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MSA REPORT

Quarterly Report
January – March 2003

28 April, 2003

MARKET SURVEILLANCE
ADMINISTRATOR

Market Highlights

- The average price of electricity in the Alberta wholesale spot market for Q1/03 was $83.94/MWh, more than double the price in Q1/02 ($35.74/MWh). However, the price of natural gas - a significant driver of electricity prices, also rose in price from the $3 - $4/GJ range in Q1/02 to the $6 - $8/GJ range in Q1/03. Considering the increased price of gas, electricity prices might have been expected to be higher yet.

- The Balancing Pool had considerable success in their MAP II auctions, most recently moving all of the Genesee plant capacity (in strips) out of their control and into the hands of market participants. Some of the new strip holders are new participants in the Alberta market. Accordingly, the Balancing Pool's own portfolio is quite small (H.R. Milner - 143MW and Clover Bar 3 - 157MW) and the MSA will no longer make specific references to the Balancing Pool's position in the market. They will be treated as any other participant as long as their market share remains at the low levels of today.

- New projects in Q1/03 comprised the Calpine Plant (250MW) near Calgary and the Muskeg River Plant near Fort McMurray (170MW). This new capacity offsets the loss of Wabamun #3 that retired late in 2002 and the recent modest load growth. Peak demand grew some 3.5% from Q1/02 to Q1/03 whereas the total additions (net of Wabamun #3) in that period summed to 536 MW, about 5% of total supply.

- The MSA recently completed some significant studies and highlights are presented herein. These studies included:

    - Study of effects of the growth of zero offers into the energy market. Zero offers are energy offers at $0/MWh, but do not necessarily mean that the generator is expecting to receive a zero payment for the output.

    - Study of the effectiveness of the rule change by the Power Pool in December 2001 creating the Intra Day Market in which participants became able to register direct sales at the Pool during the trading day, much closer to the time of the flow of energy.

    - Study of the effectiveness of the rule change by the Power Pool in December 2001 requiring importers and exporters to be price takers in the market.

    - Review of the effectiveness of the Aggregator Protocol designed by the Balancing Pool as a means of aggregating strip offers to unit offers that can be accommodated at the Pool.

- Overall, the market appears to have functioned well in Q1/03 with market outcomes corresponding reasonably to the relevant market fundamentals.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

i) **Electricity Prices**. On a monthly average basis, pool prices trended moderately upward over the quarter as can be seen in Figure 1 and Table 1, from $80.52/MWh in January to $89.80/MWh in March, continuing an upward trend from mid-2002 that closely mirrors the upward trend in gas prices over the same period. Prices were significantly higher in Q1/03 relative to the same period last year when monthly average prices ranged from $22.37/MWh to $55.14/MWh. Again, the level of gas prices appear to be a significant variable as Q1/02 gas prices were in the $3.00-4.00/GJ range while Q1/03 gas prices rose to the $6.00-8.00/GJ range on a monthly average basis and spiked into the $12.00-15.00/GJ range in the spot market on several occasions. Off-peak prices moved higher relative to last quarter particularly in the month of March due in large measure to strong off-peak export volumes to BC as well as the fact that when gas units were setting marginal price in off-peak hours, they did so at levels not significantly lower than levels at which they set price during on-peak hours. Figure 1 shows that the volatility of Pool prices moved lower through Q1/03 after increasing through Q4/02. This is partially a function of price variations being compared against larger mean prices. The highest and most volatile prices observed in Q1/03 occurred in early March due to tight availability resulting from a combination of forced and planned outages at Joffre, Genesee #2, Keephills #2, and Sundance #3. Looking at the price duration curves in Figure 2, it can be seen that prices in Q1/03 were higher than prices through both Q4/02 and Q1/02 more than 90% of the time. Pool prices exceeded $100/MWh 23% of the time in Q1/03 vs. 8% of the time last quarter and 2% of the time in the same period a year ago. Although higher prices were seen over the majority of the quarter relative to Q4/02 and Q1/02, Q1/03 saw marginally fewer price spikes above $400/MWh.

	Average Price	On-Pk Price	Off-Peak Price	Std Dev[1]	Coeff. Variation[2]
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%**
Oct -02	44.33	56.07	28.13	39.23	88%
Nov -02	69.07	88.32	45.00	82.47	119%
Dec -02	70.88	83.39	56.34	108.00	152%
Q4 / 02	**61.34**	**75.93**	**43.16**	**82.50**	**134%**
Jan -02	28.43	35.90	18.96	16.34	57%
Feb -02	22.37	28.30	14.46	13.60	61%
Mar -02	55.14	64.39	43.40	56.34	102%
Q1 / 02	**35.74**	**42.86**	**25.61**	**38.02**	**106%**

1 - Standard Deviation of hourly pool prices for the period

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

Table 1, Pool Price Statistics

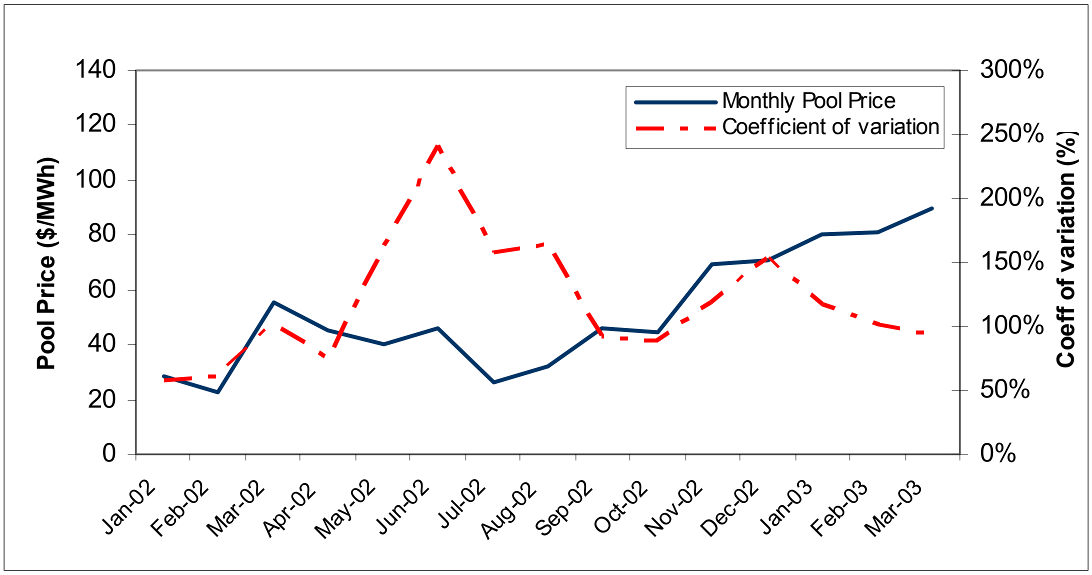


Figure 1, Pool Price with Pool Price Volatility

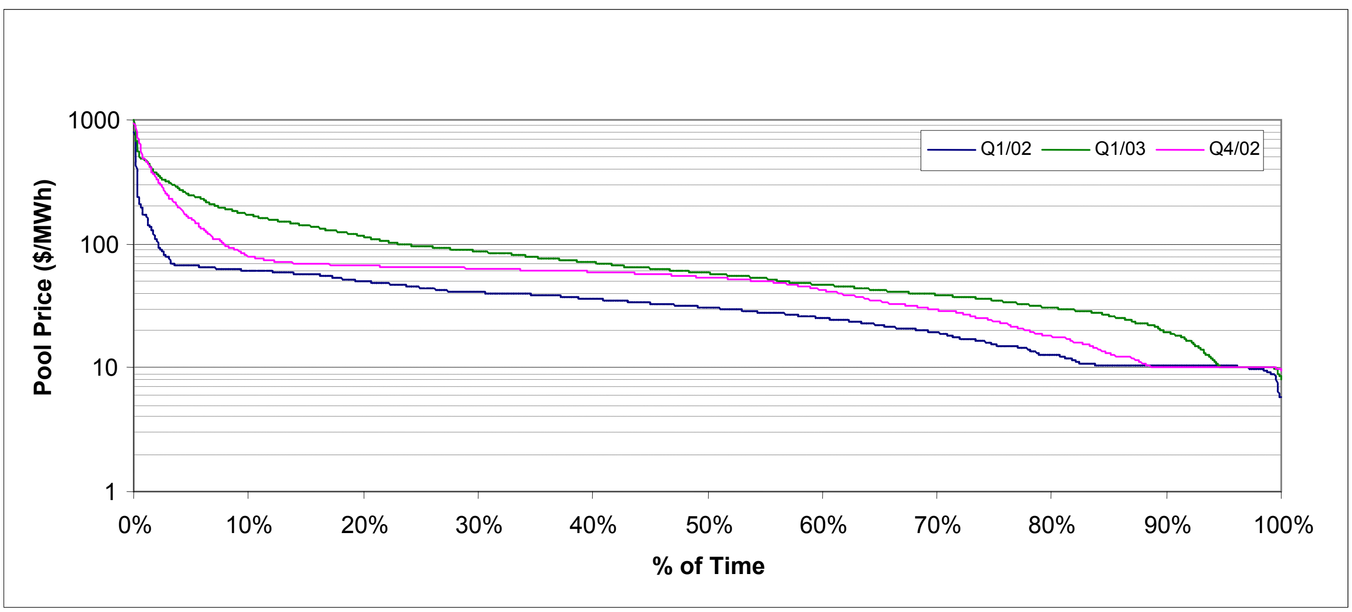


Figure 2, Quarterly Pool Price Duration Curves

ii) Natural Gas Prices. The marginal generating unit in Alberta is often gas-fuelled and therefore, the price of gas has a significant impact on pool prices. In Q1/03, pool price was set by gas-fired generation 39% of the time at a weighted average system marginal price (SMP) of $127.26 as compared to 51% of the time in Q4/02 at a weighted average SMP of $73.51, and 53% of the time in Q1/02 at a weighted average SMP of $47.27; all numbers on an on-peak hours basis. The reduction in share of price setting activity can be attributed in part to higher coal unit availability, greater import volumes in Q1/03 relative to both Q4/02 and Q1/02, and new cogeneration capacity with must-run capacity offered in as a price taker. Figure 3 compares the monthly gas price in Alberta with the average pool price. The correlation of the two commodities over the period shown is quite evident and was calculated to be 0.92 on a monthly average basis. Based on daily average pricing data, the correlation coefficient reduces to 0.57. Monthly average gas prices climbed markedly in January and February due to falling gas storage levels and also due to weather related demand in the eastern U.S. but leveled off in March.

