

Issue No.	Issue	Raised by	Response
1	<p>It was unclear whether the study had modeled the Manitoba - Ontario transmission interface at all. The key transmission links cited in the presentation listed all of Ontario's transmission interfaces that were modeled, including the Minnesota link at International Falls (90/140 MW transfer capability). However, there wasn't any mention of the much larger Manitoba-Ontario interface.</p> <p>If the study model inadvertently omitted the Manitoba - Ontario interface, the IESO must repeat the analysis, this time including the Manitoba- Ontario interface in order for the study results to be meaningful.</p>	Manitoba Hydro	<p>There are multiple transmission interfaces connecting Ontario and adjacent dispatch areas or markets, or virtual markets in the case of how PJM is considered in the study. Slide 7 of the Export Transmission Service (ETS) Charge Scenario Analysis - Overview: Draft Preliminary Report and Findings (“overview presentation”) shows the links between the IESO-administered market and adjacent dispatch regions that were considered in the study. Slide 80 of the overview presentation is intended to provide a summary of the aggregate transfer capability of the interfaces between the IESO-administered market and other dispatch areas considered in the study. The reference to Ontario-Minnesota transfer limit is not to suggest that this interface is representative of a separate dispatch area in the model; rather, it is to show the Ontario-Minnesota transfer capability within the aggregate MISO dispatch area. Also, it is not intended to suggest that the Ontario-Manitoba transfer capability was not taken into account in the study. The IESO will update slide 80 to show the Ontario-Manitoba transfer limit that is included in the aggregate MISO dispatch area total.</p>
2	<p>The study has lumped Manitoba inside the MISO market. That is, Manitoba isn't treated as a separate market like the Hydro-Quebec system. Why was that study approach taken?</p> <p>Although Manitoba Hydro coordinates transmission service with the Midwest</p>	Manitoba Hydro	<p>The study doesn't treat Manitoba as a separate dispatch area; but rather as part of the MISO footprint given that electricity trades between Ontario and Manitoba, as well as transmission reservations are facilitated through the IESO and MISO markets. For example, Manitoba Hydro's Open Access Transmission Tariff (OATT) requires that the processing of short-term firm and non-firm point-to-point</p>

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	<p>ISO, the Manitoba Hydro open access transmission tariff is an independent tariff and MH Transmission Services can have a different export tariff than MISO.</p> <p>Recently, Manitoba Hydro's transmission tariff rate was removed from the MISO schedules (schedule 7 for firm point-to-point service and 8 for non-firm service). Manitoba Hydro's rates are no longer included in the MISO system average rate for drive-out transmission service. These changes were driven by a revision to the MH-MISO coordination agreement, effective Nov 1, 2008. Due to the current "carve-out" of Manitoba Hydro's transmission rates, it is not appropriate to lump the Manitoba system inside the MISO region. Manitoba's interaction with the Ontario market should be explicitly modeled, similar to the HQ system.</p>		<p>transmission service request be conducted by MISO on behalf of Manitoba Hydro.</p> <p>Unbundling Manitoba into a separate and distinct market would effectively result in the creation of a sub-market within the MISO dispatch foot print. For the purposes of the ETS study, this would be a significant and costly undertaking which we do not believe would add any additional benefit to the study or change the results in a material way. In addition, while Manitoba is permitted to administer a separate OATT from that of MISO, export and wheel-through transactions that originate in Manitoba and terminate in Ontario would not be put at a disadvantage with respect to applicable transmission charges given the reciprocity and non-discriminatory requirements of the two tariffs. Likewise, transactions destined for Manitoba from Ontario will attract the same transmission charges as with other zones within the MISO footprint. Furthermore, Manitoba has not demonstrated how modeling it as part of the MISO footprint will limit or adversely impact its ability to trade with Ontario market participants, or facilitate wheel-through transactions through Ontario under any of the Export and Wheel-through Tariff (EWT)options under consideration.</p> <p>While Manitoba's transmission tariff, including the EWT has been unbundled from the MISO transmission tariff schedules for point-to-point services, in our view this has little impact on the ETS Study, especially given the relatively small</p>

