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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

October 7, 2009

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

Dear Ms. Walli:

EB-2008-0272 – Hydro One Networks' 2009-2010 Transmission Rate Application Supplemental Filing– Responses to Interrogatory Questions

Please find attached three (3) copies of responses provided by Hydro One Networks, OPA, and IESO to Interrogatory questions. Also provided is an index page to show the original intervenor question numbers and the equivalent tab and schedule numbers.

An electronic copy of the complete application, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

Hydro One Networks will post electronic copies of the interrogatory responses on the Hydro One Networks’ website for public access.

Copies of the Interrogatories will be provided to Intervenors within the next few business days.

Sincerely,

ORIGINAL SIGNED BY ANDY PORAY FOR SUSAN FRANK

Susan Frank

Attach.

c. EB-2008-0272 Intervenors

Supplementary Interrogatory Index							
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit I				
OEB Staff	1	1	Tab	1S	Schedule	92
OEB Staff	1	2	Tab	1S	Schedule	93
OEB Staff	1	3	Tab	1S	Schedule	94
OEB Staff	1	4	Tab	1S	Schedule	95
OEB Staff	1	5	Tab	1S	Schedule	96
OEB Staff	1	6	Tab	1S	Schedule	97
OEB Staff	1	7	Tab	1S	Schedule	98
SEC	1	1	Tab	4S	Schedule	35
SEC	1	2	Tab	4S	Schedule	36
SEC	1	3	Tab	4S	Schedule	37
SEC	1	4	Tab	4S	Schedule	38
SEC	1	5	Tab	4S	Schedule	39
SEC	1	6	Tab	4S	Schedule	40
VECC	1	1	Tab	6S	Schedule	70
VECC	1	2	Tab	6S	Schedule	71
VECC	1	3	Tab	6S	Schedule	72
VECC	1	4	Tab	6S	Schedule	73
VECC	1	5	Tab	6S	Schedule	74
VECC	1	6	Tab	6S	Schedule	75
VECC	1	7	Tab	6S	Schedule	76
VECC	1	8	Tab	6S	Schedule	77
CME	1	1	Tab	9S	Schedule	9
AMPCO	1	1	Tab	10S	Schedule	12
AMPCO	1	2	Tab	10S	Schedule	13
AMPCO	1	3	Tab	10S	Schedule	14
AMPCO	1	4	Tab	10S	Schedule	15
AMPCO	1	5	Tab	10S	Schedule	16
AMPCO	1	6	Tab	10S	Schedule	17

Ontario Energy Board (Board Staff) SUPPLEMENTARY INTERROGATORY #1 List 2

Interrogatory

Reference:

a) Supplementary Evidence/Exh B/Tab 1/Sch. 1/from p.1, line 4 to p.3, line 5

b) Ministry of Energy directive dated December 20, 2007 in regard to "The Hydro Electric Energy Supply Agreements" to develop about 500 MW of hydroelectric generation (from 4 specific projects)

c) Ministry of Energy Directives dated August 27, 2007 requiring the OPA to procure up to 2,000 MW of Renewable Energy Supply by 2011.

Preamble:

Justification of the two projects D7 and D8 as outlined in Hydro One Supplementary Evidence [see Reference a)] is based on:

1) a Ministry of Energy directive dated December 20, 2007, see Ref b) in regard to developing about 500 MW of hydroelectric generation in addition to another (updated projections[1]) generation from variety of technologies amounting to 762 MW (387 MW of in-service and committed plus 375 MW)

2) maintaining the supply reliability for customers north of New Liskeard in the event of a single contingency on the 500 kV single–circuit, which also contributes to meeting the IESO's criteria in assessing connection proposals[2] ;

Clarification:

In regard to the two directives in References b) and c), please provide responses to the following two statements indicating for each statement whether Hydro One agrees, or if not, provide an explanation why it disagrees:

(i) Statement: Hydro One's non-discretionary obligation to the noted Ministry directives is to provide connections either to specific sites, or to take steps (after contracting is completed between the OPA and the project proponent) to connect such generation sites to Hydro One's transmission system.

(ii) Statement: The options and plans on how to modify the transmission system to accommodate generation projects on its system is carried out by judiciously evaluating alternatives to select the most suitable one based on economic evaluation

[1] Supplementary Evidence, Exh C/Tab 1/Sch 2/p. 7/ Table 4
[2] Ontario Resource and Transmission Assessment Criteria

of alternatives. This is regarded according to the Board's "Filing Requirements"[3] as a discretionary project and as such should be accompanied by quantitative economic evaluation and be documented and filed for approval as was carried out for the Bruce to Milton project.

Response

Hydro One disagrees with both statements. Projects D7 and D8 are clearly of a non-discretionary nature and both projects are required to expeditiously facilitate the growth of renewable generation connections in Northern Ontario.

A key step in project categorization is to distinguish whether the project need is determined beyond the control of the Applicant ("Non-discretionary") or determined at the discretion of the Applicant ("Discretionary"). As per the Board's Filing Requirements for Transmission and Distribution Applications, November 14, 2006, section 5.2.2/para 2 (EB-2006-0170), non-discretionary projects may be triggered or determined by such things as:

a) Mandatory requirement to satisfy obligations specified by Regulatory Organizations including NPCC/NERC (NAERO in the near future) or by the Independent Electricity Market Operator (IESO);

b) Need to accommodate new load (of a distributor or large user) or new generation (connection);

c) To relieve system elements (transmission lines, circuit breakers, etc.) where the loading exceeded their capacities or where short circuit levels on these system elements exceeded their withstand capabilities;

d) Projects identified in an approved IPSP;

e) Projects required to achieve Government objectives that are prescribed in governmental directives or regulations;

f) To comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

The non-discretionary triggers relating to these two projects are:

1. The need to accommodate new generation in the area by reinforcing the grid (item b above) and to relieve loading on system elements (item c above). Substantial renewable generation projects are either in-service or have been committed as shown

[3] Filing Requirements for Transmission and Distribution Applications, November 14, 2006 (EB-2006-0170)/Sec. 5.2.2

by the OPA at C-1-2 Table 4 (762 MW of committed and other resources, compared with 380 MW initially identified in the OPA's May 2008 letter). This is in addition to the 517 MW of hydroelectric generation that the OPA was required to procure by the Minister of Energy under the "Hydroelectric Energy Supply Agreements ("HESA") directive. Over 1250 MW of new renewable resources would cause southbound flows on the North-South Interface to greatly exceed its present operating capability of 1400 MW. This was confirmed by the OPA in its supplemental supporting evidence at C-1-2. The need to accommodate this new generation goes beyond simply providing the connection facilities to the network; rather it will largely deliver the renewable energy to other load centres in southern Ontario.

2. Projects required to meet Government objectives that are prescribed in governmental directives and regulations (item e above). The additional generation identified in item 1. above, is largely driven by OPA initiatives in response to various government directives, namely (a) the December 20, 2007 HESA Ministry of Energy directive; (b) the June 13, 2006 IPSP Goals directive (c), the August 27, 2007 Renewable Energy Supply directive; and (d) the earlier Renewable Energy Supply directives (RES 1 & II) and the Renewable Energy Standard Offer Program (RESOP). The enactment of the Green Energy and Green Economy Act and the subsequent launch of the Feed-in Tariff program on October 1, 2009 is expected to further add renewable resources in northern Ontario and further increase the southbound flows on the North-South Interface. It is clear that the Government policy direction is to replace coal-fired resources with renewable resources to the extent possible. Delivery of new renewable resources, prescribed by governmental directives, in northern Ontario to southern Ontario will be necessary to meet this objective. Therefore, as supported by the OPA, increasing the capability of the North-South Interface by 2010 is required to deliver the desired resources. Currently the regional transmission capability on the OPA's website for the Feed-in Tariff ("FIT") program identifies 100 MW of connection availability in northwestern Ontario and 300 MW in northeastern Ontario. These connection availability values assume that projects D7 and D8 would proceed. Without the completion of projects D7 and D8, as noted by the OPA in response to interrogatories I-4S-38, I-6S-72 and I-6S-73, part d, there would be no connection availability for FIT projects to proceed in Northern Ontario.

