Appendix: Summary of Analytic Methodologies Used to Compute Estimated Impacts of Options to 12 Times Ramp Rate as Presented in Table 1 and Table 2

1. APPrO Ramp Payment

   The estimated impact on annual uplift was computed as follows.
   During the period November 1, 2005 to April 30, 2006, for each 5 minute interval and each dispatchable generator a ramping quantity was computed. This ramp quantity was measured as the absolute value of the difference in the amount of MW scheduled in the constrained schedule in the current interval less the MW scheduled in the constrained schedule in the prior interval. This ramp quantity was then multiplied by a fixed ramp payment of $4.24/MWh (the estimated ramping cost reported in the APPrO commissioned report). The payments per interval were then summed across the period to compute a semi-annual amount. The annual estimate of $70 Million per annum was computed by multiplying the semi-annual amount by 2.

   The IESO believes that this amount is likely an over statement of the annual payment for the reasons outlined in the text of the report. A subjective analysis of the impact of these factors lead to a rough estimate that the annual impact of this option would be an increase in uplift of roughly $50 M.

2. Ramp Cost Guarantee (RCG)

   Under this option, when a generator's revenue in an hour less its generation cost (estimated through its offer prices) is greater than the ramping cost (i.e. $4.24 times the ramping quantity in the hour), the generator will be eligible for a "top-up payment". That is, a generator would be eligible for a RCG equal to:

$$RCG = \begin{cases} 0 & if \quad revenue > generation\_cost + ramping\_cost \\ Min(ramping\_cost, ramping\_cost + generation\_cost - revenue) & if \quad revenue \le generation\_cost + ramping\_cost \end{cases}$$

   For fossil generators, the calculation of generation costs excludes the output range from zero to the Minimum Loading Point (MLP). This assumption was made to account for the strategic offers whereby a generator offers at "low prices" below its actual cost, to ensure that the unit starts and stays on-line at a level at least as large as its MLP. Not adjusting for these strategic offers would understate the estimated generation costs and overstate the revenue contribution.

Note that the revenue is estimated based on real time MCP and dispatch in the constrained sequence, and includes the revenue from the energy market and the constrained-on payment. The constrained-off payment is not estimated due to the difficulty of distinguishing being constrained-off from derating. Ignoring constrained-off payments will not materially affect our estimation result because a unit will typically receive sufficient revenue in the energy market compared to its cost implied by its offers. Thus RCG is usually not needed when a unit is constrained off.

The estimated impact on annual uplift was computed for the period November 1, 2005 to April 30, 2006, by computing a RCG for each dispatchable generator, in each delivery hour, and then summing up all the RCG payments across the period and then multiplying this number by 2.

3. 3x Ramp Rate Myopic

The impact on prices and uplifts of moving to a 3x ramp rate assumption were computed through simulation. The simulations were performed for each 5 minute interval for the period from November 1, 2005 through April 30, 2006.

The model assumes no behavioural change on either the demand or the supply side. The price change in each interval is attributed entirely to the change in the ramp rate assumption. The price changes in each 5 minute interval were averaged to compute a semi-annual average price increase of $1.50. This represented a 2.6% price increase from the average HOEP of $57 for the period.[1] The annual impact simply assumed a similar average for the remaining 6 months of the year.

Due to the complexity of calculating a CMSC payment for each 5 minute interval under a new ramp rate, the IESO selected three days during the period to compute the daily CMSC impacts of the change in ramp rate, and extrapolated an annual impact from these three days. The three days chosen were (December 8, 2005, January 16, 2006, and February 12 2006). Two of the days were selected to reflect different degrees of volatility between the simulated 3 times and 12 times prices. December 8, 2005 showed a large and volatile price difference (3x MCP - 12x MCP). February 12, 2006 was a Sunday and had a small and stable price difference. January 16, 2006 was chosen because of a large amount of CMSC payments.
For each day, the IESO ran a base case simulation if the CMSC impact under 12 times ramp rate and then compared them to the actual CMSC estimates to ensure that there was a close match between the simulated and actual CMSC payments.

For the three days, the IESO estimated that with 3 times ramp rate pricing, CMSC payments were 6.4% lower on average, implying about a $12 million reduction in annual CMSC payments based on the current $200 million annual CMSC.

[1] On a monthly basis, the price increase was consistently in the 2.5% range.

The estimated impact on IOG payments was computed as follows. There were roughly 1.3 TWh of imports during the period that received IOG. An estimated HOEP increase of $1.5 per MWh would reduce the IOG payments by about 1.5 * 1.3 ~ $2 M (or $4 M for a year). Note these imports represent about 1/3 of all imports and energy payments to imports.

The IESO's Market Assessment Unit also estimates the global efficiency loss due to a higher shadow price in Ontario than the market price in New York. That is an export from Ontario to New York is inefficient if the cost of providing the export in Ontario (represented by the shadow price at Beck E_Bus) is greater than its value in New York (represented by the New York real-time price in the Ontario Zone). The annual efficiency gain from lowering the ramp rate was estimated as follows. First, estimate the long run elasticity of export on the New York interface. These estimates implied that a 10% increase in HOEP would result in an 18% reduction in exports (See August 4th presentation to the MPWG titled "Market Response to Price Changes"). Given this estimated elasticity, the IESO then estimated the hourly change in exports scheduled as a result of the price change induced by the lower ramp rate. .

The formula to estimate the efficiency loss is

$$Global\_Efficiency\_Loss = \sum (Shadow\_Price_t - NY\_Price_t) * Net\_Export_t / 2$$ [2]

Where $Shadow\_Price_t$ is the shadow price at Beck E_Bus in hour t, NY_Price_t the New York real time price in hour t in the Ontario Zone, and Net_Export_t the hourly change in net export on the New York interface. An hourly efficiency gain or loss was computed across the period November 2005 through April 2006.

Using this formula, the IESO estimated a semi-annual efficiency gain as a result of a better match between the 3 times HOEP and the shadow price at Beck of roughly $7 million. The annual estimates were computed by multiplying the $7 million estimate by 2.

The impact on consumers' annual wholesale energy expenditure was computed by multiplying the estimated $1.50 by 150 TWh which is the annual consumption in the province. This was estimated to be $225 million. This annual expenditure impact was based solely on simulated outcomes. It does not incorporate other mitigating factors such as the global adjustment or changes in market participants'' behaviour – i.e., reduced demand from exporters. With these mitigating factors included, the expected impact on consumers' annual wholesale energy expenditure is less than $20 million.

[2] An underlying assumption for the approach is that the cost curve (implied by the system offer curve) is linear in the relevant range from the level of New York price to the Shadow price, and thus the formula approximates the cost below the offer curve in the relevant range.

The annual expenditure impact can also be examined using 2006 estimates of consumption and annual price levels. The annual consumption for 2006 is expected to be 158 TWh. The average HOEP for 2006 to date is roughly $46. Assuming a 2.5% increase in price ($1.15) as a result of a change to 3 times ramp rate multiplier, would imply an unmitigated impact on annual expenditure of $181.7 million. After mitigation due to global adjustment and export demand reduction, this impact would be reduced further to approximately $15 million.