Addressing the Twelve Times Ramp Rate Multiplier

Meeting of the IESO's Stakeholder Advisory Committee
September 5, 2006

Introduction

1. In December, 2005, at the time of the approval of the high-level DACP design, the IESO Board accepted recommendations from the Stakeholder Advisory Committee and directed IESO Management to examine the role of the ramp rate multiplier in real-time price calculations. The issue has been extensively addressed at the Market Pricing Working Group (MPWG) throughout 2006. In addition, there have been numerous submissions by market participants and their associations on this subject. The IESO appreciates the significant efforts that have been put forward by all concerned stakeholders on this issue throughout the process. This report to the Advisory Committee provides a summary of the proceedings and an analysis of the options as viewed by IESO Management. Management is pursuing Advisory Committee input prior to making its recommendation to the IESO Board at their September meeting.

2. The use of a ramp rate multiplier in the market schedule has a direct impact on pricing but does not directly impact how the IESO dispatches resources to meet demand, and hence has little direct impact on reliability. However, any action that raises or lowers the Hourly Ontario Energy Price (HOEP) will impact on market results by creating different incentives. Embedded non-dispatchable generators, non-dispatchable consumers that are charged HOEP, and exporters of power to neighbouring jurisdictions can all be expected to change their behaviours in response to a change in HOEP, thereby changing the required dispatch.

3. The combination of using the unconstrained methodology and the 12x ramp rate multiplier results in generators being under-compensated by the real-time energy price relative to what would be expected in any other real-time electricity market.

4. Constrained-on payments to dispatchable resources mitigate the underpayment to some extent, but may not cover additional costs (e.g. ramp, start-up/minimum run costs) or provide profit opportunities as those payments only compensate resources relative to their bid or offer prices, rather than through a market mechanism. Use of constrained-on payments also generates uplift charges which are generally not preferred, eliminating the possibility of market responses, and resulting in a charge to loads which cannot be managed through contracts or their own actions.

5. Ontario has been living with a dampened energy price for over 4 years. The main contributors to the dampening of the price signal are the 12x ramp rate assumption and the disregard for the effects of transmission limitations. This examination is only addressing the impacts of the 12x ramp rate multiplier. A separate initiative is underway to examine the impacts of locational prices in Ontario.

6. Real-time markets are generally expected to be volatile in nature, reflecting the ups and downs of balancing supply and demand within the constraints of the transmission system. Ideally, only those consumers or producers who can change their consumption or production with very short notice should be exposed to the real time price. Most consumers and producers are expected to protect themselves from the volatile prices by any of contracting forward, locking in prices in a day-ahead market, or changing their consumption or production plans for the next day based on day-ahead price signals. Ontario participants do not have the opportunities or the tools necessary to permit them to take these actions. Ontario does not currently have a day-ahead market or even a reliable day-ahead price signal – a shortcoming that will soon be addressed as the IESO and stakeholders explore the design of a day-ahead market for Ontario. As for forward contracting, it has been stated by some that forward contracting is illiquid, although the Global Adjustment provides a significant forward hedge against price changes. Without these opportunities, there are real limitations on the degree of volatility that Ontario's current real-time price can exhibit. This is essentially why little progress has been made to date on the existing 12x/unconstrained pricing algorithm.

7. The most-recent Market Surveillance Panel report highlighted several inefficiencies in the current market design that directly result from the current unconstrained pricing algorithm, and in that report, they recommended that the IESO take action to address these inefficiencies.

8. The Advisory Committee unanimously supported a resolution to recommend that the IESO conduct a study of locational marginal pricing and its potential implications to Ontario. This work has just started, under the guidance of the Market Pricing Working Group, and is considered to be a high-priority task in conjunction with the Day-Ahead Market (DAM) consultations.

9. There is generally strong support for the development of a day-ahead market in Ontario. A draft stakeholder engagement plan for day-ahead market discussions will be issued shortly.

10. All indications are that today's decision on immediate actions to address the 12x ramp rate will be a temporary measure – likely enduring through to roughly the end of 2008, the current target date for an Ontario DAM to come in service. In that light, the chosen option should be simple in concept, easily implemented, and pragmatic in nature.

