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MSA REPORT

Quarterly Report

January - March, 2010

30 April, 2010

MARKET SURVEILLANCE ADMINISTRATOR

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Wholesale Market: The Q1/10 average Pool price of $40.78/MWh and corresponding average market heat rate of less than 10 GJ/MWh accord with a market situation exhibiting few occasions of supply-demand tightness. There was little volatility in Pool prices as generating unit outages were more evenly spread through the quarter. Alberta exported some 131 GWh (primarily in the off-peak) and imported 333 GWh (primarily in the on-peak). Alberta's Pool prices were closer to the corresponding prices in adjacent markets in part through the imports and exports. The few interesting price events of Q1/10 did not provide any concerns that the market is not functioning in a competitive fashion.

Net Revenue Analysis: Net revenue calculations for 2009 and Q1/10 indicate much lower returns for hypothetical new entrants. This outcome accords with the general view on market prices and supply overhang evident in the supply cushion for this period.

Operating Reserves (OR): The MSA examined an issue related to active reserve trades on NGX that are ultimately cancelled. There is an AESO requirement that total amounts per asset must be at least 5 MW. Frequently, sellers who compete over the 5-day period do not total to 5 MW of sales and their trades are cancelled. The cancelled volumes are then procured on OTC. There is a modest price effect due to this practice which should be addressed in the AESO's redesign process for the OR market.

Load Data Issues: Over a period spanning November 2009 to March 2010 there had been a number of errors in AESO reports all pertaining to load values. The AESO has successfully corrected the errors as of late March. The errors were mostly quite small but a few were greater than 100 MW. None of these errors affected Pool price. Some of the MSA's own daily and weekly reports in this period include these errors and the reports will not be corrected.

Retail Data: The RRO rates of the three main providers continue to track closely and to also track the equivalent forward market prices. With lower wholesale prices over 2009 and Q1/10 and declining forward prices, competitive retailers have reduced the prices of their long-term offers to customers. A new retailer has entered the residential market with a 'Pool price flow through' model that is also offered by one of the large incumbents.

AESO Rules Compliance: The big effort this quarter has been setting up the MSA for compliance enforcement related to mandatory reliability standards. The MSA has held meetings with affected parties to develop a framework describing both our expectations of them and a process for how we will deal with such matters. Negotiated settlements are a very effective way for the MSA to manage its case load and have similar benefits for the affected market participants. These are then presented to the AUC as a consent order. An issue that occurs relates to the treatment of confidentiality whilst the matter is being considered by the AUC for adjudication. The MSA has applications before the AUC requiring a resolution on this important matter.

MSA Activities: The MSA has embarked on an important consultative initiative to establish our framework for monitoring the market for behaviours that potentially raise questions under section 6 of the EUA and the associated FEOC regulation. This work will be ongoing through at least the end of Q2/10. An important decision by the AUC was rendered on April 22, 2010 concerning the MSA's recent costs applications. Our rationale for seeking partial reimbursement is discussed.

The MSA's above-noted consultations on offer behaviours will impact this series of quarterly reports. A report was published on April 27, 2010 (http://www.albertamsa.ca/files/Foundational_Elements_100427.pdf) and a second paper is in development that will outline details of the analytical framework that the MSA will use to guide its enforcement actions. Consistent with that, there will be a gradual evolution of this quarterly report series to align with the revised vision. There are only a few differences in styling in this particular report compared with previous versions, but the evolution will become more apparent in future editions. As always, we welcome your comments on any changes we make to our reports and feel free to call or email Mike Nozdryn-Plotnicki at 403-705-8503 or mike.nozdryn-plotnicki@albertamsa.ca.

2 WHOLESALE MARKET

2.1 Wholesale Market Fundamentals

Pool Price

Q1/10 electricity prices in Alberta averaged $40.78/MWh (Table 1 in Appendix A). This is 12% lower than Q4/09 ($46.27/MWh) and 36% lower than Q1/09 ($63.36/MWh). In large measure this was due to low Pool price volatility as evidenced by a standard deviation of $22.52/MWh and coefficient of variation of 55%. These are the lowest values for at least six years. Further evidence is implied in the Pool price duration curve (Figure 1) wherein it can be seen that only 1.3% of the hours were above $100/MWh.

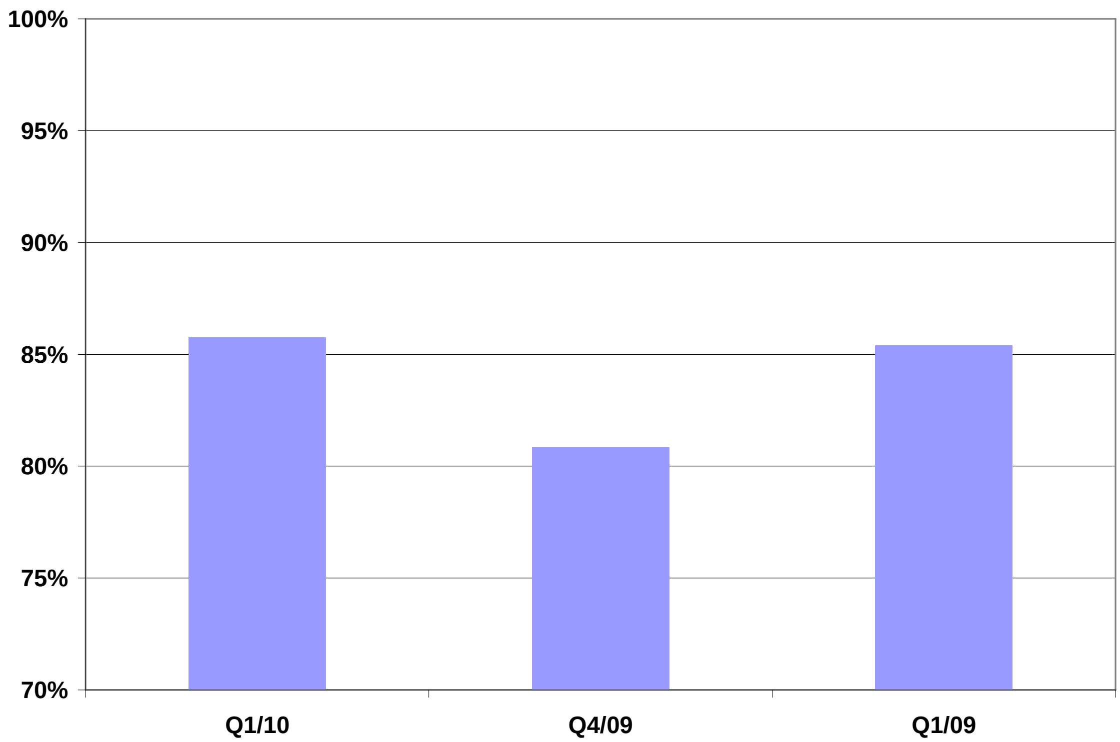
Natural Gas

In Q1/10, the average AECO natural gas prices increased 8% over the previous quarter, from $4.31/GJ to $4.69/GJ (Figure 3 in Appendix A). Compared with the same period a year ago, the natural gas price in Q1/10 was flat.

Demand

Average hourly demand in Q1/10 was 8410 MW, 2% higher than the previous quarter (8274 MW) and 1% higher than Q1/09 (8329 MW). However, the variability in hourly demand was smaller, resulting in the highest load factor among the three quarters (Figure i). The main drivers of volatility in Pool prices are variability in load, supply interruptions (outages) and participants' market strategies. A higher load factor suggests less variability in the first of the three components. Clearly this would be expected to be a contributor to the lower volatility observed in Alberta's Pool prices in Q1/10.

Figure i: Quarterly Load Factor



Supply

In Q1/10, the 66 MW wind generator Summerview 2 (IEW2) was added to the province's generating fleet. However, with the retirement of the 272 MW coal-fired unit Wabamun 4 (WB4) and the retirement of a 48 MW gas-fired unit in Medicine Hat (CMH1) the total net generating capacity dropped by about 250 MW as of the end of Q1/10.[1]

Overall in Q1/10, both the average AC and the average Capacity Factor (CF) of the coal fleet were higher than Q4/09 and the same quarter last year. The natural gas-fired units, on the other hand, had lower AC and CF

[1] Since WB4 retired on the last day of Q1/10, there was no impact on the average MC and the Available Capacity (AC) in Q1/10.

(Table 2 in Appendix B). Lower AC of the gas fired units was primarily due to the planned maintenance of Calgary Energy Center (CAL1), which, along with weaker market heat rates (Figure 6 in Appendix A), contributed to the lower CF as well.

Energy Market Supply Cushion

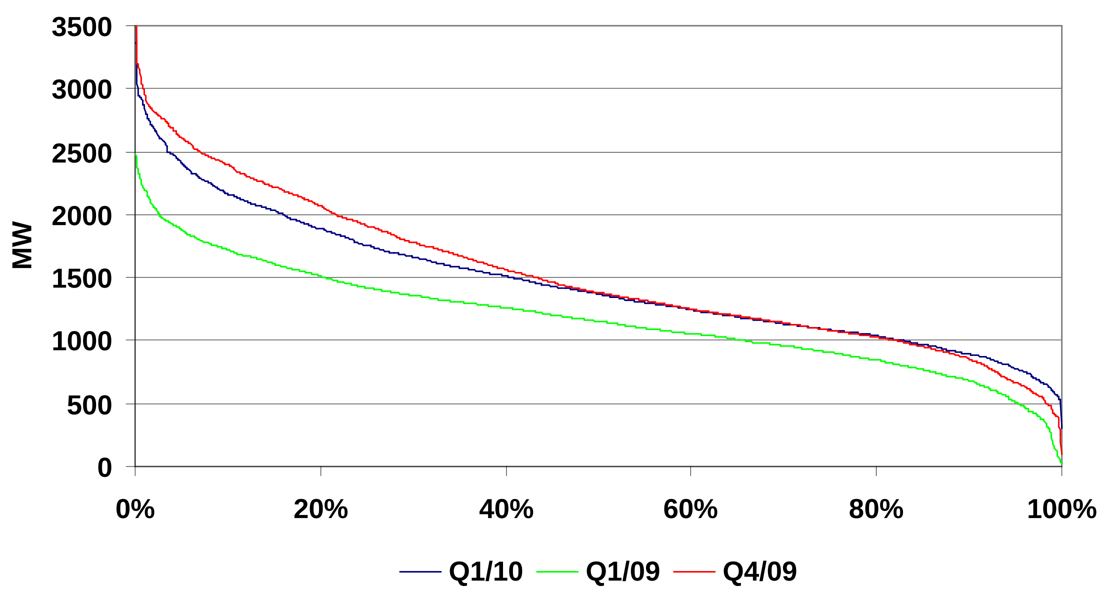
In Q1/10, the frequency of a very low supply cushion was noticeably less than in Q4/09 and Q1/09. The percentage of hours with a supply cushion <500 MW was less than 0.5% in Q1/10 (compared with 5% in Q4/09 and 2% in Q1/09). The reason for the lack of tightness suggested by Figure ii is a combination of:

- Load peaks were not extreme as indicated by the high system load factor;
- Net supply throughout Q1/10 was higher than Q4/09 except on March 31 when WB4 retired; and,
- The shape of the cushion-duration curve for Q1/10 versus Q4/09 clearly shows it is a flatter line indicating that supply curtailments were more evenly spread through Q1/10.

Less frequent occurrences of a thin supply cushion are consistent with fewer price spikes in Q1/10 (Figure 1 in Appendix A) and thus lower volatility in the wholesale market price.

The absence of low supply cushion values is a reflection of the enhanced supply overhang in the market through Q1/10. The MSA observes there are more hours where generators' offers are driven down closer to variable cost in this more competitive environment as they compete for the right to generate.

Figure ii: Supply Cushion Duration Curves



2.2 Imports and Exports

In Q1/10, the AB-BC and AB-SK interties flowed imports 75% and 65% of the time, and flowed exports 25% and 8% of the time, respectively. The AB-BC intertie was fully used for imports 6% of the time (Figure 25 in Appendix E). Overall, Q1/10 saw a total of 333 GWh imports and 131 GWh exports (Figure 30 in Appendix E), down from last quarter's 394 GWh and 167 GWh respectively.

The price differentials show that, on average, on-peak Pool prices in Q1/10 were higher than those of the nearby markets. However, compared with other periods, the on-peak Pool price was more convergent to other markets (Figure 26 in Appendix E). This indicates that on-peak importers would need to be more selective of which hours to flow to yield good profits as compared with previous quarters. The off-peak price differentials (Figure 27 in Appendix E) show a continued moderate economic opportunity to export to Mid C. Neither the on-peak nor the off-peak price differentials suggested significant unrealized arbitrage values on the interties in Q1/10 (Figures 28 and 29, Appendix E).

2.3 Constrained Down Generation

An increase in constrained down generation was noted beginning mid February which persisted through most of March (Figure 22 in Appendix D). The majority of the constrained down generation was due to the outage on the 240 kV transmission line, 9L57, which impacted the Fort McMurray area transfer-out-limit.[2] The transfer-out-limit was reduced from 550 MW to 320 MW, causing units in the Fort McMurray area to be constrained down at various times during the 9L57 outage.

The greatest amount of constrained down generation in Q1/10 was witnessed on March 28 when an average of 250 MW of hourly generation in the KEG area was constrained down due to a 903L outage. Wind generation was also constrained down in much of Q1/10, contributing to 10% of the constrained-down generation in February and 27% of the constrained down generation in March. This was due to transmission maintenance work in the area.

2.4 Forward Market

Forward market volumes in Q1/10 at 75% of the physical spot market were down form Q4/09 (98%) and about the same as Q1/09 (74%). The number of market participants in the forward market has remained quite stable in the range 20 to 22. The MSA recently published a paper on the Alberta forward financial electricity market at http://www.albertamsa.ca/files/Financial_Electricity_Market.pdf. That paper provides a general introduction to the forward market as well as a summary of longer term market statistics.

[2] Please refer to AESO Operating Policies and Procedures 505 for details (http://www.aeso.ca/downloads/OPP_505_Interim.pdf)

2.5 Price Events

It is customary to have a section in these quarterly reports that describes the background to price events that have occurred in the quarter. This is done to contribute to transparency. It is a by-product of our daily internal exercise to understand market outcomes with a view to identifying impediments to competition. The primary criterion for selecting the events is simply that at least one significant component of the market that contributes to price formulation was seen to show an unusual change, especially if there is a lack of transparency for the average observer.

January 20th 2010: Pricing Up and Exporting

The average pool price that day was $55.38/MWh, and the daily high price was $116.55/MWh. Market conditions were not exceptionally tight, by historical standards, however there was about 400 MW of energy re-priced by a participant from below reference price[3] to between $80 and $160 for a few hours in the middle of the day.

There were also exports scheduled in the late morning and early afternoon hours, coincident with the re-pricing of energy mentioned above.

These two actions, taken independently, would suggest divergent views on, and expectations of, the market during the mid-day period. However, the MSA observed that the majority of the exports in those hours were scheduled by the same participant who re-priced its energy offers higher. Although demonstrating apparently conflicting views, these two actions of pricing up offers in Alberta and at the same time exporting contributed to the higher Pool prices on that day. The MSA's hypothesis is that the exports were done for portfolio reasons meaning the exporting company did not expect them to be economic on a stand-alone basis. This could potentially have run afoul of the MSA's existing Intertie Conduct Guideline;[4] However that guideline is under review at this time as part of the overall discussions that the MSA is having with stakeholders on offer behaviour.

In the supper hours, coinciding with the evening ramp, the same participant again priced up some 350 MW of offers which contributed to setting the daily high Pool price of $116.55/MWh. In this instance, there were no exports scheduled by the participant.

During the events the MSA did not observe any direct competitive response that may have been due to the (T-2) lockdown. However, given that this was an isolated event in Q1/10 with a very modest overall effect on Q1/10 average Pool price of less than a dime, the MSA has concluded that the effect on market efficiency was small. The MSA has not concluded whether the (T-2) lockdown rule impedes competition in cases such as this one.

[3] The reference price for January was $68.67/MWh.
[4] http://www.albertamsa.ca/files/Intertie_Conduct_Guideline_071408(3).pdf

February 8th 2010: Changes in Imports

The evening of February 8th, saw Pool price increase to $264.81/MWh in HE21. Prices through the day had been stable, and at or below reference price,[5] even through the daily peak demand in HE19. Entering HE21 the merit order lost about 300 MW of supply due to decreased import schedules. Changes to intertie schedules are done over a 20-minute period spanning the top of the hour and can present a significant ramp for the system controllers to manage.

SMP increased in quick succession through the first 10 minutes of HE21,[6] with 6 dispatches, for 380 MW, that brought SMP up from ~$65 to over $700/MWh. SMP remained at this level for about 10 minutes. As load decreased through the hour, SMP dropped quickly back down to ~$115/MWh, where it resided for the last 35 minutes of the hour.

A feature of the market is that dispatches in excess of the volumetric desired change are often required to accommodate the ramp rate demanded by the change in supply and demand. In this instance, it was ramp induced primarily by intertie schedules. About 80 MW more than the change in imports were required to cope with the ramp. Note that this result could be avoided by increasing the amount of regulating reserve available to the system controllers. However, the more regulating range used in the control room the more Pool prices become muted to the changes in supply and demand. The present system has the minimum amount of regulating range available to the system controllers to achieve their reliability objectives. It is believed that this provides for the maximum amount of price fidelity to be achieved in the market.

March 9th, 2010: Scarcity of Supply and Pricing up

On March 9th, 2010, Pool price averaged $135.58/MWh and was above $100/MWh in nearly all the on-peak hours. The higher prices were driven in large part by scarcity of supply. Three large coal units were offline, and several others derated through the day, resulting in a cumulative coal fleet available capacity of only ~4500 MW. Further limiting supply were outages of a combined cycle plant, and simple cycle gas units, while wind generation was near zero through the on-peak hours. Exacerbating the situation was planned transmission line maintenance that resulted in moderate constraints to both co-generation output, and import ATC on the BC intertie.

A unit that had been dispatched above $500/MWh in the early on-peak hours restated its offer for the next available opportunity (two hours ahead as required by ISO rules) to a significantly higher price. As a result, in that hour the unit was put out of merit by its higher priced offer – and, in effect, was disciplined by the market.

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[5] The reference price for February 2010 was $64.61/MWh

[6] The first of the six dispatches within the 20 minute intertie ramp period was made near the end of the HE20, with the majority of the dispatches, occurring at the start of HE21.

The MSA also observed some other re-pricing in response to scarcity, as about 75 MW offered from coal-fired units were priced between $100/MWh and $350/MWh. Some of this offered energy set the SMP through a good deal of the afternoon, and into the evening, when Pool price rose above $250/MWh. The pricing up began in HE10, and continued incrementally, until HE14, when the highest priced block was offered at $350/MWh and remained offered at that price until HE20. The offer prices were reduced for HE21 onwards, presumably in recognition of the load going down and the market becoming less tight. Generally, pricing up in response to scarcity was not widely observed that day.

The response to high prices on the AB-SK intertie was timely, but limited in volume, as little more than 1/3 of the posted ATC was filled with imports. Typically, high Pool prices over a sustained number of hours have attracted import flows near capacity, similar to what was observed on the BC intertie that day. Generally the interties provide very responsive supply to the signal of higher prices in Alberta, subject only to the (T-2) AESO rules.

Low Prices in Late February and March

The average Pool price in Q1/10 was quite low. However, there was not much evidence of unusually low prices. As winter began to wane in late February and throughout March there were a total of 16 hours with Pool prices less than $10/MWh, with the lowest value being $8.09/MWh (which occurred in 7 of the 16 hours). Prices less than $10/MWh are very close to the marginal cost of the mine-mouth coal plants in Alberta.

