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MSA REPORT

Quarterly Report

January - March, 2005

2 May, 2005

MARKET SURVEILLANCE ADMINISTRATOR

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Market Highlights

- The Average wholesale price of electricity in the Alberta spot market in Q1/05 was $45.90/MWh which was lower relative to both last quarter ($54.95/MWh) and the same quarter a year ago ($48.81/MWh).

- Implied market heat rates trended downward through Q1/05, averaging 7.0 GJ/MWh for the quarter on an all-hours basis. In the month of March, the overall average implied market heat rate declined to 6.3 GJ/MWh.

- Alberta was a net exporter of 163,742 MWh of electricity in Q1/05. 88% of import volumes occurred during on-peak periods while 79% of export volumes occurred during off-peak periods.

- Weighted average PPA availability was 93% in Q1/05 vs. target availability of 87%

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

Pool prices in Q1/05 moved lower both on an on-peak and off-peak basis relative to last quarter as well as the same quarter a year ago, as is shown in **Table 1**. The monthly average price of $42.67/MWh in February was the lowest monthly average price observed since March of last year when the average monthly price reached $42.46/MWh. The price duration curves in **Figure 1** show the distribution of Pool price on a comparative quarter over quarter and year over year basis. In Q1/05, Pool price was $100/MWh or above 6% of the time and below $20/MWh 27% of the time. While the distribution curves shown in **Figure 1** are quite close, one can see that prices in Q1/05 were below Q4/04 levels about 90% of the time. The figure also shows that the distribution of Pool prices in Q1/05 was remarkably similar to that of Q1/04. **Figure 2** shows that price volatility was elevated in January but moderated significantly for the balance of the quarter. Price volatility was approximately equal to the same period last year.

Table 1 - Pool Price Statistics

	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Jan - 05	50.24	54.73	45.02	66.94	133%
Feb - 05	42.67	48.49	34.90	33.65	79%
Mar - 05	44.78	49.60	38.10	36.69	82%
Q1 - 05	**45.90**	**50.94**	**39.34**	**48.65**	**106%**
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%
Q4 - 04	**54.95**	**65.74**	**41.33**	**66.67**	**121%**
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%**

1 - Standard Deviation of hourly pool prices for the period

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

Figure 1 - Quarterly Pool Price Duration Curves

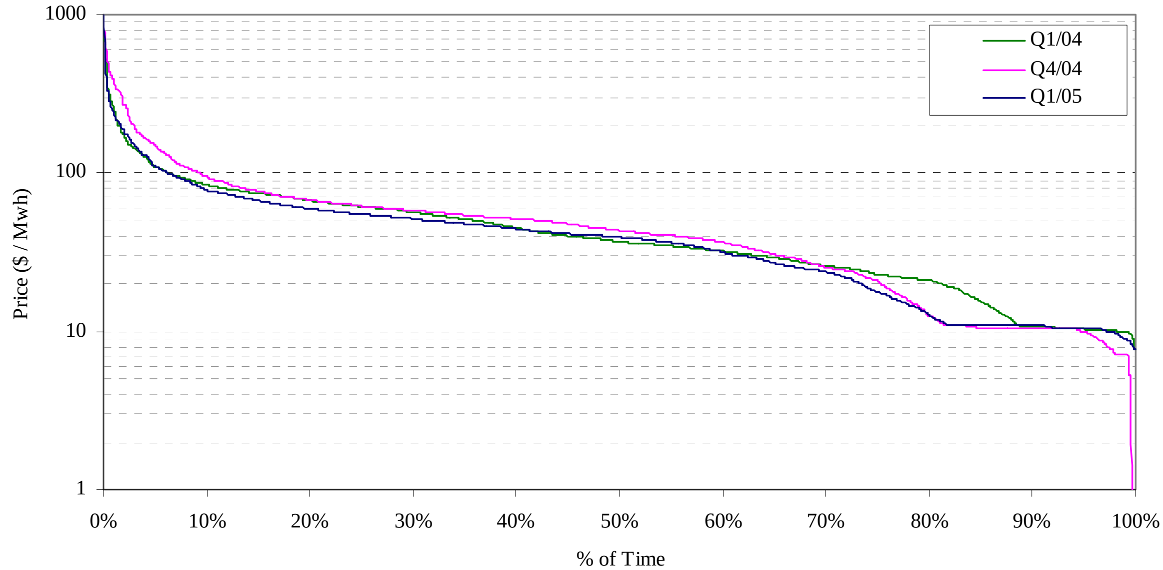
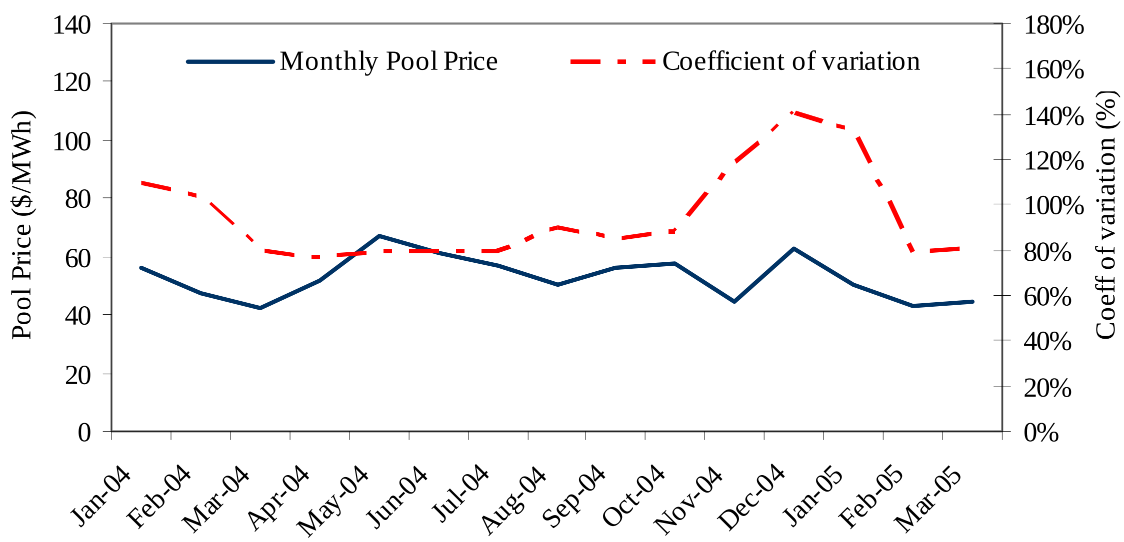


Figure 2 - Pool Price with Pool Price Volatility



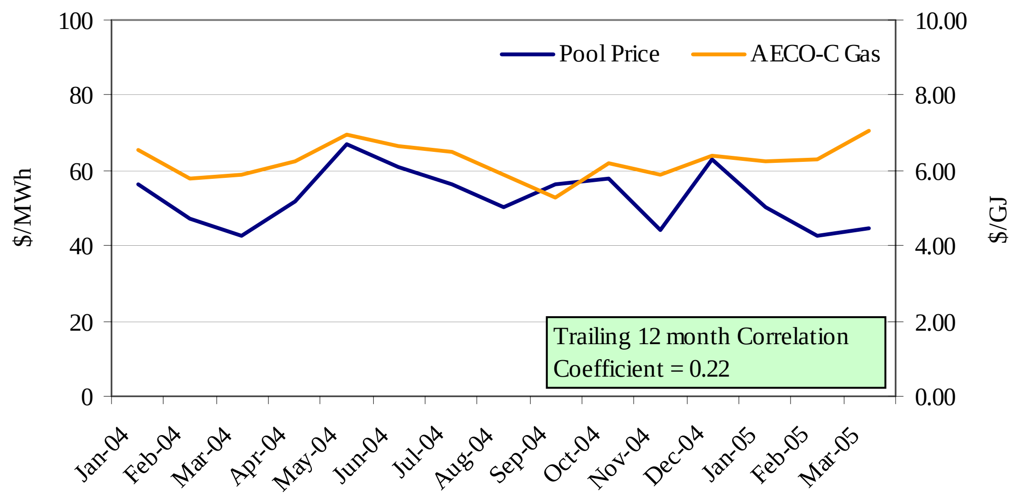
1.2 Natural Gas Prices

Alberta spot gas prices were relatively flat through much of Q1/05, in the $6.20/GJ range but began moving upward through the month of March averaging $7.06/GJ. **Figure 3** compares monthly average gas prices in Alberta with monthly average Pool price. The trailing 12 month correlation of monthly Pool price to gas price weakened from the end of

2004 to the end of Q1/05 as Pool prices fell while gas prices remained strong.

Strength in natural gas prices appears to be driven by ongoing robust crude prices as gas storage levels are significantly above last year's levels as well as historical levels.

Figure 3 - Wholesale Electricity Price with AECO Gas Price



1.3 Price Setters

Figure 4 shows the five most frequent marginal price setters in Q1/05 as compared to the prior quarter along with the weighted average price at which they set the system marginal price (SMP). The leading price setter in Q1/05 set price approximately 27% of the time at a weighted average price of $11.83/MWh. The five most frequent marginal price setters together set SMP 81% of the time in Q1/05 as compared to 77% of the time in Q4/04. Note that the identity of the price setter at each ranking may or may not be the same from Q4/04 to Q1/05 – the chart simply shows a ranked distribution of the leading five price setters.

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

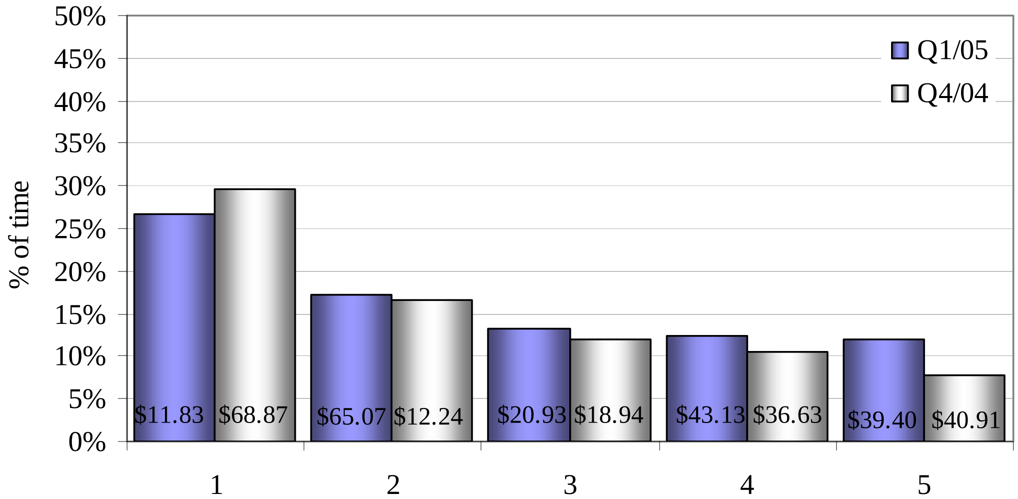
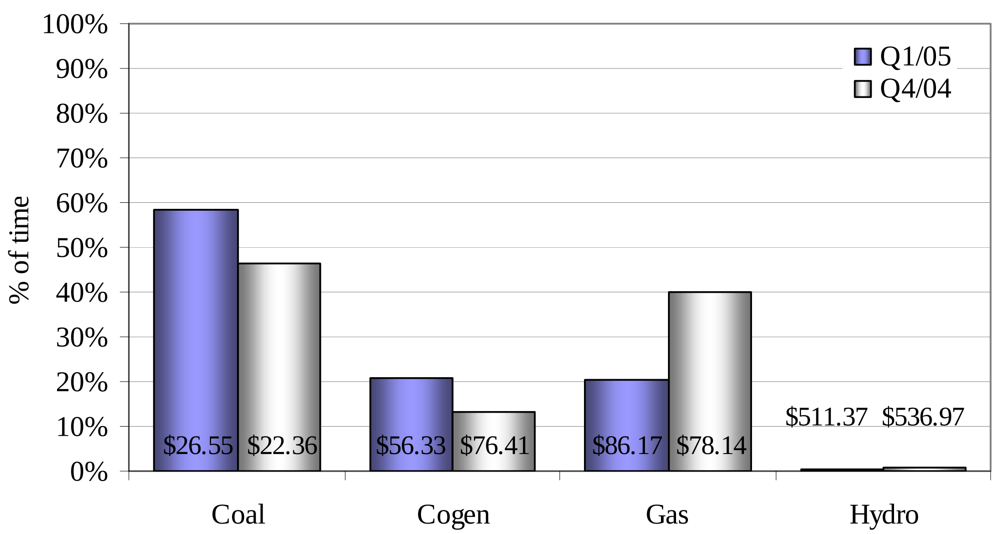


Figure 5 shows a similar distribution on the basis of fuel type of the marginal unit. In Q1/05 coal units were the marginal units approximately 59% of the time – up from 46% of the time in the previous quarter and at a marginally higher weighted average SMP. All gas units (co-gen and other gas combined) were marginal units 41% of the time vs. 53% of the time in Q4/04; not so surprising an outcome given the lean implied heat rates observed in the wholesale market in Q1/05.

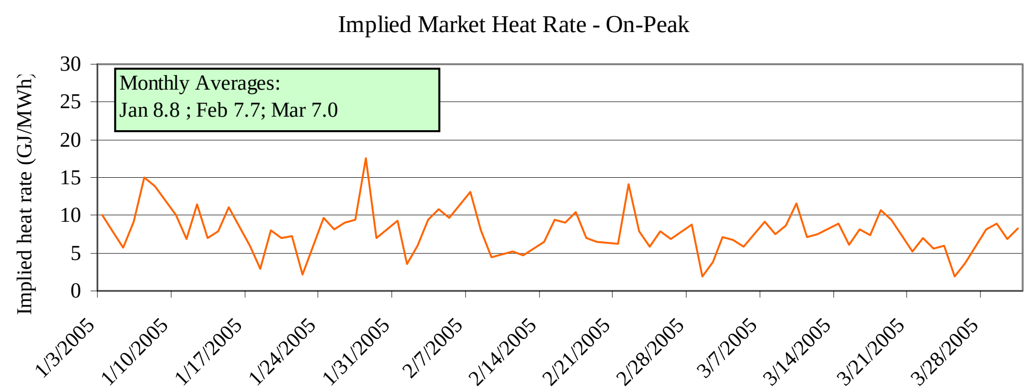
Figure 5 - Price Setters by Fuel Type (All Hours)



1.4 Implied Market Heat Rate

Implied market heat rates moved lower in Q1/05 relative to Q4/04 and Q1/04. Overall, implied heat rates averaged 7.0 GJ/MWh for Q1/05. **Figure 6** shows that both on-peak and off-peak heat rates declined through the quarter with the all hours implied heat rate falling to 6.3 GJ/MWh for the month of March. **Figure 7** indicates that even a high efficiency newer combined cycle generator with a thermal efficiency rating of 7.5 GJ/MWh would have met its cost of fuel only about 30% of the time in Q1/05 while the last gas units built under regulation would have been able to generate profitably perhaps 10% of the time, considering only variable cost of fuel.

