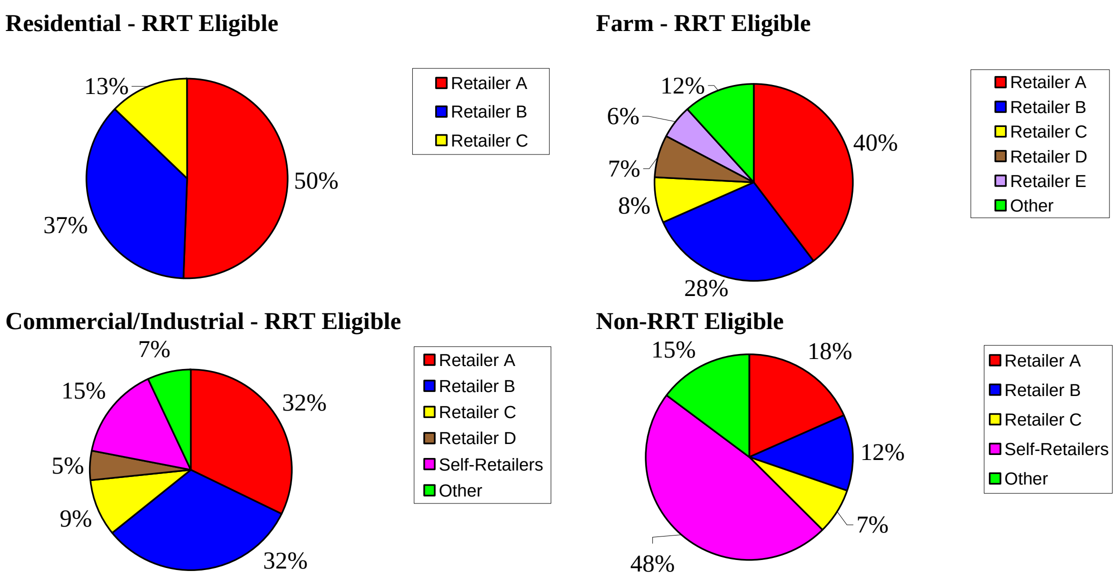
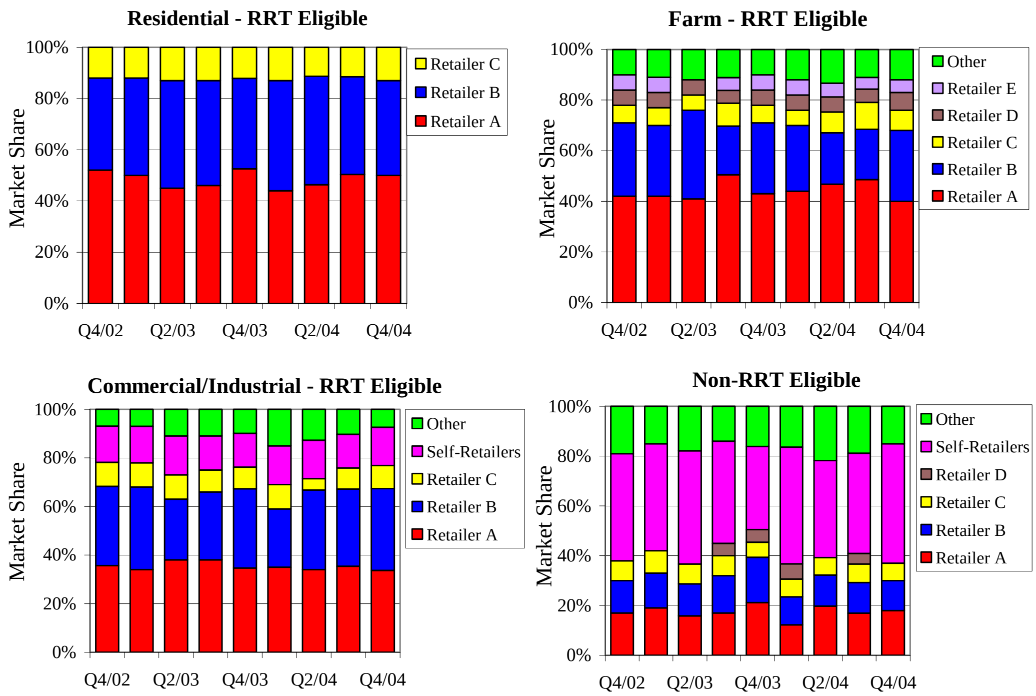


Figure 41 is another way to look at the shift in market share in the four categories. The picture is useful in providing an overall view of the change in market share over the past two years and demonstrates the dynamic nature of the retail market. It is worthwhile to note the entry and exit of new retailers in the graphs which clearly shows the ongoing battle for market share in certain parts of our retail market.

