Board Staff Interrogatories

Hydro One Networks Inc.

2013 and 2014

Transmission Revenue Requirement and Rates

EB-2012-0031

August 28, 2012

Hydro One Networks Inc.
Transmission Revenue Requirement and Rate Hearing
2013 and 2014
EB-2012-0031
BOARD STAFF INTERROGATORIES
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GENERAL

1) Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

1.0-Staff-1
Ref: Exhibit A/Tab 6/Sch1
Hydro One mentions that the application satisfies the Filing Requirements and Handbook requirements except where it was not practical or appropriate to do so based on previous comments and direction from the Board, or as a result of specific government regulation. Please provide a brief summary of where the Filing Requirements and Handbook requirements are not satisfied and the rationale for each item or area.

2) Is the overall increase in 2013 and 2014 revenue requirement reasonable?

2.0-Staff-2
Ref: Exhibit A/Tab 4/Sch1/p 11
Hydro One mentions that it is a bidder through its one-third interest in the East-West Tie partnership. Please provide the background information on how the cost of this bid is treated by Hydro One. How does or will this bid impact Hydro One's transmission or distribution businesses?

2.0-Staff-3
Ref: Exhibit A/Tab 4/Sch1/pp 12 & 13
Under the section entitled North American Reliability Framework, Hydro One provides an overview of its obligations under the framework and mentions that 60 of the 120 standards apply to Hydro One. What is the status of Hydro One's compliance with these standards? Where, in this application do the bulk of the costs of compliance fall and are costs falling or growing into the test years?

2.0-Staff-4
Ref: Exhibit A/Tab 2/Sch1/p 1
At this reference, Hydro One indicates that the rates revenue requirement will increase by 0.6% in 2013 and 9.0% in 2014. Please provide the detailed calculation of these percentage increases, with reference to Exhibit E1/Tab1/Schedule1.

2.0-Staff-5
Ref: Exhibit A/Tab 2/Sch 1/p 1
Please provide the detailed background calculations used to derive the quoted average customer's total bill increase of 0.0% in 2013 and 0.7% in 2014.

2.0-Staff-6
Ref: Exhibit A-13-1/Appendix A
At this reference, Hydro One shows the 2012 Business Planning Assumptions. The Forecasts mentioned are quite dated, for instance:

- Ontario-CPI forecasts are dated April 2011.
- Bond Rate forecast is dated October 2011.
- 90-day Banker's Acceptance Rate forecast is dated June 2011.
- 10 year Government of Canada Forecast and the DEX mid-term spread are both dated October 2011.

It appears from the evidence at Exhibit A/Tab15/Schedule1 that more recent forecasts are available. Why were more recent forecasts not used for this section of the application? Please provide an update for the quoted sources and the impact of these updates on the application.

2.0-Staff-7
Ref: Exhibit A-13-1/Appendix A
The Ontario CPI forecast from 2012 to 2016 averages 2.0% for each year. On page 2 under labour escalation, Hydro One uses assumptions of 3.0% for economic increases for Society, PWU and MCP staff for the same period. Why is 3.0% used when the evidence indicates a significantly lower forecast of inflation? Please provide an estimate of the cost savings achievable if a labour escalation rate of 2% is used for the test years.

2.0-Staff-8
Ref: Exhibit A-13-1/Appendix A/p 4
Please provide another version of the table on Benefit Cost Rates and include 2009, 2010 and 2011.

2.0-Staff-9
Ref: Exhibit A/Tab 16/Sch1/p 4
Hydro One indicates that it has adopted the Medical Attentions measure in favour of the Lost Time Injury metric. However, the Lost Time Injury metric is still shown at Figure 1. Please provide the Medical Attentions measure in a similar graph. With regard to the current Figure 1, what is responsible for the increase from 2010 to 2011? How is the duration of the injury reflected in this measurement?

2.0-Staff-10
Ref: Exhibit A/Tab 16/Sch1/p 5
Hydro One indicates that the change in the Recordable Injury Frequency from 2010 to 2011 as shown in Figure 2 has increased but that the causes are still being researched by safety experts. Can Hydro One provide any update on the causes of this increase injury frequency at this time?

2.0-Staff-11
Ref: Exhibit A/Tab 16/Sch1/pp 12 - 18
Figures 1 through 10 appear to show that Hydro One's delivery performance to be consistently below the CEA Composite levels from 2003 to 2010, with an anomaly (forest fire) in 2011 that causes a sudden increase. In light of these results, how does Hydro reconcile its plans to significantly increase spending in replacing/refurbishing assets in the test years?

2.0-Staff-12
Ref: Exhibit A/Tab 17/Sch1/Figure 2
Please provide the compensation amounts that are used for the Compensation line of the graph shown at Figure 2.

2.0-Staff-13
Ref: Exhibit A/Tab 17/Sch1/Table 4
Please provide the results from 2009 to 2011 and a preliminary figure for 2012 as shown in Table 4.

2.0-Staff-14
Ref: Exhibit A/Tab 17/Sch2/p 3
Hydro One indicates that it chose three activity metrics from the suggested Oliver Wyman metrics, based on materiality and business impact. Please provide additional detail on the materiality/business impacts of the three metrics and why others were not selected.

2.0-Staff-15
Ref: Exhibit E1/Tab1/Sch1/pp 3&5
The tables on these pages show the proposed 2014 total revenue requirement is 6.4% above the proposed 2013 requirement, and 9.9% above the approved 2012 requirement. While a brief explanation is provided below each table, please provide additional detail on the main reasons for the 2014 increase relative to previous years.

LOAD FORECAST and REVENUE FORECAST

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

3.0 -Staff IR#16
Ref: Exhibit A/Tab 15/Sch1
The forecasts for Ontario CPI and Cost Escalation appear to be more recent than in Exhibit 13, dated February 2012 and January 2012. Have more recent forecasts been released? If so, please provide these forecasts and also indicate if the changes in the forecasts are material and how the application would be affected.

3.0-Staff-17
Ref: Exhibit A/Tab 15/Sch1/p 4
Please update the forecast for Allowance for Funds Used During Construction using the most recently available Consensus Forecast.

3.0-Staff-18
Ref: Exhibit A/Tab 15/Sch2/Table 3
This table shows that Ontario Demand (before deducting impacts of Embedded Generation and CDM) grows by 0.9% in 2012, 1.3% in 2013 and 1.3% in 2014. At pages 5 and 6 of this same exhibit it appears that Provincial GDP and particularly Industrial Production are forecast to grow at much higher rates. Given the latter, why is the demand forecast so low?

3.0-Staff-19
Ref: Exhibit A/Tab 15/Sch2/p 8

Hydro One indicates that its forecast CDM peak impacts are consistent with the Long-Term Energy Plan released by the Ontario Government in November 2010 with a provincial target of achieving peak savings of 4,550 MW by 2015 and 7,100 MW by 2030. The CDM savings information is provided in Exhibit A-15-2/Attachment 1/Appendix A. Did Hydro One analyse the information provided on a program by program basis to determine whether the CDM targets could be met in the test years? What level of confidence does Hydro One have in the OPA CDM targets which were incorporated in the forecast? Please provide any analysis conducted on the CDM targets to determine their achievability.

3.0-Staff-20
Ref: Exhibit A/Tab 15/Sch2/Table 5
In this table, for 2010 a larger than typical variance of 1.00% is shown for Peak Demand. What are the reasons for this variance in 2010?

3.0-Staff-21
Ref: Exhibit A-15-2/Attachment 1/p 74
Under E.5 Comparison of the Three Methods, Hydro One cites two specific challenges for Method 3. Please show how Hydro One addressed/overcame those challenges to determine that Method 3 should be chosen.

3.0-Staff-22
Ref: Exhibit A-15-2/Attachment 1/p 75
Hydro One indicates that Method 3 is 'technically sound and efficient'. Please provide the specific reasons for this.

4) Are Other Revenue (including export revenue) forecasts appropriate?

No questions.

OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

5) Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?

5.0-Staff-23
Ref: Exhibit C1/Tab3/Sch2/p 3
Hydro One indicates that the 2012 Sustaining work program was adjusted to stay within the overall Transmission business OM&A envelope approved in the EB-2012-0002 decision. In light of the evidence in this proceeding that indicates a deterioration of the system and an urgency to replace and repair assets, what was the rationale for the cut to the sustaining budget in 2012 by over $25 million or 10.5%?

5.0-Staff-24
Ref: Exhibit C1/Tab3/Sch2/p 39
Site security costs increase significantly from the historical years in both test years (to $30.8 Million in 2014) and this is mainly attributed to copper theft. What evidence is there that copper theft will increase in the test years over existing levels?

