Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	**MR-00332-R00**		
Subject:	**Operating Reserve (OR)**		
Title:	**Reducing Synchronized OR Requirement due to Regional Reserve Sharing Program Changes**		
Nature of Proposal:	☒ Alteration	☐ Deletion	☐ Addition
Chapter:	5	Appendix:	
Sections:	4.6		
Sub-sections proposed for amending:	4.5.6B		

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Draft for Technical Panel Review	June 8, 2007
2.0	Published for Stakeholder Review and Comment	June 14, 2007
Approved Amendment Publication Date:		
Approved Amendment Effective Date:		

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

This amendment would allow the IESO to reduce its synchronized and/or non-synchronized ten-minute operating reserve (OR) requirement by a total of 100 MW, in accordance with Northeast Power Coordinating Council's (NPCC) recently approved changes to it Regional Reserve Sharing program (RRS).

The efficiency gains that would result from this change are estimated to be between $1 - $1.5 million per year.

Background

In June 2005, NPCC approved a voluntary program of 100 MW of regional reserve sharing (RRS). The purpose of the RRS is to improve regional reserve market efficiency in a manner that maintains reliability.

Although RRS allows for 100 MW of energy to be delivered under the program in the event of contingency, initially each participating area was only permitted to count 50 MW towards its non-synchronized ten-minute OR requirement, subject to availability and deliverability of the associated energy. The provision to count only 50 MW towards the non-synchronized ten-minute OR requirement was imposed by NPCC's Reliability Coordinating Committee (RCC) pending a review by the Task Force on Coordination of Operation (TFCO) of the effectiveness of RRS six months after implementation. RRS was implemented on January 4, 2006.

A November 2006 report on RRS prepared by the Control Performance Working Group (CO-1) of TFCO concluded that:

- "RRS in its present form has been successful in promoting reliability and should be continued.
- Consideration should be given to allowing regional reserve sharing energy to count towards ten-minute synchronized reserve requirements in the future."[1]

Based on the conclusions of the CO-1 report and subsequent discussions, on April 27, 2007, NPCC approved changes to RRS that allow participating areas to reduce their ten-minute OR requirement (synchronized and/or non-synchronized) by a total of 100 MW when the associated energy is available and deliverable in the event of a contingency.

[1] Source: NPCC web site at http://www.npcc.org/PublicFiles/openProcess/C-3820070312clean.pdf

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

The existing market rules regarding RRS permit the IESO to reduce its requirement for domestic supply of non-synchronized ten-minute reserve by up to 100 MW. A market rule amendment is required to allow the IESO to reduce its synchronized and/or non-synchronized ten-minute OR requirement by 100 MW, as permitted by the changes approved by NPCC.

- **Reliability Impacts**

Between January 4, 2006 and December 31, 2006, there were three contingency event that resulted in a request for, and delivery of, the energy associated with the RRS[2]. The IESO was counting 50 MW of RRS towards satisfying its non-synchronized ten-minute reserve requirement at the time of those contingencies.

An NPCC review of the first nine months of RRS concluded that NPCC Balancing Areas and Reliability Coordinators have not experienced any negative reliability impacts resulting from the implementation of RRS.

The IESO is satisfied that reliability will not be put at risk as a result of the greater flexibility to mange the IESO-controlled grid permitted under the proposed amendment

- **Market Efficiency Impacts**

The purpose of RRS is to improve regional reserve market efficiency in a manner that maintains reliability. The IESO conducted an efficiency analysis of the proposed changed (refer to the attached draft cost-benefit analysis). The results suggest that reducing the synchronized ten-minute OR requirement by 100 MW rather than reducing the non-synchronized ten-minute OR requirement would yield net benefits of approximately $1 – $1.5 million per year.

Discussion

It is proposed to amend section 4.5.6B of Chapter 5 by removing the term “non-synchronized” from the reference to the ten-minute operating reserve requirement. The existing market rule definition of ten-minute operating reserve means “those operating reserves required to respond fully within ten minutes of being called upon by the IESO”. Therefore, ten-minute operating reserve includes both synchronized and non-synchronized ten-minute reserves if no other qualifiers are specified.

Removing the term “non-synchronized” from the reference to the ten-minute operating reserve requirement would allow the IESO to reduce its synchronized and/or non-synchronized ten-minute OR requirement by a total of 100 MW in accordance with NPCC’s recently approved changes to its Regional Reserve Sharing program.

[2] This statement corrects and provides additional information than was included in amendment submission MR-00332-Q00. MR-00332-Q00 indicated that since January 4, 2006, there has only been one contingency event resulting in the delivery of the energy associated with RRS. Between November 1 and December 31 2006, there were two other contingency events that resulted in a request for, and delivery of, the energy associated with the RRS. Both of these events were due to a nuclear unit turbine trip and they occurred on November 23 and December 19, respectively.

