**EB-2017-0049**

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

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**VECC COMPENDIUM**

**PANEL 1**

**JUNE 11, 2018**

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# 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
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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

The Custom Revenue Cap Index (RCI) is expressed as:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor, as determined annually by the OEB.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

Although Hydro One is seeking the Board's approval for a Revenue Cap IR and Revenue Cap Index, the overall approach is consistent with the RRF and is similar to the custom Price Cap IR and Price Cap Index methodology approved by the Board in EB-2014-0016, for Toronto Hydro-Electric System Limited.

The proposed Revenue Cap IR has a number of advantages versus a Price Cap IR. The Revenue Cap IR:

- Gives Hydro One the needed flexibility to introduce new rate classes in 2021 to fully integrate Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc. ("Norfolk", "Haldimand", and "Woodstock", together the "Acquired Utilities"), as described in Exhibit A, Tab 7, Schedule 1;
- Permits the continued transition to fully-fixed rates for residential customers (EB-2014-0416);
- Provides adequate flexibility to reset customer rates should the OEB proceed with the elimination of the Seasonal Rate Class over the 2018 to 2022 Custom IR term (EB-2013-0416/EB-2016-0315);
- Provides adequate flexibility to reset customer rates as the OEB advances its initiative relating to rate design for Commercial and Industrial electricity customers (EB-2015-0043); and

- Allows Hydro One to update its billing determinants to reflect estimated changes in the load forecast over the Custom IR term, consistent with its proposal to integrate the Acquired Utilities.

## 1.1 INFLATION FACTOR

In its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379), the OEB established a methodology for determining the annual Inflation Factor ("I") to be used in incentive-based rate adjustment mechanisms. The Inflation Factor is based on the weighted sum of:

- 70% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 30% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

Although specifically created for use for incentive rate setting under the Price Cap IR and Annual Index plans, Hydro One proposes to use the same Inflation Factor in its custom Revenue Cap IR and Revenue Cap Index, and to update the Inflation Factor annually for 2019 through 2022, consistent with current Board practice.

The latest Inflation Factor of 1.9% was released by the Board on October 27, 2016 for use in applications for rates effective in 2017. Hydro One has used the 2017 Inflation Factor on a pro-forma basis in its RCI calculation for each of the 2019 to 2022 test years, for the purpose of this Application. The Inflation Factor will be updated annually; when the OEB calculates and makes available the Inflation Factor in each of 2018 to 2021, effective 2019 to 2022, respectively.

# ***Canadian Manufacturers & Exporters Interrogatory # 1***

## ***Issue:***

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

## ***Reference:***

A-03-02 Updated

## ***Interrogatory:***

a) For the 5 bullet points shown on pages 2 & 3, please explain how Hydro One would address each of the points if the OEB were to approve a price cap plan rather than the proposed revenue cap plan.

b) Please explain how the need to update the cost of capital parameters in 2021 to reflect estimated changes in the industry and load forecast over the term are related to the proposal to integrate the Acquired Utilities.

c) Please provide a detailed list and description for each mid-term review component that is being proposed by Hydro One.

## ***Response:***

a) See Hydro One's response to Exhibit I-7-VECC-3. Under Price Cap IR, the integration of the acquired utilities in to Hydro One's rate structure would be significantly complicated by the inability to update the billing determinants underpinning current rates.

b) The acquired utilities last rebased in 2011 (Woodstock), 2012 (Norfolk) and 2014 (Haldimand). Their integration in to Hydro One's rate structure marks the first time that the cost of capital for their assets has been updated since acquisition. The update of the cost of capital parameters ensures that their costs are appropriately reflected and allocated when they are added to Hydro One's rate base in 2021.

c) See response to Exhibit I-13-CCC-15.

# ***Vulnerable Energy Consumers Coalition Interrogatory # 3***

## ***Issue:***

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

## ***Reference:***

A-03-02 Page: 2

## ***Interrogatory:***

a) Starting at page 2 of the reference are five factors Hydro One claims make a Revenue Cap approach superior to Price Cap rate setting. For each of these factors please explain why Hydro One's proposal is a superior approach. For example, Hydro One claims Revenue Cap provides greater flexibility under which to eliminate rate classes (Seasonal). However, it is not clear why this should be the case. Please explain.

## ***Response:***

a) The proposed Revenue Cap Index is superior to Price Cap rate setting for Hydro One's overall circumstances because it allows for better flexibility and provides greater transparency when integrating the Acquired Utilities in to Hydro One's rate structure.

In keeping the rate setting mechanism at the revenue level, rather than the price level, Hydro One can more easily, and more transparently:

- add the incremental rate base and OM&A associated with the Acquired Utilities to Hydro One's revenue requirement;
- update its billing determinants and load forecast to integrate customers of the Acquired Utilities in to the proposed and existing rate classes, as applicable; and
- complete an updated cost allocation study at the time of integration to ensure fairness in the allocation of costs across all rate classes.

