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MSA REPORT

Quarterly Report

January - March, 2004

10 May, 2004

MARKET SURVEILLANCE ADMINISTRATOR

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Market Highlights

- The average price of electricity in the Alberta wholesale spot market in Q1/04 was $48.81/MWh which compares to $54.81/MWh for Q4/03 and $83.94 for Q1/03. See p.2 of the report for further details.

- Implied market heat rates declined month on month through Q1/04, averaging 8.0 GJ/MWh for the quarter on an all-hours basis. For the month of March, the average implied market heat rate declined to 7.2 GJ/MWh. See p.6 of the report for further details.

- Peak demand in Q1/04 increased approximately 6.3% from peak demand in Q1/03, however, supply additions over the same period were approximately equal. See p.8 of the report for further details.

- As an outcome of the MSA's ancillary services market review, the ancillary services market section of the quarterly report has been substantially enhanced. See p.19 of the report for further details.

- The MSA conducted studies of residential load profiles and settlement system code during Q1/04 and a brief synopsis of both are included herein. See p.38 and p.47 of the report for further details.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

Pool prices in Q1/04 overall, moved lower relative to both the last quarter and the same quarter a year ago. While overall average and on-peak average prices were down in Q1/04, off-peak average prices were up marginally from levels in Q4/03. As shown in **Table 1**, monthly average prices trended downward through the quarter on an overall average basis and on an on-peak basis with March being the lowest average price month in the 15 month window shown in **Figure 1.** In addition, March is the lowest monthly average Pool price since August, 2002. The price duration curves in **Figure 2** show the distribution of Pool price through the periods shown. In Q1/04 as in the previous quarter, prices exceeded \$100/MWh less than 7% of the time while prices were at or below \$30/MWh 37% of the time. Coal unit availability remained high through Q1/04 contributing to lower average prices.

The variability of prices as reflected by coefficient of variation, was similar to levels observed both last quarter and in Q1/03.

Table 1 - Pool Price Statistics

	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%
Q1 - 04	**48.81**	**55.08**	**40.20**	**50.02**	**102%**
Oct - 03	67.45	87.62	39.63	78.96	117%
Nov - 03	52.56	61.10	42.80	48.37	92%
Dec - 03	44.34	52.52	33.95	37.62	85%
Q4 - 03	**54.81**	**67.08**	**38.79**	**58.58**	**107%**
Jan - 03	80.52	93.78	63.70	94.47	117%
Feb - 03	81.23	99.42	56.98	82.15	101%
Mar - 03	89.80	93.24	85.43	84.77	94%
Q1 - 03	**83.94**	**95.48**	**68.70**	**87.52**	**104%**

1 - Standard Deviation of hourly pool prices for the period

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

Figure 1 - Pool Price with Pool Price Volatility

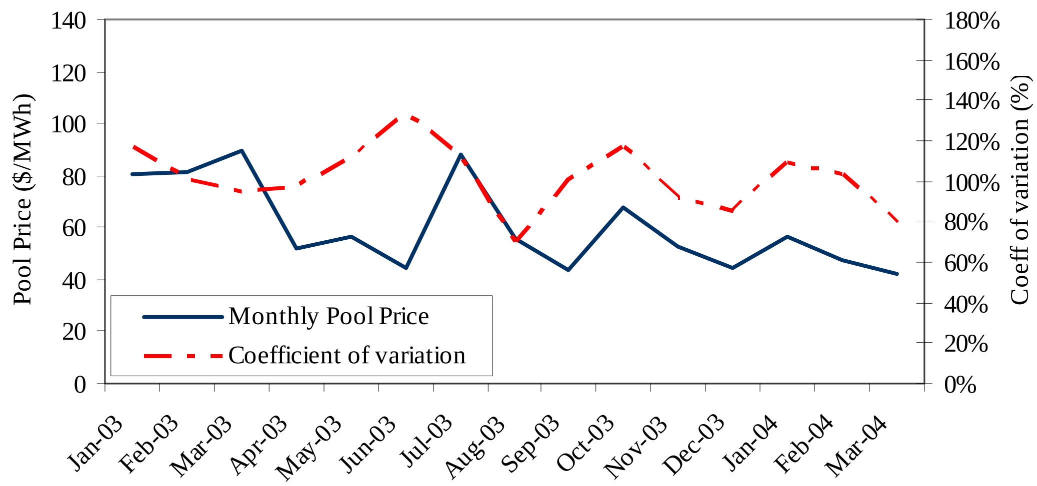
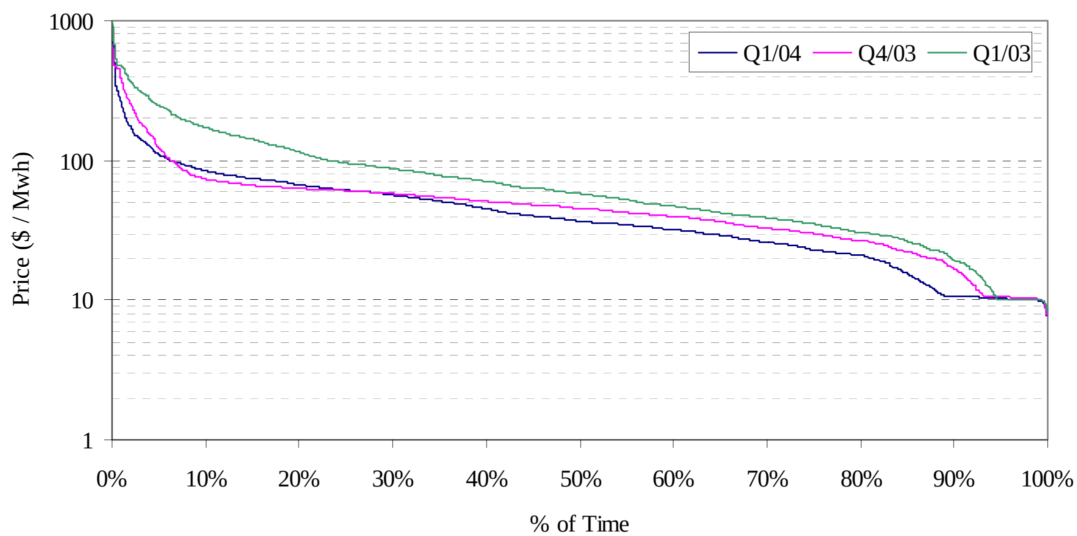


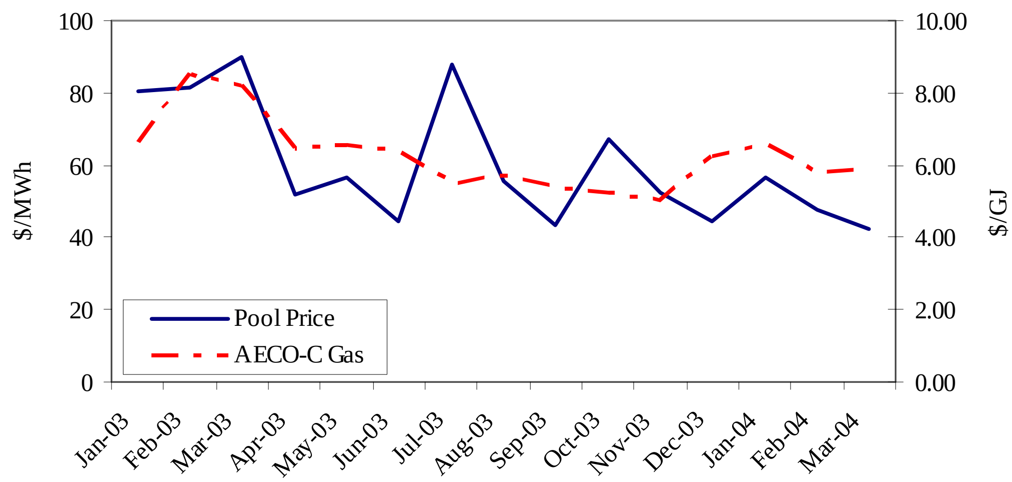
Figure 2 - Quarterly Pool Price Duration Curves



1.2 Natural Gas Prices

Alberta gas prices remained relatively steady in a band from $5.90 - $6.50/GJ through Q1/04 which was up from levels observed through the previous quarter but substantially lower than levels in the same quarter a year ago. **Figure 3** compares monthly gas prices in Alberta with the average Pool price. Correlation statistics show that the Pool price to gas correlation breaks down as the rolling 12 month window moves forward to the end of Q1/04. This seems to suggest that even though gas-fuelled generation is the price setting unit a significant proportion of the time, the offers of gas units over time have become more strategic and less cost-based and this is in large measure, a result of the overall shape of the market supply curve.

Figure 3 - Pool Price with AECO Gas Price



1.3 Price Setters

Figure 4 shows the 5 most frequent marginal price setters in Q1/04 relative to the previous quarter together with the weighted average price at which they set the system marginal price (SMP). The leading price setter in Q1/04 set the system marginal price approximately 25% of the time on an all hours basis, at a weighted average price of $28.99/MWh, as compared to the quarterly average price of $48.81/MWh. Price setting activity was somewhat more concentrated in Q1/04 with the top 5 price setters setting SMP 85% of the time as compared to 73% of the time in Q4/03.

Figure 4 - Price Setters By Customer (All Hours), Q1/04

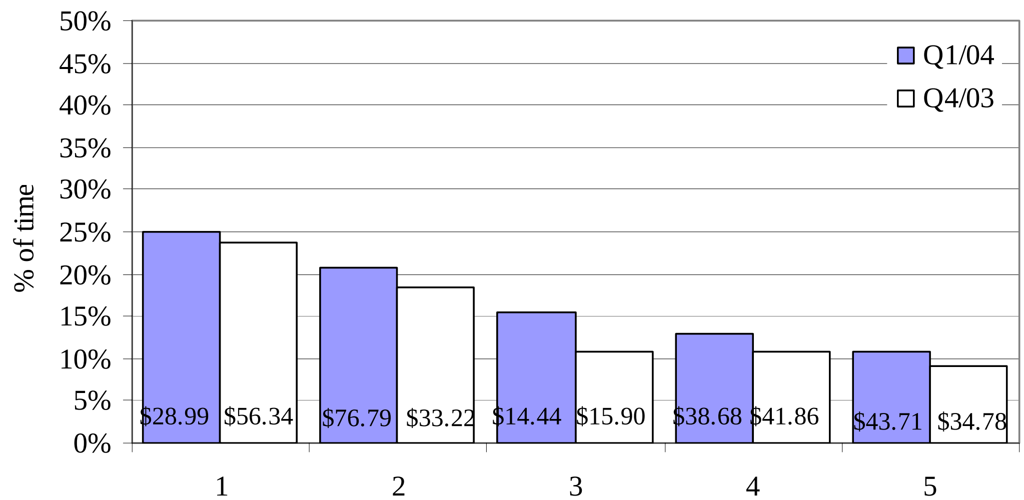
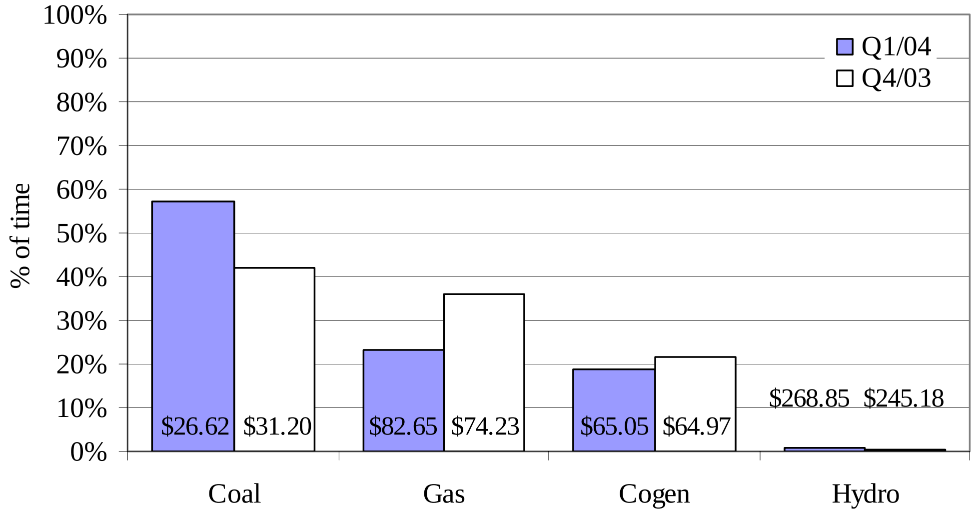


Figure 5 shows a similar ranking of price setters by fuel type of the price setting unit. It can be seen that Coal fired units were more often the marginal unit in Q1/04 as compared to Q4/03. Coal units set price approximately 57% of the time in Q1/04 at a weighted average price of $26.62/MWh while in the previous quarter, coal units set price 42% of the time at a somewhat higher average price of $31.20/MWh. With high levels of coal unit availability in Q1/04, it is not surprising that coal units have been on the margin more often. Gas units (including co-gen) set price 42% of the time in Q1/04 at a weighted average price of approximately $74.81/MWh. Lower than average levels of price setting activity by gas units is an expected market outcome considering the prevailing market heat rates observed in Q1/04.

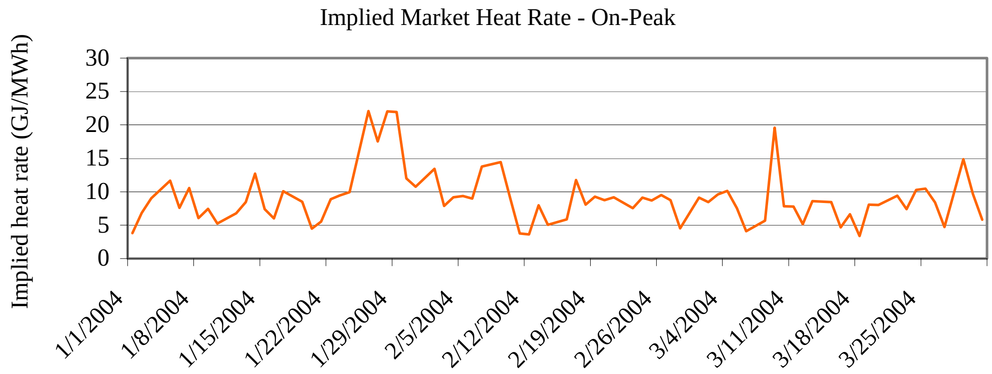
Figure 5 - Price Setters By Fuel Type, Q1/04



1.4 Implied Market Heat Rate

Implied market heat rates declined markedly in Q1/04 as gas prices have remained in a relatively narrow range while Pool prices trended downward through Q1/04. **Figure 6** shows the daily implied market heat rate for Q1/04 on both an on-peak and an off-peak basis. On-peak implied heat rates strengthened in late January and early February and briefly in mid-March although as the heat rate duration curves in **Figure 7** demonstrate, implied heat rates were below levels observed last quarter and the same quarter a year ago 100% of the time. In the context of a newer gas generator in the market, prices in Q1/04 were such that fuel costs could be met about 50% of the time while in both Q4/03 and Q1/03 the same generator would have been able to recover fuel costs about 70% of the time. The last gas generator built under the previously regulated regime would have been able to recover its variable fuel costs only 15% of the time in Q1/04.

