EB-2017-0049

Hydro One Networks Inc.
Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022

VECC COMPENDIUM

PANEL 2

JUNE 14, 2018

TAB 1

Vulnerable Energy Consumers Coalition Interrogatory # 54

Issue:

Issue 40: Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate (excluding executive compensation)?

Reference:

C1-01-06 Page: 1-2

Interrogatory:

a) Please provide schedules that for 2016, 2017 and 2018 set out the allocation of the total Common Corporate OM&A costs (per Table 1) between Hydro One's distribution and transmission businesses and each of its unregulated accounting segments.

b) Are any of the Common Corporate OM&A costs allocated to Hydro One's distribution business subsequently assigned to the acquired utilities Norfolk, Haldimand and Woodstock?
   i. If no, why not – particularly for purposes of the 2018 proposed revenue requirement?
   ii. If yes, please indicate what the amounts were for 2016, 2017 and 2018 and provide a schedule that reconciles these amounts with the amounts allocated to Hydro One's distribution business (per part (a)) and the amounts included in the proposed revenue requirement (per page 2, Table 2).

Response:

a) Allocation is shown below for each of the three years.

2016 Other OM&A Allocation

	Dx	Tx	Telecom	Remotes	Holding
Planning	27.1%	72.9%			
Common Corporate Functions	47.2%	47.0%	1.2%	0.7%	3.9%
Information Technology	59.3%	39.6%	0.8%	0.3%	
Cost of External Revenue	50.5%	49.5%			
Other OM&A	47.6%	52.4%			

2017 Other OM&A Allocation

	Dx	Tx	Telecom	Remotes	Holding
Planning	27.9%	72.1%			
Common Corporate Functions	43.6%	47.6%	1.1%	0.7%	7.0%
Information Technology	58.8%	40.5%	0.5%	0.2%	
Cost of External Revenue	50.0%	50.0%			
Other OM&A	47.5%	52.5%			

2018 Other OM&A Allocation

	Dx	Tx	Telecom	Remotes	Holding
Planning	28.0%	72.0%			
Common Corporate Functions	43.7%	47.7%	1.1%	0.7%	6.8%
Information Technology	58.3%	40.9%	0.6%	0.2%	
Cost of External Revenue	55.1%	44.9%			
Other OM&A	46.9%	53.1%			

Note: The Tx values include the small amount allocated to B2M and to Hydro One SSM.

b) The common corporate OM&A costs in Exhibit C1-01-06 have not been allocated to any of the acquired customers.

i. As part of the MAAD application approvals, a five-year deferral period was approved for each utility. The Handbook to Electricity Distributor and Transmitter Consolidation says "to encourage consolidations, the OEB has introduced policies that provide consolidating distributors with an opportunity to offset transaction costs with any achieved savings[1]." Savings in Common Corporate OM&A cost are part of the synergy savings achieved as a result of these transactions. Hydro One has not forecast any incremental increase in common corporate costs as a result of these transactions. Therefore, the common corporate costs as provided in Exhibit C1-01-06 are recovered from legacy ratepayers only until December 31, 2020 (the period when the proposed distribution rate freeze period would cease). In 2021, for rate-making purposes, overhead allocations are applied to determine cost-based rates.

ii. Not Applicable

[1] Handbook to Electricity Distributor and Transmitter Consolidation, page 11

TAB 2

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10

Interrogatory:

Reference: Exhibit A/T2/S1, page 2 (lines 1-10) and page 9 (lines 10-16)

a) What were OPDC's actual total OM&A costs for 2015? If materially different (10%) from the forecast Year 1 Status Quo Forecast costs please explain why.

b) What portion of the OM&A reduction shown in Table 1 is due to the proposed elimination of 29 local positions (per page 9)? What are the sources for the balance of the assumed savings?

c) Please confirm that the Hydro One Forecast OM&A in Table 1 does not include any costs associated with administration or support services (e.g. back-office services, customer service, finance, human resources, distribution system planning& design, executive & governance, etc.).

d) It is noted that OPDC is just one of a number of recent acquisitions by HONI which also include Norfolk Power Distribution, Haldimand County Hydro and Woodstock Hydro. Cumulatively, have/will these acquisitions require HONI to add additional staff or retain additional contract services in order to provide administration and support services.

Response:

a) OPDC's actual OM&A spend for 2015 was $4.8 million. The Year 1 Status Quo Forecast is also $4.8 million.

b) The savings from reducing local positions by 29 is approximately $2.4 million per annum.

   The response to Exhibit I, Tab 1, Schedule 2 addresses the projected OM&A savings shown in Table 1.

c) Not confirmed. The Hydro One Forecast OM&A includes an evaluation of incremental administrative and support services costs as a result of absorbing the OPDC service territory.

d) The review of the costs associated with serving the acquired utilities referenced above will be subject to a future review and rate application by the OEB. When Hydro One files its 2018 to 2022 distribution rates application, per the Conditions of Approval of the above-mentioned MAAD acquisitions, Hydro One will provide a report on costs associated with these service areas.

TAB 3

2.2.1 CORPORATE CONTROLLER

The Corporate Controller function provides leadership and direction regarding financial reporting, corporate and regulatory accounting, accounting and internal control policies, and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles. The group is also accountable for the pay and expense management functions; ensuring payroll runs are on time and accurate and ensuring that the automated expense reporting tool is working as designed.

This function oversees the development of actual financial information and manages reporting processes for appropriate audiences or stakeholders. This function is also responsible for managing and providing direction to the company on internal control matters, employing measures such as “organization authority registers” and financial policies and procedures. It also provides leadership on compliance with Ontario securities laws, including Bill 198, and the Multi-Jurisdictional Disclosure System rules for a foreign-issuer registered with the U.S. Securities Exchange Commission.