Changing the Market schedule to 1x MIO

11. The IESO's initial thought on how to address the 12x issue was to bring the market schedule, (the pricing schedule), in alignment with the dispatch algorithm by converting it from a myopic process to one that uses actual ramp rates under a multi-interval optimization process (MIO). MIO was implemented in the dispatch sequence in the spring of 2004 but was never implemented in the pricing sequence. MIO was designed to allow the dispatch algorithm to look ahead and take action to prepare for expected ramping requirements. Using this same methodology in the pricing algorithm should permit use of realistic ramp rates with price impacts being dampened by the look-ahead capability of MIO. Further, aligning the dispatch methodology between the two sequences would create efficiencies by reducing the congestion management settlement credit payments (constrained-on and constrained-off payments) that are generated when there are differences between how the dispatch uses a resource and how that resource was used in the market schedule. Generators disagree with the use of MIO in the market schedule, as will be discussed later.

12. Three different methodologies for incorporating MIO into the pricing sequence were discussed. IESO price simulation results indicated that on average, MIO prices were close to the current prices (from a reduction of 0.5% for "MIO incremental", to an increase of 0.3% for "MIO Modified Incremental", to an increase of 2.6% for "MIO High Slice Price"). The shape of the prices throughout the day was only marginally changed from the shape using the 12x multiplier. The conclusion was that the efficiency gains of implementing MIO in the market schedule were going to be marginal.

13. Implementation of MIO in the market schedule would be a complex process. Firstly, the exact methodology would have to be determined. Secondly, one of the MIO methodologies would require the development of a production cost guarantee payment to generators, requiring additional design and development. Thirdly, the market schedule algorithm would have to be changed, tested and implemented. And finally, settlement systems would have to be changed to accommodate the production cost guarantee calculation.

14. In the end, the IESO abandoned the idea of implementing MIO in the market schedule for this interim period, since it would only result in a marginal efficiency gains at the cost of significant effort to complete and implement the design. The opportunity cost of delaying both IESO and stakeholder efforts on furthering a day-ahead market design for Ontario was considered too high by both the IESO and most stakeholders.

Changing from 12x to 1x Myopic

15. Ontario generators have uniformly held the opinion that the market schedule should simply have the 12x ramp rate multiplier replaced with actual facility ramp rates (1x). They argue that this was the original market design, and that it would return the market schedule to reality. The IESO disagreed with this position, believing that this "1x myopic" method would overstate the value of ramping as it could signal ramping shortages when none actually existed on the system since the actual dispatch is performed using the MIO methodology which is preparing the system for the known ramp conditions.

16. The 1x myopic proposal results in an increase in payments to all energy producers in proportion to energy production at the time, and is not therefore focussed on the ramping generators alone. This is a feature AMPCO in particular has objected to. The IESO believes this is the correct pricing philosophy, and comments on this further in paragraph 26 below.

17. Some initial IESO price simulations (i.e., not adjusted for participant behaviour) indicated that the average price using the 1x myopic method would increase by about 12% relative to the 12x prices. This increase was observed in both the on peak and off peak periods. It must be recognized that these price increases would be mitigated in a couple of significant ways, as is true for any price changes. Firstly, by modified participant behaviour. An increase of this magnitude would result in less exports from Ontario, increased operation of embedded generation in Ontario, and increased demand response to the price. So the price increase would likely be significantly less than the simulated 12%, but there is no current method to estimate the mitigating impact of this behaviour change, especially in response to a large price change such as this. Secondly, the net impact on consumers of any price change in Ontario is currently mitigated by the Global Adjustment and the OPG rebate. Roughly speaking, only 25% of any wholesale market energy price change actually impacts on consumers' bills. Hence, an increase of 12% would net out to be roughly 3% higher consumer bills, and likely lower after participant behaviour changes.

18. As stated in an APPrO presentation to the MPWG, "Despite these arguments, APPrO recognizes that the conditions to win acceptance of 1x (myopic) ramp rate may not be present. APPrO has therefore considered other possible approaches in a spirit of cooperation with other market participants."

19. For these reasons, the option of converting the market schedule to operate based on a 1x ramp rate is not being actively considered for this temporary period.

APPrO Supplemental Ramp Payment Proposal

20. As an alternative to implementing the 1x myopic option, APPrO presented an approach in which a payment would be made for ramping to every generator which changes its output level in response to IESO dispatch instructions. The payment would be made for each MW of output change, at a price ($/MW) that would be set after cost analysis. The costs of making this payment to ramping generators would be recovered through a new uplift charge. APPrO commissioned a study of the costs of ramping by the consulting firm LeCG. The LeCG study concluded that the cost of ramp is conservatively calculated to be $4.24/MW of ramp.