Figure 41 - Change in Categories



The overall progression of customer sites off of the RRT to competitive electricity contracts, as shown in **Figure 42**, has held relatively steady over last several quarters but has risen somewhat during Q4. As of December 31, 2004, 7.6% of all RRT eligible customer sites have chosen to enter into a competitive contract with a retailer.

Figure 42 - Progression of RRT Eligible Sites Switching off RRT

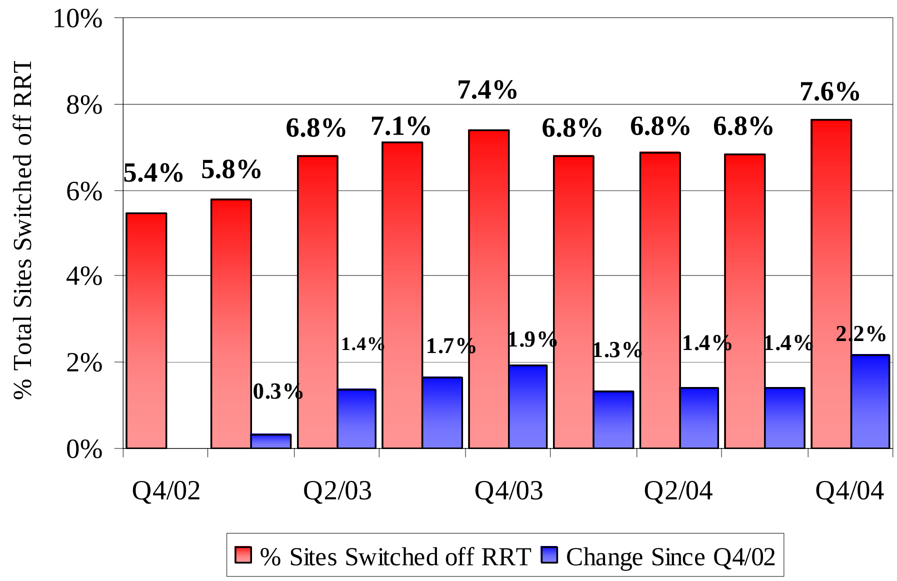


Figure 43 - Progression of RRT Eligible Sites Switching Off RRT by Customer Type

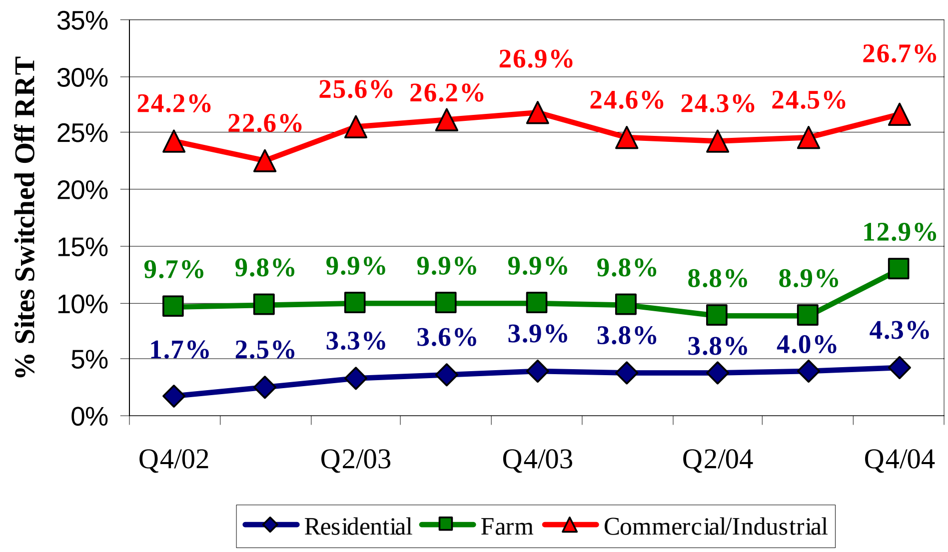


Figure 43 shows the progression of RRT eligible sites switching off RRT for the last eight quarters by customer type. Switching results are encouraging in the Farm category where switching rates have increased by 3% from 8.9 % in Q3/04 to 12.9% in Q4/04. This is a good sign but it should be noted that the relative market is not extremely large so the switching of somewhat few customers translates into a large percentage gain.

