DTS Operating Reserve Charge Design
Discussion Paper

AESO 2010 Tariff Consultation

June 4, 2009

Contents

1 Introduction

The AESO's Tariff was most recently approved in AUC Order U2008-217 concerning the AESO's 2007 General Tariff Application ("GTA") filed on November 3, 2006. The tariff includes the use of deferral accounts to ensure no annual profit or loss results from the AESO's operation. Deferral accounts allow the AESO to address differences between actual revenues and costs incurred in providing system access service to customers. The AESO's tariff includes Working Capital Deficiency/Surplus Rider B, Deferral Account Adjustment Rider C, and Losses Calibration Factor Rider E, all of which are used to address differences between actual revenues and costs incurred by the AESO.

In the AESO's Demand Transmission Service ("DTS")rate, the Operating Reserve (OR) charge is calculated as a product of metered energy in each hour and 3.33% of Pool Price (PP) in that hour. The AESO procures OR from suppliers in the market on behalf of customers using a variety of means. Differences between revenue obtained through the OR charge and costs incurred are dealt with through Rider C. The AESO forecasts the OR revenue and cost shortfall or suplus balance at the end of the upcoming quarter, and then calculates the net amount to be recovered or distributed in that quarter via a Rider C $/MWh charge or credit to reduce the balance to zero.

2 Issue

The currently-approved approach to recovery of OR costs discussed above became effective in 2006. The OR charge was based on forecasted 2006 PP, forecasted 2006 DTS energy volume, and forecasted 2006 OR cost. The 2006 OR rate was 3.87% of PP, was intended to recover the 2006 annual OR cost, and was in effect from January 1, 2006 until July 31, 2008..

For the AESO's 2007 tariff application, the OR charge was based on forecasted 2007 PP, forecasted 2007 DTS energy volume, and forecasted 2007 OR cost. The 2007 OR rate was 3.33% of PP, was intended to recover the 2007 annual OR cost, and has been in effect since August 1, 2008.

As shown in the table 1 below, actual revenue and cost were substantially different thus requiring that these large difference be dealt with via Rider C. Additionally, Rider C works on a prospective basis and large differences in forecasted and actual quantities resulted in situations where customers were charged significant amounts in one quarter and then refunded significant amounts in the following quarter. Recovery or refund of shortfalls or surpluses through deferral account Rider C is imprecise, as the rider is designed on a simple $/MWh basis. As well, recovery or refund of amounts through Rider C is effectively done on an interim basis, and is "unwound" when deferral account balances are allocated to customers more precisely on a revenue basis in later deferral account reconciliations. If large variances between costs and revenues are addressed through deferral account Rider C, the final allocation to customers in a deferral account reconciliation is subject to greater uncertainty. The deferral account reconciliation also occurs after year-end, several months later than the initial deferral account rider recovery or refund. The deferral account rider process therefore results in timing delays between when costs are incurred to provide system access service and when those costs are finally and accurately recovered from customers.

Table 1 – Actual OR Cost and Revenue

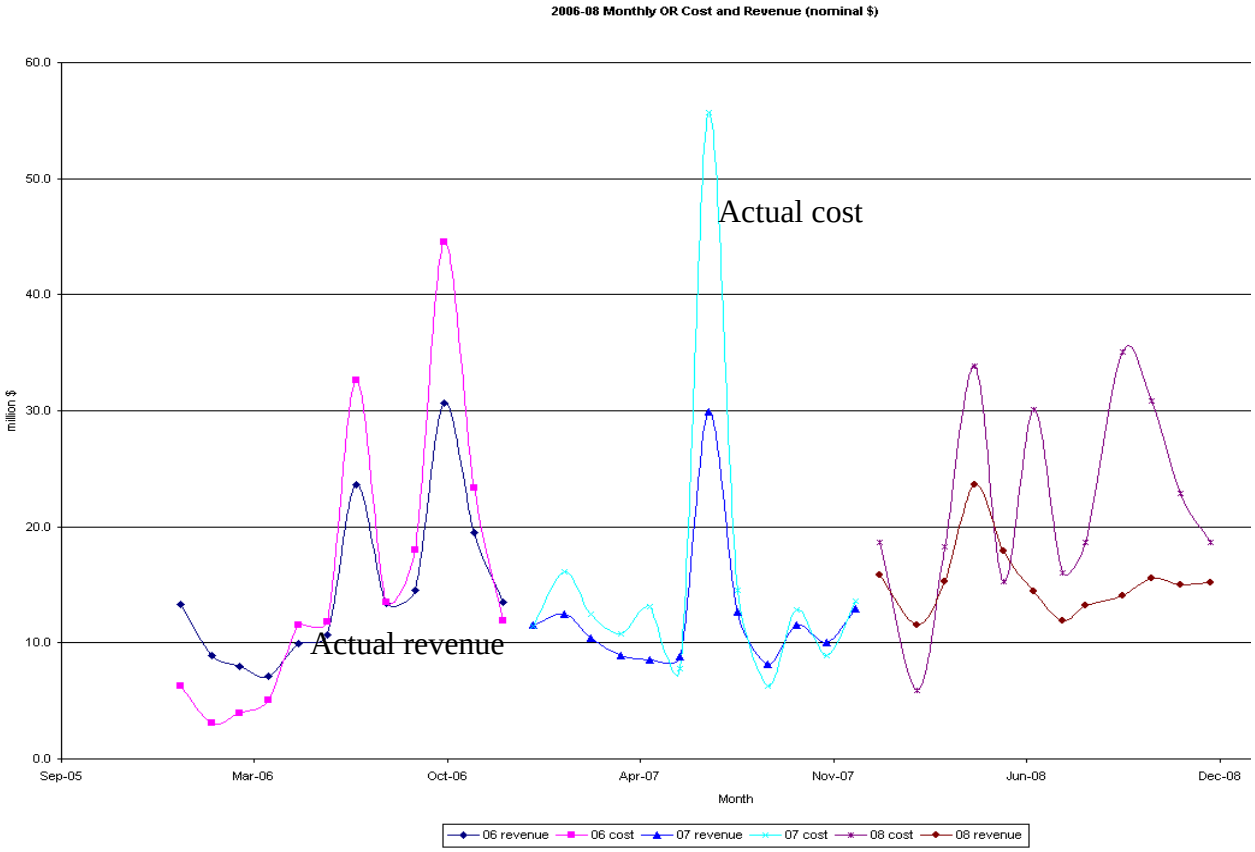
Month	2006			2007			2008		
	OR Cost	OR Revenue	Surplus/ Shortfall	OR Cost	OR Revenue	Surplus/ Shortfall	OR Cost	OR Revenue	Surplus/ Shortfall
January	6.3	13.3	7.0	11.4	11.5	0.1	18.7	15.8	-2.9
February	3.1	8.9	5.8	16.1	12.5	-3.6	5.9	11.5	5.6
March	3.9	8.0	4.1	12.5	10.4	-2.1	18.3	15.3	-3.0
April	5.1	7.1	2.0	10.8	8.9	-1.9	33.8	23.6	-10.2
May	11.5	9.9	-1.6	13.1	8.5	-4.6	15.3	17.9	2.6
June	11.8	10.7	-1.1	7.8	8.8	1.0	30.1	14.4	-15.7
July	32.6	23.6	-9.0	55.7	29.9	-25.8	16.0	11.9	-4.1
August	13.5	13.4	-0.1	14.5	12.7	-1.8	18.7	13.2	-5.5
September	18.0	14.5	-3.5	6.3	8.2	1.9	35.1	14.1	-21.0
October	44.5	30.7	-13.8	12.8	11.5	-1.3	30.8	15.6	-15.2
November	23.3	19.5	-3.8	8.9	10.0	1.1	22.9	15.0	-7.9
December	11.9	13.5	1.6	13.6	12.9	-0.7	18.7	15.2	-3.5
Annual	**185.5**	**173.1**	**-12.4**	**183.5**	**145.8**	**-37.7**	**264.3**	**183.5**	**-80.8**

All numbers in $ million

Table 1 above shows that the AESO is primarily under-collecting OR costs. The AESO has to carry the resulting shortfall until Rider C recovers this amount. The largest monthly shortfall in each year was $13.8 million in October 2006, $25.8 million in July 2007, and $21.0 million in September 2008. The largest quarterly shortfall in each year was $16 million in the 4th quarter of 2006, $25.7 million in the 3rd quarter of 2007, and $30.6 million in 3rd quarter of 2008.

Figure 1 below presents the information in a graphic form.

Figure 1

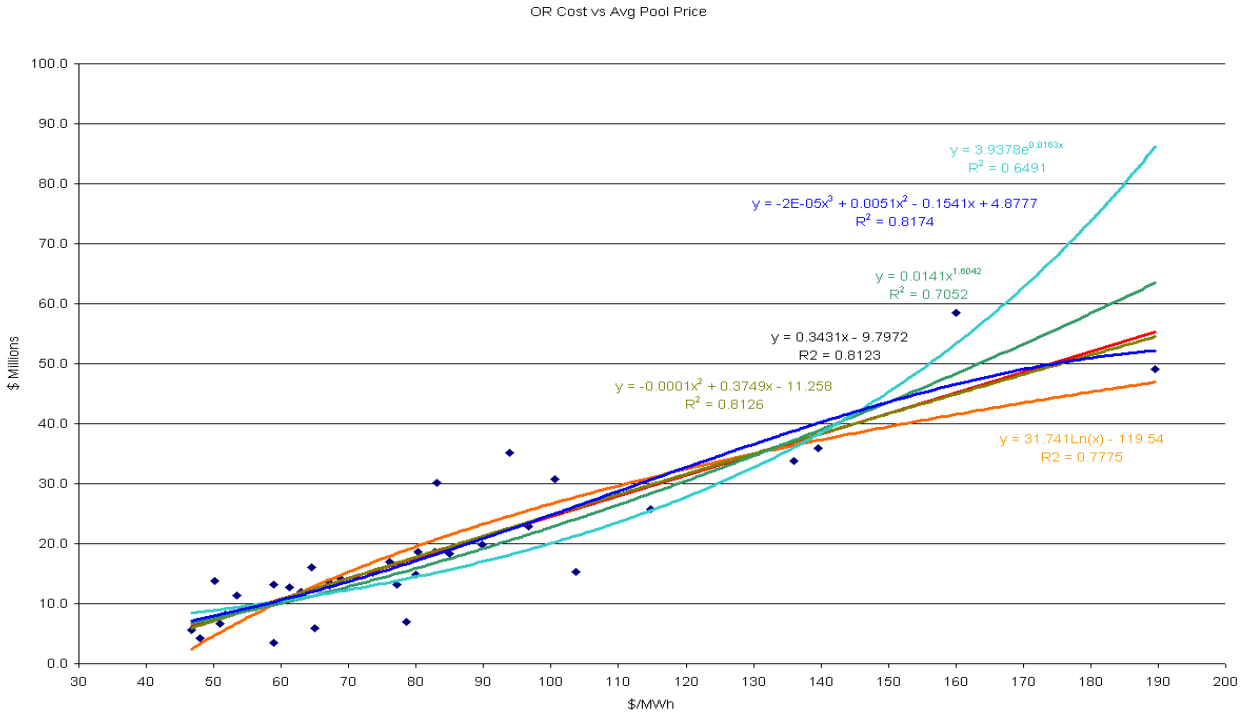


3 Cost Drivers

OR cost primarily depends on PP. OR offers are linked to PP and are priced at a discount or premium to the PP. Other factors also affect OR cost, including outages, weather, load, load characteristics, power flows, imports, exports, fuel price, and market participant behavior. These factors are expected to be reflected in large part by the PP.