Price Cap IR and Revenue Cap IR are equally capable of continuing the transition to fully-fixed residential rates, eliminating the seasonal class and accommodating changes to the rate design of commercial and industrial electricity customers over the Custom IR term. Hydro One listed these additional items to provide comfort to the OEB and intervenors that the proposed Revenue Cap IR approach would not negatively impact the implementation of these key policy initiatives.

# ***Energy Probe Research Foundation Interrogatory # 6***

## ***Issue:***

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

## ***Reference:***

A-03-01 Page: 6
A-03-02 Page: 2

## ***Interrogatory:***

Hydro One lists a number of advantages of its proposed Revenue Cap IR model over a Price Cap IR Model.

a) Is "a Price Cap IR model" that Hydro One refers to the 4GRIM Price Cap IR model used by other electricity distributors in Ontario?

b) Is this a comprehensive list of advantages? If not what are other advantages?

c) Are there any disadvantages of the proposed Revenue Cap IR model over a Price Cap IR Model?

d) Please file all presentations, reports, memos and e-mails that were given to Hydro One senior management to obtain their approval to use the proposed Revenue Cap IR model in the EB-2017-0049 OEB application.

## ***Response:***

a) A Price Cap IR model is one where the IR mechanism is used to directly adjust distribution rates. The OEB's 4GIRM Price Cap IR model is an example of such an approach.

b) Hydro One is not aware of any other significant advantages of Revenue Cap IR over Price Cap IR. Hydro One believes that a Revenue Cap IR model more appropriately suits its overall circumstances for the reasons described in Exhibit A, Tab 3, Schedule 2 and in response to Exhibit I-7-VECC-3.

c) Hydro One is not aware of any material disadvantages over a Price Cap IR model other than the requirement of a few additional mathematical operations in order to derive rates.

# TAB 10

## 2. THE CUSTOM IR PROPOSAL

Hydro One's Application is based on a Custom Incentive Rate-Setting approach for a five-year period. The revenue requirement for the first year (2018) is determined using a cost of service, forward test year approach. To establish the annual revenue requirements from 2019 to 2022, Hydro One is proposing a Revenue Cap IR, whereby the revenue for the test year t+1 is equal to the revenue in year t adjusted annually by the revenue cap index (RCI).

The custom RCI is expressed as:

$$RCI = I - X + C$$

Where:

- "I" is the inflation factor, as determined annually by the OEB.
- "X" is the productivity factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

A detailed discussion of these components is found in Exhibit A, Tab 3, Schedule 2.

The proposed Revenue Cap IR model has several advantages over a Price Cap IR model. Specifically, the Revenue Cap IR:

- provides the needed flexibility to introduce new rate classes in 2021 to fully integrate Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc. (together the "Acquired Utilities"), as described in Exhibit A, Tab 7, Schedule 1;

- permits the continued transition to fully-fixed rates for residential customers (EB-2014-0416);
- provides adequate flexibility to reset customer rates should the OEB proceed with the elimination of the seasonal rate class over the Term (EB-2013-0416/EB-2016-0315);
- provides adequate flexibility to reset customer rates as the OEB advances its initiative relating to rate design for commercial and industrial electricity customers (EB-2015-0043); and
- allows Hydro One to update its billing determinants and cost of capital parameters in 2021 to reflect estimated changes in the industry and load forecast over the Term, consistent with its proposal to integrate the Acquired Utilities.

A summary of the capital- and OM&A-related revenue requirement components is set out in Table 2.

**Table 2: Summary of Revenue Requirement Components ($ Million)**

| Line | | Reference | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|
| 1 | Rate Base | D1-1-1 | 7,671.6 | 8,049.8 | 8,477.9 | 9,036.5 | 9,436.6 |
| | | | | | | | |
| 2 | Return on Debt | E1-1-1 | 191.6 | 201.1 | 211.8 | 225.7 | 235.7 |
| 3 | Return on Equity | E1-1-1 | 269.4 | 282.7 | 297.7 | 317.4 | 331.4 |
| 4 | Depreciation | C1-6-2 | 392.6 | 413.5 | 428.6 | 448.1 | 463.0 |
| 5 | Income Taxes | C1-7-2 | 61.5 | 64.7 | 66.4 | 72.7 | 72.7 |
| 6 | Capital Related Revenue Requirement | | 915.1 | 962.0 | 1,004.5 | 1,063.9 | 1,102.8 |
| 7 | Less Productivity Factor (0.45%) | | | (4.3) | (4.5) | (4.8) | (5.0) |
| 8 | **Total Capital Related Revenue Requirement** | | **915.1** | **957.7** | **1,000.0** | **1,059.1** | **1,097.8** |
| 9 | OM&A | C1-1-1 | 584.8 | 593.3 | 601.9 | 610.6 | 630.4 |
| 10 | Integration of Acquired Utilities | A-7-1 | | | | 10.7 | |
| 11 | **Total Revenue Requirement** | | **1,499.9** | **1,551.0** | **1,601.9** | **1,680.4** | **1,728.2** |
| | | | | | | | |
| 12 | Increase in Capital Related Revenue Requirement | | | 42.6 | 42.3 | 59.1 | 38.8 |
| 13 | Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement | | | 2.84% | 2.73% | 3.69% | 2.31% |
| 14 | Less Capital Related Revenue Requirement in I-X | | | 0.88% | 0.90% | 0.91% | 0.91% |
| 15 | **Capital Factor** | | | **1.96%** | **1.83%** | **2.78%** | **1.39%** |

Exhibit Reference: A-3-2

To align Hydro One's business interests with those of customers and provide an additional element of protection for customers, Hydro One is also proposing the following features:

In other words, the 1.2% increase in the revenue requirement since the blue page update would result in an additional 1.2% increase to the proposed base distribution rates and associated impacts relative to approved 2017 rates. Given the relatively modest change to the proposed revenue requirement, Hydro One has not updated its bill impact calculations as the differences are not expected to be materially different.

