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

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab 12/Sch 1 Appendix A

At page 1, price and cost escalation information is found in the first table. Many of the sources quoted are quite dated. Please provide updated data for the years in the table and the date the update was developed. Will Hydro One update the application to account for more recent data? If so, please provide the updates. If not, why not?

Response

See table below for the current updated data available for the years.

	2009	2010	2011	2012	2013	2014
CPI – Ontario (%)	0.4	2.4	2.1	2.1	2.0	2.1
Tx cost escalation for Construction (%)	-2.6	1.5	1.8	2.8	3.0	3.8
Tx cost escalation for Operations & Maintenance (%)	0.0	1.8	2.4	2.6	2.0	2.6
Dx cost escalation for Construction (%)	1.3	1.9	1.6	2.3	3.2	3.8
Dx cost escalation for Operations & Maintenance (%)	-0.8	2.8	2.1	2.3	2.1	2.3
Exchange Rate (CDN$/US$)	1.142	1.030	1.021	1.050	1.067	1.086

CPI- Ontario and cost escalation forecasts were based on the Global Insight July 2010 forecast. The exchange rate for 2009 is the average from the Bank of Canada. The exchange rate forecasts for 2010 to 2012 are based on the July 2010 edition of Consensus Forecasts. The exchange rate forecasts for 2013 and 2014 are based on the Global Insight July 2010 Forecast.

Hydro One is not planning to update its 2011/12 transmission rate filing for changes in planning assumptions.

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

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab 12/Sch 1 Appendix A

The evidence indicates that Hydro One has used a Global Insight forecast dated December 2008 for an application submitted in May 2010. Why was a more recent forecast not used for this application?

Response

As explained in lines 7-9 in Exhibit A, Tab 12, Schedule 1, the 2009 Business Plan for 2010-14 forms the basis of this application in relation to 2011-2012. The Global Insight December 2008 forecast was the most recent information available at the time the business plan instructions were issued.

Ontario Energy Board (Board Staff) INTERROGATORY #3 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab 13/Sch 1
Under Productivity, Hydro One indicates that for 2009, transmission unit cost is "10.1%, slightly lower than plan". Please provide further explanation of this measure and also include information this measure from 2004 to 2009.

Response

The transmission unit cost measure used to assess productivity in 2009 was defined as follows:

$$\text{Transmission Unit Cost} = \frac{\text{Operations and Maintenance (O\&M) costs + Total Capital}}{\text{Asset Value (Gross Fixed Asset (GFA))}}$$

The measure value is expressed as a percentage. Nominally, a lower percentage is better.

This measure was derived and is used by Canadian Electricity Association (CEA) member utilities. This measure allows utilities to monitor their own productivity year-over-year and measure themselves against other comparable utilities.

In order to accurately compare the measure across a wide sample, common definitions of calculation inputs have been applied by the CEA. For example, operations and maintenance expenses are included, whereas some expenses as specified by the CEA are excluded to account for different accounting and reporting practices between member utilities. Further, capital expenditures include development, sustainment, operations and common costs such as transport and work equipment and information technology. Gross fixed assets are in-service costs for capital.

In 2009 this measure was incorporated into the Hydro One Corporate Scorecard. For 2009, the target Transmission Unit Cost was 10.6% compared to the actual value of 10.1%. This variance from plan is largely attributable to development capital project delays such as the new 500kV Bruce to Milton Double Circuit Line project; installation of SVC's at Porcupine TS, Kirkland Lake TS and Nanticoke TS; and the Woodstock Area Transmission Reinforcement.

The 2009 calculation of the Transmission Unit Cost is shown to be:

O&M	$228.5M
+ Capital	$ 918.6M
Total expenditures	$1,147.1M
Gross fixed assets	$11,344.6M
Total expenditures per GFA	10.1%

As shown in Table 1 below, the Transmission Unit Cost has been trending up the last several years due primarily to necessary increases in Total Capital.

Table 1
Transmission Unit Cost (%)

Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Transmission Unit Cost	6.3%	5.6%	6.1%	7.7%	8.6%	10.1%

This measure allows Hydro One to compare its performance year-over-year internally and against other comparable utilities. Industry wide, this measure is viewed as a collaborative opportunity and it allows Hydro One to gain valuable insights into best practices and processes.

This measure also provides for a common reference base for performance against industry comparables. This measure provides a performance gauge for Hydro One to compare its performance relative to other industry comparable. Using the industry wide sample, Hydro One can identify the top quartile productivity performance threshold and identify a roadmap to achieve industry leading performance.

Insight into current performance and longer term goals provides Hydro One with valuable information which is integrated into operational and implementation decisions. Hydro One is cognizant of this measure, while it strives to ensure transmission reliability measures also remain favorable relative to industry comparables.

Ontario Energy Board (Board Staff) INTERROGATORY #4 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab 12/Sch7/p.9
The savings that Hydro One has realized as a result of outsourcing are shown the table on this page. Please explain how these savings were calculated for each year and whether these are capital or O&M savings.

Response

The referenced table does not provide "savings that Hydro One has realized as a result of outsourcing". Rather, as stated on Exhibit A, Tab 12, Schedule 7, page 9, line 16, this table provides "the total dollars of outsourced work". As stated on the referenced page, a greater use is being made of external outsourcing contracts due to the increased number and size of many projects required to expand and develop the transmission system.

The outsourced work totals provided in the table are for capital projects only.

Ontario Energy Board (Board Staff) INTERROGATORY #5 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab13/Sch1/Appendix B

Please provide the reasons behind the deterioration of the performance measures regarding transmission unavailability in 2009 shown in Table B4 and Table B5.

Response

Figures B4 and B5 illustrate transmission unavailability performance for transmission lines and major transmission station equipment respectively. These charts are reproduced below with a linear trend over the full historical period of the results presented in the evidence.

In 2009, the unavailability of transmission lines due to line-related forced outages was elevated due to two separate events. The first event involved heavy ice and wind conditions in the North-Eastern region that destroyed 10 towers resulting in an outage that lasted 16 days in March 2009. The ice and wind loading exceeded the design capabilities of the towers. The second event was a long outage in the Southwest region in September caused by conductor damage that affected 3 circuits and lasted up to 19 days. A unique self damping conductor was installed on these circuits as a pilot in the 1970/80's that wore out resulting in damaged strands with no option other than to replace.

In 2009, the unavailability of major station equipment was slightly elevated from 2008 primarily due to a prolonged outage to replace a 500kV power transformer at Porcupine TS.

Although there is variation in actual results from year to year, the trend for each of these measures clearly shows a stable performance over the 10 year historical period.

Figure B4 from Exhibit A, Tab 13, Schedule 1 with linear trend included over the 10 year historical period.

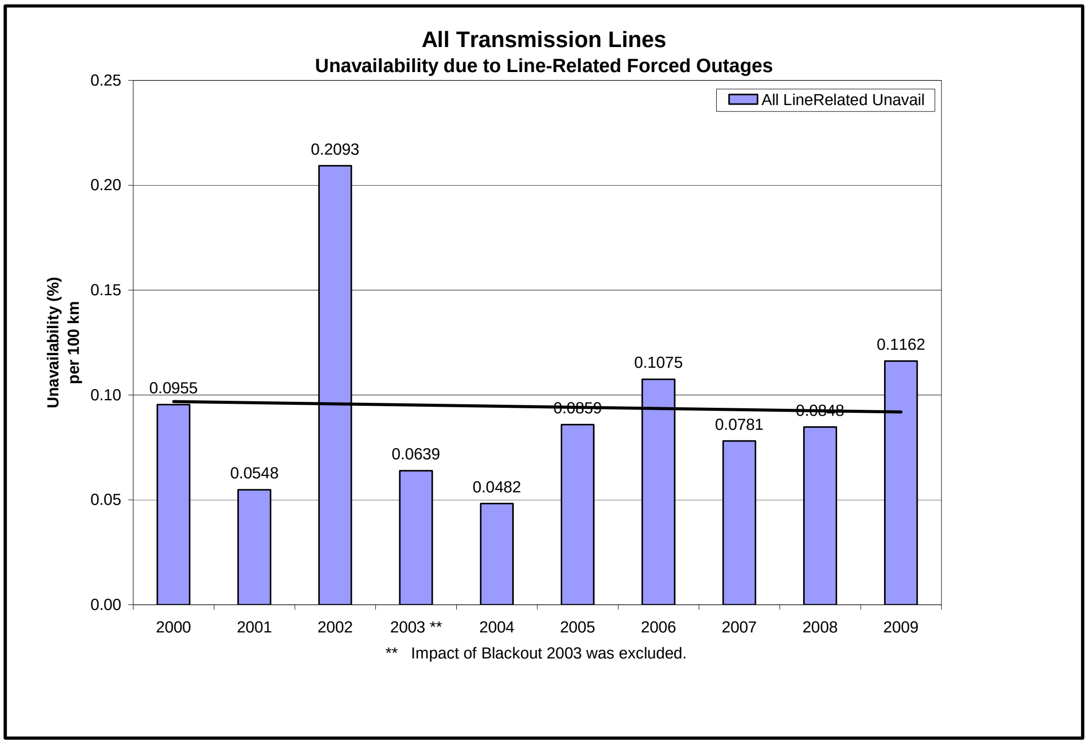
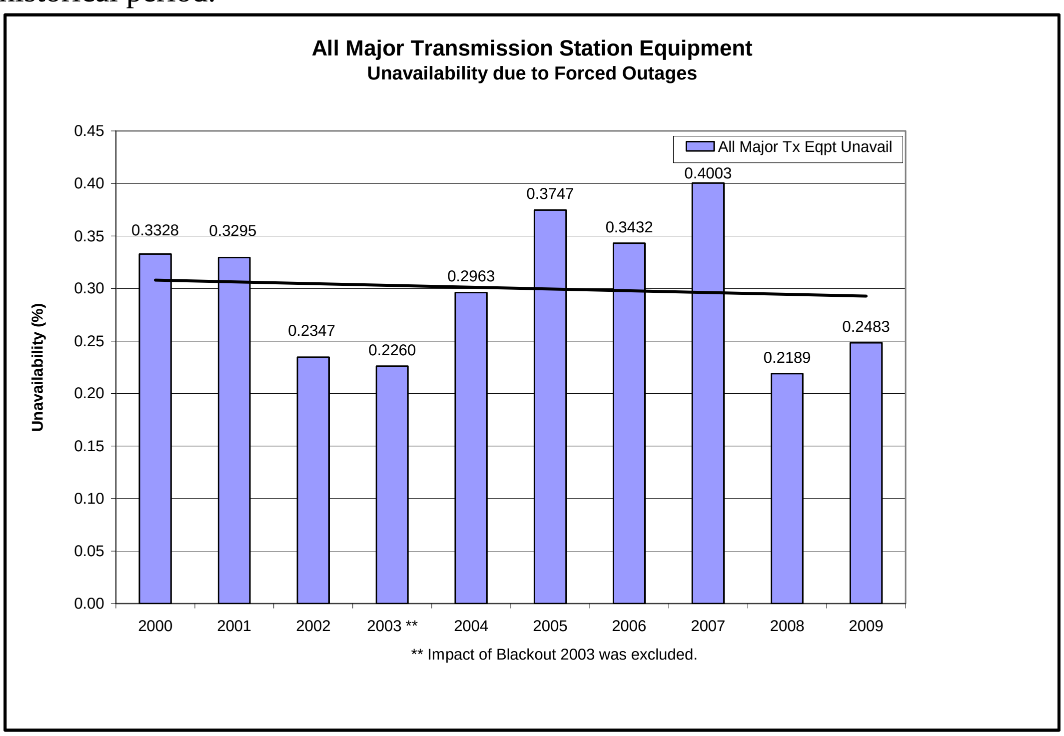


Figure B5 from Exhibit A, Tab 13, Schedule 1 with linear trend included over the 10 year historical period.



Ontario Energy Board (Board Staff) INTERROGATORY #6 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab13/Sch1/Appendix C
Regarding actions taken as a result of the Customer Delivery Point Performance Standards, please provide information on how Hydro One has taken action to address performance as a result of these standards. Please outline all actions taken in this regard in the bridge and test years, including specific illustrative examples.

Response

For clarity, the Response has been broken into three parts to match the three separate questions asked: Part 1: Hydro One Actions to address performance outliers; Part 2: Hydro One's Planned actions in the bridge and test years; Part 3: Specific illustrative examples of Hydro One's actions

Part 1: Hydro One actions to address performance outliers

Hydro One is addressing the performance of "outlier" delivery points identified by the Customer Delivery Point Performance Standards [CDPPS] by performing detailed analysis of those identified delivery points to determine root cause(s) and thus develop proper mitigation alternatives.

The proper mitigation alternatives include: increased animal deterrents; fault indicators on complex circuits to better isolate problem area; installation of surge arrestors in high lightning areas; installation of phase spacers on circuit sections experiencing wind-induced line galloping; installing switches to allow sectionalizing of long complex lines to reduce customer impacts and improve restoration times.

Further, a high level of co-ordination has been initiated with the Transmission Sustaining and Development programs to focus the investments which could also improve the performance of the identified outlier delivery points.

Part 2: Hydro One's planned actions in the bridge and test years

Hydro One has planned the following actions to address the CDPPS identified performance outlier customer delivery points.

Bridge Year

- Installation of animal deterrents at Stations
- Installation of 115kV Fault Indicators
- Switch installations to sectionalize long lines
- Stations Transformer Rod Gap replacements with Surge Arrestors

Test Years

- Continued installation of animal deterrents at Stations with new options being
  - improved Station Gates
  - a full perimeter fencing system
- Installation of 115kV Fault Indicators on another Outlier circuit
- Implementation mitigation options identified by 115kV Fault Indicators from Bridge Year
- Continue switch installations to sectionalize long lines
- Continued Stations Transformer Rod Gap replacements with Surge Arrestors

Part 3: Specific illustrative examples of Hydro One's actions

Three examples of the mitigation actions under way and being planned:

1. Ordered and installing 115 kV Fault Indicators on the complex L7S circuit in Southwestern Ontario [London-area] to isolate which of the 7 line sections is causing the problem(s). This will allow for better targeting of mitigation measures. For example, the identification and subsequent installation of Phase Spacers on line sections that are prone to galloping conductor.

2. Animal contact induced outages are an issue at many of our GTA stations, several being Tx Outlier Delivery Points. Investments are being made to install bus cover-ups, anti-dig barriers around fencing and improved gate and fencing designs are being investigated to better secure the perimeter.

3. The replacement of Transformer Rod gaps with Surge Arrestors to better protect the station transformer from external flashover.

Ontario Energy Board (Board Staff) INTERROGATORY #7 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab14/Sch1/p. 10
With regard to Corporate Culture, and specifically employee engagement, please provide any information on employee engagement surveys and how employee engagement has changed from 2004 to 2009.

Response

Employee engagement was not measured between 2004 and 2007. Hydro One completed its first employee engagement survey in December 2008. A second survey was completed in October 2009, and the next survey is scheduled for Fall 2010. Over the period 2008-2009, the number of engaged employees has increased by 23%.

Ontario Energy Board (Board Staff) INTERROGATORY #8 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref. Exhibit A/Tab14/Sch1/p. 11
With regard to Corporate Scorecards, in the last Hydro One distribution rates case, EB-2009-0096, Hydro One provided information (Exhibit H/Tab1/Sch29) on First Quartile and CEA studies. Have the results for these studies been updated since the EB-2009-0096 case? If so, please provide a summary of the results including the key tables presented in Undertaking J6.8 in the EB-2009-0096 case.

Response

Yes, the Distribution and Transmission results of the community benchmarking study have been updated by First Quartile with latest data up to 2008. A summary of the benchmarking report using First Quartile Consulting benchmarking community transmission data is provided in Attachment 1.

The updated key Distribution tables or relevant reports (with Hydro One marked on the chart) of the benchmarking study are provided in Attachment 2.

Also provided are equivalent Transmission tables or relevant reports (with Hydro One marked on the chart) of the benchmarking study are provided in Attachment 3.

The Canadian Electricity Association has also updated its benchmarking report and a summary is available in Attachment 4.

There is not an equivalent report for Transmission from The Canadian Electricity Association.

HYDRO ONE TRANSMISSION BENCHMARKING SUMMARY USING FIRST QUARTILE CONSULTING DATA

HYDRO ONE TRANSMISSION BENCHMARKING SUMMARY USING FIRST QUARTILE CONSULTING DATA

1. FINDINGS FROM THE BENCHMARKING ANALYSIS

This table provides a summary of the community benchmarking survey undertaken by First Quartile Consulting in 2009 with latest data up to 2008. The study involves a community of utilities and not a specific panel of utilities. The table shows the results from the key performance metrics including cost, service levels (reliability) and safety. All monetary figures are in US dollars. Where indicated, the summary figures in the table are built on 4-year averages (2008, 2007, 2006 and 2005) or for just 2008 depending on the data that was available through the community survey.

	Mean	*Median*	*1st Q*	*H-1*	*H-1 Quartile*
Cost Metrics					
4 year Avg Transmission Line Capital Spending per Asset	19.70%	13.82%	23.60%	5.61%	Q4
2008 Transmission Line O&M Expense per Asset	3.20%	2.68%	1.79%	0.93%	Q1
4 year Avg Transmission Line O&M Expense per Circuit mile	$5,190	$3038	$1956	$1618	Q1
4 year Avg Transmission Substation O&M Expense per Asset	7.29%	7.32%	3.12%	2.56%	Q1
2008 Transmission Substation O&M Expense per Asset	1.70%	1.20%	1.10%	2.37%	Q4
Transmission Reliability					
4 year Avg Number of Sustained outages per Transmission circuit	0.70	0.52	0.50	0.13	Q1
4 year Avg Number of Sustained outages per 100 Transmission circuit mile	3.24	3.24	1.33	1.58	Q2
4 year Avg Sustained outage hours per Transmission circuit	8.38	7.91	4.25	1.51	Q1
Substation					
2008 Percent mis-operation for relays	4.34%	4.49%	8.17%	8.00%	Q1
Safety					
4 year average Lost Time Incident Rate –(T&D)	3.94	2.05	0.95	0.38	Q1

HYDRO ONE TRANSMISSION BENCHMARKING SUMMARY USING FIRST QUARTILE CONSULTING DATA

The table shows the average and variability in each of the metrics. By providing the values for mean, median, first quartile and standard deviation, the reader is able to better understand the performance of the community and put Hydro One's performance into a more complete perspective; however it must be noted that this is a community study , not a panel of utilities study.

1.1 COST

The cost results for Hydro One indicate reasonable performance in managing the transmission system. Hydro One is ahead of the industry with Line Expense per Asset while the low Capital Spending per Asset indicate lower spending than the industry

1.2 RELIABILITY

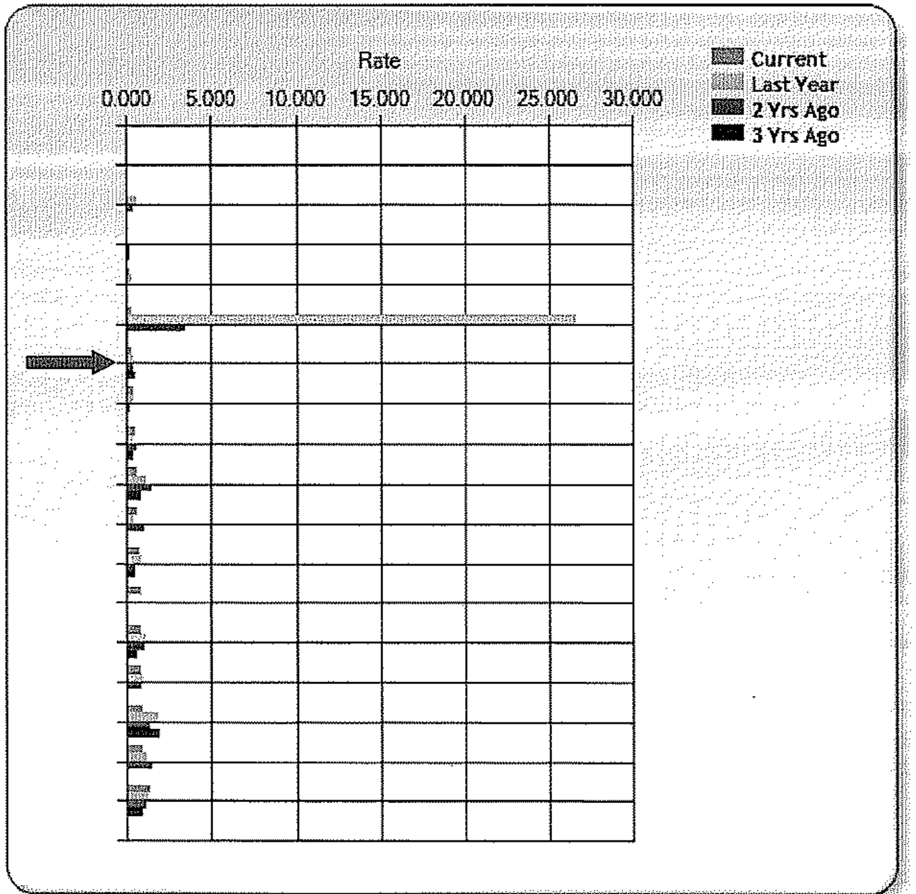
The reliability measures in use for transmission reliability focus on outages and the impact on the end use customer. Hydro One's reliability figures are better than the industry standard.

1.3 SAFETY

One of the key areas of the community benchmarking is Safety. Hydro One achieved first quartile with lost time incidents and is well ahead of the community.

Filed: August 16, 2010
EB-2010-0002
Exhibit I-1-8
Attachment 2
Page 1 of 8

4-YEAR LOST TIME INCIDENT RATE: TOTAL T&D



Mean Quartile

Mean	3.936
Quartile 1	0.950
Quartile 2:	2.050
Quartile 3:	3.660

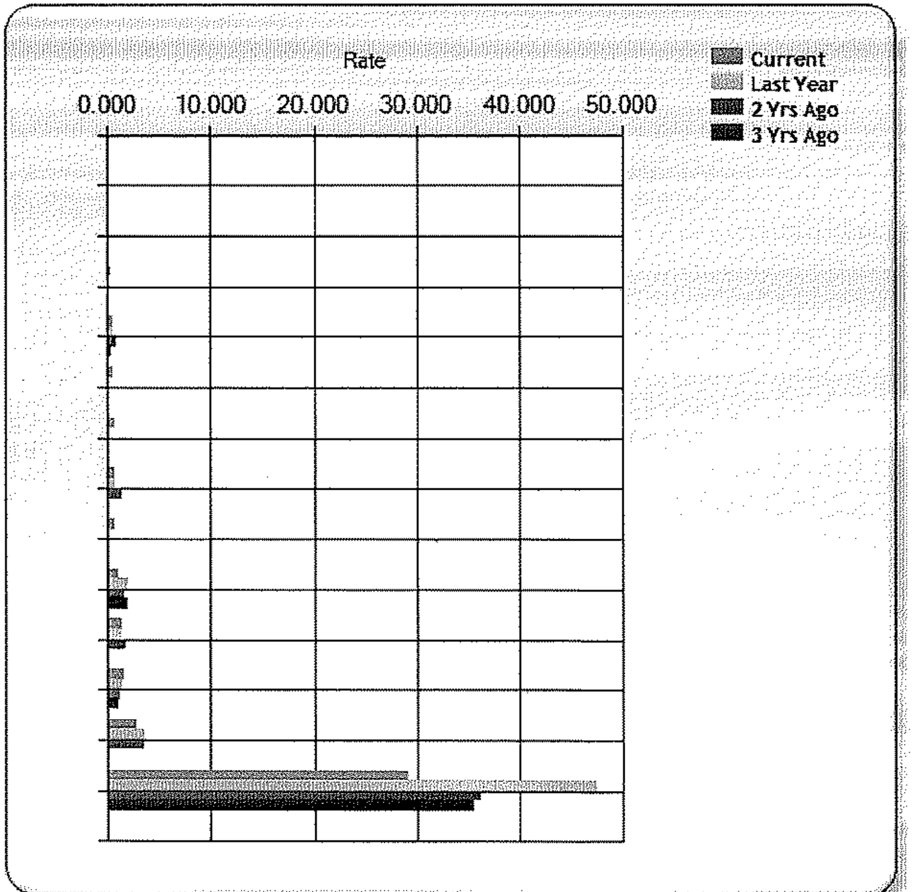
Comments

Calculation used

D5.2A , D10.2A , D15.2A , D16.2A

 HO DID NOT PARTICIPATE

4-YEAR LOST TIME INCIDENT RATE: DISTRIBUTION LINES



Mean Quartile

Mean	14.162
Quartile 1	0.690
Quartile 2:	2.410
Quartile 3:	5.240

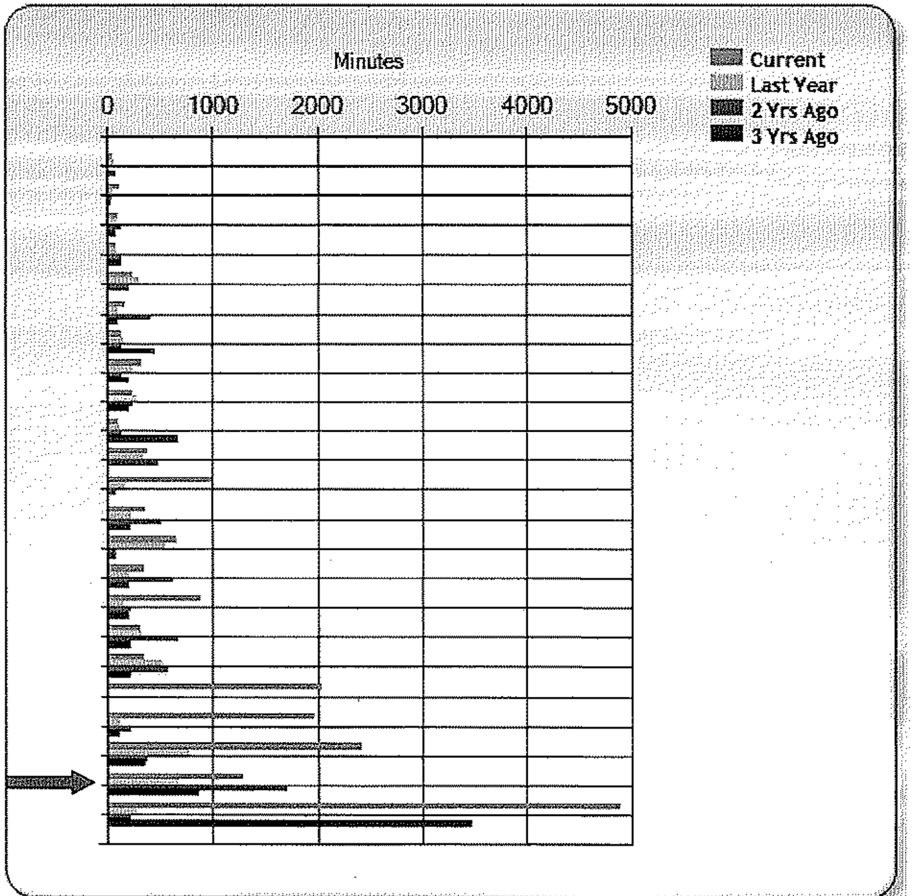
Comments

Calculation used

D5.2D , D10.2D , D15.2D , D16.2D

FIRST QUARTILE CONSULTING

4-YEAR SAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile

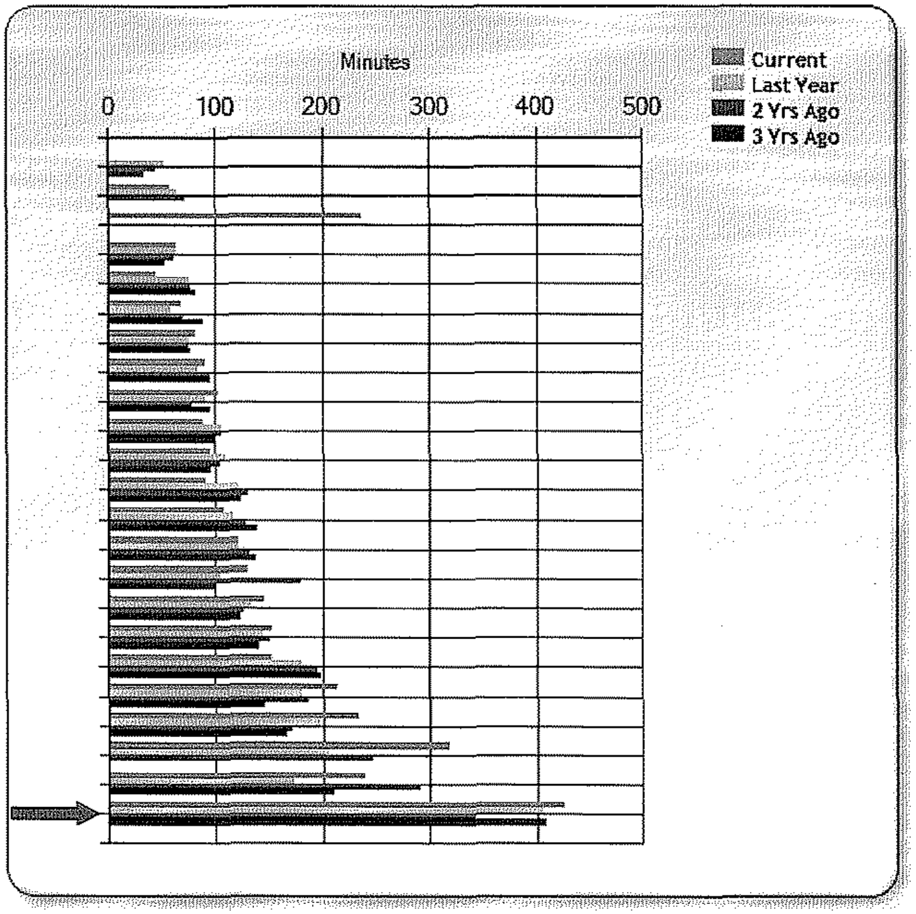
Mean	1743
Quartile 1	848
Quartile 2:	1261
Quartile 3:	1628

Comments

Calculation used

G5.1A , G10.1A , G15.1A , M5.1A

4-YEAR SAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile

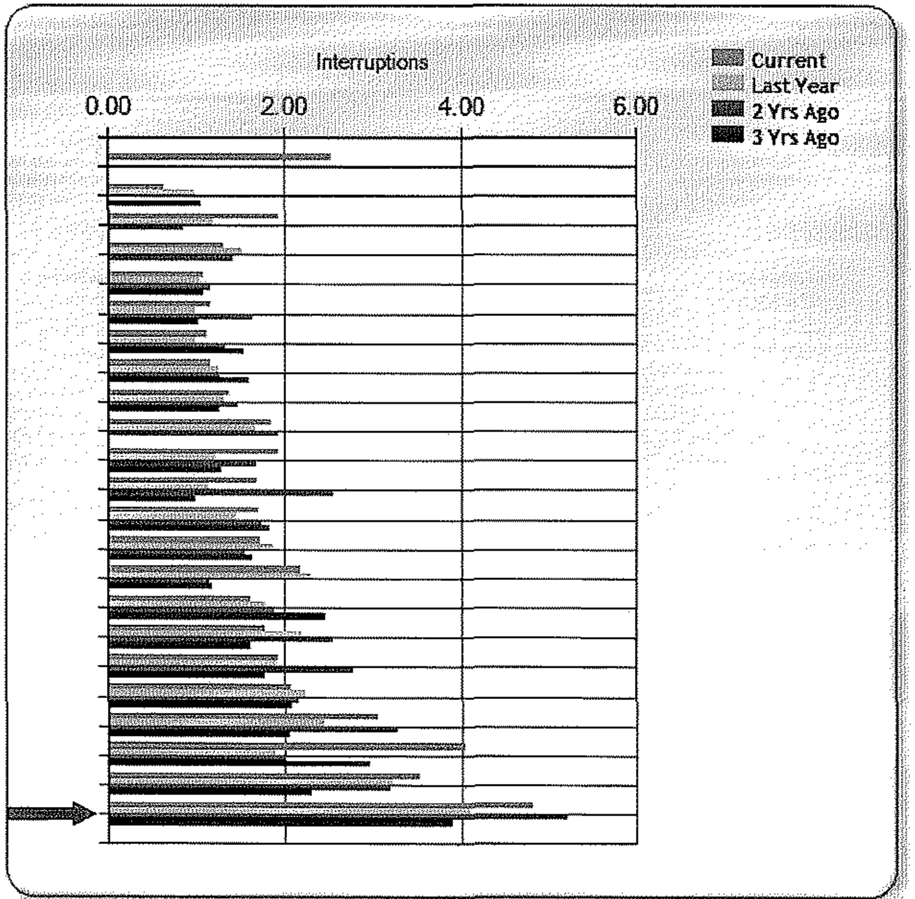
Mean	514
Quartile 1	299
Quartile 2:	464
Quartile 3:	658

Comments

Calculation used

G5.1B , G10.1B , G15.1B , M10.1A

4-YEAR SAIFI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile

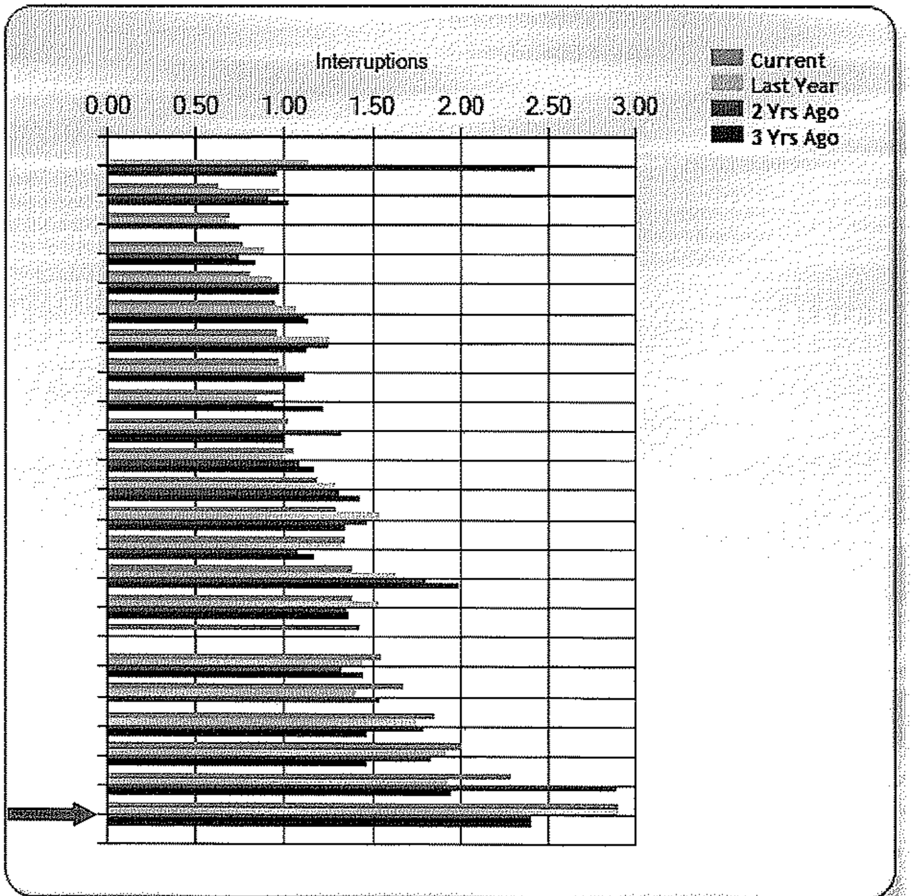
Mean	7.02
Quartile 1	4.91
Quartile 2:	6.38
Quartile 3:	8.26

Comments

Calculation used

G5.2A , G10.2A , G15.2A , M5.2A

4-YEAR SAIFI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile

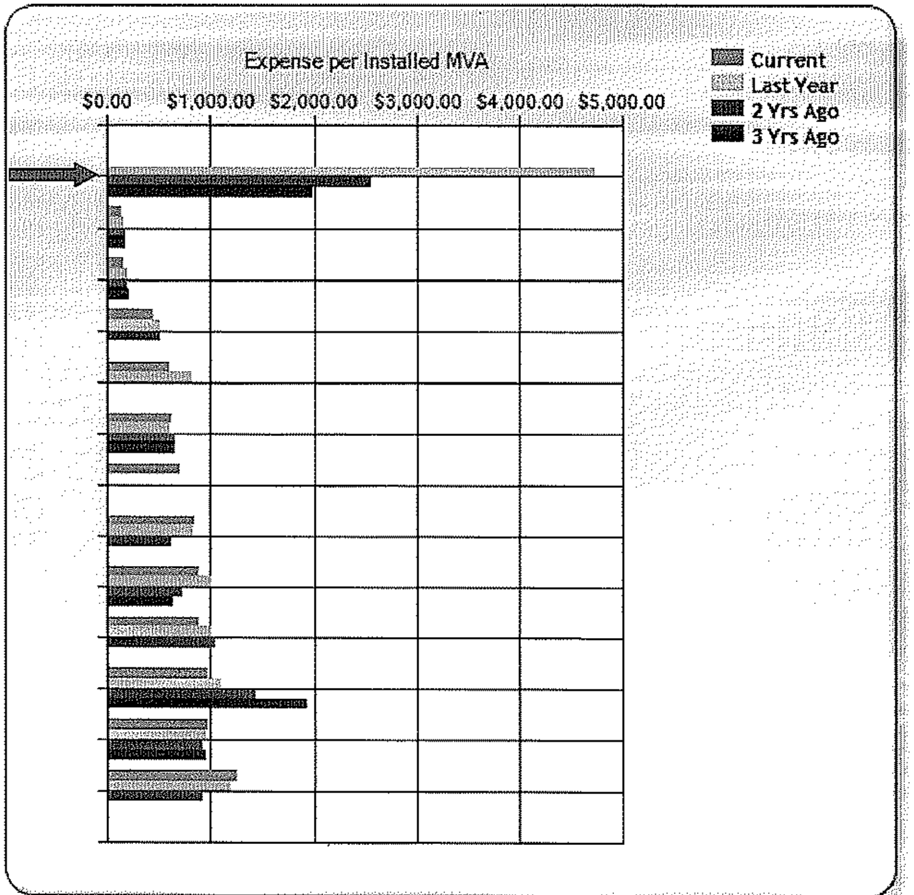
Mean	5.08
Quartile 1	4.12
Quartile 2:	4.59
Quartile 3:	5.72

Comments

Calculation used

G5.2B , G10.2B , G15.2B , M10.2A

4-YEAR DISTRIBUTION SUBSTATION O&M EXPENSE PER INSTALLED MVA [FERC]



Mean Quartile

Mean	$2,927.498
Quartile 1	$1,418.764
Quartile 2:	$2,540.825
Quartile 3:	$3,375.346

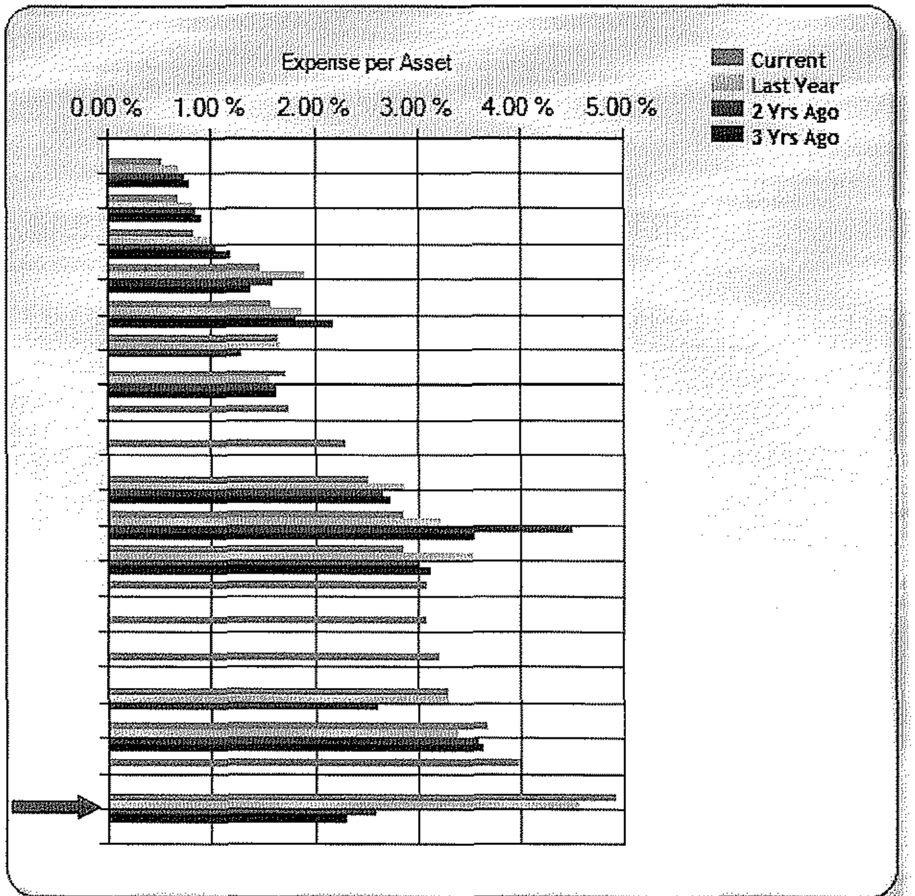
Comments

Calculation used

C25.5A / A115.1A , C25.5B / A115.1B , C25.5C / A115.1C , C25.5D / A115.1D

FIRST QUARTILE CONSULTING

4-YEAR DISTRIBUTION SUBSTATION O&M EXPENSE PER ASSET [FERC]



Mean Quartile

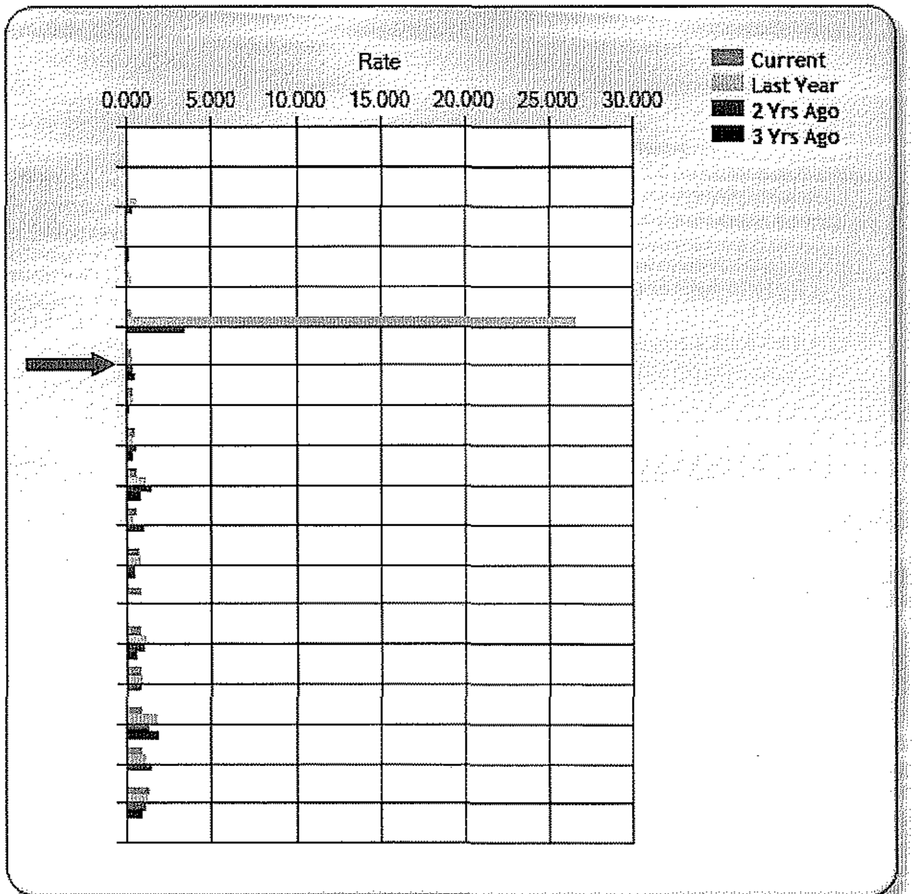
Mean	6.739 %
Quartile 1	3.147 %
Quartile 2:	4.627 %
Quartile 3:	10.009 %

Comments

Calculation used

C25.5A / C55.2A * 100 , C25.5B / C55.2B * 100 , C25.5C / C55.2C * 100 , C25.5D / C55.2D * 100

4-YEAR LOST TIME INCIDENT RATE: TOTAL T&D



Mean Quartile

Mean	3.936
Quartile 1	0.950
Quartile 2:	2.050
Quartile 3:	3.660

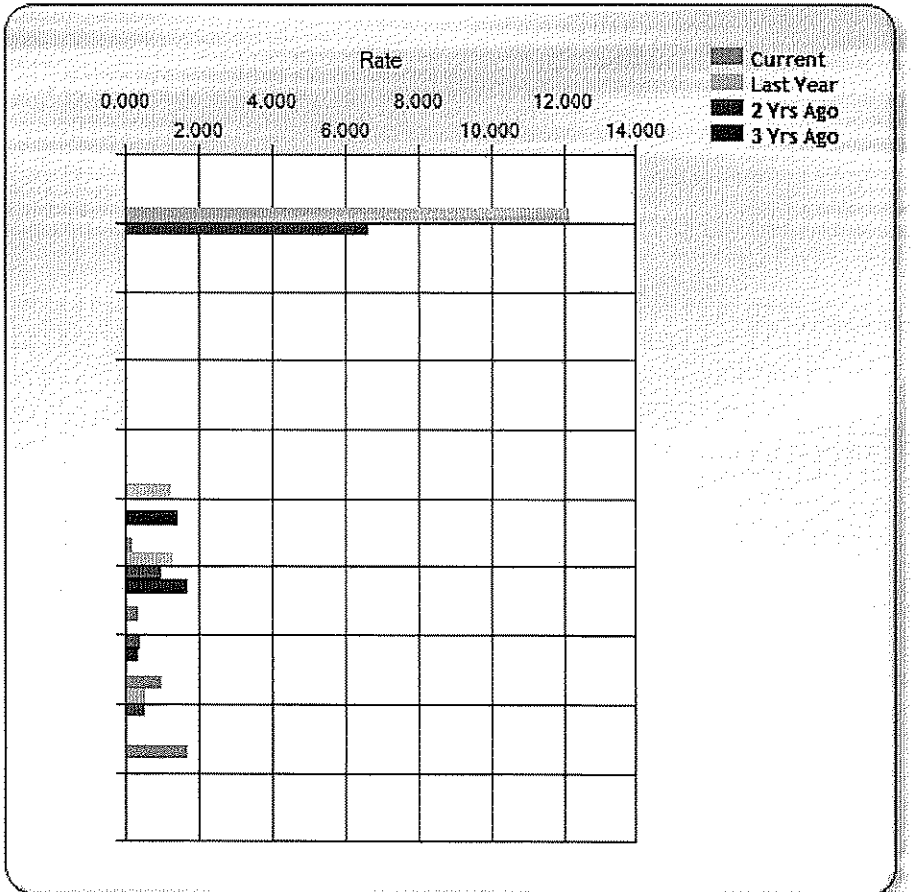
Comments

Calculation used

D5.2A , D10.2A , D15.2A , D16.2A

HO DID NOT PARTICIPATE

4-YEAR LOST TIME INCIDENT RATE: TRANSMISSION LINES



Mean Quartile	
Mean	3.368
Quartile 1	0.000
Quartile 2:	1.670
Quartile 3:	2.690

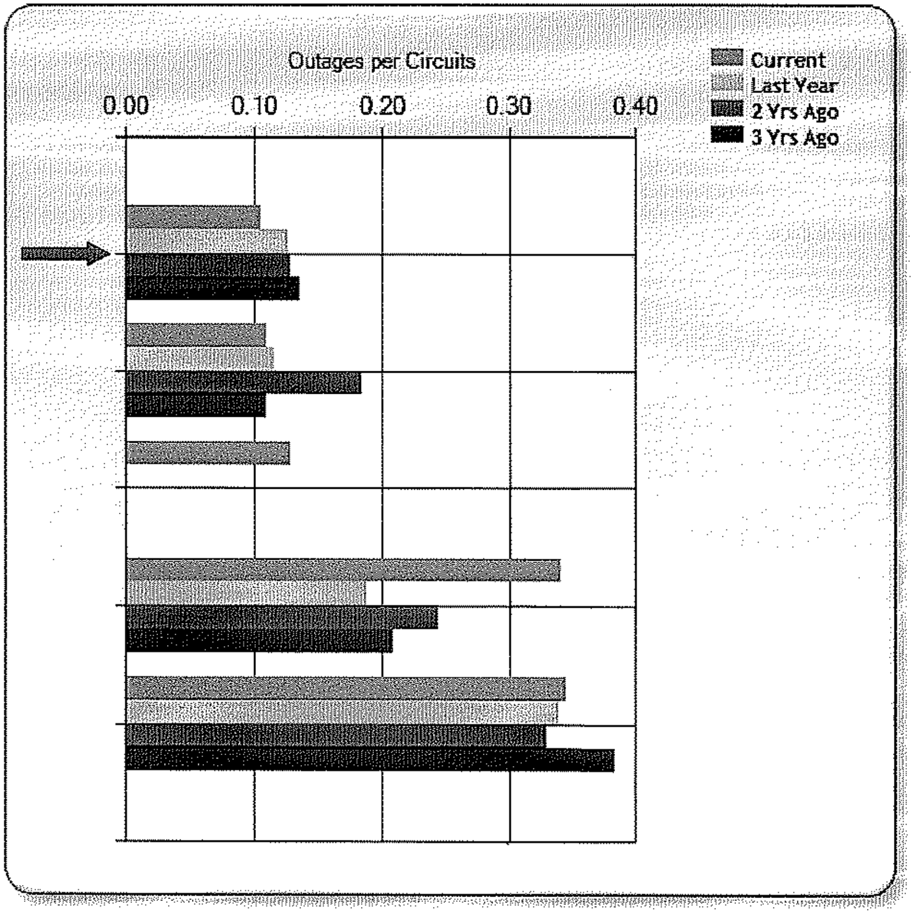
Comments

Calculation used

D5.2B , D10.2B , D15.2B , D16.2B

FIRST QUARTILE CONSULTING

4-YEAR NUMBER OF SUSTAINED OUTAGES ["AUTOMATIC"] PER TRANSMISSION CIRCUITS



Mean Quartile

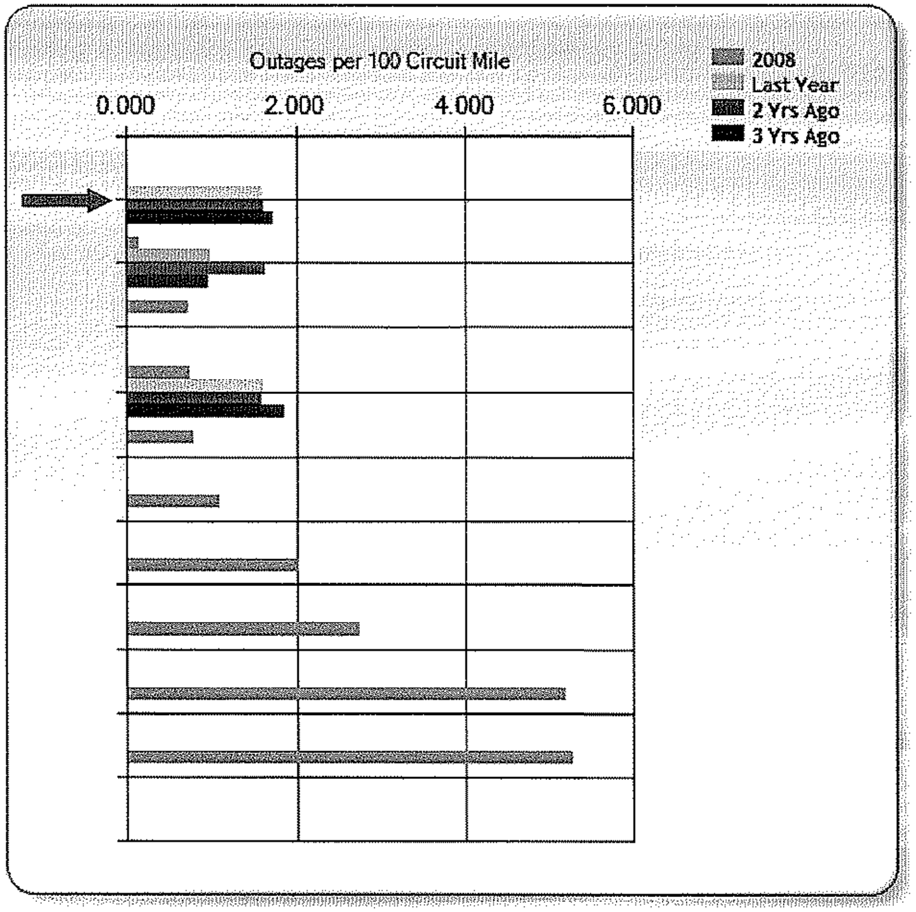
Mean	0.70
Quartile 1	0.50
Quartile 2:	0.52
Quartile 3:	0.98

Comments

Calculation used

(I5.1G + I5.1H) / (A135.1C + A135.2C + A135.3C + A135.4C + A135.5C + A135.6C) , (I10.1G + I10.1H) / (A135.1C + A135.2C + A135.3C + A135.4C + A135.5C + A135.6C) , (I15.1G + I15.1H) / (A135.1C + A135.2C + A135.3C + A135.4C + A135.5C + A135.6C) , (I16.1G + I16.1H) / (A135.1C + A135.2C + A135.3C + A135.4C + A135.5C + A135.6C)

4-YEAR NUMBER OF SUSTAINED OUTAGES ["AUTOMATIC"] PER 100 TRANSMISSION CIRCUIT MILE



Mean Quartile

Mean	3.236
Quartile 1	1.329
Quartile 2:	3.239
Quartile 3:	5.138

Comments

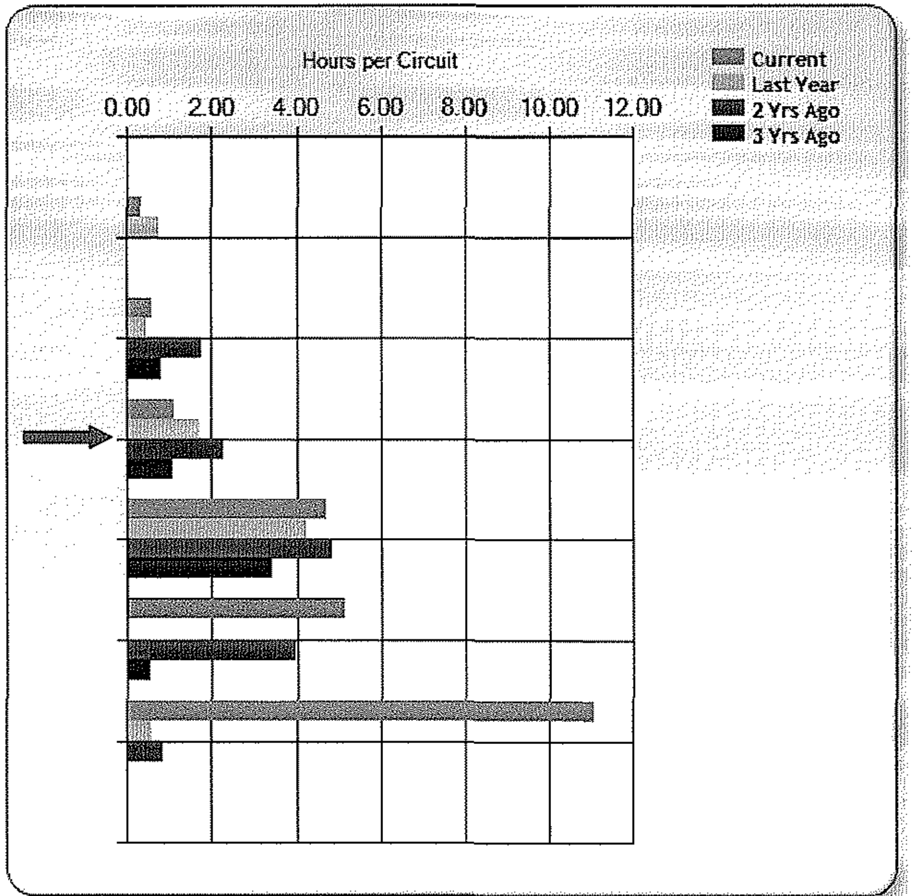
Calculation used

(I5.1A + I5.1B) / ((Trans Circ Mile 09) / 100) , (I10.1G + I10.1H) / (A140.1B / 100) , (I15.1G + I15.1H) / (A140.2B / 100) , (I16.1G + I16.1H) / (A140.3B / 100)

FIRST QUARTILE CONSULTING

Transmission Reliability

4-YEAR SUSTAINED OUTAGE HOURS ("AUTOMATIC") PER TRANSMISSION CIRCUIT



Mean Quartile

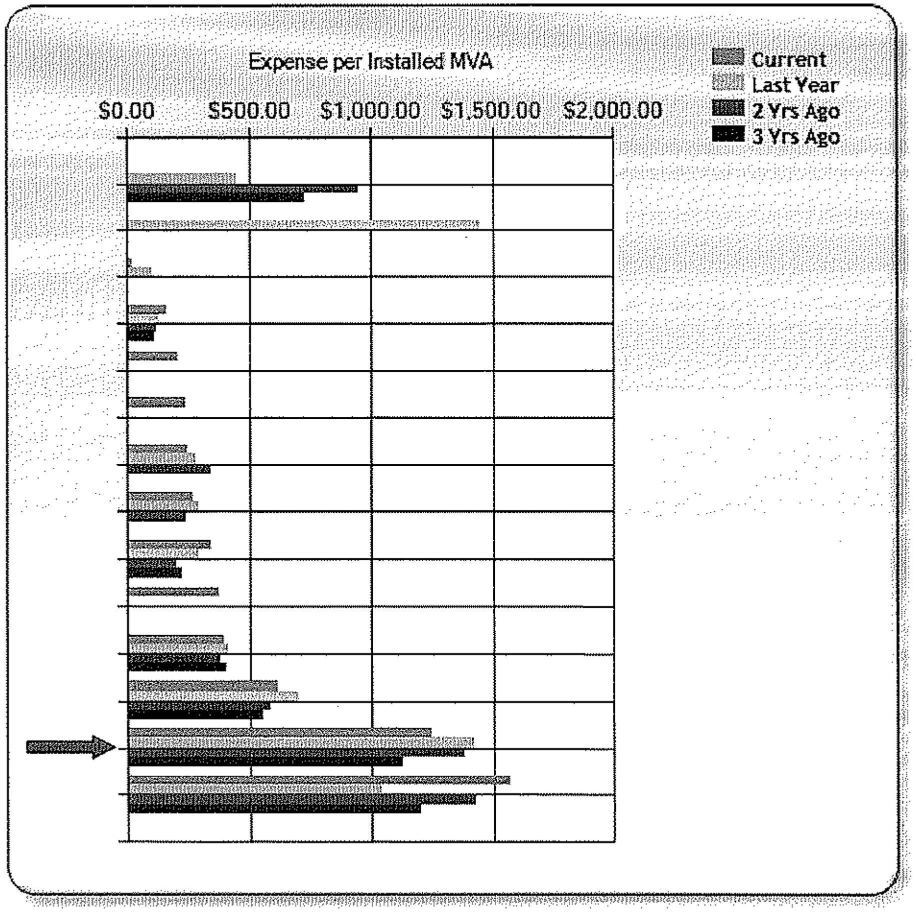
Mean	8.38
Quartile 1	4.25
Quartile 2:	7.91
Quartile 3:	11.83

Comments

Calculation used

((I5.8G + I5.8H) / 60) / (Trans Circuit 09) , ((I10.8G + I10.8H) / (Trans Circuit 09)) / 60 , ((I15.8G + I15.8H) / (Trans Circuit 09)) / 60 , ((I16.8G + I16.8H) / 60) / (Trans Circuit 09)

4-YEAR TRANSMISSION SUBSTATION O&M EXPENSE PER INSTALLED MVA [FERC]



Mean Quartile

Mean	$1,585.384
Quartile 1	$407.976
Quartile 2:	$968.103
Quartile 3:	$1,985.198

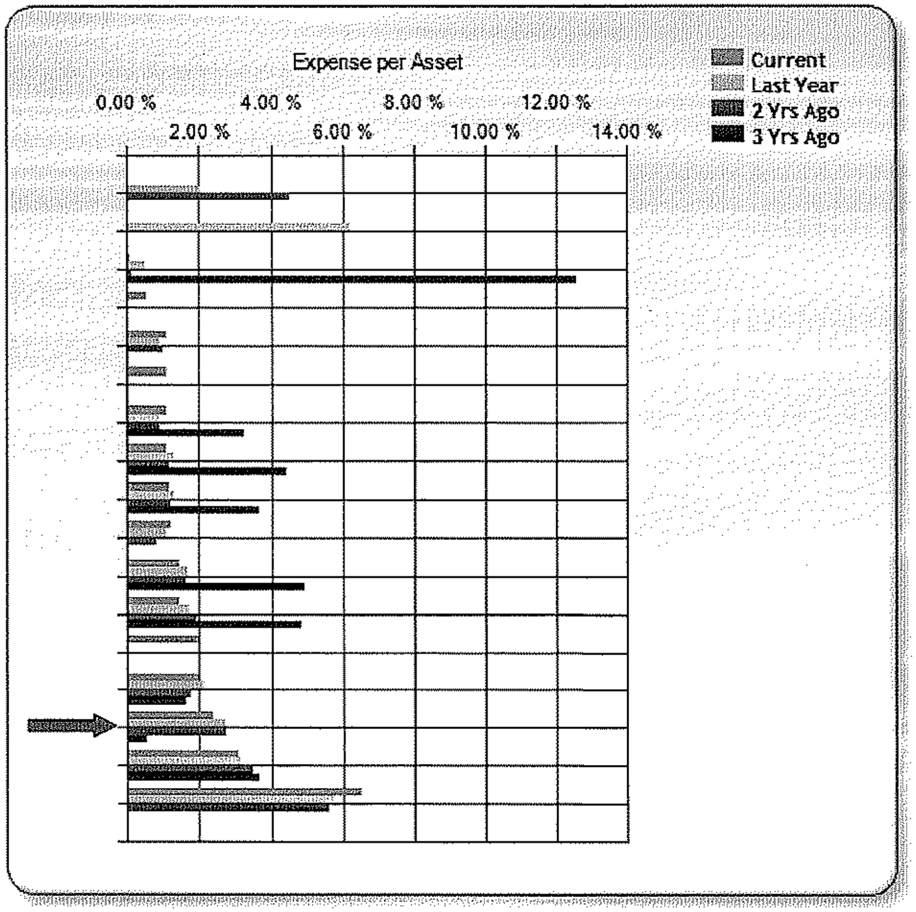
Comments

Calculation used

C90.5A / A120.1A , C90.5B / A120.1B , C90.5C / A120.1C , C90.5D / A120.1D

FIRST QUARTILE CONSULTING

4-YEAR TRANSMISSION SUBSTATION O&M EXPENSE PER ASSET [FERC]



Mean Quartile

Mean	7.292 %
Quartile 1	3.116 %
Quartile 2:	7.321 %
Quartile 3:	9.707 %

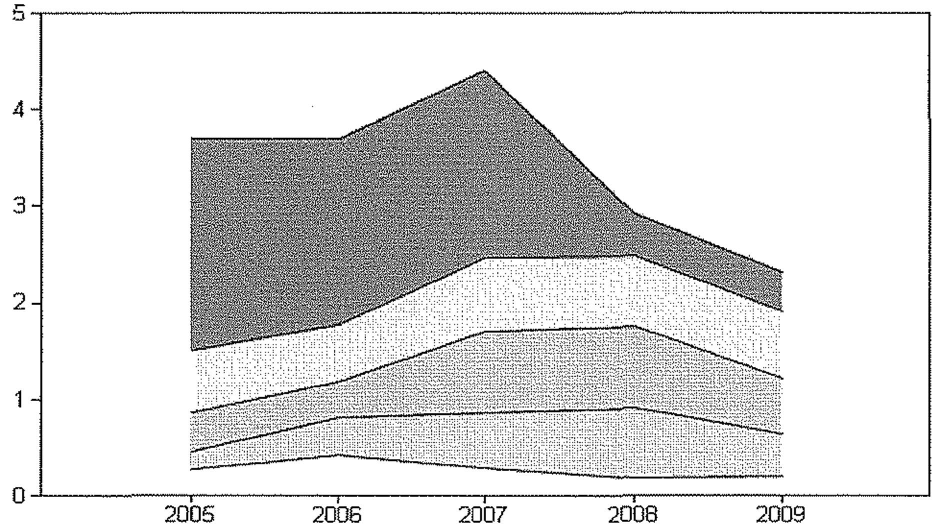
Comments

Calculation used

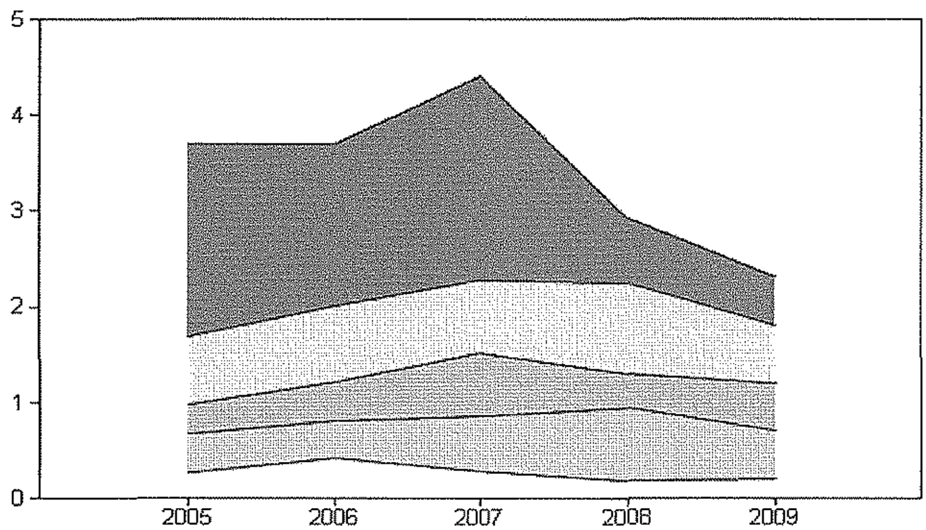
C90.5A / C130.1A * 100 , C90.5B / C130.1B * 100 , C90.5C / C130.1C * 100 , C95.8D / C130.1D * 100

Canadian Electricity Association
Association canadienne de l'électricité

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

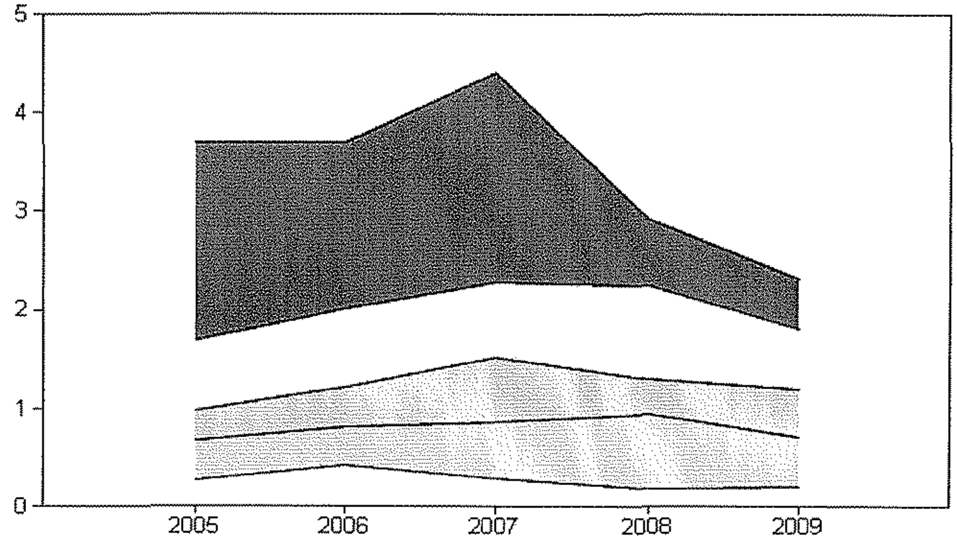


Graph 6-13: Region 1. SAIFI. Excluding MPEs.



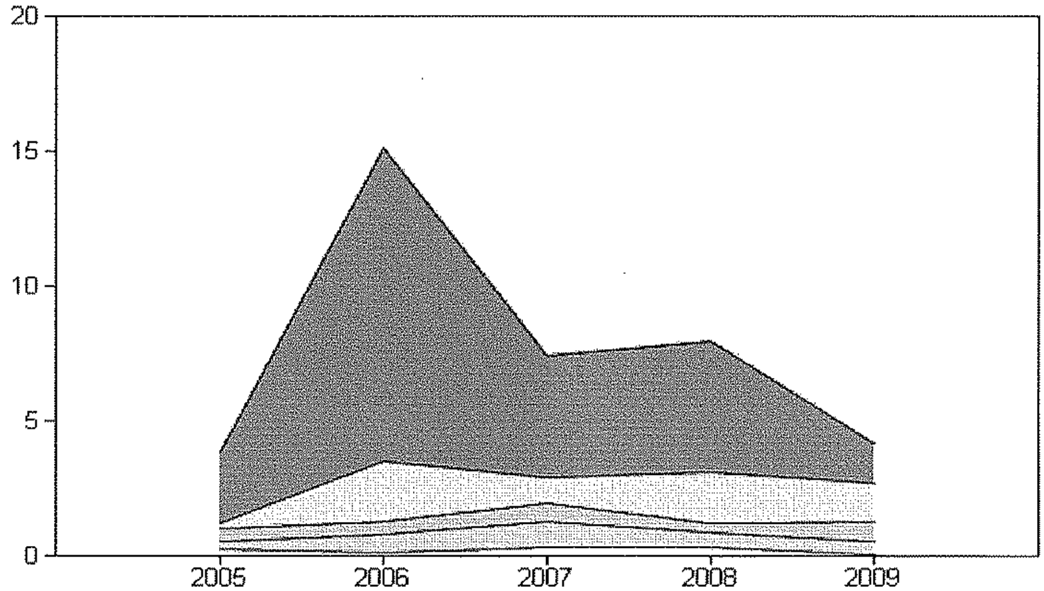
Graph 6-14: Region 1. SAIFI. Excluding Significant Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

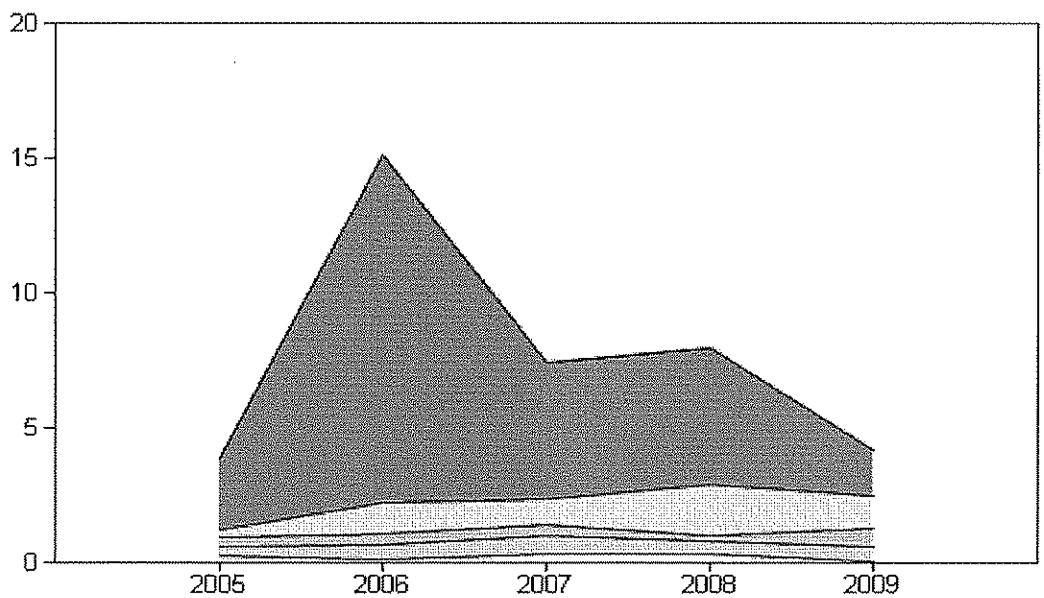


Graph 6-15: Region 1. SAIFI. Including All Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

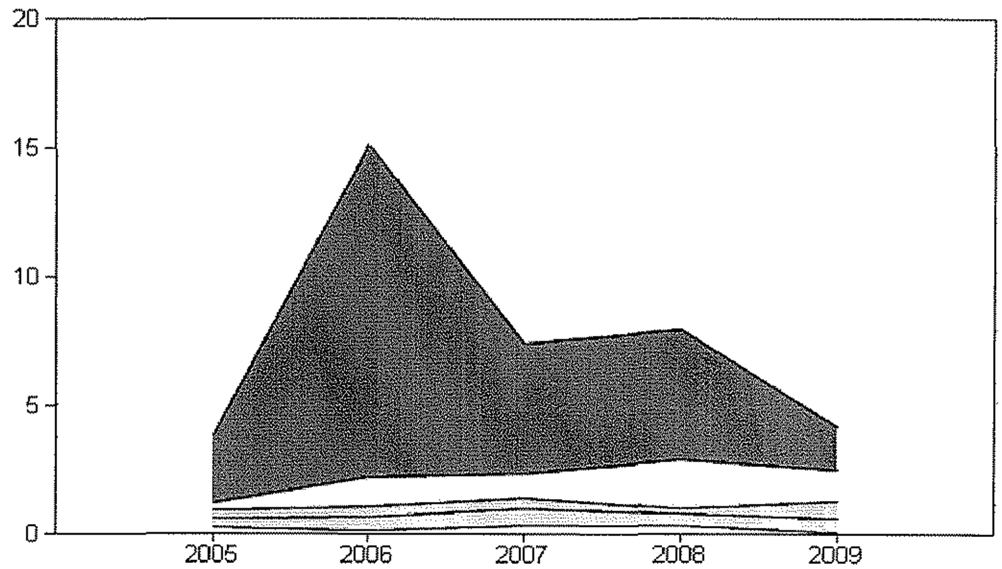


Graph 6-1: Region 1. SAIDI. Excluding MPE

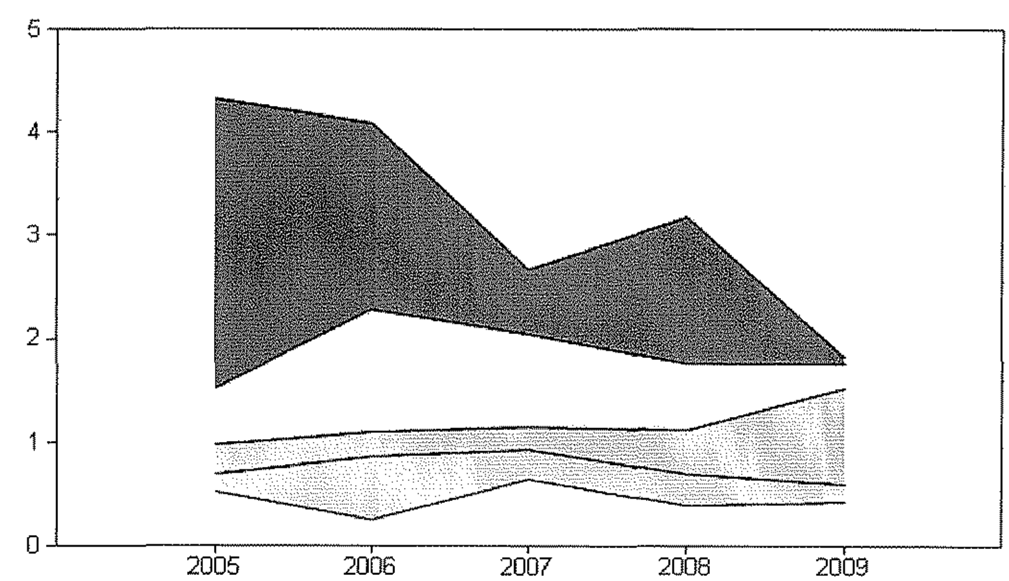


Graph 6-2: Region 1. SAIDI. Excluding Significant Events

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

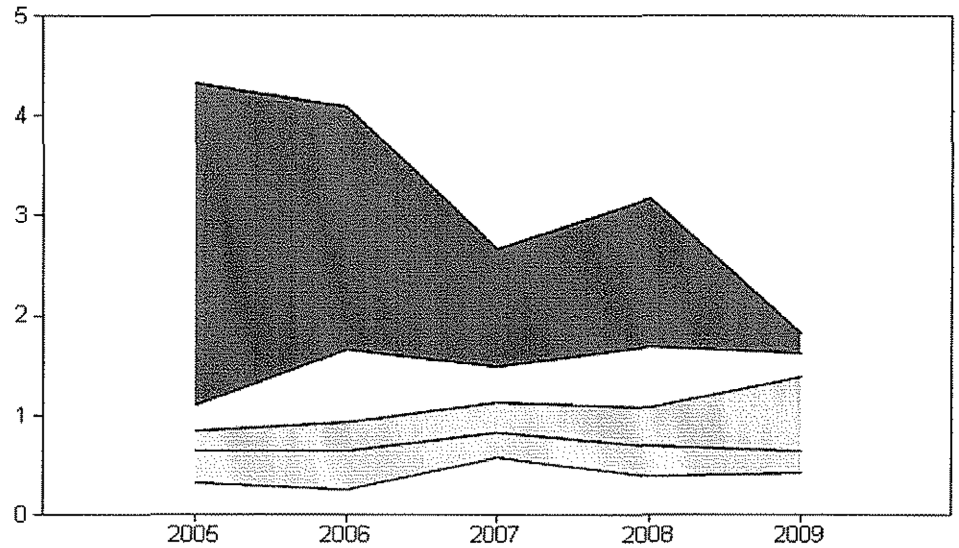


Graph 6-3: Region 1. SAIDI. Including All Events.

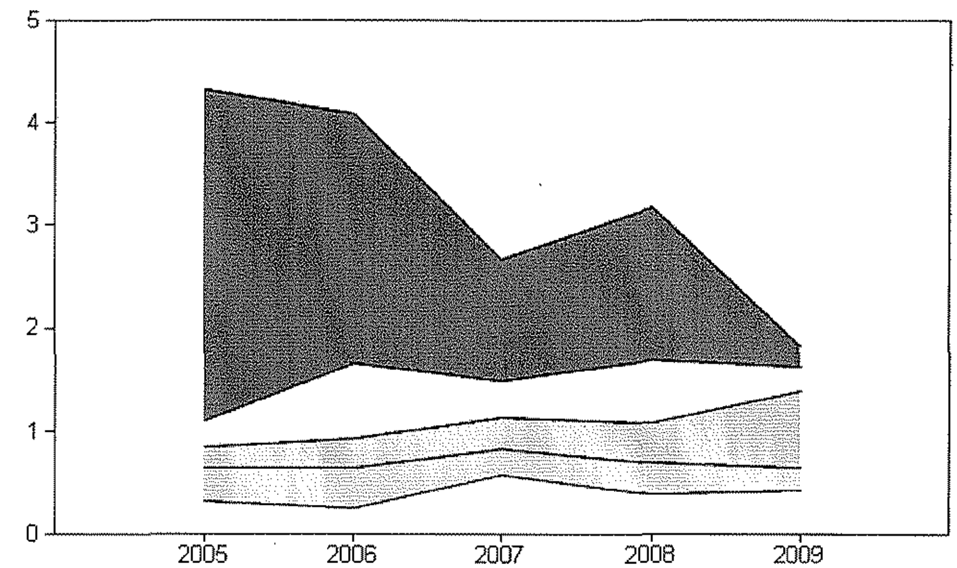


Graph 6-4: Region 1. CAIDI. Excluding MPE

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)



Graph 6-5: Region 1. CAIDI. Excluding Significant Events



Graph 6-6: Region 1. CAIDI. Including All Events.

Ontario Energy Board (Board Staff) INTERROGATORY #9 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref: Exhibit A/Tab12

(a) At page 4 of ExhA/Tab12/Sch.1, the evidence states that "The investment plan prepared during 2009 provided the basis for the 2011 and 2012 plans". Please describe the effect on the original plan of:

- The proclamation of the *Green Energy and Green Economy Act, 2009*; and
- The letter from the Minister of Energy to Hydro One dated September 21, 2009.

(b) In which investment category (Sustaining, Development, Operations and Shared Services) was spending reduced in order to accommodate green energy related demands on the transmission system?

(c) What tradeoffs would there be if there was a more aggressive program to renew existing infrastructure rather than expand to meet green energy needs? Please be specific with respect to projects proposed in this application.

Response

(a) The original plan was approved by Hydro One's Board of Directors in November of 2009 and already included consideration of the GEGEA and the Minister's letter. Given the long lead time for the development phase of transmission projects, the bulk of capital spending on projects in the Minister's September 21, 2009 letter will occur beyond the test years.

(b) The projects that are related to the passage of the GEGEA and the Minister's letter are all in the Development category. For the reasons stated in part a) above, the Development capital spending for green projects was planned as part of the normal project prioritization process as discussed in Exhibit A, Tab 12, Schedule 5, page 11.

(c) Hydro One's current infrastructure renewal programs have not been constrained by Green Energy initiatives, but by customer bill impact concerns. If the focus was changed to a more aggressive program on existing infrastructure renewal Hydro One could advance a number of the sustaining activities that are required to address issues associated with aging assets subject to the availability of cost efficient resources.

Hydro One would accelerate its renewal programs on power transformers and on end of life circuit breakers to enhance reliability. As well, there would be an effort to increase tower coating as these assets represent long term sustainment challenges. In addition, Hydro One would look at proactive replacement of insulators as defects are starting to materialize in greater numbers. Manageable amounts of added protections and controls would be scheduled for replacement based upon availability of scarce P&C resources.

Ontario Energy Board (Board Staff) INTERROGATORY #10 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref: Exhibit A/Tab12/Sch5 & Sch7

Please describe how Hydro One's Investment Prioritization Process and the resulting Investment Plan are affected by:

- Government policy and OPA input regarding the connection of renewable generation; and

- Concerns regarding affordability and the impact on electricity consumers of an increase in transmission rates.

Please indicate whether, in Hydro One's view, either of these two factors will delay investment that is necessary or desirable to preserve or enhance system reliability. Please explain your answer.

Response

As discussed in the response to Exhibit I, Tab 1, Schedule 9, there was little impact on the Investment Plan in the test years due to Government policy as the bulk of the Green investments will occur beyond the test years. In developing the capital investment plan, Hydro One considered advancing some other sustaining activities but customer impact issues took priority over the opportunity to advance sustainment programs.

Ontario Energy Board (Board Staff) INTERROGATORY #11 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref: Exhibit C & Exhibit D

(a) Please summarize the work (development, sustaining, operations) planned for the test years that is directed at preserving or improving the reliability of the transmission system.

(b) Please summarize Hydro One's plans for the next ten years for preserving or improving system reliability.

(c) What would be the early indicators of reliability problems with the transmission system? Have these indicators been observed in Hydro One's system? If yes, in which locations?

Response

(a) The following provides a description of the type of work planned to preserve reliability and improve reliability, as well as further definition of these terms in the context of the transmission system. It must be recognized that reliability is one decision criterion for investments and in a number of instances other factors also drive the need for investments. These other factors may include safety, life cycle cost, regulatory consideration, etc. The discussion below takes place in three segments, Sustaining, Development and Operations.

Sustaining

Sub-systems, equipment and components that make up a transmission system have been designed for specific levels of reliability and performance. For example, transmission lines are designed for a level of security against lightning outages, and generally that level of security increases with voltage. Equipment is typically rated to a level of performance based on electrical criteria, e.g., current, voltage. Activities that preserve reliability strive to restore the performance of equipment, electrical components or systems to as close to new as feasible when performance or reliability risks become unacceptable. The work involved to preserve or restore reliability can be grouped into three categories:

- Inspections and diagnostics required to asses and monitor the system, identify problems and correct defects.

- Major maintenance required to achieve full utilization of the expected life of an asset.
- Replacement of end-of-life assets required to preserve or restore reliability.

This does not mean that in some instances one cannot exceed the original design performance of a system through the replacement of outdated designs with new and more efficient designs. Generally, however, sustainment replacements do not fall into this category, with perhaps the exception of telecom and increased security investments, as noted below.

Improving reliability, on the other hand, strives to bring the reliability above the original design of the system thereby improving system security and customer reliability. These investments, for the most part, take place under Development or Operations and are discussed in greater detail below.

The following tables provide an overview of the investments where one of the primary drivers is to preserve and/or improve reliability.

Table 1: Sustaining OM&A Programs

Program	**Sub-Program**	**Preserve**			**Improve**	**Comments**
		Insp & Defect	**Refurb**	**Repl**		
Power Equipment	Preventative & Corrective	✓				
	Transformer & Breaker Refurb.		✓			
	Other Maintenance	✓			✓	Wildlife control improves
Ancillary Systems	Preventative & Corrective	✓				
	Other Maintenance	✓				
P&C, Monitoring	Re-verifications,	✓				
	Corrective	✓				
	Support Systems	✓				
Cyber Security		✓				
Telecom		✓				
Site Infrastructure	Security	✓				
Vegetation Mng’t	Line Clearing	✓				
	Patrol & Demand	✓				
Overhead Lines		✓				
Underground Cable		✓				

Note: Land Assessment and Remediation and Environmental Management Programs are not reliability driven and are not been included in the above table.

Table 2: Sustaining Capital

Program	**Project**	**Preserve**	**Improve**	**Comments**
Circuit Breakers	S1, S2, Other	✓		
Station Re-investment	S3 – Metal Clad	✓		
	S4 - Beck	✓		
	S5 – Abitibi	✓		
	S6,S7,S8,S9,S10 - ABCB	✓		
	S11 - Merivale	✓		
	S12 – NRC TS	✓		
Power Transformers	S13, S14, S15, S16, Other	✓		
Other Power Equip.	S17, S18, Other	✓		
Ancillary Systems	S19 – Station Service, Other	✓		
Protection, Control & Metering	S21, S22, S23 - Projects	✓		
	S24, S25, S26 - Programs	✓		
	Other Projects/Programs	✓		
Auxiliary Telecom	S27, S28. S29 DC Signaling &Tone	✓	✓	New technology
	S30 – Power Line Carrier	✓		
	Other Projects/Programs	✓	✓	Fault location improves
Cyber Security	S31 – Cyber Security, Other		✓	Added security
Site Facilities	S33 – Station Security		✓	Improved station security
Overhead Lines	S34, S35, S37, EOL+ Other Repl	✓		
Lines Re-Investment	A6P Refurb	✓		
Underground Cables	S39 – H2JK/K6J Cables, Other	✓		

<u>Development</u>

The majority of Development Capital work is required to connect generation and load to the transmission system, as outlined in Exhibit D1, Tab 3, Schedule 3, Projects D1 to D10, D15 to D23, and D28 to D45. Although these projects also provide improved reliability, it is not the primary driver. It should be recognized that the planning for these projects includes a review of the performance of the connecting system; where opportunities exist that are technically feasible and cost effective, reliability improvements are made.

The Development Capital work planned for the test years directed at preserving or maintaining the reliability of the existing transmission system includes: End-Of-Life Upgrades (Projects D11, D12, D13 and D24 to D27) and Risk Mitigation (Projects D47). Projects D12 and D13 also facilitates the connection of generation although it is not the primary driver.

Project D14 has both preserving and improving reliability aspects as it addresses an end-of-life cable replacement and provides for increase supply capacity.

Investments in Performance Enhancements (Project D46) improve reliability in a targeted manner to address delivery point performance outliers and poor performing assets. The Delivery Point Performance Outliers are discussed in Exhibit A, tab 13, Schedule 1, page 12.

Operations

Operations investments can preserve or improve reliability through ongoing maintenance of operating tools, modifications/enhancements of these tools or the installation of new equipment and tools to enhance operations and system effectiveness. The table below provides an indication of which investments improve or preserve reliability.

Table 3: Operations Programs/Projects

Program/Project	**Preserve**	**Improve**	**Comments**
OM&A			
Operations Support	✓		
Capital			
NMS Enhancements		✓	
Hub Site	✓		
Telemetry		✓	Improved alarms to manage system
Miscellaneous	✓	✓	Improved fault locating

(b) Hydro One plans to continue to renew its assets in a prudent and measured manner through its sustaining programs which are aimed at preserving reliability and bringing reliability closer to the as-new condition or original design reliability. It is expected that investment levels will need to increase over time in order to maintain the current reliability levels, let alone bring them closer to the as-new condition. As part of the asset renewal, Hydro One will introduce new technologies to facilitate improvements. This is expected to occur in the areas of telecommunications and protections and controls, which will provide added functionality and data to improve investment and operating decisions. As well, improvements in standards are expected to enhance existing reliability to some degree, for example, replacing the old wood arms on structures with steel results in added line security.

It must be recognized that in some areas unknowns exist regarding the rate of degradation and the extent of future problems and as the system ages the risks associated with emerging issues will increase. For example, the underground cable plant would be considered mature, with close to 20% having a service life of over 50 years. These cables are critical to the supply of the major centres in the province and it is imperative that these cables be monitored closely and problems identified early in order to respond before failure, as the consequences are significant. The situation is similar with protections and controls. In order to mange these and other reliability risks, Hydro One has adopted a monitoring and analytical approach as part of its asset management practices that takes into consideration all key elements of the electrical system. Additionally, Cornerstone Phase 1 and 2 are now complete and proposed developments include more robust analytic capabilities; it is expected that these improvements will provide the ability to identify asset degradation patterns at an earlier stage and improve the response to emerging problems.

From a development perspective, the majority of the Development Capital work takes approximately 3 to 5 years to execute; Exhibit D1, Tab 3, Schedule 3 provides a summary of the key work identified for the next 5 year timeframe. Beyond 5 years, many projects have yet to be confirmed. Development work is being undertaken on some of the 20 projects outlined in Exhibit C1, Tab 2, Schedule 4. The need for other Development work may be identified by the OPA's ECT process. This could provide the basis for future capital projects subject to Government direction, OPA support of need, and key approvals being obtained. Additional load and generation customer requests are expected to come forth and define new connection related capital projects. Future updates of the OPA's IPSP are expected to identify new projects and establish further direction for future Development Capital work.

In operations, timely updates and replacements of OGCC systems and equipment will continue to be undertaken, as these systems are essential for the operation of the system and to maintain reliability and customer supply. This includes the completion of the new Backup Control Centre in the first 5 years, enhancements to operating tools including NMS, as well as continuing to make the necessary changes and upgrades to meet NERC and NPCC reliability requirements and standards.

Improving reliability presents significant financial challenges, as the system has an inherent level of reliability based on the original design. Hydro One will continue to address outliers and will add or modify facilities in a cost effective manner as part of future development work. Some of the less costly investments include the addition of lightning arrestors and animal mitigation that address specific problems and in the process improve the performance of a local system. These types of improvements, however, have limited effectiveness on the overall reliability measures.

In summary, Hydro One's strategy includes the renewal of assets as a primary objective thereby preserving reliability, improving system reliability in a targeted manner where it is cost effective to do so, and improving reliability as part of expansion projects where opportunities arise. As well as targeting stations and lines assets, there will continue to be investments that improve system performance through operations, asset management practices and improvements to standards. In addition, Hydro One will continue to monitor system performance against its peers in order to assist in identifying areas in need of improvement.

(c) Hydro One has and continues to look for early indicators of reliability problems and, depending on the consequences of failure, action is taken in the appropriate time frame to avoid failure. A number of the investments included in this submission are scheduled based on information that would be considered an early indicator. For example, diagnostics carried out on transformers identify dissolved gas in oil that point to internal degradation; a number of the transformer replacements in this submission are based on these indicators. As well, system failure of protections can have severe consequences of cascading type outages that would affect large portions of the electrical grid. In consideration of these consequences, the integrity of protections is closely monitored and when the failure trend increases to unacceptable levels, protections are scheduled for replacement.

In other cases, it is the performance of equipment that can be an early indicator of reliability issues. A large portion of the Hydro One system has built-in redundancy, or more than one source for supply. Because of this redundancy, equipment failures generally do not result in loss of supply to customers. If, however, the rate and duration of equipment failures increase, redundancy will be reduced over longer periods of time thereby exposing customers to outages should a second or third element fail. Hydro One tracks the performance of its equipment and equipment that is likely to fail such as the CGE transformers and the Air Blast Circuit Breakers and these are replaced in a proactive manner to restore system security. Descriptions of these investments can be found in Exhibit D2, Tab 2, Schedule 3, S4 to S10 and S14.

Further to the above, the discussions below provide a more comprehensive view of early indicators of reliability issues associated with specific equipment and system components.

Hydro One's asset condition assessment, diagnostic and monitoring programs are designed to identify equipment and component reliability problems at an early stage, as well as assets in need of maintenance or replacement. Reliability management includes focus in five areas: anticipation of problems, condition assessment and diagnostics, reliability monitoring/investigations, identification of those defects that require immediate action and emergency response. Anticipatory action usually results in some form of investigation to identify the next steps, where asset condition assessment, diagnostics and reliability monitoring/investigations can provide an early indication of reliability problems. These are discussed below at an asset specific level, as well as Hydro One's experience on early signs of reliability problems.

Transmission Lines

Overhead Conductor and Shieldwire:

- Defective dampers point to vibration problems and the possibility of damage to conductors. Hydro One has observed this on a number of circuits in the southwestern parts of the province, where laminar wind conditions exist that cause high frequency conductor vibrations similar to that of a violin string. This issue is addressed under Planned Corrective Maintenance and Projects as noted in Exhibit C1, Tab 2, Schedule 3, page 53.
- Follow-up engineering assessments are completed to assess the severity and extent of the problem as well as conductor testing.
- Conductor samples are removed from old lines and analyzed in a laboratory to identify the more so normal degradation associated with corrosion and loss of strength and ductility. Early indications include depletion of the protective zinc layer with some corrosion of the steel wires, but strength and ductility are still acceptable.

Steel Structures:

- Any above ground issues are identified as part of our normal asset condition assessment programs with the more severe problems usually require engineering assessment to identify if, and to what extent member replacement is required.
- Most of the steel towers in Hydro One's system are supported on buried steel foundations. Early signs of issues include leaning structures and tower member distortion due to uneven settling, frost action or weakening of foundation members due to corrosion. All of these issues have been noted on our towers and are being managed under the respective OM&A and capital lines programs.

Wood Structures:

- Premature wood decay is identified as part of the asset condition assessment.
- Failure investigations have identified the type of wood arms that are more susceptible to rot and failure. A failure investigation identified the deterioration mechanism on the 230 kV Gulfport type structures as noted in Exhibit D1, tab 2, Schedule 3, page 58, starting on line 3.