Analysis of Figure 1 indicates that changes in cost are larger than changes in revenues which suggests the OR charge needs to be a stronger function of PP. Currently, the OR charge varies directly with PP. Figure 2 maps monthly OR cost to monthly average PP using several different functions. The correlation between OR cost and PP varies from $r^2 = 0.8123$ for a linear function, to $r^2 = 0.8126$ for a quadratic function, and to $r^2 = 0.8174$ for a cubic function. These correlations demonstrate that OR cost is strongly influenced by PP.

Figure 2



4 Rate Design

As discussed above, the OR charge needs to a stronger function of PP than the current one. The AESO considers that any revision to the OR charge should be somewhat gradual especially since forecasting PP is quite difficult. Rates that are a stronger function of PP yet not radically different from the current rate include the following.

- On/Off-Peak: $x1 \times PP$ for 7am-11pm and $x2 \times PP$ for 11pm-7am
- Block: $x1 \times PP$ when PP is in block 1 (0-P1) and $x2 \times PP$ when PP is in block 2 (P1-1000)
- Exponential: $x1 \times e^{(PP \times x2)}$
- Linear: $(x1 \times PP) + x2$ (current rate is linear with x2 being zero)
- Quadratic: $(x1 \times PP^2) + (x2 \times PP) + x3$
- Power: $x1 \times PP^{x2}$
- Block Continuous: $x1 \times PP$ when PP is in block 1 (0-P1) plus $x2 \times (PP-P1)$ when PP is in block 2 (P1-1000)

- Block Continuous with Floor: $x1/MWh plus x2 × PP when PP is in block 1 (0-P1) plus x3 × (PP-P1) when PP is in block 2 (P1-1000)

For any of the above rates, the OR charge for an hour will be the rate for that hour multiplied by the DTS energy volume for that hour.

5 Criteria

The AESO believes that the possible OR rates should be compared using following criteria:

- Recovery of forecasted annual OR cost
- Minimization of monthly shortfall or surplus
- Sensitivity to PP
- Sensitivity to DTS energy volume
- Simplicity
- Clarity
- Ease of administration

6 Method

To assess each possible OR rate, a rate was first determined using forecasted hourly PP and forecasted annual OR cost so as to minimize the difference between forecasted annual OR cost and annual OR revenue under the rate. For block rates, P1 was taken as the simple average of forecasted PP for the year.

The second step was to compare the monthly root mean square (RMS) variance between actual monthly OR cost and monthly OR revenue under the rates and to examine the sensitivity of monthly RMS variance to PP and DTS energy volume.

The third step was to analyze the three block rates using break points other than average PP. This determined if a break point existed that would further reduce monthly RMS variance between actual monthly OR cost and monthly OR revenue under these rates.

The final step was to fix the ratio of the rates in two blocks. This constrained the solution and simplified it as well. Analysis of the results determined if there is a ratio which further reduces monthly RMS variance between actual monthly OR cost and monthly OR revenue under these rates.

This analysis was repeated for 2006, 2007, and 2008. Results were analyzed to see if any particular combination of block rate, break point, and ratio of the rate in two blocks can work for all three years.

7 RMS Variance

Results show that block rates result in the least RMS variance between actual monthly OR cost and monthly OR revenue under these rates. The Block Continuous rate has the least monthly RMS variance of $4.64, $5.78, and $6.76 million for 2006, 2007, and 2008 respectively.

Table-2 Monthly RMS Variance

Rate	Monthly RMS ($M)		
	2006	**2007**	**2008**
Hourly On/Off-peak	6.37	6.63	7.08
Block	5.35	6.38	7.18
Exponential	14.69	12.52	9.67
Linear	6.29	7.13	7.49
Quadratic	64.71	25.29	6.65
Power	14.72	12.56	9.68
Block Continuous	4.64	5.78	6.76
Block Continuous with Floor	25.05	5.78	6.76
Actual	5.83	7.74	10

* P1 was rounded simple average of forecasted hourly PP for the year

8 Sensitivity

Block rates are also among the least sensitive to PP and DTS energy volume when measured in terms of change in monthly RMS variance between actual monthly OR cost and monthly OR revenue under these rates.

Figure 3

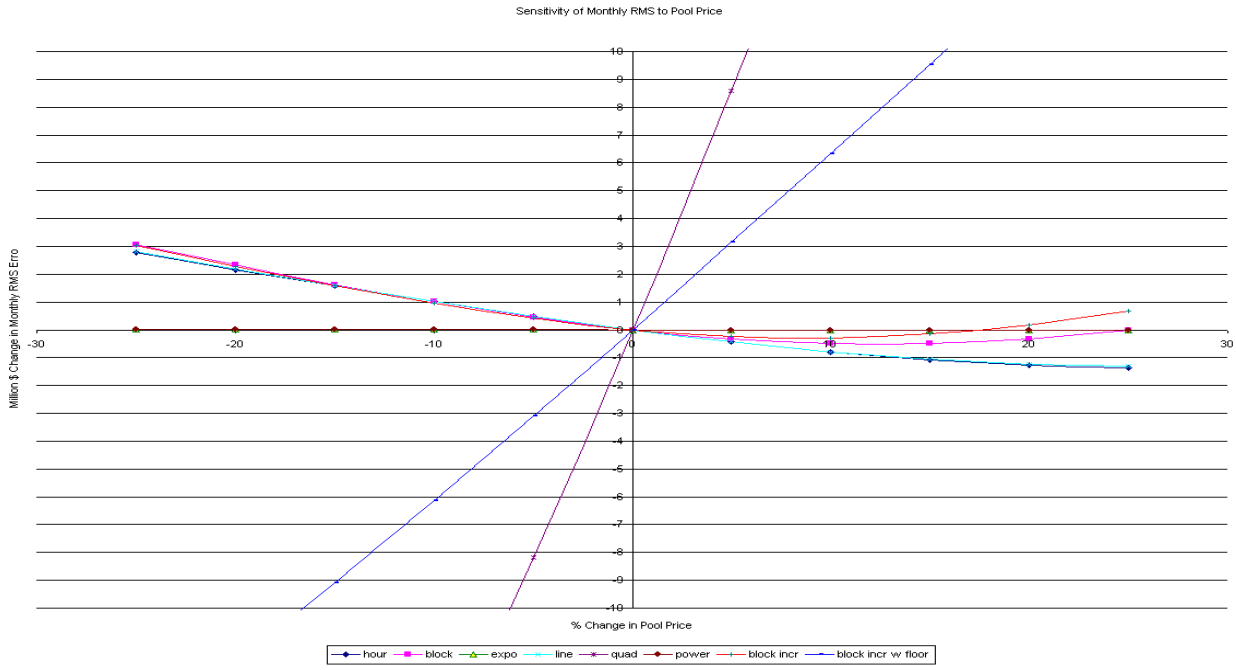
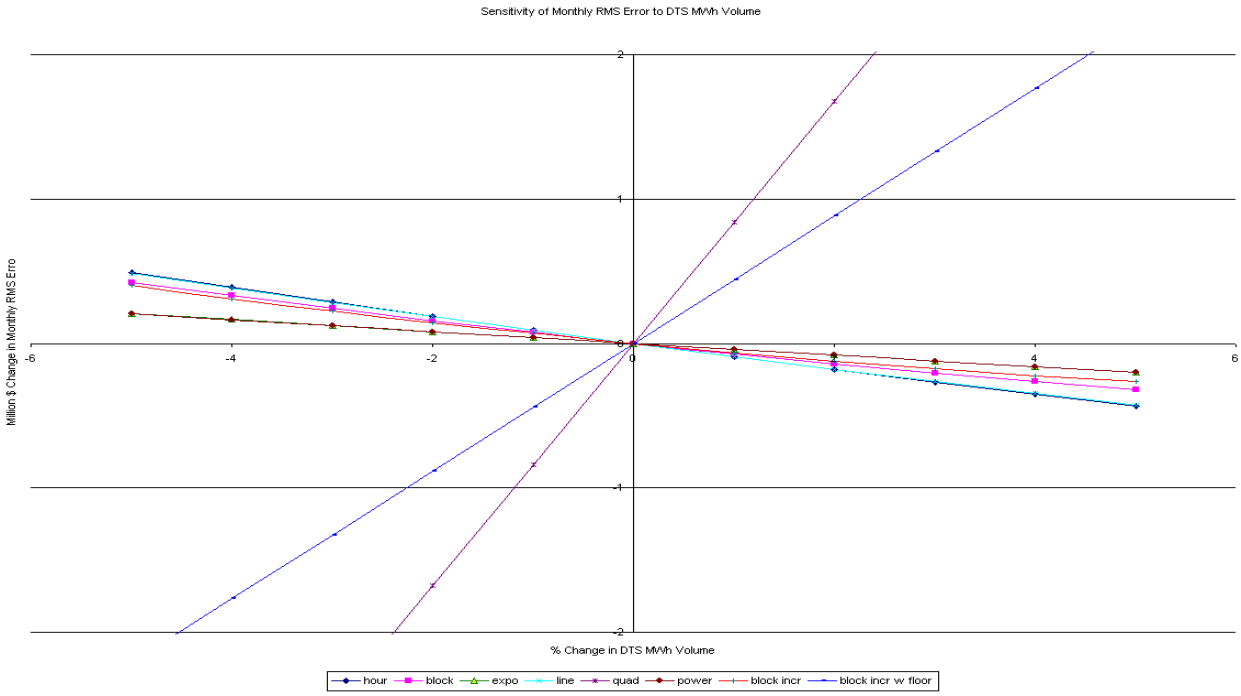


Figure 4



As Figures 3 and 4 show, for 2006, monthly RMS variance varied by about $3 million as PP varied by 25% and by about $0.5 million as DTS energy volume varied by 5%. Usually the difference between forecasted and actual PP and DTS energy volume is less than 25% and 5% respectively.

