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February 1, 2010

Ontario Energy Board
P.O. Box 2319
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2300 Yonge Street
Toronto ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Hydro One Networks Inc.
Distribution Rates Application, 2010/2011
Board File Number EB-2009-0096
Board staff Submissions

Please see attached the Board staff submissions for the EB-2009-0096 proceeding.

Please forward to Hydro One Networks Inc. and all intervenors in this proceeding.

Yours truly,

Original Signed By

Harold Thiessen
Ontario Energy Board Staff
Case Manager – EB-2009-0096

Ontario

ONTARIO ENERGY BOARD

BOARD STAFF SUBMISSION

2010 AND 2011 DISTRIBUTION RATES

HYDRO ONE NETWORKS INC.

EB-2009-0096

February 01, 2010

Hydro One Networks Inc.
Distribution Revenue Requirement and Rates, 2010 & 2011
EB-2009-0096

Board Staff Submissions

INTRODUCTION

Hydro One Networks Inc. ("Hydro One") is the largest electricity distributor in Ontario with approximately 120,200 circuit kilometers of distribution line and 1005 distribution and regulating stations. It delivers electricity at voltages below 50 kV to 34 Local Distribution Companies, about 1.2 million retail customers and 44 directly connected large users.

Hydro One submitted this application for 2010 and 2011 rates on July 13, 2009 and updated the application on September 25, 2009. The oral hearing for this proceeding took place on December 7, 8, 10, 11, 14, 15, 17, 18, 2009 and resumed on January 11 and 12, 2010. Hydro One presented oral Argument-In-Chief on January 14, 2010.

The issues list for this proceeding was established on September 22, 2009. Issue 9.3: "Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?" was proposed to be addressed at a later date when the Board's EB-2009-0349 report on this topic is released. The Board requested parties' submissions on how this issue is best addressed in this proceeding. Staff's submission on this procedural question is found at page 44 of this document.

Hydro One has requested an updated revenue requirement of $1,150 million for 2010 and $1,264 million for 2011. As indicated in Exhibit J4.4, using the formula in the Board's EB-2009-0084 Cost of Capital Report (released on December 11, 2009), these revenue requirements are now $1,194 million in 2010 and $1,293 million in 2011. The major components of the 2010/2011 revenue requirements are shown in the table below.

2010 and 2011 Revenue Requirement ($ millions)			
		2010	**2011**
OMA Expenses		$ 560	$ 575
Depreciation		$ 259	$ 291
Capital Taxes		$ 4	$ 0
Income Taxes		$ 27	$ 48
Return on Capital		$ 344	$ 379
Total Revenue Requirement		**$ 1,194**	**$ 1,293**
Other items:			
Rate Base		$ 4,836	$ 5,146
Capital Expenditures		$ 565	$ 577
Deferral & Variance Accounts	(Refund)	$ 13	$ 13
External Revenues		$ 48	$ 48

Hydro One is in the midst of a rate harmonization plan, approved as part of the EB-2007-0681 proceeding, where 280 customer classes are being reduced to 12 new classes. However, Hydro One still administers 89 separate rate schedules until this harmonization is complete in 2012.

Hydro One expects its system will be used increasingly to serve distributed generators and has submitted a Green Energy Plan to facilitate distributed generation (this plan also includes Hydro One's Smart Grid and CDM plans).

The delivery rate increase for an average customer was expected to be 9.5% in 2010 and 13.3% in 2011 and these increases were reflected in the Notice published in Ontario newspapers in August 2009. In response to the Notice, the Board received 162 Letters of Comment from ratepayers across Ontario, the vast majority expressing concern with the high level of the proposed rate increases in 2010 and 2011.

As a result of the Cost of Capital Report, principally the impact of the change in allowed ROE from 8.11 % to 9.75%, Hydro One has estimated that the average residential rate increases will now be approximately 14.1% in 2010 and 11.6% in 2011.[1]

Consumer's Coalition of Canada (CCC) brought a motion before the Board on January 12, 2010 requesting that the Board order Hydro One to republish its Notice citing the change in rate impact and to correct a number of other perceived deficiencies in the Notice. On January 14, 2010 the Board ruled that a new Notice would not be required.

Hydro One's current distribution rates were determined through an Incentive Rate Mechanism (IRM) (EB-2008-0187). Instead of remaining on the IRM plan, Hydro One chose to make this application based on a cost of service, forward test year methodology. As a result, rate impacts are significantly higher than would have been the case under the IRM scheme.

These submissions reflect observations and concerns arising from Board staff's review of the oral and written evidence, and are intended to assist the Ontario Energy Board (the "Board") in evaluating Hydro One's application and setting just and reasonable rates. The submissions also pose questions on certain issues that all parties may wish to address in their written arguments. Not all issues on the Issues List are addressed in this submission. Only those issues which, in Board staff's opinion, require some comment or adjustment are addressed. This submission contains staff comments on the following topics/issues:

- Revenue Requirement Increase
- Implementation Date Change
- Load Forecasts
- Operations, Maintenance & Administration Costs
- Compensation and Staffing
- Capital Expenditures
- Cost of Capital
- Deferral and Variance Accounts
- Cost Allocation & Rate Design
- Green Energy Plan

[1] Exhibit J4.4

REVENUE REQUIREMENT INCREASE

Hydro One originally applied for an increase in revenue requirement to $1,181 million in 2010 and $1,294 million in 2011. For 2010, this represented an increase of 14.9% from the revenue requirement set when 2008 rates were approved ($1,128 million).

Subsequent evidence updates and the implementation of the Board's December 11, 2009 EB-2009-0084 Cost of Capital Report (increase in ROE to 9.75%) changed the applied-for revenue requirements to $1,194 million in 2010 and $1,293 million in 2011 and changed the rate impacts as mentioned above.[2] In response to the Notice published in August 2009, the Board received 162 Letters of Comment from ratepayers across Ontario, the majority expressing concern with the high level of the proposed rate increases in 2010 and 2011.

Through interrogatory H-1-8, Board staff asked for Hydro One's reaction to these letters and this issue became a significant topic of cross examination. Hydro One witnesses reviewed the planning and prioritization process followed by Hydro One management and underlined that they took the issue of customer satisfaction very seriously and referred to the balanced scorecard customer satisfaction value.[3] The planning process, as illustrated in response to VECC interrogatory H-7-51 (Investment Prioritization Process) does reveal that "customer" is noted as a risk, but does not specifically mention rate or bill impacts.

The response to staff interrogatory H-1-9 also included the text of the letter used by Hydro One to respond to the customer letters. The letter emphasizes process issues such as how Hydro One followed the OEB's guidelines and not on the details of the application itself, or Hydro One's operations and cost drivers that led to the published rate increase. There was some concern, expressed by CCC in cross examination, that this letter could lead customers to "…reach the conclusion that it is the Ontario Energy Board that is the cause of the rate impacts."[4]

Board staff shares this concern and urges Hydro One to, in future, amend any customer response letters in this respect.

Under cross examination Mr. Struthers testified that he had not read all of the letters,[5] yet Mr. Van Dusen testified that he had prepared a briefing note for the Chair of the Board of Directors.[6] Counsel for CCC asked a number of questions that revealed that Hydro One did not specifically consider or take steps to reduce spending as a result of the rate impacts and customer concerns.[7]

Board staff's position is that Hydro One should give more specific attention to rate and bill impacts within the customer satisfaction risk criteria, when making decisions on Capital and O&M programs. It appears to Board staff that specific bill and rate impacts should be more explicitly reflected in the investment prioritization process and other decision making tools such as the balanced scorecard. This is especially relevant as updates to this application have significantly increased the bill impacts to customers.

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[2] Exhibit J4.4
[3] Tr. Vol. 3, p. 74
[4] Tr. Vol. 3, p. 95
[5] Tr. Vol. 3, p. 91
[6] Tr. Vol. 4, p. 203
[7] Tr. Vol. 3, p. 81

As for mitigating the absolute level of rate impacts in this application, Board staff addresses this part of the issue in the O&M and Capital Expenditures section of this submission.

Board staff filed a report[8] from the November 2009 issue of Public Utilities Fortnightly on utilities that were mandated by their regulators to cut costs given the current poor state of the economy. In Connecticut, the Connecticut Department of Public Utility Control "…required the Connecticut Natural Gas Corporation to share in the economic difficulties of Connecticut citizens by aggressively managing its operational expenses and capital investments." In New York, the New York Public Service Commission in a Consolidated Edison of New York rates case, indicated that the distributor "…should impose additional cost-cutting measures and directed the company to identify and implement an austerity budget that would reduce its revenue requirement by $60 million for the coming year." Board staff provided this evidence as an example of how regulators in other jurisdictions have responded to the economic downturn.

Board staff also shares the concerns of the intervenors, that the rate increases related to this application, both for distribution rates and Green Energy Plan impacts for all ratepayers (including Hydro One's) will be exacerbated by increasing wholesale market service rates, RTS rates and the impact of the HST.

IMPLEMENTATION DATE CHANGE

Hydro One originally requested a change to its rate implementation date to January 1, 2010. Hydro One's rationale was that the earlier rate implementation date would facilitate the incorporation of the new Hydro One Sub-Transmission (ST) rates by other LDCs into their own rates that would usually take effect on May 1. The new implementation date would also line up Hydro One's financial year with its rate year. The response to Board staff interrogatory H-1-7 indicated that this change would increase Hydro One's revenue by $44 million in 2010.

Hydro One has subsequently indicated that it would not pursue the January 1, 2010 date but would accept an implementation date as soon as possible in 2010 upon the completion of the proceeding but that it was still requesting that 2011 rates be implemented on January 1, 2011. Hydro One did not apply to the Board for interim rates as of January 1, 2010.

Board staff notes that the primary reason for the implementation date change, to allow other utilities to use Hydro One's approved rates as input to their rates, may no longer have validity as a number of other distributors show a desire for a January 1st rate implementation date.

Board staff notes that a Board policy consultation to address the issue of aligning rate years with fiscal years for electricity distributors (EB-2010-0423) has been initiated. Board staff takes no position on Hydro One's request for a January 1, 2011 implementation date at this time.

LOAD and REVENUE FORECAST

Hydro One has demonstrated that its load forecast has tracked actual results in a consistent manner (within one standard deviation) over the past several years.[9] The load forecast for 2010 for the test years including the impact of CDM, is 38,306 GWh electricity delivered to 1,196,000

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[8] Exhibit K4.5
[9] ExhibitA/Tab4/Sch4

distribution customers. CDM and the economic downturn are the major influences on the 2010 forecast resulting in a 4.3 percent decrease from 2008 with a slight increase of 1.3 percent over 2008 customer count. For 2011 the forecast features a continuing decrease in electricity load to 38,049 GWh but customer numbers growing to 1,204,000 (a .07 percent increase).

Response to Board staff interrogatory H-1-12 indicated that while some macroeconomic inputs had changed since the last forecast was produced, these changes were of a minor nature and that the forecast would not be updated.

Regarding the Board's direction in EB-2007-0681, Hydro One was unable to provide a new proposal for incorporating CDM into the load forecast. Hydro One did inform the Board and intervenors that a consulting study had been commissioned but that the results were not available until early 2010 (despite indicating initially in Board staff Interrogatory H-1-11 that the study would be done by September 2009). Hydro One did file a "Net Load Impact of Conservation and Demand Management" report in response to AMPCO interrogatory H-12-2.

Board staff submits that Hydro One should file a comprehensive methodology which incorporates the impact of CDM efforts into the load forecast in their next rate application.