Figure 6 - Implied Market Heat Rates – Q1/05



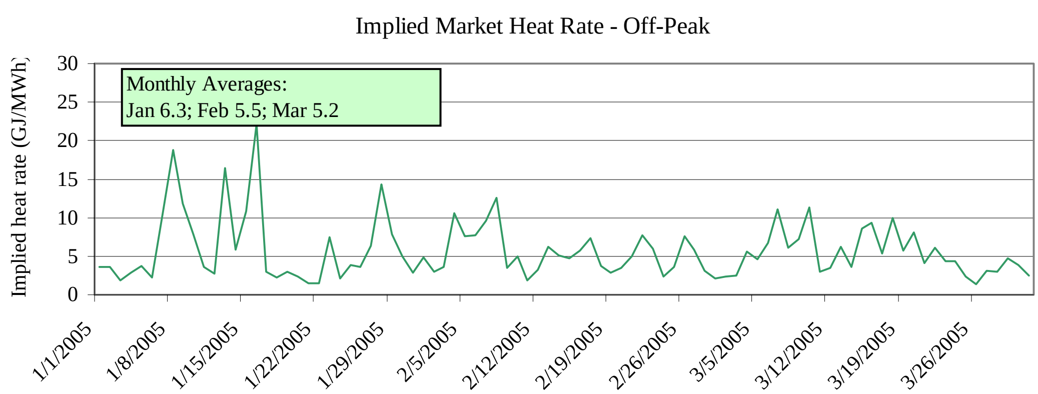
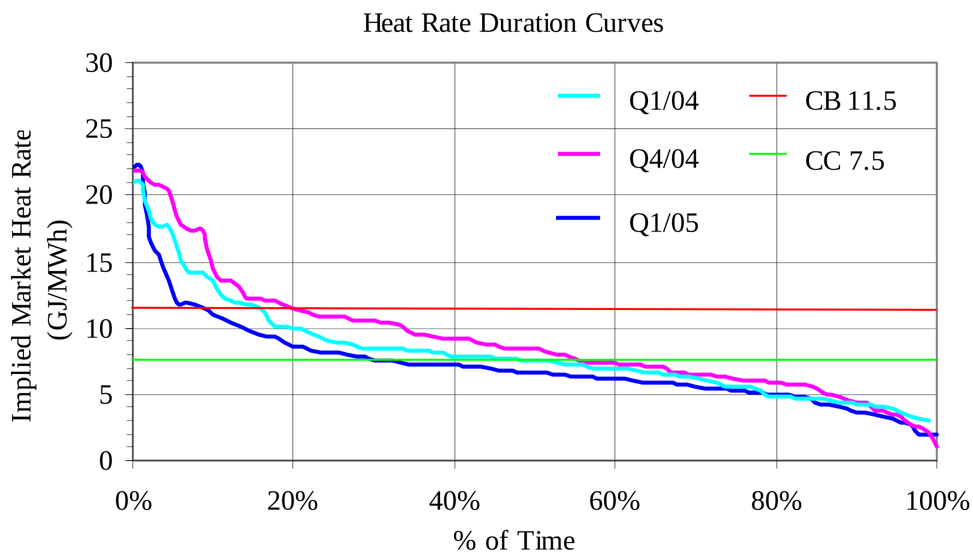


Table 2 - Implied Market Heat Rates (Q1/05)

	all hrs	on-pk	off-peak
Jan-2005	8.0	8.8	6.3
Feb-2005	6.8	7.7	5.5
Mar-2005	6.3	7.0	5.2
Q1/05	**7.0**	**7.8**	**5.7**

Figure 7 - Quarterly Heat Rate Duration Curves - (All Hours)



1.5 New AESO Rules

There were no significant changes to AESO rules during Q1/05.

1.6 New Supply and Load Growth

There were no noteworthy changes on the supply side of the system through Q1/05 in terms of generation additions or retirements.

The monthly average hourly system demand for electrical energy in Q1/05 was:

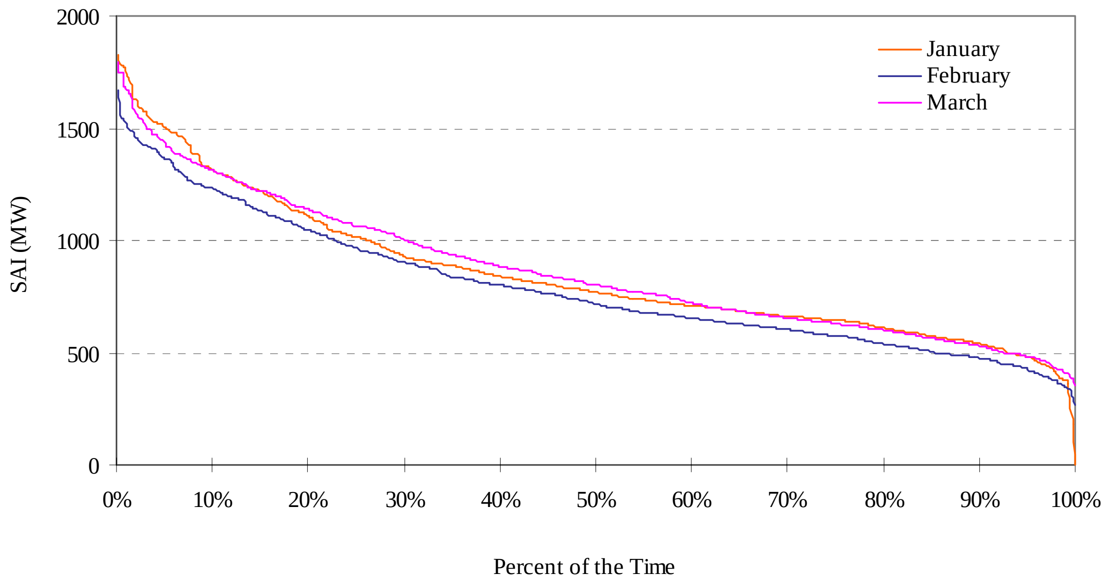
January	7966 MW	+ 2.1% vs. Jan 2004
February	7730 MW	+2.2% vs. Feb 2004
March	7495 MW	+0.9% vs. Mar 2004

Peak demand in Q1/05 was 9172 MW which occurred in HE 18 on January 4 at a price of $63.13/MWh. Peak demand increased approximately 2.3% from peak demand in Q1/04.

1.7 Supply Availability Index

SAI is a metric which approximates short-term residual supply available to the system as it is the quantity of supply offered into the merit order above the level of dispatch. **Figure 8** shows duration curves for the three months of Q1/05. It can be seen that the month of March exhibited a lower SAI, however, this did not translate to the highest price volatility of the quarter due to moderate average system load during March. This underscores that two other important factors need to be considered together with SAI in explaining price dynamics and these are the shape of the supply curve, as well as system demand. The new STA initiative may be having an effect as well.

Figure 8 - SAI Monthly Duration Curves, Q1/05



1.8 Imports, Exports, and Prices in Other Electricity Markets

Activity on the transmission interconnections between Alberta and BC and Saskatchewan is a significant part of the operation of the Alberta electricity market. **Table 2** summarizes the activity on the tie-lines for Q1/05.

Table 3 - Tie Line Activity Q1/05

	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	83,277	84,844	(1,567)	8,844	10,557	(1,713)	92,121	95,401	(3,280)
February	53,892	93,053	(39,161)	12,786	5,366	7,420	66,678	98,419	(31,741)
March	20,084	140,846	(120,762)	7,959	15,918	(7,959)	28,043	156,764	(128,721)
Total	**157,253**	**318,743**	**(161,490)**	**29,589**	**31,841**	**(2,252)**	**186,842**	**350,584**	**(163,742)**
On-Peak	89%	18%		83%	59%		88%	21%	
Off-Peak	11%	82%		17%	41%		12%	79%	

Note: Negative net imports indicate exports

Alberta was an overall exporter for the quarter with 163,742 MWhs of net exports. Import volumes were notable on both the BC and SK tie lines during the on peak period. However, the export activity on the BC tie overshadowed the total imports significantly. For the most part, BC exports occurred during the off-peak hours when Alberta prices were relatively low when excess supply exists in the Alberta market.

The Saskatchewan tie-line was used for both imports and exports with similar quantities flowing each way. The SK tie netted out to slightly over 2,200 MWh of exports for Q1/05.

Over the course of the quarter, Alberta imported close to 187,000 MWh and exported over to 350,000 MWh of electricity. From a fundamental perspective, the large amounts of exports could be attributed to relatively moderate demand levels in Alberta and high levels of base load generation availability. These fundamental factors were undoubtedly influenced by mild weather and few planned outages in Q1/05. Elevated export volumes may also be attributed to a storage buildup in BC due to forecasts of drought in the Pacific Northwest raising the possibility of significantly higher prices in Q3/05 and Q4/05.

During Q1/05, 88% of total imports occurred during on-peak hours and 79% of exports occurred during off-peak hours. This pattern is consistent with previous quarters as Alberta imports from other markets to cover energy shortfalls due to forced outages and typically exports during the night (off peak) through the BC intertie.

Figure 9 shows the relative market shares of importers and exporters in Q1/05. The figures include imports and exports on both the BC and Saskatchewan tie-lines. Both importing and exporting were dominated by one market participant with a 33% market share of imports and a 81% market share of exports. The second largest importer has increased its market share slightly by 3% (up to 24% from 21% last quarter) and the third largest importer increased by 9% from last quarter to a level of 19%. This move caused a shift in position amongst the third and fourth largest importers from Q4/04 time frame to Q1/05.

The market shares for the bulk of participants remained generally constant on the export side with the only notable change being that a small portion of market share was lost by the second and third largest exporter to the largest player which increased their share of the export market from 76% in Q4/04 to 81% in Q1/ 05.

Figure 9 - Market Share of Importers and Exporters, Q1/05

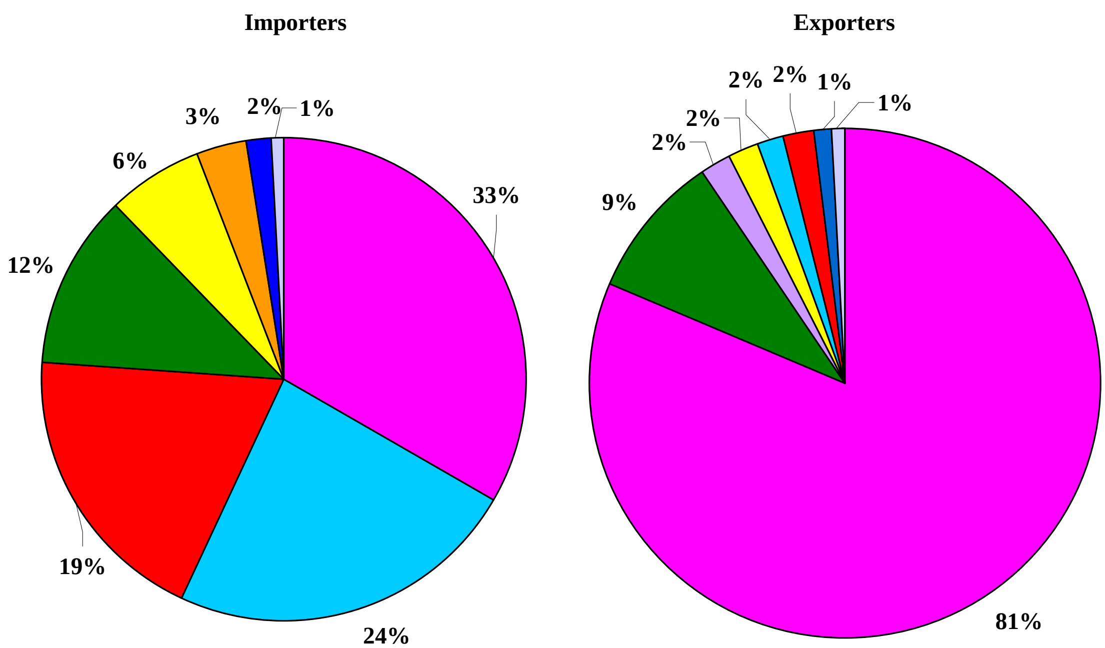
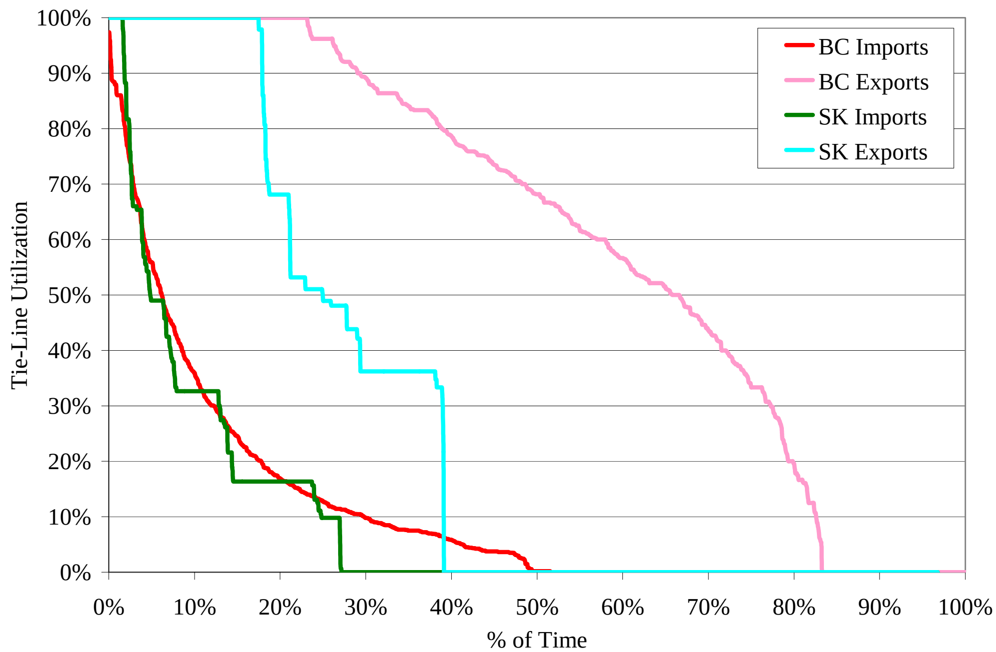


Figure 10 shows duration curves for tie-line utilization in Q1/05 as a function of posted available transfer capability (ATC)[1]. The figure shows that there is often some unutilized capacity available on both of the tie-lines. The BC export ATC was the most effectively utilized in Q1/05 as there was some volume of energy being exported from Alberta to (or through) BC approximately 83% of the time that the line was available. The BC import ATC was substantially less used, coming in at 51% utilization. The Saskatchewan import capacity was by far the most underutilized during the quarter.

Figure 10 – Tie-Line Utilization, Q1/05



It is not reasonable to 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, market price and the market position of each participant contribute to determining whether or not it is profitable to make use of the available tie-line capacity.

Activity on the tie-lines can be highly dependent on the Alberta market price. **Figures 11 and 12** plot total monthly imports with a weighted average monthly import prices and total monthly exports with weighted average monthly export prices respectively for the January 2004 through March 2005 period.