Figure 6 - Implied Market Heat Rates, Q1/04



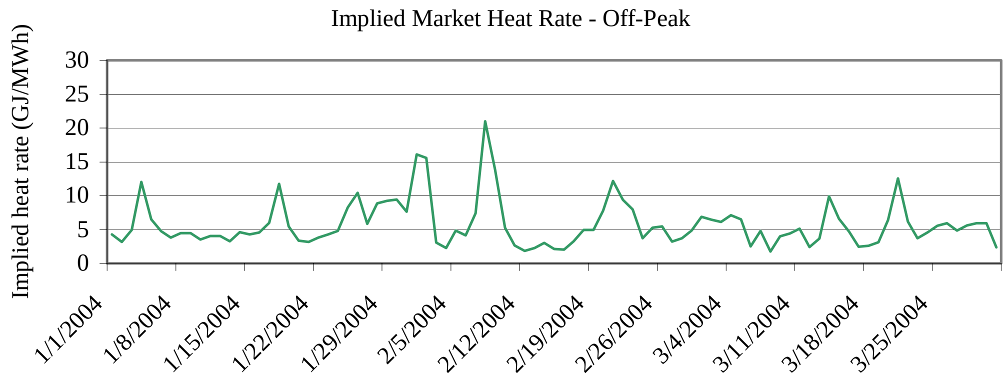
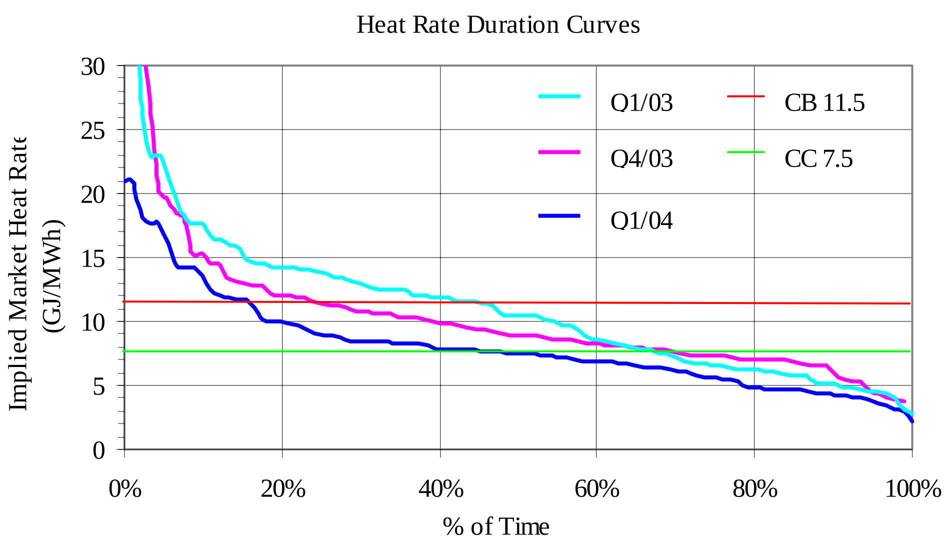


Figure 7 - Heat Rate Duration Curves (All Hours)



1.5 New AESO Rules

There were no substantial changes to AESO rules during Q1/04.

1.6 New Supply and Load Growth

No significant new generation was added to the system through Q1/04.

The monthly average hourly system demand for electrical energy in Q1/04 was:

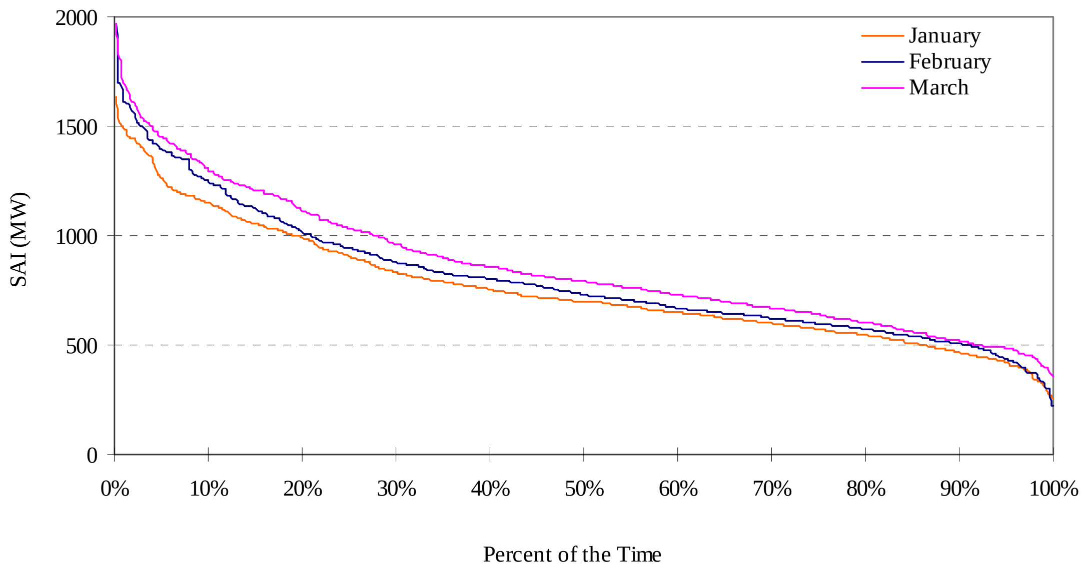
January	7798 MW	+ 5.6 % vs. Jan 2003
February	7563 MW	+ 2.8 % vs. Feb 2003
March	7427 MW	+ 3.3 % vs. Mar 2003

Peak demand in Q1/04 was 8967 MW which occurred in HE 18 on January 26 at a pool price of $317.37/MWh. Peak demand increased approximately 6.3 % from peak demand in Q1/03. Despite the noted increase in peak demand year over year, supply additions over the same period were approximately equal.

1.7 Supply Availability Index

SAI approximates the residual supply available in the market on a short term basis since it is determined by summing the volume of energy in the merit order above the level of dispatch in each hour. **Figure 8** shows duration curves of SAI for each month in Q1/04. It can be seen that each subsequent month in the quarter had a marginally higher SAI than the prior month the majority of the time. This corresponds to the month on month decreases in average Pool price through Q1/04. In Q1/04 the correlation coefficient between SAI and Pool price was determined as -0.47 which compares to -0.48 in Q4/03 indicating that the correlation has remained essentially constant.

Figure 8 - SAI Monthly Duration Curves, Q1/04



1.8 Imports, Exports, and Prices in Other Electricity Markets

Activity on the interties between Alberta and BC and Saskatchewan is an integral part of the operation of the Alberta electricity market. **Table 2** summarizes the activity on the tie-lines for Q1/04.

Table 2 - Tie Line Activity Q1/04

	BC			Saskatchewan			Overall		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
January	*112,900*	*53,100*	59,900	*10,200*	*21,400*	(11,200)	123,200	74,400	48,700
February	*49,900*	*88,300*	(38,500)	*6,500*	*18,800*	(12,400)	56,400	107,200	(50,800)
March	*42,100*	*103,200*	(61,100)	*7,700*	*8,100*	(400)	49,800	111,300	(61,500)
Total	**204,900**	**244,600**	**(39,700)**	**24,400**	**48,300**	**(24,000)**	**229,400**	**292,900**	**(63,600)**
On-Peak	94%	21%		92%	63%		94%	28%	
Off-Peak	6%	79%		8%	37%		6%	72%	

Note: Negative net imports indicate net exports

In Q1/04, Alberta was an overall net exporter. Exports were once again dominated by activity on the BC tie-line (83%) – primarily in the off-peak hours. On the BC tie-line, exports increased throughout the quarter while imports decreased. Conversely, on the Saskatchewan tie-line, both export and import activity trended downward throughout the quarter. Higher import levels in January are likely due to higher prevailing Pool prices in January compared to the other months in the quarter. Note that on the BC tie-line, imports occur primarily in the on-peak hours while exports are more frequent during off-peak hours. On the Saskatchewan tie-line there tends to be more activity in both directions (import and export) during the on-peak hours. Over the course of the quarter, Alberta imported over 229,000 MWh and exported approximately 293,000 MWh of electricity.

Figure 9 shows the relative market shares of importers and exporters in Q1/04. The figures include imports and exports on both the BC and Saskatchewan tie-lines. Both importing and exporting were dominated by one market participant (Powerex) with a 52% market share of imports (up from 43% last quarter) and a 74% market share of exports (down from 88% last quarter). Relative market shares of other participants have also changed somewhat since last quarter. The second largest importer has increased its market share by 10% (up to 23% from 13% last quarter) while the third largest importer has decreased its market share by 9% (11% down from 20% in Q4/03). Other than the change in Powerex's market share, the biggest difference quarter over quarter in terms of export market shares is an increase in market share of 9% (from 2% up to 11%) of the second largest exporter in Q1/04. Market shares of other participants generally remained static.

Figure 9 - Market Share of Importers and Exporters, Q1/04

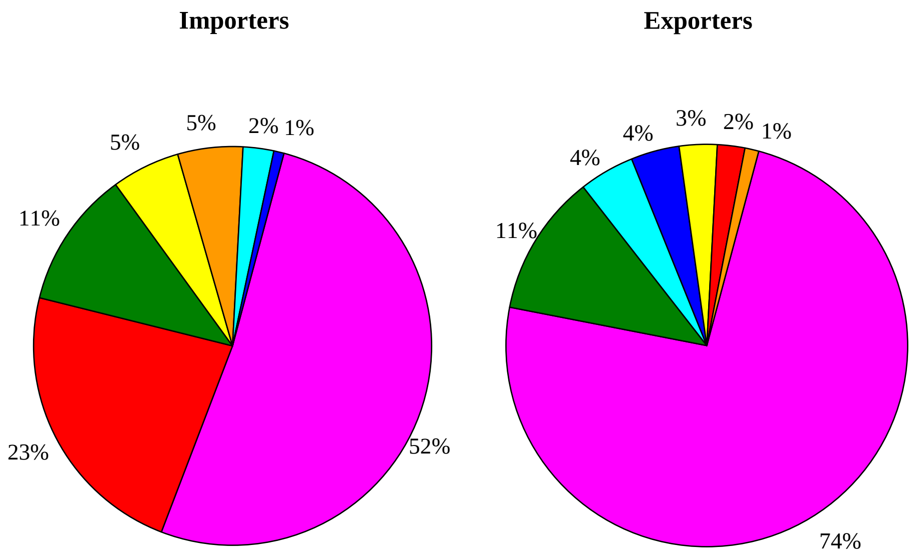
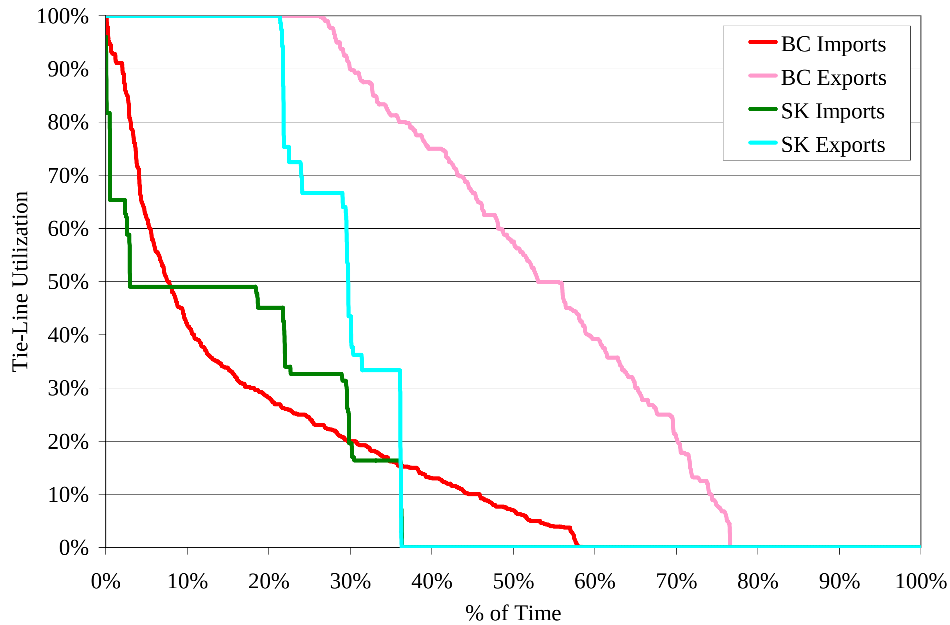


Figure 10 shows a duration curve of tie-line utilization in Q1/04 as a function of available transfer capability (ATC)[1]. The figure shows that there is unutilized capacity available on all of the tie-lines almost all of the time. The BC export ATC was the most effectively utilized in Q1/04 as there was some volume of energy being exported from Alberta to (or through) BC approximately 76% of the time that the line was available. In addition, the BC export capacity was being fully utilized approximately 27% of the time. The Saskatchewan import capacity was the most underutilized in Q1/04. This capacity was essentially never fully utilized and was not used at all approximately 73% of the time.

[1] ATC is the maximum amount of energy which can be moved across the tie-line in any given hour. 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 200/500 or 40%. ATC is posted on the AESO website and varies on an hourly basis.

Figure 10 – Tie-Line Utilization, Q1/04



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.

The capacity of the BC export tie-line was significantly derated during most on-peak hours in Q1/04. Load, generation and transmission constraints on both sides of the tie-line affect the volume of energy that can be moved across the tie-line. During most of Q1/04 the ATC of the BC export line was seriously affected by a Calgary Area capacitor bank being out of service. The effect on the ATC varied with internal load: as the load increased, the export ATC decreased. Because January through March are typically high load months, the BC export ATC was often fully derated (ATC = 0 MW) – particularly in the heavy load on-peak hours. There were no other significant tie-line outages or derates during the quarter.

Activity on the tie-lines can be highly dependent on Pool price. **Figures 11 and 12** plot total monthly imports with average price paid to Importers and total monthly exports with average price paid by Exporters respectively for the January 2003 through March 2004 period. During Q1/04, 94% of imports occurred during on-peak hours and 72% of exports occurred during off-peak hours, which is characteristic of the typical flow distribution.