As spring progresses and loads in light load hours reduce further, as Mid C spring runoff season starts to likely yield more imports and as wind power generates at higher levels, the MSA anticipates a greater potential for the occurrences of $0/MWh prices for the market.

3 NET REVENUE ANALYSIS

The MSA undertook a directional analysis of the potential profitability for hypothetical new generation in Alberta's market. The analysis reported herein serves as a simple check on what levels of return on capital the Pool prices of 2009 and Q1/10 could have provided to new entrants.[7]

The analysis herein assumes that the hypothetical new entrants were available at the beginning of 2009. It also assumes that the existence of new generation has no effect on the Pool price.[8]

[7] Most recently this analysis was presented in the MSA's *Foundational Elements* discussion paper http://www.albertamsa.ca/files/Foundational_Elements_100427.pdf which estimated annual returns to hypothetical investments made in 2001. The results of that exercise do not match the results of this new analysis due to the difference in the capital cost of building new units in 2001 compared to 2009.

[8] Although increased capacity likely does have an effect on market price, adjusting Pool price is well beyond the scope of this analysis.

The hypothetical new entrants analyzed are a coal unit, a combined cycle plant running on natural gas, a peaking combustion turbine unit and a wind project. The development costs associated with the new entrants are listed in Table i.[9]

Table i: Key Costs and Technical Parameters of New Entrants

		Unit			
		Coal	**Gas**	**Combined Cycle**	**Wind**
Maximum Output	(MW)	450	47	250	66
Availability Factor	(%)	92%	94%	92%	100%
Capital Cost	($)	$1,575,000,000	$47,000,000	$375,000,000	$112,200,000
Annual Fixed Cost		$33,794,778	$3,041,530	$16,897,389	$1,650,000
Minimum Output	(MW)			85	
Variable Cost					
O&M	($/MWh)	$1.15	$0.55	$1.15	
Fuel Cost	($/MWh)	$10.00	variable	variable	
Heat Rate - Full Load	(GJ/MWh)		10	8	
Heat Rate - Min Stable	(GJ/MWh)		10	10	
Supply Transmission Service					
Actual Avg. System Loss 2009	(%)	4.49%	4.49%	4.49%	4.49%
Forecast Avg. System Loss 2010	(%)	4.42%	4.42%	4.42%	4.42%
Start up Cost	($/start)		$340		

For each type of unit, assumptions are made about typical operation in the market and then simulated on an hourly basis to calculate hourly revenues and variable costs. The hourly revenues and variable costs are summed up for each month to generate monthly revenues and monthly variable costs. The monthly profit is calculated by subtracting monthly variable and fixed costs from the monthly revenue.

3.1 Coal-Fired Unit

Since the majority of new coal generation in the province has been built at existing facilities, the analysis herein assumes that the hypothetical new coal unit was also built at an existing site (as opposed to a green field site). The rated capacity of the unit is assumed to be 450 MW.

Coal plants are base-loaded units and therefore for this analysis it is assumed that the hypothetical unit runs full load for the entire period, with no interruption. Even when the Pool price is lower than its variable cost the unit is assumed to continue to generate, as if it were offered at $0/MWh. The effect of the outages is mimicked by simply scaling annual generation parameters by the availability factor.

Results of the monthly cash flow analysis for the coal unit are presented in Table ii. The simulated average generation output for the hypothetical coal unit is 414 MW. With an average Pool price of about $48 in 2009 and $41 in Q1/10, the revenue generated by the unit is about $173 million in 2009 and 36 million in Q1/10. Once variable and fixed costs have been accounted for, the net revenue as a percentage of capital is 5.8% in 2009 and 1% in Q1/10. Significant uncertainties exist regarding the costs of climate change

[9] Note that the assumptions are estimates and actual costs associated with the development of a new project will vary on a case by case basis.

on the future operational costs of newly built coal units. For this analysis, no emission costs are included in the calculations.

Table ii: Estimated Monthly Cash Flows of Hypothetical Coal Generation

Year	Month	Monthly Revenue (In $1000)	Monthly Costs (In $1000)			Monthly Net (In $1000)	% Capital Cost
			Variable	Fixed	Total		
2009	1	$28,637	$4,720	$2,816	$7,536	$21,100	1.3%
	2	$14,702	$3,762	$2,816	$6,578	$8,123	0.5%
	3	$13,291	$4,027	$2,816	$6,843	$6,448	0.4%
	4	$9,398	$3,746	$2,816	$6,562	$2,836	0.2%
	5	$9,830	$3,876	$2,816	$6,692	$3,138	0.2%
	6	$9,980	$3,772	$2,816	$6,588	$3,392	0.2%
	7	$12,747	$4,007	$2,816	$6,823	$5,924	0.4%
	8	$10,658	$3,913	$2,816	$6,729	$3,929	0.2%
	9	$21,833	$4,304	$2,816	$7,120	$14,713	0.9%
	10	$10,759	$3,917	$2,816	$6,734	$4,025	0.3%
	11	$14,971	$4,000	$2,816	$6,817	$8,155	0.5%
	12	$16,567	$4,174	$2,816	$6,990	$9,578	0.6%
Annual		**$173,373**	**$48,217**	**$33,795**	**$82,012**	**$91,361**	**5.8%**
2010	1	$13,376	$4,026	$2,816	$6,842	$6,535	0.4%
	2	$12,212	$3,642	$2,816	$6,458	$5,754	0.4%
	3	$10,863	$3,910	$2,816	$6,726	$4,137	0.3%
YTD		**$36,452**	**$11,577**	**$8,449**	**$20,026**	**$16,426**	**1.0%**

3.2 Combined Cycle Unit

The hypothetical combined cycle new entrant is rated at 250 MW and its operation is highly dependent on the price of natural gas. The plant is assumed to be running at full capacity when the Pool price exceeds the variable cost and at minimum stable generation for all other hours. Outages are treated in the same fashion as the coal unit, i.e. the generation parameters are scaled down to reflect the availability factor of the unit.

The revenue generated by the hypothetical combined cycle gas-fired unit is about $82 million in 2009 and $14 million in 2010, corresponding to net revenue as a percentage to capital of 3.9% and a loss of 1% respectively (Table iii). The simulated operation of the unit indicates the unit would be operational 65% of the time in 2009 and 55% of the time in Q1/10. A number of operational strategies are available to combined cycle generators that may differ from the strategy assumed in the analysis. For example, the plant operators may turn off the unit during the off-peak hours. Hence, the net revenue in this analysis is likely understated.

Table iii: Estimated Monthly Cash Flows of Hypothetical Combined Cycle Generation

Year	Month	Monthly Revenue (In $1000)	Monthly Costs (In $1000)			Monthly Net (In $1000)	% Capital Cost
			Variable	Fixed	Total		
2009	1	$14,048	$6,222	$1,408	$7,630	$6,418	1.7%
	2	$7,296	$5,172	$1,408	$6,581	$716	0.2%
	3	$6,219	$4,597	$1,408	$6,005	$214	0.1%
	4	$4,192	$3,569	$1,408	$4,977	-$785	-0.2%
	5	$4,153	$3,540	$1,408	$4,949	-$796	-0.2%
	6	$4,428	$2,981	$1,408	$4,390	$38	0.0%
	7	$6,307	$3,615	$1,408	$5,024	$1,283	0.3%
	8	$5,139	$3,128	$1,408	$4,536	$603	0.2%
	9	$11,142	$3,519	$1,408	$4,927	$6,215	1.7%
	10	$4,653	$4,450	$1,408	$5,858	-$1,205	-0.3%
	11	$7,501	$4,484	$1,408	$5,892	$1,609	0.4%
	12	$7,373	$5,477	$1,408	$6,885	$488	0.1%
Annual		**$82,450**	**$50,755**	**$16,897**	**$67,652**	**$14,798**	**3.9%**
2010	1	$4,604	$4,749	$1,408	$6,157	-$1,553	-0.4%
	2	$4,983	$4,757	$1,408	$6,165	-$1,182	-0.3%
	3	$4,198	$3,645	$1,408	$5,053	-$855	-0.2%
YTD		**$13,785**	**$13,151**	**$4,224**	**$17,375**	**-$3,591**	**-1.0%**

3.3 Combustion Turbine Unit

A 47 MW single GE LM6000 gas turbine generator set is chosen to represent a typical new gas-fired peaking unit in the Alberta market. Peaking units do not typically run all of the time and are generally more opportunistic in their operation and tend to offer their energy at higher prices. The unit is assumed to run at full output when Pool price is greater than the variable operating costs. The effect of outages is again simulated by scaling the annual generation parameters by the availability factor.

The revenue generated by the hypothetical peaking unit is about $12 million in 2009 and 0.8 million in Q1/10, corresponding to net revenues of 5.9% and a loss of 1.2% respectively. Under the assumed generating conditions, the unit would only be running 16% of the time in 2009 and 6% of the time in 2010 (Table iv).

Table iv: Estimated Monthly Cash Flows of Hypothetical Gas-Fired Generation

Year	Month	Monthly Revenue (In $1000)	Monthly Costs (In $1000)			Monthly Net (In $1000)	% Capital Cost
			Variable	Fixed	Total		
2009	1	$2,180	$711	$253	$964	$1,216	2.6%
	2	$1,005	$720	$253	$974	$32	0.1%
	3	$785	$532	$253	$786	$0	0.0%
	4	$430	$325	$253	$579	-$149	-0.3%
	5	$393	$253	$253	$506	-$113	-0.2%
	6	$651	$349	$253	$602	$49	0.1%
	7	$1,049	$587	$253	$841	$208	0.4%
	8	$815	$459	$253	$712	$102	0.2%
	9	$1,921	$441	$253	$695	$1,226	2.6%
	10	$330	$283	$253	$537	-$207	-0.4%
	11	$1,151	$645	$253	$898	$252	0.5%
	12	$793	$401	$253	$655	$138	0.3%
Annual		**$11,504**	**$5,707**	**$3,042**	**$8,749**	**$2,755**	**5.9%**
2010	1	$189	$160	$253	$413	-$224	-0.5%
	2	$251	$229	$253	$482	-$231	-0.5%
	3	$391	$251	$253	$504	-$113	-0.2%
YTD		**$831**	**$639**	**$760**	**$1,400**	**-$569**	**-1.2%**

3.4 Wind Unit

The new entrant wind farm is assumed to be rated at 66 MW, comprised of 22 units at 3 MW each. Since the development of wind farms in Alberta has generally been in the southwest of the province, the hypothetical new entrant is assumed to be located in the general area of existing wind farms. For this analysis, the generation output for the new entrant is based on the capacity factor for all existing wind farms in the province.

Results of the monthly cash flow analysis for the hypothetical wind farm are presented in Table v. Estimated Net revenues include the Federal Government's production incentive of $10/MWh.[10] We did not include any revenues that would accrue from the sale of renewable energy credits and thus the returns are somewhat understated. The hypothetical wind farm generated net revenues of about $7 million in 2009 and $1.5 million in Q1/10, corresponding to 6.7% (2009) and 1.4% (Q1/10) of the capital cost. Average production was 22 MW, representing a capacity factor of 33%. Due to the price-depressing effect of generation from wind farms, the new entrant only received 88% and 85% of average Pool price in 2009 and Q1/10, respectively.

[10] The ecoEnergy program of the Federal Government provides $10/MWh incentive for renewable electricity projects constructed between April 1, 2007 and March 31, 2011 (ecoENERGY - ecoENERGY for Renewable Power).

Table v: Estimated Monthly Cash Flows of Hypothetical Wind Farm Generation

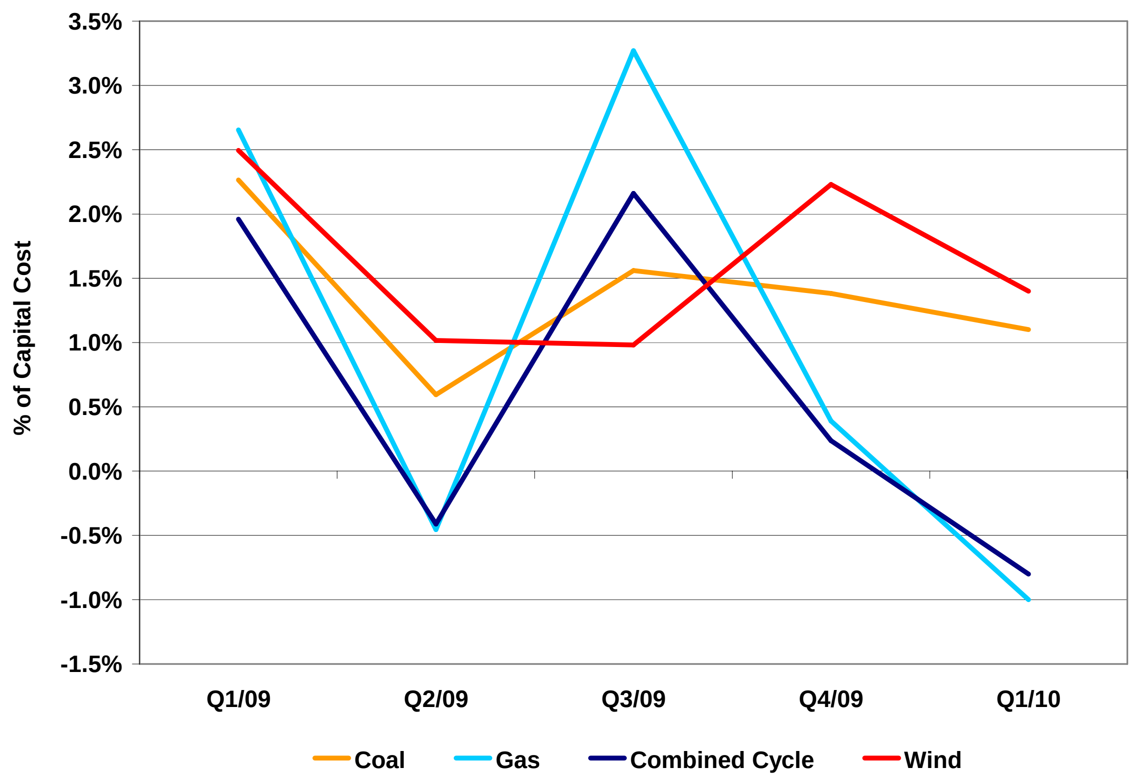
Year	Month	Monthly Revenue (In $1000)	Monthly Costs (In $1000) Variable	Fixed	Total	Monthly Net (In $1000)	% Capital Cost
2009	1	$1,399	$245	$138	$138	$1,506	1.3%
	2	$526	$138	$138	$138	$527	0.5%
	3	$695	$210	$138	$138	$768	0.7%
	4	$404	$171	$138	$138	$438	0.4%
	5	$456	$158	$138	$138	$477	0.4%
	6	$254	$109	$138	$138	$226	0.2%
	7	$227	$74	$138	$138	$163	0.1%
	8	$232	$83	$138	$138	$178	0.2%
	9	$761	$136	$138	$138	$760	0.7%
	10	$414	$149	$138	$138	$425	0.4%
	11	$1,332	$314	$138	$138	$1,508	1.3%
	12	$546	$160	$138	$138	$569	0.5%
Annual		**$7,247**	**$1,946**	**$1,650**	**$1,650**	**$7,544**	**6.7%**
2010	1	$490	$124	$138	$138	$476	0.4%
	2	$410	$101	$138	$138	$374	0.3%
	3	$627	$217	$138	$138	$706	0.6%
YTD		**$1,527**	**$442**	**$413**	**$413**	**$1,556**	**1.4%**

3.5 Summary of Net Revenue Results

Figure iii depicts the quarterly net revenue of the four types of hypothetical unit. Compared with the net revenue calculated in the MSA's Net Revenue Analysis in 2008, the returns in 2009 and Q1/10 dropped across the board.[11] The revenues for the wind farm appear to be the most attractive, although none of the results suggest a strong build signal – consistent with observed supply over hang in the market at the moment. Also, the returns are much lower than the average values over the period 2001 to 2009 based on 2001 costs as reported in the MSA's Foundational Elements paper.[12]

[11] The MSA "2008 Year in Review", http://www.albertamsa.ca/files/2008_Year_in_Review_amended_140509(1).pdf
[12] http://www.albertamsa.ca/files/Foundational_Elements_100427.pdf

Figure iii: Estimated Quarterly Net Revenue

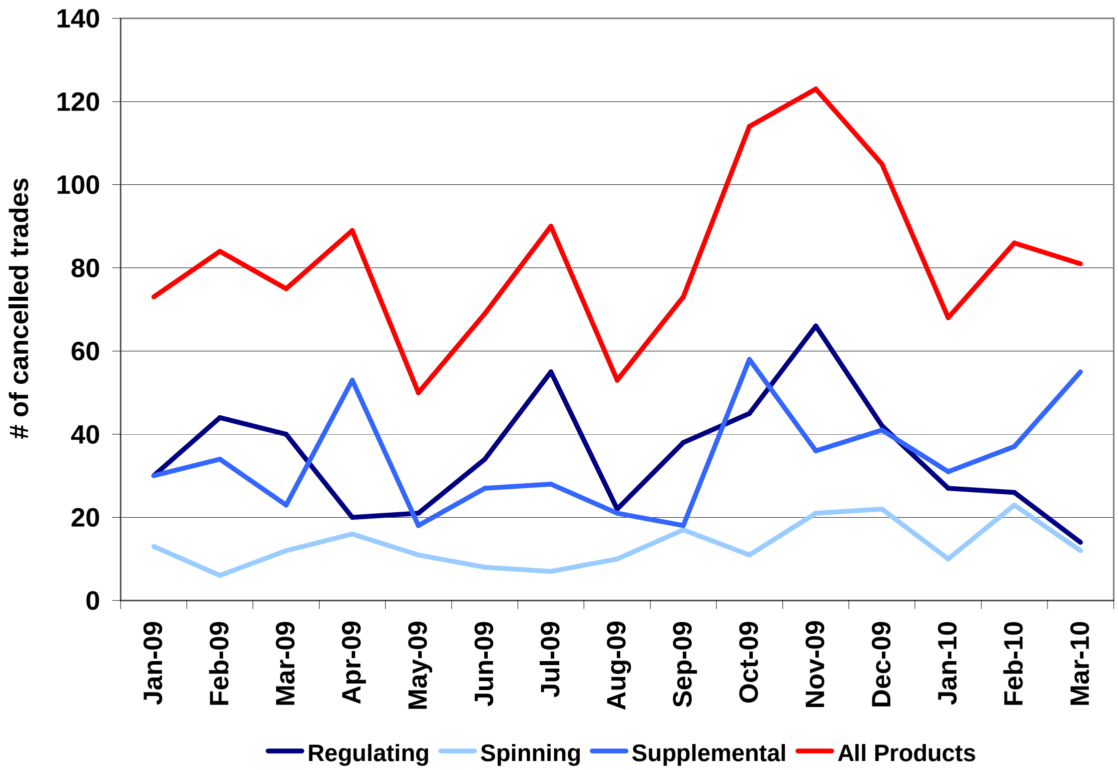


4 OPERATING RESERVES CANCELLED TRADES

The AESO has an operating practice whereby a minimum of 5 MW of Active Reserves per asset must be purchased to be qualified. On occasions, NGX finds that on completion of (D-1) purchases, some assets have 'sold' less than the 5 MW minimum. These trades are then cancelled by NGX and AESO simply adds the cancelled volumes to its 'shape' requirements on the Over-the-Counter market.

The MSA recently compiled the cancelled trade data for the period from January 2009 and March 2010. It was found that over the 15 months a total of 1,233 active reserve trades were cancelled averaging about 3 cancelled trades per delivery day. Those due to trade volumes being less than 5 MW accounted for 98% of the total. The balance was mainly trade errors on the part of the sellers. Figure iv breaks down the cancelled trades in terms of regulating, spinning and supplemental reserves. A greater number of regulating and supplemental reserves trades were cancelled than spinning reserves.