[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 11 – Imports and Weighted Average Pool Price

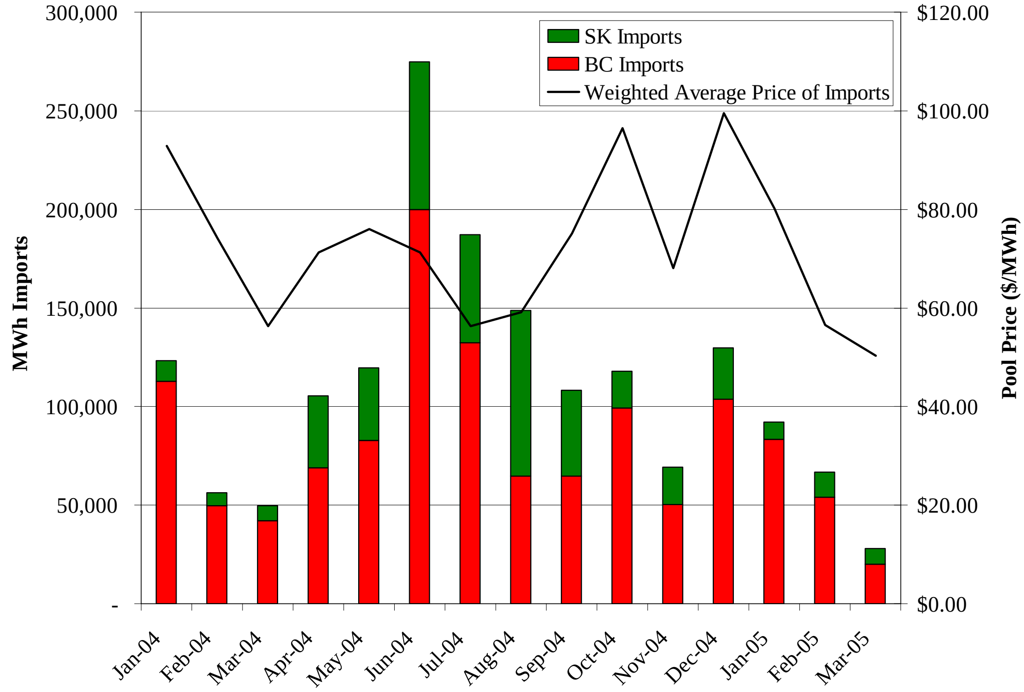
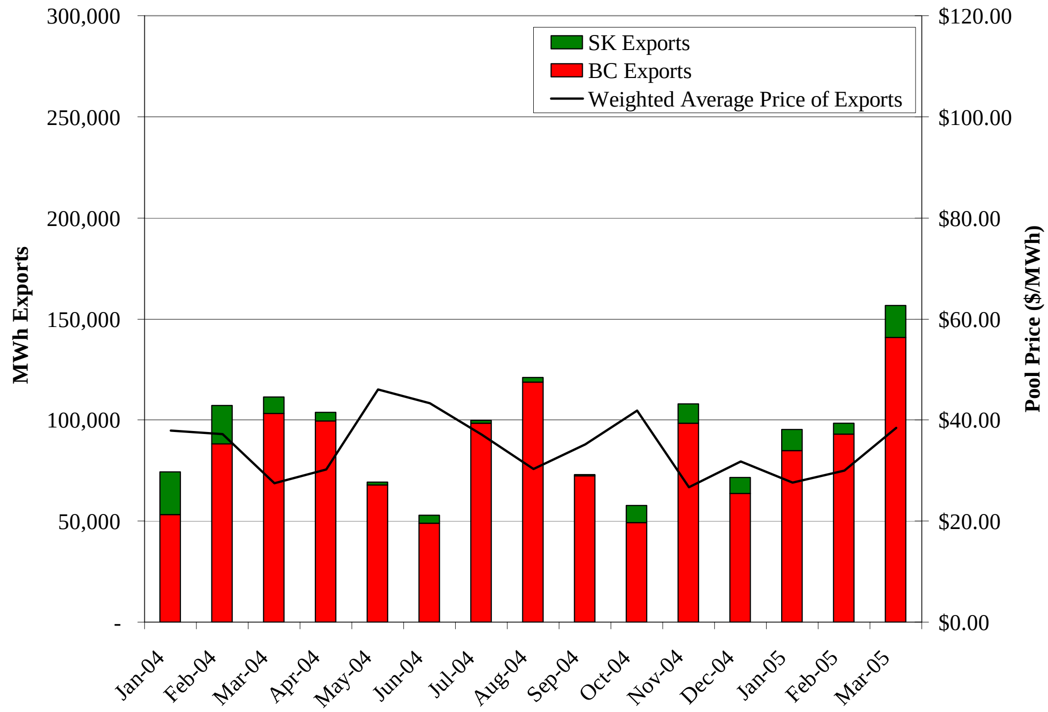


Figure 12 – Exports and Weighted Average Pool Price



Over the quarter, import volumes corresponded fairly well with Pool prices – as prices increased, the volume of imports increased. The expected inverse relationship between Pool price and export volumes was apparent during the quarter. It is clear in these graphs that a downward trend in total imports had occurred in Q1 and a less obvious trend upward in exports took place in the same time period.

Prices in other markets have an impact on the economics of moving 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 daily exchange rates.

Figure 13 - On-Peak Prices in Other Markets

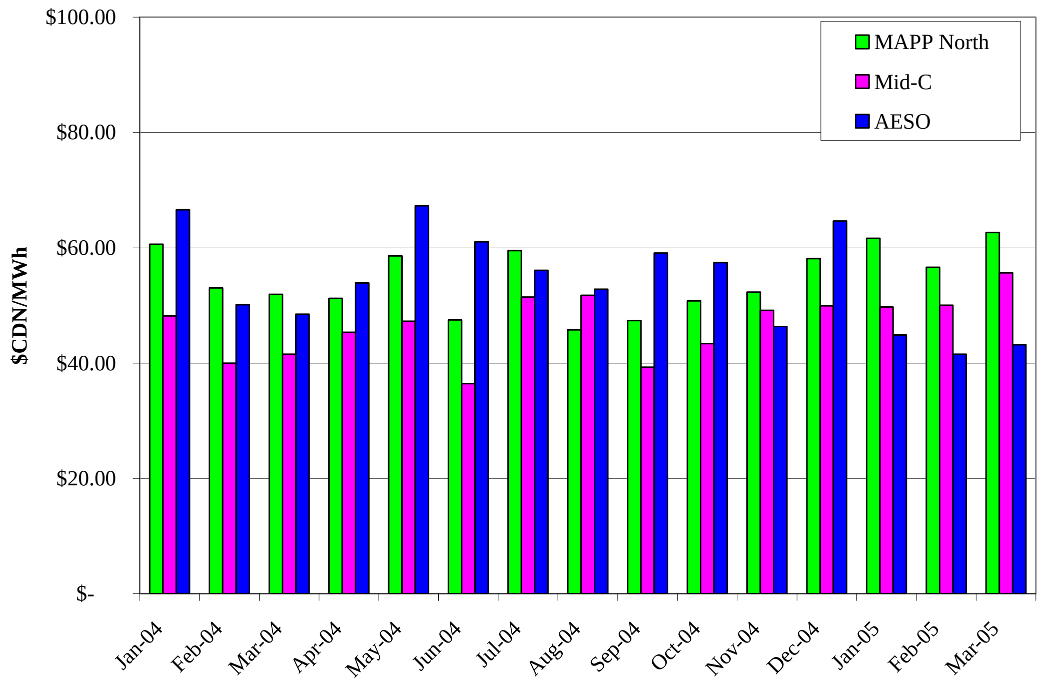
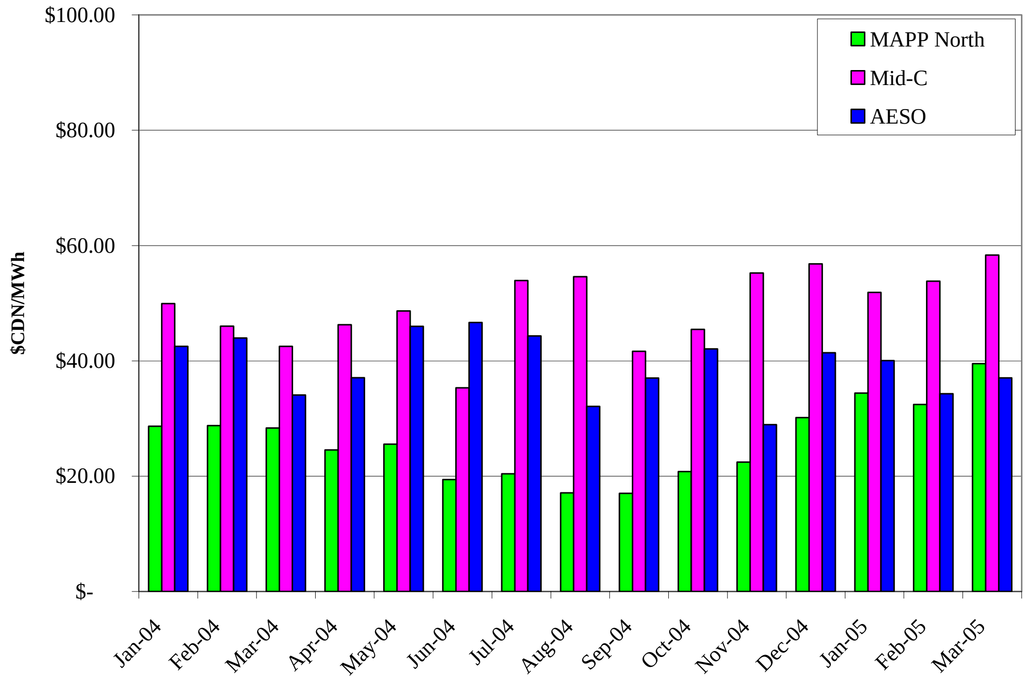


Figure 14 - Off-Peak Prices in Other Markets



On-peak prices at MAPP-N and at Mid-C were significantly higher relative to Pool prices through the quarter which generally supported export activity.

Alberta prices were generally lower than both Mid-C prices and MAPP-N prices on an off-peak basis. These price differentials tend to support off-peak exporting to Mid-C and to MAPP-N and are often reflected in the actual import/export activity observed over the last quarter.

With the recent market changes in the US Midwest area and the creation of the Midwest Independent System Operator (MISO), it was announced in late March that MAPP-N reference price would be replaced by a Minneapolis Hub price that would suitably capture the market price for the Midwest power market.

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]. **Figure 15** attempts to capture the economic use of the BC and Saskatchewan tie-lines over the last quarter

[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.

In January 2005, the MSA published a report on the use of the BC tie line by participants. Based on analyzing index-to-index economics, it appeared that many of the transactions were unprofitable. As such, that is not a concern to the MSA. What does concern the MSA is any activity that results in a degradation of the fidelity of the price signal. Uneconomic tie line transactions have that capability. The MSA continues to be concerned about this matter and is undertaking additional analyses as well as collecting more information to assist in the assessment.

Figure 15 shows BC tie line data from Q1/05. **Figure 15(a)** plots the total net flows on the line against the deemed profit (index-to-index and allowing for transmission costs). In an efficient market, unless the tie line is binding (on maintenance or full to capacity) the market prices should converge so that only modest profits ensue. The exception to this is the dominant tie line user, Powerex, who is generally not flowing the energy index-to-index since they have access to storage in BC.

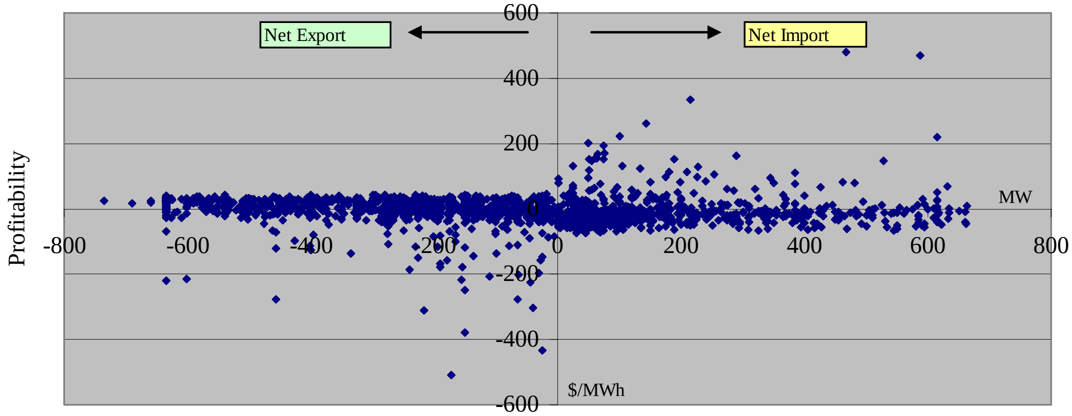
Figure 15(b) removes the Powerex component of the net flows from the total. Simply from the greatly reduced number of points, we can clearly see how dominant a position Powerex has, particularly on the export side. The figure indicates that there are several hours of imports when large profits were made. We have not screened out hours where the line was full but that is a relatively infrequent occurrence. In many of those hours greater efficiency could have occurred with increased flows. On the exports side, a very modest number of hours appear to have had very significant losses.

Figure 15(c) magnifies **Figure 15(b)** over the profit range $-100 to $+100. Clearly it can be seen that there are many hours of import that appear unprofitable. Outcomes such as these have been of concern to the MSA for some time. Market efficiency would improve in these hours with reduced import volume. On a lesser scale, there are hours of export with good profits that suggest under-exporting. In these cases market efficiency would improve with greater exports. These occurrences probably reflect issues of access to markets.

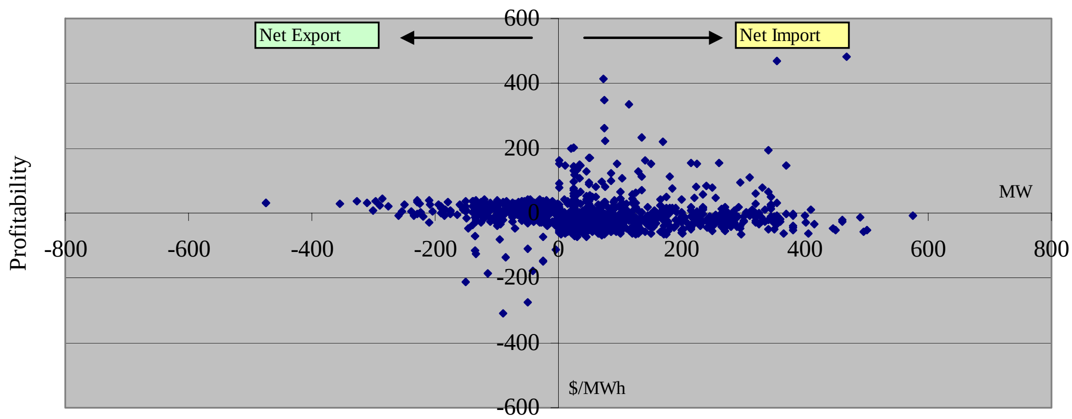
Beginning with the MSA paper - *A Review of Imports, Exports, and Economic use of the BC Interconnection*, the MSA has attempted to provide guidance with respect to how participants should conduct themselves when importing and exporting. The MSA is closely monitoring the market in this respect and where appropriate, will continue to seek changes to behaviour.

