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Michael Janigan
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June 13, 2014

VIA MAIL and E-MAIL

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

Dear Ms. Walli:

Re: EB-2013-0416 Hydro One Networks Inc.

Please find enclosed the interrogatories of VECC in the above-noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

Attachment

cc: Ms. Erin Henderson
e-mail: regulatory@HydroOne.com

REQUESTOR NAME	**VECC**
INFORMATION REQUEST ROUND NO:	**# 1**
TO:	**Hydro One Networks Inc. ("Hydro One or Hydro One Networks")**
DATE:	**June 13, 2014**
CASE NO:	**EB-2013-0416**
APPLICATION NAME	**2015 Electricity Distribution Rate Application**

1.0 CUSTOM APPLICATION

1.1. To what extent does the application reflect the objectives and approaches described in the RRFE Report?

1.1 - VECC - 1

Reference: A/T1/S1/pg.1

The Board's Renewed Regulatory Framework (RRFE) policy states:

The Board is establishing three rate-setting methods. Each distributor will select the method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. 4th Generation Incentive Rate-setting ("4th Generation IR"), which builds on 3rd Generation IR, is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.

Distributors with relatively steady state investment needs (i.e., primarily sustainment), may prefer the Annual Incentive Rate-setting Index ("Annual IR Index").

The Custom Incentive Rate-setting ("Custom IR") method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures.

Webster's Ninth Edition defines incentive as "*something that incites or has a tendency to incite to determination or action*"

a) Which of the three proscribed rate setting methods does Hydro One believe this Application falls under?
b) If Hydro One is applying under the Customer Incentive Rate-Setting please list each of the incentive mechanisms which will be applied during the rate period. For each incentive mechanism please

categorize it into one of the four functions of: (1) Revenues; (2) Costs (3) Reliability/Service Quality; (4) Safety. Describe how each mechanism will incite action to improve performance in one of these areas.

1.1 - VECC - 2
Reference: A/T4/S1/pg.2

a) Throughout the Application and in the earlier parts of this proceeding Hydro One has explicitly noted the Application as being “Custom Cost of Service” or “Custom Application” and avoided calling it an “incentive” rate application. Please explain why.
b) Please explain how this application differs from a standard multi-year cost of service application in which one simply forecasts costs and revenues for the defined period.

1.1 - VECC - 3
Reference: A/T3/S1/pg.

HONI notes that its Application promotes the four outcomes endorsed in RRFE. The RRFE also sets out related policies “to facilitate the achievement of these performance outcomes (RRFE Report, pg.3)”. These are: (1) Rate Setting; (2) Planning; (3) Measuring Performance. The Board has not yet articulated the requirements of Measuring Performance.

a) In the absence of Board approved Performance Measurements what measures does Hydro One propose?
b) What Performance Reporting measurements does Hydro One propose?

1.1-VECC-4
Reference: A/T4/S1/

a) At page 2-6 of the above reference Hydro One articulates how it tried to reduce its forecast risk by adjustments and off-ramps. What mechanisms did Hydro One include in this Application to mitigate the risk to customers that Hydro One would risk 6

1.2. Has Hydro One Distribution responded appropriately to all relevant Board directions from previous proceedings, including commitments from prior settlement agreements?

Cost Allocation Methodology

1.2 – VECC –5
Reference: G1/T3/S1, pg. 3-4
G2/T1/S1, pg. 8

a) Please explain what activities are reflected in the Management and Salaries Expenses (Account #5610) that are directly allocated to the DG, ST and various GS customer classes and how the assignment to the individual classes was determined.
b) Please explain what activities are reflected in the General Administrative Salaries and Expenses (Account #5615) that are directly allocated to the DG, ST and various GS customer classes and how the assignment to the individual classes was determined.
c) Please explain what activities are reflected in the Outside Services Employed (Account #5630) that are directly allocated to the DG, ST and various GS customer classes and how the assignment to the individual classes was determined.
d) Please explain what activities are reflected in the Miscellaneous General Expenses (Account #5665) that are directly allocated to the DG, ST, Sentinel Lighting and various GS customer classes and how the assignment to the individual classes was determined

1.2 – VECC – 6
Reference: G1/T3/S1, pg. 4, lines 12-20

a) Please indicate where in Hydro One Networks' CAM the changes were made so as to include directly allocated O&M costs in the O&M allocator.
b) What would be the impact on the R/C ratios for 2015, by customer class, if the directly allocated A&G costs had been included when developing the allocator for purposes of allocating other A&G costs?
c) Please confirm that Version 3.1 of the OEB's CAM issued August 13, 2013 includes all directly allocated OM&A in the O&M allocator used to allocation A&G costs.

1.2 – VECC – 7

Reference: G1/T3/S1, pg. 5

a) Please confirm that in Hydro One Networks' CAM all Miscellaneous Revenues are allocated to customer classes using the composite OM&A allocator. If this is not the case, please explain what elements of Miscellaneous Revenues are not allocated in this manner, what allocators are used instead and why.

1.2 - VECC – 8

Reference: G1/T3/S1, pg. 6-7
G1/3/2, pg. 3

a) Please explain how the number of feeders has decreased between the preparation of the 2010 CAM and the current update (i.e. from 2,553 to 2,366).
b) The data in G1/3/1, Table 2 suggests that there have been no new transformers placed into service since the 2010 CAM was prepared even though the number of customers has increased by almost 8%. Please explain how this is the case.

1.2 – VECC – 9

Reference: G1/T3/S1, pg. 10, lines 8-13

a) Please explain why the density weights are applied to transformation assets as well as line assets.
b) Applying the density weights the transformation assets effectively increases the number of transformers in lower density areas to account for the greater distance between customers. Given this effect why is it necessary to also apply the density weights to the secondary line assets which are "downstream" of the transformation assets?

1.2 – VECC – 10

Reference: G1/T3/S1, pg. 9-11
EB-2012-0136, I/T13/S1.03 (Staff 36 (c))
EB-2012-0136, I/T13/S5.16 (VECC 64 (b))

Preamble: The response to the referenced Staff interrogatory from EB-2012-0136 states:

The purpose of Density Weights is to redistribute the costs within a customer segment that has both urban and rural customers (i.e. residential and general service customers).

Similarly, the response to referenced VECC interrogatory from EB-2012-0136 states:
Hydro One's proposed Density Study Adjustment does not change the total costs allocated by the CAM to the density differentiated customer segments (i.e. residential customers, GS<50 customers, GS>50 customers), but rather it re-distributes the total costs allocated by the CAM to those customer segments in order to better align with the relative cost of serving density-differentiated customers as demonstrated by the Density Study.

a) Please confirm that the incorporation of the density factors into the CAM as currently filed has the same effect (e.g., does not change the total costs allocated to the Residential segment consisting of UR, R1, R2 and Seasonal).
b) If not confirmed in part (a), please explain why the change in approach was made for this application and re-do the CAM model results using the approach adopted for EB-2012-0136.

1.2 – VECC – 11
Reference: G1/T3/S1, pg. 11, Table 3
EB-2012-0136, D/T1/S1, pg. 4-5 and Table 4

a) Please explain why density factors adopted for Seasonal, GSe and GSd in the current application (3.6, 2.4 and 2.2 respectively) differ from those used in EB-2012-0136 (1.9, 2.6 and 1.9 respectively).

1.2 – VECC – 12
Reference: G1/T3/S1, pg. 10, lines 8-13
EB-2012-0136, D/T1/S1, Attachment 1

a) Please provide a schedule that compares: i) the USOA accounts to which the density weightings were applied in HON's proposed CAM with ii) the USOA accounts used to determine the relative costs of low-, medium- and high-density sample areas in the original Consultant's Study filed in EB-2012-0136.

b) To the extent there is any misalignment, please explain why the density factors were not applied to same cost accounts used by the Consultant to derive the relative values.
c) Please provide a revised version of Hydro One Networks' CAM for 2015 where the density factors are only applied to the cost accounts included in the initial derivation of the factors.

1.2 – VECC – 13
Reference: G1/T3/S1, pg. 10, lines 8-13
G2/T1/S1, Table1

a) The text at G1/T3/S1 states that the density factors were applied to all lined and transformation assets associated with providing primary and secondary service but not bulk system assets. In contrast, Table 1 (G2/1/1) indicates that the density factors were applied to >50 kV assets (Accounts 1805, 1806, 1808, and 1810) and also bulk assets (Accounts 1815-1, 1830-3B, 1835-3B, 1840-3, and 1845-3). Please reconcile.
b) Please provide a revised 2015 CAM where the density factors are not applied to >50 kV assets or to bulk assets.

Conservation and Demand Management

1.2 – VECC – 14
Reference: A/T16/S3, pg. 2, lines 10-12
EB-2009-0096, A/T14/S4, pg. 18-19