Figure 5

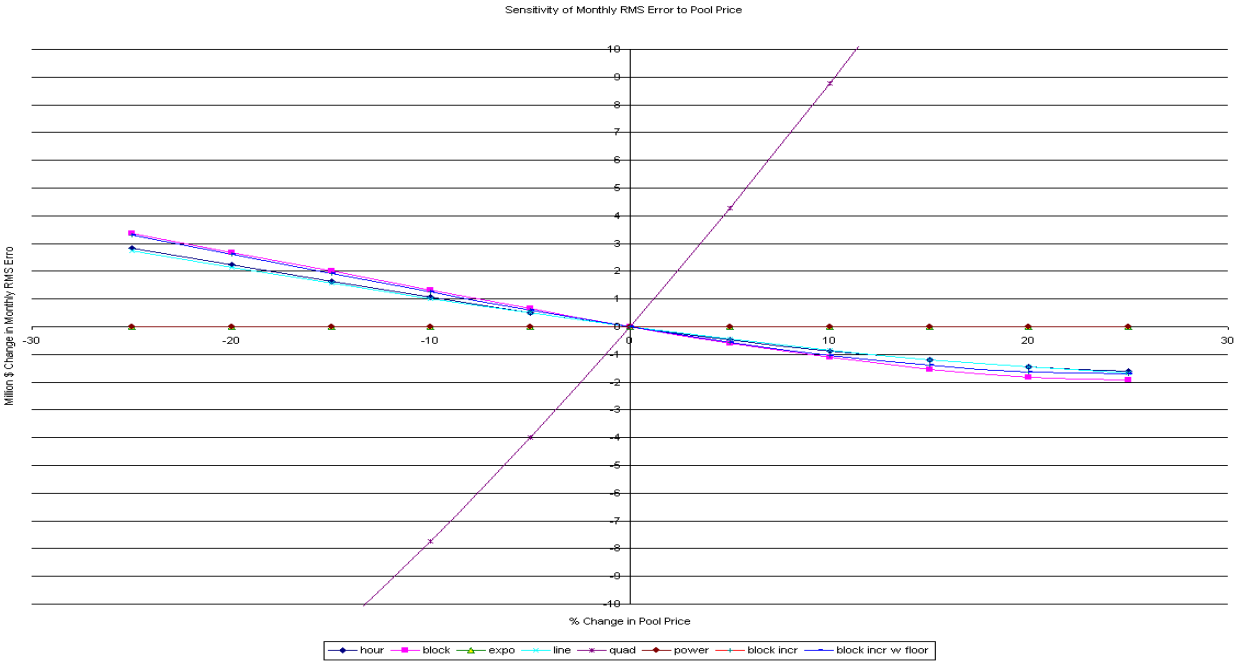
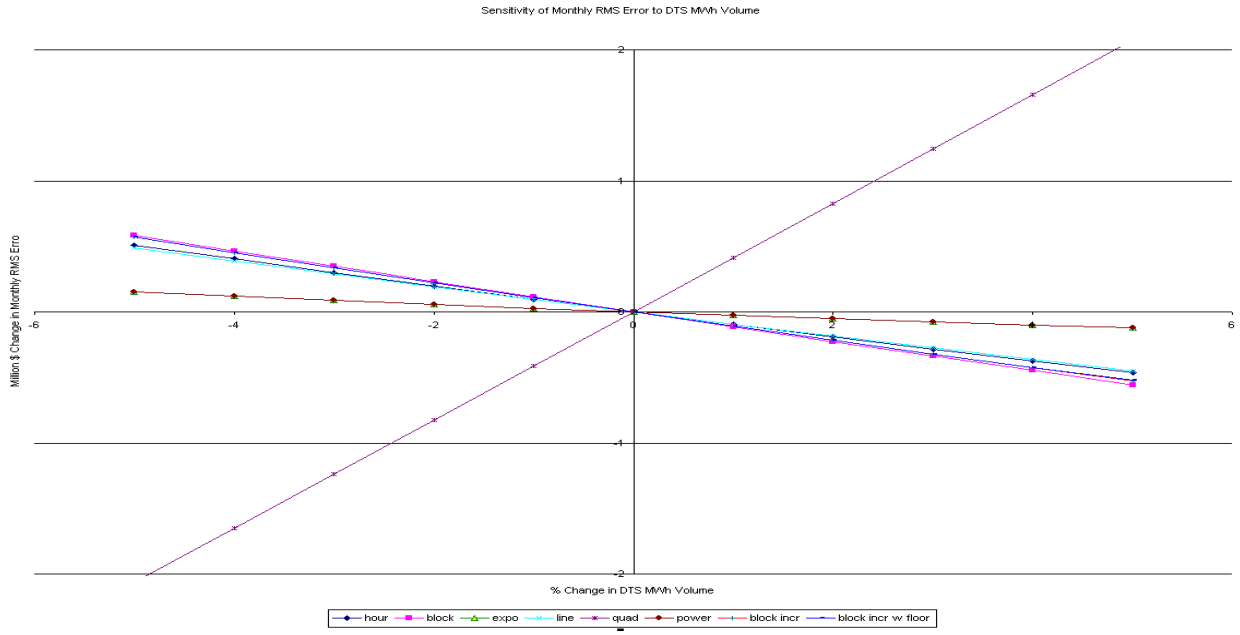


Figure 6



As Figures 5 and 6 show, for 2007, monthly RMS variance varied by about $3.5 million as PP varied by 25% and by about $0.5 million as DTS energy volume varied by 5%.

Figure 7

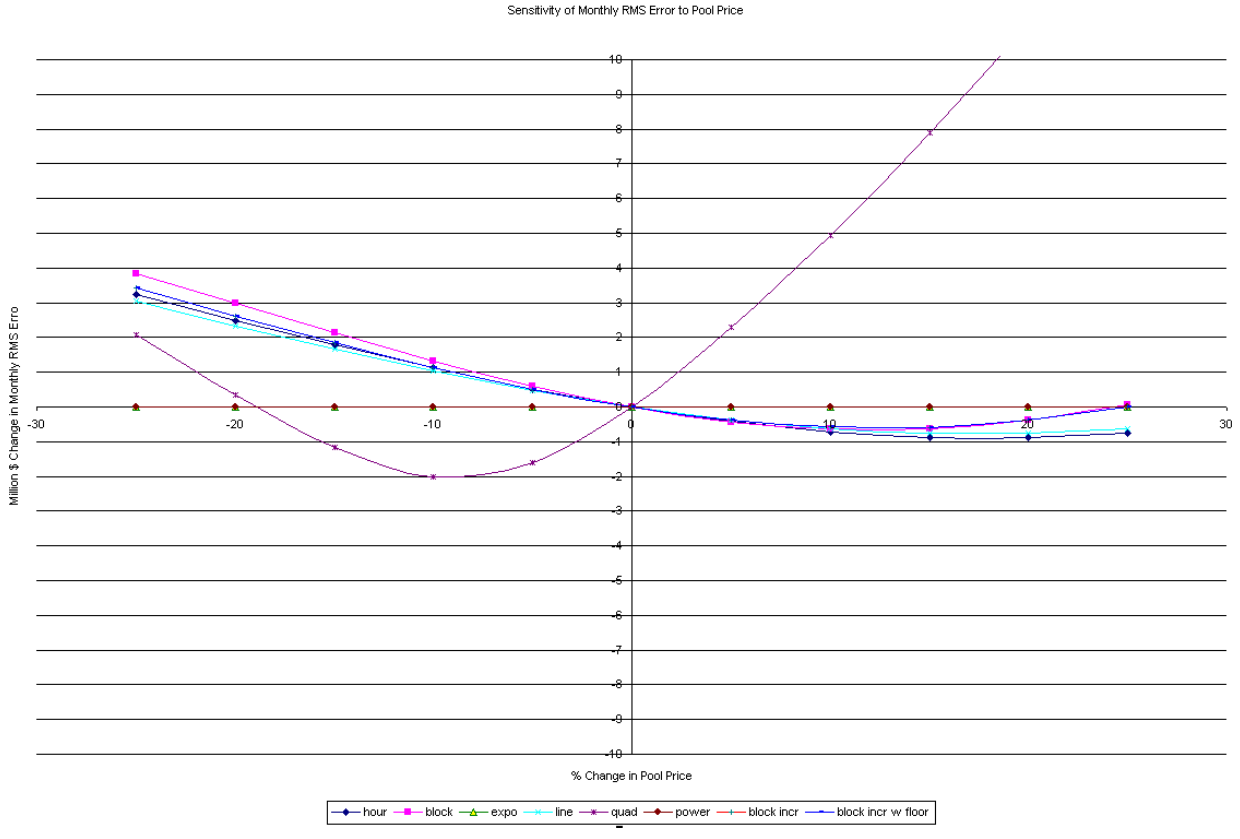
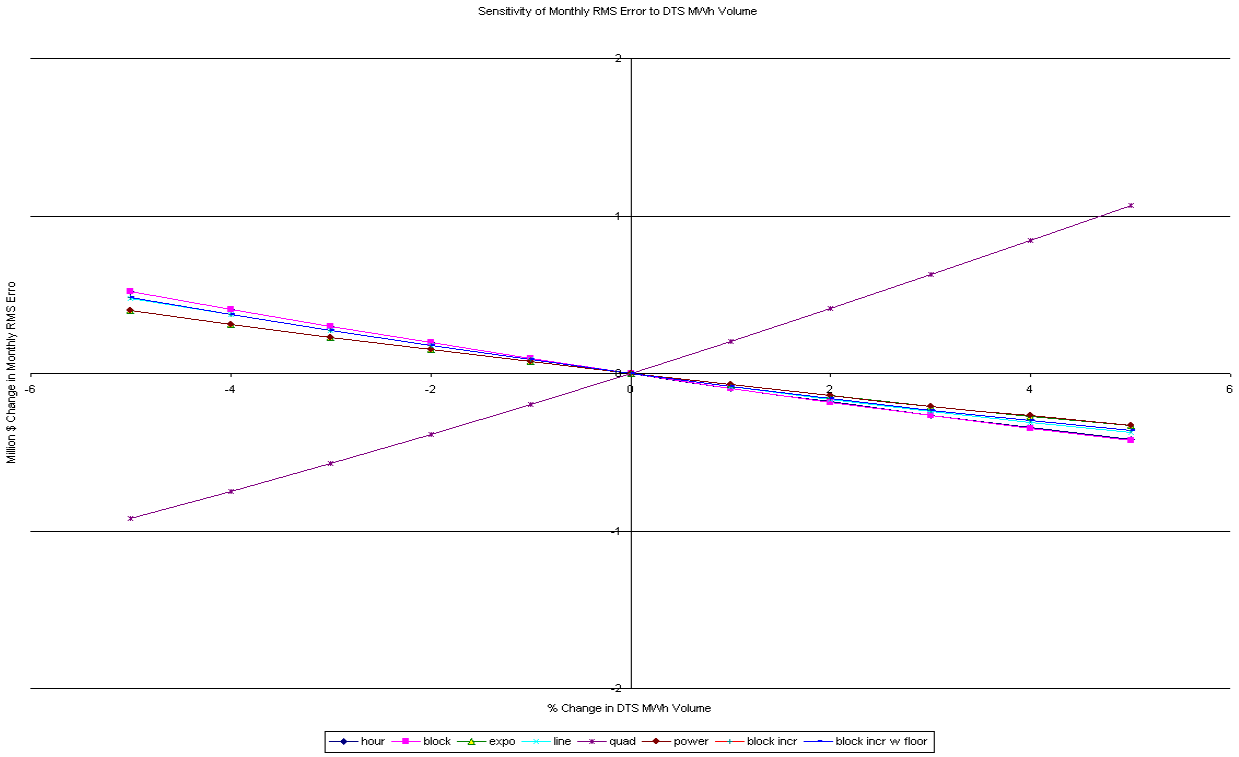


