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MSA Report

Quarterly Report

April – June 2003

30 July, 2003

Market Surveillance Administrator

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PREAMBLE

New Electric Utilities Act (EUA) and Regulations

As anticipated, the new *Electric Utilities Act* came into force June 1, 2003, along with various related regulations. The new Act reflects a changed industry structure, with the Independent System Operator, Balancing Pool and Market Surveillance Administrator (MSA) recognized as new corporate entities, each under a distinct governance structure. By repealing the previous legislation, the new Act provides that the Power Pool Council ceases to exist.

Along with other duties, the Independent System Operator entity (AESO) has been given responsibilities previously handled by the Transmission Administrator. The Balancing Pool entity has been assigned duties similar to those previously handled by the Power Pool Council and the Balancing Pool Administrator for the Balancing Pool function.

The MSA entity is given broad responsibilities under the new Act. For the most part, the MSA mandate reflects the duties and responsibilities handled by the MSA under the previous legislation; however, the MSA is now also mandated to review matters pertaining to transmission insofar as they are related to the new Act, regulations, and the ISO rules, and the fair, efficient and openly competitive operation of the market.

The individual appointed as the Market Surveillance Administrator is selected by the Minister of Energy, upon recommendation made by the Chair of the Alberta Energy and Utilities Board (EUB). The Chair of the EUB has several functions in relation to the MSA entity: (i) approval of the annual budget of the MSA and forwarding of the approved budget to the AESO for payment; (ii) receiving the annual report of the MSA and forwarding that report to the Minister; (iii) establishing a pool of qualified individuals from whom persons may be selected to serve on a tribunal; (iv) receiving and acting upon any notice from the MSA for the calling of a tribunal; (v) receiving and responding to complaints filed in relation to the conduct of the MSA.

As referenced above, the new Act establishes a three member tribunal for the purpose of hearing matters brought by the MSA. The tribunal panel will consist of one EUB member who is never the Chair of the EUB, and two independent persons, selected by the Chair of the EUB. The tribunal is given broad powers to address inappropriate conduct by market participants, or to recommend changes to market rules. Appeal of a tribunal order lies to the Court of Appeal of Alberta, and may only be made on questions of law or jurisdiction.

Pursuant to the new Act which repealed the previous legislation of the same name, the Power Pool Council was given a limited existence after June 1, 2003. The reason for this was the changed industry structure implemented by the new Act, including the creation of the new Independent System Operator, Balancing Pool and Market Surveillance Administrator entities which would become successors in interest (and responsibilities) to the Power Pool Council.

The Power Pool Council was continued after the new act came into force, for the express purpose of allocating its assets and liabilities amongst the new entities and designating which party would hold responsibility for decisions made by the Power Pool Council before June 1, 2003.

As such, the final piece of business conducted by the Power Pool Council was the formal determination required pursuant to section 151 of the new Act. In respect of the MSA, apart from relevant assets and liabilities passed from the Power Pool Council to the new MSA entity, those decisions taken by the Power Pool Council under previous legislation or regulation in relation to the mandate or a responsibility or power of the MSA are to be orders of a tribunal.

MARKET HIGHLIGHTS

Proclamation of the new Electric Utilities Act occurred as expected on June 1 bringing the new Act into force. With the new Act, the MSA has gained additional scope to carry out its mandate of ensuring a fair, efficient, and openly competitive market.

- The average price of electricity in the Alberta wholesale spot market in Q2/03 was $50.94/MWh; down substantially from $83.94 in Q1/03.
- Volatility was marginally higher in Q2/03 relative to last quarter but was primarily driven by significant outages in late June.
- Alberta's PPA units have performed well over the first half of 2003. The shift away from planned outages and into unplanned outages that was seen last year appears to be reversing itself, with a greater balance between planned and unplanned outages being recorded so far this year.
- Gas prices have not softened as they usually do going into summer due to strong demand for replenishing gas storage in the Northeast U.S. This suggests high gas prices in the upcoming winter.
- Export volumes to BC Hydro have increased significantly during Q2/03 reaching a 15 month high in May. BC Hydro had anticipated a very dry spring until late spring precipitation returned reservoir levels to within 96% of average.
- 6.0% of RRO eligible customers have chosen to sign a competitive contract. This represents an increase of 1.4% since the end of Q4/02.
- The MSA has completed its review of pool price forecasts by the AESO and highlights are presented herein.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

As is normal market activity, prices did fluctuate in the Alberta market through Q2/03, however price spikes seen in the quarter were limited in duration and were not attributed to any untoward market activity. In a properly functioning market, periods of scarcity send a price signal which prompts the market to respond and thus to correct the imbalance which tends to return market price to previous levels. Price levels also need to be viewed in the context of not only meeting the variable plant operating costs of participants but also in allowing for recovery of capital and profit which provides incentive for additional generation to be built.

On a monthly average basis, pool prices were significantly lower in Q2/03 as compared to last quarter, as shown in **Figure 1** and **Table 1**, but moderately higher relative to prices in the same period a year ago. The average monthly price has trended downward since March when it reached $89.80/MWh after a generally increasing trend observed since July 2002. The price duration curves in **Figure 2** show that pool price through Q2/03 remained below Q1/03 levels almost 100% of the time for the quarter although above Q2/02 levels the majority of the quarter. Pool price trends have continued to be closely correlated with gas prices as can be seen in Figure 3. This correlation is underscored by a calculated correlation coefficient between monthly average pool price and monthly average Alberta gas price of 0.83 over the last 15 month period. Volatility of pool prices increased month on month through Q2/03, as it did in Q2/02. The higher volatility seen in June was largely a function of price excursions over the last week in June which are attributed to outages at both Battle River 3 and Sundance 3. Although price volatility moved higher through the quarter, as seen in Figure 2, there were fewer price spikes above $250/MWh in Q2/03 than both last quarter and Q2/02.

Table 1 - Pool Price Statistics

	Average Price	On-Pk Price	Off-Peak Price	Std Dev[1]	Coeff. Variation[2]
Apr -03	51.68	62.57	36.71	50.74	98%
May -03	56.50	69.57	39.94	62.87	111%
Jun -03	44.47	59.57	25.59	59.25	133%
Q2 / 03	**50.94**	**63.90**	**34.08**	**58.09**	**114%**
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%**
Apr -02	45.03	57.73	27.60	33.47	74%
May -02	40.44	49.66	28.74	64.99	161%
Jun -02	46.23	71.59	14.52	111.12	240%
Q2 / 02	**43.86**	**59.66**	**23.62**	**76.70**	**175%**

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

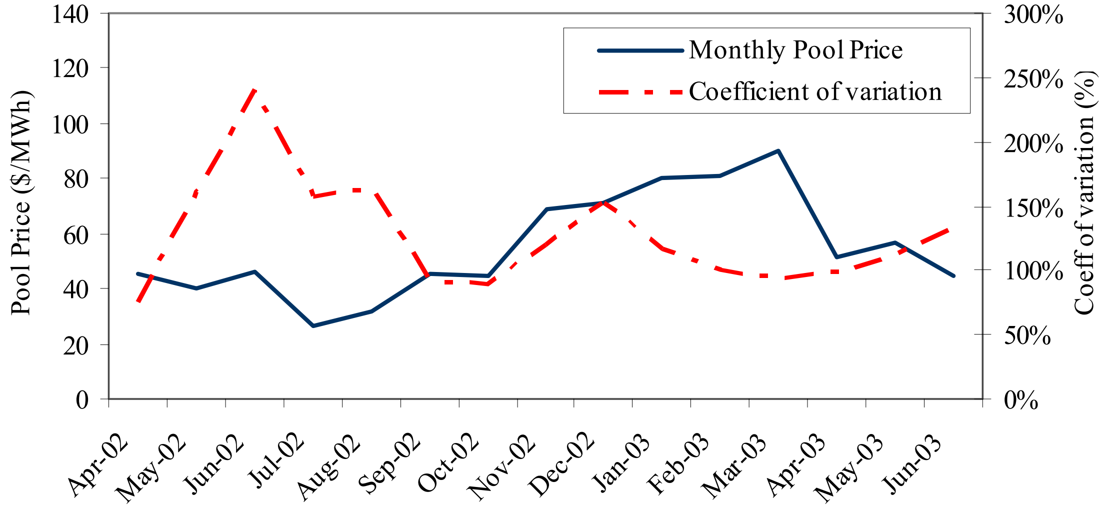
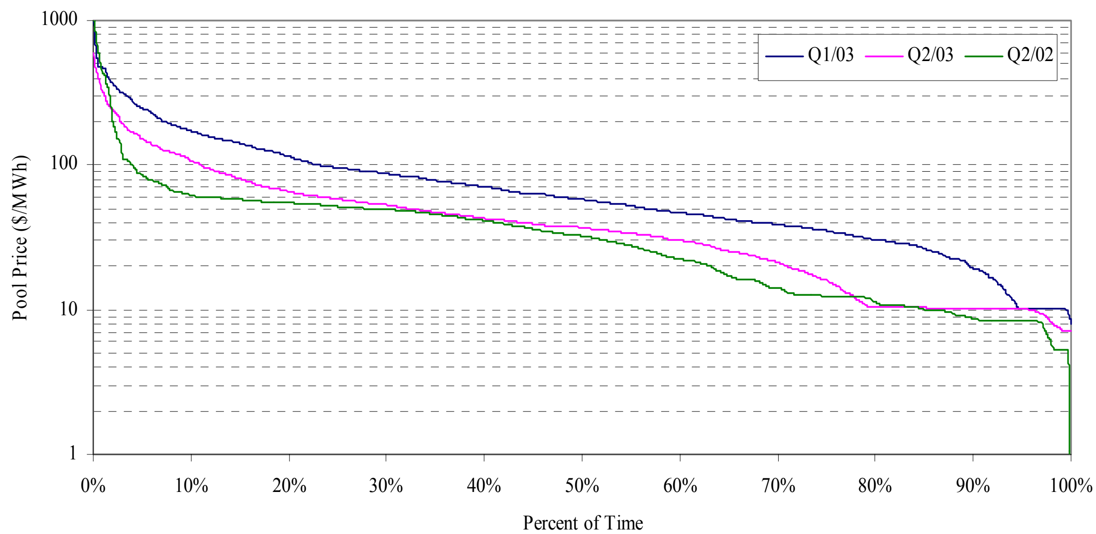


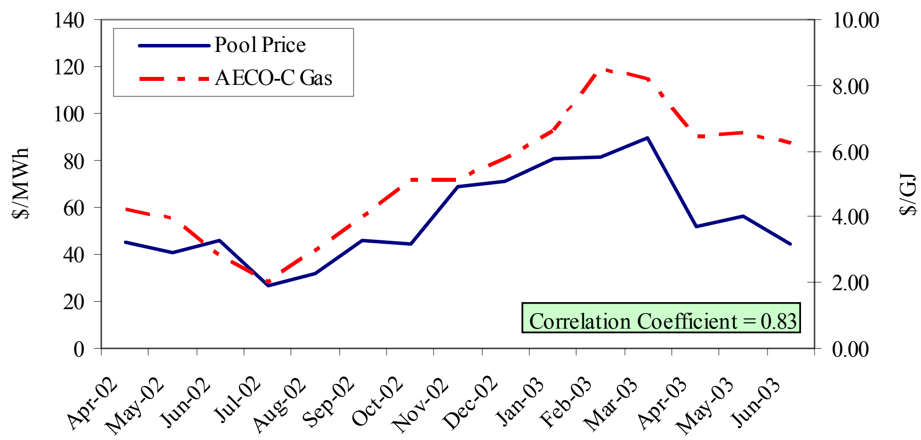
Figure 2 - Quarterly Pool Price Duration Curves



1.2 Natural Gas Prices

Alberta gas prices remained relatively flat through Q2/03 in the $6.50/GJ range as shown in **Figure 3**, which was down significantly from levels seen in Q1/03. Pool prices and Alberta gas prices have remained strongly correlated as indicated by a monthly correlation coefficient of 0.83 over the prior 15 month period, which was down marginally from the 15 month period ending March 2003. The strong correlation of gas price to pool price is due in large measure to the fact that the marginal generating unit in the Alberta system is often gas-fuelled, therefore, the market price of gas tends to flow through to the energy market via the offers of gas generators. In Q2/03 gas generators and co-generation units (also gas-fired) set marginal price approximately 51% of the time in on-peak hours vs. 48% of the time for coal generators. Historically, we have observed gas units setting SMP close to 50% of the time on an on-peak basis.