Switching rates in the Commercial/Industrial – RRT eligible category are also increasing and have reached 26.7%. This market is substantially larger than the Farm category and the increase rate of switching indicates that retailers are able to find customers in this category who find competitive contracts an attractive option to the regulated rate.

The Non-RRT eligible category remains the most hotly contested market where the greatest numbers of retailers are active. This is the market for larger electricity consumers that historically consume more than 250 MWh per year. To put this in perspective the average household consumes less than 8 MWh each year.

3 MARKET ISSUES

3.1 TPG Enforcement

During 2004, the MSA addressed a fundamental issue in the Alberta electricity market concerning the asymmetry around outage and derate information (collectively referred to as outage information). That is, certain participants have access to information not generally available to other market participants. In the real time market, Pool prices respond to unit outages. Thus, a market participant who has advance knowledge of such an outage has a material advantage over other participants for trading in the forward market. A market participant's use of information which is not in the public domain creates the perception and/or reality of unfairness in the forward market.

In order to "level the information playing field," the MSA established the Trading Practices Guideline (TPG). This guideline provides that:

> ***Market participants must not trade on the basis of 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.***

The TPG was published on February 18, 2004. In the months following, the MSA met with market participants and held an open workshop in June to discuss how the TPG would be put into effect and on July 5, 2004 the MSA implemented the Information Disclosure Procedure (IDP). The IDP is in support of the TPG and is designed to assist market participants with their TPG compliance by facilitating the disclosure and publication of outage information. The MSA commenced formal enforcement of the TPG in conjunction with implementation of the IDP. Further information concerning the TPG and IDP can be found at the following link: http://www.albertamsa.ca/TradingPracticesGuidelinesandInformationDisclosureProcedure.html

A key feature of the IDP is the publication of daily outage reports. The reports provide market participants with a graphical summary of generation and demand outages on a short and long term basis. The publication of outage information is also consistent with the MSA's general philosophy that information transparency helps to facilitate a competitive market.

In terms of the IDP process, outage information is first submitted to the AESO via e-mail pursuant to OPP 601. These emails are then forwarded to the MSA for consolidation and publication. Three reports are published daily; 8 am, 10 am and 3 pm.

Future Activities in Support of the TPG/IDP

The MSA continues to work on two key areas of the TPG including improving the method for submitting, reporting and publishing information in order to align the reporting of outages closer to real time and development of performance metrics for evaluating the efficacy of the initiative.

The MSA recognizes that reporting outage information as close to real-time as possible will be of significant benefit to market participants. In this regard, the MSA is continuing to work with the AESO to enable real-time updates of the outage reports using the ETS system to facilitate the submission of outage information. The ETS system was developed by the AESO in relation to OPP 705 and its initiative around short-term adequacy. The MSA is cautiously optimistic that the roll out will occur during Q2/05. The beneficial result of this effort will be a significant improvement in the quality and timeliness of outage information. Once the EST changes are implemented, outage reporting by the MSA will be on a continuous basis rather than three times per day.

The MSA previously indicated that the TPG/IDP is aimed at improving market fairness, efficiency and competitiveness, and if this does not appear to be the case, it will be adjusted or eliminated. The AESO liquidity survey of 2004 provides a benchmark for that element which the TPG/IDP is expected to improve. However, it is also known that market liquidity is affected by many other factors including changing market fundamentals, credit, market stability, and corporate attitudes to trading risk. As previously committed, the MSA will seek empirical evidence and market feedback after one year of operation of the TPG/IDP.

In terms of performance measurement the MSA is considering a number of possible metrics in the areas of market fundamentals, participant operating performance (asset performance), trading activity (breadth and depth of the forward market), and participant offer strategy (participant behaviour). These metrics will help in determining whether market conditions are improving as a result of the TPG and/or other market factors.