Many routine financial services are outsourced to Inergi LP, such as accounts payable, accounts receivable, fixed asset accounting, general accounting, planning budgeting and reporting and pension support, human resources pay services, and a number of administrative services. The costs of these outsourced services comprise a major portion of the corporate controller costs and are detailed in Exhibit C1, Tab 5, Schedule 1.

The Corporate Controller’s function manages increasingly complex statutory and regulatory filing requirements (external reporting, regulatory reporting, reporting related to debt and equity offerings). These requirements are continually evolving and require timely and accurate compliance. Timely compliance helps to maintain the Company’s positive standing with capital markets, which helps to keep financing costs down.

TAB 4

2.2.2 CORPORATE TAX

Corporate Tax services manage the tax affairs (namely, compliance, audits and planning) for each legal entity, partnership and trust within the Hydro One group of companies. This includes matters related to corporate income taxes, harmonized sales tax, debt retirement charge, land transfer tax, payroll and non-resident withholding tax, and the employer health tax. Corporate Tax services ensure that internal and external tax compliance requirements are met. Moreover, tax consulting services are provided to other departments with respect to payroll tax, taxable benefits, agreements, financing, and all transactions and information about tax costs for regulatory purposes.

2.2.3 TREASURY

Treasury costs are associated with the following activities:

- executing on borrowing plans and issuing commercial paper and long-term debt;
- ensuring compliance with securities regulations, banks and debt covenants;
- managing the company's daily liquidity position, control cash and manage the company's bank accounts;
- settling all transactions and managing relationships with creditors; and
- communicating with debt investors, banks and credit rating agencies.

A portion of the treasury budget is recovered through the cost of long-term debt, as stated in Exhibit D1, Tab 2, Schedule 2.

Included in treasury costs are expenses for the negotiation and purchase of insurance policies, and claims management and settlement. These expenses cover premiums paid for corporate shared services insurance coverage and the cost to self-insure against

TAB 5

REVIEW OF ALLOCATION OF COMMON CORPORATE COSTS (DISTRIBUTION) – 2016

BLACK & VEATCH PROJECT NO. 188588

PREPARED FOR

Hydro One Networks Inc.

December 21, 2016

BLACK & VEATCH
Building a world of difference.

For the activities listed in Task 2, Hydro One's departmental managers distributed the resource costs among one or more business units, based on the business units that caused the costs to be incurred. When possible, all or a portion of costs were assigned to a specific business unit.

Task 7. Any portion of an activity that was not assigned to a specific business unit due to its generalized nature was allocated among business units using cost drivers, as described in Task 7. Assigned cost drivers

As discussed above, the costs of activities were directly assigned to business units when possible. The purpose of this task was to select cost drivers for the portion of costs which were not directly assigned in Task 6.

The principles that Black & Veatch used to assign cost drivers are discussed in Section II.D- Cost Drivers. Black & Veatch selected cost drivers based on applying the principles discussed above, its experience in performing cost allocation studies, consultations with Hydro One as to the nature of each activity, and industry practices and regulatory requirements.

Section II.E Types of Cost Drivers describes the types of cost drivers.

Table 5 summarizes the direct assignments and types of costs drivers used to distribute the Common Corporate Costs among the business units. Amounts include the Inergi charges.

Table 5 - Direct Assignments and Cost Drivers for Common Corporate Costs

TYPE	2018	2019	2020	2021	2022
(% of Total)	%	%	%	%	%
Direct Assignment	58.56%	57.79%	57.76%	57.63%	58.54%
Physical	13.03%	13.27%	13.52%	13.57%	13.75%
Financial	20.76%	21.10%	21.39%	21.52%	21.83%
Internal	7.65%	7.84%	7.33%	7.29%	7.33%
Total	100.00%	100.00%	100.00%	100.00%	101.44%

Task 8. Populated cost drivers

The purpose of this task was to determine the values of each cost driver that are attributable to each business unit in order to distribute the costs of each activity among the business units. The supporting information was provided by Hydro One.

Task 9. Reviewed 2015 Time Study

This Task is discussed in Section V.

Task 10. Computed total common corporate costs for each business unit

The purpose of this task was to distribute the total cost of each activity among the business units. The amount distributed was the sum of the amounts directly assigned in Task 6, and allocations based on the cost drivers identified in Task 7.

For allocations based on the cost drivers, the amount allocated to each business unit was computed by multiplying the activity cost to be allocated by the cost driver value for the business unit.

TAB 6

Exhibit B: Types of Cost Drivers

TYPE	DESCRIPTION	EXAMPLES
External Cost Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Headcount (of employees), number of workstations, invoices to vendors
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Program Project Costs, Total capital, Total revenue
Blended	Weighted combinations of other drivers, used when one or more drives are applicable and none is clearly preferable; weights determined by judgment	Non-energy Rev_Assets Blend = 50% weight for Non-Energy Revenue and 50% weight for Assets
Driver xBusiness Unit	Any driver may be modified by excluding one or more business units to which the activity does not apply	Cost driver for Business Process Improvements is Operating Maintenance Capital, but Telecom and Remotes business units do not use the shared service, therefore activity cost driver is called Oper Maint Cap xTxR (i.e., Gross Utility Plant excluding Telecom and Remotes)
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

TAB 7

Vulnerable Energy Consumers Coalition Interrogatory # 51

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

A-06-03
Exhibit C1, Tab 1, Schedule 1, Table 1
Exhibit A, Tab 7, Schedule 1, Table 4