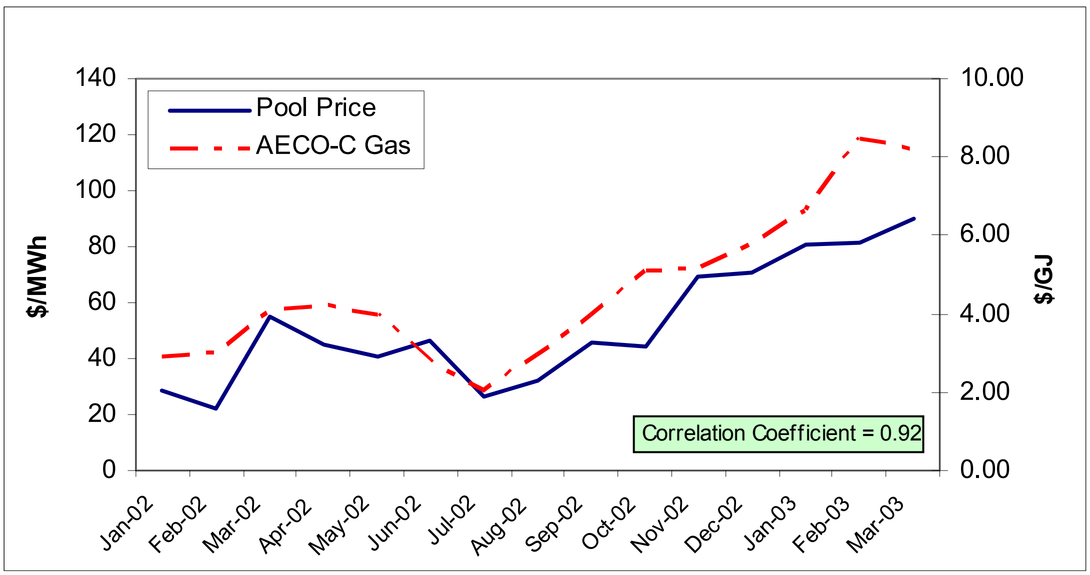


Figure 3, Pool Price with AECO-C Price

iii) Price Setters in 2002. Figure 4 shows the top 5 participants (unnamed) who have set pool price most often through Q1/03 together with the weighted average price at which they set system marginal price (SMP). As can be seen in Figure 4, no one generator has a dominant market share in terms of setting the price. The weighted average price set by the leading price setter in Q1/03 was $60.08/MWh on an all hours basis and $69.16/MWh on an on-peak hours basis. In terms of the MSA's reporting and analysis of price setters on a current and a go-forward basis, the Balancing Pool will no longer be singled out and identified as it has now divested control over the large majority of generation assets that were under its control. It should be noted that in the discussion of price setters in the MSA's 2002 annual report, the Sheerness units should have been separated from the Balancing Pool as their offers were controlled by strip owners from late-Q4/02 to the end of the year. This overstated the price setting frequency of the Balancing Pool from 23% to 25% of the time in 2002 on an all hours basis. The lower number would have underscored the point being made even further that the Balancing Pool, with the success of MAP II, is no longer a dominant factor in the market. Going forward, Sheerness strips and Genesee strips will each be grouped for the purpose of defining the price setting participant.

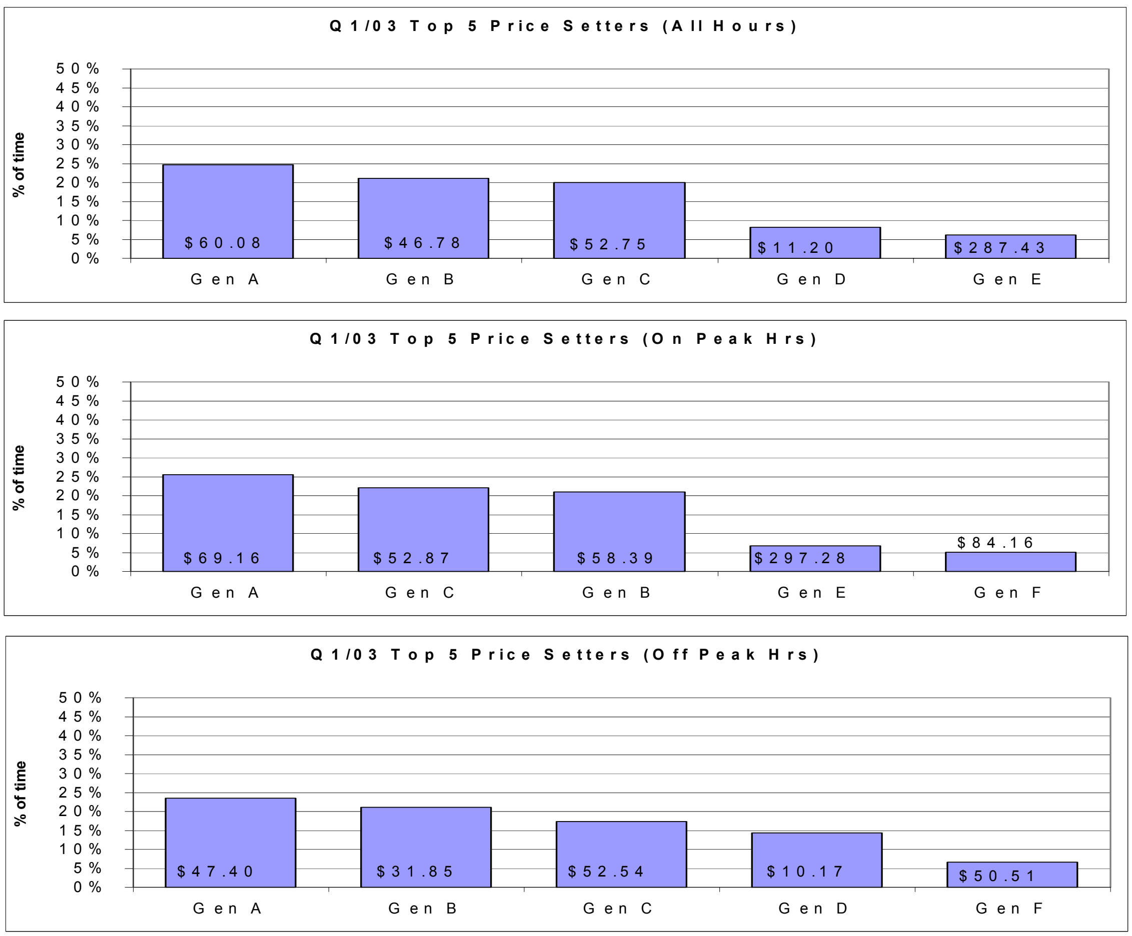


Figure 4, Price Setters by Customer, Q1/03

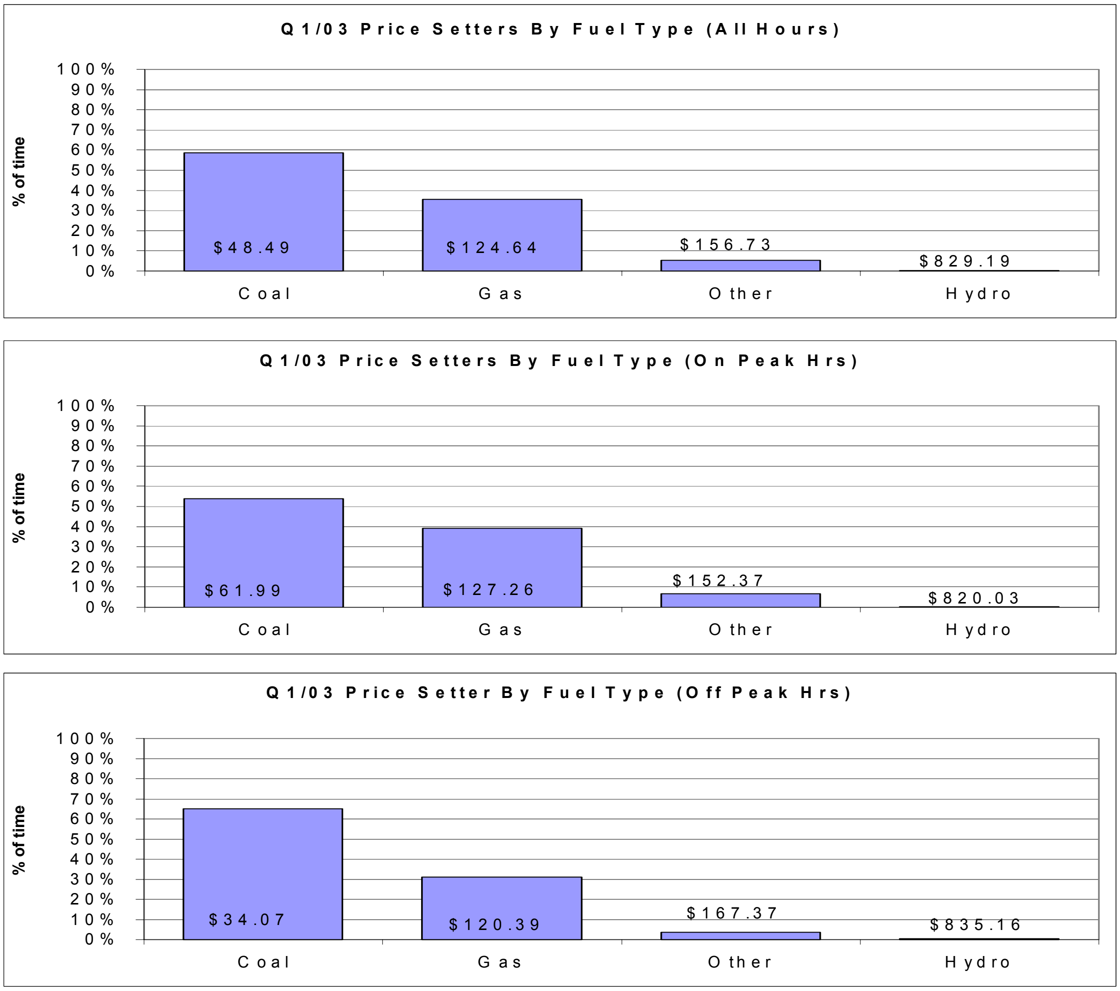
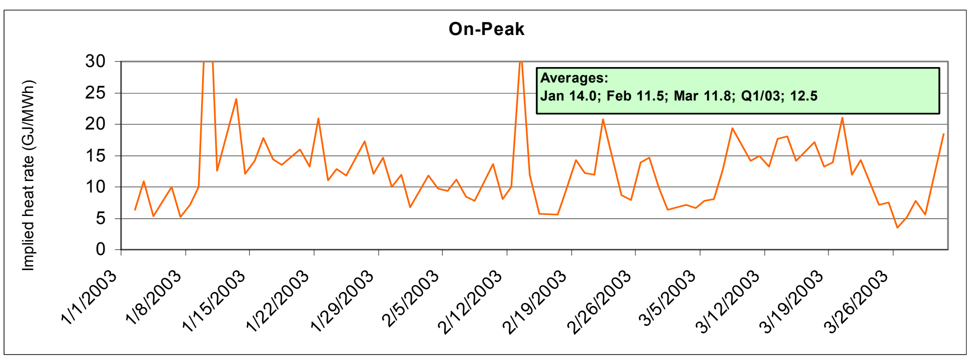