   One of the projects identified for completion by 2015 in the Minister's letter of September 21, 2009 to the Chair of Hydro One (Attachment 1), is the installation of a new 500 kV line North-South Tie from Sudbury to Barrie. Completion of projects D7 and D8 will provide the additional capacity necessary by 2010 until a new line is completed. As noted by the OPA at C-1-2, page 5 and in response to SEC Interrogatory I-4S-38 these two projects will still provide on-going value after the new line is completed.

The installation of the Nobel Series Capacitors (D8), on its own, will increase the North-South transfer capability by 340 MW. The installation of the Static Var Compensators

(SVC's) at Porcupine TS and at Kirkland Lake TS (D7) will further increase the North-South transfer capability by 160 MW (total increase of the North-South transfer capability from both projects is 500 MW). In addition, Project D7 will expand the transfer capability of the flow south from Porcupine to about 1450 MW and therefore allow the incorporation of generation development north of Timmins. Both projects D7 and D8 are required to enable the incorporation of Lower and Upper Mattagami Development which are included in the HESA directive of December 20, 2007. The IESO's System Impact Assessment 1st Addendum report filed as C-1-5 confirmed the installation of SVC's at Porcupine TS and Kirkland TS (D7) and series capacitors at Nobel SS (D8) will allow the connection of the forecast generation facilities to the system.

These projects are not driven primarily by a need to eliminate or reduce energy congestion; they are driven by the three factors above. In addition, there are no reasonable alternatives that provide the required capability and meet the required in-service date, as described in the qualitative analysis of options for project D7 at B-1-3 and at B-2-3 for project D8. As such, the need to do the type of quantitative economic evaluation suggested by Board staff, is not warranted. It is clear from a review of the options considered, that completion of projects D7 and D8 are the most practical solution to meet the timelines for the development of the planned and committed renewable generation resources in Northern Ontario while mitigating the potential for significant interruptions to load customers north of New Liskeard as the peak southbound transfers, and the duration during which the transfer level exceeds the 650 MW (which exposes the loads to the risk of interruption following a transmission contingency) are likely to increase as new planned hydroelectric generation comes in service north of Porcupine TS. The very fast acting SVC characteristics will provide reactive support during the initial power surge when voltages are severely depressed, and, following the initiation of generation rejection, they will provide the capability to absorb excess reactive power when voltages are very high. The OPA provided their own assessment of a number of alternatives at C-1-2, page 5 and provided three reasons in support of the two projects.

Similarly, Board staff is contemplating the Board requiring a quantitative economic evaluation of the projected benefits that are attributed to the reinforcements measured on the basis of avoided costs over a period of 15-20 years (i.e., potential congestion reduction or alleviated bottled energy), and whether Hydro One could provide the evaluation with the help of the OPA and/or IESO. The Board did not request this of Hydro One; presumably on the basis that this information is not necessary pursuant to the Board's filing requirements given the nature of the proposed facilities (i.e., non-discretionary) and the basis for which the reinforcements are needed. Also, as noted earlier, congestion relief is not the primary driver for the proposed facilities. The primary driver for this project is the need to provide additional transmission capability to facilitate connection of new renewable generation resources required by and consistent with Government policy. In addition, congestion studies of the sort completed by Board staff are fairly complex undertakings. In order to achieve reasonable results, these congestion studies require a significant amount of data and resources including detailed information, amongst other things, about the type and characteristics of future generation resources, load forecast and electricity prices. Furthermore, the study results obtained from such an undertaking would provide the Board with little, if any, information of value towards its review of the project need.

Board staff has also asked if Hydro One would provide an economic evaluation based on the assessment of the loss of load probability for load customers north of New Liskeard (I-1S-94), assuming the incorporation of the new generation resources without installation of the SVCs at Porcupine TS and Kirkland Lake TS (D7). Again, given the non-discretionary nature of projects D7 and D8, and the fact that both projects are needed to support the connection of the committed renewable resources, there is no benefit from completing the requested study.

Minister of Energy and Infrastructure

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Ontario

September 21, 2009

Mr. James Arnett
Chair
Hydro One Inc.
483 Bay Street
15th Floor, North Tower
Toronto ON M5G 2P5

Dear ~~Mr. Arnett~~ Jim:

As you know, our government is committed to increasing renewable energy generation across Ontario and ensuring that the necessary infrastructure is in place to enable it. To that end we have passed the *Green Energy and Green Economy Act, 2009* (GEA) providing a comprehensive framework for developing renewable energy generation in Ontario.

The GEA sets the framework for, among other things, the introduction of a feed-in tariff program for renewable energy. To accommodate the anticipated increase in renewable energy generation associated with a feed-in tariff program, it will be necessary to implement a number of major projects to upgrade the transmission and distribution systems.

In anticipation of this, I understand that the Ontario Power Authority (OPA) and Hydro One have worked together to identify areas of the province that would benefit from specific transmission and distribution upgrades to enable new renewable generation likely to be forthcoming through the feed-in tariff program. These projects are reflected in the attached Schedules. I am pleased that Hydro One has been proactive in planning for this much needed expansion of its transmission and distribution systems, in addition to planning for the development of a smarter grid infrastructure that will enable greater integration of renewables.

Given the immediate importance of the projects shown in the attached Schedules, I would ask that Hydro One complete the following activities in anticipation of the feed-in tariff program and high demand for renewable connections:

.../cont'd

1. Immediately proceed with the planning, development and implementation of Transmission Projects outlined in the attached Schedule A, including seeking approvals for the upgrades as soon as there is a reasonable basis to do so.

2. Collaborate with the OPA in defining the scope of work, including termination points, target capacity, number of lines, technical options and sequencing necessary for the Transmission Projects, as well as collaborating with the Independent Electricity System Operator on System Impact Assessments and reliability impacts.

3. Develop and implement smart grid infrastructure in accordance with upcoming government policy, including establishing novel ways of managing network infrastructure for renewables more efficiently.

4. Given the magnitude of work required to complete the Transmission Projects:
    a. Identify the commercially reasonable opportunities for entering into partnership arrangements with qualified third parties/partners for the execution of the Projects;
    b. Work with the Shareholder to identify commercially reasonable criteria that will be used to select qualified third parties/partners;
    c. Use best efforts to enter into those commercially reasonable arrangements; and,
    d. Identify projects as appropriate where the planning, development and implementation of the project would be better accomplished by a qualified third party other than Hydro One.

5. Provide opportunities for participation in the projects by potentially-affected Aboriginal peoples.

6. Immediately proceed with the planning, development and implementation of upgrades to enable distribution system connected generation, as outlined in the attached Schedule B, including collaborating with the OPA and the Independent Electricity System Operator in defining the scope of work necessary for the transmission facilities to enable distribution system connected generation.

7. Begin planning and preliminary development to explore and preserve options for longer-term, high-capacity, transmission link between Thunder Bay and the Greater Toronto Area, including associated collaboration with the OPA for planning.

8. Subject to Crown oversight, engage in consultations with and, where appropriate, accommodate Aboriginal peoples respecting their section 35 rights of the Canadian *Constitution Act*, potentially affected by transmission and distribution projects listed in the attached Schedules.

.../cont'd

To be clear, I am seeking your cooperation on these matters as a key enabler for the feed-in tariff program to be implemented under the GEA and in order to establish a more modern and reinforced electricity grid in Ontario. In no way does my request relate to the implementation or methods used to carry out the work described in this letter, including following appropriate consultation and approvals processes. In light of that, I would expect that Hydro One will develop a comprehensive implementation plan to achieve these objectives.

Furthermore, in order to be informed about Hydro One's progress toward implementing and meeting these objectives, and in keeping with the purpose of the Memorandum of Agreement between Hydro One and the Shareholder, I request that Hydro One report back to me on a semi-annual basis on planning, development and implementation activities undertaken, and progress made in connection with Transmission and Distribution Projects that will enable the feed-in-tariff program. I would appreciate receiving a first report by no later than the end of November 2009.

I am appreciative of Hydro One's continued leadership in moving towards Ontario's green energy future and look forward to seeing your progress in meeting the government's objectives on transmission and distribution system expansion.

On behalf of the Hydro One Board, would you please confirm your understanding of the above, and your concurrence with all that is contemplated, by signing in the space provided below. Thank you for your prompt attention to these matters.

