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June 23, 2008

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BY ELECTRONIC MAIL & COURIER

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2007-0050 – Hydro One Networks Inc. ("Hydro One") – Bruce to Milton Transmission Reinforcement Project

Please find enclosed the Argument in Chief of Hydro One.

Yours very truly,

for: Gordon M. Nettleton
GMN:njm

c. All Interested Parties in EB-2007-0050

File: EB-2007-0050

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), (the "Act")

AND IN THE MATTER OF an Application by Hydro One Networks Inc. pursuant to section 92 of the Act, for an Order or Orders granting leave to construct a transmission reinforcement Project between the Bruce Power Facility and Milton Switching Station, all in the Province of Ontario (the "Leave to Construct Application")

HYDRO ONE NETWORKS INC.
ARGUMENT IN CHIEF
June 23rd, 2008

OSLER HOSKIN & HARCOURT LLP
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TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

INTRODUCTION

Hydro One Networks Inc. ("Hydro One") has applied to the Ontario Energy Board ("Board") for leave to construct a 500 kV electricity transmission line, beginning at the Bruce Power Complex in Kincardine and terminating at the Hydro One switching station in Milton, pursuant to section 92 of the *Ontario Energy Board Act, 1998* (the "Project").[1]

The application before the Board is first and foremost one that concerns the public interest and ensuring that the public interest is best served when taking into account the Board's jurisdiction and authority under sections 92 and 96 of the Act: whether the applied-for facilities are the best alternative to meet the identified need under the applicable criteria of price, quality and reliability of electricity service. It is a case that results from a transmission system planning exercise and the urging of the Ontario Power Authority ("OPA") for Hydro One to apply for and construct the Project. Given this, and given the positions taken by others during this proceeding, it is a case that concerns the credibility of those who are in fact the experts in the field of transmission planning and who have the experience and knowledge applicable to Ontario. Hydro One's position in this regard is straightforward: the OPA and the Independent Electric System Operartor ("IESO") are in the best position to assess generation forecast requirements and to assess system reliability impacts, respectively. This is so, given their legislated mandates, given their wealth of experience and knowledge of the complexities of how, in fact, the transmission system has historically been designed and has operated. The credibility of the OPA and the IESO's evidence in this regard is overwhelming and demonstrates that the Project is the only alternative that meets the identified need and satisfies Ontario transmission reliability criteria.[2]

The need for the Project is real and urgent: the OPA has prepared a generation forecast largely based on Ministerial Directives requiring procurement of refurbished nuclear generation, wind generation and other renewable energy generation. Although the project is non-discretionary according to the Board's filing guidelines, throughout the proceeding the applied-for facilities

[1] In addition to section 92 relief, Hydro One is also seeking approval pursuant to section 97 of the Act for the forms of agreement filed.

[2] The technical witnesses appearing for Hydro One had multiple decades of experience in transmission system planning and transmission system operations. See Exhibit A, Tab 5, Schedule 4.

have nonetheless been demonstrated to be the best option based on a rigorous analysis of locked-in energy and losses that would be avoided by the Project.

The evidence before the Board demonstrates that approval of the applied-for facilities will provide the necessary incremental transfer capability for the transmission of renewable and emissions-free power, in fulfillment of the Ministerial Directives. The applied-for facilities will provide relief to a stressed transmission system, thereby enhancing the quality and reliability of Ontario's power grid.

The hearing process into the application has been remarkable and appropriate given the public interest involved in this case. Over the course of the approximately 15 months since Hydro One's application was first filed, more than 700 written interrogatories were asked of Hydro One. The oral phase of the hearing comprised 14 full days and took place over a span of six weeks. Two technical conferences were also held into the application, given the complexity of its subject-matter and the integrated roles and functions of the Applicant, Hydro One, and those of the OPA and the IESO. There can be no dispute that the hearing process has at all times been fair, transparent and comprehensive in addressing the public interest.

While the hearing process has examined many of the tasks and areas of responsibility within the purview of the OPA and the IESO, the relief sought in this case concerns only leave of the Board to allow construction of the applied-for facilities. This case is not about pre-approving elements of the OPA's Integrated Power System Plan ("IPSP") application. This application precedes and is distinct from the IPSP. Nor is this case seeking approval or any formal Board determination of whether the IESO acts reasonably in the manner in which it seeks to obtain approval for special protection system modifications from the Northeast Power Coordinating Council ("NPCC"). It is also not about the manner in which the IESO has established and interpreted its own reliability standards that govern the Ontario power grid. Instead, this is a case about ensuring that the applied-for transmission facilities appropriately address the criteria set forth in section 96(2) of the Act, namely, price, quality and reliability of electricity service.

The following sections of this Argument in Chief are organized to address each of the Issues List Items set out in Procedural Order 5 and the oral comments made by the Chair on June 11, 2008 regarding Issue 6:

1. Project Need and Justification

2. Project Alternatives

3. Near Term and Interim Measures

4. Reliability and Quality of Electricity Service

5. Land Matters

6. Aboriginal Peoples Consultations

7. Conditions of Approval

Through this analysis it will be shown that the evidence found on the face of the record in respect of each Issue is clear and in all cases overwhelmingly supports the relief sought by Hydro One.

1. PROJECT NEED AND JUSTIFICATION

1.1 Has the need for the proposed project been established?

The need for the applied-for transmission facilities arises due to forecast increases in transfer capability requirements from the Bruce Area. The existing transmission system presently has a transfer capability of approximately 5,000 MW, less than its historic capability, because the load flow along the 500 kV system connecting with the Bruce Area has changed as a result of domestic load requirements, as explained by Messrs. Chow and Falvo during the Technical Conference in October.[3] Load flow pattern changes from the Bruce Area to the Greater Toronto Area ("GTA") will also influence the future flow away from the Bruce Area. No party seriously challenged these perspectives or suggested that load flow serving the GTA does not need to be taken into account in transmission planning exercises.

A. Content of the OPA Forecast

The need for the applied-for facilities is also based upon the OPA's generation and transmission forecast. This generation forecast is largely shaped by Ministerial Directives issued to the OPA, as well as the expected output from the Bruce Nuclear Complex in the future. The forecast describes an increase in generation from about 5,000 MW currently to 8,100 MW by 2015 and is composed of four components:

- 1,500 MW of refurbished nuclear generation at the Bruce "A" plant (per Ministerial Directive),
- 700 MW of committed wind generation (per Ministerial Directive),
- 1,000 MW of planned wind generation (per Ministerial Directive), and
- The refurbishment or replacement of Bruce "B" nuclear units when they reach end-of-life between 2015-2020.

[3] Exhibit C, Table, Schedule 1.3; Transcript, Vol. 2, May 2, 2008, page 45 line 22 – page 46 line 3.

Figure 1: Bruce Area Available Generation & Transmission Capacity (2007 – 2014)

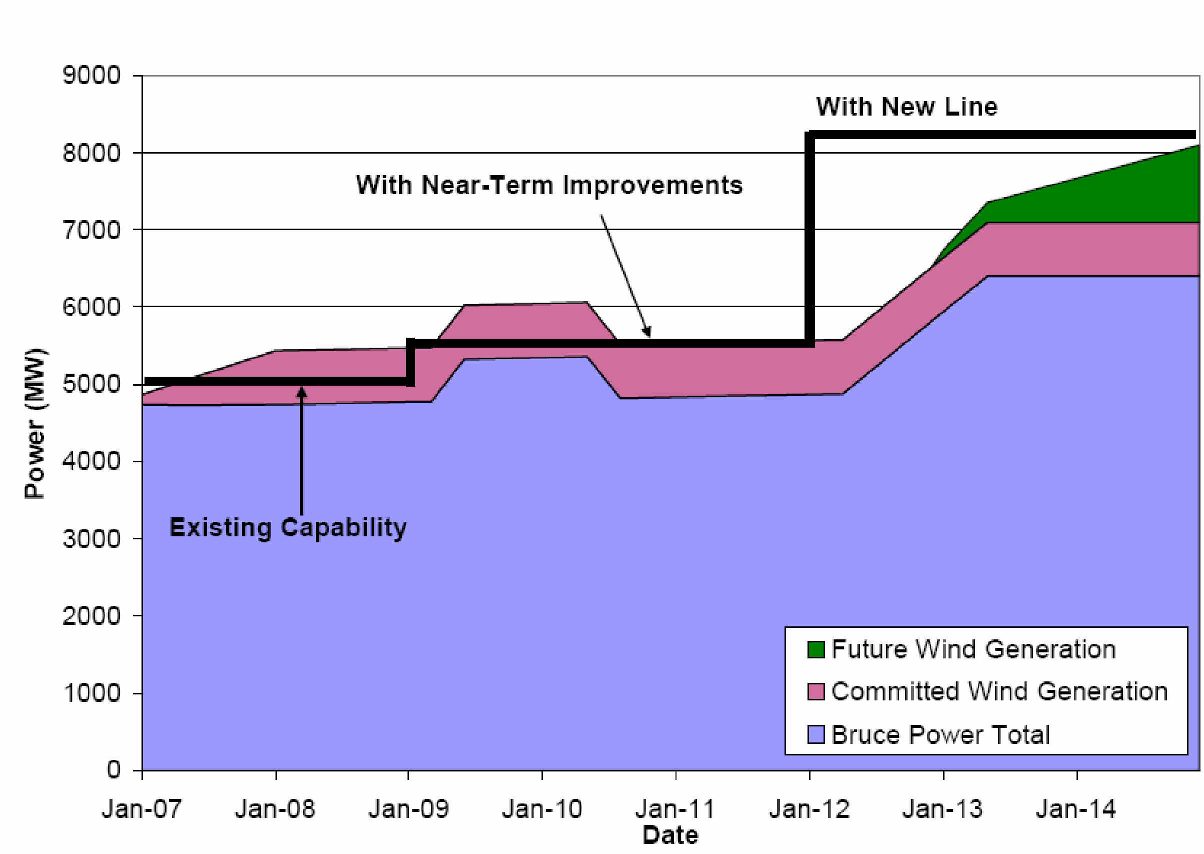

Exhibit B, Tab 3, Schedule 1, page 2

The nuclear component of the forecast takes into account the fact that two of the Bruce A units are currently being refurbished, and are scheduled to return to service in 2009. This will add 1,500 MW to Bruce nuclear generation when all units are in-service by 2013.

With respect to the "committed wind" estimate of the forecast, the evidence is that there is wind generation under contract that will come onto the system by 2009.[4] The evidence also shows that due to current transmission constraints – the "Orange Zone" moratorium – generation produced by other wind projects in the Bruce Area is unable to access the transmission system.

The third component of the forecast is 1,000 MW of "planned wind"[5] that is expected to be in service by 2015. As Mr. Chow explained, the planned wind estimate is based on two elements:

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[4] Exhibit B, Tab 1, Schedule 1, page 3.

[5] Exhibit B, Tab 6, Appendix 5; Exhibit C, Tab 1, Schedule 2.1.1.

700 MW of large wind farm generation and 300 MW from the Standard Offer Program ("SOP").[6] The reasonableness of this projected amount is underscored by the description of the pent-up demand to access the Bruce wind basin in the IESO queue that Mr. Falvo provided,[7] and by the August 27, 2007 renewable power Directive from the Minister of Energy in regard to sourcing an additional 2,000 MW of renewable power, about one third of which is expected to come from the Bruce Area, as noted by Mr. Chow.[8]

Finally, the generation forecast also takes into account the very strong interest that exists to have the Bruce B units refurbished or replaced, when they reach end of life in the period 2015 – 2020.[9]

[6] Exhibit B, Tab 6, Appendix 5; Exhibit C, Tab 1, Schedule 2.2.1; Transcript, Vol. 4, May 6, pages 39-58.

[7] Transcript, Vol. 8, May 12, pages 42-44.

[8] Transcript, Vol. 1, May 1, page 84 line 26 – page 85 line 2.

[9] Exhibit K10.1, Tab 20.

B. Reasonableness of the Generation Forecast

The need for the applied-for facilities is directly attributed to the OPA's generation forecast. The core question of whether the forecast is appropriate is whether each of the four components described above is reasonable. No party has suggested that generation from Bruce A nuclear units ought not to be included in the forecast. Similarly, the reasonableness of committed wind is uncontroverted. No party has suggested that such generation ought not to be included in the forecast. The only disputed areas lie with the longer term forecast for: (i) planned wind, and (ii) the reasonableness of including continued Bruce B generation. The record of this hearing, and the evidence of Hydro One and the OPA, demonstrate that each component is reasonable.

1. Planned Wind

(a) Reasonableness of Planned Wind

The planned wind forecast estimate is based on two sub-components: (i) SOP generation related to small wind projects;[10] and (ii) large wind projects. The SOP estimate amounts to 300 MW. The reasonableness of this forecast component has not been seriously challenged, and for good measure. The Standard Offer Program was oversubscribed and is the subject-matter of "Orange Zone" procurement restrictions.

The large wind component of the planned wind has been based upon an assessment that up to 1,400 MW is expected to be developed in the Bruce Area, commencing in 2013. For purposes of the transmission planning forecast exercise, the OPA conservatively adjusted this expected output level by a factor of 50%.[11] Thus, the result is that only 700 MW of large wind has been included in the planned wind forecast category.[12]

While no party challenged or took issue with the conservatism of the OPA's 50% adjustment factor, the reasonableness of the planned wind level was further demonstrated by examining evidence concerning the current IESO queue levels.[13] The IESO queue shows that new generation projects are in fact in the development stage and are undergoing impact assessments

[10] Exhibit B, Tab 6, Appendix 5; Exhibit C, Tab 1, Schedule 2.1.1.

[11] Transcript, May 1, page 84 lines 3-16; Exhibit C, Tab 1, Schedule 2.1.1.

[12] Transcript, May 1, page 84 lines 3-16; Exhibit C, Tab 1, Schedule 2.1.1.

[13] Exhibit K10.1, Tab 13.

by the IESO to ensure adverse system impacts do not result. The IESO queue information is publicly available from their website. Projects in the queue that are from the Bruce Area today well exceed the 700 MW: 813 MW of generation in the queue presently have their System Impact Assessment ("SIA") on hold, and there is an additional 1498.4 MW of generation in the queue for the Bruce Area.[14] Thus the OPA's inclusion of only 700 MW in the planned wind category of the transmission planning forecast is further demonstration of the conservatism and reasonableness of the forecast presented and relied upon to justify need for the Project.

The significance of the queued capacity and concomitant reasonableness of the 700 MW level included in the planned wind category becomes even more apparent when one considers the Ministerial Directive issued to the OPA and dated August 27, 2007.[15] Under that Directive, the OPA has been directed to procure up to 2,000 MW of renewable generation from across the province by 2011 – less than three years from now. Wind power is by definition a renewable generation resource, and the OPA has estimated that 700 MW of the directed 2,000 MW of renewable resources would be large wind projects procured in the Bruce Area,[16] one of the "most fruitful windsheds in Ontario."[17] Establishing a forecast that assumes that only one third of the overall total renewable supply under the Directive will come from this region, notwithstanding the IESO queue levels, and notwithstanding the relative proximity which this region has to Ontario load, further demonstrates that a prudent and conservative forecasting approach has been taken by the OPA.

(b) Opposition to OPA's Planned Wind Forecast Estimate

The only party seriously challenging the inclusion of the 700 MW of the planned wind component of the OPA's forecast was Mr. Russell for the Saugeen Ojibway Nations ("SON"). Mr. Russell contended that, despite the OPA and the IESO's evidence, the inclusion of 700 MW in the planned wind category was not reasonable given the lack of certainty and foundation to support this forecast estimate.

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[14] Exhibit K10.1, Tab 13, pp. 11-12: heading 2 lists all Bruce Area wind projects whose SIA is on hold and heading 3 holds Bruce Area projects in the queue.

[15] Exhibit C, Tab 11, Schedule 1, Attachment 1.

[16] Transcript, Vol. 1, May 1, page 84 line 26 – page 85 line 2.

[17] Transcript, Vol. 2, May 2, page 70 lines 8-18.

Despite such assertions it became apparent that Mr. Russell's position was not one that was informed by all of the relevant facts, particularly the implications of the Ministerial Directives. Curiously, Mr. Russell contended that the IPSP must first proceed so that "transmission penalties" can be assigned to individual projects in the Bruce Area and, absent that process, it would be premature to assume that the OPA will act on the August 27, 2007 Ministerial Directive to procure 2,000 MW of wind generation, and do so from the Bruce Area:[18]

> MR. RUSSELL: In this case, we're being told the upgrade is needed for this 1,000 megawatts of wind, of which the 700 is not standard offer and would be supposedly subject to this competitive acquisition.
>
> We have been told here that the transmission upgrades are needed for it, but over in the -- and you would assume logically that costs would be allocated to the wind in the Bruce area to reflect that this transmission is being added, so its penalty to the ratepayer would be properly reflected.
>
> However, when we go to the IPSP, this proceeding is assumed to be decided and to have been decided in Hydro One's favour, and all of the costs of the upgrades under discussion here, which are supposedly necessary to the wind in the Bruce, are not charged to those Bruce area generators. There has just been a very different approach to accountability for upgrades between the IPSP and this proceeding.

This is not, however, how the process works in Ontario. As a network reinforcement, the cost of the Project will not be attributed to any generator, consistent with the requirements of the Transmission System Code in relation to network costs.[19] The situation in Ontario is different from those FERC jurisdictions in which Mr. Russell has been qualified as an expert witness. Mr. Russell's overwhelming experience in those jurisdictions, and the admission that he had not consulted Hydro One's transmission tariff, perhaps explains the position he has adopted in his testimony.[20]

Mr. Russell also suggested that that there ought to be contracts, certifications, lending agreements, and authorizations present before any of that projected generation is incorporated into the OPA forecast. Recall Mr. Russell's testimony during cross-examination as it concerned the inclusion of planned wind of 700 MW in the forecast:

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[18] Transcript, Vol. 14, June 11, 2008, page 27 line 20 – page 21 line 9.