OPERATIONS MAINTENANCE and ADMINISTRATION COSTS

The distribution Operations, Maintenance and Administration (OM&A) Costs 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. While the percentage change for each of the 4 years do not appear at first glance to be excessive, Board staff notes that the 2010 increase over the Board approved 2008 level (of $466 million), is 20% over that two year period.

Board staff also notes that the OM&A expenditures for a test year will have an immediate impact on rates, that is, the high rate impacts in this case are significantly related to OM&A budget increases.

OM&A Expenditures 2008 – 2011
($ million)

Category	2008 Actual	2009 Bridge	2010 Test	2011 Test
Sustaining	**284.5** 4.4%	**296.4** 4.2%	**318.5** 7.5%	**340.5** 6.9%
Development	**8.0** 90.4%	**14.5** 81.2%	**21.7** 49.6%	**21.9** 0.9%
Operations	**12.4** -0.2%	**12.5** 0.8%	**16.7** 33.6%	**17.6** 5.4%
Customer Care	**99.3** 2.3%	**106.7** 7.4%	**106.3** -0.4%	**102.4** -3.7%

Shared Services & Other	**62.9** -31.5%	**92.4** 46.9%	**92.1** -0.3%	**88.1** -4.3%
Tax other than Income Tax	**4.3**	**4.6**	**4.7**	**4.8**
Total	**471.3** -3.1%	**527.1** 11.8%	**560.0** 6.2%	**575.2** 2.7%

OM&A Increases in Relation to Inflation

Reflecting a concern with the increases in the OM&A budget, Board staff submitted interrogatory H-1-14 which asked Hydro One for a scenario where 2010 test year OM&A levels are held to $494 million (assuming a 3% inflationary increase in 2009 and 2010 from the 2008 Board approved level of $466 million.) Hydro One did not provide the requested scenario, but just mentioned that this scenario would increase the risks to its business values.

Board staff notes that inflation itself has tracked at considerably less than 2% as shown in updated forecasts presented at H-3-1, where CPI inflation is shown as 0.9% in 2009, 1.7% in 2010 and 2.0% in 2011. The same exhibit shows a marked reduction in other inflationary pressures for Hydro One:

	2008	**2009**	**2010**	**2011**
Distribution Cost Escalation for Construction (%)	9.2	0.9	-0.1	1.4
Distribution Cost Escalation for O & M (%)	7.6	-2.3	0.1	2.3

In this context, the Board staff scenario in H-1-14 of 3% cost escalation could be viewed as generous. The suggested OM&A level for 2010 of $494 million represents a cut of $66 million from Hydro One's applied for amount. A similar 3% increase for 2011 would yield a level of $509 million and a similar cut of $66 million from applied-for levels.

OM&A Cost per Customer

Board staff interrogatory H-1-15 requested O&M per customer and OM&A per km calculations. These calculations revealed that OM&A per customer grew from $394.9/customer in 2008 to $459.5/customer in the 2010 test year, an increase of 16.3% over the two year period, and 1.7% for 2011. The increase for O&M/circuit km from 2008 to 2010 was 15.8% and 1.4% respectively. These are increases well in excess of the inflationary measures quoted above.

Benchmarking Studies

At the request of Energy Probe, Hydro One filed undertaking J6.8 where several key tables from the First Quartile benchmarking study (first filed at H-1-29) were submitted with the Hydro One bar chart lines identified by year. Hydro One displays the highest Distribution substation O&M expense per installed MVA, and is ranked in the middle-of-the-pack for Substation O&M expense per Asset.

Significant O&M increases

Board staff would point out that there are many areas of significant increases in the OM&A proposal as shown in the table below:[10]

	2010 Test % from 2008 A	2011 Test % from 2010 Test
Sustaining		
- Stations	14.4%	2.0%
- Lines	5.6%	5.7%
- Meters/Telecom/Control	107.0%	12.7%
- Vegetation Management	12.7%	8.5%
Development		
- Data & Studies	65.8%	1.5%
- Standards & Technology	28.9%	2.0%
- Smart Grid S&T ($0 in 2008)	$10 million	$10 million
Operations		
- Operations	42.6%	3.2%
- Operations Support	16.2%	11.6%
Customer Care		
- Base Services	4.3%	-3.0%
- Bad Debt	10.3%	-5.3%
- Reg. Compliance	5.5%	15.8%
- Service Enhancements	106.2%	-24.2%
Shared Services		
- CCFS	20.2%	-1.9%
- Asset Management	66.2%	6.1%
- Information Technology	47.3%	3.5%

OM&A in the Green Energy Plan

Hydro One's proposal for its Green Energy Plan does not include OM&A costs for potential recovery from all ratepayers. Some OM&A costs for Renewable Generation and Smart Grid were identified, but for recovery from Hydro One ratepayers only. The bulk of the Hydro One CDM costs were also identified to be recovered from the OPA.

There was considerable cross examination and discussion regarding this aspect of the plan. Hydro One was able to provide a rough estimate of $10 - 15 million of OM&A costs that were characterized as "indirect" [11] and were also described as costs that would not be incurred if not for the Green Energy Plan.[12] During cross examination, Hydro One witness Mr. Gee indicated that O&M costs may be considered for GE Plan recovery in the future.[13]

[10] Exhibit C1/Tab2/Schedules 2-6
[11] Tr. Vol. 4, p. 159
[12] Tr. Vol. 4, p. 194
[13] Tr. Vol. 6, p. 76

In addition, Hydro One also indicated that roughly $1 million in OM&A costs were to be expended on CDM programs but not for recovery from the OPA. Board staff pointed out that the Board's guidelines for CDM programs EB-2008-0037[14], specifically allow for indirect CDM costs to be recovered from the OPA.[15]

Smart Grid development costs were identified to be recovered only from Hydro One customers, as Hydro One felt that the "... investments will provide significant benefits to Hydro One distribution customers for the future enablement of the Smart Grid."[16] However, under cross examination by CCC, Hydro One conceded that information sharing with other LDCs and ratepayers in the province was desirable along with the potential cost efficiencies that could be achieved.[17] Board staff observes that sharing of results of the Smart Grid pilot could indicate that a portion of these costs should be recovered from all ratepayers.

Increasing Customer Risk due to High Rate Impacts
In cross examination counsel for SEC explored the concept that as rate impacts increased significantly with the application update, that Hydro One should add higher weight to customer satisfaction in the decision risk matrix and reduce expenditures to address that risk.[18] While the Hydro One witness, Mr. Gee, did not fully endorse this concept, staff does see merit in such an approach.

Submission
Board staff submits that OM&A costs should be reduced. It appears to Board staff, that in this time of slow economic growth, job losses, plant closings and reduced inflation (as noted numerous times by the 162 letter writers) that applied-for OM&A costs could be reduced, acknowledging there may be some affect on the business value risks as noted in H-1-14.

Board staff understands that it is inappropriate to micro-manage Hydro One's activities and therefore recommends that Hydro One reduce the OM&A cost envelope in areas they see most appropriate. This submission is made in light of the points made above:

- OM&A cost increases from 2008 are very high.
- Inflation is lower than forecast in the application.
- Cost escalation is lower than forecast in the application.
- OM&A cost per customer and cost per circuit KM are rising significantly and the benchmarking measure showed Hydro One at the top in one measure and in the middle of the range in the other.
- Rate impacts will be higher than originally forecast in the application and more weight should be given to the customer satisfaction business value, with an emphasis on rate impacts.
- Not all avenues of cost sharing with the OPA (regarding CDM expenditures) or with all ratepayers (regarding sharing legitimate GE Plan O&M costs with all ratepayers, or including some Smart Grid costs) were pursued.

[14] Exhibit K3.3
[15] Tr. Vol. 3, p. 33
[16] Exhibit A/Tab14/Sch 2/p.30
[17] Tr. Vol. 1, pp. 57-58
[18] Tr. Vol. 5, pp. 125-127

- Little additional evidence was provided to refute the Mercer report findings on compensation or to show that the $4 million reduction for Transmission should not be proportionally applied to Distribution ($9 million) (see below).
- As shown in the Public Utilities Fortnightly article, other jurisdictions have taken into account the economic situation when approving utility operating budgets.

It is Board staff's submission that reductions to bring the OM&A cost level for 2010 to at least half the Board staff '3% inflation' scenario, are achievable if Hydro One "sharpens its pencil" to operate as efficiently as possible in these times when customers are suffering due to economic difficulties. For 2010, this is defined as approximately $33 million ($560 million less $494 million/2).

Staff acknowledges Hydro One's efforts and accomplishments in reducing the clearing cycle for Vegetation Management, but would also encourage further economies where possible in achieving a goal of greater efficiency and cost reductions. Staff also acknowledges the steps taken by Hydro One to increase efficiencies [19] and while laudable, these efficiency gains are lost in the overall OM&A increase in the application.

Board staff also emphasizes 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.

COMPENSATION and STAFFING

Compensation was raised as a major issue in this proceeding, similar to other recent Hydro One cases. Hydro One's evidence on this issue[20] 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 (excerpts were filed in this case as Exhibit K8.2).

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 noted that it did have success in reducing compensation costs over that period, compared to the other companies. In response to a VECC interrogatory H-7-67, (attachment 3), the PWU table was augmented by Hydro One Brampton figures.

Hydro One highlighted the progress it had made in collective bargaining and the fact that although its work program was expanding by 33% its regular employee count was growing by only 16%. Cross examination revealed the fact that total staffing numbers were growing by 37%[21] and the continuing uninterrupted growth in staffing at Hydro One from 2004 to 2011.[22]

Hydro One has maintained that it needed high wages to attract skilled staff that were in demand across the sector, however cross examination based on the Hydro One Brampton figures

[19] ExhibitA/Tab16/Sch1
[20] Exhibit C1/Tab 3/Sch2
[21] Tr. Vol. 8, p.141
[22] Tr. Vol. 8, p. 133

indicated that even the lower skilled categories showed substantial premiums for Hydro One staff. In particular, stock keepers (17% higher at Hydro One) and labourers (20% higher at Hydro One) were highlighted. Hydro One conceded that it was not having difficulty filling these types of positions.[23]

Hydro One witness Mr. McDonell indicated that the attrition rate at Hydro One was in the 2 – 4 % range and for 2008 was 3.5%. Under cross examination, it was established that of the 171 employees that left the organization in 2008, 116 were the result of retirements and only 55 were non-retirement terminations.[24] Board staff submits that this is an extremely low rate of turnover.

Energy Probe interrogatory H-3-59, showed that Hydro One has not had problems attracting apprentices to any of its trades classifications. Mr. McDonell also indicated that Hydro One was quite successful in hiring apprentices and new graduates. He did note that senior positions were more difficult to fill as well as protection and control engineers, power system engineers and CAD technicians.[25]

It is Board staff's position that Hydro One has not made the case that the findings of the Mercer report as presented in the 2009 transmission case are not valid for the purposes of this application. 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 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 made by the Board in the EB-2008-0272 case. In fact, the argument that high wages are required for attracting highly skilled staff were devalued when non-skilled wages were shown to be substantially higher as well. This means more progress is required in these areas. 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 hiring qualified workers is generally not an issue except for a few specific areas.

These facts all lead staff to conclude that the Board's findings in the transmission case are still valid. In Board staff's view, it is not reasonable to pass excessive compensation costs on to ratepayers. In SEC interrogatory H-10-40, Hydro One provided an estimate ($9 million) of the distribution equivalent of the $4 million reduction in compensation costs ordered by the Board in the EB-2008-0272 transmission case.