Figure 15 – Q1/05 Implied Tie-line Economics vs. Net Flow

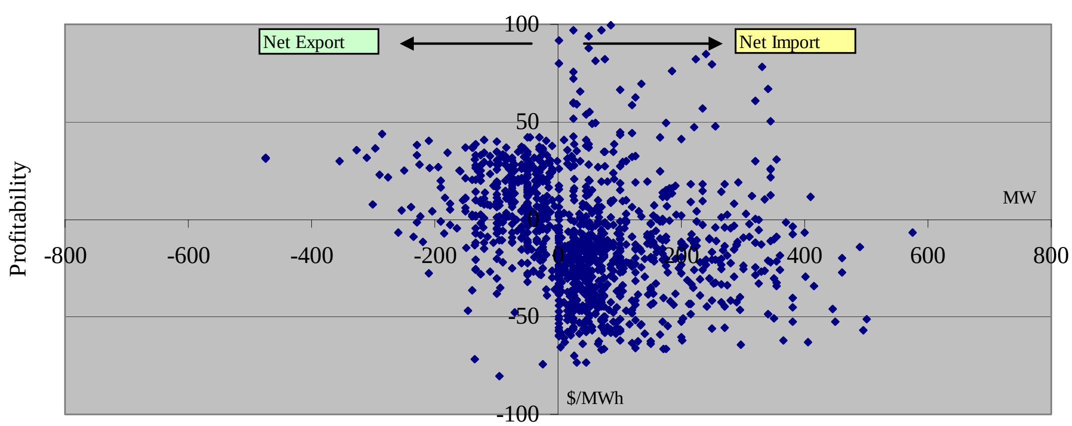
(a) All Firms



(b) Excluding Powerex



(c) Excluding Powerex



1.9 Ancillary Services Market

Active Reserves Markets

Active reserve contracts are transacted at a differential to the prevailing Pool price. **Figure 16** provides a view of these differentials over the trailing 15 month period including those reserve volumes transacted through the Alberta Watt Exchange (Watt-Ex) and volumes transacted through the OTC market. The figure shows that trade differentials have held steady through Q1/05 for spinning reserve and supplemental reserve while regulating reserve differentials have closed somewhat over the quarter. This is likely due at least in part to softer Pool prices as the energy component of providing the reserve is less.

Figure 16 - Active Trade Indices - (Watt-Ex & OTC)

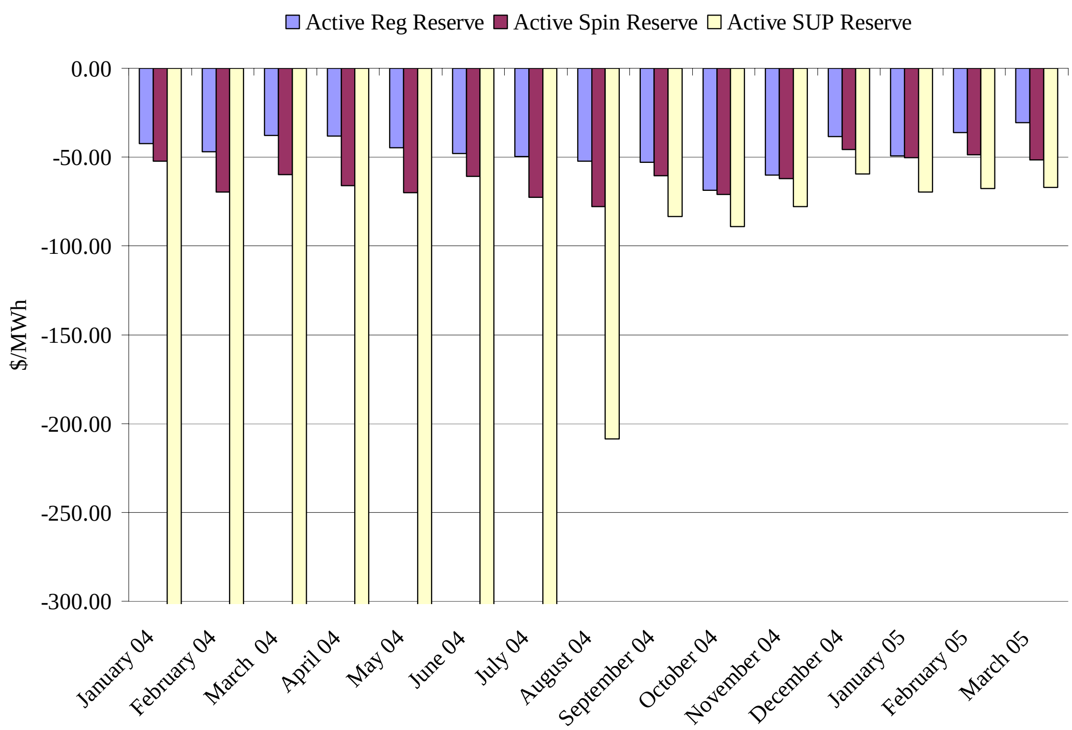
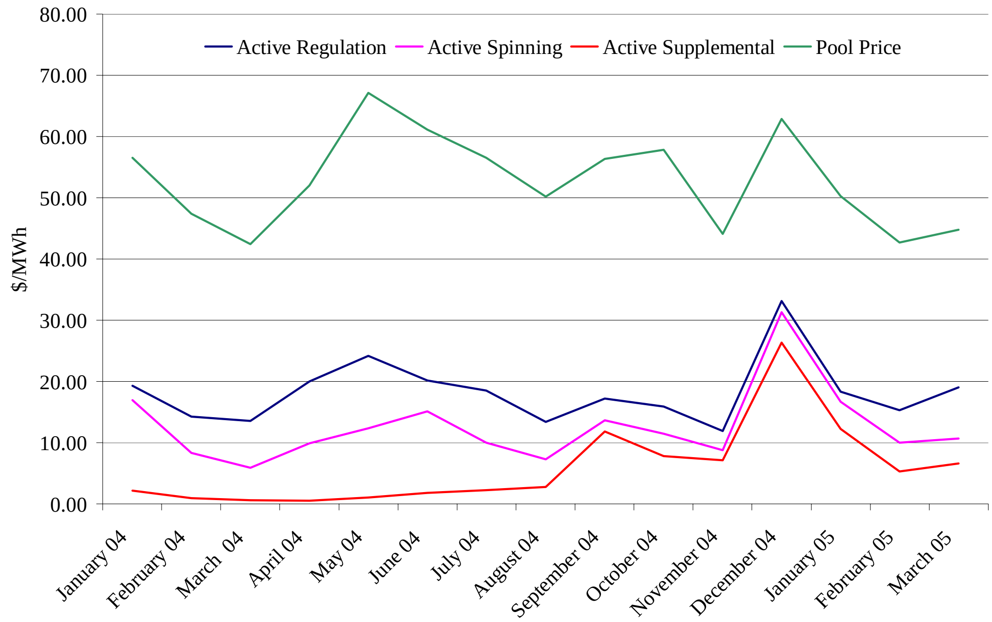


Figure 17 shows monthly average settlement prices for each of the three active reserve products. Declining Pool prices resulted in a downward trend in active settlement prices although less so for regulating reserves as a result of narrowing trade differentials through Q1/05.

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



Standby reserve products, unlike active reserve products, trade in a manner similar to options in that they have a premium price and an activation price. Average premiums for standby reserves are shown in **Figure 18** which indicates that generally, premiums declined through Q1/05 although regulating premiums rebounded in the month of March. The variability in premiums tends to reflect the prevailing frequency of activations, which is a function of system contingencies as well as reserve procurement practices.

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

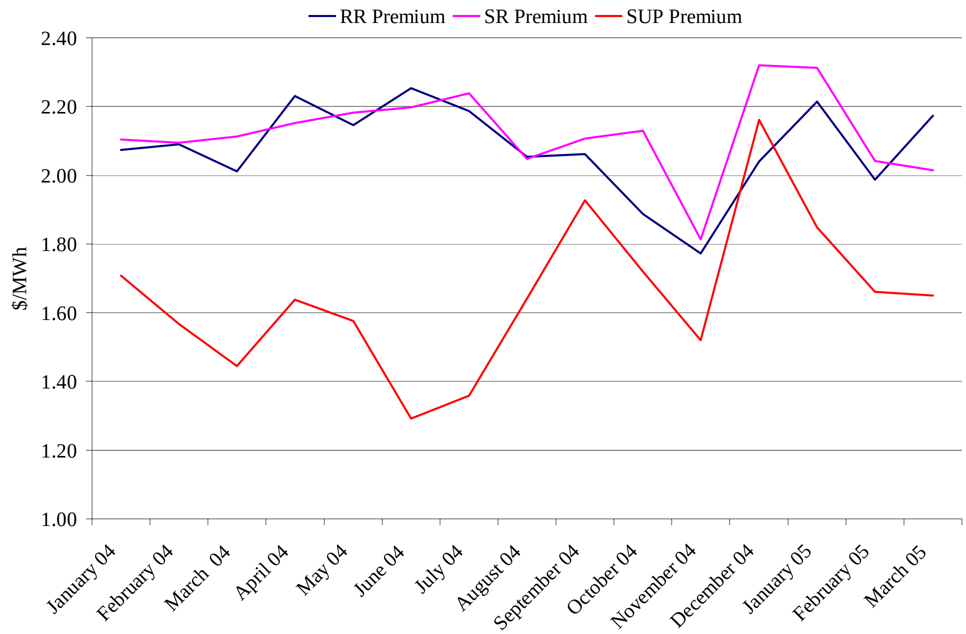


Figure 19 shows standby reserve activation prices over the last 15 months. Activation prices, after sharply moving higher in November and December, trended downward through Q1/05. Prevailing Pool price levels have a significant bearing on the level of activation prices supported by the market.

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

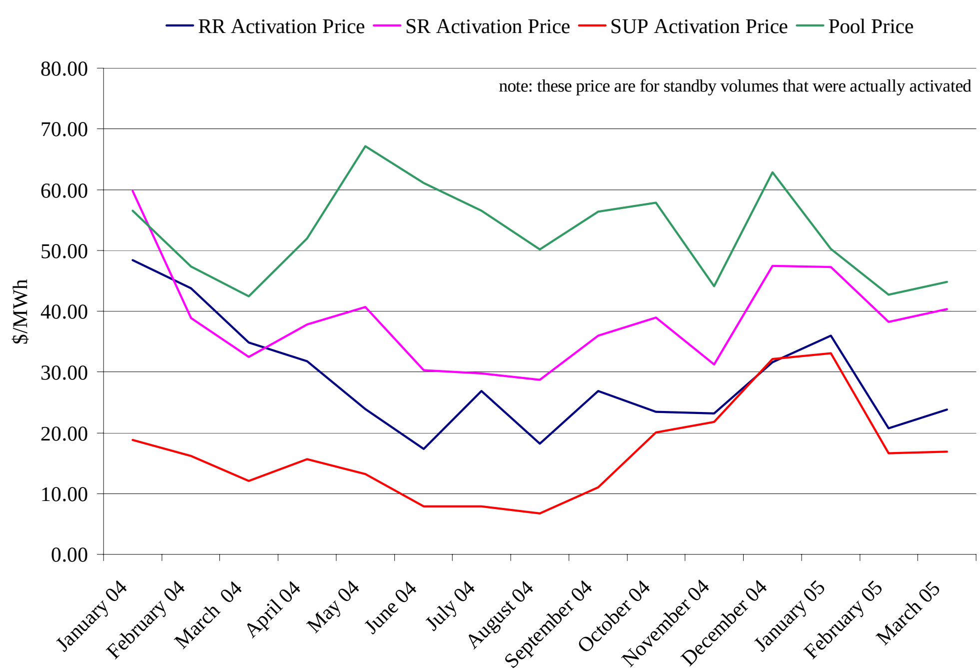
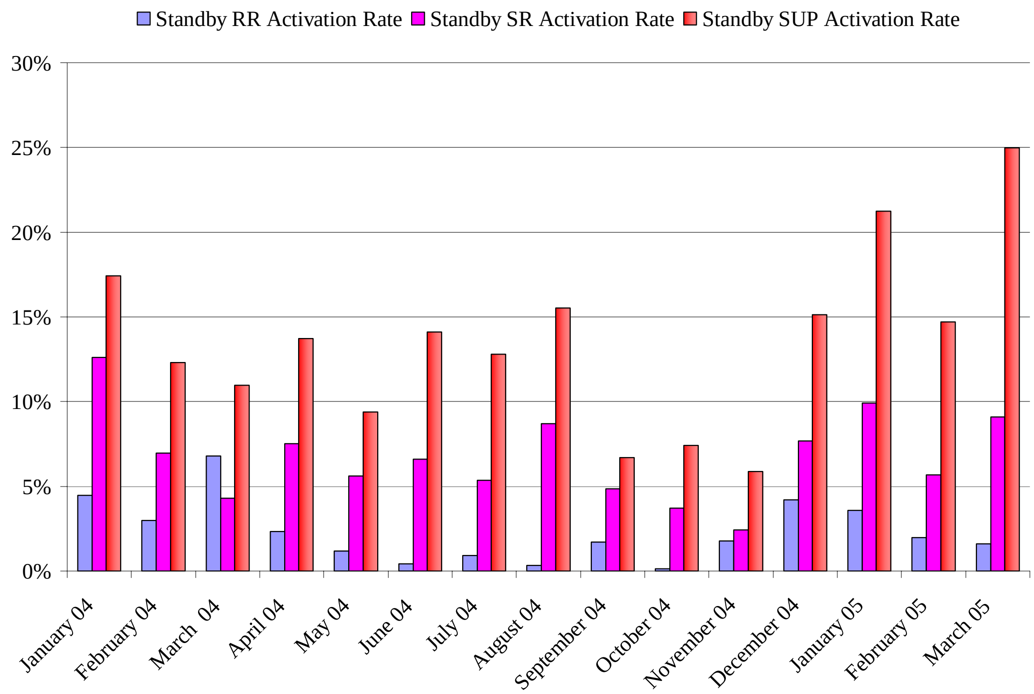


Figure 20 shows standby reserve activation rates which reflect the proportion of standby reserve volumes that were activated. Activation rates for regulating reserve have been relatively stable over the time horizon while spinning and supplemental reserve activations have fluctuated.

Figure 20 - Standby Activation Rates



The AESO procures system reserve requirements both via the Alberta Watt Exchange, as well as via an OTC mechanism directly from counter-parties. **Figure 21** shows that OTC procurements have become a much more substantial component of total reserve procurements over the last seven months relative to earlier periods. In Q1/05, over 40% of procured volumes of active regulating reserves were transacted OTC. Longer term one week, two week, and month long contracts have become a more frequent part of the AESO procurement strategy and these contracts have tended to transact OTC which has contributed to the increase in OTC transacted volumes.