Figure 5, Price Setters by Fuel Type, Q1/03

Figure 5 shows price setters by fuel type for Q1/03. Gas-fired units typically set price most often during on-peak hours while coal units are usually on the margin most often in off-peak hours. In Q1/03, coal units set the price most often both in on-peak hours as well as in off-peak hours. In on-peak hours, coal units set SMP 53% of the time at a weighted average SMP of $61.99/MWh while in off-peak hours, coal units set SMP 65% of the time at a weighted average SMP of $34.07. Clearly coal units on average, have been offering at least some of their energy into the market above variable cost, which they have every right to do in a competitive market. As with all generators, they must recoup more than just variable operating costs to remain in business. Coal units would appear to logically be "shadowing" gas units to the extent possible in order to maximize revenue since gas units have been forced to offer their energy at higher prices due to the increasing cost of gas. Hydro units set price at an average SMP of $820.03 on an on-peak basis in Q1/03, but did so only 0.23% of the time. Since hydro units are fuel constrained, they generate infrequently and only when it is most profitable to do so which is normal and expected for these assets.

iv) **Implied Market Heat Rate.** The implied market heat rate is simply the break-even heat rate determined by the market price of electricity divided by the spot price of natural gas. The implied market heat rate is a useful metric that provides some context to prices set by gas fired units as it takes into account the variable cost of natural gas. Figure 6 shows the daily implied market heat rate for Q1/03 both on an on-peak and an off-peak hours basis. As can be seen in Figure 6, there were brief periods in mid-January and mid-February that were particularly profitable for gas units. Although gas units set marginal price 39% of the time on an on-peak basis in Q1/03 at a weighted average SMP of $127.26/MWh, the average on-peak implied market heat rate was 12.5 GJ/MWh. In the context of a gas unit such as Clover Bar with a heat rate of 12-15 GJ/MWh, the unit on average, would have lost money the majority of the time in the quarter, which explains why these units have not been running recently. The equivalent implied on-peak heat rate values for Q4/02 and Q1/02 were 14.4 GJ/MWh and 12.5 GJ/MWh respectively, indicating that the on-peak market economics for gas units have been fairly uniform. Looking at the market impact of gas units, which was determined by taking the implied heat rates just for gas units, and weighting this by the share of time in which gas units set price, this weighted contribution to the on-peak implied market heat rate was actually lower for Q1/03 relative to Q4/02 and Q1/02 suggesting that gas units had a lower impact on on-peak market prices in Q1/03.



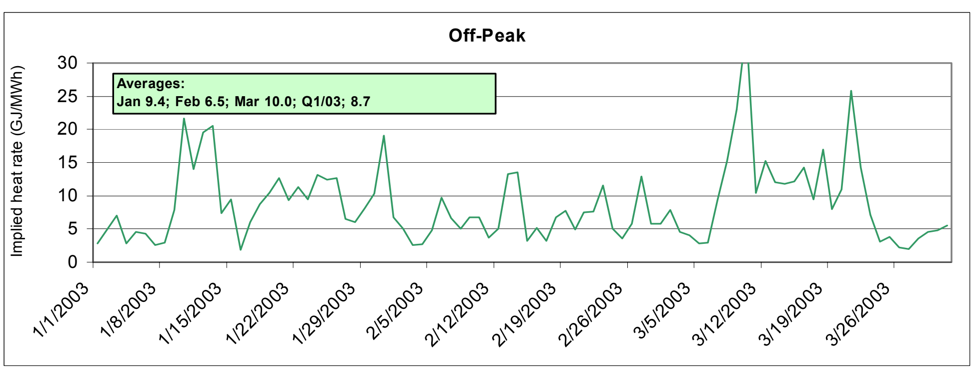


Figure 6, Implied Market Heat Rates, Q1/03

v) **New Power Pool Rules**. There have been no major changes to Pool Rules in Q1/03.

vi) **New Supply and Load Growth.** A total of 420 MW of new generation was commissioned in Q1/03, representing an increase in Alberta generation of about 3.5% in the quarter. This increase is comprised of the following significant projects:

- Calpine – Gas (250 MW)
- Muskeg River – Gas (170 MW)

The monthly average hourly system demand for electrical energy in Q1/03 was:

January	7385 MW
February	7358 MW
March	7189 MW

Peak demand in Q1/03 was 8433 MW which occurred on January 14 and is an increase of approximately 3.5% (adjusted for the change in load reporting effective June 17, 2002) over peak demand in the same period a year ago. Supply has increased approximately 5% from the end of Q1/02 to the end of Q1/03; indicating that the increase in generation capacity has more than compensated for the increase in peak demand over the last 12 month period.

vii) **Supply Availability Index (SAI).** This indicator provides a straightforward measure of market tightness based on the remaining volume of MW in the merit order above dispatch level. This approximates the supply that would be available to the system controller within the hour, to meet system demand. Offers in the merit order do not have a strict obligation to generate when dispatched, therefore, this metric should be viewed as representative. Figure 7 shows the minimum, maximum, and average SAI for Q1/03 which reflects that intra-hour availability can change due to restatements, and the three together show an availability band. It can be seen in Figure 7 that the SAI had more concentrated periods of relative tightness in mid-January and in early March, which were coincident with high levels of forced and planned outages in the system. SAI and price are generally negatively correlated, that is, price tends to be relatively high when the difference between demand and short term availability is low, and vice versa. For the Q1/03 period, the correlation coefficient between SAI and hourly pool price (not shown) was determined to be -0.39 which is a reasonably strong negative correlation. The shape of the supply curve in the energy market, however, is an important variable that can influence the degree of this correlation from one hour ending (HE) to the next.

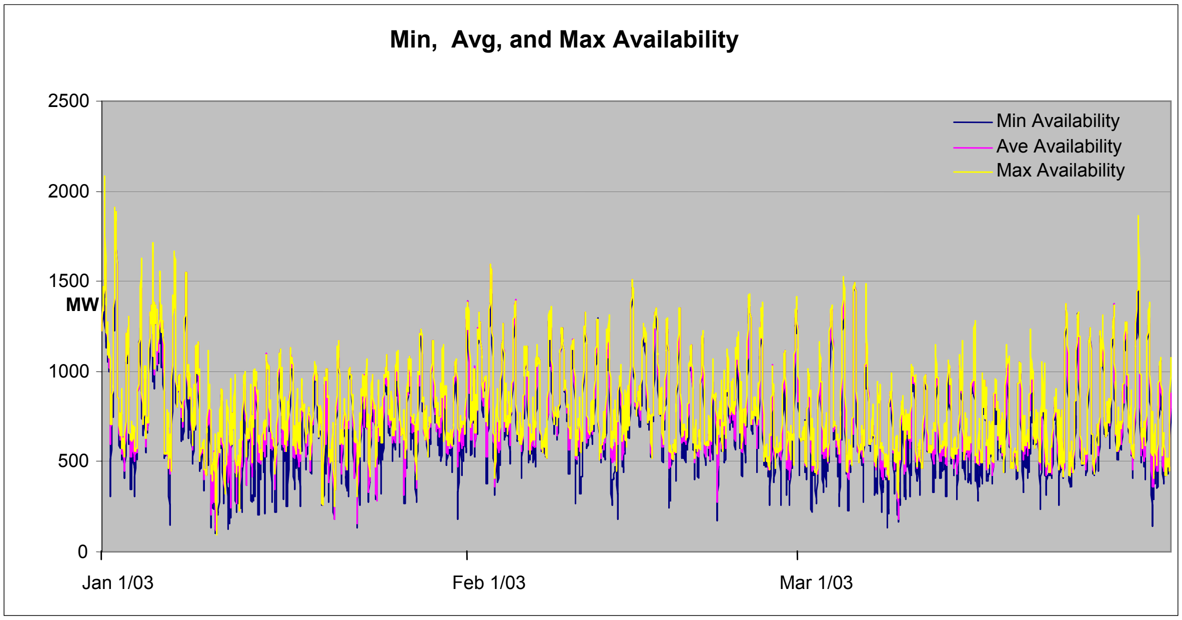


Figure 7, Supply Availability Index, Q1/03

viii) Imports, Exports and Prices in Other Electricity Markets. As part of the interconnected electric system, neighbouring markets have an impact on price behaviour in the Alberta market within the physical and operational constraints of the transmission interconnections.

- Figure 8 shows on-peak Pool prices together with those in neighbouring electricity markets over the last 15 month period. Relative to other western markets, the differential of on-peak prices with on-peak Alberta prices continued to grow from Q4/02 into January but contracted in February and again in March as a result of rising prices in the other markets. This suggests that there was some lag in the effect of gas prices on the western U.S. hubs. As well, higher relative prices in Alberta in late Q4/02 were due in part to unit outages.

