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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

November 21, 2012

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2012-0136 - Hydro One Networks Inc. 2013 IRM Distribution Rate Application – Hydro One Networks Responses to Technical Conference Questions and Update to Interrogatory Responses

Please find attached an electronic copy of written responses provided by Hydro One Networks to Technical Conference Questions. Ten (10) hard copy responses will be given to the Board prior to the Technical Conference.

I am also attaching an electronic copy of Hydro One Networks' update to Exhibit I, Tab 2, Schedule 5.05 VECC 8 page 2. Ten (10) hard copies of the blue page updates will be given to the Board prior to the Technical Conference.

Hydro One has provided written responses to Technical Conference questions that require data intensive responses. Hydro One Technical Conference participants will answer any other questions orally.

An electronic copy of the responses and the update have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Attach.

A detailed list of the Responses are provided below:

OEB Staff Question 1, Parts a, b, c
OEB Staff Question 6, Parts a, b
OEB Staff Question 10, Parts b, c
OEB Staff Question 12
OEB Staff Question 13
Energy Probe Question 5
Energy Probe Question 6, Parts a-e
Balsam Lake Coalition Question 1
Balsam Lake Coalition Question 2
Balsam Lake Coalition Question 3
VECC Questions 1
VECC Question 3
VECC Question 4 a-c, e, f
VECC Question 5
VECC Question 7
VECC Question 8 b-c
VECC Question 9
VECC Question 10
VECC Question 14
VECC Question 15
VECC Question 17
VECC Question 18
VECC Question 19
VECC Question 21
VECC Question 22
VECC Question 23
VECC Question 24
VECC Question 27
VECC Question 30
VECC Question 31
VECC Question 32
VECC Question 33
VECC Question 34
VECC Question 35
VECC Question 36
SEC Question 2
SEC Question 4 c-d, f, g
SEC Question 5
SEC Question 5.1
SEC Question 7
SEC Question 8
SEC Question 12
SEC Question 13
SEC Question 14
SEC Question 17
SEC Question 19
SEC Question 20
SEC Question 21
SEC Question 23
SEC Question 24
SEC Question 25
SEC Question 26
SEC Question 27
AMPCO Question 1
AMPCO Question 6
AMPCO Question 7
AMPCO Question 8
AMPCO Question 9
CCC Questions 1-6
CME Question 1

Ontario Energy Board (Staff) Question #1 List 1

Question

Ref: Exhibit I/Tab2/Schedule 1.01 Staff 2
On page 2 of 7 at line 26:

a) When did the vendor of the current CIS stop supporting the product?

b) Who has provided support in the interim period since the vendor stopped supporting the product?

c) What was the plan to support the product in the years beyond 2013 prior to the decision that the system should be replaced in 2013?

Response

a) The vendor stopped providing support services for Hydro One's Customer/1 implementation in 2001.

b) Since Andersen Consulting/Accenture stopped supporting the product it has been hosted and maintained by Inergi as part of the outsourcing contract for application maintenance services which was entered into in 2002 and extended to February 2015.

c) The plan included Inergi supporting the current CIS under their outsourcing contract with Hydro One until that contract expires in February 2015.

Ontario Energy Board (Staff) Question #6 List 1

Question

Ref: Exhibit I/Tab2/Schedule 1.06 Staff 7
On page 2 of 3:

a) At d) Hydro One indicates it "believed that use of the 2010 actual for comparison to 2011 was appropriate." Why did Hydro One consider this more appropriate?

b) If the Board finds that the actual 2011 revenue was more appropriate, would the threshold level be exceeded? Please calculate the threshold value that would result and provide the detailed calculation.

Response

a) Page V of Appendix B of the Supplemental Report of the Board issued under proceeding EB-2007-0673 indicates that "If a distributor applies in [2009] then "g" will be the % difference between [2007 actuals and 2008 Board-approved base]" Hydro One is applying in 2012. Therefore, applying the timeframe above, the "g" should be equal to the difference between 2010 actuals and 2011 Board-approved rates.

b) If 2011 Actual revenue was used as the denominator and 2010 actual revenue were used as the numerator in the comparison then the Growth rate would be 0.59% and the Threshold, holding all other items constant, would be $414.1Mn. The in-service capital requirement for 2013 is $644Mn. Therefore the ICM threshold is exceeded and application under ICM is appropriate.

Ontario Energy Board (Staff) Question #7 List 1

Question

Ref: Exhibit I/Tab2/Schedule 1.07 Staff 8
On page 2 of 3:

At line 28, Hydro One explains why depreciation should be included in an assessment of whether or not the threshold value is exceeded: "Depreciation of $283M was included in the original award but ICM 2013 calls for in-servicing of $414M. Therefore, upon completion of the planned spending, Rate Base will grow in 2013 by $131M."

a) Please explain why including the depreciation for the in-serviced asset along with the capital value of the asset being placed in service does not over-value the assets which are being placed in service in 2013? Why should this be a consideration over and above the actual capital expenditure in the determination of the threshold value for ICM 2013?

b) Should the depreciation not be recovered in the following year? Does including depreciation in rate base not represent an inappropriate increase in the capital expenditure that is being compared with the threshold value?

c) How is the addition of the depreciation in assessment of the threshold value consistent with the Board's statement (quoted at line 5) that "… adjustment in rates will be linked solely to the costs of the incremental capital."

d) In the analogy example quoted by Hydro One in part d) of the response on page 3, Hydro One provides an example of a $400 asset which is depreciated on a straight line accounting basis and compares this with the replacement cost of the asset which price has escalated to $880 on a compound basis and shows that they are not equivalent amounts.

  i) For this analogy, would Hydro One at the time of the rate hearing in 1972 have applied to the Board for a rate increase on the basis of a capital expenditure of $880? Would that be an appropriate description of the capital expenditure requirement at the time?

  ii) Is Hydro One suggesting that depreciation should represent the full amount of inflation in each year?

  iii) Does Hydro One agree that the proposed approach is not consistent with accounting practice in the rest of the province? Is this an issue which Hydro One should be arguing before a forum on accounting principles rather than at the Board?

  iv) There are many assets (e.g. wood poles) that have been in useful service beyond their years for which depreciation was recovered, and which could be considered as "over-funded" and which should now be deducted from the rate base in this application. Would Hydro One concur that it would be appropriate for these depreciated assets to be taken into account at any point where there is a claim based on the fact that depreciation is not equal to expenditure? Does this imply that Hydro One is recalculating (deducting from) the rate base by recognizing assets which have been fully depreciated but which are still providing useful service and a continuing revenue stream?

v) Would this not lead to the conclusion that no new capital expenditure authorization would ever be needed for replacement because Hydro One would have the full capital in hand when replacement of assets is required?

vi) Would this example represent an inter-generational transfer allocation, since revenue would be being recovered from current customers to fund future price escalation?

Response

Ontario Energy Board (Staff) Question #10 List 1

Question

Ref: Exhibit I/Tab2/Schedule 1.11 Staff 12
On page 3 of 5:

a) Please provide a more comprehensive and detailed response to the original questions a) and b).

b) Please reconcile the EB-2009-0096 evidence (Exhibit D1/Tab 3/Sch2/pg.4) for Stations Sustaining capital to the $3.2 million and $25.8 million found in the response provided in the original c).

c) In the response to k), Hydro One indicates that the cost of refurbishment of 23 used transformers would cost $3.5 million as opposed to the cost of purchasing new spares of $13.3 million. How does Hydro One then justify the significant additional cost of purchase over refurbishment?

Response

b) The following table compares the category descriptions for Stations Sustaining Capital between the 2011 expenditures from the EB-2009-0096 and the EB-2012-0136 proceedings.

EB-2009-0096		EB-2012-0136	
Description	**2011 Test Year**	**Description**	**2011 Base Year**
Station Projects & Demand	8.4	Station Refurbishments	3.2
		Other Station Component Replacements and Demand	5.2
Strategic Spare Transformers	4.1	Transformer Spares & Replacements	4.1
Mobile Substation Investments	2.8	MUS Reinvestment	2.8
Total	**15.3**	**Total**	**15.3**

The 2011 expenditures within the Stations Projects & Demand category for both the EB-2009-0096 and EB-2012-0031 proceedings have remained consistent at $8.4 million; however there was a slight adjustment to the expenditures at the project level, in particular Station Refurbishments was decreased from $3.4 million to $3.2 million to fund an additional $0.2M demand work that was required to address the failure of components and to correct emergency situations.

c) Refurbishment of transformers is a Sustaining OM&A expenditure. Purchase of new transformers is a Sustaining Capital expenditure. Although the $13.3 million expenditure to purchase new transformers is higher, this expenditure is capitalized and hence has a lower impact on revenue requirement. The revenue requirement for the purchase of 23 new transformers is approximately $1.0 million compared with the alternative of transformer refurbishment which is $3.5 million as OM&A costs directly impact revenue requirement.

Ontario Energy Board (Staff) Question #12 List 1

Question

Ref: Exhibit I/Tab8/Schedule 1.03 Staff 25
In this response, Hydro One included a revised Attachment 1 which showed an updated DVA continuity schedule.

- In the revised Attachment 1, it appears that the Column "Transactions Debit/ (Credit) during 2010 excluding interest and adjustment" was reduced by the amount that was approved for disposition in 2010 [EB-2009-0096] for each deferral/variance account, as compared to the same column in the pre-filed DVA continuity schedule. A similar adjustment was also made in the 2010 carrying charge section of the DVA continuity schedule.

- It appears that in the revised Attachment 1, the amount that the amount the Column "Transactions Debit/ (Credit) during 2010 excluding interest and adjustment" was reduced by was recorded in the Column "Adjustments during 2010 – other". A similar adjustment was also made in the 2010 carrying charge section of the DVA continuity schedule.

It is not clear to Board staff from reviewing the revised DVA continuity schedule if the journal entry to transfer the 2010 Board approved amount from each deferral/variance account to Account 1595 was actually done in 2010.

Please provide a copy of the journal entry (both sides – debits and credits) that shows the transfer to Account 1595 from each deferral/variance account for the amount approved for disposition in 2010 (principal and carrying charges), EB-2009-0096. Please ensure that the journal entry shows the date the entry was made to the general ledger.

Response

Hydro One confirms that the transfer journal (as shown below) was actually posted in the accounting general ledger on May 31st 2010.

Journal for the transfer of regulatory account balances approved for disposition in 2010 (principal and carrying charges), EB-2009-0096.

Mandatory Fields Header :	Company Code, Posting date (yyyy.mm.dd), Doc Header Text
Line Items:	Account (G/L Account); Amount put (-) sign for credit postings
Fields not to changed:	Ledger Group (leave it blank)

Header	
Company Code	1200
Posting Date	2010.05.28
Reference Document	520226
Doc Header Text	Rider 6 Establishment
Document Type	ZX
Ledger Group	
Balance	**0.00**

Item

USofA Account	Amount	Text
1590	33,858,099.67	Reg Asset Recovery Act-Princ
1590	(10,966,269.50)	Reg Asset Recovery Act-Interes
1518	2,833,365.22	RCVA Retail Cost-Princ
1518	113,366.60	RCVA Retail Cost-Interest
1548	(504,065.45)	RCVA - STR - Principal
1548	(23,677.95)	RCVA - STR - Interest
1580	26,508,006.13	RSVA-WM Services - principal
1580	256,311.81	RSVA-WM Services - Interest
1584	9,172,727.94	RSVA-Network Service Charge-P
1584	250,413.99	RSVA-Network Service Charge-I
1586	5,875,060.69	RSVA-STR - Principal
1586	32,682.01	RSVA-STR - Interest
1588	(13,176,663.05)	RSVA-Global Adjustment-P
1588	(81,321.99)	RSVA-Global Adjustment-I
1550	(6,928,672.15)	RSVA - LV - Principal
1550	(57,738.59)	RSVA - LV - Interest
1555	(11,476,768.74)	Smart Meter - Capex - P
1555	(100,928.22)	Smart Meter - Capex - I
1556	(4,382,909.32)	Smart Meter - OM& - P
1556	(44,274.02)	Smart Meter - OM& - I
1595	(41,778,180.94)	RARA 6 - Principal
1595	10,621,435.86	RARA 6 - Interest

Ontario Energy Board (Staff) Question #13 List 1

Question

Ref: Exhibit I/Tab8/Schedule 1.05 Staff 27

In this response, Hydro One indicated that it is attempting to estimate line losses experience on the system and that such an estimation is based on a system assessment. Hydro One stated that the calculation requires that the data be linked to the actual time that the energy was provided. Hydro One articulated that it is attempting to track the dollar value of the variance but that nothing has been recorded in the general ledger to date.

Board Decision EB-2009-0096, which directed Hydro One to track the dollar value of variances between the Board approved losses recovered in rates and actual line losses, commencing January 1, 2010, was issued on April 9, 2010.

a) Please confirm if Hydro One has been tracking the dollar value of variances between the Board-approved losses recovered in rates and actual line losses, as per the EB-2009-0096 decision. Please state the effective date of tracking these values and where these variances are being tracked. If the dollar value of such variance is not being tracked, please explain.

b) Please clarify what Hydro One means by "attempting" to track the dollar value of such variance. Please explain.

c) If Hydro One has been tracking the dollar value of such variance, please provide a status update and more details, including the dollar value of the variance as at September 30, 2012.

d) Please explain why Hydro One has not recorded an estimate for the variance in its general ledger from 2010 through 2012. Please indicate why such a variance has not been recorded in Account 1588, particularly since other estimates are recorded in Hydro One's general ledger and audited financial statements at year-end (e.g. unbilled revenue).

Response

a) Hydro One is currently undertaking an internal study for estimating line losses at the total system level and assessing different approaches to establish the dollar value of this variance account. Due to factors that are unique to Hydro One (i.e. various rate classes and billing cycles), there are many estimates and assumptions which have to be examined in this study. Hydro One intends to file this study at the next cost of service proceeding and intends to seek approval from the Board of the recommended approach in establishing the dollar values.

b) “Attempting” to track the dollar value means Hydro One is assessing different approaches to establish the dollar value of the variance account.

c) Please see response to a).

d) Please see response to a).

Association of Major Power Consumers in Ontario (AMPCO) Question #1 List 1

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Question #1
Reference: General

Question

As a result of the interrogatory process, please confirm the growth rate, threshold CAPEX and incremental revenue requirement by capital investment type, proposed by Hydro One in this application.

Response

The growth rate = -1.04%

Threshold capital = $332 million

Incremental revenue requirement:
- Typical = $14 million
- Escalated Issue = $6 million
- Non-typical = $7 million

Association of Major Power Consumers in Ontario (AMPCO) #6 List 1

Question

Reference: Ex I, Tab 2, Sch 7.03 CCC#7

In its response, Hydro One provided a 2012 forecast of Typical Capital Spending. Please provide actual spending to date.

Response

Actual 2012 January 1 to September 30 - Typical Capital Spending ($M)

Sustainment	159.0
Development	117.2
Operations	0.3
Shared Services	43.2
Total Capital	319.7

Association of Major Power Consumers in Ontario (AMPCO) Question #7 List 1

Question

Reference: Ex I, Tab 2, Sch 7.06 CCC#10

Hydro One provided the 2012 year-end forecast (as of June 30, 2012). Please provide the year-end forecast based on current year to date information.

Response

The 2012 year-end forecast (as of September 30, 2012) is still $52.8 million.

Association of Major Power Consumers in Ontario (AMPCO) Question #8 List 1

Question

Reference: Exhibit I, Tab 10, Schedule 1.02 Staff#30

Preamble: Hydro One's interrogatory response provided 2012 Actuals, 2012 Forecast and Total Forecast as of June 30, 2012.

Please provide the 2012 Actuals, 2012 forecast and Total Forecast based on updated year to date information.

Response

Smart Grid Capital	**2010**	**2011**	**2012 Actuals***	**2012 Forecast**	**Total Actuals***	**Total Forecast**
Actuals*	**18.0**	**29.9**	**35.3**	**43.8**	**83.2**	**91.7**

Smart Grid OM&A	**2010**	**2011**	**2012 Actuals***	**2012 Forecast**	**Total Actuals***	**Total Forecast**
Actuals*	**2.5**	**3.1**	**3.4**	**14.6**	**9.0**	**20.2**

*Actuals as of September 30, 2012.

Association of Major Power Consumers in Ontario (AMPCO) Question #9 List 1

Question

Reference: Exhibit I, Tab 10, Schedule 9.01 AMPCO #5(k)

In the above interrogatory, AMPCO requested the driver for each business objective in Table 3. In its response, Hydro One stated that the business objectives in Table 3 are consistent with Hydro One's overall business values. Hydro One was unclear what the word `driver refers to. At Ex I, Tab 2, Sch 1.01 Staff 2(a) (ii), Hydro One provides four core drivers that necessitate the replacement of the CIS system. AMPCO is seeking specific core drivers that necessitate each business objective in Table 3. Please provide.

Response

The drivers for the business objectives in Table 3 are the same as those previously established in EB-2009-0096. The Green Energy Plan (EB-2009-0096 Exhibit A, Tab 14, Schedule 2) laid out the two major drivers: meeting the requirements set out in the Green Energy & Green Economy Act (GEGEA) of 2009 and accomplishing elements of the Corporation's strategy.

Hydro One is continuing to execute on the smart grid elements of its Green Energy Plan which stated: "The Smart Grid will help meet the objectives of:

- increasing use of renewable energy
- expanding capabilities to provide demand response, price information and load control
- accommodating the use of innovative and energy saving technologies and system control applications"

Balsam Lake Coalition (BLC) Question #1 List 1

Question

Exhibit I
Tab 10
Schedule 3.01 BLC 1
Page 1 of 1

Issue 10: Is Hydro One's proposed Smart Grid rate adder appropriate?

Original Interrogatory: 10.0-BLC-01

Ref. Exhibit E1-2-1, Attachments 2-4, pages 1-4.

What is the basis for assigning the Smart Grid rider as a volumetric charge instead of a fixed charge?

Original Response:
The Smart Grid Rider collects incremental 2013 revenue associated with Smart Grid OM&A expenses as detailed in Exhibit C1, Tab 1, Schedule 1. Hydro One proposes using a variable rate rider to be consistent with the approach used by the Board in collecting incremental revenue in their Decisions on Guelph"s (EB-2010-0130), Oakville"s (EB-2010-0104) and Kingston Hydro"s (EB-2011-0178) IRM applications

Follow Up Questions
10.0-BLC-01-001

The Decisions referenced in the initial response to this IR, quoted OEB Decisions for Guelph Hydro (EB-2010-0130), Oakville Hydro (EB-20120-0104) and Kingston Hydro (EB-2011-0178). The referenced utilities all serve a single urban residential class of customers with a similar usage profile across that class. Hydro One on the other hand, has 4 different residential rate classes with differing consumption profiles and different revenue/cost relationships. What is **Hydro One's** basis for establishing the Smart Grid Rider, given that Hydro One"s customer base is so different from those of the referenced utilities?

Response

Hydro One is proposing an approach for collecting Smart Grid revenues that aligns with previous Board approvals. Hydro One is not aware that differing consumption profiles has been a Board consideration in approving the use of only a volumetric rider.

A volumetric charge will apply to all rate classes, each of which has customers of differing consumption profiles. Hydro One does not know the extent to which customers in other distributor's rate classes have differing consumption profiles.

Balsam Lake Coalition (BLC) Question #2 List 1

Question

Exhibit I
Tab 10
Schedule 3.02 BLC 2
Page 1 of 1

Issue 10: Is Hydro One"s proposed Smart Grid rate adder appropriate?

Original Interrogatory 10.0-BLC-02
If indeed a volumetric charge is appropriate, why was it not set uniformly across all rate classes?

Original Response:
See response at Exhibit I, Tab 10 Schedule 7.06 CCC 20

Exhibit I, Tab 10, Schedule 7.06 CCC 20
"The magnitude of the Smart Grid volumetric charge for each rate class is established using the Board's IRM methodology. The Board's methodology determines the amount of Smart Grid Revenue to be collected from each rate class based on the total revenue share by rate class as shown in column A of Exhibit E1, Tab 2, Schedule 1, Attachment 2 and determines the volumetric charge by dividing the revenue to be collected from each class by the forecast volumetric billing determinant (e.g. kWh consumption for residential rate classes). The charge for Seasonal customers is higher because of the relatively low kWh consumption of the Seasonal rate class."

Follow Up Question:

a) Why do the revenue $ shown in Column A of Exhibit E1, Tab 2 Schedule 1, Attachment 2 not agree with the revenue $ shown in Exhibit D, Tab 1, Schedule 1 tables 3,4,5 & 6?

b) Given that the Revenue Collected is significantly overstated for both Urban and Seasonal rate classes, according to the Density study, what are the appropriate adjustments to be made to the proposed Smart Grid Rider (Exhibit E1, Tab 2 Schedule 1, Attachment 2, page 1 of 1) when those revenue targets are corrected?

c) Given that the benefits from the Smart Grid program are recognized by all Hydro One customers independent of their consumption profile, and that Hydro One"s Total Distribution costs are not significantly volume related (reference Density Study Econometric Model Exhibit D-1-1, Attachment 1, pages 12 & 13 Figures 3, 4, 5&6), why would Hydro One not recommend a uniform volumetric rate across all customer classes? The proposed model is totally inequitable in that it assesses some „above average" seasonal customers with not only a punitive rate but also an excessive total incremental cost.

Response

a) Exhibit E1, Tab 2, Schedule 1, Attachment 2 shows the **approved** 2011 revenue to be collected by rate class, while the figures in the tables referenced in Exhibit D1, Tab 1, Schedule 1 are from the output of the 2010 Cost Allocation (CA) Model which was based on the **proposed** 2010 Revenue Requirement included in Hydro One's rates application EB-2009-0096.

b) Hydro One has applied the Board's methodology which uses the most recently approved load forecast and currently approved rates to determine the revenue collected from each rate class. This revenue share is the basis for splitting the Smart Grid costs to be collected from each rate class. If the Board approves the proposed Density Study adjustments the rider amounts could be recalculated based on the adjusted revenue requirement by rate class as shown in Exhibit D1, Tab 1, Schedule 1, Attachment 3.

c) Hydro One has applied the Board's methodology in calculating the rider amounts. The Board methodology recognizes that once Smart Grid costs are included in the CA Model, as part of a rebasing application, the costs will be allocated to the various rate classes per the approved methodology which uses a number of allocators (e.g. # of customers, customer load) and allocation factors (e.g. minimum system, density weights, billing factors). The currently approved share of revenue requirement by rate class is a reasonable indicator of how Smart Grid costs will eventually be allocated to the various rate classes.

Balsam Lake Coalition (BLC) Question #3 List 1

Question

Exhibit I
Tab 13
Schedule 3.05 BLC 7
Page 1 of 1

Issue 13: Is Hydro One"s proposal for the implementation of the Density Study findings appropriate?

Original Interrogatory: 13.0-BLC-07
Please provide a summary of the number of Seasonal class customers located in each of the Residential density zone (i.e. UR, R1 & R2).

Original Response:
"UR", "R1", "R2" and "Seasonal" are customer rate classes, not density zones. These four rate classes account for all residential customers in Hydro One"s distribution service territory. By definition, there are no Seasonal customers in UR, R1 and R2 rate classes.

Follow Up Questions:

Exhibit I
Tab 13
Schedule 3.05 BLC 7

13.0 – BLC-07- 001
Please provide a summary of the number of Hydro One Residential customers by customer class (Residential Urban, Residential R1, Residential R2 & Seasonal) for each of the 48 Operating Territories, effective 31 December, 2011.

13.0 – BLC-07 – 002
For each of the 48 Operating Territories, please provide the number of Seasonal customers who are served on the same feeder network as: Urban customers; Residential R1 customers and Residential R2 customers.

13.0 – BLC – 07 – 003
Please provide consumption profiles (# of customers, average, median, and standard deviation) for Years 2009, 2010 & 2011, by Operating Territory for the following Residential Rate Classes:

Urban Residential – UR
Medium Density Residential – R1
Low Density Residential – R2
Seasonal Residential

Response

BLC 07 – 001

The data effective December 31, 2011 is broken out into 50 operating areas, and is provided below.