[19] Exhibit B, Tab 4, Schedule 3, page 1, lines 22-24, as updated on Nov. 30, 2007.

[20] Transcript, Vol. 14, June 11, 2008, page 144 lines 21-24.

> MR. RUSSELL:…You've got to get some indicators of certainty. You've got a real live person on the other side of the table. He has a wind machine under contract. The turbine is going to be produced and delivered at a certain time. He has an interconnection agreement. He has a purchase agreement. He has, you know, rights to the site. He has an EPC contractor. He has -- his substation is built, and so on and so forth.[21]

The implications of Mr. Russell's submission, particularly in the nascent Ontario marketplace, are untenable at best. The suggestion is that perfect certainty must first exist in respect of new wind developments before upgrades to the transmission network are planned for their interconnection. It is anomalous to, on the one hand, suggest the Board set perfect certainty as the standard which must be demonstrated yet on the other hand give credence to the fact that in Ontario, a central planning authority exists and whose mandate consists of long-term forecasting, i.e., making predictions in an absence of certainty, and whose mandate also includes acting as the counter-party for the procurement of generation under Ministerial Directives. Mr. Russell's suggestion also ignores the fact that the OPA forecast is eminently robust and reasonable. Indeed, it would seem that Mr. Russell urges a higher threshold for Ontario wind developments when other jurisdictions with other rate designs, such as California, accept imperfect certainty as the basis to plan and execute public policy. Mr. Russell's view here would seem to differ with the basis of his FERC testimony on behalf of California wind developers in the Tehachapi project,[22] explored during the hearing, and it is unclear to what extent that view relates to his involvement with the IPSP.

Even in the FERC context, transmission projects have proceeded in circumstances similar to the Bruce Area where a forecast for new renewable generation exists, but all of the development pieces are not yet in place. For example, with respect to the Tehachapi area referred to by Mr. Russell, the California Public Utility Commission stated as follows:

> While our prior directives go a long way toward reconciling the bid ranking process with the general preference of building transmission as economically as possible, existing rules governing actual cost responsibility remain problematic. Current FERC policy requires an interconnecting generator to initially fund (or "finance") transmission upgrades which would not have been built but for the interconnecting generator's request for service. However, if the upgrades are classified as "network" facilities, the upgrade costs can be "rolled-in" to general transmission rates, and the transmission owner would repay the interconnecting generator, with interest, in monthly payments amortized over a number of years

[21] Transcript, Vol. 14, June 11, 2008, page 104 lines 16 – 22.

[22] Exhibit K10.1, e.g., page 3: rolled-in rate treatment to expand transmission to encourage wind development.

> beginning when the new generation is available to the grid. In contrast, gen-tie costs must be permanently funded by new generators and thus absorbed as part of the cost of producing power.
>
> The burdens this policy places on generators may be acceptable in circumstances where no economic advantage is gained by sizing the expansion in excess of what is needed to support a known generator project. However, there are significant problems with this approach in situations where the optimally sized expansion, based on expectations of future market entry, exceeds the capacity needed to support known projects.
>
> . . .
>
> <u>CalWEA suggests that the Commission should avoid reading the "necessary to facilitate" language to require certainty that a transmission facility will be needed if [Renewable Portfolio Standard] goals are to be met and instead look to an array of evidence, without setting particular thresholds regarding actual generation project developments.</u> [emphasis added]
>
> CEERT suggests that the Commission find that transmission facilities planned and built to access known, concentrated renewable resources areas in California and to serve multiple renewable generators should be deemed necessary to facilitate achievement of the renewable power goals of the RPS program. CEERT asserts that the renewable resource areas studied by the Tehachapi Collaborative Study Group and the Imperial Valley Collaborative Study Group are "known, concentrated renewable resource areas."[23]

In this California example, where Mr. Russell acted on behalf of wind developers, the "indicators of certainty" he demands in this case did not exist; what existed instead was a legislative mandate to improve renewable portfolio supplies. The analogy is compelling. Whereas Ontario has Ministerial Directives, California had legislation. Whereas Ontario has an independent planning authority and forecasts wind generation using a 50% factor and its Independent System Operator has an established queue, California had and relied upon a queue. And whereas California had generation rate design issues, Ontario does <u>not</u> because the nature of the service has been and will be treated as a Network Cost and not the responsibility of generators. The fact that there are indeed fundamental cost responsibility and rate design differences between FERC jurisdiction utilities and Ontario simply did not appear to be taken into account at all by Mr. Russell's analysis.

[23] Order Instituting Investigation to Facilitate Proactive Development of Transmission Infrastructure to Access Renewable Energy Resources for California, CPUC Decision 06-06-034 - Interim Opinion On Procedures To Implement The Cost Recovery Provisions Of Public Utilities Code Section 399.25, CPUC Investigation 05-09-005, pp. 11 and 27.

Mr. Russell admitted that, in Tehachapi, transmission projects proceeded on the basis of forecast generation, such as the construction of 500 kV lines initially energized only at a 230 kV level.[24] The expectation was that generation would arrive and justify the early construction, and expense, of 500 kV infrastructure, so as to meet public policy goals of the State of California, all without the contracts, certifications, lending agreements, and authorizations which Mr. Russell now claims to be essential to any approval.[25]

As further evidence of Mr. Russell's unfamiliarity with the Ontario context, his pre-filed evidence attacked the OPA's forecast on the basis that it included "two significant sources of generation that had not been approved or committed …. 1,000 MW of potential wind generation …. [and] 4 refurbished Bruce B units."[26] On this basis, Mr. Russell concluded that "a decision to construct the Bruce-Milton Lines should not be made until there is an approved decision for, and commitment to, new nuclear generation or substantial new wind generation in the Bruce area."[27]

Mr. Russell argued that the various Ministerial Directives, including the August 27, 2007 Directive, did not alter the uncertain status of the 1,000 MW of planned wind because OPA procurements of this wind still required necessary approvals. On cross-examination, Mr. Russell maintained that OPA procurement of this planned wind was subject to approval, although Mr. Russell admitted that he did not know what approval was required:

> MR. NETTLETON: We'll get there. Let me turn to the next tab, which is tab 4 of my aid to cross, and that is the August 27th directive, August 27, 2007. That was the directive made by the minister Duncan in a letter addressed to Dr. Jan Carr. Do you have that?
>
> MR. RUSSELL: I have, yes.
>
> MR. NETTLETON: Now, Mr. Russell, you were asked an interrogatory by Hydro One in respect of this directive. It was Hydro One Networks, Inc. to Saugeen Ojibway Nation interrogatory 1(b). Do you have that?
>
> MR. RUSSELL: We're back in tab 22, is that where you are?

---

[24] Transcript, Vol. 14, June 11, 2008, page 162 line 4 – page 164 line 13.

[25] Transcript, Vol. 14, June 11, 2008, page 168 line 4 – page 169 line 6.

[26] SON Evidence, page 10.

[27] SON Evidence, page 4.

MR. NETTLETON: That's correct. It's actually -- I believe it is tab 21.

MR. RUSSELL: 21, okay I have it. What number was it?

MR. NETTLETON: It's number 1(b).

MR. RUSSELL: Yes.

MR. NETTLETON: The question was that was asked was:

"Please explain how you took into account this directive for the procurement of 2,000 megawatts of large wind renewable energy supply, in addition, i.e. incremental, to the generation within the standard offer program RES I and RES II programs."

Do you see that?

MR. RUSSELL: Yes.

MR. NETTLETON: And the answer you provided says that, that you had understood that the 2,000 megawatts of large wind renewable energy supply was a target level.

MR. RUSSELL: Yes.

MR. NETTLETON: -- of the IPSP, and that procurements would need to be approved before becoming the subject matter of a binding commitment on OPA and Hydro One.

Do you see that?

MR. RUSSELL: Yes.

MR. NETTLETON: Help me understand what approval you are speaking of.

MR. RUSSELL: I was speaking of a contract to purchase wind power from a project.

MR. NETTLETON: Whose approval are you thinking of in that response?

MR. RUSSELL: I had assumed that there was a process by which approval was given to wind purchase contracts.

MR. NETTLETON: Approval from whom?

MR. RUSSELL: I wasn't sure. I am not that familiar with that process. [emphasis added][28]

As is evident from the above excerpt, Mr. Russell's critique of the OPA's forecast of planned wind was based on his incorrect assumption that the OPA's power to procure wind was subject

[28] Transcript, Vol. 14, June 11, 2008, page 113 line 10 - page 114 line 1.

to further approval; that, of course, is not the case. In fact, the Directive of August 27, 2007 concluded by stating:

> It is expected that, as a consequence of this direction, the OPA will enter into such contracts with suppliers as necessary to implement the initiative.

The *Electricity Act* provides that the OPA shall develop procurement processes for managing electricity supply in accordance with its approved IPSPs and shall have such processes approved by the Board.[29] However, the *Electricity Act* also provides that before approval of the IPSP, the Ministry may direct the OPA to assume the powers of the Crown under any procurement issued or pursued by the Crown (or under any contract entered into by the Crown pursuant to a procurement initiative), and where the OPA enters into contracts following such procurements, such contracts *shall be deemed to be procurement contracts approved by the Board*.[30] Accordingly, contrary to Mr. Russell's assumption, the OPA does not have to obtain any approval, as part of the IPSP or otherwise, to procure wind generation (including wind generation it has identified in the Bruce Area) pursuant to the August 2007 directive. Moreover, projects that are the subject of Ministerial Directives issued prior to the date of the approval of the IPSP – namely Bruce nuclear refurbishment and Bruce Area wind generation projects[31] – are not subject to the IPSP review process.[32]

When confronted with the August 27, 2007 Ministerial Directive, Mr. Russell continued to demonstrate his unfamiliarity with the Ontario process, describing it as little more than "guidelines" that did not tightly bind the OPA in procuring that generation.[33]

Yet the Directive is unambiguous and speaks for itself: the OPA must enter into contracts for up to 2,000 MW of renewable electricity supply by 2011. This is a large amount of electricity to be procured in a short time. It is again sensible to expect the OPA to use 35% of this limitation from an abundant source of renewable energy, wind power, and from one of its most fruitful and

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[29] S.O. 1998, c. 15, Sched. A, ss. 25.31(1) – (4).

[30] *Ibid.,* ss.25.32(4) – (7).

[31] Exhibit B, Tab 6, Schedule 5, Appendices 8,9,10 and 12.

[32] IPSP Filing Guidelines (EB-2006-0207, p. 9). See also Exhibit B, Tab 4, Schedule 3, page 1.

[33] Transcript, Vol. 14, June 11, 2008, page 117, line 10.

accessible locations, particularly given the demand in the IESO queue.[34] The Government of Ontario has made deliberate policy choices towards replacing coal generation with renewable generation and instructed the OPA to take certain steps as part of that overall plan.[35] That reason, and those Directives, are why the OPA has incorporated planned wind into its forecast. It has done so prudently and conservatively. If the Directive was as malleable as suggested by Mr. Russell, e.g., "a work plan of sorts,"[36] it would serve little purpose. Moreover, the OPA would be negligent in its mandate if it were to interpret it that liberally.

What more indicators of certainty should the OPA reasonably require before allocating 700 MW of the directed 2,000 MW renewable energy procurement to Bruce Area wind generation? It has government direction to procure the wind without further authorization; a short deadline; a rich wind resource; proximity to load and strong commercial interest already as shown by the IESO queue.

2. Reasonableness of Continued Bruce B Generation

The second area of dispute concerning the generation forecast is whether Bruce "B" units will be refurbished or replaced with a new build.

Some parties to the proceeding have suggested that it is unreasonable for the OPA to have assumed that the existing level of Bruce nuclear generation will continue past the present expected 2018-2019 retirement date of the Bruce B units. These parties suggest that for transmission system planning purposes it is, in fact, unreasonable to assume that either:

(i) Bruce B will be refurbished, or

(ii) A new build will replace it ("Bruce C").

But what is the basis of such a contention, and how does this position compare to the justifications advanced for the proposition that the transmission system planning process should be inclusive of such outcomes (i.e., refurbishment or new build replacement)?

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[34] Exhibit K10.1, tab 13, pp. 10-11.

[35] Exhibit B, Tab 6, Schedule 5, Appendix 7, page 2.

[36] Transcript, Vol. 14, June 11, 2008, page 117, lines 10-11.

The transmission system planning exercise justifying the applied-for facilities entails making informed choices to address future need. Forecasts ought to be assessed based on their robustness, which in turn requires consideration of the reasonableness of the underlying assumptions made.

The OPA's assumptions in this regard and related to Bruce B refurbishment have been clearly articulated and are, in all respects, reasonable and cogent. The continuation of Bruce B generation output is assumed to exist based on:

- The continued need for nuclear electricity generation in Ontario to serve baseload electricity requirements of 14,000 MW, and to this end the Supply Mix Ministerial Directive directs the OPA to make plans for such an outcome;[37]

- Grid access and existing infrastructure at the Bruce Complex allows continued historic levels of nuclear output (apart from transmission transfer capability);

- The local Bruce Area community supports the continued and expanded nuclear generation; and

- The operator of the Bruce nuclear facility has expressed interest in continuing nuclear generation in the context of either Bruce B refurbishment and/or replacement.[38]

These factors demonstrate that the OPA used sound judgment in the development of its forecast. While more recent government announcements now provide further confirmation of the OPA's expected outcomes and assumptions, what has remained as an unknown are the justifications from opponents of the project supporting the view that Bruce Area nuclear generation will *decline* in the future. There is no evidence to support such an outcome in this proceeding. Given this, Bruce refurbishment or replacement remains as a more realistic and likely outcome. Inclusion, therefore, in the OPA's generation forecast is sensible and reasonable.

Pollution Probe and the SON have each suggested in their evidence that, as with planned wind, the absence of absolute certainty means that an amount of generation equivalent to current Bruce

[37] Exhibit B, Tab 6, Schedule 5, Appendix 7, page 2.

[38] Exhibit K10.1, Tab 20.

B generation should be ignored. That, however, belies clear Government directives, the role of the OPA and the nature of a forecast.

C. Reasonableness of Planning Transmission Capability Based on Nameplate Generation

The use of generation nameplate capacity for purposes of planning transmission facilities was also the subject matter of some debate in this proceeding.

Hydro One, OPA and the IESO have all indicated that use of nameplate capacity for planning transmission facilities has been a longstanding practice. In their view, there is no reason to depart from this planning approach notwithstanding the fact that wind generation is now involved. The main reason for this position is that that the transmission system has not, and should not, be planned to require congestion or to constrain off generation resources.

It is true that, from an operating perspective, nuclear and wind generation do not generate at 100% of their nameplate rating all of the time. But the relevance of this operational attribute to a transmission system planning exercise has not been made out by those opposing the Project – let alone explained why such an approach could be consistent with government policies to promote renewable energy and the reduction of congestion.

There is a significant difference between comparing the nameplate capacity of a generation resource to its operating history, and using the nameplate capacity of a resource to plan for an appropriate transmission system. For example, Pollution Probe's witnesses have held out an operational study as a transmission planning exercise. However, undersizing the transmission system would result in constant congestion management and prevent full capture of the benefits of the generation resource, both from policy and economic perspectives. It would also put the transmission system at greater risk with respect to system reliability.

The best evidence before the Board is that, as per longstanding practice in Ontario, good transmission planning is to design the system not to match average operational performance, but to meet maximum output of the generation assets, i.e., nameplate capacity, supported by a sound economic rationale:

> MR. CHOW:….In the planning of the transmission, to get the generation out of the Bruce, we are assuming, again, as I stated before lunch, the planning for a

> system would to provide for output at installed capacity, one that will allow to minimize the congestion.
>
> Now, that's again a practice we had in Ontario for many times and elsewhere in the utility.
>
> I think there's a question to me, say, Okay, does the wind change that? In our view, it doesn't change it, because we follow a planning standard that we use in planning for Ontario, and the planning standard body that set that planning criteria is the IESO.
>
> MR. FALVO: I would support that, Mr. Ross. The standards that are in place for Ontario, set by the IESO, don't have any exemptions or special treatment for wind. In terms of designing the transmission system, it should be designed to deliver all of the forecast generation.[39]
>
> . . .
>
> MR. FALVO: …and the locked-in energy assessment is the financial evaluation that will demonstrate the value of one plan over another, in terms of getting the energy out.
>
> MR. SKALSKI: That's right. And the locked-in energy assessment here clearly indicates that the line is the better alternative because it provides the greatest level of savings of locked-in energy and losses.[40]

The Board has been provided with evidence that nuclear generation units at the Bruce not only operate at their maximum continuous rating ("MCR"), i.e., nameplate capacity, but in fact have limited manoeuvrability to generate at less than their MCR, except within a narrow limit of about 50 MW. Because they can only be "derated" in a limited fashion, the nature of their output is effectively either "on or off."[41] The Board has also been provided with evidence that, according to the IESO's Market Rules, wind generation has preference in the IESO dispatch order (i.e., is self-scheduling) and hence, when the wind is blowing, wind generation will always be accepted by the system as an "in-merit" resource.[42] As such, the Market Rules maximize the amount of wind included in the generation mix.[43] Accordingly, when periods of peak wind production coincide with periods of peak nuclear production, the required transmission capability to accommodate that combined amount of generation is nameplate capacity. For example, the operating nuclear units at the Bruce Power complex and Amaranth and Kingsbridge wind farms

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[39] Transcript Vol. 2, May 2, page 89, beginning at line 14.

[40] Transcript Vol. 3, May 5, page 133, lines 10-16.

[41] Transcript Vol. 7, May 9, page 63 lines 26-28 and page 64 lines 1-4.

[42] Exhibit K1.1.