Board staff submits that recovery for compensation costs be reduced by at least $9 million in this application. This amount is included in the recommended O&M reduction of $33 million as noted above.

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[23] Tr. Vol. 8, pp. 117-118
[24] Tr. Vol. 8, p. 129
[25] Tr. Vol. 8, pp. 132-133

CAPITAL EXPENDITURES and RATE BASE

Rate Base

Hydro One's forecast distribution rate base for 2010 and 2011 is $4,835.6 million and $5,145.7 million respectively. For 2010, the proposed rate base is 13.9% higher than the approved rate base for 2008 of $4,247.4 million.

Working capital for 2010 is forecast to be $300.7 million for 2010 (11.7% of OM&A and Cost of Power expenses) and $305.4 million for 2011 (11.9% of OM&A and Cost of Power expenses).

Capital Expenditures

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.

Capital Expenditures 2008 – 2011
($ million)

Category	2008 Actual	2009 Bridge	2010 Test	2011 Test
Sustaining	**170.7** 16.2%	**176.5** 3.4%	**185.8** 5.3%	**202.5** 9.0%
Development	**153.2** -0.6%	**167.9** 9.6%	**205.7** 22.5%	**252.4** 22.7%
Operations	**0.9** -55.0%	**2.4** 166.7%	**8.1** 237.5%	**11.2** 38.3%
Shared Services & Other	**110.6** 14.3%	**103.5** -6.4%	**164.8** 59.2%	**110.8** -32.8%
Total	**435.3** -8.8%	**450.5** 3.5%	**564.4** 25.3%	**576.9** 2.2%

Note: Total Development Capital is *net of* $13.3M (2010) and $26.8M (2011) to be funded by generators and *net of* $138.6M (2010) and $235.9M (2011) to be funded by revenues from external sources.

The development expenditures of $205.7 million for 2010 and $252.4 million for 2011 include the Green Energy Plan investments that are proposed to be allocated directly to Hydro One ratepayers; that is $46 million in 2010 and $95 million in 2011. Stand alone development capital expenditure for 2010 is $159.7 and 2011 is $157.4, so without the impact of the GE Plan, development expenditure actually falls.

When the full impact of the Green Energy Plan expenditures (i.e. including the costs Hydro One proposes to recover from generators and all provincial ratepayers) is included, Hydro One capital expenditures grow to $716.3 million in 2010 and $839.6 million in 2011. This represents an increase of 59% in 2010 and 17.2 % in 2011.

Investment Planning and Prioritization Process

Hydro One's planning process can be broadly divided into four steps. First, asset planners are required to determine a list of investments for the various investment categories based on the assumption that no constraints exist. After a series of challenges the list of investments is finalized. Next this list undergoes a prioritization process resulting in a portfolio of individual investments that together make up a preliminary Investment Plan. Third, the preliminary Investment Plan is reviewed by senior management who may further modify it based on various considerations.[26] The end result is a prioritized Investment Plan proposal, which is recommended to the Hydro One Board of Directors for approval as part of the Corporation's business plan.

Hydro One's prioritization process considers risk mitigation against the dimensions of the set of business values to select the proposed levels of investment. The process incorporates a probability-severity-of-outcome risk matrix to determine the impact ratings for each business value. The Probability scale ranges from Remote to Very Likely and Severity of Outcome scale ranges from Minor to Catastrophic. The accomplishment levels are established and evaluated for a period of five years. The lowest level of investment is referred to as Minimum Level. Minimum Levels of investment are those required to avoid unacceptable risk. The area regarded as unacceptable risk is identified in Table 2 of the Investment Prioritization Process exhibit.[27]

In VECC interrogatory H-7-39, Hydro One provides the results of the prioritization process. This interrogatory identifies the Minimum Level of investments for Hydro One's capital expenditure budget. The capital expenditure budget based on Minimum Level of funding in 2010 is $487 million, compared to the as-filed budget of $564 million. Similarly, the Minimum Level in 2011 is $505 million, compared to the as-filed $577. In both years, the Minimum Level funding is approximately 13% (or $75 million) lower than Hydro One's filed budget.

Hydro One indicated that if an area of business were limited to only Minimum Level of investment over the planning period, it is very probable that an unacceptable risk would be realized.[28] In cross examination the witness stated that the Minimum Level funding is intended to keep the investment outside of the area of unacceptable risk, however with time the probability of an occurrence increases.[29] Further, Hydro One states that "in the absence of any specific risk tied to a shorter timeframe within the 5 year planning horizon, <u>specific investments may be rescheduled from one time period to another within the 5-year planning horizon</u>.

[26] Exhibit A/Tab14/Sch5/p. 2
[27] Exhibit A/Tab14/Sch6/p.8
[28] Tr. Vol. 3, p. 140
[29] Tr. Vol. 3, pp. 164 & 165

[Emphasis added] In cross examination the witness confirmed that investments are moved around, albeit from one year to another.[30]

The average year over year increase in capital spending from 2006 to 2009 is approximately 6%. In 2010, Hydro One proposes to increase capital spending by 25%. Board staff acknowledges that a portion of this increase is attributable to Green Energy Plan investments. While the probability of an occurrence that may impact a business value over the 5 year planning period increases under Minimum Level funding, Board staff notes that Minimum Level funding by definition is intended to mitigate unacceptable risk. Board staff also notes that Hydro One does on occasion re-prioritize projects to mitigate operational concerns.

Given the sizeable increases proposed in this application and the fact that Hydro One has the ability to re-prioritize projects, Board staff invites parties to comment on the appropriateness of deferring certain capital investments beyond the test years. Board staff submits that a re-prioritization of capital programs could allow Hydro One to focus on Green Energy Plan investments and may also alleviate some of the impact on customers.

The economic indicators used in the business planning process were already discussed under Operations and Maintenance above. The reduction in the rate of inflation and in the distribution costs escalators were discussed in the context of overall revenue requirement and O&M increases.

As noted in the updates filed at H-3-1, the cost escalator for construction for 2009 fell from 1.8% in the original application to 0.9% in the update. The cost escalator for construction for 2010 fell from 1.3% in the original application to -0.1% in the update. For 2011, the update of 1.4% was very close to the original 1.3%.

In cross examination Hydro One stated that it does not plan to update the as-filed capital budget based on the revised number. Hydro One argued that "in any forecasting process, once it's out the door, it already is subject to the vagaries of change, and we're well aware that some of the factors have changed in the economic indices, but there are many other factors that go plus and minus".[31]

Given the significant size of the capital plan and the substantial drop in the value of the escalators, in both 2009 and 2010, Board staff submits that Hydro One should revise its capital expenditure estimates to account for the change in the escalator. Parties are invited to comment on this proposal.

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[30] Tr. Vol. 3, p. 159
[31] Tr. Vol 3, pp. 103-104

Board staffs concerns with specific capital programs under the four investment categories are outlined below.

Sustaining Capital

Hydro One's capital budget related to Sustainment investments is $186 million in 2010 and $203 million in 2011. Capital expenditures related to Sustaining programs make up approximately 1/3 of the total capital budget.

Hydro One manages its Sustaining capital program within three program categories: Stations, Lines, and Meters. The Lines program makes up over 90% of the total Sustaining capital budget. The test year budget for the lines program is $168 million in 2010 and $183 million in 2011.

The Lines program is further sub-divided into three categories – Trouble Call and Storm Damage, Joint Use and Relocation Programs and Asset Replacements.

The Asset Replacement program category makes up over 50% of the total lines budget. Hydro One proposes to spend $78 million in 2010 and $94 million in 2011. A significant portion of this spending is related to the Wood Pole Replacement program and is summarized in Table 4, at D1/T3/S2/p. 20. Board staff's concerns relate to the Wood Pole Replacement program capital budget.

Wood Pole Replacements

Based on inspection results accumulated up to the end of 2008, Hydro One estimates that approximately 5% of the wood poles in the system are in "Poor" to "Very Poor" condition. Those poles that are found to be in poor conditions are replaced as part of the Wood Pole Replacement program.[32]

Hydro One proposes to replace 7,500 poles in 2010 and 9,500 poles in 2011. The capital needed is $46 million in 2010 and $59 million in 2011. Hydro One argues that due to the changing demographics of the system's pole plant, an increasing number of poles will need replacement. Hydro One also states that planned replacement of poles will be less costly than emergency/reactive replacements.

In Board staff interrogatory H-1-81 Hydro One provided a summary of the capital expenditures and number of poles replaced over the 2006 to 2009 period. From 2006 to 2009, Hydro One has replaced a total of approximately 26,000 poles under the wood pole replacement program. In 2010 and 2011 Hydro One proposes to replace 17,000 poles. The total capital spent over 2006 to 2009 was $155 million, while the capital requested in the test years is $105 million.

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[32] Exhibit D1/Tab3/Sch2/p. 20

In addition to the concerns with pole demographics, Hydro One has also identified 55,000 red pine poles that contain premature rot and need to be replaced. As part of that replacement program, Hydro One is proposing to replace the first set of 500 red pine poles in 2010 and another 2,000 poles in 2011. Therefore of the 17,000 poles to be replaced in the test years, 2,500 are red pine poles.

Board staff submits that Hydro One's proposal to replace 17,000 poles in two years is a significant increase from prior years. On an average basis, over the 2006 to 2009 historical period Hydro One replaced approximately 6,445 poles per year. In the test years, Hydro One proposes to replace on average 8,500 poles per year. This represents an average increase of 32% over the historical trend and a 35% increase in costs. Approximately 20% of the increase in pole replacements is due to red pine pole replacements.

The Wood Pole Replacement program is a necessary and useful program and Board staff agrees that the red pine pole issue needs to be addressed. However, red pine poles affect a very small subset of Hydro One's total 1.7 million poles and Board staff questions the appropriateness of having a separate accelerated red pine replacement program in addition to the regular Wood Pole Replacement program. Board staff also notes that in addition to the poles that are proposed to be replaced under the Wood Pole Replacement program a "significant" number are also replaced through other distribution capital programs.[33] In that regard Board staff questions if some of the red pine pole replacements can also be handled through the other programs.

Board staff invites parties to comment on whether it is appropriate to incorporate the red pine pole replacements as part of the regular maintenance schedule, at least in the two test years.

Operations Capital

Operations Capital investments are found at Exhibit D1/Tab3/Sch4 and are used to enhance and modify the physical infrastructure, systems and tools required for distribution operations. Hydro One proposes to spend $8 million in 2010 and $11 million in 2011. The 2010 budget $6 million higher than capital expenditures in 2009 and the 2011 budget is $3 million higher than 2010.

A significant portion of the increase in test year capital expenditures is driven by investments in Hydro One's Green Energy Plan. The prudence of capital expenditures in the Green Energy Plan are addressed in Board staff's submissions under issue 9.

[33] Tr. Vol. 5, p. 48

Development Capital

Development Capital investments are needed to connect new load and generation customers and to enhance existing, or construct new, distribution facilities. Hydro One proposes to spend $206 million in 2010 and $252 million in 2011.

The Development Capital budget is found at Exhibit D1/Tab3/Sch3/p. 2 and is divided into the categories of Connections, Upgrades and Cancellations, System Capability Reinforcement, Generation Connections, Generation Connection Enhancements, Wholesale Revenue Meters and Smart Grid.