Figure iv: Number of Cancelled Active Reserves Trades on NGX



The MSA found that the cancellation of the aforementioned trades occurs after the market clearing price is set. As a result, the market clearing price is determined with such cancelled volumes included in the operating reserve (OR) supply curve. Sometimes the market clearing price is set by the volumes that are ultimately cancelled.

The price effect depends on how the additional quantity is procured to make up for the cancelled volumes:

- If the cancelled volume is procured on the Over-the-Counter (OTC) market (as it currently is), the market clearing price without cancelled trade volumes included would have been lower.
- If the cancelled volume is procured on NGX by going up the OR supply curve, the market clearing price without cancelled trade volumes included would have been higher.

With cancelled trades currently contributing to setting OR market clearing prices, the MSA is concerned of its impact on price fidelity, albeit a moderate effect in most instances.

The AESO is currently in the process of re-designing parts of the OR market, and the issue of 5 MW minimum offer blocks has been examined in

AESO's most recent OR market re-design recommendation paper.[13] The MSA supports AESO's efforts that would help reduce the occurrences of trade cancelations and remove this moderate price distortion.

5 AESO ALBERTA INTERNAL LOAD (AIL) REPORTING ISSUES

On March 25, 2010, the AESO released a public notice advising market participants and interested parties that errors in the AESO AIL figures reported on their website dating back to 18 November 2009 had been corrected.[14]

These data reporting errors were carried through to the MSA's Daily Snapshot and Market Monitor reports for the period in question. The MSA has examined the data it published in the Daily Snapshot and Market Monitor, comparing it to the AESO's corrected data.

The full range of reporting errors occurred from November 18th 2009 to March 12, 2010, with the majority of errors occurring before February 23 2010. The errors were mostly small, averaging only 0.36% change in absolute value across all affected hours, but some of the hours did have large differences, with a range of -382 MW to 123 MW (or as much as ~4% of demand in the hour).

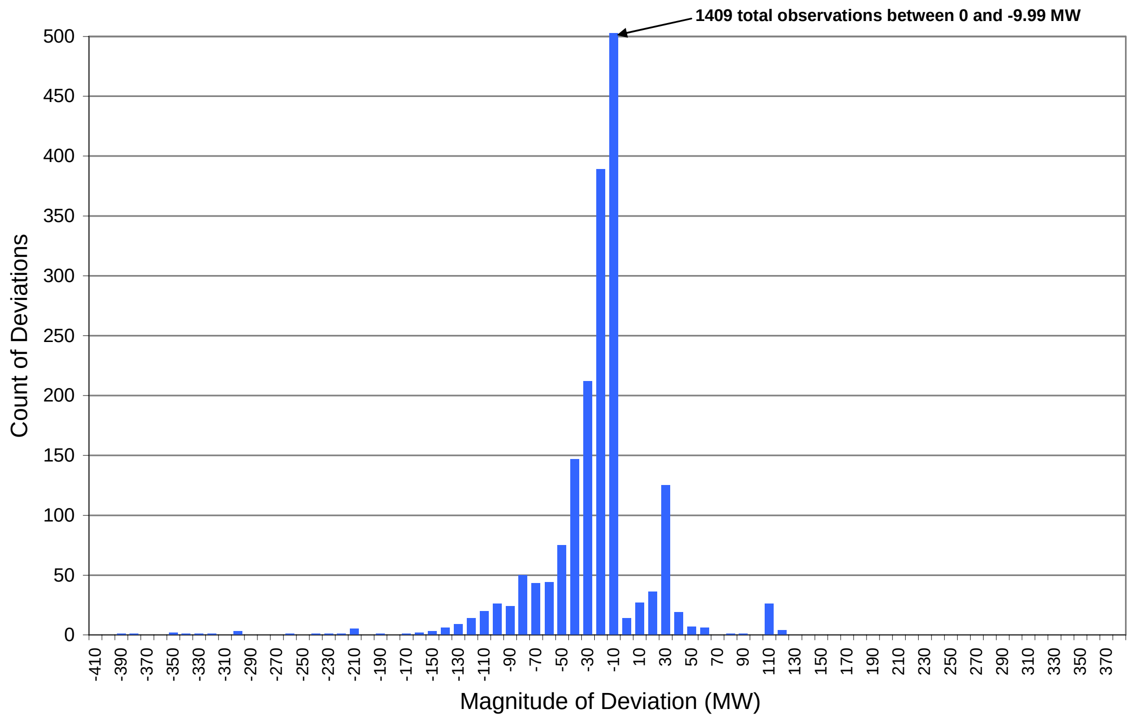
Table vi summarizes the frequency and direction of the errors within the period in question, while Figure v summarizes the reporting errors, in histogram format.

Table vi: Summary of AIL Reporting Errors

Item	No. Hours	MW
# Hours Without Errors	832	
# Hours With Negative Errors	1662	
# Hours With Positive Errors	266	
Maximum Negative Error		-382
Maximum Positive Error		123

[13] Please refer to http://www.aeso.ca/downloads/Revised_AESO_Recommendation_Paper_-_Operating_Reserves_Market_Redesign_-_March_2010.pdf
[14] http://www.aeso.ca/downloads/Actual_Forecast_Report_final.pdf

Figure v: Histogram of AIL Reporting Errors



While a small number of the reporting errors are substantial, the MSA will not undertake to revise the affected Daily Snapshots or Market Monitor publications, and instead advises participants seeking demand information for the period in question to consult the AESO's website for corrected AIL information.

It is important to note that SMP and Pool price were never incorrectly reported by the AESO in this period. There is the possibility that the somewhat miss-leading load values could have influenced decisions by loads and generators in terms of their participation in the market, but the MSA believes this would be unlikely given the moderate sizes of most of the errors.

6 RETAIL PRICES [15]

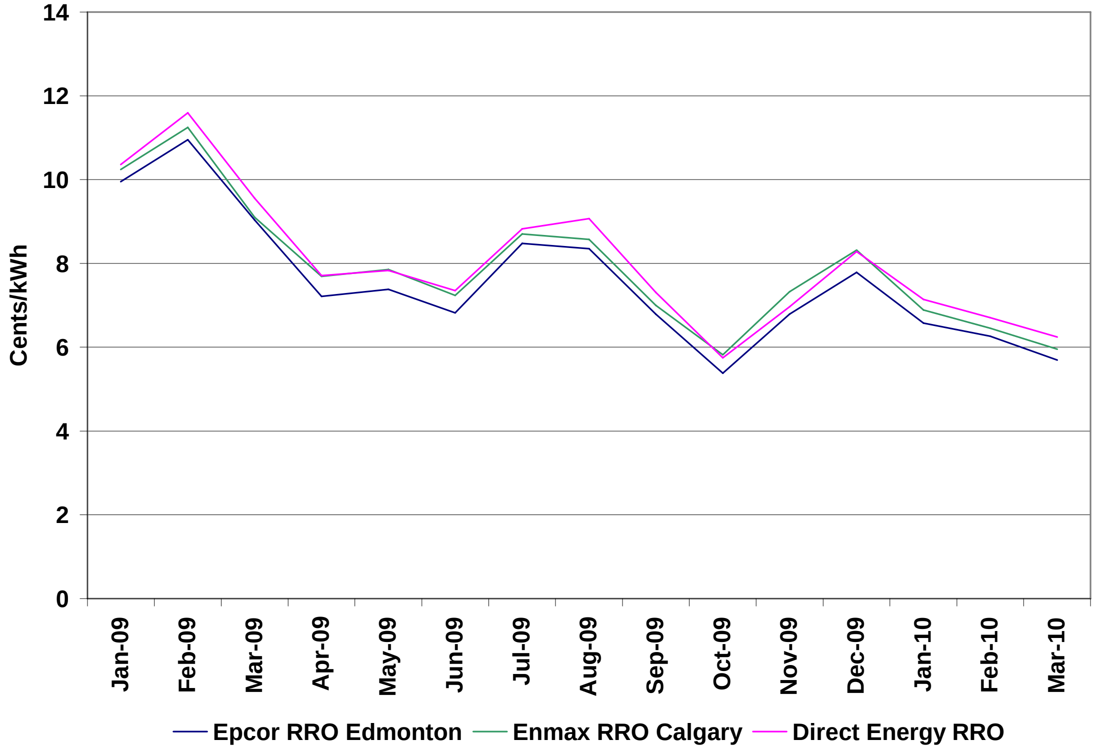
The retail prices in recent months have reduced in response to the weakening of wholesale electricity prices. Both Regulated Rate Option (RRO) and competitive rates have been trending downward.

6.1 The RRO Prices

Figure vi plots the residential RRO rates of ENMAX (Calgary), EPCOR (Edmonton) and Direct Energy. There is an obvious downward trend in the RRO prices.

[15] Data in this section are from Utilities Consumer Advocate (http://www.ucahelps.gov.ab.ca/4.html)

Figure vi: The Residential RRO Prices



For ENMAX and EPCOR, the RROs are priced off the Nature Gas Exchange (NGX) RRO indices, including NGX Flat RRO Index, NGX Extended Peak RRO Index and NGX Super Peak RRO Index.[16] Figure vii – Figure ix compare the NGX indices with the Pool Price. All these indices have been moving downwards.

[16] For the definitions of these indices, refer to "*NGX Price Index Methodology Guide*" (http://www.ngx.com/pdf/NGXPIMG.pdf).

Figure vii: NGX Flat RRO Index vs Flat Pool Price

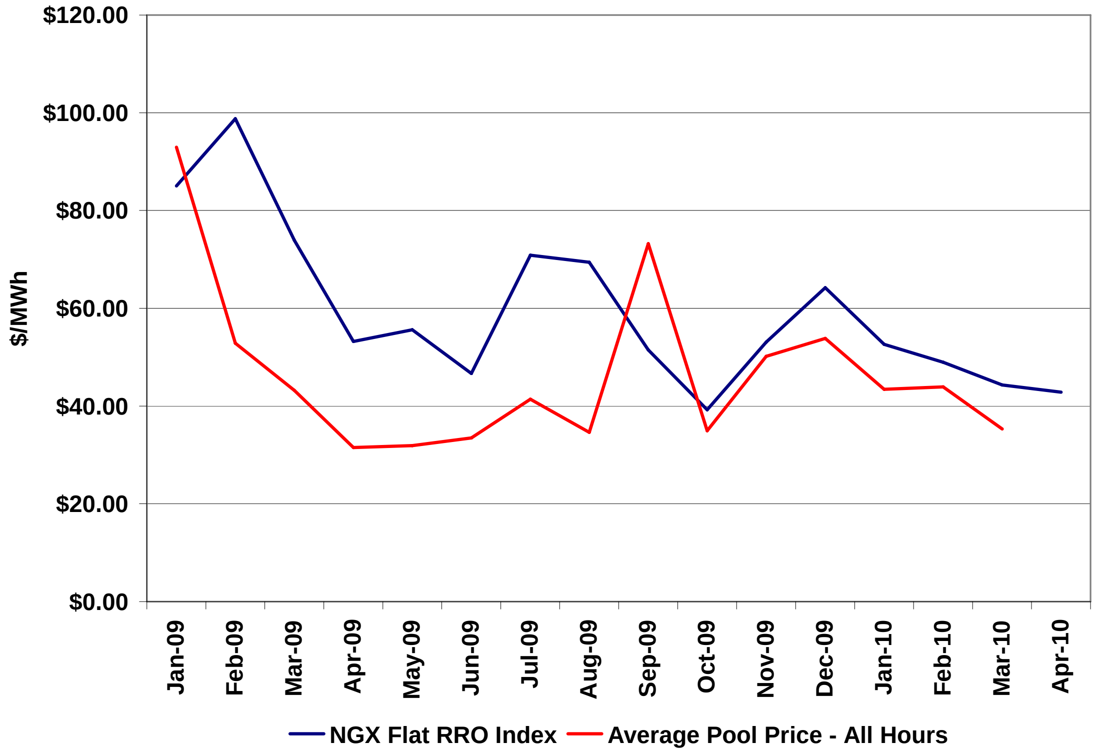


Figure viii: NGX Extended Peak RRO Index vs Pool Price in the “Extended Peak” Hours

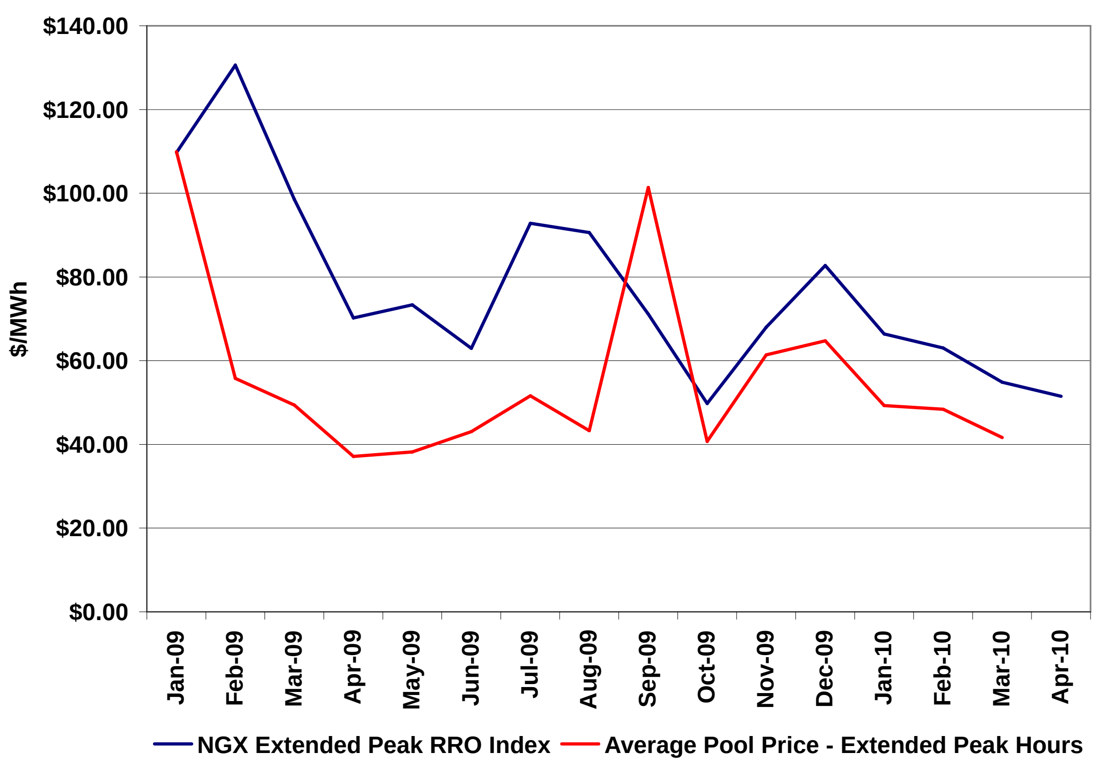
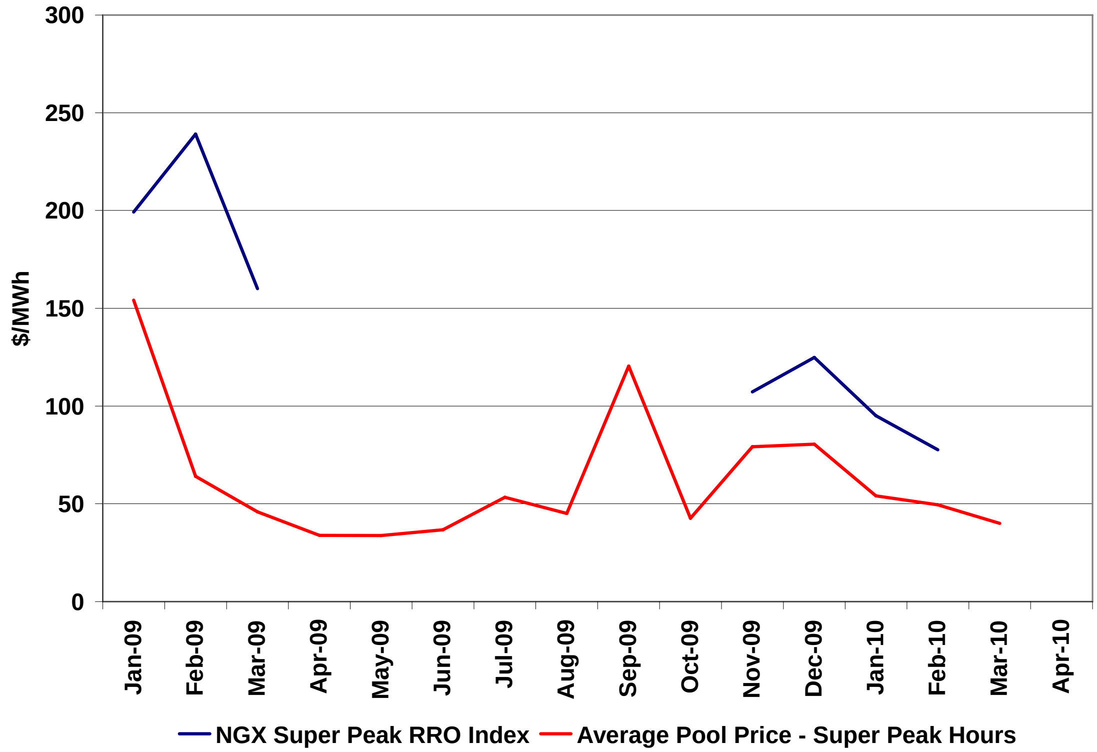


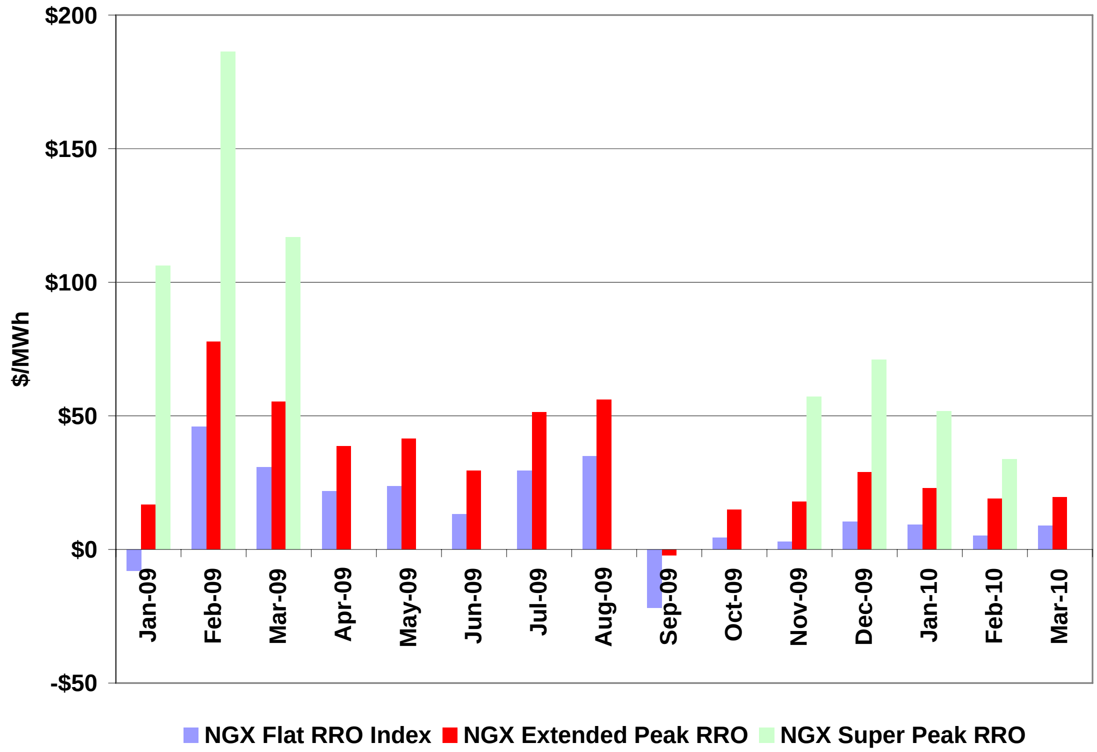
Figure ix: NGX Super Peak RRO Index vs Pool Price in the "Super Peak" Hours



Lower Pool Price volatility caused decreases in the premiums of the NGX RRO Indices over the Pool Price in Q1/10 (Figure x). The NGX RRO Indices are calculated based on qualified bids and offers and trade prices of the monthly financial contracts.[17] Lower premiums of the NGX RRO Indices over the Pool Price suggested the lessening of perceived Pool Price volatility in the forward market.

