EB-2008-0272
2009-10 Transmission Rate Application
Hydro One Networks' Undertaking Responses

Undertaking	Description	Filed Date
J1.1	To provide a sample of an OPA letter recommending a particular project	February 26, 2009
J1.2	To provide answer to where extra $60 million in 2008 capital spending went by project	February 26, 2009
J1.3	To provide recommendation letter from OPA with respect to projects for which the applicant has recommendations	February 26, 2009
J1.4	To identify which of the seven non-discretionary category 2 projects had alternatives considered, and for those that no alternatives were considered, if any, explain why no alternatives considered	February 26, 2009
J2.1	To advise If Hydro One Networks provided a cost-effectiveness analysis for the transmission components of Exhibit K1.1 projects; to provide what was produced in that context for the OPA for each of the non-section 92 approved projects	February 27, 2009
J2.2	To provide the total transmission lines for 2008, 2009, 2010 and total units transmitted in terawatt hours for 2008, 2009 and 2010	February 26, 2009
J2.3	To provide a breakdown of additional work to be performed under the ancillary systems	March 5, 2009
J2.4	To identify which projects are not related to IPSP in Exhibit C1, tab 2, schedule 3, page 7	February 26, 2009
J2.5	To file an interrogatory response, AMPCO Interrogatory No.	February 26, 2009
J2.6	To confirm that projects 11 through 14 are still required contingency plans under the OPA's IPSP with respect to generation facilities	February 27, 2009
J2.7	To provide the minimum levels going into the planning process, as well as any context necessary to provide a better understanding of the numbers	February 26, 2009
J2.8	To reconcile the apparent difference in the data between Exhibit C1, tab 2, schedule 2, page 15, figure 1 versus Exhibit I, tab 1, schedule 22	March 5, 2009
J3.1	To provide 2009 and 2010 forecast yield shown in table 4 of Exhibit B1, Tab 2, Schdule 1 and Whether it will be updated based on Current Ingormation available.	March 2, 2009
J3.2	To provide the actual 2008 export transmission revenues shown in response to VECC IR no.66.	February 27, 2009
J3.3	To explain the net adjustement of the $30 million reduction in class 47 in the 2007 CCA Calculation and to explai why there is no net adjustement I the calculation.	March 3, 2009
J3.4	To provide the increased credit that resulted in line 8 and tables 2 and 4 under the scenario of a deferral-account clearance over two years, rather than 4	March 3, 2009
J3.5	To provide the impact on the overall revenue requirement if hydro one compensation was equivalent to the median or to provide the explanation why that cannot be done	March 5, 2009
J3.6	To provide reports or analyses if any from accenture with respect to the cornerstone project for the test years	March 2, 2009
J4.1	To file a copy of the Shpigler	March 3, 2009
J4.2	To provide a description of what was included in the capital category and the implications of eliminating	March 5, 2009
J4.3	To provide the productivity indicators from the Mercer Wyman study using forecast 2009 data for Hydro One, only.	March 5, 2009
J4.4	To describe what Phase 1 is and how it is used and useful for the 2010 test year	March 3, 2009
J5.1	To add a column to tables 1 and 2 of Exhibit A, tab 14, schedule 3 showing actual peak monthly demand.	March 3, 2009
J5.2	To provide a copy of letter from the Board dated February 24, 2009.	March 3, 2009
J5.3	To provide the actual dollar impacts and dollar increases for each customer, for the 45 delivery points	March 5, 2009
J5.4	To provide the calculation for the 430 megawatt increase in peak.	March 3, 2009

UNDERTAKING

Undertaking

To provide a sample of an OPA letter recommending a particular project

Response

Please refer to the response provided for Undertaking J1.3.

UNDERTAKING

Undertaking:

To provide answer to where extra $60 million in 2008 capital spending went by project.

Response:

The table below provides a breakdown of the specific Development Capital projects with more than $1M variance between the 2008 projected spending and the actual 2008 spending provided in the February 13, 2009 update to Table 1 of Exhibit D1, Tab 3, Schedule 3.

Hydro One notes that the $62.8M variance in 2008 cash flow does not materially impact the in-service dates or total cost of the projects identified. As such, the update to the 2008 cash flow does not impact the requested revenue requirement for the test years.

		Gross Cash Flow ($ Millions)			
Item	**Description**	**Forecast**	**Actual**	**Variance**	**Variance Explanation**
D2	New 500kV Bruce to Milton Double Circuit Transmission Line	30.9	44.8	+13.9	Advanced the purchase of some material to facilitate achieving the required in-service dates.
D15	Southern Georgian Bay Transmission Reinforcement	41.1	48.3	+7.2	Advanced the removal of temporary construction roads due to completion of line work ahead of schedule.
D5	Cherrywood TS x Claireville TS: Unbundle 500kV Circuits	19.5	25.1	+5.6	Advanced construction work to maintain project schedule.
D3	Installation of Seven 230kV Capacitor Banks in Southwestern Ontario	22.3	24.9	+2.6	Advanced purchase of material to facilitate achieving in-service dates.
D23	Kingston Gardiner TS: Add Transformation Capacity	6.1	8.6	+2.5	Delays from the customer resulted in delaying material purchase from 2007 to 2008.
D16	Hurontario Station and Transmission Line Reinforcement	15.9	18.3	+2.4	Advanced purchase of key materials.

		Gross Cash Flow ($ Millions)			
Item	**Description**	**Forecast**	**Actual**	**Item**	**Description**
D24	Holland TS: Build new 230/44kV TS & Line Connection	12.3	14.7	+2.4	Advanced work to expedite the in-service of the project required to manage the load growth in the area.
D18	Woodstock Area Transmission Reinforcement	2.1	3.8	+1.7	Work initiated on required temporary by-pass in order to facilitate meeting the target in-service dates.
D19	Replacement of Switchgear & Main Bus in 115kV Switchyard at Burlington TS	0.8	2.1	+1.3	Advanced work to facilitate meeting the required in-service date.
D27	Churchill Meadow TS: Build new 230/44kV TS & Line Connection	1.1	2.2	+1.1	Advanced work to facilitate meeting required customer driven in-service date.
D26	Vansickle TS: Increase capacity to supply new load	0.0	1.0	+1.0	Advanced work to facilitate meeting the required customer driven in-service date.
	Balance of Capital Projects	115.2	136.2	+21.1	Primarily attributed to carryover of 2007 uncompleted work and new unplanned development work in 2008.
	Total Development Capital	**267.2**	**330.0**	**+62.8**	

UNDERTAKING

Undertaking

To provide recommendation letter from OPA with respect to projects for which the applicant has recommendations.

Response

The four recommendation letters from OPA with respect to the following projects are attached:

Project	Investment Description	Attachment
Project D2	New 500kV Bruce to Milton Double Circuit Transmission Line	**Attachment 2** (dated March 23, 2007)
Project D3	Installation of Seven 230kV Capacitor Banks in Southwestern Ontario	**Attachment 3** (dated December 3, 2007)
Project D4	Bruce Special Protection System Modifications for Bruce Area	**Attachment 1** (dated December 22, 2006)
Project D7	Northeast Transmission Reinforcement: Installation of Static Var Compensators at Porcupine TS & Kirkland Lake TS	**Attachment 4** (dated May 20, 2008)
Project D8	Installation of Series Capacitors at Nobel SS	**Attachment 4** (dated May 20, 2008)
Project D12	Installation of two 125Mvar Shunt Capacitor Bank at Porcupine TS	**Attachment 4** (dated May 20, 2008)

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Ontario Power Authority

December 22, 2006

Ms. Laura Formusa
Acting CEO, Hydro One
483 Bay Street
Toronto, ON
M5G 2C9

Mr. Paul Murphy
CEO, IESO
Station A, Box 4474
Toronto, ON
M5W 4E5

Mr. Duncan Hawthorne
President & CEO, Bruce Power
177 Tie Road
PO Box 3000, B0602
Tiverton, ON
N0G 2T0

Dear Sirs/Madam:

Re: Transmission from Bruce Area

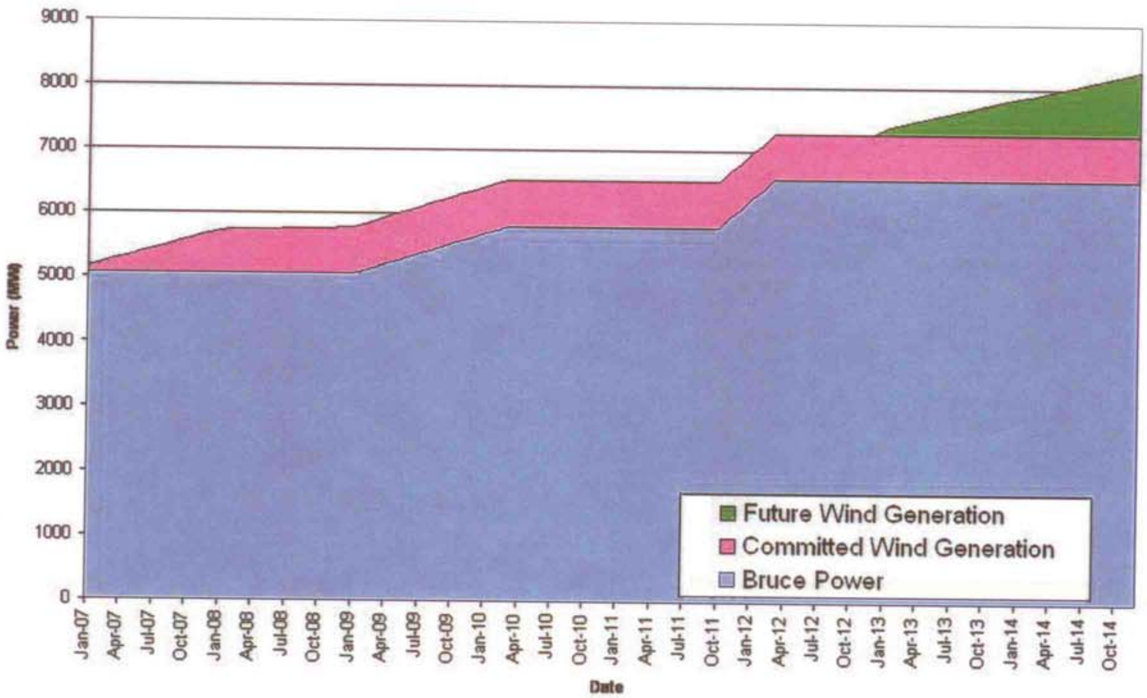
The OPA is writing, in keeping with its mandate to plan the electricity system in Ontario and support the goal of ensuring adequate, reliable and secure electricity supply in Ontario, to bring a matter of concern to the OPA to your attention. The OPA believes that action must be urgently taken to ensure that there is adequate system capacity to permit all available generation in the Bruce area to be transmitted. The OPA's analysis of this matter is found in section 2.3.6 of the OPA's Discussion Paper 5 on Transmission, issued as part of OPA's stakeholder process on the IPSP. This Paper was released on November 13, 2006 and was discussed as part of a workshop on the IPSP held by the OPA on November 22-24, 2006.

Summary of OPA Analysis:

As you are aware, Bruce Power is refurbishing and returning to service the two "laid-up" generating units, Units 1 and 2, at the Bruce A nuclear plant. These units, each rated at 725 MW, are scheduled to be returned to service in 2009. They will add 1450 MW of base load generation to the Ontario system, which will improve the province's reliability of supply. Coincidental to the return of the two Bruce units, Bruce Power is scheduling the outage of other units at the Bruce A plant for extended maintenance work from 2009 to 2011. Thus, in effect, an equivalent of one Bruce unit is added between 2009 and the end of 2011, and two units thereafter.

Additionally, about 725 MW of wind generation has been committed for the Bruce area. Our latest studies done for preparation of the Integrated Power System Plan identifies a potential for another 1000 MW or more of wind generation that could be developed in this area. Together, these new resources add to about 1500 MW by 2009, about 2250 MW by 2012, and over 3000 MW in the longer term. The generation increases in the Bruce area between now and 2012, and the possible amount to 2014 are shown in Figure 1.

Figure 1 - Bruce Area Generation



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The existing transmission system that transmits power from the Bruce area to the Greater Toronto Area (GTA) was last expanded around 1990 and has sufficient capacity for the existing generation there now, namely 4 units at Bruce B and two units at Bruce A, with a combined output of about 5060 MW. There is some additional capacity to incorporate the committed wind generation in the Bruce area once the critical sections of two of the Bruce 230 kV circuits, between Hanover and Orangeville, have been uprated and additional static or dynamic shunt reactive sources installed at the Middleport, Orangeville and Detweiler stations. OPA staff has discussed these system reinforcements with Hydro One and IESO staff. Hydro One is currently assessing the extent of the work required to uprate the 230 kV circuits. The OPA recommends that this uprating work should proceed immediately to enable an in-service date of mid 2009. The OPA also recommends that project development work for the addition of static or dynamic shunt reactive sources be commenced in accordance with any requirements that may be established by the IESO or the OPA.

As stated in the OPA's Transmission Discussion Paper #5, a new 500 kV line from the Bruce area to the GTA is required to address the long term transfer capability requirements out of the Bruce area. However, following the determination of the optimum route, expected approval timelines for a project of this magnitude will not enable the required in-service date of 2009 to be met. Therefore, further measures are required beyond the immediate transmission enhancements described above to bridge the two year gap between the return to service of the Bruce Units 1 and 2 in 2009 and the expected in-service date for the new 500 kV line of late 2011.

Staff of the OPA and the IESO have worked together in the past year to identify and assess interim measures for increasing the transfer capability between Bruce and the GTA. The interim measures that were found to be the most effective are:

- generation rejection (GR) of up to 1500 MW (two Bruce units or one Bruce unit and wind generation) and, subject to confirmation from the due diligence study noted below
- 30% series compensation of the Bruce to Longwood and Longwood to Nanticoke 500 kV circuits.

The IESO has assessed these interim measures. Their results show that the immediate enhancements combined with GR, which can be placed in service in 2009, will allow the output from seven Bruce units and committed wind generation to be transmitted. Thirty percent (30 %) series compensation may be used as a stop-gap measure to further expand transmission capability to accommodate eight Bruce units if approvals for the new 500 kV line are unduly delayed.

The interim measures are not alternatives to the long-term solution since they increase the risk to the security and reliability of the power system. The use of GR as an interim measure until a more permanent solution is in place is subject to NPCC approval. With regard to the use of series compensation, a new technology for Ontario, for increasing the transmission capability out of Bruce, Hydro One Networks has expressed concern regarding the system and equipment risks. The OPA appreciates this concern and will retain third party experts to undertake a due diligence study to assess the suitability and risks associated with the use of series compensation for this application. Staff of Hydro One Networks and the OPA have drafted a document that addresses the scope of technical issues and concerns to be covered by this study. The process to retain an appropriate consultant has commenced.

Conclusion:

We recommend that:

- Hydro One Networks proceeds as quickly as possible with the work to upgrade the Hanover x Orangeville 230 kV circuits and install static or dynamic shunt reactive sources as identified by the IESO or the OPA, and
- Hydro One Networks, IESO and Bruce Power proceed as quickly as possible with the work to install generation rejection for the Bruce generation.

Further, the OPA is committed to undertaking the due diligence study on series compensation as quickly as possible. OPA staff will attempt to assist you in providing any other information that you may require on these matters.

If you have any questions, I would be happy to discuss them with you.

acting for

Jan Carr
CEO, OPA

cc. Howard Wetston, Chair of OEB

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THE OFFICE OF LAURA I. FORMUSA
FILE
RECEIVED
MAR 23 2007
B.F.
REFER TO
COPY FOR

March 23, 2007

Ms. Laura Formusa
President and CEO (Acting)
Hydro One Inc.
483 Bay Street
Toronto, ON
M5G 2P5

Dear Laura:

Re: A New Transmission Line from the Bruce Area to the Greater Toronto Area

The purpose of this letter is to urge Hydro One Networks Inc. to initiate the activities necessary to construct a new double-circuit 500 kV line between the Bruce Nuclear Power Complex and Hydro One's existing Milton switching station located in the Town of Milton in the western part of the Greater Toronto Area (GTA) for in-service by December 1, 2011. These activities include, but are not limited to, seeking and acquiring required permits, regulatory and environmental approvals, and conducting engineering work and prudent purchase of materials needed to meet the required in-service date.

Our letter to you, Mr. Paul Murphy of the IESO, and Mr. Duncan Hawthorne of Bruce Power, dated December 22, 2006, provided the background, basis and rationale for the need for a long-term solution to reinforce the transmission system out of the Bruce area. The OPA has determined that this long-term solution is a new 500 kV line from the Bruce area to the GTA.

Recognizing that the time needed to complete a project of this magnitude would not meet the timing required to fully tap into additional generation capacity available in the Bruce area, the December 2006 letter recommended that a set of near-term and interim measures should also proceed as soon as possible. These measures are expected to provide the required increase in transmission capability to permit the available power in the Bruce area to be transmitted to Ontario load centres until a long-term solution is in place.

