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Ontario

BY E-MAIL

October 22, 2010

Board Secretary
Ontario Energy Board
2300 Yonge Street, Ste. 2701
Toronto ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Board Staff Submissions
2011/2012 Electricity Transmission Revenue Requirement and Rates
Hydro One Networks Inc. - Board File No. EB-2010-0002

Please find attached Board staff submissions for this proceeding. Please forward the attached to Hydro One Networks Inc. and to all intervenors in the proceeding.

Sincerely,

Original Signed By

Harold Thiessen
Board Staff
Case Manager, EB-2010-0002

Attachment

Hydro One Networks Inc.

2011 and 2012 Transmission
Revenue Requirement and Rates

EB-2010-0002

Board Staff Submissions

October 22, 2010

Hydro One Networks Inc.
Transmission Revenue Requirement and Rates, 2011 & 2012
EB-2010-0002

Board Staff Submissions

INTRODUCTION

Hydro One Networks Inc. ("Hydro One") is the largest electricity transmitter in Ontario with approximately 29,000 circuit kilometers of transmission line, 247 transformer stations and 33 switching stations. The network connects 91 generating stations, 51 Local Distribution Companies (LDC's) and 65 end-use transmission customers (89 connection points).

Hydro One submitted this application to the Ontario Energy Board for 2011 and 2012 transmission revenue requirement and rates on May 19, 2010. The oral hearing for this proceeding took place on September 20, 21, 23, 24, 27, 28 and October 1, 4, and 5 2010. Hydro One presented oral Argument-In-Chief on October 7, 2010.

The issues list for this proceeding was established on July 20, 2010 and was attached to Procedural Order No. 1.

Hydro One is seeking approval of a transmission revenue requirement of $1,446 million for 2011 and $1,547 million for 2012 and approval of changes to the provincial uniform transmission rates that Hydro One charges for electricity transmission to be effective January 1, 2011 and January 1, 2012.

The major components of the 2011 and 2012 revenue requirements are shown in the table below.

2011 & 2012 Transmission Revenue Requirement ($ millions)			
		2011	**2012**
OM&A Expenses		$ 436	$ 450
Depreciation		$ 303	$ 335
Income Taxes		$ 81	$ 70
Return on Capital		$ 625	$ 693
Total Revenue Requirement		**$ 1,446**	**$ 1,547**
Other items:			
Rate Base		$ 8,379	$ 9,135
Capital Expenditures		$ 1,152	$ 1,008
External Revenues		$ 31	$ 25

Hydro One indicated, in its published Notice, that if the application was approved as filed, the resulting increase in the Hydro One Transmission Revenue Requirement will be 15.0% in 2011 and 7.0% in 2012. These increases represent an estimated average increase on total customer bills of 1.2% in 2011 and 0.7% in 2012. For a residential customer consuming 800 kWh per month, the estimated increase on the customer's total monthly bill is $1.39 in 2011 and $1.00 in 2012.

In response to the Notice, the Board received 13 Letters of Comment from ratepayers across Ontario, the vast majority expressing concern with the requested increase in transmission rates.

Twenty seven parties were given intervention status, with the Association of Major Power Consumers in Ontario (AMPCO), Consumers Council of Canada, Canadian Manufacturers and Exporters (CME), Energy Probe Research Foundation ("Energy Probe"), Pollution Probe Foundation, Building Owners and Managers Association of the Greater Toronto Area (BOMA), School Energy Coalition (SEC), Power Workers Union and Vulnerable Energy Consumers Coalition (VECC) taking active roles in the oral hearing.

Hydro One Motion

Hydro One brought a motion before the Board on June 16, 2010 requesting an Order severing the issue of the AMPCO proposal to alter the method of determining the transmission network charge, termed the "High 5 Proposal" (Issue 8.1), for review and assessment in a separate generic proceeding. The Board heard this motion July 20, 2010 and denied the motion in an oral decision delivered on that day.

Intervenor Evidence

Two intervenors brought evidence before the Board: AMPCO provided evidence on the High 5 charge determinant issue (Exhibit M-1), and CME provided evidence on Total Ontario Electricity Bill Impacts (Exhibit N-1).

Board Staff Submission

This submission reflects observations and concerns arising from Board staff's review of the oral and written evidence, and is intended to assist the Board in evaluating Hydro One's application and setting just and reasonable rates. Not all issues on the Issues List are addressed in this submission. Only those issues which, in Board staff's opinion, require comment or analysis are addressed. This submission contains staff comments on the following topics:

- Operations, Maintenance & Administration ("OM&A") Costs
- Compensation and Staffing
- Capital Expenditures and Green Energy Plan
- Accelerated Recovery of Construction Work in Progress ("CWIP")
- Capital Structure and Cost of Capital
- Deferral and Variance Accounts
- Transition to International Financial Reporting Standards ("IFRS")
- Cost Allocation & Rate Design including the High 5 Proposal
- Export Transmission Service Rate
- Bill Impacts

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

The transmission OM&A Costs proposed by Hydro One for the two test years are summarized by major cost category in the table below.[1] The table includes the percentage change from the previous year. Board staff notes that the 2011 increase over the 2010 level approved in the last Hydro One transmission rates case ($426.2 million), is 2.4%.

Transmission OM&A Expenditures 2009 – 2012
($ million)

Category	2009 Actual	2010 Bridge	2011 Test	2012 Test
Sustaining	**213.5** *13.9%*	**224.4** *5.1%*	**233.0** *3.8%*	**243.1** *4.3%*
Development	**14.0** *52.2%*	**19.0** *35.7%*	**18.2** *-4.2%*	**18.9** *3.8%*
Operations	**52.6** *1.7%*	**62.1** *18.1%*	**66.3** *6.8%*	**68.2** *2.9%*
Customer Care	**0.9** *-30.8%*	**1.1** *22.2%*	**1.1** *0.0%*	**1.2** *9.1%*
Shared Services & Other	**70.8** *19.2%*	**58.6** *-17.2%*	**46.9** *-20.0%*	**46.4** *-1.1%*
Tax other than Income Tax	**65.2** *0.6%*	**69.4** *6.4%*	**70.8** *2.0%*	**72.2** *2.0%*
Total	**417.0** *11.5%*	**434.6** *4.2%*	**436.3** *0.4%*	**450.0** *3.1%*

This table does not include OM&A development spending of $132.7 million in a deferral account as referenced at Exhibit A/Tab11/Schedule 4/page 46.

In response to Board staff Interrogatory I-1-38, Hydro One stated that it had made reductions of $19.4 million in OM&A costs from the originally planned proposal for 2011. These OM&A reductions were made up of a $12.9 million reduction in Sustaining OM&A and a reduction of $6.5 million in Shared Services and Other Costs. The interrogatory response indicated that the assessment used to reduce costs took into account: asset condition, safety and environmental risks, performance, system function, customer impact, and statutory requirements. No reductions were made in the Development and Operations OM&A budgets in either test year.

During cross examination, Hydro One witness Ms. Vines indicated that the related reductions for 2012 were a $11.3 million reduction in Sustaining and $8.6 million reduction in Shared Services & Other Costs, for a total OM&A reduction of $19.9 million.[2]

Board staff have no comment on the specific levels of OM&A expenditures for the Sustaining category.

[1] ExhibitC1/Tab2/Schedule1/p. 3

[2] TR Vol. 7, p. 130

Board staff note that the reductions are only 4.3% of the original total OM&A budget for 2011 and 4.2% of the original budget for 2012. Board staff also note that, with reference to Exhibit J2.3, the submitted OM&A budget is still $34.5 million above the Hydro One defined “minimum” requirements for 2011 and $37 million above “minimum” requirements for 2012. Board staff submit that the evidence suggests that further reductions in OM&A spending could be made, particularly in the following three categories.

Development and Operations (excluding compensation)

Exhibit J2.2 shows reductions in capital investment from original plans, similar to the OM&A reductions. Development Capital is reduced by $110 million in 2011 and $261 million in 2012, but there is no corresponding decrease in Development OM&A. Although the Hydro One witness Mr. Young provided some examples of development OM&A costs[3], and additional detail was provided in Exhibit J3.12, Board staff suggest that the evidence is not persuasive that all reasonable reductions in Development OM&A were made to the application for the test years.

In the Operations category, no reductions from the original plans were made, and the Operations OM&A budget grows from the 2009 approved level of $53.7 million to $66.3 million in 2011, an increase of 23% in two years. Board staff submit that the applicant has not demonstrated that reductions in this category were properly considered, nor is there evidence of the reasons for the decision not to reduce spending.

Compensation

Compensation was again a major issue in this proceeding, similar to other recent Hydro One cases. Hydro One’s evidence on this issue[4] again focused on the historical background for compensation and benefits and also referred to the Mercer Compensation Cost Benchmarking study filed in the EB-2008-0272 transmission case.

As in the recent distribution rates case (EB-2009-0096) Hydro One also filed evidence comparing wages from 1999 to 2009 for Ontario Hydro successor companies; Hydro One, Bruce Power and the OPA and also included the IESO in the Society-based comparisons. Hydro One stressed its success in reducing compensation costs over that period, compared to the other companies.

Hydro One underlined the fact that it operates in a highly unionized environment and has limited scope in reducing compensation, especially when union agreements are in place for a number of years. In addition, Hydro One maintained that it needed to be competitive to attract skilled staff that were in demand across the sector.

The response to Energy Probe Interrogatory I-2-49 showed that voluntary terminations for Management Compensation Plan (MCP) staff were extremely low. In 2007, only 11 of 516 (2.1%) voluntarily left; in 2008, only 13 of 567 (2.3%) voluntarily left, and in 2009 only 6 of 609 (1.0%) voluntarily left. Board staff submits that this is an extremely low rate of turnover and indicates, that even at the MCP level, (where the Mercer study showed compensation to be at or near median levels) the level of employee retention is very high.