The 2010 Development Capital budget is 23% (or $38 million) higher than in 2009 and the 2011 budget is 23% (or $47 million) higher than 2010. A significant portion of the spending is related to investments in the Green Energy Plan. Board staff's concerns with those capital programs are addressed under issue 9.

Connections, Upgrades and Cancellations

At the oral hearing, VECC raised two issues with respect to Hydro One's interpretation of the DSC. The first deals with Hydro One's interpretation of certain expansion and enhancement activities in the DSC. The second issue deals with Hydro One's interpretation of section 3.3.4.

In VECC interrogatory H-1-83 (d), Hydro One was asked to provide "the types of investment activities it considers to be "enhancements" as opposed to "expansion" for the purpose of applying the cost recovery provisions of the DSC, particularly with respect to load and non-renewable energy generation customers".

In its response Hydro One stated, "Hydro One will use the same definitions for expansion and renewable enabling improvements for non-renewable generation customers as those that have been proposed for renewable generation customers in the DSC". Hydro One also identified the activities in each category, based on its interpretation of the DSC:

> Expansion activities as interpreted by Hydro One are:
> 1) building a new line,
> 2) upgrading an existing single phase line to three phase,
> 3) bringing in a higher voltage line to supply loads above 500 kW.
>
> Enhancement activities as interpreted by Hydro One are:
> 1) increasing the size of the distribution station transformer,
> 2) re-conductoring an existing line,
> 3) modifications to, or the addition of voltage regulating equipment,
> 4) increasing the size of the breakers or reclosures, and

5) modifications that improve system operating characteristics such as the ability to change supply configurations.

VECC noted that the first three activities that are considered to be enhancement activities by Hydro One are in fact categorized as expansion activities in section 3.2.30.[34]
In undertaking J6.5, Hydro One further clarified its position and states:

> "If an individual or group of customers being connected is the sole reason for any of the main distribution system changes described in 3.2.30 of the DSC, Hydro One does treat this as an expansion and the costs are borne by the connecting customer(s) as per section 3.2.1 of the DSC. Typically this requires a large load connection for the required main distribution system changes to be specifically attributed.
>
> Where there has been system wide load growth over a period of time, the required main distribution system changes are considered an enhancement per section 3.3.1 of the DSC. Under this situation, enhancements to the main distribution system can include the same type of investments as described under expansions in section 3.2.30 and detailed in the response to interrogatory Exhibit H, Tab 7, Schedule 83".

In cross examination, Hydro One noted that if the Board finds that the activities it has interpreted to be enhancements are in fact expansion, the impact would be a reduction of $2 million per year in the Connections, Upgrades and Cancellations program capital budget.[35] The reason being that unlike enhancement activities, expansion activities attract capital contributions and would be recovered through capital contributions.

Board staff invites parties to comment on Hydro One's interpretation of expansion and enhancement activities in the DSC.

The second issue raised by VECC deals with the interpretation of section 3.3.4 of the DSC. The DSC states that:

> 3.3.3 Subject to section 3.3.4, the distributor shall bear the cost of constructing an enhancement or making a renewable enabling improvement, and therefore shall not charge:
> (a) a customer a capital contribution to construct an enhancement; or
> (b) a customer that is connecting a renewable energy generation facility a capital contribution to make a renewable enabling improvement.
>
> 3.3.4 Section 3.3.3(a) shall not apply to a distributor until the distributor's rates are set based on a cost of service application for the first time following the 2010 rate year.

[34] Tr. Vol. 6, p. 38
[35] Tr. Vol. 6, p. 55

VECCs interpretation of section 3.3.4 is,

> "That suggests to me that the new rules won't apply for the 2010 rate year, and that because this application is to be considered before the 2010 rate year, it wouldn't apply to 2011 either".[36]

Hydro One's position was provided by Mr. Gee:

> "And I understand that could be the reading of that, and, if that's the case, we're fine. What you have as an impact is that we would not apply that case for now, but also individual load customers would have to pay the higher contributions that you set. So as long as we line them up both -- our read was this is the 2010 cost of service ratemaking. It's going for two years. We will apply it at this point, and, after 2010, it is in place, but we are fine with however the approach is, as long as we do both sides of it".[37]

Board staff invites parties to comment on the Hydro One's interpretation of section 3.3.4.

Shared Services & Other Capital

Capital expenditures under the Shared Services program support the Sustainment, Development, and Operations work programs of both the Transmission and Distribution businesses.[38] Shared Services assets include information technology, Cornerstone Initiative, Facilities and Real Estate ("FRE"), Transport and Work Equipment ("TWE"), Service Equipment, CDM and Other.

The Distribution portion of the total Shared Services capital budget for 2010 is $165 million and $111 million for 2011. The 2010 budget is 59% (or $61 million) higher than capital expenditures in 2009, the 2011 budget is -33%, or $54 million lower than 2010.

Over 50% of the test year capital expenditure is driven by the TWE category.[39] TWE provides vehicle and specialized equipment support to work programs across the company. Hydro One proposes to spend $101 million in 2010 and $56 million in 2011. This represents a significant increase in TWE spending compared to historical years. The test year total of $157 million is higher than the total TWE capital expenditure from 2006 to 2009 of $132 million.

Hydro One states that TWE expenditures are based on the number of vehicles required to execute the planned work programs, additional staffing requirements and the additional Distribution and Transmission work requirements as a result of the GEGEA.

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[36] Tr. Vol. 6, p. 41.
[37] Tr. Vol. 6, p. 56
[38] Exhibit D1/Tab3/Sch5
[39] Exhibit D1/Tab3/Sch 9

With respect to the initiatives in the GEGEA driving the need for the increase TWE spending, Hydro One explained,

> "...as a result of the GEGEA and the OPA's anticipated Feed-In-Tariff, Hydro One Distribution anticipates a significant increase in workload associated with Generation Connections. Due to this increase in volume, Hydro One Distribution is preparing to conduct work associated with connections (e.g. building line taps, upgrading conductors and poles, installing new protective devices) and this will place significant pressure on labour, TWE and Service Equipment".[40] [Emphasis added]

Hydro One estimates the total (Transmission and Distribution) impact of the increased work programs as a result of the GEGEA to be approximately $117 million over the two test years.[41] Based on the proportions provided in evidence, Board staff estimates the impact on the Distribution portion to be approximately $89 million.

Hydro One expects to connect 468 generators by 2011.[42] A majority of these connections are expected from the FIT program. Based on the response in undertaking J1.6, it appears that the take-up of the FIT program (250 connections) has been lower than that estimated by Hydro One. Board staff is therefore concerned that if the take-up of the FIT program is less than estimated, the portion of the TWE budget that is driven by GEGEA work programs may be overstated.

Board staff submits that given the uncertainties with one of the key assumptions of the TWE budget, the Board may wish to consider if a deferral account mechanism is appropriate for these expenditures.

CAPITAL STRUCTURE and COST OF CAPITAL

Cost of Capital

Board staff notes that Hydro One has indicated that it expects that the return on equity and cost of capital parameters will be updated and adjusted to reflect the results of the EB-2009-0084 Cost of Capital Report. [43]

Board staff submits, that while Hydro One has used a 9.75% Return on Equity (ROE) in the undertaking on the Cost of Capital impact (J4.4), that this should not be the final number. Board staff submits that the final cost of capital parameters, to be published in February 2010 based on January 2010 data using the formulae in the Board's Report, will determine the ROE and

[40] Exhibit D1/Tab3/Sch9/p.1
[41] Exhibit D1/Tab3/Sch9/p. 5
[42] Exhibit D1/Tab3/Sch3/p.11
[43] Tr. Vol. 11, p. 37

other applicable rates for determination of the final revenue requirement for rate setting purposes.

Board staff also notes that during the oral hearing, reference is made to an Energy Probe interrogatory H-3-29 where Hydro One debt issues for 2009 are listed. Mr. Van Dusen testifies that he believes the debt instruments list submitted by Hydro One would not be updated.[44]

Board staff submits that the Cost of Long-term Debt used by Hydro One should be updated to reflect the actual debt instruments used by the utility. This is in accordance with the Cost of Capital Report, which states at page 53,

> "…the onus is on the distributor that is making an application for rates to document the actual amount and cost of embedded long-term debt and, in a forward test year, forecast the amount and cost of new long-term debt to be obtained during the test year to support the reasonableness of the respective debt rates and terms." Further, on the same page of the Cost of Capital Report: "**The Board will primarily rely on the embedded or actual cost for existing long-term debt instruments.**" [Emphasis in original]

Since Hydro One Networks has executed some of the new debt forecasted in late 2009, Board staff submits that actual interest expense in the test year based on the now known terms for this recent debt, rather than that forecasted originally 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.

DEFERRAL and VARIANCE ACCOUNTS

Hydro One is proposing to clear the balances in certain deferral and variance accounts, and also establish 5 new accounts.

Clearance of Accounts

Hydro One is requesting disposition of certain deferral/variance account balances as at December 31, 2009. The principal balances and interest in these accounts are forecast beyond December 31, 2008 audited balances. The accounts being requested for disposition and the balances are summarized in the table below.

[44] Tr. Vol. 4. pp. 198-199

Table 1: Deferral/Variance Account Balances[45]			
Account Number	**Description**	**Balance at December 31, 2008 ($ millions)**	**Balance at December 31, 2009 ($ millions)**
1518/1548	RCVA	(1.7)	(1.9)
1555 and 1556	Smart Meter Minimum Functionality Under-recovery Jan. 1 to Dec. 31, 2008	.9	.9
1555 and 1556	Smart Meter Exceeding Minimum Functionality Under-Recovery between Jan. 1 to Dec. 31, 2008	1.1	1.1
1580	RSVA Wholesale Market Services	(11.4)	(18.7)
1584	RSVA Tx Network & Tx Network Aggregation	(14.0)	(7.2)
1586	RSVA Tx Connection & Tx Connection Aggregation	(2.9)	.8
1588 Sub-account Global Adjustment	RSVA Provincial Benefit	5.5	19.6
1550	RSVA Low Voltage	1.9	2.6
1590	Regulatory Asset Recovery Phase 1	(18.7)	(23.0)
	Total Requested for Disposition	**(39.3)**	**(25.8)**

Hydro One is proposing to refund the regulatory asset total balance of $(25.8) million, or $(12.9) million per year, starting January 1, 2010 over a two year period. Hydro One's application assumes that distribution rates will be effective January 1, 2010.

Should the Board approve forecast principal balances for disposition?

Hydro One is requesting recovery of forecast principal balances to April 30, 2009, and carrying charges to December 31, 2009, for all accounts (except Smart Metering, for which recovery is requested to December 31, 2008) as summarized in Table 1 above. The principal balances in these accounts are forecast beyond December 31, 2008 audited balances. Board staff is concerned with Hydro One's proposal to recover forecast principal balances, rather than audited principal balances, as is the usual practice.

It is common practice for natural gas utilities when requesting disposition of deferral and variance account balances to forecast principal and interest on these balances to the end of the current Bridge year. These forecasts typically do not exceed two or three months and are updated before a decision is issued. The forecast balances are then trued up to the actual and any differences are recorded in a deferral account for disposition at a later date.

[45] Exhibit F1/Tab1/Sch1 and Exhibit H/Tab1/Sch110

This is not the practice in the electricity sector. The usual practice of the Board in the electricity sector is to rely on the most up-to-date audited balances, plus forecast of carrying charges to the start of the new rate year on those balances. The Board has adopted this approach in most cost of service applications in recent years.

Board staff submits that in this case the December 31, 2008 balances are the most recent audited values.