The long-term solution for reinforcing the Bruce transmission must (a) meet the need to deliver the existing, committed and forecast renewable and other resources in the Bruce area in a safe, reliable and cost-effective manner, and (b) be consistent with Ontario's land use policy. The need and rationale for this line are discussed in more detail in the OPA's Transmission Discussion Paper #5 and Discussion Paper #7, the OPA's preliminary IPSP, which were presented to stakeholders in the OPA's Integrated Power System Plan (IPSP) Stakeholder Workshop held in Toronto last November 22 to 24.

Existing resources in the Bruce area total about 5,000 MW. The committed resources will increase the total to about 6,500 MW between 2009 and 2012, and to 7,300 MW after 2012. The OPA, in the development of the IPSP, also identified the potential for another 1,000 MW of renewable generating resources in the Bruce area. Thus, the long-term solution must be able to increase the transmission capability of the Bruce system from today's 5,000 MW level to about 8,300 MW. From this perspective, the only technically acceptable and practical solution is a new 500 kV double-circuit line from the Bruce area directly to the GTA.

.... 2

Provincial land use policy requires that existing transmission corridors be utilized to the extent possible for new transmission lines. This policy narrows the transmission options to two alternatives – from Bruce to Milton or from Bruce to Essa via Orangeville, as shown in Figure 1.

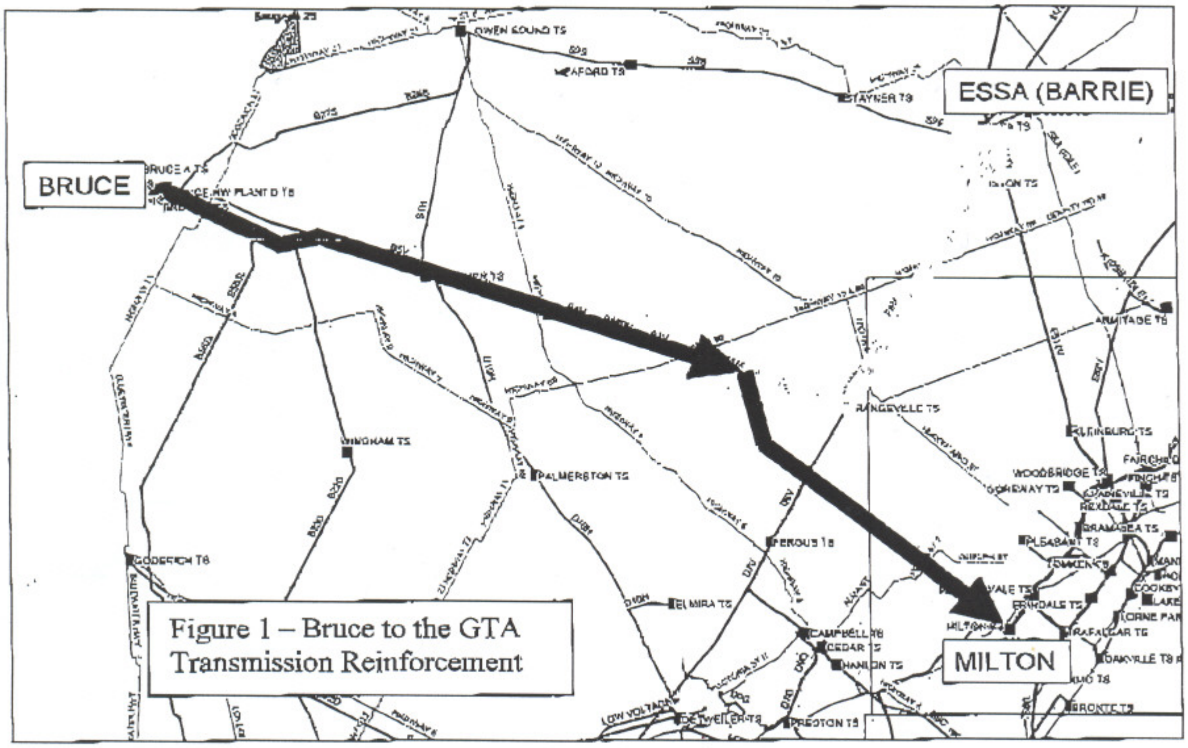

Figure 1 – Bruce to the GTA Transmission Reinforcement

In the past months, OPA, Hydro One, and IESO staff assessed the technical impacts of the two options - Bruce to Milton, and Bruce to Essa. These studies revealed:

- the Bruce to Essa option increases transmission capacity to deliver committed future generation in the Bruce area, including approximately 700 MW of renewable energy capacity. However it does not accommodate the additional 1,000 MW of forecast renewable generating resources, and
- the Bruce to Milton option offers greater capability to deliver future, renewable, generation developments in the Bruce area. Furthermore, unlike the Bruce to Essa option, it does not consume transmission capacity of the Essa (Barrie) to Claireville (GTA) transmission path that is required to accommodate future renewable generation developments north of Barrie.

The feedback from the OPA's IPSP stakeholder workshop has been generally positive concerning the Bruce transmission proposal. Most participants concurred that the transmission capability out of Bruce should be reinforced, particularly to permit the development of renewable generation potential in the Bruce area. Some also commented that, if the new transmission is built, it should have sufficient capability to deliver the existing, committed and future generation in the area. As well, the transmission capability between Barrie and the GTA should be preserved for generation developments north of Barrie.

.... 3

Since early December 2006, OPA and Hydro One staff have consulted with regional/municipal planners in communities that are impacted by the proposed Bruce to Milton line. In total, eleven municipalities, four counties and one region were contacted. During those consultations, OPA and Hydro One staff explained the need for the line and the rationale for routing the new line within a widened existing Bruce to Milton corridor.

Conclusion:

We have concluded that the Bruce to Milton option is the only transmission alternative that meets the overall need to transmit the existing and committed generation in the Bruce area, to facilitate the development of future resources both in the Bruce area and north of Barrie, to be consistent with provincial land use policy; and to reflect the general support to date from stakeholders for a long-term solution within a widened existing transmission corridor.

We believe that it is crucial that implementation work on the Bruce to Milton transmission line project proceed as quickly as possible. This project was included in the OPA's preliminary IPSP. Although this project is consistent with the IPSP, we do not believe that it can await the outcome of the IPSP proceeding if it is to meet the earliest possible in-service date, which Hydro One staff have indicated is December 1, 2011. If you choose to proceed with this project as the project proponent, you will have the support of the OPA in the regulatory process for this project.

Please feel free to contact us should you require any clarification or additional information.

Yours truly,

Jan Carr
Chief Executive Officer

cc Howard Wetston, Chair - OEB
Paul Murphy, CEO - IESO

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Ontario Power Authority™

December 3, 2007

Mr. Geoff Ogram
Vice-President, Asset Management
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2C9

Dear Geoff:

Re: Reactive Power Compensation Facilities for the Southwestern Ontario Transmission System

The purpose of this letter is to recommend Hydro One Networks Inc. to proceed with the installation of various capacitor banks at Buchanan TS, Middleport TS, and Nanticoke TS, for in-service in 2009.

In the OPA's letter from Dr. Jan Carr to Ms. Laura Formusa dated December 22, 2006, we identified the need for certain near-term and interim measures to increase the transfer capability of the Bruce and southwestern Ontario transmission systems for the delivery of 1500 MW of additional generation at the Bruce A nuclear plant and the committed 700 MW wind generation developments in the Bruce area to the Ontario power grid in 2009. These included:

- Upgrading the Hanover x Orangeville 230 kV circuits,
- Installing static or dynamic shunt reactive sources at a number of stations in southwestern Ontario (these are termed as the near-term measures), and
- Expanding the generation rejection (G/R) capability of the existing Bruce Special Protection Scheme to provide for expanded G/R coverage (one of the termed interim measures).

In Ms. Laura Formusa's letter to Mr. Jan Carr dated January 17, 2007, she indicated that based on the OPA's recommendations, Hydro One has allocated funding and commenced project development work on the above near term and interim measures.

In the past few months, the staff of Hydro One, the IESO and the OPA have been working to develop the specific scope of the required static or dynamic shunt reactive sources. Based on the recommendation of the team, the OPA is hereby recommending that Hydro One Networks Inc. proceed to commit work to install the following capacitor banks:

- One 200 MVAr 230 kV static capacitor bank at Buchanan TS;
- Four 250 MVAr 230 kV static capacitor bank at Middleport TS;
- Two 250 MVAr 230 kV static capacitor bank at Nanticoke TS; and

These facilities were selected in consideration of the transfer capability need, the system performance requirements and the space and size considerations. If additional engineering studies by Hydro One Networks Inc. indicate that there are concerns related to technical or physical limitations in installing these facilities at the stations identified, the location may be changed to other nearby stations after discussing the matter with the OPA and the IESO staff.

The above are in addition to the 250 MVAr 230 kV static capacitor bank at Detweiler TS and 250 MVAr 230 kV static capacitor bank at Orangeville TS that Hydro One is currently installing. All of these facilities are required as soon as possible for in-service by 2009. These facilities have long-term value even after the installation of the new Bruce GS x Milton SS 500 kV line.

Over the next several months, the OPA will provide additional recommendation regarding Static Var Compensation (SVC) facilities that are also likely to be required at Detweiler TS and Nanticoke TS. These requirements cannot be finalized at this time since further studies are required to establish the mix of static /dynamic facilities, speed of response, equipment configuration, and alternate locations of these facilities.

Please feel free to contact us should you require any clarification or additional information.

Yours truly,

Amir Shalaby,
Vice-President, Power System Planning
Ontario Power Authority

cc. Derek Cowbourne, the IESO

OPA

Ontario Power Authority™

May 20, 2008

Mr. Geoff Ogram
Vice-president,
Asset Management
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2C9

Dear Geoff:

Re: Increasing the Transfer Capabilities of the North-South and Sudbury-North Transmission Systems

The purpose of this letter is to recommend Hydro One Networks Inc. to proceed with the installation of series compensation facilities on the Hanmer to Essa 500 kV circuits at Nobel SS, and static and dynamic reactive power resources at Hanmer TS, Kirkland Lake TS, Porcupine TS and Essa TS, for in-service in 2010. These facilities will permit increases in the power transfer capabilities between Sudbury and the GTA (the North-South Tie) and between Timmins and Sudbury to meet the near-term need for incorporating new renewable generation in northern Ontario. These projects are consistent with and a component of the longer term transmission development plan to increase the transfer capabilities along these two power delivery paths to facilitate the development of the large renewable generation potentials in northern Ontario.

The North-South Tie, which comprises two 500 kV circuits between Hanmer TS in Sudbury and Essa TS in Barrie and one 230 kV circuit from Holden GS (east of North Bay) and Des Joachims GS (near Chalk River), is the transmission path by which the surplus generation in northern Ontario is delivered to electricity consumers in southern Ontario. In the past few years, a number of resources developments that came into service in northern Ontario have increased the level of southbound flows on the North-South Tie so that it is operating near its capacity of about 1,300 MW, and occasionally to 1,400 MW with the use of generation rejection. The Ontario Power Authority (OPA) forecasts another 900 MW of new resources, much of it renewables, to be in-service in northern Ontario by 2013. They include:

- the Lac Seul hydroelectric project (12 MW) – 2008
- the Hound Chute hydroelectric project (10 MW) – 2009
- the Upper Mattagami River hydroelectric project (35 MW) – 2009/2010
- the Lower Mattagami River hydroelectric project (450 MW) – 2011/2013

These projects, totalling just over 500 MW, were directed by the Minster of Energy to the OPA with a letter dated December 20, 2007 to assume the responsibility of the Crown and negotiate a financial energy supply agreement with Ontario Power Generation Inc. Thus, there is a high certainty that the above four projects would proceed.

Beyond the projects listed above, other planned generation in that time frame includes additional hydroelectric, wind, and combined heat and power generation that totals to about 400 MW. Although, there are more uncertainties associated with these generation developments, much of these are expected to develop requiring increase in the transfer capability of the North-South Tie.

On the transmission system north of Sudbury, as most of the generation projects related to Minister of Energy direction are located north of Timmins, the transfers on the transmission path from Pinard TS (near Fraserdale) and Sudbury will be significantly increased when they come into service in the 2010 to 2013 period. At this time, this system is already operating at its capability and requires the use of generation and load rejection special protection measures. Additional power transfers will further aggravate the reliability of this regional network.

Thus, in order to facilitate the development of committed and planned renewable and other resources forecast for northern Ontario in the 2010 to 2013 time frame, reinforcement of the North-South Tie and the transmission system north of Sudbury to increase the power transfer capabilities of these systems is required. Because of the urgency to provide the required increased capabilities in the 2010/11 timeframe, options that involve new transmission lines were considered but rejected because of the lead times required to develop these projects. Hydro One Networks, working in coordination with the Independent Electricity System Operator and the OPA, identified the recommended near-term solution for increasing the capabilities of the North-South Tie and the transmission system north of Sudbury as follows:

- Installation of series capacitors for 50% compensation of the Essa TS x Hanmer TS 500 kV lines (X503E and X504E) at Nobel SS at an estimated cost of approximately $ 45 M.

- Installation of a static-var-compensator (SVC) at Porcupine 230 kV TS with +300/-100 MVAr rating and another SVC at Kirkland Lake 115 kV TS with +200/-100 MVAr rating at a total estimated cost of about $ 100 M.

- Installation of two shunt capacitor banks at Porcupine 230 kV TS (125 MVAr @ 220 kV each), one bank at Hanmer 230 kV TS (149 MVAr @220 kV), and one bank at Essa 230 kV TS (182 MVAr @220 kV) at a total estimated cost of about $ 25 M.

Dynamic reactive resources are required in this transmission reinforcement in order to control voltages on the system north of Sudbury and New Liskeard. Increased transfers from Timmins to Sudbury as the result of new renewable generation developments north of Timmins further aggravate the reliability of supply to customers in this area. Hydro One Networks' proposal is to split the SVC need into two installations as described above, one at Porcupine TS in the Timmins area and one at Kirkland Lake TS in the New Liskeard area. This arrangement will provide a dual benefit of being able to control voltages on the 500 kV system north of Sudbury under varying power transfer conditions and provide voltage support to the 115 kV system north of New Liskeard following transmission outages.

The facilities proposed by Hydro One Networks will increase the transfer capabilities of the North-South Tie by 750 MW, from 1,300 MW to 2050 MW, and facilitate the incorporation of planned generation developments in northern Ontario. They will also allow increase in the transfer capability of the transmission system north of Sudbury to facilitate the development of directed hydroelectric development north of Sudbury totalling about 500 MW. They will also be an integral part of long-term developments of this system which ultimately involves installation of new transmission lines to enable further development of renewable generation in northern Ontario.

The OPA recommends that Hydro One Networks Inc. proceeds with the installation of the above transmission facilities immediately to enable the target in-service date ranging from fall 2010 to spring 2011. We understand that the project involving shunt capacitor may involve locating the identified shunt capacitor banks at different transformer stations as further project development work takes place.

Please feel free to contact us should you require any clarification or additional information.

Yours truly,

Amir Shalaby
Vice-President
Power System Planning

cc. Ken Kozlik, the IESO

UNDERTAKING

Undertaking:

To identify which of the seven non-discretionary Category 2 projects had alternatives considered, and for those that no alternative were considered, if any, explain why no alternatives considered.

Response:

The Table below identifies the alternatives that were considered and rejected for the Category 2 investments identified in Table 2 on page 33 of Exhibit D1-3-3.

Item	Investment Description	Alternatives Considered
D3	Installation of Seven 230kV Capacitor Banks in Southwestern Ontario	Alternative 1: *Do Nothing*. Rejected as it would constrain generation and would be inconsistent with the OPA recommendation.
D4	Bruce Special Protection System Modifications for Bruce Area	Alternative 1: *Do Nothing*. Rejected as it would constrain generation and would be inconsistent with the OPA recommendation. Alternative 2: *BSPS Replacement*. Considered as it would be capable of satisfying all current requirements and provide future expansion capability; but was rejected as it does not satisfy the timeline outlined by the OPA.
D5	Cherrywood TS x Claireville TS: Unbundle 500kV Circuits	Alternative 1: *Do Nothing*. Rejected as it would limit imports and constrain generation. Alternative 2: *Unbundle the existing 500kV "super circuits". Defer replacing four air blast breakers at Cherrywood TS*. Rejected as the benefits of combining the ‘Unbundling of Circuits’ and ‘Refurbishment’ work outweighed the $1.3M NPV cost increase associated with combining the two components of work.
D6	Installation of Static Var Compensator at Lakehead TS	Alternative 1: *Do Nothing*. Rejected as it would leave Northwestern Ontario with sub-standard reactive support. Alternative 2: *Repair Synchronous Condenser C7*. Rejected as parts for repair are not available. Alternative 3: *Replace Sync Condenser C7 with Another Sync Condenser*. Rejected as replacement would require installation of multiple units and capacitor banks to achieve the desired reactive power due to condenser capacity size limitations.