[43] Undertaking J7.2.

were simultaneously producing power at or above their maximum continuous rating for 37 days during 2007.[44]

Messrs. Chow and Falvo repeatedly explained why this is longstanding and prudent Ontario policy: to do otherwise means that the system would be designed to operate in a constrained, congested way.[45] To plan for congestion would impair the operation of the electricity system, limit the ability to utilize renewable resources and contravenes the wording of the supply mix Ministerial Directive, namely, to minimize congestion.[46] Other jurisdictions, such as Alberta and Texas also have mandated a minimization of congestion for transmission planning purposes.[47] Ministerial Directives place Ontario in similar circumstances, namely to minimize congestion through the transmission system planning processes undertaken by the OPA.

To design otherwise is to ensure that power will not be available to people who have paid for it. As Mr. Chow explained, that will detrimentally affect the development of the wind generation market.[48] Additionally, the lost energy would need to be replaced by a less environmentally benign and potentially more expensive source of generation, <u>contrary</u> to the August 27, 2007 Directive which articulated the objectives of "ensuring electricity supply and mitigating the environmental impacts of electricity production". This approach to transmission planning is not new, and eminently sensible in an effort to maximize the potential of renewable resources.

The acceptance of congestion in the context of the Bruce Area would also be a repudiation of policy goals to pursue clean forms of generation. There is a social cost when congested renewable megawatts are replaced by megawatts from a gas-fired peaking plant. The OPA is procuring the clean nuclear and wind resources in the Bruce Area as a result of, as articulated by Mr. Skalski, policy choices of the Ontario Government.[49] This power cannot be stored and therefore is "wasted" if it cannot be delivered due to congestion. This is unlike the situation in areas comprised of hydro-electricity and wind power, where renewable energy can be "stored" in

[44] Exhibit C, Tab 12, Schedule 20

[45] Transcript Vol. 3, May 5, page 125, lines 24-28 and page 127, lines 1-3.

[46] Exhibit B, Tab 6, Schedule 5, Appendix 7, page 1.

[47] *Transmission Regulation*, A.R. 86/2007, s. 15(1)(e); Exhibit K10.1, Tabs 14, 15 and 16.

[48] Transcript Vol. 7, May 9, page 49, lines 1-7.

[49] Transcript, Vol. 3, May 5, 2008, page 73 line 20 – page 74 line 22.

the hydro dam. It would be perverse if the government were to direct the OPA to procure more renewable resource capacity, and contract for Bruce nuclear refurbishment, only to have the OPA plan transmission in a way that will constrain both renewable and nuclear generation resources.

Congestion results in locked-in energy, and there is an economic cost associated with locked in energy. It is the antithesis of reasonableness to create a forecast using assumptions that induce congestion. Synapse Energy Economics ("Synapse")/Mr. Fagan, on the part of Pollution Probe, and Mr. Russell for the SON, have suggested that the more economically efficient approach in sizing transmission capability is to tolerate certain amounts of congestion, although they do not say how much, nor do they point to a policy to that effect in use in Ontario or elsewhere.

There can be little doubt that their suggested approach, without more, would stifle a nascent wind market before it gets off the ground and work against the reliability standards of the IESO. Scaling down available transmission capability in the Bruce Area below nameplate, and accepting that congestion will occur as a result, asks wind developers to bear the risk that there is sufficient diversity within the Bruce wind basin such that when the wind blows at one site, it is not blowing at other sites in the Bruce Area. Although both Mr. Fagan and Mr. Russell speculate that there is a high level of wind diversity in the Bruce wind basin, neither provides any evidence in that regard. Neither expert has provided evidence to support their view on wind and climate in the Bruce Area. However, the OPA has retained respected consultants Hélimax Energy Inc. and AWS Truewind, LLC for the purpose of their forecasting and used their data accordingly. The Board must make a credibility determination. Hydro One submits that the issue of credibility ought to overwhelmingly be decided in favour of the evidence it and the OPA provided.

Alternatively, as Mr. Fagan effectively admitted when pressed about contractual elements that would likely have to be in place to shore up the market,[50] it is Ontario ratepayers that will bear the risk through higher prices for wind power that will be necessary to attract wind investment if his unsupported assumptions are correct, namely that there is (i) a significant diversity of wind within the Bruce Area – a factor that is counter-intuitive and unsupported by any evidence on the record, or (ii) that the post-refurbishment performance of the Bruce units will be poor and they

[50] Transcript, Vol. 13, June 4, 2008, page 91, lines 1-16.

will not operate as designed – and there is again, nothing beyond speculation on the record that this will be the case. That is therefore an unreasonable risk to ask ratepayers to shoulder.

In summary, and as it relates to Issue 1.1, the best evidence before the Board is that prudent transmission planning and fulfillment of policy goals require planning to the nameplate capacity of the Bruce generation forecast – a forecast which is reasonable. The only way to achieve the nameplate generation forecast, unchallenged by the submissions of both Pollution Probe and the SON, and which requires an 8,100 MW transfer capability design, is by way of the applied-for facilities.

1.2 Does the project qualify as a non-discretionary project as per the OEB's Filing Requirements for Transmission and Distribution Applications and if so what categories of need as referred to in Section 5.2.2 of these Filing Requirements are relevant?

The second sub-issue under the heading of Issue 1 Project Needs and Justification relates to the non-discretionary nature of the Project. According to section 5.2.2 of the Board's Filing Requirements, non-discretionary projects are those required to, among other things, (i) "achieve Government objectives that are prescribed in governmental directives or regulations," and (ii) "to accommodate new generation." In these circumstances, the Ministerial Directives on the record[51] require the procurement of new generation, driving the need for the Project and, therefore qualify it as non-discretionary.[52]

These Ministerial Directives require the OPA to minimize congestion, maintain nuclear baseload generation, and increase reliance on renewable energy. The Directives set explicit targets for an additional 3,300 MW of renewable energy[53] pursuant to requests for proposals ("RFPs"), and created the Standard Offer Program to encourage smaller projects outside the timing requirements of the RFP process. These Directives, as previously discussed, underlie the reasonable generation forecast of 8,100 MW of transfer capability required to transmit power from the Bruce Area. Because the Project is required to achieve the aims of these Directives, it is properly categorized as non-discretionary.

1.3 Have all the appropriate project risk factors pertaining to the need and justification (including but not limited to forecasting, technical and financial risks) been taken into consideration in this project?

The third sub-issue under the heading of Issue 1 is whether appropriate risk factors related to project need have been considered in the application. A discussion of the following risk factors, which comprise forecasting, technical and financial risks, and also relate to the section 96 criteria of price, quality and reliability of service, is presented below:

A. Generation forecast,

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[51] Exhibit B, Tab 6, Schedule 5, Appendices 7-9, 11-12; Exhibit C, Tab 11, Schedule 1, Attachment A.

[52] Exhibit B, Tab 6, Schedule 5, Appendix 1, pages 3-4.

[53] 300, 1,000 and 2,000 MW from the RES I, RES II and Aug. 27 Directives found at Exhibit B, Tab 6, Schedule 5, Appendices 8 and 9, and Exhibit C, Tab 11, Schedule 1, Attachment A, respectively.

B. Near term and Interim Measures,

C. Ontario Power System Operation,

D. Cost estimate and Rate impact, and

E. Locked-in Energy.

A. Generation Forecast

The risk associated with forecasting the need for the Project relates to the robustness of the OPA's forecast. This has been discussed in sub-Issue 1.1 and, again, it is Hydro One's view that the forecast is conservative, robust and reasonable.

B. Near term and Interim Measures

The timing of the need identified by the OPA requires that near-term and interim measures be adopted before the Project comes into service. Two of these measures are generation rejection and, if needed, series capacitors. Generation rejection at the Bruce facility is provided by the Bruce Special Protection System ("BSPS"). The interim measures propose to expand and intensify the use of the BSPS to increase the transfer capability out of the Bruce Area until the Project is in service.[54] Doing so will increase the operational complexity of the system, which has sparked concern on the part of the NPCC.[55] Throughout this proceeding, the IESO has consistently been of the view that long-term reliance upon generation rejection is an unacceptable practice.[56] In cross-examination, for example, Mr. Lanzalotta for Pollution Probe admitted that such an approach would expose Ontario and its neighbours to an increased risk of blackouts and equipment failure.[57] However, assuming that the Project is approved, the measure will only be temporary, although if the Project does not go into service and the use of the BSPS accordingly intensifies, then the reliability of the system will be eroded.

[54] Exhibit B, Tab 3, Schedule 1, page 1; Exhibit K12.1.

[55] Exhibit K10.5.

[56] Exhibit B, Tab 6, Schedule 5, Appendix 2, page 3; Transcript, Oct. 15, 2008, Technical Conference Day 1, page 30, lines 3-6; Exhibit C, Tab 1, Schedules 2.6(iv), lines 7-9; 2.8(ii), lines 15-17; 3.2, page 2, lines 27-36; Exhibit C, Tab 2, Schedules 16, page 4, lines 2-9; 17, page 1, lines 28-32; Transcript Vol. 12, May 28, 2008, page 47, lines 1-4.

[57] Transcript, Vol. 13, June 4, 2008, page 127 line 19 - page 130 line 21.

C. Ontario Power System Operation

The evidence in this proceeding demonstrates that the Project is also needed to de-stress an already stressed system. Once the Project is in service the Ontario interconnected electric system will operate at a level farther away from its limit, reducing a risk presently faced by the system. The Project will provide more of a margin for contingencies and scheduling maintenance, reduce the amount of operating reserve required during outage conditions, and have less complicated re-dispatch actions following contingencies and lower power losses.[58]

D. Cost Estimate and Rate Impact

The $635 million budget initially filed has been confirmed throughout the hearing process and remains the relevant amount.[59] No party has seriously suggested that, for a new 500 kV double circuit line, this is an unreasonable amount. The debate instead has concerned alternative options. Hydro One also provided careful responses as to why its $635 million budget remains the applicable figure and has not escalated since the application was filed. Mr. Girard, for example, testified that Hydro One's cost of materials has in fact decreased since filing the application.[60] As such, the evidence Hydro One has presented demonstrating the minor price impact the Project will have to Ontario ratepayers remains applicable, being a 9-10% increase to the Network Pool rate, estimated at a 0.45% increase to a typical residential electricity bill.[61] Again, no party has challenged the appropriateness of this impact relative to the Project.

E. Locked-in Energy Calculation

Much time and attention was spent in this proceeding on the OPA's calculation of locked-in energy. This calculation is a forecast of the cost that Ontario consumers would bear in the event that the Bruce to Milton facilities were not constructed and thus inadequate transfer capability for Bruce Area generation resulted. The OPA's estimated net present value ("NPV") of locked-in

[58] Exhibit C, Tab 1, Schedule 3.2.

[59] Transcript, Vol. 3, May 5, 2008, page 37 line 23 – page 3 line 11.

[60] Transcript, Vol. 5, May 7, 2008, page 165 line 16 – page 166 line 1.

[61] Exhibit B, Tab 4, Schedule 3 (updated Nov. 30, 2007), page 3, line 16 and page 4, line 12, respectively.

energy costs amounted to approximately $1.3 billion.[62] This amount is well in excess of the forecast capital cost of the applied-for facilities.

The OPA's estimate was based on its sophisticated Financial Evaluation Model ("the model").[63] The model's methodology was described extensively in this proceeding and notably in the extensive responses to Pollution Probe Interrogatories 7, 9 and 47 and comprising some 33 pages of text.[64] In addition to this, it will be recalled that the OPA presented an 85 slide PowerPoint presentation during the day-long Technical Conference on May 9, 2008, which was followed by a day of cross-examination on May 12, 2008.[65]

Model results depict the cumulative net present value of costs, including transmission losses and locked in energy, both for the applied-for facilities and those associated with other alternatives. Graphs depicting these results were submitted in evidence and show "cross-over points" where the costs of one option rise above those of the other being considered. Cross-over points of the cumulative cost of an alternative expressed on a NPV basis demonstrate which alternative has a higher or a lower cost in the long-term.

In particular, Pollution Probe and the SON have presented detailed arguments that a series capacitor-based alternative, which would require intensified use of generation rejection, is a better alternative on an economic basis, largely ignoring in the process the remaining section 96 factors of reliability and quality of service. This argument, as phrased by Mr. Russell, is that much of the benefits of the Project can be captured at a fraction of its cost.[66] Yet it is entirely inappropriate for Hydro One to adopt this alternative because it neither comports with the reliability standards that the IESO has set out, nor provides the amount of transmission capability that the OPA has identified as required in its forecast. More than that, however, careful consideration of the use of series capacitors as suggested reveals that even on the (incorrect) terms suggested by Pollution Probe and the SON (a world in which the Board would infringe

[62] Exhibit C, Tab 2, Schedule 10.

[63] Exhibit C, Tab 2, Schedule 9, Attachment 1.

[64] Exhibit C, Tab 2, Schedules 7, 9, 47.

[65] Exhibit K7.1

[66] Transcript, Vol. 14, June 11, 2008, page 29, lines 2-3.

upon the mandates and responsibilities of the IESO and the OPA), the series capacitors/generation rejection option is not a better alternative from an economic perspective.

During this proceeding the OPA model was used to compare the Project to the series capacitors/generation rejection alternative. As the graph below indicates, on a cumulative NPV basis there is a cross-over point between 2018 and 2019, beyond which the Project is the better economic alternative of the two. The Project quickly becomes the more attractive economic choice as the costs of the locked-in energy that the series capacitor/generation rejection option cannot deliver and transmission loss costs accumulate.

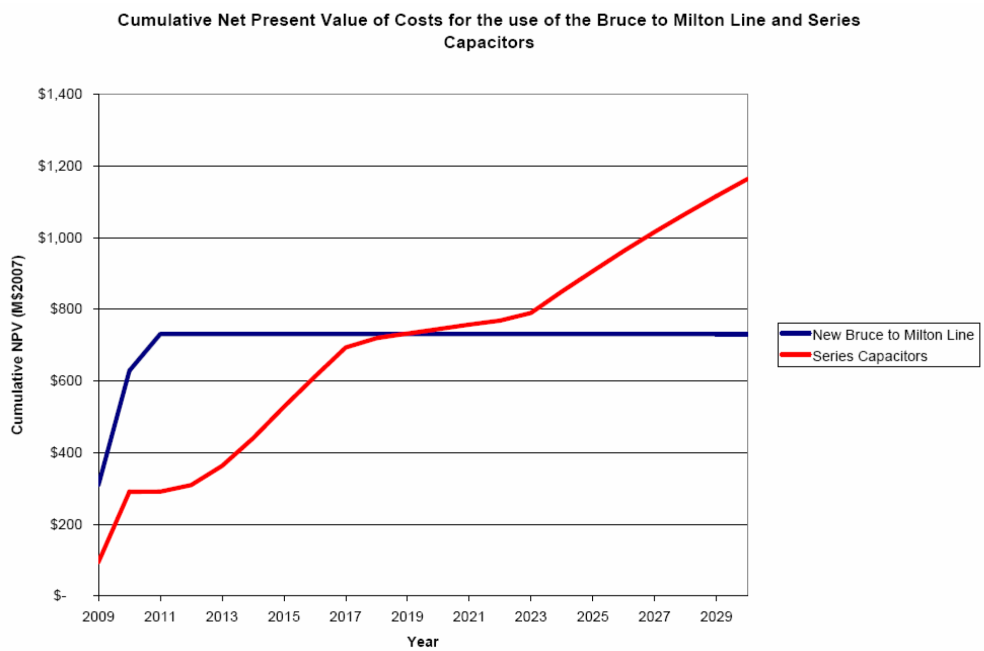


Exhibit C, Tab 1, Schedule 3.4

Even in the case where a substantial amount of generation is removed from the forecast, such as if Bruce B units are not refurbished or rebuilt, the Project remains the better option. As the graph below indicates, by the time the refurbishment point is reached in about 2018/2019, the Bruce to Milton line is economically equivalent on a cumulative NPV basis to the series capacitors/generation rejection alternative (i.e., the cumulative NPV costs are the same). However, if the line is built it will have provided, up to the cross-over point, the significant reliability benefits that the series capacitors/generation rejection "alternative" does not.