21. APPrO has argued that the costs incurred from ramping are significant and are largely unpredictable due to the extreme lengths the IESO's dispatch algorithm will go to in search of the most economic dispatch. Hence it is neither practical nor efficient to expect a generator to incorporate these costs in their offer prices. They argue that were they to do so, the resultant outcome would be sub-optimal. The LeCG report provides five arguments why including the ramping costs in the offers is problematic (see pages 15 to 17 in the LeCG report).

22. The IESO has calculated that in 2005, the dispatch instructions generated over 18 million MW of instructed changes of output. If all of these dispatch instructions were fully met, then the ramp payments would have totalled about $75 million. This total should be viewed as an upper bound on the cost of this ancillary payment for two reasons. Firstly, the assumption that all dispatch instructions are fully met is not reasonable. While the IESO does monitor compliance to dispatch instructions, it recognizes that precise compliance to all dispatch instructions is not always possible. This can be due to a number of factors with the most significant being that the IESO dispatch algorithm cannot precisely model the inertial characteristics of generators. The second reason the actual costs will likely be below the value stated above is due to the progress made to date by the IESO and dispatchable generators on dispatch issues, by reducing the number of output changes required. Throughout 2005, the compliance deadband on dispatch instructions was 10 MW. Recently, that deadband has been raised to 15 MW. This alone offers significant relief to generators in responding to dispatch instructions. Combining all of these factors, the IESO is of the opinion that a very rough estimate of $50 million is much more realistic in terms of the likely cost of the ramp payment option going forward.

23. The IESO estimated that implementation of a Ramp Payment Proposal would require 6 months following IESO Board approval. Implementation would involve finalizing design of the program, passing of required market rules, and IESO settlement systems development. IESO development costs would be under $1 million, and well within the portion of the IESO's capital expenditures budget that was allocated for the 12x initiative in 2006.

24. AMPCO responded to this proposal by rejecting it on the grounds that uplift charges do not permit appropriate market responses, that uplift charges cannot be hedged by consumers, that cost-based side payments are not transparent to the market, that this approach does not improve either allocative or dynamic efficiency under any foreseeable market structure, and that generators are not being harmed in a way that would justify urgent action of the type proposed.

25. AMPCO has previously stated that "a new mechanism to compensate generation that provides ramping services should not increase revenue to entities that do not provide ramping services." With the Ramp Payment Proposal only paying for actual ramping in response to dispatch instructions and since baseload generation is rarely called upon to ramp, then presumably virtually all of the ramp payment would be made to generators actually ramping, with no additional revenue stream to baseload providers, thereby meeting this requirement.

26. In April, 2006, the IESO wrote: "Fundamentally, the IESO does not support the concept of supplementary payments as permanent features of our market design. We are wary of creating additional side payments to certain energy producers that would result in an increase in uplift charges to consumers at the cost of an understatement of the value of energy at any particular time, and removal of volatility that should be present in a real-time pricing signal. When considering what would be enduring features of future market evolution, the IESO would find it difficult to support supplementary payments to a subset of generators for their actual use for ramping or for their response to dispatch instructions. However, there is some evidence that supplementary payments may be considered by both generators and consumers if the current twelve times unconstrained price is left in place, recognizing that the current pricing methodology dampens market signals and, at times, limits generator compensation. If used at all, such payments should only be introduced as a temporary measure while progress is made on enduring market evolution initiatives that would render such payments unnecessary." The IESO is still of this opinion, and would only consider a ramp payment as a temporary feature; the need for which would be regularly reviewed in light of any subsequent market evolution.

IESO Variation on APPrO Proposal – Ramping Cost Guarantee

27. The IESO believes that a guarantee methodology for paying ramping costs is a better method of ensuring generators are paid in a manner that recovers their ramp costs. However, given the complexity of constructing such a scheme (completed design, market rule formulation, and settlement systems development), we do not see it as a viable path forward for this temporary measure. Hence the Ramp Cost Guarantee is not being considered further at this point. It has been included in this report to provide a reference for the sort of revenue that we feel consumers should reasonably be expected to pay for ramp payments.