Insulators:

- Hydro One tests a number of insulators each year on a sample basis and the number of failed units identified determines the likelihood of future reliability problems. The testing program has identified a high number of defective insulators on the 500 kV system in southern Ontario. This testing plus the fact that a few insulators have failed which has caused outages, has resulted in testing all insulators on these critical circuits and replacing those insulator strings that were identified to be defective. The sampling practice has also identified problems on some of the 115 kV and 230 kV lines requiring extensive insulator replacement.

- Specific insulator failures can point to system issues as was the case in the 1980s. Hydro One experienced a number of failures on dead end strings that pointed to what is referred to as cement growth - an expansion of the cement that bonds the steel cap to the porcelain and in the process causes the porcelain to crack. This problem exists on all Ohio Brass and Canadian Porcelain insulators manufactured between about 1965 and 1982. The degradation process is accelerated with dead-end insulators due to their somewhat horizontal arrangement and higher mechanical stresses than suspension insulators. This cement growth problem is now showing up in more suspension insulators and Hydro One's testing program is designed to identify those line sections at risk.
- Other early indicators of problems include a large number of flash marks on insulators and a high number of momentary outages. In many cases these indicators point to poor grounding.

Underground Cables:

- Sheath current measurements identify breaches in the outer protective layer, also referred to as the jacket of low pressure cables. These breaches can result in degradation of the lead sheath and when this occurs, the cable may need to be replaced. This is the case with circuits H2JK and K2 identified in Exhibit D1, tab 3, Schedule 2 page 2, line 22.
- Oil top up identifies oil leaks that can point to a damaged cable sheath.
- Polymerization tests on insulation paper are also carried out. When the insulation is identified to be defective this will usually lead to failure and replacement of the cable.
- Dissolved gas in oil provides an indication of electrical discharge and possible damage to the insulation. Hydro One has drained and replaced oil in cables that have a high concentration of dissolved gas to prevent damage to the insulation.
- Cathodic protection readings provide an indication if corrosion is taking place on high pressure oil filled pipe type cables.

<u>Stations</u>

Station reliability is primarily driven by the performance of circuit breakers, transformers, and protection systems whereas other station assets such as station service and disconnect switches contribute to system reliability to a lesser extent. It must be recognized, however, that station service assets can have a pronounced impact on the performance of the primary equipment.

Macro assessment of future performance can be made by:

- assessing historic performance at both population and individual asset-levels

- assessing asset demographic information at the population and individual asset levels

Leading indicators for performance are outlined below at an asset-specific level for circuit breakers, transformers, and protection schemes.

Circuit Breakers
- Consideration of the number of fault and switching operations since the previous maintenance or major overhaul can be used to predict when individual assets may become less reliable. This may trigger maintenance or replacement of the asset, depending on various factors, including:
  - Oil Circuit breakers in general purpose positions are typically maintained when they surpass the number of allowable operations
  - Air blast breaker performance will degrade significantly if the major rebuilds are not completed approximately every 20-30 years
  - Breakers in capacitor or reactor switching positions see a high number of operations with severe duty and there is a very strong correlation to number of operations and degradation of breaker reliability.
- Preventive maintenance test results provide condition information which is generally a leading indicator of performance degradation
  - Oil and SF6 testing is used to identify symptoms of incorrect operation (contact burning, partial discharge, dielectric degradation, etc.)
- Technical Obsolescence and availability of spare parts and service is a leading indicator of performance degradation. As defects are identified through routine operation and maintenance activities, availability of parts and service affects Hydro One's ability to mitigate performance degradation in terms of both frequency and duration of outages. This is particularly true for air-blast breakers and early generation oil circuit breakers.

Specific investments that are targeted at sustaining reliability of circuit breakers are noted in Exhibit D1, Tab 3, Schedule 2, S1 – S11.

Transformers:
- Oil analysis is completed as part of the preventive maintenance program, and provides insight into the aging of the transformer's main insulation systems. This is the primary leading indicator for transformer reliability.
  - Dissolved gas analysis (DGA) provides an indication of defects within a transformer and the associated tap changer that will eventually lead to failure.
  - Assessment of Furanic compounds can provide an indication of the strength of the transformer's insulation, failure of which will ultimately cause the transformer to fail.
  - Assessment of the oil condition (dielectric, acidity, moisture content) and how it affects the cellulose insulation systems.

- Engineering design review studies which utilize modern design tools to compare capabilities of in-service equipment against designed functionality. Having a clear understanding of an asset's capabilities vs. the intended operation allows for assessment of future reliability impacts
  - A design review has identified a series of deficiencies with the 19 230-44kV 125MVA CGE transformers which are being replaced under the S14
  - Limitations of a group of the 500kV autotransformer population has resulted in the 500kV autotransformer remediation program outlined in Exhibit C1, Tab 2, Schedule 3 page 18
- Assessment of historical transformer loading and projected load growth
- Assessment of the number of tap changer operations relative to expected design life. This provides an indication of internal damage and in many cases will determine end of life of the tap changers.

Specific investments that are targeted at sustaining reliability of transformers in Exhibit D1, Tab 3, Schedule 2 include: S12 – S15.

Protections:
Failure of protection systems will cause serious reliability problems for the transmission system as described on page 54 of Exhibit D1, Tab 2, Schedule 1. For older protection systems that are not self diagnosing and are the majority of the protections in service today, the primary approach to detect early indications of pending protection system failures is to track the failure rates of specific makes and models of relays observed from the periodic re-verifications and event analyses. An elevated rate of failure for a particular make and model of relay relative to the rate expected in a normal lifetime is an indication of pending end of life. The degree to which the failure rate is elevated is a primary factor in the Health Index which is used to schedule the protection replacement program identified in Exhibit D2, Tab 2, Schedule 3, S24 and S25. Over the past decade, this approach has been used to target about 10 specific makes and models of protective relays with increasing failure rates and schedule their replacement before they would cause a noticeable deterioration in transmission reliability.

Controls:
The loss of the ability to monitor and control a transmission station can also cause serious reliability problems for the transmission system as a result of the loss of situational awareness and the loss of the ability to respond to alarms and contain evolving events on the system. The critical asset in the station control system is the Remote Terminal Unit (RTU). Observed trends in failure rates are also used, along with other factors to detect pending end-of-life of RTU's; replacement of these units is scheduled before their failure can impact transmission reliability. Over the past decade, six makes and models of RTU have been identified and replaced before they could cause deterioration in transmission reliability.

Telecommunications:
Telecommunications support both protections and control and hence failure of telecommunications can have serious impact on transmission reliability for the same reasons identified above. It must also be recognized that these systems connect directly to the OGCC; any loss in security or communication will have a significant impact on the ability to operate the system resulting in serious reliability consequences. The health of telecommunications devices and systems are also monitored using a similar approach to that of protections and RTU's.

Over the past decade, replacements have been completed on most of the power line carrier based and microwave based telecommunication systems before their failure could cause deterioration in system reliability. Failure rates on tone channel devices were observed to be increasing in 2001 and a replacement program for them was subsequently implemented. To date, 200 out of 370 of these units have been replaced before their failure could cause transmission outages. Over the past decade, failure rates and repair time on Direct Current remote trip channels has been observed to be deteriorating with effects on transmission reliability. A program has been put in place for their replacement as noted in Exhibit D2, Tab 3, Schedule 2, page 43, line 15.

Operating Systems & Tools:
Operating tools are monitored regularly and defects logged, i.e. defective routers, hard drives, etc. As well, vendor support is tracked and when there are indications that the support will cease, plans are made to address this issue. Through the defect monitoring Hydro One has had to replace hard drives and loss of vendor support has resulted in the replacement of routers.

Ontario Energy Board (Board Staff) INTERROGATORY #12 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref: Exhibit A/Tab12/Sch.5, Exhibit C & Exhibit D

A recent outage in Toronto on July 5, 2010 originating at Manby TS has been attributed by some media reports to Hydro One's aging transmission system and equipment.

(a) In Hydro One's view, is there a connection between the incident at Manby TS and the age of the system or equipment?

(b) Were there any previous indications in Hydro One's asset assessment algorithms predictive of imminent failure at the Manby TS and if so what corrective measures were taken? If Hydro One's asset assessment mechanisms were not able to predict this occurrence what adjustments to these mechanisms are being contemplated?

(c) Please provide an example of a "severe" event and an example of a "catastrophic" event as mentioned at page 5 of Ex. A/Tab12/Sch.5. Into what column of Table 2 at page 10 of Exhibit A/Tab 12/Sch.5 would the Manby outage fall?

(d) Is the Manby outage incident symptomatic of a lack of reliability in the transmission system in general?

(e) In Hydro One's view, is supply to Toronto sufficiently reliable? Is the restoration of that supply (3 hour outage) acceptable for a large urban centre?

(f) What are the causes of any lack of reliability in Toronto's electricity supply? Can the lack of reliability be addressed through transmission projects?

Response

(a) It is Hydro One's view that the incident at Manby TS does have some correlation to the age of the system, but not pronounced, as the oil circuit breaker that failed had been in-service for 32 years which is below the normal end of life range for breakers of this type. One would expect some signs of aging with a breaker in this age group, as the degradation process would have started as a result of thermal cycling, number of operations, electrical loading, etc. and any defects would amplify over time eventually leading to failure. In this particular case, the degradation process occurred relatively quickly and resulted in a premature failure.

(b) Hydro One is going to great lengths to understand the root cause of this event, however the analysis and investigation at this time is not complete. When all of the facts have been revealed, Hydro One will assess the suitability of its inspections and diagnostic assessments and will make the appropriate adjustments to protect against a reoccurrence. It is noted that maintenance for the subject breaker was up to date without indication of impending failure.

(c) From a reliability perspective, the Manby TS incident would be considered a severe event as the Transmission Unsupplied Energy was above 4 system minutes and impacted about 1550 MW of load that was restored in stages over a 3 hour period. From a regional supply reliability perspective, a catastrophic event would result in unsupplied energy of 8 system minutes, or an event that would have been about 2 to 3 times that of Manby TS. An event such as this would impact not only the western parts of Toronto, but extend into parts of Mississauga, Oakville and Brampton.

The Manby outage would fall into the severe category with an unlikely probability.

(d) No, as this is considered a rare occurrence.

(e) It is Hydro One's view that the supply to Toronto is sufficiently reliable. The plan in progress and work proposed in this rate submission will maintain and enhance reliability. We consider the Manby TS outage as highly abnormal and would not expect that a breaker would fail in such a highly explosive manner. Of note is that the failure of the breaker itself did not result in a direct interruption of load. It was the tripping of the adjacent circuits and equipment due to oil and debris contamination from the explosion that resulted in the loss of load. This type of outage is very unusual. Observers noted that flames shot up over 30 meters and smoke and soot engulfed parts of the station causing adjacent electrical equipment to fault.

Hydro One is concerned whenever transmission system issues impact upon the reliable supply of electricity to its customers; these concerns are amplified when large numbers of customers, such as in an urban centre, are impacted. However, given the extreme nature of the Manby TS event as well as the time required to extinguish the fire and create a safe situation to allow staff to restore faulted equipment, Hydro One believes that the restoration time was acceptable under these conditions.

(f) Hydro One does not see any lack of reliability in the Toronto's supply from a power system design perspective. The transmission system to Toronto meets or exceeds all applicable NERC standards, NPCC criteria and IESO market Rules including the Ontario Resource and Transmission Assessment Criteria (ORTAC) with respect to the adequacy and security of supply. Sustaining programs and projects as proposed in this rate submission include the "end of life" management of assets that will ensure that reliability levels will be maintained.

Please refer to Exhibit D2, Tab 2, Schedule 3 for investments planned for the Toronto area. Development projects are included in Investment Summary Documents D11, D12, D13 and D14. Sustaining projects include S3, S8, S13, S15, S28 and S39.

On a more specific note concerning the type of breaker that failed, Hydro One has a replacement program in place to remove oil circuit breakers that present significant reliability risks as detailed in Exhibit D1, Tab 2, Schedule 3, Page 9, line 6 to 18. The removal of these breakers will reduce the likelihood of a severe explosive failure and a reoccurrence of a similar incident to Manby.

In addition, Hydro One is replacing protection and control systems as noted in Exhibit D1, Tab 3, Schedule 2, page 38 starting at line 17 and page 39 starting at line 1 in order to ensure the system shuts down in a safe, coordinated and predictable manner when incidents such as Manby occur. Had the protection systems been defective and not operated as designed, this would have resulted in added equipment damage and the outage would have propagated to other connecting stations thereby impacting many more customers. Protection systems are designed to contain these types of power disturbances and it is imperative that those protections that are nearing end of life be replaced in a proactive manner as noted in the above references.

Ontario Energy Board (Board Staff) INTERROGATORY #13 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref:(a) Letter from Hydro One Networks filed on December 3, 2009 in regard to "Approved Deferral Account for IPSP & Other Long Term Projects Preliminary Planning Costs – Additional Projects"
Ref:(b) Board Decision with Reasons, May 28, 2009 Re Hydro One's 2009 and 2010 Transmission Rates (EB-2008-0272)
Ref:(c) Proceeding (EB-2008-0272)/Exhibit C1/Tab2/Sch3/p7/ Table 1/Item 15 – New Supply to City of Toronto

In its letter of December 3, 2009, Hydro One requested the inclusion in the deferral account established by the Board, preliminary planning costs for IPSP-related and other long term capital projects. The description of the project "New Supply to City of Toronto", Item #15 at Reference (c), identified expenditures of $1.4 million in each of the two years 2009 and 2010.

(a) Please provide a detailed report on this project describing the work that has been completed to date including any preliminary planning and engineering undertaken in 2009 and 2010.

(b) Please provide an update to the cost estimate of $600 million quoted for the "Central and Downtown Supply", described in Reference (a).

Response

(a) The "New Supply to City of Toronto" identified in Reference (c) has been put on hold as the OPA has not reconfirmed the need for this project following several recent developments, as described in Board Staff Interrogatory 14, part c). The project was therefore not included in the current filing. No planning or development work was carried out in 2009 or is planned to be carried out in 2010.

(b) As mentioned above, the project is on hold and estimates have not been updated.

Ontario Energy Board (Board Staff) INTERROGATORY #14 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref: IPSP Proceeding EB-2007-0707/Exhibit E/Tab5/Sch5/Section 5.3/p31-42

In Section 5.3, pages 31-36, of the Reference above, there is a description of three transmission alternatives:

- 5.3.1 Parkway Station to Hearn Station Option
- 5.3.2 Beck Station to Hearn Station Option
- 5.3.3 Bowmanville Station to Hearn Station Option.

At pages 36-39, section 5.3.4, there is a "Preliminary Review of the Transmission Solutions", and at section 5.3.5 there is a "Transmission Solution Project Schedule".

(a) Please confirm whether any of these options is under construction or planned to be under construction in the test years.

(b) Please provide an update to the description of the three options described section 5.3.4, and an update to their cost estimates.

(c) Please provide an update to "Transmission Solution Project Schedule" shown in section 5.3.5.

Response

(a) The OPA has not confirmed the need for these projects. No work is planned on any of these options during the test years.

(b) The OPA has not confirmed the need for these projects. No work is being done on these options and no updates are available.

(c) At the present time, no update is available. Since the publication of the IPSP, a number of developments have occurred that have led to alternative viable options within an integrated plan and therefore the originally specified work did not need to be completed in accordance with the original schedule. These developments include:

- Lower than expected demand due to the recession.
- Good progress on conservation programs and initiatives, including prospects for demand response (DR).

- Good prospects for distributed generation (as indicated in the July 2009 report prepared by Navigant Consulting).
- The inclusion of resource-based alternatives that can be accommodated given the short circuit upgrades proposed for Leaside TS, Manby TS and Hearn TS.

Further studies will establish timing and scope of work for this area.

Ontario Energy Board (Board Staff) INTERROGATORY #15 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref: Proceeding EB-2007-0707/Exhibit E/Tab5/Sch5/Section 7. - Near Term Needs/p41-42

At page 42 (corrected on October 19, 2007), lines 11-22 of the reference above, it is stated:

"To meet the potential range of needs facing Downtown Toronto, the OPA identifies the need for the following development work in the near term:

1. Technical and survey studies to assess potential performance issues and costs, and to develop a plan for large scale application of distributed generation in Downtown Toronto;
2. Investigations to explore the feasibility and scope of work of increasing the short circuit capacity at Leaside, Manby and Hearn stations;
3. Engineering and technical studies to establish the scope of facilities and detailed costs for the transmission options;
4. Due diligence study for suitability of VSC HVDC technology for supply to Downtown Toronto; and
5. Initiation of the work to obtain the necessary EA approvals for the preferred plan."

(a) Please describe the "development work" that was completed for each of the 5 items identified.

(b) For any of the five items, where the "development work" has not been completed, please provide:
   - reasons why such work was not undertaken;
   - an indication as to whether Hydro One intends to complete this work;
   - the schedule for completion.

Response

(a) The status of the five items is as follows:

1. Hydro One has not carried out any studies on developing a plan for large scale applications of distributed generation in the City of Toronto.
2. This work is underway as described in the evidence in Exhibit A, Tab 11, Schedule 4 and Exhibit D1, Tab 3, Schedule 3 and in other Interrogatory responses.
3. No work has been carried out.
4. No work has been carried out.
5. No EA work has been carried out.

(b) Apart from the Hearn, Leaside and Manby station short circuit uprating, the need for the work as described, has not been confirmed and the work is on hold. Hydro One will initiate the work once the need has been confirmed by the OPA. At present, there is no schedule for the work.

Ontario Energy Board (Board Staff) INTERROGATORY #16 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Ref: (a) Proceeding EB-2007-0707, OPA's response to Board Staff Interrogatory 38, dated June 18, 2008/Exhibit I/Tab1/Sch 38
Ref: (b) Transmission System Code ("TSC")

In Table 1, page 2 of Reference (a), the estimated cost for the project "Central and Downtown Toronto Supply" is $600 million in the year 2007.

(a) Please indicate whether Hydro One approached Toronto Hydro to explore financing arrangements for each of the transmission alternatives. Please explain your answer with reference to relevant sections of the TSC.

(b) Please provide a summary of any financial arrangement(s) reached.

Response

(a) Hydro One has not approached Toronto Hydro to explore financing arrangements.

(b) There are no financial arrangements to report.

Ontario Energy Board (Board Staff) INTERROGATORY #17 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

17) Ref: Exhibit D1/Tab3/Sch3 and Exhibit A/Tab11/Sch4

It is generally accepted that the total load in the Toronto Downtown area[1] is approximately 2000 MW. One of the planning criteria when considering a third supply for Toronto Downtown is to ensure that for a single contingency, the two other supply sources can carry the full load of 2000 MW. Generation, including distributed generation, is considered a substitute or proxy for a third transmission circuit, if it can be developed in time and with sufficient dependability to meet the load.

To assess this possibility, please provide two sets of information, one for the area served by Leaside T.S, and one for the area served by the Manby Sector:

(a) For existing generation in each area: the location, size in (kW or MW), and generation type of each site (e.g., gas-fired cogen, wind, photo-voltaic);

(b) For generation in each area for which FIT contracts are already signed: the location, size, and generation type of each site;

(c) For generation in each area where FIT contracts are anticipated but awaiting transmission reinforcement: the location, size, and generation type of each site, and the nature of the reinforcement required.

Response

a) The existing generation is given in the Table below:

Number	Sector	Station	Type	Size (kW)
1	Leaside	Basin	Photovoltaic	36.0
2	Leaside	Bridgman	Unknown	355.0
3	Leaside	Cecil	Gas Turbine	6,000.0
4	Leaside	Cecil	Bi-Fuel Reciprocating Engine (Natural Gas & Diesel	1,275.0

[1] Proceeding EB-2009-0139, Exh Q1/Tab4/Sch 1-1/Execeutive Summary Presentation bb Navigant to the Ontario Power Authority and Toronto Hydro, dated July 28, 2009, page 2, first paragraph

Number	Sector	Station	Type	Size (kW)
5	Leaside	Charles	Photovoltaic	5.5
6	Leaside	Esplanade	Gas Engine	150.0
7	Leaside	Esplanade	Gas Turbine	7,012.5
8	Leaside	Hearn	Portlands	585,000.0
9	Leaside	Terauley	Diesel Engine	2,300.0
10	Manby	John	Diesel Engine	1,500.0
11	Manby	John	Diesel Engine	1,800.0
12	Manby	John	Steam	11,000.0
13	Manby	Strachan	Wind Turbine	750.0
14	Manby	Strachan	Gas Engine	1,600.0
15	Manby	Strachan	Photovoltaic	100.0
16	Manby	Wiltshire	Diesel Engine	500.0
			SubTotal (Projects > 5kW):	619,384
			Subtotal (66 Projects <= 5kW):	131
			TOTAL (kW)	**619,515**

b) Below is a summary of FIT applications which have applied to the Leaside and Manby 115kV systems as of July 29th, 2010, and have either been offered FIT contracts, or may receive a contract offer pending application review. All applications were for Solar PV installations.

Sector	Contract Offered		Under Review	
	# of apps	total kW	# of apps	total kW
Leaside	14	1458	3	274
Manby	19	3290	5	287

Additionally, as of July 26th, 2010, 63 micro-FIT applications, totaling 147 kW, have been offered contracts within the areas of Central Toronto and East York. Due to the simplified nature of these applications, data has not been collected to link these projects to specific transformer stations or to the Leaside or Manby systems.

c) The only FIT application which has so far been denied a contract for connection to either the Leaside or Manby system is a 9.9MW biogas facility which applied for connection to the Leaside system. This application will not be eligible for a contract until the short circuit level constraint at Leaside TS is removed. As of June 4th, any new applications for connection to the Leaside system, even those which qualify as Capacity Allocation Exempt, will exceed the short circuit capacity of Leaside TS.

Ontario Energy Board (Board Staff) INTERROGATORY #18 List 1

Interrogatory

Issue 1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable?

Ref: Exhibit A/Tab 2/Sch 1

Please provide the detailed calculation used to determine the customer bill impacts found in the Notice published by Hydro One.

Response

The average customer bill impacts were estimated by determining the transmission Rates Revenue Requirement impact and factoring in transmission's share of the total bill.

The data used to determine the 2011 and 2012 impacts shown in the Notice and referenced in Exhibit A, Tab 2, Schedule 1, page 1, is provided below:

	2010	2011	2012
OM&A		436.3	450.0
Depreciation		302.9	334.8
Income tax		80.9	70.0
Cost of Capital		625.3	692.6
Revenue Requirement	**1,257.3**	**1,445.5**	**1,547.4**
Increase over prior year		**15.0%**	**7.0%**
Less: External Revenues	(18.0)	(31.3)	(24.7)
Less: Export Revenue Credit	(12.0)	(10.1)	(10.2)
Less: Other Cost Charges	(20.3)	(10.0)	2.6
Add: Low Voltage Switchgear (LVSG)	10.8	11.8	12.5
Rates Revenue Requirement	**1,217.7**	**1,405.8**	**1,527.5**
Increase over prior year		**15.4%**	**8.7%**
Impact of load forecast change		0.3%	1.1%
Rates Revenue Requirement Impact		**15.7%**	**9.8%**

The information shown above up to the row "Rates Revenue Requirement" is included in Table 2 and Table 4 of the pre-filed evidence at Exhibit E1, Tab 1, Schedule 1.

The 1.2% and 0.7% average customer's total bill impact in 2011 and 2012 noted in Exhibit A, Tab 2, Schedule 1, page 1, and referenced in the Notice published by Hydro One factors in that transmission represents about 7.5% of the total bill.

This 7.5% figure was arrived at using the following information:

Transmission as a % of Total Bill (2009)		
	¢/kWh	Source
Commodity	6.217	IESO December 2009 Monthly Market Report page 26
Wholesale Market Service Charges	0.609	IESO December 2009 Monthly Market Report page 26
Wholesale Transmission Charges	0.772	IESO December 2009 Monthly Market Report page 26
Debt Retirement Charge	0.7	IESO December 2009 Monthly Market Report page 26
Distribution Service Charges	<u>2.06</u>	$2.788 B-2008 OEB Yearbook page 7/135.187 TWh sales (per IESO data)
Total	10.36	
Transmission as a % of Total	7.5%	

Therefore, 7.5% of the Rates Revenue Requirement impact of 15.7% results in a 1.2% estimated increase in bills for 2011. For 2012, 7.5% of the Rates Revenue Requirement impact of 9.8% results in a 0.7% estimated increase.

The calculation of the estimated dollar increase in a residential customer's total monthly bill is provided in the response to interrogatory Exhibit I, Tab 4, Schedule 9.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #19 List 1</u>

<u>Interrogatory</u>

Issue 1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable?

<u>Ref: Exhibit A/Tab11/Sch3/p1-9.</u>

Hydro One has stated in evidence that it intends for revenue requirement purposes to adopt modified IFRS in 2012 in a manner consistent with the Board Report of EB-2008-0408, with two exceptions. The Board Report states on page 25 that the utility should describe the aggregate impact of any changes arising from the adoption of IFRS as well as identify the impact arising from individual IFRS drivers. Without disclosing amounts, Hydro One appears to be stating that it will offset the impact of adopting IFRS in the two areas where it may arise by adopting the two exceptions (overhead capitalization and group depreciation) thereby suggesting that it is unnecessary to state the impact.

a) Please confirm that the above is an accurate description of how Hydro One is positioning its application for 2012 and its adoption of IFRS.

b) Please explain how the treatment differs in 2012 from 2011 given Hydro One's comments that the assumption is that MIFRS equals CGAAP with two exceptions.

c) Please confirm that there are no other impact areas arising from the transition to IFRS except as may arise from other changes to IFRS for which Hydro One has requested a separate deferral account entitled *Impact for Changes in IFRS Account* (for 2012 only).

d) Please state the estimated aggregate impact of adopting IFRS in 2012 as required in the Board Report from EB-2008-0408, page 25, without the exceptions requested and state the mitigation actions that Hydro One would propose should any such impact be material. This estimate should include the full secondary effects of changes to the amount in Property Plant and Equipment on depreciation expense and return on rate base and disclose the component cost drivers making up the aggregate impact.

Response

a) Board Staff's description of the basis of Hydro One's 2012 submission is not accurate. Hydro One submitted a request for an exception to the guidance on accounting for overhead costs that was included in the Board's February 24, 2010 letter to Distributors. In addition, Hydro one requested a deferral account for premature asset retirement losses. The two requests do not offset.

   The exception requested was based on the materiality of the expected rate impact of applying IFRS overhead accounting and the fact that no other offsetting IFRS adoption impacts are expected. Some Distributors expect to experience an offsetting reduction in their revenue requirement calculation from reduced depreciation expense. Hydro One will not experience this offset as it already uses an asset hierarchy which is IFRS-compliant in respect of asset componentization. Further, service lives under Canadian generally accepted accounting principles have been based on previously approved independent asset service life studies, the recommendations of which were implemented in 2007.

   The estimated financial and rate impacts of implementing IFRS without the requested overhead accounting exception was not included in the Company's submission as work to estimate the impact was still in progress at the time of filing. This assessment is still on-going.

   Note that Hydro One no longer expects that this exception will be needed for 2012 as it anticipates the date of IFRS adoption will be deferred to 2013, consistent with the proposal included in the July 28, 2010 exposure draft released by the Canadian Accounting Standards Board. This exposure draft entitled "Adoption of IFRSs by Entities with Rate-Regulated Activities" allows qualifying entities to adopt IFRS in 2013 rather than in 2011. We anticipate the proposals in the exposure draft will be finalized by year-end 2010 given the need for an expedient solution for rate-regulated entities in Canada. As such, Hydro One anticipates deferring implementation of IFRS to 2013 given that significant changes in the accounting for rate regulated activities could result. Hydro One considers it probable that the Board will consider an analogous change in the implementation date of IFRS for regulatory purposes. Beyond 2012, it is possible that a request for a similar exception to the Board's overhead accounting guidance will be made in a future cost of service rate submission.

b) Hydro One's submissions for 2011 and 2012 were prepared on the same basis, after consideration of the requested above overhead accounting exception and the variance account for premature asset retirement losses. The request for a variance account for premature asset retirement losses is discussed in Exhibit I, Tab 1, Schedule 90, part b. Hydro One has not identified any additional significant impacts on the revenue requirement from adopting IFRS.

c) The proposed "Impact for Changes in IFRS Account" is analogous to that approved by the Board in EB-2009-0096, and was intended to capture the aggregate impact on the 2012 revenue requirement resulting from any changes in IFRS accounting standards or the interpretation thereof, whether by the accounting profession or by the Board and its Staff when such change occurs after the date of Hydro One's submission. It was not intended to capture the impact of known IFRS issues if Hydro One omitted them from its submission. If IFRS implementation is delayed for regulatory purposes, Hydro One would not require this account for 2012.

d) Based on its IFRS implementation analysis performed to date, and the current IFRS accounting standards, the estimated aggregate impact of adopting IFRS in 2012 will be an increase in revenue requirement of approximately $200 million for 2012. This is a very high level estimate of the impact based on current business and accounting assumptions and current interpretations of IFRS. By necessity certain assumptions have been made to translate the expected reduction in 2012 capital expenditures from adopting IFRS into a rate base and revenue requirement estimate. For example, fixed asset additions, depreciation expense and CCA have all been estimated based on high level assumptions.

With the proposed deferral of implementation of IFRS for rate-regulated entities to 2013, the accounting that Hydro One would follow under IFRS in the future may be very different. As such, the impacts of adopting IFRS on Hydro One's results may change significantly.

This increase is primarily attributable to the after tax impact of increased OM&A and reduced capital expenditures attributable to changing Hydro One's capitalization policy to conform to the current requirements of IAS 16 "Property, Plant and Equipment." The dollar impact of losses on premature retirement of fixed assets cannot be predicted but such losses are reasonably likely to be material. As stated in the Company's application, other impacts of adopting IFRS in 2012 are not expected to be material at this time based on current interpretations of IFRS. It should also be noted that a delay in IFRS implementation to 2013 is reasonably likely to occur following recent actions taken by the Canadian Accounting Standards Board to propose such a delay, to be exercised at the option of qualifying rate regulated utilities. This delay means that the accounting for rate-regulated activities could still change significantly.

As noted in Exhibit I, Tab 1, Schedule 20, Hydro One continues to refine its capitalization policy based on interpretations of IFRS. As well, Hydro One continues to assess all reasonable accounting and business process changes to continue refining its capitalization policy. We anticipate that after all reasonable measures have been taken there could still be an on-going material shift from capital to OM&A.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #20 List 1</u>

<u>Interrogatory</u>

Issue 1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable?

<u>Ref: Exhibit A/Tab11/Sch3/p1-9.</u>

The first of the two exceptions described on page 5 beginning at line 20 is a deviation from the specific requirement to apply IAS 16, Property Plant & Equipment, as set out in the Board's Report from EB-2008-0408 and the Board's clarification letter posted on the Board's website on February 24, 2010. Hydro One describes this exception as affecting capitalized training cost, CSF&S and indirect line management and supervision costs. Hydro One states that these costs are "a likely material classification shift of Hydro One's expenditures from capital to OM&A". Hydro One also states that this change "cannot be mitigated without a significant and sustained annual rate increase." Hydro Ones states that they have based their proposal on "legacy practices including supporting independent studies based on the regulatory principles of cost causality and benefit".

a) Please identify the amount attributed to this exception in 2012 and the amount proposed to be capitalized in 2011 under existing policy for the same categories of cost. Please provide the amounts for each of the three sub-categories of cost identified by Hydro One.
b) Please identify the business actions that would be taken by Hydro One to mitigate the impact of the change in capitalization, such as those mentioned at page 16 of the Board's Report (EB-2008-0408)
c) Please identify any further rate mitigation measures that may be required..
d) Please provide copies of the independent studies referred to in the exhibit and indicate whether they pre-date the decision to implement IFRS in Canada by the Canadian Accounting Standards Board.
e) Please describe whether Hydro One capitalization policy draws any distinction between training cost incurred for initial staff of new facilities and ongoing training costs, and provide rationale for capitalization of any ongoing training costs.
f) Please state the amount of "immediate and sustained annual rate increase" that would arise from adoption of the Board's policy as stated in EB-2008-0408 and the letter of February 24, 2010 and demonstrate its materiality.

Response

a) For the three specific categories noted, the current estimate of the amount requested for continued capitalization as an exception in 2012, for each sub-category of cost is estimated as follows:

Sub-component	($'s in millions)
Training	12
Line Management & Supervision	19
CSF&S & Asset Manager	121

This estimate is based on Hydro One's work in this area to date and continues to be subject to future change prior to the implementation of IFRS. Note too that on July 28, 2010 the Canadian Accounting Standards Board released an exposure draft entitled "Adoption of IFRSs by Entities with Rate-Regulated Activities" that allows qualifying entities to adopt IFRS in 2013 rather than in 2011. If the option is finalized, Hydro One anticipates deferring implementation of IFRS to 2013 given that significant changes in the accounting for rate regulated activities could result.

The analogous amount proposed to be capitalized in 2011 under CGAAP (i.e. the same overhead accounting policy as that requested as an exception), for the same three sub-categories is estimated as follows:

Sub-component	($'s in millions)
Training	21
Line Management & Supervision	29
CF&S & Asset Manager	126

Training and Line Management costs are partially disallowable under current IFRS while CF&S and Asset Manager costs are currently assumed to be entirely disallowable as capital under IFRS as it stands today.

b) Hydro One has continuously refined its capitalization policy since the date of its submission to better qualify amounts for capitalization under current IFRS. This process leads to a reduction in the original impact of adopting an IFRS-based capitalization policy. Some additional amounts for capitalization could still be identified as the Company continues to assess all reasonable accounting and business process changes.

However, even after all reasonable accounting and business process alignment steps have been taken in the Company, significant expenditures could still not be allowable as capital once IFRS is adopted. We would anticipate these to include most shared corporate functions and services expenditures that are currently allocated to the Company's subsidiaries and businesses under approved causality and benefit studies.

c) As the Company expects that its corporate functions and services and some other overhead amounts will be disallowed as capital and will instead be classified as OM&A following the adoption of IFRS, there will be a need to address mitigation to avoid an adverse rate impact. If IFRS remains unchanged in two years, this accounting impact would represent a permanent shift in expenditure classification. Hydro One's view is that this impact is best addressed by the Board approving a continuance of the legacy overhead accounting allowed under Canadian generally accepted accounting principles (CGAAP). This exception would represent a modification to IFRS as applied for regulatory accounting purposes for Hydro One's Transmission Business.

d) Hydro One has provided copies of the relevant Black and Veatch (formerly Rudden) studies on shared cost allocation and capitalization; please refer to Attachments 1 and 2 respectively of this exhibit. Updates to these reports are found in Exhibit C1, Tab 5, Schedule 1 Attachment 1 and Exhibit C1, Tab 5, Schedule 2, Attachment 1 respectively. These reports were prepared prior to the Canadian Accounting Standards Board's February 13, 2008 confirming decision that publicly accountable entities would be required to adopt IFRS. Hydro One is unclear what relevance the date of the AcSB decision has, however, as the overhead studies prepared for regulatory purposes are based on management accounting principles of causality and benefit and not on specific CGAAP pronouncements.

e) Currently, under CGAAP, Hydro One's policy is that it would generally only capitalize asset-specific training expenditures as an integral cost of those assets when the assets or facilities are new to Hydro One's operations. Such a treatment is rare. An exception to this general treatment is that direct training expenditures are not capitalized as part of the cost of new IT systems. Staff training expenditures, such as those required to meet health and safety standards and regulations and those incurred to keep staff certifications current, continue to be capitalizable.

Hydro One is still developing its written IFRS capitalization policy. However, it is expected that the final detailed policy will not allow for the capitalization of any asset-specific training expenditures.

f) Hydro One Transmission has estimated the rate impact of following the Board's policy as stated in EB-2008-0408 and the letter of February 24, 2010, assuming that the requested asset costing exception is not approved, as a rate increase of approximately 14.5% for 2012. This estimate is based on a high level estimated revenue requirement adjustment (please see Exhibit I, Tab 1, Schedule 19, part d) derived based on the Company's current view of which overhead and other expenditures would likely be disallowed as capital under MIFRS. This is not a one-time increase as a similar reclassification of expenditures from capital to OM&A would occur in all subsequent years.

EXHIBIT C1, TAB 5, SCHEDULE 1, ATTACHMENT A – EB-2006-0501

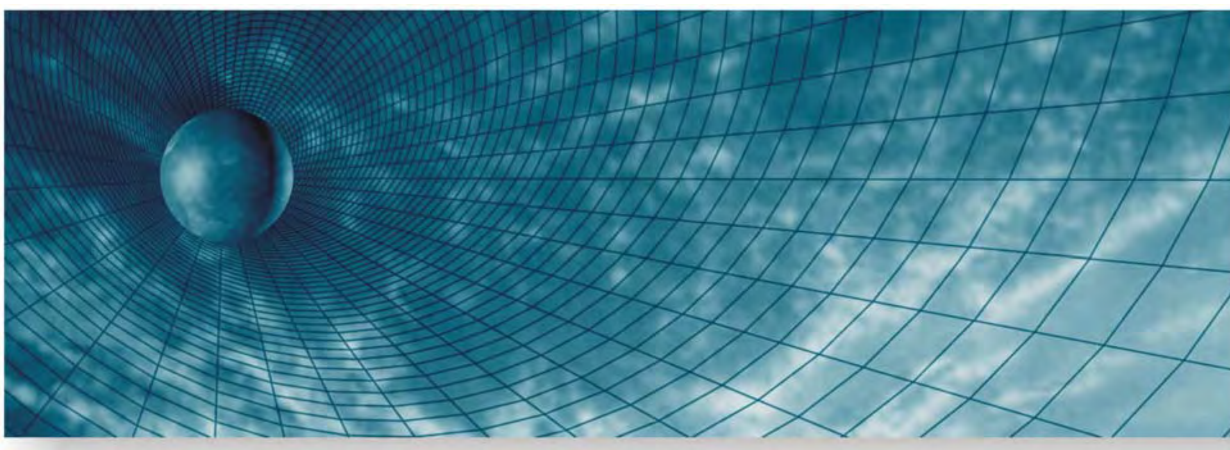
Report to

Hydro One Networks Inc.

Regarding

Review of Implementation of Common Corporate Costs Methodology

May 31, 2006



R·J·Rudden® ASSOCIATES
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Review of Implementation of Common Corporate Costs Methodology

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EXHIBITS

Review of Implementation of Common Corporate Costs Methodology

I. SUMMARY

R. J. Rudden Associates ("Rudden" or "we") is pleased to submit this Report on our Review of Implementation of Common Corporate Costs Methodology ("Review") to Hydro One Networks Inc. In 2004, Rudden was engaged by Hydro One Networks Inc. to recommend a best practice methodology to distribute the costs of providing the common corporate functions and services ("CCFS"), including costs under its outsourcing contract with Inergi LP, to Hydro One Inc. and its various subsidiaries. Rudden recommended, Hydro One adopted, and the Ontario Energy Board ("OEB") approved a methodology, described in our *Report on Common Corporate Costs Methodology Review* dated May 20, 2005 ("2005 Report"). In this Report, that OEB-approved methodology is applied to Business Plan 2007-2011 ("BP 2007") data for the years 2007 and 2008. No changes were made to the OEB-approved methodology. The reader is referred to the 2005 Report for additional information.

Hydro One Inc. is wholly owned by the Province of Ontario. It operates primarily through wholly owned subsidiaries: Hydro One Networks Inc., which includes the Transmission business and the Distribution business; Hydro One Brampton Inc. and Hydro One Brampton Networks Inc. ("Brampton"); Hydro One Remote Communities Inc. ("Remotes"); and Hydro One Telecom Inc. ("Telecom"). See Section III.D Table 6-Business Units for further information on these businesses.

CCFS comprises the functions and services identified below; Exhibit A further describes the functions and services.

TABLE 1 FUNCTIONS AND ACTIVITIES IN CCFS	
• Hydro One Inc. Corporate Office	• Customer Support Operations
• Corporate Services	• Settlements
• Finance	• Finance and Accounting Services
• General Counsel	• Human Resources
• Telecom Services	• Supply Management Services
• ETS- Applications Support and Infrastructure Support	

The BP 2007 includes approximately C$218.3M in 2007 and C$219.2M in 2008 to provide the common corporate functions and services. These functions and services are provided, and the costs are incurred, for the benefit of the business units listed in Section III.D Table 6- Business Units.

Approximately half of the CCFS costs are incurred under an outsourcing arrangement with Inergi LP ("Inergi"). In this Report, CCFS includes the portions of Inergi services identified in BP 2007-2011 as sustainment.

Our approach was designed to ensure compliance with OEB precedent including Docket RP-2002-0133, and compliance with relevant provisions of the Affiliate Relationships Code for Electricity Distributors and Transmitters, November 24, 2003 revision. In addition, we addressed the following aspects: Cost incurrence (Are the costs needed to perform services needed by the business units?); Cost allocation (Were the costs appropriately allocated to the recipient business units?) and Cost / benefit (Did the benefit received equal or exceed the cost?).

Our approach is described in Section II- Approach. Our approach uses direct assignment of costs to business units when possible and, consistent with OEB precedent, uses costs drivers to allocate costs when direct assignment is not possible. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The use of cost drivers conforms to OEB precedent, including Docket RP-2002-0133.

The guiding principle that Rudden used in assigning cost drivers was cost causation, which means there is a causal relationship between the cost driver and the costs incurred in performing the activity. Where cost causation cannot be easily implemented or established, selecting cost drivers based on benefits received is a fair and consistent treatment. Other factors considered included practicality; stability; and materiality.

Consistent with standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., counts of workstations, counts of FTEs, budgeted amounts), subject only to overall reasonableness and actual contrary knowledge, but without independent confirmation.

This Report presents the Total Amounts and the amounts in the Transmission business unit. All amounts in this Report are in Canadian dollars.

Table 2 shows the CCFS costs distributed to each business unit for 2007 and 2008.

TABLE 2 TOTAL CCFS COSTS, 2007 AND 2008 BUDGET

Business Unit	2007 Budget ($000s)	2008 Budget ($000s)
Transmission	$ 73,136	$ 73,419
Distribution	121,046	120,986
Others	24,161	24,765
Total CCFS Costs	$218,343	$219,170

II. APPROACH

The purpose of our Common Corporate Costs Methodology Review was:

> Recommend a best practice methodology to distribute the cost of providing Hydro One Inc.'s common corporate functions and services among the business units that use the functions and services. The methodology must use cost drivers that reflect causality and benefit and meet the requirements of the OEB. The cost drivers should also take into account cost effectiveness, simplicity, regulatory acceptability and flexibility.

Our approach was to:

- Identify the functions and services included in CCFS;
- Identify activities that are performed in order to provide the CCFS;
- Distribute the 2007 and 2008 budgeted cost to perform each function and service among the activities required to perform it, based on time and/or cost studies;
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not.

A. Principles Of Cost Distribution

There are two methods to distribute shared costs among business units – Direct Assignment and Allocation. Direct Assignment is used when the portion of an activity used by a business unit can be reasonably established. Direct assignment is preferable to Allocation because it is based on a more direct relationship. Approximately 33% of CCFS budgeted costs were assigned directly to one or more of the business units.

Allocation is used when more than one business unit uses an activity, but the portions of the activity that each uses cannot be directly established. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The principles used by Rudden to assign cost drivers are discussed below.

B. Cost Drivers

As stated above, a cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The guiding principle that Rudden used in assigning cost drivers was cost causation, which means that there is a causal relationship between the cost driver and the costs incurred in performing the activity. In some cases, cost causation cannot be easily implemented or established, in which cases selecting cost drivers based on benefits received is a fair and consistent treatment.

Other factors considered included practicality (cost drivers should be understandable, obtainable at reasonable cost and objectively verifiable); stability (estimates should be reasonably accurate and unbiased); and materiality (when choosing between cost drivers, small differences can often be ignored in favor of practicality and stability).

C. Types of Cost Drivers

Cost drivers can be classified as External or Internal. External drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts. Internal drivers are based on values computed as part of the allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised. Table 3 describes the types of cost drivers.

TABLE 3 DESCRIPTION OF TYPES OF COST DRIVERS

TYPE	DESCRIPTION	EXAMPLES
External Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Number of customers, employees, phone calls or workstations; time studies; MWh or MW
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Oper Maint (expense), Total assets, Total capital, Total revenue
Blended	Weighted combinations of other drivers, used when one or more drives are applicable and none is clearly preferable; weights determined by judgment	Non-energy Rev_Assets Blend = 50% weight for Non-Energy Revenue and 50% weight for Assets

TABLE 3 DESCRIPTION OF TYPES OF COST DRIVERS		
TYPE	**DESCRIPTION**	**EXAMPLES**
Driver *xBusiness Unit*	Any driver may be modified by excluding one or more business units to which the activity does not apply	Cost driver for payroll preparation activity is FTEs (Full-Time Employees), but Brampton business unit prepares its own payroll and does not use the shared service, therefore activity cost driver is called FTE xB (Full-Time Employees excluding Brampton)
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

Table 4 summarizes the types of cost drivers used to assign the CCFS costs for 2007. The results for 2008 would be very similar.

TABLE 4 DIRECT ASSIGNMENTS AND COST DRIVERS USED FOR CCFS COSTS		
TYPE	**2007 $ ASSIGNED (C$ 000s)**	**% OF TOTAL**
Direct Assignment	$71,351	32.7%
Physical	36,414	16.7%
Financial	72,949	33.4%
Internal	37,629	17.2%
Total CCFS Costs	$218,343	100.0%

D. Summary of Tasks

Our Review comprised the tasks listed in Table 5. Where the results of a task or other information are presented in an exhibit, the exhibit is identified. Section III of this report, Description of Each Task, provides a detailed discussion of each task.

TABLE 5 TASKS

TASK	DESCRIPTION	EXHIBITS
Task 1	*Identified the functions and services* included in the common corporate functions and services (CCFS).	Table 1, Exhibits A, B
Task 2	*Identified the activities* that are performed in order to provide each of the CCFS identified in Task 1.	Exhibit B
Task 3	*Determined 2007 and 2008 budgeted* cost for the CCFS identified in Task 1.	Exhibit B
Task 4	*Identified the business units* (service recipients or beneficiaries) which use the CCFS.	Table 6
Task 5	*Distributed total budgeted resources* (time for labor and cost for non-labor and Inergi) required for each of the CCFS identified in Task 1, among the activities identified in Task 2.	Exhibit B
Task 6	*Assigned activity costs* to business units.	Exhibit C
Task 7	For activities where less than all of the resources were directly assigned to business units in Task 6, *assigned a cost driver* that reflects cost causation.	Exhibits C
Task 8	*Populated* the cost drivers.	Exhibit D
Task 9	*Computed total cost of CCFS* distributed to each business unit.	Exhibits E, F
Task 10	*Reviewe*d inputs and results for reasonableness and consistency.	

III. Description of Each Task

A discussion of each subtask follows, including the purpose of the subtask, the detailed steps performed, the source of the information and the results. In most cases the detailed results are presented in exhibits.

Changes from the information in the 2005 Report were minor.

A. Task 1: Identified Functions and Services Included in CCFS

The purpose of this subtask was to identify and understand the common corporate functions and services; the allocation of the cost of the CCFS is the goal of this Review.

The CCFS support the Hydro One Networks Inc. Transmission and Hydro One Networks Inc. Distribution business units and also support the Remotes, Brampton and Telecom business units of Hydro One Inc. as well.

CCFS comprises the functions and services identified in Table 1 in Section I.- Summary. Exhibit A further describes the functions and services. This information was obtained from Hydro One Inc. internal documents, the Inergi Scopes of Work, and discussions with Hydro One Inc. personnel.

B. Task 2: Identified Activities Performed to Provide Each of the CCFS

The purpose of this subtask was to identify the activities that are performed in order to provide each of the CCFS.

Functions and services (identified in Task 1) are performed for the benefit of the business units, while *activities* (discussed in this subsection) are the tasks performed in order to render the functions and services. *Functions and services* can be measured in benefits received, while *activities* are measured in resources used.

To distribute the resources used in providing the CCFS among the business units on the basis of cost causation, it is necessary to identify and understand the activities that are performed to provide the CCFS.

The activities performed to provide the CCFS were identified in discussions among Hydro One Inc. management personnel, Rudden, and the Hydro One manager responsible for each of the functions and services identified in Task 1. Rudden summarized the information, following which the Hydro One managers verified that the list of activities was complete and the descriptions were accurate.

Exhibit B and Exhibit B (2008) list each of the CCFS (column A) and the activities performed to provide the CCFS (column B). Exhibit B and Exhibit B (2008) also shows other information that will be discussed under Task 3, Task 5 and Task 7.

C. Task 3: Determined 2007 and 2008 Budgeted Cost for Each of the CCFS

This task was to obtain the 2007 and 2008 budgeted cost for each of the CCFS. As part of this subtask, Rudden identified the labour and non-labour portions of the budget for each of the CCFS and identified and obtained descriptions of major non-labour items.

The information was obtained from Hydro One Inc. Exhibit B and Exhibit B (2008) show the 2007 and 2008 budgeted cost, respectively, for each of the CCFS (column E).

D. Task 4: Identified Business Units

The purpose of this task was to identify the business units that use the common corporate functions and services. The information was obtained from Hydro One Inc. In addition, in discussions with the management of each business unit, it was confirmed that the business unit uses the common corporate functions and services for which it was assigned costs. The business units that use the CCFS are listed in Table 6.

TABLE 6 BUSINESS UNITS

BUSINESS UNIT	DESCRIPTION
Trans-mission	Owns and operates substantially all of Ontario's electricity transmission system.
Distribution	Owns and operates a distribution system which spans approximately 75% of Ontario and serves approximately 1.1 million customers.
Brampton	Owns, operates and manages electricity distribution systems and facilities in Brampton, Ontario.
Remotes	Owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario
Telecom	Sells dark fibre to other carriers and high bandwidth telecommunication services to carriers, Internet service providers and others.

TABLE 6 BUSINESS UNITS	
BUSINESS UNIT	**DESCRIPTION**
Shareholder	Represents activities performed exclusively for the benefit of the sole shareholder of Hydro One Inc.
Note- The cost distribution methodology also identified the costs to include in the Materials Surcharge, which are included in materials costs and ultimately charged to business units.	

E. Task 5: Distributed Total Budgeted Resources for Each CCFS Among Activities

The purpose of this task was to distribute the resources (time for labour and costs for non-labour and Inergi) required for each of the CCFS identified in Task 1, among the activities identified in Task 2. In subsequent tasks, the cost of each activity was either directly assigned to one or more business units or allocated using cost drivers.

To distribute budgeted labor costs, the Hydro One manager responsible for each CCFS unit estimated the portion of annual time spent by the personnel under his or her supervision on each of the activities identified in Task 2. Some managers based their estimates on concurrent time records that they maintain, some conducted interviews with their personnel, and some used their informed judgment. The information provided by the managers was reviewed by Hydro One Inc. and Rudden, and compared to information in the 2005 Report, and was found to be reasonable.

To distribute the budgeted non-labour costs, $22.0M, or 78.0%, of the 2007 budgeted total of $35.1M, were specifically examined and distributed based on direct assignment or allocation. This included OEB invoices, communications programs, insurance costs and claims, human resources programs, labour Relations programs, actuarial and tax consultants, audit fee and donations. The balance of non-labour costs includes items such as training and development, non-specific expenses and general expenses (such as travel).

The costs of the functions and services provided by Inergi were distributed among the activities, based on information provided by Hydro One Inc., assignments and allocations by Hydro One Inc. and Rudden, and the application of judgment by Rudden. The approach for each of the CCFS provided by Inergi is described below.

- Customer Support Operations – Hydro One Inc. estimated the portion of total effort required by Inergi to perform each activity. The amounts were very close to the historical efforts when Hydro One personnel performed the work.

- Settlement – Only one activity, no distribution of costs required.

- Supply Management Services – Hydro One Inc. estimated the portions of total effort required by Inergi to perform each activity.

- Finance – Rudden assigned costs among activities based on historic salaries of Hydro One employees that formerly performed similar activities.

- Human Resources – Only one activity, no distribution of costs required.

- Enterprise Technology Services –Hydro One analyzed the activities distributed the 2007 costs among the following ETS activities: customer support operations applications; finance applications; human resources applications; Passport applications; Market Ready applications; telecom services; and infrastructure services.

The results of this task are shown in Exhibit B and Exhibit B (2008), which shows the percent of 2007 and 2008 total budgeted cost, respectively, for each CCFS that was distributed to each activity (column F), and cost distributed to each activity (column G).

F. Task 6: Assigned Activity Costs To Business Units

The purpose of this task was to assign, among the business units identified in Task 4, the resources (time for labour and costs for non-labour and Inergi) for each activity identified in Task 2. In subsequent tasks, these assignments were used to distribute the costs of each activity among the business units.

This task was performed concurrently with Task 5 – Distributing Total Budgeted Resources for Each CCFS Among Activities. The results of this task are shown in Exhibit C and Exhibit C (2008) for 2007 and 2008, respectively.

For each activity identified in Task 2, the Hydro One manager responsible for the CCFS was asked to divide the resources among one or more business units, based on which business units caused the costs to be incurred. Wherever possible, the costs were assigned directly. The amounts assigned directly are shown in Exhibit C and Exhibit C (2008), columns C through E.

When less than 100% of an activity was assigned directly, it was allocated among the business units using cost drivers, as described in Task 7.

G. Task 7: Assigned Cost Drivers

As discussed above, when an activity cannot be 100% directly assigned to one or more business units, it must be allocated using a cost driver. The purpose of this task was to find appropriate cost drivers for the activities which were not 100% directly assigned in Task 6. In subsequent tasks, the cost drivers were used to distribute the activity costs among the business units.

The portion of each activity not directly assigned in Task 6 was determined to be:

- Caused by Transmission and Distribution only, and the split cannot be determined (Exhibit C and Exhibit C (2008), column G), or

- Caused by Transmission or Distribution and at least one other business unit, and the split cannot be determined. (Exhibit C and Exhibit C (2008), column H), or

- Assigned to be recovered in Material Surcharge (Exhibit C and Exhibit C (2008), column I).

The principles that Rudden used to assign cost drivers are discussed on page 3, section II.B. – Cost Drivers, including both economic criteria and implementation considerations. Rudden assigned cost drivers by applying the principles discussed above, Rudden's experience in performing cost allocation studies, consultations with Hydro One Inc. to ascertain the nature of each activity, and knowledge of industry practices and regulatory requirements.

Section II.B. Types of Cost Drivers describes the types of cost drivers. The cost driver assignments for each activity are shown in Exhibit B and Exhibit B (2008), column C and Exhibit C and Exhibit C (2008), column F.

H. Task 8: Populated Cost Drivers

The purpose of this activity was to determine the values of each cost driver that are attributable to each business unit, in order to distribute the costs of each activity among the business units. The information was obtained from Hydro One Inc.

Exhibit D lists and describes each cost driver. The values of each cost driver attributable to each business unit are shown on pages 1, 3 and 5; the portion that each business unit is of the cost driver total is shown on pages 2, 4 and 6.

The Asset Management time study ratios were based on a time study conducted in April 2006, which is described in Section V. The results of the time study were similar to the results of Asset Management time studies performed by Hydro One in March 2003 and April 2006.

I. Task 9: Computed Total Cost of CCFS Distributed To Each Business Unit

The purpose of this task was to distribute the total cost of each activity among the business units. The amount distributed was the sum of the amounts directly assigned in Task 6 and allocations based on the cost drivers identified in Task 7.

For allocations based on the cost drivers, the amount allocated to each business unit was computed by multiplying the cost to be allocated, shown in Exhibit C and Exhibit C (2008), columns G through I, by the cost driver portion value for the business unit.

The cost drivers were developed by Rudden based on the criteria established on page 3, section II.A. Principles Of Cost Distribution. The cost driver methodology meets the criteria established by the OEB and is consistent with industry practice for allocating the types of costs included in CCFS.

J. Task 10: Reviewed Inputs and Results

The purpose of this task was to ensure that the inputs were reasonable and accurate and that the results were reasonable. This included a review of:

- Proportions of total cost distributed to each business unit
- Levels of total cost and of cost for selected departments, which were reviewed by Rudden in a separate assignment performed for Hydro One Networks Inc.
- Levels of total cost assigned to each business unit

The inputs and results were reviewed by Hydro One Inc. and by Rudden, and the results were then reviewed with each business unit to which the costs of the common corporate functions and services were distributed.

IV. SUMMARY OF RESULTS

A. Results

Exhibit E and Exhibit E (2008) present the budgeted cost of each activity distributed to each business unit for the 2007 and 2008 budgets (from BP 2007), respectively.

Exhibit F and Exhibit F (2008) summarize the information for each of the common corporate functions and services for the 2007 and 2008 budgets (from BP 2007), respectively.

B. Implementation

This section reports on the resolution of issues related to implementation that were discussed in the 2005 Report.

Absorption of Overage/Underage; True-ups

Hydro One confirms that differences arising from the use of estimates are charged or credited to the appropriate business unit as an end of the year adjustment.

Updates

Hydro One confirms that it is following the schedule for updates recommended in the 2005 Report.

V. ASSET MANAGEMENT

The Asset Management group, which includes Asset Management and Operators, is responsible for the utility's operating assets, including investment strategy and investment planning. The Operators portion of the group is responsible for the day-to-day operation of the Ontario Grid Control Centre. Work includes 24 hour/day monitoring of grid system status, coordination of system outages and remote operations/switching of Transmission system assets. Substantially all Asset Management and Operators costs are labor and labor-related.

Hydro One determined the portion of Asset Management costs devoted to capital projects by performing a time study for these personnel for the five-week period ending April 7, 2006. Asset Management personnel are able to determine with reasonable accuracy, on a current basis, the time they spend on Distribution Operations and Maintenance, Distribution Capital Projects, Transmission Operations and Maintenance and Transmission Capital Projects.

It is easier for Asset Management personnel to determine the time spent on these areas, because the projects on which they work are more clearly defined than for the common corporate functions ands services. In addition, a four-week period will closely approximate full-year results for Asset Management, while that is not so for the common corporate functions and services personnel, because their work varies during the year.

A properly performed time study measures cost causation and is widely accepted as a basis for allocating costs. Rudden reviewed the time study method used by Hydro One for Asset Management personnel and found it to be appropriate. It was not practical to perform a full-year study, but any effects of performing the study over four weeks, instead of a full year, are believed to be minimal. To support this judgment, Rudden reviewed the two prior Asset Management studies performed by Hydro One and found that the results are similar.

Therefore, Rudden found the time study to be a proper basis for assigning Asset Management costs between the Distribution and Transmission business units.

The results of the Asset Management performed by Hydro One for the five weeks ended April 7, 2006 are summarized in Table 7.

TABLE 7 ASSET MANAGEMENT TIME STUDY, APRIL 2006

	Transmission		Distribution		Total	
	Oper. and Maint.	Capital Projects	Oper. and Maint.	Capital Projects	Oper. and Maint..	Capital Projects
Asset Management	41.6%	26.0%	22.8%	9.6%	64.4%	35.6%
Customer Care	3.3%	1.2%	93.9%	1.6%	97.2%	2.8%
Operations	70.4%	6.8%	20.3%	2.5%	90.7%	9.3%
Total Asset Management	50.9%	16.9%	25.9%	6.3%	76.8%	23.2%
Total Transmission and Distribution	67.8%		32.2%		100.0%	

GLOSSARY

Brampton means Hydro One Brampton Networks Inc., a wholly owned subsidiary of Hydro One Brampton Inc. Hydro One Brampton Inc. is a wholly owned subsidiary of Hydro One Inc.

CCFS means Common Corporate Functions and Services, a major cost category for Hydro One Networks Inc.

Inergi means Inergi LP, an Ontario limited partnership that provides outsourced services to Hydro One Networks Inc. under a ten-year contract

OEB means the Ontario Energy Board

Remotes means Hydro One Remote Communities Inc., a wholly owned subsidiary of Hydro One Inc.

Review means the Hydro One Shared Functions and Service Review 2004, the subject of this Report

Telecom means Hydro One Telecom Inc., a wholly owned subsidiary of Hydro One Inc.

Rudden means R. J. Rudden Associates, A Unit of Enterprise Management Solutions, Black & Veatch Corporation

EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Hydro One Inc. Corporate Office	
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
Chair	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
President and CEO	The CEO's primary accountability is leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. The CEO develops and updates Hydro One's strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.
CFO's Office	The CFO provides Hydro One and its subsidiaries with strategic review and approval with respect to all financial and investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting are also provided by the CFO to Hydro One Inc. and its subsidiaries as required.
Treasurer's Office	Treasurer's Office is responsible for Debt and equity issuance, Capital structure management and oversight of Finance- Treasury function.
Donations	Includes donations made to support injury prevention, corporate donations (e.g. Salvation Army), energy education, United Way support and local community causes.
Corporate Services	
Human Resources	Focused primarily on Employee and Labour Relations.

EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Labour Relations	Provides full-scale service pertaining to bargaining, Ontario Labour Relations Board hearings, grievance and arbitration hearings, advice and guidance, plus training to all levels of Hydro One management. This involves interaction with 21 different unions and 24 collective agreements**.**
Corporate Communications	Supports all communications initiatives, both external and internal. Interacts with most other Hydro One departments but has a special focus on working with Customer Service department.
Supply Management Services (Hydro One)	Management of the Inergi SMS services; Over-all supply and procurement strategic direction including contracting with outside parties.
Corporate Services- SVP	Oversight of Corporate Services departments
Information Management & Information Technology	Enterprise IT Architecture, Governance of IT architecture, Business Analysis and Information Management, Project Management & Control, Large Project Management, Inergi & Telecom services management.
Finance	
Corporate Controller	Revenue Management; Financial Modeling & Analysis; Corporate Planning & Reporting, Support & Accounting Policy; Corporate Accounting Policies & Systems; Regulatory Finance; Inergi Finance; Financial Strategy

EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Treasury	• Risk management including insurance purchasing • Insurance claims settlement • Financial risk management-foreign exchange, interest, credit • Cash & banking operations-cash forecasting, strategy & banking relationships, bank account management • Debt management-prospectus, debt issuance, borrowing, maintain relationship with shareholders • Funds management-deployment of short term funds and manage longer term funds • Investor Relations is responsible for: Relationship with shareholders, creditors, equity analysts & rating agencies
Taxation	Meet internal and external tax compliance requirements and reduce the overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, GST, PST, and DRC returns for all entities), tax accounting, lobbying for legislative tax changes, and government tax audits.
Financial Strategy	Provides financial support services, including business case review and preparation, project management, decision support, business valuation, transaction support, deal structuring, and business consulting services.
Internal Audit & Risk Management	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.
General Counsel	

EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Regulatory Affairs	Coordinate filings with OEB; Manage relationship with OEB; Cost Allocation and Rate Design for regulated Tx and Dx, in particular, rate structures and rates for Tx and Dx Tariffs; Assist implementation of approved Tx and Dx rates; Support transmitters' representative on IESO Technical Panel; Provide load forecasts for all business units of Hydro One and for IESO; Manage MV Star to support wholesale and retail settlement; Provided strategic and analytical support to load research and CDM initiatives.
Regulatory Affairs- OEB Cost	OEB costs for Tx and Dx activities.
Law	Provides legal advice to all business units, acting as an internal "law firm" for the Corporation on most aspects of law affecting it, and is also well acquainted with day- to-day requirements of the Corporation.
Corporate	Oversee and support Law, Regulatory and Corporate Secretariat General Counsel functions.
Corporate Secretariat	Provides direction and analysis in areas of: 1) Board and Committee(s); 2) Support to the Office of the Chair and members of the Board of Directors; 3) Code of Business Conduct; 4) Community Citizenship; 5) Freedom of Information and Privacy, 6) Corporate Archives, 7) Corporate Records, and 8) Corporate Secretariat Support.

EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Telecom Services	Telecom Services provides telecommunications infrastructure across the Province, including both voice and data. Links staff and business applications at Trinity, Richview TS, Markham and London Call Centers, Mill Creek data centre, 125 field offices (400 total sites including stations) and customers via Call Centres and Web sites.
Customer Support Operations	Inbound Call Handling; Bill Production; Collections; Data Services
Settlements	Wholesale Settlements - Provide settlement and reconciliation services for power procured from the Independent Electricity Market Operator and embedded Retail Generators with due consideration to legislative initiatives for fixed energy prices for low volume customers and Business Protection Plan Rebates, transmission revenues and inter-utility load transfers, and cost of power reporting, and; Retail Settlements - Provide complex billing for interval meter accounts.
Finance and Accounting Services	Accounts Payable Billing; Accounts Receivable (Non-energy related); Fixed Asset and Project Cost Accounting; General Accounting and Planning, Budgeting and Reporting
Human Resources	Payroll
Supply Management Services	Demand Planning, Demand Management and Procurement, Sourcing, Vendor Management and Inventory Management, Process Development and Data Management, Negotiating and managing transportation contract with logistics providers, Asset Disposal

EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Applications Support	Support the following applications: Customer Support Operations, Finance, Human Resources, Passport, Market Ready, Telecomm Services,
Infrastructure Support	Support the infrastructure including platforms, servers, printers, workstations, IT communications and Help Desk

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Human Resources	Administer Compensation & Benefits Programs	FTEs	5,069,000	8.3%	418,760
	Decision support	FTEs		10.2%	518,060
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		13.7%	694,340
	Administer Pension Plan	FTEs		14.4%	727,440
	Administer Inergi HR	Inergi HR (Internal)		4.1%	209,380
	Consulting support to LOBs and corporate functions	FTEs		42.0%	2,128,600
	Director	HR Dept. Labor (Internal)		7.3%	372,420
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs	1,389,000	43.3%	602,000
	Negotiate with Bargaining Units	FTEs		13.1%	181,450
	Participate in grievance and arbitration filings	FTEs		34.9%	485,150
	Participate in OLRB hearings	FTEs		8.7%	120,400
	Internal vacancy management	FTEs		0.0%	0
Communications	Provide communications support for corporate safety program & activities	FTEs	5,527,000	7.7%	427,700
	Provide communications support for customer information requirements	Direct Dx		20.2%	1,119,050
	Provide Media Program for Community Info & Employee Contributions	FTEs		28.4%	1,570,400
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital		15.5%	855,400
	Provide Support to CDM and Other Special Programs	Direct Dx		5.0%	276,350
	Provide other internal communications support	FTEs		7.7%	427,700
	Other departmental activities	Non-energy Rev_Assets Blend		15.4%	850,400
	General departmental expenses	CorpComm Dept. Labor (Internal)		0.0%	0
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	1,399,000	71.8%	1,004,513
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend		18.3%	256,487
	General departmental expenses	Strategic Dept. Labor (Internal)		9.9%	138,000
Corporate Security	Provide Security Services for Company Assets	Assets	2,291,000	100.0%	2,291,000

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR	18,960,000	13.2%	2,500,000
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR		15.8%	3,000,000
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR		0.2%	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)		0.7%	125,000
	Transportation	Oper Maint Cap xBxTxR		21.1%	4,000,000
	Investment Recovery	Gross utility plant xBxTxR		1.1%	200,000
	Inergi Inspection Project	Inergi SMS (Internal)		6.3%	1,200,000
	Other departmental activities	Oper Maint Cap xBxTxR		0.5%	93,750
	Purchasing	Oper Maint Cap xB		26.6%	5,051,093
	Transportation	Oper Maint Cap xB		1.0%	189,416
	Asset disposal and Investment recovery	Gross utility plant xBxTxR		2.0%	378,832
	Strategic Sourcing Initiative	Oper Maint Cap xBxT		4.7%	883,941
	Support management of warehouse facilities	Total Assets xBxTxR		3.3%	631,387
	Other departmental activities	Inergi SMS (Internal)		3.6%	675,331
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)	1,075,000	100.0%	1,075,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	6,061,000	18.8%	1,139,673
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		7.4%	446,706
	Support Asset Management activities and projects	Asset Manager		12.8%	773,145
	Support Finance activities and projects	Finance Labor Costs (Internal)		12.4%	750,237
	Provide operational support for Transmission and Distribution activities	Asset Manager		1.5%	91,632
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		27.6%	1,672,284
	Support Inergi operations	Inergi IT (Internal)		11.9%	721,602
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		2.2%	131,721
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		5.5%	334,000

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	6,995,000	22.0%	1,541,475
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend		16.9%	1,178,775
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)		11.0%	770,738
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)		0.0%	0
	Revenue analysis and reporting	Total Revenue		6.3%	438,263
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend		14.7%	1,027,650
	Internal controls	Total Revenue_Assets Blend		5.8%	408,038
	Other departmental activities	Contr. Dept. Labor (Internal)		9.7%	680,063
	Actuarial consultants	FTEs		10.7%	750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend		0.0%	0
	General departmental expenses	Contr. Dept. Labor (Internal)		2.9%	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB	3,904,000	5.3%	208,800
	Insurance- Claims	Non-energy Rev_Assets Blend xB		79.7%	3,112,308
	Fiduciary insurance policy	FTEs		1.4%	55,091
	IT Costs	Total Capital		0.0%	0
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		13.5%	527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	1,663,000	38.3%	636,363
	Tax Planning	OperMaint Exp_Assets Blend		19.2%	318,903
	Support Debt issuance	Total Debt		0.8%	12,987
	Special Projects	OperMaint Exp_Assets Blend		1.6%	25,974
	Support regulatory filings	GC_Reg Dept. Labor (Internal)		1.1%	18,759
	Support Construction activities	Capital Expenditures		1.2%	20,202
	Other departmental activities	Tax Dept. Labor (Internal)		24.6%	409,812
	Tax Consultants	Tax Dept. Labor (Internal)		9.0%	150,000
	General departmental expenses	Tax Dept. Labor (Internal)		4.2%	70,000
Financial Strategy	Support Regulatory Activities	All Direct	2,084,000	8.6%	178,400
	Support Business Activities	All Direct		4.3%	89,200
	Special Projects	All Direct		8.6%	178,400
	Decision support for lines of business	All Direct		51.4%	1,070,400
	DSM	All Direct		8.6%	178,400
	Ontario Hydro Energy	All Direct		4.3%	89,200
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		14.4%	300,000

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	2,783,000	69.0%	1,919,130
	Purchasing	Oper Maint Cap		6.8%	189,210
	IMIT	Fin_IMIT Dept. Labor (Internal)		11.7%	324,360
	Human Resources	HR Dept. Labor (Internal)		1.0%	27,030
	Finance	Finance Labor Costs (Internal)		7.8%	216,240
	Customers	Total Revenue		1.0%	27,030
	General departmental expenses	IntAudit Dept. Labor (Internal)		2.9%	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct	7,709,000	29.4%	2,269,465
	Manage HO Relationship with OEB (incl. complaints)	All Direct		0.7%	52,235
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct		0.0%	0
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct		22.4%	1,727,872
	Provide Load Forecasts for HO and IMO	All Direct		10.2%	783,522
	Support Wholesale and Retail Settlement Process	All Direct		15.0%	1,159,475
	Section 92 Applications	All Direct		2.7%	209,627
	Code Reviews	All Direct		3.7%	282,480
	Other departmental activities	GC_Reg Dept. Labor (Internal)		5.0%	388,325
	All other costs	All Direct		10.8%	836,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct	12,229,000	100.0%	12,229,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	6,811,000	73.6%	5,011,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		24.5%	1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		1.9%	128,571
Telecom Services	Management of Telecoms Services	Telecom Services	16,962,230	18.7%	3,178,000
	Data backbone, assets and lines for all users	Workstations		28.5%	4,832,030
	Voice backbone, assets and lines for all users	Telephones		22.7%	3,849,400
	Repairs, adds, changes to telephones	Telephones		30.1%	5,102,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)	26,441,859	25.5%	6,732,405
	Support Finance Applications	Inergi Finance (Internal)		17.0%	4,488,270
	Support HR Applications	Inergi HR (Internal)		13.6%	3,590,616
	Support Passport Applications	ProgramProjectCosts		11.9%	3,141,789
	Support Market Ready Applications	Market Ready		27.0%	7,142,298
	Support Telecommunications Infrastructure	Telephones		5.1%	1,346,481

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)	25,583,140	13.6%	3,477,265
	Direct Assignments	All Direct		4.0%	1,014,964
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		82.4%	21,090,911
Customer Support Operations	Inbound calls / correspondence	All Direct	38,619,000	55.8%	21,549,402
	Bill Production	All Direct		24.6%	9,500,274
	Data Services- Timesheets for field personnel, Tx operations	All Direct		8.0%	3,089,520
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct		11.6%	4,479,804
Settlements	Wholesale and Retail Settlements	All Direct	3,000,000	100.0%	3,000,000
Finance	Accounts Payable processing	Invoices To Vendors	10,330,000	17.7%	1,828,262
	Accounts Receivable processing	Other Bills To Customers		13.2%	1,367,043
	Fixed Assets processing	Gross utility plant xB		6.3%	655,035
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		52.2%	5,387,497
	Pension support	FTEs		0.5%	53,193
	Inergi Corp. Finance	Inergi Total (Internal)		10.1%	1,038,970
HR - Pay Services	Payroll Services and Recordkeepping	FTEs	3,481,000	100.0%	3,481,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	326,000	92.3%	301,000
	General departmental expenses	Non-energy Rev_Assets Blend		7.7%	25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend	1,275,000	0.0%	0
	Audit Fee	Total Revenue_Assets Blend xBxTxR		54.7%	697,529
	General departmental expenses	Non-energy Rev_Assets Blend		45.3%	577,471

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct	2,575,000	4.2%	107,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct		16.7%	430,800
	Develop and maintain relationships with major customers and customer groups	All Direct		16.7%	430,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct		16.7%	430,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct		8.4%	215,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct		16.7%	430,800
	Plan for management succession	All Direct		4.2%	107,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		16.3%	421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	671,000	88.8%	596,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		11.2%	75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	309,000	67.6%	209,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		32.4%	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	1,071,000	15.7%	168,250
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)		12.6%	134,600
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)		3.1%	33,650
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend		6.3%	67,300
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend		9.1%	97,585
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend		6.3%	67,300
	Support BOD	Non-energy Rev_Assets Blend		3.1%	33,650
	Ensure access to capital on reasonable terms	Total Capital		6.3%	67,300
	Other departmental activities	CFO Dept. Labor (Internal)		0.3%	3,365
	General departmental expenses	CFO Dept. Labor (Internal)		37.2%	398,000
Donations	Donations	Direct Holding Company	1,750,000	100.0%	1,750,000
Total CCFS			218,343,229		218,343,229

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Direct Assignment Transmission	Direct Assignment Distribution	Direct Assignment Other
(A)	(B)	(D)	(C)	(E)
Human Resources	Administer Compensation & Benefits Programs			
	Decision support			
	Staffing & Leadership- Recruitment, Hiring, Succession			
	Administer Pension Plan			
	Administer Inergi HR			
	Consulting support to LOBs and corporate functions			
	Director			
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements			
	Negotiate with Bargaining Units			
	Participate in grievance and arbitration filings			
	Participate in OLRB hearings			
	Internal vacancy management			
Communications	Provide communications support for corporate safety program & activities			
	Provide communications support for customer information requirements			
	Provide Media Program for Community Info & Employee Contributions			
	Provide Support for Shareholder and External Stakeholder Relationships			
	Provide Support to CDM and Other Special Programs			
	Provide other internal communications support			
	Other departmental activities			
	General departmental expenses			
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations		167,461	
	Develop working relationships with customers, regulators, shareholder, lenders	44,892	166,704	
	General departmental expenses			
Corporate Security	Provide Security Services for Company Assets	1,056,600	616,350	44,025

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocation: Allocated to T&D, Others	Allocation: Materials Surcharge	Total 2007 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Human Resources	Administer Compensation & Benefits Programs	FTEs		418,760		418,760
	Decision support	FTEs		518,060		518,060
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		694,340		694,340
	Administer Pension Plan	FTEs		727,440		727,440
	Administer Inergi HR	Inergi HR (Internal)		209,380		209,380
	Consulting support to LOBs and corporate functions	FTEs		2,128,600		2,128,600
	Director	HR Dept. Labor (Internal)		372,420		372,420
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs		602,000		602,000
	Negotiate with Bargaining Units	FTEs		181,450		181,450
	Participate in grievance and arbitration filings	FTEs		485,150		485,150
	Participate in OLRB hearings	FTEs		120,400		120,400
	Internal vacancy management	FTEs				-
Communications	Provide communications support for corporate safety program & activities	FTEs	427,700			427,700
	Provide communications support for customer information requirements	Direct Dx	1,119,050			1,119,050
	Provide Media Program for Community Info & Employee Contributions	FTEs	1,570,400			1,570,400
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital	855,400			855,400
	Provide Support to CDM and Other Special Programs	Direct Dx	276,350			276,350
	Provide other internal communications support	FTEs	427,700			427,700
	Other departmental activities	Non-energy Rev_Assets Blend	155,000	695,400		850,400
	General departmental expenses	CorpComm Dept. Labor (Internal)				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	837,052			1,004,513
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend	44,892			256,487
	General departmental expenses	Strategic Dept. Labor (Internal)		138,000		138,000
Corporate Security	Provide Security Services for Company Assets	Assets		574,025		2,291,000

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Direct Assignment: Transmission	Direct Assignment: Distribution	Direct Assignment: Other
(A)	(B)	(D)	(C)	(E)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management) Warehouse (Provincial lines) Strategic Sourcing Initiative Supervise Inergi- SMS Transportation Investment Recovery Inergi Inspection Project Other departmental activities Purchasing Transportation Asset disposal and Investment recovery Strategic Sourcing Initiative Support management of warehouse facilities Other departmental activities			
Corporate Services SVP	Manage all Corp Services Departments			
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements Support Asset Management activities and projects Support Finance activities and projects Provide operational support for Transmission and Distribution activities Manage IT capital projects and IT strategy Support Inergi operations Other departmental activities General departmental expenses		74,451	

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocation: Allocated to T&D, Others	Allocation: Materials Surcharge	Total 2007 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR			2,500,000	2,500,000
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR			3,000,000	3,000,000
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR			31,250	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)			125,000	125,000
	Transportation	Oper Maint Cap xBxTxR			4,000,000	4,000,000
	Investment Recovery	Gross utility plant xBxTxR			200,000	200,000
	Inergi Inspection Project	Inergi SMS (Internal)			1,200,000	1,200,000
	Other departmental activities	Oper Maint Cap xBxTxR			93,750	93,750
	Purchasing	Oper Maint Cap xB			5,051,093	5,051,093
	Transportation	Oper Maint Cap xB			189,416	189,416
	Asset disposal and Investment recovery	Gross utility plant xBxTxR			378,832	378,832
	Strategic Sourcing Initiative	Oper Maint Cap xBxT			883,941	883,941
	Support management of warehouse facilities	Total Assets xBxTxR			631,387	631,387
	Other departmental activities	Inergi SMS (Internal)			675,331	675,331
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)		1,075,000		1,075,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations		1,139,673		1,139,673
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		372,255		446,706
	Support Asset Management activities and projects	Asset Manager		773,145		773,145
	Support Finance activities and projects	Finance Labor Costs (Internal)		750,237		750,237
	Provide operational support for Transmission and Distribution activities	Asset Manager		91,632		91,632
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		1,672,284		1,672,284
	Support Inergi operations	Inergi IT (Internal)		721,602		721,602
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		131,721		131,721
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		334,000		334,000

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Direct Assignment: Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
Corporate Controller	Accting policies; External reports; External audit / review			57,428
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections			49,569
	Regulatory Finance Activities			18,135
	Manage Inergi- General and Inergi- Finance contract			
	Revenue analysis and reporting			12,090
	Monitor and support Financial systems and Corporate accounting			54,405
	Internal controls			24,180
	Other departmental activities			
	Actuarial consultants			
	Consultants- Bill 198 (Canadian SOX) compliance			
	General departmental expenses			
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management			
	Insurance- Claims			
	Fiduciary insurance policy			
	IT Costs			
	General departmental expenses			
Taxation	Compliance activities including tax filings and audits			111,111
	Tax Planning			12,987
	Support Debt issuance			
	Special Projects			1,443
	Support regulatory filings			2,886
	Support Construction activities			1,443
	Other departmental activities			
	Tax Consultants			
	General departmental expenses			
Financial Strategy	Support Regulatory Activities		178,400	
	Support Business Activities		89,200	
	Special Projects		178,400	
	Decision support for lines of business	610,128	406,752	53,520
	DSM		178,400	
	Ontario Hydro Energy			89,200
	General departmental expenses			

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocation: Allocated to T&D, Others	Allocation: Materials Surcharge	Total 2007 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	1,484,048			1,541,475
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend	1,129,206			1,178,775
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)	752,603			770,738
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)				-
	Revenue analysis and reporting	Total Revenue	426,173			438,263
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend	973,245			1,027,650
	Internal controls	Total Revenue_Assets Blend	383,858			408,038
	Other departmental activities	Contr. Dept. Labor (Internal)	317,363	362,700		680,063
	Actuarial consultants	FTEs		750,000		750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend				-
	General departmental expenses	Contr. Dept. Labor (Internal)		200,000		200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB		208,800		208,800
	Insurance- Claims	Non-energy Rev_Assets Blend xB		3,112,308		3,112,308
	Fiduciary insurance policy	FTEs		55,091		55,091
	IT Costs	Total Capital				-
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		527,801		527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	512,265	12,987		636,363
	Tax Planning	OperMaint Exp_Assets Blend	305,916			318,903
	Support Debt issuance	Total Debt		12,987		12,987
	Special Projects	OperMaint Exp_Assets Blend	24,531			25,974
	Support regulatory filings	GC_Reg Dept. Labor (Internal)	15,873			18,759
	Support Construction activities	Capital Expenditures	18,759			20,202
	Other departmental activities	Tax Dept. Labor (Internal)	409,812			409,812
	Tax Consultants	Tax Dept. Labor (Internal)		150,000		150,000
	General departmental expenses	Tax Dept. Labor (Internal)		70,000		70,000
Financial Strategy	Support Regulatory Activities	All Direct				178,400
	Support Business Activities	All Direct				89,200
	Special Projects	All Direct				178,400
	Decision support for lines of business	All Direct				1,070,400
	DSM	All Direct				178,400
	Ontario Hydro Energy	All Direct				89,200
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		300,000		300,000

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Direct Assignment: Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
Internal Audit & Risk Mgmt	Audits	648,720	378,420	162,180
	Purchasing			
	IMIT			
	Human Resources			
	Finance			
	Customers			
	General departmental expenses			
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,435,770	806,203	27,492
	Manage HO Relationship with OEB (incl. complaints)	687	51,548	
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates			
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	428,875	1,298,997	
	Provide Load Forecasts for HO and IMO	372,517	411,005	
	Support Wholesale and Retail Settlement Process	503,104	656,372	
	Section 92 Applications	209,627		
	Code Reviews	107,219	175,262	
	Other departmental activities	144,333	243,992	
	All other costs	275,283	560,717	
Regul. Affairs- OEB Cost	OEB Billed costs	6,736,526	5,492,474	
Law	Overall Assignment of Time			325,715
	Consultants and External Legal Counsel			
	General departmental expenses			
Telecom Services	Management of Telecoms Services			
	Data backbone, assets and lines for all users			
	Voice backbone, assets and lines for all users			
	Repairs, adds, changes to telephones			
ETS - Applications Support	Support CSO Applications			
	Support Finance Applications			
	Support HR Applications			
	Support Passport Applications			
	Support Market Ready Applications			
	Support Telecommunications Infrastructure			

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocated to T&D, Others	Materials Surcharge	Total 2007 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	729,810			1,919,130
	Purchasing	Oper Maint Cap		189,210		189,210
	IMIT	Fin_IMIT Dept. Labor (Internal)		324,360		324,360
	Human Resources	HR Dept. Labor (Internal)		27,030		27,030
	Finance	Finance Labor Costs (Internal)		216,240		216,240
	Customers	Total Revenue		27,030		27,030
	General departmental expenses	IntAudit Dept. Labor (Internal)		80,000		80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct				2,269,465
	Manage HO Relationship with OEB (incl. complaints)	All Direct				52,235
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct				1,727,872
	Provide Load Forecasts for HO and IMO	All Direct				783,522
	Support Wholesale and Retail Settlement Process	All Direct				1,159,475
	Section 92 Applications	All Direct				209,627
	Code Reviews	All Direct				282,480
	Other departmental activities	GC_Reg Dept. Labor (Internal)				388,325
	All other costs	All Direct				836,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct				12,229,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	4,685,285			5,011,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		1,671,429		1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		128,571		128,571
Telecom Services	Management of Telecoms Services	Telecom Services		3,178,000		3,178,000
	Data backbone, assets and lines for all users	Workstations		4,832,030		4,832,030
	Voice backbone, assets and lines for all users	Telephones		3,849,400		3,849,400
	Repairs, adds, changes to telephones	Telephones		5,102,800		5,102,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)		6,732,405		6,732,405
	Support Finance Applications	Inergi Finance (Internal)		4,488,270		4,488,270
	Support HR Applications	Inergi HR (Internal)		3,590,616		3,590,616
	Support Passport Applications	ProgramProjectCosts		3,141,789		3,141,789
	Support Market Ready Applications	Market Ready		7,142,298		7,142,298
	Support Telecommunications Infrastructure	Telephones		1,346,481		1,346,481

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services			
	Direct Assignments		1,014,964	
	General Infrastructure Support			
Customer Support Operations	Inbound calls / correspondence		21,549,402	
	Bill Production		9,481,755	18,519
	Data Services- Timesheets for field personnel, Tx operations	463,428	2,626,092	
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,464,886	14,918
Settlements	Wholesale and Retail Settlements	450,000	2,550,000	
Finance	Accounts Payable processing			
	Accounts Receivable processing			
	Fixed Assets processing			
	Corporate accounting, Budgeting, Analysis			
	Pension support			
	Inergi Corp. Finance			
HR - Pay Services	Payroll Services and Recordkeepping			
Chair	Overall Assignment of Time			19,565
	General departmental expenses			
Board	Overall Assignment of Time			
	Audit Fee			
	General departmental expenses			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

			Allocation			
Function or Service	Activities Performed	Cost Driver	Allocated to T&D	Allocated to T&D, Others	Materials Surcharge	Total 2007 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)		3,477,265		3,477,265
	Direct Assignments	All Direct				1,014,964
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		21,090,911		21,090,911
Customer Support Operations	Inbound calls / correspondence	All Direct				21,549,402
	Bill Production	All Direct				9,500,274
	Data Services- Timesheets for field personnel, Tx operations	All Direct				3,089,520
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct				4,479,804
Settlements	Wholesale and Retail Settlements	All Direct				3,000,000
Finance	Accounts Payable processing	Invoices To Vendors		1,828,262		1,828,262
	Accounts Receivable processing	Other Bills To Customers		1,367,043		1,367,043
	Fixed Assets processing	Gross utility plant xB		655,035		655,035
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		5,387,497		5,387,497
	Pension support	FTEs		53,193		53,193
	Inergi Corp. Finance	Inergi Total (Internal)		1,038,970		1,038,970
HR - Pay Services	Payroll Services and Recordkeepping	FTEs		3,481,000		3,481,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	281,435			301,000
	General departmental expenses	Non-energy Rev_Assets Blend		25,000		25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend				-
	Audit Fee	Total Revenue_Assets Blend xBxTxR		697,529		697,529
	General departmental expenses	Non-energy Rev_Assets Blend		577,471		577,471

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Direct Assignment Transmission	Direct Assignment Distribution	Direct Assignment Other
(A)	(B)	(D)	(C)	(E)
President/CEO Office	Establish performance targets for safety, customer service, reliability	58,158	47,388	2,154
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	232,632	189,552	8,616
	Develop and maintain relationships with major customers and customer groups	232,632	189,552	8,616
	Develop and maintain relationships with regulators, shareholder, lenders	232,632	189,552	8,616
	Monitor, assess and remediate risks to operational and financial performance	116,316	94,776	4,308
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	232,632	189,552	8,616
	Plan for management succession	58,158	47,388	2,154
	General departmental expenses			
Corporate	Overall Assignment of Time			38,740
	General departmental expenses			
Corp. Secretariat	Overall Assignment of Time			13,585
	General departmental expenses			
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans			6,730
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder			5,048
	Ensure financial services are provided efficiently and reliably			6,730
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities			6,730
	Monitor performance against operational, financial and regulatory targets			30,285
	Ensure sufficient revenue for operating, financial and regulatory needs			6,730
	Support BOD			
	Ensure access to capital on reasonable terms			10,095
	Other departmental activities			
	General departmental expenses			
Donations	Donations			
TOTAL CCFS		14,650,867	54,765,965	1,268,562

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Cost Driver	Allocation			Total 2007 Activity Budget
			Allocated to T&D	Allocated to T&D, Others	Materials Surcharge	
(A)	(B)	(F)	(G)	(H)	(I)	(J)
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct				107,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct				430,800
	Develop and maintain relationships with major customers and customer groups	All Direct				430,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct				430,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct				215,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct				430,800
	Plan for management succession	All Direct				107,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		421,000		421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	557,260			596,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		75,000		75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	195,415			209,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		100,000		100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	161,520			168,250
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)	129,553			134,600
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)	26,920			33,650
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend	60,570			67,300
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend	67,300			97,585
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend	60,570			67,300
	Support BOD	Non-energy Rev_Assets Blend		33,650		33,650
	Ensure access to capital on reasonable terms	Total Capital	57,205			67,300
	Other departmental activities	CFO Dept. Labor (Internal)		3,365		3,365
	General departmental expenses	CFO Dept. Labor (Internal)		398,000		398,000
Donations	Donations	Direct Holding Company		1,750,000		1,750,000
TOTAL CCFS			19,480,035	109,217,798	18,960,000	218,343,229

EXHIBIT D

HYDRO ONE COMMON CORPORATE COST MODEL
COST DRIVERS - 2007

DRIVER	DESCRIPTION	EXTERNAL DRIVER VALUES: Total	Trans-mission	Distrib-ution	Other	EXTERNAL DRIVER %: Total	Trans-mission	Distrib-ution	Other
Direct Dx	Place all costs of an activity into one business unit	1		1	-	100.0%	0.0%	100.0%	0.0%
Direct Tx	Place all costs of an activity into one business unit	1	1		-	100.0%	100.0%	0.0%	0.0%
Direct Shareholder	Place all costs of an activity into one business unit	1			1	100.0%	0.0%	0.0%	100.0%
All Direct	Placeholder when activity is 100% directly assigned	-			-	0.0%			
Physical									
Asset Manager	Results of Asset Manager time study, December 2004	100.0%	67.8%	32.2%	0.0%	100.0%	67.8%	32.2%	0.0%
Facilities SqFt	Square feet of facilities included in LBSS activities, 12/31/05 values (Shared)	130,858	71,201	59,072	585	100.0%	54.4%	45.1%	0.4%
FTEs	Full time equivalent employees, 12/31/05 values (Shared)	4,936	2,351	2,487	98	100.0%	47.6%	50.4%	2.0%
Invoices To Vendors	Self-explanatory, 2005 and 12/31/05 values (Shared)	90,260	40,694	44,114	5,452	100.0%	45.1%	48.9%	6.0%
ProgramProjectCosts	Program and Project Costs for Capital and OM spending on Transmission and Distribution for 2005	100.0%	47.6%	52.4%	0.0%	100.0%	47.6%	52.4%	0.0%
Other Bills To Customers	Bills to customers other than retail bills to customers, 2005 values	28,737	13,834	12,527	2,376	100.0%	48.1%	43.6%	8.3%
Telephones	Self-explanatory, 2005 and 12/31/05 values (Shared)	4,948	2,357	2,494	97	100.0%	47.6%	50.4%	2.0%
Workstations	Self-explanatory, 2005 and 12/31/05 values (Shared)	4,880	2,337	2,451	92	100.0%	47.9%	50.2%	1.9%

Each cost driver marked (Shared) included common portions in addition to portions due to business units. These common portions were allocated between Transmission and Distribution using ProgramProjectCosts cost driver or Asset Manager driver, as appropriate.

