NORTON ROSE

Barristers & Solicitors / Patent & Trade-mark Agents

Norton Rose Canada LLP
Royal Bank Plaza, South Tower, Suite 3800
200 Bay Street, P.O. Box 84
Toronto, Ontario M5J 2Z4 CANADA

F: +1 416.216.3930
nortonrose.com

On January 1, 2012, Macleod Dixon joined
Norton Rose OR to create Norton Rose Canada.

October 1, 2012

Filed on RESS and Sent by Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Your reference
EB-2012-0031

Our reference
01015413-0030

Direct line
+1 (416) 216-1927

Email
john.beauchamp@nortonrose.com

Dear Ms. Walli:

Hydro One Networks Inc. – Transmission Rates (EB-2012-0031)

Please find attached the intervenor evidence for APPrO in connection with the above-noted proceeding, as follows:

A. the evidence of Cliff Hamal (Managing Director, Navigant Economics); and

B. the evidence of Marc-André Laurin, an employee (Senior Trader for Ontario-Quebec), Brookfield Energy Marketing LP and member of APPrO.

Please do not hesitate to contact me should you have any questions or concerns.

Yours very truly,

Original signed by

John Beauchamp

JB/mnm

cc: David Butters, APPrO
Pasquale Catalano, Hydro One
Donald Rogers, Counsel for Hydro One
Anita Varjacic, Counsel for Hydro One
All Interested parties

DOCSTOR: 2527594\1

A

Evaluation of the Export Tariff

By Cliff W. Hamal

On Behalf of the
Association of Power Producers of Ontario
(APPrO)

For Filing in the
Hydro One Networks, Inc.
Rate Proceeding Before the
Ontario Energy Board
EB-2012-0031

October 1, 2012

I. Introduction

I have been asked by the Association of Power Producers of Ontario (APPrO) to offer an opinion regarding the level of the tariff on electricity exported from Ontario. This tariff, currently set at $2/MWh, is under review as part of the Hydro One Networks Inc. (HONI) rate application before the Ontario Energy Board (Board). HONI has not taken a position regarding the appropriate tariff level. Neither has the Independent Electricity System Operator (IESO). A report on the subject, the "Export Transmission Service (ETS) Tariff Study," dated May 16, 2012, was prepared for the IESO by Charles River Associates (CRA) at the direction of the Board. A second report by CRA, "Export Transmission Service Tariff Study, Review of Rates in Neighbouring Markets," (CRA Tariff Study) was also prepared for the IESO on the same date. While the CRA Report and CRA Tariff Study provide background information on this issue, CRA does not make a recommendation or draw a conclusion regarding the tariff rate.

Economic theory and practice make clear that export tariffs reduce economic efficiency. The added cost impedes trade and results in less efficient production across the entire region. A tariff can create winners and losers if it shifts costs among classes of market participants, but Ontario's unique market structure results in such costs ultimately being borne by consumers. This simplifies implications of the tariff on market participants in Ontario. Both Ontario as a whole and consumers in particular will be better off with a reduction in the export tariff. This conclusion is supported by the analysis in the CRA Report, particularly when proper consideration is given to the distribution of the Intertie Congestion Revenue (ICR) and the benefits accruing to Ontario Power Generation (OPG).

It is my opinion that the export tariff should be reduced, and consideration should be given to its elimination. Such actions will increase efficiency of the overall market, lower customer costs and increase export responsiveness during the hours in coming years when surplus baseload generation (SBG) problems will reach unprecedented levels. The SBG issue is particularly important. While a variety of actions are being taken to deal with increasing levels of SBG, an increase in the export tariff would undercut a pro-competitive, efficient, market-based solution to this problem precisely when it is most needed.

In preparing my evidence, I draw on my experience as a consultant specializing in economic issues in the electricity industry including past projects involving market design, power contracting, electricity trading, power generation asset valuation, competitive strategy, antitrust analysis and damages assessment. I have provided evidence before the Board on market design issues in the past and have provided testimony in cases before Canadian Superior Court, the Alberta Utilities Commission, the US Federal Energy Regulatory Commission (FERC), US federal and state courts, other regulators and in arbitration. My curriculum vitae is provided as attachment 1.

II. Export Tariff Reductions Will Benefit Ontario And Ontario Consumers

A reduction in the export tariff will provide benefits to Ontario. While no party has thus far taken a position on what export tariff level is appropriate, the CRA Report was prepared at the request of the Board and will undoubtedly play a significant role in the Board's evaluation. I conclude that the CRA Report is both helpful and flawed. It is helpful in the sense that it provides a comprehensive analysis, accounting for changes in market prices, trade and benefits to participant classes. The flaws, unfortunately, are significant; the approach taken to determining the effect of tariff changes on the market render its specific calculations incredible. Overall, the CRA Report, properly interpreted, can be helpful in assessing the directional effects of a change in export tariff, and is consistent with a non-quantitative evaluation of the issue.

This section of my report provides the overall basis for my conclusions in the four subsections that follow. The first subsection deals with what can be concluded based on general theory and consideration of Ontario's unique circumstances, without consideration of the CRA Report's analysis. I then turn to the CRA Report and consider what conclusions can be drawn from its analysis, without critiquing its underlying mechanics and assumptions. In the third subsection I address the underlying shortcomings of the CRA Report and their implications for the conclusions. Within these three subsections I only consider uniform changes to the tariff. In the fourth subsection I draw on this analysis to evaluate tiered rate structures, where the tariff is different during on- and off-peak periods.

a. Benefits From A Tariff Reduction Result From Ontario's Unique Circumstances

Tariffs create barriers to trade and reduce the economic efficiency of the marketplace. There may be other issues to consider, but the efficiency concerns are often of primary importance because they create the benefits that can be enjoyed by all participants. This is true in considering the export tariff, and as a result it is clear that reducing the tariff will create efficiency benefits.

The issue of efficiency benefits is of particular importance as a result of the challenges facing Ontario in dealing with SBG. In the near term, Ontario will face unprecedented challenges in dealing with SBG. A lower tariff will make it easier to export when supply is excessive, reducing the surplus supply problem through standard market mechanisms. This problem is being addressed by the IESO through a variety of actions such as nuclear shutdowns, nuclear generation curtailment, wind curtailment and spill of hydroelectric generation. These will help address the problem, but a market solution is clearly preferred. In particular, reliance on the market to increase exports, where the electricity is purchased, used and does not involve payments for curtailing generation, will benefit all. Exports have long been recognized as a partial solution to the SBG problem. Lowering the tariff will make them more accessible and effective.

Another consideration is the distribution of the efficiency benefits and other effects on various classes of market participants. This relates to questions of fairness, which can be broad in scope and involve judgments beyond those typically associated with economics. Ontario's unique market structure plays an important role in evaluating distribution effects. The vast majority of generation in Ontario is either paid a regulated cost-of-service rate or covered under power contracts, such that the substantial benefits associated with efficiency improvements will accrue to consumers. There is only a small portion of Ontario generation that is paid the market rate; as virtually all of this generation is owned by OPG, its net income will ultimately accrue to the province and customers. As a result, while other jurisdictions might have contentious debate as to the allocation of costs and benefit among market participants, in Ontario, benefits associated with a tariff reduction will flow to consumers.

Beyond issues of efficiency and distribution fairness, consideration could be given to other issues such as administrative efficiency, consistency with other jurisdictions, simplicity, regulatory history, legal precedence and cost causality. These other issues either act to support the reduction of the tariff or are indifferent to it. While other jurisdictions impose an export fee, the efficiency benefits of reducing the fee have been recognized by the FERC and others, and the tariff has been reduced to zero across some actively traded interfaces in the U.S., demonstrating the desire to increase efficiency through tariff reductions. From a cost causality standpoint, exports do not result in any incremental costs to HONI and receive an inferior level of service as they can be curtailed. To charge exports a tariff under the theory that exports should share in paying for the system is counterproductive when one recognizes that the efficiency losses from the tariff are then borne by consumers.

b. CRA Report Supports An Export Tariff Reduction

The CRA Report supports the view that Ontario as a whole, and consumers in particular, will be better off with a tariff reduction. In drawing this conclusion, I focus primarily on the near term which is of immediate concern and is the period when SBG is expected to be most critical. It is also the period of greatest certainty, as the potential for unexpected changes in the supply portfolio, environmental regulations, fuel costs and market features grows over time.

In interpreting the CRA Report, it is important to recognize two key factors, both dealing with interpreting the results of the analysis. These involve the beneficiaries of the ICR and the producer surplus. In both cases it is reasonable to conclude that all, or at least a very large portion, of these figures will accrue to consumers.

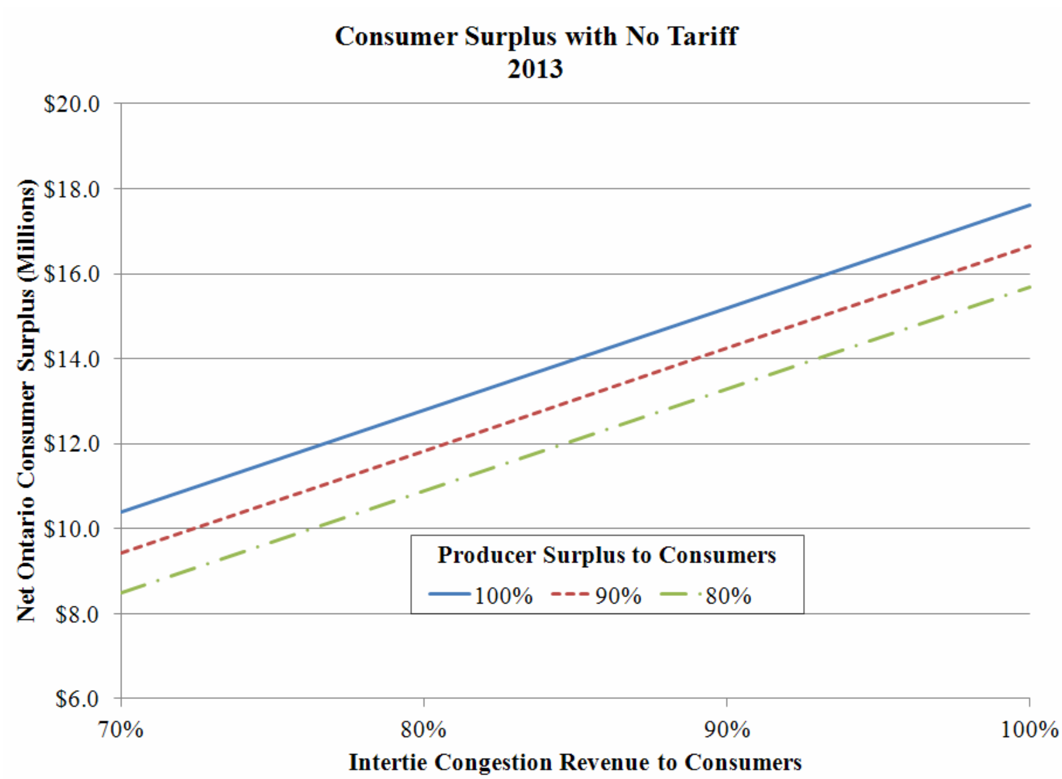
With respect to the ICR, this is the revenue captured by the IESO when exports are constrained by intertie transmission limits. In that circumstance, the IESO market establishes a price at the border that is higher than HOEP—which is the price generators get paid. The price difference stays with the IESO. While it is not transferred immediately to consumers, it is reasonable to assume that consumers ultimately receive this benefit in time. Complicating the analysis of ICR is the IESO's sale of transmission rights (TRs). TR holders receive payments tied to the amount of congestion on the export interface, but they pay for this hedging vehicle. In an efficient market, the amount paid will equal the TR payouts. While the IESO will use both the TR sale prices and ICR to cover TR payouts in the short run, over the long run it is expected that the ICR will be passed on to consumers. The process by which this is accomplished is not direct, but ultimately rests on the assumption that Ontario markets are efficient and policies do not require paying market participants super-normal profits. The ICR will go to consumers, as they would in other markets that are similarly structured with transmission rights.

With respect to the change in producer surplus, the vast majority of that money is paid to OPG for its unregulated hydroelectric generation. Many generators in Ontario are exposed to market prices from the standpoint of having incentives to dispatch optimally, but only OPG's non-prescribed generation will profit (i.e., obtain an increase in the producer surplus) if market prices increase. As OPG is owned by the province, it "affects Ontario's fiscal balance to the benefit of Ontario taxpayers /consumers."[1] Therefore, this additional income ultimately accrues to consumers. Subject to further discovery underway, I expect that the CRA Report's Producer Surplus includes only OPG's portion of the incremental market rate revenue, making it fully attributable to the province.

The chart below presents the results for 2013 assuming that a substantial portion of these two categories of economic surplus are accredited to consumers. The range is provided with respect to both the allocation of the ICR and producer surplus in order to demonstrate the robust nature of the overall conclusion that consumers are better off with a tariff reduction.

[1] CRA Report, p. 23.

Figure 1



Across the range of sharing of the ICR and producer surplus, consumers are better off if the tariff is eliminated. In my further analysis of the consumer surplus, I assume that 100% of the ICR, and 95% of the producer surplus, accrues to consumers. The slight difference between these two assumptions reflect the fact that while I see no logical basis (consistent with the CRA Report) for assuming the ICR would go to others, I recognize that it is possible that the analysis might include analysis of contract terms that allow some of the producer surplus to stay with producers other than OPG. Further discovery on this issue is still in progress.

Figure 2

Summary of Surplus Changes
($2011/MWh)

	2013		2015		2017	
Surplus Component	**No Tariff**	**EANC**	**No Tariff**	**EANC**	**No Tariff**	**EANC**
CRA Analysis						
Consumer Surplus	-$16.1	$24.1	-$32.6	$60.1	-$18.9	$23.5
Intertie Congestion Revenue	$24.0	-$17.7	$10.1	-$7.9	$3.9	-$5.8
Producer Surplus	$9.6	-$29.2	$22.2	-$47.9	$10.5	-$18.6
Total						
Ontario Surplus	$17.6	-$22.8	-$0.3	$4.2	-$4.5	-$1.0
Consumer Surplus	$17.1	-$21.3	-$1.4	$6.6	-$5.0	-$0.1

The table above provides the results of the CRA Report with the described adjustments. Three scenarios are effectively presented, as the results are presented relative to a change from the status quo of a $2.00/MWh tariff. Reducing the tariff to zero for 2013 is clearly better for Ontario in general and consumers in particular. The other alternative, increasing the tariff to $5.80/MWh in what the CRA Report calls the Equivalent Average Network Charge (EANC) scenario, substantially increases costs to Ontario and consumers. Results for 2015 and 2017 are also presented. I expect 2014 results would be similar to 2013, thus supporting the cut of the export tariff to zero for the HONI rate period, as the CRA Report details many changes in the marketplace that are assumed to start in 2015. The analysis assumes Ontario participates in the Western Climate Initiative (WCI) beginning in 2015 and there are significant environmental regulations that are assumed to take effect in the U.S. in that year. The analysis for 2015 and beyond is more uncertain as a result of these assumptions, in addition to the general increase in uncertainty that is associated with looking further into the future.