Interrogatory:

a) Please explain the treatment of the OM&A costs related to the acquired utilities Norfolk, Haldimand and Woodstock in both Exhibit A, Tab 6, Schedule 3 and Exhibit C1, Tab 1, Schedule 1, Table 1.

b) Please reconcile the difference between the OM&A values for 2017 and 2018 as reported in the two references in part (a) (e.g. for 2018 - $594 M vs. $591.1 M).

c) Please provide a breakdown of the forecast 2017 and 2018 OM&A costs associated with Norfolk, Haldimand and Woodstock using the same categories as set out in Exhibit C1, Tab 1, Schedule 1, Table 1.

d) If the differences noted in part (b) are (in part or whole) related to the OM&A costs associated with Norfolk, Haldimand and Woodstock, please reconcile the variances noted in part (b) for 2017 and 2018 with the forecast 2017 and 2018 OM&A costs for these acquired utilities as set out in Exhibit A, Tab 7, Schedule 1, Table 4.

Response:

Please note that OM&A costs for the acquired customers will not impact any revenue requirement request until 2021. As part of the MAAD application approvals, a five-year deferral period was approved for each utility. Each acquired utility had their previous OEB-approved distribution rates reduced by 1% and froze for five years. Per “Rate-Making Associated with Distributor Consolidation” policies[1], this deferral period allows shareholders the opportunity to

[1] Rate-making Associated with Distributor Consolidation 2007 and 2015

offset the costs of a MAADs transaction[2]. Therefore cost to serve these customers will not impact the Hydro One Distribution revenue requirement or customer's rates until January 1, 2021.

a) The acquired utilities OM&A costs have not been included in any revenue requirement request for 2017 nor 2018. Therefore incremental OM&A costs, as shown in Exhibit A, Tab 7, Schedule 1, are not included in Table 1 "Summary of Recoverable OM&A Expenses" provided in Exhibit C1, Tab 1, Schedule 1.

The OM&A costs, as shown in the Pro Forma Statement of Income in Exhibit A, Tab 6, Schedule 3, do not include the acquired utilities.

b) The numbers referenced in the question were updated on June 7, 2017 as follows:

	2017	**2018**
Exhibit A, Tab 6, Schedule 3	575	587
Exhibit C1, Tab 1, Schedule 1	572.8	584.8

The difference of approximately $2.0 million each year relates to OM&A costs associated with the provincially funded green energy program. For rate-making purposes, these costs are excluded from OM&A.

c)

Acquired LDC Forecast OM&A Costs

	Norfolk		Haldimand		Woodstock	
	2017 ($M's)	**2018** ($M's)	**2017** ($M's)	**2018** ($M's)	**2017** ($M's)	**2018** ($M's)
Sustainment	0.78	0.80	2.03	2.07	0.42	0.37
Development	-	-	-	-	-	-
Operations	0.67	0.67	0.43	0.43	0.33	0.33
Customer Care	0.85	0.87	1.17	1.20	0.76	0.78
Common Corporate Costs & Other[3]	0.79	0.81	1.39	1.40	0.63	0.62
Total	3.10	3.10	5.00	5.10	2.10	2.10

d) Not applicable.

[2] EB-2014-0138, page 5

[3] As indicated throughout Exhibit A, Tab 7, Schedule 1, OM&A costs for the acquired utilities are provided on an incremental basis, therefore there is no allocation of corporate overhead costs. For rate-making purposes, overhead allocations were applied to determine cost-based rates.

TAB 8

Table 1 consolidates information previously provided in Hydro One's last distribution rate application (EB-2013-0416) in Tables 1 to 3 of Exhibit C1, Tab 2, Schedule 5, as described in the notes to Table 1.

Table 1: Summary of Customer Care OM&A Allocated to Distribution ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
Call Center Operations [1]	79.5	56.4	38.5	41.5	38.8	43.8	39.9	44.5
Meter Reading	23.5	18.7	14.9	17.8	14.3	19.4	14.0	19.2
Third Party Support [2]	13.6	13.2	12.2	14.1	12.5	14.0	12.9	14.6
Field Support	4.9	12.0	7.1	14.0	7.3	10.0	7.5	8.1
Regulatory Compliance (LEAP)	2.2	4.2	2.1	4.1	2.2	4.3	2.3	4.3
Net Bad Debt	66.8	29.5	15.5	6.8	15.4	21.1	14.4	21.1
Customer Care Staffing [3]	18.9	21.5	21.3	20.5	20.4	20.1	20.6	19.8
Total Customer Care OM&A [4]	**209.3**	**155.4**	**111.6**	**118.8**	**110.9**	**132.6**	**111.6**	**131.6**

[1] Previously referred to as "Customer Service Operations", "Customer Operations" and "Settlements".
[2] Previously referred to as "Service Support" and "Service Enhancements".
[3] Previously referred to "Customer Service Management", "Customer Business Relations", "Customer Care Management", "Customer Experience", and "Conservation and Demand Management".
[4] Costs associated with the Smart Grid Pilot are now included in the Exhibit C1, Tab 1, Schedule 4 (Operations OM&A) Exhibit.

TAB 9/

Consumers Council of Canada Interrogatory # 75

Issue:

Issue 55: Are the proposed line losses over the 2018 – 2022 period appropriate?

Reference:

F1-03-01 Page 4

Interrogatory:

HON is proposing to establish a Lost Revenue Adjustment Mechanism Variance Account. Please describe how this account will operate. For 2018 what is the proposed Board-approved CDM adjustment? How was that amount derived?

