# HYDRO ONE NETWORKS INC.
# 5 Year Custom Distribution Rate Application
# EB-2013-0416

## **Board Staff Submission**

October 7, 2014

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# 1. Introduction

Hydro One Networks Inc. (“Hydro One” or “the Company”) filed an application on December 19, 2013 with the Ontario Energy Board (the “Board”) under section 78 of the Ontario Energy Board Act, S.O. 1998, c.15, Schedule B for an order or orders approving distribution rates for a five year period, commencing January 1, 2015.

Hydro One indicated that the application was submitted under the Board’s *Renewed Regulatory Framework for Electricity Distributors (RRFE)* under the “Custom IR” rate-setting option as Hydro One anticipated the need for multi-year capital investments. Hydro One characterized the application as “Custom Cost of Service”.

Hydro One also submitted that the application reflects Hydro One Distribution’s investment plan to maintain fourth quartile reliability service levels through the test years, while keeping total electricity bill impacts for the average customer below the forecasted 2.0% annual increase in the Consumer Price Index.

The application sought approval for revenue requirements of $1,415 million in 2015, $1,523 million in 2016, $1,578 million in 2017, $1,615 million in 2018 and $1,660 million in 2019. The application included proposals for an entire 5 year rate setting plan which included an annual adjustment mechanism, off-ramp conditions, adjustments outside the normal course of business and annual outcome measurement reporting. Other significant aspects of the application included a number of changes to Hydro One’s existing cost allocation and rate design methodologies and a rate smoothing proposal over the 5 year period. If approved as filed this would result in the following percentage increases in the Distribution portion of the average residential customer bill: -1.4% in 2015, 3.8% in 2016, 2.3% in 2017, 1.2% in 2018 and 2.6% in 2019.

The Board issued a Notice of Application on January 24, 2014. Hydro One updated is pre-filed evidence in this case on January 30, 2014 and provided a further update on May 30, 2014. The Board held a series of three transcribed technical conferences on April 1, 10 and 23 and also held a transcribed session on May 12, 2014 during which Hydro One senior management made a presentation on the application. The Board approved the Issues List for this case on May 20, 2014. Following receipt of Hydro

One's responses to interrogatories, a further technical conference was held on July 21 and 22, 2014.

The Board determined that it intended to hear as part of the oral hearing those issues which relate to the implementation of the Board's policy and framework for the Custom Incentive Rate-setting option, given that this was the first electricity rate application of this type.  The Board recognized that some issues are not strictly policy related and could be suitable for settlement. A settlement conference as held on July 28, 2014 but no settlement was achieved.

The oral hearing for this proceeding began on September 8, 2014 and the evidentiary portion concluded on September 18, 2014.  Hydro One presented oral argument-in-chief on September 24, 2014.

The Board established a schedule for written argument which set Board Staff submissions for October 7, 2014, Intervenor submissions for October 15, 2014 and reply argument for October 27, 2014.

A record of all procedural matters and correspondence in this proceeding is available on the Board's web site.

These are Board staff's submissions on Hydro One's Custom 5 Year Distribution Rate Application.  The submission addresses the issues before the Board under main topic headings, rather than addressing the issues individually.

# 2. Application of the Renewed Regulatory Framework for Electricity

Hydro One Distribution is applying for distribution rates based on a five year Custom Cost of Service application under the Board's new Custom Rate-setting method.[1]

The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network. The Board's policies in relation to its performance-based approach are set out in its October 18, 2012 Report of the Board, "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (the "RRFE Report").

The Board's policies on the key elements of the Custom Incentive Rate setting ("Custom IR") rate-setting method are summarized in the RRFE Report in Table 1 on page 13 of that report. Staff's understanding of the applicant's proposed plan relative to those key elements is provided in Table 1 below.

[1] Exhibit A/Tab 4/Schedule1/Summary of Hydro One Custom Application Framework

## Table 1: Staff's High Level Comments on Applicant's Proposed Plan

<table>
<tr><th colspan="2"></th><th>Key Elements of a Custom IR<br>(Table 1 on page 13 of the RRFE Report)</th><th>Staff’s Comment on Hydro One’s Application Relative to Key Elements</th></tr>
<tr><td colspan="4">Setting of Rates</td></tr>
<tr><td colspan="2">“Going in” Rates</td><td>Determined in multi-year application review</td><td>Multi-year application proposed.</td></tr>
<tr><td colspan="2">Form</td><td>Custom Index</td><td>Rate indexing is not proposed, although a rate smoothing mechanism is proposed.<br><br>5-year cost of service, rate-of-return proposed.</td></tr>
<tr><td colspan="2">Coverage</td><td>Comprehensive (i.e., Capital and OM&A)</td><td>Comprehensive proposed.</td></tr>
<tr><td rowspan="2">Annual Adjustment Mechanism</td><td>Inflation</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor’s forecasts (revenue and costs, inflation, productivity); (2) the Board’s inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor’s forecasts</td><td>Inflation built into cost forecasts.</td></tr>
<tr><td>Productivity</td><td>Productivity factor not proposed.<br><br>Planned cost reductions built into cost forecasts.</td></tr>
<tr><td colspan="2">Role of Benchmarking</td><td>Productivity benchmarking not done. Minimal cost benchmarking evidence.</td></tr>
<tr><td colspan="2" rowspan="2">Sharing of Benefits</td><td>Productivity factor</td><td>Productivity factor not proposed.<br><br>Planned cost reductions built into cost forecasts.</td></tr>
<tr><td>Case-by-case</td><td>No explicit mechanism analogous to the stretch factor proposed.</td></tr>
<tr><td colspan="2">Term</td><td>Minimum term of 5 years.</td><td>5 year term proposed.</td></tr>
<tr><td colspan="2">Incremental Capital Module</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Treatment of Unforeseen Events</td><td>The Board’s policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors, will continue under all three menu options.</td><td>Events proposed that are not explicitly provided for in Board policy.</td></tr>
<tr><td colspan="2">Deferral and Variance</td><td>Status quo, plus as needed to track capital spending against plan</td><td>No explicit proposal to establish accounts to track capital spending against plan.</td></tr>
<tr><td colspan="2">Performance Reporting and Monitoring</td><td>A regulatory review may be initiated if a distributor’s annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.</td><td>Off-ramp conditions proposed that are not explicitly provided for in Board policy.</td></tr>
</table>

Considering the expectations in the key elements chart, Board staff submits that refinements need to be made to the proposed plan to strengthen efficiency incentives, strengthen benchmarking evidence, establish a performance contract and implement an annual scorecard approach to reporting.

To strengthen efficiency incentives and maintain consistency across the three rate plans outlined at page 13 of the RRFE Report, staff submits that Hydro One's proposed plan should be modified to:

- Include a Stretch Factor for sharing of benefits with ratepayers;
- Adopt the Board's policies in relation to the Treatment of Unforeseen Events and Performance Reporting and Monitoring; and
- Develop supporting productivity and total cost benchmarking over the term of the plan to help the Board assess progress and to inform future applications.

Staff believes that plan modification is the most appropriate way to maintain relative parity of regulatory compact across the three RRFE rate plans.

To ensure that performance commitments are made and kept, staff submits that Hydro One's Custom plan should be modified to include an explicit "performance contract" that sets out what the company is committing to and will be held to over the next five years vis-à-vis outcomes, measures, targets, and monitoring and reporting.

Staff also submits that a scorecard approach to annual performance reporting should be implemented. To implement this approach, staff submits that key elements of the performance contract (i.e., the outcomes, measures, and targets) be distilled into a Hydro One Custom IR Scorecard that would be filed annually and include reporting of actuals achieved.

## 2.1 Principle: Consistency in Risk and Benefit Sharing across Three Rate-setting Plans

The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The RRFE objectives are set out in Section 1 of the RRFE Report. In brief, policies have been set to:

- Shift the focus from activities to outcomes and utility cost to value for customers;
- Better align utility reliability and quality of service levels with customer preferences;
- Advance continuous improvement and innovation in the sector;
- Provide for a comprehensive approach to network investments to achieve optimum results;
- Better align timing and pattern of expenditures with cost recovery; and
- Provide a sustainable, predictable, efficient and effective regulatory framework.

Among other matters, the Board established three incentive based rate setting alternatives suited to individual utility circumstance. The RRFE objectives underpin all three rate setting alternatives.

With respect to the rate setting alternatives, the Board states in its RRFE Report (on pages 9 - 10) that,

> “Each distributor may select the rate-setting method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. This will provide greater flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include ‘lumpy’ investments, and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time.”

The three rate setting approaches have been designed to accommodate different investment profiles. However, staff notes that as set out in Table 1 on page 13 of the RRFE Report all three plans have been designed to have certain common elements, including:

- Annual adjustments providing for inflation offset with expected productivity gains, supported by benchmarking analyses;

- Explicit provision for the sharing of benefits;

- Consistent treatment for unforeseen events; and

- Performance reporting and monitoring.

It is staff's view that these common elements help to ensure that risks and benefits shared between distributors and their ratepayers is relatively consistent across the three rate setting plans. While recognizing that the Custom IR option is to be customized to suit the distributor's circumstances, particularly relating to capital investment, staff submits that to the extent practicable, the allocation of risks and benefits between a distributor and its ratepayers should not differ as a result of the rate plan the distributor selects.

Staff submits that maintaining relative consistency or comparability in the common elements is appropriate to ensure the Board RRFE objectives are met in the interest of ratepayers. Having these elements comparable across all three plans avoids any unintended and undesirable consequences of altering the fundamental regulatory compact underpinning the plans beyond that of accommodating a distributor's investment profile needs.

## 2.2 Strengthening Efficiency Incentives

### 2.2.1 Difference between Cost-of-Service Rate-of-Return Rate setting and Incentive Rate setting

Staff acknowledges that the applicant characterizes its plan as a Custom Cost of Service Plan.[2] Furthermore, staff acknowledges that there is no impediment to an applicant making an application to the Board for five years of cost-of-service, rate-of-return rates. However, staff does not believe that it is the Board's policy intent that Custom IR be equivalent to cost-of-service, rate-of-return rate setting.

[2] Exhibit A/Tab 4/Schedule 1, Summary of Hydro One Custom Application Framework

On page 12 of the RRFE Report, the Board states "To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable <u>to each rate method through the X factor</u>" (emphasis added). The Board describes the components of an X factor (i.e., productivity and stretch factors) on page 17 of the RRFE Report, referring to its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> **The productivity component** of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.
>
> **The stretch factor component** of the X-factor is intended to reflect the incremental [efficiency] gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected […] gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.

As Hydro One has adopted a cost-of-service, rate of return approach to its application, it has not included consideration for an X factor, productivity factor or a stretch factor in the application.

According to Table 1 on page 13 of the Board's RRFE Report, all three rate setting approaches are to include a productivity factor. The RRFE Report is non-prescriptive as to how the productivity factor is to be set under a Custom IR and states that the setting of rates under Custom IR is to be informed by the Board's analysis.

Regardless of the applicant's cost-of-service characterization of its proposed plan, staff believes that a major shortcoming of its plan is the absence of external productivity and efficiency components reasonably comparable to an X factor, a common feature of incentive rate setting. Without these factors, staff submits it is difficult to accept that

Hydro One's proposed plan is reasonable or that it shares risks and benefits appropriately with ratepayers.

Board staff cross-examined Hydro One as to why it did not propose a custom index based on its forecasts as per the RRFE Report.[3] The Hydro One witness responded that it would have been possible to translate its planned savings into a formulaic-type number, but did not see benefit of doing that. Rather, Hydro One included annual savings estimates into its forecasts associated with planned projects.[4] Staff agrees that cost of service forecasts underpinning a cost of service application should include planned savings. Staff submits that a Custom IR rate setting index should in addition include expectations for benchmark productivity and efficiency gains that are based on external benchmarks.

### 2.2.2 Difference Between Productivity and Efficiency

Staff submits that Hydro One confuses the concept of cost efficiency with the concept of productivity by characterizing forecasted cost savings as productivity. Staff submits that the Board needs to have confidence in how productive Hydro One is being, not just how much it is (or is not) spending.

In its application, Hydro One defines productivity as "The effectiveness of productive effort, measured in terms of the rate of output per unit of input".[5] However, Hydro One did not provide evidence on its historical and forecasted "rate of output per unit of input". Instead, Hydro One claims to have factored into its forecasted costs "Total Annual Savings"[6] from a series of initiatives, some of which began in 2010. Staff does not equate this with "rate of output per unit of input".

At the hearing, in response to staff's cross-examination, Hydro One stated that it "equate[s] productivity with cost efficiency and cost savings".[7] Staff disagrees and submits that productivity is more than just cost savings. Productivity is a measure of the transformation of inputs into outputs. As explained on page 12 of the Pacific Economics Group Research's final report to the Board released on November 21, 2013, entitled

[3] Tr. Vol. 1, pp. 80-81
[4] Exhibit A/Tab 19/Schedule 1/ p. 4.
[5] Exhibit A/Tab19/Schedule 1/ p. 1
[6] Table 2, Exhibit A/Tab19/Schedule1/p. 4
[7] Tr. Vol. 1, p. 81

"Empirical Research in Support of Incentive Rate Setting in Ontario", productivity is a "measure of the extent to which firms convert inputs into outputs. Comparisons can be made between firms at a point in time or for the same firm (or group of firms) at different points in time". [8]

Staff submits that costs are one of the inputs to calculating productivity. In Section 5 of the report noted above, PEG states that the inputs to its total factor productivity analysis include capital and OM&A prices and quantities, and the outputs include customer numbers (other than street lighting, sentinel lighting, and unmetered scattered loads), total kWh deliveries, and system capacity peak demand. Staff notes that the input quantities are specifically "distributor cost-based". The remaining variables in the analysis (i.e., input prices and outputs) are not distributor cost-based. This illustrates how cost is a component of productivity, but is not equated with productivity. Section 2.3 of PEG's 2011 Concept Paper on Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks provides basic definitions of productivity and efficiency and discusses the relationship between them. Staff thinks it is important that this relationship be clear to the industry and the Board so that consistent definitions, and therefore consistent measures, can be used to assess efficiency and productivity – whether company-specific or industry-wide. Staff believes that measurement of total factor productivity ("TFP") is particularly important because it measures the relationship between all the outputs provided by a distributor and all the inputs that the distributor procured to provide those outputs. As a consequence, staff submits that TFP is a reasonable "value for money" trend indicator.

### 2.2.3 Order a Comparable Productivity Study

The proposed plan lacks a productivity component comparable to that implemented in the Price Cap IR and Annual Index plans. In those plans, the productivity factor is intended to be the external benchmark which distributors are expected to achieve. The applicant's plan does not include any external benchmark that it expects to achieve.

[8] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario. November, 2013

The Board has indicated that it will continue to measure the industry's TFP over the next five years.[9] Staff acknowledges Hydro One's unique circumstances vis-à-vis the Board's industry-wide TFP analysis and appreciates its cooperation and efforts to respond to staff interrogatory Exhibit I Tab 3.3-Staff-60. That interrogatory asked Hydro One to provide its own, company-specific, forecasted total factor productivity trends for the period 2013 through to 2019 using the forecasts in its application and the PEG documentation and worksheets that are posted on the Board's web site or Hydro One's comparable analyses. Staff notes that the answer to the interrogatory showed that while Hydro One's productivity continues to be negative, it appears it may become less so. Staff also acknowledges that Hydro One expressed some concern over PEG's approach to estimating TFP; however, staff submits that productivity analyses do provide indicative or representative trends. Hydro One's answer to the interrogatory demonstrates that such analyses can be done, and staff believes that such calculations should be done in support of a Custom IR application.

In its response to staff's interrogatory, Hydro One expressed concern with the Board's industry-wide productivity analyses, noting that it has been excluded because it is considered an "outlier". Staff submits that this does not preclude Hydro One measuring its <u>own</u> total factor productivity growth over time to demonstrate its productivity improvements to ratepayers and the Board.

Staff anticipates that Hydro One may argue that the Board's productivity factor is currently set at zero and therefore Ontario electricity distribution industry productivity is a moot point. Staff acknowledges that the Board determined in November, 2013 that (1) the productivity factor for Price Cap IR of zero will be in effect until 2018; and (2) the Board will update the productivity factor in 2019.[10] In that report on page 17 the Board acknowledges that achieved productivity growth in the Ontario distribution sector has likely slowed in recent years. However, not believing it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future, the Board reasons that "[s]etting a productivity benchmark for the industry that would not encourage distributors to achieve and share productivity gains is inconsistent with the Board's policy direction – doing so would be counter to facilitating a culture of

[9] Board's EB-2010-0379 Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (issued November 21, 2013 and as corrected on December 4, 2013), p. 27 ("the Rate Setting and Benchmarking Report").

[10] The Rate Setting and Benchmarking Report

continuous improvement." The Board notes on page 18 that it may further explore some of the alternative methods to estimating total factor productivity when carrying out the 2019 update. Staff submits that this should encourage Hydro One to explore alternate methods that may, in the company's view, better measure Hydro One's long-run productivity.

For the reasons set out above, staff submits that the Board should order Hydro One to carry out productivity analysis over the next five years which is comparable to that used by the Board to estimate industry productivity to:

- establish an empirical baseline for Hydro One's performance; and
- provide an empirical foundation for Hydro One's next application.

Staff submits that the Board's planned 2019 review could be constructively informed by Hydro One bringing forward its preferred method to estimating company-specific and/or industry TFP.

### 2.2.4 Comment on the Proposed Annual Savings Included in Forecasts

Hydro One describes its application as "a bottom-up assessment of costs over the five-year period"[11] and that it includes forecasted costs savings associated with identified opportunities for improvement in its business.

Staff believes that a "bottom up" approach to identifying opportunities for improvement is good business practice and an effective way to plan savings, regardless of how rates are set. Rolling cost savings into the forecast costs is a good budgeting exercise that all utilities should be undertaking as part of their regular business. A distributor's efforts to achieve cost savings should not change – in nature or intensity – depending on how multi-year rates are set. However, this is not equivalent to long-term sustainable productivity improvements. Consequently, staff submits that some measure of externally imposed productivity expectation should be evident in rates regardless of which RRFE rate setting alternative is used to set rates.

[11] Tr. Vol. 1, p. 29

As already noted, Hydro One's application lacks the productivity analysis that staff believes is necessary to help the Board assess the company's planned commitment to productivity gains over the term of the proposed plan. Absent this evidence and any other benchmarking evidence to the contrary, staff does not equate the planned savings that the applicant claims it has built into its forecasted costs with an externally determined productivity factor. In addition, if the Board at some time determines a non-zero productivity factor for use in Price Cap IR and the Annual Index, Hydro One will be out of step with the benefits sharing between other distributors and their ratepayers.

With respect to the forecasted annual savings identified by Hydro One in Table 2 of Exhibit A Tab 19 Schedule 1 Page 4, staff notes that the lion's share of forecasted annual savings stem from efforts/investments made in the past. Based on the values in Table 2, "greenfield efforts" between 2015 and 2019 appear to be de minimis compared to those claimed as persistent savings from work done over the last five years. Staff's calculation of "greenfield" savings each year is shown in the following table.

**Table 2:**

**Excerpt from "Table 2: Total Annual Savings - Distribution ($ million)" (Exhibit A Tab 19 Schedule 1 Page 4)**

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Cumulative Annual Savings Included in Forecasts | 12.3 | 17.3 | 37.9 | 68.0 | 90.7 | 118.4 | 126.5 | 130.3 | 131.3 | 131.5 |
| Staff's Calculation of New Savings Each Year | | 5.00 | 20.60 | 30.10 | 22.70 | 27.70 | 8.10 | 3.80 | 1.00 | 0.20 |

Board staff cross-examined Hydro One on this and Hydro One attributed the savings to significant projects that resulted in the large savings "from back office, which is Cornerstone-related, business systems and business transformation" and acknowledged that new efforts between 2015 and 2019 are much less.[12] Staff submits that it does not seem appropriate that annual savings built into the underlying cost forecasts stem primarily from continuous improvements launched and/or achieved in prior years. Continuous improvement is a prospective concept – when a company decides to do something different because it saves time, reduces error and/or waste, or improves quality, the benefits could be viewed as lasting forever, but that view should not preclude on-going efforts or be entrenched in the company's continuous improvement targets. Furthermore, just as staff does not believe that a distributor's

[12] Tr. Vol. 3, p. 16

efforts to achieve continuous improvement resulting in efficiency gains should not change – in nature or intensity – depending on how rates are set, its efforts should not change based on the length of an IR plan term. Staff submits that Hydro One's "low hanging fruit" claim is insufficiently compelling to justify the declining trend in planned savings[13].