Sensitivity analyses provided in the CRA Report demonstrate the potential effect of these assumptions. The figure below provides the results if one assumes Ontario does not participate in the WCI during the study years.[2] The results for 2015 and 2017 change dramatically, and altering this assumption alone results in clear benefits to Ontario from keeping the tariff at zero for those later years.

[2] CRA Report, Appendix B, Tables 12 and 13, and the four pages that follow.

Figure 3

Summary of Surplus Changes Assuming No WCI Participation (\$2011/MWh)

	2013		2015		2017	
Surplus Component	**No Tariff**	**EANC**	**No Tariff**	**EANC**	**No Tariff**	**EANC**
Ontario Surplus	\$17.6	-\$22.8	\$4.0	-\$0.6	\$6.1	-\$10.5
Consumer Surplus	\$17.1	-\$21.3	\$3.2	\$1.6	\$5.7	-\$9.8

The results presented in the CRA Report clearly indicate that the elimination of the export tariff for the duration of the next HONI rate period will provide benefits to Ontario overall and its consumers. While there are uncertainties in later years, the zero-tariff option either produces the optimal level of benefits for Ontario, or provides financial results that are close to the optimal. Thus, the CRA Report's results support eliminating the export tariff.

c. Benefits From Tariff Reduction Are Likely Greater Than The Estimates Provided In The CRA Report

While the prior subsection accepts the analysis presented in the CRA Report, there are reasons to conclude that the underlying analysis has significant flaws.

The CRA Report relies on analysis conducted using CRA's North American Energy and Environment Model (NEEM). This is a linear programming model that determines such factors as electricity prices, generation dispatch and inter-regional electricity transfers across broad regions and over long periods of time. Such modeling approaches are deterministic, essentially assuming perfect dispatch and efficiency, and optimize the operation of the overall system under the assumption that all information is known about the market in order to meet load at the lowest cost. Computer simulations of this kind are commonly used for general price forecasts, analysis of generation supply changes, analysis of fuel switching options and assessment of environmental policies.

Here, however, the challenge is to evaluate minor changes to an export tariff rate. The critical issue concerns how a changed tariff will influence actions by traders between regions. Traders act on the basis of finding and trading on pricing imperfections; yet those imperfections are assumed not to exist by the modeling in the first place. The model essentially assumes perfectly efficient, risk-free energy exchange between regions. It is not reasonable to expect such modeling to capture the subtle differences in trading caused by a change in the tariff.

Digging into the model, one discovers that CRA found it necessary to dramatically reduce intertie capacities to get results that approximated past trading levels in the benchmarking process. Thus, in studying trading behavior, to even get the model to come close to historical results it was necessary to substantially limit the amount of trade that the model would otherwise have predicted.[3] This is not a sound basis for modeling subtle changes in the tariff. There are a number of other modeling issues that further support the conclusion that the model does not capture the changes being studied.

Of particular interest, given the challenges facing the Ontario market in coming years, is the treatment of SBG. The degree of challenge posed by this issue in Ontario is unusual and there are reasons to conclude that the NEEM analysis does not adequately capture this phenomenon. Among other things, the actions used by the IESO to manage this issue are likely to be out-of market actions and payments. These actions would come after market-based exports, so changes in exports during SBG periods would be of particular interest. The CRA Report concludes that the tariff has essentially no influence on SBG actions. This is a result of the perfect-information deterministic approach to trade within the NEEM analysis, among other problems, and is not credible. If one assumes that exports are maximized before SBG actions need to be taken, then a tariff change will not be significant. If one recognizes that in the real world trading is imperfect, SBG actions are uncertain to the traders and price effects from such actions can be unpredictable, then one reaches a very different conclusion about the effect of the tariff on SBG. And in particular, the benefits of improving exports will be particularly valuable to the market when there are growing out-of-market and difficult-to-quantify SBG management costs.

I conclude that the benefits to Ontario from a tariff reduction presented in the prior subsection are understated, because those figures do not properly recognize the benefits that result from fewer out-of-market actions to address SBG. On this basis alone, benefits appear understated. With respect to other periods, there is the potential for competing effects because of the binary manner in which the interties are generally used in the model (full/not used) as opposed to the actual pattern of use (with interties partially loaded much more often). The model clearly underestimates the subtle effects small price differences have on trade, and therefore I conclude underestimates the benefits likely to be obtained from a tariff reduction.

d. Tiered Tariff Options Are Unlikely To Provide Benefits

In addition to uniform changes to the tariff, the CRA Report evaluated two tiered options. The tiered options involve a higher tariff during the on-peak periods, relative to off-peak. Specifically, Tier A has an on-peak tariff of \$5.80/MWh and an off-peak tariff of \$0.00/MWh, while Tier B uses \$3.50/MWh and \$1.00/MWh, respectively.

Direct comparison of results is challenging because there are so few data points. My analysis demonstrates that cutting the tariff in the off-peak period provides the primary source of the overall benefits. That does not mean, however, that the on-peak tariff can be increased with impunity, relative to the off-peak level. The effective way to consider the tiered options is to compare them to other options with the same off-peak rate, such that those benefits are held constant, and then consider the implications of increasing the on-peak portion of the tariff.

[3] CRA Report pp. 6-7.

When this is done, it is clear that increasing the on-peak tariff in the Tier A option dramatically reduces benefits to Ontario on the order of $13.5 million (in 2013 according to the CRA Report's analysis). The Tier B option is less clear, with the potential for a $2.9 million gain. I conclude that this benefit is illusory, however, given many of the problems with the analysis. First, with such a dramatic swing from modest benefit to substantial loss, the results must be approached with caution in any event because they appear highly sensitive to the specific on-peak premium and only two premiums have been studied. In addition, the NEEMs model segments the year based on load intervals, rather than actual time periods. Thus, the study of a time-based tiered structure actually involves adding the tariff premium in high-load hours with more precision than would be achievable in practice. Other problems with the model that have already been discussed would further call into question whether it is reasonable to expect a tiered structure to be able to achieve this modest benefit.

In any event, if a conclusion is based solely on taking the CRA Report results at face value and a tiered structure is adopted, the options need not be limited to the two options presented. The evidence is strong that eliminating the tariff completely in the off-period provides the greatest benefits. If a $2.50/MWh on-peak premium is chosen (consistent with Tier B analysis), it should be added to a zero off-peak rate. The resulting tiered structure would then be zero in the off-peak period, $2.50/MWh on-peak.

III. Fundamental Analysis Of The Export Tariff

As a starting point, it should be recognized that the export tariff is not associated with the recovery of any variable costs. Losses are covered through other means and uplift for administrative costs is collected separately (modeled at $3.33/MWh in the CRA Report). Thus, the issue is whether exports should play a role in the recovery of the fixed costs associated with the transmission system. While exports use the transmission system, the integrated electric transmission system was built to serve Ontario consumers. Electric systems such as Ontario's have been interconnecting with neighboring systems over the past century in order to increase reliability and efficiency. While some might argue that the export tariff should be thought of as a charge to traders using the system, those traders are just the means by which today's competitive marketplace achieves the efficiency gains for Ontario consumers which motivated the construction of the interties. In addition, exports receive an inferior level of transmission service from the system, because exports may be cut when needed to meet needs in Ontario. Among other issues, this prevents exporters from providing capacity service to neighboring systems.[4] The trading activity which faces the direct consequence of the export tariff does not, by itself, impose costs on HONI.

Reducing tariffs, and reducing impediments to trade in general, increases market efficiencies. This point is well-established in the field of economics. "Tariffs create economic inefficiency. More precisely, when tariffs are imposed, the economic loss to consumers exceeds the revenue gained by the government plus the extra profits earned by producers."[5] While most tariff literature focuses on import tariffs, the overall inefficiency problems are the same for exports, as the tariff prevents the overall market from reaching equilibrium where goods are produced at the lowest cost to satisfy demand.

The benefits of reduced tariffs are not only recognized by economists, but by FERC in its policies. FERC has acted to promote trade and increase overall market efficiencies for years. This includes generally promoting open access provisions, shortening the time intervals of market clearing at the border to allow for more efficient trade between markets, and other coordination to reduce so-called "seams" issues. The desire to increase efficiency and reduce seams issues has even been a motivator in the creation and expansion of RTOs. FERC has advocated the elimination of tariffs between regions to improve efficiencies and expand markets since 1999.[6] Consistent with that policy, tariffs have been eliminated between NY ISO and ISO New England, and between MISO and PJM.[7] In its approval of PJM-MISO's tariff elimination, just weeks after similar approval of the NY ISO-ISO New England's tariff, FERC noted that it

[4] Interrogatories Schedule 6.01 HQ 1 and Schedule 6.02 HQ 2.

[5] See Paul A. Samuelson and William D. Nordhaus, "The Economic Costs of Tariffs," Economics, 1995, McGraw-Hill Inc., p. 689, and the general discussion on pp. 686-696; see also, Richard E. Caves, Jeffrey A. Frankel, and Ronald W. Jones, "Protection and the National Welfare," World Trade and Payments: An Introduction, 7th Ed., 1996, HarperCollins College Publishers, New York, pp. 219-234.

[6] FERC Order 2000, December 20, 1999, p. 517.

[7] CRA Tariff Study, p. 4.

"benefits customers by eliminating seams that impede efficient transmission system usage across two highly interconnected regional grids."[8]

Turning now to the distribution of those benefits, Ontario's unique market structure must be considered. In evaluating the effects of a tariff change, two factors are particularly important, the structure of compensation provided to generators in the province and the allocation of Intertie Congestion Rents. A change in the tariff will have an effect on both the producer surplus and the Intertie Congestion Rents. As discussed below, both of these will largely accrue to consumers.

With respect to generation in Ontario, it largely falls into three general categories. Some generation is covered under contracts such that it essentially receives a fixed monthly payment plus its variable operating costs. These contracts take various forms, such as clean energy contracts with the Ontario Power Authority, old non-utility generation (NUG) which originally had contracts with Ontario Hydro, and OPG's contingency support agreements associated with its largest coal-fired generators. While many of these generators have incentives to follow market prices in making operating decisions, their profits are generally protected from changes in market prices and the producer surplus will be unaffected by tariff changes. The second category of generation is covered under rate regulation. Again, while in practice there can be incentives for efficient performance and delays in ratemaking response to changes in market conditions, overall compensation for that generation is not affected by changes in market prices. The third category of generation is unregulated and not contracted. Generation in this third category is exposed to market prices and will see a change in profits—producer surplus—if market prices change. In Ontario, the vast majority of generation that fits this description is the non-prescribed hydroelectric generation owned by OPG. But the profits to OPG from any change in market prices accrue to the province and ultimately consumers, as a result of OPG's ownership structure.[9] As a result, while another market structure might have significant benefits flowing to producers, in Ontario these benefits accrue to consumers.

Another category of benefits involves the change in Intertie Congestion Rents. These rents result from traders exporting IESO energy that was purchased at the border price, which is higher, when there is congestion at the border, than the HOEP price paid to the generators who produced it. This extra revenue is collected by the IESO, but ultimately should be expected to go to consumers. The process by which this occurs is discussed in more detail in the next section.

In evaluating the tariff options, consideration must also be given to the current state of the Ontario market and the specific challenges it faces in the near term. High on that list are the difficulties raised by substantial and growing levels of SBG. As reported in the most recent 18-Month Outlook by the IESO:

> Since the start of 2012, out-of-market control actions were required approximately seven per cent of the time to mitigate SBG. Going forward,

[8] FERC Order in Docket EL04-135-000, dated November 18, 2004, p. 2. See also FERC Order in Docket ER04-943-000, dated November 3, 2004.
[9] CRA Report, p. 23.

> SBG events are expected to return with greater frequency and magnitude in the spring, summer, and fall of 2013. A lack of direct control over a number of factors that contribute to SBG, such as temperature, other weather parameters, consumption, and lack of generation and load response to market prices, poses challenges in handling SBG situations. These events will need to be managed in the short term until baseload generation begins to decline when nuclear refurbishment programs get underway later in the decade. With the forecast increase in SBG, we foresee an increase in out-of-market control actions, such as minimum hydro dispatch and nuclear maneuvers, to be required in order to manage the surplus, extending beyond the typical market action of exports. With wind and solar becoming more prominent resources on the electricity system, the need for maximum flexibility from all resources becomes integral for the reliable and efficient operation of the grid.[10]

The problem is not reliability per se, but rather its cost, as it is reasonable to conclude that reliability will be maintained by the IESO regardless of the export tariff. This quote makes clear that SBG can be managed, but that the challenge comes from using non-market and expensive options to manage supply and demand. This interference with normal market operations is expensive and reduces efficiency by disrupting price signals. Nuclear shutdowns, for example, are estimated by the IESO to cost $2-3 million apiece.[11] Not only is that cost not reflected in the market clearing price (which therefore fails to send the right market signal), but the reduction of production will increase prices, potentially signaling that exports should be reduced, precisely when they are most needed. Nuclear shutdowns involve output reductions for days after the SBG problem, further disrupting the market and making unavailable the low-cost nuclear energy that could have been providing valuable service. Similarly, nuclear maneuvers will result in reductions in output that extend beyond the SBG period and disrupt the market. These effects are not captured in the CRA Report's analysis.

Wind generation can also be curtailed to address SBG, but that is also expected to involve out-of-market payments for not generating. The same is true for OPG regulated hydroelectric generation. In addition, with hydroelectric spill the province loses the Gross Revenue Charge (GRC) that would have been paid had the facility actually operated. Additionally, the physical aspects of spill can be significant, as it may involve public safety issues with the flood of water or other water management concerns, and can affect multi-hour generation and spill operations even when it is no longer needed. The curtailment of wind and hydroelectric resources is a waste of resources that are particularly valuable because of their clean, renewable characteristics.