Hydro One explains that it is requesting disposition of regulatory asset balances up to December 31, 2009, as forecast balances are "reasonably predictable".[46] In response to Board staff interrogatory H-1-112, Hydro One cited the EB-2007-0681 Board decision as a precedent for clearing deferral and variance account balances based on unaudited amounts. However, during cross examination by VECC[47], the Hydro One witness agreed that the Board decision cited "extenuating circumstances" as the reason for approving unaudited balances for disposition. These circumstances included the fact that the proposed disposition led to higher refunds to customers, which then helped offset the substantial rate impacts. The witness also agreed that, disposing of the unaudited balances will increase the total bill impact relative to using the audited balances[48].

Board staff submits that only disposition of the audited balances at December 31, 2008, would be consistent with the larger body of practice associated with electricity distributors and most of the recent cost of service decisions. However, it must also be noted that forecast principal balances were approved by the Board in Hydro One's 2006 cost of service proceeding (RP-2005-0020 / EB-2005-0378)[49]. Both options have been employed by the Board and staff seeks comments from parties on whether the benefits to clearing forecast amounts outweigh the potential disruption once amounts are confirmed in an audit.

Hydro One has requested disposition of these balances over a two year period. In Board staff interrogatory H-1-116, Hydro One was asked to calculate rate-riders based on a one year disposition. Board staff notes that clearing these balances (which are credits to customers) over a shorter time period will reduce rate impacts in 2010 and therefore submits that these balances be cleared over a one year period, rather than the two year period requested.

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[46] Exhibit F1/Tab2/Sch1/p. 1
[47] Tr. Vol. 9, pp. 162-164
[48] Tr. Vol. 9, p. 166
[49] Exhibit H/Tab1/Sch 112

How should Hydro One comply with the Board Order to record the line loss variance in account 1588 RSVA Power?

Hydro One is excluding the variance relating to distribution system losses from account 1588 RSVA – Power. The distribution system loss variance is the difference between the dollar value associated with actual line losses and the value of line losses arising from applying the Board approved line loss factors to customer metered quantities.

In Board staff Interrogatory H-1-110, Hydro One stated that "Hydro One is inherently assuming that we sell everything that we purchase such that there is no difference to be accumulated in the RSVA-Power account." This treatment is not consistent with Article 490 of the APH, which states:

> "The $RSVA_{Power}$ account is established for the purpose of recording the 'net difference' in energy cost only. 'Net difference' refers to the difference between the amount charged by the IESO, host distributor or embedded generator based on the settlement invoice for the energy cost and the amount billed to customers for the energy cost. Note that these differences could be composed of differences in energy price and/ or energy quantities <u>as well as the difference between estimated and actual line loss factors</u>."[Emphasis added]

In the Recovery of Regulatory Assets – Phase 2 Decision (RP-2004-0117, RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064), section 2.0.27, the Board directed Hydro One to "...include line loss variances in Account 1588, consistent with the other three Applicants and APH490."

At the oral hearing[50] Hydro One submitted that, "Hydro One has determined that there is no practical and cost-effective way of accomplishing the measurement of actual line losses." Hydro One further explained that this issue came up in the 2006 distribution rates hearing for Hydro One, and cited two exhibits from that hearing by way of an explanation. Board staff submits that the first document referenced: EB-2005-0378 (Exhibit H/Tab4/Sch64) is a discussion of whether Hydro One's loss factors are reasonable, and the second cited exhibit is a study by Kinectrics of Hydro One's line losses. Staff submits that accounting for under/over-recovered losses is quite different from loss factors, and even when loss factors are considered reasonable, there may still be a difference between the actual dollar value of losses and those recovered in rates. Accounting for losses would mean that the difference between actual cost of power and actual billings is booked in account 1588. This is a calculated number and does not require special meters to provide accurate reading. Board staff submits that other LDCs, large and small, rural and urban, are able to calculate line loss variances in account 1588 whereas Hydro One has stated that it is not able to do so.

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[50] Tr. Vol. 10, p. 77

The loss factors for Hydro One range between 1.061 and 1.092, as per the current Tariff Sheet. A chart prepared by Board staff was presented at the oral hearing[51] showing that the actual kWh of line losses are in fact measured by Hydro One and reported to the Board under the RRR filing requirement 2.1.5. This chart shows that the actual line losses are in the range of 7.3%.

This issue relates specifically to the recording of the dollar value of variances between the Board approved losses recovered in rates, and actual line losses, in existing deferral accounts that were established for this very purpose. Board staff submits that there is a difference between the cost of actual line losses, and what is reflected in rates, and this difference should be reflected in account 1588. Board staff submits that a difference of .5 basis points in the line loss factor (e.g. 1.075 vs. 1.07) will result in $10 million difference in what is collected in rates, and what is paid for the line losses. In light of this, the actual gain or loss in relation to the approved line loss factor is being reflected elsewhere else in the accounts of Hydro One and may or may not have been included in the revenue requirement.

Board staff is also concerned that going forward without the variance account information, parties will be unable to assess the reasonableness of the loss factors chosen. Board staff submits that Hydro One should address this issue.

Should Global Adjustment/Provincial Benefit be cleared to all customers?

Hydro One has balances of $5.5 million in 2008 and $19.6 million in 2009 in its Global Adjustment/Provincial Benefit account as of Dec. 31 and described this account in this manner:

> "RSVA Provincial Benefit is related to Wholesale Market Service charges that are billed by Hydro One Distribution to customers that are non-market participants. Energy for non-market participants is the allocator proposed for this account amongst customer classes."[52]

Although, Hydro One used the allocation factor that was in accordance with the EDDVAR report[53], it has not proposed a separate rate rider to dispose of Global Adjustment/Provincial Benefit to non-RPP customers only.

Board staff submits that Hydro One should establish a separate rate rider for the disposition of the global adjustment sub-account balance. This issue has arisen in a number of other current cost-of-service rate cases. The rate rider would apply prospectively to non-RPP customers, and would exclude the MUSH sector and other designated customers that were on RPP. Board staff submits that recovering the global adjustment sub-account balance solely from non-RPP customers would be more reflective of cost causality as it was that group of customers that were

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[51] Tr. Vol. 10, p. 81
[52] Exhibit G1/Tab5/Sch1
[53] EB-2008-0046

undercharged by the distributor in the first instance. Another alternative is to recover the allocated global adjustment sub-account balance from all customers in each class. This approach would recognize the customer migration that might occur both away from the non-RPP customer group and into the non-RPP customer group.

In addition to the decision on whether a separate rate rider should be established for the disposition of the global adjustment sub-account, the Board must decide on the time period over which the rate riders should apply. Board staff submits that customer migration might occur in the low volume group. For this group of customers, there would be a benefit to dispose of the global adjustment sub-account balance over a relatively short period of time in order to reduce inter-generational inequities. Board staff submits that a disposition period no longer than one year would be appropriate, and a delay in disposition is not in customers best interests. Board staff recognizes that some volatility in electricity bills may result. That aside, Board staff believes that a one year disposition period would be appropriate.

Should the Board approve the use of the new deferral accounts requested by Hydro One?

Hydro One is requesting Board approval for five new deferral accounts. These are the Pension Cost Differential Account, OEB Cost Differential Account, Impact of Changes in IFRS, Fixed Charge for Micro-Generators, and Bill Impact Mitigation Account.

OEB Cost Differential Account

With respect to the new variance account to record OEB Cost Differential, Board staff notes that Hydro One had requested this account in EB-2007-0681. The Board denied the request and stated:

> "The Board does not consider it reasonable in this case to exempt Hydro One from the Board's current policy not to authorize an OEB cost variance account to distributors".

In response to Board staff interrogatory H-1-118 on this issue, Hydro One pointed to the Board Decision in EB-2008-0272 as a precedent for this account. During the oral hearing[54] the Hydro One witness agreed that the applicant is seeking to track the difference between approved and actual costs for 2010 and 2011 with respect to OEB cost assessments, intervenor cost awards and costs associated with OEB-initiated studies. The witness also agreed that in EB-2008-0272, the variance that was tracked related solely to the OEB assessment costs, and that it is not a "direct precedent for the additional two aspects of the account".

[54] Tr. Vol. 9, pp. 157-158

Board staff also notes that the Board disallowed a similar request in the Toronto Hydro 2008 rates case and stated that this matter required a sector-wide approach through the APH or direction by the Board through another instrument[55].

Board staff submits that the continuance of the variance account to track the differential in OEB assessment costs only, should be considered by the Board.

Impact for Changes in IFRS Account

This proposed account is intended to track the difference between costs in the current revenue requirement and any difference in revenue requirement due to changes in the application of IFRS standards once they are approved[56].

Board staff points out that the creation of such an account has been specifically considered by the Board, and rejected. Board report EB-2008-0408 dated July 28, 2009 "Transition to International Financial Reporting Standards" (Appendix 2, article 8.2), in part, states:

> "The Board will establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS. This account is exclusively for necessary, incremental transition costs, and is not to include ongoing compliance costs or <u>impacts on revenue requirement arising from changes in the timing of the recognition of expenses.</u>" (Emphasis added.)

Board staff submits that this account not be approved.

COST ALLOCATION and RATE DESIGN

Hydro One's complete cost allocation and rate design evidence is found at Exhibit G1. Board staff will address only those cost allocation and rate design related issues that, in Board Staff's opinion, require some comment or adjustment.

Harmonization and Impact Mitigation

As a result of application updates, Hydro One filed updated rate schedules (Exhibit K9.1). Hydro One proposed to continue the pattern of mitigation approved in the previous cost-of-service application (EB-2007-0681). The guideline used by Hydro One is to limit the impact of changes in delivery cost to 10%, calculated as a percentage of the total bill of an average customer in any given class.[57]

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[55] EB-2009-0680 Decision, p. 69
[56] Exhibit F1/Tab1/Sch 2; Exhibit H/Tab 1/Sch119
[57] Tr. Vol. 9, p. 19

The impact of other changes that may affect the total bill (but are not components of the delivery cost) are not factored into the mitigation plan and the proposed distribution rate design is not modified if there are increases in these other factors.[58] As a result of the update, using 10% as the maximum impact and considering only the delivery cost, the end point of the harmonization process has become 2012 for some acquired LDCs, rather than 2011 as assumed earlier.

The rate design for 2008 rates also included rate relief for small customers that would have experienced a bill impact over 15%. Staff notes that Hydro One has requested approval to continue the variance account associated with this mitigation, and has spent $100,000 to modify its billing system.[59] Staff assumes that Hydro One intends to extend this impact mitigation measure in the future and requests that Hydro One confirm this in its Reply Submission.

Density Criteria and Study

Hydro One has three Residential classes distinguished by density criteria:[60]

- UR: 3,000 or more customers with a line density of at least 60 customers per kilometre
- R1: 100 or more customers with a line density of at least 15 customers per kilometre
- R2: smaller than 100 customers or less than 15 customers per kilometer.

While individual customers or groups of customers may be re-classified as the density or number of customers in their locality changes over time, the criteria for the class definitions have not been re-examined.