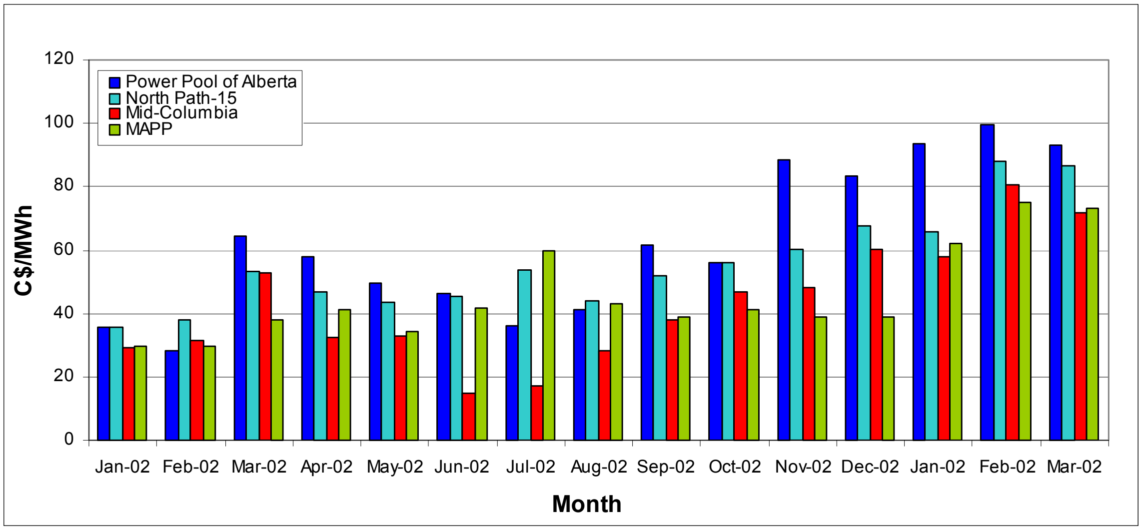
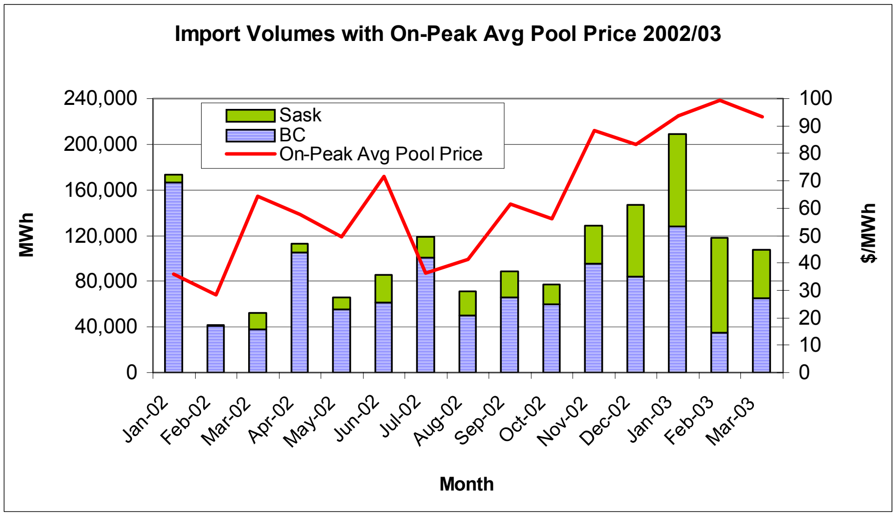


Figure 8, Monthly Average On-Peak Prices

- Figure 9 shows the volumes of imports and the prices paid. Volumes are shown relative to on-peak prices since the bulk of imports tend to occur in on-peak hours when system demand is high. Total import volumes trended higher through Q4/02 and into January but declined in February and March, reflecting the differential between Alberta on-peak prices and on-peak prices in other western hubs. Imports from Saskatchewan continued to comprise a significant proportion of total imports through January and February, continuing on from December. Prior to December, imports from Saskatchewan on average, made up only about 10% of import volumes over the prior 11 months. In terms of the prices paid for imports, volumes from B.C. were significantly higher in price relative to on-peak average Pool price through Q1/03, continuing on from late Q4/02. This suggests that although importers are price takers, BC importers have been opportunistic in selling into the Alberta market during high priced periods. Volumes from Saskatchewan were on average, close to on-peak pool price in Q1/03. In Q1/03, Alberta was a net exporter for two out of three months relative to BC and a net importer relative to Saskatchewan throughout Q1/03. Overall, Alberta was a net importer in Q1/03.



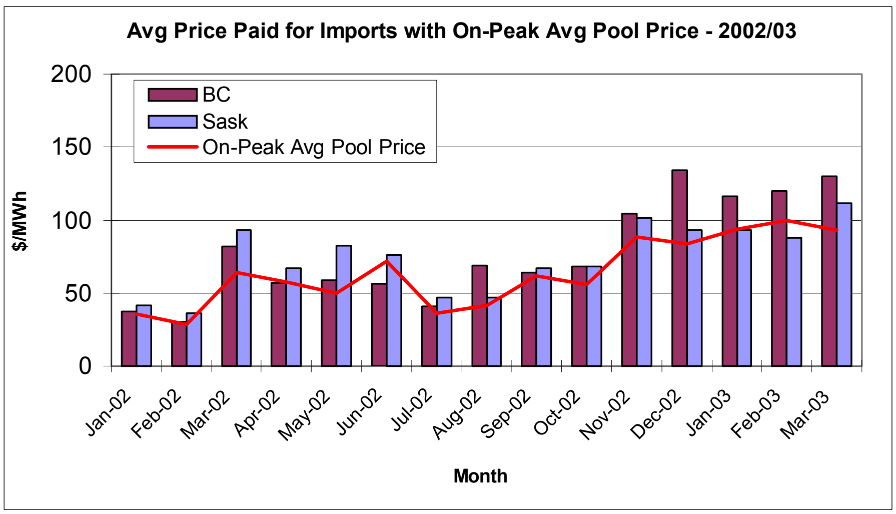
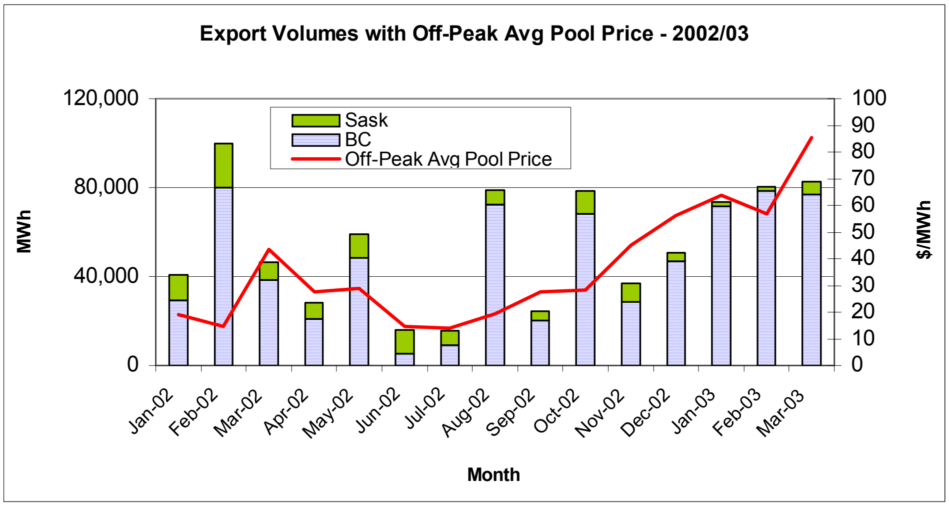


Figure 9, Monthly Imports 2002 – 2003

- Figure 10 shows the amounts of exports and the prices paid. Volumes are shown relative to off-peak prices since the bulk of exports typically occur in off-peak hours. Total exports were on average, significantly higher relative to last quarter and relative to the same period last year. The higher sustained exports in Q1/03 in light of the relatively high off-peak prices, suggests that much of these volumes may be linked to contracts rather than spot prices. Exports to BC dominated total export volumes in Q1/03 comprising 96% of the total. Export volumes to BC were on average, stable through Q1/03. Average prices paid for exports in Q1/03 were marginally lower relative to off-peak pool prices with the exception of Saskatchewan exports in January. Lower average prices paid relative to average off-peak prices indicates that the bulk of exports occur in the lowest priced hours.



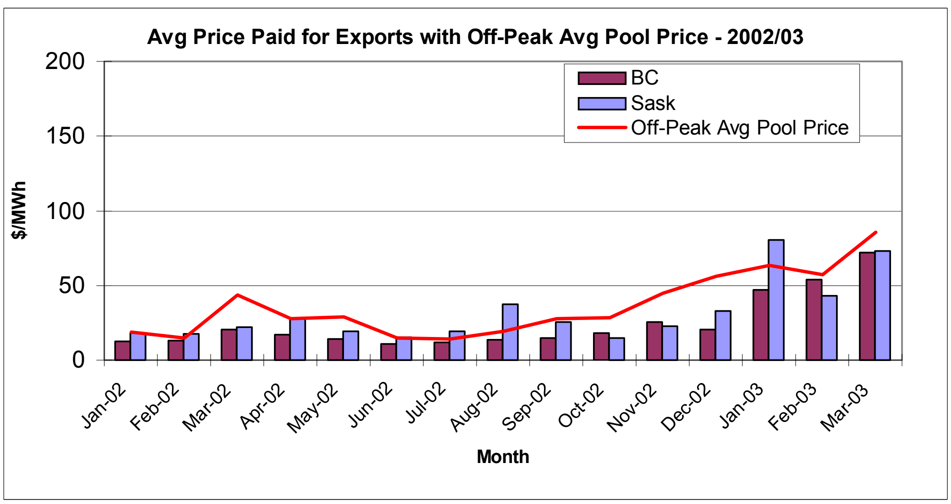


Figure 10, Monthly Exports 2002 – 2003

ix) **Ancillary Services Market**. Figure 11 shows the delivered price of active ancillary service products traded through the Alberta Watt Exchange (Watt-Ex) in Q1/03. The supplemental reserve market has remained at $0.00 through nearly all of the quarter which continues to be a market outcome resulting from the hydro PPA as discussed in prior MSA quarterly reports. Figure 11 also shows that the price of on-peak spinning reserve service dropped to $0.00 on many occasions in Q1/03. This could be attributed in part to the rise in off-peak prices which appeared to create enhanced opportunities for participants in the off-peak market but resulted in more competitive prices in the on-peak market. Nonetheless, this is a surprising outcome that does not appear to follow rational behaviour. The MSA will pay particular attention to this part of the AS market in its ongoing monitoring efforts.