Table 2 expresses the revised revenue requirement calculation over the 2018-2022 period based on the previously proposed Custom Revenue Cap Index as discussed in Exhibit A, Tab 3, Schedule 2.

**Table 2: Summary of Revenue Requirement Components ($ Millions)**

| Line | | Reference | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|
| 1 | Rate Base | D1-1-1 | 7,666.4 | 8,026.9 | 8,430.5 | 8,960.1 | 9,326.5 |
| | | | | | | | |
| 2 | Return on Debt | E1-1-1 | 199.0 | 208.4 | 218.9 | 232.5 | 242.0 |
| 3 | Return on Equity | E1-1-1 | 276.0 | 289.0 | 303.5 | 322.4 | 335.6 |
| 4 | Depreciation | C1-6-2 | 397.1 | 418.2 | 433.1 | 452.1 | 465.9 |
| 5 | Income Taxes | C1-7-2 | 65.4 | 69.0 | 71.5 | 78.9 | 79.5 |
| 6 | Capital Related Revenue Requirement | | 937.5 | 984.5 | 1,026.9 | 1,085.8 | 1,122.9 |
| 7 | Less Productivity Factor (0.45%) | | | (4.4) | (4.6) | (4.9) | (5.1) |
| 8 | **Total Capital Related Revenue Requirement** | | **937.5** | **980.1** | **1,022.3** | **1,080.9** | **1,117.9** |
| 9 | OM&A | C1-1-1 | 579.6 | 584.0 | 588.3 | 592.8 | 608.0 |
| 10 | Integration of Acquired Utilities | A-7-1 | | | | 10.7 | |
| 11 | **Total Revenue Requirement** | | **1,517.1** | **1,564.1** | **1,610.7** | **1,684.4** | **1,725.9** |
| | | | | | | | |
| 12 | Increase in Capital Related Revenue Requirement | | | 42.6 | 42.2 | 58.6 | 36.9 |
| 13 | Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement | | | 2.81% | 2.70% | 3.64% | 2.19% |
| 14 | Less Capital Related Revenue Requirement in I-X | | | 0.46% | 0.47% | 0.48% | 0.48% |
| 15 | **Capital Factor** | | | **2.34%** | **2.23%** | **3.16%** | **1.71%** |

Exhibit Reference: A-3-2

The financially impactful items are described separately below.

each year is reflected in Table 4, together with the revised 2018 OM&A forecasts escalated by the OEB's approved 2018 inflation factor of 1.2%, (less the stretch factor of 0.45%) over the 2019-2022 period.

**Table 4: Summary of Distribution Capital and OM&A Expenditures ($ Millions)**

| | Historical (previous plan and actual) | | | | | | | | | | | Forecast (planned) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 [1] | 2014 [1] | 2015 | | | 2016 | | | 2017 Bridge [2] | | | 2018 | 2019 | 2020 | 2021 | 2022 |
| | Plan | Plan | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | Test | Test | Test | Test | Test |
| CATEGORY | $M | $M | $M | | % | $M | | % | $M | | % | $M | $M | $M | $M | $M |
| System Access | 159.5 | 199.4 | 183.3 | 188.1 | 2.6 | 182.6 | 182.7 | 0.0 | 176.1 | 168.3 | (4.4) | 154.6 | 157.6 | 160.9 | 165.9 | 170.0 |
| System Renewal | 265.7 | 262.7 | 250.7 | 308.4 | 23.0 | 265.4 | 288.3 | 8.6 | 285.0 | 252.2 | (11.5) | 248.6 | 318.7 | 336.7 | 362.5 | 451.1 |
| System Service | 96.5 | 85.5 | 120.1 | 71.6 | (40.4) | 103.3 | 77.4 | (25.1) | 110.1 | 66.6 | (39.5) | 81.8 | 93.4 | 85.6 | 78.8 | 69.5 |
| General Plant | 115.3 | 99.9 | 94.8 | 110.1 | 16.2 | 103.3 | 145.9 | 41.2 | 90.1 | 146.3 | 62.3 | 143.1 | 166.7 | 116.2 | 103.7 | 105.9 |
| Total | 637.0 | 647.5 | 648.9 | 678.3 | 4.5 | 654.7 | 694.2 | 6.0 | 661.4 | 633.5 | (4.2) | 628.1 | 736.4 | 699.3 | 711.0 | 796.5 |
| System OM&A [3] | 610.6 | 674.5 | 543.1 | 572.5 | 5.4 | 589.1 | 562.6 | (4.5) | 593.0 | 572.8 | (3.4) | 579.6 | 584.0 | 588.3 | 603.5 | 608.0 |

*1) 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.*
*2) Bridge year 2017 is a forecast as of end of 2016*
*3) System OM&A values include all Operations, Maintenance and Administration expenses.*

Exhibit Reference: B1-1-1

The decreased capital forecast is the result of (a) reduced pension and OPEB expenses and (b) changes to General Plant (i.e Common Corporate Capital) investments driven by modified productivity targets and project-level changes, as indicated in Table 5 below.