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[3] TR Vol. 3, p. 204 - 206
[4] Exhibit C1/Tab 3/Sch2

In the response to Board staff Interrogatory I-1-56 Hydro One confirmed that the Mercer study as filed in the EB-2009-0272 proceeding was not updated as the data is still "quite recent and the study would be very costly to update."

In Undertaking J5.10, Hydro One also provided a current estimate for a reduction comparable to the (Mercer study related) OM&A reduction of $4 million ordered by the Board in the EB-2008-0272 case. The comparable reduction in this proceeding was estimated at $6.2 million in 2011 and $6.9 million in 2012.

It is Board staff's position that, as Hydro One has indicated, the Mercer study findings are still valid in this proceeding. The Mercer report concluded that on a weighted average basis for the positions reviewed, Hydro One's compensation was approximately 17% above the market median. The tables provided by Hydro One that compare Hydro One to its related Ontario Hydro successor companies appear to show that it has made some progress compared to these companies, but does not refute the conclusions drawn by the Board in the EB-2008-0272 case.

The evidence also shows that staffing continues to grow, that attrition is not a problem (besides retirements, very few employees leave of their own accord) and that salary levels generally do not appear to be an issue in hiring qualified workers. Hydro One plans to add over 500 employees to their head count from 2010 to 2012.[5]

Hydro One should continue its efforts to control compensation costs. In the previous transmission case the Board found:

> "Hydro One's evidence is that the revenue requirement would be $13 million less if it were based on the median compensation level from the Mercer Study. Some parties suggested that this amount should be disallowed. The Board does not believe that a reduction of that magnitude is warranted; such a disallowance would imply that the Mercer Study was precise and/or that there are no mitigating circumstances. The Board has already indicated that while the full level of compensation has not been justified, Hydro One has made strides in controlling these costs. The Board will disallow $4 million in each of the test years; this level of adjustment goes some way toward aligning Hydro One's costs with other comparable companies."[6]

In Board staff's view, the Board should consider a similar reduction in this case. Board staff suggest that recovery of the compensation related applied-for OM&A budgets could be reduced by $6 million for 2011 and $7 million in 2012.

Net Zero Policy

During the oral hearing, Board staff raised the issue of the provincial government's intention that employees in the greater public sector reach net zero compensation increases for two years following the expiration of their collective agreements.

[5] Exhibit I/Tab4/Sch 35
[6] EB-2008-0272 Decision, May 28, 2009, p. 31

Hydro One witness, Mr. Goldie, replied that this was not reflected in the application and that the PWU labour agreement expires in 2011, while the Society agreement expires in 2013. He indicated that the application includes a PWU increase of 3% for the test years and Society staff increase of 2.5% for 2011 and 2012. He also stressed that management is already subject to zero percent over the next two years.[7]

Board staff submit that if Hydro One becomes subject to the government's net zero policy that it track the savings and report on this issue in Hydro One's next transmission rates case.

Pensions

Evidence on the Hydro One Pension Plan shows that the annual pension costs (both OM&A and Capital) for 2011 and 2012 are $114 million and $118 million respectively[8]. Of these costs, the transmission share is $47 million in 2011 and $48 million in 2012.

Hydro One indicated that an actuarial evaluation of the Pension Plan was done as of December 31, 2009 and in response to Board staff Interrogatory I-1-60, Hydro One indicated that the evaluation results show an increased contribution of $26 million was required for 2011 and $22 million for 2012.

Under cross examination, the Hydro One witness Mr. Struthers, indicated that for 2010 the actuarial evaluation would result in approximately $20 million being placed in a deferral account. However, for 2011 and 2012 the company would absorb the O&M portion of the additional cost resulting in no impact in 2011 or 2012 or in the future.[9]

Board staff are not entirely clear as to how increased pension costs could fail to result in any ratepayer impact. Board staff invites Hydro One to clarify the record on this issue.

The evidence also showed that the Hydro One pension plan had registered a performance rating in the 61st percentile since inception. Under cross examination, Mr. Struthers testified that Hydro One had taken action in replacing 5 of 22 plan managers.[10]

In addition Mr. Struthers also testified that employees contribute about 20% of the cost of the pension plan.[11] In response to Undertaking J7.2, Hydro One provided some information on other pension plans with regard to employee contributions, which showed Hydro One to be at about the median of the companies surveyed.

Board staff submit that Hydro One, as part of its collective bargaining process, should consider an increase in employee contribution share of pension plan costs. In addition, in terms of performance, a ranking at the 61st percentile is also a concern. Board staff, while not submitting that the Board should deny Hydro One recovery of its pension costs at this time, suggest that the Board should encourage Hydro One to continue to take steps to improve the performance of the plan so as to reduce costs and the resulting burden on ratepayers.

[7] TR Vol. 5, page 192-193
[8] Exhibit C1/Tab3/Sch2/Appendix A
[9] TR Vol. 7, page 136
[10] TR Vol. 7, page 138
[11] TR Vol. 7, page 132

OM&A Cost Effectiveness Measures

Board staff submit that the evidence indicates a deterioration in performance on OM&A cost measures, while Hydro One's transmission system performance measures remain above average. Board staff invite the applicant to address whether costs could be reduced without noticeably reducing system performance.

Board staff Interrogatory I-1-37 requested data on the cost measures OM&A per Gross Fixed Asset and OM&A per km of transmission line. These calculations revealed that OM&A per Gross Fixed Asset remained around the 2% level up to the test years with a slight decrease to 1.9% in 2011 and 2012.

In terms of OM&A per km of transmission line, steady growth is seen from 2006 to 2012. For the test years, the OM&A per km of line grew from $8,187 in 2010 to $8,650 in 2012. This is an increase of 5.6% over the two test years.

Another related cost measure filed by Hydro One at Exhibit A/Tab 13/Sch 1 page 15 was transmission unit cost, which was cited as 10.1% in 2009. The response to Board staff Interrogatory I-1-3 revealed that the transmission unit cost had risen from the 6% level in the 2004 – 2006 period to 10.1% in 2009. In a related SEC Interrogatory I-7-2, Hydro One provided a similar measure, using only sustaining spending. In this case, it appeared that the measure was showing performance exceeding budget target but not improving from 2007 to 2009. Also unit cost targets appeared to be rising in the test years, showing deterioration in cost performance.

In cross examination, the Hydro One witness Mr. Marcello indicated that it was the sustaining measure that Hydro One would now be using to evaluate transmission unit costs.[12] Undertaking (J4.5) showed this measure compared to a composite of CEA transmission utilities with Hydro One showing poorer performance in 2008, the last year data was provided.

In response to Board staff Interrogatory I-1-8, Hydro One provided additional detail on benchmarking results in a survey undertaken by First Quartile Consulting in 2009. While there was some confusion as to the actual measures highlighted, Exhibit J4.6 provided some clarity on these measures.

Board staff note that the measure of Transmission Substation O&M Expense per Asset for 2008 for Hydro One is high at 2.37% compared to the 1st Quartile score of 1.1%. Although Hydro One pointed out that its 4 year average score was in the first quartile, Board staff see the 2008 score as a near term deterioration of cost performance.

At the same time, it appears that Hydro One Transmission system performance is high, according to the performance measures provided at Exhibit A/Tab 13/Sch p 5-12. These tables show that on top of a high level of customer satisfaction, other measures as listed below show levels of performance that in almost all cases exceed the CEA composite and the levels shown by U.S. utilities:

- Performance of Delivery Point interruptions
- Frequency of Forced Sustained Interruptions
- Duration of Delivery Point Interruptions (Forced Sustained)

[12] TR Vol. 4, page 134

- Unavailability of Transmission Lines
- Unavailability of Major Transmission Station Equipment
- Performance Relative of the Utilities in the USA

While system performance is important, the cost of system performance improvements must be taken into account in finding the optimum level of spending in this area.

Summary of OM&A Submissions
Board staff submit that some additional reductions in OM&A costs can be achieved with minimal impact on service performance. This conclusion is based on:

- Current reductions instituted to address rate impact concerns are small as a proportion of total costs;
- No cuts were made in development and operations budgets despite the growth of these budgets for both areas and in some cases presumed reduced development work load;
- Unit cost measures show more efficiency can be achieved (e.g. OM&A per km of line, transmission unit costs trends and transmission substation expense);
- Reliability measures show good performance, and additional resources to further enhance performance at this time may not be warranted; and
- Compensation costs continue to exceed reasonable levels.

Staff acknowledge the steps taken by Hydro One to increase efficiencies[13] and, while these gains are laudable, staff submit that some additional reduction in the overall OM&A increase in the application is warranted. While it is difficult to calculate a reduction in OM&A budgets using benchmarking scores, it appears to Board staff that a reduction of 2-3% is possible in addition to the specific Mercer Report related compensation reductions. Board staff understand that it is inappropriate to micro-manage Hydro One's activities and therefore recommend that Hydro One reduce the OM&A cost envelope in areas they see as most appropriate.

Board staff also emphasize that lower OM&A expenses do not necessarily mean that work is not done, or that projects cannot be completed. It can also mean that the work can be prioritized more effectively and done more efficiently.

RATE BASE

Hydro One's forecast transmission rate base for 2011 and 2012 is $8,378.5 million and $9,134.6 million respectively. For 2011, the proposed rate base is 9.7% higher than the approved rate base for 2010 of $7,636 million. Forecast 2010 bridge year rate base is $7,336 million, 3.9% below 2010 approved.

Working capital is forecast to be $24.5 million for 2011 (11.7% of OM&A and Cost of Power expenses) and $26.7 million for 2012.