Response:

Per the Board's Filing Requirements for Electricity Distribution Rate Applications, Chapter 2, Section 3.2.6 the OEB has established Account 1568 as the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) to capture the variance between the OEB-approved Conservation and Demand Management (CDM) forecast and the actual results at the customer rate class level. Distributors are expected to compare the OEB-approved CDM adjustment to the load forecast with the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

Hydro One's proposed CDM target program savings included in the 2018 load forecast is 842.6 GWH which is based on the OEB's Appendix 2-I, Load Forecast CDM Adjustment Work Form, as shown below and provided in Exhibit E1, Tab 2, Schedule 1, Attachment 2.

The forecast CDM adjustment accounts only for the 2015-2018 target programs but not the persistent savings of historical EE programs and C&S.

6 Year (2015-2020) kWh Target:						
Implementation yar	2,015	2,016	2,017	2,018	2,019	2,020
2,015	193,170,000	193,170,000	193,170,000	193,170,000	193,170,000	193,170,000
2,016		193,170,000	193,170,000	193,170,000	193,170,000	193,170,000
2,017			193,170,000	193,170,000	193,170,000	193,170,000
2,018				193,170,000	193,170,000	193,170,000
2,019					193,170,000	193,170,000
2,020						193,170,000
Total in Year	**335,528,398**	**528,017,133**	**683,208,870**	**842,605,433**	**1,001,184,662**	**1,159,020,000**

TAB 10

UNDERTAKING – JT 3.18-4

Topic: LRAMVA Threshold

Reference

55-CCC-75

46-Staff-233

Preamble:

In response to 55-CCC-75 HON confirmed it was establishing an LRAM Variance Account.

Staff-233, Table 3 sets out Hydro One's proposed LRAMVA thresholds (i.e., CDM amounts assumed in the load forecast)

Undertaking

a) Please confirm that Hydro One will be seeking recovery of:
   i. Lost revenues in 2018 from programs implemented in 2015-2018.
   ii. Lost revenue in 2019 from programs implemented in 2015-2019, and
   iii. Lost revenues in 2020 from programs implemented in 2015-2020?

   If not, please clarify Hydro One's proposals for lost revenue recovery.

b) Are the CDM savings values set out in CCC-75, Table 3 annualized values (i.e., assuming all CDM programs are implemented January 1st) or do the values represent the expected forecast savings in each year?

c) Are the values set out in CCC-75, Table 3 the base CDM savings against which Hydro One plans to calculate the LRAMVA amounts?
   i. If yes and the values are not "annualized" please provide the annualized equivalents.
   ii. If no, please provide Hydro One's proposed "annualized" LRAMVA thresholds for each year for which it will be seeking a lost revenue recovery.

d) Since the load forecast model is based on actual data up to 2016 and actual CDM savings are reported by the IESO up to 2016, why aren't the 2015 and 2016 implementation year values in Table 3 based on the actual verified Hydro One savings for 2015 and 2016?

e) Since the load forecast model is based on actual data up to 2016 and actual CDM savings are reported by the IESO up to 2016, why is it necessary to seek recovery for lost revenue from programs implemented in 2015 and 2016?

f) For the program years 2017-2020, why use the values in CCC-75 as opposed to those set out in HON's approved CDM plan – provided in response to OSEA #6?

g) Since the LRAM calculations are class specific – please provide a breakdown of the proposed LRMVA kWh threshold for each year (2018-2020) by customer class and indicate how the values were derived.

h) Staff-233 makes reference (page 2, line 14) to an attached MS Excel file. However, there does not appear to be a corresponding attachment on the OEB web-site. Please provide.

Response

a) No. Hydro One will be seeking recovery of:
   i. lost revenues due to the incremental savings in 2018 from programs implemented in 2017-2018;
   ii. lost revenues due to the incremental savings in 2019 from programs implemented in 2017-2019; and
   iii. lost revenues due to the incremental savings in 2020 from programs implemented in 2017-2020.

b) The CDM saving values set out in Exhibit I-55-CCC-75 are the annualized forecast savings in each year.

c) Yes.
   i. The values are forecasted annualized savings due to EE programs.
   ii. Not applicable.

d) Hydro One incorporates cumulative CDM impacts (including EE and C&S) in the load forecast based on the OPO information. The 2015 and 2016 actual CDM savings from the EE target programs are implicitly included in the *total* CDM assumption. When the load forecast for this Application was prepared, Hydro One did not have the 2016 verified result report and 2011-2015 persistence report from the IESO. As such, Hydro One applied Hydro One's share of the OPO EE savings for the forecast years (2017-2022).

e) Hydro One will be only seeking recovery for lost revenue due to incremental savings from programs implemented in 2017 and beyond, as indicated in the response to part a).

f) Hydro One applied its share of Ontario energy savings based on the OPO information for 2017-2022. The proposed CDM programs in the CDM plan can be updated by LDCs as often as needed to reflect actual program performance. In addition, the expected energy savings are very close to the target of 1,159 GWh by the end of 2020. Therefore, Hydro One simply used the target CDM assumptions per the OPO in preparing its load forecast.

g) The proposed 2018-2020 LRAMVA threshold by rate class is as follows:

Implementation Year	Service - Demand Billed	General Service - Energy Billed	Residential - Medium Density	Residential - Low Density	Seasonal	transmission Direct customers	General Service - Demand	General Service - Energy Billed	Urban Residential
	kW	KWH	KWH	KWH	KWH	KW	KW	KWH	KWH
2018	6,497	87,066,805	56,144,302	53,234,536	7,115,397	47,520	1,002	23,296,048	22,291,454
2019	14,410	130,006,286	84,798,946	79,316,486	10,537,861	64,340	3,953	34,902,484	33,525,240
2020	17,850	172,532,973	113,839,336	105,044,163	13,870,876	77,381	5,449	46,478,919	44,817,001

The threshold is the incremental savings in 2018-2020 compared to the savings in 2016. For the energy billed customers, the share of CDM savings by rate class was applied to the incremental six year target program CDM savings in 2018-2020 vs 2016. For the demand billed customers, the share of six year target program savings of total EE savings was applied to peak savings.

h) Please see MS Excel attachment to this reponse, which is based on OEB's template. The threshold and CDM adjustment savings for 2018 calculated in the attached file are different from the number Hydro One used in its load forecast and represent a different methodology for incorporating CDM into the load forecast.