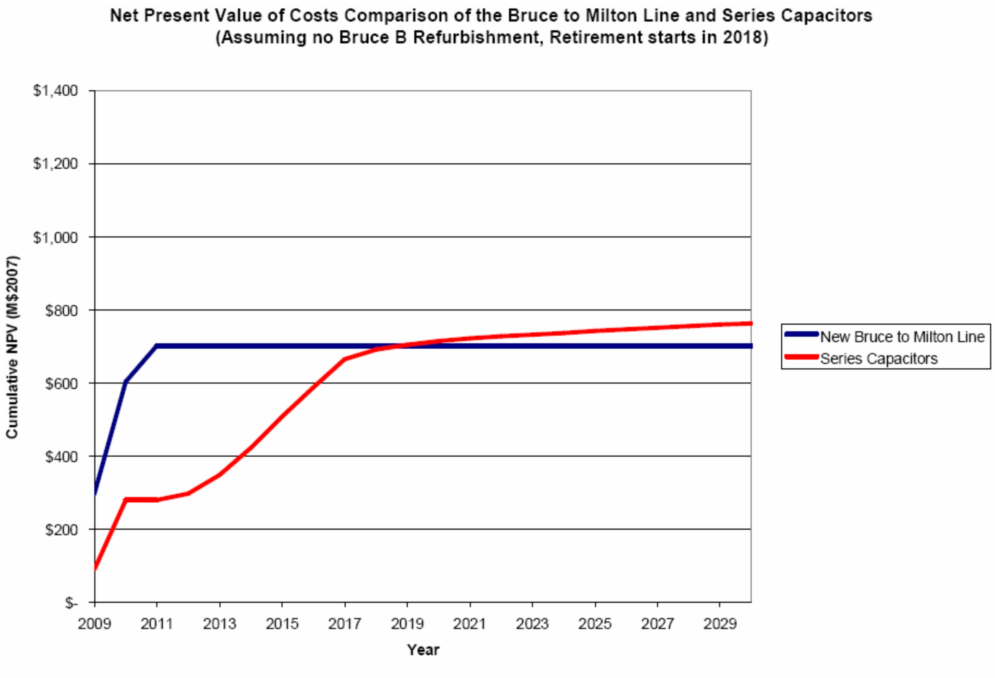
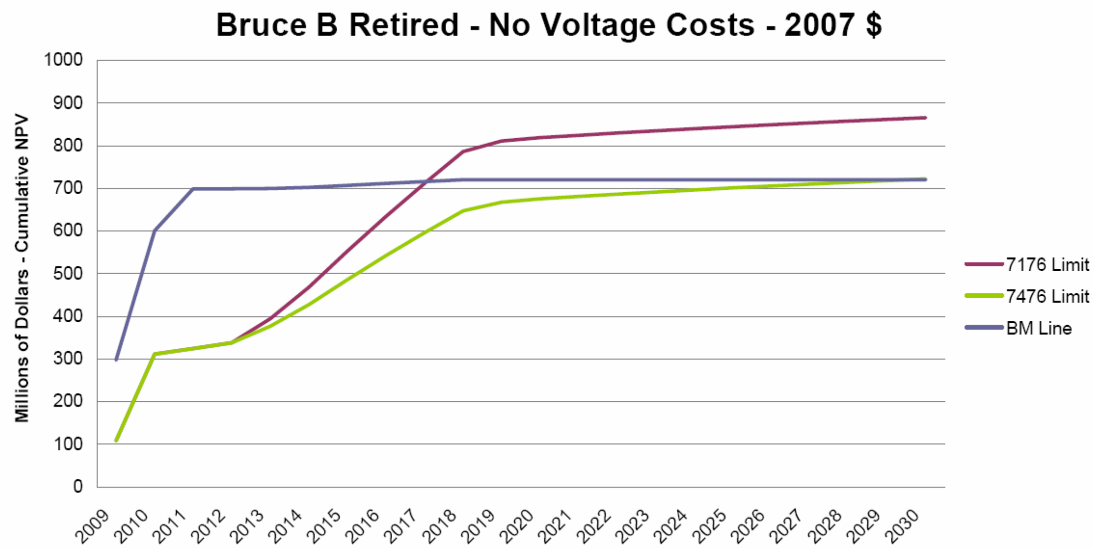


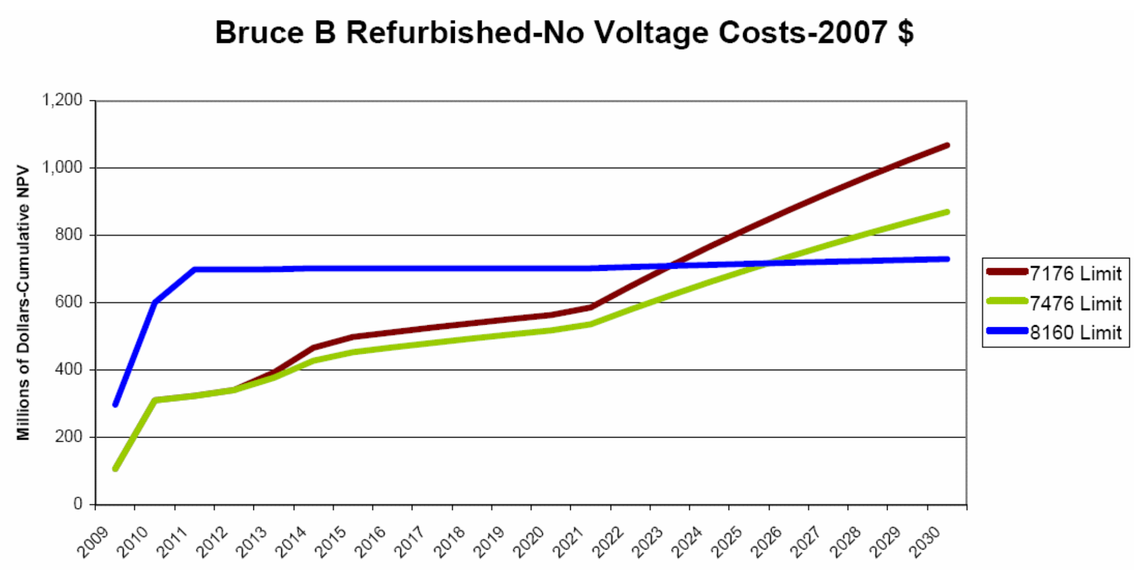
Exhibit K3.4, slide 2

Where the assumptions that were fed into the model were negatively varied by the SON, by (i) in the event that Bruce B is retired earlier than as modelled by the OPA, and (ii) adding additional voltage support on the system with the series capacitor and generation rejection alternative, to get up to a transfer capability level of 7,476 MW, the Project still continues to remain the more attractive economic option. In the most limited circumstances explored during the hearing the point of equivalence came at the latest at 2030 – which would be at only 20% of the anticipated lifespan of the Project (i.e., power lines have approximately a 100 year lifespan[67]). In most circumstances, the cross-over occurs in 2018 or 2019, at about the anticipated commencement time of the refurbishment or retirement of the Bruce B units. This result, using Mr. Russell's own supplementary evidence, indicates that the issue of the future of Bruce B can be removed from the decision-making surrounding the line. As the evidence shows, the line is economically justified even if Bruce B is not refurbished. And if refurbishment or replacement does occur, the line provides considerable upside economic and reliability benefits.

[67] Exhibit C, Tab 12, Schedule 84.



SON Supplementary Evidence, Appendix A, page 1 (cross-over occurs in 2030)



SON Supplementary Evidence, submitted June 10, 2008

Pollution Probe and the SON have challenged the model itself, and the SON also challenged the assumptions that formed the basis for the OPA's modelling results. Consideration of the record demonstrates that neither party is correct in its analysis, nor has either party provided evidence that would allow the Board to reasonably reject the expertise and experience deployed by the OPA in creating and using its model.

OPA Model Robustness

Pollution Probe presented an alternative model to that of the OPA's to calculate locked-in energy on the premise that certain aspects of the OPA model were flawed.[68] The Pollution Probe model considers three elements in simple fashion: (i) average capacity factors for nuclear generation in each of winter/summer and shoulder periods, (ii) average capacity factors for wind generation, and (iii) monthly average transmission penalties. However, these components do not better calculate locked-in energy than does the OPA model, for the following reasons.

First, the Pollution Probe model underestimates locked-in energy with the use of monthly averages for each of wind and nuclear capacity factors. As presented at the Technical Conference and shown in the graph below, average capacity factors do not capture the output profiles of a generator. For example, as the chart below indicates, an 85% capacity factor could be the result of either (i) 100% of output for 85% of the time, or (ii) 85% of output for 100% of the time. The implications for locked-in energy are quite different for each profile. If the transmission system is sized to accommodate the 85 MW capacity factor in the first profile, on the erroneous assumption that this is all the capacity that is required, locked-in energy will result. Whereas if the transmission system is correctly sized to recognize the full 100 MW of generation in the profile, locked-in energy will be avoided. As a result, using capacity factors as a proxy for the generation profile will under-estimate the amount of generation that is produced, and under-estimate the amount of locked-in energy, where the generation profile is variable, as in the case of wind.

[68] Pollution Probe Supplementary Evidence.

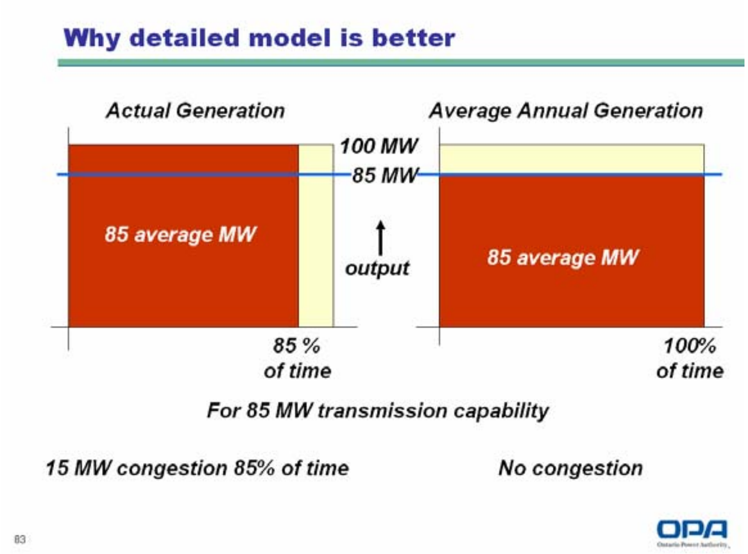


Exhibit K7.1, slide 83

In contrast, the OPA model effects a convolution between the hourly data sets of real-time nuclear unit and wind farm data. This takes into account the hourly variability of the Bruce Area generation, which averages and capacity factors do not. It thus captures the detailed generation profiles that the Pollution Probe model loses through the use of averaging.

This approach is applicable to multiple turbines, and multiple wind farms, provided that they experience the same general weather at the same time. Pollution Probe suggested that the OPA model overestimated locked-in energy because, being in different locations, not all of the wind farms would receive the same wind at the same time, i.e., “spatial diversity of wind” exists. However, Mr. Fagan did not provide any analysis using the available data to substantiate the level of spatial diversity within the (Lake Huron) Bruce wind basin. During the course of cross-examination, Mr. Fagan admitted that he had cited spatial diversity of wind caveats from the wrong AWS Truewind report (October 6, 2006 instead of April 13, 2007).[69] The October 6 report uses 10-minute mast data gathered over the course of 2005 at sites across Ontario.[70] This is a very different study than the AWS Truewind report described by Mr. Chow at the second Technical Conference, which provided an hourly data set based on the simulated aggregated generation output of three “virtual” windfarms in the Bruce Area based on 20 years of climate

[69] Transcript, Vol. 13, June 4, 2008, page 156 lines 9 - 27.

[70] Pollution Probe Supplemental Evidence, page 34.

data specific to the region.[71] Mr. Fagan has no basis to suggest that the data set used in the OPA model to represent Bruce Area wind generation is flawed.

The graph below provides a comparison between the ways that the two models treat wind energy. The graph of the winter peak period from Hydro One's response to Pollution Probe Interrogatory 47 shows the actual wind generation simulated data graphed in blue, with the model's sampling technique in red. Overlaid on top of that graph is Mr. Fagan's winter capacity factor assumption of 40% (40% of 1,700 MW of wind generation is 680 MW). The graph illustrates the better precision of the OPA model:

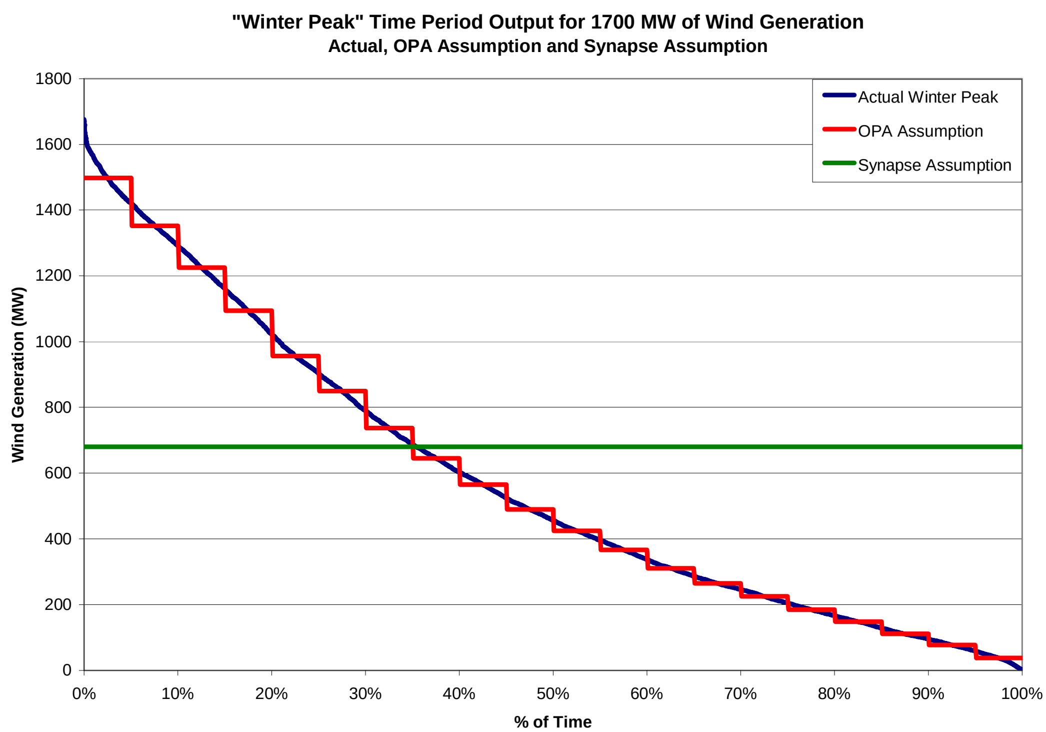


Exhibit C, Tab 2, Schedule 47, page 3 overlaid by Synapse 40% assumption

Second, Pollution Probe calculates the transmission penalty (i.e., the reduction in transmission system capability due to outages) on the basis of monthly averages. This does not capture the real-time effects of congestion, e.g., the effects from the coincidence of strong wind blowing for three hours at the same time that an unexpected transmission outage occurs would not be captured by Mr. Fagan's averaging of the data. This coincidence of high generation output with

[71] Transcript, Vol. 9, May 9, 2008, page 135 lines 7 - 18.

reduced transmission capability would produce a larger amount of locked-in energy than is recognized in the Pollution Probe model. Again, this contrasts with the use by the OPA model of hourly transmission penalty data in a convolution between the combined Bruce Area generation output and available transmission capability.[72] The graph below illustrates the distortions and imprecision of the averaging methods used in the Synapse model – the blue line is the source data (sampled in the OPA model just as the wind data is in the above graph), whereas the red line represents the shape of the same data fed into the Synapse model, but after it has been averaged.

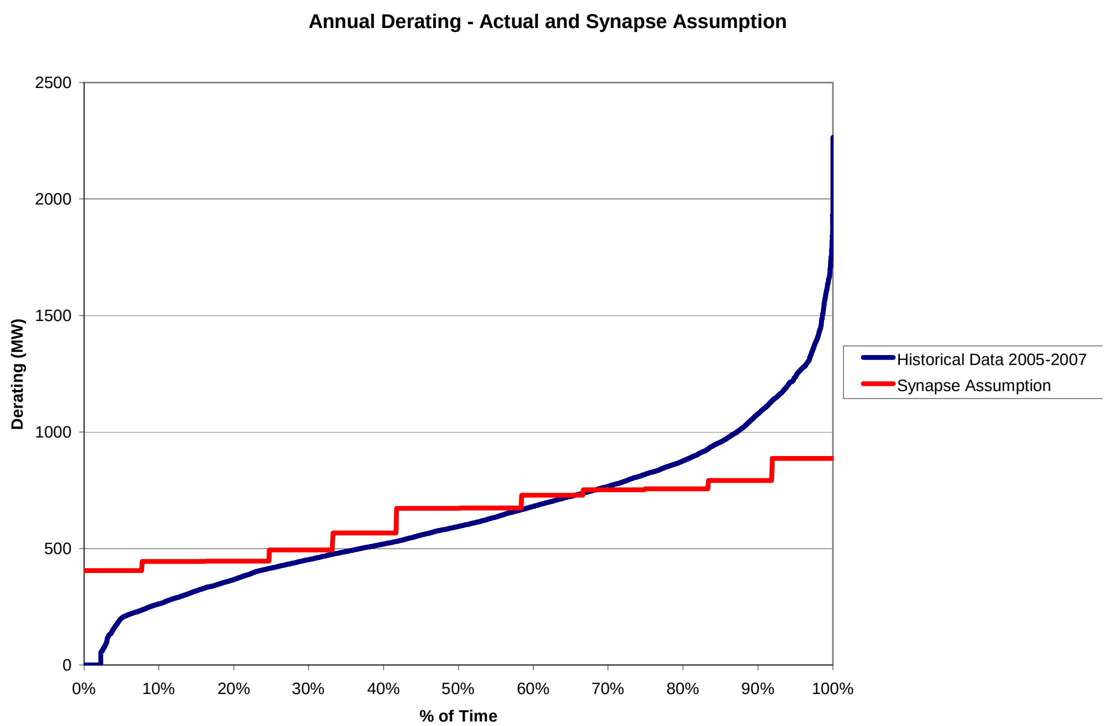


Exhibit C, Tab 2, Schedule 47, Attachment A, page 3 overlaid by Synapse monthly penalty calculation in Pollution Probe Supplementary Evidence, page 5, lines 139-144

Synapse concludes that, according to its model, the series capacitor option is economically superior.[73] However, the comparison between the Synapse result and the results of the OPA model in the Pollution Probe Supplementary Evidence uses the wrong data set. Mr. Fagan used scenario "c" from Hydro One's response to Pollution Probe interrogatory 7[74] in the Synapse

[72] Exhibit C, Tab 2, Schedule 9, Attachment 1 – "penalty" column. See also Undertaking J7.1 for the same data.

[73] Pollution Probe Supplementary Evidence, page 3, lines 72-76.

[74] Exhibit C, Tab 2, Schedule 7.

model, whereas had he used scenario "b" the locked-in energy avoided by the Project, even in the Pollution Probe model, and as confirmed by Mr. Fagan, would be much higher.[75] The same critique also ignored the higher transmission losses (and hence more locked-in energy) which would result from the Synapse series capacitor alternative. Ultimately, and by Mr. Fagan's own admissions, the Synapse evidence amounts to an interesting economic exercise, but is not relevant to this transmission planning exercise because it sets out neither a transmission system planning alternative[76] nor a generation forecast.[77]

Mr. Fagan stated that the OPA model overestimated the amounts of locked-in energy because it:

- failed to consider the spatial diversity of wind in the Bruce Area,
- failed to consider "partial outages" by improperly being a "two-step" model, and
- failed to associate transmission penalty data with suspected seasonal variations.[78]

However, these critiques do not amount to anything more than mere assertions. Similar to the above discussion concerning spatial diversity of wind and Mr. Fagan's use of the wrong report, Synapse was in no way able to substantiate its other two concerns.