Figure 3 - Pool Price with AECO Gas Price



1.3 Price Setters

The profile of the top 5 participants (unnamed) who have set pool price most often through Q2/03 are shown in **Figure 4**[1] together with the weighted average price at which they set system marginal price (SMP). The leading on-peak price setter in Q2/03 set price 29% of the time at a weighted average SMP of $50.53/MWh while the leading off-peak price setter set price 26% of the time at a weighted average SMP of $15.04/MWh. Figure 4 demonstrates that no one generator had a dominant market position in terms of setting the price. No one generator set price 30% of the time in Q2/03 while the same period last year showed a higher concentration in price setting distribution, which suggests an improvement in market efficiency.

[1] Generator labels represent the same generators in each of the three charts in Figure 4.

Figure 4 - Price Setters by Customer, Q2/03

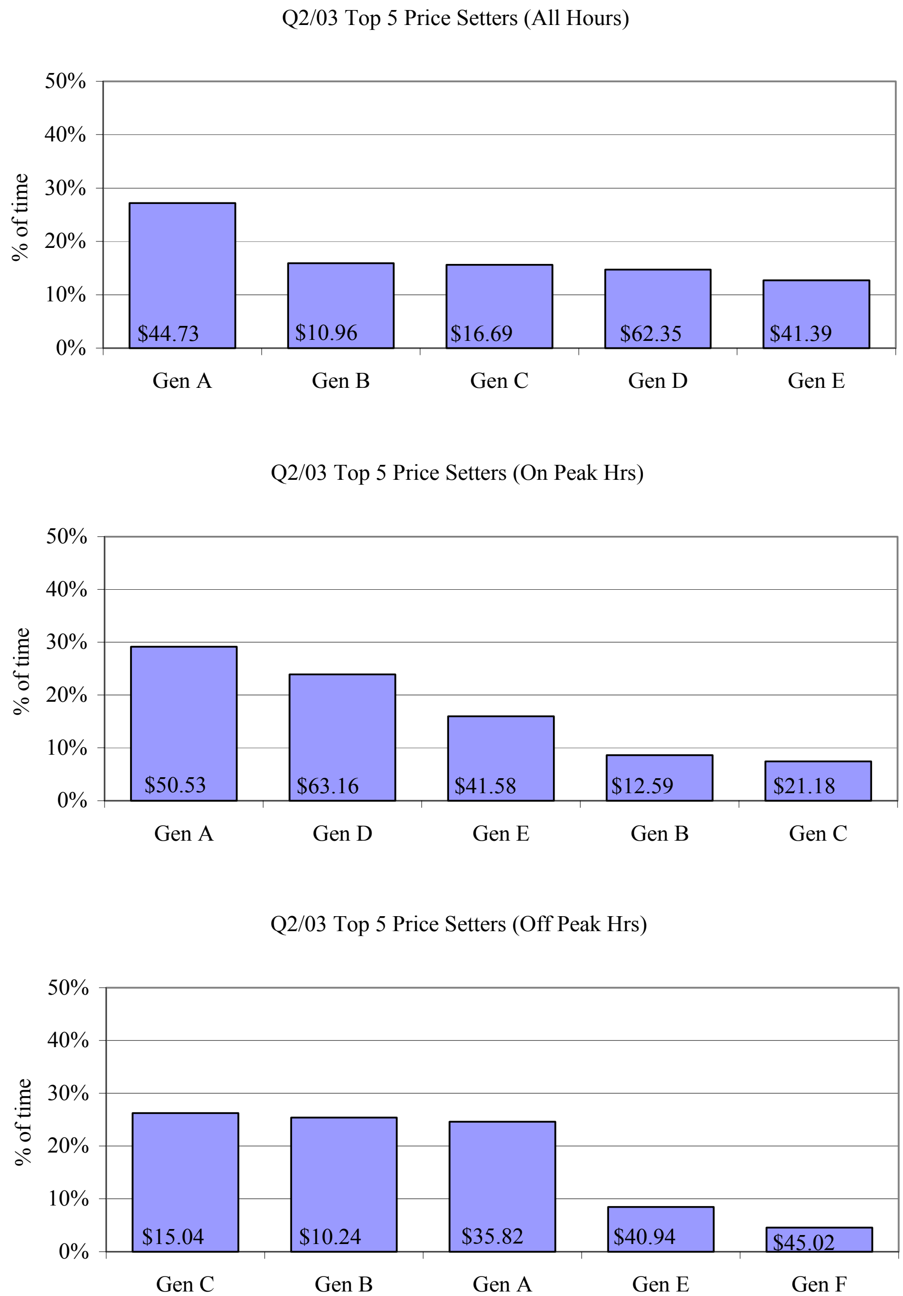
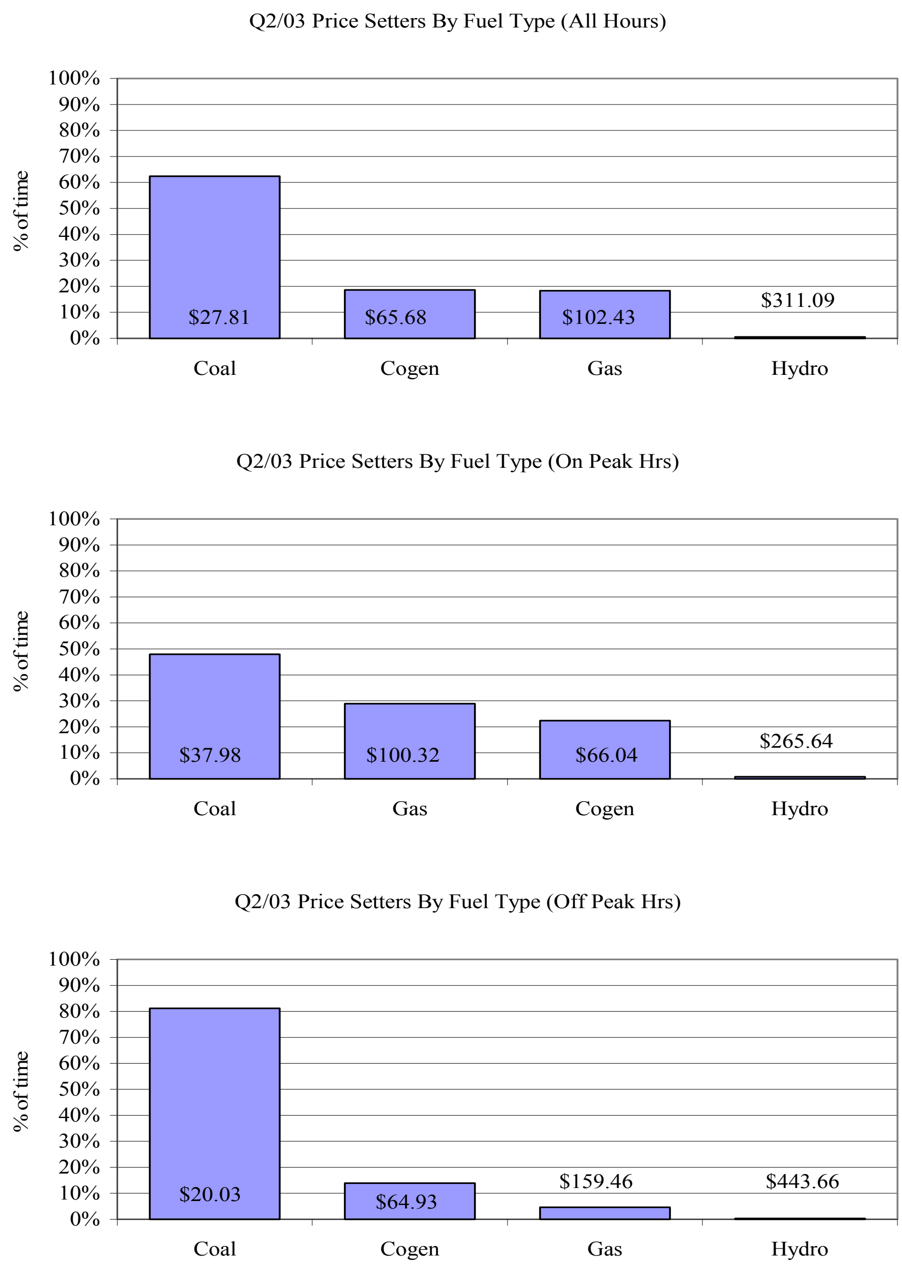


Figure 5 shows the price setting distribution in Q2/03 by fuel type. Since co-generation (co-gen) capacity has become a growing proportion of the generation capacity in the province, it has been segmented into a separate category in our analysis. Although nearly all co-gen capacity in the Alberta system is gas-fuelled, co-generation has a different set of operating parameters due to the operator's primary industrial process, and it is worth looking at these units separately as well as together with all

other gas units. Gas units typically set price the majority of the time in on-peak periods while coal units typically set price most often in off-peak periods due to their much lower variable operating costs. In Q1/03, coal units set price more often than gas units in on-peak periods however, in Q2/03, combining gas and co-gen units, gas and coal set price for nearly equal durations although at much different price levels as would be expected. In on-peak hours, coal set price at a weighted average SMP of $37.98MWh in Q2/03 while gas (including co-gen) set price at a weighted average SMP of approximately $85.36/MWh.

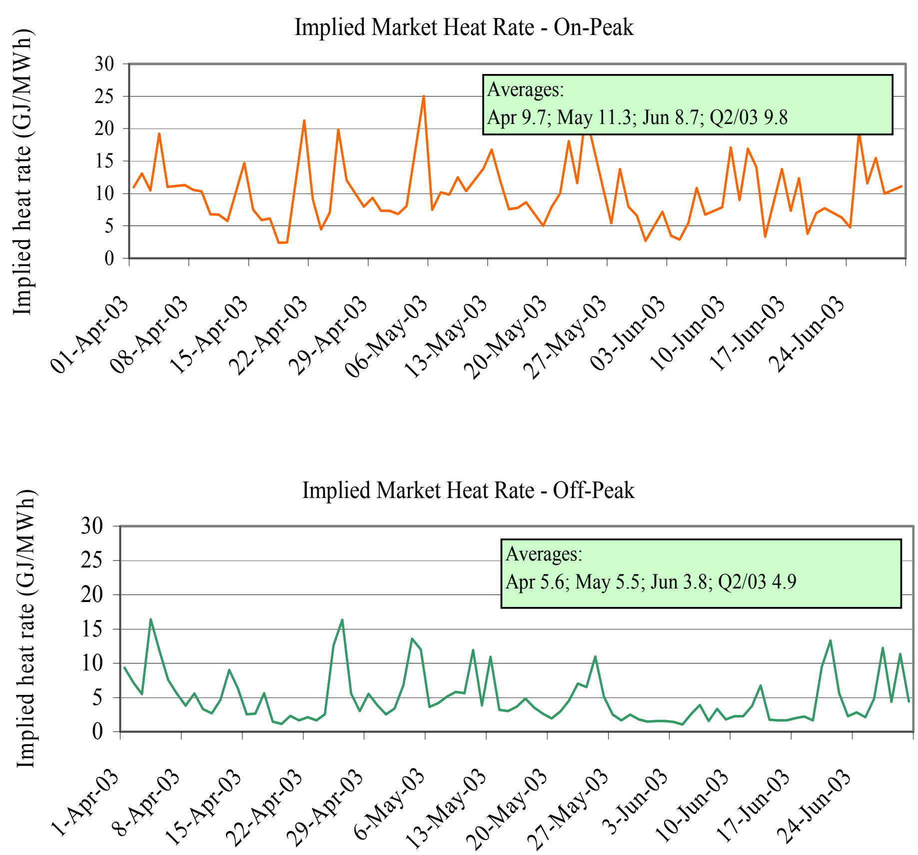
Figure 5 - Price Setters by Fuel Type, Q2/03



1.4 Implied Market Heat Rate

The implied market heat rate is a measure that provides some insight into market profitability from the perspective of gas-fuelled generating assets, or potential new gas-fuelled entrants assessing the attractiveness of the market. **Figure 6** shows the daily implied market heat rate for Q2/03 on both an on-peak and an off-peak hours basis. The figure shows that although there were intermittent periods where gas units had attractive economics, the average on-peak implied market heat rate over the quarter was a modest 9.8 GJ/MWh as compared to 12.5 GJ/MWh in Q1/03. In the context of gas generators in the market, older assets which would have heat rates in the 12-15 GJ/MWh range, would have on average been out of the money in Q2/03, and newer gas generators which would have heat rates on the order of 7-8 GJ/MWh would have on average, only marginally been in the money over the quarter. On an off-peak basis heat rates similarly declined quarter over quarter to 4.9 GJ/MWh from 8.7 GJ/MWh in Q1/03.