Figure 8

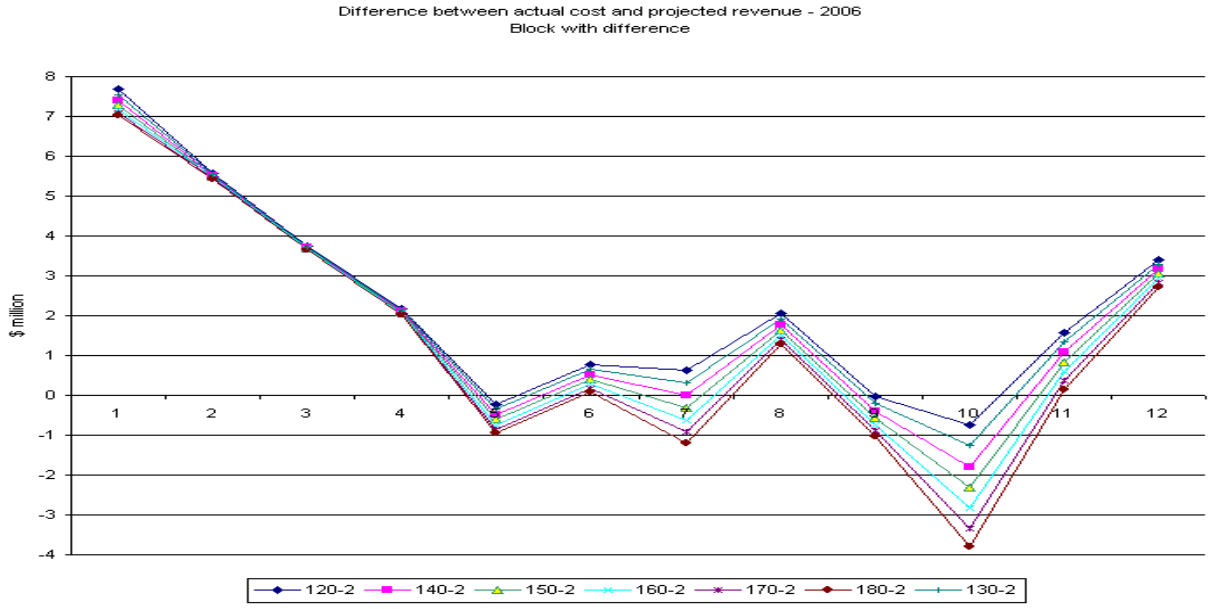


As Figures 7 and 8 show, for 2008, monthly RMS variance varied by about $4 million as PP varied by 25% and by about $0.5 million as DTS energy volume varied by 5%.

9 Best Rate for Each Year

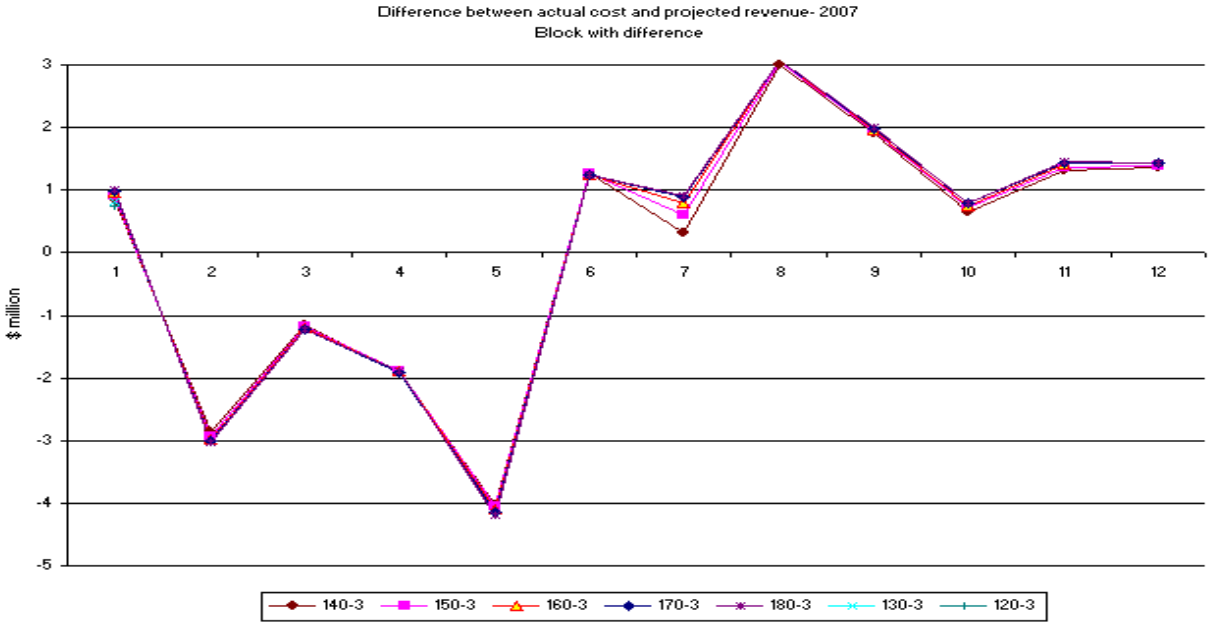
Applying the criteria listed in section 5 above, the Block Continuous rate performs best over 2006 to 2008. For 2006, a ratio of two between the rates in two blocks gives the best result (i.e. x2 is two times x1). The resulting monthly RMS variance is about $3.2 million and annual variance is about $20 million. If P1 is chosen as $150/MWh then x1 is 3.62% and x2 is 7.25%. Figure 9 below illustrates the results graphically.

Figure 9



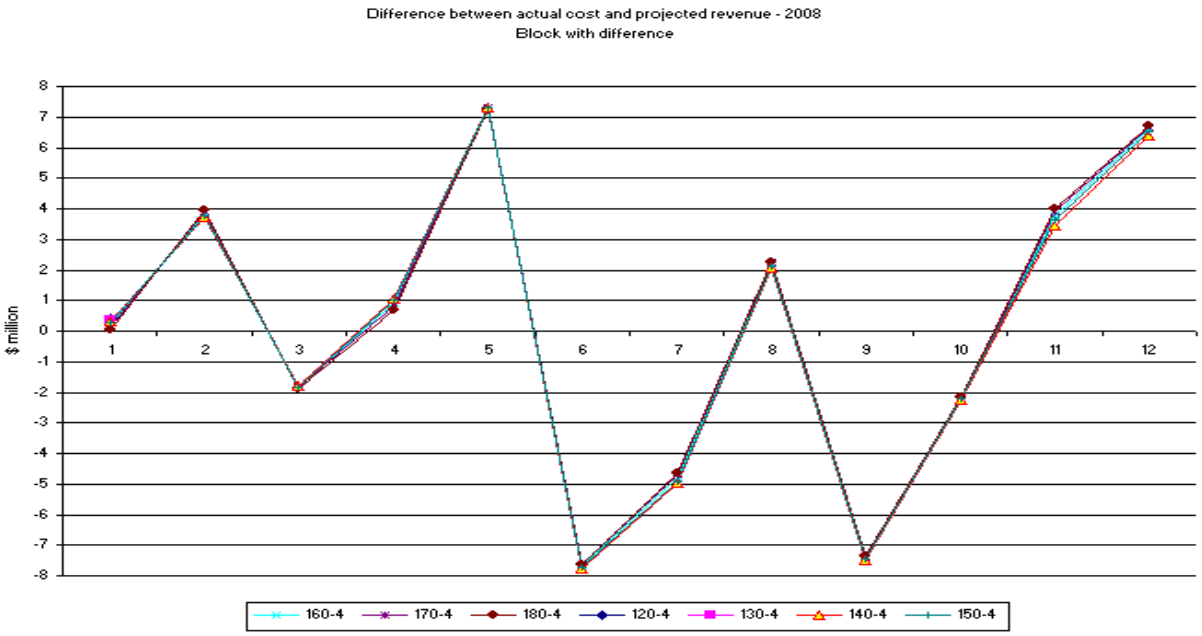
For 2007, a ratio of three between the rates in two blocks gives the best result (i.e. x2 is three times x1). The resulting monthly RMS variance is about $2 million and annual variance is less than $2 million. If P1 is chosen as $150/MWh then x1 is 3.44% and x2 is 10.32%. Figure 10 below shows the monthly RMS variance.

Figure 10



For 2008, a ratio of four between the rates in two blocks gives the best result (i.e. x2 is four times x1). The resulting monthly RMS variance is about $4.8 million and annual variance is less than $1.5 million. If P1 is chosen as $150/MWh then x1 is 2.89% and x2 is 11.57%. Figure 11 below shows the monthly RMS variance.

Figure 11



The AESO also studied the Block Continuous rate with three (rather than two) blocks. Increasing the number of blocks from two to three reduces the monthly RMS variance range by $1-2 million. Given that the optimal ratio for each year is different, that data for only three years is available, and that all three years appear to be significantly different, the AESO favours making gradual changes to the OR rate. Once actual performance of the proposed two block rate is analyzed and additional data becomes available, the AESO will review if a three block rate still provides an improvement and whether the extent of the improvement is worth the additional complexity.

10 Overall Best Rate for Immediate Future

Figures 9, 10, and 11 indicate that P1 can be selected anywhere between $120-$180/MWh without significantly increasing the monthly RMS variance for the year.