While staff identifies this as a shortcoming in Hydro One's application, due to the lack of benchmarking evidence, the Board may have to accept Hydro One's claimed annual savings "as is". Staff submits that to compensate for this shortcoming, the Board should modify Hydro One's plan to include a stretch factor.

### 2.2.5 Add a Stretch Factor

According to the RRFE report,[14] all three rate setting approaches are to include provision for the sharing of benefits with ratepayers through a productivity factor and either the Stretch Factor (under Price Cap IR and Annual Index) or something comparable to be determined on a "case-by-case" basis under Custom IR. Staff submits that the efficiency incentives in Hydro One's proposed plan could be stronger by improving on the sharing of benefits with ratepayers above and beyond the savings that Hydro One claims have been built into its cost forecasts.

The RRFE Report also states, "To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable to each rate method through the X factor." [15]

In response to interrogatory 2.2-Staff-11, Hydro One indicated that in the absence of an X-factor, it has built annual savings into its forecasted costs to ensure that benefits are shared through the rate term with its customers. In addition, Hydro One stated that "[g]iven that its forecasted productivity savings are ambitious, Hydro One does not expect to achieve additional efficiency gains over the 5-year term. Any unexpected,

[13] Tr. Vol. 1, p. 87
[14] RRFE Report, Table 1, p. 13
[15] RRFE Report, p. 12

additional gains may be redirected into work programs and projects which benefit the customer"[16].

Staff acknowledges that in the context of a single year cost of service or a multi-year incentive rate setting plan which includes an X-factor, this approach may be appropriate. However, staff submits that Hydro One's approach under its proposed plan is not justified given the lack of adequate benchmarking evidence to demonstrate the reasonableness of the gross cost forecasts, the forecasted annual savings, and consequently a reasonable sharing of benefits over the term of the plan.

Staff submits that incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses. Staff submits that that incentive power is weak under a cost-of-service, rate-of-return paradigm and therefore alternative approaches to rate-setting that are performance- and incentive-based have evolved to provide a regulatory compact with a stronger market-like paradigm that imposes additional productivity and efficiency expectations on the company. The Board acknowledges limited incentives under cost-of-service ratemaking on page 18 of its March 30, 2005 Report entitled "Natural Gas Regulation in Ontario: A Renewed Policy Framework Report on the Ontario Energy Board Natural Gas Forum". The Board states, "[i] t is important that the rate regulation framework creates incentives for the implementation of sustainable efficiency improvements and that it is structured to ensure that ratepayers share the benefits of these efficiencies. Traditional [cost of cost-of-service ratemaking] plans generally provide only limited incentives for efficiencies. A [performance based regulation] framework, on the other hand, is generally recognized to provide efficiency incentives."

Staff submits that distributors operating under Price Cap IR and the Annual Index are subject to the Board's externally calibrated productivity and efficiency expectations. Staff notes Hydro One's statement in response to a staff interrogatory in relation to penalties and rewards that "[p]lanned work lends itself to allowing more cost efficiencies and productivity gains to be realized."[17] Staff agrees, but submits that in conjunction with effective planning by a distributor, the Board's rate setting should simulate market-based cost pressures to provide strong incentives to distributors. Even with the planned savings that Hydro One has factored into its forecasts, staff believes that there will

[16] Exhibit I/Tab 2.02/Staff 11
[17] Exhibit I/Tab 2.04/Staff 18

continue to be room for service and cost efficiency improvements. However, absent strong incentives through rate setting similar to those in Price Cap IR and the Annual Index, Hydro One may not be as driven to seek and achieve continuous improvement.

As stated on page 14 of the RRFE Report, "[t]he Custom IR method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures." Consequently, staff notes that approved distribution costs underpinning rates under the Custom IR method are likely to be larger than those under the other two methods. Staff is of the view that this makes it even more important that the Board be confident in the "robust evidence of [the applicant's] cost and revenue forecasts over [the] five year horizon, as well as [its] detailed infrastructure investment plans over that same time frame."[18] Staff is not persuaded that Hydro One has provided sufficiently robust evidence in this case to support the requested cost increases in the absence of benchmarking evidence on expected productivity and efficiency gains.
Staff submits that in the absence of productivity and efficiency benchmarks to help the Board assess the reasonableness of the applicant's proposed plan, efficiency incentives should be strengthened through the addition of an explicit stretch factor to share benefits with ratepayers.

Staff notes that parties representing various ratepayer groups asked Hydro One about the inclusion of an earnings sharing mechanism in its Custom plan that would share benefits after-the-fact. Staff believes that a stretch factor, which shares expected benefits with ratepayers up front throughout the IR term provides a more powerful incentive than an earnings sharing mechanism. In particular, staff believes that monitoring and reporting will capture any over-earning by Hydro One at the expense of eroding service and/or reliability performance. Also, staff submits that relative to an earnings sharing mechanism, a stretch factor provides a better fit with an RRFE-based paradigm, whose incentive framework is generally founded upon forward-looking cost estimates, reporting and trends, and a scorecard approach to performance monitoring.

Staff recommends that the regulatory compact be determined by the Board at the start of the Custom IR plan and that the regulatory process then focus on a Scorecard approach to performance monitoring and reporting. Staff submits that implementing an

[18] RRFE Report, p. 19

explicit stretch factor in Hydro One's Custom plan would also avoid the additional administration needed for an earnings sharing mechanism.

In the Price Cap IR and Annual Index plans, a stretch factor is used to reflect the incremental efficiency gains that distributors are expected to achieve under IR. These expected gains can vary by distributor and depend on the efficiency of a given distributor. Stretch factors are generally lower for distributors that are relatively more efficient. Absent any benchmarking evidence to the contrary, staff is unable to assess the reasonableness of the applicant's claim that the planned savings that have been built into its forecasted costs are going to be challenging.

Without external productivity and efficiency benchmarks, staff believes that Hydro One's proposed plan provides less incentive than the motivation provided via the externally imposed rate reductions in the Price Cap IR and the Annual Index rate-setting methods. Staff is concerned that a less effective incentive will result in lower motivation for Hydro One to seek and achieve further efficiencies (i.e., continuous improvement) as compared to the distributors in the sector that are having their rates set by way of Price Cap IR or the Annual Index.

With respect to what value the Board should attach to the stretch factor, staff proposes that the Board begin with the value for the applicant that results from the Board's total cost benchmarking.

The Report of the Board, issued on November 21, 2013 and as corrected on December 4, 2013, entitled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" provides the Board's determination on its policies and approaches to the distributor rate adjustment parameters and the benchmarking of electricity distributor total cost performance for the period 2014 to 2018. In that report, the Board determined that each year, distributors will be assigned to one of five groups with stretch factors based on their efficiency as determined through an econometric total cost benchmarking model. As noted in Appendix D of that report, Hydro One's stretch factor for 2014 was 0.6%. On August 14, 2014, the Board released the 2013 benchmarking update for determination of stretch factor assignments for 2015. Based on its total cost benchmarking performance, Hydro One's 2015 stretch factor value is 0.6%. Staff notes that while Hydro One's stretch factor value has not changed from last year, its benchmarking performance has improved from 58.2% to 47.8% - i.e., Hydro One's actual total costs, while still significantly above their benchmark predicted total costs are at least moving toward them.

Staff submits that the Board should implement a stretch factor for Hydro One each year and apply the resultant value to Hydro One's rates at the time of Hydro One's annual updates. Staff believes this would be consistent with a performance-based approach, since applying the stretch factor adjustment to rates will have a total cost impact, leaving it to the company to figure out how best to allocate resultant revenues to deliver on its commitments. Efficiency gains may be realized through OM&A and/or capital work.

Staff proposes that the stretch factor be cumulative in order to give the distributor time and incentive to identify and deploy additional efficiency measures over the full term of the plan. A cumulative stretch factor would also compensate for the decline in planned savings noted earlier.

To determine the stretch factor to be applied each year, staff submits that an efficient and transparent starting point would be the annual stretch factor value that falls out of the Board's existing annual electricity distributor total cost benchmarking. Given Hydro One's cost performance, the stretch factor that would apply is 0.6%.

However, staff notes that the form and approach to rate-setting chosen by Hydro One reduces its risks relative to applicants on the Price Cap or Annual IR plan. This filing, if approved in the manner requested, will approve the utility's costs for five years, as well as permit annual adjustments such as to the cost of capital. Staff submits that these updates and approvals provide considerable additional certainty for the company; accordingly, staff submit, that the company should be able to provide additional cost relief in exchange. A larger stretch factor, in staff's view, is warranted.

Staff are mindful that according to Dr. Kaufmann, "[i]n practice, North American regulators have chosen the values for [stretch factors] almost entirely on the basis of judgment. This judgment has led to approved stretch factors in a relatively narrow range, between 0.25% and 1%, with an average value of approximately 0.5%".[19]

[19] PEG's February, 2008 Report "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario Report to the Ontario Energy Board, p. 21

Given the absence of benchmarking, low levels of efficiency commitments through the plan term, and the interest in ensuring that Hydro One is sufficiently motivated to pursue efficiency and productivity measures, staff submit that an annual stretch factor of 1% would be appropriate.

Staff has estimated that the value of a compounding stretch factor of 1%, applied to rates on the second through fifth years of the plan, would yield a cumulative reduction in revenues of approximately $160 million. Staff invites Hydro One to comment on this calculation in its reply. Staff submits that these amounts are not excessive given the size of Hydro One's proposed revenue requirements over these years.

The Board could either set the stretch factor at 1% for each of the years, or could apply a 0.4% premium on top of the stretch factor that will be calculated for Hydro One each year as part of the Board's annual cost performance evaluation that provides the stretch assignments for all distributors. For illustrative purposes, a 1.0% stretch factor could be set for 2016 on the basis of an 0.6% stretch assignment derived from the Board's benchmarking analysis, as well as a 0.4% premium. If the stretch factors change, the variable component of Hydro One's stretch factor would change as well, but the premium would remain constant.  For example, if the Board's stretch factor assignment for distributors in Hydro One's category changed to 0.7%, the total stretch factor would be 1.1%. This approach would preserve the incentive for Hydro One to make gains that could mean rising into a higher efficiency cohort as well as maintain better parallels between the Hydro One stretch factor design and that which applies to other distributors.

The table below illustrates the proposal, assuming a cumulative 1% stretch factor, i.e. not taking into account any change that may occur in the Board's stretch factor assignment for Hydro One.

**Table 3:  Illustration (stretch factor, cumulative 1% per year, beginning in 2016)**

| Cost of Service Base Rates proposed for Residential - Urban (UR) (Exhibit G1-4-2 Attachments 1 to 5) | | | | | |
|---|---|---|---|---|---|
| | **2015** | **2016** | **2017** | **2018** | **2019** |
| - Monthly Service Charge | 20.45 | 21.02 | 20.68 | 20.01 | 19.65 |
| - Distribution Volumetric Rate | 1.765 | 1.819 | 1.788 | 1.742 | 1.725 |
| Stretch Factor assigned to Hydro One | 0.00% | 1.00% | 1.00% | 1.00% | 1.00% |
| Compounded | | 1.00% | 2.00% | 3.00% | 4.00% |
| Rate Adjustment | | | | | |
| - Monthly Service Charge | - | -0.21 | -0.41 | -0.60 | -0.79 |
| - Distribution Volumetric Rate | - | -0.01819 | -0.03576 | -0.05226 | -0.06900 |
| Custom IR Rates Including Stretch Factor | | | | | |
| - Monthly Service Charge | 20.45 | 20.81 | 20.27 | 19.41 | 18.86 |
| - Distribution Volumetric Rate | 1.765 | 1.80081 | 1.75224 | 1.68974 | 1.65600 |

Furthermore, the Board could apply either apply the stretch factor to the 2016 to 2019 period, or begin to apply the stretch factor in 2015 for the full five years of the plan. Staff recognizes that for Price Cap IR and Annual Index rate setting, the stretch factor is applied in the year following rebasing. However, this is not a “rebasing + index” type of application. Hydro One has positioned its application as a five year cost of service application, with rate smoothing over the five years of the plan. Staff submits that application of the stretch factor in year 1 of Hydro One’s rate plan is therefore a reasonable option, consistent with the nature of the application. Staff estimates the impact of the application of a 1% stretch factor for five years to be approximately $230 million.

## 2.3 Ensure Reasonable Consistency in the Common Elements

Hydro One proposes adjustments to provide a safeguard to protect both it and its customers against unexpected results in the operation of the plan[20]. Hydro One states

[20] Exhibit A/Tab 4/Schedule1/p. 3

that it proposes these adjustments only for events that are externally driven and beyond the control of management. The adjustments have been classified into three categories: (i) annual adjustments, (ii) adjustments outside of normal course of business, and (iii) off-ramps. With respect to the latter two adjustments, Hydro One proposes that they result in either a particular component or the entire plan being examined and adjusted or even possibly terminated.

Staff is concerned that the applicant's proposed off-ramps and adjustments outside the normal course of business differ from the policies set out in the RRFE Report. While the two elements are conceptually similar to the Board's Off-ramp and Z-factor elements, the details differ. Staff submits that customization of these elements would unduly alter the risk sharing between the applicant and its customers.

### 2.3.1 Annual Adjustments

As part of its 5-year plan Hydro One has proposed three annual adjustments for what it has categorized as recurring events that are mechanical in nature and do not require a prudence review. This proposal is found in the pre-filed evidence at Exhibit A Tab 4 Schedule 2.

The three proposed annual plan adjustments are updates of cost of capital and working capital as well as clearance of variance accounts. These updates would be accomplished through an annual Draft Rate Order approval process. Hydro One indicated it used input heard in the 2013 stakeholder sessions to develop the annual adjustments proposed in this application.

#### Cost of Capital

With regard to the proposed adjustment to Cost of Capital, this proposal is similar to Hydro One's current practice when they have sought and been granted approval of for two test years, most recently the EB-2009-0096 distribution application and the EB-2012-0031 transmission application. In these cases, the Board directed Hydro One to update rates for the latest return on equity and cost of short term debt parameters issued by the Board. In addition, Hydro One is also permitted to update its overall cost of debt to include the cost of any long term debt issued in the past year.

Although it is Board staff's view that adjustments under RRFE rate plans should be minimized, Hydro One has positioned this application as a five year cost of service application. If the Board accepts the application in this form (and staff has not argued that it be rejected on the basis of form), staff submits that an annual cost of capital adjustment to bring Hydro One in line with the most current Board cost of capital parameters, could be appropriate, considering Hydro One's past history with its two year applications. The Board also approved an annual update to cost of capital for the Enbridge 2014 to 2018 rate application (EB-2012-0459).

On the other hand, Board staff would also point out that for the Board's Price Cap "IR" option, cost of capital (equity and debt) are set at the beginning of the term for the whole five year term because the Board has determined that both equity and debt are costs that should be reviewed as part of the overall cost of service. It would therefore also be reasonable for the Board to treat this application in a similar manner as a Custom "IR" and set the cost of capital using the 2015 parameters for the term of the plan.

**Working Capital**

Hydro One indicated that stakeholders suggested that the amount of working capital Hydro One should be allowed each year will vary depending on electricity commodity prices. The commodity cost of electricity is beyond the control distributors. Hydro One proposes to use the prior year's commodity costs to calculate the annual adjustment to working capital.

Board staff submits that annual updates of the elements of a Custom IR should be minimized, and undertaken only where Board policy supports the adjustment. Board staff is of the view that reasonable forecasts can be made of commodity costs and that there is no reason to add complexity to this plan through the update of the Working Capital in each year. Therefore, Board staff would propose that the working capital allowance be fixed in 2015 for the five-year term of the plan.

**Clearing of Variance Accounts**

Hydro One is proposing to clear the balances in variance accounts annually where a prudence review is not required, as part of its annual rate order submission. These accounts would include the RSVA account, the 2014 Smart Grid account, the Tax Rate Changes account and the Pension Cost Differential account.

Hydro One's evidence notes that the RSVA account, when the materiality threshold has been met, can be cleared without a prudence review. Hydro One has included such a request in previous applications and the Board has approved clearing of the RSVA account. The account balances in the RSVA account are reported to the Board quarterly and are transparent.

Hydro One indicates that the smart grid variance account approved in EB-2013-0141 for 2014 expenditures will not require a prudence review. In the Board Decision in that case, the settlement proposal was accepted and part of that proposal was an agreement that the 2014 smart grid variance account would not be subject to a prudence review in a subsequent proceeding.

In this proceeding, Hydro One has requested the continuation of the Tax Rate Changes account[21]. Hydro One's position is that since changes to statutory tax rates can be calculated in a purely mechanical way, there is no issue of prudency in spending to be reviewed.

Also in Exhibit F1 Tab1 Schedule 2 Hydro One has requested the continuation of a pension cost differential account. Hydro One indicates that changes to the balance in this account are determined by actuarial valuation, so there would be no issue of prudency in spending to be reviewed.

Board staff submits that the annual clearing of these variance accounts is acceptable in the 5 year plan. Board staff notes that there are only a small number of accounts to be cleared and that clearing of RSVA accounts (which deal with pass-through amounts) is currently provided for in existing Board policy. Clearing all of these accounts on an annual basis will avoid the buildup of excessive balances that could cause rate instability by the end of the 5 year plan.

### 2.3.2 Off-Ramps

The Board has provided a mechanism for a regulatory review to be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.[22]

[21] Exhibit F1/Tab1/Schedule 2
[22] RRFE Report/Table 1/p. 13

Hydro One proposes to add two additional off-ramp conditions in its plan: industry restructuring; or a major change to Hydro One's service territory. Staff submits that the Board's existing policies sufficiently capture the advent of such conditions and therefore need not be specially approved by the Board in this case. Staff notes that these conditions are events more appropriately considered as examples under the Board's Z-factor policies. Furthermore, such events are not necessarily specific to Hydro One. Staff submits that appropriate and responsive Board policy already exists to accommodate such events and those policies should prevail. Staff does not agree that customization of Off-ramp policies is necessary or appropriate. Staff submits that customization would unduly alter the risk sharing between the applicant and its customers compared to that balance under Price Cap IR or the Annual Index.

### 2.3.3 Regulatory Treatment of Unforeseen Events

According to Table 1 on page 13 of the RRFE Report, the Treatment of Unforeseen Events and Performance Reporting and Monitoring will be the same under all three rate setting approaches.

The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options. In brief, the Board has provided a mechanism for an applicant to apply to the Board to recover from ratepayers costs which meet the Board's eligibility criteria and were incurred in relation to events that the applicant claims were not within management's control.

Hydro One proposes that adjustments outside of normal course of business will be sought for unexpected events that materially impact the operation of the company and which are outside of the company's control.[23] Hydro One acknowledges that these adjustments would require a prudence review and states that it would expect a written hearing would be held to test the evidence. With respect to materiality, Hydro One proposes a materiality threshold for these adjustments of 0.5% of test year revenue requirement and acknowledges that this is an alternative to the materiality threshold found in the Board's Filing Requirements for Electricity Distribution Rate Applications.

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[23] Exhibit A/Tab 4/Schedule 3/p. 1

The threshold for Hydro One in Chapter 2, Section 2.4.4 is $1 million, which Hydro One believes may trigger adjustments more often than necessary. Hydro One's proposed 0.5% of revenue requirement is approximately $7.5 million.

Finally, in the application, Hydro One proposes specific events that could trigger a need for an adjustment outside of normal course of business, including:

- new government directives or legislation,
- material changes to codes or standards, or
- material unforeseen weather events.

With respect to the specific events identified by Hydro One, staff does not believe that the events could not be captured under the Board's existing policies. Hydro One agreed that the events cited were examples, and the company was not seeking any pre-approval for these events.[24]

With respect to Hydro One's request for a higher materiality threshold, staff supports the change because it transfers risks from customers to the company and its shareholders and brings the threshold in line with the materiality ratio (0.5%) that applies to the significant portion of Ontario distributors with revenues greater than $10 million and up to $200 million. Staff also recognizes the simple practicality of Hydro One's proposal, given the size of the company, and the reduction in regulatory effort that an increase in the materiality threshold would permit. However, Hydro One's willingness to take on the additional risk suggests that if the Board chooses to increase the materiality threshold, staff recommends that the Board indicate that this change is specific to the circumstances of this distributor.