D7	Northeast Transmission Reinforcement: Installation of Static Var Compensators at Porcupine TS and Kirkland Lake TS	Alternative 1: *Do Nothing.* Rejected as it would not relieve the existing transmission restrictions and would be inconsistent with the OPA recommendation. Alternative 2: *Install Mechanically Switched Capacitor/Reactor Bank.* Rejected as it would only minimally increase the transfer capability; hence generation would still be constrained. Alternative 3: *Install series capacitors on the Porcupine to Hanmer 500kV circuit.* Rejected as it would only minimally increase the transfer capability; hence generation would still be constrained. Alternative 4: *Build a New Parallel Single Circuit 500kV line from Pinard to Hanmer*. Considered as it would address the transfer capability and system reliability issues; but rejected as it does not satisfy the in-service date outlined in the OPA recommendation and would be approximately ten times more costly.
D8	Installation of Series Capacitors at Nobel SS	Alternative 1: *Do Nothing.* Rejected as it would not relieve the existing transmission restrictions and would be inconsistent with the OPA recommendation. Alternative 2: *Install a new 500kV switching station mid-way between Hanmer and Essa.* Rejected as it would only minimally increase the transfer capability; hence generation would still be constrained. Alternative 3: *Build a new single circuit 500kV line to connect Hanmer to an existing or new 500kV station in or near the GTA.* Considered as it would address the transfer capability and system reliability issues; but rejected as it does not satisfy the in-service date outlined in the OPA recommendation and would be approximately ten times more costly.
D9	Installation of 100MVar Shunt Capacitor Bank at Algoma TS	Alternative 1: *Do Nothing.* Rejected because the installation of the recommended capacitor banks at Mississagi TS is supported by the OPA as a near-term project to relieve congestion issues on the Mississagi East transfer limits. See EB-2007-0707, Exhibit E, Tab 3, Schedule 2, Page 7.
D10	Installation of two 75MVar Shunt Capacitor Banks at Mississagi TS	Alternative 1: *Do Nothing.* Rejected because the installation of the recommended capacitor banks at Mississagi TS is supported by the OPA as a near-term project to relieve congestion issues on the Mississagi East transfer limits. See EB-2007-0707, Exhibit E, Tab 3, Schedule 2, Page 7.

UNDERTAKING

Undertaking

To advise If Hydro One Networks provided a cost-effectiveness analysis for the transmission components of Exhibit K1.1 projects; to provide what was produced in that context for the OPA for each of the non-section 92 approved projects.

Response

Hydro One Networks did not provide a cost-effectiveness analysis to the OPA for any of the transmission projects identified in Exhibit K1.1. The OPA is an independent organization that seeks input from various organizations before arriving at their decisions. The information that Hydro One provides to the OPA with regard to transmission projects is the estimated cost of transmission alternatives. We understand that the OPA then uses this input, as well as input from other sources, to conduct their cost-effectiveness analysis.

UNDERTAKING

Undertaking

To provide the total transmission lines for 2008, 2009, 2010 and total units transmitted in terawatt hours for 2008, 2009 and 2010

Response

The total transmission lines operating at 115 kV and above for 2007 to 2010 are provided in the response to VECC interrogatory Exhibit I-6-3, and reproduced in the Table below for convenience.

The terawatt-hours (TWH) for 2008 to 2010 are included in the Table below.

Unit	2007	2008	2009	2010
Transmission Lines (circuit-km) *(Note 1)*	28,589 *(Note 2)*	28,601	28,682	28,767
Energy Transmitted (TWH)	152.2	148.7	149.0	145.1

Note 1: Includes overhead and underground lines from Exhibit I-6-3.
Note 2: This value is different from that provided in SEC Exhibit K2.2 due to the fact that the SEC values are extracted from the Hydro One Annual Report, which includes all transmission lines owned by Hydro One, including those below 115 kV Transmission.

UNDERTAKING

Undertaking

To provide a breakdown of additional work to be performed under the ancillary systems

Response

The increased OM&A spending on ancillary systems, as described in section 3.5 of Exhibit C1, Tab 2, Schedule 2, is attributable to the increased work being accomplished in the following areas:

i) Planned Maintenance

An increase in preventative planned maintenance expenditures is required to maintain the aging fleet of ancillary equipment. The following table shows the test year increases in planned maintenance activities for Ancillary Systems:

Ancillary System	Maintenance Description	Number of Maintenance Activities		
		2008	2009	2010
AC Transfer scheme	Function test transfer scheme, perform overhaul on transfer scheme equipment, visually inspect fuses	1168	1576	1776
DC Transfer Scheme	Function test DC, perform overhaul on transfer scheme equipment, perform battery maintenance including load test	2294	4153	4153
Generation	Visual inspections, function test	275	576	576
High Pressure Air Systems	Visual checks, oil samples, function tests, pressure relief valve replacements	2124	2378	2378
Grounding System Maintenance	Visual and Mechanical Inspection, Point to Point and System Ground Grid Impedance Testing. This is a new requirement being introduced in 2010.	0	0	100

ii) Corrective Maintenance

Increased corrective maintenance expenditures are required in the test years in order to respond to unplanned equipment problems and maintain adequate performance of end-of-life ancillary system assets until such time as they can be replaced. Corrective maintenance costs have been increasing in recent years, going from $2.2M in 2007 to $3.9M in 2008. These costs are forecast to grow to $4.6M in 2010.

iii) Grounding Studies & Evaluations and Grounding Repairs

Grounding studies performed by external organizations have been useful in identifying a number of major issues, which will need to be addressed under Ancillary System Capital. The number of grounding studies is being increased from 10 in 2008 to 12 in each of 2009 and 2010. As a result of past grounding studies, the number of Station grounding repairs required to be completed is increasing from 12 in 2008 to a total of 14 in each of 2009 and 2010.

iv) Ancillary System Refurbishments

Additional work is being done to refurbish a number of ancillary systems in the test years as noted in the table below.

Activity	2008	2009	2010
Station Service Breaker Repairs (number of breakers)	0	0	8
VRLA battery rehydration (number of batteries)	0	14	14

v) Other Ancillary Maintenance Work

There are also increased expenditures related to a number of other ancillary maintenance activities, which includes the following:

- New funding that allows Hydro One to address high risk, emergent discovery work (beyond corrective repairs) such as recommendations derived from failure investigations, corrective trends analysis, peer reviews and equipment audits. Examples of work in this area include the installation of anti-condensation heaters at Automatic Transfer Scheme (ATS) cable raceways to prevent equipment corrosion, and installation/modification of portable ground attachment points or ground grid and bond attachment points as a copper theft deterrent.
- Additional work on oil farm operations to support Hydro One’s transformer and breaker oil management system (e.g. replacement of filter elements in oil farm operations resulting from batch oil quality issues).

UNDERTAKING

Undertaking

To identify which projects are not related to IPSP in Exhibit C1, tab 2, schedule 3, page 7

Response

All of the projects in Table 1 on page 7 of Exhibit C1-2-3 are related to the IPSP. In the case of Project 18, incorporation of Darlington B, the scope of the development work contemplated in the IPSP was increased following the decision by the Ministry of Infrastructure and Energy to install new nuclear generation at Darlington GS. Hydro One is now working with Ontario Power Generation on the scope of work required to incorporate the new station.

UNDERTAKING

Undertaking

TO FILE AN INTERROGATORY RESPONSE, AMPCO INTERROGATORY NO. 1

Response

The Ontario Power Authority response to AMPCO Interrogatory # 1 (Interrogatory Exhibit I, Tab 3, Schedule 1 from Proceeding EB-2008-0312) is attached.

AMPCO INTERROGATORY 1

Interrogatory # 1

Strategic Objective #1 - Power System Planning

Issue 1.1

Is the Operating budget of $5.79 million allocated to strategic objective # 1 reasonable and appropriate?

Reference:

Exhibit A/Tab 1/Schedule 1/Page 12
Exhibit B/Tab 1/schedule 1/ Pages 1-3

The OPA states at A-1-1 page 12 that supporting the development and implementation of the conservation, generation, and transmission options identified in the IPSP will continue as a priority for the period 2009-2011.

At B-1-1 Pages 1-3, the actions to achieve strategic objective 1 are listed and supporting IPSP 1 implementation is described as initiative 1.

Question:

a) Has the OPA specifically requested Hydro One Networks Inc. to undertake preliminary project development work on IPSP projects?

b) If yes to a) please provide details of the work requested by the OPA including milestones, timelines and the progress to date.

c) If no to a) does the OPA plan to request that Hydro One Networks Inc. undertake preliminary project development work on IPSP projects?

d) Does the OPA have an agreement with Hydro One Networks Inc. to provide compensation for IPSP project development work?

e) Please comment on whether project development work undertaken at the request of the OPA is transferable to a third party.

RESPONSE

a) The OPA has not specifically requested Hydro One Network Inc. (“HONI”) to undertake preliminary project development work on IPSP projects. However, the OPA has had preliminary discussions with HONI and other interested parties on a number of projects in the IPSP for which the OPA has identified that development work should proceed. The projects covered in the discussions include Little Jackfish/Lake Nipigon and Manitoulin enablers and the reinforcements of the North-South and Toronto area transmission. HONI has indicated their interest in pursuing the development work with all the projects identified in the IPSP in their recent transmission rates application to the OEB. Other parties have also expressed similar interest in select projects.

b) Please refer to OPA's response to (a) above. As there is currently no party formally selected as the developer of the various projects identified in the IPSP for development work, milestones, timelines and progress have not been established at this time for these projects

c) The OPA is awaiting guidance in such matters as the selection of transmitters for project development work from the amendments to the Transmission System Code (EB-2008-0003) or OEB decisions, such as HONI's 2009/2010 Transmission Revenue Requirement & Rate Application (EB-2008-0272), before actively working with the select transmitters on the development projects.

d) The OPA does not have an agreement with HONI to provide compensation for IPSP project development work.

e) The OPA has no comment on this matter. The OPA expects that this is a matter that would be dealt with by the OEB.

UNDERTAKING

Undertaking

To confirm that projects 11 through 14 are still required contingency plans under the OPA's IPSP with respect to generation facilities

Response

Hydro One confirms that all four of these projects are still required contingency plans.

Although Project 11 is related to the Northern York Region Generation request for proposal (RFP) conducted by OPA that recently concluded with a successful proponent, the proponent has yet to commit to their project. Past experience with generation procurement RFP's has shown that the successful proponent does not necessarily proceed to a project. For example, some of the successful proponents have cancelled their contracts for all of the Renewable Energy Supply 1, Renewable Energy Supply 2, and Clean Energy Supply generation procurement RFPs prior to commencing project construction. Hydro One plans to continue the budgeted $1.2M in development work for this project until there is certainty that the successful proponent will proceed to the construction phase.

Similarly, Projects 13 and 14 are both related to the Southwest GTA generation procurement RFP that is currently underway. Until the outcome of that RFP is known, and the successful proponent starts construction on their project, Hydro One proposes to continue the development work.

Project 12 is related to a potential future RFP in the Cambridge area. There is no certainty at this time that the Cambridge generation procurement RFP will proceed and hence, Hydro One proposes to carry out the development work.

UNDERTAKING

Undertaking

TO PROVIDE THE MINIMUM LEVELS GOING INTO THE PLANNING PROCESS, AS WELL AS ANY CONTEXT NECESSARY TO PROVIDE A BETTER UNDERSTANDING OF THE NUMBERS

Response

By definition, the approved Business Plan represents the minimum, aggregate, set of investments to achieve corporate goals.

The Minimum Level of investment is neither a sustainable level of investment nor is it in any way an acceptable target level of investment. Considerations of risk and risk mitigation are probabilistic in nature. It follows that, if an area of Hydro One's business were limited to only minimum levels over the planning period, it would compromise long-term costs, reliability and customer satisfaction among other business values.

It should be noted that it is not acceptable to do only the minimum level for all of the planned investments as some of the investments are interrelated. For such investments, going to a minimum level for one investment category would necessitate spending above the minimum level on the related investment category. In summary, all investments cannot simultaneously be reduced to a minimum, as the aggregate effect of the reductions would be greater than the sum of the individual reductions.

Specific investments may be rescheduled from one time period to another within the 5 year planning horizon during the planning process. The company would do so in response to such drivers as critical resource limitations, availability of outages etc. This re-direction is done with due care that such a rescheduling would limit any material deterioration of associated risk.

The minimum levels for OM&A and Capital expenditures contained within Hydro One's Transmission Investment Plan for 2009-2010 are attached.

With reference to the attachment, two spreadsheets are provided: one for Transmission Capital and one for Transmission OM&A. Each spreadsheet addresses the test years 2009 and 2010, providing a breakdown of investment levels contained in Hydro One's 2009 / 10 Transmission Rate Submission and the Minimum Levels identified during the investment planning process. Finally, the variances between the Plan and Minimum Level are shown.

A description of Hydro One's Planning Process is provided in Exhibit A-14-1 and the Investment Prioritization Process is provided in Exhibit A-14-5.

HYDRO ONE NETWORKS INC.
TRANSMISSION OM&A 2009/10 PLAN

	2009			2010		
	Filed	Minimum Level	Variance	Filed	Minimum Level	Variance
Sustaining						
Stations						
Land Assessment and Remediation	1.6	1.5	0.1	1.2	1.1	0.1
Environmental Management	9.1	7.2	1.9	9.9	7.7	2.2
Power Equipment	74.7	44.7	30.0	82.0	59.3	22.7
Protection, Control, Monitoring, Metering and Telecommunications	39.5	38.9	0.6	41.6	37.4	4.2
Ancillary Systems Maintenance	18.2	14.4	3.8	21.0	15.2	5.8
Site Infrastructure Maintenance	24.8	22.6	2.2	25.5	22.8	2.7
Total Stations	**167.7**	**129.3**	**38.4**	**181.2**	**143.5**	**37.7**
Lines						
Vegetaton Management	23.3	19.8	3.5	24.6	19.5	5.1
Overhead Lines Programs	22.1	16.2	5.9	20.9	19.3	1.6
Undergournd Cable Programs	3.3	2.5	0.8	3.3	2.5	0.8
Total Lines	**48.7**	**38.5**	**10.2**	**48.8**	**41.3**	**7.5**
Engineering and Environmental Support	**10.2**	**9.7**	**0.5**	**10.2**	**9.6**	**0.6**
Total Sustaining	**226.5**	**177.5**	**49.0**	**240.1**	**194.4**	**45.7**
Development						
Research and Development	6.0	5.9	0.1	9.2	6.2	3.0
Standards Development	7.9	1.1	6.8	7.1	1.5	5.6
Total Development	**13.9**	**7.0**	**6.9**	**16.3**	**7.7**	**8.6**
Operations						
Operations	33.1	33.1	-	34.0	34.0	-
Operations Support	17.1	17.6	(0.5)	17.5	17.6	(0.1)
Environment, Health and Safety	2.1	2.2	(0.1)	2.1	2.1	-
Total Operations	**52.3**	**52.9**	**(0.6)**	**53.7**	**53.7**	**(0.1)**
TOTAL Sustaining, Development & Operations	**292.7**	**237.4**	**55.3**	**310.1**	**255.8**	**54.3**
Shared Services and Other OM&A						
Common Corporate Functions & Services	47.5	47.5	-	47.9	47.9	-
Customer Care	1.5	1.5	-	1.5	1.1	0.4
Asset Management	76.7	76.7	-	81.2	76.7	4.5
Information Technology	49.9	47.5	2.4	50.3	47.6	2.7
Cornerstone	(3.4)	(3.4)	-	(8.9)	(5.6)	(3.3)
Cost of Sales	4.1	4.1	-	3.7	3.7	-
Other OM&A	(104.6)	(104.6)	-	(109.3)	(101.4)	(7.9)
Total Shared Services & Other	**71.6**	**69.2**	**2.4**	**66.4**	**70.1**	**(3.7)**
Property Taxes and Rights Payments	**70.9**	**70.9**	**-**	**73.1**	**70.9**	**2.3**
TOTAL TRANSMISSION OM&A	**435.2**	**377.5**	**57.7**	**449.7**	**396.8**	**52.9**