In service capital additions are forecast at $798.2 million for 2010, $870.6 million for 2011 and $1,618.8 million for 2012.[14]

[13] ExhibitA/Tab14/Sch1
[14] Exhibit D1/Tab1/Sch 1&2

CAPITAL EXPENDITURES

Transmission capital expenditures proposed by Hydro One for the two test years are summarized by major cost category in the table below. The table includes the percentage change from the previous year.

Transmission Capital Expenditures 2009 – 2012[15]
($ million)

Category	2009 Actual	2010 Bridge	2011 Test	2012 Test
Sustaining	**300.0** *7.0%*	**308.3** *2.8%*	**424.0** *37.5%*	**443.4** *4.6%*
Development	**516.2** *66.0%*	**537.9** *4.2%*	**617.2** *14.7%*	**456.8** *-26.0%*
Operations	**20.0** *-13.4%*	**10.1** *-49.5%*	**44.3** *338.6%*	**57.4** *29.6%*
Shared Services	**81.5** *-9.2%*	**73.6** *-9.7%*	**66.3** *-9.9%*	**50.6** *-23.7%*
Total	**917.8** *30.3%*	**930.0** 1.3%	**1,151.8** *23.8%*	**1,008.3** *-12.4%*

The level of capital expenditures associated with the rate approval for 2010 is $1,057.6 million, an increase of 8.9% in 2011.

Board staff do not have any specific concerns with Hydro One's Sustaining, Operations or Shared Services budget. Board staff's concerns deal with the Development capital budget, and specifically the Green Energy Plan investments that are contained in that budget.

Green Energy Plan

Background

Hydro One's Transmission Green Energy Plan (the "GE Plan") outlines the company's strategy to implement the Government of Ontario's policy objectives in the *Green Energy Act*. Hydro One is seeking Board approval for its GE Plan and for the test year capital expenditures on Green Energy projects.

In a letter dated September 21, 2009, the Minister of Energy and Infrastructure instructed Hydro One, to "immediately proceed with the planning, development and implementation" of certain transmission projects and upgrades.[16] The twenty major transmission projects in Schedule A[17] of that letter and five enabling projects in Schedule B were developed by the Ontario Power Authority ("OPA") and Hydro One. All the projects and associated timelines identified in that

[15] Exhibit D1/Tab3/Sch1 p. 2
[16] Exhibit A/Tab11/Schedule 4/Attachment A
[17] Two projects in Schedule A of the Minister's letter were merged in Hydro One's GE Plan and therefore the GE Plan identifies only 18 projects.

letter are included in Hydro One's GE Plan. The Schedule A projects are described as Major projects in the GE Plan and Schedule B projects are described as Other projects. A list of projects is found at Exhibit A/Tab11/Schedule 4/ page 1 & page 30.

Cost of the GE Plan

The total gross cost of the GE Plan is $7.7 billion. The cost of the Schedule A projects is $6.9 billion and the cost of Schedule B projects is $840 million.

In this application, Hydro One is seeking approval for a capital budget of $126.7 million in 2011 and $198.1 million in 2012 for Green Energy projects.[18] This includes spending on two Schedule A projects and a number of Schedule B projects. However, only $11.4 million in 2011 and $198 million in 2012 will be booked to rate base. These amounts are related to capital expenditures on Short Circuit upgrades to Leaside TS and Hearn TS, and In-Line Circuit Breakers and Protection and Control ("P&C") upgrades. The resultant revenue requirement is $0.9 million in 2011 and $10.3 million in 2012.

In addition to capital expenditures, Hydro One proposes to spend $35.7 million in 2011 and $46.7 million in 2012 on OM&A development work. These OM&A costs are in a deferral account and do not affect the test year revenue requirement. On May 7, 2010, the Minister sent a letter to the OPA requiring new advice regarding transmission planning.[19] As a result of this letter, and pending updated instructions from the Minister, Hydro One suspended work on all projects. Hydro One is not seeking approval for these amounts at this time.

Board staff have concerns with the appropriateness of the GE Plan in the present circumstances and the reasonableness of certain test year capital expenditures. Board staff are also concerned with the proposed cost responsibility for the Short Circuit upgrades and the P&C upgrades.

GE Plan Approval

Hydro One's GE Plan is based on the Minister's September 21, 2009 instruction.[20] The projects and the sequencing of projects in that instruction were established before the results of the Feed-in-Tariff ("FIT") program were fully known and before the arrangement with the Korean Consortium was finalized. As noted, the Minister has directed the OPA to provide an updated transmission plan. Specifically, the Minister directed the OPA "to develop and submit an updated transmission expansion plan updating the September 2009 instruction to Hydro One and considering the sequencing necessary to meet the needs of the FIT program and the Korean Consortium".[21]

The work by the OPA is currently underway and it is not known what transmission projects will be recommended by the OPA, or when an update will be provided to Hydro One. While the extent to which the updated OPA plan may affect Hydro One's GE Plan is not definitively known, there is little doubt the GE Plan will change. In Board staff's view once the capacity from the FIT program and Korean Consortium are considered, it is likely that the sequencing of the

[18] ExhibitI/Tab3/Schedule 12
[19] ExhibitI/Tab1/Schedule 98/Attachment 1
[20] TR Vol. 2, p. 41
[21] Exhibit I/Tab1/Schedule 98/Attachment 1

projects in the GE Plan will be altered. It is also quite possible that the projects themselves will need to be reconsidered.

Board staff also note that a number of projects in the GE Plan were first identified in the 2007 Integrated Power System Plan ("IPSP"). Staff understand the IPSP is also being updated and could influence Hydro One's current GE Plan. Furthermore, Hydro One's witnesses confirmed that "not all projects may go ahead"[22] and that some "Schedule A projects may change"[23]. Given that the instructions on which the GE Plan is premised are currently under review, and the likelihood is that the GE Plan will change, staff submit that the Board does not have sufficient information at the present time to approve the GE Plan as filed.

Staff also note that the need and location of a number of Schedule A and B projects are not presently known. For example, the need for 8 out of the 18 Schedule A projects will be confirmed by the OPA only after the Economic Connection Test ("ECT") is performed. Further, the location and need for a number of In-line Circuit Breakers and Enabling TSs is also not known. In staff's view the pending confirmation of need for some projects and the lack of specificity in case of others, adds a further level of uncertainty to the GE Plan. Board staff also note that the significant size (6,500 MW) of capacity awaiting an ECT could materially affect projects and the sequencing of projects in the GE Plan.

Recognizing the uncertainty associated with GE Plan, in argument-in-chief, Hydro One submitted that it is not seeking Board approval for the individual projects in the GE Plan, but is asking the Board to approve the GE Plan conceptually. Hydro One further submitted that at a minimum, the Board should approve the capital expenditures on Schedule B projects expected to go ahead in the test years.[24]

In staff's view, the overall approach relied on by Hydro One is reasonable and the company cannot be faulted for the uncertainty around the scope of the GE Plan. However, the level of uncertainty with respect to the GE Plan and the pending updated instructions from the Minister make it difficult to assess the appropriateness of the GE Plan, even at a conceptual level. The company has indicated that it expects to file an updated five year transmission GE Plan in its next rates filing[25]. In staff's view, Hydro One will likely have far better information at that time and the Board may wish to consider if it is more appropriate to wait for an updated plan.

Board staff also note that not approving the GE Plan appears to have little effect on revenue requirement in this case or on Hydro One's ability to undertake projects. For example, the approval for all Schedule A projects will be sought in future cost-of-service applications or Section 92 applications. Therefore it is Board staff's understanding that not approving these projects at this time does not affect the GE Plan or influence Hydro One's ability to undertake these projects in the future. Board staff also note that the Schedule A projects are long-term and the focus in the test years is on development work. The cost of development work is recorded in a deferral account and while this work has been suspended for the moment, Hydro One intends to resume the work after it receives updated instructions from the Minister. This, in staff's view, ensures that the initial pre-planning work on the Schedule A projects can continue, regardless of whether the GE Plan is approved at this time.

[22] TR Vol. 2, p. 53
[23] *Ibid.*, 54
[24] TR Vol. 11, p. 8
[25] *Ibid., 8*

Notwithstanding the concerns with the appropriateness of the overall GE Plan, staff submit that the Board could approve the GE Plan in part. The Board could, for example, find that some proposed investments are needed to meet the goals of the *Green Energy Act*, and that the related expenditures are reasonable, while others are not. In this respect, Board staff agree with Hydro One that the Board should at a minimum consider approving those projects that are expected to go ahead in the test years.

Board staff's submissions regarding these test year capital expenditures are discussed in the following sections.

Reasonableness of Test Year Green Energy Capital Budget
Hydro One is seeking approval for a test-year capital budget of $126.7 million in 2011 and $198.1 million in 2012 for Green Energy projects. This includes spending on two Schedule A projects and a number of Schedule B projects.

The two Schedule A projects are the Sudbury to Algoma Project and the Northwest Transmission Project. These projects are not in rate base and Hydro One confirmed that the projects do not impact the test year revenue requirement. Hydro One further stated that it was not seeking project approval in this proceeding and will do so in a future Section 92 application. The reason for including the projects was to inform the Board of Hydro One's future intent.

Board staff submit that there are no guarantees that the two Schedule A projects will proceed and the costs of the projects should be removed from the capital budget. The project costs will be reviewed when approval is sought for these projects in a future application. Board staff also notes that pending instructions from the Minister, Hydro One suspended development work on both projects. If the projects were expected to continue, Hydro One would not have suspended this work.