Figure 21 - OTC Procurement as a % of Total Procurement

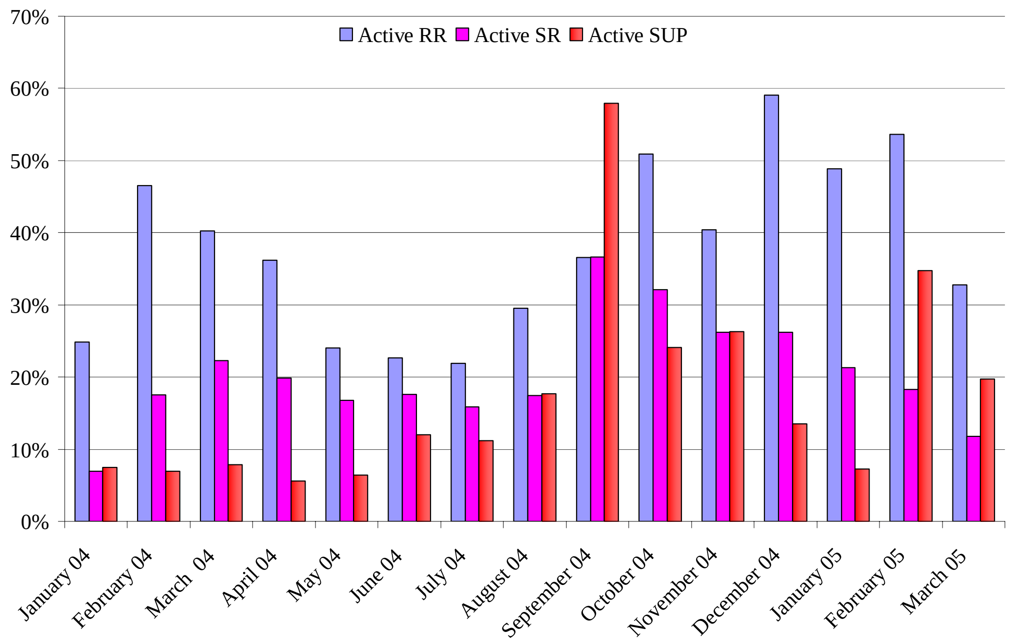
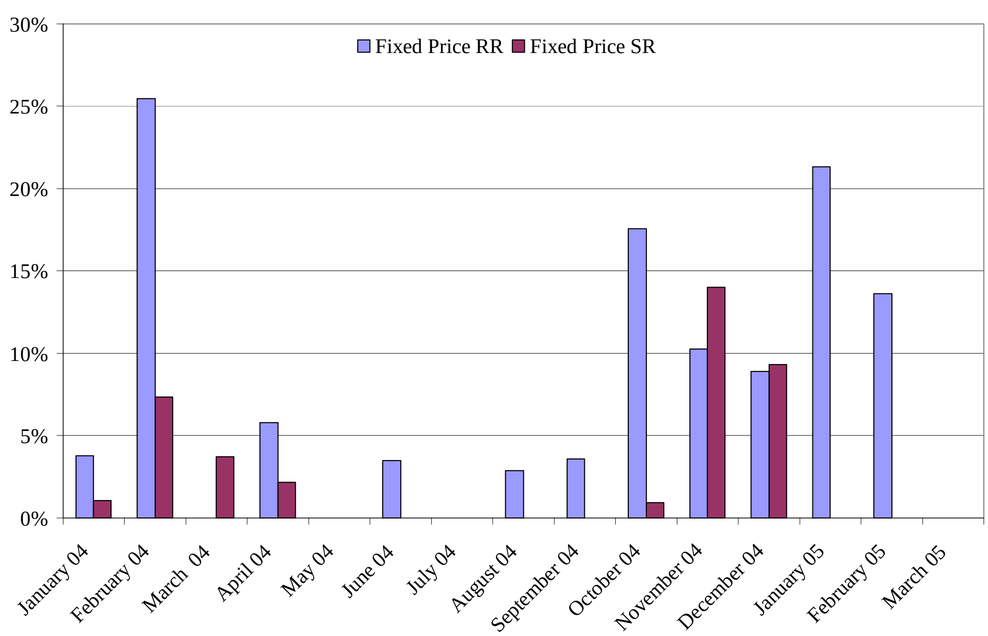


Figure 22 shows that fixed price reserve procurement was somewhat less prominent in Q1/05 as compared to the previous quarter as only active regulating contracts were transacted at fixed prices while in Q4/04, both a substantial proportion of both regulating and spinning reserve volumes were transacted at fixed prices.

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



Figures 23, 24, and 25 show weighted average settlement prices over the last 15 months for regulating, spinning, and supplemental reserves respectively. The figures show that in Q1/05, regulating reserves procured OTC did appear to command a noticeable premium to exchange traded volumes in January and February, although settlements converged in March. In the spinning reserve market, OTC and exchange traded volumes settlement had very little separation in Q1/05. For supplemental reserves, OTC volumes settled slightly below exchange traded volumes on a monthly weighted average basis.

Figure 23 - Active Regulating Reserve Settlement by Market

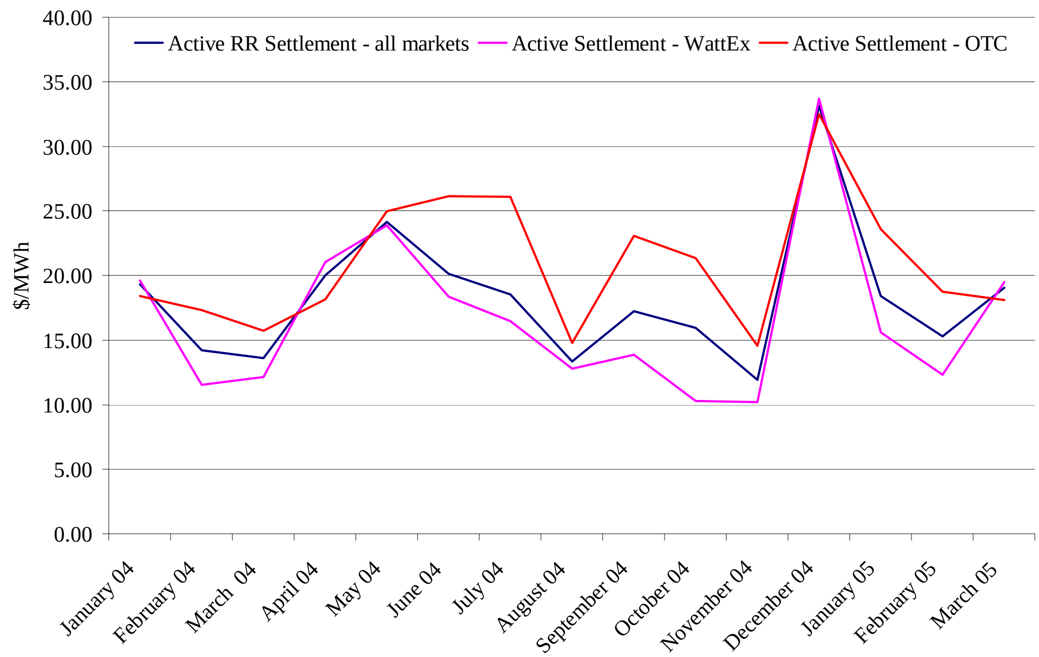


Figure 24 - Active Spinning Reserve Settlement Price by Market

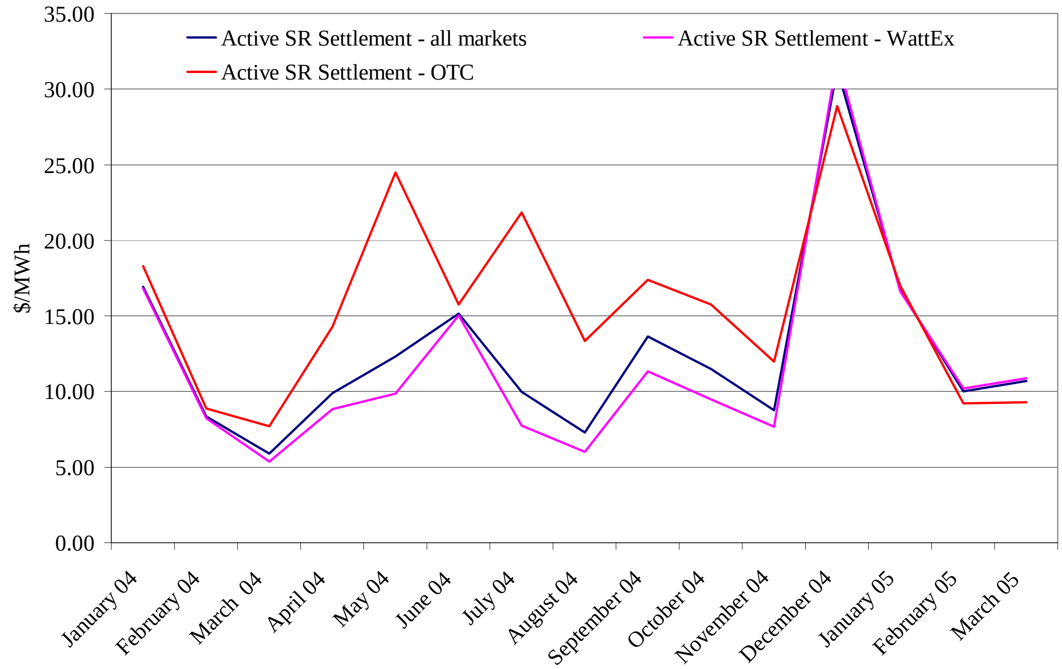
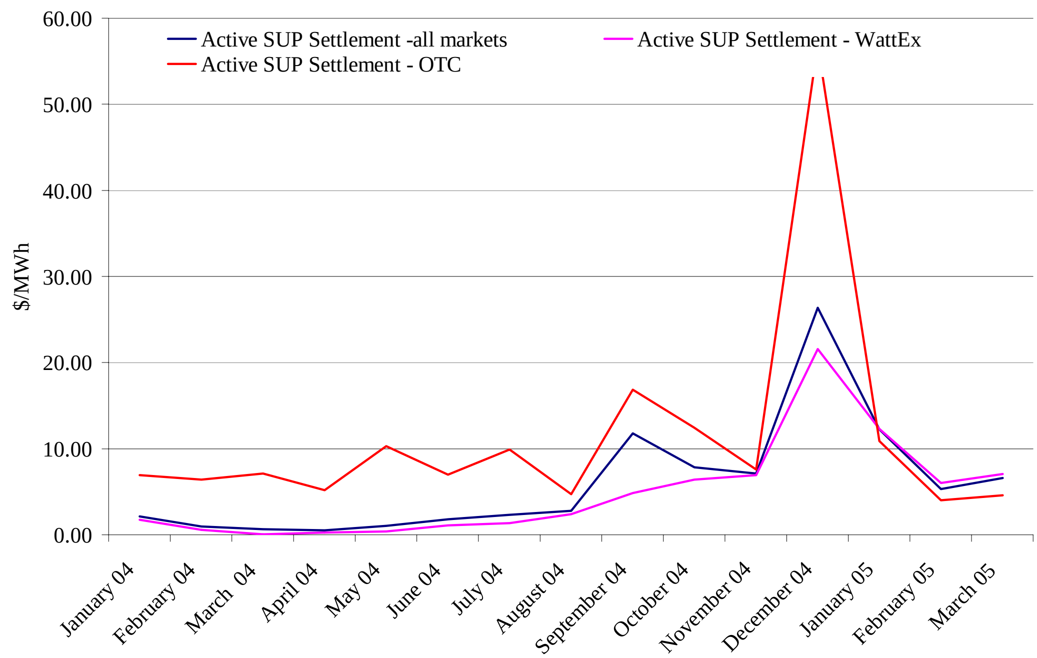


Figure 25 - Active Supplemental Reserve Settlement Price by Market



Figures 26, 27, and 28 show the market share distribution by fuel type for regulating, spinning, and supplemental reserves for the trailing 15 month period. For regulating reserves, market share of gas units trended downward through Q1/05 with the difference being made up about equally between coal and hydro units. For spinning reserves, contribution from the tie line declined through Q1/05 while gas units made up most of the difference. These figures also show that the hydro units continued to pursue the higher value regulating market as they have pulled back from the supplemental reserves market. The fuel type distribution for supplemental reserves also indicates an encouraging increase in load participation in this market.