Operating Centre	R1	R2	Seasonal	UR
Algoma	3263	2282	1510	5377
Alliston	4167	8615	367	1
Arnprior	5972	7797	1593	3008
Aylmer	4640	6968	188	
Bancroft	5298	7054	12733	
Barrie	12408	8136	2832	2
Beachville	7156	11293	82	
Bolton	4990	5945	59	7069
Bowmanville	10721	5731	380	6496
Bracebridge	2549	4286	11768	
Brockville	4576	9534	2428	8197
Clinton	9354	7737	2643	
Cobden	8022	8084	2008	3883
Dryden	7641	1713	729	3
Dundas	12581	4915	213	9261
Essex	15579	7214	1608	5989
Fenelon Falls	15240	8700	6916	6396
Guelph	2916	7546	642	
Huntsville	4327	6156	8264	
Kapuskasing	5192	1999	806	
Kenora	2322	5998	5553	
Kent	5121	10517	911	
Kingston	16604	11529	4221	12198
Lambton	9717	5108	1597	
Lincoln	5882	2846	625	5918
Listowel	5273	5082	437	
Manitoulin	2946	3215	2842	1
Minden	4736	2634	11044	
New Liskeard	8737	3627	1500	3383
Newmarket	19442	9372	1172	16209
Nipissing	5077	9585	3861	
Orangeville	2378	9785	343	1515
Orillia	9909	3760	3680	
Orleans	8508	4397	70	21046
Owen Sound	12451	11905	9757	8207
Parry Sound	1597	4441	10530	
Penetanguishene	5642	4313	9378	1
Perth	6410	12726	5715	10275
Peterborough	16791	13635	4913	
Picton	11248	8383	1575	
Simcoe	2551	9931	1363	
Strathroy	7490	10403	50	2
Sudbury	15495	6934	2963	6138
Thunder Bay	10467	5442	3226	
Timmins	3676	2531	1162	12231
Trenton	13621	6937	374	6252
Tweed	7433	11303	6926	2
Vankleek Hill	8277	11738	456	2
Walkerton	6578	10991	2811	1
Winchester	19201	17711	191	28

BLC 07 - 002

Over 99% of all Seasonal customers, across all Operating areas, are on feeders that are also used to supply other residential rate classes.

BLC 007 - 003

The requested information has been provided for all customers in Hydro One's service territory as the level of detail requested is not readily available by Operating Territory. The Tables below provide the requested data for the residential rate classes for 2010 and 2011. Data for 2009 is broken down by Hydro One's rate class definition (prior to harmonization) and cannot be practically mapped to the new rate classes used in this application.

	Actual Billing Quantities and Consumption Profiles for 2010				
Rate Class	**No. of Customers**	**Sales (GWh)**	**Average Consumption per customer (kWh)**	**Median (kWh)**	**Std. Deviation (kWh)**
UR	156,008	1,541	9,881	9,123	6,062
R1	393,658	4,393	11,159	9,793	7,245
R2	366,295	5,494	14,999	11,902	13,777
Seasonal	158,247	718	4,537	2,182	6,410

	Actual Billing Quantities and Consumption Profiles for 2011				
Rate Class	**No. of Customers**	**Sales (GWh)**	**Average Consumption per customer (kWh)**	**Median (kWh)**	**Std. Deviation (kWh)**
UR	159,086	1,541	9,684	8,219	5,546
R1	402,173	4,402	10,946	8,913	9,015
R2	368,479	5,491	14,903	11,263	12,523
Seasonal	157,017	701	4,466	2,056	6,287

Consumers Council of Canada (CCC) Question #1 List 1

Question

T1/S 7.01 (CCC #1) Attachment 1, p. 12/28 (redacted)
The 2013 rate increase set out in the April 5, 2012 Submission to the Board of Directors is 4.9%. Is this consistent with HON's current application? If not, please explain how this number relates to the 2.9% set out in the Application.

Response

The primary difference in the 4.9% presented in the early 2012 Board of Directors submission and the 2.9% increase in the current application is the inclusion in the latter of the disposition of Group 1 Variance Accounts. This has the effect of lowering rates by 1.7%. All other changes are less than 0.1%.

Consumers Council of Canada (CCC) Question #2 List 1

Question

T//S7.01 (CCC #1) Attachment 2, p. 3
The interrogatory states that the Threshold is $292 million. Please reconcile this with the proposed threshold of $332 set out in other references.

Response

The $292M listed in the submission spells out the amount of capital above the threshold. The threshold calculated at the time came to $353Mn. The difference between this number and the currently filed threshold of $332 is based upon a change in the distribution revenue change from load growth. At that time, a factor of -0.64% was used rather than the -1.04% that is embedded in the current calculation. Therefore, the threshold value was higher.

Threshold Calculation Summary		
($Mn)	Current Evidence	At time of Submission in CCC #1 Attach, 2
In-service Additions:	644	644
Calculated Threshold Value	332	353
Excess Above Threshold	312	292

Consumers Council of Canada (CCC) Question #3 List 1

Question

T2/S 5.02 (VECC #5)
Actual Distribution Revenue was $1,165.8 M in 2011 as compared to the approved amount of $1,149 M. Please explain the reasons for the variance.

Response

Please refer to Exhibit I, Tab 2, Schedule 5.02 VECC 5, part d.

Consumers Council of Canada (CCC) Question #4 List 1

Question

T2/S7.01 (CCC #5)
The question was looking for forecast and actual capital expenditures for each year 2006-2011. The answer only provided actuals. Please provide the forecast numbers.

Response

Actual and OEB Approved Capital Expenditure												
	2006		2007		2008		2009		2010		2011	
	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved
Typical Capital Spending	378.1	333.0	399.9	N/A	435.3	393.0	455.5	N/A	430.5	469.9	431.9	437.6

All smart meter, smart grid, renewable generation and CIS capital expenditures have been excluded
2007 and 2009 rates were not based on Cost of Service applications and therefore no approved capital expenditure was available

Consumers Council of Canada (CCC) Question #5 List 1

Question

T2/S7.03 (CCC# 7)
The question asked for a detailed budget for "typical" spending and 2012 actual spending to date. Please provide.

Response

2012 Actual Typical Capital Expenditure (up to September 30)	
	2012 YTD
Sustaining	159.0
Development	117.2
Operations	0.3
Shared Services	43.2
Total Typical Capital Spending	319.7

Consumers Council of Canada (CCC) Question #6 List 1

Question

T10/S 1.02 (Board Staff 3# 30)
Please explain how the variances between forecast capital and OM&A and actual levels of spending with respect to the Smart Grid will be trued up.

Response

Smart Grid expenditures are tracked in a variance account. At the next Cost of Service filing the audited balance will be disposed of.

Canadian Manufacturers & Exporters (CME) Question #1 List 1

Question

With respect to Hydro One's response at Exhibit I, Tab 17, Schedule 4.01; the Board's expectation expressed at page 25 of its October 18, 2012 Renewed Regulatory Framework for Electricity ("RRFE") Report that "... distributors ... consider total bill increases when they engage in planning ..."; and total electricity price increases that electricity consumers are likely facing over the years 2013 to 2016, CME seeks further details with respect to the customers that Hydro One classifies as manufacturers, including the different rates under which members of this constituency take service, as well as Hydro One's estimates of the total electricity price increases that these customers are likely facing in 2013 and the four (4) years beyond.

In the context of those likely total electricity price increases, we also seek Hydro One's best estimates of the extent to which its 2013 and 2014 settled transmission rates, its proposed distribution rates in 2013 and in years, the Global Adjustment ("GA"), and other factors comprise components of the total "all in" price increases that manufacturers are likely facing.

Having regard to the foregoing, we seek from Hydro One the following additional information:

a) The total number of distribution customers used for the purposes of deriving the rate impacts shown in Exhibit E1, Tab 3, Schedule 1;

b) The number of customers in each rate class and sub-class that Hydro One classifies as manufacturers;

c) The consumption in each rate class and sub-class attributable to customers that Hydro One classifies as manufacturers, with that total amount expressed as a percentage of the total consumed by all customers;

d) The proportion, expressed as a percentage, of demand-related costs allocated to each rate class serving manufacturers, for which the manufacturers in that class are responsible, along with the proportion, expressed as percentage, of the company's total demand-related costs for which manufacturers are responsible;

e) Using the data that Hydro One considers to be appropriate, Hydro One's best estimate of the approximate total "all in" electricity price increases its manufacturer customers are facing in 2013 over 2012 and year over year thereafter to 2016;

f) The proportion of the estimated price increases provided in response to subparagraph (e) attributable to each of the following:
(i) Hydro One Distribution proposed rate increases;
(ii) Hydro One Transmission rate change;

(iii) The GA with a breakdown between the various factors the contribute to the GA to be provided to the extent that Hydro One internally has estimates of these components; and

(iv) Other factors.

Response

a) The total number of customers by rate class used in the load forecast that is the basis of the rate impacts shown in Exhibit E1, Tab 3, Schedule 1 are those used in the cost allocation model submitted under Hydro One's Rate application in EB-2009-0096 as shown in interrogatory response Exhibit 1, Tab 13, Schedule 5.10 VECC58.

b) Manufacturers are included in the Sub-transmission (ST) and General Service rate classes. Hydro One does not have a specific forecast for the number of manufacturers within those classes.

c) The total forecast load consumption for the ST and General Service rate classes are included in the data provided in Sheet 10 of the IRM Model at Exhibit E2, Tab 1, Schedule 1. Hydro One does not have a specific forecast of the consumption of manufacturers within those classes.

d) The share of demand-related costs allocated to the rate classes that serve manufacturers is provided in the table below. This data is per the information included in Tab O5 of the Cost Allocation Model submitted in Hydro One's 2010/2011 Rates Application EB-2009-0096. Hydro One does not have information on the amount of those demand related costs that are specifically allocated to manufacturers.

	GSe	UGe	GSd	UGd	ST	All Rate Classes
Demand Related OM&A Costs ($M)	$33.6	$2.6	$54.1	$4.9	$12.5	$274.3
% Share of Total Demand-related OM&A Costs	12%	1%	20%	2%	5%	

e) Hydro One's estimate of the total bill impacts facing manufacturers in 2013 over 2012 are those shown for the ST and General Service rate classes in the detail impact sheets provided in Exhibit E2, Tab 3, Schedule 1, and summarized in Table 1 of Exhibit E1, Tab 3, Schedule 1. An estimate of the bill impacts beyond 2013 is outside the scope of this proceeding.

f) The breakdown of the impact associated with the Energy, Distribution, Transmission, and Regulatory bill components is included in the rate impact sheets produced by the Board's IRM model, which are provided at Exhibit E2, Tab 3, Schedule 1. The GA costs are included as part of the Energy bill component and Hydro One does not have a breakdown of the GA portion or an estimate of the factors that contribute to the GA costs.

Energy Probe (EP) Question #5 List 1

Question

**Ref: Exhibit I Tab 2, Schedule 5.05 VECC 8 and
Exhibit B, Tab 1, Schedule 1, Page 9 Table 3**

a) Please provide a schedule showing the actual (2012 YTD) and forecast in service date by month for all 2012 and 2013 *major* capital projects by category including Typical Capital, Escalated Issue Capital, CIS and Other Capital.

b) Indicate any changes to 2012/2013 ISA dates forecast in EB-2009-0096.

c) Reconcile to the amounts of 2012 and 2013 CAPEX and ISA in part a) to the above references.

d) Please provide the Rate Base and Revenue Requirement impact of a delay of $10 million in scheduled ISA for 2013.

Response

a)
- In-Service additions have been updated in Exhibit I Tab 2 Schedule 5.05
- Actual 2012 Capital Expenditures Year-To-Date is available in Technical Conference response CCC 5
- Please refer to Technical Conference Response VECC 5, Part a) for 2013 Typical Capital
- Exhibit B Tab 1 Schedule 2 Page 5 includes details for all Other Capital

b) Among the list of major capital programs/projects submitted in EB-2009-0096, only one had projected in-service date in 2012/2013 - "Cornerstone Phase 3 – Enhance Integrated Planning" or "IT2". For more information about this project, please refer to EB-2009-0096, Exhibit D2, Schedule 2, Tab 2 and Exhibit D2, Schedule 2, Tab 3, IT2.

The ISA date for this project did not change. It went in-service in 2012 as planned (indicated in the EB-2009-0096 pre-filed evidence).

c) The list of projects in part a) is just a subset of the total 2013 CAPEX and ISA presented in Exhibit I, Tab 2, Schedule 5.05 VECC 8 and Exhibit B, Tab 1, Schedule 1, page 9, table 3.

d) Rate Base and Revenue Requirement impacts are partially dependent on the Deprecation and CCA parameters associated with the asset in question. Therefore, it is not possible to accurately provide details without further detailed knowledge of the asset whose delay is causing the reduction.

Nonetheless, assuming the asset in question is part of Typical Capital and uses the same average depreciation and CCA rates then the Revenue Requirement impact of a $10M reduction in ISA would be $1.0M.

Energy Probe (EP) Question #6 List 1

Question

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Ref: Exhibit I, Tab 4, Schedule 2.02 Energy Probe 16 Parts d) and e)

a) Please explain/reconcile the annual CIS Revenue Requirement for 2013/2014 of $6.08 million provided in the response relative to the amounts shown in Line 8 of Table 3 (Updated).

b) Are the net revenue requirement amounts shown on Line 8 the difference between the gross RR on Line 6 and the RR net of benefits/cost reductions?

c) Please show the amounts of benefits/cost reductions included in the calculation of the net revenue requirement on Line 8 of Table 3.

d) Please reconcile these amounts to the response Exhibit I, Tab 4, Schedule 2.03 EP 17 parts c) and d).

e) Please provide a schedule that shows the 3 requested levelized cost calculations (EP 16 part e)) for the full life of the new CIS 2013-2024.

f) Is Hydro One prepared to commit to a 10 year levelized cost per customer for CIS?

g) If not, why not? If so, what would be the annual amount per customer and what conditions/caveats would Hydro One require (e.g. no change in regulatory requirements)?

Response

a) The figures for the 2013 CIS Revenue Requirement that were provided in the original response ($6.8M), align with the figures provided in Table 3 ($6,798,917).

b) Line 8 depicts Hydro One's net revenue requirement. It is calculated by taking Line 7: CIS Project Costs and subtracting benefits & cost reductions. The benefits & cost reductions that have been removed in each are provided below.

Benefits Removed from Line 7													
Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTAL
Benefits Removed from Line 7 ($M)*	$0.00	$0.00	($23.71)	($23.90)	($23.91)	($23.94)	($24.06)	($23.98)	($23.99)	($24.04)	($24.04)	($24.14)	**($239.72)**

*For 2013 and 2014 savings are offset by cumulative project costs, therefore the benefit is $0.00.

CIS Business Benefit Breakdown by LOB ($M)								
Line of Business	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Customer Service	$2.3	$5.5	$9.3	$9.5	$9.5	$9.5	$9.5	$1.9
IT	$0.0	$2.9	$17.7	$15.2	$7.6	$7.7	$7.6	$1.5
Finance	$5.3	$8.0	$8.0	$8.0	$8.0	$8.0	$8.0	$1.6
TOTAL	$7.6	**$16.4**	**$35.0**	**$32.6**	**$25.0**	**$25.2**	**$25.1**	**$5.0**
CIS Project OM&A costs	($13.6)							

The primary difference between the two tables is that the second table includes items that relate to capital investments for system upgrades etc. which have been avoided with the implementation of the new CIS.

c) See response to part b) above

d) See response to part b) above

e)

Average Cost per Customer Comparison														
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2013 - 2024 Total	2013 - 2024 Average
i) CIS Project Cost @ 40% equity	$5.52	$5.47	$24.64	$23.63	$22.39	$21.20	$20.01	$18.84	$17.68	$16.54	$7.95	$0.00	**$183.87**	**$15.32**
ii) Average Cost per Customer as Filed	$5.52	$5.47	$5.77	$4.79	$3.72	$2.68	$1.57	$0.63	($0.38)	($1.38)	($9.81)	($17.67)	**$0.89**	**$0.07**
iii) Levelized Cost per Customer	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93	**$11.11**	**$0.93**
iv) Levelized Cost per Customer Inflated at CPI	$0.93	$0.95	$0.97	$0.99	$1.01	$1.03	$1.06	$1.08	$1.10	$1.13	$1.15	$1.18	**$12.56**	**$1.05**

Total Cost to Rate Payer Comparison ($M)														
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2013 - 2024 Total	2013 - 2024 Average
i) CIS Project Cost @ 40% equity	$6.80	$6.80	$30.96	$29.97	$28.67	$27.40	$26.11	$24.81	$23.50	$22.19	$10.76	$0.00	**$237.95**	**$19.83**
ii) Average Cost per Customer as Filed	$6.80	$6.80	$7.25	$6.07	$4.76	$3.46	$2.05	$0.82	($0.50)	($1.85)	($13.28)	($24.14)	**($1.77)**	**($0.15)**
iii) Levelized Cost per Customer	$1.14	$1.15	$1.16	$1.17	$1.19	$1.20	$1.21	$1.22	$1.23	$1.24	$1.25	$1.27	**$14.43**	**$1.20**
iv) Levelized Cost per Customer Inflated at CPI	$1.14	$1.18	$1.21	$1.25	$1.29	$1.33	$1.38	$1.42	$1.46	$1.51	$1.56	$1.61	**$16.35**	**$1.36**

DX Rate Impact Comparison (%)													
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2013 - 2024 Average
i) CIS Project Cost @ 40% equity	0.59%	0.59%	2.69%	2.61%	2.50%	2.38%	2.27%	2.16%	2.05%	1.93%	0.94%	0.00%	**1.73%**
ii) Average Cost per Customer as Filed	0.59%	0.59%	0.63%	0.53%	0.41%	0.30%	0.18%	0.07%	-0.04%	-0.16%	-1.16%	-2.10%	**-0.01%**
iii) Levelized Cost per Customer	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	**0.10%**
iv) Levelized Cost per Customer Inflated at CPI	0.10%	0.10%	0.11%	0.11%	0.11%	0.12%	0.12%	0.12%	0.13%	0.13%	0.14%	0.14%	**0.12%**

Notes Accompanying the Tables Above

1. Scenario i) above shows the CIS Project Costs @ 40% equity. This corresponds to line 7 in EB-2012-0136 Exhibit B, Tab 3, Table 3 divided by the total number of customers.
2. Note that this is what the rate payers would have been asked to pay if the project did not have any financial benefits
3. Scenario ii) above shows the CIS Revenue Requirement. This corresponds to line 8 in EB-2012-0136 Exhibit B, Tab 3, Table 3 divided by the total number of customers
4. Scenario iii) above shows the CIS Revenue Requirement with costs levelized on a per customer basis between 2013 & 2024
5. Scenario iv) above shows the CIS Revenue Requirement with costs levelized on a per customer basis between 2013 & 2024, inflated at CPI
6. CPI is assumed to be 2.2% per year
7. For the DX Rate Impact Calculations, we have assumed total the total DX Revenue Requirement to be fixed at 2011 OEB approved rates.

School Energy Coalition (SEC) Question #2 List 1

Question

[I/1/5.03] Please provide the full calculations of the 4.7% return on rate base and the 11.4% return on equity.

Response

Please refer to Technical Conference Response VECC 3 parts a) and c).

School Energy Coalition (SEC) Question #4 List 1

Question

[I/1/7.01] With respect to the submission to the board of directors:

a. p. 1. Please explain the phrase "have resulted in the Distribution rate increase being requested for 2012 being below the required regulatory rate threshold for a COS application."

b. p. 2. Please provide a detailed explanation, including calculations, with respect to the increase of $40 million in budgeted revenues and the increase of $29 million in net income for 2012.

c. p. 4. Please provide a calculation of the dollar impact of the change in allowed ROE from the 9.66% baked into rates to the most recent Board-approved level, showing the difference in ROE between the two levels based on 2011 Board approved common equity, and the gross-up to reflect a before-tax equivalent using forecast 2013 tax rates.

d. p. 6. Please provide the November 2011 and April 2012 distribution load forecasts for 2013, and any more recent load forecast currently available for 2013.

e. p. 8. Please confirm that the proposed capital spending for 2013 is "consistent with previous capital spending levels already approved by the OEB in the 2011 Distribution COS application". Please explain how the proposed ICM spending is "incremental".

f. p. 12. Please compare the 4.9% distribution rate increase for 2013 on this slide with the actual distribution rate increase in the Application, and provide details on the reasons for any variance.

g. p. 25. Please recalculate the revenue line in the table to show the actual revenue that would have been necessary to produce the Board's formula ROE in each year, assuming costs remained constant. By way of example, for 2013 reduce the figure of$3,783 sufficiently so that, without changing costs, interest rates, equity thickness or tax rates, the result in the ROE (GAAP) line would as a percentage be equal to the Board's formula ROE percentage.

h. p. 28. Please compare the 4.9% rate increase in this document to the rate increase forecast in the November 2011 update, and provide details on the main reasons for any difference.

Response

c) Review of Capital Cost parameters is something that is only done at a Cost of Service proceeding. In an IRM/ICM proceeding there exists no mechanism to allow for a change in revenue to account for changes in capital costs. Nevertheless, we have provided an estimate of the change in Revenue Requirement below:

	Final Rate Order	Update ROE	Difference
($ millions)	**2011**	**2011**	**2011**
OM&A	525.0	525.0	-
Depreciation	283.7	283.7	-
Capital Tax	-	-	-
Return on Debt	161.3	161.3	-
Return on Equity	192.7	182.7	(10.0)
Income Tax	34.2	27.6	(6.6)
Green Energy Rate Riders/Adders	20.6	20.6	-
Base Revenue Requirement	**1,217.5**	**1,201.0**	**(16.6)**
Deduct: External Revenue	48.1	48.1	-
Deduct: Green Energy Rate Riders/Adders	20.6	20.6	-
Rates Revenue Requirement	**1,148.9**	**1,132.3**	**(16.6)**
Rate Base	4,986.6	4,986.6	
Capital Structure			
Short Term Debt	4%	4%	
Long-Term Debt	56%	56%	
Common Equity	40%	40%	
Rate of Returns			
Short Term Debt	2.43%	2.43%	
Long-Term Debt	5.60%	5.60%	
Common Equity	9.66%	9.16%	
Returns			
Short Term Debt	4.8	4.8	
Long-Term Debt	156.5	156.5	
Common Equity	192.7	182.7	
Taxes			
Return on Equity	192.7	182.7	
Regulatory Income Tax	34.2	27.6	
Regulatory Net Income (before tax)	226.9	210.3	
Timing Differences	(100.8)	(100.8)	
Taxable Income	126.1	109.5	
Tax Rate	28.25%	26.50%	
Income Tax	35.6	29.0	
less: Income Tax Credits (R&D, Education)	(1.4)	(1.4)	
Regulatory Income Tax	34.2	27.6	

d) Both the November 2011 and April 2012 updates to the Board are using the load forecast prepared in October 2011, which is provided below:

Rate Class	2013 forecast GWh	2013 forecast kW
UR	1,588	
R1	4,567	
R2	5,526	
Seasonal	741	
GSe	2,260	
GSd	2,937	10,225,509
UGe	400	
UGd	710	1,961,207
St Lgt	137	
Sen Lgt	24	
DGen	7	60,141
ST	16,436	30,123,232

The GWh forecast was updated in June 2012 and is provided below. Please note that the June 2012 forecast did not include an update for kW.

Rate Class	2013 forecast GWh
UR	1,583
R1	4,547
R2	5,517
Seasonal	722
GSe	2,313
GSd	2,963
UGe	398
UGd	710
Lgt	149
DGen	8
ST	16,678

f) Please refer to Technical Conference Response CCC 1.

g) Please refer to Technical Conference Response VECC 8.

School Energy Coalition (SEC) Question #5 List 1

Question

[I/1/7.01] With respect to the submission to the Regulatory and Public Policy Committee:

a. p. 1. Please confirm that the rate rider with respect to smart grid and advanced distribution system OM&A costs is being sought as a Z factor for IRM purposes. If this is not the case, please provide details of the regulatory basis on which the rate rider is being sought.

b. p.2. Please provide details of the two scenarios presented at the February 8, 2012 meeting. Please identify the main differences between the tow.

Response

a. The rate rider with respect to smart grid and advanced distribution system OM&A costs is not being sought as a Z factor. For IRM purposes, the Z factor is for recovery of extraordinary expenditures beyond the Company's control. Smart grid OM&A does not belong to this category.

b. The two scenarios presented at the February 8, 2012 meeting were:

   1. File a Combined Distribution and Transmission Cost-of-Service application for 2013 and 2014 by June 2012.
   2. File an IRM application for 2013 distribution rates including an ICM, in July 2012 and an IRM filing in 2013 for 2014 rates with an ICM. No application would be filed for 2012 rates. The OEB directed Density Study, might be filed to initiate the correction needed to urban rates.

School Energy Coalition (SEC) Question #5-1 List 1

Question

*[I/2/1.01(b)(i)] Please confirm that the premise of this Application is that the current 3rd generation IRM structure does not provide appropriate recovery for continued capital spending, at a constant rate, but in excess of depreciation.

Response

What this application demonstrates is that in order to maintain an amount of Typical Capital spending in line with what was defended and approved in EB-2009-0096, a material increase in Rate Base is required. This increase in Rate Base is not directly funded and as such, should Hydro One proceed with these investments it would endure a punitive reduction in its equity return potentially below Board approved rates. Hydro One would necessarily seek to reduce its capital spending plans which would in turn increase the risk of degradation of performance of the system.