5.0-Staff-25
Ref: Exhibit C1/Tab3/Sch4/p 3
Hydro One indicates that the Operations Support spending shows an increase in the bridge year and similar increases in the test years is due to standard cost escalation. What does Hydro One mean by the term 'standard cost escalation'?

5.0-Staff-26
Ref: Exhibit C1/Tab1/Sch1
Please provide a table that identifies the O&M cost per km of transmission Line and O&M per total fixed transmission assets from 2006 to the 2014 test year inclusive.

5.0-Staff-27
Ref: Exhibit C1/Tab2/Sch2/p 3
Hydro One mentions that there is 'redundancy' found in the transmission system and that an equipment failure to have only a momentary impact on the power system. Has Hydro One defined its level of redundancy in any consistent way and is its redundancy level higher or lower than other North American transmitters?

5.0-Staff-28
Ref: Exhibit C1/Tab2/Sch2/p 7
Hydro One mentions that sustaining work programs are focused on replacing or refurbishing lines equipment with the greatest impact on system reliability. How does Hydro One determine this and how does this focus impact sustaining work program priorities?

5.0-Staff-29
Ref: Exhibit C1/Tab2/Sch2/pp 9 & 19
In the Circuit Breakers at a Glance table (p.9), capital investment in 2009-11 is $48 million accounting for 71 replacements, or $0.68 million per replacement. For 2012-14, capital investment is $106 million accounting for 95 replacements, or $1.1 million per replacement. This is an increase of 62% per replacement. Please provide the rationale for this increase.

In the Transformers at a Glance table (p.19), capital investment in 2009-11 is $82 million accounting for 10 replacements, or $8.2 million per replacement. For 2012-14, capital investment is $123 million accounting for 19 replacements, or $6.5 million per replacement. This is a per unit decrease of over 20%. Why are Transformer capital costs falling per unit when the Circuit Breaker costs as cited above are increasing?

5.0-Staff-30
Ref: Exhibit C1/Tab2/Sch2/p 16
The table on this page shows that the number of Sustaining Circuit Breaker replacements falls from 100 in 2011 to 57 in 2012, and then increases to 104 in 2013 and 124 in 2014. What are the reasons for the fall in replacements in 2012, considering the tone of the evidence that replacements are urgently needed?

5.0-Staff-31
Ref: Exhibit C1/Tab2/Sch2/p 22/Figure 7
The table on this page shows that the number of Transformers in very poor condition grows in 2012 to 18 from 4 in 2008 and 5 in 2009. Considering the number of Replacements cited on the same page at lines 15-17, why is there still such growth in the number of very poor transformers?

5.0-Staff-32
Ref: Exhibit C1/Tab2/Sch2/p 45
In the Tx Wood Poles at a Glance table, capital investment per pole is constant from 2009-11 to 2012-14, however OM&A grows from $3 million to $5 million, a 67% increase. Why do OM&A costs increase so significantly for wood pole replacements?

5.0-Staff-33
Ref: Exhibit C1/Tab2/Sch2/p 53
Hydro One indicates that it plans to begin using composite poles to replace a small portion of its wood pole population to evaluate this emerging technology. Please answer the following: What are composite poles, how do costs compare to current poles, why are they being considered and when will Hydro One be in a position to decide if these poles should be used exclusively in the pole replacement program?

5.0-Staff-34
Ref: Exhibit C1/Tab2/Sch2/p 67
In the Tx Conductors at a Glance table, capital investment and Km of line replaced, double from 2009-11 to 2012-14, however the cost per km did not change. In addition, OM&A costs grow by 33%. Why is there no capital cost per replacement saving realized as in the case of transformers and why do OM&A costs grow so significantly?

5.0-Staff-35
Ref: Exhibit C1/Tab2/Sch2/pp 70 & 72
The two figures on this page depict Forced Outage Frequency and Duration for Conductor. Both figures show a trend of reduced frequency and flat or reduced duration (if 2009 is treated as a non-recurring event). What event caused the 2009 impact? Considering these figures, why is such a significant ramp up required in conductor replacement? (The table on page 72 shows a 240% increase in circuit km and a 318% increase in capital for 2013, continuing in 2014.)

6) Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

6.0-Staff-36
Ref: Exhibit C1/Tab4/Sch2/p 2
Hydro One attributes higher CCFS costs to 'higher Real Estate Costs for additional space in the company's work program'. Why do these real estate costs increase so significantly in 2012 (levels continuing to the test years) when the evidence shows a reduction of staff in 2011 and moderate staff growth from 2012 to 2014 (Exhibit C1-5-2/Attachment 2)?

6.0-Staff-37
Ref: Exhibit C1/Tab4/Sch2/p 2
Table 1 shows that along with higher Real Estate costs, Hydro One shows large Bridge Year increases in many categories: Finance 7.5%, General Counsel and Secretariat 17.6%, Regulatory Affairs 11.4%, Security Management 23% and Internal Audit 35%. In many cases these increased levels carry on into the test years. While the following pages of the evidence provide details of the work programs, no overall rationale is provided for the excessive increases in these programs and why such high increases are justified. Please provide further justification for the increases in these areas.

6.0-Staff IR-38
Ref: Exhibit C1/Tab4/Sch4/p 8
Table 4 shows that IT Development categories Enhancements and Upgrades almost double from 2012 to 2013. Why is such a steep increase required in 2013? Please explain whether or not this spending could be smoothed over a number of years? What is the urgency that drives these increases in the test years?

7) Are the 2013/14 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?

7.0-Staff-39
Ref: Exhibit C1/Tab5/Sch1/pp 10&11
Hydro One mentions that it uses Temporary, Casual and Contract staff. What is the approximate percentage saving to Hydro One from using each of these staffing sources instead of regular employees?

7.0-Staff-40
Ref: Exhibit C1/Tab5/Sch2/pp 2&3
With regard to the findings in the Mercer study, Hydro One indicates that, "PWU staff were found to be 18% above market median, an improvement from the 2008 result of 21% above market median reflecting the increased use of hiring hall staff and the increased pension contributions negotiated as part of the new collective agreement." Hydro One also mentions that Hiring Hall staff do not receive Hydro One benefits or join the Hydro One Pension plan.

a) How was Hiring Hall staffing accounted for in the Mercer Study?
b) Besides the lack of benefits and the pension plan, are there any other savings realized by using Hiring Hall staff?
c) Are there any restrictions or limits on how extensively Hydro One can use the Hiring Hall?
d) What is the percentage of work currently performed by Hiring Hall staff?
e) What is the approximate percentage saving to Hydro One from using Hiring Hall rather than regular staff?

7.0-Staff-41
Ref: Exhibit C1/Tab5/Sch2/p 6
Hydro One indicates that it, "…sought to achieve overall cost reductions by negotiating increased management flexibility to run the operations as opposed to wide scale reductions in wages benefits and pensions." Please provide some examples of the increased management flexibility achieved and how this will save or reduce resources required.

7.0-Staff-42
Ref: Exhibit C1/Tab5/Sch2/p 7
Hydro One indicates that its, "…work program is expected to increase by approximately 15.8% while the regular headcount is only expected to increase from year 2011 by 1.9% by year end 2014."
a) Please provide the background numbers used to make these calculations.
b) Please provide a similar calculation using total staffing numbers, not just regular staff.

7.0-Staff-43

Ref: Exhibit C1-5-2/Attachment 2

These tables show numbers of total employees by category from 2009 to 2014. In 2009 Regular Employees make up 71.3% of the total, Temporary Employees 4.7% of the total and Casual Employees 24%. In 2014 the percentages are: Regular Employees make up 73.1%, Temporary Employees 5.5% of the total and Casual Employees 21.4%. Why does Hydro One move to a less intensive reliance on Casual Employees in the test years?

7.0-Staff-44

Ref: Exhibit C1/Tab 5/Sch3/p 4

Hydro One reports a pension plan performance of 5.3% annualized return from 2001 to 2011, above the benchmark of 5.12%. Is Hydro One satisfied with this performance? In EB-2010-0002 Hydro One reported that the pension fund was ranked in the 61st percentile since inception. What is the current percentile ranking for the fund?