PART 4 – PROPOSED AMENDMENT

Regional Reserve Sharing

4.5.6B The *IESO* may participate in regional reserve sharing programs with neighbouring *control areas*. Subject to availability and deliverability of the associated energy, the *IESO* may count towards its ~~non-synchronised~~ *ten-minute operating reserve* requirement a contribution of up to 100 MW from neighbouring *control areas* in accordance with applicable regional reserve sharing programs and applicable *reliability standards.* The *IESO* shall activate *energy* from regional reserve sharing programs in accordance with applicable *reliability standards*.

PART 5 – IESO BOARD DECISION RATIONALE

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DRAFT Cost Benefit Analysis:
Operating Reserve Initiative 2 - Reducing the 10-minute synchronized OR requirement

ieso
Power to Ontario.
On Demand.

1. Purpose:

The IESO is advocating that a cost-benefit analysis (CBA) accompany any future market rule amendments that are expected to have a material impact on market outcomes and market efficiency. A finding that the market rule amendment passes a CBA would be a necessary first step for the IESO to recommend the approval of the amendment to the IESO Board. The IESO is also encouraging the Technical Panel to use a CBA as input into their recommendations of proposed amendments.

This paper provides a preliminary CBA of market rule amendment proposal MR-00332-R00. This amendment would allow the IESO to reduce the ten-minute synchronized operating reserve requirement (OR) by 100 MW in accordance with Northeast Power Coordinating Council's Regional Reserve Sharing (RRS) program (referred hereto as the "10s initiative"). The IESO is using MR-00332-R00 as a "test case" for illustrating how it would apply CBA to future proposed market rule amendments.

The IESO is seeking stakeholder comments and feedback on this preliminary CBA.
The IESO would appreciate comment both respect to (i) whether there are material costs or benefits ignored in the draft CBA and, if so evidence of their existence and an estimate of their significance or how you would propose to value them, and (ii) more general comments on the use of CBA as a means to facilitate a more rigorous consideration of rule amendments and whether, and how, the content can be better organized in future CBAs.

2. Summary of CBA Methodology:

The following provides a summary of the CBA methodology to be applied in this report. In general, a CBA seeks to measure the welfare impacts of a change in policy (such as a market rule amendment) on all affected individuals/groups, including generators, consumers, and other market participants. If it is determined that the welfare gains to individuals resulting from the change exceed the welfare losses to individuals, then the proposed change is deemed to pass the CBA.[1] A proposed change will pass a CBA if it leads to an improvement in allocative, productive or dynamic efficiency (assuming of course that there were no other offsetting costs such as implementation costs).

[1] This is referred to as the Kaldor-Hicks criterion whereby a change is approved if the winners from the change could hypothetically compensate the losers and still be better off. More accurately, the change is approved if the gains to 'winners' exceed the losses to 'losers', such that the change creates benefits that are sufficiently large to offset the losses. This criterion does not require that losers are actually compensated or that winners 'bribe' losers to accept a change; it only requires that winners or losers could provide compensation or 'bribes', in the sense that they could provide compensatory transfers to other parties to make them at least as well off as before while themselves remaining better off than under the status quo. See Trebilcock et al.

The welfare impacts of a change on any individual/group are typically measured as the change in their surplus (i.e., consumer or producer surplus).[2] This change may be either positive or negative for a given individual/group. If the change in an individual's/group's surplus is negative then this is considered a cost of proceeding with the change, while if the change in an individual's/group's surplus is positive then this is a benefit attributable to the initiative. The individuals'/groups' surpluses are aggregated and compared to determine the net change in surplus anticipated from the 10s initiative. The present value of any net change in surplus is then compared to any implementation cost of making the change to determine the net cost or benefit of the project.

The sources of the impacts on individual welfare from a change in policy are typically the result of changes in the prices at which various goods and services can be purchased, changes in the quantities produced, and changes in the prices and quantities of inputs that are required to produce them. In the case of the 10s initiative, potential impacts could include: reductions in the Ontario prices for OR and energy; reduced quantities of generation output capacity required to meet demand for energy and OR; and increased (and possibly inefficient) exports of energy to neighbouring jurisdictions such as New York. Economic theory can be used to identify the various potential impacts, and simulation and econometric modelling are helpful in estimating the sizes of these impacts. Both theory and modeling are used in this preliminary CBA.

In general, a change of the sort considered here would be expected to yield net positive benefits in the form of productive efficiencies, i.e. supplying the same level of Ontario demand with the same level of reliability but with fewer or less costly resources and with very little in the way of implementation costs expected. However, the presence of pre-existing distortions in the regional electricity sector can cast doubt on this general expectation. It is possible that a policy change that would yield a net benefit in the absence of pre-existing distortions may actually result in net losses if those distortions exist. A relevant pre-existing distortion in the Ontario electricity sector is the uniform price regime and the resulting problem of inefficient exports to New York. The 10s initiative is expected to have downward pressure on energy prices which could result in an increase in inefficient exports. These inefficiencies could offset at least some of the expected net benefits attributable to the use of fewer or less costly resources and hence should be considered in a CBA.