Figure 11 – Imports and Price Paid to Importers

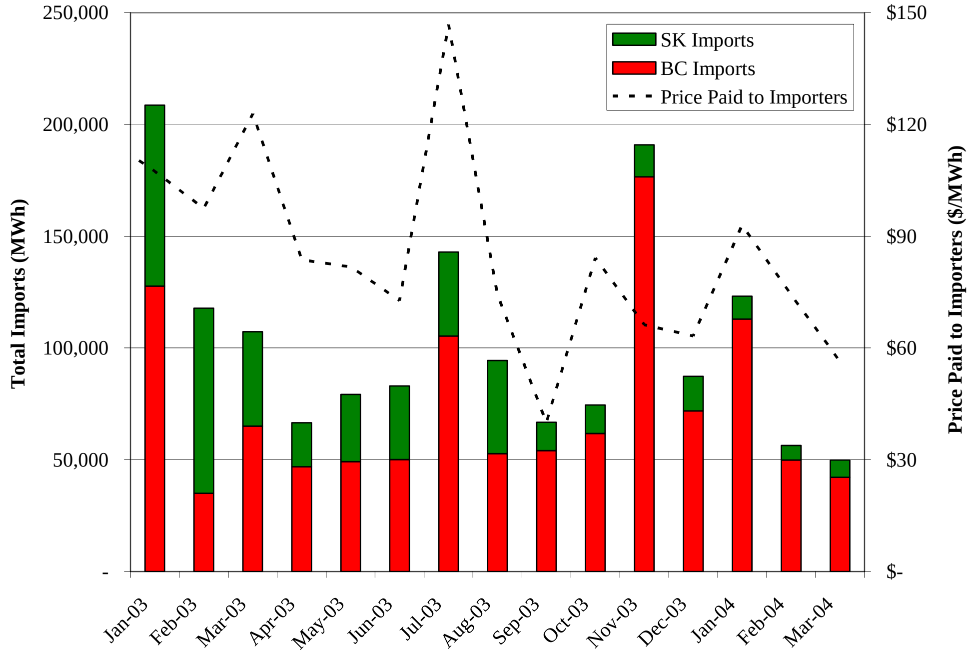
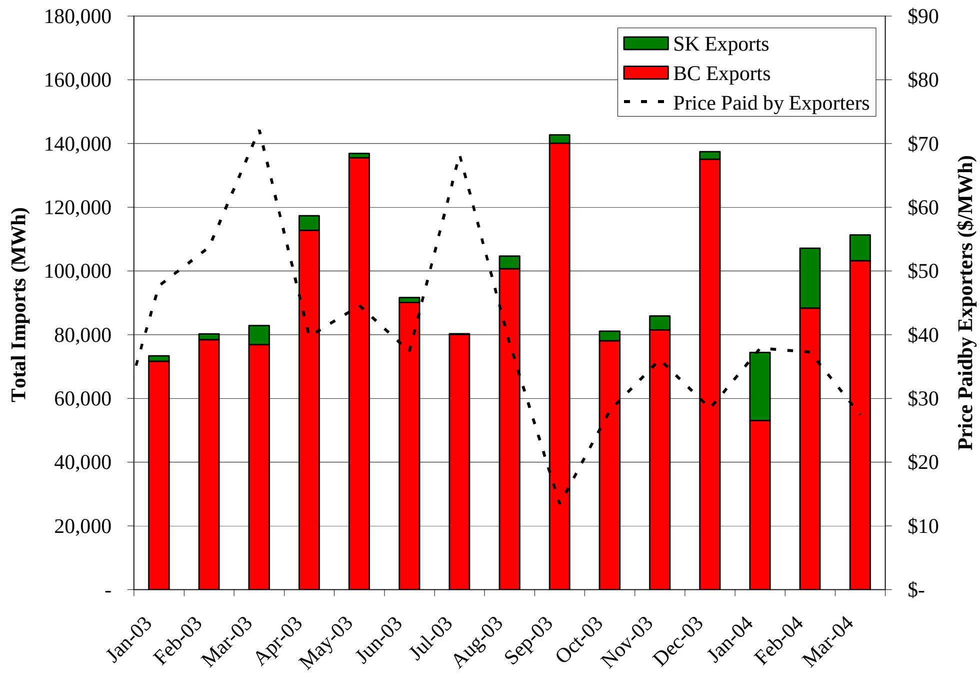


Figure 12 – Exports and Price Paid by Exporters



During Q1/04, import volumes corresponded fairly well with Pool prices. On average, both prices and import volumes have decreased since Q4/03. The average on-peak Pool price in Q1/04 was $55.08/MWh and a total of over 229,000 MWh of electricity were imported compared to Q4/03 when approximately 353,000 MWh was imported and the average on-peak Pool price was $67.08/MWh. Low average quarterly import volumes were a result of low import volumes in both February and March. Import volumes reached a 15-month low in March 2004 with just under 50,000 MWh of imports for the month. This corresponds to a 15-month low on-peak Pool price of $48.50/MWh. Overall import volumes were once again dominated by imports over the BC tie-line.

Exports on the BC tie-line reached a 15-month low in January. This could be due to a number of factors but is likely a result of fairly modest price differentials between Alberta and Mid-C. Exports to (and through) Saskatchewan have increased dramatically this quarter over last quarter. In Q4/03 exports on the Saskatchewan tie-line totaled only 9,700 MWh while in Q1/04 exports on this the-line increased nearly five fold to 48,300 MWh. The largest increase was in exports moving from Alberta to Saskatchewan rather than through Saskatchewan to either Manitoba or the Eastern US.

For the quarter, the average price paid to importers was $74.27/MWh while the average price paid by exporters was $34.88/MWh. (These values are exclusive of the cost of transmission and losses.) In general, the average price received for imports is directly related to the volume of imports in the month. Although the relationship is less obvious, the average price paid for exports tends to be inversely related to the volume of exports in the month. These are the types of relationships we would expect to see in a well-functioning market.

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 13 and 14** 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 and have been converted at an exchange rate of 1.35 CDN/US.

Figure 13 - On-Peak Prices in Other Markets

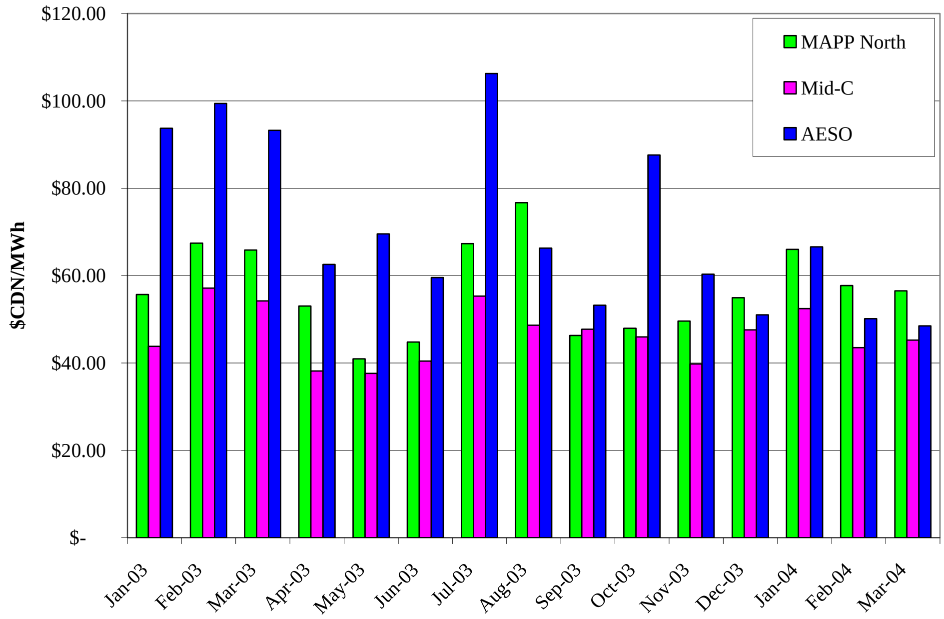
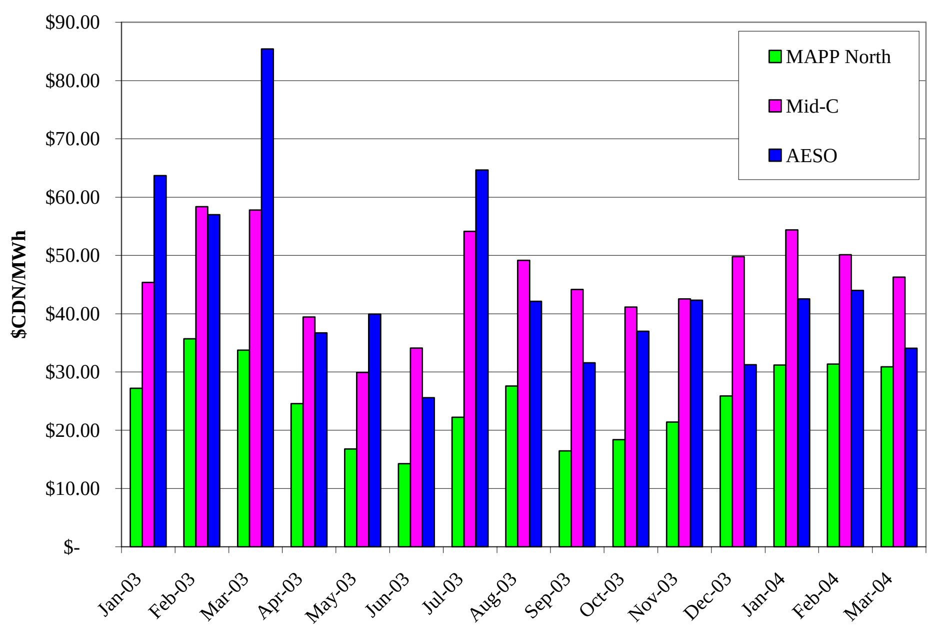


Figure 14 – Off-Peak Prices in Other Markets



On-peak prices generally declined in all three markets over the course of the quarter. Prices at MAPP-N were fairly strong (compared to recent values) and were approximately equal to or greater than Pool prices in all months. This would encourage on-peak exporting over the Saskatchewan tie-line – which is in fact what happened (63% of exports on the Saskatchewan tie-line occurred in on-peak hours). On-peak prices at Mid-

C were generally lower than Pool prices – particularly in January. This corresponds well with observed activity on the BC tie-line as 94% of imports from the west occurred in on-peak hours and most import activity was observed in January.

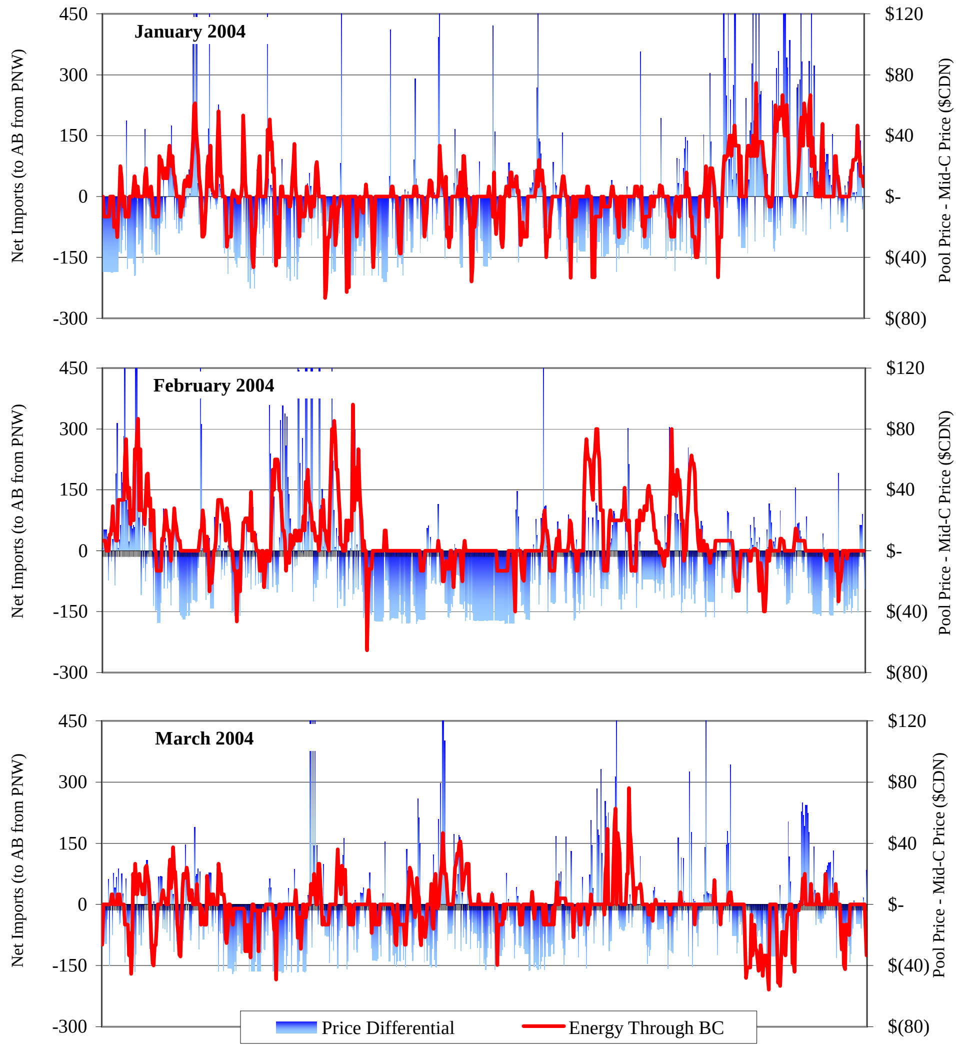
Off-peak prices at MAPP-N were fairly stable all quarter while on-peak prices at Mid-C gradually declined throughout the quarter. Alberta prices were generally between the higher Mid-C prices and lower MAPP-N prices. These price differentials tend to support off-peak exporting to Mid-C and off-peak importing from MAPP-N and are reflected in the actual import/export activity observed over the last quarter.

Because neither BC nor Saskatchewan operate open markets, it is difficult to assess the economics of moving energy to and from these areas. However, energy is often moved through BC and Saskatchewan to markets in the US[2]. **Figures 15 and 16** attempt to capture the economic use of the BC and Saskatchewan tie-lines over the last quarter. In the graphs, hourly net imports from beyond BC and Saskatchewan are plotted with daily on and off-peak price differentials. Lines and bars on the same side of the x-axis indicate economically efficient tie-line usage. Calculations do not take into account the cost of transmission from one jurisdiction to another. Energy that originated in or was delivered to BC or Saskatchewan is not included in the analysis.

When assessed on this basis it was found that in Q1/04, 83% of the energy moving through BC was moving in the apparent correct economic direction while 88% of the energy moving through Saskatchewan was moving in the right economic direction. Note that daily index prices are used for this analysis and not actual trade prices. The analysis should therefore be considered directional in nature.

[2] The difference in the price at which energy can be bought and sold gives an indication of the economically correct direction for energy to be moving across the tie-line. For example, if the Pool price in Alberta is $50/MWh and the price at MID-C is $100/MWh, it would be most economically efficient to buy energy in Alberta and sell it at MID-C (i.e. exporting). Energy being imported during that price scenario would be seen to be economically inefficient use of the tie-line.

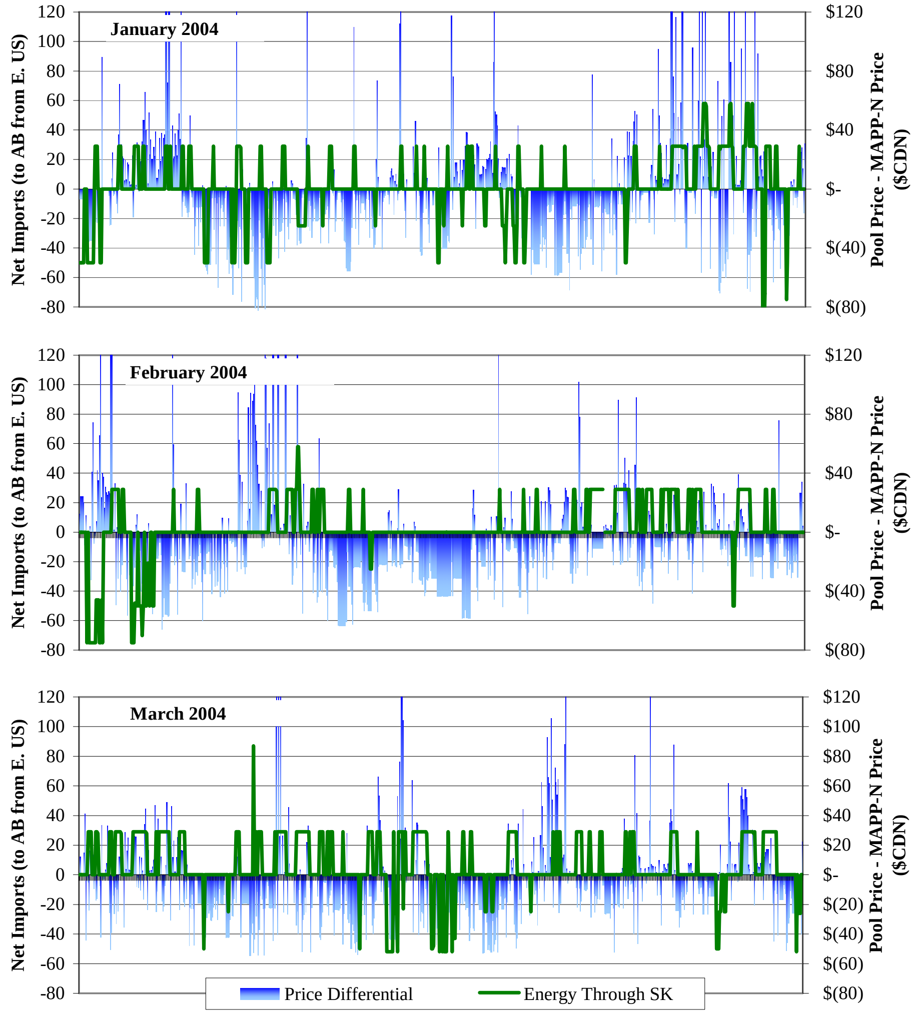
Figure 15 - Economic Use of the BC Tie Line



Note: logical economic direction is indicated when the blue and red lines move in the same direction.