Sincerely,

George Smitherman

George Smitherman
Deputy Premier, Minister

I concur,

James Arnett

James Arnett
Chair of the Board, Hydro One

Enclosures

Schedule A - Transmission Projects

Item #	Project	Key Driver	Target In-Service Year*
Core Transmission (Bulk transmission upgrades)			
1	East-West Tie: Nipigon x Wawa (230 kV)	Bulk Transmission Capability for FIT program	2015
2	North-South Tie: Sudbury Area x Barrie (500 kV)	Bulk Transmission Capability for FIT program	2015
3	Barrie x GTA (500 kV)	Bulk Transmission Capability for FIT program	2015
4	Sudbury Area x Algoma Area (Mississagi Transformer Station, 70km east of Sault Ste. Marie) (500 kV)	Bulk Transmission Capability for FIT program	2014
5	London Area x Sarnia (500 kV or 230 kV)	Bulk Transmission Capability for FIT program	2016
6	Bowmanville x GTA (500 kV)	Bulk Transmission Capability for reliability and FIT program	2016
Enabling Transmission (Local enabler connection lines for renewable clusters)			
7	Goderich Enabler	Connections in anticipation of high renewables demand	2013
8	Manitoulin Island Enabler	Connections in anticipation of high renewables demand	2014
9	Huron South Enabler (Wanstead Transformer Station)	Connections in anticipation of high renewables demand	2016
10	Pembroke Enabler	Connections in anticipation of high renewables demand	2014
11	Parry Sound Enabler	Connections in anticipation of high renewables demand	2015
12	North Bay Enabler and 230 kV Line Upgrade	Connections in anticipation of high renewables demand	2015
13	Thunder Bay Enabler	Connections in anticipation of high renewables demand	2015
Regional Transmission (Regional transmission lines for renewables)			
14	Pickle Lake x Nipigon	Renewables, Reliability, and Load Growth	2013
15	Cornwall x Ottawa	Renewables and load growth	2015
16	Belleville x Napanee (Selby Junction)	Renewables and load growth	2014
17	Chenaux x Arnprior Area (Galetta Junction)	Renewables and reliability	2014
Longer-Term (Post-2016)			
18	Sudbury North (500 kV)	Bulk Transmission Capability for FIT program	2017
19	London x Hamilton Area (500 kV)	Bulk Transmission Capability for FIT program	2020
20	Kenora x Thunder Bay	Bulk Transmission Capability for FIT program	2020

* Scope, sequencing and details of implementation subject to detailed Implementation Plan

Schedule B - Projects to Enable Distribution System Connected Generation

Item #	Project	Target In-Service Year*
Transmission Facilities to Enable Distribution-connected Generation		
1	Install 3 Static Var Compensators in Areas of high FIT Uptake	2012-2014
2	Install up to 7 Enabling Transformer Stations in Areas of High FIT Uptake	2012-2015
3	Upgrade Short Circuit Capability of Toronto Area Stations (Hearn TS, Manby TS, Leaside TS)	2012
4	Install in-line Circuit Breakers at up to 7 Locations to Enable Generation Connections	2012-2015
Distribution		
5	<u>Targeted Dx Enhancements to Support Distributed Generation</u> -10 New Distribution Feeders (in areas of high FIT uptake) -Other Minor Investments	2009-2012
Protection, Control, and Telecom (enabling distributed generation)		
6	<u>DG Connection Cost Reduction</u> -Wide Area Telecommunication Infrastructure -Wide Area Island Detection -Transmission Protection Change for Tap-Connected Generation -Stop-Gap Wireless Remote Trip -GPRS (Cellular) Telemetry -Pulse-signalling Island Detection -OGCC System Changes	2009-2012
7	<u>Protection</u> -Feeder Protection Replacements -Telecom to In-Line Reclosers -TS Bus Protection Replacements	
8	<u>TS Capacity Expansion</u> -Generation Trip and Block Scheme -Automated Generation Dispatch System -Transfer Protection Replacements -Tapchanger Control Upgrades -OGCC System Changes	
9	<u>Product Quality</u> -Feeder Voltage Regulator Replacement -OGCC System Changes	
10	<u>Bulk System Reliability</u> -Distribution Station SCADA and Protection Upgrades -OGCC System Changes -Load Rejection Systems Modifications	

* Scope, sequencing and details of implementation subject to detailed Implementation Plan

Ontario Energy Board (Board Staff) SUPPLEMENTARY INTERROGATORY #2 List 2

Interrogatory

Reference:

a) Supplementary Evidence/Exh A/Tab 2/Sch 2/section 2. "Supporting Evidence for Projects D7 and D8"/from p.2, line 20 to p. 3 line 2.

b) Hydro One's Response to Board Staff IR # 61 in regard to Projects D7 and D8, dated December 23, 2008 (Exh I/Tab 1/Sch. 61/p. 1.

c) Filing Requirements for Transmission and Distribution Applications, November 14, 2006 (EB-2006-0170)/Sec. 5.3.2/paragraph 3

Preamble:

(1) In Reference a), It is partly stated that:

"Hydro One notes the Board's satisfaction with the level of supporting detail provided by the OPA in the Bruce to Milton Leave to Construct proceeding and has tried to balance the level of detail required for a section 92 application with the detail that can be provided for approval of a transmission project as part of a revenue requirement application."

(2) In Board staff Interrogatory # 61 under "Preamble" it is stated in part that:

"Reference c)"[1] indicate that even though the net present value for a non-discretionary project need not be shown to be greater than zero, an evaluation of the economic benefits e.g., the evaluation of the reduced congestion on the system is appropriate."

In that Board staff Interrogatory # 61, under the related "Request" section, it is stated that:

"Please provide an estimate of the reduced congestion attributable to the two projects over an appropriate study horizon, and listing all assumptions."

Hydro One's response to that Board staff Interrogatory # 61 stated that:

The Independent Electricity Operator (IESO) provided an estimate of the reduced congestion in their System Impact Assessment Report, IESO_REP_0379 for these two projects. This report is included in the OPA's IPSP filing, EB-2007-0707, Exhibit E, Tab 3, Schedule 1, Attachment 1 which is available from the OEB's website (http://www.oeb.gov.on.ca/OEB/). A copy

[1] Reference c) in Board Staff Interrogatory # 61, is the same as Reference c) in this Board Staff Interrogatory #1

of the attachment is also included with this interrogatory as Attachment 1. The IESO estimate of reduced congestion on the North- South interface amounts to 700 MW. The referenced report includes all assumptions used to derive that figure."

Questions:

Given that the evidence provided by Hydro One in the original submission for Projects D7 and D8 was not satisfactory to the Board, evidenced by the requirements for submission of additional evidence, please respond to the following:

(i) What are the reasons for not providing evidence in accordance with the Board's "Filing Requirements" as noted in Reference c) and Preamble 2), which requires conducting a quantitative economic evaluation for the proposed D7 and D8 projects?

It is expected that an economic evaluation for the two projects (D7 and D8) would compare the cost of the two projects versus the benefits assessed on the basis of avoided costs. For these two projects, the benefits are typically assessed based a present value over a study period of 15-20 years of congestion reduction or the bottled energy in absence of the two projects. The latter approach to assessment of bottled energy was presented in the evidence for the Bruce-Milton project by the OPA.

(ii) In the event that the Board requires a quantitative economic evaluation for the D7 and D8 projects:

(a) Could Hydro One provide the quantitative economic evaluation with help from the OPA and/or the IESO?

(b) If the answer to (a) is "Yes", when can such an analysis be completed and filed with the Board?

(c) If the answer to (a) is "No", please provide the reasons for it.

Response

(i) & (ii) Please see the response to I-1S-92.

Ontario Energy Board (Board Staff) SUPPLEMENTARY INTERROGATORY #3 List 2

Interrogatory

Reference:

a) Supplementary Evidence/Exh B/Tab 1/Sch 1/from p.2, line 24 to p. 3 line 5.

Preamble:

In Reference a), It is indicated that

- The need with respect to maintaining supply reliability for customers north of New Liskeard is attributed to events of a single-circuit contingency on the 500 kV line from Porcupine TS to Hanmer TS, where the whole power system north of Timmins is connected to the rest of network via two weak 115 kV circuits connected to Kirkland Lake TS.
- Without the dynamic reactive power support from the proposed SVCs, instability could cause the transmission system to separate at Kirkland Lake TS.