[17] "*NGX Price Index Methodology Guide*", pp. 17-22 (http://www.ngx.com/pdf/NGXPIMG.pdf).

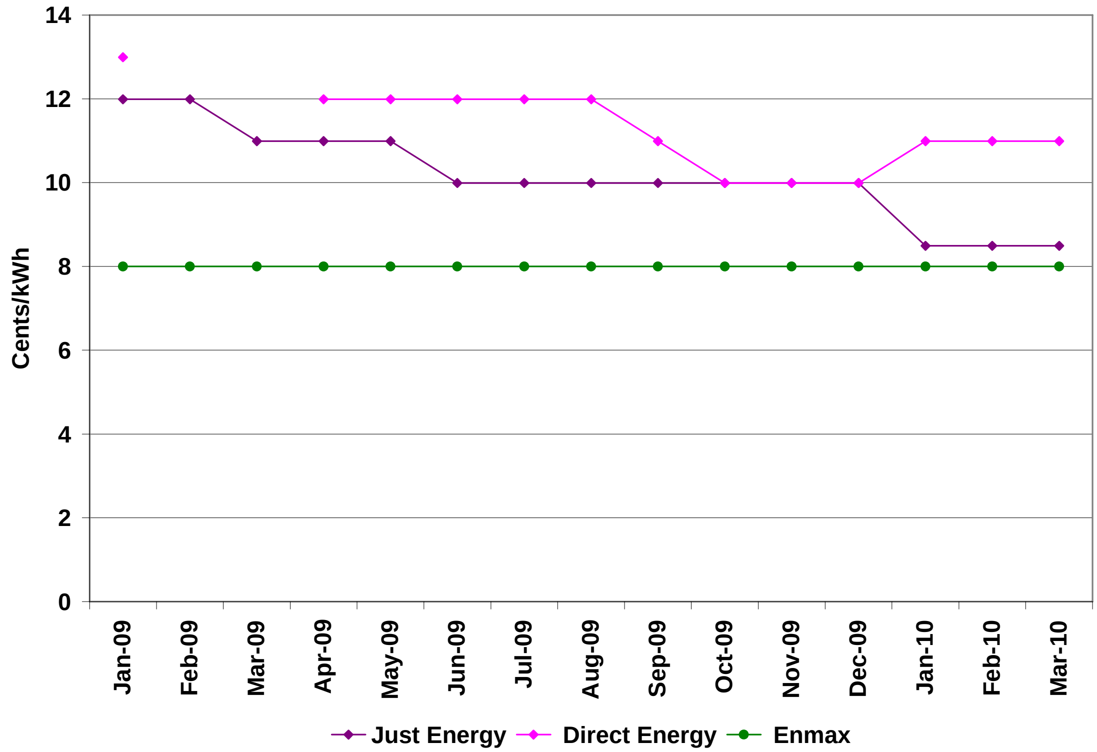
Figure x: Average Premiums of NGX Indices Over Average Pool Price by Month



6.2 Competitive Retail Prices

Lower and less volatile wholesale Pool prices that continued through Q1/10 have to some extent flowed into the forwards market. It has provided opportunities for the retail electricity providers to price retail electricity more competitively. Figure xi plots the 5-year retail electricity contract rates. Two of the three retail electricity providers lowered their 5-year retail rates through 2009. One of them continued to price more competitively in Q1/10. Overall, the 5-year competitive rates were lower in Q1/10 than the same period last year.

Figure xi: The 5-Year Retail Electricity Contract Price



Prices of retail electricity contracts with shorter terms also dropped. For example, compared with the same period last year, the price of the1-year rate offered by Direct Energy reduced from 12.99 cents/kWh to 7.79 cents/kWh in Q1/10. In Q1/10, Just Energy Alberta lowered its 3-year contract price from 7.99 cents/kWh to 7.70 cents/kWh.

Since inception, the RRO has been a cheaper alternative than most of the competitive fixed price schemes. However, competitive retailers do not compete for market share on price alone. They also compete by offering differentiated services tailored to the different needs of customers who have different tolerant levels of price risk. Also, it must be remembered that the RRO price is a single month value that fluctuates with the market. The fixed-price 5-year offerings are removing the price risk from the consumer and there is a cost for that price protection.

An encouraging observation was the addition in participation and product to the residential segment, where early last year Spot Power started to offer a floating price that is based on the hourly wholesale price. Direct Energy has a similar offering. The uniqueness of this product is that the unit cost of electricity to the customers is exposed to the Pool Price volatility and unknown before consumption. The fact that these competitive offerings exist and attract buyers is interesting. Taking Pool price flow through is the most direct way that a retail customer can access the wholesale market price. Yet it is the most 'risky' from the customer's perspective remembering that Pool prices can range from $0/MWh to $1,000/MWh.

As of the end of Q1/10, a variety of retail choices were available for retail electricity customers, including 1-year, 3-year and 5-year contracts, floating rates, dual fuel services, seasonal plans and green products.

7 AESO RULES AND COMPLIANCE UPDATE

Table vii provides an update of the MSA's ISO rules compliance activities as of the end of Q1/10. During Q1/10, 9 notices of specified penalty were issued by the MSA. In 4 other instances the MSA chose to forbear and 6 matters remained under review.

Additionally, 15 referrals have been addressed through negotiated settlements between the MSA and participants. In furtherance to section 44(2) of the *Alberta Utilities Commission Act* (AUCA), such matters must proceed to the Alberta Utilities Commission (AUC) for final approval. As at the end of Q1/10, 11 of these referrals were filed with the AUC while the remaining 4 were still under preparations to be filed. Five of these 15 referrals were referred to the MSA within Q1/10 while the other 10 were referred in 2009.

Nineteen new files were opened in Q1/10 similar to the 21 figure for Q1/09.

Table vii: Q1/10 Compliance Files

	Under review	Notice of Specified Penalty	AUC Filed Administrative Proceeding	Not Yet Filed Administrative Proceeding	Forbearance
6.6	3	4			1
3.5.3	1	1			
3.5.5	0	1			
6.3.3	1	3	6		2
6.5.3	1		4	4	1
OPP 102	0		1		
Total	6	9	11	4	4

The contravention dates of the 9 notices of specified penalty issued in Q1/10 ranged from August 2009 through February 2010 (Table viii). Four of the nine notices issued were for contraventions of ISO rule 6.6 that occurred in September 2009. Eight of the Notices of Specified Penalty issued in Q1/10 related to matters referred to the MSA by the AESO – the remaining Notice of Specified Penalty related to a matter self reported to the MSA. Table viii further segments the second, third, and sixth columns of Table vii by month of the contravention date.

Table viii: Q1/10 Compliance Files by Month of Contravention

		2009					2010			Total
	Rule	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	
Under Review	6.6			1		1	1			3
	3.5.3					1				1
	3.5.5									0
	6.3.3		1							1
	6.5.3								1	1
	Total		1	1		2	1		1	6
NSP	6.6		4							4
	3.5.3							1		1
	3.5.5			1						1
	6.3.3	2				1				3
	6.5.3									
	Total	2	4	1		1		1		9
Forbearance	6.6							1		1
	3.5.3									
	3.5.5									
	6.3.3							1	1	2
	6.5.3	1								1
	Total	1						2	1	4

At the beginning of Q2/10, the MSA has offered an additional incentive for self-reporting of non-compliance matters provided certain criteria are met. If a market participant meets the criteria listed in MSA's Compliance Review 2009, there is a high probability the MSA will forbear. A modification to those criteria in the forthcoming MSA compliance process document is for self reports of ISO rules compliance matters to also be copied to the AESO at: marketcompliance@aeso.ca.

7.1 Emerging Non-Compliance Trends

In Q1/10, the MSA dealt with 10 compliance matters related to ISO rule 6.5.3 – Ancillary Service Expectations. Since ISO rule 6.5.3 is not currently listed in AUC rule 019 – Specified Penalties for Contravention of ISO Rules, no specified penalty is available and accordingly, compliance matters relating to this rule have been addressed by the MSA through negotiated settlements. ISO rule 6.5.3 will become subject to specified penalties effective May 1, 2010 when a revised version of AUC rule 019 comes into force.

However, for all the ISO rules still not specified within the AUC rule 019 penalty tables and other conducts, the MSA will continue to pursue negotiated settlements where appropriate. The MSA believes it to be the most effective way of dealing with such matters. They can then be presented to the AUC as a consent order for its deliberations and decisions. An issue that crops up quite frequently is the desire by affected parties to maintain confidentiality through this process in light of the possibility that the case may need to be prosecuted in front of the AUC. The AUC has this matter before them in more than one MSA proceeding.

7.2 AUC Rule 019

AUC rule 019 provides direction to the MSA and to market participants in respect of the issuance of specified penalties for contravention of ISO rules. Rule 019 has been the subject of an AUC stakeholder consultation process, the outcome of which was an amended rule approved by the Commission on March 23, 2010 for effect on May 1, 2010.

Added to Category 1 of the rule 019 penalty table are: OPP 003.2, OPP 102, OPP 403, OPP 404, OPP 603, and OPP 806. Added to Category 2 of the rule 019 penalty table are: ISO rules 3.5.4, 6.4.3, 6.5.2, 6.5.3 and 10.10. No changes have been made to the current version of the Category 3 penalty table, applicable only to ISO rule 6.6.

8 MSA ACTIVITIES

8.1 Stakeholder Consultation Process on Participants Offer Behaviour

In Q/10, the MSA initiated a stakeholder consultation process on participants' offer behavior. The process started with a Roundtable discussion on issues identification on February 18, 2010. Subsequently, the MSA published a summary note of the meeting and stakeholders' comments (http://www.albertamsa.ca/1102.html). Based on the understanding developed through the Roundtable discussion and stakeholders' comments, on April 27, 2010 the MSA released a discussion paper that identifies the foundational elements that shape the MSA's approach to offer behaviours (http://www.albertamsa.ca/files/Foundational_Elements_100427.pdf).

8.2 MSA Compliance and Reliability Workshop

On March 10, 2010 the MSA held a Compliance and Reliability Workshop with Stakeholders. The session included an industry panel on best practices which addressed compliance programs, specific compliance monitoring tools, and industry compliance groups. The MSA presented an update on its 2009 Compliance Review regarding procedural changes concerning rules enforcement. The MSA also presented its anticipated process concerning enforcement of Alberta Reliability Standards and solicited comments on its intended enforcement approach of Alberta Reliability Standards (http://www.albertamsa.ca/1103.html). The MSA has also begun a stakeholder consultation process on compliance matters related to reliability standards (http://www.albertamsa.ca/1123.html).

8.3 AUC Proceedings

Listed below are various AUC proceedings of note involving the MSA during Q1/10; some proceedings have carried forward from prior months.

MSA v. ENMAX Corporation, ENMAX Energy Corporation and ENMAX Energy Marketing Inc. (ENMAX)

Application 1605352

Proceeding ID 269

On January 18, 2010 the parties filed a proposed Consent Order and related settlement materials for consideration by the AUC pursuant to section 54 of the AUCA.

On March 31, 2010 the AUC issued Decision 2010-143, approving the Consent Order as proposed by the parties. Accordingly, ENMAX was ordered to pay an administrative penalty of $25,000 in relation to a contravention of the *Electric Utilities Act* (EUA), the MSA withdrew the remaining allegation against ENMAX, and the parties each agreed to bear their own costs in relation to the proceeding.

MSA v. Syncrude Canada Ltd.

Application 1605552

On September 22, 2009 the AUC issued Decision 2009-144, confirming a Specified Penalty issued by the MSA and ordering Syncrude to pay the amount owing ($8,000.00) within 30 days (see Proceeding ID 168).

This is the MSA's first application for costs arising out of an AUC proceeding. It resulted from our view of the special circumstances of this matter and does not signal a policy decision by the MSA to seek costs as a matter of course. In the end, on April 22, 2010 the AUC issued its Market Costs Order 2010-001[18] awarding the MSA only a portion ($10,000) of the costs incurred in the original hearing and sought in our application. It is worth highlighting the decision principles underlying the MSA's application for costs in this case.

The original enforcement proceeding dealt with a disputed Notice of Specified Penalty ($8,000) issued by the MSA on June 23, 2008 for a contravention of ISO rule 6.6. As is well known the Commission has identified certain provisions (AUC Rule 019) that can be dealt with in a streamlined fashion, without a proceeding – unless the party disputes the contravention or does not pay the penalty within 30 days. In this particular case the market participant elected to dispute the Notice of Specified Penalty and the matter was therefore bound over to the AUC for adjudication, an option that is part of the checks and balances provided for in the compliance framework. Subsequently, on September 22, 2009 the AUC issued Decision 2009-144, confirming the Specified Penalty issued by the MSA (http://www.auc.ab.ca/applications/decisions/Decisions/2009/2009-144.pdf).

[18] http://www.auc.ab.ca/applications/orders/market-orders/Market%20Orders/2009/M2009-001.pdf

In our view the Commission decision was a foregone conclusion because the evidence clearly showed both the rule contravention and the underlying cause, and, by virtue of previous AUC decisions regarding ISO rule 6.6, the applicable law also seemed to be well settled. While the ability to challenge a finding of the MSA is a legitimate protection afforded market participants, in the circumstances, we did not see why Pool participants should fund our costs in the proceeding. (The MSA's budget is provided by a levy in the form of a trading charge.) As a consequence, we launched an application against the participant for reimbursement of our costs in the proceeding that it initiated. It is important to note that we did not seek reimbursement for that portion of MSA costs incurred before the original Notice of Specified Penalty was issued because, in our view, that is a normal part of our business function. We also made two separate offers to settle (to no avail) before the major costs of defense would have been incurred.

In summary our view is that where the law is not well settled or the facts may reasonably give rise to a successful defense, the market at large benefits from the proceeding and the MSA costs may appropriately be paid through its budget without recovery from the other party. On the other hand, if there is no new ground being explored in the proceeding then it is more appropriate to seek to recover MSA costs.

In coming to its decision to award only part of the costs we sought, the AUC appeared to place particular weight on the principle that costs awards should not be so large as to deter or discourage market participants from raising disputes or defenses. Further, that costs awards should be commensurate with the level of penalty assessed and degree of impact of the event under review, and should not by their relative size effectively be 'punitive'.

With respect to future enforcement proceedings, and particularly applications to recover related costs, the MSA will take account of the guidance offered by the AUC decision and its impact on MSA resource allocation and budgets.

MSA v. ASTC Power Partnership

Application 1605688

Proceeding ID 415

On February 5, 2010 an Application was filed by the MSA seeking approval of a Settlement Agreement pursuant to Section 44 and Section 51 of the AUCA in relation to an alleged contravention of ISO rule 6.5.3. For its part ASTC did not contest either the alleged contravention or the proposed administrative penalty.

On April 7, 2010 the AUC issued decision 2010-150, approving the Settlement Agreement, finding a contravention of ISO rule 6.5.3 and ordering ASTC to pay an administrative penalty of $500 as proposed by the parties.

The significance of the AUC decision includes that it was the first affirmation of a “no contest” approach in relation to the AUCA. In addition, it was the first use of AUCA Section 44 to address a contravention of an ISO rule (on a non-adversarial basis) where that rule is not eligible for a Specified Penalty pursuant to AUC Rule 019.

MSA v. Syncrude Canada Ltd.

Application 1605913

Proceeding ID 501

On February 11, 2010 an Application was filed by the MSA seeking approval of a Settlement Agreement pursuant to Section 44 and Section 51 of the AUCA in relation to alleged contraventions of OPP 102 (part of the ISO rules).

By preliminary motion, the MSA requested on behalf of the parties that portions of the Settlement Agreement be treated as confidential and not be filed on the public record unless the AUC approves the Application. The request was made on the basis that those portions contained without prejudice content in furtherance of the settlement proposed by the parties.

The parties await the decision of the AUC in relation to the request for confidentiality and in relation to the Application itself. This is a specific example of the types of confidentiality issues elaborated upon in Section 7.1.

MSA v. ATCO Power Canada Ltd.

Application 1605954

Proceeding ID 525

On February 26, 2010 an Application was filed by the MSA seeking approval of a Settlement Agreement pursuant to Section 44 and Section 51 of the AUCA in relation to alleged contraventions of ISO rule 6.5.3. For its part ATCO did not contest either the alleged contraventions or the proposed administrative penalty.

The parties await the decision of the AUC.

MSA v. NorthPoint Energy Solutions Inc.

Application 1606004

Proceeding ID 559

On March 15, 2010 an Application was filed by the MSA seeking approval of a Settlement Agreement pursuant to Section 44 and Section 51 of the AUCA in relation to alleged contraventions of ISO rule 6.3.3.

By preliminary motion, the MSA requested on behalf of the parties that portions of the Settlement Agreement be treated as confidential and not be filed on the public record unless the AUC approves the Application. The request was made on the basis that those portions contained without prejudice content in furtherance of the settlement proposed by the parties. In addition, the MSA requested that certain information be permanently kept confidential on the basis that it is considered to be commercially sensitive for other reasons.

The parties await the decision of the AUC in relation to the request for confidentiality and in relation to the Application itself.

Applications pursuant to Section 3 of Fair, Efficient and Open Competition (FEOC) Regulation – Information Sharing

Section 3 of the FEOC Regulation prohibits the preferential sharing of certain information (price and quantity offers) except in prescribed circumstances, including where the AUC has issued an order permitting the sharing of such records pursuant to Subsection 3(3) of the FEOC Regulation.

The MSA is given notice of any application seeking such an order, and can participate in the related proceeding (which otherwise is kept private). In all cases to date the MSA has intervened, in some cases to support the application and in others to object to the application.

A number of such applications were filed in Q1. In addition, as a result of inquiries posed by some applicants the AUC commenced a generic proceeding regarding the application of Section 3 of the FEOC Regulation in the context of the Power Purchase Arrangements (PPAs).