Figure 15 indicates that for the majority of the quarter, energy moving through BC was traveling in the right economic direction and in general, high price differentials were captured in both directions. The only times where imports and/or exports appeared to be moving in the wrong economic direction were when the price differentials between the two markets were fairly modest and would not likely cover the cost of transmission and losses between the source and sink of the power.

Figure 16 - Economic Use of the Saskatchewan Tie Line



Note: logical economic direction is indicated when the blue and green lines move in the same direction.

Figure 16 also indicates that for the majority of the quarter, energy moving through Saskatchewan was traveling in the right economic direction. Some hours of apparent uneconomic importing occurred, however most of these imports originated from Manitoba – another regulated market. Price differentials are not as relevant to energy moving to and from Manitoba as they are to other open markets to the east of Saskatchewan. The MSA did not observe any instances of apparent uneconomic importing and/or exporting in Q1/04 which it felt warranted further investigation.

1.9 Ancillary Services Market

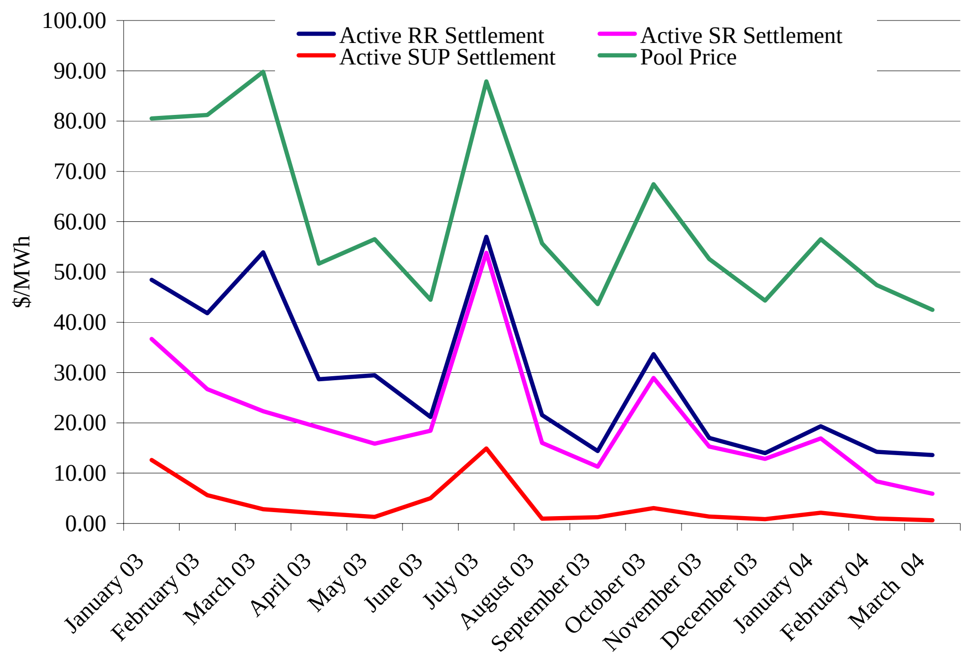
The AESO procures system support services through the Alberta Watt-Ex Market and through bilateral over-the-counter (OTC) deals with ancillary service providers. These system support services include active and standby regulating reserves, spinning reserves and supplemental reserves

The MSA is currently engaged in a review of the ancillary services market (AS) in order to improve our understanding of market trends, supplier economics and the interaction between the energy and AS market. Part of the process entails reworking the AS information presented in our quarterly and annual reports.

Active Prices

Figure 17 provides an overview of monthly Pool prices and settlement prices for active products including both Watt-Ex and OTC transactions. Active products are priced at a negative differential to Pool price. Therefore the settlement price reflects the Pool price less the discount. As **Figure 17** shows, the active products have trended with Pool price, reflecting the indexation to Pool price and generally soft market conditions that have prevailed over the last 15 months in both the energy and ancillary services markets.

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



Energy versus Active Spinning Capacity Prices

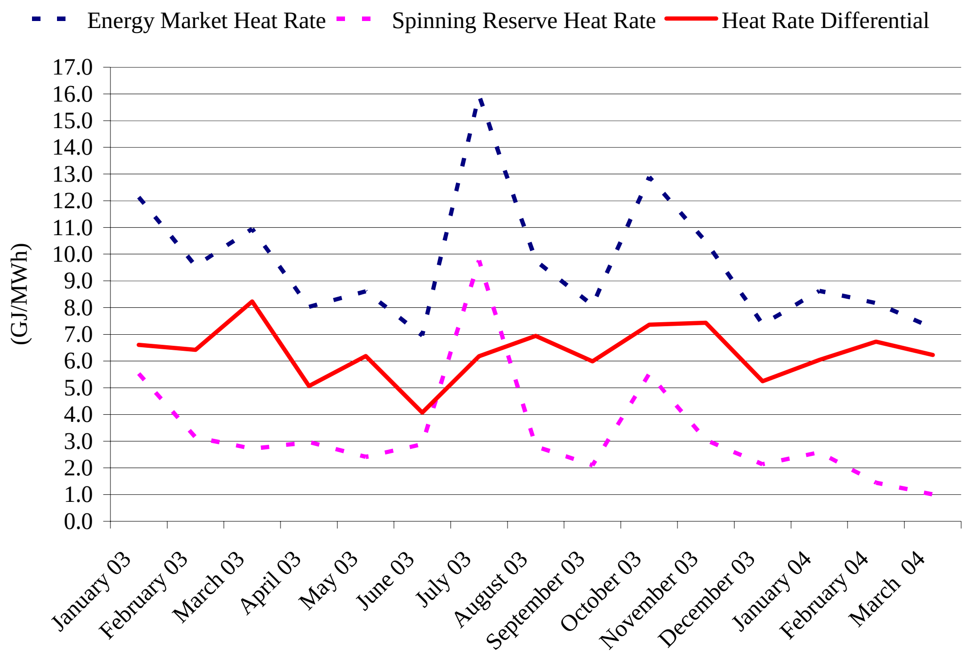
Understanding the interaction of the energy market and AS market is extremely complex. As an example, **Figure 18** reports the energy market heat rate (Pool Price *$/MWh* / AECO-C Spot Gas *$/GJ*) and active spinning reserve heat rate (SR settlement price *$/MWh* / AECO-C Gas *$/GJ*), along with the differential (energy market heat rate minus the spinning reserve heat rate). In theory, spinning reserves should be priced such that it reflects the foregone value of generating energy. As a very stylized example, a gas turbine with a heat rate of 10GJ/MWh, with $5/GJ gas, has a pure fuel variable cost of $50/MWh. If the Pool price exceeds the unit's variable cost, then in theory the unit should not participate in the spinning market if the heat rate differential is less the 10GJ/MWh. The differential between the energy market heat rate and spinning reserve heat rate should therefore reflect the average variable cost of a unit providing spinning reserve.

Care must be taken when interpreting **Figure 18** however. Supplier economics are a moving target. For example, supplier economics change depending on whether the plant is in or out-of-the-money in the energy market (whether there is an actual opportunity in the energy market), and whether plants have 'sunk' costs in terms of a must-run component (in the case of a co-generation unit), which changes the speed no-load cost equation. Therefore determining the exact 'opportunity cost' pricing of spinning capacity is complex given that the opportunity costs will be driven by plant type, circumstances and the energy market heat rate. Further, the opportunity cost approach only provides the minimum acceptable price – sellers will look for the best price they can get.

Also, active spinning reserve is generally provided by hydro, imported hydro and gas-fired capacity (See **Figure 27** for market share breakdowns). Intra-Alberta and imported hydro account for about 60% of the spin market. Hydro capacity from stored water is priced on an opportunity cost basis relative to the market. Thus, participation by hydro in the active spinning market is even more complicated than thermal units. Added to this is the additional complexity surrounding obligations arising from the Hydro PPA.

These caveats taken into account, **Figure 18** demonstrates the average heat rate differential for Q1/04 was 6.0 GJ/MWh. This is down from an average differential of 7.1 GJ/MWh in Q1/03, 6.7 GJ/MWh in Q4/03 and a 2003 yearly average differential of 6.3 GJ/MWh. This suggests that the market for spinning capacity has become increasingly competitive as compared to the market for energy over the last 6 months, after recovering from a particularly tight period in June 2003.

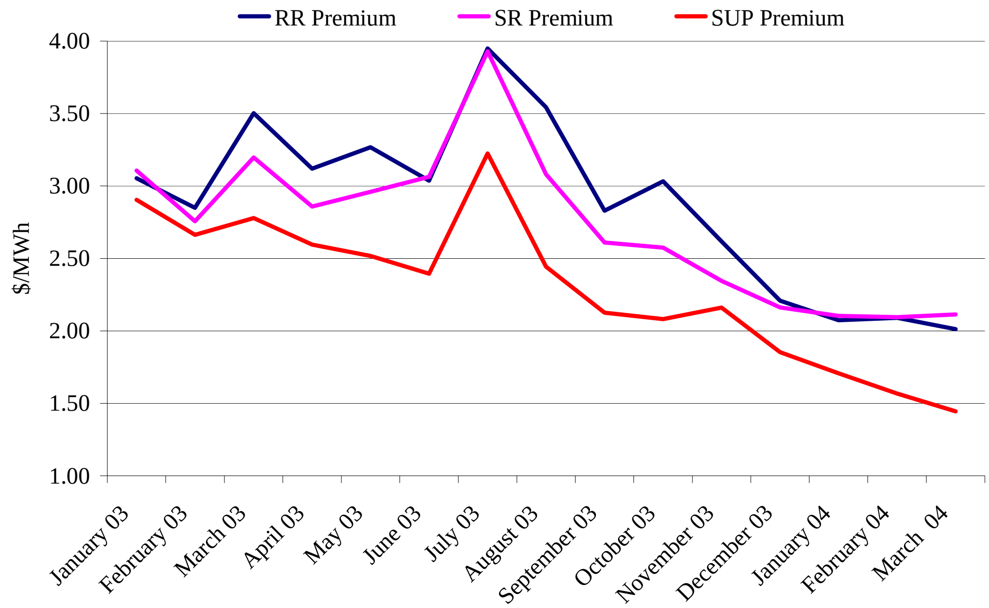
Figure 18 - Energy and Spinning Reserve Heat Rate Differential



Standby Ancillary Services

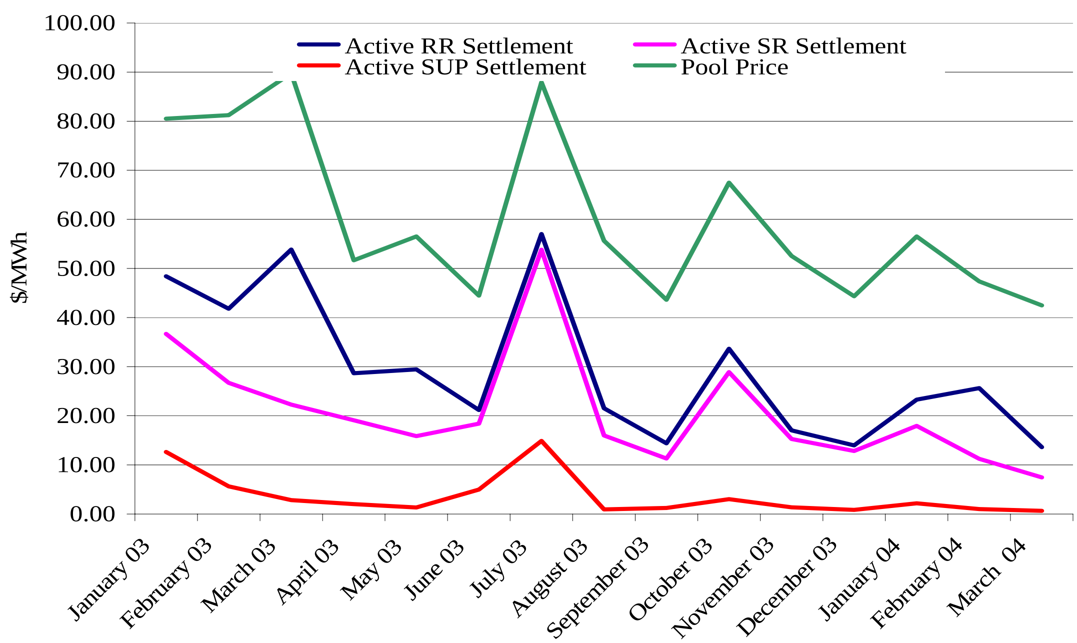
Standby reserve services are compensated using a two part option type payment with a premium payment for availability in the standby market and a fixed activation price if the unit is called for active service. As with the active market, both the premium payment and the activation prices have trended downwards with overall average energy prices and market heat rates. **Figure 19** outlines monthly average premium payments for standby regulation, spinning and supplemental reserves. Since peaking in July 2003, at monthly average premiums of $3.95/MWh, $3.93/MWh and $3.22/MWh for regulating, spinning and supplemental respectively, premium payments have declined by 46% to 55% by March 2004. In Q1/04 premiums averaged $2.06/MWh, $2.10/MWh and $1.57/MWh for regulating, spinning and supplemental respectively.

Figure 19 - Standby Premiums - All Markets (Watt-Ex and OTC)



Standby activation prices have also trended down **Figure 20**. Since peaking in July 2003, average standby activation prices have declined by 59%, 69% and 80% for regulating, spinning and supplemental reserves compared with average prices in March 2004. Average Pool price declined by 51% over the same period, with the average energy market heat rate falling 55%.

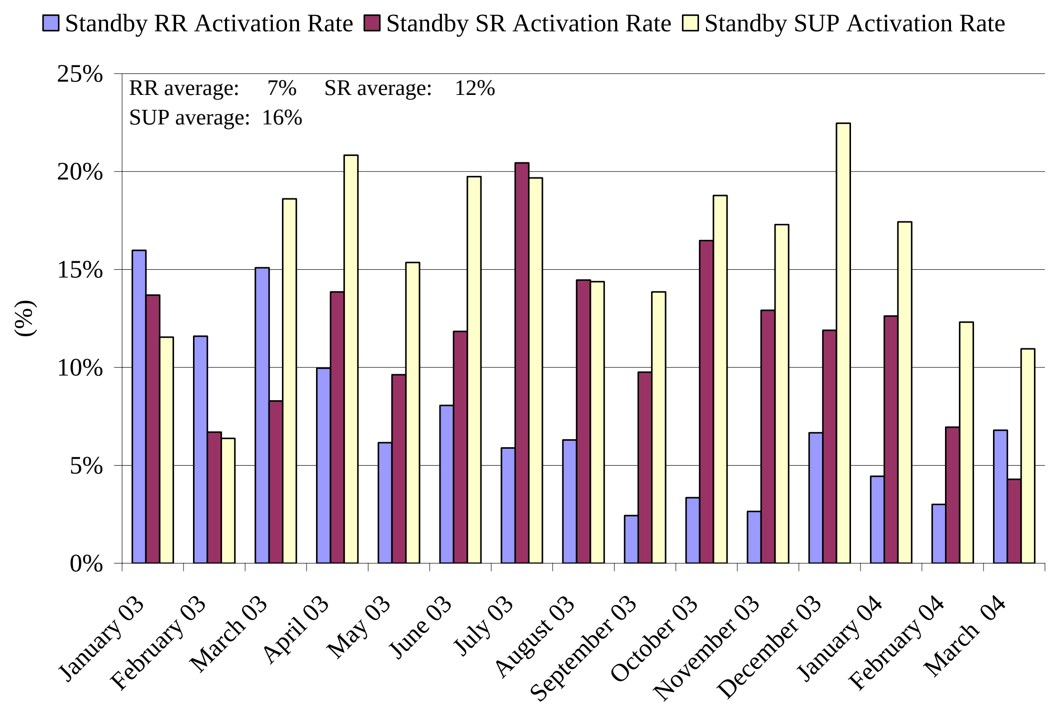
Figure 20 - Standby Activation Price - All Markets (Watt-Ex and OTC)



Activation Rates

Activation rates in the standby market have shown some variability over time (**Figure 21**). Variability is expected because standby activations occur due to (random) mechanical failures at units providing active reserves or due to forecast error. Over the past 15 months, activation rates for standby regulating, spinning and supplemental reserves have averaged 7%, 12% and 16% respectively. In Q1/04, rates have been lower for all services (5%, 8% and 4% respectively). This is not surprising given the relatively high level of generating unit availability that the system has seen in the first quarter of 2004.