School Energy Coalition (SEC) Question #7 List 1

Question

[I/2/1.01, Attach. 2, p. 6] Please confirm that the GDP-IPI inflator provides for are venue requirement increase related to capital spending, before recognition of growth in load or number of customers, productivity gains, or stretch factor, of $13.44M[($354M+$283.7M+$34.3M) times 2%], which represents the annual revenue requirement for approximately $135M in incremental capital spending. Please provide details of the productivity improvements expected to be achieved by the Applicant relative to capital spending in the Test Year, and any variance between the revenue requirement impact of those improvements, and the $7.53M in revenue requirement savings assumed by the combination of the productivity factor and the stretch factor.

Response

While Capital Investments often yield productivity savings, those savings don't normally materialize until well into the future. As such, the investments described for 2013 do not yield substantial productivity savings in 2013.

School Energy Coalition Question #8 List 1

Question

[I/2/1.06, p. 3] Please confirm that actual revenue for 2011 is approximately 9.3% greater than actual revenue for 2010. Please confirm that actual revenue for 2011 is approximately 1.5% higher than 2011 rebased revenue requirement. Please reconcile these growth rates with the negative growth rate claimed of -1.02%.

Response

Actual 2011 Revenue	$1,168		
Actual 2010 Revenue	$1,066	Increase of 2011 over 2010	9.5%
2011 Revenue Requirement	$1,149	Increase of Actual of Base 2011	1.6%

2011 Revenue Requirement	1,149		
2010 Revenue at 2011 Rates	1,161	Decrease due to Load in 2011	-1.04%

<u>School Energy Coalition (SEC) Question #10 List 1</u>

Question

[I/2/1.09(j)] Please provide a calculation of the long term savings resulting from the increase in the wood pole replacement program. Please provide any internal documents that analyze the costs and benefits of this program.

Response

School Energy Coalition (SEC) Question #11 List 1

Question

[I/2/1.11(h)] Please provide the internal documents showing the calculation of the "lowest total sustainment cost over time through a combination of capital and OM&A solutions" for each of the major areas in which a spending increase is being proposed.

Response

School Energy Coalition (SEC) Question #12 List 1

Question

[I/2/1.14] Please provide the average number of spares in each category for each of the years 2006 through 2011.

Response

Please refer to Technical Conference Response for VECC 10 part c).

School Energy Coalition (SEC) Question #13 List 1

Question

SEC - 13 [I/2/2.06] Please provide the average life of a transformer after it has been refurbished, by category and by cost.

Response

As indicated in Exhibit I, Tab 2, Schedule 1.11 Staff 12 part k), refurbishment of a transformer does not extend the expected service life (ESL). The remaining ESL of a transformer following refurbishment is therefore primarily a function of the age when it is refurbished, as well as the scope of the refurbishment work.

Planned refurbishment of distribution transformers is typically only considered when the transformers have symptoms of degradation commonly found in units older than 40 years. The average age of a transformer when it is refurbished is 44 years, and therefore average expected service life following refurbishment is approximately 6 years. As noted in Exhibit I, Tab 2, Schedule 2.05 EP 7 part (e), the typical OM&A refurbishment cost is $150,000 but can vary between $15,000 and $400,000 depending on the scope of the refurbishment work.

School Energy Coalition (SEC) Question #14 List 1

Question

[I/2/2.06(c)] Please provide the formula for the trend line in figure EP-1.

Response

The trendline in Figure EP-1 of Exhibit I, Tab 2, Schedule 2.08 EP 9 is based on linear regression of the total Class 1 and Class 3 failure data which has a corresponding formula of $y = 1.1697x + 7.8667$.

School Energy Coalition (SEC) Question #17 List 1

Question

[I/2/8.14] Please provide the report on the Board's Form 2-K for 2013 as requested in the original question.

Response

The Board's Form 2-K for 2013 is included as Attachment 1.

There are no incremental full time employees.

There are 30 casual construction trade FTE's in 2013 for the station refurbishment work at a cost of $3.9 million.

There are up to 40 to 50 Hydro One staff supporting the CIS project for parts of 2013 at a cost of $4.7 million and their positions will be backfilled with contract or temporary employment positions.

Therefore total incremental contract staff will be 70 - 80 at a cost of $8.6 million.

File Number:	EB-2012-0136
Exhibit:	X
Tab:	Y
Schedule:	Z
Page:	xx
Date:	

Appendix 2-K
Employee Costs

	LRY - Board Approved	LRY - Actual	Historical Year 2	Historical Year 1	Bridge Year	Test Year
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management						
Non-Union						70 - 80
Union						
Total	-	-	-	-	-	-
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union						
Total	-	-	-	-	-	-
Total Salary and Wages						
Executive						
Management						
Non-Union						
Union						
Total	$ -	$ -	$ -	$ -	$ -	$ -
Current Benefits						
Executive						
Management						
Non-Union						
Union						
Total	$ -	$ -	$ -	$ -	$ -	$ -
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union						
Union						
Total	$ -	$ -	$ -	$ -	$ -	$ -
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$8.6M
Union	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -
Compensation - Average Yearly Base Wages						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Overtime						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Incentive Pay						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Benefits						
Executive						
Management						
Non-Union						
Union						
Total						
Total Compensation	$ -	$ -	$ -	$ -	$ -	$ -
Total Compensation Charged to OM&A						
Total Compensation Capitalized	$ -	$ -	$ -	$ -	$ -	$ -

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

School Energy Coalition (SEC) Question #19 List 1

Question

[I/4/2.01] Please explain how, without tracking costs in the manner suggested in the question, the Applicant is able to calculate ROI for the CIS investment. Please advise what costs are tracked that allow an ROI calculation to be done.

Response

Hydro One does not report total costs based upon the functions listed – namely Meter Reading, Work Management, etc. Since we are unable to accurately provide project costs on a functional basis, an ROI calculation on a functional basis is not possible.

The benefits and the costs of the overall project are assessed to come up with the Business Case metrics.

School Energy Coalition (SEC) Question #20 List 1

Question

Please provide the values in (e) before inclusion of the negative taxcost. Please extend those values out five more years.

Response

Average Cost per Customer Comparison - No Negative Tax - 7 Year Depreciation								
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2009 - 2024 Total**
i) Average Cost per Customer	$25.81	$25.56	$11.31	$9.78	$8.23	$6.70	$5.12	**$92.51**
ii) Levelized Cost per Customer	$13.90	$13.90	$13.90	$13.90	$13.90	$13.90	$13.90	**$97.27**
iii) Levelized Cost per Customer Inflated at CPI	$13.90	$14.20	$14.51	$14.83	$15.16	$15.49	$15.83	**$103.93**

Total Cost to Rate Payer Comparison ($M) - No Negative Tax - 7 Year Depreciation								
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2009 - 2019 Total**
i) Average Cost per Customer	$31.79	$31.79	$14.21	$12.41	$10.54	$8.66	$6.67	**$116.06**
ii) Levelized Cost per Customer	$17.11	$17.28	$17.46	$17.63	$17.79	$17.96	$18.13	**$123.36**
iii) Levelized Cost per Customer Inflated at CPI	$17.11	$17.66	$18.23	$18.81	$19.41	$20.03	$20.66	**$131.92**

DX Rate Impact Comparison (%) - No Negative Tax - 7 Year Depreciation							
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
i) Average Cost per Customer	2.77%	2.77%	1.24%	1.08%	0.92%	0.75%	0.58%
ii) Levelized Cost per Customer	1.49%	1.50%	1.52%	1.53%	1.55%	1.56%	1.58%
iii) Levelized Cost per Customer Inflated at CPI	1.49%	1.54%	1.59%	1.64%	1.69%	1.74%	1.80%

School Energy Coalition Question #21 List 1

Question

[I/4/2.03] Please provide a calculation of working capital allowance reflecting the Finance impact of the new CIS.

Response

Final Working Capital amount will be calculated in the next Cost of Service proceeding using the lead / lag model and inputting the financial parameters in place at that time.

For purposes of a draft estimate, the monthly revenue from RPP customers is estimated at $175M. Improvement in cash flow of 13 days leads to a working capital reduction of $75M.

Estimated Revenue Requirement Reduction - $M	Current
Capital Reduction	75
Interest Cost Reduction	2.1
Equity Cost Reduction	2.7
Tax Effects	1.0
Total Estimated Reduction	**5.8**

Cost of Capital uses 2013 estimated rates

School Energy Coalition (SEC) Question #23 List 1

Question

[I/4/8.04] Please provide the detailed calculations requested.

Response

The original question asked for detailed calculations for each of Rows 4 through 7 for each year. Providing the detail for rows 4 to 6 as requested would result in the public disclosure of commercially sensitive information with respect to licensing & support costs of third party vendors. Such a disclosure would potentially be in breach of those agreements. Moreover, negotiations are currently in progress with vendors on some of the future expenditures. Public disclosure of those estimates could significantly damage Hydro One's bargaining position and thus may potentially raise costs to customers as a result. If the Board deems that production of this information is necessary to determine prudency of the CIS project then Hydro One would be prepared to discuss the filing of this detail in confidence in accordance with OEB guidelines.

The detailed calculation for row 7 has been provided in the response to Technical Conference Response EP 16 d).

School Energy Coalition (SEC) Question #24 List 1

Question

[I/4/8.07] Please provide a breakdown of the cost overruns between a) HCL Axon, b) Hydro One staff, and c) Inergi staff, and reasons in each case.

Response

Contingency Cost Breakdown ($M)	
HCL Axon	$3.2
Hydro One	$5.3
Inergi	$12.8
Interest & Overhead	$4.2
TOTAL	**$25.5**

a) Although Hydro One has a fixed price agreement with our integrator HCL Axon, there has been $3.2M of incremental expenditure with the firm. This expenditure was required due to additional scope that was added to the project after the fixed price agreement was signed. One example of additional scope added was the incremental effort required to address the recent OEB decision to only apply the Ontario Clean Energy Benefit to the first 3000 kWh of consumption per month. Other items include enhanced customer complaint management functionality and more robust address validation/correction capabilities.

b) Additional complexity in various areas of the project including meter data acquisition, Ontario deregulation and data conversion has resulted in an increase in the staff required. Moreover, the project schedule has been necessarily extended to accommodate this increased workload. Hydro One (and Inergi) staff members are billed to the project based upon the total effort expended. The combined effect of the longer duration and increased number of staff required has led to the increase in expenditure.

c) Same as part b) above

School Energy Coalition (SEC) Question #25 List 1

Question

[I/4/9.01] Please provide the two "TBD" figures in (g).

Response

Table 4
Costs for Hydro One Resources on the Project

($M)	2011	2012	2013
Hydro One Labour Cost	$4.70	$6.80	$4.70
Min Number of Hydro One Employees on the Project	25	35	**40**
Max Number of Hydro One Employees on the Project	30	40	**50**

School Energy Coalition (SEC) Question #26List 1

Question

[I/5/2.02 and 5.02] Please provide a calculation of the revenue requirement impact of the CIS for 2013 on the assumption that both depreciation and CCA are calculated on a full-year basis.

Response

Please refer to Exhibit B Tab 1 Schedule 2 Page 6.

School Energy Coalition Question #27List 1

Question

[I/6/8.02] Please provide depreciation and CCA calculations on a project by project basis, i.e. using actual forecasts for each, not averages.

Response

Hydro One does not have available specific depreciation and CCA calculations for every contemplated project adding up to the $414M of in-service capital. Similar projects, especially the smaller ones, are grouped into categories and averages are used to estimate the resulting depreciation and CCA.

Vulnerable Energy Consumers Coalition (VECC) Question #1 List 1

Question

Reference: Exhibit I, Tab 1, Schedule 2.01 EP 1

a) What was Hydro One's actual 2011 Distribution revenue (i.e., comparable to the approved amount of $1,149 M)?

b) Please recalculate the Threshold Value using all the same parameters as in the original Application (Exhibit B, Tab 1, Schedule1, page 1) but calculate the growth factor using the actual 2011 revenues as opposed to the approved 2011 revenues.

Response

a) Please refer to Technical Conference Response SEC 8.

b) Please refer to Technical Conference Response Staff 6.

Vulnerable Energy Consumers Coalition (VECC) Question #3 List 1

Question

Reference: Exhibit I, Tab 1, Schedule 5.03 VECC 3
OEB RRR Filing Guide, April 2012, page 63 and Appendix 5
Exhibit I, Tab 1, Schedule 7.01 CCC 1

a) Per the original question, please provide a schedule that sets out the calculation of the 4.7% Return on Rate Base and the 11.4% Return on Equity for 2011.

b) Please confirm that the 10.5% actual ROE for 2011 for Hydro One overall (per CCC 1, Attachment 1, page 14 of 28) was calculated on the same basis as the 11.4% ROE for Hydro One Networks Distribution.

c) Please reconcile the 11.4% ROE for 2011 for the Distribution business reported in the response to VECC 3 with the 11.8% ROE for 2011 reported to the Hydro One Board per CCC 1, Attachment 1, page 26 of 28).

d) Please provide Hydro One Networks Distribution's 2011 ROE on a deemed basis using the prescribed approach set out in Appendix 5 of the Board's April 2012 RRR Filing Guide.

Response

a) Return on Rate Base:
($236M – Net Income) / ($4,969M – Rate Base) = 4.7%
Return on Equity is detailed in part c)

b) The 10.5% actual ROE for 2011 Hydro One was calculated based on the same factors as the 11.8% and includes notional dividends.

c)

	not including notional dividends	including notional dividends
	2011	2011
Net Income	236.0	236.2
Notional Preferred Dividends		(7.4)
Net Earnings	236.0	228.8
Opening Excess of Assets Over Liabilities	1,976.0	1,976.0
Cumulative Notional Dividends		(130.5)
Closing Excess of Assets Over Liabilities	2,168.0	2,168.0
Cumulative Notional Dividends		(137.9)
Average Excess of Assets Over Liabilities	2,072.0	1,937.8
Net Earnings/Average Excess of Assets Over Liabilities	11.4%	11.8%

d) Using the prescribed approach set out in Appendix 5 of the Board's April 2012 RRR Filing Guide, the deemed ROE is 9.66%.

Vulnerable Energy Consumers Coalition (VECC) Question #4 List 1

Question

Reference: **Exhibit I, Tab 2, Schedule 1.01, Staff 2, part (a)**
OEB EB-2009-0096 Decision
Exhibit I, Tab 2, Schedule 5.05, VECC 8 c)
Exhibit I, Tab 2, Schedule 5.06, VECC 9 a)
Exhibit I, Tab 2, Schedule 5.16, VECC 19
Exhibit I, Tab 2, Schedule 9.01, AMPCO 1

a) With respect to the response to Staff 2 (a), in its EB-2009-0096 Decision, did the OEB find that the approved level of typical capital spending was “non-discretionary”? If yes, please provide the relevant reference.

b) Please confirm that the Board approved levels of capital spending for 2010 and 2011 were in excess of the Minimum Level investment that Hydro One (during the preceding) indicated was required for those years (per Board Decision, page 25). If not confirmed, please explain why not.

c) With respect to VECC 8 & 9 and AMPCO 1, please provide Schedules that set out for each of the years 2010 and 2011:

- The proposed/approved capital spending per Hydro One’s EB-2009-0096 Application broken down between Sustaining, Development, Operations and Other/Shared Services;

- The proposed/approved typical capital spending per Hydro One’s EB-2009-0096 Application broken down between Sustaining, Development, Operations and Other/Shared Services (i.e., adjusted for the factors set out in VECC 8 c));

- The actual capital spending broken down between Sustaining, Development, Operations and Other/Shared Services;

- The actual typical capital spending broken down between Sustaining, Development, Operations and Other/Shared Services (i.e., adjusted for the factors set out in VECC 8 c));

- The Minimum Level of Capital spending (per Hydro One’s EB-2009-0096 evidence) broken down between Sustaining, Development, Operations and Other/Shared Services (Note – Please provide EB-2009-0096 references for the values used); and

- The Minimum Level of “typical” Capital spending (i.e., the Minimum Level of Capital spending from above adjusted for the factors set out in VECC 8 c)) broken down between Sustaining, Development, Operations and Other/Shared Services as per Hydro One's EB-2009-0096 Application.

d) Per the response to Staff 2 (a) (ii), please provide the evidence/analysis that shows that without the accelerated spending on Distribution & Regulating Stations (i.e., both Station Refurbishment and Transformer Spares & Replacement) and Wood Pole Replacement programs specifically in 2013 there will be an unacceptable degradation of service to customers and an unacceptable increase in safety risks, such that this 2013 spending is non-discretionary and cannot be deferred.

e) When did the "vendor" cease supporting the current CIS system?

f) Please explain more fully what is meant by the statement that the current CIS "has reached its end of life" and why this means it must be replaced in 2013.

Response

a) Hydro One's position is that the Typical Capital of $437Mn that was approved in EB-2009-0096 is necessary and must be done. The Typical Capital in this application is materially the same in nature as that approved previously and thus warrants approval.

b) Confirmed (please see tables in part c).

c)

EB-2009-0096 Proposed and OEB Approved Capital Expenditure				
	2010P	**2010B**	**2011P**	**2011B**
Sustaining	185.8	190.4	202.5	207.3
Development	205.7	168.5	252.4	169.1
Operations	8.1	1.4	11.2	1.4
Shared Services	164.8	109.7	110.8	59.8
Typical Capital Spending	564.4	469.9	576.9	437.6

P=proposed, B=Board Approved

Note: The OEB approved Capital Expenditure does not include Smart Grid and Distribution Generation Expenditures as they are currently tracked in variance accounts ($46.6.million and $95.9 million in the 2010 and 2011, respectively), as per the EB-2009-0096 OEB Decision. For more information, please see EB-2009-0096 Draft Rate Order, Exhibit 1.3, page 1, filed April 16, 2010.

EB-2009-0096 Proposed and OEB Approved Capital Expenditure	2010P	2010B	2011P	2011B
Sustaining	185.8	190.4	202.5	207.3
Development (including smart grid and distribution generation)	205.7	N/A	252.4	N/A
Development (Smart Grid and distribution generation component)	37.3	N/A	83.3	N/A
Development (excluding smart grid and distribution generation)	168.4	168.5	169.1	169.1
Operations (including smart grid)	8.1	N/A	11.2	N/A
Operations (smart grid component)	6.7	N/A	9.8	N/A
Operations (excluding smart grid)	1.4	1.4	1.4	1.4
Shared Services (including smart grid)	164.8	N/A	110.8	N/A
Shared Services (smart grid component)	2.7	N/A	2.6	N/A
Shared Services (excluding smart grid)	162.1	109.7	108.2	59.8
Total Capital Spending (including smart grid and distribution generation)	564.4	N/A	576.9	N/A
Total Capital Spending (excluding smart grid and distribution generation)	517.7	469.9	481.2	437.6
P=Proposed, B=Board approved				

N/A: The OEB approved Capital Expenditure does not include Smart Grid and Distribution Generation Expenditures as they are currently tracked in variance accounts, as per the EB-2009-0096 OEB Decision.

Actual Typical Capital Expenditure	2010	2011
Sustaining	185.5	205.5
Development	150.6	143.6
Operations	1.2	1.3
Shared Services	93.2	81.4
Total Typical Capital Spend	430.5	431.9

****Actual Capital Expenditure = Actual “Typical” Capital Expenditure**

EB-2009-0096 Minimum Level and OEB Approved Capital Expenditure				
	2010M	2010B	2011M	2011B
Sustaining	149.4	190.4	166.3	207.3
Development	158.5	168.5	162.1	169.1
Operations	1.1	1.4	1.1	1.4
Shared Services	136.4	109.7	91.6	59.8
Total Capital Spending	445.4	469.9	421.1	437.6
M=Minimum, B=Board Approved				

****Minimum Level of Capital Expenditure = Minimum Level of "Typical" Capital Expenditure**

Note: Capital Expenditures associated with Smart Grid and Distribution Generation are not included as they are currently tracked in variance accounts, as per the EB-2009-0096 OEB Decision.

e) The vendor stopped providing support services for Hydro One's Customer/1 implementation in 2001.

f) End-of-life is a term used with respect to a product supplied to customers, indicating that the product is in the end of its useful lifetime and a vendor will no longer be marketing, selling, or sustaining a particular product and may also be limiting or ending support for the product.

With respect to Hydro One's implementation of Accenture's Customer/1 product - the statement that has reached end of life reflects the fact that:

- its last implementation was in 1999
- it has not been sold since then
- there have been no upgrades or enhancements to the product by the vendor since then
- the vendor has not actively marketed support services for the product since then.

As a software product, Customer/1 is frozen; any new business requirements that Hydro One has must be met by custom enhancements to the product and/or employing other software to meet the need and interfacing that software with Customer/1.

In addition, Hydro One is experiencing performance challenges with the current CIS, which are beginning to impact the service Hydro One is providing to its customers. These are caused by the age of the application and the mainframe hardware that the application runs on.

Taken together, these factors have led Hydro One Networks Inc. to conclude that the application is at end of life and needs to be replaced now.

Vulnerable Energy Consumers Coalition (VECC) Question #5 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 1.01, Staff 2, part (b) (i)
EB-2009-0096, Exhibit D1, Tab 3, Schedule 3, page 9

Preamble: In response to Staff 2 Hydro One states (page 5) that "a significant item in typical capital is the funding for system capability reinforcement. These reinforcements take place in a planned fashion at a relatively steady level from year to year. Presumably, in approval of the capital portion of EB=2009-0096, the Board directed Hydro One to continue its system reinforcement program in future years; not just 2011".

In EB-2009-0096, Hydro One indicated that:
"Capability reinforcement investments, for the most part, address customer growth after the fact, except for larger load connections that require significant modifications to the distribution system prior to connection. This program addresses customer growth that has in some cases occurred many years ago, but the system has remained within rated limits until such time as an incremental load increase will approach the system."

a) Please indicate what portion of the historical typical capital spending was for "system capability reinforcement".

b) The EB-2009-0096 description suggests that capability reinforcement investments are triggered by load growth. How has Hydro One's calculation of the ICM related revenue requirement accounted for these increased revenues that would arise from this load growth?

c) The EB-2009-0096 description suggests that system capability investment requirements are not "steady" but rather periodically triggered when load increases reach system limits. Please reconcile this description with Hydro One's current characterization of system capability reinforcement requirements.

Response

Hydro One is providing a list of 2013 incremental typical capital projects to facilitate a better understanding of the nature of this work. Project summaries are attached. These have been grouped into four categories: Lines (DL), Stations (DS), Fleet (F) and Enterprise Applications Upgrades (E).

Table 1
Summary of Incremental Typical Capital Projects
($ Million)

Description	2013 In Service Projects
Lines	64.2
Stations	7.5
Fleet	32.0
Enterprise Applications Upgrades	28.9
Total	132.6

LIST OF CAPITAL EXPENDITURE PROGRAMS/PROJECTS IN EXCESS OF $1M TEST YEAR – 2013

*($Millions)

1.0 LINES

		2013
DL1	Timmins Downtown Underground Refurbishment Phase 1	1.1
DL2	Morrisburg TS 18M23 Relief	1.5
DL3	Kemptville West DS F2 Relief	1.4
DL4	Deep River Rehabilitation	1.1
DL5	2013 Duart TS Feeder Construction	2.6
DL6	Doane DS Transformer Addition and Feeder Development	3.8
DL7	Napanee Area Study	1.8
DL8	Port Severn DS and Line Work	4.4
DL9	Muskoka TS New M5 Feeder	1.4
DL10	Ballantrae DS Load Balancing	0.3
DL11	Port Hope TS 50M16 Relocation	2.9
DL12	Brockville TS M3 and M4 Underground Replacement	5.7
DL13	Martindale TS 9M5 Phase 3 of 6	1.0
DL14	Distribution System Modification	8.8
DL15	Joint Use and Line Relocations – MTO	4.0
DL16	Joint Use and Line Relocations – Road Authority	1.4
DL17	Joint Use	3.0
DL18	Huntsville DS F3 Feeder Development	2.0
DL19	Brockville TS M2 Phase 3 of 6	1.6
DL20	Alexander DS Monitoring	0.3
DL21	Kam Reg DS Voltage Conversion Stage 2	1.5
DL22	Lauzon Belle River Reconfiguration	1.1
DL23	South Porcupine DS Conversion	1.4
DL24	Sidney TS 12M7 Reconductor	1.1
DL25	Owen Sound TS M28-M23 Tie Line	1.0
DL26	Woods DS F5 and F7 Line Refurbishment	1.1
DL27	Petewawa Craig DS Monitoring	0.6
DL28	City of Owen Sound Refurbishment Phase 2	2.1
DL29	Comber DS Removal	0.9
DL30	Edgeware TS M2 Relocation	0.4
DL31	Haileybury DS Voltage Conversion	1.0
DL32	Lyndhurst DS Area Improvement	0.7

DL33	Malden TS M12 Expansion	0.2
DL34	Minden DS Area Improvement	0.6
DL35	Norwich DS F1 Hatchley Line	0.4
Total		**64.2**

2.0 STATIONS

		2013
DS1	Distribution Stations Recloser Upgrades	1.0
DS2	Distribution Stations Single Phase Transformer Changeouts	1.1
DS3	Distribution Stations Spill Containment Installations	1.1
DS4	Mobile Substation Purchase and Refurbishment	3.2
DS5	Planned Station Component Replacement	1.1
Total		**7.5**

3.0 FLEET

		2013
F1	Fleet Replacement Project	32.0
Total		**32.0**

4.0 ENTERPRISE APPLICATIONS UPGRADES

		2013
E1	Cornerstone Phase 3 - Enhanced Asset Management	10.4
E2	Final Destination Enterprise GIS Database Development	10.9
E3	Enterprise Application Replacement	7.6
Total		**28.9**

Date: November 2012

Hydro One Networks – Investment Summary Document
Timmins Downtown Underground Refurbishment – Phase 1

Reference #: DL1

Investment Name: Timmins Downtown Underground Refurbishment – Phase 1 **In-Service:** December 2013

Need:

In the City of Timmins, underground vaults housing transformers and oil switches have been damaged by water and require replacement. Due to issues with the vault design, including inaccessibility, poor drainage and confined space issues, these are being upgraded to padmount transformers.