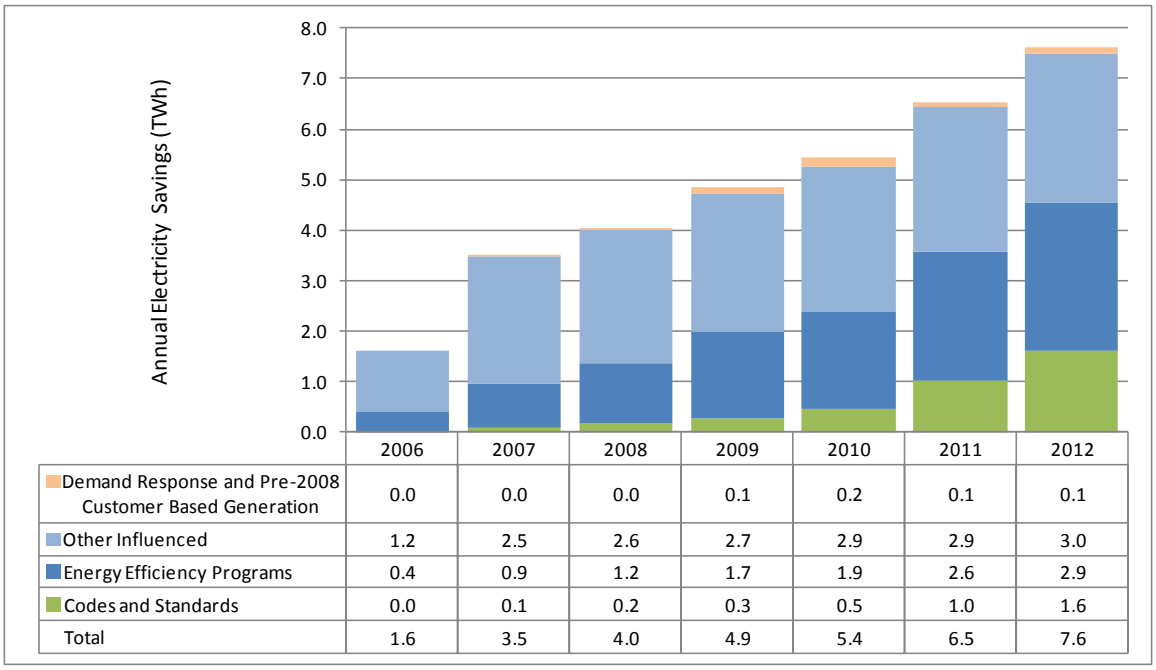
Preamble: The EB-2009-0096 Application stated that "Hydro One Distribution's distribution system is forecast to <u>deliver</u> a total of 38,306 GWh in 2010 and 38,049 GWh in 2011 on a weather-normal basis. Table 4 presents the load forecast before and after deducting the impact of CDM." (emphasis added)
Table 4 reported a CDM value of 1325 GWh for 2010 and 1604 GWh for 2011

a) The above statement from EB-2009-0096 suggests that the values reported in Table 4 were delivered and not wholesale GWhs as suggested by the reference from the current Application. Please reconcile.
b) Please identify where in the record from EB-2009-0096 the end-use

CDM impact values of 1299 GWh in 2010 and 1488 GWh in 2011 can be found (per page 2).

1.2 – VECC – 15
Reference: A/T16/S3, pg. 3-4
2013 LTEP, Module 2, Slide 6

Preamble: The detail LTEP Information Breakdown provided by the OPA (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf) includes the following data regarding historical conservation savings.



	2006	2007	2008	2009	2010	2011	2012
Demand Response and Pre-2008 Customer Based Generation	0.0	0.0	0.0	0.1	0.2	0.1	0.1
Other Influenced	1.2	2.5	2.6	2.7	2.9	2.9	3.0
Energy Efficiency Programs	0.4	0.9	1.2	1.7	1.9	2.6	2.9
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6
Total	1.6	3.5	4.0	4.9	5.4	6.5	7.6

a) Please provide a schedule that aligns the results reported for the five CDM categories used by Hydro One Networks (per Table 1) with the four categories used by the OPA (see Preamble and accompanying Figure).

1.2 – VECC – 16
Reference: A/T16/S3, pg. 6-7 and pg. 30-55

a) Please complete the following schedule (for the first year of each program please report the annualized results) for the Non-Target

CDM Programs initiated by Hydro One:

	Results by Year (Actual/Forecast)										
Program Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
2005											
2006											
2007											
2008											
Total											

b) Table 2 on page 7 reports annual energy savings for 2005 of 8.2 GWh. However, the sub-totals from Table A.1 (page 31) only sum to 7.8 GWh. Please reconcile.

1.2 – VECC – 17
Reference: A/T16/S3, pg. 7-8 and pg. 57-80

a) Please complete the following schedule (for the first year of each program please report the annualized results) for the Non-Target CDM Programs initiated by the OPA::

	Results by Year (Actual/Forecast)									
Program Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006										
2007										
2008										
2009										
2010										
Total										

1.2 – VECC – 18
Reference: A/T16/S3, pg. 9-11 and pg. 81-86

a) Please complete the following schedule (for the first year of each program please report the annualized results) for the Target Programs:

	Results by Year (Actual/Forecast)				
Program Year	2011	2012	2013	2014	2015
2011					
2012					
2013					
Total					

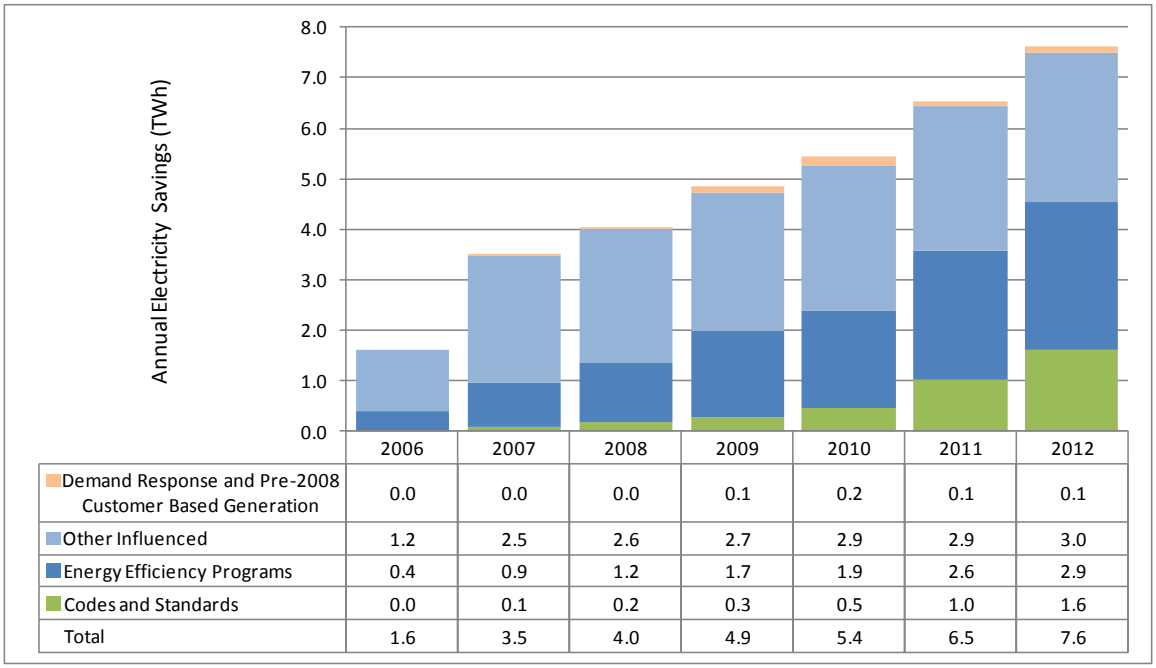
b) Please provide a copy of the OPA's 2012 final report regarding Hydro One Networks' CDM activities.

c) Please provide any reports prepared by the OPA regarding Hydro One Networks' 2013 CDM activities (based on either partial or full year results).

1.2 – VECC – 19

Reference: A/T16/S3, pg. 11-12 and pg. 87-92
2013 LTEP, Module 2, Slide 6

Preamble: The detail LTEP Information Breakdown provided by the OPA (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf) includes the following data regarding historical conservation savings.

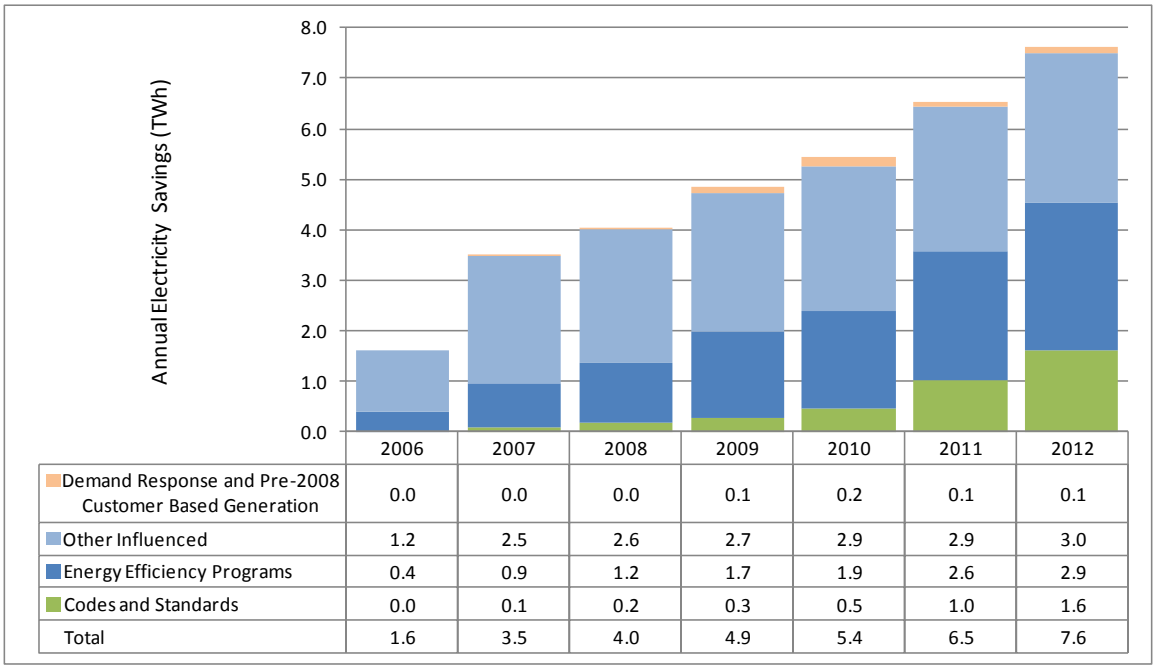


	2006	2007	2008	2009	2010	2011	2012
Demand Response and Pre-2008 Customer Based Generation	0.0	0.0	0.0	0.1	0.2	0.1	0.1
Other Influenced	1.2	2.5	2.6	2.7	2.9	2.9	3.0
Energy Efficiency Programs	0.4	0.9	1.2	1.7	1.9	2.6	2.9
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6
Total	1.6	3.5	4.0	4.9	5.4	6.5	7.6

a) Please provide the total Ontario energy savings for each of the years 2006-2013 from CDM programs initiated by Other Agencies as determined by the OPA for the 2013 LTEP (per page 11, line 17)
b) Please indicate how these values relate to the historic CDM savings reported by the OPA in the 2013 LTEP, Module 2 (i.e. what category do they relate to and what other sources of savings are also reflected in the LTEP category?).
c) Using 2010 as an example, please document how the Hydro One Networks portion of the total provincial savings was determined.