## 2.4 Develop Benchmarking over Plan Term

Hydro One's application does not include total cost or productivity benchmarking, nor does it include analyses informed by the Board's total cost or productivity benchmarking.

[24] Tr Vol 1 p. 105 - 106

On pages 19 and 20 of the RRFE Report, the Board states that the allowed rate of change in the rate over a Custom IR term will be determined by the Board informed by empirical evidence including: the distributor's forecasts; the Board's inflation and productivity analyses; and <u>benchmarking to assess the reasonableness of the distributor forecasts</u> (emphasis added). That Report also states that "[b]enchmarking will [ ] continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans."[25]

In response to a staff interrogatory, Hydro One identified a limited number of benchmarking reviews that were used to estimate costs for some of the proposed activities.[26] In addition, Hydro One stated in that response that "No external or internal benchmarking studies have been undertaken to estimate the productivity gains that will be achieved during the rate term." Staff notes that absent this benchmarking evidence to support Hydro One's forecasts, the Board must rely on the company's word to determine whether its forecasts are reasonable.

Staff is aware that a transmission cost benchmarking study has been agreed to by parties in the 2015 – 2016 Hydro One Transmission Settlement Agreement (EB-2014-0140) and that it will entail a consultative approach. The text in the settlement proposal indicates that:

> "…intervenors want to better understand the cost of Hydro One's work relative to similar companies. A cost benchmarking study would also be supportive of the Board's Renewed Regulatory Framework. Hydro One agrees to complete an independent Transmission Cost Benchmarking Study that will be filed with Hydro One's next Transmission rates application. Intervenors and Board Staff will be consulted, and agreement will be sought, in defining the Terms of Reference that will be included in the Request for Proposal document.
>
> The Request for Proposal document will be used in the selection process for the independent party that will complete the Study. After Hydro One selects the independent party that will complete the Study, Intervenors and Board Staff will

[25] RRFE Report/p. 60
[26] Exhibit I/Tab 2.06/Staff 33/p. 1

> review the Study proposal provided by the independent party to help ensure that the proposal meets the requirements of the Terms of Reference. Intervenors and Board Staff will also be provided with an opportunity to review and provide comments on the preliminary results prior to finalizing the Study. Hydro One agrees to fund Intervenors for their participation as consistent with Hydro One's past practice."[27]

Staff hopes that Hydro One Distribution would also be prepared to engage in further distribution total cost benchmarking. Staff submits that the Board should order Hydro One to, in consultation with stakeholders, carry out total cost benchmarking studies over the next five years, reasonably comparable to the Board's total cost benchmarking, to:

- establish an empirical baseline for Hydro One's performance; and
- provide an empirical foundation for Hydro One's next application.

All of which, staff submits, will help support Hydro One's rate applications and tell its "success story" to its customers. It may also help inform the Board's periodic review of its productivity and benchmarking models[28].

## 2.5 Establish a Performance Contract & Scorecard

The Board has regulated the Ontario electricity distributors since 1999. A distributor licensed by the Board must comply with all of the conditions of its licence, including compliance with any of the codes listed in its licence, as well as with applicable legislation. Codes set out minimum requirements for licensed electricity distributors, as applicable in relation to various regulated activities and in relation to interactions with affiliated companies. Among other matters the requirements set out in the relevant codes address quality of service to customers, distributor efficacy in delivery of service to customers, and cycle-times experienced by customers in certain processes. The Board Electricity Reporting and Record Keeping Requirements ("RRR") and application filing requirements set out minimum reporting, record keeping, and filing requirements for distributors.

[27] EB-2014-0140 Application, Section II, pp. 14-15
[28] The Rate Setting and Benchmarking Report, p. 29

Leveraging its existing RRR requirements and benchmarking work, the Board established an Electricity Distributor Scorecard for electricity distributors in March, 2014. The Board requires all distributors to report on their performance results against the scorecard measures with their annual April RRR filings.

### 2.5.1 Undertaking J4.9 as Base Scorecard

To complement its annual Electricity Distributor Scorecard, Hydro One is proposing a set of eight custom outcome measures targeted to areas where Hydro One is proposing to increase Capital or OM&A expenditures over its proposed five-year Custom plan.[29] Hydro One designed these performance measures to monitor its success in delivering results (outcomes) over the course of the plan. Targets have been proposed for each measure. Hydro One believes the targets are achievable assuming normal levels of weather-related contingencies, significant events and customer driven requests. The outcome measures will be annually tracked and be reported to the Board. The proposed areas to be measured are:

- Vegetation Management;
- Pole Replacement;
- PCB Line Equipment;
- Substation Refurbishments;
- Distribution Line Equipment Refurbishments;
- Customer Experience;
- Handling of Unplanned Outages; and
- Estimated Bills.

In Exhibit A Tab 4 Schedule 4, Hydro One provides descriptions of its proposed outcomes, associated measures, and comparator cost trends for each outcome measure (i.e., over the next five years, we will spend $x as compared to the $y spent over the last five years). Staff submits that this information is very helpful as it provides a basis for some trend analysis (e.g., unit cost measures such as $ per pole replaced can be calculated). In response to a staff interrogatory, Hydro One completed a summary chart which included proposed targets for each of its proposed outcome

[29] Exhibit A/Tab 4/Schedule 4

measures.[30] This chart was refined over the course of this proceeding resulting in the version provided in Undertaking J4.9 Attachment 1.

The chart combines the eight measures and targets over the plan period into a base year scorecard format. For each outcome, the chart shows:

- A statement of the *Desired Outcome*;
- The *Area* of the business being addressed by the Desired Outcome;
- The proposed *Measure* of the Desired Outcome;
- An *Overview* of the proposed Measure;
- *2010-2013 Actuals & 2014 Forecast*;
- *Total Spend* (2010-2014);
- A statement on any *Performance Benchmarking* done in general or in relation to the Desired Outcome;
- A statement for the *Performance Projection* over the term of the Custom Plan;
- *Cost Projection* (i.e., forecasted costs to achieve outcome);
- *Benefits Projection* (i.e., forecasted benefits of achieved outcome – performance targets);
- A statement regarding any *Consequences of outcome being met, exceeded or not met*;
- *Exhibit References for Costs*; and
- *Notes* offering certain clarifications, if needed.

Staff submits that, subject to any refinements that the Board may believe necessary subsequent to its review of this rate application proceeding, Hydro One's response to Undertaking J4.9 provides the Board with the basis for a performance contract to underpin Hydro One's Custom IR plan. During the hearing, Hydro One agreed that the chart summarizes what Hydro One is committing itself to over the next five years in terms of outcomes, measures, targets, forecasted cost to deliver on the outcomes, and agreed it could appropriately be used as a type of performance contract for Hydro One's five-year custom plan.[31]

[30] Exhibit I/Tab 2.04/Staff 17/Attachment, p. 1
[31] Tr. Vol. 5, p. 85

### 2.5.2 Actual Expenditures by Outcome

While varying views and some concerns were expressed at the Hearing on certain details associated with Hydro One's proposed measures, staff supports Hydro One's overall integrated approach and appreciates Hydro One's efforts and responsiveness to stakeholder comments and recommendations throughout this proceeding. Staff believes Hydro One's proposed set of outcome measures provide a strong foundation for its Custom IR performance contract.

Staff submits that Hydro One should also annually report its cost "performance-against-plan" progress to the Board for each outcome and that it be included on its Custom IR Scorecard. Hydro One has established OM&A and Capital budgets (i.e., forecasted costs) for each outcome measure for Board approval. Staff submits that Hydro One's annual reporting should be made at this same level.

### 2.5.3 Report Using a Custom IR Scorecard

As noted previously, Hydro One agrees that Exhibit J4.9 reflects what it is committing to over the next five years. During the hearing, Hydro One also agreed that Exhibit J4.9 could be used as its annual report to the Board on its performance if it was updated to include, for each outcome, the actuals to date for cost spent and measures achieved. [32]

Staff has prepared the illustration in Table 4 on page **Error! Bookmark not defined.** to show the recommended form and content of the Custom IR Scorecard report for Hydro One might look like. Only one of Hydro One's eight outcomes is profiled in detail in the illustration.

Hydro One also agreed that if a scorecard were established, Hydro One would be willing to prepare documentation to support it, similar to that which the Board prepared in Appendix A of the Board's March 5, 2014 Report of the Board entitled "Performance Measurement for Electricity Distributors: A Scorecard Approach". [33] That appendix provides descriptions and explanations of the performance measures and how the results should be interpreted this information is necessary in order for the Scorecard to be understood by customers.

[32] Tr. Vol. 5, p. 86
[33] Tr. Vol. 1, p. 134

Staff submits that Hydro One's Custom IR Scorecard, completed with all eight outcome measures, should be published every year along with Hydro One's Electricity Distributor Scorecard. To help minimize unnecessary work and duplication of effort, staff submits that Hydro One's annual Custom IR filing could be made at the same time as its annual RRR filings.

Staff submits that the Board should order Hydro One to:

- implement a Custom IR Scorecard similar to that illustrated in
- on page **Error! Bookmark not defined.**;
- file with the Board supporting documentation for that Scorecard which provides descriptions and explanations of the performance measures; and
- report to the Board its performance results (i.e., file the Custom IR Scorecard) annually commencing in April 2016.

In response to staff interrogatories 1.3-Staff-1 and 2.5-Staff-28, in relation to how Hydro One proposes the Board treat any differences between actual spending against approved planned spending, Hydro One states: (i) "At the end of the rate term, as per the RRFE Report, Hydro One intends to true-up its actual rate base to reflect actual in-service capital additions made during the rate term"; and (ii) "that no adjustments be made during the 5-year term to reflect differences between actual spending and planned spending".[34] Staff discusses its position on this matter in Section 4 of this submission regarding Hydro One's distribution system planning.

[34] Exhibit I/Tab 1.03/Staff 1

**Table 4: Illustration of Custom IR Scorecard**

| Desired Outcome | Area | Measures | | | | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Reduced number of vegetation-related interruptions during the 5 year plan (Excludes Force Majeure events) | Vegetation Management | Number of vegetation related customer outages | Results | Targets | | 6,300 | 6,300 | 6,200 | 6,100 | 6,000 |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | $ 142.0 | $ 177.6 | $ 180.3 | $ 161.1 | $ 152.9 |
| | | | | | OM&A | $ 142.0 | $ 177.6 | $ 180.3 | $ 161.1 | $ 152.9 |
| | | | | | Capital | $ - | $ - | $ - | $ - | $ - |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| Approximately 4,500 additional end-of-life poles will be replaced per year by 2019. | Pole Replacement | Poles replaced per year | Results | Targets | | | | | | |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| Address Federal PCB regulations and ensure Hydro One's communities' environmental concerns are addressed by decreasing the number of pole top | PCB Line Equipment | Number of pole top transformers with PCB oil that have been replaced | Results | Targets | | | | | | |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| Reduced number of substation interruptions during the 5 year plan. (Excludes Force Majeure events and planned outages) | Substation Refurbishmen ts | Number of substation interruptions over the five year period | Results | Targets | | | | | | |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| Reduced number of distribution line equipment caused interruptions during the 5 year plan. (Excludes Force Majeure events) | Distribution Line Equipment Refurbishmen ts | Number of distribution line equipment interruptions over the five year period | Results | Targets | | | | | | |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| Become a trusted partner to our customers by improving the quality of interactions and meeting their expectations regarding reliable power supply. | Customer Experience | Overall Customer Satisfaction | Results | Targets | | | | | | |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| Maintain current levels of distribution reliability, while improving customer service and satisfaction | Handling of Unplanned Outages | Percent of customers satisfied with the way Hydro One handled the unplanned outage | Results | Targets | | | | | | |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| Reduced number of estimated bills during the 5 year plan | Estimated Bills | Percent of estimated bills issued | Results | Targets | | | | | | |
| | | | | Achieved | | | | | | |
| | | | Costs | Budget ($M) | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |
| | | | | Actuals | Total | | | | | |
| | | | | | OM&A | | | | | |
| | | | | | Capital | | | | | |

# 3. Rate Base and Capital Investment

Hydro One provided its proposed Rate Base for each of the 5 years of the Custom Plan at Exhibit D1/Tab1/Schedule 1. The rate base underlying each of the test years' revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance.

Net fixed assets were calculated as gross plant in service minus accumulated depreciation and contributed capital. Working capital includes an allowance for cash working capital as well as materials and supplies inventory.

Rate base is set to increase from $6,553.3 million in 2015 to $7,869.6 million in 2019. The last test year for which the rate base established was 2011, and since that time significant assets have entered service. For instance, in 2011 the gross plant in the rate base was approved at $7,603.4 million. In this application, the 2015 gross plant is $2,496.5 million or 32.8% higher at $10,099.9 million.

The growth in gross plant in 2015 primarily reflects the in-service additions made to Hydro One's Distribution property, plant and equipment during the IRM period from 2012 to 2014 as well as amounts previously recorded as regulatory assets. For instance, as of January 1, 2015, $564.9 million of Smart Meter, Smart Grid and Distributed Generation gross fixed assets previously recorded as regulatory assets and tracked in deferral accounts were transferred into rate base.

Hydro One's proposals for working capital over the 5 year period are backed-up with an updated 2013 Working Capital lead-lag study by Navigant Consulting Inc.[35]. Hydro One Distribution's net cash working capital requirement for the 2015 test year is $249.9 million or 7.4% of OM&A ($564.3M) and Cost of Power expenses ($2,816.2M). Applying the same formula the remaining test years shows similar ratios.

Board staff has no disagreement with the calculation of the applied-for rate base. Staff notes that a large part of the increase requested in this application is due to capital additions coming into service since the last rebasing for Hydro One. Staff recommends that the Board require Hydro One, over the term of the rate plan, to report in-service

[35] Exhibit D1-1-3/Attachment 1

capital additions.  The reporting of these amounts each year will allow to Board to monitor the likelihood of another large bump-up in rate base at the time of Hydro One's next rates application.

Board staff accepts the methodology and results of the working capital allowance generated by the application of the Navigant report. Board staff points out that the Navigant working capital study is a good example of how Hydro One can credibly document a key aspect of its rate application with the submission of an updated, well known and credible external study.

## 3.1 Overhead Capitalization Rate

Hydro One has proposed overhead capitalization rates of 14% in 2015 and 13% for 2016-2019.[36] Hydro One adopted US GAAP in place of IFRS and the Board approved this choice in EB-2011-0399. The company has concluded that its overhead and indirect cost capitalization methodology is consistent with legacy and existing US GAAP. Hydro One believes that its methodology achieves intergenerational equity and avoids cross-subsidization.[37]  Hydro One has provided studies prepared by Black & Veatch to support its conclusions.

Board staff submits that for the current application, the evidence supports the proposed capitalization rates based on the continuation of Hydro One's past practices. It is important for the Board to understand that Hydro One may have capitalization policies that are only acceptable under USGAAP because they have been approved by the regulator.  However, board staff recognizes that there is limited evidence on the record for the Board to consider any changes from past practice at this time.  Board staff submits that Hydro One should include in its next cost based application (cost of service or Custom IR) an additional capitalization study based on IFRS principles even if it still prepares its financial statements under US GAAP. Hydro One should compare and contrast the results under both US GAAP and IFRS capitalization principles to highlight where there may be material differences that result in higher capitalization under US GAAP in areas such as direct and indirect overhead, depreciation[38] and interest.[39]

[36] Exhibit C1/Tab5/Schedule 2/p.2/Table1
[37] Ibid. p. 4
[38] Exhibit C1/Tab6/Schedule 1/pp. 2-3
[39] Exhibit D1/Tab4/Schedule 1

## 3.2 Capital Investment

The following section discusses overall investment levels in various categories of capital spending. This section is intended to convey information on general trends and drivers for major categories. It is intended as a complement and introduction to staff commentary on Hydro One's asset prioritization and planning process, found at Section 4.

Table 5 shows Hydro One's capital investment for a 10 year period from 2010 to 2019. Over the course of the 5 year plan, Hydro One's total investment is planned to grow from $624.5 million the 2014 bridge year to $669.1 in 2019, an increase of 7.1%

**Table 5**

Hydro One Distribution, EB-2013-0416
Capital Expenditure by Major Category
2010 - 2019, $ millions

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Sustaining** | 314.0 | 274.2 | 261.8 | 303.0 | 286.4 | 308.2 | 335.2 | 359.7 | 380.4 | 383.5 |
| | | -12.7% | -4.5% | 15.7% | -5.5% | 7.6% | 8.8% | 7.3% | 5.8% | 0.8% |
| *5 years from 2014 to 2019* | | | | | | | | | | 33.9% |
| **Development** | 162.9 | 157.1 | 185.9 | 193.0 | 200.2 | 223.3 | 206.3 | 185.7 | 183.5 | 199.1 |
| | | -3.6% | 18.3% | 3.8% | 3.7% | 11.5% | -7.6% | -10.0% | -1.2% | 8.5% |
| *5 years from 2014 to 2019* | | | | | | | | | | -0.5% |
| **Operations** | 1.2 | 1.3 | 2.7 | 8.9 | 5.1 | 9.4 | 18.8 | 7.0 | 7.0 | 4.2 |
| | | 8.3% | 107.7% | 229.6% | -42.7% | 84.3% | 100.0% | -62.8% | 0.0% | -40.0% |
| *5 years from 2014 to 2019* | | | | | | | | | | -17.6% |
| **Customer Service - Smart Grid** | 18.4 | 30.1 | 43.1 | 16.3 | 22.9 | 22.6 | 9.9 | 3.9 | 0.0 | 0.0 |
| | | 63.6% | 43.2% | -62.2% | 40.5% | -1.3% | -56.2% | -60.6% | -100.0% | n/a |
| *5 years from 2014 to 2019* | | | | | | | | | | |
| **Common Corporate Costs** | 93.2 | 133.0 | 142.5 | 127.8 | 109.9 | 85.4 | 84.5 | 83.1 | 84.2 | 82.3 |
| | | 42.7% | 7.1% | -10.3% | -14.0% | -22.3% | -1.1% | -1.7% | 1.3% | -2.3% |
| *5 years from 2014 to 2019* | | | | | | | | | | -25.1% |
| **Distribution Capital** | 589.7 | 595.7 | 636.0 | 649.0 | 624.5 | 648.9 | 654.7 | 639.4 | 655.1 | 669.1 |
| | | 1.0% | 6.8% | 2.0% | -3.8% | 3.9% | 0.9% | -2.3% | 2.5% | 2.1% |
| *5 years from 2014 to 2019* | | | | | | | | | | 7.1% |

Source: Exhibit D1/Tab3/Schedule 1

The largest segment, Sustaining Capital, shows the greatest growth, up 34% from 2014 to 2019 growing steadily to $383.5 million. Development investment remains relatively stable and Common Cost Investment falls by 25.1% over the 5 year time span.

The increase in Sustaining Capital is largely due to pole replacements and expenditures to address station assets that have reached the end of their expected service life. Development Capital expenditures increase in 2015 and 2016 largely due to investments in system capability reinforcement and investments to facilitate an increasing number of customer connections and upgrades. The increase in Operations Capital in 2016 is to fund the development of the Backup Control Centre facility. Funding then falls to historical levels by 2019.

The decrease in Customer Service and Corporate Common Costs spending is largely due to the completion of the Customer Information System implementation in 2013, other Cornerstone initiatives in 2014 and the Smart Grid pilot project completion in 2017.

### 3.2.1 Sustaining Capital

Sustaining capital investment accounts for over 45% of total capital investment, growing to 57% of total investment by 2019. Hydro One indicates that sustaining capital investments are intended to maintain the viability of the distribution system, ensure public and employee safety, ensure operational effectiveness by providing an acceptable level of reliability, deliver on customer commitments to demonstrate customer focus, and address public policy responsiveness by complying with all legislative, regulatory, and environmental requirements. [40]

The selection of planned sustaining capital investments is guided by the asset risk assessment process described in Hydro One's evidence at Exhibit A, Tab 17, Schedule 7. This process takes into account the condition, age, performance, criticality and utilization of specific assets and applies an economic evaluation is also performed as part of the process. The risk assessment process is discussed more specifically at Section 4 of this submission.