The remaining amounts in the capital budget are for Schedule B projects. There are two categories of projects in the capital budget – projects that will be in-service in the test years, and projects that have capital expenditures in the test year but will not be in-service in the test years. Hydro One is seeking Board approval for capital expenditures in both categories of projects. Hydro One classifies the latter category as Category 3 investments. With respect to these investments Hydro One states, "it is seeking guidance from the Board on the appropriateness of need, proposed solution and recoverability of project cost". [26]

The projects in this category include the Short Circuit upgrade to Manby TS, two Enabling TSs, one Static Var Compensator and four In-line circuit breakers.

Board staff note that with the exception of the short circuit upgrade to Manby TS, need for the remaining projects has not been confirmed by the OPA. Further, the location for many of these projects is currently unknown.[27] For example, as noted by Hydro One witnesses, only the location of two In-line Circuit Breakers is definitively known. Further, as acknowledged, there is also the possibility that the project costs could change. Given these limitations, Board staff submit that the Board does not have sufficient information at this time to provide the guidance that Hydro One seeks.

[26] ExhibitD1/Tab3/Schedule3/p.11
[27] TR Vol. 2, pp. 163 & 166

With respect to expenditure on projects that will be in-service in the test years, Hydro One is proposing to spend $122 million on Short Circuit upgrades to Leaside TS and Hearn TS, $41 million on two In-line Circuit Breakers and $39.8 million on P&C upgrades.[28] Staff note that the need for the Short Circuit upgrades to Leaside TS, Hearn TS and Manby TS were confirmed by the Board in Hydro One's last rate filing (EB-2008-0272). With respect to the In-line Circuit Breakers and P&C upgrades, these are needed to enable the connection of FIT connections that have already received a contract from the OPA.[29] Therefore, subject to staff's submissions below regarding cost responsibility for the Short Circuit upgrades and the P&C upgrades, Board staff submit that the need for spending in the test years has been demonstrated for these projects .

Cost Responsibility

A. Upgrade Short Circuit Capability Projects

Projects: [D11 (Hearn - 2012); D12 (Leaside - 2012), and D13 (Manby - 2013)]

Board staff agree with Hydro One that these projects are needed, and that the need for each of these three projects is driven by the objective of connecting a significant amount of distributed generation in the City of Toronto. In addition, the upgrades at Hearn are justified based on the Transmission System Code ("TSC")[30] since all the station equipment is at end of life.

Hydro One's evidence is that for the projects at Leaside and Manby, the portion of the cost of the short circuit upgrades attributable to the anticipated generation connection is the cost of replacing the station equipment ahead of the anticipated end of life of the equipment, which is about five years.[31] These advancement costs are estimated by the OPA to be $5.9 million for Leaside and $4.9 million for Manby.[32]

Hydro One agrees that the D12 (Leaside) and D13 (Manby) projects are classified as assets in the line connection pool. As such, the TSC would dictate a user pay approach for the upgrade advancement. Board staff submit that under the TSC, these advancement costs should not be collected from transmission ratepayers, but contributed by Toronto Hydro Electric System Limited ("Toronto Hydro"), the customer who benefits from the advancement. Toronto Hydro and its customers will benefit from the increased reliability of the distribution system afforded by the connection of local generation.

However, neither the TSC nor the Distribution System Code ("DSC") appears to provide guidance on how Toronto Hydro could recoup the amount of the capital contribution from the connecting generators. The normal approach for a distributor to include capital contributions paid to a transmitter in its distribution rate base would result in the cost being borne solely by Toronto Hydro ratepayers. Board staff note that where a distributor makes an "eligible investment" for the connection of renewable generation, costs of that investment, less the direct benefits to the local system, can be recovered from provincial ratepayers, not merely the distributor's own local ratepayers.

[28] Two year total from Board staff Interrogatory I-1-64, p.6
[29] *Ibid., 176*
[30] TSC, section 6.7.2 states that "Where a transmitter's connection facility is retired, the transmitter shall not recover a capital contribution from a customer to replace that connection facility"
[31] Exhibit I/Tab1/Schedule 113/Question (d)/pp. 5-6
[32] Exhibit I/Tab1/Schedule 113/Question (d)/p. 5/lines 26-27

Hydro One's proposal for pool financing the total cost of the three projects rests on two arguments. The first is articulated in the response to Board staff Interrogatory I-1-110:

> "The D11, D12 and D13 projects are classified as assets in the Line Connection pool. D12 and D13 address the need to replace breakers which are nearing end-of-life and to provide a short circuit capability of 50kA for 115kV facilities that is established in Appendix 2 "Transmission System Connection Point Performance Standards" of the TSC. As per Section 6.7.2, Section 4.3.1 and Appendix 2 of the TSC, a capital contribution will not be sought."

Section 6.7.2 of the TSC deals with retirements of connection facilities. Board staff do not suggest that the TSC would require that the entire cost of the work be recovered from Toronto Hydro, only the cost of advancing the work before the end-of-life of the facilities.

Section 4.3.1 and Appendix 2 deal with facilities standards, and Hydro One appears to imply that its facilities are somehow not up to standard or are not compliant with the TSC. Without the addition of the proposed generation facilities, the equipment at Manby TS and Leaside TS is compliant with the TSC. Section 4.6.1 of the TSC deems older facilities to be compliant with the performance standards in the TSC, including Appendix 2. There is therefore no bar to seeking a contribution from the customer based on the TSC sections cited by Hydro One in the interrogatory response.

The second argument made by Hydro One for pool financing is that collecting contributions from attaching generators would be complex, and the cost of a contribution could be a barrier to connection for small generators. Hydro One's witness Mr. Young indicated that the advancement costs, if a capital contribution is required, would be properly allocated to the generators, which are typically small.[33] The first generator or the first few generators may not be in a position to fund that level of investment. Mr. Young suggested that rather than complicating or further delaying the work by waiting until the necessary allocations or agreements are in place with the connecting generators, the work should be funded from the transmission pool.

Board staff submit that allocation problems do not arise at the transmission level, as staff understand that the transmission customer responsible for the capital contribution would be Toronto Hydro.

It is Board staff's submission that Hydro One's proposal to recover all the costs of the short circuit upgrades at Leaside and Manby from transmission ratepayers is not compliant with the TSC requirements. If the Board accepts this interpretation and chooses to require compliance with the TSC in this situation, Board staff submit that the Board should reduce the proposed capital budget by $10.8 million (sum of the advancement costs of $4.9 million + $5.9 million)[34] to recognize the contributions that should be sought from Toronto Hydro for the advancement of the work. However, as noted above, it appears to Board staff that the operation of the TSC in this situation may be unfair to Toronto Hydro and its ratepayers.

[33] TR Vol. 3, pp. 182 - 183
[34] Exhibit I/Tab1/Schedule 113, p. 5

Board staff note that under the current rules, the ECT which the OPA will be conducting to determine which generators can be economically connected, considers only transmission network investments, not investments in transmission connection facilities. There is as yet no corresponding economic evaluation from the OPA for transmission connection facilities. There are a large number of transformer stations on the system that would require short circuit upgrades to accommodate the connection of renewable generation. In the absence of a test of the economics of such connections, uneconomic investments are a clear risk. Permitting recovery of such investments from transmission customers moves the risk of uneconomic connections onto ratepayers from the connecting generators, and could result in unwarranted increases in transmission rates in the province. At the same time, requiring a distributor's local ratepayers to bear the cost of the investments may be unfair, and inconsistent with the scheme of the Green Energy Act, which provides for rate protection for local customers for eligible investments made by distributors[35].

In the slide deck from the OPA website[36], both the OPA and Hydro One recognized this issue. The OPA, at page 60 of the slide deck, indicated that during the ECT, it would work with FIT applicants, transmitters and distributors to facilitate solutions. At page 66, the OPA said:

> "Where a transformer station is owned by a transmitter and considered a connection asset, the cost of the upgrade will be recovered from the FIT applicant(s) who triggers the upgrade. Cost will be passed to the FIT applicant via the applicant's LDC."

Hydro One, at page H91 of the slide deck agreed, stating:

> "Costs of any upstream upgrades to the system of a host distributor or a transmitter would be passed on to the distributor; these costs are then passed by the distributor on to the distribution-connected generator."

It is not clear to Board staff, under the current rules in the TSC and DSC, how the distributor would recover the capital contribution from the connecting generators, except through negotiation and the offer to connect. With respect to these projects, Toronto Hydro may have already finalized the offer to connect without anticipating the need to include the advancement costs. When questioned about the role of the OPA in facilitating such negotiations for the costs of the Leaside and Manby projects, Mr. Young suggested that it may be too early for the OPA to facilitate a contribution from generators, as the ECT has been delayed[37].

Board staff recognize that the total advancement costs for the projects ($10.8 million) are not highly material in the context of Hydro One's transmission capital budget. However, Board staff submit that it would be unfortunate for the Board to create a precedent in this case for the collection of costs from transmission ratepayers that, in Board staff's submission, should be allocated to transmission system users. If the Board does decide to allow Hydro One to recover the costs of the advancement work in transmission rates, staff recommend that the Board make it clear that this is a response to a transitional issue, and not a policy for the future allocation of such costs. In future, it may be necessary for Hydro One or the OPA to devise a model for apportioning transmission upgrade costs, possibly based on electrically significant zones in the province.

[35] Section 79.1 *Ontario Energy Board Act, 1998* and Regulation 330 under that Act.
[36] Exhibit K 3.6
[37] Tr. Vol 3, page 185.

B. Protection & Control for Enablement of Distribution Connected Generation
Projects: [D43 - Station Protection Upgrades and D44 - Transfer Trip Facilities]

Hydro One seeks to recover the costs of the P&C projects D43 and D44 from transmission ratepayers. Board staff submit that the Board should consider reducing the requested capital budget by $10 million in 2011 and $29.8 million in 2012[38] to recognize that the facilities in question are classified as connection, and that the TSC prescribes a user-pay approach for such facilities.