Figure 26 - Regulating Reserve Market Share by Fuel Type

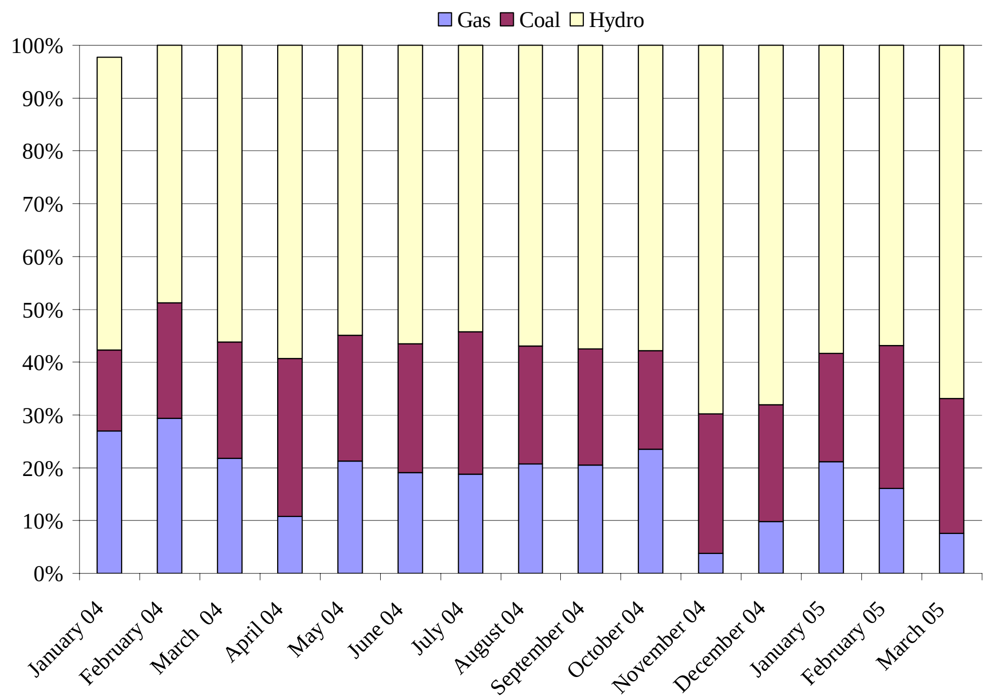


Figure 27 - Spinning Reserve Market Share by Fuel Type

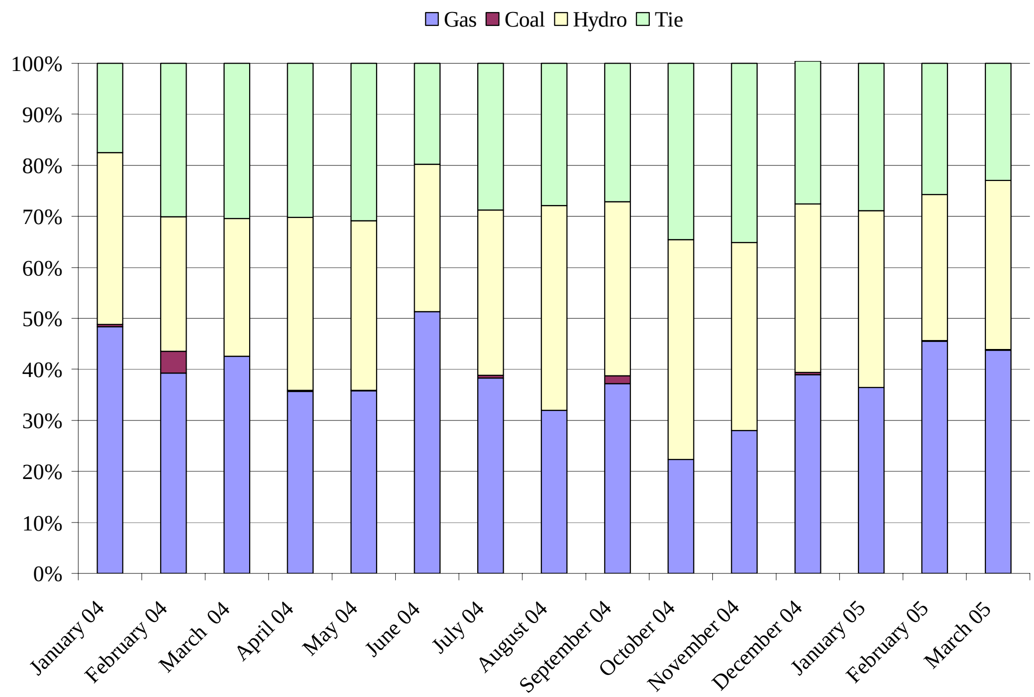
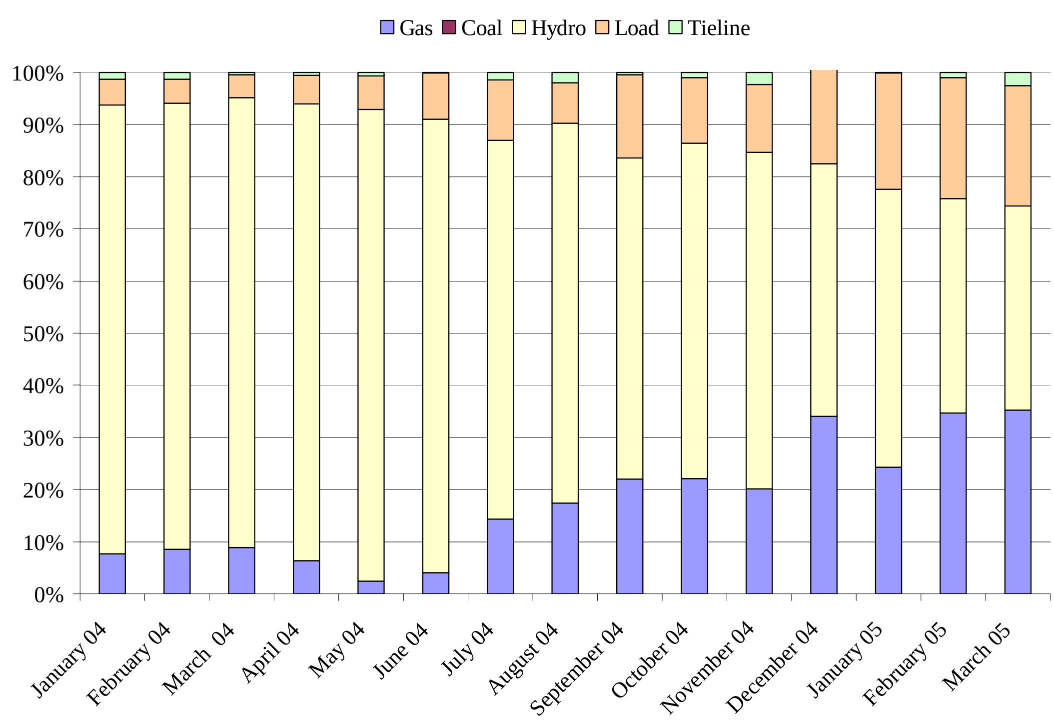


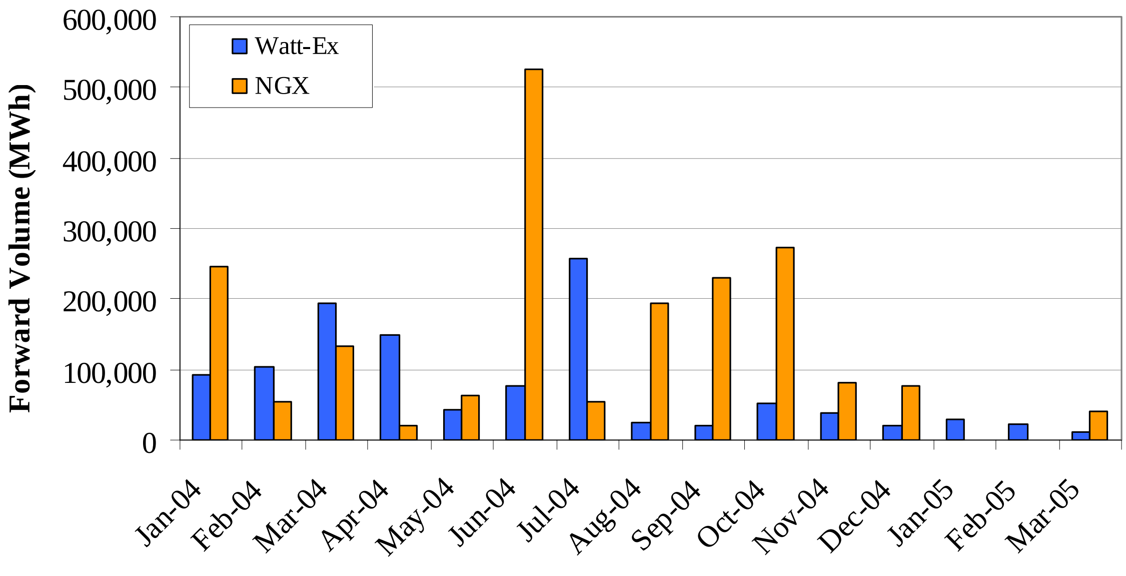
Figure 28 - Supplemental Reserve by Fuel Type



1.10 Forward Markets

Exchange traded forward energy volumes on Watt-ex and NGX declined markedly in Q1/05 as shown in **Figure 29**. In fact, there were no forward energy volumes transacted on NGX in the month of January for the first month since forward power contracts commenced trading on the NGX platform in April, 2003. While exchange-traded volumes have thinned, anecdotal evidence suggests these volumes have likely migrated to the OTC broker market where the majority of forward trade continues to reside.

Figure 29 - Exchange Traded Forward Energy Volume



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 thermal generation units that are operated under the terms and conditions of the Power Purchase Arrangements (PPAs). Outages at these PPA plants tend to have a large impact on Pool price as they represent a major contingent of total installed generating capacity in Alberta and also make up a substantial portion of what could be considered "base load" generation. When base load generating units are derated or on outage, a higher cost peaker unit often is employed to replace the base load energy that is unavailable in order that system demand is met.

Whenever the amount of outage exceeds a unit's historical average, the MSA seeks to understand the cause of the variation and will request information from the generation owner.

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 2005 are declining for two owners from the levels of the last quarter. Owner B has experienced a slight increase in outage levels compared to the previous quarter but nothing that is extremely away from the norm. Owner C experienced the most outages as a percentage in Q1 with the majority of these being unplanned.

It is typical to see very few planned outages in the first quarter of the year as this time period is historically a high demand season with colder weather expected. It should be noted that some variation is expected on a year over year basis due to the nature of multi-year planned outage schedules of large coal plants. When reviewing the historical outages for each owner it has been observed that major turnaround maintenance on certain units is not necessarily completed each year. With this in mind it could not be considered overly unusual for varied levels of outage to be experienced year over year. The MSA will continue to monitor outage of specific owners to ensure they are reasonable and within tolerances given the age and past performance of their generation units.

Figure 30 – Quarterly Outage Rates by Owner

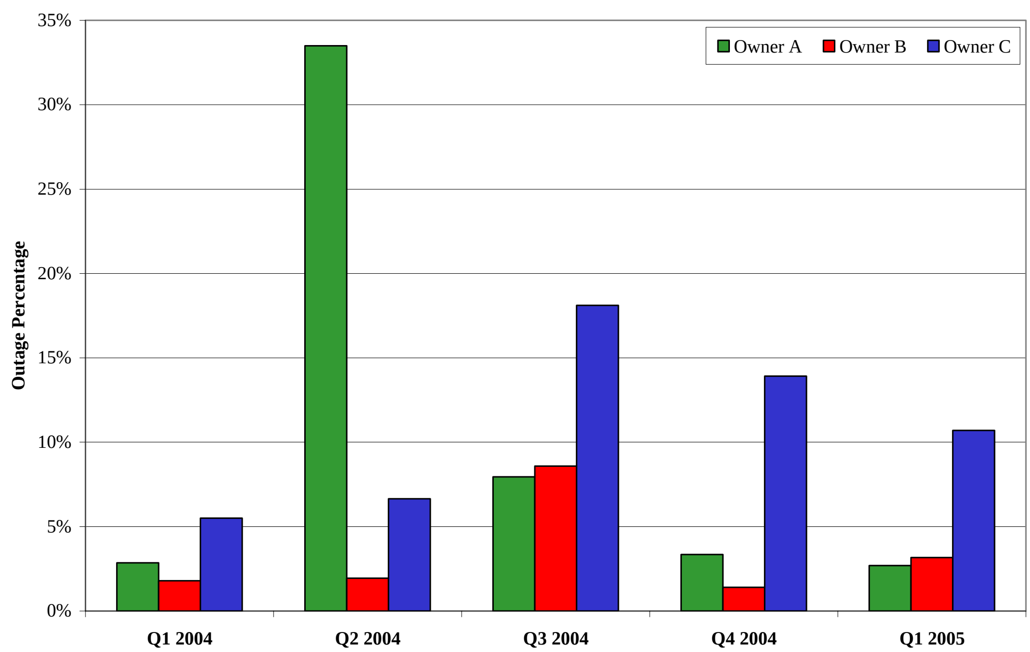


Figure 31 shows the comparison to last years outages during the same time period. It appears that Owner C is consistent in its behaviour and experiences outages more frequently in Q1 and has had an abnormal number of unplanned outages this year in particular.

Figure 31 - Outage Rates by Owner (Q1/05 vs Q1/04)

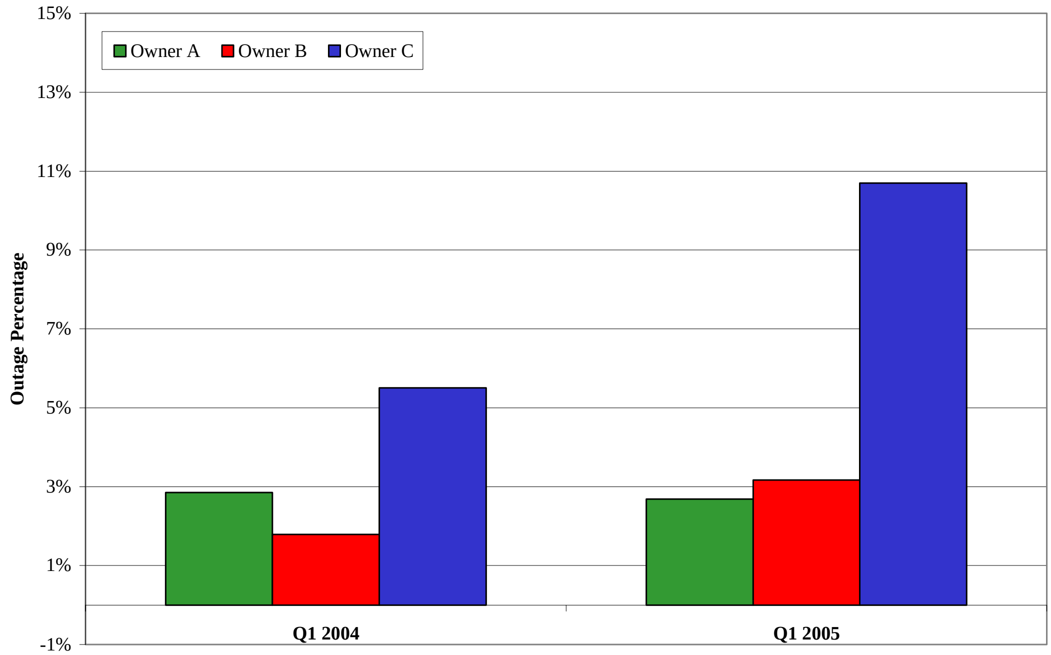


Table 3 reports the unplanned outages on a quarterly basis for the first quarter of 2005 and also provides a look at the annual unplanned outages for reference. Overall, Q1/05 unplanned outages are in line with previous years and are particularly higher for Owner C. It would be expected that Owner C would resolve many of its operational issues through the impromptu maintenance it has been forced to take this past quarter.

Table 4 - Percentage of Unplanned Outages for PPA Coal Units

	Q1/05	2004	2003	2002	2001
Owner-A	**2.6%**	6.1%	4.9%	4.2%	3.2%
Owner-B	**3.1%**	1.5%	1.5%	0.5%	1.2%
Owner-C	**8.9%**	6.3%	5.7%	10.8%	8.8%
PPA weighted average	**6.2%**	5.5%	4.9%	7.7%	6.3%

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

Each PPA document specifies the target availabilities for each of the PPA units and these targets are determined with information based on historical performance and factors such as the unit age and design. By owner **Table 4** reports the MW weighted average target availability for each coal-fired portfolio and the actual availability achieved during 2003 and 2004 along with Q1/05. The PPA owners normally achieve higher actual availability than their target availability. In Q1/05, Owner C was very near its target availability while others were well above. This is not of great concern to the MSA as the target availability is an annual criteria and Owner C has the balance of 2005 to bring up its average availability level.

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

	Target Availability 2003	Actual Availability 2003	Target Availability 2004	Actual Availability 2004	Target Availability 2005	Actual Availability Q1 2005
Owner-A	87%	92%	87%	88%	87%	97%
Owner-B	90%	94%	90%	97%	89%	97%
Owner-C	85%	88%	87%	89%	87%	89%
PPA weighted Average	87%	90%	87%	90%	87%	93%

2 REVIEW OF THE RETAIL MARKET

2.1 Code of Conduct

Compliance Plan Approvals

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

In February, 2005, the MSA approved the compliance plan of Valeo Power Corporation, which is an affiliate of ENMAX Power Corporation and ENMAX Energy Corporation.

In March, 2005, the MSA approved compliance plans for South Alta REA Ltd. and Southern Energy Ltd., affiliates of South Alta Rural Electrification Association Limited.

This brings the total number of approved compliance plans to 17.

Self Retail

In March, 2005 the MSA received a complaint from an REA (rural electrification association) member concerned about an approach being put forward by their REA as “self retail”. As described, the approach involved the REA contracting with members for energy at non-regulated rates.

The approach was described in newsletters and other communications issued by the REA. Various concerns were expressed by the REA member, including that the communications were intimidating and involved an “opt out” or negative option approach which tried to bind the REA member to a retail electricity option without their consent.

The MSA raised the member’s concerns with the REA, and brought forward additional concerns. In particular, the MSA clarified its view that the “self retail” approach would constitute retailing in the context of the *Electric Utilities Act* and the Code, and thus would (among other things) require the REA to have an approved compliance plan before it commenced retailing. The MSA also expressed its view that the negative option approach would not be allowable under the *Fair Trading Act*.

The MSA is working with the REA, and with Alberta Energy and other government bodies, to assist in developing an approach that will be acceptable under the legislation and regulations.

Interim Approvals – Review

As previously reported, 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. Aquila Networks Canada (Alberta) Ltd. later became FortisAlberta Inc.