Figure 6 - Implied Market Heat Rates, Q2/03



1.5 New Power Pool Rules

With the proclamation of the new Electric Utilities Act (Act) on June 1, 2003, the AESO has begun a transition process to integrate existing Pool Rules into a new comprehensive ISO rules document which will also comprise settlement system code, Power Pool Code, and Transmission Administrator Operating Policies (TAOPs). Consolidation of Pool Code and the TAOPs into a new set of operating policies and procedures has been indicated by the AESO in this process. Under the new Act, existing Pool Rules are continued for a period of 60 days from June 1, 2003 or until those rules are repealed by the AESO. In relation to this transition process, the AESO has announced that no substantive changes to existing Pool Rules will occur however, to comply with the new Act, some changes to terminology will occur. For further details see http://ets.powerpool.ab.ca/part_info/news_articles/ISO_Rules_cover.pdf.

1.6 New Supply and Load Growth

No significant new generation was brought on line during Q2/03 although the Calpine units mentioned in the Q1/03 report came on stream on March 31, 2003. Effectively, those additional 250 MW of generating capacity were added to the system at the beginning of Q2/03 and did not benefit the system during Q1/03.

The monthly average hourly system demand for electrical energy in Q2/03 was:

- April 6927 MW
- May 6803 MW
- June 6745 MW

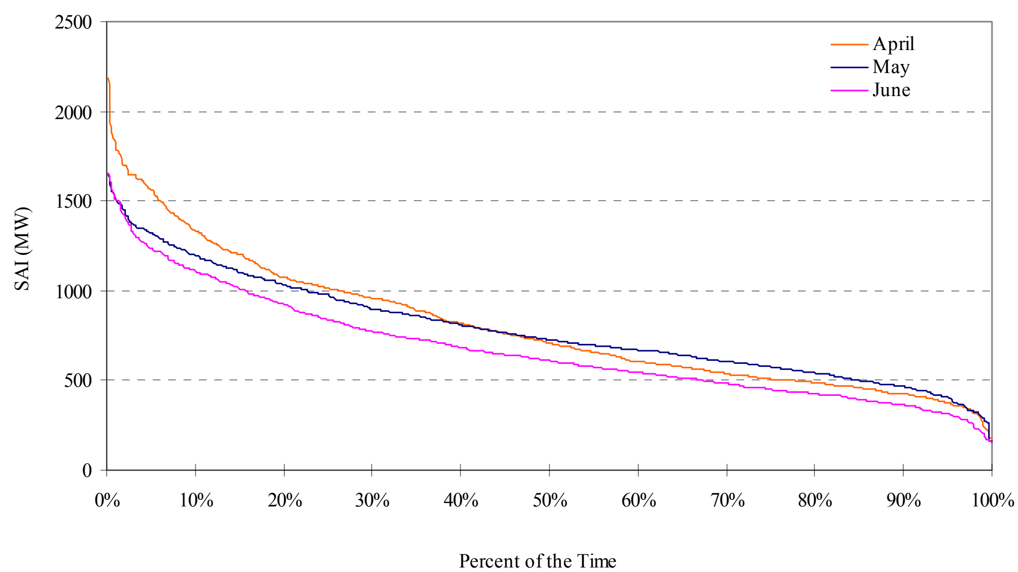
The decreasing trend in demand through Q2/03 depicts the typical seasonal effect of Alberta system demand reaching a trough in the late spring and early summer months. This effect tends to be offset somewhat by the onset of maintenance season for generators.

Peak demand in Q2/03 was 7801 MW which occurred in HE 16 on June 18 and is a decrease of approximately 1.8 % from peak demand in the same period a year ago.

1.7 Supply Availability Index

This indicator was introduced in the last quarterly report as a measure of market tightness based on the remaining volume of MW in the energy merit order above dispatch for each hour. Since this measure is intended to approximate the supply available to the system controller within the hour, any surplus tie line availability is not considered since intertie schedules are fixed 20 minutes prior to the next hour. **Figure 7** shows duration curves for SAI on a monthly basis for Q2/03 which reflects the distribution of time for which SAI was above or below a given level. The figure indicates clearly that June was the tightest month of the quarter which coincides with the month of June having the highest pool price volatility in the quarter. On a quarter over quarter basis, average supply availability increased 6% from 766 MW in Q1/03 to 812 MW in Q2/03. It should be noted that availability and price are generally negatively correlated – meaning that as supply availability decreases, price tends to increase, and vice versa. This correlation is highly dependant on the shape of the supply curve in the energy market. In Q2/03, the correlation coefficient between SAI and hourly pool price was determined as -0.47 as compared to -0.39 in Q1/03, meaning that the correlation strengthened in Q2/03 relative to previous quarter.

Figure 7 – SAI Monthly Duration Curves, Q2/03



1.8 Imports, Exports, and Prices in Other Electricity Markets

The interconnections between Alberta and neighboring markets/jurisdictions play an integral part in the operation of the Alberta electricity market. The prices in other markets affect the activity on the interties which in turn has an impact on activity (and price) in the Alberta market. **Table 2** summarizes the activity on the tie-lines for Q2/03.

Table 2 - Tie Line Activity Q2/03

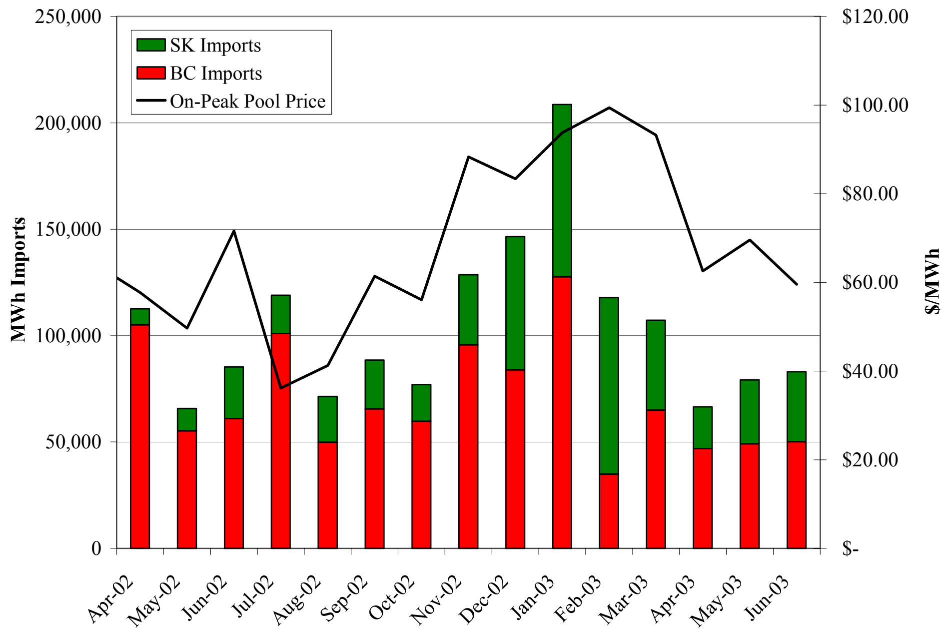
	BC			Saskatchewan			Overall		
	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)
April	46,831	112,738	(65,907)	19,720	4,577	15,143	66,551	117,315	(50,764)
May	49,159	135,521	(86,362)	30,046	1,339	28,707	79,205	136,860	(57,655)
June	50,123	90,110	(39,987)	32,897	1,564	31,333	83,020	91,674	(8,654)
Total	146,113	338,369	(192,256)	82,663	7,480	75,183	228,776	345,849	(117,073)
On-Peak	87%	22%		54%	75%		77%	24%	
Off-Peak	13%	78%		46%	25%		23%	76%	

Note: Negative net imports indicate net exports.

In all three months in Q2/03, Alberta was an overall net exporter of electricity. This is primarily due to high levels of exports flowing over the BC tie-line. In Q2/03, 98% of the exports out of Alberta flowed to the west over the BC tie-line. Only 64% of imports entered Alberta over the BC tie-line – a relatively small portion considering the BC tie-line has a nominal capacity of over five times that of the Saskatchewan tie-line.

Activity on the tie-lines has a significant impact on price. **Figures 8 and 9** plot imports with on-peak Pool prices and exports with off-peak Pool prices respectively on a monthly average basis for the April 2002 through June 2003 period. 77% of Q2/03 imports occurred during on-peak hours and 76% of Q2/03 exports occurred during off-peak hours, therefore comparisons with on and off-peak prices are appropriate.

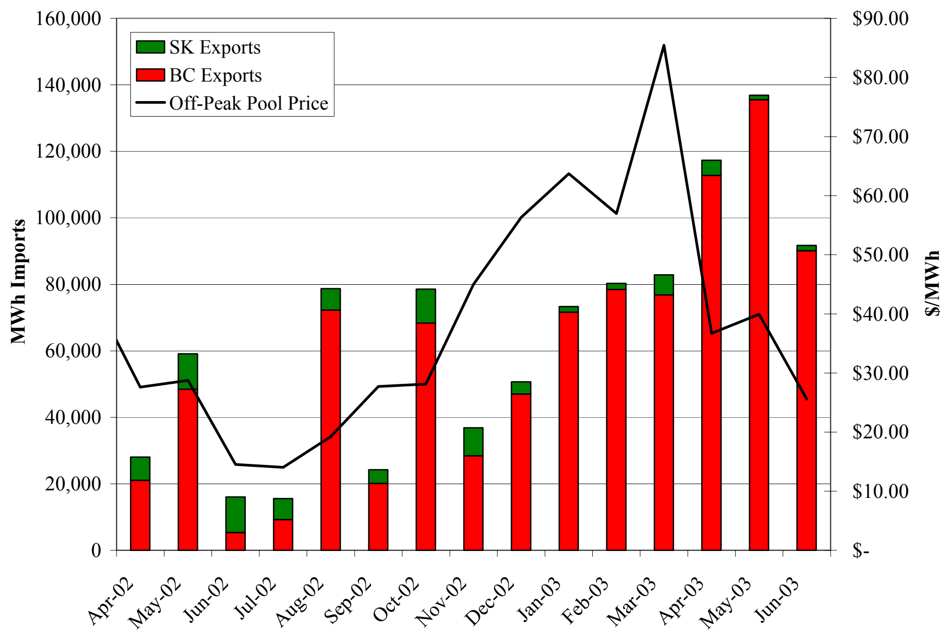
Figure 8 - Total Monthly Imports and On-Peak Avg Pool Price



The volume of imports corresponds well with on-peak Pool price – as price increases, the volume of imports increase. This would be expected as higher priced on-peak hours tend to attract greater import volumes. However, this relationship is influenced by the relative price differential between source and sink.

Both prices and import volumes have decreased in Q2/03 from Q1/03. The average on-peak Pool price in Q1/03 was $95.48/MWh with a total of over 434,000 MWh of electricity being imported compared to 229,000 MWh being imported at an average price of $63.90/MWh in Q2/03. The greatest difference is in the volume of imports that flowed over the Saskatchewan tie-line. Total Q2/03 imports of 228,776 MWh are slightly lower than the same period last year when a total of 264,000 MWh were imported at an average price of $59.66/MWh.