The remainder of this memo will present the preliminary findings of the CBA as applied to the 10s initiative and will proceed according to the following structure. First, a general description of the rule amendment and the motivation for its proposal is provided. Second, results of an initial simulation, ignoring any eventual behavioural responses are presented. Third, the theory and assumptions supporting the likely behavioural responses to the 10s initiative and the projected equilibrium outcome are presented. Fourth, the impact on all affected individuals'

[2] Consumer surplus is calculated as the difference between what a consumer is willing to pay for a product and the amount paid. Producer surplus is calculated as the difference between what the producer is paid for its product and the cost that it incurs to produce the product (profit).

welfare post participants' behaviour responses is estimated. The final step in the CBA is the aggregation of the individual effects and the assessment of the net benefit/cost of the proposed change. This is the basic template that the IESO is proposing to apply to future CBA conducted for market rule amendments.

3. Application of a CBA to Market Rule Amendment Proposal MR-00332-R00

a. Description of the 10s initiative and its motivation

Recently approved changes to NPCC's Regional Reserve Sharing program (RRS) allow participating areas to reduce their non-synchronized (10n) and/or synchronized (10s) OR by a total of 100 MW when the associated energy is available and deliverable.

The existing market rules regarding RRS permit the IESO to reduce its requirement for domestic supply of non-synchronized ten-minute reserve by up to 100 MW. The proposed market rule amendment MR-00332-R00 would allow the IESO to reduce its synchronized ten-minute OR requirement by 100 MW, and, therefore, fully align Ontario OR requirements with the NPCC's policy on RRS.

Table 1 provides a summary of how RRS impacts the reserve requirements, assuming that the first and second largest contingencies are 1000 MW. The change in the OR requirements would be implemented in both the constrained and unconstrained dispatch algorithms.

Table 1: Reserve requirements assuming a first and second largest contingency of 1000MW

Reserve Class	Prior to RRS	Status quo (100 MW RRS reduction in 10n)	MR-00332: 100 MW RRS reduction in 10s
10-min (total)	10s + 10n ≥ 1000 MW	10s + 10n ≥ 900 MW	10s + 10n ≥ 900 MW
10-min spin	10s≥ 25% x 1000 = 250MW	10s≥ 25% x 1000 = 250MW	10s≥ (25% x 1000)-100=150 MW
Total Reserve	10s+10n+30n*≥ 1500 MW	10s +10n +30n ≥ 1400 MW	10s + 10n +30 ≥ 1400 MW

*30n requirement is equal to 50% of the second largest contingency.

Are there any reasons to expect the changes outlined in Table 1 to be beneficial considering the important role OR plays in ensuring reliability? Consider the middle column of Table 1. The reduction in required OR comes at little or no cost in reliability on account of the province's access to OR from other jurisdictions that RRS provides. The sharing of OR among jurisdictions within NPCC allows each jurisdiction to reduce their requirements because the major contingencies each jurisdiction faces are independent events or, in other words, uncorrelated. That is, in the event that Ontario's single largest contingency takes place (i.e., the loss of a Darlington unit), New York's largest contingency is no more or less likely to occur. The independence of these contingencies across jurisdictions, along with sharing of reserves, means that each jurisdiction can maintain a lower level of OR with no significant decrease in reliability.

With little or no cost in reliability, the 100 MW reduction in the ten-minute OR requirement is one of two basic benefits resulting from the IESO's participation in the RRS program. By using 100 MW less OR, Ontario will save the resource costs that previously were being incurred to provide this quantity of reserve.

The second benefit of the IESO's participation in RRS is the expected improvement in productive efficiency associated with the change proposed under MR-00332. By allowing Ontario to reduce the usually more costly 10s requirement by 100 MW instead of the 10n requirement, the province's demand is met with less costly resources while maintaining an acceptable level of reliability. Again, this change comes at little or no cost in terms of reliability as the reliability benefit of this quantity of 10s is sourced from other jurisdictions. The incremental change proposed under MR-00332 is the subject of this CBA.

To illustrate the source of the potential increases in productive efficiency, consider the following simple example. First, assume that the market operates under the reserve constraints presented in column 2 of Table 1. Assume that, based on the offers and bid and the Ontario demand in a given hour, the constrained dispatch algorithm scheduled 250 MW of 10s, all offered at a cost of $2.00/MWh and 1150 MW of 10n, all offered at a cost of $1.00/MWh. In this example, 650 MW of the 10n reserve offered was scheduled to meet the 900 MW 10-minute requirement (250 MW of 10s plus 650 MW of 10n equals the 900 MW requirement). An additional 500 MW of the 10n reserve that was offered was schedule to satisfy the total reserve requirement as it was offered at a cost lower than any of the available 30n reserve. Assume also that there was an additional 200 MW of 10n offered at a cost of $1.00/MWh.