TAB 11

UNDERTAKING – JT 1.17-3

Reference

Exhibit I, Tab 44, Schedule CME-36

The evidence indicates that there is a $21.9 million difference in the depreciation expense in 2018 between using the existing depreciation rates and changing to the 2016 Foster Associates study. Part (c) of the question asked if this would result in rate base being more than $100 million higher by the end of 2022 under the Hydro One proposal to continue to use the existing rates rather than those recommended in the Foster Associates study. The response indicates that this would not be the case.

Undertaking

a) Is this response based on the $21.9 million figure in the evidence, or was it based on the updated information as provided in the response to part (a) of the response, which is based on the Exhibit Q updates?

b) If the response is based on the original evidence, please explain why rate base would not be more than $100 million higher at the end of 2022, given the lower depreciation of $21.9 million in 2018, and comparable reductions in 2019 through 2022.

c) If the response is based on the Exhibit Q updates, what is the approximate increase in rate base at the end of 2022?

Response

a) The response provided in Exhibit I, Tab 44, Schedule CME-36 was based upon the Exhibit Q updated information.

b) Not applicable.

c) The impact on rate base of maintaining the current depreciation rates is $81 million by the end of 2022.

Canadian Manufacturers & Exporters Interrogatory # 36

Issue:
Issue 44: Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

Reference:
C1-06-01 Updated

Interrogatory:
a) Please provide a table that shows for each of 2018 through 2019 the total depreciation and amortization expense based on Hydro One's historically approved depreciation rates and based on the 2016 Foster Associates study, along with the difference for each year.

b) What is the change in the revenue requirement impact on the 2018 test year of using the depreciation rates based on the 2016 Foster Associates study as compared to using the current approved rates?

c) Based on the $21.9 million difference noted on page 1, will Hydro One's rate base at the end of 2022 be more than $100 million higher under the proposal to retain the existing depreciation rates as compared to changing to the rates from the 2016 Foster Associates study beginning in 2018

Response:
a) The table below provides a comparison for depreciation expense as per Exhibit Q between currently proposed depreciation rates and 2016 Foster Associates updated study rates:

Description	**Test**	
	2018	**2019**
Total Depreciation Expenses	383.9	406.4
Total Amortization Expenses	17.3	16.2
Exclude Other Regulatory Amortization	4.2	4.5
Total	**397.1**	**418.2**
Update for 2016 study - Dx specific and Common rat	13.1	16.2
New Depreciation total	**410.2**	**434.4**

b) Based on a comparison to Exhibit Q, the impact to revenue requirement in 2018 is $17.4M.

c) Hydro One’s rate base will not be more than $100 million higher under the current proposal to retain the existing rates as compared to changing to the rates from the 2016 Foster Associates study beginning in 2018.

Canadian Manufacturers & Exporters Interrogatory # 37

Issue:
Issue 44: Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

Reference:
C1-06-01 Updated
A-03-02

Interrogatory:
a) What is the impact on the total revenue requirement in each of 2019 through 2022 of using the 2016 Foster Associates study depreciation rates in place of the current approved rates?

b) Please provide a version of Table 1 from Exhibit A, Tab 3, Schedule 2 that shows the impact on the calculation of the capital factor if Hydro One used the depreciation rates from the 2016 Foster Associates study.

Response:
a) The impact on the total revenue requirement is provided below based on Exhibit Q update:

	2018	2019	2020	2021	2022
Total Capital Related Revenue Requirement	17.4	20.4	22.3	24.1	27.9

b) Summary of Revenue Requirement Components is provided below based on Exhibit Q update and the depreciation rates from the 2016 Foster Associates study.

	Reference	2018	2019	2020	2021	2022
Rate Base	D1-1-1					
Return on Debt	E1-1-1	198.9	207.9	217.9	231.0	239.9
Return on Equity	E1-1-1	275.8	288.2	302.1	320.3	332.7
Depreciation	C1-6-2	410.2	434.4	451.6	473.0	490.9
Income Taxes	C1-7-2	70.0	74.5	77.7	85.7	87.5
Capital Related Revenue Requirement		954.9	1,005.0	1,049.3	1,110.0	1,151.0
Less Productivity Factor (0.45%)			(4.5)	(4.7)	(5.0)	(5.2)
Total Capital Related Revenue Requirement		**954.9**	**1,000.5**	**1,044.6**	**1,105.0**	**1,145.8**
OM&A	C1-1-1	579.6	584.0	588.3	592.8	608.0
Integration of Acquired Utilities	A-7-1				10.7	
Total Revenue Requirement		**1,534.5**	**1,584.5**	**1,632.9**	**1,708.5**	**1,753.8**
Increase in Capital Related Revenue Requirement			45.6	44.1	60.4	40.8
Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.97%	2.78%	3.70%	2.39%
Less Capital Related Revenue Requirement in I-X			0.47%	0.47%	0.48%	0.49%
Capital Factor			**2.51%**	**2.31%**	**3.22%**	**1.90%**

TAB 12

2016 Depreciation Rate Review

hydro one

— *Distribution Operations*
— *Common Operations*

foster associates

foster associates

Ronald E. White, Ph.D.
President

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December 15, 2016

Mr. Arthur McGlashan
Manager, Corporate Accounting
HYDRO ONE NETWORKS INC.
483 Bay Street, T48
Toronto, Ontario MSG 2P5

RE: 2016 Depreciation Rate Review

Dear Mr. McGlashan:

Foster Associates is pleased to submit our report of the 2016 Depreciation Rate Review for Hydro One Networks Inc. (Hydro One Networks). The attached report presents the results of our review leading to a recommendation to adopt straight–line, vintage–group, remaining–life rates and record depreciation expense for BU 220 (Distribution) and BU 300 Common) facilities.