Consider the evidence on the face of the record. At the second Technical Conference on May 9, 2008 Mr. Fagan explained his concern that the aggregate generation away from the Bruce station was distorted by the "on or off" nature of the two-step model. However, Mr. Chow in response noted that each individual unit is modelled on a two-step basis, consistent with the minimal operating flexibility of a CANDU nuclear unit, as previously discussed.[79] As a result, the aggregate output from the Bruce station in the OPA model, comprised of six to eight units depending on the model's configuration, reflects actual output, just as Mr. Fagan attempts to do in a more simple fashion with the use of capacity factors. The difference, however, is that the two-step model for nuclear generation allows for more real-time precision in respect of

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[75] Transcript, Vol. 13, June 4, 2008, page 166 line 20 – page 168 line 7.

[76] Transcript, Vol. 13, June 4, 2008, page 116, lines 3-4.

[77] Transcript, Vol. 13, June 4, 2008, page 92, line 18.

[78] Pollution Probe Supplementary Evidence, page 10 line 189 – page 11 line 227.

[79] Transcript, Vol. 7, May 9, 2008, page 62 line 17 - page 64 line 13.

calculating locked in energy in conjunction with hourly wind and penalty data. The two-step "on or off" behaviour of nuclear units is readily apparent from the below graph:

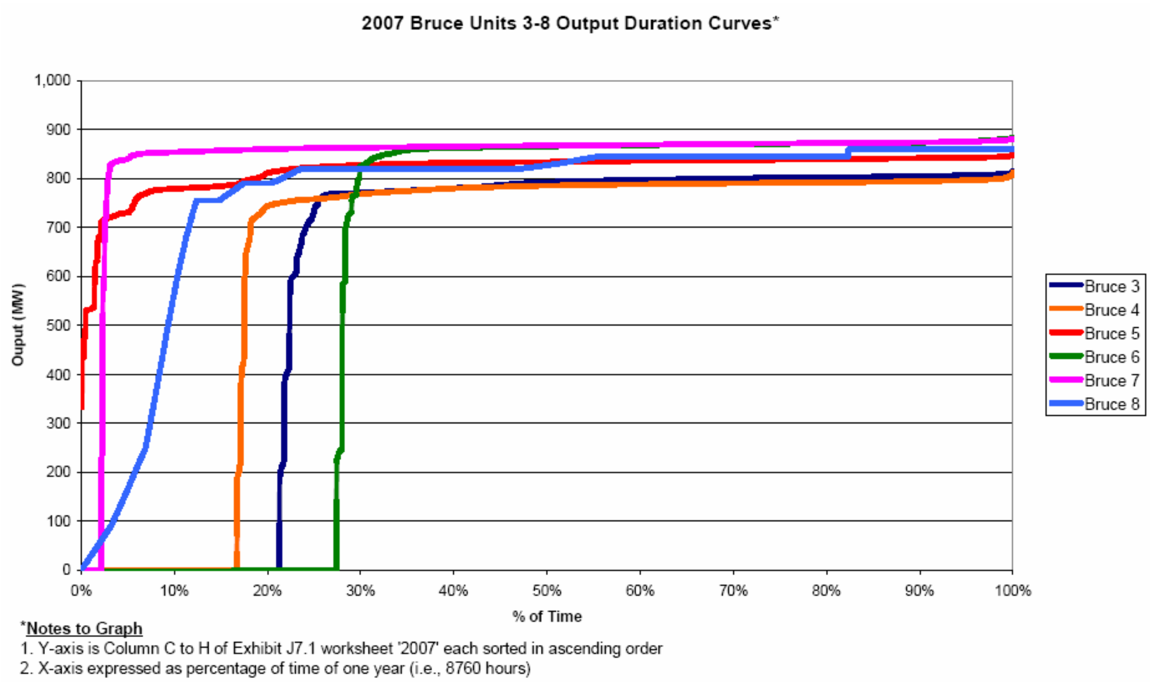

Exhibit K13.1

Mr. Fagan also, by his own admission, did not undertake any statistical analysis to either (i) demonstrate that there are patterns in the shoulder time periods of the transmission penalty data or, (ii) consider the impacts that incorporating such patterns into the OPA's financial model would have on the model's results.[80] Mr. Fagan posed this question to Mr. Chow at the second Technical Conference, but the subsequent Pollution Probe critique[81] completely ignores Mr. Chow's response as to why transmission outages cannot reasonably be expected to be scheduled during the shoulder period on a consistent basis:

> MR. CHOW: We are talking here transmission outages. When a system is operated in a very complex fashion like southwestern Ontario, there are very few times in the year where you could just say, Boy, the system is not needed, nor can you, for example, foresee outages on the system which then you could then take advantage of.
>
> It is a very stressed system of which, when equipment is going out of service, you can't wait for the weekend. It is going to be taken out.

[80] Transcript, Vol. 13, June 4, 2008, page 163, lines 18-21.

[81] Pollution Probe Supplemental Direct Evidence, page 7 lines 154 - 159.

. . .

> So the answer to your question is, we have the three years of information from the operator. We did not assume that there is a way to -- no should we assume that -- in the future that those outages can be coincide or specified. We are assuming that they are occurring relatively random in nature. And for any particular time period there is equal probability of that kind of derating happening.[82]

The critique also ignores the conservative assumptions built into the transmission penalty data, as explained in Hydro One's interrogatory response to Pollution Probe 47:

> The Model takes into account historical de-rating patterns and uses these results in the consideration of future transmission capability. The resulting reduction in the transmission capability (i.e. the penalty) to the Bruce Area transmission system would be the same for each transmission system configuration (e.g., series capacitors, new Bruce to Milton line, etc.). The Model also assumes that the penalty would be the same for the study duration. Both of these assumptions are conservative as it is likely that a transmission system employing the new Bruce to Milton line would be more robust and would have a lower penalty due to transmission system outages, as compared to one employing series capacitors. This is because stress caused to the existing system using series capacitors would expected to be much higher and a larger transmission penalty (i.e. consequences) would likely result for any particular outage.[83]

Furthermore, Mr. Fagan agreed that the timing of generator outages is commercially sensitive information in a competitive generation marketplace and any coordination would have to be overseen and managed by the IESO.[84] The corollary to this is that, even if the operational difficulties spoken to by Mr. Chow were not present, the practical coordination of transmission outages with generation outages to allow for seasonal penalty patterns to develop would be a difficult task. The Board should not give any weight to this bare criticism because it is directly at odds with Mr. Chow's extensive transmission system experience, and runs counter to what would be expected from a common-sense commercial perspective.

OPA Model Assumptions

Mr. Russell, for the SON, challenged the assumptions used in the OPA's financial model to suggest that series capacitors should be preferred on an economic basis. The SON analysis suggested that:

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[82] Transcript, Vol. 7, May 9, 2008, page 53 line 26 – page 55 line 4.

[83] Exhibit C, Tab 2, Schedule 47, page 5.

[84] Transcript, Vol. 13, June 4, 2008, page 165 lines 13-17 and page 166, lines 1-8.

- the OPA forecast should exclude the 1,000 MW of planned wind,
- the OPA forecast should assume that Bruce B generation will be retired, and
- long term reliance upon the BSPS meets reliability standards.

As discussed previously, Mr. Russell's analysis with respect to the inclusion of planned wind in the OPA forecast is flawed. Mr. Russell did not take into account the binding nature of Ministerial Directives, because he viewed them as "guidelines" that the Board had "latitude" to interpret.[85] Mr. Russell did not consult the IESO queue,[86] despite the fact that it demonstrates that there is already in excess of the targeted 700 MW of large planned wind present in the queue.[87] As Mr. Russell admitted, he viewed the renewable goals in the Directives as "targets",[88] rather than the binding commitments they represent. Mr. Russell's planned wind analysis was also inconsistent, in that he admitted that in other jurisdictions, such as California, transmission projects proceeded on the basis of forecasts and demonstrated demand, in the absence of rock solid certainty.[89]

The Supplemental Evidence of Mr. Russell suggested that series capacitors could, with an additional $70 million of voltage support costs, increase transmission capability to 7,476 MW. In so doing, this would extend the point of cross-over (economic equivalence) by several years. However, Mr. Russell admitted that he had not closely followed the testimony of Mr. Falvo, to the effect that the static VAR cost estimate he used was likely low,[90] and that if voltage support costs were increased to, for example, $105 million the cross-over point would advance by about five years, making the net effect of the additional series capacitors nil. Alternatively, he suggested that the same result could be had by converting Nanticoke generators into synchronous condensers. This alternative, however, does not take into account the likelihood, or consequences, of Nanticoke units being both decommissioned and converted less than three

[85] Transcript, Vol. 14, June 11, 2008, page 132 line 26 – page 133 line 1.

[86] Transcript, Vol. 14, June 11, 2008, page 132 lines 5-11.

[87] Exhibit K10.1, tab 13, pp. 9-10.

[88] HONI-SON INTERROGATORY # 1, p. 2.

[89] Transcript, Vol. 14, June 11, 2008, page 168 line 4 – page 169 line 6.

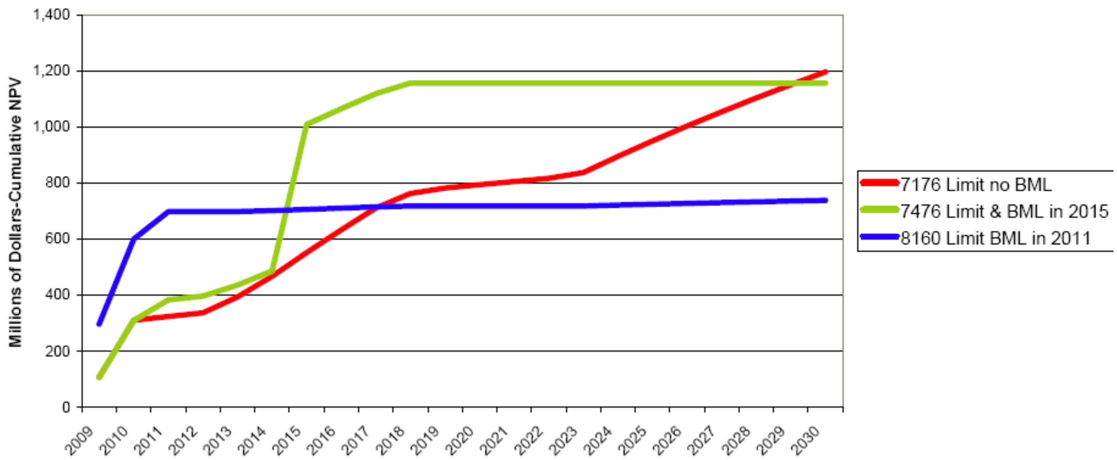
[90] Transcript, Vol. 14, June 11, 2008, page 239 line 1 – page 240 line 11.

years from now, and does not provide any specific estimates of facility, equipment, staffing, operational, or maintenance costs particular to the Nanticoke context.

Mr. Russell's ultimate conclusion in his testimony in respect of series capacitors was that the decision to build a line could be delayed until several years before the point of economic equivalence, until more certainty could be had in respect of planned wind and Bruce B.[91] The uncertainty with respect to Bruce B is very small in light of the previously discussed factors in the OPA's forecast, and confirmed by recent government announcements. Also, as discussed above, the planned wind forecast is conservative, robust and reasonable. Regardless, Mr. Russell in his "wait and see" testimony has misunderstood the fundamental nature of the OPA model. The model presents options on a <u>cumulative NPV cost</u> basis and allows the user to determine what the best economic option is over the study period, i.e., which line has the lesser value at the end of the graph. Given that the graphs and numerical results are presented on a cumulative NPV cost basis, the cross-over point represents the point of economic equivalence to that point in time. It does not represent, as Mr. Russell suggested, the cross-over point of the annual NPV cash flows. Mr. Russell's testimony that indicated that the graphs could be used to determine <u>when</u> to choose between options is flawed as a result. It would be appropriate if the OPA model operated on an <u>annual NPV cost</u> basis, i.e., it depicted financial states on a year-by-year basis. If so, it would allow one to move between options. However, Mr. Russell's testimony in regard to waiting to implement the line after first installing series capacitors did not reflect that when the two options are combined, the cumulative costs of the two options must also be combined.

In furtherance of this point, Hydro One requested Mr. Russell to undertake to provide a net present value analysis of the "wait and see" proposal he had outlined. Mr. Russell filed two undertaking responses and included a number of new criticisms of the OPA model, which did not appear in either his pre-filed evidence or his supplementary evidence. The result of Undertaking J14.1 demonstrates that if one adopts the "wait and see" approach of Mr. Russell and pursues the series capacitor/generation rejection option before adopting the Project, the total NPV cost to meet the 8,100 MW need would be $1.16 billion. This compares to the total NPV cost of the new line of $739 million according to Mr. Russell's evidence.

[91] Transcript, Vol. 14, June 11, 2008, page 43 line 5 - page 44 line 24.



In Mr. Russell's written component of Undertaking J14.1, however, he qualified the graph by stating that the cross-over points presented cannot be compared to other cross-over points because it includes the installation of both series capacitors and the proposed line. The point that the undertaking seeks to illustrate is that series capacitors would not be required to meet the generation forecast if the line is installed first; therefore if series capacitors are installed first and the line follows, the series capacitors would be redundant. Combining the costs of the options to comport with Mr. Russell's staged approach is accordingly a perfectly valid representation of the resulting costs, and the cross-over points of that staged option are indeed comparable with the other scenarios under analysis.

Mr. Russell indicates in Undertaking J14.1 that a figure of 10%, instead of the real social discount rate of 4% mentioned earlier, ought to be used as the discount factor in the model. The OPA's use of a real social discount rate of 4% was first presented in the response to Pollution Probe Interrogatory 9, which was filed on March 7th, 2008.[92] No Interrogatories were asked on this point, nor was it pursued at the Technical Conference or in cross-examination, nor was it mentioned in Mr. Russell's initial or supplementary evidence. Nevertheless, Mr Russell's determination that a 10% discount rate should be used is incorrect. Mr. Russell at Undertaking J14.2, item 3 points to Hydro One's evidence concerning the revenue requirement impact of the project and suggests that because the incremental annual revenue requirement of the line is

[92] Exhibit C, Tab 2, Schedule 9.

between $53 million to $59 million per year, ratepayers would save “about 10%” annually through deferral of the project. This suggestion is incorrect for the following reasons:

- First, the revenue requirement includes depreciation as one of its components. Depreciation is an allocation of the capital cost of the project over its service life; it is not a financing cost. To build depreciation into the project’s cost of capital would therefore overstate the cost of capital.

- Second, the revenue requirement includes the incremental operating cost of the line whereas, as Mr. Russell indicates in Undertaking J14.1, the OPA model does not include an O&M component. As a result, he suggests that the discount rate should be increased to reflect the carrying value of these (omitted) costs. This suggestion also is inappropriate. What is important in comparing alternatives is the difference in operating costs between the Project and the series capacitors/generation rejection proposed alternative. While there is evidence on the record about the annual operating costs of the line (1% of initial capital per annum is used in determining the Project’s rate impact),[93] there is no evidence on the record concerning the operating costs of the series capacitors/generation rejection alternatives. Mr. Russell asked neither interrogatories seeking this information, nor questions at the second Technical Conference, nor was the subject pursued in cross-examination, despite the SON’s advocacy of the series capacitor/generation rejection alternative.

  Despite the lack of specific information on the subject, Hydro One suggests that it is likely that the operating costs associated with series capacitors/generation rejection alternative are likely to be significant, especially when one considers the indirect impacts on the Bruce transmission network from operating it on a “stretched” basis, as would be the case with series capacitors/generation rejection.[94] Operating a stretched system would result in more wear and tear on lines and equipment and require more and lengthier outages to deal with the resulting maintenance issues. There would also be increased labour costs for overtime. Adding all of these factors together across the Bruce

[93] Exhibit B, Tab 4, Schedule 4.

[94] Transcript, Vol. 1, May 1, 2008, page 91, lines 10-12; Vol. 5, May 7, 2008, page 182 lines 6-9 and page 184 lines 9-14.

transmission system would produce significant operating costs, such that the difference in operating costs between the Project and the proposed series capacitors/generation rejection alternatives could well be immaterial. Accordingly, there is no basis to adjust the project's discount factor to account for operating costs, as suggested by Mr. Russell.

- Third, the $53 million to $59 million revenue requirement of the project equates to 8% to 9% of the project's capital cost, not 10%.

For the reasons above, the 10% discount rate proposed by Mr. Russell is not a valid figure. The use of an artificially high discount rate in the model tends to advantage the proposed series capacitor/generation rejection alternatives (either the 7,176 MW transfer capability limit or the 7,476 MW limit) as compared with the line. This is because the series capacitor/generation rejection alternatives have higher locked-in energy and losses associated with them than does the line (which has none). By using an artificially high discount rate, these locked-in energy and losses amounts would have lower discounted values, which would reduce the overall NPV cost of those alternatives compared with the line.

As noted in the interrogatory response to Pollution Probe 9, in Hydro One's view, and uncontradicted by any evidence in this proceeding, other than Mr. Russell's last-minute comments in J14.1, it is advisable when discounting unescalated, non-utility cash flows such as locked-in energy, to use a real social discount rate rather than a utility-specific, nominal, rate.[95] Hydro One stands by this view and believes that the OPA's 4% real social discount rate, which is also used in the IPSP, is appropriate. Hydro One suggests that the Board should dismiss Mr. Russell's attempt to establish an artificially high discount rate.