Now assume that the IESO changed the reserve requirements to the constraints presented in column 3 of Table 1. With the relaxing of the 10s constraint, the algorithm is no longer required to schedule a minimum of 250 MW of 10s. It is now free to schedule up to 100 MW of additional 10n instead of the more expensive 10s. In this new equilibrium, the algorithm schedules only 150 MW of 10s at a cost of $2.00/MWh and 1,250 of 10n at a cost of $1.00/MWh. The productive efficiency is measured as the resource cost savings as a result of the shifting of a reliance on 10s to 10n (with negligible impact on reliability). This is equal to the difference between the cost of 10s ($2.00) and the cost of 10n ($1.00) times 100 MW, or $100.

b. <u>Outcome of preliminary simulations ignoring any behavioural responses</u>

The IESO conducted two simulations to gauge the impact on market prices of the changes to the reserve requirements as allowed by NPCC under the RRS program. The simulations were conducted for the real-time unconstrained schedule for a six month period in 2006.[3] These simulations consider a change in the reserve requirements only and ignore the possible behaviour responses. These simulations provide a measure of the direction of the price change and an upper bound of the magnitude of the price change. Since the simulations ignore

[3] The simulations were conducted for 6 months: January, March, May, July, September, and November. The simulations compute prices and quantities for each of the 5-minute intervals in the 6 month period.

participant responses to the change, they are not a projection of the eventual price outcomes. Behaviour responses to the change will provide some mitigation to any price pressure indicated by the simulations. The IESO's projection of behavioural responses to the change and the eventual price outcomes is provided in the next section of this report.

For the purpose of conducting a CBA, these simulations are helpful in that they provide information that is useful for predicting possible behaviour responses to the proposed change (and hence in predicting the ultimate price impacts and welfare impacts of the change). For example, if simulations indicate that the clearing prices are likely to decrease after the change then one anticipated behaviour response will be an increase in exports (given the high degree of demand elasticity estimated in previous IESO work). Furthermore, the magnitude of the simulated price decrease, along with elasticity estimates can be used to project the amount of increase in the quantity of exports in response to the change.

The IESO has implemented the NPCC RRS policy in stages the first of which was on January 4, 2006. At that time the IESO reduced the 10n and total reserve requirements by 50 MW. On May 17, 2007, the IESO reduced the 10n and total reserve requirement by an additional 50 MW (for a total of 100 MW). The next step under review is the 10s initiative.

In its first simulation, the IESO used all of the same inputs that were used in the actual unconstrained dispatch with the exception of the 10n and total reserve requirements. Instead, the IESO used the constraints as outlined in column 2 of Table 1. This first simulation provides us with a benchmark against which we can measure the price pressure impacts attributable solely to the 10s initiative. The second simulation simply re-ran the first simulation but instead lowered the reserve requirement for the 10s by 100 MW (i.e., used the reserve constraints as presented in the final column of Table 1). This simulation provides an indication of the downward price pressure caused by the 10s initiative – the focus of this CBA. The average prices for the simulation period are summarized in Table 2 below.

Table 2: Average Simulated Prices Ignoring Behaviour Responses, 6-Month Period 2006

Simulation	**10n ($/MWh)**	**10s ($/MWh)**	**30R ($/MWh)**	**MCP ($/MWh)**	Reduction in Production Cost $ per hour
Simulation 1: (Benchmark)	1.19	3.19	1.17	47.82	
Simulation 2: (10s initiative)	1.19	1.33	1.17	47.76	87.00
Price Change due to 10s initiative	0.00	1.86	0.00	0.06	

The results of these simulations demonstrate the following:

- The 10s initiative results in a modest decrease in the energy price ($0.06) but a considerable reduction in the 10s reserve price ($1.86). The reduction in the 10s price occurs in only those hours when the 10s requirement was otherwise binding (i.e., the IESO was only scheduling 10s in the amount of 25% of the largest contingency). This occurred in roughly 57% of the hours in our simulation period. The reduction in the energy price occurred only in those hours where the 10s requirement was binding and when co-optimization was affecting the energy price. This occurred in only 25% of the hours in our simulation period. *In all other hours, the changes proposed under market rule amendment MR-00332 would not have an impact on any of the market prices.* The maximum hourly energy price reduction in the period was $8.58 while the maximum hourly 10s reserve price reduction was $29.80.
- The second simulation indicated that by reducing the 10s requirement by 100 MW, there was a substitution of 10s reserve for 10n reserve in roughly 55% of the hours. On average, this meant a reduction of 44 MW of 10s scheduled per hour and an increase in 44 MW of 10n scheduled per hour.
- The 10s initiative leads to a reduction in the average hourly uplift of roughly $445. This reduction is due to the substitution from the higher cost 10s to the lower cost 10n as well as due to the lower 10s price. This amounts to a reduction of roughly $0.02/MWh in uplift.
- The simulation allows for a computation of how the 10s initiative results in a change in the total production cost of serving Ontario demand and exports. This is a reduction in the production cost of the unconstrained sequence. The total cost is measured as the sum of the individual offer prices times the amount of energy or reserve supplied at the offer price. In other words it is measured as the area under the offer curves (energy and the 3 classes of reserve). The simulations show that the 10s initiative leads to an average hourly reduction in total production cost of $87. The reduced production cost is roughly equal to the reduction in 10s scheduled (which on average was 44 MW\h) times the difference between the 10s price and the 10n price (which on average was $2.00\MWh). Additional cost savings come through co-optimization of reserve and energy whereby the relaxation of the 10s requirement frees-up resources to provide energy.
- This estimated reduction in total production cost is a measure of improved productive efficiency. The simulation used the unconstrained schedule. However, any efficiency gains that would accrue would come within the constrained schedule – the efficiencies are based on the actual change in dispatch. The IESO does not have a constrained dispatch simulator to estimate the similar efficiency savings. However, given that the constrained dispatch generally has less supply available due to transmission constraints, losses or other distortions such as the 12-times ramp rate assumption, the actual efficiency gains realized in the constrained dispatch as a result of the 10s initiative would be larger. For the 6 month period in 2006 that were covered in our simulation of the unconstrained schedule, the average hourly prices for the reserve products were