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table 1: Pool Price Statistics

	Average Price[1]	On-Pk Price[2]	Off-Pk Price[3]	Std Dev[4]	Coeff. Variation[5]
Jan-10	43.43	50.84	34.03	15.56	36%
Feb-10	43.90	49.30	36.69	14.33	33%
Mar-10	35.31	43.41	24.07	31.64	90%
Q1-10	**40.78**	**47.75**	**31.52**	**22.52**	**55%**
Oct-09	34.93	41.57	25.73	12.76	37%
Nov-09	50.16	65.07	31.57	63.57	127%
Dec-09	53.86	64.93	38.52	65.13	121%
Q4-09	**46.27**	**56.99**	**31.94**	**53.55**	**116%**
Jan-09	92.97	116.46	60.44	157.89	170%
Feb-09	52.84	57.54	46.58	34.30	65%
Mar-09	43.21	49.83	34.78	51.45	119%
Q1-09	**63.36**	**75.60**	**47.08**	**101.67**	**160%**

1 - $/MWh

2 - On-peak hours in Alberta include HE08 through HE23, Monday through Saturday

3 - Off-peak hours in Alberta include HE01 through HE07 and HE24 Monday through Saturday, and HE01 through HE24 on Sundays

4 - Standard Deviation of hourly pool prices for the period

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

Figure 1 - Pool Price Duration Curves

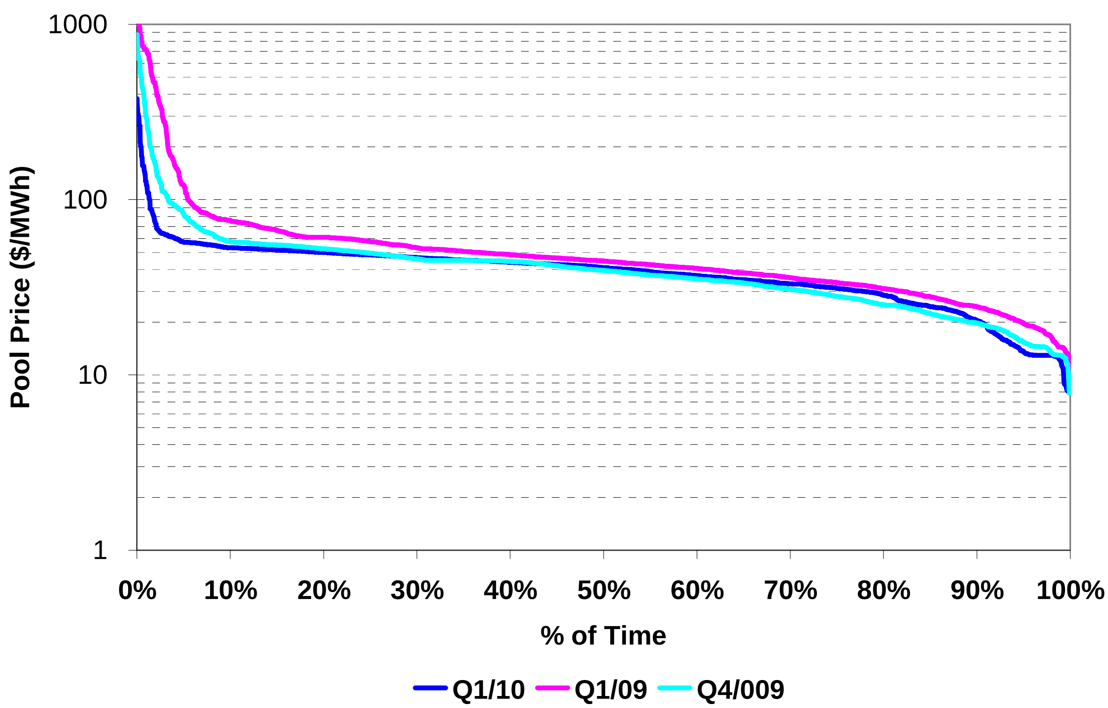


Figure 2 - Pool Price with Pool Price Volatility

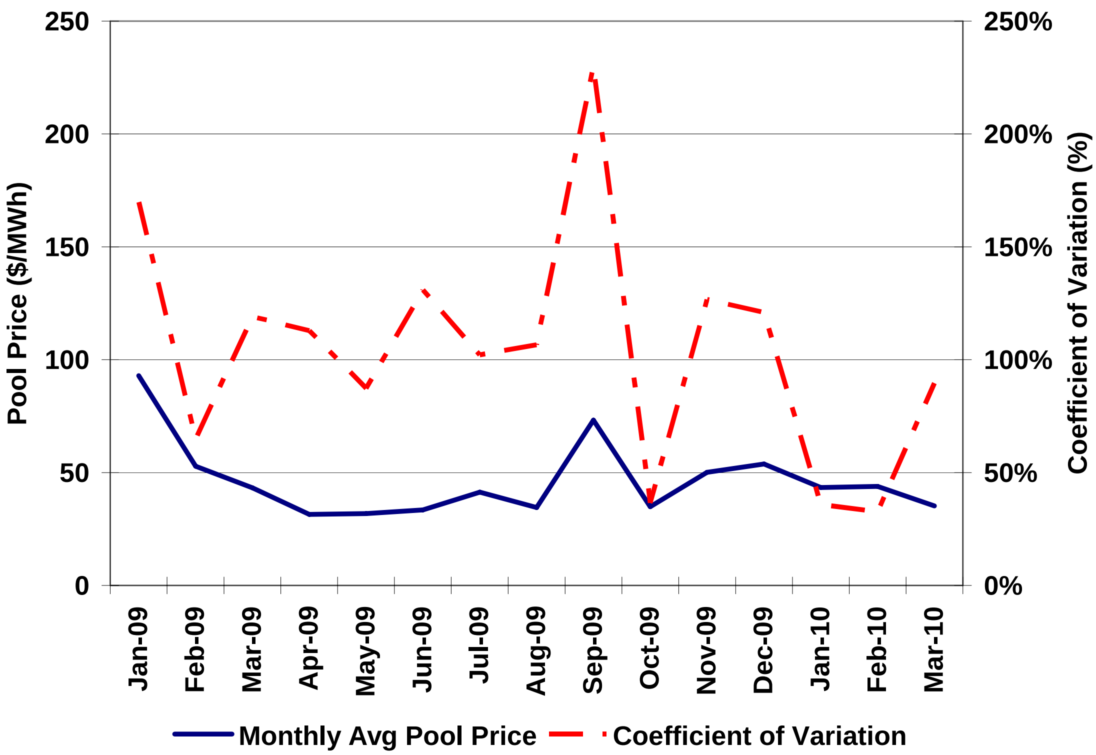


Figure 3 - Pool Price with AECO Gas Price

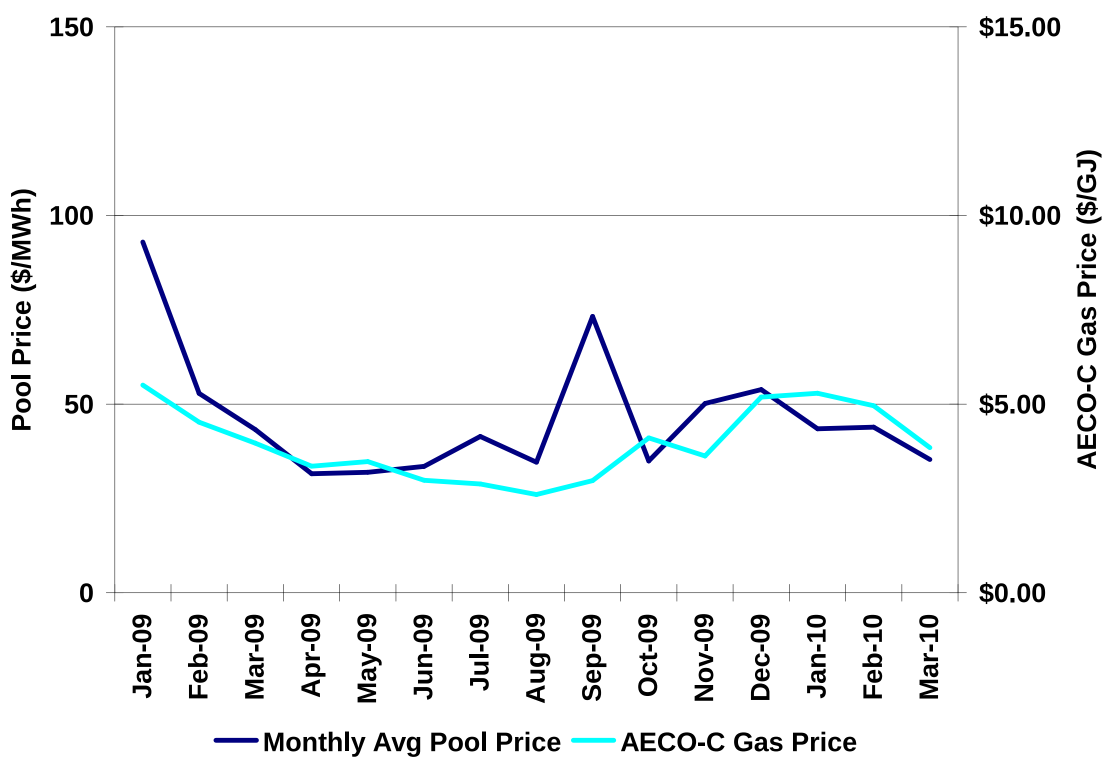


Figure 4 - Price Setters by Pool Participant (All Hours)

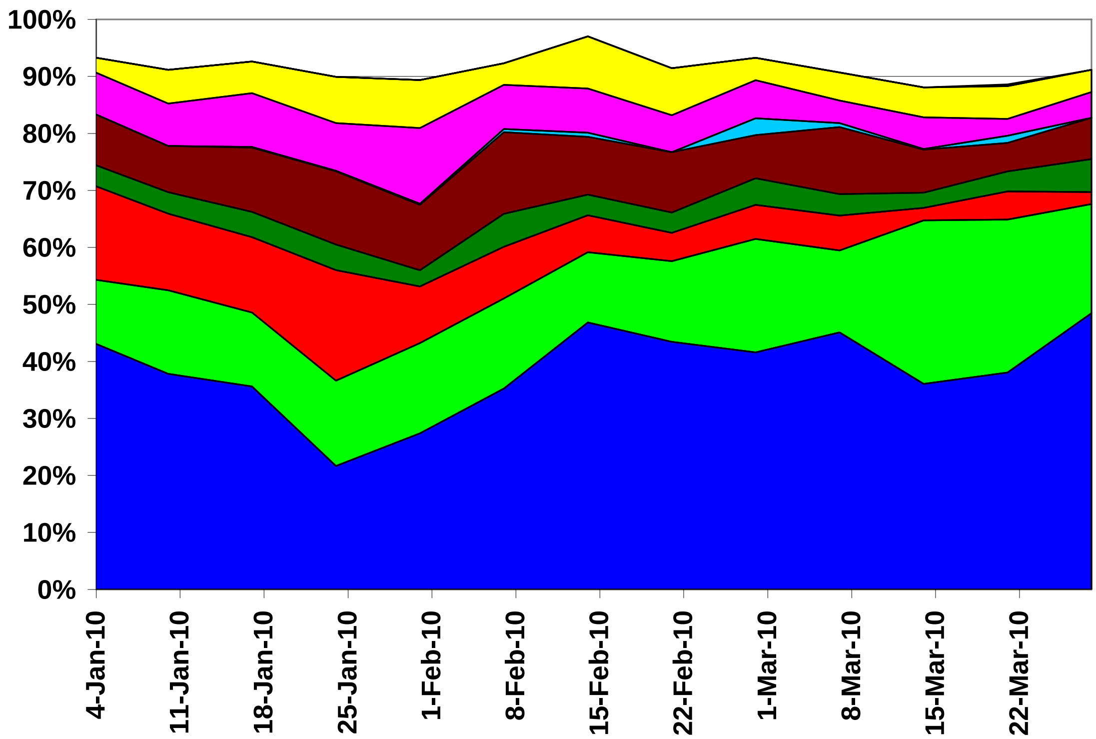


Figure 5 - Price Setters by Fuel Type (All Hours)

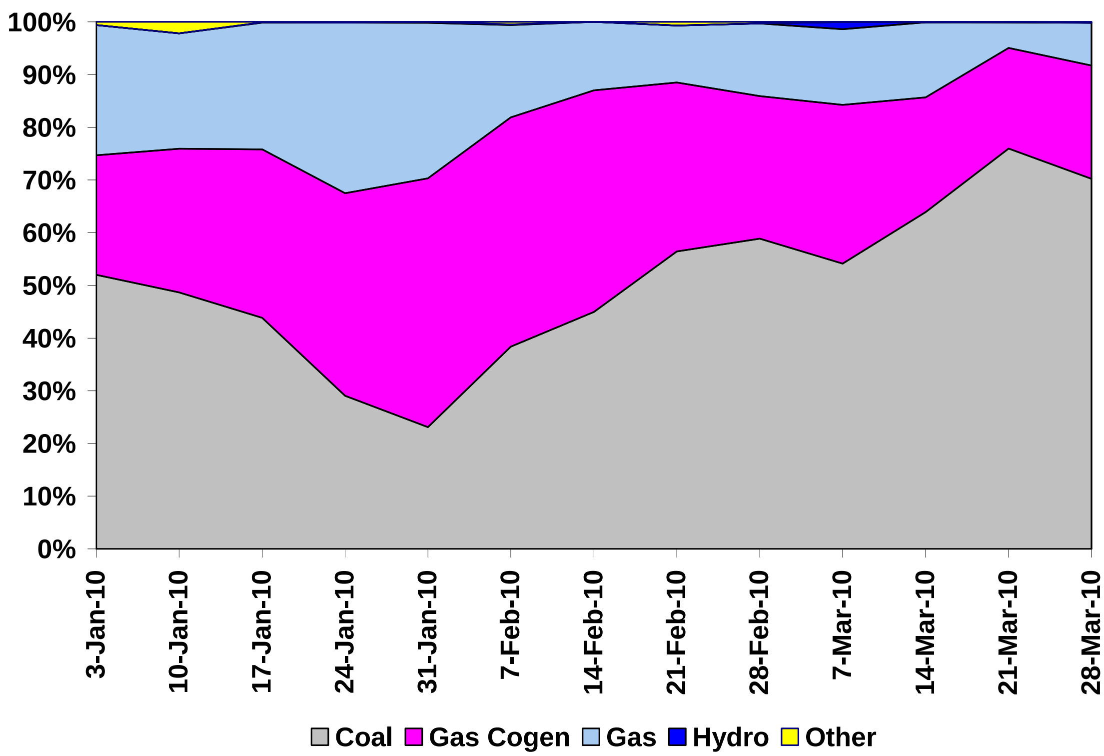


Figure 6 - Heat Rate Duration Curves (All Hours)

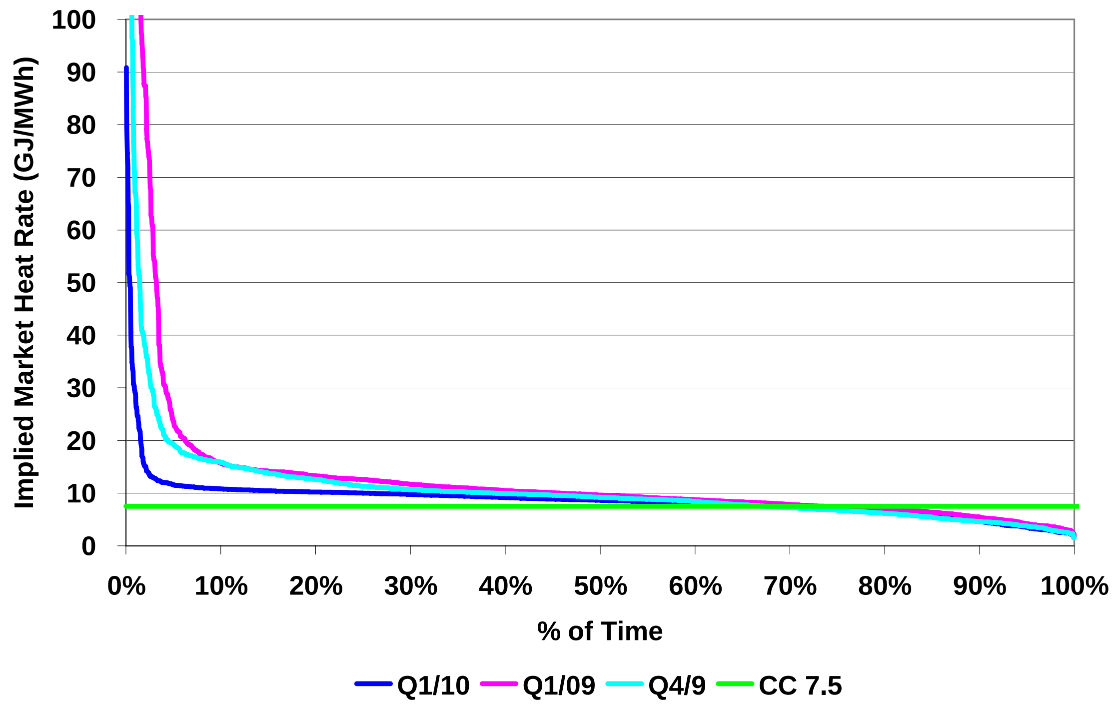


Figure 7 - Implied Market Heat Rates On-Peak

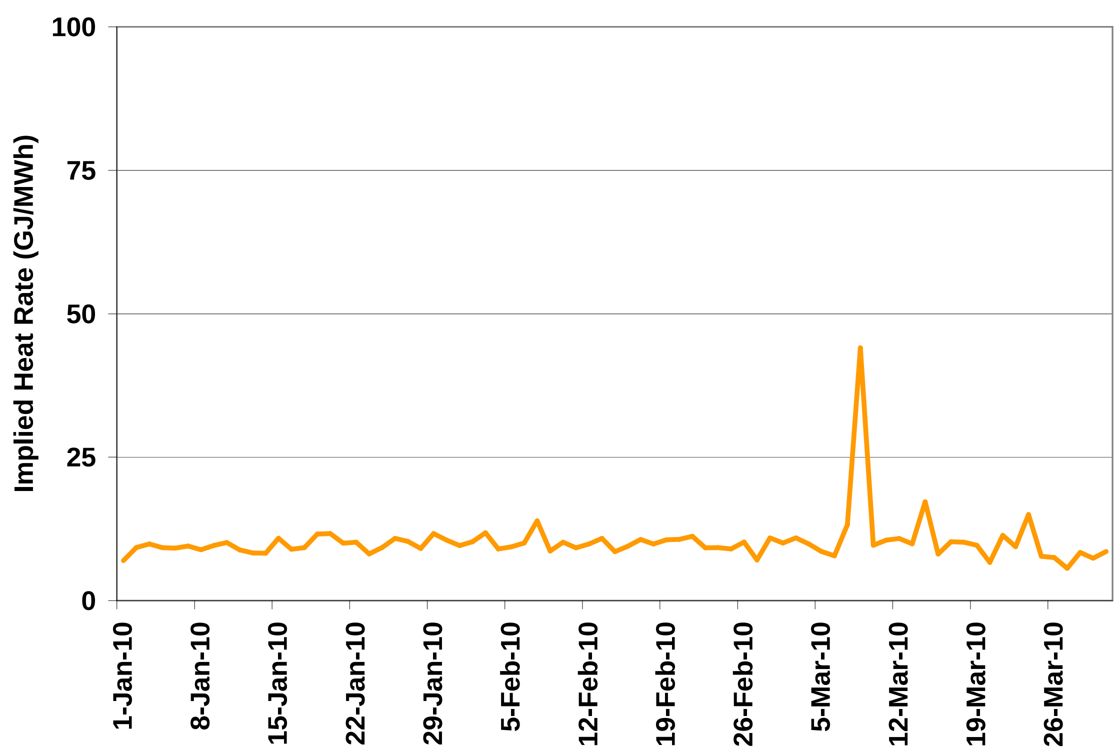
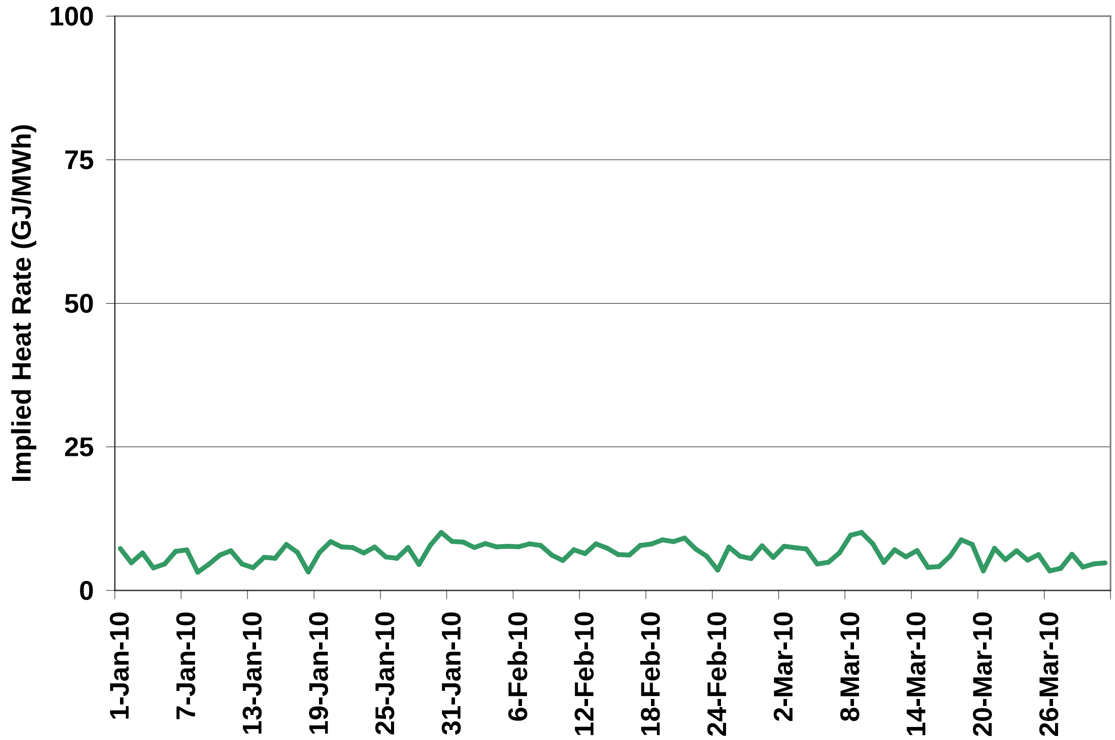