28. The IESO accepts the basic finding of the APPrO/LeCG report that there are non-trivial costs incurred by generators as they ramp their output up and down in response to dispatch instructions. We also understand and accept that the decision on whether or not to include these costs in an offer price is a difficult one that involves risks regardless of which decision is made by the generator. In some ways, the risks of whether or not to include this cost in an offer are similar to the sort of risks a generator faces when deciding whether or not to include a component in their offers to cover start-up costs – in the case of the start-up costs, their decision on how much of an adder to include depends on their expectations looking forward of how long the generator will operate for over the day, and how frequently over that period the unit will be the marginal source and not be earning profits to cover this cost. Most electricity market designs have recognized such generator risks, and have chosen to address these risks for the generator by offering bid production cost guarantees. In Ontario, a form of such a guarantee exists through the real-time and day-ahead generator cost guarantee programs. Ramping costs could be treated in a similar fashion, by creating a Ramping Cost Guarantee (RCG).

29. The guarantee would ensure that when a generator is a marginal resource, and is therefore subject to frequent IESO dispatch and unlikely to be earning profits relative to fuel costs, they would at least cover their incremental costs of following dispatch over an hour. A top-up payment would be provided in each hour in which the revenues did not cover the incurred incremental costs. Incremental costs for RCG purposes would be defined as a combination of their variable costs, (as defined by their energy output above and beyond unit minimums over the hour multiplied by their offer prices for that output), and their ramping costs, (as defined by their actual response to IESO dispatch instructions in MW over the hour multiplied by the agreed-upon per-MW ramping cost).

30. The guarantee calculation would be made on an hourly basis to eliminate end-of-day disincentives for the generator to continue to make its facility available to the system. If the guarantee was over a longer period such as exists for the generator cost guarantee program, then at the end of the day, a generator could be just eating away previously earned profits by staying on line. They may decide to shut down, as their prospect for additional profits in that day are minimal. By staying on line, they contribute to the benefits inherent in a more robust offer curve – greater market resilience to contingencies or demand changes, both in terms of price effects and reliability.

31. The guarantee would only apply to the dispatchable portion of the output of a generator – output above the minimum load level. If the guarantee was evaluated against total unit output, then the profit calculation relative to bids would be skewed. The skewed profit picture comes from the use of strategic offers by generators for their minimum output levels. Frequently generators offer their minimum load levels into the market using very low offer prices that are not really reflective of their costs, but are there to ensure that the unit is not

dispatched below this level. This strategic offer creates a false sense of profitability, which would nullify any possibility of RCG payment.

32. A guarantee payment methodology based on offer prices is particularly complex for energy-limited hydroelectric generators. At times, hydroelectric resources are called upon despite offering into the market at high prices, expecting not to be called upon to produce energy but instead be earning operating reserve revenues. In such cases they receive a constrained-on payment that results in them receiving their offer price. In such instances, their offer price is based on an opportunity cost of running additional water when they would prefer not to. These calculations of the opportunity cost are very complex. They can include assessments of future market opportunities, of inefficiencies of operating in some future period due to head losses or cascade plant miscoordination, and at times, even expected weather and inflow conditions. Given the imprecise nature of the cost calculation in this opportunity cost calculation, it seems inappropriate to then also award a very precise cost-based RCG payment. However, when hydroelectric resources have offered in periods when they would like to run, then it may be reasonable to pay the RCG payment, as they are incurring efficiency losses as a result of frequent dispatch instructions. This would suggest a guarantee construct that would be able to differentiate between these two circumstances. This is an obvious area of complexity that would require significant additional effort.

33. The IESO simulated the change in ramp payments if the guarantee philosophy was employed as described above over the first 6 months of 2006, based on use of the $4.24/MW price from the LeCG report, actual dispatch instructions, and actual offer prices. The ramp payments were reduced by more than 50% when compared to straight payment of the ramp charge. Based on the rough estimate of an annual charge of $50 million for straight ramp payments (see paragraph 21), then a similar rough estimate of the payments under the guarantee process would be in the range of $20 to 25 million.

An Adjusted Ramp Rate Other Than 1 Times

34. The IESO agrees that generators are generally under-compensated as a result of the current 12x/unconstrained pricing construct, and believe that it is reasonable that consumers be prepared to make payments similar in total to those flowing from the hourly ramping payment guarantee. However, there are several drawbacks to any ancillary ramp payment program, especially when viewed as an interim solution:
    i. it would require significant implementation effort by both the IESO and stakeholders, diverting attention away from other significant activities such as advancing a DAM design,
    ii. it would not be available for several months following an IESO Board decision to proceed,

iii. it would create additional burden on the uplift charge to consumers, which does not facilitate any additional efficiencies in the market and cannot be hedged by consumers, and
iv. it would be seen by many to be another patch on the already-unique Ontario market.