As well, the ratio of rates in the two blocks has significant effect on the monthly RMS variance. For 2006, the best performance was obtained at a ratio of two, for 2007 at a ratio of three, and for 2008 at a ratio of four. Thus it is not clear what ratio should be chosen for future years. The AESO considers that years that are expected to be similar to the immediate future years should be given more weight. To understand differences between 2006, 2007, and 2008, the AESO

Table 3 – Key Forecasted and Actual Numbers

	2006	2007	2008	2009
Forecasted PP (simple average)	41.2	66.89	84.81	84.43
Actual PP (simple average)	80.79	66.95	89.95	--
Forecasted PP (volume weighted average)	41.93	68.75	87.79	86.78
Actual PP (volume weighted average)	84.02	69.93	92.96	--
Standard deviation of forecasted PP	27.97	65.94	100.4	65.85
Standard deviation of actual PP	119.41	103.73	129.53	--
Standard deviation of forecasted DTS energy volume	576.57	568.82	552.5	544.25
Standard deviation of Actual DTS energy volume	237.15	567.71	573.93	--
Standard deviation of product of forecasted PP and forecasted DTS energy volume	184,399.14	438,106.37	677,530.32	453,302.30
Standard deviation of product of actual PP and actual DTS energy volume	782,182.82	699,255.37	853,151.52	--
Forecasted annual OR Cost	85.35	155.25	215.1	235.5
Actual annual OR Cost	185.5	183.5	264.3	--

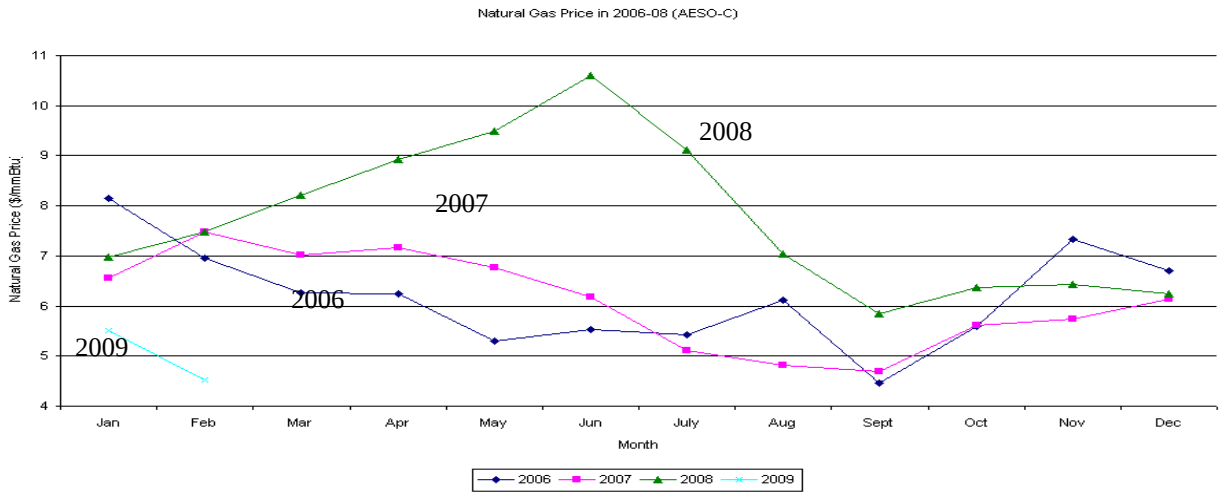
PP in $/MWh
OR Cost in $ million

looked at the underlying data and events to gain further insight. Table 3 summarizes some factors that may have caused results to differ.

Forecasted and actual PP were quite close for 2007 and 2008 but were under-forecasted in 2006. Standard deviation of actual PP is stable while that of forecasted PP is increasing and getting closer to the actual. Standard deviation of forecasted DTS energy volume is stable and is close to the actual except for 2006 when the actual was significantly lower. Standard deviation of the product of actual DTS energy volume and actual PP is quite stable while the comparable forecasted amount is increasing and getting closer to the actual. The 2009 PP forecast is similar to that of 2008, the standard deviation of 2009 forecasted PP is close to that of 2007, and the standard deviation of the product of 2009 forecasted DTS energy volume and forecasted PP is close to that of 2007. The last two rows of the table show that annual OR cost has been consistently under-forecasted.

The natural gas price (AESO-C) varied from $4.45 to $8.16 per mmBtu in 2006, from $4.70 to $7.49 per mmBtu in 2007, and from $5.85 to 10.60 per mmBtu in 2008. As figure 12 shows, in 2008, natural gas prices increased in the first half of the year and then fell in the second half. This trend is quite different from what went on in 2006 and 2007. The 2009 prices to date have been much lower than any of 2006-2008.

Figure 12



The AESO, the sole buyer of OR, began purchasing a majority of OR on a day ahead basis since May 2008. Prior to May 2008, AESO purchased OR anywhere from five days ahead to one day ahead.

Another significant difference may be the actual availability of Power Purchase Agreement (PPA) units, which was 88% in 2008 compared to 91% in 2006 and 2007 on a PPA-weighted average basis.

Because of the recent economic downturn, the Pool Price and thus the OR cost in 2009 is expected to be lower than in 2008. Also, the approval and future implementation of WECC BAL-002 standard is expected to reduce OR requirements somewhat thus possibly reducing OR volumes. The AESO Budget Review Process (BRP) resulted in approval of the 2009 forecast reflecting a simple average 2009 forecasted PP of $84.43/MWh, a volume-weighted average 2009 forecasted PP at $86.88/MWh, and a forecast 2009 annual OR cost of $235.5 million. The AESO considers that using the AESO Board approved forecast is reasonable, and does not propose to use later forecast information that has not been subject to such approval. However, new information can be taken into account when selecting the best overall rate. In the AESO's opinion, it appears that 2009 and perhaps 2010 could be closer to 2007 and 2006 rather than 2008 with respect to characteristics that might be relevant to the OR charge design.

11 Selection

This section compares monthly RMS variance for a ratio of rates in the two blocks at 2, 2.5, and 3 with P1 varying from $120-180/MWh.

Figure 13

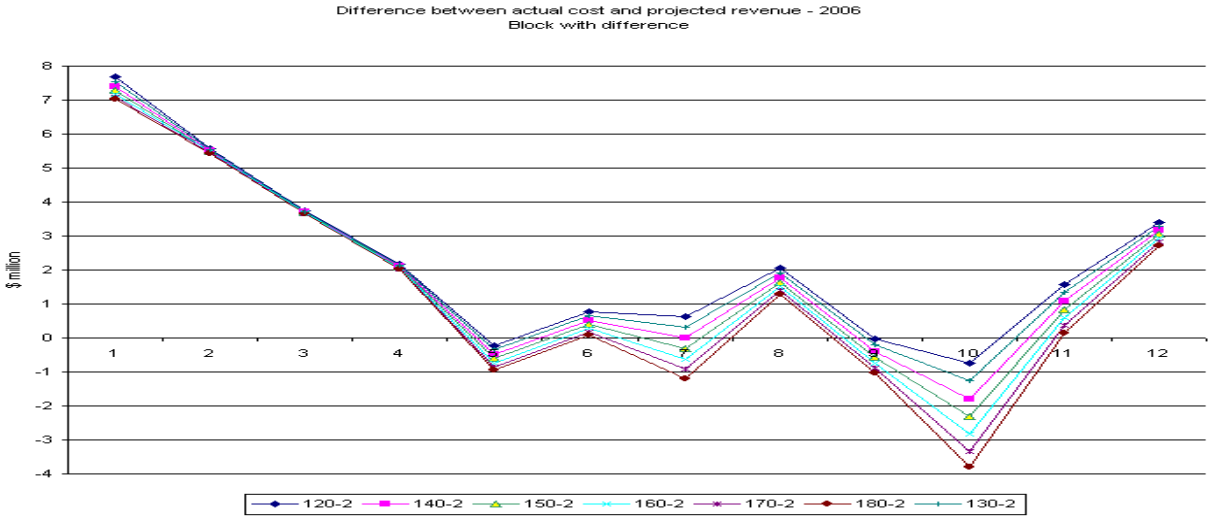


Figure 14

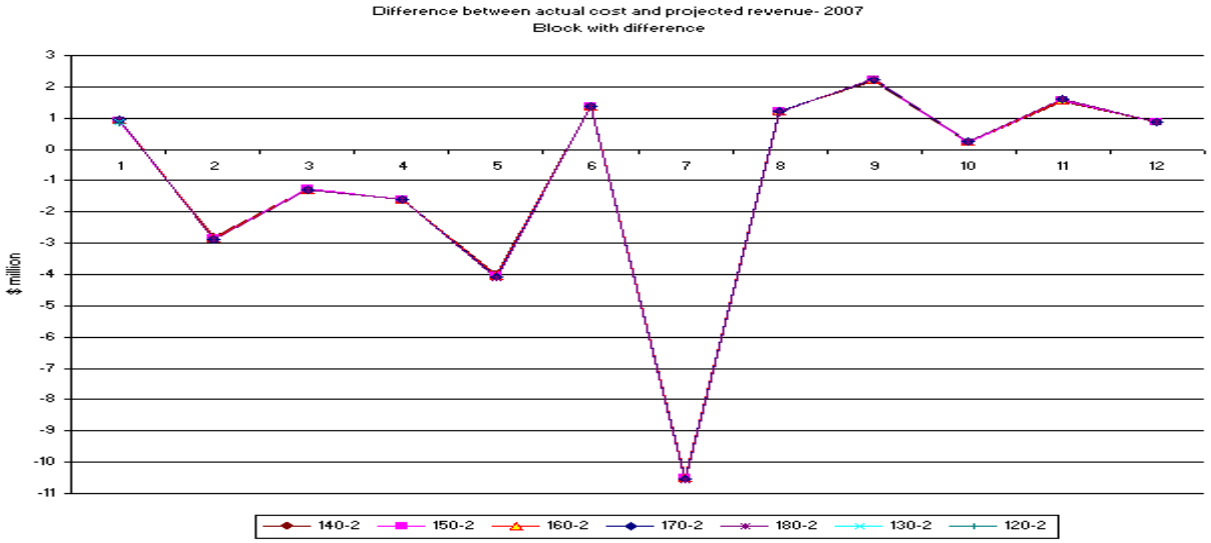
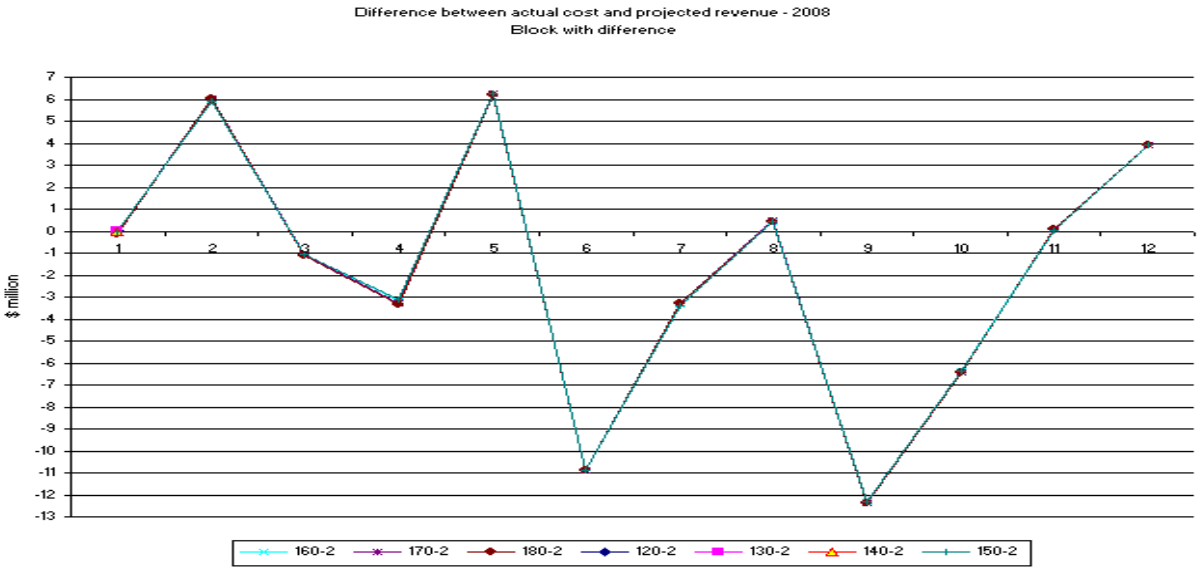


Figure 15



Figures 13, 14, and 15 show that for a ratio of two, the maximum monthly RMS variance is between $7.7 million and -$3.8 million for 2006, between $2.2 million and -$10.9 million for 2007, and between $6.3 million and -$12.4 million for 2008.

