BOARD STAFF INTERROGATORIES

HYDRO ONE NETWORKS INC.
2011/2012 ELECTRICITY TRANSMISSION REVENUE REQUIREMENT AND RATES APPLICATION
EB-2010-0002

1. GENERAL

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

1) 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?

2) 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?

3) 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.

4) 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.

5) 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.

6) 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.

7) 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.

8) 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.

9) 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.

10) 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.

11) 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?

12) 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?

13) 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).

14) 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.

15) 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.

16) 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.

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.

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

18) 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.

19) Ref: Exhibit A/Tab11/Sch3/p1-9.

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-

[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

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.

20) Ref: Exhibit A/Tab11/Sch3/p1-9.

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.

2. LOAD FORECAST and REVENUE FORECAST

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

21) 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?

22) Ref: Exhibit A/Tab12/Sch3/Pages 6-8

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?

23) 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?

24) 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?

25) 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?

26) 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.

27) 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.

28) 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.

29) 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).

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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.

30) 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).

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

31) 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?

32) 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?

33) 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.

34) 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?

35) 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?

36) 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.

3. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

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

37) 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.

38) 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).

Sustainment

39) 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?

40) 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?

41) 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?

42) 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?

43) 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).

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.

Issue 3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

45) 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.

46) 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

47) 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.

48) 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.

49) 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?

50) 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?

51) Ref. Exhibit C1/Tab2/Sch8/p.3-18
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?

52) 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?

53) 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.

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?

54) Ref. Exhibit C1/Tab3/Sch2/p. 9
Please provide the annual number of employees that correspond to these payroll levels by year.

55) 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"?

56) 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?

57) 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.

58) 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?

59) 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.

60) 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?

61) 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 61st 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?

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?

62) 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?

Issue 3.6 Are the amounts proposed to be included in the 2011 and 2012 revenue requirements for income and other taxes appropriate?

63) 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.

CAPITAL EXPENDITURES and RATE BASE

Issue 4.1 Are amounts proposed in rate base in 2011 and 2012 appropriate?

64) Ref: Exhibit D1/T1/S2/Table 1 and Exhibit D1/T3/S1/Table 1

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

65) 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.

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

66) 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?

67) 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 Transfomers	
Perimeter Fence - Cost/km	
Control, Metering, Relaying & Annunciation Systems (Richview & Hanmer) - Cost/System	

68) 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.

69) 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.

70) 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.

71) 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.

72) 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?

73) 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.

74) 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.

75) 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.

76) 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.

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.

78) 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?

79) Ref: (a) Exhibit D1/Tab3/Sch3/p19/ Project D10 & Appendix A, p3, Table 3, Project D10 – Rebuild Burlington TS 115 kV Switchyard
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]

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

80) Ref: Exhibit D2/Tab2/Sch3/Investment Summary Document/ Project D15 – Guelph Area Transmission Reinforcement
Please indicate when the OPA is expected to provide its assessment of the need for this project.

81) 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.

82) 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;

83) 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.

84) 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.

85) 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.

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.

87) 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.

6. DEFERRAL/VARIANCE ACCOUNTS

Issue 6.1 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

88) 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.

89) <u>Ref: Exhibit F2/Tab1/Sch3</u>

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.

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

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.

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.

92) 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 Hydro One from the Board's current policy not to authorize an OEB cost variance 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?

Issue 7.1 Has Hydro One Networks' cost allocation methodology been applied appropriately?

93) <u>Ref: Exhibit G2/Tab2/Sch1 and Exhibit H1/Tab 2/Sch 1</u>

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.)

Issue 8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network Service?

94) 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 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?

95) 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.

96) 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?

97) 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.

Issue 9.1 Are the OMA and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

98) 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.

99) 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?

100) 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.

101) 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.

102) 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”?

103) <u>Ref: Exhibit A/Tab11/Sch4/p.8</u>

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.

104) <u>Ref: Exhibit A/Tab11/Sch4</u>

(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.

105) <u>Ref: Exhibit A/Tab11/Sch4/p. 9 – Table 1</u>

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?

106) <u>Ref: Exhibit C1/Tab2/Sch 4 – Table 1</u>

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).

107) 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).

108) 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?

109) Ref: Exhibit A/Tab11/Sch4/p.42
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.

110) 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.

111) 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.

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.

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.

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?

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.

116) 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.

117) 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?

118) 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?

Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce to Milton line and for Green Energy Projects appropriate?

119) 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.

120) 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?

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?

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.

123) 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?

124) 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?

125) 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?

126) 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.