Questions:

(i) Did Hydro One perform an economic evaluation based on the assessment of the loss of load probability for load customers identified in Reference a), assuming the incorporation of the new generation resources without installation of the SVCs at Porcupine TS and Kirkland Lake TS? If "yes", please provide the results of that study;

(ii) If the answer to (i) is "No", could Hydro One complete such a study and filed with the Board with help from the OPA and/or the IESO? If the answer is "No", please provide the reasons for that.

Response

(i) & (ii) Please see the response to I-1S-92.

Ontario Energy Board (Board Staff) SUPPLEMENTARY INTERROGATORY #4 List 2

Interrogatory

Reference:

a) Supplementary Evidence/Exh B/Tab 1/Sch 1/p. 2 /lines 18-19

b) Supplementary Evidence/Exh B/Tab 2/Sch 1/p. 1 /lines 25-26

Clarification

In Reference a), and in Reference b), the sentence states that:

> *"The transfer capability is further increased to 2,050 MW through use of the existing post contingency generation rejection scheme."*

There appears to be a minor error in both Reference a) and Reference b), because the amount of transfer capability should be 2,150 MW[1], and not 2,050 MW. Please confirm.

Response

Yes, there is an error in both references. Project D8 together with the SVCs (Project D7) will increase the North-South Interface transfer capability by 500 MW to 1,800 MW. The transfer capability is further increased to 2,150 MW through the use of the existing post contingency generation rejection.

[1] Supplementary Evidence, Exh C/Tab 1/Sch 5/System Impact Assessment Report:1st Addendum, (August 15, 2007)/p. 3/ Summary of the maximum transfers that could be supported across the Flow-South Interface

Ontario Energy Board (Board Staff) SUPPLEMENTARY INTERROGATORY #5 List 2

Interrogatory

Reference:

a) Supplementary Evidence/Exh C/Tab 1/Sch 2/p. 7/Table 4/"Other Resources"

b) Existing Atikokan Generating Station Capacity Information

Source - Ontario Power Generation Website: http://www.opg.com/power/fossil/atikokan.asp

c) Existing Thunder Bay Generating Station Capacity Information

Source - Ontario Power Generation Website: http://www.opg.com/power/fossil/thunderbay.asp

Preamble:

1) In Reference a) there are two projects Biomass Atikokan with Capacity of 200 MW, and Thunder Bay Biomass with Capacity of 150 MW

2) In Reference b), it is indicated that Atikokan GS has one coal-fueled generating unit that produces over 200 MW of electricity.

3) In Reference c), it is indicated that Thunder Bay GS has two coal-fueled generating units that together produce up to 306 MW of electricity.

Questions:

(I) At Atikokan G.S

(i) Is the 200 MW listed as Biomass Atikokan project in Reference a) replacing the 200 MW of existing coal-fueled capacity at Atikokan GS identified in Reference b)? If so please provide the expected date of phasing out the existing coal-fuel unit, and the in-service date of the Biomass facility. In responding to this question please reference the source of the information (OPG, OPA, Ministry of Energy and Infrastructure).

(ii) If the new 200 MW Biomass at Atikokan is replacement for the existing 200 MW coal-fueled Capacity at that Station, and the two events occur within a short period, please confirm that once the replacement occurs, there will be no new/ incremental power flow contribution through the North –South Interface. If this assumption is not accurate please provide a full explanation.

(II) At Thunder Bay G.S

(i) Is the 150 MW listed as a Thunder Bay Biomass in Reference a) <u>a partial replacement for 306 MW</u> of existing coal-fueled capacity at Thunder Bay GS as identified in Reference c)? If so please provide the expected date of phasing out the existing coal-fuel units, and the in-service date of the Biomass facility. In responding to this question please reference the source of the information (OPG, OPA, Ministry of Energy and Infrastructure).

(ii) If the new 150 MW Biomass at Thunder Bay is part replacement for the existing 306 MW coal-fueled Capacity at Thunder Bay Station, and the two events occur within a short period, please confirm that once the partial replacement occurs, there will be incremental reduction in the power flow contribution through the North–South Interface by about 156 MW. If this assumption is not accurate please provide a full explanation.

<u>Response</u>

(I) (i) Yes, it is expected that the existing coal-fired generation unit at Atikokan Generation Station will be converted to biomass operation. The biomass unit will provide the same maximum continuous rating (MCR) as the coal-fired unit but will provide less energy annually. Preliminary indications are that the unit would be converted to biomass operation for an expected in-service date of 2012. This date is based on information provided by OPG.

(ii) Yes, the conversion of the existing coal-fired generation unit at Atikokan Generation Station to biomass operation will replace the existing coal-fired generation and will not have an incremental impact on the maximum southbound flow on the North-South Tie when compared with the existing facilities. However, output from the Atikokan Generation Station was initially planned to be lower. This was noted in the OPA's May 2008 letter, where the conversion of the Atikokan coal-fired generation unit was expected to only provide a maximum capacity of 35 MW (please refer to C-1-2, Table 2). This allowed other new resources to be added with the expectation that they would utilize much of the capacity currently available for this coal-fired unit. Therefore, the generation outlook today has an incremental capacity increase of 165 MW (200 MW – 35 MW = 165 MW) as compared to the May 2008 generation outlook.

(II) (i) Yes, the 150 MW biomass generation facility listed in C-1-2 Table 4 is the conversion of one of the existing coal-fired generation units at Thunder Bay Generation Station. The biomass unit will provide the same maximum continuous rating (MCR) as the coal-fired unit but will provide less energy annually. Preliminary indications are that the unit would be converted to biomass operation for an expected in-service date of 2013. This date is based on information provided by OPG.

(ii) Yes, the conversion of the existing coal-fired generation unit at Thunder Bay Generation Station to biomass operation will replace one of the existing coal-fired units and will reduce the maximum southbound flow on the North-South Tie. However, generation at the Thunder Bay Generation Station was initially planned to be completely phased out. This was noted in the OPA's May 2008 letter, where the conversion of any of the coal-fired units at Thunder Bay Generation Station to biomass was not contemplated. This allowed other new resources to be added with the expectation that they would utilize much of the capacity currently available for these coal-fired units. Therefore, the generation outlook today has an incremental capacity increase of 150 MW (150 MW – 0 MW = 150 MW) as compared to the May 2008 generation outlook.

Ontario Energy Board (Board Staff) SUPPLEMENTARY INTERROGATORY #6 List 2

Interrogatory

Reference:

a) Supplemental Evidence, exhibit A/Tab 2/Schedule 1/page 2/Paragraph 5

b) Letter dated June 11, 2009 from Hydro Networks Inc. to the Board Secretary titled "EB-2008-0272 Hydro One Networks 2009-2010 Electricity Transmission Requirements - Final Revenue Requirements and Charge Determinants in Accordance with Decision"

Preamble:

Paragraph 5 indicates that the resulting impact on the 2010 Revenue Requirement is estimated to be $7.1 million, using the same cost of capital assumptions as in the Order issued by the Board on July 3, 2009.

Request:

Please provide the calculations which indicate how the $7.1 million figure has been determined. This could be in the form of the relevant parts of Exhibits 1 and 2 provided in reference b) above i.e. in a format similar to what was provided to the Board in preparation for issue of the UTR.

Response

The $7.1 million increase in Revenue Requirement is summarized as follows:

	Change M$
OM&A	-
Depreciation	1.6
Capital Tax	0.1
Return on Debt	2.5
Return on Equity	2.5
Income Tax	0.5
	7.1

The calculations are provided as follows in the reference b) format.