7.0-Staff-45

Ref: Exhibit C1/Tab 5/Sch3

As per Exhibit C1/Tab 5/Schedule 3, Hydro One is proposing to recover pension costs in the 2013 and 2014 test years on a cash basis.

a) Has Hydro One explored switching to the accrual basis to account for pension costs for financial reporting purposes and for regulatory purposes? Please provide any supporting documentation or memorandum that analyses a switch by Hydro One to the accrual basis.

b) What would the pension costs for the 2013 and 2014 test years amount to under the accrual basis of accounting? Please provide supporting documentation, including underlying assumptions.

c) Please confirm that the cash basis is more volatile compared to the accrual basis under both positive and negative asset and liability shocks. Please provide supporting documentation. If this is not the case, please explain.

d) Please confirm that the cash basis will produce lower costs than the accrual basis when market conditions or discount rates are favourable because gains on a cash basis can be realized immediately through contribution holidays. However gains on an accrual basis are amortized over the expected average service life. If this is not the case, please explain.

e) Please confirm that the cash basis will produce higher costs than the accrual basis when market conditions or discount rates are not favourable because losses on a cash basis are amortized over a small time period. However, losses on an accrual basis are amortized over the expected average service life. If this is not the case, please explain.

f) Please provide Hydro One’s justification for using the cash method versus the accrual method for pension costs.

g) Please provide any documentation from Hydro One’s external auditor regarding the choice of the cash method versus the accrual method – particularly the external auditor agreeing or disagreeing with Hydro One’s choice of the cash method for pension costs.

h) Please list the relevant section of the USGAAP accounting standards that permits the use of the cash method for pension costs for financial reporting purposes.

7.0-Staff-46
Ref: Exhibit A/Tab10/Sch2/Attachment 2 and EB-2011-0268 Response to Board Staff Interrogatory #22
As per Exhibit A/Tab10/Schedule2/Attachment 2, Hydro One included the Hydro One Inc. Management's Discussion and Analysis ("MD&A") and Consolidated Financial Statements as at June 30, 2012.

As per page 29 of the quarterly financial statements, Hydro One describes the use of a regulatory asset for financial reporting purposes to record the net underfunded projected benefit obligation for pension and other post-employment benefits ("OPEB"). In the absence of regulatory accounting, Hydro One states that this amount would be recognized in accumulated other comprehensive income ("AOCI").

As per page 41 of the quarterly financial statements, Hydro One states that a portion of actuarial gains and losses and prior service costs and credits is recorded within regulatory assets for financial reporting purposes. In the absence of regulatory accounting, Hydro One states that this amount would be recognized in other comprehensive income ("OCI").

As per page 54 of the quarterly financial statements, Hydro One lists the following balances under USGAAP:

As at January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases): *(Canadian dollars in millions)*

	January 1, 2011	December 31, 2011
Deferred pension asset	(460)	(466)
Regulatory assets [1]	450	902
Other long-term liabilities:		
Pension benefit liability	297	779
Post-retirement and post-employment benefit liability	153	123
Regulatory liabilities [2]	(460)	(466)

[1] Represents off-setting regulatory assets for incremental obligation for pension and non-pension obligations of $297 million and $153 million on January 1, 2011, and $779 million and $123 million on December 31, 2011, respectively.

[2] Represents write-off of deferred pension asset regulatory liability under Canadian GAAP.

a) Please provide an explanation and reconcile the different numbers relating to regulatory assets and liabilities for pension and OPEB, as recognized for financial reporting purposes, on pages 29, 41, and 54 of the June 30, 2012 Hydro One Inc. quarterly financial statements.

b) Please provide an explanation of footnotes 1 and 2 on page 54 of the quarterly financial statement, as quoted above.

c) Does Hydro One plan to recover and refund in rates the regulatory assets and liabilities for pensions and OPEB that are recognized for financial reporting purposes, ie the $902 million regulatory asset and the $466 million regulatory liability recognized as at December 31, 2011 under USGAAP?

   i. If so, how and when? Please explain.

   ii. If so, please explain in light of Hydro One's response to Board Staff Interrogatory #22 in EB-2011-0268. Hydro One stated that they would not record any component of the $460 million Deferred Pension Asset in the "Pension Cost Differential Account" or the "Impact for USGAAP Account." In part e) of the response Hydro One stated that they would not attempt to recover any portion of the Deferred Pension Asset because "Both Hydro One Networks' Distribution and Transmission businesses recover their pension costs on a cash basis."

   iii. If so, please explain if and how a proposed recovery or refund of the regulatory asset and regulatory liability listed in part iii) above would change if Hydro One switched to accounting for pension costs on the accrual basis for regulatory purposes.

   iv. If not, please explain.

8) Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?

No questions.

9) Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

9.0-Staff-47
Ref: Exhibit C2/Tab5/Sch1 and Exhibit C2/Tab5/Sch2
Hydro One filed the calculation of 2009, 2010, 2013, and 2014 utility income tax at Exhibit C2/Tab 5/Schedule 1.

a) Please provide the calculation of 2011 and 2012 utility income tax and supporting schedules. Please reconcile the 2011 and 2012 utility income tax to the amounts approved in EB-2010-0002.

b) Please disclose any significant changes that Hydro One Transmission has incorporated into its 2013 and 2014 utility income tax calculation compared to its last rebasing proceeding, EB-2010-0002. Please compare Hydro One's proposed methodology in EB-2012-0031 to the methodology that was approved by the Board in EB-2010-0002. The changes should include but not limited to the:

   i. impact from the transition to USGAAP;
   ii. CCA class changes for Hydro One's existing capital assets;
   iii. CCA rate changes for Hydro One's existing capital assets; and

iv. CCA class and rates chosen for the capital assets additions in 2013 and 2014.

9.0-Staff-48
Ref: Exhibit C2/Tab5/Sch1 and Exhibit D1/Tab1/Sch 2
Capital Expenditures on UCC Schedule and Rate Base Schedule

a) Please reconcile the capital expenditures on Exhibit D1/Tab 1/ Schedule 2 of:
   - $ 791.8 million for 2011
   - $ 1,294.7 million for 2012
   - $ 904.1 million for 2013
   - $ 1,023.0 million for 2014

   to the capital expenditures reported on the respective UCC schedules on Exhibit C2/Tab 5/Schedule 1 of:
   - $ 696.8 million for 2011
   - $ 1,182.7 million for 2012
   - $ 789.5 million for 2013
   - $ 902.3 million for 2014

   and provide explanations for differences.

b) Please clarify which capital expenditures are the correct numbers.
c) Please update Hydro One's evidence where appropriate (e.g. rate base section or tax provision section of application).

9.0-Staff-49
Ref: Exhibit C2/Tab5/Sch1 and Exhibit C1/Tab8/Sch1
Depreciation and Amortization Expense and Calculation of Utility Income Taxes

a) Please reconcile the depreciation and amortization expenses on Exhibit C1/Tab 8/Schedule 1 of:
   - $340.4 million (depreciation) and $8.5 million (amortization) for 2013
   - $367.7 million (depreciation) and $9.3 million (amortization) for 2014

   to the depreciation and amortization expenses reported on the respective calculation of utility income taxes schedules on Exhibit C2/Tab 5/Schedule 1 of:
   - $346.7 million for 2013
   - $374.7 million for 2014

   and provide explanations for differences.

b) Please clarify which depreciation and amortization expenses are the correct numbers.
c) Please update Hydro One's evidence where appropriate (e.g. depreciation/amortization section or tax provision section of application).

10) Is Hydro One Networks' proposed depreciation expense for 2013 and 2014 appropriate?

No Questions.

CAPITAL EXPENDITURES and RATE BASE

11) Are the amounts proposed for rate base in 2013 and 2014 appropriate?

11.0-Staff-50
Ref: Exhibit D1/Tab1/Sch1/p 2/Table 1 Transmission Rate Base
Please expand the table at the above reference to include the years 2009 to 2012. For the years 2009 to 2011 please provide actual data and for the year 2012 please provide the Bridge Year Forecast.

11.0-Staff-51
Ref: Exhibit D1/Tab1/Sch1/p 3/Table 2 Continuity of Fixed Assets
With respect to the table referenced above, please elaborate on the reasons for the elimination of $11 million from "Transfers", in the August 15th update compared to the May 28th filing.

11.0-Staff-52
Ref: Exhibit D1/Tab1/Sch2/p 1/Table 1 – In-Service Capital Additions 2011 - 2014

Please expand the table at the above reference and provide the actual in-service capital additions and the Board approved in-service capital additions for the years 2007 to 2010.
In the table at the above reference, the estimate for the 2012 Bridge Year is noted as "projected". Please clarify if the bridge year estimate is a "year to date" estimate (i.e. actual plus forecast) or a 12 month forecast.