Figure 9 - Total Monthly Exports and Off-Peak Avg Pool Price



Exports over the BC tie-line (primarily to BC) have increased dramatically since Q1/03 and reached a monthly high for the last 15 months in May when over 135,000 MWh were exported. In addition, the average quarterly off-peak Pool price has decreased to $34.08/MWh from $68.70/MWh in Q1/03 making exporting more attractive – again this is dependent on the relative price differential between source and sink. Conversely, exports to Saskatchewan reached a 15 month low in May 2003 when only about 1,400 MWh of electricity flowed over the Saskatchewan tie-line. The only significant outage on the BC tie line effecting exports occurred for 44 hours between April 20th and 22nd. On the Saskatchewan interconnection, outages of 102, 54, and 33 hours occurred in late May, early June, and early April respectively, which affected exports.

Because of the abundance of hydro generation in BC and the Pacific Northwest, import and export activity into and out of these areas is an indicator of the water available in the system. As spring 2003 was drier than spring 2002, high volumes of exports and low volumes of imports (relative to Alberta) would be expected. This is in fact what has been observed.

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 10** and **11** show monthly average on-peak and off-peak price indices for MAPP-North (US Mid-West), Mid-C (US Pacific Northwest) and North-Path 15 (California) compared to Pool price. All prices are in Canadian dollars and have been converted at an exchange rate of 1.3475 CDN/US.

Figure 10 - On-Peak Prices in Other Markets

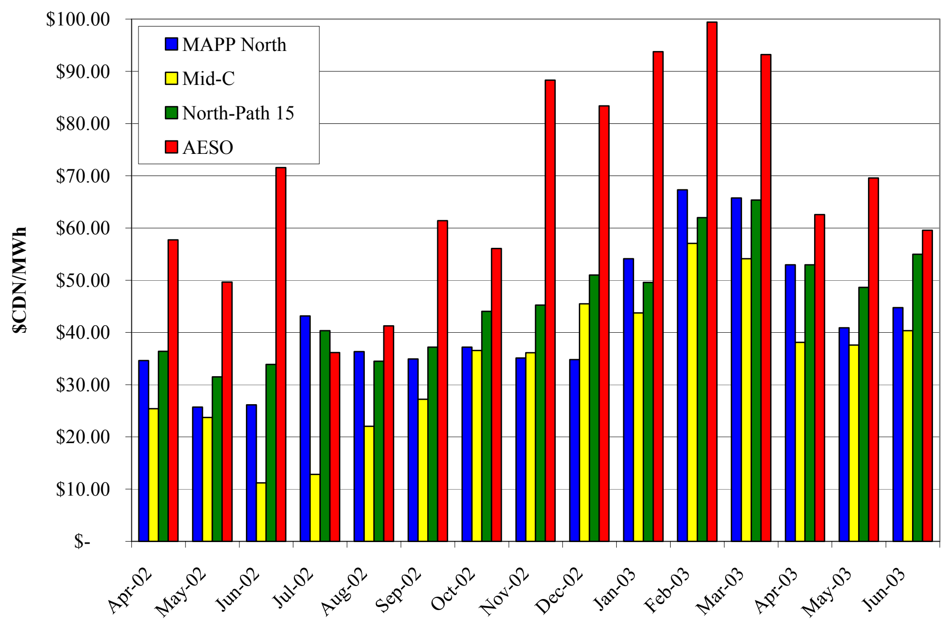
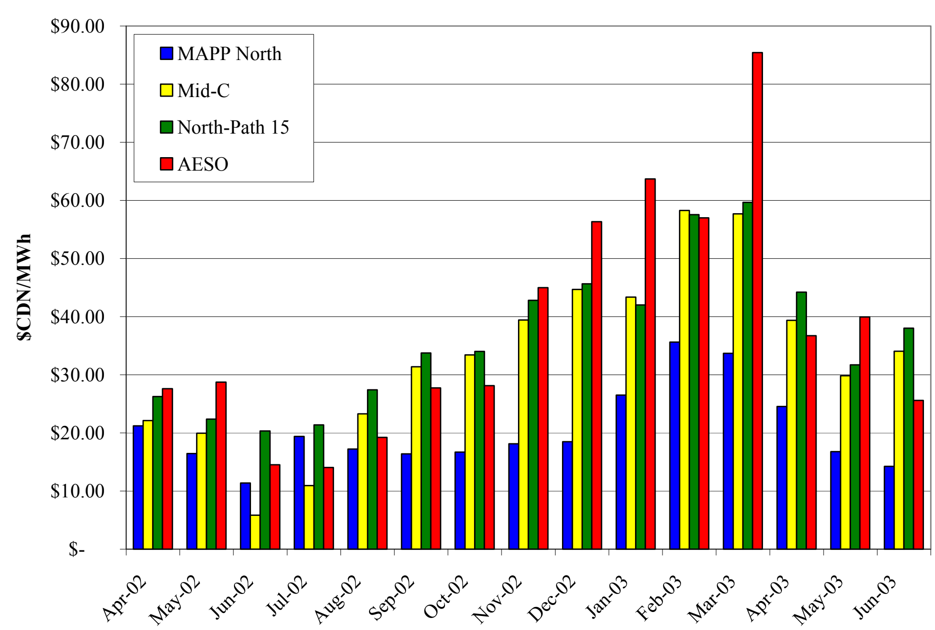


Figure 11 – Off- Peak Prices in Other Markets



On-peak prices in Alberta have remained strong relative to prices in neighbouring markets, although price differentials in Q2/03 have generally decreased since Q1/02 primarily due to softer Alberta prices. Higher prices in Alberta relative to other markets imply an opportunity to profit from importing energy into the province.

Off-peak prices in Alberta have remained strong compared to MAPP-North prices but were weaker relative to both Mid-C and North-Path 15 prices. These price differentials could account for the occurrence of increased imports over the Saskatchewan tie-line in off-peak hours.

Figures 12 and 13 capture the economic use of the tie-lines over the last 15 months. Monthly average net imports (net imports are positive and net exports are negative) are plotted with on-peak and off-peak price differentials between Alberta and the nearest competitive market. Calculations do not take into account the cost of transmission from one jurisdiction to another.

Figure 12 - Economic Use of the BC Tie Line

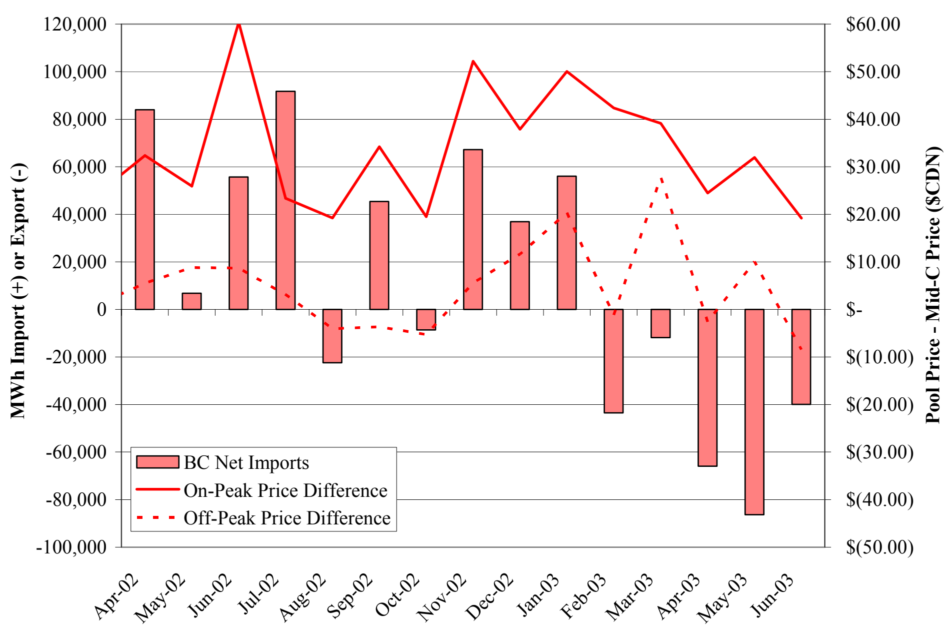


Figure 12 shows the net direction in which volumes moved on the Alberta-BC interconnection together with on-peak and off-peak price differentials between Alberta and Mid-C. One would expect that on average, the flow direction should coincide with the direction of the price differential – for example, if pool prices exceed Mid-C prices, resulting in a positive differential, that net imports should be observed. In interpreting Figure 12, months of net import activity should be viewed together with the on-peak price differential since the majority of import activity tends to occur in on-peak hours when Alberta system demand is high. Likewise, months of net export activity should be viewed together with the off-peak price differential since the majority of export activity tends to occur in off-peak hours when Alberta system demand is low. For Q2/03, Figure 12 indicates that net exports in the months of April and June were economically consistent with higher off-peak prices at Mid-C while in May, the flow appears to be counter-intuitive as strong net exports were seen while off-peak prices were relatively better in the Alberta market. The figure implies that all energy flowing on the BC tie-line is bought or sold at either Pool price or the Mid-C index price, although this is not necessarily the case. This assumption of transaction price does not account for electricity with a source or sink in BC where the Mid-C index price is irrelevant. The majority of exports that occurred in Q2/03 were actually delivered to BC, and therefore the economics calculated should be considered as directional only.

Figure 13 - Economic Use of the Saskatchewan Tie Line

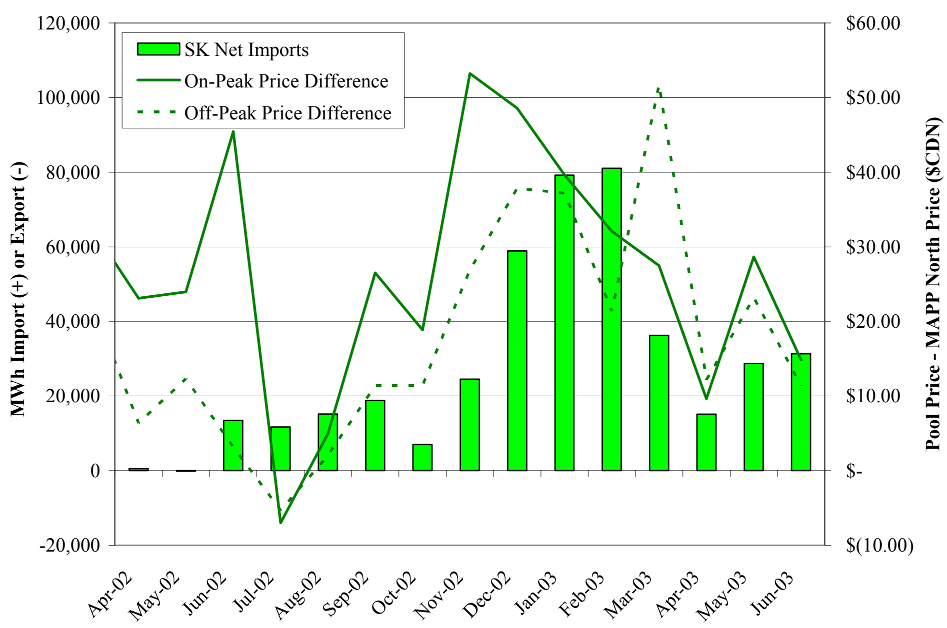


Figure 13 shows that on average it has been more profitable to import energy into Alberta than export it to the MAPP-North market for almost all of the past 15 months. This is reflected in the actual import/export activity on the Saskatchewan tie-line. This also shows the rationale behind relatively high levels of imports in the off-peak hours.