**Table 5: Changes to Capital Forecast**

| **$Millions** | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|
| **Original Forecast** | **633.9** | **756.8** | **719.0** | **740.7** | **827.2** |
| Pension Capital Reduction | (8.2) | (8.9) | (10.6) | (11.9) | (12.5) |
| OPEB Capital Reduction | (1.8) | (1.9) | (2.0) | (2.1) | (2.0) |
| Common Corporate Capital Adjustments / Productivity | 4.2 | (9.5) | (7.0) | (15.7) | (16.2) |
| **Total Capital December Update** | **628.1** | **736.4** | **699.3** | **711.0** | **796.5** |

Since Hydro One filed its Application in March 2017, in addition to the OPEB and pension forecast changes reflected in Table 5, the Common Corporate Capital forecasts have changed as follows.

## VECC EXHIBIT MODIFIED TABLE

### Table 2: MODIFIED - Summary of Revenue Requirement Components ($ Million) And Projected Capital Spending

| Line | | Reference | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|
| 1 | Rate Base | D1-1-1 | 7,666.4 | 8,026.9 | 8,430.5 | 8,960.1 | 9,326.5 |
| 1.a | **Year-to-year Difference in Rate Base** | | | **360.5** | **403.6** | **529.6** | **366.4** |
| 1.b | **Capital Expenditures Q/T1/S1/pg.7** | | **628.1** | **736.40** | **699.3** | **711.0** | **796.50** |
| 2 | Return on Debt | E1-1-1 | 199.0 | 208.4 | 218.9 | 232.5 | 242.0 |
| 3 | Return on Equity | E1-1-1 | 276.0 | 289.0 | 303.5 | 322.4 | 335.6 |
| 4 | Depreciation | C1-6-2 | 397.1 | 418.2 | 433.1 | 452.1 | 465.9 |
| 5 | Income Taxes | C1-7-2 | 65.4 | 69.0 | 71.5 | 78.9 | 79.5 |
| 6 | Capital Related Revenue Requirement | | 937.5 | 984.5 | 1,026.9 | 1,085.8 | 1,122.9 |
| 7 | Less Productivity Factor (0.45%) | | | (4.4) | (4.6) | (4.9) | (5.1) |
| 8 | **Total Capital Related Revenue Requirement** | | **937.5** | **980.1** | **1,022.3** | **1,080.9** | **1,117.9** |
| 9 | OM&A | C1-1-1 | 579.6 | 584.0 | 588.3 | 592.8 | 608.0 |
| 10 | Integration of Acquired Utilities | A-7-1 | | | | 10.7 | |
| 11 | **Total Revenue Requirement** | | **1,517.1** | **1,564.1** | **1,610.7** | **1,684.4** | **1,725.9** |
| | | | | | | | |
| 12 | Increase in Capital Related Revenue Requirement | | | 42.6 | 42.2 | 58.6 | 36.9 |
| 13 | Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement | | | 2.81% | 2.70% | 3.64% | 2.19% |
| 14 | Less Capital Related Revenue Requirement in I-X | | | 0.46% | 0.47% | 0.48% | 0.48% |
| 15 | **Capital Factor** | | | **2.34%** | **2.23%** | **3.16%** | **1.71%** |

# ***School Energy Coalition Interrogatory # 67***

## ***Issue:***

Issue 33: Are the amounts proposed for the rate base from 2018 to 2022 appropriate?

## ***Reference:***

D1-01-01 Tables 1-4

Appendix 2-BA

## ***Interrogatory:***

Please provide an update to the following tables and appendices to reflect 2017 actuals:

a) [D1-1-1] Tables 1-4

b) Appendix 2-BA

## ***Response:***

a) Please see tables 1-4 below based on information presented in Exhibit Q and updated to reflect 2017 actuals:

**Table 1: 2017 Board-approved versus 2017 Historic Year Forecast Rate Base (Updated for 2017 Actuals) ($ Millions)**

| **Rate Base Component** | **2017 Historic Year** | **2017 Board-approved** | **Variance** |
|---|---|---|---|
| Mid-Year Gross Plant | 11,296.7 | 11,239.1 | 57.6 |
| Less: Mid-Year Accumulated Depreciation | (4,250.4) | (4,311.7) | 61.3 |
| **Mid-Year Net Utility Plant** | 7,046.3 | 6,927.4 | 118.9 |
| Cash Working Capital | 310.2 | 255.7 | 54.5 |
| Materials & Supply Inventory | 4.0 | 6.8 | (2.7) |
| **Total Rate Base** | **7,360.5** | **7,189.9** | **170.7** |