Revenue Requirement Summary

($ millions)	**Supporting Reference**	**Per Rate Order 2010**	**Impact 2010**	**Total 2010**
OM&A	Exhibit 1.1	426.2	-	426.2
Depreciation	Exhibit 1.2	279.7	1.6	281.3
Capital Tax	Exhibit 1.3	5.9	0.1	6.0
Return on Debt	Exhibit 1.4	253.4	2.5	255.9
Return on Equity	Exhibit 1.4	246.7	2.5	249.2
Income Tax	Exhibit 1.5	30.3	0.5	30.8
Base Revenue Requirement		**1,242.2**	**7.1**	**1,249.3**

Exhibit 1.1 OM&A
OM&A Details

($ millions)	Supporting Reference	Per Rate Order 2010	Impact 2010	Total 2010
OM&A		426.2	-	426.2

Exhibit 1.2 Depreciation
Depreciation Details

($ millions)	Supporting Reference	Per Rate Order 2010	Impact 2010	Total 2010
Depreciation	*See supporting details below*	279.7	1.6	281.3

Depreciation per Rate Order		**279.7**	a
Additional in-service amounts	D7	108.6	b
	D8	47.2	c
		155.8	d=b+c
Half-year rule		50.0%	e
Depreciation Rate		2.0%	f
Associated Depreciation		1.6	g=d*e*f
Adjusted Depreciation		**281.3**	h=a+g

Exhibit 1.3 Capital Tax
Capital Tax Summary

($ millions)	Supporting Reference	Per Rate Order 2010	Impact 2010	Total 2010
Capital Taxes	*See supporting details below*	5.9	0.1	6.0

Capital Tax per Rate Order		**5.9**	a
Additional IS	155.8		b
Less: Associated Depreciation	(1.6)		c
	154.2		d=b+c
Capital Tax Rate	0.075%		e
Increase in Capital Tax	0.1		f=d*e
Adjusted Capital Tax		**6.0**	g=a+f

Exhibit 1.4 Rate Base and Return on Rate Base Details

Rate Base and Return on Rate Base Details

($ millions)	Supporting Reference	Per Rate Order 2010	Impact 2010	Total 2010
Rate Base	*See supporting details below*	7,558.9	77.1	7,636.0
Return on Debt	*See supporting details below*	253.4	2.5	255.9
Return on Equity	*See supporting details below*	246.7	2.5	249.2

Return on Debt per Rate Order		**253.4**	a
Return on Equity per Rate Order		**246.7**	b
Rate Base per Rate Order	7,558.9		c
Additional IS	155.8		d
Associated Depreciation	1.6		e

Average of Additional IS	77.9		f=d / 2
Less: Average of Associated Depreciation	(0.8)		g= - e / 2
Average increase in rate base	77.1		h=f+g
Adjusted average rate base	7,636.0		i=c+h
Allowed Return:			
Third-Party long-term debt	5.76%		j
Deemed long-term debt	5.76%		k
Short-term debt	1.33%		l
Common equity	8.16%		m
Capital Structure:			
Third-Party long-term debt	58.0%		n
Deemed long-term debt	-2.0%		o
Short-term debt	4.0%		p
Common equity	40.0%		q
Return on Capital:			
Third-Party long-term debt	2.6		r=h*j*n
Deemed long-term debt	(0.1)		s=h*k*o
Short-term debt	0.0		t=h*l*p
Increase in Return in Debt	2.5		u=r+s+t
Increase in Common Equity	2.5		v=h*m*q
Adjusted Return on Debt		**255.9**	w=a+u
Adjusted Return on Equity		**249.2**	x=b+v

1

Exhibit 1.5 Income Tax
Income Tax Summary

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**OEB Approved 2010**	**OEB Decision Impact 2010**
Income Taxes	*See supporting details below*	30.3	0.5	30.8

Income Tax per Rate Order		**30.3**	a
Average Increase in Rate Base	77.1		b
Common Equity Capital Structure	40.0%		c
Return on Equity	8.16%		d
Increase in Return on Equity	2.5		e=b*c*d
Increase in Regulatory Income Tax	0.5		f
Regulatory Net Income (before tax)	3.0		g=e+f
Change in Timing Differences (note 1)	(1.6)		t
Taxable Income	1.4		i=g+h
Tax Rate	32.0%		j
Increase in Regulatory Income Tax	0.5		k=i*j
Adjusted Regulatory Income Tax		**30.8**	l=a+k

Note 1

Timing Differences per Rate Order		**(181.1)**	m
plus: depreciation related to D7&D8 projects	1.6		n
less: CCA claim			
Additional In-Service	155.8		o
Half-year Rule	50%		p
CCA Rate	4%		q
CCA claim related to D7&D8 projects	(3.1)		r = -o*p*q
Total Timing Differences		**(182.7)**	s = m+n+f
Change in Timing Differences		**(1.6)**	t=s-m

Ontario Energy Board (Board Staff) SUPPLEMENTARY INTERROGATORY #7 List 2

Interrogatory

Reference:

a) Exhibit B/Tab 1/Schedule 2

b) Exhibit B/Tab 2/Schedule 2

Preamble:

The question below relates to potential landowner concerns.
Reference a) refers to "landscaping" (line 16) and a "High Voltage Line tap from the 115kV D4 Bus to the SVC" (line 22).
Reference b) refers to "new 550kV tapping structures" (line 13), "access roads, landscaping" (line 16) and a "new station site" (line 26).

Question:

Please indicate if each of the projects D7 and D8 introduce or have outstanding any landowner issues, and if so please provide full details.

Response

Neither Project D7 nor Project D8 has any outstanding landowner issues. Project D8 had access road issues which were resolved.

School Energy Coalition (SEC) SUPPLEMENTARY INTERROGATORY #1 List 2

Interrogatory

Please state what relief, if any, HON is requesting in this application in respect of projects D9 and D10.

Response

As stated in A-2-2, Page 2, Lines 9-13, Hydro One is no longer seeking inclusion of Projects D9 and D10 in rate base as part of the current proceeding for the 2010 test year. Approval for rate base inclusion for these projects will now be requested as part of Hydro One Transmission's 2011-2012 transmission rate application as the required in-service date for these two projects is now December 2011 as noted at C-1-3, Page 2.

School Energy Coalition (SEC) SUPPLEMENTARY INTERROGATORY #2 List 2

Interrogatory

For projects D7 and D8, please provide a summary of any change in scope, as well as the associated change in cost, as between the current evidence and the evidence originally filed as part of the Application

Response

There has been no change in scope, nor associated change in cost, between the recently filed supplemental evidence and the evidence originally filed as part of the Application.

School Energy Coalition (SEC) SUPPLEMENTARY INTERROGATORY #3 List 2

Interrogatory

A-2-1, p. 2: the evidence states that the current evidence would increase 2009 approved capital spending by $82.7 million. Please provide the current status of projects D7 and D8, including all expenditures incurred to date.

Response

The work for Projects D7 and D8 is currently underway. Most of the detailed design and engineering is completed and tenders for the turn-key contract, covering procurement and installation, have been awarded. The equipment is now being manufactured and site surveys are underway so that the projects can be placed in service by the end of 2010.

Project Expenditures as of June 30, 2009 ($ M)

Project	**Net $ Year to Date**	**Net $ Lifetime To Date**	**Total Gross $**
D7—SVC Porcupine TS	1.9	4.0	4.0
D7—SVC Kirkland Lake	0.3	0.4	0.4
D8—Series Capacitors at Nobel SS	3.2	5.0	5.1
Total Projects D7 and D8	5.4	9.4	9.5

School Energy Coalition (SEC) SUPPLEMENTARY INTERROGATORY #4 List 2

Interrogatory

1. Ref. Exhibit C-1-2, pg. 5 of 9: the OPA evidence refers to the Reinforcement Projects as an alternative to building a new transmission line but then (at lines 22-24) states that the Reinforcements "provide a smaller incremental increase in transmission capability and do not prevent the installation of a new transmission line at a later time if it is needed." Is there a possibility that, despite the Reinforcement Projects being completed, a new transmission line will still be needed? If so, please discuss to what extent the Reinforcement Projects will have been a redundant exercise?

Response

The need for additional capability is not expected to diminish the need for, or the value of, the Reinforcement Projects.

The Reinforcement Projects were preferred to the construction of a new line because they maximize the use of existing facilities without the need for additional right-of-way, provide capability in a much earlier time frame than a new line, and provide an incremental increase in transmission capability that would continue to provide on-going value. Furthermore, the Reinforcement Projects will allow the development of renewable resources in Northern Ontario to occur earlier, which will be important to allow proponents to develop generation through the FIT program as soon as possible in order to achieve government policy goals.

The OPA expects that additional capability will be needed in the future for transfers between Northern and Southern Ontario. This is based on the interest in renewable energy procurement processes held to date (such as the Renewable Energy Supply programs), the forecast interest in the Feed-in Tariff (FIT) program that was launched on October 1, 2009, and the renewable potential identified by the OPA.

To maximize the transfer capability of the Interface and to ensure equal flow distribution between each of the 500kV circuits, any additional transmission line between Sudbury and the GTA would need to be equipped with series compensation in the same manner as the existing two lines. The existing series capacitors would therefore complement those that would need to be installed on any new transmission facilities.