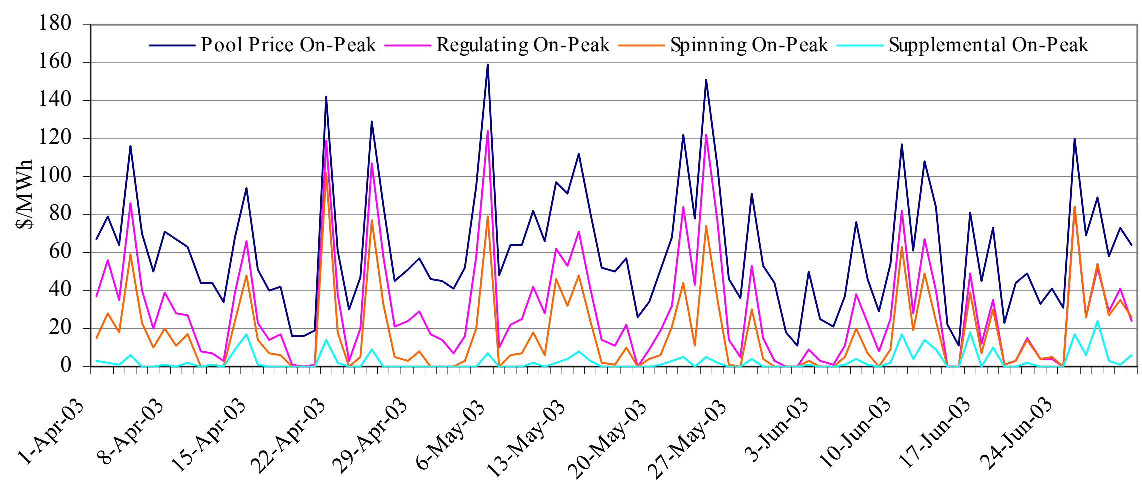
1.9 Ancillary Services and Forward Markets

The proclamation of the new *Electric Utilities Act* (the "Act") has given rise to a liability concern among ancillary service providers. The interpretation of the Act, among service providers, is that the Act no longer provides indemnification to them against unlimited liability in the event of non-performance, contrary to the situation under the previous Act. As a result of these concerns, certain participants have withdrawn in varying degrees from the ancillary services market until the issue can be resolved. To some extent other providers have stepped in to take up greater market share although an outcome of these concerns has on occasion, been a thin ancillary services merit order that has caused directives to be issued by the system controller due to insufficient procured reserves.

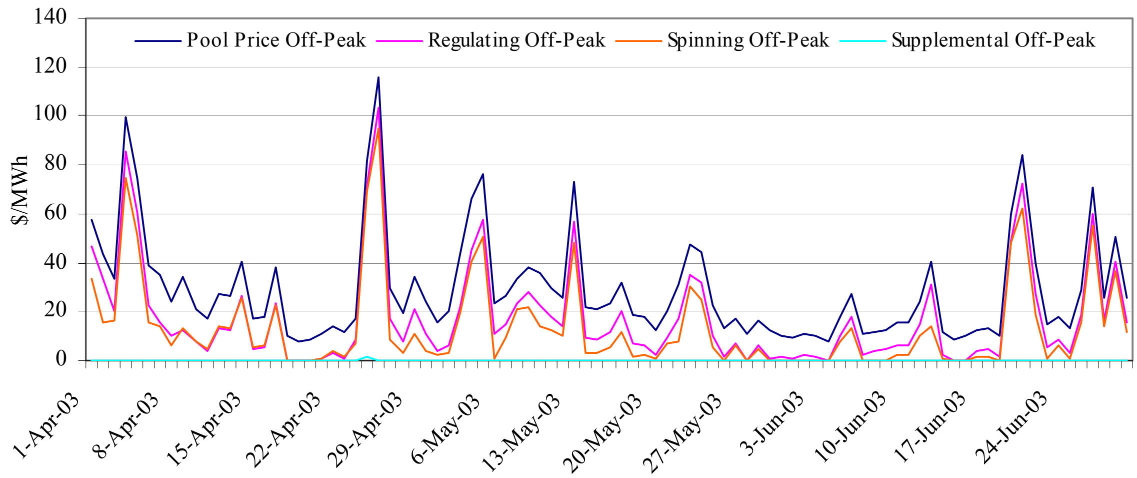
Figure 14 shows the delivered price of active ancillary service products traded on Watt-Ex thought Q2/03. Noteworthy is the fact that on-peak supplemental cleared above $0.00 through much of Q2/03 which indicates that although the hydro PPA effect in the supplemental market has persisted, it has not been ubiquitous through all trading days for each delivery date, therefore there have been market opportunities available in the on-peak market on the remaining trading days.

Figure 14 - Ancillary Services Clearing Prices - Q2/03

Weighted Average (on-peak)



Weighted Average (off-peak)



Prior to the impact of the liability issue discussed above, which was noted in late June, the spinning reserve market remained highly competitive in Q2/03 with clearing prices on occasion reaching $0.00 for both on-peak and off-peak contracts. In addition to a highly competitive market, this outcome appears to be in part, a function of increasing pool price volatility through the quarter. Trading indices suggest that sellers have been willing to accept a high probability of receiving $0.00 in the spinning market over several days with the hope of capturing one or two subsequent days when increasing price volatility increases the likelihood of seeing significant pool price spikes. In other words, participants appear to be viewing the spinning market as an option on the energy market particularly in periods of higher pool price volatility.

Market depth in the Watt-Ex forward energy market continued to be relatively thin in Q2/03 although volumes stepped up sharply in the month of May. June volumes were the lowest thus far in 2003.

A new development for the forward electricity market occurred in mid-April when the Natural Gas Exchange (NGX) launched a fixed-for-floating electricity financial swap contract. Thus far, intermittent trade has been observed although volumes have been quite thin.

1.10 Outages and Derates

The MSA monitors the outages and derates of the previously regulated thermal generating units that are now operated under the terms and conditions of the Power Purchase Arrangements. In addition to real time monitoring, the MSA has developed a number of data filters which indicate when the timing or duration of outages and derates deviates significantly from a unit's historical performance. When the amount of outage exceeds a unit specific threshold, a flag is raised and the MSA seeks to understand from the owner more about the causes leading to the situation.

Historically, outages and derates, both planned and unplanned, tend to fluctuate or appear cyclical on both a quarterly and annual basis. The amount of outage can vary from one time period to the next because planned outages are generally scheduled on a multi-year basis. This in turn impacts upon unplanned (maintenance and forced) outages. **Figure 15** illustrates planned and unplanned outage levels for 2001, 2002, and January through June 2003. The figure illustrates that overall PPA outage at the coal-fired facilities has been relatively stable from 2001 through June 2003. Although the overall level has been stable, there have been fluctuations at the owner level. For instance, TransAlta's overall outage level has trended downward in each of the last 3 years, from a high of 14.2% in 2001 to a low of 11% for the first half of 2003. Atco's overall outage level has cycled from 5.6% in 2001, up to 8.1% in 2002 and back down to 5.4% for January to June, 2003. Epcor's coal fired PPA outage has also shown some variability, from 5.4% in 2001 to 2.9% in 2002 and up to 4.3% for the first half of 2003.

As has been the case historically, TransAlta has the highest overall outage rate, due to the size and vintage of its generating fleet. Included here is a portfolio of 3290MW of coal-fired generation, some of which was commissioned as early as the 1950s. Atco's overall outage rate, from a portfolio of 1420MW of coal–fired generation, is somewhat lower than TransAlta's. Atco's portfolio includes the Sheerness Plant[2], commissioned in the mid-1980's, and the Battle River Plant, commissioned in stages between 1969 and 1981. Epcor's portfolio is comprised of the Genesse Plant. Given that it is the newest coal plant in Alberta, it generally experiences a lower rate of outage.

The first half of 2003 has seen a higher rate of planned outages as a percentage of total outages than was experienced during 2002. In 2002, the planned outage rate was 2.7%, which represented only 26% of all outages. The first half of 2003 has seen the planned outage rate rebound to 4.5%, which represents almost 54% of all outages. The relatively low

[2] Sheerness is owned 50-50 by Atco and TransAlta but is operated by Atco and thus included as part of Atco's portfolio.

planned outage rate in 2002 was driven by a low occurrence of planned outages by TransAlta. The low planned outage rate for TransAlta can be partly explained by the rescheduling of planned outages, which led them to be reclassified as unplanned maintenance outages.

Traditionally, outages have been considered either planned, forced or maintenance. Planned outages are normally scheduled in conjunction with the AESO, and are well known in advance. Forced outages are imminent or immediate outages with little scheduling flexibility. Maintenance outages are similar to forced outages, except that they can be held off for up to a week. The definitions between maintenance and planned outages can become administratively blurred when planned outages are rescheduled, which can lead to a previously planned outage being recorded as a maintenance outage (unplanned).

Figure 15 - Planned vs. Unplanned Outage, PPA Covered Coal-fired Units

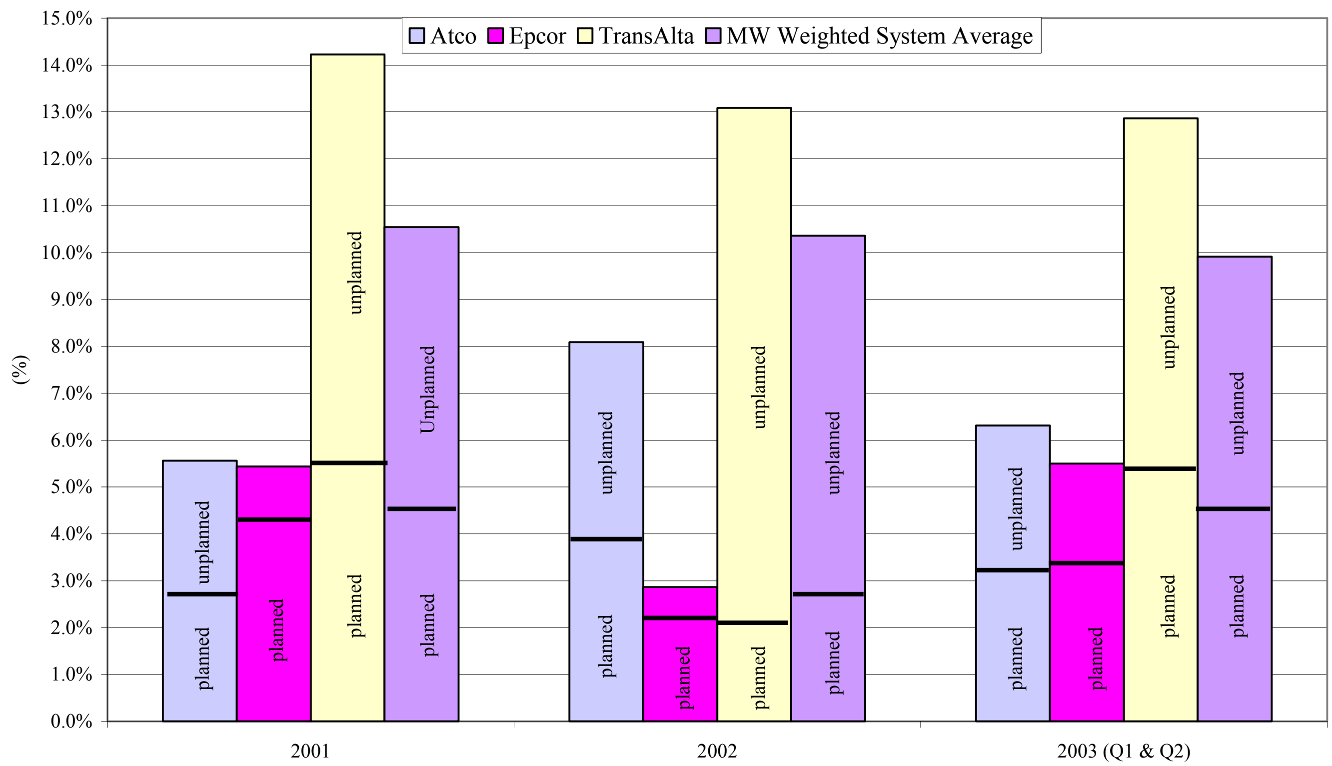


Table 3 below, reports unplanned outages on a quarterly basis for 2003, the 2003 year-to-date average, as well as 2002 and 2001 annual averages. On a quarterly basis, overall MW weighted average unplanned outages (the number of MWhs lost to forced and maintenance outage by the PPA

coal units) in Q2/03 was very similar to Q1/03. Q1/03 unplanned outage was 4.6%, while Q2/03 was up slightly at 4.7%. Year to date, unplanned outages are below 2002 levels and below the long term average. This is consistent with the fact that there has been a higher rate of planned outages during the first half of 2003. Both Atco and Epcor experienced slightly lower unplanned outage rates in Q2/03 than in Q1/03, down 2.3% and 1% respectively. TransAlta's unplanned outage rate is up slightly over Q1/03, by 0.8%.