1.2 – VECC – 20
Reference: A/T16/S3, pg. 12-13 and pg. 93-109
2013 LTEP, Module 2, Slide 6

Preamble: The detail LTEP Information Breakdown provided by the OPA (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf) includes the following data regarding historical conservation savings.



	2006	2007	2008	2009	2010	2011	2012
Demand Response and Pre-2008 Customer Based Generation	0.0	0.0	0.0	0.1	0.2	0.1	0.1
Other Influenced	1.2	2.5	2.6	2.7	2.9	2.9	3.0
Energy Efficiency Programs	0.4	0.9	1.2	1.7	1.9	2.6	2.9
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6
Total	1.6	3.5	4.0	4.9	5.4	6.5	7.6

a) Using 2010 as an example, please explain fully how the specific Hydro One savings associated with Codes and Standards were derived from the OPA total Ontario values (per page 13, lines 4-6)
b) Using 2012 as an example, please explain how the 2013 LTEP

information and the achievable potential CDM as estimated by ICF Marbek were used to derive the Hydro One savings associated with Codes and Standards.

1.2 – VECC – 21
Reference: A/T16/S3, pg. 15, Table 10

a) Please explain how the values set out in Table 10 were derived from the various studies and analyses described on the subsequent pages.

1.2 – VECC – 22
Reference: A/T16/S3, pg. 15-17 pg. 110-113

a) Please define what is meant by "naturally occurring conservation" and how it differs from "increased conservation effect".
b) Please indicate whether customers' response to average increases in the cost of electricity (as opposed to TOU) is considered to be "naturally occurring conservation" or "increased conservation effect" and why.
c) What is the basis for assuming that naturally occurring conservation is 0.5% per year (per page 16, line 18)?
d) Given the parameters of the regression model used are the differences attributed to ICE for 2010-2012 statistically significant?

1.2 – VECC – 23
Reference: A/T16/S3, pg. 17-18 and pg. 114-117

a) In undertaking the customer billing analysis why was the price of electricity (i.e. average price) not considered to be a relevant factor in explaining electricity usage along with disposable income?
b) Is disposable income used as an explanatory variable in any of Hydro One Networks' load forecast models? If not, why not if it is deemed relevant for purposes of this analysis?

1.2 – VECC – 24
Reference: A/T16/S3, pg. 19-20 and pg. 118-141

Preamble: The survey asks for information on participation in conservation programs, response to TOU pricing and

"conservation actions taken your own".

a) How does the analysis ensure that "naturally occurring conservation" and the effect to codes and standards are separated out from "customers' own actions"? In responding please indicate what variables are used in the regression equation to measure the changes due to Other Impacts (per page 120, line 28).

1.2 – VECC – 25
Reference: A/T16/S3, pg. 22

a) Please define what spillover and free-ridership effects are and how/if they differ from naturally occurring conservation.

1.3. What actions should the Board require Hydro One Distribution take at or near the end of the 5-year rate term (e.g. rebasing, plan assessment, measurement of customer satisfaction)?

1.4. Is the proposed rate-smoothing mechanism appropriate? Given Hydro One's rate smoothing proposal, should the application include any other ratepayer protection measures such as an earnings sharing mechanism?

1.4-VECC-26
Reference: F1/T1/S2/pg.4-5

a) Hydro One suggests that there are "significant benefits" to customers of rate smoothing. Please explain what these are.
b) Please explain what customer research has been done to verify that the answer to a) is what customers believe are benefits.
c) Is it Hydro One's intention to notify customers of the rate mitigation plan (i.e. through bill inserts)? If not why not?
d) What is the forecast carrying cost of the rate mitigation plan?

2.0 OUTCOMES AND INCENTIVES

2.1 Does Hydro One Distribution's Custom Application adequately consider customer feedback and preferences? Have customer feedback and preferences been adequately reflected in the OM&A and capital spending plans?

2.1-VECC-27
Reference: A/T5/S1/pg.3 & 6 A-5-1/Attachment 1

a) Please provide the summary results (i.e. the report presented to Hydro One Senior Management) of the Transactional Survey for the years 2009 through 2013.

2.1-VECC-28
Reference A/T5/S1/pg.15 & A/T6/S1/pg.4

a) Given that the main concern of Hydro One's customers is with reducing bill costs why does the rate plan include no metrics or benchmarks regarding cost reductions, efficiencies or employee/FTEs per customers?
b) Given customers' concerns about prices why does Hydro One have neither a strategic objective or five year vision to lower prices to its customers?

2.2 Does Hydro One Distribution's Custom Application promote and incent acceptable outcomes for existing and future customers (including, for example, cost control, system reliability, service quality, bill impacts)?

2-VECC-29
Reference: A/T3/S2

a) Since Hydro One has better knowledge of its costs than anyone else it can reduce its risk by forecasting each year's OM&A and on capital expenditures. If the Utility underspends during any given year of the Plan it will have a better than expected actual return. Given this why is not reasonable to assume that Hydro One has an incentive to over forecast (be more cautious) its costs and to

underspend (be more aggressive) its approved costs? What measures does the Utility propose to counter these perverse incentives?

2.3-VECC-30
Reference: A/T6/S1/pg.19-20 ; A/T18/S1

a) Please explain why 10% of customers were chosen as the definition for a force majeure event.
b) In the description of force majeure events it is not clear if the definition of "affecting 10% of customers" means the number of customers with an outage or the number of customers in an area with outages (see for example pages 15 of 18). Please clarify the meaning of "affected customers.
c) Does the 10% of customers need to be in contiguous service areas and related to a common cause?
d) Do force majeure events include service interruptions that are caused by anything other than weather (i.e. are all the force majeure events shown in figure 6 at page 19-20 due to the impact of weather on equipment and plant)?

2.2-VECC-31
Reference: A/T18/S1

a) Are the service reliability indicator forecasts for 2014 through 2019 operational targets of the rate plan? If so please indicate what the consequences of exceeding the target are. If Hydro One has not incorporated SAIDI, SAIFI or CAIDI indicators as plan targets please explain why not.

2.1-VECC-32
Reference :A/T5/S1/pg.3 & T18/S1/pg.3 /Appendix A

a) Please explain what incentives/disincentives are in place to ensure that Hydro One meets the current Distribution System Code sections 7.5.1/7.5.2 with respect to meeting missed and re-schedule appointments 100% of the time. How does reducing this metric align with customer feedback and preferences?
b) The relevant Code section has two parts – contacting the customer

prior to the missed appointment and contacting the customer within 1 business day to reschedule. All of the reasons provided for the exemption have to do with contacting the customer prior to the missing the appointment. Please provide the percentage of times (2010- 2013) in which HON was unable to contact the customer within 24 hours after a missed appointment to reschedule. Please explain why relief is required from this part of the requirement.

c) Please provide a breakdown of the Missed Appointment rescheduling by regional office.

2.3 Does the Custom Application adequately incorporate and reflect the four outcomes identified in the RRFE Report: customer focus, operational effectiveness, public policy responsiveness and financial performance?

2.3-VECC-33
Reference: A/T4/S4/pg.17

At the above reference Hydro One makes the following statement: "[T]*he metrics had to be targeted to areas where Hydro One intends to increase investment, as opposed to broad measures affected by many factors, such as reliability measures applicable to Hydro One's entire system*."

a) Please explain this statement. Specifically why must metrics be targeted to one area only? For example, why is Hydro One not proposing a metrics on the number of FTEs per customer, OM&A per customer or other broad measures which would provide incentives for, and indications of, increased efficiency?

2.3-VECC-34
Reference: A/T4/S4, pg. 17

a) At the reference it states: "[*A]t this stage, we have not proposed specific targets for each measure; our initial emphasis is on measurement, reporting, and directional improvements corresponding to the Plan.*" The statement appears at odds with the prior discussion and tables 1-8 which appear to show such targets. Please explain this apparent discrepancy.

b) For each of the proposed targets (i.e. Table 1 through 8) please explain the consequence of not meeting the target.

2.3-VECC-35
Reference: A/T4/S4/pg. 6

a) Please provide update Table 1 to show the actual vegetation caused interruptions in 2014 to date.
b) In 2012 there appears to be a significant increase in vegetation caused outages. Please explain.

2.3-VECC-36
Reference: A/T4/S4/pg.8

a) Please provide the outages in each of years 2009 to 2014 that were due to pole failure.
b) Please explain why a reduction to outages due to pole failure is not being proposed as an outcome metric given the proposal to significantly increase capital expenditures in this area.

2.3-VECC-37
Reference: A/T4/S4/pg.9

a) With respect to PCB Line Equipment – please modify Table 3 to include the number of pole top transformers (PCB type or otherwise) replaced in each year 2009 through 2019)

2.3-VECC-38
Reference: A/4/S4/

a) Please explain why the 2015-19 targets for substation caused interruptions are greater than 3 of the last five years of actual experience?
b) Please update Table 4 to include :
    i. number of interruptions including force majeure,
    ii. number of interruptions due to planned events ;
    iii. the related capital budget for each year
    iv. the related OM&A maintenance spending for each year
c) Please provide a definition of force majeure explaining how it is different than other forms of equipment failure.

2.3-VECC-39
Reference: A/4/S4/

a) Please explain why the average 5 years of targets for Distribution Line Equipment caused interruptions are higher than the actual 5 years previous ending in 2013.
b) Please update Table 5 to include :
   i. number of interruptions including force majeure,
   ii. number of interruptions due to planned events ;
   iii. the related capital budget for each year
   iv. the related OM&A maintenance spending for each year

2.3-VECC-40
Reference: A/T4/S4/pgs.12-16

a) Please provide the survey questions which will be used in determining overall customer satisfaction
b) Please explain how the targets for customer satisfaction were chosen.

2.3-VECC-41
Reference: A/T4/S4/pg.16

a) Please modify Table 8 to show for each year the percentage of customers who are not served by Hydro One's smart meter network (if this it is the same as the % receiving estimated bills provide that response).
b) Please describe the strategy that is being employed to reduce estimated bills.
c) Please provide the planning documentation for that strategy.

2.3-VECC-42
Reference: A/T19/S1

a) Please show the derivation and of the productivity savings shown in Table 1 for years 2013 through 2019.

2.3-VECC-43
Reference: A/T19/S1/pg.4

Please Modify Table 2 for the following:

a) For each category (row) in Table 2 please show the associated total budget for each year.