Similarly, the SVCs at Porcupine TS and Kirkland Lake TS would continue to be required not only to improve transient stability response for contingencies involving the transmission facilities south of Sudbury, but also to improve the post-contingency performance of the transmission system north of Sudbury.

School Energy Coalition (SEC) SUPPLEMENTARY INTERROGATORY #5 List 2

Interrogatory

The IESO's System Impact Assessment states that "the enhanced transfer capability provided by the installation of these new facilities would be adequate to accommodate all of the existing and committed generating facilities north of Sudbury together with an increase of 433MW in the output from the expanded Mattagami River plants." Does the IESO believe the Reinforcements would be adequate to also accommodate the additional generating facilities listed as "Other Resources" in the OPA's evidence (which totalled 134MW as of May 2008, but which now are projected to total 375MW- see C-1-2, pp. 3 and 7 of 9) or other generation currently being contemplated? **In the IESO's opinion**, how likely is it that, despite the Reinforcement projects described in this application, a new transmission line will still be needed?

Response

It is the IESO's opinion that the Reinforcement Projects will be adequate to accommodate the 375MW of additional generating facilities listed as "Other Resources" in the OPA's evidence.

The Reinforcement Projects are adequate to provide an increase of approximately 750 MW in the transfer capability (to a total of about 2150MW) southward towards Toronto, through the use of generation rejection. (C-1-5, Page 2). This will be sufficient to accommodate the 500 MW of committed resources shown in Table 3 of C-1-2, and about 250 MW out of generation resources identified in Table 4 of the same exhibit. With the installation of the shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS as recommended in C-1-5, the use of post-contingency generation rejection would increase the maximum transfer that can be accommodated across the Flow-South Interface to 2500 MW. With the expectation that a new 500kV line will be installed between Sudbury and the GTA by 2015 (as instructed by the Minister of Energy and Infrastructure in his letter to Hydro One Inc. dated 21st September 2009), the IESO would allow generation rejection to be used [for a Type I SPS] during the interim period until the new line is placed in-service. This would allow the output from a further 350MW of generating capacity to be accommodated and would be sufficient for the resources shown in Table 4 of Exhibit C-1-2.

School Energy Coalition (SEC) SUPPLEMENTARY INTERROGATORY #6 List 2

Interrogatory

Recently, it was reported that the Minister of Energy and Infrastructure instructed HON to proceed with $2.3 Billion in transmission expansion and reinforcement projects.[1] Does the Direction from the Minister include work that could render the Reinforcement Projects discussed in the current evidence redundant. (For example, does the direction include a new single circuit 500kV line described in HON's current evidence as 'Alternative 4' or 'Alternative 3' at Exhibit B-1-3, p. 3 and B-2-3, p. 2 respectively?)

Response

The Minister's letter of September 21, 2009 does reference a 500 kV line at Schedule 2. Please refer to interrogatory response I-1S-92, Attachment 1. Construction of a 500 kV line would not make the facilities associated with projects D7 and D8 redundant as noted in Hydro One's response to the same interrogatory and in response to I-4S-38.

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[1] See *Ontario bets billions on wind,* Toronto Star, September 22, 2009: http://www.thestar.com/sciencetech/environment/article/698928

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #1 List 2

Interrogatory

Reference: i) Exhibit B/Tab 1/Schedule 1, page 2, lines 12-22
ii) Exhibit B/Tab 1/Schedule 1, page 1, lines 9-16

a) With respect to reference (i), please provide a schedule setting out a) the maximum southbound flows on the North-South Interface for the each of the most recent 24 months and b) the estimated transfer capability (both with and without the use of post contingency generation rejection). Please also identify those months where the use of post contingency generation rejection was required.

b) With respect to reference (ii), please provide a schedule setting out which additional resources discussed are already in service by the end of the period used in response to part (a) and their capacity.

Response

a) The following table summarizes the maximum southbound transfers across the Flow-South Interface for each of the latest 24 months. Also shown are the prevailing operating limits and the amount of generating capacity that was armed for rejection. Note that the flows shown below are historical flows which are based on a constrained dispatch to respect operating limits. Therefore, actual flows could have been greater if northern generation resources had not been limited by the capability of the North-South Tie.

Peak Monthly Flow-South Transfers for each of the preceding 24 months				
		Flow-South Transfer		
Date:	**Time:**	**Recorded Peak MW**	**Operating Limit MW**	**Generation Rejection Armed**
2007				
6th September	15:00:00	962.54	1300.00	
5th October	15:00:00	939.85	1300.00	
15th November	18:00:00	1326.75	1400.00	100MW
3rd December	20:00:00	1017.87	1053.44	
2008				
2nd January	18:00:00	1153.15	1300.00	
1st February	18:00:00	1156.48	1300.00	
7th March	20:00:00	1072.00	1100.00	
29th April	08:00:00	1471.25	1400.00	100MW
1st May	11:00:00	1398.45	1400.00	100MW
5th June	17:00:00	1390.36	1400.00	100MW
17th July	14:00:00	1232.57	1300.00	
14th August	12:00:00	1233.04	1300.00	
3rd September	17:00:00	866.80	1300.00	
30th October	18:00:00	1080.71	1300.00	
11th November	18:00:00	1023.22	1300.00	
16th December	18:00:00	898.68	1300.00	
2009				
19th January	18:00:00	1030.08	1300.00	
10th February	20:00:00	1111.96	1300.00	
23rd March	19:00:00	1005.93	1300.00	
27th April	19:00:00	1417.06	1400.00	100MW
14th May	06:00:00	1462.70	1400.00	100MW
5th June	08:00:00	1501.00	1400.00	100MW
28th July	20:00:00	1383.93	1400.00	100MW
5th August	08:00:00	1302.80	1300.00	
2nd September	13:00:00	1301.77	1300.00	

b) The following are the additional resources referred to in reference ii) that are already in service, and their capacities:

Project	**Capacity (MW)**	**Commercial operation**
Umbata Falls (Hydro)	23	November, 2008
Algoma Steel (CHP)	63	June, 2009
Lac Seul (Hydro)	12	February, 2009
RESOP (various)	5	Total In-Service as of August 2009

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #2 List 2

Interrogatory

Reference: i) Exhibit B/Tab 1/Schedule 1, page 1, lines 17-18
ii) Exhibit B/Tab 1/Schedule 1, page 2, line 24 to page 3, line 13

a) Do the reliability concerns regarding supply to customers north of New Liskeard arise only with the development of additional northern generation or do they exist under present day circumstances? Please provide a full explanation.

Response

a) The reliability concerns exist today. Currently, at transfers above 200-300 MW southbound from Porcupine TS, a significant amount of generation rejection is required in the north to maintain system security following the loss of the 500 kV circuit. When these flows exceed 650 MW, even the maximum available amount of generation rejection does not ensure stability nor avoid the risk of a separation ("islanding") of the system north of New Liskeard. During generation rejection, and especially when islanding, there is often large frequency and voltage fluctuation, causing a significant risk of equipment damage and supply interruption to electricity users in the area.

In 2006, transfers approached 900 MW and exceeded the 650 MW level. Outage statistics indicate that, over the period 1995 to 2008, the loss of 500 kV Porcupine TS x Hanmer TS circuit occured on average once per year and there were 3 occurrences when such an islanding situation occurred in the area.

The reliability concerns will increase as new planned renewable generation comes into service over the period 2010-14. If these concerns were not addressed by installing an SVC at Kirkland Lake TS, the required Flow South from Porcupine would not permit the Lower Mattagami Development to be connected as required by the OPA and the Government directive.

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #3 List 2

Interrogatory

Reference: i) Exhibit C/Tab 1/Schedule 1, page 4 of 9, lines 23-28
ii) Exhibit B/Tab 1/Schedule 1, page 3, lines 22-23

a) The OPA's original recommendation for a 2010 in-service date appears to have been based, per reference (i), on the need to mitigate the potential for delays in the transmission projects coming into service. Is this still a consideration in the OPA's current recommendation? If not, please explain what has changed such that risk of delays is no longer a concern to the OPA.