EXHIBIT D

HYDRO ONE COMMON CORPORATE COST MODEL
COST DRIVERS - 2007

DRIVER	DESCRIPTION	EXTERNAL DRIVER VALUES Total	Trans-mission	Distrib-ution	Other	EXTERNAL DRIVER % Total	Trans-mission	Distrib-ution	Other
Financial ($ millions)									
Capital expenditures	Budgeted amounts for 2007	752	389	333	31	100.0%	51.7%	44.3%	4.1%
Gross utility plant	Projected balances as of 12/31/07	16,059	9,742	5,770	547	100.0%	60.7%	35.9%	3.4%
Gross utility plant xB	Gross utility plant excl. Brampton	15,652	9,742	5,770	140	100.0%	62.2%	36.9%	0.9%
Gross utility plant xBxTxR	Gross utility plant excl. Brampton, Telecom, Remotes	15,512	9,742	5,770	-	100.0%	62.8%	37.2%	0.0%
Net utility plant	Projected balances as of 12/31/07	10,080	6,254	3,502	325	100.0%	62.0%	34.7%	3.2%
Non-energy revenue	Budgeted amounts for 2007	2,267	1,199	961	108	100.0%	52.9%	42.4%	4.8%
Oper Maint Cap	Budgeted amounts for 2007	1,364	649	632	82	100.0%	47.6%	46.4%	6.0%
Oper Maint Cap xB	Oper Maint Cap excl. Brampton	1,328	649	632	46	100.0%	48.9%	47.6%	3.5%
Oper Maint Cap xBxT	Oper Maint Cap excl. Brampton, Telecom	1,298	649	632	16	100.0%	50.0%	48.7%	1.2%
Oper Maint Cap xBxTxR	Oper Maint Cap excl. Brampton, Telecom, Remotes	1,282	649	632	-	100.0%	50.7%	49.3%	0.0%
Oper Maint Exp	Budgeted amounts for 2007	612	261	299	52	100.0%	42.6%	48.9%	8.4%
Total Assets	Projected balances as of 12/31/07	11,736	6,800	4,452	484	100.0%	57.9%	37.9%	4.1%
Total Assets xBxTxR	Total Assets excl. Brampton, Telecom, Remotes	11,252	6,800	4,452	-	100.0%	60.4%	39.6%	0.0%
Total Capital	Projected balances as of 12/31/07	10,177	6,214	3,563	400	100.0%	61.1%	35.0%	3.9%
Total Debt	Projected balances as of 12/31/07	6,042	3,654	2,109	279	100.0%	60.5%	34.9%	4.6%
Total Revenue	Budgeted amounts for 2007	4,412	1,199	2,824	389	100.0%	27.2%	64.0%	8.8%
Total Revenue xB	Budgeted amounts for 2007 excl. Brampton	4,085	1,199	2,824	62	100.0%	29.3%	69.1%	1.5%
Derived Financial									
Assets	Average Net utility Plant, Total Assets	100.0%	59.99%	36.33%	3.67%	100.0%	60.0%	36.3%	3.7%
Non-energy Rev_Assets Blend	50% Non-energy Revenue, 50% Assets	100.0%	56.43%	39.35%	4.21%	100.0%	56.4%	39.4%	4.2%
Non-energy Rev_Assets Blend xB	Non-energy Rev_Assets Blend excl. Brampton	97.4%	56.43%	39.35%	1.58%	100.0%	58.0%	40.4%	1.6%
Non-energy Rev_Assets Blend xBxTxR	Non-energy Rev_Assets Blend excl. Brampton, Telecom, Remotes	96.3%	59.99%	36.33%	-	100.0%	62.3%	37.7%	0.0%
OperMaint Exp_Assets Blend	50% Oper Maint Exp, 50% Assets	100.0%	52.77%	42.15%	5.08%	100.0%	52.8%	42.1%	5.1%
Non-energy Rev_Workstations Blend	50% Non-energy Revenue, 50% Workstations	100.0%	50.39%	46.29%	3.32%	100.0%	50.4%	46.3%	3.3%
Non-energy Rev_Workstations Blend xB	Non-energy Rev_Workstations Blend excl. Brampton	98.7%	50.39%	46.29%	1.98%	100.0%	51.1%	46.9%	2.0%
Total Revenue_Assets Blend	50% Total Revenue, 50% Assets	100.0%	43.58%	50.17%	6.24%	100.0%	43.6%	50.2%	6.2%
Total Revenue_Assets Blend xBxTxR	Total Revenue_Assets Blend excl. Brampton, Telecom, Remotes	93.8%	43.58%	50.17%	-	100.0%	46.5%	53.5%	0.0%

HYDRO ONE COMMON CORPORATE COST MODEL
COST DRIVERS - 2007

DRIVER	DESCRIPTION	INTERNAL DRIVER VALUES Total	Trans-mission	Distrib-ution	Other	INTERNAL DRIVER % Total	Trans-mission	Distrib-ution	Other
CFO Dept. Labor (Internal)	Self-explanatory	669,635	333,398	262,471	73,765	100.0%	49.8%	39.2%	11.0%
Contr. Dept. Labor (Internal)	Self-explanatory	5,364,938	2,653,910	2,495,221	215,807	100.0%	49.5%	46.5%	4.0%
CorpComm Dept. Labor (Internal)	Self-explanatory	2,781,600	1,117,754	1,663,846	-	100.0%	40.2%	59.8%	0.0%
Corp Svcs Group (Internal)	Self-explanatory	25,426,000	12,353,649	12,852,062	220,289	100.0%	48.6%	50.5%	0.9%
Finance Labor Costs (Internal)	Self-explanatory	16,427,810	7,958,634	7,726,471	742,705	100.0%	48.4%	47.0%	4.5%
Fin_IMIT Dept. Labor (Internal)	Self-explanatory	5,595,279	2,684,803	2,819,494	90,981	100.0%	48.0%	50.4%	1.6%
Fin_Strat Dept. Labor (Internal)	Self-explanatory	1,784,000	610,128	1,031,152	142,720	100.0%	34.2%	57.8%	8.0%
Fin_Treas Dept. Labor (Internal)	Self-explanatory	240,000	144,062	91,055	4,883	100.0%	60.0%	37.9%	2.0%
GC_Corp Dept. Labor (Internal)	Self-explanatory	596,000	328,321	228,939	38,740	100.0%	55.1%	38.4%	6.5%
GC_Law Dept. Labor (Internal)	Self-explanatory	5,011,000	2,760,427	1,924,858	325,715	100.0%	55.1%	38.4%	6.5%
GC_Reg Dept. Labor (Internal)	Self-explanatory	6,484,676	3,057,798	3,399,386	27,492	100.0%	47.2%	52.4%	0.4%
GC_Secy Dept. Labor (Internal)	Self-explanatory	209,000	115,133	80,282	13,585	100.0%	55.1%	38.4%	6.5%
HR Dept. Labor (Internal)	Self-explanatory	4,054,440	1,930,917	2,043,026	80,497	100.0%	47.6%	50.4%	2.0%
Insurance Costs xB	Self-explanatory	4,751,237	2,866,631	1,785,007	99,599	100.0%	60.3%	37.6%	2.1%
IntAudit Dept. Labor (Internal)	Self-explanatory	2,703,000	1,480,346	1,031,090	191,564	100.0%	54.8%	38.1%	7.1%
IntAudit TD Audits (Internal)	Self-explanatory	0	0	0	-	100.0%	63.2%	36.8%	0.0%
Pres_CEO Dept. Labor (Internal)	Self-explanatory	2,154,000	1,163,160	947,760	43,080	100.0%	54.0%	44.0%	2.0%
Security Dept. Labor (Internal)	Self-explanatory	1,761,000	1,083,012	632,346	45,642	100.0%	61.5%	35.9%	2.6%
Strategic Dept. Labor (Internal)	Self-explanatory	1,261,000	564,506	696,494	-	100.0%	44.8%	55.2%	0.0%
Tax Dept. Labor (Internal)	Self-explanatory	1,033,188	500,863	401,197	131,128	100.0%	48.5%	38.8%	12.7%
Telecom Services	Self-explanatory	13,517,636	6,578,987	6,938,649	-	100.0%	48.7%	51.3%	0.0%
Inergi CSO (Internal)	Self-explanatory	34,139,196	463,428	33,657,249	18,519	100.0%	1.4%	98.6%	0.1%
Inergi Finance (Internal)	Self-explanatory; excl. Inergi Corp. Finance to avoid circularity	9,291,030	5,038,057	3,935,151	317,822	100.0%	54.2%	42.4%	3.4%
Inergi HR (Internal)	Self-explanatory	3,481,000	1,657,818	1,754,070	69,112	100.0%	47.6%	50.4%	2.0%
Inergi IT (Internal)	Self-explanatory	52,024,999	20,350,054	30,901,761	773,184	100.0%	39.1%	59.4%	1.5%
Inergi SMS (Internal)	Self-explanatory	7,134,669	3,624,295	3,316,850	193,524	100.0%	50.8%	46.5%	2.7%
Inergi Total (Internal)	Self-explanatory	106,070,894	31,133,651	73,565,082	1,372,161	100.0%	29.4%	69.4%	1.3%
Inergi Finance_Total Blend (Internal)	Self-explanatory	100.00%	41.79%	55.85%	2.36%	100.0%	41.8%	55.9%	2.4%

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2007 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
Human Resources	Administer Compensation & Benefits Programs	199,433	211,012	8,314	418,760
	Decision support	246,725	261,050	10,286	518,060
	Staffing & Leadership- Recruitment, Hiring, Succession	330,678	349,877	13,786	694,340
	Administer Pension Plan	346,442	366,556	14,443	727,440
	Administer Inergi HR	99,717	105,506	4,157	209,380
	Consulting support to LOBs and corporate functions	1,013,740	1,072,598	42,262	2,128,600
	Director	177,364	187,662	7,394	372,420
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	286,701	303,347	11,952	602,000
	Negotiate with Bargaining Units	86,415	91,432	3,603	181,450
	Participate in grievance and arbitration filings	231,051	244,466	9,632	485,150
	Participate in OLRB hearings	57,340	60,669	2,390	120,400
	Internal vacancy management				-
Communications	Provide communications support for corporate safety program & activities	207,817	219,883		427,700
	Provide communications support for customer information requirements		1,119,050		1,119,050
	Provide Media Program for Community Info & Employee Contributions	763,049	807,351		1,570,400
	Provide Support for Shareholder and External Stakeholder Relationships	543,662	311,738		855,400
	Provide Support to CDM and Other Special Programs		276,350		276,350
	Provide other internal communications support	207,817	219,883		427,700
	Other departmental activities	454,730	366,369	29,301	850,400
	General departmental expenses				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	493,165	511,347		1,004,513
	Develop working relationships with customers, regulators, shareholder, lenders	71,340	185,147		256,487
	General departmental expenses	61,778	76,222		138,000
Corporate Security	Provide Security Services for Company Assets	1,408,961	822,660	59,379	2,291,000

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2007 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)			2,500,000	2,500,000
	Warehouse (Provincial lines)			3,000,000	3,000,000
	Strategic Sourcing Initiative			31,250	31,250
	Supervise Inergi- SMS			125,000	125,000
	Transportation			4,000,000	4,000,000
	Investment Recovery			200,000	200,000
	Inergi Inspection Project			1,200,000	1,200,000
	Other departmental activities			93,750	93,750
	Purchasing			5,051,093	5,051,093
	Transportation			189,416	189,416
	Asset disposal and Investment recovery			378,832	378,832
	Strategic Sourcing Initiative			883,941	883,941
	Support management of warehouse facilities			631,387	631,387
	Other departmental activities			675,331	675,331
Corporate Services SVP	Manage all Corp Services Departments	522,307	543,379	9,314	1,075,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	545,847	572,341	21,486	1,139,673
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	252,509	194,197		446,706
	Support Asset Management activities and projects	524,441	248,704		773,145
	Support Finance activities and projects	363,461	352,858	33,918	750,237
	Provide operational support for Transmission and Distribution activities	62,156	29,476		91,632
	Manage IT capital projects and IT strategy	654,129	993,302	24,853	1,672,284
	Support Inergi operations	282,261	428,616	10,724	721,602
	Other departmental activities	63,204	66,375	2,142	131,721
	General departmental expenses	160,264	168,305	5,431	334,000

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2007 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Corporate Controller	Accting policies; External reports; External audit / review	874,356	609,692	57,428	1,541,475
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	665,294	463,912	49,569	1,178,775
	Regulatory Finance Activities	356,395	396,208	18,135	770,738
	Manage Inergi- General and Inergi- Finance contract				-
	Revenue analysis and reporting	127,004	299,168	12,090	438,263
	Monitor and support Financial systems and Corporate accounting	452,422	520,823	54,405	1,027,650
	Internal controls	178,440	205,418	24,180	408,038
	Other departmental activities	342,991	322,482	14,590	680,063
	Actuarial consultants	357,186	377,924	14,891	750,000
	Consultants- Bill 198 (Canadian SOX) compliance				-
	General departmental expenses	98,935	93,020	8,045	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	125,978	78,445	4,377	208,800
	Insurance- Claims	1,803,913	1,257,876	50,519	3,112,308
	Fiduciary insurance policy	26,237	27,760	1,094	55,091
	IT Costs				-
	General departmental expenses	316,817	200,245	10,740	527,801
Taxation	Compliance activities including tax filings and audits	291,666	232,926	111,771	636,363
	Tax Planning	170,085	135,831	12,987	318,903
	Support Debt issuance	7,854	4,534	599	12,987
	Special Projects	13,639	10,892	1,443	25,974
	Support regulatory filings	7,517	8,356	2,886	18,759
	Support Construction activities	10,102	8,657	1,443	20,202
	Other departmental activities	227,546	182,266		409,812
	Tax Consultants	72,716	58,246	19,037	150,000
	General departmental expenses	33,934	27,182	8,884	70,000
Financial Strategy	Support Regulatory Activities		178,400		178,400
	Support Business Activities		89,200		89,200
	Special Projects		178,400		178,400
	Decision support for lines of business	610,128	406,752	53,520	1,070,400
	DSM		178,400		178,400
	Ontario Hydro Energy			89,200	89,200
	General departmental expenses	102,600	173,400	24,000	300,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2007 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
Internal Audit & Risk Mgmt	Audits	1,109,653	647,297	162,180	1,919,130
	Purchasing	90,076	87,718	11,416	189,210
	IMIT	155,639	163,447	5,274	324,360
	Human Resources	12,873	13,620	537	27,030
	Finance	104,760	101,704	9,776	216,240
	Customers	7,346	17,303	2,382	27,030
	General departmental expenses	43,813	30,517	5,670	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,435,770	806,203	27,492	2,269,465
	Manage HO Relationship with OEB (incl. complaints)	687	51,548		52,235
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	428,875	1,298,997		1,727,872
	Provide Load Forecasts for HO and IMO	372,517	411,005		783,522
	Support Wholesale and Retail Settlement Process	503,104	656,372		1,159,475
	Section 92 Applications	209,627			209,627
	Code Reviews	107,219	175,262		282,480
	Other departmental activities	144,333	243,992		388,325
	All other costs	275,283	560,717		836,000
Regul. Affairs- OEB Cost	OEB Billed costs	6,736,526	5,492,474		12,229,000
Law	Overall Assignment of Time	2,760,427	1,924,858	325,715	5,011,000
	Consultants and External Legal Counsel	920,746	642,040	108,643	1,671,429
	General departmental expenses	70,827	49,388	8,357	128,571
Telecom Services	Management of Telecoms Services	1,516,807	1,599,729	61,464	3,178,000
	Data backbone, assets and lines for all users	2,314,303	2,426,632	91,096	4,832,030
	Voice backbone, assets and lines for all users	1,833,792	1,940,144	75,463	3,849,400
	Repairs, adds, changes to telephones	2,430,892	2,571,873	100,035	5,102,800
ETS - Applications Support	Support CSO Applications	91,390	6,637,363	3,652	6,732,405
	Support Finance Applications	2,433,762	1,900,975	153,532	4,488,270
	Support HR Applications	1,710,022	1,809,305	71,289	3,590,616
	Support Passport Applications	1,495,437	1,646,352		3,141,789
	Support Market Ready Applications	1,440,958	5,701,340		7,142,298
	Support Telecommunications Infrastructure	641,442	678,643	26,396	1,346,481

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2007 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	1,766,394	1,616,552	94,319	3,477,265
	Direct Assignments		1,014,964		1,014,964
	General Infrastructure Support	10,770,649	9,896,266	423,996	21,090,911
Customer Support Operations	Inbound calls / correspondence		21,549,402		21,549,402
	Bill Production		9,481,755	18,519	9,500,274
	Data Services- Timesheets for field personnel, Tx operations	463,428	2,626,092		3,089,520
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,464,886	14,918	4,479,804
Settlements	Wholesale and Retail Settlements	450,000	2,550,000		3,000,000
Finance	Accounts Payable processing	824,274	893,555	110,433	1,828,262
	Accounts Receivable processing	658,118	595,896	113,028	1,367,043
	Fixed Assets processing	407,705	241,475	5,855	655,035
	Corporate accounting, Budgeting, Analysis	3,122,627	2,177,421	87,450	5,387,497
	Pension support	25,333	26,804	1,056	53,193
	Inergi Corp. Finance	304,956	720,574	13,440	1,038,970
HR - Pay Services	Payroll Services and Recordkeepping	1,657,818	1,754,070	69,112	3,481,000
Chair	Overall Assignment of Time	165,813	115,622	19,565	301,000
	General departmental expenses	14,109	9,838	1,053	25,000
Board	Overall Assignment of Time				-
	Audit Fee	324,253	373,276		697,529
	General departmental expenses	325,892	227,246	24,332	577,471

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2007 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
President/CEO Office	Establish performance targets for safety, customer service, reliability	58,158	47,388	2,154	107,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	232,632	189,552	8,616	430,800
	Develop and maintain relationships with major customers and customer groups	232,632	189,552	8,616	430,800
	Develop and maintain relationships with regulators, shareholder, lenders	232,632	189,552	8,616	430,800
	Monitor, assess and remediate risks to operational and financial performance	116,316	94,776	4,308	215,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	232,632	189,552	8,616	430,800
	Plan for management succession	58,158	47,388	2,154	107,700
	General departmental expenses	227,340	185,240	8,420	421,000
Corporate	Overall Assignment of Time	328,321	228,939	38,740	596,000
	General departmental expenses	41,316	28,809	4,875	75,000
Corp. Secretariat	Overall Assignment of Time	115,133	80,282	13,585	209,000
	General departmental expenses	55,087	38,413	6,500	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	95,163	66,357	6,730	168,250
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	65,735	63,817	5,048	134,600
	Ensure financial services are provided efficiently and reliably	13,659	13,261	6,730	33,650
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	28,157	32,413	6,730	67,300
	Monitor performance against operational, financial and regulatory targets	39,651	27,649	30,285	97,585
	Ensure sufficient revenue for operating, financial and regulatory needs	35,686	24,884	6,730	67,300
	Support BOD	18,990	13,242	1,418	33,650
	Ensure access to capital on reasonable terms	36,357	20,848	10,095	67,300
	Other departmental activities	1,675	1,319	371	3,365
	General departmental expenses	198,156	156,001	43,843	398,000
Donations	Donations			1,750,000	1,750,000
TOTAL CCFS		73,136,118	121,045,890	24,161,221	218,343,229

EXHIBIT F

HYDRO ONE COMMON CORPORATE COST MODEL SUMMARY OF CCFS COSTS DISTRIBUTED TO BUSINESS UNITS - 2007				
Function or Service	**Transmission**	**Distribution**	**Other**	**Total**
Human Resources	2,414,099	2,554,261	100,641	5,069,000
Labour Relations	661,508	699,915	27,577	1,389,000
Communications	2,177,075	3,320,623	29,301	5,527,000
External Relations	626,284	772,716		1,399,000
Corporate Security	1,408,961	822,660	59,379	2,291,000
Suppy Management Services			18,960,000	18,960,000
Corporate Services SVP	522,307	543,379	9,314	1,075,000
Info Management & Info Technology	2,908,272	3,054,174	98,554	6,061,000
Corporate Controller	3,453,022	3,288,646	253,332	6,995,000
Treasury	2,272,945	1,564,326	66,729	3,904,000
Taxation	835,059	668,891	159,050	1,663,000
Financial Strategy	712,728	1,204,552	166,720	2,084,000
Internal Audit & Risk Mgmt	1,524,159	1,061,607	197,234	2,783,000
Regulatory Affairs	3,477,414	4,204,094	27,492	7,709,000
Regulatory Affairs- OEB Cost	6,736,526	5,492,474		12,229,000
Law	3,752,000	2,616,285	442,715	6,811,000
Telecom Services	8,095,795	8,538,378	328,058	16,962,230
ETS - Applications Support	7,813,012	18,373,979	254,869	26,441,859
ETS - Infrastructure	12,537,042	12,527,782	518,315	25,583,140
CSO	463,428	38,122,136	33,436	38,619,000
Settlements	450,000	2,550,000		3,000,000
Finance	5,343,013	4,655,725	331,262	10,330,000
HR	1,657,818	1,754,070	69,112	3,481,000
Chair	179,922	125,460	20,618	326,000
Board	650,145	600,522	24,332	1,275,000
President/CEO Office	1,390,500	1,133,000	51,500	2,575,000
Corporate	369,636	257,749	43,615	671,000
Corporate Secretariat	170,220	118,695	20,085	309,000
CFO Office	533,230	419,791	117,979	1,071,000
Donations			1,750,000	1,750,000
Total	73,136,118	121,045,890	24,161,221	218,343,229

EXHIBIT B (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Human Resources	Administer Compensation & Benefits Programs	FTEs	5,252,000	8.2%	432,880
	Decision support	FTEs		10.1%	528,280
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		13.6%	712,920
	Administer Pension Plan	FTEs		14.2%	744,720
	Administer Inergi HR	Inergi HR (Internal)		4.1%	216,440
	Consulting support to LOBs and corporate functions	FTEs		42.4%	2,228,400
	Director	HR Dept. Labor (Internal)		7.4%	388,360
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs	1,471,000	42.4%	623,000
	Negotiate with Bargaining Units	FTEs		13.5%	198,850
	Participate in grievance and arbitration filings	FTEs		35.7%	524,550
	Participate in OLRB hearings	FTEs		8.5%	124,600
	Internal vacancy management	FTEs		0.0%	0
Communications	Provide communications support for corporate safety program & activities	FTEs	5,641,000	7.8%	439,100
	Provide communications support for customer information requirements	Direct Dx		20.1%	1,136,150
	Provide Media Program for Community Info & Employee Contributions	FTEs		28.2%	1,593,200
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital		15.6%	878,200
	Provide Support to CDM and Other Special Programs	Direct Dx		5.0%	282,050
	Provide other internal communications support	FTEs		7.8%	439,100
	Other departmental activities	Non-energy Rev_Assets Blend		15.5%	873,200
	General departmental expenses	CorpComm Dept. Labor (Internal)		0.0%	0
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	1,440,000	72.0%	1,037,173
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend		18.4%	264,827
	General departmental expenses	Strategic Dept. Labor (Internal)		9.6%	138,000
Corporate Security	Provide Security Services for Company Assets	Assets	2,350,000	100.0%	2,350,000

EXHIBIT B (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR	19,303,000	13.2%	2,550,598
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR		15.7%	3,036,141
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR		0.2%	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)		0.6%	125,000
	Transportation	Oper Maint Cap xBxTxR		21.9%	4,229,497
	Investment Recovery	Gross utility plant xBxTxR		1.1%	209,758
	Inergi Inspection Project	Inergi SMS (Internal)		6.6%	1,269,391
	Other departmental activities	Oper Maint Cap xBxTxR		0.5%	97,364
	Purchasing	Oper Maint Cap xB		26.0%	5,014,875
	Transportation	Oper Maint Cap xB		1.0%	188,058
	Asset disposal and Investment recovery	Gross utility plant xBxTxR		1.9%	376,116
	Strategic Sourcing Initiative	Oper Maint Cap xBxT		4.5%	877,603
	Support management of warehouse facilities	Total Assets xBxTxR		3.2%	626,859
	Other departmental activities	Inergi SMS (Internal)		3.5%	670,489
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)	1,099,000	100.0%	1,099,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	6,260,000	18.8%	1,179,274
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		7.4%	462,228
	Support Asset Management activities and projects	Asset Manager		12.8%	800,010
	Support Finance activities and projects	Finance Labor Costs (Internal)		12.4%	776,306
	Provide operational support for Transmission and Distribution activities	Asset Manager		1.5%	94,816
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		27.6%	1,730,392
	Support Inergi operations	Inergi IT (Internal)		11.9%	746,676
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		2.2%	136,298
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		5.3%	334,000

EXHIBIT B (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	7,010,000	22.0%	1,545,300
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend		16.9%	1,181,700
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)		11.0%	772,650
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)		0.0%	0
	Revenue analysis and reporting	Total Revenue		6.3%	439,350
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend		14.7%	1,030,200
	Internal controls	Total Revenue_Assets Blend		5.8%	409,050
	Other departmental activities	Contr. Dept. Labor (Internal)		9.7%	681,750
	Actuarial consultants	FTEs		10.7%	750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend		0.0%	0
	General departmental expenses	Contr. Dept. Labor (Internal)		2.9%	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB	3,913,000	5.5%	216,630
	Insurance- Claims	Non-energy Rev_Assets Blend xB		79.6%	3,113,478
	Fiduciary insurance policy	FTEs		1.4%	55,091
	IT Costs	Total Capital		0.0%	0
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		13.5%	527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	1,713,000	38.4%	658,413
	Tax Planning	OperMaint Exp_Assets Blend		19.3%	329,953
	Support Debt issuance	Total Debt		0.8%	13,437
	Special Projects	OperMaint Exp_Assets Blend		1.6%	26,874
	Support regulatory filings	GC_Reg Dept. Labor (Internal)		1.1%	19,409
	Support Construction activities	Capital Expenditures		1.2%	20,902
	Other departmental activities	Tax Dept. Labor (Internal)		24.8%	424,012
	Tax Consultants	Tax Dept. Labor (Internal)		8.8%	150,000
	General departmental expenses	Tax Dept. Labor (Internal)		4.1%	70,000
Financial Strategy	Support Regulatory Activities	All Direct	1,896,000	9.7%	184,600
	Support Business Activities	All Direct		4.9%	92,300
	Special Projects	All Direct		9.7%	184,600
	Decision support for lines of business	All Direct		58.4%	1,107,600
	DSM	All Direct		9.7%	184,600
	Ontario Hydro Energy	All Direct		4.9%	92,300
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		2.6%	50,000

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	2,878,000	69.0%	1,986,580
	Purchasing	Oper Maint Cap		6.8%	195,860
	IMIT	Fin_IMIT Dept. Labor (Internal)		11.7%	335,760
	Human Resources	HR Dept. Labor (Internal)		1.0%	27,980
	Finance	Finance Labor Costs (Internal)		7.8%	223,840
	Customers	Total Revenue		1.0%	27,980
	General departmental expenses	IntAudit Dept. Labor (Internal)		2.8%	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct	7,996,000	28.5%	2,277,059
	Manage HO Relationship with OEB (incl. complaints)	All Direct		0.7%	52,410
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct		0.0%	0
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct		21.7%	1,733,654
	Provide Load Forecasts for HO and IMO	All Direct		9.8%	786,144
	Support Wholesale and Retail Settlement Process	All Direct		14.5%	1,163,355
	Section 92 Applications	All Direct		2.6%	210,328
	Code Reviews	All Direct		3.5%	283,426
	Other departmental activities	GC_Reg Dept. Labor (Internal)		4.9%	389,624
	All other costs	All Direct		13.8%	1,100,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct	11,945,000	100.0%	11,945,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	6,985,000	74.2%	5,185,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		23.9%	1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		1.8%	128,571
Telecom Services	Management of Telecoms Services	Telecom Services	17,068,830	21.5%	3,675,000
	Data backbone, assets and lines for all users	Workstations		28.3%	4,832,030
	Voice backbone, assets and lines for all users	Telephones		22.6%	3,854,000
	Repairs, adds, changes to telephones	Telephones		27.6%	4,707,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)	26,472,864	25.5%	6,740,299
	Support Finance Applications	Inergi Finance (Internal)		17.0%	4,493,533
	Support HR Applications	Inergi HR (Internal)		13.6%	3,594,826
	Support Passport Applications	ProgramProjectCosts		11.9%	3,145,473
	Support Market Ready Applications	Market Ready		27.0%	7,150,673
	Support Telecommunications Infrastructure	Telephones		5.1%	1,348,060

EXHIBIT B (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)	25,613,137	13.6%	3,481,342
	Direct Assignments	All Direct		4.0%	1,016,154
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		82.4%	21,115,641
Customer Support Operations	Inbound calls / correspondence	All Direct	38,190,000	55.8%	21,310,020
	Bill Production	All Direct		24.6%	9,394,740
	Data Services- Timesheets for field personnel, Tx operations	All Direct		8.0%	3,055,200
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct		11.6%	4,430,040
Settlements	Wholesale and Retail Settlements	All Direct	3,000,000	100.0%	3,000,000
Finance	Accounts Payable processing	Invoices To Vendors	9,825,000	17.7%	1,738,884
	Accounts Receivable processing	Other Bills To Customers		13.2%	1,300,213
	Fixed Assets processing	Gross utility plant xB		6.3%	623,012
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		52.2%	5,124,120
	Pension support	FTEs		0.5%	50,592
	Inergi Corp. Finance	Inergi Total (Internal)		10.1%	988,178
HR - Pay Services	Payroll Services and Recordkeepping	FTEs	3,516,000	100.0%	3,516,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	338,000	92.6%	313,000
	General departmental expenses	Non-energy Rev_Assets Blend		7.4%	25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend	1,275,000	0.0%	0
	Audit Fee	Total Revenue_Assets Blend xBxTxR		54.7%	697,529
	General departmental expenses	Non-energy Rev_Assets Blend		45.3%	577,471

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct	2,635,000	4.2%	110,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct		16.8%	442,800
	Develop and maintain relationships with major customers and customer groups	All Direct		16.8%	442,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct		16.8%	442,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct		8.4%	221,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct		16.8%	442,800
	Plan for management succession	All Direct		4.2%	110,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		16.0%	421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	689,000	89.1%	614,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		10.9%	75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	317,000	68.5%	217,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		31.5%	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	1,079,000	16.2%	174,750
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)		13.0%	139,800
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)		3.2%	34,950
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend		6.5%	69,900
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend		9.4%	101,355
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend		6.5%	69,900
	Support BOD	Non-energy Rev_Assets Blend		3.2%	34,950
	Ensure access to capital on reasonable terms	Total Capital		6.5%	69,900
	Other departmental activities	CFO Dept. Labor (Internal)		0.3%	3,495
	General departmental expenses	CFO Dept. Labor (Internal)		35.2%	380,000
Donations	Donations	Direct Holding Company	2,000,000	100.0%	2,000,000
Total CCFS			219,170,831		219,170,831

EXIBIT C (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
Human Resources	Administer Compensation & Benefits Programs			
	Decision support			
	Staffing & Leadership- Recruitment, Hiring, Succession			
	Administer Pension Plan			
	Administer Inergi HR			
	Consulting support to LOBs and corporate functions			
	Director			
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements			
	Negotiate with Bargaining Units			
	Participate in grievance and arbitration filings			
	Participate in OLRB hearings			
	Internal vacancy management			
Communications	Provide communications support for corporate safety program & activities			
	Provide communications support for customer information requirements			
	Provide Media Program for Community Info & Employee Contributions			
	Provide Support for Shareholder and External Stakeholder Relationships			
	Provide Support to CDM and Other Special Programs			
	Provide other internal communications support			
	Other departmental activities			
	General departmental expenses			
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations		172,906	
	Develop working relationships with customers, regulators, shareholder, lenders	46,351	172,124	
	General departmental expenses			
Corporate Security	Provide Security Services for Company Assets	1,083,811	632,223	45,159

EXHIBIT C (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocated to T&D, Others	Materials Surcharge	Total 2008 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Human Resources	Administer Compensation & Benefits Programs	FTEs		432,880		432,880
	Decision support	FTEs		528,280		528,280
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		712,920		712,920
	Administer Pension Plan	FTEs		744,720		744,720
	Administer Inergi HR	Inergi HR (Internal)		216,440		216,440
	Consulting support to LOBs and corporate functions	FTEs		2,228,400		2,228,400
	Director	HR Dept. Labor (Internal)		388,360		388,360
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs		623,000		623,000
	Negotiate with Bargaining Units	FTEs		198,850		198,850
	Participate in grievance and arbitration filings	FTEs		524,550		524,550
	Participate in OLRB hearings	FTEs		124,600		124,600
	Internal vacancy management	FTEs				-
Communications	Provide communications support for corporate safety program & activities	FTEs	439,100			439,100
	Provide communications support for customer information requirements	Direct Dx	1,136,150			1,136,150
	Provide Media Program for Community Info & Employee Contributions	FTEs	1,593,200			1,593,200
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital	878,200			878,200
	Provide Support to CDM and Other Special Programs	Direct Dx	282,050			282,050
	Provide other internal communications support	FTEs	439,100			439,100
	Other departmental activities	Non-energy Rev_Assets Blend	159,156	714,044		873,200
	General departmental expenses	CorpComm Dept. Labor (Internal)				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	864,268			1,037,173
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend	46,351			264,827
	General departmental expenses	Strategic Dept. Labor (Internal)		138,000		138,000
Corporate Security	Provide Security Services for Company Assets	Assets		588,808		2,350,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment: Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management) Warehouse (Provincial lines) Strategic Sourcing Initiative Supervise Inergi- SMS Transportation Investment Recovery Inergi Inspection Project Other departmental activities Purchasing Transportation Asset disposal and Investment recovery Strategic Sourcing Initiative Support management of warehouse facilities Other departmental activities			
Corporate Services SVP	Manage all Corp Services Departments			
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements Support Asset Management activities and projects Support Finance activities and projects Provide operational support for Transmission and Distribution activities Manage IT capital projects and IT strategy Support Inergi operations Other departmental activities General departmental expenses		77,038	

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocation: Allocated to T&D, Others	Allocation: Materials Surcharge	Total 2008 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR			2,550,598	2,550,598
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR			3,036,141	3,036,141
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR			31,250	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)			125,000	125,000
	Transportation	Oper Maint Cap xBxTxR			4,229,497	4,229,497
	Investment Recovery	Gross utility plant xBxTxR			209,758	209,758
	Inergi Inspection Project	Inergi SMS (Internal)			1,269,391	1,269,391
	Other departmental activities	Oper Maint Cap xBxTxR			97,364	97,364
	Purchasing	Oper Maint Cap xB			5,014,875	5,014,875
	Transportation	Oper Maint Cap xB			188,058	188,058
	Asset disposal and Investment recovery	Gross utility plant xBxTxR			376,116	376,116
	Strategic Sourcing Initiative	Oper Maint Cap xBxT			877,603	877,603
	Support management of warehouse facilities	Total Assets xBxTxR			626,859	626,859
	Other departmental activities	Inergi SMS (Internal)			670,489	670,489
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)		1,099,000		1,099,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations		1,179,274		1,179,274
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		385,190		462,228
	Support Asset Management activities and projects	Asset Manager		800,010		800,010
	Support Finance activities and projects	Finance Labor Costs (Internal)		776,306		776,306
	Provide operational support for Transmission and Distribution activities	Asset Manager		94,816		94,816
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		1,730,392		1,730,392
	Support Inergi operations	Inergi IT (Internal)		746,676		746,676
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		136,298		136,298
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		334,000		334,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment: Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
Corporate Controller	Accting policies; External reports; External audit / review			57,570
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections			49,692
	Regulatory Finance Activities			18,180
	Manage Inergi- General and Inergi- Finance contract			
	Revenue analysis and reporting			12,120
	Monitor and support Financial systems and Corporate accounting			54,540
	Internal controls			24,240
	Other departmental activities			
	Actuarial consultants			
	Consultants- Bill 198 (Canadian SOX) compliance			
	General departmental expenses			
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management			
	Insurance- Claims			
	Fiduciary insurance policy			
	IT Costs			
	General departmental expenses			
Taxation	Compliance activities including tax filings and audits			114,961
	Tax Planning			13,437
	Support Debt issuance			
	Special Projects			1,493
	Support regulatory filings			2,986
	Support Construction activities			1,493
	Other departmental activities			
	Tax Consultants			
	General departmental expenses			
Financial Strategy	Support Regulatory Activities		184,600	
	Support Business Activities		92,300	
	Special Projects		184,600	
	Decision support for lines of business	631,332	420,888	55,380
	DSM		184,600	
	Ontario Hydro Energy			92,300
	General departmental expenses			

EXHIBIT C (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocation: Allocated to T&D, Others	Allocation: Materials Surcharge	Total 2008 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	1,487,730			1,545,300
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend	1,132,008			1,181,700
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)	754,470			772,650
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)				-
	Revenue analysis and reporting	Total Revenue	427,230			439,350
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend	975,660			1,030,200
	Internal controls	Total Revenue_Assets Blend	384,810			409,050
	Other departmental activities	Contr. Dept. Labor (Internal)	318,150	363,600		681,750
	Actuarial consultants	FTEs		750,000		750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend				-
	General departmental expenses	Contr. Dept. Labor (Internal)		200,000		200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB		216,630		216,630
	Insurance- Claims	Non-energy Rev_Assets Blend xB		3,113,478		3,113,478
	Fiduciary insurance policy	FTEs		55,091		55,091
	IT Costs	Total Capital				-
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		527,801		527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	530,015	13,437		658,413
	Tax Planning	OperMaint Exp_Assets Blend	316,516			329,953
	Support Debt issuance	Total Debt		13,437		13,437
	Special Projects	OperMaint Exp_Assets Blend	25,381			26,874
	Support regulatory filings	GC_Reg Dept. Labor (Internal)	16,423			19,409
	Support Construction activities	Capital Expenditures	19,409			20,902
	Other departmental activities	Tax Dept. Labor (Internal)	424,012			424,012
	Tax Consultants	Tax Dept. Labor (Internal)		150,000		150,000
	General departmental expenses	Tax Dept. Labor (Internal)		70,000		70,000
Financial Strategy	Support Regulatory Activities	All Direct				184,600
	Support Business Activities	All Direct				92,300
	Special Projects	All Direct				184,600
	Decision support for lines of business	All Direct				1,107,600
	DSM	All Direct				184,600
	Ontario Hydro Energy	All Direct				92,300
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		50,000		50,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
Internal Audit & Risk Mgmt	Audits	671,520	391,720	167,880
	Purchasing			
	IMIT			
	Human Resources			
	Finance			
	Customers			
	General departmental expenses			
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,440,574	808,901	27,584
	Manage HO Relationship with OEB (incl. complaints)	690	51,720	
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates			
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	430,310	1,303,344	
	Provide Load Forecasts for HO and IMO	373,763	412,381	
	Support Wholesale and Retail Settlement Process	504,787	658,568	
	Section 92 Applications	210,328		
	Code Reviews	107,578	175,848	
	Other departmental activities	144,816	244,808	
	All other costs	362,214	737,786	
Regul. Affairs- OEB Cost	OEB Billed costs	6,580,081	5,364,919	
Law	Overall Assignment of Time			337,025
	Consultants and External Legal Counsel			
	General departmental expenses			
Telecom Services	Management of Telecoms Services			
	Data backbone, assets and lines for all users			
	Voice backbone, assets and lines for all users			
	Repairs, adds, changes to telephones			
ETS - Applications Support	Support CSO Applications			
	Support Finance Applications			
	Support HR Applications			
	Support Passport Applications			
	Support Market Ready Applications			
	Support Telecommunications Infrastructure			

EXHIBIT C (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Cost Driver	Allocated to T&D	Allocated to T&D, Others	Materials Surcharge	Total 2008 Activity Budget
		Allocation				
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	755,460			1,986,580
	Purchasing	Oper Maint Cap		195,860		195,860
	IMIT	Fin_IMIT Dept. Labor (Internal)		335,760		335,760
	Human Resources	HR Dept. Labor (Internal)		27,980		27,980
	Finance	Finance Labor Costs (Internal)		223,840		223,840
	Customers	Total Revenue		27,980		27,980
	General departmental expenses	IntAudit Dept. Labor (Internal)		80,000		80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct				2,277,059
	Manage HO Relationship with OEB (incl. complaints)	All Direct				52,410
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct				1,733,654
	Provide Load Forecasts for HO and IMO	All Direct				786,144
	Support Wholesale and Retail Settlement Process	All Direct				1,163,355
	Section 92 Applications	All Direct				210,328
	Code Reviews	All Direct				283,426
	Other departmental activities	GC_Reg Dept. Labor (Internal)				389,624
	All other costs	All Direct				1,100,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct				11,945,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	4,847,975			5,185,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		1,671,429		1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		128,571		128,571
Telecom Services	Management of Telecoms Services	Telecom Services		3,675,000		3,675,000
	Data backbone, assets and lines for all users	Workstations		4,832,030		4,832,030
	Voice backbone, assets and lines for all users	Telephones		3,854,000		3,854,000
	Repairs, adds, changes to telephones	Telephones		4,707,800		4,707,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)		6,740,299		6,740,299
	Support Finance Applications	Inergi Finance (Internal)		4,493,533		4,493,533
	Support HR Applications	Inergi HR (Internal)		3,594,826		3,594,826
	Support Passport Applications	ProgramProjectCosts		3,145,473		3,145,473
	Support Market Ready Applications	Market Ready		7,150,673		7,150,673
	Support Telecommunications Infrastructure	Telephones		1,348,060		1,348,060

EXHIBIT C (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services			
	Direct Assignments		1,016,154	
	General Infrastructure Support			
Customer Support Operations	Inbound calls / correspondence		21,310,020	
	Bill Production		9,376,427	18,313
	Data Services- Timesheets for field personnel, Tx operations	458,280	2,596,920	
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,415,288	14,752
Settlements	Wholesale and Retail Settlements	450,000	2,550,000	
Finance	Accounts Payable processing			
	Accounts Receivable processing			
	Fixed Assets processing			
	Corporate accounting, Budgeting, Analysis			
	Pension support			
	Inergi Corp. Finance			
HR - Pay Services	Payroll Services and Recordkeepping			
Chair	Overall Assignment of Time			20,345
	General departmental expenses			
Board	Overall Assignment of Time			
	Audit Fee			
	General departmental expenses			

EXHIBIT C (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

		Allocation				
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2008 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)		3,481,342		3,481,342
	Direct Assignments	All Direct				1,016,154
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		21,115,641		21,115,641
Customer Support Operations	Inbound calls / correspondence	All Direct				21,310,020
	Bill Production	All Direct				9,394,740
	Data Services- Timesheets for field personnel, Tx operations	All Direct				3,055,200
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct				4,430,040
Settlements	Wholesale and Retail Settlements	All Direct				3,000,000
Finance	Accounts Payable processing	Invoices To Vendors		1,738,884		1,738,884
	Accounts Receivable processing	Other Bills To Customers		1,300,213		1,300,213
	Fixed Assets processing	Gross utility plant xB		623,012		623,012
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		5,124,120		5,124,120
	Pension support	FTEs		50,592		50,592
	Inergi Corp. Finance	Inergi Total (Internal)		988,178		988,178
HR - Pay Services	Payroll Services and Recordkeepping	FTEs		3,516,000		3,516,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	292,655			313,000
	General departmental expenses	Non-energy Rev_Assets Blend		25,000		25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend				-
	Audit Fee	Total Revenue_Assets Blend xBxTxR		697,529		697,529
	General departmental expenses	Non-energy Rev_Assets Blend		577,471		577,471

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment Transmission	Direct Assignment Distribution	Direct Assignment Other
(A)	(B)	(D)	(C)	(E)
President/CEO Office	Establish performance targets for safety, customer service, reliability	59,778	48,708	2,214
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	239,112	194,832	8,856
	Develop and maintain relationships with major customers and customer groups	239,112	194,832	8,856
	Develop and maintain relationships with regulators, shareholder, lenders	239,112	194,832	8,856
	Monitor, assess and remediate risks to operational and financial performance	119,556	97,416	4,428
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	239,112	194,832	8,856
	Plan for management succession	59,778	48,708	2,214
	General departmental expenses			
Corporate	Overall Assignment of Time			39,910
	General departmental expenses			
Corp. Secretariat	Overall Assignment of Time			14,105
	General departmental expenses			
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans			6,990
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder			5,243
	Ensure financial services are provided efficiently and reliably			6,990
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities			6,990
	Monitor performance against operational, financial and regulatory targets			31,455
	Ensure sufficient revenue for operating, financial and regulatory needs			6,990
	Support BOD			
	Ensure access to capital on reasonable terms			10,485
	Other departmental activities			
	General departmental expenses			
Donations	Donations			
TOTAL CCFS		14,691,995	54,510,242	1,302,887

EXHIBIT C (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Cost Driver	Allocation: Allocated to T&D	Allocated to T&D, Others	Materials Surcharge	Total 2008 Activity Budget
(A)	(B)	(F)	(G)	(H)	(I)	(J)
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct				110,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct				442,800
	Develop and maintain relationships with major customers and customer groups	All Direct				442,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct				442,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct				221,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct				442,800
	Plan for management succession	All Direct				110,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		421,000		421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	574,090			614,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		75,000		75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	202,895			217,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		100,000		100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	167,760			174,750
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)	134,558			139,800
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)	27,960			34,950
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend	62,910			69,900
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend	69,900			101,355
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend	62,910			69,900
	Support BOD	Non-energy Rev_Assets Blend		34,950		34,950
	Ensure access to capital on reasonable terms	Total Capital	59,415			69,900
	Other departmental activities	CFO Dept. Labor (Internal)		3,495		3,495
	General departmental expenses	CFO Dept. Labor (Internal)		380,000		380,000
Donations	Donations	Direct Holding Company		2,000,000		2,000,000
TOTAL CCFS			19,907,876	109,454,831	19,303,000	219,170,831

EXHIBIT E (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2008 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
Human Resources	Administer Compensation & Benefits Programs	206,158	218,128	8,594	432,880
	Decision support	251,592	266,199	10,489	528,280
	Staffing & Leadership- Recruitment, Hiring, Succession	339,526	359,239	14,154	712,920
	Administer Pension Plan	354,671	375,263	14,786	744,720
	Administer Inergi HR	103,079	109,064	4,297	216,440
	Consulting support to LOBs and corporate functions	1,061,270	1,122,887	44,243	2,228,400
	Director	184,955	195,694	7,711	388,360
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	296,702	313,929	12,369	623,000
	Negotiate with Bargaining Units	94,702	100,200	3,948	198,850
	Participate in grievance and arbitration filings	249,816	264,320	10,414	524,550
	Participate in OLRB hearings	59,340	62,786	2,474	124,600
	Internal vacancy management				-
Communications	Provide communications support for corporate safety program & activities	213,356	225,744		439,100
	Provide communications support for customer information requirements		1,136,150		1,136,150
	Provide Media Program for Community Info & Employee Contributions	774,127	819,073		1,593,200
	Provide Support for Shareholder and External Stakeholder Relationships	558,153	320,047		878,200
	Provide Support to CDM and Other Special Programs		282,050		282,050
	Provide other internal communications support	213,356	225,744		439,100
	Other departmental activities	467,597	375,341	30,262	873,200
	General departmental expenses				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	509,200	527,973		1,037,173
	Develop working relationships with customers, regulators, shareholder, lenders	73,660	191,167		264,827
	General departmental expenses	61,778	76,222		138,000
Corporate Security	Provide Security Services for Company Assets	1,445,246	843,846	60,908	2,350,000

EXHIBIT E (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2008 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)			2,550,598	2,550,598
	Warehouse (Provincial lines)			3,036,141	3,036,141
	Strategic Sourcing Initiative			31,250	31,250
	Supervise Inergi- SMS			125,000	125,000
	Transportation			4,229,497	4,229,497
	Investment Recovery			209,758	209,758
	Inergi Inspection Project			1,269,391	1,269,391
	Other departmental activities			97,364	97,364
	Purchasing			5,014,875	5,014,875
	Transportation			188,058	188,058
	Asset disposal and Investment recovery			376,116	376,116
	Strategic Sourcing Initiative			877,603	877,603
	Support management of warehouse facilities			626,859	626,859
	Other departmental activities			670,489	670,489
Corporate Services SVP	Manage all Corp Services Departments	533,968	555,511	9,522	1,099,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	564,814	592,228	22,232	1,179,274
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	261,283	200,945		462,228
	Support Asset Management activities and projects	542,664	257,346		800,010
	Support Finance activities and projects	376,090	365,119	35,097	776,306
	Provide operational support for Transmission and Distribution activities	64,316	30,500		94,816
	Manage IT capital projects and IT strategy	676,859	1,027,817	25,717	1,730,392
	Support Inergi operations	292,069	443,510	11,097	746,676
	Other departmental activities	65,400	68,681	2,216	136,298
	General departmental expenses	160,264	168,305	5,431	334,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2008 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
Corporate Controller	Accting policies; External reports; External audit / review	876,525	611,205	57,570	1,545,300
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	666,945	465,063	49,692	1,181,700
	Regulatory Finance Activities	357,279	397,191	18,180	772,650
	Manage Inergi- General and Inergi- Finance contract				-
	Revenue analysis and reporting	127,319	299,911	12,120	439,350
	Monitor and support Financial systems and Corporate accounting	453,545	522,115	54,540	1,030,200
	Internal controls	178,883	205,927	24,240	409,050
	Other departmental activities	343,842	323,282	14,626	681,750
	Actuarial consultants	357,186	377,924	14,891	750,000
	Consultants- Bill 198 (Canadian SOX) compliance				-
	General departmental expenses	98,935	93,020	8,045	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	130,702	81,386	4,541	216,630
	Insurance- Claims	1,804,591	1,258,349	50,538	3,113,478
	Fiduciary insurance policy	26,237	27,760	1,094	55,091
	IT Costs				-
	General departmental expenses	316,817	200,245	10,740	527,801
Taxation	Compliance activities including tax filings and audits	301,772	240,997	115,644	658,413
	Tax Planning	175,978	140,538	13,437	329,953
	Support Debt issuance	8,127	4,691	620	13,437
	Special Projects	14,111	11,270	1,493	26,874
	Support regulatory filings	7,777	8,646	2,986	19,409
	Support Construction activities	10,452	8,957	1,493	20,902
	Other departmental activities	235,430	188,582		424,012
	Tax Consultants	72,716	58,246	19,037	150,000
	General departmental expenses	33,934	27,182	8,884	70,000
Financial Strategy	Support Regulatory Activities		184,600		184,600
	Support Business Activities		92,300		92,300
	Special Projects		184,600		184,600
	Decision support for lines of business	631,332	420,888	55,380	1,107,600
	DSM		184,600		184,600
	Ontario Hydro Energy			92,300	92,300
	General departmental expenses	17,100	28,900	4,000	50,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2008 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Internal Audit & Risk Mgmt	Audits	1,148,653	670,047	167,880	1,986,580
	Purchasing	93,242	90,801	11,817	195,860
	IMIT	161,109	169,191	5,460	335,760
	Human Resources	13,325	14,099	556	27,980
	Finance	108,442	105,278	10,120	223,840
	Customers	7,604	17,911	2,465	27,980
	General departmental expenses	43,813	30,517	5,670	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,440,574	808,901	27,584	2,277,059
	Manage HO Relationship with OEB (incl. complaints)	690	51,720		52,410
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	430,310	1,303,344		1,733,654
	Provide Load Forecasts for HO and IMO	373,763	412,381		786,144
	Support Wholesale and Retail Settlement Process	504,787	658,568		1,163,355
	Section 92 Applications	210,328			210,328
	Code Reviews	107,578	175,848		283,426
	Other departmental activities	144,816	244,808		389,624
	All other costs	362,214	737,786		1,100,000
Regul. Affairs- OEB Cost	OEB Billed costs	6,580,081	5,364,919		11,945,000
Law	Overall Assignment of Time	2,856,279	1,991,696	337,025	5,185,000
	Consultants and External Legal Counsel	920,746	642,040	108,643	1,671,429
	General departmental expenses	70,827	49,388	8,357	128,571
Telecom Services	Management of Telecoms Services	1,754,017	1,849,906	71,076	3,675,000
	Data backbone, assets and lines for all users	2,314,303	2,426,632	91,096	4,832,030
	Voice backbone, assets and lines for all users	1,835,984	1,942,463	75,553	3,854,000
	Repairs, adds, changes to telephones	2,242,720	2,372,788	92,291	4,707,800
ETS - Applications Support	Support CSO Applications	91,497	6,645,145	3,656	6,740,299
	Support Finance Applications	2,436,616	1,903,205	153,712	4,493,533
	Support HR Applications	1,712,027	1,811,427	71,372	3,594,826
	Support Passport Applications	1,497,190	1,648,283		3,145,473
	Support Market Ready Applications	1,442,648	5,708,025		7,150,673
	Support Telecommunications Infrastructure	642,194	679,439	26,427	1,348,060

EXHIBIT E (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2008 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	1,768,465	1,618,448	94,430	3,481,342
	Direct Assignments		1,016,154		1,016,154
	General Infrastructure Support	10,783,278	9,907,870	424,494	21,115,641
Customer Support Operations	Inbound calls / correspondence		21,310,020		21,310,020
	Bill Production		9,376,427	18,313	9,394,740
	Data Services- Timesheets for field personnel, Tx operations	458,280	2,596,920		3,055,200
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,415,288	14,752	4,430,040
Settlements	Wholesale and Retail Settlements	450,000	2,550,000		3,000,000
Finance	Accounts Payable processing	783,978	849,872	105,034	1,738,884
	Accounts Receivable processing	625,945	566,765	107,503	1,300,213
	Fixed Assets processing	387,774	229,670	5,569	623,012
	Corporate accounting, Budgeting, Analysis	2,969,972	2,070,974	83,175	5,124,120
	Pension support	24,094	25,493	1,004	50,592
	Inergi Corp. Finance	290,048	685,348	12,783	988,178
HR - Pay Services	Payroll Services and Recordkeepping	1,674,486	1,771,707	69,807	3,516,000
Chair	Overall Assignment of Time	172,423	120,232	20,345	313,000
	General departmental expenses	14,109	9,838	1,053	25,000
Board	Overall Assignment of Time				-
	Audit Fee	324,253	373,276		697,529
	General departmental expenses	325,892	227,246	24,332	577,471

EXHIBIT E (2008)

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

Function or Service	Activities Performed	Total Activity Cost to Business Unit: Transmission	Distribution	Other	Total 2008 Activity Budget
(A)	(B)	(D)	(C)	(E)	(F)
President/CEO Office	Establish performance targets for safety, customer service, reliability	59,778	48,708	2,214	110,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	239,112	194,832	8,856	442,800
	Develop and maintain relationships with major customers and customer groups	239,112	194,832	8,856	442,800
	Develop and maintain relationships with regulators, shareholder, lenders	239,112	194,832	8,856	442,800
	Monitor, assess and remediate risks to operational and financial performance	119,556	97,416	4,428	221,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	239,112	194,832	8,856	442,800
	Plan for management succession	59,778	48,708	2,214	110,700
	General departmental expenses	227,340	185,240	8,420	421,000
Corporate	Overall Assignment of Time	338,236	235,854	39,910	614,000
	General departmental expenses	41,316	28,809	4,875	75,000
Corp. Secretariat	Overall Assignment of Time	119,540	83,355	14,105	217,000
	General departmental expenses	55,087	38,413	6,500	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	98,839	68,921	6,990	174,750
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	68,275	66,283	5,243	139,800
	Ensure financial services are provided efficiently and reliably	14,187	13,773	6,990	34,950
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	29,244	33,666	6,990	69,900
	Monitor performance against operational, financial and regulatory targets	41,183	28,717	31,455	101,355
	Ensure sufficient revenue for operating, financial and regulatory needs	37,065	25,845	6,990	69,900
	Support BOD	19,724	13,754	1,473	34,950
	Ensure access to capital on reasonable terms	37,762	21,653	10,485	69,900
	Other departmental activities	1,740	1,370	385	3,495
	General departmental expenses	189,195	148,945	41,860	380,000
Donations	Donations			2,000,000	2,000,000
TOTAL CCFS		73,419,215	120,986,261	24,765,355	219,170,831

HYDRO ONE COMMON CORPORATE COST MODEL
SUMMARY OF CCFS COSTS DISTRIBUTED TO BUSINESS UNITS - 2008

Function or Service	Transmission	Distribution	Other	Total
Human Resources	2,501,252	2,646,474	104,274	5,252,000
Labour Relations	700,560	741,234	29,205	1,471,000
Communications	2,226,590	3,384,148	30,262	5,641,000
External Relations	644,638	795,362		1,440,000
Corporate Security	1,445,246	843,846	60,908	2,350,000
Suppy Management Services			19,303,000	19,303,000
Corporate Services SVP	533,968	555,511	9,522	1,099,000
Info Management & Info Technology	3,003,759	3,154,451	101,790	6,260,000
Corporate Controller	3,460,459	3,295,638	253,904	7,010,000
Treasury	2,278,347	1,567,740	66,913	3,913,000
Taxation	860,298	689,108	163,594	1,713,000
Financial Strategy	648,432	1,095,888	151,680	1,896,000
Internal Audit & Risk Mgmt	1,576,188	1,097,845	203,967	2,878,000
Regulatory Affairs	3,575,061	4,393,355	27,584	7,996,000
Regulatory Affairs- OEB Cost	6,580,081	5,364,919		11,945,000
Law	3,847,852	2,683,123	454,025	6,985,000
Telecom Services	8,147,024	8,591,789	330,016	17,068,830
ETS - Applications Support	7,822,173	18,395,523	255,168	26,472,864
ETS - Infrastructure	12,551,742	12,542,472	518,923	25,613,137
CSO	458,280	37,698,655	33,065	38,190,000
Settlements	450,000	2,550,000		3,000,000
Finance	5,081,810	4,428,122	315,068	9,825,000
HR	1,674,486	1,771,707	69,807	3,516,000
Chair	186,532	130,070	21,398	338,000
Board	650,145	600,522	24,332	1,275,000
President/CEO Office	1,422,900	1,159,400	52,700	2,635,000
Corporate	379,552	264,663	44,785	689,000
Corporate Secretariat	174,627	121,768	20,605	317,000
CFO Office	537,213	422,927	118,860	1,079,000
Donations			2,000,000	2,000,000
Total	73,419,215	120,986,261	24,765,355	219,170,831

EXHIBIT C1, TAB 5, SCHEDULE 2, ATTACHMENT A – EB-2006-0501

Filed: September 12, 2006
EB-2005-0501
Exhibit C1-5-2
Attachment "A"

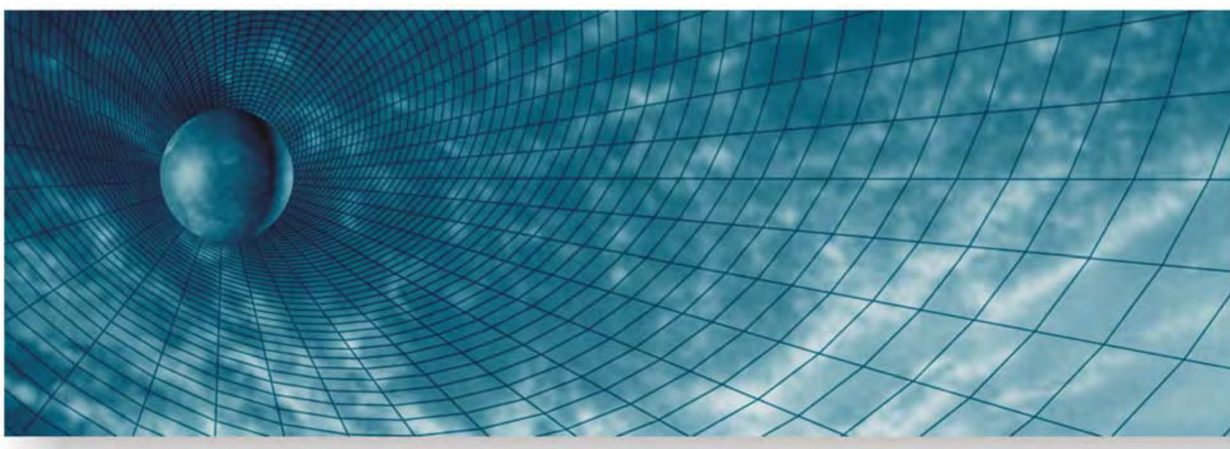
Report to

Hydro One Networks Inc.

Regarding

Transmission Overhead Capitalization Rate Method

April 30, 2006



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I. OVERVIEW

A. Introduction

In this Report, R. J. Rudden Associates ("Rudden" or "we") presents the Ontario Energy Board ("OEB")-approved method for Hydro One to compute its Transmission Overhead Capitalization Rate (Tx OH Cap Rate). The methodology used in this Report is the same methodology as approved by the OEB for development of the Distribution Overhead Capitalization Rate.

The Tx OH Cap Rate is used to distribute the Transmission business portion of Common Corporate Functions and Services including Inergi ("CCFS") costs and Asset Management costs, between Transmission business Operations and Maintenance ("OM&A"), and Transmission business Capital Projects. The Tx OH Cap Rate is a percentage that is applied to the cost of Transmission Capital Projects each year; the result is the amount of Transmission business CCFS costs and Transmission business Asset Management costs that are capitalized to capital projects for the year.

Rudden recommended, Hydro One adopted, and the OEB approved a Distribution Overhead Capitalization Rate methodology, described in our *Distribution Overhead Capitalization Rate Method* report (May 20, 2005) using information from our *Report on Common Costs Methodology Review* (May 20, 2005). This Tx OH Cap Rate applies the same, OEB-approved method, updated for significant changes.

This Report includes Attachment A (2007 results) and Attachment B (2008 results).

B. Criteria for Cost Allocation Methods

CCFS and Asset Management activities support both Transmission business OM&A and Transmission business capital projects. **The Tx OH Cap Rate is used to distribute the Transmission business portion of CCFS costs and Asset Management costs, between Transmission business OM&A, and Transmission business Capital Projects.** The Tx OH Cap Rate is only used to allocate costs to Capital Expenditures. The following are the criteria that Rudden used in selecting and evaluating methods to distribute Transmission business CCFS and Asset Management costs between Transmission business OM&A and Transmission business Capital Projects:

- The method should be based on *cost causation*.
- If cost causation can not be used or is determined to be inappropriate in the circumstances, the method usually considered next is *benefits received*.
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- If the method uses estimates, results should be unbiased and reasonably consistent with the results that would be obtained from using actual data.

C. Description of OEB-Approved Tx OH Cap Rate Method

<u>Asset Management and Operators</u>

The Asset Management group is responsible for the utility's operating assets, including investment strategy and investment planning. The Operators group is responsible for the day-to-day operation of the Ontario Grid Control Centre. Work includes 24 hour/day monitoring of grid system status, coordination of system outages and remote operations/switching of Transmission system assets. Substantially all Asset Management and Operators costs are labor and labor-related.

Hydro One determined the portion of Asset Management costs devoted to Transmission business capital projects by performing a time study for the four-week period ending December 19, 2004. Asset Management personnel are able to determine with reasonable accuracy, on a current basis, the time they spend on Transmission Operations and Maintenance, Transmission Capital Projects, Distribution Operations and Maintenance and Distribution Capital Projects.

A properly performed time study measures cost causation, and is widely accepted as a basis for allocating costs. Rudden reviewed the time study method used by Hydro One for Asset Management and found it to be appropriate. It was not practical to perform a full-year study, but any effects of performing the study over four weeks, instead of a full year, are believed to be minimal. To support this judgment, Rudden reviewed the results of Asset Management time studies performed by Hydro One in March 2003 and April 2006, and found the results to be consistent among the three time studies.

Therefore Rudden found the time study to be a proper basis for determining the portion of Asset Management costs that should be charged to Transmission business Capital Projects.

Common Corporate Functions and Services Costs

Ideally, the amount of Transmission business CCFS costs to be capitalized to Transmission business Capital Projects would be based on time studies for labor costs, and special studies for other costs, for each CCFS activity, to determine the portions of time and costs related to Transmission business Operations and Maintenance versus Transmission business Capital Projects. However, as Rudden found in the Common

Corporate Costs Methodology Review, while the departments that perform the CCFS activities can determine with reasonable accuracy the portions of time they spend on Transmission, Distribution and the other business units, they are unable to determine with reasonable accuracy the time they spend on Operations and Maintenance versus Capital Projects. Therefore, it is necessary to compute the amount of costs to be capitalized to Transmission business Capital Projects using other allocation methods such as cost causation or benefits received.

In traditional utility cost of service studies, administrative and general costs are allocated based on one or more factors including Labor costs, Operating & Maintenance costs, Investment in Plant or a weighted combination of two or more. Rudden considered the following two bases for allocating the Transmission business CCFS costs, which are similar to administrative and general costs, between X) Operations and Maintenance and Y) Capital Projects:

- Labor Content Method- Labor Content of Transmission business Operations and Maintenance versus Transmission business Capital Projects
- Total Spending Method- Total Spending on Transmission business Operations and Maintenance versus Transmission business Capital Projects

The Transmission business CCFS costs to be allocated are causally related to both potential allocation bases. Therefore the Tx OH Cap Rate method with regard to CCFS costs is based on a weighting of 50% Labor Content and 50% Total Spending.

- Using the following formula, the Tx Labor Capital Content for 2007 is 66.3%:

  Tx Capital Labor Content = Tx Labor $ in Tx Capital Projects / (Tx Labor $ in Tx Capital Projects +Tx Labor $ in Tx Operations and Maintenance)

- Using the following formula, the Tx Total Spending for 2007 is 64.6%:

  Tx Capital Spending Rate = Tx $ in Capital Projects / (Tx $ in Capital Projects + Tx $ in Operations and Maintenance)

The weighted average using 50% Labor Content and 50% Total Spending is 65.4%; therefore 65.4% of Tx CCFS costs should be capitalized.

It is appropriate to compute the amount of CCFS costs and Asset Management costs to be capitalized based on the weighted Labor Content / Total Spending developed by Rudden. Once the amount to be capitalized is computed, it can be applied based on Total Cost or Labor Content. The OEB-approved method states the capitalization rate based on Total cost, and applies it to Total cost dollars, because it is easier to plan and implement based on Total cost than Labor content. In addition, this is the typical industry practice.

Rudden believes that allocating Transmission business CCFS costs to Transmission business Capital Projects based on 50% Labor Content / 50% Total Spending is the most appropriate method for Hydro One, and is consistent with industry practice and with the nature of the Transmission business CCFS costs that are being capitalized.

II. COMPUTATION OF TX OH CAP RATE USING OEB-APPROVED METHOD

A. Formula

The following formula is used by Rudden to compute the Tx OH Cap Rate:

Tx OH Cap Rate=(Tx CCFS Cap +Tx AM Cap) /Transmission Capital

Where

Tx_AM_Cap= Amount of Asset Management costs capitalized to Transmission business capital projects

Applicable Tx CCFS and F&RE costs = Transmission business CCFS costs and F&RE costs that are subject to capitalization

Transmission Capital = Cost of Transmission business capital projects supported by CCFS and Asset Management; also, total cost of Transmission business capital projects to which the Tx OH Cap Rate is applied

Tx CCFS Cap = Amount of Transmission business CCFS costs capitalized to Transmission capital projects, where:

Tx CCFS Cap = (Tx Capital Labor Content X 50% + Tx Total Spending X 50%) X Applicable Tx CCFS and F&RE Costs

E_Factor = Difference between A) Amount of Transmission business CCFS and Transmission business Asset Management costs actually capitalized for a prior year and B) Amount that would have been capitalized for that year using actual data instead of estimates in the Tx OH Cap Rate calculation

Tx Capital Labor Content = Tx Labor $ in Tx Capital Projects / (Tx Labor $ in Tx Capital Projects + Tx Labor $ in Tx Operations and Maintenance)

Tx Total Spending = Tx Capital Projects / (Tx Capital Projects + Tx Operations and Maintenance)

These terms are further discussed below.

B. OEB-Approved Method

This section discusses the OEB-approved to compute the Tx OH Cap Rate. The recommended method is shown in Attachment A (2007 results) and Attachment B (2008 results). This example uses projected data for 2007 and 2008. Due to the timing of this Report, most of the 2007 and 2008 values are from the Business Plan 2006-2010. However, because the method includes a true-up (page 11), any continuing effect will be not significant.

Amounts include the Transmission business unit of Hydro One. The discussion below refers to the 2007 numbers for examples; the same methodology was applied for 2008.

1. *Transmission Capital*
   (Att. A, rows 5-14)

Transmission Capital represents the cost of Transmission business Capital Projects that are supported by Transmission business CCFS activities and Asset Management activities, and is the total cost of Transmission business Capital Projects to which the Tx

OH Cap Rate is applied. Transmission Capital equals total spending for Transmission business Capital Projects reported for financial accounting for 2007, excluding Turnkey Projects (see Section III), adjusted as follows:

- Adjustment for Incremental Capital Spending, representing the amount of capital spending above the Business Plan adjusted for Capitalized Interest to be consistent with the adjustments discussed below.

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little CCFS or Asset Management support. Capitalized Overhead is removed to avoid redundancy.

- Capital Contributions by Customers are added because the CCFS and / or Asset Management effort required is related to gross capital cost, not net capital cost. Removal Costs are added because removal of capital assets requires CCFS or Asset Management effort.

Transmission Capital for 2007 (that is, capital spending for financial accounting adjusted by the items shown above), based on Business Plan 2006-2010 plus incremental capital spending, is $577.1M *(Att. A, row 13, Reference A).*

2. *Applicable Tx CCFS / F&RE Costs*
   (Att. A, rows 15-26)

Applicable Tx CCFS and F&RE costs represents those Transmission business CCFS and Facilities and Real Estate ("F&RE") costs that are subject to capitalization. This amount equals the CCFS costs allocated to the Transmission business unit for the years 2007 and 2008 in the Common Corporate Cost Model *(Att. A, row 16)*, adjusted as follows:

- The Transmission F&RE costs are added, because they are part of the full cost to be considered in computing the Tx OH Cap Rate.
- Strategic Planning is removed as this is no longer part f the CCFS but is now included in Asset Management.
- The portion of Transmission business CCFS costs representing operating-type costs is removed because these functions do not support OM&A or capital projects. These activities include Inergi- Customer Support Operations, Inergi- Settlements, Inergi-ETS costs to support CSO Applications and Inergi-ETS costs to support market transition costs.

Applicable Tx CCFS / F&RE Costs for 2007, based on Business Plan 2006-2010, are $98.6 million *(Att. A, row 25, Reference B).*

3. *Tx Capital Labor Content*
   (Att. A, rows 27-31)

Tx Capital Labor Content represents the portion of total Transmission business labor costs that is included in Transmission Capital Projects. The computation for 2007, based on Business Plan 2006-2010 adjusted for 2007 additional capital spending and additional OM&A, is shown below.

Tx Capital Labor Content = Tx Labor $ in Tx Capital Projects / (Tx Labor $ in Tx Capital Projects + Tx Labor $ in Tx Operations and Maintenance)

Labor $ in Tx Operations and Maintenance	$ 116.6M	33.7%
Labor $ in Tx Capital *(Att. A, row 29, Reference C)*	229.1M	66.3%
Total Tx Labor $ *(Att. A, row 30, Reference D)*	$345.7M	100.0%

Labor $ are fully burdened labor.

The Tx Capital Labor Content to Capital for 2007 is 66.3% *(Att. A, row 31, Reference E = Reference C / Reference D).*

4. *Tx Total Spending*
   (Att. A, rows 32-36)

Tx Total Spending represents the portion of Transmission total spending that is included in Transmission business Capital Projects. The computation for 2007, based on Business Plan 2006-2010 adjusted for 2007 additional capital spending and additional OM&A, is shown below. Tx Total Spending is computed as follows:

Tx Total Spending = Tx Capital Projects / (Tx Capital Projects + Tx Operations and Maintenance)

Tx Operations and Maintenance	$ 316.2M	35.4%
Tx Capital *(Att. A, row 34, Reference A)*	577.1M	64.6%
Tx Total *(Att. A, row 35, Reference F)*	$893.3M	100.0%

The Tx Total Spending to Capital for 2007 is 64.6% *(Att. A, row 36, Reference G= Reference A / Reference F).*

5. *Tx CCFS Cap*
   (Att. A, rows 37-43)

The Tx Capital Labor Content of 66.3% *(Att. A, row 31, Reference E)* times 50% weight plus the Tx Total Spending of 64.6% *(Att. A, row 36, Reference G)* times 50% weight, results in 65.4% *(Att. A, row 40, Reference H)*, representing the portion of Applicable Tx CCFS / F&RE costs to be capitalized. Multiplying this rate by the Applicable Tx CCFS /

F&RE costs results in the amount of CCFS costs capitalized, or $64.5M *(Att. A, row 42, Reference J)*.

6. *Tx AM Cap*
   (Att. A, rows 44-59)

Tx AM Cap represents the amount of Asset Management costs capitalized to Transmission business Capital Projects. The time study performed by Hydro One for the four weeks ended December 19, 2004 showed that 32.9% of Asset Management, 4.4% of Operating & Outage Management and 5.5% of Customer Care time, are related to Transmission business Capital Projects. When applied to the Business Plan 2006-2010 values for 2007 Asset Management, Operating & Outage Management and Customer Care costs, this results in a total of $18.6M capitalized to Transmission business Capital Projects *(Att. A, row 58, Reference K)*.

7. *E_Factor*
   (Att. A, rows 60-64)

Rudden recommends that a true-up procedure be implemented for the Tx OH Cap Rate. The OEB-approved method relies on estimates of future amounts, and a true-up will allow Hydro One to rectify the inevitable differences between actual and estimated amounts. Although it is not expected that differences will be significant, it is appropriate to rectify them because they affect rate-making and financial accounting for years. Prospective true-ups are recommended because the benefit of immediate recognition is outweighed by the disruption of implementing changes in the last quarter of the year.

Rudden recommends that the true-up be implemented by computing an E_Factor for each year, equal to the difference between A) Amount of Transmission business CCFS and

Transmission business Asset Management costs actually capitalized for a prior year and B) Amount that would have been capitalized for that year using actual data instead of estimates in the Tx OH Cap Rate calculation.

The E_Factor for any year is included in the Tx OH Cap Rate calculation for a subsequent year. For example, not all actual data for 2007 will be available in 2008, so the E_Factor arising in 2007 will be included in the Tx OH Cap Rate for 2009.

The E_Factor for 2007 is zero *(Att. A, row 63, Reference L)*.

8. *Tx OH Cap Rate*

The Tx OH Cap Rate equals A) the sum of items 5 (*Att. A, row 66, Reference J),* 6 (*Att. A, row 67, Reference K)* and 7 (*Att. A, row 68, Reference L)* above, $83.1M, divided by B) Capital spending, $577.1M (*Att. A, row 70, Reference A)*. The Tx OH Cap Rate for 2007 is 14.4**%** *(Att. A, row 69)*.

The Tx OH Cap Rate for 2008 is 13.1**%** *(Att. B, row 69)*.

III. TURNKEY PROJECTS

Hydro One anticipates that some of the Transmission capital projects it will need to perform in 2007and 2008 will have substantial outsource components and / or include large land acquisitions. These projects are referred to as "Turnkey Projects". The CCFS support they require is much less than typical Transmission capital projects, which do not fit this profile. Therefore, they should be excluded from the Tx OH Cap Rate computation because including them would have the following adverse effects:

- It would inappropriately increase the total capitalized amount, due to the Tx Total Spending component)
- It would materially affect the distribution of that amount, due to the Tx Capital Labor Content component.

Most Transmission capital projects have labor content of approximately 40%. Projects that have labor content of under 15% should be identified at the start of each year, and reviewed to consider whether they should be excluded from the Tx OH Cap Rate computation. When the calculation for a year is trued up, it can be determined if these projects did require much less CCFS support than typical Transmission capital projects.

HYDRO ONE
CALCULATION OF TRANSMISSION OVERHEAD CAPITALIZATION RATE
APPROVED METHOD APPLIED TO 2007 (Amounts C$ Millions)

				Reference
TRANSMISSION CAPITAL				
Capital, incl. Cap OH			407.1	
Adjustment for Incremental Capital			244.3	
Less: Minor Fixed Assets			(15.2)	
Less: Capitalized Overhead			(57.5)	
Less: Capitalized Interest			(25.9)	
Add: Capital Contributions			10.0	
Add: Removal Costs			14.3	
TOTAL CAPITAL			577.1	A
APPLICABLE TRANSMISSION CCFS COSTS				
Tx CCFS Costs from Cost Distribution Model			97.0	
Tx F&RE costs			4.9	
Tx Strategic Planning			(0.5)	
Operating-Type Tx CCFS costs:				
Inergi-CSO in Tx CCFS			(0.6)	
Inergi-ETS CSO Apps in Tx CCFS			(0.1)	
Inergi-ETS Market Ready in Tx CCFS			(1.6)	
Inergi-Settlements in Tx CCFS			(0.5)	
			(2.9)	
TOTAL APPLICABLE Tx CCFS COSTS			98.6	B
Tx LABOR CONTENT				
Labor in OM			116.6	
Labor in Capital			229.1	C
			345.7	D
Tx LABOR CONTENT			66.3%	E=C/D
Tx TOTAL SPENDING				
Total Tx OM&A			316.2	
Capital Spending (excluding Overhead Capitalized)			577.1	A
			893.3	F
Tx TOTAL SPENDING			64.6%	G=A/F
Tx CCFS Cap=Capitalized Tx CCFS costs				
Labor Content	50.0%	66.3%	33.1%	E
Total Spending	50.0%	64.6%	32.3%	G
Weighted Average Rate			**65.4%**	H
Applicable CCFS Costs			98.6	B
Tx CCFS Cap=Capitalized Tx CCFS costs			**64.5**	J=H*B

HYDRO ONE
CALCULATION OF TRANSMISSION OVERHEAD CAPITALIZATION RATE
APPROVED METHOD APPLIED TO 2007 (Amounts C$ Millions)

Line			Reference
44	**Asset Management Costs**		
45	Asset Management:		
46	Total Asset Management costs	86.6	
47	Less: Total F&RE costs	(40.3)	
48	Add: Large Customer & Generator Relations	4.0	
49		50.3	
50	Operating & Outage Management	37.0	
51	Customer Care Management	7.1	
52		94.4	
53			

Line	Capitalized Asset Management Costs	Total Costs	Tx Capitalized	Capitalized $	Reference
55	Asset Management	50.3	32.9%	16.6	
56	Operating & Outage Management	37.0	4.4%	1.6	
57	Customer Care	7.1	5.5%	0.4	
58	**Tx AM Cap = Capitalized Asset Management Costs**	94.4		**18.6**	K
59					

Line			Reference
60	**E-Factor**		
61	Amount capitalized for prior year		
62	Amount that would have been capitalized for prior year		
63	**E-Factor**	0.0	L
64			

Line	TOTAL OVERHEAD CAPITALIZATION RATE	Total Capitalized	Capitalization Rate	Reference
66	Tx CCFS Cap=Capitalized Tx CCFS costs	64.5	11.18%	J
67	Tx AM Cap = Capitalized Asset Management Costs	18.6	3.22%	K
68	E-Factor	0.0	0.00%	L
69	**Total**	**83.1**	**14.40%**	
70	Capital	**577.1**		A
71				

HYDRO ONE
CALCULATION OF TRANSMISSION OVERHEAD CAPITALIZATION RATE
APPROVED METHOD APPLIED TO 2008 (Amounts C$ Millions)

				Refer-ence
TRANSMISSION CAPITAL				
Capital, incl. Cap OH			430.4	
Adjustment for Incremental Capital			305.5	
Less: Minor Fixed Assets			(14.5)	
Less: Capitalized Overhead			(59.7)	
Less: Capitalized Interest			(24.2)	
Add: Capital Contributions			2.0	
Add: Removal Costs			14.4	
TOTAL CAPITAL			653.9	A
APPLICABLE TRANSMISSION CCFS COSTS				
Tx CCFS Costs from Cost Distribution Model			97.0	
Tx F&RE costs			4.9	
Tx Strategic Planning			(0.5)	
Operating-Type Tx CCFS costs:				
Inergi-CSO in Tx CCFS			(0.6)	
Inergi-ETS CSO Apps in Tx CCFS			(0.1)	
Inergi-ETS Market Ready in Tx CCFS			(1.6)	
Inergi-Settlements in Tx CCFS			(0.5)	
			(2.9)	
TOTAL APPLICABLE Tx CCFS COSTS			98.5	B
Tx LABOR CONTENT				
Labor in OM			116.1	
Labor in Capital			249.8	C
			365.9	D
Tx LABOR CONTENT			68.3%	E=C/D
Tx TOTAL SPENDING				
Total Tx OM&A			308.9	
Capital Spending (excluding Overhead Capitalized)			653.9	A
			962.8	F
Tx TOTAL SPENDING			67.9%	G=A/F
Tx CCFS Cap=Capitalized Tx CCFS costs				
Labor Content	50.0%	68.3%	34.1%	E
Total Spending	50.0%	67.9%	34.0%	G
Weighted Average Rate			**68.1%**	H
Applicable CCFS Costs			98.5	B
Tx CCFS Cap=Capitalized Tx CCFS costs			**67.1**	J=H*B

HYDRO ONE
CALCULATION OF TRANSMISSION OVERHEAD CAPITALIZATION RATE
APPROVED METHOD APPLIED TO 2008 (Amounts C$ Millions)

4					Refer-ence
44	**Asset Management Costs**				
45	Asset Management:				
46	Total Asset Management costs			87.2	
47	Less: Total F&RE costs			(40.6)	
48	Add: Large Customer & Generator Relations			4.1	
49				50.7	
50	Operating & Outage Management			36.5	
51	Customer Care Management			7.4	
52				94.6	
53					
54	**Capitalized Asset Management Costs**	Total Costs	Tx Capital-ized	Capital-ized $	
55	Asset Management	50.7	32.9%	16.7	
56	Operating & Outage Management	36.5	4.4%	1.6	
57	Customer Care	7.4	5.5%	0.4	
58	**Tx AM Cap = Capitalized Asset Management Costs**	94.6		**18.7**	K
59					
60	**E-Factor**				
61	Amount capitalized for prior year				
62	Amount that would have been capitalized for prior year				
63	**E-Factor**			0.0	L
64					
65	**TOTAL OVERHEAD CAPITALIZATION RATE**		**Total Capitalized**	**Capital-ization Rate**	
66	Tx CCFS Cap=Capitalized Tx CCFS costs		67.1	10.26%	J
67	Tx AM Cap = Capitalized Asset Management Costs		18.7	2.86%	K
68	E-Factor		0.0	0.00%	L
69	**Total**		**85.8**	**13.12%**	
70	Capital		**653.9**		A
71					

Ontario Energy Board (Board Staff) INTERROGATORY #21 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Page 5 and Appendix 5

Hydro One's forecast of Provincial GDP and Provincial Housing relies on a survey of forecasts from a number of sources. One of the forecasts cited is already one year old, and the most recent is September 2009. Does Hydro One plan to update the survey and the forecast during the course of this proceeding?

Response

Updated Ontario GDP and housing starts forecast survey results are presented below.

Survey of Ontario GDP Forecast (annual growth rate in %)

	2009	**2010**	**2011**	**2012**
Global Insight (July 2010)	-3.1	3.5	3.0	3.1
Conference Board (July 2010)	-3.1	4.5	3.0	3.4
U of T (July 2010)	-3.0	4.3	2.8	2.6
C4SE (July 2010)	-3.1	3.7	2.9	2.5
CIBC WM (July 2010)	-3.1	3.7	2.4	
BMO (July 2010)	-3.1	3.6	2.7	
RBC (June 2010)	-3.2	3.8	3.5	
Scotia (July 2010)	-3.1	3.6	2.4	
TD (May 2010)	-3.2	4.0	2.7	
Desjardins (Summer 2010)	-3.4	3.9	2.8	
Average	**-3.1**	**3.9**	**2.8**	**2.9**

Survey of Ontario Housing Starts Forecast (in 000's)

	2009	**2010**	**2011**	**2012**
Global Insight (July 2010)	50.4	59.6	57.4	63.3
Conference Board (July 2010)	50.4	63.5	71.7	83.2
U of T (July 2010)	50.4	62.1	61.5	63.4
C4SE (July 2010)	50.4	64.4	64.8	63.6
BMO (July 2010)	50.1	59.0	60.0	
RBC (June 2010)	50.1	59.6	59.5	
Scotia (July 2010)	50.0	63.0	60.0	
TD (May 2010)	50.1	60.0	54.0	
Desjardins (Summer 2010)	50.4	57.6	56.9	
Average	**50.3**	**61.0**	**60.6**	**68.4**

Updated August 3, 2010

The following table compares the latest Ontario GDP and housing starts survey results (August 3, 2010) with the survey results of September 16, 2009 as presented in Appendix 5 of Exhibit A, Tab 12, Schedule 3.

Comparison of Cumulative Growth between 2009 and 2012

	GDP (%)	Housing Starts (000's)
Sept 2009 Survey	9.7%	193
July 2010 Survey	9.6%	190

The 2 survey results show similar growth for the 2009-2012 period. Hydro One does not plan to update the load forecast.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #22 List 1</u>

<u>Interrogatory</u>

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

<u>Ref: Exhibit A/Tab12/Sch3/Pages 6-8</u>
In its EB-2008-0272 Decision with Reasons, May 28, 2009, the Board noted at page 6 that the IESO had a different forecast from Hydro One's forecast. The Board expressed its satisfaction at page 8 with Hydro One's explanation that the differences stem from the treatment of CDM and embedded generation effects.

Is Hydro One aware whether the IESO again has its own forecast? If so, are there again differences in the respective forecasts of demand due to CDM and embedded generation, and are there any differences in the respective forecasts net of the effects of CDM and embedded generation?

<u>Response</u>

The latest IESO 18-month forecast was released in May 2010.

Based on discussions with the IESO load forecasting staff in July 2010, Hydro One and IESO agreed that key factors identified in the forecast comparison study prepared by Hydro One (submitted as Exhibit A, Tab 14, Schedule 3 in EB-2008-0272) to explain the forecast differences between Hydro One and IESO are still valid. These included the use of Wednesday for peak day selection versus any day during the week and the treatment of demand response programs as increment on the resources side versus decrement on the demand side.

Hydro One does not have the CDM and embedded generation forecast details from the IESO and therefore cannot make any forecast comparison netting out the impacts of CDM and embedded generation.

Ontario Energy Board (Board Staff) INTERROGATORY #23 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: ExhibitA/Tab12/Sch3/Page 8

In the description of the adjustment for Embedded Generation in the load forecast, at p. 8, lines 27-29, Hydro One notes that "Potential embedded generation by-pass resulting from new contracts awarded by the OPA under the feed-in tariff (FIT) program has not yet been reflected in the load forecast."

Does Hydro One intend to update its load forecast during this proceeding to include this effect on the load?

Response

Hydro One does not plan to update its forecast on embedded generation by-pass.

Ontario Energy Board (Board Staff) INTERROGATORY #24 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Pages 12-13 (Figures 1 and 2)

a) Please confirm that the graphs in Figures 1 and 2 each show temperature values for a single day each year.

b) Does Hydro One have data that show a larger number of days each year, and if so does the same pattern emerge (apparently showing more extreme summer highs and less extreme winter lows)?

c) Given that the maximum temperatures appear to be getting more extreme and the minimums less so, is the accuracy of Hydro One's forecast of billing quantities improving, worsening, or unaffected?

Response

(a) Yes, the graphs in Figures 1 and 2 show the average temperature values for a single day each year.

(b) Figures 1b and 2b below present the information for all summer and winter days. The figures show historical weather patterns are very volatile.

(c) As explained in lines 1-4 on page 12 in Exhibit A, Tab 12, Schedule 3, Hydro One takes into consideration most recent trends in the relationships between energy and peak in the load forecasting process. Consequently, Hydro One's forecast accuracy of billing quantities remain unaffected.

Ontario Energy Board (Board Staff) INTERROGATORY #25 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Page 16

Hydro One conducted a survey in the spring of 2009, comprising customers with loads above 5 MW and certain customers that generate electricity for their own use.

a) Please provide a more complete description of the survey. For example, did Hydro One's survey include distributors as customers? Did the survey include end-use customers within distributors? How many distributors and how many end-use customers were included in the survey. Did all of the customers provide all of the information requested?

b) How many delivery points are represented by the customers in the survey, and what percentage is this of the total?

Response

a) The survey was sent to all distributors (LDCs), large industrial customers with >5 MW of load, and power producers connected to Hydro One transmission system. In 2009, a total of 55 distributors (excluding Hydro One Distribution), 49 large industrial customers and 115 power producers received the survey. End-use customers within the distributors did not get the survey because their load would be covered by the distributors. In total, 21 distributors (excluding Hydro One Distribution), 14 large industrial customers and 2 power producers responded to the 2009 survey. The questionnaire used in the 2009 survey is provided below.

Transmission Customer Load Forecast, Year 2009

Transmission Customer Name: **Hydro One ID #:**

Hydro One Account Executive: **Tel.:**

Deliver Point (DP) 2008 Actual & 2009-2013 Forecast in kW:

DP Name:	TS Name:	DP ID:	Load	2008	2009	2010	2011	2012	2013
			Summer						
			Winter						

Comments & Supporting Details

Note: If any of the numbers above do not match your records, feel free to make corrections. Please provide details below identifying the timing for any significant load or generation changes. If possible, please indicate the load impact of conservation, demand management, and the on-going economic crisis in the past few years (or months) and future.

b) The survey was sent to all directly connected Transmission customers covering all customer delivery points or 100% of Hydro One transmission system load.

Ontario Energy Board (Board Staff) INTERROGATORY #26 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Page 17

In the description of the delivery point forecast, at lines 9-10, Hydro One explains that "The forecasts for all customer delivery points are calibrated to add up to the regional and the total transmission system forecast."

Please explain what this sentence means, and describe what effect the calibration has on the forecast that Hydro One uses for rates and revenues.

Response

The sentence simply means that all delivery point forecasts were scaled to add-up to the regional and total transmission system forecast. This calibration has no impact on the revenue and rates.

Ontario Energy Board (Board Staff) INTERROGATORY #27 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Page 18

Hydro One is forecast to deliver electricity in 2011 at 23,152 MW, based on a 12-month average peak (reference: line 25). To understand the definition of definition:

a) Please confirm that Network Connection MW may be defined as the sum of Network billing demands at all delivery points, whether in the peak period or at 85% of the peak outside the peak period. Confirm that the sum of the loads at the 12 monthly peaks of all delivery points measured simultaneously would be a different (smaller) quantity.

b) The amount appears in Table 3 under the heading Ontario Demand, and is approximately 460 MW lower than the comparable forecast in the next column called Network Connection. Please explain whether the difference is due to the load served by other transmitters in Ontario, or due to a difference in how MW is defined, or due to some other factor.

Response

a) Yes, network Connection MW is the sum of the Network billing demands for all delivery points connected to Hydro One transmission system determined as the higher of customer coincident peak demand in the hour of the month when the total hourly demand of all customers is highest for the month and 85% of the non-coincident customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by the IESO. Yes, the sum of coincident peak for all delivery points would be smaller than the Network Correction MW.

b) The difference is due to the following 3 factors:

- Load served by other transmitters;
- Transmission loss because Ontario demand is measured at the generation level while Network connection is measured at the delivery point level;
- Ontario demand is measured at the coincident level, while Network connection is based on the definition as described in (a) above.

Ontario Energy Board (Board Staff) INTERROGATORY #28 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Page 21 (Table 5)

a) Please confirm that a negative amount in Table 5 indicates an instance in which Hydro One's forecast was lower than actual (after making a weather correction and the indicated adjustments for CDM and embedded generation). If so, would it be reasonable to conclude that Hydro One's forecast of its average monthly peak demand turns out to be higher than actual more often than it is lower than actual?

b) The final row in Table 5 is titled "One standard deviation (+/-)", and the explanation following the table states that there is a two in three chance that the actual would fall within one standard deviation. The standard deviation in each column does not appear to be calculated from the amounts in the column above it. Further, no amounts in the columns are larger than the standard deviation. Please show how the standard deviation is derived from the amounts in the main part of the table. If not derived from the data in the table, please explain how it is derived.

c) The following table shows the corresponding table from the previous application (EB-2008-0272). Please explain why the amounts for each column 2003 – 2007 are now different that what they were when filed in 2008, and also explain why the standard deviation is identical in the current version of the table despite having two new years of data.

Filed: September 30, 2008
EB-2008-0272
Exhibit A
Tab 14
Schedule 3
Page 24 of 24

Table 5
Comparison of Average Monthly Transmission Peak Demand Forecast with Actual
(Variance of forecast as percentage of actual on weather corrected basis)

Forecast made In Year	Forecast for current year	Forecast for 2nd Year	Forecast for 3rd Year
1999	-0.92%	-2.22%	-2.30%
2000	0.18%	0.26%	0.22%
2001	-0.14%	-0.29%	0.41%
2002	0.15%	0.36%	-0.14%
2003	0.25%	0.09%	0.83%
2004	0.08%	0.59%	0.89%
2005	0.17%	0.36%	0.97%
2006	-0.69%	0.41%	n.a.
2007	0.93%	n.a.	n.a.
Mean	0.00%	-0.05%	0.12%
One standard deviation (+/-)	1.79%	2.36%	2.63%

Note. The forecasts are gross of the load impact of CDM and embedded generation and are compared to the weather corrected actual figures after adding to it the load impact of CDM and embedded generation.

Response

a) Yes, a negative amount indicates Hydro One's forecast is lower than actual. As shown in Table 5, Hydro One's forecast is higher than actual more often than it is lower than actual over the period in question.

b) Yes, the one standard deviation is not derived using data presented in Table 5. It was based on longer-term data representing range of forecast errors from model-based forecasting techniques.

c) In our previous application (EB-2008-0272), the figures in Table 5 were comparing weather-corrected actuals and corresponding forecasts after deducting the load impact of CDM and embedded generation. In the current application (EB-2010-0002), the comparison is made using a revised definition comparing weather-corrected actuals and corresponding forecasts before deducting CDM and embedded generation in order to have a consistent dataset for variance analysis for pre-CDM (prior to 2005) and post-CDM periods (starting 2005). On average, the difference between the two definitions is minimal, as shown in the following Table.

Comparison of Average Monthly Transmission Peak Demand Forecast with Actual
(Variance of forecast as percentage of actual on weather corrected basis)

Forecast made In Year	Forecast for current year	Forecast for 2nd Year	Forecast for 3rd Year
After deducting the load impact of CDM and Embedded Generation			
1999-2007	0.00%	-0.05%	0.12%
1999-2009	-0.05%	0.00%	0.19%
Before deducting the load impact of CDM and Embedded Generation			
1999-2007	0.02%	-0.08%	0.14%
1999-2009	-0.03%	0.00%	0.19%

The standard deviation remains almost the same (not distinguishable using figures up to 2 decimal places) as it is based on long-term data.

Ontario Energy Board (Board Staff) INTERROGATORY #29 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Page 19 (Table 3) and Appendix 4

a) Please confirm that the weather correction for 2009 Network Connection is approximately -473 MW, as calculated from the third from last row in the two tables in Appendix 4, which are actual load and weather corrected load respectively.

b) The following shows the table in the previous application (EB-2008-0272) that corresponds with Table 3 in the current application. Please confirm that the updated assessment of the 2009 impact of Embedded Generation on Network Connection is 50 MW lower per month than had been forecast (i.e. 280 MW compared to 230 MW), and the 2009 impact of CDM is assessed to be 26 MW lower per month than forecast (i.e. 1242 MW compared with 1216 MW).

Filed: September 30, 2008
EB-2008-0272
Exhibit A
Tab 14
Schedule 3
Page 22 of 24

Table 3
Load Forecast Before and After Embedded Generation and CDM
(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand (MW)	Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2008	22,676	22,101	21,042	18,192
2009	22,946	22,364	21,293	18,409
2010	23,147	22,560	21,480	18,571
Load Impact of Embedded Generation				
2008	190	190	10	10
2009	280	280	10	10
2010	350	350	10	10
Load Impact of CDM				
2008	993	968	922	797
2009	1,274	1,242	1,183	1,022
2010	2,063	2,011	1,915	1,655
Load Forecast after Deducting Embedded Generation and CDM				
2008	21,492	20,943	20,111	17,386
2009	21,391	20,842	20,100	17,376
2010	20,734	20,199	19,555	16,905

Note. All figures are weather-normal.

Response

a) Yes, we need to add 473 MW to 2009 actual Network Connection to bring it to weather corrected level.

b) Yes, compared to the forecast in the previous application (EB-2008-0272), the load impact for embedded generation on Network Connection is 50 MW lower per month and the load impact of CDM is 26 MW lower per month.

Ontario Energy Board (Board Staff) INTERROGATORY #30 List 1

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A/Tab12/Sch3/Tables 3 and 5

To enable a clearer understanding of the accuracy of Hydro One's forecasts, please provide a detailed calculation of the amount for 2009 in Table 5, which is (0.22%). Please show how the 2009 actual amount in Table 3 is used in the calculation, together with adjustments for weather, CDM and Embedded Generation, and if applicable, the 2009 forecast in Hydro One's previous application (EB-2008-0272).

Response

As requested, the detailed calculation for the variance of -0.22% and the variance comparing to the 2009 forecast used in the last rate application (EB-2008-0272) are presented below:

	MW
2009 Ontario Demand actual	20,798
Plus weather correction (WC) for 2009	542
2009 Ontario Demand WC actual (Table 3)	21,340
Plus Embedded Generation (Table 3)	230
Plus CDM (Table 3)	1,274
2009 Ontario Demand WC before deduction of embedded generation & CDM (Table 3)	22,844
2009 Ontario Demand forecast WC prepared in 2009 before deduction of embedded generation & CDM	22,794
% variance of 2009 forecast compared to 2009 actual (Table 5) ((22,794-22,844)/22,884	-0.22%
2009 Ontario Demand forecast WC before deduction of embedded generation & CDM prepared in May 2008 for EB-2008-0272 (Table 3)	22,946
% variance of 2009 forecast in EB-2008-0272 compared to 2009 actual (22,946-22,844)/22,844	0.44%

Ontario Energy Board (Board Staff) INTERROGATORY #31 List 1

Interrogatory

Issue 2.2 Are Other Revenue (including export revenue) forecasts appropriate?