2.4 Is the monitoring and reporting of performance proposed by Hydro One Distribution adequate to demonstrate whether the planned outcomes are achieved?

2.3-VECC-44
Reference: A

a) Please provide a sample scorecard that Hydro One proposed to use to communicate the annual rate plan outcomes.

2.5 Are Hydro One Distributions' proposed off-ramps, annual adjustments and annual adjustments outside the normal course of business appropriate?

2.5-VECC-45
Reference: A/T4/S1/pg.4-6

a) Hydro One suggest that service area amendments might trigger an off ramp. Does Hydro One believe that service area amendments which are related to future customers (as opposed to existing customers) should result in an off-ramp? If so explain why.

2.5-VECC-46
Reference: A/T4/S1

As noted by Hydro One (A/T4/S1/pg.5) the Board's RRFE policy contemplates a review if a distributor performs outside of a ± 300 basis point earnings dead band.

a) What adjustment mechanism (if any) does Hydro One propose to be implemented if the Utility falls outside the dead band?

2.5-VECC-47
Reference: A-4-1, page 4 and A-4-3

a) What is the basis for choosing 0.5% of the test year revenue requirement as a materiality threshold (or approximately $7.5 million) rather than $1 million?
b) Please clarify whether the materiality threshold of 0.5% is based on the annual impact of an event or the cumulative impact of the event (i.e. for an event impacting more than one year would the impact in a given year have to exceed the 0.5% criterion?).
c) In those instances where the threshold is exceeded, please clarify whether the adjustment sought would be for entire "cost" or just the amount in excess of the threshold.
d) What is the annual spending associated with the "normal" level of storm activity and is it conceivable that actual spending could fall below this level by $7.5 M

2.5-VECC-48
Reference: A-6-1, pages 21-22 / A-18-1

a) Please explain the rationale for using 10% of customers as a "force majeure." Please also explain how the 10% is defined. For example, is it necessary for the 10% of customers to be in a single distribution area, contiguous areas, or in areas close in proximity? Why was 5%, 15% or some other figure not chosen as the definition?

2.6 Are Hydro One's forecasts (revenue, costs, inflation and productivity) reasonable? Should Hydro One be expected to provide benchmarking evidence as an indicator of reasonableness?

2.6-VECC-49
Reference: C1/T2/S7/pg.4

a) Please provide the benchmarking review study completed by TPI Sourcing Consultants
b) Please provide a list of all other benchmarking studies commissioned by Hydro One over the past 5 years.

2.7 Is Hydro One's proposed annual reporting and stakeholder engagement process appropriate?

2.7-VECC-50

Reference: A

a) What is Hydro One's proposal to publicly report on its progression of capital programs during the five year rate plan?

2.7-VECC-51
Reference: A/T4/S1/pgs.3-6

Section 21 of the OEB Act contemplates that the Board hold a hearing where any party is materially affected. At section 1.4 Hydro One suggests that Board Staff review its annual adjustments.

a) Does Hydro One believe its proposal for an Annual Adjustment (i.e. without a hearing) is in compliance with Section 21? If yes please explain how.
b) Please address the same question with respect to Adjustments Outside of Normal Course of Business.

2.8 Should the application provide appropriate incentives for line loss reduction?

3.0 PROGRAM AND PROJECT EXPENDITURES

3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

3.1-VECC-52
Reference: C1/T2/S1/pg.3

a) Table 1 shows that Hydro One has not reduced actual OM&A costs to reflect the last two Board Approved amounts. Please explain what efforts were made to reduce costs subsequent to the Decisions. Specifically, please provide any internal memos, strategies, business plans or other documents stemming from the Board's decisions and which dealt with the issue of the need to reduce costs.

3.1-VECC-53
Reference: C1/T2/S1/Table 1

a) If Table 1 does not show 2013 actuals please update the table for this data.
b) Please add a column showing 2014 actuals to date.
c) Please provide a table which shows for each OM&A for each category for the same period to date in 2012 (the purpose of which is to understand the percentage of 2014 capital budget to date spent as compared to an equivalent period in 2012.

3.1-VECC-54
Reference: C1/T2/S2/ - Sustaining OM&A

a) For each of the OM&A categories in Tables 2 through 10 please compare (and provide) the three year average spending from 2010 through 2012 to the average for 2015 through 2019. In a third column please calculate the percentage difference between the two averages*. Where the difference is 10% or more please provide the following:
    i. The cost-benefit analysis that was performed for the increase in that category of spending.
    ii. The target or metric that is being used to compare the pre and post annual spending outcome/metric results;
    iii. If no cost-benefit analysis was performed and no metrics developed to assess the effectiveness of the increase spending please explain why
    iv. In the alternative, if the program is being done to pursue an external regulatory requirement (e.g. Environment Canada-PCB/Measurement Canada Meters etc.) please show the analysis by which Hydro One concluded it would be unable to meet these requirements without the increase in spending.

*(For example Table 10 Category “Line Clearing” 2010-12 annual average = $82.9m vs 2015-2019 average =$108.04m = 30% increase)

3.1-VECC-55
Reference: C1/T2/S3/pg.10

a) Please provide the reason(s) for the significant increase in smart

grid studies beginning in 2014 as compared to the previous 4 years.

b) Please provide a list of the studies being done in 2014; their expected cost and their expected completion date.
c) Please provide the list of studies and abstracts for the studies undertaken or planned for 2014, 2015 and 2016.

3.1-VECC-56
Reference: C1/T2/S4/pgs.5,8-9/Table 1

a) For each of the years 2014 through 2019 please provide a list of smart grid projects that are contemplated in Table 1. Please identify separately the amounts solely for the Distribution Management System (page 5) and provide the number of FTEs required to operate the three applications listed.
b) Please explain what "new system" are being contemplated as being commissioned over the test period

3.1-VECC-57
Reference: C1/T2/S5/pg.9-11

a) Table 2 does not show a significant decline in meter reading costs. Please explain how this is consistent with the objective of reducing estimated bills. That is, do the strategies to reduce estimated bills include connecting more customers to the smart meter network and reducing the number of manual reads?

3.1-VECC-58
Reference: C1/T4/S1/pg.14-15 Fleet Management

a) Please explain the increase in Operations and Repairs as compared to the historical average.
b) Please provide the same with respect to Depreciation

3.1 - VECC -59
Reference: C1

For each year in the period 2010 through 2019 please provide the amounts separately for:

i. EDA Membership Fees
ii. MEARIE Insurance Premiums;
iii. Other Corporate memberships over $25,000 per annum

3.2 Is the level of planned capital expenditures appropriate for the period 2015- 2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

3.2-VECC-60
Reference: A/T17/S3

Preamble: The proposed capital expenditure for the rate period is significantly in excess of the prior period. The purpose of this interrogatory is to understand the changes in Hydro One's business planning that led to past under investments in distribution plant.

a) When did Hydro One begin the implementation of the Asset Analytics tool?
b) Was the Asset Analytics tool the main instrument used to discover what past under investments needed to be addressed?
c) Please explain the relationship (if any) between the Asset Analytics tool and the new Asset Investment Planning (AIP) solution.

3.2-VECC-61
Reference: A/T17/S4/pg.8 D1/T2/S1

Pre-amble: The illustrative example for prioritization of the Distribution Station Transformer Replacement programs concludes by noting that the historical replacement rate of transformers is lower than the expected life would require. This situation might have occurred for a number of reasons including: (1) Hydro One has recently changed its capital planning policy from run to failure to preemptive replacement; (2) there was previously insufficient data on asset age and condition or to make the noted assessment; (3) while the data was available insufficient effort was put into analyzing this data for planning purposes; or (4) the Utility choose to under invest in assets during prior rate periods in order to improve returns or for some other reason.

a) Hydro One is proposing significant increases in the capital program for the following areas:
    i. Transformers (other than line transformers)
    ii. Reclosers/Breakers

iii. Station Switches/Fuse
iv. Poles
v. Line Projects
vi. Line Transformers

For each these areas while Hydro One has described the reasons for accelerating its capital program it has not explained why took until 2015 to recognize the need for a change to its capital planning. Please explain what has changed since the last cost of service application to cause a departure from past spending practices. Please address the question of why the Board should not find that the Utility acted imprudently in the past by under investing in capital projects.

3.2-VECC-62
Reference D1/T2/S1/pg.31 & C1/T2/S2/pg.15

With respect to Line Transformers:

a) What year legislation came into effect requiring transformers containing PCB s were required to be removed.
b) Please explain the capital budget policy prior to this year that was addressing this issue.
c) Please explain why a run to failure policy is not being continued for all transformers that do not contain PCBs (i.e. those manufactured after 1985).

3.2-VECC-63
Reference D1/T2/S1/pg.17-19 & D1/T3/S2

a) Why does the accelerated capital program to improve transformers, breakers, switches etc., not have an impact (reduction) on the number of Mobile Unit Substations being required over the period of the rate plan?
b) For each of the last 3 years what was the deployment/use rate for the MUS (e.g. 90% in 2013 would indicate that the units were deployed and operating 90% of the time).

3.2-VECC-64
Reference D1/T2/S1/pg.6

a) How does Hydro One determine that a transformer major failure

was avoided when it proactively removes a transformer (i.e. prior to failure)?

b) Why reasons does Hydro One believe account for actual transformer failures decreasing since 2009?

c) Has Hydro One done a cost-benefit analysis of a run to failure vs. proactive replacement policy? If so please provide this. If not please explain why not.

3.2-VECC-65
Reference: D1/T3/S2/pg.6

a) At the noted reference Hydro One makes the claim that reduction in sustaining capital would have impact on three listed areas. Please provide the cost-benefit analysis which supports that statement. That is, please provide the analysis which was undertaken to show the impact of budget dollar changes on service reliability.

b) The statement is made without qualification – that is it claims a "marked reduction" in reliability standards for any reduction in capital spending. Clearly this cannot be true as Hydro One is unlikely (except by serendipity) to have actual spending precisely equal its forecasts. Please provide the sensitivity analysis that was undertaken to show likelihood of reliability or regulatory requirement adverse effects should the budgets be underspent.