11.0-Staff-53
Ref: Exhibit D1/Tab1/Sch2/p 1/Table 1 – In-Service Capital Additions 2011 – 2014; Board Staff Interrogatory #64 EB-2010-0002
The in-service additions in 2011 were $43 million lower than Board Approved and are projected to be $297 million lower than Board Approved in 2012.

a) In its response to Board staff Interrogatory#64 (a&b) in EB-2010-0002, Hydro One provided a list of projects that were to be placed in-service in 2011 and 2012. Using that same list, please identify the projects that are/may be delayed and will not be in service in 2011/2012. With respect to the projects under $3 million, please provide as a total. With respect to each of the delayed projects, please provide: (i) The original planned in-service; (ii) The new in-service date; (iii) The Board approved capital expenditure; (iv) Actual capital expenditures incurred in 2011 and/or 2012; (v) If additional capital expenditures are proposed in 2013 and/or 2014, please provide the expenditures by year. Please provide the capital expenditures in the form of amounts (i.e. net costs) that will be added to rate base. Please reconcile your answer with the variances noted in the preamble above and with the variance analysis presented at Exhibit D1/Tab1/Sch2/pp 1 - 4.

b) With regard to projects that may have been delayed and are not going to be in-service in 2011 or 2012 as originally planned, how does Hydro One propose to correct for the fact that its 2011 and 2012 rate base may contain costs of projects that are not currently used and useful?

12) Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

12.0-Staff-54
Ref: Exhibit D1/Tab3/Sch1/p 2/Table 1
In this table, the Sustaining component shows a 45% increase in 2013 compared to 2012. Given that the 2012 component was already 30% above the 2011 actual, this represents an 88% increase from 2011 to 2013. Similarly in the Operations component, the proposed 2014 level is 19% higher than the proposed 2013 level, in spite of the fact that 2012 saw a 4-fold increase in this component relative to 2011.

a) While a brief summary is provided of the factors contributing to these increases, please provide additional specific summary detail on the main factors contributing to these significant increases in the proposed capital expenditures.

b) What process does Hydro One have in place for the planning and prioritization of capital expenditures to deal with these fluctuations?

12.0-Staff-55
Ref: Exhibit D1/Tab3/Sch1/p 4 & 6/Table 2 & Table 3 – Board Approved versus Actual Capital Expenditures
Please provide, in table format, the Board Approved Capital Expenditures and Actual Capital Expenditures for the years 2007 to 2010.

12.0-Staff-56
Ref: Exhibit D1/Tab1/Sch2/p 1/Table 1 – In-Service Capital Additions 2011 – 2014 & Board Staff Interrogatory #64 in EB-2010-0002

(a) Please provide a breakdown of all capital programs, for Sustaining, Operations and Shared Services, that are included in the in-service additions table at the above reference. Please provide this information in table format, identifying the capital program, ISD #, in-service year, Gross Cost, capital contributions, and test year capital expenditure that are booked to the test year rate base. In a separate table, please identify all projects that are included in the capital expenditure budget, but will not be added to the test year rate base. Please provide your response in a format similar to that provided in Board staff interrogatory 64 (a) in EB-2010-0002.

(b) With respect to Development Capital projects, please provide in table format and in a format similar to that in Board staff interrogatory 64 (b) in EB-2010-0002, 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 2012 and 2013. Please identify the projects that are included in the Green Energy Plan. In a separate table, please identify all Development Capital (& Green Energy Plan) projects that are included in the capital expenditure budget, but will not be added to the test year rate base.

12.0-Staff-57
Ref: Exhibit D1/Tab3/Sch2/p 14 – Air Blast Circuit Breakers (ABCB) Replacement Projects

a) What is the total population of ABCBs in Hydro One’s system? How many of these ABCB’s are in “Poor” or “Very Poor” condition as described in the 10 Year Asset Management Outlook?

b) Please provide the number of ABCB units replaced in each of the years for the period 2007 to 2012.
c) How many ABCB units are planned to be replaced in 2013 and 2014 respectively?
d) What is Hydro One's planned schedule of replacement of ABCBs beyond 2014?

12.0-Staff-58

Ref: Exhibit D1/Tab3/Sch2/p 15 and ISD # S6 Hanmer TS – 500kV ABCB; ISD # S9 Hanmer TS ABCB Re-investment in EB-2010-0002

a) The description of the project in ISD # S6 in the current application appears to be very similar to the description of the project in ISD# S9 in EB-2010-0002. Please clarify if the Hanmer TS ABCB project in the current application is a new project or if it is the same project (ISD# S9) for which Hydro One received Board approval in EB-2010-0002.

b) Is the project as proposed in EB-2010-0002, on schedule to be placed in-service in "Late 2012"? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please also provide a brief description of the work that was performed in 2011/2012 and a high level cost breakdown for this work.

d) If the projects in part (a) are the same project, please explain the reasons for the additional expenditure (i.e. in addition to the $18.8 million proposed in EB-2010-0002) of $7.5 million in the current application. Please provide a brief description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

12.0-Staff-59

Ref: Exhibit D1/Tab3/Sch2/p 15 and ISD # S7 Orangeville TS – 230kV ABCB Replacement; ISD # S7 Orangeville TS ABCB Re-investment in EB-2010-0002

The Board approved the Orangeville TS ABCB Re-investment project in EB-2010-0002. This project is expected to be in-service in 2013. In EB-2010-0002, the project (gross) costs were stated to be $23 million with a proposed expenditure of $10.3 million and $10.6 million in 2011 and 2012 respectively. In the current application, Hydro One is proposing to spend additional capital of $ 9 million in the test years.

a) Please provide reasons for the additional spending that is proposed in 2013.

b) Please provide a description of the work undertaken in 2011 and 2012 and the work that will be undertaken in 2013 and 2014. Please provide a high level cost breakdown for the work done in 2011 and 2012 and the work expected to be done in 2013 and 2014.

12.0-Staff-60

Ref: Exhibit D1/Tab3/Sch2/p 14 &15 and ISD # S8 Pickering A SS – 230kV ABCB; ISD # S10 Pickering A switchyard: ABCB Re-Investment in EB-2010-0002

a) Please clarify if the project described at ISD# S8 in the current application is a new project or the same project for which Hydro One received Board approval (ISD#10) in EB-2010-0002.

b) Is the project as proposed in EB-2010-0002 on schedule to be placed in-service in 2012? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please provide a brief description of the work that was performed in 2011/2012 and a high level cost breakdown of this work.

d) If the projects in part (a) are the same project, please explain the reasons for the additional expenditure (i.e. in addition to the $7.3 million proposed in EB-2010-0002) of $6.8 million in the current application. Please provide a brief description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

12.0-Staff-61
Ref: Exhibit D1/Tab3/Sch2/p. 15 and ISD # S9 Richview TS – 230 kV ABCB; ISD # S8 Richview TS ABCB Re-investment in EB-2010-0002

a) The description of the project in ISD # S9 in the current application appears to be similar to the description of the project in ISD# S8 in EB-2010-0002. Please clarify if the project in the current application is a new project or if it is the same project (ISD# S8) for which Hydro One received Board approval in EB-2010-0002.

b) Is the project as proposed in EB-2010-0002 on schedule to be placed in-service in Late 2012? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please provide a brief description of the work that was undertaken in 2011/2012 and a high level cost breakdown for this work.

d) If the two projects in part (a) are the same, please provide the reasons for the significant increase in project cost from $17.1 million in EB-2010-0002 to $61.2 million in this current application. Please provide a brief description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

12.0-Staff-62
Ref: Exhibit D1/Tab3/Sch2/p 9 – Oil Circuit Breakers (OCB) Replacement Projects

a) What is the total population of OCBs in Hydro One’s system? How many of these OCB’s are in “Poor” or “Very Poor” condition as described in the 10 Year Asset Management Outlook?

b) 29 OCB’s are planned for replacement in 2013 and 2014. Please provide the number of OCB units replaced in each of the years for the period 2007 to 2012.

c) At the above reference Hydro One states that the annual replacement rate of 0.8% is expected to increase in the future. What is Hydro One’s planned schedule of replacement of OCBs beyond 2014?

12.0-Staff-63
Ref: Exhibit D1/Tab3/Sch2/p 16 – End of Life Reconfiguration Projects and ISD# S13 – Abitibi Canyon SS/ Pinard TS: Reconfiguration and Demerge; ISD# S5 Abitibi Canyon SS and Pinard TS - Replace Oil Circuit Breakers (OCB) and other EOL Components, in EB-2010-0002

a) The description of the Abitibi Canyon/Pinard TS project in ISD # S13 in the current application and in ISD # S5 in EB-2010-0002 appears to be very similar. Please clarify if the project described at ISD# S13 in the current application is a new project or if it is the same project for which Hydro One received approval in (ISD# S5) EB-2010-0002.

b) Is the project as proposed in EB-2010-0002 on schedule to be placed in-service in 2012? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please provide a brief description of the work that was performed in 2011/2012 and a high level cost breakdown for this work.

d) If the projects in part (a) are the same project, please explain the reason for the significant increase in the project cost, from $21.7 million in EB-2010-0002, to $47 million in this current application. Please provide a description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

12.0-Staff-64
Ref: Exhibit D1/Tab3/Sch2/p 13 – ISD# 3 Metalclad Switchgear Replacement Projects

a) Please confirm if the project at the above reference is the same project as that described in ISD # S3 - *2011/2012 Metalclad Circuit Breakers Replacement – GT* for which Hydro One received Board approval in EB-2010-0002.

b) The project in EB-2010-0002 was to be in-service in "Late 2012". Please clarify if the project is on schedule to be in-service in 2012. If there is a possibility that the project may be delayed, please provide the new in-service date.

c) Please provide a description of the work undertaken in 2011 and 2012 and provide a high level cost breakdown for this work.

d) In EB-2010-0002, the total project (gross) costs were stated to be $23.5 million. In this application the costs (for what appears to be the same project) are stated to be $52.3 million. Please explain the reasons for the significant increase in project cost.