The sustaining capital program is broken down into 3 main sections, Stations, Lines and Meters.

[40] Exhibit D1/Tab3/Schedule 2

**Stations**

The overall Stations Capital investment for the test year 2015 is 25% greater than the 2014 bridge year, growing steadily by an additional 52% to 2019. Hydro One indicates that these expenditures reflect the increased asset replacement rates required to maintain reliability and risk levels on an on-going basis.

Hydro One claims the primary drivers for the escalation in this investment are the increase in transformers required to address the ageing demographics and degradation of the asset condition and increase in the number of station refurbishments to improve the existing risk profile of the station assets in order to sustain the safe and reliable operation of the distribution system.

Over 50% of Stations expenditure is Refurbishments which grow from levels of $2 – 3 million per year in 2010- 2103, to $26.1 million in 2014 and growing steadily to $45.2 million in 2019. Response to Interrogatory PWU#6[41] indicates that the rate of station replacements will rise from 4 per year to 32 per year and transformer replacements from 6 per year to 36 per year in the plan years.

In terms of productivity improvements, Hydro One's evidence noted the introduction of the integrated Modular Distribution Station which will provide a more cost effective solution to station refurbishments.[42] When asked about these efficiencies in response to IR Exhibit I/Tab 3.02/Energy Probe 30, Hydro One indicated that the cost of a conventional 44kV station is approximately $2.4 million and that the average cost of a complete refurbishment, utilizing an integrated modular distribution station (iMDS) for a 44 kV distribution station based on the pilot of this technology in 2013 was $1.9 million.

However, Hydro One did not commit itself to achieving these savings, claiming it is too early in the pilot project to quantify efficiencies gained or cost savings. This pilot project is still underway and once completed, Hydro One will be in a better position to quantify cost savings.

[41] Exhibit I/Tab.02/PWU 6
[42] Exhibit D1/Tab 3/Schedule 2

**Lines**

The Lines segment grows from $203.9 million in 2014 to 295.8 million by 2019, an increase of 45% over the 5 year period. The major sub-segment is Asset Replacement (accounting for over 70% of the total Lines budget) where investment grows by 71% between 2014 and 2019, to a level of $204.4 million.[43]

Poles are the biggest item of the Asset Replacement category, accounting for over 60% of that budget in 2019. Pole Replacement capital expenditures grow from $82.5 million in 2015 to $125.8 million in 2019.

**Meters**

The proposed spending for meters drops significantly in the 2015 test year but then increases on average by 20% until 2018, when it drops to $10.5 million. Hydro One indicated that this is primarily as a result of required telecommunication upgrades that will be completed by 2018, when the program resumes to historical spending levels.

In addition, the proposed spending for the sustainment of the meter inventory is also increasing on average by 5% annually over the five year period to address a higher anticipated rate of failure for meters.

## 3.3 Overall Increase in Spending

Board staff notes that overall capital costs grow 7% over the planning period, under the 2% forecast annual rate of inflation. Board staff does not suggest a specific reduction in the capital budget, but does submit that the need for large increases in pole and station spending call into question Hydro One's prioritization process for asset management. This is discussed further in the following section.

[43] Exhibit D1/Tab 4/Schedule 1

# 4. Distribution System Plan

Hydro One's evidence on its Distribution System Plan was filed at Exhibit A/Tab7/ Schedule 1 which provided a plan overview in Table 1, and referred to the many other exhibits that were part of the plan. This included exhibits found at Exhibit A/Tab 17 on the Planning Process, Asset Management Planning, Investment Plan Development, Investment Prioritization Process, Project/Program Approval & Control and Asset Risk Assessment.

Other key exhibits referred to were the Distribution Asset exhibits under Exhibit D1, such as the Distribution Assets Investment Overview, Summary of Capital Expenditures, List of Capital Expenditure Programs/Projects and the Investment Summary for Programs/Projects in excess of $1 million. In addition, reference was also made to the Operations Maintenance and Administration exhibits under Exhibit C1.

## 4.1 Need for a Consolidated Plan

Chapter 5 (Consolidated Distribution System Plan Filing Requirements) of the Board's Filing Requirements for Electricity Distribution Rate Applications states that "…a Distribution System Plan ("DS Plan") consolidates documentation of a distributor's asset management process and capital expenditure plan."[44] While section 5.2 of Chapter 5 contemplates that an applicant may present its DS Plan in a different order and with different section headings than set out in Chapter 5, Board staff submits that it does not contemplate an unconsolidated filing under Chapter 5 such as that submitted by Hydro One.

Hydro One indicated that the DS Plan evidence as presented reflects the planning process within the company, and that using the format expected by the Board would add complexity to Hydro One's preparations and make comparisons to earlier evidence more difficult.[45] Staff submits that given the Board's expectations for distribution system plans under the RRFE, and the use by Hydro One of new planning tools since the last cost of service filing, year over year comparisons provide less value to the Board than a consolidated plan. While the evidence as filed may reflect the company's planning

[44] Chapter 5 Consolidated Distribution System Plan Filing Requirements, p. 1.
[45] TC Tr (July 21, 2014); p. 7.

process, the purpose of a regulatory filing is to present to the regulator coherent and useful information.

In staff's view, the coherence and consistency of Hydro One's evidence in relation to their asset management process and capital expenditure plan would have benefitted greatly from presentation in a consolidated form. A consolidated description of future expenditures and their associated drivers would allow a better understanding of how different planning initiatives fit together and help shape a comprehensive view of the distributor's work.

## 4.2 Need for Greater Clarity in Description of Planning and Prioritization

Staff's understanding is that the development of Hydro One's DS Plan involves a multi-step process at the core of which is an investment selection and "risk-based" prioritization process that is used to "identify the appropriate level of investments that will ensure the achievement of customer commitments, maintain safety and reliability while minimizing customer bill increases."[46]

Hydro One indicates that this Asset Risk Assessment methodology, while built on the foundation of the Asset Condition Assessment approach it used previously, now includes data collected via an inventory of its key distribution assets and centralized in a repository linked to "non-condition" based information such as outage and customer data.[47]

It is staff's understanding that this data, accessed through a software package referred to in evidence as the "Asset Analytics Tool" ("AAT"), is used to produce prioritized lists by asset (e.g. transformer) or asset system (e.g. distribution station) for the purposes of planning distribution system asset maintenance and replacements.[48]

[46] Exhibit A Tab 17 Schedule 4; p. 10.
[47] Exhibit A Tab 17 Schedule 7; p. 1.
[48] Exhibit A Tab19 Schedule 1; p. 8. System asset replacements are referred to generally in Hydro One's evidence as "Sustainment" investments, most of which would be included in the 'System Renewal' investment category as set out in Chapter 5 (at p. 6).

Hydro One states that "Asset Analytics is a valuable input into the investment planning process that assists in prioritization of investments and optimization of asset life."[49] Since the AAT is "continually updated any time any maintenance, refurbishment, replacement or new construction occurs", Hydro One states that "planners have constant up to date information to determine the most effective business plan to meet the customer, business and corporate requirements".[50]

Staff further understands that Hydro One's Asset Risk Assessment methodology includes, since 2013, the use of a software application called the "Asset Investment Planning (AIP) solution"[51] (also referred to as "the Asset Investment Planning Tool"[52]). The AIP uses information on alternative levels of spending and corresponding levels of asset-related risk reduction to produce a "draft investment plan which is reviewed and discussed by senior management when finalizing the priority and pacing of proposed investments."[53]

The evidence shows that the AAT and AIP each employ specific risk categories, risk weightings and risk scoring methodology; the inputs and outputs of both are described in some detail. Staff found the various descriptions and demonstrations of the AAT particularly helpful.

Board staff submits that taken in isolation, the processes for condition and asset risk assessments make sense. In addition, Board staff expects that the use of the AAT as a dynamic asset register is helping Hydro One get more accurate and current information on its assets. This tool should help Hydro One manage system upgrades and maintenance more effectively, and support continuous improvement and reliability and quality of service upkeep.

However, how the risk assessment results in a consistent approach in prioritizing investments is less clear. The evidence suggests that the application of the AIP in the preparation of Hydro One's DS Plan – while straightforward for some categories of investment – was much less so for others.

[49] Exhibit A Tab 17 Schedule 3; p. 5.
[50] Exhibit A Tab 17 Schedule 3; p. 5.
[51] Exhibit A Tab 17 Schedule 4; p. 2
[52] Tr. Vol. 4; p. 97
[53] Tr. Vol. 4; p. 97

This disconnect is illustrated by the lack of nomenclature consistency between descriptors used at Exhibit D2, Tab 2, Schedule 3 and the descriptors generated by the AIP. Hydro One acknowledged at the hearing[54] that the two do not correspond. The evidence in relation to certain investments indicates that "demographics" – asset age relative to "expected life" – plays a dominant role in determining the number of assets of a particular type to be replaced through a sustainment investment program. It is not clear what role asset condition and other risk factors tracked by the AAT play in investment prioritization. When asked for the percentage of each asset category that represented a high risk, Mr. Brown indicated that the results would be pretty close to the expected service life models.[55]

Board staff cross-examined the company's witnesses with respect to the planning process for the wood pole replacement and station upgrade programs. Several examples were discussed which Board staff submits illustrate the lack of clarity in the evidence presented around the planning and prioritization process.

The role of Hydro One's AIP tool in the selection of the level of investment for pole replacements, which is described in Exhibit D2/2/3 S10 as "'Increased Rate' (Recommended)" is unclear. Exhibit TCK1.1 at p. 44 Hydro One shows that when planning the level of wood pole replacement, four alternatives were considered for assessment using the AIP tool, three of which addressed in varying degrees 'safety', 'reliability', 'shareholder' and 'customer' risk. The alternative indicated as selected ('Vulnerable Reduced') is consistent with the cost and number of pole replacements mentioned in D2/2/3 S10, but is shown in TCK1.1 as having no impact on any of the relevant risks. The lack of evaluation of risk for the investment level actually selected appears to staff to be a significant gap in the evidence.

It became clear during the hearing that the investment categories provided in the output from the asset investment planning tool are insufficiently granular for the company's purposes[56]. Board staff submits that the investment levels are not yet properly aligned with the actual condition of the assets.

[54] Tr. Vol. 5, p. 21 (line 25) – p.24 (line 13)
[55] Tr. Vol. 5, p. 136 & 138.
[56] Tr. Vol. 5, p.20

The evidence regarding station refurbishment indicates that "[m]aintain[ing] the safe operation and reliability of the distribution station by addressing all ageing and degrading equipment in an integrated manner" is Hydro One's expected outcome of the investment in relation to 'Operational Effectiveness'. Staff notes that maintaining – not improving upon – the *status quo* is reflected in Hydro One's performance metric for this investment: the target is to maintain over the forecast period the average number of station related outages recorded over the historical period.[57] This level of investment is partly determined, as staff understands it, by the availability of funding and a desire not to exceed the target bill impacts.

Notwithstanding this target, the description of the "recommended" investment alternative in D2-2-3 reads as follows: "Refurbish entire stations or parts of a station to current Hydro One Distribution standards in order to improve the reliability of the distribution system." In addition, Hydro One counts "reducing the risk of lengthy equipment outages caused by equipment failure or malfunction" as one of the expected results of this investment.[58]

The apparent contradiction between Hydro One's *status quo* stations interruptions target and their objectives to reduce risk and improve reliability performance in relation to stations assets was explained by saying that any reliability improvements would be in relation to the reduced performance that would result if the investments were not undertaken as proposed[59] – in effect, Hydro One's implied metric is avoided interruptions, not a reduction from current levels. The evidence does not, however, provide any quantitative information on expected reliability performance in relation to stations interruptions for any of the alternatives considered, which would have provided an indication of the reliability considerations pertinent to the investment level chosen.

Hydro One proposes to refurbish a total of 194 or about 19% of its 1,004 total stations over the forecast period. Included in the stations refurbishment investment is the replacement of 126 transformers by 2019, which when combined with 30 more replaced in the Transformer Spares and Replacements program will result in the replacement of about 13% of Hydro One transformer fleet (not including units replaced on an

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[57] Exhibit A Tab 4 Schedule 4; p. 10. Hydro One complicates its performance metric information by showing status quo targets accompanied by the statement that "Hydro One's goal is to reduce the number of substation interruptions during the 5 year plan."
[58] Exhibit D2/Tab 2/Schedule 3 S07; p. 4.
[59] TC Tr of July 21, page 62.

“unplanned” basis). It is not clear from the evidence how the ‘Stations’ vs. individual transformer (and other component) replacements investments were optimized to minimize costs while achieving the stated objectives.

The apparent disconnect between the evidence presented at D2-2-3, the investment summary for station work, and the output of the AIP is illustrated by the inconsistency in the type of risks discussed in each document. At D2-2-3 several risks are listed such as safety and environmental risks, which might be relevant to the non-electrical costs of the work. However, at TCK1.1, only reliability risk is evaluated. Mr. Brown gave the following explanation[60]:

> “So once all of these investments do go into the asset investment planning tool and an investment planning proposal is pulled together, it gets multiple levels of review, and the elements associated with risk that we were talking about that perhaps are missing in this particular input to the asset investment planning tool, they are covered through our oversight review and discussions around the table around what those risks are that we're actually dealing with on a program-by-program basis.
>
> This is -- this is new ground for us. While this is an excellent tool, this one investment here, I would suggest we may have -- we may have, as an input to the tool, not put some of those things in that I would have considered should be there. However, that I can tell you has been addressed at a more senior level as we talk about these kinds of investments. We talk about all of those types of risks that would include, for example, an environmental safety risk. And judgment -- there is judgment by planners as they put these things into the tool. In this particular case the reliability risk certainly is the most important thing that we need to address with refurbishments.”

While staff accepts that judgment and multiple levels of review are necessary in the investment planning process, the purpose of evidence filed as a DS Plan is to give the regulator a clear picture of the planning process. According to Hydro One, depending on the scope of the station refurbishment, “the percentage of costs attributed to the replacement of deteriorated structures, fences, grounding systems, site issues, safety concerns and environmental compliance issues can range up to 40% of the total project

[60] Tr. Vol. 5, pp. 25 - 26

cost."[61] How these costs – which as a percentage of the total proposed investment could represent up to $80 million over five years – were evaluated using Hydro One's AIP tool is not made clear in the evidence.

## 4.3 Cost of Planned Work

The lack of clarity in the asset investment planning and prioritization process should be of concern to the Board, given the proposed increase in spending levels on certain programs.

In Exhibit D1 Tab 3 Schedule 2 at page 28 Hydro One details its proposal to increase spending on wood pole replacements from $320.2 million over the historical period to $529.8 million over the forecast period. Staff estimates that this represents an increase of approximately 66% in both spending and the number of wood poles replaced compared to the previous period.

In Exhibit D1 Tab 3 Schedule 2 at page 8 Hydro One details its proposal to increase spending on 'Station Refurbishments' from $63.4 million over the historical period to $203.3 million over the forecast period. Staff estimates that this represents an increase of approximately 220%. Staff recognizes that Hydro One's proposed investments in 'Transformer Spares and Replacements' (D2/2/3; S01); 'Spill Containment' (S03); 'Station Components' (S04); 'Recloser Upgrades' (S05); 'Demand Work' (S06); and 'Station Refurbishments' (S07) programs each also involve the replacement of assets located at Stations.[62] Staff estimates that taken together, Hydro One proposes to increase spending on these programs from $162.9 million during the historical period to $334.5 million over the forecast period, an overall increase of approximately 105%.

Board staff considered recommending to the Board the denial of recovery of some of the proposed spending for the poles and stations programs. However, the record in staff's view is insufficient to allow a recommendation for reduction to be made that is not to some degree arbitrary. Staff believes Hydro One's evidence is probably sufficiently accurate that reduction of spending in the program areas would not avoid costs but defer spending until later years, when the costs may be higher[63].

[61] Exhibit I/Tab 2.04/Staff 24; p. 2.
[62] Exhibit D1Tab 3 Schedule 2; p. 15.
[63] Tr. Vol. 5, p. 39

Staff also recognizes that the aim of Hydro One's increased spending is to create an "asset optimal" level of spending for its investments, which for Hydro One is the point at which total lifecycle costs of the asset are minimized.[64] This is a laudable goal, as the minimization of life cycle costs provides value for money for the utility and its customers in the long term. Life cycle costing provides a unified approach to managing capital and OM&A costs, but underscores the importance of project selection. In staff's submission, the DS Plan in this case does not clearly demonstrate the process by which Hydro One ensures the most effective use of capital and O&M spending.
Board staff also urges Hydro One to find a way to monetize the benefits of the DS Plan to customers. Some expression of the value of the planned spending in dollar terms or net present value, rather than an undefined risk score, would help the Board and Hydro One's customers understand why Hydro One is choosing to spend ratepayers' money on the selected projects and programs.

Staff is concerned with the lack of benchmarking evidence and lack of evidence of improvement in unit costs. While staff is not recommending a specific cost reduction, the total cost stretch factor proposed earlier in this submission should incent the company to find efficiencies in the work it has proposed to undertake.

## 4.4 Recommendations for Filing and Reporting

Hydro One has been using the AAT only since 2012[65], and acknowledges that the company is still learning about the AIP process. Board staff suggests that this new planning process is not yet fully integrated within the company. Board staff also acknowledges that this is the first Custom IR filing the Board has received from an electricity distributor, and therefore Hydro One did not have the benefit of prior Board decisions to consider as it prepared the DS Plan.

Board staff is not questioning the expertise of Hydro One's engineers and planning staff. Hydro One has successfully operated a radial distribution system in difficult service territory for nearly 100 years[66]. However, the <u>evidence</u> of the process of distribution system planning in this application is inadequate, in staff's view and is not reflective of a distributor with Hydro One's experience.

[64] Tr. Vol 5, p. 19
[65] Tr. Vol. 4, p. 107
[66] Exhibit A/Tab6/Schedule 1; p. 5

Board staff submits that the Board should find that the form and content of the DS Plan presented by Hydro One in this application is not consistent with the Board's expectations under RRFE or Chapter 5 of the Filing Requirements. Board staff further urges the Board to require Hydro One to file, as part of its next rate filing at the end of this plan term, a consolidated DS Plan, containing a clear and consistent description of the planning and prioritization process undertaken to justify the proposed spending contained in the consolidated DS Plan.

The evidence was clear that there has been no third party review of either the asset analytics tool or the asset investment planning process. Judgment is needed in both these tools at several stages, such as the inputs of asset status and the weighting of the various risk factors considered in the models. Mr. Brown indicated that these tools and the risk evaluation that is conducted with them is new ground for the company and the industry[67]. He indicated that Hydro One is discussing and testing out new ideas with the CEATI group. Mr. Brown further indicated that the results of the consultation and research, as well as the demonstration of the success of the asset analytics tool, can be expected over the next five years[68].

Board staff notes the statement in the RRFE Report that "the Board sees merit in receiving the evidence of third party experts as part of a distributor's application"[69], and recommends that a third party review of the asset investment planning and prioritization process be undertaken and presented as evidence to support the DS Plan at the next rate hearing for the company at the end of this rate plan term.

Hydro One agreed to report annually on the results of its capital programs in the form presented in undertakings J1.1 (and J4.9).[70] Staff submits that in addition, Hydro One should report annually on some measure of asset condition. Staff recognizes that all distributors, including Hydro One, report on reliability measures as part of RRR reporting. However, staff submits that reliability can be considered a lagging indicator of problems in the system. Asset condition is a leading indicator of the health of the distribution system. Changes in asset condition or risk profile should provide some indication of the correctness of Hydro One's program prioritization and its effectiveness

[67] Tr. Vol. 5, p.134
[68] Tr. Vol. 5, p. 135
[69] RRFE Report p. 37
[70] Tr. Vol. 5, p.86.

in reducing those very risks which it seeks to measure and control by virtue of its asset investment plan. Reporting on how the company is managing its assets on a risk-adjusted basis should also aid in making more patent the value the company is delivering to its customers – a goal consistent with RRFE principles.