In Hydro One’s most recent distribution cost-of-service application (EB-2007-0681), the Board heard argument that the density criteria should be re-examined, and the Board provided the following direction (p. 31):

> “…..the Board directs Hydro One to provide a more detailed analysis on the relationship between density and cost allocation to the Board. This should consider whether the number of Residential and General Service customer classes in the new class structure is adequate, and whether the customer class demarcations approved in this Decision offer the best reflection of cost causation. The study should include consideration of alternative density weightings, with descriptions and criteria for comparing alternatives. Comparisons with the costs of distributors similar in size and location to Acquired Distributors would also be useful. The Board requires that Hydro One submit this information in its next cost of service application.
> It would have assisted the Board if Hydro One had been able to provide a cost study relating to the customers in the territories of the Acquired Distributors. Hydro One’s response to this issue is that it does not have the necessary data because it only has “one set of books”. The Board must accept that as a fact. However, as is indicated above, the Board expects Hydro One to provide comparative analysis to allow the Board to better assess cost differences between the Legacy and Acquired customers.”

[58] Tr. Vol. 9, p. 93
[59] Tr. Vol. 9, p. 159
[60] Exhibit G2/Tab 4/Sch2/p. 4

The Board's summary of the CME and SEC argument under the issue of impacts is also helpful (p. 42):

> "… the customers most adversely affected are the customers of the former municipally owned utilities which Hydro One has acquired, the Acquired Distributors. Hydro One justified the rate increase that its harmonization proposal imposes on customers of Acquired Distributors on the grounds that they are being subsidized by the legacy customers. As stated earlier in this Decision, both CME and SEC questioned whether these customers really are being subsidized. They stated that it is equally possible that they have lower costs and the lower rates reflect those lower costs. CME noted that many of the utilities acquired by Hydro One are in more urban communities and may exhibit lower costs than those experienced in Hydro One's primarily rural system."

Staff notes that the direction to file the detailed analysis with the next cost of service application was given in early 2009. The assumption at that time was that Hydro One would be filing an IRM application in 2010, which would have allowed for more time to do the work prior to the next cost of service application. [61]

In Board staff interrogatory H-1-123, Hydro One submitted that a staged approach to this finding is appropriate. As the first stage, a report prepared by John Todd of Elenchus Research Associates on alternative methodologies was filed at ExhibitG1/Tab2/Sch5. SEC also filed evidence on density based rates, by Dr. C.K. Woo, of Energy and Environmental Economics Inc. (Exhibit K4.3)

Staff submits that the Board should repeat its direction to Hydro One for its next cost-of-service application. Hydro One provided several reasons that results of the study should be delayed or perhaps not implemented at all. The complexity of the on-going rate harmonization, and uncertainty about future rate design throughout the province were cited.[62] Staff submits that these considerations do not diminish the need for the study of costs, even if they might not lead immediately to changes in the rate tariff.

Hydro One has the responsibility to decide on the most informative and cost-effective methodology. Mr. Todd's report along with the expert testimony of Dr. Woo contains a number of alternatives and discussions of their likely advantages and disadvantages.

Staff notes that both experts have pointed out that it is more usual in other jurisdictions to have rate class boundaries coincide with municipal boundaries. However, even with this method Dr. Woo has recommended that different definitions of "urban" versus "rural" would be developed, and compared to each other empirically to see which split yields a reasonable reflection of cost, fair cost apportionment and acceptable impacts as noted at Interrogatory H-7-5.

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[61] Tr. Vol. 10, p. 49
[62] Tr. Vol. 9, p. 12

Hydro One indicated that it would appreciate some direction from the Board on which alternatives should be investigated.[63] Board staff supports the general approach found in Hydro One's existing density-based rates. Staff submits that it is generally accepted that the distance between customers along a feeder, and the number of customers located in close proximity in a locality, are factors that do affect the cost of the distribution system, and Hydro One has indicated that it does find cost differentials amongst the classes that are defined by these factors.[64] Other density-related factors are listed on page 2 of the Elenchus Report and in Dr. Woo's testimony and response to VECC Woo interrogatory 2. (Exhibit K5.1)

Staff submits that the Board should encourage Hydro One to proceed with the analysis of sample data (described in section 5.2.3 of Mr. Todd's report or with the engineering study method (section 5.2.4) or a combination of these methods.

Hopper Foundry

Hopper Foundry has paid for its electricity distribution services on a time-of-use rate structure since 1981, when as a customer of Forest PUC, according to correspondence filed as Exhibit K7.5. In 1992, the company received a grant under Ontario Hydro's Load Shifting Program. In Hydro One's previous cost-of-service application (EB-2007-0681), the Board heard testimony that the time-of-use distribution rate has been extended to Hopper Foundry as part of an experiment over a number of years, and the Board ordered that Hydro One should continue that status until April 30, 2010. The Board noted that the two-year extension would enable Hopper Foundry to explore its options and to take steps in preparation for paying an ordinary approved distribution rate.

The Board has been presented with three main alternatives for the distribution rate structure:

- a further extension of the status quo time-of-use rate structure,
- the General Service Demand-billed class in Forest, which is the approved rate class that Hopper Foundry would be in ordinarily,
- extending the Sub Transmission (ST) class to include Hopper Foundry and 13 other customers, as described by Hydro One at Exhibit G1/Tab9/Sch1.

Board staff submits that a fourth alternative could be to order a gradual phase-out of the time-of-use rate differential, establishing a succession of rates designed to make a smooth transition and arrive at the General Service rates over a period of several years.

It is Board staff's understanding that Hopper Foundry already pays a non-time-of-use transmission service rate, and that (regardless of the distribution rate structure) has and will continue to have access to the market price for the electricity commodity.

[63] Tr. Vol. 9, p. 11
[64] Tr. Vol. 9, p. 140

Hydro One witness, Mr. Roger testified that the best available estimate of the bill impact if Hopper Foundry were to be placed in the GSd class is approximately 190% as shown in H-13-1.[65] If Hopper Foundry were to be placed in the ST class the bill impact would be approximately 44% as shown at interrogatory H-12-33. Staff notes that these impacts were both calculated in October 2009, prior to consideration of an increase in the return on equity, so an update of the impacts would likely show a larger impact. On the other hand, the estimates appear to assume that Hopper Foundry would not shift any of its load into the peak period, which would achieve a lower billing demand compared to its high billing demand caused by limiting its operations almost entirely to the off-peak period.

Hydro One has observed, but not recommended, that Hopper Foundry and others could be reclassified as ST customers. It points out that certain embedded distributors benefit from having all of their delivery points included in the ST class, despite having a voltage at lower than 13.8 kV. This is a long-standing rate structure inherited from the previous structure of the electricity industry. The rationale appears to be simply that there is already an exception being granted to some customers, without reference to cost allocation.

Staff submits that grandfather provisions such as this should not be extended further than they already are, and if anything such provisions should be phased out if they are not supported by cost allocation results. Staff does not support the suggestion that Hopper Foundry and others should be added into the ST class. Classifying Hopper Foundry or other customers into the ST class is not supported by the available cost information, and there has been no evidence presented to the Board that doing so would be consistent with cost allocation principles.

Staff notes that Hydro One has requested that a revenue shortfall due to implementing the ST rate option should be recovered from other customers, likely the GSd class.[66] Staff submits that the other rate options outlined above would also involve a revenue shortfall relative to putting Hopper Foundry on the Forest GSd rate. Staff submits that it would be reasonable in any of these options that Hydro One should recover the shortfall in the GSd class rate design. Staff submits that the same solution would be reasonable for a revenue shortfall arising from other rate options as well, such as continuing the status quo or phasing in the GSd rate over an extended period.

Staff suggests that a more detailed analysis of costs in Hydro One's large system may warrant a larger number of rate classes or sub-classes than in the currently approved tariff structure. It submits that Hydro One should determine whether a rate could be developed that would be more favourable to Hopper Foundry and similar customers, that would be consistent with cost allocation principles. One alternative would be to include the cost of Hydro One's distribution facilities in some voltage range below 13.8 kV along with the cost of the its sub-transmission

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[65] Tr. Vol. 10, p. 99
[66] Tr. Vol. 9, p. 6 and Vol. 10, p. 104

facilities for the purpose of cost allocation, which might then support re-classifying certain customers such as the 14 customers identified by Hydro One. As another alternative, while still maintaining the existing definition of the ST class, perhaps there is a cost differential between serving larger customers, ie, larger than 500 kW, compared to serving smaller customers in the GSd class. Staff submits that the Board could direct Hydro One to prepare a cost allocation study or studies focusing on this aspect of its system, and present a report on its analysis with its next cost-of-service application.

In terms of an immediate solution, Staff submits that Hydro One should charge Hopper Foundry a rate in the same format as its GSd rate, but implemented in gradual steps such that the impact of the distribution rate changes would be no more than a bill impact ceiling on the total bill before Hydro One's next cost-of-service application.

Milton LV Assets

The Board indicated in its previous cost-of-service Decision (EB-2007-0681) that its preferred outcome was that Hydro One would sell certain LV assets that are used to serve Milton Hydro, thereby eliminating the issue of whether the latter is being charged a fair rate. Further, the Board stated that, if the sale did not occur before May 2010, then Hydro One should bring forward evidence that could be used to construct a specific rate for Milton Hydro's circumstances.

Hydro One submitted that a rate could be designed for customers whose circumstances are similar to Milton Hydro's, by using line-length as the charge determinant being line-length rather than billing demand. (ExhibitG1/Tab4/Sch4/p. 4-5) Hydro One also submitted evidence that it has made a proposal to Milton Hydro for the sale of LV facilities, and as of October 19, 2009 was waiting for a response. (H-1-1). The record does not have information on the current status of the Milton situation.

Staff submits that it would be reasonable for the Board to not give any further direction at this time. If the specific matter is resolved to Milton Hydro's satisfaction, then the Board does not need to consider the issue unless and until other parties raise a concern about whether the format of the ST rate is a good reflection of any underlying cost differences.

Un-metered Scattered Load (USL)

Hydro One considers USL to be a sub-class of its GSe class, and charges each USL connection at the monthly service charge of an ordinary load customer in that class less a credit that reflects the cost savings from the absence of a meter. This rate structure was approved by the Board in the previous cost-of-service Decision (EB-2007-0681).

Staff submits that Hydro One's classification is not inconsistent with any Board policy.

Staff notes that Hydro One did not provide cost allocation information using a hypothetical classification of customers in which USL would be treated as a separate class, on the basis that the required amount of effort was not readily available.[67] Staff submits that there are cost factors other than meters that might affect the allocation of cost within the GSe class as it is currently defined, such as the typical number of connections per bill. Staff notes that the Distribution Rate Handbook allows for direct allocation to USL of any costs associated with estimating the amount of the unmetered loads. Staff submits that Hydro One should provide with its next cost-of-service application a cost analysis with sufficient precision to determine whether a separate USL class is warranted in the future.

GREEN ENERGY PLAN

Hydro One's Green Energy Plan (the "Plan") presents the Hydro One's response to certain provisions of the *Green Energy and Green Economy Act, 2009 ("GEGEA")*. The Plan covers the five year period from 2010 to 2014 and includes the incorporation of renewable energy generation, development of a Smart Grid and promotion of energy conservation. Issues 9.1 to 9.5 on the Board approved issues list relate to the Plan.

Using the Board's *Guidelines: Deemed Condition of Licence: Distribution System Planning – G: 2009-0087, issued on June 16, 2009* (the "Guidelines"), Hydro One presented the O&M and capital expenditures related to renewable generation under the categories of Connection, Expansion and Renewable Enabling Improvements ("REI").

The cost responsibility for Connections, Expansion and REI investments were developed in accordance with the proposed DSC amendments issued by the Board on June 5, 2009 and subsequently updated on September 11, 2009. The DSC amendments were finalized on October 21, 2009, subsequent to the filing of Hydro One's Plan.