HYDRO ONE NETWORKS INC.
TRANSMISSION CAPITAL 2009/10 PLAN

	2009 Filed	2009 Minimum Level	2009 Variance	2010 Filed	2010 Minimum Level	2010 Variance
Sustaining						
Stations						
Circuit Breakers	12.5	15.0	(2.5)	21.1	16.4	4.7
Station Re-investment	64.6	56.1	8.5	43.5	26.0	17.5
Power Transformers	50.6	35.7	14.9	62.5	40.2	22.3
Other Power Equipment	12.0	14.4	(2.4)	21.6	14.1	7.5
Protection, Control, Monitoring and Telecommunications	39.3	75.6	(36.4)	64.9	72.9	(8.0)
Ancillary Systems	13.6	16.9	(3.4)	17.2	16.8	0.4
Transmission Site Facilities and Infrastructure	12.1	11.6	0.5	13.1	10.8	2.3
Station Environment	4.3	4.3	-	3.7	3.9	(0.2)
Total Stations	**208.8**	**229.6**	**-20.8**	**247.6**	**201.1**	**46.5**
Lines						
Overhead Lines Refurbishment and Component Replacement	49.1	37	12.1	53.4	37.74	15.7
Transmission Lines Reinvestment	16.5	9.3	7.2	16.1	13.54	2.6
Underground Lines Cable Refurbishment and Replacement	5.6	3.1	2.5	4.4	2.7	1.7
Total Lines	**71.2**	**49.4**	**21.8**	**74.0**	**54.0**	**20.0**
Total Sustaining	**280.0**	**279.0**	**0.9**	**321.6**	**255.1**	**66.5**
Development						
Inter Area Network Transfer Capability	396.5	527.7	(131.2)	509.6	384.5	125.1
Local Area Supply Adequacy	101.3	168.1	(66.8)	50.4	75.0	(24.6)
Load Customer Connection	39.0	46.8	(7.8)	58.1	49.1	9.0
Generation Customer Connection	6.0	5.8	0.2	23.1	24.2	(1.1)
TS Upgrades to Facilities Distribution Generation	-	16.0	(16.0)	-	16.0	(16.0)
Performance Enhancement and Risk Mitigation	7.2	12.8	(5.6)	14.2	13.6	0.6
Smart Grid	3.5	-	3.5	3.4	-	3.4
Total Development	**553.5**	**777.2**	**(223.7)**	**658.8**	**562.4**	**96.4**
Operations						
Grid Operating and Control Facilities	15.1	12.1	3.0	9.8	9.2	0.6
Operating Infrastructure	3.1	24.9	(21.8)	19.1	19.7	(0.6)
Total Operations	**18.2**	**37.1**	**(18.9)**	**28.9**	**28.9**	**0.0**
TOTAL Sustaining, Development & Operations	**851.7**	**1,093.3**	**(241.6)**	**1,009.3**	**846.4**	**162.9**
Shared Services and Other Costs						
Transport, Work & Service Equipment	14.5	11.4	3.1	16.2	8.9	7.3
Information Technology	10.9	10.1	0.8	12.3	9.8	2.5
Cornerstone	50.5	59.7	(9.2)	28.4	12.1	16.3
Facilities and Real Estate	16.3	5.8	10.5	7.9	5.8	2.1
Conservation and Demand Managemen	0.2	0.2	-	0.1	0.2	(0.1)
Total Shared Services and Other	**92.4**	**87.1**	**5.3**	**64.9**	**36.8**	**28.1**
TOTAL TRANSMISSION CAPITAL	**944.1**	**1,180.4**	**(236.4)**	**1,074.2**	**883.2**	**191.0**

UNDERTAKING

Undertaking

TO RECONCILE THE APPARENT DIFFERENCE IN THE DATA BETWEEN EXHIBIT C1, TAB 2, SCHEDULE 2, PAGE 15, FIGURE 1 VERSUS EXHIBIT I, TAB 1, SCHEDULE 22.

Response

Figure 1 in Exhibit C1, Tab 2, Schedule 2, "Sustaining OM&A" is based on a broad use of the term "Power Transformers", and it includes a total of 688 "Other Transformers" as shown in Table 2 of Exhibit A, Tab 4, Schedule 1.

The results provided in Interrogatory Response Exhibit I, Tab 1, Schedule 22 are based on the more typical use of the term "power transformers" and only include Autotransformers (150) and Stepdown transformers (591) for a total of 741.

UNDERTAKING

Undertaking

TO PROVIDE 2009 AND 2010 FORECAST YIELD SHOWN IN TABLE 4 OF EXHIBIT B1, TAB 2, SCHEDULE 1, AND WHETHER IT WILL BE UPDATED BASED ON CURRENT INFORMATION AVAILABLE. PLEASE ALSO PROVIDE THE IMPACT ON FILED 2009 REVENUE REQUIREMENT OF USING THE ROE OF 8.01%, THE DEEMED SHORT-TERM DEBT RATE OF 1.33% AND THE DEEMED LONG-TERM DEBT RATE OF 7.62% ISSUED BY THE BOARD FOR USE IN 2009 DISTRIBUTION RATE REBASING APPLICATIONS ISSUED ON FEBRUARY 24, 2009.

Response

Attached is a revised Table for based upon the January, 2009 Consensus Forecasts.

Table 4
Forecast Yield for 2009 - 2010 Issuance Terms

	2009		
	5-year	**10-year**	**30-year**
Government of Canada	1.89%	2.90%	3.71%
Hydro One Spread	2.52%	2.68%	2.82%
Forecast Hydro One Yield	4.41%	5.58%	6.53%
	2010		
	5-year	**10-year**	**30-year**
Government of Canada	2.09%	3.10%	3.91%
Hydro One Spread	2.52%	2.68%	2.82%
Forecast Hydro One Yield	4.61%	5.78%	6.73%

Each rate is comprised of the forecast Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2010 and 2011 is based on the January, 2009 Consensus Forecasts**.** For 2009 it is based on the average of the 3 month out (April 2009) forecast of 2.70% and 12 month out (January 2010) forecast of 3.10%. For 2010, it is based on the 12 month out forecast (January 2010) of 3.10%. The five- and 30-year Government of Canada bond yield forecasts are derived by adding the January, 2009 average spreads (five-year to ten-year for the five-year forecast and 30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for January, 2009 obtained from the Company's MTN dealer group for each planned issuance term.

The table below provides the impact of using the Cost of Capital parameters issued on February 24, 2009 for use in the 2009 rate year Distribution Cost of Service applications on the 2009 and the impact on the 2010 Hydro One Transmission Revenue Requirement of using the January, 2009 Consensus Forecast for determining the 2010 Cost of Capital parameters. Hydro One continues to believe the correct methodology for updating the Cost of Capital parameters is as described in response to Exhibit I, Tab 1, Schedules 3, 4 and 5 using data available in March 2009 for the 2009 test year and in October 2009, for the 2010 test year.

Allowed Return & Revenue Requirement

Allowed Return	2009 Filed	2009 Updated	2010 Filed	2010 Updated
3rd Party LT Debt	5.90%	5.98%	5.80%	5.88%
Deemed LT Debt	6.19%	7.62%	7.29%	7.82%
Deemed ST Debt	4.47%	1.33%	4.75%	1.43%
Common Equity	8.53%	8.01%	9.35%	8.17%
$ millions				
OM&A	435.2	435.2	449.7	449.7
Depreciation	258.0	258.0	281.5	281.5
Capital Tax	16.4	16.4	6.0	6.0
Return on Debt	251.2	250.2	269.8	264.0
Return on Common	240.0	225.4	286.1	250.0
Income Tax	31.9	24.7	48.0	31.0
Revenue Requirement	1232.7	1209.8	1341.1	1282.3
Change		(22.9)		(58.8)

UNDERTAKING

Undertaking

TO PROVIDE THE ACTUAL 2008 EXPORT TRANSMISSION REVENUES SHOWN IN RESPONSE TO VECC IR NO. 66.

Response

Revenues received for export transmission service for the periods January 2006 to September 2008 are as follows:

in K$	**2006**	**2007**	**2008**
Jan	1,380.8	862.6	2,299.2
Feb	1,211.3	1,285.6	1,758.5
Mar	1,288.5	1,022.0	1,899.6
Apr	1,334.8	1,275.8	2,480.4
May	1,272.5	1,215.2	2,876.7
Jun	1,018.4	1,166.7	2,727.1
July	1,068.1	1,428.8	2,585.3
Aug	1,282.4	1,302.7	1,853.0
Sep	916.2	1,054.6	1,430.1
Oct	1,083.5	940.5	1,614.5
Nov	705.8	1,041.3	1,520.6
Dec	687.8	1,535.8	1,544.6
Total	**13,250.1**	**14,131.5**	**24,589.6**

UNDERTAKING

Undertaking

TO EXPLAIN THE NET ADJUSTMENT OF THE $30 MILLION REDUCTION IN CLASS 47 IN THE 2007 CCA CALCULATION AND TO EXPLAIN WHY THERE IS NO NET ADJUSTMENT IN THE CALCULATION.

Response

The ($30.4) million adjustment to Class 47 in Exhibit C2, Tab 6, Schedule 2, Attachment 1, "2007 T2 Corporation Income Tax Return" Schedule 8 represents a Ministry of Finance ruling on the methodology for reflecting the treatment of prior years capitalized overhead items. This is a one time adjustment for the prior years.

With respect to Exhibit C2, Tab 6, Schedule 1, Attachment 2, the 2009 and 2010 schedules have been prepared in accordance with the Ministry of Finance ruling and the appropriate capital overhead treatment is reflected in the 2009 and 2010 Net Additions column.

UNDERTAKING

Undertaking

TO PROVIDE THE INCREASED CREDIT THAT RESULTED IN LINE 8 AND TABLES 2 AND 4 UNDER THE SCENARIO OF A DEFERRAL-ACCOUNT CLEARANCE OVER TWO YEARS, RATHER THAN FOUR

Response

The following shows the disposition period for 18 months ending Dec. 2010. As per Exhibit F1 Tab1 Schedule 1 Table 1 \$(18.3)M / 18 = \$(1.017)M per month. Yearly calculation:

July to Dec. 2009 =	\$(6.1)M
Jan. to Dec. 2010 =	\$(12.2)M
Total	\$(18.3)M

The following are the updated numbers to Exhibit E1, Tab 1, Schedule 1, Tables 2 and 4, Line 8:

Table 2, Line 8, new value for Year 2009 is \$(14.9)M (annualized)
Table 4, Line 8, new value for Year 2010 is \$(21.0)M

Please note that the \$(14.9)M includes \$(4.4)M already refunded in rates from January 1 to June 30, 2009.

	Refunded Jan. – June 2009	2009 Revenue Requirement	2010 Revenue Requirement	Requested for Approval
Recovery of Market Ready Project	2.2	2.2	4.4	
Recovery of Export Credit Revenue	(6.6)	(6.6)	(13.2)	
Sub-total (approved in EB-2006-0501)	**(4.4)**	**(4.4)**	**(8.8)**	
Refund of Tax Rate Changes		(4.6)	(9.3)	(13.9)
Refund of OEB Cost Assessment Differential		(1.4)	(2.8)	(4.2)
Refund of Pension Cost Differential		(0.1)	(0.1)	(0.2)
Sub-total (requested for approval in EB-2008-0272)		**(6.1)**	**(12.2)**	**(18.3)**
TOTAL OTHER COST CHARGES	**(4.4)**	**(10.5)**	**(21.0)**	

In calculating rates revenue requirement for 2009 with a rate change effective July 1, 2009 the regulatory asset refund amount should be $(10.5)M for 2009 and $(21.0)M for 2010.

UNDERTAKING

Undertaking

TO PROVIDE THE IMPACT ON THE OVERALL REVENUE REQUIREMENT IF HYDRO ONE COMPENSATION WAS EQUIVALENT TO THE MEDIAN, OR TO PROVIDE THE EXPLANATION WHY THAT CANNOT BE DONE.

Response

As explained in Exhibit C1, Tab 3, Schedule 2, page 2, approximately 90% of Hydro One's workforce is unionized and wages and benefits are covered by the respective collective agreements which expire beyond the end of 2010, the second test year. Collective agreements are legally enforceable contracts and cannot be unilaterally changed. As such, any reductions in our Revenue Requirement to approximate market median compensation will not reduce wages and benefits but would require a reduction in work programs.

It is estimated that if Hydro One Networks compensation was equivalent to the market median, as established in the Compensation Cost Benchmarking Study by Mercer/Oliver Wyman (the Mercer Study) found in Exhibit A, Tab 16, Schedule 2, Attachment 1, the impact would be to reduce requested Transmission Revenue Requirement in the range of about $13 million in each of 2009 and 2010.

The detailed calculations to arrive at this illustrative estimation are provided in the table on the next page. The steps taken to arrive at this estimate are as follows:

- The detailed breakout of 2009 and 2010 Hydro One Networks payroll costs (the total for the integrated workforce utilized in both the Transmission and Distribution businesses) by MCP, Society, PWU and Casual staff classifications as provided in Exhibit I, Tab 1, Schedule 19 was used as the starting point. These payroll costs are consistent with those found in Exhibit C1, Tab 3, Schedule 2, page 10, Table 3.
- As the Mercer Study did not include overtime costs, these costs were excluded from the estimation of the impact of moving compensation to market median (Column C in the table).
- The market median payroll costs for each staff category was estimated (Column D in the table) using the results in the Mercer Study, page 3, table 1. This identifies MCP ("Non-Represented") staff as 0.99 of market median, Society ("Represented Engineering") staff as 1.05 of market median, and PWU ("Power Workers") as 1.21 of market median. It was assumed that Casual staff were at the same level of market median as PWU staff for total cash compensation (+16%).
- The pension and benefits costs of the adjustment of total compensation to market median was estimated using base compensation multipliers for these costs as estimated by Mercer in their Study (Column F in the table).

- The total adjustment required to move total Hydro One Networks compensation to the equivalent to the market median is estimated as the sum of the wages adjustment and the pension/benefits adjustment (Column G in the table).
- Using data provided to Rudden in their review of the Transmission Overhead Rate Capitalization Methodology, filed as Exhibit C1, Tab 5, Schedule 2 Attachment 1, it is estimated that 16% of total Networks compensation costs are attributed to the Transmission OM&A program in 2009, and 15% in 2010. These percentages were applied to estimate the impact on proposed Transmission Revenue Requirement in both years of reducing total Hydro One Networks compensation to the equivalent of the market median (Column RR in the table).

IMPACT OF MOVING TO BENCHMARKED MEDIAN COMPENSATION

($)

2009	A	B	C	D	E	F	G	RR
			= A-B	=C/(1+% from M)	= D-C	=E*P/B Multiplier	= E+F	=G*OM&A%
Representation	TOTAL WAGES (5)	Overtime (Incl Premium)	TOTAL less Overtime (1)	Market Median (2)	Median Adj.	Pension/ Benefits (3)	TOTAL ADJ	Tx OM&A 16% (4)
PWU Reg	300,145,964	49,412,196.28	250,733,768	207,217,990	(43,515,778)	(20,073,828)	(63,589,606)	
SOCIETY Reg	101,174,860	2,394,606.36	98,780,253	94,076,432	(4,703,822)	(2,169,873)	(6,873,694)	
MCP Reg	87,181,260		87,181,260	88,061,879	880,619	387,032	1,267,651	
Total Reg	488,502,084	51,806,803	436,695,281	389,356,300	-47,338,981	-21,856,669	-69,195,650	
Total Temp (6)	2,664,343	72,578.76	2,591,764	2,346,276	-245,488	-113,284	-358,772	
CASUAL	98,033,573	10,620,618.60	87,412,954	75,355,995	(12,056,959)	0	(12,056,959)	
Total	**589,200,000**	**62,500,000**	**526,700,000**	**467,058,572**	**-59,641,428**	**-21,969,953**	**-81,611,381**	**-13,057,821**

2010

Representation	TOTAL WAGES (5)	Overtime(Incl Premium)	TOTAL less Overtime (1)	Market Median (2)	Median Adj.	Pension/ Benefits (3)	TOTAL ADJ	Tx OM&A 15% (4)
PWU Reg	313,038,398	52,033,561	261,004,837	215,706,477	(45,298,360)	(20,896,134)	(66,194,494)	
SOCIETY Reg	111,006,705	2,518,773	108,487,932	103,321,840	(5,166,092)	(2,383,118)	(7,549,210)	
MCP Reg	90,329,523	0	90,329,523	91,241,943	912,419	401,008	1,313,428	
Total Reg	514,374,626	54,552,334	459,822,293	410,270,260	-49,552,033	-22,878,243	-72,430,276	
Total Temp (6)	922,176	76,342	845,834	733,417	-112,417	-51,876	-164,294	
CASUAL	103,456,175	11,171,324	92,284,851	79,555,906	(12,728,945)	0	(12,728,945)	
Total	**619,900,000**	**65,800,000**	**554,100,000**	**490,559,583**	**-62,393,395**	**-22,930,120**	**-85,323,515**	**-12,798,527**

Notes: (1) The Mercer Compensation Benchmarking study did not include overtime costs so it has been excluded from the estimation.

(2) As per the Mercer Compensation Benchmarking study, PWU compensation is 21% above median, Society 5% above median and MCP 1% below median

(3) Mercer derived base labour multipliers to estimate the value of benefits and pension, as used in the Compensation Benchmarking Study were applied

(4) Based on Rudden study inputs, 16% in 2009 and 15% in 2010 of Total Networks compensation costs are in the Transmission OM&A work program

(5) Source of Compensation Data is I-1-19 Attachment 1. These values do not reflect the revenue requirement for compensation for this Application

(6) Average Base Pay for Temporary (Non-Regular) employees are not meaningful because the period of employment could be significantly less than 1 year.