12.0-Staff-65
Ref: Exhibit D1/Tab3/Sch2/p 14 – Albion TS Metalclad Switchgear Replacement and ISD# S4
In the current application, Hydro One is proposing to replace Metalclad switchgears at Albion TS. This project is identified as a separate project in the current application and has its own ISD number, that being ISD # S4. There is no comparable project in EB-2010-0002 (Ex D2/T2/S2). However, in the current application, Hydro One states that the "Metalclad replacement work at Albion TS has been delayed…."

a) Please clarify if the replacement of metalclad switchgears at Albion TS, was part of the project (ISD # S3) that received Board approval in EB-2010-0002. If it was not part of project ISD # S3 that received Board approval in EB-2010-0002, please identify the proceeding in which this project was approved by the Board.

b) Hydro One states that the Albion TS replacements have been delayed. What was the original in-service date for this project?

12.0-Staff-66
Ref: Exhibit D1/Tab3/Sch2/p 17 and ISD# S14 Beck # 1 SS – Build New Switchyard; ISD #S4 in EB-2010-0002
At Exhibit D1/Tab3/Sch2/p 17, (lines 7 -17), Hydro One states "Beck # 1SS Reconfiguration was identified in EB-2010-0002 as project S4".

a) Please clarify if the project described at ISD# S14 in the current application is a new project or is it the same project for which Hydro One received approval in EB-2010-0002?

b) This project was expected to be in-service in 2012 and appears that it may be delayed to 2016/2017. Please provide a high level cost breakdown of the work that was undertaken in 2011 and 2012.

c) Please explain the reason for the significant increase in the project cost, from $47 million in 2012 to $83.4 million in the current application.

12.0-Staff-67
Ref: Exhibit D1/Tab3/Sch2/p 16 – Merivale GIS Replacements
At the above reference Hydro One confirms that the Merivale GIS project has been delayed by 6 months and that in-service date had shifted to 2013.

a) In EB-2010-0002, the Board approved the above referenced project. Hydro One proposed to spend $6 million in 2011 and 2012 respectively. Please provide a description of the work that was undertaken in 2011 and 2012 and provide a high level cost breakdown for this work.

b) In the current application, Hydro One is proposing to spend additional capital of $4.9 million. Please provide the reasons for this additional spending. Please provide a description of the work that will be undertaken in 2013 and 2014.

12.0-Staff-68
Ref: Exhibit D1/Tab3/Sch2/p 21 – Power Transformers; 10 Year Asset Management Outlook 2012 – 2021, p 36

a) In its last rate application (EB-2010-0002), at Ex D1/T3/S2/p. 18, Hydro One stated "In total, -Hydro One has *1467* transmission transformers in service". In the 10 Year Asset Management Outlook and in the current application Hydro One states, "In total, Hydro One has *719* large transmission class transformers in service". Please explain the large difference in the total number of transformers noted in the two filings.

b) 25 power transformers are planned to be replaced in 2013 and 2014. Please provide a breakdown by class of transformers (Step-down, Auto-transformer, Phase Shifters or Regulators) that will be replaced in the test years.

c) Please provide the number of transformers, by class, which were replaced in each of the years for the period 2007 to 2012.

d) Please provide the total number of transformers in-service in each of the years from 2007 to 2014 (estimate).

12.0-Staff-69
Ref: Exhibit D1/Tab3/Sch2/p 38 – ISD# S30 – Bruce Special Protection System (BSPS) Replacement

a) It appears the project will be delayed from 2012 to 2014. Please provide a description of the work that was undertaken in 2011/2012 and a high level breakdown of the costs incurred in 2011 and 2012.

b) Please provide a description of the work that will performed in 2013/2014 and a high level cost breakdown for this work.

12.0-Staff-70
Ref: Exhibit D1/Tab3/Sch2/p 38 and ISD# S31 – Interprovincial Transmission Company – Line Protection Replacements; ISD# 22 in EB-2010-0002

Hydro One states that the above project "has been previously included in EB-2010-0002 proceeding as project S22...."

a) Please clarify, if the above referenced project is the same project that received Board approval in EB-2010-0002.

b) Please clarify if the project approved in EB-2010-0002 is on schedule to be in-service by "Late 2012" as originally proposed. If the there is a possibility that the project may be delayed, please provide the new in-service date.

c) Please provide a description of the work that was undertaken in 2011/2012 and a description of the work that will be undertaken in 2013/2014. Please provide a high level cost breakdown for the work performed in 2011/2012 and a cost breakdown for work that is planned in 2013/2014.

12.0-Staff-71
Ref: Exhibit D1/Tab3/Sch4 – Operations Capital
In EB-2010-0002 Hydro One received Board approval to undertake a building expansion of the OGCC. The cost of the project over two years was $23.1 million. In that application Hydro One stated "**As an alternative to expanding the OGCC building, consideration was given to moving staff to nearby "overflow" locations or decentralizing some departments.** Analysis of these options revalidated the one centre strategy that lead to the creation of the OGCC. In addition to being more costly due to lease costs and lost time due to travel, the effectiveness of operations would be diminished. The operations functions at the OGCC manage real time or near real time plans, actions and events and need to interact tightly, promptly and efficiently to do so. This can only be achieved if all staff are in one building. The best option is to enhance and expand the OGCC building facilities". [Emphasis Added]
However, in the current application, Hydro One appears to have deferred the OGCC expansion project and appears to have exercised options that were previously deemed to be not cost effective.

a) Please clarify when Hydro One undertake the work proposed in ISD # O1 (in EB-2010-0002 or confirm if the project been cancelled.

b) Please explain the rationale for not undertaking the project and the reasons for implementing solutions that were previously deemed to be "more costly".

c) Please clarify if the cost of the expansion that was approved in EB-2010-0002 but not performed is included in the company's 2011/2012 Board Approved Transmission Rate base.

12.0-Staff-72

Ref: Exhibit D2/Tab2/Sch3 - ISD# D1 Bruce to Milton project

With respect to the costs of the Bruce to Milton Project, Hydro One received Board approval to add to rate base the cost of the project in 2012 on the basis that it would be in-service by December 31, 2012. The total cost was stated to be $752 million. In the current application, Hydro One states that the costs are lower at $709 million.

Please clarify if the 2013 transmission rate base has been adjusted to reflect the updated costs of the project.

13) Are the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures appropriate?

No Questions.

14) Are the methodologies used to allocate shared services and other capital expenditures to the transmission business, appropriate?

No Questions.

15) Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

No Questions.

16) Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14?

16.0-Staff-73

Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p.25, Fig. 4.3 a, 4.3 b and 4.3 c

a) Please provide the average of the CEA Composite Index and Hydro One's actual average number of momentary interruptions per Delivery Point, for the period 2002 – 2011both of which are represented in Fig 4.3 a.

b) Please provide the average of the CEA Composite Index and the Hydro One's actual average number of forced sustained interruptions per Delivery Point, for the period 2002 – 2011both of which are represented in Fig 4.3 b.

c) Please provide the average of the CEA Composite Index and the Hydro One's actual average minutes of interruptions per Delivery Point, for the period 2002 – 2011both of which are represented in Fig 4.3 c.

16.0-Staff-74
Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p. 36 – Power Transformer Portfolio

a) Fig. 5.2 (a) provides the Power Transformer Demographics of Hydro One's population of transformers. Please provide the transformer demographics for power transformers in the CEA's multi-utility database.

b) Fig. 5.2 (b) provides the Power Transformer Condition of Hydro One's population of transformers.

   i. Please provide the transformer demographics for power transformers in the CEA's multi-utility database.

   ii. What is the average age of transformers in the three asset condition categories in Fig. 5.2(b)?

c) At page 37 of the above reference, Hydro One has provided various equipment replacement scenarios based on number of units replaced per year. In Hydro One's view what is an appropriate replacement rate for its population of transformers?