TPG Investigations

The MSA investigated three potential breaches of the TPG involving seven market participants during the second half of 2004. Early in 2005 the MSA published its investigation report that described in general terms the actions of the parties involved and the conclusion of the MSA. In one case involving a generating unit which is subject to a Power Purchase Arrangement (PPA), two of the potential breaches involved trading activity that was conducted by the PPA Owner and the PPA Buyer. The other case involved trading in the forward market after a generating unit that was placed on forced outage status but before the outage was reported to the AESO pursuant to OPP 601. Based upon the circumstances made known to the MSA during the investigations, it is clear that breaches of the TPG took place around those outages. The MSA carefully weighed the circumstances around the breaches, and taking into account the nascent nature of the TPG at the time of the breaches and the undertaking given by the MSA to the industry that TPG enforcement would be sensitive to the learning curve issues, the MSA decided to exercise its powers of forbearance and not pursue any of the remedies available to it under the Electric Utilities Act.

In general the parties were very cooperative with the MSA in meeting our information requests and in modifying trading policies and procedures. With respect to the investigation involving the PPA Owner and Buyer owner disclosure some parties noted that existing disclosure requirements might have the effect of disadvantaging a PPA Owner. The combined effect of the PPA and the ISO Rules is that outage information typically flows from the Owner to their counterparty the Buyer and from that party to the Independent System Operator (AESO). The Buyer will thus be directly aware of when an outage has been disclosed to the AESO, but the Owner will not be certain that the disclosure has occurred unless advised by the Buyer. The MSA recognizes that it would be inappropriate for an Owner, having made the Buyer aware of an outage, to be left uncertain as to when the Buyer has made disclosure to the AESO.

We are pleased to note that PPA Buyers appear to have now broadly adopted the approach of advising their counterparties of the outage disclosure concurrent with the disclosure to the AESO, leaving both parties then free to trade in a manner compliant with the TPG and the *fair, efficient and openly competitive* operation of the market.

We are generally pleased with the way that industry is trying to work with the MSA on the TPG/IDP. Over the course of the last six months the MSA and the AESO have observed an improvement in the quality of outage data submitted and increased compliance with the reporting requirements of OPP 601.

3.2 Ancillary Services Review

In 2004 the MSA focused a good deal of resources on addressing issues in the AS market. The MSA undertook a number of AS focused reports, investigations and initiatives, outlined below:

January 2004: *Spinning Reserve Event Report*. In November 2003, the MSA noticed a significant downward shift in the Watt-Ex spinning reserve price index. The downward shift was a result of TransAlta (TAU) optimizing its portfolio in light of the Notional Reserve Quantities Agreement (NRQA) arising out of the Hydro PPA between TAU and the Balancing Pool. As a result of the NRQA, if TAU was unable to meet its notional obligation it would implement a trading strategy whereby it would offer sufficient volumes at a discount of -$999 in order to minimize the payment that was due to the Balancing Pool. As a result of this circumstance, TAU routinely received $0 for providing supplemental reserves to the AESO and passed on $0 to the Balancing Pool under the terms of its agreement. This outcome began to occur in the supplemental reserve market beginning in August 2002, and on occasion, spilled over to the spinning and regulating markets, as observed in November 2003.

The MSA recommended to TransAlta and the Balancing Pool that they needed to address the NRQA and implement appropriate solutions to prevent this type of behavior in the future. As a result, TransAlta and the Balancing Pool negotiated a new agreement, taking effect in the beginning of August, 2004. Subsequently, the trade index for active supplemental reserves has returned to more rational levels.

May 2004: *Ancillary Services in Alberta, A White Paper* presented to the Department of Energy's Wholesale Market Policy Review Taskforce. The MSA assisted the AESO and DOE in drafting a White Paper that provided an overview of AS market performance for the DOE's wholesale market review. The paper identified three issues with the market; the hydro PPA (this issue was ameliorated with the renegotiation of the NRQA), the single buyer issue and the overall market complexity. Despite these issues, the study indicated a strong degree of arbitrage between the energy and ancillary services markets.

June 2004: OTC Transparency Initiative. Starting in the second half of 2003, the MSA noted an increased in the reliance on OTC trades for reserves procurement and believed this should be accompanied by increased OTC market transparency to facilitate efficient decision making by participants in the AS market. As such the MSA worked with the AESO to help implement OTC price and volume disclosure via the AESO's website. In order to achieve this outcome, the AESO successfully adopted a new Master Agreement with participants which allows for price and volume disclosure. As well, the MSA started publishing monthly data on standard and fixed price OTC products in its Quarterly Report, starting in Q1/04. Notwithstanding these enhancements, the MSA will continue to evaluate the level of OTC transparency to assess whether OTC practices are fair and reasonable to participants.