Hydro One witness Mr. Young testified that although these investments are being made at connection stations, they have benefits to the larger network system. Mr. Young also indicated that some of the facilities would be installed at network stations.[39] Board staff acknowledge that these facilities may have benefits to the larger network system, but where such equipment is installed at connection facilities, the rules in the TSC dictate a user-pay approach for all or part of the costs.

Mr. Young also indicated that P&C systems are highly integrated, and for cost efficiency and technical implementation reasons, including outage coordination, it is appropriate to do the all of these P&C upgrades at once, and at a time which accommodates bundling with other station work. This can mean that the timing of investments cannot be sequenced with certainty to the execution of individual connection cost recovery agreements from generators. At one point, Mr. Young explained the complexities of trying to attribute P&C upgrade costs to connecting generators at connection facilities:

> "On the distribution side, where the generators are much smaller and the type of generators are much more diverse, and the timing of these generators could be, you know, quite a different time apart, my belief is that there is very few situations for which you have that level of predictability to be able to sequentially order the connections and make the necessary contractual arrangements in a timely fashion so that, then, we can coordinate the work at the station in an effective manner."[40]

Board staff acknowledge the difficulties involved in situations involving many individual customers. However, it seems likely that in nearly all cases, the customers driving the upgrade at connection facilities will not be a group of generators, but one or more distributors. The fact that the upgrades benefit the transmission system and may be bundled with other work may not be a sufficient reason to deviate from the cost responsibility provisions of the TSC. As explained in the previous section, staff acknowledge the potential unfairness of requiring distributors and their ratepayers to fund the investment if the distributor cannot recover the capital contribution from connecting generators, or from a provincial pool.

While there may be complexities involved in the application of the rules in the TSC and the DSC to the situations described by Hydro One, Board staff submit that the Board should have regard to the danger of the risks of uneconomic investments being passed through to transmission ratepayers.

[38] Exhibit I/Tab1/Schedule 64, p. 6
[39] TR Vol. 3, p. 189
[40] TR Vol. 3, p. 190

Accelerated Recovery of CWIP for the Bruce to Milton Project

Hydro One applied for accelerated cost recovery for the Bruce to Milton transmission project (approved by the Board in a leave to construct proceeding in 2008). [41] The applicant is requesting that during the construction phase, before the project is in service, 100% of CWIP expenditures be included in the transmission rate base (using the half year rule in 2011), and that the carrying costs of this rate base addition be recovered from ratepayers. Hydro One relies on the January 15, 2010 Report of the Board: The Regulatory Treatment of Infrastructure Investment in Connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario (the "Report")[42] in proposing this alternative mechanism for cost recovery.

<u>The Board's Report</u>

In the Report, the Board indicated that an applicant, in order to have an infrastructure project considered for accelerated cost recovery, must establish the need for the project and demonstrate a requisite relationship exists between the alternative mechanism sought and the demonstrable risks and challenges of the project. The applicant's proposal must be tailored to address these risks and challenges. The Board did indicate that in most instances, conventional regulatory mechanisms will likely be sufficient to address the investment risks of infrastructure projects. It appears from the Report that the alternative mechanisms discussed in the Report are to be used only in circumstances where conventional mechanisms are demonstrated to be inadequate.

At page 21 of the Report, the Board listed several factors it would consider in determining whether an alternative mechanism should be applied in any particular case. The list was not exclusive:

> "In considering a proposal for one or more alternative mechanisms, the Board will evaluate the following factors, among others:
>
> - the need for the project (if not already demonstrated through another process as discussed in section 3.5 below);
> - the public interest benefits of the project and of granting the alternative mechanism(s) requested;
> - the overall cost of the project in absolute terms;
> - the cost of the project in proportion to the current rate base of the utility;
> - the risks or particular challenges associated with the completion of the project;
> - the reasons given for not relying on conventional cost recovery mechanisms; and
> - whether the utility is otherwise obligated to undertake the project."

Board staff submit that the evidence related to the Bruce to Milton proposal in this case can be analyzed in relation to this list.

<u>Need and Costs</u>

The first and last items on the list, the need for the project, and whether the utility is otherwise obligated to undertake the project, appear not to be at issue in this application. The need for the project was accepted by the Board in the section 92 proceeding, and reconfirmed in the recent Ministerial directive to the OPA requiring that a portion of the Bruce to Milton line should be reserved for the transmission of energy generated by the facilities to be built by Samsung in the

[41] EB-2007-0050
[42] EB-2009-0152

Bruce area[43]. Similarly, the first half of the second item, the public interest benefits of the project, has been accepted by the Board in its approval of construction. The overall cost of the project (the third listed item) is stated to be $753 million, representing nearly 10% of the utility's 2010 rate base (the fourth listed item).

Risks and Challenges

The fifth bullet point in the Board's list of factors is "the risks or particular challenges associated with the completion of the project". Several times in the Report, the Board emphasizes that the alternative mechanisms are designed to address "unique" risks posed by *Green Energy Act*-related investments. Board staff submit that the evidence in this application is not persuasive that the risks and challenges of the Bruce to Milton project are unique from other major projects. The primary risk cited by Hydro One is further delay in project completion. In addition, weather delays, 3rd party intervention, regulatory challenges, land acquisition challenges, First Nations consultation and unanticipated construction problems were named as additional risks[44].

Staff submit that the Board will need to consider whether these risks, some of which no doubt existed and may still exist for the Bruce to Milton project, are sufficiently "unique" to warrant the special treatment contemplated in the Report. Indeed, the evidence from Hydro One is that the company intends to ask for similar relief for all large transmission projects.[45]

Staff submit that the Board should carefully consider whether the accelerated cost recovery mechanisms in the Report are an appropriate regulatory tool for all complex, capital intensive projects, which clearly involve a variety of risks, or should be reserved for unique risks that are not common to all projects. For example, one risk of some *Green Energy Act* investments may be the cancellation of renewable generation projects after the transmission project has been partially developed or constructed. The evidence suggests that this is not a risk of the Bruce to Milton project. The risks cited for the Bruce to Milton project appear to be common to all large transmission construction investments in Ontario at the present time. The Board could find that the risks associated with this project are not unique, and that conventional cost recovery methods are sufficient to address these risks.

Benefits to Ratepayers

During the hearing, Hydro One indicated that the main reason it was seeking accelerated cost recovery for the Bruce to Milton project was not because the utility would have difficulty raising capital for the project, but rather because the proposal benefits ratepayers.[46] This evidence relates to the second last item on the Board's list of factors, why the applicant is not relying on conventional cost recovery mechanisms, and the second part of the second listed item, the public interest benefits of granting the alternative mechanism.

Hydro One's evidence was that the total cost of the project, and therefore the total recovered from ratepayers, would be lower by $68 million under the accelerated recovery of CWIP approach than under conventional recovery methodologies. [47] The company's evidence on this

[43] Exhibit K3.4
[44] Exhibit A/Tab11/Schedule 5, pp 5-6, and TR Vol. 3 p. 199
[45] TR Vol. 3, p. 199-200
[46] TR Vol. 2, p. 73
[47] Exhibit I/Tab1/Schedule 122 & TR Vol 11, p. 9

point was challenged by several intervenors, who pointed out the sensitivity of the benefit calculation to the discount rate assumed in the comparison of the two alternatives.

In addition, Hydro One's evidence was that ratepayers would benefit by the rate smoothing due to the recovery of these costs commencing earlier and being spread over a longer recovery period. As is confirmed in Undertaking J3.5, ratepayers will pay more cumulatively in the first twelve years of a fifty year recovery period, and cumulatively less from that point on. The cross-over year is 2024. However, according to that same undertaking, on a nominal basis, the impact of Bruce to Milton on rates using the accelerated CWIP methodology will be nearly 10% less starting in 2013 when compared to the AFUDC alternative ($60.3 million versus $66.2 million).[48]

In determining whether it is in the ratepayer's interest to grant the proposed accelerated cost recovery mechanism for this project, the advantage of rate smoothing must be balanced against the immediate concern of mitigating rate impacts in 2011 and 2012. The Board may wish to consider whether the present concern of ratepayers over rising total electricity costs is sufficiently pressing to discount the benefits of the rate smoothing over a longer period provided by the accelerated recovery of CWIP proposal.

CAPITAL STRUCTURE and COST OF CAPITAL

Hydro One's deemed capital structure for rate making purposes is 60% debt and 40% common equity. This capital structure is consistent with the Board's report on the cost of capital (EB-2009-0084). The 60% debt component is comprised of 4% deemed short term debt and 56% long term debt.

The Hydro One evidence reflects a return on equity of 10.16% for the test year 2011 and 10.41% for the test year 2012. This is based on the Board's formulaic approach in the EB-2009-0084 Report, using the Long Canada Bond Forecast for 2011 and 2012, based on the September Consensus Forecast and Bank of Canada data which was available in October 2009 and the change in the spread of A-rated Utility Bond Yield.

Hydro One has assumed that the return on equity for each test year will be updated in accordance with the Cost of Capital Report. For rates effective January 1, 2011, the Board would determine the ROE for Hydro One Transmission based on the September 2010 Consensus Forecasts and Bank of Canada data which would be available in October 2010 and the change in the spread of the A-rated Utility Bond Yield. For rates effective January 1, 2012 a similar update would take place in the fall of 2011.

In response to VECC Interrogatory I-4-49 Hydro One indicated that it would not be updating its 2011 and 2012 debt costs.

Board staff submit that the cost of long-term debt used by Hydro One should be updated to reflect the actual debt instruments used by the utility as noted on page 53 of the Cost of Capital Report.