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			transfer capability (342 MW) and limitations on the Ontario and Manitoba transmission interface. The IESO has confirmed with the Ontario Power Authority that there is currently no plan for increasing the transfer capability with Manitoba. Accordingly, regardless of whether Manitoba is treated as a separate market or integrated as part of the broader MISO footprint or the applicable EWT, we do not believe that this will have a material impact on the basis for determining a reasonable EWT for Ontario. In comparison to the Quebec interface, the Ontario-Manitoba transfer capability is almost five times smaller.
3	General concerns on the CRA NEEM model, which is non-chronological and significantly aggregates the data into large averaged load blocks. Such a coarse model cannot adequately capture operational issues and hence the CRA NEEM model may underestimate the potential impact of Option 2 and Option 3 ETS rate designs. It is unclear what impact these Options may have on uplift payments to nuclear generators and fixed price contracts for wind. In order for the IESO to capture operations issues (such as SBG) as it has tried to do, it will need to utilize an hourly chronological market model.	Manitoba Hydro	<p>The study did not aim to establish the detail or quantify the potential impacts of the ETS options on potential operation and implementation issues (e.g., potential impact on uplift payments to nuclear and wind generators that may be subject to fixed price contracts or hourly SBG events). For example, with respect to surplus baseload generation (SBG), the aim was to observe the potential impact of each option on SBG events in respect of their magnitude, duration (e.g. # of hours/month) and timing. In our earlier stakeholder meeting we also identified and discussed certain potential limitations of the analysis that was to be undertaken; in particular, we explained that the study did not account for any price protection and obligations that may be afforded to contracted generators, as well as material changes in uplift costs and revenues.</p> <p>While more detailed inputs such as contracted nuclear and</p>

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			wind generator arrangements and requirements might have provided more granular insights into potential impacts on various operational and administrative issues such as SBG and uplifts, the NEEM model was deemed to be satisfactory by those present at the initial stakeholder meeting for carrying out the objectives, and the scope of work which was outlined in the ETS Stakeholder Plan. Accordingly, we are confident that the NEEM model is appropriate to undertake the quantitative analysis (impact on HOEP, export revenues, export and wheel-through volumes and market efficiency) of this study.
4	How was Hydro Quebec’s hydro fleet modelled	OPG	The total hydro electric output used in the model for Quebec is 192 TWh (Source: Hydro-Quebec annual report) and the month-to-month variation in Quebec hydropower output was inferred by the shape of Quebec demand plus net exports (Source of net exports: Canada National Energy Board; Source of demand forecast: NERC); While the analysis released in June 2009 had the Quebec hydropower resources operating flat within each month, the final July 2009 analysis has a run-of-river portion which is sized to approximately meet the minimum load in each month. The remainder of each month’s hydro output is optimized.
5	On page 9 of the report (page 11 of the overview presentation) we have stated that the cap for CO2 in 2015 is 11.5 million metric tonnes. There is general	Bruce Power	The Ontario coal units are retired in the CRA NEEM model by 2015, with the exception of tiny fractions of units needed to avoid modeling infeasibilities. Therefore, the modeled emissions of CO2 from Ontario’s coal-fired generation are

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	concern regarding this number considering there should be no emissions from coal fired plants in 2015		<p>essentially zero in 2015. The amount of CO2 emissions from the Ontario coal in 2015 have no practical significance whatsoever and do not affect the analysis conclusions.</p> <p>The Ontario Government’s Shareholder Declaration (dated May 15, 2008) and Resolution (dated May 16, 2008) requires OPG to stage the reduction measures to meet, on a forecast basis, the interim CO2 emission targets of 19.6 million tonnes in 2009, and 15.6 million tonnes in 2010.</p> <p>Proposed amendment to the current enabling regulation would require a reduction in CO2 emissions to 11.5 million tonnes beginning in 2011, from CO2 emissions of 34.5 million tonnes in 2003. The limit would continue on an annual basis until December 31, 2014.</p> <p>The table on page 9 will be revised to show 0 tonnes of CO2 in 2015.</p>
6	Concern from Stakeholders that the model uses a flat hydroelectric production profile for the analysis. Many think that this is an incorrect assumption as hydro units would be used for peak shaving in future years	OPG	Please refer to responses to issue no. 4 and 13
7	On page 13 the prices shown for natural gas for Ontario seems way too high and the curve is too steep. There is a	APPrO	The 2010 gas prices used in the analysis are based on NYMEX futures (Henry Hub) from the beginning of April 2009. These prices are the futures that were available at the