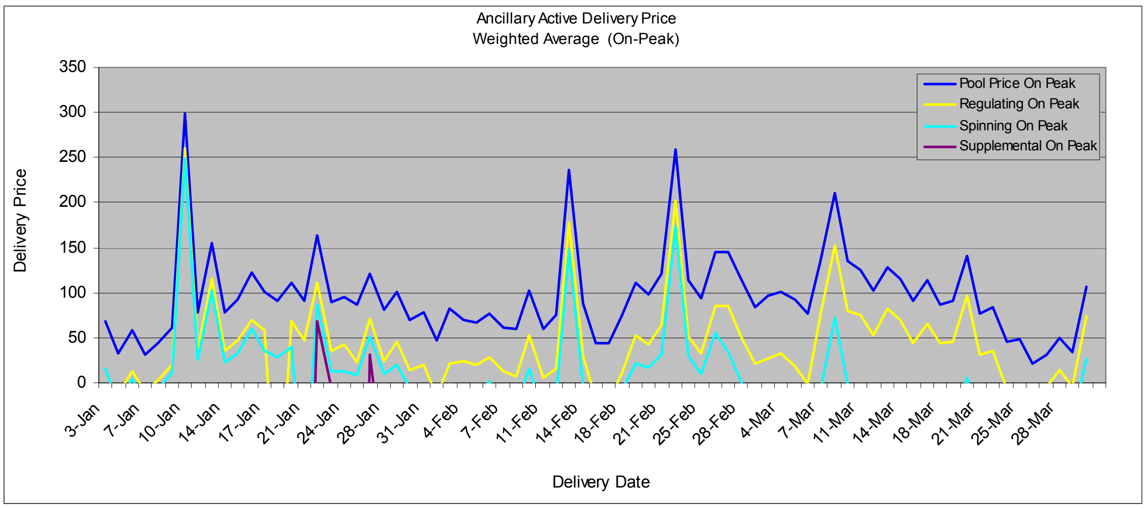


Figure 11, On-Peak Active Market Prices – Q1/03

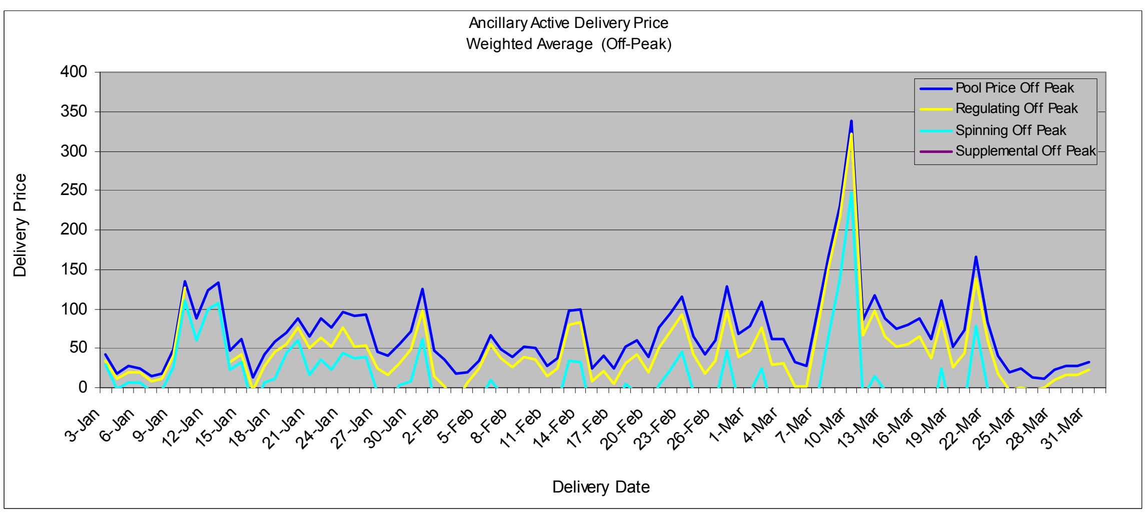


Figure 12, Off-Peak Active Market Prices – Q1/03

x) **Outages and Derates.** By regulation, the MSA is required to monitor the outages and derates of the previously regulated generating units that are now operated under the terms and conditions of the Power Purchase Arrangements (PPAs). In addition to its real-time monitoring of outages and derates, 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 more about the causes leading to the situation.

Historically, the level of outages and derates, both planned and unplanned, have shown a great deal of variability on both a quarterly and annual basis. The amount of outage can vary from one time period to the next because planned outages are scheduled on a multi-year basis. This, in turn, impacts upon unplanned and forced maintenance. Table 2 below shows the amount of unplanned equivalent outage, which includes all unplanned outages and derates, in Q1/03. For comparison, unplanned outage rates for the previous quarter (Q4/02), the same quarter last year (Q1/02), 2002, and the longer term historical average (1996 - 2002) are also reported.

Overall, the weighted average unplanned outage rate at the thermal PPA units was half of the rate seen during the previous quarter, coming in at 4.7% versus 9.6%. This result is being driven by significantly lower outage rates recorded by TransAlta Utilities Corporation. TransAlta's outage rate has moved closer to its historical level and at 7.0% is almost identical to its outage rate in Q1/02 (7.1%). The high outage rate in Q4/02 was due to a number of factors, including forced maintenance and the rescheduling of some outage from 2003 into the last quarter of 2002.

Epcor's PPA units experienced low outage rates. Excluding planned outages, Epcor's units were unavailable 0.4% of the time during Q1/03. Epcor's outage rate is low for a number of reasons. First, market conditions continue to limit the higher cost Clover Bar and Rossdale Plants' participation in the market, reducing the probability of unplanned outages. Second, Epcor's coal units (Genesee 1 and 2) are the newest in the Alberta coal-fired fleet, having been commissioned in 1989 and 1994.

Atco's Q1/03 outage rate (4.3%) is up slightly from the same quarter last year (3.0%), although it is tracking last year's yearly average (4.5%) closely. Atco's outage rate is up slightly due to forced maintenance at its Battle River Facility. There is no word on whether concerns about the low water level in the Battle River, which were reported late last year, will continue to threaten the units operations during the summer season.

Overall, for the PPA thermal units, operating hours lost during Q1/03 from unplanned maintenance was lower (4.7%) than the historical average (6.9%) and in line with the outage rate for the same period last year.

	Q1/03	Q4/02	Q1/02	2002	1996-2002
Epcor					
Total	0.4	0.8	1.0	1.1	3.0
Atco					
Total	4.3	2.6	3.0	4.5	6.6
TransAlta					
Total	7.0	17.0	7.1	11.2	9.0
Weighted Average	4.7	9.6	4.6	7.1	6.9

Table 2, Outage for PPA Units (%, *excluding planned outage*)

2 REVIEW OF THE RETAIL MARKET

The MSA will continue in 2003 to be involved in retail market issues. The following are some of the key issues the MSA had a role in moving forward through the quarter.

i) Competitive Retail Market

It is part of the MSA's mandate to monitor the operation of all electricity markets within the province of Alberta to ensure that they operate in a fair, efficient and openly competitive manner. To date, the focus of the MSA's work has been primarily on the wholesale market. Very little emphasis has been placed on the retail electricity market, and in particular, the retail market for small (< 250,000 kWh/year) customers.

Since its deregulation in January 2001, the retail market for small customers has been slow in developing. Despite the push to promote competition, the majority of small customers have not signed contracts with retailers and a limited number of new retailers have entered the market. Most Regulated Rate Option (RRO) customers have remained on RRO. According to a study conducted by the Center for the Advancement of Energy Markets (CAEM)[1], only 2.16%, 3.23% and 23.25% of Alberta's residential, farm and small commercial/industrial customers have chosen to sign competitive contracts. As such, the MSA has undertaken a review of the market metrics that might be used to assess the competitiveness of the evolving Alberta retail electricity market.

The review included a study of the components of competitive market theory (barriers to entry, entry and exit, information requirements, economies of scale, and customer choice) and how they apply to the Alberta retail electricity market. It also included an assessment of the methods used to report on the competitiveness of retail markets in other jurisdictions (Texas, Australia and the UK). Based on these assessments, the MSA has developed a set of proposed Retail Market Monitoring Metrics to be applied to the Alberta retail electricity market. The proposed new Retail Market Monitoring Metrics are:

- Number of active retailers (total and by customer class)
- Retailer entry and exit from the market
- Market share (load and/or number of customers) of retailers by customer class
- Customer switching off RRO to a competitive contract
- Price mark-up of competitive contracts with respect to Pool price

[1] *Electricity Retail Energy Deregulation Index 2003*, CAEM, April 2003.

With the exception of price mark-up data, all data can be obtained from the four Load Settlement Agents (LSAs) in the province. It is proposed that all data will be aggregated to develop a province-wide summary that portrays a sense of the development of the retail market without revealing any commercially sensitive retailer information.

In order to assess the distribution of the competitiveness in the market, market share and customer switching data will be split into four customer type categories: Residential – RRO Eligible, Farm (including irrigation) – RRO Eligible, Commercial/Industrial – RRO Eligible, and Non-RRO Eligible. To alleviate participants' concerns of commercially sensitive information being made public through the Retail Market Monitoring Metrics, market share data is somewhat disguised. For purposes of publishing, no retailer is identified by name, and retailers who are active in more than one category have different pseudonyms for each customer class in which they participate. To further simplify reporting, all retailers in a category that have a market share of less than 5% will be aggregated and all self-retailers will be summed to form a single category.