Impeding exports at precisely the point of market evolution where exports are most needed to solve over-supply problems is not helpful. It is not that these other actions will not work, but

---

[10] IESO, *18-Month Outlook from September 2012 to February 2014*, An Assessment of the Reliability and Operability of the Ontario Electricity System, p. 16, http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2012sep.pdf.

[11] "Export Settlement Treatment – Exports and Negative Prices," Inter-Jurisdictional Trading SC, May 13, 2012, p. 8. http://www.ieso.ca/imowebpub/201206/IJT-20120531_Export_Settlement_Treatment.pdf.

instead that they are clearly inferior to exports. Exports that result from traders responding to price signals are consistent with normal market operations and support the overall goal of market efficiency. The elimination of the tariff allows exports to be maximized before these non-market interventions are needed by the IESO to deal with SBG. And these challenges will reach their zenith in the next few years.

Lastly, as of October 1, the IESO begins blocking negative export settlement prices through a rule change. This essentially eliminates the circumstance where neighboring regions are paid significant amounts to take delivery of Ontario electricity. The details associated with that rule change are not important to this analysis, other than to note that such a rule change will work like a variable export tariff, to assure export prices are not negative.[12] Thus, there has already been an action to increase the effective export tariff, and discourage exports, before consideration of this tariff change.

[12] This marker rule change was not considered in the CRA Report, but it should be noted that negative prices were never produced by that study in the first place. Since negative prices have occurred with increasing frequency, and such prices were significant enough to produce a rule change to the market, this is just an indication of the problems with the CRA Reports analysis.

IV. CRA Report Supports The Tariff Reduction Conclusion

The CRA Report provides a comprehensive analysis of the tariff issue, with results presented for years 2013, 2015 and 2017. As I have already discussed, in later years there are increased uncertainties and therefore, my focus is on 2013.

a. ICR Should Accrue To Consumers

The CRA Report calculates ICR and attributes it to Ontario's benefit in its totality.[13] The report does not, however, allocate these revenues to either producers or consumers. This is an incomplete analysis, as benefits cannot accrue to Ontario without going to some entity within Ontario. The CRA Report makes clear that the ICR is initially retained by the IESO, as it is the difference between what the IESO is paid for exports and what it has to pay generators for that electricity.[14] I conclude that this shortcoming is appropriately addressed by allocating this revenue to consumers. This conclusion can be supported from several different perspectives, as I do below. I note a seeming reluctance to make this allocation in the report and in responses to interrogatories. While some might take issue with allocating this revenue to consumers, there is no evidence of which I am aware that would point to justifying that this benefit should flow to producers or some other party. Thus, no other alternative has been presented. To leave $24.0 million floating along unallocated and assume that no one will notice is implausible. To complete my analysis I address what I believe may be the most significant criticisms of the "benefits flow to consumers" conclusion.

First, it should be noted that the surplus must be allocated to either producers or consumers. There is no third category in the study. And there is no basis for concluding that it accrues to producers. Producers sell into the market at market prices. They do not have any call on the incremental revenues obtained by the IESO in exporting power during times of congestion. By default, one can conclude that the revenues must go to consumers.

The path by which consumers will receive this benefit is neither immediate nor direct. The revenues first stay with the IESO[15] and are retained as part of its management of transmission

---

[13] CRA Report, p. 25.
[14] CRA Report, p. 24.
[15] In response to Board Staff interrogatory Schedule 1.04 Staff 87, a long discussion is provided that focuses on the difference between the ICR, which is presented in the CRA Report, and the Intertie Congestion Rent, which is determined by the IESO under the Market Rules. Despite considerable discussion of this issue in the interrogatory response, the essence can be boiled down to the fact that the Rent is the amount determined in the real market and the ICR is merely the CRA Report's estimate. Everything in the CRA Report is merely an estimate, however; that is the nature of such modeling exercises. If one wants to ignore the ICR because it is merely an output of the modeling, one might as well dismiss all of the analyses and the insights the modeling might provide. Similarly, in Schedule 1.08 Staff 91the answer to part b calls for additional analysis to determine exactly how ICR might be allocated between the importing and exporting jurisdictions. Again, we can either accept that the analysis has some merit overall, or dismiss it. The CRA Report made clear on page 25 that these revenues accrue to Ontario. Thus, in this case, despite stating "There is no practical way of forecasting the precise allocating this Intertie Congestion Revenue between exporting and importing markets", and bemoaning the lack of public data necessary to do a full

payment obligations.[16] As IESO is not a for-profit entity, that extra revenue must be paid to some entity, under a process overseen by the Board.[17]

The IESO was asked whether the ICR should be classified as Consumer Surplus, and the response given can only be summarized as obfuscation and avoidance. While stating that a portion of the ICR should be classified as Consumer Surplus, it concluded that none should be thus classified because CRA did not provide an estimate.[18] Further, the IESO has taken the position in an interrogatory that, "It would only be appropriate to re-classify all of the ICR as a Consumer Surplus component if all of the ICR was forecasted to be re-distributed to consumers in the model years considered in the CRA study."[19] No justification is provided for this assertion. It is as if to say that tariff implications that are long-lasting or involve time lags should be ignored. If one did not consider multi-year implications, one could not justify a capital expenditure where the benefits were not realized in the year it was made. I know of no basis upon which one should ignore such benefits simply because there is a delay.

The complicating factor in the analysis of the ICR is the actual practice of the IESO of retaining that money (as Intertie Congestion Rents in actual practice) to address cover potential TR payment shortfalls. There seems to be an unstated theory that the ICR might, in some way, accrue to traders across the interfaces, or to holders of TRs. Such theories do not withstand scrutiny. As a starting point, it is worth noting that traders are not even modeled or represented in the CRA Report. Traders are important in markets, with the expectation that in a well-functioning market they will trade on price differences—thereby reducing those differences—and make the markets more efficient overall. The analysis underlying the CRA Report essentially assumes this trading takes place to create the underlying efficient markets in the study, with no substantial profits going to traders. Thus, in the CRA Report, one cannot conclude that the ICR accrue to traders because traders are not assumed to be making any substantial profits. To assume otherwise is to attack the fundamental assumption of the dispatch in the model that underlies the entire analysis.

But the actual process by which transmission rights are paid, and the history of such payments in Ontario, is more complicated. This issue was addressed comprehensively in the August 2010 Market Surveillance Panel market monitoring report[20] (MSP Report). As discussed in the MSP Report, the IESO uses an auction to sell TRs at the interfaces with neighboring regions, which entitle the TR holder to payments based on the actual price differences associated with congestion. The revenue available to the IESO to make these payments comes from the sale price of the TRs (i.e., the auction revenue) and the actual congestion revenue in each hour. I

---

analysis, there is no support for allocating these revenues in any other way. It should also be noted that the same answer concludes that allocating the ICR to Ontario during exports "may slightly overstate the net benefit…" This is hardly indicative of a major problem.

[16] Interrogatory Schedule 1.05 Staff 88.

[17] Ibid.

[18] Interrogatory Schedule 6.11 HQ 11, a.

[19] Interrogatory Schedule 6.11 HQ 11, b.

[20] Monitoring Report on the IESO-Administered Electricity Markets, for the Period from November 2009 – April 2010, by the Market Surveillance Panel. See, in particular, p. 140-268.

recognize that the Intertie Congestion Rents are therefore available to make these payments, but it should be expected that in an efficient market, the price paid for the TR should approximate the payments the owners receive over the year. To assume that the auction is managed to guarantee substantial profits such that TR holders both get back their initial purchase price in addition to all of the congestion rents is unsustainable and unreasonable.[21]

Therefore, ICR should be assumed to accrue to consumers.

b. The Producer Surplus Is Associated With OPG's Non-Prescribed Hydroelectric Generation And Should Accrue To Consumers

Generation in the Ontario market is largely paid under either contracts or regulation, such that a change in the market price does not produce a change in profitability after considering the additional payments made and funded through the Global Adjustment. This is not to say that producers are not incented to follow price signals. It is just that if one assumes that the generators are operating in a rational manner, an overall change in market prices will not change the generators' profits. The producer surplus calculated in the CRA Report will only accrue to those producers that are paid, and allowed to keep, the full market price.[22]

To my knowledge, only OPG's non-prescribed hydroelectric generation is exposed to market prices in this way. And as a result of OPG's ownership structure, the change in profits will flow to consumers. As the report states, "…that revenue flows to OPG's bottom line, which in turn affects Ontario's fiscal balance to the benefit of Ontario taxpayers/consumers."[23] In evaluating tariff options those benefits that flow to consumers indirectly should still be recognized for what they are—consumer benefits. Some may flow directly, and others with some uncertainty and time delay, but they still flow to consumers. To not recognize this flow would be to distort the analysis, because one would have to assume the benefit is retained by some other entity which clearly does not enjoy this benefit over the long term.

In evaluating the producer surplus, I have concluded that the best evidence is that the entire surplus is attributable to OPG's non-prescribed hydroelectric generation and therefore the benefit will accrue to consumers. As far as I am aware, there are no other significant generation sources in Ontario that are directly exposed to the market price. There is no reference to such generation in the CRA Report. Nevertheless, I assume that there is a slight reduction because of

---

[21] This issue is the major focus of the 128 page section of the MSP Report. According to the report, the IESO took the view that its only obligation was to insure that the TR market remain closed (that is, not dependent on additional money from consumers to fund TR payments) (p. 152). The MSP makes it clear that it disagrees with this interpretation (p. 152) and points out that the Market Rules require that congestion rents alone should be sufficient to cover TR payments (p. 151, footnote 122). The MSP Report acknowledges that historically, TR holders have enjoyed substantial profits. But going forward, and in particular with respect to the change in congestion revenues associated with a tariff change, there is no basis for concluding that the TR market will not be efficient such that the prices paid for the TRs are commensurate with actual TR payments, and the congestion rents themselves will be available for payment to consumers.

[22] CRA Report describes this dynamic on page 24.

[23] CRA Report p. 23.

uncertainties over how CRA conducted its analysis. Thus, in my analysis of consumer surplus I assume 95% of the producer surplus eventually accrues to consumers. The response to a specific interrogatory on this question did not provide any basis upon which to conclude that the figure should be lower.[24]

[24] Interrogatory Schedule 11.07 APPrO 7.

V. Analysis In The CRA Report Is Flawed And Most Likely Underestimates The Benefits Of Reducing The Export Tariff

In evaluating the ability of CRA's NEEM model to analyze a change in the export tariff, some broad perspective is helpful. Increasing the efficiency of system dispatch has long been recognized as a means for lowering costs and creating benefits for consumers in electricity markets. Utilities agreed to participate in power pools in some areas decades ago. The creation of competitive markets under the oversight of ISOs that optimize dispatch based on pricing signals is a continuation of that trend. The interface between ISOs, the so-called seams, has been a challenge, because the efficiencies available to an ISO operating within its boundaries are not readily achievable between ISOs. One solution is the expansion of the ISO itself, which is best exemplified by PJM's evolution. There has also been considerable work among ISOs to minimize seams issues and increase efficiencies. But there is one substantial and inescapable difference. Within an ISO, the system operator effectively has perfect information and can dispatch (and create price signals) that strive for perfect optimization. Between ISOs, the optimization falls to traders seeking to profit through trading on price differences. The traders need to place bets based on expected price differences with all the complexity, uncertainty and risk that such trading entails.

An evaluation of different export tariff levels should focus on its impact on trading behavior and the resultant change in the amount of exports.

a. NEEM Model Fails To Capture The Critical Elements Of Trade

The NEEM model is a linear program that captures the broad market region and minimizes the cost of meeting demand. Models of this nature are routinely used and can be effective for issues such as studying overall resource balancing, price analysis, implications of environmental policies and fuel usage studies, as discussed on CRA's website.[25] The use of such a model to study trading activity, however, creates insurmountable problems because it assumes a level of optimization that is impossible. Not only does such modeling assume perfect dispatch, but "NEEM is a perfect foresight model."[26] As such, NEEM assumes a level of perfection that is better than an ISO could achieve within its own boundaries. NEEM does not begin to deal with the trading difficulties between ISOs associated with imperfect information and the behavior of traders. Indeed, other than adding so-called "friction costs" of up to $3/MWh,[27] NEEM assumes perfection in trading.

[25] http://www.crai.com/consultingexpertise/Content.aspx?tID=828&subtID=842&tertID=894.
[26] CRA Report, Appendix A, p. 48.
[27] Export Transmission Service (ETS) Tariff Study, Responses to Stakeholder Comments and Questions, from the meeting of May 24, 2012, IESO, question 1. http://www.ieso.ca/imoweb/pubs/consult/se94/se94-20120622-Responses_to_Stakeholder_Questions.pdf.

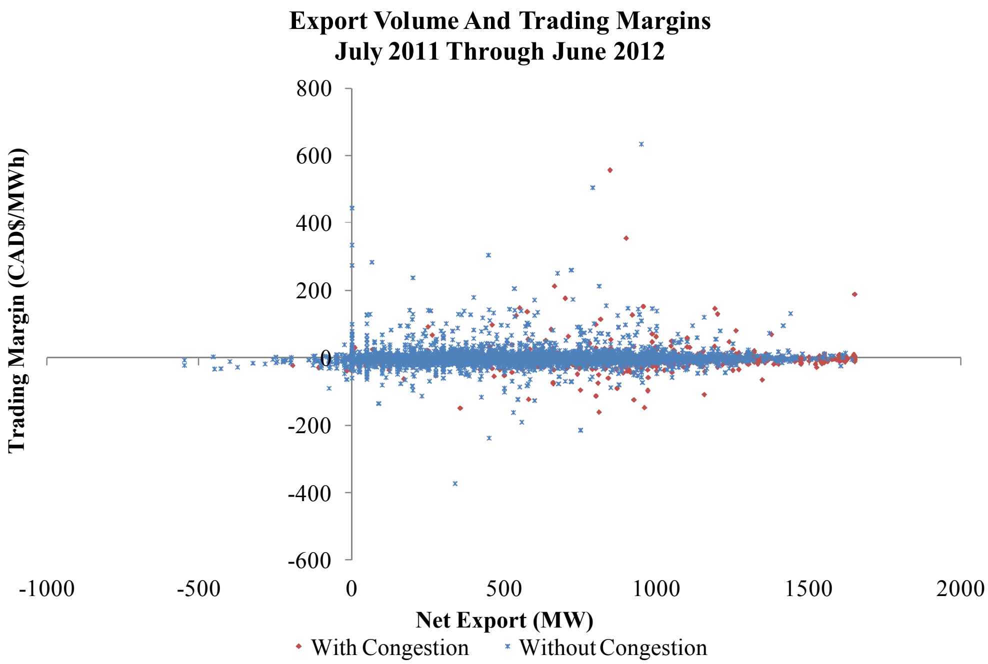
NEEM models the entire North American system in 39 demand regions, which include five in New York and perhaps nine covering PJM and MISO.[28] For this study, the Ontario region, normally captured as a single region, was subdivided into three.[29] My criticism is not with how these divisions are made, but instead with the fundamental issue that NEEM treats all these regions the same. The market will optimize dispatch across multiple regions within an ISO very differently than between ISOs. Within NEEM energy flow between the three Ontario regions (or between the five New York regions) occurs with the same efficiency as trade between Ontario and New York—and with the same efficiency as between Ontario and Michigan, PJM and Quebec.