Witness: JODOIN Joel

**Table 2: Distribution Rate Base (Updated for 2017 Actuals) ($ Millions)**

| Description | Test | | | | |
|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 |
| Mid-Year Gross Plant | 11,834.3 | 12,413.5 | 13,072.2 | 13,917.1 | 14,595.9 |
| Mid-Year Accumulated Depreciation | (4,468.7) | (4,703.5) | (4,972.4) | (5,317.5) | (5,646.5) |
| **Mid-Year Net Plant** | **7,365.6** | **7,710.0** | **8,099.8** | **8,599.6** | **8,949.4** |
| Cash Working Capital | 321.2 | 335.7 | 348.3 | 378.5 | 395.3 |
| Materials and Supply Inventory | 4.1 | 5.5 | 6.5 | 5.9 | 5.5 |
| **Distribution Rate Base** | **7,690.9** | **8,051.2** | **8,454.5** | **8,984.0** | **9,350.2** |

**Table 3: Continuity of Fixed Assets Summary - Rate Base (Updated for 2017 Actuals) ($ Millions)**

| Description | Historic Years | | | |
|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 |
| Opening Gross Asset Balance | 9,256.2 | 9,832.0 | 10,533.1 | 11,087.3 |
| In-Service Additions | 623.7 | 755.3 | 654.8 | 687.2 |
| Retirements | (38.7) | (36.1) | (87.6) | (127.2) |
| Sales | (10.2) | (18.5) | (15.2) | (24.8) |
| Transfers | 1.0 | 0.4 | 2.1 | 2.6 |
| **Closing Gross Asset Balance** | **9,832.0** | **10,533.1** | **11,087.3** | **11,625.1** |
| Less Future Use Land | (0.3) | (0.3) | (1.3) | (1.3) |
| Less Provincial Funded Assets | (28.4) | (42.9) | (56.3) | (60.1) |
| **Gross Asset Balance for Mid-Year Rate Base** | **9,803.3** | **10,489.9** | **11,029.6** | **11,563.7** |

# TAB 11

# ***Vulnerable Energy Consumers Coalition Interrogatory # 11***

## ***Issue:***

Issue 9: Are the values for the proposed custom capital factor appropriate?

## ***Reference:***

A-03-02

## ***Interrogatory:***

a) What is the theoretical linkage supporting the productivity factor as part of the CCF?

b) What is the relationship between the CCF and customer growth?

c) What is the relationship between the CCF and capital investment related reliability outcomes?

## ***Response:***

a) The reduction of the costs in the CCF by the productivity factor is driven by OEB policy. On page 25 of the OEB's *Handbook for Utility Rate Applications*, the OEB states that "incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast)." This is also consistent with the OEB's findings that the stretch factor should apply to capital costs in the Custom IR proceeding for Toronto Hydro-Electric System Ltd. (EB-2014-0016).

b) See Hydro One's response part (a) of Exhibit I-8-Staff-21.

c) As stated in Exhibit A, Tab 3, Schedule 2, the CCF is designed to ensure that the total revenue resulting from the proposed Custom IR is able to meet Hydro One's proposed capital investments set out in Hydro One's Distribution System Plan (Exhibit B1, Tab 1, Schedule 1). The reliability outcomes that are expected to be achieved by Hydro One's planned capital investments are discussed in Section 2.4 of the Distribution System Plan.

# ***OEB Staff Interrogatory # 21***

## ***Issue:***

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

## ***Reference:***

A-03-02 Page: 1-2 – Revenue Cap Proposal
Hydro One describes its Custom IR proposal as:

> *"Hydro One's application is based on a Custom Incentive Rate-Setting approach for a 5- year period. The methodology utilized is a Revenue Cap IR in which revenue for the test year t+1 is equal to the revenue in year t inflated by the Revenue Cap Index ("RCI") set out below."*

On page 2, Hydro one gives the formula as:

The Custom Revenue Cap Index (RCI) is expressed as:
RCI = I – X + C

Where:

- "I" is the Inflation Factor, as determined annually by the OEB.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

Typically, a revenue cap formula is of the form:

$$Rev_t = Rev_{t-1} \times (1 + (I - X + g))$$

where the I and X are as described above, and g (growth) is based on growth in demand (customers, consumption, energy demand). Revenues are capped by the formula, with rates set to recover the annual revenue requirement updated by this formula.

In Hydro One's proposal, the updated revenue requirement will be converted into rates each year based on the demand forecasted (where forecasted numbers of customers, kWh and kW, as

applicable) are used as the billing determinants for the revenue requirement as allocated between customer classes and between fixed and variable charges.

***Interrogatory:***

a) Growth in operating scale is an important driver of cost growth. What is the rationale for a revenue cap index that does not include a scale escalator?

b) Please confirm that, under Hydro One's proposal, it has an opportunity, under certain conditions, of earning more revenues than the revenue requirement adjusted by the annual RCI. For example, if actual demand (as a combination of number of customers, kWh and kW) exceeds Hydro One's forecasted demand, Hydro One would receive more revenues as it would be the lower forecasted demand which would be the billing determinants for establishing rates in the year. In the alternative, please explain.

c) Why does Hydro One characterize its proposal as a revenue cap, even though it is little different than Toronto Hydro-Electric System Limited's Custom IR approved in EB-2014-0016, which was characterized there as a Price Cap?