Table 3 - Outage for PPA Units (%, excluding planned outages)

	Q2/03	Q1/03	2003 YTD	2002	2001
Atco	1.4%	3.7%	2.6%	4.2%	2.8%
Epcor	2.1%	1.1%	1.6%	0.5%	1.2%
TransAlta	6.8%	6.0%	6.4%	10.8%	8.8%
PPA weighted average	4.6%	4.7%	4.6%	7.7%	6.0%
Note: PPA units by Owner include: Epcor (Genesee 1 & 2); Atco (Battle River 4, 5, 6, Sherness 1 & 2); TransAlta (Wabamun 1, 2, 3 [up to Nov 28 2002], 4, Sundance 1 - 6, Keephills 1 & 2).					

The design of the PPAs stipulates a target availability for each PPA covered unit, based on historical performance and factors such as a unit's age and design. By owner, **Table 4** reports the MW weighted average target availability for each PPA coal fired portfolio and the actual availability achieved during the first half of 2003[3]. On average, each PPA owner reported higher actual availability than target availability.

Table 4 - Target Availability - Coal-fired PPA Units

MW Weighted Portfolio Target Availability (%) vs Actual Availability (%) - Coal Fired PPA Units		
	Target Availability 2003	**Actual Availability 2003 YTD**
Atco	87%	94%
Epcor	90%	95%
TransAlta	85%	87%

[3] Actual availability in the PPAs is defined as the minimum of the declared availability or committed capacity, whichever is less. The actual availability reported here is not calculated using availability declarations, but is instead calculated using data provided by the PPA owners.

In terms of overall availability, and compared with historical trends, Alberta's PPA units have performed well over the first half of 2003. The shift away from planned outages and into unplanned outages that was seen last year appears to be reversing itself, with a greater balance between planned and unplanned outages being recorded so far this year.

2 REVIEW OF THE RETAIL MARKET

2.1 Load Settlement Monitoring and Compliance

The MSA continued its work with the Alberta Settlement Committee (ASC) and various interested parties in respect of load settlement issues. At the sub-committee level, the MSA was involved with the Compliance Monitoring Committee, whose work related to the development of monitoring and compliance approaches in relation to load settlement.

The Compliance Monitoring Committee brought forward its proposed changes to the Settlement System Code in April. The new standards are to be implemented in Version 9.2 of the Settlement System Code, anticipated to come into effect July 28, 2003. Included in the new standards are requirements for letters of compliance, representation and disclosure from load settlement participants, and additional compliance reporting.

Other changes proposed to be implemented in Version 9.2 include the type of claims, and time and materiality limits, in respect of the Post Final Adjustment Mechanism (PFAM).

Pursuant to the new *Electric Utilities Act*, the Settlement System Code is the responsibility of the Independent System Operator (AESO), being a component of the "ISO rules" as defined in the Act. The ISO rules, including the Settlement System Code Version 9.2 can be found on the AESO website at www.aeso.ca .

Effective April, 2003, the ASC has changed the manner in which it will conduct its business, from a regular meeting format to other means of information exchange and review. The AESO is responsible for the ASC process.

2.2 Code of Conduct

During April and May, the MSA completed its review of the audits and other reporting required from the owners of electric distribution systems pursuant to the existing *Code of Conduct Regulation*.

By letter dated May 15, 2003, the MSA reported out to the market on the review. A copy of the letter can be found on the MSA website at www.albertamsa.ca .

In conjunction with the new *Electric Utilities Act*, a new *Code of Conduct Regulation* (Code) came into force effective June 1, 2003.

As before, the Code seeks to address the relationships between owners of electric distribution systems, affiliated retailers, non-affiliated retailers, and customers. Although similar to the previous regulation in some respects, the new Code reflects significant new approaches, including greater focus upon reporting and compliance by the affiliated retailer. Other changes include that the MSA now has power of approval in relation to the compliance plans required to be filed by each of the owners and affiliated retailers, and also in relation to the choice of auditor and the audit work plan required of those parties under the Code. The MSA is also given responsibility for the granting of exemptions from Code compliance; previously this was the responsibility of the Alberta Energy and Utilities Board (EUB).

In accordance with its responsibilities under the Code, the MSA has begun a series of meetings with stakeholders in preparation for the reviews and approvals which will be required before the end of 2003.

2.3 Retail Market Metrics

In the Q1/03 quarterly report the MSA reported that it had undertaken a review of possible metrics for measuring the competitiveness of the retail electricity market and was in the process of developing a series of Retail Market Monitoring Metrics to be applied to the Alberta market. The metrics have now been determined and market data has been collected for Q4/02, Q1/03 and Q2/03.

The established metrics are:

- 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 to a competitive contract by RRO[4] eligible customer class.

As this is the first instance of reporting the Retail Market Monitoring Metrics, three quarters worth of data is presented. In future quarterly reports the current quarter of data will be reported on and compared to the "base case" of Q4/02. Data has been collected from load settlement agents and aggregated to develop a province-wide summary.

As of June 30, 2003 there were 106 active retailers in the Alberta electricity market, 74 of which are self-retailers. This is an increase of 3 retailers since the end of Q1/03 and 10 retailers since the end of 2002. Although the total number of retailers has increased, 4 retailers have left the market since December 31, 2002. This level of retailer entry and exit from the market appears to indicate a fairly healthy level of competition given the size of the market.

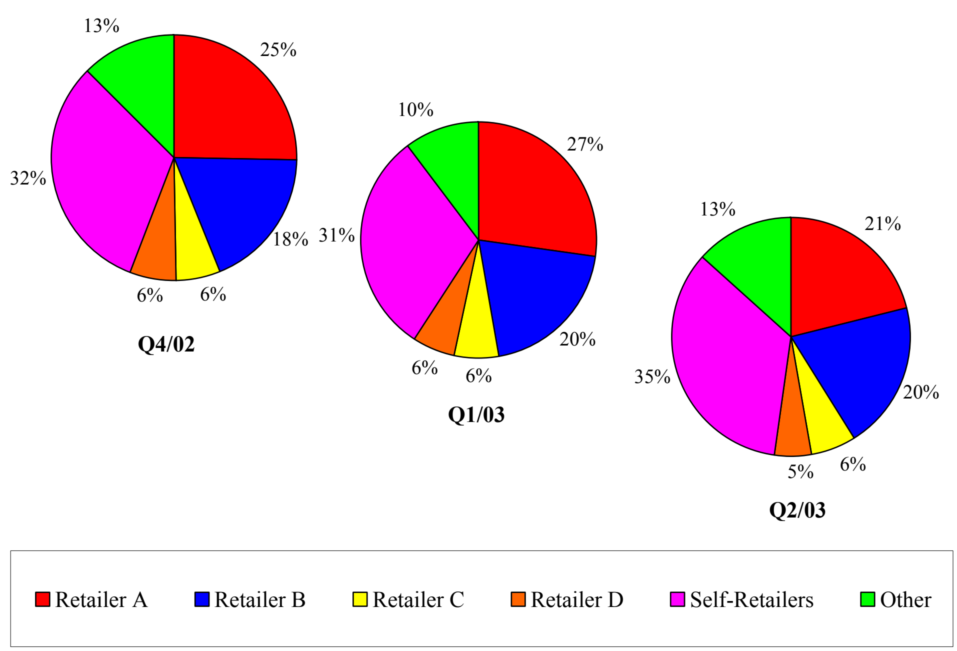
For the purpose of the market share and customer switching metrics, customer classes have been identified as Residential – RRO Eligible, Farm

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

(including irrigation) – RRO Eligible, Commercial/Industrial – RRO Eligible and Non-RRO Eligible. In addition, names of individual retailers in the market share metrics have been disguised to alleviate concerns of making public commercially sensitive information. Note that retailers are listed in order of decreasing market share and the same retailer label does not necessarily represent the same retailer across different customer classes.

Figure 16 shows the total market share of retailers for Q4/02, Q1/03 and Q2/03. The figure shows that there are four retailers in the province with market shares (by load) of at least 5%. It also shows that since Q4/02, the market share of these four retailers has decreased from 55% to 52% while the market share of self-retailers has increased from 32% to 35%. The variation in market shares of retailers indicates load movement between retailers - a healthy sign of competition.

Figure 16 - Overall Market Share of Retailers



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

Figure 17 - Q2/03 Market Share of Retailers by Customer Class

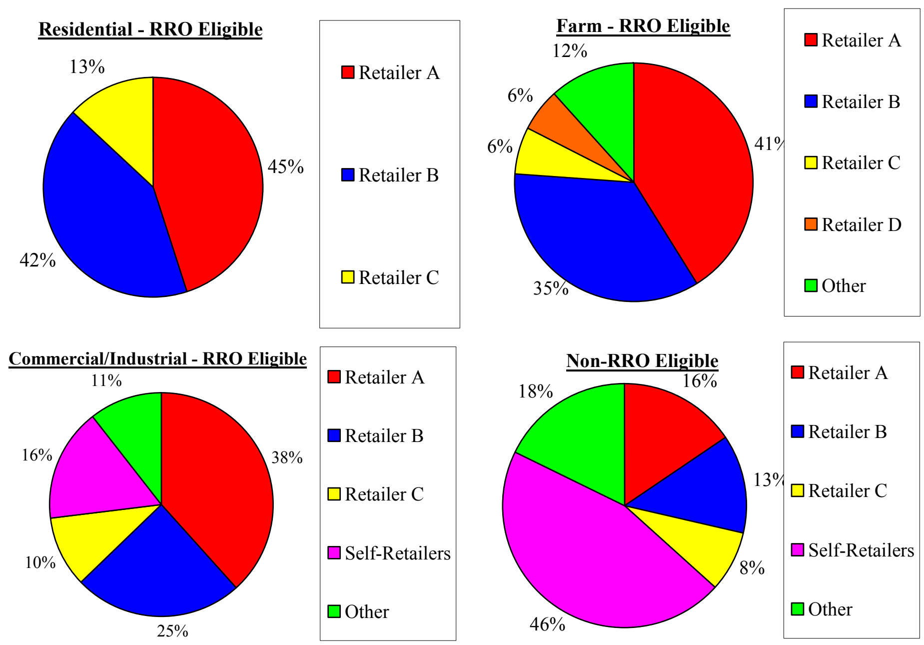
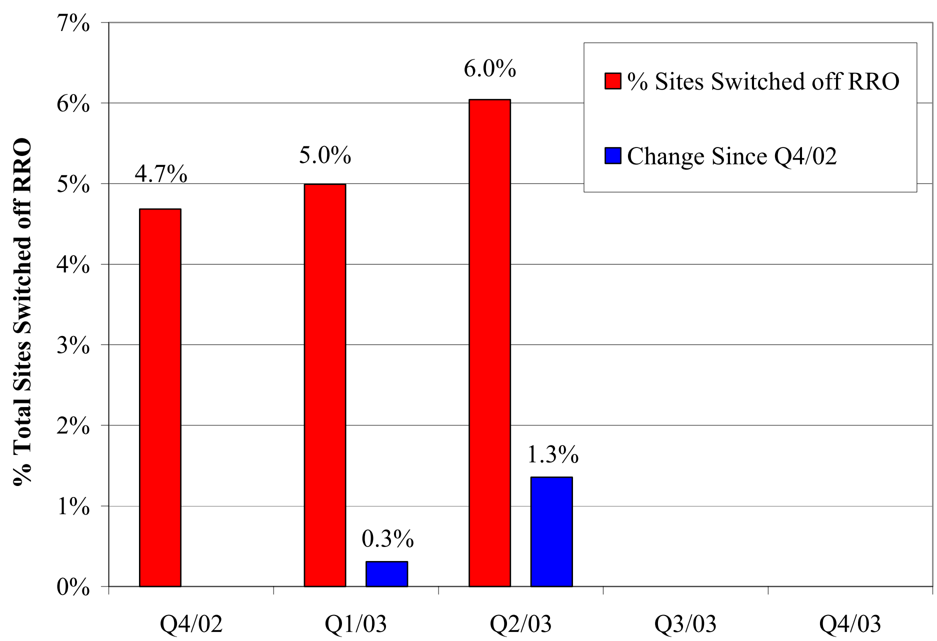


Figure 17 shows retailer market share by customer class for Q2/03 and also reflects the relative number of active retailers in those classes. There are only (for all intents and purposes) three active retailers in the Residential – RRO Eligible sector of the market while in the Non-RRO Eligible market sector there are over 100 retailers (including individual self-retailers). The figure also shows that the larger load classes are more competitive in terms of market share segmentation. The largest representative in each market class had market shares in Q2/03 of 45%, 41%, 38% and 16% for the residential, farm, commercial/industrial and non-RRO eligible classes respectively. The analysis generally indicates that there is in fact competition in the retail market although it is currently more developed in the larger load markets. The impending introduction of Direct Energy as a small customer retailer may help to increase competition in these smaller load markets.