Ref: Exhibit E1/Tab1/Sch2/Pages 2-3

a) Is the forecast of External Revenue from Secondary Land Use, $12.6 million in 2011 and $12.5 in 2012, primarily a fee for managing contracts or revenue from unexpired agreements? If the latter are a material amount, do any agreements expire during the test years and what is the revenue impact?

b) Is the External Revenue in Table 1 net of the cost of providing the service under the PSLUP program and any costs incidental to the unexpired agreements, or are the amounts shown the gross revenues?

Response

a) The forecast of External Secondary Land Use Revenue of $12.6 million in 2011 and $12.5 in 2012 represents revenue stream primarily generated by charging land rentals to external parties including new agreements and subsequent agreement renewals.

Several agreements will expire during the test years; however these agreements will be transferred to the Provincial Secondary Land Use Program (PSLUP). The PSLUP program uses a revenue sharing model to split land use revenues between Hydro One and the Province. Hydro One's share of the PSLUP revenue in 2011 and 2012 Hydro is expected to increase by $1.1 million which will offset the decrease in revenue associated with expiring land use agreements.

b) The Secondary Land Use Revenue amounts shown in Table 1 represent gross revenue.

Ontario Energy Board (Board Staff) INTERROGATORY #32 List 1

Interrogatory

Issue 2.2 Are Other Revenue (including export revenue) forecasts appropriate?

Ref: Exhibit E1/Tab1/Sch1/page 5 (Table 4), and Exhibit H1/Tab1/ Sch2/Attachment 1 (page 16 (Table 3)

a) Please confirm that the "Export Revenue Credit" is calculated under the assumption that the Export Transmission Service Charge will be $1/MWh.

b) Please provide a calculation of the revenue credit under Option 2 in the IESO study, reflecting the assumption that the charge would be $5/MWh together with a decreased export volume of 35% (per first column of the Table in Exhibit H1).

c) Is it a valid conclusion that the gain in consumer surplus of $207 million (in 2010 terms) under Option 2 would be partly due to the Export Revenue Credit being higher enabling lower Network Transmission rates within the province?

Response

The response to part c) is provided by the IESO.

a) Hydro One confirms that the "Export Revenue Credit" is calculated under the assumption that the Export Transmission Service Charge will be $1/MWh. As stated in Exhibit H1, Tab 5, Schedule 1, page 2, lines 7 to 10, the forecast volume is based on the IESO's 2010-2012 Business Plan filed in Proceeding EB-2009-0377, (Exhibit B, Tab 4, Schedule 1, page 2). The IESO's forecast volume for 2011 is 10.1 TWh and for 2012 it is 10.2 TWh.

b) Based on the forecast volumes in the IESO Business Plan, a reduction of 35% would result in volumes for 2011 and 2012 of 6.6 TWh. Using the $5/MWh charge would result in revenue credit of $33 million each year.

c) No, consumer surplus is the amount that consumers benefit by being able to purchase electricity for a price that is less than what they would otherwise be willing to pay. The gain in consumer surplus of $207 million in 2010 is due to the lower wholesale prices that are projected under Option 2. The IESO ETS Tariff Study does not make assumptions of how the Export Revenue Credit would be allocated. In particular, it does not assume that the higher Export Revenue Credit would lead to lower Network Transmission rates for Ontario consumers. Instead, the higher Export Revenue Credit was treated separately in the calculation of the net benefit to the province. If the Export Revenue Credit is reallocated so that the Network Transmission rates for Ontario Consumers declines, then this benefit would represent a further increase in Ontario consumers' surplus.

Ontario Energy Board (Board Staff) INTERROGATORY #33 List 1

Interrogatory

Issue 2.2 Are Other Revenue (including export revenue) forecasts appropriate?

Ref: Exhibit H1/Tab1/ Sch2/Page 5 (line 11), and Attachment 1, p. 20

At Exh H1/Tab 5/ Hydro One indicates that there are expected to be increased occurrences of surplus base-load generation ("SBG events") over the next few years, which appears to be a factor supporting the recommendation to maintain the status quo with respect to the Export Transmission Service (ETS) Charge.

Please reconcile the reference in the Application with the IESO study (at p. 20) in which the authors do not expect any SBG events.

Response

This response is provided by the IESO.

As noted in Section 6.3 of the ETS Tariff Study Report, the IESO study employed a simplified model based on a set of assumptions and available information about future market conditions and planning initiatives. The report noted that a material change in any of the key inputs or assumptions could have an impact on the outcome of the model. From these assumptions, and the input data used, a set of results was produced showing SBG not to be a material concern in the test years 2010 and 2015 for any of the ETS Tariff options considered. Based on updated information including a refined demand forecast and a better appreciation of the potential timing and amount of additional renewable resources to be incorporated under the Feed-In Tariff program, the IESO believes that increased occurrences of SBG events over the next few years are likely.

Ontario Energy Board (Board Staff) INTERROGATORY #34 List 1

Interrogatory

Issue 2.2 Are Other Revenue (including export revenue) forecasts appropriate?

Ref: Exhibit H1/Tab1/Sch2/Page 6 (lines 25-27), and Attachment 1/Page 17

a) The Application states that the IESO believes that steps toward the elimination of the ETS tariff with neighbours will contribute to maximizing market efficiency. Is this an accurate depiction of the IESO's outlook, given that its study at p. 17 (Table 4, third pair of columns)) shows a minimal effect on market efficiency in 2010 and a small decrease in efficiency by 2015?

b) Regardless of part (a), does Hydro One concur that the elimination of the Export Transmission Service (ETS) tariff (in a reciprocal manner) will make a contribution to maximizing market efficiency?

c) If so, is it a contribution toward efficient use of Hydro One's transmission system resources, or is it a net contribution despite potentially less efficient use of Hydro One's system?

d) The IESO study does not take into account limitations on the transmission system (ref: attachment 1/page 25). Notwithstanding this assumption in the IESO study, are there times and places in which Hydro One's system has been used at or near its limit to accommodate exports, and if so, does Hydro One plan to use resources to increase the capability of those parts of its transmission system?

e) Does Hydro One have an estimate of when reciprocal arrangements with other jurisdictions will be in place? What is the progress so far?

Response

The responses to a) c) d) and e) are provided by the IESO, with input from Hydro One on part d).

a) Yes, this is an accurate depiction of the IESO's outlook. The IESO believes that the joint elimination of the export tariff with Ontario's neighbours will maximize regional market efficiency. The study findings as indicated in Table 4 (page 17 third pair of columns, Reciprocal Treatment-Joint ETS tariff elimination) reflect the change in total surplus (the IESO's measure of market efficiency) for ***Ontario only*** in 2010 and 2015.

b) Yes, HONI concurs that reciprocal elimination of the ETS tariff in all markets will contribute to maximizing regional market efficiency.

c) The IESO believes this will contribute toward efficient use of Hydro One’s transmission system resources. Elimination of the ETS tariff will promote efficient electricity trades which in turn lead to more efficient use of Ontario’s generation assets. To the extent more efficient trades occur and Ontario export volumes increase, the average embedded network cost will be reduced (i.e., more productive use of Hydro One’s transmission system). In addition, efficient trades also have the potential to indicate the congestion nodes on the transmission system. This in turn can lead to more efficient allocation of investment resources for new transmission facilities.

d) Yes, there have been occurrences where key export transmission interfaces were at or near their limits due to, among other things, export and wheel-through volumes. Hydro One has no plans to increase transmission capability for export purposes. Hydro One has not been advised by the OPA or IESO of any need to increase transmission capability for the purpose of facilitating higher levels of exports.

e) Please see Exhibit I, Tab 9, Schedule 3.

Ontario Energy Board (Board Staff) INTERROGATORY #35 List 1

Interrogatory

Issue 2.2 Are Other Revenue (including export revenue) forecasts appropriate?

Ref: Exhibit H1/Tab5/Sch2/Attachment 1/Page 16 (Table 3)

Please confirm that a comparison of the first three entries in the first column may be interpreted that an increase in the ETS Charge from $1/ MWh to $5/MWh would decrease the quantity exported by 35%, and that decreasing it from $1/MWh to $0/MWh would increase the quantity by 38%.

Does Hydro One have calculations of the elasticity of demand in the ranges above and below the status quo price, considering the total price including the ETS Charge, that would be consistent with these impacts? If so, what is the elasticity? If not available, is Hydro One able to calculate the elasticity (or elasticities above and below the status quo) that would be implied by the impacts in Table 3?

Response

This response is provided by the IESO.

Yes, it is correct that an increase in the ETS Tariff from $1/MWh to $5/MWh (i.e., Option 2-Average Embedded Network Rate), while maintaining the export tariff in other jurisdictions at their current levels, was estimated to decrease the quantity exported by 35% in 2010. It is also correct that decreasing the ETS Tariff from $1/MWh to $0/MWh (i.e., in Ontario) would increase exports by 38% in 2010; however, this occurs when export tariffs are simultaneously reduced to zero from their current level in all jurisdictions (i.e., under Option 3, Scenario 1 – Reciprocal Treatment-Joint Elimination). Joint elimination would have a large impact on regional power trading, including the trade flows in and out of Ontario. Accordingly, it is not consistent to compare Option 3, Scenario 1 with Option 2 in terms of the effect of Ontario's tariff change on imports/exports. We note that Option 4, Scenario 1 involves a unilateral decrease in the ETS Tariff from $1/MWh to $0/MWh and is therefore a consistent and more direct comparison to Option 2.

No, the ETS study did not calculate export demand elasticities nor does the model used in the study allow for export demand elasticities to be calculated. Demand elasticities are also not inputs to the model. Instead, the model assumes that demand is perfectly inelastic (i.e., zero elasticity) in all regions/jurisdictions. Export/import volumes are sensitive to changes in the ETS Tariff charge in the model, but the sensitivity is based on a generation-side (i.e., supply-side) calculation of inter-regional dispatch. For example, for a given load block, if the marginal cost of producing electricity in jurisdiction A (plus transaction costs, including the ETS Tariff from jurisdiction A) is less than the marginal cost of producing electricity in jurisdiction B, then power is exported from jurisdiction A and imported to jurisdiction B. In equilibrium, in a given load block, power will flow from jurisdiction A to jurisdiction B until either (i) the marginal prices, net of transaction costs, are equal in the two jurisdictions, or (ii) the power flow on the transmission lines connecting the two jurisdictions reaches the transfer limit. Changing the ETS Tariff will effectively change the relative prices among jurisdictions and hence leads to an adjustment in the export/import volumes. We do not believe it would be informative to calculate export demand elasticities from this model because the model does not include a price-sensitive demand representation.

Because each jurisdiction has a different generation mix, the sensitivity of exports with respect to the ETS tariff is different between Ontario and each jurisdiction. These sensitivities also differ by load block /load level for Ontario's exports to a given jurisdiction.

Ontario Energy Board (Board Staff) INTERROGATORY #36 List 1

Interrogatory

Issue 2.2 Are Other Revenue (including export revenue) forecasts appropriate?

Ref: Exhibit H1/Tab5/Sch2/Attachment 1/Page 16 (Table 4)

Please confirm that Hydro One has adopted the Status Quo option over the Average Embedded Network Rate option despite the finding of the study that if the latter were adopted there would be an estimated Net Ontario Benefit of $20 million in 2010 and (presumably) an annual benefit of $13 million for a number of years.

Response

Hydro One confirms that it has adopted the Status Quo option consistent with the IESO recommendation of maintaining the ETS tariff of $1/MWh as stated in Exhibit H1, Tab 5, Schedule 2, page 7, lines 19 to 22.

Ontario Energy Board (Board Staff) INTERROGATORY #37 List 1

Interrogatory

Issue 3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Ref. Exhibit C1/Tab 1/Sch1
Please provide a table that shows the O&M cost per km of transmission line and O&M cost per total fixed transmission assets from 2006 to 2012 test.

Response

	2006	2007	2008	2009	2010	2011	2012
OM&A per GFA	2.0%	2.2%	2.0%	2.1%	2.0%	1.9%	1.9%
OM&A per KM	6,902	7,778	7,073	7,900	8,187	8,405	8,650

Ontario Energy Board (Board Staff) INTERROGATORY #38 List 1

Interrogatory

Issue 3.1 **Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?**

General

Ref. Exhibit C1/Tab1/Sch1

In its June 11, 2010 letter to the Board regarding the draft Issues List, Hydro One mentioned that the revenue requirement was reduced by 25% from the level that Hydro One was originally intending to propose. Please provide information on what OM&A programs where cut to achieve this reduction in each of the test years and the rationale for the cut in each specific category (category detail as shown in Exhibit C1/Tab2/Schedules 3 to 9).

Response

Please note the 25% reduction refers to the percentage reduction in rates revenue requirement not the absolute reduction in revenue requirement dollars.

The reduction in the OM&A cost from the original proposal is $19.4M for 2011 which represents 34% of the net revenue requirement reduction from the original proposal. The OM&A reductions are shown in Table 1 below and are made up of a $12.9M reduction in Sustaining OM&A and a $6.5M in Shared Services and Other Costs.

TABLE 1

Transmission OM&A ($ millions)	**2011**
Sustaining	
Transmission Stations	
Environmental Management	(1.5)
Power Equipment	(4.5)
Protection, Control, Monitoring, Metering and Telecommunications	(3.6)
Ancillary Systems Maintenance	(0.5)
Site Infrastructure Maintenance	(1.0)
Total Transmission Stations OM&A	**(11.1)**
Transmission Lines	
Overhead Lines	(1.8)
Total Transmission Lines OM&A	**(1.8)**
Total Sustaining OM&A	**(12.9)**
Shared Services and Other Costs	
Asset Management costs	(1.1)
Common Corporate Functions & Services costs	(3.3)
Information Technology	(4.7)
Other	2.5
Total Shared Services and Other Costs	**(6.5)**
Total Transmission OM&A Reduction	**(19.4)**

<u>Sustaining OM&A reduction ($12.9M):</u>

A risk based assessment of the Transmission System at reduced OM&A Sustainment spending levels was carried out to ensure that risks could be managed within acceptable levels over the test years. This assessment took into account the following:

- asset condition,
- safety and environmental risks,
- performance,
- system function,
- customer impact, and
- statutory requirements

Below are the 2011 results of this assessment.

- <u>*Environmental Management ($1.5M)*</u> – Reduced oil leak reduction program from improve to status quo. Accomplishment remains slightly above historic.

- *<u>Power Equipment ($4.5)</u>* – SAP functionality, part of Cornerstone Phase 1 & 2, facilitates analysis of maintenance activities allowing for targeted reductions to those previously planned. Expenditures remain close to historic amounts without expected improvements in reliability, but adequate over the next two years to manage deterioration associated with aging assets. Extending mid life refurbishment of transformers sacrificing reliability improvements.

- *<u>Protection, Control, Monitoring, Metering and Telecom ($3.6M)</u>* – Protection re-verifications reduced on lower risk assets thereby minimizing reliability impacts. Maintenance deferred rather than improve current condition.

- *<u>Ancillary Systems Maintenance ($0.5M)</u>* - SAP functionality facilitates analysis of maintenance activities and frequency allowing for targeted reductions similar to power equipment.

- *<u>Site Infrastructure ($1.0M)</u>* – Deferral of selective site and facility maintenance to manage risks to acceptable levels.

- *<u>Overhead Lines ($1.8M)</u>* - Deferral of conductor repairs by applying inspection and diagnostic risk management practices.

<u>Shared Services & Other Costs reduction ($6.5M):</u>

- *<u>Asset Management ($1.1M)</u>* - With the implementation of Cornerstone Phase 1 & 2, Asset Management was able to reduce the organizational cost because of improved accessibility to data and reporting.

- *<u>Common Corporate Functions and Services (CCFS) ($3.3M)</u>* - CCFS costs were reduced in 2011 due to a) lower External Relations costs as a result of staff retirements and b) lower Facilities costs as a result of a reduction in spending related to accommodation requirements associated with Green Energy Act projects.

- *<u>IT ($4.7M)</u>* - IT costs were reduced in 2011 due to a) future staffing needs being reduced due to synergies achieved relating to IT reorganization; b) increased savings related to the Inergi contract extension; c) retiring/removing software applications no longer needed due to SAP.

- *<u>Other $2.5M</u>* - Other costs increased as a result of lower overheads capitalized due to the reduction in the 2011 Transmission capital expenditures and shared services costs. This increase was partially offset by a $0.7M reduction to reflect the impact of the MCP compensation freeze.

Ontario Energy Board (Board Staff) INTERROGATORY #39 List 1

Interrogatory

Issue 3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Sustainment

Ref. Exhibit C1/Tab2/Sch3/p. 10

Sustainment - Environmental Management. Hydro One indicates that the forecast presented for the test years for PCB and waste management is based on anticipated regulatory relief from Environment Canada. On what basis is this relief requested? How likely is it that relief will be granted and when? What would the $ amount impact of this be if no relief was granted in 2011 and 2012? Would Hydro One then update this application?

Response

Hydro One has been lobbying with Environment Canada (EC), through the Canadian Electrical Association's (CEA) PCB Task Group, since the changes to the PCB Regulations were proposed in 2000. The two most impactive issues are identified in Exhibit C1, Tab2, Schedule 3, Page 12, Line 5, summarized in the following table with the basis for the anticipated regulatory relief outlined below.

Issue	Likelihood of relief	Expected Relief	Incremental Impact of No Relief in 2011/12 ($M)			
			OM&A		Capital	
			2011	2012	2011	2012
Bushings ≥500ppm End of Use Extension to 2025	Good	YE 2010	4.9	4.7	0.3	3.0
Reuse of Oil ≥2ppm	Very Good	YE 2010	5.6	5.8	-	-

Should the relief not be granted, Hydro One does not plan to update the 2011/12 rate application. Overall OM&A work would be managed within the approved budgets, and some planned work would have to be deferred. This would have a negative impact on reliability. Capital programs would take some period of time to be affected, allowing for necessary equipment orders and design work. Capital would ramp up through late 2012-

late 2014. Future rate applications would include increases in OM&A and capital programs as the 2014 End of Use (EOU) date approaches.

Both prior to and following the enactment of the regulations, Hydro One has had many interactions with EC both directly and through the CEA. EC has been made increasingly aware of the challenges these two issues are causing for the utility sector in terms of efficiency, significant increase in system outages for testing and replacement as well as expedited design modifications to retrofit old equipment. This correspondence has taken place throughout EC from the Minister through to the policy makers, with members of the Hydro One and other CEA-member utility senior management teams.

Proposed Extension of End of Use Date for Bushings to Dec. 31, 2025

Section 15(2) defines and End of Use (EOU) date for oil filled equipment containing ≥500ppm by December 31, 2009. Hydro One has received the maximum allowable extension under Section 17(3) for equipment of both known and unknown concentration, to December 31, 2014.

Hydro One's preferred option is to propose managing the removal of low volume PCBs (i.e. bushings, instrument transformers, pole-top transformers) ≥500ppm through attrition and is working to influence the CEA and EC in that direction. At the time EB-2010-0002 was filled, it was unclear what position the CEA PCB Task Group was going to take: attrition or 2025 EOU. Hydro One's 2011 and 2012 investment programs were defined based on the 2025 EOU extension. Current Hydro One experience is that the percentage of equipment with oil containing PCB ≥ 500 ppm is in the 1% to 2% range and it is the industry's opinion that the regulations impose overly arduous requirements relative to the level of PCB addressed as part of a 2014 EOU date.

On July 16, 2010, the CEA requested EC to consider a formal amendment to the PCB Regulations to align with the United Kingdom's regulation defined in Statutory Instrument 2000 no. 1043. The UK regulation allows for equipment with unknown concentration to be managed through attrition, and those with known concentrations PCB ≥500ppm to be retro-filled or replaced as they become known. Please see Attachment 1

Historical correspondence with EC has centered on the following issues:

- Hydro One PCB removal accomplishment to date based on previous regulation and attrition
- Impact of regulations on customer reliability and employee safety
- Limited benefits of regulations to ecosystem
- Incremental costs, which were grossly underestimated by EC prior to enactment

Recent correspondence with EC has been promising, and there is a good chance of relief when the interpretation guide is provided later in 2010. Failing relief in the interpretation guide, there is optimism the regulations will opened for amendment in 2011.

Proposed revision to Section 16(3) – Reuse of Oil ≥2ppm PCB

Section 14(1)(d) of the PCB Regulations allows the continued use of electrical insulating oil <50ppm PCB; there is no end of use date. The majority of Hydro One's insulating oil contains trace amounts of PCB, typically in the range of 3-10ppm.

Section 16(3) of the PCB Regulations states:

> *"A person may use a liquid containing 2 mg/kg or more of PCBs that is in equipment until the day on which the liquid is removed from the equipment.*"

It is normal utility practice to remove insulating oil from equipment for maintenance purposes, during which Hydro One Transmission handles over 3.5 million liters per year. Current regulations require the majority of this oil be replaced with oil <2ppm, which can only be attained through using new oil or reconditioned oil.

Early in 2010, EC indicated that an interpretation guide would be issued, which is expected to eliminate the need to replace oil ≥2ppm and <50ppm when removed for maintenance purposes, given that it returns to the same equipment it was removed from. This interpretation guide will serve as the basis until such point in the future the regulation is updated.

Canadian Electricity Association | Association canadienne de l'électricité

July 16, 2010

Ms. Cynthia Wright
A/Assistant Deputy Minister
Environmental Stewardship Branch
Environment Canada

RE: PCB – International Regulations: Statutory Instrument 2000 No. 1043

The Canadian Electricity Association (CEA) is committed to participating in the action plan for the gradual phase-out of polychlorinated biphenyl (PCB) in Canada. In order to accomplish such a goal, it is crucial that CEA companies have appropriate time to ensure proper management of PCB equipment in an effective, reliable and economically feasible manner. The information below is provided per the request from Environment Canada during our meeting on August 20, 2009 to evaluate international commitments in PCB management.

According to the current PCB regulations, bushings and instrument transformers (IT) having a PCB concentration equal to or greater than 500 parts-per-million (ppm) were due to be removed from service by December 31, 2009 unless an end-of-use extension was granted by the Minister. The maximum extension period ends on December 31, 2014. The granted extensions have allowed CEA members to comply with the PCB regulations as currently written, and are grateful for Environment Canada's effort in working with CEA to complete and approve these applications.

CEA members however, currently face operational and technical difficulties in meeting the extended end-of-use deadline of December 31, 2014. This deadline does not provide sufficient time to address the large inventory of equipment involved (as described by CEA members during the extension application process). As such, CEA is proposing an amendment to the current PCB regulation that would ascribe bushing and instrument transformers (ITs) an end-of-use date beyond 2014. This will allow time for utilities to minimize operational impacts by optimizing resources and securing capital stock required in undertaking the tasks of testing and replacing this equipment.

It should be noted that companies who have been granted an end-of-use extension continue to seek and identify PCB equipment as part of their regular activities. The extension will in no way diminish the environmental integrity of the management of PCB equipment nor will it compromise the environmental responsibilities of our members. Companies continue to maintain the environmental safeguards described in the end-of-use extension requirements.

CEA has emphasized the cost associated with replacing PCB equipment that has not reached the end of its economic life and the subsequent impact on consumers. CEA has also described the challenges of providing a reliable supply of electricity to the public while scheduling outages to access equipment in efforts to meet the current deadlines. CEA recognizes the ongoing international efforts regarding the elimination of PCB, such as the Stockholm Convention on Persistent Organic pollutants (POPs), to which many developed countries, including the United Kingdom and Canada, are signatories. In May 2000, the UK implemented a statutory instrument (UK Statutory Instrument 2000 no. 1043) to fulfill its obligations under the Stockholm Convention. Excerpts of the instrument can be found below and are submitted to demonstrate support for the proposed amendment to Canada's PCB Regulation.

According to the UK instrument, equipment that is known to be over 500 mg/kg must be decontaminated to below 50 ppm PCB. There is no stipulation of a time limit in the instrument that would force sampling of the equipment; rather PCB equipment must be dealt with as it is discovered. Equipment below 500 ppm may be used until the end of its useful life. See Table 1 below for additional detail.

Table 1

Legislation	**Reference within Legislation**	**Details**
UK Statutory Instrument 2000 no. 1043	Section 2(1)	"contaminated equipment" means any equipment that contains PCBs other than equipment that contains a total volume not exceeding $5dm^3$ (or approximately 5 Litres).
	Section 2 (1)	"PCBs" means polychlorinated biphenyls, polychlorinated terphenyls, monomethyl-dibromo-diphenyl methane, monomethyl-dichloro-diphenyl methane, monomethyl-tetrachlorodiphenyl methane, or any mixture of the above in concentration of more than 50 ppm.
	Section 4 (3)	Equipment <500 ppm can be used until end of its useful life
	Section 4(4)	Equipment >500 ppm must be decontaminated to <50 ppm levels.

The UK Statutory Instrument regarding the elimination of PCBs allows for the phase-out of PCB equipment while maintaining international commitments under the Stockholm Convention and does so in an economically feasible manner that allows for capital stock turnover and testing in a reasonable timeframe.

CEA supports equipment end-of-life as the end-of-use criteria for PCB elimination for managing PCB bushings and ITs in the electricity sector and hopes Environment Canada will consider amending the Canadian PCB regulations with similar end-of-life criteria for certain PCB equipment as in the UK instrument. CEA reemphasizes the need for a regulatory amendment to address the large amount of equipment that would require inspection, testing and potentially removal in such a short timeframe.

The full text of the UK Statutory Instrument is attached for your review and can be found at the following URL: http://www.opsi.gov.uk/SI/si2000/20001043.htm. Thank you for the opportunity to provide this information, and I look forward to continuing this dialogue to determine the best path forward.

Regards,

Eli Turk

Eli Turk
Vice President
T: 613-230-9876
Email: turk@electricity.ca

cc. Mr. Randall Meades – Director General, Public and Resources Sectors

Mr. Timothy Gardiner – Director, Waste Reduction and Management

Mr. Robert Larocque – Chief, Waste Programs, Waste Reduction and Management

Ontario Energy Board (Board Staff) INTERROGATORY #40 List 1

Interrogatory

Issue 3.1 **Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?**

Sustainment

Ref. Exhibit C1/Tab2/Sch3/p. 22

Sustainment – Ancillary Systems Maintenance. Hydro One indicates that program spending for 2010 grew to $14.9 million, then growing further from that level to $15.8 million in 2011 (up 6%) and to $16.6 million (up 5%) in 2012. What was the primary rationale for the 20% increase in the bridge year and why is it necessary to sustain and increase this level of spending for 2011 and 2012?

Response

The primary factors influencing the 2010 bridge year increase from the 2009 historic year are as follows:

Corrective Maintenance

Spending in 2010 is projected $1.10 million higher than 2009 due to an increased volume of corrective work, specifically grounding systems and high pressure air systems. Repair of defects on these assets is imperative to system reliability and safety of the public and Hydro One staff. Grounding repairs are required to maintain an adequate ground grid to safely control fault currents and step and touch potentials. Performance of the air-blast circuit breakers is dependant on a reliable high-pressure air supply.

Preventive Maintenance

Spending projected in 2010 is $0.7 million higher than 2009 due to increased accomplishment of planned work needed to maintain reliability, safety and comply with regulatory requirements. More of these assets are nearing the end of life region and to obtain full utilization and maintain reliability added maintenance is required as identified below:

- Additional maintenance on batteries and chargers supplying DC to critical telecom loads, (ST-3 compliance testing as mandated by NPCC and NERC)
- Additional maintenance on HP air system components (compressors, dryers, air receivers, valves, etc),
- Additional maintenance on AC station service breakers and transfer schemes.

<u>Other Maintenance Activities and Costs</u>

Spending increase in the 2010 bridge year is $0.7 million higher than the 2009 historic year driven by several programs, including additional testing and engineering studies associated with grounding systems due to increasing need to manage the aging infrastructure and respond to copper theft, and increased costs for operating the Oil Farm in response to the PCB regulations.

The increases in the test years relative to the bridge year are caused by an additional volume of preventive and corrective maintenance, which is a combination of two primary issues:

- The need to complete work which has been deferred from previous years following the EB-2008-0272 Decision.
- Additional work to adequately maintain the aging Ancillary Systems allow them to reach end of life, at which point they will be replaced or decommissioned.
    - i.e. additional maintenance of station service breakers and transfer schemes to provide reliable AC-supply during contingencies and adequately address safety issues associated with arc-flash hazards at 600V and 208V.

Continued preventive and corrective maintenance of the ancillary systems is required to ensure reliability to the main power system elements they support, the safety of Hydro One staff and the public in the vicinity of Hydro One stations, and maintain Hydro One in good standing with external regulatory bodies (NPCC, TSSA, etc).

Ontario Energy Board (Board Staff) INTERROGATORY #41 List 1

Interrogatory

Issue 3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Sustainment

Ref. Exhibit C1/Tab2/Sch3/p. 29
Sustainment – Protection, Control, Monitoring, and Metering Equipment. Hydro One indicates that 174 metering points remain in Hydro One's asset base under transitional arrangements. Please provide a table showing then number of meters under transitional arrangements from 2006 to 2012. What are the cost savings realized as more meters are removed from the Hydro One asset base? At what point is it expected that all meters will exit the program?

Response

Number of wholesale metering points under transitional arrangement 2006-2012.

2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
513	469	317	252	174	100*	75*

* Forecast number

Meters exit the transitional arrangement at the seal expiry date when the full upgrade of an installation is complete and complies with the market rules. Meter points move to either Hydro One Distribution or customers of Hydro One Transmission. Ongoing maintenance would then be the accountability of and funded by the respective organization.

Hydro One plans to finish the transition of it's legacy wholesale metering installations to Hydro One Distribution by 2012. The 75 wholesale metering points past 2012 are customer owned, and at this time it is not clear when these will be transferred as it is the customers who must decide on the timing of upgrades.

The average spending requirement for a wholesale meter point is $8,400 per year. These costs are recoverable from the wholesale meter customers as noted in Exhibit H1, Tab 4, Schedule 1. As wholesale meters are removed from Hydro One Transmission's rate base, the associated costs are no longer incurred and customers also no longer pay the wholesale meter charge. As such, there are no net savings realized as wholesale meters are removed from the system.

Ontario Energy Board (Board Staff) INTERROGATORY #42 List 1

Interrogatory

Issue 3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Sustainment

Ref. Exhibit C1/Tab2/Sch3/p. 37
Sustainment – Site Security. What were the site security costs from 2006 to 2010? Why are costs increasing from 2010 to 2012 if copper prices are falling from previous levels, thereby reducing the incentive for copper theft?

Response

Site security costs from 2006 to 2010 were as follows:

2006 - $1.9 million
2007 - $2.2 million
2008 - $3.9 million
2009 - $2.3 million
2010 - $4.2 million

Hydro One is placing added emphasis to deter copper theft as the removal of copper from station fences, equipment and structures presents serious safety hazards to workers and the public, as well as those removing the copper. This problem has persisted over the last 3 years since the price of copper increased to about $3 per pound and copper prices still remain above this level today. Interest in copper theft is expected to continue and action is required to deter theft in order to prevent unsafe conditions, disruptions in equipment operation and eliminate unnecessary expenditures.

For further details please also refer to Exhibit I, Tab 2, Schedule 56.

Ontario Energy Board (Board Staff) INTERROGATORY #43 List 1

Interrogatory

Issue 3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Sustainment

Ref. Exhibit C1/Tab2/Sch4/p. 6

Development – Smart Zone Development. Please provide an explanation as to how these funds are related to the Smart Zone project spending approved in the Hydro One distribution decision (EB-2009-0096).

Response

Hydro One's Smart Zone Development includes the interface between the transmission system and the distribution system, to make them integrated and interoperable. While the majority of the work and assets will be on the distribution system as approved in EB-2009-0096, there is work and assets required on the transmission system. In addition to the OM&A dollars for transmission related work, there are also capital dollars as shown in Exhibit D1, Tab 3, Schedule 3, Table 10 in order to test the IEC 61850 communications standard in the Smart Zone.

Ontario Energy Board (Board Staff) INTERROGATORY #44 List 1

Interrogatory

Issue 3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Sustainment

44) Ref. Exhibit C1/Tab2/Sch5/p. 5
Operations – Support. Operations support cost grew by 36% in 2010 and continue to increase by 9.7% and 4.4% in 2011 and 2012 respectively. Please provide a detailed rationale for the significant 2010 increase and the continuing inflation-exceeding growth for the test years.

Response

The necessary increase in Operations Support costs is driven by the requirements of the Network Management System (NMS) upgrade which was completed in 2009. Further discussion of the new NMS is provided below. A cost increase is seen in 2010 because, for the first time, ongoing vendor support costs and licensing fees for the new NMS were incurred and additional in-house support is required for the new NMS and associated tools. These required costs continue beyond the test years.

In addition, in the test years, it is anticipated that there will be increasing support requirements associated with new tools such as the NOMS (Networks Outage Management System) and changes associated with evolving Critical Infrastructure Protection standards. A portion of the increase is also attributed to additional field switching that will be required to support the increase in sustaining and development work programs.

The NMS upgrade, which was completed in 2009, included complete end-of-life replacement of all hardware components associated with the NMS along with a major operating system upgrade which incorporated both software and architecture changes required to bring the NMS into compliance with NERC Critical Infrastructure Protection standards. Additionally, new operational requirements were added to ensure the NMS and associated tools would meet business needs over its expected life cycle. Of note, the system was designed to accommodate a 50% increase in the number of data points, required to support Distributed Generation and future system growth. To meet the increased data storage capacity requirements, an enterprise-class storage architecture had to be adopted. Enterprise-class storage architecture is, by design, used for larger systems, however, the associated hardware, licensing and support costs have increased with the introduction of this technology. A fuller discussion of the NMS Upgrade project and the new operational tools and estimated operator efficiencies it provides can be found in Exhibit I, Tab 2, Schedule 66.

A further discussion of these NMS support costs is provided in Exhibit I, Tab 2, Schedule 18.

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch6/p. 4

Shared Services and Other OM&A Costs. Table 2 was also submitted in the EB-2009-0096 Distribution proceeding (updated September 25, 2009) and included the 2011 test year. It appears that the costs allocated to Tx have increased substantially in the current proceeding. Please provide a comparison of the evidence provided in the distribution case and provide an explanation regarding the changes in the 2011 test year in this proceeding.

Response

The following table provides the comparison of Shared Services and Other OM&A for the 2011 test year as submitted in EB-2009-0096 and EB-2010-0002.

Table 1
Comparison of 2011 Shared Services and Other OM&A Costs from EB-2009-0096 & EB-2010-0002 ($M)

Function/ Service	*EB 2009-0096*				*EB 2010-0002*				*Variance*			
	Total	Tx	Dx	Other	Total	Tx	Dx	Other	Total	Tx	Dx	Other
CCF&S	102.5	52.8	46.6	3.1	154.9	79.7	72.1	3.1	52.4	26.9	25.5	(0.0)
Asset Management	145.8	73.3	72.5	0.0	74.9	35.6	39.4	0.0	(70.9)	(37.8)	(33.1)	0.0
Information Technology	155.3	71.1	81.9	2.3	148.1	67.5	78.3	2.3	(7.2)	(3.6)	(3.6)	0.0
Shared Cost Summary	403.6	197.3	201.0	5.4	377.9	182.8	189.8	5.4	(25.7)	(14.5)	(11.1)	0.0
Allocation %		*48.9%*	*49.8%*	*1.3%*		*48.4%*	*50.2%*	*1.4%*				
Cornerstone	(26.1)	(18.3)	(7.8)	0.0	(17.9)	(12.5)	(5.4)	0.0	8.2	5.8	2.4	0.0
Allocation %		*70.1%*	*29.9%*	*0.0%*		*69.8%*	*30.2%*	*0.0%*				
Cost of Sales	24.7	14.9	9.8	0.0	24.7	14.9	9.8	0.0	0.1	0.0	(0.0)	0.0
Allocation %		*60.3%*	*% 39.7*	*0.0%*		*60.3%*	*39.7%*	*0.0%*				
Other Shared Services[1]	(253.1)	(138.2)	(114.9)	0.0	(253.4)	(138.3)	(115.2)	0.0	(0.3)	(0.0)	(0.3)	0.0
Allocation %		*54.6%*	*45.4%*	*0.0%*		*54.6%*	*45.5%*	*0.0%*				
Total	149.0	55.6	88.1	5.4	131.3	46.9	79.0	5.4	(17.7)	(8.8)	(9.1)	0.0
Allocation %		*37.3%*	*59.1%*	*3.6%*		*35.7%*	*60.2%*	*4.1%*				

[1] Other Shared Services from EB-2009-0096 has been normalized to reflect removal of IPSP credit.

Table 1 shows a decrease in the percentage of costs allocated to Transmission between EB-2009-0096 and EB-2010-0002 for CF&S, Asset Management and Information Technology. Further, the percentage of the Cornerstone and Cost of Sales costs allocated to Transmission are approximately the same.

Other Shared Services totals shown in EB-2009-0096 have been normalized. There is an implied $33.1M increase in the amounts attributable to Transmission in the current application when compared to the corresponding table shown in EB-2009-0096. This is primarily the result of a $30.1M credit allocated 100% to Transmission in EB-2009-0096. The credit represented the off-set to the proposed preliminary development work to advance transmission projects requested by the Ontario Government. For the purpose of this application, the credit has been appropriately removed from Other Shared Services as Hydro One is not seeking to recover the costs for this preliminary work as part of base revenue requirement and is proposing to continue to collect these costs in a deferral account for future disposition.

Ontario Energy Board (Board Staff) INTERROGATORY #46 List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch7

The shared services exhibit only provides Tx allocations for the two test years. Please provide the Tx allocations for the years 2007 to 2010 in the detail provided at:

a) Table 1 CCFS at Exhibit C1/Tab2/Sch7/page 2
b) Table 1 Asset Management at Exhibit C1/Tab2/Sch8/page 3
c) Table 1 Information Technology at Exhibit C1/Tab2/Sch9/page 2
d) Table 5 Business Telecom at Exhibit C1/Tab2/Sch9/page 14

Response

a)

2007 - 2010 CCF&S Costs Allocated to Transmission ($M)				
Description	**2007**	**2008**	**2009**	**2010**
Corporate Management	3.6	3.3	3.2	2.9
Finance	11.8	14.9	16.3	17.3
Human Resources	6.4	7.3	8.3	10.2
Corporate Communications	3.8	4.6	5.4	6.7
General Counsel and Secretariat	4.1	3.5	3.5	4.7
Regulatory Affairs	11.5	10.8	9.9	10.6
Corporate Security	0.9	1.1	1.1	1.5
Internal Audit	1.3	1.3	1.5	1.7
Real Estate & Facilities	21.7	18.8	23.8	27.5
Gross CCF&S Costs	65.1	65.7	73.1	83.1
Allocation to Subs	(1.1)	(1.2)	(1.3)	(1.7)
Total Costs	**64.1**	**64.5**	**71.8**	**81.3**

b)

2007 - 2010 Asset Management Costs Allocated to Transmission ($M)				
Description	**2007**	**2008**	**2009**	**2010**
Strategy & Business Development	3.4	4.3	5.1	5.1
System Investment	12.6	16.4	21.3	18.8
Work Program Optimization	2.2	2.3	2.1	3.8
Business Integration	5.3	6.5	8.0	3.2
Business Transformation	1.8	1.4	1.1	0.8
Processes and Policies	0.6	0.9	2.4	1.3
Total Cost	**25.9**	**31.8**	**40.0**	**33.0**

c)

2007- 2010 Information Technology Costs Allocated to Transmission ($M)				
Description	**2007**	**2008**	**2009**	**2010**
Sustainment	27.6	30.8	33.2	38.4
Development	3.8	1.8	1.5	4.9
Business Telecom	8.1	8.1	9.8	11.1
IT Management & Project Control	6.7	10.0	11.6	13.8
Total Cost	46.2	50.7	56.1	68.1

d)

2007- 2010 Business Telecom Costs Allocated to Transmission ($M)				
Description	**2007**	**2008**	**2009**	**2010**
Operations and Carrier Management	2.0	2.0	2.2	2.6
Field Services	1.8	1.3	2.5	1.9
Voices Services	1.9	2.2	2.7	3.0
Data Network Services	2.4	2.6	2.3	3.6
Total	**8.1**	**8.1**	**9.7**	**11.1**

Ontario Energy Board (Board Staff) INTERROGATORY #47 List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch7/p.9
Table 4 on this page shows that that the Hydro One Insurance program grew significantly from 2009 to 2011. Please provide the major reasons for this growth and provide the Transmission share of these costs from 2007 to 2012.

Response

Hydro One's insurance program in 2011 is larger than 2009 for the following reasons:

i) Hydro One's loss experience has deteriorated over the last number of years

ii) The replacement value of Hydro One's assets has increased

iii) In certain instances the deductibles have been increased to mitigate rising insurance premiums, which would increase self-insurance costs

When purchasing insurance Hydro One takes into consideration many factors including premium costs at various deductible/self insurance levels as well as the company's loss experience.

The following table provides the Transmission portion of the Insurance Program in millions:

	Historic			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Total Insurance Program Costs	$6.1	$6.5	$7.4	$8.8	$9.2	$9.3
Amount Allocated to Transmission	$3.3	$3.9	$4.4	$4.6	$3.8	$3.9

Ontario Energy Board (Board Staff) INTERROGATORY #48 List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch7/p.14

The exhibit indicates that First Nations and Metis Relations costs are growing to $3.5 million in 2011 and $3.6 million in 2012, with about 60% of these costs allocated to transmission. Please provide the total Hydro One costs and those allocated to transmission from 2007 to 2010.

Response

Please refer to the table below.

First Nations and Metis Relations Costs (Total Cost from 2007-12 and Tx Allocations)			
Year	**Total ($M)**	**Tx ($M)**	**Tx (%)**
2007	0	0	0
2008	0.3	0.2	53.9
2009	0.5	0.3	53.3
2010	2.1	1.2	57.6
2011	3.5	2.1	59.4
2012	3.6	2.1	59.3

Ontario Energy Board (Board Staff) INTERROGATORY #49List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch7/p.23
Hydro One's corporate level real estate and facilities costs appear to be leveling off in the test years, however, these costs have grown significantly for 2008 to 2010. What were the major drivers for these increases from 2008 to 2010 and if big projects were financed and completed at that time, why have costs not fallen more significantly in the test years?

Response

	Historic			**Bridge**	**Test**		**Allocation to Transmission**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2011**	**2012**
Real Estate	6.4	7.0	7.9	9.3	8.8	9.4	7.2	7.7
Facilities	31.1	34.9	42.7	49.3	45.2	45.6	20.4	20.6
Total Costs	**37.5**	**41.9**	**50.6**	**58.6**	**54.0**	**55.0**	**27.6**	**28.3**

The primary drivers of the cost increase from 2008 to 2010 are higher facilities costs at our 140 different locations across the province. Hydro One is committed to efficiently managing company accommodation requirements and to provide the accommodation solutions necessary to support execution of the company's work programs. The company is also dedicated to maintaining employee workspace and facility assets to ensure that they comply with all legislative and other related health, safety and environmental standards.

Facilities cost increases are driven by growth in the company's work programs, business and operating requirements, fixed cost contractual obligations and the current regulatory environment (including health and safety requirements).

As a result of the company's larger work program additional workspace was added from 2008 to 2010 including 35,000 square feet of additional space at our head office location (483 Bay Street, Toronto). Other facilities additions from 2008 to 2010 include:

- Office space @ Atrium on Bay, (20 Dundas West, Toronto)
- Office space @ Meter Reading & Relay Services Facility, (6135 Danville Rd, Mississauga)

- Office space @ 95 Mural Street, Richmond Hill)
- Barrie Cross Dock/Warehouse
- Heliport at the Lake Simcoe Regional Airport

Facilities costs in 2011 and 2012 decrease as a result of the deferral of additional accommodation requirements associated with Green Energy Act initiatives.

Ontario Energy Board (Board Staff) INTERROGATORY #50List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch8/p.3
Hydro One's total asset management costs increased significantly in the past few years (26% increase in 2009, 17.5% increase in 2010) to a level of $75 million in the 2011 test year. What specific projects and activities were accomplished in this time period, and how it is that these spending levels continue into the two test years?

Response

The Asset Management cost increases are driven by the growth in our Capital & OM&A Sustainment and Development Work Programs primarily impacting the System Investment Function costs. The activities driving these higher System Investment Function costs are outlined on page 8 of the Exhibit. Of significance, are the increased demands to support the Development Program, driven by increased work volumes associated with the introduction of the Green Energy Act and Distributed Generation.

Additional factors driving our cost increases in other Asset Management Function areas include, regulatory compliance requirements intensifying from oversight bodies like NERC, NPCC, IESO, support to the government influenced Smart Grid initiative and an increased overall Work Program which leads to an increased workload in Business Integration activities between the Asset Management Group and the Work Execution Groups. (A more detailed explanation regarding the increase in the Strategy and Business Development function within Asset Management is noted in the response found at Exhibit I, Tab 10, Schedule 18).

All of these factors that are driving our increased workload and associated costs are on-going in nature right through 2011 & 2012 and thus result in the spending levels presented.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #51 List 1</u>

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

<u>Ref. Exhibit C1/Tab2/Sch8/p.3-18</u>
Hydro One's evidence describes 4 separate business functions under Asset Management, including Work Program Optimization, Business Integration, Business Transformation, and Processes & Policies. The funding for these programs is growing from $20 million in 2009 to $25 million in 2012. It appears, from the description provided, that each of these functions perform similar tasks. Has Hydro One considered merging or consolidating these functions to achieve greater efficiencies in this program? If not, why not?

Response

Please see Exhibit I, Tab 1, Schedule 38, which describes the cost reductions from plan in the years 2011-2012. As noted, these reductions are primarily driven by the efficiencies brought into the Asset Management organization through the implementation of Cornerstone Phase 1 & 2. Staff and cost reductions were made in concert with a realignment of Functional area responsibilities which did include Business Integration, Work Program Optimization and Process & Policies. (The Business Transformation Function primarily supports project specific work and does not perform the core support activities like the other 3 areas). All 4 functional areas will continue to be maintained for the time being refocused on specific and distinct deliverables through 2012 and beyond, however, if opportunities for continued efficiencies arise through consolidation this will be pursued.

Ontario Energy Board (Board Staff) INTERROGATORY #52 List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch9/p.10
In this schedule, it appears that Hydro One's major growth category in IT sustainment is in Other Incremental Sustainment with increases of 77% in 2009, 19% in 2010, 10% in 2011 and 7.3% in 2012. Costs appear to be decreasing in all other categories. Why is Hydro One not able to control costs in Other Incremental Sustainment as it has in the other areas?

Response

The growth in Other Incremental Sustainment costs in 2009 and 2010 is primarily due to the ongoing SAP Application Support needed after the SAP phase 1 and phase 2 go-live dates in 2008 and 2009, respectively. 2010 represents a full year of SAP application support costs. 2011 and 2012 costs increase due to Smart Metering Application Support being introduced into this category as well as the required Application Support of other solutions such as Mobile IT. The incremental IT costs includes application support cost and 3rd party software licensing and maintenance by the software vendors.

There is also an expected increase in Microsoft licensing costs as products (i.e. Exchange/Outlook, Office, Windows 7) are upgraded and usage of new products such as Office Communicator, SharePoint and LiveMeeting expands.

Ontario Energy Board (Board Staff) INTERROGATORY #53List 1

Interrogatory

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch8/p.15
Hydro One mentions the assessments done by the Shpigler Group in 2006 and 2008 regarding Business Telecom. Yet in 2009 there is a significant increase of 21% in costs followed by a 10% increase in 2011. Please relate these increases and the justification of the increases to the findings of the Shpigler report.

Response

The 21% increase in costs in 2009 followed by a 10% increase in 2011 pertain to the total Telecom costs including Operations and Carrier Management, Field Services, Voices Services, and Data Network Services. The scope of the Shpigler report only pertains to Operations and Carrier Management which relates to telecommunications management services provided by Hydro One Telecom.

The increases in Operations and Carrier Management in 2009 is 9% followed by an increase of 18% in 2011. These increases are due to the operation, monitoring and security of additional or expanded business data networks on a year-over-year basis. Specifically, security enhancements are being introduced over these years which require incremental resources to manage and operate. Further, as data traversal expands through software applications throughout the province, new and expanded bandwidth – both wired and wireless - are needed to support the business processes. Considering these services are an expansion of existing services including 'ensuring physical and logical security of network', they are consistent with the findings of the Shpigler report.

Ontario Energy Board (Board Staff) INTERROGATORY #54 List 1

Interrogatory

Issue 3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref. Exhibit C1/Tab3/Sch2/p. 9
Please provide the annual number of employees that correspond to these payroll levels by year.

Response

Year	Annual number of employees
2006	5301
2007	5893
2008	6547
2009	7130
2010	8410
2011	8788
2012	8938

Ontario Energy Board (Board Staff) INTERROGATORY #55 List 1

Interrogatory

Issue 3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref. Exhibit C1/Tab3/Sch2/p. 9
Hydro One indicates that the total work program is expect to increase by approximately 6.6% and the regular plus non-regular staff increase is expect to increase by approximately 6.3%. Please provide a break out of regular vs non-regular increases in staff. In addition please provide an explanation as to why this "work program vs. staff increases" assertion has changed from that filed in the EB-2009-0096 distribution case, where Hydro One indicated that a work program expansion of 35% yielded a staff increase of 16%. What are the major factors that explain the change in the "gap"?

Response

The break-out of regular vs non-regular increases in staff for 2010, 2011, and 2012 is as follows:

	2010	**2011**	**2012**
Regular staff	5856	6165	6306
Non-regular staff	2554	2623	2632
Total	8410	8788	8938

The major factor that explains the change in the "gap" of "work program vs. staff increases" is a decrease in forecast Transmission costs. In the 2009-0096 Distribution case, a higher forecast was used as the basis for the Transmission portion of the 2011 work program [as provided in the confidential EB-2009-0096 Exhibit H, Tab 13, Schedule 1, Attachment 3]. The current transmission application reflects delays in the anticipated transmission green energy plan spending, thus decreasing the work program total cost for 2011 through 2012. Another factor contributing to the change in the "gap" was that the 35% work program increase reflected Hydro One's anticipated spending in 2010 and 2011, whereas the 6.6% work program increase for this application reflects the actual Board approved spending for Distribution in EB-2009-0096. Finally, the growth difference between the bridge year and second test year work programs was larger in EB-2009-0096 Distribution case than it is in the current application.

Ontario Energy Board (Board Staff) INTERROGATORY #56 List 1

Interrogatory

Issue 3.3 **Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Ref. Exhibit C1/Tab3/Sch2/p. 10

The Mercer Benchmarking study was completed for the EB-2008-0272 proceeding. Has Hydro One taken steps to update the study? Why or why not? If the study is to be updated, when would updated results be available?

Response

Hydro One has not updated the study. The data is still quite recent and the study would be very costly to update.

Ontario Energy Board (Board Staff) INTERROGATORY #57 List 1

Interrogatory

Issue 3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref. Exhibit C1/Tab3/Sch2/p. 17
Hydro One quotes a wage increase study for the Canadian utility sector. Please provide a copy of that study and the Mercer source that provides the 3.5% forecast for 2010.

Response

The Canadian utility sector study is a Wage Tabulation from 1999 to 2009, prepared by Strategic Policy, Analysis, and Workplace Information Directorate. A copy of the study is attached as Attachment 1. The source that provides the 3.5% forecast for 2010 is Mercer's Compensation Planning Survey (CPS) published in August 2009. Hydro One did not purchase a copy of the CPS, however a principle from Mercer provided the reference.

Date of Study: 13 January 2010

Wage tabulation from 1999 to 2009

Total Agreements 147
Total Employees 240,945

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1999																
1234801	221	ATCO Gas Edmonton, Alta. Calgary, Alta.	Natural Gas Employees' Association (Independent-local) (plant and maintenance employees)	P	N	800	19991216	20000101	20021231	36.0	13.39	3.0	3.0	3.0	3.0	3.0
0865404	221	B.C. Gas Utility Ltd. province-wide, B.C.	Office & Professional Empls. Intl. Union (CLC) (office employees, technical employees)	P	N	660	19990531	19980401	20000331	24.0	13.97	0.5	0.5	0.0	1.0	
0865304	221	BC Gas Utility Ltd. province-wide, B.C.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	650	19990908	19980401	20010331	36.0	19.54	0.7	0.7	0.0	0.0	2.0
0412808*	221	British Columbia Hydro and Power Authority province-wide, B.C.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	1390	19990127	19971001	20020331	54.0	18.67	0.7	0.7	0.0	1.0	0.0
0412907	221	British Columbia Hydro and Power Authority province-wide, B.C.	Office & Professional Empls. Intl. Union (CLC) (office employees, technical employees)	P	N	2660	19990129	19970401	20020331	60.0	10.48	0.6	0.6	0.0	1.0	0.0
1100902	221	Epcor Utilities Inc. Edmonton, Alta.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	590	19991026	19990101	20011229	35.9	17.33	2.8	2.8	2.5	3.0	3.0
0408808*	221	Hydro-Quebec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (technical employees)	P	N	2400	19991111	19990101	20031231	60.0	16.17	2.5	2.5	1.5	2.5	2.5
0408908*	221	Hydro-Quebec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (general tradesmen)	P	N	6500	19991126	19990101	20031231	60.0	15.98	2.5	2.5	1.5	2.5	2.5
0409008*	221	Hydro-Quebec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (office employees)	P	N	5400	19991111	19990101	20031231	60.0	20.35	2.5	2.5	1.5	2.5	2.5
0408707	221	Hydro-Québec province-wide, Que.	Synd. professionnel des ingénieurs d'Hydro-Qc inc. (Independent-natl.) (engineers)	P	N	1500	19990323	19951227	20031231	96.1	18.38	1.8	1.8	0.0	0.0	0.0

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
0979704	221	Ontario Hydro province-wide, Ont.	Society of Ont. Hydro Professional & Administrative Empls. (Independent-natl.) (scientific and other professional employees, administrative services employees)	P	N	5570	19990125	19990101	20001231	24.0	21.31	2.5	2.5	2.5	2.5	
0879504	221	SaskEnergy Inc. province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees, field employees)	P	N	760	19990219	19980201	20010131	36.0	13.23	2.0	2.0	2.0	2.0	2.0
0411906	221	SaskPower province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (administrative services employees)	P	N	640	19990401	19980201	20010131	36.0	11.80	1.7	1.7	2.0	1.0	2.0
1187601	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (outside employees)	P	Y	960	19990312	19990201	20010131	24.0	16.57	1.8	2.4	2.5	2.3	
1187701	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (inside and outside employees)	P	Y	640	19990312	19990201	20010131	24.0	15.25	1.7	2.4	2.5	2.3	
0412508	221	TransAlta Utilities Corporation province-wide, Alta.	Transalta Empls'. Assn. (Independent-local) (office employees, general and field support employees)	P	N	620	19991201	19990101	20011231	36.0	11.88	2.2	2.2	0.0	3.0	3.5
		Weighted Average				31740				49.5	17.21	2.1	2.1	1.5	2.1	1.9
2000																
1261301	221	Consumersfirst province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees and technicians)	P	N	560	20000101	19991001	20010331	18.0	13.16	0.0	0.0	0.0	0.0	
1261501	221	Enbridge Consumers Gas province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (utility workers, office employees and technicians)	P	N	780	20001210	20000401	20021231	33.0	19.08	2.2	2.2	2.0	2.0	2.0

WAGE INCREASES IN MAJOR AGREEMENTS - WID

Date of Study: 13 January 2010

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1236101	221	Hydro One Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees, general tradesmen)	P	N	4000	20000331	20000401	20010331	12.0	28.78	3.0	3.0	3.0		
1256401	221	Hydro One Inc. province-wide, Ont.	Society of Energy Professionals (Independent-natl.) (scientific and other professional employees, administrative services employees)	P	N	1000	20001222	20010101	20011231	12.0	22.77	3.0	3.0	3.0		
0411607	221	Manitoba Hydro province-wide, Man.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees)	P	N	800	20000907	20000330	20030326	35.9	11.26	2.6	2.6	2.7	2.3	2.8
0411706	221	Manitoba Hydro province-wide, Man.	Association of Manitoba Hydro Staff and Supervisory Employees (Independent-local) (office employees, supervisors)	P	N	540	20000914	20000330	20030326	35.9	18.94	3.3	3.3	2.7	4.3	2.8
0411509	221	Manitoba Hydro-Electric Board province-wide, Man.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (service and maintenance employees)	P	N	2300	20001102	20000525	20030521	35.9	12.28	2.7	2.7	3.0	2.3	2.8
1243701	221	New Brunswick Power Corporation province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (operational employees, technical employees)	P	N	750	20000524	20000101	20001231	12.0	12.68	3.0	3.0	3.0		
0857006	221	Newfoundland and Labrador Hydro province-wide, N.L.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (plant and maintenance employees)	P	N	510	20000422	19990401	20020331	36.0	15.06	3.0	3.0	2.0	2.0	5.0
1256201	221	Ontario Power Generation Inc. province-wide, Ont.	Society of Energy Professionals (Independent-natl.) (scientific and other professional employees, administrative services employees)	P	N	1420	20000816	20010101	20031231	36.0	22.77	2.5	2.5	3.0	2.5	2.0
1256301	221	Ontario Power Generation Inc. province-wide, Ont.	Society of Energy Professionals (Independent-natl.) (scientific and other professional employees, administrative services employees)	P	N	2510	20000816	20010101	20031231	36.0	22.77	2.5	2.5	3.0	2.5	2.0

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1236001	221	Ontario Power Generation Inc. (Non-Nuclear) province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	N	2600	20000331	20000401	20011231	21.0	19.44	4.9	4.9	5.6	3.0	
1235901	221	Ontario Power Generation Inc., Nuclear province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	N	6600	20000331	20000401	20011231	21.0	15.70	4.9	4.9	5.5	3.0	
0414108	221	Union Gas Limited Southwestern Region, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (service and maintenance employees, utility workers)	P	N	700	20000725	20000101	20021231	36.0	18.28	2.4	2.4	2.0	2.5	2.5
		Weighted Average				25070				24.5	19.20	3.5	3.5	3.8	2.7	2.5
2001																
0865305	221	BC Gas Utility Ltd. province-wide, B.C.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	650	20011005	20010401	20060331	60.0	19.93	2.0	2.0	0.0	1.0	3.0
0865405	221	BC Gas Utility Ltd. province-wide, B.C.	Office & Professional Empls. Intl. Union (CLC) (office employees, technical employees)	P	N	660	20010926	20000401	20020331	24.0	14.11	1.7	1.7	0.0	3.4	
1261302	221	Enbridge Home Services, Division of Enbridge Services Inc. province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees and technicians)	P	N	560	20010607	20010401	20030331	24.0	13.53	0.0	0.0	0.0	0.0	
1236102	221	Hydro One province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees, general tradesmen)	P	N	3530	20010330	20010401	20020331	12.0	19.60	3.0	3.0	3.0		
1256402	221	Hydro One Inc. province-wide, Ont.	Society of Energy Professionals (Independent-natl.) (scientific and other professional employees, administrative services employees)	P	N	1000	20011212	20020101	20021231	12.0	23.46	1.9	1.9	1.9		

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1249601	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (scientific and other professional employees)	P	N	2400	20010419	19981221	20011231	36.3	15.54	2.2	2.2	1.5	2.5	2.5
1236002	221	Ontario Power Generation Inc. (Non-Nuclear) province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	Y	3180	20011003	20020101	20060331	51.0	17.00	2.3	2.3	2.0	3.0	2.5
1235902	221	Ontario Power Generation Inc., Nuclear province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	Y	5150	20011003	20020101	20060331	51.0	22.00	2.3	2.3	2.0	3.0	2.5
0879505	221	SaskEnergy Inc. province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees, field employees)	P	N	740	20010517	20010201	20040131	36.0	14.49	3.0	3.0	3.2	3.3	2.5
0411907	221	SaskPower province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (administrative services employees)	P	N	640	20010718	20010201	20040131	36.0	12.40	3.0	3.0	3.5	3.0	2.5
0412007	221	SaskPower province-wide, Sask.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (plant and maintenance employees)	P	N	1340	20010110	20010101	20031231	36.0	14.80	3.0	3.0	3.8	3.0	2.3
1187602	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (outside employees)	P	Y	900	20010215	20010201	20030131	24.0	17.50	2.3	2.5	2.5	2.5	
1187702	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (inside and outside employees)	P	Y	540	20010215	20010201	20030131	24.0	16.10	2.3	2.5	2.5	2.5	
		Weighted Average				21290				36.0	18.32	2.4	2.4	2.2	2.7	2.5

2002

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1285501	221	ATCO Electric province-wide, Alta.	Canadian Energy Workers' Assn (Independent-local) (linemen)	P	N	610	20020327	20020101	20041231	36.0	10.69	3.6	3.6	4.0	3.3	3.3

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
0865406	221	BC Gas Utility Ltd. province-wide, B.C.	Office & Professional Empls. Intl. Union (CLC) (office employees, technical employees)	P	N	620	20020524	20020401	20060930 W 20070331	54.0	14.60	2.3	2.3	1.5	3.0	3.0
0412809	221	British Columbia Hydro and Power Authority province-wide, B.C.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	1380	20020403	20020401	20050331	36.0	19.24	0.0	0.0	0.0	0.0	0.0
0412908	221	British Columbia Hydro and Power Authority province-wide, B.C.	Office & Professional Empls. Intl. Union (CLC) (office employees, technical employees)	P	N	3000	20020531	20020401	20050331	36.0	14.34	0.0	0.0	0.0	0.0	0.0
1283301	221	Bruce Power province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (general tradesmen, office employees)	P	N	2350	20020131	20020101	20031231	24.0	22.00	3.6	3.6	3.1	4.0	
1100903	221	Epcor Utilities Inc. Edmonton, Alta.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	610	20020927	20011230	20031227	23.9	18.84	4.0	4.0	4.0	4.0	
1236103	221	Hydro One Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees, general tradesmen)	P	N	3100	20020328	20020401	20030331	12.0	20.19	3.0	3.0	3.0		
1256403	221	Hydro One Inc. province-wide, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees, administrative services employees)	P	N	780	20021119	20030101	20050331	27.0	23.91	3.1	3.1	3.1	2.9	1.0
1249602	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (scientific and other professional employees)	P	N	2800	20020719	20020101	20041231	36.0	16.58	2.7	2.7	3.0	3.0	2.0
1286101	221	Inergi L.P. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (administrative and support employees)	P	N	630	20020510	20020401	20040930	30.0	21.40	2.4	2.4	3.0	2.0	1.0
1284901	221	New Brunswick Power Corporation province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (customer service employees)	P	N	780	20020417	20010101	20051231	60.0	14.15	2.0	2.0	2.0	2.0	2.0

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1285001	221	New Brunswick Power Corporation province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (operating employees, technical employees, plant and maintenance employees)	P	N	700	20020927	20010101	20071231	84.0	15.56	4.1	4.1	2.1	8.2	5.8
0857007	221	Newfoundland and Labrador Hydro province-wide, N.L.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (plant and maintenance employees)	P	N	500	20021202	20020401	20050331	36.0	16.45	4.4	4.4	7.7	2.5	3.0
1187603	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (outside employees)	P	Y	770	20021221	20030201	20060131	36.0	18.48	3.0	3.0	3.0	3.0	3.0
1187703	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (inside and outside employees)	P	Y	500	20021221	20030201	20060131	36.0	17.00	3.0	3.0	3.0	3.0	3.0
		Weighted Average				19130				33.0	17.90	2.4	2.4	2.4	2.5	1.7
2003																
1234802	221	ATCO Gas Edmonton, Alta. Calgary, Alta.	Natural Gas Employees’ Association (Independent-local) (plant and maintenance employees)	P	N	850	20030211	20030101	20041231	24.0	14.63	3.8	3.8	4.2	3.3	
1261502	221	Enbridge Gas Distribution province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (utility workers, office employees and technicians)	P	N	770	20030430	20030101	20031231	12.0	20.25	3.1	3.1	3.1		
1100803	221	Epcor Utilities Inc. Edmonton, Alta.	Civic Service Union No. 52 (Independent-local) (office employees)	P	N	780	20030214	20011230	20031227	23.9	12.87	4.0	4.0	4.0	4.0	
1261303	221	Essential Home Services, Division of Direct Energy Marketing Ltd. province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees and technicians)	P	N	600	20030621	20030401	20050331	24.0	13.53	3.0	3.0	3.0	2.9	
0416406	221	Greater Vancouver Regional District Vancouver, B.C.	Greater Vancouver Regional Dist. Empls. Union (Independent-local) (operating employees, construction employees)	P	Y	540	20030312	20000401	20061231	81.0	17.00	2.6	2.6	4.1	0.0	5.6

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1236104	221	Hydro One province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees, general tradesmen)	P	N	3100	20030509	20030401	20050331	24.0	20.80	3.0	3.0	3.0	3.0	
0408708	221	Hydro-Québec province-wide, Que.	Synd. professionnel des ingénieurs d'Hydro-Qc inc. (Independent-natl.) (engineers)	P	N	1490	20030522	20040101	20061231 W 20081231	36.0	23.94	2.0	2.0	2.0	2.0	2.0
0408809	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (technical employees)	P	N	2420	20030522	20040101	20061231 W 20081231	36.0	18.30	2.0	2.0	2.0	2.0	2.0
0408909	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (general tradesmen)	P	N	5890	20030522	20040101	20061231 W 20081231	36.0	18.09	2.0	2.0	2.0	2.0	2.0
0409009	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (office employees)	P	N	5350	20030522	20040101	20061231 W 20081231	36.0	23.02	2.0	2.0	2.0	2.0	2.0
0411608	221	Manitoba Hydro province-wide, Man.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees)	P	Y	1030	20031020	20030327	20060322	35.8	13.57	2.1	2.8	3.0	3.3	1.9
0411707	221	Manitoba Hydro province-wide, Man.	Association of Manitoba Hydro Staff and Supervisory Employees (Independent-local) (office employees, supervisors)	P	Y	550	20030911	20030327	20060322	35.8	20.97	2.0	2.7	3.0	3.0	1.9
0411510	221	Manitoba Hydro-Electric Board province-wide, Man.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (service and maintenance employees)	P	Y	2480	20031020	20030522	20060531	36.3	16.89	2.0	2.6	3.0	3.0	1.9
		Weighted Average				25850				33.8	19.22	2.3	2.4	2.5	2.4	2.1

2004

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1285502	221	ATCO Electric province-wide, Alta.	Canadian Energy Workers' Assn (Independent-local) (linemen)	P	N	620	20041208	20050101	20071231	36.0	11.87	2.5	2.5	2.5	2.5	2.5
1234803	221	ATCO Gas Edmonton, Alta. Calgary, Alta.	Natural Gas Employees' Association (Independent-local) (plant and maintenance employees)	P	N	1290	20041201	20050101	20061231	24.0	15.76	3.2	3.2	3.4	3.1	

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1234903	221	ATCO Gas Edmonton, Alta. Calgary, Alta.	Natural Gas Employees' Association (Independent-local) (office employees)	P	N	540	20041215	20050101	20061231	24.0	12.60	2.6	2.6	2.6	2.6	
1283302	221	Bruce Power LP, General Partner Bruce Power Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (general tradesmen, office employees)	P	Y	2480	20040810	20040101	20061231	36.0	17.26	3.0	3.0	3.0	3.0	3.0
1320201	221	Bruce Power LP, General Partner Bruce Power Inc. Toronto, Ont.	Society of Energy Professionals (Independent-natl.) (scientific and other professional employees)	P	N	810	20040220	20040101	20041231	12.0	22.00	4.0	4.0	4.0		
1261503	221	Enbridge Gas Distribution province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (utility workers, office employees and technicians)	P	N	770	20040114	20040101	20061231	36.0	20.87	3.0	3.0	3.0	3.0	3.0
1100804	221	Epcor Utilities Inc. Edmonton, Alta.	Civic Service Union No. 52 (Independent-local) (office employees)	P	N	910	20040909	20031228	20061223	35.8	13.92	3.4	3.4	3.5	3.5	3.0
1100904	221	Epcor Utilities Inc. Edmonton, Alta.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	650	20040916	20031228	20061223	35.8	20.37	3.3	3.3	3.5	3.5	3.0
1285002	221	New Brunswick Power Corporation province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (operating employees, technical employees, plant and maintenance employees)	P	N	700	20041018	20080101	20101231	36.0	20.66	2.5	2.5	3.5	4.0	0.0
1284802	221	New Brunswick Power Generation Corporation province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (operational employees, technical employees)	P	N	540	20041215	20050101	20061231	24.0	12.79	2.5	2.5	2.5	2.5	
1256202	221	Ontario Power Generation Inc. province-wide, Ont.	Society of Energy Professionals (Independent-natl.) (scientific and other professional employees, administrative services employees)	P	N	900	20040322	20040101	20041231	12.0	24.51	3.0	3.0	3.0		

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1256203	221	Ontario Power Generation Inc. province-wide, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees, administrative services employees)	P	N	900	20041209	20050101	20051231	12.0	25.25	3.0	3.0	3.0		
1256302	221	Ontario Power Generation Inc. province-wide, Ont.	Society of Energy Professionals (Independent-natl.) (scientific and other professional employees, administrative services employees)	P	N	2100	20040322	20040101	20041231	12.0	24.51	3.0	3.0	3.0		
1256303	221	Ontario Power Generation Inc. province-wide, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees, administrative services employees)	P	N	2100	20041209	20050101	20051231	12.0	25.25	3.0	3.0	3.0		
		Weighted Average				15310				23.5	20.10	3.0	3.0	3.1	3.1	2.6

2005

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
0412810	221	British Columbia Hydro and Power Authority province-wide, B.C.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers, powerhouse employees)	P	N	1500	20050516	20050401	20060331	12.0	19.24	2.0	2.0	2.0		
0412909	221	British Columbia Hydro and Power Authority province-wide, B.C.	Canadian Office and Professional Employees Union (CLC) (office employees, technical employees)	P	N	2700	20050706	20050401	20060331	12.0	14.34	2.0	2.0	2.0		
1320202	221	Bruce Power LP, General Partner Bruce Power Inc. Toronto, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees)	P	Y	840	20050215	20050101	20091231	60.0	32.78	3.1	3.1	3.3	3.3	3.0
1261304	221	Essential Home Services, Division of Direct Energy Marketing Ltd. province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees and technicians)	P	N	610	20050629	20050401	20070331	24.0	14.35	2.8	2.8	2.8	2.8	

WAGE INCREASES IN MAJOR AGREEMENTS - WID

Date of Study: 13 January 2010

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1236105	221	Hydro One Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees, general tradesmen)	P	Y	3860	20050324	20050401	20080331	36.0	22.06	3.3	3.3	3.5	3.5	3.0
1256404	221	Hydro One Inc. province-wide, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees, administrative services employees)	P	Y	780	20051222	20050401	20080331	36.0	25.63	3.0	3.0	3.0	3.0	3.0
1284902	221	New Brunswick Power Distribution (Customer Service Corporation) province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (customer service employees)	P	N	600	20051115	20060101	20071231	24.0	15.63	3.0	3.0	2.5	3.5	
1256204	221	Ontario Power Generation Inc. province-wide, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees, administrative services employees)	P	Y	900	20051222	20060101	20101231	60.0	26.02	3.0	3.0	3.0	3.0	3.0
1256304	221	Ontario Power Generation Inc. province-wide, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees, administrative services employees)	P	Y	2100	20051222	20060101	20101231	60.0	26.02	3.0	3.0	3.0	3.0	3.0
0879506	221	SaskEnergy Incorporated province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees, field employees)	P	Y	830	20050714	20040201	20070131	36.0	15.84	1.4	1.8	0.0	1.1	4.4
0411908	221	SaskPower province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (administrative services employees)	P	Y	700	20050826	20040201	20070131	36.0	13.54	0.0	0.0	0.0	0.0	0.0
0412008	221	SaskPower province-wide, Sask.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (plant and maintenance employees)	P	Y	1340	20050106	20040101	20061231	36.0	17.54	1.9	2.5	2.0	3.9	1.6

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1187604	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (outside employees)	P	Y	770	20051220	20060201	20090131	36.0	20.19	3.3	3.3	3.5	3.2	3.2
1187704	221	Toronto Hydro Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (salaried employees)	P	Y	500	20051220	20060201	20090131	36.0	18.58	3.3	3.3	3.5	3.2	3.3
		Weighted Average				18030				34.7	20.38	2.6	2.6	2.6	3.0	2.8
2006																
1234904	221	ATCO Gas & Pipelines Ltd. Edmonton, Alta. Calgary, Alta.	Natural Gas Employees' Association (Independent-local) (office employees, technical employees)	P	N	550	20061214	20070101	20081231	24.0	13.27	4.4	4.4	4.4	4.3	
0412811	221	British Columbia Hydro and Power Authority province-wide, B.C.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers, powerhouse employees)	P	N	1600	20060327	20060401	20100331	48.0	19.62	2.0	2.0	2.0	2.0	2.0
0412910	221	British Columbia Hydro and Power Authority province-wide, B.C.	Canadian Office and Professional Employees Union (CLC) (office employees, technical employees)	P	N	1540	20060317	20060401	20100331	48.0	15.73	1.6	1.6	1.3	1.3	2.0
1387601	221	Enmax Corporation Calgary, Alta.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees)	P	N	540	20060608	20060101	20081231	36.0	12.73	4.4	4.4	4.5	5.1	3.5
0408709*	221	Hydro-Québec province-wide, Que.	Synd. professionnel des ingénieurs d'Hydro-Qc inc. (Independent-natl.) (engineers)	P	N	1490	20060628	20070101	20081231	24.0	25.41	2.0	2.0	2.0	2.0	
0408810*	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (technical employees)	P	N	2420	20060628	20070101	20081231	24.0	19.42	2.0	2.0	2.0	2.0	
0408910*	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (general tradesmen)	P	N	5890	20060628	20070101	20081231	24.0	19.20	2.0	2.0	2.0	2.0	
0409010*	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (office employees)	P	N	5350	20060628	20070101	20081231	24.0	24.43	2.0	2.0	2.0	2.0	

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1249603	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (scientific and other professional employees)	P	N	3400	20060607	20050101	20091231	60.0	17.94	1.7	1.7	0.5	2.0	2.0
0411511	221	Manitoba Hydro province-wide, Man.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (service and maintenance employees, linemen)	P	N	2850	20060919	20060601	20090527	35.9	18.26	2.5	2.5	2.5	2.5	2.5
0411609	221	Manitoba Hydro province-wide, Man.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees)	P	N	1180	20060914	20060323	20090318	35.8	14.67	2.5	2.5	2.5	2.5	2.5
0411708	221	Manitoba Hydro province-wide, Man.	Association of Manitoba Hydro Staff and Supervisory Employees (Independent-local) (technical employees, supervisors)	P	N	640	20060905	20060323	20090318	35.8	22.67	2.5	2.5	2.5	2.5	2.5
1235903	221	Ontario Power Generation Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	Y	4660	20060302	20060401	20090331	36.0	24.28	3.0	3.0	3.0	3.0	3.0
1236003	221	Ontario Power Generation Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	Y	2280	20060302	20060401	20090331	36.0	18.76	3.0	3.0	3.0	3.0	3.0
0865306	221	Terasen Gas Inc. province-wide, B.C.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	530	20060905	20060401	20110331	60.0	21.99	2.9	2.9	2.9	2.5	3.0
0865407*	221	Terasen Gas Inc. province-wide, B.C.	Canadian Office and Professional Employees Union (CLC) (office employees, technical employees)	P	N	500	20061018	20061001	20070331	6.0	16.19	2.8	2.8	2.8		
		Weighted Average				35420				34.0	20.30	2.3	2.3	2.2	2.3	2.6

2007

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1285503	221	ATCO Electric province-wide, Alta.	Canadian Energy Workers' Assn (Independent-local) (office employees, technical	P	N	925	20071120	20080101	20091231	24.0	12.78	5.4	5.4	5.5	5.4	

employees, trade employees)

WAGE INCREASES IN MAJOR AGREEMENTS - WID

Date of Study: 13 January 2010

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1234804	221	ATCO Gas Edmonton, Alta. Calgary, Alta.	Natural Gas Employees' Association (Independent-local) (plant and maintenance employees)	P	N	1290	20070905	20070101	20081231	24.0	16.80	4.4	4.4	4.2	4.5	
1283303	221	Bruce Power LP, General Partner Bruce Power Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (general tradesmen, office employees)	P	Y	2600	20070107	20070101	20091231	36.0	20.76	3.2	3.2	3.2	3.2	3.0
1261504	221	Enbridge Gas Distribution province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (utility workers, office employees and technicians)	P	N	810	20070125	20070101	20081231	24.0	22.81	3.0	3.0	3.0	3.0	
1100805	221	Epcor Utilities Inc. Edmonton, Alta.	Civic Service Union No. 52 (Independent-local) (office employees, technical employees)	P	N	940	20070722	20061224	20101225	48.0	15.36	5.1	5.1	4.8	5.0	5.3
1100905	221	Epcor Utilities Inc. Edmonton, Alta.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers)	P	N	800	20070605	20061224	20091221	35.9	22.47	5.0	5.0	4.8	5.0	5.3
1261305	221	Essential Home Services, division of Direct Energy Marketing Ltd. province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees and technicians)	P	N	600	20070615	20070401	20090331	24.0	15.16	3.0	3.0	3.0	3.0	
1256405	221	Hydro One Inc. province-wide, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees, administrative services employees)	P	Y	800	20070629	20080401	20130331	60.0	28.01	2.8	2.8	3.0	3.0	3.0
1284803	221	New Brunswick Power Generation Corporation province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (operating employees, technical employees)	P	N	500	20070205	20070101	20111231	60.0	13.44	3.3	3.3	3.1	2.9	2.9
0408110	221	Nova Scotia Power Incorporated province-wide, N.S.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers, service and maintenance employees)	P	N	800	20070810	20070801	20120331	56.0	22.52	3.0	3.0	2.5	3.5	4.0

WAGE INCREASES IN MAJOR AGREEMENTS - WID

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
0879507	221	SaskEnergy Incorporated province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees, technical employees, field employees)	P	N	800	20070604	20070201	20100131	36.0	16.86	4.1	4.1	4.1	4.0	4.1
0411909	221	SaskPower province-wide, Sask.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees, technical employees)	P	N	740	20070731	20070201	20091231	35.0	13.76	4.1	4.1	8.1	4.0	0.0
0412009	221	SaskPower province-wide, Sask.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (utility workers, powerhouse employees)	P	N	1340	20070530	20070101	20091231	36.0	19.21	4.6	4.6	5.7	4.0	4.0
0865408	221	Terasen Gas Inc. province-wide, B.C.	Canadian Office and Professional Employees Union (CLC) (office employees, technical employees)	P	N	500	20071116	20070401	20120331	60.0	16.65	2.8	2.8	2.5	3.0	3.0
		Weighted Average				13445				37.9	18.77	3.9	3.9	4.1	3.9	3.5

2008

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1387602	221	Enmax Corporation Calgary, Alta.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees)	P	N	650	20081218	20090101	20101231	24.0	14.47	5.9	5.9	7.7	4.0	
0416407	221	Greater Vancouver Regional District Vancouver, B.C.	Greater Vancouver Regional Dist. Empls. Union (Independent-local) (operating employees, construction employees, technical and maintenance employees)	P	N	600	20080808	20070101	20111231	60.0	20.22	3.5	3.5	3.0	3.0	3.5
1236106	221	Hydro One Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, technical employees, general tradesmen)	P	Y	3470	20080411	20080401	20110331	36.0	24.34	3.0	3.0	3.0	3.0	3.0
0408811	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC)	P	N	2160	20080512	20090101	20131231	60.0	20.20	2.0	2.0	2.0	2.0	2.0

			(technical employees)													
0408911	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (general tradesmen)	P	N	5060	20080512	20090101	20131231	60.0	19.98	2.0	2.0	2.0	2.0	2.0

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
0409011	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (office employees)	P	N	4120	20080512	20090101	20131231	60.0	19.64	2.0	2.0	2.0	2.0	2.0
1249604	221	Hydro-Québec province-wide, Que.	Cdn. Union of Public Empls. (CLC) (scientific and other professional employees)	P	N	3500	20080501	20100101	20141231 W 20141231	60.0	19.52	1.6	1.6	2.0	2.0	2.0
1284903	221	New Brunswick Power Corporation province-wide, N.B.	Intl. Bro. of Electrical Workers (AFL-CIO/CLC) (customer service employees)	P	N	600	20080208	20080101	20121231	60.0	16.58	3.3	3.3	3.0	3.0	3.0
		Weighted Average				20160				54.7	20.33	2.3	2.3	2.4	2.3	2.3

2009

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
1234805	221	ATCO Gas, division of ATCO Gas and Pipelines Ltd. Edmonton, Alta. Calgary, Alta.	Natural Gas Employees' Association (Independent-local) (plant and maintenance employees)	P	N	1250	20090204	20090101	20101231	24.0	18.30	5.1	5.1	5.2	5.0	
1234905	221	ATCO Gas, division of ATCO Gas and Pipelines Ltd. Edmonton, Alta. Calgary, Alta.	Natural Gas Employees' Association (Independent-local) (office employees, technical employees)	P	N	500	20090204	20090101	20101231	24.0	14.45	5.1	5.1	5.3	5.0	
1283304	221	Bruce Power L.P., General Partner Bruce Power Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (general tradesmen, office employees)	P	N	2360	20090806	20100101	20101231	12.0	22.78	3.0	3.0	3.0		
1320203	221	Bruce Power L.P., General Partner Bruce Power Inc. Toronto, Ont.	Intl. Fedn. of Professional & Technical Engineers (AFL-CIO/CLC) (scientific and other professional employees)	P	N	850	20090807	20100101	20101231	12.0	37.65	3.0	3.0	3.0		
1261505	221	Enbridge Gas Distribution province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (utility workers, office employees and technicians)	P	N	750	20090329	20090101	20101231	24.0	24.19	3.0	3.0	3.0	3.0	

1261306	221	Essential Home Services, division of Direct Energy Marketing Ltd. province-wide, Ont.	Communications, Energy and Paperworkers Union of Canada (CLC) (office employees and technicians)	P	N	530	20090629	20090401	20110331	24.0	16.08	3.0	3.0	3.0	3.0	

Agt. Number	SIC	Employer and Location	Union	Jur.	Cola	No. of Empls.	Sett. Date	Wage Eff. Date	Wage Exp. Date	Dur	Prev. Wage	Neg. Incr.	Ave. Ann. Incr.	1st Yr. Incr.	2nd YR. Incr.	3rd Yr. Incr.
0411709	221	Manitoba Hydro province-wide, Man.	Association of Manitoba Hydro Staff and Supervisory Employees (Independent-local) (technical employees, supervisors)	P	N	750	20091003	20090319	20121231	45.4	24.42	2.3	2.3	2.9	3.5	2.5
1235904	221	Ontario Power Generation Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	Y	5310	20090415	20090401	20120331	36.0	26.53	3.0	3.0	3.0	3.0	3.0
1236004	221	Ontario Power Generation Inc. province-wide, Ont.	Cdn. Union of Public Empls. (CLC) (office employees, general tradesmen)	P	Y	2400	20090415	20090401	20120331	36.0	20.50	3.0	3.0	3.0	3.0	3.0
1187605	221	Toronto Hydro-Electric System Ltd. Toronto Hydro Energy Services Toronto, Ont.	Cdn. Union of Public Empls. (CLC) (outside employees)	P	Y	800	20090106	20090201	20140131	60.0	22.28	3.0	3.0	3.0	3.0	3.0
		Weighted Average				15500				30.4	23.79	3.2	3.2	3.3	3.3	3.0

* Result of a wage reopener.
W Agt. expiry date.

..... END REPORT .....

Ontario Energy Board (Board Staff) INTERROGATORY #58 List 1

Interrogatory

Issue 3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref. Exhibit C1/Tab3/Sch2/p. 17

Hydro One quotes a wage increase forecast in the Mercer study for 2010 to be 3.5% and compares this to the 3% economic increases negotiated by PWU and Society for 2010. Are these figures strictly comparable as they do not include progression through the ranks increases for the PWU and the Society?

Response

These figures are comparable for the majority of employees represented by the PWU and Society. Although the 3% economic increase does not account for wage progressions, past experience (i.e. 2007) indicates that only 15% of the PWU population is actually eligible for progressions. For Society-represented employees, approximately 57% of the population was eligible in 2008; however, the number of PWU-represented employees is approximately four times greater than the number of Society employees.

Ontario Energy Board (Board Staff) INTERROGATORY #59 List 1

Interrogatory

Issue 3.3 **Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Ref. Exhibit C1/Tab3/Sch2/p. 17

When Hydro One quotes the average wage increase from 1999 to 2009 from the above mentioned study to be 3.2% per year, and then indicates that the comparable PWU and Society figures are 3.35% and 3.0%, does this include all aspects of the wage? ie, base inflationary increase plus progression through the ranks? Please confirm that the two percentage changes are strictly comparable.

Response

The percentage increase used in the Wage Tabulation study and the comparable PWU and Society figures reflect negotiated wage increases only and do not include other factors that could impact wages. Therefore, the two percentage changes are comparable.

Ontario Energy Board (Board Staff) INTERROGATORY #60 List 1

Interrogatory

Issue 3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref. Exhibit C1/Tab3/Sch2/Appendix A

Hydro One indicates that an actuarial valuation of the pension plan as at December 31, 2009 will take place for submission to FSCO in September 2010. Are the results of this valuation currently available? Does Hydro One expect that there will be significant changes in pension costs as a result of the updated valuation?

Response

The actuarial valuation, which is being performed by the pension plan's actuary, Mercers, was approved by Hydro One's Board of Directors on August 12, 2010 and will be filed with the Financial Services Commission of Ontario in September 2010. The valuation results indicate that Hydro One will have to contribute approximately $140 million into the pension plan starting in 2010. The contributions represent an increase of about $26 million from the 2011 planned level of $114 million, and $22 million from the 2012 planned level of $118 million, originally noted in Exhibit C1, Tab 3, Schedule 2, Appendix A. A summary from Mercer is provided as Attachment 1.

MERCER

Consulting. Outsourcing. Investments.

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

16 August 2010

Hydro One Pension Plan Valuation Results at December 31, 2009

Scott Clausen, Toronto

2010 Required Contribution (000s)

	2010
Total Current Service Cost (5.50%)	$114,000
Estimated Required Employee Contributions	($23,000)
Estimated Employer's Current Service Cost	$91,000
Employer Current Service Cost as a Percentage of Member's Pensionable Earnings	19.6%
Going Concern Special Payments	$48,000
Solvency Special Payments	$0
Total 2010 Required Employer Contributions	$139,000

Going-Concern Position at December 31, 2009 (000s)

	31/12/03	31/12/06	31/12/09
Valuation Interest Rate	6.00%	6.00%	5.5%
Mortality Table	UP94 Generational	UP94 Generational	UP94 Generational
CPI/Salary (excluding merit)	2.25%/3.00%	2.50%/3.25%	2.25%/2.75%
Market Value of Assets[1]	$3,940,000	$5,130,000	$4,346,000
Smoothing Adjustment	$201,000	($544,000)	$425,000
Actuarial Value of Assets	$4,141,000	$4,586,000	$4,771,000
Liabilities	$4,309,000	$4,802,000	$5,206,000
Surplus/(Deficit) with Asset Smoothing	($168,000)	($216,000)	($435,000)
Surplus/(Deficit) without Asset Smoothing	($369,000)	$328,000	($860,000)
Total Current Service Cost	$75,000	$87,000	$114,000
Estimated Employee Contributions	($15,000)	($17,000)	($23,000)
Estimated Employer Contributions	$60,000	$70,000	$91,000
Going Concern Unfunded Liability Payments (Annual)	$17,000	$24,000	$48,000[1]
Total Employer Required Contribution	$77,000	$94,000	$139,000

[1]With solvency smoothing

Wind-up Position (000s)

	Dec. 31, 2006	Dec. 31, 2009
Market Value of Assets	$5,130,000	$4,346,000
Wind-Up Expense	($13,000)	($12,000)
Wind-up Assets	$5,117,000	$4,334,000
Wind-Up Liabilities	$5,820,000	$6,469,000
Wind-Up Surplus/(Deficiency)	($703,000)	($2,135,000)
Transfer (Wind-up) Ratio	88%	67%

Solvency Position (000s)

	Dec. 31, 2006	Dec. 31, 2009
Smoothing	No	Yes
Market Value of Assets	$5,130,000	$4,346,000
Wind-Up Expense	($13,000)	($12,000)
Solvency Assets	$5,117,000	$4,334,000
PV Special Payments	$107,000	$216,000
Smoothing Adjustment	N/A	$425,000
Adjusted Solvency Assets	$5,224,000	$4,975,000
Wind-Up Liabilities	$5,820,000	$6,469,000
Excluded Liabilities (indexing)	($1,569,000)	($1,860,000)
Solvency Liabilities	$4,251,000	$4,609,000
Smoothing Adjustment	N/A	($118,000)
Adjusted Solvency Liabilities	$4,251,000	$4,491,000
Solvency Surplus/(Deficiency)	$973,000	$484,000

Appendix
Valuation Assumptions

Going Concern Assumptions

	Dec. 31, 2006	Dec. 31, 2009
Economic Assumptions		
Discount Rate	6.00%	5.50%
Inflation	2.50%	2.25%
Salary Scale	3.25% + PPM	2.75% + PPM
YMPE	3.50%	3.25%
Demographic Assumptions		
Mortality Table	UP94 Generational	UP94 Generational
Retirement Age & Termination Scale	Tables	Tables

Wind-Up/Solvency Assumptions

	Dec. 31, 2006	Dec. 31, 2009
		-
Mortality Rates		
Lump Sum	UP 94 projected to 2015	UP 94 projected to 2020
Annuity Purchase	UP 94 projected to 2015	UP 94 projected to 2015
Solvency Rates		
Transfer Value Rates	4.75%/4.75%	4.66%/5.46%
Annuity Purchase	4.60%	4.57%
Wind- Up Discount Rates		
Transfer Value	2.25%/2.25%	2.10%/2.70%
Annuity Purchase	4.60% with inflation increase of 2.44%	1.53%
Termination Expenses	0.25% of assets	0.25% of assets

MERCER

MMC MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

www.mercer.ca

Ontario Energy Board (Board Staff) INTERROGATORY #61 List 1

Interrogatory

Issue 3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref. Exhibit C1/Tab3/Sch2/Appendix A

Under Pension Plan Governance and Performance, Hydro One cites the outperformance regarding passive market indices from 2001 to 2009, by 0.17% and the plan's 61^{st} percentile ranking since inception. Is Hydro One concerned with the pension plan performance? Has Hydro One taken any steps to improve plan performance going forward?

Response

In the period from June 29, 2001, (the Fund's inception date) to December 31, 2007, the Fund outperformed its benchmark return by 0.52% and ranked in the 21st percentile. However, the recent financial and liquidity crisis hampered the ability of investment managers such as those utilized by the Hydro One Pension Fund to outperform benchmarks. We continually monitor the performance of these managers and will replace any unable to meet the mandate for which they were hired. In 2009 and 2010, changes were made with some of the Fund's investment managers to improve performance going forward

Pension Fund percentile rankings are both volatile and end date sensitive. For the period from June 29, 2001 (the Fund's inception date) to December 31, 2007, the Fund's percentile ranking has ranged between the 4^{th} and 96^{th} percentile. Overall, the Fund has ranked better than median about 62% of the time.

Ideally, Hydro One would prefer to see the Fund's performance ranked median or above among similar plans in Canada over the long term. However, the percentile ranking of a pension plan is influenced more by the differences in its asset mix, which is determined by the long term strategic decision of plan specific factors, than the ability of its investment managers to outperform benchmarks. As a result, comparability of returns among plans is limited due to differences in asset mix. For example, Hydro One's real return bond allocation used to match inflation sensitive liabilities is about 15%, notably higher than the majority of pension plans which do not have similar liabilities linked to inflation and as a result have a higher allocation to nominal bonds. In 2008, a significant factor resulting in the ranking amongst other plans was due to the real return bond allocation. Specifically, the DEX real return bond index returned 0.42% and underperformed nominal bonds (DEX Universe bond index) which returned 6.41%. However in 2009, the Fund's rank improved significantly and was mainly due to the outperformance in real return bonds (DEX real return bond index returned 14.50% and outperformed nominal bonds which returned 5.41%). The higher allocation to real return bonds is plan specific and will improve ranking amongst other funds in periods in which real return bonds outperform nominal bonds but detrimental during periods such as 2008 when they underperform. More importantly, the allocation to real return bonds is a match to the Fund's liabilities and helps reduce overall contribution volatility.

Hydro One periodically conducts asset mix studies to determine whether its current asset mix continues to be appropriate to meet its objectives. We plan to conduct such a study in 2010.

Ontario Energy Board (Board Staff) INTERROGATORY #62 List 1

Interrogatory

Issue 3.4 Are the OM&A development costs allocated to the "IPSP and Other Preliminary Planning Costs" deferral account for 2009, 2010, 2011 and 2012 appropriate?

Ref. Exhibit C1/Tab2/Sch4/p. 7
Development to Support the Green Energy and Green Economy Act. Table 1 on page 10 shows a number of projects for which development O&M costs are recorded. In addition on page 11, a number of other projects are lists as eligible for the deferral account but have not attracted development funds. Please provide the reasons for each of these 11 projects not progressing within the test years?

Response

1. Transmission Line – Thunder Bay Area: Birch x Lakehead
   The OPA is currently reassessing the needs for this area. Until advice from the OPA is received, Hydro One is not proceeding with development work at this time.

2. Major Transmission – Manitoba Border x Southern Ontario
   Hydro One does not foresee any significant power purchase agreements to warrant development work at this time.

3. Bruce Peninsula Enabler Line
   Funding was not included in 2011/12 because this enabler line was not identified in the Minister's Letter to Hydro One dated September 21, 2009.

4. New 500/230kV Oshawa Area TS
   Hydro One understands that the earliest retirement of Pickering B is in 2016 and that OPG is considering "Continued Operation" of the Pickering B units and therefore Hydro One feels development work can be delayed. If conditions change there could be a need for development work in 2011 and/or 2012.

5. Northern York Transmission Reinforcement
   The Generation option is proceeding; hence development work on the Transmission option is no longer required as noted in EB-2008-0272 Exhibit C1, Tab2, Schedule 3, page 7, Note 2.

6. Kitchener-Waterloo-Cambridge-Guelph ("KWCG") Transmission Reinforcement
   Hydro One understands from the OPA that load growth has declined in the area. The OPA and LDCs are currently reassessing the needs for this area and hence until

advice from the OPA is received Hydro One is not proceeding with development work at this time.

7. 230kV Transmission Line – Parkway x Richmond Hill
The Generation option is proceeding; hence development work on the Transmission option is no longer required as noted in EB-2008-0272 Exhibit C1, Tab2, Schedule 3, page 7, Note 2.