***Response:***

a) Under Hydro One's RCI, any additional capital requirements required to serve any load/demand growth would be captured in the formula through the Custom Capital Factor. The expected growth in billing determinants would be captured in rates through the rate design process outlined in Exhibit H1, Tab 1, Schedule 2, wherein billing determinants are updated annually in line with the expectation of the load forecast. As a result of these two factors, Hydro One does not believe that a growth factor is required in the RCI.

b) The potential to over-recover revenue, as described by OEB staff's question, exists in all instances where rates are set based on forecast billing determinants. Likewise there is potential that Hydro One could under earn revenue if the actual number of customers, kWh and kW is lower than forecasted billing determinants. This risk is not driven by Hydro One's proposed RCI but by the fact that actual load will not exactly match the load forecast underpinning rates. A utility that was under a multi-year cost of service rate setting framework would have the same opportunity to over/under earn revenue as a utility subject to an incentive rate-setting structure such as Hydro One's proposed RCI.

c) Hydro One's proposal is appropriately characterized as a Revenue Cap Index (RCI) because the index is used to escalate the prior year's revenue requirement. Toronto Hydro's Custom IR Price Cap Index is used to directly adjust the prior year's base distribution rates.

# TAB 12

# ***Vulnerable Energy Consumers Coalition Interrogatory # 10***

## ***Issue:***

Issue 9: Are the values for the proposed custom capital factor appropriate?

## ***Reference:***

A-03-02

## ***Interrogatory:***

a) Please confirm that the proposed Custom Capital Factor (CCF) is based on the forecast present in Table 1 (page 6). That is, does the capital factor vary over time from the value shown in Table 2?

b) Given that capital expenditures are completely within the control of management (except for emergency repairs) why is it reasonable to calculate the proposed capital factor on a forecast rather than actual basis (i.e. as a trailing adjustment)?

c) If Hydro One used actual capital spending, capped at the forecast expenditures would the CISVA Account be necessary (i.e. would the outcome for rates be similar or the same)?

## ***Response:***

a) The CCF is based on the forecast present in Table 1. As noted in response to Exhibit I-7-VECC-5, Hydro One proposes to update the calculations for the 2021 and 2022 capital factors to reflect updated cost of capital parameters.

b) As noted on page 24 of the OEB's Handbook for Utility Rate Applications, under Custom IR "rates are set for five years considering a five-year **forecast** of the utility's costs". [Emphasis added]

c) As noted in (b) the OEB sets rates on the basis of forecast costs.

# ***Vulnerable Energy Consumers Coalition Interrogatory # 13***

## ***Issue:***

Issue 9: Are the values for the proposed custom capital factor appropriate?

## ***Reference:***

A-03-02

## ***Interrogatory:***

a) The CCF averages to 2% per year over the life of the rate program. Given an objective of rate stability (and if the adjustment is, apparently, to be made on a forecast not actual basis) why would it not be preferable to simply adjust the revenue requirement by the average of 2% per annum for capital additions over the rate program period?

## ***Response:***

a) As stated on page 24 of the OEB's *Handbook for Utility Rate Applications*, rates are set for five years based on a forecast of a utility's costs under the Custom IR method. The value of the proposed CCF is appropriately set based on a detailed five-year forecast of Hydro One's capital requirements.

# TAB 13

# ***Consumers Council of Canada Interrogatory # 14***

## ***Issue:***

Issue 9: Are the values for the proposed custom capital factor appropriate?

## ***Reference:***

A-03-02 Page 10

## ***Interrogatory:***

HON is proposing a Capital In-service Variance Account (CISVA) to track the difference between the revenue requirement associated with the actual in-service capital additions in a test year and the revenue requirement associated with the OEB-approved in-service additions. HON plans to report on this account on an annual basis. Please indicate the level of detail that will be included in the annual report. When will this be filed each year?

## ***Response:***

Exhibit A, Tab 3, Schedule 2, page 10 refers to the revenue requirement impact being computed and reported in the variance account on an annual basis. This refers to the recording of the revenue requirement impact in the variance account. The balance of this variance account will be reported in the annual RRR submitted to the OEB. At the time of disposition of the account, data and calculations will be provided to support the balance reported.

# TAB 14

average of actual and forecasted spending over the three-year ICM period (2012-2014), and (iii) the proposed level of capital spending for each of the five years in the planning horizon.