$17.02 for 10n and $21.74 for 10s.[4] We would expect that the 10s initiative would likely lead to a larger substitution from 10s to 10n than the 44 MW predicted by the unconstrained simulation. However, using the 44 MW change and the difference between the 10s and 10n constrained prices we have a rough approximation of the hourly average production cost savings attributable to the 10s initiative: ($21.74 - $17.02) x 44 MW = $4.72 x 44MW = $207.68/MWh. Note that this estimate may be an overstatement for two reasons. First, the shadow prices include instances when there were shortages of reserve and these shortages were reflected in the prices. In this regard, the estimate include more than just the out-of-pocket costs of providing reserve but also the opportunity cost (based on the penalty factors capped at $2000) of not meeting the reserve requirements. Second, the estimates use prices that evaluate the cost of 10s and 10n at the margin. Given that the reserve offer curves are downward sloping, some of the reserve costs saved will be lower than the marginal price. If we assume that the offer curves are linear, we can estimate the impact of a downward sloping offer curve by dividng our estimate by 2. That is, the estimated hourly average cost savings would be roughly $207.68/MWh/2 which is equal to $103.84

c. <u>Predicted participants' responses and the projected equilibrium outcome:</u>

The preceding analysis did not consider potential responses by market participants to the changes in prices generated by the 10s initiative. This section incorporates behavioural response. Several assumptions have been made in order to arrive at predicted behavioural response. The following discussion identifies these assumptions and provides supporting rationale.

Ontario Consumers: ***We assume no consumer response to the price changes in Table 1.*** Generally, reductions in prices (and uplift charges) would provide consumers with an incentive to consume more of a product. However, given the modest impact that the 10s initiative has on the energy price or on the amount of hourly uplift per MW that any one consumer would pay, it is unlikely that this initiative would lead to more consumption by the province's consumers.

Exporters: We make two alternative assumptions regarding exporter response and therefore generate two scenarios for comparison. Previous analysis indicates that export demand is highly elastic to changes in the HOEP relative to New York price.[5] The elasticity estimate was negative 4.7 which implies that a 1% decrease in the HOEP would lead to 4.7% increase in the quantity of exports.[6] We expect a similar level of elasticity with respect to exports to other jurisdictions. Note that unlike Ontario, some jurisdictions such as New York are not planning on reducing their reserve requirements (either the 10n or the 10s) as permitted by the NPCC RRS program. Therefore, any potential export responses will be a result of downward pressure

[4] In computing these averages we capped the price at $2000 in those hours where the actual prices exceed $2000 due to shortage conditions in the constrained sequence.
[5] See the analysis econometric analysis presented to the MPWG on May 13, 2007.
[6] Our analysis indicated that there was a 95% probability that the elastic would fall within the range of -2.9 and -6.3.

in the Ontario HOEP relative to the neighbouring prices. The simulated HOEP decrease due to the 10s initiative is modest at $0.06 cents. The cumulative HOEP plus uplift is also modest at $0.09. The average hourly amount of exports for the period 2006 was 1,300 MW. Therefore, using the elasticity of minus 4.7 and the simulated price decrease of approximately 0.1% we would expect that at most there would be an average hourly increase of 6 MW of exports. However, given the simulated HOEP impact is so modest, we think it is equally as likely that the 10s initiative would have negligible impact on the quantity of exports. To capture this potential range we construct two scenarios: the export response scenario (6 MW increase in exports); and the de minimus export response scenario (0 responses in exports).

If other jurisdictions were implementing RRS in the same manner as Ontario, it is likely that their energy and reserve prices would fall as well. This would most likely eliminate any price differentials between Ontario and the other jurisdictions and more firmly ground Ontario within the de minimus scenario.

Importers: ***We assume no change in the quantity of imports.*** While we do not have a formal estimation of the elasticity of imports as we do for exporters, we expect that import arbitrage is also fairly elastic: a 1% decrease in the HOEP would lead to more than a 1% decrease in imports. Simulations indicate that the 10s initiative would result in a modest decrease in the HOEP. The 10s initiative will be implemented in both the real-time and pre-dispatch sequences with the 10s initiative also affecting the pre-dispatch price in a manner similar to the real-time price. As a result, there could be some instances in which fewer imports are scheduled in pre-dispatch following the implementation of the 10s initiative. However, as was the prediction with export demand, given the modest impact on Ontario prices, this impact is likely negligible. Furthermore, the 10s impact is typically realized more in off-peak periods when the 10s reserve constraint is binding. These are periods when Ontario is a net exporter. This would suggest that an export response is more likely than an import response. As a result, and for the purpose of the analysis in this CBA, we can assume that the impact of the 10s initiative will result in virtually no change in the quantity of imports.