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 the requirement for additional reporting. Each of the parties ultimately obtained final approval for their compliance plan during the month of June, 2004.

In relation to the interim approvals, the MSA undertook a review of the operations and conduct of each of those parties for the period January 1 through June 30, 2004. The review involved testing around key Code provisions, to provide assurance that the parties adequately met the other requirements of the Code despite their failure to obtain final compliance plan approval on a timely basis. The MSA retained Grant Thornton LLP to assist in the review.

Summary reports were published in March 2005, describing the review and relevant findings. They can be found on the MSA website under Reports

Code of Conduct Audits 2005

In response to a common desire to make the audits as cost and resource efficient as possible, the MSA has agreed with affected parties that the next regular Code testing should occur after 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 are also at the forefront. The changed timing will align with the change of the Code testing period, generally now being activities during July 1 through June 30 each year.

As previously indicated, the MSA is planning to have all of the regular Code testing conducted by one independent audit firm retained by the MSA, utilizing one common testing plan, rather than having each of the parties seek approval for its own auditor and audit plan. Again, the intent is to make the testing as efficient and effective as possible.

The MSA is continuing its planning discussions with the parties directly affected by these initiatives.

Access to Customer Information

The MSA continued to participate in discussions with representatives of 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 in this regard are to further the fair, efficient and openly competitive operation of the retail market.

The discussions have been productive, and have led to concrete proposals which would change the manner in which customer information is handled under the Code. It is important 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.

Regulatory Proceedings

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

EUB - Transmission – North/South

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

Apart from the magnitude of the proposed transmission upgrade(s), the Application was particularly significant in that the Alberta Department of Energy requested, and received, permission to intervene. Further, the proceeding took into account the new *Transmission Regulation*.

Final argument was heard in January 2005, with a decision to be issued in early Q2 2005. The decision was in fact issued April 14, 2005 (2005-031), and will be discussed in the MSA's Q2 reporting.

EUB - Article 24 Application

In August, 2004, the AESO submitted an application to the EUB for amendments to the existing Article 24 of the ISO Tariff (Application 1357161).

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 should be referred to the MSA.

Ultimately, the EUB determined to proceed to hear the Application. A hearing was set down for April, 2005. However, the matters were subsequently put on hold to take into account relevant policy initiatives which had been commenced by Alberta Energy. To the extent that the matters still require a hearing after the conclusion of the policy initiatives, the EUB has anticipated and reserved a process.

The MSA published a report pertaining to TMR in February, 2005, a copy of which can be found on the MSA website.

BCUC – Open Access Transmission Tariff

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

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

While the MSA did not directly intervene in the proceeding, certain of its views were brought into evidence. In particular, the proceeding took into evidence the 2003 MSA Annual Report and an MSA Report entitled *A Review of Imports, Exports, and Economic Use of the BC Interconnection* published January 10, 2005 on the MSA website (and which can be found there under Reports).

The MSA will report on the BCUC decision in coming months.

FERC – Enron

The Federal Energy Regulatory Commission (FERC) has been conducting a broad "show cause" proceeding into the activities of various Enron entities during the period leading up to the bankruptcy of those companies. There are various lawsuits involving Enron (through its trustees) and other parties, dealing with contracts entered into by the various Enron entities.

One of the parties engaged in the FERC proceeding and also in litigation with Enron is Snohomish Public Utility District, a Washington State utility. Those matters received considerable media attention in Alberta after Snohomish made public allegations and evidence around Enron's activities in Alberta during 1999 and 2000.

The MSA had previously investigated Enron activities during that period, and had referred certain matters to the federal Competition Bureau pursuant to its jurisdiction under the *Competition Act.* The Competition Bureau determined at that time that it did not find evidence to show a contravention of that Act, and closed its inquiry accordingly.

The MSA reviewed the new information obtained and concluded that the Enron activities had in fact been dealt with by the MSA in 1999 and 2000 to the full extent of its jurisdiction under provincial law. Further, the MSA concluded that the rule changes put in place as a result of the MSA investigation in 1999 had worked to prevent reoccurrence of the activities at issue.

As to federal law, in light of the new information the MSA asked the Competition Bureau to reopen its previous inquiry or to initiate a new inquiry into the activities, insofar as implications under the *Competition Act.*

The MSA issued two news releases in respect of these matters, one in February 2005 and the second in March 2005, which can be found on the MSA website under Notices and Decisions.

The Competition Bureau is continuing its review into the matters, and the MSA is continuing its monitoring and communications with other parties as appropriate.

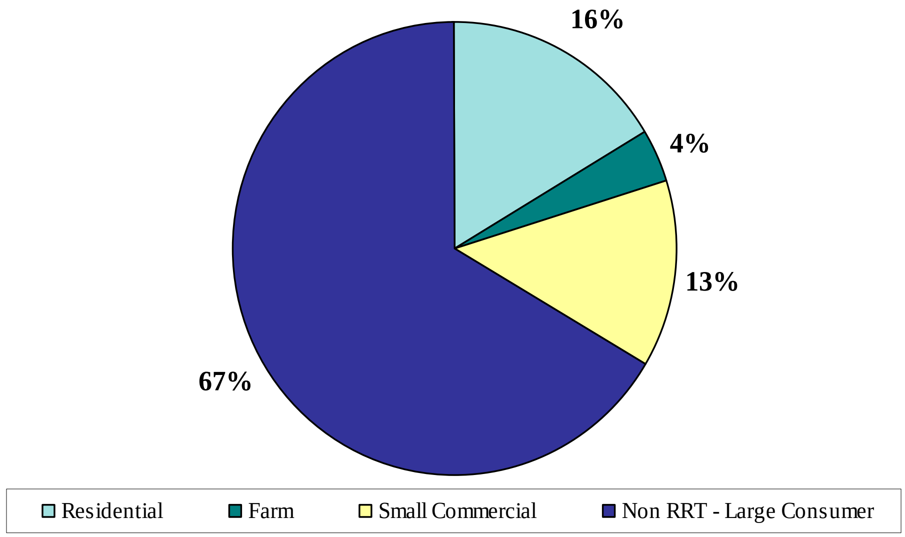
2.2 Retail Market Metrics

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

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

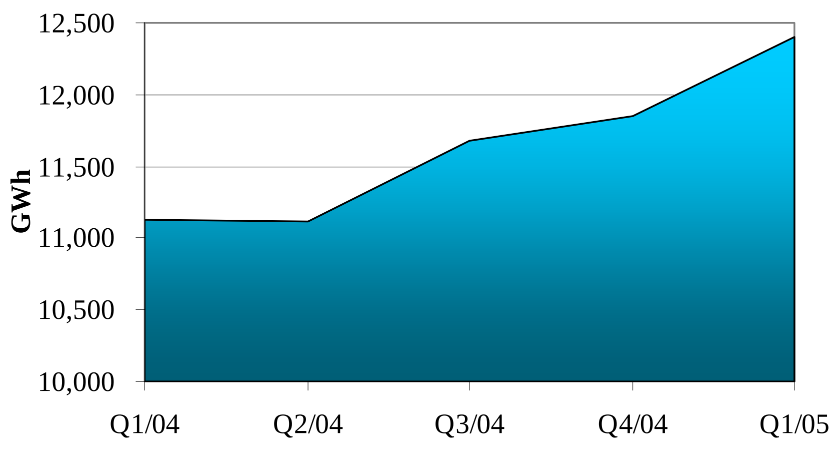
An overview of Alberta’s consumption by category is provided below in **Figure 32**. For Q1, 2005, the Residential market with over one million customer sites consumed about 16% of the total internal load. The Farm category represents approximately 4% and the Small commercial sites encompass about 13% 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 67% of the provincial internal load.

Figure 32 - Consumption by Category (Q1/05)



It can be challenging to identify trends in retail market share due to month to month variability in total system demand. Changes in weather patterns as well as provincial economic growth cause large deviations in overall demand for electricity. **Figure 33** provides a context for the market share by load graphs by reviewing the fluctuation in load by quarter. There is a clear upward trend in electricity consumption for the province which is not surprising considering the strong economic growth that has been experienced in recent months.

Figure 33 - Alberta Site Consumption



As of March 31, 2004 there were 116 active retailers in the Alberta electricity market, 80 of which are self-retailers.

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.

In an effort to provide more insight on the makeup of the Alberta retail electricity market, **Figure 34** displays the consumption continuum of retail customer sites on a percentage basis.

Figure 34 - Retail Customer Distribution by Consumption

SMALLER USAGE ⟷ LARGER USAGE

Less than 62.5 MWh/Q	62.5 to 249 MWh/Q	250 to 1,249 MWh/Q	1,250 to 2,499 MWh/Q	Over 2,500 MWh/Q
98.8%	0.8%	0.35%	0.05%	0.02%

The figure shows that on a percentage basis, 98.8% of all sites are included in the under 62.5 MWh/ quarter consumption category. The quantity 62.5 MWh/ quarter is equivalent to 250 MWh annually which is the current cutoff level for RRT as defined in government regulations.

This category would include most of the residential customers and smaller businesses. As you move along the continuum, the middle range of statistics would represent larger users such as larger condominiums, businesses and office buildings. The final category is probably larger industrial complexes and account for only around 200 sites in the entire province.

There are approximately 1.4 million meter sites in Alberta and it should be noted that some customers may possess more than one site making a straight evaluation among sites and customers difficult.

Typically most sites with higher consumption are equipped with interval meters rather than the mechanical or cumulative meters that need to be read regularly by meter readers. These interval meters have the capability to transmit consumption data multiple times per hour at regular intervals. This technologically advanced method of data collection enables load settlement entities to track usage patterns more accurately and allocate costs appropriately.

Figure 35 - Consumption by Meter Type

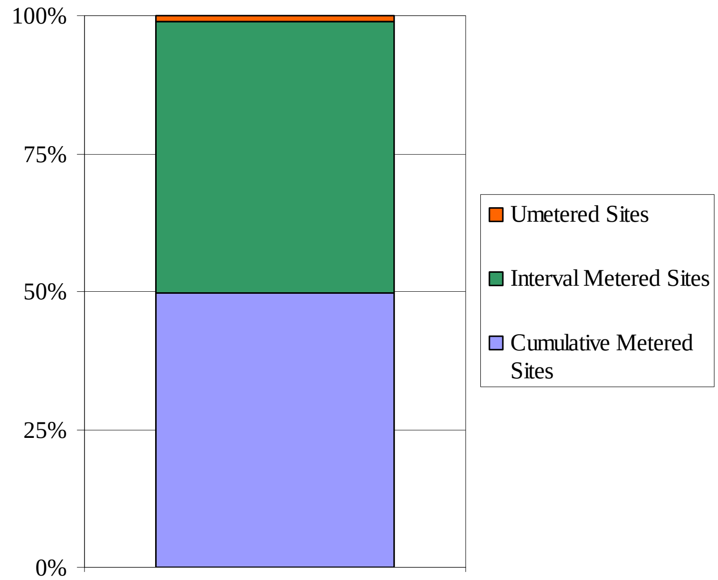


Figure 35 demonstrates that while cumulative meters account for the over whelming majority of sites (approximately 98% of all sites are cumulative metered sites) the bulk of the power gets consumed by interval metered sites which are larger industrial sites.

There are about 5,500 interval meters in the province representing less than ½ a percent of total sites. These interval metered sites use approximately one half of the total electricity in the province.

Unmetered sites include items such as traffic lights and street lights which are still allocated energy charges but due to their routine operation, their consumption can be accurately estimated without the use of metering devices.

At the end of 2004, Alberta Energy Savings L.P., an affiliate of the Energy Saving Group, entered the Alberta market and began to act as an energy retailer focusing on providing 4 and 5 year energy contracts to all customer segments. Alberta Energy Savings L.P. purchased a large number of contracted mass market customers from EPCOR and entered into a 5 year agreement to have EPCOR continue the billing and collection function for their organization. EPCOR did not sell their RRT customers and will remain as an RRT provider. As a result of this new entry, readers will notice a shift in many of the reoccurring metrics, including the addition of a new retailer in several of the following graphs.

Figure 36 - Current Retailer Market Share by Load (Q1/05)

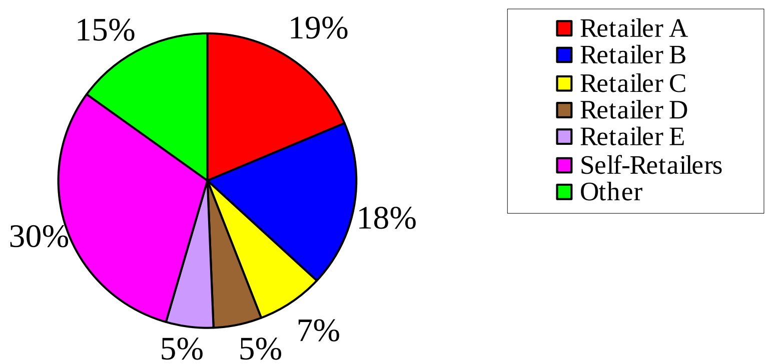
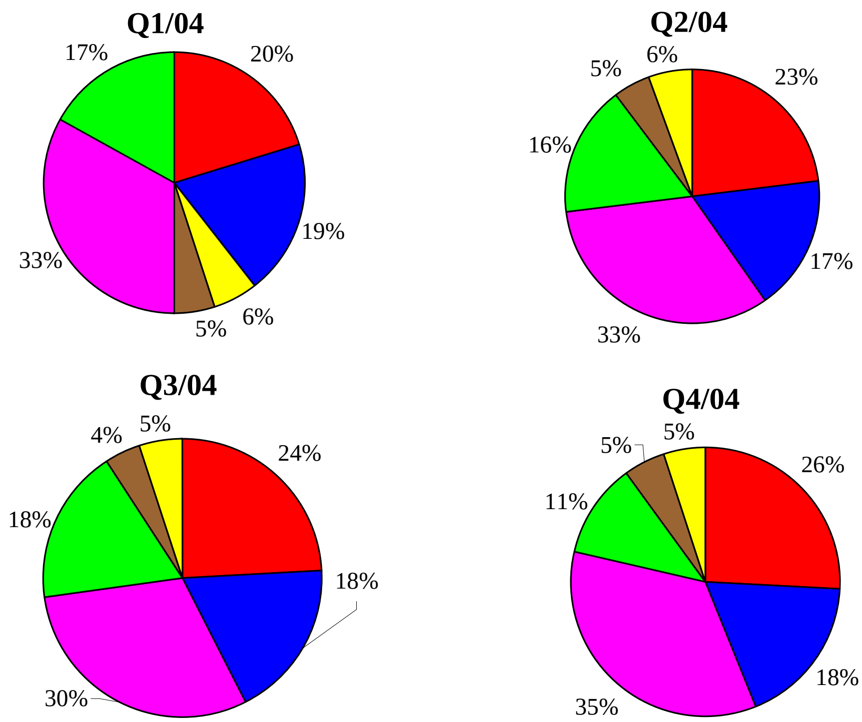


Figure 36 shows the overall provincial market share of retailers for Q1/05. The largest five retailers are servicing over 55% of the total provincial load. Self-retailers, usually large industrial organizations, make up another 30%, while assorted smaller retailers are competing for the remaining 15% 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, D and E). This is largely due to the entry of a new retailer. "Other" refers to all other retailers that have a market share of less than 5 %. Since the last assessment in Q4, the "Other" category has increased its share by 4 % while the "Self Retailer" portion has decreased by 5%.