August 2004 *Powerex Active Spinning Reserve Review* This informal investigation examined whether Powerex, the marketing arm of BC Hydro, was responsible for making the intertie the single largest contingency (SLC), resulting in the curtailment of their Active Spinning Reserve (ASR) contracts by the AESO. When reserves were not delivered due to curtailment, Powerex continued to receive payment for their curtailed contracts. Other AS providers do not receive payment for undelivered reserves and are also assessed liquidated damages for non-delivery.

The MSA found that the AESO's treatment of Powerex in regard to payment for undelivered reserves was not consistent with their treatment of other AS providers. The analysis demonstrated that curtailment of Powerex's reserves as a result of the intertie becoming the SLC was not necessarily a random event and arose from Powerex's actions in response to market conditions. MSA considered the practice of payments to Powerex for undelivered reserves as unfair to other AS suppliers.

As a result of the informal investigation, the MSA recommended that the AESO cease making payment to Powerex for non-delivery of AS reserves when the intertie becomes the SLC. Further, the MSA recommended that the AESO enforce the terms of the Watt-Ex contract (and OTC contracts, if applicable) in respect of all AS suppliers in a consistent manner.

September 2004: *A Review of Regulating Reserves Performance in Alberta*. Market participants expressed concern that they believe, at times, System Controllers 'lean' on regulating reserve rather than dispatch up the merit order. As evidence, participants observed that small blocks of energy set the system marginal price (SMP) for extended periods of time, and did so when demand is ramping up. The allegation of improper use of regulating reserve and the supporting rationale led to the review of regulating reserve performance.

The analysis performed in this work did not provide supporting evidence that the System Controllers are engaged in systematic misuse of regulating reserves. The evidence showed that the variability in the utilization of regulating energy across hours was consistent with the overall system dynamics, which include load ramps, generation offer profiles, interchange activity and AS contract timing. The results showed that the System Controllers are most active in dispatching through the merit order when the system is in its most dynamic hours. The evidence suggested that the strategies of the System Controllers in minimizing CPS2 violations coupled with the lack of dispatch fidelity on the load and generation side are leading to a repeated sub-optimal outcome resulting in small blocks setting SMP for extended periods of time. It also showed there is a key interrelationship between dispatch fidelity (what is asked for equals what is provided and needed) and price fidelity (sufficient dispatch through the merit order to provide an efficient price signal).

From the results of this study, the MSA made the following recommendations: 1) The AESO, DOE and participants consider the relationship between dispatch and price fidelity when considering changes to the market design; 2) The AESO review training and education provided to market participants around the use of regulating reserves; 3) The AESO consider appropriate disclosure of operating and reliability data; and, 4) The AESO provide System Controllers on-going training with respect to operational guidelines to promote consistency in dispatching.

October 2004 *Competitiveness of the Alberta TMR Market*. In October 2004, the Market Surveillance Administrator initiated an investigation into the competitiveness of the market for Transmission Must Run (TMR) services in Alberta. The investigation was prompted by the MSA's observation that market participants have found it necessary to refer to regulatory authorities a number of times in a relatively short period seeking changes to TMR arrangements. The most recent dispute has seen ATCO Power and the AESO in protracted disagreement with respect to payment for the provision of TMR service in the Rainbow Lake area, as well as an application to the Alberta Energy and Utilities Board ("AEUB") to amend the pricing provisions of Article 24 of the AESO's Terms and Conditions, which governs payment for conscripted TMR service.

A key part of this investigation included engaging Charles River Associates (Asia Pacific) Pty Ltd ("CRA") to conduct an independent assessment of the competitiveness of TMR in Alberta.

The MSA concluded its investigation in February 2005. The MSA found that overall processes and outcomes for TMR, viewed over a number of years, have not been consistent with the promotion of a fair, efficient and openly competitive process. This finding was supported by the CRA study.