3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

3.3-VECC-66
Reference: A/T17/S4/pg.4

a) With few exceptions the Measure/Key Performance Indicators shown in Table 1 are vague. For example, the business value of Reliability has as a measure "reliable delivery of electricity" but no actual target or measure. Please provide the specific measure that are associated with each Measure/Key Performance Indicator. If none is available please explain what steps are being taken to develop specific measures.

3.4 Is the company's effort to reduce line losses appropriate?

4.0 COMMON COSTS AND PROCESSES SHARED BY HYDRO ONE NETWORKS' TRANSMISSION AND DISTRIBUTION BUSINESSES

4.1

4.2 Are the business planning processes, assumptions and policies used by Hydro One Networks to develop and allocate its distribution and transmission revenue requirements appropriate?

4.3 Is the proposed level of 2015-2019 common corporate costs spending appropriate with an adequate demonstration of efficiencies over the 5-year period?

4.2-VECC-67
Reference: A/T11/S3/

a) Please provide the basis/rationale for the forecast costs payable by affiliates to Networks (Table 2).
b) Please provide the same for Fees Payable by Networks (Table 3).

4.2-VECC-68
Reference: C1/T5/S1/pg.3
a) Please provide the Allocation of CCF&S tables for 2010 through 2014.

4.4 Are the methodologies used to allocate common corporate costs to the distribution and transmission businesses and to determine the overhead capitalization rate for 2015-2019 appropriate?

4.3-VECC-69
Reference: C1/T5/S2

a) Please explain the variation in overhead capitalization rates during the period 2015-2019

4.5 Is the compensation strategy for 2015-2019 appropriate and does it result in reasonable compensation costs?

4.1-VECC-70
Reference: C1/T3/S1

a) Please provide the training budgets for each of the years 2010 through 2019 for (a) engineering/operations and (b) corporate/financial/general

4.1-VECC-71
Reference: C1-3-2 Attachment 2

a) Please create a line graph showing (separately) the number of regular, temporary and casual employees for the years 2010 through 2019.
b) Please create a separate line graph with the total of all employees for the same period

4.1-VECC-72
Reference: C1-3-2 Attachment 2

a) The evidence shows a significant increase in the number of temporary employees beginning in 2014 and continuing throughout the rate plan period (over 100% from 2013). Please explain the reason for this.
b) What percentage of temporary employees in 2013 were retirees of Hydro One?
c) What are Hydro One's policies with respect to (a) rehiring retirees; (b) hiring persons who are family members of a current employee?

4.1-VECC-73
Reference: C1/T3/S1

a) Please explain how the forecast for 2014 – 2019 for causal employees was derived.
b) The evidence suggests that casual employees are highly correlated with the capital budget plans. If Hydro One were to maintain 2012 capital budget amounts what would be impact on the forecast of casual employees (i.e. what is the sensitivity of budget dollars to causal FTEs)?

5.0 DEFERRAL AND VARIANCE ACCOUNTS

5.1 Are the proposed amounts, disposition, discontinuance and

continuance of Hydro One Distribution's existing deferral and variance accounts, as set out in the Custom Application, appropriate?

5.2 Is it appropriate to include in rate base, effective January 1, 2015, the following in-service assets which are presently recorded as regulatory assets:

a) smart meter assets as of December 31, 2013, the costs for which are recorded in variance accounts 1555 and 1556;
b) smart grid assets as of December 31, 2013, the costs for which are recorded in account 1536; and
c) assets to facilitate distributed generation as of December 31, 2013, the costs for which are recorded in account 1533.

6.0 REVENUE REQUIREMENT

6.1 Is the rate base component of the revenue requirement for 2015 as set out in the Custom Application appropriate?

6.2 Is the capital structure and cost of capital component of the revenue requirement for 2015 as set out in the Custom Application appropriate?

6.2-VECC-74
Reference: A/T3/S1/pg.3/ B1/T1/S1

a) What is the rationale for adjusting equity returns during the plan period rather than embedding the 2014 rate of returns into rates for the 5 year period as might be done under an incentive rate plan?
b) Please provide a similar explanation/rationale for the proposal to adjust short term and long-term debt during the plan.

6.3-VECC-75
Reference: A/T2/S1/pg.9

a) Please provide the revenue requirement for 2016 through 2019 assuming the cost of capital (debt and equity) is fixed for the 5 year period.

b) Please provide the rate impacts (unmitigated) under the same scenario.

6.3-VECC-76
Reference: B1

a) Please provide the actual returns of Hydro One Inc. and notional regulated rates of return of Hydro One Distribution for each of the years 2008 through 2013

6.3 Is the depreciation component of the revenue requirement for 2015 as set out in the Custom Application appropriate?

6.3-VECC-77
Reference: C1/T6/S1/pg.2

a) Please explain how the asset removal costs are forecast for 2015 through 2019.

6.4 Is the taxes / PILs component of the revenue requirement for 2015 as set out in the Custom Application appropriate?

6.5 Is the OM&A component of the revenue requirement for 2015 as set out in the Custom Application appropriate?

6.6 Is the load forecast a reasonable reflection of the energy and demand requirements of the applicant? Is the forecast of other rates and charges appropriate? Is the forecast of other revenues appropriate?

6.6 – VECC – 78
Reference: A/T16/S2, pg. 3 (Updated)

Preamble: Hydro One Networks' current application addresses rates for an initial "Plan Year" plus four more subsequent years.

a) With respect to the footnote for Table 1, please confirm that "Retail Customers" represent all customers except those in the ST class.

b) Please provide a schedule similar to Table 1 but include the variances as between past forecasts and actual sales for the 4th and 5th years.

6.6 – VECC – 79

Reference: A/T16/S2, pg. 5 (Updated)
A/T16/S2, pg. 5 (As originally filed)
A/T16/S2, pg. 13
A/T16/S2, Appendix E, Table E.4

a) Please explain more fully how the customer count forecast for each customer class is developed.
b) With respect to the updated Table E.4, please confirm that the value reported for 2013 (1,267,680) is the actual mid-year customer count.
c) Please explain why the 2015-2019 total customer counts in the May update are lower than those in the initial Application, even though the actual value for 2013 is higher than originally forecast and the forecast customer count for 2014 is now higher than originally forecast.

6.6 – VECC – 80

Reference: A/T16/S2, pg. 12 and pg. 49 (Updated)
A/T16/S3, pg. 4, Table 1 (Updated)

a) With respect to Table 3 (A/T16/S2), which years' values are actual results versus forecast results?
b) If, as stated at A/T16/S2, page 1 (lines 16-17, the values reported in Table 3 are at the wholesale level, please provide the end-use equivalents and explain the basis for the loss factors used.
c) Please reconcile the 2012 and 2013 CDM values for Retail Customers reported in Table 3 (A/T16/S2) with those reported in Table 1 (A/T16/S3). Note: The values in Table 3 are lower than those in Table 1 even though those in the former table are purportedly wholesale values whiles those in the later are end-use.
d) Please reconcile the 2013 values reported in Table 3 (A/T16/S2) with those reported in Table E.9 (A/T16/S2).

6.6 – VECC – 81

Reference: A/T16/S2, pg. 14-15 and Appendix E (Updated)

a) For which years were actual loads available and used in the development of the updated load forecast? If 2013 loads were not available to be used, please explain why.
b) Please confirm that Table E.5 is based on wholesale loads whereas Tables E.6 through E.9 are end-use values.
c) In Table E.5 the 2013 values appear to be actual values (i.e. actual/forecast and normalized are different). However, in Tables E.6 and E.7 the 2013 values appear to be based on forecast (i.e. the actual/forecast and weather normalized values are the same). Please confirm if this is the case and, if so, explain why.
d) Please provide a schedule that set outs the actual weather corrected total Retail load for each year from 2004 up to the most recent year as used for purposes of developing the load forecast, the annual CDM added back in for each of the historical values and the resulting total (per page 14 – Figure 2).
e) Please indicate where the actual CDM adjustments used in response to part (d) are found/reported in A/T16/S3.

6.6 – VECC – 82

Reference: A/T16/S2, pg. 17-19 and Appendices A, B, C & E (Updated)

a) Please provide the forecast of total annual Retail energy for each year 2014-2019 inclusive based on the Monthly Econometric Model (per Appendix A) before any adjustments for CDM.
b) Please provide the forecast of total annual Retail energy for each year 2014-2019 inclusive based on the Annual Econometric Model (per Appendix B) before any adjustments for CDM.
c) Please provide the forecast of total annual Retail energy for each year 2014-2019 inclusive based on the End-Use Model (per Appendix C) before any adjustments for CDM.
d) Please provide additional details as to how the results of the three models are combined to establish the overall Retail load forecast prior to accounting for CDM. As an illustration, please provide the detailed calculations for 2015.
e) Please details as to how the overall Retail class forecast is broken down in order to establish the load forecast by customer class prior to the CDM adjustment. As an illustration, please provide the detailed calculations for 2015.
f) For Table E.7, please confirm that kWh values reported are after the

adjustment for CDM?

g) Please confirm that the forecast adjustment for CDM is performed on a customer class basis using the values per Table E.9.
h) Please reconcile the 2013 CDM results for Retail Customers reported in Table E.9 (1,339-154=1,185 GWh) with the value reported in A/T16/S3, Table 1 (1,592.5 GWh).

6.6 – VECC – 83
Reference: A/T16/S2, pg. 14-15; pg. 19-20 and pg. 24

a) Please provide the econometric models used to forecast embedded utilities and embedded industrial/commercial load included in the ST class.
b) Please provide the annual forecast for 2015-2019 inclusive for these embedded utilities and embedded industrial/commercial customers based on the econometric models prior to any adjustments for CDM.
c) For each of these customer segments please indicate the adjustments that were made, based on the results from the customer survey, in order to arrive at the forecast included in the Updated Application prior to CDM (per page 24).
d) How does Hydro One Networks ensure that the customer survey results do not include the effects of future CDM initiatives by these customers?