Mr. Brown stated that Hydro One has developed a risk index score for major power system assets which gives a full picture of the risk profile of these assets in the company's distribution system[71]. He indicated that Hydro One now uses a risk-based approach to asset condition which includes additional factors than were used in the previous asset condition assessment[72]. Staff submits that Hydro One should be able to provide to the Board a risk profile for its main power system assets. Board staff recommends that the Board require Hydro One to report annually, as part of its reporting on the plan, risk scores on the "condition", "performance" and "demographics" measures as of December 31st of each year beginning with the bridge year (2014) calculated using its Asset Analytics Tool for each of the following assets and asset systems: wood poles; (station) transformers (excluding Mobile Unit Substations); Stations; and Lines. Board staff recognizes that some risk measures are correlated, and invites Hydro One to comment on which asset class scores and risk measures would provide the best picture of the health of the system.

It is staff's belief that annual data on asset condition would be a valuable supplement to additional specific reporting on outcome measures, as well as to the reliability, spending and financial results reported via the Board scorecard. Together these data points should provide the Board with a suite of indicators that will permit the effective ongoing monitoring of Hydro One's performance envisioned in the RRFE.

Staff has already submitted that Hydro One should track in-service capital additions over the term of the plan. Given the size of the capital budget and the lack of evidence on the scale of some of the investments therein, staff submits that a variance account be established with features similar to the account proposed in the EB-2014-0140 Hydro One Transmission Settlement Proposal. In that proposal, parties agreed that Hydro One should create a net cumulative asymmetrical variance account for 2014, 2015, and 2016 to track the impact on revenue requirement of any in-service capital additions shortfall compared to Board approved amounts, for

[71] Tr. Vol. 5, p. 33
[72] Tr. Vol. 5, p. 130

disposition in a future rates application. In this (Distribution) case, the applicable years would be expanded to 2014, 2015, 2016, 2017, 2018 and 2019.

Staff submits that the implementation of a variance account is an appropriate response to the uncertainty regarding the robustness of the rationale for Hydro One's capital plan. It should provide customers some degree of shelter from some of the risks inherent in the company's refinement of its risk-based approach to planning and investment. It would more firmly define the capital envelope eligible for recovery from customers and ensure that distribution customers would only pay for assets actually put into service over the course of the 5 year plan while allowing Hydro One flexibility to adjust its plan as it improves its assessment techniques over time. If Hydro One does make changes to its plan that increase costs, staff submits that Hydro One's reported asset condition metrics over time will be instructive in evaluating the prudence of the changes.

# 5. Operations, Maintenance and Administration Costs

Hydro One applied for Operations, Maintenance and Administration Costs (OM&A) for each of the 5 years in the rate plan. The pre-filed evidence is found in Exhibit C1. The amounts included are summarized by major cost category in Table 5 below.

**Table 5**

**Hydro One Distribution EB-2013-0416**
**Operations, Maintenance and Admin. Expenditures by Major Category**
**2010 - 2019, $ millions**

| | | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Sustaining** | | 305.9 | 317.1 | 307.9 | 318.1 | 320.4 | 329.5 | 374.4 | 380.1 | 363.2 | 358.1 |
| | | | 3.7% | -2.9% | 3.3% | 0.7% | 2.8% | 13.6% | 1.5% | -4.4% | -1.4% |
| | *5 years from 2014 to 2019* | | | | | | | | | | 11.8% |
| **Development** | | 12.3 | 15.8 | 14.7 | 12.1 | 18.4 | 15.4 | 17.7 | 17.0 | 17.3 | 17.8 |
| | | | 28.5% | -7.0% | -17.7% | 52.1% | -16.3% | 14.9% | -4.0% | 1.8% | 2.9% |
| | *5 years from 2014 to 2019* | | | | | | | | | | -3.3% |
| **Operations** | | 18.6 | 18.1 | 21.0 | 22.8 | 30.4 | 30.3 | 34.4 | 34.8 | 42.3 | 41.0 |
| | | | -2.7% | 16.0% | 8.6% | 33.3% | -0.3% | 13.5% | 1.2% | 21.6% | -3.1% |
| | *5 years from 2014 to 2019* | | | | | | | | | | 34.9% |
| **Customer Services** | | 114.7 | 113.3 | 116.7 | 137.3 | 133.7 | 117.8 | 116.3 | 114.7 | 113.5 | 115.4 |
| | | | -1.2% | 3.0% | 17.7% | -2.6% | -11.9% | -1.3% | -1.4% | -1.0% | 1.7% |
| | *5 years from 2014 to 2019* | | | | | | | | | | -13.7% |
| **Allocated Common Corporate** | | 94.9 | 85.5 | 88.6 | 102.8 | 73.8 | 66.7 | 62.5 | 62.4 | 62.4 | 62.3 |
| **Costs** | | | -9.9% | 3.6% | 16.0% | -28.2% | -9.6% | -6.3% | -0.2% | 0.0% | -0.2% |
| | *5 years from 2014 to 2019* | | | | | | | | | | -15.6% |
| **Property Taxes** | | 4.6 | 4.6 | 4.5 | 4.5 | 4.6 | 4.7 | 4.9 | 5.0 | 5.2 | 5.4 |
| **& Rights Payments** | | | 0.0% | -2.2% | 0.0% | 2.2% | 2.2% | 4.3% | 2.0% | 4.0% | 3.8% |
| | *5 years from 2014 to 2019* | | | | | | | | | | 17.4% |
| **Total OM&A** | | 551.0 | 554.4 | 553.4 | 597.6 | 581.3 | 564.4 | 610.2 | 614.0 | 603.9 | 600.0 |
| **($ millions)** | | | 0.6% | -0.2% | 8.0% | -2.7% | -2.9% | 8.1% | 0.6% | -1.6% | -0.6% |
| | *5 years from 2014 to 2019* | | | | | | | | | | 3.2% |

Source: Exhibit C1/Tab 2/Schedule1

As shown in the table, in general it appears that Hydro One's OM&A costs are reasonably controlled over the life of the plan. The increase over the 5 year period is 3.2%. Staff notes that inflation is forecast to be 2% over that period.

Staff also inquired [73]about the OM&A cost per customer over the plan period and learned that Hydro One's OM&A cost per customer from 2014 to 2019 is set to decline slightly (1.3%). The same interrogatory response showed that on an

[73] Exhibit I/Tab 3.01/Staff 38

OM&A cost per km of line basis, costs will be increasing by 3.2% over the 5 year period.

In terms of the specific OM&A spending categories, Operations activities show the largest growth during the rate plan with a 35% increase, while reductions are found in Development, Customer Services and Corporate Costs.

Over 60% of OM&A is accounted for in the Sustaining category with a 2019 spend of $358 million and a 5 year increase of 12%. Notable is the spike in spending in 2016, driven mainly by Vegetation Management increases, which taper off as Hydro One approaches the desired 8 year clearing cycle.

## 5.1 Sustaining Vegetation Management

Vegetation Management accounts for about 40% of the Sustaining OM&A program. According to the pre-filed evidence, Hydro One plans to spend $139 million on Vegetation Management in 2014, growing to $142 million in 2015, $178 million in 2016, $180 million in 2017.[74] Spending declines to $161 million and $153 million in 2018 and 2019, respectively. Hydro One indicated that it is currently on a 9.5 year clearing cycle but is moving to achieve an 8 year cycle, largely in the time span of this application.

In the Executive Panel presentation on May 12, 2014, Hydro One showed the accomplishments or achievements for Vegetation Management in cost per unit of line clearing and cost per unit of brush control.[75] In the case of Line Clearing, the PD1 Exhibit showed the cost per km cleared for 2013 is $7,994, which increases by 18% to $9,407 in the 2014 bridge year. However, by 2019 the cost per km amount falls to $7,829, showing only a slight (2%) increase in efficiency from 2013.
As for Brush Control, a 9.4% decrease in cost per km controlled is found from 2014 to 2019. Board staff notes that the evidence shows some increase in efficiency for these activities.

However, Board staff points out that Hydro One presented no evidence on how well Hydro One is performing on this key metric, as Hydro One did not perform or take part in a meaningful benchmarking study of Vegetation Management. The Board and

[74] Exhibit C1/Tab2/Sch2/pg.4/Table 1
[75] Exhibit PD1/p. 9

intervenors are familiar with benchmarking for Vegetation Management as a comprehensive study was filed in Hydro One's EB-2009-0096 rates case.

The Vegetation Management study filed in that case was undertaken by CN Utility, dated September 18, 2009.[76] The study concluded, among other things, that Hydro One Distribution's vegetation management efficiency is generally better than average on the basis of labour hour measures and slightly worse than average on the basis of unit costs.

Board staff questions why Hydro One did not perform another benchmarking study such as the CN Utility study of 2009 in advance of an application for a 5 year rate approval, particularly when the there is a proposal to decrease the clearing cycle. If this study had been performed, the Board would have been in a position to evaluate how well Hydro One was performing in this crucial area of their operations, both in its current operations and also in its predictions of future productivity improvements.

In the course of the oral hearing, it was revealed through the KPMG study information that Hydro One had taken part in a less rigorous Vegetation Management study in 2012.[77] (KPMG was engaged by the Ministry of Energy in 2012 to undertake a critical review of existing compensation, efficiency and productivity benchmarking studies that have been complete on Hydro One.) Hydro One eventually produced this study as an undertaking[78].

Another area of major OM&A expenditure is Lines Sustaining work, specifically, the Demand Work category (comprised of trouble calls, underground cable locates, and disconnects/reconnects). The Hydro One witness, Mr. Brown, was asked about benchmarking or looking for best practices regarding this work. The witness replied that Hydro One had not, "…undertaken any review of best practices in the industry or benchmarking of any kind." [79]

[76] Filed in EB-2009-0096 as Exhibit A/Tab15/Schedule 2/Attachment 1
[77] Tab 3.3/SEC 31/Attachment 1
[78] Exhibit J3.10
[79] Tr. Vol. 4, p. 206

## 5.2 Operations

As noted above, Operations OM&A costs are planned to grow from $30.4 million to $40.1 million from 2014 to 2019, an increase of 35%. Staff notes that almost all of this increase is driven by Smart Grid costs which rise from $6.1 million in 2014 to $15.1 million in 2019, an increase of 147% over the period. Board staff acknowledges the benefits that can be provided by Smart Grid activities in the modernization of a distribution system. However such large increases in budgets without indicating how efficiencies are being pursued over the period, leaves questions as to the value for money of these growing expenditures.

## 5.3 Common Corporate Costs

Common corporate costs are forecast to drop by 15.6% over the course of the plan from the 2014 Bridge year budget. Board staff reviewed the evidence for these costs and notes that Hydro One provided an updated Black and Veatch common cost allocation methodology submitted in Exhibit C1/Tab 5/Schedule 1. Board staff notes that Hydro One, in continually updating and improving the Black & Veatch study, ensures that common cost allocation methodologies are clearly described and documented for the application. Staff has no concerns with the methodology as filed in this application.

## 5.4 Customer Services- Inergi Agreement

Customer Service costs are forecast to fall by 14% from 2014 to 2019. As part of its Customer Service function, Hydro One outsources its information technology services, customer service operations, settlements, source-to-pay, payroll, and finance and accounting services. It entered into a 10-year services agreement with Inergi LP ("Inergi") on December 28, 2001 for services commencing on March 1, 2002. The agreement provided for an optional 3-year extension to the original 10-year term, but before the initial term of the original agreement expired, the parties agreed to amend the underlying business terms, to make them consistent with current market practices and business requirements. This resulted in a 12% average annual reduction in fees over the extended 3 year period.

Board staff notes that in the third quarter of 2013, Hydro One opted for an optional third party benchmarking of the fees charges under the agreement. The report was completed in February 2014 by TPI Sourcing Consultants Canada Corp, an affiliate of Information Services Group Inc. The report concluded that the adjusted fees charged by Inergi do not exceed the "benchmark price" as defined in Agreement. As a result, there were no changes to the fees charged by Inergi as of March 1, 2014.[80]

Board staff also notes that the Inergi agreement has a provision where global best practices are to be suggested by CapGemini resulting in cost savings, (primarily in strategic sourcing and infrastructure storage reduction). [81]

As the current agreement will be expiring on February 28, 2015, Hydro One has provided an description of its transition plan and plan to tender the contract [82]and has indicated that it has defined objectives to increase cost effectiveness and efficiencies in providing services to the customer. These objectives are: service delivery to reflect global practices, flexibility for Hydro One to change volumes and scope and access to new technologies.[83] In the schedule of future costs provided at Exhibit C1/Tab 2/Schedule 7/Appendix B, it appears the contact will result in only moderate cost increases, increasing 3.8% from 2015 to 2019.

## 5.5 Compensation and Staffing

Compensation and staffing costs are the major contributor to Hydro One's overall OM&A costs. Hydro One's overall staffing and compensation numbers were provided at C1-3-2 Attachment 2 and show, in aggregate, that Hydro One staffing levels are set to decrease slightly from 8,223 in 2014 to 8,162 in 2019. Total wages increase by 6.5% over the 5 year plan period reaching $859 million in 2019.

Hydro One also filed an updated Mercer compensation study (C1-3-2 Attachment 1), after filing similar studies in 2009 and 2012. Compensation in this case includes base wages and salaries, as well as benefits and pensions. The 2013 study findings are shown in Table 2 below. The findings indicate that on an overall weighted average basis, Hydro One's total compensation was 10% above the market median in 2013. This is an improvement relative to the 2008 Mercer study where Hydro One's overall

[80] Exhibit C1/Tab 2/Schedule 7/p. 4
[81] Exhibit C1/Tab 2/Schedule 7/p. 5
[82] Exhibit C1/Tab 2/Schedule 7 pp. 6-13
[83] Exhibit I/Tab 4.02/Staff 63

weighted average was found to be 17% above market median. The 2011 study indicated that Hydro One was 13% above the median showing steady progress on this measure.

**Table 7**

**Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation**

| Employee Group | 2013 Survey Results | 2011 Survey Results | 2008 Survey Results | Total Change from 2008 to 2013 |
|---|---|---|---|---|
| **Management** | -1% | -17% | -1% | 0% |
| **Society** | 9% | 5% | 5% | 4% |
| **PWU** | 12% | 18% | 21% | -9% |
| **Overall** | 10% | 13% | 17% | -7% |

Board staff was concerned that Hydro One make progress to achieve the market median in the future. Hydro One witness, Mr. Struthers indicated that:

> "…the company intends to approach the median. That's one of its objectives." [84]

When Mr. Struthers was asked if the total compensation figures as shown in the total compensation tables at C1-3-2 Attachment 2 were consistent with Hydro One's desire to move compensation towards the industry median, he replied that:

> "It reflects the budgeting assumption, which was a 2 percent increase (per annum)".[85]

Board staff also notes that in response to staff Interrogatory #68 [86]Hydro One indicated that it is also planning on an increase in the employee pension contribution percentage from 28% in 2015 to 35% in 2019, showing some progress in moving the contribution ratio to 50/50, which is the norm for public sector defined benefit pension plans. In Board staff's submission, these are all good indications that costs are generally on a slight decline and some efficiencies are being achieved over the time span of this plan.

[84] Tr. Vol. 2, p. 142
[85] Tr. Vol. 2, p. 144
[86] Exhibit I/Tab 4.03/Staff 68

Board staff's discussion of accounting for Pension and Other Post-Employment Benefits are provided separately at the end of this section.

## 5.6 Need for Further Benchmarking Evidence

As Board staff has mentioned, the overall increases in OM&A over the course of the 5 year plan seem reasonable and show increases below the forecast inflation rate. Also, on a per customer basis, OM&A costs decline slightly from 2015 to 2019.

However, that being said, there is very little evidence to show 1) that Hydro One is efficient or cost effective as it begins the five year plan, and 2) that planned efficiency improvements are sufficient throughout the years of the plan.

The RRFE Report makes it clear that a Custom IR application must include benchmarking to help assess the reasonableness of the distributor's forecast.[87] Board staff submits that more comprehensive external benchmarking evidence is needed to show current operating efficiencies compared to others in the industry.

Staff has already submitted in Section 2 that better evidence, in the form of a productivity analysis of its own total factor productivity would be useful to demonstrate how Hydro One can credibly increase productivity over the course of the plan. In the absence of documentation of any productivity investments that could improve performance over time, there is little certainty that the cost increases in certain significant OM&A line items, such as vegetation management, are delivering continuous improvement in cost performance.

In Board staff's view, Hydro One has provided an inconsistent record in this case with regard to benchmarking. Hydro One filed the Mercer compensation study, which is a well-documented study, familiar to both intervenors and the Board, showing progress over the last several years and providing a measurable goal for the future. The Mercer study is a good example of how benchmarking provides persuasive evidence of improving cost performance. Similarly, the Inergi Contract evidence suggested that the current contract is delivering value for customers, and the tendering process for a new services contract will reduce costs.

[87] RRFE Report, page 13.

However, there is no current benchmarking evidence to justify the proposed costs for Vegetation Management, a key program with significant spending. Hydro One filed a credible benchmarking study in EB- 2009-0096 (CN Study), but chose not to file a study for this current 5 year plan. Other program elements of the OM&A budgets (such as Lines Work) could also have been supported by benchmarking, productivity and best practices studies, but these were not initiated or provided.

Overall, Board staff submits that the trends in many OM&A areas generally appear reasonable over the 5 year term, with some benchmarking evidence to support these costs. However, there are several shortcomings in the OM&A forecasts which need to be addressed in order to deliver better value for customers. Since many of the costs or activities themselves lack any justification through benchmarking either to peers or to even within the company over time, there is doubt that the initial and overall levels are reasonable or provide value to customers.

Finally, for areas such as line sustainment and demand work, the Company does not appear sufficiently committed to identifying and adopting best practices that will lead to efficiencies. The evidence overall suggests that the company still has work to do to achieve a comprehensive orientation towards continuous improvement and delivering value for ratepayers as expected by the RRFE.

As the single largest line item in Hydro One’s revenue requirement, OM&A should also be the single largest opportunity for savings and cost efficiency. Board staff submits that Board should not be persuaded that Hydro One has done all it can to create value for ratepayers. Board staff is therefore of the view that the Board should impose the stretch factor as recommended in Section 2 of this submission.

Staff also submits that more comprehensive benchmarking evidence is required prior to the company’s next rebasing. Staff’s submits that Hydro One should, at its next rates application, provide benchmarking studies for key areas of its operations, most notably Vegetation Management, Lines Work and Customer Service. The December 15, 2011, Oliver Wyman study, filed in Exhibit I/Tab 3.3/SEC 30 was a step in the right direction, but no such study was undertaken in support of this application.

Board staff has already noted (in Section 2 of this submission) the proposal in the Settlement Agreement for the recently submitted Hydro One Transmission Rates application EB-2014-0120. Board staff submits that Hydro One, in addition to total cost benchmarking, should undertake benchmarking of significant aspects of its distribution business. Staff recognizes that separate studies will be required for transmission and distribution, but hopes that undertaking the studies at the same time will be cost effective.

## 5.7 Pensions and Other Post-Employment and Post-Retirement Benefits ("OPEBs")

Board staff submits that the pension and OPEB costs requested for recovery in this application are reasonable and recovery is supported under the current policy environment. Board staff supports the request for continuation of the Pension Cost Differential Account as proposed by Hydro One. However, Board staff submits that in the longer term, a mechanism is required to ensure that amounts collected from ratepayers for OPEBs are set aside for that purpose. Staff acknowledges that further research is warranted into the need for and implementation of such a mechanism.

Hydro One recovers pensions and OPEB costs from ratepayers in different ways. The pension costs are included in revenue requirement based on the forecast contributions to the pension plan. These contributions are determined by actuaries, and recovered on a cash basis (i.e. in the year payment is made to retirees). OPEBs are also determined by actuaries and the forecast accounting costs comply with US GAAP requirements. OPEBs are recovered on an accrual basis, and historically the actual cash payments to retirees are less than the costs recovered from ratepayers.[88]

Hydro One capitalizes approximately 50% of its total pension costs in fixed assets and the remainder is recovered in OM&A costs. Approximately 54% of OPEB costs are capitalized in fixed assets.[89] Hydro One has a Board-approved variance account for pension costs. The difference between the forecast pension cost recovery in OM&A and the actual pension costs not capitalized each year is recorded in the variance account. Variances on the amounts capitalized are not captured in the variance account.[90]

[88] TCJ1.19
[89] ExhibitC1/Tab3/Schedule 3; Exh. I/Tab4.03/Staff 65; Exhibit I/Tab4.03/Staff 70
[90] TC Tr. Vol. 1, pp. 191-192.