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	concern that this may have a significant impact since the model is cost based		<p>time the model was loaded in the model. The 2015 prices are based on the EIA AEO 2009 (April release) forecast.</p> <p>We do not believe it is material to update the gas price forecast for the following two reasons: 1) since all regions are subject to the same underlying gas price forecast, the effect of different gas prices on the differential impact of the tariff scenarios is likely immaterial, 2) while it is possible that the 2010 gas prices currently in the model could be too low relative to next year's actual gas prices, it is also possible that the assumed 2010 gas price will be very realistic for 2011 or 2012 and therefore remains quite meaningful to establishing an appropriate ETS for Ontario (regardless of the exact time path of actual future gas prices).</p>
8	On page 15 there is a need to provide a justification for the new build and retirement numbers for wind and nuclear. There is concern that the nuclear numbers are too high and the wind is too low.	Bruce Power	<p>The information was provided by the OPA and is consistent with its planned resource scenario.</p> <p>Committed nuclear in year 2010 includes the Bruce units 3 and 4 at 1500 MW installed capacity. In 2010, it is anticipated that Bruce units 1 and 2 (each 770 MW) are taken out of service for refurbishment. They are subsequently assumed to return to service in years 2012 and 2013 and factored into the committed nuclear annual installed capacity for those years. Similarly, in year 2013, Pickering B unit 4 at 516 MW is taken out of service for refurbishment and assumed to return in service in year 2015 and subsequently an additional Pickering B unit 6 and Bruce unit 5 coming out of service in 2015. This is summarized in the table below:</p>

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					2010	2015
			Additional Capacity		Bruce Units 3 and 4 -1500 MW	Bruce Units 1 and 2 – 1540 MW
						Pickering – 516 MW
				Total	1500 MW	2056 MW
			Planned Refurbishment		Bruce Units 1 and 2 – 1540 MW	Pickering B – 4 & 6 Units & Bruce Unit 5 – 1829 MW
				Total	1540 MW	1829 MW
			<p>The installed wind capacity represents nameplate capacity and is consistent with the OPA’s publicly announce planned resource scenario.</p>			
9	For the data shown on page 18 of the overview presentation it is unclear what bidding/offer strategies were assumed and if this was used for current and future years	Multiple	<p>For the 2007 calibration, NUGS were modeled as price takers, combined-cycle gas were exposed to market prices and oil/gas units (predominantly Lennox units) had their bids adjusted downward by roughly 15-25%. The coal units’ bids were also adjusted by lowering the effective heat rate. None of the bid adjustments affect the actual costs borne by the</p>			

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			<p>units. For the future years of 2010 and 2015, we used same adjustments with the exception of the following: Oil/gas units (other than NUGs/CHP) - The bid adjustments were removed for future years to reflect that contractual arrangements for Lennox are expected to change. NUGS/CHP units – The units are modeled as per OPA issued capacity factors.</p>
10	<p>On page 24 of the overview presentation, CRA had included additional information to the far right of the slide indicating the price differences used in the model. These should be explained</p>	Multiple	<p>Over the study period (i.e., 2007-2010 and 2007-2015) ETS “all-in costs” were estimated to increase by the annualized change in Consumer Price Index (CPI) as forecasted by the Toronto Dominion Economics as at March 2009. The annual CPI change forecast for 2015 is kept at the 2013 levels. Projected currency valuation (exchange rates used for converting US and Canadian dollars) is also based on Toronto Dominion’s Bank Exchange Rate and Inflation Forecasts. The exchange rate for 2015 is kept at 2010 levels. The forecasts can be found at: www.td.com/economics/qef/long_term_mar09.pdf.</p> <p>The Toronto Dominion’s Consumer Price Index Adjustments was also used to rebase, in 2003 US dollars, for 2010 and 2015 ETS all-in costs and the US Energy Information Administration’s (EIA) Annual Energy Outlook (AEO) 2009 chain-type price index was used to convert 2003 US dollars to 2008 US dollars. The latter can be found at: http://www.eia.doe.gov/oiaf/aeo</p> <p>The example below shows the sources for the consumer price</p>