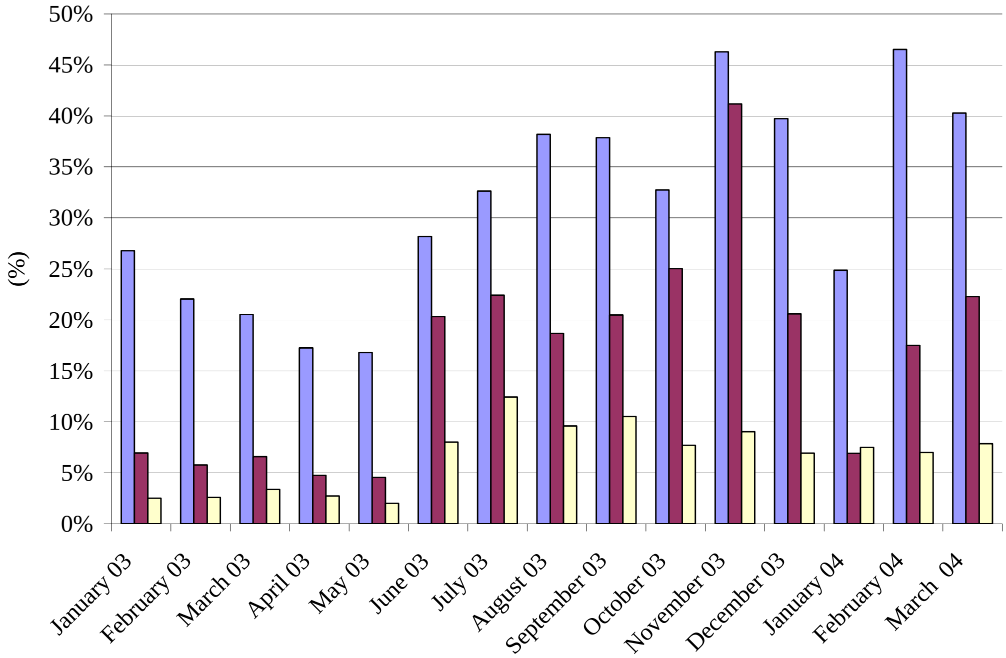
Figure 21 - Standby Reserve Activation Rates



OTC Procurement

Since June of 2003, there has been a noticeable shift in the AESO's procurement strategy, with more volumes being procured through bi-lateral OTC deals rather than standard Watt-Ex products. **Figure 22** shows this trend for active products. For the first 5 months of 2003, OTC procurement of active reserves was 20.7%, 5.7% and 2.6% for active regulating, spinning and supplemental, respectively. For the remaining 7 months of 2003 these figures jumped to 36.5%, 24% and 9.2% (for RR, SR and SUP, respectively). In Q1/04, 37% of regulating reserve was procured OTC, 15.6% of spinning and 7.4% of supplemental.

Figure 22 - OTC Procurement as a Percentage of Total Procurement



Figures 23, 24 and 25 report Watt-Ex, OTC and overall MW weighted average prices (all markets) for active regulating spinning and supplemental. In general, OTC procured volumes for regulating and spin are, on average, priced slightly higher than Watt-Ex purchased volumes. The price differential may be due in part to the AESO's requirement to purchase custom products, such as shaping contracts in the OTC market. The Watt-Ex exchange does not trade these custom products. Rather it focuses on standard on-peak, off-peak and flat products. As for the supplemental market, the larger price differential is a consequence of the Hydro PPA.

Some market participants have expressed concern that the increased OTC procurement creates less market transparency and price discovery than the exchange traded market. The MSA concurs with this view and has encouraged the AESO to implement measures to address this issue. In particular, the MSA has asked for a generic description of the nature of the features that would influence OTC prices. This issue is currently under consideration by the AESO

Figure 23 - Active Regulating Reserve Settlement by Market

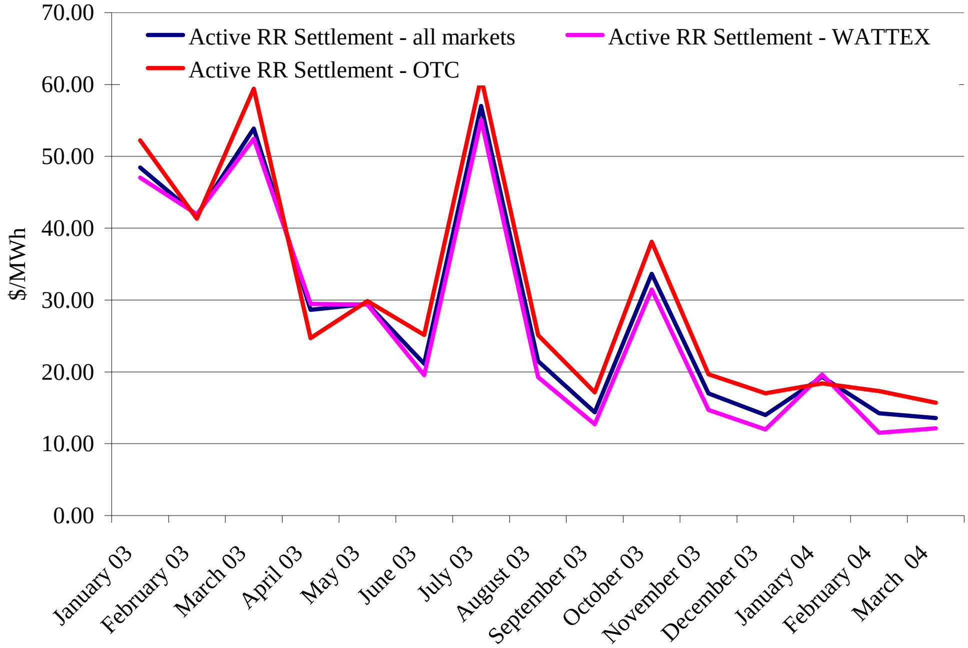


Figure 24 - Active Spinning Reserve Settlement Price by Market

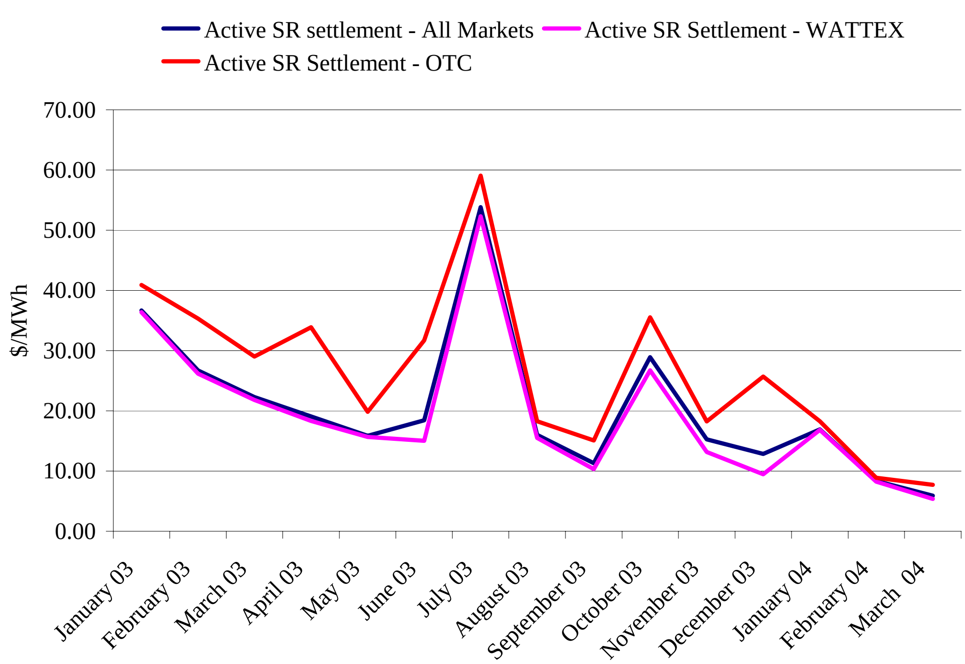
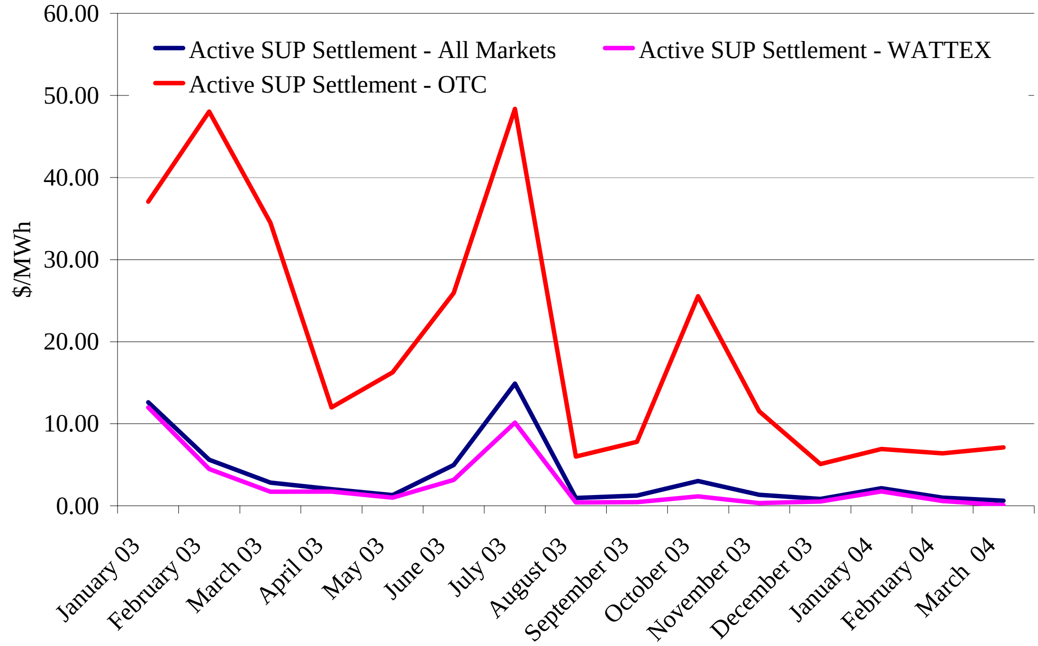


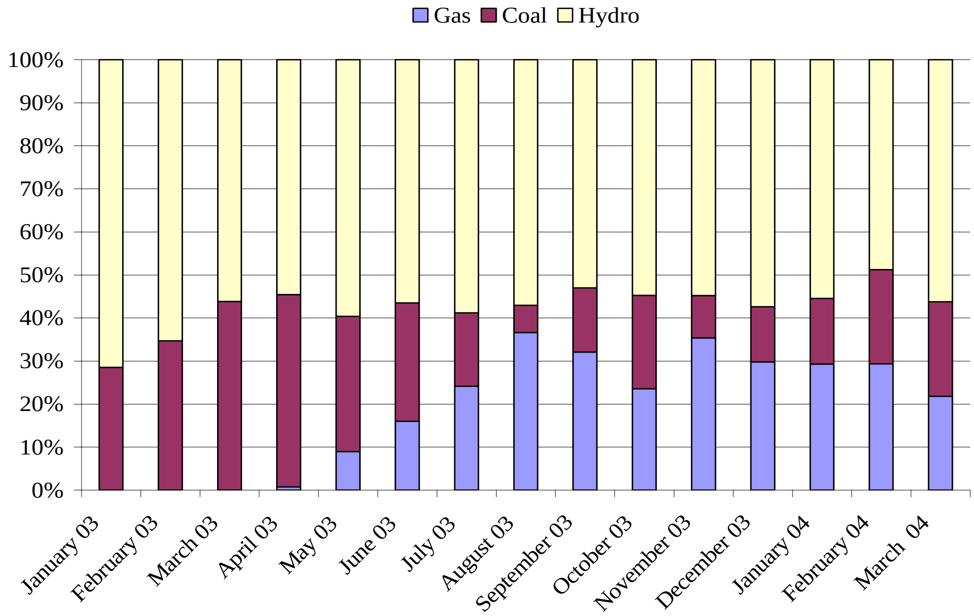
Figure 25 - Active Supplemental Reserve Settlement Price by Market



Market Share

Figures 26, 27 and 28 provide market shares by type (coal, gas, hydro, load and tie-line imports) for active regulating, spinning and supplemental reserves. Of particular interest is the shift in active regulating reserve market share (**Figure 26**) from coal-fired units to gas-fired units. In the first half of 2003, 4 gas-fired units entered the regulating market. Because gas fired units have higher variable costs than coal units, theory suggests they should offer at deeper discounts than the lower variable cost coal units, thereby taking some market share from the coal units. **Figure 26** supports this market dynamic, with the gas-fired share of the active regulating reserve market increasing from zero in March 2003 to a high of 37% in August 2003. For Q1/04, gas-fired active regulating market share averaged 27%

Figure 26 - Regulating Reserve Market Share by Fuel Type



Gas-fired generation has also made some in-roads in the spinning market, given the participation of several newer units in the market (**Figure 27**). In Q3/2003, gas fired participation dropped off in the market, largely due to the supplier liability issue that arose out of the new Electric Utilities Act in June of 2003. The slack was picked up by some coal-fired participation, along with increased hydro and import market share. Since then, gas fired units have reentered the market. The market share for the gas units averaged 43% in Q1/04, up from 29% in Q1/03 and 33% for 2003 as a whole.