Figure 16

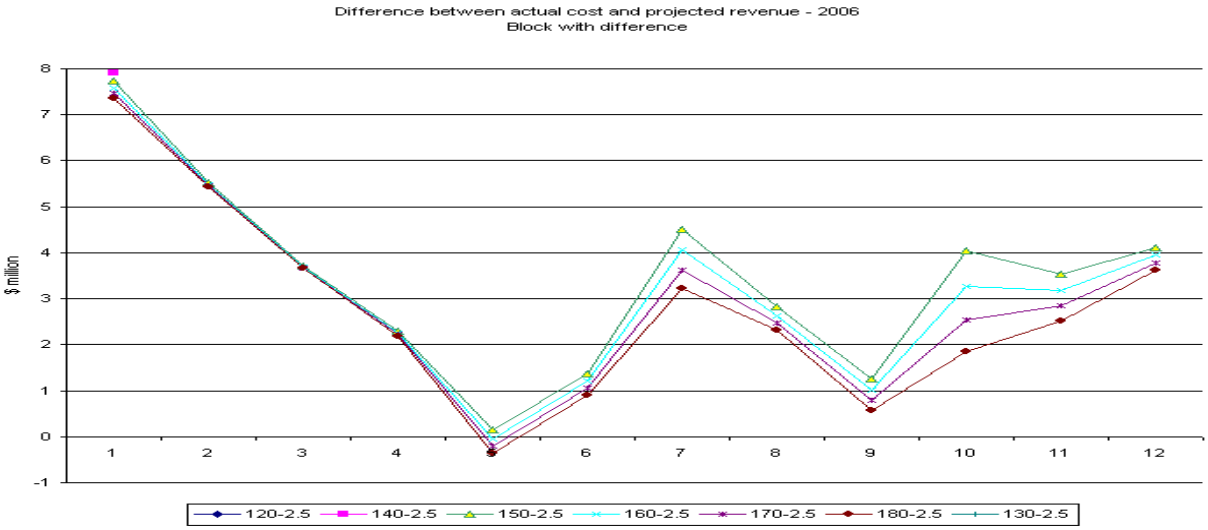


Figure 17

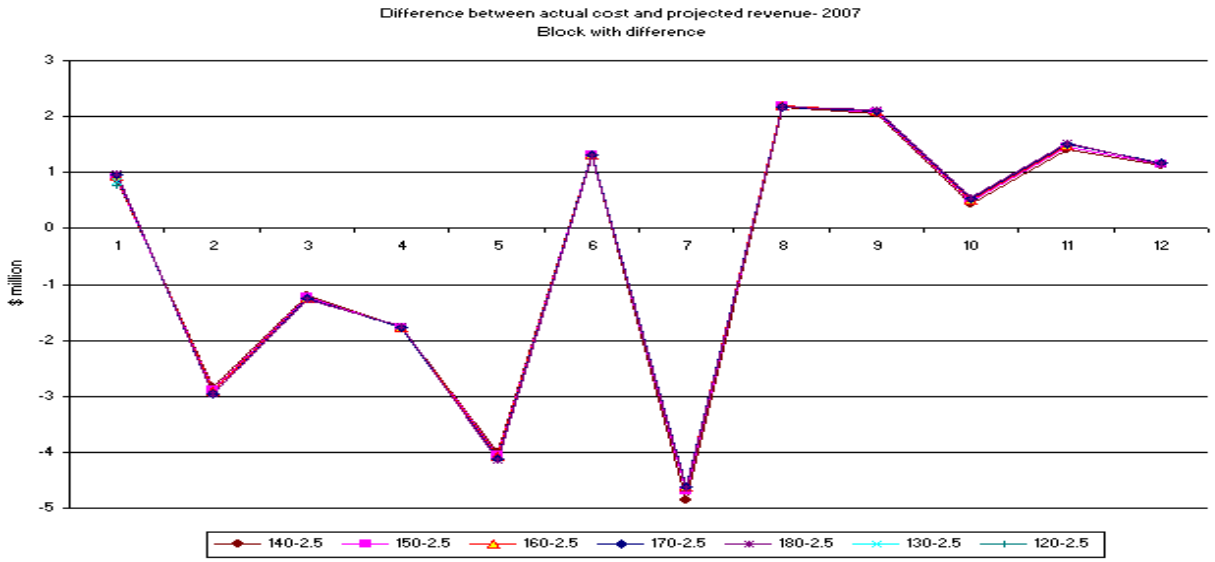
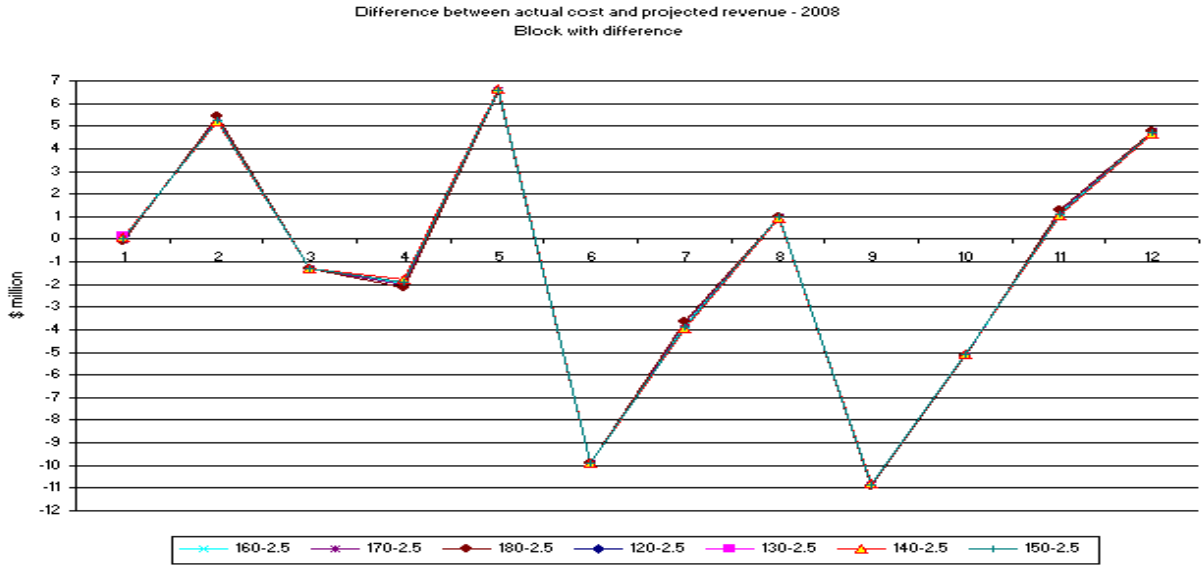


Figure 18



Figures 16, 1,7 and 18 show that for a ratio of 2.5, the monthly RMS variance is between $8.3 million and -$0.4 million for 2006, between $2.2 million and -$5.5 million for 2007, and between $6.6 million and -$10.9 million for 2008.