Not proceeding with this investment would increase safety and reliability risks associated with deteriorated equipment and substandard vault designs.

Investment Summary:

The City of Timmins has an underground 27.6 kV network that includes 8 underground vaults housing transformers and oil switches. Water damage has deteriorated ground bonds, access ladders and transformer cases. In addition, there are issues with accessibility, poor drainage and confined space. To address these issues the vaults are being upgraded to padmount installations.

Results:

Safety and reliability risks associated with deteriorated equipment and substandard designs are mitigated

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.3**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
Morrisburg TS 18M23 Relief

Reference #: DL2

Investment Name: Morrisburg TS 18M23 Relief **In-Service:** December 2013

Need:

Morrisburg TS 44 kV Feeder 18M23 is heavily loaded, well above its 25MVA rating and requires immediate relief.

Not proceeding with this investment will result in low voltage to customers and continuing overloading on the Morrisburg TS 18M23 feeder that is already above its loading guideline

Investment Summary:

This investment proposes to extend lightly loaded Morrisburg TS feeder 18M24 to offload Morrisburg TS feeder 18M23 to reduce its loading to be within the feeder loading guidelines. The planned work would also provide capability and options for future relief of the 18M25 feeder because this feeder is also approaching its planning capacity.

Results:

- Improve system performance and reliability.
- Maintain supply within standards.
- Optimize backfeed and supply capability for these feeders.

Costs:

	2013($M)
Capital and Minor Fixed Assets (A)	1.5
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**1.5**
Recoverable (C)	0
Net Investment Cost (A+C)	**1.5**

Date: November 2012

Hydro One Networks – Investment Summary Document
Kemptville West DS F2 Relief

Reference #: DL3

Investment Name: Kemptville West DS F2 Relief

In-Service: December 2013

Need:

Prolonged overloading of the Kemptville West DS F2 feeder has resulted in carbonous deposits on the contacts of the feeder recloser. These deposits have resulted in two recloser failures in the last year. Load relief is required to bring the feeder loading within the rated capability of the recloser.

Not remedying this situation will result in continued and increasing risk of mal-operation or non-operation leading to potential equipment damage and possible non-tripping for fault conditions which could compromise public safety. Therefore continued operation under these conditions is unacceptable.

Investment Summary:

The Kemptville West DS is loaded to its planning load limit and requires relief of incremental load. The recloser is a Cooper Type "L" rated for a maximum load of 280A. Load at the recloser has been measured to be 284 A, with reasonable proration to a peak of 307 A.

This investment proposes to extend Acton Corners DS F1 feeder to relieve Kemptville West DS F2 feeder. Both the Acton Corners DS and its F1 feeder have sufficient spare capacity and the feeder is located at a convenient point to facilitate this action.

Results:

- Bring device loading within rating specification values.
- Provide capacity to supply future growth in the vicinity of the expanding northeast edge of Kemptville.
- Optimize the backfeed and supply capability of the feeders.
- Mitigate safety risks.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.4
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**1.4**
Recoverable (C)	0
Net Investment Cost (A+C)	**1.4**

Date: November 2012

Hydro One Networks – Investment Summary Document
Deep River Rehabilitation

Reference #: DL4

Investment Name: Deep River Rehabilitation

In-Service: December 2013

Need:

A portion of Deep River DS 12.5 kV feeder F2 requires conversion from an overhead to underground build due to accessibility issues and end-of-life assets.

Not proceeding with this investment would result in reliability and safety risks and long restoration times.

Investment Summary:

A total of 2 km of sections on the Deep River DS feeder F2 are at end of life and run through back lots, making the feeder inaccessible. The existing overhead line was installed in the 1950s and there is not sufficient clearance on the road allowance for a new overhead line.

This feeder is being converted to underground build on road allowance to ensure that line crews are able to access the equipment and that there is adequate clearance for the new underground build.

Results:

- Safety risks associated with inaccessible line equipment are mitigated.
- Productivity improvements due to reduced repair and response times.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

Hydro One Networks – Investment Summary Document
2013 Duart TS Feeder Construction

Reference #: DL5

Investment Name: 2013 Duart TS Feeder Construction **In-Service:** December 2013

Need:

St Thomas TS is at end-of-life and is being decommissioned. The feeders are required to be transferred to the new transformer station Duart TS. Not doing this work would result in the inability to supply load.

Investment Summary:

St. Thomas TS is a 27.6kV three-wire facility that has reached end-of-life. The new transformer station Duart TS is a four-wire 27.6kV station that has been built to offload both St. Thomas TS and Kent TS (4-wire 27.6kV). This transfer results in enhanced reliability due to the ability to now transfer load between Kent TS and Duart TS.

The purpose of this project is to construct two new feeders M5 and M6 out of the Duart TS and transfer loads from the soon to be decommissioned St Thomas TS and the overloaded Kent TS to Duart TS.

Results:

- Build two new feeder positions from Duart TS to supply the St-Thomas feeders.
- Enhanced reliability due to the ability to transfer loads between Kent TS and Duart TS.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	2.6
Operations, Maintenance & Administration and Removals (B)	0.3
Gross Investment Cost (A+B)	**2.9**
Recoverable (C)	0.0
Net Investment Cost (A+C)	**2.6**

Hydro One Networks – Investment Summary Document
Doane DS – Transformer Addition & Feeder Development

Reference #: DL6

Investment Name: Doane DS – Transformer Addition & Feeder Development **In-Service:** May 2013

Need:

Doane DS has reached its capacity and will exceed it in 2013. This plan seeks to provide relief to Doane DS.

Not proceeding with this investment would result in overloading existing assets leading to inadequacy of supply and increased reliability and customer risks.

Investment Summary:

Doane DS transformer will be reaching its summer planning load limit of 12.5MVA by 2013 in the East Gwillimbury area; mainly in Queensville, Sharon and Holland Landing areas.

The Regional Municipality of York forecasts an annual population growth rate of 5.7% between 2006 and 2031 for the town of East Gwillimbury. This is a load increase of about 23 MVA in the next 10 years.

In order to provide load relief to Doane DS, it is necessary to install a second three-phase 12 MVA, 44/27.6 kV transformer bank at Doane DS with a planned capacity of 13.8 MVA. In addition, the existing T1 reclosers will be converted from hydraulic to electronic for future conversion to SCADA and monitoring. Existing distribution stations in the area will absorb the remaining load. This work also includes overbuilding about 2 kilometers of 27.6kV 3-phase line.

Results:

Install a second transformer at Doane DS and provide adequate and reliable supply capacity to the town of East Gwillimbury.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	3.8
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**3.9**
Recoverable (C)	0
Net Investment Cost (A+C)	**3.8**

Date: November 2012

Hydro One Networks – Investment Summary Document
Napanee Area Study

Reference #: DL7

Investment Name: Napanee Area Study

In-Service: December 2013

Need:

Two 44 kV feeders in the Napanee area are loaded above the 25 MVA planning guideline and some segments are in poor condition and require rehabilitation.

Not taking action to address the identified shortcomings in the area will lead to the inability to serve the load and the potential incorrect operation of protections.

Investment Summary:

The Napanee area is served by a 4.16 kV distribution system requiring station and feeder protection and load balancing. The current situation could lead to incorrect protection operation, unbalanced transformer/feeder loadings which could contribute to asset life reduction and substandard voltage performance. Mobile Unit Station facilities are not available at the distribution stations and load transfer ability is limited.

An Area Study was initiated to analyze the electrical system and recommend a minimum level of cost effective improvement required to satisfy electrical needs within the planning period.

This investment proposes to implement station and feeder setting and configuration upgrades, as well as the addition of one primary distribution feeder. These upgrades will provide load and phase current balancing for town loads supplied by the distribution system. It also provides relief for the heavily loaded 44 kV feeders by extending a nearby lightly loaded feeder and transferring loads.

Results:

Stations and feeders serving the town will have adequate protections, balanced loads, and have capability to transfer load in the event of a failure. The distribution system will be capable of supplying the growing loads for the foreseeable future. The two 44 kV feeders will be relieved to loading levels well within the planning guideline.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.8
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**2**
Recoverable (C)	0
Net Investment Cost (A+C)	**1.8**

Date: November 2012

Hydro One Networks – Investment Summary Document
Port Severn DS and Line Work

Reference #: DL8

Investment Name: Port Severn DS and Line Work

In-Service: December 2013

Need:

This investment is required to relieve overloaded 12.48 kV feeders and an overloaded 44-12.48 kV distribution station, and to improve reliability of supply in the Port Severn area.

Not doing this work will result in an increased risk of equipment failure and continued poor reliability of supply in the area.

Investment Summary:

Honey Harbour and Port Severn are in the Big Chute area located near Pentanguishene. These loads are supplied by Honey Harbour DS and Big Chute DS. Feeders out of those stations supply approximately 15 MVA of peak load at 12.48 kV.

Two of the feeders in this area (i.e. Honey Harbour DS F1 and Big Chute DS F2) are currently among the worst performing feeders on the distribution system. Both of these feeders serve primarily waterfront properties with difficult access and limited back feed capability, which makes trouble call power interruption response time consuming. In addition to the reliability issues, a new residential development is underway near Port Severn which will add an additional 3 MVA of load to Honey Harbour DS over the next 5 years. To assess the adequacy of the system to supply this and other future loads, an Area Supply Planning Study was carried out. The study's finding with relation to the Port Severn area were:

- Honey Harbour DS's peak load forecast will exceed the Emergency Load Limit by 2013.
- Several single-phase laterals on the Honey Harbour DS F2 and Big Chute DS F2 feeders supplying Gloucester Pool and Six Mile Lake that are excessively loaded. Substandard feeder protection schemes are in-service on Honey Harbour DS F2 and Big Chute DS F2 due to heavy loading on single-phase laterals.

In order to address the loading and reliability issues associated with the Honey Harbour DS F2 feeder and the Big Chute DS F2 feeder, the plan is to build a new 44-12.48 kV Port Severn DS near the village of Port Severn, and develop new 12.48 kV feeders from this station to provide relief to the existing system. This new station will also provide the necessary capacity to meet forecast load growth and avoid overloading Honey Harbour DS. The relief of the existing feeders and the establishment of loop feeds for heavy loaded line sections will reduce outage times and improve reliability for customers fed from these circuits.

Results:

- Maintain 44-12.48 kV station and 12.48 kV feeder loading within design ratings and mitigate the risk of equipment failures and supply reliability.
- Avoid customer and reliability risks associated with overloaded equipment and feeders and heavily loaded line sections with no loop feeds.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	4.4
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**4.4**
Recoverable (C)	-
Net Investment Cost (A+C)	**4.4**

Date: November 2012

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Hydro One Networks – Investment Summary Document
Muskoka TS – New M5 Feeder

Reference #: DL9

Investment Name: Muskoka TS – New M5 Feeder

In-Service: November 2013

Need:

The purpose of this investment is to relieve two heavily loaded 44 kV feeders at Muskoka TS.

Not doing this work represents customer, reliability and reputation risks due to overloaded equipment and a lack of load transfer capability during planned or emergency equipment outages.

Investment Summary:

The Muskoka TS M1 and M9 feeders are presently loaded at 30 MVA and 32 MVA respectively which is well above the planning guideline of 25 MVA for a 44 kV feeder. Loading above the guideline results in risks of unsupplied load due to overloaded equipment and an inability to transfer load during planned or emergency equipment outages.

An area supply study has been completed for the Muskoka - Parry Sound area to determine the long-term needs. The recommended plan is to relieve the M1 and M9 feeders by developing a new M5 feeder from Muskoka TS and transferring load from the two overloaded feeders to the new feeder. Providing relief to the Muskoka TS M1 feeder also frees up capacity on this circuit for relief of Parry Sound TS which is at capacity, via load transfers to Muskoka TS. The Muskoka TS is expected to have sufficient capacity for the area for the next 5 to 10 years.

Results:

Mitigate customer, reliability, and reputation risks by transferring load from two heavily loaded 44 kV feeders to a new feeder from Muskoka TS.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.4
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**1.4**
Recoverable (C)	0
Net Investment Cost (A+C)	**1.4**

Date: November 2012

Hydro One Networks – Investment Summary Document
Ballantrae DS Load Balancing

Reference #: DL10

Investment Name: Ballantrae DS Load Balancing **In-Service:** June 2013

Need:

Loading on the Ballantrae DS T2 transformer is over its planned loading limit and load relief is required.

Not doing the work will result in the risk of transformer failure that would cause power outages.

Investment Summary:

Loading on the Ballantrae DS T2 transformer was at 8300kVA during the summer of 2011. This level is 33% above the planned loading limit (PLL) of the T2 transformer which is at 6250kVA. The T1 transformer has reached the end of life and has already been scheduled for replacement with a 10000kVA transformer which has the summer PLL rating of 11500kVA.

In order to provide load relief to the T2 transformer the F1 feeder position is proposed for transfer to the T1 transformer. The larger T1 transformer will be able to accommodate the load transfer as the combined loading will be 9MVA while the loading on the T2 transformer will fall to 4MVA.

Results:

Provide load relief to the Ballantrae T2 transformer by load transfer to the T1 transformer so that the station retains the adequate capacity.

Costs:

	2013($M)
Capital and Minor Fixed Assets (A)	0.3
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**0.4**
Recoverable (C)	0.0
Net Investment Cost (A+C)	**0.3**

Date: November 2012

Hydro One Networks – Investment Summary Document
Port Hope TS 50M16 Relocation

Reference #: DL11

Investment Name: Port Hope TS 50M16 Relocation

In-Service: December 2013

Need:

Two sections of the Port Hope TS 44 kV 50M16 have a large number of wood poles that have reach end-of-life and require replacement. These sections are located off-road and are being relocated along road allowances as part of this replacement.

Not proceeding with this investment risks prolonged outages, reliability issues, and safety concerns for the public and employees.

Investment Summary:

A total of 8 km of line split between two sections of the Port Hope TS 44kV 50M16 feeder require replacement. A large portion of the wood poles on these sections have reached end-of-life and some locations require upgrades to meet the standards of the Ontario Regulation 22/04 (Electricity Safety Act). As these lines are located off-road, they are simultaneously being moved along road allowances to improve accessibility and improve operational efficiency.

This investment covers the cost of the relocation and any upgrades necessary to ensure that the new build is up to standard.

Results:

- Minimize the risk of end-of-life pole failure and mitigate associated reliability and safety issues.
- Increase productivity through reduced repair and response times.
- Address end-of-life equipment and components and comply with regulatory requirements.
- Reduce potential safety hazards to the public and Hydro One employees.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	2.9
Operations, Maintenance & Administration and Removals (B)	0.4
Gross Investment Cost (A+B)	**3.3**
Recoverable (C)	-
Net Investment Cost (A+C)	**2.9**

Date: November 2012

Hydro One Networks – Investment Summary Document
Brockville TS M3 and M4 Underground Replacement

Reference #: DL12

Investment Name: Brockville TS M3 and M4 Underground Replacement **In-Service:** December 2013

Need:

Two sections of underground cable on the Brockville TS 44 kV M3 and M4 feeders have reached their end of life and have exhibited signs of failure. Their replacement prior to irreparable failure is required.

Not proceeding with this work will increase safety and reliability risks associated with end of life equipment. It would also affect cost and operational efficiency as repair of these cables is difficult, time consuming, and costly.

Investment Summary:

Two sections of underground cable on the Brockville TS 44 kV feeders have reached their end of life. These cables supply Brockville Water DS and have exhibited signs of failure. The cables have been reparable to date, but these repairs have been costly and time consuming.

This investment covers their replacement prior to irreparable failure. It also covers the costs to remove the end of life cables to ensure that they do not cause any future contamination issues.

Results:

- Minimize the risk of end of life underground cable failure and mitigate associated reliability and safety issues.
- Increase operational efficiency through reduced repair time and costs.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	5.7
Operations, Maintenance & Administration and Removals (B)	0.8
Gross Investment Cost (A+B)	**6.5**
Recoverable (C)	-
Net Investment Cost (A+C)	**5.7**

Hydro One Networks – Investment Summary Document
Martindale TS 9M5 Phase 3 of 6

Reference #: DL13

Investment Name: Martindale TS 9M5 – Phase 3 of 6

In-Service: December 2013

Need:

This investment is required to address end-of-life poles, crossarms, and other components and to improve reliability on the Martindale TS 9M5 feeder.

Not proceeding with this investment would result in end-of-life components remaining on the system and increasing reliability, customer, and safety risks.

Investment Summary:

The Martindale TS 9M5 is a radial 44 kV feeder that is 80 km in length and serves a peak load of 12 MVA. Based on reliability performance, the feeder is considered to be among the worst performing feeders in the Province.

Contributing to this performance is the fact that approximately 80% (i.e. 64 km) of the feeder, between McFarlane Junction in Sudbury and Alban DS is located off-road through the bush with access only by helicopter or off-road vehicles. In addition, the line crosses numerous swamps that are completely inaccessible by vehicles.

Asset condition assessment activities on the first 7 km of the 9M5 feeder identified that 50% of the poles are at end-of-life. Condition assessments related to the remaining portions of the feeder are currently underway and are expected to yield similar results. The plan is to re-establish the 9M5 feeder alongside Highway 69 from McFarlane Junction to Highway 64.

The recent relocation of existing rural lines due to re-alignment of Highway 69 south of Sudbury provided an opportunity to establish extra pole height along the highway to accommodate the Martindale TS 9M5. This work covers the relocation of a 3.7 km section along McVittie Road south to McVittie GS.

Results:

- Replace end-of-life poles and components to comply with regulatory requirements.
- Mitigate reliability and safety risks by removing end-of-life components.
- Relocate the Martindale TS 9M5 feeder from off-road, inaccessible locations (e.g. swamp) to road allowance and significantly reduce the likelihood of prolonged power interruptions.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.0
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.1**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.0**

Date: November 2012

Hydro One Networks – Investment Summary Document
Distribution System Modifications

Reference #: DL14

Investment Name: Distribution System Modifications **In-Service:** December 2013

Need:
This investment covers projects focussed on correcting feeder load balance, voltage quality and protection coordination issues that arise over time due to natural load growth and economic changes.

Not proceeding with this investment increases reliability and safety risks associated with low feeder end voltages, overloaded equipment, and improper protection operation. It also increases the risk of not adherring to industry standards for voltage regulation and current.

Investment Summary:
Due to load growth and economic changes, the distribution of load along feeders can vary significantly. These changes can affect the voltage quality and conductor loading; cause improper protection operations; and potentially cause equipment ratings to be exceeded. This investment covers work to modify feeder equipment, load balances, voltage issues, and protection coordination to mitigate these risks.

For 2013, over 100 projects focussing on these objectives are planned.

<u>Changes to Protections and Line Balancing</u>
The following feeders are scheduled for protection and line balancing work:

Bolton Hardwick DS M1, M2
Boston Mills DS F1, F3
Bourget DS F1, F2, F3
Brant TS M21
Casselman DS F1, F2, F3
Centralia DS F1, F3
Chesley Hawkins DS F1, F2, F3
Chesterville Brannen DS F1, F2, F3
Chesterville Frood DS F1, F2, F3
Clarence DS F1, F2
Clayton DS F1
Cochrane West DS F1
Cookstown West DS F1, F3
Dutton DS F2, F3
Dwight DS F1
Essex DS F1, F2
Exeter Sanders DS F1, F2, F3
Fergus TS M7
Ferndale DS F1, F3
Geraldton South DS F1, F2
Glencoe DS F2, F3
Glengarry DS F1, F2
Hillsburgh DS F1, F2, F3
Hinchinbrooke DS F1, F2, F3
Huron Park F1, F3
Ingersol TS M44, M46, M50
Ingleside DS F1, F2
Ingleside West DS F1, F2, F3
Keewatin DS F1, F2
Kemptville Harriett DS F1, F2, F3
Kemptville King DS F1, F2, F3, F5
Kemptivile Van Buren DS F1, F2, F3
Kemptville West DS F1, F3
Kerwood DS F1, F2, F3
Kirkton DS F1, F2, F3
Larchwood DS F1, F2, F3
Marmion DS F1
Meaford TS M1
Medonte DS F1, F2
Mount Hope DS F1, F3
Newington DS F1, F2
Noelville DS F1, F2
Norwich North DS F1, F2, F3
Oil Springs F1, F2
Paisley DS F1, F2
Pakenham DS F1, F2, F3
Perth Halton DS F1, F2, F3
Perth North DS F1, F2, F3, F4, F5
Perth Scotch Line DS F1, F2, F3, F4
Perth Sunset DS F1, F2, F3, F4
Perth Wilson DS F2, F3, F4
Port Elgin DS F2
Pucker DS F1, F2, F3
Puslinch DS F1
Roseville DS F2
Shabaqua DS F1
St. Thomas DS F1, F2
Tara DS #2 F1, F2, F3
Thorold Port Robinson DS F2
Tilbury Peltier DS F1, F2
Tory Hill DS F1, F2, F3
Valley East DS F1, F2, F3
Wallaceburg DS F1, F2, F3
Wallbridge DS F1, F2
Wardsville DS F2
Warren DS F1, F2, F3
Welland Effingham DS F1, F3
West Flamborough DS F1, F2
West Lorne DS F1, F2
Wilsonville DS F1
Wingham Ds F1, F2
Woodstock Zorra DS F1, F2, F3
Zurich DS F1, F2

Date: November 2012

Changes to Feeder Configuration

The following projects involve feeder reconfiguration:

Brighton DS F2 - Smithfield DS F3	Greely DS F4	McNab DS F1, F2
Elgin DS	Huntsville TS M4, M9, M10	Omemee DS F1, F2, F3
Embrun DS	Armitage TS M22, M32 - Ballatrae DS	Welcome DS - Campbellcroft DS
Footes Bay DS F3		

Expansions and New Feeders

The following projects involve line expansion work, line upgrades (single phase to multi-phase) or new feeder installations:

Berwick DS F1	Lake St. George DS F2	Pefferlaw DS F2
Carley DS F3	Milford DS	Shannonville DS
Chesterville TS	Mindemoya DS F3	Springville DS F3
Jones Creek DS	Newboro DS	Wallbridge DS F3

Voltage Conversion

The following feeders are scheduled for voltage conversions:

Belleville DS F1	Ivy Lea DS F3	Otonabee TS M10
Brighton DS F1	Marionville DS F2	South Gower DS F1
Eamer DS F1		

Results:

- Mitigate reliability and safety risks associated with improper protection coordination, overloaded equipment, and non-standard voltage levels.
- Maintain system voltage and current levels within industry standards.
- Improved operational efficiency with effective protection schemes.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	8.8
Operations, Maintenance & Administration and Removals (B)	1.2
Gross Investment Cost (A+B)	**10.0**
Recoverable (C)	0
Net Investment Cost (A+C)	**8.8**

Hydro One Networks – Investment Summary Document
Joint Use and Line Relocations - MTO

Reference #: DL15
Investment Name: Joint Use and Line Relocations - MTO
In-Service: December 2013

Need:
This investment covers line relocation work that must be carried out at the request of the Ministry of Transportation of Ontario (MTO) as per the requirements of the Public Service Work on Highways Act and associated Ministry of Transportation guidelines.

Not proceeding with this investment would place Hydro One in contravention of legal agreements and statutes.

Investment Summary:
This investment covers the work required in response to road modifications initiated by the MTO. Hydro One occupies road allowances at no cost and in return is required, on occasion, to install, relocate or reconstruct its facilities in order to accommodate the specific requirements of the MTO. Most commonly, this involves relocating lines to accommodate changes to roads, highways and bridges.