The overall progression of customers from RRO rates to competitive electricity contracts is also encouraging. As of June 30, 2003, 6.0% of all RRO eligible customers[5] have chosen to sign a competitive contract with a retailer, as shown in **Figure 18**. This represents a 1.3% increase since the end of Q4/02.

[5] Note that although street lights are considered to be RRO eligible in some service areas, street lights have not been included in the switching off RRO statistics.

Figure 18 - Progression of RRO Eligible sites Switching off RRO



Although customer switching off RRO is generally on the rise, switching statistics are not uniform through the different customer classes. **Table 5** shows the progression of RRO eligible sites switching off RRO for the last three quarters by customer type.

Table 5 – Progression of RRO Eligible Sites Switching off RRO

	% Customers NOT on RRO			
	Residential RRO Eligible	**Farm RRO Eligible**	**Commercial/ Industrial RRO Eligible**	**Overall**
Q4/02	1.8 %	3.2 %	23.8 %	4.7 %
Q1/03	2.5 %	3.4 %	21.9 %	5.0 %
Q2/03	3.3 %	3.5 %	25.2 %	6.0 %

There has been a steady increase in the number of residential and farm customers moving away from RRO over the past three quarters. This indicates an encouraging increase in competitiveness in both of these retail markets. The number of small commercial/industrial sites not on RRO has changed the most dramatically. While the percentage of non-RRO customers decreased slightly in Q1/03, it rebounded quite substantially in Q2/03.

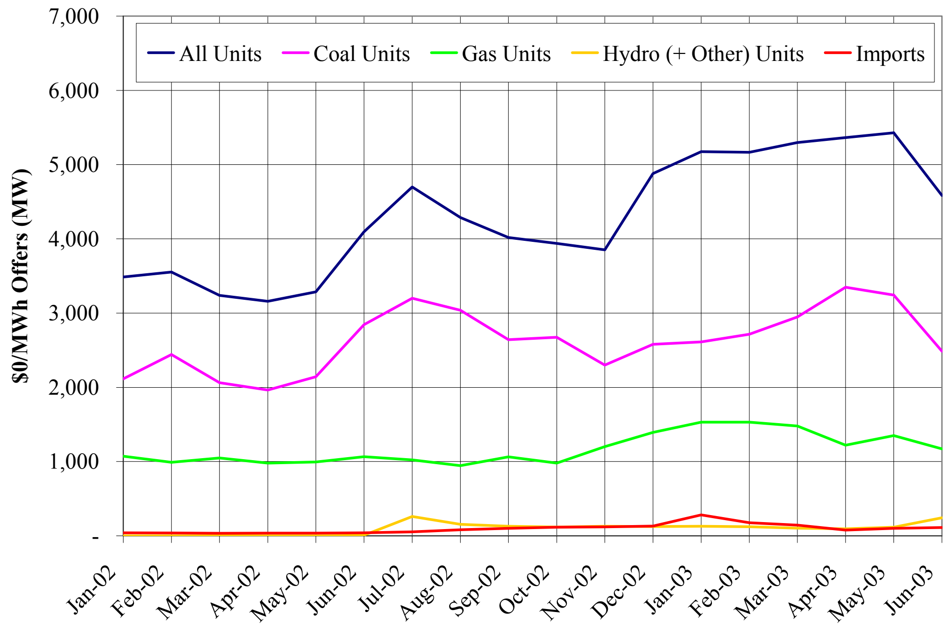
Note that on January 1, 2003, ATCO introduced its flow-through RRO rate to small commercial/industrial customers. On April 1, 2003 this flow-through rate was implemented for residential and farm (including irrigation) customers. This change in RRO for ATCO customers may be a factor in the increased numbers of customers moving away from RRO.

3 MARKET ISSUES

3.1 Zero Offers

In the Q1/03 Quarterly Report, the MSA reported on the results of its Zero Offers study and announced its intention to monitor zero offer behavior on an ongoing basis and report on its findings. **Figure 19** plots monthly average MW offered at $0/MWh by unit type for 2002 and 2003 to date.

Figure 19 - Zero Dollar Offers



The figure shows that total zero offers have generally increased since the end of 2002 and reached a monthly average high (to date) of approximately 5,430 MW in May 2003. Average zero offers for Q2 have almost tripled since 2001 as Q2 zero offers increased from 1,785 MW in 2001 to 3,513 MW in 2002 and 5,126 MW in 2003. Despite high zero offers in May, on a quarterly average basis, zero offers were actually higher in Q1/03 than in Q2/03. This is primarily due to lower volumes of zero offers in June when average monthly zero offers decreased to 4,585 MW – lower than they had been since November 2002.

Total zero offer volumes continue to be primarily influenced by coal unit zero offers; however gas units have started to have more of an impact on zero offer levels. This is quite clearly shown in the first few months of [6]2003 when the volume of gas unit zero offers increased by approximately 500 MW. This increase is partially due to the addition of 420 MW of gas

[6] The full Zero Offers report was subsequently posted on the MSA's website (www.albertamsa.ca).

generation to the system in the early part of 2003 – a portion of which is routinely offered at $0/MWh.

The large decrease in zero offers for the month of June is primarily caused by a large reduction in coal unit zero offers due to unit outages. During these periods of outage, some of the capacity is replaced by higher priced gas units which generally do not zero offer. Some units also change their offers during periods of outage and redistribute their offers so that less energy is in the $0/MWh block. Both scenarios have the effect of decreasing total zero offers.

Although the number of zero offers has continued to increase through 2003 year to date, the MSA is of the view that this increase has not had an adverse impact on the fair, efficient, and openly competitive operation of the market, although the MSA will continue to monitor and track the frequency of zero offers.

3.2 Review of Pool Price Forecast

There has been some debate regarding the role of the AESO in price forecast generation, the usefulness of the forecasts produced and the ability of the forecasts to promote the operation of a fair, efficient and openly competitive market. In Q2/03, the MSA undertook its second review project for 2003 - a review of the Pool price forecasting conducted by the AESO with the goal of answering the following questions:

- Should the AESO generate price forecasts?
- If price forecasts should be generated, are both day-ahead and real-time forecasts necessary?
- If price forecasting should continue, are the current methods of generating price forecasts adequate?
- If the current methods are inadequate, how can the AESO's price forecasting methods be improved?

The review included discussions with the AESO's Operations group, Market Development group and System Controllers, a brief analysis of the accuracy of the AESO's price forecasts, a survey of price forecasting practices in other electricity markets, and a limited survey of stakeholder opinions.

Three price forecasts are published on the AESO's website: a six-day-ahead forecast, a day-ahead forecast and a real-time forecast. In addition to being mandated to produce price forecasts (see AESO rules 10.2, 10.3 and 10.4 effective July 28, 2003) the AESO is motivated to publish price forecasts to provide both load and generation with a price signal. The six-day-ahead forecast is not generally used by market participants as this forecast is a poor representation of the price situation on the day of delivery due to uncertainty in the data made available by participants at the time the forecast is prepared. The six-day-ahead price forecast was not addressed in the MSA's review of price forecasting.

Day-Ahead Price Forecast

The day-ahead forecast is prepared by the System Controller each day after the noon-day-ahead gate-close for offers and bids. The day-ahead forecast is generated using the AESO's Resource Scheduling software and relies on two primary inputs: the day-ahead load forecast (generated by the AESO); and the day-ahead offers (submitted by the generators) and bids (submitted by loads) received by the AESO. Imports and exports that are scheduled for the next day that the System Controller is aware of at the time of the day-ahead forecast preparation are also included in the forecast.

The resource scheduling software combines the day-ahead load forecast with the day-ahead offers and essentially generates a series of 24 supply-demand curves – one for each hour of the day. Resource scheduling takes into account factors such as unit constraints, minimum up/down times, ramp rates, generation status at the time of the forecast preparation, provision of ancillary services, Transmission Must Run (TMR) services, and hourly AGC operating ranges[7]. The price of the offer block that coincides with the forecasted load for that hour is the day-ahead price-forecast for that hour. Preparation of the day-ahead price forecast is mostly automated and requires only a small time investment on the part of the System Controller.

A brief analysis of the accuracy of the day-ahead price forecast revealed that the relative root mean squared error[8] of the day-ahead price forecasts for Q1/03 ranged from 0.64 (for HE 4) to 2.78 (for HE 18) with a mean value of 1.22. This indicates that on average, the forecasted price was over 100% different from the actual Pool price. The analysis also showed that day-ahead forecast prices tend to be lower than the actual Pool price.

The poor accuracy of the day-ahead price forecast is primarily a function of the lack of reliability of the day-ahead offer information (including operating characteristics and ramp rates) provided by the generators. As the day-ahead offers are not binding, there are a number of problems associated with using them for price forecasting purposes:

- Day-ahead offers are often "standing offers". This can result in energy being offered into the market that is not physically available (i.e. undergoing maintenance). At present, there is not a

[7] Most of these inputs are submitted by generators with their day-ahead offers. Only the generator status at the time of the forecast preparation and the AGC operating ranges are manually entered by the System Controller when the day-ahead price forecast is prepared.

[8] Relative root mean squared error is a measure of the error of an estimation about the actual value, relative to the actual value.

mechanism in place to force participants to submit offer (and bid) information in “good faith”.

- Day-ahead offers do not account for energy restatements which may occur at any time between the gate-close for the day-ahead offers and the time of delivery.
- Although importers are required to submit day-ahead offers just like any other participant, the nature of the Alberta market design makes it impractical for most importers to submit meaningful offers until much closer to the hour of delivery. As hourly non-firm transmission on the BC tie-line (the transmission vehicle most used by Alberta importers/exporters) is not released until the hour before delivery, importers must use energy restatements to offer the volume of energy they wish to import on an hourly basis.

Most market participants surveyed indicated that due to the inaccuracies in the day-ahead price forecast, they do not rely on it. The day-ahead price forecast does, however, provide a directional price signal to the market. Although the actual forecasted prices are most often numerically wrong, the day-ahead forecast is an indicator of whether supply is expected to be tight or not for the upcoming day. For example, if on-peak day-ahead price forecasts have been in the $10 - $20 range for quite some time and the next day’s on-peak price forecasts are in the $800 - $1000 range, the forecast sends the signal that supply could be tight. In essence it is the change in the day-ahead price forecast and the shape of the forecast price curve that provides the signal to the market rather than the actual forecasted prices themselves.

The day-ahead forecast also provides some of the slower-starting units with an advanced warning of what could occur in terms of pricing on the following day. These older units need more time to respond to potential market conditions than is covered by the real-time forecast. The day-ahead forecast may also be useful to importers and exporters who may be contemplating trying to procure daily (or longer) transmission access.

Despite the poor accuracy of the day-ahead price forecast, it does provide a small service to the market. More importantly, it does not do any disservice to the market or hinder the market from behaving in a fair, efficient or openly competitive manner. Because the method of generating the forecast is automated and the information used to produce it is not collected solely for the purpose of preparing the price forecast, the cost of maintaining a day-ahead price forecast is small. Although the benefits of the day-ahead price forecast are limited, there are no overwhelming benefits to removing the forecast from the public domain although some minor changes to the day-ahead forecast may be warranted.

The outcome of the day-ahead price forecast is undeniably flawed. However, this is not a situation that can be solved by modifying the method of determining the day-ahead prices, but rather a limitation of the accuracy of the information available at the time the forecast is prepared.

The major source of error in the day-ahead price forecast is the inaccuracy of the offer information so far in advance of the hour of delivery. At the time the forecast is prepared, a reasonable portion of the information available is not in its final form and it is therefore difficult to predict future prices with any degree of accuracy. The timing of information available to the AESO (i.e. generation offers, import and export schedules and restatements) is determined by the AESO rules and ultimately governed by the Alberta market design and seams issues between Alberta and neighboring markets. Since the flow of this information is governed by the market design, little can be done to improve the accuracy of the day-ahead forecast without changing the underlying market design. A case could be made for the AESO to provide the market with a volume outlook which would provide participants with a view of the projected load and supply volumes for the upcoming day. This might act as a surrogate to the day-ahead price forecast.