Response

a) Yes, the recommended in-service date was based in part on the need to mitigate delays to transmission facilities to ensure that transmission capability is available at the time when the generation resources are expected to come into service. The primary driver for the recommended in-service date was the expected in-service date of the generation resources that required the additional transmission capability. Both of these aspects are still a consideration in the OPA's current recommendation, although as the implementation of these transmission projects continues to progress, the risk of major delays is somewhat reduced. These projects are required to enable the full utilization of over 350 MW of contracted generation resources that are expected to come into service by 2010 or have come into service since the OPA's May 2008 letter to Hydro One. In addition, there is a large amount of renewable generation that is expected to be procured through the FIT program that will utilize the transmission capability provided by the Reinforcement Projects, and any delay to the Reinforcement Projects will also delay the development of these renewable resources.

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #4 List 2

Interrogatory

Reference: i) Exhibit B/Tab 1/Schedule 1, page 2, lines 7-10
ii) Exhibit C/Tab 1/Schedule 1, page 7 of 9

a) Are all 387 MW of Committed Resources (Reference (ii)) expected to be in-service by December 2010? If not, please indicate the which resources will not be in-service then and their expected In-service dates.

b) Please provide a schedule that sets out how much of the 375 MW of capacity (Reference (ii)):
- Was In-Service at Year End 2009
- Is Expected to be In-Service by Year-End 2010
- Is Expected to be In-Service by Year-End 2011

c) Based on the response to parts (a) and (b) and the currently anticipated in-service dates for the four projects directed by the Minister of Energy, please provide a schedule that sets out the anticipated maximum southbound flow for each month in 2011.

d) Please describe the impacts anticipated in 2011 if both projects (i.e., D7 and D8) were not completed and in-service until mid-2011. In doing so, please also include discussion as to the likelihood of the impacts occurring.

Response

a) No, not all of the 387 MW of Committed Resources at Reference (ii) are expected to come into service by 2010. The 99 MW Greenwich Wind Farm that was procured through the Renewable Energy Supply III program is not expected to come into service until 2011. The remaining 288 MW, however, are expected to be in-service by 2010.

b) The table below sets out the amounts of the 375 MW of other resources that were in-service by the end of 2009, expected to come into service by the end of 2010, or expected to come into service by the end of 2011.

Category	**Capacity (MW)**
Expected to come into service at the end of 2009	0
Expected to come into service by the end of 2010	15
Expected to come into service by the end of 2011	15
Expected to come into service by the end of 2013	375

c) The anticipated maximum southbound flows on the North-South Tie for each month in 2011 are provided in the table below based on the best available information at this time. Note that this study assumed no limit on the North-South Tie so flows were not constrained.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Maximum Southbound Flow (MW)	1950	1900	2000	2100	2200	2200	2250	2200	2200	2150	2000	1900

Source: OPA

d) There are several impacts that are likely to occur if the Projects D7 and D8 were not implemented by the end of 2010, and instead were delayed until mid-2011. First, generation proponents in Northern Ontario, expecting to develop under the FIT program or other OPA procurement, would not be able to connect until the Reinforcement Projects were complete (mid 2011 in the scenario provided). Second, as demonstrated by the table in response c), it is anticipated that there would be a larger amount of congestion on the North-South corridor. Southbound flow would need to be constrained more often to respect system limits. Finally, there would be operability and reliability impacts without the Reinforcement Projects in place because of the continued use of generation rejection and the lack of voltage support facilities on the transmission system north of Sudbury.

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #5 List 2

Interrogatory

Reference: i) Exhibit B/Tab 1/Schedule 1
ii) Exhibit B/Tab 2/Schedule 1
iii) Exhibit C/Tab 1/Schedule 5, page 3

a) Reference (iii) suggests that Project D8 will (on its own) increase the Flow-South Interface Transfer Capability by 340 MW and that Project D7 (on its own) will increase the value by a further 160 MW. However, the discussion in references (i) and (ii) implies that both projects D7 and D8 required in order to increase the North-South transfer capability.
   - Does either project, if implemented on its own, have any impact on the North-South transfer capability? If not, please explain why. If yes, please the individual impacts.

b) Please re-do the response to Question 4 d) assuming Project D7 is in-service as planned in 2010 but project D8 is not in-service until mid 2011.

c) Please re-do the response to Question 4 d) assuming Project D8 is in-service as planned in 2010 but project D7 is not in-service until mid 2011

Response

a) Implementing the projects individually would provide incremental benefits in the transfer capability across the Flow-South Interface.

The Flow-South transfer capability is limited by the transient performance of the generating units north of Sudbury following a contingency resulting in the loss of either of the 500kV circuits between Hanmer TS (Sudbury) and Essa TS (Barrie). These are the two circuits that are being equipped with series capacitors.

Loss of one of these circuits means that all of the generating capacity north of Sudbury is effectively connected to the remainder of the system by a single 500kV circuit. Installing series capacitors in each of these circuits to reduce their impedance provides the greatest contribution to improving the transient stability. Installing the series capacitors by themselves is shown to result in an increase in the transfer capability across the Flow-South Interface of 340MW.

The SVCs, with the series capacitors already in-service, are shown to increase the transfer capability across the Flow-South Interface by a further 160MW. In addition, the installation of the SVCs also benefits the system north of Sudbury. The SVCs at

Porcupine TS and Kirkland Lake TS improve the post-contingency voltage profile since this also has an effect on the post-contingency transient stability performance.

Although analysis has not been performed to establish what incremental benefit the SVCs, by themselves, would provide it is expected that the increase in the transfer capability would be between 100MW and 150MW.

b) The same impacts as discussed in Interrogatory response I-6S-73 would result if Project D8 was not in-service, except that the impacts would be somewhat mitigated by the additional capability provided by Project D7.

c) The same impacts as discussed in Interrogatory response I-6S-73 would result if Project D7 was not in-service, except that the impacts would be somewhat mitigated by the additional capability provided by Project D8.

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #6 List 2

Interrogatory

Reference: i) Exhibit B/Tab 1/Schedule 2, page 2
ii) Exhibit B/Tab 2/Schedule 2, page 2

a) Please provide a schedule setting out the interest rates used to determine the AFUDC charges and the total AFUDC costs for each project.

b) Please explain the basis for the forecast AFUDC rates used.

c) Please confirm that the cost estimates presented in the current filing for each project are the same as those submitted in Hydro One Networks' original EB-2008-0272 Application. If not, please identify any differences.

Response

a) The interest rates used to determine the AFUDC costs for each project are consistent with EB-2008-0272 D1-4-1.

The total AFUDC costs are $6 million for Project D7 and $2 million for Project D8.

b) Please refer to EB-2008-0272 D1-4-1. Please refer to EB-2008-0272 A-14-2, Table 7, page 6 for the schedule setting out the calculation of the AFUDC rate.

c) Please see interrogatory response I-4S-36.

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #7 List 2

Interrogatory

Reference: Exhibit A/Tab 2/Schedule 1, page 2

a) Please provide a schedule setting out the calculation of the $7.1 M increase in 2010 revenue requirement associated with the two projects.

Response

Please see interrogatory response I-1S-97.

Vulnerable Energy Consumers Coalition (VECC) SUPPLEMENTARY INTERROGATORY #8 List 2

Interrogatory

Reference: i) Exhibit B/Tab 1/Schedule 1, page 2
ii) Exhibit C/Tab 1/Schedule 4, page 3 of 92

a) Please reconcile the 1,300 MW existing North-South Transfer capability noted in reference (i) with the 1,400 MW value used by the IESO in reference (ii).

Response

The present day Flow South transfer limit is 1300 MW without use of the generation rejection scheme and the transfer capability is further increased to 1400 MW through use of the generation rejection scheme.

Canadian Manufacturers & Exporters (CME) SUPPLEMENTARY INTERROGATORY #1 List 1

Interrogatory

1. Reference: Exhibit A, Tab 1, Schedule 1, page 2

The evidence indicates that approval of capital Projects 07 and 08 will increase the Board approved capital program for 2009 by $82.7M, from about $853.8M to $936.5M; and for 2010 by $62M, from $995.6M to $1,057.6M. As a consequence, Hydro One appears to be asking the Board to increase the 2010 Revenue Requirement by $7.1 M. In connection with this evidence, please provide the following information:

a) Please provide a status report on the Board approved 2009 capital spending of 853.8M, based on eight (8) months of actual spending and four (4) months of projected spending. In particular, we are interested in determining whether actual spending to date and expected spending for the four (4) months September to December 2009 inclusive is likely to be less than the current Board approved amount for 2009 of $853.8M.

b) Please provide a status report on actual in-service dates for major capital spending projects in 2009, year-to-date, compared to the in-service dates reflected in the Board approved capital spending plan of $853.8M.

c) In particular, has there been any material slippage in actual compared to planned in-service dates in 2009? If so, then please provide an estimate of the extent to which the Board approved 2009 revenue requirement would be reduced if the actual 2009 in-service dates for 2009 capital spending are used in its calculation.

d) Please provide a status report on the current Board approved capital expenditures for 2010 of $995.6M having regard to actual 2009 capital spending to August 31, 2009, and expected 2009 capital spending between September and December 2009.