UNDERTAKING

Undertaking

TO PROVIDE REPORTS OR ANALYSES, IF ANY, FROM ACCENTURE WITH RESPECT TO THE CORNERSTONE PROJECT FOR THE TEST YEARS.

Response

No specific third party reports or analyses with respect to the reasonableness of Cornerstone costs were provided by Accenture. However, the following steps were undertaken with respect to Cornerstone Phase 1 and 2 to ensure the reasonableness of Cornerstone costs:

- separate, competitive RFPs were issued for each phase to select a system integrator to implement Hydro One's SAP solution. By virtue of this process, the most cost effective solution was selected for each phase. Both RFPs included a request for total cost to implement each phase.
- Accenture was selected as integrator for Phase 1, and subsequently for Phase 2, following extensive evaluation of the responses to the RFPs, including presentations by short-listed respondents;
- For both Phases, an identical planning and pricing process was completed:
    - completed Discovery with Accenture and established a Statement of Work
    - received from Accenture a fixed-price proposal for Phase 1 and Phase 2
    - worked with Inergi to develop an estimate of the requirement for their participation. Note that this work was contracted with Inergi on a time-and-materials basis;
- Validated the Phase 2 cost estimate by conducting a benchmarking exercise.

UNDERTAKING

Undertaking

TO FILE A COPY OF THE SHPIGLER REPORT

Response

Attached is a copy of the SHPIGLER report titled "Hydro One Telecom Inc. Services Review and Benchmarking" dated May 2008.

Filed: March 3, 2009
EB-2008-0272
Exhibit J4.1
Attachment

Hydro One Telecom Inc. Services Review and Benchmarking

Prepared for:

hydro One

Prepared by:

THE SHPIGLER GROUP
STRATEGY MANAGEMENT CONSULTING SERVICES

May 2008

Table of Contents

Executive Summary

Over time, nearly every electric utility has established some form of telecommunications capabilities in support of their normal operations. As the demands of operating an electric utility grow in complexity, many utilities have built extensive telecommunications transport networks in support of such applications as teleprotection, SCADA, telemetry, and others. As demands on these telecom networks have grown, the capital resources allocated to them and the staff that oversees their operations has grown in size and scope. As such, it is often useful to perform periodic studies to compare the efficiency of such telecom units to a group of similar utilities to ensure that existing cost levels are in line with industry norms and to identify emerging best practices. Hydro One Networks operates as the dominant provider of electricity within the province of Ontario, with 97 percent of the transmission system and about one-third of the province's distribution system, spanning 75% of the province. The transmission network involves some 28,600 kilometers of lines and the distribution network supports over 1.1 million electric customers across rural Ontario. Hydro One Networks is the largest operating subsidiary of Hydro One Inc., which is wholly owned by the Province of Ontario. Hydro One, Inc. operates four distinct business lines: Hydro One Networks (transmission and distribution across the entire province), Hydro One Brampton (distribution network within the City of Brampton), Hydro One Remotes (electric operation in the Northern Ontario region), and Hydro One Telecom (fiber optic business).

Hydro One has an extensive telecommunications operation in place to serve its core energy business. The telecom group reached a point in its development where their capabilities had the potential to add value as a shared service in conjunction with the commercial telecommunications operations. The telecommunication group’s expertise in operating a sophisticated telecommunications network to commercial availability standards on a daily basis, its knowledge of the commercial market and of the special needs of electric power systems made the outsourcing of network and vendor management appealing. Hydro One Networks Inc. (HONI) determined that by having Hydro One Telecom (HOT) manage network control and third party telecommunications contracts, they had the opportunity to control costs and optimize their network monitoring.

Even as the telecommunications group supports the communications needs of Hydro One's Network, there is an ongoing desire to better understand the competitiveness of the group's operations. More specifically, HONI chooses to benchmark the performance of its telecommunications group to determine how it compares to peers with respect to operating efficiency. The Shpigler Group was engaged in 2005 and 2006 to research and analyze this issue by evaluating the group's performance as defined in the Service Level Agreement (SLA) and benchmarking the activities against similar operations. We have been re-engaged in 2008 to review the SLA for 2009-2010, to evaluate the competitiveness of HOT for the past year and assess the projected competitiveness for the new SLA duration. The following analysis is based on updated benchmarks from the 2006 report and compares expected future performance against the same peer group.

A close review of the 2009-2010 SLA to the 2007-2008 SLA indicates that there were no material changes between the two SLAs except for the increase in the predefined work scope and wage and benefit labor increases. The similarity of the two SLAs allows a forward looking comparison to be made after verifying that the peer utilities were proportionately stable, which they are. Therefore, we determined that the updated benchmarking data along with our understanding of the projected changes for each utility would allow us to estimate the relative performance of utilities for the 2009-2010 SLA and reach a conclusion.

In our opinion, the unique voltage potential of a power system has created the need for electric utilities to create their own telecommunications entities that can isolate and insulate the telecommunication infrastructure, which protects communications during electrical disturbances. Protecting electrical equipment requires sophisticated systems that need to communicate between substations and power plants. The need to isolate electrical and telecommunications facilities for safety and service reliability has supported the development of large utility telecommunication entities. Even with fiber optic channels negating some interfacing concerns, the need for end electronics equipment to interface with optical equipment at risk to voltage surges still exists. Network operation centers of public and private telecommunications companies rarely have the experience or knowledge necessary to manage a power systems telecommunication system. Therefore, for benchmarking purposes, we determined that the most meaningful and comparative data would need to be obtained from similar Canadian utility telecommunication entities.

Through this engagement, our efforts have centered on evaluating the existing service level agreement with HOT, evaluating the performance of HOT as compared to the defined deliverables and industry standards, analysis of the cost structure, and an audit of third party pass-through contracts and charges. The benchmarking data was collected from three comparable Canadian utilities and compared to results for the past year. The other utilities studied were Manitoba Hydro, Hydro Quebec, and BC Hydro; they were chosen for their similar telecommunications needs and service territories. The report and our conclusions are based on primary research from interviews, secondary data collection and benchmarking comparisons between these three utilities. In addition, we have included insights gathered from other utilities regarding “best practices” in network monitoring.

Analysis of HOT operations was centered on the following:

- SLA applicability to present services provided
- SLA deliverable performance
- HOT cost breakdowns
- HOT third party contract management, costs and savings
- HOT Network Management services benchmarking

Through interviews with top level management, detailed data analysis, and review of third party invoice handling practices and benchmarking, our findings are as follows:

- Benchmarking results continue to indicate that the HOT Network Operation Center is comparable to the other Canadian utilities' 24x7 telecommunication operation centers and the overall Service Level Agreement is at market.
- The 2009-10 Service Level Agreement was reviewed and is similar to past agreements with the addition of some carrier management dealings.
- All reporting as specified by the Service Level Agreement was reviewed and was found to be complete.
- In the current benchmarking exercise the analysis included a review of costs, projected growth and shift coverage. The results of this exercise indicated that HOT is providing coverage similar to the other utilities that provide 24x7 services.
- HOT's competitive cost position, which existed from 2005-2008, even when increased for labor costs and scope changes in 2009-2010 will maintain a lower or competitive cost of service when compared to other network monitoring operations.
- Benchmarking also indicates that the shared services concept has provided an advantage over other methods. HOT needs a fewer number of operations positions than other utilities that manage a power system-only workload, even as the amount of work and size of the telecommunications system increases.
- Adjusting for future assumptions, HOT maintains a lower or equivalent cost of service with the comparator group
- The pass-through costs for third party handling are in line with original billings from the third party. A review of invoices supported the conclusion that third party costs are passed through directly to HONI without markup.
- The HOT charge for handling third party contracts is significantly less than what they have been able to save in contract re-negotiations. Having a dedicated unit focusing on the telecommunications-related issues (like bill accuracies) coupled with the combined purchase power of a larger entity has proven beneficial to not just the HONI staff, but also to the efficiency of the telecom functions.
- Leveraging the commercial knowledge and acuity of the HOT staff continues to benefit the entire corporation.

- We believe that the benefits of a commercial telecommunication approach of the HOT staff coupled with the power system knowledge is an effective tool in extracting value for both HONI and HOT in their respective areas of responsibilities.

Our full report which includes some operating recommendations is included below.

Background on The Shpigler Group

The Shpigler Group is a strategy management-consulting firm focused on the telecommunications and technology sector. The Shpigler Group works with utilities, municipalities, telecom service providers, and infrastructure and technology developers in solving complex issues involving strategic assessment, market analysis, business case development, economic evaluation of network design, and competitive and partnership assessment. The Shpigler Group has been heavily involved in the utility telecommunications industry, dealing with operational and strategic issues involving networks with fiber, wireless, power line, satellite, microwave, and other access approaches.

David Shpigler, President of the firm, brings an extensive background in strategy consulting to companies in high technology industries. Prior to founding The Shpigler Group, he was with Cambridge Strategic Management Group, Dean & Company, and Accenture, all leading strategy consulting firms focused on serving the telecommunications, high technology, and utility industries. In addition to his work with The Shpigler Group, David has served as the Director of Research for United Telecom Council, developing research studies for the utility telecommunications industry. He has also served as Adjunct Professor of Operations Management at Berkeley College. David has a B.S. in Business Economics from the University of the State of New York, Albany and an MBA from the Graduate School of Business at the University of Chicago.

Heather McGinnis, an Associate at the firm, brings a deep understanding of project management, production scheduling and process improvement. Before joining the Shpigler Group, she ran a business services and manufacturing firm in Northeastern Pennsylvania. She has extensive experience in business development, customer relationship management, and IS design and implementation. Ms. McGinnis graduated summa cum laude from Pennsylvania State University with a BS in Management, Information Systems, and International Business and recently earned her Project Management Professional (PMP®) certification.

Project Methodology

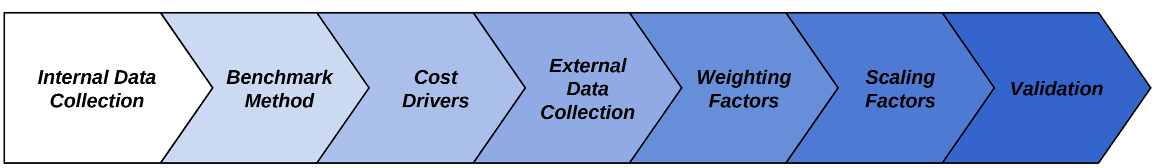
Some choices were made in the commission of this benchmarking report. Initially, the choice was made to focus on a smaller number of utilities and conduct detailed research gathering with each rather than try to generate higher-level surveys with a larger group of utilities. Even though the quantity would have been more statistically significant, we felt it might generate questionable findings. Next, the specific utilities targeted were chosen for the nature of their operations; that is, utilities with some critical mass with respect to overall service territory were targeted. Although the original desire was to benchmark cost positions of utilities relative to one another, it became apparent that to do so would lead to some questionable conclusions because the cost positions are driven by a number of completely unrelated and in some cases uncontrollable factors. For example, differences in accounting practices – like burden rates – can skew results, shielding us from gaining a complete understanding of true operational efficiency. As a result, the benchmarking study was based on headcount positions at each of the utilities as they related to network monitoring work output levels. Finally, since each utility profiled featured a very different organizational structure, we embarked to benchmark the job functions rather than individual work groups.

We believe that the information gathered in this report should offer a strong perspective for the desired benchmarking effort. Ultimately, the reader should be cautioned that the data collected and the resultant conclusions within this report represent important findings regarding overall trends, but with error margins due to the lack of complete "apples-to-apples" comparisons. Furthermore, each of the utilities profiled in many cases shared the fact that their operating practices are in flux, with many of the practices currently undergoing changes. As a result, the conclusions reached as part of this report reflect a current status of a "moving target" in many cases.

In order to thoroughly understand the services and charges for services from HOT to HONI we needed to ensure that we established a methodology that supported the key goals of the project. The key steps that we needed to account for as part of the process included:

- Analyze the 2009-2010 Service Level Agreement (SLA) to determine required services and reporting
- Assess deliverables required by the SLA
- Analyze major cost component areas
- Collect data from key process owners
- Perform review of third party pass through costs
- Determine appropriate method for performing benchmarking
- Collect data from benchmark utilities
- Calculate weighting factors
- Perform scaling function to address discrepancies in volumes
- Compare results across benchmark companies
- Refine analysis as needed

In order to account for each of these issues, we followed a methodology involving a seven-step plan:



Step 1 – To start, we conducted initial interviews with HONI and HOT staff to understand key processes, work functions, and output levels. In doing so, we were able to get a basic understanding of the tasks at hand and to understand the HOT- HONI relationship, organizational structure and work output. After initial discussions with HOT and HONI, it became apparent that the key operational function performed by HOT for HONI was the Network Monitoring function. All other functions found in the utility telecommunications groups (planning, engineering, construction etc.) were part of HONI, and, as result did not require benchmarking.

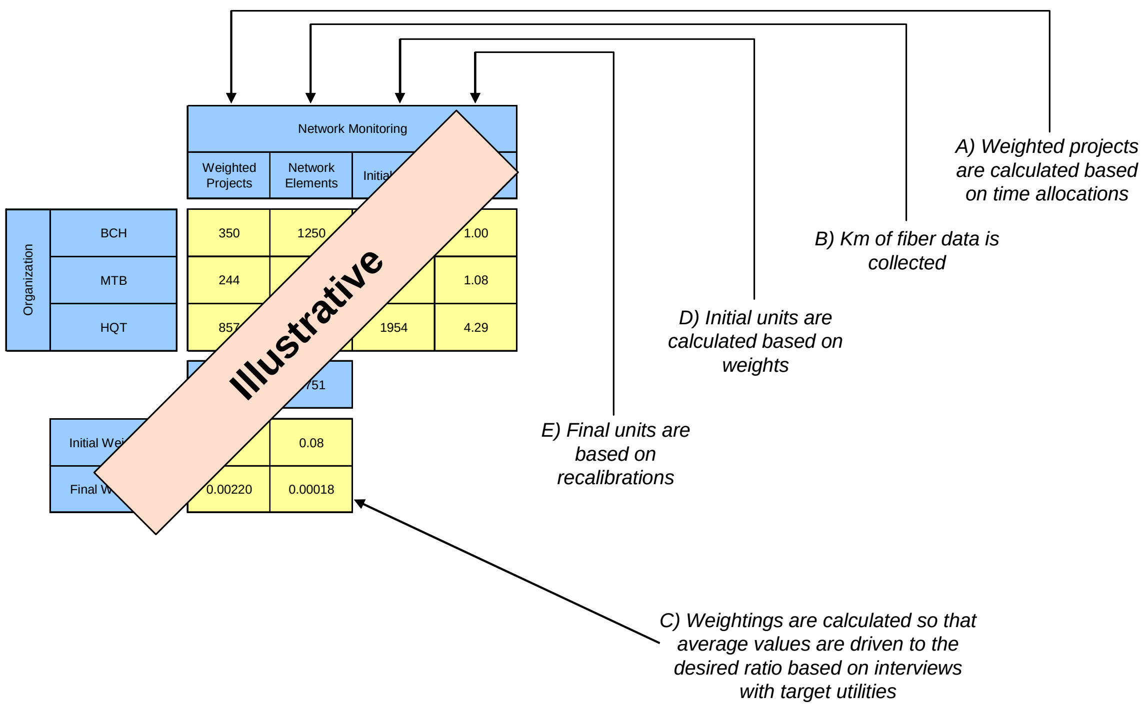
Step 2 – Next, it was necessary to develop a methodology for the overall benchmarking effort. Given that each utility had a different amount of work that it generated on an annual basis, applicable cost drivers needed to be established for each organization. Due to the potential differences in labor rates, cost allocation methodologies, and burden factors that are outside the control of HOT, we embarked on an effort to determine efficiency levels based on full time equivalents (FTEs) rather than on pure dollars.

Step 3 – Through interviews, a set of specific definitions was established for each activity area that was common to all electric utilities interviewed:

- Ensuring physical and logical security of network
- Conducting remote fixes of network when available
- Major alarm investigation
- Client services associated with network monitoring
- Monitoring technology platforms within the network

Step 4 – Having set up the overall methodology to process information and to structure the study, the next effort now focused on conducting detailed direct interviews with each of the targeted utilities. Our desire was to target as many Canadian electric utilities that would offer as fair a comparison to Hydro One as possible. Given that there is no utility that features a fully comparable mix of customer count and service territory size, it became apparent that a precise match would be impossible. However, we embarked on an effort to identify the most comparable utilities that would offer meaningful benchmarks based on having a service territory of some substance, a critical mass of customers, and some portion of the network in rural/remote areas.