The following table provides a comparison of current and recommended depreciation rates and annualized accruals for calendar year 2016, based upon plant investments and deprecation reserves at December 31, 2015.

Function	Accrual Rates			2016 Annualized Accrual		
	Current	Recommended	Difference	Current	Recommended	Difference
A	B	C	D=C-B	E	F	G=F-E
BU 220						
Intangible	9.16%	9.16%	0.00%	$ 18,914,882	$ 18,914,882	$ -
Generation	-11.69%	-6.60%	5.09%	(82,565)	(46,603)	35,962
Distribution	2.27%	2.31%	0.04%	203,124,592	206,335,725	3,211,133
General	6.04%	6.22%	0.18%	23,209,879	23,894,092	684,213
Total BU 220	2.57%	2.61%	0.04%	$245,166,788	$249,098,096	$ 3,931,308
BU 300						
Intangible	9.47%	9.47%	0.00%	$ 38,214,409	$ 38,214,409	$ -
General	5.56%	9.29%	3.73%	24,021,413	40,131,254	16,109,841
Total BU 300	7.45%	9.38%	1.93%	$ 62,235,822	$ 78,345,663	$16,109,841
Total				$307,402,610	$327,443,759	$20,041,149

A continued application of currently approved rates for BU 220 would provide annual depreciation expense of $245,166,788 compared with an annual expense of $249,098,096 using the rates recommended in the study. The resulting change in depreciation rates produces an annualized 2016 expense increase of $3,931,308. Current rates for BU 300 would provide annual depreciation expense of $62,235,822 compared with a recommended annual expense of $78,345,663, or an increase of $16,109,841.

It is the opinion of Foster Associates, however, that Hydro One Networks could elect to adjust any or all of the recommended accrual rates without violating the dual objective of depreciation accounting, *i.e.*, cost allocation over economic life in proportion to the consumption of service potential. The service potential of an asset (or group of assets) is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone. Depreciation *expense* is the difference between the present value of future net revenue at the beginning and end of an accounting interval.

The dual accounting objective is implicitly achieved under regulation as a consequence of the ratemaking process in which the amount of revenue a utility is authorized to collect is determined from a revenue requirement equation that includes depreciation expense as one of the elements of recoverable cost. Assuming revenue sufficient to cover cash operating expenses and a fair rate of return, the change in the present value of future net revenue will be equal to the depreciation expense allowed by regulation. It is because of regulation that the dual accounting objective will be achieved regardless of the timing of depreciation expense.

The scope of our investigation included:

- Collection of plant and reserve data;
- Reconciliation of assembled database to Company records;
- Discussions with Hydro One Networks plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

The results of our investigation are presented in the attached report in four sections. The Executive Summary provides an overview of the review and a discussion of the principal findings. The Study Procedure section describes the steps undertaken in conducting a depreciation review and the specific procedures used in this engagement. The Statements section provides a comparative summary of current and recommended depreciation parameters, rates and accruals. The report concludes with an Analysis section that includes an example of supporting schedules prepared in conducting the review.

We wish to express our appreciation for this opportunity to be of service to Hydro One Networks and for the assistance provided to us. We would be pleased to discuss our report and review with you or others at your convenience.

Respectfully submitted,
FOSTER ASSOCIATES CONSULTANTS, LLC
by

Ronald E. White, Ph.D.
President

REW:ml

The Society of Energy Professionals Interrogatory # 20

Issue:

Issue 44: Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

Reference:

C1-06-01 Page: 2

Networks states in its depreciation evidence (reference Exhibit C1 Tab 6 Schedule 1 page 2) that "the 2016 Foster Associates study would create, if implemented, increased depreciation rates and expense over the 2018 to 2022 rate setting period. Planned capital expenditures over the five-year term of the Application however may result in an increase in the average remaining life of these asset pools, requiring a future decrease in depreciation rates and expense."

Networks appears to base its proposal not to adopt the 2016 depreciation recommendation of its independent external consultant on adverse rate impact and on a hope that future capital expenditures might offset the impact of deprecation rate changes recommended by Foster and Associates based on its observations.

Interrogatory:

a) Please explain in more detail why the Board should not require Networks to adopt Foster and Associates' recommended depreciation rates when Foster Associates is an independent technical expert and ratepayers effectively fund the cost of their work.

b) Foster and Associates' states its theoretical basis for Networks' having a choice on whether to propose adoption of any or all its recommendations (in its transmittal memo found at C1-6-1 Attachment 1). Foster and Associates seems to make a case that depreciation expense is based on the consumption of asset service potential and that consumption rate is measured by changes in the net present value of future net revenues (cash flows). Has Networks previously applied this conceptual approach to measuring the consumption of service potential of its assets? Please provide any available documentary evidence or precedents.

c) Please explain the specific technical, asset service life experience or accounting factors driving the material differences between Networks' current depreciation parameters and those initially recommended by Foster and Associates with particular attention to the significant impacts that appear to result from the changes attributable to BU 300.