Figure 27 - Spinning Reserve Market Share by Fuel Type

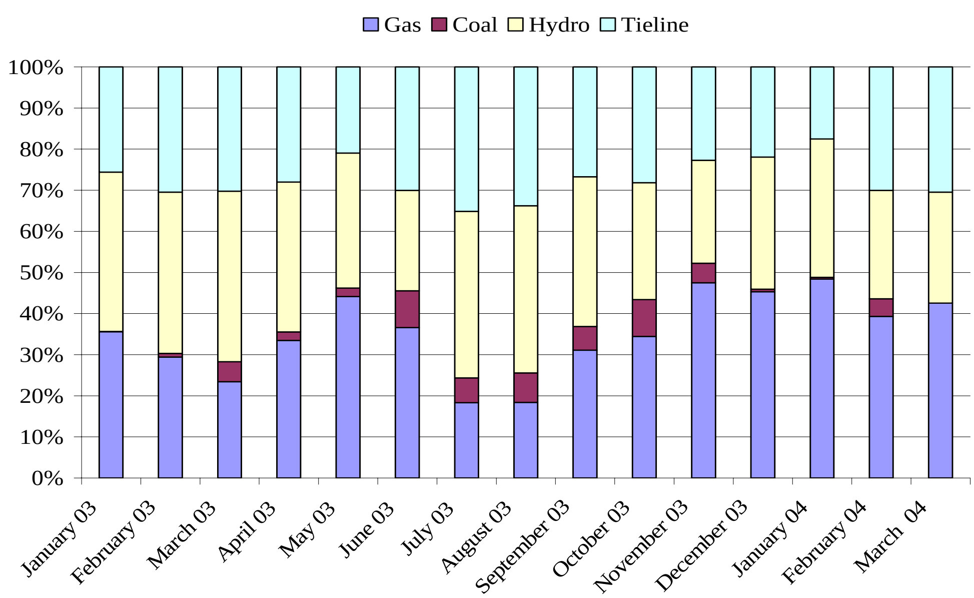
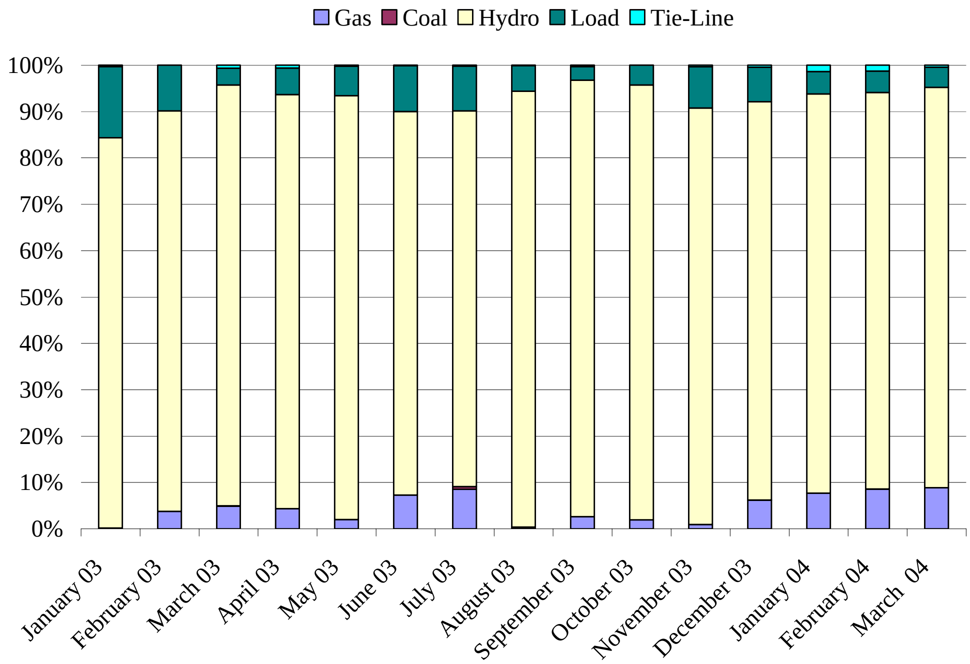


Figure 28 - Supplemental Reserve Market Share by Fuel Type



It seems logical and macro-efficient that the net effect of recent adjustments in ancillary services market share has been to re-deploy coal assets to the energy market where they are the lowest cost producer and to back down the relatively expensive (for energy production) gas-fired assets to provide reserves. The combined energy and ancillary services price signals would appear to be allocating resources to their most productive use.

Summary

The AS market has become increasingly competitive over time, reflecting growth in available capacity and generally low heat rates and prices in the energy market. This has lead to inevitable questions about the sustainability of the market.

AS market sustainability needs to be viewed from both a short-term and long-term perspective. In the short term it is tied to cyclical and relatively transient energy market fundamentals. Falling AS prices and returns in the short-run may lead to some participants souring on the market and simply leaving. However, if they are out of the money in the energy market, this will lead to a reduced opportunity cost and a willingness to settle for a minimal risk adjusted return in the AS market. Any opportunity cost arbitrage between the two markets falls apart if there is no opportunity for profitability in the energy market.

In the longer term, sustainability may also be a function of AS market design. If the market design is such that excess supply and excessive price risk will always exist and drive AS returns to zero, then investors may sour on the market in the long run. Since there appears to be a strong arbitrage between the energy and AS market, in terms of overall price and heat rate trends, it may be premature to conclude that the current market design would not be sustainable in the long run.

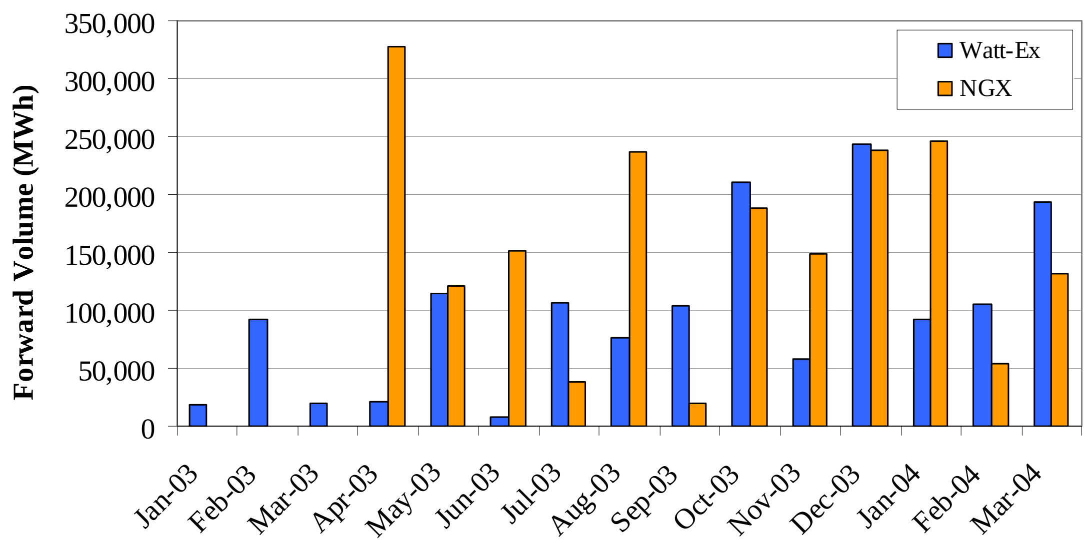
The bigger issue may be that the returns for ancillary service suppliers are caught in a squeeze, bounded on one side by lower returns in the energy market and on the other side by their own variable cost structure.

1.10 Forward Markets

Energy is traded forward both on an exchange traded basis and through the broker market. Anecdotally, the majority of forward trading is believed to occur through the broker market, however, visibility into this market is limited in terms of price and more so in terms of volumes traded. Watt-Ex and NGX comprise the on-screen forward trading activity in the Alberta market. Historical traded volumes by month are shown in **Figure 29** which indicates that although NGX trading commenced in April 2003, NGX has been a significant competitor to Watt-Ex in terms of volumes traded since NGX electricity contracts commenced trading on NGX.

In Q1/04, forward volumes on both Watt-Ex and NGX declined relative to levels observed in the previous quarter. Forward volumes traded in Q1/04 were 390,609 MWh and 432,680 MWh respectively on Watt-ex and NGX. NGX forward volumes traded have exceeded Watt-Ex forward volumes traded in each of the previous four quarters which is attributed to more frequent trading of longer term contracts (ie: month and quarter) on NGX.

Figure 29 - Forward Energy Volumes Traded



1.11 Outages and Derates

The MSA continually monitors the outages and derates of generating units in Alberta. Of particular interest are the coal fired units that are operated under the terms and conditions of the Power Purchase Arrangements (PPAs). Outages at these PPA plants tend to have a large impact on Pool price as they represent a major proportion of total installed generating capacity in Alberta. When the amount of outage exceeds a unit's historical norm, the MSA seeks to understand the cause of the deviation.

Figure 30 illustrates the total outage levels at the coal fired generation facilities and is separated by PPA owner. This graph indicates that the outage levels for the first quarter of 2004 are significantly below the levels of the same period in 2003. However, some variation is expected on a year over year basis due to the nature of the multi-year planned outage schedules. The planned outages that occurred in Q1/04 are negligible (less than 0.5 % of all outages) so this graph represents unplanned outages almost exclusively, for the 2004 time frame.

Figure 30 – Outage Rates by Owner

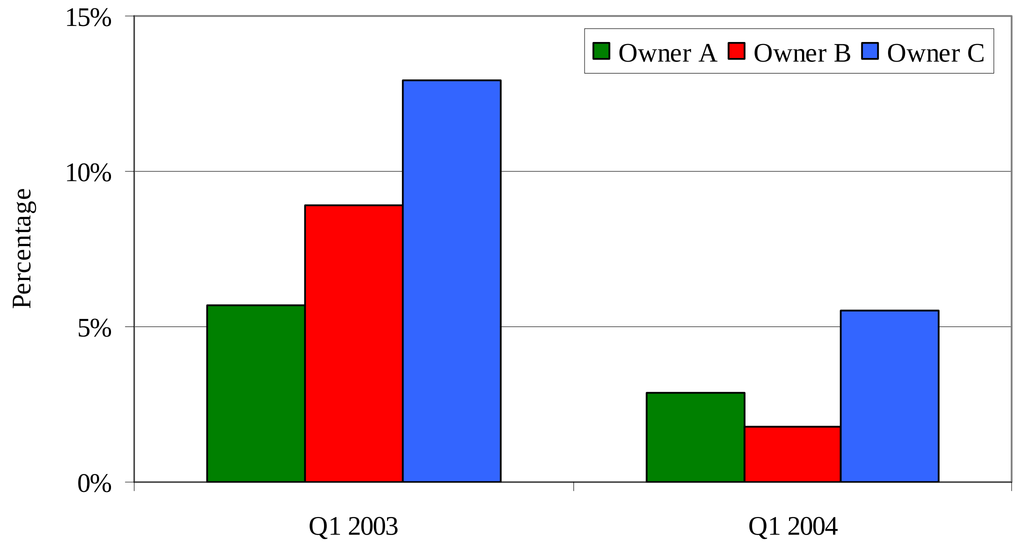


Table 3 reports the unplanned outages on a quarterly basis for the first quarter of 2004 and 2003 and also provides a look at the annual unplanned outages for reference.

Overall, Q1/04 unplanned outages are slightly below Q1/03 and significantly lower than the annual outages for 2002 and 2001.

Table 3 - Outage For PPA Coal Units (excluding planned outages)

	Q1/04	Q1/03	2003	2002	2001
Owner-A	**2.8%**	3.7%	4.9%	4.2%	3.2%
Owner-B	**1.8%**	1.1%	1.5%	0.5%	1.2%
Owner-C	**5.5%**	6.0%	5.7%	10.8%	8.8%
PPA weighted average	**4.3%**	4.9%	4.9%	7.7%	6.3%

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

The design of the PPAs stipulate target availabilities for each PPA unit and are determined based on historical performance and factors such as the unit age and design. By owner **Table 4** reports the MW weighted average target availability for each coal fired portfolio and the actual availability achieved during 2002 – Q1 2004. The PPA owners have consistently achieved higher actual availability than target availability.

The availability of the PPA coal units has been especially high over the past quarter with few planned outages occurring over the first three months of 2004.

Table 4 - MW Weighted Portfolio Target Availability (%) vs Actual Availability (%)

	2002		2003		Q1 2004	
	Target Availability	**Actual Availability**	**Target Availability**	**Actual Availability**	**Target Availability**	**Actual Availability**
Owner-A	88%	92%	87%	92%	87%	97%
Owner-B	90%	97%	90%	94%	90%	98%
Owner-C	85%	87%	85%	88%	87%	94%
PPA weighted Average	87%	90%	87%	90%	87%	96%

2 REVIEW OF THE RETAIL MARKET

2.1 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 are due by January 30 of each year, for the preceding calendar year. The MSA may at its discretion publish all or part of the annual compliance reports received from owners and affiliated retailers.

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.

The MSA has not yet received annual compliance reports from all relevant parties. Further, many of the reports were filed after the January 30th due date. It appears some parties were challenged by the deadline, insofar as ensuring that their board of directors would have an opportunity to deal with the matters prior to January 30th. In a related fashion, the fact that 2003 was a transition year (from the old regulation to the new Code) may have created unanticipated challenges for some parties. In any event, the MSA believes that all parties are working in good faith to meet this reporting obligation and will continue to follow up in this regard to close out the 2003 reporting.

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.

For owners with affiliated retailers, the MSA has taken the approach that the quarterly reports are to be provided to the MSA by each party, beginning Q1 2004. The requirement is built into each relevant compliance plan, as part of the approval process. The reasoning by the MSA is that the quarterly reporting must be made by senior management to their board of directors in any event, and thus there is no incremental burden in providing them to the MSA. Further, the matters discussed in the quarterly reports will ultimately be made known to the MSA through the annual compliance reports, but in a less timely manner.

The MSA has received quarterly compliance reporting as requested, and will be following up as required.

Compliance Plans

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.

In December, 2003 the MSA issued interim 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.

Full compliance plan approvals have been granted to the following parties: Battle River REA Ltd., Battle River Rural *Energy* Limited, Direct Energy Marketing Limited (in respect of Direct Energy Regulated Services), and Direct Energy Partnership. The approvals will facilitate the entry into the retail market by the parties, in accordance with their respective business plans.

Audits

Preliminary discussions around audit plans also 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 delivered thereafter. The MSA expects to report on the results of the audits during Q2.

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.

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.

A copy of the Notice of Application and Decision was posted to the MSA website on February 12, 2004.

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.

The Decision granted approval for the disclosure and use of customer information upon certain conditions, including conditions which effectively established an end date to the approval.

Condition 5 g) stipulated as follows: In the event that the retail sale transaction involving ATCO and the Direct parties does not close by February 29, 2004, all customer information received from ATCO pursuant to this exemption, and all information derived from that customer information, will be returned to ATCO or destroyed, and the return and destruction will be confirmed to ATCO in writing by the Supervisory Person.

Condition 6 stipulated as follows: In the event that the retail sale transaction involving ATCO and the Direct parties does not close by February 29, 2004, ATCO will confirm in writing to the MSA that all customer information provided by ATCO pursuant to this exemption, and all information derived from that customer information, has been returned to ATCO or destroyed, as confirmed to ATCO in writing by the Supervisory Person.

A copy of Decision 2003 – 00101 is 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 request became Application 2004 - 00102). The extended date would be April 15, 2004.

In support of its request, ATCO enclosed an excerpt from correspondence received from Direct Energy Marketing Limited ("DEML"), providing the rationale for extending the date. The correspondence also makes reference to Direct Energy Regulated Services (DERS).

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.

A copy of the Notice of Application and Decision 2004 – 00102 was posted to the MSA website.

MSA Guideline Re: Code of Conduct Regulation Reporting

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 on the MSA website.

Default Supply Issue

At the end of 2003, the MSA was informed by ENMAX Energy Corporation 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.

The MSA was still reviewing the matters at the end of March, but expects to close out the issue soon. The MSA does note that ENMAX has been very cooperative throughout the discussions and inquiries, and appreciates their efforts toward resolution of the issue.

2.2 Residential Load Profiles

In Q1/04 the MSA completed an analysis of the effect of load profiling on bills of residential customers. The purpose of the exercise was to determine the effect of load profiling and location on a customer's bill and to assess the variability of monthly electricity bills based on an assumed monthly electricity consumption.

The results of the analysis have clearly shown the effect of location and the variability of residential electricity bills throughout the province. The conclusions of the analysis are the following:

- Differences in total monthly electricity bills for residential customers are more dependent on other (system access, distribution, etc…) charges than they are on the energy charge.
- While residential and NSLS load profiles appear quite different on an hourly basis, when the energy component for monthly billing is calculated, the differences are actually quite small. This indicates that profile type does not have a large impact on energy charges.
- Variability in monthly energy charges is highly dependent on Pool price (when energy charges are calculated using a Pool price flow-through.
- The 2003 (residential) profile-weighted average Pool price was higher than the average Pool price for the year in each service area. This indicates that residential customers tend to consume more energy during higher priced hours.
- Customers on 2003 RRO rates paid less for the energy they consumed than customers on Pool price flow-through in their respective service areas. This is not necessarily the case in all years.

This analysis can be viewed in full at:
http://www.albertamsa.ca/files/ResidentialLoadProfiles042804.pdf .