Figure 8 - Implied Market Heat Rates Off-Peak

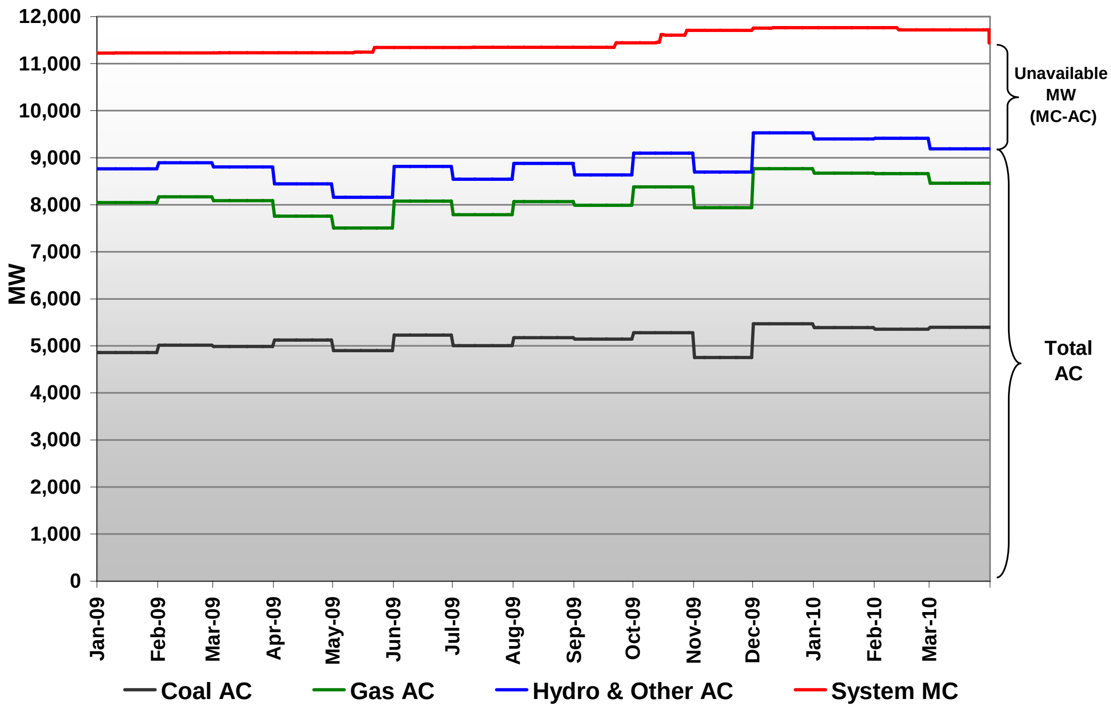


APPENDIX B – SUPPLY AVAILABILITY METRICS

Table 2: Availability Factor and Capacity Factor

Fuel Type	Quarter	Average MC	Average AC	Availability Factor	Generation	Capacity Factor
		[A]	[B] MW	[C]=[B]/[A]	[D]	[E] = ([D]x1000)/([A]xhrs)
		(MW)	(MW)	(%)	(GWh)	(%)
All Fuels *(excl. Wind)*	Q1/10	11,739	9,331	79%	16,304	64%
	Q4/09	11,671	9,111	78%	16,228	63%
	Q1/09	11,228	8,819	79%	15,755	65%
Coal	Q1/10	6,054	5,379	89%	10,970	84%
	Q4/09	6,048	5,173	86%	10,677	80%
	Q1/09	6,011	4,953	82%	10,186	78%
Natural Gas	Q1/10	4,768	3,216	67%	4,934	48%
	Q4/09	4,706	3,194	68%	5,129	49%
	Q1/09	4,302	3,147	73%	5,144	55%
Hydro & Other	Q1/10	917	735	80%	400	20%
	Q4/09	917	745	81%	423	21%
	Q1/09	915	720	79%	424	21%
Wind	Q1/10	600	n/a	n/a	448	35%
	Q4/09	563	n/a	n/a	517	42%
	Q1/09	497	n/a	n/a	447	42%

Figure 9 - Availability Capacity (AC) vs Maximum Capacity (MC)



APPENDIX C – OPERATING RESERVE MARKET METRICS

Ancillary services are the system support services that ensure system stability and reliability. The Alberta Interconnected Electric System (AIES) is required to carry sufficient operating reserves in order to assist in the recovery of any unexpected loss of generation or an interconnection. Operating reserves are competitively procured by the AESO through the Alberta NGX Exchange (NGX) and over the counter (OTC). Standard operating services products (contracts) include active and standby products for each of Regulating, Spinning, and Supplemental operating reserves. The majority of active operating reserve products are indexed and settled against the Pool price prevailing during the contract period. Standby operating reserve products are priced in a similar manner to options with a fixed premium and an exercise price (activation price). The activation price is only paid in the event that the contract is activated.

Figure 10 - Active Settlement Prices - All Markets (NGX and OTC)

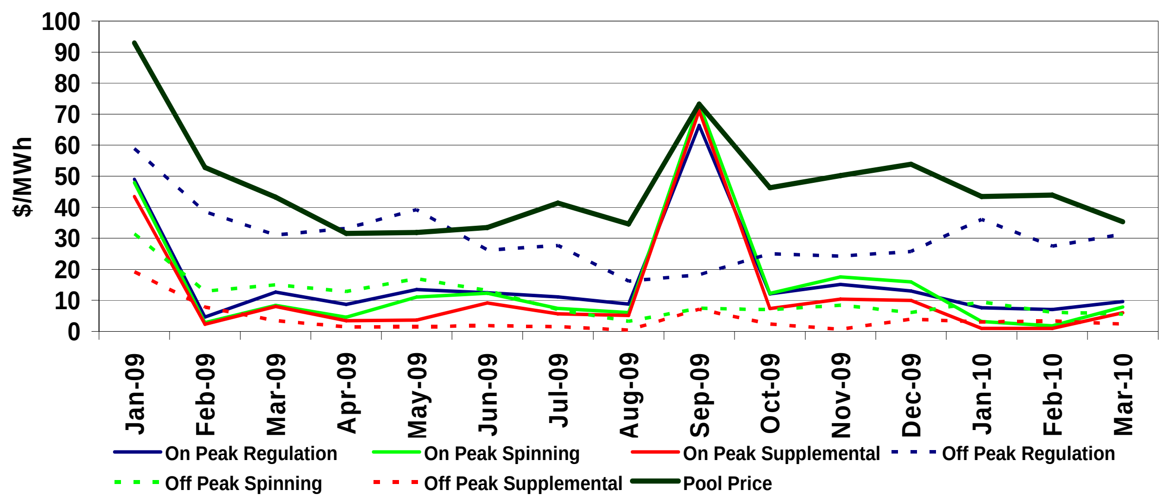


Figure 11 - Standby Premiums – All Markets (NGX and OTC)

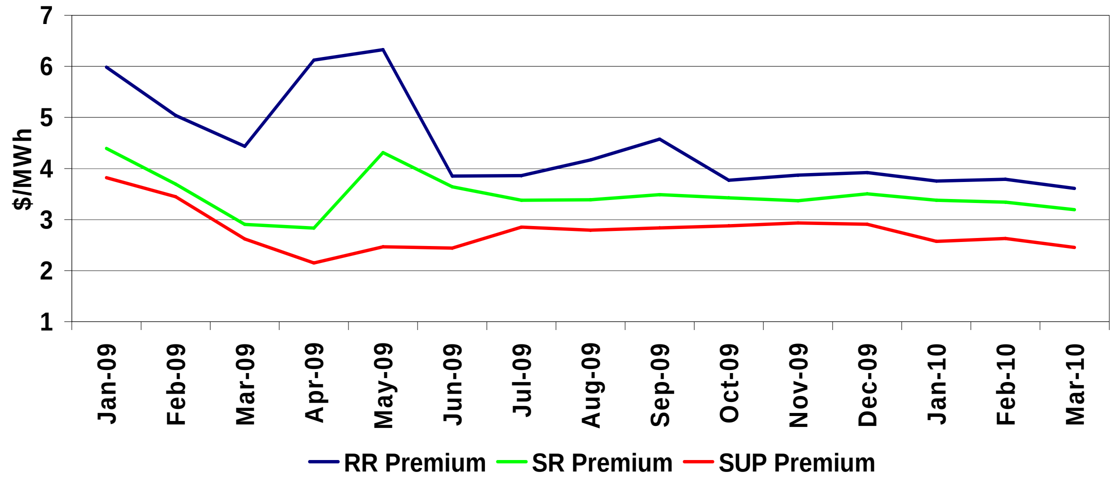


Figure 12 - Standby Activation Prices – All Markets (NGX and OTC)