Step 5 – Once the data was collected from each utility, we needed to calculate appropriate weightings to apply to work outputs in order to make cross-company comparisons. To illustrate the methodology on which these weightings were developed, the following is an example of how we approached the subject on calculating weighting factors:



In using weighting factors, certain issues need addressing:

- *Issue A* – First, we gathered data from each of the benchmark utility telecommunications groups related to the commission of project related work. This factor was determined to be significant in determining work load for a network monitoring function. We arrived at a measure of "weighted projects" by determining point values for large projects (25 points for projects lasting over 6 months), medium projects (4 points for projects lasting 6 weeks to 6 months), and small projects (1 point for projects lasting under 6 weeks). We then multiplied the point values for the number of projects and arrived at a weighted project value for each benchmark utility.

- *Issue B* – We also identified the number of managed network elements as a key factor involved in determining network monitoring workload. Accordingly, we collected information about the network elements in each benchmark utility's telecommunications network.

- *Issue C* – Next, we needed to arrive at a methodology to calculate the combined effects of both factors of workload under consideration – projects and network elements. Based on interviews with each of the utilities as well as prior experience in the field, we concluded that these factors impacted workload equally. However, the difference in scale resulted in an inability to simply combine the totals of each measure. To normalize these factors, we used weighting multiples to arrive at an expression of relative workload that maintained the desired 50/50 split in impact.

- *Issue D* – We multiplied the benchmark results for weighted projects and network elements by the weighting factors to arrive at preliminary measures of relative workload for each of the utility telecommunications unit.

- *Issue E* – Because the work units are based on a somewhat arbitrary scale, the resultant numbers are meaningful when compared against one another, but not necessarily in isolation. In order to process the information using a more manageable scale, we reduced each of the work load unit counts by an equivalent coefficient so that the utility with the lowest work load among the peer group would be assigned a value of one and all other utilities would be indexed off of that value.

Step 6 – Calculating the relative workloads of each group required a scaling function be performed to compare differing levels of activities at equivalent rates. We know the total number of people performing various job functions at each of the utilities based on the interviews conducted. Then, based on the procedures in step # 5, we also know the amount of work conducted by each group. With these two pieces of information, we can calculate unit costs – the headcount per work unit – and make comparisons between utilities. However, doing so would lead to an error in methodology. Certainly, we are aware of the existence of scale efficiencies – the ability of organizations to perform functions at higher efficiency levels as they grow in size. To illustrate this concept, consider two utilities performing a certain job function at the same unit cost, but one utility is substantially larger in size than the other. This shows that the smaller utility operation is more efficient because it is able to achieve the same unit cost without the benefit of scale efficiency. To operate at the same efficiency level, the larger utility would need to leverage its size to amortize some of the fixed costs across the larger base of operations and achieve a superior cost position. In order to account for this issue, we then developed calculations concerning scale curves.

Step 7 – Once the data was collected from each utility and comparisons were made, a number of data points appeared to show questionable results – and were validated through additional interviews.

Network Monitoring

Workload: The complexity of HONI's network demands a high focus on network monitoring to support successful ongoing operation of the telecom transport network. Based on research into the amount of work output supported by each network-monitoring group, we calculate that HOT supports the second highest work output among the peer group based on work supporting HONI:

	Network Monitoring			
	Weighted Projects	Network Elements	Initial Units	Final Units
Hydro One	1,039	4,378	1,591	2.40
Manitoba Hydro	285	2,990	662	1.00
Hydro-Québec	857	13,462	2,555	3.86
BC Hydro	610	1,300	774	1.17

Initial Weighting	1	0.13
Final Weighting	0.00151	0.00019

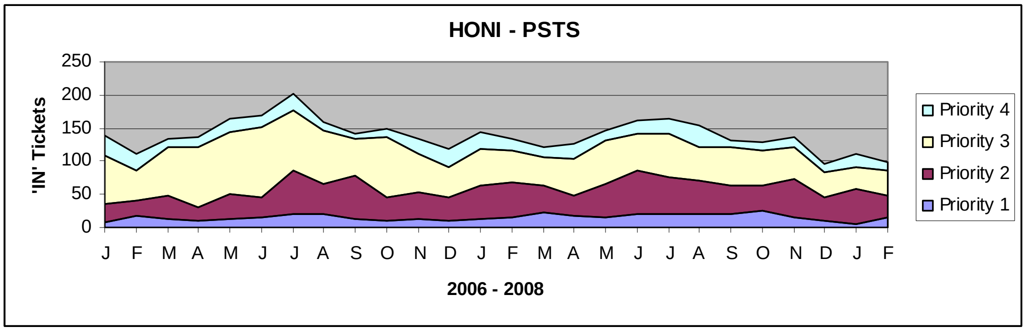
Cost Positions: We calculate that the cost assumed by HONI as a result of HOT operation of the network monitoring the telecommunications network is based on supporting the equivalent of 15.09 FTEs. We conducted a similar analysis for each of the benchmark utilities and further adjusted the scale so that headcount equivalents were based on the average workloads in the industry. Based on this exercise, we calculate that HONI's operation of the network monitoring function is still comparable to the peer group. As a point of reference, the HONI's FTE count of 13.70 compares with an equivalent FTE count of 10.77 for Hydro-Québec, 12.13 for Manitoba Hydro, and 18.53 for BC Hydro. This shows that HONI and Manitoba Hydro are within 1 headcount of maximum industry efficiency standards.

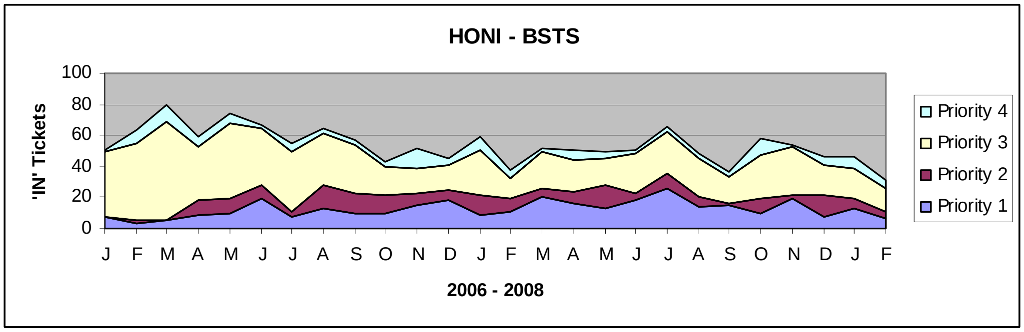
	FTEs	Work Units	Unit Cost	Comparable FTEs	FTEs in Excess of Industry Average	% Difference from Industry Efficiency
Hydro One	15.09	2.40	5.40	13.70	0.97	7.66%
Manitoba Hydro	7.00	1.00	12.97	12.13	-0.60	-4.70%
Hydro-Québec	16.81	3.86	3.36	10.77	-1.96	-15.40%
BC Hydro	12.00	1.17	11.09	18.53	5.80	45.61%

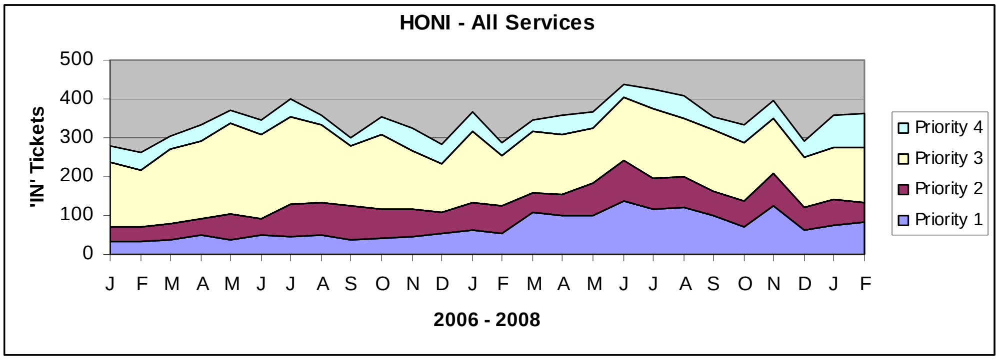
The breakdown of the HOT budget indicates that costs continue to be driven by the labor portion of the budget due to the demands of the required 24 x 7 network management coverage. The average increase in wages of 5.7% accounts for the only increase in the HOT budget for 2009 and 2010 aside from an identified incremental workload increase of $139,500, or 14.34%, as required by HONI to cover an additional carrier/vendor management services. The total cost to HONI is strictly labor-related as all third party bills for maintenance and equipment are directly invoiced to HONI. Any and all replacements and additions are justified through analysis. The only opportunity for HOT to increase efficiency is from the labor portion of the budget, which it does not control because the labor force is represented by a group agreement with HONI. HOT's efficiency has improved as can been seen by the additional workload they've absorbed in the past few years without increasing headcount Technology continues to push more work into the Network Operations Centers with self-diagnosing field equipment, alarms, and remote servicing capabilities. As equipment replacements at HONI continue, workload has increased for HOT.

Even with the cyclical increases in alarms in the summer months, the overall number of tickets has decreased for both the PSTS and BSTS groups over the last two years. The All Services graph includes the alarm work for HOT system as well. The overall trend here, however, continues to indicate a growth in alarm activity.

January 2006 – February 2008







SLA Analysis

There are several key components in Service Level Agreements that are critical to the unique operational requirements of electric utilities when transferring responsibilities to a shared services organization. The key elements of developing a successful shared services understanding are as follows:

- *Service Level Agreement*: Planning and preparation for service provisions and service level agreements should be conducted once a year by both the shared service organization and the individually affected business units
- *Monthly Billing*: Costs for the provided services are charged to each client on a monthly basis via internet application which in turn files the invoice into an accounting system
- *Detailed Performance Reports*: A variety of monthly detailed charge-out reports are created which identifies costs charged to the client organization. Monthly reports on detailed charges are compared against previous work and standard marketplace costs
- *Markup for Third Party Costs*: Typically, shared services organizations are treated as a cost center with no mark up included unless specifically agreed upon in the affiliate transactions related regulations
- *Key Performance Metrics are Established*: Establishing and agreeing upon clearly defined performance metrics is critical to the effective functioning of a shared services organization
- *Ongoing Efficiency is Expected*: Shared services performance should be measured for ongoing internal improvements in efficiency and effectiveness as well as overall improvements compared to the rest of the market place
- *Both Parties Share in Accountability*: Shared services performance measures should reflect shared accountability between the shared services organization and the different business units

The Shpigler Group originally examined the 2005-2006 Service Level Agreement established in 2005 against the above list of key SLA components and has determined that the SLA contains all the aspects of a sound service level agreement. Upon examination of the 2009-2010 Service Level Agreement we determined it to be similar to the 2005-2006 SLA, and 2007-2008 SLA with the exception of the expanded scope for carrier management services. However, a line by line audit of Schedule A of the SLA uncovered several sections that do not match the agreed upon work descriptions.

When the original SLA was written, it appears that the parties involved understood the applicability and frequency of certain activities. However, when new personnel not privy to the original negotiations and agreements read these same passages, they are open to interpretation. To preserve a successful ongoing relationship, we recommend that verbiage should be tightened to clearly reflect the exact requirements as well as identify any activities that are not covered under the SLA. We focused our examination on the metrics and reporting that is prescribed in the agreement and found that HOT continues to provide the services and reports as agreed and will continue to be held accountable to those same standards.

Service Level Agreement **–** There are defined services related to the monitoring, management, and operation of the Power System:

- Alarm Based Services
- Coordinated Network Management Services
- Systems Analysis Services
- Carrier/Vendor Management Services

Monthly Billing – All charges for network management and business services are electronically charged to the HONI accounting systems as pre-determined by both parties and reviewed annually.

Detailed Performance Reports – The following is a list of examples of the reports that are provided as defined in the SLA:

- Vendor Invoicing Error Report and Service Billing Report– Monthly
- Bill Savings Report - Annual
- PSTS Significant Events – Daily & Annual
- Year to Date Costs – Monthly
- Business Telecom Significant Events Report – Daily and Annual

All reports were reviewed and found to be in compliance with prescribed metrics. Verbal arrangements regarding the frequency of some of these reports have been made. For instance, the significant events reports are generated on a request-only basis.

Markup for Third Party Costs – A thorough review of all third-party billing was conducted to ascertain that costs billed to HONI were without markup. Billings from the largest vendor ($1,000,000 per month) to the smallest vendors ($100 per month) were reviewed, including the data inputted into the HONI accounting system, and all charges were without markup. The Shpigler Group again reviewed invoices and determined that all charges are being passed to HONI without markup.

Key Performance Metrics are Established – At the time of the last review, the performance metrics associated with contract handling and billing were centered on eliminating late payment fees and meeting new service dates. HOT solved the late payment issues by establishing a credit card payment system for billing for large vendors with next month corrections, and they have significantly reduced late payment fees. HOT has also established a monthly meeting with large suppliers for resolution and correction of billing issues, meeting reports are issued, and followed to resolution. On the network services side, restoration metrics were incorporated for loss of critical services (4 hours) and loss of redundancy (next day resolution). Also, performance measures were established for other trouble calls and corrective maintenance activities.

Priority 2, 3, and 4 levels with corresponding services response of 8 hours, 5 working days, and 10 working days were established. A review was made indicating that HOT is performing these services as defined.

Ongoing Efficiency is Expected – Efficiency expectations are established through fixed annual contract cost discussion and agreement between both parties. Since the inception of the contract an efficiency gain of 28.5% has occurred.

Both Parties Share in Accountability – Through annual discussion and adjustment memorandums, any change in scope of services is mutually agreed upon. However, there have been additional adjustments that while agreed upon, have not been noted in the formal SLA.

Cost Analysis

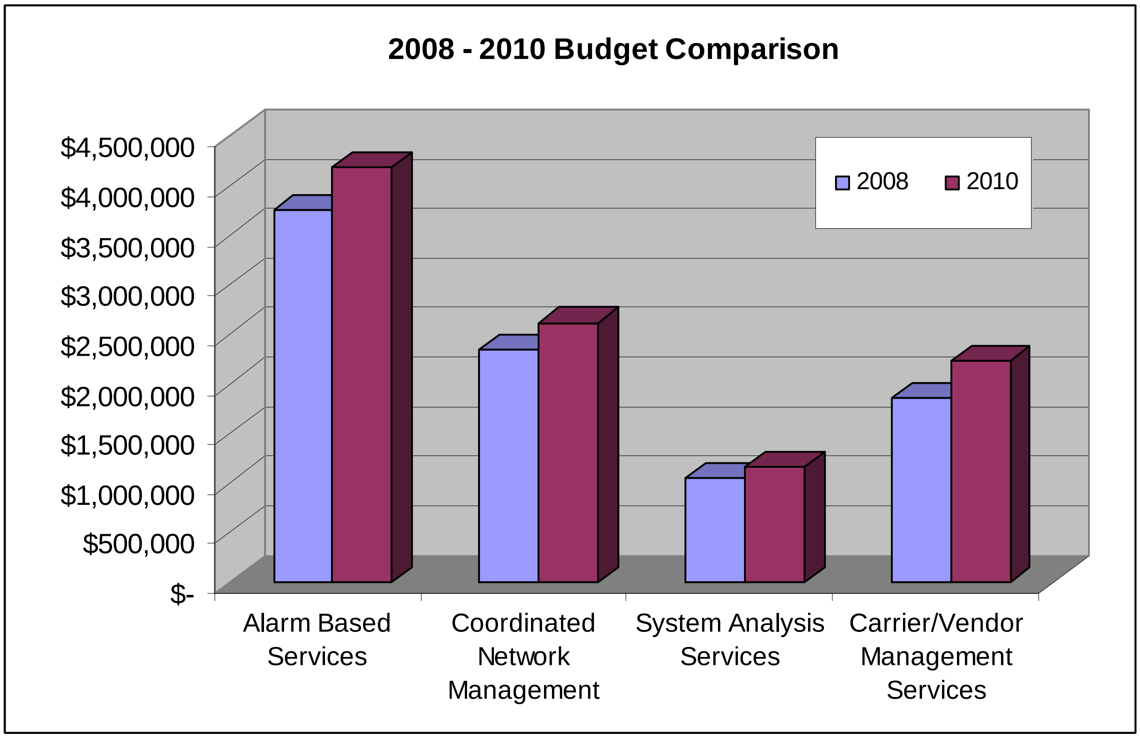
Our analysis on cost centered on the key components of costs and trends in costs.

<u>HOT Vendor Management</u> **–** The work performed by HOT is related to carrier and vendor management services. Since all bills and services are charged directly to HONI, HOT manages contracts, new orders, change orders, and bill analysis and payments. While there have been significant cost containment measures brought about by HOT contract negotiations, thorough bill analysis, and vendor interactions, the function remains labor intensive and is not conducive to ongoing efficiency increases or headcount reductions. Historically telecom billing engines have been error-laden. All major telecommunication service users perform detailed billing analysis to avoid over payment. We see this as a best practice and recommend continued close monitoring of service provider billings. Any efficiency gain is through the reduction in contract costs charged directly to HONI. Since 2002 HOT has identified $6.2 million in billing errors and has diligently sought correction to those errors. Over $2.5 million were annualized savings that would have continued to occur each year had they not been identified.