This assumption of perfect efficiency between ISOs is not credible. Traders buy and sell between regions based on imperfect information, and their trades are a reflection of the imperfections that exist. Traders place offers to buy and sell in a structured, but imperfect process, hoping to make money over the long run. Some trades will actually lose money and in other cases traders will have missed what could have been a profitable trade. Traders are not perfect. The end result does not align with perfect efficiency.

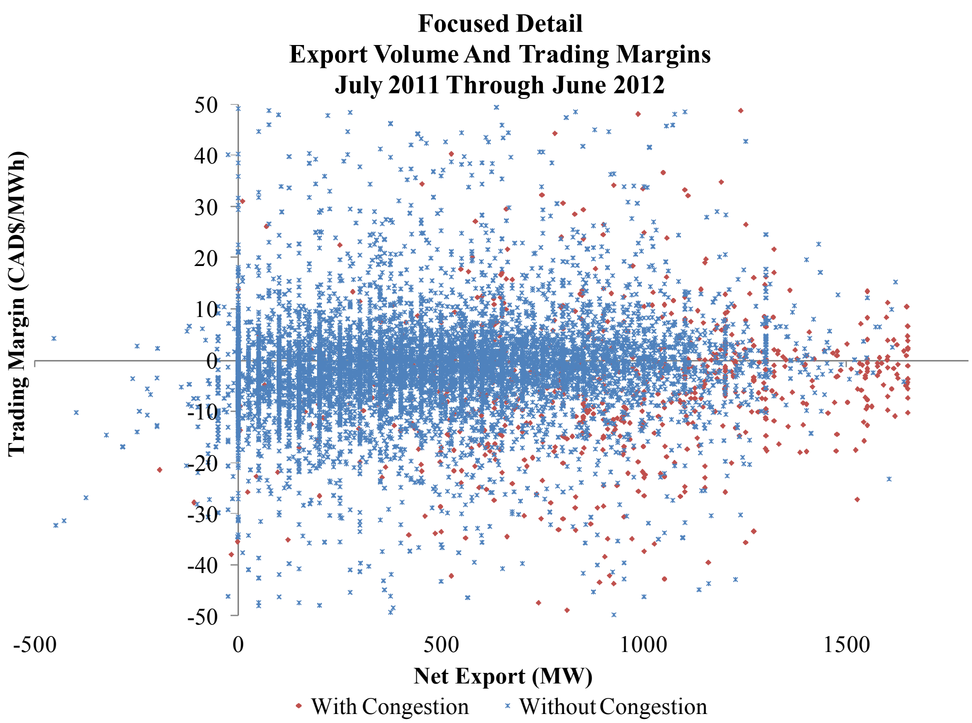
The graph below plots the hourly net trades between IESO and NYISO for the 12 months ending with June 2012 against the price differences between the markets. In this graph I have plotted the hours where the line is not congested in blue, and the hours with congestion in red, although I recognize that with 8,760 data points there is so much overlap between the two that the difference is difficult to detect. The second graph provides a more detailed view of the region of the graph where most trades occur. In calculating the price difference, I have subtracted the cost of trading, including uplift and other fees. The resulting price difference is the potential profit that could be captured by the trader in making the trade. While the additional quantity of sales that could have been sold is not available, by plotting the actual sales scheduled for each hour, one can get an impression of the relationship between sales and profit opportunity.

[28] CRA Report, Appendix A, p. 48, based on interpretation of the map.
[29] CRA Report, p. 3 and Appendix B, p. 51.

Figure 4



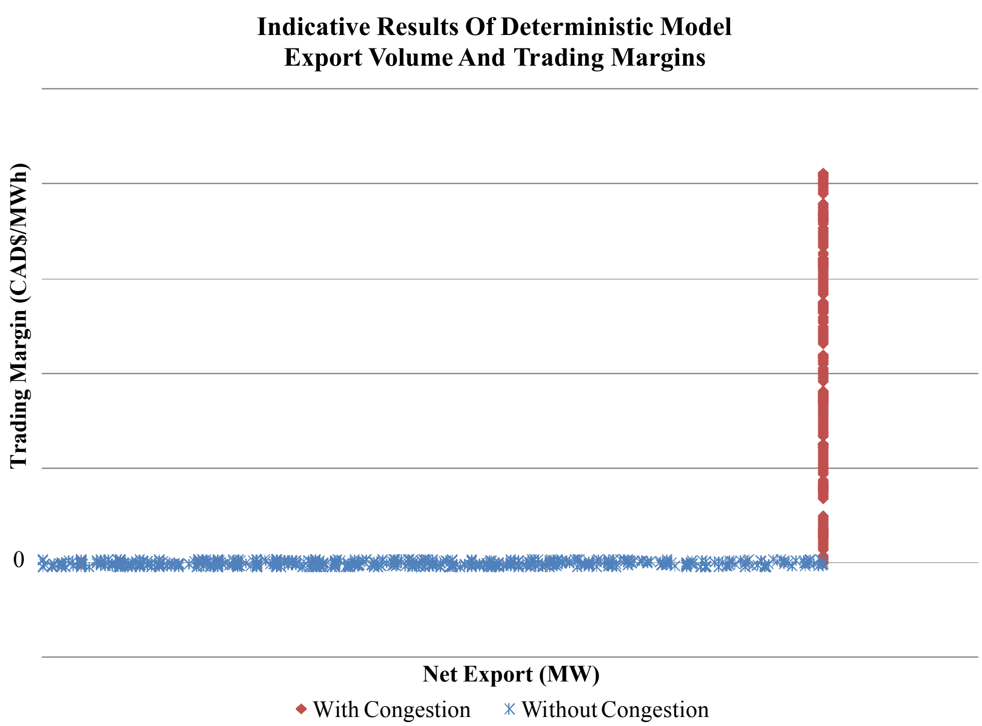
Note: Trading margin is the real-time price difference between NYISO and IESO markets less outbound fees. Outbound fees include hourly, daily, and monthly uplift charges, IESO fees, and Hydro One fees.



The graph provides an indication of the messy business that is trading. There are a lot of exports that were completed at times when the analysis indicates margins were negative. The comparison is between the Ontario export price and the real time price in New York. Actual trades could be competed bilaterally or in the day ahead New York market, such that profits were actually positive when the analysis indicates a loss. Other exports could be associated with energy wheeling through Ontario, which is not captured in this analysis. Also, trades are often conducted bilaterally on a multi-hour basis such that they could be profitable overall even if margins appear negative in some hours. And sometimes trades that are expected to be profitable turn out as losses. Trading is sometimes thought of as arbitrage, but, technically-speaking, arbitrage occurs when profits can be locked in without risk. There is inherent risk in dealing with volatile electricity markets.

In contrast, consider what a graph of trading would look like for a deterministic model. The graph below is not based on actual data, but is conceptual based on the mechanics of a deterministic model with perfect information, such as NEEM. To understand the logic underlying the graph, imagine that one first determines the profit opportunity between markets absent any trade. The profit opportunity spans a wide range. If the opportunity is negative (trade at a loss), then no trading occurs in this example. If it is positive, then the volume of trading is either at the point where the price difference disappears (again, assuming a perfect optimization), or it goes up to the point where the intertie is congested. Thus, it is a simple, two-line chart.

Figure 5



In this deterministic model, now consider what happens if the tariff is increased. If the line was congested, and the profit opportunity was greater than the tariff increase, those points remain in the vertical line. There is no change. For the other points, the trading volume will be reduced and this is captured in the NEEM analysis. But the essential assumption is perfect optimization of large, connected markets across an interface. The analysis will produce a result that will not reflect real market behavior.

Alternatively, consider how the chart of actual trading margins would change with an increase in the tariff. I suspect the first reaction would be to question how a small change would affect such a wide and seemingly unruly scatter of data. But all of that trading activity involves chasing a trading margin, however imperfectly, and the tariff increase would certainly discourage trade. The evidence of Marc-André of Brookfield Energy Marketing LP discusses these effects in general and also with particular emphasis on trading in forward markets. These margins are small and will be significantly affected by a tariff change of a dollar or more.

The evidence also discusses risk premiums. Traders inherently weigh the potential profit against the risks inherent in the trade. When a tariff is increased, it raises a cost that must be paid regardless of whether the trade is profitable. This increased fixed cost has a magnified effect on trading volume because, in addition to reducing the margins, it drives up the overall cost of trading. Fixed costs discourage trading because the greater costs have to be financed and managed.

b. Additional Errors In The NEEM Analysis

There are several other significant problems with the NEEM modeling.

The model does not produce any negative prices in Ontario. This should be expected with the assumption that nuclear, spillable hydroelectric and wind generation all bid small positive values in the NEEM analysis. As result, the output of this otherwise non-dispatchable generation is reduced as necessary for the market to clear and prices never fall below zero. Unfortunately, this fails to reflect Ontario's reality. In part, this is because these generators do not bid their output at these levels and would not respond in this manner to these prices. The recent market change to create an export settlement floor price of -$8/MWh may produce results in the future closer to that produced by the NEEM model, but this comparison misses the bigger picture. The market behavior modeled by NEEM does not reflect what really takes place in Ontario. If it did, the recent efforts to change the market rules and prevent substantially negative prices for export would not be required. This recent market initiative, if anything, proves that the negative prices missed by the NEEM modeling error are of sufficient importance that the required a change in the market design. In any event, the lack of negative prices is not credible.

Nuclear units do not bid their output at their fuel cost, as included in the NEEM model, for many reasons, one of which is that once they are shut down they cannot be restarted immediately. Even the curtailment of nuclear output short of a full shutdown will have multi-hour implications. To address this major shortcoming, a separate analysis was performed that relies on the NEEM output. This separate analysis is described on pages 10-12 of the CRA Report, complete with a discussion of the number of shutdowns (for a minimum of 72 hours), the MWh of output curtailed, and a summary of additional nuclear maneuvers. This summary does not include any cost estimates or consideration of how this would change dispatch in other hours. After all, if the unit is not in operation in other hours, other generation would have to be operated. And since this additional analysis does not feedback into the NEEM output, it does not influence those cost calculations.

But none of this matters, because the CRA Report never has a change in nuclear output that is a result of a different tariff assumption. To be specific, the nuclear output varies by year and in scenarios where there are substantial changes of assumptions, such as which generation (nuclear or wind) is first curtailed as load declines and the market approaches an SBG event. But within any such scenario, as one changes the tariff on exports, the nuclear output never changes. Thus, the nuclear outage and dispatch never contributes to the incremental costs associated with different tariff assumptions. The post-NEEM analysis projects substantial nuclear shutdowns and maneuvers, yet these results never produce a change in nuclear output when the tariff changes. Therefore, none of these effects change the cost and surplus calculations. This is simply not credible.

One of the troubling aspects of the model was the approach taken to "calibrate the model". The calibration section concludes with, "In our judgment, the calibration was reasonably close to actual. In particular, …the relative pattern of exports closely aligned with actuals."[30] But this statement must be put in context. Earlier the report describes how the export limits were reduced during the lowest load hours to make the results consistent with the 2011 export levels.[31] Thus, an arbitrary export limit was imposed to make the output match history, and then the model was deemed "calibrated" because it matched history. This is particularly problematic because the reason for conducting the modeling exercise is to capture the changes in exports and the export limit was arbitrarily selected just so that the results would match historical levels. The arbitrary reduction of intertie capacity so that export levels "calibrate" to historical levels in one year results in a simulation that is not credible. Also, the seemingly arbitrary decision to decrease the export limit in only some of the lowest load intervals produces the peculiar result that exports are sometimes lower in the SBG periods than other load intervals when the market is not facing supply/demand imbalances.

The CRA Report states that average monthly HOEP ranged from 7% below actuals to 16% above, among other statistics.[32] Assuming fuel costs and the generation resources could be determined with reasonable accuracy, it is clear that this wide variation should not be characterized as "closely calibrated".

The model was conducted using aggregated load data, where each month is represented by only ten different periods. This simplification will completely miss the trades made on an hourly basis that reflect subtle market differences that create short-term opportunities for profitable

[30] CRA Report, p. 14.
[31] CRA Report, pp. 7 and 56.
[32] CRA Report, p. 13.

trades. The problem is of particular concern when trading and pricing patterns involve changes over the course of a day, because the entire chronological nature of the electricity market is lost in this approach. This is a major issue in evaluating tariff structures that vary by time of day and this will be discussed further in the next section. Further, the difference between average load levels in a given period, and the full range of variation that was actually incurred, can be significant and important to evaluating trading activity.

c. Conclusions On The Tariff's Effects On Exports And SBG Are Not Credible

The CRA Report concludes that changes in the export tariff will have no effect on exports during SBG periods.[33] This is not credible. As the CRA Report states, "It appears that the differentials in baseload variable costs between Ontario sources and US baseload generation, which is mainly coal based, are so large that none of the proposed tariff changes would alter export decisions during SBG events."[34] To put that another way, as SBG conditions develop (as load, prices and output from dispatchable units fall), the transmission lines become full in the exporting direction before an actual SBG situation develops.