35. Hence, the IESO investigated if an opportunity exists to advance the efficiency of the market, with immediate implementation by changing the ramp rate multiplier from 12x to another level such as 3x. While there may not be a specific rationale for a 3x ramp rate multiplier; it does have the benefit of paying generators more appropriately than under the current construct, costing customers no more than the ramp rate payment alternatives, helping efficiency since the energy price would be higher than today when ramping, and being implemented very quickly and at almost no cost or effort since the ramp rate is an easily-changed variable. This alternative was suggested early in the deliberations on the 12-times ramp rate, and at that time the IESO had not thought that such a compromise solution was likely, but since there has been little convergence on the issue between stakeholder classes, we revisited this possibility.

36. IESO examined this option by simulating what price would have been using a 3x ramp rate multiplier over a 6 month period (November, 2005 to April, 2006). We also estimated the efficiency gains from a reduction in uneconomic exports (referenced in the most recent Market Surveillance Panel report), estimating the reduction in CMSC payments (constrained-on and –off payments) due to a higher Ontario Market Clearing Price (MCP), and estimating the reduction in Intertie Offer Guarantee (IOG) payments that would occur with a higher Ontario MCP. In addition, the calculations provide an estimate of the impact on the Ontario consumer after Global Adjustment is accounted for, as well as by providing commentary on the likely impact of arbitrage and customer response as a result of the higher Ontario MCP.

37. The "mechanical" simulation of the price change from moving from a 12x multiplier to a 3x multiplier indicated an average price increase of $1.50/MWh, which corresponds to higher energy charges over a year of about $225 million. However, if the price mitigation effects of the Global Adjustment are accounted for, the impact of the increase is reduced by about 75% down to about $56 million.

38. The IESO is confident that the arbitrage opportunities available to importers and exporters of electricity will result in the actual price impact being significantly reduced. Increasing HOEP by an average of $1.50/MWh will have a direct impact on the volume of exports from Ontario to other jurisdictions, as the exports are charged HOEP, and routinely bid in the pre-dispatch process to be scheduled when HOEP is economic for their transactions. In recent years, Ontario has been a significant exporter of electricity. In 2005, 10.2 TWh of energy was exported from Ontario, and over the six months of the simulation, there was an average

export from Ontario of 1,750 MW. Additionally, our analysis shows that the most times the export market is fully satisfied, in other words, congestion has not been reached. This is significant, as so long as congestion has not been reached, there are likely low margin exports that have been scheduled. The presence of low-margin exports strengthens the likely impact of arbitrage. Precise simulations or calculations are not currently available to estimate the affect of arbitrage on Ontario energy prices. However, our judgement is that for the relatively small price increases that a change to a 3x ramp rate multiplier would bring, export arbitrage would be significant and could result in as much as a 50% reduction in impact. This would bring the possible energy price increase down in the order of $0.75/MWh, or under $30 million net of Global Adjustment.

39. An increase in HOEP will reduce inefficient exports, which will therefore reduce the amounts currently paid via constraint payments to Ontario resources to permit these exports to flow. Also, an increase in HOEP will result in a reduction in intertie offer guarantee payments. IESO estimates that CMSC payments under a 3x ramp rate multiplier will reduce by about $12 million per year, and Intertie Offer Guarantee payments will reduce by about $4 million. These savings lower the impact of the energy price increase to result in net increases in payment for electricity by consumers of about $40 million net prior to arbitrage, and probably well below $20 million after participant response.

40. When judged against the AMPCO's five criteria for any new mechanism, this proposal has many advantages. By not using uplift to supplement generator payments but instead including any increases in the energy price, the transparency of the market signals would be continued. This option would provide incentives for appropriate market responses, including potential demand response to these new, more appropriate price signals. This option should improve the efficiency of the electricity sector of today by decreasing the uplift (CMSC and IOG payment reductions) and by starting to address one of the significant findings of the most recent Market Surveillance Panel report by eliminating some of the inefficient export transactions. Finally, this proposal does not satisfy AMPCO's criterion that compensation for ramping services should only be paid to generators that actually ramp. However, in IESO Management's judgement the improvement in the fidelity of the energy price signal more than offsets the resultant small in increase in net cost to consumers.