Although the method of preparing the day-ahead forecast is not really flawed (the flaws are more in the quality of information), the term "day-ahead price *forecast*" could be seen to be misleading. The term "forecast" implies some sort of analysis was conducted to determine the expected value. It may be more prudent to adopt the term "day-ahead price *outlook*" when referring to the day-ahead prices published by the AESO. In addition, the AESO should make market participants aware of the general method used to generate the outlook and some of its limitations. Providing participants with some knowledge of how the day-ahead outlook is prepared (but now allowing them access to the actual algorithm) will promote a better understanding of the outlook by participants.

Real-Time Price Forecast

The System Controller is also responsible for posting the real-time price forecast. This forecast is generated using real-time offers, the real-time load forecast, typical price responsiveness of loads and anticipated import and export schedules. Unlike the day-ahead price forecast, all of these inputs (other than real-time offers) are tempered by the System Controller's judgment with respect to how the inputs will affect the ultimate price. This process is more ad-hoc than the generation of the day-ahead price forecast and the real-time forecast is not adjusted or updated on a regular (scheduled) basis. However, it is generally accepted that the real-time forecast is more accurate than the day-ahead forecast as many of the unknowns of the day-ahead forecast have been determined.

The biggest problem with the real-time price forecast is its inconsistency resulting from a lack of tools and methods to manage the forecast. Because this forecast is a manual estimate performed by the System Controller, it can be inconsistent from day to day and hour to hour in terms of the timing of the forecast posting, the frequency of forecast updates and how far in the future forecasts are posted. In addition, each individual System Controller draws on a different set of experiences when making his price estimate. Whether or not it is intended, each System Controller may add a certain bias to the forecasts he makes. Some System Controllers are very good forecasters and may contribute to the accuracy of the forecast while others are not as good. This variation adds to the inconsistencies in the real-time forecast.

A brief analysis of the AESO price forecast performance confirmed that the accuracy of the real-time price forecast is also quite poor – particularly during higher demand hours. Although the distribution of the forecast prices about the actual price was more even (higher and lower than actual Pool price) than the distribution of the day-ahead forecast prices, real-time forecast prices were as much as $800 different than the posted Pool price in Q1/03. The analysis calculated the relative root mean squared error of the real-time price forecast for Q1/03 ranged between 0.40 (for HE 4) and 2.28 (for HE 18) with a mean value of 0.86. While the accuracy of this forecast is not as bad as the day-ahead forecast, the real-time forecast is an average of 86% different from the actual Pool price.

Most market participants use the real-time forecast in some decision making aspects of their business. Some smaller market participants contest that removing the real-time price forecast would put them at a disadvantage. Despite the small level of confidence placed in the forecast, it is available to all market participants. Larger players may have the means to generate their own forecast, but smaller players are generally without this capability. Removal of the real-time price forecast from the public domain may be perceived to be unfair to the smaller market participants.

The majority of other deregulated markets surveyed do not publish real-time price forecasts for their markets. Other jurisdictions rely on day-ahead markets and forward price curves (published by others) to provide their participants with price signals and leave the individual participants to generate their own price forecasts as part of their risk management programs. The current forwards market in Alberta is extremely illiquid and does therefore not provide the required price signal to the market.

One important distinction between the Alberta market and other markets is the presence of price-responsive load. Alberta has approximately 300 - 500 MW of price-responsive load in a market with an average load of approximately 7,000 MW – a very high percentage compared to other markets. As almost no load actually bids into the merit order, most response comes about as a result of load anticipating high prices and shutting down their processes (or offering their own generation used for these processes into the merit order) until price has fallen to a more reasonable level. The AESO real-time price forecast provides some portion of this load with a price signal that assists these customers in determining whether or not it is in their best interest to shed part of their loads. Price-responsive load is considered a desirable element in the market and every effort should be made to encourage the participation of price-responsive load. Removal of the real-time price forecast would work against this goal.

The price signal provided by the real-time price forecast is also important to importers and exporters. In the Alberta market, importing and exporting electricity is primarily viewed as opportunistic and should not be discouraged. Opportunistic users of the tie-lines may make use of the price signal provided by the real-time forecast to determine if it is in their best interest to schedule any energy in to or out of the province. Removal of this signal would discourage opportunistic importing and exporting and likely have the effect of increasing Pool price volatility – an undesirable situation.

In the summer of 2002 the MSA instituted a new guideline regarding locking restatements. In essence the guideline stated that the use of a locking restatement within 30 minutes of the effective time of the locking restatement would not be permitted unless the locking restatement was for operational reasons. The rationale behind the T-30 cut-off was to provide the market with the opportunity to react to the change in market conditions by way of the real-time price forecast. If the real-time forecast was removed, the market would not have a chance to react to any locking restatements. This would essentially give the party who submitted the locking restatement a competitive advantage and create a less efficient market. This is another argument against the discontinuation of price forecasting.

The discontinuation of price forecasting by the AESO would not promote a fair, efficient and openly competitive market in Alberta. In fact, the removal of this price signal may be seen to be unfair to some market participants (i.e. smaller players and loads) and even give others (i.e. more sophisticated market participants who are able to generate their own price forecasts) a competitive advantage. In addition, the benefits resulting from publishing the price forecast (price-responsive load, imports and exports and the effects of locking restatements) support the notion of maintaining the price forecast or some form of price signal, however the method of determining the real-time forecast could be improved.

Problems with the methods used in determining the real-time price forecast are generally related to inconsistencies and judgments made by the System Controller. If the process were automated in some way, a lot of the inconsistencies could be removed. The automated forecast would still provide the price signal required by the market. An automated forecast would be generated on a pre-determined schedule and take into consideration all of the factors known at that moment in time, including: energy restatements, locking restatements, import and export schedules and units that are down for maintenance. As many of these factors are not known until relatively close to the hour of delivery, the band of uncertainty around the forecast would widen the further away from real-time the forecast is made. The forecast price for two or three hours in the future would be less meaningful than the forecast price for the next hour but should still be better than the day-ahead forecast. However, the accuracy of the near real-time expected price may actually improve because the price estimate would be generated on a regular basis and not be dependent on other things going on in the System Coordination Centre which may distract the System Controller from posting a revised forecast.

Automating the real-time price forecast could also have the benefit of taking price information out of the hands of the System Controller. Some market participants (as well as the MSA) believe that the System Controller should not have any exposure to the offer and bid prices because they might influence their dispatch process. If no prices were visible, the System Controller could dispatch based on volume alone without the possibility of being influenced by prices. Although System Controllers currently use the price aspect of the merit order to judge participant responses (i.e. price-responsive load), the knowledge of SMP (which is publicly posted) and the System Controller's experience should provide enough information for him to ensure system reliability. Removal of the price from the System Coordination Centre will remove any speculation from the System Controller's job. Encouraging load to bid into the merit order would also help the System Controller to manage price-responsive load.

It could be argued that the current real-time price forecast is a true forecast as it does incorporate some degree of analysis. If the forecast was to be automated, this level of analysis would be removed from the process and the price estimate generated should be more correctly labeled a "real-time price *outlook*".

Conclusions

This review has revealed that although the price forecasts prepared by the AESO are not very accurate, they do provide a useful signal to market participants. Although the forecast prices are rarely correct, they generally give an indication of the direction of price movement and price volatility in the market. Both the day-ahead and real-time forecasts are used by market participants to various degrees ranging from not referring to the forecasts at all to relying on the real-time forecast to decide whether or not to shed load.

As the price forecasts, based on submitted offers, provide a signal to the market regarding the supply of energy available to the market and thus indicating when system reliability may be at risk, it can be argued that the AESO is the best party to be conducting and publishing price forecasts. Discontinuing the publication of price forecasts altogether without replacing it by another form of price signal would prevent the AESO from carrying out its mandate of maintaining system reliability.

Published price forecasts contribute to maintaining a fair, efficient and openly competitive Alberta electricity market. Making the same information available to all market participants is a way of promoting fairness in the market. Removing the forecasts could be interpreted as unfair to smaller, less sophisticated market participants. The price signal generated by the price forecasts encourages market efficiency – a high price signal will encourage generation (including imports) and result in a lower price. Discontinuing price forecasting would not benefit the fair, efficient and openly competitive operation of the Alberta electricity market.

The MSA realizes that no price forecast will be 100% accurate. However, if modifications can be made in the name of improving the fair, efficient and openly competitive operation of the market then actions should be taken. The MSA is currently discussing with the AESO adjustments which may be helpful in addressing the issues identified in this review.

3.3 Information Sharing Issues

Pursuant to the mandate granted under the new *Electric Utilities Act*, the MSA is responsible for surveillance of the market to ensure that it operates in a fair, efficient and openly competitive manner.

The sharing of confidential information within organizations and between market participants is contemplated by the nature of the market and the industry. It is part of doing business. However, from a market perspective, "information sharing" issues may arise (that is, the potential for inappropriate sharing and use of confidential information). Thus, to the extent that information flows and information asymmetry can affect the fair, efficient and openly competitive operation of the market, effort is required to limit inappropriate information sharing.

Existing business structures such as the power purchase arrangements, agency relationships and joint ventures are obvious examples of commercial arrangements within which confidential commercial information must flow on a regular basis. Further, the MSA has seen a rise in the number of innovative business arrangements being contemplated and brought forward by market participants, and sees this as a positive occurrence for the market.

Given that such arrangements are integral to the operation of the market, the MSA is of the view that measures undertaken to address any information sharing issue must not only address the targeted behavior but must also take into account goals such as facilitation of the market, costs of monitoring and compliance, and other practical and policy considerations.

In order to obtain feedback on the issues, and on measures which might be available to address any concerns around information sharing, the MSA undertook a series of workshops and other meetings during April and May. These workshops generated considerable discussion amongst the parties, and were well received in general. The MSA is continuing its work in this area.

3.4 Uneconomic Exports

The MSA has a mandate to ensure that pool prices are the result of a fair, efficient, and openly competitive market. Export and import activity which is motivated primarily by a desire to influence pool price is not considered by the MSA to be acceptable market behavior.

During the month of May, the MSA observed significant export activity that did not appear to be logically supported by the relative economics at each end of the interconnection.

The participant in question was asked to discuss the nature of their export activity. After detailed discussions with the participant, the MSA was satisfied that no untoward activity took place and has closed the file on this matter.

4 OTHER MSA ACTIVITIES

4.1 Appointment of Martin Merritt to MSA

Effective July 1, 2003, Martin Merritt, who is well known in industry circles, was appointed as Market Surveillance Administrator, replacing outgoing MSA Tom Cumming. Tom is moving on in his new role as Chairman of the Balancing Pool and we would like to thank Tom for his strong leadership through wide ranging industry changes and restructuring as we welcome Martin on board as MSA.

4.2 Stakeholders Meeting

The MSA has scheduled its fall stakeholder meetings in Calgary on September 24 and in Edmonton on September 30 to update stakeholders on the activities of the MSA and to provide a forum for stakeholders to give their feedback to the MSA on any market issues or concerns. Details of the meetings will be posted at www.albertamsa.ca .

4.3 Regulatory Proceedings

The MSA has continued its regular watch of proceedings before the Alberta Energy and Utilities Board (EUB), including matters relating to transmission, rural electrification associations, and exemptions granted by the EUB in relation to the *Code of Conduct* Regulation.

Further, the MSA has intervened in several applications before the EUB, for reason that they may significantly impact the mandate of the MSA.

The intervention contemplates that the MSA is particularly interested in the information filed in relation to the applications and the hearing itself.

These applications in which the MSA has intervened before the EUB relate to the proposed sale of the ATCO retail electricity and gas businesses to Direct Energy, the proposed regulated tariffs for Direct Energy in respect of the sale of gas and electricity in the ATCO service territory, and the unbundling of 2003 gas rates pertaining to ATCO.

The MSA may also intervene in the applications by ENMAX and EPCOR in respect of distribution tariffs and regulated rate tariffs for the period(s) commencing January 1, 2004.

Outside of Alberta, the MSA has intervened in the British Columbia Utilities Commission Inquiry into a Heritage Contract for BC Hydro's Existing generation Resources and into Stepped Rates and Transmission Access.