d) Networks uses the term "may" when discussing the potentially offsetting impact of its future capital investments on deprecation rates. Please describe the assurance that Networks has that Foster and Associates' currently observed depreciation rate adjustments will be exactly offset by new capital investments in specific asset pools in the rate period?

e) Is this potential future offset expected to impact each year of the rate setting period exactly equally?

f) Has Networks produced any financial models illustrating this potential future offset? If so, please provide them and attach any relevant assumptions or caveats.

g) Is Networks aware of any regulatory precedents where an independent depreciation study recommending a material adjustment to depreciation expense has not been implemented based on an expectation of possible future reversals or offsets within the rate setting period? If so, please provide any such precedents.

h) Is the acceptance of this position by Networks' independent external auditor based on an expectation that the existing rates will be approved by the OEB? More specifically, is the auditor's concurrence predicated on an expectation of OEB approval giving rise to a regulatory accounting exception to US GAAP requirements as they would apply to an unregulated entity?

Response:

a) As per the Transmittal Letter from Foster Associates, Hydro One could elect to adjust any or all of the proposed rates in the Depreciation Study and not violate the objective of depreciation accounting, which is to allocate the economic life of the asset in proportion to the potential consumption of the asset. Accrual rates recommended in the 2016 Depreciation Rate Review were designed to achieve goals and objectives of depreciation accounting. Deferring on adoption of the recommended rates will do little more than shift the timing of capital recovery.

b) Networks has "preciously applied this conceptual approach" by virtue of being a rate–regulated entity. As Dr. White noted in his transmittal memo, "The dual accounting objective is implicitly achieved under regulation as a consequence of the ratemaking process in which the amount of revenue a utility is authorized to collect is determined from a revenue requirement equation that includes depreciation expense as one of the elements of recoverable cost. Assuming revenue sufficient to cover cash operating expenses and a fair rate of return, the change in the present value of future net revenue will be equal to the depreciation expense allowed by regulation. It is because of regulation that the dual accounting objective will be achieved regardless of the timing of depreciation expense."

c) It was noted in the 2016 Depreciation Rate Review, page 10, that "… category lives recommended and approved in the 2013 review were retained in the 2016 review." Accordingly, recommended adjustments to accrual rates were not driven by technical or asset service life experience. The change in accruals for BU 300 is mostly attributable to to large capital expendutures in 2015 and an appropriate rebalancing of reserves. Rebalancing was undertaken to: a) eliminate a negative reserve for Account 1980 (System Supervisory Equipment); and b) to properly realign reserves for amortizable categories. These two factors resulted in a change in the accrual for Account 1955 (Communication Equipment) from negative $9.4 milion to positive $2.0 million, or an increase of $11.4 million.

d) Hydro One does not have assurance that currents rates will be exactly offset by future capital spend, however if the OEB finds that the revenue requirement impact of higher depreciation expense is warranted and not overly burdensome to customers, Networks is prepared to implement higher depreciation rates for BU300.

e) See above response to part d.

f) No.

g) See above response to part d.

h) The setting of depreciation rates are the responsibility of management, and Networks determines them in conjuction with recommendations from Foster Associates depreciation study. The external auditor bases their audit opinion on the financial statements as a whole, to ensure they are not materially misstated and not on specific estimation decisions. In relation to depreciation expense, external auditors will assess to determine if the asset, in this case property, plant and equipment is recoverable over a period not to exceed their useful lives. The transmittal letter issued by Foster and Associates provides an expert opinion that coronborates management's estimate that the revised depreciation rates not be adopted.

TAB 13

Vulnerable Energy Consumers Coalition Interrogatory # 36

Issue:

Issue 37: Is the forecast of long term debt for 2018 and further years appropriate?

Reference:

D1-02-02 Page: 5

Interrogatory:

a) Please update Tables 4 to show the actual (2017) and updated forecast (2018) yield and spreads.

Response:

a) Please see the table below as requested.

Table 4 summarizes the updated forecast of Hydro One Inc. yield for each of the planned issuance terms for 2018. Hydro One did not issue any long term debt in 2017, thus the yield is not applicable.

Table 4: Forecast Yield for 2017-2018 Issuance Terms (updated)

	2017			**2018**		
	5-year	**10-year**	**30-year**	**5-year**	**10-year**	**30-year**
Government of Canada	n/a	n/a	n/a	2.10%	2.40%	2.76%
Hydro One Spread	n/a	n/a	n/a	0.72%	0.98%	1.42%
Forecast Hydro One Yield	n/a	n/a	n/a	2.82%	3.38%	4.18%

The following information relating to a portion of long term debt to be issued by Hydro One Inc. is provided for regulatory planning purposes only and not intended be relied upon for any purpose other than for analysis in the Ontario Energy Board Proceeding EB-2017-0049 concerning Hydro One Networks Inc.'s application for distribution rates approval. This response includes forward-looking information and is based on a variety of factors and assumptions. Actual principal amounts of debt, the term of the debt, or the related coupon may differ from what is expressed herein.

TAB 14

Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook
for
Utility Rate Applications

October 13, 2016

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

- Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete.

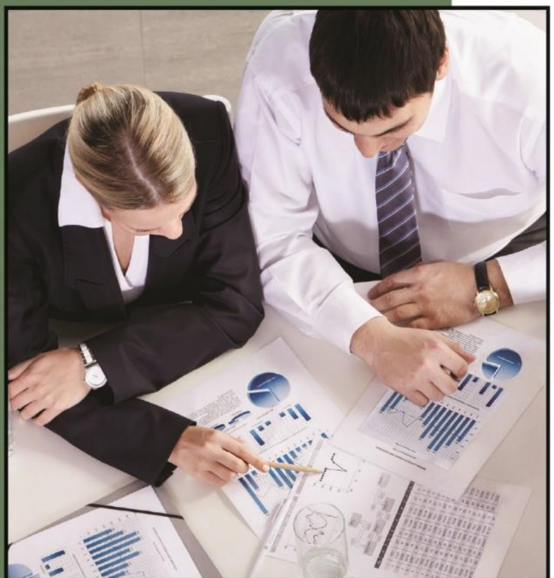
- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to

TAB 8

Power System Engineering, Inc.
Full-service consultants



Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry

Prepared by:

Power System Engineering, Inc.