2.3 Retail Market Metrics

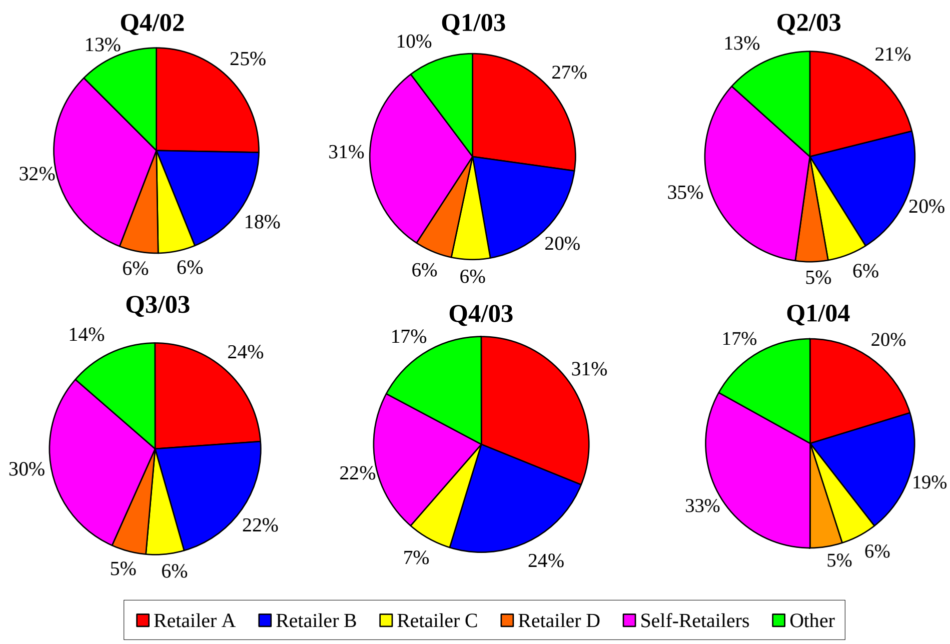
The MSA continues to track performance in the retail market based on the following metrics:

- Number of active retailers
- Retailer entry and exit from the market
- Market share (with respect to load) of retailers by customer class
- Customer switching off the regulated rate option (RRO)[3] to a competitive contract by RRO eligible customer class.

[3] As discussed in the new EUA, RRO is now termed regulated default supply.

As of March 31, 2004 there were 107 active retailers in the Alberta electricity market, 75 of which are self-retailers. During the quarter, 3 new retailers entered the market and no retailers exited the market. Since monitoring of retailer activity began in Q4/02, 18 retailers have entered the market and 9 retailers have left the market. Most of the movement in and out of the market is by self-retailers. The observed level of entry and exit is indicative of a healthy market.

Figure 31 - Overall Market Share of Retailers by Load



Note: Retailer labels do not necessarily represent the same retailer for each quarter.

Figure 31 shows the overall (all classes) market share of retailers for the last six quarters. In Q1/04, we see a fairly dramatic change in distribution of market shares as the cumulative market share of retailers with at least 5% market share has dropped to 50% (retailers A, B, C and D). The biggest change since Q4/03 is in the market shares of the two largest retailers dropping from 31% and 25% to 20% and 19% respectively. The majority of this market share has been made up by the self-retailers. The shift of load from major retailers to the self-retail and other categories could indicate that more loads are choosing to take more control of their energy options as opposed to relying on default supply options provided by the incumbent retailers. When compared to market share statistics for the same period last year, the shift is not as dramatic but the trend is clearly away from larger retailers to smaller retailers. The movement of loads between retailers is a healthy sign of competition.

Figure 32 – Q4/03 Market Share of Retailers by Customer Class

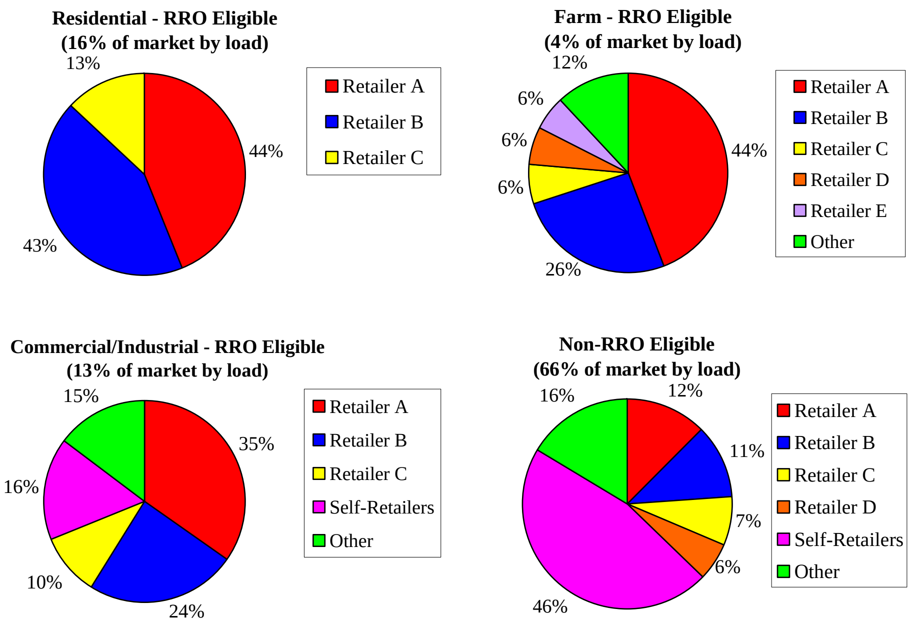
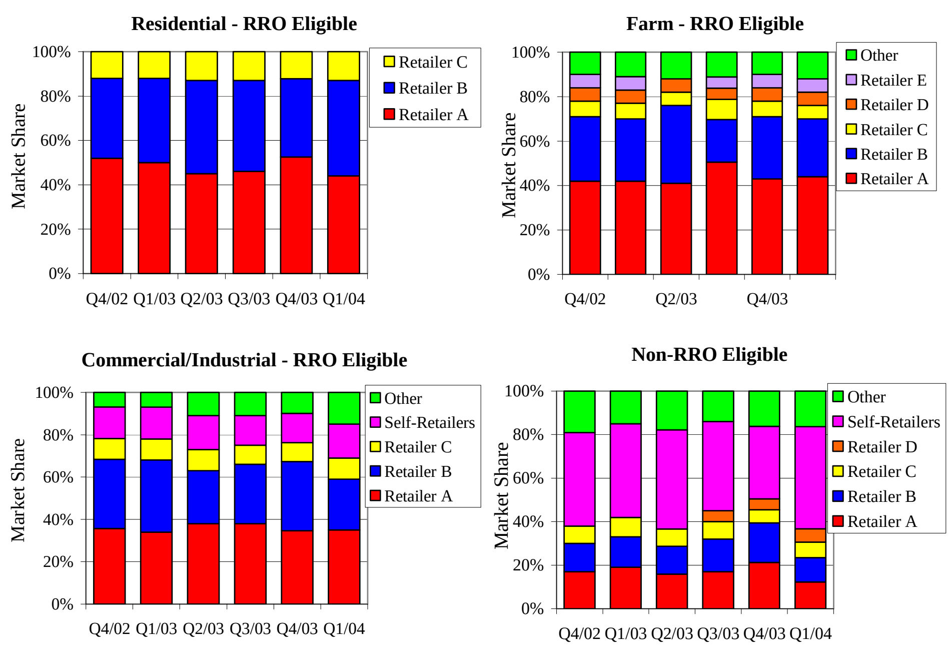


Figure 33 – Progression of Retailer Market Share by Customer Class



Note: Retailer labels do not necessarily represent the same retailer for each category.

Figure 32 shows retailer market share by customer class for Q1/04, and **Figure 33** shows the progression of market share by customer class since Q4/02.

Market shares of the three dominant retailers in the Residential – RRO Eligible class have not materially changed over the last six quarters. There has been some jockeying for position between the two largest retailers, but over the past six quarters the cumulative market share of these two retailers has ranged between 87% and 88%. Market shares of the dominant retailers should decrease as more residential retailers enter the market. In the Farm – RRO Eligible category, market shares have also remained fairly static since Q4/02.

Q1/04 saw a drop in the market shares of the three dominant retailers in the Commercial/Industrial – RRO Eligible category. The cumulative market share of these three retailers fell to 69% this quarter from 77% last quarter. Most loads appear to have moved into the "other" category. This indicates that customers in this load category are likely opting for some of the new retail options that continue to be offered to them.

Again, the most significant changes in market share distribution have been in the Non-RRO Eligible category. The cumulative market share of the four dominant retailers has decreased to 36% in Q1/04 compared to 50% in Q4/03, while the market share of self-retailers has increased from 33% to 46% over the same time frame. The most marked change was in the market share of Retailer A which has decreased to an all-time low of only 12%. The movement of loads away from the incumbent retailer to smaller retailers and self-retail in this customer class is very encouraging. Changes in market share statistics through time show that the retail market in this sector is dynamic and compared to the other market sectors, there appears to be more competition in the Non-RRO Eligible category.

The overall progression of customers off of RRO to competitive electricity contracts has decreased for the first time since monitoring of this statistic was initiated. As of March 31, 2004, 7.1% of all RRO eligible customers have chosen to sign a competitive contract with a retailer, as shown in **Figure 34**. This represents a 0.3% decrease since the end of Q4/03. Despite the recent decline, this is still a 1.7% increase in overall switching since the end of Q4/02.

Figure 34 - Progression of RRO Eligible Sites Switching Off RRO

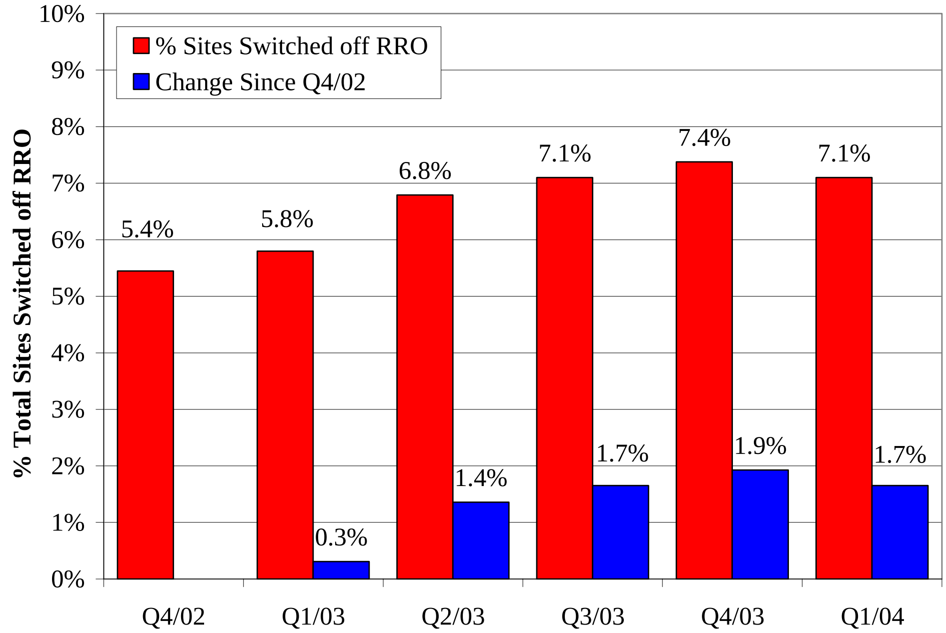


Figure 35 - Progression of RRO Eligible Sites Switching Off RRO by Customer Type

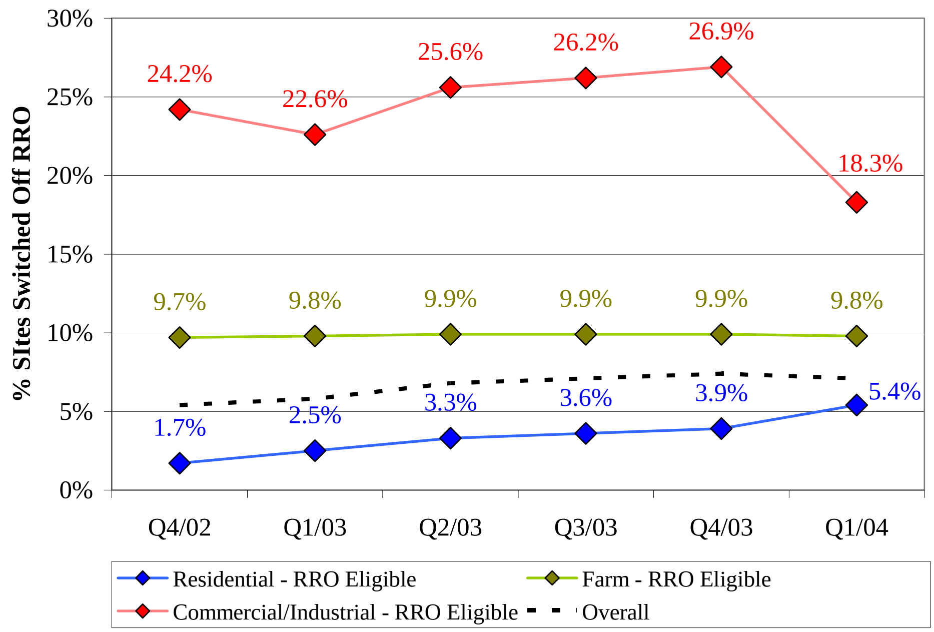


Figure 35 shows the progression of RRO eligible sites switching off RRO for the last six quarters by customer type. Switching results are encouraging in the residential category where switching rates have increased by 1.5% from 3.9% in Q4/03 to 5.4% in Q1/04. This is the most

dramatic increase in residential switching rates that has been seen to date. Switching rates in the farm category remain virtually unchanged from the previous five quarters.

Switching rates in the Commercial/Industrial – RRO eligible category are not nearly as encouraging and have in fact dropped 8.6% in the last quarter to an all-time low of 18.3% since monitoring of this statistic began. During Q4/03, a change in policy pushed back the deadline for Commercial/Industrial – RRO Eligible customers to choose a competitive contract or be subject to Pool price flow-through from the end of 2003 to July 1, 2006. This change in policy could be the driving force behind the decreased switching rates observed this quarter.

3 MARKET ISSUES

3.1 TPG / IDP

The MSA published the Trading Practices Guideline (TPG) and Information Disclosure Procedure on February 18, 2004 and March 5, 2004, respectively. The TPG focuses on the use of asset outage information for trading in the forward market. The IDP provides market participants with a mechanism to be in compliance with the TPG. The MSA is currently receiving feedback from market participants regarding the IDP and it is our expectation that full implementation of the Guideline will take place in the June to July 2004 time period.

The TPG simply states 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 the marketplace. Fundamentally, the TPG addresses an issue of fairness concerning access to non-public information which may result in an unfair competitive advantage.