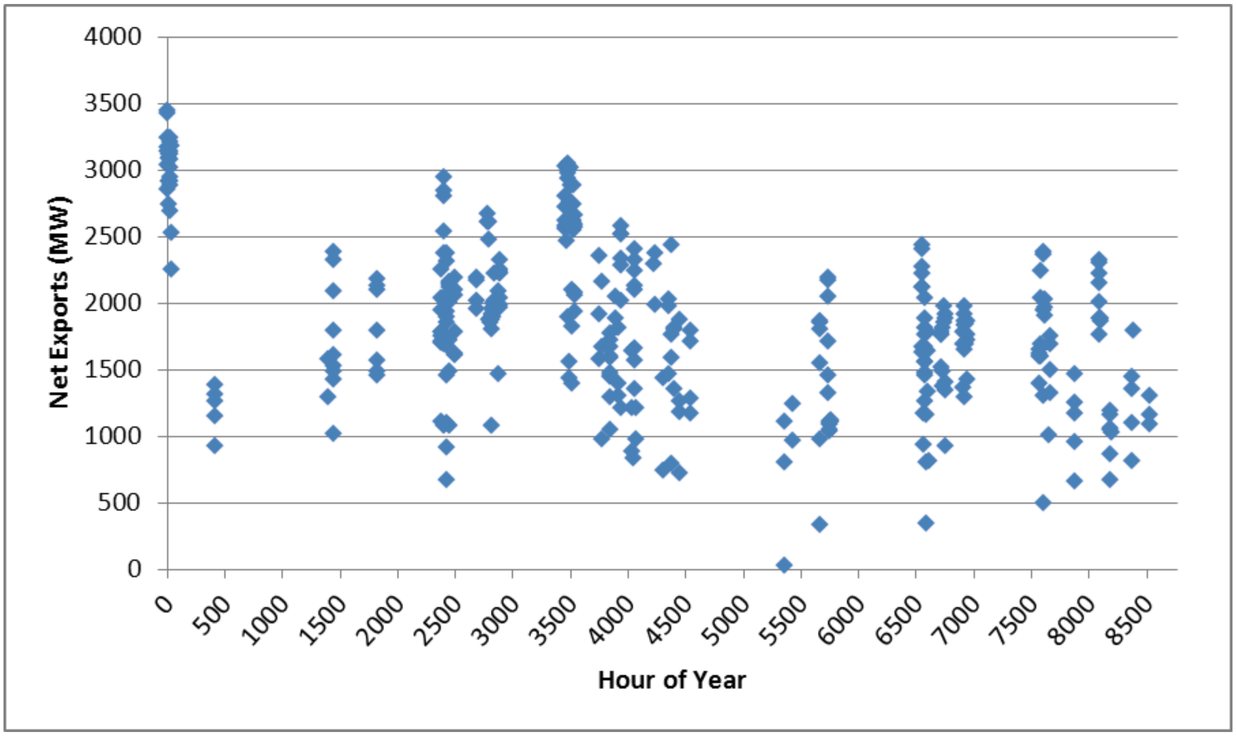
In the real world, traders want to export when the price differences are greatest, but there is always considerable uncertainty. The actions taken by the IESO can actually increase Ontario prices because they can involve significant decreases in supply, such as from shutting down a nuclear unit. The CRA Report itself provides a chart of exports during SBG events from 2011 which is not indicative of the transmission lines being full.

---

[33] CRA Report pp. iv and 22.
[34] CRA Report, p. 22.

Figure 6

Figure 1: Ontario Net Exports During 2011 SBG Maneuvers



While the CRA Report offers some reasons why exports may be limited during SBG events, it fails to consider the behavior of traders and market prices.[35] That is, the report fails to consider the available incentives to trade during such hours. In discussing the results of the NEEM modeling, the CRA Report states, "With respect to SBG, the model results indicate that SBG is invariant to all the ETS tariff scenarios. This is true for both curtailment cases: nuclear first and wind first."[36] This report discusses sensitivity analyses where the export limit was changed, and finds the insensitivity to tariff levels holds true. It concludes that price differences between Ontario and the US markets, "are so large that none of the proposed tariff changes would alter export decisions during SBG events."[37] Underlying this statement are model results indicating the tie lines are full whenever a SBG event occurs, under any of the scenarios and sensitivities that were conducted. There is no evidence that this actually happens. There are many reasons to conclude that exports do not fill the interties at these times. Thus, the analysis totally fails to study what is perhaps the most critical issue associated with the export tariff.

A related point concerns the level of prices in neighboring regions during SBG events and whether the model reasonably reflects actual events. The NEEM analysis indicates price

[35] CRA Report, p. 7.
[36] CRA Report, p. 22.
[37] Ibid.

differences sufficient to export energy at the limit of the interties, but evidence suggests this may not be true. Further discovery on the NEEM analysis is underway.

d. Assessing The Effect Of A Tariff On Trading Activity

There are alternative approaches to evaluating the effect of tariff changes on trading behavior. Several years ago the IESO conducted statistical analysis of the price elasticity of exports.[38] This historical analysis does not capture the pressing problems of SBG, as that phenomenon is relatively new, but the approach would do a better job of estimating changes in trader's ability to capture price differences in the real world.

The interplay among trading behavior, a change in tariffs and SBG is far more complicated than simply assessing the price difference caused by tariff. IESO actions taken to deal with the SBG problem can significantly disrupt the price signal. Impending SBG conditions do not necessarily encourage exports by traders, as such conditions also serve to warn them of particularly uncertain Ontario prices because of the potential effects of IESO actions.

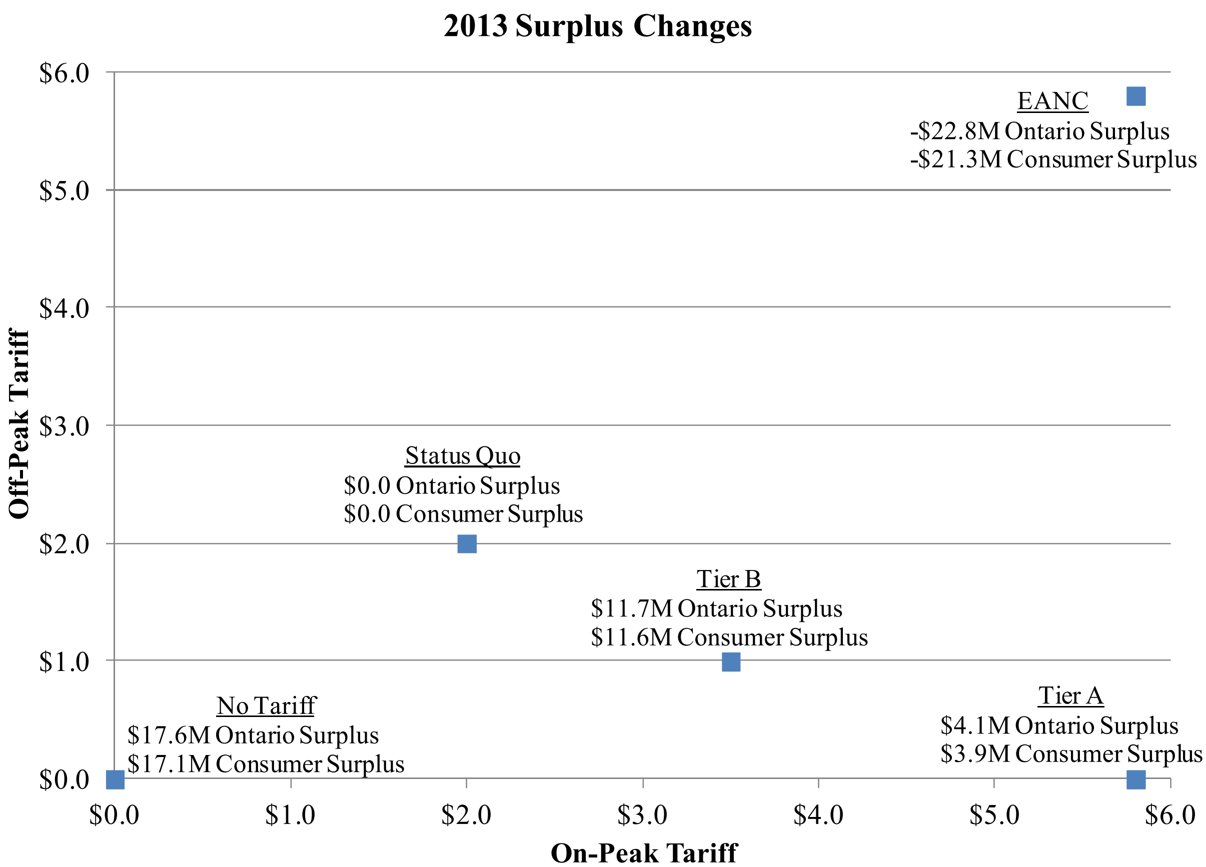
The solution to making the markets more efficient is to promote exports and decrease out-of-market IESO intervention. This is somewhat circular: the greater the exports, the less IESO intervention is required, the more confidence traders will have in predicting market behavior and therefore the higher level of exports they will generate. This is a virtuous circle, benefiting the market and consumers.

[38] "Estimating the price elasticity of export demand in the Ontario electricity market." An IESO Working Paper by the Market Evolution Analysis and Research Group, 2008 – 01.

VI. The Tiered Tariff Structure Is Unlikely To Provide Benefits To Ontario

As a starting point in my analysis of the tiered tariff structures in the CRA Report, I prepared the following graph which shows the different scenarios evaluated. The calculated surplus for Ontario overall and for just Ontario consumers are presented for each scenario.

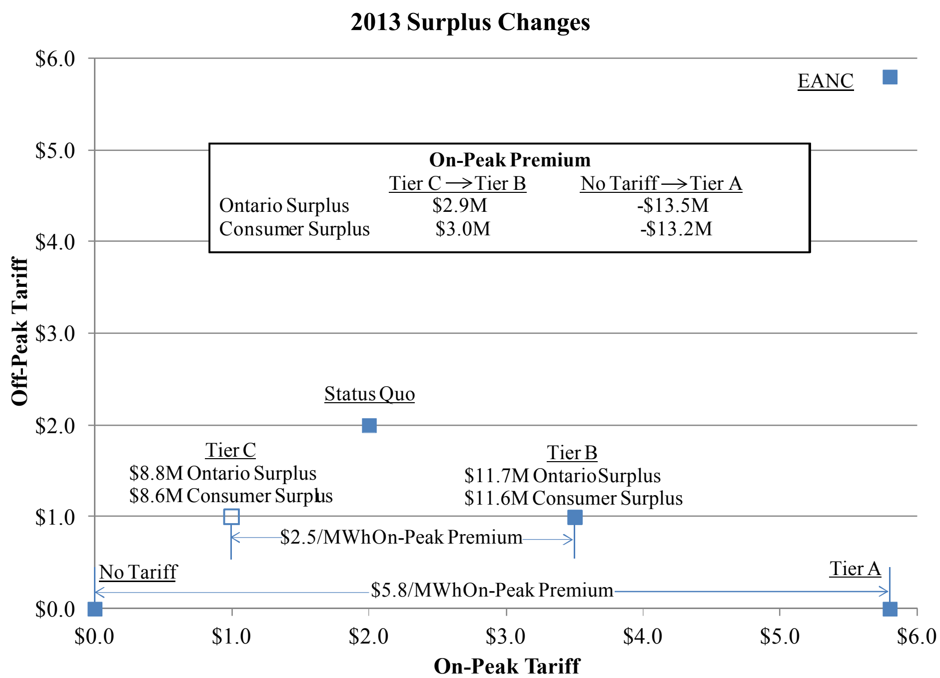
Figure 7



The analysis indicates that the best outcome involves eliminating the tariff. Tier A can be compared to that option, as they both have the same off-peak tariff of zero, and the analysis shows that the benefits are reduced dramatically, around $13 million, if the on-peak tariff is increased to $5.80/MWh. By the same token, if Tier A is compared to the EANC alternative, where they both have the same on-peak tariff, one can see that reducing the off-peak tariff to zero provides benefits of around $22 million. The overall conclusion is that there are benefits from decreasing both the on-peak and off-peak premiums, and the Tier A option is not preferred.

The analysis of Tier B is less clear, and with a surplus of over $11 million it might appear promising. The problem is that there is no other scenario with which it can be directly compared. I think it is reasonable, on the basis of the analysis provided, to estimate another option, that I call Tier C, which has a uniform tariff of $1/MWh in both the on- and off-peak periods. I note that cutting the tariff by $2.00/MWh increases the surplus by $17.6 million and increasing the tariff by $3.80/MWh (to $5.80/MWh) reduces the surplus by $22.8 million. This is fairly linear. One might therefore estimate the Ontario surplus associated with a uniform tariff of $1.00/MWh in all hours at $8.8 million (half way between the status quo and no-tariff scenarios), and the similarly calculated consumer surplus at $8.6 million. This is shown in the figure below.

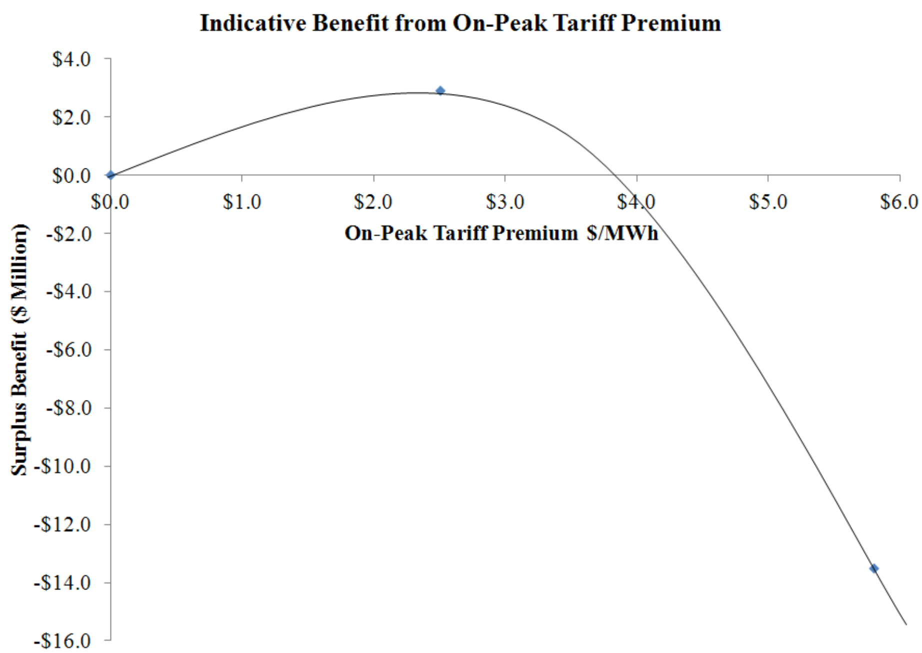
Figure 8



The comparison of Tier B and Tier C allows for a more focused analysis of the effect of the increase in the on-peak tariff. Both have $1.00/MWh in the off-peak, with the difference being the $2.50/MWh increase in Tier B's on-peak tariff relative to Tier C. As one can see, the lion's share of the overall surplus increase comes from reducing the off-peak rate. The incremental value of increasing the on-peak tariff is positive, but only amounts to $2.9 million from an Ontario surplus perspective and $3.0 million for the consumer surplus. The results are summarized in the table presented on the graph. The other direct comparison is from the zero tariff to Tier A, where both have an off-peak tariff of zero, and the on-peak tariff is increased to $5.80/MWh in Tier A. In that comparison, the Ontario surplus is reduced by $13.5 million (17.6 – 4.1) when the on-peak tariff is increased. The analysis seems to indicate that a moderate on-peak increase could produce some modest increase in the surplus, but if the increase is too great, it could produce much greater reductions in the surplus.