16.0-Staff-75
Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p. 40 – Overhead Conductor Portfolio

a) Fig 5.4 (b) provides the Asset Condition Assessment of the overhead conductors.

   i. Please provide the average age of conductors in each of the three asset condition categories?

   ii. Based on fig 5.4 (b), approximately 50% of conductors are in "good" condition, 34% are in "fair" condition and 16% are in poor condition. In Hydro One's view, what is a reasonable/sustainable ratio for the three categories of asset conditions?

   iii. Please provide the asset demographics of overhead conductors in the CEA's multi-utility database.

b) With respect to the Historical Equipment Replacement in fig. 5.4 (e), please explain the large drop in conductor replacement in 2008.

c) At page 41 of the above reference, Hydro One has provided various equipment replacement scenarios based on number of kilometers of conductors replaced per year. In Hydro One's view what is an appropriate replacement rate for its population of overhead conductors?

16.0-Staff-76
Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p. 46 – Wood Pole Portfolio

a) Fig. 5.7 (b) provides the Asset Condition Assessment of wood poles. Please provide the average age of poles in each of the three asset condition categories.

b) Hydro One's historical replacement rate has averaged 710 poles/year, and has increased slightly over the years. In Hydro One's view what is an appropriate replacement rate for its wood pole portfolio?

COST OF CAPITAL/CAPITAL STRUCTURE

17) Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

No Questions.

18) Is the forecast of long term debt for 2012-2014 appropriate?

No Questions.

DEFERRAL/VARIANCE ACCOUNTS

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

19.0-Staff-77

Ref: Exhibit F1/Tab1/Sch1/Table 2 and Exhibit A/Tab9/Sch1/Attachment 3

a) Please complete a continuity schedule for the deferral and variance accounts requested for approval at Exhibit F1/Tab1/Schedule1/Table 2 similar to the "2013 EDDVAR Continuity Schedule" used in cost of service distribution proceedings. The continuity schedule should show balances from December 31, 2009 (i.e. the balance sheet date that was cleared in the most recent rates proceeding) and forward. The schedule should at a minimum display transactions incurred during the year, any adjustments, carrying charges incurred, and Board approved transactions to clear the regulatory accounts. The link to the "2013 EDDVAR Continuity Schedule" is below:

http://www.ontarioenergyboard.ca/OEB/_Documents/2013EDR/2013_EDDVAR_Continuity_Schedule_CoS_v2_20120706.xlsm

b) Please reconcile the continuity schedule to the December 31, 2011 Audited Financial Statements, at Exhibit A/Tab 9/Schedule1/Attachment 3. Please provide an explanation if the continuity schedule differs from the December 31, 2011 Audited Financial Statements.

c) Please provide a statement as to whether Hydro One has made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding). If this is the case, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

19.0-Staff-78

Ref: Exhibit F1/Tab1/Sch1 and Exhibit F1/Tab1/Sch2

At Exhibit F1/Tab 1/Schedule 2, Hydro One stated that it is not seeking continuance of the "Deferred Export Service Credit Revenue" variance account and the "Long Term Project Development Costs" deferral account in this proceeding. At Exhibit F1/Tab1/Schedule1, Hydro One also indicated that the following deferral and variance accounts have a zero balance forecasted as at December 31, 2012:

- Market Ready Costs
- OEB Incremental Assessment Costs
- IFRS Incremental Transition Costs

a) Is Hydro One seeking discontinuance of the following deferral and variance accounts in this proceeding?

   i. Market Ready Costs
   ii. OEB Incremental Assessment Costs
   iii. IFRS Incremental Transition Costs

b) If Hydro One is not seeking discontinuance of these accounts, please provide an explanation, particularly:

   i. Is there no longer a need for these accounts? and
   ii. the balances in these accounts are forecast to be zero as at December 31, 2012.

19.0-Staff-79

Ref: Exhibit A/Tab3/Sch1 and Exhibit F1/Tab1/Sch2

As per Exhibit A/Tab 3/Schedule 1, Hydro One is proposing to continue the following variance accounts:

i. Impact for Changes in US GAAP variance account
   As per Exhibit F1/Tab1/Schedule 2, Hydro One Transmission proposes to record any impacts of changes to US GAAP compared to the basis of those approved in this filing by the OEB as part of 2013 and 2014 Transmission Rates test years.

ii. US GAAP Incremental Transition Costs variance account
   As per Exhibit F1/Tab 1/Schedule 2, Hydro One Transmission proposes to record the differences between actual USGAAP incremental transition costs and estimated USGAAP incremental transition costs for the 2013 and 2014 Transmission Rate test years.

a) Hydro One's adoption of USGAAP is a one-time occurrence. Please explain why Hydro One would need continuance of the Impact for Changes in USGAAP variance account and the USGAAP Incremental Transition Costs variance account, when USGAAP was adopted by Hydro One for financial reporting purposes on January 1, 2012.

b) Please disclose the balances in the following variance accounts as at June 30, 2012:
   i. Impact for Changes in US GAAP variance account
   ii. US GAAP Incremental Transition Costs variance account

c) Please disclose the estimated USGAAP incremental transition costs embedded in the proposed 2013 and 2014 Transmission Rate test years. Please explain why Hydro One is seeking to recover such amounts in the 2013 and 2014 test years when the adoption of USGAAAP occurred in 2012.

19.0-Staff-80

Ref: Exhibit F1/Tab1/Sch1 and Exhibit F1/Tab1/Sch2

As per Exhibit F1/Tab 1/Schedule 2, Hydro One stated that it proposes to continue to record the difference between the actual pension costs booked using the actuarial assessment provided by Mercer and filed with the Financial Services Commission of Ontario ("FSCO") in September 2010, and the estimated pension costs approved by the Board as part of 2013 and 2014 Transmission Rates.

As per Exhibit F1/Tab 1/Schedule 1, Hydro One proposes to recover from ratepayers a balance of $12.8 million in the Pension Cost Differential Account as at December 31, 2012.

a) Please provide a breakdown of the composition of the $12.8 million balance in the Pension Cost Differential Account as at December 31, 2012. Please show how the debits and credits were derived and provide supporting documentation.

b) If the Board grants the approval for Hydro One to continue the use of the Pension Cost Differential Account, why is Hydro One proposing to generate balances in the account going forward using the actuarial assessment provided by Mercer as at December 31, 2009 and filed with the FSCO in September 2010, instead of the actuarial assessment expected to be provided by Mercer as at December 31, 2012? Please explain.

c) Please explain why annual Accounting Updates to the actuarial assessments prepared by Mercer every three years are not proposed to be used in calculating the balance in the Pension Cost Differential Account.

d) Please explain if the Pension Cost Differential Account would be required if Hydro One switched to the accrual basis for accounting for pension costs for regulatory purposes.

20) Are the proposed new Deferral and Variance Accounts appropriate?

20.0-Staff-81

Ref: Exhibit A/Tab2/Sch1 and Exhibit F1/Tab1/Sch2

As per Exhibit A/Tab2/Schedule1, Hydro One is seeking the establishment of the following new deferral accounts in this proceeding:

i. External Revenue – Partnership Transmission Projects deferral account
The intent of the External Revenue – Partnership Transmission Projects Account is to record costs for services provided by Hydro One employees for work they are performing for partnership companies.

ii. Long-Term Transmission Future Corridor Acquisition and Development deferral account
The establishment of the Long-Term Transmission Future Corridor Acquisition and Development Account is to allow Hydro One Transmission to record transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure.

Page 55 of the *Filing Requirements For Electricity Transmission and Distribution Applications* issued by the Board on June 28, 2012 [EB-2006-0170] states:

In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:

- Causation - The forecasted expense must be clearly outside of the base upon which rates were derived.
- Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence - The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

a) Please provide an explanation as to how Hydro One meets each of the above eligibility criteria for the proposed establishment of the following new deferral accounts:

    i. External Revenue – Partnership Transmission Projects deferral account
    ii. Long-Term Transmission Future Corridor Acquisition and Development deferral account

b) Please prepare a draft accounting order for the two new proposed deferral accounts mentioned in part a), including a description of the mechanics of the account, proposed journal entries, and the manner in which Hydro One plans to dispose of the account.

c) Regarding the External Revenue – Partnership Transmission Projects deferral account, Hydro One proposes to track employee time and any expenses and the resulting costs will be invoiced to the appropriate partnered company. Is any dollar amount with respect to this employee time and the associated expenses incorporated in the proposed 2013 and 2014 test year revenue requirement?

    i. If so, please state the dollar amount and specific section of the revenue requirement.
    ii. If not, please state where this amount is captured.
    iii. If so, please provide an explanation as to why this amount is captured in the revenue requirement and not excluded from the revenue requirement.
    iv. Please list the partnership companies and the approximate amounts attributable to each partnership company that would be tracked in the External Revenue – Partnership Transmission Projects deferral account.

d) Regarding the Long-Term Transmission Future Corridor Acquisition and Development deferral account, Hydro One stated that it has not included the costs for this work in the 2013 or 2014 revenue requirement. Please explain in detail as to why an estimate cannot be made for these costs and why a deferral account is necessary.