The vendor management services performed by HOT produces value for both organizations by increasing buying power. This is achieved by leveraging HOT's extensive commercial experience and thorough understanding of the market place

Based on a Utilities Telecommunications Council (UTC) report on shared services within utility telecommunications, entities indicate shared services costs are typically 40% labor, 40% vendor management and 20% infrastructure. The budget breakdown for HOT's management of HONI's telecommunications has a labor related component of 78% and a vendor management portion of 22%. Infrastructure related expenditures are not a part of this budget, but the higher labor to vendor ratio indicates that HOT continues to be in line with industry practices and is cost effectively managing vendors.

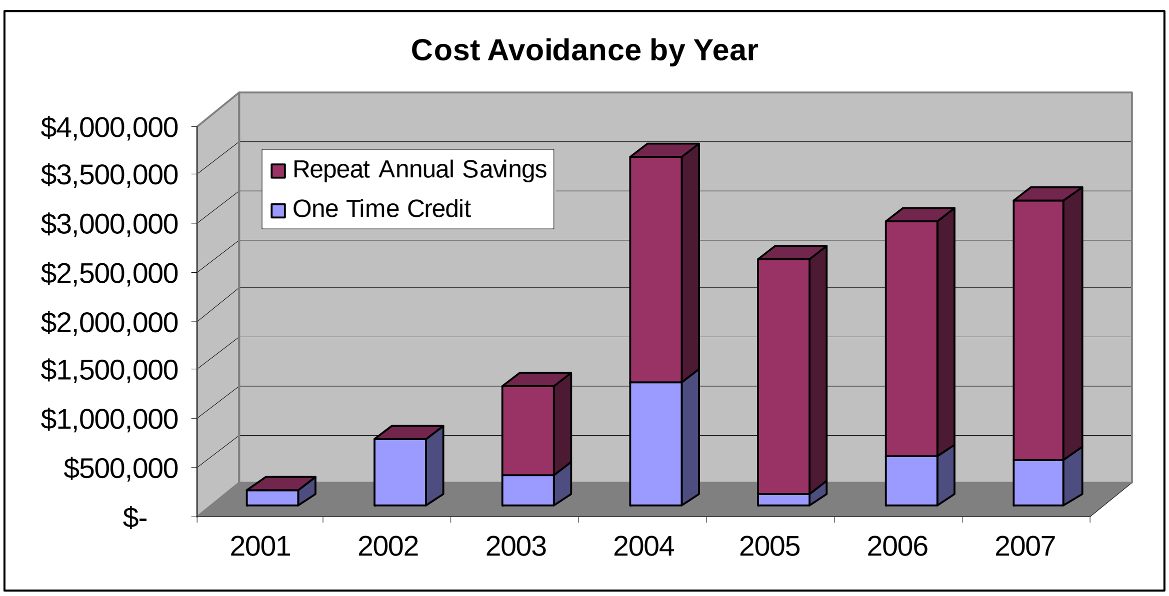
Budget Review



A comparison of budgets for 2008 and 2010 indicates slightly larger increases in alarm based services, coordinated network management and vendor management services, which is proportional to the increase in network elements. As per the 2009-2010 SLA agreement the only additional costs in this budget are associated with pre–defined workload increases and labor wage increases. The SLA contains a 5.7% per year wage increase for both 2009 and 2010.

HOT Cost Efficiencies – The cost effectiveness of the shared services offered by HOT is seen through the analysis of contract costs since the inception and the actual cost incurred by HOT. The expenditures for HOT operations are 100% labor as material; contract costs, equipment maintenance and upgrades are charged directly to HONI. HOT utilizes labor under the collective bargaining agreements of HONI and are bound by those contract terms, wages, and benefits. The contract to HONI did not increase from 2002 through 2006 even though wage increases were required by labor contract, indicating that HOT had to increase efficiencies to offset those increases which were approximately 5.7% per year. Had the telecom functions remained in HONI and not experienced the shared service with HOT, HONI would be paying 28.5% more than it is now paying HOT. The budgets for 2009 and 2010 have increased over 2008 budget due to an increase in new incremental work (14.34%) and a labor wage increase (5.7%). There were no increases to the charges for service other than the mandated increases. Workload has continued to increase since the last review. During the last review, the total SLA charges were among the lowest of the reporting utilities. Even with the additional charges in the 2009-10 SLA, the overall SLA is still within an acceptable range of market standards as compared to the comparator group.

<u>Third Party Billing Analysis</u> - A thorough review of third party invoices and bills indicates that HOT has been performing well in controlling contracted costs and capturing billing errors. The following graph indicates the SLA cost for contract managements are far outweighed by the cost avoidance through billing corrections identified by HOT. It is a best practice for purchasers of extensive telecommunication services to have staff monitor bills and usage patterns to manage costs and internal usage. There is also an advantage to knowing call patterns and volume in extracting value for future service changes and contracted services. One can also expect to see the trend in savings reduce over time as vendor relationship and scrutiny tends to reduce errors. Since 2002, HOT's diligence has saved HONI $14.2 million dollars in both billing corrections and annual contract savings.



Conclusion

The shared services concept for telecommunications operations between HONI and HOT initiated in 2002 is providing the benefits that were perceived at its inception with the network monitoring cost for HONI being contained while providing for the unique services of a power system network and meeting the demands of a customer oriented commercial telecommunications network. The vendor management function is also providing the envisioned savings of a larger telecommunications entity.

- The decision to house a 24 x 7 network operations center dedicated to telecommunications operations has resulted in cost savings with some utilities, while others have seen troubling results. In situations where the monitoring center for the power system operations can be well trained on alarm dispatch procedures for telecommunications, the handoff to this group can be a viable approach to saving on operating demands. By contrast, where the electric monitoring center staff is not well trained, the results can be disastrous, as dispatch procedures are not followed and actual costs and overall impacts to the viability of the network can be challenging. The HOT operations have developed operator expertise in both the power systems and commercial telecommunications areas. The cost advantage that HONI is realizing is in shared network monitoring with commercial system expansions.
- A factor that we see as a large driver of determining the appropriateness of a 24x7 network operations center deals with the size of the utility and its telecommunications needs. For a smaller utility like Manitoba Hydro, outsourcing many of the network operations center activities during off-hours is not yet seen as a large work burden for the electric NOC personnel. However, implementing such a practice at a larger utility like Hydro One would prove to be very cumbersome and not provide the level of service required for both a power system and commercial telecom operation.
- The differentiating factor for the HONI operations as compared to the benchmarked utilities is that they have found a way to interject a commercial

telecommunication approach with a solid power system telecommunication operation to bring a successful and cost effective solution to both businesses.

- Benchmarking analysis to justify the specific expenditure for network monitoring services is difficult due to the wage and benefit structure among utilities; however our approach to base cost effectiveness on headcount and workload indicates that HOT is as good, if not better, than the other three Canadian utilities with network monitoring centers.
- The Service Level Agreement between HONI and HOT contains all of the necessary elements to define the scope of work, deliverables, reports and metrics to insure a successful partnership including shared accountability. However, the report needs to be updated to reflect the adjustments in scope that were verbally agreed upon during the normal course of operations in the last few years.
- Cost of services increases to HONI since 2002 have been less than if the network monitoring function had remained within HONI. HOT was at the bottom of the market when compared to the peer group of utilities in the 2005 review and even with labor and pension uplift in 2007-2008 SLA, HOT retained its position as one of the most cost competitive providers among the comparator group. The moderate increases in this most recent review of the 2009-2010 agreement still fall within acceptable norms of the industry.
- Vendor management services provided by HOT are enjoying advantages in both buying power and reduced unit costs for third party services.
- Bill monitoring and contract negotiations continue to result in considerable cost avoidance.

The Shpigler Group has extensive experience in utility telecommunications activities throughout North America and has investigated a number of integrations of commercial and utility network operations and vendor management. We believe that the benefits of a commercial telecommunication approach coupled with the power system knowledge is an effective tool in extracting value for both HONI and HOT in their respective areas of responsibilities. The key to any partnership is communication and pursuing common objectives. The HOT/HONI Service Level Agreement and its interactions, when corrected to reflect verbal adjustments, will provide the direction and expectation for continued successful operations.

UNDERTAKING

Undertaking

Part 1 - TO PROVIDE A DESCRIPTION OF WHAT WAS INCLUDED IN THE (TS UPGRADES TO FACILITATE DISTRIBUTION GENERATION) CAPITAL CATEGORY AND THE IMPLICATIONS OF ELIMINATING IT. [IMPACT OF ZERO SPEND].

Part 2 - PLEASE EXPLAIN THE VARIANCES IN CAPEX FOR:

a) PROTECTION, CONTROL, MONITORING & TELECOMMUNICATION [ADDRESS NEGATIVE VARIANCES FOR ($36.4)M IN 2009 AND ($8)M IN 2010];
b) LOCAL AREA SUPPLY ADEQUACY ($66.8)M IN 2009 AND ($24.6)M IN 2010;
c) OPERATING INFRASTRUCTURE, ($21.8) M IN 2009.

Part 3 - PLEASE EXPLAIN THE OM&A VARIANCE FOR POWER EQUIPMENT OF $30.0M IN 2009 AND $22.7M IN 2010. [PLEASE EXPLAIN THE LARGE OVERSPEND OVER MINIMUM LEVEL].

Response

The following provides a discussion of the variance between the minimum levels and the proposed (i.e. filed) spending levels shown in the response to Undertaking J2.7.

Part 1 - TS Upgrades to Facilitate Distributed Generation

This work was to initiate proactive investments in upgrades at transformer stations to allow an increase in the amount of generation that could be incorporated into the distribution system connected to a particular station.

The minimum level reflects investments Hydro One was reviewing in the initial stage of the business planning process. These investments were intended to align with the Ontario Government's direction to facilitate more renewable generation in the province. Subsequent to the initial planning stage of the business planning process, Hydro One determined that it could not fully and properly assess the overall costs and benefits of the required transmission investments to support the Distributed Generation (DG) Standard Offer Program. The $16M in funding initially proposed for 2009 or 2010 was removed from the transmission rate filing because currently the pool funding option is not explicitly available to enable proactive investments in the transmission system in support of DG. Hydro One will continue to monitor the cost allocation requirements for guidance on this matter.

<u>Part 2 a)</u> - P&C, Monitoring & Telecom

The decrease in requested spending for P&C Monitoring and Telecom work relative to the minimum levels initially proposed is due to the re-assessment of the risks associated with shifting some of the work to the later years of the business plan period. The re-assessment included consideration of the limitations associated with availability of critical resources to do the work. As a result, these programs were adjusted to reduce the accomplishments in 2009 and 2010, but accelerate accomplishments in subsequent years to achieve all of the required work over the business plan period.

<u>Part 2 b)</u> - Local Area Supply Adequacy

The decrease in requested spending for the Local Area Supply Adequacy category of work relative to the minimum spending level initially proposed at the start of the business planning process is largely attributable to the following:

- About 60% of the decrease in spending over the two test years resulted from a deferral in project cash flows associated with project delays that Hydro One became aware of after the initial minimum levels were proposed and prior to submitting its Application. The project delays are attributable to such factors as delays in obtaining the required permits and delays in obtaining property rights.
- Close to 30% of the decrease in spending over the two test years is attributable to project deferrals resulting from the re-prioritization and re-assessment of the risks associated with deferring the project need dates. The decrease includes the deferral of all spending on two projects (i.e. Keith TS Upgrade of T11/T12 autotransformers and Upgrade of 115 kV circuits J3E/J4E) to beyond the test year period.
- In the case of project D15 (Southern Georgian Bay Reinforcement) the 2009 cash flow decreased from what was initially proposed as the minimum level due to the advancement of some 2009 work into 2008 to take advantage of available resources.

The implication of these project deferrals is the continued risk to some customers of substandard Local Area Supply reliability in selected areas. These risks are recognized by Hydro One and are being managed in the short-term via operational measures.

<u>Part 2 c)</u> – Operating Infrastructure

The difference between minimum and proposed spending on Operating Infrastructure is primarily related to changes in the Telecom Wide Area Network project, which is described in section 4.2 of Exhibit D1, Tab 3, Schedule 4. The deployment of the Wide Area Network project was delayed by one year and scaled down slightly based on a re-assessment of the risks associated with delaying this work. The re-assessment included consideration of the availability of critical resources and the need for more time to coordinate the scope of the Wide Area Network project with the emerging needs for connecting new generation and the Smart Grid (described in Section 3.6 of Exhibit D1, Tab 3, Schedule 3).

<u>Part 3</u> - Power Equipment OM&A

Power Equipment OM&A spending consists of work in a number of areas. The spending level proposed in Hydro One's filing is the minimum sustainable level the Company believes is required to address the deteriorating reliability and condition of its aging stations power equipment. A discussion of the need to spend above the unsustainable levels proposed during the initial stage of the business planning process (i.e. "minimum" level) in each of the Power Equipment OM&A areas is provided below:

<u>Planned Maintenance</u> ($5.7M in 2009, $3.1M in 2010)

The increase above "minimum" level is necessary to complete additional preventive diagnostic and maintenance activities, which will avoid the increased risk associated with relying solely on analytical calculations and breaker oil analysis to minimize the amount of breaker maintenance being conducted. Without these additional activities, there will be an increased risk of premature, and or catastrophic failure, of some equipment.

<u>Corrective Maintenance</u> ($6.1M in 2009, $5.0M in 2010)

The increase above "minimum" level is required to address the increasing trend in corrective maintenance observed in 2007 and 2008 (as shown in the response to undertaking J2.3) and to address the expected increasing number of asset performance issues associated with our aging infrastructure. These asset performance issues, if not addressed in a timely manner, are expected to have a significant and direct impact on our customers.

<u>Transformer Refurbishments</u> ($13.7M in 2009, $10.4M in 2010)

The increase above "minimum" is required to address the continued deterioration in transformer performance as detailed in Section 3.3 of Exhibit C1, Tab 2, Schedule 2 and in the interrogatory responses Exhibit I, Tab 1, Schedule 30 and Exhibit I, Tab 6, Schedule 28.

Spending below the levels proposed in this Application will not address the accelerated failure rate experienced on some transformer classes and is expected to contribute to a premature End of Life.

<u>Breaker Refurbishments</u> ($4.5M in 2009, $4.3M in 2010)

The increase above "minimum" is required to address the continued deterioration in breaker performance detailed in Section 3.3 of Exhibit C1, Tab 2, Schedule 2 and in the interrogatory responses Exhibit I, Tab 1, Schedule 30 and Exhibit I, Tab 6, Schedule 28.

Spending below the levels proposed in this Application is expected to contribute to a premature End of Life and will further degrade Hydro One's breaker performance when compared to the CEA all-Canada benchmarks.

UNDERTAKING

Undertaking

TO PROVIDE THE PRODUCTIVITY INDICATORS FROM THE MERCER WYMAN STUDY USING FORECAST 2009 DATA FOR HYDRO ONE, ONLY.

Response

The Transmission and Distribution and Customer Service forecast results for 2009 for Hydro One, are provided in the tables below and have been calculated consistent with the methodology employed by Mercer (Canada) Limited and Oliver Wyman at Exhibit A, Tab 16, Schedule 2, Attachment 1.

Compensation Metrics for Transmission and Distribution		**2009 Forecast**	**2006 Exhibit A-16-2 Attachment 1**
Compensation per MWh	**$/MWh**	**2.75**	**2.14**
Compensation per Asset	**$/$1000 asset**	**32**	**31**
Compensation per Line KM	**$/KM**	**4080**	**3599**
Compensation Per Service Territory	**$/Sq. KM**	**807**	**670**

Compensation Metrics for Customer Service		**2009 Forecast**	**2006 Exhibit A-16-2 Attachment 1**
Compensation per MWh	**$/MWh**	**0.32**	**0.21**
Compensation per Asset	**$/$1000 asset**	**3.72**	**3.05**
Compensation per Line KM	**$/KM**	**472**	**351**
Compensation Per Service Territory	**$/Sq. KM**	**93**	**65**

To provide further clarification of the metrics used in the study, Hydro One requested Mercer and Oliver Wyman provide a letter describing the metrics in more detail. Their letter is attached as Attachment 1 to this response.

The differences in the 2009 to 2006 metrics are expected as Hydro One's annual work requirements have increased substantially since 2006. Consequently any changes in Hydro One results year-over-year cannot be evaluated effectively without comparisons of peer results over the same time period which would require a new study.

LETTER FROM OLIVER WYMAN
SUBJECT: RESPONSES TO COMPENSATION COST BENCHMARKING STUDY QUESTIONS

OLIVER WYMAN

Mark Hirschey
Principal

Oliver Wyman
200 Clarendon Street
Boston, Massachusetts 02116

05 March 2009

Mr. Glen MacDonald
Senior Advisor – Regulatory Affairs
Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, ON   M5G 2P5

Private & Confidential

Subject: Responses to Compensation Cost Benchmarking Study Questions

Dear Glen,

As requested, this letter provides clarification of the metrics employed in the Compensation Cost Benchmarking Study ("the Study") conducted by Mercer and Oliver Wyman for Hydro One last year.