With respect to cost recovery, Hydro One has assumed that the revenue requirement associated with a portion of the capital investments contained in the Plan will be recovered through an external funding mechanism that recovers the required revenue from all electricity consumers in Ontario. This issue is captured under issue 9.3 below.

Staff will address the 5 Green Energy Plan issues in the following order: 9.4, 9.5, 9.1, 9.2 and 9.3.

[67] Exhibit H/Tab8/Sch3

Issue 9.4 – To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (ie, 2010 and 2011) in the current application?

It its Argument-in-Chief[68], Hydro One sought two specific approvals with respect to the Plan:

- That the Board accept the five year plan as fulfilling Hydro One's obligation to put forward a Green Energy Plan pursuant to the Green Energy Act, and

- That the Board specifically approve the levels of spending set out in the Plan for the years 2010 and 2011 for rate-making purposes.

Given these requests, issue 9.4, which related to the approval of projects or expenditures beyond the test years, is in staff's view, no longer an issue in this proceeding. Hydro One's proposed projects and expenditures beyond 2011 may provide context for the near term proposals, but for practical purposes, no specific approval is sought for specific projects or project costs beyond 2011.

Issue 9.5 - What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Issue 9.5 deals with the Board's role, criteria for approval and impacts of approval of the Plan. Board staff agrees with Hydro One's statement at page 33 of the Plan, that it is too early to identify specific criteria, such as a required level of capacity increase, for assessment of Green Energy Plans, and submits that issues 9.1 and 9.2 as articulated by the Board are appropriate tests for the Plan filed in this case.

Staff further submits that the Board's role in approval of a Green Energy Plan does include testing of the prudence of proposed investments and expenditures. Board staff agrees with Hydro One's response in this regard in interrogatory H-9-52. It follows that any given Plan does not have to be approved, or not approved, as a whole. The Board could, for example, find that some proposed expansions or reinforcements meet the goals of the Green Energy Act, and that the related expenditures are reasonable and prudent, and also find that some proposed investments in the Plan do not pass those tests. The Board, staff submits, can delineate some proposals in a Green Energy Plan as approved, and other proposals as not approved.

This distinction is relevant to a consideration of the impacts of approval.

[68] Tr. Vol. 11, p. 16

The most immediate impact of approval of part or all of a Green Energy Plan is that the spending for approved projects is to be recovered from ratepayers (possibly including provincial ratepayers). Once approved in a Plan, the need, selection, and budget of a project will not be revisited in subsequent proceedings except in regard to material deviations (Board *Guidelines: Deemed Conditions of Licence: Distribution System Planning* G-2009-0087).

A second impact of approval is that a distributor can be required to expand or reinforce its system, or make smart grid investments, in accordance with an approved Plan (OEB Act s. 70(2.1)3). If the Board accepts the submission above, that a filed Plan can be approved in whole or in part, this section of the Act would require investments in accordance with whatever investments in the Plan are approved by the Board.

Thirdly, approval of all or part of a Plan is one way a distributor can be obliged to pay all the costs of an expansion (section 3.2.5A Distribution System Code), and enabled to recover some costs from provincial ratepayers for eligible investments (section 79.1 (4)(c) OEB Act and section 1(2) of O. Reg. 330/09 under the OEB Act).

Issue 9.1 - Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Issue 9.1 asked whether Hydro One's Green Energy Plan met the Board's filing guidelines (as they then existed: *Guidelines: Deemed Conditions of Licence: Distribution System Planning* G-2009-0087, June 16, 2009) and the objectives in the Green Energy Act. Staff submits that the Green Energy Plan filed by Hydro One does meet the objectives in the Green Energy Act, to the extent that those objectives can be identified in section 70(2.1) of the OEB Act. Staff notes that, in contrast to the request for approval made by Hydro One's counsel in Argument-in-Chief,[69] there is as yet no "obligation" for Hydro One to put forward a Green Energy Plan. The obligation to prepare and file plans arises when the Board mandates such filing, and as yet the Board has not done so.

Board staff submits, however, that Hydro One's Plan may not meet the Board's filing guidelines in two ways: the absence of a section providing a current assessment of the capacity of the system to accommodate the connection of renewable generation (required at page 10 of the guidelines), and a failure to provide sufficient detail to enable the Board to carry out its mandate to evaluate the Plan.

There is no section in Hydro One's Plan entitled "current assessment", and more importantly, in the Plan itself, this information seems to be missing. Staff appreciates the answer Hydro One

[69] Tr. Vol. 11, p. 18

provided to undertaking J3.1, which summarized the information available on the record (attached to interrogatory H-10-6) and on Hydro One's website regarding the current capacity of the system. In staff's submission, it would have facilitated the review of the Plan to have at least a summary of this information in the Plan itself.

Staff also submits that the absence of detail of the proposed projects and investments posed another difficulty for the Board. Hydro One agreed (in interrogatory H-9-52 and in oral testimony) that the Board's review of the Plan should be consistent with the review normally done in a cost of service application in terms of testing the evidence. The level of detail in the Plan itself, however, did not allow such a review to be conducted. The actual projects, their locations and the specific need to be addressed by each project was not set out in the Plan. Staff accepts that Hydro One, at the time of writing the Plan, probably had insufficient information to provide all these details. Unfortunately, in the absence of such information, the Board may not be able to provide the approval Hydro One seeks.

Some detail does appear elsewhere on the record. Exhibit D1/TabT3/Sch3 contains information about proposed investments, and the table at page 2 of that exhibit is helpful. Interrogatory H-7-87 provides some detail about generation connection and generation connection enhancements. The business cases found at Exhibit D2/Tab2/Sch3, particularly ISD # 27, 28, 29, 30, 31, 32 and 33 provide useful information. By tracing a path through these exhibits, information about the proposed Green Energy investments becomes somewhat clearer.

For example, the investments in Generation Connection Enhancement are summarized in Table 5, Exhibit D1/Tab3/Sch3/p.16. As noted in the table, there are 5 types of investments under this category and in the pre-filed evidence, Hydro One has identified the related ISD for each investment category. For instance, the ISD for "Targeted Enhancement to Support DG" is ISD #29. This is noted at Exhibit DI/Tab3/Sch3/p.17, lines 8 and 9. And using the information in interrogatory H-7-87, one can identify whether it is a connection, expansion or REI investment. In this specific case the investment is REI type investment, as noted on page 2 of H-7-87.

Similarly, the ISD for "Station, Upgrades for Protection Control & Load Rejection" is ISD # 30. This is noted at Exhibit D1/Tab3/Sch3/p. 18, line 4. In H-7-87, p. 2, this is identified as an REI type investment.

Staff invites the applicant and intervenors to consider whether the lack of detail in the Plan prevents the Board conducting the necessary evaluation and approval of the investments proposed within the Plan.

For the reasons set out in the section below dealing with issue 9.2, Board staff proposes in any event, that the Board not make a finding, at this time, on the prudence of the expenditures proposed in the Plan.

Issue 9.2 - Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?

Hydro One's Plan covers the five year period from 2010 to 2014. The three main categories in the Plan are Renewable Generation, Smart Grid and Energy Conservation. The Plan assumes that Conservation and Demand Management ("CDM") program costs will continue to be externally funded, similar to the funding currently provided by the Ontario Power Authority ("OPA") for CDM programs.

In this proceeding Hydro One is seeking Board approval for capital expenditures (excluding generator funded capital) in the first two years of the Plan. With respect to the expenditures in the 2012 to 2014 period, Hydro One submitted that it will reapply in 2011 with an updated Plan.[70] The capital costs in the Plan are summarized below:

Capital Costs in Green Energy Plan (Exhibit A/Tab14/Sch1)			
$ millions	**2010**	**2011**	**2012-2014**
Capital Costs in Green Energy Plan:			
Renewable Generation	168	296	930
Smart Grid	30	62	250
Energy Conservation/CDM	0	0	0
Total Capital Expenditures	**198**	**358**	**1180**

The capital expenditure related to renewable generation accounts for over 84% of the total capital costs in the Plan. The other 16% is attributed to the Smart Grid program.

Renewable Generation Capital Expenditures

Hydro One proposes to connect 3500 MW of renewable generation to its system by 2011. The capital required to connect this level of generation is projected to be $464 million over two years. The capital expenditures by DSC category are summarized below:

[70] Tr. Vol. 1, p. 158

	Renewable Generation Capital ($ millions)							
	Connection		**Expansion**		**REI**		**Total**	
	2010	2011	2010	2011	2010	2011	2010	2011
Generator Funded	13	27	0	0	0	0	**13**	**27**
Externally Funded	0	0	60	118	79	118	**139**	**236**
Dx Funded	0	0	12	25	4	8	**16**	**34**
Total Capital	**13**	**27**	**72**	**143**	**83**	**127**	**168**	**296**

One of the key assumptions in the capital budget is the expected number of renewable generation connections. Hydro One has assumed that a majority of these new connections will be from the Feed-In-Tariff ("FIT") program. However, when Hydro One's capital expenditure forecast was developed, the actual results of the FIT program were not definitively known. Board staff is therefore concerned with the reliability of Hydro One's capital expenditure projections. Updated information was provided in undertaking J1.6, as discussed below.

In Board staff interrogatory H-1-146, Hydro One noted that it does not have a detailed forecast of renewable generation connections by MW and by location..." In cross examination Hydro One confirmed that it does not know with certainty where some of the capital investments will be needed until the results of the FIT program are known. For example, with respect to certain specific system upgrades (12 new breaker positions, 360 kilometers of express feeders and 30 kilometers of feeder upgrades) proposed in Investment Summary Document D29, the witness confirmed that only half of the locations were precisely known.[71] Similarly, with respect to the six express feeders, which is a significant Plan investment, the witness confirmed that "there is no specific, 'this TS is going to be built, and these feeders are going to be built' [in the] Plan right now, in terms of what is in front of the Board".[72] Further, Hydro One's witness also confirmed that until the location, size and other details about the new connections are known, there will be some uncertainty around the projected costs.[73]

Hydro One's capital budget was therefore prepared on an aggregate basis.[74] Hydro One's witness summarized the approach as, "...we have a reasonable expectation what will happen with the FIT and we have a reasonable expectation of what work will have to be undertaken in response to that, and we have a good estimates on what the unit cost will be of the type of work."[75]

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[71] Tr. Vol. 2, pp. 191-192
[72] Tr. Vol. 3, p. 60
[73] Tr. Vol. 1, p. 151
[74] Tr. Vol. 1, p. 150
[75] Tr. Vol. 1, p. 155

Hydro One's position is that the capital expenditure projections are reasonable and should be recovered as proposed. In that regard, given that generator connections are a major driver of the capital budget, Board staff is concerned that not knowing the location, size or mix of connections may affect the overall accuracy of the capital budget projections.

Appropriateness of the Generation Connection Forecast

To establish if the overall capital expenditure budget is appropriate, the reasonableness of the generation and connection forecasts that the capital budget is based on, must be tested. The capital expenditures are predicated on 3500 MW of renewable generation[76] connecting to Hydro One's distribution system by 2011. Hydro One forecasts it will connect 1280 MW in 2010 and 2220 MW in 2011.[77] The capital needed to connect this level of generation is $168 million in 2010 and $296 million in 2011.[78]

In 2010, Hydro One forecasts that it will connect 540 MW of capacity from RESOP contracts[79] and 740 MW from FIT contracts.[80] Hydro One did not account for any capacity from RESOP contracts in 2011.[81] Therefore, the 2011 forecast is based entirely on contracts expected from the FIT program.