[48] Exhibit J3.5

As shown in response to BOMA Interrogatory I-6-33, Hydro One Networks has executed some of the new debt forecast and Board staff submits that actual interest expense in the test years based on the actual terms for this recent debt, rather than the forecast expense in the application, should be reflected in the determination of the test year revenue requirement and distribution rates in compliance with the Cost of Capital Report.

TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

Hydro One's evidence that summarized IFRS implementation indicated that the areas with highest potential to affect its reporting due to IFRS were: "rate regulated accounting, accounting for property, plant and equipment, payments in lieu of corporate income taxes, employee future benefits, and the impact of initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS"*[49].

Hydro One used Canadian Generally Accepted Accounting Principles (CGAAP) for the 2011 filing. This is consistent with the July 28, 2009 Report of the Board on Transition to IFRS (EB-2008-0408) ("Board IFRS Report"). For 2012, Hydro One filed its submission as a Modified IFRS (MIFRS) submission, using the assumption that MIFRS equals CGAAP, with two significant exceptions.

Continued Capitalization of Expenditures

The first requested exception is to allow Hydro One to continue to capitalize overhead expenditures associated with the construction and bringing into service of new capital works such as training, Common Corporate Functions and Services and line supervision that would not otherwise be capitalized under IFRS. The specific proposal is for such costs to continue to be capitalized for regulatory purposes based on legacy practices.

The Board IFRS Report addressed the topic of accounting for overhead costs in the cost of new capital work effective January 1, 2011 in Issue 3.3. The report stated the following:

> "3.3 The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS… Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified."

The Board issued a letter on February 24, 2010, clarifying and reinforcing the capitalization policy stated in the Board IFRS Report. The letter states:

> "This letter is to clarify that the Board's position on Issue 3.3 from the Board Report applies independently of what the approval outcome of the IASB draft standard may be, as follows:
>
> - As stated in the Board Report at Issue 3.3, the Board is requiring full compliance with IFRS requirements (e.g. IAS16) as applicable to non-regulated enterprises and only where the Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable."

[49] Exhibit A/Tab11/Schedule3

During the oral hearing, Hydro One witness, Mr. Fraser, stated that the applicant is requesting a costing exception. However, he also said that a deferral account would be another option[50].

Section 7 of the Board IFRS Report states that all rate impacts should be considered in aggregate, and then any mitigation mechanisms should be addressed, if required.

> "7.2 Rate impacts should be considered in aggregate to determine the significance of the cumulative effect. [Distributors] must provide specific information regarding the individual cost drivers making up the aggregate impact.
>
> 7.3 Utilities must provide a proposal for a rate mitigation mechanism if the impact is material and mitigation appears to be required."

Hydro One was asked to state the estimated aggregate impact of adopting IFRS in 2012, without the two exceptions requested. In addition, Hydro One was asked to state the mitigation actions that Hydro One would propose should such impact be material[51].

Hydro One indicated that the estimated aggregate impact of adopting IFRS in 2012 without the exceptions would be an annual increase in revenue requirement of approximately $200 million. However, Hydro One did not provide a response to the question on any mitigation actions. Hydro One's solution is to request an exemption from the Board's IFRS policy to allow them to continue existing accounting policy even though it does not conform to IFRS.

It appears from the evidence that Hydro One had expected that the date of IFRS adoption would be deferred to 2013, consistent with the proposal included in the July 2010 exposure draft released by the Canadian Accounting Standards Board. This exposure draft entitled "Adoption of IFRS by Entities with Rate-regulated Activities" proposed that rate regulated entities be permitted to elect to adopt IFRS in 2012 or 2013 rather than 2011.

However, the Accounting Standards Board made a decision on September 7-8, 2010 to allow the rate-regulated entities to elect to defer the adoption of IFRS only to January 1, 2012 (instead of the exposure draft date of up to January 1, 2013).

Board staff submit that the evidence from Hydro One fails to provide any reasons for granting the exception aside from rate impact. It is staff's recommendation that rather than granting the requested exception at this time, the Board should require Hydro One for regulatory purposes to adopt MIFRS regarding the capitalization of overhead in accordance with the Board's stated policy, and further, require Hydro One to undertake and report on reasonable business measures to reduce the impacts arising from adopting this policy. The company should record any remaining difference from CGAAP arising in 2012 in a deferral account.

Staff suggest that reasonable business measures should include considerations that go beyond the allocation of costs, including:

- finding ways to reduce the cost of the functions and services themselves,

[50] TR Vol. 7, page 38
[51] Exhibit I/Tab1/Schedule 19, part d)

- considering alternate departmental configurations to attribute costs directly to capital work that are otherwise treated as costs in common while not increasing organizational costs inappropriately.

For example, Board staff observe that the amount of non-payroll costs added to base labour and allowances rates in the example given at Exhibit C1/Tab4/Schedule1 pages 2 and 3 for a Regional Maintainer- Electrical, of 286% are a large percentage[52]. Staff also observe that while the capital program has doubled since 2007, it does not follow that the amounts of overheads capitalized should also increase proportionately. The cost drivers are based on the content of the capital work program and therefore may concentrate more on allocation than on whether increases in the actual expenditures on common costs are actually justified.

Notwithstanding that the impact affects succeeding years after 2012, staff submit that the deferral account should capture any residual impact in 2012 only. Hydro One can report on the success of its mitigation efforts at the next rates case or at such earlier time as the company seeks disposition of the amounts in the deferral account.

New Variance Account

The second exception requested by Hydro One is for a new variance account to hold gains and losses on tangible and intangible asset sales or losses resulting from premature asset retirements.

The Board IFRS Report indicated at page 41:

> "Gains and losses on disposition of assets:
>
> Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the Board."

In the pre-filed evidence[53], Hydro One stated that under CGAAP, using group depreciation, most asset losses were charged to accumulated depreciation and recovered over the remaining service life of other related assets. However using group depreciation is not consistent with IFRS. Hydro One states that it has requested this account because it cannot reasonably forecast the losses to be incurred upon premature asset retirements under IFRS, and Hydro One expects the amounts to be material.[54]

Board staff submit that it appears reasonable to allow Hydro One to record gains and losses on premature retirements in a deferral account, which would be subject to Board review prior to

[52] The base labour and payroll allowances amount to $44.04 per hour, being 58% of $75.93 per hour as per Table 1. Thus an amount of 286% is added to the base labour hourly rate in deriving the amount of labour cost to be applied to work including capital work, inclusive of overhead for this example employee.
[53] Exhibit A/Tab11/Schedule 3
[54] Exhibit I/Tab1/Schedule 92

disposition. Board staff also submit that such a deferral account should be separate and distinct from the account associated with the capitalized overheads issue.

DEFERRAL and VARIANCE ACCOUNTS

Balances Proposed for Disposition

Hydro One has requested disposal of a credit balance of $7.4 million in each of the two test years as shown in the table below:[55]

Description	Account	Balance Dec. 31/09 $Million	Balance Dec. 31/10 $Million
Export Service Credit Revenue	2405	(4.8)	(4.9)
External Secondary Land Use Revenue	2405	(3.2)	(3.2)
External Station Maintenance and E&CS Revenue	2405	(4.4)	(4.4)
Subtotal for disposition proposed over 1 year		**(12.4)**	**(12.5)**
IPSP & Other LT Project Planning Costs	1508	1.9	2.0
Pension Cost Differential	2405	3.1	3.1
Subtotal for disposition proposed over 2 years		**5.0**	**5.1**
Total Balance for proposed disposition		**(7.4)**	**(7.4)**

The Export Service Credit, External Secondary Land Use and External Stations and Engineering Construction Services Revenue balances are requested to be disposed of over a 12 month period to mitigate the impact of the requested rate increase in 2011. The IPSP & Other Long Term Planning Costs and Pension Cost Differential balances are being requested to be disposed of over 24-month period, consistent with the test years of this application.

Board staff would point out that these are forecast balances and not audited balances and it is common Board practice to dispose of only audited year end balances. However, in past Hydro One distribution and transmission cases, forecast balances were approved for disposition[56]. Board staff do not have any submissions on the balances proposed for disposition.

Regulatory Accounts Requested to Continue or Establish New Accounts

Hydro One requested approval to continue or establish new deferral accounts for the following:

- Impact for Changes in IFRS Account (2012 only)
- IFRS – Gains and Losses Account (2012 only)
- IFRS Incremental Transition Costs Account
- Pension Cost Differential Account
- Long-term Project Development OM&A Account
- Tax Rate Changes Account
- OEB Cost Differential Account[57]

[55] Exhibit F1/Tab 1/Schedule 1/p.3
[56] EB-2005-0020/EB-2005-0378 and EB-20080-272
[57] Exhibit F1/Tab1/Schedule 2

Board staff submit that Hydro One provided sufficient justification for all of the above accounts, with the exception of OEB Cost Differential account.

This account was originally created for electricity distributors by Article 220 of the Accounting Procedures Handbook as follows:

> "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."

The account was closed to new principal entries after April 30, 2006 as the distributors' revenue requirements included amounts for Board cost assessments beginning in 2006.
The evidence on the record[58] indicates that Hydro One's revenue requirement also includes an amount for OEB cost assessments. Board staff sees no reason why this deferral account is still required for Hydro One Transmission.

Hydro One has not asked to continue the following 3 variance accounts:

- Export Service Credit Revenue
- External Secondary Land Use Revenue
- External Station Maintenance and E&CS Revenue

The response to BOMA Interrogatory I-6-7 indicates that Hydro One is projecting lower revenues and tighter margins for the test years for these accounts. Another BOMA Interrogatory I-6-8 shows significant variances in these accounts in 2009 and 2010. During cross examination by Board staff counsel, Hydro One witness Mr. Fraser testified that Hydro One is focusing more on its core business, and is trying to reduce its amounts for work such as station maintenance.[59]

Board staff note that Hydro One had a total credit of $12.5 million in these accounts as of December 31, 2009[60], and submit that it would be premature to discontinue the use of these accounts at this time until it is proven that the variances are sufficiently immaterial to justify tracking them in the variance accounts.