8. 230kV Transmission Line – Richview x Manby
The Generation option is proceeding; hence development work on the Transmission option is no longer required as noted in EB-2008-0272 Exhibit C1, Tab2, Schedule 3, page 7, Note 2.

9. New Supply to City of Toronto
Reduced demand for electricity and the continued success of Conservation programs have resulted in deferral of plans in this area.

10. 115kV Leaside and Manby TS – Uprate Short Circuit Capability
These projects are proceeding as per the Minister's Letter to Hydro One dated September 21, 2009. The projects have been documented in Exhibit D1, Tab 3, Schedule 3 as Project D12 and D13 respectively.

11. Milton Transformer Station
Hydro One understands from the OPA that the general load growth in the Western GTA has not increased at the rate anticipated in EB-2008-0272 and hence development work has been deferred. Depending on future load growth in this area there may be a need for development work in 2012.

Ontario Energy Board (Board Staff) INTERROGATORY #63 List 1

Interrogatory

Issue 3.6 Are the amounts proposed to be included in the 2011 and 2012 revenue requirements for income and other taxes appropriate?

Ref: Exhibit C/Tab7/Sch1/p1-7, Exhibit C/Tab2/Sch2

a) Please provide the 2009 tax return.

b) Please provide 2008 and 2009 Notice of Assessment and any Notice(s) of Reassessment with respect to those years.

Response

a) The 2009 Hydro One Networks Income Tax return is attached as Attachment 1 to this interrogatory response.

b) The Hydro One Networks 2008 Notice of Assessment dated July 20, 2009, is attached as Attachment 2 to this interrogatory response. The 2009 Notice of Assessment has not been received as yet.

Canada Revenue Agency · Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 87086 5821 RC0001

Corporation's name
002 Hydro One Networks Inc.

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 483 Bay Street, 8th Floor
012 South Tower
City: 015 Toronto
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 M5G 2P5

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031
032
City: 035
Province, territory, or state: 036
Country (other than Canada): 037
Postal code/Zip code: 038

040 Type of corporation at the end of the tax year
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ________ YYYY MM DD

To which tax year does this return apply?
Tax year start: 060 2009-01-01 (YYYY MM DD)
Tax year-end: 061 2009-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

	Line	Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

	Line	1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (Only complete if **yes** was entered at line 281) 282 ______

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

			%
284	Electricity	285	100.000 %
286		287	%
288		289	%

	Line	1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		X

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ (YYYY MM DD)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300	77,473,522	A
Deduct: Charitable donations from Schedule 2	311		
Gifts to Canada, a province, or a territory from Schedule 2	312		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction *	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal			B
Subtotal (amount A **minus** amount B) (if negative, enter "0")		77,473,522	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360	77,473,522	
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)		77,473,522	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	76,403,201	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax	405	77,473,522	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000 x Number of days in the tax year before 2009 / Number of days in the tax year 365 = ... 1

500,000 x Number of days in the tax year after 2008 365 / Number of days in the tax year 365 = ... 500,000 2

Add amounts at lines 1 and 2 500,000 4

Business limit (see notes 1 and 2 below) 410 500,000 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 *** 1,746,047 D / 11,250 = ... 77,602,089 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ______ F

Small business deduction

Amount A, B, C, or F whichever is the least ______ x Number of days in the tax year before January 1, 2008 ______ / Number of days in the tax year 365 x 16 % = ______ 5

Amount A, B, C, or F whichever is the least ______ x Number of days in the tax year after December 31, 2007 365 / Number of days in the tax year 365 x 17 % = ______ 6

Total of amounts 5 and 6 – enter on line 9 430 ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		77,473,522	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Amount used to calculate the credit union deduction from Schedule 17	D		
Amount from line 400, 405, 410, or 425, whichever is the least	E		
Aggregate investment income from line 440	1,070,321 F		
Total of amounts B to F	1,070,321 ▶	1,070,321	G
Amount A **minus** amount G (if negative, enter "0")		76,403,201	H

Amount H	76,403,201	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 365	x 7 %	=	I
Amount H	76,403,201	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	J
Amount H	76,403,201	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x 9 %	= 6,876,288	K
Amount H	76,403,201	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x 10 %	=	L
Amount H	76,403,201	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x 11.5 %	=	L1
Amount H	76,403,201	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	L2

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L2 .... 6,876,288 M

Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	O		
Amount QQ from Part 13 of Schedule 27	P		
Amount used to calculate the credit union deduction from Schedule 17	Q		
Total of amounts O to Q	▶		R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 365	x 7 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x 9 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x 10 %	=	W
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x 11.5 %	=	W1
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	W2

General tax reduction – Total of amounts T to W2 X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440	1,070,321	x 26 2 / 3 % =		285,419 A
Foreign non-business income tax credit from line 632					
Deduct: Foreign investment income from Schedule 7	445		x 9 1 / 3 % =		
			(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")					285,419 C

Taxable income from line 360			77,473,522	
Deduct:				
Amount from line 400, 405, 410, or 425, whichever is the least				
Foreign non-business income tax credit from line 632	x 25 / 9 =			
Foreign business income tax credit from line 636	x 3 =			
		▶		
			77,473,522	
			x 26 2 / 3 % =	20,659,606 D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			13,764,808	
Deduct: Corporate surtax from line 600				
Net amount			13,764,808 ▶	13,764,808 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			450	285,419 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460		
Deduct: Dividend refund for the previous tax year	465		
		▶	G
Add the total of:			
Refundable portion of Part I tax from line 450 above		285,419	
Total Part IV tax payable from Schedule 3			
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480		
		285,419 ▶	285,419 H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485		285,419

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	145,464,377	x 1 / 3	48,488,126 I
Refundable dividend tax on hand at the end of the tax year from line 485 above			285,419 J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)			285,419

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . 550 29,439,938 A

Corporate surtax calculation

Base amount from line A above	29,439,938	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	7,747,352	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		

Total of lines 2 to 6	7,747,352	7
Net amount (line 1 **minus** line 7)	21,692,586	8

Corporate surtax*

Line 8 21,692,586 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 365 x 4 % = 600 ________ B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . 602 ________ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440		1,070,321	i
Taxable income from line 360	77,473,522		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	77,473,522 ▶	77,473,522	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . 604 71,355 D

Subtotal (**add** lines A to D) 29,511,293 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	7,747,352	
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624 ________			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount M	638	6,876,288	
General tax reduction from amount X	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	1,122,845	
Subtotal		15,746,485 ▶	15,746,485 F

Part I tax payable – Line E **minus** line F . . . . 13,764,808 G

Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	13,764,808
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		13,764,808

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	36,667,857	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		36,667,857 ▶	36,667,857
Total tax payable	770		50,432,665 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784	285,419	
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	59,357,060	
Total credits	890	59,642,479 ▶	59,642,479 B

Balance (line A **minus** line B) -9,209,814

Refund code 894 2 Overpayment 9,209,814

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ________ Branch number

914 ________ Institution number 918 ________ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

Certification

I, 950 ALICANDRI (Last name in block letters) 951 VINCENT (First name in block letters) 954 Vice President, Corporate Tax (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2010-06-29 (Date (yyyy/mm/dd)) ________ Signature of the authorized signing officer of the corporation 956 (416) 345-6778 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 BRIAN SOARES (Name in block letters) 959 (416) 345-6782 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency · Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				449,492,310 A
Add:				
Provision for income taxes – current		101	19,354,849	
Provision for income taxes – deferred		102	14,398,142	
Interest and penalties on taxes		103	474,132	
Amortization of tangible assets		104	505,419,444	
Taxable capital gains from Schedule 6		113	1,070,321	
Scientific research expenditures deducted per financial statements		118	3,249,195	
Non-deductible meals and entertainment expenses		121	6,353,886	
Reserves from financial statements – balance at the end of the year		126	1,334,642,640	
Subtotal of additions			1,884,962,609 ▶	1,884,962,609
Other additions:				
Capital items expensed		206	4,974,646	
Debt issue expense		208	2,700,290	
Miscellaneous other additions:				
600 Other additions (see attached)		290	24,340,787	
601 Capital tax expensed (a/c 683010)		291	31,241,489	
602 OCI-Unrealized hedge loss		292	13,265	
603 Federal apprenticeship credit 2008	636,693			
Ontario Co op and apprenticeship credits in OMA 2009	2,350,852			
Total	2,987,545	293	2,987,545	
604				
Subtotal of other additions		199	66,258,022 ▶	66,258,022
Total additions		500	1,951,220,631 ▶	1,951,220,631
Deduct:				
Capital cost allowance from Schedule 8		403	716,196,717	
Cumulative eligible capital deduction from Schedule 10		405	7,427,834	
Deferred and prepaid expenses		409	6,279,236	
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	2,496,802	
Reserves from financial statements – balance at the beginning of the year		414	1,265,300,644	
Subtotal of deductions			1,997,701,233 ▶	1,997,701,233
Other deductions:				
Miscellaneous other deductions:				
700 Interest cap for acct, exp for tax (761401-13)		390	57,185,552	
701 Capital tax deduction		391	30,044,211	
702 Federal ATC and ITC's credited to OM&A in 2009		392	841,693	
703 Deduct OPEB costs capitalized in Sch013 addback		393	30,297,784	
704 Other deductions (see attached)	204,775,993			
Reverse insurance proceeds taken into income	2,392,953			
Total	207,168,946	394	207,168,946	
Subtotal of other deductions		499	325,538,186 ▶	325,538,186
Total deductions		510	2,323,239,419 ▶	2,323,239,419
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				77,473,522

* For reference purposes only

Attached Schedule with Total

Line 290 – Amount for line 600

Title C-Sch 001 - Misc. Other Additions (line 290)

Description	Amount
Opening balance adjustment - Schedule 13	24,340,787 00
Total	24,340,787 00

Attached Schedule with Total

Line 409 – Deferred and prepaid expenses

Title D-Sch 001 - Deferred or prepaid expenses deducted for tax(line 409)

Description	Amount	
Def Underwriting costs deductible for tax	3,337,005	00
Def Prospectus fees deductible for tax	195,230	00
Bond Premium/Discount amortization (761120,761130)	2,567,001	00
Bond Discount	180,000	00
Total	6,279,236	00

Attached Schedule with Total

Line 206 – Capital items expensed

Title A-Sch 001 - Capital items expensed added back for tax (line 206)

Description	Amount	
Computer system software (A/C 620040)	250,019	00
Computer Application Software (A/C 620046)	2,943,446	00
Equipment under 2k (A/C 620510)	1,781,181	00
Total	4,974,646	00

Attached Schedule with Total

Line 208 – Debt issue expense

Title B-Sch 001- Debt issue expenses added back for tax (line 208)

Description	Amount	
Acc amortization of Prospectus fees (761780)	2,152,412	00
Acc amortization of Underwriting fees (761790)	547,878	00
Total	2,700,290	00

Attached Schedule with Total

Line 704 – Amount

Title 32

Description	Amount	
Removal Costs	6,728,022	00
Reverse environmental valuation reflected on S-13	72,228,744	00
Reverse environmental interest reflected on S-13	12,351,075	00
Amortization of WSIB gain included in income	1,776,969	00
Capitalized Overhead general and administration	40,916,904	00
Pension Cost Deductions	45,414,379	00
Hedging loss amortization, deduct accounting (761770)	13,265	00
Landscaping adjustments	1,877,798	00
Amortization of Capital contribution (741701)	234,036	00
RARA Amortization included in Depreciation addback	23,234,801	00
Total	204,775,993	00

Attached Schedule with Total

Line 392 – Amount for line 702

Title Line 392 – Amount for line 702

Description	Amount
2009 Federal credits in OMA reduction to be taxed in 2010	841,693 00
Total	841,693 00

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "1" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected			
Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
1		2			
				Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

			If payer corporation is not connected, leave these columns blank.		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
1					
Total (enter amount of column F on line 320 of the T2 return)					
					J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . ______

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax . . . . . . **320** ______

Subtotal ______

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . **330** ______

Non-capital losses from previous years claimed to reduce Part IV tax . . . **335** ______

Current-year farm loss claimed to reduce Part IV tax . . . . **340** ______

Farm losses from previous years claimed to reduce Part IV tax . . . **345** ______

Total losses applied against Part IV tax ______ x 1 / 3 = ______

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . **360** ______

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation **400**	Business Number **410**	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD **420**	Taxable dividends paid to connected corporations **430**	Eligible dividends (included in column D)
1	Hydro One Inc.	86999 4731 RC0001	2009-12-31	145,464,377	

Note

If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 145,464,377

Total taxable dividends paid in the taxation year to other than connected corporations . . . . **450** ______

Eligible dividends (included in line 450) . . . . **450a** ______

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) **460** 145,464,377

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above) 145,464,377

Other dividends paid in the taxation year (total of 510 to 540) . . . . ______

Total dividends paid in the taxation year **500** 145,464,377

Deduct:

Dividends paid out of capital dividend account . . . . **510** ______

Capital gains dividends . . . . **520** ______

Dividends paid on shares described in subsection 129(1.2) . . . . **530** ______

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . **540** ______

Subtotal ______ ▶ ______

Total taxable dividends paid in the taxation year for purposes of a dividend refund 145,464,377

SCHEDULE 5

Canada Revenue Agency / Agence du revenu du Canada

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1); or
  - is claiming provincial or territorial tax credits or rebates (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 402 Corporations not specified — Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes X	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre; the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see line 760 of the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
77,473,522		77,473,522	10,846,293

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	10,846,293			
Deduct: Ontario small business deduction (from schedule 500)	402				
Subtotal (if negative, enter "0")		10,846,293	▶	10,846,293	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			▶		B6
Subtotal (amount A6 **plus** amount B6)				10,846,293	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414	12,993			
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal		12,993	▶	12,993	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				10,833,300	E6
Ontario research and development tax credit (from Schedule 508)	416	129,161			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				10,704,139	F6
Deduct:					
Ontario corporate minimum tax credit (from schedule 510)	418				
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				10,704,139	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	30,044,211			
Subtotal		30,044,211	▶	30,044,211	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				40,748,350	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	1,036,194			
Ontario apprenticeship training tax credit (from Schedule 552)	454	3,044,299			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and televison tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Subtotal		4,080,493	▶	4,080,493	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290			36,667,857	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories at line 255.

Net provincial and territorial tax payable or refundable credits	255	36,667,857

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

SCHEDULE 6

Canada Revenue Agency | Agence du revenu du Canada

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss, or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act*, if the control of the corporation has been acquired by a person or group of persons.

For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide.*

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes ☐ 2 No ☒ If *Yes*, attach a statement specifying which properties are subject to such a designation.

Part 1 – Shares

	No. of shares 100	Name of corporation 105	Class of shares 106	Date of acquisition YYYY/MM/DD 110	Proceeds of disposition 120	Adjusted cost base 130	Outlays and expenses (dispositions) 140	Gain (or loss) (column 120 less cols. 130 and 140) 150	Foreign source
1									
				Totals					

Total adjustment under subsection 112(3) of the ITA to all losses identified in Part 1 . . . . . . 160 ______

Actual gain or loss from the disposition of shares (total of line 150 **plus** line 160) . . . . . . ______ A

Part 2 – Real estate – Do not include losses on depreciable property

	Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	Date of acquisition YYYY/MM/DD 210	Proceeds of disposition 220	Adjusted cost base 230	Outlays and expenses (dispositions) 240	Gain (or loss) (column 220 less cols. 230 and 240) 250	Foreign source
1	[redacted] Real Estate Sale		2,115,895	33,650		2,082,245	
2	Other Real Estate Sales		282,867	222,788	1,683	58,396	
3							
		Totals	2,398,762	256,438	1,683	2,140,641 B	

Part 3 – Bonds

	Face value 300	Maturity date 305	Name of issuer 307	Date of acquisition YYYY/MM/DD 310	Proceeds of disposition 320	Adjusted cost base 330	Outlays and expenses (dispositions) 340	Gain (or loss) (column 320 less cols. 330 and 340) 350	Foreign source
1									
				Totals				C	

Part 4 – Other properties – Do not include losses on depreciable property

	Description 400	Date of acquisition YYYY/MM/DD 410	Proceeds of disposition 420	Adjusted cost base 430	Outlays and expenses (dispositions) 440	Gain (or loss) (column 420 less cols. 430 and 440) 450	Foreign source
1							
		Totals					D

Part 5 – Personal-use property (Do not include listed personal property)

	Description 500	Date of acquisition YYYY/MM/DD 510	Proceeds of disposition 520	Adjusted cost base 530	Outlays and expenses (dispositions) 540	Gain only (column 520 less cols. 530 and 540) 550	Foreign source
1							
	Note: Losses are not deductible	Totals					E

Part 6 – Listed personal property

	Description 600	Date of acquisition YYYY/MM/DD 610	Proceeds of disposition 620	Adjusted cost base 630	Outlays and expenses (dispositions) 640	Gain (or loss) (column 620 less cols. 630 and 640) 650	Foreign source
1							
		Totals					

Note: Net listed personal property losses may only be applied against listed personal property gains

Subtract: Unapplied listed personal property losses from other years **655** ______

Amount from line 655 is from line 530 in Part 5 of Schedule 4

Net gains (or losses) ______ F

Part 7 – Determining allowable business investment losses

Property qualifying for and resulting in an allowable business investment loss

	Name of small business corporation 900	Shares, enter 1; debt, enter 2 905	Date of acquisition YYYY/MM/DD 910	Proceeds of disposition 920	Adjusted cost base 930	Outlays and expenses (dispositions) 940	(Loss)(column 920 less cols. 930 and 940) 950	Foreign source
1								
			Totals					G

Note: Properties listed in Part 7 should not be included in any other parts of Schedule 6

Allowable business investment losses . . . . Amount G ______ x 50 % = ______ H

Enter amount H on line 406 of Schedule 1

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss)		2,140,641	I
Add:			Foreign source
Capital gains dividend received in the year	875		J
Capital gains reserve opening balance (from Schedule 13)	880		K
Subtotal (**add** amounts I, J, and K)		2,140,641	L
Deduct: Capital gains reserve closing balance (from Schedule 13)	885		M
Capital gains or losses (amount L minus amount M)	890	2,140,641	

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses (amount from line 890 above) .... 2,140,641 N

Deduct the following gains that are included in the amount N:

Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the *Income Tax Act*

					Foreign source
realized prior to May 2, 2006	______	x 50 % =	______	O	☐
realized after May 1, 2006			______	P	☐
		Subtotal: O **plus** P **895**	______		

Gain on donation of ecologically sensitive land

					Foreign source
realized prior to May 2, 2006	______	x 50 % =	______	Q	☐
realized after May 1, 2006			______	R	☐
		Subtotal: Q **plus** R **896**	______		

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) .... ______ R-2 Foreign source ☐

Total: line 895 plus line 896 plus R-2 ______ S

Amount N minus amount S .... 2,140,641 T

Total capital losses: If amount T is a loss, enter it on line 210 of Schedule 4

Taxable capital gains: If amount T is a gain, enter it on this line and multiply .... 2,140,641 x 50 % = 1,070,321 U

Enter amount U on line 113 of Schedule 1

SCHEDULE 7

Canada Revenue Agency | Agence du revenu du Canada

CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part 1 Tax" in the *T2 Corporation – Income Tax Guide.*

Part 1 – Aggregate investment income calculation

The aggregate investment income is the aggregate **world** source income.

The eligible portion of taxable capital gains included in income for the year			002	1,070,321 A
Deduct:				
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	012	B		
Net capital losses of other years claimed on line 332 on the T2 return	022	C		
Amount B **plus** amount C		▶		D
Amount A **minus** amount D (if negative, enter "0")				1,070,321 E
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)			032	F
Deduct:				
Exempt income	042	G		
Amounts received from AGRI Fund No. 2 that were included in computing the corporation's income for the year	052	H		
Taxable dividends deductible (total of Column F on Schedule 3)	062	I		
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	072	J		
Total of amounts G to J		▶		K
Amount F **minus** amount K				L
Amount E **plus** amount L				1,070,321 M
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)			082	N
Amount M **minus** amount N (if negative, enter "0")			092	1,070,321 O

Enter amount **O** on line 440 of the T2 return.

Part 2A – Canadian investment income calculation

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13	1,070,321 1.1		
Reserve's eligible portion (addition/deduction)	1.2		
The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts 1.1 and 1.2)	1,070,321	▶	1,070,321 1
Deduct:			
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	2		
Net capital losses of other years claimed on line 332 on the T2 return	3		
Total of amounts 2 and 3		▶	4
Amount 1 **minus** amount 4 (if negative, enter "0")			1,070,321 5

Part 2A – Canadian investment income calculation (continued)

Taxable dividends		6.1		
Real estate rental properties (under regulation 1100(11))		6.2		
Other property income		6.3		
Total income from property from a source **Canadian**		▶		6
Deduct:				
Exempt income		7		
Amounts received from AGRI Fund No. 2 that were included in computing the corporation's income for the year		8		
Taxable dividends deductible (total of Column F on Schedule 3)		9		
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		10		
Total of amounts 7 to 10		▶		11
Amount 6 **minus** amount 11				12
Amount 5 **plus** amount 12			1,070,321	13
Losses from rental properties (under regulation 1100(11))		14.1		
Other losses from property		14.2		
Total losses from property from a source **Canadian**		▶		14
Amount 13 **minus** amount 14 (if negative, enter "0")			1,070,321	15

Part 2 – Foreign investment income calculation

The foreign investment income is all income from only sources outside of Canada.

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13			P1		
Reserve's eligible portion (addition/deduction)			P2		
The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts P1 and P2)			▶ 001		P
Eligible portion of allowable capital losses for the year (including allowable business investment losses)			009		Q
Amount P **minus** amount Q (if negative, enter "0")					R
Taxable dividends			S1		
Real estate rental properties (under regulation 1100(11))			S2		
Other property income			S3		
Total income from property from a source **outside Canada**			▶ 019		S
Deduct:					
Exempt income	029		T		
Taxable dividends deductible (total of Column F on Schedule 3)	049		U		
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	059		V		
Total of amounts T to V			▶		W
Amount S **minus** amount W					X
Amount R **plus** amount X					Y
Losses from rental properties (under regulation 1100(11))			Z1		
Other losses from property			Z2		
Total losses from property from a source **outside Canada**			▶ 069		Z
Amount Y **minus** amount Z (if negative, enter "0")			079		AA

Enter amount **AA** on line 445 of the T2 return

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A Partnership name 200	B Total income (loss) of partnership from an active business 300	C Corporation's share of amount in column B 310

D Adjustments [add prior-year reserves under subsection 34.2(5), and deduct expenses incurred to earn partnership income, including any reserve under subsection 34.2(4)] 315	E Corporation's income (loss) of the partnership (column C **plus** column D) 320	F Number of days in the partnership's fiscal period 325	G Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")** 330	H Column E **minus** column G (if negative, enter "0")	I Lesser of columns E and G (if column E is negative, enter "0") 340
Total	350		Total	385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . **370** ______ BB

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) . . . . **380** ______ CC

Amount BB **plus** amount CC ______ DD

Amount at line 385 or line DD, whichever is less . . . . **390** ______ EE

Specified partnership income (line 360 **plus** line EE) . . . . **400** ______ FF

* Use one of the following business limits to calculate column G, whichever applies:
- $400,000 if the corporation's tax year ends in 2007 or 2008; or
- $500,000 if the corporation's tax year ends after 2008.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 in Part 3 (if the net amount is negative, enter "0" on line KK) . . . . ______ GG

Add:

Specified partnership loss (from amount CC in Part 3) . . . . ______ HH

Subtotal ______ II

Deduct:

Specified partnership income (from amount FF in Part 3) . . . . ______ JJ

Partnership income (enter on line SS in Part 5) . . . . **450** ______ KK

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return			77,473,522	LL
Deduct:				
Foreign business income after deducting related expenses*	500	MM		
Taxable capital gains **minus** allowable capital loss (amount A **minus** amount B* in Part 1)**	1,070,321	NN		
Net property income (amount F **minus** amounts G, H, and N* in Part 1)		OO		
Personal services business income after deducting related expenses*	520	PP		
Total of amounts MM to PP	1,070,321	▶	1,070,321	QQ
Net amount (line LL **minus** line QQ)			76,403,201	RR
Deduct:				
Partnership income (line KK in Part 4)				SS
Income from active business carried on in Canada (enter on line 400 of the T2 return – if negative, enter "0")			76,403,201	TT

* If negative **add** instead of **subtracting**.

** This amount may only be negative to the extent of any allowable business investment losses.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		4,654,767,543	7,621,261		2,521,853	2,549,704	4,657,317,247	4	0	0	186,292,690	4,473,574,261
2.	2		1,198,691,446			0		1,198,691,446	6	0	0	71,921,487	1,126,769,959
3.	3		274,600,321	364,012		0	182,006	274,782,327	5	0	0	13,739,116	261,225,217
4.	6		30,920,878	5,266,798		107,592	2,579,603	33,500,481	10	0	0	3,350,048	32,730,036
5.	7		66,920			0		66,920	15	0	0	10,038	56,882
6.	8		72,141,892	13,290,575		134,655	6,577,960	78,719,852	20	0	0	15,743,970	69,553,842
7.	9		7,534,785	1,492,929		0	746,465	8,281,249	25	0	0	2,070,312	6,957,402
8.	10		152,051,755	47,450,950		994,875	23,228,038	175,279,792	30	0	0	52,583,938	145,923,892
9.	12		62,870,208	163,903,304		0	81,951,652	144,821,860	100	0	0	144,821,860	81,951,652
10.	13	Leases	1,148,449	818,024		0	409,012	1,557,461	N/A	0	0	413,375	1,553,098
11.	17		15,543,477	7,495,827		0	3,747,914	19,291,390	8	0	0	1,543,311	21,495,993
12.	35		393,820			0		393,820	7	0	0	27,567	366,253
13.	42		63,552,020	44,395,925		0	22,197,963	85,749,982	12	0	0	10,289,998	97,657,947
14.	45	Computers - old cl.10 post Mar 2	11,237,184			0		11,237,184	45	0	0	5,056,733	6,180,451
15.	46	cl.8 post Mar 22/04	8,598,191	989,261		0	494,631	9,092,821	30	0	0	2,727,846	6,859,606
16.	47	Electricity Assets > 22-02-2005	1,651,893,587	776,160,802		2,903,805	386,628,499	2,038,522,085	8	0	0	163,081,767	2,262,068,817
17.	50	Computers	36,268,029			90,969		36,177,060	55	0	0	19,897,383	16,279,677
18.	52	Computers > 27-01-09 and < 01		22,625,278		0		22,625,278	100	0	0	22,625,278	
		Total	8,242,280,505	1,091,874,946		6,753,749	531,293,447	8,796,108,255				716,196,717	8,611,204,985

SCHEDULE 9

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RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Hydro One Inc.		86999 4731 RC0001	1					
2.	Hydro One Remote Communities In		87083 6269 RC0001	3					
3.	Hydro One Telecom Inc.		86800 1066 RC0001	3					
4.	Hydro One Telecom Link Limited		88786 7513 RC0001	3					
5.	Hydro One Brampton Networks Inc.		86486 7635 RC0001	3					
6.	Hydro One Lake Erie Link Managem		87892 1519 RC0001	3					
7.	Hydro One Lake Erie Link Company		87560 6519 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

Canada

SCHEDULE 10

Canada Revenue Agency / Agence du revenu du Canada

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 105,435,384 A

Add:

Cost of eligible capital property acquired during the taxation year **222** 902,044

Other adjustments . . . . **226** ______

Subtotal (line 222 plus line 226) 902,044 x 3 / 4 = 676,533 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** ______ x 1 / 2 = ______ C

amount B minus amount C (if negative, enter "0") 676,533 ▶ 676,533 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** ______ E

Subtotal (add amounts A, D, and E) **230** 106,111,917 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** ______ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** ______ H

Other adjustments . . . . **246** ______ I

(add amounts G,H, and I) ______ x 3 / 4 = **248** ______ J

Cumulative eligible capital balance (amount F minus amount J) . . . . 106,111,917 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . **249** ______

amount K 106,111,917

less amount from line 249 ______

Current year deduction . . . . 106,111,917 x 7.00 % = **250** 7,427,834 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 7,427,834 ▶ 7,427,834 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 98,684,083 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

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Canada

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3				
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4				
Line 3 minus line 4 (if negative, enter "0")		▶			5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7				
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8				
Subtotal (line 7 plus line 8)	409	▶			9	
Line 6 minus line 9 (if negative, enter "0")					▶	O
Line N minus line O (if negative, enter "0")						P
Line 5				× 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")						R
Amount R				× 2 / 3 =		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					410	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability Short Term	39,382,000				39,382,000
2	OPEB Liability Long Term	884,510,424		32,506,540		917,016,964
3	Enviromental Short Term	13,302,250		8,706,051		22,008,301
4	Environmental Long Term	228,799,908		66,345,768		295,145,676
5	Contingent Liabilities	17,327,079			973,373	16,353,706
6	Regulatory Accounts	81,372,691			36,698,123	44,674,568
7	Tenant Inducement	606,292			544,867	61,425
	Reserves from Part 2 of Schedule 13					
	Totals	1,265,300,644		107,558,359	38,216,363	1,334,642,640

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Inc.	483 Bay Street Toronto ON CA M5G 2P5			4,848,305		
2	Hydro One Telecom Inc.	65 Kelfield St Rexdale ON CA M9W 5A3			11,474,000		
3	Hydro One Brampton Networl	175 Sandalwood Parkway We Brampton ON CA L7A 1E8			1,430,000		
4	Hydro One Communities Inc.	483 Bay Street Toronto ON CA M5G 2P5			92,961		

T2 SCH 14 (99)

Canada

SCHEDULE 15

Canada Revenue Agency / Agence du revenu du Canada

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	109,618,618	1059104			

Note 1: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule .... 109,618,618 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements 109,618,618 B

Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0") C

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

Canada

T2 SCH 15 (06)

SCHEDULE 31

Canada Revenue Agency / Agence du revenu du Canada

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward for credits earned in tax years that end after 1997 and did not expire before 2008 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired* 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 ______ x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied 901	
2nd previous tax year				Credit to be applied 902	
3rd previous tax year				Credit to be applied 903	

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures

Current expenditures (from line 557 on Form T661)		3,120,034		
Add:				
Contributions to agricultural organizations for SR&ED under paragraph 37(1)(a)*				
Deduct:				
Government and non-government assistance*				
Contributions to agricultural organizations for SR&ED*				
Current expenditures (including contributions to agricultural organizations for SR&ED)*		3,120,034	350	3,120,034
Capital expenditures (from line 558 on Form T661)			360	
Repayments made in the year (from line 560 on Form T661)			370	
Total (this must equal the amount from line 570 on Form T661)*			380	3,120,034

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? **385** 1 Yes [X] 2 No [ ]

Complete lines 390, 395 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). **390** ______

b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return). **395** ______

c) Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. **398** ______

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1: Tax year ends before February 26, 2008.
[($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)] . . . . ______

Calculation 2: Tax year starts after February 26, 2008 and ends before January 1, 2010.
[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ______

Calculation 3: Tax year includes February 26, 2008.
AA + [(BB **minus** AA) x (CC **divided by** DD)] where,
- AA = [($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)];
- BB = [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- CC = number of days in the tax year after February 25, 2008;
- DD = number of days in the tax year. . . . . ______

Calculation 4: Tax year starts after December 31, 2009.
[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ______

Calculation 5: Tax year includes January 1, 2010.
EE + [(FF **minus** EE) x (GG **divided by** HH)] where,
- EE = [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- GG = number of days in the tax year after December 31, 2009;
- HH = number of days in the tax year. . . . . ______

Enter the amount from Calculation 1, 2, 3, 4 or 5, whichever is applicable ______ *G

For associated corporations:
If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ______ *H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ______ x Number of days in the tax year 365 / 365 = ... ______ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ______

* Amount G or H cannot be more than $3,000,000 ($2,000,000 if tax year ending before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=		J
Line 350 minus line 410 (if negative, enter "0")	430	3,120,034	x	20 %	=	624,007	K
Line 410 minus line 350 (if negative, enter "0")			L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=		M
Line 360 minus line L (if negative, enter "0")	450		x	20 %	=		N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 %	=		
480		x	20 %	=		
			Total			O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 624,007

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	510		
Credit expired*	515		
Subtotal			
ITC at the beginning of the tax year		520	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	530		
Total current-year credit	540	624,007	
Credit allocated from a partnership	550		
Subtotal		624,007	624,007
Total credit available			624,007
Deduct:			
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	624,007	
Credit carried back to the previous year(s) (from Part 13)			P
Credit transferred to offset Part VII tax liability	580		
Subtotal		624,007	624,007
Credit balance before refund			Q
Deduct:			
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)		610	
ITC closing balance on SR&ED		620	

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . 650 1 Yes [ ] 2 No [X]

Credit balance before refund (amount Q from Part 12)	____ R	
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)	____ S	
Refundable credits (amount R or S, whichever is less)*		____ T
Amount J from Part 11	____ U	
Subtract: Amount T or U, whichever is less		____ V
Net amount (if negative, enter "0")		____ W
Amount W ____ x 40 %		____ X
Add: Amount V		____ Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)		____ Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)		____ AA
Amount J from Part 11	____ BB	
Subtract: Amount AA or BB, whichever is less		____ CC
Net amount (if negative, enter "0")		____ DD
Amount M from Part 11		____ EE
Amount DD or EE, whichever is less ____ x 40 %		____ FF
Add : Amount CC above		____ GG
Refund of ITC (amounts FF **plus** GG)		____ HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula **(A x B) - C**	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) ________ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 ________ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts at column 826	▶		VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . . ________

Deduct:

Credit deemed as a remittance of co-op corporations . . . . **841** ________

Credit expired* . . . . **845** ________

Subtotal ________ ▶ ________

ITC at the beginning of the tax year . . . . **850** ________

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . . **860** ________

Expenditures from line YY in Part 18 . . . . . **870** ________ x 10 % = ... **880** ________

Total credit available . . . . ________

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) . . . . **885** ________

Credit carried back to the previous year(s) (from Part 20) . . . . ________ CCC

Subtotal ________ ▶ ________

ITC closing balance from pre-production mining expenditures . . . . **890** ________

* The credit is eligible for a 20 year carryforward effective for credits earned in 2003 and later tax years.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	921	
2nd previous tax year				Credit to be applied	922	
3rd previous tax year				Credit to be applied	923	

Total (enter on line CCC in Part 19) ________

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
	Subtotal			
ITC at the beginning of the tax year			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (total of column 605)	640	498,838		
Credit allocated from a partnership	655			
	Subtotal	498,838		498,838
Total credit available				498,838
Deduct:				
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	498,838		
Credit carried back to the previous year(s) (from Part 23)			DDD	
	Subtotal	498,838		498,838
ITC closing balance from apprenticeship job creation expenditures			690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year 715 ____ EEE

Add: Specified child care start-up expenditures from the current tax year . . . 705 ____ FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . ____ GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) . . . 725 ____ HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") ____ III

Add: Repayments of government and non-government assistance . . . 735 ____ JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) . . . 745 ____

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
	Subtotal		▶	
ITC at the beginning of the tax year			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount MMM above)	780			
Credit allocated from a partnership	782			
	Subtotal		▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B5 in Part 30)	785			
Credit carried back to the previous year(s) (from Part 27)			NNN	
	Subtotal		▶	
ITC closing balance from child care spaces expenditures			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2008-12-31	Credit to be applied	941	
2nd previous tax year	2007-12-31	Credit to be applied	942	
3rd previous tax year	2006-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . . 792 ______ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . 795 ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . . 797 ______

Amount from line 795 or line 797, whichever is less . . . . . . ______ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC 799 ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . . . ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	624,007	B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	498,838	B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	1,122,845	B6

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

	Line	Amount		
Add the following amounts at the end of the year:				
Reserves that have not been deducted in computing income for the year under Part I	101	1,334,642,640		
Capital stock (or members' contributions if incorporated without share capital)	103	3,362,893,010		
Retained earnings	104	1,693,689,461		
Contributed surplus	105	4,107,012		
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	6,985,823,348		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		13,381,155,471	13,381,155,471	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal				B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		13,381,155,471	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:
- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:		
A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	13,939,977
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	13,939,977

Notes:
1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		13,381,155,471	C
Deduct: Investment allowance for the year (line 490)		13,939,977	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	13,367,215,494	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 13,367,215,494 × (Taxable income earned in Canada **610** 77,473,522 / Taxable income 77,473,522) = **Taxable capital employed in Canada** **690** 13,367,215,494

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada		701	
Deduct the following amounts:			
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711		
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712		
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713		
Total deductions (add lines 711, 712, and 713)		►	E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")		790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.00225)		I

Enter this amount at line 415 of the T2 return

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Schedule 33 - Supplementary Schedule

Description	Amount	
Inter-company demand facility	191,048,743	00
LT Debt payable within a year (FS) A/C 330000	600,000,000	00
Primary Debt (FS) A/C 302000	6,109,000,000	00
Customer deposit (390000/391010/392000)	50,869,785	00
P/Port Amounts withheld from contracts (425001)	892,584	00
Dividends Payable (443020)	5,113,529	00
WSIB(451070)	3,549,024	00
Banked Vacation(362100)	6,580,694	00
Mark to Market Adjustment (304300)	11,350,820	00
Prepayments (211820/810) outstanding >365 days	6,256	00
Unearned Revenue (Cash Deposits) A/C 427000 - 427100	7,411,913	00
Total	6,985,823,348	00

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Schedule 33/CT23 - Supplementary Schedule

Description	Amount	
Trade Receivables outstanding over 365 days	2,948,072	00
Prepaid insurance(277180)	303,296	00
Prepaid Inergi (277190)	10,688,609	00
Total	13,939,977	00

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in computing income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description	Amount	
Schedule 13 Adjustments	1,334,642,640	00
Future Income Tax Liability	669,404,086	00
Regulatory Future Income Tax Asset	-669,404,086	00
Total	1,334,642,640	00

SCHEDULE 50

Canada Revenue Agency / Agence du revenu du Canada

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	Hydro One Inc.	86999 4731 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

SCHEDULE 53

Canada Revenue Agency / Agence du revenu du Canada

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

On: 2009-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☐ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	952,863,588 A
Taxable income for the year (DICs enter "0") *		110	77,473,522 B	
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	1,070,321		
Subtotal (**add** lines 120, 130, and 140)		1,070,321	1,070,321 C	
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")		150	76,403,201	
After-tax income (line 150 x general rate factor for the tax year ** 0.68)			190	51,954,177 D
Eligible dividends received in the tax year		200		
Dividends deductible under section 113 received in the tax year		210		
Subtotal (**add** lines 200 and 210)				E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)		220		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)		230		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)		240		
Subtotal (**add** lines 220, 230, and 240)			290	F
Subtotal (**add** lines A, D, E, and F)				1,004,817,765 G
Eligible dividends paid in the previous tax year		300		
Excessive eligible dividend designations made in the previous tax year		310		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. Subtotal (line 300 **minus** line 310)				H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			490	1,004,817,765
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	1,004,817,765

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year		319,101,605 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)		N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		319,101,605	319,101,605 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year
(line V1 **multiplied by** the general rate factor for the tax year 0.68) . . . . **500** ______

Second previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year 537,428,722 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) 195,907 M2

Subtotal (**add** lines K2, L2, and M2) 195,907 ▶ 195,907 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 537,232,815 ▶ 537,232,815 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year
(line V2 **multiplied by** the general rate factor for the tax year 0.68) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year		545,572,415	J3	
Enter the following amounts before specified future tax consequences from the current tax year:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L3			
Aggregate investment income (line 440 of the T2 return)	636,852 M3			
Subtotal (**add** lines K3, L3, and M3)	636,852 ▶	636,852	N3	
Subtotal (line J3 **minus** line N3) (if negative, enter "0")		544,935,563 ▶		544,935,563 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences		P3		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	Q3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	R3			
Aggregate investment income (line 440 of the T2 return)	S3			
Subtotal (**add** lines Q3, R3, and S3)	▶	T3		
Subtotal (line P3 **minus** line T3) (if negative, enter "0")		▶	U3	
Subtotal (line O3 **minus** line U3) (if negative, enter "0")			V3	

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.68) . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		AA
Eligible dividends paid by the corporation in its last tax year	BB	
Excessive eligible dividend designations made by the corporation in its last tax year	CC	
Subtotal (line BB **minus** line CC)	▶	DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ________ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ________ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ________
Net capital losses . . . . ________
Farm losses . . . . ________
Restricted farm losses . . . . ________
Limited partnership losses . . . . ________

Subtotal ________ ▶ ________ HH

Subtotal (**add** lines FF, GG, and HH) ________ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ________ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ________ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ________ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ________ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ________ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ________ ▶ ________ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ________ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

– line 220 for a corporation becoming a CCPC;
– line 230 for post-amalgamation; or
– line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to four decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	....	=	0.6800	QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	___ / 365	....	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	___ / 365	....	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	___ / 365	....	=		TT

General rate factor for the tax year (total of lines QQ to TT) .... 0.6800 UU

SCHEDULE 55

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PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation,* or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		145,464,377		
Total taxable dividends paid in the tax year	100	145,464,377		
Total eligible dividends paid in the tax year			150	
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	1,004,817,765
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%)		x 20 %	190	

Enter the amount from line 190 at line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)				B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%)		x 20 %	290	

Enter the amount from line 290 at line 710 of the T2 return.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- References to subsections and paragraphs are from the federal *Income Tax Act.*
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return.*

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	365 / 365	x	14.00 %	=	14.00000 %	A1
Number of days in the tax year after June 30, 2010 and before July 1, 2011 / Number of days in the tax year	/ 365	x	12.00 %	=	%	A2
Number of days in the tax year after June 30, 2011 and before July 1, 2012 / Number of days in the tax year	/ 365	x	11.50 %	=	%	A3
Number of days in the tax year after June 30, 2012 and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 14.00000 ▶ 14.00000 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 77,473,522 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . 10,846,293 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, from of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)					76,403,201	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)					77,473,522	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	x	500,000 / 500,000 (line 4 on page 4 of the T2 return)	=	500,000	3
Enter the least of amounts 1, 2, and 3					500,000	D
Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories **			77,473,522.00 / 77,473,522	=	1.00000	E
Ontario small business income (amount D **multiplied** by amount E)					500,000	F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	365 / 365	x	8.50 %	=	8.50000 %	G1
Number of days in the tax year after June 30, 2010 and before July 1, 2011 / Number of days in the tax year	/ 365	x	7.50 %	=	%	G2
Number of days in the tax year after June 30, 2011 and before July 1, 2012 / Number of days in the tax year	/ 365	x	7.00 %	=	%	G3
Number of days in the tax year after June 30, 2012 and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5

OSBD rate for the year (total of rates G1 to G5) . . . . . 8.50000 % G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) . . . . . H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia, and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD, and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction.*

Note: You do not need to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *	77,473,522	I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	10,811,534	J		
Aggregate adjusted taxable income (amount I **plus** amount J)	88,285,056	▶	88,285,056	K

Deduct:

Ontario business limit	500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)	87,785,056	L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 365 / 365 x 4.25 % = 4.25 % M

Note: For days in the tax year after June 30, 2010, the small business surtax rate is reduced to 0%.

Multiply: Amount L x % on line M = 3,730,865 N

Amount N x Ontario small business income (amount F from Part 3) / 500,000: 500,000 / 500,000 = 3,730,865 O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H in Part 3) ______ P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount D in Part 3 500,000 Q

Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 8.50000 %: ______ / 0.08500 = ______ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D in Part 3 of Schedule 17			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	8.50000 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 on Schedule 5.

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SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or claiming the Ontario transitional tax credit.
- Unless otherwise noted, references to parts, subsections, paragraphs, subparagraphs, and clauses are from the federal *Income Tax Act*.
- For more information on how to complete this schedule, see Guide T4012, *T2 Corporation – Income Tax Guide*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- Transition time is defined under subsection 46(1) of the *Taxation Act*, 2007 (Ontario) as:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on the last day of 2008, or
  - the beginning of the corporation's tax year that includes the beginning of 2009 in any other case.
- An eligible amalgamation refers to an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An eligible post-2008 windup means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year during which it received the assets of the subsidiary ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An eligible pre-2009 windup means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The completion time of a windup is the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A specified pre-2009 transfer under section 52 of the *Taxation Act*, 2007 (Ontario) is a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	8,242,280,505
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	105,435,384
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (from line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year	160	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		8,347,715,889 A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A **minus** line 170)	180	8,347,715,889

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.
Note 2: Enter "0" if control of the corporation was acquired at transition time.
Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.
Note 4: Do not include losses that arose before control of the corporation was last acquired.

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	8,242,280,505
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	105,435,384
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	464,026
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included in the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	8,348,179,915

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

- have been earned and are available without restriction to the corporation;
- are attributable to qualifying Ontario SR&ED expenditures;
- have not been deducted under subsection 127(5) or (6) of the federal Act; and
- do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1) or total federal balance at the end of the previous tax year (line 330)	300	8,347,715,889		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the tax year		8,347,715,889 ▶	330	8,347,715,889

Total Ontario balance:

Total Ontario balance (from line 280 in Part 2) or total Ontario balance at the end of the previous tax year (line 370)	340	8,348,179,915		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the tax year		8,348,179,915 ▶	370	8,348,179,915
Transitional balance at the end of the tax year (line 330 **minus** line 370)			390	-464,026

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation.*

Part 4 – Election to reduce federal SR&ED expenditure pool

This election may be made if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? **400** 1 Yes [ ] 2 No [X]

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)		B
Deduct:		
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)	1	
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)	2	
Subtotal (amount 1 **plus** amount 2)	▶	C
Subtotal (amount B **minus** amount C) (if negative, enter "0")		D
Federal balance before election (amount A from Part 1)		
Deduct:		
Total Ontario balance (amount from line 280 in Part 2)		
Subtotal (if negative, enter "0")		E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period of a corporation starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:
– five calendar years after the time immediately before the corporation's first tax year ending after December 31, 2008; or
– December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
– the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:
– the end of the corporation's reference period; or
– the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:
– the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
– the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a permanent establishment in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:
– enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . **435** ______
– enter the number of days remaining in the corporation's reference period that are on or after the first day of the tax year (do not include February 29, 2008, or February 29, 2012) . . . . **440** ______

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.
If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

Ontario taxable income* / Taxable income** ______ = ______

Ontario allocation factor (OAF) . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary - Corporations*. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3			G
Amount G x	14 %		H
Amount H x OAF (from line F in Part 6)	1.00000		I

Number of days from line 440 in Part 5 (if applicable) or number of days in the corporation's reference period that are in the tax year (do not include February 29, 2008, or February 29, 2012) / Number of days in the corporation's reference period from line 410 in Part 5 = 365 / 1,825 = 0.20000 J

Transitional tax debits before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J) .... K

Post-2008 SR&ED balance at the end of the year (amount HH from Part 12) **460**

Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14) **470**

Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470) L

Total transitional tax debits (amount K **plus** amount L) .... M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5 .... 10,846,293 N

Deduct:

Ontario resource tax credit (from line 404 of Schedule 5)			
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)			
Ontario foreign tax credit (from line 408 of Schedule 5)			
Ontario credit union tax reduction (from line 410 of Schedule 5)			
Subtotal			O
Subtotal (amount N **minus** amount O)		10,846,293	P

Number of days in the amortization period that are in the tax year (from line 420 in Part 5) / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012) = 365 / 365 = 1.00000 Q

Ontario tax payable for purposes of the current year transitional credit (amount P **multiplied** by amount Q) **510** 10,846,293

Amount from line 390 in Part 3 (enter as a positive amount)		464,026	R
Amount R x	14 %	64,964	S
Amount S x OAF (from line F in Part 6)		64,964	T

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5 = 365 / 1,825 = 0.20000 U

Current-year transitional tax credit (amount T **multiplied** by amount U) **520** 12,993

Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0") **530** 10,833,300

Transitional tax credit:
Lesser of amounts on line 510 and 520 .... 12,993 V

Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530 .... W

Transitional tax credit (amount V **plus** amount W) .... 12,993 X

Enter amount X on line 414 of Schedule 5.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)*			1	
Add:				
Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup*	560		2	
Unused transitional tax credit available (amount 1 **plus** amount 2)			▶	Y
Add:				
Current-year transitional tax credit (amount from line 520 in Part 8)			12,993	Z
Subtotal (amount Y **plus** amount Z)			12,993	3
Deduct:				
Transitional tax credit applied (amount X from Part 8)			12,993	AA
Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA)	580			

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a)	610			
Capital SR&ED expenditures in the year under paragraph 37(1)(b)	614			
Repayment of assistance under paragraph 37(1)(c)	618			
Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year	624			
Subtotal (total of lines 610 to 624)			▶	BB
Deduct:				
Assistance under paragraph 37(1)(d)	638			
Investment tax credits deducted under paragraph 37(1)(e)	644			
Subtotal (line 638 **plus** line 644)			▶	CC
Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC)	650			

If the amount on line 650 is positive, enter it on line II In Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

- the corporation's OAF for the tax year that includes its transition time (from line F in Part 6) .... %
- the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) .... %
- the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008 .... %

Relevant OAF .... 660 ______ %

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

- the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;
2) a corporation that wound up into the particular corporation under subsection 88(1); or
3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . ________ DD

SR&ED expenditure amount deducted in the year under subsection 37(1) . . . . **670** ________

Deduct:
Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) . . . . . **675** ________
Subtotal (line 670 **minus** line 675) (if negative, enter "0") ________ ▶ ________ EE

Subtotal (amount DD **plus** amount EE) ________ FF

Amount FF x 14 % ________ GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . ________ HH
Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) . . . . ________ II
Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 . . . . **700** ________
Subtotal (line II **plus** line 700) ________ JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 . . . . **705** ________

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . **710** ________

Deduct:
Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year . . . . **715** ________
Subtotal (line 710 **minus** line 715) **720** ________

$$\frac{\text{Line 720}}{\text{Relevant OAF (from line 660 in Part 11) x 14 \%}} = \_\_\_\_\_\_\_\_ \blacktriangleright \_\_\_\_\_\_\_\_ \text{ KK}$$

Subtotal (line 705 **minus** amount KK) ________ ▶ **730** ________

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") . . . . ________ LL
Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1* . . . . **735** ________ MM
Relevant OAF* (from line 660) **multiplied** by amount MM . . . . ________ NN
Amount NN x 14 % . . . . ________ ▶ ________ OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up . . . . **740** ________
Subtotal (amount OO **plus** line 740) ________ PP

Deduct:
Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . **750** ________

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . ________ QQ
Enter amount QQ on line 470 in Part 7.

* For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

SCHEDULE 508

Canada Revenue Agency / Agence du revenu du Canada

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return*.

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	2,870,245	A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		2,870,245	C		
Add: Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		2,870,245	▶	2,870,245	E
Deduct: Eligible expenditures the corporation transferred to another corporation			115		F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")			120	2,870,245	G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)		2,870,245	x	4.50 %	= 200	129,161	H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205		I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210		x	4.50 %	= 215		J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =	x	4.50 %	= 225		K
Current part of the ORDTC (total of amounts H to K)					230	129,161	L

* If there is a disposal or change of use of eligible property, see Part 6

Canada

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year			M
Deduct: ORDTC expired after 20 tax years	300		N
ORDTC at the beginning of the tax year (amount M **minus** amount N)	305		O
Add:			
ORDTC transferred on amalgamation or windup	310		P
Current part of ORDTC (amount L in Part 2)		129,161	Q

Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 [ ] No 2 [X]

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320		R	
Subtotal (amount Q **minus** amount R)		129,161 ▶	129,161	S
ORDTC available for deduction (total of amounts O, P and S)		129,161 ▶	129,161	T
Deduct:				
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)		129,161		U
ORDTC carried back to a previous tax year (from Part 4)				V
Subtotal (amount U **plus** amount V)		129,161 ▶	129,161	W
ORDTC balance at the end of the tax year (amount T **minus** amount W)	325			X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2008-12-31	Credit to be applied	901	
2nd previous tax year	2007-12-31	Credit to be applied	902	
3rd previous tax year	2006-12-31	Credit to be applied	903	

Total (enter amount on line V in Part 3)

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
1990-03-31	
1991-03-31	
1992-03-31	
1993-03-31	
1994-03-31	
1995-03-31	
1996-03-31	
1997-03-31	
1998-03-31	
1999-03-31	

	Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
	1999-12-31	
	2000-12-31	
	2001-12-31	
	2002-12-31	
	2003-12-31	
	2004-12-31	
	2005-12-31	
	2006-12-31	
	2007-12-31	
	2008-12-31	
Current tax year	2009-12-31	

Total (equals line 325 in Part 3) ______

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y	Z	AA
	Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) ______ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ________ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . 760 ________ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ________ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ________ LL

Amount KK **plus** amount LL . . . . ________ x 23.56 % = ________ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ________ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ________ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation.**

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures		**Current Expenditures**		**Capital Expenditures**	
Total expenditures for SR&ED		3,249,195			
Add					
• payment of prior years' unpaid expenses (other than salary or wages)	+				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+				
• expenditures on shared-use equipment			+		
• other additions	+		+		
Subtotal	=	3,249,195	=		
Less					
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–				
• prescribed expenditures not allowed by regulations	–		–		
• other deductions	–	378,950	–		
• non-arm's length transactions					
– expenditures for non-arm's length SR&ED contracts	–				
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		–		
Subtotal	=	2,870,245 I	=		II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			=	2,870,245	III

Enter amount III on line 100 of Schedule 508.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations*. File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act*, 2007 (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

	Line	Amount		
Amount A from Part 1 of Schedule 33	100	13,381,155,471		
Add:				
Accumulated other comprehensive income at the end of the year	105			
Subtotal		13,381,155,471	13,381,155,471	A
Deduct:				
Amount B from Part 1 of Schedule 33	110			
Amount on line 490 from Part 2 of Schedule 33	115	13,939,977		
Subtotal		13,939,977	13,939,977	B
Taxable capital (amount A **minus** amount 8) (if negative, enter "0")	120		13,367,215,494	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? 190 1 Yes [ ] 2 No [X]

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

$$\frac{\text{Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)} \quad \mathbf{200}\ 13{,}367{,}215{,}494}{\text{Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *} \quad \mathbf{210}\ 13{,}367{,}215{,}494} \times 15{,}000{,}000\ \$ = \textbf{Capital deduction}\ \mathbf{220}\ 15{,}000{,}000$$

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

$$\frac{\text{Allocation of net deduction (from line 600 for the filing corporation from Schedule 516)} \quad \mathbf{300}\ \_\_\_\_}{\text{Ontario allocation factor (OAF) (amount I in Part 3)}} = \textbf{Capital deduction}\ \mathbf{305}\ \_\_\_\_$$

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies **320** 13,367,215,494

Deduct:
Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2) . . . . 14,232,613 B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . 13,352,982,881 C

Amount C 13,352,982,881 × (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) 365 / 365 × 0.00225 = 30,044,211 D

Amount C 13,352,982,881 × (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) ____ / 365 × 0.00150 = ____ E

Subtotal (amount D **plus** amount E) 30,044,211 F

Amount F 30,044,211 × OAF (amount on line I) 1.00000 = ... 30,044,211 G

Amount G 30,044,211 × (Number of days in the tax year * / 365) 365 / 365 = ... 30,044,211 H

Deduct:
Capital tax credit for manufacturers (enter amount J from Part 4) . . . . **350** ____

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") **400** 30,044,211

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations.*

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

(Ontario taxable income ** / Taxable income ***) ____ = ____

Ontario allocation factor . . . . 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

(Ontario manufacturing labour cost* **405** / Total Ontario labour cost** **410**) ____ × 100 = ... **420** ____ %

If the percentage on line 420 is 20% or less, enter "0" on line J.
If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.
If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

((percentage from line 420) – 20% / 30%) ____ % / 30.000 % × 30,044,211 Amount H from Part 3 = ____

Capital tax credit for manufacturers . . . . ____ J
Enter amount J on line 350 in Part 3

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)
** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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SCHEDULE 524

ONTARIO SPECIALTY TYPES

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2009-12-31

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  - its tax year includes January 1, 2009;
  - the tax year is the first year after incorporation or an amalgamation; or
  - there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- [ ] 01 Family farm corporation – See subsection 64(3).
- [ ] 02 Family fishing corporation – See subsection 64(3).
- [ ] 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act.*
- [ ] 04 Credit union – See subsection 137(6) of the federal Act.
- [ ] 06 Bank – See subsection 248(1) of the federal Act.
- [ ] 08 Financial institution prescribed by regulation only – See clause 66(2)(f).
- [ ] 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- [ ] 10 Farm feeder finance co-operative corporation
- [ ] 11 Insurance corporation – See subsection 248(1) of the federal Act.
- [ ] 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- [ ] 13 Specialty mutual insurance
- [ ] 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- [ ] 15 Bare trustee corporation
- [ ] 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act.
- [ ] 17 Limited liability corporation
- [ ] 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- [x] 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- [ ] 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- [ ] 21 Mining corporation
- [ ] 22 Non-resident corporation
- [ ] 99 Other (if none of the previous descriptions apply)

Continuity of Capital Dividend Account

At: 2009-12-31 **(see Note)**

Capital gains

Non-taxable portion of capital gains realized in prior years		6,991,660	
Non-taxable portion of capital gains for the year	+	1,070,321	8,061,981

Capital losses

Non-deductible portion of capital losses incurred in prior years			
Non-deductible portion of capital losses for the year	+		
Non-deductible portion of business investment losses	+		
Excess of non-taxable portion of gains over losses			8,061,981

Capital dividends received

Aggregate of dividends received in prior years			
Dividends received during the year	+		

Eligible capital property

Non-taxable portion of net proceeds on sale of E.C.P – Balance from priors years			
Disposition incurred during the taxation year ending after October 17, 2000			
Amount to be included under subsection 14 (1)(b).			
Amount from line S on Schedule 10 for the taxation years ending after October 17, 2000 – for the current year			
Appropriate portion of amount deducted as a credit loss (paragraph 20(4.2)) or capital losses (paragraph 20(4.3)) for the taxation years ending after October 17, 2000 – for the current year	–		
Non-taxable portion of net proceeds on sale of E.C.P.			

Life insurance policies

Proceeds from life insurance policies received in prior years			
Proceeds from life insurance policies received in year	+		
Adjusted cost base of life insurance policies disposed of in prior years	–		
Adjusted cost base of life insurance policies disposed of in year	–		

Capital gains paid out by a trust

Non-taxable portion of capital gains paid out by a trust – Balance from prior years			
Non-taxable portion of capital gains paid out by a trust – for the current year	+		
Non-taxable dividends earned from a CDA and paid out by a trust – Balance from prior years			
Non-taxable dividends earned from a CDA and paid out by a trust – for the current year	+		

Capital dividend account balance before capital dividends paid or payable	8,061,981

Capital dividend account balance before capital dividends paid or payable	8,061,981

Capital dividends paid or payable

Aggregate of dividends – prior years		
Dividends paid or payable for year	+	

Capital dividend account balance	8,061,981

Balance of the capital dividend account at the end of the preceding taxation year

Balance of the capital dividend account on 2008-12-31	6,991,660

Note: The time period in which the CDA applies commences on the first day of the first taxation year ending after 1971 and after the corporation last became a private corporation and ends immediately before the balance in the CDA is to be determined.

Ontario
Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990

from 2008/01/01 to 2008/12/31

	Account No.	Assessment Date (year, month, day)	Page
HYDRO ONE NETWORKS INC.	1800029	2009/07/20	1 of 1

ASSESSMENT NO. 473

Tax: Federal and Provincial PIL		126,817,414.00
Assessment Interest		233,394.63
Total Assessment Liability		127,050,808.63

SUMMARY OF 2008/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	128,635,482.69CR	
Interest	133,673.28CR	
Sub-Total		128,769,155.97CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		1,718,347.34CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Adjustment to the computation of Total Tax payable.

Adjustment to the computation of Investment Allowance. Taxable Capital revised

Mathematical error in computation of Taxable Paid-up Capital.

Adjustment to the computation of Capital Tax.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #64 List 1</u>

<u>Interrogatory</u>

Issue 4.1 Are amounts proposed in rate base in 2011 and 2012 appropriate?

<u>Ref: Exhibit D1/T1/S2/Table 1 and Exhibit D1/T3/S1/Table 1</u>
In Table 1 at Ex D1/T1/S2 summarizes the in-service capital additions that will be added to rate base in 2011 and 2012. The in-service additions are grouped by investment category (i.e. Sustaining, Development, Operations & Other). Table 1 at Ex D1/T3/S1 summarizes the capital expenditures in the test year by investment category.

Board staff notes that there is a significant difference between the capital expenditure budget and the proposed in-service additions. Please provide the following information:

(a) Please provide a breakdown of all capital programs, for Sustaining, Operations and Shared Services, that are included in the in-service additions table. Please provide this information in table format, identifying the capital program, ISD #, in-service year, Category of investment (i.e. Category 1, 2, 3or 4), Gross Cost, capital contributions, and test year capital expenditure that is booked to rate base. In a separate table, please indentify all projects that are included in the capital expenditure budget, but will not be added to the test year rate base.

(b) With respect to Development Capital, Board staff has prepared the following table. The table attempts to identify all Development Capital additions in the test year. However staff was unable to reconcile to the in-service additions table in Exhibit D1/T1/S2. Please provide a similar table that identifies all the development capital programs, related ISD #, in-service year, Category of investment, Gross Cost, Capital contributions and capital that is booked to rate base in 2011 and 2012. Please identify the projects that are included in the Green Energy Plan. In a separate table, please indentify all projects that are included in the capital expenditure budget, but will not be added to the test year rate base.

				Development Capital in $ millions			
			I/S	**Proj. Cost**		**Rate Base Amounts**	
ISD #	**Investment Summary Description**	**Cat.**	**year**	**G.Cost**	**C.Cont.**	**2011**	**2012**
D1	New 500 kV Bruce to Milton Double Circuit T.L	1	2012	695.5		$ 184.4	$ 94.3
D2	Northeast Trans.Reinforcem: SVC's at Prcupine & Kirkland Lake	1	2011	121.6		$ 33.1	$ -
D3	Nanticoke TS - 500 kV, 350 MVar Static Var Compensator	1	2011	84.6		$ 22.1	$ -
D4	Installation of Static Var Compensator at Detweiler TS	1	2011	80.3		$ 34.9	$ -
D5	Installation of 1 Shunt Capacitor Bank at Essa TS	2	2011	6.3		$ 5.9	$ -
D6	Installation of 2 Shunt Capacitor Banks at Porcupine TS	2	2011	11.7		$ 10.3	$ 0.2
D7	Installation of 1 Shunt Capacitor Bank at Hanmer TS	2	2011	8.5		$ 7.9	$ 0.1
D8	Installation of Shunt Capacitor Bank at Dryden TS	3	2013	10.7		$ 0.1	$ 10.3
D9	Woodstock Area Transmission Reinforcement	1	2011	70.9		$ 20.7	$ -
D10	Rebuild Burlington TS 115kV Switchyard	2	2012	56.4		$ 30.4	$ 1.4
D11	Toronto Area:Upgrades Short Circ.Capability:Rebuild Hearn SS	2	2012	84.9		$ 54.6	$ 27.0
D12	Toronto Area:Upgrades Short Circ.Capability:Leaside TS Uprate	2	2012	37.4		$ 13.5	$ 21.9
D13	Toronto Area:Upgrades Short Circ.Capability:Manby TS Uprate	3	2013	30.4			
D14	Midtown Transmission Reinforcement Plan	4	2013	107.3			
D15	Guelph Area Transmission Reinforcement	4	2014	50.7			
D16	Commerce Way TS&Line Connection(formerly Woodstock East)	1	2012	45.8	24.2	$ 27.1	$ 6.5
D17	Kirkland Lake TS: Reconnect Idle K4 Line	2	2011	13.7	13.7	$ 13.3	$ 0.2
D18	South Halton Tremaine TS: Build new Transformer Station	2	2012	28.5	19.1	$ 20.9	$ 5.5
D19	Ancaster TS: Build new TS & Line Connection	3	2013	24.1			
D20	East Ottawa TS: Build new Transformer Station	3	2013	33.4			
D21	Leamington TS: New 230/27.6kV DESN & Line Connection	4	2013	62.4			
D22	Build New TS & Line Connection in Northern Mississauga	3	2014	39.3			
D23	New Enfield TS & Line Connection(Formerly Ottawa Area TS)	3	2014	28.7			
D24	Long Lac TS: Replace End-of-Life 115/44kV Transformers	2	2011	19.8		$ 5.3	$ -
D25	North Bay: Upgrade to a 115/44kV Transformer Station	2	2012	26.8		$ 18.3	$ 8.4
D26	Barwick TS: Build new Transformer Station	2	2012	15.5		$ 8.8	$ 6.2
D27	New Duart TS & Line Connection (formerly Rodney TS)	2	2012	26.7		$ 12.1	$ 12.6
D28	500MW Renewables III RFP: Talbot Wind Farm	2	2011	25.0	25	$ 23.0	$ -
D29	350MW Peaking Generation in Northern York Region	2	2011	4.9	4.9	$ 4.5	$ -
D30	Chatham Wind Generation Connection (260MW)	2	2012	4.2	4.2	$ 0.1	$ 4.1
D31	Lower Mattagami Generation Connections**[Note $31.6 million**]	4	2012	8.3	8.3	$ 2.0	$ 4.0
D32	Enabling 230/44kV TS #1 and Short (<2km) Tap	3	2013	33.8			
D33	Enabling 115/44kV TS #1 and Short (<2km) Tap	3	2013	33.8			
D34	Algoma x Sudbury Transmission Expansion	4	2015	431.6			
D35	Northwest Transmission Reinforcement	4	2014	399.5			
D36	Static Var Compens. #1 at Existing Station in Southwestern ON	3	2013	78.7			
D37	In-Line Circuit Breakers #1	2	2012	20.3		$ 13.4	$ 6.9
D38	In-Line Circuit Breakers #2	2	2012	20.3		$ 13.4	$ 6.9
D39	In-Line Circuit Breakers #3	3	2013	20.8			
D40	In-Line Circuit Breakers #4	3	2013	20.8			
D41	In-Line Circuit Breakers #5	3	2014	21.6			
D42	In-Line Circuit Breakers #6	3	2014	21.6			
D43	Station Protection Upgrades for Distributed Generation					$ 5.3	$ 15.8
D44	Transfer Trip Facilities					$ 4.7	$ 14.0
D45	End/End Testing-Interop.Bus Archit're(O.Sound and Meaford TSs)					$ 5.5	$ 5.5
D46	Various lines and TSs outliers-inliers					$ 4.0	$ 4.0
D47	Mitigate Reliability Problems of HV Shunt Capacitor Instalations					$ 16.8	$ -
Others (Less than $3 Million)						$ 21.4	$ 44.3
						$ 637.8	**$ 300.1**
Less Capital Contributions						43.6	55.8
Balance						**594.2**	**244.3**
In-service additions as per Table 1(D1/T1/S2)						$397.80	$1,083.40

Response

(a) Please find the requested tables (Table 1, 2, and 3) that includes a breakdown of all capital programs, for Sustaining, Operations and Shared Services, that are included in the in-service additions table. This table includes information identifying the capital program, in-service year, Gross Cost, capital contributions, and test year capital expenditure that is booked to rate base.

Please note that per Exhibit D1, Tab 3, Schedule 3, the Capital Project Category classification is specific to Development projects. Where possible, groups of projects have been associated with a comparable development Capital Project Category.

Table 1
Sustainment Projects – Test Year In-Service Additions (ISA)

ISD#	Investment Summary Description	Gross Cost ($M)*	Cap. Contr.	I/S	2011 ISA ($M)	2012 ISA ($M)
S1	2011/2012 Oil Circuit Breaker Replacement Program	16.5	-	2012	4.5	7.6
S2	2011/2012 SF6 Breakers Type SP Replacements	29.5	-	2012	8.6	13.3
S3	2011/2012 Metalclad Circuit Breakers Replacement - GTA	23.6	-	2012	8.9	10.7
S4	Beck #1 SS: Air Blast Circuit Breaker (ABCB) Re-Investment	47.5	-	2012	21.7	13.7
S5	Abitibi Canyon Switching Station (SS) and Pinard Transformer Station (TS) - Replace EOL Components	21.7	-	2012	9.3	11.3
S6	Nanticoke TS: Air Blast Circuit Breaker (ABCB) Re-Investment	4.9	-	2011	4.3	0.0
S7	Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment	22.9	-	2013	6.7	6.9
S8	Richview TS 230 kV Switchyard: Air Blast Circuit Breaker (ABCB) Re-Investment	17.1	-	2012	4.6	10.8
S9	Hanmer TS 500 kV ABCB Replacement	18.8	-	2012	7.6	9.3
S10	Pickering A switchyard : Air Blast Circuit Breaker (ABCB) Re-Investment	7.3	-	2012	2.7	3.8
S11	Merival GIS ITE Bus Replacement	20.7	-	2012	5.7	7.0
S13	Richview TS - Replace EOL Transformer	10.1	-	2012	4.8	4.4
S14	Replace EOL CGE Transformers	73.5	-	2012	28.6	31.0
S15	Leaside TS - Replace EOL Transformers	12	-	2012	3.7	7.7
S16	Purchase Spare Transformers	26.5	-	2012	9.9	13.3
S17	2011/2012 Station HV Disconnect replacement Program	11.4	-	2012	4.3	4.4
S18	Capacitor Bank Replacement	7.1	-	2012	2.6	2.8
S19	2011/2012 Station Service Upgrades	26	-	2012	7.5	11.7
S20	2011/2012 Spill Containment Refurbishment - Major	17.8	-	2012	4.4	8.5
S21	BSPS Replacement of End-of-Life Equipment	19.1	-	2012	0.0	18.7
S22	ITC - Line Protections Replacements	9.9	-	2012	4.3	5.4
S23	NYPA Tie Lines - Beck Line Protections Replacements	6.9	-	2012	2.9	3.8
S24	2011 - 2012 Station P&C Replacement	46.6	-	2012	19.8	20.0
S25	2011-2012 Protection Replacements	20.3	-	2012	7.3	10.6
S26	2011-2012 RTU Replacement	10.8	-	2012	4.5	5.5
S27	DC Signaling (Remote Trip) Replacements	13.7	-	2012	6.3	5.8
S29	NPCC Regulated Lines - Tone Equipment Replacements	14	-	2012	5.0	7.4
S30	PLC Replacement Program	5.5	-	2012	2.9	2.0
S31	TDCN Cyber Security	10.4	-	2012	0.0	10.4
S32	2011/2012 Spill - Major Drainage	9.2	-	2012	2.2	4.4
S34	2011/2012 Transmission Wood Pole Replacement Program	69	-	2012	21.6	21.9
S35	2011/2012 Steel Structure Coating Program	12	-	2012	5.5	6.5
S36	2011/2012 Shieldwire Replacement Program	9.5	-	2012	4.2	4.3
S37	2011/2012 Transmission Lines Emergency Restoration	14.4	-	2012	6.6	6.6
S38	Circuit A6P - Reserve Jct. to Port Arthur TS Transmission Line Refurbishment	14	-	2012	0.0	13.3
			Total In-Service Additions listed above		243.5	324.6
Sustainment Projects & Programs <$3M						
	Other Projects & Programs	156.9	-	2011/2012	123.3	74.8
			Total In-Service Additions less than $3M #		123.3	74.8
			Total Sustainment In-Service Additions		**366.8**	**399.4**

*Note: Gross Cost includes Removals
Table 1 includes projects that are comparable to Category 2 projects

Table 2
Operations Projects – Test Year In-Service Additions (ISA)

ISD	Investment Summary Description	Gross Cost ($M)*	Cap. Contr.	I/S	2011 ISA ($M)	2012 ISA ($M)
O1	Network Operations Buildings	23.1	-	2012	10.1	9.2
O2	NMS Upgrade & Enhancements	7.8	-	2012	3.8	4.0
O3	Tx Operating Facilities Sustainment	10	-	2012	6.5	3.5
O4	Hub Site Management Program	7.2	-	2012	2.9	4.3
O5	Telemetry Expansion	6.9	-	2012	3.4	3.5
O6	Wide Area Network	37.1	-	2011-21014	11.0	25.1
Other	Projects & Programs <$3M	9.7	-	Annual	4.6	5.1
				In-Service Additions	**42.3**	**54.7**

*Note: There are not Removal costs associated with Operations Projects
Table 2 includes projects that are comparable to Category 2 Projects.

Table 3
Shared Services Projects – Test Year In-Service Additions (ISA)

ISD	Investment Summary Description	Gross Cost ($M)	Cap. Contr.	Removals	I/S	2011 ISA ($M)	2012 ISA ($M)
IT1	Cornerstone Phase 2						
IT2	Cornerstone Phase 3*	9.3	-	-	2012	-8.9	22.5
IT3	Mobile IT Platform	2.8	-	-	2011	1.7	1.1
IT4	GIS Implementation	6.1	-	-	2014	3.1	2.8
IT5	MFA PC and Printer Hardware	4.5	-	-	Annual	2.7	1.8
IT6	Software Refresh & Maintenance - Enterprise Application Software	3.8	-	-	Annual	1.8	2.0
IT7	MFA UNIX Servers	3.6	-	-	Annual	1.8	1.8
IT8	MFA Windows Servers	2.3	-	-	Annual	1.5	0.8
	Other IT	10.2	-	-	Annual	6.1	4.1
C1	Real Estate Facilities Capital	24.7	-	-	Annual	14.1	10.6
C2	Real Estate Head Office and GTA Facilities Capital	18.3	-	-	Annual	9.9	8.4
C3	Shared Services Capital – Service Equipment	6.3	-	-	Annual	3.8	2.5
C4	Shared Services Capital – Transport & Work Equipment	32.2	-	-	Annual	17.8	14.4
S33	Station Security Infrastructure	16.8	-	-	Annual	8.3	8.5
				In-Service Additions		**63.7**	**81.3**

*Cornerstone figures are net of savings.
Table 3 includes projects that are comparable to Category 2 Projects.
Figures in Table 3 represent only the Transmission allocated amounts.

Table 4
Projects not added to the test year rate base

ISD#	Investment Summary Description	I/S
S39	H2JK / K6J Cable Replacement (Riverside Jct. x Strachan TS)	2013
S12	N.R.C Transmission Station	2013
S28	DC Signaling Replacements (Toronto North & East)	2013

Table 4 includes projects that are comparable to Category 3 Projects.

(b) Please note that with respect to this question, the table that Board Staff prepared is fundamentally incorrect as the amounts included as “Rate Base Amounts” are the gross cash flows, which is why the balances do not reconcile to the in-service additions within Table 1 of Exhibit D1, Tab 1, Schedule 2. Please find the requested table below that identifies all development capital projects, related ISD number, in-service year, Category of investment, Gross Cost, Capital contributions and capital that is booked to rate base in 2011 and 2012. The projects that are included in the Green Energy Plan have been identified in the table.

Table 5
Development Projects – Test Year In-Service Additions (ISA)

ISD#	Investment Summary Description	Gross Cost ($M)	Cap. Contr.	Cat	Green	I/S	2011 ISA ($M)	2012 ISA ($M)
D1	New 500 kV Bruce to Milton Double Circuit Transmission Line4	695.5	-	1		2012	-	695.5
D2	Northeast Transmission Reinforcement: Install SVC's at Porcupine TS & Kirkland Lake TS	121.6	-	1		2011	49.1	-
D3	Nanticoke TS - Install 500 kV, 350 MVar Static Var Compensator	84.6	-	1		2011	84.6	-
D4	Detweiler TS – Install 230 kV, 350 MVar Static Var Compensator	80.3	-	1		2011	80.3	-
D5	Essa TS – Install 250 MVar Shunt Capacitor Bank	6.3	-	2		2011	6.3	-
D6	Porcupine TS - Install two100 MVar Shunt Capacitor Banks	11.7	-	2		2011	11.7	-
D7	Hanmer TS - Install 149 MVar Shunt Capacitor Bank	8.5	-	2		2011	8.5	-
D8	Dryden TS – Install a Shunt Capacitor Bank	10.7	-	3		2013	-	-
D9	Woodstock Area Transmission Reinforcement	70.9	-	1		2011	70.9	-
D10	Rebuild Burlington TS 115kV Switchyard	56.4	-	2		2012	-	56.4
D11	Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	84.9	-	2	Green	2012	-	84.9
D12	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Update	37.4	-	2	Green	2012	-	37.4
D13	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Update	30.4	-	3	Green	2013	-	-
D14	Midtown Transmission Reinforcement Plan	107.3	44.2	4		2013	-	-
D15	Guelph Area Transmission Reinforcement	50.7	-	4		2014	-	-
D16	Commerce Way TS: Build new TS and Line Connection (formerly Woodstock East TS)	45.8	24.2	1		2012	-	21.6
D17	Kirkland Lake TS: Reconnect Idle K4 Line	13.7	13.7	2		2011	-	-
D18	South Halton Tremaine TS: Build New Transformer Station	28.5	19.1	2		2012	-	9.4
D19	Ancaster TS: Build new Transformer Station and Line Connection	24.1	8.2	3		2013	-	-
D20	East Ottawa TS: Build new Transformer Station	33.4	30.2	3		2013	-	-
D21	Leamington TS: New 230/27.6 kV DESN and Line Connection	62.4	-	4		2013	-	-
D22	New 230/28 kV Transformer Station in Northern Mississauga & Line Connection	39.3	30.2	3		2014	-	-
D23	Enfield TS: Build 230/44 kV DESN and Line Connection (formally Oshawa Area TS)	28.7	8.0	3		2014	-	-
D24	Long Lac TS: Replace End-of-Life 115-44 kV Transformers	19.8	-	2		2011	19.8	-
D25	North Bay TS: Upgrade to a 115-44 kV Transformer Station	26.8	-	2		2012	-	26.8
D26	Barwick TS: Build new Transformer Station	15.5	-	2		2012	-	15.5
D27	Duart TS: Build new Transformer Station and Line Connection (formerly Rodney TS)	26.7	-	2		2012	-	26.7
D28	500 MW Renewables III RFP (Talbot Wind Farm)	25.0	25.0	2		2011	-	-
D29	350 MW Peaking Generation in Northern York Region	4.9	4.9	2		2011	-	-
D30	Chatham Wind Generation Connection (260MW)	4.2	4.2	2		2012	-	-
D31	Lower Mattagami Generation Connections	8.3	8.3	4		2012	-	-
D32	Enabling 230/44kV TS #1 and Short (<2km) Tap(Item #2 in Schedule B)	33.8	-	3	Green	2013	-	-
D33	Enabling 115/44kV TS #1 and Short (<2km) Tap(Item #2 in Schedule B)	33.8	-	3	Green	2013	-	-
D34	Algoma x Sudbury Transmission Expansion4(Item #4 in Schedule A)	431.6	-	4	Green	2015	-	-
D35	Northwest Transmission Reinforcement4(Item #14 in Schedule A)	399.5	-	4	Green	2014	-	-
D36	Static Var Compensator #1 at Existing Station in South Western Ontario (Item #1 in Schedule B)	78.7	-	3	Green	2013	-	-
D37	In-Line Circuit Breakers #1 (Item #4 in Schedule B)	20.3	-	2	Green	2012	-	20.3
D38	In-Line Circuit Breakers #2 (Item #4 in Schedule B)	20.3	-	2	Green	2012	-	20.3
D39	In-Line Circuit Breakers #3 (Item #4 in Schedule B)	20.8	-	3	Green	2013	-	-
D40	In-Line Circuit Breakers #4 (Item #4 in Schedule B)	20.8	-	3	Green	2013	-	-
D41	In-Line Circuit Breakers #5 (Item #4 in Schedule B)	21.6	-	3	Green	2014	-	-
D42	In-Line Circuit Breakers #6 (Item #4 in Schedule B)	21.6	-	3	Green	2014	-	-
D43	Station Protection Upgrades for Distributed Generation				Green	Annual	5.3	15.8
D44	Transfer Trip Facilities				Green	Annual	4.7	14.0
D45	End to End Testing for Interoperable Bus Architecture at Owen Sound and Meaford Transformer Stations						-	11.0
D46	Various lines and TSs outliers-						4.0	4.0
D47	Mitigate Reliability Problems of HV Shunt Capacitor Installations						48.1	-
	Other Capital Projects						4.5	23.8
Total				**Total In-Service Additions listed above**			**397.8**	**1,083.4**
In-service additions as per Table 1(D1/T1/S2)							**397.8**	**1,083.4**

Also, please find a separate table that identifies all projects that are included in the capital expenditure budget, but will not be added to the test year rate base.

Table 6
Development Projects not added to the test year rate base

ISD#	Investment Summary Description
D8	Dryden TS – Install a Shunt Capacitor Bank
D13	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Update
D14	Midtown Transmission Reinforcement Plan
D15	Guelph Area Transmission Reinforcement
D19	Ancaster TS: Build new Transformer Station and Line Connection
D20	East Ottawa TS: Build new Transformer Station
D21	Leamington TS: New 230/27.6 kV DESN and Line Connection
D22	New 230/28 kV Transformer Station in Northern Mississauga & Line Connection
D23	Enfield TS: Build 230/44 kV DESN and Line Connection (formally Oshawa Area TS)
D32	Enabling 230/44kV TS #1 and Short (<2km) Tap(Item #2 in Schedule B)
D33	Enabling 115/44kV TS #1 and Short (<2km) Tap(Item #2 in Schedule B)
D34	Algoma x Sudbury Transmission Expansion4(Item #4 in Schedule A)
D35	Northwest Transmission Reinforcement4(Item #14 in Schedule A)
D36	Static Var Compensator #1 at Existing Station in South Western Ontario (Item #1 in Schedule B)
D39	In-Line Circuit Breakers #3 (Item #4 in Schedule B)
D40	In-Line Circuit Breakers #4 (Item #4 in Schedule B)
D41	In-Line Circuit Breakers #5 (Item #4 in Schedule B)
D42	In-Line Circuit Breakers #6 (Item #4 in Schedule B)

Ontario Energy Board (Board Staff) INTERROGATORY #65 List 1

Interrogatory

Issue 4.1 Are amounts proposed in rate base in 2011 and 2012 appropriate?

Ref: Exhibit D1/T3/S3/Appendix A

At the above reference Hydro One provides a summary of Development Capital projects. In Tables 2 through 8, Hydro One has an entry that states "Other Historic Projects (Pre-2011)".

(a) In Note 6 in Table 1 Hydro One has provided a brief explanation for this entry. Please provide a more detailed explanation for this entry.

(b) In Note 6 in Table 2, Hydro One states that "Other Historical Projects" comprise accumulated cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012". However, Table 2 indicates $2.6 million is budgeted in 2011. Please explain.

(c) In Table 5, Hydro One has budgeted $40.4 million from capital contributions related to "Other Historical Projects (pre 2011). Please explain the reasons for this expense.

Response

(a) The "Other Historical Projects" category is an amalgamation of projects with in-service dates prior to the test years but that have accumulated gross cash flows in the Historical and Bridge years.

Examples of "Other Historical Projects" include:

- EB-2008-0272, Exhibit D1, Tab 3, Schedule 3, Table 2, Item #D1 "Hydro One – Hydro Quebec: 1250MW Interconnection". This project was slated for in-service in 2009 with gross cash flows spanning 2006 to 2009 with a total gross cost of $122.8M.
- EB-2008-0272, Exhibit D1, Tab 3, Schedule 3, Table 3, Item #D15 "Southern Georgian Bay Transmission Reinforcement". This project was slated for in-service in 2009 with gross cash flows spanning 2005 to 2009 with a total gross cost of $88.0M.

(b) The $2.6 million indicated in Table 2 under "Other Historical Projects" was recorded in 2011 by error; this capital expenditure is being spent in 2010. The rate base is not affected as the in-service addition and rate requirement included the $2.6 million in 2010.

(c) The “Other Historical Projects” in Table 5 has a capital contribution of $40.4 million; the main contributor to this was the “Sarnia Generation Connection Plan” which incorporated connection of two generators (Greenfield Energy Center and St. Clair Energy Center) as well as addressed upgrades and station modifications at Lambton TS and Sarnia Scott TS which were network pool funded.

Ontario Energy Board (Board Staff) INTERROGATORY #66 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Sustaining Capital

Ref: (a) Exhibit D1/Tab2/Sch1/p5-6; Ref: (b) Exhibit C1/Tab2/Sch2/Appendix A/Section 4.0-Station Asset Performance/Figures 30 – 44

In the noted references, Hydro One indicated that the overall results of the analysis of Hydro One's breaker and power transformer equipment performance is in most cases worse than the national composite averages (from CEA). The key findings included:

- Transformer performance for frequency has been about 1.6 times worse than the CEA national average that includes other Canadian transmission utilities in the CEA survey;
- Transformer performance for unavailability has been about equal to CEA average for 230 kV transformers, but over 7 times worse than the average for 500 kV transformers;
- Breaker performance for frequency has been 1.4 times worse than the CEA national average that includes other Canadian transmission utilities in the CEA survey.
- The frequency of sustained outages for lines is slightly above the CEA average for 115 kV circuits and about 1.5 times for the CEA average for 230 kV lines.

(a) In what year did Hydro One begin comparing the performance of its system elements (transformers, lines and breakers) with the CEA national average performance of corresponding system elements?

(b) In what year did Hydro One begin formulating a comprehensive new sustainment capital strategy to address the poor performance of the system elements?

(c) What are the main features of the old sustainment strategy that lead to the poor results noted above?

(d) Describe how the new sustainment strategy improves on the old sustainment strategy in addressing the root causes for the poor performance of the various system elements.

(e) Based on the new sustainment strategy, when does Hydro One expect, for each of the reported system elements, to be at or better than the CEA national average performance of corresponding system elements?

Response

(a) Comparisons to CEA reliability information have been made since about 2000 after Hydro One centralized the asset management function. The current methodology that uses a 5 year rolling average and compares Hydro One to the CEA national averages started being used in a structured manner in 2008. Prior to that, the CEA information was made available to planning staff and used as a guide.

(b) Hydro One's initial capital sustainment strategy to address asset performance was developed in about 2000. Further to that, the strategy to address delivery point performance outliers was finalized in 2005.

(c) It is believed that many of the reliability issues that Hydro One is facing today are the result of the former decentralized asset management approach. The following provides specifics:

- Underinvestment in the renewal of assets during the 1990's.
- Transitioning from a regional asset management organization to a centralized organization. This took several years starting in 1999. The process to centralize asset data, develop asset condition assessment and planning standards and implement an investment prioritization process took several years to complete. Until that time, information and analytics were not available to optimize investment decisions.
- To acquire asset condition information on all station assets takes about 8 years, the average cycle for inspections. In many cases trending information is required that can take several years to acquire before effective plans can be developed. As such, there is a significant delay before a centralized organization can make decisions that will address the most problematic assets.

(d) The centralized sustainment strategy includes a reliability centered maintenance approach, asset condition assessment standards, reliability measures, comparisons to peers and a uniform assessment of problems These asset management practices plus the new SAP work management system provides the analytics to make effective decisions to address poor performing assets. The earlier decentralized approach lacked consistency in a number of areas, e.g., data collection, asset condition assessment and did not have the analytics of today. For further information on reliability management refer to Exhibit I, Tab 1, Schedule 11.

(e) As the comparisons to CEA member utilities have only recently (2008) been adopted as a formal practice, Hydro One has not yet made a decision if one of its targets will be to achieve equipment performance equivalent to the national average. The strategy at this time is to compare Hydro One's equipment and lines performance to CEA member utilities and strive to improve over time applying a prudent and measured approach. Hydro One uses the CEA member utility average performance as a guide to provide focus to areas that need attention as part of good utility practice.

Ontario Energy Board (Board Staff) INTERROGATORY #67 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: (a) Exhibit D1/Tab3/Sch2/p14; Ref: (b) Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Station Reinvestment/5 Projects (S6 to S10 inclusive)

In Reference (a), a summary of the 5 projects categorized as "Stations Re-investment" is presented, and in Reference (b), more details are given for each of these projects.

Please complete the following Table:

System Element or Installation	Average Installed Cost/Element $
230 SF6 Breakers	
500 SF6 Breakers	
High Voltage Switches	
High Voltage Instrument Transformers	
High Voltage Line Ground switches	
Main Station Service Transformers	
Perimeter Fence - Cost/km	
Control, Metering, Relaying & Annunciation Systems (Richview & Hanmer) - Cost/System	

Response

The following table provides a range of costs for individual units within the five projects as outlined in S6 - S10

System Element or Installation	Average Installed Cost/Element($M)
230 SF6 Breakers (to replace existing air-blast breakers)	0.8 – 1.8
500 SF6 Breakers (to replace existing air-blast breakers)	2.5 – 3.0
High Voltage Switches	0.1 - 0.25
High Voltage Instrument Transformers	0.1 – 0.25
High Voltage Line Ground switches	0.1 – 0.2
Main Station Service Transformers	0.5 – 1.0
Perimeter Fence - Cost/km	0.65 – 0.75
Control, Metering, Relaying & Annunciation Systems (Richview & Hanmer) - Cost/System	4.0 – 8.0

Projects of this complexity undergo detailed site-specific scoping and estimating because there is a large amount of variability from one project to the next.

Some of the issues which affect the scope and cost of the project are outlined below:

- Amount of reconfiguration work that may be required or included in the project
  - S7 - Orangeville TS, includes the addition of a third breaker diameter and re-termination of the existing circuits (refer to Exhibit I, Tab 9, Schedule 21 part c for additional details)
  - S10 – Pickering A SS, includes the removal / bypass of two existing breakers which have supported mothballed Pickering generators
- Variation in specifications of major equipment
- Possible need to upgrade grounding, buswork, etc. due to equipment condition or changes in required functionality/ratings
- Physical size of the station as it affects cabling, bus configuration, and amount of available space for project execution while managing the on-going operation of the station.
- Need for major civil works, including drainage systems and spill containment.
- Reusability of existing bus-work (foundations, bus, insulators, etc.)
- Reusability of existing AC & DC station service
- Reusability of existing Protection, Telecom, and Control assets, which may result in significant costs associated with design and construction in accordance with regulated standards (i.e. physical separation of A&B protection systems)
- Interface issues with customers, including:
  - Demerger of drawings and physical assets
  - Protection and insulation coordination
  - Outage constraints at major generating stations
- Short circuit requirements.

Ontario Energy Board (Board Staff) INTERROGATORY #68 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Station Reinvestment/5 Projects/S7

The noted reference indicates that the in-service date for project S7 "Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment" is 2013.

(a) Is the in-service date actually expected in 2013?

(b) If yes, did Hydro One include the investment in rate base for 2012? If so, please provide the rationale for doing so.

Response

(a) Yes, the project is planned to be entirely complete and in-service by the end of 2013.

(b) Generally the projects that include replacement of multiple pieces of equipment are completed in a staged manner to maintain electrical supply. For this particular project, 2/3 of the equipment is scheduled to be in-service by the end of 2012 and will be placed into rate base.

Please refer to Exhibit I, Tab 1, Schedule 064 for additional detail on in-service additions.

Ontario Energy Board (Board Staff) INTERROGATORY #69 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital-Station - Power Transformers/S16

Please provide the estimated installed costs per transformer of the following:

- 230 kV 125 MVA;
- 115 kV 115 MVA;
- 230 kV 75 MVA;
- 115 kV 78 MVA;
- 115 kv 42 MVA; and
- Station Service Transformer.

Response

The following table summarizes Hydro One's planned expenditures in the test years to purchase spare transformers to support the in-service population listed in S16.

	Installed Cost ($M)
230 kV 125 MVA	2.6
115 kV 115 MVA*	2.3
230 kV 75 MVA	2.3
115 kV 78 MVA	2.3
115 kV 42 MVA	1.3
Station Service Transformer	0.3

**Note in Ex. D2/Tab 2/Sch.2/Ref# S16, this item should have read 230-115kV 115 MVA*

These installed costs include the cost of the transformer DDP (delivery and duty paid) to Pickering, Ontario, costs to receive and prepare for long-term storage ready for deployment (oil filling and storage of accessories). The transformers identified in S16 and the costs above do not include deployment and installation in a transmission station.

Ontario Energy Board (Board Staff) INTERROGATORY #70 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital-Station - Other Power Equipment/S18

Please provide the average estimated installed costs per capacitor bank of the following:

- High –voltage capacitor; and
- Low-voltage capacitor.

Response

The estimated installed costs for capacitor bank replacements are as follows:

High Voltage Capacitor Bank Replacement	$1.4M – 2.7M
Low Voltage Capacitor Bank Replacement	$0.5M – 1.1M

In addition to the variation of capacitor bank sizes (voltage and capacitance), there are significant variations between replacements due to site-specific and asset-specific issues, such as:

- Condition and usability of the existing cap bank foundations and supporting structures
- Condition and usability of the existing cabling and bus connections
- Condition of existing fencing and grounding.
- Replacement of disconnect switch, if required
- Replacement of grounding switch(es), if required
- Replacement of surge arresters, if required
- Replacement of instrument transformers, if required
- Replacement of reactors, if required

Ontario Energy Board (Board Staff) INTERROGATORY #71 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital-Station - Ancillary Systems/S19

Please provide the estimated installed costs for the station service transfer schemes for the following:

- Cherrywood TS, 500 kV yard AC;
- Cherrywood TS, 230 kV yard AC;
- Hanover TS (AC);
- Richview TS (AC);
- St. Lawrence TS (AC);
- St. Lawrence TS (DC);
- Each of 10, 208 kV transfer scheme at a DESN type station.

Response

Estimated installed costs for BES and DESN transfer schemes replacements are identified below.

Project	Estimated Installed Cost, Gross
Cherrywood TS, 500kV AC transfer scheme	$3.7 M
Cherrywood TS, 230kV AC transfer scheme	$3.7 M
Hanover TS, AC transfer scheme	$1.8 M
Richview TS, AC transfer scheme	$3.7 M
St. Lawrence TS, AC transfer scheme	$3.7 M
St. Lawrence TS, DC transfer scheme	$0.8 M
Each of 10, 208kV ATS at DESNs	$ 0.7 – 1.0 M

The most significant variation between the station service projects is the configuration or complexity of the transfer scheme.

In addition to the variations due to configuration, there are variations between installations due to site-specific issues, such as:

- Condition and usability of the existing cabling, both power and control
- Condition and usability of the existing distribution panels
- Usability of the existing concrete pad, foundations, and/or enclosures
- Usability of the existing metering and protective relaying
- Possible bus reconfigurations
- Possible replacement of HV and LV station service fusing
- Possible replacement of the station service transformers
- Possible P&C Modifications to meet IESO & NPCC requirements

Ontario Energy Board (Board Staff) INTERROGATORY #72 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital-Station - P&C – Bruce Special Protection Scheme (BSPS)/S21

(a) Please provide more details as to the additional functionality of the proposed new BSPS regarding breaker outages, and details in regard to accommodating both the existing renewable generation and expected future generation.

(b) Did Hydro One compare the cost of the proposed new BSPS system with similar and recently installed systems in North America? If it did, please provide the comparison with appropriate description and explanation. If not, why was no cost comparison undertaken?