Mr. Russell further suggests that the Project's rate impact is incorrectly calculated using the average embedded cost of debt, and that the rate impact is therefore understated because Hydro One's incremental cost of capital is forecast to rise above the embedded cost. Mr. Russell's assertion is incorrect. Hydro One's evidence has in fact used the incremental cost of capital in determining the Project's rate impact. The incremental cost of capital is shown in the bottom box in Exhibit B, Tab 4, Schedule 4, page 5.

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[95] Exhibit C, Tab 2, Schedule 9.

Mr. Russell adds additional criticisms of the OPA's financial evaluation model on the basis that it does not use the most recent Navigant avoided cost data, and on the basis that the model does not compensate for the financial arrangements presented to wind generators by the OPA. Curiously, Mr. Russell addressed these concerns neither at the second Technical Conference nor in his supplementary evidence.

Mr. Russell asserts that a "known error" of the model is that the OPA used "unduly low and dated avoided cost data" and its model therefore does not accurately measure avoided energy costs. However, Mr. Russell was in attendance when Mr. Chow explained to Mr. Millar that a simple 2.5% escalation was the only difference between the costs in the updated Navigant avoided cost data[96] and those used by the OPA model – there were no new calculations.[97] The Navigant update was released after Hydro One filed its interrogatory responses and, for consistency with those responses, the new data has not been used in subsequent model runs. Also, using the older data conservatively underestimates locked-in energy costs. There is no "known error" here. However, Mr. Russell does ignore the conservative marginal cost feature of the model in respect of the Navigant data. The assumption is that the data applies to bulk power purchases when, in reality, the acquisition of power on the market to replace the large locked-in energy amounts calculated by the model would escalate the costs beyond the Navigant data. This was explained at the second Technical Conference which Mr. Russell attended.[98]

Mr. Russell also suggests that the calculation of avoided costs should be those in the Navigant study less the cost of wind energy, because "ratepayers are relieved of those payments to wind generators if wind energy is locked-in." This demonstrates again that Mr. Russell's analysis does not take into account of Ontario's electricity market. As explained to Mr. Russell at the second Technical Conference:

> MR. RUSSELL: All right. If I've got a wind generator and it its production is curtailed because of insufficient transmission, I had understood the earlier testimony to be that you don't pay for wind that you don't receive.
>
> MR. FALVO: My understanding was the wind from the large wind farms, the renewable energy supply RFPs, was not a take-or-pay.

[96] Exhibit K7.3.

[97] Transcript, Vol. 7, May 9, 2008, page 145, lines 1-5.

[98] Transcript, Vol. 7, May 9, 2008, page 146 line 2 – page 147 line 1.

I don't believe that is the case for the standard offer.

MR. CHOW: But I also believe that Mr. Falvo said a number of times, when he looked -- for non reliability-related for dispatching, he will dispatch based on the bid stack order, which, in other words, you are going to turn down generation, you turn down the most expensive that was bid into the system; right, Mr. Falvo?

MR. FALVO: Right.

MR. CHOW: Then he also indicated that wind is a price taker. Essentially, it is bidding or offering in zero dollars. You will take whatever the price the market clears.

So in that stack of dispatch order, it is on the bottom of costs. So it would make -- I understand the way it works is that you will not take the bottom of the stack, which is the lowest cost, and remove that.

You will take the highest cost generation that would solve that particular congestion problem and remove that. And the assumption that we have made is nuclear would have a higher cost in the stack order than the wind.

MR. RUSSELL: Yes. And I agree that that would be logical, but I am going to two separate things.

One is the payment versus the dispatch stack, and what I heard is that the payment to the standard offer generators would be 11 cents irrespective of whether they bid in zero.

MR. CHOW: But for one thing, standard offer do not bid into the market.

MR. LEE: No.

MR. CHOW: They just run. When they run, they get paid. They're not into re-dispatching.

MR. RUSSELL: If they are not run, they are not paid?

MR. CHOW: They are not -- there is no ability to kick them off the system.

MR. RUSSELL: Well, if you had a constraint in moving power from the wind energy in Bruce, what would you kick off first? Would you kick off the bilateral purchases, the standard offer or the nuke? What is the order of curtailment on the logic of your model and in real life?

MR. FALVO: In real life, it would be dispatched down, in order of the offer price, dispatchable resources first, so the most expensive dispatchable resource first. That could be the nuclear. It could be the import from Michigan. And we would work our way down until we got to the wind.

MR. RUSSELL: Okay, I follow. I think I follow.[99]

[99] Transcript, Vol. 7, May 9, 2008, Page 115 line 5 – page 117 line 2.

Evidently, Mr. Russell did not follow. The evidence he attempts to advance in Undertaking J14.2 is predicated on the notion that the market can and does constrain wind on economic merit order. However, as explained in Undertaking J7.2, which Mr. Russell himself references:

> In the rare event that all available generation resources, including wind, are being considered for curtailment based on their economic order, the wind generators would be the last of the available resource to be considered for curtailment given their place in the generation resource stack and the fact that they are considered price takers.

Wind generators will not be curtailed for economic reasons, but rather reliability reasons, because the Market Rules always make wind the most economic choice. Mr. Russell's analysis fails to recognize this concept. Mr. Russell's further suggestion, that ratepayers consider whether purchasing wind-generated electricity is worthwhile, belongs to a different proceeding, and to a different Ontario, one which has, or is contemplating, turning its back on renewable resources because they cost too much. The economic exercise he suggests would discourage further wind power development from investing in Ontario, and would require a revision of the Market Rules.

Additionally, the assertion that "actual transmission data shows that most large deratings occur during the spring and fall…<u>when both transmission facilities and generation tend to be taken out together for maintenance</u>" [emphasis added] is unsupported. The data in Undertaking J7.1 shows that maximum transmission capability deratings in <u>each season</u> are very large. As previously noted in respect of the same assertion by Mr. Fagan, Mr. Chow has stated that, very simply, based on his experience transmission facilities are not deliberately taken out of service to coincide with other system conditions, entirely contrary to Mr. Russell's conclusion:

> Mr. Chow:…It is a very stressed system of which, when equipment is going out of service, you can't wait for the weekend. It is going to be taken out.[100]

The Board must make a determination as to which conclusion concerning the operation of the southwestern Ontario power system is more credible.

Finally, the criticism that the model does not consider the losses or outages for "enabler lines" for wind generation is beside the point. The concern is presumably trivial enough that no questions were posed during the Interrogatory process (i.e., the Project does not consist of any

[100] Transcript, Vol. 7, May 9, 2008, page 54, lines 10-12.

"enabler lines"), and it was not mentioned in either of the pre-filed or supplementary evidence of Mr. Russell. The concern also ignores Mr. Chow's response when cross-examined on the issue. When questioned about the likely percentage of transmission losses on a hypothetical enabler line Mr. Chow responded that he could not speculate at this point. He did note that a direct connection would imply losses of 0.5-1%.[101] The evidence on the record with respect to the IESO queue specifies the connection points of the wind resources comprising over 700 MW targeted in the Bruce Area, most of which are very proximate to the current 230 kV and 500 kV lines in the area.[102] In any evident, the loss and outage effects of enabler lines contemplated by Mr. Russell would be common to any new or modified network transmission alternative under consideration. Therefore these would be irrelevant in an economic comparison between two alternatives.

The record in respect of Mr. Russell's evidence is not persuasive because it is either unsupported by analysis or misunderstands the structures of the Ontario regulatory framework and Market Rules. Hydro One submits that the OPA's locked-in energy estimates as calculated by the OPA model are the best evidence on the record and clearly support the Project as the best option.

1.4 Is the project suitably chosen and sufficiently scalable so as to meet all reasonably foreseeable future needs of significantly increased or significantly reduced generation in the Bruce area?

The applied-for Bruce to Milton Project transmission facilities have been shown to meet all reasonably foreseeable future generation requirements in the Bruce Area. That is because the Bruce to Milton Project facilities provide the necessary transfer capability increase from 5,000 MW to 8,100 MW in order to meet the reasonable and conservative generation forecast requirements determined and set out in the OPA's generation forecast.

The Project therefore has been suitably chosen and is sufficiently scalable. Reliance upon near-term and interim measures to increase transfer capability requirements during the period in which the applied-for 500 kV transmission facilities are proposed to be constructed and come into service is a logical and appropriate planning approach and addresses the scalability attribute.

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[101] Transcript, Vol. 4, May 6, 2008, page 64 line 18 – page 65 line 28.

[102] Exhibit K 10,1, Tab 13.

There is simply no credible evidence to suggest that the applied-for facilities constitute some massive “overbuild” or that any reasonable possibility exists in respect of declines in forecast generation from the Bruce, so as to downplay the timing and need for the applied-for facilities. That position is demonstrably not the best evidence that is before the Board. The best evidence consists of the well-founded and cogent reasons of the OPA in forecasting (i) the continuation of Bruce Complex generation levels into the future due to Bruce B refurbishment or rebuild; and (ii) wind generation becoming an important and prolific source of generation from the Bruce Area in the near future.

2. PROJECT ALTERNATIVES

2.1 Have all reasonable alternatives to the project been identified and considered?

The approach used by Hydro One to evaluate potential projects consisted of an initial screening process, as presented at the October 15 and 16 Technical Conference.[103] In the screening process the following attributes were judged to be essential components of any successful option, and were set up as binary, "go/no-go" decisions to streamline the evaluation process:

- Required capability,
- Limited effect on other paths,
- Proven technology,
- Reasonable cost, and
- Consistent with Provincial Land Use Policy.

No party has taken issue with the appropriateness of any of these attributes during the process. This approach was reasonable and has allowed a relative comparison of all reasonable options to be made on a uniform basis, and screened out alternatives that did not meet necessary thresholds. As explained by Mr. Chow, it is not of any use to fully consider project alternatives which, from the outset, cannot be implemented because they do not meet key requirements.[104]

The screening approach identified the Project as the only reasonable alternative, such that issues 2.1 through 2.4 on the Issues List relate to the content and adequacy of the screening process used to identify and consider the Project. Had there been more than one option, additional steps would have been followed using the OPA's evaluation methodology to determine the preferred option. Because that was not necessary in these circumstances the OPA and Hydro One took a reasonable and prudent approach.

[103] Exhibit KT.1, slide 31. See also Exhibit C, Tab 1, Schedule 2.4.

[104] Transcript Vol. 2, May 2, 2008, Page 107, lines 1-17; Transcript, Technical Conference Day 1, Oct. 15, 2007, page 24, lines 3-19; Exhibit KT.1, slide 27.

The potential Project options considered in the screening process were 500 kV power lines to either Milton, Barrie (Essa), Longwood, Kleinburg or Crieff, "HVDC Lite" technology, and a HVDC line. During the hearing, there was also discussion of implementing "ACCR" conductor technology. In addition, to respond to intervenor concerns, the series compensation alternative was considered. The Technical Conference summary slide is reproduced below for ease of reference:

Summary of option screening results

Options	Provide required capability?	Limited effect on other paths?	Proven technology?	Reasonable relative cost ?	Consistent with Land Use Policy?
Series Capacitors on 500 kV lines	NO	NO			
Bruce to Essa 500 kV line	NO	NO			
Bruce to Longwood to Middleport 500 kV line	NO	NO			
HVDC "lite cable" from Bruce to Milton	YES	YES	NO		
HVDC 500 kV line from Bruce to Milton	YES	YES	YES	NO	
Bruce to Kleinburg to Claireville 500 kV line	YES	YES	YES	YES	NO
Bruce to Crieff TS 500 kV line	YES	YES	YES	YES	NO
Bruce to Milton 500 kV line	YES	YES	YES	YES	YES

Exhibit KT.1, slide 31[105]

During the hearing no party questioned screening out any of the Kleinburg, Crieff, Essa or Longwood options, or any of the HVDC options. The bulk of the discussion at the hearing focussed on whether a series capacitor option coupled with intensified use of generation rejection

[105] Note that, contrary to the slide, the Bruce to Crieff option does not actually meet the need; see Exhibit C, Tab 2, Schedule 39.

ought to be preferred to the Project. For completeness, before addressing that discussion the reasons for which other options were screened out are also discussed, as set out below:

A. "Do Nothing,"

B. ACCR Technology,

C. HVDC Options,

D. Bruce to Essa and Bruce to Longwood Options,

E. Bruce to Kleinburg and the Bruce to Crieff Options, and

F. Generation Rejection and Series Compensation.

A. The Do Nothing Approach

The do-nothing approach is rooted in the view that the transmission capability presently in place used to be adequate for eight nuclear generation units, and should be adequate now. That view of the world is, with respect, myopic, and contrary to the record of this hearing.

The evidence that the world has changed was provided by Mr. Chow and Mr. Falvo, both in this hearing and at the Technical Conference. Both witnesses indicated that at the time that the Bruce nuclear facilities were designed and put in place, the power flow was significantly different from the present and anticipated power flows. At the time that the Ontario transmission system was enhanced for the Bruce nuclear facilities, there was significant local load in the Bruce Area and the power flow in Ontario was typically to the west in support of power exports. As explained by Mr. Chow and Mr. Falvo, and presented in Interrogatory responses, that is no longer the case.[106]

In particular, the do-nothing option ignores the following considerations:

- The technical consideration of local load: heavy water plants that used to function at the Bruce Power Complex no longer do so.[107]

[106] Exhibit C, Table, Schedule 1.3; Transcript, Vol. 2, May 2, 2008, page 45 line 22 – page 46 line 3.

[107] Exhibit C, Tab 1, Schedule 1.3(i), page 2, lines 37-42.

- The vast amount of wind resources in the Bruce Area: the do-nothing strategy would not take that resource into account, and yet the government organizations charged with planning and implementing the Ontario transmission system must consider that renewable resource in ensuring that Ontarians receive environmentally responsible power.[108]

- The directive to ensure an adequate supply mix, included in which is the government's off-coal program and the necessary realignment of transmission facilities to accomplish that goal, is another consideration that the do-nothing approach ignores.[109]

The do-nothing approach asks the Board to <u>ignore</u> government policy, which makes the option entirely unreasonable.

B. ACCR Technology is not Realistic

In response to the suggestion by Mr. Pappas that ACCR conductor technology be considered as an alternative, Mr. Sabiston explained that restringing the existing Bruce to Milton 500 kV line with ACCR conductor is not reasonable because it does not provide the required transfer capability.[110] To do so would also require restringing other major transmission paths out of the Bruce with similar conductor. This would result in a cost of about $1.8 billion and be a 15 year project, which did not allow this option to be considered even at the screening level.[111] Reconductoring is not an alternative to the Project.

Mr. Brill, of SEA Ltd. and who submitted expert evidence for the Ross Group and the Fallis Group, suggested that ACCR technology be considered.[112] However, while his evidence provided a magazine article on the technology, it did not explore whether this technology could be installed in the Bruce Area to meet the identified need, and do so in a time and cost sensitive manner. As such, the Board should give no weight to Mr. Brill's speculation.

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[108] Exhibit B, Tab 6, Appendices 8-9, 11-12; Exhibit C, Tab 11, Schedule 1, Attachment 1.

[109] Exhibit B, Tab 6, Appendix 7.

[110] Transcript, Vol. 1, May 1, page 93, lines 21-24.

[111] Transcript, Vol. 1, May 1, page 109, lines 19-24; Undertaking J1.1.

[112] SEA Report, pp. 2 and 11-13.

C. HVDC Options are not Realistic

The "HVDC lite" alternative was screened out on the basis that it is not proven technology.[113] No party challenged the reasonableness of that conclusion. Likewise, no party seriously questioned the reasonableness of screening out the HVDC 500 kV line based on costs.[114] It would be unreasonable to provide further consideration of options when the same performance can be obtained at far less cost.

D. The Bruce to Essa and Bruce to Longwood Options

Neither the Bruce to Essa nor Bruce to Longwood options allow for 8,100 MW of transmission capability and hence were eliminated from further consideration by use of the OPA screening criteria. The Bruce to Essa option would allow for eight Bruce units and the 700 MW of committed wind generation, but would not be able to accommodate the 1,000 MW of planned wind in the OPA forecast.[115] It would also take up capacity on the North-South transmission system needed for future generation transmitted from northern Ontario to Toronto.[116] The Bruce to Longwood option is constrained by the limits regarding "NBLIP," the power flow from London to Toronto, and also would only accommodate seven Bruce units and the 700 MW of committed wind.[117]

E. Bruce to Kleinburg and the Bruce to Crieff Options

Consistent with provincial land use policy regarding the optimization of existing transmission infrastructure,[118] the Kleinburg and Crieff alternatives were screened out based on their significantly greater land requirements – lands required where there is no existing adjacent

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[113] Transcript, Technical Conference, October 15, 2008, page 28 lines 17-23.

[114] Transcript, Technical Conference, October 15, 2008, page 28 line 28 - page 29 line 4.

[115] Transcript, Technical Conference, October 15, 2008, page 27 lines 19 - 22.

[116] Transcript, Technical Conference, October 15, 2008, page 28 lines 6 - 9.

[117] Transcript, Technical Conference, October 15, 2008, page 27 line 23 - page 28 line 5.

[118] Exhibit B, Tab 6, Schedule 5, Appendix 13, page 10, section 1.62.

transmission corridor in the context of the Project. The greater land requirements would have negative land-use and landowner impacts.[119]

Timing is an additional factor. It is reasonable and logical to eliminate for timing reasons projects that require altogether new siting and greenfield land requirements. Such projects are likely to face significantly higher public opposition than alternatives that minimize those sorts of siting challenges, and will require more time for approvals.

The land use policy is simply an articulation of a logical and practical reality: linear disturbance developers prefer placing new facilities in common corridors, or adjacent to existing infrastructure to minimize the impacts otherwise resulting to owners of land. The evidence before the Board is that this is the case in these circumstances. By locating the new line next to an existing corridor, the land requirement is minimized relative to a greenfield project. It is reasonable, practical and logical to avoid new corridors by using existing corridors. That is why the Bruce-Milton 500 kV line was evaluated as being preferred to Bruce-Kleinburg and Bruce-Crieff.