Given the need to promote stability and confidence in the TMR market and establish compensation under Article 24 in a fair, open and (dynamically) efficient manner, the MSA has advanced a number of recommendations. They include:

- Design of a formal TMR procurement process. The process includes procurement stages that move from Expression of Interests (EOIs), to Request for Proposals (RFPs) and bilateral negotiations. A formalized process for arbitration and if necessary, regulated outcomes is also proposed.
- Clarification of roles and responsibilities of the AESO and interpretation of its mandate, in particular, as they relate to ensuring system reliability and promoting a fair, efficient, and openly competitive market.
- Improved timeliness and transparency for TMR in the planning stages.
- Shifting conscription of TMR services out of the dispatch timeframe (except for unforeseen emergencies) and into the planning stage using medium term contracting approved by the EUB.
- Increased reliance on formal competitive processes for procuring TMR.
- Increased transparency and reporting when non-competitive processes are used to procure TMR.

The MSA's next step is to consult with implementing agencies including the Alberta Department of Energy, Alberta Energy and Utilities Board and the AESO, to improve market transparency and develop a formalized procurement process for TMR using the recommendations provided.

As a result of the ancillary services projects, investigations and initiatives outlined above, the MSA believes the Ancillary Services market has gained greater fairness and transparency. It is our hope that by continuing to provide analysis and guidance, the market will continue to evolve and mature in a fair, efficient and openly competitive manner.

3.3 Uneconomic Tie Line Activity

In the second half of 2004, the MSA undertook a review of uneconomic import and export activity on the Alberta-BC tie line. This was initiated in part to address concerns expressed by certain participants that other parties were systematically importing and exporting energy at a loss in order to manipulate Pool price to suit their portfolio position. Pool price fidelity is a fundamental tenet for the MSA – as such, promoting Pool price fidelity also underscored the need to review this behaviour.

The first stage of this review involved the determination of the basic economics of imports and exports over a 19 month period ending July 31, 2004. Results from first stage work indicated that overall, imports were reasonably profitable for the 5 parties under consideration whereas exports were generally unprofitable. The review pointed to the asymmetric price risk between the Alberta and Mid Columbia (Mid C) markets being a key factor. Our profitability model indicated that imports were more frequently unprofitable but also had "home run" profitability potential and such hours of high profitability made imports profitable overall for participants in the study period. Exports on the other hand were more frequently profitable but were subject to "home run" losses due to the relative volatility of Pool price and Mid C prices.

A follow up stage of this review involved a closer examination of the frequency and duration of intervals in which uneconomic behaviour was apparent. We also attempted to tie these observations to deemed shortness of participants. There appeared to be a willingness by firms to tolerate significant losses (approximately $20/MWh on average) when covering deemed short positions.

To summarize this review, the MSA published a report in early January 2005 which discussed findings and contained a number of recommendations including: 1) allowing imports and exports to set price; 2) ensure that reliable and timely ATC information is available to the market; 3) a renewal of efforts to address seams issues between Alberta and BC; 4) restoration of full tie line capacity.

The report was also intended to serve notice to participants that uneconomic behaviour on the tie that appears to be driven by an effort to manage Pool price is unacceptable and may result in a formal investigation by the MSA. The full report is available for review at: http://www.albertamsa.ca/1630.html .

4 OTHER MSA ACTIVITIES

4.1 Participation in WMPTF & STA

The MSA has been involved in the Wholesale Market Policy Task Force and Short Term Adequacy debates, and is supportive of the DOE in these efforts to further enhance the operation of the market.

4.2 Stakeholder Meetings

The MSA held its twice annual stakeholder meetings which are intended as an update for participants on MSA initiatives, as well as an opportunity for participants and stakeholders to put forth market concerns and issues to the MSA. Presentation packages for these meetings are available for download from the MSA website at www.albertamsa.ca.

4.3 Other Papers published in 2004

In addition to the studies and reviews noted elsewhere in this report, the MSA also published papers on residential load profiles, as well as economics of new entry. The study of residential load profiles sought to determine the effect of load profiling and location on customer's bills, and to assess the effect of Pool price volatility on monthly electricity bills based on an assumed monthly consumption level.

The study on economics of new entry presented a simulation of cash flows for three different new plant configurations with the goal of illustrating directionally, what the current market price signal is telling prospective generators. Both these reports are available for review on the MSA website at www.albertamsa.ca .

4.4 Energy Intermarket Surveillance Group

The MSA continues to be an active participant in activities of the Energy Intermarket Surveillance Group (EISG) – a primarily North American but also international affiliation of electricity market monitoring agencies in other jurisdictions. The group continues to be a valuable sounding board for issues of mutual interest and concern.