I have taken these two data points and created the graph below. This chart is based on very little data and I believe should be viewed with caution. In addition, there are significant analytical issues associated with the underlying analysis of the tiered rate structures.

Figure 9



As has been detailed earlier, the modeling has substantial weaknesses in capturing actual trading activity. There are specific issues with respect to the treatment of on- and off-peak hours which become critical to this analysis. As was described earlier, the NEEMs model is not chronological, and instead bundles similar hours together for similar treatment. As always, the implication of such simplifications depends on what is being studied. Here, the critical issue is how a tariff change based on the time of day will affect outcomes. The bundling of hours was done on the basis of relative demand in a given month. While load is typically higher on-peak, the relationship is not direct. Therefore, the bundling of hours on a load basis provides a very poor model from which to study time-of-day tariff issues.

I conducted an analysis based on the load data for the full year 2011. Using the monthly breakdown consistent with the CRA analysis, and looking solely at the load levels, I determined which hours had the highest load. I then determined how many of those hours actually fell within the HONI on-peak definition of 5x12 hours per week. On a percentage basis, only 70%

of the hours were actually on peak.[39] Thus, there is a major difference between the actual high-load hours and the on-peak-by-time-of-day definition.

The claimed analysis of a time-based differential tariff is really a load-based differential analysis. This is a substantial error. If there is a benefit of increasing the tariff during peak load hours, the CRA Report's simplified approach would overestimate the extent to which this benefit could be captured through a tariff. This does not provide a reliable basis upon which to deviate from past practices of having a uniform tariff.

I conclude that a tiered rate structure is not advisable. Taking the CRA Report at face value, the potential benefits are small while there is the potential for much greater losses if the on-peak premium is too high. There are obvious flaws when one looks at the analysis more closely and I expect those problems result in overestimating the potential benefit of a tiered structure. Overall, I conclude that there is no reliable evidence that the tiered structure provides any benefits.

If it was concluded that an on-peak tariff premium was worth pursuing, there would be two further questions to ask. First, there is no apparent reason to keep the off-peak level at $1/MWh. The graph supports the view that the primary benefit from the reduction in the tariff occurs in the off-peak period and none of the results support an off-peak rate higher than zero. Second, the level of the on-peak premium should be chosen with care, because the analysis indicates that a premium that is too high will produce substantial losses. The conservative approach would be to cautiously err toward a premium that was too low rather than risk one that is too high. Overall, taking the results at face value provides very little support for placing a premium on on-peak hours.

[39] The 70% figure means that there is a 70% chance that an hour deemed to be on-peak in the load-based CRA Report analysis actually would have been designated as on-peak by HONI's definition.

VII. Conclusion

The efficiency of markets is improved by the reduction, up to the elimination, of tariffs. This has led to the elimination of tariffs between some electricity markets and in trade in general. A complicating factor in some instances is the allocation of benefits among market participants. In Ontario, as a result of its unique market structure, all the benefits of efficiency flow to consumers. Ontario will be better off if the tariff is reduced.

The CRA Report provides a very detailed and sophisticated analysis. I have reviewed that analysis in some detail, with conclusions that directly support the overall conclusion that reducing the tariff will provide benefits. That is true if one accepts the CRA Report at face value, or if one digs deeply in the problems in the analysis.

As a result, whether one accepts the general theory, the CRA Report analysis, or the deeper critique of that analysis, the results all point in the same direction. Cutting the tariff will provide benefits to Ontario consumers and Ontario overall.

NAVIGANT
ECONOMICS

ATTACHMENT 1

NAVIGANT
ECONOMICS

Cliff W. Hamal
Managing Director & Principal

SUMMARY

Cliff Hamal specializes in economic issues in the electric power and related industries. For over 30 years he has been involved in a wide variety of engagements, as an economic consultant since 1989 and in technical roles involving power system operations in prior years. Mr. Hamal brings to each assignment a deep understanding of the industry, its operations, and the dynamics of its markets. He approaches each engagement openly, allowing the unique circumstances of each situation to determine the analyses and methodologies most likely to provide insights into the relevant issues. He particularly enjoys unique challenges that require tailored solutions. His clients have included vertically integrated electric utilities, unregulated electric generation companies, load serving entities, fuel and pipeline companies, equipment suppliers, a debt rating agency, a hedge fund and the US Department of Justice. He has provided testimony in cases before the Federal Energy Regulatory Commission, federal courts, state public utility commissions, arbitrators and the Ontario Energy Board.

TOPICAL SURVEY OF PRIOR ENGAGEMENTS

Market Design

Support electricity market development, including analysis of rules, development of modifications, evaluation of likely participant behavior, and assessment of strategic implications. Analyze capacity markets and provide recommendations for their development and evolution. Review dispatch algorithms to determine how subtle changes could affect market prices and efficiencies. Develop market rules that address the potential exercise of market power during periods of congestion.

Competitive Strategy

Assess investment opportunities in electricity generation market. Evaluate a new merchant transmission project with unique technical challenges. Analyze the potential for repowering a generation facility. Assist in the establishment of a power marketing organization and the development of its business strategy. Model a large generation portfolio and evaluate divestiture options. Evaluate business opportunities and public policy options for equipment suppliers.

Power Purchase Agreements

Negotiate and renegotiate power purchase agreements. Evaluate contract pricing terms in light of changed market circumstances. Review implications of “good faith” terms on specific circumstances related to changed market circumstances. Review whether changes to force majeure provisions could lower energy costs. Analyze the value of a power contract to assess employee compensation claims.

Investment Analysis

Evaluate the value of power generation facilities for a potential buyer. Analyze partnership opportunities related to projects in development. Evaluate strategic alternatives for managing spent nuclear fuel in the U.S. Evaluate price forecasts and revenue projections for project-financed investments to support credit ratings by Standard & Poor's. Evaluate investment opportunities at existing facilities related to repowering, pollution control upgrades, and other modifications.

Environmental Strategy

Analyze implications of cap-and-trade and carbon tax climate change initiatives. Investigate strategic implications of changing environmental regulations. Provide a comprehensive analysis of the effect on the U.S. economy of policies targeting technologies considered favorable for the environment. Evaluate pollution control equipment upgrades and fuel switching options related to meeting emission standards. Consider implications of new environmental regulations on asset values.

Market Power Analysis

Evaluate market power issues in energy, capacity and ancillary services markets. Evaluate the implication of mergers and asset acquisitions on market power before the Federal Energy Regulatory Commission and the US Department of Justice. Prepare market based rate applications using FERC's market screen and Appendix A methodologies. Evaluate claims of antitrust violations under the Clayton Act.

Market Participant Behavior

Evaluate participant behavior in markets, including bidding patterns and generation unit availability. Analyze participant behavior in real-time, day-ahead, and longer-term energy markets. Evaluate claims of inappropriate market behavior by generators. Evaluate the behavior of a financial participant in energy and financial transmission rights (FTR) markets. Evaluate ancillary services markets regarding the implications of different market structures on participant behavior. Analyze the potential for specific trades to influence reported market prices.

Economic Testimony

Testify regarding damages in cases involving breach of contract. Testify on power contracting issues. Opine on market design issues. Testify regarding cost responsibilities for must run generation in a dispute centering on changes in the electricity market structure. Testify regarding electricity price forecasts. Serve as an arbitrator in an insurance claim matter involving the value of lost electricity generation.

PROFESSIONAL HISTORY

Since 2011	Navigant Economics	1996-2010	LECG
	1200 19th Street, NW, Suite 850	1995-1996	The Tesla Group, Inc.
	Washington, DC 20036	1993-1994	JFG Associates, Inc.
	Direct: 202.481.8303	1989-1993	Putnam, Hayes and Bartlett, Inc.
	Main: 202.973.2400	1983-1989	Westinghouse Electric Corporation
	Fax: 202.973.2401	1981-1983	General Electric Corporation
	cliff.hamal@naviganteconomics.com	1980-1981	Trinidad Lines and Marine Transport Line

EDUCATION

MS (with Distinction), Industrial Administration, Carnegie Mellon University, 1989.

BS (with Honors), Marine Engineering and Marine Transportation, U.S. Merchant Marine Academy, 1980.

TESTIMONY

On behalf of Montana Alberta Tie Ltd. (a subsidiary of Enbridge Inc.), before the Alberta Utilities Commission, June 15 and September 18 and 19, 2012, Proceeding 1633. Subject: The Alberta Electric System Operator's rule modification, Section 203.6, concerning transmission rights following the addition of a merchant transmission interconnection.

On behalf of Ontario Power Generation, Inc., before the Ontario Superior Court of Justice, Canada, August 26, 2011, February 9, 10 and 13, 2012, Court File No.: 03-CV-252820CMZ. Subject: Review of Mishkeegogamang's claim for damages from electricity sales.

On behalf of PacifiCorp, before the U.S. District Court for the District of Oregon, February 22, 2011, Docket No. 09-1012-HZ. Subject: Dispute over pricing in a power purchase agreement concerning generation, transmission, ancillary services and power in the form of hydroelectric pondage.

On behalf of H.Q. Energy Services (U.S.) Inc., before the Federal Energy Regulatory Commission (FERC), September 1, 2010, Docket nos. ER010-787-000, EL10-50-000 and EL10-57-000. Subject: Changes in the forward capacity market in New England.

On behalf of the Narragansett Electric Company (National Grid), before the Rhode Island Public Utilities Commission, December 9, 2009 and March 9, 2010, Docket no. 4111, regarding the Town of New Shoreham Project. Subject: Power price review relevant to the Deepwater offshore wind project.

On behalf of Ontario Power Generation, Inc., before an arbiter under the Canadian Arbitration Act, in 2009, regarding a confidential matter.

On behalf of Ontario Power Generation Energy Trading, Inc., before the FERC, June 19, 2009 (filed June 23, 2009), Docket no. ER08-580-002. Subject: Market power evaluation for market based rate application for the Midwest ISO market.

On behalf of COALSALES II, L.L.C., before the U.S. District Court for the Northern District of Florida, Pensacola Division, August 19, 2008, December 11, 2008 and February 16, 2010, Docket no. 3:06 CV 270/MCR/MD, in the matter of Gulf Power Company v. COALSALES II, L.L.C. Subject: Damages analysis associated with a claimed breach of a coal sales agreement.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated August 4, 2008, Docket no. 04-0033C, in the matter of Consolidated Edison Company v. The United States of America. Subject: Analysis of sale prices of coal and nuclear generation units.

On behalf of Ontario Power Generation Energy Trading, Inc., before the FERC, June 19, 2008 (filed June 27, 2008), Docket no. ER08-580-001. Subject: Market power evaluation for market based rate application for the New York ISO market.

In a non-public investigation before the FERC, June 3, 2008, in response to a request for information. Subject: Analysis of financial transmission right (FTR) trading activity.

On behalf of the Ameren Energy Marketing Company, before the FERC, June 12, 2007 (filed June 18, 2007), Docket no. EL07-47-000. Subject: Review and comment on the economic issues raised in a complaint by the Illinois Attorney General concerning the September 2006 auction used to procure wholesale electricity supplies in Illinois.

On behalf of the Narragansett Electric Company, before the U.S. District Court for the District of Massachusetts, Central Division, May 18, 2007, and June 11, 2007, Docket no. C.A. No. 05-40076, in the matter of TransCanada Power Marketing, LTD v. Narragansett Electric Company. Subject: Review of pricing issues in a wholesale power contract and pricing issues in electricity power contracting more generally.

On behalf of The Association of Power Producers of Ontario (APPrO), before the Ontario Energy Board, March 9, 2007, Docket no. MR-0031-R00. Subject: Evaluation of a proposed change in the pricing algorithm in the Ontario electricity market, with the change related to how generator ramp rates are considered in setting prices.

On behalf of American Electric Power Service Corporation, before the FERC, January 29, 2007, Docket no. EC07-56-000. Subject: Evaluation of the competitive effects of the acquisition of the Lawrenceburg Electric Generation Station.

On behalf of American Electric Power Service Corporation, before the FERC, January 19, 2007, Docket no. EC07-49-000. Subject: Evaluation of the competitive effects of the acquisition of the Darby Electric Generation Station.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated June 29, 2006, testimony on October 12 and 16, 2007, and declaration dated September 17, 2008, Docket no. 00-697-C, in the matter of Wisconsin Electric Power Company v. The United States of America. Subject: Evaluation of decisions made by the utility in managing spent nuclear fuel at the Point Beach Nuclear Power Plant.

On behalf of Reliant Energy Services, Inc., before the U.S. Superior Court of California for the County of San Diego, May 25, 2006, in the matter of Jerry Egger, et al., v. Reliant Energy Services, Inc. et al., Wholesale Electricity Antitrust Cases I and II. JCCP Case Nos. 4204 and 4205. Subject: Analysis of purchases made by Montana-based utilities in California markets.

On behalf of The United Illuminating Company, before the FERC, January 20, 2006 and February 28, 2006, Docket no. EL05-76-001. Subject: Evaluation of issues in a contract dispute involving cost responsibilities for reliability must-run generators.

On behalf of Reliant Energy Services, Inc. and four individuals, before the U.S. District Court for the Northern District of California, San Francisco Division, October 7, 2005, Docket no. CR 04-0125 VRW, in the matter of United States of America v. Reliant Energy Services, Inc. et al. Designated as an expert in case involving claims of price manipulation and a criminal violation of the Commodity Exchange Act. Subject: The operation of the California electricity market, price artificiality, and the behavior of market participants.