COST ALLOCATION

21) Is the cost allocation proposed by Hydro One appropriate?

No Questions.

GREEN ENERGY PLAN

22) Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

22.0-Staff-82
Ref: Exhibit A1/Tab14/Sch1 – Green Energy Plan; Exhibit D1/Tab3/Sch3 – Projects approved in EB-2010-0002
In its current Green Energy Plan, Hydro One has identified the projects that were approved in EB-2010-0002. It appears from the evidence that some of these have been delayed and may not be placed in-service on the originally proposed date.
In table format, please identify the projects that were approved as part of Hydro One's Green Energy Plan in EB-2010-0002 and with respect to each project, please provide the following additional information:

(i) The original planned in-service date;
(ii) The new in-service date;
(iii) The Board approved capital expenditure;
(iv) Actual capital expenditures incurred in 2011 and/or 2012(forecast);
(v) If additional capital expenditures are proposed in 2013 and/or 2014, please provide the expenditures by year. Please provide the capital expenditures in the form of amounts (i.e. net costs) that will be added to rate base.

22.0-Staff-83
Ref: Exhibit A/Tab14/Sch1/p 9/Table 1: Projects to Facilitate Green Energy in the Current Application
Please expand Table 1 at the above reference and provide a breakdown of all capital programs under the eight "items" noted in the table. With respect to the capital programs please provide the ISD #, in-service year, Gross Cost, capital contributions, and the test year capital expenditure that are booked to the test year rate base. In a separate table, please identify all projects that are included in the capital expenditure budget in Table 1, but will not be added to the test year rate base. With respect to the capital programs please provide the ISD #, in-service year, Gross Cost, capital contributions and net costs.

EXPORT TRANSMISSION SERVICE RATES

23) What is the appropriate level for Export Transmission Rates in Ontario?

23.0-Staff-84
Ref: Exhibit H1-5-2/Appendix B/p 8
In the 6th bullet point on this page, it is noted:
"None of the tariff changes studied has a material impact on the volume of baseload exports during the SBG periods;"

a) It is Board staff's understanding that exports are undertaken during SBG periods, in part, to maintain reliability of the Ontario grid. Does the above imply that there is therefore no impact on reliability of the Ontario grid under different export tariffs?

b) Is the reason that there is little effect on exports under the various rates because the level of exports is constrained by the capacity of the interties, as shown in Appendix E at p. 56? If there are other reasons, please explain.

23.0-Staff-85
Ref: Exhibit H1-5-2/Appendix B/p 10
In the first paragraph on this page, it is stated:

"Charles River Associates ("CRA") was engaged by the Ontario Independent System Operator ("IESO") to perform an analysis of four different Export Transmission Service ("ETS") tariff scenarios for the years 2013, 2015 and 2017."

a) Who picked the tariffs to be modelled and how were they determined?

b) Was reciprocity with the connected regions considered as a tariff? i.e. charging the exporter at the interconnection the exact fee that an importer at the connection would be charged.

    i. If so, why was it not modelled?
    ii. If not, why not?

c) Appendix B, page 49 (Page 40 of the study) footnote # 11 mentions the study "Review of Rates in Neighbouring Markets". Is this study included in the record of this proceeding, or a previous proceeding? If neither, please provide this study.

23.0-Staff-86
Ref: Exhibit H1-5-2/Appendix B/pp 22&23
In the bullet list on the bottom of page 22 and first paragraph on 23, a list of high-level calibration metrics are noted and it is stated:

"In our judgement, the calibration was reasonably close to actuals. In particular, generation by type, wholesale prices, and the relative pattern of export closely aligned with actuals. This gave us comfort in the starting point for the ETS study."

Given those calibration metrics, has CRA calculated the confidence level of the study conclusions? Alternatively, is there a confidence interval around the main conclusions, eg. the change in total surplus?

23.0-Staff-87
Ref: Exhibit H1-5-2/Appendix B/p 30

In the section labelled **Intertie Congestion Revenue** related to the scenario Unilateral Tariff Elimination, the study defines this revenue as the difference between the price the IESO sells power for on congested transmission lines and the price it pays Ontario producers.

a) How does the IESO determine each of these prices?

b) Is the price determined on an hourly basis, or on some longer-term basis?

Please confirm that the congestion revenue is in addition to the "Uplift" that is charged by the IESO.

23.0-Staff-88
Ref: Exhibit H1-5-2/Appendix B/p 33
In the section labelled **Intertie Congestion** Revenue related to the Equivalent Average Network Charge scenario, the study states:

"Whenever an intertie connected to Ontario is export congested, the price at that intertie zone is higher than the Ontario price. Exporters end up paying the IESO a higher price to take away power than what the IESO pays Ontario generators to supply the power. This price difference between the intertie zone and Ontario times the export quantity flowing over the constrained intertie is the congestion rent accrued to the IESO."

a) Does the IESO keep the revenue generated by the Intertie Congestion Revenue? If so, does it lower the amount that Ontario customers pay to the IESO to fund activities?

b) Did the study consider internal Ontario congestion and the payment of congestion management settlement credits caused by export flows or wheel-through transactions between the Ontario zones identified or within the zones?

23.0-Staff-89
Ref: Exhibit H1-5-2/Appendix B/p 52
In the first bullet of the section of the table labelled Consistency, it is stated:

"Consistent with ETS rates between NYISO and ISONE and between MISO and PJM (Note that these are bilateral deals, not unilateral actions)."

a) What would be the benefits if the Board were to direct the IESO to negotiate bilateral deals with interconnected jurisdictions that vary from an established ETS down to a level of $0/MWh?

b) Could the IESO accomplish this at the same time as it determines the amount of *Intertie Congestion* Revenue?

23.0-Staff-90
Ref: Exhibit H1-5-2/Appendix B/pp 41, 46 & 92
In Table 13 of the main study and in the Addendum (assuming the Ontario joins the Western Climate Initiative before 2015 and does not join it before 2018, respectively), the option "Two-tiered Scenario B" shows consistently positive Total Ontario Surplus and Class B Consumer Surplus relative to the status quo scenario. Further, this option has only a small effect on ETS revenue and the summary at p. 46 appears to contain no serious drawbacks.

Why does Hydro One not recommend this option, rather than continuing with the status quo (single tier @ $2/MWh)?

23.0-Staff-91
Ref: Exhibit H1-5-2/Appendix B/pp 51 & 56
Please confirm that there is no intertie between the Ontario Northeast Sub-Region and Michigan. Please confirm that the transfer limits between Michigan and the "Rest of Ontario" are expected to decline in future relative to the current capacity, and describe what is causing the decline.

Has Hydro One or IESO filed for the record of this proceeding the Responses to Stakeholder Comments and Questions that were distributed on June 22, 2012?

If or when this document is available, there are two questions relating to item # 8 (p 6):

a) Please describe what is meant by "friction cost", and how is it determined?

b) Is the assumption that CRA has used concerning allocation of Intertie Congestion Revenue reasonably accurate – i.e that the revenue accrues to Ontario when the intertie is congested by exports and none accrues to Ontario when the intertie is congested by imports?

23.0-Staff-92
Ref: Exhibit H1-5-1/p 4 Next Steps
Does the IESO and/or Hydro One have a recommendation for when the CRA study should be repeated so that ETS tariffs could potentially be revised?

CONNECTION PROCEDURES

24) Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

24.0-Staff-93
Ref: Exhibit A/Tab12/Sch1/p 14
On page 14, Hydro One states:

> *"Connection and integration of renewable generation to the transmission system is relatively new to Hydro One and often requires unique engineering and never done before connection designs which in turn requires significantly more time than traditional load or generator connections to connect. Hydro One requests the Board approve the following typical connection process timeline for new load and generation customers. To this end Hydro One would like to replace the existing table entitled " Hydro One Customer Connection Process Timelines" with the following table:"*

Please identify the number of transmission connections that Hydro One has actually connected since implementation of the Board approved Transmission Connection Procedures, until the date of this Application for the following Transmission Customers ("TCs"):

1) TCs with Conventional Generation Connections
2) TCs with Renewable Generation Connections

3) TCs with Load Connections
4) TCs with mix of 1) and 3)
5) TCs with mix of 2) and 3)

Please comment on the view that for connection of Transmission Customers under categories 1), 3) and 4), it is still workable and appropriate to adhere to the existing Board approved "TIMELINES FOR CONNECTION PROCESS", shown at Section 5 of the Board approved Transmission Connection Procedures for Hydro One Networks Inc.("HONI"), February 12, 2008, (EB-2006-0189).