6.6 – VECC – 84
Reference: A/T16/S2, pg. 21-22 and pg. 46-48

a) For which rate classes was hourly data <u>not</u> available for all customers (page 21, lines 12-13)? In each of these, what percentage of the actual 2012 load was hourly data available for purposes of scaling?
b) Please clarity what is meant by a “customer delivery point” (page 21, lines 20-25).
c) Are the kW values shown in Tables E.8 a) and E.8 b) before or after the adjustment for CDM (i.e. have historical actual values been increased for CDM and have the forecast values been adjusted downwards for CDM)?
d) For those customer classes that are demand billed please provide a schedule that calculates the (billing) load factor for each customer class (i.e. average monthly kWh/average monthly billing kW

delivered) for each historic year 2008-2013 using the weather normalized values.

e) For those classes that are demand billed how were the forecast billing kW for 2015-2019 derived from the forecast kWh?
f) For those customer classes that are demand billed please provide a schedule that sets out the annual forecast kWh and billing kW for each class for 2015-2019. Using this data please calculate the (billing) load factor for each customer class (i.e. average monthly kWh/average monthly billing kW delivered) for each of the years 2015-2019.

6.6 – VECC – 85
Reference: A/T16/S2, pg. 40-41
A/T16/S1, pg. 2-4

a) Why is the Consensus Forecast used for GDP and Housing Starts but the Global Insight forecast is used for Distribution Cost Escalation; CPI and Exchange rates?
b) What is the source of the GDP, Population and Housing forecasts set out in Table E.3?

6.6 – VECC – 86
Reference: A/T16/S3, pg. 4
A/T16/S4, pg. 5
A/T16/S2, pg. 12 and 49

a) Does Table ES 1 (A/T16/S4) include just Hydro One Networks' Retail Customers or also its ST Customers?
b) If Table ES 1 does not include ST customers, how were the forecast CDM savings attributable to this class (per A/T16/S2, pg. 12 and 49) established?
c) Please explain why the Hydro One CDM savings reported in Table 3 (A/T16/S2, pg. 12) for 2014-2019 differ for those reported in Table ES 1 (A/T16/S4, pg. 5). Please provide a schedule that reconciles the two.
d) Please explain why the Hydro One CDM savings reported in Table 3 (A/T16/S2, pg. 12) for 2013-2019 differ for those reported in Table E.9 (A/T16/S2, pg. 49). Please provide a schedule that reconciles the two. In particular, please reconcile the material difference between the two in terms of the CDM for the ST Class.

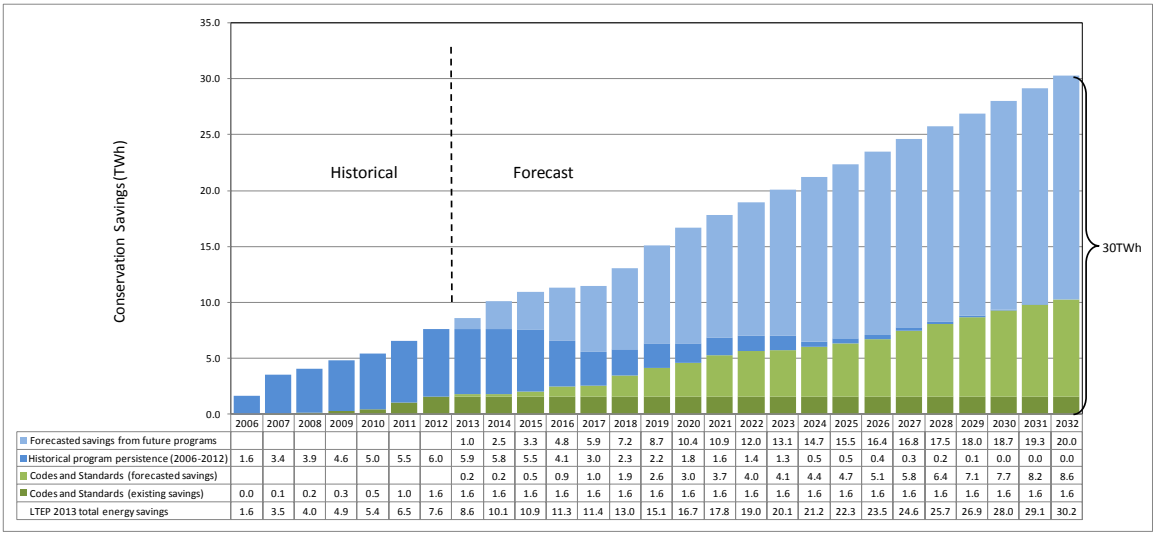
e) Are the totals reported in Table 1 (A/T16/S3, pg. 4) consistent (in terms of definition) with the totals reported for Table ES 1 (A/T16/S4, pg. 5)? If not, what is the difference?

f) How do the CDM categories used in Table 1 (A/16/3, pg. 4) relate to the CDM categories used for Table ES 1 (A/16/4, pg. 5)? Please provide a schedule that reconciles the two.

6.6 – VECC – 87

Reference: A/T16/S4, pg. 4-5
2013 LTEP, Module 2, Slide 10

Preamble: The detail LTEP Information Breakdown provided by the OPA (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf) includes the following data regarding forecast conservation savings.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Forecasted savings from future programs								1.0	2.5	3.3	4.8	5.9	7.2	8.7	10.4	10.9	12.0	13.1	14.7	15.5	16.4	16.8	17.5	18.0	18.7	19.3	20.0
Historical program persistence (2006-2012)	1.6	3.4	3.9	4.6	5.0	5.5	6.0	5.9	5.8	5.5	4.1	3.0	2.3	2.2	1.8	1.6	1.4	1.3	0.5	0.5	0.4	0.3	0.2	0.1	0.0	0.0	0.0
Codes and Standards (forecasted savings)								0.2	0.2	0.5	0.9	1.0	1.9	2.6	3.0	3.7	4.0	4.1	4.4	4.7	5.1	5.8	6.4	7.1	7.7	8.2	8.6
Codes and Standards (existing savings)	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
LTEP 2013 total energy savings	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0	20.1	21.2	22.3	23.5	24.6	25.7	26.9	28.0	29.1	30.2

a) How do the CDM categories used by Hydro One Networks in Table ES 1 relate to the OPA's CDM categories as used in the 2013 LTEP?

b) Please re-state Hydro One Networks' forecast 2014-2019 CDM savings using the OPA's CDM categories.

c) Please provide a schedule that sets out the savings expected in each of the years 2014-2019 from Target Programs offered in 2011-2014 showing the impact of each year's programs separately.

d) Using 2015 as an example, please detail how the Hydro One Networks' forecast CDM savings due to Codes and Standards was

derived and broken down by customer class.

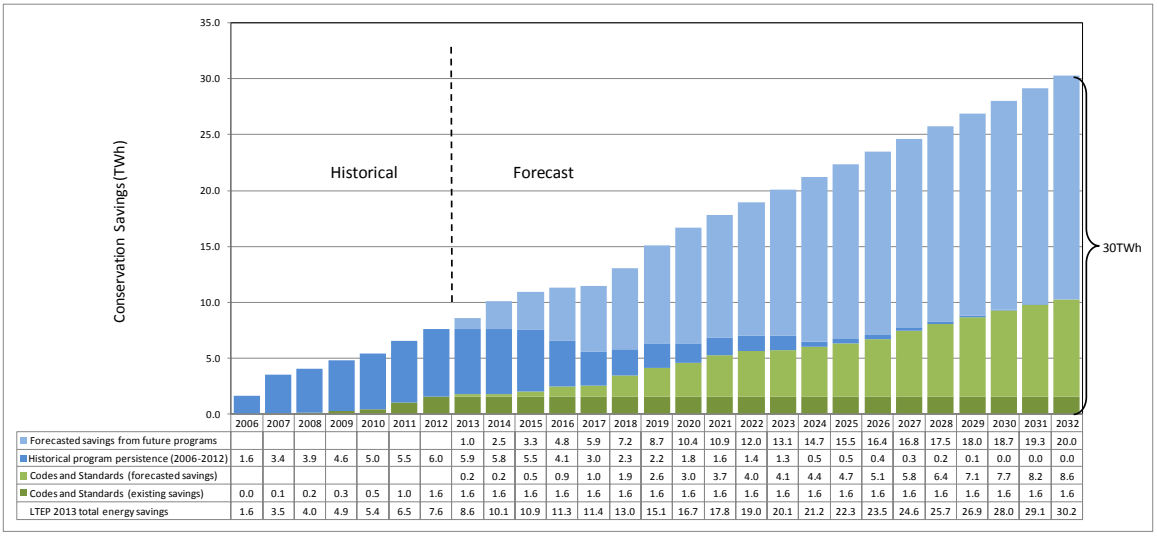
e) Using 2015 as an example, please detail how Hydro One Networks' forecast CDM savings attributed to "Forecast Savings from Future Programs" was derived and broken down by customer class.

f) How did Hydro One Networks ensure there was no double counting as between its categories for "Target Program Persistence (2011-2014)" and "Forecast Savings from Future Programs" (per Table ES 1) given that the 2013 LTEP's definition of "future programs" includes savings for 2013 and 2014 programs?

6.6 – VECC – 88

Reference: A/T16/S4, pg. 4-5
2013 LTEP, Module 2, Slide 10
A/T16/S3, pg. 4

Preamble: The detail LTEP Information Breakdown provided by the OPA (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf) includes the following data regarding forecast conservation savings.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Forecasted savings from future programs								1.0	2.5	3.3	4.8	5.9	7.2	8.7	10.4	10.9	12.0	13.1	14.7	15.5	16.4	16.8	17.5	18.0	18.7	19.3	20.0
Historical program persistence (2006-2012)	1.6	3.4	3.9	4.6	5.0	5.5	6.0	5.9	5.8	5.5	4.1	3.0	2.3	2.2	1.8	1.6	1.4	1.3	0.5	0.5	0.4	0.3	0.2	0.1	0.0	0.0	0.0
Codes and Standards (forecasted savings)								0.2	0.2	0.5	0.9	1.0	1.9	2.6	3.0	3.7	4.0	4.1	4.4	4.7	5.1	5.8	6.4	7.1	7.7	8.2	8.6
Codes and Standards (existing savings)	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
LTEP 2013 total energy savings	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0	20.1	21.2	22.3	23.5	24.6	25.7	26.9	28.0	29.1	30.2

a) Please restate the Hydro One Networks' historic CDM savings as set out in Table 1 (A/T16/S3, pg. 4) using the 2013 LTEP CDM categories.

b) Please restate the Hydro One Networks' historic CDM savings as set out in Table 1 (A/T16/S3, pg. 4) using the Hydro One Networks' CDM categories as per Table ES 1 (A/T16/S4,pg. 5)

6.6 – VECC – 89
Reference: A/T16/S2, pg. 24, Table 6
A/T16/S2, pg. 49, Tables E.7 and E.9
A/T16/S4, pg. 5, Table ES 1

a) Please provide a schedule that reconciles the CDM impact values reported Table E.9 with those reported in Table ES 1 for each of the years 2013 to 2019. If losses are part of the reconciliation, please indicate the loss factor assumed and the basis for the assumption.
b) Please provide a schedule that reconciles the load forecast (after the CDM adjustment) as reported in Table 6 and Table E.7.
c) Overall, please indicate where in the Application or the preceding interrogatory responses the determination of the forecast CDM savings set out in Table 6 are set out. Otherwise, please provide a clear explanation as to the basis for the values in Table 6.