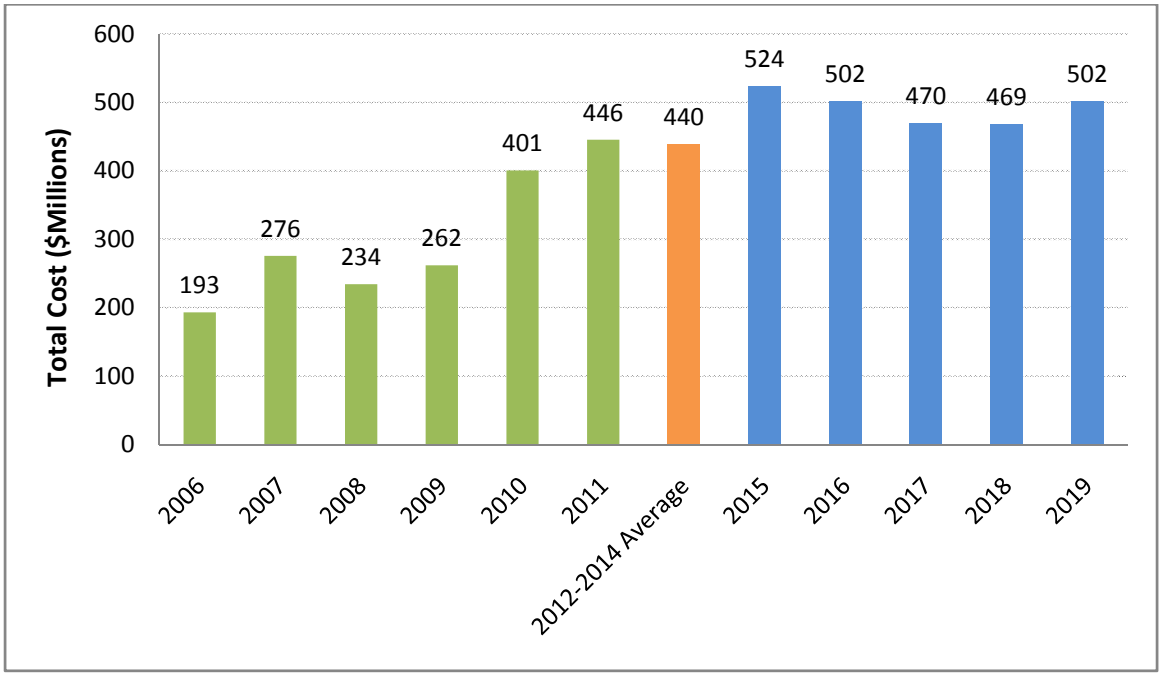


**Figure 1: Historical and Forecast Capital Spending (2006 – 2019) ($Millions)**

As shown above, the average annual level of investment for the proposed capital program is comparable to the level of spending during the utility's 2012-2014 IRM/ICM period. This level of investment is required primarily to address the large and growing backlog of end-of-life and obsolete assets, while also addressing critical system challenges and operational needs at a pace and in a manner that moderates rate increases and is consistent with customer preferences. As demonstrated in the DSP, and as validated in the Navigant Report (Appendix B of this Schedule), this level of spending is the minimum level of investment that is appropriate during the 2015-2019 period given the distribution system's needs. While the optimal level of capital investment exceeds the

# DISTRIBUTION CUSTOMER ENGAGEMENT REPORT

## DEVELOPMENT OF DISTRIBUTION INVESTMENT PLAN

**AUGUST 2016**

This report has been prepared by
Ipsos for Hydro One Networks Inc.
The conclusions drawn and opinions
expressed are those of the authors.

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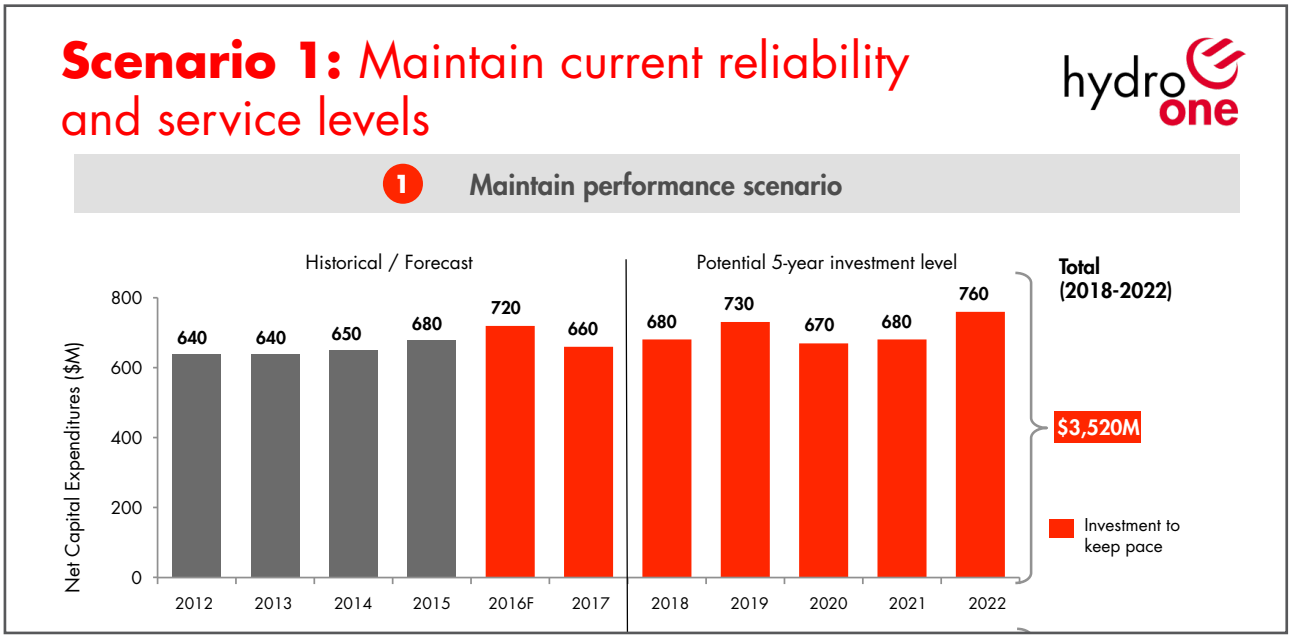