Board staff recommend that Hydro One continue to track the variances for the above 3 revenue accounts.

COST ALLOCATION and RATE DESIGN

High 5 Rate Design Proposal

Hydro One applied to continue with the current charge determinant to recover Network costs, in place since 2002. The Network monthly charge determinant for each delivery point is the higher of two loads: the load at the hour of highest system load, or 85% of the highest load in an hour during the off-peak period.

[58] Exhibit C1/Tab2/Schedule 7, page 18
[59] TR Vol. 7, page 140
[60] Exhibit F1/Tab1/Schedule 1/p. 3

In the previous transmission rates hearing (EB-2008-0272), AMPCO proposed an alternative charge determinant, described as “High 5”, which is the load at each delivery point at the hour of highest system load on 5 different days during the year. The load at each delivery point during those 5 hours, as a proportion of the total system load, would determine the proportion of Network revenue requirement to be charged to the customer in the following year. Hydro One’s position was that the initial implementation date of the High 5 charge determinant should be 2012 at the soonest, as the customer’s load during the relevant hours establishes its Network cost the following year, whereas in the current design the customer’s load establishes the cost during the current month.

In its October 15, 2010 submission in this proceeding, the IESO also advocated that the implementation date for High should be January 1, 2012.

In the Board’s EB-2008-0272 Decision, Hydro One Transmission was directed to further analyze the AMPCO proposal, and to propose an implementation plan in the event the Board decides to change the network charge determinant in 2011. Hydro One retained Power Advisory LLC to further analyze the High 5 Proposal and provided the report in its pre-filed evidence.

AMPCO filed its own evidence on the High 5 Proposal, with an analysis by Dr. Anindya Sen of the University of Waterloo.[61]

Summary of Evidence

The most obvious difference between the current charge determinant and High 5 is the number of hours that determine the customer’s annual contribution toward the Network revenue requirement. In the status quo, it is determined by the load at each delivery point during 12 hours, each in a different month, whereas under High 5 it would be determined by the load during 5 hours, usually during fewer than 5 months. The other main difference is that in the status quo, the customer’s charge determinant could be established during an off-peak hour (i.e. 7:00 pm – 7:00 am or weekend), whereas none of the High 5 hours would ever happen during the off-peak period.

For Network service, the charge determinant for more than half of the Directly Connected customer monthly bills has been established in the off-peak period[62] . This indicates that the highest load during off-peak hours was considerably higher than the load coincident with the system peak. AMPCO witnesses testified that the design of the charge creates a disincentive to shift more load toward the off-peak if the charge determinant is being set in off-peak months and off-peak hours of the day. On the other hand, if the charge determinant were changed to High 5, the Network charge would no longer create a disincentive for further load shifting.[63]

The Power Advisory analysis of the High 5 charge determinant includes a calculation of the proportion of Network revenue requirement that is borne by Hydro One customers in three groups: Direct Customers (Directs), Distributors (LDCs), and Power Producers (generators). Corrections were made to the original report and are found in the response to Energy Probe Interrogatory I-2-36a. The analysis shows that, under the status quo charge determinant, Directs would be charged $66.0 million, Power Producers $10.1 million, and the LDCs $763.6 million, totaling $839.7 million. With the High 5 and the existing load profiles, i.e. with no load

[61] Exhibit M-1, Attachment 1
[62] Exhibit I/Tab4/Schedule 62
[63] Exhibit M-1, p. 2 & TR 10 pp. 37 & 96 & 101

shifting beyond what has already occurred, the Directs would be charged $51.7 million (down by $14.2 million), the Power Producers $2.1 million (down by $8.0 million), and the LDCs $785 million (up by $21 .4 million).

The Power Advisory report indicates that the effective cost of electricity during the critical five hours of the year would be very high, as the load during that short period would determine the Network bill for the following year. The analysis includes an assumption about how many hours would be considered as having an appreciable chance of being one of the five hours, and the annual cost over those hours is defined as the "shadow price" of Network service. The analysis also includes an estimate of the elasticity of substitution, i.e. the sensitivity of consumption during this relatively small number of hours compared to consumption during all other hours as a result of the effective differential in costs between the periods. This elasticity differs for the customer groups, and is assumed to be zero for the LDCs.

The potential for load shifting, together with the calculated differential between the shadow price during potential peak hours and the price of $0/ MW in all other hours, enables an estimate of the amounts that would be charged to each customer group.

In the Power Advisory evidence, the Directs would shift approximately 430,000 kW from the High 5 hours and pay $48.6 million, Power Producers would not shift load and pay $2.1 million, and the LDCs would also not shift load and pay $789.0 million.

Board staff filed a summary of a proposed regulation to amend O. Reg. 429/04, currently out for comment, that would apportion the cost of the Global Adjustment by means of a charge determinant nearly identical to the AMPCO proposal for the Network charge.[64] The AMPCO witness panel stated that any differences that exist in the details of the draft regulation and the AMPCO proposal for the Network charge should be reconciled during the initial year. In this way, the effective charge determinant would be simplified and would enhance the ability of all customers to shift their load away from the highest hours.

The evidence includes information on when the Network has experienced peaks in the various regions of the province.[65] The regional peaks occur at different hours of peak days, different days during the months of highest load, as well as occurring predominantly on winter days in some regions and summer days in other regions.

Board staff submit that the High 5 proposal raises a number of unresolved issues. Staff question whether the High 5 charge determinant is based on too few hours to properly charge for the network revenue requirement. If the Board accepts the High 5 proposal, staff submit that the implementation of the proposal occur over a number of years in order to smooth the impacts on LDC customers.

Fairness of Impact on Customer Groups

Staff submit that the rate-making objective of fairness is an issue if a new charge determinant is to be implemented that creates a major change in the proportions of the revenue requirement associated with existing network facilities. Staff submit that the rate-making objective of cost causation is important when considering who causes the cost of facilities that will be added in the future, but not so important when the main issue is recovery of the costs of existing facilities.

[64] Exhibit K8.1
[65] Exhibit I/Tab 4/ Schedule 13

The objective of fairness includes consideration of who caused the costs already incurred for existing facilities, along with consideration of who benefits from the existing system.

With a change to High 5 as the charge determinant, Directs and Power Producers as a group would enjoy a lower share of the Network revenue requirement without any incremental load shifting, and this necessarily imposes a larger cost for the customers of distributors as a group. Within these respective groups, the impacts would differ amongst individual customers and may be in the opposite direction to the group's impact.[66] The impact on the average customer of a distributor is not large. Nonetheless, the reduced cost for Directs and Power Producers is a windfall from the viewpoint of the transmission Network rate, whether it results from different load profiles in the first place, or from loads shifted to the off-peak in response to prices in the commodity market. The evidence shows that there would be a substantial financial gain to the Directs, based on the existing load profiles, and a corresponding loss for customers of distributors.

In addition, a customer embedded within a distributor would as a result pay more for transmission services than an identical customer directly connected to the transmission system unless the charge determinant for all customers paying retail transmission service rates to distributors are also adjusted.[67]

Staff recognize that the proportions of Network revenue requirement contributed by the various groups should not be frozen in time. There must be the opportunity to consider alternatives to the charge determinant currently in place. However, the size of the windfall changes caused by moving from the status quo to High 5 are large, and the Board may consider them unacceptable from the viewpoint of fairness.

Staff also submit that the simplicity of having identical charge determinants for transmission Network and recovery of Global Adjustment balances is not a compelling reason to adopt High 5 as the Network charge determinant. Invoices issued by the IESO are complex with or without identical charges, and there is no reason to think that customers (especially Direct Customers who have demonstrated flexible load profiles) will have trouble coping with charge determinants that are not identical.

Uncertainty of Avoiding Transmission System Investment

Staff submit that there may be some additional load shifting that would be incented by implementing High 5 for the Network revenue requirement. However, staff submit that it is very difficult to produce an accurate estimate of the extent to which High 5 would incent additional load shifting, because High 5 is quite different from the charge determinant that was in place when the data was generated. Power Advisory attempted to model High 5 on a comparable basis to the current charge determinant by calculating a shadow price. The shadow price is far outside the range of actual prices, so the estimated effect is an extrapolation beyond any load profiles that could have been observed.

In addition, it appears that a larger price differential will be created by the proposed Global Adjustment recovery mechanism than by a High 5 Network charge determinant. If the Global Adjustment regulation is implemented as the summary presents, it is reasonable to assume that

[66] Exhibit I/Tab1/Schedule 96, a) and c)
[67] TR Vol. 10, pp. 104-106

there will be at least some Direct Customers who will be able to adapt to that charge, and would thereby enjoy an additional saving from the High 5 charge determinant for Network revenue requirement. It is doubtful that the amount of load shifting posited by Power Advisory remains a valid estimate of the additional load shifting that would occur over and above the load shifting incented by the Global Adjustment charge.[68]

Even if additional load shifting were to occur due to High 5 allocation of the Network revenue requirement, any real system cost savings are small and far in the future[69]. Staff acknowledge AMPCO's evidence that there is necessarily a time lag between implementing a new charge determinant and getting the load shifting that it would ultimately induce.[70] However, staff submit that the Power Advisory conclusion is valid - the cost savings of forestalling future Network investments by further load shifting as a result of High 5 do not appear significant at this time.