Response

(a) The Bruce area has enough nuclear generation capacity to produce more than a quarter of Ontario's record peak power demand and this power has to be transmitted to the load centers that are hundreds of kilometers away. With full production from the Bruce Nuclear Complex and from wind generation in the Bruce Area, and inadequate transmission facilities in service, grid contingencies in the Bruce area and throughout south-western Ontario can cause power system instability, thermal overloads and excessive voltage declines affecting not only the Hydro One bulk electric system, but also the interconnected systems of the neighbouring utilities. It is the BSPS that provides the controls over the grid to prevent the detrimental occurrences noted above. Even after the completion of the new Bruce to Milton circuits, there will be inadequate transmission facilities whenever there is an outage. Forced outages are a regular occurrence throughout the southern Ontario system and many planned outages are required each year to complete maintenance and development programs. The Bruce Special Protection System (BSPS) was integrated to the grid in 1991 to minimize restrictions on production in the Bruce Area during times of inadequate transmission by performing pre-defined control actions promptly following contingencies. With the use of these automated control actions, such as generation and load rejection, generation restrictions and other system restrictions can be reduced or eliminated, while still observing the design and operating criteria of the NERC and NPCC reliability standards.

There are hundreds of contingencies that must always be respected in the Bruce and South Western Ontario portion of the grid. The specific control actions to be executed by the BSPS following each contingency is “programmed” into the BSPS continuously by the operators at the IESO using a feature of the BSPS called the “Arming Matrix.”. There are hundreds of breakers in the South Western Ontario portion of the grid and when any of these are out of service, the effect of one or more of the respected contingencies changes and the arming must be changed accordingly to match. The current BSPS does not have the capability to allow these changes for the grid configuration that will exist following the addition of the new Bruce to Milton circuit. The consequence is that the generation in the Bruce Area, both nuclear and renewable would have to be curtailed during these outages. There are typically over 120 planned breaker outages per year in this area and this number will grow as aging breakers require more frequent maintenance.

(b) The BSPS is one of the largest and most complex Special Protection Systems (SPSs) in North America. As part of the conceptual design process for the replacement BSPS, Hydro One conducted an industry survey of similar protection systems that have been deployed across the world. Hydro One then contacted Pacific Gas and Electric, Southern California Edison and the Salk River Project to discuss their recent Special Protection System (SPS) deployments. While the functional requirements that each of these SPSs satisfy are very unique, they employ a similar centralized architecture and use the same international standards for data communication and logic processing. Hydro One has decided to use a similar approach, but instead of using customized equipment, Hydro One will be tendering for off-the-shelf equipment that can be easily configured, tested, maintained and upgraded. Since each SPS is very unique, meaningful cost comparisons are not feasible.

In addition to contacting other utilities, Hydro One has solicited input from various vendors and reviewed recent CIGRE and IEEE documentation on SPS deployments. Hydro One is also actively participating in the IEEE Power Systems Relaying Committee working group that is responsible for developing reports and standards on SPSs. Hence Hydro One has thoroughly benchmarked the design of the replacement BSPS against the industry standards.

Ontario Energy Board (Board Staff) INTERROGATORY #73 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital-Station - Station P&C Replacement/S24

Please provide the number of load supply stations whose protection systems as well as Remote Terminal Units ("RTU") are reaching end of life and where Hydro One proposes to use a "standardized packaged design" solution.

Response

Hydro One plans to replace protections and RTUs in a "standardized package design" at 34 load stations over the next 5 years.

Ontario Energy Board (Board Staff) INTERROGATORY #74 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: (a) Exhibit D2/Tab1/Sch1/Investment Summary Documents/ Sustaining Capital-Station - Station P&C, Telecom and Metering/S25
Ref: (b) Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital-Station - Station P&C, Telecom and Metering/S26

(a) For the protection replacements described in Reference (a), please provide a longer term plan, covering at least 5 years past the 2 test years i.e., 2013-2017 inclusive, setting out the number of protection system replacements, and the estimated cost of these replacements.

(b) For the RTU replacements described in Reference (b), please provide a longer term plan (5 years) to replace RTUs reaching "Poor or Very Poor Health Index". Please include the number and estimated cost of these replacements.

Response

(a) Protection replacements are expected to increase from the yearly average of 67 systems during the test years at a cost of $10.2 million to 265 systems by 2014 until 2017. Future costs would increase in proportion to the number of systems replaced.

(b) RTU replacements are expected to increase from the yearly average of 14 RTUs during the test years at a total cost of $5.4 million at an increasing trend, reaching 30 RTUs by 2017. Future costs would increase in proportion to the number of RTUs replaced.

Ontario Energy Board (Board Staff) INTERROGATORY #75 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital-Lines - Transmission Lines Emergency Restoration/S37

Please provide a breakdown of the expected investment into the two categories: wood pole lines and steel structure lines.

Response

Emergency restoration investment for future years is based on historical spending patterns. The last three years was used to forecast spending patterns for 2011/2012.

Table1 shows expected investment for 2011/2012.

Table 1
Expected Investment Tx Emergency Restoration

Investment in $M

	Total	Wood	Steel
2011	6.6	4.9	1.7
2012	6.6	5.0	1.7

Ontario Energy Board (Board Staff) INTERROGATORY #76 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Ref: Exhibit D2/Tab2/Sch3/Investment Summary Documents/ Sustaining Capital - Lines - UG Cables Component Refurbishing/ H2JK / K6J Cable Replacement (Riverside Jct x Strachan TS)/S39

(a) Please provide a single line diagram showing the location of the 5. 6 km cables designated for replacement.

(b) Please indicate the type of cables which will be used for replacement.

(c) Given that the expected completion date is 2013, did Hydro One include the investment in rate base for 2012? If so, please provide the rationale for doing so.

Response

(a) The route is outlined in red below:

(b) The cables will be Cross-Linked Polyethylene (XLPE) type with a 4000 kcmil copper conductor and concrete ductbank enclosure.

(c) No, this project has not been included in the rate base. For additional details concerning in-service additions refer to Exhibit I, Tab 1, Schedule 64.

Ontario Energy Board (Board Staff) INTERROGATORY #77 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Development Capital

77) Ref: (a) Exhibit D1/Tab3/Sch3/p14-15/Project D1 – Bruce to Milton Double Circuit Transmission Line & Appendix A/p2/Table 2 – Project D1
Ref: (b) Proceeding EB-2008-0272, Exhibit D1/Tab3/Sch3/p33/Table 2/Project D2- New 500 kV Bruce to Milton Double Circuit Transmission Line

(a) Please provide a copy of the letter dated January 5, 2010 relating to this project from Hydro One to the Board.

(b) Please provide a detailed breakdown of the reasons for the cost increase of $75.7 million (from $619.8 million at Reference (b) to the amount of $695.5 million shown at Reference (a) - see Appendix A/ p2/Table 2). Please include:

- The higher than expected bids received for construction separate from the amounts attributed to material, broken down by major components such as steel towers, transformers, breakers, P&C, communication…etc.;
- The effects of the sixteen month approval delay; and
- Any other factors.

Response

a) Please see Attachment 1.

b) Please note that the cost of $619.8 million dollars in reference b) was updated when the Section 92 Application was filed with the Board. The cost estimate in the Section 92 was $635M. The main reasons for the increase in project cost include:

- A sixteen month delay in the forecast start date for construction due to delayed approvals. This resulted in increased carrying costs including additional cost for storage of equipment and construction material.
- An increase of material costs (steel, towers, electrical equipment) at an unprecedented rate exceeding 20% for most materials. The original estimates had assumed a 3% annual escalation.
- Higher than expected bids received for the construction and materials contracts.

Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5700
Fax: (416) 345-5870
Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

January 5, 2010

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

Dear Ms. Walli:

EB-2007-0050 – Hydro One Networks' Section 92 Bruce - Milton Transmission Reinforcement Application – EA and NEC Approvals

Further to my letter of August 31, 2009, I am writing to advise the Board of developments related to the Bruce to Milton Transmission Reinforcement Project ("the project").

In December, Hydro One received approval under the *Environmental Assessment Act* for the project. Earlier in the fall Hydro One also received approval from the Niagara Escarpment Commission (NEC) for that part of the project that is subject to NEC development control. Although the NEC approval is presently under appeal, Hydro One expects the appeal process to be completed within the next few months.

Hydro One has undertaken a comprehensive and effective initiative to voluntarily acquire the necessary land rights to enable the project. With respect to land that Hydro One has been unable to obtain to date, we intend to continue negotiations under this program until late February in order to encourage additional voluntary agreements. After this date Hydro One will file an expropriation authorization application under section 99 of the *OEB Act*, *1998* so that rights to the remaining lands may be obtained. The scope of this application will be dependent upon the status of the NEC appeal process. An additional section 99 application pertaining specifically to required lands within the NEC development control area may be necessary.

As Project construction is planned to commence shortly, Hydro One anticipates filing its construction plan pursuant to Condition 2.5 of the Board's Leave to Construct Approval by mid-January 2010. The revised project cost estimate is now $695 million and the target in-service date is December, 2012.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Ontario Energy Board (Board Staff) INTERROGATORY #78 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Development Capital

Ref: (a) Exhibit D1/Tab3/Sch3/p17/Project D8– Installation of Shunt Capacitor Banks at Dryden TS;
Ref: (b) Exhibit D2/Tab2/Sch3/Investment Summary Document/Project D8 - Installation of Shunt Capacitor Banks at Dryden TS

Project D8 at Reference (b) is justified based on various anticipated developments such as the retirement of Atikokan GS, and ability to connect up to 50 MW of new generation. Hydro One indicated that it would commit to project D8, if the Ontario Power Authority ("OPA") recommends that project.

Has Hydro One received a confirmation from the OPA as to the necessity for the project? If not, when is Hydro One expecting the support documents from the OPA for project D8?

Response

Because of the uncertainties associated with developments in the area west of Thunder Bay in Northwestern Ontario, such as FIT uptake, the future of Atikokan and demand changes, the need for this investment has not been determined. OPA is studying the integrated need now and would be further informed by the outcome of the FIT ECT process expected in Q2 of 2011.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #79 List 1</u>

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

<u>Development Capital</u>

<u>Ref: (a) Exhibit D1/Tab3/Sch3/p19/ Project D10 & Appendix A, p3, Table 3, Project D10 – Rebuild Burlington TS 115 kV Switchyard</u>
<u>Ref: (b) Proceeding EB-2008-0272, Exhibit D1/Tab3/Sch3/p33/Table 3/Project D19 [Replacement of Switchgear & Main Bus in 115 kV Switchyard at Burlington TS] and Project D20 [Replacement of Twelve 115 kV Circuit Breakers at Burlington TS]</u>

In Reference (a), on page 19, Hydro One states, “The primary reason for increase in cost estimate over the cost submitted in the EB-2008-0272 proceeding is attributable to scope changes to the project.”

The cost of project D10 at Reference (a) is $ $ 56.4 million and the total cost of the two projects D19 and D20 at Reference (b) are $ 25.9 million ($11.8 million for D19 and $ 14.1 million for D20). The cost variance is $30.5 million.

Please provide a detailed breakdown of the cost variance of $30.5 million which is attributable to scope changes. Please provide the breakdown of the variance by the major components such as breakers, switches, P&C, communications…etc

Response

Please see the table below for the detailed breakdown of the cost variance.

	<u>Variance</u>
Material	**+$16.5M**
• *Breakers*	*+$2.3M*
• *Structures*	*+$3.5M*
• *Foundations*	*+$1.2M*
• *Electrical Lines*	*+$3.0M*
• *P&C, Telecom*	*+$1.3M*
• *Electrical Hardware*	*+$2.2M*
• *Civil /Site*	*+$3.0M*

Labour	**+$13.9M**
• *Project Mgmt*	*$0.0M*
• *Engineering*	*+$0.9M*
• *Construction*	*+$11.2M*
• *Commissioning*	*+$1.8M*
Overhead	**+$1.7M**
Interest	**+$0.6M**
Risk	**-$2.2M**
Total	**+$30.5M**

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<u>Ontario Energy Board (Board Staff) INTERROGATORY #80 List 1</u>

<u>Interrogatory</u>

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

<u>Development Capital</u>

<u>Ref: Exhibit D2/Tab2/Sch3/Investment Summary Document/ Project D15 – Guelph Area Transmission Reinforcement</u>

Please indicate when the OPA is expected to provide its assessment of the need for this project.

<u>Response</u>

As noted in the referenced exhibit, this investment requires further approvals by the OEB in the way of Leave to Construct approval under Section 92. This Leave to Construct application will either reference or include documents prepared by the Ontario Power Authority that provide its assessment for the need of the project. Hydro One currently expects to file the Leave to Construct application in either Q4-2010 or Q1-2011.

Ontario Energy Board INTERROGATORY #81

Interrogatory

Issue 4.2: Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Question:

Ref: (a) Exhibit D1/Tab3/Sch3/p22-23/Project D 16 & Appendix A/p4/Table4, Project D16 – Commerce Way TS: Build New TS and Line Connection (Formerly Woodstock East TS)
Ref: (b) Proceeding EB-2008-0272, Exhibit D1/Tab3/Sch3/p33/Table4/Project D37- Woodstock East TS: Build New TS & Line Connection

(a) Please provide the reasons for the cost increase of $ 15.2 million (from a gross total cost of $30.6 million at Reference (b) to the gross total cost of $45.8 million shown at Reference (a)). Please provide a breakdown of the variance in cost by major system element such as transformers, breakers, switches, towers, etc, and also by material, labour, over heads, etc.

(b) Please provide the spread sheet and the results of the economic evaluation (if preliminary, please indicate so) for this project showing the amounts of capital contribution by the two distributors.

Response

(a) Please see the list below for the cost breakdown of the variance.

	Variance
Material	**+ $8.0M**
• *Transformer*	*+$1.5M*
• *Spill Containment*	*+$0.9M*
• *Electrical Lines*	*+$2.0M*
• *Telecom*	*+$3.0M*
• *Other*	*+$0.6M*
Land	**+ $0.8M**
Labour	**+ $1.9M**
• *Project Mgmt*	*+$0.1M*
• *Engineering*	*+$0.8M*
• *Construction*	*+$0.6M*
• *Commissioning*	*$0.4M*
Overhead	**+ $1.0M**

		Variance
Interest		**+ $1.0M**
Risk/Contingency		**+$2.5M**
	Subtotal	**+ $15.2M**

(b) The requested spread sheets were filed with EB-2009-0079 Exhibit B/ Tab 4/ Schedule 3 Pages 7-14. For convenience, they are attached as Attachment 1.

Note: The capital contribution amounts in the attached economic evaluations differ from that documented in EB-2010-0002. At the time of filing, there was a misinterpretation of the Table provided in EB-2009-0079 Exhibit B/Tab4/Schedule3/Page 3 with respect to the "Customers Cost Responsibility" and the "Capital Contribution" amount.

HYDRO ONE EB-2009-0079 EXHIBIT B, TAB 4, SCHEDULE 3
PAGES 7-14

Table 1a – DCF Analysis, Hydro One, Line Connection Pool, page 1

Date:	24-Mar-09
Project #	12971

SUMMARY OF CONTRIBUTION CALCULATIONS
Planner's estimate

hydro one

Facility Name: Commerce Way TS

Scope: Hydro One Networks - Line Pool

		Month Year	In-Service Date Dec-31 2011	Dec-31 2012 (1)	Dec-31 2013 (2)	Dec-31 2014 (3)	Dec-31 2015 (4)	Dec-31 2016 (5)	Dec-31 2017 (6)	Dec-31 2018 (7)	Dec-31 2019 (8)	Dec-31 2020 (9)	Dec-31 2021 (10)	Dec-31 2022 (11)	Dec-31 2023 (12)
				<— Project year ended - annualized from In-Service Date —>											
Revenue & Expense Forecast															
Load Forecast (MW)				8.5	9.9	11.3	12.5	13.6	14.7	15.8	16.9	18.0	19.4	20.4	21.4
Tariff Applied ($/kW/Month)				0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Gross Revenue - $M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
OM&A Costs (Removals & On-going Incremental) - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Income Taxes (incl. LCT)			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)
Operating Cash Flow (after taxes) - $M			0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		Cumulative PV @ 5.60%													
PV Operating Cash Flow (after taxes) - $M	**(A)**	1.5	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(0.3)												
- Overheads			(0.0)												
- AFUDC			(0.0)												
Total upfront capital expenditures			**(0.4)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(0.4)**												
PV Proceeds on disposal of assets - $M			**0.0**												
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	**(B)**	(0.3)	**(0.3)**												
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	1.1	**(0.3)**	**(0.3)**	**(0.2)**	**(0.2)**	**(0.1)**	**(0.1)**	**(0.0)**	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.4**

Discounted Cash Flow Summary
(Based on Economic Study Horizon - Years): **25**

Discount Tariff - % **5.60%**

		Before Contribution $M		After Contribution $M	Impact of Contribution $M
PV Incremental Revenue		2.2		2.2	
PV Incremental OM&A Costs		(0.1)		(0.1)	
PV Ontario Capital Tax and Municipal Tax		(0.0)		(0.0)	
PV Income Taxes and LCT		(0.7)		(0.7)	
PV CCA Tax Shield		0.1		0.1	
PV Capital - Upfront	(0.4)		(0.4)		
Add: PV **Capital Contribution**	**0.0**	(0.4)	**0.0**	(0.4)	
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		1.1		1.1	N/A
Profitability Index*		**4.2**		**4.2**	

*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Start Date:	1-Jan-10
In-Service Date:	31-Dec-11
Payback Year:	2018
No. of years required for payback:	7

Contribution Required (before GST) - $M	**0.0**
GST @5% - $M	**0.0**
Contribution Required (incl. GST)* - $M	**0.0**

* Payment from customer must include GST.

Table 1a – DCF Analysis, Hydro One, Line Connection Pool, page 2

Date:	24-Mar-09
Project #	12971

SUMMARY OF CONTRIBUTION CALCULATIONS
Planner's estimate

Facility Name: Commerce Way TS

Scope: Hydro One Networks - Line Pool

		Month	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31	Dec-31
		Year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
			13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast															
Load Forecast (MW)			22.5	23.6	24.6	25.7	26.8	27.9	29.0	30.2	32.6	33.1	33.6	34.1	34.6
Tariff Applied ($/kW/Month)			0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Gross Revenue - $M			0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
OM&A Costs (Removals & On-going Incremental) - $M			(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M			(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Income Taxes (incl. LCT)			(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M			0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PV Operating Cash Flow (after taxes) - $M	**(A)**		**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC															
- Overheads															
- AFUDC															
Total upfront capital expenditures															
On-going capital expenditures			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures															
Total capital expenditures - $M															
PV Proceeds on disposal of assets - $M															
PV CCA Residual Tax Shield - $M															
PV Working Capital - $M															
PV Capital (after taxes) - $M	**(B)**														
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**		**0.4**	**0.5**	**0.6**	**0.6**	**0.7**	**0.7**	**0.8**	**0.9**	**0.9**	**1.0**	**1.0**	**1.1**	**1.1**

Table 1b – DCF Analysis, Woodstock Hydro, Line Connection Pool, page 1

Date: 24-Mar-09
Project # 12971

SUMMARY OF CONTRIBUTION CALCULATIONS
Planner's estimate

Facility Name: Commerce Way TS

Scope: Woodstock Hydro - Line Pool

		Month / Year	In-Service Date Dec-31 **2011**	Dec-31 **2012**	Dec-31 **2013**	Dec-31 **2014**	Dec-31 **2015**	Dec-31 **2016**	Dec-31 **2017**	Dec-31 **2018**	Dec-31 **2019**	Dec-31 **2020**	Dec-31 **2021**	Dec-31 **2022**	Dec-31 **2023**
			← Project year ended - annualized from In-Service Date →	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)				25.8	28.2	30.6	32.7	34.1	35.5	36.9	38.2	39.6	41.0	42.2	43.5
Tariff Applied ($/kW/Month)				0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Gross Revenue - $M				0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
OM&A Costs (Removals & On-going Incremental) - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			0.0	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Income Taxes (incl. LCT)			0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M			0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		Cumulative PV @ 5.60%													
PV Operating Cash Flow (after taxes) - $M	(A)	3.2	**0.0**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(0.3)												
- Overheads			(0.0)												
- AFUDC			(0.0)												
Total upfront capital expenditures			**(0.4)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(0.4)**												
PV Proceeds on disposal of assets - $M			**0.0**												
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	(B)	(0.3)	**(0.3)**												
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	2.8	**(0.3)**	**(0.2)**	**(0.1)**	**0.1**	**0.2**	**0.4**	**0.5**	**0.7**	**0.8**	**1.0**	**1.1**	**1.2**	**1.4**

Discounted Cash Flow Summary
(Based on Economic Study Horizon - Years): 25

Discount Tariff - % **5.60%**

		Before Contribution $M		**After Contribution** $M	**Impact of Contribution** $M
PV Incremental Revenue		4.8		4.8	
PV Incremental OM&A Costs		(0.1)		(0.1)	
PV Ontario Capital Tax and Municipal Tax		(0.0)		(0.0)	
PV Income Taxes and LCT		(1.5)		(1.5)	
PV CCA Tax Shield		0.1		0.1	
PV Capital - Upfront	(0.4)		(0.4)		
Add: PV **Capital Contribution**	**0.0**	(0.4)	**0.0**	(0.4)	
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**2.8**		**2.8**	**N/A**
Profitability Index*		**9.0**		**9.0**	

*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Start Date:	1-Jan-10
In-Service Date:	31-Dec-11
Payback Year:	2014
No. of years required for payback:	3

Contribution Required (before GST) - $M	**0.0**
GST @5% - $M	**0.0**
Contribution Required (incl. GST)* - $M	**0.0**

* Payment from customer must include GST.

Table 1b – DCF Analysis, Woodstock Hydro, Line Connection Pool, page 2

Date:	24-Mar-09
Project #	12971

SUMMARY OF CONTRIBUTION CALCULATIONS
Planner's estimate

hydro one

Facility Name: Commerce Way TS

Scope: Woodstock Hydro - Line Pool

Month / Year	Dec-31 2024	Dec-31 2025	Dec-31 2026	Dec-31 2027	Dec-31 2028	Dec-31 2029	Dec-31 2030	Dec-31 2031	Dec-31 2032	Dec-31 2033	Dec-31 2034	Dec-31 2035	Dec-31 2036
	13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast													
Load Forecast (MW)	44.7	45.9	47.1	48.3	49.6	50.8	52.0	53.2	64.4	64.6	64.8	65.0	65.2
Tariff Applied ($/kW/Month)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Gross Revenue - $M	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
OM&A Costs (Removals & On-going Incremental) - $M	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Income Taxes (incl. LCT)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Operating Cash Flow (after taxes) - $M	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
PV Operating Cash Flow (after taxes) - $M (A)	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M													
Upfront - capital cost before overheads & AFUDC													
- Overheads													
- AFUDC													
Total upfront capital expenditures													
On-going capital expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures													
Total capital expenditures - $M													
PV Proceeds on disposal of assets - $M													
PV CCA Residual Tax Shield - $M													
PV Working Capital - $M													
PV Capital (after taxes) - $M (B)													
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**1.5**	**1.6**	**1.7**	**1.9**	**2.0**	**2.1**	**2.2**	**2.3**	**2.4**	**2.5**	**2.6**	**2.7**	**2.8**

Table 2a – DCF Analysis, Hydro One, Transformation Connection Pool, page

Date:	24-Mar-09
Project #	12971

SUMMARY OF CONTRIBUTION CALCULATIONS
Planner's estimate

hydro one

Facility Name: Commerce Way TS

Scope: Hydro One Networks - Transformation Pool

	Month Year	In-Service Date Dec-31 2011	Dec-31 2012 (1)	Dec-31 2013 (2)	Dec-31 2014 (3)	Dec-31 2015 (4)	Dec-31 2016 (5)	Dec-31 2017 (6)	Dec-31 2018 (7)	Dec-31 2019 (8)	Dec-31 2020 (9)	Dec-31 2021 (10)	Dec-31 2022 (11)	Dec-31 2023 (12)
			←—— Project year ended - annualized from In-Service Date ——→											
Revenue & Expense Forecast														
Load Forecast (MW)			8.5	9.9	11.3	12.5	13.6	14.7	15.8	16.9	18.0	19.4	20.4	21.4
Tariff Applied ($/kW/Month)			1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Gross Revenue - $M			0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
OM&A Costs (Removals & On-going Incremental) - $M		0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M		0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3
Income Taxes (incl. LCT)		0.0	0.1	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0
Operating Cash Flow (after taxes) - $M		0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Cumulative PV @ 5.60%													
PV Operating Cash Flow (after taxes) - $M (A)	4.3	**0.0**	**0.2**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC		(10.4)												
- Overheads		(1.1)												
- AFUDC		(0.5)												
Total upfront capital expenditures		**(11.9)**												
On-going capital expenditures			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures		0.0												
Total capital expenditures - $M		**(11.9)**												
PV Proceeds on disposal of assets - $M		**0.0**												
PV CCA Residual Tax Shield - $M		**0.1**												
PV Working Capital - $M		**(0.0)**												
PV Capital (after taxes) - $M (B)	(11.8)	**(11.8)**												
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	(7.5)	**(11.8)**	**(11.7)**	**(11.4)**	**(11.1)**	**(10.8)**	**(10.6)**	**(10.4)**	**(10.1)**	**(9.9)**	**(9.7)**	**(9.6)**	**(9.4)**	**(9.2)**

Discounted Cash Flow Summary
(Based on Economic Study Horizon - Years): **25**

Discount Tariff - % **5.60%**

		Before Contribution $M		After Contribution $M	Impact of Contribution $M
PV Incremental Revenue		5.1		5.1	
PV Incremental OM&A Costs		(0.7)		(0.7)	
PV Ontario Capital Tax and Municipal Tax		(1.2)		(0.3)	0.9
PV Income Taxes and LCT		(1.1)		(1.4)	(0.3)
PV CCA Tax Shield		2.2		0.6	(1.6)
PV Capital - Upfront	(11.9)		(11.9)		
Add: PV **Capital Contribution**	**0.0**	(11.9)	**8.5**	(3.4)	8.5
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**(7.5)**		**0.0**	**7.5**
Profitability Index*		**0.4**		**1.0**	

*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Start Date:	1-May-09
In-Service Date:	31-Dec-11
Payback Year:	2036
No. of years required for payback:	25

Contribution Required (before GST) - $M	**8.5**
GST @ 5% - $M	**0.4**
Contribution Required (incl. GST)* - $M	**8.9**

* Payment from customer must include GST.

Table 2a – DCF Analysis, Hydro One, Transformation Connection Pool, page 2

Date:	24-Mar-09
Project #	12971

SUMMARY OF CONTRIBUTION CALCULATIONS

Planner's estimate

Facility Name: Commerce Way TS

Scope: Hydro One Networks - Transformation Pool

	Month / Year	Dec-31 2024	Dec-31 2025	Dec-31 2026	Dec-31 2027	Dec-31 2028	Dec-31 2029	Dec-31 2030	Dec-31 2031	Dec-31 2032	Dec-31 2033	Dec-31 2034	Dec-31 2035	Dec-31 2036
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		22.5	23.6	24.6	25.7	26.8	27.9	29.0	30.2	32.6	33.1	33.6	34.1	34.6
Tariff Applied ($/kW/Month)		1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Gross Revenue - $M		0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7
OM&A Costs (Removals & On-going Incremental) - $M		(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Ontario Capital Tax and Municipal Tax - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Income Taxes (incl. LCT)		0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M		0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
PV Operating Cash Flow (after taxes) - $M	(A)	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
PV Proceeds on disposal of assets - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	(B)													
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	**(9.0)**	**(8.9)**	**(8.7)**	**(8.6)**	**(8.5)**	**(8.3)**	**(8.2)**	**(8.1)**	**(7.9)**	**(7.8)**	**(7.7)**	**(7.6)**	**(7.5)**

1 **Table 2b – DCF Analysis, Woodstock Hydro, Transformation Connection Pool, page 1**

Date: 24-Mar-09
Project # 12971

SUMMARY OF CONTRIBUTION CALCULATIONS
Planner's estimate

hydro one

Facility Name: Commerce Way TS

Scope: Woodstock Hydro - Transformation Pool

	Month Year	In-Service Date Dec-31 **2011**	Dec-31 **2012** 1	Dec-31 **2013** 2	Dec-31 **2014** 3	Dec-31 **2015** 4	Dec-31 **2016** 5	Dec-31 **2017** 6	Dec-31 **2018** 7	Dec-31 **2019** 8	Dec-31 **2020** 9	Dec-31 **2021** 10	Dec-31 **2022** 11	Dec-31 **2023** 12
			←— Project year ended - annualized from In-Service Date ——→											
Revenue & Expense Forecast														
Load Forecast (MW)			25.8	28.2	30.6	32.7	34.1	35.5	36.9	38.2	39.6	41.0	42.2	43.5
Tariff Applied ($/kW/Month)			1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Gross Revenue - $M			0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8
OM&A Costs (Removals & On-going Incremental) - $M		0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M		0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		0.0	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Income Taxes (incl. LCT)		0.0	0.0	0.2	0.1	0.1	0.1	0.0	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)
Operating Cash Flow (after taxes) - $M		0.0	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Cumulative PV @ 5.60%													
PV Operating Cash Flow (after taxes) - $M (A)	**8.3**	**0.0**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC		(10.4)												
- Overheads		(1.1)												
- AFUDC		(0.5)												
Total upfront capital expenditures		**(11.9)**												
On-going capital expenditures			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures		0.0												
Total capital expenditures - $M		**(11.9)**												
PV Proceeds on disposal of assets - $M		**0.0**												
PV CCA Residual Tax Shield - $M		**0.1**												
PV Working Capital - $M		**(0.0)**												
PV Capital (after taxes) - $M (B)	**(11.8)**	**(11.8)**												
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**(3.6)**	**(11.8)**	**(11.5)**	**(10.9)**	**(10.4)**	**(10.0)**	**(9.5)**	**(9.1)**	**(8.7)**	**(8.3)**	**(7.9)**	**(7.5)**	**(7.2)**	**(6.9)**

Discounted Cash Flow Summary
(Based on Economic Study Horizon - Years): **25**

Discount Tariff - % **5.60%**

		Before Contribution $M		**After Contribution** $M	**Impact of Contribution** $M
PV Incremental Revenue		11.0		11.0	
PV Incremental OM&A Costs		(0.7)		(0.7)	
PV Ontario Capital Tax and Municipal Tax		(1.2)		(0.8)	0.4
PV Income Taxes and LCT		(3.0)		(3.1)	(0.1)
PV CCA Tax Shield		2.2		1.5	(0.8)
PV Capital - Upfront	(11.9)		(11.9)		
Add: PV **Capital Contribution**	**0.0**	(11.9)	**4.1**	(7.9)	4.1
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**(3.6)**		**0.0**	**3.6**
Profitability Index*		**0.7**		**1.0**	

*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Start Date:	1-May-09
In-Service Date:	31-Dec-11
Payback Year:	2036
No. of years required for payback:	25

Contribution Required (before GST) - $M	**4.1**
GST @5% - $M	**0.2**
Contribution Required (incl. GST)* - $M	**4.3**

* Payment from customer must include GST.

2

Table 2b – DCF Analysis, Woodstock Hydro, Transformation Connection Pool, page 2

Date: 24-Mar-09
Project # 12971

SUMMARY OF CONTRIBUTION CALCULATIONS
Planner's estimate

hydro one

Facility Name: Commerce Way TS

Scope: Woodstock Hydro - Transformation Pool

	Month / Year	Dec-31 2024	Dec-31 2025	Dec-31 2026	Dec-31 2027	Dec-31 2028	Dec-31 2029	Dec-31 2030	Dec-31 2031	Dec-31 2032	Dec-31 2033	Dec-31 2034	Dec-31 2035	Dec-31 2036
		13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast														
Load Forecast (MW)		44.7	45.9	47.1	48.3	49.6	50.8	52.0	53.2	64.4	64.6	64.8	65.0	65.2
Tariff Applied ($/kW/Month)		1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Gross Revenue - $M		0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.3	1.3	1.3	1.3	1.3
OM&A Costs (Removals & On-going Incremental) - $M		(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Ontario Capital Tax and Municipal Tax - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	1.1	1.1	1.1	1.1	1.1
Income Taxes (incl. LCT)		(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Operating Cash Flow (after taxes) - $M		0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8
PV Operating Cash Flow (after taxes) - $M	(A)	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
PV Proceeds on disposal of assets - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	(B)													
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	**(6.6)**	**(6.3)**	**(6.0)**	**(5.7)**	**(5.5)**	**(5.2)**	**(5.0)**	**(4.7)**	**(4.5)**	**(4.2)**	**(4.0)**	**(3.8)**	**(3.6)**

Ontario Energy Board (Board Staff) INTERROGATORY #82 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Development Capital

Ref:(a) Exhibit D1/Tab3/Sch3/Appendix A/p4/Table 4/Projects:
D18 – South Halton Tremaine TS :Build New TS [Category 2, In-service 2011, Sec 92 Not Required];
D25 – North Bay TS: Upgrade to a 115-44kV TS [Category 2, In-service 2012, sec 92 Not Required]
D26 – Barwick TS: Build New TS [Category 2, In-service 2012, sec 92 Not Required]
Ref:(b) Exhibit D2/Tab2/Sch3/Invest.Summary/Ref.#D18, #D25, #D26

Hydro One is seeking approval in this hearing for the three "Load Customer Connection" projects whose in-service dates are within the two test years 2011/2012.

Please provide for each project a copy of the spread sheet depicting the economic evaluation, showing all assumptions including the discount rate, etc, pursuant to the requirements of the TSC section 6.3. Where for any project, more than a single customer is contributing capital, please provide the details of the study for each customer;

Response

Project D18 – South Halton Tremaine TS
Hydro One is in the process of seeking consent from the affected customers to release the requested information and will provide the requested evaluations once customer consent is obtained following the Board's confidentiality filing guidelines.

Project D25 – North Bay TS
The need for this project was based on the end-of-life replacement of an existing facility as noted in Exhibit D2, Tab 2, Schedule 3; hence no capital contribution is necessary based on the Transmission System Code Section 6.7.2 and therefore no economic evaluation was completed.

Project D26 – Barwick TS

The need for this project was based on the end-of-life replacement of an existing facility as noted in Exhibit D2, Tab 2, Schedule 3; hence no capital contribution is necessary based on the Transmission System Code Section 6.7.2 and therefore no economic evaluation was completed.

Ontario Energy Board INTERROGATORY #83

Interrogatory

Issue 4.2: Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Question:

Ref:(a) Exhibit D1/Tab3/Sch3/Appendix A/p4/Table 4/Projects:
D19 - Ancaster TS: Build new TS and Line Connection [Category 3, In–service 2013, Sec 92 TBD]
D20 – East Ottawa TS: Build New TS [Category 3, In-service 2013, Sec 92 Not Required]
Ref:(b) Exhibit D2/Tab2/Sch3/Invest.Summary/Ref #D19, #D20

Hydro One is "seeking guidance" in this hearing for the two "Load Customer Connection" projects whose in-service dates are beyond the two test years 2011/2012.

Please provide for each project a copy of the spread sheet depicting the economic evaluation (and if this is a preliminary evaluation, please indicate that), showing all assumptions including the discount rate, etc., pursuant to the requirements of the TSC section 6.3. Where for any project, more than a single customer is contributing capital, please provide the details of the study for each customer.

Response

Copies of the economic evaluations are attached for both Ancaster TS and East Ottawa TS. The capital contributions have been revised based on the latest load forecast projections from the customer, Hydro One Distribution. For Ancaster TS the capital contribution has increased from $8.2M to $20.6M and for East Ottawa it has decreased from $30.2M to $23.2M.

Please note that the capital contribution amounts are considered preliminary as the load forecast and the project costs are both subject to change. The costs will be finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service.

Hydro One has received customer consent to provide the requested economic evaluations for these projects which are at a preliminary planning stage and scheduled for in-service beyond the test years. This information is filed in confidence with the Board and will be made available to Intervenors that sign a Declaration and Undertaking form in accordance with the Board's Proactive Direction on Confidential Filings.

Ontario Energy Board INTERROGATORY #84

Interrogatory

Issue 4.2: Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Question:

Ref: (a) Exhibit D1/Tab3/Sch3/Appendix A/p4/Table4, Project D23 – Enfield TS: Build 23-/44 kV DESN and Line Connection (formerly Oshawa Area TS)
Ref: (b) Proceeding EB-2008-0272, Exhibit D1/Tab3/Sch3/p35/ Table4/Project D33 Enfield TS: Add Transformation Capacity

Hydro One is seeking guidance in this hearing for the Construction of the Enfield TS. The Total Gross Cost at Reference (a) is $28.7 million with capital contribution of $8.0 million, while at Reference (b), the total gross cost of the same project is $25.6 million with capital contribution of $13.6 million.

(a) Please provide the reasons for the cost increase of $ 3.1 million by providing a breakdown of the variance into major system element such as transformers, breakers, switches, towers, etc, and also broken down by material, labour, over heads, etc.

(b) Please provide the reasons for the decrease in capital contribution of $5.6 million (a decrease from $13.6 to $8.0 million). How is a decrease in capital contribution justified, given the increase in total project costs?

(c) Please provide a copy of the spread sheet depicting the economic evaluation (and if this is a preliminary evaluation, please indicate that), showing all assumptions including the discount rate, etc.

Response

(a) Please see the below table for the cost breakdown.

	Variance
Material	**+ $0.4M**
• *Transformer*	*-$0.4M*
• *Structural Steel*	*+$0.4M*
• *Foundations*	*+$0.2M*
• *Lines*	*+$0.2M*

		Variance
Labour		**+ $1.8M**
• *Project Mgmt*		*+$0.2M*
• *Engineering*		*+ $0.5M*
• *Construction*		*+$1.1M*
• *Commissioning*		*+$0.0M*
Overhead		**- $0.0M**
Interest		**+ $0.6M**
Risk		**+ $0.3M**
	TOTAL	**+ $3.1M**

(b) The peak station load in Reference (b) was limited to 106MW corresponding to the capability of a 50/83MVA station. This resulted in a capital contribution requirement of $13.6M. The capital contribution in Reference (a) is based on updated forecast information with the station loaded up to 170MW corresponding to the capability of a 75/125MVA station.

(c) Hydro One is in the process of seeking consent from the affected customers to release the requested information. Once customer consent is obtained, Hydro One will provide the requested evaluations following the Board’s guidelines for confidential filing.

Ontario Energy Board (Board Staff) INTERROGATORY #85 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Development Capital

Ref: (a) Exhibit D1/Tab3/Sch3/Appendix A/p4/Table4, Project D27 – Duart TS:Build New TS and Line Connection(Formerly Rodney TS)
Ref: (b) Proceeding EB-2008-0272, Exhibit D1/Tab3/Sch3/p35/ Table4/Project D36 Rodney TS: Build new TS & Line Connection

(a) Please provide the reasons for the cost increase of $ 7.8 million (from gross total cost of $18.9 million to a gross total cost of $ 26.7 million). Please provide a breakdown of the variance in cost by major system element such as transformers, breakers, switches, towers, etc., and also broken down by material, labour, over heads, etc.

(b) Please provide a copy of the spread sheet depicting the economic evaluation (and if this is a preliminary evaluation, please indicate that), showing all assumptions including the discount rate, etc.

Response

(a) Please see the cost breakdown.

	Variance
Material	**+ $5.0M**
• *Transformer*	*+$3.0M*
• *Structural Steel*	*+$0.4M*
• *Foundations*	*+$0.5M*
• *Spill Containment*	*+$1.0M*
• *Lines*	*+$0.1M*
Labour	**+ $0.7M**
• *Project Mgmt*	*-$0.8M*
• *Engineering*	*+$0.1M*
• *Construction*	*+$1.1M*
• *Commissioning*	*+$0.3M*
Overhead	**+ $0.6M**
Interest	**+ $0.8M**
Risk Allowance	**+ $0.7M**
TOTAL	**+ $7.8M**

(b) The need for this project was based on the end-of-life replacement of an existing facility as noted in Exhibit D2, Tab 2, Schedule 3; hence no capital contribution is necessary based on the Transmission System Code Section 6.7.2 and therefore no economic evaluation was completed.

Ontario Energy Board (Board Staff) INTERROGATORY #86 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Operations Capital

86) Ref: (a) Exhibit D1/Tab3/Sch4/ p9-10/Table 3 & Section 3.3 – O1 Network Operations Building
Ref: (b) Exhibit D2/Tab2/Sch3/Investment Summary Document/ Project O1-Network Operating Building Expansion/Summary:

The evidence in Reference (a), at page 9, lines 8-11 states in part that:
"the investment deals with both the primary control facility, the Ontario Grid Control Centre located in the Barrie area, and the back up control facility located in the Toronto area."

The evidence in Reference (b), last paragraph under "Summary" states in part that:
"a review of options for the back-up Control Centre (BUCC) is in progress…."

At Ref: (b), paragraph 2 under "Summary", it is stated in part that:
"As an alternative to expanding the OGCC building, consideration was given to moving staff to nearby "overflow" locations or decentralizing some departments. Analysis of options revalidated the one-centre strategy that lead to creation of the OGCC."

(a) Please provide a breakdown of the estimated costs, for each of the two years, 2011 and 2012, between the additions to the OGCC in Barrie and the proposed BUCC in Toronto;

(b) Please provide the analysis of the options, along with all assumptions that led to the noted conclusion.

(c) Please provide implications of delaying implementation of the proposed O1 project for 2 full years such that investment would commence in 2013 instead of 2011.

Response

a)

Estimated Costs	2011($M)	2012 ($M)
OGCC	1	1
BUCC	11.1	10

b) Over the next three years, a final Barrie space solution will be developed with the intent to have it implemented by the end of an interim lease. This solution will consider the longer term staffing and space requirements of the affected Lines of Business and will evaluate all options including a new build, leasing and purchase. At present the space issues at the OGCC are being addressed as part of a coordinated space/facilities plan which covers all Hydro One staff and functions currently working out of the Barrie area. This plan presents a consolidated approach that addresses the business needs of each Line of Business which has staff and facilities located in the Barrie area. Based on this study and review the recommendation was made to obtain a lease facility for a minimum of 3 years (with options for an additional 2 years,) which will house OGCC staff overflow and meet the staff and space requirements for other Lines of Business working out of the Barrie area. The lease facilities will be ready for occupancy in the fourth quarter of 2010.

Over the next three years the OGCC in Barrie requires mechanical plant expansions to support the HVAC system currently at capacity due in part to the buildings maximized occupancy. The estimated cost is $1M in each of 2011 and 2012.

The review of the options for the Backup Control Centre (BUCC) has confirmed that a significant investment in the BUCC is required. The current BUCC is located at the Richview facility; this facility is forty years old and was never designed to accommodate the facilities and critical infrastructures associated with today's real-time operating systems. As a result, the Richview facility is currently at capacity from both a space and infrastructure requirements perspective. Many of the existing sub-systems are at end-of-life, at full capacity, and cannot accommodate any new operating systems. Operating systems that are currently being considered to meet specific distributed generation, smart grid and cyber security requirements cannot be incorporated into the existing BUCC building and infrastructure. The options considered and under review are presented in the following table.

Alternatives	Cost	Analysis
Enhancement of Richview, including expansions to the computer room, control rooms and infrastructure	$25.2M	This option would provide limited future scalability and flexibility which may render it increasingly difficult to comply with NERC standards in the future. It would require some existing tenants to vacate causing significant disruption to the business.
Build a new BUCC at a Hydro One TS site with Fibre Optics communication connection	$31M	This option would provide a new building with reliable power and communication connections. The facility and infrastructure would be flexible and scalable. This option is advantageous as the possible available sites would offer reduced travel time in the event of a failover. However, the possible sites may be eliminated due to environmental and zoning reasons.
Build a new BUCC at a Hydro One TS site without Fibre Optics communication connection	$35.2M	This option would provide a new building with a reliable power connection and infrastructure that is flexible and scalable. It is also desirable because the possible sites available would offer reduced travel time in the event of a failover. There, however, is an incremental cost from the previous option due to communication connection costs.
Move BUCC to other Hydro One property	Varies, >31M	Analysis of this option revealed disadvantages in increased costs and reduced reliability of power and communication connections. Additionally, , the physical locations of these properties were evaluated and determined to be disadvantageous and non compliant with NERC standards for a BUCC.
Buy/Lease	Varies, >35M	Initial analyses determined that it would be cost prohibitive to buy or lease land to develop a new BUCC. Further, the cost associated with the required reliable power supply and communication connections would also add to the prohibitive expense.
Co-location of Computer Room to off site facility, Back Up Control Room remains	40.6M	This option would present the shortest implementation period, would be flexible and scalable and would be the least disruptive to the business. This option, however, relies on a third party. It would also lack the reliability of power supply, and the communications connections would likely need to be upgraded. Also, the presence of two control centres would mean relying on added communication paths, adding complexity which may reduce reliability.

c) The time frames to build a new facility or for major refurbishment of the Richview facility is estimated to be three years. The existing Richview BUCC cannot support the minimum operating infrastructure requirements beyond three years without implementing one of the alternatives under consideration and thus it is not viable to delay this investment.

Deferring the mechanical plant investments at the OGCC is not a possibility as the upgrades are required to support the chillers that are necessary to keep the computer facilities cool.

Ontario Energy Board (Board Staff) INTERROGATORY #87 List 1

Interrogatory

Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Operations Capital

Ref: (a) Exhibit D1/Tab3/Sch4/ p15-17/Table 4 & Section 4.3.3 – O6 Telecom Wide Area Network
Ref: (b) Exhibit D2/Tab2/Sch3/Investment Summary Document/ Project O6- Wide Area Network Project

At Reference (a), Section 4.3.3, in regard to the total investment in Project O6 totaling $37.1 million over 2011 and 2012, it is stated in part that: "Studies have shown that this investment will pay back in five years through reduced future telecom lease costs beyond the test years."

At Reference (b) it is stated in part under "Need:" that: "Depending on the rate of deployment of some new systems such as smart grid, video conferencing and improved enterprise systems, the requirement could range from doubling of service capacity to a sevenfold increase over the next five years."

Also in Reference (b) it is stated in part Under "Summary" that: " this technology, which is readily Scalable, will provide the capacity to meet all telecom needs over the next five years and beyond and avoid large leased telecom services costs."

(a) Please provide the studies noted in Reference (a), along with assumptions covering the economic evaluation of Project O6.

(b) Please indicate whether the proposed investment would be adequate to meet the needs if the requirement of service capacity increases to "sevenfold" as noted in Reference (b).

(c) Please explain what is meant by "improved enterprise systems", noted in Reference (b). Please provide an explanation as to which groups within Hydro One Networks would be utilizing the systems, and what benefits or cost reductions are achieved by such systems.

(d) What would be the payback of the investment under two scenarios where the triggers for the need (smart grid deployment, video conferencing, and improved enterprise systems) are assumed to be 25% and 50 % of the amount forecasted.

Response

a) A study was conducted to determine the future projection of the telecommunication requirements of Hydro One over the next 5 years. The study examined the detailed needs of programs and projects scheduled in the 2010 – 2014 Business Plan in terms of the number of telecom services they require and the bandwidth requirements of each service. Three scenarios were considered: the expected growth rate, the highest rate of growth considered possible and the lowest rate of growth considered possible.

A cost analysis study was conducted comparing this capital investment, which leverages Hydro One's own fibre optic system, to purchasing the telecom services from 3rd parties. The assumptions used in the study included:

- A projection of 75% of scheduled applications and services to go in-service during the program and project life cycles.
- Cost of leased circuit services provided by 3rd parties and any associated maintenance costs would not escalate throughout the study period
- Equipment costs and labour costs for the capital project alternative are based on the current fair market value and current rates respectively

The following is a summary of the telecom services studied**:**

Corporate Hydro One Wide Area Network (HWAN)
This is the network used for enterprise systems such as the ERP system (i.e. SAP), email, file storage, internet, geographic information system, record management systems and others. The expectation is that the current requirement of 10/100 Mbps access and 10 Mbps for dedicated bandwidth will expand from the current 29 corporate sites on the Hydro One fibre system today, to approximately 59 sites by the end of 2015. The need for increased bandwidth is due to organic growth and the provisioning of a Quality of Service network to support the technology roadmap of Hydro One's Information Services Division. The roadmap will provide staff efficiency gains in the form of audio, video and collaboration based on Internet Protocol (IP) based telephony and unified messaging. This will result in less travel time required and quicker access to information.

Power System Real-Time SCADA
Real-time SCADA communications will continue to grow based on the number of remote sites connected in parallel to both the OGCC and Backup Control center. The expectation is that only a small number of additional active and backup circuits will be required for new Hub Sites. However, additional circuits will be required to meet the demands of Distributed Generation, reflecting an overall anticipated growth on circuit counts and bandwidth required for real-time data traffic over the next 5 years.

Power System Non-Operational Data

Access to non-operational data from digital protections and other new smart devices at the stations is essential for event analysis, and represents a significant opportunity for asset condition tracking leading to improvements in maintenance scheduling, planning and engineering design. Minimal additional bandwidth is anticipated for these services over the next 5 years at existing sites. However, the expectation is that non-operational data extraction will be required from all transformer stations, resulting in approximately 240 additional sites connected by the end of 2015.

Physical Perimeter Security

There are a number of programs for improving the physical security at sites and stations that are planned over the next 5 years. Included in these is the provision of improved intrusion detection and access control. Increased numbers of telecom services and bandwidth will be required for security cameras, card readers and locking systems as well as perimeter detection systems. The plan is to deploy these security systems at a rate of 10 Transformer stations and 20 Distribution stations (minimum) per year.

Cyber and IT Security

To provide for Cyber and IT security over the next 5 years, a projected 30% increase in circuit bandwidth for all services will be required. This bandwidth is required for the distribution of antivirus signature updates, patches, systems intrusion detection, and vulnerability scans.

Monitoring, Control and Configuration of Telecommunication Systems (TDCN)

A network exists called the Telecom Device Control Network (TDCN) which provides the management and control of all of the telecommunication devices used for power system telecommunications (i.e. Synchronous Optical Network (SONET) devices, routers, switches and multiplexers). There will be an increase in bandwidth required for the direct reporting and monitoring of new devices that will be added to this network.

Advanced Distribution Systems (ADS)

The ADS is being deployed to enable connection of generation to the distribution system (Renewable Enabling Improvements), as well as improved reliability and cost efficiency through remote monitoring and control distribution stations and in-line reclosers. To enable the ADS, Hydro One plans to deploy a wireless telecommunicate network to reach across the vast geography of the Hydro One distribution service territory. The back-haul site requirements for this wireless network will grow steadily over the next 5 years with a requirement for a guaranteed backbone of 10 Mbps.

P&C Remote Access to Critical Cyber System Information

It is a NERC requirement that the information about all critical cyber systems must be kept secure. To comply with this requirement, such information that was kept locally at the stations is removed to secure central servers. Protection & Control field staff require access to this information when at the stations to perform troubleshooting and routine management tasks on these cyber assets. Additional bandwidth is required to allow staff to access drawings and databases from the stations for this purpose.

Bandwidth Requirements (Backbone)

The Bandwidth requirements for each service were based on the following estimates in Table 1 below. For the business case analysis, these estimates were challenged to conservative values (i.e. lower rather than higher estimates).

Table 1
Service Bandwidth Requirements

Service Type	*Bandwidth Requirement per Service (Mbps)*	*Expected Growth in # of Services By 2015*
Corporate	10.0	30
SCADA	0.5	19
Non-operational data	0.5	240
Physical Security	1.0	60
IT Security	0.5	257
Telecom DCN	0.5	12
ADS	10.0	78
P&C Access to CCA Information	1.0	240
TOTAL		**936**

Backbone Services

Chart 2 provides the bandwidth requirements for the backbone over the next 5 years. The existing SONET can support up to a maximum of 1.2 Gbps on the backbone. Based on the anticipated projections, the existing SONET infrastructure will meet the base requirement for the bandwidth on the backbone by the end of 2012, but will exceed the base requirements for the backbone by the middle of 2013. (Total services ~687 or 60% of projected services)

Chart 2
Anticipated Bandwidth Requirements

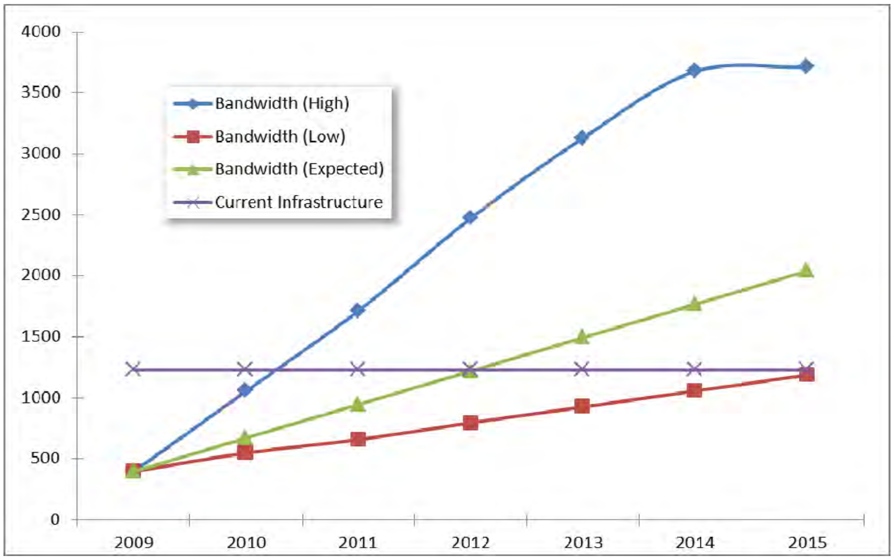
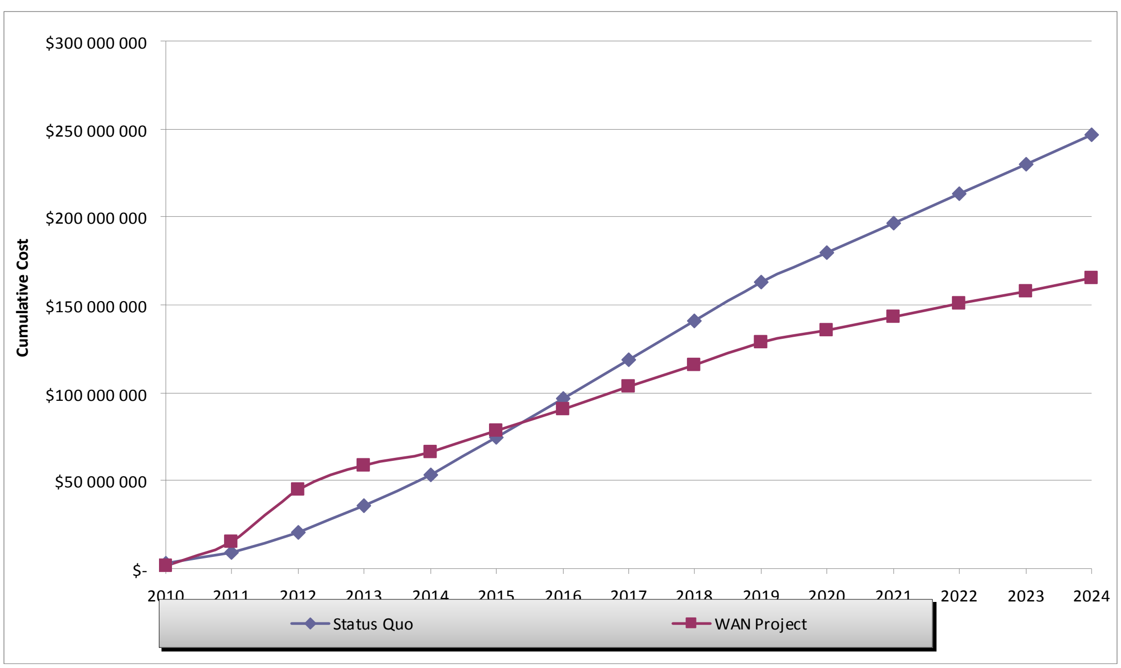


Chart 3, provides a cost comparison between Hydro One to using its existing fibre with the WAN project to meet projected needs versus leasing telecom services from 3rd parties. As can be seen, the WAN project alternative will become lower in cost relative to leasing telecom services during the fifth year.

Chart 3
Cost Analysis between the Build in-house vs. Lease through 3rd Party



b) The cost is based on a scalable design that will meet 75% of the expected service bandwidth projections of all programs and projects currently in the business plan. As new services are added or old service requirements change, these can be met by incremental modifications on the installed equipment such as adding cards or expansion chassis. In this way the incremental costs are incurred only when the need for the service is certain.

c) See the item "Corporate Hydro One Wide Area Network (HWAN)**"** in the response to part a). All business groups (i.e. Grid Operations, Engineering & Construction Services, Asset Management, Customer Operations and the IT function) of Hydro One will use corporate applications on enterprise systems and benefit from improved system performance.

Enhancements and expanded deployments of these systems will require the 30 increased services shown in Table 1 for proper network and application performance for users. Services/applications on enterprise systems that will be used by all business groups at Hydro One will have improved performance with the increase in service. Key services/applications that will have benefits and costs reductions include:

1. Voice over IP telephony to reduce the costs associated with leased circuits on corporate PBX systems

2. Corporate approved audio bridging, web-based meeting facilities and video conferencing systems to reduce employee travel, improve employee productivity and reduce bridge services from third parties.

3. Quality of Service (QoS) capability of the WAN hardware will provide the required bandwidth and network performance to systems that host critical core applications thus increasing employee productivity and reducing employee frustrations

4. Reduction in number of Help One calls by employees on system performance and instability

5. Centralization of applications and services will reduce hardware costs, and software costs. In addition it will enhance managed of services, and decrease time to repair services.

6. Full deployment of mobile systems for collecting station inspection results, defect condition reports, and for accessing geographic information systems and drawings to save labour costs and enable efficiencies throughout process streams due to better quality of information.

The detailed business case for these investments was not the subject of the study for the WAN project. However, the study did confirm that these services have sufficiently strong business cases to justify proceeding in the absence of the WAN project. The WAN project allows the telecom costs for these investments to be reduced.

d) With an assumption of 25% of the amount forecasted for in-service, the return on investment is not valid. However, using 50% of the amount forested for in-service; the break even is within 8.5yrs with a 15yr End-of-Life.

Ontario Energy Board (Board Staff) INTERROGATORY #88 List 1

Interrogatory

Issue 6.1 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Ref: Exhibit F1/Tab1/Sch1/p3 and Exhibit A-8-1, Attachment 3 (Audited Financial Statements for 2009)

Amounts requested for approval in Table 2 of this exhibit do not match the amounts reported by Hydro One to the Board under Quarterly Q4 2009 RRR 3.1.1 (deferral and variance account balances).

a) Please file a copy of Hydro One's Q4 RRR 3.1.1 reporting to the Board.

b) Please reconcile the amounts in the application to the amounts reported under RRR 3.1.1 and to the Audited Financial Statements, and explain the differences.

Response

a) Please find a copy of Hydro One's Q4 2009 RRR 3.1.1 report to the Board as Attachment 1 to this interrogatory.

b) Tables 1 and 2 reconcile the amounts in the application to the amounts reported under RRR 3.1.1. Tables 3 and 4 reconcile the amounts in the application to the Audited Financial Statements.

Table 1

	$M's	**Reference**
Per Q4 RRR 3.1.1 Account 2405 – Other Regulatory Liabilities	**(25.5)**	As per attachment in response to a) above.
Is comprised of the following sub-accounts:		
2405 - Export Service Credit Revenue	(4.8)	F1, Tab1, Schedule 1 Table 2
2405 – External Secondary Land Use Revenue	(3.2)	F1, Tab1, Schedule 1 Table 2
2405 – Ext. Station Maintenance & EC&S Rev.	(4.4)	F1, Tab1, Schedule 1 Table 2
2405 – Pension Cost Differential	3.1	F1, Tab1, Schedule 1 Table 2
2405 – Deferred Export Service Credit [1]	(16.2)	
Total	**(25.5)**	

[1] Account 2405 (Deferred Export Service Credit) was not included in the pre-filed evidence F1, Tab 1, Schedule 1 Table 2 (Regulatory Assets Requested for Approval) as it was approved for recovery in the decision for EB-2006-0501.

Table 2

	$M's	Reference
Per Q4 RRR 3.1.1 Account 1508 – Other regulatory assets	**(0.9)**	As per attachment in response to a) above.
Is comprised of the following sub-accounts:		
1508 – OEB Costs [2]	(2.8)	
1508 – IPSP & Other LT Project Planning Costs	1.9	F1, Tab1, Schedule 1 Table 2
Total	**(0.9)**	

[2] Account 1508 (OEB Costs) was not included in the pre-filed evidence F1, Tab 1, Schedule 1 Table 2 (Regulatory Assets Requested for Approval) as it was approved in the decision for EB-2008-0272.

Table 3

	$M's	Reference
Per Audited Annual Financial Statements Note 8 "Other Regulatory Assets"	**10** [3]	A, Tab 8, Schedule 1 Attachment 3
Comprised of the following sub-accounts:		
1508 – IPSP Development Costs	1.9	F1, Tab1, Schedule 1 Table 2
1570 – Qualifying Transition Costs [4]	5.4	
2405 – Pension Cost Differential	3.1	F1, Tab1, Schedule 1 Table 2
Total	**10.4**	

[3] Audited Annual Financial Statements are rounded to the nearest million.
[4] Account 1570 (Qualifying Transition Costs) was not included in the pre-filed evidence F1, Tab 1, Schedule 1 Table 2 (Regulatory Assets Requested for Approval) as it was approved for recovery in the decision for EB-2006-0501.

Table 4

	$M's	Reference
Per Audited Annual Financial Statements Note 8 "External revenue variance account"	**(12)** [5]	A, Tab 8, Schedule 1 Attachment 3
Comprised of the following sub–accounts:		
2405 – Excess Export Services Credit	(3.2)	F1, Tab1, Schedule 1 Table 2
2405 – Ext. Station Maintenance and E&CS Rev	(4.4)	F1, Tab1, Schedule 1 Table 2
2405 – Excess Export Service Credit	(4.8)	F1, Tab1, Schedule 1 Table 2
Total	**(12.4)**	

[5] Audited Annual Financial Statements are rounded to the nearest million.

Filed: August 16, 2010
EB-2010-0002
Exhibit I-1-88
Attachment 1
Page 1 of 2

Clicking Save or Apply will not automatically submit this filing. To SUBMIT this filing, scroll to the end of the page, select Yes in the Submit drop down then click the SAVE button.

Other Deferral/Variance Accounts

Report Summary

Filing Year: 2010	Filing Form Name: 3.1.1	Filing Form Description: Variance Account Balances
RRR Filing No: 549	Reporting Period: January- 2010Hydro One Networks Inc., Toronto: Corporation; ET-2003-0035; ;	Extension Granted:
Report Version: 1	Due: February 1, 2010	Extension Deadline:
Status: Revised	Submitted On: July 13, 2010	Expiry Date: July 17, 2010
Submitter Name: Pasquale Catalano	Licence Type: Transmitter	
For the Quarter Ending on: Dec 31, 2009	For the Period from: Oct 1, 2009	For the Period Ending to: Dec 31, 2009

Deferral Accounts

For the quarter ending: Dec 31, 2009

Account	Quarter Opening Balance DR/-CR	Carrying Charges DR/-CR this Period	Carrying Charges DR/-CR to Date	Net Accruals DR/-CR this Period	Net Accruals DR/-CR to Date	Other Adjustment DR/-CR this Period	Other Adjustment DR/-CR to Date	Quarter Closing Balance DR/-CR	To Date Check	Comments
1508 Other regulatory assets	-2,723,059.00	-2,984.00	-138,030.00	1,873,131.00	-714,882.00	0.00	0.00	-852,912.00	-852,912.00	
1525 Miscellaneous deferred debit	122,339,865.00	1,516,942.00	16,433,010.00	-93,000.00	90,893,364.00	27,190,457.00	43,627,890.00	150,954,264.00	150,954,264.00	
1570 Qualifying transition costs	6,405,016.00	7,416.00	1,346,530.00	-961,271.00	4,104,631.00	0.00	0.00	5,451,161.00	5,451,161.00	
1572 Extraordinary event costs										
1574 Deferred										

rate impact amounts										
2425 Other deferred credits										
2405 Other Regulatory Liabilities	-22,996,373.00	-29,096.00	-4,074,884.00	-2,475,552.00	-21,426,137.00	0.00	0.00	-25,501,021.00	-25,501,021.00	
1592 PILS and Taxes Variances	-11,385,521.00	-14,224.00	-366,559.00	2,316,665.00	-8,716,521.00	0.00	0.00	-9,083,080.00	-9,083,080.00	

Submit?

* Submit Form

No

Ontario Energy Board (Board Staff) INTERROGATORY #89 List 1

Interrogatory

Issue 6.1 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Ref: Exhibit F2/Tab1/Sch3

a) Does this Continuity Schedule include all of Hydro One's deferral and variance account balances?

b) If not, please provide the balances of all regulatory deferral and variance accounts, including those not being requested for disposition.

c) Please provide a breakout of the sub-accounts, including the continuity of any such sub-accounts.

Response

a) No, the continuity schedule in Exhibit F2, Tab1, Schedule 3 does not include all of Hydro One's deferral and variance account balances.

b) Please see response for part c).

c) Please see Attachment 1 for a continuity schedule that breaks out all of Hydro One's deferral and variance accounts by sub-account.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity Schedules - Regulatory Assets
(M$)

Year Ending December 31, 2007

Account Description	Account Number	Opening Principal Amounts	Transactions During Year	Closing Principal Balance	Opening Interest Amounts	Interest	Closing Interest Balance	Total Principal plus Interest
Tx Market Ready	1570	$13.2	($0.5)	$12.7	$4.7	($4.7)	$0.0	$12.7
OPEB including Amortization	1465	$36.0	($18.0)	$18.0	$0.0	$0.0	$0.0	$18.0
Primary Environmental	1525	$9.7	($3.8)	$5.9	$7.0	$0.9	$7.9	$13.8
OEB Costs	1508	$6.5	($7.4)	($0.9)	$0.6	($0.7)	($0.0)	($0.9)
Tx Bypass Rebate	1508	$11.8	$2.5	$14.3	$1.8	$0.6	$2.4	$16.8
Deferred Export Tx Service Credit Revenue	2405	($43.0)	$6.8	($36.1)	($5.8)	$3.7	($2.1)	($38.3)
Deferred Rev Tx Earning Sharing	2405	($33.2)	$6.1	($27.1)	($1.2)	$0.0	($1.2)	($28.4)
Tx Reg Liability Tax Change Def Acct	1592	$0.0	($3.5)	($3.5)	$0.0	($0.0)	($0.0)	($3.5)
Pension Cost Differential	2405	$0.0	($1.3)	($1.3)	$0.0	$0.0	$0.0	($1.3)
Tx Reg Liability - Tx Revenue RDDA	2405	$0.0	($71.7)	($71.7)	$0.0	($1.5)	($1.5)	($73.2)
External Secondary Land Use Revenue	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
External Stations & ECS Revenue	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
IPSP & Other Long Term Project Planning Costs	1508	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export Service Credit Revenue	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Reg Asset IFRS	1508	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total		$0.9	($90.7)	($89.8)	$7.1	($1.7)	$5.5	($84.3)

Year Ending December 31, 2008

Account Description	Account Number	Opening Principal Amounts	Transactions During Year	Closing Principal Balance	Opening Interest Amounts	Interest	Closing Interest Balance	Total Principal plus Interest
Tx Market Ready	1570	$12.7	($4.9)	$7.8	$0.0	$1.1	$1.1	$8.9
OPEB including Amortization	1465	$18.0	($18.0)	$0.0	$0.0	$0.0	$0.0	$0.0
Primary Environmental	1525	$5.9	$102.2	$108.1	$7.9	$2.5	$10.4	$118.5
OEB Costs	1508	($0.9)	($2.3)	($3.2)	($0.0)	($0.1)	($0.1)	($3.3)
Tx Bypass Rebate	1508	$14.3	($14.3)	$0.0	$2.4	($2.4)	$0.0	$0.0
Deferred Export Tx Service Credit Revenue	2405	($36.1)	$12.4	($23.7)	($2.1)	($1.2)	($3.3)	($27.1)
Deferred Rev Tx Earning Sharing	2405	($27.1)	$27.1	$0.0	($1.2)	$1.2	$0.0	$0.0
Tx Reg Liability Tax Change Def Acct	1592	($3.5)	($6.2)	($9.7)	($0.0)	($0.2)	($0.2)	($9.9)
Pension Cost Differential	2405	($1.3)	$1.8	$0.5	$0.0	($0.1)	($0.1)	$0.4
Tx Reg Liability - Tx Revenue RDDA	2405	($71.7)	$71.7	$0.0	($1.5)	$1.5	$0.0	$0.0
External Secondary Land Use Revenue	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
External Stations & ECS Revenue	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
IPSP & Other Long Term Project Planning Costs	1508	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export Service Credit Revenue	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Reg Asset IFRS	1508	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total		($89.8)	$169.5	$79.7	$5.5	$2.3	$7.8	$87.5

Year Ending December 31, 2009

Account Description	Account Number	Opening Principal Amounts	Transactions During Year	Closing Principal Balance	Opening Interest Amounts	Interest	Closing Interest Balance	Total Principal plus Interest
Tx Market Ready	1570	$7.8	($4.0)	$3.8	$1.1	$0.1	$1.2	$5.0
OPEB including Amortization	1465	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Primary Environmental	1525	$108.1	$26.5	$134.5	$10.4	$6.0	$16.4	$151.0
OEB Costs	1508	($3.2)	$0.6	($2.6)	($0.1)	($0.0)	($0.1)	($2.8)
Tx Bypass Rebate	1508	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Deferred Export Tx Service Credit Revenue	2405	($23.7)	$12.0	($11.7)	($3.3)	($0.2)	($3.6)	($15.3)
Deferred Rev Tx Earning Sharing	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Tx Reg Liability Tax Change Def Acct	1592	($9.7)	$1.0	($8.7)	($0.2)	($0.1)	($0.4)	($9.1)
Pension Cost Differential	2405	$0.5	$2.7	$3.2	($0.1)	$0.0	($0.1)	$3.1
Tx Reg Liability - Tx Revenue RDDA	2405	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
External Secondary Land Use Revenue	2405	$0.0	($3.2)	($3.2)	$0.0	$0.0	$0.0	($3.2)
External Stations & ECS Revenue	2405	$0.0	($4.4)	($4.4)	$0.0	$0.0	$0.0	($4.4)
IPSP & Other Long Term Project Planning Costs	1508	$0.0	$1.9	$1.9	$0.0	$0.0	$0.0	$1.9
Export Service Credit Revenue	2405	$0.0	($4.8)	($4.8)	$0.0	($0.0)	($0.0)	($4.8)
Reg Asset IFRS	1508	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	($0.0)
Total		$79.7	$28.1	$107.9	$7.8	$5.7	$13.5	$121.4

Ontario Energy Board (Board Staff) INTERROGATORY #90 List 1

Interrogatory

Issue 6.1 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Ref: Exhibit A/Tab11/Sch3/p1-9.

The second exception described and for which a variance account is requested is for gains and losses on tangible and intangible asset sales or losses resulting from premature asset retirement in 2012.

a) Please confirm that Hydro One group depreciation methods were used in calculating the amount of $295.5M of depreciation expense in 2011 and that the same methods were used in calculating the amount of $326.9M in 2012 in the application. If the methods are not the same, please state the amount arising from the change, and explain what has changed and why.

b) If the amount of depreciation expense included in the revenue requirement for assets depreciated under CGAAP using Hydro One's group method in 2011 has been calculated using the same method in 2012, please explain why a variance account is required in 2012 if an amount, continuing the use of the 2011 methodology, is already included in the revenue requirement for any gains and losses arising from premature asset retirement. Please explain this in the context of a utility such as Hydro One that is in a relatively mature state of asset management where the variability from year to year in depreciation cost should be minimal and where the difference in cost impact between methods chosen to deal with group assets and associated gains and losses on disposition is therefore also expected to be minimal.

c) Please confirm that, if the requested variance account is approved by the Board, the account should be reduced by the amount of depreciation expense otherwise included in rates as described in b) arising under the existing methodology.

d) On page 8 of 9 Hydro One states that accumulated depreciation reserves were maintained at the uniform system of accounts level. Please provide information for the historical and two prior years as to the amounts added to these accumulated depreciation accounts for group assets attributable to gains and losses resulting from premature asset retirements and included in the application for 2011 and for 2012.

e) Please explain why gains and losses on tangible and intangible asset sales should be included in the proposed variance account when the matters of concern appear to relate primarily to premature retirement of group assets. Please explain how gains and losses on tangible and intangible asset sales have been recorded in the past, how they have been reflected in the revenue requirement and why different treatment is required in 2012.

Response

a) Hydro One confirms that the 2011 and 2012 revenue requirements were both based on group depreciation applied under Canadian generally accepted accounting principles (CGAAP). The year-over-year increase in depreciation expense in 2012 is due to increased in-service assets in the rate base, and not a difference in the mechanics of the depreciation calculation.

We have since estimated the expected impact of using IFRS depreciation (straight-line item procedure) on 2010. Transmission depreciation under IFRS is estimated to exceed CGAAP group depreciation by approximately $4.6 million if followed in 2010. However, since the time of filing, the Canadian Accounting Standards Board issued on July 28, 2010 an exposure draft proposing to allow reporting entities with rate regulated activities the option of deferring their implementation of IFRS until 2013.

b) As noted under (a) above, Hydro One expected to manage the expected increase in its actual depreciation expense applied on an IFRS basis within its approved revenue requirement for 2012. As Hydro One now anticipates to adopt IFRS for external reporting purposes in 2013 rather than in 2011, it is anticipated that an analogous delay will be considered by the OEB given the transition date for IFRS of January 1, 2011 in the Board's Report, *Transition to International Financial Reporting Standards*, will have passed. In such a case, straight line item depreciation under IFRS would commence in 2013 and the requested losses deferral account would not be needed until that date.

Hydro One requested the losses variance account to capture the expected losses resulting from premature asset retirements under an IFRS straight line item procedure, thus ensuring capital recovery. Under CGAAP group depreciation, 'losses' on premature asset retirements were recorded as adjustments to accumulated depreciation and did not impact results of operations. As a result, no immediate recovery of losses is included in the submitted 2011 or 2012 revenue requirements.

Under the depreciation method to be used for IFRS, any asset component that is retired prior to being fully depreciated will trigger an accounting loss in the Statement of Operations. These future losses cannot be projected now based on historic trends as insufficient information exists. While Hydro One does have extensive historical information on its asset retirements, it does not have access to information on the related accounting losses because such losses were not calculated under CGAAP where accumulated depreciation reserves were maintained at the uniform system of accounts level rather than at the individual asset level. Asset net book value information was only derived on an exception basis when required to account for a sale. We expect that better information on actual losses under IFRS will be developed prior to the expected 2013 adoption of IFRS.

However, under IFRS, a loss will be recorded whenever an asset retires before its expected end of accounting life. Thus, the amount of losses in a given period will be contingent on the specific in-service year of assets retired, whether through planned or unplanned work. As such, losses will be difficult to accurately forecast given unanticipated events such as major storms, demand driven asset upgrades, changes in business circumstances and the fact that specific asset vintages and carrying values can not be considered when planning sustainment work.

c) The Company agrees that the variance account should be credited for any depreciation expense in rates that is attributable to prematurely retired assets. The depreciation credit would be calculated based amount of depreciation in approved revenue requirement that will not be incurred as a result of an asset premature retirement.

d) Hydro One accounts for all of its fixed assets on a group basis. When an asset is retired, the original capital cost and an equal amount of accumulated depreciation is removed from the balance sheet. No loss is recorded in the Statement of Operations or “added” to the accumulated depreciation accounts.

e) Under CGAAP, fixed asset gains and losses on sale are recorded in the Statement of Operations as a component of depreciation expense. Hydro One has historically not estimated future asset sales or resultant gains and losses when forecasting depreciation expense. Given that a variance account is being requested for premature asset retirement losses under IFRS, Hydro One considered it reasonable to include actual gains and losses on asset sales that are not in the forecast revenue requirement.

Ontario Energy Board (Board Staff) INTERROGATORY #91 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

91) Ref: Exhibit F1/Tab1/Sch2/p1-5

The 8% Ontario provincial sales tax ("PST") and the 5% Federal goods and services tax ("GST") were harmonized effective July 1, 2010, at 13%, pursuant to Ontario Bill 218 which received Royal Assent on December 15, 2009.

Prior to this event the PST would have included in Hydro One's OM&A expenses and capital expenditures. PST therefore would have been included in Hydro One's revenue requirement and therefore recovered from ratepayers through UTR rates.

Now PST and GST are harmonized, Hydro One will pay the HST on purchased goods and services and is eligible to claim a full input tax credit ("ITC") on the HST portion paid. Therefore, Hydro One will no longer incur that portion of the tax that was formerly applied as PST.

In the majority of 2010 electricity rate applications the Board ordered the establishment of a deferral account to record the amounts, after July 1, 2010 and until the distributors next cost-of-service rebasing application, that were formerly incorporated as the 8% PST on capital expenditures and OM&A expenses incurred, but which would now be eligible for an ITC.

a) Please confirm that Hydro One agrees that its current rates include recovery of PST costs for the period July 1, 2010 to December 31, 2010.

b) How would Hydro One propose that the Board fairly address the PST savings arising from July 1, 2010 to December 31, 2010 and ensure PST savings are returned to consumers?

c) Please confirm that Hydro One has reflected the reductions in proposed OM&A and capital expenditures due to the elimination of PST in its application for 2011 and 2012?

d) If Hydro One has not reflected the elimination of PST in its application for 2011 and 2012, please provide an estimate of the amounts that should be removed from its 2011 and 2012 proposed OM&A and capital expenditures.

Response

a) Confirmed. Hydro One's current rates include recovery of PST costs for the period July 1, 2010 to December 31, 2010.

b) In both EB-2008-0272 and EB-2009-0096 Hydro One agreed to develop a methodology to ensure that the estimated PST savings in approved rates will be captured in a deferral account for disposition in future rate applications. The revenue requirement impact driven by the harmonization of the PST and GST will be captured in deferral account 1592.

c) The elimination of the PST has not been reflected in the 2011 and 2012 proposed OM&A and capital expenditures.

d) Hydro One is in the process of establishing the methodology that will capture the revenue requirement impact driven by the harmonization of the PST and GST. The current best estimate of the amounts included in the 2011 and 2012 proposed OM&A and capital expenditures are as follows:

	2011 $M	**2012 $M**
OM&A	$5.2	$5.3
Capital Expenditures	$42.6	$35.8

Hydro One will record the revenue requirement impact of the estimated reduction in our proposed 2011 and 2012 expenditures in deferral account 1592.

Ontario Energy Board (Board Staff) INTERROGATORY #92 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

Ref: Exhibit F1/Tab1/Sch2/p1-5

Hydro One is requesting approval to continue or establish seven new deferral accounts.

Impact for Changes in IFRS Account (2012 only)

a) What account number does Hydro One propose to use in the USoA for this account?
b) What are the journal entries to be recorded?
c) Please provide Hydro One's estimate of the costs that would be recorded in this account.
d) Is there any new or additional information since the May 19, 2010 filing of this application that would assist the Board in assessing this request?

IFRS – Gains and Losses Account (2012 only)

e) Please provide an estimate of the costs that would be recorded in this account in 2012.
f) Please provide an estimate of the impact on revenue requirements going forward indicating at a minimum the directional impact, based on historical experience and other analysis.
g) If the costs are not known, what is the basis for the approval to record these amounts in a deferral account?
h) What account number does Hydro One propose to use in the USoA for this account?
i) What are the journal entries to be recorded?
j) Is there any new or additional information since the May 19, 2010 filing of this application that would assist the Board in assessing this request?

IFRS Incremental Transition Costs Account

k) What amount is currently in the revenue requirements for these costs?
l) How much variance was in this account as of December 31, 2009?
m) How much does Hydro One expect to record in this account in 2011 and 2012?
n) What is the current balance in this account?
o) Why does Hydro One require the continuing use of this account in 2011 and 2012, given that the implementation date for IFRS is January 2011 and it is reasonable to expect Hydro One to have incurred the majority of the transition costs by the implementation date?
p) What account number does Hydro One propose to use in the USoA for this account?

q) What are the journal entries to be recorded?

r) Is there any new or additional information since the May 19, 2010 filing of this application that would assist the Board in assessing this request?

OEB Cost Differential Account

On page 4, lines 15 – 22, Hydro One has stated that this account is a continuation of the account accepted in EB-2008-0272. However, the description of the account that was approved for continuation (Decision With Reasons, Table Deferral/Variance Accounts Balances as of June 30, 2009 on page 55) is "OEB Cost Assessment Differential" and not "OEB Cost Differential Account". The former is strictly for recording OEB Cost Assessment differential, while the latter (i.e. the proposed account) will also track differences in intervenor cost awards, and costs associated with OEB-initiated studies.

In two other recent Hydro One Distribution decisions (EB-2007-0681, and EB-2009-0096) the Board denied Hydro One's request for the same account that is being requested in this application, stating the following:

> "The Board does not consider it reasonable in this case to exempt HydroOne from the Board's current policy not to authorize an OEB costvariance account to distributors." (EB-2007-0681); and

> "The Board concurs with Board staff and the intervenors. The extended coverage sought by Hydro One is not available to other distributors, and no compelling reason has been provided for why Hydro One should be treated differently." (EB-2009-0096)

s) What is the reasoning for Hydro One to continue to accrue amounts in OEB Cost Assessment account in 2011 and 2012? (According to Article 220 of the APH: "This account shall be used to record the difference between OEB costs assessments invoiced to the distributor for the Board's 2004/05 and 2005/06 (up to April 30, 2006) fiscal years and OEB costs assessments previously included in the distributor's rates.")

t) Does Hydro One agree that the account being requested will record costs that are in addition to what was approved for continuation in EB-2008-0272?

u) Does Hydro One agree that the account description approved in EB-2008-0272 is different from what is being proposed by Hydro One in this application?

v) Can Hydro One provide any reasons as to why the Board should allow this account in the form proposed by Hydro One, given that the Board has disallowed the expanded coverage for recording costs in this account in EB-2007-0681, and EB-2009-0096?

w) Is there any new or additional information since the May 19, 2010 filing of this application that would assist the Board in assessing this request?

Response

Impact for Changes in IFRS Account (2012 only)

a) Hydro One would use Account 1508 Other Regulatory Assets, Sub Account Impact of Changes in IFRS.

b) Hydro One cannot reasonably predict specific entries that would result from future changes in IFRS accounting standards or from changes in external interpretations of IFRS standards. In general, increases in revenue requirement attributable to such changes would be debited to the account and decreases would be credited.

c) Given that the account is meant to capture the impact of unforeseeable accounting changes, Hydro One does not currently have any reasonable basis to estimate possible impacts.

d) Yes, on July 28, 2010, the Canadian Accounting Standards Board (AcSB) issues an exposure draft proposing that publicly accountable entities that are required to adopt IFRS be given the option of deferring adoption for 2 years until 2013. Hydro One would likely take advantage of this delay if it is approved. If the Board reconsiders its IFRS implementation date as a result, this account would not be required for 2012.

IFRS – Gains and Losses Account (2012 only)

e) Hydro One has requested this account because it cannot reasonably forecast the losses to be incurred upon premature asset retirements under IFRS. Please see Exhibit I, Tab 1, Schedule 90 for more information on the reasons for this.

f) While the amount of losses cannot reasonably be quantified or estimated within a range, Hydro One does expect to incur significant net losses (after inclusion of gains on sale). These losses would be recorded in this proposed account to allow for future review and recovery from customers.

g) In the absence of an approved deferral account to record premature asset losses, all such losses that were not included in revenue requirement on a forecast basis would be charged to the shareholder. This would unfairly burden the shareholder with accounting losses that Hydro One is not reasonably able to predict or in some cases control. For example, assets retied as a result of storm activity or customer upgrade requests can retire earlier than expected, thus resulting in accounting losses under

IFRS. Losses on premature retirement need to be recovered to ensure full capital recovery of prudently installed fixed and intangible assets.

h) Hydro One would use Account 1508 Other Regulatory Assets, Sub Account Net Losses on Asset Premature Retirements.

i) If a loss is recorded in the IFRS Statement of Operations:

Debit: 1508 Net Losses on Asset Premature Retirements
Credit: 4360 Loss on Disposition of Utility and Other Property

If a gain is recorded in the IFRS Statement of Operations:

Debit: 4355 Gain on Disposition of Utility and Other Property
Credit: 1508 Net Losses on Asset Premature Retirements

j) Consistent with Hydro One's response to (g) above, this account would not be used in 2012 if IFRS is deferred. See also discussion at Exhibit I, Tab 1 Schedule 90.

IFRS Incremental Transition Costs Account

k) The amount that is the transmission revenue requirement, for 2010, is approximately $0.9 million.

l) The balance in this account as at December 31, 2009 was $19,602.

m) In light of the Canadian Accounting Standards Board's July 29, 2010 proposal to require the adoption of IFRS by qualifying rate-regulated entities effective January 1, 2013, Hydro One is re-assessing its transition plan and inherently the costs related to that plan. As such, it is difficult to provide an expectation of the amounts to be recorded in 2011 and 2012, hence the continued need for the variance account.

n) The balance in this account as at June 30, 2010 is $414,436.

o) Please refer to response in part m) above.

p) The account is a continuation of the account established in 2009, as per the Board's guidance in the Accounting Procedures Handbook (APH) FAQ, October 2009. Consistent with the new accounts approved in the APH FAQ, Hydro One proposes to use a sub-account of account 1508.

q) Where incremental IFRS transition costs recovered in rates are lower than actual costs, the journal entry to be recorded will be:

Debit: IFRS Incremental Transistions Costs Account (1508)
Credit: Revenue(4080)

Where incremental IFRS transition costs recovered in rates are higher than actual costs, the opposite entry would apply.

r) Please refer to response in part m) above.

OEB Cost Differential Account

s) Hydro One inadvertently included the title and scope of the account from the last Distribution submission. That was not intended. Hydro One meant to request continuance of the existing account with no changes to account title or scope. Hydro One regrets any confusion caused.

Hydro One's request to continue to accrue the differential between approved and actual OEB cost assessments in this account for 2011 and 2012 is completely consistent with the existing account and with the discussion and Board Findings in the Board's Decision with Reasons for EB-2009-0096 (pages 57 - 58).

t) No – Please see Hydro One's response to (s) above.

u) No – Please see Hydro One's response to (s) above.

v) Please see Hydro One's response to (s) above.

w) Please see Hydro One's response to (s) above.

Ontario Energy Board (Board Staff) INTERROGATORY #93 List 1

Interrogatory

Issue 7.1 Has Hydro One Networks' cost allocation methodology been applied appropriately?

Ref: Exhibit G2/Tab2/Sch1 and Exhibit H1/Tab 2/Sch 1

The table in Exhibit G2 titled 'Allocation Factors for Dual Function Lines' contains a number of facilities that are either 100% Network or 100% Connection. In at least some cases, the same was true of the same facilities in the previous rate application (identical reference in EB-2008-0272).

a) Why are such facilities termed Dual Function, and how frequently is this functionalization updated.

b) Please confirm that there is no actual impact of the "dual" designation, eg. the ultimate allocation of the cost based on the load forecast is identical whether the facility is "Dual Function / 100% Network" or simply Network function.

c) To assist the Board in understanding the allocation of Dual Function facilities, please provide a brief explanation of why the allocation of a given facility changes from year to year. (For example all sections of A4H have increased from 78% to 84% Network since 2008. Is this the outcome of a different load forecast based on a customer survey, a change in the relative size of metered downstream delivery points, a forecast shift toward the peak period, etc.)

Response

a) These facilities can be used for both the common benefit of all customers and for providing a connection between a Network station and load supply point(s) for one or few customers. Accordingly, they are categorized as Dual Function Line per the methodology described on page 5 of Exhibit G1, Tab 2, Schedule 1. This functionalization is updated when the connectivity of the facility changes resulting in a change to its functional category.

b) Hydro One confirms that the end result of the allocation of costs for a facility that is "Dual Function / 100% Network" is identical to the allocation of Network facility costs.

c) The allocation of Dual Function Line (DFL) costs between the Network and Line Connection pools can change from year to year because the allocation is based on the annual average coincident peak demand of customer load connected to the DFL and the minimum of the average summer and winter transmission capacity, as described on pages 11-12 of Exhibit G1, Tab 2, Schedule 1. For example, the forecast customer load connected to DFL A4H drops from 162MW to 120MW, while the line capacity stays the same, which accounts for the increase in Network allocation from 78% to 84%.

Ontario Energy Board (Board Staff) INTERROGATORY #94 List 1

Interrogatory

Issue 8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network Service?

Ref: Exhibit H1/Tab3/Sch1/Page 3

Hydro One summarizes the AMPCO proposal for Network charges as a fixed monthly charge calculated for each customer based on that customer's average coincident demand on the IESO's 5 highest peak days of the previous year.

a) Does the AMPCO proposal decrease Hydro One's revenue risk related to the volume of throughput?

b) In the event that an important customer of a local distribution company were to go out of business after the 5 days, would Hydro One expect that the LDC's fixed monthly charge would be unaffected for the first year?

c) In the event that a Direct customer or Power Producer were to go out of business, would Hydro One expect the customer to continue to pay a fixed monthly charge?

Response

a) Under the AMPCO proposal, Hydro One's network revenue requirement is apportioned among customers based on the ratio of the customer's average High 5 coincident demands to the system's average High 5 coincident demand, as such there is no risk associated with actual demands being lower than forecast. Revenues would deviate from the approved revenue requirement to the extent that existing customers go out of business or new customers are added.

However, as also noted in the Power Advisory Report (page 23), Hydro One may face increased earnings risk under the High 5 proposal. Under the current network charge determinants approach higher than anticipated costs from increased equipment outages as a result of higher than forecast peak loads are offset by higher revenues. Under the High 5 proposal there would be no offsetting increase in revenues. Under these circumstances, Hydro One's earnings would suffer from earnings attrition due to the break in the relationship between revenues and costs.

b) Yes. Hydro One assumes that rates would not be recalculated, and the loss of an important customer's load reflected, until the following year. For example, if a customer of an LDC were to go out of business in late 2010, the LDC's charge determinants would not be reduced until 2011 and used to calculate rates to be paid by the LDC in 2012. Thus, the LDC would pay transmission charges in 2011 as if its lost customer were still in business. However, the earnings impact on the LDC would be mitigated by the existing Retail Service Variance Account which ensures that LDC's customers pay the amount of transmission charges that the LDC incurs on their behalf. Therefore, the revenue shortfall would ultimately be borne by the LDC's other customers.

c) No. Hydro One assumes that the transmitter would absorb the revenue shortfall until rates are recalculated based on reduced charge determinants. This is similar to the current circumstances where transmitters absorb the revenue risk attributable to the normal ebb and flow of customer demands.

Ontario Energy Board (Board Staff) INTERROGATORY #95 List 1

Interrogatory

Issue 8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network Service?

Ref: Exhibit H1/Tab3/Sch1/Attachment 1/Pages iv and vi

a) Has Hydro One investigated alternatives to the status quo other than the High 5 charge determinant?

b) If so, please describe the alternative(s), including a brief description of how the alternative method(s) tracks the costs of building and operating the Network part of Hydro One's transmission system.

c) For any alternative(s), please show the total monthly or annual charge determinant and the proportions that would be attributable to LDCs, Directs, and Power Producers comparable to the information in Table ES 3 on page vi of the Executive Summary.

Response

a) No. As stated on page 69 of the OEB's Decision With Reasons on Proceeding EB-2008-0272 issued May 28, 2009, Hydro One was not directed to investigate alternatives to the status quo other than the High 5 charge determinant.

b) Not Applicable.

c) Not Applicable.

Ontario Energy Board (Board Staff) INTERROGATORY #96 List 1

Interrogatory

Issue 8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network Service?

Ref: Exhibit H1/Tab3/Sch1/Attachment 1/ Pages vi-vii and Page 50 (Table 12)

The report by Power Advisory calculates that the Network cost responsibility of Directs would decrease by 26.5% in aggregate as a result of changing the methodology.

a) Has Hydro One calculated the individual percentage impacts, and if so what is the largest percentage decrease and what is the smallest decrease (or increase) amongst its Direct customers?

b) Does Hydro One have calculations of the percentage decreases that could be enjoyed with the combination of the High 5 methodology plus load shifting as described in Table 12 on Page 50? If so, what percentage decrease would be experienced by Directs in the "center" and "high" load shifting scenarios?

c) It is calculated that the Network cost responsibility of LDCs would increase by 3.3%% in aggregate as a result of changing the methodology. Has Hydro One calculated the individual percentage impacts, and if so what is the largest percentage increase and what is the smallest increase (or decrease) amongst the LDCs?

Response

a) Power Advisory does not have data for individual customers and therefore presented its analysis at an aggregate level, noting that the impact would vary by customer. Hydro One calculated the Network cost responsibility percentage impacts based on 2009 data for each individual Network Delivery Point, as a result of changing the methodology. The table below presents percentage impacts amongst Hydro One's Direct customers.

Impact of a Change in Methodology

Description	**Direct Customers**
Largest % Decrease	95.6%
Smallest % Decrease or Increase	1.2% Increase
Largest % Increase	92.1%

Hydro One is not able to calculate the transmission cost impact as a result of load shifting by individual customers, as this depends on the particular circumstances and behavioural responses of each customer. An attempt to estimate these impacts would therefore be speculative.

b) Hydro One interprets this question to refer to the load shift impacts on a percentage basis for each of the industries reported in Table 12. This is calculated below by dividing the load shifts in Table 12 by the Peak Demand (MW) for each industry that are also reported in Table 12.

	Peak Demand (MW)		Load Shifts			Percentage Impacts	
			Central	High		Central	High
Pulp and Paper	439.3		-19	-31		-4.3%	-7.1%
Iron and Steel	536.1		-35	-58		-6.5%	-10.8%
Metal Mining	517.2		-30	-55		-5.8%	-10.6%
Non-metallic Minerals	65.5		-2	-3		-3.1%	-4.6%
Petroleum Refining	199.8		0	-3		0.0%	-1.5%
Motor Vehicles	137.7		0	-2		0.0%	-1.5%

Power Advisory has not estimated the impact of a change in methodology by type of industrial customer. The average impact for direct customers is an additional 21.6% reduction under both the central and high cases. It should be cautioned that these impacts could vary significantly among customer types and customers.

c) Power Advisory does not have data for individual customers and therefore presented its analysis at an aggregate level, noting that the impact would vary by customer. Hydro One calculated the Network cost responsibility percentage impacts based on 2009 data for each individual Network Delivery Point, as a result of changing the methodology. The table below presents percentage impacts amongst its LDCs customers.

Impact of a Change in Methodology

Description	LDCs
Largest % Increase	83.2%
Smallest % Increase or Decrease	0.03% Decrease
Largest % Decrease	100.0%

For the reasons expressed in the response to part a of this Interrogatory, Hydro One has not attempted to estimate the impacts of load shifting for individual LDCs.

Ontario Energy Board (Board Staff) INTERROGATORY #97 List 1

Interrogatory

Issue 8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network Service?

Ref: Exhibit H1/Tab3/Sch1/Attachment 1/ Page 54

Power Advisory had requested load data from IESO to enable an analysis of cost responsibility comparable to Table 14.