24.0-Staff-94
Ref: Exhibit A/Tab12/Sch1/p12
On page 12, lines 7 to 14, Hydro One states:

> *"In a case where more than one customer triggers the need for a transmission upgrade, a customer may be required to provide an additional security deposit or extend the term of a security deposit after Hydro One has executed Agreements and collected initial security deposits. This would occur when a customer's proportional share of the upgrade cost increases because of other customer projects being delayed or cancelled that would have been contributors to the upgrade as originally planned and calculated in the Agreements"*.

(a) Please explain how the modification proposed by Hydro One would be met in a practical and feasible manner by proponents that must arrange for financing well in advance of in-service dates. Has Hydro One considered the implications and added risk that proponents would face under such a new proposed rule?

(b) Please explain how the paragraph proposed to be added under section 2.3 "Additional Security Deposit" would be consistent with section 6.5 of the Transmission System Code.

(c) How does Hydro One confirm by letter (or in some other manner) to proponents/customers that they are the trigger for upgrades? Were more than one customer to trigger an upgrade, does Hydro One confirm for each proponent that additional projects (presumably by size and connection point only) have also been deemed jointly responsible for the same upgrades?

(d) Hydro One addresses the case where projects that share/trigger upgrades are delayed/cancelled, and where Hydro One has proposed collecting an additional security deposit. However, Hydro One has not mentioned if *excess* security deposits would be refunded where *additional* customers seek to connect after the initial customers that triggered made an application and security deposits were estimated. How would Hydro One address this issue?

(e) As an alternative to the proposed new paragraph under the heading *"Additional Security Deposits"*, had Hydro One considered its existing clause of its *Transmission Connection Procedures* under the heading *"Right to Retain All or Part of a Security Deposit"*, which states:

> *"Hydro One may retain **all** or a part **of a security deposit** that has been given in relation to the construction or modification of a connection or network facilities in any one or more of the follow circumstances:*

> *(a)* ***Where the customer subsequently fails to connect*** *its facilities to Hydro One's new or modified connection facilities."*(Page 21)
> [emphasis added; sub-clauses "b" through "d" omitted for brevity]

For what reason, if any, would Hydro One be unable to enforce the above clause with respect to customer(s) that have provided a deposit and fail to connect? Please comment on the pros/cons of enforcing existing language versus modifying Hydro One's *Transmission Connection Procedures* document, and also comment on added language and any perverse incentives or disincentives that may result.

24.0-Staff-95
Ref: Exhibit A/Tab12/Sch1/pp 12&13
At this reference, regarding O.Reg 326/09, CIA and SIA interdependence and timing, Hydro One has proposed significant extensions to connection timelines.

> *"For renewable energy projects awarded by the OPA in accordance with OReg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days* ***after the IESO starts the service guarantee clock for the performance of SIA/CIA studies.****"*
> (emphasis added)

O.Reg 326./09 s3.(2) states that:

> *"…an application for connection assessment is* ***complete*** *when it contains information sufficient to allow both the IESO and the transmitter to carry out their connection assessment activities."* (emphasis added)

Board staff understands that the transmitter (Hydro One) is responsible for the Customer Impact Assessment, per the TSC, and the IESO is responsible for the System Impact Assessment, per the Market Rules.

(a) Do all renewable energy projects require a CIA?

(b) Do all non-renewable energy projects require a CIA?

(c) Please explain why a "complete" application would not allow both the SIA and CIA to be completed in parallel given that "information sufficient" to allow assessment by both the IESO and transmitter is available for a complete application.

(d) Is there any interdependency between work necessary for the CIA by Hydro One and the SIA by the IESO? Please explain.

(e) In Hydro One's experience how much time lapses from receipt of application until the application is deemed complete by the IESO in terms of the:

    i. best case/shortest time elapsed
    ii. worst case/longest time elapsed
    iii. average time elapsed

(f) Please confirm that O.Reg 326/09 does not use the term "service guarantee clock", and that Hydro One's evidence at Exhibit A/Tab12/Sch1/p.12/lines 20-21 errs in this assertion.

Given that O.Reg 326/09 makes no mention of the term "service guarantee clock", please confirm whether it would be more appropriate and consistent with the language in governing legislation at O.Reg 326/09 for Hydro One to request the following instead of its proposed language at Exhibit A/Tab12/Sch1/pp12-13 of the application:

> *"For renewable energy projects awarded by the OPA in accordance with OReg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days* ***after the IESO deems the application complete for the purpose of completing SIA/CIA studies.****"*
> (emphasis reflects the deletion and addition of modified language)

(g) On the basis of language in part (f), would the "trigger" language at Table 3 of Exhibit A/Tab12/Sch1/p15 for the start of the Hydro One CIA more accurately be "IESO deems application complete" or similar? How would this affect the time estimate in Table 3 with respect to completion of Phases I & II?

(h) Does O.Reg 326/09 clearly state that the IESO SIA and the Hydro One CIA are activities that cannot be completed in parallel?

(i) If the answer to (a) is "no", please indicate on what basis Hydro One is requesting that these activities be treated as if they were serially dependent activities with respect to generation or load connection projects.

(j) Please explain the meaning of the asterisk at Exhibit A/Tab12/Sch1/p15/Table3/row2.

24.0-Staff-96
Ref: Exhibit A/Tab12/Sch1/p 14
Board staff has summarized the information found on pages 14 and 15, Tables 2 and 3 in the table below:

Hydro One Customer Connection Process Timelines

Phase of Project	Table 2	Table 3	Extension in Days to Existing	Basis for Extension
	(months)	(months)	(days)	
Phase I - Connection Application	0.5	2	45	(A)
Phase II _ Customer Impact Assessment (CIA)	3	5	60	(B)
Phase III - Connection Estimates	1.5	8	195	(C)
Phase IV - Connection Approval	1	1	0	-
Phase V - Design & Build	24	24	0	-
Phase VI – Commissioning	1.5	2	15	(D)

(a) In evidence, Hydro cites that "integration of renewable generation […] requires significantly more time than traditional load or generator connections to connect". Hydro One goes on to request the changes for "new load and generation customers".
Is Hydro requesting that the extension to connection timelines apply only to renewable generation connections?

(b) If the answer to part (a) is “no”, please explain the basis for applying processing extensions for all new *generation* connections, and provide references to Hydro One evidence that provide a basis for these extensions for non-renewable connections.

(c) If the answer to part (a) is “no”, please explain the basis for applying processing extensions for all new *load* connections, and provide references to Hydro One evidence that provide a basis for these extensions in the case of non-renewable load connections.

(d) Hydro One has proposed that Phase III be extended from a “best efforts” basis of 45 calendar days to approximately 240 days, representing 195 additional days of processing time.

i. Please provide the amount of time that Hydro One expects it will take to prepare and complete the additional Phase III step of “Execute Pre-CCRA Long lead Items Agreement”.

ii. Please provide time estimates for all other activities that contribute to the incremental 195 days to complete Phase III/connection estimates.

(e) For all extensions requested and set out in the Board Staff Table above, please provide an explanation for “Basis for Extension”. Please provide particulars of additional activities that are undertaken by Hydro One and the additional time associated with these activities. If the complexity of existing activities has resulted in longer review periods, please provide further explanation.

(f) When did Hydro One first begin advising customers that the timelines at Section 5.0 of the *Transmission Connection Procedures* were unreasonable with respect to the connection of new generation and/or load? Please provide any letter or other communication that Hydro One provided to customers in this regard.

24.0-Staff-97
Ref: Exhibit A/Tab12/Sch1/p 13, Schedule of Charges and Fees
Please provide an estimate of all costs associated with the:

a. Preliminary Engineering Agreement; and
b. Pre-CCRA Letter Agreement for Purchase of Long Lead Items

and indicate any/all assumptions associated with these cost estimates.

Please indicate the confidence interval associated with the “actual costs” of these agreements and if Hydro One will have the ability to change the “actual costs” at any later stage of the connection process. In other words, comment on the risk to the proponent of unforeseen costs at a later stage in the proceeding.

ACCOUNTING STANDARDS

25) Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified, and reflected in the appropriate manner in the Application, the revenue requirement for the Test Years and the proposed rates?

25.0-Staff-98
Ref: EB-2011-0268 Response to Board Staff Interrogatory #21

In Board Staff Interrogatory #21, EB-2011-0268, Hydro One was asked to describe the differences between CGAAP and US GAAP that would be incorporated into the Impact for USGAAP Regulatory Account. In the response to this interrogatory, Hydro One stated that it had not yet identified any significant differences that would be recorded in this account.

a) Has Hydro One identified any significant differences between CGAAP and USGAAP at this time? Please explain.

b) Please explain if any of the differences noted in the answer to part a) of this interrogatory would be incorporated into the Impact for USGAAP regulatory account or the proposed revenue requirements for 2013 and 2014.

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