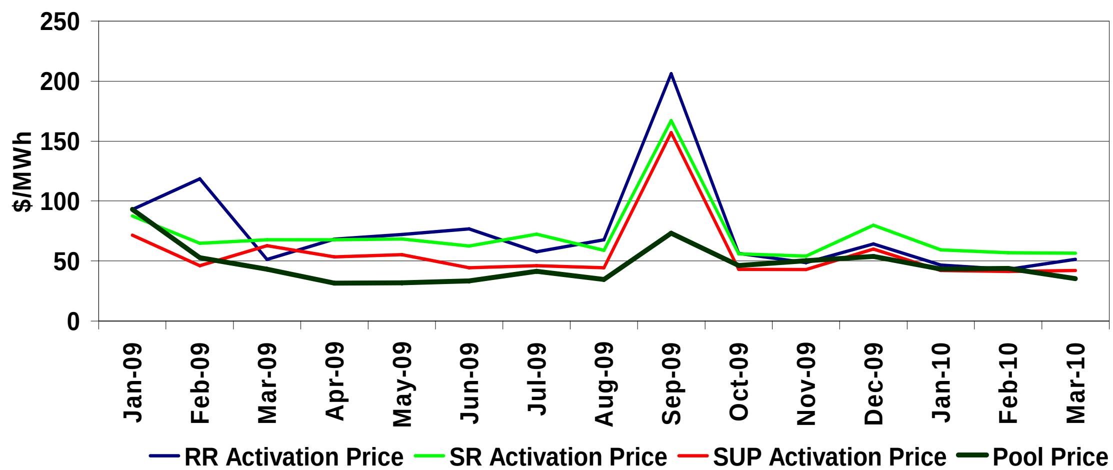


Figure 13 - Standby Activation Rates

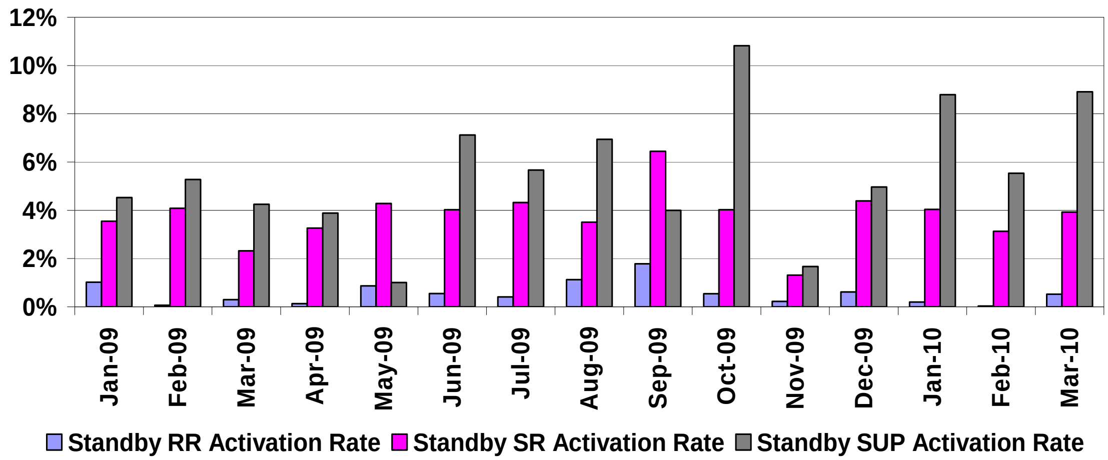


Figure 14 - OTC Procurement as a % of Total Procurement

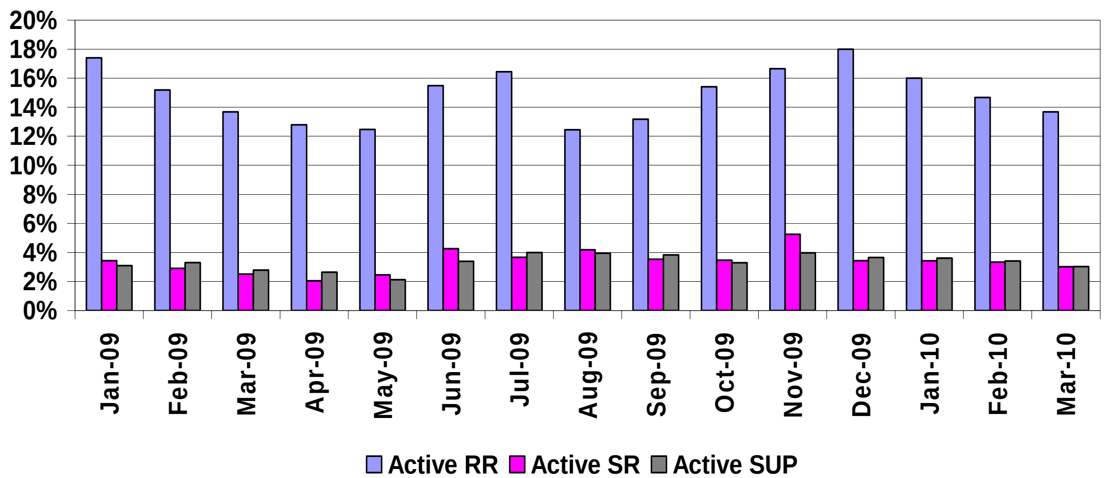


Figure 15 - Active Regulating Reserve Settlement by Market

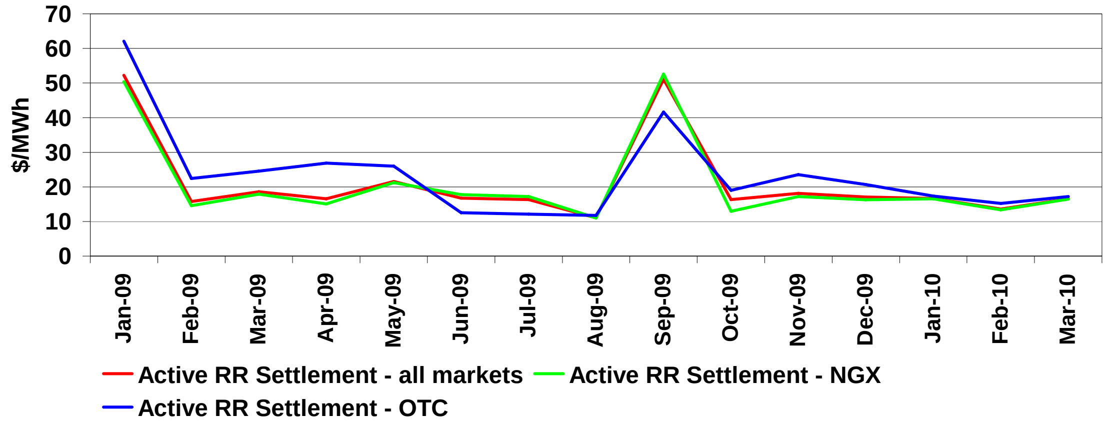


Figure 16 - Active Spinning Reserve Settlement Price by Market

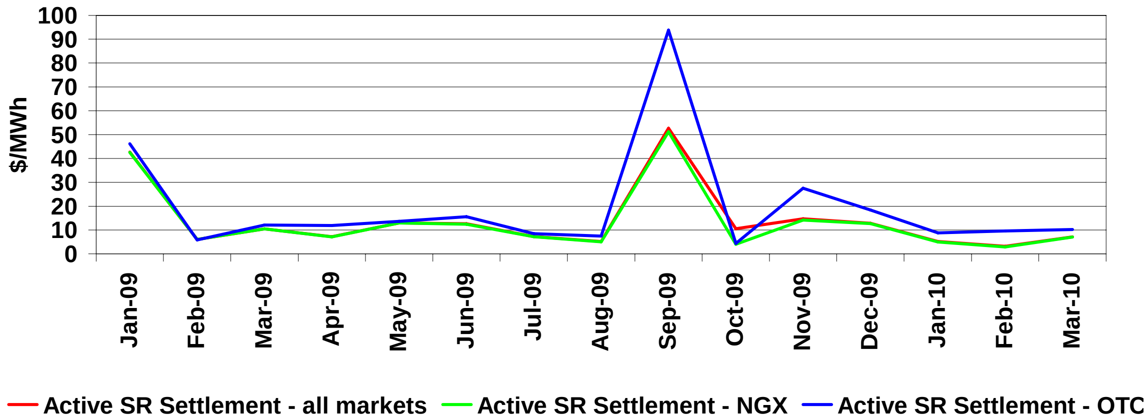


Figure 17 - Active Supplemental Reserve Settlement Price by Market

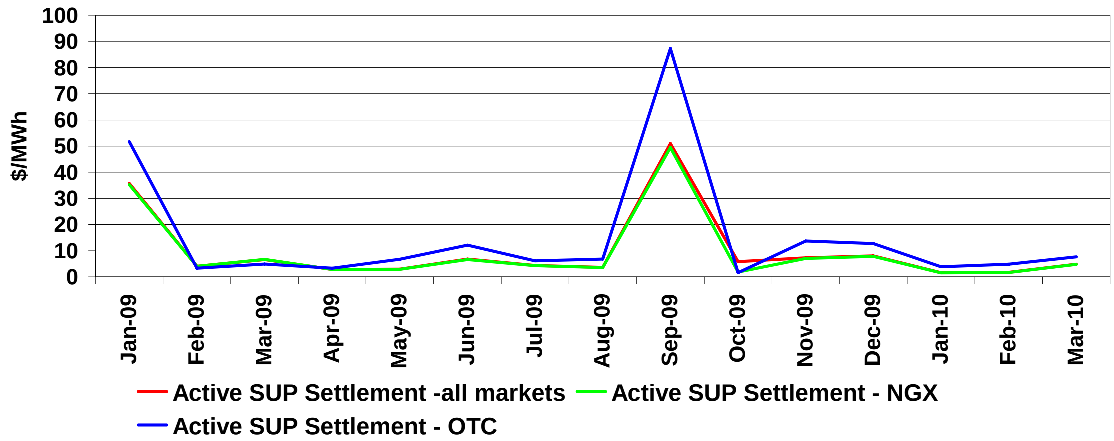


Figure 18 - Active Regulating Reserve Market Share by Fuel Type

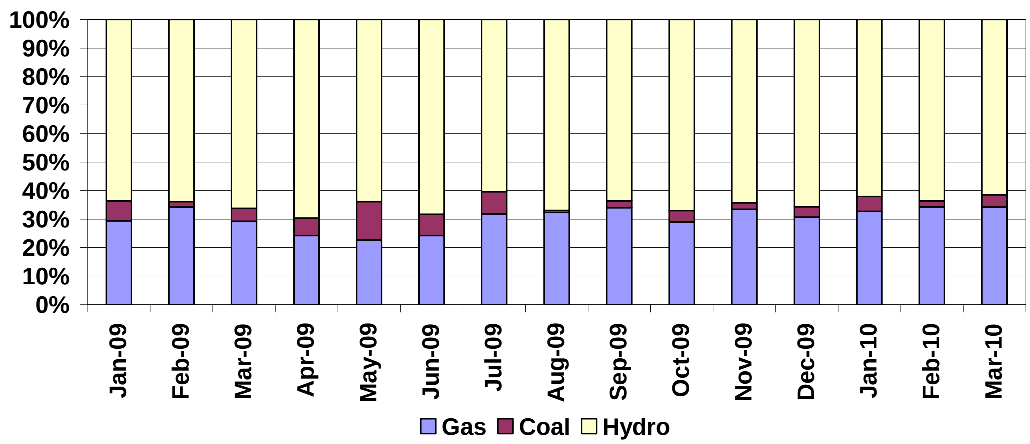


Figure 19 - Active Spinning Reserve Market Share by Fuel Type

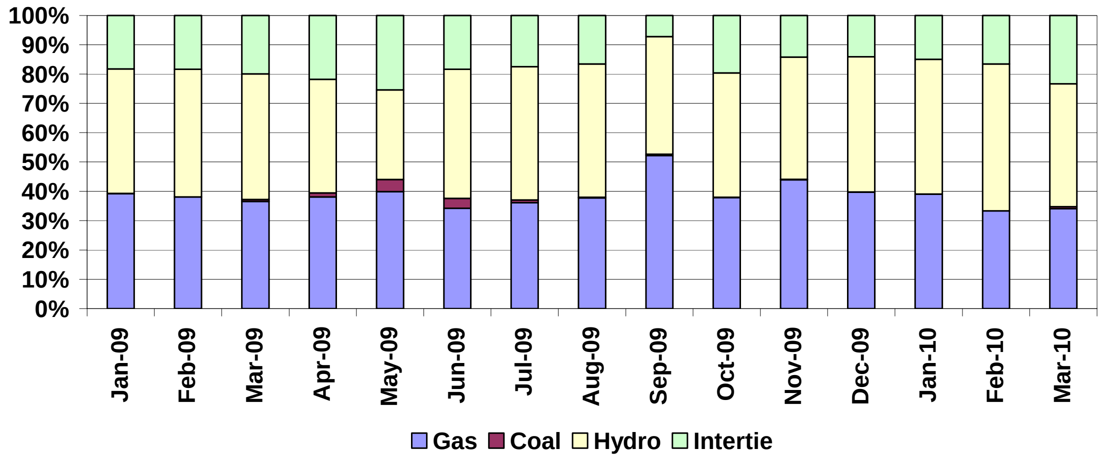
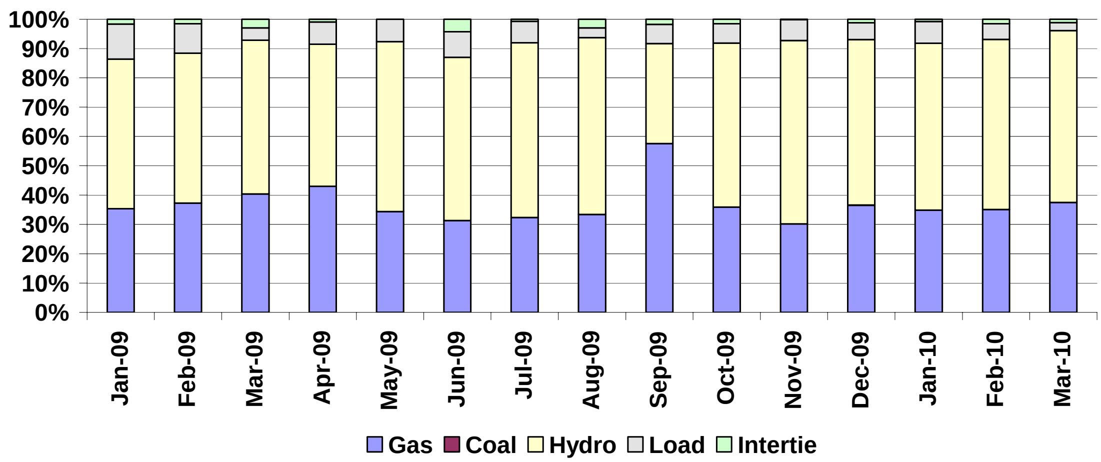


Figure 20 - Active Supplemental Reserve by Fuel Type



APPENDIX D – DDS METRICS

Table 3: DDS Costs and Revenues

Month	Total Payment ($M)	Total Dispatched (MWh)	Total Energy Production (MWh)	Estimated DDS Charge ($/MWh)	Estimated Revenue to DDS
	[A]	[B]	[C]	[A]/[C]	[A]/[B]
January	$1.31	76,417	5,168,664	$0.25	$17.18
February	$0.86	56,741	4,675,091	$0.18	$15.16
March	$0.63	46,405	4,864,723	$0.13	$13.58
Total	$2.80	179,564	14,708,478	$0.19	$15.61

Figure 21 - Average Daily TMR, Available, Eligible & Dispatched DDS Volumes (MW)

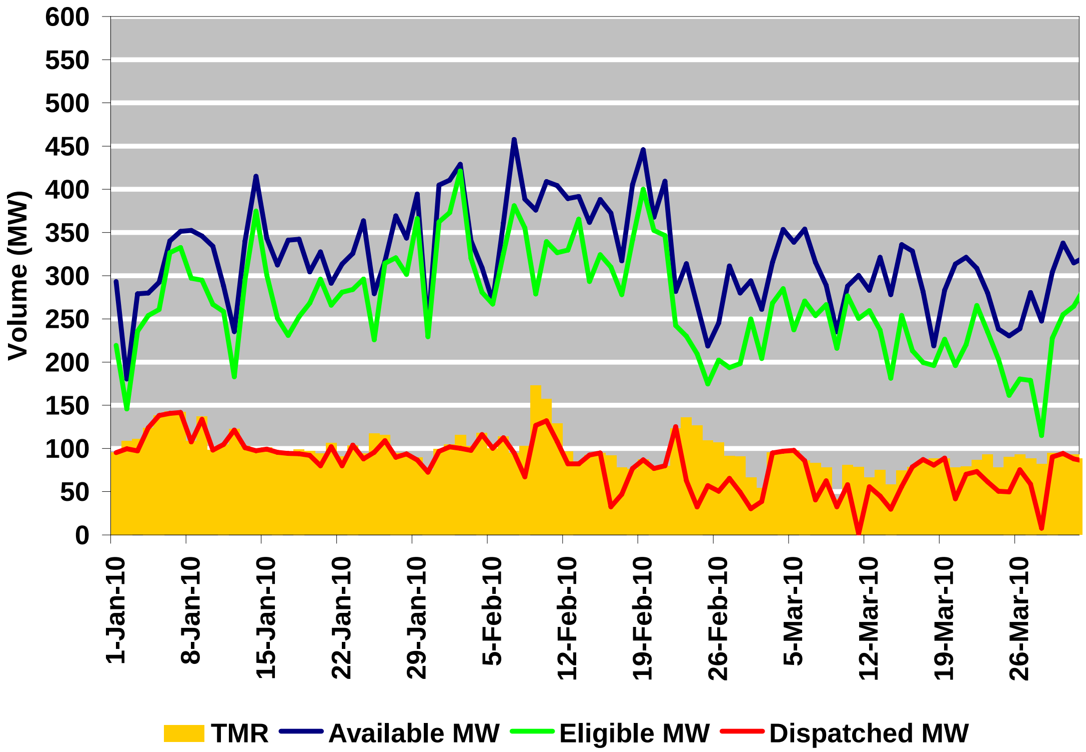


Figure 22 - Average Daily DDS Dispatched and Constrained Down Volume (MW)

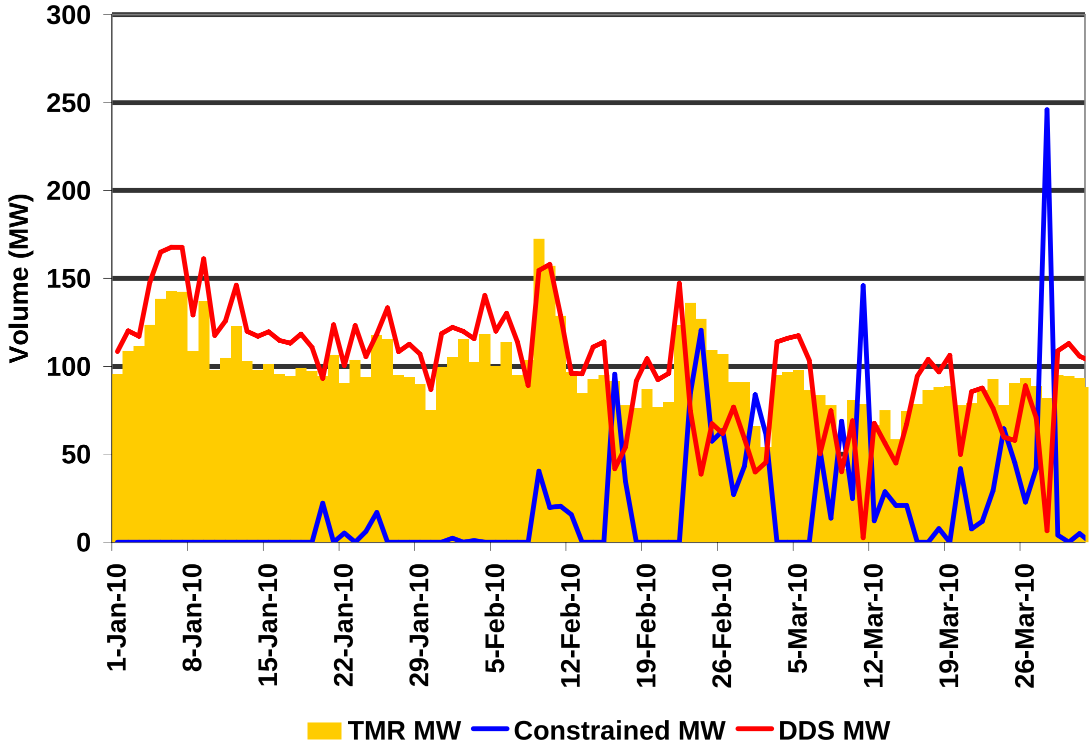


Figure 23 - Average Weekly DDS Market Share by Submitting Participants

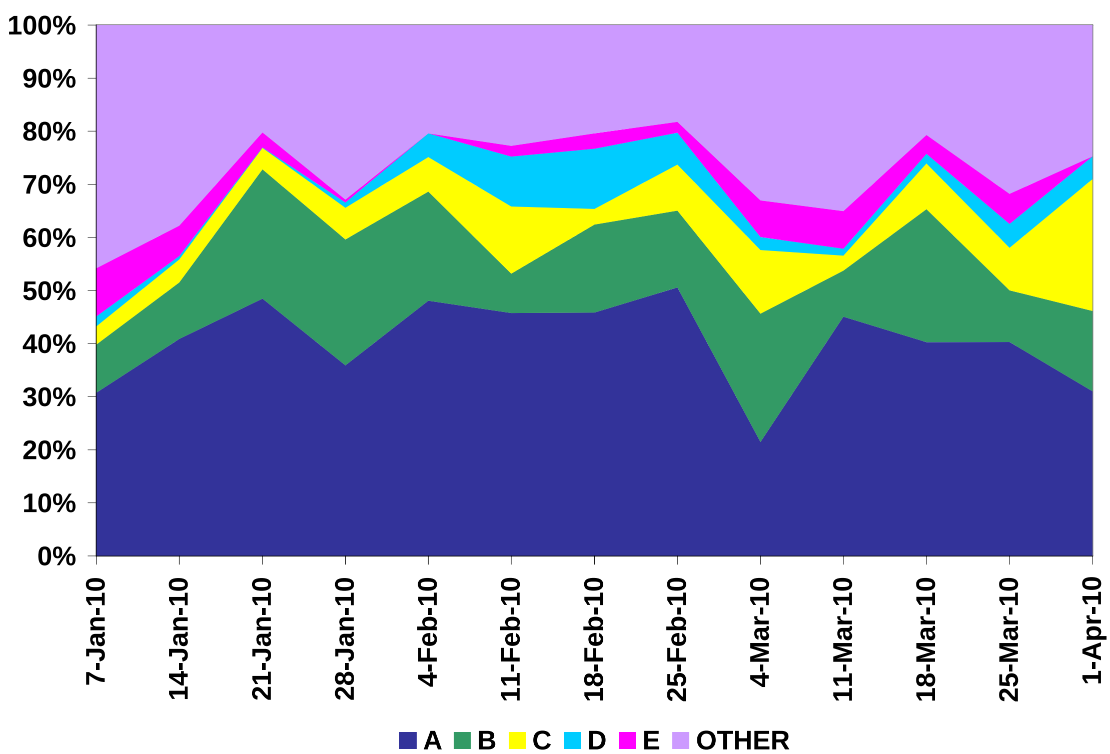
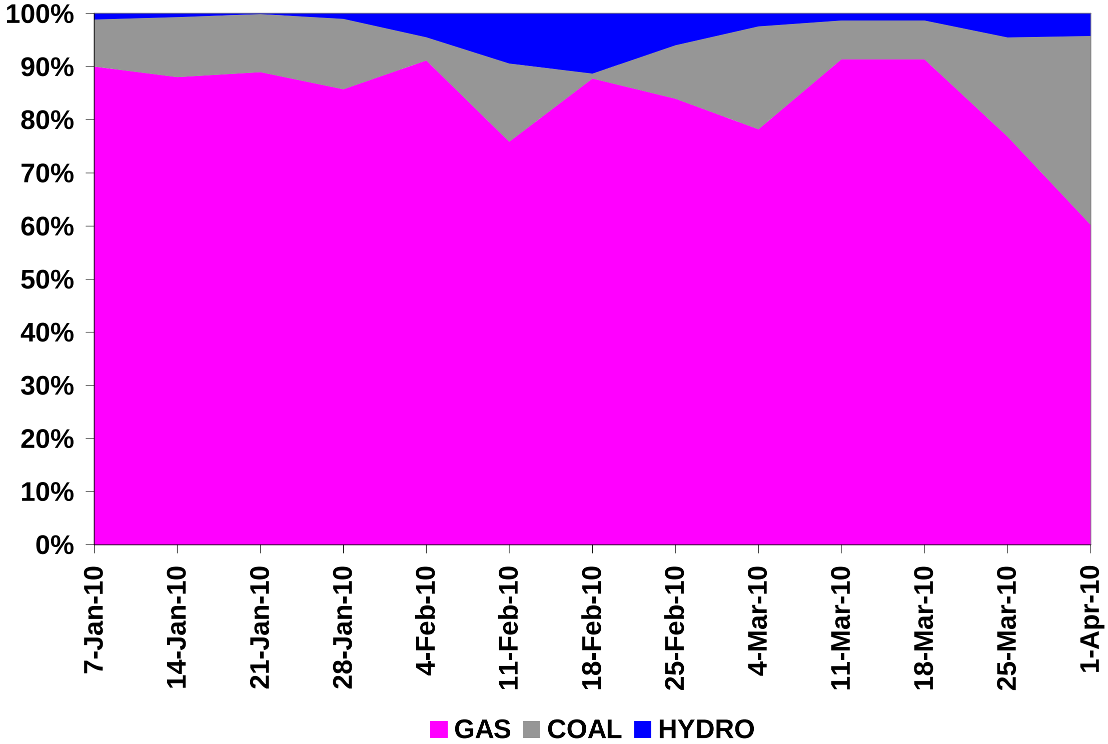