6.6 – VECC – 90
Reference: E1/T1/S2

a) Please provide completed versions of Appendix 2-H (Other Operating Revenues) for the years 2010-2019 inclusive.
b) Why are there no forecast external revenues attributed to Account 4405 (Interest and Dividend Income)?
c) What were the Account 4405 annual revenues for the years 2010-2013 inclusive?

6.6 – VECC – 91
Reference: E1/T1/S2, pg. 4-5

a) Please reconcile the sentinel light volumes reported in Table 4 with the number of sentinel light customers reported in Exhibit G1/T4/S2 (Attachments 1-4) for the years 2015-2019.

6.6 – VECC – 92
Reference: E1/1/2, page 7

a) Please clarify whether the “standby administration charge” referenced on line 20 is a separate charge or the same charge as the “standby charge” referenced on line 14.

b) What were the actual annual revenues from tingle voltage test charges and (all) standby charges for 2010 to 2013?

7.0 COST ALLOCATION AND RATE DESIGN

7.1 Are the rate classes and their definitions proposed by Hydro One appropriate?

7.2 Is the proposed definition of "seasonal" customer class appropriate? Particularly, is residency an appropriate criterion in defining a class? Has this criterion been applied consistently?

7.2 – VECC – 93
Reference: G1/T2/S1, pg. 5-6
Technical Conference, April 30, 2013, pg. 26, lines 6-7; pg. 31, lines 2-6; pg. 35, lines 24-27 and pg. 64, lines 14-23

a) Please explain more fully the basis for the choice of i) 9,600 kWh per year and ii) at least 600 kWh monthly for a minimum of 10 months as the criteria for treating currently defined Seasonal customers as Residential customers. In particular, for the second criterion why were 600 kWh and 10 months chosen?
b) Please provide a schedule that sets out the average use per customer for 2013 for each of the following customer classes:
   - UR
   - R1
   - R2
   - Seasonal

   If possible please provide both the actual and weather normalized average use per customer.
c) What is the forecast total and average per customer 2015 total kWh usage for the roughly 11,000 Seasonal customers reclassified as Residential? If the 2015 forecast values are not available please indicate their current usage.
d) Please provide a schedule that indicates how many of the roughly 11,000 were reclassified to the R1 versus R2 classes and the 2015 forecast usage (or current usage if forecast is not available) in each case.

e) Based on the most recent 12 months of data available, please provide a frequency distribution for each of the UR, R1, R2 and Seasonal classes that indicates the number of customers that fall into each of the following usage categories:
   - 0 to 100 kWh per month
   - >100 to 250 kWh per month
   - >250 to 500 kWh per month
   - >500 to 800 kWh per month
   - >800 to 1,000 kWh per month
   - >1,000 to 1,500 kWh per month
   - >1,500 to 2,000 kWh per month
   - >2,000 kWh per month.

f) Based on the most recent 12 months of data available, please provide a frequency distribution for each of the UR, R1, R2 and Seasonal classes that indicates the number of customers that fall into each of the following usage categories for the ten months with the highest usage:
   - 0 to 250 kWh per month for those ten months
   - >250 to 450 kWh per month for those 10 month
   - >450 to 600 kWh per month for those 10 months
   - >600 to 1,000 kWh per month for those 10 months
   - >1,000 to 1,500 kWh per month for those 10 months
   - >1,500 to 2,000 kWh per month for those 10 months
   - >2,000 kWh per month for those 10 months

7.2 – VECC – 94

Reference: G1/T2/S1, pg. 5-6
G1/T3/S1, pg. 15 (line 11)
Technical Conference, April 30, 2013, pg. 31, lines 11-12

a) Using the actual 2012 smart meter data, please provide graphs that for each of the UR, R1, R2 and Seasonal classes (as currently defined) plots the average monthly use for each customer versus the customer's "NCP load factor" as defined by the ratio of the customer's average hourly use to the customer's average 4NCP value (i.e. the customer's 4 NCP value divided by 4).

b) Using the actual 2012 smart meter data, please provide graphs that for the UR, R1, R2 and Seasonal classes (as currently defined) plots the average monthly use for each customer versus the customer's

"CP load factor" as defined by the ratio of the customer's average hourly use to the customer's average 12CP value (i.e. the customer's 12CP value divided by 12).

c) If the data is available, please re-do parts (a) and (b) using 2012 weather normalized data for each customer.

d) Using the 2012 actual smart meter data, please provide schedules that set out for each of the UR, R1, R2 and Seasonal classes (as currently defined) the i) total kWh, ii) 4 NCP value and iii) 12 CP value for each of the following categories of the following usage categories
   - 0 to 100 kWh per month
   - >100 to 250 kWh per month
   - >250 to 500 kWh per month
   - >500 to 800 kWh per month
   - >800 to 1,000 kWh per month
   - >1,000 to 1,500 kWh per month
   - >1,500 to 2,000 kWh per month
   - >2,000 kWh per month.

e) Using the 2012 actual smart meter data, please provide schedules that for each of the UR, R1, R2 and Seasonal classes (as currently defined) the i) total kWh, ii) 4 NCP value and iii) 12 CP value for each of the following usage categories for the ten months with the highest usage:
   - 0 to 250 kWh per month for those ten months
   - >250 to 450 kWh per month for those 10 month
   - >450 to 600 kWh per month for those 10 months
   - >600 to 1,000 kWh per month for those 10 months
   - >1,000 to 1,500 kWh per month for those 10 months
   - >1,500 to 2,000 kWh per month for those 10 months
   - >2,000 kWh per month for those 10 months

f) If the data is available, please redo parts (d) and (e) using 2012 weather normalized data for each customer.

7.2 – VECC – 95

Reference: G1/T2/S1, pg. 5-6
G2/T2/S1, pg. 2
Technical Conference, April 30, 2014, pg. 35, lines 20-28

a) Please provide the eligibility requirements for Rural or Remote

Electricity Rate Protection (RRRP) applicable to Hydro One Networks' customers per O. Reg. 442/01.

b) Please confirm that it is Hydro One Networks' proposal to provide RRRP to all R2 customers, including those customers that were formerly Seasonal customers.
c) Please explain how the definition of the year round residential customer (per G2/2/1) as used for purposes of the R2 class conforms to the definition of an eligible "residential premises" as set out in O. Reg. 442/01.
d) Please explain how the inclusion of Seasonal customers as being eligible for RRRP conforms to the definition of an eligible "residential premises" as set out in O. Reg. 442/01.
e) Please explain how the amount of RRRP each R2 customer receives is determined (i.e. is it based on divvying up a defined amount of dollars amongst the eligible customers?). Does changing the number of eligible customers change the amount of RRRP each customer receives monthly?

7.3 Is the reclassification of customers to reflect findings of the company's review of existing customer rate classifications appropriate?

7.3 – VECC – 96
Reference: G1/T2/S1, pg. 1-2

a) How current was the GIS data used in the analysis (i.e., to what date had the GIS system data been updated to?).
b) Please explain more fully step 1 of the methodology and, in doing so, also explain what is meant by "core clusters of contiguous customers".
c) Please confirm whether it was after Step 1, Step 2 or Step 4 that the density classification for each defined zone was established, subject to the 10% deadband rule.
d) Per page 2 (lines 15-18), for how many "zones" and "customers" did the density zone value fall below the 10% deadband? In responding please indicate the number of customers that would be transferred from: i) UR to R1, ii) R1 to R2, iii) UR to R2, iv) UGe to GSe and v) UGd to GSd if the 10% criterion was strictly applied.
e) In these circumstances why was it not possible to redefine the

boundaries (per Step 2) in order to stay within the 10% deadband?

7.4 Is moving revenue-to-cost ratios for all rate classes to within 98% to 102% over the 2015-2019 period appropriate?

7.4 – VECC – 97
Reference: G2/T3/S1
Hydro One Networks' 2015 CAM, Tab I6.1

a) Please explain why the existing monthly fixed charge for GSe used in the 2015 CAM ($35.92) is not the same as the approved 2014 fixed charge for the class ($36.36).
b) Please explain why the existing volumetric charge for UGd used in the 2015 CAM ($6.935) is not the same as the approved 2014 volumetric charge ($6.99).
c) Please explain why the existing volumetric charge for GSd used in the 2015 CAM ($11.433) is not the same as the approved 2014 volumetric charge ($11.495).
d) Please explain why kW value for the demand billed classes used in Tab I6.1 do not match the forecast values set out at A/T16/S2, pg. 47, Table E.8 a).

7.4 – VECC – 98
Reference: G1/T3/S1, pg. 14, lines 17-22

a) Are all classes except for Residential and Seasonal also responsible for the maintenance and replacement of their service connection assets?
b) Are these requirements set out in Hydro One Networks' Conditions of Service and, if so, where?

7.4 – VECC – 99
Reference: G1/T3/S1, pg. 12-14
G2/T1/S1, pg. 7
Hydro One Networks' 2015 CAM

a) With respect to Tab I7.1 (Meter Capital), please explain why the per meter capital costs are higher for the R2 and Seasonal classes than for R1 and UR.
b) With respect to Tab I7.2 (Meter Reading), were the previously

approved meter reading weighting factors developed based on the assumption that all residential and general service meters required manual on-site reading or based on meter reading for roughly 40,000 customers as is currently the case.

c) Please provide a schedule that sets out the allocated/directly assigned 2015 cost per meter read for each customer class, including ST and DG.