Need for Additional Alternatives

Board staff agree with AMPCO that the status quo charge determinant is likely creating disincentives for load shifting that could otherwise save commodity costs and line losses.[71] As noted above, staff submit that a change to High 5 from the status quo may not be appropriate. On the other hand, to the extent that the format of the Network charge determinant is giving Directs an incentive to shift loads during months when the load never approaches the limits of Network capacity, some modifications to the status quo may be warranted.

The record in this application includes only two alternatives for the Network charge determinant, and the two alternatives have quite different outcomes. Hydro One testified that it had not developed other alternatives because the Board had not so directed.[72]
To avoid repeating this situation, staff submit that the Board should direct Hydro One to develop several alternative charge determinants for its Network revenue requirement, and at its next transmission rate case to present analysis of the alternatives in terms of how well each achieves widely-accepted rate-making objectives.

EXPORT TRANSMISSION SERVICE RATE

The Export Transmission Service (ETS) Rate of $1.00/MWh was established in 2002. The matter of how to update this rate has been an issue in various proceedings since then, but the tariff has remained unchanged. In its Decision on a Settlement Proposal in 2006 the Board accepted that the IESO would analyze the situation and make a recommendation to Hydro One, and that Hydro One would propose a tariff for the Board's approval.[73]

In its EB-2008-0272 Decision, the Board agreed with intervenor submissions on the need to complete the IESO study, and directed Hydro One to act on its recommendation by filing a new ETS rate proposal within 60 days of the study's release. While the stated preference was to

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[68] Exhibit I/Tab 6/Schedule 36 a) Table 15 corrected
[69] Exhibit H1/Tab3/Schedule1/Attachment 1/pages vii, 77
[70] Exhibit M-1, p. 8
[71] Exhibit M-1, p. 12-13
[72] Exhibit I/Tab 1/Schedule 95 a) and TR Vol. 8, p. 141
[73] EB-2006-0501, Exhibit M/Tab 1/Schedule 1 p. 17

negotiate reciprocal elimination of the tariff with neighbouring jurisdictions, a recommendation on the appropriate tariff was required regardless of the outcome of negotiations.

Summary of Evidence

The record in this application includes a report prepared for the IESO by Charles River Associates (CRA), dated July 30, 2009[74]. The report is based on forecasts of electricity prices in neighbouring jurisdictions and in Ontario, and estimates the quantity of transactions that would require Hydro One's transmission facilities for imports and exports to the Ontario market, and wheeling power through Ontario. The quantity of transactions is a function of the ETS rate, because a higher rate is assumed to discourage any transaction where the price differential between two jurisdictions is lower than the ETS rate. The alternative ETS rates considered by CRA in 2010 are:

- Status quo @ $1.00/MWh
- Average Embedded Network Rate at $5.15/MWh
- Reciprocal Treatment with separate rates to each neighbouring jurisdiction
- Several scenarios with the Ontario rate at $0/MWh[75]

The record also includes a report prepared by the IESO, dated August 2009. The report extends the quantitative results of the CRA study, as well as adding a qualitative assessment. Scenarios were developed in which certain changes in the tariffs charged by neighbouring jurisdictions are assumed. However, the summary in the IESO analysis covers only the three alternatives in which the Ontario ETS tariff is characterized as $0, $1 and $5 per MWh, and the rates charged by neighbouring jurisdictions are assumed to remain constant.

The IESO report uses an analytical framework in which the consumers' surplus for Ontario consumers is quantified, compared to a base case which assumes an ETS price of $1.00/MWh. It also quantifies the producers' surplus that accrues to electricity producers in Ontario, along with a calculation of revenue to Hydro One from the ETS tariff. The evaluation framework in the IESO report is the net Ontario benefit, comprised of the sum of consumers' surplus, producers' surplus, and revenue from the ETS tariff.

The consumers' surplus is found to be higher with higher ETS rates, as the Ontario market-clearing price is lowered because export transactions are discouraged by the higher cost of exporting power. Similarly, consumers' surplus tends to be lower with the lower ETS rate of $0/MWh, as the Ontario market clears at higher prices due to larger exports. Conversely, producers' surplus is larger with a lower ETS rate and smaller with a higher ETS rate.

The forecast amounts of consumers' surplus in 2010 with an ETS rate of $5/MWh is higher by $207 million than with the status quo, and $111 million lower than the status quo with ETS rate at $0/MWh. The corresponding amounts of producers' surplus are $214 million lower than status quo with ETS rate at $5/MWh, and $102 million higher with ETS rate at $0/MWh.[76]

In summary, the IESO framework identifies the higher ETS rate of $5/MWh as the alternative that maximizes consumers' surplus plus producers' surplus, once the additional revenue to Hydro One is factored in as a revenue offset that benefits Ontario consumers.

[74] Exhibit H1/Tab5/Schedule 2 Attachment 1 – Appendix A
[75] Exhibit H1/Tab5/Schedule 2/Attachment 1/Appendix B, pp. 84-88
[76] Exhibit H1/Tab5/Schedule 2/Attachment 1, p. 16-17 Tables 3 & 4

For completeness, staff point out that the evidence in the IESO study includes results for a number of other scenarios. Of particular interest initially were scenarios in which other jurisdictions would be persuaded to change their export tariffs in a reciprocal way. Staff's submission deals no further with the results under such scenarios because there has been no headway gained in negotiations and no further negotiations are contemplated.[77]

Despite the results of the study, the IESO recommended maintenance of the status quo ETS rate. The IESO had determined that the CRA scenarios were out-of-date in three ways even before completion of the initial study:

- load deterioration due to the economy,
- changes arising with the *Green Energy and Green Economy Act*, and
- Surplus Baseload Generation (SBG)[78].

In particular the likely increase of SBG that would be available in Ontario was thought to be a significant consideration, which had not been the case at the outset of the CRA study. With this in mind, the IESO recommended continuation of the rate of $1/MWh.

Staff Recommendation

Board staff can make no recommendation for 2011 and 2012 other than to continue with the status quo of $1/MWh. The evidence in this proceeding does not support any other specific rate. Staff submit that the forecasts of consumers' surplus and producers' surplus that would result from the ETS rate near $5/MWh are large extrapolations, and that the conclusion of a comparatively small net Ontario benefit cannot be relied on at this time.

Staff note that the IESO's recommendation to remain with the status quo was made more than one year ago and reiterated in their submissions in this case. Staff do not contend that the factors cited by the IESO in supporting the present ETS tariff are insignificant, but staff submit that an updated study is required. The Board should be presented with a wider range of alternatives, supported by quantitative evidence.

Staff submit that the IESO's proposal to re-examine the matter after it feels it has dealt fully with changes arising from the *Green Energy and Green Economy Act* would create an unnecessary and unproductive delay. As Mr. Finkbeiner acknowledged, it is impossible to predict what length of time must pass before the Ontario market matures and the effects of the connection of FIT generation, or the effect of further new policy changes, are evident.[79] Staff suggest that there is no guarantee that waiting several years to allow the Ontario market to evolve will improve the quality of the data or reduce the number of assumptions that must be made for a new study.

Staff recommend that the Board should direct that the IESO analyze the market again, using the CRA model or a comparable approach, and produce that updated analysis, with the IESO's analysis and recommendation, at the next transmission rates case, or at such other time as the Board considers useful.

[77] TR Vol. 9, p. 83-84
[78] Exhibit H1/Tab5/Attachment 1, p. 9
[79] TR Vol. 9, p. 96-97

In addition, it is staff's position that Hydro One should become involved in the rate design flowing from the study and the IESO's conclusions. Although the utility's bottom line is not directly affected by the ETS rate, Hydro One has a responsibility to optimize its ETS revenue on behalf of Ontario consumers, and ensure that its transmission rates recover its costs fairly from the various users of its Network and Connection facilities. These costs include facilities that are designed for power flowing to and from neighbouring jurisdictions.

BILL IMPACT ANALYSIS

On August 26, 2010, CME filed evidence in this proceeding prepared by Bruce Sharp of Aegent Energy Advisors Inc. entitled Ontario Electricity Total Bill Impact Analysis, August 2011 to July 2015.[80] This analysis included the impacts of all other factors (commodity, taxation, distribution, TOU pricing, government initiatives, etc) in the Ontario Energy Market on the price of electricity, not just the impacts of the matter before the Board in this proceeding.

The analysis concluded that Non-Residential electricity costs would increase at an annual compound rate of 8.0 to 10.4 percent (depending on usage levels) from August 2010 to July 2015. For Residential customers electricity costs would increase at an annual compound rate of 6.7 to 8.0 percent (depending on usage levels) over the same time period.

In response to Board Staff Interrogatory N2-1-1, CME provided additional background to the evidence including how it proposed the evidence be used in this proceeding. In short, CME submitted that Board should consider total bill impacts and not just the impacts of the transmission application when making this rates decision.

> "Having regard to the Board's obligation under the *Ontario Energy Board Act, 1998* (the *"OEB Act"*) to protect consumers with respect to electricity prices when carrying out its responsibilities under the *Act*, a consideration by the Board of evidence of the total bill impacts customers are experiencing and facing is mandatory."[81]

Board staff notes what was said by the Board in the Issues Decision in this application:

> "…the Board does not see this proceeding as the appropriate forum for the development of measures to evaluate consumer impacts and affordability…It is the Board's view that the development of objective measures or specific methodologies for the evaluation of customer impacts and affordability is a subject matter that falls outside the scope of this case.[82]"

Board staff submit that any decision by the Board to pursue the approach suggested by CME should be made in the context of a broader policy initiative of the Board and not a specific rate case such as the present proceeding.

All of which is respectfully submitted.

[80] Exhibit M-2
[81] Exhibit N-2/Tab1/Schedule 1/p. 2
[82] TR Motion Hearing / Issues Day July 20, 2010 page 38.