The number of relocation projects can vary significantly from year to year depending on the number of government infrastructure projects and economic conditions influencing individual third party development projects. As of October 2012, 10 projects have been committed for 2013. The net total amount committed towards these 10 projects for 2013 are listed below:

1. **Relocate Bradford DS F1 for MTO work on HWY 400, Wist Rd, Davis R** – As per MTO request, remove and relocate 15 total poles, and 4 transformers to accommodate widening of HWY 400 and diversion of Wist Rd. and Davis Rd.
2. **HWY 15 Line Relocate** – As per MTO request, relocate any poles encroaching on passing lanes and intersections from 1.24km south of CR42 to 0.25km south of Young's Hill Rd. (~3km stretch)
3. **HWY 69 Relocate -** As per MTO request, relocate 1600m of 3 phase line, one 44 kV pole, 600m of single phase line.
4. **HWY 69 Relocate for Railway Construction** – Relocate 10 spans to allow for highway bypass for new railway. Relocate to east side to avoid swamp, this will involve an additional 10 spans.
5. **Shawanaga River Relocate** – As per MTO request, relocate along HWY 69 from Shawanaga River to Point au Baril.
6. **Point au Baril Relocate (HWY 69/HWY559)** – As per MTO request, relocate along HWY 69 and southern portion of HWY 559 from Point au Baril to Harris Lake.
7. **Armour/Strong MTO Relocate** – As per MTO request, relocate a 10km stretch of overhead line consisting of 200 poles; from South Service Rd to South Horn Lake Rd., from Barriedale Rd to North Pickeral Lake Rd, Muskoka Rd from South Bernard Lake Rd. to HWY 11 and Barriedale Rd intersection.
8. **Alvanley Round About Relocation** – As per MTO request, provide the necessary relocations to accommodate for MTO round-about creation at Alvanley corner.
9. **HWY 11-17 Relocate** – As per MTO request, relocate from 4.8km west of HWY 628 east 11.5km to 1.5km west of HWY 585
10. **Mississagi Bridge Replacement** – As per MTO request, de-energize 3 phase line adjacent to bridge for craning operations, relocate a single phase tap, remove an overhead secondary service and relocate it to underground

Results:
Hydro One will meet its contractual and legal obligations, and maintain property rights for Hydro One lines located on road allowances.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	5.0
Operating, Maintenance & Administration and Removals (B)	0.6
Gross Investment Cost (A+B)	**5.6**
Recoverable (C)	(1.0)
Net Investment Cost (A+C)	**4.0**

Date: November 2012

Hydro One Networks – Investment Summary Document
Joint Use and Line Relocations – Road Authority

Reference #: DL16
Investment Name: Joint Use and Line Relocations – Road Authority **In-Service:** December 2013

Need:
This investment covers line relocation work that must be carried out at the request of Municipal and Provincial road authorities as per the requirements of the Public Service Work on Highways Act and associated Ministry of Transportation guidelines. It also includes relocation work requested by customers in accordance with Hydro One's Conditions of Service.

Not proceeding with this investment would place Hydro One in contravention of legal agreements and statutes.

Investment Summary:
This investment covers the work required in response to road modifications initiated by Provincial or Municipal Road Authorities. Hydro One occupies road allowances at no cost and in return is required, on occasion, to install, relocate or reconstruct its facilities in order to accommodate the specific requirements of the road authorities. Most commonly, this involves relocating lines to accommodate changes to roads, highways and bridges.

The number of relocation projects can vary significantly from year to year depending on the number of government infrastructure projects and economic conditions influencing individual third party development projects. As of October 2012, 9 projects have been committed for 2013. The net total amount committed towards these 9 projects for 2013 are listed below:

1. **Essex County Rd 34 Relocate** – Relocate approximately 650m of existing pole line along CR34 between CR37 and CR33 to accommodate construction of new paved shoulder on CR34.
2. **Bar 150 Relocation** – Relocate approximately 16 poles as required for HWY 50 road construction. Poles are currently on 3 different roads.
3. **County Road 50 Relocate South of Loretto** – Replace 50 poles for up coming road widening on County Road 50; the 50 poles in question are spread out over 2.5 km.
4. **Bathurst St. Relocate** – Relocate existing single phase line (~5 poles) to accommodate road improvements and widening. Rebuild with pole height to accommodate future 44 kV and 27.6 kV feeders out of Holland DS/TS.
5. **Udora Bridge Conflict Plan** - Remove existing 35 foot poles with 1-phase primary and install new 50 foot poles, framing and transformers to new positions along road allowance, and transfer conductor to new poles in order to accommodate road relocation and construction of new Udora Bridge.
6. **Umphrey Bridge Conflict Plan -** Remove existing 40 foot poles with 3-phase primary and install new 50 foot poles, framing and new transformers to new positions along road allowance, and transfer conductor to accommodate road relocation and construction of new Umphrey Bridge.
7. **McCully Bridge Relocate -** Municipality is rebuilding the McCully bridge. Relocate line for clearances. Relocate 4 existing poles which will require 7 poles at completion of work.
8. **Country Road 90 Reconstruction** – Country Road 90 is being widened, relocate a number of poles are in conflict with ditching improvements, intersection improvements, and turning lane requirements.
9. **Vivian Rd Relocate from HWY 48 to Durham Rd 30** – Relocate approximately 1700m of line (29 line and 12 road crossing poles) to a new position in right of way to accommodate road reconstruction.

Results:
Hydro One will meet its contractual and legal obligations, and maintain property rights for Hydro One lines located on road allowances.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.7
Operating, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.9**
Recoverable (C)	(0.3)
Net Investment Cost (A+C)	**1.4**

Date: November 2012

Hydro One Networks – Investment Summary Document
Joint Use

Reference #: DL17

Investment Name: Joint Use **In-Service:** December 2013

Need:

This investment covers joint use work that Hydro One is obligated to provide in order to meet its contractual obligations to joint use partners in accordance with existing Joint Use Agreements.

Not proceeding with this investment would place Hydro One in contravention of legal agreements and statutes.

Investment Summary:

This work covers changes/upgrades to Hydro One assets to accommodate the use of the assets by joint use partners such as telecommunication or cable companies (communication circuits), municipalities (street lighting), local distribution companies (power circuits), or distributed generators (power circuits). The cost sharing provisions in joint use agreements allow Hydro One to recover its costs resulting from requests to add new attachments to poles. Costs recovered include those to increase pole class to accommodate changes in pole loading, increased height to obtain appropriate ground clearances for public safety, as well as costs associated with premature retirement of in-service assets.

As of October 2012, 9 projects have been committed for 2013. The net total amount committed towards these 9 projects for 2013 are listed below:

1. **44 KV Relocation at Bruce Nuclear** – Relocate an existing 44 kV two circuit line off of an existing easement strip and secure a new easement.
2. **LDC Pole Upgrades** – Frame 15 LDC poles for 44 kV, work required for new turning lane.
3. **LDC Connections Under Build** – Rebuild 1.5km stretch of line including 44 kV and 27.6 kV lines on Toronto Street in Newcastle, to accommodate LDC request to under build Hydro One line.
4. **Airport Parkway Extension** – As per LDC request, extend three phase line on Hydro One poles to feed LDC customers and separate Hydro One customers from LDC customers.
5. **LDC LTLT Casselman Rebuild** – LDC requests rebuild of 1.8km section of line so the LDC can provide dedicated circuit to their customers. Work includes replacement of 26 poles, one interspaced pole, and upgrade of the conductor.
6. **LDC Request for Load Transfer** – LDC requires to attach their own phase to 1.5km of Hydro One line. Portion of line is currently off road and will need to be relocated out to road to allow work.
7. **Joint Use Partner Aerial Project** – Prepare line for new Joint use starting at LDC/Hydro One boundary on Sunnidale Road going West to intersection of CR 28/Sunnidale Road. South on CR 28 to intersection of CR 28/Hwy 90. West on Hwy 90 to rail tracks just North of Hwy 90/Holmes Drive.
8. **Joint Use Partner Fiber To the Home Chelmsford and Azilda Exchange** – Alter/add attachments to 1588 Hydro One owned poles to prepare for Fiber to The Home project.
9. **HWY 28E Request** – Joint Use partner requests to move pole from third party property to Hydro One joint use line. Existing line consists of 44 kV, all with suspect insulators. Replace at risk poles to accommodate request.

Results:

Hydro One will meet its contractual and legal obligations, and maintain property rights for Hydro One lines located on road allowances.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	3.7
Operating, Maintenance & Administration and Removals (B)	0.5
Gross Investment Cost (A+B)	**4.2**
Recoverable (C)	(0.7)
Net Investment Cost (A+C)	**3.0**

Date: November 2012

Hydro One Networks – Investment Summary Document
Huntsville DS F3 Feeder Development

Reference #: DL18

Investment Name: Huntsville DS F3 Feeder Development **In-Service:** December 2013

Need:

The purpose of this investment is to provide load relief to an existing overloaded distribution station.

Not doing this work represents customer, reliability, and reputation risks due to potential failure of overloaded equipment.

Investment Summary:

Hydro One load in the Town of Huntsville is supplied at 12.48 kV from Aspdin DS, Lake Vernon DS, and Huntsville DS. All three stations have 6 MVA nameplate transformers with a winter Planned Load Limit (PLL) of 9.6 MVA each. The winter peak load on Aspdin DS exceeded its PLL by 15% in 2010 and by 5% in 2011, while the peak load on Lake Vernon DS is at 90% of its PLL.

Load growth is continuing to occur in the Town of Huntsville within HONI service territory, specifically in the north-west commercial growth area which is served by Lake Vernon DS and in the south-east which has been designated for future residential/institutional growth in the Town of Huntsville Official Plan. Huntsvillle DS is located in the north-east part of the Town and is only loaded to about 25% of its PLL.

In order to address the existing overloading of Aspdin DS and develop a plan for supply of future load growth in the Town of Huntsville, an area supply study was carried out. The preferred plan identified in this study is to provide immediate relief to Aspdin DS and Lake Vernon DS by developing a third feeder out of Huntsville DS. The feeder will be constructed with additional pole height for a 44 kV circuit to accommodate the future construction of a new "Brunei DS" in the south-east part of Huntsville DS.

Results:

Mitigate customer, reliability, and reputation risks by transferring load from an overloaded distribution station to a station that has spare capacity available.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	2.0
Operations, Maintenance & Administration and Removals (B)	0.3
Gross Investment Cost (A+B)	**2.3**
Recoverable (C)	0
Net Investment Cost (A+C)	**2.0**

Date: November 2012

Hydro One Networks – Investment Summary Document
Brockville TS M2 – Phase 3 of 6

Reference #: DL19

Investment Name: Brockville TS M2 – Phase 3 of 6

In-Service: December 2013

Need:

A section of the Brockville TS 44kV M2 feeder requires replacement because the poles have reached end-of-life. As this section is off-road with poor accessibility, the line section is being relocated along the road to reduce repair and response time, and to improve reliability.

Not proceeding with this investment risks prolonged outages, reliability issues, and safety concerns for the public and employees.

Investment Summary:

This investment identifies refurbishment work that is required on the Brockville M2 feeder located in the Brockville area. This feeder, approximately 50km in total length, supplies a peak load of approximately 20 MVA with continued load growth of approximately 1% annually over the next five years.

Asset condition assessment activities indicate that the majority of the poles in the section between the communities of Mallorytown and Athens have tested poorly, with the majority not meeting acceptable standards. This section of feeder is off-road and has experienced poor performance as a result of equipment and component failures that are difficult to access and repair. In the vicinity of the line section is another pole line that supports an 8.32 kV feeder on road allowance. The poles on this particular pole line have an average age of approximately 40 years and their replacement would normally be expected within a 10 year timeframe. Given the existence of the 8.32 kV line, there is an opportunity to relocate the Brockville M2 line section onto a shared line on road allowance.

The plan is to re-establish the Brockville M2 feeder section on road allowance with an 8.32 kV under build circuit. This project would address end-of-life components in conjunction with line relocation that will alleviate off-road and geographic obstacles.

Results:

- Minimize the risk of end-of-life pole failure and mitigate associated reliability and safety issues.
- Increase productivity through reduced repair and response times.
- Address end-of-life equipment and components and comply with regulatory requirements.
- Reduce potential safety hazards to the public and Hydro One employees.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.6
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.8**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.6**

Date: November 2012

Hydro One Networks – Investment Summary Document
Alexander DS Monitoring

Reference #: DL20

Investment Name: Alexander DS Monitoring **In-Service:** December 2013

Need:

Alexander DS has exceeded its loading limit based on its station Planning Load Limit (PLL) and Oil Natural Air Natural (ONAN) rating. The installation of monitoring is required to permit utilization of the Oil Natural Air Forced (ONAF) ratings hence increasing allowable loading at the station.

Not proceeding with this investment would result in the continued overloading of these assets without monitoring capability potentially resulting in reliability and customer risks.

Investment Summary:

Alexander DS, the largest 44/27.6 kV distribution station in the province based on capacity, is a 2 transformer station that is at its PLL. The PLL is calculated at 22.5 MVA summer and 26 MVA winter calculated on ONAN rating. The measured load in January 2010 reached over 30 MVA.

The transformers are equipped with fans and the ONAF ratings can be used to re-calculate the PLL if the banks are monitored for fan failure together with transformer over temperature. Installation of remote monitoring from the Ontario Grid Control Center (OGCC) is required to enable this capacity release. Feeder current monitoring and control at this critical facility is required to maintain reliability.

This investment proposes to add substation monitoring and feeder control to Alexander DS. These changes are expected to provide adequate capacity for a 5 year period during which an Area Study will establish future needs for the area.

Results:

The station will be upgraded to have a PLL of 31 MVA summer and 36 MVA winter by adding fan and transformer temperature monitoring. Feeder control will be enhanced by adding feeder ampere monitoring, along with remote control to the Hydro One feeders.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	0.3
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**0.3**
Recoverable (C)	0
Net Investment Cost (A+C)	**0.3**

Date: November 2012

Hydro One Networks – Investment Summary Document
Kam Reg DS Voltage Conversion – Stage 2

Reference #: DL21

Investment Name: Kam Reg DS Voltage Conversion – Stage 2 **In-Service:** December 2013

Need:

The purpose of this investment is to address the end of life of Kam Reg DS through voltage conversion of the load and retirement of the station.

Not proceeding with this investment would result in reliability and safety risks.

Investment Summary:

Kam Reg DS is a 27.6-12.48 kV station supplying about 3 MVA of load in the north-west area of the City of Timmins which is a rural area.

A condition assessment has concluded that the station is at end-of-life with all major components (wood structures, foundation, transformer) needing replacement. In addition, the 12.48 kV F1 feeder fed from this station includes many poles/insulators/etc. that are also at end-of-life and require refurbishment.

The preferred plan to address these issues is to convert the 12.48 kV load supplied from Kam Reg DS to 27.6/16 kV operation and eliminate the distribution station.

Results:

- Improve system performance and reliability.
- Optimize the backfeed and supply capability.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.5
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**1.5**
Recoverable (C)	0
Net Investment Cost (A+C)	**1.5**

Date: November 2012

Hydro One Networks – Investment Summary Document
Lauzon/Belle River Reconfiguration

Reference #: DL22

Investment Name: Lauzon/Belle River Reconfiguration **In-Service:** May 2013

Need:

The purpose of this investment is to relieve heavily loaded 27.6 kV feeders, ensure sufficient connection capacity is available to supply load in the areas east of Windsor, and remove a distribution station that is at end of life.

Not doing this work will result in increased customer and reliability risks due to overloaded equipment and end-of-life assets.

Investment Summary:

The area east of Windsor including the Towns of Tecumseh and Belle River is supplied at 27.6 kV from Malden TS, Lauzon TS and Belle River TS. The Lauzon TS M26 feeder which supplies Tecumseh area is currently loaded to 24 MVA which is well beyond the planning guideline of 17 MVA for a 27.6 kV feeder. Also located in this area and connected to the Lauzon TS M26 is the Tecumseh DS which supplies a small section of load at 4.16 kV via the Tecumseh DS F1 feeder. An asset condition assessment has indicated that Tecumseh DS is at end-of-life and needs replacement. By 2015, the combined load at Lauzon TS and Malden TS is expected to exceed the available capacity of these stations.

In order to address these issues, an area supply study was conducted to determine the preferred plan for providing relief. The recommended plan is to convert the Tecumseh DS F1 feeder to 27.6 kV operation and transfer load from the Lauzon TS feeders to the Belle River TS M1 feeder. This work will require extending the Lauzon TS M25 27.6 kV feeder for 2 km and converting the Tecumseh DS F1 feeder to 27.6 kV operation such that the end-of-life Tecumseh DS can be de-commissioned and removed.

Results:

Provide relief to overload feeder Lauzon M26, maintain loading within the existing system capacity, and remove end-of-life Tecumseh DS.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	0
Net Investment Cost (A+C)	**1.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
South Porcupine DS Conversion

Reference #: DL23

Investment Name: South Porcupine DS Conversion **In-Service:** December 2013

Need:

The 4.16 kV F1 and F3 feeders on the South Porcupine DS have reached end-of-life and require replacement. As part of their replacement, they are being converted to 27.6 kV to be consistent with the supply voltage of other feeders in the area.

Not proceeding with this investment would result in maintaining sub-standard equipment in the area, and a decrease in operational efficiency due to the presence of non-common voltage for the area.

Investment Summary:

The South Porcupine DS 4.16 kV F1 and F3 feeders have reached end-of-life. In addition, the framing, clearances and some of the equipment on these feeders have been identified as substandard. As part of the reconstruction, these feeders are being upgraded to 27.6 kV, which is the common voltage for feeders in the area. South Porcupine DS is to be removed as part of this conversion, as the upgraded feeders will be supplied by the 27.6 kV Timmins TS.

This investment covers the reconstruction of the two feeders at the new voltage level of 27.6 kV and the removal of the South Porcupine DS.

Results:

- Safety and reliability risks associated with substandard and end-of-life equipment are mitigated.
- Increased load capacity, improved voltage levels, and an increase in operational efficiency and flexibility due to conversion to a higher, common voltage.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.4
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.6**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.4**

Date: November 2012

Hydro One Networks – Investment Summary Document
Sidney TS 12M7 Reconductor

Reference #: DL24

Investment Name: Sidney TS 12M7 Reconductor **In-Service:** December 2013

Need:

Sections of conductor on the 44kV Sidney TS 12M7 feeder have reached end-of-life and require replacement.

Not proceeding with this investment would result in reliability, safety and power quality risks

Investment Summary:

A total of 5 km of the Sidney TS 44 kV 12M7 feeder have 100 year old 4/0 conductor. This conductor is annealed at some sections and breaks under loading conditions that are well below its rated capacity. This conductor is to be replaced with 556 Al conductor and these sections are to be reframed to meet current standards.

Results:

- Mitigate reliability and safety risks associated with end-of-life equipment.
- Meet current overhead line standards.
- Improve voltage quality and loading capacity.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.3**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
Owen Sound TS M28-M23 Tie Line

Reference #: DL25

Investment Name: Owen Sound TS M28-M23 Tie Line **In-Service:** December 2013

Need:

The Owen Sound TS M24 feeder supplies 26MVA of load in the Bruce Peninsula which is significantly beyond its planned loading limit of 14 MVA. The current overload on the feeder is estimated to be one of the causes of the M24 poor reliability performance.

Not proceeding with this investment would result in reliability, customer and safety risks due to continued overloading of assets.

Investment Summary:

To off-load the overloaded Owen Sound TS M24 feeder, the Colpoys Bay DS will be permanently transferred to the Owen Sound TS M23 feeder. In order to offset the effect on the Owen Sound TS M23 feeder, the Owen Sound Brookholm DS will be transferred to the Owen Sound TS M28 feeder. This will require approximately a 1.2km extension of Owen Sound TS M28 feeder from Owen Sound 24th St West DS to Owen Sound Brookholm DS.

This work is expected to improve the reliability of the Owen Sound TS M24 feeder by decreasing the number of customer supplied by the M24 feeder as well as improving protection performance. In addition the reliability of the Owen Sound Brookholm DS which supplies urban customers is expected to improve since it will be supplied by a shorter and better performing feeder. The new configuration would also provide flexibility to transfer the Owen Sound Brookholm DS between the Owen Sound TS feeders M23 and M28.

Results:

Improve reliability of the feeder and improve protection performance to mitigate overall risk.

Costs:

	2013($M)
Capital and Minor Fixed Assets (A)	1.0
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**1.0**
Recoverable (C)	0
Net Investment Cost (A+C)	**1.0**

Date: November 2012

Hydro One Networks – Investment Summary Document
Woods DS F5 & F7 Line Refurbishment

Reference #: DL26

Investment Name: Woods DS F5 & F7 Line Refurbishment **In-Service:** December 2013

Need:

Sections of the Woods DS 4.16 kV F5 and F7 feeders contain end-of-life equipment that requires replacement. This includes end-of-life wood poles, deteriorated hardware, deteriorated open-wire bus and substandard clearances.

Not proceeding with this work will increase safety and reliability risks associated with equipment that is end-of-life and is not up to standard.

Investment Summary:

The Woods DS 4.16 kV F5 and F7 feeders require refurbishment due to end-of-life and substandard equipment. The refurbishment work includes replacing end-of-life wood poles, deteriorated hardware, and deteriorated open-wire bus, as well as addressing substandard clearance issues.

Results:

Mitigate safety and reliability risks associated with end-of-life equipment and substandard clearance issues.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
Petawawa Craig DS – Monitoring

Reference #: DL27

Investment Name: Petawawa Craig DS – Monitoring **In-Service:** June 2013

Need:

Petawawa Craig DS has exceeded its loading limit based on the transformer's Planned Loading Limit (PLL) rating. The installation of monitoring is required to permit utilization of fan cooled ratings hence increasing allowable loading at the station.

Not increasing capacity to serve loads will result in overloaded station equipment with increased risk of failure and overloaded feeders with substandard voltage supply resulting in reliability and customer risks.

Investment Summary:

Petawawa Craig DS load is above the transformers PLL rating.The transformers are equipped with fans and the Oil Natural Air Forced ratings can be used to re-calculate PLL to a higher level if the banks are monitored for fan failure together with transformer over temperature. Installation of remote monitoring from the Ontario Grid Control Center (OGCC) is required to enable capacity release. Feeder current monitoring and control at this critical facility is required to maintain reliability.

This investment proposes to add substation monitoring and feeder control at Petawawa Craig DS. These changes will increase reliable capability of these facilities.

Results:

Station capability and control will be enhanced by adding feeder ampere monitoring along with remote control.

Costs:

	2013($M)
Capital and Minor Fixed Assets (A)	0.6
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**0.7**
Recoverable (C)	0.0
Net Investment Cost (A+C)	**0.6**

Date: November 2012

Hydro One Networks – Investment Summary Document
City of Owen Sound Refurbishment Phase 2

Reference #: DL28

Investment Name: City of Owen Sound Refurbishment – Phase 2 **In-Service:** December 2013

Need:

Distribution assets in the City of Owen Sound have reached end-of-life and require replacement.

Not proceeding with this investment would present reliability and safety risks associated with end-of-life assets.

Investment Summary:

About 80% of the load in the City of Owen Sound is supplied via a 4.16/2.4 kV distribution network fed from six 44kV to 4.16 kV Distribution Stations. Asset Condition Assessment activities on the system have identified poor conditions categorized by end-of-life and defective equipment, and substandard installations.

Of particular concern is the downtown area of the city (i.e. feeders supplied from Second Ave. East DS & Twelfth Street East DS) where refurbishment needs are acute. These needs include the replacement of deteriorated poles, cross-arms, and secondary services. They also include issues with restricted and potentially hazardous insulators, switches, and primary conductor. In addition, a number of installations in the city do not meet current Hydro One Distribution standards and include non-standard framing, guying, and transformer installations.

Given the urban nature of the area and the safety risks associated with deteriorated equipment and components, a multi-year plan has been established to carry out line refurbishments within the City of Owen Sound. This investment covers the work to be undertaken in Phase 2.

Results:

- Replace end-of-life equipment to comply with regulatory requirements.
- Replace deteriorated equipment that is at an increased risk of failure to mitigate reliability and safety risks within an urban area.
- Upgrade current installations to meet existing Hydro One standards.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	2.1
Operations, Maintenance & Administration and Removals (B)	0.3
Gross Investment Cost (A+B)	**2.4**
Recoverable (C)	-
Net Investment Cost (A+C)	**2.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
Comber DS Removal

Reference #: DL29

Investment Name: Comber DS Removal

In-Service: June 2013

Need:

Address end-of-life station assets at Comber DS located in the Essex Operational area. Not proceeding with this investment would present safety, reliability, customer, and reputation risks due to the eventual failure of major station equipment.

Investment Summary:

Comber DS is a 27.6-8.32 kV station fed from Tilbury West DS that supplies 2 MVA of load in the area west of Tilbury. This station has been in-service for 60+ years and has reached its end-of-life. The structure of the station is tube and clamp and has rusted through in several locations. The regulator pad has sunk on one side and is currently leaning. Several safety concerns have been raised by field staff at Comber DS due to inadequate equipment clearances and the presence of energized equipment in very close proximity to ground level. Also, there are no feeder reclosers at this station and therefore transient feeder faults result in blown fuses and sustained outages. The level of reliability is lower than most rural customers experience.