7.4 – VECC – 100

Reference: G1/T3/S1, pg. 15, lines 3-16
G2/T1/S1, pg. 7
Hydro One Networks' 2015 CAM

a) For which classes was the 2012 smart meter data used to update the load profiles?
b) Was the 2012 smart meter data used the actual 2012 meter readings or were the results weather normalized?
c) What was the basis for establishing the load profiles for the other customer classes and, in particular, what changes were made from the previously filed CAM in Hydro One Networks` last cost of service based rate case?

7.4 – VECC – 101

Reference: G1/T3/S1, pg. 15, lines 3-16
G2/T1/S1

a) Please identify those changes to the CAM for 2015 (per G2/T1/S1) that Hydro One Networks considers to be "improvements" (per G1/T3/S1, pg. 15, line 9) as opposed to changes that would normally be undertaken to update the model for new forecast data. In doing so, please specifically note those changes in the assignment of OM&A costs by USofA and breakout of fixed assets by USofA that Hydro One Networks considers to be improvements.
b) With respect to the improvements identified in part (a), please indicate which of these are in response to compliance with the Board's EB-2010-0219 Review of Electricity Distribution Cost Allocation Report.

7.4 – VECC – 102
Reference: G1/T3/S1, pg. 15-17

a) Please re-calculate the CAM ratios in Table 6 for the years 2016-2019 using the current 2014 rates in Tab I6.1 as the basis for determining revenues at "existing rates" for this Tab and for Tab O1.

7.5 Is the addition of a new "Unmetered Scattered Load" rate class appropriate?

7.5 – VECC – 103
Reference: G1T/2S/1, pg. 4-5

a) For what other types of USL customers were load profiles established (per pg. 4, lines 14-16) for purposes of determining the overall load profile of the USL class.
b) Please provide a schedule that breaks down the 5,647 USL customers forecast for 2015 (per G1/T4/S2, Attachment 1) by type and that indicates both the forecast 2015 MWh and the basis of the load profile for each type.

7.6 Are Hydro One's proposed charges for street lighting appropriate?

7.6 – VECC – 104
Reference: G1/T4/S1, pg. 7

a) As the proposal to limit the increase in the Sentinel and Streetlight class fixed charges for 2015 is based on bill impact concerns, please explain why the proposed fixed percentage of the rate design for these classes isn't increased further in 2016-2019 in order to approach their CAM Scenario 3 values.

7.7 Is an increase to the fixed charges revenue appropriate?

7.7 – VECC – 105
Reference: G1/T4/S1, pg. 4

a) Based on the load profile for each customer class and the PLCC

values what are the annual kWh/customer for each customer class that are implicitly captured by the minimum system costs reflected in Hydro One Network's proposed fixed charges.

b) Please provide a schedule that for each customer class sets out the fixed charge and volumetric charge for distribution service (exclusive of any rate riders) for the years 2008-2013. Note: For those classes receiving RRRP, please show the fixed charge both before and after the RRRP discount.
c) Please provide a schedule that sets out the actual distribution revenues by customer class for the years 2008-2013 and, for each year, show the percentage of total revenues recover via fixed versus volumetric charges. For those classes that receive RRRP please report the RRRP-related revenues received by Hydro One Networks separately.

7.7 – VECC – 106
Reference: G1/T4/S1, pg. 6

a) Please confirm that Hydro One Networks' CAM does not include revenues received by the Company to cover the RRRP discount.
b) For Table 4, what is the proposed 2015 fixed charge for R2 prior to netting out the RRRP credit?
c) Please explain why the proposed R2 fixed charge (prior to the RRRP credit) was not set at the CAM Scenario 3 value as is the case for most other customer classes.
d) As the proposal to limit the increase in the Seasonal fixed charge for 2015 is based on bill impact concerns, please explain why the proposed fixed percentage of the Seasonal rate design isn't increased further in 2016-2019 in order to approach the CAM Scenario 3 value.

7.7 – VECC – 107
Reference: G1/T4/S1, pg. 6 (Table 4) and pg. 10-11 (Table 5)

a) Page 11 outlines how the ST fixed charge is based on the Minimum System with the PLCC Adjustment value from Sheet O2 of the CAM adjusted to exclude low voltage meter costs which are recovered through a separate Meter Rate. However, the proposed fixed service charges and meter rates for the ST class (per Table 5) total more than the unit cost per CAM Scenario 3 (per Table 4). Please

reconcile.

7.7 – VECC – 108
Reference: G1/T4/S1, pg. 15, lines 1-8
G2/T2/S1
G2/T1/S8, pg. 1

a) Which energy billed customer classes include customers that provide their own transformation?
b) Based on the 0.14 cents/kWh credit, what is the forecast total dollar credit applicable to each of these classes for 2015?
c) From which customer classes is the "cost" of this credit recovered and what is the impact on the proposed rates for each of these classes for 2015?
d) For these classes where is the recovery of the cost of the credit reflected in the proposed 2015 rate schedules per G2/T2/S1?
e) If the recovery is included proposed volumetric charges for these classes, please explain why the rates set out in G2/T2/S1 are the same as those used in the 2015 Revenue Reconciliation (G2/T1/S8, pg. 2) for all energy billed classes.

7.7 – VECC – 109
Reference: G1/T4/S1, pg. 15, lines 1-3 and 10-16 (including Table 6)
G2/T2/S1
G2/T1/S8, pg. 1

a) Which demand billed customer classes include customers that provide their own transformation?
b) Based on the $0.60 / kW credit, what is the forecast total dollar credit applicable to each of these classes for 2015?
c) From which customer classes is the "cost" of this credit recovered and what is the impact on the proposed rates for each of these classes for 2015?
d) For these classes where is the recovery of the cost of the credit reflected in the proposed 2015 rate schedules per G2/T2S/1?
e) What would be rate adders for each class if the cost of providing the transformer allowance to each class' customers was recovered from the same class as opposed to being uniformly recovered from all three classes using the same rider? Please show the calculations.

7.7 – VECC – 110
Reference: G1/T7/S1, pg. 4

a) Please explain why the RRRP credit is constant for the 2015-2019 period when the number of R2 customers is increasing each year.
b) Please provide the derivation of the proposed $30.50 per month RRRP credit.

7.8 Are the proposed charges for miscellaneous services over the 2015-2019 period reasonable?

7.8 – VECC – 111
Reference: G2/T5/S1, pg. 31

a) Please confirm that the costs shown in Table 16 for the years 2016-2019 were determined by applying a 1% / annum escalation rate to the 2015 costs. If not, please explain how the values were established.
b) Why is 1% per year a reasonable escalation rate for the Joint Use - Telecom charge?
c) What has been the historical escalation rate in the costs underlying this charge from since the currently approved rate was established up to the forecast 2015 costs?

7.8 – VECC – 112
Reference: G2/T5/S1, pg. 32-33

a) Please confirm that the costs shown in Table 17 for the years 2016-2019 were determined by applying a 1% / annum escalation rate to the 2015 costs. If not, please explain how the values were established.
b) Why is 1% per year a reasonable escalation rate for the Joint Use – LDC and Generator charge?
c) What has been the historical escalation rate in the costs underlying these charges since the currently approved rate was established up to the forecast 2015 costs?

7.9 Are the adjustments to reflect the Board-directed line loss study appropriate?

7.9 – VECC – 113
Reference: G1/T8/S2, Attachment 1, pg. 27

Preamble: The report states that the final list of feeders used serve over 80% of Hydro One Networks' customers.

a) What percentage of Hydro One Networks distribution load is serviced by these feeders?

7.9 – VECC – 114
Reference: G1/T8/S2, Attachment 1, pg. 29

a) Since the purpose of the study is to determine loss factors which are related to electricity use, why was number of customers by class used to segment the feeders into clusters as opposed to the load (i.e. kWh) by class?

7.9 – VECC – 115
Reference: G1/T8/S2, Attachment 1, pg. 32-35

a) Why did the loss analysis focus on kW as opposed to kWh losses?
b) In determining kW losses, what was the "peak" used (i.e. was it the peak of the originating feeder per Figure 21)?
c) In measuring the "peaks" of the downstream segments and transformers were they all based on the "peaks" coincident with the peak of the originating upstream feeder? If not, how were they determined?
d) Given that the actual peaks for the various downstream segments and transformers may occur at a different time (and be higher) why is this approach appropriate?

7.9 – VECC – 116
Reference: G1/T8/S2, Attachment 1, pg. 35

Preamble: The report states that secondary losses were estimated for each customer based on the estimated contribution of each customer

to the load on the transformer.

a) How was this contribution determined? For example, was it based on each customer's contribution to the peak for the transformer or to each customer's contribution to the peak of the originating upstream feeder?
b) Is the determination of the contribution of each customer consistent with the definition of "peak" and "peak losses" as outlined in the section titled "Allocation of Losses to Distribution Transformers" (pg. 34-35)? Please explain why.

7.9 – VECC – 117
Reference: G1/T8/S2, Attachment 1, pg. 35-36

Preamble: The report states (page 35) that where the distribution transformer served customers in different customer classes, the estimated peak load contribution of each type of customer was used as the basis for allocating losses. The equation on page 36 sets out the model used to estimate these values.

a) Over what timeframe was the model estimated?
b) Please confirm that a separate regression analysis done for each feeder, such that there were different estimated peak load contributions by customer class for each feeder?
c) Please provide the resulting estimates of average peak load contribution for each customer class by feeder.
d) Why was it assumed that the UR, R1 and R2 classes would all have the same average contribution per customer?
e) What was the average load factor as determined for each of the customer classes (page 36)? In responding please indicate how the "peak load" value used in determination of the average load factor was determined.
f) For each customer class, was the same load factor used for all feeders? If yes, why is this appropriate given that all feeders do not peak at the same time?
g) What is the rationale for the formula (page 36) used to estimate LLF and, in particular, the basis for the "k" values used?

7.10 Are the proposed rate mitigation plans appropriate for some customers moving between rate classes in accordance with the results of the rate class review?

7.10 – VECC – 118
Reference: G1/T7/S1, pg. 5

a) What is the expected cost (in terms of revenue reduction) for the proposed 2015 bill impact mitigation plan?
b) What is the expected cost of implementing the proposed bill impact mitigation (as distinct from the anticipated revenue reduction)?

End of document