F. Series Compensation and Generation Rejection

There are three broad reasons, as extensively canvassed during the hearing process, that series compensation in concert with intensified generation rejection is not a viable alternative to the Project. First, series capacitors and generation rejection do not meet the need identified by the OPA. Second, series capacitors pose operational challenges and will take until the end of 2011 to implement, diminishing their utility as a solution to the identified need. Third, intensified generation rejection on a long term basis breaches the reliability standards of the IESO and has inspired concern on the part of the NPCC. These three obstacles are discussed more particularly below.

1. Series Compensation plus Generation Rejection Does Not Meet the Need

Series compensation coupled with generation rejection is not a reasonable alternative because it does not meet the need. Hydro One's evidence is that it only provides 7076 MW of transfer capability and no party advocating this option has demonstrated that it meets the 8,100 MW

[119] Transcript, Technical Conference, October 15, 2008, page 29 lines 5 - 12.

transfer capability requirement. Indeed, quite the opposite has been done: parties attempt to whittle down the need to meet the capability of the options.

2. Series Compensation Creates Operational Complexities

While series compensation is a complex and difficult concept to grasp, its complexities have not been lost on the OPA or Hydro One. Series compensation is a well understood technology – but the issue is whether that well-understood technology can be implemented in a safe and reliable manner to meet a generation forecast from the Bruce Area, and on as critical and complex a system as the Bruce Area transmission network which, in addition to supplying local loads, also delivers 20% of Ontario's bulk power needs to the provincial grid.[120]

The OPA commissioned Electranix Corporation to consider the general issue of implementing series capacitors in southwestern Ontario. Mr. Woodford, the President of Electranix, testified as part of Hydro One's second panel. The evidence of Mr. Woodford is clear, and no party seriously challenged him. It is that series compensation can be implemented in southwestern Ontario, subject to vital studies that take into account the technology's effects.[121] In response to a request from Pollution Probe, Hydro One provided a "Gant chart" setting out the reasonable time estimates for those studies, which shows that series compensation can be in place at the end of 2011 – but not immediately.[122]

Hydro One's position in respect of series compensation is not that the technology does not work, but rather that implementing it creates operational complexities, and it must be studied and carefully implemented in the complex Bruce network to ensure that the quality and reliability of the transmission system remain intact.

3. Generation Rejection is not an Appropriate Long Term Solution

The third reason that series compensation plus generation rejection is no solution at all is because it is not an appropriate long term solution. The Ontario Transmission System Code requires that

[120] Exhibit B, Tab 1, Schedule 1, page 3, line 41.

[121] Exhibit A, Tab 5, Schedule 3, page 12; Transcript, Vol. 6, page 5 line 27 – page 6 line 3.

[122] Undertaking J6.1.

transmitters "ensure compliance with the standards of all applicable reliability organizations."[123] The mandate of the IESO under the *Electricity Act*[124] is to "direct the operation and maintain the reliability" of the grid[125] and "participate in the development…of [transmission systems reliability] standards and criteria."[126] The IESO is defined as a reliability organization under the Transmission System Code, and has been given that mandate legislatively.[127] The IESO is responsible for the Ontario Resource and Assessment criteria ("ORAT"), which provides that:

> [A]n SPS associated with the bulk power system may be planned to provide protection for infrequent contingencies, for temporary conditions such as project delays, for unusual combinations of system demand and outages, or to preserve system integrity in the event of severe outages or extreme contingencies.[128]

In particular, in the case of a "Type I" SPS (where the consequences of a failure to operate could extend beyond the power area's borders, i.e., into New York in the case of the Bruce) reliance on the BSPS is "reserved only for few specific conditions, including transition periods to enable new transmission reinforcements to be brought into service."[129] The ORAT does not permit long term reliance on generation rejection in the manner recommended by Pollution Probe and the SON, and the IESO has accordingly advised that doing so is not an acceptable transmission planning option. When asked during the interrogatory process specifically why increased reliance upon generation rejection was of concern, the IESO cited the above standards and explained further as follows below:

> The use of generation rejection brings additional risks to the reliability of the bulk power system, as it relies on the use of complex electronic control equipment and circuit breakers to operate correctly, automatically, and at very high speed to manage and control the integrity of the power system immediately following a system contingency. [130]

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[123] Exhibit K10.2, Tab 18, OEB Transmission System Code, s. 8.1.1.

[124] S.O. 1998, c. 15.

[125] *Ibid.*, s. 5(c).

[126] *Ibid.*, s. 5(d).

[127] *Additional Objects of the IESO,* O. Reg. 452/06.

[128] Exhibit K10.2, Tab 19, ORAT, s. 3.4.1.

[129] *Ibid.*

[130] Exhibit C, Tab 1, Schedule 3.2, page 2, lines 1-36.

Mr. Chow provided the analogy of shoulders on a highway to assist in understanding generation rejection.[131] Highway design does not take into account the presence of a shoulder to accommodate projected traffic volumes. It is only when there is an emergency incident on the highway that the purpose and usefulness of the shoulder takes effect. The evidence before the Board demonstrates that, due to the restart of Bruce A units in the last few years, out of the 8,760 available hours in a year, traffic occurs on the shoulder of the Bruce transmission grid some 5,000 hours per year.[132] The generation rejection plus series compensation option would plan for more hours to be spent on the shoulders. In other words, that some of the remaining 3,760 hours should be put onto the shoulder so as to avoid building a new power line.

Mr. Falvo also discussed the risk relating to generation rejection, being that of contingencies. If one is already on the shoulder of the road and a contingency occurs, then what?[133] Moreover, the Ontario government has made reducing congestion, and hence less reliance on generation rejection, a policy directive as part of encouraging the development of renewable energy. Why would developers come to Ontario if faced with a transmission system that is constrained and unreliable by design, knowing that this increases the possibility that their wind production will be rejected during their highest generation periods without compensation for foregone revenues? Likewise, why is it reasonable for Ontarians to pay the higher prices for wind power that, as Mr. Fagan admitted,[134] would be required in order to entice developers to proceed with projects for a system that is, from the outset, planned to deliver power on a congested and hence less than reliable basis?

Mr. Chow indicated that the system is stressed already[135] and that one of the objectives of the project is the construction of a new lane of traffic, so that appropriate room can be provided without resorting to continuous use of the shoulder for relief. It is not reasonable to implement an option that places long term reliance on generation rejection when all of the planned transmission elements are in service.

[131] Transcript Vol. 1, May 1, 2008, pages 89-90, lines 17-24.

[132] Exhibit C, Tab 2, Schedule 46, page 6 line 37 – page 7 line 2.

[133] Transcript Vol. 1, May 1, 2008, page 67, lines 17-26.

[134] Transcript, Vol. 13, June 4, 2008, page 91, lines 1-16.

[135] Transcript Vol. 7, May 9, 2008, page 54, lines 4-12.

Mr. Falvo clearly explained that the Project will reduce reliance on generation rejection on a planning basis from its current use with all elements in service, to its more appropriate use in outage (or contingency) conditions.[136] Mr. Falvo also noted that on an operational basis, with the new line the use of generation rejection is expected to decrease from its present level of arming approximately 60% of the time, and the anticipated arming of 75% of the time during the interim measures period, to less than 50% of the time. In addition to that quantitative change, there is also a key qualitative change that must be understood: Mr. Falvo explained that the generation rejection responses selected will be much less complicated than at present.[137]

Pollution Probe[138] and the SON[139] have suggested that because the NPCC has never rejected a request related to the BSPS it may continue to be relied upon for normal system operation. Neither of those two considerations affect the fact that ORAT is the appropriate standard for this decision making in Ontario, and ORAT says that generation rejection is not a reasonable long term planning tool. Complementing this point is the fact that the NPCC Task Force on System Studies ("TFSS") has expressed its concern about the complexity of the expanded BSPS the IESO has applied for as part of the interim measures (concerns attenuated by the prospect of additional transmission capability resulting from the Project).[140] Full, long term reliance is that much more difficult.

Mr. Lanzalotta's only rationales for the ability to use generation rejection as part of Pollution Probe's recommended alternative are that it has been used in the past, or that the forecast is wrong.[141] Indeed, shoulders on highways do exist, and will continue to exist. But at what point should, and can, the IESO choose to stop driving on the shoulder of the highway as part of normal transmission operations and say "enough" – this practice is no longer safe or reasonable?

Similarly, Mr. Russell explained that "competing principles" in the ORAT ought to justify a departure from the IESO's interpretation of the appropriate amount of reliance that is permitted

[136] Transcript, Technical Conference Day 1, October 15, 2007, page 30, lines 1-12.

[137] Transcript, Vol. 12, page 152 line 10 – page 153 line 4.

[138] Pollution Probe Evidence, pp. 21-23.

[139] SON Evidence, pp. 4-5.

[140] Exhibit K10.5.

[141] Transcript, Vol. 13, June 4, 2008, page 17 line 19 – page 18 line 11.

to be placed upon a SPS. With respect, standards exist for good reason, and by definition do not lend themselves to liberal interpretations such as proposed by Mr. Russell. When pressed in cross-examination, he admitted that long-term reliance on generation rejection did not, in fact, comport with ORAT. [142]

The IESO has said in this proceeding that the long-term use of generation rejection under normal operating conditions is that point, and that should be the end of the matter. There is simply no basis on the record for the Board to do anything more with this proposal and, in light of the IESO's legislated mandate to devise and enforce transmission and reliability standards, the IESO's evidence must be preferred over that of Messrs. Russell, Fagan and Lazalotta.

G. The Longwood to Middleport Line Does Not Meet the Need

Pollution Probe has suggested that a 500 kV single circuit line from Longwood to Middleport could enhance transmission system capacity in the event that the preferred Pollution Probe alternative of series capacitors/generation rejection must reduce its generation rejection reliance. This option, however, at 7,025 MW[143] falls short of the identified need by more than 1,000 MW, and is not carefully priced. Pollution Probe engages in speculation and ratios to make broad assumptions about Hydro One's costing efforts in respect of the proposed line, distilling a cost estimate of $659 million to $486 million.[144] The premise for this reduction is that Hydro One used over-expensive double and triple circuits in certain places along the route in its interrogatory response.[145] However, Hydro One did so as the presumptively cheaper option in response to local siting conditions, i.e., to reflect the need to pass through urban areas (near London), with increased land acquisition costs.[146]

Pollution Probe's criticism, and the validity of its manipulation of the Hydro One effort by way of ratio, is not backstopped by any evidence or serious analysis, and does not take into account the rationale of minimizing urban land acquisitions costs, provided by Hydro One. Indeed, when

[142] Transcript, Vol. 14, June 11, 2008, page 227 line 16 – page 228 line 12.

[143] Pollution Probe Evidence, pages 23.

[144] Pollution Probe Evidence, page 24 para. 4 - page 25.

[145] Pollution Probe Evidence, pages 24 and 25.

[146] HONI-Pollution Probe Interrogatory 5, page 3.

presented the opportunity to clarify this aspect of the calculation during the interrogatory process, Pollution Probe's simple response was that Messrs. Fagan and Lanzalotta "did leave what they believe are allowances for extra costs," without providing the details of such extra costs. The response avoided the question.[147] The Board does not have any substantial evidence before it as to what the actual costs are for Pollution Probe's proposed single-circuit line. Also, although the line would only yield 7,025 MW, when added to the series compensation capital costs and the estimated costs of locked-in energy it would still cost roughly $24 million more then the Project.[148] This is both an unclear and an unreasonable alternative.

2.2 Are the project's rate impacts and costs reasonable for:

- **The transmission line;**
- **The station modifications; and**
- **The Operating, Maintenance and Administration requirements.**

The record shows that the total budget of $635 million will result in between a 9 and 10% increase in the Network Pool cost, which in turn will result in a 0.45% increase to the bill of the typical residential bill, or about $0.50 per month. Hydro One submits that this is a reasonable cost. This conclusion was not challenged by any party and it is the best evidence before the Board.

The only alternative advanced against the Project on an economic basis was the use of series capacitors and intensified generation rejection. The cost summary and comparison from the interrogatory response on this point is presented in Exhibit C, Tab 2, Schedule 16 and is reproduced below. It sets out the time periods and associated costs during which the near term and interim measures come into effect and the capital cost of the options. The series capacitor/generation rejection option is admittedly a less costly option than the Project in terms of up-front capital, but cost alone does not satisfy the price, reliability and quality of electricity service criteria of section 96. The costs in the table also do not include the costs of locked-in energy and losses which, as previously discussed, favour the line over the series capacitor/generation rejection alternative.

[147] HONI-Pollution Probe Interrogatory 5, page 3.

[148] Pollution Probe Evidence, page 24.

Table 1 – Summary of Costs, Capabilities and Suitability of the Bruce Transmission System Improvements

	A	B	C	D	E	F	G	H	I
Scenario	**Incremental Cost of Upgrade ($M)**	**Total Cost of Upgrade ($M)**	**Incremental Cost Incurred in (year)**	**Increase in Transfer Capability (MW)**	**Total Transfer Capability (MW)**	**Shortfall from Identified Need (MW)**	**Increased Capability Available in (year)**	**Suitable for Long-Term Use?**	**Meets the Need?**
Existing System	-	-	-	-	5000	(3100)	-	Yes	No
a) Near Term Measures (NTM) (includes upgrade of Hanover to Orangeville 230 kV line; and shunt capacitors and static var compensators to accommodate additional flow out of the Bruce Area and to replace the reactive power lost due to the phase out of the Nanticoke units)	+216	216	2007-2010	+385	5385	(2715)	2009 - 2010	Yes	No
b) NTM + Expansion of Bruce Special Protection System (BSPS) for use under normal system conditions	+7	223	2008-2010	+941	6326	(1774)	2010	No	No
c) NTM + Series Capacitors + BSPS for use during outage conditions	+97	320	2008-2011	+941 [above a]	6326	(1774)	2012	Yes	No
d) NTM + Series Capacitors + BSPS for use under normal system conditions	+0	320	2008-2011	+750	7076	(1024)	2012	No	No
e) NTM + Proposed Bruce x Milton Line + BSPS for use during outage conditions	+645 [above (b)]	868 [216+7+645]	2007-2011	+1084 [above (d)]	8160	+60	2012	Yes	Yes

3. NEAR TERM AND INTERIM MEASURES

3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

The near-term measures are comprised of uprating the Hanover to Orangeville 230 kV line by 2009 and adding dynamic and static reactive resources to southwestern Ontario. The interim measures are comprised of maintaining the Orange Zone, expanding the BSPS to allow for additional use, and installing series capacitors in the event of project delay beyond the end of 2011.

No party has seriously challenged the uprating of the Hanover to Orangeville 230 kV line by 2009 or implementing dynamic and static reactive solutions in southwestern Ontario. The evidence is that these near term measures will increase transfer capability by 400 MW.[149] Similarly, the evidence of Pollution Probe and the SON endorse the interim measures of the installation of series capacitors and the use of generation rejection. However, as shown at the Technical Conference, the near term and interim measures do not meet the forecasted need over the long term.[150] More transmission capability is required by 2009 if both the committed wind resources and the Orange Zone are taken into account. The OPA stated that lifting the Orange Zone and granting of contracts under the SOP will not occur until the new line is put into service. That part of the interim measures is necessary because the near term measures do not allow for all the generation offered under the SOP to gain access to the transmission system.[151]

The other interim measure is to expand the generation rejection system and employ generation rejection to maximize transfer capability, during the interim period before the line is placed in service. After the Project proceeds the evidence shows that the planned use of generation rejection will revert to its proper level (i.e., to meet outage conditions), and operationally is expected to significantly decrease, both quantitatively and qualitatively. Mr. Falvo has testified that the amount of time that a generation unit is armed for rejection will decrease and, significantly, the complexity of measures to be taken following a contingency will decrease.[152]

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[149] Transcript, Technical Conference, Oct. 15, 2007, page 32, line 26 – page 33, line 12.

[150] Exhibit KT.1, slide 39.

[151] Transcript, Technical Conference, Oct. 15, 2007, page 33, line 24 – page 34, line 1.

[152] Transcript, Vol. 12, May 28, 2008, page 152 line 16 - page 153 line 4.

3.2 Can the proposed near term and interim measures be utilized longer than the suggested two to three year time frame?

As previously discussed, generation rejection is not a long term option, and the increased generation in the OPA forecast will require a more intense reliance on it without the new line. The IESO has consistently stated that this not a long term solution.[153] Accordingly, this aspect of the interim measures should not be used for longer than the suggested time frame.

3.3 If these proposed near term and interim measures could be utilized for a longer period than proposed, could they (or some combination of similar measures) be considered an alternative to the double circuit 500 kV transmission line for which Hydro One has applied?

As discussed in detail above, the proposed interim measures are not long term options and accordingly cannot be considered as an alterative to the Project. They do not reach the 8,100 MW of transmission capability identified by the OPA and the long term use of generation rejection in normal conditions breaches reliability standards.

[153] Exhibit B, Tab 6, Schedule 5, Appendix 2, page 3; Transcript, Oct. 15, 2008, Technical Conference Day 1, page 30, lines 3-6; Exhibit C, Tab 1, Schedules 2.6(iv), lines 7-9; 2.8(ii), lines 15-17; 3.2, page 2, lines 27-36; Exhibit C, Tab 2, Schedules 16, page 4, lines 2-9; 17, page 1, lines 28-32; Transcript Vol. 12, May 28, 2008, page 47, lines 1-4.

4. RELIABILITY AND QUALITY OF ELECTRICITY SERVICE

4.1 For the preferred option, does the project meet all the requirements as identified in the System Impact Assessment and the Customer Impact Assessment?