Hydro One uses the difference between the amounts collected for OPEBs and the amounts paid out for general corporate purposes, such as contributions to the pension plan.[91] Hydro One does not have a set-aside mechanism, such as a trust fund, into which the over-recoveries are deposited in a manner similar to the pension plan.

Board staff asked why the cash basis for recovery of OPEBs in rates was not possible given that the company recovers pension costs on a cash basis. The company's witness provided references in US GAAP that appear to preclude the recognition of regulatory assets for the difference between the cash and accrual methods related to OPEBs.[92]

Since 2000, Hydro One Inc. has recovered approximately $217 million more than it has paid to retirees. The Hydro One Networks Distribution portion of this amount is over 50%. Hydro One has asked that it be allowed to continue to recover its current costs on an accrual basis in rates even though it has a net over-recovery from ratepayers.

Board staff also cross-examined company witnesses on the need for a set-aside mechanism for the OPEB amounts recovered in excess of the cash payments to retirees. The company stated that tax vehicles to fund OPEBs are not tax efficient in Canada.[93] Contributions to pension funds are deductible for tax purposes. Hydro One indicated that contributions to trust funds are currently taxed at rates as high as 50%, and as a result less money would be in the fund earning a return.

Board policy is that regulatory accounting should be consistent with accounting for financial reporting by utilities, except where such consistency would prevent the setting of just and reasonable rates.[94] The Board cannot be constrained or fettered by GAAP standard setters in discharging its responsibilities under the *OEB Act* to customers of regulated utilities. Where necessary, the Board has created regulatory accounting policies that are different than GAAP, such as for deferred taxes.

Board staff submits that where over-recovery of OPEB costs is material, either recovery of those costs on a cash basis or some form of set-aside mechanism is required to protect ratepayers. In Board's staff's view, there should be a direct link between pension and OPEB costs approved in rates and the ultimate payments to be made to, or

[91] Tr. Vol. 2, pp. 145-149.
[92] Tr. Vol. 2, pp. 152-156; J2.7.
[93] Tr. Vol. 2, pp. 157-158; Also Exhibit I/Tab4.03/Staff 73/page3(c).
[94] Accounting Procedures Handbook, December 2011, Article 315, p. 5

on behalf of, retirees. Recoveries from ratepayers for OPEBs in the test period are meant to be used to pay for retiree benefits in the future.[95] However, staff submits that that facts in this present application do not require a ruling from the Board on this issue at this time.

In undertaking J2.7 Hydro One compared the impact of the cash and accrual methods of recovery on revenue requirement in the test period 2015-2019. In this proceeding, the cash and accrual amounts over the test period have virtually the same impact on rates. For the period of the plan, Board staff has no objection to the amounts that Hydro One proposes to recover as outlined in J2.7.

In the longer term, Board staff submits that further investigation of the need for, and the types of, possible set-aside mechanisms is necessary. Hydro One suggested that a generic proceeding would be the appropriate venue for the Board to consider issues around pension and OPEBs, as those costs are common to all regulated companies.[96] Board staff recommends further research in this area as the starting point for a possible generic policy.

[95] Tr. Vol. 2, p. 149-151.
[96] Tr. Vol. 2, pp. 156-158; Also TC Vol. 1, p. 197.

# 6. Effect on Customers

## 6.1 Reflecting Customer Preferences

The Board's RRFE report has established Customer Focus as one of the primary outcomes distributors must achieve. Customer Focus is described as: services are provided in a manner that responds to identified customer preferences.[97]
Hydro One provided its Customer preferences evidence at Exhibit A/Tab5/Schedule 1, entitled Voice of the Customer. In this exhibit Hydro One described the many ways it tries to determine what its customers value in electricity distribution services.
Hydro One indicated that data is collected to evaluate the overall satisfaction of its customers and is then used to identify issues to be addressed. Hydro One described the channels through which it listens to its customer's needs:

Customer survey research (impression and perception) is the largest channel that incorporates a broad range of customers. Hydro One provided a full description of its efforts with Residential and Small Business customers, Business to Business surveys Transactional Surveys and how it determines customer satisfaction.

Hydro One also outlined its efforts with the use of Customer Advisory Boards, Customer Focus Groups, Stakeholder meetings and the operation of its Customer Relations Centre.

Parties at the hearing focussed on the results shown at Table 2 on page 6 of the exhibit where the dominant concern of small business and residential customers was demonstrated to be rates and prices (at 61% and 2011 and 2012 and 56% in 2013). Reliability and outage handling were lower priorities (at 15%, 16% and 25% respectively for those three years). Hydro One acknowledged that it needed to focus on costs while reducing focus on improving reliability. As Ms. Frank testified,

> "Fourth quartile allows that appropriate balance between cost to customers and reliability that our shareholders see as appropriate."[98]

[97] RRFE Report, p. 2
[98] Tr. Vol. 1, p. 39

Board staff sees Hydro One's efforts within the scope of this application to determine customer needs, to gauge customer satisfaction and to measures changes in these levels as appropriate and has no specific submissions in this area.

## 6.2 Revenue Requirement

A major component of the concern for pricing and costs is Hydro One's proposal for revenue requirement over the 5 years of the plan. Hydro One has applied for revenue requirement approval for each year from 2015 to 2019. The table below summarizes the major components of revenue requirement in the application, including the last approved cost of service year, 2011 (EB-2009-0096).

**Table 8**
**Components of the Revenue Requirement**
**($ millions)**

| **Components** | **2011** | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|---|
| OM&A | 525.0 | 564.3 | 610.2 | 614.0 | 603.9 | 600.0 |
| Depreciation & Amortization | 283.7 | 355.4 | 374.9 | 390.2 | 402.9 | 413,6 |
| Income Taxes | 34.2 | 52.5 | 60.5 | 63.0 | 65.4 | 69.5 |
| Return on Capital | 354.0 | 442.7 | 477.0 | 510.8 | 543.3 | 576.5 |
| **Total Revenue Requirement** | **1,196.9** | **1,414.9** | **1,522.6** | **1578.0** | **1,615.4** | **1,659.7** |
| External Revenues & Other | 48.1 | 47.9 | 48.9 | 49.9 | 49.2 | 49.9 |
| **Rates Revenue Requirement** | **1,148.9** | **1,367.0** | **1,473.7** | **1,528.1** | **1,566.1** | **1,609.9** |

Source: Exhibit E1/Tab1/Schedule 1

Rates revenue requirement grows by 17.8% in the 4 year period from 2015 to 2019. Of the major components, the largest, OM&A, was addressed at Section 5 of this submission.

However, another key element of the increase in overall costs to Hydro One customers is the 19% growth in revenue requirement in 2015 relative to 2011, due to the rise in gross plant, reflecting in-service additions made to rate base during the IRM period from 2012 to 2014 as well as amounts previously recorded as regulatory assets ($564.9 million of Smart Meter, Smart Grid and Distributed Generation gross fixed assets previously recorded as regulatory assets and tracked in deferral accounts were transferred into rate base). Recovery of these amounts in just the 2015 rate year could result in a significant rate impact, and as a result Hydro One proposed a rate smoothing scheme as outlined below.

Depreciation and Amortization evidence is presented at Exhibit C1/Tab 6/Schedule 1. Hydro One has been using the same methodology for depreciation and amortization expense since 2006 with periodic updates provided since that time. The depreciation rates in the RP-2005- 0020/EB-2005-0378 proceeding (2006 rates) were supported by a depreciation study conducted by Foster Associates Inc.

The Board accepted the costs flowing from this depreciation study for the purpose of supporting Hydro One Distribution's rates in 2006 and similarly accepted the methodology again in the EB-2007-0681 proceeding for 2008 rates. Hydro One updated the study with Foster Associates covering Hydro One Networks' distribution and common assets for purposes of determining depreciation and amortization expense for the 2015 – 2019 test years.  The study was submitted as Exhibit C1 Tab 6 Schedule 1, Attachment 1.  Staff has no concerns with the depreciation and amortization amounts filed in this application. However, given the length of time that Hydro One has been applying its depreciation methodology, a review of its approach to depreciation by the time of its next rebasing application would help to determine whether this approach continues to be appropriate and in the interest of current and future customers. Staff submits that the Board should require Hydro One to complete a new depreciation study for filing in its next main rates application.

Evidence on Income Taxes (PILS) is found at Exhibit C1/Tab7/Schedule 1of the pre-filed evidence.  Staff has reviewed this filing and has no submissions.  Regarding Return on Capital, staff has already made a submission on the options available to the Board.  In addition, staff points out that Hydro One has used the Board's prescribed debt/equity ratios.  Therefore, staff has no further submissions on Cost of Capital.

External Revenues are address in the pre-filed evidence at Exhibit E1/Tab1/Schedule 2. Staff has no concerns with the amounts Hydro One has presented under external revenues.

## 6.3 Rate Smoothing Proposal

As a result of a large increase in revenue requirement in 2015, Hydro One included a rate smoothing proposal in its application[99]. Hydro One proposed to establish a rate-smoothing deferral account to allow rates to be charged to customers on a smoothed annual basis over the five-year rate setting period. In the first 3 years of the 5-year rate setting period, rates will be lower than full recovery of annual revenue requirements would require.

Recovery of part of the 2015, 2016 and 2017 revenue requirements will be deferred until 2018 and 2019, to reduce the impact of the 2015 rate increase and facilitate rate stability through the 5-year period. The adjustments to rates revenue requirement as a result of using the new deferral account are ($ million):

| | |
|---|---|
| 2015 | (52.3) |
| 2016 | (68.7) |
| 2017 | (22.4) |
| 2018 | 41.1 |
| 2019 | 102.1 |

The smoothing will be accomplished through negative and positive rate riders in each of the five years. The amounts listed above do not include any carrying charges, but Hydro One indicated that if the proposed amounts are approved, the account will be managed consistent with other Hydro One Distribution variance and deferral accounts and Board prescribed interest rates would be applied to the account balances.

Hydro One initially presented Exhibit PD1 at the May 12 Executive Presentation to illustrate how the rate smoothing would work to bring the average revenue requirement increase from a peak of 11.5% in 2015 to a smoothed annual increase of 7% in each

[99] Exhibit F1/Tab2/Schedule1

year of the plan. This was updated in the hearing to a possible 10.5% rate impact in 2015 and a smoothed impact of 6.3% over the life of the plan.[100]

Staff supports the proposal for rate smoothing since it will mitigate the first year impact of the increased revenue requirement and provide more stable rates for customers over the 5 year term.

Staff also notes that the response provided to a CCC interrogatory[101] where rate and bill impacts for a typical R1 class residential customer (Hydro One's most populous rate class), using 800 kWh per month are shown:

Table 9

| | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|
| **Rate Impacts** | -1.4% | 3.8% | 2.3% | 1.2% | 2.6% |
| **Bill Impacts** | -1.55 | 1.3% | 0.8% | 0.4% | 0.9% |

The bill impacts presented here do not include commodity increases, nor are they representative of all classes. While there was some discussion in the oral hearing concerning how best to forecast the total bill impacts when commodity costs and other bill components are unknown, staff notes that as other bill components increase, the proportionate impact on the bill from distribution increases will diminish further, keeping impacts for this customer class below the anticipated rate of inflation for each year (forecast in this case at 2% per year).

Staff points out that its recommendations for a stretch factor and its submission for a reduction in smart meter cost recovery will lower the impact on customer rates and bills for the 5 year period of the plan.

Any adjustments to cost allocation and rate design from those proposed will alter rate impacts for this class from those shown in Table 9; other classes will also be affected. Cost allocation is discussed further at Section 8.

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[100] Exhibit J3.3, Attachment 1
[101] Exhibit I/Tab1/CCC 1

# 7. Economic and Load Forecasts

Hydro One's pre-filed evidence on economic indicators is found at Exhibit A/Tab 16/Schedule 1, while the load forecast is included at Exhibit A/Tab16/Schedule 2, with specific information on conservation and demand management (CDM) in Schedules 3 and 4 of the same exhibit tab.

Regarding overall economic indicators, Hydro One indicated that it relies on Global Insight forecasts for distribution cost escalation for construction, operations & maintenance costs, for determining the Consumer Price Index forecast from 2015 to 2019 and for the exchange rate forecast for those years. Labour escalation rates are also cited as increasing 2% per year in line with inflation.

Board staff had some concerns about the use of Global Insight forecasts that were dated January 2013, but was satisfied with the response of the Hydro One witness in the Technical Conference held on July 22, 2014 that the use of more recent forecasts had no material impact on the application.[102]

Hydro One provided detailed evidence of its load forecast process and the combination of various data sources and analysis that leads to the final load forecast, including how CDM is incorporated.

Board staff notes the considerable interest shown by some intervenors regarding the CDM inputs to the forecast model at the oral hearing. In reviewing the responses of the Hydro One witness to these concerns, staff is of the view that Hydro One has appropriately accounted for CDM in its forecast given that the Ontario Power Authority forecast has yet to be finalized.

Hydro One also demonstrated at Table 1 on page 3 of the Exhibit A Tab 16 Schedule 2, how its forecasts compared with actual over from 1997 to 2013. Between 1997-2001, the average variance of customers' energy purchase forecast compared to the weather corrected actual energy consumed is within one standard deviation of the forecast. Table 2 on page 4 of the same exhibit provided the accuracy of the load forecast approved in the last distribution rate case (EB-2009-0096) with the weather corrected

[102] TC Tr. Vol. 2, pp. 69 – 71

actuals. The comparison showed variances of -0.14 in 2009, -0.25 in 2010 and -0.78 in 2011.

The resulting load and customer forecast for the test years (2015 – 2019) is:

| Year | GWh Delivery | Distribution Customers |
|---|---|---|
| 2015 | 37,620 | 1,288,000 |
| 2016 | 37,824 | 1,300,000 |
| 2017 | 38,108 | 1,312,000 |
| 2018 | 38,111 | 1,325,000 |
| 2019 | 37,961 | 1,337,000 |

Board staff also notes that Hydro One provided responses addressing two directives from the Board's April 9, 2010 Decision on Hydro One's Distribution rate application for 2010 and 2011 (EB-2009-0096) requiring Hydro One to: 1) track the difference between the CDM forecast assumed in the load forecast and CDM impacts actually achieved in 2010 and 2011; and 2) to provide a detailed analysis for estimating the CDM impacts and to develop a methodology to incorporate these impacts into the load forecast.

Board staff has no concerns with Hydro One's economic or load forecasts in this proceeding. Hydro One's methodology, its demonstration of its track record in both the long and short term, and its detailed reporting on the Board's request regarding CDM aspects in its load forecast are, in Board staff's submission, persuasive. Staff notes there is also now an LRAMVA mechanism that will track the difference between the CDM forecast included in rates and the actual CDM results.

# 8. Cost Allocation and Rate Design

Hydro One's evidence on Cost Allocation and Rate Design is found at Exhibit G1/Tab1/Schedule 1. Hydro One indicates that the evidence was prepared in accordance with Section 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications issued July 17, 2013 and Hydro One has followed the cost allocation policies outlined in the Board's Report of March 31, 2011, "Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219)".

Hydro One proposed to make a number of changes related to the rate classification of its customers consistent with directions from the Board. This included the addition of a new Unmetered Scattered Load ("USL") rate class, changes to the definition of its Seasonal customer class, and incorporating the results of a rate class review across all of Hydro One Distribution's service territory to ensure all customers are classified in accordance with the currently approved density-based rate class definitions.

In addition, Hydro One proposed to move the revenue-to-cost ("R/C") ratios for all its rate classes to within the range of 98% to 102% over the five year period of the custom application.

Hydro One has also proposed increasing the amount of revenue collected via fixed charges using the values calculated in their Cost Allocation Model. Rate riders to recover regulatory assets and for smoothing the revenue requirement bill impacts over the Custom COS period are also proposed.

## 8.1 Rate Class Review

As agreed to in the Settlement Agreement in Hydro One's 2013 IRM application (EB-2012-0136), Hydro One reviewed its customer rate classification to ensure that all customers were classified in accordance with its currently approved density-based rate classes.

The rate class review relied on Hydro One's Geographic Information System ("GIS") to identify clusters of customers and the circuit kilometers of distribution line required to serve those customers to verify that the density zone criteria for Hydro One's density-based rate classes were being satisfied.

Hydro One's residential and general service rate classes are tied to the following density zones:

- High (Urban) Density Zone: >= 3000 customers and >= 60 customers/circuit-km
- Medium Density Zone: >=100 customers and >= 15 customers/circuit-km
- Low Density Zone: Areas that are not Medium or High Density

Hydro One found that 134,568 (or 11%) of its current customers should be reclassified into other classes. Board staff notes that there was little concern with the quality or accuracy of the density study or how it was performed during the course of the hearing, and Board staff has no concerns with Hydro One's proposal to reclassify its customers to appropriate rate classes.[103]

Table 10 below shows the number of customers that are proposed to change classes as a result of the density study findings.

**Table 10**
**Summary of Rate Class Review Results**

| | **Number of Customers** | **Percent of Total** |
|---|---|---|
| Total | 1,222,548 | 100.0% |
| No Change | 1,087,980 | 89.0% |
| Total Changing | 134,568 | 11.0% |
| **Lower Rates** | **112,019** | **9.2%** |
| R1 to UR | 40,023 | 3.3% |
| R2 to UR | 1,815 | 0.1% |
| R2 to R1 | 63,670 | 5.2% |
| GSe to UGe | 5,733 | 0.5% |
| GSd to UGd | 778 | 0.1% |
| **Higher Rates** | **22,549** | **1.8%** |
| UR to R1 | 5,704 | 0.5% |
| UR to R2 | 439 | <0.1% |
| R1 to R2 | 16,028 | 1.3% |
| UGe to GSe | 311 | <0.1% |
| UGd to GSd | 67 | <0.1% |

[103] Exhibit G1/Tab2/Schedule 1

Hydro One indicated that the changes in the numbers of customers in each class results in a drop of about $40 million in revenue at current rates. While many individual customers will have lower bills, there will be a 3.4% increase on average across all rate classes to make up for the revenue deficiency resulting from the large number of customers moving to rate classes with lower rates.[104]

Hydro One proposed to update the rate class review on a province-wide basis every 5 years to coincide with the resetting of rates as part of a rates application. Individual density zones will be updated in the interim period between rates applications if there are property developments within or adjacent to a density zone that result in a material change to the rate classification of affected customers.[105]

## 8.2 Hydro One Rate Class Reclassification Policy

While Hydro One has completed a province-wide review of its customer classification pursuant to the settlement agreement in EB-2012-0136, Board staff is also interested in the frequency and manner in which the company plans to review density changes over time. Board staff submits that fair ratemaking and customer service principles would generally call for any utility with density-based customer classes to have a defined policy and supporting business processes in place that enable review and adjustments as density changes over time.

Hydro One has stated that it proposes to review customer density on a province-wide basis only once every five years[106]. The company states that it expects its process for new customer connections, coupled with the up-to-date information on current density in its geographic information system (GIS) tool, to yield sufficient information to ensure its classifications remain based on updated data in an ongoing manner[107] . Since it is expected that this ongoing monitoring will capture the effects of significant developments on an ongoing basis, the planned update in five years' time is expected only to take "into account the very small incremental changes"[108] that can materialize

[104] Exhibit G1/Tab2/Schedule 1, p. 3
[105] Exhibit G1/Tab2/Schedule 1, p. 3
[106] Exhibit G1/Tab 2/Schedule 1, page 4
[107] Tr. Vol. 7, p. 76
[108] Tr. Vol. 7, p. 71

over a longer period of time. Consequently, more frequent review of its province wide data, in Hydro One's submission, would not be worthwhile given the effort it involves.

With respect to customer inquiries for reclassification Board staff notes that Hydro One has confirmed its intention to maintain the ability for customers to be reclassified upon inquiry from a customer if subsequent investigation reveals that a different classification is warranted. Hydro One has also confirmed that reclassification of a given customer would trigger review of adjacent customers' classifications[109] and would result in further reclassifications if warranted. Board staff submits that this is an appropriate way to deal with customer inquiries however, in Board staff's submission, this reactive way of dealing with customer reclassifications is not in itself sufficient to ensure that all customers are in appropriate rate classes.