41. This proposal would represent a small step toward providing generators market-based payments that are closer to those that would be available in most any other real-time electricity market. It would result in a similar net payment to generators as would the ramp payment proposals, but offers market efficiencies that are simply unattainable from a cost-based payment option. The distribution of revenues between generators is very different than would be received under a ramp payment proposal, but are directionally consistent with the distribution that would result from use of a 1x myopic implementation, which is APPrO's stated

preferred approach. The net effect to each generator of energy payment increases varies widely depending on their contractual commitments or regulatory regimes.

42. After much consideration, this proposal is the IESO Management's preferred alternative.

Status Quo While Additional Market Development Unfolds

43. The IESO and its stakeholders are about to embark on the design of a day-ahead market for Ontario. This effort will build upon the work and efforts of past DAM discussions, but will by necessity address numerous issues that relate to the interaction of the day-ahead and real-time market prices and quantities. Many of the current real-time market issues will have to be addressed and rationalized. To name a few, the day-ahead market discussions will address:
    i. The extent to which day-ahead market prices and real-time prices converge,
    ii. The role of intertie transactions in setting both day-ahead prices and real-time prices,
    iii. The appropriateness of having hourly day-ahead prices and 5-minute real-time prices,
    iv. Whether day-ahead market dispatch should be based on peak hourly demand or average hourly demand, and whether hour-ahead pre-dispatch must use the same assumption, and, of course,
    v. The appropriate treatment of locational price signals in Ontario, which could result in prices being calculated by the constrained schedule, with the market schedule being retired, thereby ending all conversations about appropriate ramp rate multipliers forever.

44. With this degree of reflection about energy pricing in Ontario on the horizon, one could reasonably ask whether now was the time to pursue changes to real-time pricing, with the issue instead being decided in an integrated context with the work on DAM.

45. While maintaining the status quo throughout the interim period of DAM discussions is an option, doing so may represent a missed opportunity that exists with the current set of contracts and regulations of the day to address some of the inefficiencies and inequalities that currently exist under the 12x/unconstrained pricing regime.

Table 1: Estimated Impacts of Options

OPTIONS		Status Quo	APPrO Ramp Payment	Ramp Cost Guarantee	3-Times Ramp Rate Myopic
Implementation Costs	**Tool/software development ($)**	No Implementation Cost	Just under $1 Million	$ 1 Million	No Implementation Cost
	Time to Implement	No Implementation Time	6 to 8 Months	8 to 12 Months	minimal
	In Service Date	Currently In Service	Mar-07	Sep-07	Implemented shortly after IESO Board approval
Opportunity Cost		No additional IESO or stakeholder effort	Distract effort by IESO and stakeholders on DAM design for 6 Months	Distract effort by IESO and stakeholders on DAM design for 10 Months	No additional IESO or stakeholder effort
Impact on Prices	**Impact on Average Annual HOEP ($/MWh)**	No Change	Minimal Change	Minimal Change	Increase approx. $1.50 (For net impact on customers' bills see Table 2)
	Impact on Annual Uplift ($/MWh)	No Change	Increase approx. $70 Million	Increase approx. $20 Million	Approx. decrease CMSC=$12 Million IOG=$4 Million
Impacts on Economy	**Estimated annual efficiency Gains (Allocative Efficiency) ($)**	No Change	Minimal Change	Minimal Change	Approx. $14 Million*
	Impact on Investment Decisions (Dynamic Efficiency)	No change	Minimal Change	Minimal Change	Minimal Change

*Efficiencies based on estimates of change in net exports due to price change.

Table 2: Impact on Ontario Consumers

OPTIONS	Status Quo	APPrO Ramp Payment	Ramp Cost Guarantee	3-Times Ramp Rate Myopic
Impact on Annual Energy Expenditure Prior to Global Adjustment ($)*	No Change	Minimal Change	Minimal Change	Increase approx. $225 Million
Estimated Rebate under Global Adjustment ($)*	No Change	Minimal Change	Minimal Change	Subtract 75% for GA - $169 Million
Impact on Annual Uplift ($)*	No Change	Increase approx. $50 Million	Increase approx. $20 Million	Subtract uplift savings -$16 Million
Net Change in Annual Expenditure ($)*	No Change	$50 Million	$20 Million	$40 Million (prior to market responses)*

*Based on simulations that assume no change in participant behaviour. Net impact on annual expenditure expected to be lower due to participant responses. See paragraph 38.