The System Impact Assessment ("SIA")[154] assessed whether the Project would have an adverse impact on the reliability of the integrated power system. The SIA concludes that the Project will not result in material adverse effects to the power system, subject to the installation of dynamic compensation, specified shunt capacitors banks and the enhancement of the BSPS (all of which form part of the near term and interim measures).

Similarly, the Customer Impact Assessment ("CIA")[155] considered the potential impacts to customers resulting from the Project by studying customers connected to stations near the terminals of the new line. The CIA concludes that, following the analysis of short-circuit and voltage performance studies, the Project can be "incorporated without any adverse impacts on south western Ontario customers."

Accordingly, the Project meets all requirements of the SIA and the CIA, and this evidence is uncontroverted before the Board.

4.2 Does the project meet applicable standards for reliability and quality of electricity service?

The transmission reliability and quality standards that apply in Ontario are set out in a comprehensive legislative and regulatory scheme through licence conditions, the Transmission Code, the ORAT and the Market Rules. Compliance with these standards is largely overseen by the IESO. This is not a case about whether those standards are just and reasonable, or prudent and fair. It would be very inappropriate for Hydro One to present an application to this Board that deliberately contravened the established regime of the OEB-established Code, or the licence conditions and reliability standards administered by the IESO. The issue in this case is whether the project meets these established Code, licence and reliability standards.

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[154] Exhibit B, Tab 6, Schedule 5, Appendix 2.

[155] Exhibit B, Tab 6, Schedule 5, Appendix 3.

The Board has had the benefit of having the Ontario reliability standards authority, the IESO, testify before it. By definition, the best evidence of whether a project comports with those standards is that of the standard-making body. That is the evidence of Mr. Falvo, and is found in the SIA. It was also thoroughly conveyed in Hydro One's responses to Interrogatories, echoed by the letter response from the NPCC Task Force on System Studies,[156] and constitutes the best evidence before the Board.

Mr. Falvo's evidence, to be clear, is that the line represents the best alternative that meets the need from the perspective of reliability. No party suggested that there is a better option from a reliability perspective, with the exception of the idea that the BSPS would become more complex if the Project were to proceed. However, Mr. Falvo has said precisely the opposite: the BSPS will operate less frequently and with less complicated required responses if the Project proceeds.[157]

4.3 Have all appropriate project risk factors pertaining to system reliability and quality of electricity service been taken into consideration in planning this project?

Relevant risk factors that this project has taken into consideration are the effects of generation rejection, the potential addition of new technology to a critical part of the Ontario power system, and common right of way considerations.

As mentioned above, the IESO is of the view that continued reliance on generation rejection represents a reliability risk that should be addressed in expanding the transmission capability of the Bruce transmission system. Long term use of a SPS does not accord with NPCC and IESO reliability standards, and reducing reliance on the BSPS during normal operating conditions was accordingly a project objective. The Project addresses this objective and will hence have a positive effect on the reliability of the transmission system.

The interim measures proposed for the Project contemplate the use of series capacitors, if required as a result of Project delays. Series capacitors would be a new technology to what is a critical part of the Ontario power system. However, Mr. Woodford's report concluded that series capacitors could be installed in southwestern Ontario provided that necessary studies were

[156] Exhibit K10.5.

[157] Transcript, Vol. 12, May 28, 2008, page 152 line 16 – page 153 line 4.

undertaken. Hydro One and the OPA have identified the necessary studies, and the Project provides for sufficient time in which to carry them out to put series capacitors in place during 2012, if necessary. This risk has been carefully considered and addressed.

Both Mr. Russell[158] and Mr. Brill[159] take issue with two 500 kV lines in a common corridor, raising the prospect of tornadoes. Their evidence, however, does not take into account the evidence on the record that multiple 500 kV lines on a common corridor does not breach reliability standards and there are risk management procedures already in place in the event that such circumstances were to arise. The IESO has considered whether the location of a double circuit 500 kV line in a common corridor with the existing Bruce-Milton 500 kV line represents an undue risk. Its conclusion is straightforward, and has been repeated throughout the proceeding: the location of these two lines in the common corridor does not contravene either the IESO or NPCC planning standards.[160] There are mitigation measures and operational responses that the IESO employs to address such concerns:

> MR. FALVO: …we do have procedures in place. We monitor adverse weather. We get regular reports. So where we can get an advance indication, we can take actions to reduce or mitigate that risk. And we included several of the steps, which would include redispatching and switching, and we could even use a special protection system in that case, where we would consider that a rare contingency to lose the entire right of way. [161]

Mr. Lanzalotta agreed in cross-examination that the twin aspects of risk assessment are the probability of an event, and the consequences of the event.[162] Mr. Falvo explained that the IESO's risk assessment takes a <u>conservative</u> approach by assuming that an extreme weather related contingency (such as a tornado) will occur, and then evaluating how the system will react and how procedures in place can respond appropriately:

> MR. FALVO: …our requirement is to assess the consequences and be prepared ….It is not our goal to assess the probability of that. We've got to be satisfied

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[158] SON Evidence, page 18.

[159] SEA Report, page 10.

[160] Exhibit C, Tab 1, Schedule 2.10.

[161] Transcript, Vol. 1, May 1, 2008, page 173, lines 2-14.

[162] Transcript, Vol. 13, June 4, 2008, page 127, lines 12-17.

> that we can deal with it, if it happens, and that the consequence is something that is acceptable and manageable.[163]

In summary, the potential reliability risks arising from the Project have been considered and approved by the relevant regulatory authority.

[163] Transcript, Vol. 1, May 1, 2008, page 173 line 23 – page 174 line 1.

5. LAND MATTERS

5.1 Are the forms of land agreements to be offered to affected landowners reasonable?

No party has challenged the forms of land agreements as presented in the pre-filed evidence. Powerline Connections, moreover, as the group representing over one hundred properties who will be offered those agreements, has expressed its support for the Project – support which extends to the forms of agreement.

5.2 What is the status and process for Hydro One's acquisition of permanent and temporary land rights required for the project?

Throughout this proceeding, significant time, care and attention have been placed by Hydro One on the implications that a project of this magnitude and of this size would have on individual landowners. Significant time and effort has been taken to inform stakeholders of the Project and, indeed, one of the primary concerns expressed through that consultation is the process through which lands required by the process would be obtained. One of the most significant landowner intervenors in this proceeding has assisted Hydro One in developing and addressing concerns that, in effect, fall outside of the jurisdiction of this Board, namely, the compensation for land acquisition.

This has had a significant impact in removing uncertainty and providing clarity, on fundamental issues of importance to landowners. Working with Powerline Connections, Hydro One has established the land acquisition compensation principles for the Project.[164] These principles provide for the voluntary acquisition of land rights in a fair, transparent and consistent manner. This approach is one that will be mutually beneficial, and one that seeks to avoid the expropriation process. Land acquisitions will move forward, with the overwhelming endorsement of Powerline Connections, which will no doubt assist Hydro One in attaining its objectives in a timely manner.

As Mr. Sperduti indicated at the start of this proceeding: "[t]he land acquisition compensation principles represents a very positive step forward in putting landowner concerns first."

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[164] Exhibit K9.11.

The status of the acquisition of the necessary property interests is that all pieces are in place and the Project has received the specific endorsement of a group representing a significant number of directly affected landowners.

6. ABORIGINAL PEOPLES CONSULTATIONS

6.1 Have all Aboriginal Peoples whose existing or asserted Aboriginal or treaty rights are affected by this project been identified, have appropriate consultations been conducted with these groups and if necessary, have appropriate accommodations been made with these groups?

A. What Crown Consultation and Accommodation is required for the purposes of approving a Section 92 Leave-to-Construct application?

The Board must carefully consider how its role fits with the obligation of the Crown to consult with Aboriginal peoples in certain circumstances.

Canada's Aboriginal people hold rights under section 35 of the Constitution of Canada. In *Haida Nation v. British Columbia (Minister of Forests)*[165] and *Taku River Tlingit First Nation v. British Columbia (Project Assessment Director),*[166] the Supreme Court of Canada ruled that "the honour of the Crown" requires the Crown to consult with and, where circumstances warrant, address the potential effects of its decision making (i.e., accommodate them). The scope of the Crown's duty to consult is proportionate to the strength of the asserted right and the potential for an adverse effect and will differ with the circumstances under consideration.

Crown consultation with Aboriginal peoples, as a constitutional obligation, is not the same thing as an applicant's consultation with individuals potentially directly affected by the Project. Both types of consultation are ultimately necessary for the Project to proceed. However, the Board is only able to assess the Crown's duty to consult Aboriginal peoples within the ambit of its jurisdiction, namely sections 92 and 96 of the *Ontario Energy Board Act, 1998* ("the Act") dealing with price, quality and reliability of electricity service.

The Project must also receive an authorization under the environmental assessment process. Approval is required from the Ontario Ministry of the Environment under the *Environmental Assessment Act* in accordance with the *Electricity Projects Regulation*.[167] This is the appropriate process for dealing with environmental and archaeological issues relevant to potential adverse effects to aboriginal and treaty rights and interests.

[165] 2004 SCC 73 ("*Haida*").

[166] 2004 SCC 74.

[167] O. Reg. 116/01.

Accordingly, the general degree of Crown consultation required in this proceeding, namely for a facilities application under section 92 of the Act and taking into account that an environmental assessment of the Project is still required, is nil or at best at the low end of the consultation spectrum. In these circumstances the actual Crown consultation carried out in respect of this facilities application has, nevertheless, far exceeded the legal minimum.

The Supreme Court of Canada in *Haida* also made it clear that the duty to consult is owed by the Crown and not third parties. *Haida* additionally confirmed that the provincial Crown must consult with Aboriginal groups whose Aboriginal rights or title may be affected by project-related decisions, including tenure and operational permitting decisions. While the Court recognized that government can delegate procedural aspects of the consultation obligation to third parties, the ultimate legal responsibility rests solely with the responsible government.

It is true that the Board may rule on issues of law, pursuant to section 19 of the Act, and that this ability allows the Board to apply the Constitution of Canada and consider arguments rooted in section 35 and Aboriginal rights.[168] To do so, however, there must be a valid intersection between the Board's specific section 92 mandate and the potential infringement or adverse effect on Aboriginal or treaty rights or interests. Hydro One submits that this intersection cannot exist in these circumstances because of the limited nature of the section 92 application and the fact that an environmental assessment which contemplates socio-economic issues, including the potential infringement to Aboriginal rights, is a necessary precondition for the Project to proceed.

The record of this proceeding itself will form part of the Crown's ultimate consultation exercise. Crown decision-making processes which may affect Aboriginal interests give rise to the duty to consult and are a forum for fulfilling the Crown's duty to consult. The environmental assessment process, a necessary component to putting the Project into place, ultimately results in a Ministerial determination. That determination requires Crown consultation, and will be informed by the record of this proceeding – not only the consultation evidence filed by Hydro One, but the participation of potentially affected Aboriginal groups in the leave to construct hearing process. As part of its decision making process, the Board should consider the evidence before it, including the evidence of consultation carried out by the applicant and the Crown, all

[168] *R. v. Paul*, 2003 SCC 55.

within the context of the section 92 application before it and within the context of an ongoing environmental assessment which will ultimately result in a Ministerial decision. The Board may make findings of fact as to the consultation record that has occurred to date to assist in the Project's environmental assessment.

B. What, if any, Consultation and Accommodation issues are within the Board's jurisdiction in this case?

As described above, the Crown's duty to consult Aboriginal peoples is not an obligation which belongs to Hydro One, except to the extent that Hydro One has carried out the procedural aspects of the duty. Hydro One submits that the Board should not exercise jurisdiction to assess the adequacy of such consultation efforts.

In the present case, Hydro One has indeed been delegated certain procedural aspects of the Crown's duty to consult Aboriginal peoples pursuant to the Memorandum of Understanding between Hydro One and the Ministry of Energy ("MOU").[169] Pursuant to the MOU the Crown can rely on Hydro One's Project-related consultation activities in the course of satisfying the Crown's constitutional obligations. *Haida* confirms that the substantive obligation to consult Aboriginal peoples rests with the Crown, and only procedural aspects of consultation may be carried out by third parties. By extension, *Haida* stands for the proposition that it cannot be for the Board to assess the adequacy of Crown consultation.

A useful comparator for how the Board ought to deal with determinations concerning Crown consultation is the National Energy Board ("NEB"). In both the Enbridge Pipelines Inc. Alberta Clipper Expansion Project proceeding[170] and Enbridge Southern Lights proceeding[171] the Standing Buffalo Dakota First Nation ("SBDFN") filed a Notice of Motion requesting decisions that: (i) the NEB had no jurisdiction to consider the applications on its merits without first determining whether the SBDFN had a credible claim within the meaning of the *Haida* decision;

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[169] Exhibit K8.1

[170] Enbridge Pipelines Inc., Alberta Clipper Expansion Project, Reasons for Decision OH-4-2007, February 2008, at 5-13 & 35-43.

[171] Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines Inc., Reasons for Decision OH-3-2007, February 2008, at 6-12.

and (ii) the duty of fairness requires that the Crown be required to attend and respond to the SBDFN's claim.

In denying the Motion in both proceedings the NEB ruled that it only needs evidence before it that Aboriginal consultation has been carried out, and nothing more. Proponents are required to consult with all potentially affected parties, including Aboriginals, and present that consultation to the Board. As an independent, quasi-judicial administrative tribunal the NEB provides a fair and impartial decision-making process where all potentially impacted parties, including Aboriginal groups, are provided an equal opportunity to participate.

The evidence before the Board is that Hydro One has actively consulted with Aboriginal groups having been identified as potentially affected by the Project – both in respect of dealing with individuals who may be affected by the Project and to assist the Crown in carrying out its duty to consult Aboriginal peoples. Because of the very limited scope of the facilities application before the Board in respect of its potential impact on Aboriginal peoples' interests or rights, and the ongoing environmental assessment process, it is clear that the environmental assessment process is the appropriate forum for consideration of all or, in the alternative, the bulk of the Crown's duty to consult Aboriginal peoples and to consider the concerns and issues raised by Aboriginal peoples to date (as they relate to their Aboriginal interests and rights). This is so because (i) the environmental assessment process ends with a Ministerial determination, and (ii) the record of this proceeding will inform that Ministerial determination and, in so doing, serve as part of the Crown's consultation exercise.

C. Has the required Consultation and possibly Accommodation been done?

The issue before the Board under Issue 6.1 is narrow: has Hydro One, as the applicant, adequately consulted with potentially directly affected Aboriginal groups? The consultation efforts evidenced by Hydro One in its interrogatory responses represent tremendous efforts.[172] For the purposes of the section 92 facilities application, the consultation conducted to date has been robust. Through Hydro One's efforts, significant information has been shared, including providing funding for Aboriginal groups, and their communities, to become informed in respect

[172] Exhibit C, Tab 1, Schedule 6, Attachments A and C.

of the Project.[173] Additionally, the concerns heard and issues raised to date by Aboriginal groups are matters not within the scope of the section 92 facilities application, but rather matters that will be considered by Hydro One and the Crown within the Project's environmental assessment where appropriate accommodation will be considered. Hydro One submits that its consultation efforts respecting the Project have been more than adequate for the Board to conclude that such consultation, as part of the Crown's overall efforts, has been robust.

[173] Transcript, Vol. 9, May 13, 2008, page 164, lines 14-25.

7. CONDITIONS OF APPROVAL

7.1 If Leave to Construct is approved, what conditions, if any, should be attached to the Board's order?

Hydro One has indicated in its testimony that it considers the standard conditions suggested by Board Staff to be appropriate and reasonable.[174] As Hydro One has stated previously, the appropriate additional condition here is that construction does not begin until such time as Hydro One has secured environmental assessment approval.

[174] Transcript, Vol. 9, May 13 , page 157, lines 7-9.

CONCLUSION

This facilities application is about planning to meet future needs in a manner that will provide real, tangible benefits to all of Ontario. If the Bruce to Milton transmission reinforcement project is approved, a significant amount of wind generation will be enabled, allowing government policies to be fulfilled, increased levels of nuclear generation will be enabled, and the transmission system will be allowed to operate in compliance with mandatory reliability standards. That is what the evidence in this proceeding tells us.

What the evidence in this proceeding also tells is that if, however, the Bruce to Milton project is not approved the existing system will remain stressed. The prospect of additional wind generation installation will diminish, government directives will not be met, locked-in energy and economic costs will result, transmission losses will occur, and the transmission system's reliability will continue to erode.

Thorough testing of the OPA's generation forecast has occurred. The forecast has withstood this testing and should be relied upon to justify the underlying transfer capability increase requirements that underscore the need for the applied for facilities. That is what the evidence in this proceeding tells us.

The OPA has participated with Hydro One in providing compelling evidence that the Bruce Area will remain a centre of nuclear generation and constitutes a fruitful and readily available wind basin. Leaving aside reliability issues, the OPA's modelling work demonstrates that the Project will result in substantially less locked-in energy than the series compensation/generation rejection "alternative," and hence is economically superior. Similarly, the IESO's evidence is that the applied-for facilities comport with Ontario's transmission system reliability standards. Moreover, the IESO has been very clear that the "better alternative" proposed by Project opponents is not feasible, because long term reliance on generation rejection for normal operating conditions breaches IESO standards.

In the end what the Board must do is assess the evidence in this proceeding by examining the price, reliability and quality of electricity service requirements set out in section 96 of the Act. The OPA and the IESO are experts in and familiar with the Ontario system, the Ontario market and Ontario policies with respect to transmission planning and operations. It is because of their expert testimony that the evidence of Hydro One is to be preferred and relied upon in approving this application. The record before the Board is clear and compelling: the best evidence is that of Hydro One and the best alternative is the applied-for facilities.

In view of the foregoing, Hydro One submits that the Board should approve the Project as applied for.

In view of the foregoing, Hydro One submits that the Board should approve the Project as applied for.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 23rd day of June, 2008.

HYDRO ONE NETWORKS INC.

By its counsel

GORDON M. NETTLETON