In Board Staff's view, Hydro One's plan to rely on its internal business process as a means of ensuring that its density information is up to date depends on not merely the accuracy of the information currently in its GIS system but also the internal integration of the new connections business process with the data in its GIS. Each of these contains some degree of risk of error.

Board staff recognizes Hydro One's concern that too-frequent review of province-wide classifications may not provide value. Board staff agrees with the company that new connections are the likely source of the majority of system changes that stand to be material to a density calculation for a given area; further, only those areas that are already approaching a given density threshold are those that require active monitoring.

However, given the relative recency with which Hydro One has been using GIS for classification purposes, Board staff submits that a province-wide review of customer classifications after three years is reasonable. The results of the review should be reported to the Board during the first annual adjustment filing following the conclusion of the study. If this review does not indicate material levels of reclassifications, a shift to a five year review cycle may be warranted. The results may also inform a decision on what Hydro One should report at its next rebasing application. On the other hand, if there are material numbers of reclassifications after a three year period, staff submits

[109] Tr. Vol. 7, p.71

that the Board may determine that further steps to ensure accuracy of customer classifications are warranted.

Regarding the ongoing maintenance of classifications through its business processes, Board staff also suggests more reporting would provide additional confidence that Hydro One's classifications remain up-to-date. Board staff submits that Hydro One should report annually the total number of customer complaints regarding density and the number of reclassifications that actually result from those complaints. Staff believes that such measures would provide a means to evaluate the effectiveness of Hydro One's internal processes in ensuring classifications reflect up-to-date information. Any growth in the volume of reclassifications that arise from customer complaints should indicate that the GIS data is lagging the actual characteristics of its system. Likewise, any fall in the rate of reclassifications stemming from complaints should provide supporting evidence that Hydro One's new customer connection information is helping to maintain the accuracy of GIS data, provided that the internal verification process once a complaint is initiated remains rigorous.

## 8.3 Seasonal Customer Rate Class Review

Also as a result of the Settlement Agreement in Hydro One's 2013 IRM application, Hydro One consulted with interested stakeholders to review the rates for seasonal customers. Hydro One reported that 38 participants took part in these consultations, representing 31 various cottager associations and also indicated that another 19 indicated they would attend but did not.[110] Hydro One indicated that the preferred option of its focus group participants was to move seasonal customers with consumption characteristics similar to residential customers to its standard residential classes. [111]

Hydro One determined, through a review of historical consumption data, that a number of seasonal customers that have annual consumption and monthly load profile characteristics very similar to that of year-round residential customers. Hydro One indicated that to better align with the ratemaking principles of cost causality and fairness, it proposed that seasonal customers that i) consume at least 9,600 kWh

[110] Exhibit G1/Tab 2/Schedule 2
[111] Exhibit G1/Tab2/Schedule1, p. 5

annually and ii) consume at least 600 kWh monthly for a minimum of 10 months of the year, would be reclassified as year-round residential customers.[112]

This would result in a move for approximately 11,000 seasonal customers to the R1 and R2 rate classes. As shown in Exhibit I/Tab7.02/VECC 93, 4,734 seasonal customers will be classified to R1 and 6,265 seasonal customers would shift to the R2 class. Hydro One indicated that the net impact of the proposed seasonal customer change is a drop of about $7 million in revenue at current rates. While those seasonal customers moving to year-round residential classes will see lower bills, all customer classes will experience an average increase of about 0.5% to make up for the revenue deficiency resulting from this change.[113]

At the Technical Conference, Hydro One witness Mr. Andre indicated that under this proposal the high-volume seasonal customers that would move to the R2 class would receive the RRRP credit for because it would be administratively simpler to grant this credit than to establish a process to verify a customer's eligibility. [114]

At the oral hearing, Mr. Andre stated that Hydro One was basing its proposal to move seasonal customers on the fact that "…from a consumption and a usage standpoint, they look like a year-round residential" customer. Mr. Andre then stated that Hydro One "…recognize[s] that it is somewhat stretching the definition that's in the Ontario regulation" and that Hydro One "would be in the hands of the Board in terms of whether that would be appropriate or not." [115]

Board staff does not have an issue with Hydro One's proposal to move seasonal customers with consumption patterns similar to a year-round residential customers to the appropriate density-based residential class, as matter of cost causality and fairness. However, Board staff does not believe it would be appropriate for the Board to approve Hydro One's proposal to apply the RRRP to customers moving from the seasonal class to the R2 class. Staff submits that the provision of RRRP assistance to these customers without confirmation of their residency status would place Hydro One in breach of legislation.

[112] Exhibit G1/Tab2/Schedule 1, p. 6
[113] ibid
[114] TC, Tr. Vol. 7, p. 95
[115] Tr. Vol. 6, p. 9

The rules for the calculation and implementation of RRRP are contained in Regulation 442/01 under the *OEB Act*. The provisions of the regulation include a description of the customers who are entitled to receive RRRP. The relevant description in this case is that unless otherwise qualified, customers must occupy “residential premises", which means a dwelling occupied as a residence continuously for at least eight months of the year.

Hydro One's definition of the R2 class prior to this application was based on both density and residency. That definition appears at Exhibit G2 Tab 2 Schedule 1 page 2 under “Residential Service Classifications”, and in numbered paragraphs 1 to 4 sets out criteria for determining that a customer was a year-round residential customer.

As part of this application, Hydro One is proposing to expand the definition of the R2 class by adding the following paragraph:

> “A customer that does not meet all of the above criteria, but consumes at least 9,600 kWh annually and at least 600 kWh monthly for a minimum of 10 months of the year also qualifies for year-round residential customer classification.”

The inclusion of customers with this consumption pattern in the R2 rate class is understandable, as this consumption pattern is similar to other members of the class. However, Hydro One proposes to provide the RRRP subsidy to all members of the R2 class without determining whether the former seasonal customers qualify for the subsidy under the provisions of the Regulation. Hydro One is intending to use the consumption pattern of these customers as a proxy for residency.

Board staff acknowledges the practicality of this approach, and also notes that the amount of RRRP for other customers will increase slightly to $30.50 per month as a result of shifts of customers between classes (6,265 from Seasonal to R2, 439 from UR to R2, 16,028 from R1 to R2 but 65,485 from R2 to UR and R1 classes).[116] Nevertheless, Board staff submits that the Board should not accept Hydro One’s proposal to provide RRRP to the former seasonal customers regardless of actual residency status. Not only would Hydro One likely be in breach of the Regulation, the

[116] Exhibit G1/Tab2/Schedule1, p. 3

Board could also be in breach of the Regulation if it accepted that all customers in the newly defined R2 class are eligible to receive RRRP.

Section 4(4)3 of the Regulation reads:

> “The Board shall take reasonable steps to ensure that an amount equal to the amount calculated under subsections (2) and (3.1) for the year is used to provide rate protection to consumers who are in the class described in paragraphs 4 and five of section 2.”

Section 2(5)ii refers to consumers who occupy "residential premises". The Board should not accept the number of customers in the newly defined R2 class as representing the number of customers eligible to receive rate protection. Board staff does not agree that administrative simplicity is sufficient rationale for circumventing the requirements of the regulation.

Board staff submits that Hydro One has several options:

1. Do not redefine the R2 class so as to include customers based on consumption, i.e. keep the class definition as in prior years. This would likely prevent the movement of seasonal customers into that class, although some may move to R1.

2. Accept customers into the R2 class based on consumption, but provide RRRP to the new customers only once they have provided proof of residency equivalent to the requirements of the Regulation. This would involve the creation of a sub-class within the R2 class of those who do not receive RRRP. Staff submits that if this option is chosen, Hydro One should proactively make the new R2 customers aware of the requirement for providing proof of residency.

3. Accept only those customers into the R2 class whose consumption level is such that even without RRRP, they are not significantly impacted. Board staff notes that the high volume consumers in the group of 6,265 customers shifting from the Seasonal to the R2 class will not face high rate impacts when they shift to the R2 class without RRRP protection. However those consumers who use between 600 and 800 kWh per month could face significant bill increases if the RRRP

credit is not applied to their accounts. Board staff estimates that customers with a usage pattern exceeding 1000kWh per month do not face increased rates from a shift into the R2 class, even without RRRP. However, Board staff asks that Hydro One comment on the accuracy of this estimate.

4. Retain the status quo as regards seasonal customers, with the intention of coming forward with an alternate proposal at the next main rates case.

One other option that arose during the course of the proceeding was the option of eliminating the Seasonal Class altogether. Board staff asked Hydro One for an analysis of this scenario. Hydro One's response was filed as Exhibit I/Tab 7.02/Staff 94 and indicated that low use Seasonal customers would suffer severe distribution bill increases in this scenario. For instance, a Seasonal customer using 50 kWh per month would see a distribution bill increase of about 140%, if moved to the R2 class (with no RRRP assistance). A typical Seasonal customer consuming 400 kWh per month would see an increase of 40%. Using customer consumption data submitted in Exhibit I/Tab7.02/VECC 93, this adverse rate impact would affect approximately 100,000 customers. Given these circumstances, Board staff does not support the elimination of the Seasonal Class at this time.

## 8.4 Cost Allocation/Revenue to Cost Ratios

With regard to its proposed changes to cost allocation, Hydro One indicated that it had made numerous improvements to its cost allocation methodologies. [117]

Hydro One proposed to adjust class revenue recoveries as necessary to move the revenue to cost ratios for all rate classes to within a range of 98% to 102% over the five year period. The proposed range provides some flexibility in establishing rates and mitigates the undesirable result of having customer rates fluctuate up or down as a result of even minor movements around an absolute target of 1.

The approach in this application to moving the R/C ratios as determined by the Cost Allocation Model ("CAM") is to ensure that all rate classes with R/C ratios outside the Board ranges are brought within the Board approved ranges in 2015. In subsequent

[117] Exhibit G1/Tab3/Schedule 1/p. 15

years, the class with the highest R/C ratio will be phased-in over the remaining years of the 5 year period to achieve the end state target of 1.02.[118]

All other classes with ratios above the phased-in target would be brought to the 1.02 target. The decrease in revenue from rate classes whose R/C ratios are dropping would be made up by increasing the R/C ratios for those classes with ratios below 1, as required. The rate classes with ratios below 1 would be brought closer to 1, starting with the classes whose R/C ratios are the lowest, except in the case of the Sentinel Light and DGen classes whose R/C ratio will be been phased-in over five years. For any given year, the decrease in the revenue to be collected from rate classes whose R/C ratio are above 1 is offset by an equal increase in revenue to be collected from those rate classes whose R/C ratio is below 1.[119]

The proposed changes to the R/C ratios over the five year Custom period are summarized in Table 6 from Exhibit G1/Tab3/Schedule 1/p.16 (reproduced below). The table shows the R/C ratios output by the CAM and the adjustment to the R/C ratios as part of the rate design process.

Table 10: Table 6 from Exhibit G1 Tab 3 Sch 1 page 16

**Table 6**
**Revenue-to-Cost Ratios**

| Rate Class | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | Board Range |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | CAM | Rate Design | CAM | Rate Design | CAM | Rate Design | CAM | Rate Design | CAM | Rate Design | |
| UR | 129 | 115 | 118 | 113 | 115 | 110 | 111 | 105 | 106 | 102 | 85 - 115 |
| R1 | 123 | 115 | 116 | 113 | 114 | 110 | 110 | 105 | 106 | 102 | 85 - 115 |
| R2 | 92 | 94 | 94 | 94 | 95 | 96 | 96 | 98 | 98 | 99 | 85 - 115 |
| Seasonal | 91 | 94 | 94 | 94 | 95 | 96 | 97 | 98 | 98 | 99 | 85 - 115 |
| GSe | 103 | 103 | 103 | 103 | 102 | 102 | 101 | 101 | 101 | 101 | 80 - 120 |
| UGe | 71 | 94 | 95 | 94 | 93 | 96 | 95 | 98 | 97 | 99 | 80 - 120 |
| GSd | 91 | 94 | 92 | 94 | 91 | 96 | 93 | 98 | 95 | 99 | 80 - 120 |
| UGd | 93 | 94 | 92 | 94 | 91 | 96 | 93 | 98 | 95 | 99 | 80 - 120 |
| St. Lgt | 88 | 94 | 93 | 94 | 94 | 96 | 96 | 98 | 98 | 99 | 70 - 120 |
| Sen. Lgt | 89 | 91 | 90 | 92 | 92 | 95 | 96 | 98 | 99 | 99 | 80 - 120 |
| USL | 124 | 120 | 121 | 113 | 114 | 110 | 111 | 105 | 106 | 102 | 80 - 120 |
| DGen | 39 | 51 | 56 | 67 | 69 | 79 | 81 | 91 | 93 | 99 | 80 - 120* |
| ST | 72 | 94 | 94 | 94 | 95 | 96 | 95 | 98 | 97 | 99 | 85 - 115 |

* Assume same as for GSe

118 ibid
119 Exhibit G1/Tab3/Schedule1/p. 16

During the oral hearing, Hydro One witness Mr. Andre indicated that Hydro One felt it had made sufficient improvements to its cost allocation that would merit the movement of R/C ratios for all classes to the range of 98% to 102%.[120]

Mr. Andre also quoted from the Board's EB-2010-0219 report where it stated,

> "The Board's policy remains that distributors should endeavour to move their revenue to cost ratios closer to 1 if this is supported by improved cost allocations." [121]

In response to an SEC interrogatory, Hydro One summarized the improvements it has made to the inputs for its cost allocation study.[122]

In response to cross-examination from Dr. Higgin, Mr. Andre stated that if the Board felt that the improvements were not sufficient to merit the narrowing of the R/C ratio ranges that Hydro One would find the wider range of 95% to 105% to be an acceptable alternative.[123]

Board staff acknowledges the improvements that Hydro One has made to the inputs to its cost allocation study. However, Board staff does not support Hydro One's proposal to narrow the R/C ratio ranges for all classes to the range of 98% of 102%. Given the proposed annual increases in the overall revenue requirement over the 2015-2019 period, Hydro One's customers will be subject to notable rate increases. Hydro One's current R/C ratio adjustment proposal will serve to compound those rate increases further for many classes. Board staff submits that a range of 95% to 105% for the R/C ratios for each class would more appropriately balance Hydro One's goal of recovering revenues on the basis of its increased confidence in cost causality with mitigating the rate impacts on Hydro One's customers.

Board staff also notes the examples provided of other jurisdictions in the VECC Compendium [Exhibit K6.1] at Tab 20 where it is shown that R/C ratio ranges of 95 –

[120] Tr. Vol. 6, p. 108
[121] ibid
[122] Exhibit I/Tab7.4/SEC 60
[123] Tr. Vol. 7, p 7

105 are used as a range of reasonableness for Fortis Alberta, BC Hydro and Manitoba Hydro.

Board staff also notes that under Hydro One's current proposal, all classes over the upper limit of the Board's R/C ratio ranges are moved to the upper limit in 2015. The rebalancing of those revenues results in significant increases in revenues collected from some classes (e.g. DGen and UGe classes) in 2015 and significant rate impacts.

Board staff submits that a more prudent approach would be to phase in these larger increases in R/C ratios over a number of years to reduce the initial high rate increases. Board staff notes that this is the direction given in the Board's filing requirements for electricity distribution applications on page 52:

> "In these cases (when out of the range), distributors must ensure that their cost allocation proposals include adjustments to bring them into the Board-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rate burden of any particular class or classes is significant."

As staff has already submitted, eventually Hydro One could adjust all R/C ratios towards the range of 95% to 105%, rather than 98%/102%.

## 8.5 Rate Design

Hydro One is proposing to reset the fixed charge for all rate classes in 2015 to the minimum system with Peak Load Carrying Capacity (PLCC) adjustment values as calculated on Sheet O2 of the CAM, with a few exceptions.[124]

These calculations reflect the results of an updated Minimum System Study that incorporated more recent information and calculated the PLCC adjustment on the basis of the total number of feeders in Hydro One's distribution system, as opposed to assuming one feeder per distribution station. The resulting proportions of revenue from

[124] Exhibit G1/Tab 4/Schedule 1, p. 4

fixed and volumetric rates (current and fixed) are summarized in the table below, found at Exhibit G1/Tab 4/Schedule 1/page 5.

Table 11: From Exhibit G1 Tab 4 Sch 1 page 5

| Rate Class | Current (2014 rates) | | Proposed (2015 rates) | |
|---|---|---|---|---|
| | Fixed | Volumetric | Fixed | Volumetric |
| UR | 38% | 62% | 59% | 41% |
| R1 | 38% | 62% | 48% | 52% |
| R2 | 56% | 44% | 55% | 45% |
| Seasonal | 47% | 53% | 52% | 48% |
| GSe | 31% | 69% | 22% | 78% |
| UGe | 18% | 82% | 25% | 75% |
| GSd | 4% | 96% | 5% | 95% |
| UGd | 3% | 97% | 7% | 93% |
| St Lgt | 1% | 99% | 2% | 98% |
| Sen Lgt | 20% | 80% | 26% | 74% |
| USL | 67% | 33% | 78% | 22% |
| DGen | 26% | 74% | 74% | 26% |
| ST | 19% | 81% | 18% | 82% |

Board staff accepts Hydro One's updated calculations of the minimum system with PLCC adjustment resulting from the Minimum System Study filed with the application. The Green Energy Coalition filed evidence of Dr. William Marcus of JBS Energy Inc. on July 10, 2014. Mr. Marcus' primary conclusion, found on page 2 of his evidence was that the Board should "…reject Hydro One's proposals to raise fixed customer charges for residential customers to close to their ceiling levels for all but seasonal customers. Instead, the Board should make no change or make more moderate changes to retain existing incentives for energy conservation and not to place greater burdens on low income customers."

Hydro One provided its views on the Marcus evidence in Exhibit K5.2. Board staff notes that Hydro One agreed to a suggestion to adjust the Customer/Demand percentage split in its cost allocation model to reflect Dr. Marcus' recommendation regarding the treatment of service lines.

Board staff submits that Hydro One's approach to set the level of the fixed charge to reflect the minimum costs for providing service to its customers is reasonable. As noted by Hydro One, the overall change in the fixed portion of the distribution charges across all rate classes is only increasing from 40% to 42%. These changes also move Hydro One in the direction of higher fixed charges which is discussed in the draft Report of the Board in EB-2012-0410 "Rate Design for Electricity Distributors", March 31, 2014.

## 8.6 Line Losses

Hydro One was directed to track the dollar value of variances between the Board approved losses recovered in rates, and actual line losses, commencing January 1, 2010 (EB-2009-0096). Hydro One commissioned Navigant Consulting Ltd. ("Navigant") to respond to the Board's request for the years 2010 to 2012 inclusive. The Navigant study was filed as Exhibit G1-8-1 Attachment 1.

The study determined

- Actual losses on Hydro One's distribution system over the three year period from 2010 to 2012 tracked well with the Board approved losses, although there were variances from year to year.

- Based on engineering analysis, the allocation of losses to individual customer classes, and hence the total loss factors for specific customer classes should be amended to more accurately reflect the losses that occur, as a result of delivering electricity to customers in each customer class.

- Going forward, Hydro One should implement an approach that utilizes the capabilities of its Customer Information System (CIS) and is consistent with industry practice to track and report actual losses on an annual basis.

As a result of the study Hydro One proposed new loss factors for its customer rate classes. The new loss factors and the current loss factors are provided in the evidence at Table 1, Exhibit G1/Tab 8/Schedule 1/page 3.

Staff has no submissions on the proposed loss factors suggested by Hydro One as a result of the Navigant study results.

The Ontario Federation of Agriculture filed evidence in this proceeding on line losses,[125] and Mr. Cowan testified to explain his proposals to the Board. Staff acknowledges the benefits that could accrue to Hydro One's system and the utility's customers through the reduction of line losses. However, Board staff is of the view that at this time, there is insufficient evidence on the record of this proceeding to require specific action of Hydro One at this time. As mentioned in the Navigant study, the line loss data demonstrate no clear trend, and it may be advisable to have more years of line loss data, as well as a better understanding of the cost implications of programs to reduce line losses, before making an order on this issue.