November 4, 2016

inconvenience (e.g., re-setting clocks), to life-threatening situations where electricity is needed to run medical equipment.

CAIDI measures the economic costs to customers that occur subsequent to the immediate costs. CAIDI costs grow as the outage gets longer. For example, for businesses, loss of manufacturing production, customers leaving the building, spoiled products, and spoiled food all increase as the duration of an electricity outage lengthens.

To incorporate Hydro One's SAIFI and CAIDI performance into the reliability adjustments, we needed to develop weights for each one. However, assigning a specific dollar amount to customer interruption costs is a challenging task. To PSE's knowledge, a direct study from Hydro One has not been conducted to quantify interruption costs.

To estimate the SAIFI and CAIDI costs and weights, PSE used interruption estimates from a publically-available paper published in June 2009 by the Ernest Orlando Lawrence Berkeley National Laboratory and prepared for the U.S. Department of Energy. The title of the paper is *Estimated Value of Service Reliability for Electric Utility Customers in the United States*.

PSE used the following table found in the Executive Summary of the LBNL report (page xxvi). The table reveals the estimated customer interruption costs (in U.S. 2008$) for various rate classes for outages with varying interruption duration times.

Table 12 LBNL Interruption Costs

Table ES- 5. Estimated Average Electric Customer Interruption Costs US 2008$ Anytime By Duration and Customer Type

	Interruption Duration				
Interruption Cost	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

PSE examined Hydro One's RRR data in 2008 to determine the number of residential, small C&I, and Medium and Large C&I customers that correspond with the preceding table. To determine the SAIFI-related interruption costs per outage in 2008, we used the "Momentary" cost per event estimate for each rate class. To determine the CAIDI-related interruption costs per outage in 2008, we took the "1 hour" cost per event for each rate class and then subtracted out the momentary costs. For all of the estimates we also translated the U.S. dollar figure into Canadian dollars using the 2008 Canadian Purchasing Price Parity (PPP) ratio. We then multiplied by the number of customers in that rate class and by the SAIFI to ascertain the SAIFI-related costs.

For the CAIDI-related costs, we multiplied by the number of customers in each rate class and by the CAIDI value. This gives us an estimate of the cost for each outage at the average duration. We then multiplied that value by the average number of outages (i.e., the SAIFI value) to give us the total CAIDI-related costs for each rate class.

The equation to determine the 2008 SAIFI-related customer interruption costs is:

$$SAIFI\ Costs_j = Momentary\ Costs_j * PPP * Customers_j * SAIFI$$

The equation to determine the 2008 CAIDI-related customer interruption costs is:

$$CAIDI\ Costs_j = \left(1\ Hour\ Costs_j - Momentary\ Costs_j\right) * PPP * Customers_j * CAIDI * SAIFI$$

The table below provides the SAIFI-related costs by rate class and the total estimated interruption costs related to SAIFI.

Table 13 SAIFI Costs

Rate Class	Momentary Interruption Costs (US$ 2008)	2008 PPP	Number of Hydro One Customers in 2008	2008 SAIFI (no MEDs, no power supply)	Total SAIFI Customer Interruption Costs (US$ 2008)
Residential	2.10	1.23	1,077,500	3.01	$8,377,379
Small C&I	293	1.23	109,722	3.01	$119,023,562
Medium & Large C&I	6,558	1.23	31	3.01	$752,670
Sum of All Classes					**$128,153,611**

The table below provides the CAIDI-related costs by rate class and the total estimated interruption costs related to CAIDI.

Table 14 CAIDI Costs

Rate Class	1 hour - Momentary Interruption Costs (US$ 2008)	2008 PPP	Number of Hydro One Customers in 2008	2008 CAIDI (no MEDs, no power supply)	2008 SAIFI (no MEDs, no power supply)	Total CAIDI Customer Interruption Costs (US$ 2008)
Residential	1.20	1.23	1,077,500	2.69	3.01	$12,877,228
Small C&I	326	1.23	109,722	2.69	3.01	$356,233,864
Medium & Large C&I	5,929	1.23	31	2.69	3.01	$1,830,489
Sum of All Classes						**$370,941,582**

The total SAIFI and CAIDI costs are weighted based on their proportion to Hydro One's distribution total costs in 2008 calculated in the TFP study. The 2008 weights are applied for all years of the study. This leads to the following weights for each reliability component:

Table 15 Reliability Weights

Reliability Performance Component	Weight
SAIFI	9.9%
CAIDI	28.6%

There are a number of assumptions embedded in the calculation of the weights. One key assumption is that the system-wide SAIFI and CAIDI metrics are applicable to each of the rate classes. That is to say, all customers experience the same reliability levels. A second assumption is that Hydro One customers are similar to the U.S. customers that formulate the interruption costs in the 2009 LBNL reliability study (i.e. the 2009 study adequately reflects the true interruption costs of Hydro One customers). Another assumption is that interruption costs have not changed since the 2009 LBNL study. Given these and other uncertainties with determining the value of service (VOS), PSE views these weights as a "first approximation" proposal. We are certainly open to suggestions on how to best formulate the weights when making these reliability adjustments.