On behalf of American Electric Power Service Corporation, et al, before FERC, September 8, 2005, Docket no. EC05-134-000. Subject: Evaluation of the market power implications of the acquisition of Reliant Energy’s Ceredo generation station with respect to capacity and ancillary service markets.

On behalf of Niagara Mohawk Power Corporation, et al, before FERC, July 19, 2005, Docket no. ER96-2585, et al. Subject: Market-based ratemaking application for National Grid USA affiliated companies.

On behalf of American Electric Power Service Corporation, et al, before FERC, June 24, 2005, Docket no. EC05-98-000. Subject: Evaluation of market power implications of the acquisition of the PSEG Waterford generation unit with respect to capacity and ancillary services markets.

On behalf of Ontario Energy Trading International Corp., and Ontario Power Generation, Inc., before the FERC, April 11, 2005, Docket no. ER02-1021-000. Subject: Evaluation of the potential for market power in U.S. markets using pivotal supplier and market share screens.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated November 22, 2004, testimony on March 28, 2005 and April 1, 2005, Docket no. 98-488C, in the matter of Sacramento Municipal Utility District v. The United States of America. Subject: Review of the damages claim made by SMUD associated with alleged breach of contract for the disposal of spent nuclear fuel.

On behalf of National Grid USA, before FERC, November 4, 2004 (revised November 19, 2004), January 10, 2005, January 28, 2005, March 14, 2005, and March 17, 2005, Docket no. ER03-563-030. Subject: Review of the locational capacity market proposal filed by ISO New England with consideration given to market design, participant behavior, the mechanics of implementing the market, and the cost of new generation capacity.

On behalf of Reliant Energy Services, Inc. and four individuals, before the U.S. District Court for the Northern District of California, San Francisco Division, December 10, 2004, Docket no. CR 04-0125 VRW, in the matter of United States of America v. Reliant Energy Services, Inc. et al. Subject: Review of a report concerning the market effects of certain bidding actions by Reliant on California electricity markets in the summer of 2000.

On behalf of New England Power Co. before FERC, December 24, 2003, March 9, 2004, and April 15, 2004, Docket no. EL03-37-000. Subject: Evaluation of the electricity price forecast used for setting a contract termination charge, as well as the determination of variable costs and generation asset sale prices.

On behalf of Koch Power, Inc., before the Harris County, Texas District Court, Cause no. 2001-48858, in the Matter of Tim Beverick v. Koch Power, Inc., provided testimony summary on August 25, 2003. Subject: Evaluation of the potential for savings under a renegotiated power purchase agreement and the contributions of certain individuals to the renegotiation process.

On behalf of Reliant Energy Services, Inc. before the FERC, April 16, 2003, Docket no. EL03-59-000. Subject: Evaluation of the implications of certain trades of forward energy contracts on the overall electricity market.

On behalf of Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. before the FERC, March 3, 2003, with rebuttal March 20, 2003, Docket nos. EL00-95-069 and EL00-98-058. Subject: Investigation into alleged manipulative practices by market participants in the California electricity markets in the 2000-2001 timeframe.

On behalf of Ontario Energy Trading International Corp., and Ontario Power Generation, Inc. subsidiary, before the FERC, February 14, 2002, Docket no. ER02-1021-000. Subject: Evaluation of the potential for market power in U.S. markets.

On behalf of The New Power Company before the FERC, July 13, 2001 (filed July 17, 2001), Docket no. EL01-105-000. Subject: Evaluation of the capacity credit market in PJM, primarily focusing on market power issues.

On behalf of National Grid USA before the FERC, January 16, 2001, Docket no. EL00-62-005 and EL00-62-013. Subject: Analysis of the incentives for new generation facilities in New England, and in particular the role of the $8.75/kw-month installed capacity deficiency charge.

On behalf of Oklahoma Gas & Electric before the Arkansas Public Service Commission, November 30, 2000, Docket no. 00-326-U. Subject: Analysis of OG&E's potential market power in a restructured, retail open-access environment.
On behalf of National Grid USA and TransCanada OSP Holdings, LTD before the FERC, August 7, 2000, Docket no. EC00-122. Subject: Analysis of the competitive effects of the proposed acquisition of interests in the Ocean State Power generation facility by TransCanada.

On behalf of Central Illinois Light Company and the AES Corporation before the FERC, February 19, 1999, Docket no. EC99-40. Subject: Analysis of competitive effects of the proposed acquisition of Central Illinois Light Company by the AES Corporation.

On behalf of Public Service Electric & Gas Co., before the United States District Court for the Eastern District of Pennsylvania, Docket no. 96-CV1705, in the Matter of Delmarva Power & Light Company and PECO Energy Company v. Public Service Enterprise Group, Inc. and Public Service Electric and Gas Co., March 28, 1997. Subject: Replacement power costs associated with the multi-year forced outage of the Salem Nuclear Station.

SPEECHES & PAPERS

"Opportunities in Spent Nuclear Fuel Consolidation," as part of a workshop sponsored by the United States Nuclear Infrastructure Council, Baltimore, MD, May 31, 2012.

"How can an economist help with complicated technical and political issues?" in the session, "Spent Nuclear Fuel Storage and Repository Options," for the Institute of Nuclear Materials Management Spent Fuel Workshop XXVII, Arlington, VA, February 2, 2012.

"Five Thoughts on Evolutionary Change," in the session, "Market Evolution in the Context of the Electricity Market Forum Road Map and the Post-Election Environment," APPrO 2011, Toronto, Canada, November 16, 2011.

"Spent Nuclear Fuel Management: How centralized interim storage can expand options and reduce costs," with Julie M. Carey and Christopher L. Ring. A study conducted for the Blue Ribbon Commission on America's Nuclear Future, May 16, 2011.

"Nine Trends to Watch in the Renewable Transformation," with Julie M. Carey. *Dialogue*, United States Association for Energy Economics, Volume 18, Number 3 - 2010.

"Capacity Market Design Fundamentals." Workshop for EUCI's conference, "Capacity Resources: Issues and Market Dynamics," Baltimore, MD, October 27, 2010.

"The Impact of Transmission Expansion and New Renewable Generation on the Evolution of FTR Markets." Panel moderated for EUCI's conference, "Financial Transmission Rights: Trends and Trajectory," Arlington, VA, July 19, 2010.

"Managing FTR Credit Risk." Panel moderated for EUCI's conference, "Financial Transmission Rights: Where Are We Now?" Washington, DC, July 28, 2009.

"Credit Coverage Requirements for FTR and Virtual Bidding." Session moderated for EUCI's conference, "Unsecured Credit: Is it the right policy for RTOs/ISOs?" Alexandria, Virginia, April 29, 2009.

"Force Majeure Risk and Ontario Power Authority's Power Contracts." Whitepaper with Julie M. Carey, on behalf of the Ontario Power Authority, March 31, 2008.

"Financial Accommodation for Force Majeure Events." Whitepaper with Julie M. Carey, on behalf of Ontario Power Authority, January 21, 2008.

"Market Design Choices for Ancillary Services Products," with Cleve Tyler. Presented at the EUCI Ancillary Services Conference, Minneapolis, Minnesota, September 12, 2007.

"Cost-Benefit Analysis In the Evaluation of Market Rule Changes: Comments on MR-00332-R00." Whitepaper on behalf of Ontario Power Generation, Inc., July 12, 2007.
"Adopting a Ramp Charge to Improve Performance of the Ontario Market." Whitepaper with Arun Sharma, on behalf of The Association of Power Producers of Ontario (APPrO), June 21, 2006.

"Shifting Regulatory Oversight of Utility Mergers," with Cleve Tyler, *Innovating for Transformation*, The Energy and Utilities Project, Volume 6, 2006, page 37.

"Allocation of Emission Allowances for the Regional Greenhouse Gas Initiative." Whitepaper regarding an initiative under consideration in mid-Atlantic and Northeastern regions of the United States, written with Alan Madian, September 20, 2005.

"Toward a Capacity Demand Curve Market," with Julie Murphy, *Innovation for the Future*, The Energy and Utilities Project, Volume 5, 2005, page 46.
"LICAP Key Issues." Presented to Commissioners and staff of the Massachusetts Department of Telecommunications and Energy, Boston, Massachusetts, March 28, 2005.

"Market Power Screens." Presented at the Electric Power Supply Association (EPSA) Annual Fall Membership Meeting, Washington, DC, November 10, 2004.

"Ancillary Service Pricing Dynamics." Presented at the EUCI Ancillary Service Conference, Westminster, Colorado, March 13, 2003.

"California's Electricity Markets: Structure, Crisis, and Needed Reforms." Contributor, January 16, 2003.

"Capacity Payment Schedules: A Workable Approach for Resource Adequacy." Presented to the Energy Bar Association, Washington, D.C., December 12, 2002.

"Power Market Panel." Speaker in the Standard & Poor's 2002 Project, Power & Energy Credit Conference, New York, New York, November 13, 2002.

"Market-Based Pricing of Ancillary Services: Market Design Choices, Consequences and Performance." Presented at the EUCI Ancillary Services Conference, Atlanta, Georgia, September 27, 2002.

"Ancillary Service Market Performance During the Summer of 2002." Presented at the EUCI Ancillary Services Conference, Atlanta, Georgia, September 26, 2002.

"Revenue and Risk from the Lender's Perspective." Presented at the Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

“Preparing for Antitrust Scrutiny.” Panel discussion at the Utility Mergers & Acquisitions Conference, Washington, D.C., July 15, 1998.

“Perspectives of Investors and Developers.” Presented at the American Education Institute Conference on Power Contracts in affiliation with the United States Energy Association to the Romanian Electric Authority, Washington, D.C., March 19, 1997.

“Risk and Risk Management in Electricity Markets.” Presented at the Electric Load Aggregation Conference, Washington, D.C., November 18, 1996.

“Developing Firm Plans During Uncertain Times: Anticipating Change.” Presented during a session titled “Integrated Resource Planning and Demand Side Management After Federal Endorsement,” to the Institute of Public Utilities, Williamsburg, Virginia, December 15, 1992.

Numerous speeches and training programs regarding nuclear power plant operations, accident analysis, nuclear engineering and related subjects were given to operators and technical engineering personnel from power plants around the world, 1984-1986.

AFFILIATIONS AND PROFESSIONAL QUALIFICATIONS

Member, International Association for Energy Economics.

Member, Non-Attorney Professional, Energy Bar Association.

Mr. Hamal has held U.S. Nuclear Regulatory Commission certification as Senior Reactor Operator; U.S. Department of Energy qualifications as Nuclear Plant Engineer and Nuclear Engineer Officer of the Watch; and U.S. Coast Guard licenses as Third Assistant Engineer and Third Mate.

September 2012

B

Evaluation of the Export Tariff

By Marc-André Laurin

Brookfield Energy Marketing LP
(BEMLP)
Member of Association of
Power Producers of Ontario

For Filing in the
Hydro One Networks, Inc.
Rate Proceeding Before the
Ontario Energy Board
EB-2012-0031

October 1, 2012

I. Introduction

I am a Senior Trader (Ontario-Quebec) at BEMLP (CV provided at attachment 2), a member of the Association of Power Producers of Ontario (APPrO). I have been asked by APPrO to offer an opinion regarding the level of the Export Transmission Service (ETS) tariff on electricity exported from Ontario. This tariff, currently set at $2/MWh, is under review as part of the Hydro One Networks Inc. rate application before the Ontario Energy Board. My opinion will be limited to an analysis of the impact of the ETS tariff under the options covered in the CRA Study evaluating the benefits of exporting power out of Ontario. The ETS tariff scenarios evaluated in my analysis are as follows:

- Status Quo: $2 per MWh
- Unilateral elimination of the ETS tariff (No tariff): $0.00 per MWh
- Equivalent Average Network Charge (EANC): $5.80 per MWh
- Two-Tiered Scenario A: On-peak at $5.80 per MWh and off-peak at $0.00 per MWh
- Two-Tiered Scenario B: On-peak at $3.50 per MWh and off-peak at $1.00 per MWh

Before explaining the analysis, it is important to understand the distinction between trading decisions based on the results of a deterministic model and trading decisions in the real world. Contrary to a deterministic model, such as the one used in the CRA study, we traders do not have perfect knowledge of the state of the market. We need to incorporate into our business decisions an evaluation of risk. Since we do not have a perfect knowledge of the future, we do not know with certainty the prices at which the various underlying trades will settle. Each trading decision is made on expected price spreads. If these expectations turn out to be wrong, then we may suffer significant losses.

In order to manage our risk, an approach used extensively by Brookfield and others is to protect our physical transactions (i.e. exposures) by entering into financial contracts (i.e. SWAPs) and purchasing financial transmission rights (FTR) to act as an assurance against price fluctuation. The other aspect of these hedging strategies is that they cover periods of time extending beyond the hourly resolution of scheduling transactions. The hedging strategy may cover a period of time greater than one hour. We may hedge commodity prices on a daily, weekly, monthly or even yearly resolution.

Forward data for 2013 is available which allows us to assess the likely implication of a tariff change on trading activities for the year 2013. We also decided to limit our analysis to the Ontario - New York Zone A intertie. We based our analysis on trading decisions focusing on monthly transactions using forward values (as off September 26 2012) for the following elements:

- Monthly currency exchange rate;

- Monthly on-peak and off-peak electricity price for Ontario in Canadian dollars; and
- Monthly on-peak and off-peak electricity price for New York Zone A (which is the most liquid and tradable Zone in west New York against Zone O) in U.S. dollars.

It is also important to note that the definitions of "on-peak" and "off-peak" hours commonly used by traders differ from those used in the CRA report. In the CRA report, the on-peak hours are defined as 5X12. In the industry, on-peak hours are defined as 5X16 or from 7:00 am to 11:00 pm during weekdays. The analysis estimates the monthly price basis net of export fees between NY Zone O and Ontario. In order to evaluate the value of power in 2013 for NY Zone O, we use the closest liquid market where forward values are available. We used the forward value for NY Zone A and we apply the historical basis to price Zone O. As expected, an increase in the export fee shrinks the tradable basis between these two regions. The size of that spread is directly linked to the quantity of exports that will flow between these two markets. It is also important to consider the size of the estimated price spread compared to the cost of doing the trade. Having a smaller estimated basis with a higher cost of transaction is the equivalent a having a lower rate of return on an investment. Trading decisions are closely linked to the rate of return.