Due to the above issues, it is proposed to off-load Comber DS through partial voltage conversion to 27.6 kV fed directly from Tilbury West DS and 8.32 kV load transfers to Tilbury Peltier DS. Tilbury West DS and Tilbury Peltier DS both have sufficient capacity to supply the Comber DS load.

This investment covers the conversion of a 4km section of 8.32 kV line to 27.6 kV, the installation of step-down transformers, and transfer of load to Tilbury West DS and Tilbury Peltier DS. The work will also include the removal and disposal of all station equipment at Comber DS as well as land remediation requirements as identified in the completed Phase 2 ESA assessment.

Results:

Mitigate safety, reliability, customer and reputation risks by eliminating Comber DS.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	0.9
Operations, Maintenance & Administration and Removals (B)	0.7
Gross Investment Cost (A+B)	**1.6**
Recoverable (C)	0
Net Investment Cost (A+C)	**0.9**

Date: November 2012

Hydro One Networks – Investment Summary Document
Edgeware TS M2 Relocation

Reference #: DL30

Investment Name: Edgeware TS M2 Relocation

In-Service: December 2013

Need:

A section of the Edgeware TS 44 kV feeder M2 requires replacement because the poles have reached end-of-life. As this section is off road with poor accessibility, the line section is being relocated along the road to reduce repair and response time, and to improve reliability.

Not proceeding with this work will increase safety and reliability risks associated with end-of-life equipment and will reduce productivity due to equipment inaccessibility.

Investment Summary:

A 10 km section of wood poles on the Edgeware TS 44 kV feeder M2 have reached end-of-life. This section is located off road with difficult accessibility. This line is being relocated along road allowance, with new wood poles. This work covers part of the reconstruction of this line section along the road with new poles.

Results:

- Minimize the risk of end-of-life pole failure and mitigate associated reliability and safety issues.
- Increase productivity through reduced repair and response times.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	0.4
Operations, Maintenance & Administration and Removals (B)	0.0
Gross Investment Cost (A+B)	**0.4**
Recoverable (C)	-
Net Investment Cost (A+C)	**0.4**

Hydro One Networks – Investment Summary Document
Haileybury DS Voltage Conversion

Reference #: DL31

Investment Name(s): Haileybury DS Voltage Conversion **In-Service:** December 2013

Need:

The purpose of this investment is to eliminate a 4.16 kV section of distribution system surrounded by facilities operating at a 12.48kV.

Not doing this work represents customer, reliability, and reputation risks due to an inability to transfer load between different sources within a confined geographic area.

Investment Summary:

Haileybury DS supplies 2 MVA of load at 4.16 kV within the Town of Haileybury. Surrounding load within the town of about 6 MVA is supplied at 12.48 kV from North Cobalt DS and New Liskeard Nipissing DS. Operating at two different system voltages within a confined geographic area results in increased operating costs and reduced reliability due to an inability to transfer load between two different sources.

The preferred plan to remedy this situation is to convert Haileybury DS to operate at 12.48 kV and establish ties between this station and the surrounding stations. Since the majority of the existing 4.16 kV distribution lines are already insulated for 12.48 kV operation and Haileybury DS is equipped with a dual-voltage transformer, the required work consists mostly of changing distribution transformers and upgrading secondary services to meet present day standards.

Results:

Mitigate customer, reliability, and reputation risks by converting the Town of Haileybury to a single system operating voltage with ability to transfer load between alternate sources during planned and unplanned outages.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.0
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**1.0**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.0**

Date: November 2012

Hydro One Networks – Investment Summary Document
Lyndhurst DS – Area Improvement

Reference #: DL32

Investment Name: Lyndhurst DS – Area Improvement **In-Service:** December 2013

Need:

This investment is required to address reliability, feeder coordination and phase balance issues identified by a planned system study on Lyndhurst DS and its feeders, located in the Brockville area.

Not proceeding with this investment risks substandard supply to customers, equipment overload, inadequate protection coverage, and potential safety concerns for the public and employees.

Investment Summary:

This investment identifies voltage conversion, phase balance and fuse coordination work that is required on both feeders out of Lyndhurst DS. The Lyndhurst DS supplies about 800 customers with a peak load of approximately 3.5 MVA and annual load growth in the 1% range.

Distribution feeders are studied for load and protection optimization purposes on a cyclical basis and recommended changes are implemented to ensure operability, reliability and safety for the next cycle period.

In this case, severe station phase imbalance has triggered the need for immediate action. The balance situation will be alleviated with line upgrades.

Results:

- Improve system performance and reliability.
- Maintain supply within standards.
- Minimize potential safety hazards to the public and Hydro One employees.

Costs:

	2013($M)
Capital and Minor Fixed Assets (A)	0.7
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**0.8**
Recoverable (C)	0.0
Net Investment Cost (A+C)	**0.7**

Date: November 2012

Hydro One Networks – Investment Summary Document
Malden TS M12 Expansion

Reference #: DL33

Investment Name: Malden TS M12 Expansion

In-Service: March 2013

Need:

The purpose of this investment is to improve operational efficiency and improve reliability of supply in the Amherstburg area.

Not proceeding with this investment would result in continued reliability and productivity risks due to ineffective operational configurations.

Investment Summary:

Load in the Amherstburg area south of Windsor is supplied at 27.6 kV by an LDC and Hydro One. There are presently three feeders supplying this area, the Keith TS 23M3 and the Malden TS 24M7 and 24M12. At present, the 23M3 is dedicated to the LDC, while the 24M7 and 24M12 are shared between both companies. For the 24M7 and 24M12, the feeder ownership changes between the LDC and Hydro One as the lines enter and leave LDC service territory.

The current situation results in additional operational and administrative costs. It has also caused longer customer interruption times for the customers of both the LDC and Hydro One due to double call-outs of repair crews following outages.

To address these issues, a joint plan has been developed between the LDC and Hydro One to reconfigure the existing feeders and make the 24M12 feeder dedicated to LDC and the 24M7 dedicated to Hydro One. In order to implement this plan, a short extension of the Malden TS 24M12 is required.

This investment covers the necessary work on the Malden TS 24M12 feeder for the new system configuration.

Results:

Improve operating efficiency and improve reliability for customers in the Amherstburg area.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	0.2
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**0.2**
Recoverable (C)	0
Net Investment Cost (A+C)	**0.2**

Date: November 2012

Hydro One Networks – Investment Summary Document
Minden DS – Area Improvement

Reference #: DL34

Investment Name: Minden DS – Area Improvement **In-Service:** December 2013

Need:

This investment is required to address reliability, feeder coordination and phase balance issues identified by a planned system study on Minden DS and its feeders, located in the Minden area.

Not proceeding with this investment risks substandard supply to customers, equipment overload, inadequate protection coverage, and potential safety concerns for the public and employees.

Investment Summary:

This investment identifies phase balance and fuse coordination work that is required on all 3 feeders out of Minden DS. The Minden DS supplies about 1300 customers with a peak load of approximately 5.1 MVA and an annual load growth in the 1% range.

Distribution feeders are studied for load and protection optimization purposes on a cyclical basis and recommended changes are implemented to ensure operability, reliability and safety for the next cycle period

In this case, severe feeder phase imbalance requires the need for immediate action. Line upgrade is required to balance the load.

Results:

- Improve system performance and reliability.
- Maintain supply within standards.
- Minimize potential safety hazards to the public and Hydro One employees.

Costs:

	2013($M)
Capital and Minor Fixed Assets (A)	0.7
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**0.8**
Recoverable (C)	(0.1)
Net Investment Cost (A+C)	**0.6**

Date: November 2012

Hydro One Networks – Investment Summary Document
Norwich DS F1 - Hatchley Line

Reference #: DL35

Investment Name: Norwich DS F1 - Hatchley Line

In-Service: December 2013

Need:

The section of the 8.32 kV Norwich DS F1 along Hatchley Line requires new framing and relocation due to ongoing reliability issues.

Not proceeding with this work will increase safety and reliability risks associated with equipment that is not up to standard.

Investment Summary:

This section of line consists of old framing (very small 25A cross-arms) that enables conductors to swing and come into contact with each other. These conductor contacts cause multiple outages. In addition, this section of line is off-road and requires regional line maintainers to walk the full concession every time there is an outage, as there is no visibility of this section from the road allowance.

This work involves the relocation of approximately 1.1 km of overhead line from a forested area to road allowance. The framing for this line section will also be updated as part of this investment.

Results:

- Improve reliability and accessibility to distribution assets.
- Meet current overhead line standards.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	0.4
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**0.5**
Recoverable (C)	-
Net Investment Cost (A+C)	**0.4**

Date: November 2012

Hydro One Networks – Investment Summary Document
Distribution Stations Recloser Upgrades

Reference #: DS1
Investment Name: Distribution Stations Recloser Upgrades
In-Service: December 2013

Need:

This investment is required to maintain customer reliability and performance by systematically replacing oil filled reclosers that are at end-of-life.

Not proceeding with this investment will result in increasing maintenance costs over time, reduced reliability and an increased risk of customer outages.

Investment Summary:

Hydro One's distribution system has approximately 6,000 reclosers. This investment provides for the retirement of type D oil-filled reclosers that have reached end-of-life and are technically obsolete as a result of being discontinued by their manufacturer. The reclosers will be replaced with new reclosers with vacuum technology, This new technology provides remote control and monitoring features consistent with Smart Grid requirements, reduced maintenance cycles, and more flexibility and accuracy with settings. The new vacuum reclosers that are being installed also reduce costs associated with fuse coordination by providing more replacement flexibility due to their higher fault current ratings and structure adaptability. Recloser settings can be changed without the need for intrusive upgrades to the recloser.

In 2013, 27 reclosers that are at end of life will be replaced with new vacuum type reclosers, as outlined in the list below.

- 2 reclosers at Vineland DS (F1, F2)
- 2 reclosers at Dewitts Corners DS (F3, F4)
- 3 reclosers at Eamer DS (F1, F2, F3)
- 3 reclosers at Cataraqui DS (F1, F2, F3)
- 3 reclosers at Brown Hill DS (F1, F2, F3)
- 4 reclosers at Horsey Bay DS (F1, F2, F3, F4)
- 3 reclosers at St. Isidore DS (F1, F2, F3)
- 3 reclosers at Aspdin DS (F1, F2, F3)
- 3 reclosers at Chesters Corners DS (F1, F2, F3)
- 1 recloser at Battersea DS (F3)

Results:

- Replace oil-filled reclosers that are at end-of-life with new vacuum reclosers.
- Reduce future maintenance costs and minimize reliability and customer outage risks.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.0
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.1**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.0**

Date: November 2012

Hydro One Networks – Investment Summary Document
Distribution stations Single Phase Transformer Changeouts

Reference #: DS2
Investment Name: Distribution Stations Single Phase Transformer Changeouts **In-Service**: November 2013

Need:

This investment is required to maintain customer reliability and performance by replacing end-of-life single phase transformers with new three phase transformers.

Not proceeding with this investment would increase distribution system operational risks and risks of transformer failures in distribution stations.

Investment Summary:

Hydro One's distribution system consists of 141 single phase transformer positions. This investment will target the end-of-life single-phase transformers by replacing them with new 3-phase transformers. When single-phase transformers were first installed, the strategy only provided for a single-phase transformer failure. When the failure occurred, an on-site spare transformer was connected to replace the failed unit. As the single-phase transformer ages and the condition degrades, the risk of failure of all units increases therefore the replacement of the entire single-phase transformer is required. Based on the configuration and condition of the existing transformer supporting infrastructure, this investment will also require replacement of this infrastructure in order to accommodate the new 3-phase transformer.

In 2013, three (3) single phase transformers will be replaced with new 3 phase transformers at the following stations:

- Birch Island DS
- Wolsey Lake DS
- Bothwell DS #2

Results:

- Replace single phase transformers that are at end-of-life with new 3 phase transformers.
- Reduce future maintenance costs as there is less equipment to maintain
- Minimize reliability and customer outage risks.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
Distribution Stations Spill Containment Installations

Investment Name: Distribution Stations Spill Containment Installations

Reference #: DS3
In-Service: September 2013

Need:

This investment is required to install new transformer spill containment systems which capture and control transformer oil spills and leaks, minimizing the risk of environmental impacts. These installations minimize the risk of human health and environmental impacts.

Not proceeding with this investment would increase distribution system environmental risks.

Investment Summary:

Approximately 40 of the 1,005 Distribution Station facilities are equipped with a spill containment system. Approximately 55 stations that do not currently have a spill containment system have been identified as high risk sites and are candidates for spill containment installations based on their proximity to waterways. These sites are being addressed in a systematic manner. In 2013, this investment will fund the installation of two DS spill containment systems, one at Mountain Lake DS and the second at Hamner Kenneth DS.

Results:

- Install two new transformer spill containment systems to capture and control transformer oil spills and leaks, should they occur.
- Minimize the risk of adverse environmental impacts due to oil spills.

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
Mobile Substation Purchase and Refurbishment

Investment Name: Mobile Substation Purchase & Refurbishment

Reference #: DS4
In-Service: October 2013

Need:

This investment is required to ensure that a safe and adequate fleet of mobile unit substations (MUS) is available and can be deployed to meet station outage needs during emergency failures, maintenance, and PCB testing.

Consequences of not investing in the fleet of MUSs include increased safety risks during transportation, an inability to restore power in a timely manner during a failure, and the inability to complete maintenance and PCB testing programs.

Investment Summary:

Hydro One's distribution spare transformer strategy requires the availability of MUSs for first-response power restoration**.** In addition, current maintenance practices require the availability of MUSs to perform transformer diagnostic activities and PCB testing that would otherwise require lengthy and unacceptable customer outages.

As transportable mobile units, MUSs must adhere to the requirements of the Highway Traffic Act. They receive annual inspections (time-based) for trailer certifications and power system components, as well as detailed inspections that occur each time units are dispatched for service. Inspection reports are used to track asset condition and to prioritize refurbishment.

Based on MUS asset conditions and the increasing maintenance demands (e.g. PCB testing), in 2013 the following MUSs investments are required.

- Purchase a new 115 kV-27.6-25-12.47-8.32 kV MUS
- Refurbish the trailer and reclosers on MUS 29, and
- Replace the transformer on MUS 20

Results:

- Maintain customer reliability by ensuring the availability of mobile substations to restore power when in-service transformers fail.
- Enable transformer and station maintenance to occur without unacceptable outage impacts to customers.
- Ensures mobile substations remain in good repair and do not present safety hazards.
- Minimize the life cycle costs of station facilities by reducing operating and maintenance expenditures and outage requirements through an integrated spares and mobile substation utilization

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	3.2
Operations, Maintenance & Administration and Removals (B)	-
Gross Investment Cost (A+B)	**3.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**3.2**

Hydro One Networks – Investment Summary Document
Planned Station Component Replacement

Reference #: DS5
Investment Name: Planned Station Component Replacement **In-Service**: December 2013

Need:

This investment is required to maintain the safe operation and acceptable performance of Distribution Stations by replacing end-of-life components.

Not proceeding with this investment would decrease customer reliability and compromise employee safety.

Investment Summary:

Components are replaced when their condition has deteriorated to a point where there is a risk of failure and the component has reached end-of-life, or where the performance has reached unacceptable levels. Component replacements are identified through ACA, routine station inspections and safety investigations.

Component Replacements include replacements of reclosers, switches, fences and gates, surge arrestors, MUS structures, and transformer and regulator components. Component replacements are undertaken to address public safety and security issues, reliability issues, and employee safety concerns.

In 2013, component replacements will take place at the 18 distribution stations listed below.

- Hinchinbrooke DS
- Forest Lea DS
- Clarence DS
- Wiarton RS
- Marmora Reginald DS
- Haycroft DS
- Porridge Lake DS
- Kirkland Lake Woods DS
- Scotland DS
- Noelville DS
- Island Grove DS
- Violet Hill DS
- Russell DS
- Ufford DS
- Coldwater DS
- Garson DS
- Limoges DS
- Reddendale DS

Results:

- Improve system reliability by replacing end-of-life components
- Replace end-of-life assets to comply with regulatory requirements

Costs:

	2013 ($M)
Capital and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

Date: November 2012

Hydro One Networks – Investment Summary Document
Fleet Replacement Project

Reference #: F1

Investment Name: Fleet Replacement Project **In-Service:** December 2013

Need:

This investment is required to provide adequate fleet units for the field workers to support the overall work program. Not making this investment will result in a shortage in appropriate fleet units available and will constrain the ability of Hydro One to complete its planned work program.

Investment Summary:

Hydro One controls and manages 6,372 fleet units, which support the various Lines of Business, including Provincial Lines, Stations, Forestry and E&CS. Vehicles must be maintained at an optimum level to ensure public and employee safety, meet Ministry regulations such as CSA 225, Highway Traffic Act, CVOR regulations, and minimize environmental impacts and optimize LOB's productivity, utilization, safety and reliability by minimizing downtime.

A decrease in down time and a substantial increase in utilization have resulted as we approach our target of 45% NBV to OVC. Since 2002, our core fleet has undergone significant productivity improvements with fleet utilization increasing from 68% to 80%. Fleet Capital requirements are based on industry standards (manufacturer's recommendations) for life cycle expectancy, Net Book Value (NBV) to Original Capital Value (OCV) ratios and operating cost drivers which are then linked to the Business Plan and Work Programs. In addition to our primary goal of maintaining our core fleet, any year-over-year changes to our capital requirements are directly related to changes within the Lines of Business Work Programs (ie, staffing requirement changes, new programs/projects, etc).

Results:

- The Essential Risk Mitigation (minimum level) funding accomplishment ($31.1 M) primarily addresses the minimum equipment required for the Lines of Business work programs.
- 25 Forestry Chippers ($0.9 M) mandated by Health & Safety to replace 1/3 of our chippers which are not equipped with safety shutoff bars.

Costs:

	2013 ($M)*
Capital and Minor Fixed Assets (A)	32.0
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**32.0**
Recoverable (C)	-
Net Investment Cost (A+C)	**32.0**

**Distribution portion only*

Date: November 2012

Hydro One Networks – Investment Summary Document
Cornerstone Phase 3 - Enhanced Asset Management

Reference #: E1

Investment Name: Cornerstone Phase 3 - Enhanced Asset Management **In-Service:** Mar/Dec 2013

Need:

These investments will enhance integrated planning by leveraging Hydro One's existing SAP solution and integrating key systems/technologies to drive additional business value, improve collaborative end-to-end process efficiency and improve asset lifecycle management. Not proceeding with this investment would eliminate the integrated tools, analytics and systems that are needed to optimize asset lifecycle decisions and improve operational efficiency. It would also result in continued reliance on existing disparate systems/databases.

Investment Summary:

- **Asset Analytics (AA)**

Analytic tools will be developed to consistently provide a comprehensive and cascading information view of asset risks/priorities based on demographic, condition, performance, criticality, customer and other operational risks. This will facilitate knowledge transfer and improve data quality awareness for the complete lifecycle management of our transmission and distribution assets in one central system.

- **Asset/Investment Planning (AIP)**

AIP will deliver business value through revised business processes and tools that will optimize investment planning decisions aligned with Hydro One strategic objectives and improve the collaborative end-to-end investment planning processes.

- **Enhanced Extract, Transform & Load (ETL), Performance and Reporting Capability**

Enhance the reporting analytics architecture in three key areas: Improve the ETL (Extract, Transform & Load) capabilities; high performance data retrieval and report rendering; and self-serve reporting capability of the SAP Business Warehouse.

- **SAP Business Objects Planning & Consolidation (BPC)**

The business planning & forecasting module will allow for the development of detailed financial business planning documents & analytics for the forecast 10-year period based on inputs provided during the business planning process. The SAP Business Objects Planning & Consolidation ("BPC") tool provides the framework in which to include the entire business planning, forecasting & reporting process and will be fully integrated with other existing SAP modules.

- **Engineering Design Transformation (EDT)**

Improve the process for designs in order to improve productivity and reduce time lines. Adopt the industry standard tool set to allow for inoperability with 3rd party vendors in sharing designs.

Results:

- Capital Cost Reductions by providing a consistent asset management tool set to allow staff to make informed decisions based upon a better understanding/consistent view of the asset risks.
- Maintenance Cost Reductions by implementing CBM and RCM analytics to provide early identification of "bad" performers and awareness of lifecycle expenditures to lower corrective maintenance costs. Implement work bundling to reduce number of planned outages.
- Productivity Improvement by streamlining the end-to-end processes and improve information transparency.
- Asset Condition Assessment improved reporting to provide near real time asset condition/risk assessment.
- Reduce data extracting and shared services costs associated with supporting planning, forecasting & consolidation.
- Refinement to cash flow projections and potential opportunity to reduce borrowing costs.

Costs:

	2013($M)*
Capital and Minor Fixed Assets (A)	10.4
Operations, Maintenance & Administration and Removals (B)	0.7
Gross Investment Cost (A+B)	**11.1**
Recoverable (C)	-
Net Investment Cost (A+C)	**10.4**

**Distribution portion only*

Date: November 2012

Hydro One Networks – Investment Summary Document
Final Destination Enterprise GIS Database Development

Reference #: E2

Investment Name: Final Destination Enterprise GIS Database Development **In-Service:** Jan 2013

Need:

The lack of a complete, current and integrated dataset to represent distribution assets, co-located with transmission assets, presents a challenge both to realization of operational benefits for improved efficiency and effectiveness of foundational investments to support the Green Energy Act, including Smart Grid,
Distributed Generation and Advanced Distribution Management. Lack of such a dataset also presents challenges to a coordinated Enterprise Asset Management (EAM) strategy that enables Hydro One to embrace a culture of reliability centered maintenance. There are a number of spatial data repositories for distribution assets in use within Hydro One, but none of them represents required levels of accuracy in terms of attribution, position or currency. At the same time, there is considerable duplication of required effort to maintain these databases. This is a foundational investment to address these challenges.

Investment Summary:

Geospatial information and technology is a foundational infrastructure that enables LOBs across Hydro One, and is a requirement for many utility operations and business processes as well as for Green Energy Act related goals. Geospatial information also facilitates safety and efficiency goals. At the present time, there is no single system of record for distribution spatial data. Spatial data is managed in autonomous databases with incomplete or redundant data maintenance activities.
To meet business needs, Hydro One is proposing to complete post-processing of field collected distribution data (previously initiated by Customer Operations as an OM&A vertical effort, but now made a project, tracked and measured by the GIS Program) and to consolidate this data with the other core distribution spatial databases, in an environment co-located with spatial transmission data. Hydro One also proposes to address gaps and redundancies in business processes to author, maintain and consume this data. The proposed end result is the 'Final Destination' enterprise GIS database.

Results:

- Complete post-processing of field collected distribution feeder data (dependent on field collection) and consolidation of geospatial distribution asset data from customer operations, outage management, mapping, distribution planning and smart meters into the 'Final Destination' Enterprise GIS Database.
- Business process transformation recommendations to support completeness and currency of 'Final Destination' enterprise GIS concurrent with post-processing and consolidation
- Complete necessary modifications to support products from the consolidated database including automated map production, ERP integration and OMS extract, transform and load (ETL).

Costs:

	2013($M)*
Capital and Minor Fixed Assets (A)	10.9
Operations, Maintenance & Administration and Removals (B)	0
Gross Investment Cost (A+B)	**10.9**
Recoverable (C)	-
Net Investment Cost (A+C)	**10.9**

**Distribution portion only*

Date: November 2012

Hydro One Networks – Investment Summary Document
Enterprise Application Replacement

Reference #: E3

Investment Name: Enterprise Application Replacement

In-Service: March 2013

Need:

User applications operate with the system and with each other through a set of enterprise level applications. These high level systems provide for functionality such as interoperability, unified security and user interfaces across many user applications including SAP, GIS and many others. The systems described below have reached their end of life and will no longer be maintained by the vendor. In order to minimize risk of failure of core systems these enterprise systems need to be replaced with current versions.

Investment Summary:

- **Geospatial Information System (GIS) Upgrade**

Hydro One's major GIS vendors, ESRI and Telvent, have discontinued support for the software versions currently in use, thus posing a risk to Hydro One's investment. Upgrading the software and the aging supporting infrastructure will allow Hydro One to keep its GIS systems up-to-date, deliver performance improvements, facilitate current and future projects and ensure day to day business operations are not impacted. In addition, the updated GIS software version will align with Hydro One's Windows 7 project.

- **Tivoli Upgrade- Hardware refresh and software reconfiguration**

The Tivoli Identity and Access Management infrastructure, which serves as a system of record for Hydro One users and allows access to our environment, is at end of life and does not meet the requirements for current and future enterprise business needs.