The various measures of "output" or "production" reflect the various components of a Transmission and Distribution network. Specifically, below are the indicators that were developed to measure Hydro One's workforce productivity:

$$\frac{\text{Total Compensation}}{\text{Gross Fixed Assets (T\&D)}} \qquad \frac{\text{Total Compensation}}{\text{MWh sold}} \qquad \frac{\text{Total Compensation}}{\text{KM of line}} \qquad \frac{\text{Total Compensation}}{\text{Service Territory (km}^2\text{)}}$$

Summarized below is our commentary on each measure:

- ***Total Compensation:*** Is fully described at page 27 of Exhibit A, Tab 16, Schedule 2, Attachment 1, page 27.

- ***Gross Assets***: Reflect the combined gross fixed assets of the transmission and distribution systems. For companies that have more distribution in their mix, they will have more distribution compensation costs, but will also have more distribution assets to normalize the compensation value.

OLIVER WYMAN

- ***Line KM***: These are the combined line KM of the transmission and distribution systems. For companies that have more distribution in their mix, they will have more distribution compensation costs, but will also have more distribution line KMs to normalize the compensation value.

- ***Service Territory***: This measure was the combined service area of a company.

Service territory was provided to us in our survey as "the area (sq. km) over which service is provided to customers." Where possible we checked the calculations for appropriateness. When both a distribution and transmission service territory were provided, we used the "union" of those measures so that overlapping territory was not double counted. The service territory area that was provided represents only 60% of Ontario's total area. For companies that have more distribution in their mix, they will have more distribution compensation costs, they will have more service territory to normalize this.

- ***MWh***: This measure includes the Transmission and Distribution MWh sold through the system.

Finally, to clarify the definition of median, the median value is the median value of the comparison set excluding Hydro One. Hydro One is then compared against that comparison set. This is a standard practice in benchmarking studies.

Glen, I trust this letter provides the necessary clarification on the Study metrics. If you require any further information, please do not hesitate to contact me.

Sincerely,

Mark Hirschey

Mark Hirschey
Principal

Copy:
Iain Morris, Mercer (Canada) Limited
Mark MacCharles, Mercer (Canada) Limited

UNDERTAKING

Undertaking

TO DESCRIBE WHAT PHASE 1 IS AND HOW IT IS USED AND USEFUL FOR THE 2010 TEST YEAR

Response

Phase 1 of the Bruce x Milton project as referenced in Interrogatory Response I-1-75 is the construction and placing into service, in 2010, of some of the new facilities of the Bruce x Milton project. The facilities planned to be brought into service during 2010 include:

- A new two circuit 500 kV transmission line on the west side of the existing lines from Milton SS northwards to Highway 7 and the reconfiguration of the circuits along this portion of the right-of-way. The line to be constructed in 2010 will become part of and replace a portion of the existing Milton SS x Middleport TS line.

- Required station work at the existing Milton SS including the installation of four new circuit breakers and the physical retermination of one of the existing Milton x Trafalgar circuits as per one of the recommendation of the IESO System Impact Assessment report for the Bruce x Milton Project (as documented in EB-2007-0050 Exhibit B, Tab 6, Schedule 2, Page 14).

- Required station work at the existing Bruce B SS including the installation and placing into service a new circuit breaker and swapping of the switching position of the existing Bruce B x Milton circuit with that of the new one.

- The stringing and placing into service an optical ground wire along the existing Bruce A TS x Bruce B SS 500 kV circuit, B569B.

- Station service equipment replacement at both Bruce A TS and Bruce B SS.

UNDERTAKING

Undertaking

TO ADD A COLUMN TO TABLES 1 AND 2 OF EXHIBIT A, TAB 14, SCHEDULE 3 SHOWING ACTUAL PEAK MONTHLY DEMAND.

Response

Revised Table 1 and Table 2 are provided below with actual monthly peak demand included.

Table 1

Comparison of Latest IESO and Hydro One Monthly Peak Forecasts (MW)

Forecast Period	IESO Forecast (1)	Hydro One Forecast (2)	Difference Due to Day Effect (3)	Difference Due to Definition of CDM & Embedded Generation (4)	Hydro One Forecast Adjusted (5)=(2)+(3)+(4)	Difference in Forecasts: Hydro One Less IESO (6)=(5)-(1)	Actual*
2008:Apr-Dec	22,303	21,286	650	380	22,316	13	21,668
2009:Jan-Sep	22,530	21,554	650	420	22,624	94	n.a.
18-Month Total	22,416	21,386	650	400	22,436	20	n.a.
Summer 2008	24,892	23,932	650	360	24,942	50	24,195
Winter 2008-09	23,441	22,742	650	240	23,632	191	n.a.
Summer 2009	24,754	23,851	650	400	24,901	147	n.a.

(1) From IESO April 2008 18-month outlook, Planned Resource Scenario.
(2) Hydro One forecast used in the current rate submission.
(3) Difference between transmission peak-load in Wednesdays (used by IESO) compared to average (used by Hydro One).
(4) Difference due to definition of CDM used by Hydro One compared to IESO and Embedded Generation.

*Note: Actual average monthly peak demand for the forecast period is not available and is marked “n.a.”.

Table 2

Comparison of IESO and Hydro One Monthly Peak Forecasts - History (MW)

Year	IESO Forecast (1)	Hydro One Forecast (2)	Difference Due to Day Effect (3)	Difference Due to Definition of CDM & Embedded Generation (4)	Hydro One Forecast Adjusted (5)=(2)+(3)+(4)	Difference in Forecasts: Hydro One Less IESO (6)=(5)-(1)	Actual*
2002	22,190	22,068	650	0	22,718	528	22,773
2003	22,711	22,226	650	0	22,876	165	22,281
2004	22,646	22,381	650	20	23,051	405	22,934
2005	22,959	22,169	650	440	23,259	300	23,043
2006	23,702	21,656	650	850	23,156	-546	22,929
2007	23,233	21,709	650	940	23,299	67	22,223

(1) From IESO July 18-month outlook for each year indicated above.
(2) Hydro One forecast over 18-month period starting in July of each year indicated above.
(3) Difference between transmission peak-load in Wednesdays (used by IESO) compared to average (used by Hydro One).
(4) Difference due to definition of CDM used by Hydro One compared to IESO.

*Note: Actual average monthly peak demand provided pertains the same 18-month period in (1) and (2).

UNDERTAKING

Undertaking

TO PROVIDE A COPY OF LETTER FROM THE BOARD DATED FEBRUARY 24, 2009.

Response

A copy of the letter from the OEB dated February 14, 2009 Re; Cost of Capital Parameter Updates for 2009 Cost of Service Applications is attached.

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656

Commission de l'Énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656

February 24, 2009

To: All Licensed Electricity Distributors
All Registered Intervenors in 2009 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2009 Cost of Service Applications

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term and Short-Term debt rates for use in the 2009 rate year Cost of Service applications.

On December 20, 2006, following the consultative process conducted under Board Files EB-2006-0087/0088, the Board issued the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report"). The Board Report documents the methodologies and formulae used to determine the Cost of Capital parameters: the Return on Equity ("ROE") and the deemed Long-Term and Short-Term debt rates (collectively, the "Cost of Capital parameters").

The methodologies documented in the Board Report stated that the updated parameters will be derived from *Consensus Forecasts* and Bank of Canada/Statistics Canada three (3) months ahead of the implementation date for the proposed rates. Therefore, the January 2009 data will be used for estimating the Cost of Capital parameters used for setting new distribution rates to be effective May 1, 2009.

The Board has applied the methodologies as documented in the Board Report to update the Cost of Capital parameters. The source for the Long-term Bond Yields – All Corporates, used in the calculation of the deemed long-term debt rate is TSX Inc. available to the Board on a subscription basis. The terms of the agreement preclude the Board from publishing the TSX Inc. data but permit it to be viewed in the Information Resource Centre (the "IRC") at the Board's offices during normal business hours.

The Board has determined the values for the updated Cost of Capital parameters, shown in the following table:

Parameter	**Value for 2009 Cost of Service Applications (assuming May 1, 2009 implementation date for rate changes)**
Return on Equity	8.01%
Long-Term Debt Rate	7.62%
Short-Term Debt Rate	1.33%

These values will be used in the Board decisions regarding approval of the rates for the 2009 electricity Cost of Service applications. A summary of the calculation of the ROE is provided in Appendix A.

In addition, the Board wishes to advise parties that it will be initiating a review of its current policy regarding the cost of capital. The Board considers that such a review is appropriate at this time. The Board will consider the appropriateness of the parameters in different economic and financial conditions and their impact on infrastructure investment. Details of this initiative will be announced in due course.

All queries on the cost of capital parameters should be directed to the Board's Market Operations hotline, at 416 440 7604 or market.operations@oeb.gov.on.ca .

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Appendix A
Summary of Return on Equity Calculation
For 2009 Cost of Service Electricity Distribution Rate Applications

Step		
1	Ten Year Government of Canada Bond Yield – end of April 2009 (*Consensus Forecasts*, January 2009)	2.7%
	Ten Year Government of Canada Bond Yield – end of January 2010 (*Consensus Forecasts*, January 2009)	3.1%
	Average of three- and twelve-month forecasts	2.9%
2	Add the average spread between 30-year and 10-year Government of Canada bonds for all business days in January 2009 as posted by the Bank of Canada	0.814%
3	Equals the forecasted yield on Long-term Government of Canada Bonds	3.714%

Per the mathematical formula documented in Appendix B of the Board Report:

4.	Updated ROE calculated as: 9.35% + (0.75 X (3.714% - 5.50%))	8.011%
5.	Maximum allowed ROE (rounded to two decimal places)	8.01%

UNDERTAKING

Undertaking

TO PROVIDE THE ACTUAL DOLLAR IMPACTS AND DOLLAR INCREASES FOR EACH CUSTOMER, FOR THE 45 DELIVERY POINTS

Response

The following table only reflects the impact on the 45 delivery points that currently do not pay line connection charges. Customers may be served through other delivery points where network charges would be impacted by the change.

Customer	DP	Type	Existing Tx Charge	Tx Charge (LC Added)	Tx Charge Increase ($)	Tx Charge Increase (%)
C1	DP1	Direct	$ 132,150	$ 567,505	435,355	329.4%
C2	DP2	Utility	$ 280,875	$ 344,178	63,302	22.5%
C3	DP3	Utility	$ 1,695,129	$ 2,074,435	379,307	22.4%
C3	DP4	Utility	$ 1,790,339	$ 2,192,769	402,431	22.5%
C3	DP5	Utility	$ 3,111,408	$ 3,799,884	688,475	22.1%
C3 Total			**$ 6,596,875**	**$ 8,067,088**	**$ 1,470,213**	**22.3%**
C4	DP6	Utility	$ 3,137,793	$ 3,948,522	810,730	25.8%
C5	DP7	Utility	$ 2,995,580	$ 3,664,236	668,656	22.3%
C6	DP8	Utility	$ 54,594	$ 75,284	20,690	37.9%
C6	DP9	Utility	$ 2,558,446	$ 3,129,421	570,976	22.3%
C6	DP10	Utility	$ 2,233,307	$ 2,728,471	495,164	22.2%
C6	DP11	Utility	$ 3,948,875	$ 4,831,624	882,749	22.4%
C6	DP12	Utility	$ 792,151	$ 970,461	178,310	22.5%
C6	DP13	Utility	$ 1,562,369	$ 1,918,278	355,909	22.8%
C6	DP14	Utility	$ 606,659	$ 744,882	138,223	22.8%
C6	DP15	Utility	$ 4,159,875	$ 5,085,134	925,259	22.2%
C6	DP16	Utility	$ 2,381,248	$ 2,922,324	541,076	22.7%
C6	DP17	Utility	$ 2,429,179	$ 2,970,136	540,957	22.3%
C6	DP18	Utility	$ 732,337	$ 894,944	162,607	22.2%
C6	DP19	Utility	$ 750,251	$ 947,958	197,707	26.4%
C6	DP20	Utility	$ 3,128,307	$ 3,821,889	693,582	22.2%
C6	DP21	Utility	$ 3,771,656	$ 4,616,551	844,895	22.4%
C6	DP22	Utility	$ 1,178,677	$ 1,442,596	263,919	22.4%

Customer	DP	Type	Existing Tx Charge	Tx Charge (LC Added)	Tx Charge Increase ($)	Tx Charge Increase (%)
C6	DP23	Utility	$ 1,153,869	$ 1,420,644	266,775	23.1%
C6	DP24	Utility	$ 1,425,186	$ 1,797,866	372,680	26.1%
C6	DP25	Utility	$ 5,829,592	$ 7,122,409	1,292,817	22.2%
C6	DP26	Utility	$ 224,863	$ 276,219	51,356	22.8%
C6	DP27	Utility	$ 289,193	$ 355,895	66,703	23.1%
C6	DP28	Utility	$ 1,654,079	$ 2,021,451	367,372	22.2%
C6	DP29	Utility	$ 2,584,591	$ 3,260,665	676,075	26.2%
C6	DP30	Utility	$ 2,184,650	$ 2,673,499	488,850	22.4%
C6	DP31	Utility	$ 2,000,930	$ 2,448,229	447,299	22.4%
C6	DP32	Utility	$ 1,714,494	$ 2,099,765	385,271	22.5%
C6	DP33	Utility	$ 4,497,454	$ 5,494,029	996,575	22.2%
C6	DP34	Utility	$ 1,272,287	$ 1,558,037	285,749	22.5%
C6	DP35	Utility	$ 2,619,140	$ 3,204,179	585,039	22.3%
C6	DP36	Utility	$ 3,062,788	$ 3,740,818	678,030	22.1%
C6 Total			**$60,801,046**	**$74,573,659**	**$13,772,613**	**22.7%**
C7	DP37	Utility	$ 1,709,605	$ 2,088,389	378,784	22.2%
C7	DP38	Utility	$ 203,330	$ 279,739	76,409	37.6%
C7	DP39	Utility	$ 1,136,378	$ 1,395,587	259,209	22.8%
C7 Total			**$ 3,049,312**	**$ 3,763,714**	**$ 714,402**	**23.4%**
C8	DP40	Direct	$ 1,882,639	$ 2,683,871	801,232	42.6%
C9	DP41	Utility	$ 3,469,321	$ 4,257,069	787,747	22.7%
C9	DP42	Utility	$ 1,168,392	$ 1,433,768	265,376	22.7%
C9 Total			**$ 4,637,713**	**$ 5,690,836**	**$ 1,053,123**	**22.7%**
C10	DP43	Utility	$ 9,899,731	$12,085,863	2,186,132	22.1%
C11	DP44	Utility	$ 4,805,127	$ 5,869,574	1,064,447	22.2%
C11	DP45	Utility	$ 4,389,100	$ 5,355,910	966,810	22.0%
C11 Total			**$ 9,194,226**	**$11,225,484**	**$ 2,031,257**	**22.1%**

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UNDERTAKING

Undertaking

TO PROVIDE THE CALCULATION FOR THE 430 MEGAWATT INCREASE IN PEAK.

Response

The Ontario 1-hour peak load factor, which represents the energy to peak relationship, averaged 0.776 over the 1994-2005 period (see table provided below). The load factor dropped to 0.761 in 2006 (1.9 % drop) and remained low (0.756) in 2007. The 2007 load factor was considered too low due to unusually high peak load during shoulder months (May and September) and high peak load in both summer and winter months.

In preparing the transmission system load forecast for this application, the load factor of 0.761 (1.9% drop) was used for the forecast period (2008-2010) to be consistent with recent trends. The reduction in load factor resulted in an upward shift of 430 MW in the 12-month average peak over the forecast period (2008-2010) before reduction for CDM and embedded generation. The calculation for the 430 MW is shown below:

2007 weather-corrected 12-Month average peak = 22,420 MW
1.9% adjustment is about 425 MW and rounded to 430 MW (22,420*0.019 = 425)

The energy to peak relationship will be reviewed and updated as part of an on-going process in load forecasting.

History of Ontario 1-Hour Peak Load Factor

Year	Energy (Av MW)	Peak (MW)	Load Factor
1994	15397	19955	0.772
1995	15644	20422	0.766
1996	15638	19962	0.783
1997	15796	20147	0.784
1998	15974	20631	0.774
1999	16449	21060	0.781
2000	16729	21566	0.776
2001	16771	21658	0.774
2002	17461	22737	0.768
2003	17319	22317	0.776
2004	17468	22375	0.781
2005	17919	23074	0.777
2006	17244	22650	0.761
2007	17375	22988	0.756
1994-2005 Average			0.776
2006			0.761
2006 vs. Average (%)			-1.9