Information required to analyze price mark-ups includes competitive contract offers of retailers (available on retailers' websites) and actual Pool price data. The mark-up will be calculated for each retailer's competitive offer for each contract term affected in the quarter in question as follows:

$$\text{Mark-Up}_{(\text{retailer, term})} = \frac{(\text{Offer}_{(\text{retailer})} - \text{Average Pool Price}_{(\text{term})})}{\text{Average Pool Price}_{(\text{term})}}$$

The MSA is in the process of collecting the data required for the Retail Market Monitoring Metrics from the LSAs for Q4/02. The next step will then be to prepare a sample report with this data as the MSA proposes to publish in its ongoing quarterly report series. Once the retailers have had a chance to suggest any minor tune ups that may be required, the LSAs will be requested to provide the data on a quarterly basis. Data from Q4/02 will be used as a benchmark against which progress will be measured. With the cooperation of the LSAs and retailers, Retail Market Monitoring Metrics for Q1/03 and Q2/03 will likely be included in the next edition of the MSA's Quarterly Report and will continue to be reported on a go-forward basis.

ii) Code of Conduct Compliance Audits

In accordance with its responsibilities under the *Code of Conduct Regulation* ("Code"), the MSA requested that ENMAX Power Corporation and EPCOR Distribution Inc. provide certain reporting in relation to the Code for the calendar 2002 period. The reporting was agreed to consist of specified procedures designed to test for compliance by these owners and their affiliated retailers, in relation to particular sections of the Code selected by the MSA.

The reporting was received at the end of Q1/03, and is presently under review by the MSA, along with other reporting required of the parties in pursuant to the Code. At this time, the MSA would like to thank ENMAX and EPCOR for their efforts both in helping to design the specified procedures utilized for the 2002 period, and in providing the reporting on a relatively short turnaround.

In respect of ATCO Electric Ltd., the MSA has continued to monitor the proposed agreement for the sale of ATCO's retail energy business and related proceedings before the EUB. These matters left ATCO effectively exempt from certain Code requirements and accordingly lessened ATCO's reporting requirements for the 2002 calendar year.

iii) Load Settlement

The MSA has continued its work with the Alberta Settlement Committee ("ASC") and various interested parties in respect of load settlement issues. At the committee level, the MSA has been involved with both the ASC and the Compliance Monitoring Committee.

3 MARKET ISSUES

The MSA has completed work on a number of market issues that have been discussed in recent stakeholder meetings as undertakings of the MSA. A synopsis of each of these items is included below:

i) Zero Offers.

The issue of $0/MWh offers was brought to the attention of the MSA by several market participants on an informal basis. These participants had noticed that the volume of energy being offered into the real-time energy market (market) at a price of $0/MWh (zero offer) had been steadily increasing since full deregulation of the Alberta electricity market in January 2001. The common fear of these participants was that these zero offers were depressing Pool prices for all market participants. Participants' fears were realized during two hours in the early morning of June 30, 2002 when the Pool price reached an all-time low of $0.01/MWh. The MSA undertook a study of zero offer behaviour in the Alberta electricity market for the 2001 – 2002 period with the intent of determining if this behaviour had significantly impacted the fair, efficient and openly competitive operation of the market.

Since January 2001, the amount of energy offered into the market at a price of $0/MWh has increased dramatically, as shown in Figure 13. At the start of 2001, the only units offering their energy at $0/MWh were a number of gas units offering their minimum stable capacity and some co-gen units that required their plants to be generating to sustain their primary process. Notably, none of the coal units were offering in energy at $0/MWh at this time. Over the course of 2001, more capacity was added to the system than was required to meet the growing demand and thus the competition to remain in merit increased. This was particularly true in the off-peak/overnight hours when demand is at its lowest. It became necessary for the large coal units to offer their minimum stable generation level at $0/MWh to ensure not being dispatched off. Moving into 2002, even more units came on-line and the trend of increasing $0/MWh offers continued. Although peak demand was higher in 2002 than in the two years previous, total energy traded for the year was lower. This has the effect of further increasing competition.

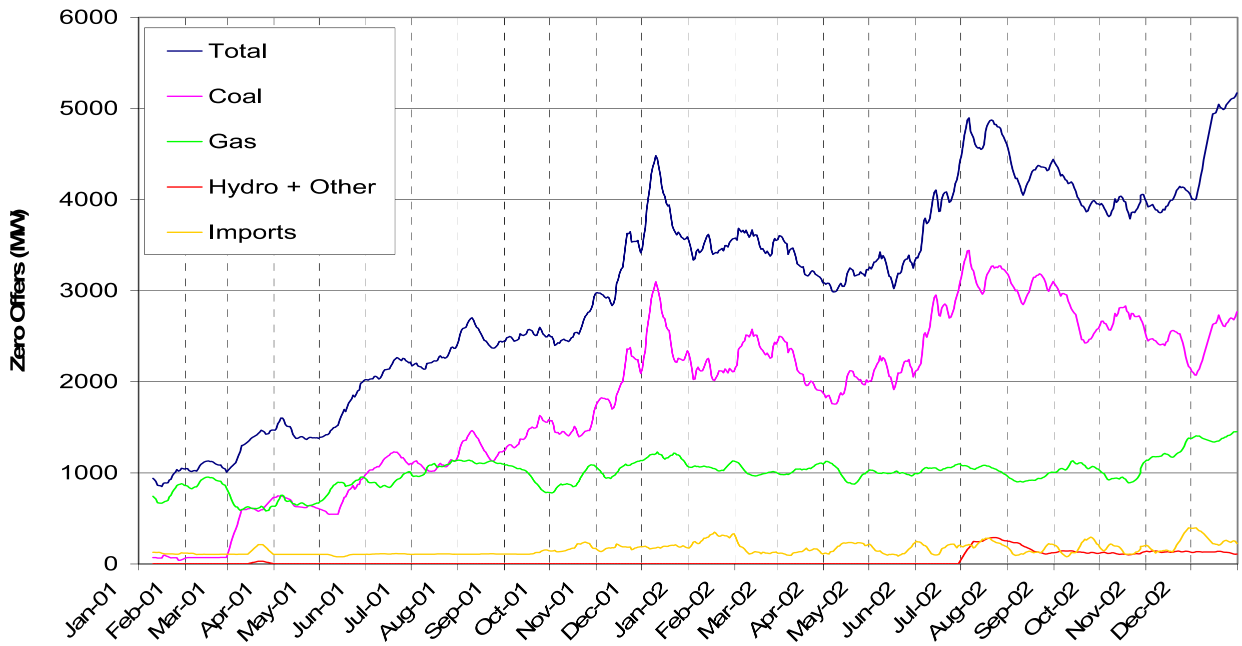


Figure 13 – 2001-2002 Zero Offers by Fuel Type

There are many operational and market/regulatory reasons why generators might offer their energy into the market at a $0/MWh price. In all cases, it is not the intent of the generator to actually receive a price of $0/MWh for the energy sold. More often than not, zero offers are a means by which generators can ensure that their units will remain in merit and not be dispatched down. Operational reasons vary depending on the generating fuel source and include avoidance of shut-down/start-up, minimum run constraints, minimum stable generation and unit testing or commissioning among others. Market and Regulatory reasons for zero offering include imports being required to offer at $0/MWh, participation in the ancillary services market, qualification for IBOC and LBC-SO credits, energy sold forward, strategic/competitive behaviour, fuel contracts, and price chasing.

In addition, increasing zero offers have had the effect of steepening the merit order curve. A steeper merit order curve results in higher Pool price volatility. Figure 14 shows the average monthly zero offers and Pool price volatility (measured as the coefficient of variation of monthly Pool price). The correlation coefficient is 0.66, which indicates a reasonable correlation. This further confirms the increase in Pool price volatility as the volume of zero offers increases.

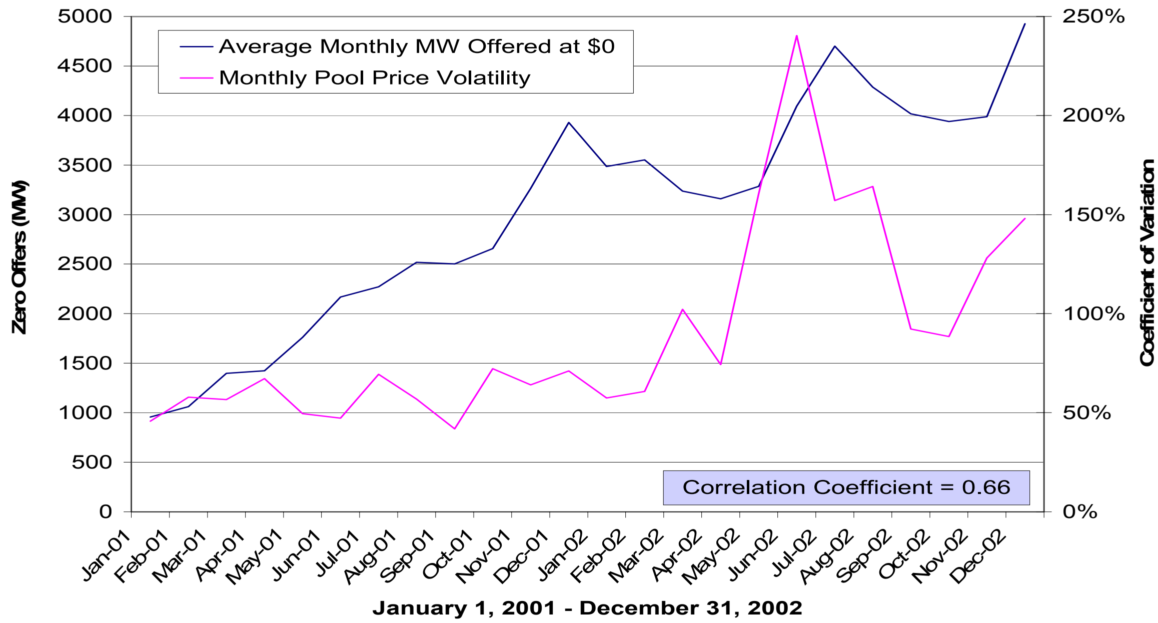


Figure 14 – Zero Offers and Pool Price Volatility

Results of the study indicate that zero offers are not seen to be hindering the operation of a fair, efficient and openly competitive market. The resulting increase in Pool price volatility could be seen to indicate a somewhat less efficient market, however, the nature of the market is such that various conditions will affect its operation. It is natural that Pool prices will rise and fall as a result of market conditions. It is possible that what at first seems like Pool price depression due to increased zero offers could in actuality be the normal operation of the market. The MSA will continue to monitor the situation and report back periodically on its findings.

ii) Intra Day Market (IDM).

The Intra Day Market was developed in response to a perceived need for a mechanism to allow market participants (Participants) in the Power Pool of Alberta to manage price risk by entering into forward physical contracts (including both direct sales agreements and exchange traded physical contracts) near to real time and to take these contracts to delivery through the Real Time Market (RTM). The MSA completed a review of the IDM during Q1/03 with respect to the "fair, efficient, and openly competitive" market criteria.