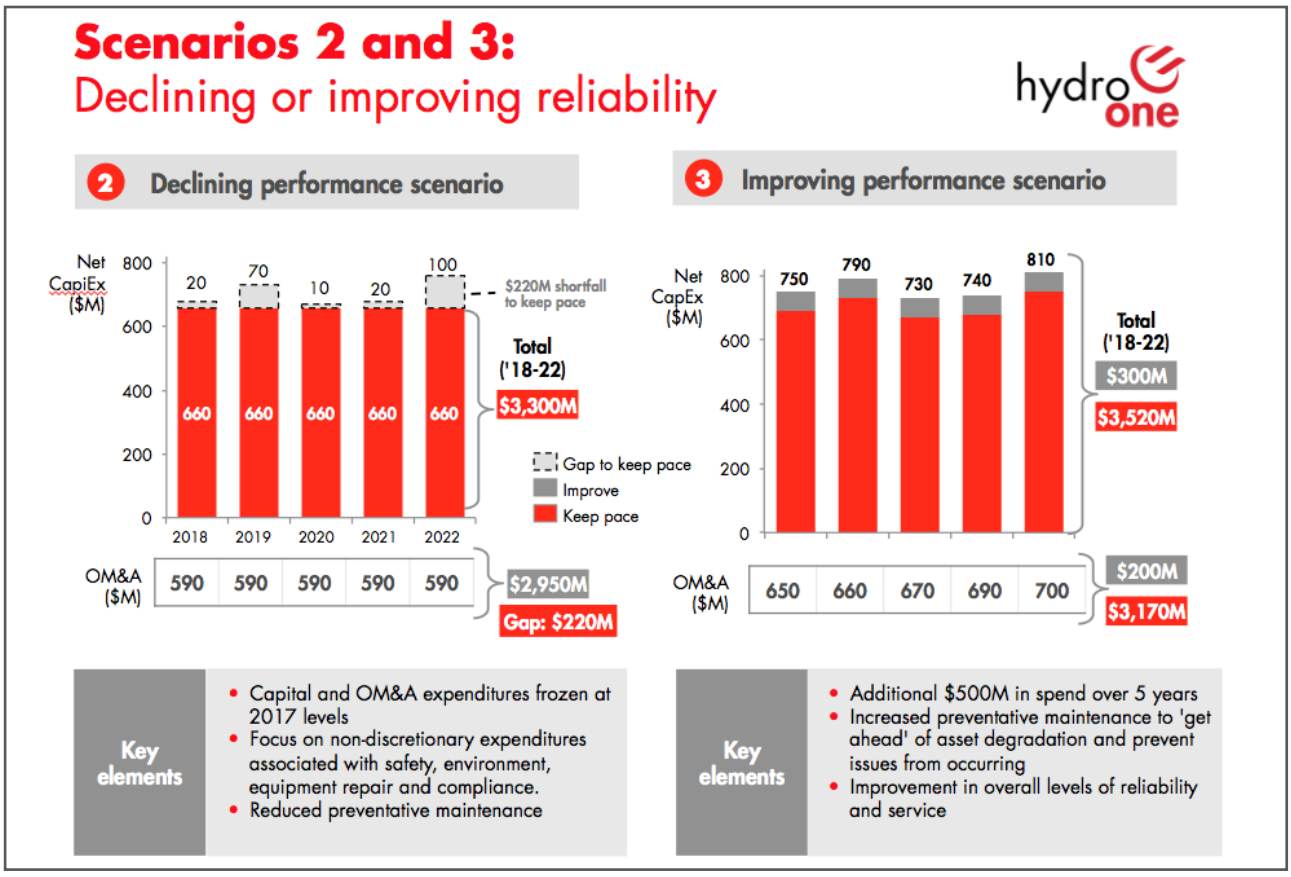


Overall, the majority of Large Customers are not willing to accept any of the rate impacts proposed in the illustrative examples (ranging from 2.5% - 4.0% on the distribution delivery rate). As shown in the chart, the vast majority of customers will not accept a rate increase (2.5% on the distribution rate delivery) where reliability declines. Customers are more likely to accept the larger rate impacts of 3.4% or 4.0% on the distribution delivery rate where reliability is at least maintained or improved. As shown in the qualitative section that follows, customers take issue with the idea that they would be asked to pay more for worse service.