Ontario Generators: ***We assume no change in generator behaviour in the short term. In the medium to long term we anticipate less investment by generators in the ability to provide 10s reserve and a gradual reduction in the amount of 10s capacity within the province.*** The simulations indicate modest downward pressure on the energy price but considerable reduction in the 10s price. This implies that there would be downward pressure on the revenues to all generators but particularly to the revenues of the 10s providers. Given the modest energy price impact indicated by the simulation and the current offer practice of Ontario generators, we predict that there is unlikely to be a short term response from Ontario generators following the implementation of the 10s initiative. First, generators within the province typically offer to supply energy at their short-term incremental cost. The 10s initiative would not change the generators' incentives in this regard. Furthermore, programs such as the SGOL program and the GCG program of the DACP allow for the recovery of fixed costs such as start-up and speedno-load costs. With these programs in place and the modest impact on energy revenues, it is unlikely that the start-up decisions of generators would change. As a result, in the short term, the 10s initiative is unlikely to lead to a change in generator offers or start-up decisions. Over the medium to long term and as a result of the reduction in revenues available to 10s providers, these providers may choose not to maintain the ability of their resources to provide 10s reserve. As a result, over time some resources that currently possess the capability to provide this reserve may no longer be capable of providing this reserve.

Predicted Equilibrium: Based on the above assumptions and forecasts regarding participants' responses, we anticipate the following market equilibrium outcomes for the two scenarios:

Scenario 1: De minimus export response :

- No change in the quantity of electricity consumed by Ontario consumers;
- No change in the quantity of imports/exports or energy produced by Ontario generators;
- An average hourly reduction in the quantity of 10s reserve schedule in the unconstrained sequence of roughly 44 MW with a corresponding increase in the amount of 10n reserve scheduled of roughly 44 MW; the substitution of 10s for 10n will occur mainly in off-peak periods. The reduction in 10s scheduled in the constrained sequence will be larger than 44 MW;
- A modest reduction in energy prices of $0.06. (The impact on energy prices is a result of the joint-optimization of energy and reserve; the reduction in the 10s reserve requirement means that at times, capacity that would otherwise be used for 10s reserve is released to provide energy.)
- A reduction in the 10s reserve price of roughly $1.86/MWh and a corresponding reduction in the average total hourly uplift of roughly $445/MWh. No change in the 10n and 30-minute reserve prices.
- There will be a negligible reduction in the constrained-off and constrained on payments.
- There will be a negligible reduction in the level of reliability.

Scenario 2: Modest export response:

- No change in the quantity of electricity consumed by Ontario consumers;
- A modest increase in the quantity of exports of electricity from Ontario to surrounding jurisdictions – likely less then an average of 6MW per hour and mainly in off-peak periods;
- A negligible increase in the quantity of electricity produced by Ontario generators equal to the amount of any increase in exports (less than 6 MW per hour on average);
- No change in the quantity of imports from surrounding jurisdictions;
- A negligible decrease in energy prices (less than $0.06 as projected in scenario 1 – the response from exports would mitigate the initial downward pressure on the HOEP
- An average hourly reduction in the quantity of 10s reserve schedule of roughly 44 MW with a corresponding increase in the amount of 10n reserve scheduled of roughly 44 MW- the substitution of 10s for 10n will occur mainly in off-peak periods. The reduction in 10s scheduled in the constrained sequence will be larger than 44 MW;

- A reduction in the 10s reserve price of roughly $1.86/MWh and a corresponding reduction in the average total hourly uplift of roughly $445/MWh.
- There will be a negligible reduction in the constrained-off and constrained on payments.

d. <u>Estimation of impacts on affected individual's/group's welfare</u>

We estimate the impact on Ontario consumers, Ontario generators, importers and exporters and neighbouring consumers and generators under the two equilibrium scenarios described above. For our preliminary estimation of the welfare impacts, we use hourly average measures of key variables to approximate the welfare impacts of the change.

Scenario 1: De minimus export response

The CBA seeks to measure the change in welfare for each class of affected market participant. The change in welfare is measured as the change in either consumers' or producers' surplus. For the purpose of a CBA, an increase in group's surplus is treated as a benefit and a decrease in a group's surplus is treated as a cost. Table 3 provides a complete listing of the changes in the surplus measures of each of the classes of participants.