The IDM evolved out of extensive discussions with Stakeholders during 2001 concerning the expiry of the Pool Price Deficiency Regulation

(PPDR)[2], the associated "Uplift" rules and the future direction of the Alberta electricity market design. The objectives of the IDM are to: (1) Serve as a bridge to allow forward prices to converge to RTM conditions; (2) Provide a mechanism for importers to mitigate the loss of price certainty associated with Uplift; and (3) Provide Participants with a general mechanism to manage price risk closer to the real time delivery of energy.

The IDM has not developed for a number of reasons. The IDM may not satisfactorily address the risk management needs of market participants. In this regard, there appear to be a variety of risk management alternatives available to Participants that may provide them with more opportunities to customize risk management strategies. In addition, a number of other factors may also have contributed to the IDM's failure to develop including: (1) Previously established contractual arrangements between energy buyers and sellers; (2) Participants may not be able to appropriately value risk premiums given the lack of convergence between the forward market and the RTM; (3) A lack of anonymity in the IDM may be creating an unintended barrier to entry; and (4) A general perception about low prices over the next several years may be creating a disincentive for participating in the IDM.

With respect to the MSA's "fair, efficient, and openly competitive" criteria, it cannot be said that the IDM does nor does not meet these criteria due to the failure of Participants to register even one arrangement with the Pool during 2002. There is no basis upon which to reach a definitive conclusion.

In terms of the future of the IDM, the MSA believes that the first task is to determine the risk management needs of market participants in relation to the overall framework of the Alberta energy market. Assuming a positive determination of market need, the MSA believes that the following alternatives could be considered by the Alberta Electric System Operator (AESO): (1) Elimination of the IDM; (2) Modification of the existing market design to provide a greater incentive to participate; (3) Extension of the gate close on the forward market to more closely align with the real time delivery hour; (4) Establishment of a formal IDM exchange; and (5) Market design changes in the RTM such as the development of a Day Ahead Market or rolling gate closures which could have the benefit of reducing price risk. In deliberations about these and other alternatives, the

[2] Prior to 2001, interchange assets, and in particular import assets, were permitted to set Pool Prices. The collapse of the California market, in conjunction with other factors such as a tightening supply/demand balance in Alberta, resulted in a significant escalation of Pool Prices as a result of higher priced imports. The intent of the PPDR was to mitigate the impact of the price escalation by removing interchange energy from the merit order.

AESO will consider, at a minimum, the tangible benefits and costs of any option.

iii) Interchange Energy.

Pool Rule 3.5.1 was revised effective December 20, 2001 to prevent interchange energy (i.e., imports and exports) from setting prices in the Alberta Real Time Electricity Market (RTM)[3]. The effect of the Rule change is that import and export assets participate in the RTM as price takers. The Rule change was implemented to better align the scheduled nature of interchange energy in neighboring jurisdictions with the real time dispatchable operation of the Alberta RTM; to put decision-making back into the hands of market participants (Participants) rather than the System Controller about how much interchange energy should be scheduled; and to ease the arrangement, management, and coordination of interchange schedules for both Participants and the System Controller.

During Q1/03, the MSA completed a review of the Rule change with respect to its impact on the operation of the Alberta RTM. In particular, the review assessed the impact of the Rule change on the level of Pool prices, price volatility, the volume of interchange energy as a component of Alberta electricity supply and demand, and market dynamics (i.e., competitor market share and behaviour). The MSA has considered some of the potential options for accommodating the participation of interchange energy as a "price setter" in order to provide a "price signal" to Alberta market participants. This was done, in part, and as a means to provide the Government with an additional perspective with respect to the policy of imports and exports setting price.

Interchange energy plays a critical role in the Alberta market. Interconnections with external markets facilitate both reliability of physical supply for markets on either side of an interface, and provide a mechanism to take advantage of economic opportunities that may exist between regional markets from time to time. Alberta has two main interconnections with adjacent markets. These interconnections have a combined capacity of 953 MW. The Alberta/BC inter-tie accounts for 800 MW[4] of capacity and the Alberta/Saskatchewan inter-tie accounts for 153 MW. The majority of activity across the inter-ties during 2002 was related to the importation of energy, predominantly from British Columbia.

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[3] Pool Rule 3.5.1 Daily Offers and Bids was revised as follows:

Importers will be allocated one asset per interconnection comprised of one block with a $0 offer price; and

Exporters will be allocated one asset per interconnection comprised of one block with a $999.99 bid price.

[4] The WECC capacity rating is 1200 MW but for operational and reliability reasons the inter-tie capacity is rated at 800 MW.

The MSA's review focused primarily on the Alberta/B.C. inter-tie and related energy imports. The review covered a number of topics including: (1) comparative advantages arising from the various policy, rules and procedures; (2) a supply analysis; (3) a competitive analysis; (4) the economics of interchange energy; (5) imports as a price signal; (6) a theoretical model of market performance; and (7) an overall assessment of the impact of the Rule change from the perspectives of "fairness, efficiency and market competitiveness". The review did not include consideration of inadvertent energy, reserve energy or import participation in the Ancillary Services market (Watt-Ex and the OTC market). The MSA, however, recognizes the importance of these other types of interchange energy and will address them in market monitoring activities and future market reviews.

The MSA concluded from its review that the Rule change has had an impact on the Alberta RTM; however, the MSA believes that the Rule change has not had a material or adverse effect on the market. The Rule change may discriminate against importers by preventing them from participating in the merit order as price setting assets although this does not appear to harm importers in a material or adverse manner. In fact, importers increasingly utilized a zero offer strategy during the later part of 2001 in order to ensure dispatch by the System Controller. Further, there are alternative mechanisms available to importers for risk management as a result of the requirement for importers to be price takers.

The Rule change benefits Alberta consumers by removing Uplift, thus reducing the price uncertainty for domestic load customers. In terms of domestic suppliers, the Rule change does not appear to favour importers relative to domestic Participants as these Participants also have the ability to offer at $0/MWh in order to ensure dispatch. Nevertheless, the combination of industry standard practices pertaining to interchange energy, limitations on the ability of Alberta Participants to access transmission service outside of Alberta, and Pool rules governing offer behaviour may benefit some importers to a greater degree than domestic suppliers. Fundamentally, as a result of the control of transmission rights outside Alberta, some importers have a greater opportunity to manage volumes on an hourly basis to mitigate risk or capture additional economic value as Pool prices increase or reduce volume as prices decline. Domestic suppliers only have one opportunity to adjust offers in response to changing market conditions (i.e.: the Locking Restatement Rule). The MSA has already expressed its concern over domestic participants using zero offers and energy restatements as market tools (so-called price chasing behaviour).

The Rule change appears to have had a slight impact on Pool prices and related price volatility; however, due to the short time period for the analysis (i.e., one year) it is not possible to definitively conclude that the Rule change has had an adverse impact on the efficiency of the market. The Rule change has nonetheless, contributed to the overall level of zero offer behaviour in the Alberta RTM. Continued increases in the level of zero offers could become problematic for the Alberta market at some time in the future if market liquidity in the ‘price setting zone’ begins to erode. Ideally, if imports were included in the merit order, it would be to provide a price signal and to add to the depth of market liquidity. This may be particularly important in terms of providing a signal for new capacity investment. However, the analysis suggests that importers manage energy volumes to take advantage of price changes in the market place. Thus import volumes themselves can, to some degree, be used as an implicit price signal.

The Rule change recognizes the reality of the situation that “seams issues” exist between Alberta and adjacent markets. The Rule change does not appear to have had a material adverse impact on competitiveness of the Alberta market. However, under other Pool Rules, some importers actually appear to have a competitive advantage relative to Alberta participants. Interchange energy does not compete in the Alberta market in the same manner as domestic Participants.

The MSA considered the rationale for allowing interchange energy to participate as price setters in order to provide a price signal to Alberta market participants for the purpose stimulating new plant investment. Moreover, allowing interchange energy to participate in the merit order could help to increase market liquidity and “widen the shoulder” thereby increasing competition at the margin. Economic theory suggests that accurate price signals are necessary to encourage economic efficiency, effective investment decision-making, and so on. In principle, allowing interchange participants to submit offers other than $0/MWh could provide a signal to marketers about importing or exporting energy and to new suppliers about building incremental generating capacity.

The MSA has completed its work on the assessment of the effect of the Rule change and has shared the results with both the AESO and the Alberta Government. The intent now is to build on the work undertaken in order to develop an enhanced monitoring and understanding of both the utilization of the inter-ties and the effects of interchange energy upon the Alberta market.

iv) Review of the Balancing Pool Aggregator Protocol and Rules.

The Balancing Pool was created by the Government of Alberta in 1999, in part to manage the unsold Power Purchase Arrangements (PPAs) from previously regulated thermal generating capacity and the Hydro PPA. In August 2000, the first auction of PPAs was completed by the Government of Alberta. The PPAs provided successful bidders the rights to generation capacity from the formerly regulated generating units. In the auction, 4250MW of capacity was sold for $1.1 billion. Left unsold from the auction was 2291MW from the following generating stations: HR Milner (144MW), Genesee (762MW), Sheerness (756MW) and Clover Bar (629MW). Control of this capacity was held by the Balancing Pool.

In December 2000, a second auction took place. This auction, part of the Market Achievement Plan (MAP) by the Balancing Pool achieved the sale of forward contracts for 2001, 2002 and 2003 based on the unsold PPAs. The contracts were primarily for 2001, with smaller quantities for 2002 and 2003. The sale proceeds were approximately $2.3 billion from over 2800MW of electricity contracts sold to 45 bidders.

In April 2002, the Balancing Pool initiated the Market Achievement Plan II (MAP II) in an effort to transfer control of the remaining PPA covered units (Clover Bar, Sheerness and Genesee) to market participants. MAP II successfully transferred all but one Clover Bar unit into the hands of independent market participants. Prior to MAP II, the Balancing Pool canvassed the industry and recognized that unit level 390MW - 20 year contracts, such as those offered in the original auction carried more risk and credit requirements than many market participants were willing to take on. The Balancing Pool marketed smaller strips of capacity from the larger units for approximately 3-year terms. Therefore, the Sheerness and Genesee Plants were auctioned as sub-unit level derivative (strip) contracts which require aggregation to unit-level offers before being submitted to the Alberta Electric System Operator (AESO) electricity market.