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			<p>indices used for rebasing and exchange rates for converting to US and Canadian dollars and associated calculations:</p> <p>Option 3, Scenario 1: Ontario decreases rate by \$0.95 Cdn</p> <ul style="list-style-type: none"> • 2007 ON ETS: \$1.00 Cdn • Used the annualized March 2009 TD Forecast for CPI Index to reflect 2010 ON ETS: \$1.02 Cdn (escalation factors for 2008:+2.4%; 2009:-0.8%; 2010:+0.8%) • Used US Exchange Rate @ 1.136525 to convert to USD for 2010 ON ETS: \$0.90 USD (\$1.02*1.136525) • Rebased in 2003 USD for 2010 ON ETS using TD Forecast CPI Adjustment of 1.165652: \$0.77 USD (\$0.90*1.165652) • Used CPI adjustment of 1.145 to convert to 2008 USD and Exchange Rate @ 1.078 to convert back to Cdn: \$0.95 (\$0.77*1.145*1.078)
11	On page 27 of the report there was a request for further explanation of the numbers for HQ in 2010 and 2015 specifically concerning the peak/off peak hours.	Bruce Power	For the draft preliminary analysis, the hydroelectric shapes in the region were all flat. The level varied by month and the resources were different in the different regions (e.g., Quebec and Ontario hydro resources are modeled as separate units in their respective regions). One consequence of this simplified assumption (flat shapes) was that Quebec had excess hydroelectric power off-peak but was short on-peak. This resulted in Ontario exporting to Quebec significantly more during the on-peak hours than in the off-peak hours.

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			<p>This is not realistic given Quebec’s storage capabilities.</p> <p>For the revised final analysis, all hydroelectric resources in the region are divided into a run-of-river resource and a portion that can be optimized and thus used more intensively on-peak. Consequently, in the revised analysis, Ontario tends to export to Quebec predominantly during the off-peak hours. This is consistent with the comments received during the June 2009 stakeholder meeting.</p>
12	On page 39 of the report (page 30 of the overview presentation) need to clarify that non-NY neighbours includes HQ, MISO and PJM	Hydro Quebec	Report has been adjusted to clarify that non-NY neighbours include HQ, MISO and PJM.
13	<p>General concerns with the SBG analysis including:</p> <ul style="list-style-type: none"> - Size and shape of the demand curve - Hydro electric profile - Lack of granularity of the model - Results are counterintuitive - Wind inputs - Imports from Quebec 	Multiple	<p>The IESO is carrying out a review of the SBG analysis taking into account the various concerns expressed by stakeholders, including confirming the seasonal demand forecast used in the earlier runs, use of Ontario on-peak and off-peak hydro production forecasts, and refining Quebec’s hydro production assumptions. For example, the refined approach for modeling Ontario hydro production is as follows: Ontario’s Hydroelectric output has been separated into a base-load (Run-of-River) component and a “storable” component. The approach used in the model is to allocate total hydro electric generation between baseload and storable components. The quantity allocated to the baseload component varies by month and by seasons. The historical off peak hydro electric output has been used as a proxy for</p>

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			<p>baseload. In the model, the storable component is allowed to manoeuvre in response to economic conditions such that peaking hydro resource production correlates with the highest price periods. The net result of this approach is an improved hydroelectric production profile which we believe should address the concerns of stakeholders.</p> <table border="1" style="margin-left: auto; margin-right: auto;"> <thead> <tr> <th colspan="3" style="text-align: center;">Ontario Hydro Resources</th> </tr> <tr> <th></th> <th style="text-align: center;">2010 (MW)</th> <th style="text-align: center;">2015 (MW)</th> </tr> </thead> <tbody> <tr> <td>Run of River</td> <td style="text-align: center;">3,100-4,700</td> <td style="text-align: center;">3,300-4,900</td> </tr> <tr> <td>Storable</td> <td style="text-align: center;">3,200-4800</td> <td style="text-align: center;">3,800 - 5,400</td> </tr> <tr> <td>Total Ontario Hydroelectric Output (incl. Run of River and Storable)</td> <td style="text-align: center;">7,900</td> <td style="text-align: center;">8,700</td> </tr> </tbody> </table>	Ontario Hydro Resources				2010 (MW)	2015 (MW)	Run of River	3,100-4,700	3,300-4,900	Storable	3,200-4800	3,800 - 5,400	Total Ontario Hydroelectric Output (incl. Run of River and Storable)	7,900	8,700
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