The launch period for the FIT program closed on November 30, 2009. In undertaking J1.6 Hydro One provided "actual" information regarding the take-up of the FIT program. The response indicates that the OPA has received FIT applications for capacity far lower than that assumed by Hydro One in its Plan. To date the OPA has received FIT applications to connect 75 MW in 2010 and 1683 MW in 2011,[82] compared to Hydro One's estimate of 740 MW and 2220 MW, respectively.

In response to the level of take-up of the FIT program, Hydro One stated that it has capacity to accommodate more FIT applications depending where on the system the connection is requested.[83] While that may be true, Board staff notes the FIT program launch rules were designed to allow those projects that had reached certain development milestones and as such were eligible for priority access to available capacity. Applications received after the launch period will likely include applications that did not meet the initial criteria and could take a longer to reach commercial operation, possibly beyond the 2011 period.

[76] Argument-in-Chief, Tr. Vol. 11, p.19
[77] Tr. Vol. 1, p. 48 and Vol. 2, p. 169
[78] Includes Generator Funded capital
[79] Tr. Vol.1, p. 45
[80] Tr. Vol. 1, p. 47
[81] Tr. Vol. 2, p. 174, l. 20
[82] Undertaking J1.6
[83] Undertaking J1.6

Using 75 MW of capacity from the FIT applications, the estimate for 2010 is 602 MW (527 MW+75 MW) or 53% lower than forecast. Similarly, based on the number of FIT applications, Hydro One can expect to connect at least 1683 MW in 2011, 24% lower than forecast. Board staff also acknowledges that the FIT information is based on preliminary information and that, as Hydro One stated, "these numbers do not necessarily describe the applications which will receive FIT contracts".[84]

Similarly, Hydro One's forecast of generation connections also appears to be overstated. The capital investments in Expansion and REI are driven by the number of connections expected to connect to the distribution system. Hydro One forecasts it will connect 468 generator connections by 2011.[85] With the exception of the 60 RESOP connections in 2010[86], the other 408 connections are largely expected from the FIT program. [87] However, based on the actual information on the take-up of the FIT program, the OPA has received 250 applications that expect to connect by 2011, or 39% lower than Hydro One's estimate of 408 FIT connections.

Similarly, with respect to the 2009 Bridge Year forecast of 66 generator connections, Hydro One had only connected 11 at the time of the hearing and was expecting to connect 18-20 by year end. This represents a variance of approximately 70% from forecast, based on 20 connections by year end. Board staff agrees that some of this variance was due to the anticipated launch of the FIT program. However staff notes that in some respects it does demonstrate the difficulty in forecasting generator connections[88].

Board staff is concerned that the proposed capital budget may be more than actually required, given the fewer than forecast number of connections and generation. Board staff does not have the ability to accurately assess the impact that lower than forecast generation has on the overall capital budget, but on a $/MW basis, the average cost per MW is $132,571/ MW.[89] Applying this ratio to the revised generation estimate of 2285 MW[90], results in an average estimate of $303 million in capital, compared to the proposed $464 million. On a $/connection basis and based on 310 connections,[91] the estimate is $308 million.

Board staff invites parties to comment on the possible impact of a lower than forecast generation and generation connection forecast on the capital expenditure budget.

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[84] Undertaking J1.6
[85] Exhibit D1/Tab3/Sch3/p.11, Table 3
[86] Tr. Vol. 2, p. 170
[87] Tr. Vol. 2, p. 174
[88] Tr. Vol. 2, pp. 170-171
[89] (168+296)/3500
[90] 602 MW+1683 MW
[91] 250 FIT connections + 60 RESOP.

Rate Recovery Proposal

The total capital spend on renewable generation in 2010 is forecast to be $168 million, of which $17 million will be funded by Hydro One's distribution rates. In 2011, the capital spend is $296 million, of which $33 million will be funded directly by Hydro One's distribution rates. Under Hydro One's proposal, the remaining portion (excluding generator funded capital) will be recovered from all provincial customers. Hydro One has determined the revenue requirement associated with the externally funded capital investments to be $8.0 million in 2010 and $30.7 million in 2011. This revenue requirement was calculated with an amortization of 20 years, the life of the generation contract as outline in staff IR H-1-151. SEC interrogatory H-10-23 provided the same calculation but over the life the assets and yielded revenue requirements of $7.5 million for 2010 and $28.3 million for 2011.

With respect to costs that are attributed to Hydro One's customers, the approach is to recover these costs in revenue requirement. Hydro One argues that the investments in the Plan are "necessary, will be used and useful in the rate period, and are sufficiently well defined to include as a part of its cost of service in the test years." [92]

With respect to the overall accuracy of the planned investments, Hydro One states "the plan that we have put forward is based on a very substantial experience in terms of the RESOP program, as well as <u>a careful assessment in terms of the projects that are likely to proceed in the 2010 and 2011 period</u>. … And so we have confidence that in fact the program that we have put forward, the Green Energy Plan, is a solid and defensible plan that should go forward as our application."[93] [Emphasis added]

With respect to why the deferral account approach outlined in the Board's Guidelines is not appropriate, Hydro One argued "... it is important to us that we do have the necessary funding and the necessary certainty around that funding in able -- in order to be able to do the work. ...as I say, the times are much tighter than they used to be. We are certainly aware of the economics, and we are certainly aware of issues with respect to raising debt in the market".[94]

In its Argument-in-Chief, Hydro One stated that it is not opposed to a variance account and funding adder approach.[95]

With respect to the argument about financing, Board staff submits that Hydro One has not provided any concrete evidence to indicate that under a deferral account mechanism, it will have difficulty in raising capital.

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[92] Argument-in-Chief, Tr. Vol. 11, p. 22
[93] Tr. Vol. 1, p. 51
[94] Tr. Vol. 3, p. 75
[95] Argument-in-Chief, Tr. Vol. 11, p. 22

Smart Grid Capital Expenditures and Rate Recovery Proposal

Hydro One plans to spend $30 million in 2010 and $62 million in 2011 on Smart Grid capital investments. Hydro One proposes that the investments should be included as part of its rate base for the test years. Hydro One argues that its Smart Grid investments are necessary, used and useful, and sufficiently well defined to include as part of its rate base.[96]

The Smart Grid plan was developed following a three step process. The first step was to focus on integrating renewable energy generation, CDM, and system automation. Secondly, Hydro One formulated plans to utilize pilots to investigate new innovative technologies. The final step is the implementation of pilot projects. The capital expenditures on smart grid program are summarized below:

Smart Grid Capital Expenditures				
		2010		**2011**
Energy Storage	$	2	$	2
Smart Zone Pilot	$	13	$	42
PHEV Trials	$	1	$	1
Distribution System Innovation	$	5	$	5
Facilities/System Upgrades	$	7	$	10
Technology Work (GIS)	$	3	$	3
Total Smart Grid Capital	**$**	**30**	**$**	**62**

A significant portion of the investments are related to the smart zone pilot project. The main objective of this project is to innovate, test and prove new and emerging technologies. The technologies that will be implemented in the smart zone are presented at Exhibit D1/Tab3/Sch3/p. 23.

Hydro One issued an RFP in 2009, the results of which are yet to be finalized. This RFP (submitted in H-12-46) covers the research and development and the other development work that will be undertaken in the smart zone pilot.[97]

In cross examination, the witnesses confirmed that until the RFP process is completed, the final costs may vary. However, Hydro One argued that the costs estimates have been developed in a prudent manner and that it expects the final costs will reflect Hydro One's projections.[98]

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[96] ExhibitA/Tab14/Sch
[97] Tr. Vol. 1, p. 38
[98] Tr. Vol. 1, p. 41

Board staff is concerned with Hydro One's proposal to recover the smart grid costs in revenue requirement. Board staff submits that the smart grid program is in the initial stages of development and there are many uncertainties. Unlike other typical distribution investments, smart grid investments can be exposed to higher risks because of changes to system requirements because of increasing distributed generation, uncertainty with regards to the structure of the grid and changes in technology. Similarly, Board's Guidelines state, "Accounting, funding and planning for smart grid development will also evolve as the objectives of the smart grid, for example in relation to interoperability, and the standards for smart grid technologies are developed". [99]

Considering the uncertainty in the planning scenario as outlined above, Board staff feels that approval of the Hydro One Green Energy Plan presents too high a level of risk for Hydro One ratepayers and Provincial ratepayers. At the same time, however, Board staff does not want to unreasonably restrict the government's intent with regard to renewable generation or progress in developing the Smart Grid. Therefore, Board staff submits that the funds for the Plan could be recovered from Hydro One and all provincial ratepayers (in proportions as suggested in the Plan) as rate adders. In addition, Board staff is of the view that a deferral account be created to record revenues from each adder and also record actual Plan expenditures. These amounts could be brought forward for disposition at Hydro One's next rates case, where the Board would rule on the magnitude and prudence of the expenditures and adjust the adder revenues accordingly.

In addition, Board staff submits that the recovery adders to be collected from Provincial ratepayers be based on the calculations using the conventional life of the asset calculations and not those based on the 20 year life of the electricity contracts. It is apparent to Board staff that the assets will still be used and useful when the initial contracts expire and notes that Hydro One has not provided any rationale for why this is not the case.

Issue 9.3 – Is Hydro One's methodology for allocating Green Energy Plan O&M and capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?

Issue 9.3 dealt with the allocation of Green Energy Plan expenditures between Hydro One customers and provincial ratepayers. As the Board noted in its letter of January 20, 2010, the Board expressed a preference for awaiting the Board's report on *Rate Protection and the Determination of Direct Benefits under Ontario Regulation 330/09* (EB-2009-0349) before making a decision on this issue. However, given that the report has not yet been issued, the Board invited parties to address procedural options for resolving this issue in their submissions.

[99] G-2009-0087 Guidelines, p. 2

Hydro One proposed, by submission dated January 18, 2010, that the Board reconvene the hearing as soon as possible to examine Hydro One's proposed allocation, and set rates which include a determination of the appropriate allocation of costs. Hydro One noted that its own proposal for allocation was largely consistent with the Board staff paper released for comment, and that the staff paper itself contemplated that until a standardized approach is developed, each distributor would estimate direct benefits for its own customers. The applicant further submitted that the materiality of the cost proposed to be allocated to provincial ratepayers is not large, and that a significant deviation from this result in the Board's final policy is unlikely.

Board staff recognizes merit in Hydro One's proposed procedural approach. Staff also invites all parties to comment on the following alternative, which has the advantages of expediency and consistency with Board policy.

Staff submits that the Board could determine the allocation to provincial ratepayers on a provisional basis, subject to later adjustment. In this scenario, the Board would establish a deferral account in which the applicant would record amounts collected from its own ratepayers. A parallel account would be established to record recovery from provincial ratepayers.

When the Board makes its final determination of the percentage of direct benefits to Hydro One's ratepayers of Plan expenditures in 2010 and 2011 (which may not be until the next rates case) the Hydro One ratepayer account can be credited or debited, and any over or under-collection from provincial ratepayers can be taken into account in setting the amount to be collected in subsequent years.

Staff further submits that if this approach is adopted, the Board need not reconvene the hearing at this time to determine the amount of direct benefits to Hydro One ratepayers. The Board could choose to adopt Hydro One's proposal or a different percentage allocation, for example, 15%, as a default allocation to Hydro One's ratepayers. The final allocation would be determined in a subsequent proceeding.

-All of which is respectfully submitted-