As part of its ongoing monitoring of Alberta's electricity market for fair, efficient, and openly competitive behaviour, the MSA has undertaken a review of the Aggregator function and associated Protocol and Rules. The Aggregator role in the market is to coordinate the strip offers arising from the derivative contracts sold from the Sheerness and Genesee Generating Stations. The Sheerness contracts transferred control from the Balancing Pool to strip buyers on October 1 and December 1, 2002, depending on the sale date of the contract. The Genesee contracts transferred control effective April 1, 2003. Although the analysis presented below focuses solely on the Sheerness Plant, which has developed a short operational history since fall, 2002, the general discussion of the Aggregator, Rules and Protocol applies equally to both plants.

Strip Contracts

The strip contracts sold under the Sheerness and Genesee PPAs subdivide each plant into 8 strips of capacity (6 X 100MW of energy only and 2 x 78MW [2 x 81 MW for Genesee] of energy or ancillary services). Each plant consists of 2 separate generating units. The energy strips are non-unit-specific, while the ancillary service strips are unit-specific. Because of these characteristics, the strip offers must be aggregated to unit level offers, and in the case of energy only strips, assigned to a particular unit prior to being offered to the energy market by the Balancing Pool. The Aggregator Protocol and associated Rules define how the Aggregator coordinates offers and provides settlement on a daily basis. The Protocol also sets out how the Aggregator will deal with minimum load requirements, reduced capacity of a unit and buyer-initiated start ups and shut downs.

The term 'Aggregator' refers to both the computer program designed to aggregate strip offers and the Balancing Pool staff who work the Aggregator desk. Each strip buyer submits offers to the Balancing Pool via a browser-based interface called the MAP II Online Buyers Interface (MOBI) system. After the system has received the offers, MOBI automatically compiles and allocates offers to the two units according to the Aggregator Protocol. The Aggregator desk is staffed 24 x 7. The staff is responsible for submitting unit level offers, modifying offers using energy and locking restatements in response to real time operational events and to respond to ancillary service dispatches from System Control.

The strip contract provides the Buyer with three strip offer blocks, a $0/MWh block (shared), a variable cost block (shared) and a discrete block ($0 < Discrete Block < $999). With this allocation, each generating stations' 14 available offer blocks are utilized; 8 discrete blocks (1 per buyer, 4 per unit), 2 zero priced blocks (1 per unit), 2 variable cost blocks (1 per unit) and 2 excess energy blocks (1 per unit). The strip buyer must choose, when offering for the coming day whether to be 'active' in the market or 'inactive'. If the buyer chooses to be active, they must offer the full strip capacity (78MW or 100MW) in every hour. If they choose to be inactive, they must offer 0MW at $0 for the entire day. This rule prevents buyers from taking advantage of intra-day price events and essentially 'free-riding' on the other buyers.

Individual strip buyers do not have the option of exercising a unit's daily locking restatement in order to adjust their individual strip offers into higher or lower priced blocks. Locking restatements can only be performed by the Aggregator desk, in order to position the unit(s) for ancillary services or in order to maintain minimum stable generation. Generally, the MSA views the use of a locking restatement to maintain minimum stable generation as unacceptable if done during or within 30 minutes of the time that the restatement takes effect. In the case of aggregated offers, where no one individual strip can insure the unit maintains its minimum stable generation, an exception has been made to the guideline.

The MSA reviewed strip offers and aggregate unit offers over a reference week to test whether the automated aggregation procedure compiled through MOBI accurately converted the strip offers into aggregate unit offers as outlined by the Protocol and Rules. The MSA found that MOBI accurately and completely compiled the strip offers into unit-level offers.

Sheerness Unit Performance

Has the Sheerness Plant performed differently under the strip contracts than under the previous offer regime, where the Balancing Pool was offering the unit under a publicly disclosed variable cost regime? The Plant's performance during the first 2 months of 2003 is compared to the performance from the same period in 2002 to ascertain whether the unit has performed differently under the strip contracts.

Plant output data, along with hourly prices, locking restatement data, outage data and ancillary service data were reviewed in order to assess the plant's physical performance under the Aggregator. Due to the confidential nature of much of this data, only general results can be provided in this summary.

A number of considerations need to be kept in mind when comparing output data and unit performance across years. First, physical availability may differ significantly because of operational events unrelated to the differing dispatch rights or commercial contracts. There were slight differences in the Sheerness Plants maintenance and availability during January and February 2002 compared with the same period in 2003. These events were removed from the data to assure consistency across years.

Plant output is higher in January and February 2003 compared to the same months in 2002. Average output across both units has increased from 699MW/h to 746MW/h, an increase of 7%. Part of this can be attributed to the increase in committed capacity from 378MW per unit to 383MW per unit. The Balancing Pool negotiated this increase in committed capacity with the plant's owner, Atco Power Ltd. Previously, these 5MW blocks were offered in under a different contract at a price above the variable cost block. The new commitment added these blocks to the $0 or variable cost offer from the units, which are almost always fully dispatched.

A factor that may influence unit output is the market price. Generally, the market was tighter in January and February 2003 compared with the same period in 2002. This has likely contributed to the higher output levels under the strip contracts. Average hourly pool price is more than 3 times higher in the first 2 months of 2003 than the same period in 2002 and pool price volatility is more than twice as large during the same period of 2003 than in 2002. Higher prices reduce the likelihood that the unit will be dispatched down because the pool price has fallen below the plants variable cost offer.

The provision of ancillary services will also impact unit output. If active spinning reserves are being provided, energy equivalent to the spinning reserve must be withdrawn from the energy market and placed on reserve in the AS market. If regulating reserves are being provided, on average the units output will be reduced by half of the dispatched regulating level. Therefore, increased levels of ancillary service provision can lead to reduced unit output.

Under the strip contracts the Sheerness plant has used locking restatements to position itself for ancillary service and to maintain minimum stable generation. Compared to 2002, the use of locking restatements has been relatively infrequent.

Along with examining unit output and performance, a number of strip buyers were contacted to get a sense of how they feel the Aggregator is functioning. In general the reviews were favorable. No major issues were identified by the strip purchasers with regard to the Aggregator design or Rules. Some commentary was received around settlement and information sharing under the Aggregator, which is somewhat more complicated than in a normal PPA setting.

Balancing Pool: Code of Conduct

The Balancing Pool has energy to sell into the market place as well as the responsibility for the operation and aggregation of the strip contracts. As such there are real and perceived conflicts of interest around the knowledge of unit offers. Because of these roles, the Balancing Pool is separated into two functional groups, the Market Optimization Group (MOG) and the Operations and Aggregator Group (BPAG). The MOG is responsible for managing the unsold PPA capacity. At the close of MAP II, this capacity is limited to Clover Bar Unit 3 (157MW) and the HR Milner plant (143MW). If the MOG staff were to gain knowledge of the strip contract offers, it could potentially influence their offer strategy. This would be in conflict with Pool Rule 2.9, Sharing of Confidential Information, and would be viewed as a serious breach of trust by market participants and stakeholders.

To alleviate this concern, the Balancing Pool has required staff in both groups to sign an Operating, Service and Code of Conduct Guiding Principle. This document sets out that each group shall maintain independent financial and operational records. It stipulates that the MOG and BPAG shall not release, disclose or provide access to information to each other, other than information that is released or disclosed publicly. It also stipulates that each group will also maintain segregated working space.

Conclusions

The Aggregator function in the market appears to be operating as intended. No major problems or issues were uncovered during the MSA's review of its operations. Unit output during the first 2 months of 2003 was up compared to the same period in 2002. The aggregator Protocol and Rules appear to be well designed and to have anticipated all possible operational contingencies to date. The Balancing Pool has implemented and enforced its Code of Conduct in order to prevent any conflict of interest issues that arise from its unique position in the market, both overseeing the aggregation of strip offers and managing unsold PPA capacity.

4 OTHER MSA ACTIVITIES

i) **Locking Restatement Compliance.** The AESO has assumed enforcement oversight of the locking restatement guidelines which was previously conducted by the MSA up to January 15, 2003. As with all other market rules and guidelines, the MSA will monitor to ensure that the locking restatement guidelines are being enforced and that they are applied in an even handed fashion.

ii) **Changes to governing legislation and regulations.** The MSA has remained an active participant in the process led by Alberta Energy around amendments to the *Electric Utilities Act* and related regulations. With the introduction of the draft Act in the Legislature early in 2003, the Alberta government began public consultations in respect of a series of regulations. It is expected that this work will culminate in Q2/03. The MSA is very pleased with the collaborative efforts of the government, industry, and other stakeholders in respect of these matters.

iii) **Information Sharing.** In the course of its monitoring and surveillance, it has become apparent to the MSA that there are various commercial arrangements within which information sharing issues may arise (that is, the potential for inappropriate sharing and use of confidential information to the detriment of the market). Given that such commercial arrangements are integral to the operation of the Alberta Electricity market, the MSA has been working to develop a general analytical framework through which to assess any information sharing concerns and appropriate responses. Further, based upon that general framework, the MSA may look toward implementation of specific protocols around participant behaviour where deemed necessary to meet a specific set of circumstances. The MSA has workshops scheduled in the coming weeks to gain input from affected parties.

iv) **Stakeholders Meeting.** The MSA held stakeholder meetings in Calgary on March 6 and in Edmonton on March 11 to update stakeholders on the activities of the MSA and to allow stakeholders the opportunity to provide feedback to the MSA on any issues and concerns they may have. The presentation from the stakeholder meetings can be viewed at www.albertamsa.ca .

v) **EISG Conference.** The EISG is the Energy Inter-market Surveillance Group, which is an association of electricity market monitors from Canada, U.S., Australia, New Zealand, and Korea. The EISG meets twice per year to discuss issues of mutual interest and the MSA is a charter member of the group. The MSA recently presented at the spring meeting hosted by ERCOT in Austin, Texas.

vi) **MSA Relocation.** As part of the industry restructuring and formation of the AESO, the MSA is in the process of creating a separate legal entity and relocating to physically separate premises. It is expected that the relocation will occur on or about the end of April. See the following page for new MSA contact information.

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