<u>Results of the analysis</u>

The table bellow summarizes the results of the analysis. A more comprehensive set of results is provided in attachment 1.

Price differential (Basis in USD) for the year 2013 between NYISO Zone O and Ontario										
	Current ETS		**$ 0 ETS**		**EANC ($ 5.80 ETS)**		**Two-Tiered Scenario A ($5.80 on-peak and $0 off-peak)**		**Two-Tiered Scenario B ($3.50 on-peak and $1 off-peak)**	
	Peak	**OFF**	**Peak**	**OFF**	**Peak**	**OFF**	**Peak**	**OFF**	**Peak**	**OFF**
January	2.94	4.16	4.94	6.16	-0.86	0.36	-0.86	6.16	1.44	5.16
February	3.48	4.66	5.48	6.66	-0.32	0.86	-0.32	6.66	1.98	5.66
March	3.04	3.97	5.04	5.97	-0.76	0.17	-0.76	5.97	1.54	4.97
April	2.81	3.17	4.81	5.17	-0.99	-0.63	-0.99	5.17	1.31	4.17
May	3.01	3.05	5.01	5.05	-0.79	-0.75	-0.79	5.05	1.51	4.05
June	3.17	3.20	5.17	5.20	-0.63	-0.60	-0.63	5.20	1.67	4.20
July	4.00	3.77	6.00	5.77	0.20	-0.03	0.20	5.77	2.50	4.77
August	3.76	4.11	5.76	6.11	-0.04	0.31	-0.04	6.11	2.26	5.11
September	3.50	3.74	5.50	5.74	-0.30	-0.06	-0.30	5.74	2.00	4.74
October	3.54	4.83	5.54	6.83	-0.26	1.03	-0.26	6.83	2.04	5.83
November	3.51	4.80	5.51	6.80	-0.29	1.00	-0.29	6.80	2.01	5.80
December	3.57	1.83	5.57	3.83	-0.23	-1.97	-0.23	3.83	2.07	2.83
Cal13	3.36	3.77	5.36	5.77	-0.44	-0.03	-0.44	5.77	1.86	4.77

These results show that under the current tariff, the expected trader benefit net of export fees for the year 2013 is $3.36 for on-peak hours and $3.77 for off-peak hours. If ETS is increased to $5.80 per MWh, then the expected benefit goes down to -$0.44 for on-peak hours and -$0.03 for off-peak hours.

These results show the expected value of a trade between these two markets without taking into consideration several additional risks that are difficult to specifically quantify. As an example, congestion at the intertie is a risk that has to be taken into account when we decide to export power out of Ontario. That risk may be alleviated by the purchase of a FTR. The cost of the FTR is not included in the analysis above and is significant. When we look at the figures presented in the table above, we have to add a risk premium to all of these figures which will reduce the trading margins. This risk premium is difficult to assess and may be different for each trader, but one thing is certain—that premium is a non-negative value. Adding a risk premium would reduce the price basis shown in the table above. A related issue is one of timing. When conducting long-term forward trades, traders not only consider the current margins available, but the potential for those margins to improve. Thus, when margins are small a trader may decide to wait to see if those margins improve rather than take a major, long-term position that would preclude a similar position in the future with better margins.

Wheeling power through an intermediate market introduces additional costs and risks that a trader must account for. For example, exporting power from Ontario to PJM through MISO clearly has additional costs and risks when compared to the Ontario to New York trade discussed above.

There is also the potential for very short-term trading, which warrants some additional considerations. In addition to these market-based risks, we have to take into consideration other risks that are inherent in the current structure of the Ontario market. The imposition of a -$8 floor price on exports is a significant risk factor in intertie trading. This new measure will be implemented on October 1, 2012 and will create a lot of uncertainty in the determination of the value of trade. Traders also have to take into consideration out-of-market intervention in the Ontario wholesale market. As an example, if there is an expectation of severe SBG, the IESO may decide to shut down a nuclear unit for several days. These actions are difficult to forecast and may significantly impact energy prices. A nuclear shut down may solve a SBG situation, but it may also create a scarcity situation for the following hours. Any out-of-market control actions create uncertainty in the market. More uncertainty is usually reflected by higher risk premiums being incorporated into intertie trading decisions.

The issue of risk is particularly problematic during hours when the IESO is predicting SBG problems. While one might think traders would view those hours as periods when prices in Ontario will be lowest, and therefore particularly attractive for export, this is simply not true. Actions taken by the IESO to deal with the SBG problem are often made before the clearing price is established and actual prices can be much higher than expected as a result of those actions. Typically, these actions are taken during the “closed window” in Ontario when a trader's bids are locked. These potential SBG hours are particularly uncertain and approached by traders with caution.

In the current state of the wholesale power market in Ontario and in surrounding jurisdictions, any ETS tariff higher than $0 would greatly reduce the incentive to export out of Ontario, especially in periods of surplus baseload generation.

Attachment 1

As of Sep 26 2012		PEAK ONT and ZA			ONT OFF				ZONE A OFF			Basis NY ZA / ZO		ZO over ONT (USD)	
Month	FX	ONT	ONT USD	ZONE A	2x16	7x8	OFF USD	ONT	2x16	7x8	OFF	5x16	OFF	Peak	OFF
Jan-13	0.9860	34.72	35.21	44.10	29.18	24.54	26.24	25.88	36.13	34.26	34.95	2.19	1.23	6.70	7.48
Feb-13	0.9867	32.71	33.15	41.55	27.15	25.70	26.23	25.88	35.07	34.88	34.95	1.26	0.75	7.14	7.97
Mar-13	0.9874	29.88	30.26	37.95	25.04	21.66	22.99	22.70	32.12	29.70	30.65	1.14	0.55	6.55	7.12
Apr-13	0.9882	29.84	30.19	37.90	27.15	16.60	20.27	20.03	29.50	25.74	27.05	1.39	0.60	6.32	6.18
May-13	0.9889	29.09	29.41	36.95	27.64	15.37	19.88	19.66	30.43	24.30	26.55	1.05	0.63	6.49	6.04
Jun-13	0.9897	30.78	31.10	39.10	29.59	13.88	20.16	19.95	32.09	23.52	26.95	1.27	0.58	6.73	6.21
Jul-13	0.9905	37.47	37.83	47.60	30.15	18.06	22.50	22.29	33.85	27.92	30.10	1.88	0.71	7.89	6.89
Aug-13	0.9913	33.22	33.52	42.20	30.94	17.57	22.48	22.29	33.46	28.15	30.10	1.25	0.38	7.43	7.24
Sep-13	0.9921	29.92	30.16	38.00	29.19	15.74	21.12	20.96	32.39	25.58	28.30	0.84	0.38	7.00	6.80
Oct-13	0.9921	28.78	29.01	36.75	23.78	19.00	20.63	20.47	33.17	26.77	28.95	0.75	0.46	6.99	7.86
Nov-13	0.9921	29.28	29.52	37.35	25.63	17.37	20.67	20.50	30.60	27.93	29.00	0.85	0.50	6.98	7.83
Dec-13	0.9921	32.53	32.79	41.15	31.29	25.44	27.73	27.52	34.26	33.17	33.60	1.15	0.65	7.21	5.22
Cal13	0.9898	31.52	31.85	40.05	28.06	19.24	22.57	22.34	32.76	28.49	30.10	1.25	0.62	6.95	6.90

	Current ETS						0.00$ ETS					
	Export cost				Net Spread ZA -		Export cost				Net Spread ZA -	
Month	Peak ETS	Peak Uplift	ETS OFF	Uplift OFF	Peak	OFF	Peak ETS	Peak Uplift	ETS OFF	Uplift OFF	Peak	OFF
Jan-13	2.00	1.76	2.00	1.31	2.94	4.16	0.00	1.76	0.00	1.31	4.94	6.16
Feb-13	2.00	1.66	2.00	1.31	3.48	4.66	0.00	1.66	0.00	1.31	5.48	6.66
Mar-13	2.00	1.51	2.00	1.15	3.04	3.97	0.00	1.51	0.00	1.15	5.04	5.97
Apr-13	2.00	1.51	2.00	1.01	2.81	3.17	0.00	1.51	0.00	1.01	4.81	5.17
May-13	2.00	1.47	2.00	0.99	3.01	3.05	0.00	1.47	0.00	0.99	5.01	5.05
Jun-13	2.00	1.56	2.00	1.01	3.17	3.20	0.00	1.56	0.00	1.01	5.17	5.20
Jul-13	2.00	1.89	2.00	1.12	4.00	3.77	0.00	1.89	0.00	1.12	6.00	5.77
Aug-13	2.00	1.68	2.00	1.12	3.76	4.11	0.00	1.68	0.00	1.12	5.76	6.11
Sep-13	2.00	1.51	2.00	1.06	3.50	3.74	0.00	1.51	0.00	1.06	5.50	5.74
Oct-13	2.00	1.45	2.00	1.03	3.54	4.83	0.00	1.45	0.00	1.03	5.54	6.83
Nov-13	2.00	1.48	2.00	1.03	3.51	4.80	0.00	1.48	0.00	1.03	5.51	6.80
Dec-13	2.00	1.64	2.00	1.39	3.57	1.83	0.00	1.64	0.00	1.39	5.57	3.83
Cal13	2.00	1.59	2.00	1.13	3.36	3.77	0.00	1.59	0.00	1.13	5.36	5.77

	5.80$ ETS						Two-tiered Option A: 5.80$ ETS Peak and 0.00$ OFF					
	Export cost				Net Spread ZA -		Export cost				Net Spread ZA -	
Month	Peak ETS	Peak Uplift	ETS OFF	Uplift OFF	Peak	OFF	Peak ETS	Peak Uplift	ETS OFF	Uplift OFF	Peak	OFF
Jan-13	5.80	1.76	5.80	1.31	-0.86	0.36	5.80	1.76	0.00	1.31	-0.86	6.16
Feb-13	5.80	1.66	5.80	1.31	-0.32	0.86	5.80	1.66	0.00	1.31	-0.32	6.66
Mar-13	5.80	1.51	5.80	1.15	-0.76	0.17	5.80	1.51	0.00	1.15	-0.76	5.97
Apr-13	5.80	1.51	5.80	1.01	-0.99	-0.63	5.80	1.51	0.00	1.01	-0.99	5.17
May-13	5.80	1.47	5.80	0.99	-0.79	-0.75	5.80	1.47	0.00	0.99	-0.79	5.05
Jun-13	5.80	1.56	5.80	1.01	-0.63	-0.60	5.80	1.56	0.00	1.01	-0.63	5.20
Jul-13	5.80	1.89	5.80	1.12	0.20	-0.03	5.80	1.89	0.00	1.12	0.20	5.77
Aug-13	5.80	1.68	5.80	1.12	-0.04	0.31	5.80	1.68	0.00	1.12	-0.04	6.11
Sep-13	5.80	1.51	5.80	1.06	-0.30	-0.06	5.80	1.51	0.00	1.06	-0.30	5.74
Oct-13	5.80	1.45	5.80	1.03	-0.26	1.03	5.80	1.45	0.00	1.03	-0.26	6.83
Nov-13	5.80	1.48	5.80	1.03	-0.29	1.00	5.80	1.48	0.00	1.03	-0.29	6.80
Dec-13	5.80	1.64	5.80	1.39	-0.23	-1.97	5.80	1.64	0.00	1.39	-0.23	3.83
Cal13	5.80	1.59	5.80	1.13	-0.44	-0.03	5.80	1.59	0.00	1.13	-0.44	5.77

	Two-tiered Option B: 3.50$ ETS Peak and 1.00$ OFF					
	Export cost				Net Spread ZA -	
Month	Peak ETS	Peak Uplift	ETS OFF	Uplift OFF	Peak	OFF
Jan-13	3.50	1.76	1.00	1.31	1.44	5.16
Feb-13	3.50	1.66	1.00	1.31	1.98	5.66
Mar-13	3.50	1.51	1.00	1.15	1.54	4.97
Apr-13	3.50	1.51	1.00	1.01	1.31	4.17
May-13	3.50	1.47	1.00	0.99	1.51	4.05
Jun-13	3.50	1.56	1.00	1.01	1.67	4.20
Jul-13	3.50	1.89	1.00	1.12	2.50	4.77
Aug-13	3.50	1.68	1.00	1.12	2.26	5.11
Sep-13	3.50	1.51	1.00	1.06	2.00	4.74
Oct-13	3.50	1.45	1.00	1.03	2.04	5.83
Nov-13	3.50	1.48	1.00	1.03	2.01	5.80
Dec-13	3.50	1.64	1.00	1.39	2.07	2.83
Cal13	3.50	1.59	1.00	1.13	1.86	4.77

Attachment 2

Brookfield

Brookfield Renewable Energy Group
Brookfield Energy Marketing Inc.
480 de la Cité Blvd
Gatineau, Québec J8T 8R3

Tel 819.561.2722
Fax 819.561.7188
www.brookfieldrenewable.com

For Filing in the Hydro One Networks, Inc. Rate Proceeding Before the Ontario Energy Board EB-2012-0031.

Curriculum Vitae of **Marc-André Laurin**

Current role for BEM LP: **Senior Trader, Ontario and Québec**

- Evaluate, develop and manage standard hedging strategies along with highly structured transactions;
- Monitor regulatory development in the Ontario / Québec market and advise managements of any impacts;
- Execute long and short term transactions intended to maximize the value of the company's generation;
- Develop a daily view of market direction and implement strategies to maximize profits, enhance profitability and limit risk;
- Assess the liquidity of market in order to advise on the capacity of hedging substantial marketing positions;
- Determine future business opportunities and develop new electricity products and services;
- Execute trades within the Brookfield Power Risk Management Policy;
- Supervise and motivate a small group of short time traders and schedulers;
- Develop and maintain relationships with key counterparties.

EXPERIENCE

Brookfield Renewable Power
Ontario & Québec Senior Trader **2009 – Current**

Brookfield Renewable Power
Ontario & Québec Short-term Trader **2006 - 2009**

Brookfield Renewable Power
New-York Scheduler **2004 - 2006**

Brookfield Renewable Power
Real-time Trader **2003 - 2004**

EDUCATION

Université du Québec en Outaouais (U.Q.O)
Certificate in Business Administration **2010**

Cité Collégiale
College degree in Computer Programming **2002**