Please explain what data would be available from IESO, and how it might have improved the information in Table 14 if it had been provided to Power Advisory.

Response

Power Advisory and Hydro One have had ongoing discussions with the IESO regarding data that could be used to calculate transmission cost shifting impacts. The data provided by Hydro One to Power Advisory is based on Hydro One's calculation of the current and High 5 charge determinants for its own customers using IESO data. The IESO has reviewed Hydro One's approach and confirmed that the data and methodology employed by Hydro One was appropriate. The information regarding the other transmitters was not available; however, had it been considered it is expected to have made a minimal impact on the results .

Ontario Energy Board (Board Staff) INTERROGATORY #98 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4 & Exhibit D1/Tab3/Sch3/Appendix A

(a) In Tables 6, 7, 8 and 9 at D1/T3/S3/Appendix A and in Table 1 at D1/T3/S3 Hydro One refers to "government instruction". Does this refer to the Minister's letter of September 21, 2009? If not, to what "instruction" does this refer?

(b) The Minister of Energy, by letter dated May 7, 2010, sought the advice of the Ontario Power Authority ("OPA") regarding a transmission plan updating the September 2009 instruction to Hydro One. Has Hydro One received any new or updated instructions from the Minister regarding transmission projects or transmission plan priorities? If yes, please provide these instructions. If no new or updated instructions have been received from the Minister, is Hydro One aware if the OPA has provided the advice to the Minister sought in the May, 7, 2010 letter?

(c) Please provide a copy of the OPA's advice to the Minister, if such information is in Hydro One's possession. If Hydro One is not in possession of the advice provided by the OPA to the Minister, please seek this information from the OPA and file it in response to this interrogatory.

(d) To the extent that Hydro One has been given new or updated instructions regarding transmission projects or transmission plan priorities, or is aware of the nature of the advice provided to the Minister by the OPA, please provide:
   - i A comparison of the instructions given in the September 21, 2009 letter and the updated Ministerial instruction or OPA advice.
   - ii A description of how this updated instruction or advice affects Hydro One's plans for transmission projects as described in the Green Energy Plan.
   - iii An updated version of Hydro One's Transmission Green Energy Plan that is consistent with the updated instruction or advice.

Response

(a) Yes, the reference to "government instruction" refers to the Minister's letter of September 21, 2009.

(b) Hydro One has not received any new or updated instructions from the Minister regarding transmission projects or transmission plan priorities.

(c) Hydro One has been advised by the OPA that it has not finalized its advice to the Minister of Energy and Infrastructure, as requested by the Minister in his letter of May 7, 2010.

(d) As noted in response to part (b), Hydro One has not received any new or updated instructions from the Minister.

Hydro One began development activities for the Green Energy (GE) projects in response to anticipated demand for the Northwest Transmission Expansion project. In addition, Hydro One began the development work for other priority GE projects in response to the Minister of Energy and Infrastructure's letter dated September 21, 2009. Schedule A of the letter lists 20 GE projects and target in-service dates. As explained in the Green Energy Plan, due to the amount of time needed for consultation, approvals and construction of large transmission projects, development work had to begin on the priority GE projects from that list in order to meet their target in-service dates. Hydro One selected the GE projects where there was an urgency to begin development work primarily based on the target in-service date.

In a letter dated May 7, 2010 (Attachment 1) the Minister of Energy and Infrastructure requested that the OPA develop and submit to him an updated transmission expansion plan updating the September 2009 instruction to Hydro One and considering the sequencing necessary to meet the needs of the FIT program and the Korean Consortium.

In recognition of the OPA's pending update to the Minister and of a letter from the Minister to Hydro One dated May 5, 2010 (Attachment 2) Hydro One began to suspend the development work on all GE projects. In his May 5 letter, the Minister asked Hydro One to "focus [Hydro One's] forthcoming transmission rates application on … projects … [that] are critical to the connection of renewable generation projects that have been identified by the Ontario Power Authority as part of the government's green energy agenda." Hydro One is waiting for project specific direction from the Minister, which is expected after the OPA provides the requested information to the Minister.

Ministry of Energy and Infrastructure

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754
www.ontario.ca/MEI

Ministère de l'Énergie et de l'Infrastructure

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754
www.ontario.ca/MEI

Ontario

MAY - 7 2010

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. ~~Andersen~~: Colin

I would like to take this opportunity to express my appreciation for the hard work performed to-date by the Ontario Power Authority (OPA) on the Feed-in-Tariff (FIT) program and associated power system planning, which has been crucial to the progress achieved in implementing the *Green Energy Act*. I am pleased to see the tremendous interest across the province in developing new renewable energy projects since the FIT program has been launched.

Given this interest, it is clear that timely, well-planned and co-ordinated transmission infrastructure is a critical enabler for both the *Green Energy Act* and FIT program. In September 2009, my predecessor instructed Hydro One to begin the planning, development and implementation of 20 major transmission projects across the province in anticipation of the FIT program launch in October 2009.

Since the time of the instruction to Hydro One, there have been a number of developments in the electricity sector, including an unprecedented response to the FIT program, as well as an historic agreement with a Korean Consortium to develop 2,500 MW of renewable energy projects and to bring wind and solar manufacturing jobs to Ontario.

These developments have underlined the need for co-ordinated transmission planning to account for the many factors and timelines involved. As such, I am writing, pursuant to my authority under subsection 25.26(1) of the *Electricity Act*, to require that the OPA develop and submit to me an updated transmission expansion plan updating the September 2009 instruction to Hydro One and considering the sequencing necessary to meet the needs of the FIT program and the Korean Consortium.

. . . /cont'd

I would expect that the plan will contain recommendations for development sequencing of priority transmission projects and an implementation approach that would ensure that key government commitments are met. I also understand that such advice can only be provided in anticipation of the economic connection test, which is currently being established as part of the FIT program.

A key element of the instruction to Hydro One was to work with the OPA in defining the scope of work, including the sequencing necessary for the implementation of the projects. I understand that Ministry staff have been working extensively with the OPA and Hydro One toward this end. I would expect that your report will continue to build on these extensive efforts to-date, and ask that you provide your advice by June 11, 2010.

Thank you for your prompt attention to this issue, and I look forward to receiving your report.

Sincerely,

Brad Duguid
Minister

Ministry of Energy and Infrastructure

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754
www.ontario.ca/MEI

Ministère de l'Énergie et de l'Infrastructure

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754
www.ontario.ca/MEI

Ontario

MC-2010-1609

MAY - 5 2010

Ms Laura Formusa
President and CEO
Hydro One Inc.
483 Bay Street, 15th Floor, North Tower
Toronto ON M5G 2P5

Dear Ms ~~Formusa~~ LAURA:

I am writing in regards to Hydro One Networks' pending 2011–2012 transmission rates application to the Ontario Energy Board.

As you are aware, the Province of Ontario has keenly felt the impact of the recent recession, and this has been reflected in the government's 2010 budget. We are aggressively pursuing internal cost savings to meet our fiscal targets. At the same time we are committed to ensuring government agencies and Crown corporations across the public sector are equally focused on delivering cost savings that are under their control.

Bearing that in mind, I would request that Hydro One Networks carefully reassess the contents of its transmission rates application prior to filing with the Ontario Energy Board. I would like Hydro One Networks to demonstrate concerted efforts to identify cost saving opportunities and focus your forthcoming transmission rates application on those items that are essential to the safe and reliable operation of your existing assets or projects already under development and approved by the Ontario Energy Board, or are critical to the connection of renewable generation projects that have been identified by the Ontario Power Authority as part of the government's green energy agenda.

Also, as part of Hydro One's efforts to mitigate rate pressures and consistent with the government's policy on the introduction of the harmonized sales tax (HST), I would request that Hydro One commit to tracking for return to ratepayers the full cost reduction impact of input tax credits from items that were previously subject to the Retail Sales Tax (RST).

.../cont'd

I am confident that Hydro One Networks and the Ministry of Energy and Infrastructure can continue working together to provide good value to Ontario electricity customers.

Sincerely,

Brad Duguid
Minister

Ontario Energy Board (Board Staff) INTERROGATORY #99 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4/p.2
At the above reference, Hydro One states "While the timing and nature of some GE Projects will depend on the results of the FIT program, this Plan encompasses transmission investments that will form the backbone of an electricity system re-designed to integrate up to 10,000 MW and beyond of potential renewable generation".

(a) Please identify all projects in the Green Energy Plan (GEP) whose "timing and nature" depend on the results of the FIT program.

(b) Given that the "timing and nature of these projects will depend on the results of the FIT program", what assumption(s) has Hydro One made to estimate the test year costs (Capital and/or Development) for these projects?

Response

(a) The timing and nature of all the Green Energy (GE) projects depend on the addition of new renewable energy facilities, either through the FIT program or other means of procurement with the exception of the Northwest Transmission Reinforcement project.

(b) The OM&A Development costs that are included in the test years are driven by the Minister's letter of September 21, 2009 and the target in-service dates in that letter. Please see Exhibit I, Tab 1, Schedule 98.

Due to the long lead times of transmission projects, the majority of the capital spending for GE projects will occur beyond the test years. The total dollars for GE capital projects that are forecast to come into service in the test years is provided in the table below.

GEGEA: In-Service Capital Additions 2010 – 2012 ($ M)

	2009 - Historic Year	2010 - Bridge Projected	Test Years	
			2011	2012
Development	3.3	0.6	11.4	198.9

The projects included in this table that are forecast to go into service in the test years are described in Exhibit A, Tab 11, Schedule 4 and in Exhibit D1, Tab 3, Schedule 3. They are projects D11 Hearn TS, D12 Leaside TS, D37 & D38 In-Line Circuit Breakers and D43 and D44 Protection and Control for Enablement of Distribution Connected Generation.

The revenue requirement impact of these projects is approximately $0.9M in 2011 and $10.3M in 2012.

Ontario Energy Board (Board Staff) INTERROGATORY #100 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4

At pages 2 and 3 of the above reference, Hydro One identifies the reasons why GEP projects are required.

(a) As the first reason, Hydro One states "The vast majority of potential renewable generation is remote from the transmission grid and/or the Province's load centres". Please provide the analysis/study relied on as the basis for the above statement. Please also indicate when this analysis/study was prepared.

(b) As the second reason why GEP projects are required, Hydro One states "The present capability of the transmission system is inadequate for the incorporation and transfer of additional power". Please provide the analysis/study relied on as the basis for the above statement.

Response

(a) The statement is based on ongoing consultation with the OPA and the experience of the RESOP program and earlier RFPs. The results to date of the FIT program and the Transmission Availability Test confirm this statement to be true.

(b) Please see Exhibit I, Tab 1, Schedule 101 for the Transmission Availability Test (TAT) results. On April 8, 2010 the OPA awarded 2,421 MW of contracts to 184 applicants. The transmission system will require improvements for the incorporation and transfer of additional renewable resources given the locations where generators are requesting connection. Exhibit I, Tab 1, Schedule 101 also provides information on the projects that did not pass the TAT.

Ontario Energy Board (Board Staff) INTERROGATORY #101 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4/p.3
At the above reference Hydro One states, "The OPA performed the Transmission Availability Test (TAT) to determine which FIT applications could connect using existing transmission capacity. Renewable generation that did not qualify under TAT would require additional transmission facilities. In this regard the OPA is developing the Economic Connection Test (ECT) analysis. The ECT will assist in assessing where transmission facilities will be required to connect FIT applicants who cannot connect to the existing transmission network due to lack of available capacity".

(a) Please provide project location, type of generation, nameplate capacity and region for FIT contracts that have cleared the TAT and have been offered a contract by the OPA. If necessary, please ask the OPA for this information.

(b) Please provide project location, type of generation, nameplate capacity and region for FIT contracts that did not clear the TAT and are awaiting the results of the ECT. If necessary, please ask the OPA for this information.

Response

(a) Information on the FIT applications that have cleared the TAT and have been offered a contract by the OPA is available on the OPA's website at the link below and a copy of the list is provided in Attachment 1.

http://fit.powerauthority.on.ca/Storage/100/10989_FIT_Contracts_Offered_April_8_10_-_Applicant_Legal_Name_Order3.pdf

(b) Information on the FIT applications that did not clear the TAT and are awaiting the ECT is available on the OPA's website at the link below and a copy of the list is provided in Attachment 2.

http://fit.powerauthority.on.ca/Storage/100/10988_FIT_Awaiting_ECT_April_8_10_-_Applicant_Legal_Name_Order3.pdf

FIT Contracts April 8 10 - Applicant Legal Name Order

Applicant Legal Name	Project Name	Project City	Project Source	Nameplate Capacity (kW)	Region	Current State
2176047 Ontario Inc.	2176047	Brockville	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2176050 Ontario Inc.	2176050	Brockville	Solar PV Groundmount	9,000	East	CONTRACT OFFERED
2225045 Ontario Inc.	Welland Ridge Road	Welland	Solar PV Groundmount	10,000	Niagara	CONTRACT OFFERED
2225049 Ontario Inc.	Longueil TS Malbouef	Alfred	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225050 Ontario Inc	Norfolk Bloomburg TS	Simcoe	Solar PV Groundmount	10,000	Niagara	CONTRACT OFFERED
2225051 Ontario Inc.	Belleville TS Demorestville	Demorestville	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225053 Ontario Inc.	Napanee TS Taylor Kidd	Odessa (Millhaven)	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225054 Ontario Inc.	Kingston Gardiner TS Odessa	Odessa	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225055 Ontario Inc.	Kingston Gardiner Hwy2 North	Odessa	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225056 Ontario Inc.	Kingston Gardiner Hwy2 South	Odessa	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225128 Ontario Inc	Kingston Gardiner TS Unity Road	Elginburg (Glenburnie)	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225213 Ontario Inc.	Mississippi Mills Solar Park	Mississippi Mills	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225228 Ontario Inc.	Alfred	Alfred	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
2225249 Ontario Inc	Burritts Rapids	Ottawa	Solar PV Groundmount	7,000	East	CONTRACT OFFERED
2225256 Ontario Inc.	Liskeard 1	Temiskaming Shores	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
2225342 Ontario Inc.	Liskeard 3	Timiskiming Shores	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
2225345 Ontario Inc.	Liskeard 4	Temiskaming Shores	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
6324827 Canada Inc.	Birch Creek Hydro	Webbwood	Water	1,000	Northeast	CONTRACT OFFERED
6718710 Canada Corporation	Latchford Dam	Latchford	Water	838	Northeast	CONTRACT OFFERED
6718710 Canada Corporation	Latchford Dam 2	latchford	Water	419	Northeast	CONTRACT OFFERED
Alderville First Nation	Alderville 3	Alnwick Township	Solar PV Groundmount	5,000	East	CONTRACT OFFERED
Amik-BBF HydroKap L.P.	Big Beaver Falls Hydroelectric Project	Kapuskasing	Water	5,500	Northeast	CONTRACT OFFERED
Amik-CTR HydroKap L.P.	Camp Three Rapids Hydroelectric Project	Kapuskasing	Water	5,500	Northeast	CONTRACT OFFERED
Big Thunder Wind Park LP	Big Thunder Beta Windpark	Municipality of Neebing	Wind On-Shore	16,500	Northwest	CONTRACT OFFERED
Bow Lake Phase 1 Wind Farm Ltd.	Bow Lake Phase 1	Montreal River Harbour	Wind On-Shore	20,000	Northeast	CONTRACT OFFERED
Bow Lake Phase 2 Wind Farm Ltd.	Bow Lake Phase 2a	Montreal River Harbour	Wind On-Shore	20,000	Northeast	CONTRACT OFFERED
Bow Lake Phase 2 Wind Farm Ltd.	Bow Lake Phase 2b	Montreal River Harbour	Wind On-Shore	20,000	Northeast	CONTRACT OFFERED
Bracebridge Generation Ltd.	Wilson Falls Generating Station	Bracebridge	Water	2,300	Central	CONTRACT OFFERED
Bracebridge Generation Ltd.	Bracebridge Falls Generating Station	Bracebridge	Water	2,000	Central	CONTRACT OFFERED
BWP Wind Limited Partnership	Merlin Wind Farm	Merlin	Wind On-Shore	10,000	West of London	CONTRACT OFFERED
Canadian Shield Wind Power Inc.	Little Brit Power	Sudbury	Wind On-Shore	1,500	Northeast	CONTRACT OFFERED
Capital Power GP Holdings Inc.	Port Dover and Nanticoke Wind Project	Walpole	Wind On-Shore	105,000	Niagara	CONTRACT OFFERED
CLEAN BREEZE WIND PARK GRAFTON LP	CLEAN BREEZE WIND PARK GRAFTON	GRAFTON	Wind On-Shore	10,000	East	CONTRACT OFFERED
CLEAN BREEZE WIND PARK LP	CLEAN BREEZE WIND PARK	BALTIMORE	Wind On-Shore	12,500	East	CONTRACT OFFERED
Clearydale Farms	Clearydale Farms	Spencerville	Bio-Gas	498	East	CONTRACT OFFERED
CLOUDY RIDGE WIND PARK LP	SKYWAY 126 WIND ENERGY	SINGHAMPTON	Wind On-Shore	10,000	Niagara	CONTRACT OFFERED
Comber Wind Limited Partnership	Comber East - C24Z Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	CONTRACT OFFERED
Comber Wind Limited Partnership	Comber West - C23Z Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	CONTRACT OFFERED
Conestogo Wind, LP	Conestogo Wind Energy Centre	Alma	Wind On-Shore	23,000	Niagara	CONTRACT OFFERED
Confederation Power Inc.	Goulais Wind Farm	Sault Ste. Marie	Wind On-Shore	25,000	Northeast	CONTRACT OFFERED
Coughlin Controls Inc	Driftwood Power	Monteith	Water	400	Northeast	CONTRACT OFFERED
Cyntech Corporation	Black Bay Solar Project Phase 2	Dorion Township	Solar PV Groundmount	750	Northwest	CONTRACT OFFERED
De Bruin Farms Ltd.	DeBruin Farms Biogas	Wolfe Island	Bio-Gas	360	East	CONTRACT OFFERED
EFFISOLAR ENERGY CORPORATION	EffiSolar Brockville Solar Farm (10MW)	ELIZABETHTOWN-KITLEY	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
EFFISOLAR ENERGY CORPORATION	EffiSolar Beckwith Solar Farm (10MW)	Township of Beckwith	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
EFFISOLAR ENERGY CORPORATION	EffiSolar Cornwall Solar Farm A (10MW)	Township of South Glengarry	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Ernestown Windpark LP	Ernestown Wind Park	Ernestown	Wind On-Shore	10,000	East	CONTRACT OFFERED
Farm Owned Power (Melancthon) Ltd.	Farm Owned Power (Melancthon) Ltd.	Shelburne	Wind On-Shore	100,000	Niagara	CONTRACT OFFERED
Ferme Geranik Inc.	Ferme Geranik Biogas	St. Albert	Bio-Gas	499	East	CONTRACT OFFERED
Gilead Power Corporation	Ostrander Point Wind Energy Park	Prince Edward County	Wind On-Shore	24,000	East	CONTRACT OFFERED
Gillette Farms Inc.	Powerbase / Gillette Farms Inc	Embrun	Bio-Gas	498	East	CONTRACT OFFERED
GLEN MANOR WIND FARM LP	SUNNY SHORES SOLAR FARM	WELLINGTON	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Grand Valley Wind Farms Inc. on behalf of Grand Va	Grand Valley Wind Farms (Phase 2)	Dundalk	Wind On-Shore	10,800	Niagara	CONTRACT OFFERED
GREY HIGHLANDS CLEAN ENERGY LP	GREY HIGHLANDS CLEAN ENERGY	SINGHAMPTON	Wind On-Shore	20,000	Niagara	CONTRACT OFFERED
GREY HIGHLANDS ZERO EMISSION PEOPLE LP	GREY HIGHLANDS ZERO EMISSION PEOPLE	SINGHAMPTON	Wind On-Shore	10,000	Niagara	CONTRACT OFFERED
Grimsby Energy Inc	Grimsby Bioreactor Project	Grimsby	Bio-Gas	1,000	Niagara	CONTRACT OFFERED
Haliburton Forest & Wild Life Reserve Ltd	Haliburton Forest Biopower 1	Haliburton	Biomass	775	Central	CONTRACT OFFERED
High Falls Development Partnership	High Falls Hydropower Development	District of Rainy River	Water	6,400	Northwest	CONTRACT OFFERED
Horizon Hydro LP	Trout Lake River Hydroelectric Project	Ear Falls	Water	4,000	Northwest	CONTRACT OFFERED
Hybridyne Power Generation Site A Inc.	HPG Site A	Brownsville	Solar PV Groundmount	2,000	East	CONTRACT OFFERED
Index Energy Mills Road Corporation	Index Energy Mills Road Corporation	Ajax	Biomass	17,812	Central	CONTRACT OFFERED
Integrated Gas Recovery Services Inc.	Lafleche Landfill Gas Utilization	Moose Creek	Landfill	4,500	East	CONTRACT OFFERED
International Power Canada, inc.	Pointe Aux Roches Wind	Lakeshore	Wind On-Shore	48,600	West of London	CONTRACT OFFERED
International Power Canada, inc.	Plateau III Wind	Melancthon	Wind On-Shore	9,000	Niagara	CONTRACT OFFERED
International Power Canada, inc.	Plateau I & II Wind	Dundalk	Wind On-Shore	18,000	Niagara	CONTRACT OFFERED
Invenergy Solar Canada ULC	Simcoe Solar Energy Centre I	Woodville	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
Invenergy Solar Canada ULC	Simcoe Solar Energy Centre III	Woodville	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
Invenergy Wind Canada ULC	Conestogo Wind Energy Centre 2	Wallensetin	Wind On-Shore	19,500	Niagara	CONTRACT OFFERED
Invenergy Wind Canada ULC	Conestogo Wind Energy Centre 1	Drayton	Wind On-Shore	69,000	Niagara	CONTRACT OFFERED
Kagawong Power Incorporated	Charlton Dam GS Expansion	Charlton	Water	850	Northeast	CONTRACT OFFERED
Leader Energy.ca Corp.	Clarington Wind Farm	Clarington	Wind On-Shore	10,000	East	CONTRACT OFFERED
LFL Properties Inc.	Elora Hydro Electric Generating Station	Elora	Water	1,000	Niagara	CONTRACT OFFERED
Lizard Creek Power Inc.	Lizard Creek Small Hydro Project	Township of The North Shore	Water	1,040	Northeast	CONTRACT OFFERED
Magnum WInd Energy Corp.	Zurich	Zurich	Wind On-Shore	800	Bruce	CONTRACT OFFERED
M'Chigeeng First Nation	Mother Earth Renewable Energy Project - Phase I	M'Chigeeng	Wind On-Shore	4,000	Northeast	CONTRACT OFFERED
McLean's Mountain Wind L.P.	McLean's Mountain WInd Farm 1	Little Current	Wind On-Shore	50,000	Northeast	CONTRACT OFFERED
McLean's Mountain Wind L.P.	McLeans Mountain Wind Farm 3	Little Current	Wind On-Shore	10,000	Northeast	CONTRACT OFFERED
Namewaminikan Hydro Inc.	Namewaminikan Waterpower Project	Beardmore	Water	10,000	Northwest	CONTRACT OFFERED
Neeskah Energy Limited Partnership	Neeskah Project	Calstock	Water	6,500	Northeast	CONTRACT OFFERED
Nipiy-OWF HydroKap L.P.	Old Woman Falls Hydroelectric Project	Kapuskasing	Water	5,500	Northeast	CONTRACT OFFERED
Nipiy-WOF HydroKap L.P.	White Otter Falls Hydroelectric Project	Kapuskasing	Water	5,500	Northeast	CONTRACT OFFERED

North Bay Hydro Distribution Ltd	Merrick Landfill Project	North Bay	Landfill	1,600	Northeast	CONTRACT OFFERED
Northland Power Solar Abitibi L.P.	Northland Power Solar Abitibi	Cochrane	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
Northland Power Solar Belleville North L.P.	Northland Power Solar Belleville North	Ameliasburg	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Northland Power Solar Belleville South L.P.	Northland Power Solar Belleville South	Ameliasburg	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Northland Power Solar Burks Falls East L.P.	Northland Power Solar Burks Falls East	Burks Falls	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
Northland Power Solar Burks Falls West L.P.	Northland Power Burks Falls West	Ryerson, ON	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
Northland Power Solar Crosby L.P.	Northland Power Solar Crosby	Portland	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Northland Power Solar Empire L.P.	Northland Power Solar Empire	Cochrane	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
Northland Power Solar Glendale L.P.	Northland Power Solar Glendale	Cornwall	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Northland Power Solar Long Lake L.P.	Northland Power Solar Long Lake	Hunta	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
Northland Power Solar Martin's Meadows L.P.	Northland Power Solar Martin's Meadows	Cochrane	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
Northland Power Solar McCann L.P.	Northland Power Solar McCann L.P.	Portland	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Northland Power Solar North Burgess L.P.	Northland Power Solar North Burgess	North Burgess	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Northland Power Solar Rideau Lakes L.P.	Northland Power Solar Rideau Lakes	Rideau Lakes	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Okikendawt Hydro L.P.	Okikendawt Hydroelectric Project	Dokis Bay	Water	10,000	Northeast	CONTRACT OFFERED
Ontario Solar PV Fields 1 Limited Partnership	Wainwright Solar Park	Oxdrift	Solar PV Groundmount	10,000	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 10 Limited Partnership	Mattawishkwia Solar Park	Hearst	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
Ontario Solar PV Fields 11 Limited Partnership	Ramore Solar Park	Ramore	Solar PV Groundmount	8,000	Northeast	CONTRACT OFFERED
Ontario Solar PV Fields 2 Limited Partnership	Morley Solar Park	Stratton, in the Township of Morley	Solar PV Groundmount	10,000	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 3 Limited Partnership	Vanzwolf Solar Park	Township of Dawson	Solar PV Groundmount	10,000	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 4 Limited Partnership	Dave Rampel Solar Park	Township of Dawson	Solar PV Groundmount	10,000	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 7 Limited Partnership	Kap Solar Park	Kapuskasing	Solar PV Groundmount	6,000	Northeast	CONTRACT OFFERED
Pecors Power o/a Cantech Construction Ltd.	Pecors Power Small Hydro Project	Elliot Lake	Water	2,000	Northeast	CONTRACT OFFERED
Peeshoo Energy Limited Partnership	Peeshoo Project	Calstock	Water	6,500	Northeast	CONTRACT OFFERED
Penn Energy Renewables, Ltd.	Penn Energy - S. Glengarry_St. Lawrence-1	South Glengarry	Solar PV Groundmount	9,333	East	CONTRACT OFFERED
Penn Energy Renewables, Ltd.	Penn Energy - Edwardsburgh_Morrisburg-1	Edwardsburgh/Cardinal	Solar PV Groundmount	9,333	East	CONTRACT OFFERED
Penn Energy Renewables, Ltd.	Penn Energy - Hamilton_Port Hope-4	Baltimore	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Peterborough Utilities Inc.	Bensfort Road LFG Generation Project	Peterborough	Landfill	2,000	East	CONTRACT OFFERED
Pic Mobert Hydro Power Joint Venture	Gitchi Animki Niizh Generating Station	Brothers Township	Water	10,000	Northwest	CONTRACT OFFERED
Pic Mobert Hydro Power Joint Venture	Gitchi Animki Bezhig Generating Station	Brothers Township	Water	8,900	Northwest	CONTRACT OFFERED
Pukwis Wind Partner I Inc.and Pukwis Energy Co-ope	Pukwis Community Wind Park	Sutton West	Wind On-Shore	20,000	Central	CONTRACT OFFERED
purEnergy	Kawartha Biogas Inc.	Havelock	Bio-Gas	9,800	East	CONTRACT OFFERED
RE Adelaide 1 ULC	RE Adelaide 1c	Strathroy	Solar PV Groundmount	1,000	West of London	CONTRACT OFFERED
RE Adelaide 1 ULC	RE Adelaide 1d	Strathroy	Solar PV Groundmount	500	West of London	CONTRACT OFFERED
RE Breen 2 ULC	RE Breen 2	Putnam	Solar PV Groundmount	10,000	Niagara	CONTRACT OFFERED
RE Highbury 1 ULC	RE Highbury 1	Dorchester	Solar PV Groundmount	5,000	West of London	CONTRACT OFFERED
RE Ingersoll 1 ULC	RE Ingersoll 1	Ingersoll	Solar PV Groundmount	8,000	Niagara	CONTRACT OFFERED
RE Ingersoll 1 ULC	RE Ingersoll 1b	Ingersoll	Solar PV Groundmount	500	Niagara	CONTRACT OFFERED
RE Ingersoll 1 ULC	RE Ingersoll 1a	Ingersoll	Solar PV Groundmount	1,000	Niagara	CONTRACT OFFERED
RE Midhurst 2 ULC	RE Midhurst 2	Springwater	Solar PV Groundmount	3,500	Central	CONTRACT OFFERED
RE Midhurst 3 ULC	RE Midhurst 3	Oro Station	Solar PV Groundmount	3,500	Central	CONTRACT OFFERED
RE Midhurst 4 ULC	RE Midhurst 4	Oro-Medonte	Solar PV Groundmount	6,500	Central	CONTRACT OFFERED
RE Midhurst 6 ULC	RE Midhurst 6	Midhurst	Solar PV Groundmount	9,000	Central	CONTRACT OFFERED
RE Orillia 1 ULC	RE Orillia 1	Hawkestone	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
RE Orillia 2 ULC	RE Orillia 2	Hawkestone, Oro Medonte	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
RE Orillia 3 ULC	RE Orillia 3	Hawkestone	Solar PV Groundmount	6,500	Central	CONTRACT OFFERED
RE Smiths Falls 1 ULC	RE Smiths Falls 1	Smiths Falls	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
RE Smiths Falls 2 ULC	RE Smiths Falls 2	Perth	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
RE Smiths Falls 3 ULC	RE Smiths Falls 3	Smiths Falls	Solar PV Groundmount	8,000	East	CONTRACT OFFERED
RE Smiths Falls 4 ULC	RE Smiths Falls 4	Perth	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
RE Smiths Falls 5 ULC	RE Smiths Falls 5	Smiths Falls	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
RE Smiths Falls 6 ULC	RE Smiths Falls 6	Rideau Lakes	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
RE Waubaushene 3 ULC	RE Waubaushene 3	Wyebridge	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
RE Waubaushene 4 ULC	RE Waubaushene 4	Coldwater	Solar PV Groundmount	8,000	Central	CONTRACT OFFERED
RE Waubaushene 5 ULC	RE Waubaushene 5	Coldwater	Solar PV Groundmount	3,500	Central	CONTRACT OFFERED
SETTLERS LANDING WIND PARK LP	SETTLERS LANDING WIND PARK	PONTYPOOL	Wind On-Shore	10,000	East	CONTRACT OFFERED
SkyPower Glenarm LP	Glenarm	Kawartha Lakes	Solar PV Groundmount	10,000	Central	CONTRACT OFFERED
SkyPower Val Caron LP	Val Caron	Greater Sudbury	Solar PV Groundmount	10,000	Northeast	CONTRACT OFFERED
Skyway 125 Wind Energy Inc	skyway 125	singhampton	Wind On-Shore	10,000	Niagara	CONTRACT OFFERED
SNOWY RIDGE WIND PARK LP	SNOWY RIDGE WIND PARK	BETHANY	Wind On-Shore	10,000	East	CONTRACT OFFERED
South Branch Windfarm Inc.	South Branch Wind Farm	Brinston	Wind On-Shore	30,000	East	CONTRACT OFFERED
Summerhaven Wind, LP	Summerhaven Wind Energy Centre	Nanticoke	Wind On-Shore	125,000	Niagara	CONTRACT OFFERED
SunE Rutley LP	SunE Rutley	Ingleside	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
Swift River Energy LP	North Bala Small Hydro Project	Bala	Water	5,000	Central	CONTRACT OFFERED
Tempest Power Corp.	William Rutley Solar Park	Ingleside	Solar PV Groundmount	10,000	East	CONTRACT OFFERED
THE CORPORATION OF THE CITY OF KITCHENER	Consolidated Maintenance facility Solar Roof	Kitchener	Solar PV Rooftop	500	Niagara	CONTRACT OFFERED
Trout Creek Wind Power Inc.	Trout Creek	Township of Laurier, District of Parry Sound	Wind On-Shore	10,000	Northeast	CONTRACT OFFERED
Vineland Wind Power Inc.	HAF Energy	Caistors Centre	Wind On-Shore	10,000	Niagara	CONTRACT OFFERED
Wahpeestan Energy Limited Partnership	Wahpeestan Project	Calstock	Water	6,500	Northeast	CONTRACT OFFERED
Wainfleet Wind Energy Inc.	Wainfleet Wind Farm	Wainfleet	Wind On-Shore	10,000	Niagara	CONTRACT OFFERED
Wapoose Energy Limited Partnership	Wapoose Project	Calstock	Water	6,500	Northeast	CONTRACT OFFERED
Wasdell Falls Power Corporation	Wasdell Falls Waterpower Project	Washago	Water	1,900	Central	CONTRACT OFFERED
Waste Management of Canada Corporation	WM Ottawa Landfill Gas to Energy	Ottawa	Landfill	6,400	East	CONTRACT OFFERED
Wendigo Power Partnership Inc.	Wendigo Waterpower Project	Marter Township, Temiskaming	Water	3,000	Northeast	CONTRACT OFFERED
WHISPERING WOODS WIND FARM LP	WHISPERING WOODS WIND FARM	MILLBROOK	Wind On-Shore	10,000	East	CONTRACT OFFERED
White Pines Wind Farm Inc.	White Pines Wind Farm	Milford	Wind On-Shore	60,000	East	CONTRACT OFFERED

WIND FARM COLLIE HILL LP	WIND FARM COLLIE HILL	HASTINGS	Wind On-Shore	5,600	East	CONTRACT OFFERED
Windstream Wolfe Island Shoals Inc.	Wolfe Island Shoals Wind Farm	Marysville	Wind Off-Shore	300,000	East	CONTRACT OFFERED
WOOLWICH BIO-EN INC.	Woolwich Bio-En Inc.	Elmira	Bio-Gas	2,852	Niagara	CONTRACT OFFERED
wpd Canada Corp.	Ballyduff Wind Farm	Pontypool	Wind On-Shore	11,500	East	CONTRACT OFFERED
wpd Canada Corp.	Fairview Wind Farm	Stayner	Wind On-Shore	18,400	Niagara	CONTRACT OFFERED
wpd WF1 Inc.	Belwood Wind Farm	Fergus	Wind On-Shore	9,200	Niagara	CONTRACT OFFERED
wpd WF2 Inc.	Whittington Wind Farm	Orangeville	Wind On-Shore	6,900	Niagara	CONTRACT OFFERED
Xeneca Limited Partnership	McGraw Falls 2089284	Thunder Bay District	Water	2,400	Northwest	CONTRACT OFFERED
Xeneca Limited Partnership	Lapinigam Rapids 6712517	Hearst District	Water	8,200	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	At Soo Crossing 2154061	Sudbury District	Water	4,300	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Cascade Fall 1723378	Sudbury District	Water	2,100	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Ivanhoe River, Third Falls - 2118964	Cochrane District	Water	5,100	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	McPherson Fall 2154065	Sudbury District	Water	2,000	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Wanatango Falls 2124716	Cochrane District	Water	4,670	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Four Slide Falls Ltd 1713400	Elliot Lake City Limits - Sault Ste Marie Region	Water	7,300	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Wabageshik Rapid at Outlet Lake 1723377	Sudbury District	Water	3,400	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Middle Twp Buchan 6712541	Hearst District	Water	5,000	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Allen and Struthers 2130769	Alban Municipality, Sudbury District	Water	2,800	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Big Eddy at CPR Bridge	Petawawa	Water	5,300	East	CONTRACT OFFERED
Xeneca Limited Partnership	Ivanhoe River, The Chute - 2124750	Chapleau District	Water	3,600	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Marter Twp, Blanche River - 2154070	Kirkland Lake District	Water	2,100	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	McCarthy Chute 1713399 Ltd.	Elliot Lake City Limits - Sault Ste Marie Region	Water	2,000	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Near North Boundary Twp Buchan 6712568	Hearst District	Water	3,750	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Outlet Kapuskasing Lake 6773770	Chapleau District	Water	2,500	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Larder Lake & Raven Falls 2118966	Kirkland Lake District	Water	1,250	Northeast	CONTRACT OFFERED
Xeneca Limited Partnership	Half Mile Rapids PGED	Petawawa	Water	4,800	East	CONTRACT OFFERED
ZEP WIND FARM GANARASKA LP	ZEP WIND FARM GANARASKA	ORONO	Wind On-Shore	20,000	East	CONTRACT OFFERED

FIT Awaiting ECT April 8 10 - Applicant Legal Name Order

Applicant Legal Name	Project Name	Project City	Project Source	Nameplate Capacity (kW)	Region	Current State	Enabler Requested
1037193 Ontario Ltd.	SouthPoint Wind Offshore Wind Project - Leamington	Leamington	Wind Off-Shore	10,000	West of London	AWAITING ECT	
1037193 Ontario Ltd.	SouthPoint Wind Offshore Wind Project - Kingsville	Leamintgon	Wind Off-Shore	10,000	West of London	AWAITING ECT	
1037193 Ontario Ltd.	SouthPoint Wind Offshore Wind Project - Union	Leamintgon	Wind Off-Shore	10,000	West of London	AWAITING ECT	
1795205 Ontario Inc.	A&T ENERGY Solar Farm (Harty)	Harty	Solar PV Groundmount	8,250	Northeast	AWAITING ECT	
2131403 Ontario Corp.	Seaforth Wind Farm	Seaforth	Wind On-Shore	10,000	Bruce	AWAITING ECT	
2176052 Ontario Inc.	2176052	Elizabethtown-Kitley	Solar PV Groundmount	10,000	East	AWAITING ECT	
2176089 Ontario Inc.	2176089	Brockville	Solar PV Groundmount	10,000	East	AWAITING ECT	
2186632 Ontario Inc.	Arthur Wind Farm	Arthur	Wind On-Shore	6,000	Niagara	AWAITING ECT	
2224614 Ontario Inc.	Lakeport	Cobourg	Solar PV Groundmount	9,900	East	AWAITING ECT	
2224772 Ontario Inc.	Meyer Wind Farm	Paisley	Wind On-Shore	4,000	Bruce	AWAITING ECT	
2225046 Ontario Inc.	Welland Moyer Road	Welland	Solar PV Groundmount	10,000	Niagara	AWAITING ECT	
2225047 Ontario Inc.	Axio CNP Stevensville West	Fort Erie	Solar PV Groundmount	10,000	Niagara	AWAITING ECT	
2225048 Ontario Inc.	CNP Stevensville East	Fort Erie	Solar PV Groundmount	10,000	Niagara	AWAITING ECT	
2225057 Ontario Inc.	Greely DS West	Osgoode (Greely)	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225059 Ontario Inc.	Wilhaven DS	Cumberland (Ottawa)	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225211 Ontario Inc.	Laurentian Valley Solar Park	Pembroke	Solar PV Rooftop	5,000	East	AWAITING ECT	
2225212 Ontario Inc.	Renfrew Valley Solar Park	Renfrew	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225238 Ontario Inc	Greely	Ottawa	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225253 Ontario Inc.	Tillsonburg 2	Tillsonburg	Solar PV Groundmount	5,000	West of London	AWAITING ECT	
2225338 Ontario Inc.	Liskeard 2	Timiskaming Shores	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
2225348 Ontario Inc.	Liskeard 5	Temiskaming Shores	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
2225350 Ontario Inc.	Liskeard 6	Temiskaming Shores	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
2225352 Ontario Inc.	Perth Solar Power Park	Perth	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225355 Ontario Inc.	True Grid Solar 1	Marter	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
2225357 Ontario Inc.	True Grid Solar 2	Marter Township	Solar PV Groundmount	8,000	Northeast	AWAITING ECT	
2225544 Ontario Inc.	Bio-Carbon Plant Development	Kenora	Biomass	2,000	Northwest	AWAITING ECT	
2225614 Ontario Inc.	GS-02 - Preston Farm	Edwards	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225615 Ontario Inc.	GS-03 - Willem Farm	Edwards	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225616 Ontario Inc.	GS-04 - Barbers Farm	Ottawa	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225617 Ontario Inc.	GS-05 - River Farm	Burritts Rapids	Solar PV Groundmount	10,000	East	AWAITING ECT	
2225618 Ontario Inc.	Willow Hawk Solar Park	Tillsonburg	Solar PV Groundmount	10,000	West of London	AWAITING ECT	
2225619 Ontario Inc.	Tillsonburg 1	Tillsonburg	Solar PV Groundmount	3,000	West of London	AWAITING ECT	
2225712 Ontario Inc.	Schlegel Wind Farm 1	Huron Kinloss	Wind On-Shore	21,000	Bruce	AWAITING ECT	
Ameresco Canada Wind Power, Inc	Ameresco Colchester 1	Harrow	Wind On-Shore	10,000	West of London	AWAITING ECT	
Ameresco Canada Wind Power, Inc	Ameresco Colchester 2	Harrow	Wind On-Shore	10,000	West of London	AWAITING ECT	
Armow Wind Power LP	Armow Wind Farm	Municipality of Kincardine	Wind On-Shore	80,000	Bruce	AWAITING ECT	
Arran Wind Project ULC	Arran Wind Energy	Burgoyne	Wind On-Shore	115,000	Bruce	AWAITING ECT	
BEACONSFIELD BREEZES WIND PARK LP	BEACONSFIELD BREEZES WIND PARK	BURGESSVILLE	Wind On-Shore	10,000	West of London	AWAITING ECT	
Big Thunder Wind Park LP	Big Thunder Alpha Windpark	Municipality of Neebing	Wind On-Shore	16,500	Northwest	AWAITING ECT	
Big Thunder Wind Park LP	Big Thunder Gamma Windpark	Municipality of Neebing	Wind On-Shore	15,000	Northwest	AWAITING ECT	
Big Thunder Wind Park LP	Big Thunder Delta Windpark	Municipality of Neebing	Wind On-Shore	16,000	Northwest	AWAITING ECT	
Big Thunder Wind Park LP	Big Thunder Epsilon Windpark	Municipality of Neebing	Wind On-Shore	15,000	Northwest	AWAITING ECT	
Bornish Wind, LP	Bornish Wind Energy Centre	Keyser	Wind On-Shore	73,500	West of London	AWAITING ECT	
Boulevard Associates Canada, Inc.	Goshen Wind Energy Centre	Dashwood	Wind On-Shore	102,000	Bruce	AWAITING ECT	
Boulevard Associates Canada, Inc.	East Durham Wind Energy Centre	Priceville	Wind On-Shore	23,000	Bruce	AWAITING ECT	
Boulevard Associates Canada, Inc.	Jericho Wind Energy Centre	Thedford	Wind On-Shore	150,000	West of London	AWAITING ECT	ENABLER REQUESTED
Boulevard Associates Canada, Inc.	Bluewater Wind Energy Centre	Zurich	Wind On-Shore	60,000	West of London	AWAITING ECT	ENABLER REQUESTED
Brampton Brick Limited	Brampton Brick Welland Solar Rooftop Project	Welland	Solar PV Rooftop	2,500	Niagara	AWAITING ECT	
BWP Wind Limited Partnership	Harwich Wind Farm	Blenheim	Wind On-Shore	10,000	West of London	AWAITING ECT	
BWP Wind Limited Partnership	Flat Creek II Wind Farm	Blenheim	Wind On-Shore	10,000	West of London	AWAITING ECT	
BWP Wind Limited Partnership	Flat Creek I Wind Farm	Blenheim	Wind On-Shore	8,000	West of London	AWAITING ECT	
BWP Wind Limited Partnership	Walker Marsh Wind Farm	Cottam	Wind On-Shore	10,000	West of London	AWAITING ECT	
BWP Wind Limited Partnership	Arner Green Wind Farm	Kingsville	Wind On-Shore	10,000	West of London	AWAITING ECT	
BWP Wind Limited Partnership	Laurel Wind Farm	Laurel	Wind On-Shore	12,000	Niagara	AWAITING ECT	
BWP Wind Limited Partnership	St. Joachim Wind Farm	St. Joachim	Wind On-Shore	10,000	West of London	AWAITING ECT	
BWP Wind Limited Partnership	Oakland Wind Farm	Staples	Wind On-Shore	8,000	West of London	AWAITING ECT	
Canadian Shield Wind Power Inc.	North Channel Winds	Gore Bay	Wind On-Shore	3,000	Northeast	AWAITING ECT	
Capital Power GP Holdings Inc.	Kingsbridge II Wind Power Project	Goderich	Wind On-Shore	270,000	Bruce	AWAITING ECT	
Castor River Windfarm Inc.	Miller's Creek Wind Farm	Rainy River	Wind On-Shore	20,000	Northwest	AWAITING ECT	
Ches Counsell Homes Ltd.	Cargill G.S.	Cargill	Water	500	Bruce	AWAITING ECT	
Clinton Energy Ltd	Clinton Energy FD 6.0MW Site	East Huron	Wind On-Shore	6,000	Bruce	AWAITING ECT	
Coldwell Wind Limited Partnership	Coldwell Wind Project	Marathon	Wind On-Shore	100,000	Northwest	AWAITING ECT	ENABLER REQUESTED
Comber Wind Limited Partnership	Comber East - C23Z Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	AWAITING ECT	
Comber Wind Limited Partnership	Comber East - C21J Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	AWAITING ECT	
Comber Wind Limited Partnership	Comber East - C22J Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	AWAITING ECT	
Comber Wind Limited Partnership	Comber West - C22J Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	AWAITING ECT	
Comber Wind Limited Partnership	Comber West - C24Z Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	AWAITING ECT	
Comber Wind Limited Partnership	Comber West - C21J Wind Project	Town of Lakeshore	Wind On-Shore	82,800	West of London	AWAITING ECT	
Comber Wind Limited Partnership	Comber West - Phase II	Town of Lakeshore	Wind On-Shore	18,400	West of London	AWAITING ECT	
Comber Wind Limited Partnership	Comber East - Phase II	Town of Lakeshore	Wind On-Shore	18,400	West of London	AWAITING ECT	
Dairy Lane Systems Ltd	Walker Digester	Malahide township	Bio-Gas	1,000	Niagara	AWAITING ECT	
Domtar Inc	Chaudière (Ottawa) Hydro Project No 2	Ottawa	Water	5,600	East	AWAITING ECT	
Domtar Inc	Chaudière (Ottawa) Hydro Project No 5	Ottawa	Water	5,600	East	AWAITING ECT	
Domtar Inc	Chaudière (Ottawa) Hydro Project No 3	Ottawa	Water	5,600	East	AWAITING ECT	
Domtar Inc	Chaudière (Ottawa) Hydro Project No1	Ottawa	Water	5,600	East	AWAITING ECT	
Domtar Inc	Chaudière (Ottawa) Hydro Project No 4	Ottawa	Water	5,600	East	AWAITING ECT	
Domtar Pulp and Paper Products Inc.	Topping Turbogenerator Project	Dryden	Biomass	15,000	Northwest	AWAITING ECT	
Dover Wind Power Partnership	Dover Wind Energy Centre I	Chatham	Wind On-Shore	39,000	West of London	AWAITING ECT	
Dover Wind Power Partnership	Dover Wind Energy Centre II	Chatham	Wind On-Shore	40,500	West of London	AWAITING ECT	
Dryden Renewable Energy Corp	Dryden Solar Park 1	Dryden	Solar PV Groundmount	5,000	Northwest	AWAITING ECT	
Dymond Solar Power Inc.	Dymond	New Liskeard	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
EFFISOLAR ENERGY CORPORATION	EffiSolar Cornwall B Solar Farm B (7MW)	Township of South Glengarry	Solar PV Groundmount	7,000	East	AWAITING ECT	
EFFISOLAR ENERGY CORPORATION	EffiSolar Wolford Solar Farm (10MW)	Township of Merrickville-Wolford	Solar PV Groundmount	10,000	East	AWAITING ECT	
Environmental Electric Company Inc.	Heron Bay	Heron Bay	Wind On-Shore	3,300	Northwest	AWAITING ECT	
Erie Shores West Wind Farm LP & 2181967 Ontario Co	Erie Shores West Wind Farm	Vienna	Wind On-Shore	22,500	West of London	AWAITING ECT	
FESTIVAL WIND FARM LP	FESTIVAL ZORRA WIND FARM	STRATFORD	Wind On-Shore	10,000	Bruce	AWAITING ECT	
Forest Wind Power Inc.	Forest Wind Farm	Forest	Wind On-Shore	10,000	West of London	AWAITING ECT	
Grand Bend Wind L.P.	Grand Bend Wind Farm	Zurich	Wind On-Shore	100,000	Bruce	AWAITING ECT	
Grand Valley Wind Farms Inc. on behalf of Grand Va	Grand Valley Wind Farms (Phase 3)	Grand Valley	Wind On-Shore	40,000	Bruce	AWAITING ECT	
Gunn's Hill Windfarm Inc.	Gunn's Hill Wind Farm	Woodstock	Wind On-Shore	25,000	West of London	AWAITING ECT	
Hearst Biomass Energy LP	Hearst Biomass Energy LP	Hearst	Biomass	9,999	Northeast	AWAITING ECT	

Helios Project III Limited Partnership	Ottawa Solar Project	Ottawa	Solar PV Groundmount	10,000	East	AWAITING ECT	
Innergex renewable energy inc.	Rock Hill	Greater Madawaska	Wind On-Shore	100,000	East	AWAITING ECT	ENABLER REQUESTED
Innergex renewable energy inc.	Masinabik	Greenstone	Wind On-Shore	150,000	Northwest	AWAITING ECT	ENABLER REQUESTED
Innergex renewable energy inc.	Chii Noden	Greenstone	Wind On-Shore	90,000	Northwest	AWAITING ECT	ENABLER REQUESTED
Innergex renewable energy inc.	Laurier	Powassan	Wind On-Shore	100,000	Northeast	AWAITING ECT	ENABLER REQUESTED
Innerkip Windfarm Inc.	Innerkip Wind Farm	Innerkip	Wind On-Shore	19,000	Niagara	AWAITING ECT	
Integrated Gas Recovery Services Inc.	Essex Regional Landfill Gas Utilization	Essex	Landfill	4,500	West of London	AWAITING ECT	
International Power Canada, inc.	Silcote Corners Wind	Annan	Wind On-Shore	46,800	Bruce	AWAITING ECT	
International Power Canada, inc.	Erieau Wind	Chatham-Kent	Wind On-Shore	99,000	West of London	AWAITING ECT	
International Power Canada, inc.	Byng Wind	Dunnville	Wind On-Shore	9,000	Niagara	AWAITING ECT	
International Power Canada, inc.	Blue Sky Wind II	Essex	Wind On-Shore	19,800	West of London	AWAITING ECT	
International Power Canada, inc.	Blue Sky Wind I	Essex	Wind On-Shore	19,800	West of London	AWAITING ECT	
International Power Canada, inc.	Blue Sky Wind III	Essex	Wind On-Shore	9,000	West of London	AWAITING ECT	
International Power Canada, inc.	Belle River Wind	Lakeshore	Wind On-Shore	95,000	West of London	AWAITING ECT	
International Power Canada, inc.	Blue Water Wind	Ripley	Wind On-Shore	125,000	Bruce	AWAITING ECT	
International Power Canada, inc.	East Lake St. Clair Wind	Wallaceburg	Wind On-Shore	99,000	West of London	AWAITING ECT	
Kenogami Industries Inc.	Longlac Biomass Cogeneration Project	Longlac	Biomass	25,000	Northwest	AWAITING ECT	
Kent Centre Wind Farm Inc.	Kent Centre Wind Farm	Blenheim	Wind On-Shore	100,000	West of London	AWAITING ECT	
Kerr's Ridge Windfarm Inc.	Kerr's Ridge Wind Farm	Mountain	Wind On-Shore	20,000	East	AWAITING ECT	
Kruger Energy Chatham II L.P.	Chatham Extension Wind Project	Merlin (municipality of Chatham-Kent)	Wind On-Shore	7,500	West of London	AWAITING ECT	
Lac Seul First Nation	Bluffy Lake Hydro WSR-2007-49	unorganized area	Water	4,200	Northwest	AWAITING ECT	
LAKESIDE BREEZES LP	LAKESIDE BREEZES I	IONA STATION	Wind On-Shore	10,000	West of London	AWAITING ECT	
LAKESIDE BREEZES LP	LAKESIDE BREEZES II	IONA STATION	Wind On-Shore	10,000	West of London	AWAITING ECT	
Lakewind Power Cooperative Inc.	Lakewind/Bervie	Kincardine	Wind On-Shore	20,000	Bruce	AWAITING ECT	
Liberty Energy Inc.	Liberty Energy Centre Phase 1	Hamilton	Biomass	6,500	Niagara	AWAITING ECT	
Loch Lomond Hydro LP	Loch Lomond Hydro	Thunder Bay	Water	2,100	Northwest	AWAITING ECT	
Loch Lomond Wind Energy LP	Loch Lomond	Thunder Bay	Wind On-Shore	48,300	Northwest	AWAITING ECT	
LongLake 58 First Nation	LongLake 1	Longlac	Solar PV Groundmount	4,000	Northwest	AWAITING ECT	
LongLake 58 First Nation	Long Lake 2	Longlac	Solar PV Groundmount	5,000	Northwest	AWAITING ECT	
Lower Lake Hydro Limited Partnership	Lower Lake Hydroelectric Project	Terrace Bay	Water	10,000	Northwest	AWAITING ECT	
Loyalist Wind Project LP	Prince Edward County Wind Project - Phase II	Milford	Wind On-Shore	32,000	East	AWAITING ECT	
Loyalist Wind Project LP	Prince Edward County Wind Project - Phase I	Milford	Wind On-Shore	10,000	East	AWAITING ECT	
Mahekun Energy Limited Partnership	Mahekun Project	Calstock	Water	5,000	Northeast	AWAITING ECT	
Mainstream Sydenham Renewable Power Inc.	Sydenham Wind Energy Centre	RR5 Bothwell	Wind On-Shore	66,700	West of London	AWAITING ECT	
Majestic Energy Inc. (6736785 Canada Inc.)	Majestic Wind Farm	Paisley	Wind On-Shore	2,000	Bruce	AWAITING ECT	
Manitoulin Greenhead Windpark LP	Greenhead Wind Park	Town of Northeastern Manitoulin and the Islands	Wind On-Shore	8,000	Northeast	AWAITING ECT	
Marlborough Windfarm Inc.	Marlborough Wind Farm	Richmond	Wind On-Shore	20,000	East	AWAITING ECT	
Maximum Breeze Energy Co-operative	Maximum Breeze	Lucan	Wind On-Shore	10,000	Bruce	AWAITING ECT	
McLean's Mountain Wind L.P.	McLeans Mountain Wind Farm 4	Little Current	Wind On-Shore	10,000	Northeast	AWAITING ECT	
McLean's Mountain Wind L.P.	McLeans Mountain Wind Farm 5	Little Current	Wind On-Shore	10,000	Northeast	AWAITING ECT	
McLean's Mountain Wind L.P.	McLeans Mountain Wind Farm 6	Little Current	Wind On-Shore	10,000	Northeast	AWAITING ECT	
McLean's Mountain Wind L.P.	McLeans Mountain Wind Farm 2	Little Current	Wind On-Shore	10,000	Northeast	AWAITING ECT	
Merlin Quinn Wind Power LP	Merlin Quinn Wind Farm	TILBURY	Wind On-Shore	54,000	West of London	AWAITING ECT	
Michipicoten First Nation	Dore Falls Hydropower Development	Wawa	Water	2,000	Northeast	AWAITING ECT	
Morphy's Falls Windfarm Inc.	Beckwith Wind Farm	Carleton Place	Wind On-Shore	12,500	East	AWAITING ECT	
Multistream Power Corporation	Fourth Chute GS	Township of Bonnechere Valley	Water	1,800	East	AWAITING ECT	
Muskoo Energy Limited Partnership	Muskoo Project	Calstock	Water	9,999	Northeast	AWAITING ECT	
Neekik Energy Limited Partnership	Neekik Project	Calstock	Water	12,000	Northeast	AWAITING ECT	
Neguaquon Lake Hydro Development Projects LP	Myrtle Falls Hydropower Development	District of Rainy River	Water	2,000	Northwest	AWAITING ECT	
New Liskeard Solar Power Inc.	New Liskeard	New Liskeard	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
Nimaasing Wind Limited Partnership	Nimaasing Wind Project	Sault Ste Marie	Wind On-Shore	200,000	Northeast	AWAITING ECT	ENABLER REQUESTED
North Shore Power Group Inc.	Blind River Solar Generating Facility	Blind River	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
NORTHERN LIGHTS WIND PARK LP	NORTHERN LIGHTS WIND PARK	MARKDALE	Wind On-Shore	10,000	Bruce	AWAITING ECT	
Northland Power Solar Brockville L.P.	Northland Power Solar Brockville	Brockville	Solar PV Groundmount	10,000	East	AWAITING ECT	
Northland Power Solar Gold L.P.	Northland Power Solar Gold	Cochrane	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
Northland Power Solar Hunta L.P.	Northland Power Solar Hunta	Hunta	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
Northland Power Solar Ramore L.P.	Northland Power Solar Ramore	Ramore	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
Northland Power Solar Smith Falls L.P.	Northland Power Solar Smith Falls L.P.	Jasper	Solar PV Groundmount	10,000	East	AWAITING ECT	
Northland Power Solar Theriault L.P.	Northland Power Solar Theriault	Matheson	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
Ojibways of the Pic River First Nation	High Falls Hydropower Development	Heron Bay	Water	3,200	Northwest	AWAITING ECT	
Ojibways of the Pic River First Nation	Manitou Falls Hydropower Development	Heron Bay	Water	2,800	Northwest	AWAITING ECT	
Ontario Clean Power Bonfield Inc. JV with Windstream Energy	Matachewan Wind Farm	Matachewan	Wind On-Shore	100,000	Northeast	AWAITING ECT	
Ontario Clean Power South River Inc. JV with Windstream Ene	South River Wind Farm Phase 2	Powassan	Wind On-Shore	10,000	Northeast	AWAITING ECT	
Ontario Clean Power South River JV with Windstream Energy	South River Wind Farm Phase 1	Powassan	Wind On-Shore	10,000	Northeast	AWAITING ECT	
Ontario Solar PV Fields 5 Limited Partnership	Mountjoy North Solar Park	Timmins	Solar PV Groundmount	6,000	Northeast	AWAITING ECT	
Ontario Solar PV Fields 6 Limited Partnership	Dalton Road South Solar Park	Timmins	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
Ontario Solar PV Fields 8 Limited Partnership	Photon Solar Park	Kapuskasing	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
Penn Energy Renewables, Ltd.	Penn Energy - Eliza-Kitley_Brockville 1	Brockville	Solar PV Groundmount	10,000	East	AWAITING ECT	
Penn Energy Renewables, Ltd.	Penn Energy - Edwardsburgh_Brockville-2	Edwardsburgh/Cardinal	Solar PV Groundmount	7,460	East	AWAITING ECT	
Penn Energy Renewables, Ltd.	Penn Energy - Edwardsburgh_Brockville-1	Edwardsburgh/Cardinal	Solar PV Groundmount	9,333	East	AWAITING ECT	
Penn Energy Renewables, Ltd.	Penn Energy - Thunder Bay_Ft. William	Thunder Bay	Solar PV Groundmount	7,700	Northwest	AWAITING ECT	
PIONEER WIND PARK LP	PIONEER WIND PARK	Shedden	Wind On-Shore	10,000	West of London	AWAITING ECT	
POLAR BEAR WIND PARK LP	POLAR BEAR WIND PARK	WELLINGTON	Wind On-Shore	20,000	East	AWAITING ECT	
Preneal Canada Inc.	Northern Bruce Penisula 150 MW	Lion's Head, Northern Bruce Peninsula	Wind On-Shore	150,000	Bruce	AWAITING ECT	ENABLER REQUESTED
Quixote One Wind Energy Corp	Q1WEC	Tiverton	Wind On-Shore	2,500	Bruce	AWAITING ECT	
Quixote Three Wind Energy Corp.	Q3WEC	Clinton	Wind On-Shore	2,500	Bruce	AWAITING ECT	
Quixote Two Wind Energy Corp.	Q2WEC	Kincardine	Wind On-Shore	2,500	Bruce	AWAITING ECT	
RE Adelaide 1 ULC	RE Adelaide 1	Strathroy	Solar PV Groundmount	4,000	West of London	AWAITING ECT	
RE Adelaide 1 ULC	RE Adelaide 1a	Strathroy	Solar PV Groundmount	2,500	West of London	AWAITING ECT	
RE Adelaide 1 ULC	RE Adelaide 1b	Strathroy	Solar PV Groundmount	2,000	West of London	AWAITING ECT	
RE Smiths Falls 3 ULC	RE Smiths Falls 3a	Smiths Falls	Solar PV Groundmount	1,000	East	AWAITING ECT	
RE Smiths Falls 3 ULC	RE Smiths Falls 3b	Smiths Falls	Solar PV Groundmount	500	East	AWAITING ECT	
RE Smiths Falls 3 ULC	RE Smiths Falls 3c	Smiths Falls	Solar PV Groundmount	500	East	AWAITING ECT	
RE Sunningdale 1 ULC	RE Sunningdale 1	Thorndale	Solar PV Groundmount	7,000	West of London	AWAITING ECT	
RE Waubaushene 5 ULC	RE Waubaushene 5a	Coldwater	Solar PV Groundmount	1,000	Central	AWAITING ECT	
RE Waubaushene 5 ULC	RE Waubaushene 5b	Coldwater	Solar PV Groundmount	500	Central	AWAITING ECT	
RE Wonderland 1 ULC	RE Wonderland 1	London	Solar PV Groundmount	6,500	West of London	AWAITING ECT	
Redbird Energy	Redbird Energy SEGP Wind Farm	Billings	Wind On-Shore	10,000	Northeast	AWAITING ECT	
Renfrew Power Generation Inc.	First Chute	Horton	Water	1,700	East	AWAITING ECT	
Renfrew Power Generation Inc.	Clear Point	Renfrew	Water	4,000	East	AWAITING ECT	
Ronald Dagg	Eirin Wind Farm	Forest	Wind On-Shore	10,000	West of London	AWAITING ECT	
Roubos Wind Energy Ltd.	Teviotdale 2	Moorefield/Township of Wellington North	Wind On-Shore	1,200	Bruce	AWAITING ECT	
Saturn Power Inc.	Forest Lea Solar Farm	Pembroke	Solar PV Groundmount	6,500	Central	AWAITING ECT	
Saturn Power Inc.	Goshen Solar Farm	Renfrew	Solar PV Groundmount	5,000	East	AWAITING ECT	

Schneider Power Spring Bay Inc.	Spring Bay	Township of Central Manitoulin	Wind On-Shore	4,000	Northeast	AWAITING ECT	
Schouten Corner View Farms Ltd.	Schouten Corner View Farms Ltd.	Richmond	Bio-Gas	498	East	AWAITING ECT	
Schouten Dairy Farms Inc.	Schouten Dairy Farms Inc.	Richmond	Bio-Gas	498	East	AWAITING ECT	
Sequoia Loch Lomond Solar Energy LP	Giizis Power	Thunder Bay	Solar PV Groundmount	10,000	Northwest	AWAITING ECT	
Silvercreek Solar Park Inc.	Silvercreek Solar Park	Aylmer	Solar PV Groundmount	10,000	West of London	AWAITING ECT	
Sky Generation Inc.	Proof Line II	Forest	Wind On-Shore	3,600	West of London	AWAITING ECT	
SkyPower CL 1 LP	Crown Solar 1	Grant/Charlton	Solar PV Groundmount	10,000	Northeast	AWAITING ECT	
SkyPower Napanee Roads LP	Napanee Roads	Napanee	Solar PV Groundmount	10,000	East	AWAITING ECT	
SkyPower Otonabee LP	Otonabee	Peterborough	Solar PV Groundmount	10,000	East	AWAITING ECT	
Skyway 127 Wind Energy Inc.	Skyway 127	Port Elgin	Wind On-Shore	100,000	Bruce	AWAITING ECT	
Solar Semiconductor Inc.	Great Lakes One	Newburgh	Solar PV Groundmount	9,500	East	AWAITING ECT	
St. Catharines Hydro Generation Inc.	Shickluna Hydro Electric Generating Station	St. Catharines	Water	4,000	Niagara	AWAITING ECT	
St. Columban Energy LP	St. Columban 2 Wind Energy Project	Seaforth	Wind On-Shore	15,000	Bruce	AWAITING ECT	
St. Columban Energy LP	St. Columban 1 Wind Energy Project	Seaforth	Wind On-Shore	18,000	Bruce	AWAITING ECT	
Summerhaven Wind, LP	Adelaide Wind Energy Centre	Kerwood	Wind On-Shore	60,000	West of London	AWAITING ECT	
Suncor Energy Products Inc.	Camlachie Wind Power Project	Camlachie	Wind On-Shore	20,000	West of London	AWAITING ECT	
Suncor Energy Products Inc.	Cedar Point Wind Power Project Phase II	Forest	Wind On-Shore	100,000	West of London	AWAITING ECT	
Suncor Energy Products Inc.	Cedar Point Wind Power Project Phase I	Forest	Wind On-Shore	50,000	West of London	AWAITING ECT	
Suncor Energy Products Inc.	Adelaide Wind Power Project	Strathroy	Wind On-Shore	40,000	West of London	AWAITING ECT	
SunE James LP	SunE James	Township of Drummond	Solar PV Groundmount	10,000	East	AWAITING ECT	
SunE McGale LP	SunE McGale	Jasper	Solar PV Groundmount	10,000	East	AWAITING ECT	
SunE McWilliams LP	SunE McWilliams	Ottawa	Solar PV Groundmount	10,000	East	AWAITING ECT	
SunE Paddock LP	SunE Paddock	Jasper	Solar PV Groundmount	10,000	East	AWAITING ECT	
SunE Ray LP	SunE Ray	Township of North Elmsley	Solar PV Groundmount	10,000	East	AWAITING ECT	
SunE Saar LP	SunE Saar	Pembroke	Solar PV Groundmount	10,000	East	AWAITING ECT	
SunE South Stormont LP	SunE South Stormont	Newington	Solar PV Groundmount	10,000	East	AWAITING ECT	
SunE Steepe LP	SunE Steepe	Perth	Solar PV Groundmount	10,000	East	AWAITING ECT	
Superior Shores Wind Farm L.P.	Superior Shores Wind Farm	Heron Bay	Wind On-Shore	25,300	Northwest	AWAITING ECT	
Superior Windfarm LP	Superior Windfarm	Dorion	Wind On-Shore	13,800	Northwest	AWAITING ECT	
Teviotdale Wind Power Inc.	Teviotdale 1	Moorefield/Township of Wellington North	Wind On-Shore	10,000	Bruce	AWAITING ECT	
Toronto Hydro Energy Services Inc.	ABTP Biogas Cogen Plant	Toronto	Bio-Gas	9,912	Central	AWAITING ECT	
Toronto Hydro Energy Services Inc., OPPL	Green Lane	St. Thomas	Landfill	9,912	West of London	AWAITING ECT	
TTD Wind Project ULC	Twenty Two Degree Energy	Holmesville	Wind On-Shore	150,000	Bruce	AWAITING ECT	
UDI Renewables Corporation	UDI Nanticoke Wind Farm	Nanticoke	Wind On-Shore	10,000	Niagara	AWAITING ECT	
Upper Canada Windfarm Inc.	Upper Canada Wind Farm	Lansdowne	Wind On-Shore	12,500	East	AWAITING ECT	
Vortex Wind Power Limited	Kefkatikgwam Mountain Phase 3	Nipigon	Wind On-Shore	20,000	Northwest	AWAITING ECT	ENABLER REQUESTED
Vortex Wind Power Limited	Kefkatikgwam Mountain Phase 1	Nipigon	Wind On-Shore	20,000	Northwest	AWAITING ECT	ENABLER REQUESTED
Vortex Wind Power Limited	Kefkatikgwam Mountain Phase 2	Nipigon	Wind On-Shore	20,000	Northwest	AWAITING ECT	ENABLER REQUESTED
Walpole Island First Nation	Wind Bkejer	Wallaceburg	Wind On-Shore	10,000	West of London	AWAITING ECT	
Weber Wind Farm Inc.	Weber Wind Farm	Mapleton	Wind On-Shore	10,000	Niagara	AWAITING ECT	
Westhills Power Corp.	Horton Solar Park	Renfrew	Solar PV Groundmount	10,000	East	AWAITING ECT	
Wikwemikong-Preneal Wind 100 LP	Wikwemikong 100 MW	Wikwemikong	Wind On-Shore	100,000	Northeast	AWAITING ECT	ENABLER REQUESTED
Wikwemikong-Preneal Wind 26 LP	Wikwemikong 26 MW	Wikwemikong	Wind On-Shore	26,000	Northeast	AWAITING ECT	
Wind Energy Niagara LTD.	Wainfleet Wind Power Development	Wainfleet	Wind On-Shore	10,000	Niagara	AWAITING ECT	
WIND FARM STONETOWN LP	WIND FARM STONETOWN	ST. MARYS	Wind On-Shore	10,000	West of London	AWAITING ECT	
Windstream Bruce Inc.	Bruce Peninsula Wind Farm	Municipality of South Bruce	Wind On-Shore	125,000	Bruce	AWAITING ECT	
Windstream Elk Lake Inc. JV with Windstream Energy Inc & O	Elk Lake Wind Farm	Elk Lake	Wind On-Shore	200,000	Northeast	AWAITING ECT	
Windstream North Inc.	Ranger Lake Wind Farm A Phase 2	Searchmont	Wind On-Shore	50,000	Northeast	AWAITING ECT	
Windstream North Inc.	Ranger Lake Wind Farm B Phase 2	Searchmont	Wind On-Shore	50,000	Northeast	AWAITING ECT	
Windstream North Inc.	Ranger Lake Wind Farm A Phase 1	Searchmont	Wind On-Shore	50,000	Northeast	AWAITING ECT	
Windstream North Inc.	Ranger Lake Wind Farm B Phase 1	Searchmont	Wind On-Shore	50,000	Northeast	AWAITING ECT	
Windstream Temagami Inc. JV with Windstream Energy Inc. &	Friday Lake Wind Farm	Best & Gillies Limit TWP/ Latchford	Wind On-Shore	100,000	Northeast	AWAITING ECT	
wpd Canada Corp.	Shiloh Wind Farm	Alvinston	Wind On-Shore	46,000	West of London	AWAITING ECT	
wpd Canada Corp.	Napier Wind Farm	Kerwood	Wind On-Shore	5,400	West of London	AWAITING ECT	
wpd Canada Corp.	Petrolia Wind Farm	Petrolia	Wind On-Shore	18,400	West of London	AWAITING ECT	
wpd Canada Corp.	Wilkesview Wind Farm	Sombra	Wind On-Shore	13,800	West of London	AWAITING ECT	
Xeneca Limited Partnership	Quibell: Lots 2 & 6 Con III-V Wabigoon - 2127613	Dryden District	Water	4,500	Northwest	AWAITING ECT	
Xeneca Limited Partnership	Island Falls 2130760	Fort Frances District	Water	3,000	Northwest	AWAITING ECT	
Xeneca Limited Partnership	Long Rapids 2130752	Fort Frances District	Water	3,600	Northwest	AWAITING ECT	
Xeneca Limited Partnership	Wabigoon Falls - 6774008	Kenora District	Water	3,900	Northwest	AWAITING ECT	
Xeneca Limited Partnership	Above Ball Lake 2127580	Kenora District	Water	4,100	Northwest	AWAITING ECT	
Xeneca Limited Partnership	Jocko River - 2089282	North Bay District	Water	4,400	Northeast	AWAITING ECT	
Xeneca Limited Partnership	Flower Falls - 2125852	Sioux Lookout District	Water	9,900	Northwest	AWAITING ECT	
Xeneca Limited Partnership	7th - 5th Falls	Sioux Lookout District	Water	6,400	Northwest	AWAITING ECT	
Xeneca Limited Partnership	12th Falls - 8th Falls - 2125855	Sioux Lookout District	Water	5,800	Northwest	AWAITING ECT	
Xeneca Limited Partnership	13th Fall McDougall Mills 2188163	Sioux Lookout District	Water	3,000	Northwest	AWAITING ECT	
Xeneca Limited Partnership	Shabaqua Corner 2124726	Thunder Bay District	Water	2,400	Northwest	AWAITING ECT	
Xeneca Limited Partnership	Roaring Rapids 3.2km from Mouth 2118969	Thunder Bay District	Water	5,100	Northwest	AWAITING ECT	ENABLER REQUESTED
Xeneca Limited Partnership	Kamiskotia Falls 2130765	Timmins District	Water	3,800	Northeast	AWAITING ECT	
ZERO EMISSION PEOPLE PLEASANT BAY LP	ZERO EMISSION PEOPLE PLEASANT BAY	WELLINGTON	Wind On-Shore	20,000	East	AWAITING ECT	
Zurich Wind Power LP	Zurich Wind Farm	Municipality of Bluewater	Wind On-Shore	37,500	Bruce	AWAITING ECT	

Ontario Energy Board (Board Staff) INTERROGATORY #102 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4/p. 3
Hydro One states that its "strategy is to begin the preliminary Development Work on priority GE Projects, those with the highest need as identified in consultation with the OPA and based on the information presently available".

(a) Please identify the high priority projects and explain the criteria used to assign priority.

(b) What is the time period that is implied by the statement "information presently available"?

Response

(a) As explained in Exhibit I., Tab 1, Schedule 98, due to the amount of time needed for consultation, approvals and construction of large transmission projects, development work had to begin on the priority GE projects from that list (Schedule A of the Minister's letter) in order to meet their target in-service dates; and on that basis Hydro One selected the GE projects for which it was reasonable to begin development work. An excerpt from Table 1 of Exhibit A, Tab 11, Schedule 4 shows the priority projects where development work has commenced.

Item #	Investment Description	Item Number as per Schedule A
Projects where Development Work is Underway		
1	East-West Tie Expansion	1
2	Transmission Reinforcement West of London	5
3	North-South Transmission Expansion	2 & 3
4	Manitoulin Island Enabler	8
5	Algoma x Sudbury Transmission Expansion	4
6	Goderich & Huron South Area Enablers	7 & 9
7	Northwest Transmission Reinforcement	14

With respect to how the particular projects from the Minister's letter were prioritized, the following criteria were used to assign priority:

- All Core Transmission (bulk transmission upgrades) were prioritized given their wide areas of service and relatively long lead times, other than the Bowmanville SS x GTA 500 kV line which was deferred pending a decision on whether to add new nuclear capacity at Darlington (no development work is planned in the test years on this project).
- Only the Goderich and Huron South Area (called the Goderich Enabler in the Minister's letter), and Manitoulin Island Enablers were prioritized given the potential benefits and the expectation that the need would be relatively near term. Development work on all other projects is waiting for the OPA's Economic Connection Test process.
- The only "regional transmission" project prioritized was the Northwest Transmission Reinforcement (called Pickle Lake x Nipigon in the Minister's letter). This project was determined to be a priority given the various potential benefits including connection of new renewable generation, and service to additional gold mining in the area and new chromite mining in the Ring of Fire.

As set out in the Green Energy Act, the company also considered the Government's objective with respect to "fostering the growth of renewable energy (generation) projects". This is also established through the new objective of the OEB to "promote the use and generation of electricity from renewable energy sources …, including the timely expansion or reinforcement of transmission systems". In particular, Hydro One notes that the Minister's letter included a request to the company to "immediately proceed with the planning, development and implementation of the Transmission Projects outlined in the attached Schedule A."

(b) Information presently available was the Minister's letter of September 21, 2009.

Ontario Energy Board (Board Staff) INTERROGATORY #103 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4/p.8

At the above reference, Hydro One states that it expects to spend $2.5 billion in the 2010-2014 period and an additional $4.5 billion in the 2015-2020 period. Please provide a breakdown for the above estimates, identifying the projects and related spending.

Response

The amounts total to $7B over the full 2010 to 2020 period which is the total of the estimated capital costs of the 18 Schedule A projects described on pages 10 to 28 of the exhibit. These projects are listed in Table 1 on page 9 of the exhibit and a copy of that table is provided below.

Table 1
Summary of Major Green Projects

Item #	Investment Description	Estimated Cost ($M)
Projects where Development Work is Underway		
1	East-West Tie Expansion	511
2	Transmission Reinforcement West of London	706
3	North-South Transmission Expansion	884
4	Manitoulin Island Enabler	169
5	Algoma x Sudbury Transmission Expansion	431.6
6	Goderich & Huron South Area Enablers	164
7	Northwest Transmission Reinforcement	399.5
Projects where Development Work will begin once OPA Confirms Project Need		
8	Sudbury North - Pinard TS x Hanmer TS	1,234
9	Pembroke Area Enabler	137
10	Parry Sound Enabler	121
11	North Bay Enabler	84
12	Thunder Bay Enabler	119
13	St. Lawrence TS x Merivale TS (Cornwall x Ottawa)	289
14	Selby Junction x Belleville TS	105
15	Chenaux TS x Galetta Junction	104
Projects where Development Work is Not Planned in the Test Years		

16	Longwood TS x Middleport TS	306
17	Bowmanville SS x GTA	167
18	Kenora x Thunder Bay Transmission Expansion	1,006
	Total Cost	6,937

The spending in the test years for these projects is summarized in Table 4 on page 37 of the exhibit, which is also provided below.

Table 4
Projects Proposed for Accelerated Cost Recovery of CWIP in Section 92 Hearings
($Millions)

Project	**2008**	**2009**	**2010**	**2011[a]**	**2012[a]**
Northwest Transmission Reinforcement				4.5	16.9
Algoma x Sudbury Transmission Expansion					5.7
Total	**0**	**0**	**0**	**4.5**	**22.6**

Notes: (a) Excludes AFUDC (b) Total cost including future years

Ontario Energy Board (Board Staff) INTERROGATORY #104 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4

(a) Of the total test year capital expenditure budget, please provide the expenditure that is in the Green Energy Plan and how much of this expenditure will be booked to the test year rate base. If the Green Energy Plan capital expenditures are in more than one investment category, please provide this information by investment category (i.e. sustaining, development, operations and shared services). Please also indentify the amounts that are to be collected from capital contributions.

(b) Please provide an estimate of all "indirect" Green Energy Plan capital costs, if any.

(c) Please provide an estimate of all direct and indirect OMA costs in 2011 and 2012 in the Green Energy Plan.

Response

(a) Please see Exhibit I, Tab 1, Schedule 64 and Exhibit I, Tab 1, Schedule 99. The Green Energy Plan capital expenditures are all in the Development category. There are no capital contributions for these projects. A modified version of the table in Exhibit I, Tab 1, Schedule 99 is provided below with a row to include rate base additions.

GEGEA: In-Service Capital Additions and Rate Base 2010 – 2012 ($ M)

	2009 - Historic Year	2010 - Bridge Projected	Test Years	
			2011	2012
In-Service	3.3	0.6	11.4	198.9
Rate base	1.7	3.6	9.6	114.8

The projects included in this table that are forecast to go into service in the test years are described in Exhibit A, Tab 11, Schedule 4 and in Exhibit D1, Tab 3, Schedule 3. They are projects D11 Hearn TS, D12 Leaside TS, D37 & D38 In-Line Circuit

Breakers and D43 and D44 Protection and Control for Enablement of Distribution Connected Generation.

(b) There are no “indirect” Green Energy Plan capital costs.

(c) The majority of OM&A costs associated with the Green Energy Plan are included in a deferral account and have no impact on the revenue requirement in the test years. There is an additional indirect OM&A cost of approximately $2.0 million in 2011 and approximately $5.0 million in 2012 associated with the Green Energy Plan.

Ontario Energy Board (Board Staff) INTERROGATORY #105 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4/p. 9 – Table 1

Table 1 provides a summary of Major Green Projects in the GEP. With respect to projects 8 to 15, Hydro One states that Development work will begin "once OPA confirms Project Need".

(a) Please clarify if the above statement is a reference to the ECT process currently being conducted by the OPA.

(b) When does Hydro One expect the OPA to confirm project need for these projects?

(c) Development work on projects 8-15 will begin once the OPA confirms project need. Is it possible that the OPA may conclude that some of these projects are no longer needed or are to be deferred? If it is determined by the OPA that some of these projects are no longer needed or are deferred, is it appropriate to conclude that Development work in relation to the affected projects may not have to be undertaken in the test years?

Response

(a) Yes the statement is in reference to the OPA's ECT process that is currently expected to begin in the fall of 2010 and may also be influenced by the events described in Exhibit I, Tab 1, Schedule 98.

(b) The OPA's first ECT assessment cycle is currently expected to be completed in the spring of 2011 after which Hydro One will consult with the OPA to identify those projects that should proceed with Development Work.

(c) Following the first ECT assessment, the Hydro One and the OPA may conclude that Development Work on some of the projects (8-15) should not proceed at that time. However, it may be possible that subsequent ECT assessments in 2011 or 2012 could identify the need to proceed with the Development Work which will require some expenditure in the test years. Hydro One expects to consult with the OPA after each ECT assessment on the likelihood of a successful outcome in subsequent ECT assessments based on the FIT applications received and the expected renewable energy potential in order to revise the projections for potential Development Work expenditures.

Ontario Energy Board (Board Staff) INTERROGATORY #106 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit C1/Tab2/Sch 4 – Table 1
Using the categories of Development work described at Ex A/T11/S4/p. 38, please provide a breakdown of the 2009, 2010 and test year Development costs found in Table 1 (Ex C1/T2/S4/p.10).

Response

The Development costs for the projects in Table 1 have not been broken down in a table in the categories on page 38 of the Green Energy Plan in the past. As explained in the response to Exhibit I, Tab 1, Schedule 98, these projects are now on hold and the forecast of spending in the test years will be reviewed when sufficient information and direction has been provided.

Ontario Energy Board (Board Staff) INTERROGATORY #107 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4/p. 30 – Table 2 – Other Green Projects
The Other Green Project test year capital expenditures are found in various tables in D1-3-3 Appendix A. Please provide a table that groups the test year capital expenditures related to these projects under the five project descriptions provided in Table 2 (Ex A/T11/S4/p.30).

Response

Please see the table below which groups the test year capital expenditures related to these projects under the five project descriptions provided in Table 2.

Item #	Project	Capital Expenditures ($M) 2011	2012
1	**Upgrade Short Circuit Capability of Toronto Area Stations (Hearn TS, Manby TS, Leaside TS)**		
	D11 - Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	54.6	27
	D12 - Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	13.5	21.9
	D13 - Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	9.0	9.2
	Total (Item 1)	**77.1**	**58.1**
2	**Install 3 SVCs at 230kV +300/-100 MVAR (short term)**		
	D36 - Static Var Compensator #1 at Existing Station in South Western Ontario (Item #1 in Schedule B)	0.4	32.9
	Total (Item 2)	**0.4**	**32.9**
3	**Install up to 7 Enabling TS**		
	D32 - Enabling 230/44kV TS #1 and Short (<2km) Tap (Item #2 in Schedule B)	0.05	8.4
	D33 - Enabling 115/44kV TS #1 and Short (<2km) Tap (Item #2 in Schedule B)	0.05	8.4
	Total (Item 3)	**0.1**	**16.8**
4	**Install in-line circuit breakers at up to 7 locations to enable generation connections**		
	D37 - In-Line Circuit Breakers #1 (Item #4 in Schedule B)	13.4	6.9
	D38 - In-Line Circuit Breakers #2 (Item #4 in Schedule B)	13.4	6.9
	D39 - In-Line Circuit Breakers #3 (Item #4 in Schedule B)	3.2	7.2
	D40 - In-Line Circuit Breakers #4 (Item #4 in Schedule B)	3.2	7.2
	D41 - In-Line Circuit Breakers #5 (Item #4 in Schedule B)	0	1.2
	D42 - In-Line Circuit Breakers #6 (Item #4 in Schedule B)	0	1.2
	Total (Item 4)	**33.2**	**30.6**
5	**Protection, Control and Telecom**		
	D43 - Station Protection Upgrades for Distributed Generation	5.3	15.8
	D44 - Transfer Trip Facilities	4.7	14
	Total (Item 5)	10	29.8
	TOTAL	**120.8**	**168.2**

Ontario Energy Board (Board Staff) INTERROGATORY #108 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit A/Tab11/Sch4/p. 30 – Table 2

A number of the (schedule B) GEP projects are Category 3 projects (as defined at D1-T3-S3-p.11). With respect to these projects Hydro One states "The actual in-service costs would be included in rate base when the project goes in-service subject to Board approval at a future revenue requirement proceeding". Are the test-year capital costs for Category 3 GEP projects in rate base?

Response

The test-year capital costs for Category 3 projects are not included in rate base.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #109 List 1</u>

<u>Interrogatory</u>

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

<u>Ref: Exhibit A/Tab11/Sch4/p.42</u>
At pages 42 and 43 of the Transmission Green Energy Plan, Hydro One describes elements of its consultation with First Nations and Metis communities. Has Hydro One identified any opportunities for partnership (financial or otherwise) with First Nations or Metis communities? If yes, please describe. If not, please explain the reasons that such partnerships are not anticipated at this time.

<u>Response</u>

Hydro One has had discussions and continues to discuss the possibility of partnerships with First Nation and Métis communities that are directly affected by proposed Green Energy projects. Hydro One believes there is the potential for partnerships with First Nations and Métis communities on the Green Energy Plan projects and will continue to pursue this possibility for priority initiatives.

Ontario Energy Board (Board Staff) INTERROGATORY #110 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit D1/Tab3/Sch3/ p10

Table 1 summarizes proposed Development Capital under 11 specific investment types. The need for some projects included under the following four investment types is based wholly or in part on enabling distribution connected renewable generation:

- Local Area Supply Adequacy
- Enabling Facilities (Government Instruction)
- Station Equipment Upgrades & Additions to Facilitate Renewables (Government Instruction)
- Protection and Control for Enablement of Distribution Connected Generation (Government Instruction)

By their nature, the determination of need, proposed solution, prioritization and cost allocation of these projects will be potentially influenced by a number of different parties. Hydro One, as the owner and operator of the proposed assets; the OPA who requires these facilities to enable the procurement of renewable generation under its FIT program; the local distribution companies of the service area in which the generation will be connected; and the connecting generator all have an interest with respect to these projects.

(a) Please describe the process that Hydro One used to co-ordinate the needs of these various parties when developing its proposed solutions.

(b) For each of the projects listed under the four investment types above that have need based wholly or in part on the connection of distribution connected renewable generation:

   i Please indicate the amount of renewable generation that is expected to be enabled and the name of the local distribution companies that will connect the renewable generation associated with the specific project.

   ii Please indicate what other options were considered and Hydro One's basis for the selection of the proposed solution.

   iii Please indicate the criteria that Hydro One used to prioritize the need for the project with similar needs in other distributor service areas.

   iv Please provide any supporting documentation from OPA and/or the local distribution companies with respect to the proposed project.

   v Please indicate the cost responsibility Hydro One assumes for the project and the basis for that assumption. Please include in your answer:

- Hydro One's classification of the project, using the definitions in the Transmission System Code ("TSC") (e.g. network, connection, enabler);
- The section or sections of the TSC Hydro One believes determine the cost responsibility for the project;
- Where no capital contribution is being sought from the transmission customer, an explanation for the lack of such a contribution.

vi Please provide any economic analysis or other supporting information from the OPA relating to the project, if such information is not already on the record.

Response

(a) Hydro One relies on the OPA to identify the need for new transmission facilities that relates to the changes in generation resources. Hydro One works collaboratively on an ongoing basis with the OPA and provides key transmission information such as preliminary planning level costs, operational requirements and practices and physical data on existing stations and transmission lines and corridors for OPA to perform it's assessments. Generally, Hydro One seeks OPA supporting input for network and connection projects that support new generation additions and involve a pool-funded component.

Hydro One Transmission and the OPA consult on an on-going basis with LDC's including Hydro One Distribution regarding near and mid-term capacity needs and supply performance. Issues on either the LDC's distribution or Hydro One's transmission system with respect to connecting generation are also discussed when they arise.

Hydro One interacts with a number of generation proponents at various stages of their project development. Such stages could include pre-connection consultations, feasibility study requests, connection assessments or performing the connection. These interactions inform Hydro One's plans both from a project or local perspective and from an aggregate or broader system perspective. Further, operational experience gained from connected generators, in particular variable generation resources, provides further insights on the issues that need to be considered when planning transmission facilities.

(b) The answer below is categorized by "investment type":

Local Area Supply Adequacy

i There are 3 projects D11, D12 and D13 under the Local Area Supply category that can facilitate additional generation including renewables. D11 & D12 together can facilitate up to 300MVA of generation. D13 can facilitate up to 300 MVA of generation. Note that depending on the size and location of the generation, these values are not necessarily additive. Toronto Hydro Electric System Ltd. is the LDC that will connect the new generation.

ii Projects D11, D12, D13 represent the low cost solution to improve the short circuit capability at the Leaside, Hearn and Manby 115kV stations. This solution also provides end-of-life management for many facilities which are at or nearing end-of-life. The projects will also bring the short circuit capability of these stations to the levels established in the TSC. Another feasible alternative would be to provide a major new transmission path to supply the 115kV system and then reconfigure the Leaside and Manby systems into smaller subsystems in order to reduce the 115kV short circuit levels. This option would be significantly more expensive and would not address the end-of-life issues at the 115kV stations.

iii D11, D12 and D13 were identified in Schedule B of the Minister's letter. These projects are needed to allow the connection of additional generation, address end-of-life issues and bring the short circuit capability to levels established in the TSC.

iv Please refer to the OPA information provided at Exhibit D1, Tab 3, Schedule 3 Appendix B.

v The D11, D12 and D13 projects are classified as assets in the Line Connection pool. D11 is required to completely replace the entire Hearn station which is at end-of-life. D12 and D13 address the need to replace breakers which are nearing end-of-life and to provide a short circuit capability of 50kA for 115kV facilities that is established in Appendix 2 "Transmission System Connection Point Performance Standards" of the TSC. As per Section 6.7.2, Section 4.3.1 and Appendix 2 of the TSC, a capital contribution will not be sought.

vi Please refer to the OPA information provided at Exhibit D1, Tab 3, Schedule 3 Appendix B.

Enabling Facilities

i Projects D32 and D33 under this category could each enable approximately 150 to 240 MW depending on the size of the TS which will be determined by the OPA through the ECT process It is not known at this time where the Enabler TS's will be sited and therefore the affected LDC(s) cannot be determined.

ii The Enabler TS is one type of enabler facilities. Other options involving Enabler lines which are under consideration are identified in Schedule A of the Minister's letter. Hydro One expects that some Enabler TS's will be required to facilitate the connection of renewable distributed generation in areas where there are many potential projects.

iii Not applicable as Enabler TS locations have not been established.

iv Further supporting information from the OPA is expected following the ECT process.

v Hydro One expects projects D32 and D33 to be treated as “Enabler” facilities per Section 6.3 of the TSC

vi See response to IV.

Station Equipment Upgrades and Additions to Facilitate Renewables

i The amount of renewable generation that could be enabled by projects D36 to D42 cannot be determined at this time. The required size and locations of such facilities will depend on the FIT applications and the outcome of the OPA’s ECT process.

ii Projects D36 to D42 were indentified in Schedule B of the Minister’s letter as facilities needed to incorporate distribution connected generation. Project D36 provides dynamic reactive compensation that is required to incorporate significant levels of distribution connected generators that provide little, if any, dynamic reactive support to the system. Other forms of dynamic reactive compensation, such as StatCom and synchronous condensers are significantly more expensive. Projects D37 to D42 allow more connection points to the existing transmission lines. Alternatives to in-line breakers would be additional switching stations or transmission lines. Both these types of alternatives would likely be more expensive than in-line breakers.

iii Not applicable as locations of required dynamic reactive compensation and in-line breakers have not been determined.

iv Further supporting information from the OPA is expected following the ECT process.

v Hydro One expects these projects to be network facilities which will be pool funded. In addition to facilitating distribution connected generation, they also facilitate the connection of transmission connected generation and provide network benefits such as broader system voltage support and improved reliability. In the case of in-line breakers, any portions of the costs that represent the generator’s minimum connection requirement would be the responsibility of the customer.

vi See response to IV

Protection and Control

i Projects D43 and D44 will provide for up to 250 connections and could address the protection and control requirements for as much as 1900 MW depending on the complexity and size of the connections. Please see part b) of Interrogatory Response at Exhibit I, Tab 1, Schedule 118, for a preliminary list of the stations and the corresponding LDC's where the renewable generation may be connected.

ii For Project D43 – Station Protection Upgrades, there are no alternatives but to implement the protection modifications identified. Failure to do these modifications will result in protection misoperations and reduced reliability to load customers supplied from the same stations.

For Project D44 - Transfer Trip Facilities, there are no other feasible alternatives to ensure that generators connected to distribution feeders are not islanded with the load locally and portions of the grid beyond the specific TS to which they are connected.

iii Please see part a) of Interrogatory Response at Exhibit I, Tab 1, Schedule 118.

iv The planning of these projects was based on information supplied from the OPA on projects that have been awarded contracts.

v Please see part d) of Interrogatory Response at Exhibit I, Tab 1, Schedule 118.

vi Please see response to IV.

Ontario Energy Board (Board Staff) INTERROGATORY #111 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Exhibit D1/Tab3/Sch3/ p20

Hydro One indicates that projects D11, D12 and D13 pertain to upgrades at existing transmission stations that have under-rated equipment with respect to short circuit capability that limits the connection of renewable generation.

(a) Please indicate all Hydro One transmission stations where the connection of distribution connected renewable generation is limited due to under-rated equipment with respect to short circuit capability. Please indicate the name of the local distribution companies that each station serves.

(b) Please indicate the criteria that Hydro One used to determine priority in the selection of projects of this type for inclusion in its transmission rate application.

Response

(a) The following are the high voltage transmission stations where it is known at this time that the connection of distribution connected renewable generation is limited due to under-rated equipment with respect to short circuit capability:

Transmission Station	**Number of Load Stations (TS) impacted**	**LDC's served by stations at impacted TS**
Leaside TS & Hearn TS 115kV	18	Toronto Hydro
Manby TS 115kV	5	Toronto Hydro
Hawthorne TS 115kV[1]	43	Hydro Ottawa, Hydro One Distribution
Allanburg TS 115kV[1]	24	Horizon Utilities, Niagara Peninsula Energy, Niagara West, Grimsby Power, Canadian Niagara Power Inc., Welland Hydro-Electric System Corp., Hydro One Distribution, Haldimand County Hydro Inc. Niagara-On-The-Lake Hydro Inc.

[1] Not in current application

Additional transmission stations may be identified in the future as new generation seeks connection and changes to the transmission system occur.

(b) Hydro One believes that upgrading these stations are non-discretionary investments as they are needed to address end-of-life facilities, meet requirements established in the TSC, connect new renewable generation and to maintain system reliability. The projects to upgrade Leaside, Hearn and Manby were discussed at the last rate hearing and the Board in its Decision (Section 6.5.3 EB-2008-0272 dated 28 May 2008) had advised that it expected Hydro One to move expeditiously to obtain any approvals to implement the plan. Subsequently, the projects have also been identified in Schedule B of the Minister's letter to Hydro One dated September 21, 2009.