   In particular, is the actual pace of capital spending to date and expected spending for the balance of 2009, either separately or in combination with other factors, likely to reduce the amount of actual capital spending in 2010 to an amount below the currently approved sum of $995.6M? If so, then what is Hydro One's current estimate of the amount of capital that is now likely to be spent in 2010 in connection with the Board's currently approved capital spending plan of $995.6M?

e) Please provide a status report on the currently expected in-service dates for major capital spending projects in the 2010 Board approved plan compared to the forecasted in-service dates reflected in that approved plan.

f) If there is any slippage between the in-service dates reflected in the Board approved 2010 capital spending plan and the 2010 in-service dates now expected, then provide an estimate of the extent to which the Board approved 2010 Revenue Requirement of $1,242.2M would be reduced if these later in-service dates for 2010 capital spending are used in its derivation.

Response

As stated by the OEB in its Procedural Order No. 6 in EB-2008-0272 as issued on September 18, 2009:

> In its decision [in EB-2008-0272] the Board did not approve four of the Network Capital Projects (labeled in the application as D7, D8, D9 and D10). However the Board indicated that it would consider further evidence from Hydro One on these [four] projects. The Board will ensure a streamlined process to consider any new evidence on these [four] projects.

The information relevant to the above has been provided in I-4S-37. Hydro One has provided actual 2009 year-to-date expenditures for the two projects covered in its supplemental filing of September 4, 2009. The project expenditure forecasts for these two projects are still appropriate.

Association of Major Power Consumers of Ontario (AMPCO) SUPPLEMENTARY INTERROGATORY #1 List 2

Interrogatory

Reference: Ex C/Tab 1/Sch 2/page 6 of 9/Table3

Please augment Table 3 with respect to the four specific projects identified in these schedules:

Project	Existing (pre-project) Capacity (MW)	Planned Capacity (MW)	Planned or Actual In-Service Date
Lac Seul		12	In-Service
Hound Chute		10	2010
Upper Mattagami		35	2010
Sub-total			
Lower Mattagami		450	2014
Total			

Response

The "planned capacities" provided in the table above are not the "planned capacities" for all of the sites. In C-1-2 Table 3, the capacities that were provided for Lac Seul and the Lower Mattagami were incremental capacities and those provided for Hound Chute and the Upper Mattagami were planned capacities. An "Incremental Capacity" column has been added to the table above to illustrate the difference between the pre-project capacity and the planned capacity. The augmented table is provided below.

Project	**Existing (pre-project) Capacity (MW)**	**Incremental Capacity (MW)**	**Planned Capacity (MW)**	**Planned or Actual In-Service Date**
Lac Seul (Note 1)	0	12	12	In-Service
Hound Chute	4	6	10	2010
Upper Mattagami	19	16	35	2010
Sub-Total	23	34	57	
Lower Mattagami	486	450	936	2014
Total	509	484	993	

Note 1: Lac Seul Generation Station is adjacent to Ear Falls Generation Station. The capacity of Lac Seul is incremental to the capacity of Ear Falls.

Association of Major Power Consumers of Ontario (AMPCO) SUPPLEMENTARY INTERROGATORY #2 List 2

Interrogatory

Reference: Ex C/Tab 1/Sch 2/page 7 of 9/Table 4

Please provide a modified Table 4 with a column identifying the existing pre-project capacities for the generation projects noted in this table.

Response

All of the capacities listed at C-1-2 Table 4 are incremental capacities except for the Atikokan and Thunder Bay biomass conversions. Further discussion of the conversions of these coal-fired generation stations to biomass operation is provided in Interrogatory response I-1S-96. A modified Table 4 is provided below:

Site	Type	Incremental Capacity (MW)	Pre-project Capacity (MW)
In-Service and Committed Resources			
RES I Umbata Falls	Hydro	23	0
CHP Algoma	Gas	63	0
In-Service RESOP	Various	5	0
Committed RESOP	Various	177	0
RES II Island Falls	Hydro	20	0
Biomass northwest	Biomass	(Note 1)	n/a
RES III Greenwich Windfarm	Wind	99	0
	Total Committed	**387**	
Other Resources			
Cameron Falls	Hydro	4	82
Namewaminikan - 8 km & 12.8 km	Hydro	10	0
Alexander	Hydro	1	68
Mattagami Lake Dam	Hydro	6	0
Pine Portage	Hydro	4	142
Biomass Atikokan	Biomass		
Thunder Bay Biomass	Biomass		
	Total Other Resources	**25**	
	Total by 2013	**412**	

Source: OPA
Note 1: This site was included separate from the RESOP potential in the May 20, 2008 letter, but has since been contracted for through RESOP and is included in the committed RESOP site in this Table.
Note 2: Not all in-service resources are included in this Table. Only the resources that were included in May 20, 2008 letter that have since come into service are included in this Table.

Association of Major Power Consumers of Ontario (AMPCO) SUPPLEMENTARY INTERROGATORY #3 List 2

Interrogatory

Please provide an explanation of the technical consequences if one of either D7 or D8 is rejected by the Board for 2010 in-service, but the other is accepted. In other words, to what extent would the existing and emergent system concerns be addressed if only one of these projects was approved?

Response

Please see responses to Interrogatories at I-6S-73 and I-6S-74. I-6S-73 describes the impact of having neither D7 nor D8 in-service until mid 2011. I-6S-74 describes the impact of having Project D7 in-service as planned in 2010, but Project D8 not in-service until mid 2011, and vice-versa. If these projects were delayed beyond mid 2011 then the concerns described in I-6S-73 would continue to exist indefinitely and new generation could not be incorporated in Northern Ontario.

Association of Major Power Consumers of Ontario (AMPCO) SUPPLEMENTARY INTERROGATORY #4 List 2

Interrogatory

Reference: Ex C/Tab 1/Sch2/page 4 of 9, lines 2-7

Please provide a brief list of the times when generation rejection has been activated (vs. simply armed) on generation units in Northern Ontario in order to limit flows on the North-South Tie, since 2005. Please include the capacity and energy that was rejected.

Response

Since 2005, generation rejection has not been activated to limit flows on the North-South interface. However, generation rejection has been armed on numerous occasions since 2007 as shown in interrogatory response I-6S-70.

Association of Major Power Consumers of Ontario (AMPCO) SUPPLEMENTARY INTERROGATORY #5 List 2

Interrogatory

Reference: Ex B/Tab 1/Sch1

a) Please identify if and/or how often a single circuit contingency on the Porcupine – Hanmer TS 500kV circuits has led to the transmission system separating at Kirkland Lake TS.

b) Please identify what correction or mitigation measures are available (beyond 500kV circuit restoration) to the IESO and/or Hydro One in the event that a single 500kV contingency results in separation at Kirkland Lake TS.

Response

a) Please see Interrogatory response I-6S-71.

b) No other measures are available other than restoring the island and synchronizing to the grid.

Association of Major Power Consumers of Ontario (AMPCO) SUPPLEMENTARY INTERROGATORY #6 List 2

Interrogatory

Please discuss whether Hydro One or the IESO or others have considered the use of demand side options to mitigate contingencies and/or limit North-South tie flows in the period until these projects are built.

Response

The use of demand side options or CDM is not an applicable option in this case. Projects D7 and D8 are primarily driven by the need to facilitate renewable energy development including approximately 500 MW of hydroelectric generation north of Porcupine TS from four specific projects that the OPA was directed by the Minister of Energy to procure.

Since the objective is to allow new renewable resources to be delivered and since the transfer level on the North-South Tie is the difference between generation and load, changes to the northern Ontario load level through demand side options would exacerbate the regional generation surplus situation.

Currently the North-South interface allows transfer of generation surplus from northern Ontario to meet the needs at peak load periods in southern Ontario. The current transfer capability of this interface is 1400 MW with the use of the special protection scheme. It is not adequate for transferring all of the expected and planned renewable generation.