Figure 19

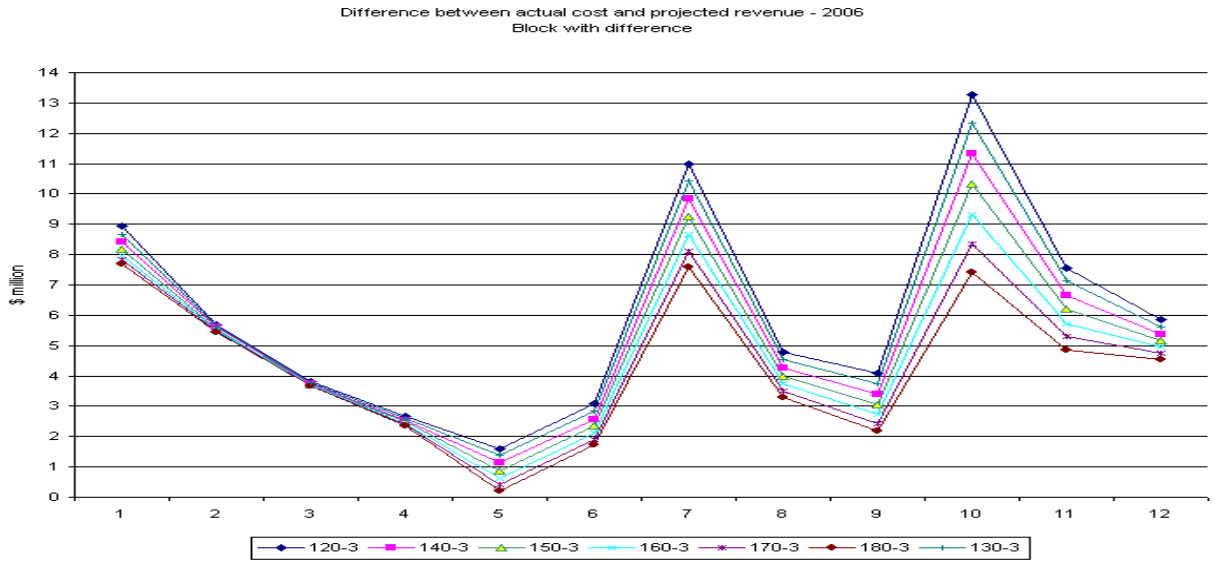


Figure 20

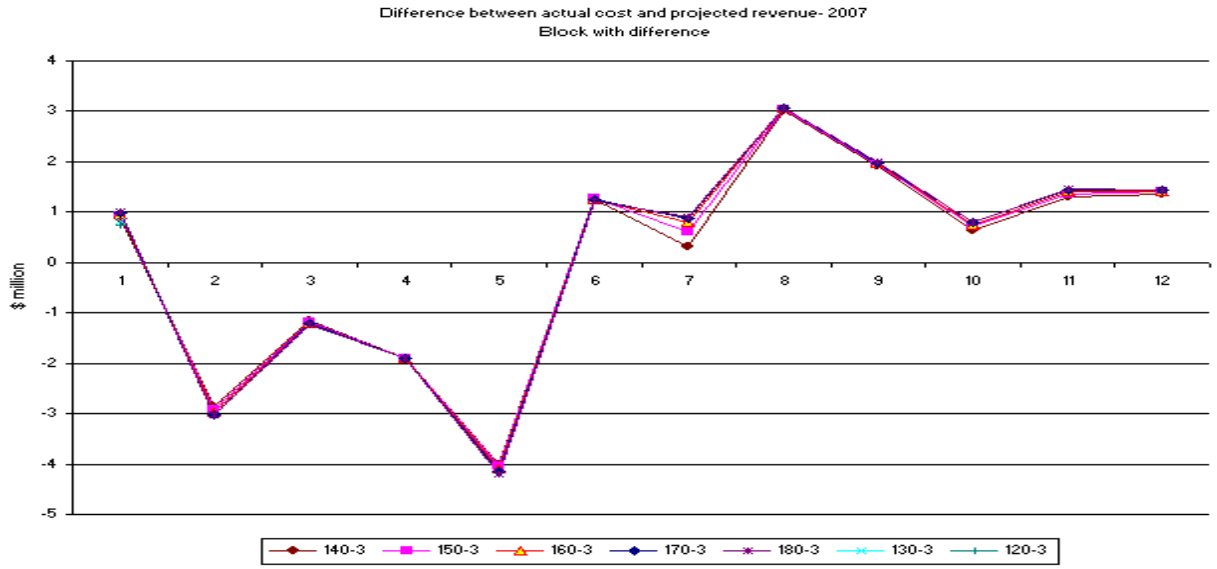
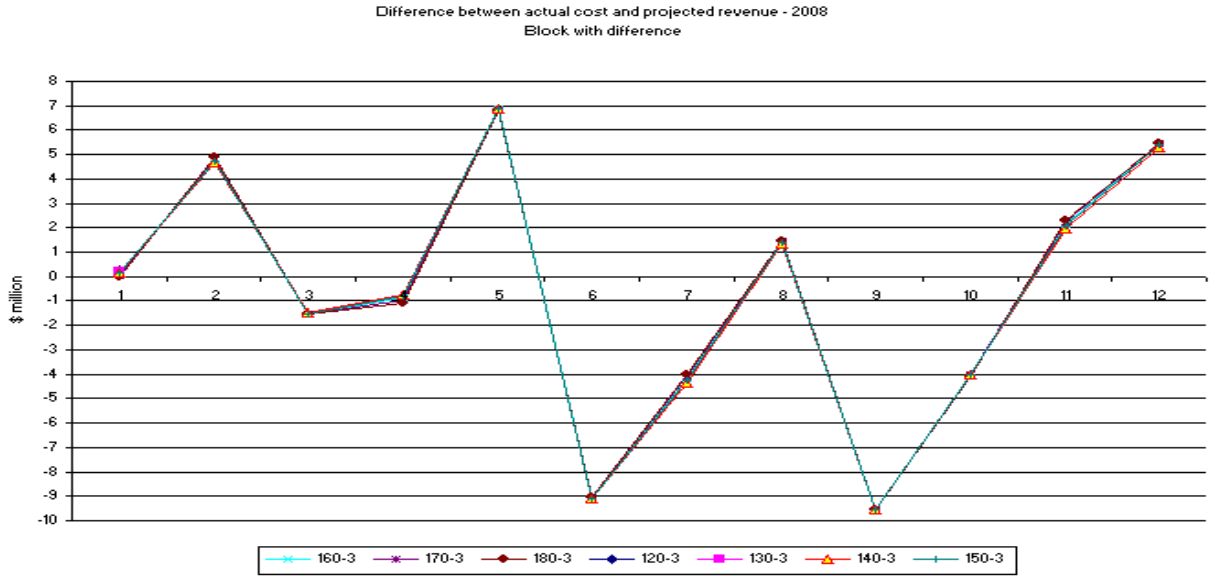


Figure 21



Figures 19, 20, and 21 show that for a ratio of three, the monthly RMS variance is between $13.3 million and $0.2 million for 2006, between $3.1 million and -$4.2 million for 2007, and between $6.9 million and -$9.6 million for 2008.

These observations are summarized in Table 4 below. The average of maximum monthly RMS variance, average of average monthly RMS variance, and average of absolute average of monthly RMS variance increase as the ratio increases, while the average of minimum monthly RMS variance and the range (i.e. difference between maximum and minimum monthly RMS variance) decrease as the ratio increases. It appears that a ratio of 2.5 works best overall.

Table 4 – Monthly Variance Using Different Ratio

Ratio	Variance	2006	2007	2008	Average Variance 2006-08	Absolute Average Variance 2006-08	Range 2006-08
2	**Maximum**	7.68	2.25	6.32	5.42	5.42	18.71
	Minimum	-3.81	-10.88	-12.39	-9.03	9.03	
	Average	1.74	-1.01	-1.73	-0.33	1.49	
2.5	**Maximum**	8.32	2.18	6.64	5.71	5.71	17.53
	Minimum	-0.36	-5.53	-10.89	-5.59	5.59	
	Average	3.44	-0.45	-1.19	0.60	1.69	
3	**Maximum**	13.29	3.06	6.91	7.75	7.75	16.54
	Minimum	0.22	-4.19	-9.63	-4.53	4.68	
	Average	5.11	0.06	-0.73	1.48	1.97	

All numbers in $ million

12 Performance

Figures 22, 23, and 24 show the monthly maximum, average, and minimum RMS surplus/ shortfall for 2006, 2007, and 2008 respectively with P1 being varied from $120-180/MWh and x2 being 2.5 times x1. It is clear that the proposed rate is an improvement over the currently approved rate, which is included and labeled as "Actual" in the figures.