Figure 37 - Historical Retailer Market Share by Load



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

Figure 37 provides a look at the changes in retailer market share in the previous four quarters for comparison to the current Q1/05. 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 38 shows retailer market share by customer class for Q1/05. 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 new entrant in this market has will likely continue to cause changes in the market shares in the Residential category.

In the Farm – RRT Eligible category, market shares have shifted somewhat as new retailing entities operate in this market. This category now has 5 retailers with market shares of 5% or better. 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 Q1/05, 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 five retailers with at least 5% market share adds up to 78% of the total load. Again, for some customers, self-retailing will be appealing to those wishing to have more control over the energy portion of their business.

Figure 38 - Q1/05 Retailer Market Share by Customer Class

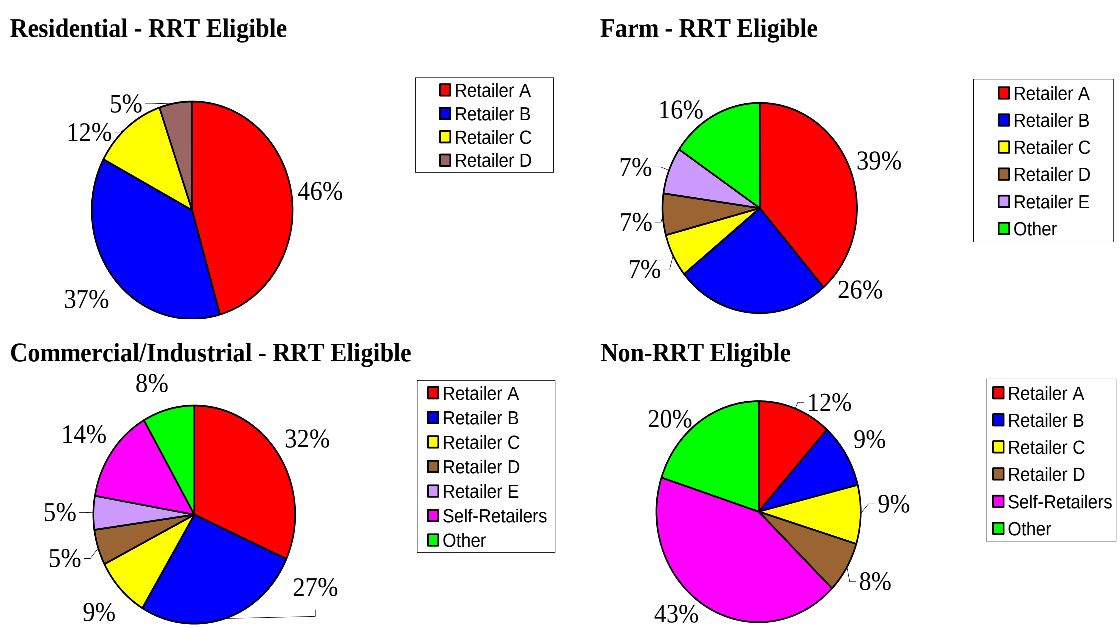


Figure 39 is another way to look at the shift in market share in the four categories. The picture is useful in providing an overall view of the change in market share over the past two years and demonstrates the dynamic nature of the retail market. It is worthwhile to note the entry and exit of new retailers in the graphs which clearly shows the ongoing battle for market share in certain parts of our retail market.

Figure 39 - Change in Categories (Q1/05)

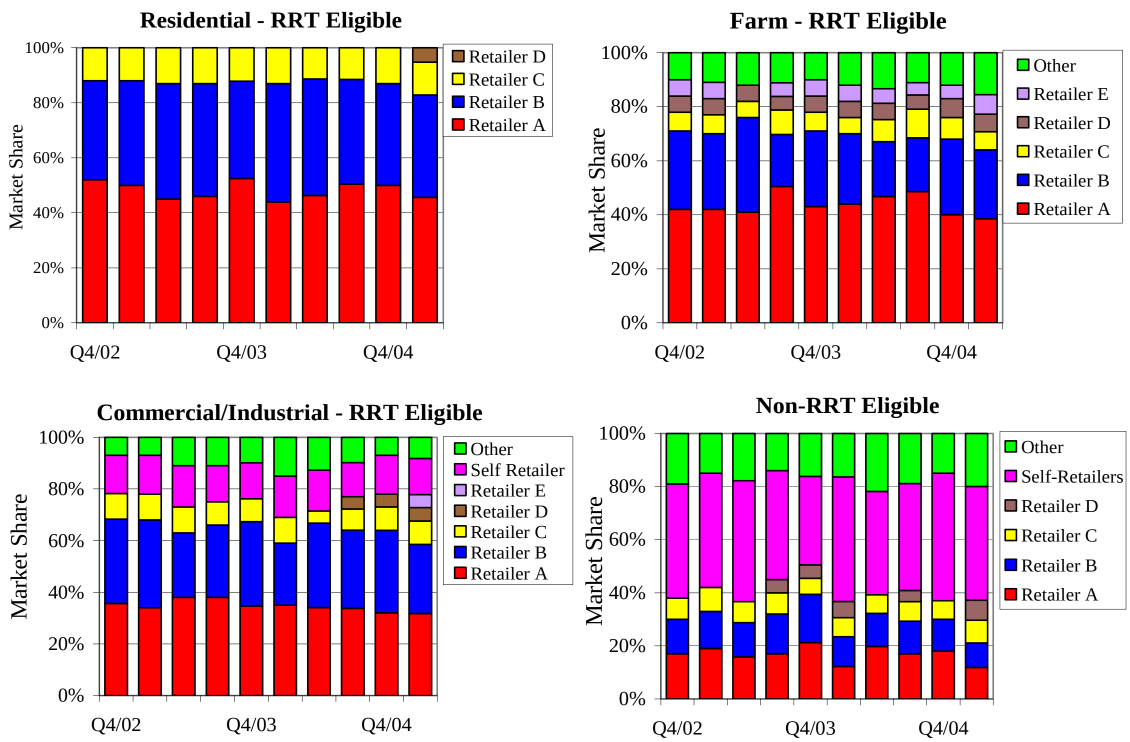


Figure 40 shows the overall progression of customer sites off of the RRT to competitive electricity contracts. As show in the figure, this metric has held relatively steady but has begun moving up over the last two quarters. As of March 31, 2005, 8.6% of all RRT eligible customer sites have chosen to enter into a competitive contract with a retailer. The increase in switching can be partially attributed to an improvement in data quality.

Figure 40 - Progression of Eligible Sites Switching off RRT

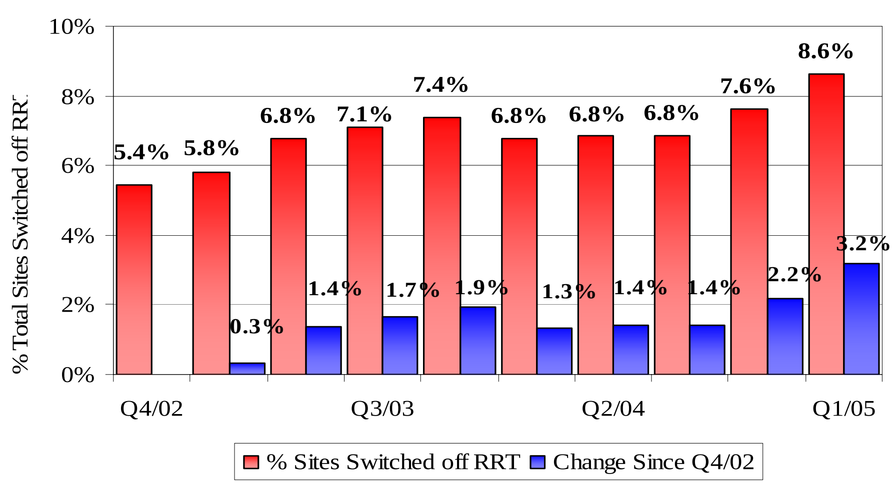


Figure 41 - Progression of Eligible Sites Switching off RRT by Customer Type

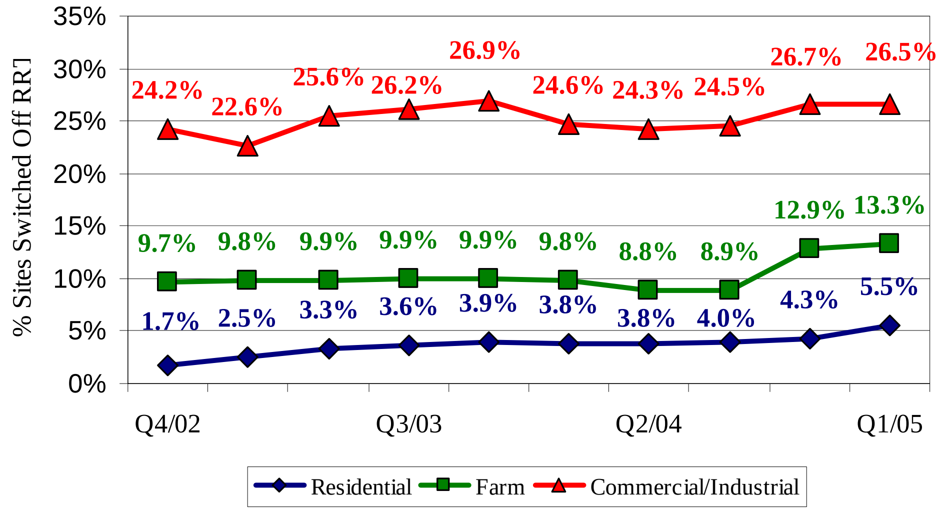


Figure 41 shows the progression of RRT eligible sites switching off RRT by customer type. Switching results are encouraging in all categories as no category has given up any substantial ground.

Switching rates in the Commercial/Industrial – RRT eligible category is the only one to experience any decrease (0.2%) and have reached the level of 26.5%. This decrease is of no significance on its own but we will continue to monitor the switching levels as it indicates retailers are able to find customers in this category who find competitive contracts an attractive option to the regulated rate. These customers are often willing and sufficiently savvy to enter into energy contracts and are an important indicator of a competitive market as they are still RRT eligible.

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.

As was shown in a previous graph, the Non-RRT eligible category is the largest users of electricity in the province at 67% of the total. As such, it stands to reason that the majority of retailers would be active in this market.

2.3 Settlement System Code Monitoring

The MSA keeps abreast of many aspects of the Settlement System Code (SSC) with the intent of the monitoring the effectiveness of the settlement process in Alberta.

The MSA has developed a number of metrics related to settlement and enforcement of the SSC. These metrics are intended to raise a flag on 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 settlement process.

Complaints

The SSC uses PFECs, PFAMs and Notices of Dispute as tools to resolve disputes resulting from the settlement process and calculations. PFECs occur prior to final settlement while PFAMs occur after or post-final settlement. 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 5** summarizes PFEC and PFAM tracking for Q1/05.

Table 6 - PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q1/05	222	56	202	11	67	NA
Q4/04.	957	251	7	979	222	NA
PFAM						
Q1/05	20	141	26	102	33	(2,648,937)
Q4/04.	137	53	13	157	20	(1,710,555)

The table shows that the number of PFECs submitted have decreased considerably from last quarter. This can largely be attributed to a single LSA that corrected an IT matter and has been able to work their way through many of the previously unresolved PFEC issues. These statistics will continue to be closely monitored by the MSA to ensure the PFECs are dealt with expeditiously.

The overall volume of PFAMs submitted increased during Q1/05. The number of incoming PFAMs is an indicator that the LSAs are receiving challenges from retailers regarding final settlement output, however the significant quantity of rejected PFAMs suggest that many of the retailer issues are not a result of the LSA settlement process.

Having 33 unresolved PFAMs is not an unusually high number however, the MSA will keep a close watch to ensure these do get resolved in a timely manner.

Notices of Dispute are used to initiate the dispute process as outlined in the SSC. This process requires parties involved in a dispute to notify the MSA of the negotiation efforts that have been made to resolve the dispute. If a dispute cannot be resolved by negotiation, then mediation or binding arbitration can be pursued and the MSA will be made aware of the outcome. Thus far in 2005, there have been no Notices of Dispute reported to the MSA.

UFE

The MSA has collected data regarding UFE in the form of UFE Reasonable Exception Reports for each of the 10 settlement zones in the province. These public 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 6** summarizes the UFE Reasonable Exception Reports (UFE reports) filed in Q1/05 relative to those filed in the previous quarter.

Table 7 - Summary of UFE Reasonable Exception Reporting

Quarter	Outstanding	New	Resolved	Unresolved
Q1/05	12	21	14	19
Q4/04	19	10	17	12

At the end of 2004 there were 19 unresolved UFE reports. By the conclusion of Q1/05 this number decreased to 12. This shows that the LSAs are slowly dealing with exceeded UFE tolerances in a somewhat acceptable manner[3].

Some LSAs are much better performers than others with one particular settlement zone being an overwhelming hindrance to the overall performance of the LSAs. For this particular area, 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 over the course of the past two quarters.

Moderately positive results have come out of recent initial settlement figures but we would expect to see continuous progress in the resolution of these UFE issues before the end of Q2, 2005. If improvement is not evident, we would expect the AESO to take strong action to compel better performance in the Ponoka settlement zone.

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-

[3] Most unresolved UFE reports are attributable to one individual settlement zone.
[4] See Section 4 of Appendix C of the SSC.

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. No Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices were filed in 2004 or to date in 2005.

Table 7 shows that no Non-Compliance notices have been issued by the AESO in Q1 2005. This appears to indicate that overall compliance with the SSC is going well.

Table 8 – Q1/05 Non-Compliance Notices

	Non-Compliance Notices Issued			
2005	**Level 1**	**Level 2**	**Level 3**	**Level 4**
Jan	0	0	0	0
Feb	0	0	0	0
March	0	0	0	0
YTD Total	**0**	**0**	**0**	**0**

3 MARKET ISSUES

3.1 TPG / IDP Update

The MSA is leading a process change whereby outage and derate information on which the currently published outage reports are based, will be submitted by participants via the AESO ETS system rather than via e-mail. The process of outage report production will then be fully automated and outage reports will be available near real time, reflecting all known outages and derates at that point in time. This process is currently in the late stages of implementation.

4 OTHER MSA ACTIVITIES

4.1 Stakeholder Meetings

The MSA recently held spring stakeholder meetings in Edmonton and in Calgary. The presentation given at these meetings can be viewed at: http://www.albertamsa.ca/files/March2005StakeholderMeeting.pdf . The MSA annual report and Year in Review report were not available for distribution at these meetings however the reports can be accessed from the MSA website.

4.2 MSA Survey

The MSA is currently conducting the second of its annual stakeholder surveys in order to gather valuable stakeholder feedback on how the MSA pursues its role and responsibilities. The MSA thanks stakeholders for their valued participation in this survey.

4.3 Changes to MSA Team

The MSA has recently added Matt Ayres to the team in the capacity of Senior Analyst. Matt holds a Ph.D. in Economics and previously led the electricity group at CERI. Part of Matt's mandate will be the development of additional new market metrics, which we expect will result in some revision of the MSA quarterly report. The MSA would like to welcome Matt on board.