Figure 24 - Average Weekly DDS Market Share by Fuel Type



APPENDIX E – INTERTIE METRICS

Figure 25 - Intertie Utilization

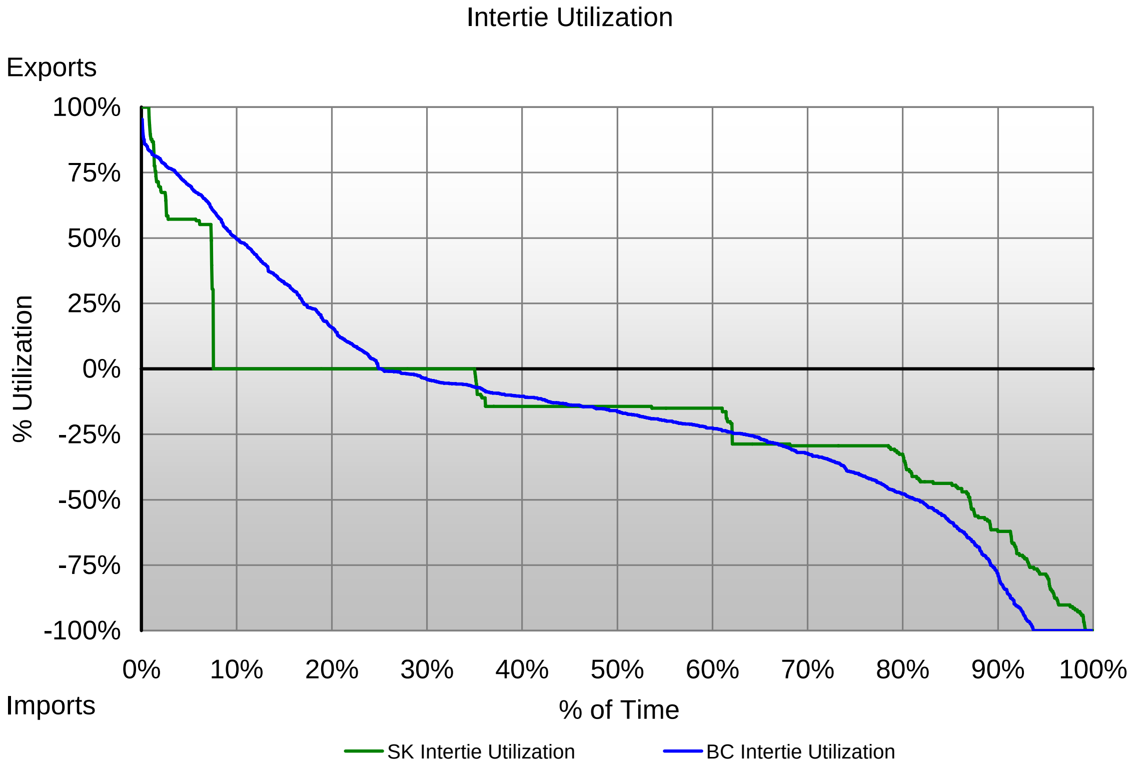


Figure 26 - On-Peak Prices

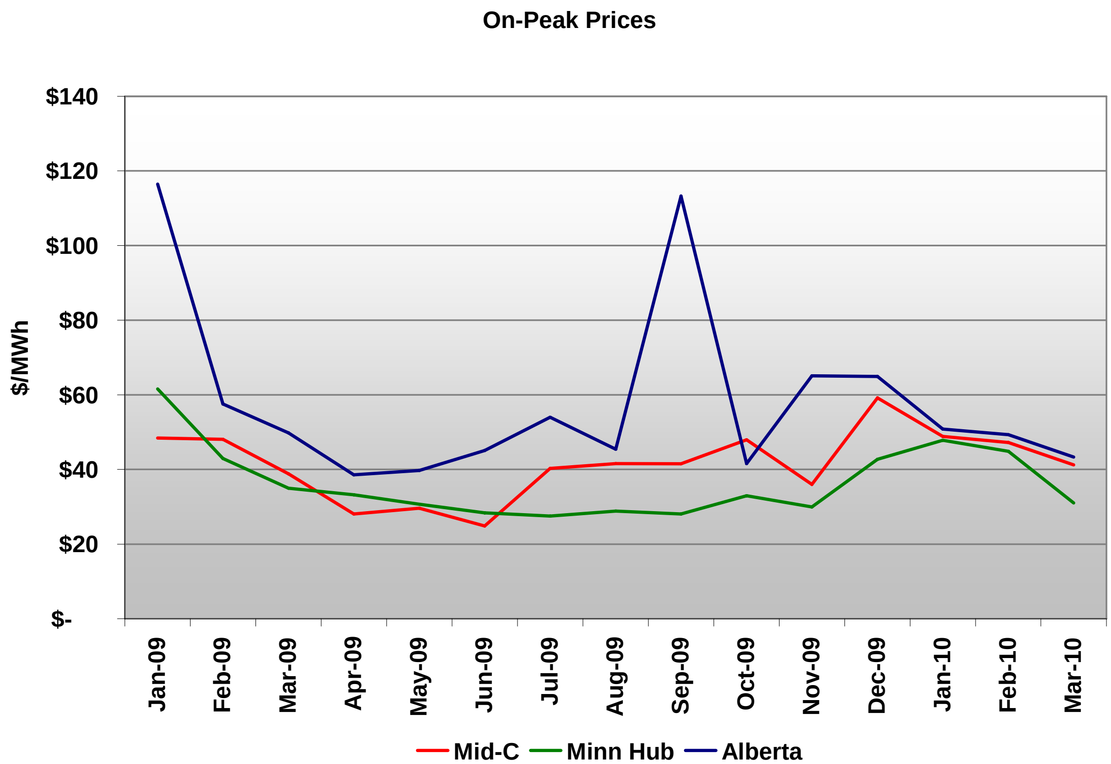


Figure 27 - Off-Peak Prices

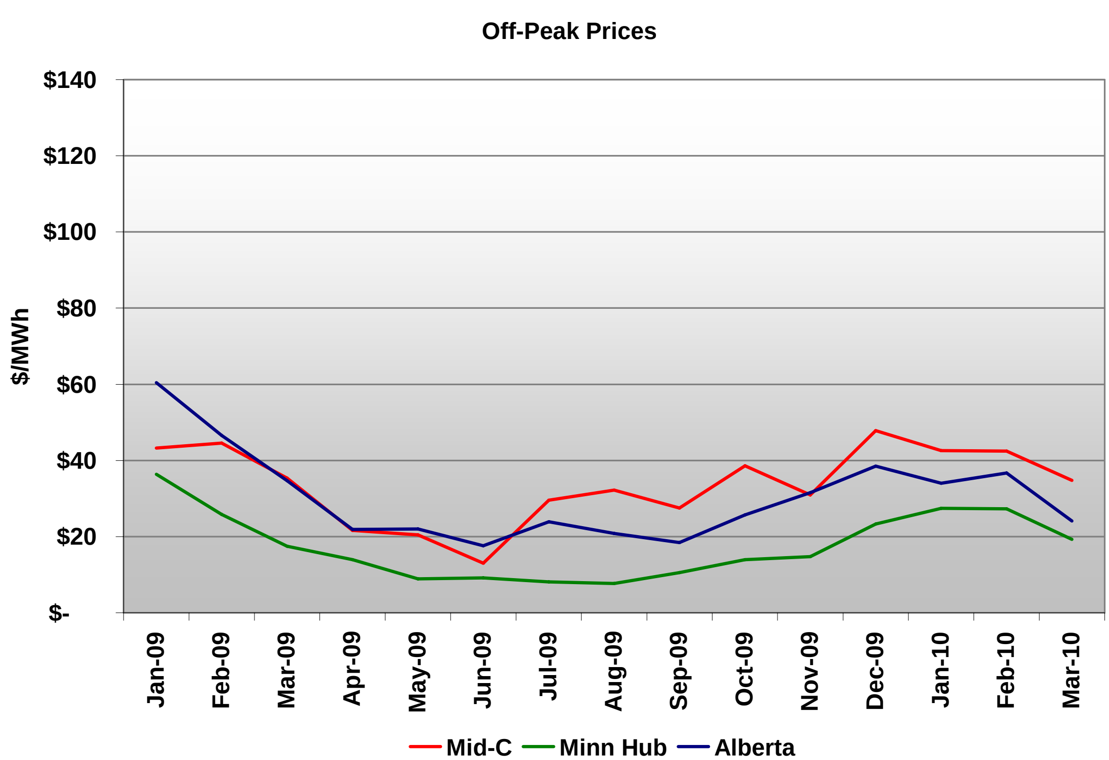


Figure 28 - BC Intertie Price Differential and Net Flow

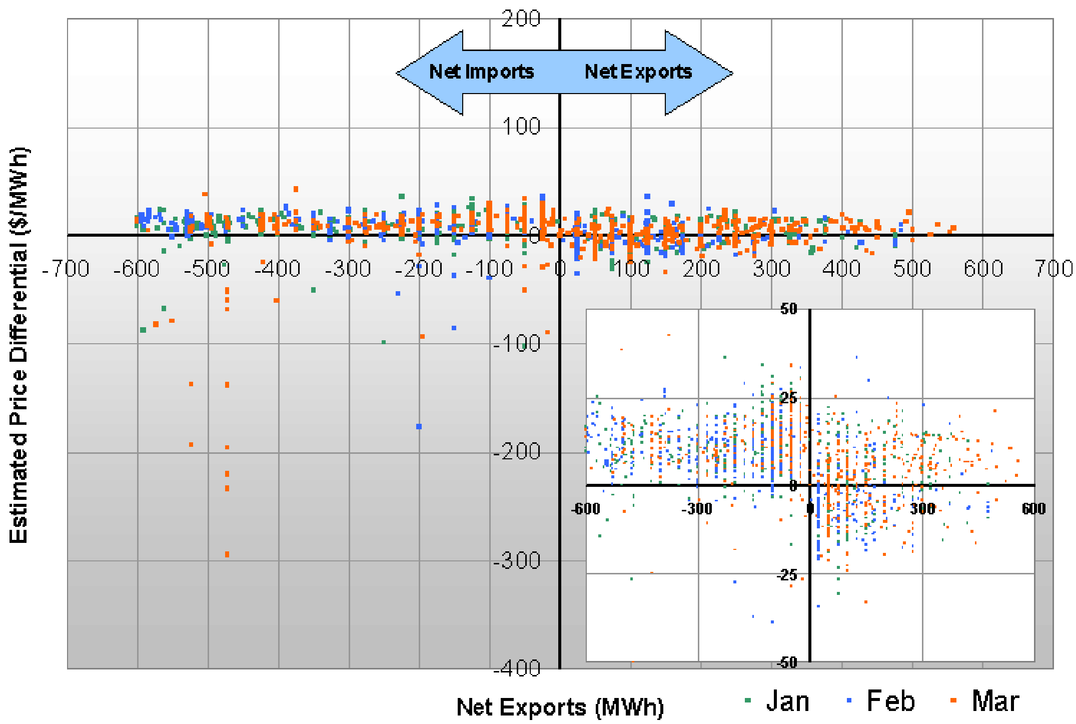
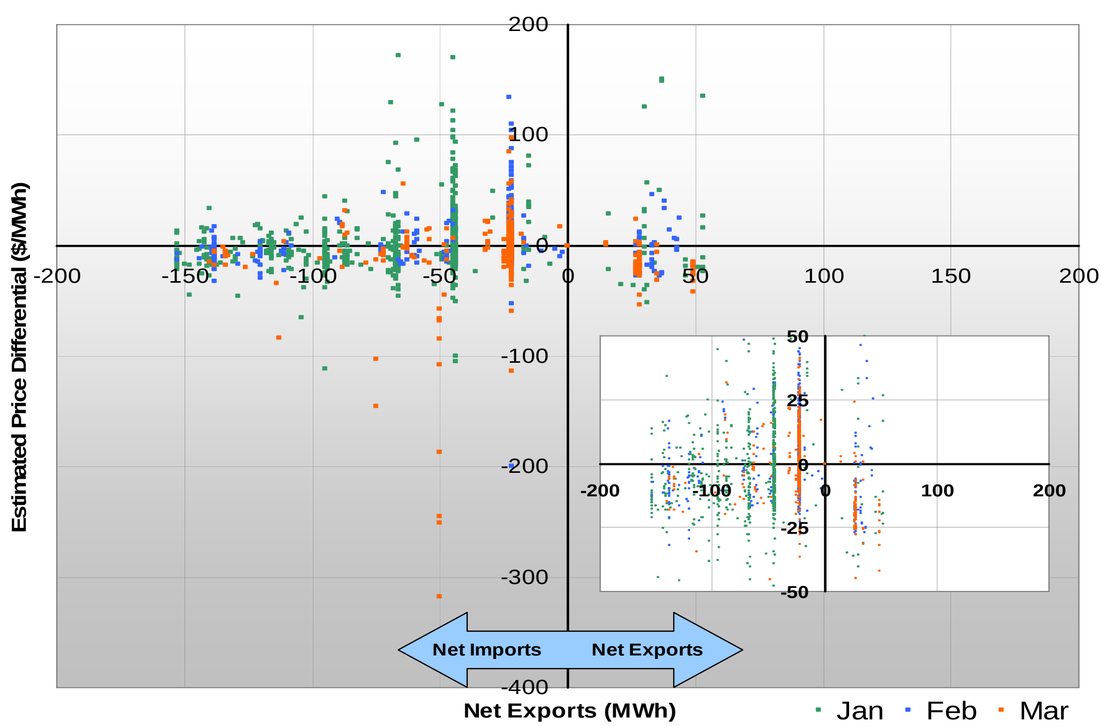
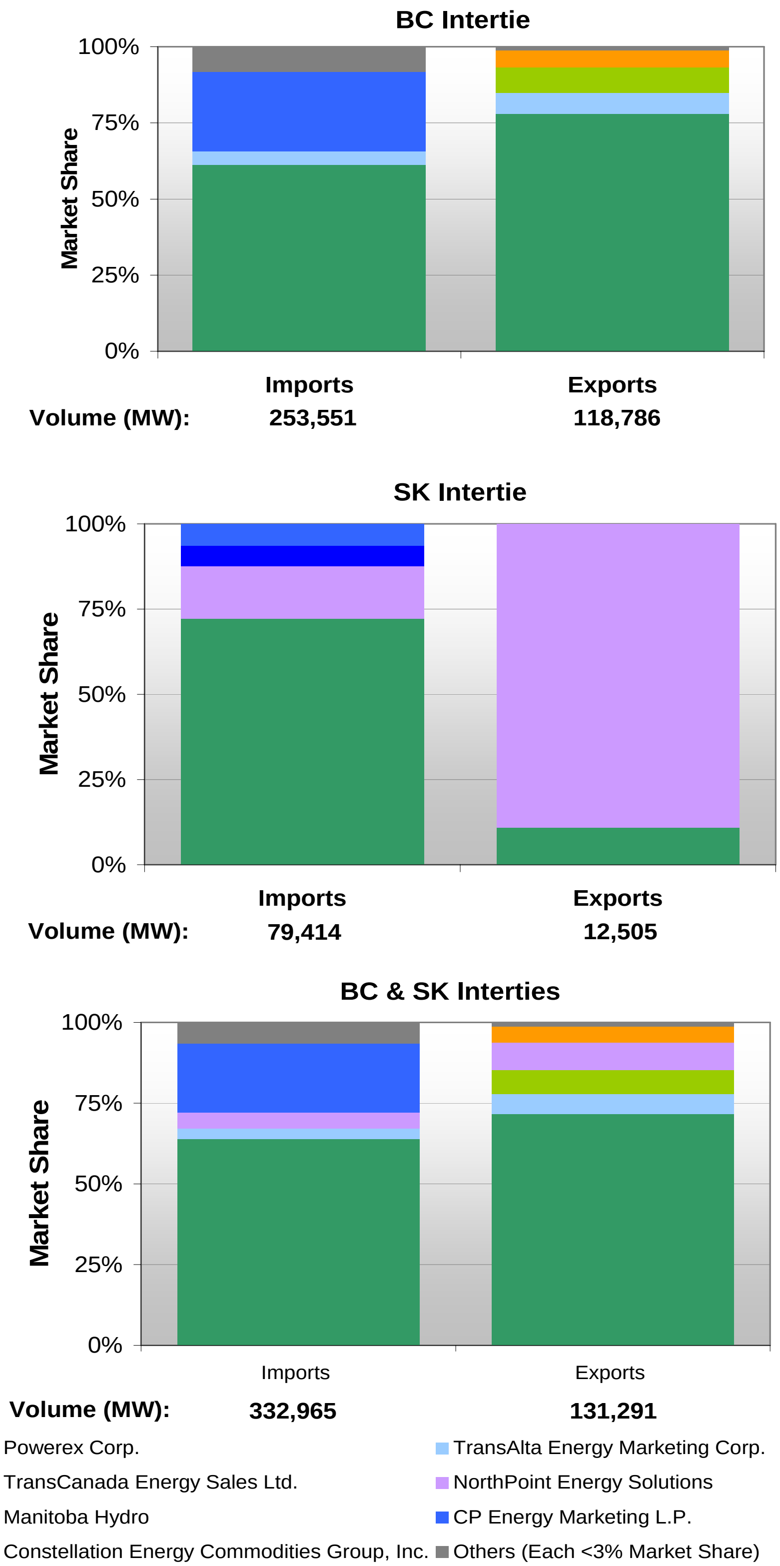


Figure 29 - SK Intertie Price Differential and Net Flow




BC Intertie
Market Share
100%
75%
50%
25%
0%
Imports
Exports
Volume (MW):
253,551
118,786
SK Intertie
Market Share
100%
75%
50%
25%
0%
Imports
Exports
Volume (MW):
79,414
12,505
BC & SK Interties
Market Share
100%
75%
50%
25%
0%
Imports
Exports
Volume (MW):
332,965
131,291
Powerex Corp.
TransAlta Energy Marketing Corp.
TransCanada Energy Sales Ltd.
NorthPoint Energy Solutions
Manitoba Hydro
CP Energy Marketing L.P.
Constellation Energy Commodities Group, Inc.
Others (Each <3% Market Share)

APPENDIX F – FORWARD MARKET METRICS

Figure 31 - Volume by Trading Month[19]

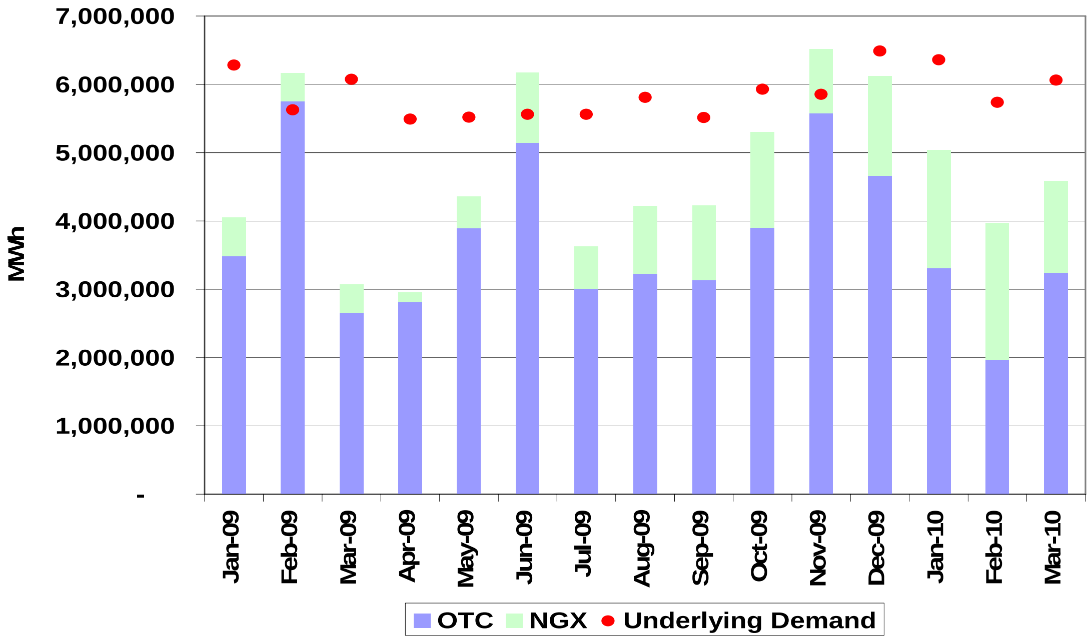
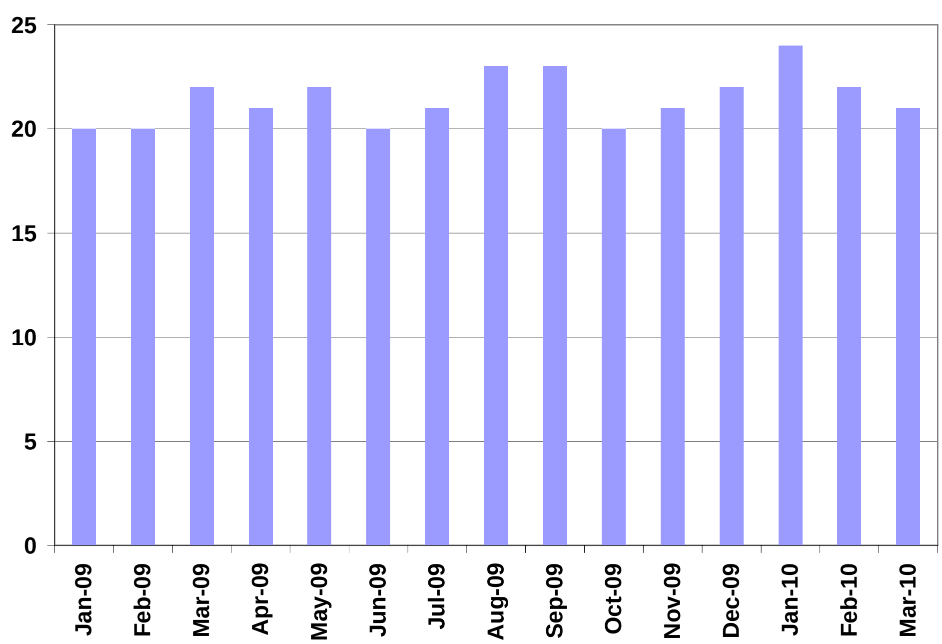


Figure 32 - Number of Participants by Trading Month



[19] The volumes include only one side of the transaction. NGX volumes do not include transactions not facilitated by but settled through NGX.