[125] Exhibit K7.2

# 9. Regulatory Accounts

## 9.1 Disposition of Certain Accounts

Hydro One has number of regulatory accounts (deferral and variance accounts) that it reports on a regular basis. The pre-filed evidence, at Exhibit F1/Tab1/Schedule 1, summarizes each of the accounts. Hydro One indicates that all of the accounts were established consistent with the Board's requirements as set out in the Accounting Procedures Handbook, subsequent Board direction, or approved by the Board as per specific requests initiated by Hydro One Distribution. Each account is reported to the Board on a quarterly basis consistent with the Board's RRR.

In total, Hydro One has 17 accounts or groups of accounts for which it is seeking disposition with a forecast balance of $21.3 million at December 31, 2014. With the setting of new Distribution rates from 2015 to 2019, Hydro One is requesting that the $21.3 million balance be recovered in a straight-line pattern over the 5 year (60-month) period. In addition, Hydro One has reported 5 other regulatory accounts for which it is not seeking disposition at the time, with a total forecast balance of -$47.2 million. The accounts and their balances are shown in Table 2 at Exhibit F1/Tab1/Schedule 1/p.3.

Board staff accepts Hydro One's proposal, and submits that Hydro One should continue to report on the status of the 5 other existing accounts for which Hydro One is not seeking disposition at this time.

## 9.2 New, Continued and Discontinued Accounts

At Exhibit F1/Tab1/Schedule 2, Hydro One requested approval to continue the Tax Rate Changes Account and the Pension Cost Differential Account. New accounts, the Bill Impact Mitigation Variance Account (to facilitate the bill mitigation proposals in this application) and the Rate Smoothing Deferral Account (also to facilitate the rate smoothing proposals in this application) were also requested for approval.

Hydro One also indicated that it was not seeking continuance of the following accounts:

- Smart Meter – Minimum Functionality;

- Smart Meter – Exceeding Minimum Functionality;
- Distribution Generation – Other Costs – HONI - Variance Account;
- Distribution Generation - Express Feeders – HONI - Variance Account;
- Smart Grid Variance Account;
- Distribution System Code (DSC) Exemption Deferral Account;
- Deferred Revenue Project Costs Variance Account (2009); and
- Generator Joint Use Revenue Variance Account.
- Special Purpose Charge Variance Account (1595 - Recovery of Regulatory Balances Account – Sub Account);
- Microfit Connection Charge Variance Account (1508 - Other Regulatory Assets – Sub Account); and
- OEB Cost Differential Account.

Board staff supports the reduction in the number of deferral and variance accounts as Hydro One enters the 5 year custom rate period, from 2015 to 2019. Staff also supports continuance of the two existing accounts requested and the establishment of the two new accounts it has requested.

## 9.3 Regulatory Accounts: Restatements

At Exhibit F1 Tab 1 Sch 1, Attachment 1; Hydro One also included information on Regulatory Accounts restated for the annual Reporting and Record Keeping Requirements (RRR).

Hydro One indicated that in February 2014, it was requested by the OEB Audit and Performance Assessment group to restate the balances of all accounts associated with Renewable Generation Connection and Smart Grid in the 2012 annual RRR report 2.1.7, as well as in the evidence of this application, in accordance with the *Accounting Procedure Handbook*.

Hydro One explained, in a letter sent to the Audit and Performance Assessment group, dated on January 15, 2014, (attached as Appendix A) Hydro One explained that its intention to report under the alternative method was to provide more helpful information to the Board and intervenors, and Hydro One believed that this approach has been consistent with the Board's previous decisions in Hydro One's last Cost of Service

Application (EB-2009-0096) and its subsequent IRM applications (EB-2012-0136 and EB-2013-0141).

Hydro One has restated the balances for the above-mentioned accounts in the RRR report 2.1.7 for 2012, and reported the balances in the RRR report 2.1.7 for 2013, consistent with the approach stated in Mr. Babaie's letter. This letter was attached to the Exhibit as Appendix B.

Hydro One provided the continuity of the account balances for restatement in Table 1 of Exhibit F1 Tab 1 Sch 1, Attachment 1. Hydro One also explained that for the purposes of seeking approvals for distribution rates, Hydro One has chosen to present the regulatory account balances in the format presented in Exhibit F1/Tab1/Schedule 1 as it explicitly shows the details supporting the amount for disposition being sought in front of the Board. Hydro One requested that the Board accept Hydro One's methodology as a more helpful way of identifying the amount for disposition.

Board staff submits that in accordance with the request by the OEB Audit and Performance Assessment Group, Hydro One should follow the Board's *Accounting Procedures Handbook* in these matters, primarily to ensure reporting consistency within the entire industry.

## 9.4 Smart Meters

Hydro One is seeking recovery of $445.1 million in smart meter capital costs and $59.4 million in OM&A costs for the period 2009 to 2014.[126] This is in contrast to the approximately $200 million in capital costs and $18 million in OM&A costs previously approved in the Combined Smart Meter Proceeding EB-2007-0063 and in Hydro One's 2008 and 2011 applications for smart meter costs for the 2006 – 2008 period.
Exhibit K3.1 was provided by Board staff to illustrate a consistent picture of smart meter costs from 2006 to 2014. Staff has updated the exhibit to reflect the 2014 data provided by Hydro One in Undertaking J3.2. This is included as an Appendix to the submission, and Board staff invites Hydro One to comment on the accuracy if the table. Hydro One has confirmed the data shown in Exhibit K3.1 for the period 2006-2013.

[126] Tr. Vol 3, pp. 6-7

Hydro One is seeking a significant amount for recovery in this application. As shown in Exhibit K3.1(updated), and also confirmed by Hydro One in Undertaking J2.8, the bulk of Hydro One's smart meter capital (61%) and OM&A costs (63.9% for capital and OM&A together) are being sought for approval in this application. However, as Exhibit K3.1 (updated) shows, over half of the smart meter installations were completed in the period 2006-2008 (about 640,000) out of 1.2 million in total.

Hydro One states that it complied with the "spirit" of the Board's smart meter cost recovery Guidelines in using its own model for tracking and calculating the deferred revenue requirement to be recovered through smart meter disposition riders. Board staff submits that Hydro One's model is basically the same as was used in the Combined Smart Meter Proceeding EB-2007-0063 and in the 2008 Cost of Service application EB-2007-0681. At that time, the Board accepted the use of this model, as Hydro One and other distributors were conducting early discretionary metering activities in accordance with the regulations.

However, Board staff points out that the Board has since evolved its policies, guidelines and models regarding smart meter cost recovery. Most distributors have used the Board-issued model and applied it in accordance with the Board's guidelines, and this has facilitated efficient processing of these applications.[127] Even where a distributor has used its own model and approach, a comparison against the results of the Board-issued model has been informative. While Toronto Hydro Electric System Limited used its own model in its EB-2013-0287 application, the Board accepted its model on the basis that THESL's approach did not materially differ from the Board-issued model.

Hydro One took the position that the Board-issued model cannot accommodate its circumstances. Board staff acknowledges that the model cannot accommodate Hydro One's numerous rate classes but this does not diminish the value of comparing the smart meter costs and aggregate deferred revenue requirement to other utilities, made possible with the Board's Model.

Hydro One eventually provided the Board issued model,[128] which provided additional information on overall capital and OM&A costs, and the nature of those costs. Board staff's main concern was whether there is sufficient information supporting the quantum

[127] Smart meter costs have been reviewed in approximately 100 applications, covering 70 utilities.
[128] Undertaking TCJ1.07

of costs for which Hydro One is seeking approval. As shown in Exhibit K3.1 (updated), the average cost per installed smart meter is $568, (combined capital and OM&A costs), for all deployed smart meters (Residential, GS < 50 kW, and FIT and microFIT generation customers). Over the 2009-2014 period, the combined capital and OM&A cost per meter is $831. However, Board staff considers these totals are not indicative of actual meter costs alone since significant costs in the 2009-14 period are also attributable to the operationalization of the AMI communications systems and other back office systems to collect and support processing of TOU data.

In Board staff's view, it is best to consider Hydro's request for recovery of smart meter costs in context of the overall program costs, both in aggregate and on a per meter cost basis. As stated above, the average cost per meter for the entire 2006-2014 period is $568.

On an overall program basis, the $568 per meter cost is significantly higher than for other distributors. The Board has completed the review of smart meter costs for all Ontario electricity distributors but for Hydro One and four other smaller distributors. Hydro One, in its response to Undertaking J3.2, explained that when the smart meter costs are reviewed issues such as large geographic territory, dispersed customer base, difficulties encountered in operationalization, and the length of time (which will primarily increase the deferred OM&A costs) need to be taken into account.

As a comparison, Board staff draws the Board's attention to the following utilities, which face similar issues of density and remoteness to Hydro One. To the best of Board staff's knowledge, these are the highest per meter costs that the Board has reviewed, and the decisions have taken into account the operational circumstances which have been drivers of higher costs for these utilities.

- Atikokan Hydro: $368 per meter reduced from $437 after the audit. [129].
- Sioux Lookout Hydro: $339 per meter[130].
- Chapleau PUC: $403 per meter.[131]
- Algoma Power: $394 per meter.[132]

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[129] Decision and Order, EB-2011-0293, p. 29 - 31, June 18, 2012 and Decision and Order, EB-2013-0019, p. 4, June 27, 2013
[130] Decision and Order, EB-2012-0245, p. 3, August 23, 2012
[131] Decision and Order, EB-2011-0322, p. 11, November 29, 2012
[132] Decision and Order, EB-2012-0104, p. 11-14, March 28, 2013

Board staff acknowledges that Hydro One faces challenges of deploying the smart meters and the AMI communications infrastructure to rural and low density areas, and faces difficulties of distance, geography and vegetation which affects remote reading. These factors will drive costs up. At the same time, Hydro One also has the advantage of economies of scale not available to the above-named distributors.

Therefore, Board staff submits that Hydro One's total (2006 – 2014) claimed costs for smart meters of $568 per meter are not in line with the costs of other distributors. While accepting that Hydro One's costs may be higher than other distributors, Board staff submits that the recovery of the significantly higher costs sought in this application has not been justified. Board staff urges the Board to deny recovery of the full cost sought. It is somewhat arbitrary to propose a figure for the Board's consideration, but staff suggests that a 20% premium above the highest previously approved per meter cost ($403) could be a reasonable amount to allow per meter. That would result in a per meter cost for Hydro One of $484. This is a reduction of about $85 per meter, amounting to a total of $103 million. However, this is not directly translated as such into the rate base and revenue requirement. Instead, it would result in reductions in two ways:

- A reduction in the allowed historical costs would reduce the amounts and the net deferred revenue requirement to be recoverable from or refundable to customers. Hydro One has used its own model for tracking this, and in its Argument-In-Chief noted that it is also correcting an accounting error.[133] Board staff is thus unable to estimate the impact, but submits that the deferred revenue requirement (i.e., the historical revenue requirement less the smart meter funding adder revenues (which Hydro One is still collecting to December 31, 2014) and applicable simple interest would change from a debit to be collected from customers to a credit to be refunded to customers; and

- A reduction in the approved per meter costs, and hence on the capital costs, would reduce the January 1, 2015 opening NBV of smart meters.

Should the Board approve a reduction in costs, Board staff submits that Hydro One should allocate the reductions between the historical capital and OM&A expenses in a

[133] Tr. Vol. 8, p. 18

reasonable manner, and calculate the adjustments for the deferred revenue requirement recoverable through the Smart Meter Deferred Revenue, and the opening January 1, 2015 smart meter assets in its rate base.

# 10. Application for DSC Exemption

As part of its May 30, 2014 update, Hydro One filed a request for exemption from the Distribution System Code ("DSC") at Exhibit A Tab 18 Sch 1 Appendix A. The Board required notice of this application to be given, and assigned file number EB-2014-0247 to the application. The exemption application was combined with the main rates application for hearing purposes.

The application seeks an interim and permanent exemption from section 7.5.2 of the DSC[134]. That section, together with section 7.5.1, sets out the obligations of a distributor with respect to contacting customers if an appointment with a customer is missed or going to be missed. The sections read:

> 7.5.1 When an appointment to which sections 7.3.1, 7.3.3, or 7.4.1 apply is missed or is going to be missed, the distributor must:
>
> (a) attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and
>
> (b) attempt to contact the customer within one business day to reschedule the appointment.
>
> 7.5.2 This service quality requirement must be met 100 percent of the time on a yearly basis.

The application of the exemption seeks the Board's acceptance for compliance ninety percent of the time. Ms. Frank, testifying for Hydro One, indicated that the company aims to achieve ninety-five percent compliance[135]. Board staff notes, as mentioned by Hydro One, that where the DSC does not require one hundred percent compliance for customer service, the ninety percent target is frequently imposed[136]. However, as pointed out by panel chair Mr. Quesnelle[137], this section is different than other sections of the DSC in that it requires only an attempt to contact the customer, not successful contact.

[134] Exhibit A-18-1 App A, TC Tr. July 21, 2014, p. 212.
[135] Hearing transcript Vol. 2, p. 124
[136] For example, sections 7.2.3, 7.3.4 and 7.4.2 of the DSC.
[137] Hearing transcript Vol. 2, p. 125

The Board granted the interim exemption on September 8, 2014 by way of oral decision[138].

Board staff does not support the application for a permanent exemption.

Section 7.5.2 of the DSC requires that a distributor meet the requirements in section 7.5.1 one hundred percent of the time. For the Board to grant a distributor-specific exemption, that distributor should have unique circumstances from those of other distributors for why the standard established by the Board should not be applied. While there may be issues with the state of communications infrastructure in parts of Hydro One's territory, and the difficulty of access to some customer locations, the requirement is only to attempt to contact the customer. An attempt that fails due to communications infrastructure, but is properly logged for record-keeping and follow-up with the customer as soon as possible, would be a reasonable approach. Therefore, it is not clear to staff how Hydro One's circumstances are sufficiently different to warrant a unique standard from all other distributors. Any review of the 100% standard is more appropriately done on a generic basis for all distributors. Board staff understands that the Board may be reviewing its Service Quality Requirements.

The Board has granted Hydro One an interim exemption. Board staff recommends that the Board indicate the interim exemption will cease to be effective on the date the Board's decision in this case is released.

[138] Hearing Tr. Vol. 1, p. 10.

# 11. Recommended Findings and Order

## 11.1 Order

Board staff submits that the Board's decision and order in this case include the following:

Approval of rates for five years based on the application, with the following adjustments:

- Addition of a stretch factor determined using the Board's stretch factor assignment for Hydro One + 0.4% premium beginning in 2015 or 2016;
- Rejection of the proposed annual adjustment for working capital;
- Retention of the Board's current Off Ramp policy and denial of Hydro One's additional proposed Off Ramps;
- No pre-approval of Hydro One's additional unforeseen event categories (Hydro One may apply for a Z-factor as necessary under the Board's existing policy);
- Approval of the proposed increased materiality threshold for applications for Z-factors specifically for Hydro One;
- An indication that providing RRRP to new R2 customers without proof of eligibility under Regulation 442/01 under the *Ontario Energy Board Act, 1998* is not acceptable;
- A denial of the entirety of smart meter costs, and an allowance for recovery on the basis of $484 per meter, which reduces the net deferred revenue requirement (which is to be collected from or refunded to customers) and the opening net book value for 2015 for smart meters;
- A denial of the proposal to bring substantially all revenue-to-cost ratios for customer classes to the edge of Board approved ranges in 2015; instead, to do so more gradually given the effect on certain classes
- A denial of the proposal to adjust revenue to cost ratios for all rate classes to 98% to 102% over five years (the Board could indicate that 95% to 105% is acceptable);
- A requirement that Hydro One follow the APH with regard to restatement of accounts associated with Renewable Generation Connection and Smart Grid; and
- Denial of the request for amendment to Schedule 3 of Hydro One's Distribution Licence to provide an exemption to section 7.5.2 of the DSC, and an indication

that the interim exemption will cease at the time of the issuance of the Board's decision.

## 11.2 Studies and Filings

Board staff submits that the Board's decision and order in this case require Hydro One to do the following:

- Undertake total factor productivity analysis of its own productivity comparable to the type of analysis the Board uses to estimate distributors' productivity, to be filed with Hydro One's next main rates application;
- Undertake total cost benchmarking analysis, with some comparison to other similar utilities, to be filed with Hydro One's next main rates application;
- Undertake cost benchmarking of primary activities (vegetation management, lines work and customer service work) with some comparison to other similar utilities, to be filed with Hydro One's next main rates application;
- Complete a new depreciation study to be filed with Hydro One's next main rates application
- Undertake a capitalization study to compare and contrast principles under each of USGAAP and International Financial Reporting Standards accounting;
- Prepare a consolidated Distribution System Plan containing clear and consistent description of Hydro One's planning and prioritization process, to be filed with Hydro One's next main rates application; and
- Undertake a density study in three years, to be filed with the Board in the first annual adjustment filing following the completion of the study.

## 11.3 Reporting

Board staff submits that the Board's decision and order in this case require Hydro One to annually report on the following, beginning in April 2016, in addition to the reporting it presently completes under RRR, Hydro One's Electricity Distributor Scorecard (as required by the Board's Report in EB-2010-0379) and other requirements under its licence:

- A Custom IR scorecard for the eight outcome measures Hydro One has proposed, in the form and with the content of the sample chart at page __ of this submission, with documentation to describe the performance measures;
- Total capital spending in the year;

- Actual in-service capital for each year compared to planned;
- Risk scores for the condition of major system assets. Staff recommended scores on condition, performance and demographics for wood poles, transformers (excluding MUS), stations and lines; and
- Total number of customer complaints regarding classification in density-based classes, and the number of reclassified customers resulting from those complaints.

## 11.4 Account

Board staff submits that the Board's decision and order in this case provide for the creation of an account to track the impact on revenue requirement of any in-service capital additions shortfall compared to Board-approved amounts, similar to the account proposed for the Transmission business.

## 11.5 Further recommendations:

Board staff suggests that the Board consider requiring or initiating the following:

- Further research on set aside mechanisms and other issues regarding accounting for pensions and OPEBs; and
- A third-party review of Hydro One's asset planning and prioritization process, to be available for Hydro One's next main rates application.

All of which is respectfully submitted.

# APPENDIX A

**Hydro One Networks Smart Meter Costs**

**Exhibit K3.1 confirmed and updated per Undertaking J3.2**

| | Approved | | | 2015-19 Custom IR application EB-2013-0416 | | | | | | Total 2006-2014 | Total 2009-2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | | |
| **Hydro One Networks** | | | | | | ($ 000,000) | | | | | |
| Capital | | | | | | | | | | | |
| - Minimum Functionality | $ 14.10 | $ 76.70 | $ 106.20 | $ 130.80 | $ 109.60 | $ 56.40 | $ 33.30 | $ 20.00 | $ 16.73 | $ 563.83 | $ 366.83 |
| - Beyond Minimum Functionality | | | | $ 8.40 | $ 20.10 | $ 9.60 | $ 5.10 | $ 1.10 | $ 2.07 | $ 46.37 | $ 46.37 |
| | | | | | | | | | | | |
| OM&A | | | | | | | | | | | |
| - Minimum Functionality | $ 4.90 | $ 6.20 | $ 6.90 | $ 9.00 | $ 4.90 | $ 6.60 | $ 5.50 | $ 7.70 | $ 10.97 | $ 62.67 | $ 44.67 |
| - Beyond Minimum Functionality | | | | $ 0.60 | $ 3.40 | $ 1.80 | $ 2.40 | $ 3.00 | $ 3.53 | $ 14.73 | $ 14.73 |
| | | | | | | | | | | | |
| | | | | | | | | | | $ 687.60 | $ 472.60 |
| | | | | | | | | | | | 68.7% |
| **No. Smart Meters Installed** | | | | | | | | | | | |
| Residential | | | 603,406 | 393,762 | 66,487 | 656 | 10,579 | 9,193 | 1,375 | 1,085,458 | 482,052 |
| GS | | | 37,366 | 30,497 | 16,309 | 14,019 | 2,689 | 907 | 2,818 | 104,605 | 67,239 |
| Other | | | | 395 | 3,145 | 6,449 | 4,256 | 2,685 | 2,675 | 19,605 | 19,605 |
| | | | | | | | | | | | |
| Total | | | | | | | | | 2014 updated: Exhibit. J3.2 | 1,209,668 | 568,896 |
| | | | | | | | | | | | |
| Average cost per meter | | | $ 335.53 | | | | | | | $ 568.42 | $ 830.73 |