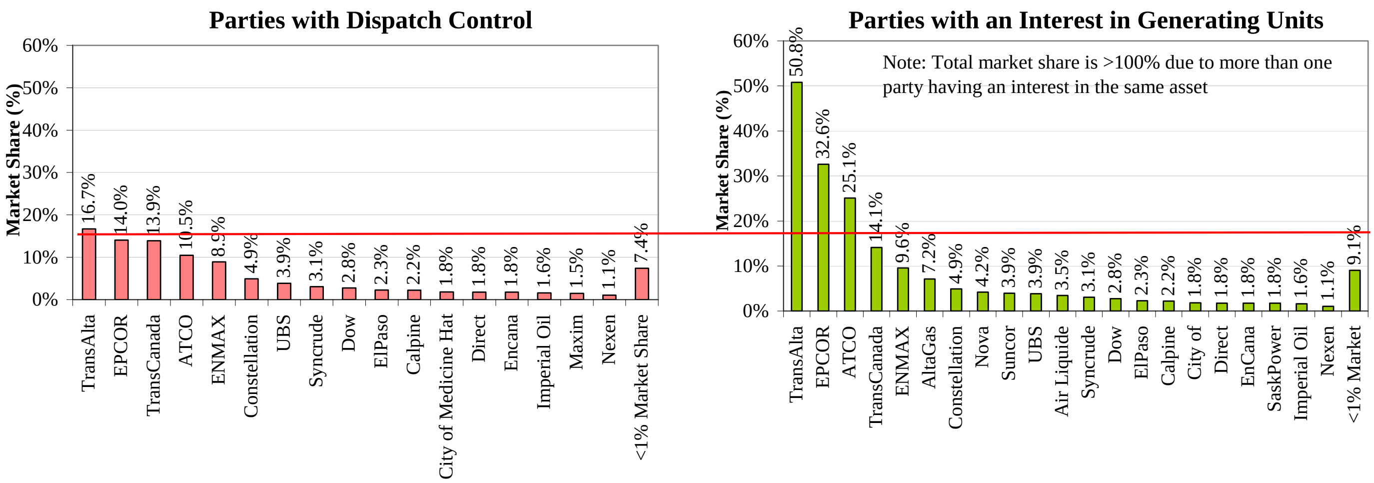
For example, a price spike often follows an outage at a generating plant. The marketplace does not know when a specific plant outage will occur; however, the asset owner does. This represents an opportunity for an asset owner to take advantage of the outage information by trading in the forward market. The misuse of outage information is analogous to insider trading in securities markets.

The MSA is concerned that trading on asset outage information creates the perception that the market is unfair and, as a result, it increases the level of uncertainty amongst market participants. The MSA is also concerned that trading on outage information reduces market efficiency. Moreover, information asymmetry (the knowledge level that anyone asset owner has about generating unit operation) combined with the negative factors associated with trading on outage information contribute to poor liquidity in the forward market. Poor market liquidity affects the ability of market participants to effectively manage risk.

Other jurisdictions, most notably the Federal Energy Regulatory Commission in the United States, have implemented regulations and behavioural guidelines such as FERC Order 2004 to deal with the unfair use of non-public information.

Figure 36 compares asset owner market share in terms of information asymmetry and control over generating unit dispatch. Control over unit dispatch is fairly well distributed amongst market participants. However, the knowledge level about unit operation is skewed in favour of a relatively small number of asset owners. Information asymmetry has the potential to provide some market participants with an unfair competitive advantage.

Figure 36 - Dispatch control vs. Interest in Generating Units



During the April 5 to April 16, 2004 time period, the MSA conducted a test of possible outage report formats. **Figure 37** illustrates generating plant outage information that has been aggregated on a monthly basis and by fuel type. **Figure 38** indicates the day over day change from the previous day's monthly graph. The changes can be either a result of an outage being re-scheduled or a new outage being scheduled or a combination of both.

Figure 37 – Expected Outages

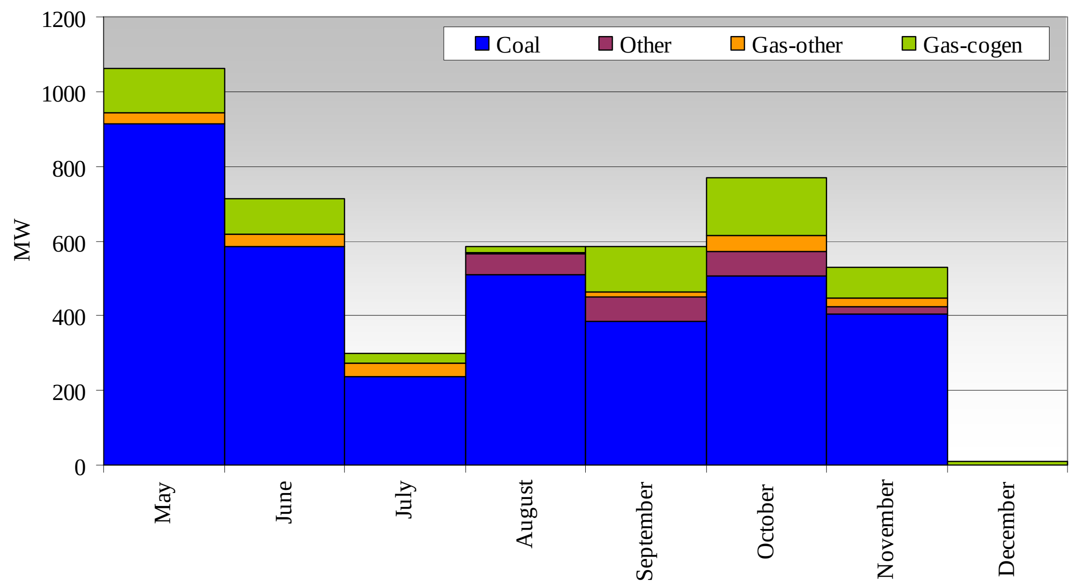
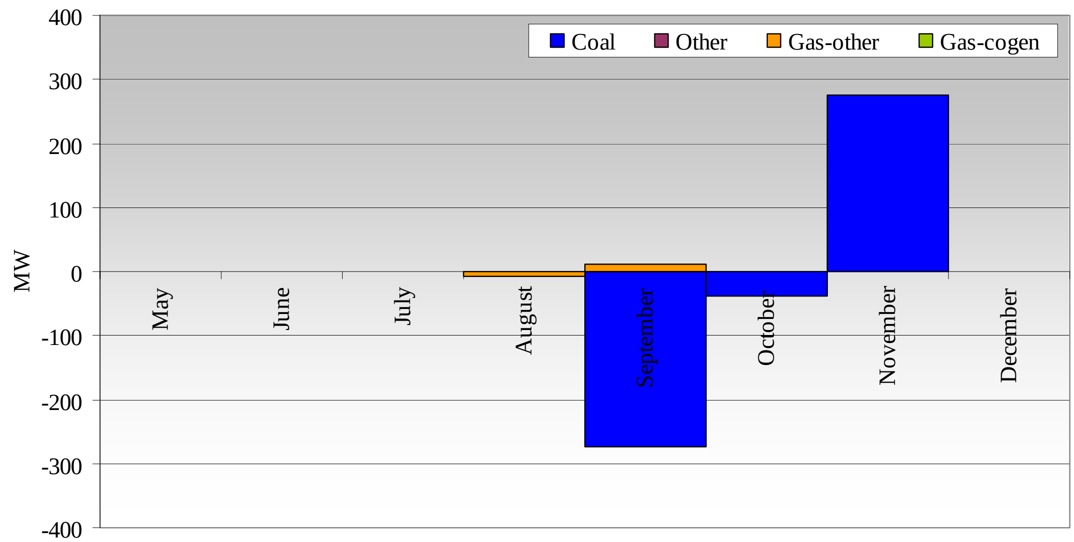


Figure 38 – Change From Previous Day



Figures 37 and 38 are taken from the April 6, 2004 outage report; the second day of the test period. The day over day change is significant and may indicate that asset owners were able to adjust future outage schedules based on the outage information published on the previous day. While the results from the test period are not statistically significant, the MSA is encouraged by positive feedback we received from market participants who indicated that the outage reports provide useful information about future market conditions. In addition, discussions with the brokers and exchanges suggested there was an increase in trading activity during the test period; another encouraging sign.

The comment period on the IDP is open to April 30, 2004 (see http://www.albertamsa.ca/files/OutageReportNotice042104.pdf). Based on the feedback received from market participants, the MSA will identify outstanding issues and conduct workshops with market participants during May in order to identify potential solutions. As stated previously, it is the MSA's expectation that full implementation of the TPG will occur during the June to July 2004 time period.

The MSA believes that the TPG will have a positive impact on the forward market by helping to "level the playing field" and by improving the level of confidence amongst market participants. This in turn will result in improved market liquidity and efficiency. The IDP will provide a mechanism for meeting compliance with the TPG and encouraging participants to monitor their own activities in the market. The MSA will also implement its own surveillance programs and develop performance indicators to monitor the efficacy of the TPG. Readers are encouraged to review the TPG, IDP, and related material by visiting the MSA's website.

3.2 Economics of New Entry

The Economics of New Entry project was initiated in order that the MSA might get a grasp of the attractiveness of the Alberta market to potential new generation. The idea was to simulate the typical cash flows of a number of new generators representing typical plant configurations that have been or will soon be added to the Alberta system in order to better understand the price signal that our current market is sending to prospective investors.

Annual capital cost repayment percentages for the three unit types for the two price years analyzed are presented in **Table 5**.

Table 5 - Annual Capital Cost Repayment Percentages, 2002-2003

Reference Year	Unit		
	Coal	**Gas**	**Combined Cycle**
2002	5.4%	4.8%	8.1%
2003	12.5%	7.1%	9.9%
Average	**9.0%**	**6.0%**	**9.0%**

Coal-fired and combined-cycle generation appear to be equally attractive options with average capital paybacks of 9.0%/year. There is, however, more volatility in the annual rates of capital payback for the coal-fired generation option as the annual rates of payback range from 5.4% to 12.5%. Gas-fired generation achieved an average rate of capital payback of only 6%/year and appears to be the least attractive option.

These capital payback figures need to be placed in the context of the merchant generator. In today's difficult investment climate a weighted average cost of capital of about 15% seems reasonable (50%/50% debt/equity ratio, 10% borrowing rate for debt and 20% desired rate for equity). As such, an annual payback of less than 15% is likely to be viewed as unattractive. This is the case for all three generation projects simulated. Clearly market prices in 2002 and 2003 did not send a "build" signal to would-be generators.

This analysis can be viewed in full at:
http://www.albertamsa.ca/files/EconomicsofNewEntry042804.pdf .

3.3 Settlement System Code Monitoring

During Q1/04 the MSA initiated new Settlement System Code (SSC) monitoring efforts. The intent of the monitoring is to assess how well settlement is working within the province and identify areas in which some improvements could be made.

The MSA has developed a number of metrics related to settlement and enforcement of the SSC, as follows:

- Tracking of complaints (including PFECs, PFAMs and Notices of Dispute[4]);
- Monitoring exceedences of unaccounted for energy (UFE) tolerances;
- Assessment of System Performance Diagnostic Reports; and,
- Tracking of Non-Compliance Notices, Enforcement Escalation Notices and Enforcement Withdrawal Notices issued by the AESO.

The metrics are intended to be indicators of potential problems with the settlement process. As detailed monitoring of settlement and compliance to the SSC is the role of the AESO, the MSAs observations will tend to be more directional in nature, identifying trends in the indicators as the settlement process develops. Available data for Q4/03 and Q1/04 has been collected. All commentary is based on this time frame.

Complaints

As defined in the SSC, PFECs, PFAMs and Notices of Dispute are the tools to be used to resolve financial disputes resulting from settlement calculations. PFECs occur before final settlement while PFAMs occur after final settlement. 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 (LSAs) in the province. **Table 15** summarizes PFEC and PFAM tracking for Q4/03 and Q1/04.

Table 6 - PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q4/03	550	414	158	3	803	NA
Q1/04	803	166	935	2	32	NA
PFAM						
Q4/03	36,583	528	27,377	2,776	6,958	(45,102,366)
Q1/04	6,958	2,089	7,500	138	1,409	(57,357,137)

The table shows that the number of PFECs submitted has decreased quarter over quarter while the number of PFECs dealt with (either accepted or rejected) has increased quarter over quarter. This activity has

[4] PFECs and PFAMs refer to pre-final error corrections and post-final adjustment mechanisms as defined in Sections 5.2 and 5.3 of the SSC. Notices of Dispute are defined in Section 5.1.2 of the SSC.

resulted in only 32 outstanding PFECs as of the end of Q1/04 (down from 803 at the end of Q4/03).

On the other hand, the number of PFAMs submitted has actually increased quarter over quarter while the number of PFAMs dealt with has decreased. Despite these discouraging numbers, the activity has nevertheless resulted in a fairly dramatic decrease in the number of outstanding PFAMs quarter over quarter.

The decreasing number of unresolved PFECs and PFAMs is an indicator that the LSAs are improving their processes for dealing with complaints. Note that one LSA received a large number of PFAMs in early 2003 creating a backlog of claims to be processed. The LSA has worked diligently and has now resolved the majority of its outstanding PFAMs.

A total of 6 Notices of Dispute were received by the LSAs in Q4/03. This number was reduced to 2 for Q1/04. As the PFEC/PFAM processes of the LSAs are improved, we would expect the number of Notices of Dispute to decline.

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 16** summarizes the UFE Reasonable Exception Reports (UFE reports) filed over the last two quarters.

Table 7 - Summary of UFE Reasonable Exception Reporting

Quarter	Outstanding (from previous quarters)	New	Resolved	Unresolved
Q4/03	5	3	1	7
Q1/04	7	11	6	12

At the start of Q4/03 there were 5 unresolved UFE reports. By the start of Q1/04 this number had increased to 7 and by the end of Q1/04 this number had increased to 12. This shows that the LSAs are not dealing with exceeded UFE tolerances in an efficient manner[5]. Not only are the new UFE reports not being resolved within the quarter in which they were submitted, but it does not appear that outstanding UFE reports are being resolved by the end of the next quarter. As the settlement process matures, we would hope to see an improvement in the turnaround time for dealing with UFE reports.

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

System Performance Diagnostic Reports

Each month, at the end of initial settlement, the LSAs are required to file System Performance Diagnostic Reports with the AESO. These reports summarize the checks and balances conducted by the LSAs for a variety of tests as listed in Rule 7 of the ISO rules. If any anomalies in the diagnostic reports are noted, the AESO will investigate the anomaly and file a report detailing the situation.

The MSA started collecting System Performance Diagnostic Reports in 2004 and has to date collected reports for January and February. During these two months, reports for all zones show that all tests have been performed and have balanced. No anomalies were reported.

Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices

In late 2003 the AESO initiated an enforcement ladder for the SSC[6]. 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 started collecting this data in 2004. **Table 17** summarizes the Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices filed by the AESO in Q1/04.

Table 8 - Q1/04 Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices

	Non-Compliance Notices Issued				Enforcement Escalation Notices Issued	Enforcement Withdrawal Notices Issued
	Level 1	Level 2	Level 3	Level 4		
January	0	0	0	0	0	0
February	4	0	0	0	0	0
March	1	1	0	0	0	0
YTD	**5**	**1**	**0**	**0**	**0**	**0**

The table shows that to date five Level 1 Non-Compliance notices and one Level 2 Non-Compliance notice have been issued by the AESO. This

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

appears to indicate that overall compliance with the SSC is going well. However, keep in mind that the enforcement ladder has just recently been implemented and as such we may witness a period of “warming up” as both the AESO and market participants become more familiar with the enforcement ladder.

4 OTHER MSA ACTIVITIES

4.1 Stakeholder Meetings

The MSA recently hosted its spring stakeholder meetings in Calgary and in Edmonton which were both well attended. The presentation given at these meetings can be found at: http://www.albertamsa.ca/files/2003YearEndReview.pdf .

4.2 Other Presentations

The MSA made presentations during Q1/04 to the IPPSA Conference, the EUA Advisory Committee, and to the EISG (Energy Intermarket Surveillance Group). The presentation given at the IPPSA conference by Martin Merritt can be found at: http://www.albertamsa.ca/files/IPPSA2004wnotes.pdf .

4.3 BCTC Tariff

With the recent break-up of BC Hydro into a generation and transmission company, the MSA is following the subsequent wholesale transmission service tariff process that is currently underway. The transmission company, BCTC, has hosted a number of information sessions and the next session is in Calgary on May 10, 2004. Information sessions have covered items such as the contractual relationships between the affiliated, but independent companies (BC Hydro and BCTC) and the design of new tariff.

4.4 MSA Survey

The MSA plans to conduct a survey of industry stakeholders in the coming weeks with the goal of soliciting feedback on the effectiveness of the MSA in discharging its role and responsibilities. The results of this survey will be posted to the MSA website at the conclusion of the study.