Ontario Consumers: The change in Ontario consumer welfare is measured as the change in their consumer surplus. Consumer surplus is measured as the difference between what consumers are willing to pay for the quantity of good or service consumed and the amount that they actually pay. Under Scenario 1, Ontario consumers consume the same amount of energy with only a slight reduction in the level of reliability. However, they pay a lower average energy price ($0.06/MWh) and a lower average hourly uplift. Given that the amount of energy consumed does not change, the change in consumers' surplus can therefore be measured as the reduction in the amount that they pay for the energy less the value of the reduced level of reliability. With an average hourly Ontario demand of 17,247 MW in 2006, the reduced energy price represents an annual increase in consumers' surplus of $0.06 x 17,247 MW x8 760hours which is roughly equal to $9.07 million per year. The estimated reduction in average hourly uplift is $445/MWh. This reduction would be shared by Ontario consumers and exporters. Average hourly exports were 1,300 MW in 2006 for a total market demand of 18,547 MW. Ontario consumers would therefore realize roughly 93 percent of the average hourly uplift reduction or roughly $3.63 million per year. NPCC has estimated that the change will reduce the level or reliability slightly. NPCC estimates that the loss of load probability prior to the change was 1 hour in 1,114 years. After the change the loss of load probability increases to 1 hour in 1,080 years. Assuming that the loss of load is 100 MWh (the amount of the 10s reduction) for the hour and the value of loss load is $10,000, then the estimated reduction in value to consumers for the reduced level of reliability is roughly $28 per year - (1/(1,080*8760)-1/(1,114*8760))*100MWh*$10,000. Therefore, under Scenario 1, the change in Ontario consumers' surplus is the reduced energy payments and hourly uplift less the increase in the expected value of loss load - which is approximately $12.70 million.

Note that this change in consumers' surplus does not factor in the impacts of Global Adjustment or the OPG Rebate. Both the GA and OPG Rebate would transfer some of the benefits of the associated $0.06 reduced energy price back to generators. This would reduce the consumers' surplus increase. The GA and OPG rebate would be expected to transfer roughly 80% of the energy price reduction in generator revenues back to the Ontario generators. Given an average annual production of 17,840 MW from Ontario generators this would mean a transfer from Ontario consumers to Ontario Generators of roughly $0.06x80%x 17,840MWx8760hours=$7.50 million. This transfer of revenues would mean a net increase (post GA and OPG Rebate) in consumers' surplus of approximately $5.20 million.

Ontario Generators: The change in Ontario generators welfare is measured as the change in producers' surplus. Producers' surplus is measured as profit. Under Scenario 1, producers will earn less energy revenue and less revenue for 10s reserve. At the same time, they will not incur the cost associated with providing the 10s reserve. Instead there will be a substitution away from the 10s reserve towards the provision of the generally cheaper 10n reserve. This is estimated to be an average hourly amount of 44 MW in the unconstrained sequence and likely something larger in the constrained sequence. The average hourly amount of energy produced by Ontario generators in 2006 was 17,840 MW. This would imply a reduction in energy revenue of approximately $0.06 x 17,840 x 8760 =$ 9.38 million. The reduced uplift payments to 10s providers is estimated to be $445 x 8760hours = $3.90 million. However, the generators will no longer incur production cost of the higher 10s reserve. The cost reduction will be equal to the difference between the cost of providing 10s and 10n. In the unconstrained sequence this difference is on average $2 per hour times the average amount of substitution from 10s reserve to 10n reserve – 44 MW. The cost saving will therefore be $88.00 x 8760 = $770,880. In the constrained sequence, this cost savings is considerably higher and estimated to be $103.84 x 8760 = $0.91 million. This reflects the actual cost savings realized by the generators. The net reduction in producers' surplus (profits) is therefore approximated to be between $9.38 million + $3.90 million - $0.91 million = $12.37 million

Once again, this estimate of producers' surplus does not factor in the impacts of Global Adjustment or the OPG Rebate. Both the GA and OPG Rebate would transfer some of the initial benefits of the associated $0.06 reduced energy price realized by consumers back to generators. As outlined above, we estimate the transfer back to producers to be approximately $7.50 million. This transfer of revenues would mean a net decrease (post GA and OPG Rebate) in producers' surplus of approximately $3.96 million.

Net exporters: Given no change in the quantity of imports or exports, the net change in surplus to imports and exports can be estimated as the reduced hourly charge due to the lower energy price and hourly uplift times the average hourly quantity of exports and the lower energy price times the average quantity of imports. In 2006, the average hourly quantity of exports was 1,300MW. This would imply an increases in surplus to exporters due to the lower energy price of $0.06 x 1,300MW x 8760 = $683,280. Their portion of the average hourly uplift savings is roughly 7% of the $445 hourly savings or $272,874 per year. Therefore, export surplus is estimated to increase by roughly $956,154 per year. The average hourly quantity of imports was 706 MW. This would imply a decrease in surplus to importers of $371,074.

External generators and consumers: Given that there is no change in imports or exports, and neighbouring jurisdictions will not reduce their requirements as permitted by NPCC under RRS, there will be no change in the welfare of external generators or consumers.

Adding up the surplus measures of all affected participants, we estimate an average annual net benefit of roughly $0.91 million. This estimated net benefit approximates the estimated productive efficiencies outlined in the previous section.