- **iHUB Upgrade**

The iHUB is Hydro One's technology integration platform that enables 65 enterprise systems to exchange data. The hardware platform for iHUB has reached end-of-life and is no longer supported by the vendor. This project seeks to install a platform replacement for iHUB to move the environment on to a supported system. If this investment is not made Hydro One will be restricted in its ability to integrate core systems.

Results:

- Hydro One's GIS system will be upgraded to the latest available version, ArcGIS/ArcFM 10.1. This will result in improved software functionality and performance, improved software usability, continued support for consolidating data models, continued support for integrating enterprise processes and it will make the updated software available to key Hydro One initiatives, such as ADS, SDx, SAP-GIS integration, Asset Analytics and Mobile IT.
- Replacement of aging hardware will result in improved performance, reliability, compatibility, flexibility and enable the enterprise solution to be managed at the appropriate service level (SL1 or SL2).
- Security: Enhanced security by addressing vulnerabilities. A software vendor backed best practice security design. Improved security by separating internal and external access systems.
- Compliance: Ease administration and compliance tracking.
- Infrastructure & Operations: Increase system capacity & improve scalability to meet future project and corporate needs. Provide High Availability and Disaster Recovery. Improve ease of operations and support.
- Support enterprise applications via consistent enterprise user based business rules on a unified authorization and authentication framework. Each application will be able to integrate with the enterprise environment providing user authentication, authorization and provisioning.

Costs:

	2013($M)*
Capital and Minor Fixed Assets (A)	7.6
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**7.7**
Recoverable (C)	-
Net Investment Cost (A+C)	**7.6**

**Distribution portion only*

Vulnerable Energy Consumers Coalition (VECC) Question #7 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 1.06 Staff 7 d)
Exhibit I, Tab 2, Schedule 5.02, VECC 5

a) Does Hydro One have the ability to determine the 2010 weather normalized billing parameters (i.e., kWh and kW)? If yes, what would be the growth rate and resulting threshold value if one used the approved 2011 distribution revenues and compared these to 2010 revenues based on 2010 weather normalized sales and 2011 rates?

Response

a) Hydro One has determined that the weather normalized Revenue for 2010 is $1,157.7 Million. Using this revenue the growth rate for the threshold calculation would be -0.76% and the revised ICM threshold would be $346.0Million.

Vulnerable Energy Consumers Coalition (VECC) Question #8 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 1.07, Staff 8 a)-c) and e)
Exhibit I, Tab 1, Schedule 7.01, CCC 1, Attachment 1, page 26

Preamble: In its response to Staff 8 Hydro One suggests that if recovery of the increase to rate base is not allowed then there will be an annual revenue shortfall.

a) Please clarify what Hydro One considers to be a revenue shortfall.

b) The response to CCC 1 indicates that the anticipated ROE for 2013 is 12.7%. Is this value based on the 2013 rates as applied for in the current Application? If not, what is the difference in terms of assumptions and resulting change in revenues for 2013?

c) Given the anticipated 2013 results (per CCC 1), what is the difference in 2013 distribution revenues that would:
- Yield an ROE equivalent to that approved for 2011 as opposed to 12.7%?
- Yield an ROE equal to the approved 2013 ROE, as opposed to 12.7%?

Response

b) The same assumptions are used in the calculations however 12.7% is done on a GAAP basis and 9.66% is done on a regulated basis.

c) To yield a (GAAP) ROE of 9.66% (2011 approved) the revenue included in the business plan would be reduced by $96.7 million.

To yield a (GAAP) ROE of 9.16% (2013 current) the revenue included in the business plan would be reduced by $112.3 million.

Vulnerable Energy Consumers Coalition (VECC) Question #9 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 1.12, Staff 13

a) Please update the 2012 YTD part of the response to October 31, 2012.

Response

a) There have not been any additional circuit breaker failures between June 30, 2012 and October 31, 2012.

Vulnerable Energy Consumers Coalition (VECC) Question #10 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 1.14, Staff 15

a) There appears to be no relationship between the number of spares required relative to the number of transformers in-service. Please explain more fully how the number of spares required in each category was determined.

b) Please explain why the planned purchases include fifteen 5-7.5 MVA transformers when this will result in more transformers on hand (45) than required spares (42).

c) Please provide a similar table that shows, at the time of the EB-2009-0096 proceeding, the required spares, the existing gaps and the proposed purchases.

d) Will any transformers be "refurbished" in 2013 and used to increase the inventory of spares? If so, how many?

Response

a) There is in fact a relationship between the number of required spare transformers and the number of transformers in-service. The information in the referenced schedule is presented in a simplified and consolidated manner. Although the transformer inventory is standardized where possible, there are over 70 distinct classifications of distribution station transformers based on factors such as voltage and capacity, in addition to specific electrical (i.e. winding vectors, tap range) and physical properties (i.e. secondary bushings versus direct cable connections, etc.). Within each of the capacity groups presented in the referenced schedule, there are many distinct sub-groups that must be effectively spared.

b) Some 5 - 7.5 MVA transformers are used to spare the in-service population of 3 MVA and less transformers. Looking at the combination of the two consolidated categories, there are 48 spare units required. The purchase of the combined 17 transformers will result in 47 spares on hand.

c) Hydro One's operating spare inventory database is based on present day information, and the database structure does not allow for historical point in time analysis. The underlying methodology to determine the required inventory complement has not changed since the EB-2009-0096 proceeding. The purchase of operating spares from the previous proceeding was to close inventory gaps that existed at that time as stated in the referenced schedule.

d) Three transformers will be refurbished in 2013 to replenish the operating spares to full complement. Refurbishment of these three transformers is technically and economically preferred to the alternative of purchasing new.

Vulnerable Energy Consumers Coalition (VECC) Question #14 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 5.12, VECC 15 (a)
Exhibit I, Tab 2, Schedule 5.17, VECC 20 (b)
Exhibit B, Tab 2, Schedule 2, pages 3 and 18

a) From the materials provided it appears that historically there have been 6 demand replacements (per page18) and 6 planned replacements, where the later included replacements under both the Station Refurbishment and Transformer Replacement Programs (per VECC 15 a)), for a total of 12 per year. Please confirm if this understanding is correct.

b) If the number of historical demand replacements was not 6, please provide the basis for the 6 demand replacements assumed for purposes of the Application.

c) The response to VECC #20 b) indicates that for the 6 replacement transformers, on average two were new and four were refurbished. Please confirm that this refers to the planned replacements each year. Also, In the case of the demand driven replacements (also 6 per annum), on average how many of these were historically new vs. refurbished?

d) Overall what is the change in requirement in 2013 for refurbished transformers taking into account the impact of increased purchases of new transformers for: i) planned replacement (4), ii) demand replacements (?); and iii) increased station refurbishment (24)?

Response

a) The Typical spending of 6 transformer replacements includes planned replacements within both the Station Refurbishment and Transformer Replacement programs as per Exhibit I, Tab 2, Schedule 5.12 VECC 15 a). The 6 Demand Replacements referenced on page 18 of Exhibit B, Tab 2, Schedule 2 are in fact the expected number to occur in 2013, not a historic level.

b) The 6 expected demand transformer replacements are based on the Class 1 failure[1] history as outline in Exhibit B, Tab 2, Schedule 2, Figure 16, with a downward adjustment based on the positive effects of increased planned replacements.

c) Yes, those 6 transformer replacements refer to planned replacements, which as noted in part (a) includes transformer replacements within both the Station Refurbishment

[1] *Class 1 Failures: Transformer automatically removed from service. Major failures which require replacement of the transformer. Typically the failure will involve the core, windings, and/or tank. Damage is beyond repair.*

and Transformer replacement programs. Also as noted in part (a) the 6 Demand transformer replacement are the expected number to occur in 2013. In the Typical capital spending of 2011 all the demand driven replacements utilized refurbished transformers.

d) In 2013 and beyond, there will be a greatly reduced dependency using refurbished transformers for planned or demand replacements. A much greater proportion of new transformers will be utilized to manage long-term demographic pressures and reduce transformer life-cycle costs and the associated revenue requirements.

Please refer to Technical Conference Response VECC 15 part (b) for a breakdown between 2011 Typical and 2013 Escalated transformer replacements.

Vulnerable Energy Consumers Coalition (VECC) Question #15 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 5.18, VECC 15 a)
Exhibit I, Tab 2, Schedule 5.22, VECC 25 a)

a) The response to VECC 15 a) suggests that the historical (planned) replacement of six transformers annually included both those associated with Station Refurbishment and Transformer Replacements where significant station refurbishment was not required. However, the response to VECC 25 a) suggests that historically there have been six planned replacements involving transformers at stations that do not required significant station refurbishment. Please reconcile.

b) For greater clarify please provide a two schedules. One that indicates what is included in typical annual capital spending (i.e. historical practice) in terms of: i) the number of stations refurbished, the associated number transformers and cost; and ii) the number of transformers replaced on a planned basis at stations not requiring refurbishment as distinct from the number of transformers expected to be replaced on a "demand basis" plus the cost. A second that indicates what is included in the accelerated spending in terms of: i) the number of stations refurbished, the associated number transformers and cost; and ii) the number of transformers replaced on a planned basis at stations not requiring refurbishment plus the number of transformers expected to be replaced on a "demand basis" along with the additional cost of each.

Response

a) The response to Exhibit I, Tab 2, Schedule 5.18 VECC 15 a) refers to the historic level of 6 planned transformer replacements combined between the categories of station refurbishment and transformer replacements.

The response to Exhibit I, Tab 2, Schedule 5.22 VECC 25 a) is based on the proposed 2013 program presented in Exhibit B, Tab 2, Schedule 2 page 18 Table 2, which shows that 6 planned transformer replacements are in addition to the 24 replacements to be performed under station refurbishment projects.

b) Refer to Table 1 and Table 2 below for the 2011 Typical capital and 2013 Escalated capital respectively for capital expenditures associated with transformer replacements.

**Table 1 – Basis of 2011 Typical Capital,
Planned Transformer Replacements ($ Millions)**

	2011 Typical	
	# units	**$ M**
4 Station Refurbishments from which included 1 transformer replacement (a)	1	0.9
Planned Transformer Replacement; new transformer (b)	2	1.2
Planned transformer replacement; refurbished transformer (c)	3*	-
Demand Transformer Replacement; new transformer (d)	0**	-
Total Transformer Replacements (a+b+c+d)	**6**	**2.1**

**Table 2 – Basis of 2013 Escalated Capital,
Transformer Replacements ($ Millions)**

	2013 Escalated	
	# units	**$ M**
32 Station Refurbishments which include 24 transformer replacements (e)	24	14.0
Planned Transformer Replacement; new transformer (f)	6	3.5
Planned Transformer Replacement; refurbished transformer (g)	0	-
Demand Transformer Replacement; new transformer (h)	6	3.5
Total Transformer Replacements (e+f+g+h)	**36**	**21.0**

* *There is no capital expenditure associated with the refurbishment of transformers, as the refurbishment costs are an OM&A expenditure.*

** *The 2011 demand replacements utilized refurbished transformers as opposed to new.*

Vulnerable Energy Consumers Coalition (VECC) Question #17 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 6.09, PWU 10 b)
Exhibit I, Tab 2, Schedule 6.10, PWU 11 b)
Exhibit I, Tab 2, Schedule 6.13, PWU 14

a) For each of the three assets shown in PWU 14, what accomplishment rate would yield the same %ESL in 2021 as reported for 2012?

b) For each of the three assets shown in PWU 14, what accomplishment rate would yield the same %ESL in 2031 as reported for 2012?

Response

a) Assuming that units are selected based only the “oldest-first” approach (regardless of other probabilistic and consequential risk factors) with a constant annual accomplishment between 2013 and 2021, the following accomplishment rates would yield the same percentage of fleet beyond expected service life in 2021 as in 2012:
- station refurbishments — 24 stations per year
- transformer replacements — 30 transformers per year
- wood poles replacements — 30,500 poles per year [(1)]

b) Assuming that units are selected based only the “oldest-first” approach (regardless of other probabilistic and consequential risk factors) with a constant annual accomplishment between 2013 and 2031, the following accomplishment rates would yield the same percentage of fleet beyond expected service life in 2031 as in 2012:
- station refurbishments — 24 stations per year
- transformer replacements — 32 transformers per year
- wood poles replacements — 26,000 poles per year [(1)]

NOTE:
[(1)] The analysis for distribution poles replacement rates does not include poles that were not treated to CSA standard.

Vulnerable Energy Consumers Coalition (VECC) Question #18 List 1

Question

Reference: Exhibit I, Tab 2, Schedule 9.03, AMPCO 3 c) & d)

a) Please review and correct (as necessary) the references provided in these two responses.

Response

a) There was a typographical error with the references in Exhibit I, Tab 2, Schedule 9.03 AMPCO 3 part (c) & part (d); the references should have been to Exhibit I, Tab 2, Schedule 1.11 Staff 12 part (d).

Vulnerable Energy Consumers Coalition (VECC) Question #19 List 1

Question

Reference: Exhibit B, Tab 3, Schedule 1, page 13, Table 3 (Updated)
Exhibit I, Tab 4, Schedule 2.03, EP 17

a) Where is the $13.6 M in Project OM&A costs for 2013 (noted in EP 17) included in the Cornerstone costs set out in Table 3?

b) If it is not included please explain why.

c) Please indicate whether the costs reported in rows 1-6 of Table 3 are OM&A expenses charged to operations or capital costs? If a mix, please provide a break out.

d) Were there depreciation costs associated with the existing CIS system in 2011 and, if so, what were they and are they shown in Table 3?

e) What were the OEB approved CIS costs for 2010 and 2011 – equivalent to those shown in rows 1-3 of Table 3?

Response

a) The OM&A costs are not included in the Cornerstone costs set out in Table 3.

b) In this proceeding, Hydro One is requesting recovery of the Capital expenditure associated with the project. Hydro One acknowledges that no mechanism exists to request recovery of the OM&A expense referred to above under the current IRM framework. In fact, Hydro One will spend approximately $24.4M of OM&A to implement the project.

c) All of the costs provided in rows 1-6 of Table 3 are OM&A expenses charged to operations.

d) The existing CIS system has been fully depreciated and therefore no depreciation costs are reflected in Table 3.

e) The OEB approved CIS costs for 2010 and 2011 are equivalent to the figures depicted in rows 1-3 of Table 3.

Vulnerable Energy Consumers Coalition (VECC) Question #21 List 1

Question

Reference: Exhibit I, Tab 7, Schedule 5.03, VECC 38

a) The referenced Staff IR does not address the question posed. The question asked why Hydro One is not proposing to allocate the recovery of the Capital Contribution portion of the ICM from its customer classes using the same approach as the Board approved for Woodstock. Please provide a response.

Response

a) Hydro One has calculated the proposed ICM Rate Rider in accordance with the methodology specified in the Board's 2013 Incremental Capital Workform. In Hydro One's situation, the Commerce Way TS Capital Contribution accounts for only $0.7M of the $26.2M in total ICM revenue to be collected via the rate rider. Using the rate class share of transmission connection revenue to split the $0.7M, instead of the Distribution revenue share as specified in the ICM workform, would have a minimal impact of reducing the ICM rate rider amounts proposed for most rate classes by less than $0.0001/kWh, with the exception of the ST rate class which would see an increase to $0.0293/kW from the currently proposed rider amount of $0.0206/kW.

Vulnerable Energy Consumers Coalition (VECC) Question #22 List 1

Question

Reference: Exhibit I, Tab 10, Schedule 1.02, Staff 30

a) Please clarify what the Total Forecast value of $87.3 M for Actual Capital is meant to represent. Is it the actual capital spending for 2010 and 2011 plus the forecast capital spending for all of 2012?

b) Please clarify what the Total Forecast value of $20.2 M for Actual OM&A is meant to represent. Is it the actual OM&A spending for 2010 and 2011 plus the forecast OM&A spending for all of 2012?

c) Please update the response with 2012 actuals as of October 31, 2012.

Response

a) Yes. The Total Forecast value on the Actual Capital row is mean to represent the actual capital spending for 2010 and 2011 plus the forecast capital spending for all of 2012.

b) Yes. The Total Forecast value on the Actual OM&A row is mean to represent the actual OM&A spending for 2010 and 2011 plus the forecast OM&A spending for all of 2012.

c) The 2012 actuals as of October 31, 2012 are not currently available. The 2012 actuals as of September 30, 2012 are:

- $35.3M actual Capital to September 30, 2012
- $3.4M actual OM&A to September 30, 2012

Vulnerable Energy Consumers Coalition (VECC) Question #23 List 1

Question

Reference: Exhibit I, Tab 10, Schedule 1.02, Staff 30
Exhibit I, Tab 10, Schedule 7.01, CCC 15

a) Please provide a schedule that sets out the annual entries for 2011 and the forecast entries for 2012 for the revenues and costs accrued in the Smart Grid deferral/variance account(s) and show the overall (forecast) balance as of December 31, 2012, including accrued interest.

Response

a)

Smart Grid Variance Account	2011		2012 (Forecast)
PRINCIPAL			
Opening Balance	(5,162,496)		(20,333,420)
Funding Received	(18,357,245)		-
Revenue Requirement	3,186,321		15,504,635
Annual Net Activity	**(15,170,924)**		**15,504,635**
Closing Balance	(20,333,420)		(4,828,785)
INTEREST			
Opening Balance	(13,715)		(206,212)
Annual Net Activity	**(192,497)**		**(419,189)**
Closing Balance	(206,212)		(625,401)
TOTAL VARIANCE ACCOUNT BALANCE	**(20,539,632)**		**(5,454,186)**

Vulnerable Energy Consumers Coalition (VECC) Question #24 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 1.01, Staff 34
Exhibit I, Tab 1, Schedule 7.02, CCC 2, Attachment 1

a) Please confirm that the materials provided to Hydro One's shareholder (the Ontario Government) regarding the current Application did not make reference to the proposed changes to R2 customer rates and bills resulting from the implementation of the Density Study. If this is incorrect, please provide the relevant references demonstrating that these impacts were communicated.

b) Before or subsequent to the filing of the Application, has Hydro One had any conversations with it shareholder regarding the impacts of implementing the Density Study on R2 customers and/or the limitations of the currently fixed amount of RRA available to offset the impacts of rate changes being experienced by these customers overtime.

Response

a) b)
Subsequent to the preparation of this rate application, Hydro One did provide a briefing note to its shareholder regarding the proposed changes to R2 customer rates and bills resulting from the implementation of the Density Study. The briefing note is included as Attachment 1.

BriefingNote

Date: June 6, 2012

Issue:

- Hydro One has applied to the OEB to reduce Urban Rates as part of its recent Distribution Rate Application.

Background

- Hydro One Networks ("HONI") has four residential rate classes and four general service rate classes that are density based. Below are the four residential rate classifications:

    1. Urban High Density (UR)
    2. Medium Density(R1)
    3. Low Density(R2)
    4. Seasonal(S)

- The methodology used to set rates for these classes is based on the cost of service, which varies based on customer density. Effectively the lower the density, the higher the cost of service

- In its Decision on HONI's 2010/2011 Distribution Rates Application, the OEB directed the company to provide a more detailed analysis of the relationship between density and cost allocation, and examine possible rate structures that appropriately reflect those differences.

- Based on the results of the density study, Hydro One believes that some adjustment to the allocation of costs and rates for density-based rate classes is warranted.

- In its recent application to the Ontario Energy Board for Distribution Rates, Hydro One is seeking to adjust the rate classifications as follows:

    Urban High Density (decrease14%)
    Medium Density (no change)
    Low Density (increase 2.5%)
    Seasonal (decrease 2%)

- It is anticipated that changes in rates to address the density study findings would likely need to be phased in over time. As such, HONI will look to start making changes to existing rates at the first available opportunity.

- For example communities such as Ottawa, which have customers in each classification (~24,000 UR, ~14,000 R1 and ~10,000 R2), the effect of this proposal would vary.

Rate Applications before the Ontario Energy Board

- Hydro One filed its 2013 – 2014 Revenue Requirement and Rate Application to the Ontario Energy Board (OEB) for its transmission and distribution application for 2013 in May of this year.
- An oral hearing at the OEB is anticipated in the later summer/early fall of 2012 with an expected OEB decision to be issued in December. The timing is intended to facilitate rates that would be effective January 1, 2013.
- If approved, this could represent an average estimated increase on total customer bills of 2.6 per cent in 2013; representing an increase of $1.74, below the rate of inflation.

Key Messages: Rate Applications

- In making our application to the OEB, the Company seeks only to recover costs that will allow Hydro One to make prudent investments to sustain the transmission and distribution systems and to replace aging and end-of-life assets, so that we can continue to provide safe and reliable power to the people of Ontario.
- Through our 2013-2014 transmission rate application, we are seeking to recover costs to bring previously OEB approved construction projects into service, such as the Bruce to Milton transmission line project, Commerce Way Transformer Station and the Midtown Transmission project in Toronto. Transmission rates also support important sustainment work on our more than 28,000 km of transmission lines underground cables as well as maintain our more than 286 transmission stations.
- Through our 2013 distribution application, we are following the OEB's incentive regulatory mechanism and intend to seek to recover costs associated with replacing wood poles; and replacing equipment at Hydro One's more than 1,000 power distribution stations.
- Hydro One believes its rates should be a true and accurate reflection of the cost to provide service.
- In its recent application to the Ontario Energy Board for Distribution Rates, Hydro One is seeking to reduce Urban Rates by 14% to bring the rate into line with OEB guidelines. If approved, this would result in an increase to Rural 2 rates by 2.5% and a decrease of 2% to Seasonal Rates.
- Hydro One's applications will undergo rigorous regulatory review and approvals by the Ontario Energy Board. The final decision with respect to our rates rests with the OEB.

Key Messages: General

- We know our customers expect us to manage in a way strikes the right balance between system reliability requirements, service and cost.

- As Ontario reaches its goal to replace coal-fired generation with cleaner forms of electricity and an improved transmission system, Hydro One has been renewing its aging electricity infrastructure; all the towers, lines, poles, and equipment that bring the electricity to Ontario's homes and businesses.

- It takes a massive amount of infrastructure to transmit and deliver electricity to the homes and businesses in Ontario from where it is generated.

- For its part, Hydro One owns and manages more than $17 billion in wires, towers, transformers, poles, land and other assets.

- We have made significant investments in the electricity transmission and distribution system to make sure it is reliable today and ready for tomorrow.

- Since 2003, Hydro One has made upgrades to 5,000 kilometres of our transmission and distribution lines — about the width of Canada from coast to coast.

- Customer rates have made these investments possible, ensuring we are able to deliver the safe reliable electricity they expect at the flick of a switch.

Vulnerable Energy Consumers Coalition (VECC) Question #27 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 5.03, VECC 51 a)
Exhibit I, Tab 13, Schedule 5.04, VECC 52 g)

a) Given the impact that DG can have on Hydro One's distribution system why haven't they been incorporated into its GIS database?

b) When does Hydro One expect to have DG customers incorporated into its GIS database?

c) Given the size of ST customers why haven't they been incorporated into Hydro One's GIS data base?

d) When does Hydro One expect to have ST customers incorporated into its GIS database?

e) Please explain why it was possible to include the ST customer count in the econometric analysis but not in the direct assignment cost analysis.

Response

a), b), c) and d)

The primary focus of the GIS database is to capture the physical assets in Hydro One's distribution system in order to provide our planners with better asset information that will improve the productivity of our work programs. As part of the implementation of the Smart Meter program, the geographic location of smart meters was a piece of data collected, which has allowed the ready incorporation of customers with Smart Meters into a GIS environment. For those customers without smart meters, the process of incorporating customer information into a GIS environment at the time the Density Study was completed was complex and costly. Since there are only about 80 DG customers and 600 ST customers (less than .1% of our customers), there would be an insignificant impact on the direct cost assignment analysis and the decision was made to not include these as part of the analysis.

The inclusion of ST and DG customer locations into the GIS database has progressed over the last year and most are now included in the GIS database, although with limited customer information.

e) ST customers were included in the econometric analysis as this analysis required only the total number of customers by operating area, which is readily available from our customer data systems. For the direct assignment cost analysis, the geographic location and connectivity of customers to the distribution system was required, which was not readily available as discussed in the response above.

Vulnerable Energy Consumers Coalition (VECC) Question #30 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 5.15, VECC 63 a)
Exhibit I, Tab 13, Schedule 5.06, VECC 54 b)
Exhibit I, Tab 13, Schedule 5.17, VECC 65

a) With reference to VECC 54 b), which sample areas were classified as low, medium and high density?

b) Please confirm that the low, medium and high density areas do not conform precisely to the density definitions used by Hydro One in its customer classification. If not confirmed, please explain how the definitions can be consistent when many of the sample areas have customers from more than one residential customer class.

c) With reference to VECC 63 a), while the Study supports that the there is a statistically significant difference in the average cost to service low, medium and high density sample area, how does this support the existing demarcation points if the Study density definitions do not match those used in Hydro One's customer classification.