Figure 22

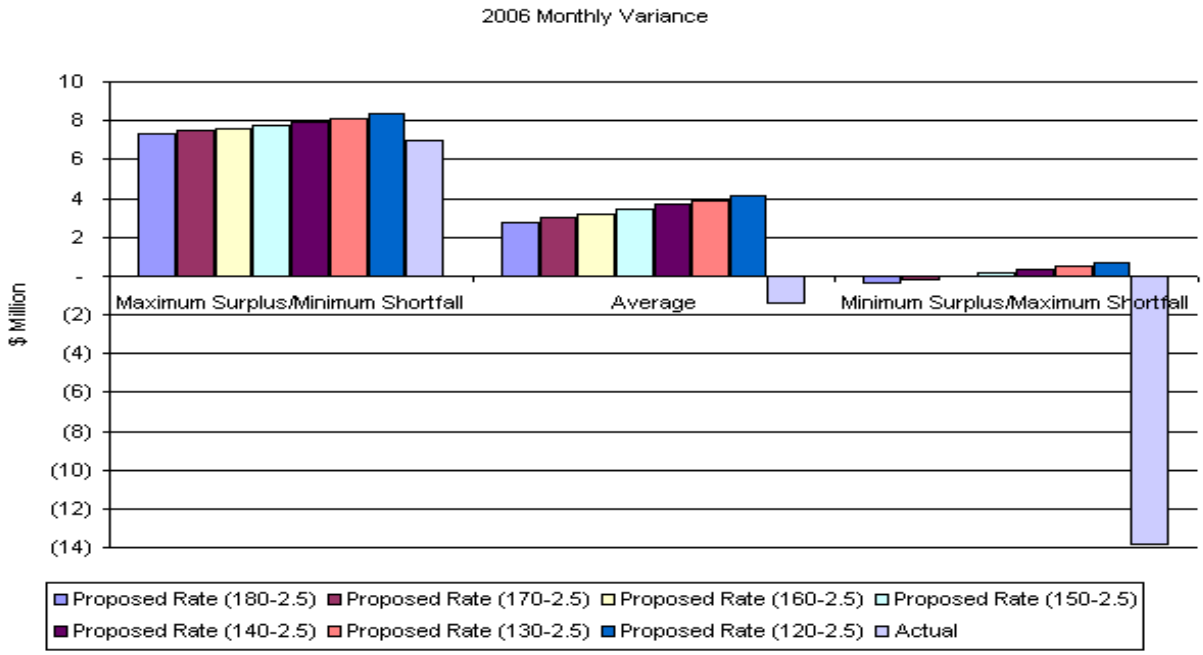


Figure 23

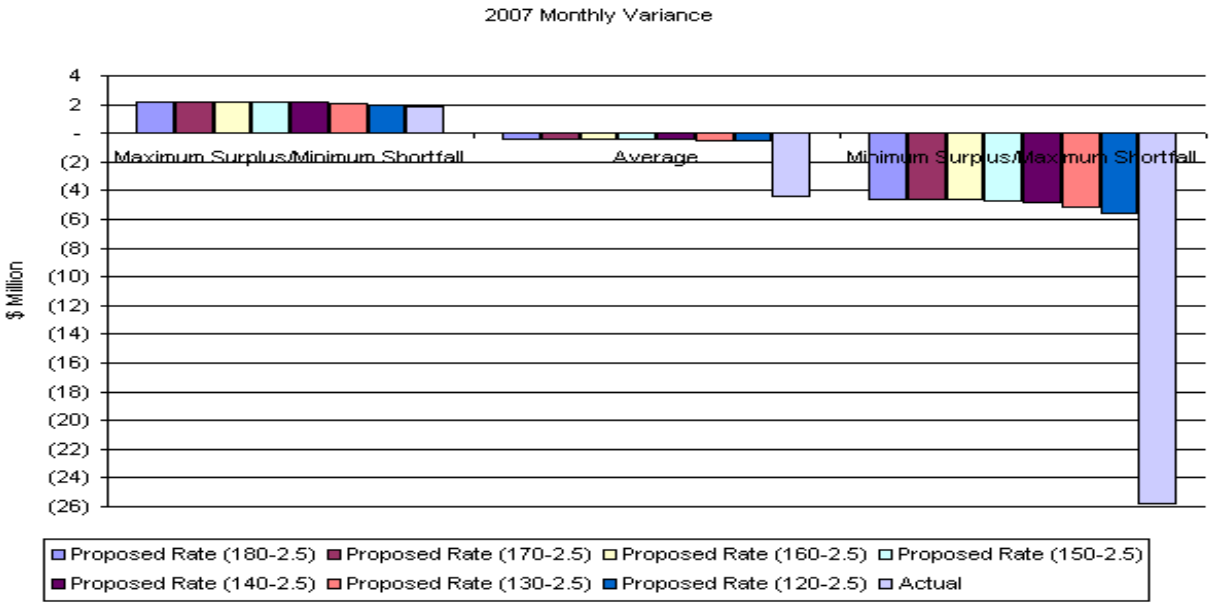


Figure 24

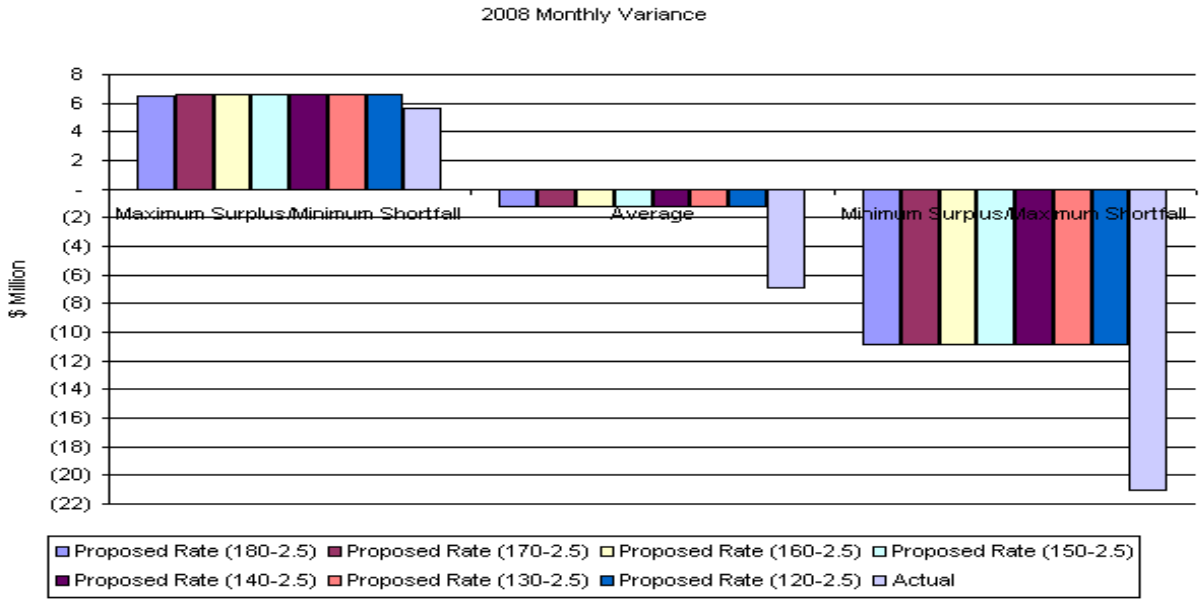
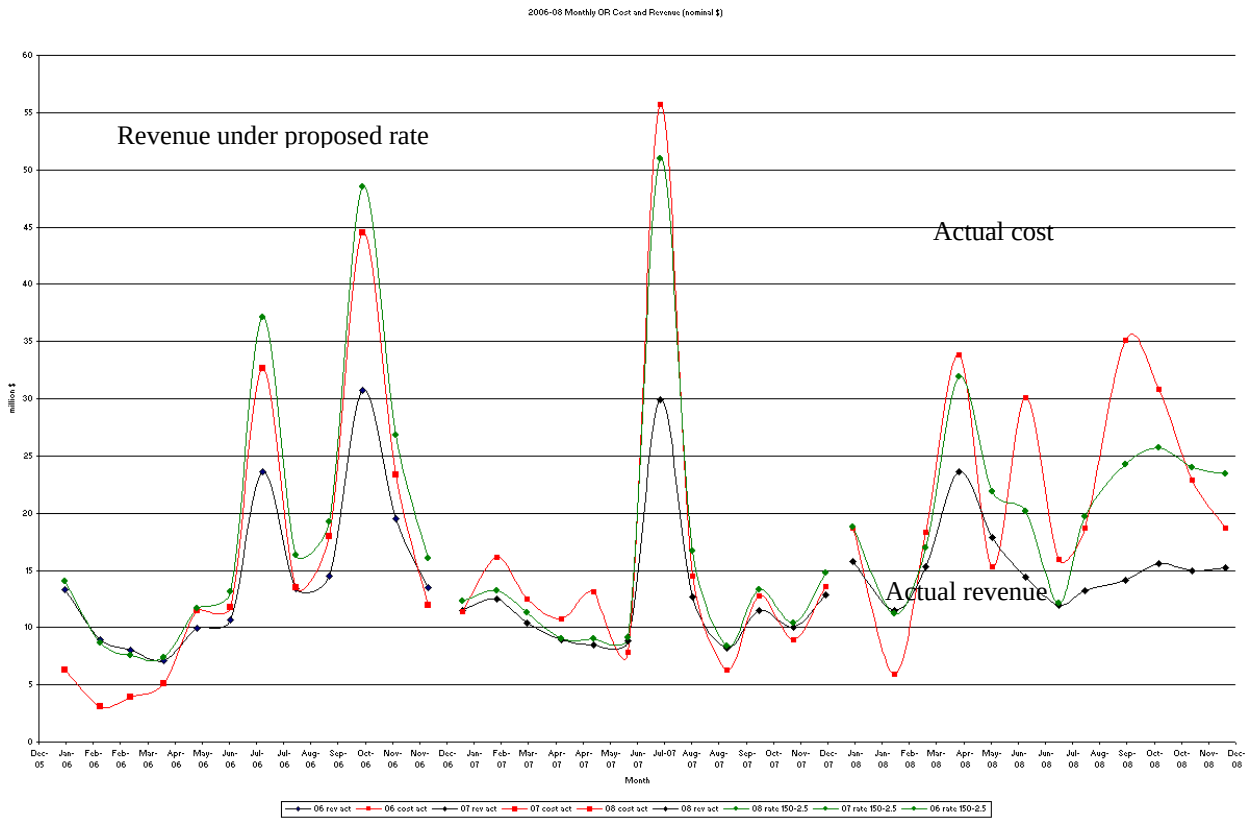


Figure 25 graphs actual OR cost, actual OR revenue (under the currently approved rate), and OR revenue that would have occurred under the proposed rate design for the years 2006-2008. This again illustrates that the proposed rate tracks actual OR cost better.

Figure 25



13 Proposed Rate

As discussed above, for 2009, a Block Continuous OR charge with P1 as $150/MWh and x2 as 2.5 times x1 would better match OR cost and revenue. For that rate design for 2009, x1 would be 4.47% and x2 would be 11.18%. Figure 26 below shows the proposed rate in graphical form. Other P1 series are included for illustrative purposes.

Figure 26

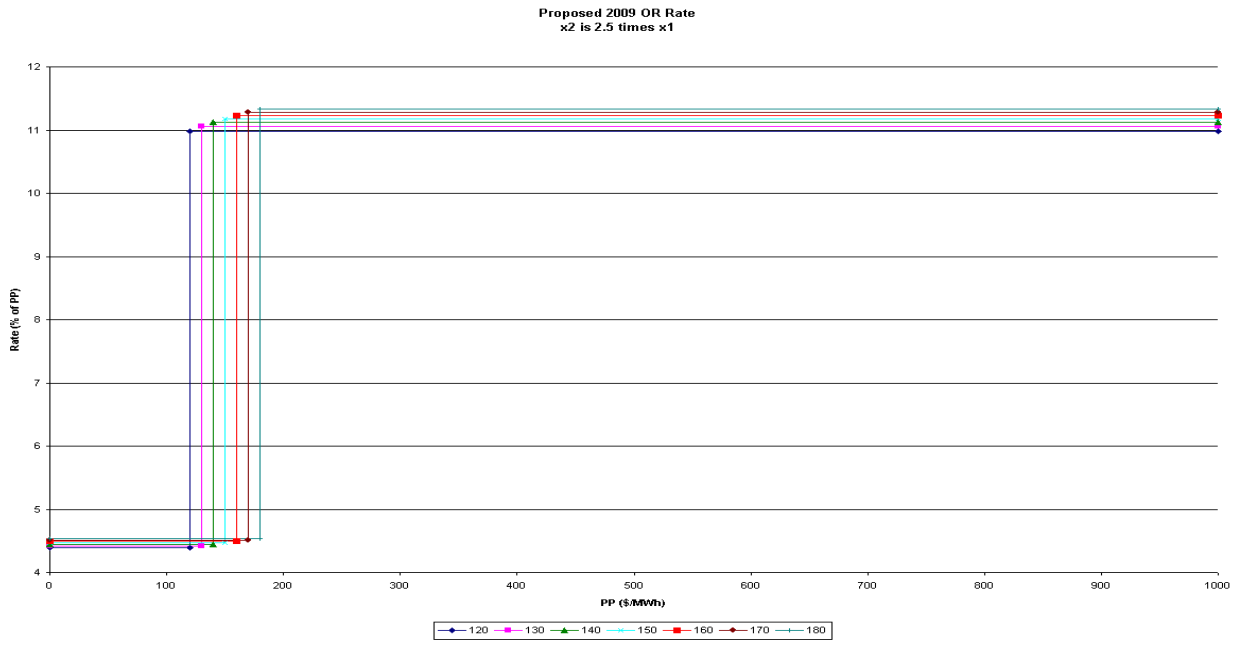
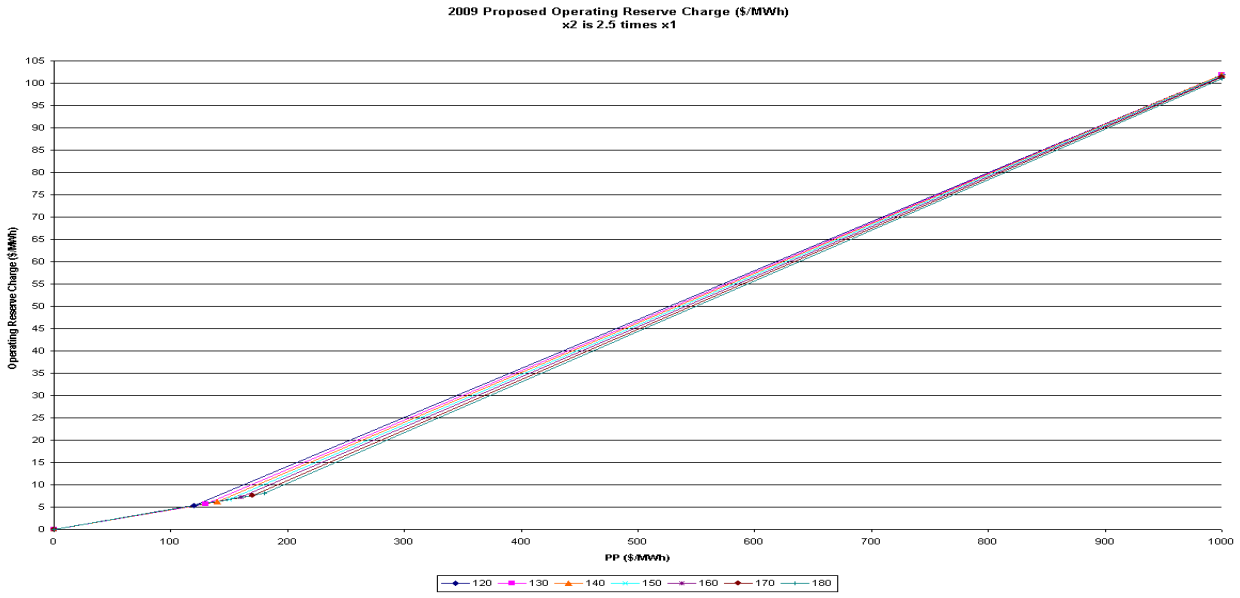


Figure 27 below shows the corresponding OR charge in $/MWh that would result.

Figure 27



14 Discussion

Bill impact for an individual customer under the proposed rate would depend on the customer's load profile and could be calculated using forecasted hourly PP and forecasted hourly DTS volume.

The AESO will continue to monitor the trends in and relations of OR cost and will study further alternatives to better match OR cost and OR revenue to reduce the variance even further.

The AESO will also investigate the possibility of implementing systems and processes to record, allocate, and bill OR cost on an hourly basis. Questions for an hourly allocation approach include whether OR cost should be divided into constituent categories and if different billing determinants should be used for the constituent categories. Since this approach will recover OR cost on an hourly basis, it should practically eliminate any over or under collection.