Scenario 2: Modest export response:

In this scenario, there will be an estimated increase in the quantity of exports. Currently, due to the uniform price regime and other distortions in the uniform price such as the 12 times ramp rate, many of these exports are inefficient. The inefficiency is the difference between the cost to produce the export in Ontario for supply to consumers in New York, represented by the shadow price and the cost to supply these same consumers through generation in New York.

Under Scenario 2, some of the efficiency gains estimated in Scenario 1 will be dissipated by the export inefficiencies. The estimated inefficiency per MW of export is an average of about $8 per MW. For a change of 6 MW, the lost efficiency would be 6 MWhx$8MWx8760 = $420,480. This lost efficiency would offset the efficiency gains from saving 10s reserve cost. Under scenario 2, the efficiency gains would be about $0.91 million less $420,480 which is roughly $0.49 million.

Long-term cost and benefits and dynamic efficiency estimates

The analysis above focuses on the short-term welfare implications of the 10s initiative. However, as discussed in section 2c above, over the medium to long-term, we anticipate less investment by generators in the ability to provide 10s reserve and a gradual reduction in the amount of 10s capacity within the province. What are the welfare implications of this medium to long term response?

In a market where prices are already sending the efficient long-term signal for investment, a change such as the 10s initiative, which would represent an improvement in short-term efficiency, would also send a long term signal that the province needed fewer 10s resources.[7] Over time, the money spent to maintain the 10s resources would be diverted to other activities in the economy (maybe more expenditure on maintaining energy capabilities of resources) with higher social value. This would be an efficient response of the owners of these facilities. In

[7] As the provinces capacity of the 10s reserve facilities declines the long-term prices for 10s may rise slightly as in some hours there would no longer be that spare 10s capacity to dampen prices. However, these prices would adjust so that just the right (efficient) amount of 10s capacity remained in the market.

general, a CBA would identify this as long-term efficiency – the efficient rationalization of society's resources.

If however, due to some market failure (or market design distortions such as uniform pricing), market prices were not sending the efficient long-term signal for investment (i.e., were too low so that there was already underinvestment) the 10s initiative could exacerbate the underinvestment problem and further reduce long-term efficiency. This could be the case in the Ontario market with respect to energy prices. In a CBA these dynamic inefficiency losses should be balanced against the short-term productive efficiency gains of the program.

The IESO believes that there is unlikely to be dynamic inefficiencies caused by the 10s initiative for the following reason. The OPA as central planner is charged with identifying future investment needs in the province and contracting for this investment. In general, they are tasked with providing the incentives (through contract) to invest when the market itself does not provide these incentives. As long as the OPA performs this role, and as long as the bigger distortions in market design exist, it is likely that changes such as the 10s initiative will not impact the level of investments in the province; prospective investors will always turn to the OPA for a contract. The concern over dynamic inefficiencies and the lack of investment in Ontario would be better addressed by addressing the broader distortions in the market then by avoiding to make changes such as the 10s initiative that provide for short-term efficiency gains.

e. <u>Estimation of aggregated net benefit/cost and present value</u>

The IESO estimates that there would be a one-time cost of approximately $5,000 to change the software and related tools. Market Participants are not expected to incur re-tooling costs or other related costs.

The annual net benefit from the 10s would be the annual net change in welfare to all participants. This is estimated to be between $0.49 and $0.91 million per year. Using a discount factor of 5% and looking at the present value of these annual net benefits over a 10 year period, the present value net benefit is estimated to be between $7.0 million and $12.9 million. The net benefits exceed the implementation cost indicating that the 10s initiative would pass the CBA.

Table 3: Welfare Impacts under Scenario 1

Participant Class	Projected Annual in Surplus
Ontario Consumers	Decrease in Energy Payment: = $0.06 x 17,247 MW x8 760hours = $9.07 million Decrease in OR Uplift Payment =93%x$445x8760hours =$3.63 million Increase in expected value of loss load =(1/(1,080*8760hours)-1/(1,114*8760hours))*100MWh*$10,000 =$28 Change in Consumers' Surplus $12.70 million Less OPG Rebate and GA -$7.50 million Net Change in Consumers' Surplus **$5.20 million**
Ontario Generators	Decrease in Energy Revenue = $0.06x17,840MWx8760hours = -$9.38 million Decrease in OR Uplift Payment =$445x8760hours = -$3.90 million Reduced Production Cost = $103.84 x 8760 =+$0.91 million Change in Producers' Surplus -$12.37 plus OPG Rebate and GA +$7.50 million Net Change in Producers' Surplus **- $4.87 million**
Exporters	Decrease in Energy Payment = $0.06x1,300MWx8760hours =$0.68 million Decrease in OR Uplift Payment =7%x$445x8760hours =$0.27 million Change in Exporters' Surplus **$0.95 million**
Importers	Decrease in Energy Revenue = $0.06x706MWx8760hours = $37 million Change in Importers' Surplus **- $0.37 million**
Annual Net Benefit/Cost	**$0.91 million**