Response

a) In the second column of the table provided in response to Exhibit I, Tab 13, Schedule 5.06 VECC 54 b), sample areas labeled "LD_" were classified as low density, sample areas labeled "MD_" were classified as medium density, and sample areas labeled "HD_" were classified as high density.

b) Confirmed. As per the methodology reviewed with stakeholders at the March 22, 2011 session, the sample areas were selected with indifference to the type of customers contained within them.

c) While the sample areas were selected with indifference to the type of customers contained within them, there is a strong relationship between the sample areas and Hydro One's existing rate classes and demarcation points. High-density customers, as defined by Hydro One and eligible for the UR, UGe, and UGd rate classes, are the single largest group of customers in the high-density sample areas (~67%). Medium-density customers, as defined by Hydro One and eligible for the R1, GSe, and GSd rate classes, are the single largest group of customers in the medium-density sample areas (~78%). Finally, low-density customers, as defined by Hydro One and eligible for the R2, GSe, and GSd rate classes are the single largest group of customers in the low-density sample areas (~93%).

Vulnerable Energy Consumers Coalition (VECC) Question #31 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 5.16, VECC 64 a) & b)
Exhibit I, Tab 13, Schedule 5.16, VECC 64 c), Sheets I6 & I8
Exhibit I, Tab 13, Schedule 5.21, VECC 69 d)

a) Please confirm that the kW per customer based on the NCP factors used to allocate costs to customers classes is higher in the case of UGSe customers that it is for GSe customers.

b) Please confirm that, as a result, the a cost allocation that takes into account both demand and density considerations would yield allocated cost per customer for the UGSe and GSe customer classes that were closer together than an allocation based strictly on density. If not confirmed, please explain why.

c) Please confirm that the kW per customer based on the NCP factors used to allocate costs to customers classes is higher in the case of UGSd customers that it is for GSd customers.

d) Please confirm that, as a result, the a cost allocation that takes into account both demand and density considerations would yield allocated cost per customer for the UGSd and GSd classes that were closer together than an allocation based strictly on density. If not confirmed, please explain why.

Response

a) Yes, the kW per customer NCP factors are higher for urban GS than for non-urban GS customers. The density weightings currently used in the CA Model are applied to the NCP factors for the purpose of allocating costs. The combined impact of NCP and density weights results in NCP factors for urban GS customers that are lower than for GS customers for the purpose of allocating fixed assets required to service the various customer classes.

b) This is confirmed as it relates to Hydro One's current allocation factors in its Board-approved CA Model. The methodology utilized in the Density Study also balances competing allocation factors. The Density Study results provide the bottom line impact of all of the allocation factors and account for the inter-play between the individual factors in the CA Model.

c) See response to Technical Conference Responses VECC # 31 a)

d) See response to Technical Conference Responses VECC # 31 b)

<u>Vulnerable Energy Consumers Coalition (VECC) Question #32 List 1</u>

<u>Question</u>

Reference: Exhibit I, Tab 13, Schedule 5.21, VECC 69 e)

a) The response does not include the USOA accounts for the fixed assets that are included in the Density Study (per D-1-1, Attachment 1, pages 25-26). Please update the response to also include the expenses associated with these accounts.

<u>Response</u>

a) The information requested is provided in Technical Conference Response VECC #1 Attachment 1.

Customer Related Costs												
UR	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**UGe**	**UGd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**Total - Customer**
$90,672	$425,028	$648,605	$219,570	$134,986	$11,924	$5,002	$1,012	$7,552	$4,514	$37	$8,970	**$1,557,872**
$34,805	$163,151	$248,972	$84,284	$51,816	$4,577	$1,920	$388	$2,899	$1,733	$14	$3,443	**$598,002**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$151,438	$977,784	$1,866,318	$618,749	$355,131	$22,130	$12,497	$975	$19,508	$11,840	$87	$3,248	**$4,039,703**
$23,587	$152,291	$290,682	$96,371	$55,312	$3,447	$1,946	$152	$3,038	$1,844	$14	$506	**$629,190**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$407,509	$1,195,951	$1,064,462	$454,937	$283,555	$169,090	$60,725	$25,962	$0	$0	$843	$360,112	**$4,023,145**
$2,603,966	$7,642,074	$6,801,865	$2,907,098	$1,830,146	$136,393	$195,969	$20,938	$108,065	$65,585	$1,632	$11,244	**$22,324,973**
$382,161	$1,121,560	$998,250	$426,649	$268,594	$20,017	$28,761	$3,073	$15,860	$9,625	$239	$1,650	**$3,276,441**
$367,788	$1,724,019	$2,630,901	$890,629	$547,537	$48,366	$20,290	$4,104	$30,632	$18,311	$150	$36,385	**$6,319,113**
$431,036	$2,020,498	$3,083,336	$1,043,791	$641,697	$56,684	$23,779	$4,810	$35,900	$21,460	$176	$42,642	**$7,405,809**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$467,009	$3,015,319	$5,755,409	$1,908,117	$1,095,163	$68,244	$38,538	$3,007	$60,160	$36,511	$268	$10,017	**$12,457,762**
$1,359,391	$8,777,134	$16,753,117	$5,554,236	$3,187,852	$198,649	$112,178	$8,753	$175,118	$106,279	$779	$29,157	**$36,262,642**
$3,713,390	$23,976,125	$45,763,782	$15,172,271	$8,708,122	$542,642	$306,432	$23,910	$478,361	$290,317	$2,128	$79,648	**$99,057,128**
$20,394	$59,853	$53,273	$22,769	$14,334	$212	$1,535	$33	$846	$514	$1	$0	**$173,764**
$98,898	$290,243	$258,332	$110,410	$69,508	$1,030	$7,443	$158	$4,104	$2,491	$4	$0	**$842,622**
$168,455	$778,157	$1,078,487	$352,294	$228,546	$17,280	$0	$0	$12,846	$7,796	$70	$7,956	**$2,651,887**
$226,465	$664,627	$591,554	$252,828	$159,070	$56,603	$18,062	$8,691	$0	$0	$360	$82,861	**$2,061,121**
$1,942,520	$6,840,163	$9,918,738	$1,322,305	$1,592,711	$353,116	$147,387	$45,846	$0	$0	$0	$0	**$22,162,786**
$1,340,438	$3,776,048	$3,422,216	$486,644	$1,758,800	$495,182	$203,410	$80,083	$54,381	$3,300	$1,753	$55,943	**$11,678,198**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
$13,829,921	**$63,600,024**	**$101,228,299**	**$31,923,951**	**$20,982,881**	**$2,205,587**	**$1,185,872**	**$231,894**	**$1,009,271**	**$582,120**	**$8,554**	**$733,783**	**$237,522,157**
140,540	**412,455**	**367,107**	**156,901**	**98,776**	**7,361**	**10,577**	**1,130**	**5,234**	**37,506**	**88**	**607**	
$98	**$154**	**$276**	**$203**	**$212**	**$300**	**$112**	**$205**	**$193**	**$16**	**$97**	**$1,209**	

USoA Account #	Account Description	Customer Related Costs												
		UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST	Total - Customer
5005	Operation Supervision and Engineering	$90,672	$425,028	$648,605	$219,570	$134,986	$11,924	$5,002	$1,012	$7,552	$4,514	$37	$8,970	**$1,557,872**
5010	Load Dispatching	$34,805	$163,151	$248,972	$84,284	$51,816	$4,577	$1,920	$388	$2,899	$1,733	$14	$3,443	**$598,002**
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5016	Distribution Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5020	Overhead Distribution Lines and Feeders - Operation Labour	$151,438	$977,784	$1,866,318	$618,749	$355,131	$22,130	$12,497	$975	$19,508	$11,840	$87	$3,248	**$4,039,703**
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$23,587	$152,291	$290,682	$96,371	$55,312	$3,447	$1,946	$152	$3,038	$1,844	$14	$506	**$629,190**
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5065	Meter Expense	$407,509	$1,195,951	$1,064,462	$454,937	$283,555	$169,090	$60,725	$25,962	$0	$0	$843	$360,112	**$4,023,145**
5070	Customer Premises - Operation Labour	$2,603,966	$7,642,074	$6,801,865	$2,907,098	$1,830,146	$136,393	$195,969	$20,938	$108,065	$65,585	$1,632	$11,244	**$22,324,973**
5075	Customer Premises - Materials and Expenses	$382,161	$1,121,560	$998,250	$426,649	$268,594	$20,017	$28,761	$3,073	$15,860	$9,625	$239	$1,650	**$3,276,441**
5085	Miscellaneous Distribution Expense	$367,788	$1,724,019	$2,630,901	$890,629	$547,537	$48,366	$20,290	$4,104	$30,632	$18,311	$150	$36,385	**$6,319,113**
5105	Maintenance Supervision and Engineering	$431,036	$2,020,498	$3,083,336	$1,043,791	$641,697	$56,684	$23,779	$4,810	$35,900	$21,460	$176	$42,642	**$7,405,809**
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5114	Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
5120	Maintenance of Poles, Towers and Fixtures	$467,009	$3,015,319	$5,755,409	$1,908,117	$1,095,163	$68,244	$38,538	$3,007	$60,160	$36,511	$268	$10,017	**$12,457,762**
5125	Maintenance of Overhead Conductors and Devices	$1,359,391	$8,777,134	$16,753,117	$5,554,236	$3,187,852	$198,649	$112,178	$8,753	$175,118	$106,279	$779	$29,157	**$36,262,642**
5135	Overhead Distribution Lines and Feeders - Right of Way	$3,713,390	$23,976,125	$45,763,782	$15,172,271	$8,708,122	$542,642	$306,432	$23,910	$478,361	$290,317	$2,128	$79,648	**$99,057,128**
5145	Maintenance of Underground Conduit	$20,394	$59,853	$53,273	$22,769	$14,334	$212	$1,535	$33	$846	$514	$1	$0	**$173,764**
5150	Maintenance of Underground Conductors and Devices	$98,898	$290,243	$258,332	$110,410	$69,508	$1,030	$7,443	$158	$4,104	$2,491	$4	$0	**$842,622**
5160	Maintenance of Line Transformers	$168,455	$778,157	$1,078,487	$352,294	$228,546	$17,280	$0	$0	$12,846	$7,796	$70	$7,956	**$2,651,887**
5175	Maintenance of Meters	$226,465	$664,627	$591,554	$252,828	$159,070	$56,603	$18,062	$8,691	$0	$0	$360	$82,861	**$2,061,121**
5310	Meter Reading Expense	$1,942,520	$6,840,163	$9,918,738	$1,322,305	$1,592,711	$353,116	$147,387	$45,846	$0	$0	$0	$0	**$22,162,786**
5320	Collecting	$1,340,438	$3,776,048	$3,422,216	$486,644	$1,758,800	$495,182	$203,410	$80,083	$54,381	$3,300	$1,753	$55,943	**$11,678,198**
5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
	Total Customer Related Costs	**$13,829,921**	**$63,600,024**	**$101,228,299**	**$31,923,951**	**$20,982,881**	**$2,205,587**	**$1,185,872**	**$231,894**	**$1,009,271**	**$582,120**	**$8,554**	**$733,783**	**$237,522,157**
	Number of Customers	**140,540**	**412,455**	**367,107**	**156,901**	**98,776**	**7,361**	**10,577**	**1,130**	**5,234**	**37,506**	**88**	**607**	
	Cost per Customer	**$98**	**$154**	**$276**	**$203**	**$212**	**$300**	**$112**	**$205**	**$193**	**$16**	**$97**	**$1,209**	

USoA Account #	Account Description	Customer Related Costs												
		UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST	Total - Customer
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$3,093,361	$10,372,924	$12,678,740	$1,694,423	$5,179,667	$7,365,265	$857,513	$1,415,183	$288,650	$49,632	$9,865	$12,469,766	**$55,474,987**
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$660,037	**$660,037**
1830-4B	Primary-Retail Fixtures	$12,682,151	$145,596,648	$331,986,127	$105,534,924	$59,448,952	$4,496,822	$1,177,932	$198,142	$3,213,384	$1,950,198	$17,630	$0	**$666,302,910**
1830-5	Poles, Towers and Fixtures - Secondary	$18,090,379	$53,091,337	$47,254,202	$20,196,316	$12,714,465	$0	$1,361,442	$0	$750,754	$455,631	$0	$0	**$153,914,526**
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$505,434	**$505,434**
1835-4B	Primary-Retail Conductors	$9,711,577	$111,493,158	$254,224,133	$80,815,198	$45,524,066	$3,443,520	$902,022	$151,731	$2,460,705	$1,493,398	$13,501	$0	**$510,233,007**
1835-5	Overhead Conductors and Devices - Secondary	$13,853,021	$40,655,612	$36,185,724	$15,465,679	$9,736,322	$0	$1,042,548	$0	$574,903	$348,908	$0	$0	**$117,862,717**
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1840-4	Underground Conduit - Primary	$304,472	$893,560	$795,317	$339,916	$213,992	$15,948	$22,914	$2,448	$12,636	$7,669	$69	$0	**$2,608,941**
1840-5	Underground Conduit - Secondary	$1,226,570	$3,599,716	$3,203,945	$1,369,357	$862,070	$0	$92,309	$0	$50,903	$30,893	$0	$0	**$10,435,763**
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1845-4	Underground Conductors and Devices - Primary	$9,687,770	$28,431,502	$25,305,596	$10,815,542	$6,808,858	$507,435	$729,080	$77,897	$402,044	$244,000	$2,206	$0	**$83,011,930**
1845-5	Underground Conductors and Devices - Secondary	$39,027,305	$114,536,671	$101,943,919	$43,570,550	$27,429,570	$0	$2,937,108	$0	$1,619,640	$982,957	$0	$0	**$332,047,720**
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,724,666	**$2,724,666**
1850-2	TRF-Rural	$57,692,765	$266,504,148	$369,361,500	$120,654,180	$78,272,762	$5,918,168	$0	$0	$4,399,522	$2,670,063	$24,138	$0	**$905,497,246**
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1860-1	Mtr-Single	$1,217,837	$3,574,086	$3,181,133	$1,359,574	$847,401	$0	$181,475	$0	$0	$0	$0	$0	**$10,361,504**
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$4,010,054	$0	$615,707	$0	$0	$19,986	$0	**$4,645,747**
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,227,564	**$7,227,564**
1860-4	Mtr-Smart	$18,756,957	$55,047,598	$48,995,381	$20,940,491	$13,182,956	$982,470	$1,411,607	$150,819	$0	$0	$11,754	$80,996	**$159,561,029**
Total Customer Related Fixed Asset Costs		**$185,344,164**	**$833,796,959**	**$1,235,115,716**	**$422,756,148**	**$260,221,081**	**$26,739,683**	**$10,715,948**	**$2,611,927**	**$13,773,141**	**$8,233,349**	**$99,150**	**$23,668,463**	**$3,023,075,730**
Number of Customers		**140,540**	**412,455**	**367,107**	**156,901**	**98,776**	**7,361**	**10,577**	**1,130**	**5,234**	**37,506**	**88**	**607**	
Fixed Asset Costs per Customer		**$1,319**	**$2,022**	**$3,364**	**$2,694**	**$2,634**	**$3,632**	**$1,013**	**$2,311**	**$2,631**	**$220**	**$1,126**	**$39,000**	

USoA Account #	Account Description	Customer Related Costs												
		UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST	Total - Customer
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$3,093,361	$10,372,924	$12,678,740	$1,694,423	$5,179,667	$7,365,265	$857,513	$1,415,183	$288,650	$49,632	$9,865	$12,469,766	**$55,474,987**
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$660,037	**$660,037**
1830-4B	Primary-Retail Fixtures	$12,682,151	$145,596,648	$331,986,127	$105,534,924	$59,448,952	$4,496,822	$1,177,932	$198,142	$3,213,384	$1,950,198	$17,630	$0	**$666,302,910**
1830-5	Poles, Towers and Fixtures - Secondary	$18,090,379	$53,091,337	$47,254,202	$20,196,316	$12,714,465	$0	$1,361,442	$0	$750,754	$455,631	$0	$0	**$153,914,526**
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$505,434	**$505,434**
1835-4B	Primary-Retail Conductors	$9,711,577	$111,493,158	$254,224,133	$80,815,198	$45,524,066	$3,443,520	$902,022	$151,731	$2,460,705	$1,493,398	$13,501	$0	**$510,233,007**
1835-5	Overhead Conductors and Devices - Secondary	$13,853,021	$40,655,612	$36,185,724	$15,465,679	$9,736,322	$0	$1,042,548	$0	$574,903	$348,908	$0	$0	**$117,862,717**
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1840-4	Underground Conduit - Primary	$304,472	$893,560	$795,317	$339,916	$213,992	$15,948	$22,914	$2,448	$12,636	$7,669	$69	$0	**$2,608,941**
1840-5	Underground Conduit - Secondary	$1,226,570	$3,599,716	$3,203,945	$1,369,357	$862,070	$0	$92,309	$0	$50,903	$30,893	$0	$0	**$10,435,763**
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1845-4	Underground Conductors and Devices - Primary	$9,687,770	$28,431,502	$25,305,596	$10,815,542	$6,808,858	$507,435	$729,080	$77,897	$402,044	$244,000	$2,206	$0	**$83,011,930**
1845-5	Underground Conductors and Devices - Secondary	$39,027,305	$114,536,671	$101,943,919	$43,570,550	$27,429,570	$0	$2,937,108	$0	$1,619,640	$982,957	$0	$0	**$332,047,720**
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,724,666	**$2,724,666**
1850-2	TRF-Rural	$57,692,765	$266,504,148	$369,361,500	$120,654,180	$78,272,762	$5,918,168	$0	$0	$4,399,522	$2,670,063	$24,138	$0	**$905,497,246**
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
1860-1	Mtr-Single	$1,217,837	$3,574,086	$3,181,133	$1,359,574	$847,401	$0	$181,475	$0	$0	$0	$0	$0	**$10,361,504**
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$4,010,054	$0	$615,707	$0	$0	$19,986	$0	**$4,645,747**
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,227,564	**$7,227,564**
1860-4	Mtr-Smart	$18,756,957	$55,047,598	$48,995,381	$20,940,491	$13,182,956	$982,470	$1,411,607	$150,819	$0	$0	$11,754	$80,996	**$159,561,029**
Total Customer Related Fixed Asset Costs		**$185,344,164**	**$833,796,959**	**$1,235,115,716**	**$422,756,148**	**$260,221,081**	**$26,739,683**	**$10,715,948**	**$2,611,927**	**$13,773,141**	**$8,233,349**	**$99,150**	**$23,668,463**	**$3,023,075,730**
Number of Customers		**140,540**	**412,455**	**367,107**	**156,901**	**98,776**	**7,361**	**10,577**	**1,130**	**5,234**	**37,506**	**88**	**607**	
Fixed Asset Costs per Customer		**$1,319**	**$2,022**	**$3,364**	**$2,694**	**$2,634**	**$3,632**	**$1,013**	**$2,311**	**$2,631**	**$220**	**$1,126**	**$39,000**	

Vulnerable Energy Consumers Coalition (VECC) Question #33 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 5.22, VECC 70, b)

a) With respect to VECC 70 b), please provide the reference to where in its Decision the Board stated that "it was appropriate that the Seasonal rate class be density weighted". Also, please confirm whether this statement was with respect to: i) the future use of density weighting for the Seasonal class or ii) simply not changing the current weighting approach subject to the completion of the Density Study.

Response

a) In Hydro One's EB-2009-0096 application Hydro One was proposing to change to density weights for the Seasonal rate class to 1.0. At page 67 in the Board Decision with Reasons issued April 9, 2010 the Board indicated that

> "Hydro One will not be permitted to change the density weighting factor for Seasonal customers at this time. This represents a further change beyond what has already been approved, which may not be adequately supported. On balance, the Board finds that is more appropriate to wait for further analysis in this area".

The Board Decision does not provide any further guidance with respect to the underlying rationale in requiring Hydro One to maintain the density weights for the Seasonal rate class.

Vulnerable Energy Consumers Coalition (VECC) Question #34 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 5.22, VECC 70 d)
Exhibit I, Tab 13, Schedule 5.19, VECC 67 e) and g)

a) Please confirm that for the methodology set out in response to VECC 70 d) to yield reasonable results for the ratio of GSe to UGSe (i.e., 2.6 to 1.0), the density characteristics of UGSe need to be similar to those for UR – since UR is the base for the R2 value of 10.0 in the CA model and the 4.8 value derived using the Density Study, both of which are used in the methodology. If not, please explain why.

b) Please confirm that, based on results shown in VECC 67 e), the UGSe class appears to exhibit a higher density than the UR class but that for purposes of the Application Hydro One has assumed they are generally the same.

Response

a) The methodology shown in Exhibit I, Tab 13, Schedule 5.22 VECC 70 d) uses the **relative** relationship for high, medium and low density areas established by the Density Study, and compares it to the **relative** Line density weightings currently used in the CA model. The absolute values of the density characteristics for UGe and UR rate classes do not need to be the same for this approach to be valid. The Density Study demonstrates that customers in a low density area cost 4.8 times as much to serve as customers in a high density area. Hydro One used available Line density weighting information for its actual customer base to show that rural residential customers, for which the target cost ratio of 4.8 is appropriate, are 10 times less dense than an urban residential customers. Available Line density weighting information for general service customers, shows that rural GSe customers are 5.4 times less dense than urban GSe customers and therefore the appropriate target cost ratio consistent with the findings Density Study would be 2.6.

b) Yes, the UGe class appears to exhibit a higher density than the UR class. Hydro One has not assumed that the UGe and UR classes exhibit the same customer density.

Vulnerable Energy Consumers Coalition (VECC) Question #35 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 5.23, VECC 71 a)
Exhibit I, Tab 13, Schedule 5.19, VECC 67 e) & g)

a) Please confirm that the density profile of UR and UGSd are more closely aligned (per VECC 67 e)) than the density profiles of R1 and GSd (per VECC 67 g)). If not confirmed, please explain why.

b) If part (a) is confirmed, is it not reasonable to conclude that the density ratio for GSd / UGSd should be greater that for R1 / UR, as opposed to being the same (i.e. 1.9) as proposed by Hydro One? If not please explain why.

c) If part (b) is confirmed, please also confirm that this conclusion does not align with the current weightings in the CA Model where the ratio of R1 / UR (3.9) is greater than the ratio for GSd / UGSd (3.5).

Response

a) The noted observations in the charts per Exhibit I, Tab 13, Schedule 5.19 VECC 67 e) and g) are confirmed.

b) From the standpoint of comparing absolute densities on a customer per sq.km the conclusion in the question is reasonable, however, the target cost ratios proposed by the Density Study take into account the impact of competing allocation factors beyond simply the difference in absolute customer density (e.g. it factors in the relative amount of fixed assets required to serve the various sample areas). As such, Hydro One is proposing to use the Lines-customer density weighting from the CA Model to establish where the GSd target cost ratio should fall relative to UGd. Use of the Lines-customer density weight is reasonable as it has a large impact on the allocation of costs in the CA Model.

c) Use of the Lines-customer density weighting, as discussed in part b), suggests that a GSd to UGSd relative weighting of 3.5, resulting in a target cost ratio for GSd of 1.7, is reasonable. Use of the average Lines-customer and Lines-energy density weights would result in a GSd to UGSd relative weighting of 3.88 as compared to a R1 to UR ratio of 3.84, which aligns with the result expected in part b) of the question.

Vulnerable Energy Consumers Coalition (VECC) Question #36 List 1

Question

Reference: Exhibit I, Tab 13, Schedule 5.25, VECC 73 f)
Exhibit I, Tab 13, Schedule 5.19, VECC 67 e)
Exhibit I, Tab 13, Schedule 5.22, VECC 70 d)

a) Please confirm that based on the currently approved weighting (VECC 70 d)) the densities for the UR and UGSe classes are more closely aligned (0.16 vs. 0.20) than the densities for the UR and UGSd classes (0.16 vs. 0.32).

b) Please also confirm that, based on the graphs set out in VECC67 e), the density difference between UR and UGSd appears to be either similar or even less than that between UR and UGSe.

c) Based on the responses to parts (a) and (b), are there not inconsistencies between the outcome of the Density Study and the allocation factors currently used in Hydro One's CAM to allocate costs across customer segments? If not, please explain why not.

Response

a) The Line customer density weightings referenced in the question, and currently used in the CA Model, are calculated to provide the correct shifting of costs *within* a customer segment. The density weightings cannot be used to compare the absolute densities on a customer per sq.km basis of rate classes within different customer segments as suggested in the question.

b) The customer density difference noted is confirmed.

c) Given the clarification of Hydro One's approach to determining the target costs ratios for the GS classes as discussed in the response to Technical Conference Response VECC #35 and the response to part a) above, Hydro One believes there are no inconsistencies between the outcome of the Density Study and the density weights currently used to allocate costs in its CA Model.