Subsequent to the filing of this rate application, Hydro One identified that the short circuit levels at Allanburg TS have exceeded the station capability. Presently Hydro One has implemented an interim operating measure to manage the situation. This mitigating measure reduces the current levels of reliability and operational flexibility. Hydro One is currently developing a plan that would involve replacing lower rated breakers to increase the station short circuit capability and restore reliability.

The breakers at Allanburg are of the same type and model as the Toronto station breakers with short circuit capability below the 50kA level established in the TSC for 115kV transmission facilities. The breakers have an average age of 45 years and with typical breaker life expectancy of 30-55 years, these breakers are approaching the upper limits of expected life. They will need to be replaced over the next 5 -10 years. Hydro One has received information from the OPA that in the Allanburg area as much as 68 MW of FIT Launch applications are currently impacted by the short circuit limitations.

The need to upgrade the Hawthorne 115kV station was also identified subsequent to the rate application filing. The short circuit limitations at Hawthorne impacts as much as 155 MW of FIT Launch applications in the greater Ottawa and surrounding areas. The breakers are again of the same type and model as Toronto and Allanburg stations and are rated below the 50kA TSC level. The average age is 42 years and these breakers would also need to be replaced over the next 5 to 10 years. Hydro One is developing a plan to replace the lower rated breakers to address the issues of end-of-life management, meet TSC short circuit levels and connect significant levels of renewable generation.

The earliest that both the Allanburg and Hawthorne TS projects can be completed is 2013 and as a result they will not affect the test year revenue requirement. Hydro One expects to manage the capital expenditures for this project within the Development Capital spending levels requested in this application.

Ontario Energy Board (Board Staff) INTERROGATORY #112 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

112) Ref: (a) Exhibit D1/Tab3/Sch3/p20/ Project D11 & Appendix A, p3, Table 3, Project D11 – Toronto Area Station Upgrades for Short Circuit Capability – Rebuild Hearn
Ref. (b) Proceeding EB-2008-0272, Exhibit D1/Tab3/Sch3/p34/Table 3
Ref: (c) Exhibit D2/Tab2/Sch3/Investment Summary Document/ Project D11 Toronto Area Station Upgrades for Short Circuit Capability – Rebuild Hearn

At Reference (a), it is indicated that $0.3 million was spent in 2009, and another $3.00 million is expected to be spent by end of 2010 on the Hearn TS project, yet at Ref: (b) Table 3 has no mention of that project.

(a) Please explain the reasons for having commenced investment in this project in 2009, even though the evidence in proceeding EB-2008-0272 does not provide any discussion of the need to address the issues presented in Reference (c);
(b) Please provide the type and age of the system components - circuit breakers, buses, switches, etc. at Hearn TS which Hydro One intends to replace.
(c) Please provide a detailed cost estimate for the station, itemized by major system elements such as buses, circuit breakers, switches, protection and control, communication,.etc., and for each category provide the cost broken down into labour, material, overheads, AFUDC etc.
(d) Please provide a schematic single line diagram of the station switchyard after the proposed upgrade, showing the station layout - transmission lines, breaker positions etc.

Response

(a) The replacement of the aging Hearn 115kV switchyard was previously included as part of the New Supply to Toronto Project (Reference EB-2008-0272, Exhibit C1, Tab2, Schedule 3, Page 7, Table 1). The project is also necessary to remove the short circuit constraints and allow incorporation of more distributed generation in the City of Toronto.

(b) Since the new supply project has been deferred, the Hearn Rebuild Project was initiated to cover off the Hearn rebuilding work. The work is also in accordance with the Board’s expectation that Hydro One will move expeditiously to obtain approvals for the plans addressing short circuit constraints (EB-2008-0272 Decision with

Reasons dated May 28, 2009 Section 6.5.3, page 49).

(c) The type and age of the components to be replaced at Hearn Station are as follows:

Equipment	Type	Number	Age (yrs)	Comments
Circuit Breakers	Oil	15	53-60	End of Life
Circuit Breakers	SF6	3	3	Newer breakers associated with Portlands GS. Will be re-used.
Circuit Breakers	SF6	4	7 -25	Cap bank breakers
Bus Work	Strain/pipe	---	50-60	Mixture of strain and old pipe buswork.
Switches	Air	54	53-60 and 3-7	36 switches rebuilt in 1990s. Newer switches associated with cap banks and Portlands GS connections
Instrument Transformers	Oil	11	35-60	No explosion resistant features on these instrument transformers
Insulators	Cap and pin	----	50-60	End-of-life.

(d) Preliminary engineering and estimate development work was used in the preparation of the Development Capital evidence. The cost breakdown of this preliminary estimate is as follows:

		Gross Cost
Material		**$40.6M**
• *GIS System including Breakers*		*$27.1M*
• *Building*		*$5.8M*
• *Protection, Control & Telecom*		*$2.7M*
• *Grounding*		*$3.3M*
• *Other*		*$1.7M*
Labour		**$15.6M**
• *Project Mgmt*		*$0.9M*
• *Engineering*		*$2.1M*
• *Construction*		*$10.8M*
• *Commissioning*		*$1.8M*
Overhead		**$9.0M**
Interest		**$4.9M**
Risk		**$14.8M**
	TOTAL	**$84.9M**

The new single line diagram is shown in Figure 1

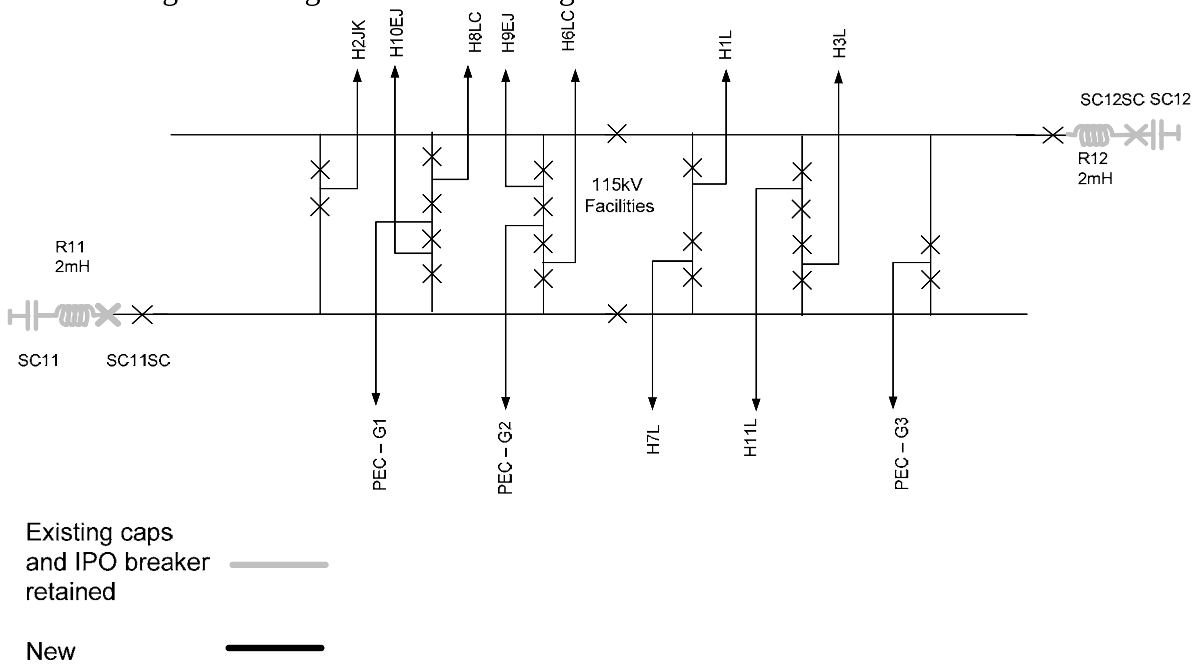


Figure 1. Rebuild Hearn SS
Initial Stage Facilities

Dwg 15600D1 R1
24 Feb. 2010

Ontario Energy Board (Board Staff) INTERROGATORY #113 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

113) Ref: (a) Exhibit D2/Tab2/Sch3/Investment Summary Document/ Project D12 and D13 - Toronto Area Station Upgrades for Short Circuit Capability
Leaside TS Equipment Upgrade (D12)
Manby TS Equipment Upgrade (D13)
Ref: (b) Exhibit D1/Tab2/Sch1/p 31-33/Section 7.1 (Circuit Breakers) and Section 7.1.1 Oil Circuit Breakers

At Reference (a), it is indicated that Hydro One is proposing to upgrade the fault current withstand capability to 50kA at various stations as per the TSC, and that will permit incorporation of up to 300 MVA of new generation in the Leaside 115 kV area and an equal amount of new generation in the Manby 115 kV area.

(a) Please provide evidence from the OPA and/or from Toronto Hydro Electric System to corroborate that there is a need to undertake the station upgrade work noted above.

At Reference (a) it is indicated that at Leaside, 28 existing oil breakers of an average age of 46 years are approaching end of life, and that at Manby 16 oil breakers have an average age of 49 years old and they are approaching end of life. Hydro One uses five primary factors for identifying oil circuit breakers end of life ("EOL"), namely: 1) Condition; 2) Reliability and Performance; 3) Technical Obsolescence; 4) Utilization and Loading; 5) Safety and Environment.

(b) Please provide any written assessments covering the five primary factors for assessing EOL that have been prepared for:
- any of the 28 Leaside oil circuit breakers; and/or
- any of the 16 Manby oil circuit breakers.

(c) Please provide an analysis to indicate the maximum amount of additional generation that can be added to:
- the Toronto Hydro distribution system which impacts the 115 kV Switchyard at Leaside TS; and/or
- the Toronto Hydro distribution system which impacts the 115 kV Switchyard at Manby TS.

(d) It would be helpful if Hydro One, with assistance from the OPA, provided an economic analysis similar to the Economic Connection Test for each of the two following scenarios:

- assume there is 300 MVA of new generation expected to connect to Toronto Hydro which is within the Leaside 11 5 kV area; and
- assume there is 300 MVA of new generation in the Manby 115 kV area.

Please include in your answer the assumptions and input parameters used in the two ECT(s), an explanation of the approach used, and an explanation of how the cost of the investment for each of the two transformer stations is balanced against the benefits from the additional new generation.

(e) Please discuss the implication of delaying the two projects such that the in-service dates are 2014 for Leaside TS, and 2015 for Manby TS.

Response

(a) Please see OPA's supporting documentation at Exhibit D1-3-3 Appendix B.

(b) The 115kV oil circuit breakers planned to be replaced at Leaside and Manby stations are of the same type and model, and have average ages of 46 and 49 years respectively. With average life expectancy of breakers ranging between 30-55 years these breakers are approaching end-of-life.

At this age these breakers are subject to problems such as failing control relays and wiring in the electrical control circuit, pneumatic component failures including air compressors, control valves, piping and mechanism components. The breakers can develop oil leaks and their high voltage bushings have internal oil leaks requiring outages for oil top up.

A brief summary assessment of the breakers at these two stations is as follows:

Condition

The breakers are in poor to fair condition based upon the information that has been collected during preventive and corrective maintenance activities.

Reliability and Performance

The degrading condition of the breakers shows up in historic breaker performance. Eight of the 28 breakers planned to be replaced at Leaside TS have a forced outage rate of 0.2 to 0.6 per year compared to the provincial average of 0.13 per year. Average unavailability for these eight breakers was over 8 hours per year compared to the average of 5.61 hours per year for general purpose 115kV breakers in Southern Ontario. Similarly, four out of the 16 breakers planned to be replaced at Manby performed below the provincial average and had an outage rate of 0.2-0.3 per year and average unavailability of over 19.4 hours.

Technical Obsolescence

This model of circuit breaker is no longer produced. The current on-hand inventory is adequate to support historic level of corrective maintenance, but is not sufficient to support projected future needs. It will become increasingly difficult and costly to obtain replacement parts as these circuit breakers are no longer being manufactured.

Utilization

These breakers are operating at 95-99% of their interrupting current rating. These ratings will be exceeded with the connection of new generation in the Leaside and Manby areas.

Safety and Environment

These breakers are susceptible to oil leaks and a few breakers have experienced repeated leaks. Failing pneumatics creates hazards for staff doing inspections and performing tests within the control cabinet.

These breakers do not have explosion/pressure relief features whereas new breakers have integrated pressure relief features for failsafe operation. Explosive failures represent a staff safety hazard and increase the risk of damage to other equipment in the yard and consequential outages.

(c) The maximum amount of generation that can be connected to the THES distribution system is limited by three constraints:

- 500MVA short circuit capacity of the 13.8kV low voltage switchgear bus
- Transformer capability
- 115kV bus short circuit capability

With the 115kV breaker upgrade work at Leaside TS and Manby TS and the rebuild of the Hearn SS, the 115kV bus short circuit capability will no longer be constraining. The maximum generation at the distribution level would be governed by local station constraints. The breaker upgrade work would also facilitate generation connecting directly at the 115kV level.

The maximum generation that can be connected to the stations connected at the distribution level in the Leaside 115kV system is given in the Hydro One Generation Connection Department allowable generation list. This list is revised every month based on generation connection information. The allowable generation for individual stations in the Leaside area – as per the July 30 list – is given in the Table below (assuming Leaside 115kV bus is no longer a constraint):

BASIN TS	A5A6	10.79
	A7A8	10.00
BRIDGMAN TS DESN 1	A1A2	8.10
BRIDGMAN TS DESN 2	LA1&LA2	9.00
BRIDGMAN TS DESN 3	LA6&LA5	3.50
BRIDGMAN TS DESN 4	LA7&LA8	9.00
CARLAW TS	A1A2	9.00
	A6A7	5.40
CECIL TS DESN 1	A1A2	0.00
	A3A4	9.00
CECIL TS DESN 2	A5A6	6.90
	A7A8	7.07
CHARLES TS DESN 1	A5A6	8.54
	A7A8	9.78
CHARLES TS DESN 2	A1A2	9.00
	A3A4	9.00
DUFFERIN TS DESN 1	A1A2	3.96
	A3A4	3.60
DUFFERIN TS DESN 2	A5A6	9.00
	A7A8	7.20
DUPLEX TS DESN 1	A1A2	9.00
	A3A4	7.20
DUPLEX TS DESN 2	A5A6	9.00
ESPLANADE TS	A1A2	11.89
	J1J2	10.62
	Q1Q2	10.27
GERRARD TS DESN 1	A1A2	0.00
GERRARD TS DESN 2	A7A9	0.00
GLENGROVE TS DESN 1	A1A2	9.52
GLENGROVE TS DESN 2	A5A6	2.97
MAIN TS	A1A2	8.10
	A3A4	9.00
TERAULEY TS DESN 1	A1A2	9.00
	A7A8	9.00
	A3A4	9.00
	A5A6	9.00
Total Leaside 115kV Area Generation		271.40

The maximum generation that can be connected on the THES distribution system on stations supplied from the Manby 115kV is as given below:

FAIRBANK TS DESN 1	YZ	12.93
FAIRBANK TS DESN 2	BQ	12.93
JOHN TS DESN 1	A17A18 A4A6	14.00 0.00
JOHN TS DESN 2	A13A14 A3A5	11.00 0.00
JOHN TS DESN 3	A11A12 A15A16	11.00 11.00
RUNNYMEDE TS	Total	15.43
STRACHAN TS DESN 1	A5A6 A7A8	8.76 8.55
STRACHAN TS DESN 2	A1A2 A3A4	9.00 9.00
WILTSHIRE TS DESN 1	T1T6	19.00
WILTSHIRE TS DESN 2	T2T5	0.00
WILTSHIRE TS DESN 3	T3T4	0.00
Total Manby 115kV Area Generation		142.61

The allowable generation may be restricted in certain conditions where Manby area stations are connected to Leaside since the generation would then impact the Leaside 115kV bus. The same would be true when Leaside area stations are connected to Manby TS.

(d) Hydro One and the OPA believe that only the cost of advancing the work to replace the 115 kV circuit breakers at Leaside and Manby transformer stations should be included in assessing the cost to connect generation, which is enabled by the increased short circuit levels. This stems from the fact that the breakers are nearing end of life and therefore a likely need date for requiring replacement can be established with a reasonable degree of certainty. Within 7 to 8 years, the large majority of breakers within the switchyards will be at or beyond end of life and the overall risk to reliability and safety will be high. The current in service date for the work at Leaside and Manby is 2012 and 2013 respectively and is timed to enable generation applications responding to the Feed in Tariff program (to date a 9.9 MW FIT project cannot connect to the Leaside supply system, as well as all future projects, including Capacity Allocation Exempt projects, which have applied after June 4, 2010) as well as projects expected to respond to any Clean Energy Standard Offer programs initiated by the OPA. Potential projects expected to respond to a Clean Energy Standard Offer program are provided within the supporting evidence provided by OPA. This timing also ensures that the work is completed in advance of 2015 Pan Am games, which will be hosted by the City of Toronto during the summer of 2015. Given the potential for increased infrastructure security leading up to and during such events it is expected to be difficult to obtain critical transmission equipment outages in the 2015 period. A 5 year advancement of the work at Leaside and Manby results in costs of $5.9M and $4.9M respectively. These costs were developed based on a three year cash flow for conducting the work at Leaside TS: yr 1 - $2.0 M; yr 2 - $13.5 M; yr 3 - $21.9 M and for Manby TS yr 1 - $9.0 M; yr 2 - $9.2 M; yr 3 - $12.2 M . An escalation rate of 2.5% and discount rate of 6.5% were used in the derivation of the advancement costs for the work at Leaside and Manby transformer stations. Assuming 300 MW of new generation is connected to the Leaside 115 kV area, as requested, results in a cost per kW of connected generation of $19.7/kW. Assuming 300 MW of new generation is connected to the Manby 115 kV area, as requested, results in a cost per kW of connected generation of $16.3/kW. It should be noted that deferring this work until 2017 / 18 would significantly delay the incorporation of generation projects within the City of Toronto and leave the City with a lower level of supply security during the 2015 Pan Am games.

The above does not account for other benefits that may be realized from these two projects, including enabling compliance with government directives identified in OPA's supporting evidence, which are mentioned in the response to part (a) above. The cost of the investment is further balanced against the benefits of enabling connection of local generation which improves the supply security to central and downtown Toronto by increasing the percentage of Toronto's peak load which can be met by in-City resources.

(e) The main impact would be the incremental risk associated with retaining aging equipment at these stations and the inability to connect new generation in the area.

Ontario Energy Board (Board Staff) INTERROGATORY #114 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

114) Ref: (a) Exhibit D1/Tab3/Sch3/ Appendix A p6
Ref: (b) Exhibit D2/Tab2/Sch3/Investment Summary Document/Projects D32 & D33
Ref: (c) Proceeding EB-2009-0096, Hydro One 2010 and 2011 Distribution Rates/ Decision with Reasons, April 9, 2010/p34-35

Table 6 at Reference (a) indicates that projects D32 and D33 are new enabling TSs.

(a) Are the locations for the two enabling TS's referenced in Table 6 known?

(b) Please indicate all existing Hydro One transmission stations where the connection of distribution connected renewable generation is limited due to station capacity. Please indicate the name of the local distribution companies that each station serves.

(c) Please indicate the criteria that Hydro One used or will use to determine priority in the selection of specific projects of this type for inclusion in its transmission rate application.

In the Board's recent Hydro One distribution rate Decision (EB-2009-0096), the Board stated at pages 34 - 35:

"The Board approves as prudent the proposed capital expenditures related to the express feeders, provided that construction does not commence until a time mandated by the Board. The revenue requirement amounts for each test year related to the feeders will be recovered by way of a rate rider and external funding. A variance account will be used for the purpose of tracking the difference between the forecast and actual expenditures for future disposition…….

Given the current uncertainty regarding the total demand for and location of the feeders, the Board does not wish its approval to result in a requirement that Hydro One expand or reinforce its system prematurely. The Board is therefore directing that the construction of the express feeders be deferred [emphasis added]. Hydro One shall inform the Board when it has sufficient information regarding requests for connection underpinning the need for each feeder and the location of each feeder. The Board will then determine when and confirm how this expansion of Hydro One's distribution system should occur, which the Board may do with or without a hearing. However, the Board does authorize Hydro One to begin the necessary development and pre-construction work associated with the express feeders. "

(d) Please provide the following information in regard to the proposed two proposed enabling TSs described in Reference (b), and how they may relate to the proposed six Express Feeders and the specific Board findings related to these six Express Feeders as outlined in Reference (c):

i Please describe in detail whether there is a connection between the proposed 6 express feeders and the proposed TSs.

ii Did Hydro One receive any connection requests from generators confirming the need for the express feeders?

iii Assuming that express feeders get subscribed to a level where a new TS may be required to allow for flow of the generation injection from the distribution to transmission, how does Hydro One propose to deal with cost responsibility for that transformer station?

Response

(a) The locations for the two enabling TS's referenced in Table 6 are not known. Hydro One expects these locations to be identified by the OPA's ECT process.

(b) Station capacity limitations restricting connection of distributed generation arise due to either thermal or short circuit capability of station equipment and depend on load and generation connected to the station.

Hydro One posts the list of station capacity on its web site (please see link http://www.hydroone.com/Generators/Documents/HONI_LSC.PDF). This list is updated monthly.

The attached Table lists currently constrained stations as per the 29 July 2010 update of the list of station capacity. Stations constrained only by high voltage transmission station short circuit limitations are not included.

Station Name	**Bus Name**	**Utility**
BEACH TS - DESN1	B1B2	Horizon Utilities
BIRCH TS	BY	Thunder Bay
BRAMALEA TS DESN 3	T5T6	Hydro One Brampton Enersource
BUCHANAN TS	Y	London Hydro Hydro One Distribution Erie Thames Power Lines Corporation
CALEDONIA TS	BY	Haldimand Hydro Hydro One Distribution
CECIL TS DESN 1	A1A2	Toronto Hydro
CLARKE TS	BY	London Hydro Hydro One Distribution
COOKSVILLE TS DESN 1	JQ	Enersource
CRAWFORD TS	EY T3T4	Enwin
CUMBERLAND TS	B	Burlington Hydro
CUMBERLAND TS	Q	Burlington Hydro
GAGE TS DESN 1	T1	Horizon Utilities
GAGE TS DESN 1	T2	Horizon Utilities
GAGE TS DESN 1	T7	Horizon Utilities
GAGE TS DESN 2	T3T4	Horizon Utilities
GAGE TS DESN 3	T5T6	Horizon Utilities
GAGE TS DESN 4	T8T9	Horizon Utilities
GERRARD TS DESN 1	A1A2	Toronto Hydro
GERRARD TS DESN 2	A7A9	Toronto Hydro
JARVIS TS	BY	Haldimand Hydro Hydro One Distribution Norfolk Power Distribution Inc.
JOHN TS DESN 1	A17A18	Toronto Hydro
JOHN TS DESN 1	A4A6	Toronto Hydro
JOHN TS DESN 2	A13A14	Toronto Hydro
JOHN TS DESN 2	A3A5	Toronto Hydro
KEITH TS DESN 1	BY	Enwin
KENILWORTH TS	B1Y1	Horizon Utilities
KINGSVILLE TS	BY	Chatham-Kent Hydro Inc. E.L.K. Energy Inc. Essex Powerlines Corporation Hydro One Distribution
KLEINBURG TS 27.6 KV	BY T1T2	Powerstream Hydro One Distribution
LAKE TS DESN 1	BY	Horizon Utilities
LEASIDE TS DESN 1	A1A2Q1Q2	Toronto Hydro
LEASIDE TS DESN 2	BY	Toronto Hydro

Station Name	**Bus Name**	**Utility**
LESLIE TS DESN	H1	Toronto Hydro
LESLIE TS DESN	H2	Toronto Hydro
LESLIE TS DESN 1	BY	Toronto Hydro
LONGWOOD TS	JQ	Middlesex Power Distribution Corporation Hydro One Distribution
MURRAY TS DESN 1	QZ	Niagara Peninsula Energy
MURRAY TS DESN 1	Y1Y2	Niagara Peninsula Energy
MURRAY TS DESN 2	J	Niagara Peninsula Energy
MURRAY TS DESN 2	K	Niagara Peninsula Energy
NEBO TS DESN 1	BY	Horizon Utilities
NEWTON TS	B	Horizon Utilities
NEWTON TS	Y	Horizon Utilities
PALERMO TS	BY	Burlington Hydro Milton Hydro Oakville Hydro
PORT ARTHUR TS #1	B1B2Y	Thunder Bay Hydro
RICHVIEW TS DESN 3	T7T8	Enersource
TALBOT TS DESN 1	T1T2	London Hydro
TRAFALGAR TS	BY	Oakville Hydro
VANSICKLE TS	BY	Horizon Utilities
WALKER TS #1	EQ	Enwin
WILTSHIRE TS DESN 1	A5A6	Toronto Hydro
WILTSHIRE TS DESN 2	A1A2	Toronto Hydro
WILTSHIRE TS DESN 3	A3A4	Toronto Hydro
WOODBRIDGE TS 44 kV - DESN1	EQ	Enersource Hydro One Brampton Powerstream Toronto Hydro
WOODROFFE TS	T1T2	Hydro Ottawa
WOODROFFE TS	T3T4	Hydro Ottawa

(c) As many as 7 enabling TS were identified in Schedule B of the Minister's letter. Hydro One has conservatively included two such stations, one at the 230kV level and one at the 115kV level, in this filing. These projects only have significant cash flows in 2012. Both are Category 3 projects as their in-service dates are not expected to fall in the test years. Hydro One will rely on the OPA's ECT process to not only establish the locations for these two enabling TS but also the need for additional enabler TS's.

(d)

i) The proposed express feeders were expected to be connected to an enabling TS. Further details will not be available until an enabling TS is identified in the OPA's ECT process.

ii) Hydro One has not yet received any connection requests from specific generators for an express feeder.

iii) Hydro One believes that the enabling TS's identified in the Minister's letter or others that may be approved by the Board in a future Green Energy Plan will be pool funded. The costs for TS's that have not been identified or approved in this way would be attributable to the connecting generators based on the TSC.

Ontario Energy Board (Board Staff) INTERROGATORY #115 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

115) Ref: (a) Exhibit D1/Tab3/Sch3/ Appendix A, p7
Ref: (b) Exhibit DD2/Tab2/Sch3/Investment Summary Document/Projects D34 & D35

(a) The evidence in regard to Project D34 at Reference (b) describes the existing transmission system situation between Wawa and Sudbury which serves about 500 MW of load and 1,100MW of generation. The evidence indicates that construction of a 210 kilometre 500 kV transmission line, to be operated initially at 230 kV, would add 450 MW of needed transfer capability, since the present transfer can potentially reach 1000 MW exceeding the present transfer limit of 670MW.

i Please provide an update to the capability status as outlined above, including any recent assessment either by Hydro One or the OPA in regard to the date the project is needed.

ii Please describe the implications to the transmission system and its customers should the project in-service date be delayed from late 2015 to late 2017.

(b) The evidence in regard to Project D35 at Reference (b) describes the benefits of the project as:

- to provide sufficient capacity to meet increasing load, especially to the mining industry;
- to improve reliability of supply to Pickle Lake;
- to enable development of renewable resources (Wind, OPG's Little Jackfish);
- to create opportunities to connect in the future First Nation communities.

i Please provide any recent assessment either by Hydro One or the OPA in regard to the date the project is needed.

ii Please describe the implications to the transmission system and its customers should the project in-service date be delayed from late 2014 to late 2016.

Response

(a)

i There is no change to the capability status since the filing of this application. For the reasons explained in Exhibit I, Tab 1, Schedule 98, there is no recent assessment of the date the project is needed.

ii Should the project in-service date be delayed from late 2015 to late 2017, no significant impact on the transmission system and its customers is expected if this delay coincides with the in-service date of the North-South Transmission Expansion.

(b)

i For the reasons explained in Exhibit I, Tab 1, Schedule 98, there is no recent assessment of the date the project is needed.

ii Should the project in-service date be delayed from late 2014 to late 2016, potential implications to the transmission system and its customers include:

- Delaying the connection of potential renewable generation projects
- Prolonging the use of diesel generation and interim measures by customers to supply their increased demand and/or postponing and/or downsizing of their expansion plans
- No reliability improvements to the service to existing customers on circuit E1C until the proposed transmission line goes into service
- Delaying the connections of several First Nations communities, which currently rely on diesel power
- Prompting mining developers to change their plans in using grid or diesel power at the mine site and on locating secondary processing facilities due to uncertainty

Ontario Energy Board (Board Staff) INTERROGATORY #116 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: (a) Exhibit D1/Tab3/Sch3/Appendix A p8
Ref: (b) Exhibit A/Tab11/Sch4, p33-34
Ref. (c) ExhD2/Tab2/Sch3/Investment Summary Document/Projects D36-D42

Table 8 of Reference (a) indicates that project D36 involves the installation of SVCs at an existing transmission station and that projects D37 – D42 involve the installation of in-line circuit breakers at six specific locations.

(a) In its Green Energy Plan at Reference (b) Hydro One indicates these projects will be determined on the basis of FIT uptake and detailed system studies. Are the locations for the SVC installations known? How were these locations selected? Please provide the technical criteria and/or the degree of FIT uptake required to establish a need for these types of projects.

(b) Please indicate the criteria that Hydro One used or will use to determine priority in the selection of specific projects of this type for inclusion in its transmission rate application.

(c) Please indicate the basis for Hydro One's assumption, as indicated in the associated Investment Summary Document at Reference (c) that these projects will be pool funded. Are these proposed capital additions to existing "Network" or to "Connection" assets? Please explain how Hydro One is interpreting Compliance Bulletin #200606 to establish cost responsibility with respect to these projects.

Response

(a) The locations of the SVC installations are not known at this time. The IESO has established a working group with representation from Hydro One and the OPA to conduct periodic reviews on the impact of high penetrations of distribution connected generation. One of the objectives of this working group will be to assess the need for dynamic reactive compensation facilities, such as SVC's in parts of the system where there is a significant level of distribution connected generation. These studies will look to identify the location, size and timing for SVC installations.

(b) Hydro One has included only one SVC installation with significant cash flows in the test years and included only two in-line breakers with in-service additions in the test years. Hydro One believes this is conservative given the number of FIT applications received during the Launch period. As described in the response to part (a) the location, size and timing of the SVC installations will be informed by the studies conducted by the IESO working group. The location and need for the in-line breakers will be determined through connection assessments of FIT projects and the ECT process for new transmission facilities.

(c) The SVC will provide dynamic reactive compensation that is needed to address system voltage performance when significant levels of distribution generation are connected. The SVC is a network facility that not only facilitates distribution connected generation but also provides broader system voltage support that can benefit other transmission customers.

The situation with in-line breakers is somewhat different. The requirement for in-line breakers results from protection complexities created by generating facilities connecting to multi-terminal transmission lines via a single line tap circuit breaker. In some of these cases the Protection Impact Assessment performed by Hydro One determined that separate zones of protection must be introduced to meet the protection industry standards, which resulted in the Connection Assessment performed by the IESO requiring the installation of in-line breakers to maintain system reliability and meet the reliability standards.

In the case of a network facility, section 6.3.5 of the Transmission System Code generally provides that "A transmitter shall not require any customer to make a capital contribution for the construction of or modification to the transmitter's network facilities that may be required to accommodate a new or modified connection." The concept of "minimum connection requirements" (Compliance Bulletin 200606) does not apply here since the additional in-line breakers identified in the Connection Assessment are driven primarily by system reliability needs. Therefore, no capital contribution is applicable in this case.

In the case of a shared line connection facility, s. 6.3.3 and 6.3.4 of the Transmission System Code permit the transmitter to construct and own such facilities, and furthermore to "require the generator customer to make a capital contribution to cover the cost of the modification." However, s. 6.3.6 provides an exemption from such capital contribution where the facility was planned by the transmitter to maintain the reliability and integrity of the transmission system. The OEB's Decision and Order, dated September 6, 2007, in Hydro One's Connection Procedures proceeding (EB-2006-0189) elaborates further on this exemption. The Decision states: "The key feature of a plan giving rise to the exception is the extent to which it addresses system reliability and integrity concerns… [and has] a long term positive effect on system reliability and integrity." The Decision further states: "Perhaps most importantly, the plan should incorporate input from other responsible agencies such as the IESO…."

For the reasons stated above, it is Hydro One's view that, for both the network and shared connection facility cases, the Pool (as opposed to the generator) would have cost responsibility for such additional in-line breakers (which exceed the generator's minimum connection requirements) that are required by the IESO to address system reliability concerns relating to protection complexities associated with multi-tapped transmission lines.

Hydro One further notes that such in-line breaker facilities could provide additional benefits to other customers. For example, in-line breakers that sectionalize a line could materially improved reliability for all connected customers on the line by significantly reducing exposure to interruptions.

Ontario Energy Board (Board Staff) INTERROGATORY #117 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref. (a) Exhibit D1/Tab3/Sch3/ Appendix A p8
Ref: (b) Exhibit D2/Tab2/Sch3/Investment Summary Document/Projects D36-D42

The evidence in regard to Projects D37 and D38 at Reference (b) indicates that the in-service date for these two projects is 2012, and at Reference (a), it is indicated that investments for the two projects commences in 2011 ($13.4 million for each) and in 2012 ($6.9 million for each).

(a) Given the timeline of the sizable investments in the two Test Years (2011 and 2012) for the two projects D37 and D38, please provide an update for each covering:

i the number and location of the in-line circuit breakers, and for each such in-line circuit breaker, the expected number and size of the generators to be accommodated;
ii whether Hydro One has included in its Rate Base the investment amounts specified at Reference (a) for Projects D37 and D38 for the two test years 2011 and 2012.

(b) In-line Circuit Breakers #1 & #2 in Table 8 (D1-3-3) are Category 2 projects (as defined at D1-T3-S3-p.11). In ISD D37 and D38, Hydro One states, “The need for the investment will be reconfirmed by the Ontario Power Authority on a project by project basis before detailed design and construction is initiated”. Have these investments been reconfirmed by the OPA?

Response

(a) The location of the in-line circuit breakers for projects D37 and D38 are not known at this time. The typical installation involves two breakers. The location and need for the in-line breakers will be determined through connection assessments of FIT projects and the ECT process for new transmission facilities. Depending on the location of the project, the in-line breakers could facilitate one or more connections to an existing transmission line. The level of generation to be accommodated will be governed by the capability of the transmission circuit on which the in-line breakers are installed and the capability of the transmission network in the area.

Hydro One has included in its Rate Base the investment amounts specified at Reference (a) for Projects D37 and D38 for the two test years 2011 and 2012.

(b) These projects have not been confirmed by the OPA at this time. The ECT process has not begun nor have connection assessments of some FIT projects advanced to a stage where the project specific need for in-line breakers has been identified.

Ontario Energy Board (Board Staff) INTERROGATORY #118 List 1

Interrogatory

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: (a) Exhibit D2/Tab2/Sch3/Investment Summary Document/Projects D43 & D44
Ref: (b) Exhibit D1/Tab3/Sch3/Appendix A/p9
Table 9 at Reference (b) indicates that project D43 and D44 are annual programs beginning in 2011 to upgrade transmission station protections and add transfer trip facilities to support the connection of down-stream distribution connected generation.

At Reference (a), the investment is detailed:

- for Project D43 – the investment is $5.3 million in 2011 and $15.8 million for 2012 ; and
- for Project D44 – the investment is $4.7 million for 2011 and $14 million for 2012.

(a) What criteria will Hydro One use to determine which transmission stations will be upgraded each year?

(b) Please indicate what stations, if any, are proposed to be upgraded in each of the test years and the local distribution companies served from these stations.

(c) For project D43 at Reference (a), Hydro One indicates that the protection changes are required, in part, to meet requirements of the Distribution System Code. Please indicate what those specific requirements are and how those requirements will be met.

(d) Please indicate Hydro One's assumption with respect to cost responsibility for these types of projects and the basis for that assumption, with reference to the TSC.

(e) Has Hydro One included in its rate base the investment amounts specified at Reference (a) for Projects D43 and D44 for the two test years 2011 and 2012?

Response

(a) The key criteria used for selecting Transmission Stations (TS) for upgrade are:

1. The amount, type and planned in-service date of generation with FIT or RESOP contracts to connect to the TS
2. The results of analytical studies that determine which protection changes are required.

(b) The following list is a partial list of TS's that are planned to be upgraded based on the assessment described in (a). The complete list cannot be determined until the actual in service dates for generators with FIT contracts become known.

2011:

Transmission Station	LDC Served
KENT TS	• HYDRO ONE • CHATHAM-KENT HYDRO INC
ST. ANDREWS TS	• BLUEWATER POWER DISTRIBUTION CORPORATION
TILLSONBURG TS	• HYDRO ONE • ERIE THAMES POWER LINES CORPORATION • NORFOLK POWER DISTRIBUTION INC • TILLSONBURG HYDRO INC
TALBOT TS	• LONDON HYDRO INC.
FORESTJURA HVDS	• HYDRO ONE

2012:

Transmission Station	LDC Served
MODELAND TS	• HYDRO ONE • BLUEWATER POWER DISTRIBUTION CORPORATION
KEITH TS	• HYDOR ONE • EN WIN UTILITIES LTD • ESSEX POWERLINES CORPORATION
BUCHANAN TS	• HYDRO ONE DISTRIBUTION • ERIE THAMES POWER LINES CORPORATION • LONDON HYDRO INC.
TIMMINS TS	• HYDRO ONE
CALEDONIA TS	• HYDRO ONE • HALDIMAND COUNTY HYDRO INC
BRANTFORD TS	• BRANT COUNTY POWER INC. • BRANTFORD POWER INC.
TILBURY TS	• CHATHAM-KENT HYDRO INC.
PALERMO TS	• BURLINGTON HYDRO INC • MILTON HYDRO DISTRIBUTION INC • OAKVILLE HYDRO ELECTRICITY DISTRIBTUION INC • HYDRO ONE

(c) The upgrades are required to meet the sections 6.2.25 and 6.2.26 of the Distribution System Code. To ensure the continued efficiency and reliability of the distribution feeders, as required in 6.2.25, while continuing to ensure the distribution system is adequately protected, as required in 6.2.26, feeder protections need to be upgraded from over-current to impedance based in order to preserve the load carrying capacity of the feeder.

The table below shows the changes required to meet the technical requirements of DSC Appendix F.2

DSC APPENDIX F.2 Specific Technical Requirements	SECTION	PROTECTION AND CONTROL MITIGATION
Synchronization	3.2 and OESC 84-006	Modifications of Synchro-check schemes at TS transformer LV circuit breakers and at HV line terminal breakers. Incorporating DG End Open signal in re-closing schemes at above breakers.
Voltage Regulating and Metering Devices	5.3	Transformer's Under Voltage Tap Changer control upgrades and metering for bi-direction power flow
Cease to Energize Loss of LDC Supply	6.1 and OESC 84-008	Facilities to generate Transfer-Trip signals for island conditions formed on the transmission assets
Over-Current Protection Coordination	6.4 and OESC 84-014	Upgrading following protections at TS - Transformer current differential - Bus blocking & Bus back-up schemes - Line back-up - Feeder
Feeder Relay Directioning	8	Voltage Polarization of current element and/or by applying Distance Protection (Hydro One's D60 standard)
Monitoring	9.	Upgrading Hydro One's Network Management System, SCADA, RTU modification and/or replacements

(d) Hydro One has assumed that these investments would be globally pooled for the following reasons:

1. These investments are identified in Schedule B of the Minister's September 21, 2009 letter.

2. These investments, although being made at connection stations, have benefits to the larger network system.

3. As soon as any distribution connected generation connects above a small threshold, the protections need to be modified. Consequently, the technical cause for the investment does not align with the financial capacity of the generator proponent and would function unfairly as a barrier to some.

4. P&C systems are highly integrated and consequently for cost efficiency and technical implementation reasons, including outage coordination, it is appropriate to do the all of these P&C upgrades at TS's at one time and at a time which accommodates bundling with other station work. This can mean that the timing of investments cannot be sequenced with certainty to the execution of individual connection cost recovery agreements from generators.

(e) For the reasons given in (d) above, Hydro One has included these costs in its rate base.

Ontario Energy Board (Board Staff) INTERROGATORY #119List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

Ref: Exhibit C1/Tab2/Sch4 – Table 1 & Board Staff Discussion Paper - Transmission Project Development Planning, dated April 19, 2010

The CWIP costs of the Northwest Transmission Reinforcement Project (Pickle Lake to Nipigon) and the Sudbury Area to Algoma Area project in the test years are in Table 4 (A-11-4). In addition to the CWIP cost, Hydro One is also proposing to spend $17.5 million and $5 million on development work related to these two projects in the test years.

(a) When is construction of the Northwest Transmission Reinforcement Project and the Sudbury Area to Algoma Area project scheduled to begin?

(b) The Board staff Report on Transmission Project Development describes Development work as, "From a regulatory perspective, this stage lasts from the approval of a transmission project development plan until leave to construct is applied for or until a project begins construction, if leave to construct is not required". (p. 4). If construction is scheduled to begin in the test years, please explain the rationale for also budgeting Development funds for these two projects. Please describe the type of Development work Hydro One is proposing to undertake in the test years.

Response

(a) For the reasons provided in Exhibit I, Tab 1, Schedule 98, Hydro One cannot say when construction of these projects will begin. Hydro One cannot start construction on these projects until it files Section 92 applications and receives approval from the Board.

(b) Hydro One started development work on some of the projects in the Minister's September 21, 2009 letter in order to meet the target in service dates set by the Minister as discussed in Exhibit I, Tab 1, Schedule 98 and Exhibit I, Tab 1, Schedule 102.

Development activities that have taken place for the Sudbury x Algoma project include:

- Initial planning and estimating work, including identification of staging options
- Information sessions for potentially affected First Nations and Métis communities
- Initial environmental work

Development activities that have taken place for the Northwest project include:
- Initial consultations with First Nations and Metis communities
- Public information centres in local communities
- Development of the Environmental Assessment (EA) Terms of Reference
- Initiation of Environmental field work
- Estimation and initial engineering work

Future planned development activities for both projects include:
- Consultations with First Nations and Métis communities
- Public information centres with local communities
- Detailed planning, engineering, and estimation
- Environmental fieldwork, and submission of the EA Terms of Reference and the EA Report
- Development of the OEB Section 92 Leave to Construct application
- Voluntary real estate acquisition processes

Both capital and development OM&A expenditures are required in 2012 for Sudbury x Algoma, and in 2011 and 2012 for Northwest. This is driven by the need to purchase long lead time materials and equipment in advance of the completion of development activities. Ordering times for some types of critical equipment require up to and beyond one year. In order to meet the in-service dates targeted in the September 21, 2009 letter from the Minister overlap in equipment orders and development activities is necessary.

The Northwest project requires two years of overlapping capital and OM&A expenditures due to the need for early initiation of engineering surveys along the preferred route. Unlike the Sudbury x Algoma project, the Northwest project is completely green field and therefore no line studies exist in the area that can be used as a benchmark for estimation. The engineering surveys will provide more specific detail on the soil types and site conditions that would impact the design of the line.

Ontario Energy Board (Board Staff) INTERROGATORY #120 List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

Ref: Exhibit D1/Tab3/Sch3/ Appendix A, Table 7

(a) Table 7 indicates that a Section 92 application with respect to the Northwest Transmission Reinforcement project is "underway". Please clarify what is meant by "underway", given that Hydro One has not yet filed a section 92 application with the Board. When is Hydro One planning to file a section 92 application for the Northwest Transmission Reinforcement Project and the Sudbury Area to Algoma Area project?

(b) Given that these two projects are identified as Category 4 projects (as defined at D1-T3-S3-p.12), are the test year amounts presented in Table 7 (D1-T3-S3-Appendix A) treated as in-service capital additions and are these amounts included in Table 1 at Exhibit D1-Tab1-Sch2?

(c) At Exhibit A/Tab11/Sch4/page 37 Hydro One states, "A complete description of the project costs and the associated amounts for accelerated cost recovery of CWIP treatment will be provided in each Section 92 application". If the detailed project costs, justification of project need and rate recovery treatment will be provided in the individual section 92 application, what approval is Hydro One seeking from the Board with respect to these costs and the proposed rate treatment in this proceeding?

Response

a. Preparation of a Section 92 application for the Northwest Transmission Reinforcement Project was underway but for the reasons provided in Exhibit I, Tab 1, Schedule 98, Hydro One is waiting for further information and direction. Hydro One is also waiting to proceed on a Section 92 application for the Sudbury to Algoma project.

b. The two projects are not included in Table 1 at Exhibit D1, Tab1, Schedule 2 as Hydro One plans to seek recovery of CWIP in rate base for these projects as part of the Section 92 applications in the future.

c. Hydro One is not seeking approvals for these projects in this application. The approval of the project cost and rate treatment will be sought in the individual Section 92 applications. Hydro One is simply advising the Board as to its future intent respecting these projects.

Ontario Energy Board (Board Staff) INTERROGATORY #121 List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

121) Ref: Exhibit A/Tab11/Sch5/p. 5-6
Please provide an update on the status of the Bruce to Milton project. Please address:

(a) The status of any outstanding regulatory, environmental or other approvals?

(b) What work has been completed so far?

(c) Has Hydro One encountered in fact any of the three risks listed in bullets on page 6, or any other threats to the schedule for completion?

(d) What is the current anticipated in-service date?

Response

a) Two approvals are outstanding:

Permit to cross the Niagara Escarpment: A Notice of Decision granting a permit to Hydro One was issued by the Niagara Escarpment Commission on October 16, 2009. There was subsequently an appeal for which an oral hearing was concluded on April 6, 2010 and Hydro One is now awaiting a decision.

Authority to expropriate interests in land: Hydro One filed an application to the Board under section 99(1) of the OEB Act, 1998, on February 26, 2010, to expropriate certain interests in land required for the Bruce to Milton project. Properties named in the application are those for which voluntary settlement agreements have not been obtained and closed. The OEB has initiated its review and approval process regarding the expropriation application. The Issues List has been established by the Board, and a procedural order was received on August 12, 2010 under which a hearing is contemplated in the fall of 2010.

There are a number of standard environmental approvals such as water crossings and protection of endangered species that are progressing in the normal manner.

b) Forestry work has commenced by the award of two forestry contracts (Winona wood Ltd., and Sturgeon Falls Brush Clearing). These were awarded on March 15, 2010 and June 7, 2010 respectfully. As of July 29, 2010, 67 (of 296) hectares have been cleared.

Hydro One civil construction commenced access road construction on April 27, 2010 and as of July 29, 2010, access roads to 120 (of 725) tower sites have been completed.

Hydro One civil construction commenced tower foundation construction on May 15, 2010 and as of July 29, 2010, 57 (of 725) foundations have been installed.

As of August 1, 2010, Valard Lines Construction commenced their awarded contract to assemble, erect and string the 725 towers.

c) To date, there have been no delays of this nature.

d) The project is successfully tracking the project schedule and Hydro One anticipates meeting the December 31, 2012 in-service date.

Ontario Energy Board (Board Staff) INTERROGATORY #122 List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

122) Ref: Exhibit A/Tab11/Sch5/p. 5-6

Hydro One states that the proposed accelerated recovery of CWIP for the Bruce to Milton project will provide a smoothing effect on rates, a reduction in borrowing costs and a reduction in the overall costs of the project. Please provide a demonstration, using sample calculations, of each of these effects. For example, please contrast the rate impact in each of 2011, 2012, and 2013 if the Board grants the accelerated CWIP recovery, and if the Board fails to grant this recovery.

Response

The attached schedules have been prepared in response to the questions above. The schedules show the revenue requirement impact over an assumed 50-year life of the assets comparing the CWIP in ratebase approach with the standard ratemaking methodology for the Bruce to Milton project. Forecast annual OM&A costs have been excluded from the analysis as they would be the same under either scenario and would not affect the comparative results. The forecast rates of debt and equity included in the application for 2011 and 2012 have been used to calculate the return on CWIP in ratebase in those years, and the forecast AFUDC rates for 2011 and 2012 are used to calculate AFUDC under the standard approach. For the 50 year period beyond 2012, after the project has gone into service, the 2012 rate of return on ratebase is used to calculate the return included in the revenue requirement. The discount rate reflects the 2012 test-year WACC. The total cost of the project under the standard approach including AFUDC is $762.9M, reflecting the current December, 2012 in-service date as well as the current forecast of AFUDC rates for 2011 and 2012 shown in Table 1 of Exhibit D1, Tab 4, Schedule 1. The project cost of $753M shown in Exhibit A, Tab 5, Schedule 11, page 6 was based on earlier assumptions.

RESULTS

Smoothing effect on rates

The smoothing effect on rates of CWIP in ratebase is illustrated in the early years of the project, pre- and post-inservice. Under CWIP in ratebase (Attachment 1), there is a higher rate impact pre-inservice (due to the recovery of return on CWIP) which is absent under the standard ratemaking approach (Attachment 2) where interest during construction (AFUDC) is capitalized into the project cost and recovered post-inservice.

In the years after in-service, however, the rate impact is lower using CWIP in ratebase. That pattern continues for the remaining life of the asset. Comparative results showing the rate impacts over the years 2011 – 2015 are extracted from the schedules and shown in Table 1 below.

Table 1

	Pre-inservice period*		**Post-inservice period**		
	2011	**2012**	**2013**	**2014**	**2015**
	1	*2*	*3*	*4*	*5*
Revenue Requirement Impact – With CWIP in RB	3.1%	3.7%	4.1%	4.1%	4.2%
Revenue Requirement Impact – With Standard	0.0%	2.2%	4.5%	4.6%	4.6%

** In-service occurs Dec/2012.*

Reduction in borrowing and borrowing costs

Under the standard rate-making approach, AFUDC is capitalized into the cost of the project and included in ratebase, and thereafter financed at Hydro One's deemed 60/40 debt/equity capital structure for ratemaking purposes. By contrast, under CWIP in ratebase AFUDC is avoided and the project costs and ratebase are lower. Therefore, there is a reduction in the amount of borrowing required for projects that use the CWIP in ratebase approach equal to the 60% of underlying debt that would otherwise have financed the AFUDC-related component of ratebase.

For the Bruce to Milton project, the reduction in borrowing amount is shown by the amount of AFUDC included on page 1 of the analysis presenting the standard ratemaking approach (Attachment 2), at line 54 under the box "Capital Expenditure by Year". The total amount of AFUDC to the 2012 in-service date is forecast at $92.1M. Of this amount, $24.8M is projected to the end of 2010 and is not affected by the application of CWIP in ratebase, which begins in 2011. The amount of AFUDC forecast for 2011 and 2012 is the difference, or $67.3M. This is the amount of AFUDC that would be avoided under the CWIP in ratebase approach for Bruce to Milton, and 60% or approximately $40.4M is the avoided debt-related component. In turn, the interest on that debt would be avoided over the depreciating life of the asset, leading to a lower lifetime revenue requirement compared with the standard methodology. The lifetime revenue requirement impacts are discussed in the next section. It should also be noted that unlike on Bruce to Milton, for projects that follow the CWIP in ratebase approach from their inception the entire amount of AFUDC incurred for the project (multiplied by 60%) would be avoided under the CWIP in ratebase approach.

In addition to a reduction in the amount of borrowing and interest costs, there is also a possibility that the improved cashflow associated with using CWIP in ratebase for the

Bruce Milton project could lead to a lower cost of debt (i.e., interest rate on new debt issues) for Hydro One's overall borrowing program through an improvement in credit quality (see Exhibit I, Tab 7, Schedule 7, Part a). However, this benefit is difficult to quantify.

Lifetime Revenue Requirement – Undiscounted and discounted basis

On an undiscounted basis, the total revenue requirement for the project using CWIP in ratebase is $2,667.9M compared with $2,856.0M using the standard approach, over the life of the asset plus the pre-inservice period. These results are shown on line 18 of page 1 of Attachments 1 and 2, respectively. CWIP in ratebase is therefore less costly, in lifetime revenue requirement terms, by $188.1M.

Recognizing the time value of money, the cost impact of the project is also compared on the attached schedules in Net Present Value terms. This is done on both a Revenue Requirement and Discounted Cash Flow basis over a 52 year period (assumed 50 year service life + 2 years pre-inservice).

On a revenue requirement basis, the analysis shows at line 25 of Attachments 1 and 2 (page 1) that the NPV of the revenue requirement is lower under the CWIP in ratebase approach. The NPV is $839.0M for CWIP in ratebase and $848.7M for the standard method – that is, CWIP in ratebase is somewhat less expensive in lifetime revenue requirement terms than the traditional approach. The reason why this is so is set out immediately below.

Why is CWIP in ratebase less costly on a lifetime NPV revenue requirement basis?

It must be borne in mind when comparing the two approaches that CWIP in ratebase does not involve simply replacing the lower AFUDC rate that would otherwise have been charged to the project over the construction period (under the standard ratemaking approach) with the higher blended debt and equity rate of return (applied under CWIP in ratebase).

Instead, the true lifetime comparison is between, on the one hand with the standard approach, a possibly lower amount of construction-period interest (due to the lower AFUDC rate compared with the all-in return) *plus* the additional return earned over time as a result of capitalizing AFUDC into ratebase; and on the other hand with CWIP in ratebase, a slightly larger amount of construction period return being recovered earlier in time but with no further return on that return being earned over time (because the return on CWIP in ratebase is not capitalized into ratebase). How those different cash streams play out – AFUDC plus long-term return on it (standard) vs. accelerated short-term debt and equity return alone, with no return on return (CWIP in ratebase) -- in terms of lifetime ratepayer impact is shown by the results above. In this case, it shows that CWIP in ratebase is actually less costly to ratepayers than the standard approach, although the difference is not large and it may not always be the case. The result is affected by spreads between the blended debt and equity rate of return and the AFUDC rate, which can vary.

The result is also affected by the length of the pre-inservice period. Typically, the longer the pre-inservice period when AFUDC costs are accumulating, the more attractive will the CWIP in ratebase approach become because it will avoid the double-compounding effect associated with AFUDC – i.e., AFUDC first compounding annually over the pre-inservice period and then return on the compounded AFUDC being earned over the post-inservice period. Being a "simple interest" calculation (i.e., the return on CWIP in ratebase in one year does not compound into the 2nd and subsequent years' return prior to in-service, and that return also does not then earn a return over the life of the asset), CWIP in ratebase avoids the compounding effect.

Lifetime Costs – DCF basis

On a DCF basis, the NPV is $602.6M for CWIP in ratebase and $608.2M for the standard approach, again illustrating that CWIP in ratebase is less costly over the long-term. Note that the large difference in the amounts between the two valuation methods (revenue requirement and DCF) stems largely from the fact that the DCF analysis is done on after-tax basis whereas the revenue requirement is before-tax. The revenue requirement analysis also reflects annual depreciation (recovery of capital) whereas the DCF reflects the true timing of expenditures (i.e., project costs are front-end loaded).

Impact of Delays

The compounding effect of the standard ratemaking approach referred to above is magnified when there are delays to the schedule. When unanticipated project delays are encountered, continuing to charge AFUDC to a project could result in large and growing pre-inservice interest costs accumulating against the project and in turn being "baked-in" to ratebase. These delays could occur and have AFUDC impacts both in the approvals process (in cases where long-lead-time equipment is required to be ordered prior to all approvals being received) or during construction (for a variety of reasons such as strikes, work stoppages, citizen action, bad weather).

An example of the schedule risk occurring over the approvals period is illustrated in the Bruce to Milton project itself, where the formal approvals process that began in late March 2007 has not yet concluded and (more importantly from a risk standpoint) still has no defined end-date.

Hydro One's ongoing experience with the Niagara Reinforcement project (NRP) is an example of construction delay risk, again with no end-point in sight. Using CWIP in ratebase would avoid the risk of growing and open-ended interest charges accumulating against a project that experienced such delays. While on the NRP recovery of the carrying costs of the project was eventually allowed to begin in order to avoid AFUDC build-up, the point remains that the CWIP in ratebase approach would avoid these costs from accumulating in the first place, and thereby eliminate the compounding effect completely. CWIP in ratebase in this way provides risk mitigation against schedule delays.

Attachments 3 and 4 provide an example of the potential impacts of delay for the Bruce to Milton project comparing the CWIP in ratebase and standard methods. A 1-year delay in the Bruce to Milton in-service date is assumed. The delay is assumed to result from a work stoppage similar to the NRP situation – i.e., the project is close to completion and most costs have been spent when the stoppage occurs.

The results show that as anticipated, the compounding effect associated with the standard approach results in the NPV of the project's lifetime revenue requirement increasing under the standard approach by more than it increases under CWIP in ratebase. That is, the gap between the two methods increases, and makes CWIP in ratebase more attractive. The NPV of lifetime revenue requirement under CWIP in ratebase is $845M with the delay (Attachment 3) compared with $875M for the standard methodology (Attachment 4), leaving a difference of $30M. This compares with the difference of $10M under the no-delay scenarios.

Conclusion

Based on the results above, Hydro One's position is that CWIP in ratebase is the approach that provides the greatest overall benefit to ratepayers due to its rate-smoothing effects, lower lifetime costs and risk mitigation. These benefits are especially important for large projects like Bruce to Milton where the costs are large and significant schedule risks are present.

Attachment 1

CWIP in Ratebase

Year	Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
Incremental Ratebase		0.0	333.4	672.9	673.3	661.9	650.6	639.2	627.9	616.5	605.1	593.8	582.4	571.1	559.7	548.4	537.0	525.7	514.3
Revenue Requirement Impact																			
Accelerated CWIP	69.5	43.6	26.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	1,548.4	0.0	25.0	50.5	50.5	49.6	48.8	47.9	47.1	46.2	45.4	44.5	43.7	42.8	42.0	41.1	40.3	39.4	38.6
Income Tax	354.5	0.0	(0.9)	(1.3)	(0.3)	0.7	1.6	2.4	3.1	3.7	4.3	4.8	5.3	5.7	6.1	6.4	6.7	7.0	7.2
Depreciation	695.5	0.0	5.4	11.1	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Incremental Revenue Requirement Impact	**2,667.9**	**43.6**	**55.5**	**60.3**	**61.5**	**61.7**	**61.7**	**61.7**	**61.5**	**61.3**	**61.1**	**60.7**	**60.4**	**59.9**	**59.4**	**58.9**	**58.4**	**57.8**	**57.1**
Base Revenue Requirement w/o BxM		**1,401.9**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement		3.1%	3.7%	4.1%	4.1%	4.2%	4.2%	4.2%	4.1%	4.1%	4.1%	4.1%	4.1%	4.0%	4.0%	4.0%	3.9%	3.9%	3.8%
PV of Revenue Requirement		42.2	50.4	51.4	49.2	46.2	43.4	40.6	38.0	35.6	33.2	31.0	28.9	26.9	25.0	23.3	21.6	20.1	18.6
NPV of Revenue Requirement	**839.0**																		
Incremental DCF of Project																			
Rate Base Additions																			
Land	(109.6)	0.0	(109.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	(492.0)	0.0	(470.4)	(21.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	(24.8)	0.0	(24.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	(69.2)	0.0	(67.5)	(1.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	(695.5)	0.0	(672.2)	(23.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP		(43.6)	(26.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax		11.4	12.5	11.2	10.6	9.7	8.9	8.2	7.6	7.0	6.4	5.9	5.4	5.0	4.6	4.2	3.9	3.6	3.3
Total CF		(32.1)	(685.6)	(12.1)	10.6	9.7	8.9	8.2	7.6	7.0	6.4	5.9	5.4	5.0	4.6	4.2	3.9	3.6	3.3
PV by Year	**(602.6)**	(31.1)	(622.8)	(10.3)	8.4	7.3	6.3	5.4	4.7	4.0	3.5	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.1
Accumulated PV		(31.1)	(653.9)	(664.2)	(655.8)	(648.5)	(642.2)	(636.8)	(632.1)	(628.1)	(624.6)	(621.6)	(619.0)	(616.7)	(614.8)	(613.1)	(611.7)	(610.4)	(609.4)

Economic Study Horizon - Years:	**52**
Construction period plus 50 year asset life	
Discount Rate (Hydro One WACC) - %	**6.62%**
	$M
PV of Accelerated Cost of Recovery in CWIP	(65.8)
PV Income Tax	93.6
PV Capital - Upfront	(630.5)
PV Surplus / (Shortfall)	**(602.6)**

Capital Expenditure by Year

	up to 2010	2011	2012	2013	Total
Land	92.1	17.5	0.0	0.0	109.6
Fixed Assets	235.8	148.6	85.9	21.6	492.0
AFUDC	24.8	0.0	0.0	0.0	24.8
Overheads	40.9	18.3	8.3	1.7	69.2
Total	**393.6**	**184.4**	**94.3**	**23.3**	**695.5**

Attachment 1

CWIP in Ratebase

Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
	19	*20*	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*	*31*	*32*	*33*	*34*	*35*	*36*	*37*
Incremental Ratebase	502.9	491.6	480.2	468.9	457.5	446.2	434.8	423.5	412.1	400.7	389.4	378.0	366.7	355.3	344.0	332.6	321.2	309.9	298.5
Revenue Requirement Impact																			
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	37.7	36.9	36.0	35.2	34.3	33.5	32.6	31.8	30.9	30.1	29.2	28.4	27.5	26.6	25.8	24.9	24.1	23.2	22.4
Income Tax	7.4	7.6	7.7	7.8	7.9	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.9	7.8	7.7	7.6	7.6
Depreciation	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Incremental Revenue Requirement Impact	**56.5**	**55.8**	**55.1**	**54.3**	**53.6**	**52.8**	**52.0**	**51.1**	**50.3**	**49.5**	**48.6**	**47.7**	**46.8**	**45.9**	**45.0**	**44.1**	**43.2**	**42.2**	**41.3**
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	3.8%	3.8%	3.7%	3.7%	3.6%	3.6%	3.5%	3.4%	3.4%	3.3%	3.3%	3.2%	3.2%	3.1%	3.0%	3.0%	2.9%	2.8%	2.8%
PV of Revenue Requirement	17.3	16.0	14.8	13.7	12.7	11.7	10.8	10.0	9.2	8.5	7.8	7.2	6.6	6.1	5.6	5.2	4.7	4.3	4.0
NPV of Revenue Requirement																			
Incremental DCF of Project																			
Rate Base Additions																			
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	3.0	2.8	2.6	2.4	2.2	2.0	1.8	1.7	1.6	1.4	1.3	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.7
Total CF	3.0	2.8	2.6	2.4	2.2	2.0	1.8	1.7	1.6	1.4	1.3	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.7
PV by Year	0.9	0.8	0.7	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Accumulated PV	(608.4)	(607.7)	(607.0)	(606.4)	(605.9)	(605.4)	(605.0)	(604.7)	(604.4)	(604.2)	(604.0)	(603.8)	(603.6)	(603.5)	(603.4)	(603.3)	(603.2)	(603.1)	(603.0)

[1] Revenue Requirer

Attachment 1

CWIP in Ratebase

Year	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
	38	*39*	*40*	*41*	*42*	*43*	*44*	*45*	*46*	*47*	*48*	*49*	*50*	*51*	*52*
Incremental Ratebase	287.2	275.8	264.5	253.1	241.8	230.4	219.0	207.7	196.3	185.0	173.6	162.3	150.9	139.6	130.8
Revenue Requirement Impact															
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	21.5	20.7	19.8	19.0	18.1	17.3	16.4	15.6	14.7	13.9	13.0	12.2	11.3	10.5	9.8
Income Tax	7.5	7.4	7.2	7.1	7.0	6.9	6.8	6.7	6.5	6.4	6.2	6.1	6.0	5.8	49.3 [1]
Depreciation	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	133.9 [1]
Incremental Revenue Requirement Impact	**40.4**	**39.4**	**38.4**	**37.5**	**36.5**	**35.5**	**34.6**	**33.6**	**32.6**	**31.6**	**30.6**	**29.6**	**28.6**	**27.6**	**193.0** [1]
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	2.7%	2.7%	2.6%	2.5%	2.5%	2.4%	2.3%	2.3%	2.2%	2.1%	2.1%	2.0%	1.9%	1.9%	13.0% [1]
PV of Revenue Requirement	3.6	3.3	3.1	2.8	2.6	2.3	2.1	1.9	1.8	1.6	1.5	1.3	1.2	1.1	7.1
NPV of Revenue Requirement															
Incremental DCF of Project															
Rate Base Additions															
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Total CF	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	1.4
PV by Year	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Accumulated PV	(603.0)	(602.9)	(602.9)	(602.9)	(602.8)	(602.8)	(602.8)	(602.8)	(602.7)	(602.7)	(602.7)	(602.7)	(602.7)	(602.7)	(602.6)

nent in final year adjusted to reflect future revenue requirement of remaining assets

Attachment 2

AFUDC Capitalized with expected in-service date

Year	Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
Incremental Ratebase		0.0	366.8	739.2	738.5	726.1	713.7	701.3	688.9	676.5	664.1	651.7	639.2	626.8	614.4	602.0	589.6	577.2	564.8
Revenue Requirement Impact																			
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	1,702.7	0.0	27.5	55.4	55.4	54.5	53.5	52.6	51.7	50.7	49.8	48.9	47.9	47.0	46.1	45.2	44.2	43.3	42.4
Income Tax	390.4	0.0	(0.9)	(1.4)	(0.3)	0.8	1.7	2.6	3.4	4.1	4.8	5.3	5.9	6.3	6.7	7.1	7.4	7.7	7.9
Depreciation	762.9	0.0	6.0	12.2	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Incremental Revenue Requirement Impact	**2,856.0**	**0.0**	**32.5**	**66.2**	**67.5**	**67.6**	**67.7**	**67.6**	**67.5**	**67.3**	**67.0**	**66.6**	**66.2**	**65.7**	**65.2**	**64.6**	**64.0**	**63.4**	**62.7**
Base Revenue Requirement w/o BxM		**1,401.9**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement		0.0%	2.2%	4.5%	4.5%	4.6%	4.6%	4.6%	4.5%	4.5%	4.5%	4.5%	4.5%	4.4%	4.4%	4.4%	4.3%	4.3%	4.2%
PV of Revenue Requirement		0.0	29.6	56.4	53.9	50.7	47.6	44.6	41.7	39.0	36.4	34.0	31.7	29.5	27.4	25.5	23.7	22.0	20.4
NPV of Revenue Requirement	**848.7**																		
Incremental DCF of Project																			
Rate Base Additions																			
Land	(109.6)	0.0	(109.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	(492.0)	0.0	(470.4)	(21.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	(92.1)	0.0	(92.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	(69.2)	0.0	(67.5)	(1.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	(762.9)	0.0	(739.5)	(23.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax		0.0	6.3	12.3	11.5	10.6	9.8	9.0	8.3	7.6	7.0	6.4	5.9	5.5	5.0	4.6	4.2	3.9	3.6
Total CF		0.0	(733.3)	(11.0)	11.5	10.6	9.8	9.0	8.3	7.6	7.0	6.4	5.9	5.5	5.0	4.6	4.2	3.9	3.6
PV by Year	**(608.2)**	0.0	(666.1)	(9.4)	9.2	8.0	6.9	5.9	5.1	4.4	3.8	3.3	2.8	2.4	2.1	1.8	1.6	1.4	1.2
Accumulated PV		0.0	(666.1)	(675.5)	(666.2)	(658.3)	(651.4)	(645.5)	(640.4)	(636.0)	(632.1)	(628.9)	(626.0)	(623.6)	(621.5)	(619.6)	(618.1)	(616.7)	(615.5)

Economic Study Horizon - Years:	**52**
Construction period plus 50 year asset life	
Discount Rate (Hydro One WACC) - %	**6.62%**
	$M
PV of Accelerated Cost of Recovery in CWIP	0.0
PV Income Tax	83.4
PV Capital - Upfront	(691.6)
PV Surplus / (Shortfall)	**(608.2)**

Capital Expenditure by Year	**up to 2010**	**2011**	**2012**	**2013**	**Total**
Land	92.1	17.5	0.0	0.0	109.6
Fixed Assets	235.8	148.6	85.9	21.6	492.0
AFUDC	24.8	26.4	40.9	0.0	92.1
Overheads	40.9	18.3	8.3	1.7	69.2
Total	**393.6**	**210.8**	**135.2**	**23.3**	**762.9**

Attachment 2

AFUDC Capitalized with expected in-service date

Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
	19	*20*	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*	*31*	*32*	*33*	*34*	*35*	*36*	*37*
Incremental Ratebase	552.4	540.0	527.6	515.1	502.7	490.3	477.9	465.5	453.1	440.7	428.3	415.9	403.5	391.0	378.6	366.2	353.8	341.4	329.0
Revenue Requirement Impact																			
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	41.4	40.5	39.6	38.6	37.7	36.8	35.8	34.9	34.0	33.1	32.1	31.2	30.3	29.3	28.4	27.5	26.5	25.6	24.7
Income Tax	8.1	8.3	8.4	8.6	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.8	8.7	8.7	8.6	8.6	8.5	8.4	8.3
Depreciation	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Incremental Revenue Requirement Impact	**62.0**	**61.2**	**60.4**	**59.6**	**58.8**	**57.9**	**57.0**	**56.1**	**55.2**	**54.3**	**53.3**	**52.4**	**51.4**	**50.4**	**49.4**	**48.4**	**47.4**	**46.4**	**45.4**
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	4.2%	4.1%	4.1%	4.0%	4.0%	3.9%	3.8%	3.8%	3.7%	3.7%	3.6%	3.5%	3.5%	3.4%	3.3%	3.3%	3.2%	3.1%	3.1%
PV of Revenue Requirement	18.9	17.5	16.2	15.0	13.9	12.8	11.9	10.9	10.1	9.3	8.6	7.9	7.3	6.7	6.2	5.7	5.2	4.8	4.4
NPV of Revenue Requirement																			
Incremental DCF of Project																			
Rate Base Additions																			
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	3.3	3.0	2.8	2.6	2.4	2.2	2.0	1.8	1.7	1.6	1.4	1.3	1.2	1.1	1.0	0.9	0.9	0.8	0.7
Total CF	3.3	3.0	2.8	2.6	2.4	2.2	2.0	1.8	1.7	1.6	1.4	1.3	1.2	1.1	1.0	0.9	0.9	0.8	0.7
PV by Year	1.0	0.9	0.8	0.6	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Accumulated PV	(614.5)	(613.7)	(612.9)	(612.3)	(611.7)	(611.2)	(610.8)	(610.4)	(610.1)	(609.9)	(609.6)	(609.4)	(609.3)	(609.1)	(609.0)	(608.9)	(608.8)	(608.7)	(608.6)

[1] Revenue Requiren

Attachment 2

AFUDC Capitalized with expected in-service date

Year	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
	38	*39*	*40*	*41*	*42*	*43*	*44*	*45*	*46*	*47*	*48*	*49*	*50*	*51*	*52*
Incremental Ratebase	316.6	304.2	291.8	279.4	266.9	254.5	242.1	229.7	217.3	204.9	192.5	180.1	167.7	155.2	145.7
Revenue Requirement Impact															
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	23.7	22.8	21.9	21.0	20.0	19.1	18.2	17.2	16.3	15.4	14.4	13.5	12.6	11.6	10.9
Income Tax	8.2	8.1	8.0	7.8	7.7	7.6	7.4	7.3	7.2	7.0	6.9	6.7	6.6	6.4	54.9 [1]
Depreciation	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	149.0 [1]
Incremental Revenue Requirement Impact	**44.3**	**43.3**	**42.3**	**41.2**	**40.1**	**39.1**	**38.0**	**36.9**	**35.9**	**34.8**	**33.7**	**32.6**	**31.5**	**30.5**	**214.9** [1]
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	3.0%	2.9%	2.8%	2.8%	2.7%	2.6%	2.6%	2.5%	2.4%	2.3%	2.3%	2.2%	2.1%	2.1%	14.5% [1]
PV of Revenue Requirement	4.0	3.7	3.4	3.1	2.8	2.6	2.3	2.1	1.9	1.8	1.6	1.5	1.3	1.2	7.9
NPV of Revenue Requirement															
Incremental DCF of Project															
Rate Base Additions															
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	0.7	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Total CF	0.7	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	1.5
PV by Year	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Accumulated PV	(608.6)	(608.5)	(608.5)	(608.4)	(608.4)	(608.4)	(608.3)	(608.3)	(608.3)	(608.3)	(608.3)	(608.3)	(608.2)	(608.2)	(608.2)

nent in final year adjusted to reflect future revenue requirement of remaining assets

Attachment 3

Accelerated Cost of Recovery in CWIP with 1 year in-service delay

Year	Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*
Incremental Ratebase		0.0	333.4	344.9	684.2	672.8	661.5	650.1	638.8	627.4	616.0	604.7	593.3	582.0	570.6	559.3	547.9	536.5	525.2	513.8
Revenue Requirement Impact																				
Accelerated CWIP	99.7	43.6	26.0	30.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base [1]	1,573.4	0.0	25.0	25.9	51.3	50.5	49.6	48.8	47.9	47.1	46.2	45.4	44.5	43.6	42.8	41.9	41.1	40.2	39.4	38.5
Income Tax [1]	353.6	0.0	(0.9)	(1.0)	(1.3)	(0.3)	0.7	1.6	2.4	3.1	3.8	4.3	4.9	5.3	5.8	6.1	6.5	6.7	7.0	7.2
Depreciation [1]	701.0	0.0	5.4	5.7	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Incremental Revenue Requirement Impact	**2,727.7**	**43.6**	**55.5**	**60.8**	**61.3**	**61.6**	**61.7**	**61.7**	**61.7**	**61.5**	**61.3**	**61.1**	**60.7**	**60.3**	**59.9**	**59.4**	**58.9**	**58.3**	**57.7**	**57.1**
Base Revenue Requirement w/o BxM		**1,401.9**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement		3.1%	3.7%	4.1%	4.1%	4.1%	4.2%	4.2%	4.2%	4.1%	4.1%	4.1%	4.1%	4.1%	4.0%	4.0%	4.0%	3.9%	3.9%	3.8%
PV of Revenue Requirement		42.2	50.4	51.8	49.0	46.1	43.4	40.7	38.1	35.7	33.4	31.1	29.1	27.1	25.2	23.5	21.8	20.3	18.8	17.4
NPV of Revenue Requirement	**845.0**																			
Incremental DCF of Project																				
Rate Base Additions																				
Land	(109.6)	0.0	0.0	(109.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	(492.0)	0.0	0.0	(492.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	(24.8)	0.0	0.0	(24.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	(69.2)	0.0	0.0	(69.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	(695.5)	0.0	0.0	(695.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP [2]		(43.6)	(55.5)	(30.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax		11.4	14.6	13.9	11.4	10.5	9.7	8.9	8.2	7.5	6.9	6.4	5.9	5.4	5.0	4.6	4.2	3.9	3.6	3.3
Total CF		(32.1)	(41.0)	(711.8)	11.4	10.5	9.7	8.9	8.2	7.5	6.9	6.4	5.9	5.4	5.0	4.6	4.2	3.9	3.6	3.3
PV by Year	**(608.1)**	(31.1)	(37.2)	(606.4)	9.1	7.9	6.8	5.9	5.1	4.4	3.8	3.3	2.8	2.4	2.1	1.8	1.6	1.3	1.2	1.0
Accumulated PV		(31.1)	(68.3)	(674.8)	(665.6)	(657.7)	(650.9)	(645.0)	(640.0)	(635.6)	(631.8)	(628.6)	(625.7)	(623.3)	(621.2)	(619.4)	(617.9)	(616.5)	(615.4)	(614.4)

1. For the 1-year delay scenarios, the project in-service date is Dec. 2013 and rates are assumed to be re-set in that year. For 2012, given that the project is not yet in-service, amounts shown for depreciation, return and taxes represent the costs for these items that were included in setting 2012 rates (i.e., they do not reflect that the project is actually in-service in 2012).

2 2012 Accelerated Cost of Recovery in CWIP includes 2012 Revenue Requirement associated with BxM

Economic Study Horizon - Years:	**53**
Construction period plus 50 year asset life	
Discount Rate (Hydro One WACC) - %	**6.62%**
	$M
PV of Accelerated Cost of Recovery in CWIP	(118.4)
PV Income Tax	102.9
PV Capital - Upfront	(592.5)
PV Surplus / (Shortfall)	**(608.1)**

Capital Expenditure by Year

	up to 2010	**2011**	**2012**	**2013**	**Total**
Land	92.1	17.5	0.0	0.0	109.6
Fixed Assets	235.8	148.6	85.9	21.6	492.0
AFUDC	24.8	0.0	0.0	0.0	24.8
Overheads	40.9	18.3	8.3	1.7	69.2
Total	**393.6**	**184.4**	**94.3**	**23.3**	**695.5**

Attachment 3

Accelerated Cost of Recovery in CWIP with 1 year in-service delay

Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
	20	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*	*31*	*32*	*33*	*34*	*35*	*36*	*37*	*38*	*39*
Incremental Ratebase	502.5	491.1	479.8	468.4	457.1	445.7	434.3	423.0	411.6	400.3	388.9	377.6	366.2	354.9	343.5	332.1	320.8	309.4	298.1	286.7
Revenue Requirement Impact																				
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base [1]	37.7	36.8	36.0	35.1	34.3	33.4	32.6	31.7	30.9	30.0	29.2	28.3	27.5	26.6	25.8	24.9	24.1	23.2	22.4	21.5
Income Tax [1]	7.4	7.6	7.7	7.8	7.9	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.9	7.8	7.7	7.6	7.5	7.5
Depreciation [1]	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Incremental Revenue Requirement Impact	**56.4**	**55.7**	**55.0**	**54.3**	**53.5**	**52.7**	**51.9**	**51.1**	**50.3**	**49.4**	**48.6**	**47.7**	**46.8**	**45.9**	**45.0**	**44.1**	**43.1**	**42.2**	**41.3**	**40.3**
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	3.8%	3.8%	3.7%	3.7%	3.6%	3.6%	3.5%	3.4%	3.4%	3.3%	3.3%	3.2%	3.2%	3.1%	3.0%	3.0%	2.9%	2.8%	2.8%	2.7%
PV of Revenue Requirement	16.2	15.0	13.9	12.8	11.9	11.0	10.1	9.3	8.6	8.0	7.3	6.7	6.2	5.7	5.3	4.8	4.4	4.1	3.7	3.4
NPV of Revenue Requirement																				
Incremental DCF of Project																				
Rate Base Additions																				
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP [2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	3.0	2.8	2.6	2.3	2.2	2.0	1.8	1.7	1.5	1.4	1.3	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.7	0.6
Total CF	3.0	2.8	2.6	2.3	2.2	2.0	1.8	1.7	1.5	1.4	1.3	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.7	0.6
PV by Year	0.9	0.7	0.6	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Accumulated PV	(613.5)	(612.7)	(612.1)	(611.5)	(611.1)	(610.7)	(610.3)	(610.0)	(609.7)	(609.5)	(609.3)	(609.1)	(609.0)	(608.9)	(608.7)	(608.7)	(608.6)	(608.5)	(608.4)	(608.4)

Attachment 3

Accelerated Cost of Recovery in CWIP with 1 year in-service delay

Year	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063
	40	*41*	*42*	*43*	*44*	*45*	*46*	*47*	*48*	*49*	*50*	*51*	*52*	*53*
Incremental Ratebase	275.4	264.0	252.6	241.3	229.9	218.6	207.2	195.9	184.5	173.2	161.8	150.4	139.1	130.6
Revenue Requirement Impact														
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base [1]	20.7	19.8	18.9	18.1	17.2	16.4	15.5	14.7	13.8	13.0	12.1	11.3	10.4	9.8
Income Tax [1]	7.4	7.2	7.1	7.0	6.9	6.8	6.6	6.5	6.4	6.2	6.1	6.0	5.8	49.2 [3]
Depreciation [1]	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	133.4 [3]
Incremental Revenue Requirement Impact	**39.4**	**38.4**	**37.4**	**36.5**	**35.5**	**34.5**	**33.5**	**32.6**	**31.6**	**30.6**	**29.6**	**28.6**	**27.6**	**192.4** [3]
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	2.7%	2.6%	2.5%	2.5%	2.4%	2.3%	2.3%	2.2%	2.1%	2.1%	2.0%	1.9%	1.9%	13.0% [3]
PV of Revenue Requirement	3.1	2.9	2.6	2.4	2.2	2.0	1.8	1.7	1.5	1.4	1.2	1.1	1.0	6.6
NPV of Revenue Requirement														
Incremental DCF of Project														
Rate Base Additions														
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP [2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Total CF	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	1.4
PV by Year	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accumulated PV	(608.3)	(608.3)	(608.3)	(608.2)	(608.2)	(608.2)	(608.2)	(608.2)	(608.1)	(608.1)	(608.1)	(608.1)	(608.1)	(608.1)

[3] Revenue Requirement in final year adjusted to reflect future revenue requirement of remaining assets

Attachment 4

AFUDC Capitalized and Project delayed 1 Year

Year	Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Incremental Ratebase		0.0	366.8	401.1	795.7	782.5	769.3	756.2	743.0	729.9	716.7
Revenue Requirement Impact											
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	1,832.6	0.0	27.5	30.1	59.7	58.7	57.7	56.7	55.7	54.7	53.8
Income Tax	413.0	0.0	(0.9)	(1.1)	(1.5)	(0.3)	0.9	1.9	2.8	3.6	4.4
Depreciation	814.8	0.0	6.0	6.6	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Incremental Revenue Requirement Impact	**3,060.4**	**0.0**	**32.5**	**35.6**	**71.3**	**71.6**	**71.7**	**71.8**	**71.7**	**71.5**	**71.3**
Base Revenue Requirement w/o BxM		**1,401.9**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement		0.0%	2.2%	2.4%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
PV of Revenue Requirement		0.0	29.6	30.3	57.0	53.6	50.4	47.3	44.3	41.5	38.8
NPV of Revenue Requirement	**875.0**										
Incremental DCF of Project											
Rate Base Additions											
Land	(109.6)	0.0	0.0	(109.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	(492.0)	0.0	0.0	(492.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	(138.0)	0.0	0.0	(138.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	(69.2)	0.0	0.0	(69.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	(808.8)	0.0	0.0	(808.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP		0.0	(32.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax		0.0	8.5	6.9	13.3	12.2	11.2	10.3	9.5	8.7	8.0
Total CF		0.0	(24.0)	(801.9)	13.3	12.2	11.2	10.3	9.5	8.7	8.0
PV by Year	**(627.7)**	0.0	(21.8)	(683.2)	10.6	9.1	7.9	6.8	5.9	5.1	4.4
Accumulated PV		0.0	(21.8)	(705.0)	(694.4)	(685.2)	(677.3)	(670.5)	(664.6)	(659.6)	(655.2)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	11	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
Incremental Ratebase	703.5	690.4	677.2	664.1	650.9	637.8	624.6	611.4	598.3	585.1
Revenue Requirement Impact										
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	52.8	51.8	50.8	49.8	48.8	47.8	46.8	45.9	44.9	43.9
Income Tax	5.1	5.7	6.2	6.7	7.1	7.5	7.9	8.1	8.4	8.6
Depreciation	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Incremental Revenue Requirement Impact	**71.0**	**70.6**	**70.2**	**69.7**	**69.1**	**68.5**	**67.9**	**67.2**	**66.4**	**65.7**
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	4.8%	4.8%	4.7%	4.7%	4.7%	4.6%	4.6%	4.5%	4.5%	4.4%
PV of Revenue Requirement	36.2	33.8	31.5	29.3	27.3	25.4	23.6	21.9	20.3	18.8
Incremental DCF of Project										
Rate Base Additions										
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	7.4	6.8	6.3	5.8	5.3	4.9	4.5	4.1	3.8	3.5
Total CF	7.4	6.8	6.3	5.8	5.3	4.9	4.5	4.1	3.8	3.5
PV by Year	3.8	3.3	2.8	2.4	2.1	1.8	1.6	1.3	1.2	1.0
Accumulated PV	(651.4)	(648.2)	(645.4)	(642.9)	(640.8)	(639.0)	(637.5)	(636.1)	(635.0)	(634.0)

1. For the 1-year delay scenarios, the project in-service date is Dec. 2013 and rates are assumed to be re-set in that year. For 2012, given that the project is not yet in-service, amounts shown for depreciation, return and taxes represent the costs for these items that were included in setting 2012 rates (i.e., they do not reflect that the project is actually in-service in 2012).

2 2012 Accelerated Cost of Recovery in CWIP includes 2012 Revenue Requirement associated with BxM, not Accelerated CWIP

Economic Study Horizon - Years:	**53**
Construction period plus 50 year asset life	
Discount Rate (Hydro One WACC) - %	**6.62%**
	$M
PV of Accelerated Cost of Recovery in CWIP	(29.6)
PV Income Tax	90.9
PV Capital - Upfront	(689.0)
PV Surplus / (Shortfall)	(627.7)

Capital Expenditure by Year

	up to 2010	**2011**	**2012**	**2013**	**Total**
Land	92.1	17.5	0.0	0.0	109.6
Fixed Assets	235.8	148.6	85.9	21.6	492.0
AFUDC	24.8	26.4	40.9	45.9	138.0
Overheads	40.9	18.3	8.3	1.7	69.2
Total	**393.6**	**210.8**	**135.2**	**69.3**	**808.8**

Attachment 4

AFUDC Capitalized and Project delayed 1 Year

Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
	21	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*	*31*	*32*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*40*	*41*
Incremental Ratebase	572.0	558.8	545.7	532.5	519.3	506.2	493.0	479.9	466.7	453.5	440.4	427.2	414.1	400.9	387.8	374.6	361.4	348.3	335.1	322.0	308.8
Revenue Requirement Impact																					
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	42.9	41.9	40.9	39.9	39.0	38.0	37.0	36.0	35.0	34.0	33.0	32.0	31.1	30.1	29.1	28.1	27.1	26.1	25.1	24.1	23.2
Income Tax	8.8	9.0	9.1	9.2	9.3	9.3	9.3	9.4	9.4	9.3	9.3	9.3	9.2	9.2	9.1	9.0	8.9	8.8	8.7	8.6	8.4
Depreciation	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Incremental Revenue Requirement Impact	**64.9**	**64.0**	**63.2**	**62.3**	**61.4**	**60.4**	**59.5**	**58.5**	**57.5**	**56.5**	**55.5**	**54.5**	**53.4**	**52.4**	**51.3**	**50.2**	**49.2**	**48.1**	**47.0**	**45.9**	**44.8**
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	4.4%	4.3%	4.3%	4.2%	4.1%	4.1%	4.0%	3.9%	3.9%	3.8%	3.7%	3.7%	3.6%	3.5%	3.5%	3.4%	3.3%	3.2%	3.2%	3.1%	3.0%
PV of Revenue Requirement	17.4	16.1	14.9	13.8	12.8	11.8	10.9	10.0	9.3	8.5	7.9	7.2	6.7	6.1	5.6	5.2	4.7	4.3	4.0	3.6	3.3
NPV of Revenue Requirement																					
Incremental DCF of Project																					
Rate Base Additions																					
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	3.2	3.0	2.7	2.5	2.3	2.1	1.9	1.8	1.6	1.5	1.4	1.3	1.2	1.1	1.0	0.9	0.8	0.8	0.7	0.7	0.6
Total CF	3.2	3.0	2.7	2.5	2.3	2.1	1.9	1.8	1.6	1.5	1.4	1.3	1.2	1.1	1.0	0.9	0.8	0.8	0.7	0.7	0.6
PV by Year	0.9	0.7	0.6	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Accumulated PV	(633.1)	(632.4)	(631.7)	(631.2)	(630.7)	(630.3)	(629.9)	(629.6)	(629.3)	(629.1)	(628.9)	(628.7)	(628.6)	(628.5)	(628.4)	(628.3)	(628.2)	(628.1)	(628.1)	(628.0)	(628.0)

Attachment 4

AFUDC Capitalized and Project delayed 1 Year

Year	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**	**2063**
	42	*43*	*44*	*45*	*46*	*47*	*48*	*49*	*50*	*51*	*52*	*53*
Incremental Ratebase	295.7	282.5	269.3	256.2	243.0	229.9	216.7	203.5	190.4	177.2	164.1	154.2
Revenue Requirement Impact												
Accelerated CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	22.2	21.2	20.2	19.2	18.2	17.2	16.3	15.3	14.3	13.3	12.3	11.6
Income Tax	8.3	8.2	8.0	7.9	7.7	7.6	7.4	7.3	7.1	7.0	6.8	58.0 [3]
Depreciation	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	157.5 [3]
Incremental Revenue Requirement Impact	**43.6**	**42.5**	**41.4**	**40.3**	**39.1**	**38.0**	**36.8**	**35.7**	**34.6**	**33.4**	**32.2**	**227.1** [3]
Base Revenue Requirement w/o BxM	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**	**1,484.8**
% Impact of BxM on Revenue Requirement	2.9%	2.9%	2.8%	2.7%	2.6%	2.6%	2.5%	2.4%	2.3%	2.2%	2.2%	15.3% [3]
PV of Revenue Requirement	3.1	2.8	2.5	2.3	2.1	1.9	1.8	1.6	1.4	1.3	1.2	7.8
NPV of Revenue Requirement												
Incremental DCF of Project												
Rate Base Additions												
Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Ratebase Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accelerated Cost of Recovery in CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2
Total CF	0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	1.6
PV by Year	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Accumulated PV	(627.9)	(627.9)	(627.9)	(627.8)	(627.8)	(627.8)	(627.8)	(627.8)	(627.8)	(627.7)	(627.7)	(627.7)

[3] Revenue Requirement in final year adjusted to reflect future revenue requirement of remaining assets

Ontario Energy Board (Board Staff) INTERROGATORY #123 List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

Ref: Exhibit A/Tab11/Sch5/p. 5

The evidence indicates that the in-service date for the Bruce to Milton project has already been delayed one year to 2012. Please describe the effect on the costs of the project of a further delay in this date to 2013. If Hydro One were aware that the in-service date was to be delayed to 2013, would that knowledge cause the company to modify its proposal for accelerated recovery of CWIP in 2011 and 2012?

Response

Please see Exhibit I, Tab 1, Schedule 122, page 4.

Based on the analysis and discussion in that above exhibit, if the in-service date was delayed to 2013, that would reinforce the need for and desirability of the CWIP in ratebase approach. It would not cause Hydro One to modify its proposal for accelerated recovery of CWIP in 2011 and 2012.

Ontario Energy Board (Board Staff) INTERROGATORY #124 List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

Ref: Exhibit A/Tab11/Sch5

The Board's *Report on the Regulatory Treatment of Infrastructure Investment*, at page 15, contemplated the expensing of prudently incurred pre-commercial costs. What would be an example of such costs in the Bruce to Milton project? Is Hydro One seeking to expense such costs in the test years?

Response

An example of prudently incurred pre-commercial costs for the Bruce to Milton project is the cost of obtaining regulatory approvals, including for the Environment Assessment process and OEB proceedings (early access, leave to construct and expropriation).

Hydro One is not seeking to expense such costs in the test years. These costs are included in Construction Work in Progress and will be capitalized once the project goes in-service.

Ontario Energy Board (Board Staff) INTERROGATORY #125 List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

Ref: Exhibit A/Tab11/Sch5

The Board's *Report on the Regulatory Treatment of Infrastructure Investment*, in section 3.6, discussed possible conditions that could accompany approval of alternative mechanisms. Is Hydro One suggesting any conditions of approval if the Board grants the request for accelerated CWIP recovery, such as status reports on the project? Is Hydro One already under an obligation to report to the Board arising out of the leave to construct decision on the Bruce to Milton project?

Response

Hydro One believes that the Board and parties already have adequate monitoring and reporting tools in relation to the company's capital program, and the Bruce to Milton project specifically, and as such it is not at this time proposing any additional conditions that could apply to its request for CWIP in ratebase treatment for Bruce to Milton. The existing tools include the Conditions of Approval accompanying the section 92 decision as well as reporting of project level information through this and future rate cases.

As noted in the Board's Report referenced above, CWIP in rate base is essentially a rate-smoothing technique which shifts cost recovery over time but unlike an increased, project-specific ROE for example, does not increase the lifetime costs that ratepayers are asked to bear, or at least not in a material way (see Exhibit I, Tab 1, Schedule 122 for a comparison of the lifetime rate impact of CWIP in ratebase vs. the standard rate-making approach). As such, in Hydro One's view the impact of CWIP in ratebase is not significant enough to warrant increased, project-specific, reporting beyond what is already required.

Condition 1.3 of the Bruce to Milton Conditions of Approval is reproduced below. It requires advance notification for material changes to the project and hence it provides an effective monitoring tool for the Board in relation to the project's progress and any potential for negative impacts arising therefrom.

> 1.3 Hydro One shall advise the Board's designated representative of any proposed material change in the project, including but not limited to changes in: the proposed route; construction techniques; construction schedule; restoration procedures; or any other impacts of construction. Hydro One shall not make a material change without prior approval of the

Board or its designated representative. In the event of an emergency the Board shall be informed immediately after the fact. [EB-2007-0050, Conditions of Approval]

Ontario Energy Board (Board Staff) INTERROGATORY #126 List 1

Interrogatory

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

Ref: Exhibit A/Tab11/Sch4/p.36, 37
The Transmission Green Energy Plan indicates at pages 37 and 38 that for certain capital projects other than Bruce to Milton, Hydro One will seek accelerated cost recovery of CWIP as part of the s.92 process.

Section 3.5 of the Board's *Report on The Regulatory Treatment of Infrastructure Investment in connection with the Rate regulated Activities of Distributors and Transmitters in Ontario*, indicates that while the need for a project may be best proven in a section 92 application, an application for an alternative mechanism is most effectively addressed in conjunction with an application for a system development plan at the time of rebasing. While the Board did not preclude the filing of an alternative mechanism application at a time other than rebasing, the Board prefers to avoid single-issue rate reviews.

Please explain why Hydro One proposes not to accept this guidance as to the timing of applications for alternative mechanisms.

Response

Hydro One notes the Board's understandable preference to avoid single-issue rate reviews, except "for unusual or exceptional circumstances" [*Report on The Regulatory Treatment of Infrastructure Investment in connection with the Rate regulated Activities of Distributors and Transmitters in Ontario*, p. 23]. Hydro One considers that most of the Green Energy projects will present just such unusual or exceptional circumstances as the Board was contemplating, in the sense that the Green Energy and other qualifying projects represent the largest capital build-out of the provincial transmission system in decades.

Based on the large costs of the build program, smoothing of rates as the Board noted in the above-noted *Report* [p. 15] will be one of the principal benefits of the CWIP in ratebase approach that Hydro One is proposing to use, and which will underlie the request for rate recovery made in a section 92 proceeding. The smoothing effect on rates resulting from the application of CWIP in ratebase will be diluted, however, if the rate re-set point is instead delayed to a subsequent rate case proceeding, at which time the impact of several projects will have accumulated and the accompanying rate shock magnified. In Hydro One's view, the beneficial effect of smoothing will be better realized if rates are re-set on an individual project basis. That said, the determination of whether to request rates to be re-set for an individual project in a section 92 proceeding will be made on a case-base basis.